European Network of
Transmission System Operators
for Electricity

Connection Network Codes – Response to the comments received during the public consultation of Implementation Guidance Documents on Frequency Stability Parameters

Period of Consultation: 20/11/17 - 21/12/17

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ENTSO-E AISBL • Avenue de Cortenbergh 100 • 1000 Brussels • Belgium • Tel + 32 2 741 09 50 • Fax + 32 2 741 09 51 • info@entsoe.eu • www.
entsoe.eu

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1. Introduction

Overview of connection codes

The European Connection Network Codes - Requirements for Generators (RfG), Demand Connection Codes (DCC) and High Voltage Direct Current Connections (HVDC) – have been developed in accordance with Regulation (EU) 714/2009 and are cornerstones to fulfil the third energy package.

The first connection network code, which entered into force on 17 May 2016, is the Commission Regulation (EU) 2016/631 of 14. April 2016 establishing a network code on requirements for grid connection of generators (RfG). The Commission Regulations on DCC and HVDC followed after that - (EU) 2016/1388 of 17. August 2016 establishing a network code on demand connection (DCC), entering into force on 18 August 2016, and the Commission Regulation (EU) 2016/1447 of 26. August 2016 establishing a network code on requirements for grid connection of high voltage direct current systems and direct current-connected power park modules (HVDC), entering into force on 8 September 2016 respectively.

In order to support the implementation of network codes at national level, and as required by the codes, ENTSO-E has produced non-binding guidance on implementation, which are also consulted by the stakeholders. This guidance is provided through so-called Implementation Guidance Documents (IGDs).

Legal background for IGDs

Commission Regulation (EU) 2016/631 of 14 April 2016 establishing a network code on requirements for grid connection of generators (RfG), (Article 58), Commission Regulation (EU) 2016/1388 of 17. August 2016 establishing a network code on demand connection (DCC) (Article 56) and the Commission Regulation (EU) 2016/1447 of 26. August 2016 establishing a network code on requirements for grid connection of high voltage direct current systems and direct current-connected power park modules (HVDC) (Article 75) – Non-binding guidance on implementation - stipulate:

1. *No later than six months after the entry into force of this Regulation, the ENTSO for Electricity shall prepare and thereafter every two years provide non-binding written guidance to its members and other system operators concerning the elements of this Regulation requiring national decisions. The ENTSO for Electricity shall publish this guidance on its website.*
2. *ENTSO for Electricity shall consult stakeholders when providing non-binding guidance.*
3. *The non-binding guidance shall explain the technical issues, conditions and interdependencies which need to be considered when complying with the requirements of this Regulation at national level.*

Objectives of IGDs

The main objective of the implementation guidance is to support system operators in the process of determination on national level of non – exhaustive requirements during the national implementation. The objectives of the implementation guidance documents are:

- to facilitate a common understanding of technical issues specified in the connection network codes, in context of new technologies and new requirements (e.g. synthetic inertia)
- to deliver broader explanations and background information and to illustrate interactions between requirements,
- to recommend coordination/collaboration between network operators (TSO) where either explicitly required by the connection codes or reasonably exercised from a system engineering perspective,
- to give guidance to national specifications for non-exhaustive requirements, and

- to express the need of further harmonisation beyond what is requested by the CNCs when reasonable from a system engineering perspective.

List of IGDs

No	Titles of IGD	Status	Short descriptions
1	Frequency Sensitive Mode	New	Frequency Sensitive Mode (or ‘FSM’) means the operating mode of a power-generating module or HVDC system in which the active power output changes in response to a change in system frequency, in such a way that it assists with the recovery to target frequency. The objective of this guidance document is to help to determine the main criteria/motivation for the specifications of the FSM capabilities of power generating modules at national level. For adequate specifications of the relevant parameters it is essential to be aware of the objective of the FSM functions and to understand how it interacts with other frequency stability requirements. For each synchronous area, proposals for national choices for the non-exhaustive FSM parameters are provided through this IGD.
2	Limited Frequency Sensitive Mode	New	The objective of this guidance document is to help to determine the main criteria/motivation for the specifications of the limited frequency sensitive mode capabilities of power generating modules at national level. Limited frequency sensitive mode at over-frequency (LFSM-O) is to be activated, when the system is in an emergency state of over-frequency and all frequency containment reserves (FCR) in negative direction have already been deployed. Limited frequency sensitive mode at under-frequency (LFSM-U) is to be activated, when the system is in an emergency state after of under-frequency and all frequency containment reserves (FCR) in positive direction have already been deployed. For adequate specifications of the relevant parameters it is essential to be aware of the objective of the LFSM-O/-U functions and to understand how it interacts with other frequency stability requirements and assumptions for a system defence plan.

			In order to implement comprehensively the LFSM-O/-U capabilities this implementation guidance may go beyond the explicit requests of NC RfG and will also make recommendations on further parameters, which are not addressed in this network code, but are nonetheless relevant to ensure an adequate performance of these features. For each synchronous area, proposals for national choices for the non-exhaustive LFSM-O/- U parameters are provided through this IGD.
3	Demand Response – System Frequency Control	New	Demand response is an important instrument for increasing the flexibility of the internal energy market and for enabling optimal use of networks. It should be based on customers' actions or on their agreement for a third party to take action on their behalf. A demand facility owner or a closed distribution system operator (‘CDSO’) may offer demand response services to the market as well as to system operators for grid security. In the latter case, the demand facility owner or the closed distribution system operator should ensure that new demand units used to provide such services fulfil the requirements set out in this Regulation, either individually or commonly as part of demand aggregation through a third party. In this regard, third parties have a key role in bringing together demand response capacities and can have the responsibility and obligation to ensure the reliability of those services, where those responsibilities are delegated by the demand facility owner and the closed distribution system operator. The objective of this guidance document is to help to determine the main criteria/motivation for the recommended settings and applications of the DR SFC capabilities of demand units at a synchronous system and national level. For adequate specifications of the relevant parameters it is essential to be aware of the objective of DR SFC, the deployment strategies that can be applied, and to understand how it interacts with other frequency stability requirements and assumptions for a system defence plan. In order to implement comprehensively the DR SFC capabilities, this implementation guidance will look beyond only DR SFC in the NC DCC, considering the proposed settings for LFSM outlined in other guidance documents. For each synchronous area, proposals for national choices for the non-exhaustive DR SFC parameters are provided in this IGD.
4	Frequency Ranges	New	This document addresses the frequency ranges required for the AC transmission and distribution lines including HVDC systems on the AC lines, the power generation and demand facilities.

			The general principle for the frequency range and time duration requirements are follows: • Frequency ranges for transmission and distribution network lines, including HVDC systems on the AC lines, to stay connected to the system shall be wider than for power generating and demand facilities • Frequency ranges for power generating facilities to stay connected to the system shall be wider than for demand facilities • Frequency ranges for demand facilities to stay connected to the system shall be narrower than for power generating facilities
5	Maximum Admissible active power reduction at low frequencies	New	The objective of this guidance document is to help determining the main criteria for the specifications/motivation, at national level, of the capability not to reduce active power output more than an admissible value due to frequency decrease. For adequate specifications of the relevant parameters it is essential to be aware of the objective of the requirement and to understand how it interacts with other frequency stability requirements and external factors such as power plant technology and ambient conditions. For each synchronous area, proposals for national choices for the non-exhaustive requirement on admissible active power reduction at low frequencies are provided through this IGD.
6	Automatic connection/reconnection and admissible rate of change of active power	New	This document addresses the issue of automatic connection/reconnection of power generating modules of type A, B and C. Automatic connection/reconnection is not allowed for type D power generating modules. The motivation for allowing automatic reconnection after an incidental disconnection or during system restoration is that neither the relevant TSO nor the relevant DSO can manage to respond to all individual start-up requests of power generating modules. In addition communication with type A power generating modules for connection/reconnection is not required. Hence they need to act autonomously according to a configured schedule in such cases. Automatic reconnection of power generating units after an incidental disconnection includes, but is not limited to, the following fundamental conditions: • Specifications of the voltage range, for which reconnection is allowed

			• Specifications of the frequency range, for which reconnection is allowed • Specification of a minimum observation time of voltage and frequency conditions • Specification of a maximum gradient of active power increase after reconnection Uncoordinated/uncontrolled reconnection of a large amount of distributed generation after system disturbance could result in system stability problems and cause system split or islanding. Therefore, some basic rules/conditions for reconnection shall be specified. In addition, coordination between frequency ranges for reconnection of power generating modules and disconnection/reconnection of demand facilities shall also be taken into account where relevant. The document provides guidance on implementing the capability of power generating modules related to voltage and frequency ranges, observation time and gradient of active power increase for connection or reconnection. Recommendation on the preferred values of voltage and frequency intervals for automatic reconnection as well as a minimum observation time and maximum gradient of active power increase after reconnection is given in the methodology section of this document and is based on current practice and for Continental Europe (CE) on the ENTSO-E report on Dispersed generation impact on CE region security.
7	Rate-of-change-of-frequency withstand capability (RoCoF)	Updated	The requirement aims at ensuring that power generating modules (NC RfG), demand units offering Demand Response (DR) services (DCC), HVDC systems and DC connected power park modules shall not disconnect from the network up to a maximum rate of change of frequency (df/dt). A large rate of change of frequency (RoCoF) may occur after a severe system incident (e.g. system split or loss of large generator in a smaller system). The facilities shall remain connected to contribute to stabilize and restore the network to normal operating states. The resulting RoCoF withstand capability will be an important input to calculate the essential minimum inertia (provided by the synchronous PGM with inherent inertia and by PPMs with synthetic inertia) for system stability in case of outage or system split, incl. asynchronous operation of control block. Therefore, there is a direct link between RoCoF and inertia related requirements.

			Please note that this IGD would be updated in respect to frequency measurement criteria once the outcome of task force on this topic is finalized and published.
8	Need for synthetic inertia for frequency regulation	Updated	System inertia is an essential parameter for frequency stability of the electrical power system. It determines the initial rate of change of frequency in case of a sudden imbalance between supply and demand (e.g. trip of a large MW source or demand). A slower rate of change of frequency provides margins for activating automated active power reserves, predominantly via Frequency Sensitive Mode (FSM) (normal state) or Limited Frequency Sensitive Mode (LFSM) (emergency state). Replacement of conventional synchronous power generating modules, whose rotating masses inherently contribute to system inertia, by power park modules largely connected through power electronics results in a decrease in the Total System Inertia (TSI). Increased application of power electronic drives at the demand side also contributes to a decrease in inertia. This decrease in TSI combined with a higher frequency volatility, particularly if no countermeasures are taken, may become an essential aspect in context of frequency stability. The objective of this IGD is to provide guidance on Synthetic Inertia (SI) aspects to be considered when choosing relevant national parameters and opting in or out of nonmandatory requirements. It should be noted that the need for SI is less when the relevant TSO is experiencing or foreseeing modest penetration of RES. The challenge of maintaining frequency stability increases dramatically when total system inertia decreases at synchronous area (SA) level. Exceptionally, during rare system splits, some TSOs normally relying upon adequate inertia from elsewhere in the SA, could experience a lack of inertia for a short critical time. If insufficient inertia is available after a system split, this could result in a major challenge to prevent an immediate system collapse.

Purpose of this document

This document demonstrates the outcomes of the consultation, which was conducted 20. November 2017 – 21. December 2017, and takes into account the views of the stakeholders resulting from this consultation. It provides a sound justification for including or not the views of the stakeholders when developing further the IGDs.

The individual comments on each IGD – as received – and the corresponding ENTSO-E position are presented below on one-to-one manner.

2. Individual comments

Frequency Sensitive Mode

Commenter	Type of comment	Comment	Remarks
BHKW-Forum e.V. (DE)	Technical	page 3, NC frame, 2nd para "Despite choices need to be made at national level, frequency-related issues normally require an equitable system-wide response and therefore collaboration between TSOs at synchronous area level is necessary." - 'normally require' is too weak. It is an indispensable condition that all control areas within a synchronous zone behave the same on frequency changes, and that this frequency behaviour of controllable units has the same direction as the natural self-regulation effect. Proposal for change: "Despite choices need to be made at national level, frequency-related issues require a similar response within the same synchronous area and therefore strict collaboration between TSOs of the same synchronous area is necessary."	Accepted. Sentence to be changed to: “Despite choices need to be made at national level, frequency-related issues require a similar response within the same synchronous area and therefore strict collaboration between TSOs of the same synchronous area is necessary.”
	Technical	page 3, Between the CNCs, bullet points:" * an early response (i.e. FSM, DR SFC) even to small frequency variation to, * a response (i.e. LFSM, DR SFC) to larger frequency variation, and; * finally, a last response by low frequency demand disconnection (LFDD) to avoid network collapse" – It is not only a question of frequency ranges (small, normal, large) to activate early response, response, and last	Rejected. The objective is to describe the sequence of activation of countermeasures, which is independent from ROCOF: FSM comes first, then LFSM and then LFDD. This does not exclude, that the next measure is activated before the former is fully deployed.

		response, as in case of fast ROCOF the early response might not be activated fully, as the activation time may be too long. Proposal for the introductory sentence: "Also there must be collaboration between all of these parties as we move typically from small frequency changes to large frequency ranges and from slow ROCOF to fast ROCOF: * an early response (i.e. FSM, DR SFC) even to small frequency variation to, * a response (i.e. LFSM, DR SFC) to larger frequency variation and fast ROCOF, and; * finally a last response by low frequency demand disconnection (LFDD) to avoid network collapse"	
	Technical	page 4, In other NCs: "Implementation of RfG requirements at national level shall ensure ..." - 'Shall' means a normative requirement. As the Implementation Guidance Documents are non-binding according to commission regulation 2016/631, article 58, the non-binding character should be underlined by using of the modal verb should (recommendation) instead of shall (requirement).	Rejected. Original text does not impair the unbinding character of an IGD, but underlines the objective of NC RfG.
	Technical	page 4, System characteristics, 2nd para: "It depends on generation or load resources made available to the TSOs, which are called frequency containment reserves (FCR) and are in fact deployed by generators running in frequency sensitive mode (FSM)." - The first part of the sentience says correctly, that both generation and load can be used for FCR aka primary balancing power. The load feature is missing in the second half of the sentence: "It depends on generation or load resources made available to the TSOs, which are called frequency containment	Accepted in a modified way. Sentence to be changed to: It depends on generation or load resources made available to the TSOs, which are called frequency containment reserves (FCR) and are in fact deployed by generators or demand units running in frequency sensitive mode (FSM). “Demand unit” instead of “load” is a defined term used in the connection codes.

		reserves (FCR) and are in fact deployed by generators or loads running in frequency sensitive mode (FSM)."	
	Technical	page 4, System characteristics, 3rd para: "It is provided by frequency restoration reserve (FRR), deployed by generators or demand units with frequency restoration capabilities." - In this technical paper we should stick to the correct terms, even if some terminology mistakes have been made in some network codes. Generator & load are one pair describing the technical sources and sinks for electrical energy; supply & demand are another pair coming from macroeconomics, the result of supply and demand meeting on a market is the clearing price; in microeconomics the term pair is producer and consumer. In this context - units extracting or injecting electricity into the grid - the correct term is "load" and "generator": "... deployed by generators or loads with frequency restoration capabilities.	Accepted in a modified way. Sentence to be changed to: "... deployed by generators or demand units with frequency restoration capabilities” “Demand unit” instead of “load” is a defined term used in the connection codes.
	Technical	page 5, system characteristics, 3rd para: "This shall not be understood as setting the same parameters for each power generating module within a synchronous area." - Please tell the reader not how something is not understood, but how a sentence is to be understood. Proposal for change: "This shall not be understood as setting the same parameters for each power generating module within a synchronous area, but that the cumulative effect of all power generating modules within a control area for which a TSO is responsible shall is the same within a common synchronous zone."	Accepted Sentence to be completed: “This shall not be understood as setting the same parameters for each power generating module within a synchronous area, but that each TSO defines those parameters in its control area to cover its required level of FCR.”
	Technical	Page 5, system characteristics, 8th para "In the event of a frequency step response, the PGM controller should carefully manage overshoot and damping of the response aiming at avoiding unnecessary active power oscillations."	This is an individual issue, which can be solved as the combination of choice of the parameters specified by the TSO shall take possible technology-dependent limitation into account.

		- How? The overshoot characteristics comes from the slow activation time (aka control rise time) of up to 30 s. Add some explanatory words how this objective should be fulfilled.	Additional details will be agreed between TSO and PGM owner.
	Technical	page 7, system characteristics, last para "An imbalance (between generation and demand) profile is applied to the system." - A correct pair would be supply and demand or generation and load. Change sentence:" An imbalance (between supply and demand) profile is applied to the system."	Accepted Sentence to be changed to: An imbalance (between supply and demand) profile is applied to the system."
	Technical	page 9, system characteristics: A clear message is lacking. Experiences from the synchronous zone in Texas, US show that after the abandoning of a frequency dead band, the frequency quality has risen and the mechanical stress in power plants declined due to less bang-bang action after leaving the deadband. Add somewhere on the page: "The use of a deadband is therefore not recommended and should be restricted to cases where no other technical solution is possible."	Even if for some power plants technologies, a deadband could cause mechanical constraints, this IGD is mainly based on system needs, which is related to frequency quality. Addition of the following statement related to power plants: "Nota :In case of a large number of power generating modules with a deadband, some power plants technologies could be impacted by mechanical constraints due to the action of switching from one side to the other side of a deadband."
	Technical	page 10, technology characteristics: "The performance criteria of this external frequency measurement need to be defined in particular by speed and accuracy." The 2nd sentence of this paragraph recommends using the rotational speed of the shaft of a synchronous machine as estimator for the power frequency. It is technically feasible to have a virtual synchronous machine and read the rotations of the virtual shaft. Parameters can be chosen (e.g. damping, inertia, strength of the "torsional spring" of the magnetic field with the polar wheel angle, etc. probably the nonlinearities should not be copied) so that a critically damped harmonic	Accepted Sentence to be changed to: "The performance criteria of this external frequency measurement need to be defined in particular by speed and accuracy, and a critically damped frequency measurement (e.g. as harmonic oscillator) should be the objective »

		oscillator in form of a virtual synchronous machine can be designed as frequency estimation. Add: "The performance criteria of this external frequency measurement need to be defined in particular by speed and accuracy, and a critically damped frequency measurement e.g. as harmonic oscillator should be the objective".	
	Other	Commenting is made easier if the document to comment has line numbers. Have also a look at ftp://ftp.cencenelec.eu/CENELEC/Forms&Templates/ISO-IEC-CEN-CENELEC-Commenting_Template.doc	N/A
Enercon	Technical	1/When we speak about 10mHz "insensitivity": does it mean +-10mHz or +-5mHz. The same for "deadband": 500mHz means +-250mHz or +-500mHz.	Accepted This is stated in the figures title but not explicitly in the text. Precisions added in the sentences: "different simulations have been performed assuming that the percentage of power generating modules having an ±10mHz-insensitivity varies from 0% to 100 % to evaluate the impact of this parameter on frequency distribution." And "different simulations have been performed assuming that the percentage of power generating modules having a ±10mHz deadband is between 0 and 100 % to evaluate the impact of this parameter on frequency distribution."
	Technical	2/Even if we only are speaking about capability to provide FSM, when TSOs will define the amount of reserve, one must consider that Wind and PV will probably not contribute to positive FSM... only negative FSM	The IGD is related to FSM capability, not to FSM contribution. We will not consider that Wind and PV don't have the capability to positive FSM to define the amount of reserve.

		Hence, we should refer to positive FSM or negative FSM.	
	Technical	3/Initial delay t1: recommended <=500ms... OK. But should ENTSO-E specify a reasonable minimum like >=100ms?	There is an inherent delay related to frequency measurement but not an intentional delay.
	Technical	4/ response time t2: please refer to German GC which stated the following :"In the case of wind energy, the increase in the active power (rise time at a frequency drop in the range of 49.8 Hz - 47.5 Hz and 51.5 Hz - 50.2 Hz) means that the wind energy plant have to responds to a change in grid frequency as fast as possible, but at least with a rise time of 5 s (in case of a power change ≤20% Pbinst). This applies depending on the available primary energy supply and above an active power production of at least 50% Pb inst. Below 50% Pb inst the response time has to be as fast as possible (according to the technical possibilities as given by the manufacturers)."	This IGD is related to FSM (not to LFSM).
	Technical	5/ Figure 1 page 7: This figure is not clear for me... are we showing here a result of a deadband or a result of an insensitivity?	Accepted. Title to be changed to : “Frequency profile observed with insensitivity modelled as an Active Dead-band (red curve)”
	Technical	6/ deadband: asymmetrical deadband should be possible (one must consider that some generation facilities are more suitable to provide either positive reserve only either negative, or both.	Rejected. Regarding the capability the deadband should be symmetrical.

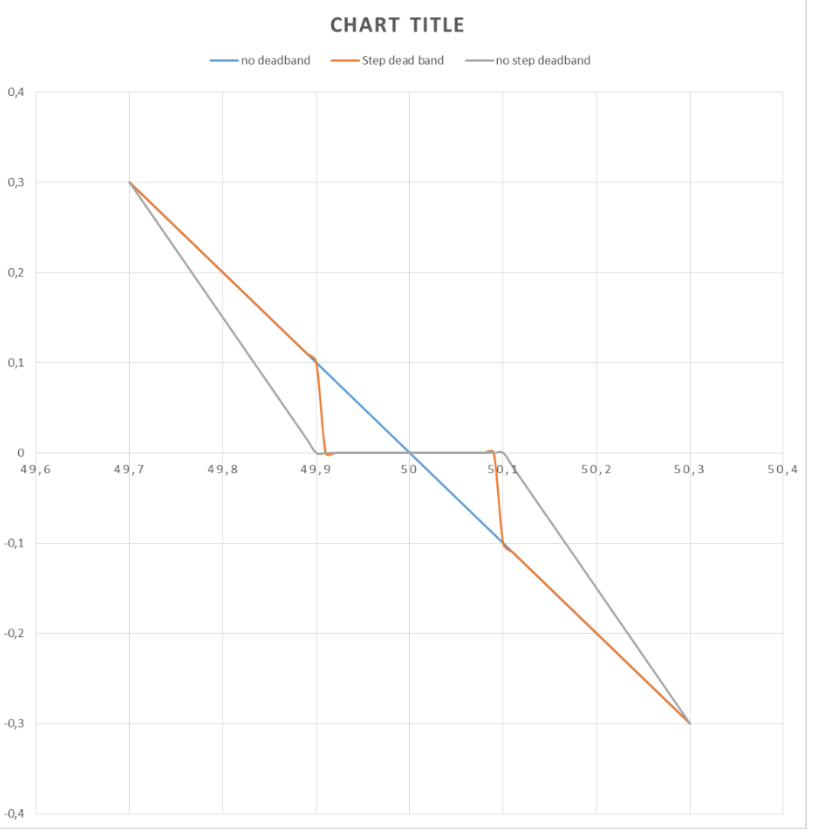
	Technical	7/ page 10 : "Wind turbines minimum regulation level shall be 10% of maximum capacity..."" i would say that minimum AVAILABLE POWER should be 10% of maximum capacity + amount of reserve	Paragraph to be adapted (cf comment from SENVION on LFSM IGD).
Energy Networks Association (GB)	Technical	It is hard to know if this IGD is sufficiently comprehensive. It provides general background to FSM. It does not appear to give any real guidance to TSOs or others in setting real-world deadband parameters	The IGD proposes a capability to set a deadband within a range and a default value for the deadband within this range.
Eugine	Technical	1.- The droop definition found in page 5 implies it is calculated based on active power range and the defined frequency deviation. This does not align with the standard droop definition equation, and impedes the setting of a droop value according to table shown just above in the text. It should be aligned with the one found in LFSM IGD.	Accepted: add the RfG definition of the FSM droop. $$s[\%] = 100 \cdot \frac{\lvert\Delta f\rvert}{f_n} \cdot \frac{P_{ref}}{\lvert\Delta P\rvert}$$
	Technical	2.- The initial delay (t1) should be for the whole plant and not per individual units (should be clearly stated to avoid confusions).	Rejected, RfG explicitly talk about the PGM response and that's what we wrote in the IGD.
	Technical	3.- Based on the "general comment", the recommendation on page 10 of an insensitivity of less or equal to 10 mHz should be increased to less or equal to 30mHz. Additionally, frequency measurement specification (measurement point, accuracy, device etc.) to be clarified.	Rejected With 30 mHz insensitivity, SOGL requirement couldn't be met, which means that the PGM will not have the minimal performances to provide FCR.

			Additionally, frequency measurement specification couldn't be provided yet, but as soon we'll have results on that subject, this IGD will be updated.
	Other	It is clearly stated that insensitivity helps the controller to avoid reaction to small frequency variations by filtering them, while still following the trend of the variations. They show this has negligible impact on the frequency distribution. The proposal is to stress the necessity of filtering and perhaps proposing a methodology to avoid constant changes in the units output when connected to the grid and responding to quick (and constant) frequency deviations.	
Eurelectric	Technical	P.3: FRR is listed in the section Codes & Articles of this IGD but there is no recommendation on this function, whose specifications are tackled in the balancing and SOGL Regulation not in Rfg. On top of that, FRR is not included in the FSM which is the title of the IGD. For these two reasons, we suggest removing FRR from this section.	Rejected The IGD states that TSOs could define relevant requirements for plant design regarding FRR capability (and add the reference to associated SOGL requirements).
	Technical	P.3: The wording of the sentence 'Despite choices need to be made at national level, frequency-related issues normally require an equitable system-wide response and therefore collaboration between TSOs at synchronous area level is necessary' is too soft from our point of view. We propose to replace 'collaboration' by 'harmonization'.	Rejected. The collaboration between TSOs results in proposals for default values and harmonized methodologies.
	Technical	P.5: We propose to add 'mainly' in the sentence reading 'FCR obligation will be mainly covered by C&D PGMs'	Accepted

		because FCR obligation could be covered through other means such as demand response for example.	Sentence to be changed to: ‘FCR obligation will be mainly covered by C&D PGMs'
	Technical	P.6-7: Several uses of ‘dead-band’ should be replaced by ‘insensitivity’.	Rejected (the change of figure 1 Title: “Frequency profile observed with insensitivity modelled as an Active Dead-band (red curve)” will improve the wording)
	Technical	P.8: The second figure shows one of the consequences if some units have a dead-band while others do not. With a dead-band, the energy effectively supplied remains below the energy supplied without a dead-band: the difference is represented by the area of the triangle between the red and blue dotted lines, close to 50Hz. A uniform application of 0mHz for dead-band is essential.	The IGD proposes 0 as default value for the deadband. Proposal to add a Title on the deadband graph: “Behavior with (red) or without (blue) a deadband”.
	Technical	P.10: concerning the argument of the recommended default value of a 0 mHz for dead-band that is 'to comply with SOGL FCR technical requirements': more precisely, Article 154 and Annex V of SOGL network code stipulate that for any FCR providing unit, the maximum combined effect of inherent frequency response insensitivity and possible intentional frequency response dead band of the governor should be equal to 10 mHz in CE synchronous zone. The frequency response insensitivity mentioned in RfG should be understood as a maximum admissible value for new power generating units, specified by the TSO between 10 and 30 mHz. However, in practice, the insensitivity can be lower than 10 mHz, and the dead-band could be between 0-10 mHz, depending on the value for insensitivity.	RfG specifications concern capabilities. The capability to be able to have a 0 mHz deadband is required.

	Other	We welcome the very valuable 'educational effort' of the IGD on FSM. The primary frequency control (FCR) is presently dimensioned for a load imbalance of 3 000 MW. It is expected that the Policy One of the Operation al Handbook will be updated in application of GLSO, but we would like to highlight the fact that harmonizing the different parameters of FSM may have impact on the behavior of the whole system (new load imbalance? new behavior –overshoot / damping - of PGMs in case of frequency step response	
EUTurbines	Technical	page 5, droop calculation There is a mismatch between the interdependency of minimum reserve for FSM, the droop range and the frequency deviation for full activation. Example: with 200 mHz and with the (maximum) droop of 12%, the resulting reserve would be 3,3%. This is higher than the minimum reserve of 2% in Germany and higher than the minimum reserve in RfG of 1,5%. It needs to be clarified. whether the droop is fixed by the TSO (resulting in a fair reserve activation among all FSM generators but a full reserve release at a df different from 200 mHz) or whether the droop needs to be variable, dependant on the current amount of reserve, but deployed at a df of 200 mHz.	Accepted Complete the sentence: "Droop should be calculated to be able to increase/decrease power from $\|\Delta P1\|$ / Pmax for FCR full activation at a defined frequency deviation, e.g. 200 mHz for PGMs within the Continental Europe synchronous area. This is important to calculate the droop to make sure the reserve ($\|\Delta P1\|$ / Pmax) could be fully deployed for the synchronous area reference frequency deviation (i.e 200 mHz for CE, 500 mHz for GB)"
	Technical	Page 6-7 active dead-band "Active dead-band" needs to be further explained. A recommendation is missing if and under which circumstances it shall be applied (only for modelling or intentional floating dead-band?) and, if yes, which	The purpose is not to allow an active deadband, but to explain how can be understood insensitivity

		parameters need to be applied. Application of this functionality requires consideration of a fair distribution of FSM among the contributing generators, as well as discussion about inherent time delay created by the filtering between true grid frequency change and change in processed frequency signal.	
	Technical	Page 8, frequency response dead-band A “step-function dead-band” needs to be further explained. It is understood to have a sudden increase/decrease of output at the borders of the dead-band. Such functionality would not only cause stress but also would be a possible reason for instability in the system frequency. Suggestion: clearly exclude a step function dead-band. It also needs to be made clear that there should be no change in the droop within the applicable frequency range, in order to make the FSM functionality not too complicated.	Proposal to change the figure to represent step deadband and no step deadband.

			 Both impact the frequency distribution and are not suitable.
	Technical	Figures 2 and 3: it is not clear what “100% insensitivity and “100% dead-band” means (missing reference value) Frequency measurement accuracy shall be defined and accounted in all those studies and results. In a real situation, for the same (true) grid frequency, a frequency	Accepted Change sentences to: different simulations have been performed assuming that the number of groups having an insensitivity is different, from 0 % to 100 %,

		measurement device may not perceive the same frequency. This question is obviously upstream of consideration of insensitivity ("inherent dead-band") and (deliberate) dead-band. As frequency measurement accuracy devices, especially of existing units, may typically range between 3 mHz and 20 mHz, it can induce a large spread onto the distribution of results, consequence of accuracy, insensitivity, and dead-band. Has the frequency measurement accuracy been considered here? What would be the results of figure 3 with, for instance, 5 mHz standard deviation (of measurement accuracy) on the European fleet? We do suspect that the inner "bath tub" shape may not look the same at all.	which means 100% of production units have an insensitivity of 10 mHz, to evaluate the impact of this parameter on frequency distribution"
	Technical	Other points to consider. - When we plot today's frequency density of probability on several grids (available from manufacturers, for instance), we typically do not see the bath tub, although many units are with static frequency dead-band. Shall we conclude here that facts defeat simulation, and study supporting frequency dead-band setting has just not the right assumptions in? - Logic prioritisation shall be addressed in the IGD. In particular, it shall be stated how to deal with other logics that can affect / control the active power output of the generating unit. Specifically, the setpoint coming from DSO, industrial process, market related logics shall be addressed in terms of priority or how to deal with such signals in light of the discussion carried out at the GC	We can conclude that there are units without deadband on the synchronous area that are contributing to the current frequency quality more than those without deadband. FSM is a capability to be able then able to provide FCR service in operation. There isn't a question of logic prioritization, because we are talking about different market products that are related to normal operation. FSM is currently done without deadband in several countries in CE area. It contributes to the current frequency quality in CE area. Enlarging the deadband shall be assessed on cost versus benefit regarding the effect. If units could have different value of deadband, the way to pay for FCR provision should be reviewed accordingly (not the same price for units with a deadband, than for units without a deadband).

		ESC. As an example, please refer to the prioritization proposal indicated in EN 50549-1/2. - Lowering the dead-band to control the number of small deviation of frequency shall be assessed on cost versus benefit. Zero dead-band might lead to unwanted effect with a multi-machine and meshed network model; the model used for in the IGD might not cover all effects of small frequency deviation.	As said by another stakeholder, the deadband could also cause mechanical stress on the unit (see p 3)
	Other	General remark relevant for all IGDs: EUTurbines welcomes the preparation of the IGDs and agrees that they can be helpful for national implementation. However, we believe that the IGDs should not be considered the only relevant support document – especially since not all relevant technical matters are covered. In this sense, the IGDs should be considered living documents and further updates should be conducted in the future as well.	IGDs are living documents and will be updated when it's needed.
	Other	Please indicate tables and figures with numbers. It is hard to reference without them.	Accepted. To be added: tables numbers and some figures numbers.
	Other	Can ENTSO-E also lead a benchmark of Frequency Sensitive Mode settings, as currently practiced in Europe? It seems that several countries have already selected various frequency related settings and are keen on keeping those going forward. This can create distortion of	ENTSO-E is monitoring national implementation of NC RfG. Information publicly available can be found on ENTSO-E website : https://docs.entsoe.eu/cnc-al/?embed

		competition between the two sides of a border in a same synchronous grid. Indeed, the price to provide frequency controls would not be the same depending on those settings. It is once more recommended to analyse thoroughly the current practices and direction taken in each country. It is a necessary step to understand how the grids currently operate, define cost effective frequency controls and equity of treatment between plant owners.	
Orgalime	Other	Table 1 (page 5) and Table 2 (page 6) are not conform on values. Value Table 1 t1 for PPM is "to be specified by the relevant TSO and in Table 2 it is stated <500 ms.	Accepted To be changed in Table 2: - add title to explain this table contains default value proposals. - Change “Initial delay t1“ to „Initial delay t1 default value“.
	Other	What is the reason why the deadband for sensitivity has to be smaller than 10 mHz (Table 1, page 4)? Is 10 mHz required only for PGM? What about PPM? What about other units line energy storage?	10 mHz insensitivity is required for each FCR provider (SPGM, PPM, or others FCR providers like storage units). 10 mHz is state of the art regarding insensitivity.
Senvion	Technical	Possible response times for active power increase are already incorporated in the IGD on LFSM (page 8) and must also be reflected here. Also, the term "response activation time" should be aligned with the term "step response time" as described in the IGD on LFSM. It is not clearly defined.	Response time is not the same for FSM or LFSM functionality: FSM is related to normal operation, system need related to response time is lower than for LFSM which is an emergency service. Initial delay and full activation time related to FSM are described in RfG (article 15.d.iii and iv, and figure 6).

	Technical	Page 10: For wind turbines, the frequency response deadband should not be set to zero. While it is well understood why this could be requested, this is not practical: It is required to set a delta of P1/Pref to the active power set-point. For this delta there must be a reference value. Due to the fluctuating nature of wind, for LFSM this is usually the active power output at the moment the LFSM threshold is reached. The same should apply to FSM. For this procedure, at least a small deadband is required. There are grid codes that require continuous calculation of the possible active power which should be used as the reference value. However, this operation mode requires almost continuous pitching of the wind turbines which would result in mechanical stress of the components. This should not increase component cost for these generators. Thus, a dead-band of zero should not be set as default	Rejected Initial delay < 500 ms is sufficient to measure the frequency and the active power reference value (if it's easier to implement, it's also possible to choose Pref = Pmax). FCR is a market-based product. This issue seems to be a commercial issue that should be covered by the market price or the remuneration of the service in case there is no market.
VGB	Technical	Page 6: the response time for GB and IE/NE is set at a lower value (resp. 10 s and 15 s) than the max. value imposed by the RfG NC Art. 15 table 5 (30 s). According to my reading of the RfG requirement, ENTSOE does not have the right to impose a lower value in the IGD. When imposing the proposed values in GB and IE/NE, the national legislation will be more stringent than the RfG code and such requirement is not allowed by European legislation. Your opinion please.	Yes, but SOGL impose those values for GB and IE/NE.

	Technical	Page 6 -7: the explanation about insensitivity and deadband is not clear for me	
	Technical	The FSM parameters have to be identical for all PGMs in a synchronous area. The IGD does not propose a value for the droop or a deadband for PGMs that not offer a FCR. But also the GL SO does not describe those parameters. In which code will those parameters be defined? In my opinion, all the FSM parameters have to be described in the GL SO or in the E&R code (for islanding situations) and not in the IGDs based on RfG NC	Identical FSM parameters is needed only for some parameters (insensitivity, deadband, response time) for FCR providers in a same synchronous area. Those for which this IGD proposes default values. Then, it would be appreciable to have requirement on those parameters settings at operational time, when FCR providers will be offering their capabilities on the same market, but it's out of scope of RfG.
WindEurope	Technical	Possible response times for active power increase are already incorporated in the IGD on LFSM (page 8) and must also be reflected here. Also, the term "response activation time" should be aligned with the term "step response time" as described in the IGD on LFSM. It is not clearly defined.	Response time is not the same for FSM or LFSM functionality: FSM is related to normal operation, system need related to response time is lower than for LFSM which is an emergency service. Initial delay and full activation time related to FSM are described in RfG (article 15.d.iii and iv, and figure 6).
	Technical	Page 10: For wind turbines, the frequency response deadband should not be set to zero. While it is well understood why this could be requested, this is not practical: It is required to set a delta of P1/Pref to the active power set-point. For this delta there must be a reference value. Due to the fluctuating nature of wind, for LFSM this is usually the active power output at the moment the LFSM threshold is reached. The same should	Rejected (same comment from SENVION) Initial delay < 500 ms is sufficient to measure the frequency and the active power reference value (if it's easier to implement, it's also possible to choose Pref = Pmax)

		apply to FSM. For this procedure, at least a small deadband is required. There are grid codes that require continuous calculation of the possible active power which should be used as the reference value. However, this operation mode requires almost continuous pitching of the wind turbines which would result in mechanical stress of the components. This should not increase component cost for these generators. Thus, a dead-band of zero should not be set as default.	FCR is a market-based product. This issue seems to be a commercial issue that should be covered by the market price or the remuneration of the service in case there is no market.
	Technical	There seems to exist an incompatibility of the max 10mHz insensitivity in the System Operation Guidelines and the possibility of having a dead-band in the RfG (up to 500mHz). A deadband is needed to reduce the mechanical stress as highlighted in the IGD; a dead-band or insensitivity of 10 mHz is not adequate. To reduce the mechanical stress appreciably a dead-band >200mHz is needed (LFSM).	Rejected Deadband is not insensitivity. Already stated in the IGD: "…Notwithstanding this, a deadband around nominal frequency may be used to deactivate FCR by setting it equal to the LFSM frequency thresholds."
	Other	This IGD would gain from clarity if it can include references such as those used in the LFSM (this captures much more details-helpful). For instance upwards and downwards regulation should also refer to the comments in the LFSM , specifically for the times when resource (e.g. wind) are limited,or operators are operating at full load.	Accepted Sentence changed in Technology characteristics: "Frequency step response can be provided by power generating modules from any active power operating point between minimum regulating level and maximum capacity, the actual delivery of active power frequency response depends on the operating and ambient conditions (see RfG, article 15.2.d.i)."

Limited Frequency Sensitive Mode – O/-U

Commenter	Type of comment	Comment	Remarks
BHKW-Forum e.V. (DE)	Technical	page 3, introduction: "Limited frequency sensitive mode at overfrequency (LFSM-O) is to be activated, when the system is in an emergency state of overfrequency and all frequency containment reserves (FCR) in negative direction have already been deployed." - As FCR needs a couple of seconds to be activated, the emergency of a system split with high ROCOF needs fast LFSM-O even if the FCR has not been deployed completely. Change sentence: "Limited frequency sensitive mode at overfrequency (LFSM-O) is to be activated, when the system is in an emergency state of overfrequency and needs fast reduction of active power production." Apply same change to next sentence on LFSM-U.	Accepted. Statement is fairly correct. The activation trigger of LFSM-O is the frequency threshold, e.g. 50.2 Hz for CE. In case of a rapid frequency increase, the threshold may be exceeded, before FSM has been fully activated (activation time of 30 s). The intention of the sentence was however to express, that active power reserves on top of FCR are made available through LFSM-O. Sentence to be adapted to avoid misinterpretation. The same applies to LFSM-U.
	Technical	page 3, NC frame: "Despite choices need to be made at national level, for frequency-related issues this normally requires a system wide response and therefore collaboration between TSOs at synchronous area level is necessary." - Not only a system wide response is needed, but a response with is similar in all control areas. If one control area moves right and the neighbouring control area moves left, then extra transits between those two CA may occur and may lead to a further worsening of an already critical emergency situation. Change sentence: "Despite choices need to be made at national level, for frequency-related issues this normally requires a consistent response within the same synchronous area and therefore collaboration between TSOs sharing the same synchronous are is indispensable."	Accepted. Sentence to be changed to: "Despite choices need to be made at national level, for frequency-related issues this normally requires a consistent response within the same synchronous area and therefore collaboration between TSOs of the same synchronous area is necessary."

	Technical	page 4, Between the CNCs: "an early response even to small frequency variation to, a response to larger frequency variation, and; Finally a last response as last response to avoid network collapse" - typo: "finally", The LFSM belongs to the same category as LFDD (under-frequency load shedding) as it has to be very quick. Load shedding occurs within 200 ms, and due to symmetrical reasons also a shedding of generators should occur within the same timeframe.	Typo accepted. LFSM categorization rejected: LFSM-U is different from LFDD. It is triggered at 49.8 Hz already (CE). Its purpose is to make available additional generation reserves to counteract to a frequency decrease and to support avoiding LFDD.
	Technical	page 4, system characteristics, 4th para: "In such cases frequency deviations larger than 50.0 Hz +/-200 mHz can be expected." - In the case of a system split with a high deficit resp. surplus, not only the frequency range is wide, but also the speed df/dt. Change sentence: "In such cases frequency deviations larger than 50.0 Hz +/- 200 mHz with a high rate of change of frequency can be expected."	Accepted.
	Technical	page 4, system characteristics, 5th para: "In such cases FCR resources are fully deployed, but system frequency cannot be stabilized and increases further." No, to reach the activation threshold of e.g. 50,2 Hz is not only a question of not sufficient amount of FCR, but also a question of the FCR being to slow for a ROCOF of >1 Hz/s. Remove sentence.	Accepted in a modified way. Sentence to be adapted, that not only insufficient FCR resources, but also its slow activation lead to high frequencies.
	Technical	page 4, system characteristics, 5th para: "For type A generators the TSO may allow alternatively that such behaviour is emulated by disconnection at randomized frequencies." - Why only type A generators? Usually type A is PV and inverters have no problem to reduce power with a control rise time of max 200ms. Wind turbines, gas turbines, etc. may need more time, but those are rather type B. A TSO may need to get rid of surplus power quickly, and if the power reduction gradient is to slow, a simple solution is the	Rejected. Staged disconnection is attributable only to Type A power generating modules according to RfG. The objective of derogations is not to introduce or extend additional requirements, but to release power generating modules from requirements, if reasonable.

		staged disconnection. If this is not covered by the RfG, then the logical consequence is to ask for a derogation. Any NRA will hopefully understand the need for this solution if the status quo of some DERs which are currently installed does not allow an adequate reaction on high ROCOF. Modify sentence: "In coordination with the NRA, the TSO may allow alternatively that such behaviour is emulated by disconnection at randomized frequencies."	
	Technical	page 5, 2nd para "This transient behaviour is determined by the system inertia, which is typically lower for small synchronous areas such as Ireland or GB," – This is not correct. The system inertia measured in a time constant T_m = 2H is the same, but a 1 GW loss in a 20 GW system is more seriously than a 1 GW loss in a 200 GW system. Change sentence: "This transient behaviour is determined by the system inertia and system size. In small synchronous areas such as Ireland or GB, a single loss of a generator or HVDC interconnector can result in a rate of change of frequency that is markedly greater than what could be in CE synchronous area."	Rejected. Inertia is not a uniform constant, but depends on system characteristics (total load, proportion of rotating generation, …).
	Technical	page 5, para 4 "Frequency sensitivity increases at low system inertia and power generating modules will be more often activated to support frequency." – This sentence give the wrong idea that it is a good idea to activate and deactivate a frequency support function. Those functions should be running continously, as each ON or OFF step is a dirac impulse on the system, that induces ocillations which need to be damped out. Modify sentence: "Frequency sensitivity increases at low system inertia and power generating modules will be needed more to support frequency."	Accepted.

	Technical	page 6, 3rd para "Due to the system-wide effect of frequency-related issues, a harmonised setting of these parameters within a synchronous area is desirable." This is extremly desirable and would rather call it "... is essential."	Accepted.
	Technical	page 7: "... lead to increased maintenance costs." - As the LFSM-O function is only used in a rare emergency event, the extra wear and tear should be manageable. Add: "... lead to increased maintenance costs, which can be considered manageable as the function is needed in rather rare emergency events."	Rejected. Since droop settings of LFSM-O and FSM shall be coordinated extra wear and tear would not occur in case of LFSM-O activation.
	Technical	page 7: "NC RfG allows for two options for defining Pref for power park modules, either Pmax or the actual active power output at the moment the LFSM threshold is reached. It is recommended to select Pmax as a reference for power park modules, which are typically operated at or near maximum capacity. For those power park modules, which are operated at partial load most of the time the preferable reference is the actual active power output at the moment the LFSM threshold is reached. This choice would enable at system level an equitable active power response to a high or low frequency event regardless of the number of power generating modules in operation." - This conclusion is not true. The only correct reference is the actual active power, as both synchronous and non-synchronous generators may operate in part load. Have a look at the lignite plants in brown: https://www.energy-charts.de/power_de.htm?source=all-sources&week=30&year=2017 A droop of e.g. 5% = gradient of 40% Hz needs a fixed reference as we want a defined system response. If you refer to the installed capacity P_max, then a situation with 100	Rejected. Comment is not logical. IGD text refers to power park modules; the comment however quotes operation of synchronous power generating modules.

		GW output at full load means a reference of 100 GW*0,4 = 40 GW/Hz. If the same output of 100 GW is generated by 50% part load, this refers to 200 GW installed capacity P_max with a system response of 80 GW/Hz. In order to have a defined system response, the only correct option is to choose P_actual as reference: thermal power plants do not run ON and OFF, but also in diverse part load constellations. Change sentence: "NC RfG allows for two options for defining Pref for power park modules, either Pmax or the actual active power output at the moment the LFSM threshold is reached. It is recommended to select the actual active power output in order to get a defined system behaviour even if generators run in partial load."	
	Technical	page 8/9: "Taking these characteristics into consideration it is recommended to distinguish between these types of power generating modules. The recommended response times for active power increase in case of decreasing frequency are: [..] The recommended response times for active power decrease in case of increasing frequency are:"- The following bullet points are much to slow if we talk about a system split. In Nov 2006, the eastern zone had a surplus of 10 GW with a system load of 50 GW. Assuming a mechanical starting time of Tm = 2H = 10s this means an initial ROCOF of 1 Hz/s. Today experts think worse cases with 2 or 3 Hz/s are possible. Measurements on smaller electric systems (geographical islands) have seen 5 Hz/s and a restabilisation. It makes no sense to distinguish between synchronous and non-synchronous generators only, as the prime move is often the main criterion. PV inverters are fast, as fast as you optimise the frequency measurement and valve control: 200 ms are possible if developers are given a clear target. Wind turbines are slower, if they only activate the pitch control to get rid of surplus power. This may need 2-3 seconds. But	The conclusions were drawn from manufacturer statements, which were received through an ENTSO-E survey on the matter in May 2018 and also in national implementation processes. They hence are considered to reflect the best available knowledge. The proposals presented by the commenter would need to check with the industry and may also lead to other drawbacks from a system engineering perspective, e.g. a slow active power recovery when using fast valving.

		they have a chopper as an energy sink needed for FRT. With the use of the chopper, the inverter just feeds less energy in the grid (same dynamics as PV), or the DFIG concept may let the rotor absorb the surplus energy. The T_m of a wind rotor is about 20s, if the WT uses gearbox and fast rotating generator this is in the range of 30s-40s. For a few seconds, the turbine rotor will only slightly accelerate. Next: thermal power plants with steam turbines are capable of fast valving and reducing power within 600-800 ms. They should be able to catch themselves in island mode at house load which needs a quick power reduction. Gas turbines and combution engines (please compare with the dynamics of a jet or motorcar) can also react quickly if they don't have to care for exhaust gases in an emergency. If the alternative of a staged disconnection is open, no manufacturer will object even if the fast path is not tested, nor certified and therefore sales ready yet. But a trip by a staged frequency setting is proven in the industry, please compare with the German Systemstabilitätsverordnung (regulation on system stability) with gigawatts of retrofitted PV sytems, wind turbines and CHP plants. It obviously needs a derogation, but this has been achieved in Italy already, where the DER island protection works via switching to a narrow frequency band, if a local fault is detected.	
Enercon	Technical	Page 5 : "LSFM-U capability shall not be understood as requiring RES generation to run at a reduced active power ...".... This is addressing the topic of economical impact in activating power reserves in WFs to provide the LFSM-U. I think behind this statement can be the idea that industry can provide already storage systems to fulfill the LFSM-U at any	Rather a statement than a comment. No action needed.

		time, and therefore, no need to guarantee permanent P positive reserves by the WECs.	
	Technical	Response time for PPM: why a different response time for wind (<5s) and no wind (<10s) ?	Distinction was based on information about capabilities obtained from manufacturers.
	Technical	Page 10: 'Wind turbines are not controllable below 10%..." In reality wind turbines are controllable but are slower.	Accepted. Change sentence to "Wind turbines are less controllable below 10%..."
	Technical	Page 10: 'These reports clearly conclude that in future response times of 1s are required..." => this is for LFSM-O	Accepted. Change sentence to: "These reports clearly conclude that in future LFSM-O response times of 1s are required...
	Technical	General: response times depends on how frequency is measured.... slow if a good accuracy in frequency measurement is required.	Rather a statement than a comment. No action needed.
Energy Networks Association (GB)	Technical	We are confused by the concept of LFMS-U blocking. There does not appear to be any scope in the RfG for LFSM-U blocking. Nor is there any obvious reason to do this in relation to local thermal or even voltage constraints. It might be helpful if the operating principles and rationale for such schemes, if they exist, was explained.	Rejected. Agree, that it goes beyond RfG requirements. However, numerous discussions with stakeholders, in particular DSOs have revealed that the option of blocking is an essential part of the LFSM-U function. Therefore the ENTSO-E view has been added to the IGD upon stakeholder request.
	Technical	We believe the LFSM-O default in Table 2 is incorrect for GB – the GB figure is 10%. The 3-5% is for FSM, not LFSM-O.	Accepted after cross-check with National Grid.
	Technical	We are also confused about the response times given. The TSO can set these for FSM in Art 15, but not for LFSM-O apart from the initial time delay (in Art 13). It is not clear if	The absence of response times has been identified as a shortcoming of RfG. Response times are acknowledged as an essential parameter to exhaustively describe LFSM-O/-U

		this IGD is proposing that TSOs specify more detail/requirements than is allowed within the RfG.	function. Upon stakeholder request ENTSO-E has added its view on these.
Eugine	Technical	On page 6 table 1 shows the activation thresholds. They are not all aligned with FSM (which is +- 200 mHz). A clarification comment is needed to the reaction of the unit in the frequency space between FSM and LFSM.	CE: thresholds are aligned with FSM FSM ranges for all synchronous areas will be added to the IGD on FSM
	Technical	Droop equation found in page 7 could cause confusion. An initial statement that it is valid for delta f values equal or above delta f1 would be recommended. Additionally, a better definition of delta f1 would be recommended (we understand this as the threshold value mentioned before). Droop definition, and mathematical equation to be clearly specified.	Rejected. The text below the equation is considered to provide sufficient explanation. Only definition of Δf1 is added." Δf_1 is the frequency threshold of the LFSM-O/-U"
	Technical	Regarding the response time: this document defines the dead time, step response time and settling times in Figure 1, but later only refers to the values given as "response time". The document should clearly specify that unless specified separately response time should be meant as Step response time	Accepted in a modified way. Change legend to figure 1 ("response time" instead "step response time").
	Technical	In page 9 this document recommends a response time for active power decrease in case of increasing frequency of less or equal to 8 seconds for an active power change of 45%. This implies a decrease ramp rate of 5.625 %Pn/s which is extremely high. This is a requirement which cannot be fulfilled by an internal combustion gas engine. In the draft of the German guideline AR-N-4110 you can also find the response time of 8s, but this response time is connected to the maximum possible power ramp of an internal combustion engine. As a consequence, according to the AR-N 4110 internal combustion gas engines only have to reduce 8.88% power within 8s. Page 10 in the second paragraph, technical	Accepted in a modified way. To be added technological constraint shall be duly taken into account, but not referring to a specific example.

		constraints related to the internal combustion Engine technology to be considered.	
	Technical	The maximum power which is mentioned needs to be defined clearly, for example, maximum registered capacity vs. available capacity and Unit vs. Plant.	Rejected. The defined terminology of RfG is used.
	Technical	IGD does not define the "tolerance ranges".	Accepted. Recommendations on tolerance ranges to be added for each synchronous area.
Eurelectric	Technical	P.3: The constructive capabilities that go beyond the scope of the RfG should be suppressed from this IGD.	Rejected. IGDs occasionally go deliberately beyond the scope of RfG. In such cases it is based on numerous discussions with stakeholders, which have asked for clarifications on shortcomings and missing parameters, etc.
	Technical	P.4: The acronyms 'DSR SFC, APC, RPC' are different from those of the IGD on FSM. They should be replaced or at least explained	Rejected. The defined terminology of DCC is used.
	Technical	P.5: Taking into account a historical incident such as the split that occurred in November 2006 has the advantage of being practical. Yet, do we have an idea of the probability that this happens again despite cooperation and harmonisation on methodologies enforced by SOGL? What was the cost of the incident? What is the cost to hedge permanently against this risk?	Severe disturbances are of a low probability / high impact nature. The likelihood of occurrence or costs of system-wide blackouts are irrelevant, they shall be considered as no-regret incidents.
	Technical	P.5: The sentence 'LFSM-U capability shall not be understood as requiring RES generation to run at a reduced active power output just to be prepared for an increase in case of an unlikely low frequency event.' is really relevant.	Accepted.

		However, it applies to any technology and not only to RES. We therefore propose to remove 'RES' from the sentence for a more technology-neutral approach.	The same principle applies to all generators. LFSM-U capability shall not restrict market-based dispatch. Sentence to be adapted accordingly.
	Technical	P.5-6: The contradiction between LSFM-U requests and issue concerning generating units connected to distribution grid should be removed from this IGD since it deals with system operation rather than with constructive capability. On top of that, we question the 'operational feasibility' of these recommendations: do DSOs have tools to send the remote control to block LFSM in real time? Do concerned generating units have tools to apply this order?	Rejected. Agree, that it goes beyond RfG requirements. However, numerous discussions with stakeholders, in particular DSOs have revealed that the option of blocking is an essential part of the LFSM-U function. Therefore, the ENTSO-E view has been added to the IGD upon stakeholder request.
	Technical	P.11: 'evidently less stringent than what would be needed from a system engineering perspective' See general comment N°2 in the IGD concerning FSM. 'any intentional delay shall be prohibited': in some situations, and to avoid unintentional islanding, the network operator needs to define an intentional delay for some PGM. We propose to indicate that an intentional delay should be activated only at the request of the network operator.	Rejected. Alternative solutions to avoid unintentional islanding need to be introduced. Identification of islanding by frequency excursions is not an appropriate means for systems with high penetration of dispersed generation. Reasons for other situations, which are claimed to need intentional delays are not given.
	other	Any topic out of the scope of the connection codes should be removed from the IGDs, which should only focus on requirements explicitly included in those codes. In particular, it is not the objective of IGDs to make recommendations on all the dynamic aspects of the frequency responses of generation units. The present IGD should stick to a numerical value for the initial delay (limited to 2 seconds). Moreover, some other dynamic aspects recommended are not compatible with some hydro power plants constraints.	Rejected. IGDs occasionally go deliberately beyond the scope of RfG. In such cases it is based on numerous discussions with stakeholders, which have asked for clarifications on shortcomings and missing parameters, etc.
EUTurbines	Technical	System characteristics: in page 5, it is said that system inertia would be lower for small synchronous areas. In our view,	Accepted.

		system inertia and the transient frequency behaviour is not a function of the size of the synchronous area but only of the share of non-synchronous generation in that area.	Sentence to be improved by adding the share of non-synchronous generation.
	Technical	Page 7: we have the following remarks: - Default droop settings are given only for LFSM-O. What about LFSM-U? - Equation for the droop should be generalised to be applicable for FSM and LFSM. - Clarify the time at which the change in active power DP is to be measured for LFSM-U and LFSM-O. - Tsr is measured when the MW reaches the tolerance range. The range and the minimum duration to hold the set value is not defined in the IGD or RfG.	No definite recommendation for LFSM-U droop is given , because it needs to be assessed based on assumptions on volume of generators to participate. Being part of emergency control, it needs to carefully coordinated and aligned with the other defense plans measures to mitigate low frequency events, e.g. LFDD. A generic droop equation may not define unambiguously the LFSM specificities. Time of change of active power is defined through the required response times. Recommendations on tolerance ranges to be added for each synchronous area.
	Technical	Page 8: The first paragraph discusses the response time and refers to different technologies for provision of inertia. It is understood that those response parameters are not related to inertia response performance. If so, it will benefit the common understanding to state this.	We believe it is clear from the text, that it is not about inertial response.
	Technical	Page 9: The response time of max 8 s for a power decrease of 45% is and will not be feasible for all synchronous generator technologies. Therefore, the following needs to be added: “Technologies which inherently are not able to perform a power decrease of 45% within 8 s shall indicate the power decrease which is technically feasible within this timeframe.” Indeed, those 8 s are referring to best available technologies.	Rejected. The currently feasible response times are already close to or even less than current and anticipated system needs. The IGD shall not indicate that manufacturers may be released from making efforts to improve performance.

	Technical	To which Df, Df1 and droop assumption, is the 45% referring to? Moreover, defining conditions for detection of events (such as rate of change of frequency, or any other signals from the grid operator) are necessary for many unit to define optimal strategy (balance reliability and speed of response). We kindly request to also include the following statement: “methodology for detection of a grid split event shall be clearly agreed between plant owner and grid operator”.	The response time and the change of active power shall apply to any droop. The IGD on RoCoF withstand capability defines the criteria for RoCoF detection. In addition, ENTSO-E is preparing a document on frequency and RoCoF measurement criteria.
	Technical	In case a plant is operated at low load and LFSM-O would result in zero load under high frequency conditions, is the plant then allowed to disconnect in order to support system stability or does it have to remain on a stable low load? In other words: is the requirement to remain connected under certain frequency conditions prevailing over the requirement of LFSM-O? IGD shall provide indication whether the generating unit shall disconnect from the grid when LFSM-O drops below its minimum operating load or whether the generating unit shall remain connected to the grid at its minimum operating load.	The IGD on “Making non-mandatory requirements at European level mandatory at national level” suggests a site-specific decision on this requirement.
Orgalime	Other	Recommended values for droop for LSFM are given. No recommendations for LSFM U!	No definite recommendation for LFSM-U droop is given, because it needs to be assessed based on assumptions on volume of generators to participate. Being part of emergency control, it needs to carefully coordinated and aligned with the other defense plans measures to mitigate low frequency events, e.g. LFDD.
	Other	There are no recommendations given in RfG on the response time.	IGDs occasionally go deliberately beyond the scope of RfG. In such cases it is based on numerous discussions with

			stakeholders, which have asked for clarifications on shortcomings and missing parameters, etc.
	Other	Response time and power: PPM (wind) "as fast as possible" - please give some value that can be commented. If it stays 5 seconds, then it is ok. Step response for wind is discussed. What is about the recuperation? After approximately 10 seconds the Wind is normally reducing its power below value that had before the disturbance. In a system this behaviour is having impact that even less active power is being generated i.e. injected into the system. There is no discussion on other PPM. Why?	Information obtained by wind turbine manufacturers indicate, that under certain circumstances 5s is not feasible. In this case, the manufacturer shall provide reasoned justification. LFSM shall not be confused with inertial response through kinetic energy, which would have to be compensated by recuperation. The IGD defines response times for all types of PPM with some extra conditions for wind turbines based on information obtained by manufacturers.
	Other	Settling time: Recommendation for SPGM and PPM strongly depends on the given band. Here is no recommendation on this. If the band tolerance is too small then it might be a problem to achieve settling times. No settling times for PPM ("no wind") recommendations.	Recommendations on tolerance ranges to be added for each synchronous area.
Senvion	Technical	Overall very good IGD. Please align the terms and definitions in the IGD. For example, "Td" (T dead time) on page 8 should be equal to "t initial delay" on page 9.	Accepted. Legend to figure 1 to be adapted.
	Other	Wind turbines are not able to be regulated below 10% of Pn not due to kinetic energy as stated in the IGD but because of mechanical constraints in the gearbox. Below around this operating point of 10% of Pn some mechanical oscillations occur due to the variable change of wind speed and direction	Accepted. Paragraph to be adapted accordingly.

		and can cause damage to the gears. This minimum regulating level depends on the turbine design and is usually around 10% (+/-3%) of Pn.	
VGB	Technical	Page 5: specifies "The economic generation dispatch hence shall not be limited by the LFSM-U performance". So according to RfG, all PGMs can be operated at max. capacity and not only RES as stipulated in this paragraph.	Accepted. The same principle applies to all generators. LFSM-U capability shall not restrict market-based dispatch. Sentence to be adapted accordingly.
	Technical	On page 6 an explanation is given regarding constrains to allow a restriction at DSO level. But due to internal technical reasons in the PGM, the operator can, in line with RfG, limit the LFSM-U. Nothing is said in this IGD about this right of the operator. Why?	We do not understand RfG to introduce a right of the PGM operator to limit LFSM-U capability.
	Technical	Page 7: table 2 describes the droop for LFSM-O. But the droop for LFSM-U is not mentioned in this IGD. Why? Who will define it in order to respect a common value at the level of the synchronous area? Are those parameters not in the scope of the operational codes?	No definite recommendation for LFSM-U droop is given, because it needs to be assessed based on assumptions on volume of generators to participate. Being part of emergency control, it needs to be carefully coordinated and aligned with the other defense plans measures to mitigate low frequency events, e.g. LFDD.
	Technical	Page 8: Figure 1 does not visualise the response times described for SPGMs, and PPMs. Figure 1 mentions "dead time", "step response time" and "settling time", the text only "response time". This has to be written coherently.	Accepted. Change legend to figure 1 (“response time” instead “step response time”).
	Technical	Page 8: A max. response time of 5 s for wind turbines seems too low. Was this value verified with the manufacturers of wind turbines?	The value has been defined based on information obtained by wind turbine manufacturers.
	Other	Too much text without real content for a reading by people familiar with this subject.	Odd statement. One objective of an IGD is to explain the matter to people, which may be less familiar with it.

	Technical	In my opinion, all the LFSM parameters have to be described in the GL SO or in the E&R code (for islanding situations) and not in the IGDs based on RfG NC.	Rather a statement than a comment. No action needed.
WindEurope	Technical	Wind turbines are not able to be regulated below 10% of Pn not due to kinetic energy as stated in the IGD but because of mechanical constraints in the gearbox. Below around this operating point of 10% of Pn some mechanical oscillations occur due to the variable change of wind speed and direction and can cause damage to the gears. This minimum regulating level depends on the turbine design and is usually around 10% (+/-3%) of Pn.	Accepted. Paragraph to be adapted accordingly.
	Other	Overall very good IGD. Please align the terms and definitions throughout the document. For example, "Td" (T dead time) on page 8 should be equal to "t initial delay" on page 9.	Accepted. Legend to figure 1 to be adapted.

Demand Response – System Frequency Control

Commenter	Type of comment	Comment	Remarks
Energy Networks Association	Technical	The IGD explains some of the background and issues and makes a valid point about harmonizing with FCR to avoid unwanted flows. However, as SFC as envisaged in this IGD is implemented in thousands or millions of discrete devices, all of which are likely to be either off or on, it would have been helpful to describe what the expectations are in achieving a behaviour like that of a droop setting. We note that we have the same question regarding how RfG Art 13 2(b) is to be implemented.	Rejected. The combined aggregation of thousand/million devices would give a linear response because of the probability curve for those devices i.e. what the normal distribution of these devices in the cycling between the max to min temperature of the devices. Applying this probability, we would expect that the devices would be in various states between their controlled maximum and minimum temperatures and therefore effecting a change in those targets proportional to the change in system frequency should mean that a linearly proportional number of units will be either switched off or on and hence provide a linear response. The larger the number of units the more statistically likely this is and also the more perfect the response.
Eurelectric	Technical	P.3: Concerning Article 29.2.g of the DCC, would it be possible to explain the meaning of the 2 values '10 mHz' and ‘50 mHz’ as well as the link between them? The IGD explains some of the background and issues and makes a valid point about harmonizing with the FCR to avoid unwanted flows. However, as SFC, the way it is envisaged in this IGD is implemented in thousands or millions of discrete devices, all of which are likely to be either off or on, it would have been helpful to describe what the expectations are in achieving a behavior like that of a droop setting. We note that we have the	Accepted. Explanation needed in IGD. Admissible frequency offset of sensor from the nominal frequency is +/-50 mHz. Insensitivity of frequency measurements is +/-10 mHz.

		same question regarding how RfG Art 13 2(b) is to be implemented.	
VGB	Technical	Page 7: An assumed 10-year replacement cycle for demand units seems extremely short and far from realistic. Adding an instrument (such as a switch or circuit-breaker) for this purpose seems more appropriate.	Rejected. Also 10-year replacement cycle is based on discussion with white goods manufacturers as part of code development, albeit that for large scale commercial devices i.e. chiller freezers in supermarkets this might be longer. However, it is expected that their controllers which would allow for a 'replacement' and this is more likely on a 10-year cycle given the redundancy rate of digital controllers.
	Technical	Page 9: the table contains in several fields the wording "tbd" (to be done???). Is such wording allowed in an IGD that comes into force shortly? When will the table be complete?	Accepted. Changes needed in IGD: "*Work in progress*" instead of "tbd". Parameters still to be defined in later stage for synchronous areas.
	Technical	Page 9: I do not understand the paragraph describing the offset of +/- 50 mHz leading to an accuracy of 10 mHz. But the DCC code is not the main subject of VGB.	Accepted. Similar explanation as above.

	Technical	An aspect that is missing in this IGD is the effect of changing load on the balance position of the supplier. The change of the load is not scheduled by the supplier, it is caused by grid problems. The supplier cannot be responsible for the unbalance due to grid problems. Are the effects of the unbalance at 50.2 Hz or at 49.8 Hz caused by DR-SFC, excluded by the Electricity Balancing code? This comment is also valid for all other unbalances outside the range 49.8 Hz - 50.2 Hz.	Rejected. It is out of scope of the IGD There is no control by suppliers on when demand is used by consumers – they cannot force a demand to rise or fall without implementing this type of control as a DSR service. Therefore, they will be competing for the demand controllability like any other service provider (for example us for DR SFC) if they want to modulate demand. Finally, as balancing will only be required after the system has avoided collapse the DSR SFC action will automatically rebalance the system to the point where other balancing actions can occur and hence if there is service also being provided by the supplier they can implement it then i.e. further reduction or increase on the demands.
VGB	Other	The link mentioned in Reference 1 is not working. Please correct this.	Accepted. Document to be adapted accordingly.
BHKW-Forum e.V.	Technical	page 4+5, System characteristics: The section talks 1,5 pages only about generators, whereas this IGD is about demand response/load shedding. Only at the end of page 5 it begins with the crucial sentence: "An alternative to adjusting generation output to address the load and generation balance is to adjust demand using DR SFC. In principle DR SFC could contribute to simulate either or both FSM, LFSM or a combination of both." It is recommended to talk less about frequency stabilisation with generation, and more about the paralells with dispatchable loads: P(f) as proportional controller (FCR aka primary control) plus an integrative controller (FRR aka secondary control).	Rejected. See explanation regarding FCR in page 4: "frequency containment reserves (FCR) are deployed by generators running in frequency sensitive (FSM) mode". Explanation regarding FRR: DR-SFC is acc. to DCC autonomously controlled, therefore not possible to utilize it in FRR.

	Technical	page 5, system characteristics: "Every power demand unit that has a latent thermal store" - latent thermal store or latent heat is not the correct term, as it is a special heat storage using phase change (solid to liquid, liquid to gaseous) without major temperature changes. The term latent thermal storage excludes ordinary thermal storages which use a delta in temperature. Remove latent. Besides, not only heat storages are suited as dispatchable load, but any storages such as battery storages as in electric vehicles. Remove thermal: "Every power demand unit that has an energy store, for example .... heating/cooling devices and battery storages could be used to provide DR SFC."	Rejected. DCC do not cover energy storage devices. Therefore, battery storages are out of scope and should be avoided as these are not considered demand units. Article 29 applies, generally speaking, to any demand unit capable of modifying energy absorption while remaining within an operating range defined by the manufacturer. So the reference to heating / cooling devices can be just an example. The use of 'latent' was to indicate a device that produces heat or cooling that has a 'store' of heat can provide whatever part of this store it does not need. It was needed to avoid thinking that devices that provide heat directly i.e. a kiln even though it does have a store of heat it cannot be used as the impact would be for the device to not perform its primary function. Therefore, latent was used on the meaning of dormant heat i.e. not being used or underdeveloped.
	Technical	page 6, system characteristics, 2nd para: "Frequency sensitivity increases at low system inertia..." - Frequency sensitivity is a term which is not very well defined in this context and could be mistaken from frequency measurement accuracy. It is better to talk about frequency changes. BTW: at what times? I wouldn't call it activation as each activation and deactivation is a step change of the system, which may stimulate oscillations which need to be damped. "Frequency changes increase at low system inertia and at times with low inertia more frequency stabilizing mechanisms are needed."	Rejected. Frequency sensitivity is well known term in power system dynamics. This term is also used in other IGDs.

		page 6, technology characteristics, 1st para: "In principle, a DR SFC service can be provided by every power demand unit that has an inherent thermal store, for example refrigeration, space heating/cooling, water heating/cooling and any other heating/cooling device." It is not only thermal stores, but any process with an energy storage. Most prominent example ist the battery storage, but you could also see a flour mill as a dispatchable load having storages: one for the grain and another one for the milled grain (flour), the flour is the substance which stores the milling energy. Use instead: "... that has an internal energy storage, for example ..."	Rejected. DCC do not cover energy storage devices. Therefore, battery storages are out of scope and should be avoided as these are not considered demand units.
	Technical	page 6, technology characteristics, 2nd para: "The trigger for this service is a change in system frequency which may be measured at the supply point" - it is unclear if you mean change in system frequency the absolute delta f or the rate of change of frequency or both. The first one would be a fast FCR as in the self-regulation effect and the second would be the emulation of inertia by loads.	Accepted. Explanation needed. Document to be adapted accordingly: “The trigger for this service is a change in system frequency - deviation from nominal value (absolute delta f) which may be measured at the supply point.”

	Technical	page 6, technology characteristics, 4th para: "Therefore tests of this service should only be considered for larger facilities which are already subject to commissioning tests for other network code connection requirements." This is not true. Also smaller unit, compare with PV inverters only a few kW large but massively deployed in electrical networks are type tested and work in a reliable way. "Therefore, the entire control and operation of DR SFC can be built into the device, minimising cost and complexity." This includes the integration of simple controllers into mass market products which are rather small (and not a few MW large for industrial applications). Remove the sentence with larger facilities and commissioning tests, as this does not reflect the reality with type tested small scale generators. There is no reason why not using the same approach for loads.	Partially agreed. Explanation needed. This is a misunderstanding of the reader as to the requirements for compliance testing in the code where the DSR SFC is to be tested by a competent body for the device i.e. a factory test and not a site test. The site testing could be possible for facilities where we are already doing other tests, but is not a binding requirement. The difference is the fact that PV cells will require a installation engineer (it is not plugged into a socket), but plugging in a domestic appliance does not. Therefore, to make onsite testing a requirement would not be practical or justifiable. Document to be adapted accordingly: “Therefore tests of this service should only be considered for larger facilities which are already subject to commissioning tests for other network code connection requirements. For small units compliance equipment certificate may be used for the purpose of replacing specific parts of the compliance process "
	Technical	page 8, technology characteristics, 3rd para: "For the same reasons to avoid the need to implement arbitrary loss of demand customers with Low Frequency Demand Disconnection the full capability of DR SFC should exhausted before LFDD is operated. This will ensure that non-essential load offered for DR SFC by demand users is disconnected before their essential load." It should be explained what essential and non-essential means. Also, it would be fine to introduce in the first sentence selective load shedding: first the non-essential loads disconnect, before the general load shedding schemes shed also essential loads at 49 Hz. Modify the section: "The full capability of DR SFC as selective shedding of non-essential loads should be activated by frequency before LFDD is operated as non-selective load	Accepted. Document to be adapted accordingly: “The full capability of DR SFC as selective shedding of non-essential loads should be activated by frequency before LFDD is operated as non-selective load shedding also affecting essential loads. This will ensure that non-essential loads offered for DR SFC are disconnected before the need to shed essential loads. In this context essential load means an electricity consuming device which the final user directly utilizes and will notice any reduced operation, whereas the non-essential load has an internal buffer which decouples the energy consumption from the practical use."

		shedding also affecting essential loads. This will ensure that non-essential loads offered for DR SFC are disconnected before the need to shed essential loads. In this context essential load means an electricity consuming device which the final user directly utilizes and will notice any reduced operation, whereas the non-essential load has an internal buffer which decouples the energy consumption from the practical use."	
	Technical	Page 9, Table: Tbd for all synchronous areas besides Ireland is a very flexible result. Please be more specific.	Accepted. Changes needed in IGD. "*Work in progress*" instead of "tbd". It needs to be assessed based on assumptions on volume of generators to participate in LFSM in coordination with LFDD. Parameters still to be defined in later stage for synchronous areas.
BHKW-Forum e.V.	Other	The document still had some track changes visible (in German)	Accepted. Document to be adapted accordingly.

Frequency Ranges

Commenter	Type of comment	Comment	Remarks
Energy Networks Association	Technical	Not sure there actually is any technical information in this IGD. It seems to be a restatement of material that is already in the CNCs. If there is a particular point or points that this IGD is trying to get across, it is lost on this reader.	Comment appreciated, but not accepted. According to some stakeholder the IGD adds value.
Senvion GmbH	Technical	f/t ranges summary of RfG on page 5 is wrong. It shall be corrected for IE and NI according to the values from RfG. Why is NI separated in the tables from IE? Why NI shall have longer times than IE? We believe that NI as geographically situated between GB and IE and with AC interconnections to IE shall not have longer frequency withstand times than IE. Why there is now requirement for IE and NI for the frequency range of 47-47.5Hz? In RfG there is no such existing! However it is fine to require this withstand capability but longer time than GB (20s) is not acceptable for all technologies. The table for NI on page 6 is wrong on the high frequency part. It is not logical to require Unlimited time for 51,5-52Hz and limited time (90min.) for the range of 51-51,5Hz. The times for NI on page 6, has to be adjusted according to IE and shall not exceed the times which are currently given for IE. Therefore, IE and NI shall be combined into one column and all TBD values to be removed.	Comment accepted in principle. Values and text reviewed and corrected accordingly.
EUTurbines	Technical	The frequency ranges as defined in the RfG have been developed in coordination with stakeholders, taking into account many	Comment accepted in principle.

		aspects, one of them the technical capabilities of generators. The table on page 5, however, now requires extended frequency ranges for the synchronous area of IE and NI. The exhaustive values given in the NC RfG do not match with the extended ranges in this IGD. Please, correct the values in the IGD according to the binding provisions of the NC RfG.	Values and text reviewed and corrected accordingly.
	Technical	The IGD shall highlight in its content that high and low frequency operations have an impact on the generating unit lifecycle, maintenance and associated operational costs. As a consequence, the system operator shall define appropriate strategy and defence plan to limit rather than enlarging the over-frequency and under-frequency operative conditions. Please, refer to the comments provided by EUTurbines during the public consultation also at the beginning of the year.	Rejected. Operational principles and attributes of the power generating facilities is up to the operators to take care of and inform their capability to the TSO / DSO.
Eurelectric	Technical	(P.2: Two bullet points - 2nd and 3rd of § Introduction - say the same thing) P.3: Regarding the following sentence 'Unless the non-mandatory requirement of article 16(2)(a)(ii) is implemented at national level…', generators would like to report that simultaneous overvoltage and under-frequency provokes over-fluxing that could deteriorate some major equipment such as transformers, alternators and engines. Manufacturers provide curves which specify the maximum duration a unit can withstand before disconnection for a given voltage/frequency ratio. Therefore, generators expect some practical recommendations based on these curves. P.3-4: Would it be possible to clarify the sentence 'For the national implementation of the non-mandatory requirement of NC RfG article 16(2)(a)(ii), no strong evidence of the system need has been demonstrated if the implementation of article 13(1)(a)(i) is following the above-mentioned recommendation.'?	P.2 Rejected. The 2nd is addressing the power generating facilities and the 3rd is addressing the demand facilities. P.3; P 3-4 Rejected. Operational principles and attributes of the power generating facilities it's up to the operators to take care of and inform their capability to the TSO / DSO.

	General	There is no recommendation on the time period in application of Article 16(2)(a)(ii), that is a shorter period in case of simultaneous over-frequency + under-voltage and under-frequency + over-voltage. So, the sole effective recommendation is the time period associated to the high level of frequency deviation: we do wonder if this justifies a dedicated IGD.	Comment appreciated, but not accepted. According to some stakeholder the IGD adds value.
ENERCON	Technical	1/ page 2: "... wider frequency ranges, longer minimum times..." =>ENERCON as a manufacturer considers that technical requirements that go beyond the ones defined in RfG should be subject to a national market of "system services", as already happens in some EU countries. 2/"...simultaneous overvoltage and under-frequency..."... => Independently of the technology PPM or synchronous, the transformer is the limitation in terms of its over-excitation. 3/ page 4 : "Despite choices need to be made at national level.... collaboration between TSOs at synchronous level is necessary"......=> necessary, avoiding unreasonable discrepancies in the level (toughness) of requirements at regional level, for example within countries sharing same sub-region like Portugal, Spain and France."	1/ Comment appreciated, but not accepted. It's fully correct that the guidance to the TSOs is going beyond the NC RfG specifications, but that's what requested from the TSOs. 2/ Comment appreciated, but not accepted. It's up to the TSO / DSO to secure the system security limits of the network components is within the component specifications. 3/ Comment appreciated, but not accepted. It's up to the TSO / DSO to secure the system security limits of the network components is within the component specifications.

VGB	Technical	This code repeats only the requirements of the RfG code. The most important item in this IGD is the sentence on page 2 : "the relevant TSO may specify shorter periods of time during which power-generating modules shall be capable of remaining connected to the network in the event of simultaneous overvoltage and under-frequency or simultaneous under-voltage and over-frequency". This is a really serious issue but the IGD does not offer any guidance to TSOs to solve this issue. Why can (or will) ENTSOE not offer guidance?	Comment appreciated, but not accepted. According to some stakeholder the IGD adds value.
	General	This is an IGD without any added value.	Comment appreciated, but not accepted. According to some stakeholder the IGD adds value.

Maximum Admissible active power reduction at low frequencies

Commenter	Type of comment	Comment	Remarks
Energy Network Association	General	The IGD contains background on this issue, but adds little to the implementation.	Noted.
Senvion	Technical	The following message on page 10 is wrong! 1. According to the wind industry, wind farms based on full converter technology have no difficulties to keep steady state operation with rated frequency with plus or minus 7Hz. - this is true only for one or few manufacturers who's auxiliaries are supplied through full scale converter as well. For full scale wind turbine generators where the auxiliaries (like small motors, pumps, SCADA controllers) are supplied through a step up transformer the frequency range is smaller and can be limited by any of the auxiliaries. Proposal: add message that the full converter based PPM's usually have larger than the required by RfG frequency ranges and each TSO may decide use the whole range of the PMM performance. 2. Wind farms based on DFIG technology do not need to reduce active power at low frequencies while frequency stays within the frequency ranges defined in NC RfG article 13(1). - this is true only if DFIG system is overdesigned (more expensive). At low frequencies and high active power the system currents are higher. Therefore, the whole wind turbine has to be designed for these cases. In the current environment with constant price push such DFIG systems are difficult to be designed. Therefore, in such cases there shall be at least reactive power reduction allowed in order to keep the wind turbine system currents below the limits.	Statement provided in the current version of the IGD has been provided by stakeholders in the survey organized by ENTSO-E. Based on the comment received, we acknowledge that presence of set-up transformer or the use of some technology could impact the wind farm output power with falling frequencies. Requirement remains however unchanged (table of page 8), which is deemed acceptable for PPM In the IGD, the wind farm section of the "Technology characteristics" part has been updated: *"According to the wind industry, wind farms based on full converter technology have very limited reduction of active power at low frequencies. Impact on active power is mainly due to auxiliary equipment and change of losses in step-up transformers. Additionally, wind farms based on DFIG technology do need to reduce slightly more the active power at lower frequency to compensate the increase of current related to the decrease frequency.* *These limitation for wind technology do not prevent wind generation to comply with the most onerous specifications allowed by the RfG. Furthermore, the initial reactive power output and the acceptability of a P over Q priority control scheme at low frequencies could further increase the wind*

		Proposal: In this IGD proposal for P over Q priority in case of low frequencies must be introduced as well.	*farm capabilities keep constant active power with falling frequencies."* In the IGD, the following has been recommended: *"Furthermore, it is recommended for the national implementation of the NC and for the compliance verification process that these define the following* *- initial voltage defined within the normal operation range (It must be acknowledged that deviation of the voltage outside of the FRT profile or steady-state voltage range could lead to PGM disconnection)* *- initial reactive power output at which the capability needs to be proven* *- mainly for PPM, the acceptability by the Network Operator of a P over Q priority control scheme at low frequencies.*
EU Turbine	Technical	Transient / steady state behaviour - relation to ambient conditions The IGD clearly states that the transient behaviour of the generators during the decline of frequency is of much higher importance for system stability than the steady-state behaviour. Under steady-state conditions (after the decline), power and demand are balanced and, therefore, the need for a certain level of output is not relevant anymore. Only the inherent (physical) behaviour of a generating unit is relevant for system stability. Any control actions during a frequency transient, to compensate for the inherent power loss, will be too late or even might further disturb the system e.g. when frequency is stabilised. Any requirement which does not consider the inherent behaviour would therefore	We do not share the view the steady-state power is not relevant anymore. Both transient and steady-state behaviour are of great importance to secure the power system. As shown in the IGD, temperature can have a major impact on the capability of the power plant to fulfill the requirement. Therefore, in order to aim support quality and reliability of system studies and to ensure sufficient level playing field, we would recommend harmonizing ambient temperature used for the definition of the requirement. However, together we a requirement defined at a reference ambient temperature at 25°C and the provision of the expected characteristic at a set of temperatures, the verification of compliance could be provided at other temperature that the one at which the requirement is defined.

		exclude this technology from access to the system, disregarding all other benefits of this technology. For SPGMs, it has to be taken into account that during a frequency drop (i.e. when the requirement is important) the inertia power response compensates the inherent power reduction to a certain amount (depending on the RoCoF). On the other hand, the NC RfG clearly states that each Member State has to define a requirement on Admissible Active Power Reduction at Low Frequencies. The IGD combines this need with the a.m. physical facts in the recommendation to define a very stringent transient behaviour (upper limit of the allowed range in Art 13 (4) & (5) and a relaxed steady state behaviour (lower limit of allowed range). Compliance with this requirement is for certain technologies (in particular for Gas Turbines) only possible under certain ambient conditions – due to the fact that they show a strong relation between inherent power loss and ambient temperature. Hence, it does not make sense to link the requirement to a fixed ambient temperature. A real test of compliance is not possible. Therefore, only a manufacturer statement based on calculations and simulations can be used as a prove of compliance. EUTurbines therefore proposes the following clear and simple approach: - Keep the recommended required values of the table (p. 8) in the IGD for transient and steady state domain as they are, in order to comply with the RfG need to state a requirement. - Require from SPGMs on a project-specific basis the inherent power vs. frequency characteristics (without any	

		power compensation control measures) with ambient temperature as a variable parameter, to be used for system stability studies and design. This calculation can be done e.g. for a defined frequency over time curve. Only such approach allows a simultaneous compliance with NC RfG and a feasible compliance process based on clear requirements with minimum complexity. EUTurbines is available to provide support to find an adequate wording to present the information in the IGD. We would welcome a request to propose and agree on a dedicated wording.	
German TSOs	No comment		Noted.
Eurelectric	Technical	Not appropriate	Noted.
	Other	Hydro generation should be studied as precisely as CCGTs and combustion turbines because hydro plants also have some constructive limits that do not permit to avoid the instantaneous decrease of active power.	Noted. The guiding principle provided in the technical characteristics section were draft based on: • the TSOs experience • the outcome of the stakeholder consultation on technical capabilities of generation technologies related to frequency stability related requirements. (May-June 2017) • Public stakeholder workshop on initial considerations on recommendations values/ranges for parameters of frequency stability related requirements (July 2017)

			• Public stakeholder workshop Frequency Stability Parameters for Connection Network Code Implementation (October 2017) No concerns for hydro generation with regards to the guidance on the requirement related to “Admissible active power reduction at low frequencies” were shared by stakeholders with ENTSO-E. Therefore, ENTSO-E do not see the need to guide national implementation of the NC for new hydro units with regards to Admissible active power reduction at low frequencies. The following sentence has however been added in the guiding document *“Some challenges have also been reported for other technologies, namely internal combustion gas engines or hydro units without that, taking into account the guidance provided in this document, the capability to fulfill the proposed implementation of this network code requirement.”*
	Technical	As previously mentioned in GENERAL COMMENT 1 for IGD/LFSM, dynamic aspects should be removed from this IGD. Indeed, the distinction between transient and steady-state is not described in the RfG (Art. 13.4&5). This requirement should be understood for steady-state only, since the allowed limits (Fig. 2) are not compatible with the inherent constraints during the transient stage of some technologies, among which CCGTs but also hydro plants.	It is acknowledged by a large number of stakeholders and TSOs that there is an added value for defined transient requirement. Furthermore, the NC RfG does not explicitly mention steady-state behavior. It is therefore proposed to keep the requirement on transient conditions in the non-binding guiding document and may be considered to go beyond the explicit requests of NC RfG on matters which are nonetheless relevant to ensure an adequate performance of the power system.
ENERCON GmbH	Technical	Page 1: "As PPMs and many topologies of SPGM do not have specific technology limitation...." ==> Not completely true! Wind Turbines transformers cannot be neglected.	Statement provided in the current version of the IGD has been provided by stakeholders in the survey organized by ENTSO-E.

			Based on the comment received, we acknowledge that presence of set-up transformer or the use of some technology could impact the wind farm output power with falling frequencies. Requirement remains however unchanged (table of page 8), which is deemed acceptable for PPM In the IGD, the wind farm section of the "Technology characteristics" part has been updated: *"According to the wind industry, wind farms based on full converter technology have very limited reduction of active power at low frequencies. Impact on active power is mainly due to auxiliary equipment and change of losses in step-up transformers. Additionally, wind farms based on DFIG technology do need to reduce slightly more the active power at lower frequency to compensate the increase of current related to the decrease frequency.* *These limitation for wind technology do not prevent wind generation to comply with the most onerous specifications allowed by the RfG. Furthermore, the initial reactive power output and the acceptability of a P over Q priority control scheme at low frequencies could further increase the wind farm capabilities keep constant active power with falling frequencies."*
	Technical	Independently from the technology, PPM or Synchronous, embbed a transformer which has its own limitations in terms of overexcitation 'overvoltage and underfrequency..."	In the IGD, the following has been recommended: *"Furthermore, it is recommended for the national implementation of the NC and for the compliance verification process that these define the following* *- initial voltage defined within the normal operation range (It must be acknowledged that deviation of the voltage*

			outside of the FRT profile or steady-state voltage range could lead to PGM disconnection) *- initial reactive power output at which the capability needs to be proven* *- mainly for PPM, the acceptability by the Network Operator of a P over Q priority control scheme at low frequencies.*
Orgalime	No comment		Noted.
EUGINE	Technical	The proposal of having a "transient" and "steady state" can be helpful, but forces units to reduce very little during the first 30 seconds of the frequency variation. The different manufacturers need to give a statement on whether or not they can withstand such operating conditions when the frequency (unit speed) is reduced.	Noted, consultation was opened to all.
	Technical	Page 10 gives no mention of the issues that internal combustion gas engines face when operating at lower frequencies (keeping the same power output results in increase of the medium effective pressure in the cylinders and also reduced mass flow in turbo chargers). EUGINE therefore kindly requests that the following text is added on page 10: "Keeping a constant power output at lower frequencies results in an increase of the medium effective pressure in the cylinders, causing an overload operation that can have an effect on the lifetime and maintenance intervals of the units. The reduction in mass flow of the turbo chargers can reduce the boost pressure causing power reduction. Additionally, there is a compressor surge risk associated with this operation condition. Like all	The challenge for internal combustion gas engines has been noted but it is important to highlight that the frequency of occurrence of large frequency deviation (i.e. frequency below 200mHz) is expected to be rare. Therefore, it is not recommended to take into account a significant impact on the lifetime and maintenance intervals of the PGM in order to define the technical capability of the PGM. Therefore, ENTSO-E do not see the need to guide national implementation of the NC for new internal combustion gas engines with regards to Admissible active power reduction at low frequencies. The following sentence has been added in the system characteristics section of the guiding document:

		dynamic behavior of IEC (internal combustion engine) the possibility of constant power output at lower frequencies is based on the methane number as well. In general, a lower methane number means lower capability to maintain constant power output at lower frequencies."	"However, large frequency deviation (i.e. frequency below 200mHz) are expected to be very rare. Nevertheless, the consequence of not having a sufficient support for running generating units can be very large. This is the reason while this requirement is a major important to ensure the stability of the power system." In the Technology characteristics section *"Furthermore, as mentioned in the system characteristics sections, the frequency of occurrence of large frequency deviation (i.e. frequency below 200mHz) is expected to be rare. Therefore, it is not recommended to take into account a significant impact on the lifetime and maintenance intervals of the PGM in order to define the technical capability of the PGM when implementing the network code or assessing potential derogation requests."* *"Some challenges have also been reported for other technologies, namely internal combustion gas engines or hydro units whithout that, taking into account the guidance provided in this document, the capability to fulfill the proposed implementation of this network code requirement."*
	Other	1. On page 6, the last paragraph mentions "… significant amount of SPGM is linked to the maximum expected RoCoF for the normative incident in case of significant penetration of SPGM within the synchronous area.", did you mean PPM instead of SPGM.	Sentence is correct but has been further clarified. It leads to the following: *"in presence of a significant amount of SPGM (low PPM penetration), the maximum speed at which the system can reach 49Hz is expected to be 0.5s. This is in line with the IGD of RoCoF which recommends a withstand capability of 2Hz/s for SPGM, having for consequence that 49Hz could be reached after 0.5s for the normative incident. The desired system value for t1 would then be 0.5s. However, taking into account current reaction and response limitations of SPGM*

			technologies, a value of t1 ≤ 2s could be acceptable in line with the time defined for similar facts in the context of FSM capabilities."
	Other	2. The following statement in page 9 is not clear: "This net additional active power output should be demonstrated at the connection point and therefore it is expected that the control system acting on the power of the primary energy source should, in addition to the increase of this power compared to the 50Hz value, further increase this power to compensate for any active power reduction at low frequencies discussed within this IGD."	The term "net additional active power output" has been defined for enhance clarification. *"where the "net active power output" is the active power exchange between the PGM and the network at the connetion point"*
VGB	Technical	Page 6: The RfG code does not mention the notion "transient characteristics". Is it legally allowed to specify requirements in an IGD without approval by the XBC? Do such requirements have any legal value? I propose to delete this.	It is acknowledged by a large number of stakeholders and TSOs that there is an added value for defined transient requirement. Furthermore, the NC RfG does not explicitly mention steady-state behavior. It is therefore proposed to keep the requirement on transient conditions in the non-binding guiding document and may be considered to go beyond the explicit requests of NC RfG on matters which are nonetheless relevant to ensure an adequate performance of the power system.
		Page 8: The table contains several values. Did ENTSOE submit those values to manufacturers such as Siemens or General Electric for all kinds of PGM technologies? What was their position?	Indeed, the draft IGD were open to public consultation and public stakeholder workshop. All comments received have been taken into account.
		Page 10: References are made to the wind industry and gas turbines. But did ENTSOE also contact manufacturers of hydro PGMs? What is their position?	The guiding principle provided in the technical characteristics section were draft based on • the TSOs experience • the outcome of the stakeholder consultation on technical capabilities of generation technologies

			related to frequency stability related requirements. (May-June 2017) • Public stakeholder workshop on initial considerations on recommendations values/ranges for parameters of frequency stability related requirements (July 2017) • Public stakeholder workshop Frequency Stability Parameters for Connection Network Code Implementation (October 2017) No concerns for hydro generation with regards to the guidance on the requirement related to "Admissible active power reduction at low frequencies" were shared by stakeholders with ENTSO-E. Therefore, ENTSO-E do not see the need to guide national implementation of the NC for new hydro units with regards to Admissible active power reduction at low frequencies. The following sentence has however been added in the guiding document *"Some challenges have also been reported for other technologies, namely internal combustion gas engines or hydro units without that, taking into account the guidance provided in this document, the capability to fulfill the proposed implementation of this network code requirement."*
		Page 14 gives the characteristic of a CCGT at several ambient temperatures. Only for temperatures below 0°C, a CCGT is compliant with the RfG diagram in the range 49.5 Hz - 50 Hz. On page 9 is written :"The UK Grid code defines 25° C as reference ambient temperature to meet the requirements. It is proposed to apply this reference to all technologies." I see a contradiction between the diagram on	The sentence has been rephrased to clarify that the different concepts explained in the IGD are coherent. *"The UK Grid code defines 25° C as reference ambient temperature to meet the requirements. It is proposed to apply this reference to all technologies. It must be highlighted that CCGTs have been complying with the UK*

		page 14 and the sentence 'It is proposed to apply this reference (meaning 25 °C) to all technologies. More explanation is desired.	*requirement for many years and have developed therefore efficient and cost-effective solutions. The capabilities of these CCGT designs should not be confused with the capability of existing CCGT based on a basic design as illustrated in the Technology Characteristics section below."*
	Other	Congratulations with the valuable statement on page 11: "Furthermore, the verification of compliance might be complex and shall be agreed with the power generating facility owner case by case." This sentence applies for all technologies.	Noted.
Wind Europe	No Comment		Noted.
BHKW-Forum e.V.	No Comment		Noted.

Automatic connection/reconnection and admissible rate of change of active power

Commenter	Type of comment	Comment	Remarks
Energy Networks Association (GB)	Technical	This IGD does nothing to advance the issue and simply states the obvious. It might be more helpful if there was a different setting on frequency and voltage protection envisaged (if indeed such protection is expected) from that allowed for reconnection. If there was a differential it would help if this IGD explained why and how it had been arrived at. It would also make sense to consider a timer that prohibits reconnection after a certain dead time – on the basis that a longer dead time is more likely to be associated with a more serious and widespread event.	Comments appreciated and understood. As seen from the revised IGD the variability in how this function is implemented in the various areas are quite numerous. The individual TSOs/DSOs have different system defence and system restoration strategies on this issue. Dynamic assessment studies are the background for selection of the various parameters. The proposal for a time out window is also observed in some countries. The remark about a time-out window will be implemented in the IGD.
Eugine	Technical	This IGD does address relay protection clearance, but the explanation is not adequate. The readiness of the plant of the disconnected components needs to be considered for reconnection before accounting the observation (Tobs).	Comments appreciated and understood. The reason for specifying a minimum observation time opens up for the said problem. The grid connection requirement is minimum observation times so it's up to the facility to reconnect when ready after the observation time has expired. As seen from the EU regulation 2016/63- NC RfG preamble (20) the protection concerns is a major part to ensure.
Eurelectric	Technical	P.2: The HVDC code evokes the conditions for automatic disconnection specified by the RSO. What about the reconnection?	Comment appreciated and understood. Automatic reconnection is not relevant for HVDC systems as an autonomous function.

	Technical	P.2: What is the definition of 'incidental disconnection'? We understand this concerns only incident on the grid and incidents that are not internal to the unit.	Comment appreciated and understood. An „incidental disconnection“ is not a defined term in the EU regulation 2016/63- NC RfG. As seen from EU regulation 2016/63- NC RfG, Preamble (20) and article 145(4)(a) the incidental disconnection is only concerned about network disturbance in the network and not incidents in the power generating facility.
	Technical	P.5: The French numerical value for maximum gradient corresponds to MV connected generators. Therefore, the value is correct, but only for MV connected generators. We propose to mention it.	Comment appreciated and understood. The intention of the IGD is not to discuss all specialties observed, but to give a general guidance to the TSO's on how this requirement could be implemented as a minimum. The relevant TSO have to specify the requirements for automatic reconnection for their control area.
	Technical	It might be more helpful if there was a different setting on frequency and voltage protection envisaged (if indeed such protection is expected) from that allowed for reconnection. If there was a differential it would help if this IGD explained why and how it had been arrived at.	Comment appreciated and understood. The specifications in the EU regulation 2016/63- NC RfG are concerned about conditions for automatic reconnection, which is the scope of the IGD. Protection settings are specified in another part of the EU regulation 2016/63- NC RfG and are out of scope for this IGD.
	Other	COMMENT 3: Some examples of present practices in some countries are provided in the IGD on automatic (re)connection. Such an overview is very interesting and even necessary to evaluate the steps leading to harmonisation. We regret that there are so few countries in the list. At least 6 or 7 of the widest countries, in terms of annual production, should be included since they have a major impact on frequency control.	Comment appreciated and understood. The individual TSOs decide if they want to add their specifications to the IGD or not.

EUTurbines	Other	There is sometimes a mismatch between the typical times provided in the IGD page 5 and technical capabilities. In the definition, it is indicated that automatic reconnection is related to connecting the generating unit after an incident (disconnection due to perturbation on the grid) or at start-up. The last one (at start-up) collides a bit with the definition of Normal connection after stand still. We recommend deleting “at start-up” or improve / clarify the definition. In addition, there had been cases for which the frequency, even if stable, continued to stay out of the permitted band (especially in countries where the frequency upper limit is 50.05 Hz) for a long period even if in stable condition. The IGD shall clarify that in such cases, the operator is allowed to manually initiate the synchronisation process – eventually in agreement with the system operator – and that such a solution is an option.	Comment appreciated and understood. Text will be checked for inconsistency and clarity. It’s always up to the relevant TSO to specify the conditions for automatic reconnection in each system state. The control strategy could be different from one system state to another.
Orgalime	Other	What about energy storage?	Comment appreciated and understood. Energy storage is out of scope of the EU regulation 2016/631 NC RfG so that’s why it not addressed in the IGD.
Senvion	Technical	In methodology the following text has to be removed: "Some TSOs may distinguish between reconnection after a frequency disturbance and automatic connection at start-up. The frequency range for automatic reconnection after a frequency disturbance could be limited." Reasoning: There can be cases where some generators will disconnect due to voltage disturbance and some may disconnect due to frequency disturbance. Therefore it shall be only one ramp rate applicable to all generators as already being used in many EU states (listed in	Comment appreciated and understood. The IGD is not a methodology, but a non-binding guidance to the TSOs in the ENTSO-E might follow or they can create their own specifications. The guidance is based on the general outcome of system dynamics simulations and as such will have local variability on voltage ranges and time window for observation before a facility is allowed to automatic reconnect.

		the examples part). Is there any evidence/study showing the advantage (cost-benefit) of such auto reconnection to distinguish between different type of grid faults?	So, the statement that “only one ramp rate” must be specified is not accepted as a general guidance. It’s always up to the relevant TSO to decide and specify.
VGB	Technical	Page 4 : I fear that the proposed frequency range 49.9 Hz - 50.1 Hz is too narrow in case of restoration of the grid. During a blackout, all DSO connected PGMs are out of service and have to be reconnected. During restoration, the frequency will vary between 49.8 Hz and 50.2 Hz. Smaller PGMs will not help to restore the network due to the observation time of 60 sec.	Comment appreciated and understood. It’s always up to the relevant TSO to specify the conditions for automatic reconnection in each system state. The control strategy could be different from one system state to another. We agree that a wider frequency range could add more value to the system restoration process and has revised the recommendations according to dynamic simulations assessment studies for the various synchronous areas. We disagree on the statement “Smaller PGMs will not help to restore the network…” as smaller PGMs could be aggregated and as such could be the only power generating facilities in some areas.
WindEurope	Technical	In methodology the following text has to be removed: "Some TSOs may distinguish between reconnection after a frequency disturbance and automatic connection at start-up. The frequency range for automatic reconnection after a frequency disturbance could be limited." Reasoning: There can be cases where some generators will disconnect due to voltage disturbance and some may disconnect due to frequency disturbance. Therefore, it shall be only one ramp rate applicable to all generators as already being used in many EU states (listed in the examples part). Is there any evidence/study showing the advantage (cost-benefit) of such auto reconnection to distinguish between different type of grid faults?	Comment appreciated and understood. The IGD is not a methodology, but a non-binding guidance to the ENTSO-E members. The TSOs might follow the guidance or they can create their own specifications. The guidance is based on the general outcome of system dynamics simulations and as such will have local variability on voltage ranges and time window for observation before a facility is allowed to automatic reconnect. So, the statement that “only one ramp rate” must be specified is not accepted as a general guidance. It’s always up to the relevant TSO to decide and specify.

Rate-of-change-of-frequency withstand capability (RoCoF)

Commenter	Type of comment	Comment	Remarks
BHKW-Forum e.V. (DE)	Technical	Page 2, Introduction, 3rd para: "Please note that this IGD would be updated in respect to frequency measurement criteria once the outcome of task force on this topic is finalized and published." - Please note that there is a working group WG07 TC8X CENELEC on power frequency management that is drafting technical requirements. If would be helpful if the above-mentioned task force on frequency measurement joins that standardization WG, as the outcome of that CLC work will not only be a non-binding IGD but a technical document to be used in industry as drafted in consensus based collaboration. Sooner or later it will probably be transferred to IEC and will then have global consequences. Please get involved - the earlier the better.	This is more of a statement rather than a comment. No action necessary.
	Technical	Page 4, last para "up to 1800 MW in GB which would commonly exceed the until recent existing GB threshold level of RoCoF-based Loss of Mains (LOM) protection [0.125 Hz/s])" - In GB the threshold of 0.125 Hz has been risen recently and the vector shift for LOM detection has been forbidden. Please correct figures. http://www.dcode.org.uk/current-areas-of-work/dc-0079.html	Accepted. Revision would be done.
	Technical	Page 6, technology characteristics, 4th para: "This again indicates the importance of time window size." - It is also important to point out that the time window for determining the immunity is a different one than the time window for ROCOF calculation as part of a control chain e.g. for synthetic inertia. This must be logically happening much faster than the 500 ms immunity check. If there is an ROCOF of 2 Hz per second, after 0,5 s we already have a frequency deviation of 51 or 49 Hz. Any corrective measure based on ROCOF aka synthetic inertia needs to be	There might be misunderstanding on the measurement time window and synthetic inertia activation time. It is important to note that any response is assumed to be as fast as technically possible and the measurement time window for RoCoF is only for compliance monitoring.

		much faster. Add: "the time window for ROCOF measurement for control actions will most probably be a different one."	
	Technical	Page 7, technology characteristics, proposed diagrams: Any inverter based generators may in principle survive a very wide ROCOF window, if the control of the whole unit is fine-tuned accordingly - but in principle no need for hardware changes. Generators based on synchronous machines, especially lightweight built aero derivative gas-turbines and turbo charged combustion engines have their limitations according to the torque applied to the shaft. So, it is the max ROCOF which causes problems, and rather not how long to operate at a frequency offset - this has to be harmonised with the mechanical stress during an FRT event. The figures are overkill and too complicated to verify, simple ROCOF immunity dates are sufficient enough.	Accepted, although there is more information rather than comment.
	Other	line numbering would be helpful for commenting	Noted
Enercon	Technical	“The selection of the maximum (df/dt) values to be withstood needs to be chosen by collaboration between the connection codes…” –When is this collaboration taking place and will industry be consulted? It is important that industry receives the opportunity to comment on the values.	During the implementation the values are already consulted by stakeholders.
	Technical	“It however becomes relevant now during significant load-generation imbalances, when larger RoCoF values may be observed because of low system inertia caused by (amongst others) disposal of synchronous generation in case of high instantaneous penetration of nonsynchronous connected generation facilities”. This is not strictly the case as R&D studies have demonstrated that high RES penetration does not necessarily correspond to high RoCoF [1] & [2]. [1] : D. Flynn et al, Inertia Considerations within Unit Commitment and Economic Dispatch for Systems with High Non-Synchronous Penetrations, 2015.	This is important to note that the research shows that the RoCoF will increase by increase of nonsynchronous penetration unless there would be mitigation actions considered to provide inertia or redispatch.

		[2] L. Ruttledge, D. Flynn, Short-term frequency response of power systems with high non-synchronous penetration levels, 2015.	
	Technical	“This capability is to be verified with a specific /predefined frequency profile and explicit measuring technique.” Does this refer to unit type testing methods or performance monitoring? To what extent does the measuring technique need to be made explicit?	Text has adapted. Although, we will not address the technique rather the measurement criteria which is error of ±1 mHz/s in 500ms measurement time window.
	Technical	“Following profiles are hence the WG CNC recommended profiles taking 2.0 Hz/s for duration of 500 ms as the minimum RoCoF to be withstood.“ Are the values 2Hz/s and 500ms the recommended values for any or all synchronous area in Europe? It is not practical or necessary to impose these values as blanket recommendations for all synchronous areas. Does "minimum RoCoF to be withstood" imply that TSOs should not set their own RoCoF requirement to be smaller than 2Hz/s? Does "following profiles are hence…" refer to the two figures? If yes, I would suggest rewording as: "The proposed over-frequency and under-frequency profiles are hence..."	Accepted. The text would be reviewed to address the ambiguity.
	Other	When setting up requirements regarding “robustness against RoCoF” also “robustness against vector shifts” is a related aspect that requires definition and guidelines. In case of synchronous generation extreme vector shifts may lead to severe mechanical stress, maybe even tripping. In case of non-synchronous (inverter-based) generation it is at least a challenge to keep track with extreme vector shifts. Without putting clear robustness requirements TSOs would implicitly allow tripping of PPMs under such events.	This seems to be a technical comment but out of scope of this IGD. This is a valid comment which requires studies to be initiated especially looking into the upcoming control schemes (Grid forming) and system needs.
	Technical	It is a description of the issues etc., but does not really go as far as making any helpful suggestions.	Noted

Energy Networks Association	Technical	We note that it suggests measuring over 500ms – but it fall short of explaining how reliable, accurate and repeatable measurements might be made.	This would be forwarded internally and possibly CENELEC.
	Technical	The graph lacks units on its X and Z axes. We can guess that the X axis is Hz/s, but it is not easy to guess what the units on the Z axis might be.	Rejected. All graphs have axis-labels
EUGINE - European Engine Power Plants Association	Other	On page 6 this document states that synchronous power generating modules can at least withstand 2.5 Hz/s with 100 ms time window. It needs to make a reference of where this was studied or presented, and clearly define to which technologies it applies.	The values are extracted from Stakeholders' feedback to the survey on "ENTSO-E Connection Codes Implementation Guidance Documents_Frequency Stability Parameters". The values are removed from the IGD.
	Other	Add "figure 3" from the following document on page 6 when the importance of time window size is mentioned: http://www.soni.ltd.uk/media/documents/Archive/RoCoF%20Modification%20Proposal%20TSOs%20Opinion.pdf	Accepted but no action taken.
Eurelectric	Technical	P.2: When will the works of the task force on frequency measurement begin? Will the stakeholders be involved?	ENTSO-E has initiated the task force and the documents would be published consequently. The focus is the measurement criteria rather than technique.
	Technical	P.6: 'repetition of high RoCoF events': there should be a maximum number, here.	This is mainly an issue of equipment stress and not scope. Also, such high RoCoF events are very unlikely to happen.
	Technical	We note that it suggests measuring over 500ms – but it fall short of explaining how reliable, accurate and repeatable measurements might be made. The graph lacks units on its X and Z axes. We can guess that the X axis is Hzs-1, but it is not easy to guess what the units on the Z axis might be.	Responded above.

	Other	P.2: To complete the second paragraph 'The resulting RoCoF … related requirements', Recital N°25 of the RfG states: 'Synchronous power-generating modules have an inherent capability to resist or slow down frequency deviations, a characteristic which many RES technologies do not have. THEREFORE COUNTERMEASURES SHOULD BE ADOPTED, to avoid a larger rate of change of frequency during high RES production. Synthetic inertia could facilitate further expansion of RES, which do not naturally contribute to inertia' The IGD does not provide any information on counter-measures that should be adopted by the TSOs. Moreover, the synthetic inertia does not represent, in the present state of the art, a real countermeasure.	The 2Hz/s is while considering the contribution from the synthetic inertia. (system inertia is continuously under monitoring and the development of Synthetic inertia would ...)
EUTurbines	Technical	SPGMs are not generally capable of withstanding a RoCoF of 2,5 Hz/s as stated in the IGD. Manufacturers are not aware of having given this value.	Responded above.
	Technical	The SPD report (https://www.entsoe.eu/Documents/SOC%20documents/RGCE_SPD_frequency_stability_criteria_v10.pdf), among others, refers to 2 Hz/s – but we would be cautious and question some of its assumptions. We indeed understand there are means available to the Grid Operators to ensure that the rate of change of frequency remains below acceptable values.	Noted
	Technical	Inertia seems overly low in some regions, assuming that synchronous technology (including hydro) may not be connected anymore. We would challenge this assumption.	Regarding the equation, reduce in total inertia would lead to higher df/dt.
	Technical	The highest rate of change of frequency only happens for largest load imbalances (40%?). Certainly, System Operating Guidelines could make sure acceptable level of load imbalance is not infringed in order not to endanger the grid stability.	This might be very expensive as it requires redispatch.

	Technical	We felt the indication of 2.5 Hz/s misleading during our discussion in many national codes, where such value had been assumed as a self-standing value, not associated, for example, to a time-rolling window.	The given 2.5 Hz/s in the IGD is with time-rolling window of 100ms (indicated as well).
	Technical	Page 6: There is an explicit inconsistency in RoCoF requirement between two studies given in the supporting documents on page 3.	The recommended requirements are addressing the system needs. The references are rather for wider and more information.
	Technical	This comment seeks to request the reasons why this IGD is not fully considering the finding of the Kema-DNV study reference [13]. Additionally, to the importance of window size, the Kema-DNV study shows that out of 8 different SPGM technologies, a 2 Hz/s RoCoF value over 500 ms is not achievable with most of generation sets, apart from the small OCGT and the salient multiple-pole Hydro machine as exceptions (see executive summary). Despite this result, the ENTSO-E WG SPD reference [7] recommends RoCoF profile withstand capability to 2 Hz/sec over 500ms as a minimum.	The study done by KEMA-DNV only analysed existing generators/technologies. The 2Hz/s can be achieved by investment in design and controllers. (future generation, system needs)
	Technical	There is an apparent inconsistency in defining such capability, with the SPD study focusing on the transmission network performance during large power imbalance and disregarding the outcome of the Kema-DNV study and subsequent discussion in Ireland and GB. The requirement and studies should focus on the capability at the generator unit level; not only at the performance of the transmission network. A detailed investigation is required with a full network representation focusing on the generating units considering the operating range, excitation system performance, benefit of fast frequency response from non-synchronous generation, the difference between islanded networks in a power deficit situation versus an island in surplus of generation. We believe that the proposed values are not in line with studies on RoCof performed by O&Ms and Kema.	The main inputs to the grid requirements are the system needs. Of course, the technical capability of the users is considered as the constraints. The discussions and studies mentioned are not available or named here to have the argument. The SPD results are considered to be sufficient for the understanding the system needs and to conclude the RoCoF withstand capability. Of course, more detailed and sophisticated studies would be required for further investigation of Generator designs and system behaviour.

	Technical	We also believe that the use of transmission infrastructural investment and better protection coordination as a means of improving RoCoF at a location weakly interconnected should be more effective and should not lead to such wider requirement than those proposed in GB or Ireland. We would recommend the use of a lower value (1Hz/s) associated to a longer rolling window (500 ms) as proposed in IE.	The recommended rolling time window is already 500ms and the risk of higher RoCoF in CE is higher than GB and IE when considering system split.
	Technical	While we understand the IGD drives requirements for generators and comes from different studies, we consider that the IGD shall point out to System Operators that high RoCoF values are, in any case, dangerous for the system and counter-measures, defence plan and any other means to limit RoCoF value at reasonable value for existing generating units need to be considered. The studies carried out should evolve taking into account such counter-measures and the RoCoF limit shall be set as a target for both generating unit technologies and System Operators.	This would be added to the IGD that TSOs are already investigating synthetic inertia, but nonetheless, high RoCoF are assumed to occur even with high synthetic inertia.
	Technical	RoCoF withstand capability and compliance through testing: It is very difficult, if not impossible, to predict and simulate the stability and the limitations of a complex technology such as a gas turbine under the extreme conditions of a high RoCoF due to the complexity of, for instance, the combustion process. Additionally, there is almost no operational experience with high RoCoF due to the very limited occurrence of such extreme events and the impossibility of testing it under real conditions.	Accepted.
	Technical	For generating units above 1 MW, it is not possible to test RoCoF requirements; in fact, there is the need for a virtual grid capable of changing its frequency to which the generating unit shall be connected. The proposed frequency profiles, therefore, can only be applied to a simulation of the controller behaviour in an adequate simulation model. Acceptance of compliance, hence, must be limited to stability of the model (e.g. no disconnection) during such simulation. As a	The compliance test would be through simulation. This would be the task of the TSO to define a set of simulation tests which would include different (sever) conditions. In case a plant in reality trips due to an unforeseen condition/situation, that would not undermine the liability of the ...

		consequence, the SPGM cannot be made liable for any unpredictable effects under such severe conditions.	
	Technical	Taking the frequency profile as a boundary profile in a real event (like for FRT) might cause conflicts with the requirements for frequency ranges. Therefore, it needs to be made clear that such profile is just the input for the simulation compliance test to confirm capability of the generating unit.	Accepted. Will be addressed via the changes recommended by German TSOs
	Technical	RoCoF withstand capability and RoCoF Protection: In the IGD, there is reference to Loss of Mains RoCoF protection. We consider LOM RoCoF could need a dedicated small chapter. In particular it shall be clearly stated that RoCoF withstand capability and LOM RoCoF protection function are two separate concepts with different definitions, measurement criteria etc. We specifically appreciated the reference to the need of collaboration in defining the appropriate settings for the LOM RoCoF. We recommend adding some complementary information including the reasoning related to the settings of the RoCoF protection and the parties to be involved.	Since the RoCoF requirement is independent and prior to the LOM setting, this topic is out of scope of this IGD (RoCoF requirement comes from the system needs). This of course can be a topic for another IGD if necessary.
	Other	The IGD is lacking on recommendations about the compliance test procedure. Limitations on the possibility of testing interact strongly with the minimum requirements to be applied.	Noted
German TSOs	Technical	The frequency-against-time Profile does not properly define the RoCoF withstand capability, because it does not define or limit the maximum RoCoF to be withstood. Instead, we propose to require that power generating modules shall stay stable and connected to grid if the rate of change of frequency is cumulatively equal or less to the following values in respect to their moving average time window: • ±2Hz/s for moving average of 500ms window • ±1,5Hz/s for moving average of 1000ms window • ±1,25Hz/s for moving average of 2000ms window	Accepted.

		Power generating modules are allowed to disconnect if any of the above mentioned criteria is violated or the frequency drops below 47,5Hz or goes above 51,5Hz. Regarding the compliance test, the IGD RoCoF recommended profile and method shall apply. One can also define multiple compliance curves which would address different possibilities which is still in line with the 3 point requirements. The main arguments are as follow: 1. There might be higher df/dt (4Hz/s) initially which is below the profile (2Hz/s) but df/dt over 500ms is smaller than 2Hz/s (e.g. 4Hz/s for 150ms then 3Hz/s for 100ms then 1Hz/s for 100ms and then stable is not seen by the profile, but would be seen with the new requirements as the df/dt over 500ms is 2Hz/s) 2. There can be more complex profiles which are not addressed via our profiles but might be more critical (e.g. frequency drop for 200ms and 1Hz/s and then the frequency rises 2Hz/s for 500ms) 3. The design of the equipment and controllers 4. The current compliance profile criteria may undermine the F/U diagram 5. For type A modules, the frequency drop can be about 100mHz in less than 100ms which is not addressed by the profile	
Orgalime	Technical	With under-frequency and over-frequency thresholds for RoCoF of 2,5 Hz/s or 2,0 Hz/s the following unrealistic detection times in seconds remain:	
	Technical	Page 5: The expected capability that will be required over the asset's life cannot be assessed as these requirements are only likely available for the next 2 to 5 years according to the network development plans of the TSOs.	Rejected. Our technical requirements are defined by taking into account the future needs and development and based on long-term scenarios which are also applied to TYNDP.

	Technical	Page 6: In an islanded network the withstand capability strongly depends on the frequency droop settings of the classical generator units and the inertia provided by the classical generator units. The short circuit capacity at the connection point has no influence on the frequency.	The withstand capability of a generator depends strongly on the grid strength at the time of fault.
	Technical	Page 7: The given over-frequency or under-frequency profiles are generic values derived from typical cases. It has to be clear that with these generic values curves only open-loop tests are possible.	The profiles would be the subject of compliance simulation.
	Technical	As the RoCoF measured at any point in time as an average of the previous 500 ms, shall be the most reasonable proposal for the minimum RoCoF withstand capability by the proposed over-frequency and under-frequency profiles on page 8 it can be observed that these 500 ms are technically not feasible as counteracting would begin to a point in time at which the frequency deviation is already high.	Would be addressed by the change from German TSOs.
	Other	Page 2 - Intro: Provisions of synthetic inertia by PPMs is according to the Article 14 "Synthetic inertia" of Network Code on Requirements for grid connection of high voltage direct current systems and direct current-connected power park modules a requirement which has to be specified by the relevant TSO. The TSO shall define a AC test network in which the minimum inherent inertia of the classical synchronous generator is given.	Of course, max RoCoF is not the main input to calculate the size of minimum inertia requirement but it is the main input.
	Other	Page 4: A to define the RoCoF withstand capability correctly, the characteristics of an entire synchronous area must be considered and therefore a suitable AC network model must be provided to the manufacturer of the HVDC.	This comment has been forwarded to the respective WG (WG SPD).
Senvion		No comment	

VGB	Technical	Page 6: It is stipulated that synchronous generators can withstand 2.5 Hz/s with a 100 ms time-window. Why does this IGD imposes a time-window of 500ms while this statement mentions 100 ms? The impact of a wider time-window is enormous.	The 100ms is the input from one stakeholder and used mainly for design and too short.
	Technical	Also, the opinion of consumers with synchronous motors, such as steel-mills and rolling-mills is paramount in this matter but not mentioned in the IGD. Did ENTSOE contact such consumers?	The representatives for this category of stakeholders were invited to the consultation and relevant workshops.
	Technical	Recital 25 of the RfG imposes: "Synchronous power-generating modules have an inherent capability to resist or slow down frequency deviations, a characteristic which many RES technologies do not have. Therefore, countermeasures should be adopted, to avoid a larger rate of change of frequency during high RES production." By imposing a RoCoF equal to 2 Hz/s, this recital is not respected. This is in contradiction with the basics of RfG ans as such not acceptable.	Answered above.
	Technical	The study "EIRGRID – SONI: RoCoF Modification Proposal–TSOs' Recommendations" specifies : "The TSOs believe that the proposed RoCoF standard of 1Hz/s measured over 500ms at the generator's connection point is a pragmatic standard that can be achieved by all plant." Why does this IGD proposes a RoCoF equal to 2 Hz/s for continental Europe with an identical time-window? It is not realistic to expect that the continental grid is less stable than the Irish grid.	In Continental Europe, the main challenge is system split which can cause much higher imbalance and RoCoF.
	Other	This IGD is a violation of the RfG recital 25. Any disrespect of this recital has to be justified with decisive arguments. By imposing a value of 2 Hz/s, grid operators transfer this issue to grid users.	Noted
WindEurope		No comment	

Need for synthetic inertia for frequency regulation

Commenter	Type of comment	Comment	Remarks
BHKW-Forum e.V. (DE)		No comments	
Enercon	Technical	"It should be noted that the need for SI is less when the relevant TSO is experiencing or foreseeing modest penetration of RES". This is not always the case; other sources of generation in a given SA can also create the need for SI [1]. [1] Tielens, Van Hertem, The relevance of inertia in power systems, 2015.	Accepted. The text has been adapted.
	Technical	RoCoF protection is a very country specific protecting, different countries have and require different regulation for RoCoF. All countries regardless if they require RoCoF protection should not have to obey the same strict limits and requirements. Even with increases in RES under normal conditions RoCoF is not an issue across Europe, issue have only been identified in Great Britain and Ireland. Ireland has recently raised their limit 1Hz/s. Firstly, both challenges are equally important, the 1st challenge may only be country specific, but for these specific countries the 2nd challenge is not less important than the first. They are both interconnected issues. According to [2] using the synthetic inertia of wind turbines would be a sufficient alternative to deal with decreasing inertial response in Germany up to 2030 and the regulatory framework conditions should be adapted to enable large scale power plants to provide inertial response. This IGD moves very fast from describing the issue to creating the technical solutions for the issue without providing any data, studies or findings as to how they came to these solutions. How big are the	The big part of the comment has informative nature. Regarding the comparison between GB and IE and CE, it is important to note that in CE, system split is the main concern and the consequences of black out in CE are very heavy.

		problem and what impact is RES having on this? R&D studies have demonstrated that high RES penetration does not necessarily correspond to high RoCoF [3] & [4]. The benefits of wind power plants providing synthetic inertia have already been demonstrated in a large scale system [5]. Note: the reference to National Grids graph is unavailable. (Interdependencies Chapter) [2] German Energy Agency (DENA) Ancillary services study 2030, Security and Reliability of a power supply with a high percentage of renewable energy, 2014. [3] D. Flynn et al, Inertia Considerations within Unit Commitment and Economic Dispatch for Systems with High Non-Synchronous Penetrations, 2015. [4] L. Ruttledge, D. Flynn, Short-term frequency response of power systems with high non-synchronous penetration levels, 2015. [5] M Asmine et al, Inertial Response from Wind Power Plants during a Frequency Disturbance on the Hydro-Quebec System – Event Analysis and Validation, WIW 2016.	
	Technical	"The expected initial df/dt should be calculated and it may be managed actively in operational timescales in context of existing df/dt robustness". A proper identification of the worst-case scenario for each system is required [3].	The reference incident for CE is system split and cannot be defined as one value since it depends strongly on geographical aspects as well as and grid connections. Nonetheless, 40% imbalance is used by SPD in their studies.
	Technical	"A short burst of active power for the purpose of limiting the initial df/dt can be drawn from the capacitive energy on the DC link". The capacitive energy on DC link is not significant, and for it to be so it will need further investment. No size has been stated for the active power burst, but this burst can be provided through adding battery storage or synthetic inertia. However, as this has a value to the grid, providers of this service should receive a payment for providing this service [7].	This is a statement rather than a comment, hence no action needed.

	Technical	Countries that have already introduced SI requirements do not use H anymore; instead they use a trigger value or active power set point in their technical requirements [5], [6] & [7] [6] Hydro-Quebec TransEnergie, Transmission Provider Technical Requirements for the Connection of Power Plants to the Hydro-Quebec Transmission System, 2013. [7] DS3 System Services Technical Definitions Decision Paper	This IGD does not recognize the Canadian solution as the only definition for synthetic inertia as it lacks some main functionalities of inertia. Regarding the Irish case, fast active power control does not also register in the inertia product category.
	Technical	"The technical feasibility of SI is not an issue by principle (although may it be not mature enough presently and need more time for further technical enhancement)". Ireland and Hydro-Québec are already providing such technology; see [5] & [7] Canada - the requirements have change since originally using H[6]	Similar answer as above.
	Technical	"Conventional frequency response for wind farms in existing grid codes". This is not conventional frequency response, this is a much faster response, namely "fast Frequency Response" (FFR) in Ireland and Inertia Response in Canada! Additional to reference #13 and #14 in the paper - also add reference to Hydro-Québec providing a stable response using proportional response [5].	Answered above.
	Technical	"A Proposal for Introduction by 2021 of Grid Forming Converter Capability with SI". This is neither optional nor required, this is still at proposal stage, a decision paper has not been published yet and there is no date available for this publication. It should also be noted that the parallel operation of such controlled voltage sources with a limited frequency bandwidth has not been yet thoroughly investigated. Stability limits are only based on research results of early stage development and stable operation in a large-scale system is yet to be proved.	Accepted. The wording has changed respectively.

Energy Networks Association		No comments	
EUGINE - European Engine Power Plants Association		No comments	
EURELECTRIC		The IGD is interesting given the fact that it presents the 'state of art'. Nevertheless, it remains quite theoretical.	This is a statement rather than a comment, hence no action needed.
EUTurbines		No comments	
German TSOs		No Comment	
Orgalime	Technical	However, the topic of Synthetic inertia (SI) needs further research and investigation efforts like the major pan European project MIGRATE. Text should be adapted as follows: Further research and development concerning the technical feasibility in a large scale of industrial equipment is required. Therefore, the requirement of synthetic inertia in grid codes or in projects in the near future should be avoided, until the technical feasibility in real, industrial solutions has been proven.	The text was reviewed.
	Other	Conflicting definition in RoCoF and SI: RoCoF Frequency measurement based on 500 ms. The PPM has to measure RoCoF and react faster than 500 ms otherwise the RoCoF-Relay could react faster - this might be corrected in part 7 (RoCoF) in the part of the average measurement for RoCoF is given. For the systems where higher RoCoF is expected (3-4hz/s) then the shorter times shall be considered.	There might be misunderstanding on the measurement time window and synthetic inertia activation time. It is important to note that any response is assumed to be as fast as technically possible and the measurement time window for RoCoF is only for compliance monitoring.

Senvion	Technical	This IGD is mainly based on the study published in the IGD HPoPEIPS which is looking into the future and is not finalized but rather initiating future studies on scenarios based on one synchronous area. Therefore This IGD is not appropriate for the current implementation of RfG. The IGD on synthetic inertia shall rather guide and pave the road to the TSO's of each synchronous area to start system wide studies and to align the needed total system inertia for the synchronous area in total considering the effect of the demand side fast frequency response.	This is a statement rather than a comment, no action needed, therefor.
	Technical	Proper CBA shall be also executed while deciding on parameters for synthetic inertia. For any PMM providing synthetic inertia means overdesigning (or permanent curtailing) of the output power in order to provide this functionality due to current limitations in the system. This definitely increases the technology costs and shall be subject to CBA, provided as an ancillary service and compared to system connected solutions as described in the related ENTSO-e study "12. ENTSO-E WG-SPD, Frequency Stability Evaluation Criteria for the Synchronous Zone of Continental Europe" - synchronous condensers, battery storage etc.	Although this topic is not the focus of this IGD, we have recognized the importance of this issue and this would be considered for future studies and implementations.
	Technical	Page 8, Canada: HQTE requests a power boost of x% of Pnom for x seconds, allowing a maximum power drop of x%. It should be noted that these are currently design criteria for existing wind turbines, not H. Also, these requirements reflect technical limitations of wind turbines. Those should be stated in the document more clearly. The need is clearly understood, but it should be made clear that contribution of wind turbines can only be limited due to their technical design.	This is out of scope of this IGD as defining the technical capabilities or design of individual technologies.
VGB	Technical	This IGD does not describe any pragmatic parameter nor effect on the stability of the electrical system. No TSO can use this IGD to impose technical characteristics at a developer of a windfarm.	Noted

	Other	This IGD has to be rewritten with more technical elements.	Noted
WindEurope	Technical	This IGD is mainly based on the study published in the IGD HPoPEIPS which is looking into the future and is not finalized but rather initiating future studies on scenarios based on one synchronous area. Therefore, This IGD is not appropriate for the current implementation of RfG. The IGD on synthetic inertia shall rather guide and pave the road to the TSO's of each synchronous area to start system wide studies and to align the needed total system inertia for the synchronous area in total considering the effect of the demand side fast frequency response.	Answered above.
	Technical	Page 8, Canada: HQTE requests a power boost of x% of Pnom for x seconds, allowing a maximum power drop of x%. It should be noted that these are currently design criteria for existing wind turbines, not H. Also, these requirements reflect technical limitations of wind turbines.	Answered above.
	Other	Although it is mentioned, it is not clear how this IGD is being related to outcome of the studies that need to be perform at synchronous area level (as part of the system operation guidelines).	The aim of this IGD is to trigger such studies besides those which are already defined in the SO GL.
	Other	Once the need for inertia has been identified and clearly measured, a proper CBA shall be also executed while deciding on parameters for synthetic inertia. For any PPM providing synthetic inertia means overdesigning (or permanent curtailing) of the output power in order to provide this functionality due to current limitations in the system. This definitely increases the technology costs and shall be subject to CBA, provided as an ancillary service and compared to system connected solutions as described in the related ENTSO-E study "12. ENTSO-E WG-SPD, Frequency Stability Evaluation Criteria for the Synchronous Zone of Continental Europe" - synchronous condensers, battery storage etc. It should be made clear that contribution of wind turbines can only be limited due to their technical design.	Answered above.

		Overall, the contribution to inertia could come from existing grid users (generation/demand), but might also be provided by network components. Thus, a CBA and a clear market mechanism to incentive its used should be pursued.	Answered above.
		With regards to risk management considerations (Pag. 9), studies from TSO on the probability of system split should be widely discussed with regulators and stakeholders to reach a common agreement on the challenge, as design strategies have important cost considerations to all users and eventually consumers.	Severe disturbances are of a low probability / high impact nature. The likelihood of occurrence or costs of system-wide blackouts are irrelevant, they shall be considered as no-regret incidents.