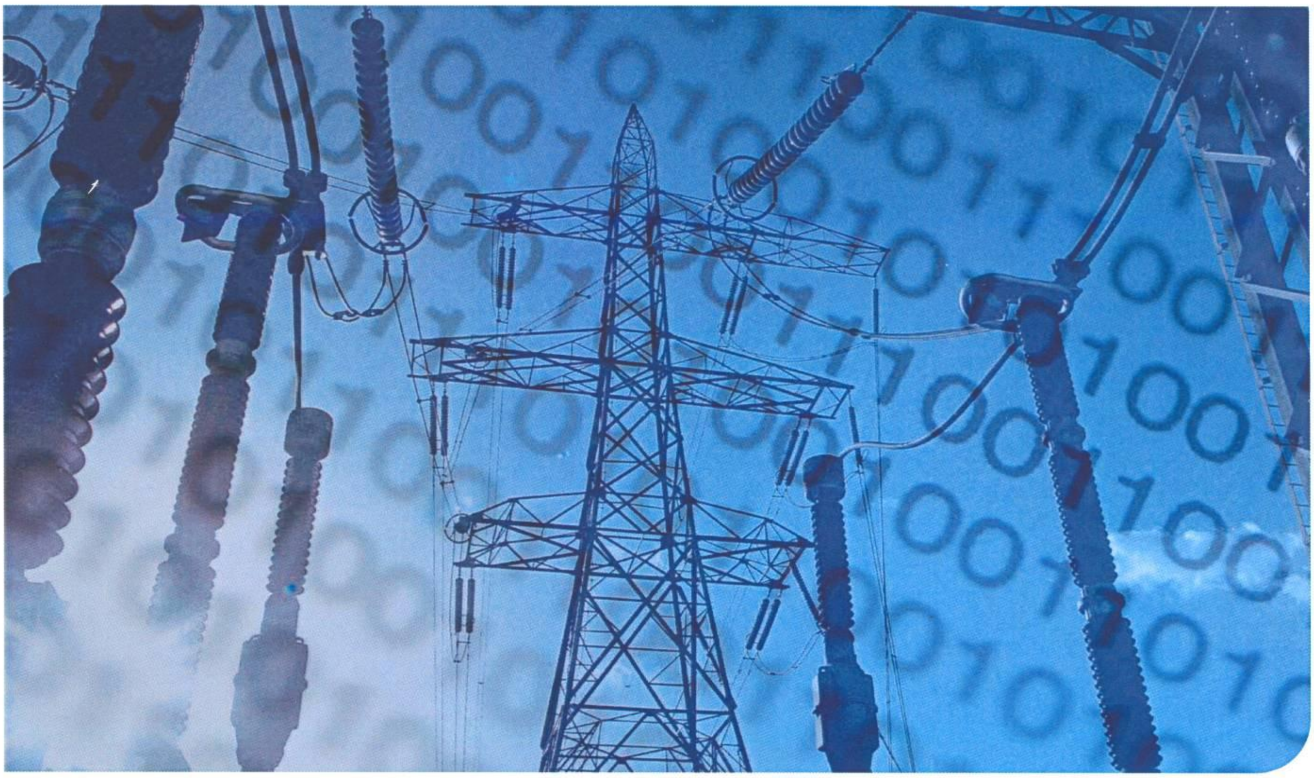
Technical Report on ENTSO-E Network Code: Requirements for Generators



Final Report

Submitted to European Commission DG TREN

Project Number: ENER/B2/151/2012

Prepared by DNV KEMA Energy and Sustainability in conjunction with COWI, Belgium 12 November 2013

Experience you can trust.

Project and Report Information

Project: Technical Report on ENTSO-E's Network Code Requirements for Generators

Client: European Commission

Contractor(s): COWI Belgium/DNV KEMA Energy& Sustainability

Report Title: Technical Report on ENTSO-E Network Code: Requirements for Generators

Date / Issue: 12 November 2013 / 0.1

Document History

Issue	Date	Author	Description / Comments
0.1	12 November 2013	Eric Davidson, Wim Kuijpers, Bob McVean, Božidar Radović	Draft following stakeholder comment to the Preliminary Report

Report Review

Name, Company	Signature	Date
Christian Hewicker, DNV KEMA		12 November 2013

0. Executive Summary

0.1 Background

The Directorate-General for Energy and Transport of the European Commission (DG ENER) sought a review of ENTSO-E's draft Network Code for Requirements for Grid Connections Applicable to all Generators (NC RfG) and a Technical Report detailing the findings. To produce this document DNV KEMA reviewed the draft versions of the code published in June 2012 and in March 2013. A number of other documents including ENTSO-E's review of the consolidated list of all the comments that have been received, the Agency for the Cooperation of Energy Regulators (ACER) Framework Guidelines and a number of submissions by individual stakeholders were also considered. Communication with key stakeholders resulted in a number of position documents also being provided for consideration. A preliminary report was prepared and DG ENER made this available to stakeholders who had been involved in the entire development process. Several made comment either before or following a stakeholders' meeting hosted by DG ENER to address some of the continuing issues. This final technical report builds on this previous work and makes use of all the available material in reaching its conclusions regarding the NC RfG. As far as practicable, this report uses the same terminology as is used and defined in the NC RfG.

The suite of European wide network codes, of which the NC RfG is only one, that the Third Package envisages, will provide some of the relevant rules to facilitate the achievement of the three objectives of the Third Package – the secure operation of European power systems; the integration of large volumes of low carbon generation; and the creation of a single European electricity market. The development of these codes is based on Article 6 of Regulation EC/714/2009 and has been in process since July 2011. Drafting of the NC RfG followed the development by ACER of non-binding Framework Guidelines on Electricity Grid Connections. The NC RfG was developed by the European Network of Transmission System Operators (ENTSO-E) which had been mandated by the European Commission to develop the suite of electricity network codes. The review that has been undertaken by DNV KEMA has been undertaken against this backdrop. It is recognised that, at present, all generators are bound by various rules governing the technical specification and performance requirements of the equipment that they connect to electricity networks as are set out in national codes – grid codes etc – and connection agreements. A significant number of existing generating units will have been connected before these national network codes were established and will not meet their requirements. It has to be recognised that, in developing the NC RfG, while looking forwards to promote the objectives of the Third Energy Package, a significant number of issues relating both to existing generating units and different approaches in the various Member States must be accommodated.

The Framework Guidelines on Electricity Grid Connections developed by ACER established that the rules should apply to significant grid users – considered to be grid users whose actions will have a cross border impact – and that the Code should define the requirements on significant grid users in relation to the relevant system parameters contributing to secure system operation. These specifically include the following:

- Frequency parameters;
- Voltage parameters;
- Reactive Power requirements;
- Load-frequency control and system balancing;
- Short-circuit current;
- Protection requirements including protection settings;
- Fault-ride-through capability; and
- Capability to provide ancillary services:

The Framework Guidelines provide for special rules for wind, PV and distribution connected generation although, recognising non-discrimination obligations, ENTSO-E have ensured, as far as is practicable, that the code is technologically neutral. There are additional sections in the Framework Guidelines setting out that the network code should also cover the treatment of existing grid users, compliance testing and information exchange. The work undertaken by ENTSO-E resulted in the development of the NC RfG and its proposal as the first draft European wide network code in electricity. While ENTSO-E had a high degree of stakeholder engagement, inevitably not all parties have been or will be satisfied with the resulting draft. Indeed, the process revealed important disagreements between grid users and transmission system operators (TSO) on the appropriate rules that should apply to generators. It must also be accepted as inevitable that not all parties will be satisfied with the recommendations developed following this review. For some, they will be too hard, for others too soft.

Operation of any power system involving multiple parties requires that all must operate together to ensure that the system can be operated safely, securely and for the benefit of all parties and especially, for the benefit of their customers, the electricity consumers. This means that some parties will incur costs for the benefit of the system and one issue to be addressed in analysing the current debate is separating those comments made because of genuine technical difficulty and those that are raised in an attempt at moving where these costs will lie. The 'battle' between system users and TSOs about the allocation and/or shifting of additional costs for system security is therefore likely to be a permanent feature of the market.

0.2 General Comments

The adoption of European or International Standards in place of former National Standards has meant that equipment manufactured for use in the EU does not differ across national borders without added costs being incurred. However, the requirements established in the various national network codes are currently different reflecting the differences in both network and generation equipment practices between the different Member States and some continuing variations are necessary. Recognising the realities of introducing change and the principles of subsidiarity, the draft NC RfG relies on a number of significant issues being addressed at a Member State level, raising the question of the balance between a European wide code addressing cross border issues and the co-existence of national codes for internal operation of the same system as is required for cross border trade. The NC RfG establishes a common framework for the specification of issues related to the connection of generation plant to the network, but many of the detailed values are left to the TSOs to insert. ACER and ENTSO-E have both stated that they expect all TSOs to continue with the values that exist in their national codes on the date that the NC RfG is implemented. The effect of this approach is to minimise the impact that the adoption of the NC RfG will, by itself, have on any party.

However, the implementation of the current national codes in each of the Member States differs because the legal status of the network code differs between Member States, the status and rights of both TSOs and network users are not identical in all Member States, also the commercial arrangements applicable to the connection to the network and operation of generating units differs between Member States. Historical development of networks requires different approaches and the level of interconnection of the Member State’s network with other Member States impacts the level of co-operation across borders. The varying levels of interconnection affect the support requirements that must be provided to the overall power system if it is to be operated securely for the benefit of all parties. In undertaking this review, several non-technical issues that may have a significant technical impact on network users in the transition from the existing arrangements to those of the NC RfG were identified. These have been addressed by considering:

a) Whether the provisions are reasonable moving forward; and

b) Whether any rights available to existing generators were adequately protected to ensure that adoption of the NC RfG is the minimalistic change that ACER and ENTSO-E intend.

The move towards the greater dependence on RES-E and other generating units embedded in the distribution system, brings with it changes in the approach towards system security especially in the distribution network and at the interface between transmission and distribution networks. By the nature of their power sources, RES-E generators are often capable of less control than traditional generation plants and the growth in dependence on them will have an impact on the future operation of interconnected transmission systems which must filter through to a forward looking network code. The transition from large scale generating units to distributed generation also brings with it a transition from large synchronous generating units that inherently provide some of the support requirements that the system needs to small asynchronous generators that must be forced to make these support requirements available. This is particularly the case where large numbers of uncontrolled RES-E generating units are affected simultaneously.

These issues have clearly been a major focus of ENTSO-E's work in drafting the NC RfG and this review has considered whether the approaches taken in the NC RfG to require these services from all generators are reasonable.

Throughout, there is a need to cater for the ability for future technological improvements being made and introduced for the benefit of society as a whole. In this respect, ACER has guided ENTSO-E towards the approach of ensuring that the NC RfG does not introduce technology specific requirements but it is clear that not all technologies have the same capabilities and, as a consequence, mechanisms for handling any essential differences – known now or that impact future technological improvements – must be available. Along with this, there is a need to consider the issues raised by the introduction of technologies that allow the operation of generation plants by people or organisations who are neither expert in the field nor that it is realistic to expect them to hold the level of expertise traditionally encountered.

Historically, the main power supply to distribution networks has been from its connection points to the transmission system and it is only recently that, in certain operational regimes, generation embedded into the distribution network has exceeded customer demand on these networks. In order to ensure the safe disconnection of faulted distribution networks, generating units connected to these networks have previously been required to stop generating in the event of a loss of voltage on the distribution network. This resulted in the safest situation for the general public, employees of the distribution system operator and for the network itself. It also ensured that restoration of supplies to affected customers could happen in the shortest possible time. The requirement to disconnect is still the safest position for faults affecting the distribution network but, with the increase in embedded generation, certain types of faults will not result in a loss of voltage, and therefore disconnection cannot be guaranteed. Where there is a net energy transfer from the distribution network to the transmission network, the TSO will wish this generation to ride through faults in the transmission network, while the DSO will wish it to disconnect for faults in the distribution network.

The conflict between the different requirements of the two groups of network operators has been considered in undertaking the review of the NC RfG. As noted above, the nature of much of the change that ENTSO-E proposes in this area is inevitable if the objectives of the Third Energy Package are to be achieved, but the reasonableness of the proposals has been considered both in the short and longer term.

0.3 Stakeholder Consultation

The NC RfG is only a part of what is usually included in a network code, other parts being drafted by other drafting teams from ENTSO-E. Major issues for any system user seeking a connection to the TSO's network or already connected to that network at the time a new code is prepared will include:

a) The technical connection requirements specified in the connection code;

b) How the connection requirements translate into operational requirements both on the user and the TSO;

c) How the code will be applied to their connection (both technical connection requirements and operational obligations) on day 1; and

d) How (all parts of) the code will be modified over time.

The NC RfG is the first part of what will effectively become one overall network code that will have been drafted by ENTSO-E. Viewing this in isolation has presented a major difficulty for stakeholders identifying exactly what the impact on them will be. This situation was exacerbated by examples of apparently conflicting requirements or statements between the various codes, particularly in the early stages of drafting.

While stakeholders raised a significant number of technical issues, many of the concerns expressed by stakeholders on these issues have not referred to the technical requirements themselves but rather to what the technical requirements might become. What the stakeholders appear to be seeking is a robust amendment and approval procedure but they have not elucidated this and, on several points, are trying to make a case on the basis that any changes in the requirements of the code will not be simply enacted but should be subjected to proper review and consideration before approval is given. What hypothetically might happen in the future could not be a concern of this review. Therefore, where it is apparent that the lack of clear governance arrangements lie at the bottom of the issue raised, these concerns have not been considered as individual technical issues, rather recommendations are made on establishing appropriate governance arrangements.

Another stakeholder comment concerns what is considered the unbalanced nature of the code in that it gives the TSOs rights and places all the requirements and obligations on the stakeholders – i.e. the generators. The code is entitled the 'Requirements for Generators' so it is only to be expected that the requirements would be placed on the generators. The obligations of the TSO should be clearly identified in other codes within the overall framework of which the NC RfG is a part. However, there are certain issues where the current drafting does appear unbalanced.

The principle responsibility of the TSOs under the NC RfG is to ensure in operating the system that the generators can and do meet their obligations to provide support to the system so that a secure electricity transport network is available for all users. ENTSO-E correctly note in part (8) of the 'Purpose and Objectives' of the NC RfG that '... system security cannot be ensured independently from the technical capabilities of Power Generating Modules. Regular coordination at the level of generation and adequate performance of equipment connected to the networks with robustness to face disturbances and to help to prevent any large disturbance or to facilitate restoration of the system after a collapse are fundamental prerequisites'. While the NC RfG places obligations on generators, a number of the other codes – particularly the Operational Security and Load-Frequency Control & Reserves codes – will have clear requirements for the TSOs to fulfil. For many of the technical issues raised, the difficulty for stakeholders is not the technical issue itself but it is the lack of clear harmonisation arrangements with other network code documents that together with the NC RfG will establish a more usual complete network code. Harmonisation is therefore an important non-technical issue with significant technical relevance.

0.4 Conclusions and Recommendations

The technical issues and non-technical issues with a technical impact that were raised by stakeholders or otherwise identified during the review were analysed in detail in sections 5 and 6. Following this analysis, recommendations were developed in the context of a change in generation mix from large generating units, with a significant proportion of synchronous generating units providing inherent support to the wider electricity network at times of network disturbances, to a dependency on much smaller distributed generating units. So far, this change has affected some TSOs much more than others but, given that there is already evidence of the cross border effects of the operation of networks with a high penetration of distributed generation, it is recognised that the issues that some TSOs have been attempting to address in recent years are issues that will ultimately affect all European TSOs. The requirements of the NC RfG have also been considered with reference to the firm statements from both ACER and ENTSO-E that:

a) changes in the current Network Codes of Member States will only occur in compliance with the current arrangements applicable in the Member State up to the date that the NC RfG would, if adopted, come into force,

b) the technical parameters applicable in the Network Code of the Member State would be carried over into the NC RfG applicable in the Member State and,

c) from the adoption date of the NC RfG, changes to the code would be subject to the change requirements contained in the NC RfG.

In this context, it is concluded that the adoption of the NC RfG will, by itself, have very limited impact on current network users provided certain existing safeguards are maintained. Against this background, ENTSO-E appear to have generally addressed the issues of operating an interconnected network with Europe wide market capabilities in a reasonable and realistic manner while recognising that the principles of subsidiarity should continue to allow each Member State to set its own regulation wherever practicable. The approach taken should ensure that the impact of the NC RfG on all currently operating generating units and all generating units genuinely in course of development would be neutral. Additional requirements are placed on new generating units but these requirements appear to be no greater than would be reasonably required to allow these smaller generating units to replace the large synchronous generating units that are currently in operation but that will be decommissioned in line with age profile and energy policy.

However, in part to address the reasonable concerns of stakeholders affected by the transition that the adoption of the NC RfG into EU Law will bring but also to recognise that there are a number of technical issues that are not fully worked through into standards that would allow their implementation by affected stakeholders, a number of minor modifications and clarifications are recommended. These are outlined below and considered in full in section 7.

0.5 Recommendations on technical issues

0.5.1 Recommendations concerning frequency ranges

It is essential that ENTSO-E determine quality parameters of the electricity network frequency. Recognising that the only obligation specified in the NC RfG is to remain connected and not to operate normally, it is proposed that the frequency ranges to be applied in the NC RfG should follow IEC Standards.

To allow for the correct representation of these standards, consideration should be given to incorporating frequency and voltage requirements into a single diagram.

For details see section 5.1.1.

0.5.2 Recommendations concerning active power output with falling frequency

The requirements should be more completely defined, particularly with obligations placed on TSOs and NRAs, when setting non-exhaustive parameters, to take account of the technical capabilities of relevant technologies. This could be achieved by extending the compliance section of the NC RfG.

For details see section 5.1.2.

0.5.3 Recommendations concerning LFSM-O and LFSM-U

For most generators, the requirements regarding Limited Frequency Sensitive Mode – Overfrequency (LFSM-O) and Limited Frequency Sensitive Mode – Underfrequency (LFSM-U) should remain as drafted.

LFSM-U settings for nuclear generators should be established when the business case is being developed and remain unchanged after the safety case has been finalised – unless a clear justification that takes account of the nuclear safety issues is later established. (LFSM-O is stated not to be an issue for nuclear generators).

In general, CHP schemes should be designed to allow compliance with the requirements as specified, but exemption should be permitted for the very small number of CHP schemes that cannot reasonably comply. This may reasonably be coupled with an obligation to disconnect as may be permitted where the equivalent CHP scheme would be adversely affected by system disturbances.

For details see section 5.1.3.

0.5.4 Recommendations concerning Voltage Ranges

Four recommendations are made, without analysis by the Consultant, based on the apparent agreement achieved at the stakeholder meeting on 16 September 2013.

1. Proposed duration of the additional overvoltage range of 1.118 pu – 1.15 pu for the Type D power generating modules in Article 11, Table 6.1 for Continental Europe, which is currently intended "... to be defined by the TSO while respecting the provisions of Article 4(3), but not less than 20 minutes", should be "defined by the TSO while respecting the provisions of Article 4(3), with a maximum time period in the range of 20 – 40 minutes".
2. Proposed duration of the additional overvoltage range of 1.05 pu – 1.0875 pu for the Type D power generating modules in Article 11, Table 6.2 for Continental Europe, which is currently intended "... to be defined by the TSO while respecting the provisions of Article 4(3), but not less than 60 minutes", should be "defined by the TSO while respecting the provisions of Article 4(3), with a maximum time period in the range of 40 – 80 minutes".
3. The additional overvoltage range of 1.0875 pu – 1.10 pu for the Type D power generating modules in Article 11, Table 6.2 for Continental Europe, should be deleted.
4. Drafting should be introduced permitting the reinstatement of the additional overvoltage range of 1.0875 pu – 1.10 pu for the Type D power generating modules in Article 11, Table 6.2 for parts of the networks of individual TSOs in Continental Europe where it is required for network configuration reasons, as approved by the NRA, provided it is neither detrimental to the operation of the power system nor to the operation of the internal market.

It is also recommended that consideration should be given to representing voltage and frequency arrangements together.

For details see section 5.2.1.

0.5.5 Recommendations regarding the use of On Load Tap Changers

No changes are proposed but it is recommended that, where On Load Tap Changers (OLTCs) are required, this should be clearly stated and not left to be inferred.

NRAs should be required to ensure that the voltage ranges selected by TSOs correctly reflect current practice in the use of OLTCs, including the tapping range in normal application or that the appropriate change review is undertaken.

For details see section 5.2.2.

0.5.6 Recommendations regarding reactive power capability

Where it is not currently standard practice for on-load tap-changers with an adequate tap range to be used, the drafting should be modified to exclude from the required voltage/reactive power profile those areas which are therefore not technically feasible.

For details see section 5.2.3.

0.5.7 Recommendations regarding provision of Reactive Power as Means of Voltage Control

Provided the issue regarding reactive power capability is addressed, it is proposed that no further change should be made to the technical requirements.

NRAs should be required to ensure that stakeholders are not materially disadvantaged by the operational demands placed on them by TSOs for the provision of Reactive Power for Voltage Control.

For details see section 5.2.4.

0.5.8 Recommendations regarding Duration of Fault Clearance Time

This article should be amended such that the ranges of permissible fault clearance times are distinguished by voltage level and, particularly at 400kV, by synchronous area. The ranges provided should more closely reflect current practice except where alternative arrangements are required for network configuration reasons as approved by the NRA provided this is not detrimental to the operation of the power system or of the internal market.

For details see section 5.3.1.

0.5.9 Recommendations regarding Fast Reactive Power Injection and Active Power Recovery for Power Park Modules types B, C & D

These issues should be clearly stated as non exhaustive requirements, specified only where Power Park Module (PPM) penetration is sufficient that they need to be addressed by TSOs. The requirements should be specified with greater precision and take due account of the capabilities of existing technologies.

For details see section 5.3.2.

0.5.10 Recommendations regarding Fault Ride Through and LV Connections

It is recommended that all generating units connected to LV networks should be exempted from the fault ride through requirements specified in Article 9. In addition to ensuring that all generating units connected to LV networks are treated equally, this addresses safety concerns associated with the operation of networks to which the general public have greatest access.

For details see section 5.3.3.1.

0.5.11 Recommendations regarding application to LV Connected Generating Units

It is recommended that, in line with current standardisation practice and to ensure that all generating units connected to the LV networks operated by DSOs are treated equally, the threshold between Type A and Type B generating units is modified such that all generating units > 800W connected to public networks operating at less than 1 kV are considered as Type A units.

For details see section 5.3.3.2.

0.5.12 Recommendations regarding conflicts relating to the operation of protection equipment

The conflicts between ensuring the correct operation of both transmission and distribution protection systems in the transition to embedded generation is the subject of a number of studies. In this particular situation, since the appropriate changes would only become apparent following completion of current studies and would be appropriate on a Europe wide basis, it would be appropriate to require that the NRA, in consultation with other NRAs apply suitable standards as the information to allow their development becomes available.

As the NC RfG is currently drafted, there is no opportunity for any affected party other than the TSO to propose modification to the NC RfG. While it is to be hoped that TSOs would propose appropriate modifications, this restriction is very unusual. To allow NRAs to apply the results of this study and to allow more general review, it is also recommended that other stakeholders, and in particular the NRA, should also be able to propose modifications.

For details see section 5.3.3.3

0.5.13 Recommendations regarding the application of transmission rules to distribution networks

The Network Codes developed by ENTSO-E should be modified to allow an overlap of the application of transmission or distribution rules depending on whether the operator is a transmission operator or a DSO.

Type A, B, or C generating units should only be deemed to be type D units where the operator of the 110kV or above network to which they are connected is not a DSO or Closed Distribution System Operator (CDSO).

For details see section 5.3.3.4.

0.5.14 Recommendations regarding compliance

Clarification of compliance requirements is essential and TSOs should be required to produce a clear, unambiguous and detailed statement of all requirements that should be subject to the approval of the NRA operating in conjunction with other NRAs.

For details see section 5.4.

0.5.15 Recommendations regarding obligations placed on non expert parties

The NC RfG should be redrafted to allow:

a) Derogations for CDSOs and small DSOs from complex technical issues allowing DSOs the right to address those issues that do arise.

b) The ability of manufacturers to represent Power Generation Facility Owners (PGFOs) in respect of:

i. All power generation modules operated by consumers; and

ii. All other power generating modules where the manufacturer is appointed to address any issue or issues by the PGFO.

For details see section 5.5.

0.6 Recommendations on Non-Technical Issues with Significant Technical Impact

0.6.1 Recommendations Concerning Harmonisation of Network Codes

It is strongly recommended that ENTSO-E ensure harmonisation of the requirements among the individual ENTSO-E network codes and that mechanisms are introduced to maintain network codes harmonised at times of revision of any code. For details see section 6.4.

It is recommended that clear governance arrangements are established for the entire suite of network codes.

0.6.2 Recommendations Concerning Cost-Benefit Analyses

It is strongly recommended that ENTSO-E develop and present in the supporting documents to NC RfG a detailed methodology for:

- Preliminary assessment of costs and benefits at the CBA preparatory stage, and
- Full Cost-Benefit Analysis

For details see section 6.2.3.

0.6.3 Recommendations concerning derogations

It is recommended that the following aspects concerning derogations from the requirements of the NC RfG are addressed:

- In the Member States, there are number of generating units currently operating under derogations from the existing network codes and in some Member States the costs of the removal of such a derogation are socialised. In order to ensure that the implementation of the NC RfG is neutral, the NC RfG should contain a clause indicating that existing derogation rights continue and that, in the event that such a derogation is removed by the retrospective application of the NC RfG to these generating units, any existing rights for compensation would continue to apply.
- The NC RfG should provide for the ability of the manufacturer or other technical advisor to make application for individual or class derogations, so that non-expert operators are not disadvantaged.

0.6.4 Application to CHP Schemes

Article 3 section 6 parts g) and h) appear to attempt to establish a reasonable compromise between the reasonable needs of TSOs and CHP operators in the situation where the proportion of small generating units is increasing. However, the current drafting does not quite achieve that and it is recommended that these parts are redrafted to ensure:

a) Smaller installations that should be exempted from the NC RfG requirements are not prevented from receiving these exemptions purely because they are embedded in industrial networks that are, in turn, connected to the public network at high voltage;

b) Arrangements can be established to meet the requirements of TSOs and allow CHP schemes to be exempted from varying electricity generation where:

   i. The level of generation cannot be decoupled from the production of heat or steam to support an industrial process;

   ii. The generation of electricity is secondary to the support provided to the industrial process; and

   iii. The required change in electricity generation would result in a variation in the production of heat or steam that would have a material effect on the safe and economic continuation of that industrial process.

0.6.5 Recommendations regarding emerging technologies

In Title 6, the opportunity for NRAs, operating in conjunction with other NRAs where appropriate, to be involved at all stages should be recognised. In establishing timescales for notification of revocation of emerging technology status, the impact of short notice periods on the commercial risk profile of technology development should be recognised.

0.7 Recommendations regarding Implementation

1) It should be clear that the subsidiary codes prepared by the individual TSOs shall carry over existing values into the non-exhaustive values. Guidance should be prepared by ENTSO-E on the completion of all values and this guidance should be published and reviewed by ACER.

2) The ranges quoted by ENTSO-E should be reviewed to ensure that they are entirely accurate. Where they are conditional on other issues, these should be stated.

Table of Contents

List of Exhibits:

1. Introduction

1.1 Background

The Directorate-General for Energy and Transport of the European Commission asked COWI Belgium, under the terms of the framework contract, to review ENTSO-E's draft Network Code for Requirements for Grid Connections Applicable to all Generators (NC RfG) and provide a Technical Report detailing their findings. COWI employed DNV KEMA to perform the key technical review and this document forms the final report required as a deliverable under this project.

In order to produce this document DNV KEMA has reviewed the draft version of the code published in June 2012 and has updated this review to take account of the version published in March 2013. They have also considered a number of other documents including ENTSO-E's review of the consolidated list of all the comments – some 6000 in total – that have been received, the ACER Framework Guidelines on Electricity Grid Connections and a number of submissions by individual stakeholders. In addition to this, communication with key stakeholders has resulted in a number of position documents being provided for consideration.

1.2 Structure of this Report

This Report sets out the key issues that DNV KEMA believed had to be considered in the review of the NC RfG. The structure of this report is as follows:

- Section 1 – Introduction
- Section 2 – Task Description
- Section 3 – Context of NC RfG for Power System Operation
- Section 4 – Stakeholders' Views
- Section 5 – Assessment of Technical Requirements
- Section 6 – Non Technical issues
- Section 7 – Conclusions and Recommendations.

As far as practicable, this report uses the same terminology as is used and defined in the NC RfG.

2. Task Description

2.1 History

On 4 February 2011, the year 2014 was set as the target for the completion of the single internal market for electricity and gas in the European Union. The Third Package of Directives and Regulations, as adopted in 2009, for the further development of the internal market is an important step in this direction. However, further efforts have to be made to allow gas and electricity to flow freely across Europe. The network codes, which are foreseen by the Third Package, will provide some of the relevant rules for this further development.

Together, the network codes will facilitate the achievement of the three objectives of the Third Package – the secure operation of European power systems; the integration of large volumes of low carbon generation; and the creation of a single European electricity market. The Network Code, Requirements for Generators (NC RfG) is the first of the network codes to be developed and proposed for adoption as a European Union wide code. Its development is based on Article 6 of Regulation EC/714/2009 and has been in process since July 2011 following the development by the Agency for the Cooperation of Energy Regulators (ACER) of non-binding Framework Guidelines on Electricity Grid Connections. The intended timetable for development is as shown in Figure 1.

The European Network of Transmission System Operators (ENTSO-E) was mandated by the European Commission to develop the NC RfG based on the Framework Guidelines submitting a document to ACER in July 2012[1]. The development process included a public consultation, as well as a number of workshops and meetings with EC, ACER and other stakeholders. ACER provided a preliminary opinion in October 2012, acknowledging that the document was in compliance with the Framework Guidelines, but recommending areas for improvement to meet stakeholders' concerns. ENTSO-E later worked with stakeholders and ACER, issuing a revised document in March 2013 when ACER recommended its adoption subject to minor changes.

[1] Submission date as recorded in the introduction to the ACER opinion. The date on the ENTSO-E document is 26 June 2012.

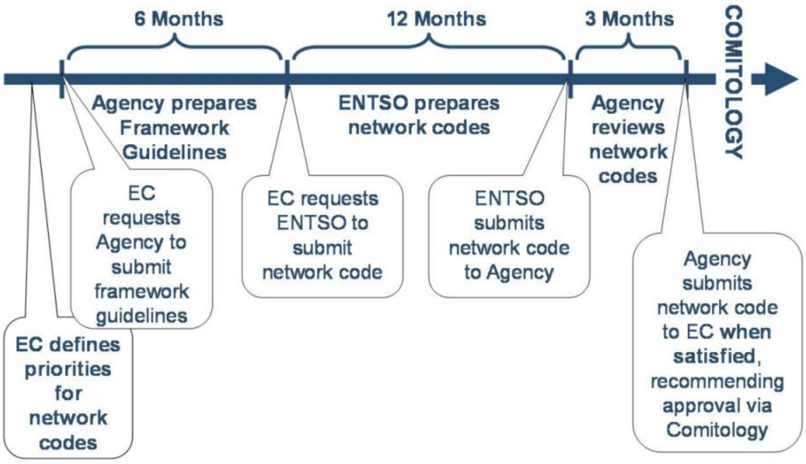


Figure 1: Process of adoption of Framework Guidelines and Network Codes (Source: ACER web site[2])

2.2 Context of Task

At present all generators are bound by various rules governing the technical specification and performance requirements of the equipment that they connect to electricity networks. These are set out in national codes – grid codes etc – and connection agreements. Due to the impact of increased penetration of distributed electricity generation and the need for a more harmonised approach in an interconnected system and integrated markets, the desirability of bringing these rules into line has been widely recognised. Regulation EC/714/2009 provides for the adoption of legally binding codes in this area and it has been made a priority by the Commission.

The Framework Guidelines on Grid Connection developed by the ACER sets out the high level approach to be taken in the development of such rules. In particular such rules should apply to significant grid users – considered to be grid users whose actions will have a cross border impact. The Framework Guidelines also specifies that the Code should define the requirements on significant grid users in relation to the relevant system parameters contributing to secure system operation. These include the following:

- Frequency parameters;
- Voltage parameters;
- Reactive Power requirements;

---

[2] http://www.acer.europa.eu/Electricity/FG_and_network_codes/Pages/default.aspx

- Load-frequency control and system balancing;
- Short-circuit current;
- Protection requirements including protection settings;
- Fault-ride-through capability; and
- Capability to provide ancillary services:

The Framework Guidelines provides for special rules for wind, PV and distribution connected generation, although ACER have stated a preference that, as far as is practicable, the code should be technology neutral. There are additional sections in the Framework Guidelines setting out that the network code should also cover the treatment of existing grid users, compliance testing and information exchange. The work undertaken by ENTSO-E has resulted in the development of the NC RfG as the first draft European wide network code in electricity.

ENTSO-E states that it has developed the draft NC RfG in order to set out clear and objective requirements for generators for network connection in order to contribute to non-discrimination, effective competition and the efficient functioning of the internal electricity market and to ensure system security. They further state that the guiding principle of this network code has been to develop requirements for grid connection of generating units with the aim of maintaining, preserving and restoring the security of the interconnected electricity transmission and distribution systems with a high level of reliability and quality in order to facilitate the functioning of the European wide internal electricity market now and in the future.

While ENTSO-E has had a high degree of stakeholder engagement, inevitably not all parties have been or will be satisfied with the resulting draft. The process has also revealed important disagreements between grid users and transmission system operators (TSO) on the appropriate rules that should apply to generators. These were clearly reflected in the consultation responses received by ENTSO-E in the process of development of the draft network code and a smaller number of these disagreements continue still. Operation of any power system involving multiple parties requires that all must operate together to ensure that the system can be operated safely, securely and for the benefit of all parties and especially, for the benefit of their customers, the electricity consumers. This means that some parties will incur costs for the benefit of the system and one issue to be addressed in analysing the current debate is separating those comments made because of genuine technical difficulty and those that are raised in an attempt at moving where these costs will lie. Inevitably, the 'battle' between system users and TSOs about the allocation and/or shifting of additional costs for system security is likely to be a permanent feature of the market.

There are a number of other key issues to be considered in the review. The principle reason behind the Code is the implementation of the 3rd Energy Package and the facilitation of a single electricity market. In parallel with this, the adoption of European or International Standards in place of former National Standards means that equipment manufactured for use in the EU will not differ across national borders without significant cost being incurred. However, recognizing the realities of introducing change and the principles of subsidiarity, the draft NC RfG relies on a number of significant issues being addressed at a Member State level, raising the question of the balance between a European wide code addressing cross border issues and the co-existence of national codes for internal operation of the same system as is required for cross border trade.

The move towards the greater dependence on RES-E in EU and Member State energy policies, brings with it changes in the approach towards system security especially in the distribution network, to which much of the RES-E generation is connected, and at the interface between transmission and distribution networks. By the nature of their power sources, RES-E generators are often capable of less control than traditional generation plants and the growth in dependence on them will have an impact on the future operation of interconnected transmission systems which must filter through to a forward looking network code. With increasing use of RES-E, where the power source is not within human control but impacts large numbers of RES-E generators simultaneously, it is likely that either greater control than has traditionally been required of RES-E generators will be required and/or that all equipment connected to power systems must be capable of operating successfully where the power system parameters are less controlled than has traditionally been the case. The application of the 'new' arrangements that, whatever is the chosen point on this balance, will require modifications to existing plant and must have an impact on the continued economic operation of that existing plant. Consequently, carefully staged or future managed arrangements will be necessary to maintain generation security during the transition process. Some of the issues associated with this migration from dependence on large thermal power stations connected to transmission systems towards small RES-E installations embedded in the distribution systems are considered initially in section 3.3 and later in the assessment of technical and non-technical issues in sections 5 and 6.

Throughout, there is a need to cater for the ability for future technological improvements being made and introduced for the benefit of society as a whole. In this respect, ACER has guided ENTSO-E towards the approach of ensuring that the NC RfG does not introduce technology specific requirements but it is clear that not all technologies have the same capabilities and mechanisms for handling any essential differences – known now or that impact future technological improvements - must be available. Along with this, there is a need to consider the issues raised by the introduction of technologies that allow the operation of generation plants by people or organizations who are neither expert in the field nor that it is realistic to expect them to hold the level of expertise traditionally encountered.

2.3 Task Approach

In undertaking the project to date, cognisance was taken of the intention by ENTSO-E to issue a revised draft code which became available in March 2013. Initially, work was undertaken based on the draft dated 26 June 2012 and updated where appropriate.

It was recognised that throughout the development of the ENTSO-E draft NC RfG, there had been a consultation process in place and that it is undesirable to open dialogue on any matter which has been resolved between ENTSO-E members and the user group associations. The Project therefore mainly operated as a desk based exercise but consultation with key stakeholders was undertaken by any mechanism that appeared appropriate. The outcome of this consultation is considered in section 4, which addresses Stakeholder's views and greater detail of the views expressed is included in the appendices.

2.4 Deliverables

The principal deliverable of the project was a preliminary report which included details of the evaluation/assessment criteria, preliminary findings and assessments and the proposed recommendations to the Commission. Where issues were outstanding at the time of submission of the report, the proposed mechanism for resolution was provided. The initial preliminary report was submitted in June 2013, with the opportunity reserved for a completed version to be submitted in July 2013. It was understood that, as a support to the Comitology process, the completed Preliminary Report would provide guidance on the technical requirements of the NC RfG. While seeking a technical report, the representatives of the Commission services made clear that no prior technical knowledge should be assumed of the prospective readership and that, as far as is possible, the report should be prepared in non-technical language.

This final report is submitted following receipt of views expressed by stakeholders in advance of and during a stakeholder meeting held by the Commission services EC DG ENER in September 2013.

3. Context of NC RfG for Power System Operation

3.1 Background

Historically, integrated electricity utilities developed their construction and operation standards to suit their own requirements and the equipment that could be acquired in their particular environment. The development of national and later international standards was influenced by the requirements of both utilities and manufacturers and impacted both what manufacturers would build and how utilities operated. However, there were always options and integrated utilities did not need to be influenced by the actions of their neighbours. Interconnection required agreement on interconnection arrangements but, while each utility company only used the interconnection as a means of mutual assistance, the operation of their networks remained a matter for them.

During this period, integrated utilities would ensure that they had sufficient highly efficient generating units to run constantly meeting the minimum constant load, with other units operating as required to meet increased demand throughout the day. Where costs dictated and geography permitted, they may have used pumped storage schemes to provide enough demand to keep base load plant operating at times of low load, releasing electrical energy back into the system to meet peak demands.

With the development of unbundling and cross border trade this changed and some level of standardisation became necessary. With unbundling came the need for network codes to document the arrangements for the operation of the separate parts of the previously integrated utility and for dealing with any incoming organisation that wished connection to the network. They did not change anything of the equipment currently connected to the network nor, initially, the means by which the system operator would call on generating units to operate to support the network. They did establish how new units would be called on to operate and, only as competition increased, how the system operator ran its business.

Initially, most network codes were effectively codes of practice and, legally, many remain codes of practice or subsidiary documents to commercial agreements even if it is possible for a regulatory authority to determine whether they are fair and whether parties have reasonably complied with their obligations under them. Only in some countries are they given the weight of law either directly or by including key parts, of what would normally be in a network code, into legislation.

The NC RfG is only part of an overall network code whereas network codes are normally prepared as complete entities. Its requirements must therefore fit with the remaining requirements in other codes in the ENTSO-E drafted suite and the overall suite should include all the requirements expected in a network code. As the connection requirements for generators, it will outline the extreme requirements of TSOs and, elsewhere in the ENTSO-E drafted suite, the TSOs should specify how these requirements will be used. Somewhere, it would be usual to include details of how the arrangements for modification to the complete code would be carried out. Modifications are inevitable in the life of a network code and in the life of any network connected to the transmission system. The rights and responsibilities of all parties during the modification process would usually be stated, including the arrangements for consultation where that is part of the national process.

3.2 System Operator Requirements

For the system operator, there are a number of key requirements to maintain active and reactive power balance – crucial if system security is to be maintained:

a) Frequency control;

b) Voltage control; and

c) Continued operation of generating units during system fault conditions.

In addition, some other specialised system services are required to be able to restart power systems after blackouts.

Frequency and voltage control are essential, both for system operators and for system users as much of the equipment used to construct the network and operated by users will be damaged by frequencies or voltages outside their design limits. Frequency drift from the nominal system frequency is an indication of imbalance between generation and active power consumption and control arrangements are established by system operators to ensure that the level of generation will follow the level of demand. This requires a level of control over generation that is easily achieved with enough traditional generating units to maintain system balance but which has not normally been required of smaller generating units generally and wind and PV installations in particular. As the penetration of these technologies has increased, those TSOs most affected have sought to apply control to allow the system as a whole to be operated securely[3]. As this is a relatively new requirement for

[3] Many of the issues that are now being addressed by TSO and result from the increased penetration of small RES-E installations connected to the LV network are outlined for PV in: Kaestle and Vrana, *Improved Requirements for the Connection to the Low Voltage Grid*, presented to the 21st International Conference on Electricity Distribution, Frankfurt, 6-9 June 2011, and available at: http://www.iee.tu-clausthal.de/fileadmin/downloads/CIRED2011_1275_final.pdf

smaller generating units, no standard arrangement has been established to address this issue.

Continued generating unit operation during system fault conditions is essential for two reasons:

a) To ensure that the system recovers once the fault condition has been isolated from the healthy portion of the system; and

b) To ensure that the fault condition can be isolated by the protection systems.

Almost all Power System Protection systems operate by monitoring current flows and using this information to detect abnormal conditions. This requires that abnormal current flows can continue until the protection system can clear the fault condition by causing the isolation of the affected network section. Failure to achieve this correctly will result in either a more widespread and extended duration failure in electricity supply or could present a hazard to equipment, to those working in the sector and to the general public.

3.3 Impact of RES-E

Traditionally, this continued operation was achieved by the inertia and dynamics of synchronous generating units and integrated utilities would ensure that sufficient synchronous generating units existed on their networks and were operating in the required locations. Unbundling removed the opportunity for system operators to influence the location or scheduling of synchronous generating units and the move towards RES-E has distorted the synchronous/asynchronous balance as, in addition to the possibility of hydro, biomass and biogas operated generating units being either synchronous or asynchronous machines, all wind and PV generating units are asynchronous in their operation. More recently, TSOs operating systems where there has been significant RES-E penetration have sought modification to their Grid Codes requiring that all generating units mimic enough of the inherent capabilities of synchronous generating units to maintain the security and safety of the electricity system. In the case of some TSOs this process commenced almost 10 years ago whereas, for others, the development of sufficient small generation to require this transition is yet to happen. In some areas, this transition is extended in these codes, either by introducing what are effectively new obligations for some TSO areas or extending the application of obligations to smaller generating units. For some issues TSOs, whose networks have been affected by this transition, have developed requirements that address their own particular issues and, for several of these requirements, no single standard yet exists.

The need for this change in emphasis by many TSOs can be seen from the change in provision of generating units in Germany. As previously noted, in the past, integrated utilities would ensure that they had sufficient highly efficient generating units to run constantly meeting the minimum constant load, with other units operating as required to meet increased demand throughout the day. However, as a result of changes to market structures and in energy policy, this situation has been changing for TSOs. In more recent times, the increased penetration of RES-E installations has reduced the need for major base load plants and the growth of PV has ensured that generation by RES-E installations increases during peak daylight periods. The effect can be seen in **Figure 2**, which shows the cumulative installed capacity of RES-E installations. The minimum demand of the German electricity system is around 35 000 MW and Figure 2 shows that this level has been exceeded by the installation of RES-E capacity, with the result that there can no longer be any guarantee that any synchronous generating units would be operating. It will therefore become essential that all types of generating units are capable of delivering those system security features traditionally provided by synchronous generating units whose operation could previously be guaranteed[4]. For some TSOs, this is a current requirement that they have had the opportunity to consider to some point. For others, this will be a future requirement as yet unconsidered.

The determination of a single definition for these requirements has not been attempted as part of the development of the NC RfG, the matter being left for resolution at national or regional level. This approach will, reasonably, result in differences between the specifications that will result. Operators of highly interconnected systems can, within the limits of their mutual support arrangements, rely on adjacent systems to assist with frequency support during fault conditions and therefore will predominantly seek voltage support to be developed from the asynchronous generating units. Operators of non-interconnected or only lightly interconnected networks would also need to deal with frequency issues and therefore will wish to apply a specification that attempts to address

[4] Some features like voltage and reactive power support can also be supplied separately from generating units, by FACTS (Flexible AC Transmission Systems) like SVC and STATCOM. These systems can be provided by either the relevant network operators or by the generators and, while each group would prefer the cost is met by the other party, examples exist of their provision by both groups. Network operators will provide them where they improve the cost effectiveness of the operation of their networks, generators will provide them where that allows their installations to comply with the requirements of the applicable Network Code. See for example: http://www05.abb.com/global/scot/scot221.nsf/veritydisplay/b9c403656feacb5348257a28006af4a0/$file/FACTS%20to%20facilitate%20AC%20grid%20integration%20of%20large%20scale%20wind%20generation.pdf; http://www05.abb.com/global/scot/scot256.nsf/veritydisplay/26ab4cd0ecbe3bcbc1256b9d004a7c88/$File/statcom.pdf; or http://www.energy.siemens.com/hq/pool/hq/power-transmission/FACTS/SVC_PLUS_The%20efficient%20Way.pdf

both frequency and voltage. However, all TSOs will require that the asynchronous generating units[5] will provide sufficient current injection during system fault conditions to ensure the operation of protection systems.

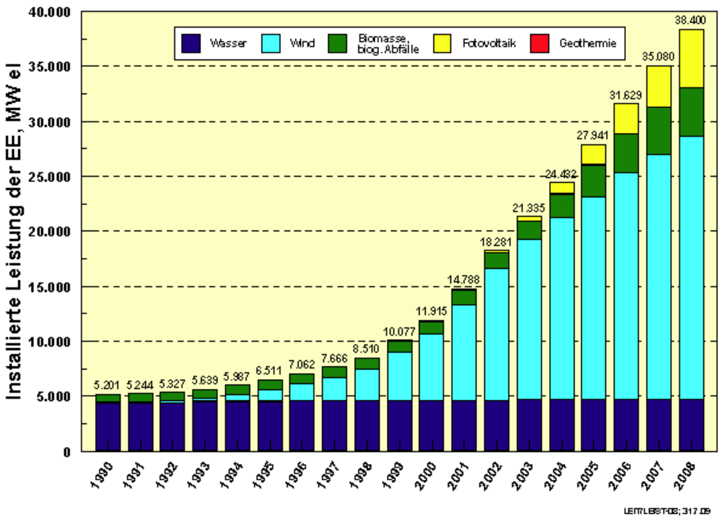


Figure 2: Cumulative installed capacity of renewable energy for power generation[6]

Much of the RES-E capacity is provided by a large number of small generating units and this has the effect that:

a) The sum of these relatively small units, whether co-located as part of a single large installation or distributed throughout the electricity networks can have an impact on cross border electricity flows that was previously not considered possible;

b) While co-located units that form part of a single installation will usually be connected to transmission networks, many of the smaller installations are connected to distribution networks. Since the plant that they displace was predominantly connected to transmission networks, this change in the point of connection has an impact on forward looking requirements for the design and operation of electricity networks.

That the connection of a large number of small installations sharing the same power source can have significant effect on cross border operation of grid systems is illustrated by an incident on 4 November 2006 considered in appendix D.

---

[5] For the avoidance of doubt, asynchronous generators can also include synchronous electrical machines that are connected to the system by means of a converter.

[6] Source: Bundesministerium für Umwelt, Naturscutz und Reaktorsicherheit, *Langfristszenarien und Strategien für den Ausbau erneuerbarer Energien in Deutschland*, 11055 Berlin, August 2009. Available at: http://refman.et-model.com/publications/1262

3.4 Effect for Distribution Networks

Historically, the main power supply to distribution networks has been from its connection points to the transmission system and it is only recently, that, in certain operational regimes, generation embedded into the distribution network has exceeded customer demand on these networks. To ensure the safe disconnection of faulted distribution networks, generating units connected to these networks have been required to stop generating in the event of a loss of voltage on the distribution network. This resulted in the safest situation for the general public, employees of the distribution system operator and for the network itself. It also ensured that restoration of supplies to affected customers could happen in the shortest possible time. The requirement to disconnect is still the safest position for faults affecting the distribution network but, with the increase in embedded generation, certain types of faults will not result in a loss of voltage and therefore disconnection cannot be guaranteed. Where there is a net energy transfer from the distribution network to the transmission network, for the reasons outlined in section 3.2, the TSO will wish this generation to ride through faults in the transmission network, while the DSO will wish it to disconnect for faults in the distribution network. The TSO will wish the distributed generation to contribute to frequency and voltage stability but it is this instability that is used to identify faults on the distribution network for which disconnection is required.

Some of the impacts of the growth in distributed generation for DSOs and the effect of some of the TSOs' requirements are considered in greater detail in appendix E. This appendix focuses on impacts on the distributed generation protection systems, distribution system protection and islanding and the fault currents that can be safely handled by the distribution networks. For some of these issues, it is not currently possible to establish meaningful data on the potential impact of this requirement on distribution networks but, while acknowledging the benefit for TSOs, it must also be recognised that there is likely to be an impact for DSOs.

As currently drafted, Article 15.2 b), dealing with fast reactive power injection, begins, "*The Relevant Network Operator, in coordination with the Relevant TSO shall have the right to require....*" and this approach should allow the DSO to ensure that its network can be operated safely. However, other sections are less clear on which network operator has the final say when other requirements are applied. In considering the TSOs' requirements in the NC RfG, it is therefore essential for public safety that the DSOs' requirements are also addressed in all cases.

One particular issue raised by DSOs relates to the application of a fault ride through requirement for the relatively small number of Type B generators that will be connected to LV networks. Fault ride through is a necessary requirement for disturbances affecting the HV network and is undesirable for faults affecting the LV network. The DSOs have raised this issue on grounds of cost and issues related to the effect on protection systems and public safety. In considering this issue, it is worth remembering that part of the LV distribution network enters all domestic and most other premises in the local area and any delay in necessary disconnection is therefore to be avoided wherever possible. It is worth also considering the normal clearance times of protection systems generally employed on LV networks. These are generally significantly longer than the clearance times to be expected for HV disturbances.

Taking all issues into account, it would appear preferable not to apply fault ride through obligations on generating units connected to LV networks. In practical terms, this has no disadvantage for the TSOs as the protection systems used with generating units connected to LV networks are unlikely to operate within the clearance times for disturbances on HV networks. However, for DSOs and public safety, avoiding this requirement will mean that no unnecessary delays will be built into the clearance of faulted LV networks.

4. Stakeholders' Views

4.1 General

In section 3, the context of the NC RfG in the operation of electricity systems has been outlined and some of the conflicts that need to be addressed between the objectives of the various stakeholders identified. It was noted that the NC RfG is only a part of what is usually included in a network code, other parts being drafted by other drafting teams from ENTSO-E. This approach has presented stakeholders with a major difficulty in establishing exactly what ENTSO-E's aims are and how the approach that has been taken will affect them.

Major issues for any system user seeking a connection to the TSO's network or already connected to that network at the time a new code is prepared will include:

a) The technical connection requirements specified in the connection code;

b) How the connection requirements translate into operational requirements both on the user and the TSO;

c) How the code will be applied to their connection (both technical connection requirements and operational obligations) on day 1; and

d) How (all parts of) the code will be modified over time.

The NC RfG is the first part of the overall network code that was drafted by ENTSO-E. Viewing this in isolation has presented a major difficulty for stakeholders identifying exactly what the impact on them will be. This situation was exacerbated by examples of apparently conflicting requirements or statements between the various documents, particularly in the early stages of drafting. As noted in section 3.1, the connection codes may detail extreme ranges of some parameters, with operational codes detailing planned normal and extreme circumstances within these ranges. A significant consultation process was undertaken as the NC RfG was being drafted, but the lack of visibility of key issues for stakeholders made this a difficult process for them to accept that their particular concerns have been addressed. During the discussions with stakeholders undertaken as part of this review, all parties described the earlier consultation process as unsatisfactory although they were prepared to move on and discuss the issues that remained for them in the current draft. One group of stakeholders, however, specifically requested that the notes of a discussion with them also recorded their stated dissatisfaction with the consultation process and the approach of ENTSO-E during it and others commented unfavourably about the late inclusion or modification of requirements without the opportunity for proper consideration and comment by stakeholders before submission of the draft NC RfG to ACER for their opinion.

Appendix A contains the agreed notes of meetings held with:

a) ENTSO-E;

b) Micro CHP Generators, represented by COGEN Europe and EHI;

c) DSOs represented by Eurelectric, CEDEX, Geode and EDSO for Smart Grids;

d) EU Turbines, representing turbine manufacturers;

e) EUR, representing the Nuclear Generators;

f) European Photovoltaic Industry Association; and

g) Thermal Generators, represented by Eurelectric and VGB.

Appendix B contains notes of meetings with other stakeholders who have not, to date, raised any objection to the points drafted, but neither have they provided their explicit approval to the version of notes included. These stakeholders include:

a) ACER, represented by the NRAs taking the lead role regarding connection codes;

b) European Wind Energy Association; and

c) CENELEC.

Meetings, teleconferences and telephone conversations were also held with representatives of individual stakeholders who had requested the opportunity to present information that would be inappropriate for discussion within a trade association environment. This information was presented with notes of confidentiality and is not recorded in this paper. Further discussions were also held with ENTSO-E and other stakeholders as prompted by the review activity.

Other stakeholders sought the opportunity to prepare and submit position papers for consideration. These papers and position papers received from stakeholders following meetings are (unless attached to the notes of meetings as clarification of material therein) attached in Appendix C.

4.2 Outcome of Initial Project Consultation

During the consultation process with stakeholders and the later period during which further representation was made to the project team, the issues raised fell into two distinct categories:

a) Technical issues; and

b) Non technical issues with a technical impact.

The requirement of this project is to provide guidance, in as non-technical a manner as possible, on the technical issues that are raised by the NC RfG. It was, however, permitted for comment to be made on any appropriate non-technical issues without recommendations being proposed. In the preparation of this report, assessment and comment has been restricted to technical issues and non-technical issues that have a direct technical impact. Because of their technical impact, some issues that may be viewed as non-technical have therefore been considered on an equal basis as entirely technical issues. Comment has been made regarding other non-technical issues that will have a material impact on the operation of the code but, in accordance with the instructions for this review, attention is drawn to these issues without recommendation being made.

While stakeholders raised a significant number of technical issues, many of the concerns expressed by stakeholders on technical issues have not referred to the technical requirements themselves but rather to what the technical requirements might become. What the stakeholders appear to be seeking is a robust amendment and approval procedure but they have not elucidated this and, on several points, are trying to make a case on the basis that any changes in the requirements of the code will not simply be enacted rather than being subjected to proper review and consideration before approval is given. What hypothetically might happen in the future cannot be a concern of this review. Therefore, where it is apparent that the lack of clear governance arrangements lie at the bottom of the issue raised, these hypothetical concerns have not been considered as individual technical issues, rather the governance arrangements are commented on as a non-technical issue in section 6.2.

Another stakeholder comment concerns what they consider is the unbalanced nature of the code in that it gives the TSOs rights and places all the requirements and obligations on the stakeholders – i.e. the generators. The code is entitled the 'Requirements for Generators' so it is only to be expected that the requirements would be placed on the generators. The obligations of the TSO should be clearly identified in other codes within the overall framework of which the NC RfG is a part. However, there are certain issues where the current drafting of the NC RfG does appear unbalanced and these issues are addressed in the relevant technical issues in section 5 and under certain non-technical issues in section 6.

The principle responsibility of the TSOs under the NC RfG is to ensure in operating the system that the generators can and do meet their obligations to provide support to the system so that a secure electricity transport network is available for all users. ENTSO-E correctly note in part (8) of the 'Purpose and Objectives' of the NC RfG that '... system security cannot be ensured independently from the technical capabilities of Power Generating Modules. Regular coordination at the level of generation and adequate performance of equipment connected to the networks with robustness to face disturbances and to help to prevent any large disturbance or to facilitate restoration of the system after a collapse are fundamental prerequisites'. In other words Power Generating Modules provide one of the tools available to TSOs in order to carry out their role and ensure system security.

As previously noted, in the form that the network codes have been drafted, the NC RfG is one of a suite of codes that together establish the arrangements for the use of the transmission system. While the NC RfG places obligations on generators, a number of the other codes - particularly the Operational Security and Load-Frequency Control & Reserves codes - will have clear requirements for the TSOs to fulfil. For many of the technical issues raised, the difficulty for stakeholders is not the technical issue itself – for example, there is particular technical relevance, considered in sections 5.1 and 5.1.3, regarding the combined effect of the use of the specified frequency and voltage ranges, not shown in NC RfG but correctly a matter for other codes – but it is the lack of clear harmonisation arrangements with the other network code documents that together with the NC RfG will establish a more usual complete network code. Harmonisation is therefore an important non-technical issue with significant technical relevance and is addressed in section 6.4.

4.2.1 Technical Issues

The technical issues raised by stakeholders include:

a) Frequency Ranges;

b) Active Power Output with falling Frequency;

c) LFSM-O and LFSM-U ;

d) Voltage ranges and the possible need for on load tap changers where not currently employed;

e) Interaction of voltage ranges and reactive power capability requirements;

f) Provision of reactive power as a means of voltage control;

g) Fault Clearance Times;

h) Fast Reactive Power Injection and active power recovery;

i) Fault Ride Through requirements as applied to LV Networks;

j) Operation of NC RfG for LV connected generators;

k) Conflicting requirements relating to the operation of protection systems;

l) Industry Structure and the application of transmission rules to distribution networks;

a) Compliance Requirements, including:

   i. Specification of requirements;

   ii. Compensation arrangements; and

m) Practical Arrangements for Addressing Obligations placed on non-expert Parties.

These issues are considered in section 5, in which the technical requirements of the NC RfG are assessed.

4.2.2 Non Technical Issues

The non technical issues raised by stakeholders include:

b) Format/Legal status of the document;

c) Arrangements for future modifications of the NC RfG;

d) Retrospective application, including:

   i. Cost benefit analysis methodology;

   ii. Carry over of derogations under existing Grid Codes;

   iii. Funding of necessary changes where retrospective application occurs;

e) Cross Code Harmonisation, in particular:

   i. NC RFG requirements vs TSO obligations in the NC LFC&R;

   ii. Harmonisation with requirements of NC Operational Security;

   iii. Harmonisation with requirements of NC Demand Connection;

f) Use of and impact on International and European Standards.

These issues are considered in section 6, in which some of the non technical issues that the NC RfG raises are addressed. A number of stakeholders requested clear and detailed explanation of a number of issues. All other ENTSO-E NCs have had their Supporting Documents issued together with the Code. ENTSO-e developed a number of documents in parallel with NC RfG, but the preparation of one single supporting document addressing those issues where there is a lack of clarity would be helpful for the commitology process.

4.2.3 Implementation Issues

From a review of stakeholders' comments within the ENTSO-E consultation process on the draft Code and later discussions with stakeholders' groups, it is clear that a major concern for stakeholders is the potential for a wide range of values to be chosen by different TSOs for certain parameters and both ACER and ENTSO-E were asked at an early stage to canvass members for a 'without prejudice' view of the likely values to be selected. Initial conversations indicated that this was unlikely to result in responses that might be helpful in the review, informal views being expressed on behalf of both groups that values would still be established after the approval of the final document to ensure compliance with its requirements.

Later discussions established that both organisations expected changes from current practice to be subject either to the current national arrangements for review of network codes until the day before implementation of the NC RfG or to review in accordance with the revised review arrangements detailed in the NC RfG. This view was repeated during the meetings recorded and for which notes of meeting are contained in the appendices. For the purposes of this review therefore, existing values have be assumed to continue beyond approval and stakeholders' concerns been considered against the arrangements for change of values and for the ongoing management of the Code.

ENTSO-E has indicated that in each location in the NC RfG that a range is indicated for non-exhaustive requirements, this range has been selected to allow the TSO to insert its current value. ENTSO-E has indicated that this is a position to which it will hold. An initial comparison of the ranges in the NC RfG with the values indicated in ENTSO-E's paper, "*Network Code for Requirements for Grid Connection Applicable to all Generators – Requirements in the Context of Present Practices*" indicates that a further review would be appropriate before making any recommendation and this will be undertaken over the coming month. In some parts of the code it is acknowledged that currently used values are quoted but it is noted that some conditions associated with these values are not included. In addition, there is little or no justification provided to support the proposed ranges being developed using the most extreme limits in the current practice without proper assessment or for the use of some of those extreme values as these are usually associated with, or defined for, specific operational circumstances .

A number of stakeholders expressed concern about the extent to which the NC RfG requirements do not match existing international or European standards. Others commented on the need for the development of standards that would facilitate the implementation of the NC RfG. These issues are briefly considered in section 6.4.2.

4.3 Later Stakeholder Consultation

Following submission by the Consultants of a Preliminary Report, EC DG ENER invited comment from ENTSO-E and stakeholders' European Associations and held a Stakeholder Meeting on 16 September 2013. Papers provided by stakeholders during this period are included in Appendix G and non-approved Notes of the Stakeholder Meeting are included as Appendix H. A significant number of comments were made immediately prior to the stakeholder meeting – and could not be taken into serious consideration in time – or were received following that meeting. Some of these comments largely repeat earlier positions, a small number express an unexpected interpretation of the recommendations in the preliminary paper and others provide new information. All have been considered in the development of the recommendations in this report.

5. Assessment of Technical Requirements

5.1 Frequency related issues

5.1.1 Frequency ranges

<table>
<tr><td>NC RfG Article</td><td colspan="2">8.1.b – Table 2</td><td>Stakeholders Commenting</td><td>EUR; Thermal Generators;</td></tr>
<tr><td colspan="2">Stakeholder Comment</td><td colspan="2">Key Analysis</td><td>Proposal</td></tr>
<tr><td colspan="2">While concerned regarding extension of frequency ranges, stakeholders’ main concern is the combined effect of frequency and voltage ranges and, at the time of commenting, the lack of visibility of TSOs’ obligations to maintain the range of normal operation and minimise the time of operations in ranges beyond normal operational range.</td><td colspan="2">In many Network Codes, frequency, voltage and required period of operation at particular points are specified together, making clear the actual effect on the connected users. NC RfG specifies frequency and voltage ranges separately. ENTSO-E reasonably state that there is some interaction reflected in the NC RfG since, at any frequency and voltage combination it would be the lower time period for which a generating unit is requested to remain connected.

However, any graphical representation of NC RfG frequency vs voltage would result in a series of squares whereas, IEC standards, recognising the technical limitations of equipments, do not result in such a representation.</td><td rowspan="2">Recognising that the only obligation for generating units specified in the NC RfG is to remain connected and not to operate normally, it is proposed that the frequency ranges to be applied in NC RfG should follow IEC Standards.

To allow for the correct representation of these standards, consideration should be given to incorporating frequency and voltage requirements into a single diagram.</td></tr>
<tr><td colspan="2">One stakeholder commented that the TSOs’ use of IEC 60034-1:2010 as the basis of the extended range is flawed since the standard only applies to rotating plant and does not take account of interacting mechanical plant.</td><td colspan="2">The stakeholder’s comment is valid and correctly records that TSOs cannot expect power stations to operate normally across the specified range. However the only obligation applied by NC RfG is to remain connected.</td></tr>
</table>

Since frequency is shared by all equipment connected in and to the network, the extended range of frequency and voltage cannot be used by TSOs unless a case is made for retrospective application.	Such a case for retrospective application must be made throughout the synchronous zone in which it is to apply. Without this, TSOs do not have ability to use the extended range until current power plants are retired. Many plants have an expected operational life of around 60 years.	

5.1.1.1 Background to the Issue

Frequency is the only common parameter for the synchronous area and, accordingly, this is the technical aspect whose quality concerns equally network operators and all grid users. Network operators and, at the top of the power system control hierarchy, TSOs, are the most responsible entities for power system safe and reliable operation, which first of all means stable frequency and voltage. This is especially the case with the growing penetration of renewables in the electrical networks at various levels and it is clearly understood why TSOs require generating units to remain connected to their electrical grids as long as possible in case of frequency deviations[7]. From that point of view, the requirement for a relatively wide range of unlimited operation at frequency deviations between 49,00Hz and 51,00Hz introduced in the NC RfG is understandable. The position of the stakeholders during the consultations was very supportive – most of the stakeholders that commented on this requirement understood the point of view of the TSOs (and ENTSO-E) and focused their concerns on frequency quality parameters, i.e. on determination of the duration and, possibly, frequency of occurrence, of operations at frequency values beyond Standard Frequency Range and/or Maximum Steady-State Frequency Deviation.

The frequency range proposed in the NC RfG for unlimited operations is wider than existing solutions in most of the national grid codes. Behind this proposal there was no proper justification from ENTSO-E beyond noting that the range specified was that of IEC 60034-1:2010 for rotating electrical machines (Part 1: Rating and performance). However there was no strong opposition either, concerns primarily focusing on the potential combined impacts of the frequency and voltage ranges. There are number of the existing Grid Codes in Europe, including those in Germany, Switzerland and Sweden, where frequency and voltage requirements are presented in a single diagram indicating clearly conditions for operations under synchronously disturbed normal voltage and frequency ranges. An example, from the

[7] Unlike for voltage deviations, where network operators may use their own resources for voltage control, in case of frequency all the control “tools” are with grid users, either generators or demand customers.

Swiss Grid Code is shown in Figure 3 below. It is noted that, when these combined impacts are established in codes in the ENTSO-E suite, they should reflect current practice if the commitment made by ENTSO-E and ACER regarding the change process is to be met.

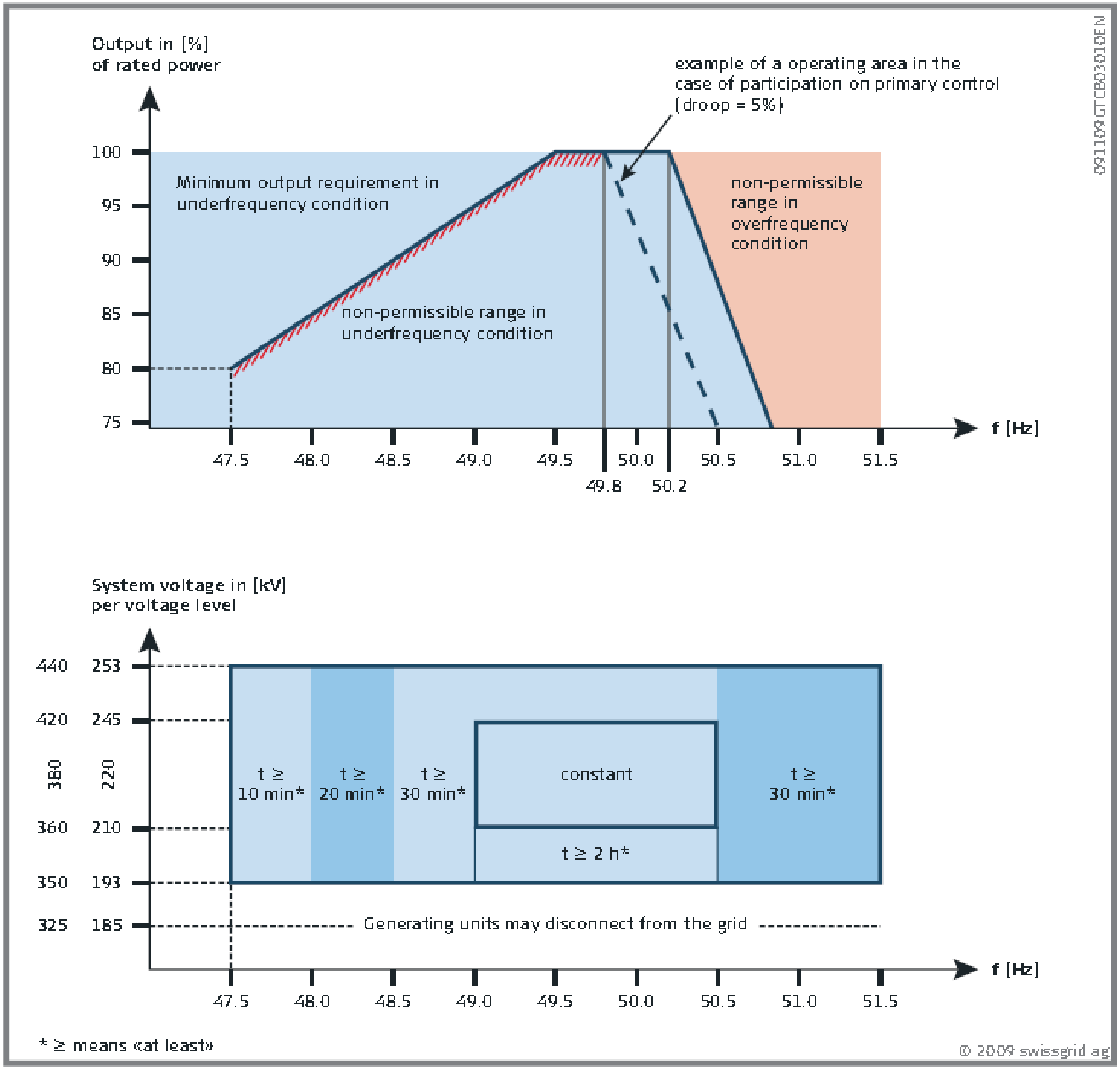


Figure 3: Power Output, Voltage and Frequency requirements for Generating Units

On the other hand, the proposal for frequency range for unlimited operations is technically feasible since it is fully compliant with the IEC standard 60034-1:2010. This standard allows for operations of the rotating machines between 47.5Hz and 51.5Hz (applied in the NC RfG for all synchronous areas except for GB), under the condition that operations in this extended range are limited in extent, duration and frequency of occurrence[8].

There is a need for caution, not apparent in ENTSO-E's documentation, in the application of the frequency ranges specified in IEC 60034-1:2010. EUR raised this issue in the terms of the situation where individual equipments in a power station meeting the requirements of IEC 60034-1:2010 will not necessarily mean that the station as a whole is capable of operating throughout the specified frequency range.

The standard is only applicable to rotating electrical machines (alternators, motors) and not the equipment mechanically connected to them (turbines, pumps, fans, compressors). When frequency drops, then the speed of the mechanical equipment reduces. The performance (power, flows, pump head etc) will be reduced. Power station engineers will take this into account when designing the auxiliary systems of the power plant to avoid power generation being affected when frequency drops. Particularly in the case of existing installations, the extension of the frequency range will not be as easy to apply as ENTSO-E suggest if normal operation is required. However, the specified requirement in NC RfG is to '*remain connected*' and it is feasible that generating units, even if affected (within reason) by the interaction of mechanical and electrical equipment affected by frequency changes should remain connected.

[8] NOTE 1: As the operating point moves away from the rated values of voltage and frequency, the temperature rise or total temperatures may progressively increase. Operation – particularly over prolonged periods - at increased temperatures causes premature aging of electrical plant, and can, at worst, result in catastrophic failure. For this reason, operators must manage the operating temperature of their equipment. Continuous operation at rated output at certain parts of the boundary of the shaded area causes temperature rises to increase by up to 10°K approximately. Generators will also carry output at rated power factor within the ranges of ±5 % in voltage and +3/-5 % in frequency, as defined by the outer boundary of Figure 1 but temperature rises will be further increased. Therefore, to minimize the reduction of the generator's lifetime due to the effects of temperature or temperature differences, operation outside the shaded area should be limited in extent, duration and frequency of occurrence. The output should be reduced or other corrective measures taken as soon as practicable.

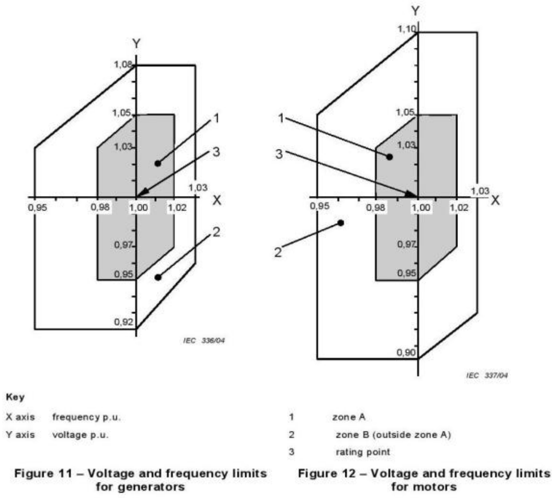


Figure 4: Voltage and Frequency limits according to the IEC standard 60034-1

Since most of the conventional power generating units use turbine driven generating units > 10 MVA, IEC standard 60034-3 is more relevant concerning frequency and voltage operational ranges (see Figure 5 below).

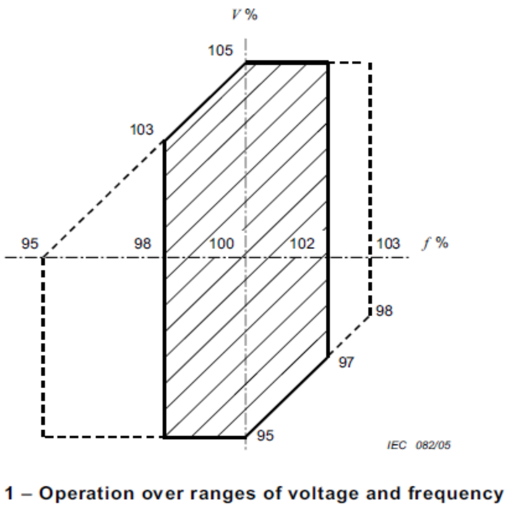


Figure 5: Voltage and Frequency limits according to the IEC standard 60034-3

Limitations concerning power system operations within extended frequency ranges are the concern of the TSO. Accordingly, they should be defined in the NC LFC&R, as a TSO obligation concerning quality of the network (power system) operations. From the technical standards point of view, power frequency quality is defined according to the CENELEC standard EN 50160 as follows:

"The nominal frequency of the supply voltage shall be 50 Hz. Under normal operating conditions the mean value of the fundamental frequency measured over 10 s shall be within a range of:

- *for systems with synchronous connection to an interconnected system:*

  50 Hz ± 1 % (i.e. 49,5 Hz... 50,5 Hz) during 99,5 % of a year;

  50 Hz + 4 % / - 6 % (i.e. 47 Hz... 52 Hz) during 100 % of the time,

- *for systems with no synchronous connection to an interconnected system (e.g. supply systems on certain islands):*

  50 Hz ± 2 % (i.e. 49 Hz... 51 Hz) during 95 % of a week;

  50 Hz ± 15 % (i.e. 42,5 Hz... 57,5 Hz) during 100 % of the time."

This kind of frequency quality requirement determination is not unknown to national codes either. In the NC LFC&R, Article 11.4, Table 2 the Frequency Quality Target Parameter is clearly defined. This is the maximum number of minutes per year outside the Standard Frequency Range (e.g. for Continental Europe frequency deviation is +/- 50mHz, which is 49,95 – 50,05 Hz).

In the Article 11.3 Table 1 all Frequency Quality Defining Parameters of the Synchronous Areas should be defined but for some synchronous areas important parameters, or pairs of parameters defining frequency quality, are missing. For example, for Continental Europe, there is defined Time to Restore Frequency[9] but it is not clearly indicated to what value, i.e. Frequency Range within Time to Restore Frequency[10] value is not defined**.** On the other hand, the same Table 1 of the NC LFC&R does not define Time to Recover Frequency[11], a parameter for which the target is very clearly defined (Maximum Steady State Frequency Deviation, which is, in case of Continental Europe, +/- 200mHz). Any other frequency quality criteria or defined limits for operation under the frequency beyond normal ranges may also be acceptable (see example from the Polish Grid Code[12]). Ideally, at least one pair of

[9] **Time to Restore Frequency** means the maximum expected time after the occurrence of an imbalance smaller than or equal to the Reference Incident in which the System Frequency returns to the Frequency Range Within Time to Restore Frequency for Synchronous Areas with only one LFC Area; for Synchronous Areas with more than one LFC Area the Time to Restore Frequency is the maximum expected time after the occurrence of an imbalance of an LFC Area within which the imbalance is compensated;

[10] **Frequency Range within Time to Restore Frequency** means the System Frequency range to which the System Frequency is expected to return after the occurrence of an imbalance equal to or less than the Reference Incident within the Time To Restore Frequency;

[11] **Time to Recover Frequency** means the maximum expected time after the occurrence of an imbalance smaller than or equal to the Reference Incident in which the System Frequency returns to the Maximum Steady State Frequency Deviation.

[12] Article II.B.3.3.1.23.of the Polish Grid Code from 2010: "The generating units should have the option of operating within the frequency range from 49,0 to 48,5 Hz continuously though 30 minutes, a total of 3 hours per year; from 48,5 to 48,0 Hz

parameters for each synchronous area should be defined in the NC LFC&R, Article 11.3, Table 1: either Time to Recover Frequency and Maximum Steady State Frequency Deviation, or Time to Restore Frequency and Frequency Range within Time to Restore Frequency. The best possible option is to determine both. If these quality parameters and targets for the TSO were clearly defined, Table 2 in Article 8 of the NC RfG, as currently proposed, would be more acceptable to stakeholders. It is however recognised that possible changes to the NC LFC&R are outside the terms of Reference for this review but it is noted that the interaction of the various codes is important for stakeholders and should be considered by NRAs when approving codes introduced by TSOs.

5.1.2 Active power output with falling frequency

NC RfG Article	8.1.e	Stakeholders Commenting	EU Turbines, EUR, Thermal Generators
Stakeholder Comment		Analysis	Proposal
This issue has been introduced into national network codes by some, but not all, TSOs and is a particular issue relating to penetration of (relatively light) CCGTs lacking the inertia associated with traditional synchronous generating units. EU Turbines note that this is maintained as a non-exhaustive requirement. Different TSOs have taken different approaches to specifying what are similar requirements and that the overall effect of complying with the full ranges as specified would result in significant derating of equipment. EU Turbines effectively seek the detailed specification by the		This issue is valid for TSOs with higher penetrations of CCGTs on their networks. Ideally, a common approach should be taken by TSOs to what is a common problem. The proposed ranges in the current drafting do not guarantee that the intrinsic operational characteristics of CCGTs will be taken into account in setting non-exhaustive requirements. Greater detail is required to clearly identify the actual requirements in a manner that can be met by equipment designers. Thermal generators operate by producing steam used to operate turbines. To maintain the flow of steam requires that the flow of water to boilers is maintained at the appropriate rate. This requires the operation of boiler feed pumps whose mechanical ability will be affected by the falling frequency applied	The requirements should be more completely defined, particularly with obligations placed on TSOs and NRAs to take account, when setting non-exhaustive parameters, of ambient temperatures and the technical capabilities of relevant technologies. This could be achieved by extending the compliance section of the NC RfG in a manner similar to that of the GB Grid Code to more clearly define the required characteristics of gas turbines operating at falling frequencies, but must also take account of the need to safely manage the

continuously through 20 minutes, a total of 2 hours per year and within the range from 48,0 to 47,5 Hz through 10 minutes, a total of 1 hour per year".

manufacturer of what is achievable by a particular machine and for the TSO to take account of this specification in system operation. Other stakeholders raise the issue of the effect of frequency on the operation of electric motors connected to mechanical equipment required to operate in a specific manner if power output is to be maintained. This issue is discussed in section 5.1.1.	to their electric drives. This is one of the frequency related issues that has to be taken into account by designers at the initial development stage, and may make retrospective applications difficult if not impossible. This issue cannot be decoupled from ENTSO-E's wish to extend upwards the maximum frequency range. A pump operating to ensure sufficient pressure to meet ENTSO-E's wish for active power to be maintained at low frequencies will produce higher pressures at ENTSO-E's proposed extended high frequency range. As in the case of the issues raised by EU Turbines, this requires clearer definition than contained in the NC RfG as currently drafted.	operation of pressure vessels.

5.1.2.1 Background to the Issue

The definition of requirements for maintaining active power output with falling frequency is one of the newer issues included in several grid codes but not yet all. As noted in section 5.1.1, there can be concerns regarding this requirement depending on how the specified frequency ranges for power stations as a whole interact with the standards applicable to individual power station elements.

In addition, this is an area where the ENTSO-E approach of defining requirements for all technology types without discrimination may inadvertently result in discrimination. Representations were made by EU Turbines regarding the potential impact of this requirement on the efficiency of operation of gas turbines where the unqualified limits shown in the NC RfG may require a significant derating of plant to meet what is an infrequent requirement. EU Turbines provided the figure included in Figure 6, which shows how the power output of a typical unit would vary according to frequency and ambient temperature.

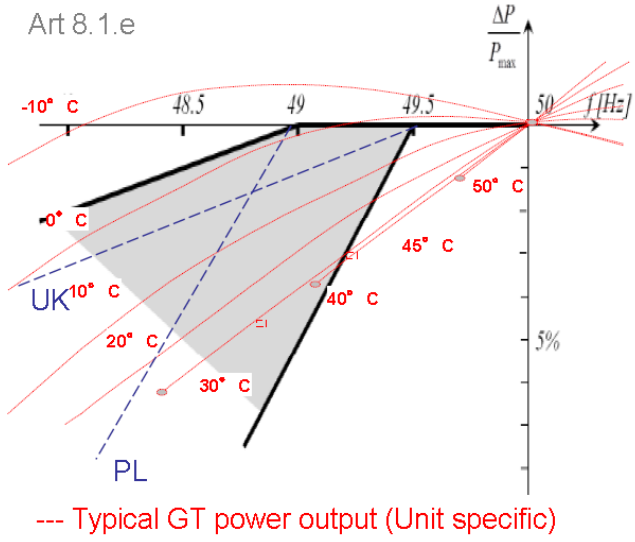


Figure 6 – Active Power Output of a Typical Gas Turbine with falling Frequency[13]

The turbine manufacturers propose that details of the intrinsic operational features of each unit are provided to the TSO, leaving the TSO to address all the issues relating to the operation of the unit in abnormal circumstances – precisely the time it will be least able to do so. However, they also note that the GB Grid Code, which they identify as including the most stringent requirement in this respect, includes additional details of the compliance requirements that are not included in the NC RfG. CCGTs installed in GB during recent years have had to comply with this requirement and the manufacturers have been developing technical measures to compensate the physical output drop as detailed in the more extensive compliance specification included in the GB grid code as shown in Figure 7.

Parameter to be Tested	Criteria against which the test results will be assessed by NGET.
Output at Reduced **System Frequency**	CC.6.3.3 - For variations in **System Frequency** exceeding 0.1Hz within a period of less than 10 seconds, the **Active Power** output is within ±0.2% of the requirements of CC.6.3.3 when monitored at prevailing external air temperatures of up to 25ºC., BC3.5.1

Figure 7: Compliance Criteria for Active Power Output with Falling Frequency

13 Source: EU Turbines. The temperature curve applicable to the operation of a gas turbine is unit specific.

Recognising:

i. That the open ended specification currently included in the NC RfG is a genuine concern for turbine manufacturers;

ii. That TSOs with a significant gas turbine penetration in the generation mix genuinely require an obligation of this type;

iii. That the proposal that TSOs manage the disparate variety of units' behaviour during times of disturbance is considered impracticable;

iv. That the turbine manufacturers have managed to comply with a fuller definition of compliance requirements;

it is recommended that a more complete definition of requirements should be introduced taking account of the technical capabilities of existing technologies, particularly at different ambient temperatures. This could be achieved by extending the compliance section of the NC RfG in a manner similar to that of the current GB Grid Code to more clearly define the required characteristics of gas turbines operating at falling frequencies.

5.1.3 LFSM-O and LFSM-U

NC RfG Article	8.1.c, 8.1.e, 10	Stakeholders Commenting	COGEN Europe; EUR; EU Turbines;
Stakeholder Comment	**Analysis**		**Proposal**
EUR note that Nuclear Generators have traditionally been exempted from Limited Frequency Sensitive Mode operation for both Overfrequency and Underfrequency and the ability – in article 10.2.b.1 – for TSOs to require changes to settings without reference to other parties is a major issue. These settings are considered as part of the safety case for operation of nuclear power plants. EU Turbines note that, traditionally, CHP schemes have been exempted from this	To allow the control of system frequency, requirements similar to those in the NC RfG have been applied. Recognising the overall generation mix, and that this is not essential from all generators, nuclear generators and smaller units have traditionally been exempted, the obligation falling on larger thermal and hydro-electric generators. As the generation mix has changed, TSOs have been forced to reconsider these exemptions – evidenced by the introduction of randomised disconnection of micro CHP units as a means of exercising some LFSM-O control. However, while this is a stage better than no control whatsoever, it is a one way operation which requires real frequency control by other generators. As the generation mix changes further, this is not a sustainable		For most generators, this requirement should remain as drafted. LFSM-U settings for nuclear generators should be established when the business case is being developed and remain unchanged after the safety case has been finalised – unless a clear justification which takes account of the nuclear safety issues is later established. (LFSM-O is stated not to be an issue for nuclear generators). In general, CHP schemes should be designed to allow

requirement and compliance would cause considerable difficulty for CHP operators where the main purpose is the operation of industrial processes and the input required by these processes is closely related to the control of electricity generation. COGEN Europe note that a much simpler arrangement for micro CHP sets to disconnect randomly where frequency increases and the operation of LFSM-O is required has been introduced for some TSOs and this solution has been ignored by the TSOs.	solution allowing reasonable expectation of system stability. The argument for or against randomised disconnection of small units must be considered from an overall system perspective, taking account of the operating regime of small generating units already connected to the system. In a study on the impact of dispersed generation on overall system security[14], ENTSO-E record the work being undertaken in some Member States to retrofit basic frequency controls to existing installations and outline the need for this to continue. In currently foreseeable conditions, system stabilisation could require the operation of first stage load shedding and therefore it is considered prudent that future installations (which, following current energy policy, will be the major contributor of new capacity) should be required to more effectively contribute to overall frequency control. The number of nuclear plants likely to be constructed in the immediate future is small and the practice of exempting this requirement in deference to the nuclear safety case is appropriate and can be handled by derogation. NC RfG allows the possibility of exempting those CHP schemes disadvantaged by other requirements of the NC RfG and consideration should be given to extending this exemption to these requirements for the very small number that would be genuinely disadvantaged. This can be handled by derogation, and it is recommended that greater clarity regarding the ability for this approach to be adopted should be included in Article 3.6.g or Article 3.6.h of the NC RfG.	compliance with the requirements as specified, but Article 3.6.h should be modified to allow exemption from LFSM-O requirements for the very small number of CHP schemes that cannot reasonably comply. This may reasonably be coupled with an obligation to disconnect as may be permitted by Article 3.6.g where the equivalent CHP scheme would be adversely affected by system disturbances.

[14] ENTSO-E: *Dispersed Generation Impact on CE Region Security, Dynamic Study Final Report*, Brussels 22 March 2013

5.1.3.1 Background to the Issue

A number of representations were made regarding the requirements for Limited Frequency Sensitive Mode operation at Over-frequency and Under-frequency, and this can be a fairly complex area. At the level of principle, this is a reasonable requirement and the requirements specified in the NC RfG are reasonable when compared with the requirements of existing grid codes. With modern controls on new equipments, it is expected that the range of requirements specified in the NC RfG should be capable of being met. A major issue is the possibility of their application to units that have previously been exempted.

One group that have historically been exempted from at least parts of this requirement are nuclear generators and EUR have made representation based on the opportunity contained in the NC RfG for TSOs to require changes to settings without reference to other parties. As the applied settings are taken into account in the development of the safety case for nuclear stations, clearly this is not appropriate and the most that TSOs should reasonably expect is the ability to specify general settings applicable for nuclear stations prior to the business case for their construction being developed. EUR is concerned that TSOs may require retrospective application of this requirement to existing nuclear installations, but it is considered that any reasonable review process would ensure that such a proposal would fail.

CHP schemes have often been exempted from this requirement but the drafting of the NC RfG applies this requirement to CHP schemes. While recognising the TSOs' reasonable need for extending the applicability of requirements of this type to previously exempted installations as the proportion of large synchronous generating units decreases, whether or not it is appropriate and reasonable to apply these requirements to a CHP scheme depends entirely on the nature of the specific scheme. The applicability of the NC RfG to CHP installations is considered more fully in section 6.3.

A proposal has been made for the modification of the LFSM-O requirements as applied to micro CHP schemes to allow the random disconnection of such units as frequency rises. The concerns raised by the proposers of this change regarding the applicability of the NC RfG active power control requirements, with a large droop range and threshold and settings to be determined by the relevant TSOs, to micro generating units are recognised. It is also recognised that the random disconnection of many small units will simulate a droop characteristic for the total group. However, adopting this approach, the 'random' disconnection settings would still need to be managed to achieve the linear power-frequency curve as a group and it is not clear how this would realistically be achieved.

One major disadvantage of the proposed arrangement is that it is unidirectional: disconnection at a certain frequency but not reconnection with the same active power immediately when the frequency drops and this would impact the ongoing stability of the power system. The proposal refers to VDE-AR-N 4105, applicable in Germany, which states that “non-variable” power generating systems are permitted to disconnect…a uniform distribution and to the German SysStabV which “…allows…randomized disconnection in case of technical restrictions at the generating unit level”. Having considered this issue it has been concluded that this proposal does provide an improvement over what has previously generally existed but, as a unidirectional operation it does not present a long term solution to the issue which has faced ENTSO-E in drafting the NC RfG – the need, to ensure stability of the overall power system, that many small installations, previously exempted from obligations relating to stabilising the system must in future be capable of contributing to the system support requirements. For these reasons, it is recommended that the NC RfG requirements in respect of LFSM-O should apply to CHP units as they are specified where, as considered in section 6.3, it is appropriate that the CHP scheme is not exempted.

5.2 Voltage/Reactive Power related issues

5.2.1 Voltage ranges

NC RfG Article	11.2.a.1 Tables 6.1 and 6.2	Stakeholders Commenting	EUR; EU Turbines;

Stakeholder Comment	Analysis	Proposal
Stakeholders have concerns regarding the increase in the upper voltage limits proposed by ENTSO-E for all of Continental Europe and the extended duration of possible overvoltage that generating units would be required to withstand. Stakeholders note that, without retrospective application which has been ruled out without existing or future modification procedures being followed, since voltage is shared between multiple connections, the application of ENTSO-	All equipment is designed with a particular upper voltage withstand value for normal operation and a frequency operating range. These are clearly stated in international standards. These standards are also clear that operation outside of these parameters at some point is inevitable, but that deviation should be limited in value, and duration and frequency of occurrence. Applying ENTSO-E’s proposals as stated will have an adverse impact on generating units. Establishing a meaningful cost would require some information regarding the frequency of excursion from current normal practice and this is not available from the ENTSO-E documentation. Indeed, the ENTSO-E drafting would allow significant deviation indefinitely, and this is clearly not in the interests of transmission equipment	1. Proposed duration of the additional overvoltage range of 1.118 pu – 1.15 pu for the Type D power generating modules in Article 11, Table 6.1 for Continental Europe, which is currently intended “... to be defined by the TSO while respecting the provisions of Article 4(3), but not less than 20 minutes”, should be “defined by the TSO while respecting the provisions of Article 4(3), with the maximum period being in a range of 20 – 40 minutes”. 2. Proposed duration of the additional overvoltage range of 1.05 pu – 1.0875 pu for the Type D power generating modules in Article 11, Table 6.2 for Continental Europe, which is currently supposed “... to be defined by the TSO while

NC RfG Article	11.2.a.1 Tables 6.1 and 6.2	Stakeholders Commenting	EUR; EU Turbines;

Stakeholder Comment	Analysis	Proposal
E's proposals cannot take effect until all existing equipment has been retired.	owners or other stakeholders. ENTSO-E has provided no information regarding the benefit of the proposal beyond stating that there are TSOs in Continental Europe that already apply the higher voltage limits. However, if there are TSOs where the higher limits are applied, this is a justification for their continued application by these TSOs, not for Continental Europe as a whole. ENTSO-E has indicated that a derogation to allow those TSOs where the higher limits are used – and for which equipment is currently designed to operate – to continue to apply existing conditions without the same rules being capable of application by other TSOs, unless cost justified, would be unacceptable. In this situation it is appropriate that the ENTSO-E proposal is rejected and the conditions specified in international standards applied. At the stakeholder meeting on 16 September 2013, an amendment to this section was proposed that was not approved during the meeting, but neither was it rejected. The consultants have not undertaken any analysis on this proposal beyond noting that it more generally fits both with appropriate standards (which are not absolutely consistent) and with established practice. It is therefore proposed as a solution on the basis that it appears to have acceptance.	respecting the provisions of Article 4(3), but not less than 60 minutes", should be "defined by the TSO while respecting the provisions of Article 4(3), with the maximum period being in a range of 40 – 80 minutes". 3. The additional overvoltage range of 1.0875 pu – 1.10 pu for the Type D power generating modules in Article 11, Table 6.2 for Continental Europe, should be deleted. 4. Drafting should be introduced permitting the reinstatement of the additional overvoltage range of 1.0875 pu – 1.10 pu for the Type D power generating modules in Article 11, Table 6.2 for parts of the networks of individual TSOs in Continental Europe where it is required for network configuration reasons, as approved by the NRA, provided it is neither detrimental to the operation of the power system nor to the operation of the internal market. Representing voltage and frequency arrangements together as outlined in section 5.1.1 should also be considered.

5.2.1.1 Background to the Issue

The draft NC RfG proposes voltage ranges for mandatory continuous or time limited operations separately for different classes of grid users (different connection point voltage level) and for different synchronous zones. ENTSO-E used a standard approach by trying to accommodate most of the existing requirements from the national codes in the proposed operational voltage ranges.

The proposed voltage ranges for unlimited operation and for limited operation in the undervoltage zone are more or less standard and in line with the existing requirements, both in terms of voltage magnitude and time duration. On the other hand, the proposed ranges for operation in the overvoltage area seem to be beyond current practices, in particular for the 400kV voltage level. The main concerns are not related to voltage levels but rather to the duration of overvoltage that generating units could be exposed to. The proposed 1.05 pu - 1.10 pu overvoltage range with a duration greater or equal to 60 minutes is relatively high and may have significant impact on generating units.

In principle, voltage ranges for operation of the *"...AC transmission, distribution and utilization systems and equipment for use in such systems with a standard frequency of 50Hz having a nominal voltage above 100 V...*" are determined according to the technical standard CENELEC EN 60038:2011. Section 3.9 of this standard specifies the highest voltage for equipment with respect either to insulation or to other characteristics which may be linked to this highest voltage in the relevant equipment recommendations. Based on this document (Article 4.4 Table 4 and Table 5), the maximum voltage for equipment is 123kV at 110kV nominal voltage (1.118 pu), 245kV at 220kV (1.1136 pu) and 420kV at 380kV nominal voltage (1.10526 pu).

Similarly, IEC standard 60034-1:2010 (Part 1: Rating and performance, Page 34, Figure 11) is rather strict concerning limitations of voltage fluctuations for rotating machines (see Figure 4 above). This standard allows unlimited operations under voltage fluctuations of +/-5% from the rated voltage and time limited operation under voltage fluctuations between +/-5% and +/-8% from the rated voltage.

The standard IEC 60034-3, which is applicable to gas and steam turbine driven generating units with P>10 MVA (the most common conventional power plants), is even more restrictive concerning voltage excursions as is shown in Figure 5 above. A frequency excursion limit of 49-51 Hz continuously, and 47,5-51,5 Hz should be possible but limited in time and occurrence. The difference with the other two figures is that the voltage is limited to +/-5% instead of +/-8%.

On the other hand, the ENTSO-E justification (offered in the document 'Requirement in the context of current practice') that EN 60034-1/3 refer to the generator voltage in contrast to the NC RfG where the voltage range is defined at the Connection Point, which is the correct location for network code obligations to be determined. For transmission and distribution networks of more than 20 kV, generating units will be connected by means of step-up transformers. Reactive power flows will result in additional voltage variations at the generating unit terminals on top of the voltage variations at the Connection Point. When on load tap changers are installed on the step-up transformers, these variations can be compensated during operation.

The explanation given in the ENTSO-E document 'Requirement in the context of current practice', based on the Cigré report 'WG 33.10, Temporary Overvoltages: Withstand Characteristics of Extra High Voltage Equipment, Electra No.179 August 1998, pp. 39-45', shows a maximum overvoltage of 1.15 pu for 20 minutes based on the test results (these results are, however, for electrical equipment other than generating units). Also, it is unlikely that overvoltage on an overhead line may damage the power line equipment. On the other hand, insulation on HV XLPE-cables, which are frequently used for internal connections in generation plants, should not be exposed to overvoltages beyond limits determined by the relevant standards (and individual manufacturers) for an extended time period. Operation at 440kV is not a problem for alternators in new plants because they are connected to step-up transformers and one can choose the voltage ratio accordingly. However, for existing plant and also for the transmission grid itself it will not be acceptable to operate at this level, unless special provision has been made in equipment design and construction to accommodate higher voltages than are normally specified. Most of the relevant network equipment (circuit breakers, transformers etc) ratings are based on IEC maximum voltage of 420 kV.

The basic approach in this assessment is that system users (mainly generators) and network operators should, at the system level, contribute equally to voltage control, subject to the circumstances at individual connection points. Similar to the frequency, the voltage level at the connection point is an issue of the power system performance quality. For power system security reasons, generating units must be capable of withstanding certain voltage deviations, either for an unlimited or for a limited period of time. Also, generators are usually obliged to offer and provide voltage control at the connection point to the electrical grid, with or without compensation. Once all the voltage control measures based on contributions from generators are exhausted or when the generating unit is out of operation for any reason, the voltage level at the connection point is solely the responsibility of the TSO and other available voltage control 'tools' must be employed. Unfortunately, this issue is addressed only in the NC Operational Security, Article 10 but without clear determination of the TSO obligations concerning time limits for restoration of voltage at the connection point.

IEC standard 60076-1:2011 for Power Transformers in section 5.4.3 specifies 'Operation at higher than rated voltage and/or at other than rated frequency', and its conclusion means that at rated frequency the voltage should not be higher than 105% of its rated value. Therefore, 110 % and 115% require special arrangements. This is not only applicable for step-up transformers but also for other transformers in the grid.

The details of this section 5.4.3 are presented in the text below:

'Methods for the specification of suitable rated voltage values and tapping range to cope with a set of loading cases (loading power and power factor, corresponding line-to-line service voltages) are described in IEC 60076-8.

Within the prescribed values of Um, for the transformer windings, a transformer shall be capable of continuous operation at rated power without damage under conditions of 'overfluxing' where the value of voltage divided by frequency (V/Hz) exceeds the corresponding value at rated voltage and rated frequency by no more than 5 %, unless otherwise specified by the purchaser.

At no load, transformers shall be capable of continuous operation at a V/Hz of 110 % of the rated V/Hz.

At a current k times the transformer rated current (0 < k < 1), the overfluxing shall be limited in accordance with the following formula:

$$\frac{U}{Ur} \times \frac{fr}{f} \times 100 \leq 110 - 5K \quad (\%)$$

If the transformer is to be operated at V/Hz in excess of those stated above, this shall be identified by the purchaser in the enquiry.'

The above mentioned limitations to overfluxing are clearly limited to a maximum of 105% at full load. This means that at rated frequency the voltage should not be higher than 105% of its rated value. Therefore, 110 % and 115% require special arrangements and shall be dealt with when specifying and ordering transformers. This is not only applicable for step-up transformers but also for other transformers in the grid.

Based on the considerations presented above, taking into account explicit definitions of the international standards and with respect to the justification and exemption raised by ENTSO-E in the 'Requirement in the context of current practice', the following conclusion was reached:

- Voltage stability is a common benefit for network operators and grid users, therefore all involved parties should employ their best efforts and available resources to maintain it within acceptable limits,
- There is a reasonable and justified need by the TSOs that generating units remain connected to the grid beyond normal operational voltage ranges,

- Long and/or frequent operation under significant overvoltages may seriously damage generating units and/or associated electrical equipment; therefore, network rules have to limit overvoltages beyond standard values not only by their magnitude but also by time of their duration and frequency of their occurrence,

In the existing NC RfG text, maximum sustainable overvoltages for unlimited operation of Type D power generating modules, as defined in the NC RfG Article 11, Table 6.1, for the generating units connected at voltage levels between 110kV and 300kV (excluding 300kV), and in the Article 11 Table 6.2, for the generating units connected at voltage levels between 300kV and 400kV, are within the limits of international standards except for the Baltic States, which operate in a different interconnection. The critical issue in this regard is the time limits for operations beyond standardised values for sustainable voltage, in particular Table 6.1. which prescribes an additional overvoltage range of 1.118 pu – 1.15 pu for Type D power generating modules for Continental Europe, with the duration to be defined by the TSO while respecting the provisions of Article 4(3), but for '*not less than 20 minutes'*, which opens the possibility for determining a longer, possibly unlimited duration. There is a similar case in the Table 6.2, again for Continental Europe, for additional overvoltage range 1.05 pu – 1.0875 pu for Type D power generating modules for Continental Europe, with the duration to be defined by the TSO while respecting the provisions of Article 4(3), but for '*not less than 60 minutes'*, which again opens the possibility for determining a longer, possibly unlimited duration, of the overvoltage. Both these values are beyond existing international standards and, even if a TSO, viewing the issue, might wish a requirement for generating units to be able to withstand certain overvoltages from the system security point of view, such a requirement utilised on a regular basis is clearly contrary to the interests of the generator. IEC 60034-1 and IEC 60034-3 both acknowledge that in practical applications and operating conditions, it may be necessary to operate a generating unit outside the recommended limits but that such operation should be limited in extent, duration and frequency of occurrence but that corrective measures, specifically reduction in output, should be taken as soon as possible.[15] This is the approach taken, for example in the Swiss Grid Code as shown in Figure 3 above, where the maximum voltage to be sustained is 1.15pu for at least 30 minutes at normal frequency but with the withstand duration and output power significantly reduced outside the normal frequency band. Where on load tap changers are used, as considered in section 5.2.2, this issue becomes one of transformer overfluxing which, as discussed above, is a result of the combined effects of frequency and voltage.

[15] See IEC 60034-1, section 7.3, Note 1 and IEC 60034-3, section 4.6, Note 1.

Currently, NC RfG does not consider the combined effects of frequency and voltage variations on the operation of the generating unit. When determining the duration and acceptable frequency of occurrence of overvoltages alone, TSOs cannot apply the same maximum values as may reasonably be selected where voltage level, frequency and power output are viewed in combination. Initiating a change to declared operating ranges now, without declaring retrospective application, would mean that they cannot be used effectively until sufficient existing generating units are decommissioned as would allow an appropriate CBA to be positive. However, where it is demonstrated that these extended operating ranges are currently used, it is reasonable to include provisions that allow the investment in non-standard equipment to be utilised.

5.2.2 On Load Tap-Changers

NC RfG Articles	11.2.a.1 Tables 6.1 and 6.2, and 13.2.b.2	Stakeholders Commenting	EUR; Thermal Generators;
Stakeholder Comment	**Analysis**		**Proposal**
Both EUR and Thermal Generators raised concerns regarding the drafting of sections of the NC RfG which inferred that the provision of on load tap changers (OLTCs) would be required at all installations. Both drew attention to the results of a *Cigré* study which indicated that 42% of transformer faults were related to failures of or within OLTCs.	The source of this issue is the extended high voltage range specified for RGCE in Tables 6.1 and 6.2 relating to Article 11.2.a.1 and the format of the voltage vs reactive power profile shown in Figure 7 and relating to Article 13.2.b.2. To meet these requirements in full would require the use of OLTCs at all connections. Currently, OLTCs are in normal use in some Member States but they are not used in other Member States. However, in the Member States where OLTCs are used, the transformers would generally need to be replaced by transformers fitted with OLTCs having an extended tapping range, when compared with those that are in use, because of the extended voltage range that had been proposed. As voltage is shared at a local network level, the requirement would need to be retrospectively applied or its use delayed until enough equipment had been retired to allow a realistic CBA to be positive. ACER and ENTSO-E have both indicated that the values to be used in the NC RfG should match the equivalent requirements on the day the NC RfG enters into effect or a full proposal		As the arrangements which would concern stakeholders have been ruled out by both TSOs and NRAs, no changes are proposed. However, it is recommended that, where OLTCs are required, this should be clearly stated and not left to be inferred. NRAs should be required to ensure that the voltage ranges selected by TSOs in Article 11 correctly reflect current practice in the use of OLTCs, including the tapping range in normal application or that the appropriate change review is undertaken.

NC RfG Articles	11.2.a.1 Tables 6.1 and 6.2, and 13.2.b.2	Stakeholders Commenting	EUR; Thermal Generators;
Stakeholder Comment	**Analysis**		**Proposal**
	developed for the introduction of new arrangements and that this would be subject to regulatory review. No such proposal has been developed and therefore the arrangements established by the TSOs much match existing arrangements. Provided this position is held, the issues raised by the stakeholders cannot therefore arise.		

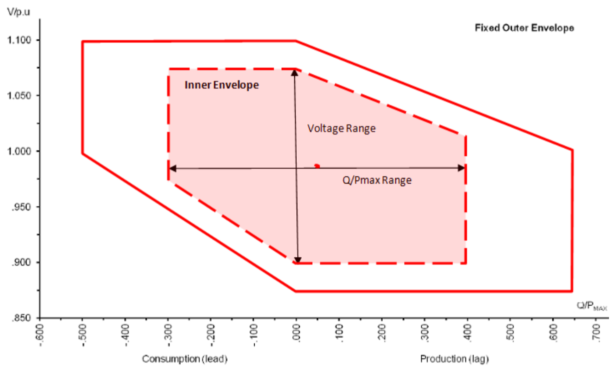
5.2.2.1 Background to the Issue

A number of stakeholders commented on the need for the installation of On Load Tap-Changers (OLTCs) if the voltage ranges proposed by ENTSO-E were to be met. Some commented on the findings of an old *Cigré* study that concluded that over 40% of transformer faults were tap changer related. While no evidence has been reviewed, it is acknowledged that the findings of this report are probably still an appropriate conclusion but it is also anticipated that transformer faults are not the major cause of non-availability of generating units. Currently, OLTCs are generally used in some Member States but not in others. ENTSO-E and ACER have made it clear that the voltage range values to be used in each Member State will be those ranges currently applied and, for so long as this position is maintained, there is no need for any change to current practice.

Therefore, an analysis of the proposals concerning voltage ranges and AVR devices did not develop any need for amendment to the existing NC RfG requirements and it is proposed that the existing text in the NC RfG is maintained. In doing so, the implications for the drafting of the NC RfG in respect of reactive power capability considered in section 5.2.3 are recognised.

5.2.3 Reactive Power Capability

NC RfG Article	13.b.2 Figure 7	Stakeholders Commenting	Thermal Generators, EUR and EU Turbines

Stakeholder Comment	Analysis	Proposal
Stakeholders comment that the limits proposed by ENTSO-E for reactive power capability are outside the physical capabilities of synchronous generating units	The stakeholders comment is valid in all cases where on-load tap-changers are not used.	The drafting should be modified to allow the existing Figure 7 to continue to be used in TSO areas where it is currently standard practice for on-load tap-changers to be used provided it is normal to employ a sufficient tap range. In other TSO areas, the figure should be amended as shown[16].  **Figure 8: Voltage/Reactive Power Profile without OLTC**

5.2.3.1 Background to the Issue

The requirements for reactive power capability are determined for synchronous power generating modules of types C and D for operations at maximum capacity. Similar requirements are determined for power park modules also of C and D types but separately for operations at maximum capacity and below maximum capacity. The reactive power capability at maximum capacity is defined in the U-Q/Pmax diagram, while reactive capacity at the power output below maximum capacity is given in the P-Q/Pmax diagram.

---

16 This figure is the alternative figure proposed by Eurelectric Thermal Generators that reflects the extremes proposed by ENTSO-E. To ensure that there could be no claim of discrimination, Eurelectric proposed a similar alternative figure for Power Park Modules. While recognising that this is a desirable approach, since the change recommended here is based on the capabilities of a technology, extending the change to other technologies has not been considered.

Being aware of the importance of this issue for power system operations and security, the stakeholders appear only to have commented on areas in these diagrams where there are significant technical constraints preventing operation of their PGMs or where operation under those circumstances may jeopardise their safety provisions or have serious impact on operational or design (or R&D) costs. The fact is that standard generating units cannot supply high reactive power at high grid voltages because of the too high generator voltage caused by the impedance of the step-up transformer and too high excitation current. Also, the absorption capability of reactive power by the generating unit at low grid voltage is less than required because the generator voltage would be too low. Consequently, operation of those generating units in lower left and upper right areas of the proposed envelopes is not recommended by equipment manufacturers as shown in the voltage/reactive power profile in Figure 9 and recognised in the requirements currently contained in the different national codes, presented for justification by ENTSO-E in the document ‘Requirement in the context of current practice’. Compliance with the requirements shown in the NC RfG, and included in red in Figure 9, is possible with the use of on load tap-changers with sufficient tapping range, which are not always available even where it is normal practice to install on load tap changers.

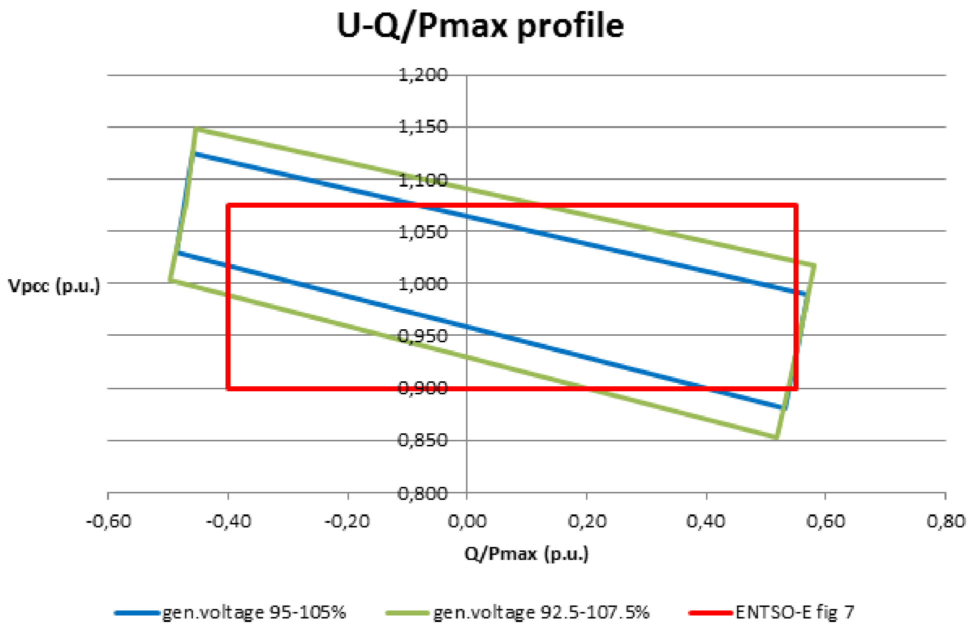


Figure 9: Voltage/Reactive Power Profile of a Typical Synchronous Generating Unit

The justification by ENTSO-E that the position of the inner envelope provides for a flexible approach was obviously not sufficient to overcome the stakeholders’ concerns. In reviewing this requirement full cognisance was taken of the stakeholders’ concerns but also of the fact that the solution offered by ENTSO-E for reactive power capability is the most flexible among the non-exhaustive requirements in the NC RfG. Also, looking at current practices, from the existing solutions in national grid codes, it seems unlikely that the TSOs will propose to the NRAs requirements that will impose on generators conditions that are not technically feasible. Before these can be applied to existing generating units and their associated equipment a full justification process, including a rigorous cost benefit analysis (CBA) will have had to be undertaken.

Given the commitment from both ENTSO-E and ACER that new requirements would not be introduced by the transition to NC RfG itself a proposal for minor adjustment of the existing drafting is proposed

- Where OLTCs of sufficient range are in normal use, Figure 7 of the NC RfG as prepared by ENTSO-E should continue to be used.
- In all other areas, TSOs and NRAs should be required, when determining their own shapes, to ensure that the bottom left and upper right areas of the envelope should be avoided.

5.2.4 Provision of Reactive Power as a Means of Voltage Control

NC RfG Article	13, 16	Stakeholders Commenting	Thermal Generators, EWEA
Stakeholder Comment	Analysis	Proposal	
Stakeholders made comment regarding the obligation for generating units to be capable of providing or absorbing reactive power as a means of voltage control and the ability of TSOs to use network components for this purpose. Some existing operators indicated that they believed this section of the NC RfG should be redrafted to make clear that generators should only be obliged to provide reactive control to traditional limits.	It is valid for stakeholders to note that other means of reactive control exist, but it has always been usual practice for generating units to provide this service. In the interests of the system and society as a whole, it is necessary for generators to be capable of continuing to provide this service. The NC RfG specifies the technical requirement for the capability of providing this service and, in this respect, it appears fair and reasonable, providing the issue discussed in section 5.2.3 is addressed. While the technical requirements for the capability of providing reactive power is correctly an issue for the NC RfG, the commercial impact of actually providing the service is correctly a matter for other	Provided the issue considered in section 5.2.3 is addressed, it is proposed that no further change should be made to the technical requirements. NRAs should be required to ensure that stakeholders are not materially disadvantaged by the operational demands placed on them by TSOs for the provision of Reactive Power for Voltage Control.	

	arrangements. Currently, a mix of mandatory and market arrangements exist and, following the principle that the transition to the NC RfG should not, of itself, change existing arrangements, it is recommended that no further change be made to the NC RfG.	

5.3 Fault Ride Through

5.3.1 Duration of Fault Clearing Time

NC RfG Article	Article 9.3.a.4 Figure 3 and Table 3.1	Stakeholders Commenting	EU Turbines, EUR, Thermal Generators

Stakeholder Comment	Analysis	Proposal
All stakeholders' comments relate to what they see as the possible increase in fault clearance times for network faults. Table 3.1 declares that the fault clearance time to be declared by TSOs in this non-exhaustive requirement should be in the range 140 – 250 ms. The period that is required for each network is a feature of the quality of power system protection devices utilised by the network operator with longer fault clearance periods being possible with less expensive protection equipment. Longer network fault clearance times can have a serious effect on generating units.	Forcing a generating unit to remain connected to a network under fault conditions is necessary to ensure the correct operation of power system protection devices to ensure the disconnection of the faulted section with minimum effect on the remainder of the system. However, depending on network conditions, the longer this period the greater is the likelihood of significant damage to generating units. The strength of the grid connection and the location of the fault are relevant factors in determining whether a generating unit would be capable of remaining connected. While the ENTSO-E drafting allows these factors to be taken into consideration when establishing fault ride through requirements, it does not require that TSOs and NRAs do so. Within ENTSO-E RGCE, the declared fault clearance time at 400kV is 150ms, although longer periods often apply at lower voltages. The Nordic Grid Code requires that generating units will remain on circuit for a	This article should be amended such that the ranges of permissible fault clearance times are distinguished by voltage level and, particularly at 400kV, by synchronous area. The ranges provided should more closely reflect current practice except where alternative arrangements are required for network configuration reasons as approved by the NRA, provided this is not detrimental to the operation of the power system or of the internal market.

	fault clearance time of 250ms for a fault at the network terminals but, because this is not always practicable, alternative requirements appear to be imposed by the TSOs.	

5.3.1.1 Background to the Issue

Considering the impact of fault clearance time on generating units there are two aspects: one is pole slip (loss of synchronism) and the second is high mechanical stress upon voltage restoration. The maximum fault clearing time without pole slip is expressed as critical fault clearing time (CFCT). For large CCGTs calculations show a CFCT of approximately 250ms.

However, 250ms may be too long when addressing risks of mechanical damage (and in such a case generating units will trip anyway). Statements were made by the stakeholders indicating that for a fault clearance time of 250ms, as proposed in the NC RfG, the forces caused by phase angle deviation between generating unit voltage and grid voltage at the moment when the grid fault is isolated and the voltage at the connection point recovers will break couplings. To overcome this problem they stated that a significant modification would have to be made to the dimensions of the coupling flange. While recognising the possible need for significant modification to meet this requirement, it is considered that, as a general description, this appears to be exaggerated. This issue depends on the specific situation including the following: phase angle at the moment of fault clearance, residual grid voltage during the fault, the impedance between fault and generator, the short circuit level of the grid etc. Therefore, it can be assessed only on a case by case basis.

In its proposal in the NC RfG, ENTSO-E appears to have tried to harmonise fault clearing time requirements over all synchronous zones (although harmonization of these requirements was not the objective of the ENTSO-E NCs), taking as the base value the most extreme requirement that exists at the highest voltages only in the Nordic synchronous area. From the discussion with numerous stakeholders, including ENTSO-E, it has been concluded that these requirements have, in many cases, not been implemented nor proved by simulations even in the Nordic countries and that this problem has usually been solved by derogations. With this approach of ENTSO-E one of the basic principles has been violated – viz significant deviation from existing practice has been made without proper justification. These facts open two possible solutions:

1. To maintain the proposal as it currently is, with an option that the fault clearance time can be reduced when the PGM owner makes clear by calculations that the generating unit could be damaged depending on the residual grid voltage.
2. Split the requirement for fault clearance time by voltage levels and between synchronous areas in a similar way to the requirements for the frequency and voltage operational ranges. In such a way, for each synchronous area fault clearance time

could be defined similar to the current requirements in the national grid codes (e.g. for Continental Europe the most common fault clearance time is 150 ms). This approach can even allow the TSOs to define, if necessary and appropriate, higher fault clearance time values for specific network configurations.

The fault clearance time issue raised a lot of concerns among existing generators with respect to potential retrospective application[17] and/or derogation from this requirement, especially by the owners and manufacturers of the large conventional thermal generating units. Most of them were related to operations in the synchronous area of Continental Europe, where existing requirements in national codes were far below the higher ranges of the current proposal in the NC RfG. Having all this in mind it was concluded that there was not sufficient justification behind the proposal to harmonise the requirement for the fault clearance times among all synchronous areas and it was decided to propose that ENTSO-E consider a minor revision of the current NC RfG drafting in accordance with option 2 presented above. This requires, in NC RfG Article 9, obligations regarding fault clearance times should be split by voltage level and between synchronous areas in a similar way to requirements for frequency and voltage operational ranges.

Following circulation of the preliminary report, the Thermal Generators acting under the auspices of Eurelectric presented very detailed proposals that are included in their paper attached in appendix G.3 . The principle of their proposal appears reasonable but the detail contains concessions that may not be acceptable to all other stakeholders.

[17] Retrospective application and derogations are addressed in the following sections of this report.

5.3.2 Fast Reactive Power Injection and Active Power Recovery for Power Park Modules types B, C & D

NC RfG Articles	15 and 16.2.a.1	Stakeholders Commenting	EPIA, EWEA, DSOs
Stakeholder Comment		Analysis	Proposal
Stakeholders expressed concern regarding the new requirement to provide fast reactive current injection and, in particular, the requirement to do so in a time period specified by the TSO of "*not less than 10 ms*". EWEA and EPIA fear that TSOs in general and particularly those who have no experience of the issue, will be encouraged by the definition used by ENTSO-E to simply choose 10ms. Many Power Park Modules are connected to distribution networks and DSOs are concerned about the potential impact of the fast reactive power injection requirement on the fault breaking capacity of their switchgear.		Type 1, 2 and 3 wind turbine generating units have a direct connection between the stator winding of the rotating generating unit and the grid. As a result, a voltage dip will automatically cause a reactive current injection without delay. The amplitude will depend on the generating unit characteristics and will decline within a few hundred milliseconds which should support the operation of fast acting protection systems. Type 4 wind generators and PV systems are connected to the grid through invertors and the fast active current injection must be created through the operation of the power electronics. The possible requirement for these to act in less than one cycle (20ms) is a technical and commercial issue for manufacturers. That reaction is fast, at least matching that of fast reacting protection systems, is an issue for TSOs.	It should be stated more clearly that the drafting intends that these are entirely non exhaustive requirements, specified only where PPM penetration is sufficient that they need to be addressed by TSOs. The requirements should be specified with greater precision and take due account of the capabilities of existing technologies. In the more precise drafting: a) the intent that the combined effect of the requirements would not impact equipment specification should be ensured. b) the ability for Relevant Network operators to ensure that the

Stakeholders are concerned about the definition of the requirement to provide post fault active power recovery where these requirements are not clearly defined. They have concerns that TSOs without experience of the issue may choose parameters that are not feasible.	Article 15.3.a allows: "*....the Relevant TSO shall specify....magnitude and time for Active Power Recovery the Power Park Module shall be capable of providing*". No range is suggested that can act as a guide to stakeholders and TSOs regarding appropriate values. Article 16.2.a.1 is also vague. This is currently an issue for a relatively small number of TSOs but may become more significant for others as the penetration of PPMs increases. As a consequence, not all TSOs would have first hand experience of the issue and the stakeholders' concerns are understandable unless clear guidance is available.	requirements will not affect the safe operation of their networks should be guaranteed, taking precedence over the TSO's rights under Article 4.4.
Stakeholders are concerned about the possible impact on equipment ratings of addressing both of these requirements simultaneously for what should be a very infrequent event.	As previously noted, the definition of these requirements is very vague and, if taken in isolation, there is nothing to prevent a TSO from specifying values that would have a significant affect on equipment ratings. From discussion with ENTSO-E, it is clear that this is not their intention but the concern is a result of the imprecise specification of the requirements.	

5.3.2.1 Background to the Issues

For Stakeholders, there are three main issues:

a) The imposition of new requirements,

b) The detail of the specified requirements which are, in some cases, difficult to meet, and

c) The combined effect of the requirements to provide both fast reactive power injection and the provision of active power following a fault ride through event.

5.3.2.1.1 Fast Reactive Current Injection

The requirement for fast reactive current injection is very important for system operators, especially with respect to the expected significant growth of the RES generation. Without the provision of reactive currents during system fault conditions, protection systems will not operate correctly to remove faulted network sections from the system. This current must be provided by generating units operating and connected to the system at the particular time. With the higher penetration of Power Park Modules, it has become necessary to look to them to provide these currents.

Consequently, ENTSO-E have proposed in NC RfG Article 15.2.b)2) the requirement for B, C and D power park modules to provide fast reactive current injection in cases of a fault. The requirement in the current ENTSO-E draft of the NC RfG, according to the representatives of the industry, differs from the solutions that have been discussed in the public consultation process. ENTSO-E faced strong opposition from the most affected stakeholders, EWEA and EPIA. They commented on the specification of fast reactive current injection during FRT, stating that the values proposed in Article 15.2.b) 2) are not based on a proper assessment and calculation and that they have not been supported by the industry. Accordingly, industrial associations offered an alternative proposal for this NC RfG article.

Type 1, 2 and 3 wind turbine generators have a direct connection between the stator winding of the rotating generating unit and the grid. By nature of this connection, a voltage dip will automatically cause a reactive current injection without delay. But the amplitude depends on the generator characteristics and will decline within a few hundred milliseconds. Type 4 wind turbine generators are connected by a converter, without direct connection between the network and the rotating generating unit. The converter has to produce a reactive current based on network voltage measurements. This requires measuring, calculation and control time. The 10ms response time (½ cycle) is not currently possible for type 4 wind turbine generators. Reaching the target value with an accuracy of 10% within 60ms is also ambitious but may be feasible.

There is another very serious issue that was also highlighted by the DSOs. Some DSO requirements limit the reactive current injection in such a way that Type 1, 2 and 3 wind turbines cannot be connected. The reason is that short circuit power is supplied from the transmission network and additional short circuit power from power generating modules would raise the short circuit level over the capability of the switchgear. This needs to be compensated by reduced transformer capacity and therefore the capacity of the distribution grid. Type B and type C Power Park Modules are mainly connected to distribution networks, therefore an exemption for reactive current injection must be possible. However, ENTSO-E has drafted this section such that the requirement to provide fast reactive power injection is the right of the "*Relevant Network Operator in coordination with the Relevant TSO*".

Providing the decision of the Relevant Network Operator takes precedence over the wishes of the Relevant TSO, the safety issues related to fault levels can be properly addressed. This issue is considered more fully in Appendix E.3.

While discussing this issue with stakeholders and ENTSO-E, as well as from the support documents to the NC RfG, it was concluded that even inside the ENTSO-E drafting team there were no sufficient facts to support such an important proposal/requirement. The alternative proposal submitted by the industrial associations has not been the subject of public consultations so, before it could be adopted, it would have to be proved and be subjected to public consultation. It cannot simply replace the existing proposal. Taking all this into account makes this a complex and serious issue for the following reasons:

- This is a relatively new issue and a similar requirement has been defined in only a few national codes,
- Practical experience is insufficient to create a proper background for determination of the NC requirement,
- There are no relevant international standards in place, and
- There was no proper investigation, analysis and consultation with the industry prior to the development of the NC RfG requirement and therefore no firm justification behind the proposal.

At the same time, CENELEC have stated that a technical committee has been created and that the relevant working group started its work on the development of European technical standards in this area. Based on the above it is proposed that instead of the existing, apparently mainly exhaustive requirements, this should clearly become a non-exhaustive requirement defined with greater precision than at present. Accordingly, those TSOs where this requirement is relevant either have it defined in their national codes or they should define it in the process of harmonisation and implementation of the ENTSO-E NCs. Where this requirement is not relevant at present – ie low penetration of RES, in particular power park modules – then this issue should remain open. Once the overall development of RES-E generation from PPM units reaches the next stage, international standards should be agreed based on appropriate requirements that have been fully reviewed and accepted. Even if CENELEC standards are not developed in the near future then practical experience from RES-E integration should provide sufficient data to enable the determination of the appropriate requirement.

To address the safety issues related to the potential impact of fast reactive current injection on system fault levels, the decision of the Relevant Network Operator must take precedence over that of the Relevant TSO.

5.3.2.1.2 Active Power Recovery after Fault Ride Through

In the NC RfG Article 15.3 ENTSO-E proposed an entirely non-exhaustive requirement for PPM capability concerning active power recovery after fault ride through. While TSOs operating in a highly interconnected system can expect frequency support from neighbouring networks, TSOs operating less interconnected systems must look for active power recovery from generating units to return the system to stable conditions without significant load shedding. Where the generating units available (operating and connected to the system at the particular time) are increasingly power park modules, this support must come from these units.

Similarly to the situation with fast reactive current injection, industrial associations and other interested stakeholders were concerned that, at the national level, a wide range of values can be proposed and adopted and this can seriously complicate further development and integration of RES-E. In order to overcome potential problems EWEA/EPIA provided an analysis and a justification and proposed the solution that an exhaustive requirement with predefined ranges of values should be specified instead of the non-exhaustive requirement proposed by ENTSO-E:

a) *With regard to post fault Active Power recovery after fault-ride-through, the Relevant TSO shall specify while respecting the provisions of Article 4(3) the magnitude and time for Active Power recovery that the Power Park Module shall be capable of providing.*

EWEA/EPIA's proposal adds to this section, so that it becomes:

a) With regard to post fault Active Power recovery after fault-ride-through, the Relevant TSO shall specify while respecting the provisions of Article 4(3) a maximum recovery time for the Active Power to reach at least the level of 90 % of the pre-fault power, measured from the time the local voltage has recovered above 90 % of the pre-fault nominal voltage value. The maximum recovery time shall be specified to a value chosen within the range of 0,5 seconds and 10 seconds for faults that are cleared within 140 ms (t_{clear} < 140 ms) and within a range of 1 second and 10 seconds for faults that are cleared in a longer time than 140 ms (140 ms > t_{clear} < 250 ms).

However, the importance of supplying the network load with active power as quickly as possible following a fault clearance in order to avoid under frequency load shedding must be recognised. The proposed active power recovery time ranges of 0,5 – 10s and 1 – 10s therefore appear to be too wide. If the EWEA/EPIA proposal is adopted, the lowest figures proposed would appear to be more appropriate, i.e. 0,5s and 1s respectively.

Stakeholders also indicated particular concerns in that in the NC RfG there is a simultaneous requirement for the provision of fast reactive current injection and of active power recovery after the FRT and this may have a significant impact on the design (and price) of future generating units for PPM. So far, in national codes neither fast reactive current injection requirement, nor active power recovery after FRT requirement have been specified, depending on the critical issues in the relevant interconnection (frequency, for smaller interconnections, or voltage for larger interconnections). That there is the potential for two separate requirements depending on the interconnection type is reasonable. For stakeholders, this would be more acceptable if it was made clear that only one requirement can be specified in each synchronous area.

Taking into account the same reasoning as for fast reactive power injection, mainly related to the lack of practical experience and relevant standards, it is concluded that the ENTSO-E proposal should remain unchanged, allowing national TSOs to determine this requirement in accordance with the actual requirements of the relevant power system. In reaching this conclusion, it is recognised that the growth of RES-E installations will make this an important issue for TSOs that they must resolve. However, according to the commitment given by ENTSO-E and ACER, values inserted by TSOs for all non-exhaustive requirements must match current values and therefore the exact nature of this requirement must be developed in accordance with the requirements of either the current or the future review process.

It is concluded that, except for introducing greater precision to its definition, the existing proposal in the NC RfG document should not change, i.e. this requirement should remain non-exhaustive but TSOs for whom this should not be an issue should be discouraged from requiring the application of this provision and TSOs for whom it has not yet been an issue should only introduce it following appropriate cost benefit analysis subject to NRA review.

5.3.2.2 Combined Effect of the Requirements

Throughout the discussions with stakeholders, concerns were raised about the combined effect of these requirements as drafted and the impact on the rating of equipment for what is an infrequent event. In the discussions with ENTSO-E, it was clear that ENTSO-E did not intend that the combined effect of these requirements should affect the specification of equipments in the manner understood by the stakeholders. This should therefore not be as significant an issue as it has become, possibly as a result of misunderstandings of the real meaning of the less precise wording of these requirements. As a result, it is recommended that the precise requirements should be more clearly defined taking account of the genuine requirements of the affected TSOs and the genuine limitations of technology.

5.3.3 Issues Related to the Impact on Distribution Networks

5.3.3.1 Fault Ride Though and LV Network Connections

<table>
<tr><td>NC RfG Articles</td><td>9 and 3.6b) and Table 1</td><td>Stakeholders Commenting</td><td>DSOs</td></tr>
<tr><td colspan="2">Stakeholder Comment</td><td>Analysis</td><td>Proposal</td></tr>
<tr><td colspan="2">
Article 9 defines the fault ride through requirements for Type B power generating modules, the thresholds for Type B units being defined in Article 3.6b) and Table 1:
<table>
<tr><th>Synchronous Area</th><th>maximum capacity threshold from which on a Power Generating Module is of Type B</th></tr>
<tr><td>Continental Europe</td><td>1 MW</td></tr>
<tr><td>Nordic</td><td>1.5 MW</td></tr>
<tr><td>Great Britain</td><td>1 MW</td></tr>
<tr><td>Ireland</td><td>0.1 MW</td></tr>
<tr><td>Baltic</td><td>0.5 MW</td></tr>
</table>
Based on this Table, it is clear that a number of type B units would be connected to LV networks.
For reasons of safety to the public, utility staff and the network, it is undesirable for generating units to be forced to hold on the system during distribution system faults while it is acknowledged that they should be remain connected for faults on the transmission system. Unfortunately, it is not possible for current protection systems to tell the difference.
Safety is a particular issue at LV as many LV protection systems will operate more slowly than those at higher voltages. LV networks are closest to the public as LV networks enter most properties and certainly domestic and small commercial premises.
</td><td>
The analysis presented by DSOs is considered to be well founded. The maximum MV/LV transformer rating threshold generally applied is in the range 1 – 2 MVA and therefore, in most networks, it is possible that Type B units would be connected to the LV network.
The public are much closer to distribution networks than they are to transmission networks and it would be undesirable for LV networks to remain live in the event of a distribution network fault.
</td><td>
It is recommended that all generating units connected to LV networks should be exempted from the fault ride through requirements specified in Article 9.
</td></tr>
</table>

5.3.3.1.1 Background to the Issue

The issues related to the application of fault ride through requirements on generating units connected to LV networks are addressed in section 3.4. Recognising both the public safety issues related to forcing LV connected generating units to stay on the system and the relatively slow operating times of traditional LV protection systems, it is recommended that no additional fault ride through requirements should be applied to LV connected generating units.

5.3.3.2 Application to LV Connected Generating Units

<table>
<tr><td>NC RfG Articles</td><td colspan="2">8.1, 9.3</td><td>Stakeholders Commenting</td><td>DSOs</td></tr>
<tr><td colspan="2">Stakeholder Comment</td><td colspan="2">Analysis</td><td>Proposal</td></tr>
<tr><td colspan="2">As noted in section 5.3.3.1, the DSOs identified that it is possible for units that will be classified as Type B units to be connected to LV systems and subject to other requirements compared to the majority of generating units connected to LV systems. In all standardisation arrangements, 1kV is a fundamental threshold establishing a difference in the operating requirements imposed. Similarly, in many regimes, the safety procedures in operation at 1kV and above are different from those below 1kV. Two different sets of requirements – for Type A and for Type B - for generating units connected below 1kV creates confusion to the operation of these networks.</td><td colspan="2">The issues raised by the DSOs are valid in terms of both:
a) Standardisation; and
b) Safe operation of networks;</td><td>It is recommended that, in line with current standardisation practice and to ensure that all generating units connected to the LV networks operated by DSOs are treated equally, the threshold between Type A and Type B generating units is modified such that all generating units > 800W connected to public networks operating at less than 1 kV are considered as Type A units.</td></tr>
</table>

5.3.3.3 Conflicts Relating to Operation of Protection Equipment

<table>
<tr><td>NC RfG Articles</td><td colspan="2">8.1, 9.3</td><td colspan="2">Stakeholders Commenting</td><td>DSOs</td></tr>
<tr><td colspan="2">Stakeholder Comment</td><td colspan="2">Analysis</td><td colspan="2">Proposal</td></tr>
<tr><td colspan="2">The increase in the number and overall capacity of small generation units connected to distribution networks results in significant changes to the direction of normal power flows in distribution and transmission networks.

This issue is recognised separately from the development of the NC RfG and a number of pilot studies have been undertaken to attempt to address the issues involved.

NC RfG focuses on the ideal situation from the perspective of the TSO without considering the impact on distribution networks.</td><td colspan="2">The issue raised by the DSOs is valid, but the approach adopted by ENTSO-E is also valid at the current time. ENTSO-E's approach is based on best current knowledge but it is also known that greater knowledge will be available in the medium term as the results of the pilot studies are known.

In this situation, the only reasonable approach must be to proceed with the NC RfG as drafted but ensure that the opportunity for improvement is available once further information is available.</td><td colspan="2">As the NC RfG is currently drafted, there is no opportunity for any affected party other than the TSO to propose modification to the NC RfG. While it is to be hoped that TSOs would propose appropriate modifications, this restriction is very unusual. It is recommended that other stakeholders, and in particular the NRA, should also be able to propose modification.

In this particular situation, since the changes that would become apparent following completion of current studies would be appropriate on a Europe wide basis, it would be appropriate to require that the NRA, in consultation with other NRAs apply appropriate standards as the information to allow the development of these standards becomes available.</td></tr>
</table>

5.3.3.3.1 Background to the Issue

The issues related to the operation of distribution protection systems and the conflict between the DSOs' wish to have embedded generation disconnected as soon as possible for faults on the distribution network and the TSOs' wish that they remain connected for long enough to allow transmission protection systems to operate correctly are discussed along with anti-islanding requirements in section 3.4 and Appendix E.

5.3.3.4 Application of Transmission Rules to Distribution Networks

NC RfG Articles	3.6	Stakeholders Commenting	DSOs

Stakeholder Comment	Analysis	Proposal
DSOs note that the NC RfG has been drafted such that all high voltage circuits operating at 110kV or above are effectively deemed to be transmission circuits whereas many DSOs operate networks in this voltage range, currently operating under the Distribution Network Rules of the Member State. This has the particular effect that all smaller generating units are deemed to be type D units subject to additional requirements purely on the decisions made by the DSO in the operation of their networks	In several Member States, DSOs operate high voltage circuits, having designed their networks using higher voltages to ensure losses are controlled as effectively as is possible. However, the network design tends to follow distribution rather than transmission practice. As the NC RfG is drafted, a type A, B or C unit becomes a type D unit purely on the basis that it is connected to a 110kV network, the apparent assumption having been made that this is a transmission voltage.	The Network Codes developed by ENTSO-E should be modified to allow an overlap of the application of transmission or distribution rules depending on whether the operator is a transmission operator or a DSO. Article 3.6 should be modified such that Type A, B, or C generating units are only deemed to be type D units where the operator of the 110kV or above network to which they are connected is not operated by a DSO or CDSO.

5.3.3.4.1 Background to the Issue

In most Member States there are regulations, the application of which relates to voltage of operation. Many standards are similarly focused. However, there are also rules established for the operation of transmission or distribution networks as appropriate. While all networks operating at 110kV will be built to very similar standards, the manner of operation will differ according to the focus of the operating company. Because of differences between Member States in the definition of transmission and distribution networks, in some Member States, networks operating at 110kV and above are firmly part of distribution networks whereas in other Member States these would be considered to be part of a transmission network albeit not part of the main transmission system.

As a result, the application of the ENTSO-E Network Codes to all circuits operating at 110kV and above, arbitrarily imposes transmission operating rules onto what are parts of distribution networks operated by DSOs. The affected DSOs would then be required to operate different parts of their networks under different regulatory regimes applying different rules to different classes of network user. DSOs have not been party to the drafting of the ENTSO-E Codes and, as currently drafted, are prevented from proposing changes to the codes under which they would be required to operate their networks if the ENTSO-E NCs take precedence over current national arrangements.

To ensure that DSOs would be required to operate under only one regulatory regime, it is proposed that an overlap of application of transmission and distribution rules should be allowed, the application of transmission or distribution rules to networks being dependent on the status of the operator of the network.

The current definitions in the NC RfG also have an impact on network users because of the requirement that all generating units are classed as Type D because of their connection to circuits operating at 110kV or above. This definition allows TSOs to treat all generating units connected to their networks in the same manner.

However, this definition also prevents DSOs operating networks at 110kV or above from treating all similar generating units that are connected to their networks in a similar manner. It is therefore proposed that the definition of Type A, B, C and D units should be modified such that a unit is not classed as a Type D unit purely because it is connected to a network operating at 110kV or higher that is operated by a DSO.

Several stakeholders suggested that a combination of the operating voltage and rating should be used to determine the obligations falling on the operator and this would go a significant way to address this situation. For the manufacturers and installers of mass market equipment, this is a reasonable proposition and the existing threshold of 1 kV often applied in European standards may be worthy of consideration. However, any proposed change must be balanced by the needs of the TSOs to ensure that the opportunity does not exist for a person or organisation to claim that a large power park is simply a large number of small installations that coincidentally operate at close to the same location and are therefore not subject to the more onerous requirements that would reasonably apply.

As noted in section 6.3 below, this issue would also be of significance to the operators of small CHP plant who, as the NC RfG is currently drafted, lose the benefit of the exemption contained in Article 3.6 h) purely on the basis of the point of connection selected by the DSO.

5.4 Compliance

NC RfG Articles	34 – 40, 9, 8.1.e	Stakeholders Commenting	DSOs, EU Turbines, Thermal Generators, EUR

Stakeholder Comment	Analysis	Proposal
Most stakeholders made comments which would be resolved by unambiguous drafting of compliance requirements. Particular compliance issues were	Analysis of the issues covered in the compliance sections of NC RfG together with sections that would potentially be affected by clarity in the definition of the	Clarification of compliance requirements is essential and TSOs should be required to produce a clear, unambiguous and detailed statement of all requirements that

NC RfG Articles	34 – 40, 9, 8.1.e	Stakeholders Commenting	DSOs, EU Turbines, Thermal Generators, EUR

Stakeholder Comment	Analysis	Proposal
raised by EU Turbines relating to active power output requirements with falling frequency and this is discussed more fully in section 5.1.2. EUR, EU Turbines and the Thermal Generators made comment relating to the genuine compliance requirements for fault ride through and these are more fully addressed in sections 5.3.1 and 6.1.1. DSOs made comment regarding the initial and ongoing compliance requirements in terms of the lack of clarity in the requirements, the conflicts with established practice developed with experience gained over several years, conflict with the legal obligations many DSOs have under existing legislation to connect users and the possible cost of up to € 2,9 billion by 2020 depending on what the vague specification of requirements actually means. Some generator stakeholders commented on the significant commercial risk that the current drafting posed in relation to both the cost of undertaking compliance tests and reviews and the opportunity costs of their inability to generate while undergoing routine retesting. In some Member States, the frequency of significant retesting is effectively controlled by obligations placed on TSOs to pay compensation during retesting where ongoing compliance is proved.	compliance requirements shows that the stakeholders' concerns are valid in relation to: a) The actual requirements are not stated unambiguously: i. At the commissioning stage; or ii. As an ongoing requirement. b) Clarity around the part that can be played by certificates issued by others; c) The frequency at which ongoing tests can or should be undertaken; d) Payment or compensation arrangements for the conduct of tests.	should be subject to the approval of the NRA operating in conjunction with other NRAs.

5.4.1 Background to the Issue

There are several valid issues regarding the compliance arrangements, including:

a) The actual requirements are not stated unambiguously:

   i. At the commissioning stage; or

   ii. As an ongoing requirement.

b) Clarity around the part that can be played by certificates issued by others;

c) The frequency at which ongoing tests can or should be undertaken;

d) Payment or compensation arrangements for the conduct of tests.

The Compliance requirements are specified in Title 4, it being assumed that Chapter 1 (articles 34 – 37) refers to all generating facilities. Article 34 details the overarching responsibilities of the Power Generating Facility Owner and are generally applicable. An exception may be the obligation in Article 34.3 which requires the reporting of all incidents to the relevant network owner. For Type B units upwards, this is perfectly reasonable. For what are effectively household appliances that also generate electricity, it may not be. While at a principle level, the NC RfG can be viewed as a reasonable and appropriate mechanism for establishing the future requirements of PGFOs in a highly distributed generation environment, the issue consistently open to question is the reasonableness of applying organisational requirements appropriate for organisations, which have or could reasonably obtain expert support, onto non experts and particularly householders. In practical terms here, the only organisation that could report incidents as required in article 34.3 would be the repair organisation assuming the owner chooses to have a repair undertaken.

Article 35.1 places the responsibility for tasks on the relevant network operator, "The Relevant Network Operator shall regularly assess the compliance of a Power Generating Module with the requirements under this Network Code throughout the lifetime of the Power Generating Facility." While this drafting clearly places responsibility on the relevant network operator, it is much less clear what is expected – or reasonably permitted. For DSOs, to whose networks the vast majority of installations are connected, this is a concern both in establishing requirements and in addressing the work activity. Calculations undertaken by the DSOs based on an estimate of the numbers of units of 5kW and above the compliance costs that may fall on them could be of the order of €2.9 billion by 2020 assuming that consistent and realistic test requirements are established.

For major generators the section 1 obligation and the rights introduced by section 2, "*The Relevant Network Operator shall have the right to request that the Power Generating Facility Owner carries out compliance tests and simulations ..... repeatedly throughout the lifetime of the Power Generating Facility*" combine to raise the issue of ensuring that the frequency of tests and simulations and the duration of any resulting interruptions to their ability to generate are proportionate. In some Member States, TSOs currently have the right to request compliance tests at any time with compensation paid to generators both to cover the costs of the tests themselves and also the costs of the lost opportunity to generate. This arrangement ensures that the TSO compliance programme is proportionate and that it causes no disproportionate loss to the generators.

The NC RfG, at Article 5, ensures that network operator's costs are covered, but is silent on the handling of the generator's costs, and this causes some stakeholders concern that the NC RfG will result in an adverse change to their risk profile. It is however noted that Article 5.4 of the Network Code Operational Security requires: "*TSOs or DSOs shall develop the methodology for recovering the costs of test of compliance foreseen by this Network Code.*" adding to the confusion for stakeholders regarding ENTSO-E's intentions towards generators.

For both those focused on small units and those concerned about the operation of traditional large power plant, there is therefore a lack of clarity regarding:

a) Commissioning documentation, the place for certificates provided by others;

b) On site tests required at commissioning and ongoing; and

c) The hierarchical structure that ensures requirements are proportionate at all plant sizes.

As has been noted in section 5.1.2 and 6.1.1, there are situations where the lack of specification of the conditions under which compliance is to be determined can have a significant effect on whether a generating unit or power generating module is capable of meeting the requirements specified in the NC RfG. To address this issue, it is recommended that the conditions to be applied to tests and simulations should also be specified in the NC RfG.

5.4.1.1 Test Details

Testing requirements required by the TSOs are not entirely clear. The proposed text contains a number of clauses where certain obligations of the PGM Owners are defined but none explicitly states that a PGM Owner is obliged to prove compliance of their generating units with all the requirements listed in different articles of the Title 2 "Requirements". Chapters 2, 3 and 4 of the Title 4 list certain tests that should be done, indicating their contents and expected results, which is very important and helpful. Where they are applicable, these tests have been considered to have a potential cross-border impact.

However, some other tests that may have significant cross-border impact have not been included in the list of the tests explicitly indicated and described. For example, in the area of the general system management requirements there are a number of requirements (listed in Article 9.5 for PGM type B, in Article 10.6 for PGM type C and in Article 11.4 for PGM type D) that are important for power system operation and may have a cross-border impact, such as control facilities, protection schemes and information exchange.

The proposed testing framework should explicitly state all mandatory tests for the PGMs, including those addressing the general system management requirements such as control facilities, protection schemes and information exchange.

5.4.1.2 Use of Equipment Certificates

The use of equipment certificates is a crucial one at a number of levels. Currently, several Member States make use of certificates provided by manufacturers and installers according to well established standards as the entire compliance proving mechanism for generation connections to certain parts of their LV and MV networks and a significant part of the compliance proving mechanism for others. ENTSO-E has attempted to reflect this arrangement in the text: *"The Equipment Certificate may be used instead of part or all of the tests below, provided that they are provided to the Relevant Network Operator."* This appears in Article 38.1 (for Type B), Article 39.1 (for Type C) and Article 40.1 (for Type D). However, Article 26.3 (for Types B, C and D) contains the text: "*The Equipment Certificate cannot indicate total compliance, but can be used as validated information about components of the Power Generating Module."*

These two statements are contradictory. The approach of using Equipment Certificates instead of all tests for certain PGMs or certain tests for others is reasonable and may contribute to efficiency of the testing/compliance process. On the other hand, the solution proposed in NC RfG to use Equipment Certificates instead of all tests, regardless of PGM type is not appropriate.

5.4.1.3 Ongoing Compliance Monitoring

Compliance monitoring is crucial for the successful implementation of any Network Code, especially in the NCs that determine requirements for grid connections, such as the NC RfG and the NC DC. Concerning the NC RfG, the proposed Compliance Monitoring framework virtually does not exist. Nowhere in the NC RfG is it defined what should be monitored, who will execute the monitoring, how will reporting, publishing and general transparency be achieved, etc. Under the name Compliance Monitoring (Title 4, Chapter 1) in the NC RfG are defined responsibilities of the parties involved in the compliance process (interestingly in the NC DC this same Chapter is titled ‘General Provisions on Compliance’).

Moreover, in the general provisions for compliance of the NC RfG the only parties listed are the Power Generating Facility Owner (PGFO) (for list of responsibilities) and the Relevant Network Operator (RNO) (for list of tasks)[18]. With respect to the role of the TSOs in development of the NC RfG, as well as the general approach to determination of the detailed requirements at the national level, it is essential to determine roles for the TSOs and NRAs in the compliance monitoring process. Consequently, ENTSO-E and ACER should play a major role in overall coordination and monitoring of the NC RfG compliance.

Within the arrangement developed, the position of non-expert operators of small generating units should also be recognised, ensuring that only the monitoring requirements strictly relevant for this group are demanded and that arrangements are established that ensures the non-expert operator is able to meet his obligations.

ENTSO-E should amend the NC RfG to define the roles of the TSOs/NRAs and ENTSO-E/ACER in the NC RfG compliance monitoring process[19]. ENTSO-E should also consider if this is required in all the NCs.

[18] Although Monitoring seems like a one-way process, common title containing tasks and responsibilities for both NROs and PGFOs should be more appropriate.

[19] There is no doubt that NRA plays a major role in this process concerning actual activities, but there should be an “umbrella” role of the higher hierarchical levels in the system operation structure, firstly in determining detailed approach and methodology (partly on association level and partly on the national level, because this is how requirements are determined), and secondly in reporting and publishing of the Compliance Monitoring results (with all the respect, of course, to confidentiality issues).

5.5 Obligations placed on Non Expert Parties

NC RfG Articles	8, 9, 10, 12, 13, 15, 24, 25, 26, 27, 34, 35, 36, 37, 38, 41, 42, 45, 46, 48, 52, 53, 54	Stakeholders Commenting	COGEN Europe, DSOs, EU Turbines

Stakeholder Comment	Analysis	Proposal
All commenting stakeholders expressed concern regarding the ability of non-expert Power Generating Facility Owners (PGFOs) to comply unaided with the requirements of the NC RfG as drafted, this drafting specifically preventing manufacturers and others from representing PFGOs or relieving PFGOs of any of their obligations. DSOs also expressed concern about where obligations would lie in the situations where private networks interfaced between the generating unit and the point of connection with the public networks. DSOs were concerned in case they, as the owners of the connection points for these networks, would shoulder the liabilities under the NC RfG, without the ability to address the issues. They were also concerned about how realistic it is to expect that all CDSOs would have the knowledge to be able to address all the issues that will arise in these interface areas.	Throughout the NC RfG, obligations are placed on Relevant Network Operators, which may be TSOs, DSOs or CDSOs. All of these obligations should be within the normal technical ability of all TSOs and all larger DSOs but some may be beyond the reasonable ability of small local DSOs and particularly CDSOs. Since the threshold for Type A units starts at 800W, this results in what are effectively normal domestic appliances falling within the scope of the NC RfG, with obligations placed on the Power Generation Facility Owner being beyond the technical capability of the typical consumer. As drafted, the NC RfG specifically prevents the manufacturer from representing the owner in addressing any issues with the NC RfG. In considering significant technical issues relating to particular plant, it is normal for even large generators to call on the manufacturer for assistance.	The NC RfG should be redrafted to allow: a) Derogations for CDSOs and small DSOs from complex technical issues, the obligation being placed on the network operator to whose network the network of the CDSO or small DSO is connected. This would also allow DSOs the right to address those issues that do arise. b) The ability of manufacturers to represent PGFOs in respect of: i. All power generation modules operated by consumers; and ii. All other power generating modules where the manufacturer is appointed to address any issue or issues by the PGFO.

5.5.1.1 Background to the Issue

The NC RfG places obligations on Relevant Network Operators and on Power Generating Facility Owners that are, in the main, appropriate and relevant where these parties are appropriately skilled to undertake them.

However, setting the lower threshold for Type A units at 800W – for good reason as discussed in section 3.3 and Appendix D – brings individuals who may not possess the relevant skills to ensure compliance with the requirements into the category of Power Generating Facility Owners. The issues relating to the difficulties faced by this group in applying unaided for derogations is discussed at length in section 6.2.4.

The definition of a Relevant Network Operator will result in operators of closed distribution systems becoming responsible for a wide range of actions, from establishing whether generating units connecting to their networks should be required to provide fast reactive current injection – an issue that has not yet reached all TSOs – to the ongoing compliance responsibilities outlined in section 5.5.

It is recommended that non expert parties should be able to seek a derogation from the application of the NC RfG obligations on them directly, with other appropriate (expert) parties identified to implement the relevant obligations. These could be the equipment manufacturers in the case of Power Generating Facility Owners or the DSO or TSO to whose network the network of a CDSO or small DSO is connected.

6. Non Technical Issues

6.1 Legal Status of the Document

The step now being taken of establishing a network code as a Commission Regulation and therefore directly applicable on all parties under civil or administrative law is a significant change in the minds of many of the stakeholders with whom the authors of this report have engaged in consultation. For these stakeholders, network codes have been documents to be adhered to as far as is reasonably practicable but the NC RfG will be a document that has to be complied with without exception.

The drafting style adopted by ENTSO-E is that of a traditional network code rather than that of network code requirements applied as legislation. An example of a legislative document containing some of the issues addressed in the NC RfG is *Arrêté du 23 avril 2008 relatif aux prescriptions techniques de conception et de fonctionnement pour le raccordement au réseau public de transport d'électricité d'une installation de production d'énergie électrique*[20].

6.1.1 Fault Ride Through Requirements

The technical issues surrounding fault ride through requirements have been considered in section 5.2.4. However the handling of this issue provides a useful demonstration of the importance to stakeholders of the drafting style employed by comparing the handling of fault ride through requirements in both the NC RfG and l' *Arrêté du 23 avril 2008.* Fault ride through requirements were raised by almost all stakeholders who are concerned about the possible application of a fault ride through requirement of 250ms without limitation.

ENTSO-E advise that the NC RfG recognition of this requirement is based on the requirement in the Nordic Grid Code where it is specified that: "*Thermal power units shall be designed so that the turbine generator set can withstand the mechanical stresses associated with any kind of single-, two- and three-phase earth or short circuit fault occurring on the grid on the high voltage side of the step-up transformer. The fault can be assumed to be cleared within 0.25 sec. Neither damage nor need for immediate stoppage for study of the possible*

[20] Original version is available in full at: http://www.journal-officiel.gouv.fr, journal no 98 of 25 avril 2008, texte 7. Current version is available (in part with references to sources of current data that must be inserted) at: http://www.legifrance.gouv.fr/affichTexte.do?cidTexte=JORFTEXT000018697930&fastPos=1&fastReqId=455432160&categorieLien=cid&oldAction=rechTexte

consequences are allowed." However, Svenska Kraftnät operates a regulation and general guidance on the design of production plants (*SvKFS 2005:2*)[21], in which further details of the fault ride through requirement for large power plants is shown as Bilaga 3, reproduced here as Figure 10:

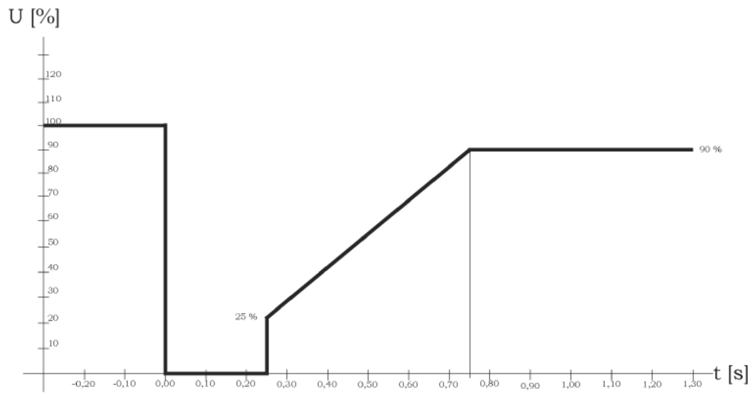


Figure 10: Fault Ride Through Requirements for Large Power Plants in Sweden

Also included in Svenska Kraftnät's regulation is an alternative fault ride through requirement at Bilaga 4, applicable to small and medium sized power plants, and this is reproduced below as Figure 11:

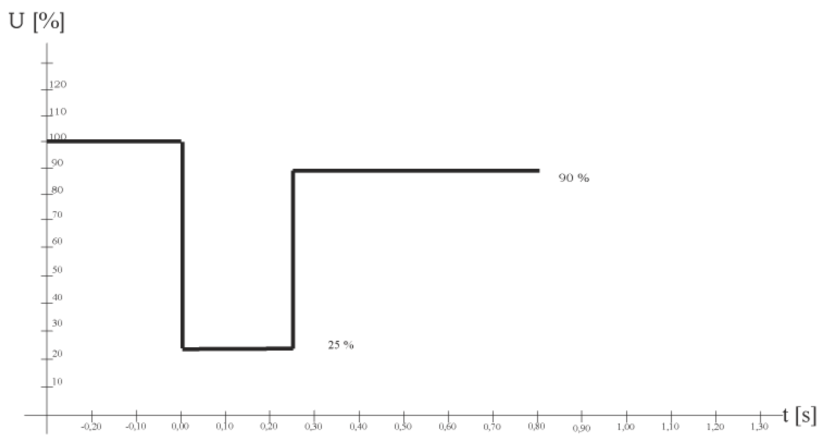


Figure 11: Fault Ride Through Requirements for Small and Medium Sized Power Plants in Sweden

When asked, ENTSO-E advised that "*Svenska Kraftnät applies the network fault (3-phase to ground) at the nearest meshed transmission substation when simulating the FRT requirement. The fault is applied and then taken away without disconnecting any equipment*

[21] Available at: http://www.svk.se/Global/07_Tekniska_krav/Pdf/Foreskrifter/SvKFS2005_2.pdf

which means that the grid is fully intact before and after the fault." ENTSO-E has subsequently advised that a similar approach is also followed in Finland[22].

The grid condition, point of application of a fault, residual voltage and generating unit inertia (larger machines generally have greater inertia) are material factors in determining whether a specified fault ride through requirement will be met by any particular generating unit, and, as shown by this example, the approach applied by the TSO cannot be determined in advance from the wording in the Nordic Grid Code. Stakeholders have expressed concern over the adoption of requirements specified in the Grid Code format into legislation with direct application via a Commission Regulation when it is known that the specified requirements are not operated in practice.

The *Arrêté du 23 avril 2008,* which also includes 250ms fault ride through requirements in certain situations, recognises different grid conditions by separately specifying fault ride through requirements for generating units connected at mesh substations and those connected by radial feeder. It also recognises different fault clearance times associated with different nominal voltage levels on the system. Only some stakeholders recognised the existence of the fault ride through requirements in France but none who were aware expressed concern over the approach followed there.

The NC RfG, as currently drafted, allows the TSO to provide either specific requirements for each connection point which may be different from those required at any other connection point and can therefore take account of grid conditions but lack clarity that non-discrimination is maintained or to provide generic values which have clarity that non-discrimination is maintained but cannot take account of grid conditions at the location. As the latter approach is that generally followed by TSOs in network codes, stakeholders are concerned that this is taken over into what they see as a document with a firmer legal standing without due account being taken of the material issues that ENTSO-E note are, in practice, being taken into consideration by the TSOs.

6.1.2 Legal Status of TSOs

The legal status of TSOs is also relevant when considering the legal status of the document. The TSOs in several Member States are state controlled organisations with a clear obligation to operate in the general interest of society at large. In some cases, the TSO is effectively permitted to establish relevant regulations without significant oversight. This fits with its public service duty enshrined in the legislation of the Member State. In other Member

[22] See Appendix F.

States, TSOs are limited liability companies which, while subject to regulation, are obliged to operate in the interests of their owners. As currently drafted, NC RfG provides both types of TSO with the same rights.

In the private discussions with individual stakeholders, two generators operating assets connected to networks operated by both state controlled and privately owned TSOs made comment relevant for this issue. One specifically stated that they were unconcerned about the manner in which the NC RfG would be implemented by the state controlled TSO, while raising a number of concerns regarding the drafting of the document. The other drew attention to areas where a TSO would be able to make use of the rights, provided exclusively to TSOs in the current drafting, to improve its revenue stream. This stakeholder noted that this is one of the obligations of the management of a privately owned company. While it is recognised that the stakeholder should have the opportunity to involve the NRA in the resolution of these issues, it is noted that the rights of the NRA to do so are also not recorded in the document as currently drafted.

6.2 Grid Code Modifications

Modifications to the manner in which users – and TSOs – are affected by the application of the Network Code arise from a number of interacting factors and a number are considered here.

6.2.1 Governance

In any Network Code it is certain that there will be changes, updates and amendments and probably many of them. For this reason there has to be a clear process for proposing, reviewing and recommending amendments to the code. While there is no single approach to this arrangement, this process often takes into account the requirement for a CBA followed by a public consultation before the final recommended changes are made. The final stage of this process would normally include the approval by ACER and/or the NRA to provide comfort to all stakeholders that the TSO cannot simply make changes unilaterally. However, it is the case that in at least one Member State, the TSO does indeed make regulations regarding access to the transmission network and effectively determines what the Grid Code requires without oversight.

Although the steps detailed above as the normal process are set out in the ENTSO-E document ‘Frequently Asked Questions’ – FAQ11 – they are not detailed in the NC RfG. It is not clear whether this is due to oversight or to deference to those TSOs with absolute rights on this issue.

For those stakeholders more accustomed to the 'consultative' process, the current drafting of the NC RfG raises a number of concerns:

1) The only party permitted to propose changes to the Network Code is the TSO.

   a) In those Member States where the Grid Code has the effect of a commercial agreement, stakeholders are accustomed to all parties having the right to propose amendments to that agreement and they perceive that the approach drafted by ENTSO-E removes their current rights.

   b) In most Member States, the NRA, acting independently in the interests of fair competition and with responsibility for consumer protection is entitled to propose modifications to all industry procedures and this right appears to be removed by ENTSO-E's drafting.

2) There is no specification of a robust consultation and impact assessment process. There is a reference to CBAs – considered in more detail in section 6.2.3 – but no clear definition regarding how it should be carried out.

Apart from the processes for making and approving changes, it is normal for there to be a clear system of document control for codes drafted in the format selected by ENTSO-E. At present the only evidence of any form of document control is a date on the first page.

6.2.2 Retrospective Applicability

The arrangements for retrospective application are of great importance for stakeholders with all current generators and most manufacturers' trade associations raising concerns regarding this issue. Previous technical rules (e.g. UCTE Operational Handbook) did not have full mandatory enforcement on one hand but on the other were applicable to all transmission grid users unless a specific derogation was sought by the user and permitted by the TSO and/or NRA. As has been made clear by both ACER and ENTSO-E, Grid Codes in each Member State can change at any time, and the effect for stakeholders faced by the possibility of retrospective application of provisions of the NC RfG is no different. However, for stakeholders, this does not address all the issues:

1) Some stakeholders advise that they have lifetime exemptions from meeting some of the requirements of the current Grid Code in their Member State. For these stakeholders, the current drafting of NC RfG does not provide comfort that these derogations will carry over to the new arrangements, changing the risk profile for their companies, in some cases very significantly.

2) Some stakeholders advise that where a derogation is issued under the Grid Code in their Member State, the costs of meeting any necessary upgrade resulting from the subsequent withdrawal of that derogation is societised. For

these stakeholders, the current drafting does not provide comfort that a change required in the best interests of society at large will result in costs being met by society at large, changing the risk profile for their companies. Some of these stakeholders are particularly concerned that the inclusion of statements regarding the funding of network operators' costs in Article 5, coupled with silence on the mechanism of funding all other parties' costs, infers that their current situation will be changed to their disadvantage.

3) Some stakeholders advise that they are only required to meet the requirements of the Grid Code in their Member State at the time a network connection is made. Should any future change be made to the Grid Code, they believe they are guaranteed a derogation or the funding of any change required by others within a reasonable asset life of their plant. For these stakeholders, the current drafting does not provide sufficient comfort that their risk profile will not be adversely affected.

4) The proposed text in the NC RfG concerning retrospective application is unclear. It is not obvious whether TSOs are obliged to assess the advantages of the NC RfG applicability to existing power generating modules or not. Reading carefully Article 33.1 of the NC RfG, it appears that this is solely a decision for the TSO and, intuitively, this should not generally be the case. While it is acknowledged that in some Member States the TSO has the right to make regulations regarding network access, in many Member States, changes to the current Grid Code only takes place following a significant review process involving representatives of all parties and a decision by the NRA acting as an independent authority. For some stakeholders, retrospective application has a similar effect.

However, from discussions with ENTSO-E and ACER, it is clear that there is no intention that this should be the issue that it is perceived. It can never be stated that all users will be exempted from the effects of changes to Network Codes just as it can never be said that no-one will be adversely affected by any other change in legislation. However, it may be possible to modify the current drafting to make clear that the implementation of the NC RfG itself will not materially disadvantage those stakeholders affected by the issues outlined above.

6.2.3 Cost-Benefit Analyses (CBA)

During the consultation meetings with the stakeholders, there was almost unanimous and very explicit opposition to the proposed methodology for determining the possible NC RfG application on existing PGMs. The more general issues are considered in section 6.2.2, but the text related to CBA which is currently in the NC RfG also raised significant concern.

There is no clear methodology defined for the preliminary assessment (the so called "preparatory stage" described in Article 33.1 of the NC RfG which required that the TSO undertakes a *"qualitative comparison of costs and benefits related to the requirement under consideration for application to Existing Power Generating Modules taking into account network-based or market-based alternatives, where applicable"*) nor for the full CBA (required by Article 33.2-7) that should be undertaken by the TSO prior to submitting a proposal to the NRA for retrospective implementation of the NC RfG, or its individual requirements, to existing PGMs.

For stakeholders, the vague nature of the qualitative comparison of costs required in Article 33.1 and described in FAQ 11[23] is not sufficiently robust to form any part of the decision making process that may result in an extensive review. Similarly, the description in Article 33.4 requiring that "*The Cost-Benefit Analysis shall be undertaken using one or more of the following calculating principles:*

- *net present value;*
- *return on investment;*
- *rate of return; and*
- *time to break even.*"

without any definition of what would result in acceptance of a proposal could result in users being required to implement significant investment projects based on a less robust analysis than their internal governance procedures would permit for disciplined investment included in their business plans. For stakeholders to be in any way supportive of the proposed arrangements, a clear business based definition of a cost-benefit analysis procedure would need to be established.

[23] See: *Network Code for Requirements for Grid Connection Applicable to all Generators Frequently Asked Questions*, ENTSO-E, 19 June 2012; available at: https://www.entsoe.eu/major-projects/network-code-development/requirements-for-generators/

6.2.4 Derogations

The issue of derogations has already been touched on in this document concerning retrospective application to existing grid users in section 6.2.2 above. Unusually, the approach in the drafting of the NC RfG is effectively to provide an automatic derogation at the NC RfG implementation date for all existing generating modules and all in a sufficiently advanced stage of development will automatically be exempted from meeting the requirements of the code where unable to do so.

In any technical or network code that includes technical requirements a derogation procedure is essential. In any code there will always be more stringent requirements such as greater accuracy, shorter or longer timescales, different frequency or voltage requirements etc. than can realistically be implemented for all existing plant. Some stakeholders with existing equipment will be unable to meet the new requirements although their equipment will have fully met the requirements that were in force at the time that the equipment was installed. The derogation procedure must be easily understood and logical with a clear process to be followed. The responsibilities of the various parties, the formats of the submissions and the timescales for the different action steps should all be clearly set out. General derogations should be for specific cases and usually derogations should be timed i.e. they should not normally be open-ended. However the overall approach and Title 5 – Derogations in particular is somewhat confusing.

Some of the specific issues that are somewhat contradictory include:

- The provisions of Title 5 apply equally to new and existing generators with the only difference being that existing generators have to make an application for a derogation – but not necessarily be granted one – 12 months from the day the requirement, with which it is not compliant, becomes applicable. It is elsewhere in the NC that the requirements on both New and Existing generators are set out, Article 3 stating that the requirements of the NC RfG shall apply to all new generating modules and only to existing modules where the NRA determines that shall be the case.
- Article 52 (1) states that '*Only the Power Generating Facility Owner shall have the right to apply for derogations for Power Generating Modules within its facility*' but Article 52 (2) states that '*It shall apply as well to Network Operators when applying for derogations for classes of both existing and new Power Generating Modules connected to their Network*.' The approach of leaning towards the owner – or operator – of the module to make the application for a derogation is the traditional approach where obligations fall on such owners or operators experienced in the operation of electrical plant. However, with a significance level set at 800W, what is generally looked on as household goods now falls within the scope of the NC RfG.

While accepting that, at least in some cases, this is reasonable, it is unreasonable to expect householders to accept responsibility for managing compliance with the NC RfG unaided as the current drafting requires.

- Article 54 (2) states that, in assessing the request for a derogation, the NO may carry out a CBA. It had been implied by the key parties that, except in exceptional circumstances, derogations would only have to be applied to existing generating units and that, before establishing the retrospective application of the code that would require an existing generator to apply for a derogation, the NO would have been required, if requested, to have carried out a CBA. Consequently, conducting a CBA for a derogation should be an exceptional event.

The stakeholder comments to this Title 5 include a number that suggest confusion between the issue of a derogation and the right of the NO to apply the requirements of this NC RfG to existing generators. The NO has the right to request the application of the requirements to existing generators requiring a full analysis and assessment including the possibility of a CBA, however the request has to be approved by the NRA. This process unless it is applied to a whole class of generating units, or all the relevant facts have not been taken into consideration, should make any subsequent derogation request unsuccessful. The TSO does not have to apply for derogations as the process above can be invoked.

There is also confusion over the rights with regard to the CBA. Generators must provide information if requested by the TSO but the TSO has no absolute requirement to request it. Since, if the TSO requests information and it is not provided, the process as drafted stalls, the logical approach for a TSO is not to request information and not conduct an efficient CBA.

The issue of how to deal with large numbers of derogations if they arise may be something that should be considered by NRAs. The requirement for a householder to apply for a derogation in respect of household equipment will only exacerbate this situation. In the current drafting, there appears to be an attempt to follow relatively standard derogation arrangements that would be operated by industry professionals without real consideration of the effect of requiring household equipment to be compliant with the requirements of the NC RfG. The design and manufacturing arrangements for such equipment are very different from those applying to 1GVA generating units where design and construction takes years and it is realistic to establish a date from which equipment should comply. Large volumes of the household equipment to be affected by the requirements of the NC RfG will leave production lines every day and it is on these large volumes that the resources required to design the next generation will depend. Already produced items will be at all stages in the supply chain with equipment installed tomorrow being taken from the installer's shelf possibly months following manufacture. Stakeholders operating in the microgeneration sphere, who have generally not been previously affected by the TSO's requirements for the connection of generating units to the network have strong concerns regarding the applicability of the scheme developed for establishing when the requirements of the NC RfG should apply to the equipment they manufacture and install and indeed whether ENTSO-E has thought through the impact of the derogation process on consumer confidence and the ability of Member States to achieve their RES-E targets.

6.2.5 Unforeseen Circumstances

As a code governing operation in real circumstances, it is normal for some arrangement to be established for dealing with circumstances unforeseen when the document was written. This issue has two parts. Firstly, providing authority to the organization responsible for dealing with the situation at the time and secondly determining how arrangements are established for dealing with the previously unforeseen circumstance should it be repeated.

6.3 Application to CHP Schemes

A number of stakeholder comments were raised regarding issues relating to the operation of CHP schemes which, historically, have been largely exempted from an obligation to contribute to system support in many Member States. While power systems were based around large controllable generation plants, this was an appropriate approach. In the transition to smaller, largely RES-E and CHP dependent systems, it must be recognised that this situation will change. Looking forwards, CHP schemes will contribute a more important proportion of the synchronous generating units connected to the network.

CHP schemes are usually installed in industrial, agricultural (greenhouses) or large commercial premises to provide heat or steam in support of industrial processes or space or water heating for commercial use. Electricity generation has traditionally been viewed as a by-product which is mainly used on site with surpluses exported to the network and shortfalls met by import. However, in some cases, the balance has changed and the opportunity to produce electricity for market trading may be as important as the production of heat or steam. For the TSO, to exempt these units from any part of the NC RfG is a significant issue which will grow as distributed generation increases. For more traditional CHP supporting industrial processes, the focus for the operator will always be the support of that process and having to consider the needs of the electricity network in any way would be problematic. ENTSO-E appears to have made a reasonable attempt at addressing both sides of this issue in the drafting of Article 3 section 6 parts g) and h), but it must be accepted that it is unlikely to fully satisfy either side. That, in itself, does not make the approach flawed.

Part g) allows an agreement to be made – which would be subject to review by the NRA if required – that, where the CHP scheme is crucial to the operation of an industrial process, it and its associated electrical load may disconnect in the event of a disturbance on the electricity network irrespective of size or connection arrangements of the generating facility. This approach appears to be a reasonable compromise between protecting industrial processes from the effects of disturbances on the electricity system where they require that protection, and ensuring other plants where that protection is not essential are available to contribute to providing the necessary system support through network disturbances.

Part h) provides that, where smaller units are crucial to the operation of industrial processes and the production of electricity and provision of heat or steam for the process cannot be separately controlled, they are exempted from the requirements to modify active power generation except to the extent required by the provisions relating to LFSM-O and LFSM-U. However, there are two problems with the approach adopted by ENTSO-E in this part. Firstly, small units connected to an industrial network where the point of connection is at 110kV or above cannot qualify for this exemption and, particularly from the perspective of a CHP operator, the reason for this is not clear, especially where the HV circuit is part of a distribution system, as considered in section 5.3.3.4 above. Secondly, the application of the LFSM-O and LFSM-U obligations to all installations, irrespective of the impact on industrial processes is unreasonable. It can be argued that the need to vary power output to comply with the LFSM-O and LFSM-U requirements is a response to a disturbance on the electricity system.

It is recognised that, given the transition from large to small generating units, it is reasonable that CHP schemes should no longer be generally exempted from the requirement to provide support to the power system as a whole. However it is also recognised that CHP schemes,

a) where the generation of electricity is clearly secondary to supporting an industrial process; and

b) where modifying the electrical output from the CHP scheme, would have a significant impact on the operation of that process;

should be exempted from all aspects of support for the power system, including LFSM-O and LFSM-U. This may require that they be disconnected on detecting a LFSM-O change requirement.

These exemptions are more likely to be required where steam pressure is managed as part of the operation of an industrial process and the general requirement to contribute to frequency control would still fall on most CHP schemes whose purpose is to produce heat – although some industrial processes require heat to be produced in finely controlled temperature ranges and may need partial exemption. This is best addressed on an individual basis, with the opportunity to reach agreement for exemption that is allowed in part g) also applying to part h). It is expected that this facility would also be used to allow the exemptions to apply to small schemes in industrial sites that are only classed as Type D units because of the point of connection to the electricity network of the site in which they are situated.

6.4 Harmonisation

6.4.1 Harmonisation between ENTSO-E Network Codes

Harmonisation between ENTSO-E Network Codes is a complex issue that needs to be taken care of all the way through the development of the entire set of the ENTSO-E Network Codes. In order to make sure that requirements in different NCs are, and will continue to be, coordinated and harmonised, ENTSO-E should introduce an inter-Code harmonisation methodology and appoint responsible person(s) to take care of it, particularly since all the Codes are in different development stages and will be adopted at different time frames. ENTSO-E has advised that the strategy concerning harmonisation among Network Codes, adopted in the beginning of the process, was to cross-refer only towards the Network Codes which have already been adopted, or at least towards the Network Codes that are expected to be adopted earlier than the Code containing the cross-reference. If implemented, it means that there should be no cross-references to other NCs in the NC RfG, NC DC could contain cross-references to NC RfG only, etc.

While understanding the logic in trying to only refer to something that already exists, the various parts of what will be, in operational terms, a single overall network code and the interdependency of the various sections, it can be argued that this approach of not recognising this interdependency with something, which will follow, is the real source of many of the stakeholders' concerns. As the package has been presented, they have first seen a significant increase in the scale of their obligations in isolation, having been presented with all of the extreme cases and only later have they seen any indication that these extreme cases may be tempered in practice. That the extremes indicated in frequency and voltage ranges, for example, may be tempered in practice is both positive and negative for stakeholders. Where extremes are specified in the NC RfG with the frequency of application clarified in other codes, this allows stakeholders to make the necessary technical and economic decisions in the implementation of their plants. Where there is no evidence that the extremes will be used, this questions the validity of the requirements specified in the NC RfG.

Requirements in different Network Codes are bilaterally interdependent to the extent that cross-references cannot be limited. The scope of individual Network Codes is different. The Parties on whom the principal obligations of each Network Code will fall is different.

Accordingly, following the segmentation approach to the preparation of the suite of codes means that each Network Code, while part of a suite, needs to be an independent and consistent technical and legal document, which further means that all general aspects of the Network Code (including cross-references where applicable) have to be defined for each Network Code at the time of its adoption.

The network connection codes (NC RfG and NC DC) are basic level codes that apply to all system users and network operators. NC RfG is the more critical since it applies to generating units and may have significant technical as well as commercial impact especially having in mind the expected growth of distributed generation from RES. Accordingly, all other Network Codes whose requirements may apply to generating units will have to make references to the NC RfG.

Concerning cross-references of the NC RfG to other Network Codes, it is limited since NC RfG is “basic level” Network Code (as indicated above). This documents sets requirements for generators and needs to be coordinated with the requirements for the connection of the demand (NC DC), simply in order to maintain non-discrimination concerning network access, which is a crucial attainment of the energy sector restructuring and liberalisation. Also, since the NC RfG determines requirements for grid users from the electrical network point of view, these requirements have to be harmonised (or at least coordinated) with the electrical network operational requirements and quality standards. In this sense, the NC RfG needs to be harmonised towards the NC Operational Security and the NC Load-Frequency Control & Reserves. The main topics that have to be checked for consistency are requirements concerning frequency, voltage, protection devices, system restoration, real-time data availability and exchange, and the arrangements for network code governance and derogations.

The requirements of other ENTSO-E Network Codes are more related to network operators and parallel operation of individual power systems in the synchronous area, so from the harmonisation towards the NC RfG point of view they have not been included in this assessment.

6.4.1.1 Harmonisation with the requirements of the NC LFC&R

The NC LFC&R, among others, determines the quality standards for frequency in the synchronous area. These values are very important for all generating units and together with the requirements for generating units concerning frequency ranges they create a consistent and reliable operational framework for all grid users and network operators. This issue is considered and a proposal presented in the text concerning frequency issues in section 5.1.1.

6.4.1.2 Harmonisation with the requirements of the NC Operational Security

The NC OS, among others, determines the quality standards for voltage ranges that have to be maintained at electrical network nodes. These values are maintained by the joint efforts of the grid users and network operators. Operation of the electrical equipment and technological processes at voltages that are above and below standardised values may cause significant damage to equipment and interruptions of the electricity supply to final customers. On the other hand, stable voltage conditions provide a safe and reliable operational framework for all grid users and network operators. Voltage ranges that grid users' equipment has to be able to sustain must be coordinated with the quality standards set for the voltage ranges at the connection point to the electrical network. This issue is considered and proposal is presented in the text concerning voltage ranges in section 5.1.3.1.

6.4.1.3 Harmonisation with the requirements from the NC Demand Connection

The NC RfG and the NC DC are synchronised to a significant extent. Below are a small number of issues that should be harmonised in these two codes although all of them have already been considered more fully in previous sections of this report.

The Network Code Demand Connection (NC DC), unlike the NC RfG, uses a voltage level of 1 kV to distinguish between different grid user groups. This voltage level is commonly used in international standards and technical standards in general as a separation threshold.

Equipment Certificates are used in the NC DC only "...instead of part of the tests...", whereas in the NC RfG they are currently used "...instead of part OR ALL of the tests..." without the different conditions being identified. In both the NC RfG and the NC DC, there are situations where certificates should be capable of replacing all tests and, more commonly, situations where they can only replace some. The wording in these codes should be harmonised, identifying the situations where each approach is applicable.

In the NC DC there is a provision for testing of compliance with the data exchange requirements. These requirements are also present in the NC RfG (Article 9.5 d) but there is no provision for similar compliance testing. Since data exchange may be critical for operational security, it should also be introduced into the NC RfG.

The NC DC is more specific on Compliance Monitoring than the NC RfG, indicating some of the activities that should be undertaken. However in the NC DC this activity is incomplete since numbers of important tasks for compliance monitoring are missing, as well as the description of the duties and responsibilities of the different parties.

6.4.2 Harmonisation with/of International and European Standards

A number of stakeholders have made comments regarding the separation between the NC RfG and international and European standards. In some areas, the existence of values in such standards is used as a justification for extending applicable ranges in the codes from normal practice but requirements in other current standards or standards under development are ignored. While others commented on the apparent rejection of work undertaken to establish revised standards currently in the approval process. These have been developed with the support of manufacturers and the TSOs that have been at the forefront of establishing the new requirements necessary to absorb the growing levels of RES-E and CHP installations.

ENTSO-E's view, supported in the discussions held with CENELEC, is that the NC RfG will establish the legal position and standards will be later developed or modified to comply with these requirements. ENTSO-E and ACER have recognised that the establishment of the non-exhaustive values to be implemented in each Member State will take some time – suggested to be of the order of 2 – 3 years following adoption of the NC RfG. This would then be the starting point for the development of any standards required to allow the established requirements to be met.

ENTSO-E and ACER have also expressed the view that the non-exhaustive requirements specified by TSOs will be the same as those applicable the day prior to the implementation date. If this arrangement is enforced, it should ensure both that the number of revisions to existing or developing standards will be limited and that those standards currently under development will be those applied.

However, it must be recognised that any delay in establishing any standards required by the development of the suite of network codes will impact on the ability of manufacturers to produce equipment that will comply. This must have an impact on the number of derogations required and is a relevant input to the consideration of the issues raised in section 6.2.4 above.

6.5 Support for Emerging Technologies

COGEN Europe and others involved in the development of new technologies, particularly those involving power generation associated with energy efficiency, expressed concerns regarding the ability of developers to commercially progress the development of technologies that are currently in the design stage or are concepts that have still to reach this stage. They see issues with their ability to bring them to market and progress them to fully comply with the requirements of the NC RfG. As has been the case with the introduction of RES-E technologies that were developed without full compliance but without having a serious impact on system stability until a certain penetration level is reached, they believe certain dispensations are essential if commercial progress is to be achieved in other areas.

While welcoming the introduction of Title 6, manufacturers and their trade associations remain concerned about the development of maximum thresholds and revocation levels.

Having considered the process outlined in Title 6, it appears to be reasonably structured and to have a reasonable process. However, it is surprising that there is no place for a review by NRAs acting together under the co-ordination of ACER of the development of threshold levels according to Article 58.

The revocation – or threat of revocation – of a classification as an emerging technology will have a significant commercial impact on the producers of such equipment and this must have an effect on their ability to obtain commercial funding for the development both of the product and of the business. While it is not a function of TSOs or NRAs to protect the operation of commercial businesses, decisions implemented without consideration of commercial reality may have an impact on the availability of future generation products. In the development of the final version of the code, it may therefore be appropriate to consider the notice periods applied to decisions made under Article 61.

7. Conclusions and Recommendations

The issues raised by the development of the NC RfG and the comments from stakeholders have been considered in the context of a change in generation mix from large generating units, with a significant proportion of synchronous generating units providing inherent support to the wider electricity network at times of network disturbances, to a dependency on much smaller distributed generating units. To date, this change has affected some TSOs much more than others but, given that there is already evidence of the cross border effects of the operation of networks with a high penetration of distributed generation, it is recognised that the issues that some TSOs have been attempting to address in recent years are issues that will ultimately affect all European TSOs. The requirements of the NC RfG have also been considered with reference to the firm statements from both ACER and ENTSO-E that:

a) changes in the current Network Codes of Member States will only occur in compliance with the current arrangements applicable in the Member State up to the date that the NC RfG would, if adopted, come into force,

b) the technical parameters applicable in the Network Code of the Member State would be carried over into the NC RfG applicable in the Member State and,

c) from the adoption date, changes to the code would be subject to the change requirements contained in the NC RfG.

In this context, the adoption of the NC RfG will, by itself, have very limited impact on current network users provided certain existing safeguards are maintained. Against this background, ENTSO-E appear to have generally addressed the issues of operating an interconnected network with Europe wide market capabilities in a reasonable and realistic manner while recognising that the principles of subsidiarity should continue in order to allow each Member State to set its own regulation wherever practicable. The approach taken should ensure that the impact of the NC RfG on all currently operating generating units and all generating units genuinely in course of development would be neutral. Additional requirements are placed on new generating units but these requirements appear to be no greater than would be reasonably required to allow these smaller generating units to replace the large synchronous generating units, currently in operation, but that will be decommissioned in line with age profile and energy policy.

However, in part to address the reasonable concerns of stakeholders affected by the transition that the adoption of the NC RfG into EU Law will bring but also to recognising that there are a number of technical issues that are not fully worked through into standards that would allow their implementation by affected stakeholders, a number of minor modifications and clarifications are recommended.

7.1 Recommendations on technical issues

7.1.1 Recommendations concerning frequency ranges

To make the operational frequency requirements for generating units, as presented in the Article 8, Table 2, acceptable as currently proposed, it is essential that ENTSO-E determine quality parameters of the electricity network frequency. Recognising that the only obligation specified in the NC RfG is to remain connected and not to operate normally, it is proposed that the frequency ranges to be applied in the NC RfG should follow IEC Standards.

To allow for the correct representation of these standards, consideration should be given to incorporating frequency and voltage requirements into a single diagram.

For details see section 5.1.1.

7.1.2 Recommendations concerning active power output with falling frequency

The requirements should be more completely defined, particularly with obligations placed on TSOs and NRAs, when setting non-exhaustive parameters, to take account of ambient temperatures and the technical capabilities of relevant technologies. This could be achieved by extending the compliance section of the NC RfG in a manner similar to that of the GB Grid Code to more clearly define the required characteristics of gas turbines operating at falling frequencies, but must also take account of the need to safely manage the operation of pressure vessels.

For details see section 5.1.2.

7.1.3 Recommendations concerning LFSM-O and LFSM-U

For most generators, this requirement should remain as drafted.

LFSM-U settings for nuclear generators should be established when the business case is being developed and remain unchanged after the safety case has been finalised – unless a clear justification that takes account of the nuclear safety issues is later established. (LFSM-O is stated not to be an issue for nuclear generators).

In general, CHP schemes should be designed to allow compliance with the requirements as specified, but Article 3.6.h should be modified to allow exemption from LFSM-O requirements for the very small number of CHP schemes that cannot reasonably comply. This may reasonably be coupled with an obligation to disconnect as may be permitted by Article 3.6.g where the equivalent CHP scheme would be adversely affected by system disturbances.

For details see section 5.1.3.

7.1.4 Recommendations concerning Voltage Ranges

Four recommendations are made, without analysis by the Consultant, based on the apparent agreement achieved at the stakeholder meeting on 16 September 2013.

5. Proposed duration of the additional overvoltage range of 1.118 pu – 1.15 pu for the Type D power generating modules in Article 11, Table 6.1 for Continental Europe, which is currently intended “... to be defined by the TSO while respecting the provisions of Article 4(3), but not less than 20 minutes”, should be “defined by the TSO while respecting the provisions of Article 4(3), with a maximum time period in the range of 20 – 40 minutes”.
6. Proposed duration of the additional overvoltage range of 1.05 pu – 1.0875 pu for the Type D power generating modules in Article 11, Table 6.2 for Continental Europe, which is currently intended “... to be defined by the TSO while respecting the provisions of Article 4(3), but not less than 60 minutes”, should be “defined by the TSO while respecting the provisions of Article 4(3), with a maximum time period in the range of 40 – 80 minutes”.
7. The additional overvoltage range of 1.0875 pu – 1.10 pu for the Type D power generating modules in Article 11, Table 6.2 for Continental Europe, should be deleted.
8. Drafting should be introduced permitting the reinstatement of the additional overvoltage range of 1.0875 pu – 1.10 pu for the Type D power generating modules in Article 11, Table 6.2 for parts of the networks of individual TSOs in Continental Europe where it is required for network configuration reasons, as approved by the NRA, provided it is neither detrimental to the operation of the power system nor to the operation of the internal market.

It is also recommended that consideration should be given to representing voltage and frequency arrangements together as outlined in section 5.1.1.

For details see section 5.2.1

7.1.5 Recommendations regarding the use of On Load Tap Changers

As the arrangements that should concern stakeholders have been ruled out by both TSOs and NRAs, no changes are proposed. However, it is recommended that, where OLTCs are required, this should be clearly stated and not left to be inferred.

NRAs should be required to ensure that the voltage ranges selected by TSOs in Article 11 of the NC RfG correctly reflect current practice in the use of OLTCs, including the tapping range in normal application or that the appropriate change review is undertaken.

For details see section 5.2.2

7.1.6 Recommendations regarding reactive power capability

The drafting should be modified to allow the existing Figure 7 to continue to be used in TSO areas where it is currently standard practice for on-load tap-changers to be used provided it is normal to employ a sufficient tap range. In other TSO areas, the figure should be amended as shown[24].

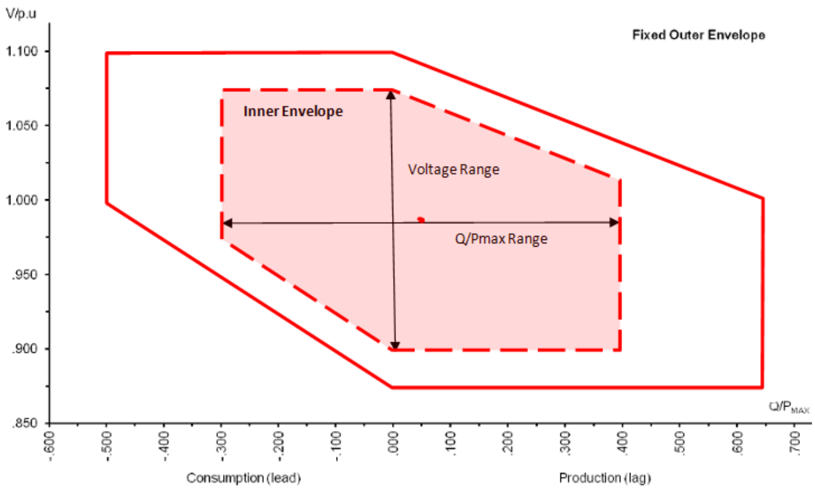


Figure 12: Voltage/Reactive Power Profile without OLTC

For details see section 5.2.3.

7.1.7 Recommendations regarding provision of Reactive Power as Means of Voltage Control

Provided the issue considered in section 5.2.3 and recommendation 7.1.6 is addressed, it is proposed that no further change should be made to the technical requirements.

---

24 This figure is the alternative figure proposed by Eurelectric Thermal Generators that reflects the extremes proposed by ENTSO-E. To ensure that there could be no claim of discrimination, Eurelectric proposed a similar alternative figure for Power Park Modules. While recognising that this is a desirable approach, since the change recommended here is based on the capabilities of a technology, extending the change to other technologies has not been considered.

NRAs should be required to ensure that stakeholders are not materially disadvantaged by the operational demands placed on them by TSOs for the provision of Reactive Power for Voltage Control.

For details see section 5.2.4.

7.1.8 Recommendations regarding Duration of Fault Clearance Time

This article should be amended such that the ranges of permissible fault clearance times are distinguished by voltage level and, particularly at 400kV, by synchronous area. The ranges provided should more closely reflect current practice except where alternative arrangements are required for network configuration reasons as approved by the NRA provided this is not detrimental to the operation of the power system or of the internal market.

For details see section 5.3.1.

7.1.9 Recommendations regarding Fast Reactive Power Injection and Active Power Recovery for Power Park Modules types B, C & D

These issues should become non exhaustive requirements, specified only where PPM penetration is sufficient that they need to be addressed by TSOs. The requirements should be specified with greater precision and take due account of the capabilities of existing technologies. In the more precise drafting:

a) the intent that the combined effect of the requirements would not impact equipment specification should be ensured.

b) the ability for Relevant Network operators to ensure that the requirements will not affect the safe operation of their networks should be guaranteed, taking precedence over the TSO's rights under Article 4.4.

For details see section 5.3.2.

7.1.10 Recommendations regarding Fault Ride Through and LV Connections

It is recommended that all generating units connected to LV networks should be exempted from the fault ride through requirements specified in Article 9.

For details see section 5.3.3.1

7.1.11 Recommendations regarding application to LV Connected Generating Units

It is recommended that, in line with current standardisation practice and to ensure that all generating units connected to the LV networks operated by DSOs are treated equally, the threshold between Type A and Type B generating units is modified such that all generating units > 800W connected to public networks operating at less than 1 kV are considered as Type A units.

For details see section 5.3.3.2.

7.1.12 Recommendations regarding conflicts relating to the operation of protection equipment

The conflicts between ensuring the correct operation of both transmission and distribution protection systems in the transition to embedded generation is the subject of a number of studies. In this particular situation, since the appropriate changes would only become apparent following completion of current studies and would be appropriate on a Europe wide basis, it would be appropriate to require that the NRA, in consultation with other NRAs apply suitable standards as the information to allow their development becomes available.

As the NC RfG is currently drafted, there is no opportunity for any affected party other than the TSO to propose modification to the NC RfG. While it is to be hoped that TSOs would propose appropriate modifications, this restriction is very unusual. To allow NRAs to apply the results of this study and to allow more general review, it is also recommended that other stakeholders, and in particular the NRA, should also be able to propose modifications

For details see section 5.3.3.3

7.1.13 Recommendations regarding the application of transmission rules to distribution networks

The Network Codes developed by ENTSO-E should be modified to allow an overlap of the application of transmission or distribution rules depending on whether the operator is a transmission operator or a DSO.

Article 3.6 should be modified such that Type A, B, or C generating units are only deemed to be type D units where the operator of the 110kV or above network to which they are connected is not operated by a DSO or CDSO.

For details see section 5.3.3.4.

7.1.14 Recommendations regarding compliance

Clarification of compliance requirements is essential and TSOs should be required to produce a clear, unambiguous and detailed statement of all requirements that should be subject to the approval of the NRA operating in conjunction with other NRAs.

For details see section 5.4.

7.1.15 Recommendations regarding obligations placed on non expert parties

The NC RfG should be redrafted to allow:

c) Derogations for CDSOs and small DSOs from complex technical issues, the obligation being placed on the network operator to whose network the network of the CDSO or small DSO is connected. This would also allow DSOs the right to address those issues that do arise.

d) The ability of manufacturers to represent PGFOs in respect of:

   i. All power generation modules operated by consumers; and

   ii. All other power generating modules where the manufacturer is appointed to address any issue or issues by the PGFO.

For details see section 5.5.

7.2 Recommendations on Non-Technical Issues with Significant Technical Impact

7.2.1 Recommendations Concerning Harmonisation of Network Codes

It is strongly recommended that ENTSO-E ensure harmonisation of the requirements among the individual ENTSO-E network codes and that mechanisms are introduced to maintain network codes harmonised at times of revision of any code. For details see section 6.4.

It is recommended that clear governance arrangements are established for the entire suite of network codes.

7.2.2 Recommendations Concerning Cost-Benefit Analyses

It is strongly recommended that ENTSO-E develop and present in the supporting documents to NC RfG a detailed methodology for:

- Preliminary assessment of costs and benefits at the CBA preparatory stage, and
- Full Cost-Benefit Analysis

For details see section 6.2.3.

7.2.3 Recommendations concerning derogations

It is recommended that the following aspects concerning derogations from the requirements of the NC RfG are addressed:

- In the Member States, there are number of generating units currently operating under derogations from the existing network codes and in some Member States the costs of the removal of such a derogation are socialised. In order to ensure that the implementation of the NC RfG is neutral, the NC RfG should contain a clause indicating that existing derogation rights continue and that, in the event that such a derogation is removed by the retrospective application of the NC RfG to these generating units, any existing rights for compensation would continue to apply.
- The NC RfG should provide for the ability of the manufacturer or other technical advisor to make application for individual or class derogations, so that non-expert operators are not disadvantaged.

7.2.4 Application to CHP Schemes

Article 3 section 6 parts g) and h) appear to attempt to establish a reasonable compromise between the reasonable needs of TSOs and CHP operators in the situation where the proportion of small generating units is increasing. However, the current drafting does not quite achieve that and it is recommended that these parts are redrafted to ensure:

c) Smaller installations that should be exempted from the NC RfG requirements are not prevented from receiving these exemptions purely because they are embedded in industrial networks that are, in turn, connected to the public network at high voltage;

d) Arrangements can be established to meet the requirements of TSOs and allow CHP schemes to be exempted from varying electricity generation where:

i. The level of generation cannot be decoupled from the production of heat or steam to support an industrial process;

ii. The generation of electricity is secondary to the support provided to the industrial process; and

iii. The required change in electricity generation would result in a variation in the production of heat or steam that would have a material effect on the safe and economic continuation of that industrial process.

7.2.5 Recommendations regarding emerging technologies

In Title 6, the opportunity for NRAs, operating in conjunction with other NRAs where appropriate, to be involved at all stages should be recognised. In establishing timescales for notification of revocation of emerging technology status, the impact of short notice periods on the commercial risk profile of technology development should be recognised.

7.3 Recommendations regarding Implementation

3) It should be clear that the subsidiary codes prepared by the individual TSOs shall carry over existing values into the non-exhaustive values. Guidance should be prepared by ENTSO-E on the completion of all values and this guidance should be published and reviewed by ACER.

4) The ranges quoted by ENTSO-E should be reviewed to ensure that they are entirely accurate. Where they are conditional on other issues, these should be stated.

A. Agreed Notes of Meetings with Stakeholders

A.1 ENTSO-E

Project: Technical Report on ENTSO-E Network Code – Requirements for Generators

Stakeholder Meeting: 24 April 2013

Location: ENTSO-E, Avenue de Cortenbergh 100, 1000 Bruxelles

Present:

For ENTSO-E	**Edwin Haesen, Senior Advisor, ENTSO-E**
	Marta Krajewska, Legal Advisor, ENTSO-E
	Helge Urdal, National Grid
	Ralph Pfeiffer, Amprion GmbH
	Wilhelm Winter, Tennet TSO GmbH
	Mark Norton, EirGrid
	Ineś de la Barreda, REE
For the European Commission	**Matti Supponen**
For DNV KEMA	**Robert McVean**
	Božidar Radovič

Retrospective application

ENTSO-E advised that their clear intention for the NC RfG is that it applies to new plants. Existing plants do not have to comply a priori with the requirements of this code. The code could only apply to existing units, provided that the procedure outlined in article 33 is followed. ENTSO-E stated that they had explained this procedure to be followed, including a quantitative CBA, public consultation and NRA approval, in the FAQs (8-9-11) prepared as supporting document in June 2012.

Non-exhaustive requirements and national implementation

ENTSO-E stated that the code is developed based on a reasonable time horizon and credible future scenarios. ENTSO-E advised that the code provides balance between exhaustive requirements and requirements where national processes will cover specific implementations to cope with local system needs at minimum cost, avoiding where possible adding unnecessary cost for all. ENTSO-E expects that all countries already have adequate processes in place for grid code revisions. These processes are closely linked to the national implementation of Directive 2009/72/EC, and in particular its Articles 5 and 37 covering NRA tasks and responsibilities in the field of grid connection. Based on mutual understanding between ENTSO-E and ACER, the code should not provide any further restrictive details on how these national processes should be organized (see ACER Opinion, and ENTSO-E's response to ACER Opinion). It was also clarified that any change from current values – including the setting of values for provisions not currently in national codes - would need to go through the initial national process. It is expected that many parameters will be those existing in Member States today. It cannot be excluded that some will change – as would be the case anyway under the current arrangements. It was always ENTSO-E's position that any change to existing arrangements would be subject to further involvement of affected parties (e.g. generation owners). ENTSO-E observed that network codes have never been static documents and have changed as circumstances have required. ENTSO-E noted that some countries are already discussing in a public forum how to proceed with the implementation of network codes, including public consultation. ENTSO-E stated its intention to continue working, together with stakeholders and NRAs, in preparing the implementation of the code before it enters into force. ENTSO-E acknowledges the benefit of clarifying national processes and possible national choices, and believes that the EC shares their view.

The approach of allowing for parameters to be set at the national level is a result of the entire process. ENTSO-E has drafted the NC RfG to meet the objectives of the third energy package and has set specific details (including values) where appropriate. For other parameters where local conditions are relevant and where otherwise implementing the most severe requirement uniformly would entail unnecessary costs, the principle of subsidiarity applies and ENTSO-E has left the setting of parameter values to national processes. ENTSO-E stressed that both exhaustive and non-exhaustive requirements are driven by their impact on cross-border flows and market integration. Even when local system characteristics require a different implementation, the NC RfG ensures that the requirement is covered across Europe in an appropriate manner and by adequate, transparent processes.

FAQ 18 clarifies ENTSO-E's understanding that if the NC RfG in a non-exhaustive requirement provides a range of values, a national implementation cannot result in a value which is more onerous than this range as this would not be compliant with the requirements of the EU network code. ENTSO-E believes that the EC share this interpretation.

ENTSO-E does not consider the development of a fully harmonized set of requirements to allow generator manufacturers to reduce the number of versions of available equipment an objective of the third energy package. ENTSO-E noted its belief that this interpretation has been confirmed in past discussions by ACER and EC.

Fault ride through requirements

ENTSO-E recognised that many stakeholders are concerned by the implied 250ms value for fault clearance time in the fault-ride-though (FRT) requirement available in the code and believes the concern is a result of misunderstanding of the requirement and/or mistrust of national processes. A considerable investment was made in Nordic countries following an incident in Southern Sweden/Northern Denmark approximately 10 years ago causing black out of half of each of the countries. A fault was not cleared in the normal manner and time due to the failure of one circuit breaker. The failure was instead detected by the circuit breaker fail protection giving a very long clearance time which caused the disconnection of more than one very large nuclear generator. Following this major incident investments were made to prevent a repeat in future including faster circuit break fail protection, to give the world's fastest circuit breaker fail back-up clearance times of 250ms. The fault ride through requirement was then introduced to generators to remain stable (ride through faults) to cover the operation of this form of back-up protection. The 250ms requirement therefore covers the time to clear a fault even when a circuit breaker fails to operate and the next in line circuit breakers have to clear the fault. ENTSO-E indicates that 250ms of fault clearance time is not an a priori fixed requirement but the upper limit of the range. ENTSO-E expects decisions to be taken in the frame of the relevant national procedures to reflect geographical and topographical network design differences. It is also noted that a fault clearance time in itself does not provide the full extent of an FRT requirement; it is key for the national implementation (as stated in the code) to also specify appropriate pre- and post-fault conditions. ENTSO-E does not consider it appropriate to split FRT requirements by synchronous area to relieve stakeholder concerns. ENTSO-E also stresses that in today's practices national specifications could consider values beyond 250ms even, whereas the NC RfG would put a constraint on this rather than drive to the most extreme values. ENTSO-E stated that until now the 250ms requirement has only existed in the Nordic region, taking into account specific pre-fault conditions. The Nordic countries however require the least challenging pre-fault conditions by requiring FRT capability only for very limited pre-fault operating conditions of a generator where as others (including GB) require the most onerous pre-fault operating conditions (including full reactive import). Therefore 250ms FRT requirement in one country may be no more onerous in terms of stability to deliver than 150ms in another, once all parameters as preconditions are taken into account.

Specific requirements for non-synchronous generation

ENTSO-E is aware of concerns expressed by stakeholders on some system support issues, as they relate to non-synchronous generators, in the NC RfG. As synchronous generators are displaced by RES-E generation, the support that is inherently provided to the system by synchronous generators must be obtained in other ways, either via grid investments, operational measures or additional grid connection requirements for RES generators which at times substitute synchronous generators. Synchronous generators can only support the power system when connected and operating. Therefore, if support cannot otherwise be obtained, it is likely that RES-E (higher merit) generators have to be constrained off, in order to allow synchronous generators to run. This can result in high financial and environmental costs and may jeopardize the achievement of the EU carbon dioxide emission reduction targets.

Fast reactive current injection

Comments have been made to ENTSO-E by some stakeholders regarding fast reactive current injection and technical constraints of providing 2/3 of the requested reactive current in 10ms. ENTSO-E pointed out that the actual wording is, "...time period specified by the Relevant TSO...which shall not be less than 10 milliseconds.", and is deliberately set to ensure that no TSO shall require less. ENTSO-E has a confidential response from one manufacturer indicating that they have a design of equipment that can meet this requirement and regrets that the common voice of the industry ignores this. As the response is confidential, ENTSO-E is unable to provide details but were asked to approach the respondent to encourage them to confirm this position to the DNV KEMA team.

ENTSO-E advised that, in 2005, National Grid implemented a requirement for fast reactive current injection during the periods of faults (typically 60-140ms). No time delay was allowed for in this current GB requirement. ENTSO-E after hearing about concerns from wind turbine manufacturers about meeting specific target values decided to split this requirement into a fast component (large kick) and slow component (relatively accurate delivery). The fast component covers a response of ⅔ of the maximum value in a time specified by the TSO as not less than 10ms, and the slower full response in 60ms. In Germany, the requirement is for full fast reactive current injection within 40ms of fault detection, with no specification for the fault detection time. Current protection systems have started measuring within 5ms and require this current contribution to ensure that the protection operates reliably and selectively within target clearance times. ENTSO-E with a need for ideally less than 5ms response time has due to concerns of manufacturers of converters (particularly full converters) decided to restrict the freedom of TSOs not to ask for anything shorter than 10ms. Due to the system need for a "crude substantial kick" (not an accurate value) there is no need in compliance to measure accurately the magnitude of the current delivered.

Active power recovery after faults

To ensure recovery from fault conditions, operators of small systems may suggest other FRT implementation priorities (bias) than the operators of large interconnected systems, due to different levels of RES-E penetration at present. In large systems, a major issue is voltage stability as the interconnected network will assist in ensuring frequency stability. In Continental Europe (CE), therefore, it is expected that TSOs will focus on reactive power provision, although even in CE risks of losses greater than 3GW have been identified by ENTSO-E with real events shown to stakeholders and therefore frequency stability is still an issue. In smaller networks, such as Great Britain and Ireland, the TSO primarily needs to address frequency stability and therefore there is an expectation that these TSOs will request in their national process that generators capabilities balance differently the provision of real power to allow frequency recovery and reactive power to maintain voltage stability. ENTSO-E's position concerning synchronous area requirements for active power recovery after fault and fast reactive current injection is that this combination, when implemented at national level, will not result in any requirement to oversize any equipment to provide support during system faults or fault recovery.

Industrial CHPs

ENTSO-E provided clarification on which units are addressed in Article 3(6)h which gives a few exemptions for industrial CHPs. One of the criteria given is that the "primary purpose of these facilities is to produce heat". ENTSO-E's intention and understanding is that 'heat' always includes 'steam' in this respect.

Voltage withstand capability

The NC RfG asks for a voltage deviation withstand capability in 400kV systems up to a maximum of 1.10pu. ENTSO-E mentioned that this is current practice in Spain and that the network (i.e. TSO assets) is designed to cater for this.

ENTSO-E states that the code leaves it open to the grid user whether to comply with the voltage range requirements via an OLTC transformer or by other means. On the topic of reliability implications of an OLTC transformer, ENTSO-E considers the impact is small compared to the overall availability/reliability of an entire power plant.

Frequency withstand capability

The frequency range for unlimited operation is shown as 49Hz – 51Hz to cope with larger frequency sensitivity even in the largest synchronous area (CE), in part due to the lower inertia provided and in part the need for time to stabilise frequency during system splits and system recovery (e.g. from very rare black-outs). A main cause of this phenomenon is the increased number of RES-E connections. ENTSO-E noted that the unlimited and time-limited frequency ranges as given in the NC RfG are present practice in many countries. Some countries (e.g. GB) at the start of RfG development had much wider (47.5 to 52Hz) frequency range (unlimited) which has been complied with by all types of generation plants including nuclear for decades.

Max active power reduction with falling frequency

Concerning the requirement on maximum active power output reduction with falling frequency (Article 8(1)e), that has been challenged by the stakeholders because of the specification of a wide range of values, ENTSO-E stated that the code clarifies that this should be addressed across Europe for all generation (down to type A), and the range covers present practices. It is acknowledged that further details (cfr. GB grid code) are needed in national implementation.

Transitional period

ENTSO-E stated that the code provides for a 3 year transition period following its entry into force as an EU Regulation. Based on the procedure for units that are not yet connected at the date of entry into force (Article 3(4)), ENTSO-E acknowledges that national implementations will need to be completed in the first two years following entry into force of the NC RfG.

A.2 COGEN Europe and EHI

Project: Technical Report on ENTSO-E Network Code – Requirements for Generators

Stakeholder Meeting: 22 April 2013

Location: Brussels

Present:

For COGEN Europe	**Dr Fiona Riddoch**
For European Heating Industry (EHI)	**Bob Knowles, Technical Manager, BDR THERMEA**
For DNV KEMA	**Robert McVean**
	Božidar Radovič

COGEN and EHI recognise the considerable change that has been made to the drafting in response to their concerns and appreciate the moves that have been made by ENTSO-E. They wished to discuss in this meeting, the impact of the code on Type A units which are effectively domestic white goods without any common drive source. The following points were made:

- Manufacturers are prepared to adapt to meet the requirements of the NC RfG;
- Time is needed to make the necessary design changes and manufacturers need to continue to sell to be able to afford to make the necessary changes;
- Considerable investment has already been made and investors have not yet seen a return on that investment as products are still new to the market and low in volume.
- Significance Test is not well enough designed, especially for small units without a common drive source;
- Some manufacturers have stable product and sales, but innovative designs are being stifled because of the lack of stability to allow funding;
- In this respect, the current wording on derogations and retrospective application has a process that theoretically should work, but is not firm enough to allow lenders to provide financial support for the necessary redesign work;
- In respect of operators' applications for derogations, this is not appropriate for micro CHP as generator owners are domestic home owners. The CHP product replaces their heating boiler. They do not have the necessary expertise and understanding to be expected to complete this process. There should be an opportunity for manufacturers to make application for a class of generators on their behalf is necessary;
- COGEN/EHI believe:

- ICE could comply but need 3+ years to make design changes (derogation by the manufacturer);
  - Stirling engines are commercially available emerging technology that should be allowed special rights up to 0.1% (deal struck in with NGET in GB) of connected capacity to allow continuing sales to fund redesign;
  - Nothing else is commercially available emerging technology and newer equipments should be designed to comply with the requirements of NC RfG from the outset.

The 0.1% of connected capacity should be permitted for each technology classed as emerging. In the case of the members of COGEN and EHI, the only technology that would qualify is the Stirling engine.

COGEN and EHI will provide some financial information to support their position.

Regarding the impact of the changes on CHP sector as a whole COGEN Europe particularly highlighted

- Fault ride through is now required for all generators whereas until 2008/9, all CHP in Europe were required to drop off during faults and not reconnect until network stability had been restored. These units have not been primarily made to produce electricity, but rather to produce heat. While recognising that the change in emphasis is inevitable, and has started in France and Germany, COGEN Europe have concern regarding the U-f envelope (voltage-frequency operation boundaries) – in particular the extremes they believe to be currently only applied in Nordic countries to non CHP plant – and the lack of a robust CBA process where design changes – especially retrospectively – are required.

COGEN Europe indicated that this point and the wider sectoral concerns would be commented on further and separately.

A.3 DSO Associations

Project: Technical Report on ENTSO-E Network Code – Requirements for Generators

Stakeholder Meeting: 25 April 2013

Location: Eurelectric, Boulevard de l'Imperatrice, Brussels

Present:

For DSO Associations	**Pavla Mandatova, Eurelectric**
	Jacques Merley, ERDF/Eurelectric
	Florian Chapalain, EDSO for Smart Grids
	Herman Poelman, Liander/CEDEC
	Marc Malbrancke, Inter-Regies/CEDEC
	Carmen Gimeno, Geode
	Johan Lundqvist, Svensk Energi /Geode/Eurelectric
For DNV KEMA	**Robert McVean**
	Božidar Radovič

DSO associations indicated that, while there are a number of areas in the NC RfG that give rise to concern, for the DSOs there are five key areas where improvement is required:

- Compliance Monitoring and Testing;
- Fault Ride Through;
- Impact on Protection Schemes;
- Responsibility Gap
- Parameterisation of Voltage Levels for Transmission and Distribution.

Using the attached presentation, DSOs discussed the implication for the NC RfG of each of these in turn.

For DSOs, a major issue is the compliance monitoring obligation placed on them without any clarity about what is required, how it will be funded – TSOs have ensured that their costs are addressed, but no-one else's are – or what will be achieved. In some countries, there must be a strong legal foundation which may require detailed rules before the compliance requirements can be enforced. In other countries, the right to connection to the public electricity network is enshrined in law and the opportunities for a DSO to refuse are limited. DSOs believe that, if they try to enforce these requirements without sufficient legal grounding and the generator does not wish to comply, they can sue for connection access and would probably win. For there to be any success in implementing these requirements, standards must be developed very quickly, especially for mass market sets, so that compliance can be confirmed through certificated arrangements recorded during the connection process.

Based on current projections of the number of units >5kW anticipated in Austria, Belgium, Germany, France, Italy and UK – 57% of EU population and a cost estimate of 250 – 500€ per installation to cover 0,5 day test + travel costs + test equipment costs + administration costs, DSOs estimate that the total cost to them of this obligation in 2020 could be up to 2,9 billion €. DSOs fear that such a vague obligation as "The Relevant Network Operator shall regularly assess the compliance of a Generating Unit with the requirements under this Network Code..." without specifying what is required, what the objective is, what 'regularly' means into a market expected to number 7,7 million units by 2020 will merely result in DSOs becoming the scapegoat any time anything goes wrong.

DSOs note that the draft System Operation Code also includes compliance obligations for the DSOs. These are different and they note that costs add up!

Some countries already have certificate arrangements provided by manufacturers and installers in an attempt to address the genuine safety and network protection issues that are recognised to exist.

DSOs note that Type B Power Generating Modules can be connected to the LV network and question the validity of the fault ride through requirements on these modules for the protection of HV networks. Fault ride through at this level increases the likelihood of faults on the LV networks – to which the public have most easy access – not being cleared appropriately. To ensure that faults on distribution networks are cleared appropriately, DSOs wish fault ride through to be overridden in the event of a distribution fault. However, they recognise that, with the increase in embedded generation, for the security of the HV networks, larger installations most probably connected to the MV network may need to be able to ride through HV disturbances while tripping instantly for MV faults. The DSOs provided evidence of the situation in Italy where currently 14GW of generation is connected to the MV network and 5GW to the LV network. In a worst case situation, without fault ride through, about 1,5GW of generation could be disconnected inappropriately. Forecast growth indicates that an additional 6,7GW will be connected to the MV network and 7,7GW connected to the LV network. Under the same analysis, a worst case position would see less than 10% of the new generation disconnected unnecessarily if fault ride through at LV is not required. On the other side, the probability of correct operation of LV protection systems is considerably increased.

DSOs are concerned about the increased risk of undesirable network islanding as a result of the introduction of several requirements making generating units more tolerant to system deviations or even self-stabilizing. The NC RfG requires generating units to maintain connection for a wider frequency and voltage bandwidth, and to try to correct deviations of these variables. The DSOs believe that Limited Frequency Sensitive Mode (Over and Under Frequency) operation, which is a major deviation from current practice in most countries, is a good illustration of the functions they believe will lead to an unacceptable increase in risk in some countries of undesired islanding. They believe that this will result in increased risk for public and workers as well as increased stress to DSO networks and connected customer equipment. The DSOs note that LV and MV distribution networks are generally much more accessible to the public than are HV networks and contact with them can be made by fishing lines and commonly used implements. DSOs believe that the NC RfG should be carefully drafted not to preclude the use of technical solutions, currently in the demonstration phase, aimed at ensuring safety and secure network operation.

The requirement for LV distributed generation to be more resilient to system disturbances will have an effect for LV and MV protection arrangements. DSOs believe that instances of undesired local islanding, unwanted disconnections and failures to disconnect will all increase. In addition, distribution network components will suffer greater stress probably resulting in higher rates of failure. Currently, local LV anti-islanding detection devices are unproved and changes to protection schemes are inevitable. At the lowest end, this is likely to be of the order of a few hundreds of Euros per generator where simple modification of settings is sufficient up to a few thousands of Euros per generator where more substantial modification of interface relay protection is required. Given the total number of generators in the EU, this has an impact of at least 100s of millions of Euros up to 10 000s of millions of Euros.

DSOs believe that there is a gap in the NC RfG relating to the definition of requirements at connection points. For generators connected to the distribution system via the consumer's network, this is an issue for DSOs. Traditionally, after a connection has been made, DSOs only have the right to disconnect a grid user when its facilities, including internal network, are manifestly unsafe or where a disturbance is caused to other users. The DSOs are concerned regarding the obligations that they may pick up where a generator unit can be shown to comply but an issue between the unit and the connection point prevents compliance at the connection to the distributor's network or at the point of connection between the distribution network and the transmission system. The obligations are not clearly specified, nor are the requirements.

DSOs note that in some countries, for example England and Wales, Netherlands and Sweden, DSOs operate HV networks up to 150kV. The NC RfG can be interpreted as indicating that these distribution networks are part of the transmission system whereas the connection arrangements are those of distribution systems. If the definitions are followed through, a type B generator connected to a HV section of a distribution network becomes a type D generator although its status in terms of effect on the transmission system or cross border effects has not changed. None of the affected DSOs have a seat at ENTSO-E nor have they had any opportunity to influence the drafting of documents which are not appropriate to distribution systems. DSOs believe that some national parameterisation should be allowed to address this issue.

DSOs noted that, in the operational codes, TSOs push to have control over the operation of larger installations without regard to the effect this might have on the operation of the distribution networks to which they are connected. Rather than accepting the risks associated with splitting control over the same network, DSOs wish to retain full control over their networks, even if this means providing some form of guarantee to TSOs at the network interconnection point.

CEDEC eurelectric EDSO for smart grids GEODE

Network Code Requirements for Generators
DSO Associations Views

Jacques Merley,
Chair of DSO TF Grid Connection Codes

Brussels, 25th April 2013

CEDEC eurelectric EDSO for smart grids GEODE

Key Issues That Need Improvement

1. Compliance monitoring & testing
2. Fault-ride through
3. Impact on protection schemes
4. Responsibility gap
5. Parameterization of the voltage level for transmission (ex Sweden, GB)

1

CEDEC eurelectric ELECTRICITY FOR EUROPE EDSO for smart grids GEODE

1. Compliance & standardization

A clearly defined procedure for compliance testing is missing:

- Risk of unenforceability of requirements without proper standards describing test procedure in place
- Risk of complications in implementation including legal disputes & widespread use of derogations

ENTSO-E proposal of third party certification (art. 35.5) only partly addresses the issue!

➢Proposal: investigate a so-called 'New approach' (EU regulation defining requirements to be filed out by standards defined by CENELEC) should be investigated (see example of Machinery Directive 2006/42/EC)

CEDEC eurelectric ELECTRICITY FOR EUROPE EDSO for smart grids GEODE

1. ***The Relevant Network Operator shall regularly assess the compliance of a Generating Unit with the requirements under this Network Code…'***

Total compliance costs estimation for the EU by 2020: ~ **2,9 billion €**

The compliance tests are not the same as in the network codes on system operation ! → THE COSTS ADD UP!

Country	2020 Scenario: expected no. of small units ≤ 3kW	Estimated compliance cost
AUSTRIA	150.000	56 M€
BELGIUM	500.000	188 M€
GERMANY	2.000.000	750 M€
FRANCE	800.000	300 M€
ITALY	580.000	218 M€
UK	350.000	131 M€

2. Fault-ride through requirements for Type B (<110 kV & PGM_{cap} ≥ max. capacity threshold)

- Necessity of LV FRT in particular (may fall under type B in some countries) is questionable
- LV FRT can be needed only for faults at HV level
- To ask for LV FRT only for new generators would increase the immunity to voltage dips of the global generation park in a negligible manner
- Transmission network reinforcement should be considered as preferred alternative for solving transmission network problems

Synchronous Area	maximum capacity threshold from which on a Power Generating Module is of Type B
Continental Europe	1 MW
Nordic	1.5 MW
Great Britain	1 MW
Ireland	0.1 MW
Baltic	0.5 MW

2. CBA on LV FRT

Italy today: 14 GW are connected to MV grid and 5 GW to LV grid

- In a very unlikely situation, MV- and LV-connected generation of about 1,5 GW could be disconnected

2013-2022 period 6,7 GW will be connected in MV and 7,7 GW will be connected in LV -> 4 GW of Type B generators

- Under the same assumptions, the worst case in 2022 can affect a new MV-connected generation of less than 400 MW (< 10% of newly-connected generation)

CEDEC eurelectric ELECTRICITY FOR EUROPE EDSO for smart grids GEODE

2. CBA on LV FRT

The cost of an integral retrofitting of MV- and LV-connected generation: **4,75 BILLION EUROS**

-> WOULD HELP AVOID DISCONNECTION OF THE EXPECTED 1,5 GW

The cost of installing LV FRT-capable inverters on new Type B PGMs only: **80 MILLION EUROS**

-> **NO IMPACT** ON THE SECURITY OF THE SYSTEM

CEDEC eurelectric ELECTRICITY FOR EUROPE EDSO for smart grids GEODE

- Equivalent analysis should be performed for all EU countries and methodology for the main issues addressed should be provided before introduction of such new requirements
- Similar analysis are difficult to be performed by other DSOs due to absence of access to Transmission Network data

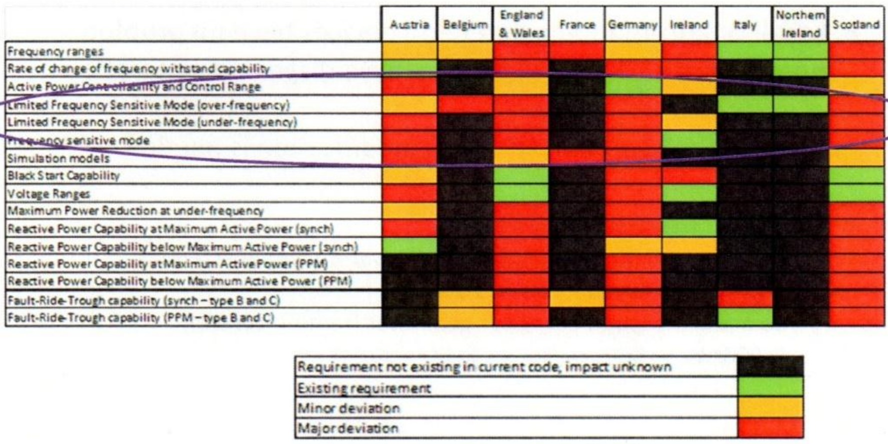
3. LFSM-O & -U & Risk of Undesired Islanding

- The NC proposes moderation of protection systems by weakening frequency and voltage based protection settings
- Possible negative consequences:
  - ➢ An unacceptable increase of electrical risk in distribution networks in some countries
  - ➢ Damages to generators and consumer appliances (under islanding operation)

➢The network code should not preclude technical solutions that would ensure the quality and safety of networks operation (currently in a demonstration phase)

➢DSOs offer their contribution to the CBA on this requirement

3. LFSM-O & -U & Risk of Undesired Islanding



3. Protection schemes are at risk with massive LV dispersed generation

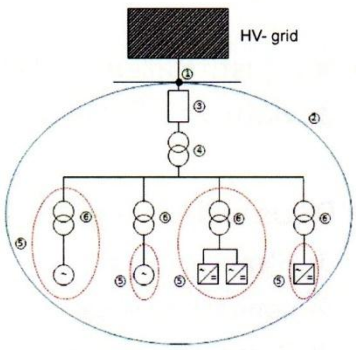
- LV Machines are required to be
  - more resilient to system perturbation (frequency, voltage, FRT)
  - able to compensate perturbations (frequency and voltage droops)
- Local MV network defaults will be harder to detect for LV DG
  - Local undesired islanding probability will increase
  - Unwanted disconnections and not executed disconnections will increase
  - The network will suffer more from additional stress during faults (increased short circuit power)

3. Protection schemes are at risk with massive LV dispersed generation *(ctnd)*

- Local LV anti-islanding detection devices have no proofed operational background with massive dispersed generation
- LV and MV Protection schemes modification is needed
- Costs will depend on solutions
  - From several hundred euros per generator (simple resetting) (100s to 1000s millions € in EU system)
  - To a few thousand euros per generator (remote control) (1000s to 10 000s millions € in EU system)

4. 'Responsibility gap' because of unclear determination of requirements at the connection point(s)

- Clear definition of requirements for generators at the grid connection point(s) to the grid are key for safe grid operation.
- RfG definition of CP is unclear
- Review of definitions and related procedures for compliance is necessary (need for well-defined compliance tests)



1 Grid Connection Point
2 Power Generating Facility
3 Point of transfer
4 Grid Transformer
5 Power Generating Unit
6 Generating Unit Transformer (not a part of the unit)

5. Parameterization of the voltage level for transmission (ex Sweden, GB)

- In countries with 132 kV distribution:
  - unclear what is defined as transmission and what is required from downstream DSOs and connected production
  - Production units of type B can be defined as type D, and consequently associated with requirements for type D, which in turn will affect the relevant DSO

A.4 EU Turbines

Project: Technical Report on ENTSO-E Network Code – Requirements for Generators

Stakeholder Meeting: 23 April 2013

Location: EU Turbines, Diamant Building, Boulevard A Reyers, Brussels

Present:

For EU Turbines	**Florien Böger, EU Turbines**
	Maxime Buquet, GE
	Kevin Chan, Alstom
	Horst Peters, MAN Diesel and Turbo
	Luca Guenzi, Turbomach
	Ulrich Tomschi, Siemens
For DNV KEMA	**Robert McVean**
	Božidar Radovič

EU Turbines represents the 11 major gas and steam turbine manufacturers in Europe selling to utility companies and many SMEs and spoke to the presentation slides attached. The group have been engaged in the development of network codes most relevant to generators, trying to understand TSO's needs and proposing technical solutions. Their involvement has resulted in some, but not many changes to the NC RfG.

The technical issues concerning the group are:

- Power Output vs Frequency
- Frequency Response vs Time
- Fault Ride Through
- Application to CHP plants
- Manufacturer's inputs to the derogation process.

On Power Output vs Frequency, EU Turbines believe that the envelop included in the NC RfG is more stringent than any existing requirements, showing a comparison of their understanding of the requirements in GB and Poland – which EU Turbines believe to be the most stringent – against the NC RfG requirements and a typical example of a GT power output (this being a unit specific) at various temperatures. EU Turbines noted that the GB requirement is limited to temperatures <25C. EU Turbines explained that this limitation to a certain ambient temperature can be helpful for complying with the requirement but acknowledges that it has no reasonable basis from system security point of view. To achieve the required operating curves would require either the derating of machines with resulting increase in costs and emissions, the introduction of partially unproven compensation techniques (water injection, steam injection. EU Turbines agreed to attempt to provide some cost basis relating to this issue.

Regarding the time actuation for frequency response, EU Turbines expressed surprise at the response time values set for frequency response for all generators and noted that this is not a technology neutral issue. For CCGT, this requires actuation of the gas inlet valve to be achieved in 2S and for the machine to ramp-up the maximum potential value setting within a time frame of significantly less than 10 s, which is not explicitly required but allowed by the network code. To achieve the ramp-up period would require the complete redesign of the CCGT rotor.

For Fault Ride Through, the first issue is understanding the actual requirement. If increased time periods are required, the short circuit ratio needs to be increased, so there will be a need to increase copper in the windings to achieve a higher short circuit rating and an increase in the weight of the rotors to create higher inertia. This will have an impact on operating costs as greater weight = more fuel.

The ability to comply will still depend on the PGM power output at time of fault, fault type and condition of the grid. A weak grid will make compliance much harder than a strong grid. 250mS, is achievable in the Nordic countries, but not necessarily for a close up fault. Currently, this is a technical requirement, analysed, discussed and resolved on a technical basis. NC RfG, expected to be a regulation, changes this issue from being a technical issue for discussion to a legal requirement. RTE, in France, also require 250mS in some locations, but solution is to tell RTE what is achievable at the machine location based on simulation and discuss resolution. For RTE, this is a requirement against specific conditions. As drafted, NC RfG is a general requirement without specifying the conditions that will apply.

EU Turbines are also concerned about the manner in which the code relates to their CHP customers, whose primary focus is the support of industrial processes. In the paper industry, for example, the major issue is maintaining steam pressure to maintain set thickness of paper and the NC RfG requirements will affect the ability of paper manufacturers to maintain pressure. Similarly, in oil refineries, constant electricity supply unaffected by external influences is crucial as blackout can require many days recirculation of liquids before production can restart. EU Turbines agreed to attempt to identify industrial customers who will be affected by the NC RfG requirements who may be willing to provide supporting evidence.

The restriction on manufacturers' input to the derogation process is a concern for EU Turbines who note that manufacturers understand the equipment the make better than do the operators. This could be resolved by the adoption of a role for 'technical advisors'.

The existing 'worst case' values in the NC RfG can result in a significant redesign cost, and less efficient operating regimes resulting in higher emissions and operating costs. EU Turbines agreed to try to quantify these effects.

EU turbines requested clarification if circuit breaker operation time is included in the FRT requirement[25]

[25] In the meeting with ENTSO-E the Consultants asked this question and ENTSO-E responded that circuit breaker operation time IS included in the FRT requirement.

EUTurbines

EUTurbines' views on NC Requirements for Generators

Brussels
23rd of April, 2013

EUTurbines

WHO we are

ALSTOM
GE Energy
SIEMENS
AnsaldoEnergia A Finmeccanica Company
MAN
ŠKODA ŠKODA POWER
DOOSAN
DRESSER-RAND
Rolls-Royce
Solar Turbines A Caterpillar Company

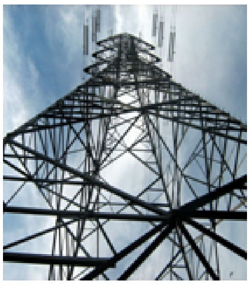
70.000 employees in the sector
Business Volume 25 billion €
More than 6 billion € purchase volume in Europe (mostly to SMEs)

Presentation of EUTurbines 2013-04-23

EUTurbines

What EUTurbines stands for...

GRIDS



- Understanding TSO's needs
- Converting into generating products

OEMs

- Explaining technical challenges behind grid stability or balancing concerns
- Proposing technical solutions

EUTurbines' role:
Active on the underlying technical challenges of NCs.
Monitoring the development of technical issues into socio-economical risks.

European Association of Gas and Steam Turbine Manufacturers

Page 3 of 27

Presentation of EUTurbines 2013-04-23

EUTurbines

Our participation in ENTSO-E activities

In the past 3 years EUTurbines has been an active participant for:

- NC RfG
- NC LFC&R
- … and is established as an observer on other codes

More than 15 meetings were held with ENTSO-E, ACER, other stakeholders . A position paper on the grid code has been edited.

EUTurbines:
Duly considered ENTSO-E's work.
Constructive discussions, part of Users' Group.
Only some of EUTurbines' queries were considered in modifications.

European Association of Gas and Steam Turbine Manufacturers

Page 4 of 27

Presentation of EUTurbines 2013-04-23

EUTurbines

Why we want to meet today

Some key technical issues remain.
Those concerns will incur:

- Cost increase of power generation
- Loss of flexibility
- Risk of system stability (risk of black out)
- Risk of employment in Europe

European Association of Gas and Steam Turbine Manufacturers

Page 5 of 27

Presentation of EUTurbines 2013-04-23

EUTurbines

Urgent Technical Concerns

- Power output vs. frequency
- Frequency response vs. time
- Fault Ride Through
- Applications for Combined Heat and Power plants
- Manufacturer's inputs on derogation process

Will describe today: Issues/ Risks/ Alternatives.
Will quantify cost impact at EU level.

European Association of Gas and Steam Turbine Manufacturers

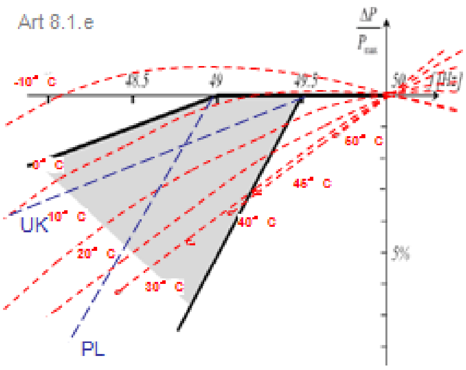
Page 6 of 27

Presentation of EUTurbines 2013-04-23

EUTurbines

Power output vs. frequency

Art 8.1.e



--- Typical GT power output (Unit specific)

— As-is

- More **stringent than any current requirement**
- No justification for those parameters and needs
- Ignores well-known technical constraints of GT
- NOT technology-neutral

— Risks/Consequences

- Need to "derate" units to provide headroom for a possibly never occurring event.
- Higher €/kW Capex for dead capacity, losing best efficiency. Creates a **0.5 B€ cost**.
- Need to develop and install compensation mechanisms with inherent activation delay times. Creates **additional 0.1 B€ cost.**
- Risk on system stability. System may fully collapse if those mechanisms fail. Risk of black out: **Several B€?!**

Alternative:
Replace by intrinsic behaviour only (manufacturers to provide curves).
Adjust load shedding schemes through simulations.

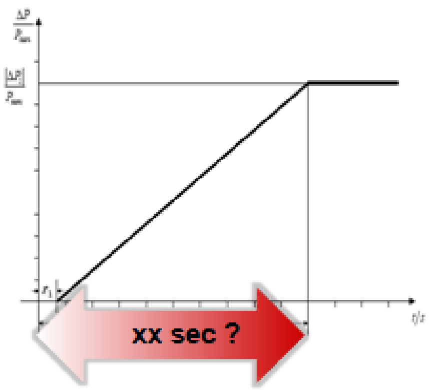
European Association of Gas and Steam Turbine Manufacturers Page 7 of 27

Presentation of EUTurbines 2013-04-23

EUTurbines

Frequency Response vs. Time

Art 10.2.c. 5



As is

- Unexpected tightening of requirement.
- Reaches technological barriers… NOT a technology- neutral rq't

Risk:

- Redesign completely shaft lines to increase time of response by 5 sec… may be **>0.1B€ per GT-type**
- Increase risk of trip of power generating units
- What to do on existing units? Should they be disconnected?

Alternative:
Keep existing requirements in members state.
Shut the door to non-exhaustive rq't.

European Association of Gas and Steam Turbine Manufacturers Page 8 of 27

Presentation of EUTurbines 2013-04-23

EUTurbines

Fault Ride Through

As is

- ENTSO-e justified need to get an FRT capability, but not the technical parameters of it.
- Requirements… non-exhaustive, subject to mis-interpretation and tightening
- Fault frequency of occurrence not defined.

Risk

- Over-redesign of equipment based on unclear requirements
- To achieve 250ms FRT, need to increase SCR (increase gen. weight), increase shaft line inertia (weight), increase ceiling factor (modify rotor insulation and exc. transformer)… thus requires **hundreds M€ of development and installation**
- No-type certification possible…Complex dynamic analysis needed for **each project**…and then, what if the results are not satisfactory ?
- **Nearly impossible to test**…if units happen to be damaged, will impact generation capacity

Alternative

- Keep and define clearly existing requirements.
- Work with manufacturers to find optimal solutions (on generation OR transmission sides)

Extreme FRT interpretations violate physics and state-of-the-art.
Requirements shall be made technically-consistent.

European Association of Gas and Steam Turbine Manufacturers — Page 9 of 27

Presentation of EUTurbines 2013-04-23

EUTurbines

Combined Heat and Power Plants

— As-is

- CHP exempted from part of the frequency support, but not all (e.g. power output vs. frequency profile…)

— Risk:

- Put at stake plants **reliability** (may happen to disconnect as not designed for frequency regulation
- Menace efficiency (design would provide freq margin…not optimized for efficiency!)… **would cost 25k€ per MWe installed…could be 4 B€ total cost by 2020.**
- **Loss of opportunities/efficiency.** Some industrial customers would prefer derating and not exporting power than to comply with this.

Alternative:
Clarify exemption for CHP on all relevant requirements.

European Association of Gas and Steam Turbine Manufacturers — Page 10 of 27

Presentation of EUTurbines 2013-04-23

EUTurbines

Derogation Process
How to get manufacturers' input ?

— **As-is:**
- Partial harmonization only (non-exhaustive values)
- Above requirements will incur **mass derogation**
- Plant operators cannot be in front line as less involved than manufacturers on the design/capabilities of prime movers.
- No room for manufacturers to raise their voice.

— **Risk:**
- Get technical discussion between TSO and plant operator without the technical specialists of generating units.
- **Mis-shape** requirements and exemptions using erroneous technical statements.
- Lead to **poor efficiency** of the grid operation and bring significant risks on **system reliability** (as may ignore technical limitations)

Alternative:
Define a role of "technical advisors" for the manufacturers in the grid code evolution or derogation process.
Define process for manufacturers to apply & discuss over derogations (hopefully with a pan-European process).

European Association of Gas and Steam Turbine Manufacturers Page 11 of 27

Presentation of EUTurbines 2013-04-23

EUTurbines

Conclusion

These points need to be amended, because they jeopardize:
- System stability
- Generation flexibility
- Cost of electricity

- The residual gap can result **in <u>several billions €</u> of development and installation, and pollutant emissions**
- This will surely incur a loss of flexibility, increased cost of the generating units and of electricity
- Alternative solutions may be more **cost effective** and more **environmentally friendly !**

As of today, there is as a risk for **economic viability of manufacturing businesses.**

European Association of Gas and Steam Turbine Manufacturers Page 12 of 27

Presentation of EUTurbines 2013-04-23

EUTurbines

Thank you

Should you have any question, please contact the General Secretariat of EUTurbines:

Florian Boeger
Manager of European Affairs
EUTurbines Brussels
+32 (0) 2 706 8211
florian.boeger@euturbines.eu

European Association of Gas and Steam Turbine Manufacturers

Page 13 of 27

A.5 EUR

Project: Technical Report on ENTSO-E Network Code – Requirements for Generators

Stakeholder Meeting: 25 April 2013

Location: EDF Luminus, Markiesstraat/Rue de Marquis 1, 1000 Brussels

Present:

For EUR	**Xavier Pouget-Abadie, Senior Safety Advisor, EDF**
	Johan Engström, Senior Specialist, Vattenfall AB
	Hervé Meljac, Power System Engineer, EDF Energy
For DNV KEMA	**Robert McVean**
	Božidar Radovič

Following introductions, the EUR representatives outlined the history of EUR in the development of the design specifications used since 1991 by the operators of all nuclear power stations in Europe and, using the attached presentation, outlined their concerns regarding the NC RfG as currently drafted. Chapter 3 of volume 2 of these specifications deals exclusively with grid connection requirements for NPPs.

A very significant issue for the NPP operators is the safety case developed for the station, which has to be built up based on the probability of certain occurrences and the transient budget which governs the station life. In addition to exporting electricity to the grid, grid connections are crucial for the safety case as the grid is considered to be more reliable than any form of back-up power.

Deviation in current practice is important to the NPP operators both in terms of the potential cost impact, but also in terms of the impact on stations' safety case. Given the 60 year anticipated life of a NPP, the provision in the NC LFC&R requiring review every 5 years is a major concern. The absolute values established for the voltage and frequency ranges without considering their interaction is another significant issue. Chapter 3 of Volume 2 of the *European Utility Requirements for LWR Nuclear Power Plants* includes the voltage/frequency operating diagram that has been in use since 2001 and shown as figure 1 which was extended in 2001, when the specification was first used in the Nordic area, to allow for continuous operation at lower frequency than previously:

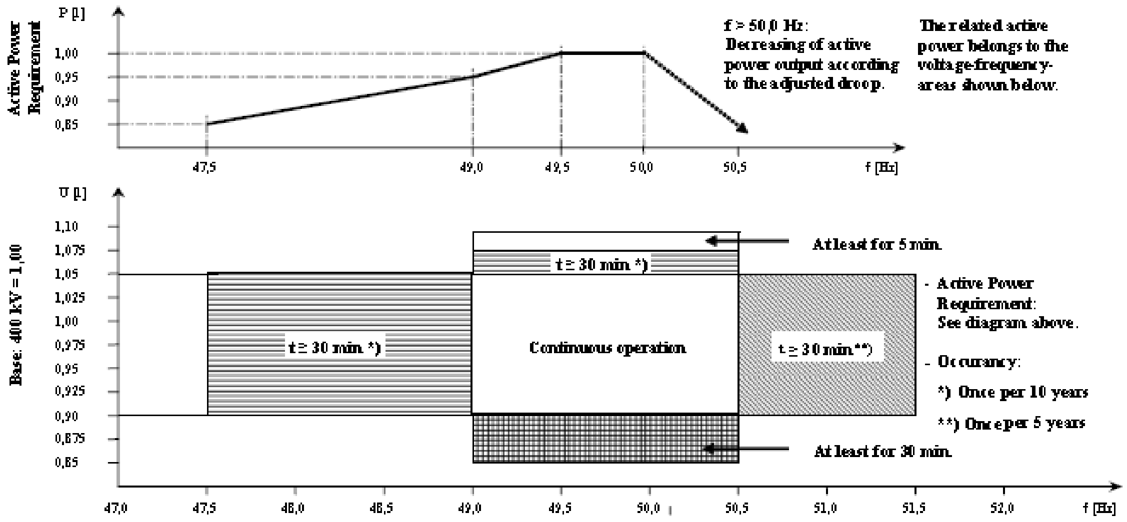


Figure 1: Voltage/Frequency Diagram for European NPP

Assuming a grid short circuit level in the range 7GVA – 44GVA, a NPP connected at 400kV is designed to ride through faults and restart normal generation. For the design safety case, it is assumed that certain combinations of voltage and frequency will only occur very infrequently.

NC RfG takes no account of the combination of events that is essential for all generators, and EUR believe that NC RfG should specify frequency and voltage operating ranges on a single chart because this is meaningful for the physics of rotating machines. While the EUR specification is more onerous than anything currently experienced, the NC RfG could present more onerous conditions on generators, and especially so when no information is given on the possible combination of events. Over frequency is a particular issue for NPPs as the effect of over frequency on the coolant drives will be added pressure on the fuel assemblies. Theoretically, approval could be obtained for the use of power converters for ‘normal cooling systems’, but they could not be used on any safety system including the coolant pumps used for fast shutdown.

LFSM-U is a problem for NPP operators who are not convinced of the necessity, given that it infers a failure to procure adequate reserves and demand side measures are commonly in place. EUR is concerned that it may not be possible to fit LFSM-U within the safety case hypothesis for NPPs. NC RfG gives the right to instruct generators to change the droop setting, subject only to notification of this instruction to the NRA. For a NPP, this requires rerunning the station safety study as the droop setting is a relevant input. NPPs acknowledge that there may be a case for FSM and propose that, for NPPs the values should be set in line with the EUR as shown in Figure 2:

Parameter	Proposed Value
Active Power range related to Maximum Capacity	3% - for CE Extendable to 5% - for smaller synchronous areas
Maximum full activation time	30 s
Full Active Power Frequency Response minimum sustainable time	15 min

Figure 2: Proposed NPP Frequency Response Parameters as per EUR

For LFSM-O, the NPP operators have no problem to deal with on individual case basis, but for safety case reasons they would prefer the probable frequency of occurrence to be defined. On the other hand, they would prefer the requirement for LFSM-U to be removed for NPPs.

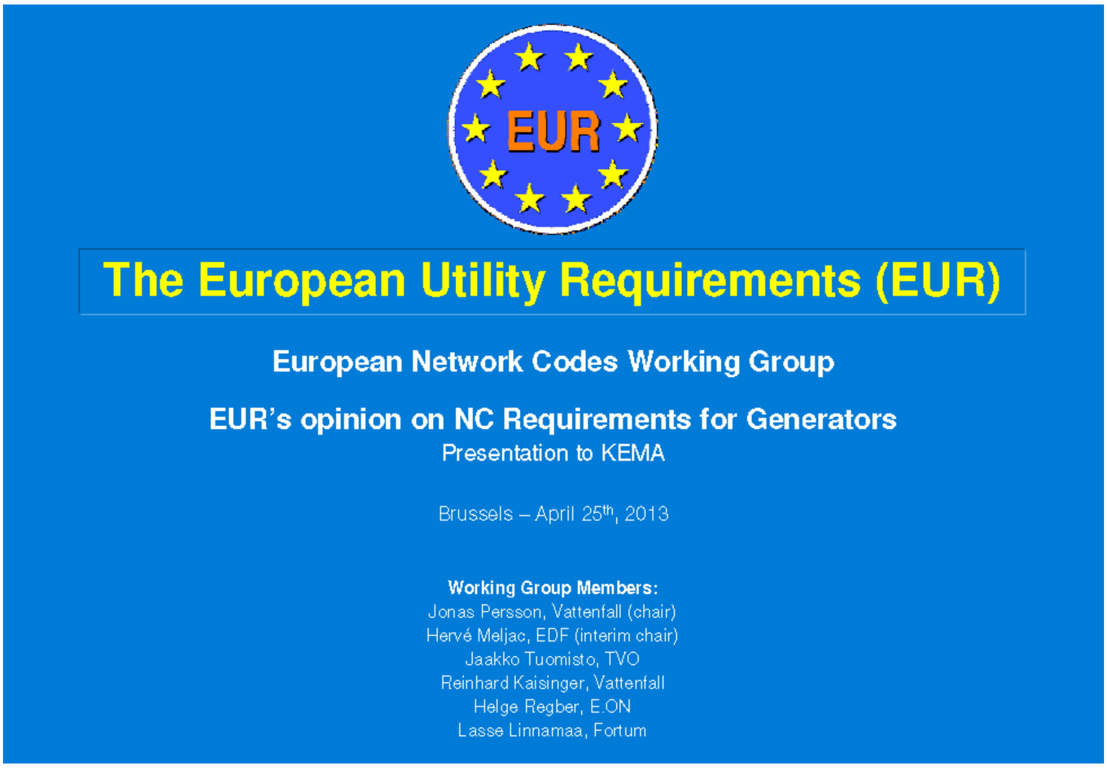
The overall voltage range specified is also a concern for NPP operators who note that the upper levels would require the use of on load tap changers (OLTC) which are not common practice in all countries. The *Cigre* report from the 1980s that indicated more than 40% of power transformer faults to be OLTC related was cited. The voltage range issue was noted, but it was agreed that should the operators wish to focus on the *Cigre* report for support, they would also provide details of the causes of all failures of NPPs in Europe to allow a full comparison to be made.

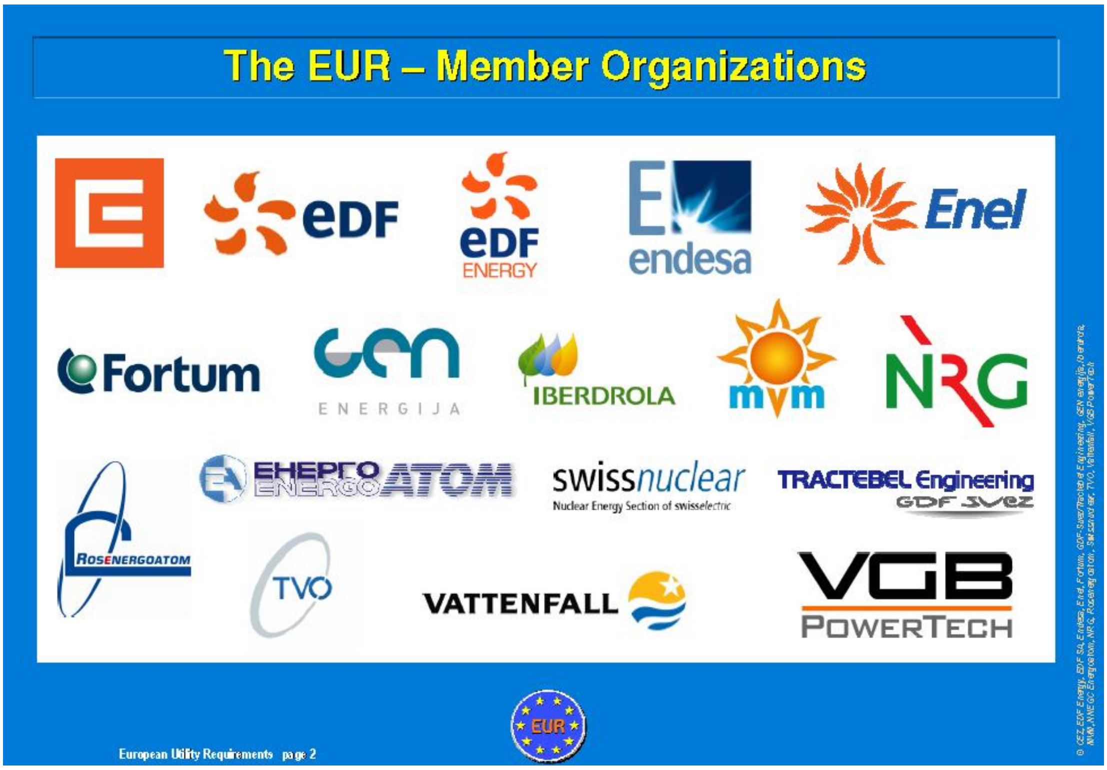
The nature and possible duration of the fault ride through requirement is also an issue for NPPs. In the NC RfG, the voltage drop is shown to be almost to zero, inferring a fault at the station terminals. In Sweden, where a 250mS ride through requirement is applied, this should include faults up to the generator transformer terminals but no plant currently fulfils this requirement although all would meet the requirement of a 250ms fault ride through for faults at the first node out from the station and an appropriate solution to this issue is being investigated. In France, where 250mS ride through requirement is required in certain cases below 400kV, different values are shown for different connection voltages, network arrangements and technology types. The 'strength' of the grid is a relevant factor in determining whether a station will ride through a network fault. In France, this is considered in terms of whether or not there is a meshed connection. In the EUR definition outlined above, it is determined by the fault level. The NC RfG makes no allowance for network conditions. There is also an interpretational issue to be considered regarding this requirement as TSOs have different approaches to the application of the voltage dip profile when determining FRT capability. Others interpret it as requiring the generators to remain connected to the grid. Again, the NPP operators envisage the adoption of the EUR values on a Europe wide basis, as the operators believe them to be more onerous than most national standards but within the capability of large synchronous generators. The NPP operators adopt a similar position with respect to required reactive power ranges noting that the envelop shown in NC RfG is unachievable.

At no point does the NC RfG make reference to the anticipated frequency of events. In establishing the safety case for a NPP, a figure is required as shown in Figure 1 above.

While acknowledging the implicit derogation for all existing and planned generation plants, the potential for retrospective application is a major concern for NPP operators. The normal life of a NPP is 60 years and achieving this is crucial to the business case for development. It also means that almost all current NPPs and all under construction would need to be operating in 2030, the target date around which ENTSO-E declared NC RfG to be written. The operators believe that the continued operation of these plants and a realistic set of grid connection conditions to allow investment in future plants are essential for Europe’s energy supply.

EUR believes the approach to future grid evolution, in particular increased renewables penetration, should be to keep power quality constant by implementing adequate mitigation measures to face intermittency and lack of inertia, rather than accepting power quality degradation and requiring TSOs and grid users to adapt to it as they perceive to be ENTSO-E’s approach in drafting NC RfG.


EUR
The European Utility Requirements (EUR)
European Network Codes Working Group
EUR's opinion on NC Requirements for Generators
Presentation to KEMA
Brussels – April 25th, 2013
Working Group Members:
Jonas Persson, Vattenfall (chair)
Hervé Meljac, EDF (interim chair)
Jaakko Tuomisto, TVO
Reinhard Kaisinger, Vattenfall
Helge Regber, E.ON
Lasse Linnamaa, Fortum


The EUR – Member Organizations
EDF
EDF ENERGY
endesa
Enel
Fortum
GEN ENERGIJA
IBERDROLA
mvm
NRG
ENERGOATOM
swissnuclear
Nuclear Energy Section of swisselectric
TRACTEBEL Engineering
GDF SUEZ
ROSENERGOATOM
TVO
VATTENFALL
VGB POWERTECH
EUR
European Utility Requirements page 2

The EUR initiative

- **EUR initiative started in 1991 aiming at:**
  - harmonisation and <u>stabilisation</u> of the conditions in which the LWR NPPs to be built in Europe will be designed, built, commissioned, operated and maintained.
  - developing common specifications for new NPP designs to be proposed by Vendors which can be licensed, built and operated in the majority of European countries, using a standard safety case and standard design studies.
- **Harmonisation and standardisation over large geographical areas are of benefit for:**
  - Nuclear safety.
  - Competition between vendors, as well as between producers.
  - Overall cost effectiveness of projects, by spreading design costs over a number of plants (fleet effect).
- **The EUR are the applicable technical reference for NPP design in Europe.**

EUR

European Utility Requirements page 3

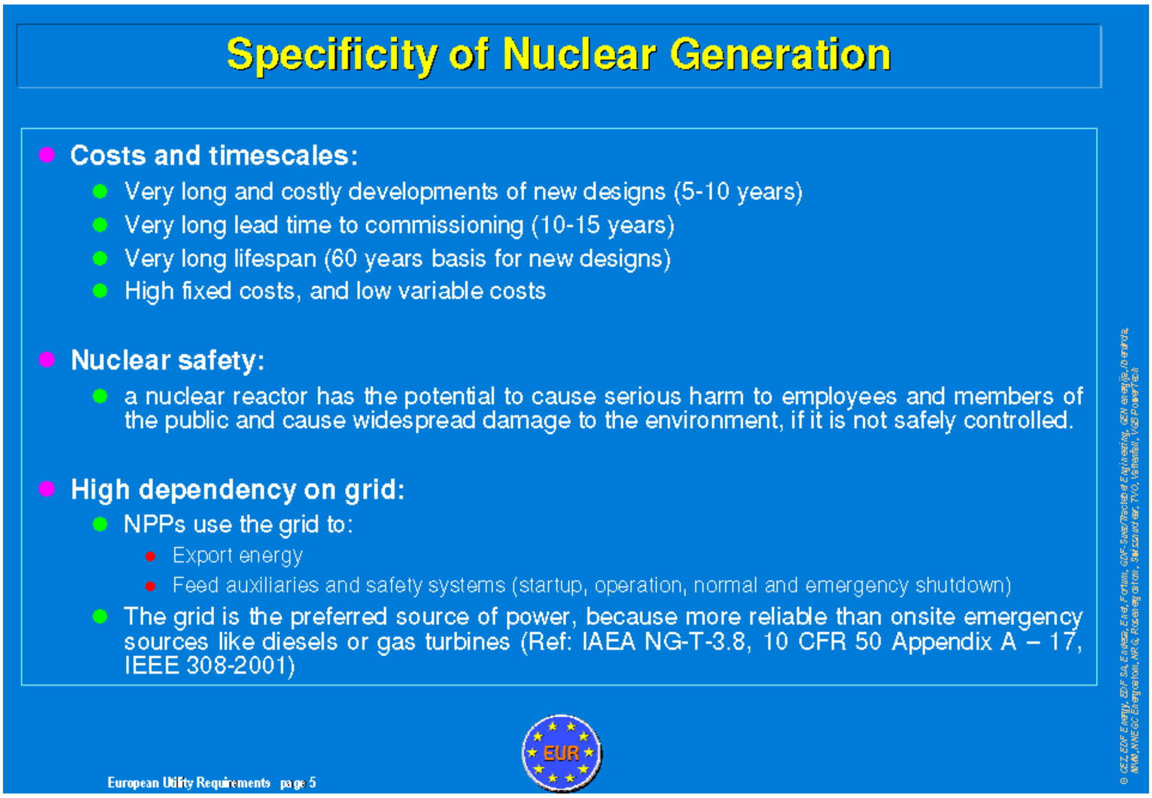
Nuclear Power Plants in Europe

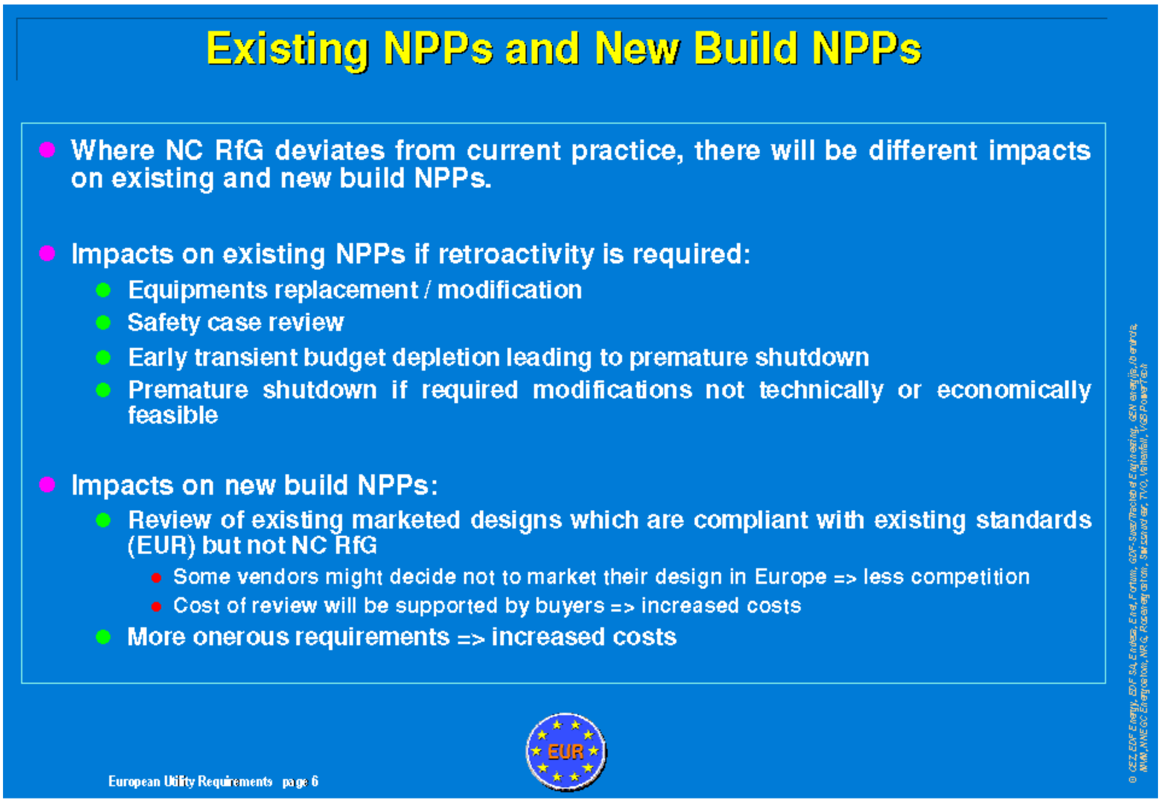
- On ENTSO-E perimeter, 136 operating nuclear generators in 15 countries
- 126,5 GW installed net capacity
  – 13,6% of 928,3 GW total
- 885,6 TWh net generation
  – 26,5% of 3 347,5 TWh total

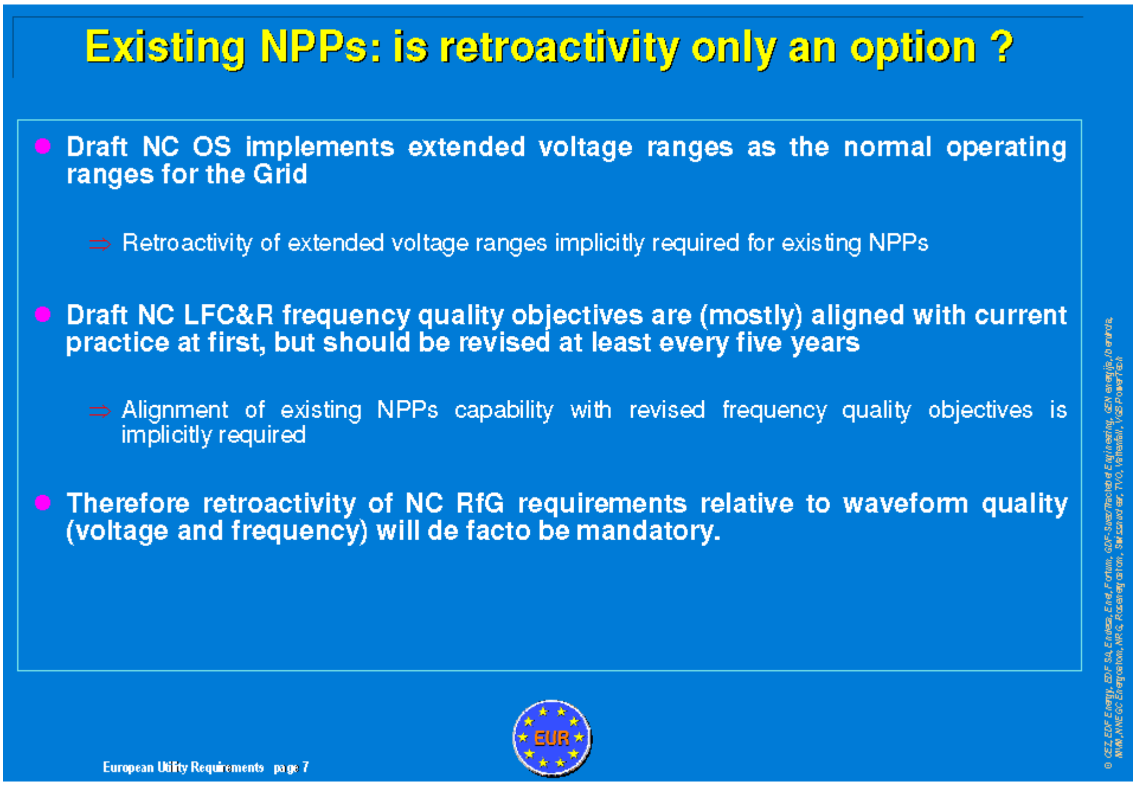
EUR

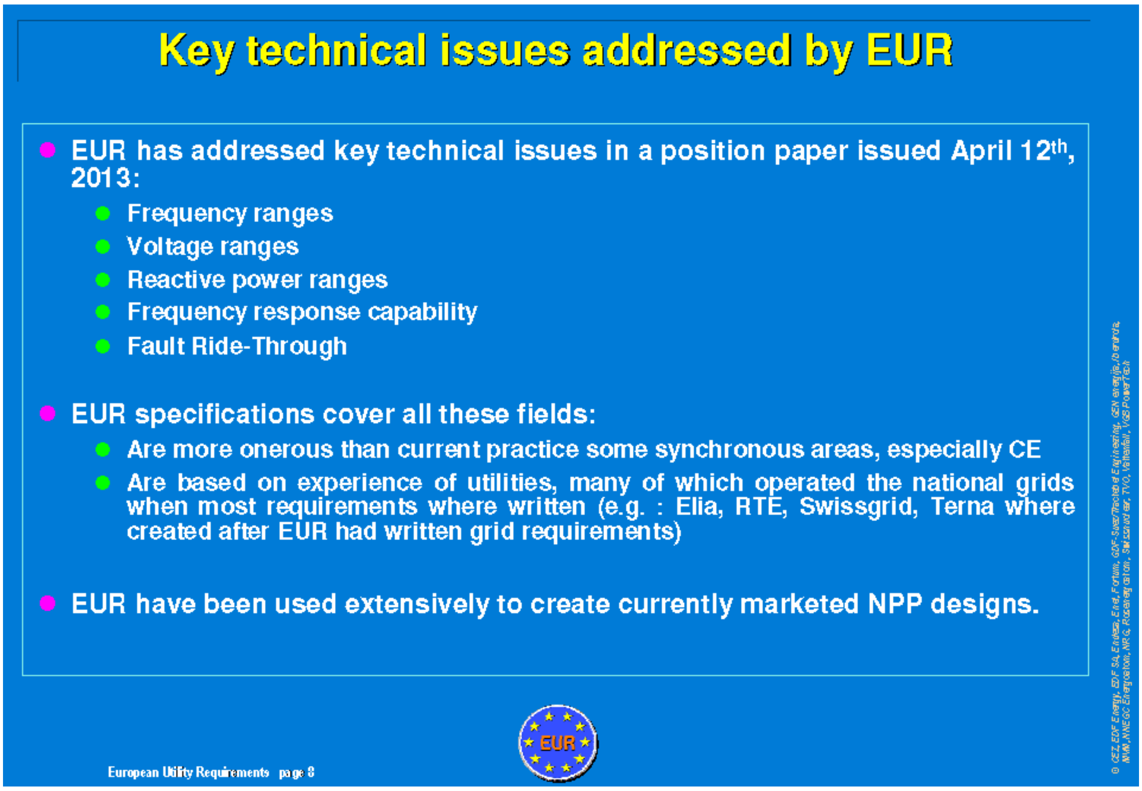
European Utility Requirements page 4

© CEZ, EDF Energy, EDF SA, Endesa, Enel, Fortum, GDF-Suez/Tractebel Engineering, GEN energija, Iberdrola, MVM, NNEGC Energoatom, NRG, Rosenergoatom, Swissnuclear, TVO, Vattenfall, VGB PowerTech


Specificity of Nuclear Generation
Costs and timescales:
Very long and costly developments of new designs (5-10 years)
Very long lead time to commissioning (10-15 years)
Very long lifespan (60 years basis for new designs)
High fixed costs, and low variable costs
Nuclear safety:
a nuclear reactor has the potential to cause serious harm to employees and members of the public and cause widespread damage to the environment, if it is not safely controlled.
High dependency on grid:
NPPs use the grid to:
Export energy
Feed auxiliaries and safety systems (startup, operation, normal and emergency shutdown)
The grid is the preferred source of power, because more reliable than onsite emergency sources like diesels or gas turbines (Ref: IAEA NG-T-3.8, 10 CFR 50 Appendix A – 17, IEEE 308-2001)
EUR
European Utility Requirements page 5


Existing NPPs and New Build NPPs
Where NC RfG deviates from current practice, there will be different impacts on existing and new build NPPs.
Impacts on existing NPPs if retroactivity is required:
Equipments replacement / modification
Safety case review
Early transient budget depletion leading to premature shutdown
Premature shutdown if required modifications not technically or economically feasible
Impacts on new build NPPs:
Review of existing marketed designs which are compliant with existing standards (EUR) but not NC RfG
Some vendors might decide not to market their design in Europe => less competition
Cost of review will be supported by buyers => increased costs
More onerous requirements => increased costs
EUR
European Utility Requirements page 6


Existing NPPs: is retroactivity only an option ?
Draft NC OS implements extended voltage ranges as the normal operating ranges for the Grid
⇒ Retroactivity of extended voltage ranges implicitly required for existing NPPs
Draft NC LFC&R frequency quality objectives are (mostly) aligned with current practice at first, but should be revised at least every five years
⇒ Alignment of existing NPPs capability with revised frequency quality objectives is implicitly required
Therefore retroactivity of NC RfG requirements relative to waveform quality (voltage and frequency) will de facto be mandatory.
EUR
European Utility Requirements page 7


Key technical issues addressed by EUR
EUR has addressed key technical issues in a position paper issued April 12th, 2013:
Frequency ranges
Voltage ranges
Reactive power ranges
Frequency response capability
Fault Ride-Through
EUR specifications cover all these fields:
Are more onerous than current practice some synchronous areas, especially CE
Are based on experience of utilities, many of which operated the national grids when most requirements where written (e.g. : Elia, RTE, Swissgrid, Terna where created after EUR had written grid requirements)
EUR have been used extensively to create currently marketed NPP designs.
EUR
European Utility Requirements page 8

EUR's participation in NC RfG process

- EUR Working Group on Network Codes created in August 2011
- 25 WG meetings from August 2011 to April 2013, vast majority on NC RfG
- 3 position papers on NC RfG:
  - September 16th, 2011
  - July 1st, 2012
  - April 12th, 2013 (sent to KEMA)
- 2 Bi(or tri)-lateral meetings with ENTSO-E:
  - November 10th, 2011 (ENTSO-E NC RfG drafting team)
  - August 29th, 2012 (EUR – ACER – ENTSO-E)
- 5 Presentations in public ENTSO-E and ACER meetings
  - February 15th, 2012
  - March 22nd, 2012
  - May 2nd, 2012
  - June 28th, 2012
  - September 3rd, 2012 (ACER)
- 50 comments posted during Public Consultation

EUR

European Utility Requirements page 9

Frequency ranges

- NC RfG requirement:

Frequency Range (Hz)	CE	Nordic	Great Britain	Ireland	Baltic
47 – 47.5	-	-	20 s	-	-
47.5 – 48.5	TbD, >30 min	30 min	90 min	90 min	TbD, >30 min
48.5 – 49	TbD, >30 min	TbD, >30 min	TbD, >90 min	TbD, >90 min	TbD, >30 min
49 – 51	Unlimited	Unlimited	Unlimited	Unlimited	Unlimited
51 – 51.5	30 min	30 min	90 min	90 min	TbD, >30 min
51.5 – 52	-	-	15 min	-	-

- Justified on the basis of IEC 60034 but:
  - Power plants are not just a collection of electrical rotating machines;
  - Even when all electrical equipments are IEC 60034 compliant, the plant as a whole is not.

- Not in line with NC LFC&R:

	CE	Nordic	Great Britain	Ireland	Baltic
Nominal Frequency	50 Hz	50 Hz	50 Hz	50 Hz	50 Hz
Standard Frequency Range	±50 mHz	±100 mHz	±200 mHz	±200 mHz	±50 mHz
Max. Instantaneous Frequency Deviation	800 mHz	800 mHz[5]	800 mHz	1000 mHz	800 mHz
Max. Steady-State Frequency Deviation	200 mHz	500 mHz	500 mHz	500 mHz	200 mHz
Time to Restore Frequency	15 minutes	15 minutes	10 minutes	20 minutes	15 minutes

- Assumes frequency will degraded over time because of decreasing system inertia, which is:
  - Not acceptable for grid users, especially NPPs
  - Evitable
- Requirement should be a U/f diagram, with maximum frequency of occurrence.

EUR

European Utility Requirements page 10

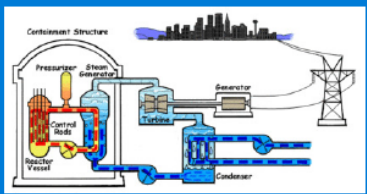
Consequences on new build NPPs

- In theory new build NPPs may be compliant.
- However this requirement would drive costs:
  - Review of designs based on EUR or current practice
  - More onerous equipments such as:
    - Pressure vessel
    - Fuel assemblies
    - Reactor coolant pumps
- Therefore, impacts on:
  - Business case
  - NPP design availability
  - Licensing

European Utility Requirements page 11

Consequences on existing NPPs

- Safety cases to be revised and equipments changed, with impacts at least on:
  - Direct-driven pumps – their speed is proportionate to frequency
  - Fuel assemblies in PWRs –increased lift forces



Picture: US NRC

- Power converters cannot be used in safety systems because they lack reliability.
- Risk of premature plant shutdown if:
  - Inherent design cannot accommodate new requirement
  - Cost of redesign not economically sustainable

European Utility Requirements page 12

EUR alternative approach

- Use a U/f diagram:
  - Showing maximum frequency of occurrence for each zone
  - Not more onerous than EUR requirement
  - [49.5Hz – 50.5Hz] continuous operation in CE to reflect system strength

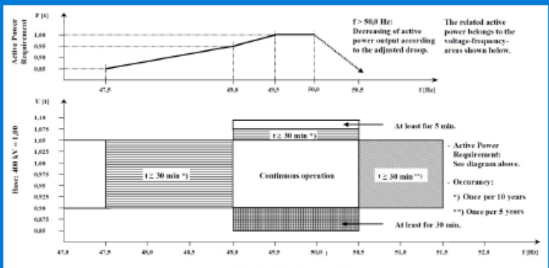


Figure 1: Voltage frequency field

- Mitigate decrease of system inertia by requiring synthetic inertia provision or equivalent by non-synchronous generators connected to the grid

European Utility Requirements page 13

Voltage ranges

- NC RfG requirement:

Synchronous Area	Voltage Range	Time period for operation
Continental Europe	0.85 pu – 0.90 pu	60 minutes
	0.90 pu – 1.118 pu	Unlimited
	1.118 pu – 1.15 pu	To be decided by each TSO while respecting the provisions of Article 4(3), but not less than 20 minutes
Nordic	0.90 pu – 1.05 pu	Unlimited
	1.05 pu – 1.10 pu	60 minutes
Great Britain	0.90 pu–1.10 pu	Unlimited
Ireland	0.90 pu – 1.118 pu	Unlimited
Baltic	0.85 pu – 0.90 pu	30 minutes
	0.90 pu – 1.12 pu	Unlimited
	1.12 pu – 1.15 pu	20 minutes

Table 6.1: This table shows the minimum time periods a Power Generating Module shall be capable of operating for Voltages deviating from the nominal value at the Connection Point without disconnecting from the Network. (The Voltage base for pu values is from 110 kV to 300 kV (excluding).)

Synchronous Area	Voltage Range	Time period for operation
Continental Europe	0.85 pu – 0.90 pu	60 minutes
	0.90 pu – 1.05 pu	Unlimited
	1.05 pu – 1.0875 pu	To be decided by each TSO while respecting the provisions of Article 4(3), but not less than 60 minutes
	1.0875 pu – 1.10 pu	60 minutes
Nordic	0.90 pu – 1.05 pu	Unlimited
	1.05 pu – 1.10 pu	60 minutes
Great Britain	0.90 pu – 1.05 pu	Unlimited
	1.05 pu – 1.10 pu	15 minutes
Ireland	0.90 pu – 1.05 pu	Unlimited
Baltic	0.88 pu – 0.90 pu	20 minutes
	0.90 pu – 1.10 pu	Unlimited
	1.10 pu – 1.15 pu	20 minutes

Table 6.2: This table shows the minimum time periods a Power Generating Module shall be capable of operating for Voltages deviating from the nominal value at the Connection Point without disconnecting from the Network. (The Voltage base for pu values is from 300 kV to 400 kV.)

- Not in line with current practice. E.g. France:
  - On the 400kV grid:
    - unlimited range [0.95 pu – 1.05 pu];
    - 5 minutes range [1.05 pu – 1.10 pu] + authorized deloading to 0.95 Pmax;
    - 90 minutes range [0.85 pu – 0.95 pu].
  - On the 225 kV grid:
    - unlimited range [0.89 pu – 1.089 pu];
    - operation during 5 minutes in the range [1.089 pu – 1.11 pu] + authorized deloading to 0.95 Pmax;
    - operation during 90 minutes in the range [0.80 pu – 0.89 pu].
- Not in line with norms (IEC 60071)
- Not harmonized
- Not in a U/f diagram
- Forces uses of on-load tap changers

European Utility Requirements page 14

Consequences on NPPs

- Forces use of OLTCs on:
  - Main transformers;
  - Auxiliary and stand-by auxiliary transformers.

- Consequences:
  - Severe impact on reliability of transformers, therefore on availability of NPPs;
  - Drives costs:
    - Overrating of transformers;
    - OLTC;
    - Modification of power evacuation platforms on existing NPPs

European Utility Requirements page 15

EUR alternative approach

- Use a U/f diagram:
  - Showing maximum frequency of occurrence for each zone
  - Not more onerous than EUR requirement

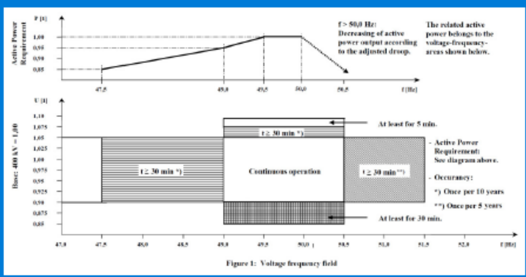
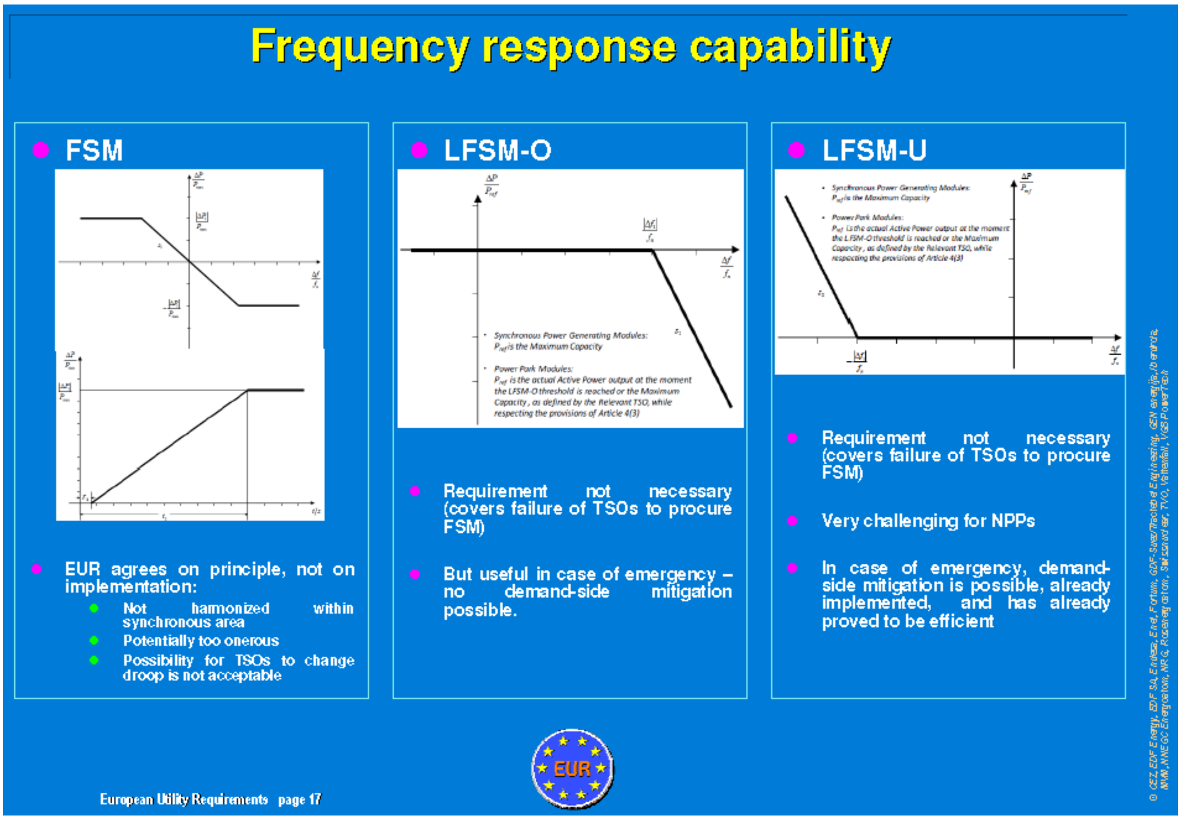
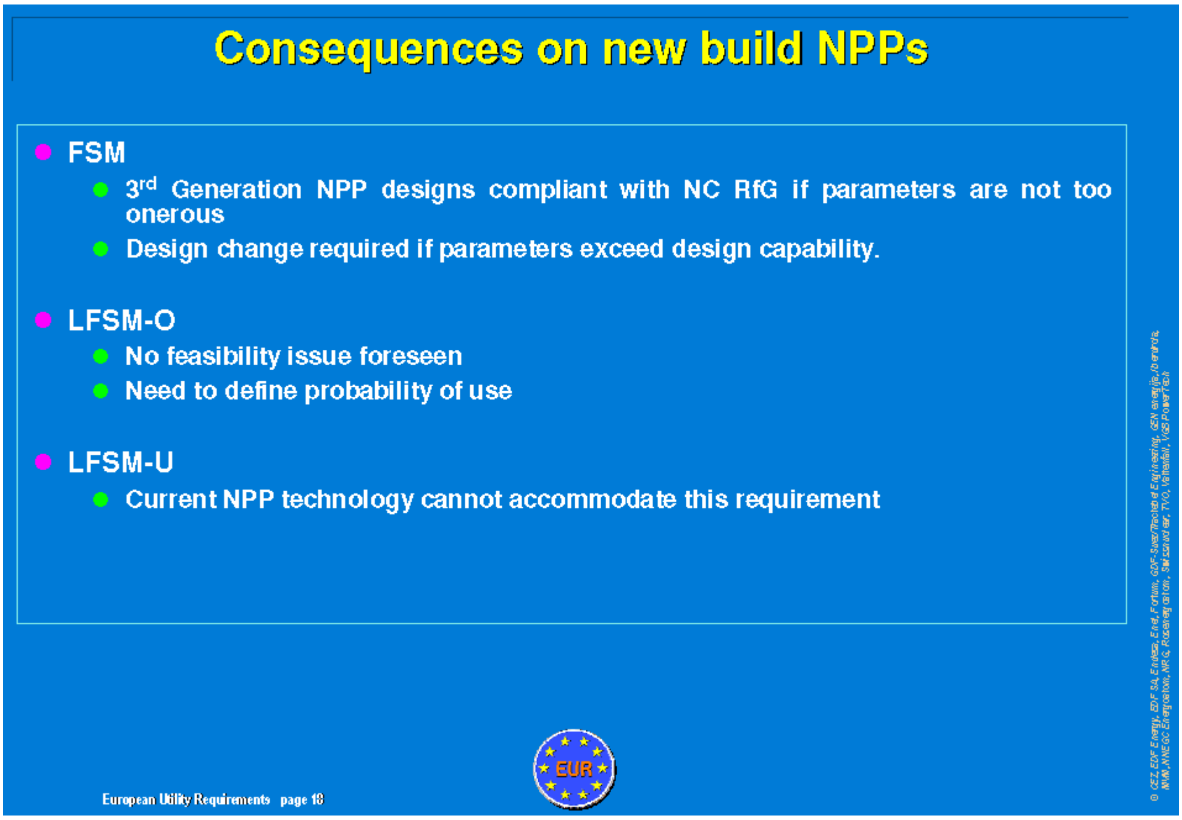


Figure 1: Voltage frequency field

- Locally different voltage ranges can be defined if:
  - Need is properly justified;
  - Impacts on grid users are properly evaluated.

European Utility Requirements page 16


Frequency response capability
FSM
EUR agrees on principle, not on implementation:
Not harmonized within synchronous area
Potentially too onerous
Possibility for TSOs to change droop is not acceptable
LFSM-O
Requirement not necessary (covers failure of TSOs to procure FSM)
But useful in case of emergency – no demand-side mitigation possible.
LFSM-U
Requirement not necessary (covers failure of TSOs to procure FSM)
Very challenging for NPPs
In case of emergency, demand-side mitigation is possible, already implemented, and has already proved to be efficient
EUR
European Utility Requirements page 17


Consequences on new build NPPs
FSM
3rd Generation NPP designs compliant with NC RfG if parameters are not too onerous
Design change required if parameters exceed design capability.
LFSM-O
No feasibility issue foreseen
Need to define probability of use
LFSM-U
Current NPP technology cannot accommodate this requirement
EUR
European Utility Requirements page 18

Consequences on existing NPPs

- Existing NPPs have different capabilities depending on:
  - Technology
  - Nuclear Safety Authority requirements
- Frequency Response capability deeply impacts plant design and safety case
- Retroactivity cannot be reasonably envisaged

European Utility Requirements page 19

EUR alternative approach

- FSM:
  - Parameters based on EUR:

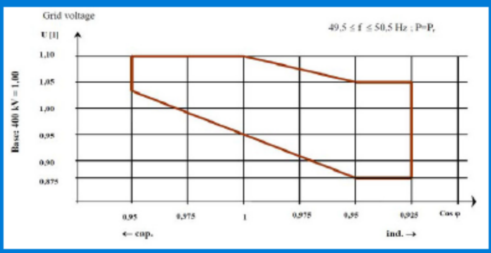
Parameter	Proposed Value
Active Power range related to Maximum Capacity	3% - for CE Extendable to 5% - for smaller synchronous areas
Maximum full activation time	30 s
Full Active Power Frequency Response minimum sustainable time	15 min

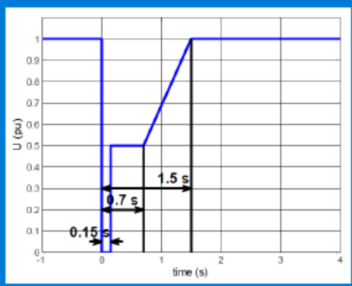
  - Generator Owner approval to change governor droop
- LFSM-O:
  - Define frequency of occurence
- LFSM-U:
  - Remove requirement

European Utility Requirements page 20

Fault Ride Through and Reactive Power ranges

- Non-exhaustive requirements which are too onerous in the maximalist approach.
- EUR recommends using EUR requirements:
  - More onerous than most current national standards
  - Feasible, even for very large synchronous machines





European Utility Requirements page 21

Conclusions

- NC RfG requirements are:
  - In theory feasible for new build NPP but:
    - At considerable cost
    - Technology or supply chain not readily available
  - Not realistically feasible for existing NPPs, therefore:
    - Risk of premature plants shutdown
    - Risk to security of supply
- Maintaining good and constant electricity quality on the Grid is essential for NPPs.
- EUR considers insertion of RES in European Power System is achievable while maintaining electricity quality
- A decarbonised European Power System requires NPPs:
  - Large, stable and controllable power output
  - Massive inertia
- Therefore NC RfG should not jeopardize safety, feasibility and business case

European Utility Requirements page 22


Thank you for your attention!
EUR
European Utility Requirements for future LWR plants
Get news at: http://www.europeanutilityrequirements.org

A.6 EPIA

Project: Technical Report on ENTSO-E Network Code – Requirements for Generators

Stakeholder Meeting: 24 April 2013

Location: EPIA, Rue d'Arlon 63, Brussels

Present:

For EPIA	**Giorgia Concas, Policy Advisor, EPIA**
	Manoël Rekinger, Technology Advisor, EPIA
For DNV KEMA	**Robert McVean**
	Božidar Radovič

While EPIA and their members have a number of issues with the NC RfG as drafted, the main issues centre around:

- The specification of the fault ride through requirements (for type B PPM), in particular, the requirement for reactive current injection;
- Concern regarding the potential interaction of the various individual parameters that may be set at a national level;
- Oversight of the setting of individual parameters in the national setting process;
- Approach to standardisation that may resolve the uncertainty that exists regarding the interaction of individual parameters; and
- Potential lack of standard approach to the setting of individual parameters and the impact on manufacturers meeting different requirements.

In the process, EPIA have not seen any proper justification for all of the significant deviations in NC RfG from existing standards and requirements, especially for the FRT requirement for type B PPM in article 15.2.b) 2) to provide reactive current injection during FRT. For the PV industry, the 10 ms measurement and operation timescale is the only real change impacting their technology and they do not therefore wish to take a stand against all the other deviations as they do not have a clear understanding of their possible consequences. The position in the ENSTO-E Briefing Note for the need to provide Fault-Ride-Through capability for type B generators is recognised and the principle is not questioned by EPIA. However, the PV industry is very concerned by the technical specifications described in this article. EPIA's concern is mainly related to the fastest value which can be requested - 10 ms. Technically, an inverter cannot detect the fault and inject 2/3 of the specified reactive current within this time frame. Based on what EPIA see as a "badly designed" specification, specific settings at national level could lead to the specification of requirements that are not feasible. Inverter technologies that are currently available are in principle able to fulfil reactive current injection but not as quickly as is required in the code. The actual requirement in the German Grid Codes (as stated in the BdEW MV guideline) in relation to this rise time aspect specifies 30 ms plus a further 20 ms for detection, i.e. 50 ms in total. Apart from the fact that this 50 ms value is not directly comparable to the 10 ms specified by ENTSO-E because of differences in detailed definitions. EPIA believe that the values in the German Grid Code could also be challenged as they may not represent the best trade off between the system needs and the cost of providing the capability. As this is a new capability requirement, EPIA believe that the possible added value and the best way to specify the real requirement are not well understood.

Voltage is defined in NC RfG as the positive sequence component and calculated over at least one period (a full cycle). This contradicts any requirement specifying a response time lower than 20 ms as this is already the time needed for the detection. Currently available technologies can detect a fault (by reference to a voltage dip) after having measured a full cycle. EPIA's members are not sure that faster detection could be implementable. This subject has never been verified in practice, but theoretically, when the generators are required to react in such a short period of time, no time is left to "sort out" the inputs (e.g. vector jumps or even simple measurement errors). This may cause incorrect triggering of the FRT modes in an erratic manner.

EPIA note that the specification of this requirement was modified after the public consultation was finalized, without proper justification or any real opportunity for discussion or engagement with the industry. The solar industry believes that there is a very high risk of unintended side effects as a result of this requirement which they believe has been introduced without:

- any real evidence that this capability (reactive current injection) is actually needed during fault at the MV level; or
- any real evidence that such fast operation bring added value at higher voltage levels.

The way the requirement is currently described in the code introduces uncertainties about its implementation at the national level (especially with respect to the minimum threshold of 10 ms). EPIA's experience, in several countries, shows that system operators tend to copy/paste requirements because of a general lack of experience of PV integration.

EPIA has raised the issue that PV can comply with this overall requirement in principle but not with the potential extremes being considered on several occasions with ACER, ENTSO-E and the European Commission. ACER has advised that it is ENTSO-E which should set technical values. During discussion with ENTSO-E, it has been stated that there will be an opportunity to address specific values in the national setting process. EPIA believe that, at least in some countries, TSOs will set impossible values.

Accepting the need for some reactive current injection EPIA, together with EWEA whose members are similarly affected by the same inverter technology, proposed an amendment to Article 15.2.b)2) and wish to see this included in the adopted legislation.

EPIA sees the absence of any reference to standards and/or the future availability of standards as a major barrier to the implementation of NC RfG. In particular the relationship between product development and manufacture, connection procedures, testing methods and the code has not been properly assessed during the NC drafting phase. For mass produced equipments, the use of European standards will be crucial in providing guidance for a progressive alignment of the national legal frameworks. It will also be necessary to rely on standards to ensure compliance with the Network Code, especially where they define test methods. The PV industry has repeatedly asked ENTSO-E to omit ranges from the NC and rely on the relevant European or International standards to avoid discrepancies, with no success. EPIA notes that ENTSO-E has not participated in the work of CENELEC TC8X WG03 which has been developing standards for micro generators, and other LV and MV connected generators. EPIA advocate the need for a proper recognition of the role of these standards by ENTSO-E and all the other stakeholders involved in the NC development process. EPIA believes that ENTSO-E should now support further work for the development of standards to support the implementation and compliance proving process at the national level. EPIA acknowledge that widespread connection of small PV units have an effect on the grid and accept that there is a need for requirements to be specified for relatively small units, but believe that there should be some reference to the connection voltage in determining what these should be.

EPIA members are taking the approach that anything defined in NC RfG that is technically feasible would be accepted but are clear that CENELEC and ENTSO-E must be jointly involved to establish the actual detailed specification to avoid the possibility of badly designed requirements and the incompatible interaction of the various individual requirements during the implementation of the NC at the national level. Beside these mains elements , EPIA are however concerned with some less critical issues, such as the potential cost impact of the remote on/off controls specified in Article 8 for small, single phase type A units and of the simultaneous P/Q requirements specified for type B and C connected at the MV level.

EPIA indicate that the cost of a communication device for remote on/off control would be lead to a 5 to 10 % cost increase for really small PV systems (3,68 kVA - single phase). EPIA does not question the need for this kind of requirement but is more concerned about the reality of its implementation. This will require the establishment of communication lines between TSOs/DSOs and these small units and EPIA questions whether these circuits will be implemented. They also question whether this requirement is the duplication of a capability which could be provided by smart meters that are already generally in the course of implementation.

While EPIA believe that the P/Q diagram can be delivered, the current specification will require the uprating of inverters. Because of the interaction of a number of parameters, particularly should the extreme values of the P/Q diagram be selected, EPIA indicated that they could not provide any meaningful indication of the likely costs involved.

A.7 Thermal Generators

Project: Technical Report on ENTSO-E Network Code – Requirements for Generators

Stakeholder Meeting: 23 April 2013

Location: EURELECTRIC, Boulevard de l'Impératrice, Brussels

Present:

For Eurelectric Generators Group	**Giuseppe Lorubio, EURELECTRIC**
	Ton Geraerds, Essent
	Eric Dekinderen, GDF Suez/Electrabel
	Philippe Lebreton, EDF
	Jörg Kerlen, RWE
For DNV KEMA	**Robert McVean**
	Božidar Radovič

The EURELECTRIC/VGB Generators Group has a number of issues regarding the requirements of the NC RfG. Some of these are purely of a technical nature, while others are related to the economic impacts of technical specifications. The principle issues are related to:

- Fault Ride Through up to 250mS;
- Voltage Ranges and Frequency Ranges;
- Voltage Control Requirements;
- Classification of Significant Generators without reference to connection voltage; and
- Modification to the NC
- Process and cost balance issues as presented to the ACER workshop on 3 September 2012 particularly, but not entirely, related to retrospective application.

The discussion centred on the first 4 of the above issues:

The Generators Group believe that all generator types ≤ 200MW should in general be mechanically capable of fault ride through up to 180mS. The limiting problem for smaller generators will be the fast acceleration of the turbine during the grid fault. As soon as the phase angle deviation between generator voltage and grid voltage goes beyond 90 degrees, it is physically impossible to remain in synchronous operation and the protection must disconnect the generator from the grid. For all thermal plants >200MW, the forces caused by phase angle deviation between generator voltage and grid voltage at the moment when the grid fault is isolated and the voltage at the connection point recovers will break couplings on restoration unless a significant modification is made to the dimensions of the coupling flanges. This again will make it impossible to demount the rotor retaining rings for future maintenance. For all current plants, the physical space available in units will either make modification impossible or render plant incapable of future maintenance. As a result, the Generators had proposed a limitation in the NC RfG to restrict the possibility of a 250mS fault ride through requirement to the Nordic countries (i.e. to split FRT requirements by synchronous areas, similarly to the frequency and voltage requirements) where investment has been made to make this more practicable. However, while accepting that a 250mS fault ride through requirement is possible for hydro-electric generators, the Generators believe that, where a 250mS fault ride through requirement exists, thermal plants are generally operating with derogations.

Generators Group are concerned that the voltage ranges specified in the NC RfG do not, in their view, fit with the voltage range requirements specified in IEC 60034. The Group believe that the maximum voltage in the range specified in IEC 60034 is 420kV for 380 kV grids, while they understand the maximum in the NC RfG is 440kV.To comply with the proposed range would require the replacement of HV equipment and of fixed tap transformers with transformers with on load tap changers (OLTC). A CIGRE study from 1983 showed that 42% of transformer faults were caused by OLTCs and they therefore are not used in many locations. In Germany, where OLTCs are normal, the ranges are not adequate to cater for the full voltage range specified in the draft NC RfG.

In regard to Voltage Control, the Group believe that this is manageable by the TSO. From their standpoint, a generator operating at a power factor of 1.0 pu does not affect voltage. Voltage is affected by the reactive power, necessary for the TSO's equipment and by the reactive power behaviour of the TSO and its customers. From the Generators' perspective, it is the TSO who allows customers to operate with a poor power factor and who chooses its own equipment; therefore, it is the TSO's task to manage its own voltage and reactive power requirements. The Group understands the historical development of the industry and recognises that, in that context it is reasonable for the generators to contribute, within limits specified in international standards, to the solution but they are of the view that the requirements of the NC RfG are excessive. They note that the simultaneous operation of generators at under-frequency and overvoltage will make the problem worse. Due to the extreme magnetic flux, this can be catastrophic for generators, motors and transformers. The Group notes that the corners of the U-Q/P diagrams in the NC RfG are not physically achievable and advise that the upper right corner and the lower left corner of the U/Q envelope do not make sense. Operating a generator overexcited when the grid voltage is already too high or under-excited when the grid voltage is already too low will only heighten the voltage deviation. Fulfilling the extremely wide range of voltage as specified in the RfG code is only possible by replacing existing step-up transformers with transformers with an On Load Tap Changers that may lead to a serious reduction of the reliability of the power plant.

They also note that reactive power from synchronous machines is only available while they are operating and therefore that the displacement of synchronous generators by RES-E is an issue that the code needs to address given that this displacement is inevitable following current energy policy. The Generators Group indicated that reactive power provision by the grid is technically easier, can be located where the reactive power is needed resulting in better voltage management and lower grid losses originating from the transport of reactive power. This approach is much cheaper and permanently available.

The Group note that the wide frequency range and unrealistically long operating times specified for under frequency conditions cannot be achieved with existing turbine technology. If the low frequencies as described in the RfG code exist during the specified periods, this may lead to simultaneous damage to all turbines of the same design. Due to the limited availability of spare parts, such as turbine blades, this, in turn, may lead to non-availability of the Power Generating Modules for very extended periods.

Generators Group believe that the classification of significant generators without reference to connection voltage is unrealistic and will lead to competition distortion, and assert that the impact of EN 50160 must be taken into account when establishing the voltage ranges to be experienced by generators connected to MV networks. It is their belief that both capacity and connection voltage are issues to be considered when establishing generator class, thereby complying with the classification set out in the ACER Framework Guidelines.

An apparent lack of coherence between several Network Codes being developed was highlighted, especially the time durations at abnormal frequencies (outside the continuous band) and the frequency range (outside the continuous band) are exaggerated in NC RfG when compared with the Load Frequency Control and Reserves code.

The change methodology is a particular for the group who recognise that network codes will change over time. All codes that the group were aware of had change management arrangements that included stakeholder representation and even the UCTE arrangements had some figures open for negotiation between TSO and plant owners. In this respect, the legal status as a regulation rather than a technical code is an issue for members of the group.

The Generators' Group specifically requested that attention be paid to the – in their view - unsatisfactory quality of the public consultation and stakeholder engagement by ENTSO-E. They believe that several answers do not fit the comment prepared by ENTSO-E and that this was demonstrated by EURELECTRIC at the ACER workshop in Ljubljana. The Generators' Group insisted that, during the workshop, 14 stakeholders expressed their frustration and unhappiness with the NC RfG and publicly stated their willingness to cooperate to come to an acceptable agreement that would satisfy all parties but that this had been ignored by ENTSO-E. The Group indicated that they intended to provide evidence supporting their position to DNV KEMA and would also provide it to the European commission on request.


eurelectric
ELECTRICITY FOR EUROPE
VGB
POWERTECH
Draft ENTSO-E Network Code on Requirements for Generators
Meeting with DNV KEMA, 23 April 2013

Agenda

POWERTECH

eurelectric

- DNV KEMA mandate: our questions
- Introducing EURELECTRIC & VGB major issues on NC RfG
- Introducing a general methodology to assess the costs generated by NC RfG
- Involvement of EURELECTRIC/VGB and feedback on process

VGB PowerTech e.V.|FOLIE 2

DNV KEMA mandate

POWERTECH

eurelectric

- Content
- Steps, key dates, transparency
  - Report/minutes: will those be publicly available?
- Inputs expected from Stakeholders
- Deliverables for the comitology procedure

VGB PowerTech e.V.|FOLIE 3

EURELECTRIC & VGB MAJOR ISSUES

POWERTECH eurelectric

1. Unbalanced allocation of responsibilities between generators and TSOs
2. Massive impact on power generation costs
3. Threats to security of supply
4. Competition issues and investment appetite
5. Lack of coherence between network codes

Supporting papers :

- Letter EURELECRIC-VGB to EC dated 22 February 2013, *VGB/EURELECTRIC's generators RfG Network Code: Needs, Feasibility, Alternative Solutions and Costs*
- Joint Stakeholders letter to ACER, dated 17 July 2012

VGB PowerTech e.V.|FOLIE 4

Massive impact on power generation cost

POWERTECH eurelectric

1. Time duration at abnormal frequency (under-frequency)
2. Time duration at abnormal voltage
3. Reactive power: transmission option such as a capacitor bank is
   - Cheaper than generation (i.e. power plant) = €7Mio. difference per 100 MVA
   - More available than generation = 8,760 hours compared to power plants operating under market conditions
4. FRT greater than 200ms is not technically feasible using existing technology according to a major turbine manufacturer

VGB PowerTech e.V.|FOLIE 6

Threats to security of supply

POWERTECH

eurelectric

1. Voltage ranges
   - According to CIGRE 42% of transformer faults are due to the OLTC
   - Voltage above IEC limits at the connection point
2. CCGT: capacity increase by falling frequency
   => procedure without experience
3. Simultaneous over-voltage and under-frequency will damage transformers, generators and motors

Combination of over-specified requirements can lead to security of supply threats greater than the individual cases specified above

VGB PowerTech e.V.|FOLIE 7

Competition issues and investment appetite

POWERTECH eurelectric

1. Non-exhaustive requirements defined at national level
2. Classification of generators
3. Deviations with international standards
4. Requirements can change every 3 years

Competition distortion

Lack of competitiveness

Lack of investment

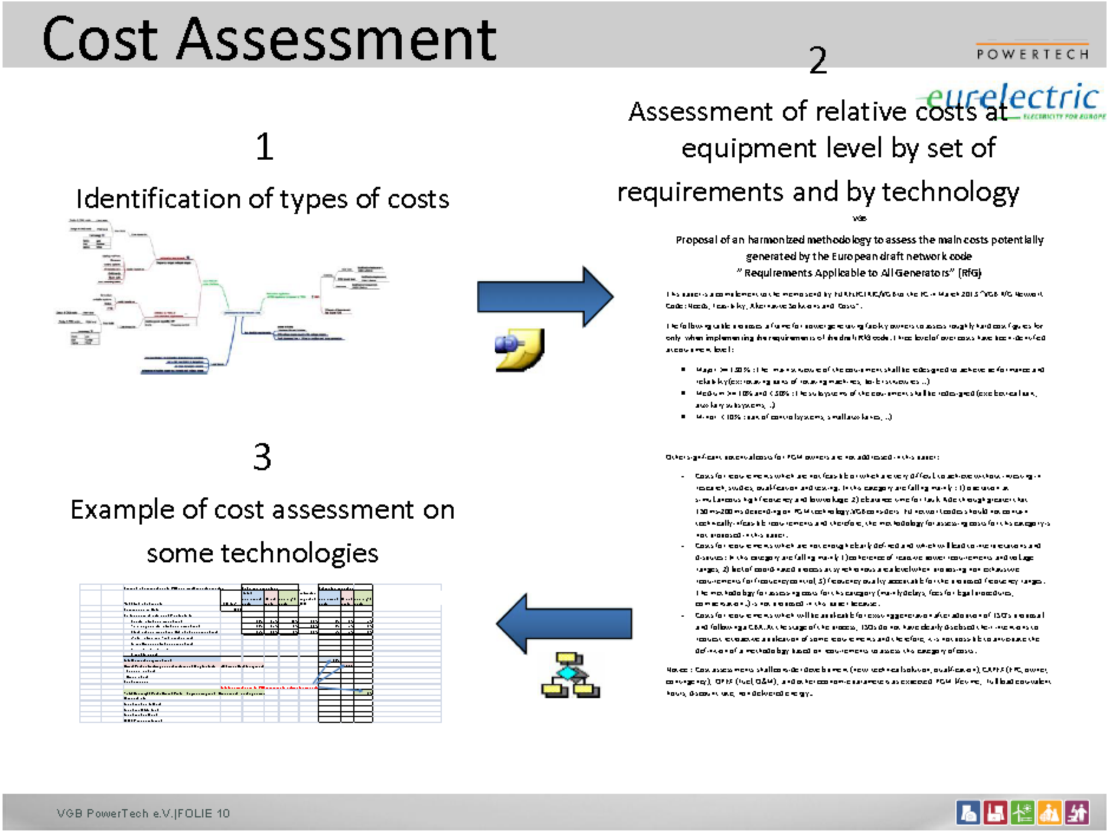
VGB PowerTech e.V.|FOLIE 8

Lack of coherence between network codes

POWERTECH eurelectric

1. LFC&R => max 15 min allowed to restore frequency vs. 30 min or more capability imposed in RfG
2. LFC&R => max frequency deviation allowed of 0.8 Hz vs. 2.5 Hz capability imposed in RfG
3. DCC => threshold voltage of 0.90 pu vs. 0.85 pu imposed in RfG
4. OS => voltage ranges controlled by TSOs not defined vs. capability to remain connected imposed in RfG

VGB PowerTech e.V.|FOLIE 9


Cost Assessment
POWERTECH
eurelectric
ELECTRICITY FOR EUROPE
1
Identification of types of costs
2
Assessment of relative costs at equipment level by set of requirements and by technology
Proposal of an harmonized methodology to assess the main costs potentially generated by the European draft network code
" Requirements Applicable to All Generators" (RfG)
3
Example of cost assessment on some technologies
VGB PowerTech e.V.|FOLIE 10

B. Other Notes of Meetings with Stakeholders

B.1 ACER

Project: Technical Report on ENTSO-E Network Code – Requirements for Generators

Stakeholder Meeting: 24 April 2013

Location: CEER, Rue Le Titien 28, 1000 Bruxelles

Present:

For ACER	**- in person**	**Reuben Aitken, Ofgem (GB)**
	- by teleconference	**Lena Jaakonanttii, Energimarknadsinpektionen (EI)(S)**
		Elozona Uchu, Authority for Consumers and Markets (NL)
		Jakub Fijalkowski, Energie-Control Austria (E-Control) (A)
For the European Commission		**Matti Supponen**
For DNV KEMA		**Robert McVean**
		Božidar Radovič

ACER has had a team of experts for each NC, responsible for preparing the Framework Guidelines and ongoing work on the relevant codes. Those present were members of the expert group for NC RfG. The principle of subsidiarity is crucial to the development of the codes and the Framework Guidelines have been drafted to ensure that those issues which have an impact on cross border network and market integration issues are addressed by harmonisation while those issues that do not have such an impact are addressed at a national level. In this respect, cross border network and market integration considerations have been limited to those concerning electricity.

Changes to non-exhaustively defined parameters are a matter for the organisational arrangements that exist in the Member States. Some Member States already have review mechanisms that involve stakeholders, others delegate responsibility to the TSO with or without supervision by the NRA. However, according to Article 4(3) of the NC RfG the principles of transparency, proportionality and non-discrimination shall be respected when national choices are made on the non-exhaustive requirements. Most NRAs expect that the NC RfG will be implemented using parameters as set at the implementation date but this is not guaranteed. The NC RfG may be used as a springboard to deliberately implement change. Any changes to currently set requirements will be subject to the review process currently applied in each Member State up until the day before implementation date of the NC RfG, and the modified review process established for the NC RfG, respecting the above mentioned high level principles, would apply from implementation date. All EU Regulations (and NCs will have that capacity upon adoption) have direct application. Individual NCs have different application timelines. A key role for ACER is monitoring NC implementation. The NRA carries out actual monitoring confirming or rejecting proposals from the TSOs for non-exhaustive requirements. ACER can provide a platform to support NRAs in this activity. ACER is considering publishing all adopted/applied non-exhaustive requirements in each country, and requesting from NRAs a report about arguments/facts that were the basis for their decisions.

The concern from stakeholders that a Member State may impose significantly stronger connection conditions to generators in the areas where decision has been delegated by the NC to the national level does not represent a significant change from the status quo, for the following reasons:

- Currently NRA/Member States have all the power and may introduce any rule/requirement they deem appropriate, and with the NCs they will be significantly limited with ranges or limit values for non-exhaustive requirements;
- According to the NC, a Member State can maintain or introduce measures that contain more detailed or more stringent provisions than those set out in the NC provided that these measures are compatible with the principles set forth in the NC;
- Article 4.1 applied to non-exhaustive requirements guarantees that position of the stakeholders must be taken into account and that process must be transparent.

In section 1.2 of the Framework Guidelines, ACER required that: “The network code(s) developed according to these Framework Guidelines take precedence over the relevant national codes and international standards and regulations. Where there are proven benefits, and if compatible with the provisions in the European network code(s), national codes, standards and regulations which are more detailed or more stringent than the respective European network code(s) should retain their applicability.” Translated into NC RfG, Article 7 states that: “This Network Code shall be without prejudice to the rights of Member States to maintain or introduce measures that contain more detailed or more stringent provisions than those set out herein, provided that these measures are compatible with the principles set forth in this Network Code.”, the statement concerning proven benefits being omitted. From ACER’s perspective, it is self-evident that any more detailed or stringent provisions would need to confer benefits, however the EC may intervene because in the

Regulation there are provisions (Article 21 of Regulation EC/714/2009 allows more detailed, but not more stringent measures…) to which Article 7 may not be fully compliant or this article may be seen as a tautology given the Regulation. However this section is about the principle in EU Law that Member States are always permitted to impose more stringent requirements or require greater benefits to be provided to its citizens, if this is justified. This is the heart of the subsidiarity principle that NRAs and Member States will always defend.

It was noted that NRAs are not explicitly foreseen to initiate a CBA and may wish to be proactive in implementing change to the overall benefit of all parties as is their duty.

Overall, ACER notes the non provision of dispute procedures in the NC RfG. Although this is a legal issue, there was a recognition that problems may result. However, the basic principle is that all EC legislation in energy sector must be in line with the 3rd Energy Legislation Package. In this particular case, Article 8 from Regulation EC/713/2009 and Article 37.1.c from Directive 72/2009/EC should apply. All NRAs have a right to determine any dispute in the electricity sector. National procedures will apply for any dispute that does not have a cross border impact and will also be followed where a dispute relating to a cross border issue is referred to a NRA. In the case of cross border issues, NRAs have a duty to co-operate and ACER has competence in ensuring NRAs act appropriately in the case of cross border issues falling under the scope of Article 8 of Regulation (EC) No 713/2009. An appropriate mechanism therefore exists although not explicitly stated in the NC RfG. Article 4(3) is intended to ensure that NRAs retain their existing competencies after the adoption of the NC RfG as a Commission Regulation.

In the determination of significant grid users, ACER is content with the intent regarding CHP, recognises that there are issues for smaller installations but these are covered by the transitional arrangements and expects that, in future, new generators will comply with the requirements of the NC RfG.

ACER recognizes that acceptance of the NCs by the system users and stakeholders may be higher if there was no option for retrospective application. However, the NC is forward-looking and there are clear benefits from having this option embedded as of the inception of the NC. For that reason, and at NRAs insistence, the procedure for retrospective application has been tailor-made, respecting the relevant high-level principles. Accordingly, TSO/NRA has to prove that there are clear benefits if a NC requirement is applied to an existing grid user. Discussions between ACER, NRAs and TSOs show that they expect only a few requests for derogations and all of them from new system users. Concerning coordination and monitoring of the derogation process, Articles 54.8 and 54.9 of the NC RfG deal with this issue, as well as Article 9.1 of Regulation EC/714/2009.

ACER believes that the applicability of the requirements to existing installations is appropriate, with CBA required where later change is proposed. NRAs are expected to always act on the basis that CBAs are to be undertaken on a societal basis with the society defined as the nation state. ACER does not see provisions of the NC RfG that could prevent type class derogations if possible and recognise that, particularly in the case of smaller installations, assistance to site owners by more expert agents would be appropriate.

B.2 EWEA

Project: Technical Report on ENTSO-E Network Code – Requirements for Generators

Stakeholder Meeting: 24 April 2013

Location: EWEA, Rue d'Arlon 80, Brussels

Present:

For EWEA	**Paul Wilczek, EWEA**
	Ivan Pineda, EWEA
	Frans Van Hulle, XP Wind
	Stephan Wachtel, GE
	Inga Skrypalle, REpower
	Frank Martin, Siemens
	Peter Christensen, Vestas
For DNV KEMA	**Robert McVean**
	Božidar Radovič

EWEA advised that their principle issues with the NC RfG are:

- Fast Reactive Current Injection Requirements;
- Lack of overall framework to ensure interaction of parameter settings is achievable;
- Active Power Recovery Specification;
- Reactive Power Supply Requirements

The most important issue for EWEA members is the requirement for the provision of fast reactive current injection, the problem being the required speed of detection and response. A sub-cycle operation timescale is being sought and this is not feasible. One reason is that the reactive current is defined by ENTSO-E in the RMS domain, which inherently excludes the sub-cycle time domain. However, even if ENTSO-E had defined the reactive current requirements in the sub-cycle time domain, EWEA believe that the detection and desired response is technically not possible in 10 ms.

EWEA indicated that state of the art to determine an RMS value is at least 20 ms to measure and evaluate a situation requiring reactive current injection only, then actuator operating time would be required before injection can take place. EWEA do not consider that the ENTSO-E requirement sufficiently specifies the boundary conditions when such a requirement shall be required to be met. EWEA state that the opinion of 10 leading manufacturers is that an overall figure of 60ms is the best that can be achieved under such insufficiently defined conditions. EWEA does not believe this requirement has been adequately justified and noted that the reference to Article 4(3) was added after the initial reasoned opinion from ACER and the message has been given by ENTSO-E that the requirement would only be asked for in exceptional cases. According to EWEA, any attempt at an impact assessment would be against a high uncertainty in the market and delays in implementation of new turbines. ENTSO-E has stated that one manufacturer has advised that they have a design to meet the NC RfG figures but EWEA has canvassed all manufacturers and obtained their best response values, none of which comply.

Before being able to implement any change towards the ENTSO-E figure, a much clearer specification would be required. Best practice in Spain, UK, and Germany has developed on the basis of realities and specified differently. ENTSO-E have put all requirements together without considering the interactions of the various components. The specification is incomplete because it does not consider the effects of auto-reclosures and multiple fault rides through. In the non exhaustive requirements, TSOs have the ability to choose any combination of parameters without being given any guidance on the overall impact. EWEA believe that the least stringent impacts specified in the NC RfG, taken together, are more stringent than anything that currently exists. The combination of active power recovery and fast reactive current injection requirements[26] with fault ride through and autoreclose requires significant inverter oversizing for use times measured in ms. EWEA believe that many countries have good detailed exciter specifications but what is included in NC RfG is weak. EWEA would be happy to enter into a structured approach with TSOs to develop the detailed interacting specification and view their experience with EirGrid to be positive.

EWEA suggested that they would provide a document with a more detailed techno-economic justification for the alternative proposal – i.e. why 60 ms is the recommended figure to reach 90% of additional reactive current – and this paper has been attached as an appendix to these notes. Also, EWEA undertook to survey its members to reconfirm the rejection of the fast reactive current injection requirement[27].

---

[26] In some countries there is an active power recovery requirement without fast reactive current injection, while in others there is a fast reactive current injection requirement without active power recovery. IN NC RfG both requirements are mandatory.

[27] On 21 May, EWEA confirmed "*We have enquired among our members on this in the meantime and can state: the manufacturing members of EWEA confirmed that the fast reactive current injection as specified in the NC RfG is technically not feasible. On this point, we as EWEA claim to represent with*

For Active Power Recovery, EWEA indicated that the risk with NC RfG is an incorrect specification in the national codes, and therefore EWEA proposed alternative, more precise, wording for this requirement. There is a high risk that the selected approach will clash with wind turbine recovery as it may hit the natural frequency of the drive train. The principle is that most numbers can be accommodated, but each would require a wind turbine redesign. EWEA proposed the figures adopted by National Grid in GB and, in the interests of ensuring that standard designs can be accommodated throughout EU, the development of appropriate standards accepted by TSOs is necessary.

EWEA are concerned that the specification for Reactive Power Supply capability requirements will result in excessive costs to supply, especially for type C and D units connected to the MV network, without the technical need for such additional investments being justified. No difference is made in the NC RfG between the requirements for HV or MV connected installations and the effect of applying the same voltage control requirements on a transmission connected installation with OLTC and on a distribution connected installation without OLTC means that the full impact of reactive power provision over wider voltage ranges falls on the wind farms.

over 700 members the entire wind industry supply chain in Europe, including all relevant wind turbine manufacturers. Therefore, this survey outcome can be regarded as comprehensive."

ENTSO-E NC RfG - Article 15: Technical rationale behind the EWEA 60 ms proposal

Introduction

With the final version of the upcoming ENTSO-E NC RfG Network C(NC RfG) in June 2012, ENTSO-E allows the specification of a rise time of 10 ms in relation to reactive current injection during FRT events.

After a network code development process of several years this fully unrealistic requirement has been presented in the very last minute, without any sort of motivation or documentation (assumptions, calculations or analysis) – and without any interaction with the industry either directly or through the established stakeholder forums linked to the code development process. In short – the industry saw the 10 ms rise time requirement for the first time when the very final code was published by ENTSO-E on June 26, 2012.

According to the opinion of the European Wind Industry represented by EWEA, including all European leading manufacturers this new requirement is technically non-viable. This opinion of the wind industry has been explained in previous papers[1].

The purpose of this paper is to provide further explanations why the 10 ms is in itself technically incorrect and cannot be fulfilled even with the best state-of-the-art technology. At the same time, the paper describes the technical motivation behind the "60 ms proposal" collectively suggested by the wind industry.

Current injection requirements in Europe valid at the moment

A brief overview of the existing reactive current injection rise time requirements in Europe is given below. This is mainly a European practice and is typically not seen outside Europe.

During FRT events some countries give priority to reactive current injection (e.g. Germany, Spain, Greece), while others give priority to recovery of active power (e.g. UK, Ireland, Rumania). Hence, depending upon country priority is given to either full (1 pu) reactive current injection or active power recovery – but currently not to both at the same time.

[1] Position Paper EWEA EPIA November 2012: http://www.ewea.org/fileadmin/files/library/publications/position-papers/EWEA_EPIA_NC_RfG_concerns_and_alternative_formulations.pdf, explanatory note EWEA February 2013: Further explanations on the EWEA-EPIA alternative formulations on the ENTSO-NC RfG, 7/02/2013

1

For historical reasons the 1 pu reactive current is most commonly defined at the LV side of the individual wind turbine transformer. Alternatively it is in some cases defined at the HV side of the wind turbine transformer (Figure 1).

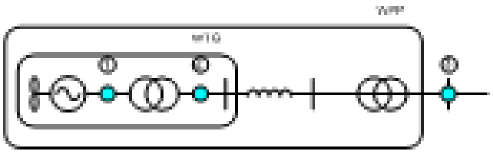


Figure 1. *Possible points of reference for reactive current injection in the single line diagram of the connected wind power plant. The following codes make reference to point 1 (Germany: EON 2006, Transmission 2007, BdeW 2008, Tennet 2012, SDLWindV, and Spain). The German SDLWindV code allows point 2 to be used as option. Point 3 represents the typical Connection Point for a transmission connected plant.*

In Spain the reactive current injection is in principle specified as 0.9 pu valid for the Connection Point. To be pragmatic, 1 pu delivered at the LV side of the wind turbine transformer is considered to be an equivalent fulfilment of the requirement.

According to best engineering practice, the rise time is normally measured with reference to 90 % of the full response to be obtained (step response definitions).
Instead of the more exact term "rise time" the term "response time" is sometimes used which causes confusion, as response is a broader term. Sometimes also the term "time for detection" or "after recognition" is used instead of the normally used term "dead time".

In general, when an event occurs it takes a certain definite time until the actuator has reached 90 % of the target value. Broadly speaking, this time consists of (i) the time needed for computer algorithms to calculate, (ii) the communication delay and (iii) the actuator movement (physical response).

An overview of the presently valid reactive current rise time requirement in Europe is given in Table 1. The table gives a broad representative of the requirements in Europe. In Germany there are several codes with slightly different requirements. What is indicated in the table for Germany can however be considered as representing current practice in Germany.

Reactive current injection rise time requirement in Europe – Mid-2013					
Country	Type of current	Character of injection current	Rise time incl. detection [ms] [detect+rise]	Time for detection assumed in code	Remark
Spain	Pos. seq.	Absolute	150	Not defined	
Germany	Pos. seq.	Additional	50 (90 %) [20+30]	20	20 ms is to be found in one code (FGW), and the 30 ms in another code (SDLWindV)
Denmark	Not defined	Not defined	100	Not defined	
Ireland	Not defined	Not defined	100 (90 %)		Introduced for the first time in Dec. 2012
UK					Requirement to max reactive current
Greece	Pos. seq.	Additional	70 (100 %) [20+50]	20	
Turkey	Not defined	Not defined	60	Not defined	Requirement to max reactive current
Europe – CENELEC TS (upcoming)	Pos. seq.	Additional	30 (90 %)	not yet defined	Most likely 20 ms will also be allowed for detection
ENTSO-E	Pos. seq.	Additional	10 (66 %)	Not defined	June 2012 NC RfG

Table 1. *Overview of best practice today regarding reactive current injection rise time requirements in Europe (2013)*

Table 1 illustrates the differences regarding the type of current, the character of the current and the requirement itself throughout Europe. These differences are extremely important when it comes to the ability to fulfil a requirement or not. In reality a broad palette of other code requirements matter also a lot in the full picture. But for simplicity these further aspects are left out here.

Originally when the reactive current injection requirement was introduced in Germany the rise time requirement was set to 20 ms. When this appeared insufficiently precise, the wording "after recognition" was added. This additionally introduced a sort of informal best practice allowing a further 20 ms for detection (recognition), i.e. in total 20 ms + 20 ms = 40 ms. Later when the SDLWindV ordinance was introduced the number changed to a rise time of 30 ms (actuator movement) and further 20 ms for fault detection (positive sequence value, FGW Guideline), i.e. 30 ms + 20 ms = 50 ms in total.

New specification and numbers introduced by ENTSO-E

ENTSO-E has introduced the following rise time requirement in the June 2012 NC RfG:

- Connection Point / terminals of the individual units
- Positive sequence voltage/current
- Additional current
- 10 ms rise time
- 66 % (2/3) of the additional reactive current (instead of the normal 90 %)

Demanding to fulfil such requirement is conceptually erroneous and physically non-viable.

When an event occurs, the first 20 ms is needed just to calculate the positive sequence quantities. By definition, positive sequence is calculated over one full fundamental cycle = 20 ms. If for simplicity we neglect communication delays, the actuator then has to accomplish the response which also takes a certain definite time (large inductances). Even in an exceptional case where positive sequence quantities are calculated at every 10 ms, i.e at half cycle intervals, actuator movement still has to follow.

The fact that it normally takes 20 ms just to calculate the positive sequence quantities is basic knowledge for electrical engineers and power electronic professionals working in close connection to this type of technology and a large number of experts can confirm this.

Thus, ENTSO-E has chosen such extreme requirement range that the full available time (10 ms) does not even allow for the positive sequence calculation to be performed – and subsequently then indeed does not allow time for actuator movement either. If 10 ms is considered as an order of magnitude, then it appears that ENTSO-E has moved the requirement approximately 5 orders of magnitude compared to one of the currently most stringent requirements (Germany).

Hence this NC RfG requirement has no chance of being implemented in any foreseeable time frame.

Technical proposal from EWEA

The explanation above should clarify why it is absolutely necessary to change the 10 ms requirement to another best state-of-the-art requirement. Such a proposal has been developed and collectively suggested by EWEA.

Full reference to this information is given in footnote 1. For convenience the proposal suggested by EWEA has been inserted below.

It should be mentioned that the EWEA 60 ms proposal has been composed structurally and wording-wise in such a way that it should allow a more or less direct transfer of a "ready for use text" into the NC RfG , i.e. it is directly prepared to fit the ENTSO-E document on the relevant spot.

> *60 ms reactive current injection rise time proposal from EWEA (Article 15, 2a, 2)*
>
> The Power Park Module [...] shall be capable of providing at least 90% of the additional reactive Current (positive sequence of the fundamental) within a time period specified by the Relevant TSO, which shall not be less than 60 milliseconds. The target value of this additional reactive Current [...] shall be reached with an accuracy of -10%/+20% within 100 milliseconds from the moment the Voltage deviation has occurred as further specified [...]. **Below 40 % retained voltage reactive current shall be supplied as far as technically feasible.**

In the EWEA proposal the 100 ms represents what is normally called settling time.

To be on the safe side EWEA has once more consulted their members regarding the technical viability to fulfill the 10 ms requirement suggested by ENTSO-E.

The following manufacturers have confirmed in May 2013 that the ENTSO-E proposal is technical non-viable with today state-of-the art technology:

- Vestas
- GE
- Siemens
- Enercon
- Repower
- Gamesa
- Acciona
- ABB
- Alstom

Technical motivation behind the EWEA proposal

In the following the technical reasoning behind the EWEA proposal is explained.

A balanced proposal should not exceed the most stringent of present requirements

Even with the current most stringent valid requirements (for example 50 ms in Germany), wind turbine manufacturers consider the values to be at the edge of what is technically possible. Important to note is also that some countries have quite longer rise times e.g. 100 ms for Denmark and Ireland.

In a normal market environment it is logical to assume that not all manufacturers can handle the most extreme requirements in a number of markets across Europe. In this context it is thus not rational that a newly created European code moves one of the most complicated requirements to the most extreme positions like for example in Germany (50 ms). Therefore one would expect the NC RfG to strive for a certain balance in order not to hurt too large parts of the industry. The 60 ms proposed by EWEA is at the edge of present requirements, and is broadly acceptable for the wind industry.

The rise time must be seen in technical context with many other requirements in order not to introduce excessive uncertainty

As a consequence of the ENTSO-E NC RfG a lot of additional uncertainty is introduced compared to today requirements. Due to the intended harmonizing effect, many national grid codes standing alone on their own individual foundation are suddenly put together. Thus, requirements which have so far been standing alone are suddenly coexisting at the same time.

The 50 ms valid for Germany today is based upon a well-known set of boundary conditions and mainly with priority to reactive current injection during FRT as the primary focus. The requirement to recovery of active power after FRT is - with its 5 or 10 s - very slow, i.e. it has almost no priority.

In UK the requirement for active power recovery is also based upon a very well-known set of boundary conditions. During FRT events recovery of active power has the main priority. No requirement for the detection of the fault and the rise time of the injected reactive current injection exists.

Now, due to code harmonisation two distinct practices from different countries are combined in the ENTSO-E NC RfG and suddenly a hitherto single existing objective becomes a double objective, i.e. a wind power plant now potentially has to perform BOTH active power recovery AND current injection at the same time.

To perform both active power recovery and current injection at the same time represents an extreme new challenge and by that also a new uncertainty (risk).

This new risk is difficult to assess and is now further increased by the fact that the ENTSO-E NC RfG also introduces the following four unknown mechanisms:

1. Excessive more reactive power capability
2. Number values of very important parameters are kept open or are unknown (e.g. active power recovery, acceptable temporary overvoltage, dead time, settling time, grid short circuit level or short circuit ratio, reactive current injection post fault support time)
3. Requirements not existing in the ENTSO-E code may/will occur in the National codes but in a new context and with numbers difficult to predict
4. Introduction of conceptually new unspecified requirements in the ENTSO-E NC RfG (short circuit level before and after fault, negative sequence current injection)

In practice, what started out being a relatively narrow single objective has ended up being a very intangible multiple objective as many relevant parameters now belong somewhere inside a huge parameter matrix and further new unspecified requirements may suddenly show up.

In total this has substantially increased the risk of wind power technology not being able to fulfil a given set of requirements. When preparing the EWEA proposal the wind power industry has included a minimum of additional margin to cover for this new unknown uncertainty – i.e. the requirement has been increased from 50 ms to 60 ms.

Summary and final recommendation

The proposal for reactive current injection with the present value of 10 ms in the NC RfG is conceptually erroneous and physically non-viable. Considering the definition of the NC RfG it is furthermore technically incorrect. It does not allow for the basic operations (calculation, communication, actuator movement) to be performed. Moreover there is not the least piece of documented technical justification for the need. Maintaining this value in the NC will have a detrimental effect on the further development of FRT related grid code requirements in Europe.

The proposal for 60 ms, as put forward by EWEA is a balanced and forward looking alternative:

- It is physically viable, as it allows time for the basic functionalities.
- It provides a fast response, in line with advanced codes in major wind energy markets (Germany, Spain, Greece, Ireland, Turkey, etc.)
- It is broadly supported across the European wind industry backed up by the leading industry experts.

With this proposal, the industry basically accepts to maintain the current state-of-the-art technological fix-point, in spite of the fact that the NC RfG introduces conceptually new requirements and will cause a sudden coexistence of formerly decoupled (individual country) requirements. However, it remains largely unknown at present whether it will be technically possible in practice, because of the huge amount of uncertainty introduced by the NC RfG.

Because of the very short remaining time, the complexity of the subject and the need for a safe fast-track solution to the challenge it is recommended to follow the proposal suggested by the wind industry. This proposal indeed can be considered as a worldwide state-of-the-art in this technical area – particularly considering all the unknowns.

The European Wind Energy Association (EWEA) is the voice of the wind industry, actively promoting the utilisation of wind power in Europe and worldwide. Over 700 members from nearly 60 countries, including manufacturers, developers, research institutes, associations, electricity providers, finance organisations and consultants, make EWEA the world's largest wind energy network.

B.3 CENELEC

Project: Technical Report on ENTSO-E Network Code – Requirements for Generators

Stakeholder Meeting: 23 April 2013

Location: CENELEC Meeting Centre, Avenue Marnix, Brussels

Present:

For CENELEC	**Fahd Sultanem, RTE (CENELEC TC8X)**
	Marcus Merkel, EWE NETZ GmbH (CENELEC BTWG 143-2)
	Wouter Vancoetsem, LABORELEC (CENELEC TC8X WG03)
For DNV KEMA	**Robert McVean**
	Božidar Radovič

CENELEC provided a presentation covering:

- the Context of Standardisation;
- CENELEC liaison with ENTSO-E;
- CENELEC TC8X WG03 documents – in general and in relation to NC RfG;
- CENELEC approaches
- expectation of CENELEC/ENTSO-E collaboration

CENELEC is one of the designated European Standards Organisations charged with the preparation of voluntary standards which help facilitate trade between countries, create new markets, reduce compliance costs and support the development of a single European market. There are a number of Technical Committees including TC 8X which addresses system aspects of electrical energy supply. WG 03 works to this committee on the requirements for the connection of generators to distribution networks and has been the focus WG for the work with ENTSO-E on NC RfG. WG03 are concerned about the effort required in a very short time to address the issues that the NC RfG brings and believe that the Commission must issue a mandate similar to M/490 to focus on addressing the gaps in standards that exist.

CENELEC has had discussions with ENTSO-E and ENTSO-E have answered questions but have not yet become involved in TC8X WG03 activities. BTWG 143-2 has been established by CENELEC to address ENTSO-E standardisation activities. WG03 are currently working on standards affected by the NC RfG – LV connected generators <16A/phase, LV connected generators >16A/phase and MV connected generators. The scope of all of these documents goes beyond that required by NC RfG, aiming to establish functional and technical requirements, evaluation criteria and test methods to demonstrate conformity.

The NC RfG has a mixture of exhaustive requirements applying throughout the EU/EEA and non-exhaustive requirements which require national specification and implementation. Non-exhaustive requirements are a problem for CENELEC since their objective is to create standards which help facilitate trade between countries, create new markets, reduce compliance costs and support the development of a single European market. Nationally specified and implemented requirements cut across this objective. WG03 intend to address this by establishing the requirements for a standard reference product with the possibility for some diverging requirements on a national basis. However, there are also some requirements where there may be a conflict with requirements established elsewhere. An example may be the power response to over frequency (Article 8.1.c) where the requirement may conflict with the operation of islanding detection methods in distribution networks.

CENELEC view the development of the NC RfG to be formulated as a Commission Regulation as establishing the legal requirements that must be met. CENELEC will develop the standards necessary to define how these requirements will be met – and how generators will be proven to meet the requirements. CENELEC are concerned about the proposed implementation timescales and believe that clear action needs to be taken to ensure there is a possibility for standards to exist when they are required. In this respect, they believe that there needs to be a strengthening of ENTSO-E's relationship with CENELEC and ENTSO-E's involvement in the standardisation process.

C. Stakeholders' Information Papers

C.1 COGEN Europe and EHI

Brussels, 30th May 2013

Subject: *Cost-benefit Analysis on amending the emerging technology classification in Title 6 and the derogation procedure in Title 5 of the NC RfG proposal*

Dear Mr. McVean,

Following your request, the COGEN Europe and EHI Micro-CHP Joint Working Group carried cost-benefit analyses (CBA) supporting the two recommendations for amendments to the NC RfG proposal made by the Joint Working Group.

The two CBAs attached make a strong case in favor of adopting the proposals of the Joint Working Group.

1) The CBA on introducing a <u>minimum threshold</u> in Title 6 for emerging technologies indicates increased investor certainty, with limited impact on the grid.

   Having a stated minimum threshold in the NC RfG, rather than delegating the task (unbounded) to TSOs in each synchronous area after the entry into force of the network code, would avoid cost of immediate retrofit estimated at € 9 - € 11 million for the sector. This would also ensure investor confidence is maintained, given that the alternative of not having a minimum threshold level in the NC RfG would translate into a financial risk of an estimated additional 2 year delay on ROI.

   In terms of costs, the technical analysis shows that including a minimum threshold will not trigger or exacerbate a grid disturbance on the electricty network. The impact on the grid of the working group's proposal of a 0.1% minimum threshold for technologies with a cumulative behavior during an underfrequency grid event is equivalent to losing a CCGT power unit in Continental Europe (300 MWel) and a local small biomass power plant in Great Britain (50 MWel)

   The minimum threshold should recognize that faults are not necessarily cumulative among different emerging technologies and that different cumulative behaviours justify different thresholds.

2) The CBA on allowing the <u>manufacturer of Type A generating units to apply for derogation</u> on behalf of small generating unit owners indicates that substantial administrative costs can be avoided by both manufacturers and network operators

   Including the manufacturer of Type A generating units as a stakeholder that can apply for derogation on behalf of small generating unit owners, such as householders, will save a manufacturer between € 500 - € 1000 in administrative costs to supply the evidence to a DSO that can formally apply for derogation. In a country like Germany, which has 900 DSOs, a manufacturer would benefit from between € 0.5 - € 1 million in avoided costs from being able to pursue an application on its own.

> The current NCRfG proposal where the householder is the appropriate party to pursue a derogation is simply unworkable. This is a particular concern for microCHP products which are already established on the market but will require access to a derogation process.

The results of the CBAs are described in more detail in the two documents attached. The Joint Working Group is committed to address all inquiries in that respect and provide further fact-based information to support DNV Kema in its assessment of costs and benefits.

Yours sincerely,

Fiona Riddoch
Managing Director
COGEN Europe

Dana Popp
Public Affairs Manager
Association of the European Heating Industry

Cost-Benefit Analysis (CBA) on allowing the manufacturer of Type A generating units to apply for derogation on behalf of small generating unit owners

30th May 2013

Introduction of asks

In the latest NC RfG proposal, from 8th of March 2013, only owners of power generating units or network operators are permitted to apply for derogation in respect of one or more requirements of the Network Code. The COGEN Europe and EHI Joint Micro-CHP Working Group proposes that manufacturers of Type A generating modules should be allowed to apply for a derogation on behalf of the owners of existing and new units, who are often householders with little or no expertise to complete a derogation application.

The CBA analysis results indicate that an amended derogation procedure allowing manufacturers of small generating units to apply for derogation on behalf of householders can lead to significant cost savings in terms of avoided administrative costs for manufacturers to interact with an intermediary DSO (€500 - €1000 per DSO) and the cumulative cost of replicating the process for each DSO in a country (€ 0.5 - € 1 million in a country like Germany), avoided costs of possibly closing down operations (€ 2- € 5 million), avoided administrative costs for a DSO (€500 - €1000) (see Annex I).

From a legal point of view allowing manufacturers to apply for derogation, would ensure that the derogation procedure is non-dsicriminatory, as required in the Framework Guidelines to the NC RfG (see Annex II).

Summary of cost-benefit analysis results for allowing manufacturers to apply for derogation on behalf of Type A generating unit owners

The results of the CBA analysis show that substantial costs can be avoided by both manufacturers and the relevant network operator (DSOs in this case) if the manufacturer of Type A generating units is allowed to apply for derogation:

Firstly, in case a manufacturer of a Type A unit is in the situation where the generating unit does not comply with one or more requirements of the NC RfG current text applies (there is no clear procedure enabling the company to apply for derogation), there are two possible courses of action:

The manufacturer engages in a costly and uncertain process of no fixed timescale to convince the Network Operator (DSO) to initiate a derogation procedure for a class of generating units.

- While the cost of collecting the evidence in support of a derogation is in the range of € 3000 - € 5000 per manufacturer, the administrative costs of interacting with the DSO, the uncertainty of the process and replicating the process for each relevant DSO could reach €500- €1000 per DSO and for all DSOs to € 0.5 - € 1 million in a country like Germany which has 900 DSOs.
- If the first step fails the costs grow arithmetically as the attempts and the market position of the product becomes more risky. If at some point the manufacturer assesses the whole process as too risky, the product will be withdrawn since a product non-compliant with the NC RfG cannot be put on the market. Cost estimates for this range from € 2 - € 5 million in closing a complete operation.

Secondly, the DSOs involved in this process will also be incurring high costs including:

- Costs of hundreds of DSOs across Europe (Germany alone has 900 DSOs) processing the same application, since the current NC RfG proposal only allows for a Network Operator to apply for derogations for classes of generating units connected to their network. The cost that each DSO will incur is estimated at €500 - €1000 per DSO
- Costs of a complex administrative procedure, including requiring input from manufacturers.

Page | 2

Annex I – Cost-benefit Analysis on allowing Type A generator manufacturers to apply for derogation under Article 52 of NC RfG

The existing proposal in NC RfG only allows Generating Unit Owners and System Operators to apply for a derogation procedure under Title 5. Obtaining a derogation for a class of generators can only be initiated by a Network Operator. The class derogation application can only be pursued in each country separately. In this situation, the manufacturer faced with a costly and uncertain derogation procedure will certainly perceive a high risk in putting the product on the market, and may evaluate the risk as too high to continue.

The COGEN Europe and EHI Joint Working Group proposes an amendment to the NC RfG to make provisions in the case of Type A Generating Modules for manufacturers of the respective units to apply for derogation on behalf of the owners of the units at the synchronous area level.

Parties	Costs	Benefits

Technology investors	One-time cost of producing the evidence in favor of a derogation for a class of generators. (€ 3000 - € 5000)	Avoided costs for a manufacturer:
		• administrative costs of initiating a derogation to the National Authority procedure via individual DSOs
		  ○ administrative costs of bringing the issue to the attention of an intermediary, the Network Operator (€ 500 - € 1000 per DSO)
		  ○ cost of uncertainty linked to the absence of a formal procedure to pursue a class derogation including the possibility of an appeal
		  ○ cost of replicating the process for each DSO in each country of a synchronous area (e.g. € 0.5 - € 1 million only for Germany that has up to 900 DSOs)
		• cost of closing down due to uncertainty (€ 2 - € 5 million)

Network Operator (DSO)		Avoided costs: • Administrative costs of further complexity linked to the derogation procedure for classes of generators • Avoided costs of processing a large number of identical applications
Householder or small business owner		Avoided: • administrative costs and complexity of multiple owners /non-competent derogation applications rather than a single manufacturer application • barrier to sale
EU energy and climate objectives		Enabling the completion of the European Internal Electricity Market. Contribution of the residential heating appliance to reduce CO_2

Annex II – Framework Guidelines

The Framework Guidelines set clear requirements according to which the derogation process shall be non-discriminatory.

The NC RfG is clearly discriminatory against small Type A generating module owners who are effectively excluded from benefitting from a derogation, as they are unreasonably required to undertake the same steps in applying for derogation as owners of much bigger generating modules. Home owners who replace their heating boiler with a micro CHP product do not have the technical expertise and understanding to be capable of applying for derogation. This is an unacceptable and unjustified burden that will only result in loss of sales. As well as being discriminatory, this disproportionate requirement can have a negative impact on the good functioning and completion of the internal electricity market, as it will create inequality in the rights of small distributed power producers.

As written, the NC RfG does not allow manufacturers of Type A modules (sold to households for example) to pursue derogation for a specific, "type certified", module on behalf of small generating module owners. As suggested by ENTSO-E in previous exchanges, there is an unwritten assumption that the manufacturer can pursue an application for derogation on behalf of a group of household generators through a TSO. This is an important issue and the absence of a clear statement covering how small type A generators shall participate in the code remains a significant handicap to the Type A generator group owners, which are de facto unable to operate under the current provision of the NC RfG.

In addition, the NC RfG creates a precedent for allocating responsibilities to parties not defined by the Framework Guidelines as within the scope of the Network Code, by allowing installers of Type A generating units to fill in the Installation Document required in Article 25 on behalf of the owner. This provision recognises that small generating units owners may not have the expertise to complete complex technical procedures, which should not impede them from owning and installing such unit. The same principle applies to the derogation process, which requires similar if not more technical skills than filling in the Installation Document.

Given that the NC RfG gives the possibility to act to other third parties, such as installers, this should be extended to include manufacturers of type A products. The manufacturer will provide the information for the derogation and where appropriate provide numbers for significance.

Page | 4

Cost benefit analysis on introducing a minimum threshold value in Title 6 of the NC RfG for emerging technologies

30th May 2013

Introduction of asks

Title 6 in the NC RfG delegates the decision on setting the values of the "maximum level of cumulative Maximum Capacity of Power generating Modules for emerging technologies" (herein referred to as "threshold") to national TSOs in a synchronous area. To provide clarity and certainty for the industry and investors in emerging technologies, the Joint micro-CHP (mCHP) Working Group proposes that the NC RfG includes a minimum threshold in Title 6 (see Annex III).

The Working Group draws the attention of the European Commission to the different nature of the risk to the grid from different kinds of fault or "non-compliance" from emerging technologies corresponding to different behavioural groups. Since the effect of different behavioural groups (underfrequency fault[1]: Stirling engine mCHP or overfrequency fault[2]: fuel cell mCHP, Stirling engine mCHP) is non-cumulative, the emerging technology minimum threshold should be set with this in mind. The joint working group is gathering further information in this regard.

The CBA analysis results indicate that amending the NC RfG proposal to include a minimum threshold would lead to important benefits linked to improved investor certainty for emerging technologies, while having a limited cost in terms of grid reliability.

- Technology investors would benefit from the avoided cost of immediately investing in re-design estimated to amount to € 9 - € 11 million for emerging technology Stirling based mCHP. Including a minimum threshold value in the NC RfG would help prevent the particularly destabilising effect of a delay in marketing products. Having a minimum threshold level in the NC RfG would reassure investors, who might otherwise not be ready to take on an expected financial risk equivalent to an additional 2 years on ROI. Moreover, the

[1] These technologies cannot comply with the requirement to stay connected during grid underfrequency conditions, e.g. switching off on frequency < 49.5 Hz

[2] These cannot comply with the requirement to stay connected during grid overfrequency conditions to operate above 50,5 Hz or to perform the droop as required e.g. due to reduced frequency range of operation or due to reduced dynamic capabilities.

Page | 1

consumer will benefit from well-priced, low-carbon and energy efficient space heater technologies that will be present on the market (see Annex I).

- In terms of grid reliability, including a minimum threshold for the emerging technologies will not trigger or exacerbate a grid disturbance (see Annex II). In the event of an underfrequency grid disturbance the loss of power associated with the minimum proposed threshold of 0.1% and hence the associated cost to the grid is equivalent to losing a CCGT power unit in Continental Europe (300 MWel) and a local small biomass power plant in Great Britain (50 MWel).

Brussels, 7 June 2013

Subject: Proposal to amend Article 8(1)c in the NC RfG to allow for a "randomised disconnection" of micro-CHP during overfrequency conditions

Dear Mc Vean,

COGEN Europe and EHI micro-CHP Joint Working Group would like to draw your attention to "randomised disconnection" as an alternative solution to address an existing gap in the NC RfG with respect to the active power reduction requirement which applies to micro-CHP units during over-frequency grid conditions.

As described in the document attached, the present NC RfG draft offers no flexibility with respect to the requirement for individual units to reduce active power within 2s during overfrequency grid conditions. While micro-CHP units, which rely on combustion processes and have inherent delay times related to gas transport, combustion processes and heat transfer, cannot comply with this requirement individually, a "randomised disconnection" of the units as a group would ensure that the needs of the transmission system are fulfilled.

The paper attached shows that the "randomised disconnection" approach has been successfully implemented in Germany as part of the German Application Rule VDE-AR-N 4105:2011 and in the retrofit programme for approximately 10 GW generating capacity from the PV sector (SysStabV). Given the proven benefits of this alternative solution in terms of stability to the grid and improved flexibility to tackle the capabilities of different generating technologies, the COGEN Europe and EHI propose that the NC RfG is amended accordingly (see attached document). The solution can be achieved by a simple compontent calibration during manufacture and represents a very cost effective approach.

COGEN Europe and EHI strongly believe that the "randomised disconnection" approach shall be included in the NC RfG as an alternative solution to meet the requirements of Article 8(1)c on the basis of the evidence provided in the attached document. The Joint working Group is available to offer further clarifications on this issue.

Yours sincerely,

Fiona Riddoch
Managing Director
COGEN Europe

Dana Popp
Public Affairs Manager
Association of the European Heating Industry

Proposal to amend NC RfG Article 8(1)c:

Allowing for "randomized disconnection" of micro-CHP

in Limited Frequency Sensitive Mode - Overfrequency (LFSM-O)

7th of June, 2013

Introduction to the issue

The Network Code RfG draft from 8th of March 2013 requires in article 8(1)c an active power reduction of each generator within a maximum initial delay of 2 s in case of over-frequency conditions. Technologies such as micro-CHP cannot comply with this requirement when considered individually (see Annex I). In contrast with purely power electronic based PV system, micro-CHP rely on combustion processes which do have inherent delay times related to gas transport, combustion processes and heat transfer. Even if the micro CHP is able to reduce power, the reaction time may be too slow in case of major disturbance. Therefore, the COGEN Europe and EHI micro-CHP Joint Working Group proposes the alternative solution of "randomized disconnection" which ensures that micro-CHP units can achieve within its entire installed population a kind of "group-droop" for active power reduction and contributing to grid stability under LFSM-O conditions.

This alternative solution to meet the requirement in the NC RfG Article 8(1)c consists of a randomized disconnection of single mCHP generators within a large population of the same type of appliances instead of performing the droop within the required time on each individual mCHP generator. This function is already implemented in the draft European Standards prEN 50438 and prTS 50549 to be adopted later this year. The same technique is used with positive results in the German Application Rule VDE-AR-N 4105:2011 and in the retrofit programme for about 10 GW generating capacity from the PV sector (SysStabV) which started in July 2012 (see Annex II).

Despite the substantial evidence that this approach has been successful in Germany and the consensus reached at the EU level work on prEN 50438 and prTS 50549 draft standards, ENTSO-E has dismissed the "randomized disconnection" during the stakeholder consultation on the NC RfG without providing sound argumentation for this decision[1]. The COGEN Europe and EHI Joint Working

[1] *"ENTSO-E states that randomized disconnection introduces an additional complexity. In addition it is not considered a long-term future-looking solution. Also Modules are allowed to trip as soon as the minimum operating level is reached." see item 7 in: "ENTSO-E 2nd User Group meeting on "Network Code for Requirements for Grid Connection applicable to all Generators" (NC RfG) 2 May 2012 - 10:30 h – 17:00 h FINAL MINUTES".*

Group believe the contrary. We find strong support in prEN 50438 and prEN 50549 for including the "randomized disconnection" approach into the NC RfG as an alternative for micro-CHP compliance with the active power reduction requirement in Article 8.1.c). Moreover, it is in line with ENTSO-E's Justification Outlines from 26th June[2] which emphasize:

> *"Due to their immediate cross-border impact, frequency requirements need to be harmonised as much as possible. In order to consider appropriately the capabilities of generation technologies some flexibility still has to remain for setting the frequency threshold of activation, the droop and the initial delay of activation."* (ENTSO-E, 26th June 2012, page 4).

Although ENTSO-E did not harmonise the droop setting within synchronous zones as a whole, the flexible approach for fulfilling the needs of the transmission system was not accepted during several user group meetings.

Proposal to modify the NC RfG Article 8(1)c

The COGEN Europe and EHI Joint Working Group propose that Article 8(1)c is amended to take into account the "randomized disconnection" approach already implemented as mentioned above, in order to reach compliance with an amended NC RfG.

Add at the end of the first paragraph and just before Figure 1 the following text of Article 8(1)c:

> *"If the Power Generating Module cannot follow the Active Power Frequency Response as individual generator in the required time, provisions shall be implemented in such Power Generating Modules, that they perform on a larger population of the same Power Generating Modules a randomized disconnection resulting in a "group-droop" so that the cross-border behavior is considered equal to performing a droop as individual generator."*

Justification: This feature is more beneficial to the grid than the current set of requirements concerning LFSM-O. The current version of Article 8(1)c allows to run at Minimum Regulation Level no matter which level of overfrequency has been reached. Generating units with a Minimum Regulating Level equal to nominal power will not react at all to over-frequency.

[2] ENTSO-E, 26th June 2012. *"Network Code for Requirements for Grid Connection Applicable to all Generators. Justification Outlines". Retrived from: http://www.acer.europa.eu/Media/News/Documents/120626%20-%20NC%20RfG%20-%20Justification%20outlines.pdf*

Annex I: Micro-CHP technical specifications in relation to Article 8(1)c requirements

The technologies used for micro-CHP, such as Internal Combustion Engine, Stirling Engine and Fuel Cell, rely on combustion processes which have inherent delay times related to gas transport, combustion processes and heat transfer. They need a certain reaction time which is significant longer than the time required by the NC RfG to respond to the active power reduction due to over-frequency.

Furthermore some micro-CHPs are designed to operate with high efficiency in a single operation mode, so they are not able to reduce active power output based on frequency conditions as an individual appliance.

Annex II: Detailed description of the "randomized disconnection" solution

In Germany, the VDE-AR-N 4105:2011-08 application rule was adopted for generators to be connected and operating in parallel with the public low-voltage distribution network. According to this rule, presented here as a state of the art solution, non-variable power generating systems are permitted to disconnect from the network in the frequency range 50,2 - 51,5 Hz for active power reduction at over-frequency. In that case, a uniform distribution of the disconnection frequency in maximum increments of 0,1 Hz emulates the effects of a droop curve, up to the maximum operating frequency, which may be lower than 51,5 Hz.

The German regulation on system stability (Systemstabilitätsverordnung – SysStabV) was drafted with the help of the four German TSOs and initiated in July 2012 the retrofit of more than 300.000 PV systems. This decree stipulates in article 4(2) a disconnection at randomised thresholds between 50.25 Hz and 51.0 Hz for low voltage units. SystStabV makes clear that the retrofit shall preferably implement a droop controlled power reduction, but allows a randomised disconnection in case of technical restrictions at the generating unit level. This shows that system stability is not endangered if almost 10 GW of distributed generation is disconnected already at 51 Hz and that randomised disconnection is a method to improve system stability in over-frequency situations.

Page | 3

C.2 Bundesverband Kraft Wärme Kopplung

B.KWK · Markgrafenstraße 56 · D-10117 Berlin

An

KEMA Consulting GmbH
Kurt-Schumacher-Str. 8

53113 Bonn

Nachrichtlich:
BMWi – Ref III B 2
BMU – Ref E I 4
BNetzA

Bundesverband Kraft-Wärme-Kopplung e.V.

B.KWK Bundesverband
Kraft-Wärme-Kopplung e.V.

Markgrafenstraße 56
D-10117 Berlin

Tel. +49 (0)30 270 1928 10
Fax +49 (0)30 270 1928 199

www.bkwk.de
info@bkwk.de

Präsident
Dipl.-Kaufm. Berthold Müller-Urlaub

Berlin, den 4.06.2013

Politikfolgenabschätzung zum Network Code "Requirements for Generators"

Sehr geehrte Damen und Herren,

der B.KWK versteht sich als Interessensvertretung, die sich für eine effiziente Energiewandlung mit Kraft-Wärme-Kopplung einsetzt, unabhängig von verwendeten Brennstoffen, Techniken und Anlagengröße. Wir sind die nationale Interessensvertretung für KWK unter dem Dach von COGEN Europe. In diesem Zusammenhang möchten wir zu dem aktuellen Entwurf des Network Codes "Requirements for Generators" Stellung nehmen, dessen Inkraftsetzung in Form eines Komitologieverfahrens in der zweiten Jahreshälfte 2013 starten soll.

Zum einen möchten wir uns den Ausführungen (siehe Anlage) anschließen, die von einer gemeinsamen Arbeitsgruppe zur Mikro-KWK der europäischen Dachverbände COGEN Europe & EHI erstellt wurden. Die ACER-Rahmenrichtlinie FG-2011-E-001 gibt vor, dass der Network Code nur für systemrelevante Netznutzer gelten soll. ("Any grid user not deemed to be a significant grid user shall not fall under the requirements of the network code(s).") Bislang fehlt eine klare Definition im Network Code, anhand derer ersichtlich ist, ob eine Erzeugungsanlage als nicht systemrelevant bzw. als nicht signifikanter Netznutzer einzuordnen ist, für die der Network Code nicht gilt.

Weiterhin ist der Ausschluss von Herstellern im Antragsverfahren um eine Ausnahmegenehmigung (Artikel 52ff) bei kleinen Typ A Anlagen, wenn nicht sogar auch bei mittelgroßen Typ B Anlagen ein Hemmnis für die dezentrale Kraft-Wärme-Kopplung. Es ist zu erwarten, dass die notwendigen Änderungen der Produkteigenschaften im Rahmen der normalen Innovationszyklen der KWK-Anlagen eingepflegt werden. Daher wird in Einzelfällen davon ausgegangen, dass manche Klauseln des Network Codes erst

1

nach der Übergangszeit von drei Jahren in techno-ökonomisch tragbaren Schritten umzusetzen ist. Die KWK-Branche ist überwiegend durch mittelständische Unternehmen geprägt. Sollte ein KWK-Anlagen-Hersteller nicht selber das Recht haben, eine Ausnahmegenehmigung zu beantragen, sondern muss dies der Anlagenbetreiber selber tun, wären seine KWK-Anlagen unverkäuflich. Ohne die Option, dass Hersteller selbst aktiv werden dürfen und mit eigener Motivation den verwaltungstechnischen Aufwand eines Genehmigungsverfahrens stemmen, ist damit zu rechnen, dass der Strauß an Anbietern und Techniken deutlich kleiner wird und die erfolgreiche Entwicklung der Hocheffizienztechnologien aus dem Feld der Kraft-Wärme-Kopplung beeinträchtigt wird.

Von unserer Seite aus ist eine klare Typ-Definition nötig. Gemäß der jetzigen Ausführung müssten etliche Aggregate je nach Bestimmungsland bzw. Synchronzone eine unterschiedliche Zertifizierung aufweisen. Daher schlagen wir eine Differenzierung zwischen Typ A und B entlang der Spannungsgrenze von 1 kV vor, wie es auch in vielen Ländern übliche Praxis ist und im Rahmen der europäischen Normung auch harmonisiert werden soll (TS 50549-1 Niederspannung, TS 50549-2 Mittelspannung). Aus technischer Sicht ist diese Trennung zu begründen, da sich Nieder- und Mittelspannung bei der Schutztechnik, den Schadeffekten von Fehlern und dem Kabelaufbau (4 vs. 3 Leiter) deutlich unterscheiden. Zudem empfiehlt auch die Rahmenrichtlinie von ACER die Orientierung am Spannungsniveau („shall take into account the voltage level at the grid user's connection point", S. 8).

Zum anderen ist neben den von Cogen Europe / EHI erarbeiteten Kritikpunkten auf ein Thema hinzuweisen, das eher größere BHKW und Gasturbinen betrifft. Der Network Code lässt die Forderung nach einem zu durchfahrenden Spannungseinbruch von bis zu 250 ms zu. Dies mag im Einzelfall bei großen und damit trägen Turbosätzen von Dampfkraftwerken möglich sein, für Blockheizkraftwerke am Mittelspannungsnetz sowie Gasturbinen ist diese Anforderung konstruktiv nach bisherigem Stand der Technik nicht erfüllbar. Diese Anlagen haben eine hohe Leistung bei geringer Trägheit (Anlaufzeitkonstanten von bspw. 1 s statt 10 s), d.h. die Synchrongeneratoren beschleunigen schnell und verlieren die dynamische Stabilität, wenn kein Netz die generierte Elektroenergie abnehmen kann. Wir verweisen daher auf den bei der Mittelspannungsrichtlinie gefundenen Konsens, auf MS-Ebene nur 150 ms bis zu einem Einbruch auf 30% der Nennspannung zu fordern. Analog sollten die Anforderungen für Typ B im Network Code gestaltet werden und bei den Typen C & D die 250 ms nur in jenen Synchronzonen zulässig sein, wo diese von den lokalen

B.KWK Bundesverband
Kraft-Wärme-Kopplung e.V.

Markgrafenstraße 56
D-10117 Berlin

Tel. +49 (0)30 270 19 28 10
Fax +49 (0)30 270 19 28 199

www.bkwk.de
info@bkwk.de

Präsident
Dipl.-Kaufm. Berthold Müller-Urlaub

Bundesverband
Kraft-Wärme-Kopplung e.V.

B.KWK Bundesverband
Kraft-Wärme-Kopplung e.V.

Markgrafenstraße 56
D-10117 Berlin

Tel. +49 (0)30 270 192 81 0
Fax +49 (0)30 270 192 81 99

www.bkwk.de
info@bkwk.de

Präsident
Dipl.-Kaufm. Berthold Müller-Urlaub

Übertragungsnetzbetreibern unbedingt benötigt werden. Ansonsten wird es für Hersteller schwer werden, den europäischen Markt gleichmäßig zu bedienen.

Generell ist bei Kundenanlagen mit Eigenverbrauch, bspw. ein industrieller Netznutzer mit Eigenerzeugung, der ausschließliche Bezug der Anforderungen auf den Netzverknüpfungspunkt problematisch zu sehen. Hier ergibt sich nicht nur ein theoretischer Konflikt aus den nicht abgestimmten Regelungen des Network Code RfG und DCC, sondern die praktische Fragestellung, wie die Anforderungen durch die Erzeugungsanlage am Netzverknüpfungspunkt zu erfüllen ist, wenn die Verbrauchercharakteristik der Kundenanlage überwiegt. Für den Fall der Prosumerzelle mit Mischeigenschaften aus Erzeugern und Verbrauchern sind daher Freiräume zu schaffen, um sinnvolle nationale Lösungen zuzulassen.

Abschließend wollen wir noch zwei Dinge im Umfeld des Network Codes ansprechen, die nicht in ihm selbst, aber begleitend geregelt werden müssten. Der Network Code nutzt Anlagenzertifikate als Konformitätsnachweis. Wir gehen davon aus, dass die europäische Kommission auf bestehende Prüf- und Zertifizierungsinfrastrukturen zurückgreifen will und nicht eine Network Code spezifische Zertifikate-Verwaltung aufbauen möchte. Daher nehmen wir an, dass Zertifikate aufbauend auf technischen Normen ausgestellt werden sollen. Es ist noch unklar, wie die Konformität einer solchen Norm mit dem Network Code bestätigt werden wird. Wir möchten hierzu anregen, dass die Kommission auf Basis eines verabschiedeten Network Codes als EU-Verordnung eine mandatierte Norm in Auftrag gibt.

Gez. i.A. Wulf Binde
Geschäftsstellenleiter

C.3 EU Turbines

EUTurbines: Post Meeting Actions after Discussion with KEMA

Brussels, 6th of June 2013

With reference to the meeting between EUTurbines and KEMA DNV about the ENTSO-E NC RfG in April 2013, please find below supplementary information from EUTurbines on three questions that were raised during our discussion:

Question:
Some of ENTSO-E NC RfG requirements will affect generation and will result in derating of some units. What is the impact of derating in terms of efficiency losses and emissions?

Answer:
One may consider a 0.5 pt to 1 pt efficiency loss for a 5% derating on a Combined Cycle Gas Turbine (CCGT).
The impact of this loss of efficiency on emission could be up to 26 tons of CO2 per year per MW installed, based on the assumptions used in the calculation below. Assuming 40 plants of 500MW would be impacted by derating across Europe, this may incur a production penalty of 520.000 tons of CO2 per year.

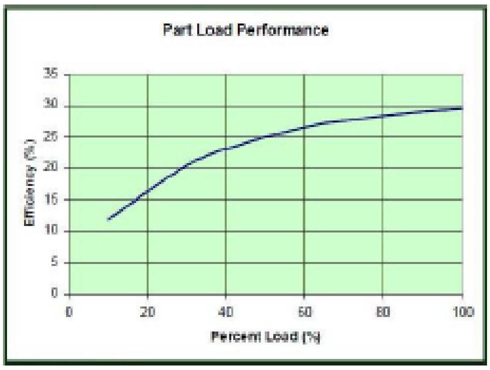


Figure 1 - Typical efficiency versus load of a gas turbine.
Source: EPA - http://www.epa.gov/chp/documents/catalog_chptech_gas_turbines.pdf

EUTurbines
www.euturbines.eu

European Association of Gas and Steam Turbine Manufacturers
President
Dr. Nicolas Vortmeyer
Secretary General
Matthias Zelinger

Lyoner Str. 18
60528 Frankfurt/Main
Germany
Phone +49 69 66 03-[illegible]
Fax +49 69 66 03-[illegible]
matthias.zelinger@vdma.org

Diamant Building
Boulevard A. Reyers 80
1030 Brussels, Belgium
Phone +32 2 706-82 [illegible]
Fax +32 2 706-82 10
[illegible]@euturbines.eu

EUTurbines – Post meeting actions after discussion with KEMA

Justification:

Efficiency: Some public information is available through EPA. For instance the below curve of efficiency versus load of a gas turbines depicts the above statement.

Emission: For the sake of simplicity we assume a 500MW CCGT plant with a perfect combustion of pure methane. For each molecule of CH4 in reactant, a molecule of CO2 will be produced.
A state of the art CCGT of this size consumes around 17kg/s of CH4 (1000 mol/s). This produces around 50kg/s of CO2. Therefore, an approximate 1pt loss of efficiency incurred by 5% derating would cause an extra 0.5 kg/s CO2 production.
Assuming a 7000h/year operation, we end up with 13,000 more tons of CO2 per year per plant of 500MW, only due to efficiency loss because of derating. (26 t/year/MW)

We assume that the mentioned derating (missing 25 MW) should be compensated by other power generation technology (presumably not carbon neutral). If this is a coal plant, firstly the LHV of fuel is lower, and secondly the efficiency is lower (~-15pt). CO2 emission can be doubled for this residual 25MW power to be produced (can increase CO2 emission by ~93,000t/year for this power, on a single plant). Assuming again that 40 plants of this size are impacted, the CO2 emission could be 3,720,000 t/year.

Furthermore, some CCGT plants not only provide electrical output to the grid, but also steam or heat. In this case, the compensation of the missing heat generated by much less efficient means (e.g. boilers…) clearly increases the carbon footprint.

Table A.II.4 | Aggregated results of literature review of LCAs of GHG emissions from electricity generation technologies as displayed in Figure 9.8 (g CO_2eq/kWh).

Values	Bio-power	Solar		Geothermal Energy	Hydropower	Ocean Energy	Wind Energy	Nuclear Energy	Natural Gas	Oil	Coal
		PV	CSP								
Minimum	-633	5	7	6	0	2	2	1	290	510	675
25th percentile	360	29	14	20	3	6	8	8	422	722	877
50th percentile	18	46	22	45	4	8	12	16	469	840	1001
75th percentile	37	80	32	57	7	9	20	45	548	907	1130
Maximum	75	217	89	79	43	23	81	220	930	1170	1689
CCS min	-1368								65		98
CCS max	-594								245		396

Note: CCS = Carbon capture and storage, PV = Photovoltaic, CSP = Concentrating solar power.

Figure 2 - CO2 emission per generation technologies
Source: Intergovernmental Panel On Climate changes - http://srren.ipcc-wg3.de/report/IPCC_SRREN_Annex_II.pdf)

Note: CO2 adder between CCGT and Coal (p50) is 532gCO2/kwh, thus 93.000tons for 25MW/7000h

EUTurbines
www.euturbines.eu

European Association of Gas and Steam Turbine Manufacturers
President
Dr. Nicolas Vortmeyer
Secretary General
Matthias Zelinger

Lyoner Str. 18
60528 Frankfurt/Main
Germany
Phone +49 69 66 03-1 [illegible]
Fax +49 69 66 03-2 [illegible]
matthias.zelinger@vdma.org

Diamant Building
Boulevard A. Reyers 80
1030 Brussels, Belgium
Phone +32 2 706-82 [illegible]
Fax +32 2 706-82 [illegible]
[illegible]@euturbines.eu

EUTurbines – Post meeting actions after discussion with KEMA

<u>Question:</u>
ENTSO-E NC RfG includes onerous Fault Ride Though (FRT) requirements. What is the impact of potential modifications to meet FRT in term of efficiency loss and emissions?

<u>Answer:</u>
Direct efficiency loss of an option (not suitable for all power plants).
In theory, plant inertia can be increased in some specific cases using flywheel system.
A non-synchronous flywheel has a typical total efficiency of 95% and in general it can be considered that the overall loss of efficiency can be higher than 2.5% for plant. The CO2 will proportionally increase of by 2.5% for the related plant.
Please note that the above values do not take into consideration the huge initial investment (flywheels are not an inexpensive technology). Moreover the available flywheels are limited today in terms of maximum power, often making this option not even possible for a specific plant configuration, operating condition and grid characteristics.

Indirect efficiency loss:
In addition to the above mentioned issues, any future technical solution will require consistent modification of the generating unit.
The associated indirect loss can be barely estimated; it can be expected to result at least in a decrease in the overall efficiency of the system of 1% due to

- Additional passive losses due to increased installed components
  (Friction losses, additional ventilation, less efficient interfaces, etc)
- Additional manufacturing activities
- Cost of transportation

Cost:
FRT can lead to major damage on the generating unit and grid black-out of an affected area as a worst case scenario.
The related cost of such scenarios considers:

- Cost to repair the generating unit (gearbox, generator, other components)
- Cost of energy not produced due to related downtime
  (Downtime can be reduced with spare present at site, with increasing of related financial)
- Cost impact to the industrial process if the generating unit is connected (production of heat by using boiler instead of high-efficiency CHP plant).

The cost to repair the generating unit is related to units itself and depends on technology, components, size, etc. The cost of the energy not produced again is a factor depending on the connection agreement.
The cost impact on the industrial process has been estimated based on information collected during major black-out events in the past. For instance the August 2003 black-out in North-America has been estimated as a 6 billion USD loss according to the U.S. Department of Energy.(See: http://www.elcon.org/Documents/EconomicImpactsOfAugust2003Blackout.pdf).
Cost related to design modifications (if possible) and lead time to have them as a reliable technology are very difficult to be estimated and therefore are not considered in this answer.

EUTurbines
www.euturbines.eu

European Association of Gas and Steam Turbine Manufacturers
President
Dr. Nicolas Vortmeyer
Secretary General
Matthias Zelinger

Lyoner Str. 18
60528 Frankfurt/Main
Germany
Phone +49 69 66 03-[illegible]
Fax +49 69 66 03-[illegible]
matthias.zelinger@vdma.org

Diamant Building
Boulevard A. Reyers 80
1030 Brussels, Belgium
Phone +32 2 706-82 [illegible]
Fax +32 2 706-82 10
florian.bergen@euturbines.eu

EUTurbines – Post meeting actions after discussion with KEMA

Question:
ENTSO-E NC RfG bears concerns for industrial (CHP) customers. What are they in terms of efficiency loss and or other issue (reliability, operational constrains...)?

Answer:
EUTurbines members have provided an explanation on adverse impacts along with the 23rd of April meeting (impact on industrial production, loss of efficiency, and risk on plant reliability...). EUTurbines members have also discussed with some industrial companies, being our end customers.

Enclosed is a letter from one of our customers (INDAVER). Contact details of KEMA have been passed to other companies and they will hopefully provide more details upon impacts. In the case KEMA does not receive any response soon on those points; EUTurbines will be pleased to follow up on those companies.

EUTurbines
www.euturbines.eu

European Association of Gas and Steam Turbine Manufacturers
President
Dr. Nicolas Vortmeyer
Secretary General
Matthias Zelinger

Lyoner Str. 18
60528 Frankfurt/Main
Germany
Phone +49 69 66 03-[illegible] 43
Fax +49 69 66 03-2[illegible] 43
matthias.zelinger@vdma.org

Diamant Building
Boulevard A. Reyers 80
1030 Brussels, Belgium
Phone +32 2 706-82 11
Fax +32 2 706-82 10
[illegible]@euturbines.eu

Mr. Horst Peters

MAN Diesel & Turbo SE
Division Process Industry
Instruments & Controls IWDI-HBG
Engineering MARC Steam Turbines
Hermann-Blohm-Strasse 5
20457 Hamburg/Germany

your message of	your reference	our reference	date
		IND-MEATH-ELE-LET-001	2013-05-29

contact person
S. Coppens

Dear Mr. Peters,

Herewith some feedback information on the frequency response as provided by the turbine generator in the Meath Waste-to-Energy plant since November 2012:

- Frequency response to under-frequencies is limited, as the boiler is always running at "100%", without substantial buffer capacity. The "100%" output is variable as it corresponds with the actual waste throughput at that moment (variable calorific value).
- Frequency response to over-frequencies is effectively taking place, by partial opening of the steam by-pass valve. The destruction of this by-pass steam due to over-frequency amounts to 2.19% (8.42 MWhe losses over a total of 384 MWhe). This was trended and measured over a 24 h period.
- On a yearly basis, the loss of steam due to over-frequencies is therefore 11064 GJ/year, which corresponds to an increase of CO_2 emissions of 1903 tonnes/year.

Best regards,

Steven Coppens

Lead engineer Electricity & Instrumentation
Indaver nv
Dijle 17a
BE-2800 Mechelen
tel +32 15 28 80 77 - fax +32 15 28 80 69 - gsm +32 474 979 939
steven.coppens@indaver.be
http://www.indaver.be
http://www.indaver.com

ENTSO-E Network Code Requirements for Generators (final, 8/3/2013), Art. 8,1 e):
Technical explanation for the comments made by EU Turbines and the related suggested amendment

1. Current requirement of Art. 8, 1 e):

e) The Relevant TSO shall define while respecting the provisions of Article 4(3) admissible Active Power reduction from maximum output with falling Frequency within the boundaries, given by the full lines in Figure 2:

- Below 49 Hz falling by a reduction rate of 2 % of the Maximum Capacity at 50 Hz per 1 Hz Frequency drop;
- Below 49.5 Hz by a reduction rate of 10 % of the Maximum Capacity at 50 Hz per 1 Hz Frequency drop.

Applicability of this reduction is limited to a selection of affected generation technologies and may be subject to further conditions defined by the Relevant TSO while respecting the provisions of Article 4(3).

A graphical representation and a comparison with some current national requirements is given in Fig. 1:

These requirements shall ensure that under extremely disturbed grid conditions, with a lack of generation exceeding the design conditions for normal frequency response, the situation is not getting worse due to a further output reduction of the generation facilities connected to the grid and operated at full output. It is at the same time common understanding that the prevailing objective in such case is to remain connected to the grid in order to stabilize it by inertia, as well as by active and reactive ouput.

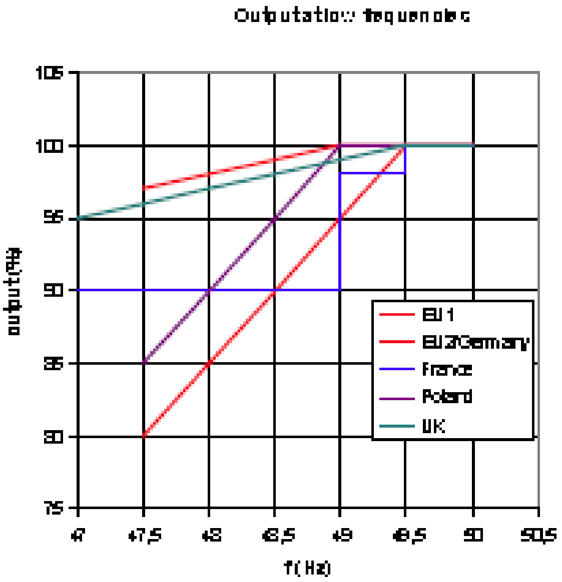


Figure 1: Requirement

It has to be noted that in UK the current requirement is limited to an ambient temperature of 25 °C and for CCGT modules to a time duration of 5 min in case frequency is below 48,8 Hz.

There exist furthermore some dynamic short term requirements (e.g. Germany, Austria and Hungary) to keep the plant on nominal output even if the frequency falls to 49 Hz (resp. 48 Hz in Austria) for a limited time (approx. 30 s).

SIEMENS Energy
E F ES EN PTEC PE3, Tomschi
Rev. 1, 2013/04/15

This requirement therefore applies

- if a generating unit is operated at its current maximum output (which is depending on ambient conditions) without intrinsical output headroom
- under extremely disturbed conditions with a large drop of frequency when the system is not far from a total black out.

2. Physical behaviour of a gas turbine at low frequencies

In contrast to e.g. a coal fired power plant, where steam generation is independent of the frequency (the small effect in the steam turbine at lower frequencies is negligible), a gas turbine shows a reduced air mass flow as a direct and immediate consequence of the decreasing grid frequency and hence the turbine rotational speed.
In addition, in order to have stable combustion conditions and not to risk any combustion disturbance with a consequent trip, the turbine outlet temperature is kept constant, adapting the fuel mass flow to the reduced air mass flow.
Both effects lead to a nearly immediate output reduction of the turbine in parallel to the frequency drop.
This behavoir is highly nonlinear, and also strongly depends on the ambient conditions. If two parameters (in this case ambient temperature and frequency) deviate largely from design conditions, the effect is overlayed.

The following figure shows a typical behaviour of a utility size gas turbine (detail values depend on the individual machine), without any addtional compensation features and without consideration of the Combined Cycle effect which reduces the output drop by approx. one third due to the virtually constant output of the steam turbine.

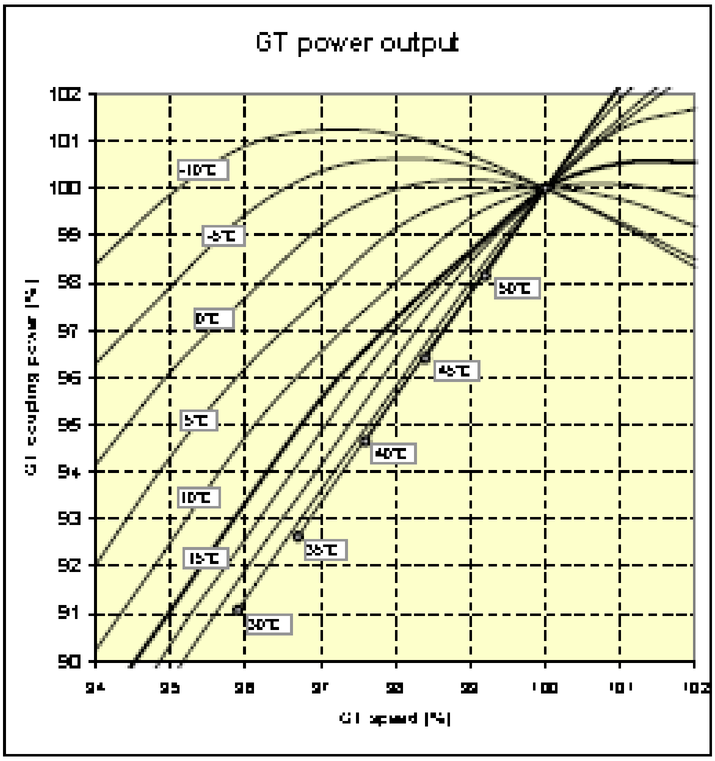


Figure 2: Gas Turbine behaviour

SIEMENS Energy
E F ES EN PTEC PE3, Tomschi
Rev. 1, 2013/04/15

Additionally to the compressor thermodynamics, operation of the compressor is limited by the protection scheme against compressor pumping, which has to be avoided in any case and therefore limits the underfrequency operation at very high ambient temperatures.

3. Handling of the requirement in the past

The most stringest requirement in Europe to be applied to GT based plants so far can be found in UK (CC 6.3.3. of the Grid Code). It is only there where also specific tests are defined which shall demonstrate compliance with the requirement.
It is obvious that such tests can not take place under real conditions, because the real grid frequency can not be reduced as required and also the real reduction of base load output of the plant can not be seen. The test therefore just allows to show the possible activation of countermeasures, triggered by a suitable signal (e.g. simulated frequency decrease), and possibly the effect of some output increase.

CCGTs installed in UK during the past years had to comply with this requirement and therefore the manufacturers have been developing technical measures to compensate the physical output drop.
Despite the fact that manufacturers have been mentioning this issue in other countries several times for specific projects, there has been and still is no clear statement and definition under which conditions compliance has to be ensured and how it should be demonstrated.

Only in the last very few years the focus of the TSOs has been shifting more towards disturbed conditions, but in our perception only in countries with a significant fraction of GT based generation this is being seen as a relevant topic.

The principles of technical countermeasures range from increasing the flame temperature (i.e. increasing the enthalpy difference available in the turbine), to increasing the mass flow by further opening the inlet guide vanes (higher air mass flow with consequent increase of fuel gas) or injecting steam or water to the compressor (combined effect of total mass flow increase and cooling). Often one measure is not sufficient and a suitable combination has to be foreseen.

4. Concerns about the current NC RfG requirement

Activation time

Neither in the UK Grid Code nor in other national regulations in Europe (except the additional more stringent dynamic requirement as mentioned in Chapter 2), nor in the NC RfG, there is a definition within which time frame such possible countermeasures have to be activated and have to reach the required compensation level.
In the view of network stability, it can be expected that the activation should take place within very few seconds, in particular in case of fast frequency drops. However, for some countermeasures (in particular temperature increase, activation of water or steam injection through specific additional systems) reaching the required output level and at the same time ensuring stable operation takes more than several seconds and therefore will be too late for the desired effect. Countermeasures with a very short or negligible activation time are currently not available.

Ambient temperature limitation

The current limitation in UK to 25°C ambient temperature is beneficial regarding the capability of compliance for the turbine (see Chapter 2). However no rationale can be seen why the grid is not needing the capability above 25°C with the same strictness at it is below 25°C. In the NC RfG

SIEMENS Energy
E F ES EN PTEC PE3, Tomschi
Rev. 1, 2013/04/15

there is no such limitation, which is reasonable from grid stability point of view, but it makes compliance much more difficult.

Reliability of countermeasures, risk of trip

As mentioned, many of the additional measures are being installed only for the purpose of compliance with the requirement and are not used under normal operation. Additionally, as also already mentioned, the test of the system is done only once and not under realistic conditions.
Therefore manufacturers can not absolutely ensure the correct function and effectivity in case of a real frequency drop.
Even more, such extremely disturbed frequency conditions are not easy to be handled and controlled by a complex system like a gas turbine even without additional measures. Therefore there is a not negligible risk of causing a trip of the machine by activation of such system exactly in that moment when all efforts should focus on keeping generation reliably connected to the grid.

Unfortunately there is absolutely no statistical data available about reliability during such incidents (they are extremely rare), but with the knowledge about the sensitivity of gas turbine combustion systems regarding disturbances we see quite a probability to cause a trip, being then possibly the reason for the final black out of the system.

Cost of compliance with requirement on generation side

The existing additional systems and measures to compensate the output drop (but with the above mentioned limitations!) require additional hardware with a certain investment volume.
Any further development in this area will be still only an additional measure to compensate a physical behaviour of a very valuable grid component with the same principle restrictions as mentioned above.
As a theoretical alternative, GT based power plants might be obliged to limit their output all the time in normal operation to a value far below their current maximum output in order to have a reliable headroom for compliance with the requirement for a hypothetical situation which possible never occurs. It is obvious that the cost of this theoretical option, considering the necessary flexiblity end efficiency of CCGTs, can not be acceptable by no side.

5. Suggested amendment of the NC RfG

In order to maintain the system safely in operation under disturbed frequency conditions, we recommend to consider an alternative approach:
The major objective of remain connected to the grid should prevail for power plants. The expected behaviour of specific power plants is known and can be disclosed and considered for network simulations. The summarized output drop of the connected plants will cause the frequency to drop with a predictable rate, which is more accurate in case the real behaviour of the plants is incorporated. This can be taken into account in measures on network side, e.g. for implementation into demand disconnection schemes.

Therefore we recommend to amend the requirement in Art 8, 1 e) as follows:

With regard to underfrequency maximum power capability reduction for some generation technologies, some synchronous generation technologies inherently deliver falling mechanical power with falling frequency. For grid stability reasons, being the main objective under such conditions, the generating unit rather should stay connected than bearing the risk of a total trip due to the necessary fast activation of power compensation measures. The generating unit owner provides data to the relevant TSO about the expected output behaviour with frequency and other relevant parameters (e.g. ambient temperature).
Acceptance of this reduction is limited to a selection of affected generation technologies decided by the Relevant TSO pursuant to Article 4(3).

SIEMENS Energy
E F ES EN PTEC PE3, Tomschi
Rev. 1, 2013/04/15

COST-BENEFIT ANALYSIS OF INTRODUCTION OF LOW VOLTAGE FAULT RIDE THROUGH CAPABILITIES FOR GENERATORS

1. SUMMARY

This document presents a possible structure of a Cost-Benefit Analysis (CBA) related to implementation of Low Voltage Fault Ride Through (LVFRT) capabilities as described in the RfG (Requirement for Generators) issued by ENTSO-E.

LVFRT will be firstly analyzed as a possible countermeasure against undesired system events, such as massive disconnection of network users in case of large voltage dips, and its real effectiveness will be discussed.

Secondly, an ex-post analysis, based on data made available by Italian NRA's project assessing Power Quality, will be exposed. It will investigate past events which have been systematically recorded in order to detect possible evidence of voltage dips causing disconnection of large amounts of generation sufficient to endanger the whole interconnected system. The Power Quality measurements will be clustered in order to give evidence whether voltage dips caused by events on EHV, UHV or HV grids, have or not produced similar effects in different network areas.

Finally, an impact evaluation and a cost comparison will be performed with other possible interventions (for instance on transmission network) alternative to introduction of LVFRT capabilities for generators in the two extreme scenarios:

– massive retrofitting of all MV- and LV-connected generators;
– introduction of requirements only for new plants > 1 MW.

2. WHY IS LVFRT ASKED

LVFRT can be defined as the capability of a network user to remain connected during a voltage dip of given characteristics.

Regarding voltage dips and the events that give rise to them, a clear distinction must be made between:

a) Short circuit (single phase, two- or three-phase) on EHV, UHV or HV network;
b) Polyphase fault on MV Distribution networks (in case of solid earthed neutral point operation, also single phase faults).

a) Short circuit (single phase, two- or three-phase) on HV Transmission network

In case of a short-circuit on a transmission line, voltage may drop dramatically at the default point before protection systems trip. This voltage dip affects also all networks at lower operational voltage (distribution ones) connected to the transmission system. Precise effects (residual voltage value, involved geographical area, etc), anyway, depend on the kind of fault[1], on the short-circuit power in the faulty point and, finally, on HV/MV transformers' group. Structure and operations of distribution network (radial, meshed, etc) may also influence the

[1] However, being mostly solid earthed operated, a single phase fault on transmission system is not so different from a three phase one.

overall effect on the voltage. Anyway, to perform this evaluation we consider the worst situation, i.e. a 3-phase fault on transmission system and a radial operated MV distribution network.

In the surroundings of the default point, the voltage also falls to values lower than the nominal one within a span that varies according to the "strength" of the network (how much the transmission network is meshed and interconnected): as a matter of fact, the highest is the short-circuit power in the point of the network in which the event occurs, the smaller is the "electrical" extension of the voltage dip. Correspondence between "electric" extension and "geographical" one depends on the physical structure of both transmission and distribution networks on the ground; anyway this has no importance with reference to the present evaluation.

By comparing LVFRT curve and Interface Protection Relay minimum voltage settings with the voltage dip (residual voltage as a function of "electric" extension) it is possible to calculate the maximum amount of DG (in terms of generated active power) who would disconnect and to compare this to the maximum tolerable generation loss for the transmission system near the fault location.

To be conservative, it would be preferable to sum the power of all generating units on distribution networks, avoiding to take into account the random intrinsic nature of RER (i.e., in the case of a fault during night, LVFRT capability of PV inverters would be of no use).

TBN: in the above described evaluation three simultaneous "worst" condition have been assumed.

To avoid that a very large voltage dip may give rise to a disconnection of generation so huge that may eventually endanger the whole interconnected EU-system, in the RfG it is asked that the new generation units of type B, C and D, according to RfG classification, may withstand voltage dips according to a voltage-against-time profile at the connection point. Type A generating units are excluded from this requirement.

This provision deserves some additional considerations.

First of all, in case of a voltage dip due to a short circuit, both generation and load disconnect; therefore avoiding disconnection of generation units only do not necessarily increase system stability, the opposite could also result. LVFRT is an immunity requirement, but in order to result in an increase of the stability of the system, if needed, it should be extended to passive load as well, as nowadays all appliances' and apparatus' immunity characteristics must be considered strictly coincident with voltage operation range (0,9 p.u. ÷ 1,1 p.u.).

Secondly, existing generation units, even large ones, do not generally provide this capability, as well as most of existing generating units connected to distribution networks.

As for synchronous generators of large units, the impossibility to fulfill LVFRT curve it's not necessarily related to the generator itself, but mostly to the prime mover.

In fact, generators must be able to withstand a short circuit at their clamps, as well as transformers, and can therefore eventually surpass a voltage dip; obviously, the control system has to be designed in such a way to allow the "hardware" to continue operating.

But prime movers may not be able to do the same. In case of a short circuit, therefore a voltage dip, first a synchronous generator is subject to the back swing, immediately after to the accelerating torque. The effect is that the turbine damage or the disconnection through the break joints happens within 40-60 ms, which is a time in which existing circuit breakers are not able to perform fault clearing.

The specific behavior depends on type of turbines. A hydro turbine or an alternative engine may be able to, but a gas turbine, especially if derivative from aircraft technologies (most common situation on distribution networks, sometimes also in HV network up to some MW or few tens MW) cannot generally withstand a deep voltage dip (maximum torque is about 4 times nominal one for aeronautic derivative gas turbines, 25 times or more for expressly designed generation gas turbines).

This seems to contradict the fact that some synchronous HV-connected existing plants result in being compliant with these requirements. However, testing of LVFRT cannot be done in real operation (a real 3-phase short circuit would be necessary), while in laboratory the upper limit, with expensive apparatus, may be around 1 MW or a little higher.

Asynchronous generators, from their side, are not able at all to have LVFRT, unless they are equipped with proper power electronics.

Finally, generating units of any rated power connected through an electronic interface (AC/AC converter, DC/AC converter, etc) could be able to be compliant with a LVFRT curve, it depends only whether the requirement was or not integrated in the design and settings of the inverter.

So, if this requirements was absolutely needed for the security of the system, it would imply a massive retrofitting activity besides the application to all new generators to be effective; in case not, the conventional generation and the static generation not retrofitted or not required to have LVFRT capability of any size, which could be disconnected in case of a voltage dip, would largely exceed the total amount of new static generators from type B to D included.

b) *Polyphase fault on MV Distribution networks (in case of solid earthed neutral point operation, also single phase faults)*

If such an event happens, the amount of DG which can be disconnected is undoubtedly negligible compared to the threshold of critical events on HV network and cannot put system stability at any risk.

As LVFRT requirement is of no interest for DSOs as well (it can also be dangerous, due to the fact that increases possibilities of asynchronous reclosing operations), there's no reason at all to ask for it.

Resuming:

- LVFRT can be needed only for faults at HV level;
- the extension of a voltage dip, i.e. the fact that he is able to affect a significant part of the network, strictly depends on the network conditions themselves, and in particular on its configuration and its components' characteristics;
- most of existing generators are not able at all to be compliant with this requirement, with the consequence that, in the last ten years, a massive GUs' disconnection may and might have happened already, to a much higher extent than the critical threshold for the transmission system security. To ask for LVFRT only for new generators would increase the immunity to voltage dips of the global generation park in a negligible manner.

Massive disconnections of generation units, if any, are inevitably linked to specific areas and possible countermeasures cannot be extended to the whole system. To say it differently: **even if effects (massive disconnections) should eventually be cross-border, if their causes (network weaknesses) are local, it makes no sense to impose cross-border remedies.**

LVFRT, in addition, **depends on the features of both transmission and distribution networks** in a **certain area, besides features of generators in the area itself. To state a general curve would result in asking for the worst possible situation present in EU, which could be present in a very limited area and could also be solved by acting on the particular area with a different approach.**

Under this respect, the provision of the Code that this requirement is not exhaustive and needs being specified at a national level by the TSO is still unsatisfactory; the applicability of the requirement itself should be technically and economically justified at national or even regional level.

This is even truer when we reflect on the fact that this specific criticality strongly depends on insufficient transmission network development and the most obvious way to solve it is local network reinforcement and/or increase of interconnection: as imposing this requirement on all generators can be seen as a way to transferring TSOs' costs on other Operators, it is of paramount importance that its consistency is made crystal clear.

3. ANALYSIS OF PAST VOLTAGE DIPS OCCURRED IN ITALIAN ELECTRIC SYSTEM

Since 2007, Italian RA "Autorità per l'energia elettrica e il gas" has decided to start a Power Quality monitoring program.

The monitoring equipment has been installed in about 20% of existing HV/MV substations, monitoring more than 10% of individual MV busbars (namely: 360) and data have been collected by RSE, an Italian Research association belonging to "Gestore dei Servizi Energetici" (GSE).

To perform this (sample) analysis it has been decided to use the voltage dips data (date, time, voltage value) which have been measured at MV busbars.

The period examined dates from February to May 2012. In this time period the monitored busbars were 275.

Data have been sorted and ordered according to their date and time; then they have been grouped, assuming that voltage dips occurring at approximately the same time have been caused by the same event. In order to consider – again – the worst possible condition, the time lag between two events for being labeled as one has been assumed twice as long than defined by Italian NRA while dealing with Power Quality issues.

The MV busbar in which the lowest voltage value was recorded has been assumed as the "center" of the event; then the span of the event has been determined as the geographical distance between the center and the furthest busbar in which the event was significantly measured.

The events involving less than 4 MV busbars have been neglected.

The severe events, representing those in which more than 8 MV busbars have been involved, have been examined in detail.

Events have been divided into four geographical clusters (North-West, North-East, Center, South) and for each one of the clusters the following indicators have been calculated:

– Number of elementary voltage dips;
– Number of severe events;
– Number of busbars with voltage < 90% in the most severe event;
– Number of busbars with voltage < 80% in the most severe event.

Data are summarized in Table 1.

	NW	NE	CE	SO	**TOT**
Number of individual events (> 4 MV busbars)	17	16	120	81	**234**
Number of severe events (> 8 MV busbars)	4	1	30	20	**55**
Number of busbars v% < 90% in most severe event	19	11	26	19	
Number of busbars v% < 80% in most severe event	9	5	6	12	

Table 1: Relevant data about voltage dips in Italy (February-May 2012)

First of all, it can be easily seen that the distribution of events is unbalanced as virtually most of them fall into the clusters defined as "Center" and "South". This seems to indicate that, while the transmission network structure in Northern Italy is robust enough to avoid propagation of voltage dips, the peninsular part of the grid needs structural reinforcement in order to perform at the same level.

Secondly, the numbers of busbars involved even by most severe event is quite small (<10% of the sample at its maximum), and the number of busbars in which the voltage fell below 80% is even smaller (around 4%). According to those data, it is quite likely that LV-connected generators didn't even experience the voltage dip, and also MV-connected generators

4. <u>IMPACT OF VOLTAGE DIPS ON DISTRIBUTION-CONNECTED GENERATION</u>

Currently, the power connected to MV+LV grid in Italy is about 19 GW; in detail, 14 GW are connected to MV grid and 5 GW to LV grid.

If we assume that:

- generators are connected uniformly through Italian territory
- all generators are producing at full power during the dip
- all MV-connected generators are affected by voltage dips in case of v% < 90%
- all LV-connected generators are affected by voltage dips in case v% < 80%

we can imagine, under this –again – very pessimistic hypotheses, the worst case ever can affect a MV- and LV-connected generation of about 1,5 GW. This amount should be compared with the critical threshold for system security, keeping in mind that being voltage dips – even wide ones - a local phenomenon, it is unlikely that they occur at the same time in many different parts of the interconnected system.

As for newly-connected generation, it has been assumed that in the 2013-2022 period 6,7 GW will be connected in MV and 7,7 GW will be connected in LV; **different results can be obtained simply changing this assumption and modifying the results accordingly**.

As Type B generators are defined as > 1 MW, under this hypothesis we can reasonably assume that Type B generators which will be connected during the 2013-2022 period account for 4 GW.

Under the same hypothesis listed above, the worst case ever (in 2022) can affect a new MV-connected generation of less than 400 MW (< 10% of newly-connected generation); if we assume an homogeneous growth in the same period, the yearly contribution to system security of the requirement will be of avoiding an "incremental" disconnection of 40 MW, which is absolutely negligible compared to the existing situation which until now has not been described as endangering the whole system.

Furthermore, it can be expected that in ten years appropriate network reinforcements in the transmission network will have been put in place; in case not, either voltage dips are not significant in endangering the whole interconnected system or they will have an effect notwithstanding the provisions of RfG.

As for TN-connected and HV-connected generation, it must be said it didn't change significantly in these last years, it never had requirements about LVFRT and in the past no evidence of conventional power plants endangering the whole system in case of voltage dips has been provided.

5. <u>COST-BENEFIT ANALYSIS</u>

Having defined the maximum amount of generation that could eventually disconnect in case of a severe event, possible countermeasures can be investigated.

The small amount of MV- and LV-connected generators which are likely to be affected and the fact that, in the time frame which has been examined, significant events have been concentrated in a few geographical areas, makes it clear that possible problems are related to the inherent weaknesses of the transmission network and not to the generation itself.

It can be therefore expected that solutions implying massive retrofit of generation plants should be much more expensive than network reinforcements; on the opposite, differential costs of using

LVFRT-capable inverters only in new plants should be much more sustainable but its effect should be negligible.

To perform a cost comparison between alternatives, the following elements have been assumed:

- all the MV- an LV- generators are connected through inverters;
- all prime movers do not need retrofitting;
- retrofitting consists only of changing the inverter;
- fulfilling RfG requirements for a new plant requires simply buying an upgraded inverter;
- cost of a new inverter is 20€cent/VA for the component and 5 €cent/VA for the installation;
- differential cost for a LVFRT-capable inverter is 2 €cent/VA.

The cost of an integral retrofitting of MV- and LV-connected generation is, under these <u>very optimistic</u> assumptions:

$$25 \times 19 \times 10^9 / 100 = 4{,}75 \text{ Billion Euros}$$

This expense at its best will avoid the disconnection of the expected 1,5 GW which in addition, according to considerations of chapter 2, is very likely not to bring any significant improvement on system security issues.

An alternative solution could imply network reinforcement in the Central and Southern Italy Regions. Assuming all reinforcements are obtained through underground 380 kV lines and 380 kV substations (the most expensive ones), the same amount of money will allow the construction of **about 1.200 km of HHV cable lines and 170 HHV/HV substations**.

These figures make it clear that it is likely that the investment needed to properly reinforce the network are much smaller than these ones. Furthermore, the two solutions are not at all equivalent, as the certainty and the degree of control of the TSO are much bigger in case of network reinforcement.

The cost of installing LVFRT-capable inverters on Type B new generation plants only, under the same <u>very optimistic</u> assumptions, is:

$$2 \times 4 \times 10^9 / 100 = 80 \text{ Million Euros}$$

The rate of expense is much lower and therefore sustainable: as it is diluted through the 2013-2022 decade, we can assume it accounts for **8 M€ per year**, but will have virtually no impact on the security of the system (at least in Italy) for a very long time, as the amount of the power currently under installation is much smaller than in the last years.

In these conditions, it is of the utmost evidence that LVFRT requirement, for new Type B plants only, would have definitely not a cross-border impact in Italy and cannot be justified for being in the Code.

The amount of money - no matter how small - related to the widespread diffusion of LVFRT capabilities in inverters would be better invested in network reinforcement, focused in the areas in which transmission network appears already to be inadequate in terms of short circuit power.

6. CONCLUSIONS

The analysis performed shows that LVFRT for MV- and LV-connected generators makes in principle little sense and, according to past events, may bring negligible benefits, at least in Italy, while implying somehow huge, and always unnecessary, costs.

The analysis also shows that the disconnection of generators in case of a voltage dip mostly depends on specific transmission network weaknesses and cannot therefore give rise to EU-wide prescriptions.

In any case, transmission network reinforcement can be still considered the preferred alternative for solving transmission network problems.

It is therefore suggested to exclude this requirement from the Code.

C.4 EWEA

EWEA
THE EUROPEAN WIND ENERGY ASSOCIATION

28 May 2013

Robert McVean
Senior Consultant
KEMA Consulting GBH

During our bilateral meeting on 24/ April /2013 it was requested to EWEA to provide additional support information of its proposed amendments to the NC RfG[1] [2]. The aim of this note is to provide such information specifically on the EWEA proposal on reactive power requirements (Arts. 16 & 17) of the NC RfG.

EWEA has proposed a distinction between reactive power capability requirements for Type C and D on the basis that current provisions impose a significant increase of such capabilities without considering differences in voltage level and consequently violating the ACER Framework Guidelines[3] and that would require installation of additional reactive power compensation equipment, such as STATCOMS and/or increased dimensioning of electrical equipment in the wind farms.

The additional investment is mainly driven due to the fast response time requested (Article 16, 3d, 2) that needs additional reactive power compensation equipment. This will lead to considerable investment costs without a prospect of cost recovery, having a negative effect on the economic feasibility of wind energy projects. For example, based on current prices[4] and assuming additional (fast) 3-4 MVAr needed for a typical 10 MW wind energy project, this would imply additional costs of approximately 400-500 k€ for such project size.

In addition to the need for reactive power compensation equipment the current rating of the entire electrical subsystem would need to be enhanced to cope with the large voltage ranges in which the reactive power compensation has to be provided. In fact, a proper solution involves a complete redesign of the entire electrical system of wind turbines, including major parts like transformer, cables, switchgear and converter. The related costs are not only due to the new hardware but also to significant R&D efforts and other aspects like certification. Furthermore, the major burden of these

---

[1] Position Paper EWEA EPIA November 2012 http://www.ewea.org/fileadmin/files/library/publications/position-papers/EWEA_EPIA_NC_RfG_concerns_and_alternative_formulations.pdf

[2] Explanatory note EWEA February 2013: Further explanations on the EWEA-EPIA alternative formulations on the ENTSO-NC RfG, 7/02/2013

[3] "The minimum standards and requirements shall be defined for each type of significant grid user and shall take into account the voltage level at the grid user's connection point" – ACER Framework Guideline on grid connection, page 8

[4] System Service Provision: An independent view on the likely costs incurred by potential System Service Providers in delivering additional and enhanced System Services. DNV-KEMA 2013

Rue d'Arlon 80 | T:+32 2 213 1811
1040 Brussels | F:+32 2 213 1890
Belgium | E: ewea@ewea.org
THE EUROPEAN WIND ENERGY ASSOCIATION asbl/vzw
www.ewea.org

costs will be borne by low and medium voltage connected projects, raising serious commercial concerns and competition issues.

As an example, and noting that a more in depth analysis would be needed, for a typical 10 MW wind energy project (type B PPM connected to MV level) the NC RfG requirement for reactive power capability would lead to additional *investment* costs in the order of 5%[5]. To this picture one must add the additional *variable* costs over a 20 year period for electrical losses, inspection and maintenance and repair costs.

These costs are of particular concern for manufacturers, developers, operators and investors given the lack of documentation for the real need for or physical possibility to utilise excessive amounts of reactive power (e.g. due to voltage profiles in distribution grids). In this sense, neither technical nor economic documentation for these requirements has been provided by ENTSO-E. Consequently, large amounts of reactive power capacity will be installed on locations where there is no technical need, notably in distribution grids.

To this end, EWEA proposed amendments aim to strike a balanced allocation of capabilities between generators, distribution and transmission in view of the lack of transparent and public documentation that justifies the need for such increased reactive power across the entire network and without a proper way for cost recovery.

Hence, EWEA has called for an in-depth cost/benefit analysis prior to decide which player (grid or generator) should provide these reactive power performances. A proper comparative evaluation should compare the solutions of implementing the required reactive power capabilities (a) centrally at network level (b) decentralised at individually connected PPMS.

Furthermore, when assessing costs at PPM level, there are factors that highly depend on each individual PPM situation. Hence, EWEA recommends in any cost evaluation of the consequences of the NC RfG should include site and project specific characteristics such as:

- Voltage level of the line;
- Distance from PPM to the Connection Point;
- Distance how far the reactive power has to be moved (for evaluation of Q losses);
- Impedance of the transformer ;
- Voltage operational ranges for the reactive power provision (depending on local requirements);
- Steady state reactive power capability of the wind turbine (to be specified as function of operating active power at rated voltage), which depends, amongst others, on wind turbine technology (for example WECC wind turbine type).

EWEA believes that such assessment is absolutely necessary before imposing excessive requirements that will clearly affect negatively the market growth of wind power and will cause serious damage the wind energy sector.

EWEA believes that this note provides the further information needed by KEMA to facilitate its assessment and is committed to support this process.

[5] Assuming 1000 €/kW installed capacity and not including the upgrading/redesign of the electrical installation of the PPM as described above.

EWEA and EPIA main concerns and proposals for solutions

ENTSO-E Network Code for Requirements for Grid Connection applicable to all Generators

January 2013

1. Introduction to principal concerns of EWEA and EPIA with the NC RfG

The European wind industry represented by EWEA has together with EPIA assessed the ENTSO-E Network Code for Requirements for Grid Connection applicable to all Generators (NC RfG) and the ACER reasoned opinion and has prepared this joint association paper as constructive input in view of the currently on-going revision process of the NC RfG.

This document summarises significant technical concerns that EWEA and EPIA want to highlight concerning the NC RfG published in June 2012, and subsequently amended in light of the ACER reasoned opinion published on 13 October 2012. These concerns are:

- FRT requirements: "Fast reactive current injection" and "Post fault active power recovery"
- Voltage/reactive power ranges for capability requirements for MV connected PPM.

The first item on FRT requirements is directly linked to the deficit in the NC identified by ACER in its reasoned opinion (missing justification in particular of the FRT specifications for type B units).

EWEA and EPIA reject the present concept of FRT specification in the NC RfG that includes inadequate requirements for fast reactive current injection and post-fault active power recovery.

The second item of concern on voltage and reactive power ranges is related in a broader way to the concern of ACER regarding deviations from present practices and leading to unjustified cost increases. We believe that if the ENTSO-E NC RfG is not amended on these items, it will hinder rather than facilitate security of supply and further wind power integration in the European network for the following reasons:

- Trade of wind power technology will be hampered because in some markets grid code requirements will go beyond state-of-the-art technology. Locally imposed minimum values in requirements may put certain manufacturers and their sub-suppliers at risk, because they can only be fulfilled by certain types of conversion systems due to physical restrictions of different technologies.

- The above mentioned requirements are estimated to result in additional investments in wind power generation technology of more than €1.5 billion by 2020. The technical and economic justification for these requirements is entirely absent; hence the resulting overall increased cost of power generation is totally unnecessary.

Thus, overall, the implementation of the NC RfG as it stands now forms a major economic threat for the renewable energy industry, and will most likely seriously affect the achievement of the European Renewable Energy targets by 2020. Moreover, as a secondary effect, National

2

Regulatory Authorities will have to cope with a multitude of derogation applications which may take years to solve and are likely to result in numerous legal challenges at national level.

The two mentioned issues (FRT and reactive capability for MV) are of huge concern for the wind and solar PV industries as they have a direct and severe impact on many key design aspects of the respective technologies. The current proposal in the NC RfG – both what is specified and not specified – is unacceptable to both industries.

In order to facilitate the on-going review process, EWEA and EPIA have proposed solutions in part 2 and part 3 of this paper, for the above mentioned key technical concerns on the subsequent pages.

2. FRT Requirements for Type B PPM

With respect of the FRT requirements for Type B PPMs, EWEA and EPIA have two major points of concern, namely:

- Specification of fast reactive current injection during FRT
- Active power recovery after the fault

In the following section, the concerns are explained, and proposed solutions are provided for the related paragraphs in Article 15.

Reactive Current Injection during FRT - Article 15.2.b)2)

In the process of drafting the June version of the NC text, the formulation of Article 15, 2b,2 was introduced by ENTSO-E at the very last minute, without transparent and sufficient interaction with the wind industry. Instead, ENTSO-E stated it had contacted some manufacturers, and proposes this interaction as principal justification for the formulation. We quote the e-mail from ENTSO-E to EWEA (30th of July 2012):

….ENTSO-E has checked its sources among leading wind turbine manufacturers which has confirmed that the change between the consulted version of a single requirement with narrow tolerance (40ms with 5% tolerance) to a split requirement including a fast component (at least 2/3rds in a TSO specified time, not faster than 10ms) along with a slower requirement with wider tolerance (60ms with 10% tolerance) makes good sense in terms of:

- *System needs: Deliver a component of fast current contribution for secure clearance of transmission system faults during high RES production when synchronous generators, normally relied upon, are displaced.*
- *Capability of wind turbine technologies (particularly the power converters): Less tight tolerances on the requirements. Note that the 10 ms is a lower limit ("shall not be less than 10 milliseconds") taking into account inherent differences in technologies.*

3

EWEA strongly contests that there has been a proper and sufficient interaction with the wind industry on this particular point and strongly objects to this narrow approach by ENTSO-E in assessing technology capabilities. The wind and solar PV industry cannot accept that an arbitrary requirement which is not underpinned by any calculation is imposed all over the EU through European law. Instead, this requirement appears to be introduced in the NC perhaps from a regionally biased perspective supported by informal contacts with a single wind turbine manufacturer.

EWEA and EPIA therefore propose the following solution for amending Article 15.2.b)2), page 40, which closely follows the formulation in the NC RfG.

Text of NC RfG (version 6/06/2012)

The Power Park Module [...] shall be capable of providing

at least ~~2/3~~ 90% of the additional reactive Current [positive sequence of the fundamental]

within a time period specified by the Relevant TSO, which shall

not be less than ~~10~~ 60 milliseconds.

The target value of this additional reactive Current [...] shall be reached

with an accuracy of ~~10%~~ -10%/+20% [of Irated]

within ~~60~~ 100 milliseconds

from the moment the Voltage deviation has occurred as further specified [...].

Below 40 % retained voltage reactive current shall be supplied as far as technically feasible.

A FEW ADDITIONAL COMMENTS HAVE TO BE MADE:

The 10 ms requirement introduced by ENTSO-E is unprecedented and beyond any current or typical best industry practice (state-of the art). The rise time aspect is only one of approximately 10-15 aspects needed for a full FRT specification. It is not acceptable for the wind and solar industry that such a crucial design impacting requirement can be introduced only at the last minute on a non-existing foundation or without an opportunity for discussion. No justification has been made publicly available, on the contrary:

- The arguments, assumptions and methodologies used to assess the supposed need for the 10 ms requirement are unknown to the industry because documentation is absent and/or inaccessible. According to ENTSO-E statements no calculations have been performed to justify the need;

4

- Potential non-intended technical disadvantages of implementing the requirement are unknown e.g. the risk of high TOV voltages (50 Hz temporary overvoltages);
- The supposed need currently seems to be related to only one national system but the NC will apply to all of Europe,
- Many TSO´s seem to disagree that there is a need for this requirement in this moment;
- The potential existence of technical alternatives is unknown and so are the associated cost comparison for these alternatives;
- There is no general consensus in the industry (manufacturers, TSO´s etc.) regarding the need or how it is to be specified properly.

The actual requirement in the German Grid Codes in relation to this rise time aspect specifies 30 ms plus a further 20 ms for detection, i.e. 50 ms in total. Apart from the fact that this 50 ms value is not directly comparable to the 10 ms specified by ENTSO-E because of differences in detailed definitions, it should be remarked that the values in the German Grid Code are debatable and lacking properly documented calculations of the need.

In general, it bears a huge risk for the manufacturers when one parameter is moved excessively but the full specification can not be seen at the same time. This applies to the current NC RfG – but it becomes even more challenging during later national implementation where TSO´s may start to combine many different sets of parameter values in an uncontrolled way. This will create a huge uncertainty and risk for all stakeholders involved in grid integration and compliance.

Beside the rise time value, the accuracy requirement in the NC RfG is excessive. The most demanding requirement in present grid codes would be the German one which requires -10%/+20% accuracy. The accuracy should be in relation to the rated current (not the target value). Contrarily to ENTSO-E statements, the accuracy during the fault does not have an impact on possible post-fault overvoltages.

The requirement for current injection for retained voltages below 10% should be excluded from the FRT requirements in Art 15, 2b, 2, and the requirement should be relaxed to a level of 40%. Problems may arise with phase angle detection during very low voltages. Moreover, the impact of reactive current contribution on the grid voltage for a retained voltage below 10% is negligible.

Active power recovery (Article 15,3)

EWEA and EPIA have significant concerns about the vague formulation of the requirement, mainly because it will cause the actual specifications for active power recovery behaviour to be determined in a scattered way all over Europe by local grid operators. This will most likely lead to discrimination against certain generator types and will cause a lot of consultation work for each national TSO. Therefore it would be very helpful if the NC RfG provides clear guidance. Requirements as to the wind turbine behaviour during active power recovery may have a significant effect on the wind turbine mechanical loads – and therefore affect its structural design. For example, careless choice of recovery time parameters may negatively interfere with wind turbine drive train dynamics and result in excessive wind turbine drive train loads. As a consequence, non-uniform grid code requirements throughout the EU will lead to different design requirements and hence to obstacles in the free movement of RES technologies.

5

Text of NC RfG (version 26/06/2012) and amended text proposal:

Type B Power Park Modules shall fulfil the following requirements referring to robustness of Power Generating Modules:

a) With regard to post fault Active Power recovery after fault-ride-through, the Relevant TSO shall specify while respecting the provisions of Article 4(3) ~~magnitude and time for Active Power recovery the Power Park Module shall be capable of providing.~~ a maximum recovery time for the Active Power to reach at least the level of 90 % of the pre-fault power, measured from the time the local voltage has recovered above 90 % of the pre-fault nominal voltage value. The maximum recovery time shall be specified to a value chosen within the range of 0.5 seconds and 10 seconds for faults that are cleared within 140 ms ($t_{clear} \leq 140$ ms) and within a range of 1 second and 10 seconds for faults that are cleared in a longer time than 140 ms (140 ms > $t_{clear} \leq 250$ ms).

3. Reactive power capability requirements for MV connected PPM Type C and Type D (Articles 16 and 17)

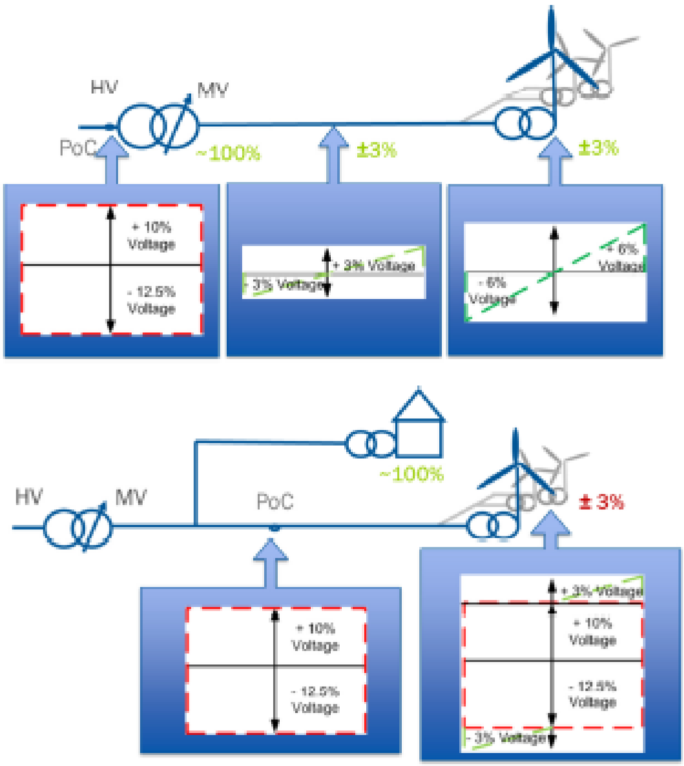
A major concern of EWEA and EPIA with respect to voltage and reactive power requirements is related specifically to the voltage range for reactive power capability requirement for Type C and Type D wind farms connected to MV, as specified in the NC RfG Article 16 and 17.

The NC RfG does not account for the difference in steady state voltage fluctuations between HV and MV voltage level when specifying the reactive capability requirements. In the case of plant connected below 100 kV (medium voltage) the stated reactive power over voltage range results in onerous requirements which cannot be met by even state-of-the-art wind turbines. In the absence of a proper justification for the presence of this reactive capability at MV level, Europe-wide implementation of this requirement will result in a huge amount of unnecessary investments and increased costs of power generation.

Moreover, the requirements in Articles 16 and 17 for MV connected plant conflict with the ACER reasoned opinion (page 8): " [...] *However, the case is less clear for voltage related issues occurring at lower voltages in the distribution networks. In particular because: a) the impact is less likely to be propagated directly up to transmission level/cross border, unless many small power generating modules of the same type are affected by the regional voltage profile significantly, and b) economic and efficient actions to correct voltage related issues are likely to vary significantly between distribution system operator areas, reflecting differences in topology, local generation and demand, and approaches to network management. Given this, justification should be provided for mandating particular solutions with relation to voltage imposed directly on grid users, versus the alternative approach of mandating voltage related requirements at the transmission/distribution boundary.*"

The following explains why these requirements are excessive:

Figure 8 of Article 16 specifies that reactive capability shall be present over a voltage range from +10 to -12.5%. In high voltage grids, a tap changer reduces the large voltage fluctuations. However, for medium voltage connected plant there is no such voltage range reduction. As a consequence, requiring the same voltage operating range for reactive power capability for PPM in medium voltage networks will result in effectively wider voltage ranges than the equipment would be designed for, and thus will lead to increased investment costs for the PPM. Because there is no technical necessity for such a requirement, there will be hardly any use for this extended capability. If this NC requirement is universally applied in Europe, a large amount of investment in reactive capability will become stranded.



In this context, one should bear in mind the wording from the ACER framework guideline: "*The minimum standards and requirements shall be defined for each type of significant grid user and shall take into account the voltage level at the grid user's connection point.*" The requirements in Article 16 in the NC RfG do not fully take into account the possible situations with respect to voltage level of the grid users, and thus do not respect the FGL. The requirements will in many cases negatively affect the business case of Type C and D wind plants connected at MV level.

Amended text proposal:

During the public consultation of the draft NC in March 2012, EWEA has proposed to ENTSO-E an amendment of the NC to take the above considerations into account. The proposal was not accepted, and no sufficient justification has been provided by ENTSO-E for its rejection. The proposal of March 2012 is therefore re-introduced here.

The proposed changes concern:

- Reactive power capability at maximum capacity: paragraph Article 16.3 b)2), to add the graph Figure 8bis and table 9bis, and to modify the text of the paragraph to include proper references to this figure and table.
- Reactive power capability below maximum capacity: paragraph Article 16.3 c)2, to add Figure 9bis, and to modify the text of the paragraph to include proper reference to the figure.

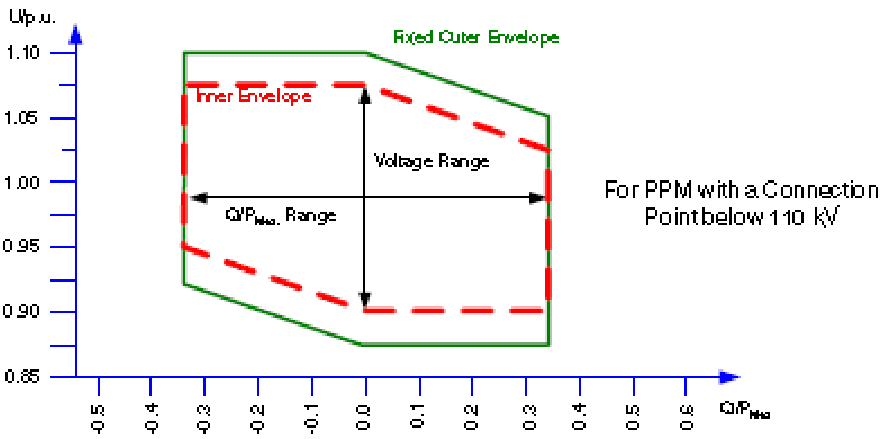


Figure 8 bis U-Q/PMax-profile for Power Park Modules with a Connection Point below 110 kV by the Voltage at Connection Point, expressed by the ratio of its actual voltage value U and its nominal value of U in per unit, against the ratio of the Reactive Power capability (Q) and the Maximum Capacity (PMax) of a Power Park Module.

Synchronous Area	Maximum range of Q/P_{max}	Maximum range of steady state voltage level in PU
Continental Europe	0.66	0.175
Nordic	0.66	0.150
Great Britain	0.66	0.100
Ireland	0.66	0. 175
Baltic States	0.66	0. 175

Table 9bis: Parameters for the inner envelope in figure 8bis for PPM with a Connection Point below 110 kV

Figure 9bis - P-Q/Pmax-profile of a Power Park Module with a Connection Point below 110 kV. The diagram represents a P-Q/Pmax-profile by the Active Power, expressed by the ratio of its actual value and the Maximum Capacity in per unit, against the ratio of the Reactive Power capability (Q) and the Maximum Capacity (Pmax) of a PPM.

For further information please contact: Paul Wilczek, EWEA: pwi@ewea.org

---

EPIA - the European Photovoltaic Industry Association – is the voice of the photovoltaic industry in the world's largest PV market, with Members active along the whole solar PV value chain: from silicon, cells and module production to systems development and PV electricity generation as well as marketing and sales. EPIA's mission is to give its global membership a distinct and effective voice in the European market, especially in the EU.

The European Wind Energy Association (EWEA) is the voice of the wind industry, actively promoting the utilisation of wind power in Europe and worldwide. Over 700 members from nearly 60 countries, including manufacturers, developers, research institutes, associations, electricity providers, finance organisations and consultants, make EWEA the world's largest wind energy network.

9

C.5 EUR

Network Code on Requirements for Grid Connection applicable to all Generators

EUR's opinion on necessity, feasibility, cost impact and alternative approaches of key requirements for nuclear generators.

April 12th, 2013

Working Group members:
Jonas Persson – Vattenfall (chair)
Hervé Meljac – EDF (interim chair)
Jaakko Tuomisto – TVO
Helge Regber – E.ON
Reinhard Kaisinger – Vattenfall
Lasse Linnamaa – Fortum

DG Energy has appointed DNV KEMA to assist the European Commission in the assessment of the draft ENTSO-E Network Code on Requirements for Grid Connection applicable to all Generators (NC RfG). As part of its mandate, the consultant shall provide advice on the specifications and rules proposed in NC RfG covering the fields of:

- Necessity of the rules and specifications;
- Technical feasibility;
- Costs and benefits;
- Alternative approaches.

The EUR was identified as an informal group representative of nuclear generators involved in the consultation with ENTSO-E during the development of the draft NC RfG. EUR fully supports the initiative and has accepted DNV KEMA's invitation to provide the consultant with input on outstanding issues which specifically affect nuclear generators. The purpose of this memorandum is to highlight the main concerns nuclear generators have with the current drafted requirements in NC RfG. It covers both existing and new build nuclear power plants. The structure of the document is meant to match the fields cited above, namely:

- Necessity;
- Feasibility;
- Cost impact;
- Alternative approaches.

TABLE OF CONTENTS

2 / 30

REFERENCES

[1] ENTSO-E – Network Code for Requirements for Grid Connection Applicable to all Generators – 8 March 2013

[2] ENTSO-E – Network Code for Requirements for Grid Connection Applicable to all Generators – Justification Outlines – 26 June 2012

[3] ENTSO-E – Network Code for Requirements for Grid Connection Applicable to all Generators – Requirements in the Context of Present Practices – 26 June 2012

[4] ENTSO-E – Draft Network Code on Load-Frequency Control and Reserves – 17 January 2013

[5] ENTSO-E – Network Code on Operational Security – 27 February 2013

[6] ENTSO-E – Statistical Yearbook 2011

[7] Opinion of the ACER No. 08/2012 of 13 October 2012 on ENTSO-E's Network Code for Requirements for Grid Connection Applicable to all Generators

[8] Treaty Establishing the European Community – EC Treaty

[9] European Utilities Requirements – Revision D

[10] European Nuclear Society website: www.euronuclear.org

[11] Arrêté du 23 avril 2008 relatif aux prescriptions techniques de conception et de fonctionnement pour le raccordement au réseau public de transport d'électricité d'une installation de production d'énergie électrique (applicable French law on requirements for generators)

[12] CIGRÉ WG 12.05, "An International Survey on Failures in Large Transformers in Service". Electra 88, 1983, page 21.

[13] IEC 60034-3 – Rotating electrical machines – Part 3: Specific requirements for cylindrical rotor synchronous machines

[14] IEC 60076-3 – Power transformers – Part 3: Insulation levels, dielectric test and external clearances in air

[15] IEC 60071-1– Insulation co-ordination – Part 1 : Definitions, principles and rules

[16] Letter from WENRA to ACER, dated October 4, 2012, provided in the Appendix

3 / 30

DEFINITIONS

Abbreviation	Definition
ACER	Agency for the Cooperation of Energy Regulators
CBA	Cost Benefit Analysis
CE	Continental Europe synchronous area
CIGRÉ	Conseil International des Grands Réseaux Électriques
ENTSO-E	European Network of Transmission System Operators for Electricity
EUR	European Utilities Requirements
FCR	Frequency Containment Reserve
FRT	Fault Ride-Through
FSM	Frequency Sensitive Mode
HPP	Hydro Power Plant
IEC	International Electrical Commission
ITT	Intention To Tender
LFC	Load-frequency control
LFSM-O	Limited Frequency Sensitive Mode – Overfrequency
LFSM-U	Limited Frequency Sensitive Mode – Underfrequency
LWR	Light Water Reactor
NC LFC&R	Network Code on Load-Frequency Control and Reserves
NC OS	Network Code on Operational Security
NC RfG	Network Code for Requirements for Grid Connection Applicable to all Generators
NPP	Nuclear Power Plant
NRA	National Regulatory Authority
NSSS	Nuclear Steam Supply System
OLTC	On-Load Tap Changer
PWR	Pressurized Water Reactor
RES	Renewable Energy Source
TbD	To be Defined
TSO	Transmission System Operator
WENRA	Western European Nuclear Regulators Association

1. INTRODUCTION

1.1. The EUR

The European Utilities Requirements organisation (EUR) was created in 1991. It involves all major European utilities which operate nuclear power stations. The purpose and main objective of the EUR is to harmonize and stabilize the conditions in which the standardised Light Water Reactor (LWR) nuclear power plants to be built in Europe in the first decades of the XXI[st] century will be designed and developed. This is expected to improve nuclear safety, nuclear energy competitiveness and public acceptance in an electricity market unified at European level.

Since it was released in 2001, the Revision C of the EUR specifications has been extensively used in the development of new LWR designs and projects, in particular in the EPR design with two units under construction in Olkiluoto and Flamanville. Revision D has been released in October 2012. It reflects the will of EUR organization to continuously match the best nuclear practice and adapt to the changing power system environment.

1.2. Nuclear power plants in Europe

In 2011, on the grids operated by Transmission System Operators (TSO) members of ENTSO-E, nuclear powers plants have accounted for:

- 885 586 GWh net generation – 26.5% of 3 347 445 GWh total[1];
- 126 447 MW net installed capacity – 13.6% of 928 311 MW total[2].

Currently, on the zone covered by ENTSO-E, 136 nuclear generators are in operation in 15 different countries[3].

1.3. Cost impact figures

The ACER noted in its reasoned opinion on NC RfG that stakeholders have not provided quantitative data on the cost impact of the requirements during public consultation[4], thus making ENTSO-E's assessment task more difficult.

However, under European Regulation (article 81 of EC Treaty [8]), utilities are not allowed to share such data within organisations like EUR as it could create competition distortion or be assimilated to prohibited concerted practices. Therefore, this memorandum does not include any such figures, but it explains the main cost-driving factors.

The EUR recommends the consultant to rely on individual utilities to get precise cost figures. However, the EUR notes that most requirements are left to each individual TSO to define precisely under Article 4(3), and are therefore not know yet. Therefore it is difficult for utilities to provide accurate cost figures at this stage.

---

[1] Source ENTSO-E – Statistical Yearbook 2011 [6]
[2] Source ENTSO-E – Statistical Yearbook 2011 [6]
[3] Source European Nuclear Society [10]
[4] Source ACER – Opinion of the ACER No. 08/2012 of 13 October 2012 on ENTSO-E's NC RfG – Page 3/10 [7]

1.4. Impacts on existing nuclear power plants and new build

According to the definitions of NC RfG, all existing nuclear power plants (NPP) in Europe are significant type D power generating modules (maximum capacity above 75MW)[5]. In this memorandum we make the assumption that all future nuclear power plants will be in the same category.

Therefore, the requirements of NC RfG applicable to type D synchronous generators will apply to new build NPPs, according to Article 3(1).

Although the application of NC RfG requirements to existing NPPs can only be required under strictly controlled conditions and if properly backed up by a sound Cost Benefit Analysis (CBA)[6], this memorandum explains the impacts on existing NPPs if NC RfG should apply to them. It also shows how NC RfG impacts existing NPPs through grid operation, regardless of the application of Article 3(2).

1.5. Safety aspects

The power grid is the most reliable source for auxiliary coolant and safety systems in NPPs. Coolant and safety systems come with very stringent capacity requirements, and are highly sensitive to deviations in both voltage and frequency. Therefore, the safe operation of NPPs is highly dependent on good power quality in terms of voltage and frequency. From an EUR's point of view, the NC allows degraded power quality which will lead to difficulties when it comes to the safe operation of NPPs and to complications with Nuclear Safety Authorities.

In order to stress this issue, the Western European Nuclear Regulators Association[7] (WENRA) informed ACER about incompatible requirements between the NC and established safety regulation in a letter dated on October 4, 2012 [16] (also provided in the Appendix). In this letter, the importance of the power grid for safe operation of NPPs is highlighted, as also illustrated by the accidents in Fukushima and Forsmark. Additionally, in the letter it is emphasized that the ranges for frequency and voltage are too large; this in turn is going to jeopardize safe operation of NPPs. The value of 48 Hz is accentuated as a limit for safe operation of NPPs.

From a technical point of view, but at significant costs and with long lead times, coolant and safety systems could be supplied with power by diesel generators or power converters. However, such additional components in safety systems are going to increase the risk of failure, which cannot be accepted by Nuclear Safety Authorities and society. In particular the software component in power converters imposes a risk that is difficult to accept in the vicinity of sensitive equipment. EUR believes that directly driven pumps are more reliable than pumps driven by power converters. It is expected that Nuclear Safety Authorities are not going to permit the use of power converters in conjunction with sensitive equipment such as coolant and safety systems in NPPs.

In the letter to ACER referred to above [16], it is proposed to add the following paragraph to the Article 3 (6) in the ENTSO-E NC: "For nuclear power plants, nuclear safety considerations are prioritized in the case of a conflict between nuclear safety considerations and the Network Code". This proposal is hereby supported by EUR.

[5] NC RfG – Article 3(6) [1]
[6] NC RfG – Article 3(2) [1]
[7] WENRA is a network of Chief Regulators of EU countries with nuclear power plants and Switzerland as well as of other interested European countries which have been granted observer status. http://www.wenra.org/

1.6. Business case for NPPs

Existing NPPs would require costly back fitting, such as OLTCs, in order to cope with the requirements imposed by the NC. Such investments jeopardize the business case of NPPs and may not be worth the effort due to expected remaining lifetime. As a result, NPPs may be shut down at a premature state, thereby putting safe power supply in Europe at risk.

In order to decrease costs for design and development of new NPPs, certain standards and norms, such as the EUR document, have been derived. Standardization and harmonization of requirements on new NPPs over large geographical areas leads to reduced investment costs and risks for both vendors and utilities.

In addition, ENTSO-E's requirements on both frequency and voltage ranges jeopardize such standardisation, and forces vendors to undergo a costly and time consuming re-design process. These ranges imply an upgrade of, in particular, the rotor in order to cope with increased magnetic flux during periods with low frequency and high voltage. Requirements on frequency response impose changes on the thermal design of plants with extended transient budget.

Characterized by long lifespan, high investment costs but low operational costs, NPPs supply power for decades at low costs for consumers. Low power prices are, in a region with limited natural resources such as Europe, a prerequisite for a competitive economy in an ever more globalized world. Therefore, safety aspects of NPPs should not be disregarded by the NC, eliminating NPPs as a major source of electrical energy.

2. EVOLUTION OF THE REQUIREMENTS IN TIME – APPLICABILITY TO EXISTING PLANTS

2.1. Grid Code modifications

The EUR is concerned by the fact that NC RfG is unclear about the applicability to power plants which will have been built using NC RfG requirements of:

- Future NC RfG modifications;
- Future modifications to the locally defined requirements (under Article 4(3)).

NPPs are built to operate on very long periods (typically 60 years for most Generation III designs), and are by nature, because of the safety and regulatory context of nuclear industry, difficult to modify after design is decided.

It should be made clear that retroactivity of future changes to the code should be governed the way retroactivity to existing plants is controlled in Article 3(2).

Moreover, NC RfG should provide guaranties that any cost incurred to generators required to fulfil new requirements under application of Article 3(2) can be recovered. EUR proposes that the Generator Owner recovers its costs from the requesting TSO, which in turns recovers the cost according to the provisions of Article 5. Such cost recovery mechanism is essential for Generator Owners or project developers to secure their business case over the lifetime of the plant.

2.2. Plant modernization or use of spare parts

The EUR is concerned by the requirement described in Article 10(6)(g):

- It basically forces type C and D generators to be progressively adapted to any change in NC RfG requirements or in requirements defined under Article 4(3), because replacement and modernization of equipments occur on a normal basis throughout the life of a plant. On that perspective this requirement is disproportionate, and not in line with the philosophy of Article 3(2) which governs the applicability of NC RfG to existing plants.
- It is practically very difficult to implement since the fulfilment of a given requirement usually depends on many different equipments, if not on the plant as a whole.

However, the EUR recognizes that it is fair to require from a power plant that its performances relative to its interaction with the grid be kept at least unchanged, if not improved, over its lifetime regardless of any equipment replacement or modernization which can take place.

When the use of spare parts is involved to mitigate unplanned contingencies, generator owners should have the right to request a Limited Operational Notification under Article 32. This is because spare parts (e.g. transformers) are often shared between different plants, and are therefore not always fully compliant with all requirements of all plants they can be used on.

The EUR suggests removing Article 10(6)(g) and replacing it with an article applicable to all generator types:

"Power Generating Modules should be compliant with all requirements which are applicable to them throughout their lifetime. When the use of spare parts is involved Power Generating Facility Owners can request a Limited Operation Notification while respecting the provisions of Article 32"

3. REQUIREMENTS ANALYSIS

3.1. Frequency ranges

3.1.1. Requirement description

Required operating frequency ranges are described in Article 8(1)(a) as such:

Frequency Range (Hz)	CE	Nordic	Great Britain	Ireland	Baltic
47 – 47.5	-	-	20 s	-	-
47.5 – 48.5	TbD, >30 min	30 min	90 min	90 min	TbD, >30 min
48.5 – 49	TbD, >30 min	TbD, >30 min	TbD, >90 min	TbD, >90 min	TbD, >30 min
49 – 51	Unlimited	Unlimited	Unlimited	Unlimited	Unlimited
51 – 51.5	30 min	30 min	90 min	90 min	TbD, >30 min
51.5 – 52	-	-	15 min	-	-

Table 1: NC RfG operating frequency ranges

3.1.2. Necessity of the requirement

The EUR notes that this requirement if far too onerous compared to the frequency quality objectives described in the draft NC LFC&R [4] which has been published for public consultation, which are[8]:

	CE	Nordic	Great Britain	Ireland	Baltic
Nominal Frequency	50 Hz	50 Hz	50 Hz	50 Hz	50 Hz
Standard Frequency Range	±50 mHz	±100 mHz	±200 mHz	±200 mHz	±50 mHz
Max. Instantaneous Frequency Deviation	800 mHz	800 mHz[9]	800 mHz	1000 mHz	800 mHz
Max. Steady-State Frequency Deviation	200 mHz	500 mHz	500 mHz	500 mHz	200 mHz
Time to Restore Frequency	15 minutes	15 minutes	10 minutes	20 minutes	15 minutes

Table 2 : NC LFC&R frequency quality objectives

For the avoidance of doubt, in Continental Europe[10] NC RfG requires generators to be able to operate continuously within the range [49 Hz ; 51 Hz], while:

- There should never be any excursion outside the range [49.2 Hz ; 50.8 Hz];
- There should never be in steady-state outside the range [49.8 Hz ; 50.2 Hz];
- In any case frequency should be back in the range [49.95 Hz ; 50.05 Hz] within 15 minutes;

It basically means that what generators should be able to withstand continuously is:

- Worse than the worst possible transient conditions;
- 5 times (weaker systems) to 20 times (stronger systems) as degraded as the worst standard conditions.

For the limited duration resilience to large frequency deviations requirement, while the EUR is broadly in line with the NC RfG minimal requirement (30 minutes), NC RfG should mention the expected frequency of occurrence of such deviations: being able to withstand very large frequency transients might be acceptable occasionally, but certainly not frequently. For instance, NPPs have a "transient budget" which is calculated in the design phase. Too frequent frequency deviations can deplete the transient budget long before the expected lifetime of the plant, therefore causing a premature shutdown.

Moreover, frequency operating ranges should be defined as a function of voltage, to take into account the physics of generators and motors in terms of magnetic flux, and match industry practice[11].

As a justification to the proposed continuous operation frequency range, ENTSO-E claims that the requirement is in line with IEC 60034 [13][12]. The EUR highlights that this alone is not a sufficient justification, since a power plant, especially a NPP, is not simply a collection of rotating electrical machines

[8] Extracted from Table 1 of NC LFC&R [4]
[9] Note that the EUR contests this value which should be ±1000 mHz to reflect current practice
[10] The same analysis is applicable to other synchronous areas
[11] In NC RfG – Requirements in the context of present practices – page 7 [3], ENTSO-E gives IEC 60034 norm as an example, which formulates requirements in a U/f chart.
[12] In NC RfG – Requirements in the Context of Present Practices – Chapter 2.1 [3]

connected to the grid. On an electrical point of view, it is a system involving many different types of equipments (not only rotating machines) with complex interactions. All rotating machines of a NPP might be individually IEC 60034 compliant, and yet the NPP as a whole might not be able to operate continuously on [49 Hz ; 51 Hz].

The EUR reckons ENTSO-E has set very onerous requirements compared to frequency quality objectives in order to anticipate a future degradation of frequency quality, based on:

- NC RfG Justification Outlines [2] which mention:
    - as one justification for the requirement "Inherent inertia of the electricity supply system will decrease due to less synchronous generators connected in future, consequently larger sudden frequency deviations occur in case of load imbalances."[13].
    - as an alternative solution "Limitations on penetration of (RES) generation without inherent inertia, however this will jeopardize achieving EU energy policy targets." [14].
- Article 9(4) of the Draft NC LFC&R [4] which allows TSOs to change the frequency quality parameters taking into account different factors, including system inertia (presumably decreasing, according to previous point);

Therefore, while ENTSO-E anticipates a degradation of the grid frequency quality and clearly designates the lack of inertia of RES generation as the root cause of the problem[15], it imposes all grid users, especially generators in NC RfG to withstand degraded grid conditions and implement mitigation measures (especially new requirements on frequency response, which are discussed in a further chapter of this memorandum).

The EUR points out that current frequency quality could be maintained in the long run without jeopardizing RES development if non-synchronous generators were required to implement synthetic inertia. This would allow aligning the frequency operating ranges requirement on currently observed frequency quality, thus making the requirement less onerous. ENTSO-E fully recognizes the existence of this solution in NC RfG Justification Outlines [2] (Page 47, relative to NC RfG Article 16(2)(a) on synthetic inertia capability). The EUR regrets the level of implementation of this idea in NC RfG (Article 16(2)(a)) is not prescriptive.

3.1.3. Feasibility and cost

3.1.3.1. New Build NPP

In theory it is possible for a NPP to comply with the NC RfG requirements on frequency operating ranges, provided that frequency of occurrence of time limited frequency deviations is clearly defined. However, the NC RfG requirement does not match current NPP industry practice for new build. In particular, EUR Volume 2 Chapter 3 [9] requires:

[13] In NC RfG – Justification Outlines – Page 2 [2]
[14] In NC RfG – Justification Outlines – Page 2 [2]
[15] There are different mentions of RES-induced frequency quality issues in NC RfG Justification Outlines [2], pages 2, 3, 4, 6, 7, 8, 9, etc.

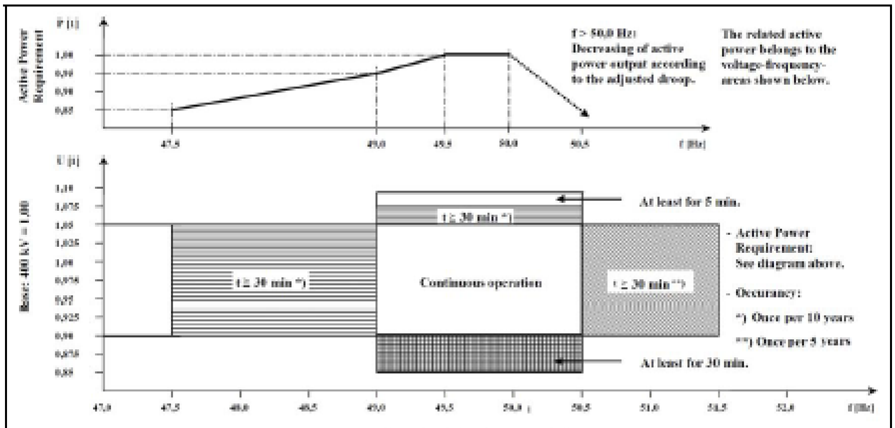


Figure 1: Voltage frequency field

The EUR requirement initially included [49.5 Hz ; 51.5 Hz] as continuous operation range (up to revision B). At that time the EUR was mainly focused on Continental Europe. The requirement was extended in Revision C (2001) to reflect the needs of smaller power systems like the Nordic system.

Therefore, adopting the RfG as it is would drive costs of new build NPPs in terms of:

- Review of designs which are based on EUR requirements – Vendors who have adapted their design to be EUR compliant (e.g. Mitsubishi have specially developed the EU-APWR, EUR compliant variant of their basic design) would recover their extra design costs on future owners. Some vendors might also prefer not to bid in ITTs, which would limit competition and therefore drive costs.
- Equipments which would be impacted by more onerous requirements, including but not limited to pressure vessel, fuel assemblies, reactor coolant pumps, auxiliary systems, core monitoring systems.

3.1.3.2. Existing NPPs

Most, if not all existing NPPs were designed to operate on frequency ranges less onerous than NC RfG requirements. In particular, most NPPs design assumptions include continuous operation in the range [49.5 Hz ; 50.5 Hz].

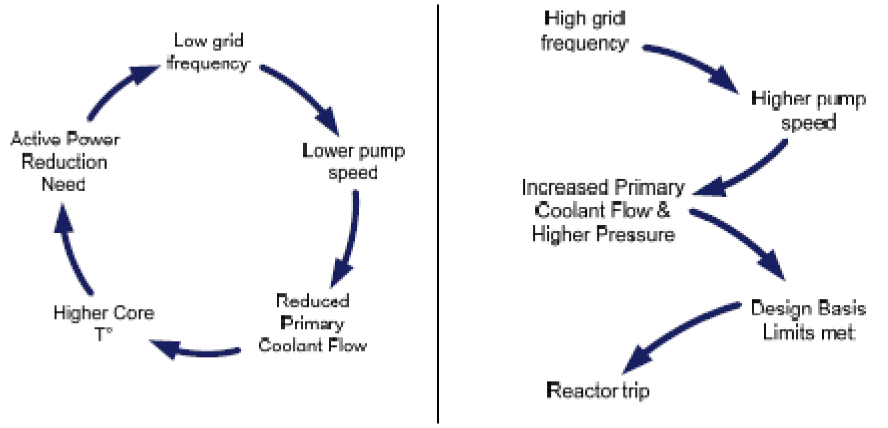
Even in countries where the current requirement for the continuous operating range is [49 Hz ; 51 Hz] (eg Great Britain), the existing NPPs do not fulfil the requirement, since the Grid Codes were established after electro-nuclear development.

If compliance to NC RfG was required from existing NPPs, this would at least imply performing new nuclear safety analysis, in particular fault studies. This process involves many man-years of work spread over a long period of time. Design assessment by Nuclear Safety Authorities would also become obsolete and should therefore be revised. Such revision is going to show impacts at least on:

- Direct-driven pumps (including PWR reactor coolant pumps, feed-water pumps, all auxiliary pumps);
- Fuel assemblies in PWRs (because of increased lift forces when coolant flow is high at high frequency);

11 / 30

How frequency deviations affect PWR operation is illustrated in the following diagrams:



The cost of equipment redesign and change might be significant. Moreover there is a risk that updated assumptions in fault studies could lead to premature plant shutdowns if it is found out that the inherent design cannot accommodate the new requirements.

In order to cope with degraded frequency, power converters could be used to supply power to coolant and safety systems. However, power converters do not provide similar reliability and availability as direct-driven pumps, in part due to their control via software. Therefore, power converters in NPPs impose a risk of failure, which cannot be accepted by Nuclear Safety Authorities and society. Additionally, power converters may physically not fit into existing NPP designs and are costly, once again jeopardizing the business case of NPPs.

The EUR stresses that if the frequency quality actually degrades over time, existing NPPs will have to cope with it whether compliance to NC RfG is requested from them or not. If the observed frequency quality comes out of a NPP's design hypothesis as described in the nuclear safety case[16], or if the transient budget is depleted, the operation of the plant is then deemed unsafe, and as a consequence the NPP has to stop operating.

Moreover, degraded frequency quality also implies increased use of frequency response capability. NPPs which provide frequency response services would be negatively impacted by increased wear and tear and maintenance needs as well as reduced lifetime of components due to extra valving and thermo-mechanical cycling constraints on fluid circuits.

[16] The nuclear safety case is the whole set of documentation which proves that operation of a NPP is safe on a nuclear point of view.

3.1.4. Alternative approach

EUR's understanding of ENTSO-E's approach to the evolution of power systems is:

- An increasing share of generation provides no or very little inertia to the system which implies frequency variations more frequent and of greater amplitude;
- The whole system has to adapt and be able to cope with an electrical waveform of decreasing quality.

EUR's opinion is that consequences on the users of such an approach have not been properly assessed and are in fact not acceptable. Not only existing NPPs are not able to operate on a degraded grid, but also lots of industries which rely on a stable frequency to run their motors (paper mills, rolling mills, etc.) will be badly affected. Moreover, less control over frequency will inevitably lead to higher risks of major instability with wide-spread consequences.

Therefore the EUR recommends an alternative approach:

- Aiming at keeping frequency quality at least as good [17] as it is in current practice [18];
- Requesting non-synchronous generators to provide synthetic inertia to mitigate the degradation of frequency quality they cause. In this process, harmonics generation should be limited.

As for the frequency ranges requirement applicable to new generators, the EUR workgroup recommends that ENTSO-E adopts a requirement not more onerous than the EUR requirement (above mentioned) and which is expressed on the format which matches industry practice in terms of equipment specification, that is:

- U/f chart requirement;
- Operating time limit for each zone within the U/f chart;
- Maximum frequency of occurrence of each zone within the U/f chart.

The EUR requirement has the following advantages:

- It matches industry practice;
- It is already stringent enough to cope with current waveform quality standards.
- Emerging NPP designs are compliant with this requirement.

Moreover, the EUR recommends keeping [49.5 Hz ; 51.5 Hz] as a continuous operating range in Continental Europe, to reflect the strength of this power system compared to the other synchronous areas.

When defining frequency (and voltage) ranges, safety aspects of NPPs shall be taken into account.

[17] The EUR reckons that it could be brought to higher standards in the smaller synchronous areas if DC interconnectors control systems were designed to provide synthetic inertia by mimicking AC line behaviour.
[18] Current practice corresponds to the frequency quality objectives described in Table 1 of NCOS [5] and recalled in Table 2 of this memorandum

3.2. Voltage ranges

3.2.1. Requirement description

Required operating voltage ranges depend on both the synchronous area of connection and the nominal voltage at grid connection point. The minimum requirements are described in Article 11(2)(a)(1) in the two tables duplicated below. Under Article 11(2)(a)(2) individual TSOs can request more onerous requirements.

Synchronous Area	Voltage Range	Time period for operation
Continental Europe	0.85 pu – 0.90 pu	60 minutes
	0.90 pu – 1.118 pu	Unlimited
	1.118 pu – 1.15 pu	To be decided by each TSO while respecting the provisions of Article 4(3), but not less than 20 minutes
Nordic	0.90 pu – 1.05 pu	Unlimited
	1.05 pu – 1.10 pu	60 minutes
Great Britain	0.90 pu–1.10 pu	Unlimited
Ireland	0.90 pu – 1.118 pu	Unlimited
Baltic	0.85 pu – 0.90 pu	30 minutes
	0.90 pu – 1.12 pu	Unlimited
	1.12 pu – 1.15 pu	20 minutes

Table 6.1: This table shows the minimum time periods a Power Generating Module shall be capable of operating for Voltages deviating from the nominal value at the Connection Point without disconnecting from the Network. (The Voltage base for pu values is from 110 kV to 300 kV (excluding).)

Synchronous Area	Voltage Range	Time period for operation
Continental Europe	0.85 pu – 0.90 pu	60 minutes
	0.90 pu – 1.05 pu	Unlimited
	1.05 pu – 1.0875 pu	To be decided by each TSO while respecting the provisions of Article 4(3), but not less than 60 minutes
	1.0875 pu – 1.10 pu	60 minutes
Nordic	0.90 pu – 1.05 pu	Unlimited
	1.05 pu – 1.10 pu	60 minutes
Great Britain	0.90 pu – 1.05 pu	Unlimited
	1.05 pu – 1.10 pu	15 minutes
Ireland	0.90 pu – 1.05 pu	Unlimited
Baltic	0.88 pu – 0.90 pu	20 minutes
	0.90 pu – 1.10 pu	Unlimited
	1.10 pu – 1.15 pu	20 minutes

Table 6.2: This table shows the minimum time periods a Power Generating Module shall be capable of operating for Voltages deviating from the nominal value at the Connection Point without disconnecting from the Network. (The Voltage base for pu values is from 300 kV to 400 kV.)

Most of existing and probably future NPPs are connected on the supergrid voltage level (400 kV across Europe), and are therefore required to comply with Table 6.2 requirements. However some NPPs are connected to lower voltage levels (in particular 225 kV) and therefore fall under Table 6.1 requirements.

3.2.2. Necessity of the requirement

While the EUR approves the necessity of a requirement on operating voltage ranges, it deeply disagrees with the implementation of such a requirement in NC RfG for the following reasons.

3.2.2.1. Harmonization

The requirement should be harmonized throughout the whole ENTSO-E grid. Unlike frequency stability which is a global characteristic of a synchronous area and is highly dependent on the overall size of that synchronous area, voltage stability is not, and is mainly affected by local characteristics of the grid (topology, short-circuit power). Therefore there is no justification for distinguishing requirements between synchronous areas. The provisions of Article 11(2)(a)(2) only jeopardizes even more any harmonization effort.

3.2.2.2. Voltage ranges not defined in a U/f chart

This issue has been explained already in the chapter on operating frequency ranges.

3.2.2.3. A requirement not in line with current practice and norms

The proposed operating ranges are in line neither with the current practice in many countries, nor with European norms practice.

A relevant example for the EUR concerns about NPPs is France, where 54 NPPs are connected to the 400 kV grid, and 4 are connected to the 225 kV grid. In France [19]:

- On the 400 kV grid:
  - unlimited duration operating range is [0.95 pu – 1.05 pu] + authorized deloading to 0.95 P_{max};
  - operation during 5 minutes in the range [1.05 pu – 1.10 pu];
  - operation during 90 minutes in the range [0.85 pu – 0.95 pu].
- On the 225 kV grid:
  - unlimited duration operating range is [0.89 pu – 1.089 pu] + authorized deloading to 0.95 P_{max};
  - operation during 5 minutes in the range [1.089 pu – 1.11 pu];
  - operation during 90 minutes in the range [0.80 pu – 0.89 pu].

Moreover, according to IEC 60076-3 on power transformers (chapter 5) [14], the U_m value (highest use voltage of the equipment) is, for each winding, the lowest value found in IEC 60071-1 [15] which is above the rated value of the winding. This applies as:

- For 400 kV transformer windings: U_m = 420 kV (1.05 pu)
- For 225 kV transformer windings: U_m = 245 kV (1.089 pu)

IEC 60071 norms [15] do not define any time limited overshooting of U_m, however it means at least that U_m should not be exceeded for an unlimited duration. The consequence is that the next available class of transformer equipments should be used to cope with ENTSO-E requirement, that is:

- U_m = 550 kV for 400 kV transformer windings;
- U_m = 300 kV for 225 kV transformer windings.

3.2.2.4. A requirement which forces the use of on-load tap changers

The operation time required outside the normal operating range of rotating machines ([0.95 pu - 1.05 pu]) is so long, that the requirement basically forces generators to use a step-up transformer equipped with an on-load tap changer (OLTC) to connect to the grid. This applies especially on the higher voltage ranges (above 1.05 pu) where:

- The impact of excessive voltage on lifetime of electrical equipments is high;
- When combined with low frequency, over-voltage creates harmful excessive flux in generators and motors.

However using an OLTC on the step-up transformer severely degrades the reliability of the transformer, as described in the well-known international survey on power transformers published by Cigre in Electra 88, 1983 [12], which revealed that in transformers equipped with an OLTC, about 41% of all failures were due to the OLTC.

[19] Source [11]

3.2.3. Feasibility and cost

3.2.3.1. New Build NPP

The requirement does not cause any feasibility issue for a new build NPP.
However, as explained earlier, it:

- Drives costs up by imposing the use of an OLTC on the step-up transformer, which means more expensive procurement, and more maintenance, which could lead to additional planned outages (maintenance on OLTC in long and complex);
- Also drives costs up by requiring the use of overrated equipment on the very high voltage side of the main transformer (as explained above);
- Severely impacts the reliability of the step-up transformer, therefore availability of the whole plant.

3.2.3.2. Existing NPPs

In many cases existing NPPs step-up transformers are not equipped with an OLTC. Therefore these transformers should be changed in case NC RfG is deemed applicable to them.

By extension, many auxiliary and stand-by auxiliary transformers may be required to be changed as many of these are not equipped with OLTC either and are connected directly to the high voltage grid in the same substation as the step-up transformer.

These modifications are technically feasible, but very expensive in terms of investment and plant unavailability during the works (which involve heavy civil works to adapt the power evacuation platform to a larger transformer: platform, oil retention pit, firewalls, etc.). Moreover, such modifications generate the reliability issues above-mentioned for new build NPP.

Although it is not in the scope of this document, the EUR warns that these modifications will have to be implemented if the NC OS [5] passes through comitology as it has been presented to ACER after public consultation. In this code[20], the voltage operating ranges defined in NC RfG are deemed applicable to the whole grid; therefore all existing users will have to cope with them.

3.2.4. Alternative approach

The EUR recommends using the EUR requirement in terms of U/f operating ranges, which is shown in the "Frequency ranges" chapter above. It has several merits compared to the ENTSO-E proposal:

- It matches the upper voltage limit defined in IEC standards;
- It matches industry practice;
- It is already stringent enough to cope with current waveform quality standards.
- Emerging NPP designs are compliant with this requirement.

Locally different voltage ranges could be defined if:

- Need is properly justified;
- Impacts on grid users are properly evaluated.

When defining voltage (and frequency) ranges, safety aspects of NPPs shall be taken into account.

---

[20] NC OS – Article 10 [5]

16 / 30

3.3. Reactive power ranges

3.3.1. Requirement description

The reactive power capability requirement is described in Chapter 13(2). It is defined as a maximum requirement which precise definition is left to local TSO initiative:

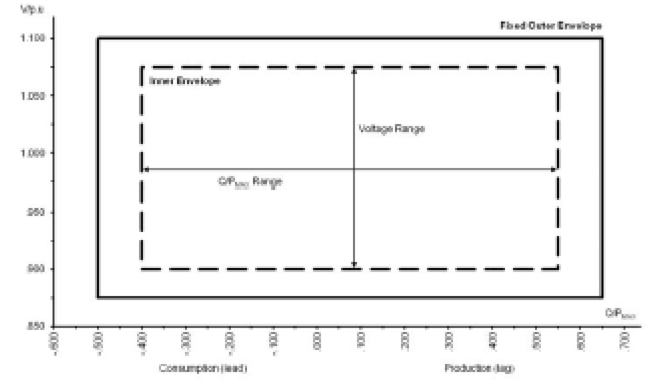


Figure 7 – U-Q/P_{max}-profile of a Synchronous Power Generating Module. The diagram represents boundaries of a U-Q/P_{max}-profile by the Voltage at the Connection Point, expressed by the ratio of its actual value and its nominal value in per unit, against the ratio of the Reactive Power (Q) and the Maximum Capacity (P_{max}). The position, size and shape of the inner envelope are indicative.

Synchronous Area	Maximum range of Q/P_{max}	Maximum range of steady-state Voltage level in PU
Continental Europe	0.95	0.225
Nordic	0.95	0.150
Great Britain	0.95	0.100
Ireland	1.08	0.218
Baltic States	1.0	0.220

Table 8: Parameters for the inner envelope in figure 7

3.3.2. Necessity of the requirement

While the EUR approves the necessity of a requirement on operating voltage ranges, it disagrees with the implementation of such a requirement in NC RfG, especially in terms of Q/P_{max} range.

17 / 30

3.3.3. Feasibility and cost

3.3.3.1. New Build NPP

The larger the reactive capability U/Q diagram is, the larger the generator gets. Therefore a more onerous requirement can dramatically increase the price of a generator. The rating of the step-up transformer is equally affected.

In extreme cases, if a TSO chooses to define a very large capability, it might not be achievable by a very large NPP, because the induced size of the generator might exceed the capacity of the world's largest forge capable of forging a rotor core.

3.3.3.2. Existing NPPs

Since no precise requirement is defined in NC RfG, it is difficult to analyse whether existing NPPs are compliant or not. However, if retroactivity is required from a NPP which is not compliant with the fully defined requirement, compliance might involve one or both of the following:

- Changing the generator for an over-rated one. This kind of modification will also include redesign of:
  - Excitation system;
  - Complete shaft;
  - Bearings;
  - Side systems;
  - Civil works (turbine generator table, turbine hall size).
- Changing the transformer for an over-rated one, possibly adding an OLTC.

3.3.4. Alternative approach

The EUR recommends defining a clear minimum requirement which is achievable at acceptable costs. If local grid conditions impose it, the requirement should be expendable (the U/Q diagram enlarged) provided it is justified by a proper CBA.
As a starting point, the EUR recommends using the requirement defined in EUR revision D [9]. It is deemed acceptable for new build NPPs, and therefore should also be acceptable for smaller generators:

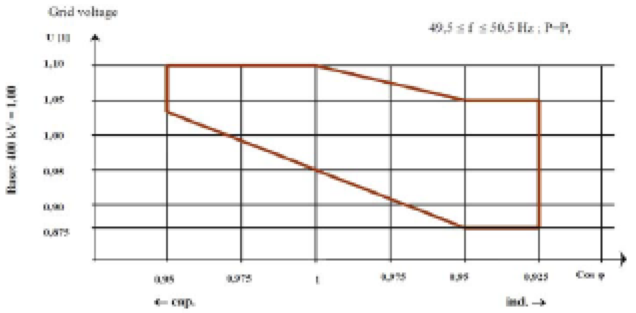


Figure 3: Reactive Power requirement at grid terminals

When defining reactive power ranges, safety aspects of NPPs shall be taken into account.

18 / 30

3.4. Frequency response capability

3.4.1. Requirement description

Frequency response capability is divided in three separate requirements:

- Limited Frequency Sensitive Mode – Overfrequency (LFSM-O) – applicable to all generators, described in NC RfG Article 8(1)(c);
- Limited Frequency Sensitive Mode – Underfrequency (LFSM-U) – applicable to type C and D generators, described in NC RfG Article 10(2)(b);
- Frequency Sensitive Mode (FSM) – applicable to type C and D generators, described in NC RfG Article 10(2)(c).

3.4.1.1. Frequency Sensitive Mode

The main features of the NC RfG requirement on FSM are hereby recalled:

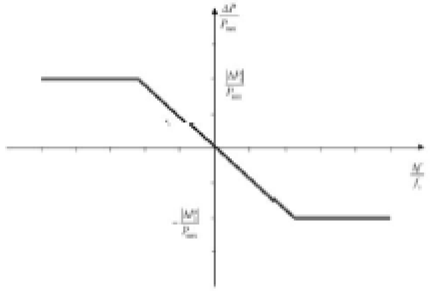


Figure 5: Active Power Frequency Response capability of Power Generating Modules in FSM illustrating the case of zero deadband and insensitivity. P_{max} is the Maximum Capacity to which ΔP is related. ΔP is the change in Active Power output from the Power Generating Module. f_n is the nominal Frequency (50 Hz) in the Network and Δf is the Frequency deviation in the Network.

Parameters		Ranges
Active Power range related to Maximum Capacity $\frac{\|\Delta P_1\|}{P_{max}}$		1.5 – 10 %
Frequency Response Insensitivity	$\|\Delta f_i\|$	10 – 30 mHz
	$\frac{\|\Delta f_i\|}{f_n}$	0.02 – 0.06 %
Frequency Response Deadband		0 – 500 mHz
Droop s_1		2 – 12 %

Table 4: Parameters for Active Power Frequency Response in FSM (explanation for figure 5)

The Frequency Response Deadband of Frequency deviation and Droop are selected by the TSO and must be able to be reselected subsequently (without requiring to be online or remote) within the given frames in the table 4, subject to notification to the National Regulatory Authority. The modalities of that notification shall be determined in accordance with the applicable national regulatory framework.

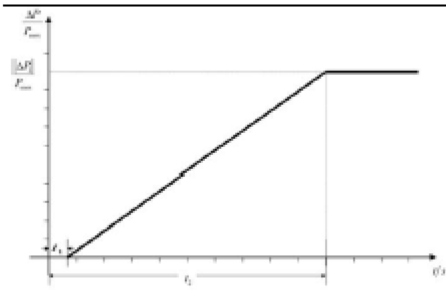


Figure 6: Active Power Frequency Response capability. P_{max} is the Maximum Capacity to which ΔP is related. ΔP is the change in Active Power output from the Power Generating Module. The Power Generating Modules have to provide Active Power Output ΔP up to the point ΔP_1 in accordance with the times t_1 and t_2 with the values of ΔP_1, $t_1$and $t_2$being specified by the Relevant TSO according to Table 5. t_1 is the initial delay, t_2 is the time for full activation.

The Power Generating Module shall be capable of providing full Active Power Frequency Response for a period specified by the TSOs, considering the technical feasibility, for each Synchronous Area between 15 min and 30 min, considering the Active Power headroom and primary energy source of the Power Generating Module.

Parameters	Ranges or values
Active Power range related to Maximum Capacity (Frequency response range) $\frac{\|\Delta P_1\|}{P_{max}}$	1.5 – 10 %
Maximum admissible initial delay t_1 unless justified otherwise for generation technologies with Inertia	2 seconds
Maximum admissible initial delay t_1 unless justified otherwise for generation technologies without Inertia	as specified by the Relevant TSO while respecting the provisions of Article 4(3)
Maximum admissible choice of full activation time t_2, unless longer activation times are admitted by the Relevant TSO due to system stability reasons	30 seconds

Table 5: Parameters for full activation of Active Power Frequency Response resulted from Frequency step change (explanation for figure 6).

3.4.1.2. Limited Frequency Sensitive Mode – Overfrequency

The main features of the NC RfG requirement on LFSM-O are hereby recalled:

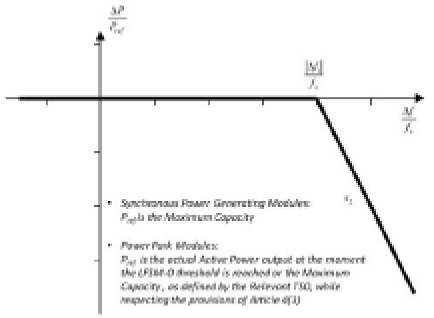


Figure 1: Active Power Frequency Response capability of Power Generating Modules in LFSM-O. P_{ref} is the reference Active Power to which ΔP is related and may be defined differently for Synchronous Power Generating Modules and Power Park Modules. ΔP is the change in Active Power output from the Power Generating Module. f_n is the nominal Frequency (50 Hz) in the Network and Δf is the Frequency change in the Network. At overfrequencies where Δf is above Δf_1 the Power Generating Module has to provide a negative Active Power output change according to the Droop S_2.

The Power Generating Module shall be capable of stable operation during LFSM-O operation. When LFSM-O is active, the LFSM-O Setpoint will prevail over any other Active Power Setpoints.

Droop s_2 in the range 2% – 12%

Δf_1 in the range 50.2Hz – 50.5Hz

LFSM-O shall be activated as fast as technically feasible, with an initial delay as short as possible

3.4.1.3. Limited Frequency Sensitive Mode – Underfrequency

The main features of the NC RfG requirement on LFSM-U are hereby recalled:

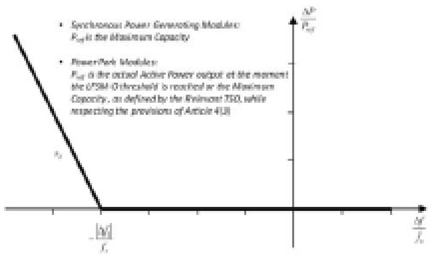


Figure 4: Active Power Frequency Response capability of Power Generating Modules in LFSM-U. P_{ref} is the reference Active Power to which ΔP is related and may be defined differently for Synchronous Power Generating Modules and Power Park Modules. ΔP is the change in Active Power output from the Power Generating Module. f_n is the nominal Frequency (50 Hz) in the Network and Δf is the Frequency change in the Network. At underfrequencies where Δf is below Δf_1 the Power Generating Module has to provide a positive Active Power output change according to the Droop S_2.

Droop s_2 in the range 2% – 12%

Δf_1 in the range 49.8Hz – 49.5Hz

LFSM-U shall be activated as fast as technically feasible, with an initial delay as short as possible

20 / 30

3.4.2. Necessity of the requirement

3.4.2.1. FSM

The EUR agrees with the necessity of the FSM requirement. It seems reasonable that in the future all large generators (type C and D in NC RfG), including NPPs, should have the capability to participate to frequency control. We recognize this will ensure the availability of this vital function on the power system. However:

- The requirement is not clearly defined in NC RfG and instead is left to TSOs to define locally under Article 4(3);
- The ranges in which TSOs can choose parameters are so wide they allow the requirement to be made very onerous, which leaves great uncertainty at this stage on feasibility and cost.

Relatively to the first point, there is no reason why the FSM requirement should be different from one TSO to another within a synchronous area. The requirement should be fully defined on a synchronous area basis in NC RfG. It would:

- Avoid competition distortion between TSO areas;
- Facilitate development of power plant designs which could be used on a wide area.

As for the second point the EUR considers that the ranges defined in NC RfG for TSOs to choose their specific requirement from are too large and not properly justified:

Parameter	Proposed Range	Comments
Active Power range related to Maximum Capacity	1.5 % - 10 %	If a value close to 10% is chosen, it might not be achievable by NPPs. The EUR requires 3% on a normal basis, and up to 5% if specifically required by the TSO.
Maximum full activation time	0 s – 30 s	The requirement lacks of a credible lower boundary (in this case, the lower the value, the more onerous the requirement). If a value below 30s is chosen, it can be very difficult to achieve by a NPP if associated with a high Active Power range value (up to 10%). The EUR requires 30s.
Full Active Power Frequency Response minimum sustainable time	15 min – 30 min	30 minutes time is not justified since the maximum time to restore frequency defined in NC LFC&C [4][21] is 20 minutes. When frequency is restored, FRC is not activated anymore. EUR requires 15 minutes, but no difficulty is foreseen for NPPs if longer time is required.

Moreover, the provision that the TSO selects the droop and can have it changed on simple request with NRA notification is not acceptable for NPPs. All transients a NPP has to be able to cope with (including but not limited to switching to house-load) are impacted by the turbine controller droop. Therefore, once this value is set, it cannot be changed at will without preliminary studies. The full impact of a change of droop should be taken into account in NC RfG (time needed to study and implement the change, cost recovery).

[21] NC LFC&R – Article 9 Table 1 [4]

3.4.2.2. LFSM-O

The EUR does not believe the LFSM-O requirement is necessary. It is meant to mitigate the risk that TSOs fail procuring enough FCR. But the EUR recognizes that in case of a very high frequency event, the situation can only be reasonably handled by lowering generation (demand-side mitigation measures would be very difficult to implement in that case). The EUR itself requires NPPs to be able to decrease their output down to minimum load in case of emergency situations.

By comparison with justification provided for LFSM-U requirement, ENTSO-E implicitly recognizes that LFSM-O is meant to mitigate emergency situations[22]. This should be explicit in NC RfG, and the requirement should be associated with a probably of occurrence of use. Such a probability of occurrence is of high importance for the design of NPPs.

3.4.2.3. LFSM-U

The EUR does not believe the LFSM-U is necessary. As for LFSM-O, it is meant to mitigate the risk that TSOs fail procuring enough FCR. It was (not properly) justified by ENTSO-E using an erroneous statement. In NC RfG – Requirements in the Context of Present Practice Chapter 3.3 [3]:

"The objective of the LFSM-U requirement is to make available additional Active Power reserves in emergency situations at low frequencies when Active Power response provided by Power Generating Modules operating in Frequency Sensitive Mode is already exhausted, but before any load shedding. Such reserves can be provided by Power Generating Modules, which are operating at partial load and hence still have the possibility to increase generation proportionally to the deviation of frequency from its nominal value. To enable this capability, no additional investments in Power Generating Modules are needed, because it makes use of anyway existing control system features, e. g. proportional frequency (speed) control of synchronous Power Generating Modules. The performance is conditional to prime mover availability as well as reduced Maximum Active Power Output at low frequencies for certain generation technologies according to Article 8(1)(d) of the NC RfG."

This is not true in the case of a NPP. When a NPP operates at part power in FSM, it is designed to procure a limited amount of FCR when frequency goes down. Once the design transient is achieved, further ramping-up is not normally possible. Core and NSSS parameters have to be stabilized and brought back to normal ranges before further increase in power is allowed. In any case, such ramping-up cannot be ordered on a normal basis by the turbine controller. It is a matter of nuclear safety.

There is a difference between:

- On one hand ramping-up from an intermediate power P to P_{max} on a normal ramp (e.g. 5% P_n/min)
- On the other hand providing full FCR (fast transient) starting from the same intermediate power P, then ramping-up to P_{max}.

Moreover, mitigation of very low frequency events is already covered by underfrequency load-shedding, which has already proved to be efficient[23], and has a low socio-economic impact, since the load to be shed in the first frequency thresholds is chosen to limit this impact.

[22] NC RfG – Requirements in the Context of Present Practice – Chapters 3.2 and 3.3 [3]
[23] E.g. in the November 4, 2006 incident

3.4.3. Feasibility and cost

3.4.3.1. New Build NPP

3.4.3.1.1. FSM

There is no feasibility issue for a new build NPP. However, a very onerous set of parameters (e.g. 10% P_{max} to be provided in 10s like in GB Grid Code today) can exceed current design standards as defined in EUR which are:

- Control range not higher than ±5% P_r;
- Full activation of FCR within 30s.

Any NPP design changes needed to comply with requirements more onerous than existing standards would drive costs.

3.4.3.1.2. LFSM-O

The EUR does not foresee any feasibility issue with the LFSM-O requirement for a new build NPP. However, the probability of using LFSM-O should be defined.

3.4.3.1.3. LFSM-U

The superposition of LFSM-U and FSM requirements goes beyond current NPP design practice. While fundamentally a NPP could be compliant with LFSM-U requirement, it is likely that currently marketed Generation III NPP designs are not compliant, because the maximum power transient acceptable on a normal basis is the full activation of FCR as defined in the FSM requirement.

3.4.3.2. Existing NPPs

Frequency response capability is very dimensioning for the whole design of a NPP. This capability cannot be added or modified after a NPP is commissioned without jeopardizing nuclear safety. Therefore retroactivity of the requirement to existing NPPs cannot be reasonably envisaged.

3.4.4. Alternative approach

3.4.4.1.1. FSM

The EUR recommends defining thoroughly the FSM requirement per synchronous area rather than leaving it to individual TSOs to define. The operational and market design codes should put in place incentives for users to provide more frequency response capability than the minimum defined in NC RfG. The combination of a minimum requirement no too stringent and incentives to provide more would:

- Ensure that all large generators have the capability to take their share of responsibility in frequency management, without imposing the cost of unnecessary extra capability (minimum requirement);
- Allow generators with inherent design capability not in line with very onerous frequency response requirements but beneficial to power system stability and decarbonisation objectives to be connected (e.g. large HPPs with long water adductions and penstocks can struggle with a very fast response requirement, NPPs can be limited in the amount of reserve they can provide, but both provide massive inertia to the system, contribute to decarbonisation objectives and are fully controllable);
- Optimize global availability and use of FCR on units highly suitable to provide it (e.g. gas turbines or some HPPs can provide massive FCR very quickly).

23 / 30

We propose using the EUR parameters as a reasonable requirement basis:

Parameter	Proposed Value
Active Power range related to Maximum Capacity	3% - for CE Extendable to 5% - for smaller synchronous areas
Maximum full activation time	30 s
Full Active Power Frequency Response minimum sustainable time	15 min

We also request that TSOs should obtain Generator Owners approval when requesting a change of droop.

3.4.4.1.2. LFSM-O

The EUR would like the requirement to be completed with a probability of occurrence of LFSM-O activation. This request is consistent with the comments on operating frequency ranges.

3.4.4.1.3. LFSM-U

The EUR proposes to remove this requirement, which was not properly justified and can prove very difficult to achieve, especially for NPPs. The power system can rely on underfrequency load-shedding to mitigate exceptional low frequency events.

3.5. Fault Ride-Through

3.5.1. Requirement description

FRT capability is requested for type B, C and D generators. The requirement is defined by different sets of parameters depending on whether the generator is of type B-C or D, and whether it is a synchronous generator or a power park module.
The FRT requirement applicable to type D synchronous generators is defined in Articles 9(3)(a) and 11 (3)(a) The main features are hereby recalled:

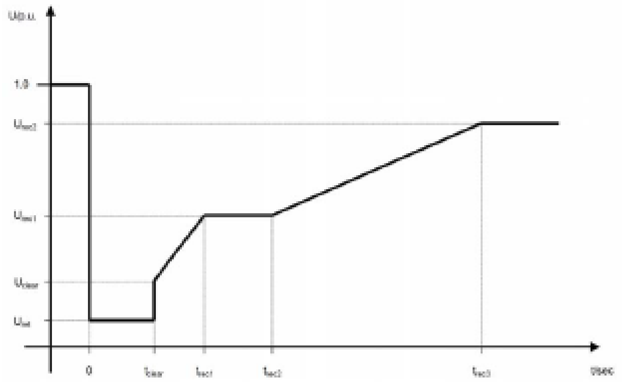


Figure 3 – Fault-ride-through profile of a Power Generating Module. The diagram represents the lower limit of a voltage-against-time profile by the Voltage at the Connection Point, expressed by the ratio of its actual value and its nominal value in per unit before, during and after a fault. U_{ret} is the retained Voltage at the Connection Point During a fault, t_{clear} is the instant when the fault has been cleared. U_{rec1}, U_{rec2}, t_{rec1}, t_{rec2} and t_{rec3} specify certain points of lower limits of Voltage recovery after fault clearance.

Voltage parameters [pu]		Time parameters [seconds]	
U_{ret}:	0	t_{clear}:	0.14 – 0.25
U_{clear}:	0.25	t_{rec1}:	t_{clear} – 0.45
U_{rec1}:	0.5 – 0.7	t_{rec2}:	t_{rec1} – 0.7
U_{rec2}:	0.85 – 0.9	t_{rec3}:	t_{rec2} – 1.5

Table 7.1 – Parameters for figure 3 for fault-ride-through capability of Synchronous Power Generating Modules.

3.5.2. Necessity of the requirement

The EUR agrees with the necessity of a requirement on FRT for Synchronous Power Generating Modules and Power Park Modules for the sake of power system stability. Also, it is appreciated that parameters for FRT are to be decided by the respective TSO(s), giving the opportunity to reflect geographical and topological properties of the power system.

Nevertheless, EUR is concerned about the upper limit for clearing time (t_{clear}, in Table 7.1 above). For NPPs, considered as a complex entity consisting of generator, transformer, pumps, other auxiliary systems and protection systems, a clearing time of up to 250 ms seem too onerous.

At present, a requirement for 250 ms only exists in the Nordic power system. However, several existing and operating NPPs do not fulfil 250 ms of clearing time, and, are granted exemption from such a requirement.

3.5.3. Feasibility and cost

3.5.3.1. New Build NPP

From a NPP point of view, FRT-capability can, for example, be improved by adding more inertia (i.e. rotating mass) to a generator, which in practice is difficult, as generators for NPPs already come with massive rotors. Other measures for fault time improvements are dynamic braking resistors, FACTS-devices, or fast valving. All these measures are associated with additional investment costs, which should be borne by an appropriate cost recovery mechanism, and may impose a risk for sub-synchronous resonance (SSR) or sub-synchronous torsional interaction (SSTI).

3.5.3.2. Existing NPPs

In order to fulfil the requirement of up to 250 ms, additional installations on the plant would have to be made. Dynamic braking resistors, FACTS-devices, fast valving, or exchange of excitation system in older plants may lead to improved fault time. Such installations may impose significant costs, which would have to be borne by an appropriate cost recovery mechanism, and may impose a risk for sub-synchronous resonance (SSR) or sub-synchronous torsional interaction (SSTI). In addition, changes on existing NPPs may interfere with their secure and safe operation.

3.5.4. Alternative approach

A maximum requirement on clearing time (t_{clear}) of 150 ms, in line with EUR's Requirements for LWR Nuclear Power Plants Volume 2 Chapter 3 [9], is proposed. EUR's requirements are graphically illustrated in Figure 3-1. The following voltage and time parameters are proposed:

Voltage parameters [pu]		Time parameters [seconds]	
U_{ret}:	0	t_{clear}:	0.14 – 0.15
U_{clear}:	0.25	t_{rec1}:	t_{clear} – 0.45
U_{rec1}:	0.5 – 0.7	t_{rec2}:	t_{rec1} – 0.7
U_{rec2}:	0.85 – 1	t_{rec3}:	t_{rec2} – 1.5

TSOs shall be in charge of undertaking appropriate measures to ensure system integrity during double contingencies. Current breaker technology allows clearing a fault in less then 150 ms, thereby securing safe operation of both the overall power system and NPPs.

26 / 30

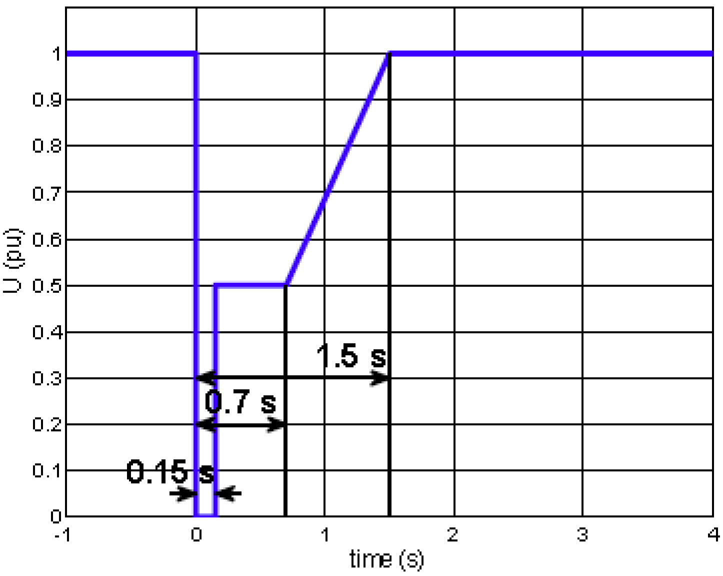


Figure 3-1: EUR's requirement on clearing time and voltage recovery [9]

For existing NPPs, the requirements, with possible exemptions for certain NPPs, on FRT should be kept as they are today.

27 / 30

4. CONCLUSIONS

The EUR concludes that it is globally technically possible for a new build NPP to comply with NC RfG requirements. However, a large number of these significantly deviate from nuclear business standards. Some of them, in particular operating frequency ranges and frequency response capability, are highly dimensioning for all parts of a NPP, especially the nuclear island. The EUR fears that many if not all of 3rd generation NPP designs which are currently marketed – these designs have been recently developed, many are under construction or planned over the world, none is operational yet – are not compliant with NC RfG as such. In order to be connectable in Europe under NC RfG, these designs would have to be reviewed in depth, which would:

- Generate high extra design costs;
- Globally lead to an increase of cost of NPP equipments;
- Jeopardize current nuclear licensing.

Retroactivity of NC RfG to existing NPPs is, for a number of requirements, achievable at considerable cost, and not reasonably conceivable for the others. The nuclear safety implications of changes in the design hypothesis of a NPP are great and should be envisaged only if no other alternative exists. In any case, nuclear operators will not implement any modification that degrades nuclear safety.

The EUR warns that the requirements relative to resilience to degraded grid conditions (voltage and frequency) will be de facto applicable to all existing generators. In fact, the operational codes NC OS [5] and NC LFC&R [4] actually implement the extended ranges (NC OS [5] for voltage), or the provisions to allow the extended ranges (NC LFC&R [4] for frequency) as normal grid operating ranges. This situation could lead to premature shutdown of NPPs on the order of Nuclear Safety Authorities, we would jeopardize security of supply across Europe and increase cost to end-users.

Overall, while the EUR agrees with ENTSO-E on the fact that the Network Codes should favour the insertion of renewable generation on the European power system as well as the decarbonising of electricity generation, it strongly disagrees on the way the transition should be handled. ENTSO-E considers that increasing renewables penetration on the grid will inevitably lead to a degradation of the waveform quality (in terms of voltage and frequency) to which other users must adapt. EUR is convinced mitigation measures (synthetic inertia, FACTS, etc.) exist, and renewables can be inserted in the system without degrading the waveform if such measures are implemented. Moreover, the EUR believes preventing a degradation of the waveform quality is ultimately a condition sine qua non of the stability of the power system because:

- Synchronous machines are essential to set the pace of the waveform and provide the massive inertia the system needs to be stable;
- Unlike renewables connected through fully controlled power converters, synchronous machines require fixed and stable in time voltage and frequency conditions.

Finally, the EUR notes that ENTSO-E has justified many requirements on the basis of existing national grid codes. Such justification alone is not valid because national grid codes contain requirements which are not realistically achievable by generators (e.g. the GB Grid Code required continuous operation in the range [47Hz ; 52Hz] until very recently). Existing plants technological capability should have taken into account more extensively.

The EUR regrets ENTSO-E has not taken into account the sound warnings conventional generators representatives have continuously and consistently sent on the impacts of the requirements through the whole process of NC RfG drafting. We hope KEMA understands our concerns and will successfully convince the European Commission to take them into account.

APPENDIX – LETTER FROM WENRA TO ACER

WENRA

WENRA | ENSI | CH-5200 Brugg | Industriestrasse 19 | Switzerland

A Post
ACER –
Agency for the Cooperation of Energy Regulators
Mr. Alberto Potoschnig
Trg republike 3
1000 Ljubljana
Slovenia

Your reference:
Our reference: WAH/MAN/SAS-40KR.WENRA
Contact person: Studer Nathalie, Phone +4156 460 8599
Brugg, 04 October 2012

Network Code for Requirements for Grid connection Applicable to all Generators

Dear Mr. Potoschnig,

I am writing to you with regards to a letter that I received from the European Nuclear Installations Safety Standards (ENISS) on 20 September 2012. In that letter, the issue of a draft standard on the grid connection with generators written by the European Network of Transmission System Operators for Electricity (ENTSO-E) called "Network Code for Requirements for Grid connection Applicable to all Generators (ENTSO-E NC)" was raised.

Some requirements in the final draft of the code (https://www.entsoe.eu/resources/network-codes/requirements-for-generators/) have the potential to negatively influence nuclear safety. In fact, the definition for the range for frequency and voltage is too large. For nuclear power plants, which are working as 100% base load power plants, the technical safety limit is 48 Hz. Under this limit, the frequency may have a negative impact on frequency dependent aggregates. Furthermore load following is contradictory to the common practice in several WENRA countries.

A safe and high-performance electrical grid is primordial for nuclear safety. The importance of the electrical grid was highlighted by the accidents of Fukushima and Forsmark. We therefore suggest to include the following statement as a new paragraph in Article 3 (6) (e) in the ENTSO-E NC: *"For nuclear power plants, nuclear safety considerations are prioritized in the case of a conflict between nuclear safety considerations and the Network Code"* or to reject the ENTSO-E NC, so as to revise it including the above mentioned concerns.

Chairperson
Hans Wanner Director General of the
Swiss Federal Nuclear Safety Inspectorate (ENSI)

Industriestrasse 19
5200 Brugg
Switzerland

Tel. +4156 460 8400
Fax +4156 460 8499
info@ensi.ch

29 / 30

WENRA

Please do not hesitate to contact us should you have any question or need further clarification. Thank you for your due consideration of our request.

Yours sincerely

Dr. Hans Wanner, Chairman
Western European Nuclear Regulators Association
Hans.Wanner@ensi.ch

Chairperson
Hans Wanner Director General of the
Swiss Federal Nuclear Safety Inspectorate (ENSI)

Industriestrasse 19
5200 Brugg
Switzerland

Tel. +4156 460 8400
Fax +4156 460 8499
info@ensi.ch

C.6 Thermal Generators

VGB / EURELECTRIC's generators
RfG Network Code:
Needs, Feasibility, Alternative Solutions and Costs

The European Commission has tasked a consortium of DNV KEMA and COWI to perform an impact assessment of the provisions contained in the Network Code on Requirements for Grid Connection Applicable to all Generators (RfG), which will investigate:

- the need to implement the envisaged requirements,
- the technical feasibility of the requirements,
- the costs and benefits associated with the implementation of the requirements applicable to generators as well as the alternative solutions when considering the proposed requirements.

VGB / EURELECTRIC's generators (referred to as EURELECTRIC thereinafter) propose to discuss and to analyse some crucial (selected) NC RfG requirements and validate them against the criteria enumerated above:

1. Needs
2. Feasibility
3. Alternative solutions
4. Costs

1

Contents

I. Needs, Feasibility, Alternative Solutions and Costs

Needs

In VGB / EURELECTRIC's opinion, the term of reference's criterion "need to implement the envisaged requirements" must be assessed under the following criteria:

- The relevance of the selected requirements,
- The allocation of these requirements to the generator categories,
- The adequacy of the requirements regarding the system security and cross border trade issues,
- The quality of the definition of the requirements (whether a capability is required or a specific solutions is prescribed),
- The benefit of implementing new or deviating requirements and finally,
- The appropriateness of the process (Article 4) proposed by ENTSO-E to implement requirements at national level.

Technical Feasibility

In VGB / EURELECTRIC's opinion, the term of reference's criterion "technical feasibility" covers not only the pure technical feasibility in terms of physics, design, construction and qualification, but must also consider the following:

- Possible interpretations of the provisions: Is the interpretation unambiguous when defining technical specifications?
- The way the provisions are implemented: Is it both possible and straightforward to implement the provision?
- And the consistency of the provisions: Are several implemented provisions simultaneously compatible? Note that the coherence with other EU network codes is difficult to ascertain as those codes are currently available only in a draft version.

EU network codes should NOT:

- Contain requirements which are not technically feasible
- Favour national codes to embark requirements which are not easy to implement
- Contain wordings generating confusion and further technical debate when defining and implementing national provisions.

Alternative Solutions

In VGB / EURELECTRIC's opinion, "Alternative Solutions" shall be considered at requirement level, as far as the whole process strategy for the development has been endorsed and validated by the EC. VGB /

3

EURELECTRIC's analysis on this area targets alternative options when considering requirements, when choosing non-exhaustive parameters or when allocating duties, e.g. between TSOs and generators.

Costs

VGB / EURELECTRIC will not issue any estimates as to the cost of implementation of the code, due to its status still being unclear in some areas and thus leaving room for interpretation.

It will be difficult to assess the cost impact on existing PGFs, if the exact frame conditions of applying the code are not known. The question on how to proceed if the implementation of the requirements is technically not feasible for existing PGF calls for a clear answer.

Nevertheless, VGB / EURELECTRIC will elaborate on how and to which degree costs accrued to PGF systems and components are impacted by some of the RfG requirements.

II. Requirements

Frequency ranges

Needs and Feasibility

RANGE FOR UNLIMITED TIME PERIOD FOR OPERATION

The draft Network Code on Requirements for Grid Connection applicable to all Generators (RfG) proposes a continuous operating range of frequency in continental Europe area doubled in size to 49 Hz – 51 Hz instead of the current range (49.5 Hz – 50.5 Hz). In ENTSO-E's justification FAQ 19, it is stated that significant frequency deviations 'may' occur with the increased penetration of renewables. This statement is effectively contradicted by the ENTSO-E's requirements in the Load Frequency Control and Reserve code (LFC&R) where the clauses describe the standard that they must meet in terms of delivering frequency quality.

The draft LFC&R code keeps unchanged the maximum quasi-steady-state frequency deviation of 200 mHz and the normal operating range of 50 Hz +/- 50 mHz for Continental Europe. The LFC&R code specifies two further frequency range parameters - the 'Frequency range within time to recover frequency' and the 'Frequency range within time to restore frequency'. The values currently proposed for those parameters are +/-500 mHz. This range is the current continuous operating range.

The TSOs undertook in the LFC &R code to bring the frequency back in those ranges within the 'Time to recover frequency' of 1 minute (UK system) and a 'Time to restore frequency' of at most 20 minutes (IR system). With the time and frequency criteria in the LFC&R code, there is no need to require generators to have the capability to operate continuously in a range double that of the frequency range within time to recover frequency or restore frequency.

No additional benefits are identified by requiring this new range. There is no in-depth justification of the new requirement. Most importantly, any costs associated with such requirements are stranded since the wider range is not required by the TSO under their own criteria.

4

VGB / EURELECTRIC:

- have not identified any benefit of doubling the unlimited frequency range in continental Europe area and do not see any appropriate justification for such doubling,
- consider generators will be much more stressed and aged if the frequency quality will get worse and will create superfluous costs,
- call for alternative solutions to be adequately assessed.

RANGES FOR LIMITED TIME PERIOD FOR OPERATION

The need for ranges covering limited time period comes from the fact that generators cannot be designed to stay connected to the grid regardless of the frequency. Therefore, it is necessary to find out an agreement between generators and TSOs to get the assurance that generators will stay connected during the time period when the frequency is out of the range covering the unlimited time. This agreement shall contain not only the ranges of limited time period for operation, but also the durations and the rate of occurrences. The ranges and the durations give TSOs the conditions and the time to launch corrective measures (activation of manual reserves, load shedding, etc.). The rate of occurrences protects generators against too many abnormal frequency situations which markedly stress generators and may cause severe simultaneous damages on plant equipments.

VGB / EURELECTRIC consider the definition of the needs for limited time period incomplete. The 30 minute minimum duration goes much beyond existing requirements[1] in most continental European countries and has not been justified. The durations have been set unilaterally and rate of occurrences is missing.

Alternative Solutions

ENTSO-E's solution (wider frequency ranges) anticipates a possible degradation of the frequency but does not really solve the problem as it does not address the root causes of frequency deviations - a reduction in system inertia, a limited knowledge of the behaviour of dispatched renewable energy sources and the dispatch of generating units in the electricity market which ignores ramping. The TSOs have not proposed solutions addressing the issues of system inertia and ramping although some work has been published in Ireland on this very matter (http://www.eirgrid.com/media/System_Services_Consultation_Products.pdf). It is clear that alternative solutions exist and should be assessed.

Besides, the conclusion of an ENTSO-E ad-hoc team investigating the deterministic frequency deviation found that there is no need for a wider frequency range (ENTSO-E/EURELECTRIC Deterministic frequency deviations – root causes and proposals for potential solutions[2]).

According to the current practices (UCTE handbook "Emergency Operations Policy 5", page 8), load-shedding has to be executed at frequencies in the range between 49.0 Hz and 48.0 Hz with delays of max 350 ms. VGB / EURELECTRIC do not understand the need to impose a minimum time period of 30 minutes for operation at abnormal frequencies if current practices impose a max delay of 350 ms. Due to the fact that, according to the current rules, every TSO has to right to define also additional actions for under-frequency load shedding, VGB / EURELECTRIC propose to define the time duration for operation at abnormal frequencies at national level according Art. 4. This proposal favours the integration of national emergency plan without over specifications.

[1] For instance, the National grid for the commissioning test in 2011 at W B (UK) plant has limited the duration at 48 Hz to 32 s. The code requests ..90 minutes !

[2] http://www.eurelectric.org/media/26970/frequency_deviations_final_february_2012-2012-030-0186-01-e.pdf

5

It is also the intention to develop an "Emergency Code"[3] in the near future. It is meaningless to stipulate at this moment Power Generation Modules (PGM) specifications for emergency situations if operational provisions for emergency procedures will be agreed later.

Costs

These requirements address the ability of electrical systems to withstand the ranges and the durations requested, particularly for auxiliary and safety systems.

- For nuclear units, safety cases have to be re-analysed and new licensing studies have to be developed. The extra costs for existing equipments or for new build may be significant if qualification processes have to be upgraded (primary pumps, feed-water and condensate pumps.). Please refer to the WENRA letter attached for further info.
- For hydro units, safety analysis may reveal excessive costs for civil engineering to implement infrastructures hosting compliant equipments (for transformers for instance).

The strongest criterion representing the quality of the frequency, the standard deviation, has been removed from the draft LFC&R Network Code, revealing the objective to allow the degradation of the frequency quality. In widening the frequency standard deviation and the unlimited operating range, VGB / EURELECTRIC expect that the time generators will be operating outside their governor deadband will increase by 30%. Increasing the service of units delivering frequency response will have significant impacts on the lifetime of the governor and turbine components. This can be seen when examining the criteria from Turbine manufacturers for Equivalent Operating Hours.

Further costs must be allotted to the risks associated with the degradation of the frequency:

- Risk of common failure modes on existing generators not designed for operation within extended limited frequency ranges. This risk is present on the whole synchronous area due to the standardisation of equipments by the manufacturers on that area.
- Risk on security of supply by having long generator outages due to damaged components with high repair/exchange durations (e.g. 18 months for delivery and replacement of turbine blades).

Reactive Power Ranges

Needs and Feasibility

VGB / EURELECTRIC recognize the need for TSOs to request a minimum reactive power capability, giving TSOs the ability to control the voltage in normal situations at the grid connection point. Reactive power is needed to energize the electrical grid and it is logical that power plants generate the variable basic need of reactive power for the grid with a range up to 0.4 rated power. However, it is not logical to prescribe extremely wide ranges as imposed in the RfG network code because cheaper alternatives may exist.

The maximum reactive range requirement proposed by ENTSO-E during the public consultation got 144 comments posted by stakeholders only on chapter *"Type C Synchronous Generating Units shall fulfil the following requirements referring to voltage stability"* and the terms *"not realistic"* is used 21 times in the

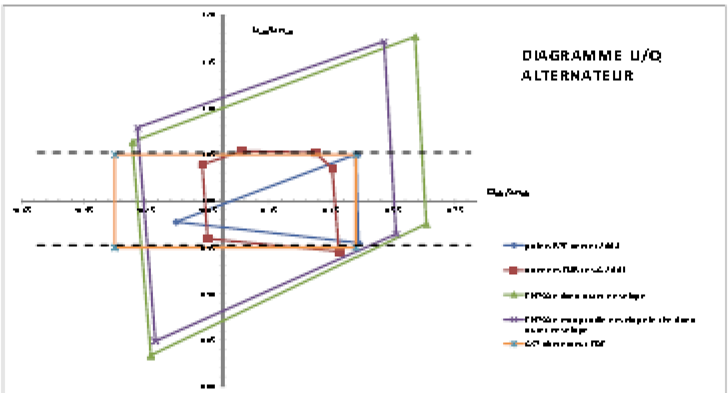
[3] http://ec.europa.eu/energy/gas_electricity/codes/codes_en.htm mentions a "NC on requirements and operational procedures in emergency" but without delivery date.

6

comments. VGB / EURELECTRIC note that ENTSO-E has not expressed maximum TSOs needs in a reasonable, comprehensive and clear manner, particularly when considering the binding character of the code. It is clear, that each TSO will have to make its choice out of the envelope being defined by the requirement. However, it is not reasonable to define a maximum range which is technically not feasible.

The choices made by ENTSO-E to set this requirement using a (V,Q/Pmax) square[4] profile and oversized ranges[5] for V and Q/Pmax give rise to the following concerns :

- The code does not clarify whether the proposed ranges would fit the future needs of the electrical system and whether this capability will be adequate.
- The possibility for TSOs to define reactive capability needs using different shapes (squares or parallelograms) will generate competition distortion because the basic needs have not been defined and harmonized.
- Art. 13 Table 8: The choice of maximum Q/Pmax values has not been justified and is not aligned with existing practices in Continental EU (0.5 to 0.75). All power plant experts consider ENTSO-E's proposal for Q/Pmax (0.95) for Continental Europe as too high, leading to extremely onerous costs for generators. The maximum range of the steady state voltage should be aligned with the unlimited voltage range. As example, following the comparison between ENTSO-E desires and the reality in France:



Comparison of U/Q diagrams at generator voltage terminals
"CST alternateur EDF" means standard EDF's specification for generators

Unclear/ non consistency of combined provisions:

[4] Continuous operation with higher voltages / higher current due to reactive power production shortens the life time of the machine. Higher currents also cause higher losses. It is therefore in the interests of the generating unit operator to deliberately limit the reactive power capability. There should at least be provision to compensate the generating unit operator for the additional investment and operating costs if the limits are to be expanded

[5] For example, the range for Q/Pmax is far too large for continental Europe in relation to current practices (ENTSO-E requests 0.95 where it is only 0.67 in France or 0.74 in Germany). All voltage ranges may vary only in a range of -10% till +10% according to EN 50160. Also according to the ENTSO-E FAQ 20 the limits have to be -10% and +10%.

7

- The outer envelope in Figure 7 in the RfG code describes the capability for a PGF to supply active and reactive power in a maximum voltage range of 0.875 pu to 1.1 pu. The real voltage range is narrower and may not exceed the inner envelop with a maximum voltage range of 0.225 pu.
- Table 6.1 imposes that all PGF remain connected to the grid for a voltage range of 0.85 pu to 1.15 pu. So at a voltage level between 0.850 pu to 0.875 pu (or more) and between 1.10 pu (or less) to 1.15 pu, a PGF must remain connected to the grid without requesting reactive power capability.

The combination of both provisions prompts the need to make investments without any potential to benefit from it, in other words, this entails a waste of money.

VGB / EURELECTRIC recommend making Art. 11 coherent with Art. 13 by imposing in Art. 11 a voltage range identical to the inner envelope according to Art. 13.

Alternative and costs

Larger reactive power ranges than those commonly admitted by the industry shall be justified by TSOs and the decision to request larger ranges should be based according a payment process (usage /capacity) delivering the best benefit for the community. Grid solutions like static VAR compensator, capacitor banks or phase-shifters should be analysed where local needs request larger reactive power capabilities.

Reactive power can be injected by a generating unit or by capacitor banks installed in the grid. Not only the installation costs are different, but also the availability, the reliability and the grid location are to be taken into account for the Cost Benefit Analysis.

The cost of additional MVAr capacity should be compared between:

The cost for the generator:

- An alternator with an extra capacity
- A step-up transformer with an extra capacity
- An energizing system

The cost for a capacitor bank:

- A capacitor bank (without filters[6])
- Installation cost
- HV bay

These requirements impact the size and the weight of the generators, including their cooling and monitoring systems. Energizing systems shall be oversized.

Theoretically, it is possible to get generators compliant with the fixed outer envelope. However, to date there is no existing factory in the world large enough and able to manufacture a 2000 MVA generator compliant with ENTSO-E fixed outer envelope.

Availability consideration: The voltage control system must always be available. A capacitor bank is always available (at exception of maintenance: 1 day / 3 years). A generating unit supplying the same reactive power can be out of service due to an internal defect or due to market conditions. At the current power market conditions, a CCGT power plant can deliver reactive power only 1000 hours/year which has to be compared with a capacitor bank which is available 8000 hours/year.

[6] The cost of a filter is defined by the measured harmonic distortion and depends on the location in the HV grid.

8

The grid operator can define an optimal place in the grid to install a capacitor bank, depending only from grid "reactive power" characteristics. The localization of a generating unit is done by an external party without any impact of the grid characteristics for reactive power management.

VGB / EURELECTRIC propose the following reactive power capability as a minimum requirement (red envelope) included in a maximum standard requirement (green envelope). If TSO's needs are larger at a specific location, then a CBA should shed light on where would be the best choice to implement the extra reactive power capability.

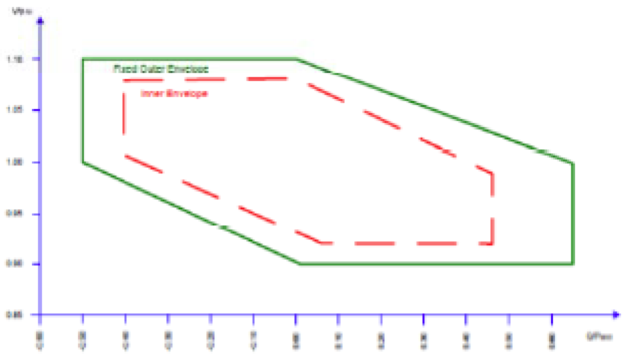


Diagram proposed by VGB / EURELECTRIC during the public consultation of the RfG code.

Voltage ranges

Needs

Voltage is a varying parameter in electrical grids. In many countries the voltage in the HV grids varies in ranges of -7.5% to +7.5% and this range is much smaller than the range imposed by the RfG network code.

The needs expressed by ENTSO-E for the voltage between 110kV and 300 kV have dramatically increased between the public consultation and the final draft:

Voltage Ranges 110kV and 300 kV grids	Public Consultation	Final Draft
0.80 pu – 0.85 pu	30 min	N.A.
0.85 pu – 0.90 pu	60 min	60 min

9

0.90 pu – 1.05 pu	Unlimited	**Unlimited**
1.05 pu – 1.0875 pu	More than 60 min	
1.0875 pu – 1.1 pu	60 min	
1.1 pu – 1.118 pu	N.A.	
1.118 – 1.15 pu	N.A.	More than 20 min

As far as we understand, stakeholders have not requested significant extensions of the unlimited range and of the higher limited range. These extensions – that have important consequences for generators – have not been justified. They impose systematically the use of step-up transformers equipped with on load tap changers and the electrical equipments at the high voltage side will need to be significantly oversized to withstand the highest voltage level.

The case of upgrading existing PGM when a new module gets connected to the same busbar shows the difficulty and the confusion when applying the voltage requirements. What would be the reasons to request the existing PGM to upgrade after the connection of the new module to the same busbar? If there is no need to withstand larger voltage ranges than existing on this busbar, why requesting the new module to comply with a larger voltage range?

To illustrate ENTSO-E's expectation of the deterioration of the voltage quality, as an example for 1 p.u. on a 380 kV system, the grid needs to stand a low voltage of 323 kV in respect of an increasing current at the same time. The lowest voltage for a limited time is nowadays in Germany at around 350-360 kV.

Regarding the voltage ranges, VGB / EURELECTRIC consider the definition of the needs for limited time period incomplete. No rate of occurrence has been defined by ENTSO-E despite the well-known fact that the ageing of the insulators is mainly caused by the duration of the exposure at high voltage levels. Ranges and durations have to be justified moreover by considering the local nature of the voltage control. The durations have been set unilaterally by ENTSO-E without stakeholders being consulted.

Feasibility

ENTSO-E has defined the value of 1 pu at 400 kV for the 400kV grid. By requesting 440 kV (1.10 pu) during 20 minutes minimum, ENTSO-E is violating IEC standards limiting permanent voltages at 420 kV (1.05 pu). This requirement is not according to IEC 60071 standard on insulation coordination. Higher overvoltages above 420 kV (1.05 pu) are only allowed due to their transient occurrence such as lightning[7]. Electrical equipments within some TSOs grids are designed for a maximum voltage for continuous operation at 420

[7] IEC 62271-1 article 6.2.7.1: Voltage higher than 420 kV is accepted only at industrial frequency for max. 60 seconds.

kV. VGB / EURELECTRIC do not accept requirements for power plant operators that are not accepted by TSOs[8].

It is impossible to operate PGM at low frequency and high voltage simultaneously due to excessive magnetic flux in generators, motors and transformers according to IEC 60034[9].

For Continental Europe, the RfG network code imposes a voltage range of 0.85 pu to 1.15 pu for 110kV to 300 kV grids and 0.85 pu to 1.10 pu for 300kV to 400 kV grids. This range is only achievable with "on-load-tap-changers" (OLTC) on step-up transformers. The additional cost of such OLTC is minimal in the total cost of a power plant. However the impact on plant reliability is huge. A survey made by CIGRÉ was published in Electra 88_1. Below, the title and the conclusion are visualized: 41 % of all failures at step-up transformers are due to the OLTC.

Both requirements have not been adequately justified nor has it been shown that this may be in line with existing practices although it is conflicting with IEC standards.

Enquête internationale sur les défaillances en service
des transformateurs de grande puissance
An international survey on failures
in large power transformers in service

Rapport final du Groupe de Travail 06 (*)
du Comité d'Etudes 12, (Transformateurs)
publié à la demande du Président
du Comité, M. W. DIETRICH

Final report of Working Group 05 (*)
of Study Committee 12 (Transformers)
Published at the request of the Chairman
of the Committee, Mr. W. DIETRICH

Considérant l'ensemble des défaillances, on peut remarquer, au sujet du premier composant impliqué, qu'environ 41 pour cent des défaillances ont été dues au CPC et environ 19 pour cent aux enroulements; 53 pour cent des défaillances ont eu des origines mécaniques et 31 pour cent des origines diélectriques.

As regards total failures, it may be noted, with reference to the first component involved, that about 41 percent of failures were due to the OLTC and about 19 percent to the windings; the failure origins were 53 percent mechanical and 31 percent dielectric.

Alternative Solutions

As general provision, VGB / EURELECTRIC propose to limit voltage ranges to ranges currently in practice in several countries so that an OLTC is not needed. Only for very specific locations where the network is weak, wider voltage ranges are acceptable.

VGB / EURELECTRIC demand to respect always the relevant IEC standards regarding the upper voltage limit.

---

[8] For instance, RTE (France's TSO) uses 420kV as standard for the highest voltage for overhead lines IEC 60060-1 ("Tension la plus élevée entre phases pour le matériel (kV valeur efficace)" in Fehler! Verweisquelle konnte nicht gefunden werden. Fehler! Verweisquelle konnte nicht gefunden werden. Fehler! Verweisquelle konnte nicht gefunden werden.

[9] For example, in Switzerland at Beznau generators ABB/ALSTOM specifications request $B_x/B_n = U/U_n \times f_n/f$ c = 1.1

VGB / EURELECTRIC recommend also making the tables 6.1 and 6.2 in Art. 11 coherent with the voltage range imposed by the inner envelope according to Art. 13.

Costs

The main equipments concerned are the step-up transformer, the auxiliary transformer and the high voltage equipments in the bay at the power station. For existing plants it needs to be taken into account that it is highly possible that the transformers are getting bigger that the foundation works and adjustments need to be respected as well. Furthermore extra costs will pile up as spare parts already purchased and stored for future use will become unusable.

OLTC are necessary to achieve the voltage ranges imposed by ENTOS-E. OLTC have a huge impact on the reliability of the step-up transformer and should be avoided in strong grids. The time to repair can take till 12 months. The total availability of the generating unit will decrease, thus influencing security of supply.

Fault Ride Through

Faults occurring on the network, within Power Generating Facilities (PGFs) or within consumer installations, can impact the security of the wider power system. To guarantee the secure operation of the system even in case of faults, measures are necessary to reduce the effects of those faults on the power supply system. These measures fall on both the Network Operators and the Power Generating Facilities owners. Requirements in the Network Code should have the objective to minimize the consequences of occurring faults in an economically and technically optimised manner for all involved stakeholders.

The expected performance of PGMs during faults resulting in deep voltage dips due to a short circuit in the network is handled in the fault ride through requirements in the draft network code.

During the time needed for the network protection to identify and clear a short circuit, the local network voltage will collapse and the PGM will not be able to deliver its electrical power onto the network. The turbine of the PGM still delivers a constant mechanical power to the shaft of the generator and the resulting imbalance between input and output power causes a fast acceleration of the rotating parts of turbine and generator. This acceleration is only stopped by the timely removal of the short circuit. If the time taken for removal of the short circuit is too long, the acceleration will result in the loss of synchronism of the PGM and tripping of the PGM becomes necessary. This maximum time is known as the 'critical clearance time' (CCT).

The critical clearance time is a physical time limit which depends on:

- the type of the fault
- the size and the type of the PGM
- the local short circuit power of the network (available directly after fault clearance)
- the behaviour of other electrical equipments connected to the local network (auxiliaries, electronics, etc.)
- the point of operation of the PGM when the fault occurred (in P/Q diagram)

The critical clearance time varies. Usual values are between 100ms and 150ms.

12

When the critical clearance time is exceeded before the fault is cleared and the voltage restored, the PGM must disconnect from the network to avoid serious damage to its equipment.

Network Operator measures: To minimise the effects of short circuit faults, the Relevant Network Operator must have installed a proper state of the art network protection system which will ensure that short circuit faults are cleared in the fastest time possible and in particular faster than 90% of the critical clearance time.

Power Generating Facility Owner measures: Due to the time needed for a circuit breaker to operate, the PGF's protection equipment must ensure that the command signal to disconnect is issued before the full critical clearance time is past. Otherwise, the unit will have lost synchronism before disconnection is achieved. The PGF owner shall implement a trip time for such protection equal to 90% of the critical clearance time. This is an essential measure to prevent severe damage and long outages.

If the fault occurs in a grid area with many significant generators and the critical clearance time is not respected, then there is a serious security of supply risk.

VGB / EURELECTRIC have got negative feedback from vendors and manufacturers to design large generators FRT capable with a 250ms critical clearance time. For smaller generators, this entails significant extra costs for generators, turbine governors, energizing systems and control systems. A Cost Benefit Analysis should be performed to compare these costs with the eventual costs of upgrading the Network Operators protection systems to achieve a faster fault clearance time. As part of this CBA, the benefits of harmonising the Fault Ride Through profile across all control areas has to be demonstrated, due to the substantial diversity of the grid protection system design at EU level.

Needed justification:

i. The requirement of critical clearance time of more than 150 ms for power plants makes only sense for substations where a "circuit-breaker-failure backup" system is installed. As far as we know, such backup systems are mainly installed in 400 kV substations.

   In substations without a "circuit-breaker-failure backup" system, the fault clearance time is 130 ms with a modern redundant protection system and a modern circuit-breaker. The clearance time is determined by:

   - 45 ms for the protection device
   - 45 ms for the mechanical activation of the circuit-breaker
   - 40 ms for the arc extinction in the circuit-breaker.

   Even older circuit-breakers can achieve fault clearing within 150 ms. If the circuit-breaker does not clear the fault, a back-up in the neighbouring substations will clear the fault after 500 ms or more.

   In substations with a "circuit-breaker-failure backup" system, a state of the art protection system and modern circuit-breaker can eliminate every fault in backup in 200 ms. The clearance time is 130 ms as mentioned above. When operating in backup, the additional time is:

   - 20 ms for a waiting time period after the refusal to trip of the first circuit-breaker

13

- 85 ms for the opening of the backup circuit-breaker.

The total clearance time is 200 ms. Imposing more than 200 ms effectively means that the TSO has not installed state of the art apparatus in the substation.

A large majority of power plants is connected to substations without a "circuit-breaker-failure backup" system where the fault clearance time is always lower than 150 ms or higher than 500 ms. Only power plants connected to substations with a "circuit-breaker-failure backup" system need a critical clearance time of 200 ms and nothing more.

ii. Review of the existing national network codes shows that nearly all TSOs expect to clear short circuits resulting in severe voltage dips in 150ms or less. This value comes from a global optimisation performed in the past time where electrical systems were integrated, balancing performances and costs between generation and transmission.
However, ENTSO-E has proposed in the draft code that PGFs should expect severe short circuits not be cleared until 250ms in the future. This dramatic reduction in performance expected from the Network Operator's protection systems is a significant degradation from existing practise and has severe implications for existing PGFs. Despite the common statement of all stakeholders for a 150ms critical clearance time, ENTSO-E has refused during the last RfG Users Group to set the critical clearance time to 150ms in all synchronous area except for Nordic, arguing that TSOs may in the future need a greater critical clearance time once again, without sound justification based on CBA. TSOs may currently define CCT for their area on a lower level as this is a non-exhaustive requirement. However, for PGF owners it is an undue risk that they have to expect larger CCT in the future whereby TSO shift costs to PGFs without justification.
The costs for loss of Equivalent Operating Hour (EOH) are also not considered by the code and would mean an additional shifting of these costs to the PGM owner.

Alternative Solutions

VGB / EURELECTRIC propose the code to consider the following values for the Maximum Clearance Time

Synchronous area	Maximum Clearance Time Without Circuit Breaker Failure Backup Systems	Maximum Clearance Time With Circuit Breaker Failure Backup Systems
Continental Europe	150ms	200ms
Nordic	250ms	250ms
Great Britain	150ms	200ms
Ireland	150ms	200ms
Baltic	150ms	200ms

14

Power by falling frequency

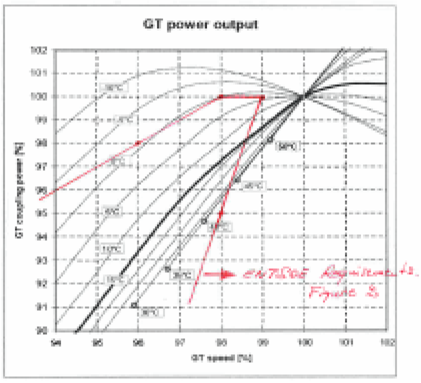
Needs and feasibility

Controlling power with falling frequency cannot ignore physics applicable for each type of PGM (gas turbines, hydro, boiler, etc.). This requirement is influenced by the size of the headroom.

For example, gas turbines:

- maintaining initial power when the frequency falls is not possible between 50Hz and approx. 49 Hz as indicated in the next graph (Source: Siemens)
- limitations occur because of "rotating stall": compressor pumping can occur depending on rotor speed and other parameters like ambient temperature and output power. It is well known, that such a rotating stall may lead to the disintegration of a gas turbine.

Commissioning and testing of such systems under real conditions is not possible. The risk exists during normal operation to trip the plant (meaning a Fast Shut Down). Reliability of continued operation at low frequencies has to prevail above a higher output with less reliability. Furthermore the behaviour of some technologies at low frequencies depends strongly on ambient conditions.



This graph from Siemens shows the power output of a gas turbine at falling frequencies for various ambient temperatures. The requirements according to Art.8 (Figure 2) are outlined in this graph. The conclusion is that the capacity decreases also for frequencies outside the area requested by the code.

Alternative Solutions

As it is written in NC RfG, this requirement allows TSOs to adapt or change dramatically the technical conditions ("*Applicability of this reduction is limited to a selection of affected generation technologies and may be subject to further conditions defined by the Relevant TSO while respecting the provisions of Article 4(3).*").

Considering the necessity to take into account the physical characteristics of the PGM and the environmental need to maximise its efficiency and its power output, VGB / EURELECTRIC propose two options to define the requirement:

15

i. a general statement without values for parameters granting maximum efficiency and output for each PGM at falling frequency
ii. a detailed statement for each type of PGM requesting active power reduction with falling frequency with values for parameters.

Costs

As currently written, the requirement imposes to operate a gas turbine at about 97% of its nominal capacity instead of 100%, thereby decreasing its efficiency by 1 percentage point and resulting in higher CO2 emission. At an average price of 65 EUR/MWh for a CCGT, this operational constraint will increase the price with 0.65 EUR/MWh. For an open cycle gas turbine, the additional cost will even be higher (about 1 EUR/MWh).

Information exchange

ENTSO-E's requirements related to information exchange (in article 9.2.5.d) are too general because of the binding character of the code. Because of the need to harmonise the system operation codes and the associated inter TSOs coordination, only a list of minimum mandatory signals should be defined. The usage of the data provided by the signals shall be clearly stated.

Besides, ENTSO-E requests in article 10.2.f six specific signals for FSM monitoring, without considering the feasibility and the security constraints. VGB / EURELECTRIC's experience shows that cyber protection or uncertainties of the calculation make usage and reliability of certain data very difficult. PGF owners cannot accept direct access by TSOs to the digital control systems due to cybersecurity reasons.

The signals requested by the code should be defined in a functional way including all relevant constraints as cyber security and TSOs shall be obliged to disclose the usage of the signals.

As already mentioned, this requirement will generate many misinterpretations and disputes.

Alternative Solutions

VGB / EURELECTRIC recommend a deeper coordination with stakeholders to define a minimum list.

Fault Recording Device

There is no doubt about the necessity to record and timestamp the electrical signals at the plant interface to analyse electrical faults and events.

All the parameters listed in the code are intended to be used by the Relevant Network Operator or Relevant TSO for the assessment of PGF performance. As all performance criteria in the network Code are defined at the connection point, i.e. in the HV network, it is obvious that the instrumentation should be installed at that location.

As far as VGB / EURELECTRIC understand, no code imposes TSO to have their own Fault Recording Device. It is the responsibility of TSOs to perform the analysis of grid events and they should use their own recording devices to do so.

16

Even though there is no need to impose PGF owners to have their own Fault Recording Device, VGB / EURELECTRIC recommend PGG owners to have them.

It should be the sole decision of the PGF Owners to decide to install a Fault Recording Device at its premises to provide fault recording and dynamic system behaviour monitoring (not only voltage, active cower, reactive power, and frequency; but also current, breaker positions, etc.)

Since

- the use of such instrumentation is for the Relevant Network Operator,
- the location of the installation of the instrumentation is under the control of the Relevant Network Operator,
- the PGF Owner has no equipment beyond the HV connections of the generator step-up transformer,

The instrumentation required to be installed for monitoring the fault performance, dynamic performance and power quality indices should be installed by the Relevant Network Operator to their own specification. This is currently the case for the Fault Recording Device used by TSOs for their own bays.

VGB / EURELECTRIC see the risk that ENTSO-E shifts the cost of the Fault Recording Device from TSOs to Generators. This option might even be understood if it was the choice of National Regulators and Authorities. However, there is no technical benefit from installing such equipment within the PGF and the data gained from the PGF would be very difficult to translate to the connection point leading to disputes and confusion.

Alternative Solutions

The Fault Recording Device should be specified and installed by TSOs on their property. Recording devices are already installed in most substations to record faults on grid elements (lines / cables / transformers). Recording faults in the connection of a PFM means only an additional rack in the existing cabinet at a very low cost.

Costs

The ENTSO-E solution is not cost optimized because it requires a stand-alone system in each PGM instead of additional equipment in the fault recording system of the TSO.

Injection of Reactive Current by PPM at Fault

Needs and feasibility

Short-circuit currents allow to detect and localize faults in a grid. The short-circuit currents are injected by power plants in the transmission grids and consequently also in distribution grids. In general transmission grids are meshed and sophisticated protection systems are in place; distribution grids are in general radial and equipped with simple over-current protection systems. The over-current relays order a trip of the circuit-breaker at currents far higher than the rated current.

Art. 15 allows the national authorities to impose for Power Park Modules (PPM) above 1 MW to inject a reactive current at fault in the network. This current is limited to the rated current.

17

The major characteristic of a PPM is the intermittent nature of the power injection. This would mean that depending on the status (injecting power or not) of the PPM, a short-circuit current will or will not be injected by the PPM imposing different protection schemes for the affected grid.

If connected at DSO level, VGB sees a number of problems due to the different flows of the fault current depending on the operational status of the PPM. But it is up to DSOs to formulate their point of view

If connected at TSO level, this feature has sense, but the specifications of 10 ms and 60 ms in Art. 15.2.b.2 are not realistic according to information from VESTAS and GE. It is true that GE made some experiments achieving 10 ms reaction time period, but this was under well-defined grid conditions without any guarantee that it is also applicable to industrial grid conditions. The comment of a manufacturer was simple: "With a time period of only 10 ms, I fear to inject flicker into the grid". This provision is not feasible for wind parks connected at TSO level because the specifications are not according to proven technology.

Alternative Solutions

VGB / EURELECTRIC support EWEA proposal for Art. 15.2.b.2:

"The Power Park Module […] shall be capable of providing at least 90% of the additional reactive Current (positive sequence of the fundamental) within a time period specified by the Relevant TSO, which shall not be less than 60 milliseconds. The target value of this additional reactive Current […] shall be reached with an accuracy of -10%/+20% (of rated current) within 100 milliseconds from the moment the voltage deviation has occurred as further specified […].
Below 40 % of the retained voltage, reactive current shall be supplied as far as technically feasible."

Changes to, Modernization of or Replacement of Equipment

ENTSO-E's requirements (*"changes to, modernisation and replacement"* Art. 10.6.g) are not proportionate and are mixed up.

- First, it should be the responsibility of the PGF owner to inform the Relevant Network Operator (RNO) on the functional changes/modernisation/replacement of equipments.
- Equipments are changed / upgraded either to maintain the plant systems with the same functions and performances (replacement) or to give the plant systems new functions and new performances (modernization). Therefore replacement and modernisation cannot be considered at the same level in the code when considering compliance to the requirements.

NEED FOR MODERNISATION

It is unlikely that the RNO has the expertise to assess the impacts of a retrofit on the performances related to the NC RfG. Modernisation is needed for functional reasons or for solving technology/industrial obsolescence.

This impact assessment of the modernisation should be a PGF owner responsibility. If the modernisation is caused by obsolescence and keeps the performance unchanged, there is no reason to request the compliance with the NC. Modernisation does not change the design bases of a PGF and therefore the technical basis remains the same, when for example the voltage regulator or the block protection needs to be replaced. The technical capability is unchanged in that case, thermodynamics, turbine, generator and main transformer remaining with the same behaviour.

REPLACEMENT OF EXISTING EQUIPMENT WITH SPARE PARTS

Most of the existing generating units have standardized components built with standardized parts. PGO have bought spare components to reduce the outage durations and often pools of spare parts from manufacturers of identical design have been ordered to cover the PGM fleets. Designing changed replacement parts, if possible at all, is expensive and will take long delivery times!

Mainly, these components have been bought at the commissioning date of the power plant and were compatible with then standards used by grid components.

There is no need to request "the use of existing spare components that do not comply with the requirements has to be agreed" unless it has been evidenced by the RNO that the absence of retrofit will lead to cross border issue or to system security threats. However, in such a case the relevant requirement of the NC for RfG would have to be adapted to existing plants according to the provisions in Art. 3(2).

Considering the "cost balanced" concept brought up in article 4.2, it is interesting to notice that no stakeholder has requested during the consultation "*the use of existing spare components by TSOs on grid equipments that are not compatible with the requirements applicable for generators has to be agreed by the Stakeholders*".

Alternative Solutions

To propose a new writing for Art. 10.6.g:

"*With regard to modernization of equipment of Power Generating Modules, any Power Generating Facility Owner intending to change plant and equipment of the Power Generating Module that may have an impact on the grid connection and on the interaction, such as turbines, alternators, converters, high-voltage equipment, protection and control systems (hardware and software), shall notify in advance (in accordance with agreed or decided national timescales) the Relevant Network Operator in case it is reasonable to foresee that these intended changes may affect the fulfillment of requirements of this Network Code and shall, while respecting the provisions of Article 4(3), agree on these requirements before the proposals are implemented with the Relevant Network Operator in coordination with the Relevant TSO.*

With regard to replacement of equipment or to use of spare parts in Power Generating Modules the compliance with the requirements will not be requested if the new equipment has the same functions and performances."

Categorisation

Except a few paragraphs in Art. 3.6, there is no document discussing the allocation of requirements to categories, no clear explanation of the usage of categories in system planning and operation, and no sound definition of category choices and thresholds.

How "*Power Generating Facility Owners shall assist and contribute to this determination of the threshold and provide the relevant data as requested by the Relevant TSO*" if they do not have any view on the choices at the origin of the thresholds in Table 1 and on associated reasons?

The Framework Guidelines clearly state (in 2.1) that: "*The network code(s) shall specify the criteria and methodology for the definition of significant grid users.*" The definition of "significant" is exaggerated for Type A generators ("*Power Generating Module which is deemed significant on the basis of its impact on the cross-border system performance via influence*") unless it is proven that a group of identical generators having the same frequency behaviour can represent a clear threat for system stability.

19

The methodology as described in the code to identify significant generators is too vague, ignores the voltage level at the connection point below 110kV for the categorisation and assumes that any kind of generator (>800 W) is supposed to become a threat for the system security, which is obviously excessive.

Two mains issues arise on the classification of PGM:

i. Contrary to the ACER's Framework Guidelines the classification of generators does not consider voltage as a criterion for the classification of PGM. A small class B generator (2 MW) will be connected at medium voltage grids and a medium class B (40 MW) generator will connected at high voltage grids. Therefore unique requirements such as FRT for type B small and for type B medium generation are not possible.
According to current practice, voltage variations in medium voltage grids are limited to -4% to +4% because the European standard EN50160 has to be respected also for low voltage consumers (also additional voltage variations in the low voltage grids apply for those consumers). Consequently imposing identical voltage ranges for generators connected at medium voltage and a high voltage will impose exaggerated requirements for medium voltage connected generators.
The justification of the need to impose FRT to all Type B generators is weak. During the stakeholder group at ENTSOE on 22/11/2012, maps of Germany, France and the UK were shown with simulations of voltage during a fault in the 400 kV grid. ENTSO-E has used these maps to justify the necessity to request FTR for Type B generators. This methodology is not relevant to impose the FRT behaviour of Type B PGM. Most of these PGM are connected to lower voltage levels separated by one or several transformers from the 400kV grid and the voltage of those grids remains higher during a fault in the 400 kV grid. Higher voltages in lower grids were also mentioned during this presentation by ENTSOE on following slides but were not retained in the final conclusion.

ii. The thresholds proposed in Table 1 appear too low when considering cross border issues. Is it absolutely necessary that all PGM in continental Europe greater than 1 MW shall be FRT-capable? Is it absolutely necessary that all PGM in continental Europe greater than 75 MW have the full features, even if they are not connected to interconnectors or to HV backbones? Thresholds have not been justified and "no significant test" has been applied for their selection.

The process to define generators' categories seems an open attempt from ENTSO-E to take control of all new EU generators from 800W to 1700 MW, without justifying the basic needs and benefits. All generators are required to improve their performances. Does this fit with the proportionality requirements?

Retroactivity

Because of the uncertain methodology of CBA, the retroactivity process as described in Article 3.2 should be restricted only to cases preventing severe system security threats. Stakeholders do not have any idea if there will be needs, now or later, to upgrade existing generation. It is unclear why, on a specific requirement, retroactivity would be requested in one country and not in the neighbouring states.

ENTSO-E has often mentioned the risk of system blackout to justify the requirements and the need for compliance. VGB / EURELECTRIC would like to underline there is no obvious and no immediate direct link between the non-compliance of one or a few PGFs with particular requirements and a severe electrical

20

system event. TSOs have to plan and operate the system with contingencies (N-1, etc) according to their knowledge and their confidence in PGM performances. The contingencies are used to cover uncertainties and local temporary non-compliance. When considering the first phase of CBA process, TSOs should be obliged to assess cliff effects (or scale effects) when thinking about retrofitting existing PGMs. Such lack would be similar to the lack of significance tests in the RfG NC development process.

Alternative Solutions

VGB / EURELECTRIC propose the code to integrate:

- A restriction of retroactive application to system security threats
- A more detailed CBA methodology including involvement of stakeholders in first phase, significance tests and cliff effects.

Legal issues

i. The implementation of the provisions will be difficult and will generate a severe administrative burden due to the poor quality of the consultation:
    1. As all provisions can be modified every three years, no guarantees exist for a business plan covering the total lifetime of a PGF.
    2. A request for derogation can only be submitted by the PGF operator, not by manufacturers. Also a class-derogation is not allowed even where external regulations impose more stringent requirements (e.g. nuclear, hydro). Because many requirements are not applicable to nuclear technology, going through local derogations for standardised plant will create a lot of additional, avoidable red-tape. Class-derogations should therefore be possible.
    3. In order to be proportionate regarding the system needs and to avoid discrimination, the repeated compliance procedure throughout the lifetime of a PGF (Art. 35.2) should take place at the same rhythm and not more frequently than every 10 years for all PGF owners.

ii. The NC RfG and the Frequently Asked Questions, 19 June 2012 page 18 stipulate that the public consultation will be carried out by the TSO instead of the NRA. As an interested party, the TSO cannot be the correct party for the consultation or indeed for the CBA which ought to be undertaken by an independent body appointed by the National Regulatory Authority.

Missing requirements

i. The FG 2.1 stipulates harmonisation as far as technically possible and economically beneficial throughout the EU. At least the values of parameters decided by the national TSO/NRA should require coordination at synchronous level.

   Alternative Solution:
   ART 4(3)
   3. Where in this code, the determination of the terms and conditions for connection and access to networks or the methodologies to establish them shall be set by the National Regulatory Authorities, or any other entity designated by a Member State in compliance with Directive 2009/72/EC, it shall be made in close cooperation with the neighbouring National Regulatory Authorities, or any other entity designated by a Member State in compliance with Directive 2009/72/EC, of the synchronous area and it shall be subject to prior public consultation of the

21

involved stakeholders and to prior recommendation of the Agency, in accordance with the rules of national law implementing Directive 2009/72/EC, and with the principles of transparency, proportionality and non-discrimination.

4. Any decision by a Network Operator other than the Relevant TSO and any agreement between a Network Operator other than the Relevant TSO and a Power Generating Facility Owner shall be approved by the Relevant National Regulatory Authority pursuant to the principles of the previous paragraph of the present Article and shall be exercised in compliance with and respecting the Relevant TSO's responsibility to ensure system security according to national legislation. Further details to ensure this principle may be specified either by national legislation or by agreements between the Relevant TSO and the Network Operators in its Control Area, as the case may be.

5. When this Network Code establishes that a requirement can or shall be agreed, the TSO can determine this requirement if national law assigns it to the TSO and such an assignment was in place at the date of the entry into force of this Network Code."

ii. A description of all derogations is not publicly available. This is a violation of the principle of "openness of government".

iii. More generally, when considering system evolution, there is a big risk of lots of derogation during the implementation phase[10]. To make matters worse, no change process has been identified that could open up the code for future adaptation or evolution.

iv. We are missing a requirement for TSOs to coordinate transparently when implementing the code (principle of openness of government).

v. The network code must aim at striking a balance between achieving high overall efficiency and lowering the total cost for all involved stakeholders. No impositions for TSO are described in the network code related to voltage regulation capacity (the voltage can be regulated by the PGF and by the TSO/DSO).

vi. Article 10.2.c.4 is an excellent example of unclear provision: "*The Frequency Response Deadband of Frequency deviation and Droop are selected by the TSO and must be able to be reselected subsequently (without requiring to be online or remote) within the given frames in the table 4.*"

In a general way, the process allowing TSOs to reselect parameters should garantee the technical[11] and the industrial feasibility.

Conclusions

This paper has highlighted some crucial requirements stemming from ENTSO-E draft NC RfG that generators feel particularly strong about. Taking a pro-active stance and using concrete evidence from the RfG code and available information as much as possible, the paper shed lights on those requirements which are:

[10] Some existing provisions are out of the ranges proposed by ENTSO-E, for example the fault ride through Tclear parameter in Poland which is 120ms, below the proposed range of 140-250ms. The second sentence of the grey bullet on page 34 of the document "Requirement In The Context Of Present Practices" appears to be incorrect.

[11] For instance, depending on the technology, a droop value may be applicable to switch from normal operation to islanding operation.

22

- ✓ Not technically feasible (e.g. reactive power ranges)
- ✓ Contradicting requirements contained in other network codes being developed by ENTSO-E (e.g. frequency ranges for limited time period of operation)
- ✓ Put disproportionate burdens onto power generators - without achieving societal benefits such as increased reliability of the grid, hence reduced risk of blackouts (e.g. voltage ranges)
- ✓ Can be re-drafted taking into account a fairer burden-sharing between PGF owners and TSOs (e.g. fault recording devices)

****

23

GLOSSARY

CBA	Cost Benefit Analysis
CCGT	Combined Cycle Gas Turbine
CIGRÉ	Conseil International des Grands Réseaux Électriques
DIN	Deutsche Institute für Normung
EOH	Equivalent Operating Hour
FRT	Fault Ride Through
FSM	Frequency Sensitivity Mode
IEC	International Electrical Commission
MVA	Mega Volt Amps
NRA	National Regulatory Authority
OLTC	On Load Tap Changer
PGF	Power Generating Facility
PGM	Power Generating Modules
PPM	Power Park Module
RNO	Relevant Network Operator

Stellungnahme

Technische Netzanschlussbedingungen für Stromerzeuger

ENTSO-E Network Code on Requirements for Grid Connection applicable to all Generators (RfG)

Berlin, 16. April 2013

BDEW Bundesverband der Energie- und Wasserwirtschaft e.V.   www.bdew.de

Zusammenfassung

Die von den europäischen Übertragungsnetzbetreibern (ÜNB) verfolgte Linie der Ausgestaltung der Network Codes und insbesondere des Network Codes on Requirements for Grid Connection applicable to all Generators (NC RfG) ist aus Sicht der übrigen Marktteilnehmer nicht geeignet, um die erforderliche Transformation der Stromnetze und des Marktdesigns im Zuge der Energiewende zu unterstützen. Der Entwurf geht in seinen maximal möglichen Anforderungen deutlich über die von der EU-Richtlinie geforderten Mindestanforderungen hinaus. Es drohen zusätzliche Belastungen vor allem für Kraftwerks- aber auch für Verteilnetzbetreiber durch zu weitgehende technische und bürokratische Vorgaben (z.B. an die Notifizierung).

Gleichzeitig schränken detaillierte technische Vorgaben an anderer Stelle den Spielraum für marktwirtschaftliche Lösungen ein – u.a. bei der Bereitstellung von Blindleistung oder Regelenergie.

Die Kosten für diese zusätzlichen Belastungen können die Wirtschaftlichkeit für Neuanlagen und – soweit zutreffend – auch für Bestandsanlagen deutlich beeinträchtigen. Damit besteht die Gefahr, dass Investitionen in Neuanlagen und zur Modernisierung von Bestandsanlagen von vornherein unterbleiben.

BDEW und VGB PowerTech plädieren daher bei der nationalen Umsetzung des NC RfG dafür, die Vorgabe für die Anschlussbedingungen von Stromerzeugungsanlagen an folgenden Prinzipien zu orientieren:

- Network Codes sind auf die Mindest-Vorgaben zu beschränken, die für die (grenzüberschreitende) Systemsicherheit europaweit zwingend erforderlich sind. Anforderungen, die neu sind oder von den bislang geltenden Regelungen abweichen, sind zwingend mit einer umfassenden Kosten-Nutzen-Analyse zu begründen, die Gegenstand einer öffentlichen Konsultation sein muss.
- Die Frage der Kostentragung für die Anforderungen aus dem NC RfG ist im Gesamtkomplex mit zu betrachten.
- Die Verantwortung für den stabilen Netzbetrieb und die dazu erforderlichen Netzanschlussbedingungen sollte beim jeweiligen Netzbetreiber liegen (unter Beachtung der EU-weit gültigen Mindest-Vorgaben).

1. Anlass

Im Rahmen der Umsetzung des 3. Binnenmarktpakets (Verordnung (EG) Nr. 714/2009) und der ACER Framework Guidelines Grid Connection vom 20. Juli 2011 hat die europäische Vereinigung der Regulierungsbehörden ACER die europäische Vereinigung der Übertragungsnetzbetreiber ENTSO-E aufgefordert, den Entwurf für einen Network Code zu den technischen Netzanschlussbedingungen von Stromerzeugungsanlagen (Network Code on Requirements for Grid Connection applicable to all Generators (RfG), kurz NC RfG) zu erarbeiten.

Ziel des NC RfG ist die rechtlich bindende europaweite Harmonisierung der Netzanschlussbedingungen für alle Stromerzeugungsanlagen, die Erhöhung der Systemsicherheit auch bei einem wachsenden Anteil fluktuierender Einspeisungen durch Erneuerbare Energien sowie die Stärkung des europäischen Binnenmarktes. Die technischen Netzanschlussbedingungen sollen für alle Arten von Erzeugungsanlagen (fossil, nuklear, erneuerbar) gelten, wenn auch differenziert nach Leistung und Spannungsebene der Einspeisung. Von den Regeln sind Bestandsanlagen nur betroffen, wenn die jeweils zuständige Regulierungsbehörde einem entsprechenden Antrag des Netzbetreibers bezüglich einzelner Anforderungen zustimmt.

2. Stand der Umsetzung

Nach einem mehr als zweijährigen Dialogprozess, der von BDEW und VGB PowerTech intensiv begleitet wurde, legte ENTSO-E den Entwurf eines NC RfG vor, der im Zeitraum vom 24.01.2012 bis zum 20.03.2012 konsultiert wurde.

Der ungeachtet der über 6.000 im Rahmen der Konsultation eingegangenen Anmerkungen nur in Teilen überarbeitete Entwurf wurde ACER am 13. Juli 2012 von ENTSO-E vorgelegt, um vor allem die Vereinbarkeit des Entwurfs mit den Leitlinien zum Netzanschluss (Framework Guidelines on Grid Connection) überprüfen zu lassen. Im Ergebnis wurde ENTSO-E durch ACER in vier eher untergeordneten Punkten zur Nachbesserung des NC RfG aufgefordert.

Nach einer erneuten Stakeholder-Konsultation hat ENTSO-E ACER dann am 12.03.2013 einen in den angesprochenen Punkten überarbeiteten Entwurf des NC RfG übermittelt.

Ende März 2013 hat ACER den Entwurf mit einer kurzen Bewertung an die Europäische Kommission weitergeleitet, die nach Prüfung und Begutachtung durch ein Konsortium von COWI und DNV/KEMA ein Komitologie-Verfahren zur endgültigen Verabschiedung durchführen wird.

Mit einem Abschluss des Verfahrens und damit der Rechtswirksamkeit des NC RfG ist Anfang 2014 zu rechnen.

Die Umsetzung des NC RfG in die nationale Regulierungspraxis der EU-Mitgliedstaaten erfolgt durch die einzelnen ÜNB nach der Genehmigung durch die jeweilige nationale Regulierungsbehörde.

3. Inhaltliche Bewertung

3.1 Generelle Einschätzung

Der NC RfG soll in Übereinstimmung mit den Vorgaben von ACER verbindliche Minimal-Anforderungen an alle Erzeugungseinheiten in Europa definieren, wie die Bedingungen und Vorgaben zum Verhalten von Kraftwerken bei Frequenz- und Spannungsschwankungen, Kurzschlüssen, Lastsprüngen, Schwarzstartfähigkeit, Inselnetzverhalten und vieles andere mehr.

Die von ENTSO-E (Fassung vom 8. März 2013) am 12. März 2013 an ACER übergebene Fassung des NC RfG räumt den nationalen ÜNB zwar im Hinblick auf die wesentlichen Anforderungen Spielräume ein. Allerdings stellen einige dieser Anforderungen auch unter Berücksichtigung der Spielräume, ungeachtet der von vielen Seiten im Rahmen des Konsultationsverfahrens geäußerten Kritik, eine deutliche Verschärfung gegenüber dem in Deutschland (Transmission Code 2007) und den in anderen europäischen Ländern geltenden Vorgaben dar. Insbesondere können weder Neuanlagen, die mit heute am Markt verfügbaren Komponenten errichtet würden, und erst recht nicht Bestandsanlagen den maximal möglichen technischen Ansprüchen genügen. Würden ferner diese maximal möglichen Anforderungen auf Bestandsanlagen angewendet (soweit technisch überhaupt möglich), müssten diese in großem Umfang nachgerüstet werden. Anderenfalls liefe der Betreiber Gefahr, dass der Netzbetreiber die Stilllegung der Anlage erzwingen würde.

Insgesamt besteht der Eindruck, dass sich die beschriebenen Methoden, Verfahren und Vorgehensweisen zumeist einseitig an den Interessen der Übertragungsnetzbetreiber orientieren und weder den Interessen der Kraftwerksbetreiber, deren Anlagen im Übertragungsnetz angeschlossen sind, noch den Anforderungen der Verteilnetzbetreiber mit einer Vielzahl kleiner und mittlerer Erzeugungsanlagen angemessen gerecht werden.

Für die endgültige Bewertung der Auswirkungen einer Umsetzung des NC RfG in seiner vorliegenden Fassung bleibt abzuwarten, wie die deutschen ÜNB ihre Spielräume zur Festlegung konkreter Werte bei der Umsetzung des Codes nach der Genehmigung durch die BNetzA nutzen werden. Bereits jetzt aber ist erkennbar, dass bezüglich der zwingend aus dem NC RfG zu übernehmenden Anforderungen für extreme Frequenz- und Spannungsbereiche und für die Blindleistungsbereitstellung bei Neuanlagen mit Verschärfungen zu rechnen sein wird. Möglicherweise werden diese erhöhten Anforderungen nach Antrag des ÜNB und Genehmigung durch die Regulierungsbehörde aber auch auf die Bestandsanlagen übertragen.

3.2 Anwendungsbereich

Angesichts der Komplexität des Themas dienen die Ausführungen in diesem Kapitel neben der Kommentierung auch der Darstellung des sachlich-inhaltlichen Zusammenhangs einzelner Aspekte, auf deren Grundlage dann im folgenden Kapitel die Bewertung vorgenommen wird.

Die Anforderungen des NC RfG gelten laut Art. 3 für Neu- und Bestandsanlagen. Bei letzteren allerdings nur in dem Maße, wie dies die jeweilige nationale Regulierungsbehörde auf Vorschlag des/der betreffenden ÜNB nach einer öffentlichen Konsultation entschieden hat. Im

Hinblick auf das Ausmaß der jeweiligen Anforderung unterscheidet der NC RfG die Anlagen nach Art und Leistungsgröße der Erzeugungseinheiten (Anlagen von Typ A bis D mit unterschiedlichen Leistungsbereichen je nach Netzregion) bzw. nach Anschluss an das 110 kV-Netz oder eine höhere Spannungsebene. Darüber hinaus differieren in den fünf Netzregionen Continental Europe, Nordic, Great Britain, Ireland und Baltic gemäß NC RfG noch weitere technische Vorgaben an die Erzeugungsanlagen - beispielsweise bezüglich der Vorgaben für zulässige Frequenzabweichungen.

Im Rahmen einer detailliert festgelegten Compliance-Prüfung müssen alle Erzeugungseinheiten den Nachweis erbringen, dass sie die jeweils für sie geltenden Anforderungen des NC RfG einhalten. Auf Grundlage dieses Nachweises erhalten sie eine Notifizierung zum Betrieb.

Vor Anwendung des NC RfG müssen die ÜNB in einer Vielzahl von Fällen die Anforderungen für ihre eigene Regelzone weiter spezifizieren. Für Deutschland könnte dies im besten Fall bedeuten, dass die neuen technischen Anforderungen im Wesentlichen den Anforderungen entsprechen, die bereits im Transmission Code 2007 enthalten sind. Ausgenommen sind die zwingend vorgegebenen Regelungen für das Verhalten von Anlagen in extremen Frequenz- und Spannungsbereichen sowie in Bezug auf erweiterte Bereiche für die Blindleistungsbereitstellung: Hier sind für Neu- wie für Bestandsanlagen Änderungen zu erwarten.

Sollten die deutschen ÜNB über die Vorgaben des bislang geltenden Transmission Codes hinausgehen, so gelten die neuen Anforderungen zunächst nur für Neuanlagen. Im Hinblick auf die Anwendung dieser erhöhten Anforderungen auf Bestandsanlagen sind die ÜNB angehalten, zunächst eine qualitative Kosten-Nutzen-Analyse durchzuführen, in deren Rahmen auch alternative Maßnahmen, z.B. auf Seiten des ÜNB selbst, zu bewerten sind. Fällt diese positiv aus, erfolgt danach eine umfassende quantitative Kosten-Nutzen-Analyse (CBA). Der ÜNB hat das Recht, seinen Vorschlag für eine Anwendung erweiterter Anforderungen auf Bestandsanlagen, die er nach Anlagengröße, -typ oder -standort differenzieren kann, nach erneuter Prüfung zu ändern, so dass dann Bestandsanlagen zusätzliche Anforderungen erfüllen müssten, dies jedoch nicht öfter als alle drei Jahre. Gleichwohl sind mit einer solchen Regelung erhebliche Investitionsunsicherheiten verbunden, wenn sich die geltenden Anforderungen in so kurzen Abständen ändern könnten.

Gemäß Art. 33 sind im Rahmen der Kosten-Nutzen-Analyse dem sozio-ökonomischen Nutzen eines geringeren Risikos von Versorgungsunterbrechungen für das Gesamtsystem vor allem die Aufwendungen des Anlagenbetreibers zur Erfüllung der jeweiligen Anforderung aber auch die Kosten alternativer Lösungen gegenüberzustellen. Das Ergebnis dieser CBA soll in einem Bericht zusammengefasst werden, der öffentlich zur Konsultation gestellt wird. Dieser Bericht und die Bewertung der eingegangenen Kommentare bilden die Grundlage der Entscheidung durch die Regulierungsbehörde. Stimmt diese zu, müssen nach einer Übergangszeit alle Bestandsanlagen entsprechend angepasst werden.

Insoweit der NC RfG auf Bestandsanlagen Anwendung finden soll, können die Betreiber von Stromerzeugungsanlagen beim zuständigen Netzbetreiber auch individuelle Ausnahmen für einzelne Anforderungen beantragen (Art. 52ff). Der Netzbetreiber prüft den entsprechenden Antrag und gibt auf Grundlage einer Kosten-Nutzen-Analyse innerhalb von sechs Monaten eine Empfehlung an die zuständige Regulierungsbehörde ab, die dann innerhalb von drei Monaten über die Ausnahme entscheiden muss. Diese individuelle Ausnahme unterliegt jedoch keiner dauerhaften Bestandsgarantie und kann vom Regulierer jederzeit begründet widerrufen werden. Bei Nichteinhaltung des NC RfG in einzelnen Punkten, die nicht unter die generelle Nichtanwendbarkeit fallen, müssen Bestandsanlagen innerhalb von zwölf Monaten eine individuelle Ausnahme beantragen. Danach ist der Netzbetreiber berechtigt, den Weiterbetrieb der Anlage zu verweigern.

3.3 Bewertung aus BDEW/VBG PowerTech-Sicht

Auf Grundlage des NC RfG in seiner aktuellen Fassung können die ÜNB den Betreibern von Stromerzeugungsanlagen unverhältnismäßig hohe Lasten aufbürden. Weder Bestandsanlagen noch mit heute am Markt verfügbaren Komponenten errichtete Neuanlagen können nach bisheriger Einschätzung die im jetzigen Entwurf formulierten, maximal möglichen Anforderungen an Lastsprünge, Kurzschlussfestigkeit/Fault Ride Through oder Frequenzstabilisierung erfüllen. Eine Begründung für diese Anforderungen, die das technisch sinnvolle und teilweise überhaupt realisierbare Maß überschreiten und die Wirtschaftlichkeit der Anlagen reduzieren können, ist ENTSO-E schuldig geblieben, obwohl dies in der ACER Rahmenrichtlinie gefordert wurde. Dabei argumentiert ENTSO-E mit dem Verursacherprinzip, obwohl jedoch der Ausbau Erneuerbarer Energien als Grund für steigende Anforderungen genannt wird, beschränken sich die technischen Anforderungen an diese Anlagen auf ein Minimum, während konventionelle Kraftwerke massiv belastet werden.

Die Kritik hinsichtlich einer fehlenden Begründung für übermäßig erhöhte Anforderungen gilt insbesondere auch für die Blindleistungsbereitstellung. Sie wird zum Teil in einem Umfang gefordert, der zum einen heute technisch nicht darstellbar ist, und zum anderen unter bestimmten Umständen sogar kontraproduktiv für die Netzstabilität wäre. Darüber hinaus sind die im NC RfG verbindlich festgelegten Anforderungen an die zeitliche Performance der Blindstromeinspeisung im Falle eines Netzfehlers in umrichtergesteuerten Erzeugungsanlagen (typisch für Photovoltaik) selbst unter rein theoretisch-mathematischen Betrachtungen nicht umsetzbar und würden in den Stromnetzen zu unzulässigen Rückwirkungen (Flicker) führen. Entgegen den Forderungen der Framework Guidelines nach einer Abweichungsanalyse hat ENTSO-E diese Ausdehnung der bisher geltenden Anforderungen nicht begründet, vor allem fehlt die geforderte Kosten-Nutzen-Analyse.

Gleichermaßen gilt dies für die Ausdehnung der Anforderungen an den Betrieb von Erzeugungsanlagen in extremen Frequenzbereichen. So müssen Kraftwerke zukünftig in der Lage sein, auch bei Frequenzen von bis zu minimal 47,5 Hz mindestens 30 Minuten am Netz zu bleiben. Bislang waren es nur 10 Minuten. Diese Vorgabe lässt jedoch die physikalischen Gesetzmäßigkeiten der Kraftwerkskomponenten unberücksichtigt, z.B. den Leistungsabfall von Pumpen und Lüftern, und ist, wenn überhaupt, nur durch eine Überdimensionierung der Kraftwerkskomponenten, verbunden mit deutlich höheren Kosten und niedrigerem Wirkungsgrad, umsetzbar.

Die detaillierten Vorgaben der ÜNB greifen zudem erheblich in die Verantwortlichkeit der Verteilungsnetzbetreiber ein: Im NC RfG fehlt die klare Aussage, dass der zuständige Netzbetreiber für die Betriebsführung seines eigenen Netzes verantwortlich ist. Mit einem direkten Zugriff des Übertragungsnetzbetreibers auf die Erzeugungsanlagen am Verteilnetz kann der verantwortliche Verteilungsnetzbetreiber einen sicheren Netzbetrieb nicht mehr gewährleisten.

Seite 8 von [illegible]

Die in diesem Zusammenhang gewählten Definitionen sind nicht eindeutig oder unvollständig, so dass rechtsfreie Bereiche bestehen – zum Beispiel in der Frage der Benennung und der Zuordnung von Verantwortlichkeiten zwischen dem Verteilungsnetzbetreiber und dem Erzeuger beim Netzanschluss einer Erzeugungseinheit. Das betrifft insbesondere die Festlegung des Ortes, für den die Umsetzung der Vorgaben nachzuweisen ist bzw. eingefordert werden kann:

- Unklare Zuständigkeiten können im Extremfall dazu führen, dass notwendige Anforderungen nicht umgesetzt werden und damit zur Systemunterstützung nicht zur Verfügung stehen.
- Zumindest besteht ein nicht unbeträchtliches Konfliktpotenzial bei der Umsetzung von Anforderungen, wenn der Erfüllungsort für die Vorgaben im konkreten Fall nicht so eindeutig bestimmt werden kann, wie das nach den derzeit in Deutschland geltenden Regelungen möglich ist.
- Ohne die eindeutige Festlegung des Erfüllungsortes kann auch das Zertifizierungsverfahren zum Nachweis der Konformität nicht funktionieren.

Inwieweit die ÜNB bei nationaler Umsetzung des NC RfG die in Deutschland geltenden Regelungen in der aktuellen Fassung beibehalten, ist offen. Entgegen den bisherigen Stellungnahmen seitens ENTSO-E ist davon auszugehen, dass es zu einer Verschärfung kommt. So ist der ÜNB auf Grund des Vorsichtsprinzips gehalten, in den Fällen, in denen der Code eine Bandbreite möglicher Parameter zulässt, in der Regel eine Verschärfung der Werte vorzunehmen, weil dies eine höhere Sicherheit verspricht. Gleichzeitig ist zu befürchten, dass entsprechend verschärfte Anforderungen dann auch auf Bestandsanlagen Anwendung finden werden. Anderenfalls sähe sich der ÜNB im Falle eines Blackouts dem Vorwurf ausgesetzt, die möglichen technischen Möglichkeiten nicht ausgeschöpft zu haben.

Ansprechpartner:

Dr. Jens Biet
Telefon: +49 30 300199-1312
jens.biet@bdew.de

Bundesverband der Energie- und Wasserwirtschaft e.V.
Reinhardstr. 32
10117 Berlin

Jörg Kaiser
Telefon: + 49-201-8128-288
joerg.kaiser@vgb.org

VGB PowerTech e.V.
Klinkestraße 27–31
45136 Essen

The European Association of Internal Combustion Engine Manufacturers

EUROMOT

EUROMOT POSITION

27 May 2013

20 YEARS Promoting Engine in Society

Cost-Benefit Analysis regarding Network Code on Requirements for Grid Connection applicable to all Generators

EUROMOT supports the development and completion of the European internal market for electricity and has actively been participating in the stakeholder consultation conducted by ENTSO-E and ACER regarding the "Network code for requirements for grid connection applicable to all generators" (NC RfG).

The NC RfG together with the other network codes currently being prepared forms a very important part of developing the EU energy market. It is essential that any harmonised rules should be proportionate and cost effective.

EUROMOT acknowledges that ENTSO-E has put a lot of effort into drafting the NC RfG and supporting documents and generally appreciates the work done. Nevertheless, EUROMOT does not agree with all assessments and continues to have substantial concerns regarding the cost-effectiveness of the treatment of fault ride through (FRT).

EUROMOT therefore welcomes the Commission's decision to prepare a cost-benefit analysis regarding the NC RfG.

President:
Michael G Hawkins

General Manager:
Dr Peter Scherm

ENGINE IN SOCIETY

A European Interest Representative (EU Transparency Register Id. No. 6284937371-73)

A Non Governmental Organisation in observer status with the UN Economic Commission for Europe (UNECE) and the International Maritime Organisation (IMO)

Article 9.3, Article (FRT)

EUROMOT recognises the need for a reasonable level of connection requirements regarding fault ride through (FRT). This is important for both generation and transmission system operators in order to provide society with the expected level of security of supply. However, the FRT requirements proposed by ENTSO-E in the RfG Network code submitted to ACER on 13th July 2012 will be technically very challenging and could un-necessarily create difficulties for generation as well as raising the overall cost level of electricity production, especially for B and C type units.

The extreme fault ride through scenarios (e.g. 250 ms clearance time!) which form part of the ENTSO-E NC RfG proposal are neither proportionate nor cost-effective for smaller synchronous power modules and will be counterproductive with regards to the overall European targets of maintaining security of supply as well as increasing renewable power generation. Synchronous generation modules, in our case driven by internal combustion engines, can provide different stabilizing services to the grid and – if powered by various bio-fuels – also form part of the renewable energy portfolio.

As the determining aspects on the network side are not exhaustively specified in the code, the material and design impact of unreasonably long fault clearance times or a zero level residual voltage during the fault cannot be exhaustively defined against the current requirements in Article 9.3 and Article 11.3 – e.g. grid side short circuit strength is location specific.

Nevertheless, in order to promote more reasonable requirements for B and C type units, we would like to technically describe and explain with the help of examples the likely impact on design for a long specified fault clearance time, as foreseen under the current proposal.

On the generator module side, the capability of a synchronous generator module to successfully pass the FRT requirements is mainly dependent on the parameters module inertia, generator and interface system reactance.

An increase of inertia of a synchronous power generating module can contribute positively to the fault ride through capability; however, in order to achieve this, a drastic deviation from any economical dimensioning will have to be made. For example, to achieve an increase of 100 ms of fault clearance time from 150 to 250 ms a doubling of the rotating inertia of the synchronous power generating module may be necessary. This will have a huge impact on the design and the amount of material needed.

Another possible solution would be to reduce the transient reactance of the generator in order to reduce the interface reactance. Unfortunately, the design changes necessary are also not economical and cost-effective. The reason for this is that if reactance has to be decreased at the same time flux will increase. Flux vs. volume cannot normally be increased without iron saturation. The only way to facilitate an increased flux is to increase the iron volume as well. This volume increase is done by increasing the length of the generator or increasing the diameter of the generator – again, this would have a large impact on the design and additional material needed.

As we have shown in the examples above, requiring unreasonably long FRT times can have a substantial material and design impact on synchronous power generating modules incurring high costs. Therefore, EUROMOT proposes a more balanced approach which would be closer to the natural capabilities of B and C type units and would ensure security of supply while at the same time being a technically proportionate and cost-effective solution:

B and C type Generation modules in distribution system < 110 kV

For B and C type generation modules in distribution systems the situation is different from the D type generation modules. In distribution systems the trip times for a fault are typically longer than in a transmission system. However, it is not likely that a fault in the distribution system is seen as a severe fault over a large area as the electrical distances are longer. It is also not likely to be seen as a severe fault in the transmission system.

A reasonable FRT requirement for generation modules connected to distribution systems will take this into consideration and should be based on the short fault clearance times already existing in the transmission systems i.e. 100 - 150ms (transmission system faults can be seen over a wider area but are cleared quickly). This should be combined with the higher residual voltage seen by a potentially larger number of generators (i.e. a retained voltage of U_{ret} of 30%) together with a reasonable normal operational consideration, or the generator slightly overexcited at nominal voltage.

EUROMOT strongly recommends setting a clearance time of 100-150ms together with a retained voltage level (U_{ret}) of 30% and reasonable normal operational considerations generator slightly overexcited and at nominal voltage for generators of type B and C connected to the distribution system.

EUROMOT – 2013-05-27

For more information please contact:

EUROMOT – The European Association of
Internal Combustion Engine Manufacturers

Paul Zepf, (+49 69) 6603-1752, paul.zepf@euromot.eu
EU Transparency Register ID number: 6284937371-73

EUROMOT is the European Association of Internal Combustion Engine Manufacturers. It is committed to promoting the central role of the IC engine in modern society, reflects the importance of advanced technologies to sustain economic growth without endangering the global environment and communicates the assets of IC engine power to regulators worldwide. For more than 20 years we have been supporting our members - the leading manufacturers of internal combustion engines in Europe, USA and Japan - by providing expertise and up-to-date information and by campaigning on their behalf for internationally aligned legislation. The EUROMOT member companies employ all over the world about 200,000 thoroughly skilled and highly motivated men and women. The European market turnover for the business represented exceeds 25 bn euros. Our EU Transparency Register identification number is 6284937371-73.

http://www.euromot.eu – your bookmark for IC engine power worldwide

Our members are:

DIESEL AND GAS ENGINE MANUFACTURERS

AGCO POWER	MAN GROUP
CASE NEW HOLLAND	MITSUBISHI TURBOCHARGER & ENGINE EUROPE
CATERPILLAR POWER SYSTEMS GROUP	MOTEURS BAUDOUIN
CUMMINS ENGINES	MWM
DAIMLER	ROLLS-ROYCE
DEUTZ	SAME DEUTZ-FAHR
DOOSAN	SCANIA
FPT INDUSTRIAL	STEYR MOTORS
GE ENERGY & TRANSPORTATION	TOGNUM
HATZ	VOLKSWAGEN INDUSTRIAL ENGINES
JCB POWER SYSTEMS	VOLVO CONSTRUCTION EQUIPMENT
JOHN DEERE	VOLVO PENTA
KOMATSU ENGINES	WÄRTSILÄ
LIEBHERR	YANMAR GROUP
LOMBARDINI	ZETOR

SMALL SI ENGINE MANUFACTURERS

BRIGGS & STRATTON	KOHLER GLOBAL POWER GROUP
DOLMAR	SOLO
EMAK	STIHL
GLOBAL GARDEN PRODUCTS	TORO EUROPE
HONDA EUROPE	WACKER NEUSON
HUSQVARNA GROUP	YAMABIKO GROUP
KAWASAKI EUROPE	

D. Incident on 4 November 2006

D.1 Background

In August and September 2003 there were, worldwide, four major electricity disturbances in what was a very short space of time. These disturbances occurred in the North Eastern part of North America affecting both the United States and Canada, the whole of Italy, parts of Sweden and Denmark and a significant area of London. None of these disturbances would have been prevented if the requirements set out in the NC RfG had been in place. In simple terms they were all basically due to either system operation or in the case of London transmission owner failings and in some of them an unwillingness to interrupt the market in order to ensure the security of the system.

However on the 4th November 2006 virtually the whole of the UCTE interconnection was affected by a major system disturbance. Again the initial incident would not have been prevented by the requirements set out in the NC RfG but the consequential difficulties that were experienced could have been prevented or at least alleviated if all the generators had been bound by and conformed to the provisions of the NC RfG.

D.2 The Incident

On the evening of November 4 a double circuit 380kV line in Northern Germany was manually de-energised in order to allow a ship to transit the Ems River to the North Sea. This had been carried out successfully several times in the previous years.

At the time of the disconnection of the 380kV line there were significant East-West power flows as a result of international power trade and the obligatory exchange of wind feed-in inside Germany. These flows were interrupted during the event. The tripping of several high-voltage lines, which started in Northern Germany, split the UCTE grid into three separate areas (West, North-East and South-East) with significant power imbalances in each area. The power imbalance in the Western area induced a severe frequency drop that caused an interruption of supply for more than 15 million European households.

In the Western Area where the frequency fell to around 49Hz due to a loss of import from the East and pump storage tripping, widespread load shedding was sufficient to stabilise the system after about 14s and within 20 minutes the system was back to normal although the impact for customers had been significant.

In the South Eastern Area there was only a small imbalance and the frequency fell to just below 49.8Hz before gradually recovering and reaching 49.9Hz after 20 minutes. Sufficient generation reserves were available to allow the restoration of the frequency to normal and no load shedding took place.

In the North Eastern area there was a surplus of generation and a high over-frequency area which was increased on this day compared with normal due to the high wind conditions in the North of Germany. The frequency rapidly increased to 51.4Hz which was reduced to 50.3Hz by pre-determined automatic actions. However some minutes after the incident the frequency started to rise as wind generators that had tripped on the initial incident were re-connected. This contributed to both frequency and loading issues. In general this uncontrolled operation of embedded generation – mainly wind and CHP – during the disturbance complicated the process of re-establishing normal system conditions.

Full resynchronization of the UCTE system was completed 38 minutes after the split and the normal situation was re-established in all European countries in less than two hours.

D.3 Causes

The basic causes were two-fold:

Firstly the failure to maintain the n-1criterion by the TSO directly involved in both its own grid and on some of its tie-lines to the neighbouring TSOs. Furthermore the resulting physical flow on one of the remaining 380kV interconnecting lines was so close to the protection settings at one end that even a relatively small power flow deviation triggered the cascade line tripping.

Secondly there was insufficient inter-TSO co-ordination. The initial planning for the manual de-energisation of the double-circuit 380kV had it scheduled for 5th November from 0100 to 0500 and all the studies were carried out on this basis. However the change of time was only communicated by the TSO to the other directly involved TSOs at a very late moment. It was also not sufficiently prepared and checked in order to ensure the secure operation of the system after the line de-energisation. The differing protection settings at the ends of one of the key lines – a critical factor because of the very high loadings – was also largely ignored by the TSO.

D.4 Generator-related Issues

During the disturbance, a significant number of generating units tripped in the Western and North Eastern areas of the UCTE area due to the frequency variations – both low and high – in these areas. This contributed to the deterioration of system conditions and to the delay in restoring secure normal conditions. However as most of these generating units were connected to the distribution grid, most of the TSOs did not have access to the real-time data of these generating units.

By far the most troublesome issue was in the North-Eastern area, where the uncontrolled reconnection of generating units induced very unpredictable conditions and the need for additional time to recover secure system operation. The uncontrolled and unexpected increase of generation causing the frequency to rise in the North-Eastern area had to be countered by a decrease in the output of other generation. However this caused critical network overloads.

D.5 Other Issues

The TSOs were also hampered by some DSOs reconnecting customers without coordination with their TSOs. This increased the difficulties for the TSOs with regard to the restoration of normal system conditions.

The dispatchers were also hampered by the limited range of actions available to them for handling grid congestions due to a German requirement that requires when taking measures to secure the grid to also take account the effects that this has on the market.

E. Selected Distribution Issues

E.1 Distributed Generation Protection

The existence of a fault for which the distribution connected generating unit should disconnect has been detected by mains failure protection, often operating by measuring vector shift and the rate of change of frequency. A vector shift device measures the length of each cycle of the voltage wave. At the moment a generating unit set becomes disconnected, the sudden change in load causes a sudden change in cycle length. The single cycle becomes shifted with time: it is either longer or shorter. The speed of sensing should be fast enough to complete the opening of the generating unit main circuit breaker before any auto-recloser on the distribution network completes reclosing. The ‘off’ time of an auto-reclose scheme depending on the system used by the DSO could be of the order of 100ms to 1s although ‘off’ times in excess of 1s are commonly applied where it is known that distributed generation is connected. A rate of change of frequency device senses stability of the frequency of the combination of the generating unit network and the distribution network to which it is connected. A generating unit in routine operation will have a normal frequency excursion due to changing loads and the compensated fuel inlet. These frequency excursions are small. The rate at which the frequency changes inside these excursions is relatively high compared with those of a large network. The speed of sensing the difference between the relatively fast (but minor) changes in frequency resulting from the operation of the generating unit itself, the relatively slower changes resulting from disturbances on the network for which the generating unit should remain stable and the network disturbances for which the generating unit should trip must be fast enough to complete the opening of the generating unit main circuit breaker before any auto-recloser completes reclosing.

However, especially for relatively non-interconnected networks, the transition from systems based predominantly around large synchronous generators to those based around asynchronous RES-E installations has an effect on the rate of change of frequency for which the unit should remain stable. In GB, this issue is still under consideration, but the TSO and DSOs have indicated to affected parties that the rate of change in frequency at which generating units should disconnect will need to increase from the current setting of

0.125Hz/s to a position that they should remain connected for a setting up to a figure still to be determined but likely to be between 1Hz/s and 2Hz/s[28].

E.2 Distribution Protection Systems and Network Islanding

The complete issue of the need to modify distribution protection schemes to accommodate significant generation embedded in distribution networks has been recognised and there are trial schemes planned and in operation attempting to resolve this dilemma for DSOs as part of the analysis being undertaken for the introduction of smart grids. Traditional protection systems operate on the basis of load flows from transmission networks to distribution networks, but as noted above and shown in Figure 13 the load flow between transmission and distribution networks – in this case for a location in Italy – can now be in both directions during the day.

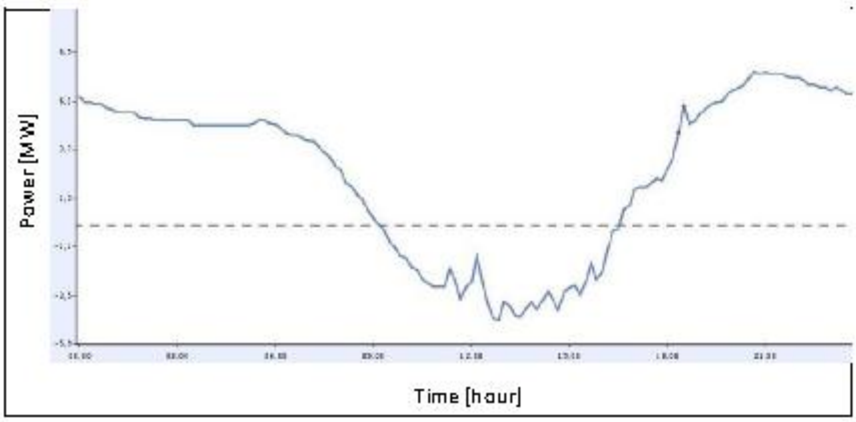


Figure 13: CP QUARTO Power Flow during 19 August 2012[29]

During the period the power flow is from the distribution network to the transmission network it is probable that a traditional protection scheme would not operate correctly. When the network is operating around the balance point, the risks of the network continuing to operate as an island network are high. In this situation, there is a possibility of unusually high voltages existing on the island network presenting a hazard to equipment, the DSO staff and the general public. Unintended network Islanding is the nightmare scenario for distribution engineers, previously thought theoretically possible but unlikely to occur because of the

[28] See: Open Letter from the Chairmen of the GB Grid Code and Distribution Code Review Panels available at: http://www.nationalgrid.com/NR/rdonlyres/13E717C8-DE42-4D8A-BF73-B22BF4C07731/59204/OpenLetteronG83andG59protectionrequirementsv4.pdf

[29] Source: Grid4EU Innovation for Energy Networks, *dD4.1 Documentation for technical coordination*, 30 October 2012. Available at: http://www.grid4eu.eu/media/6590/Grid4EU_dD4.1_DEMO4_Documentation_for_technical_coordination_V2.0.pdf

network topology and protection systems employed. This is no longer the case. See Louro and Cura: *Network Islanding – A Real Event*, CIRED 2012 for a description of one such incident[30]. Addressing the protection system issues introduced by the growth in distributed generation is a significant topic for smart grid demonstration sites. The new requirement that distributed generating units that would previously have disconnected in the event of a system disturbance are now expected by NC RfG to remain connected during a significant fault ride through period adds to this concern for DSOs.

E.3 Impact on Fault Levels

The impact of distributed generation on fault levels experienced by distribution networks has been considered an important issue for some time, but not one that should prevent the implementation of distributed generation[31]. All network equipment is susceptible to damage caused by the passage of excessive currents during fault conditions, but this is a particular issue for switchgear called to operate to disconnect the faulted network section. Studies to date have generally assumed that all generating units operating via power electronics modules – including all PV and many wind installations – would not contribute to fault currents at the time of interruption by the switchgear. Article 15.2 b) of the NC RfG attempts to change this situation and require these installations to produce current during fault conditions to aid the operation of protection systems. This is an important issue for TSOs as the contribution from large synchronous generating units decreases. However, the PGM control system will not be able to differentiate between faults on the transmission and distribution networks and will therefore now contribute to distribution network fault levels.

The 2005 GB study, referenced in footnote 31, assumed no contribution to fault break currents from power electronics based generator modules and determined that there was significant headroom in most distribution networks for the addition of distributed generation looking forward to 2010. However, the introduction of a requirement for a contribution to fault break currents from these modules places this conclusion, correct in its setting, open to serious question for the future. Based on the data available in 2005, it could be concluded that around 20% of GB distribution networks could not accept distributed generation that

30 Available at: http://www.cired.net/publications/workshop2012/pdfs/CIREDWS2012_0362_final.pdf

31 See, for example, Report for UK Department of Trade and Industry New and Renewable Energy Programme TSG WS 5 The Contribution to Distribution Network Fault Levels from the Connection of Distributed Generation, 2005 available at: http://webarchive.nationalarchives.gov.uk/20100919181607/http:/www.ensg.gov.uk/assets/14_06_2005_dgcg0000200.pdf

would contribute significantly to fault break currents. Unfortunately, as will be seen from the stakeholder evidence, whether or in what form the NC RfG specification can be met is uncertain and indeed, while ENTSO-E have attempted to draft a document that is largely technology neutral, this may be an issue on which technology plays a significant part. It is not currently possible to establish meaningful data on the potential impact of this requirement on distribution networks but, while acknowledging the benefit for TSOs, that there is likely to be an impact for DSOs must also be recognised.

As currently drafted, Article 15.2 b) begins, "*The Relevant Network Operator, in coordination with the Relevant TSO shall have the right to require....*" and this approach should allow the DSO to ensure that its network can be operated safely. However, other sections are less clear on which network operator has the final say when other requirements are applied. In considering the TSO's requirements in the NC RfG, it is therefore essential for public safety that the DSOs' requirements are also addressed in all cases.

F. Other Provided Information

RE: Fault Ride Through

Edwin Haesen [Edwin.Haesen@entsoe.eu]

Sent: 07 June 2013 10:23
To: McVean, Robert
Cc: Radovic, Bozidar
Attachments: Nordel 1975.pdf (5 MB)

Bob,

I would like to already provide you the following information on FRT applications in Sweden. More supporting proof may still be coming from the other Nordic countries. For the sake of clarity and to remove doubt when your study goes to the EC or is published eventually, we are OK if you quote the statements below in your report. If you feel that based on the evidence offered to you by others there are conflicting statements still, please let us know and we can discuss how further proof of compliance of a specific unit can be given and under which agreement.

The Swedish requirements were drafted in 2005 and came into force 2006-01-01. The 250 ms requirement was recommended back in 1975 already, please see attached document page 59, paragraph 5.4 (which is part of the English summary). Since January 2006, only units that have been commissioned or reinvested in are regulated by these requirements.
Since 2006 only a few units have been commissioned or rebuilt in Sweden, they are commented on below:

Forsmark 3 (1 190 MW to the grid) nuclear
Unit F3 has applied for an increase of output power to 1207 MW next year due to installation of new generator. F3 will meet the FRT requirement of 250 ms with this new generator.

Oskarshamn 2 (464 MW) nuclear
Unit O2 has applied for an increase of output power to 850 MW. The application has been denied due to FRT concerns.

Oskarshamn 3 (1 415 MW to the grid) nuclear
Unit O3 has increased their output power to 1 450 MW on the generator. They do not meet the FRT requirement and have a derogation while Svenska Kraftnät builds another connecting 400 kV line. When the line is commissioned, O3 will still not meet the 250 ms requirement but a secondary requirement which is 180 ms fault time + loss of the most important connecting transmission line.

Öresundsverket (436 MW) Combined Cycle
Connected to the regional network. Meets the FRT requirements.

Ryaverket (267 MW) Combined Cycle
Connected to the regional network. Meets the FRT requirements.

Ringhals 3 (1 114 MW to the grid) nuclear
Unit R3 has increased their maximum output power to 1 114 MW. They do not meet the FRT requirement of 250 ms but a secondary requirement which is 180 ms fault time. The unit is radially connected to the grid meaning that tripping the connecting transmission line will trip the unit anyhow.

Ringhals 4 (1144 MW to the grid) nuclear
Unit R4 has increased their maximum output power to 1144 MW. They do not meet the FRT requirement of 250 ms but a secondary requirement which is 180 ms fault time. The unit is radially connected to the grid meaning that tripping the connecting transmission line will trip the unit anyhow.

Värtan KVV 8 (approx. 150 MW)
Planned unit and will be connected to the regional network. Meets the FRT requirements.

Svenska Kraftnät applies the network fault (3-phase to ground) at the nearest meshed transmission substation when simulating the FRT requirement. The fault is applied and then taken away without disconnecting any equipment which means that the grid is fully intact before and after the fault. The unit may be overexcited if the network condition so requires which means that the unit most likely is over excited.

I hope this info allows you already to draw a clear conclusion that 250ms is present practice, has been used successfully in the design of plants, and has been confirmed in statements of compliance by generator owners. Let me know if you have further questions on this.

Best regards
Edwin

RE: Fault Ride Through
Edwin Haesen [Edwin.Haesen@entsoe.eu]
Sent: 10 June 2013 15:56
To: McVean, Robert
Cc: Radovic, Bozidar

Dear Bob,

Thanks for clarifying point. This last summary is indeed correct: the point at which the 250ms fault clearance time FRT applies in the Nordic grid code is in some cases directly the HV side of the generator's step-up transformer, in some other cases it is a point more remote.

I also requested more detailed info from our Finnish colleagues, which confirms the same present practice. The FRT recommendation of 250ms has been considered since the 70s in the design of power plants. Under the present Finnish grid code (in force since 2007) several large units have indicated compliance with this:

- Keljonlahti (combined cycle)
- Olkiluoto 3 (nuclear plant, 1600 MW) has demonstrated by means of extensive simulations studies that the unit fulfils the 250 ms criteria, in combination of course with explicit pre-fault conditions. Further proof-of-evidence with respect the FRT capability is to be provided at the stage of the site acceptance (i.e. commissioning) testing of Olkiluoto 3.

Regards
Edwin

RE: ENTSO-E NC RfG - Meeting Notes

Manoël Rekinger

Sent: 13 June 2013 16:22

To: McVean, Robert; Giorgia Concas

Dear Robert,

We just received the feedback from the R&D department of one of our biggest member on the 10 mS threshold for RCI during FRT. I hope it's still possible to integrate them in our contribution :

"Unfortunately they don't have any measurements. According to several discussion with the German grid operators during the last few years, reactive current is not important for an efficient FRT! Important is that the active power output recovers as soon as the voltage is back.

- The definition of a voltage excursion (and subsequently for the FRT trigger) is needed for a) comparable results and even worse b) the chance to achieve 10 ms at all. Especially regarding "shallow" dips (80% residual voltage) it is difficult to distinguish between dips and phase angle jumps (e. g. due to load switching) within a short period of time.
- The values of the voltage measurement have to be filtered due to interference of high currents that are switched in direct proximity. Using vector control (which is state of the art) additional filtering in d-/q-components is necessary as unbalances in voltages lead to sinusoidal disturbances which lead to poor output of the whole control. The d-/q-components are the reference for the reactive current.
- The positive sequence is defined for a whole cycle (20 ms). A requirement for a reaction within these 20 ms is not consistent.
- For verifying measurements all conditions (possible test rigs, definition of voltage dip, reactive current, ...) have to be will an consistently defined.
- The higher the requirement (regarding reaction time) the higher the probability of overreaction. An FRT event is triggered due to some voltage disturbance that's not caused by a fault. That will lead to transient reactive current injections and cause system perturbations."

If it's too late for the intermediary report, should we work on a new document for the final report.

Best regards,

Manoël Rekinger
Technology Advisor

European Photovoltaic Industry Association
Renewable Energy House – 63-67, Rue d'Arlon – B-1040 Brussels
Phone: +32 2 400 17 83/+32 2 465 38 84 – Fax: +32 2 400 10 10
Email: m.rekinger@epia.org - Web: www.epia.org

G. Papers Following Preliminary Report Circulation

G.1 Comment from COGEN Europe and EHI re Title 6

COGEN europe

ehi
association of the European Heating Industry

Brussels, September 9th 2013

Subject: COGEN Europe and EHI micro-CHP Joint Working Group acknowledge DNV Kema & COWI preliminary report on NC RfG and request further clarification on the "emerging technology" classification (Title 6)

Dear Mr. McVean,

The COGEN Europe and EHI Joint micro-CHP Working Group generally welcome the preliminary report submitted by DNV Kema & COWI to the European Commission on July 15th and ask for further support on the issue of the threshold in the "emerging technology" classification (Title 6).

COGEN Europe and EHI are supportive of the recommendations made by DNV Kema in its preliminary report to the European Commission "Technical Report on ENTSO-E Network Code: Requirements for Generators", especially as concerns the manufactures' role in applying for derogation on behalf of small generating unit owners/householders.

As concerns the "emerging technology" classification, the joint micro-CHP Working Group fully agree with the claim that: "*The approach taken [in the NC RfG] should ensure that the impact of the NC RfG on all currently operating generating units and all generating units genuinely in course of development would be neutral.*" (page viii). What remains a concern is that, without a threshold to define when the "emerging technology" classification will be revoked, Title 6 leaves investors in technologies currently "in course of development" with no certainty on what the impact of the NC RfG would be.

The preliminary report recommends in Section 7.3.3: "*In a number of areas of the NC RfG, compliance will be dependent on the actual assessment criteria applied and this is therefore a material issue that should be included in the document.*" (page 69). Therefore, in order to facilitate implementation and ensure enough time for compliance, minimising risk for manufacturers of "emerging technologies", Title 6 should include a minimum value for the threshold rather than delegating the task to TSOs after the NC RfG enters into force. Such a threshold can be determined based on technical reasoning during the formation of the NC RfG, as the Joint micro-CHP Working Group has shown in preceding communications.

COGEN Europe and EHI would appreciate if DNV Kema could comment on the omission of a threshold in Title 6, as the Joint Working Groups sees it as a potential obstacle to the quality of the implementation for all stakeholders involved (i.e. regulators, TSOs, customers, manufacturers).

Yours sincerely,

Fiona Riddoch and Dana Popp

G.2 Comment from Acer

ACER Further informal comments on KEMA RfG report

Dipali.Raniga@ofgem.gov.uk
Sent: 11 September 2013 17:38
To: Tadhg.O'BRIAIN@ec.europa.eu; Konrad.VON-KEYSERLINGK@ec.europa.eu
Cc: Uros.GABRIJEL@acer.europa.eu; Anne.DEGEETER@acer.europa.eu; Reuben.Aitken@ofgem.gov.uk; Mark.Askew@ofgem.gov.uk

Dear Tadhg,

I recently contacted you regarding further informal comments from ACER and regulators on the KEMA report for the European Network Code Requirements for Generators, apologies for the slight delay in sending these through.

There are a few issues in addition to the initial informal comments that we previously sent, please find these summarised below which I hope you find helpful.

We would be happy to discuss these comments if you would find this useful.

Kind regards,

Dipali

-

Comment 1: Clarification on the scope of application of the RfG for Type A units

Example:

KEMA Report:***"7.2.4 Recommendations Concerning Determination of Different Types of Significant Grid Users***

It is recommended that, in line with current standardisation practice and to ensure that all generators connected to the LV networks operated by DSOs are treated equally, the threshold between Type A and Type B generating units is modified such that all generating units connected to public networks operating at less than 1 kV are considered as Type A units."

Comment:

At the moment the RfG applies to Type A generators, which are above 800W.

Is the recommendation here to not have a de minimus (e.g. cut off at 800W)? Is it now proposed to expand the scope of the RfG to even smaller generators than it currently captures? This could likely change the scope of the RfG as it stands and be an important issue for generators that would require further justification.

Comment 2: Representation of renewables

In Chapter 3 there are some mistakes and confusing sentences, mixing different issues. We would recommend caution on these issues. The "dangers" of RES-E plants are somehow exaggerated. Two specific examples are provided below to demonstrate this.

Example 1:

> *"Frequency drift from the nominal system frequency is an indication of imbalance between generation and active power consumption and control arrangements are established by system operators to ensure that the level of generation will follow the level of demand. This requires a level of control over generation that is easily achieved with enough traditional generating units to maintain system balance but which has not generally been required of wind and PV installations. As the penetration of these technologies has increased, those TSOs most affected have sought to apply control to allow the system as a whole to be operated securely[3].*
>
> *[3]Many of the issues that are now being addressed by TSO and result from the increased penetration of small RES-E installations connected to the LV network are outlined for PV in: Kaestle and Vrana, Improved Requirements for the Connection to the Low Voltage Grid, presented to the 21st International Conference on Electricity Distribution, Frankfurt, 6-9 June 2011, and available at: http://www.iee.tu-clausthal.de/fileadmin/downloads/CIRED2011_1275_final.pdf "*

Two very different issues are mixed up in this passage, in a very confusing way:

Issue 1: The fact that the available power output of many RES-E plants (in particular wind and PV) is particularly variable, which will make it difficult to *"follow the level of demand"* in the future, in the absence of dedicated solutions (this is a very important issue indeed).

Issue 2: A problem recently raised by ENTSOE, which has already led to some changes in the connection rules of some countries (Germany, Italy, France), and which is also addressed by the LFSM-O requirement applicable to small units in the RfG: many power plants connected to distribution networks (including non-RES-E plants) have been required in the past (by system operators, because DSOs thought they needed it) to have protection systems that automatically disconnect the plant from the network as soon as the frequency reaches certain values, which endangers the European electric system (indeed many plants could be disconnected at once - 50,2 Hz being the most problematic threshold). The problem is mainly due to a lack of coordination between DSOs and TSOs. It has absolutely nothing to do with the above **Issue 1** (i.e the fact that RES-E plants does not offer much flexibility to "follow the demand") – and is not RES-E specific.

The mentioned CIRED paper specifically deals with **Issue 2**. As **Issue 2** can be seen as non-significant and temporary (it can be expected that in a few years this will have been (at least partially) solved; there are much more important issues raised by the massive arrival of RES-E plants), it is surprising that this paper is considered to outline *"many of the issues that are now being addressed by TSO and result from the increased penetration of small RES-E installations connected to the LV network".*

Example 2:

> *"Recently, TSOs operating systems where there has been significant RES-E penetration have sought modification to their Grid Codes requiring that all generators mimic enough of the inherent capabilities of synchronous generators to maintain the security and safety of the electricity system. In these codes, this is a new obligation and no single standard yet exists. As a consequence, different TSOs are developing different requirements to meet the needs of their own networks."*

In this passage, there is a very similar confusion. Which capabilities is this referencing? If these are capabilities like voltage control and RFT capability, they have been required from RES-E plants for almost 10 years in most countries on medium and high voltage networks (this would not be "recently") – and the RfG is addressing them in a very similar way to existing rules (there would be no *"new obligation"*) .

This seems to refer to the above **Issue 2** for Example 1:

"TSOs [...] *have sought modification to their Grid Codes requiring that all generators mimic enough of the inherent capabilities of synchronous generators".*

This is highly misleading. For instance, a more accurate way to say this could be *"TSOs [...] requiring that small generators are now equipped with similar frequency based protection systems than medium and large plants".*

Comment 3: Chapter 5.2.2 - On load Tap Changers

It may be appropriate to discuss *on load tap changers* in relation to *Chapter 5.2.1 on voltage ranges*.

Example - Quote from KEMA:

"ENTSO-E and ACER have made it clear that the voltage range values to be used in each Member State will be those ranges currently applied and, for so long as this position is maintained, there is no need for any change to current practice."

This is erroneous: voltage ranges for type D generators (article 11.2) is a mandatory, (mainly) exhaustive requirement; Member State won't be able to define their own ranges (unless perhaps if they require more demanding ranges).

Several (/many?) countries will have to change their national voltage ranges (sometimes quite significantly) in order to comply with the RfG (as the current rules in these countries are less demanding than the ones required in the RfG).

Some producers have warned that some future generators may not be able to withstand these new ranges, and that they would have to use transformers with on load tap changers (to maintain the voltage level on the plant side when during significant voltage variations on the grid side).

We note that there may be pros and cons to using OLTCs, and ENTSO-E is aware of stakeholders concerns in this regard (through responses to the public consultation). However, ENTSO-E emphasised that the transition to the future system operation is not a matter of minor adjustments to the existing system, but a de facto change of paradigm necessary to facilitate the transition to low carbon society.

Comment 4: Recommendation 5.3.1 (also 7.1.3.1)- Fault Ride Through

This recommendation does not appear necessary. Kema does not explain what exactly is not appropriate in the current articles. 250 ms is the high limit for clearing times, it is likely that most countries will actually require shorter clearing times (down to 140 ms).

Kema seems to suggest that the RfG requires a fault clearing time of 250 ms, while the FRT requirement is a non-exhaustive requirement: the RfG leaves the choice of the clearing time up to TSOs/national authorities, between 140 ms and 250 ms.

"Most [concerns from stakeholders] were related to operations in the synchronous area of Continental Europe, where existing requirements in national codes were far below the current proposal in the NC RfG."

This is not completely correct, and may be more appropriate to read '...The majority of existing requirements fit the lower end of the proposed FRT range proposed in the NC RfG.

Comment 5: Recommendation 5.1.2

The last paragraph of this section is a recommendation, but is not clearly marked as a recommendation.

Comment 6: Recommendation 5.2.3 (also 7.1.2.2) - Reactive power capability

Kema may also want to consider similar advice for the non-exhaustively defined requirement in Article 16.3.c to provide a more complete picture on reactive power capability. As an example, it could be advised that the Reactive Power capability below Maximum Capacity for PPMs (article 16.3.c) is defined so that the reactive range is reduced at very low power output.

Comment 7: Recommendation 5.3.2 (also 7.1.3.2) - fast reactive current injection

Kema appear to have missed the fact that fast reactive current injection is a non-mandatory requirement. Still, the sentence in the RfG "*The target [...] shall be reached with an accuracy of 10% within 60 milliseconds*" seems questionable as TSOs could be willing to require fast reactive current injection with a reaction time longer than 60 ms, which seems forbidden in the current version of the code. TSOs could under their national law require even different technical capabilities provided they are in line with the RfG.

Comment 8: Recommendation 7.2.1 - compliance

There is a lack of precision in this chapter.

As an example, the report states there would be a "*need for clarity on the use of manufacturer's certificates and the requirement for testing*".

The RfG code provides for the possible use of certificates instead of tests, to a certain extent. What needs to be clarified?

Another example is "*The rights of DSOs and users connected to DSO HV networks should not be impacted by the application of the NC RfG*"

It is unclear whether this is a recommendation that the code should not apply on distribution networks? The point here is that there should be a balanced approach to application to DSO networks, but the statement above seems to go too far.

Dipali Raniga
Policy Analyst, European Electricity Transmission Policy
Smarter Grids and Governance, Transmission
9 Millbank
London
SW1P 3GE
Tel: 0207 901 3912
www.ofgem.gov.uk

ofgem

G.3 Comment from Eurelectric Thermal Generators

10 September 2013

Proposals to amend the Draft RfG Code

This paper includes informal proposals to amend the RfG Code regarding some critical requirements taking into account the content of the code and the Cowi/DNV Kema report. For Eurelectric's comprehensive views on the RfG code, please see our earlier position papers / consultation responses and the paper provided for Cowi/DNV Kema.

FREQUENCY and VOLTAGE, ranges and durations

The Kema report proposes changes regarding the ranges and durations in Tables 2, 6.1 and 6.2 of the draft RfG code (version issued by ENTSO-E 8 March 2013). In our opinion this would lead to te following tables:

In our opinion this would lead to the following Tables:

Synchronous area	Maximum range of Q/Pmax	Maximum range of steady- state voltage level in PU
Continental Europe	0.7	0.225
Nordic	0.7	0.15
Great Britain	0.7	0.1
Ireland	0.7	0.218
Baltic	0.7	0.22

Table 2: Minimum time periods for which a Power Generating Module shall be capable of operating for different frequencies deviating from a nominal value without disconnecting from the Network.

Synchronous area	Voltage Range	Time period for operation
Continental Europe	0.85 pu – 0.90 pu	20 minutes
	0.90 pu – 1.05 pu	Unlimited
	1.05 pu – 1.10 pu	To be decided by each TSO while respecting the provisions of Article 4(3), but not more than 20 minutes
Nordic	0.90 pu – 1.05 pu	Unlimited
	1.05 pu – 1.10 pu	60 minutes
Great Britain	0.90 pu–1.10 pu	Unlimited
Ireland	0.90 pu – 1.118 pu	Unlimited
Baltic	0.85 pu – 0.90 pu	30 minutes
	0.90 pu – 1.12 pu	Unlimited
	1.12 pu – 1.15 pu	20 minutes

1

Table 6.1: This table shows the minimum time periods a Power Generating Module shall be capable of operating for Voltages deviating from the nominal value at the Connection Point without disconnecting from the Network. (The Voltage base for pu values is from 110 kV to 300 kV (excluding).)

Synchronous area	Voltage Range	Time period for operation
Continental Europe	0.85 pu – 0.90 pu	20 minutes
	0.90 pu – 1.03 pu	Unlimited
	1.03 pu – 1.05 pu	To be decided by each TSO while respecting the provisions of Article 4(3), but not more than 20 minutes
	1.05 pu – 1.0875 pu	10 minutes
Nordic	0.90 pu – 1.03 pu	Unlimited
	1.03 pu – 1.05 pu	20 minutes
	1.05 pu – 1.0875 pu	10 minutes
Great Britain	0.90 pu – 1.03 pu	Unlimited
	1.03 pu – 1.05 pu	15 minutes
	1.05 pu – 1.0875 pu	10 minutes
Ireland	0.90 pu – 1.05 pu	Unlimited
	1.05 pu – 1.0875 pu	10 minutes
Baltic	0.88 pu – 0.90 pu	20 minutes
	0.90 pu – 1.03 pu	Unlimited
	1.03 pu – 1.05 pu	20 minutes
	1.05 pu – 1.0875 pu	10 minutes

Table 6.2: This table shows the minimum time periods a Power Generating Module shall be capable of operating for Voltages deviating from the nominal value at the Connection Point without disconnecting from the Network. (The Voltage base for pu values is from 300 kV to 400 kV.)

However, if only change these tables are changed, the influence of frequency deviation on acceptable voltage deviation and vice versa (due to physical limitations) as also recognized by Kema have to be described separately. This makes the NC RfG unclear. To clarify the matter, we propose to combine the tables 2&6.1 and 2&6.2 together with power restrictions in Frequency-Voltage diagrams.

Proposal for amendments in the draft code *(new text in red)*

We propose to the following amendments to the draft code:

- Delete the article 8.1.a.1 and Table 2.
- Delete the article 11.2.a.1 and Tables 6.1 and 6.2
- Add a new article with the proposed diagrams (diagrams attached are valid for Continental Europe, we offer to prepare similar diagrams for other synchronous areas).

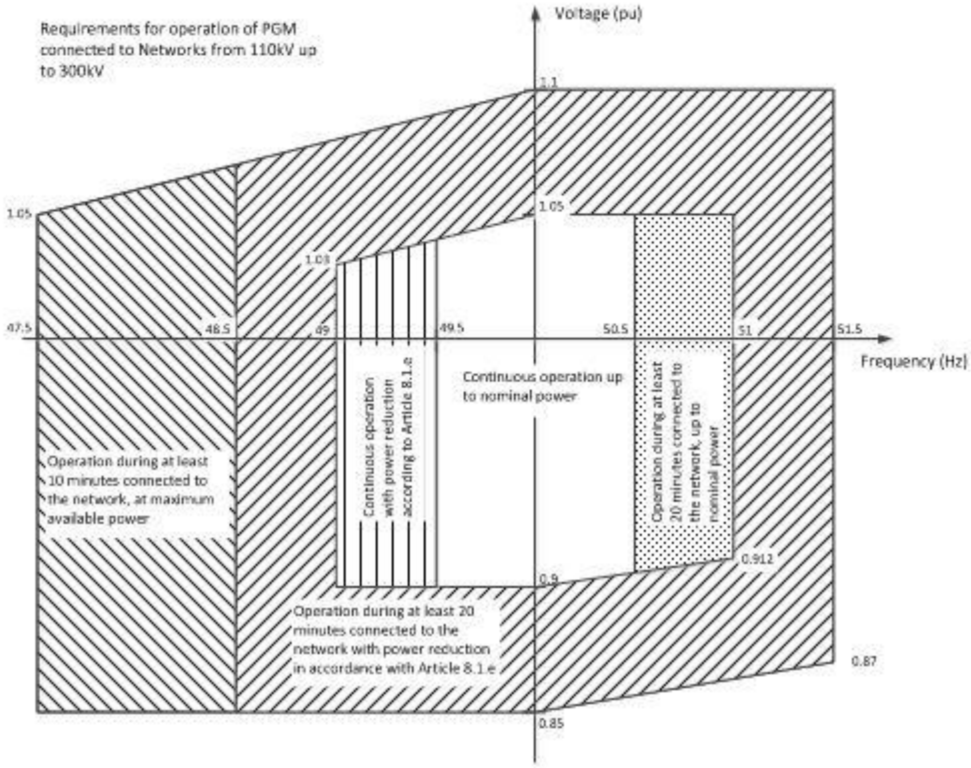
We propose the following new article to replace the content of art. 8.1.a.1, 11.2.a.1 and Tables 2, 6.1 and 6.2:

2

A Power Generating Module shall be capable of staying connected to the Network and operating within the Frequency and Voltage ranges during time periods and at power as specified in diagram 1 (for PPM with Connection Point from 110kV up to 300kV) or in diagram 2 (for PPM with Connection Point from 300kV up to 400kV).

We propose also the following U-F diagrams 110 up to 300 kV and 300 up to 400kV:

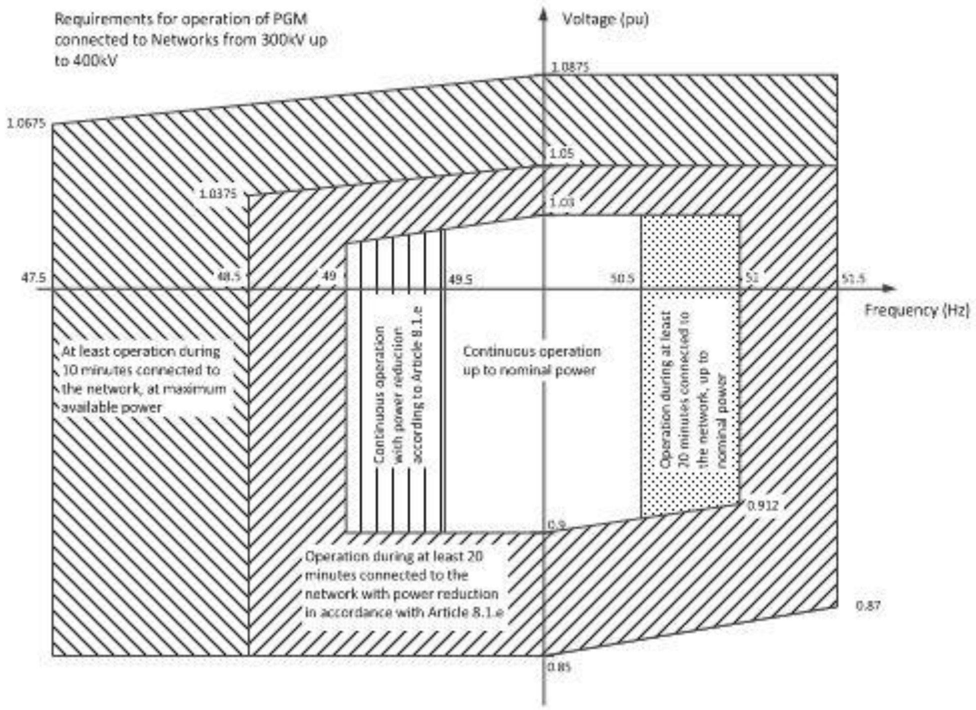
Proposed U-F diagram 110 up to 300kV



This diagram shows the minimum time periods and power a Power Generating Module shall be capable of operating for Voltages and Frequencies deviating from the nominal value at the Connection Point without disconnecting from the Network. (The Voltage base for pu values is from 110 kV to 300 kV (excluding).)

3

Proposed U-F diagram 300 up to 400kV



This diagram shows the minimum time periods and power a Power Generating Module shall be capable of operating for Voltages and Frequencies deviating from the nominal value at the Connection Point without disconnecting from the Network. (The Voltage base for pu values is from 300 kV to 400 kV.)

4

Reactive Power requirements

Referring to the provisions for reactive power in the draft NC RfG and the Kema report, Eurelectric and VGB understand the positions of ACER and ENTSO-E in the following way:

- When the NC RfG comes into force the present arrangements and requirements of the national codes will become the new national setting under the NC RfG.
- The indicated areas in Figure 7-9 in the RfG code do not consider the areas of time limited operation due to voltage and/or frequency deviations.

Accoring to the analysis in the Kema report, problems related to the technical feasibility on the manufacturers side would occur in the triangular areas at the bottom left and upper right. In addition to Kema's comments we should realise that in these corners of the original envelop the need for reactive power in combination with the voltage level is counterproductive and would even worsen and endanger the situation for the grid. Taking into account the feasibility to achieve those requirements and the fact that from the prespective of the grid there is no need to cover these areas those areas are excluded.

If the generators will be required to achieve the maximum ranges of the draft NC RfG huge additional cost will occur as stated in the paper of ´VGB / Eurelectric´s generators - RfG Network Code: Needs, Feasibility, Alternative Solutions and Costs´ (Letter to EC dated 22 February 2013) under the chapter Reactive Power Ranges.

Based on ACER's and ENTSO-E's comments to Kema we suggest EC DG Energy and Cowi/DNV Kema to recommend to limit the ´Maximum range of Q/Pmax´ in the RfG to the current typical values in Europe. This is reasonable as the code allows the inner envelope to be shifted within the fixed outer envelope for adaptation to the local grid circumstances.

For further information we refer to the following references:

Kema/Cowi ´Technical Report on ENTSO-E Network Code: Requirements for Generators´; Preliminary Report 15. July 2013;

Letter EURELECRIC-VGB to EC dated 22 February 2013, *VGB/EURELECTRIC's generators RfG Network Code: Needs, Feasibility, Alternative Solutions and Costs;* Chapter Reactive Power

Based on these arguments, we propose to change the NC RfG as follows:

Proposal for amendments in the draft code (new text in red)

Article 13

....

2. Type C Synchronous Power Generating Modules shall fulfill the following requirements referring to Voltage stability:

5

a) With regard to Reactive Power Capability, for Synchronous Power Generating Modules where the Connection Point is not at the location of the high-voltage terminals of the step-up transformer to the Voltage level of the Connection Point nor at the Alternator terminals, if no step-up transformer exists, supplementary Reactive Power may be defined by the Relevant Network Operator, while respecting the provisions of Article 4(3), to compensate for the Reactive Power demand of the high-voltage line or cable between these two points from the responsible owner of this line or cable.

b) With regard to Reactive Power capability at Maximum Capacity:

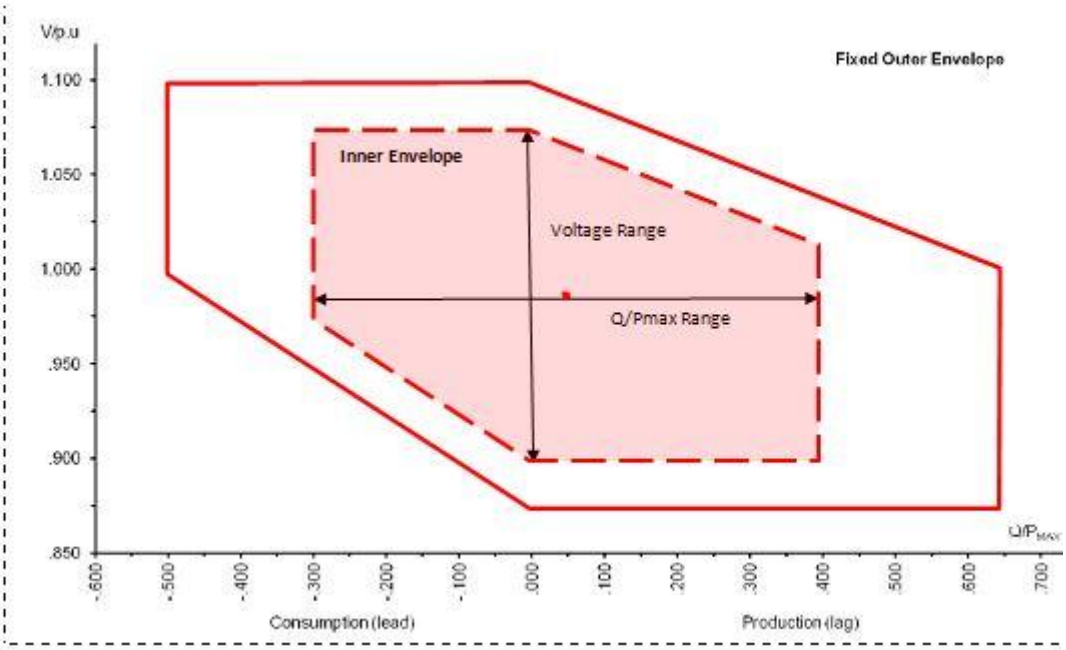
1) The Relevant Network Operator in coordination with the Relevant TSO shall define while respecting the provisions of Article 4(3) the Reactive Power provision capability requirements in the context of varying Voltage. For doing so, it shall define a U-Q/P_{max}-profile that shall take any shape within the boundaries of which the Synchronous Power Generating Module shall be capable of providing Reactive Power at its Maximum Capacity.

2) The U-Q/P_{max}-profile is defined by the Relevant Network Operator in coordination with the Relevant TSO while respecting the provisions of Article 4(3) in conformity with the following principles:

- the U-Q/P_{max}-profile shall not exceed the U-Q/P_{max}-profile envelope, represented by the inner envelope in figure 7;

- the dimensions of the U-Q/P_{max}-profile envelope (Q/P_{max} range and Voltage range) are defined for each Synchronous Area in table 8; and

- the position of the U-Q/P_{max}-profile envelope within the limits of the fixed outer envelope in figure 7



6

Figure 7 – U-Q/P_{max}-profile of a Synchronous Power Generating Module. The diagram represents boundaries of a U-Q/P_{max}-profile by the Voltage at the Connection Point, expressed by the ratio of its actual value and its nominal value in per unit, against the ratio of the Reactive Power (Q) and the Maximum Capacity (P_{max}). The position, size and shape of the inner envelope are indicative.

Synchronous area	Maximum range of Q/Pmax	Maximum range of steady-state voltage level in PU
Continental Europe	0.7	0.225
Nordic	0.7	0.150
Great Britain	0.7	0.100
Ireland	0.7	0.218
Baltic	0.7	0.220

Table 8: Parameters for the inner envelope in figure 7

.....

In line with the proposed changes in article 13 and to prevent discrimination, we propose to change the articles 16 and 20 as follows.

Article 16 3 b)

2) The U-Q/P_{max}-profile is defined by each Relevant Network Operator in coordination with the Relevant TSO while respecting the provisions of Article 4(3) in conformity with the following principles:

- the U-Q/P_{max}-profile shall not exceed the U-Q/P_{max}-profile envelope, represented by the inner envelope in figure 8, its shape does not need to be rectangular;

- the dimensions of the U-Q/P_{max}-profile envelope (Q/P_{max} range and Voltage range) are defined for each Synchronous Area in table 9; and

- the position of the U-Q/P_{max}-profile envelope within the limits of the fixed outer envelope in figure 8

7

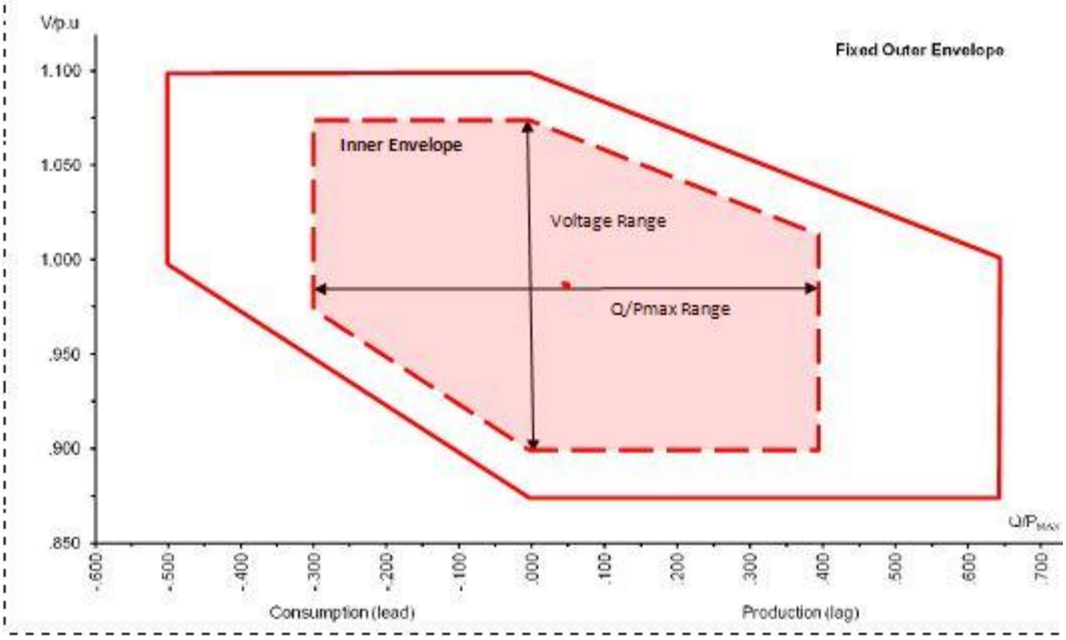


Figure 8 – U-Q/P_{max}-profile of a Power Park Module. The diagram represents boundaries of a U-Q/P_{max}-profile by the Voltage at the Connection Point, expressed by the ratio of its actual value and its nominal value in per unit, against the ratio of the Reactive Power (Q) and the Maximum Capacity (P_{max}). The position, size and shape of the inner envelope are indicative.

Synchronous area	Maximum range of Q/Pmax	Maximum range of steady- state voltage level in PU
Continental Europe	0.7	0.225
Nordic	0.7	0.150
Great Britain	0.66	0.100
Ireland	0.66	0.218
Baltic	0.7	0.220

Table 9: Parameters for the inner envelope in figure 8

Article 16 3 c)

2) The P-Q/P_{max}-profile is defined by each Relevant Network Operator in coordination with the Relevant TSO while respecting the provisions of Article 4(3), in conformity with the following principles:

- the P-Q/P_{max}-profile shall not exceed the P-Q/P_{max}-profile envelope, represented by the inner envelope in figure 9;

8

- the Q/P_{max} range of the $P\text{-}Q/P_{max}$-profile envelope is defined for each Synchronous Area in table 9;

- the Active Power range of the $P\text{-}Q/P_{max}$-profile envelope at zero Reactive Power shall be 1 pu;

- the $P\text{-}Q/P_{max}$-profile can be of any shape and shall include conditions for Reactive Power capability at zero Active Power; and

- the position of the $P\text{-}Q/P_{max}$-profile envelope within the limits of the fixed outer envelope in figure 9

3) When operating at an Active Power output below the Maximum Capacity ($P<P_{max}$), the Power Park Module shall be capable of providing Reactive Power at any operating point inside its $P\text{-}Q/P_{max}$-profile, if all units of this Power Park Module, which generate power, are technically available (i. e. not out-of-service due to maintenance or failure). Otherwise the Reactive Power capability may be less taking into consideration the technical availabilities.

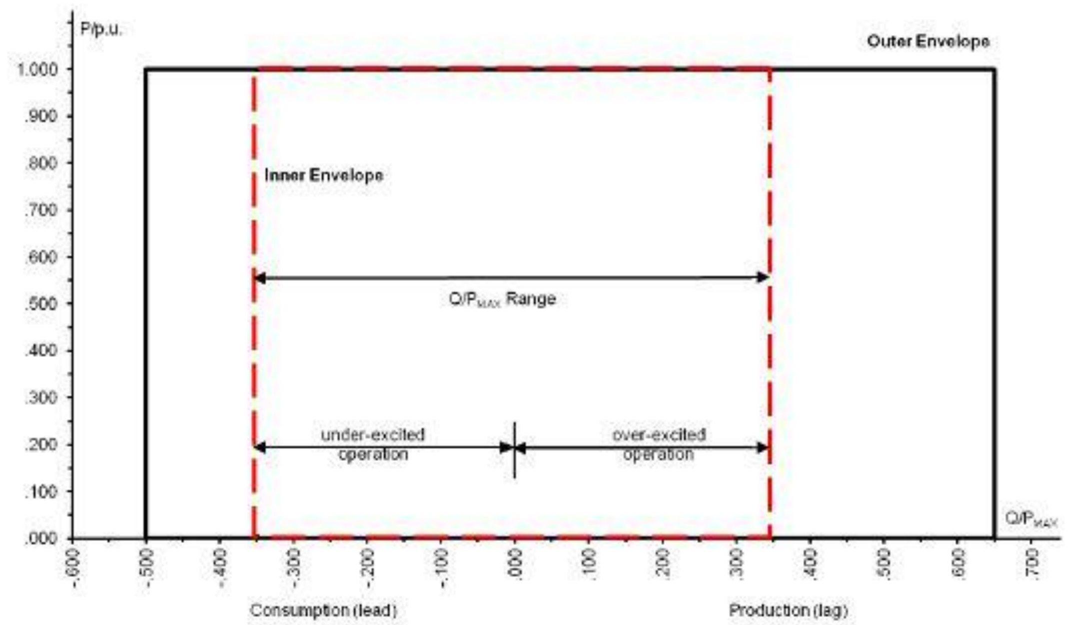


Figure 9 - $P\text{-}Q/P_{max}$-profile of a Power Park Module. The diagram represents boundaries of a $P\text{-}Q/P_{max}$-profile at the Connection Point by the Active Power, expressed by the ratio of its actual value and the Maximum Capacity in per unit, against the ratio of the Reactive Power (Q) and the Maximum Capacity (P_{max}). The position, size and shape of the inner envelope are indicative.

9

Article 20

Synchronous area	Maximum range of Q/Pmax	Maximum range of steady- state voltage level in PU
Continental Europe	0.7	0.225
Nordic	0.7	0.150
Great Britain	0* 0.33**	0.100
Ireland	0.66	0.218
Baltic	0.7	0.220

Table 11: Parameters for figure 8

Fault clearing times

In the draft NC RfG, maximum fault clearing times have been increased for Continental Europe from 150 ms up to 250 ms. This can worsen the mechanical stress for the rotating equipment (torque jerks, compressive strain or material deformation,...) which then can lead to irreparably strong damage to the equipment followed by the unit dropping off its connection to the grid and long-term non-availability.

Draft RfG Code:

Article 9.3 a and 11.3.a, table 3.1 and 7.1: The max. clearing time "t.clear" 0,14s - 0,25s is given in the table 7.1 for generators type D (see below)

Reference, e.g. 11.3.a:

10

a) With regard to fault-ride-through capability of Power Generating Modules:

1) The voltage-against-time-profile shall be defined by the TSO using parameters in figure 3 according to tables 7.1 and 7.2.

2) Each TSO shall define and make publicly available while respecting the provisions of Article 4(3) the pre-fault and post-fault conditions for the fault-ride-through capability according to Article 9(3) (a) point 3).

Voltage parameters [pu]		**Time parameters [seconds]**	
U_{ret}:	0	t_{clear}:	0.14 – 0.25
U_{clear}:	0.25	t_{rec1}:	t_{clear} – 0.45
U_{rec1}:	0.5 – 0.7	t_{rec2}:	t_{rec1} – 0.7
U_{rec2}:	0.85 – 0.9	t_{rec3}:	t_{rec2} – 1.5

Table 7.1 – Parameters for figure 3 for fault-ride-through capability of Synchronous Power Generating Modules.

Voltage parameters [pu]		**Time parameters [seconds]**	
U_{ret}:	0	t_{clear}:	0.14 – 0.25
U_{clear}:	U_{ret}	t_{rec1}:	t_{clear}
U_{rec1}:	U_{clear}	t_{rec2}:	t_{rec1}
U_{rec2}:	0.85	t_{rec3}:	1.5 – 3.0

Table 7.2 – Parameters for figure 3 for fault-ride-through capability of Power Park Modules.

11

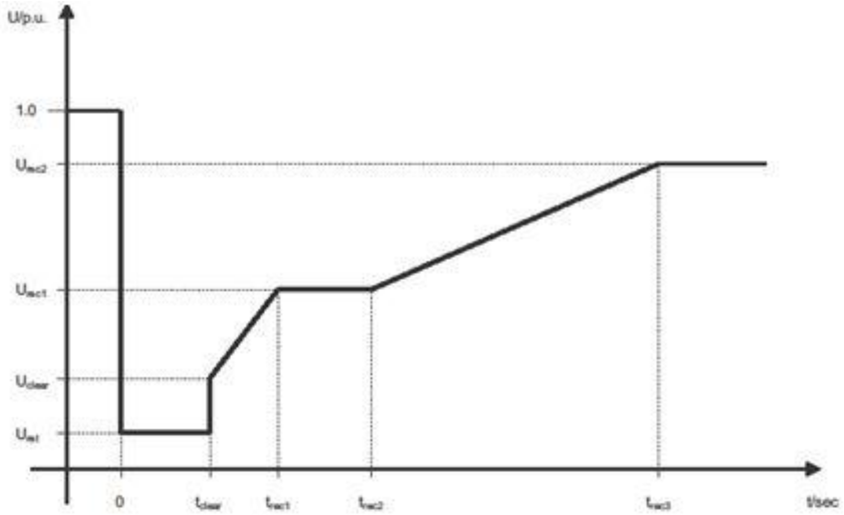


Figure 3 – Fault-ride-through profile of a Power Generating Module. The diagram represents the lower limit of a voltage-against-time profile by the Voltage at the Connection Point, expressed by the ratio of its actual value and its nominal value in per unit before, during and after a fault. U_{ret} is the retained Voltage at the Connection Point During a fault, t_{clear} is the instant when the fault has been cleared. U_{rec1}, U_{rec2}, t_{rec1}, t_{rec2} and t_{rec3} specify certain points of lower limits of Voltage recovery after fault clearance.

Proposal for amendments in the draft code (new text in red)

Justification for our proposal:

The maximum clearing time "t.clear" is 150 ms for synchronous area Continental Europe. A higher maximum value for "t.clear" is admissible only after bilateral agreement between Facility Owner and TSO, with respect to fault feasibility, to existing physical characteristics of relevant turbo sets, and after cost-benefit analysis (CBA).

Adaptation of Art. 9.3.a (changes marked in red):

3. Type B Power Generating Modules shall fulfil the following requirements referring to robustness of Power Generating Modules:
   a) With regard to fault-ride-through capability of Power Generating Modules:
      1) ...
      2) This voltage-against-time-profile shall be expressed by a lower limit of the course of the phase-to-phase Voltages on the Network Voltage level at the Connection Point during a symmetrical fault, as a function of time before, during and after the fault. This lower limit is defined by the TSO while respecting the provisions of Article 4(3) using parameters in figure 3 according to tables 3.1, *3.2 and 3.3.*
      3) *A higher maximum value t_{max} for "t.clear" is admissible only after bilateral agreement between Facility Owner and TSO, with respect to fault feasibility and to existing physical characteristics of relevant turbo sets and grid protection devices. This agreement is nevertheless subject to regulatory oversight by the NRA.*
      4) ...

12

Voltage parameters [pu]		Time parameters [seconds]	
U_{ret}:	0	t_{clear}:	0.14 – t_{max}
U_{clear}:	0.25	t_{rec1}:	t_{clear} – 0.45
U_{rec1}:	0.5 – 0.7	t_{rec2}:	t_{rec1} – 0.7
U_{rec2}:	0.85 – 0.9	t_{rec3}:	t_{rec2} – 1.5

Table 7.1 – Parameters for figure 3 for fault-ride-through capability of Synchronous Power Generating Modules.

Voltage parameters [pu]		Time parameters [seconds]	
U_{ret}:	0	t_{clear}:	0.14 – t_{max}
U_{clear}:	U_{ret}	t_{rec1}:	t_{clear}
U_{rec1}:	U_{clear}	t_{rec2}:	t_{rec1}
U_{rec2}:	0.85	t_{rec3}:	1.5 – 3.0

Table 7.2 – Parameters for figure 3 for fault-ride-through capability of Power Park Modules.

Synchronous area	*t_{max} Maximum Clearance Time Without Circuit Breaker Failure Backup Systems*	*t_{max} Maximum Clearance Time With Circuit Breaker Failure Backup Systems*
Continental Europe	*150ms*	*200ms*
Nordic	*250ms*	*250ms*
Great Britain	*150ms*	*200ms*
Ireland	*150ms*	*200ms*
Baltic	*150ms*	*200ms*

Table 7.3 – Parameters for t_{max} in table 7.1 and 7.2 as well as in figure 3 for maximum clearance time depending on synchronous area.

Adaptation of Art. 11.3.a (changes marked in red):

3. Type D Power Generating Modules shall fulfil the following requirements referring to robustness of Power Generating Modules:
   b) With regard to fault-ride-through capability of Power Generating Modules:
      1) The voltage-against-time-profile shall be defined by the TSO while respecting the provisions of Article 4(3) using parameters in figure 3 according to tables *7.1, 7.2 and 7.3.*
      2) A higher maximum value t_{max} for "t.clear" is admissible only after bilateral agreement between Facility Owner and TSO, with respect to fault feasibility, to existing physical characteristics of relevant turbo sets and grid protection devices. This agreement is nevertheless subject to regulatory oversight by the NRA.
      3) Each TSO shall define and make publicly available while respecting the provisions of Article 4(3) the pre-fault and post-fault conditions for the fault-ride-through capability according to Article 9(3) (a) point 3).

Voltage parameters [pu]		Time parameters [seconds]	
U_{ret}:	0	t_{clear}:	0.14 – t_{max}
U_{clear}:	0.25	t_{rec1}:	t_{clear} – 0.45
U_{rec1}:	0.5 – 0.7	t_{rec2}:	t_{rec1} – 0.7
U_{rec2}:	0.85 – 0.9	t_{rec3}:	t_{rec2} – 1.5

13

Table 7.1 – Parameters for figure 3 for fault-ride-through capability of Synchronous Power Generating Modules.

Voltage parameters [pu]		Time parameters [seconds]	
U_{ret}:	0	t_{clear}:	0.14 – t_{max}
U_{clear}:	U_{ret}	t_{rec1}:	t_{clear}
U_{rec1}:	U_{clear}	t_{rec2}:	t_{rec1}
U_{rec2}:	0.85	t_{rec3}:	1.5 – 3.0

Table 7.2 – Parameters for figure 3 for fault-ride-through capability of Power Park Modules.

Synchronous area	*t_{max} Maximum Clearance Time Without Circuit Breaker Failure Backup Systems*	*t_{max} Maximum Clearance Time With Circuit Breaker Failure Backup Systems*
Continental Europe	*150ms*	*200ms*
Nordic	*250ms*	*250ms*
Great Britain	*150ms*	*200ms*
Ireland	*150ms*	*200ms*
Baltic	*150ms*	*200ms*

Table 7.3 – Parameters for t_{max} in table 7.1 and 7.2 as well as in figure 3 for maximum clearance time depending on synchronous area.

Assessment of implications of the draft RfG code

The required maximum fault clearence time up to 250 ms for Power Generating Modules Type B up to Type D in case of faults in the high-voltage network is not acceptable. It represents an increase of 67 % in comparison to existing regulations e.g. the German Grid Code TC 2007.

During a failure in the network near to the Power Generating Module, the Power Generating Module must remain connected to the network and continue the original operation immediately after fault clearing. Directly after fault clearing the generating unit is subjected to a significantly increased shock torque in comparison with the normal operation, due to recovering voltage. With the extension of the fault clearance time this shock torque will significantly increase. The resulting mechanical stress leads on turbine and generator side to unacceptable high loads and to additional damage and security risks. Exceeding the elastic limit of the shaft assembly, irreversible plastic deformation especially at couplings, damage of the shaft assembly by pole slip of the generator, loss of network synchronization and disconnection from the network may occur.

Entso-E justifies the stringent requirements as concessions to the Network operators of the Nordic countries. However, there is no justification to extend the requirement for Continental Europe.

Maximum time of fault clearance which a generator must ride through is set by the performance of the TSO protection system. Modern protection systems are capable of clearing faults within 100 ms. As such, there is no reason to downgrade the TSOs protection performance which is not linked to the increase in renewables or in cross-border-trade. If there is a need, TSO can easily invest locally in transmission assets such as reactive power devices or duplicate protection systems. Investment in protection system upgrade or investment in redundancy to reduce the risks is usually much cheaper

14

than an investment in a new generator and has wider system benefits. Enforcing a higher FRT standard could result in generators being unable to operate a full output resulting in lower efficiency and higher power prices as well as in limitations on the amount of leading[1] reactive power a generator can provide, reducing system services essential for the integration of renewables.

Retention of Fault Clearance Times of up to 150 ms which is technically proven and e.g. defined in TC 2007 is therefore indispensable. Extensions e.g. required by the "Nordic synchronous areas" should be only possible as mutual agreement between the TSO and Power Generating Facility owner, in consideration of the likelihood of failures with extended Fault Clearance time, specific physical characteristics of the turbine set and after cost-benefit analysis (CBA).

Active power output with falling frequency

The KEMA Report (later on the report) states correctly that "The definition of requirements for maintaining active power output with falling frequency is one of the newer issues included in several grid codes, but not yet all". Referring to chapter 5.1.1 the report expresses concerns about applying frequency ranges to the power station.

We realize that TSOs need some certainty regarding the remaining available power in case of frequency deviations. On the other hand, there are physical limitations on the generator side. For example: when generating power, any thermal power station will need a certain mass flow of steam. The mass flow of steam affects the output of power. The steam is produced in boilers or steam generators and therefore it is necessary to refill them with water. The mass flow of water has to be equal to the mass flow of steam for the turbines, to make the system balanced. Any deviation of the frequency for example below 50 Hz will reduce the speed of the water pumps and result in reduction of the mass flow of water, because the motors of the feeding pumps are rotating slower (see the Report chapter 5.1.1 page 232). As a result we get an imbalance between "feeding and steaming". Similar problems are described in the comments:" EURs opinion on necessity, feasibility, cost impact and alternative approaches of key requirements for nuclear generators" dated April, 12th 2013 chapter 3.1.3.2. Frequency deviation within certain ranges will be absorbed by inherent reserves of the individual power stations.

The former UCTE rules solved this issue with the so called "Load shedding", see the table below (Swissgrid TC2010 V1.0, April 2010, page 28, english version)

[1] There are 2 types of reactive power: leading and lagging

15

Table 1: Load shedding plan

Level	Frequency (Hz)	Action	Accumulated load shedding / %	Activation type
1	49.8	Activation of power reserves		Manual/automatic
2	49.5	Shedding of storage pumps		Automatic
3	49.0	10-15% load shedding	10 - 15%	Automatic
4	48.7	10-15% load shedding	20 - 30%	Automatic
5	48.4	15-20% load shedding	35 - 50%	Automatic
6	48.1	15-20% load shedding	50 - 70%	Automatic
7	47.5	Disconnection of the power plants from the grid		Automatic

Looking at table 1 we realize that a deviation of only 0.2 Hz below 50 Hz leads to an activation of primary power reserves. Below 49.5 Hz load shedding will be automatically activated by reducing the load through switching off storage pump stations, because the technical possibilities of the power stations to increase the output below a certain underfrequency is limited.

In the draft NC RfG, Article 8 requirements for generators appearently are strictly defined without any consideration of the balance between existing load shedding schemes and reduction of produced power. Respecting physical limitations and the effects of load shedding schemes will lead to acceptable requirements for Generators.

Therefore it should be ensured that load shedding is covered in another NC.

Instead of forcing power stations into extreme under frequency conditions (each station[3] will do it in his own way) and risking either some serious damage in the plants or risking that the plant protection system will trip the plant, a coordinated **load shedding scheme combined with realistic maximum allowed power output reduction** is preferable. The point of ENTSO-E keeping "the grid together" is understood but from a the plant operation view this will not be as easy to apply as ENTSO-E suggest because of the different physical behaviour of the various plants.

***Proposal for amendments in the draft code** (new text in red)*

Article 8.1.e (as it is)/should be
GENERAL REQUIREMENTS FOR TYPE A POWER GENERATING MODULES

1. *Type A Power Generating Modules shall fulfill the following requirements referring to Frequency stability:*

   e) ~~The Relevant TSO shall define admissible Active Power reduction from maximum output with falling Frequency within the boundaries, given by the full lines in Figure 2:~~

[3] E.g. Wind-, Solar-, CCGT-, Coalfired-, Nuclear- and Hydro power plants

16

~~- Below 49 Hz falling by a reduction rate of 2 % of the Maximum Capacity at 50 Hz per 1 Hz Frequency drop;~~

~~- Below 49.5 Hz by a reduction rate of 10 % of the Maximum Capacity at 50 Hz per 1 Hz Frequency drop.~~
~~Applicability of this reduction is limited to a selection of affected generation technologies and may be subject to further conditions defined by the Relevant TSO while respecting the provisions of Article 4(3).~~ The maximum power reduction of the Power Generating Modules due to Frequency falling in the range of 49.5 Hz - 48.5 Hz should be less than 10% of rated power.

17

G.4 Comment from EUR

Network Code on Requirements for Grid Connection applicable to all Generators

EUR's comments on DNV KEMA / COWI preliminary report to EC dated July 15th, 2013.

September 14th, 2013

Working Group members:

Hervé Meljac – EDF (chair)

Jonas Persson – Vattenfall

Reinhard Kaisinger – Vattenfall

Jaakko Tuomisto – TVO

Helge Regber – E.ON

Lasse Linnamaa – Fortum

DG TREN has appointed DNV KEMA / COWI to assist the European Commission in the assessment of the draft ENTSO-E Network Code on Requirements for Grid Connection applicable to all Generators (NC RfG). As part of its mandate, the consultant has to provide advice on the specifications and rules proposed in NC RfG covering the fields of:

- Necessity of the rules and specifications;
- Technical feasibility;
- Costs and benefits;
- Alternative approaches.

DNV KEMA / COWI has issued a preliminary report which addresses the following topics:

- Description of the task assigned by DG TREN;
- Description of the power system context in which NC RfG has been developed;
- Summary of the concerns expressed by stakeholders consulted by DNV KEMA / COWI as part of the assigned ask;
- Assessment of technical and non-technical issues raised by stakeholders;
- Recommendations on how to amend NC RfG.

The purpose of this paper is to express EUR's main comments on DNV KEMA / COWI preliminary report.

TABLE OF CONTENTS

REFERENCES

[1] DNV KEMA / COWI – Technical Report on ENTSO-E Network Code: Requirements for Generators – Preliminary Report – 15 July 2013

[2] ENTSO-E – Network Code for Requirements for Grid Connection Applicable to all Generators – 8 March 2013

[3] EUR's opinion on necessity, feasibility, cost impact and alternative approaches of key requirements for nuclear generators – April 12th, 2013

[4] ENTSO-E – Statistical Yearbook 2011

[5] European Nuclear Society website: www.euronuclear.org

[6] VGB / EURELECTRIC's generators RfG Network Code: Needs, Feasibility, Alternative Solutions and Costs

[7] Letter from WENRA to ACER, dated October 4, 2012 – Available in appendix of **[1]** and **[3]**

DEFINITIONS

Abbreviation	Definition
ACER	Agency for the Cooperation of Energy Regulators
CBA	Cost Benefit Analysis
CE	Continental Europe synchronous area
CIGRÉ	Conseil International des Grands Réseaux Électriques
ENTSO-E	European Network of Transmission System Operators for Electricity
EUR	European Utilities Requirements
FRT	Fault Ride-Through
HVAC	High Voltage Air Conditioning
IEC	International Electrical Commission
LFC	Load-frequency control
LFSM-O	Limited Frequency Sensitive Mode – Overfrequency
LFSM-U	Limited Frequency Sensitive Mode – Underfrequency
LWR	Light Water Reactor
NC LFC&R	Network Code on Load-Frequency Control and Reserves
NC OS	Network Code on Operational Security
NC RfG	Network Code for Requirements for Grid Connection Applicable to all Generators
NPP	Nuclear Power Plant
NRA	National Regulatory Authority
RES-E	Renewable Energy Source
TSO	Transmission System Operator
WENRA	Western European Nuclear Regulators Association

1. INTRODUCTION

1.1. Purpose

The purposes of this paper are as follows:

1. To remind what previous work has been done by EUR on NC RfG, in particular that concrete amendment proposals of NC RfG have been made to tackle the different issues that were raised.
2. To express EUR's main comments on DNV KEMA / COWI preliminary report **[1]**.

1.2. The EUR

The European Utilities Requirements organisation (EUR) was created in 1991. It involves all major European utilities which operate nuclear power stations. The purpose and main objective of the EUR is to harmonize and stabilize the conditions in which the standardised Light Water Reactor (LWR) nuclear power plants to be built in Europe in the first decades of the XXIst century will be designed and developed. This is expected to improve nuclear safety, nuclear energy competitiveness and public acceptance in an electricity market unified at European level.

Since it was released in 2001, the Revision C of the EUR specifications has been extensively used in the development of new LWR designs and projects, in particular in the EPR design with two units under construction in Olkiluoto and Flamanville. Revision D has been released in October 2012. It reflects the will of EUR organization to continuously match the best nuclear practice and adapt to the changing power system environment.

1.3. Nuclear power plants in Europe

In 2011, on the grids operated by Transmission System Operators (TSO) members of ENTSO-E, nuclear power plants have accounted for:

- 885 586 GWh net generation – 26.5% of 3 347 445 GWh total[1];
- 126 447 MW net installed capacity – 13.6% of 928 311 MW total[2].

Currently, on the zone covered by ENTSO-E, 136 nuclear generators are in operation in 15 different countries[3].

[1] Source ENTSO-E – Statistical Yearbook 2011 **[4]**
[2] Source ENTSO-E – Statistical Yearbook 2011 **[4]**
[3] Source European Nuclear Society **[5]**

1.4. Previous work performed by EUR on NC RfG

The EUR Working Group on Network Codes was created in August 2011 to participate to the Network Codes elaboration process. The Working Group has been quite active ever since, consistently expressing all of its concerns in an open and transparent manner, through documented presentations and position papers.

In more details:

- 27 Working Group meetings were held from August 2011 to September 2013, the vast majority of which on NC RfG.
- 3 position papers were written on NC RfG:
    - September 16th, 2011;
    - July 1st, 2012;
    - April 12th, 2013 **[3]** (to support our discussions with DNV KEMA / COWI).
- 2 Bi(or tri)-lateral meetings were held with ENTSO-E:
    - November 10th, 2011 (ENTSO-E NC RfG drafting team);
    - August 29th, 2012 (EUR – ACER – ENTSO-E).
- 5 Presentations were given in public ENTSO-E and ACER meetings:
    - February 15th, 2012;
    - March 22nd, 2012;
    - May 2nd, 2012;
    - June 28th, 2012;
    - September 3rd, 2012 (ACER).
- EUR accepted DNV KEMA's invitation to express its views in a bilateral meeting on April 25th, 2013 (supported by the April 12th, 2013 position paper **[3]**).
- 50 comments were posted during Public Consultation.

1.5. Interactions of EUR with DNV KEMA / COWI – proposals to amend NC RfG

More specifically, the April 12th, 2013 position paper **[3]** was written for the attention of DNV KEMA / COWI to support their current work. It was designed to address specific issues on areas of NC RfG the EUR believes should be amended, and deliver a sound, explicit and technically-orientated alternative approach.

Although the present DNV KEMA / COWI report **[1]** addresses and acknowledges most of the issues covered in EUR's position paper **[3]**, the recommendations and proposals it provides do not thoroughly tackle all problems.

Should DG TREN request the EUR to provide concrete NC RfG amendment proposals, it can refer to April 12th, 2013 position paper **[3]** which contains such alternative approaches.

2. GENERAL COMMENTS

2.1. Document layout

The structure of the report is clear and fit for the purpose set in the mandate. The EUR recognize a large amount of good work has been performed interviewing numerous stakeholders, analyzing the issues raised and their root causes, and presenting results in a comprehensive way.

On the form, the EUR regret the poor quality of the appendices rendering, which makes them difficult to read. However the EUR recognizes this is probably due to the need to reduce the size of the final file to an acceptable level.

Besides, some wording is inappropriate, the EUR would appreciate if the authors would consider some amendments, in particular:

- Page 34: the CIGRE study on tap-changers failures should not be dismissed on the only reason it is "old", especially when another not very recent CIGRE study put forward by ENTSO-E to support its argument (page 30) is considered as strong evidence.
- Page 37: although DNV KEMA / COWI can disagree with them, the arguments put forward by stakeholders should not be qualified as being "something of an exaggeration".

2.2. Issues addressed

Most of the issues addressed by stakeholders are referred to and analyzed although some have been left aside, in particular:

- Plant modernization or use of spare parts, addressed by EUR in **[3]**, as well as Eurelectric and VGB Powertech in their joint position paper **[6]**.
- The concern that NC RfG is unbalanced in nature. On that point the explanation given by DNV KEMA / COWI for not addressing this in chapter 4.2. is not satisfactory. Although the EUR agree it is to be expected that the requirements in NC RfG should be placed on generators, stakeholders are under the impression that some requirements on generators are made very onerous to exempt TSOs from taking costly measures to ensure stable power system operation. This is not cost-effective and will drive cost for the generators. Hereafter are a just two meaningful examples, but the issue is much wider:
    - Larger reactive capability and operating voltages ranges, when means for reactive compensation (capacitors, reactors, SVCs, other FACTS) can be installed and operated by TSOs;
    - Potential longer FRT requirement when modern grid protection systems are much faster.

2.3. Missing recommendations

The EUR is pleased that some important issues are appropriately addressed and acknowledged in the report; however it is to be noted in some domains, while the analysis in the report suggests NC RfG does not tackle the issues, no recommendation or proposal is formulated. In particular:

- Chapter 3.3. "Impact of RES-E". The EUR agree with DNV KEMA / COWI's analysis, and has expressed the same concern throughout the NC RfG drafting process. Surprisingly, while the report recognizes NC RfG does not tackle the negative impacts or RES-E increasing penetration, it does not provide any recommendation either.
- Chapter 6.1.2. "Legal status of TSOs".
- Chapter 6.2.1. "Governance". While the executive summary suggests recommendations have been made on governance (chapter 0.3. *"recommendations are made on establishing appropriate governance arrangements"*), and while the analysis in the report clearly states that governance arrangements have to be improved, especially in the field of Grid Code modification, no recommendation is formulated.
- Chapter 6.2.2. "Retrospective Applicability". The report recommends NC RfG should be amended on that topic, but unfortunately does not provide a concrete recommendation.

3. SPECIFIC COMMENTS

Please note that the comments formulated hereafter also apply to the associated recommendations in chapter 7 of the preliminary report.

3.1. Chapter 5.1.1. – Frequency Ranges

The EUR cannot agree with statements such as "*the position of the stakeholders during the consultation was very supportive*" or "*However there was no strong opposition either*" when talking about extending the unlimited operation frequency range to 49.00 Hz – 51.00 Hz. Furthermore, it is acknowledged that the combination of proposed frequency- and voltage ranges in the NC RfG is a primary concern.

The EUR has repeatedly argued that frequency quality should be kept constant in time, and that NC RfG should reflect that objective. Moreover, while the report insists that more consistency among the different codes should be sought, it doesn't make any mention of the large discrepancy between NC RfG and NC LFC&R, in which frequency quality objectives are described and which shows that a very small proportion of the capability required in NC RfG should ever be used (maximum instantaneous and steady-state frequency deviation objectives). On a nuclear safety point of view, it is essential that large frequency transients should be both infrequent and short in duration.

Besides, the report takes on the argument that the proposed frequency ranges are consistent with IEC 60034, although different stakeholders including the EUR have explained that in a power plant grid frequency is not only relevant to rotating machines operation, but also to the design of many systems which are indirectly influenced by frequency such as:

- Nuclear safety systems.
- Nuclear Steam Supply System, where the coolant flow rate is proportional to grid frequency;
- HVAC systems performance;

Moreover, while the report recognizes that the use of a combined voltage/frequency ranges requirement is important, it does not recommend using one. In a similar manner, a proposal for limiting frequency deviations in extent, duration and frequency of occurrence is missing.

DNV KEMA acknowledges that "*Particularly in the case of existing installations, the extension of the frequency range will not be as easy to apply as ENTSO-E suggest.*" However, the report does not propose an exemption of existing installations.

The EUR points out that WENRA expressed its concerns on the extent of frequency ranges, as well as voltage ranges, in a letter to ACER dated October 4, 2012 **[7]** in these terms: "*In fact, the definition for the range for frequency and voltage is too large. For nuclear power plants, which are working as 100% base load power plants, the technical safety limit is 48Hz.*"

The proposal made at the end of the chapter suggests the definition of additional Frequency Target Parameters. Although such parameters might have a positive impact on the extent and duration of frequency deviations, they are neither going to ensure higher frequency quality nor limit frequency of occurrence of frequency deviations.

As a conclusion, the EUR believe the expressed recommendation does not tackle the issues addressed by stakeholders on operating frequency ranges, which are of prime importance for some, especially nuclear generators because of the impact on nuclear safety. EUR wants to underline once again the importance of a) combining voltage and frequency parameters in one requirement, and, b) a limitation of frequency deviations in extent, duration and frequency of occurrence is missing.

7 / 9

3.2. Chapter 5.1.2. – Active power output with falling frequency

The recommendation is quite vague and should be made more explicit.

3.3. Chapter 5.1.3. – LFSM-O and LFSM-U

The EUR cannot agree with the statement *"the requirements specified in the NC RfG are reasonable when compared with the requirements of existing grid codes. With modern controls on new equipments, it is expected that the range of requirements specified in the NC RfG should be capable of being met."*

As explained in the EUR position paper **[3]** and presentation to DNV KEMA, the issue complying with LFSM-U has nothing to do with control arrangements limitations. It has to do with the ability of plants to go through very large transients on a regular basis, in terms of mechanical constraints due to extensive temperature and pressure variations, as well as nuclear core control issues for NPPs.

Therefore the EUR disagree with the authors' conclusion.

Moreover, it is to be noted that the EUR do not fully understand the meaning of the second paragraph of the chapter, which is meant to reflect discussions between the EUR and the authors. Therefore there is a need for further clarification.

3.4. Chapter 5.2.1. – Voltage ranges

DNV KEMA addresses and acknowledges a large number of issues related to overvoltages. For instance, it recognises that *"the proposed ranges for operation in the overvoltage area seem to be beyond current practices, in particular for the 400kV voltage level."* Furthermore, it is concluded that *"Long and/or frequent operation under significant overvoltages may seriously damage generators and/or associated electrical equipment; therefore, network rules have to limit overvoltages beyond standard values by time of their duration and frequency of their occurrence"*. However, the recommendations given do not thoroughly reflect DNV KEMA's reasoning.

Also, as in the case of Frequency Ranges, DNV KEMA misses to propose the use of a voltage/frequency chart.

Although the EUR consider the conclusions and recommendations are an improvement to the current NC RfG drafting, the rationale behind the proposed new figures should be explained.

3.5. Chapter 5.2.2. – On-load tap changers

Although the use of on-load tap changers for step-up and auxiliary transformers is not a direct requirement in NC RfG, it is a consequence of the enlargement of voltage ranges, which, as explained earlier in this paper, is the result of the unbalance nature of the Network Codes.

As a consequence, the EUR maintain their concern on that topic.

3.6. Chapter 5.3. – Fault Ride-Through

The EUR find the authors conclusions contradictory. On the one hand, feasibility of a 250ms requirement is said to be not proved. On the other hand, the recommendation is to keep such as a requirement for the Nordic synchronous area. How good is a requirement which can only be met through derogation or through uneconomic solutions such as heavy curtailment of power output?

It is recognised in the report that a harmonisation of FRT-requirements is not the objective of the NC. DNV KEMA / COWI acknowledges that FRT-requirements shall be assessed on a case by case basis. Unfortunately, this acknowledgment is not reflected in the proposal.

Also, DNV KEMA / COWI states that ENTSO-E makes use of the most onerous requirement among all synchronous areas. It is concluded correctly that taking the most extreme requirement imposes a significant deviation from current practise.

Again, the EUR insist that the 250ms FRT requirement is irrelevant if TSOs are entitled to modernize their protection systems. Therefore it is another result of the unbalance nature of the Code.

3.7. Chapters 6.5.1.1. & 6.5.1.2. – Harmonization between ENTSO-E Network Codes

The EUR insist that the recommendations formulated do not tackle the large discrepancy between NC RfG requirement and the actual use of the capability predicted in the operational Codes.

NC RfG and Operational Codes should be harmonized in such a way that NC RfG would not over-specify.

3.8. Chapter 6.6 – Compliance

The recommendation should also include the aspect of cost recovery for generators.

4. CONCLUSION

The EUR conclude that the recommendations formulated in the DNV KEMA / COWI preliminary report are not strong enough to tackle the important issues which are consistently and repeatedly been addressed by stakeholders including EUR throughout the NC RfG drafting process. In its current form, the NC RfG is going to have an impact on the operation of existing NPPs. For instance, NPPs are forced to reduce power output due to low grid frequency.

During the process, individual stakeholders as well as trade associations have issued numerous position papers supported by strong justification and evidence to propose alternative approaches on controversial requirements. The EUR position paper issued on April 12th, 2013 **[3]** is among these.

The EUR reiterates its view that the aim of the Pan-European Power System should be to keep the electricity quality constant over time, and that this objective should be reflected in the Network Codes, especially NC RfG, NC OS and NC LFC&R, which is not the case in the current drafting. For Nuclear Power Plants it is a matter of Nuclear Safety, which is recognized to be predominant over Grid Safety even in NC OS (in particular Article 3).

G.5 LFSM-O Obligations - Randomised Disconnection

COGEN Europe and EHI micro-CHP Joint Working Group Argumentation on „Randomised Settings for Over-Frequency Disconnection and Reconnection"

Brussels, September 13th 2013

Summary

The COGEN Europe and EHI Micro-CHP Joint Working Group appreciates the assessment provided by DNV Kema and COWI in the preliminary report on the NC RfG regarding the randomised disconnection for over-frequency disconnection as an equivalent group droop. In the argumentation below the Micro-CHP Joint Working Group offer further evidence on the viability of the proposed solution based on:

- the priority of tackling a sudden overfrequency wave over the need to overcome the possible impacts of a delayed reconnection.
- the benefits of the randomised disconnection approach, in terms of improved reaction time of a group of generating units, over the sub-optimal solutions that are available for individual units technically unable to reduce active power in overfrequency situations in the required time.

We therefore ask that the assessment of the randomised disconnection solution in the preliminary report is amended to allow this alternative approach in the NC RfG based on the considerations presented here (i.e. its significant contribution to grid stability due to a fast disconnection behaviour).

Technical argumentation

The preliminary report on the NC RfG drafted by DNV Kema and COWI states on page 29 that *„the random disconnection of many small units will simulate a droop characteristic for the total group."* Thus it is recognised that a population of smaller units, just able to switch on and off, is able to absorb the first wave of surplus power in a smooth way. The randomisation could be easily managed either by defining values in the factory itself or by choosing and burning-in the national settings during the commissioning of the generating unit. The Joint micro CHP Working Group is eager to explain randomization algorithms which could be used to emulate the droop curve of LFSM-O, if further details are needed.

For the sake of system stability, the priority of which is to survive the first wave of overfrequency, it is essential to reduce the active power in the grid as quickly as possible (see NC RfG Article 8, 1. c) 1). The NC RfG requires, that if the time is longer than 2 s the TSO needs to be consulted.

ENTSO-E specialists on system dynamics objected to the introduction of a so called ‚intentional delay' of max two seconds in EN 50549:2013, which could lead to all generators acting close to 2 s, based on the following relevant aspects:

- The preferred reaction time is similar to under-frequency load shedding of about 200-300 ms.
- Large thermal power plants in the GW range react with their steam valve in 500-1000 ms, while the inertia of the turbine plus generator slows down any frequency reaction.
- Inertia of distributed generators based on combustion engines or gas turbines are about a factor of 10 smaller, therefore the step response time should be faster.

Generators for which it is technical not feasible to reduce power in the technically required time should have the option to disconnect very quickly (200 ms), by performing the required droop curve as a population, in order to stop further increase of frequency. In November 2006 there was a problem with wind parks disconnecting and reconnecting at 50.5 Hz. Nevertheless, while this situation was not ideal, the alternative of wind power continuing to feed in for additional 2 seconds pushing the frequency from a maximum of 51.4 Hz as shown in the final UCTE report beyond the 51.5 Hz threshold would have had more dramatic consequences to start with. The very fast randomized disconnecting function (within 200/300 ms) will contribute significantly to the grid stability and will therefore compensate for the slower reaction time of generators such as steam turbines.

Section 5.1.3. (preliminary report on the NC RfG drafted by DNV Kema and COWI) on "LFSM-O and LFSM-U" includes an assessment of the randomised disconnection solution. In this section the „unidirectional" nature of the approach is mentioned as a disadvantage. From a steady-state perspective disconnection and reconnection will occur symmetrically at the same randomized set point, thus a static droop will be fully emulated. An immediate power reduction by disconnection is possible but a delay until reconnection will occur, so dynamically there it is unidirectional behaviour. The reconnection of CHP engines needs time among others to check the mechanics, the gas train and to flush combustion chambers with fresh air to avoid an ignition of unburnt fuel. This alternative of randomized disconnection and reconnection is considered as more favourable compared to a symmetrical power increase immediately when frequency goes down again, but with an initial delay in reducing power during a sudden frequency increase. Therefore, it can be well argued that generating units with a slow ramp rate, such as stationary fuel cells (gas flow constraints and temperature in SOFC technology), stirling engines (heat flow from the combustion chamber via a separating wall to the working gas volume), some gas turbines (flame stability in transient processes) and even combustion engines (speed of the butterfly valve and other mechanical actuators) will probably not meet the symmetrical requirements that the reduction of surplus power at overfrequency is done at the same speed as the shedding of loads at underfrequency if the method to reduce power is done by the throttle control of the prime mover.

Legal argumentation

The method of randomised disconnection has been already introduced as state-of-the-art in Germany (LV Grid Connection Standard VDE 4105) and has been also part of a ministerial regulation (SysStabV). The exclusion of this already accepted way to cope with overfrequency situations will discriminate generating units with low inertia and a certain, technically induced delay. These generating units would not be technically able to contribute their share to system stability, unless the instrument of randomised overfrequency disconnection is part of the toolbox of solutions.

Conclusion

As a general principle, a fast reaction with a delayed reconnection has to be balanced against a slow symmetrical reaction in the case of an emergency Given that the LFSM-O is not for continuous operation such as frequency control in normal system state, but is preparedness for the worst case. As these events obviously happen, but with a very low frequency, before dismissing this option, it would be necessary to test via a cost benefit analysis, at least for type A generators, that the advantages of a fast disconnection to the grid stability do not outweigh the disadvantageous asymmetry between disconnection and reconnection.

The Joint Working Group therefore argues that the randomized disconnection should still be considered as one out of several viable technical solutions needed to fulfil the current and future needs of the grid.

TC8X/Sec0109/INF

Technical Committee: TC 8X
Title: SYSTEMS ASPECTS OF ELECTRICAL ENERGY SUPPLY

TC8X/WG03 Experts position on Preliminary report from DNV KEMA on the Network Code "Requirements for Generators" and the staged disconnection performing a group droop for active power reduction at over-frequency disturbances

During the last Stakeholder Meeting on the Network Code RfG which took place on September 16th in Brussels, the behavior of micro generators on LFSM-O (Limited Frequency sensitive Mode – Overfrequency) has been reviewed as part of the DNV KEMA preliminary report.

Cenelec TC8X/WG03 Experts are pleased to inform that the method of performing LFSM-O by providing a group droop through staged disconnections is part of the final draft on EN 50438 "Requirements for micro-generating plants to be connected in parallel with public low-voltage distribution networks". The FprEN 50438 was recently released for formal vote. The voting result is showing 100% approval.

This shows that the randomized disconnection to perform a group droop, especially of micro-generators which as an individual unit are not capable to react in the required time of less than 2 seconds, is a well-accepted method for active power reduction in over-frequency situations.

The Experts of Cenelec TC8X/WG03 consider that reducing the active power by performing a group droop will bring very important benefits with respect to grid stability in major over-frequency disturbances. Indeed, this group droop is provided by staged disconnections, triggered by the interface protection relay within a few hundred milliseconds, which provide the fastest reaction possible. Besides, from a system dynamics aspect, a fast reaction on frequency will avoid an over-shooting and reduce the probability of situations were fast reconnection is needed. Please also note that this method will be implemented in France. The French DSOs chose for the time being to apply a staged automatic disconnection of PV. With various frequency thresholds for disconnections, this approach is similar to the under-frequency load shedding. It will meet the technical purpose behind the RfG Network Code much better than an initial delay of up to 2 seconds.

Consequently TC8X/WG03 Experts would be pleased if the final report from DNV KEMA could take into consideration the method described here-above and part of the recently approved EN 50438 Ed2 (2013).

Copy:

Robert Mc Vean (DNV KEMA) : Robert.McVean@dnvkema.com

Marcus Merkel (CLC BTWG 143-2): Marcus.Merkel@ewe.de

Edwin Haesen (ENTSO-E): Edwin.Haesen@entsoe.eu

Catherine Vigneron (CCMC): cvigneron@cencenelec.eu

RE: TC8X/WG03 Experts position on Preliminary report from DNV KEMA on the RfG Network Code

From: Edwin Haeson

To: Nicola Cammalleri, Robert McVean, Marcus Merkel, C Vigneron

cc: Herve Rochereau, Simone Botton, Thomas Schaupp, Wouter Vancoetsum

25 October 2013 18:17

I appreciated the talk we had last Wednesday regarding future CENELEC/ENTSO-E coordination, and in which we also covered this recent letter.
From the conversation I understood that the opinion expressed in this letter is not that of CENELEC, nor of one of its committees, but of a number of experts that worked on the draft EN50438.

For those who did not attend the meeting, let me just emphasize again that it is ENTSO-E's firm position that the option of a "randomized disconnection to perform a group droop" is not an acceptable method for new generation units when coping with overfrequency situations. In those situations, the system needs to ensure above all a stable behaviour when moving back to the 50Hz target. Simply losing generation with no assurance of reconnection is not an acceptable general solution. ENTSO-E does not share the view expressed in the letter that it meets the technical purpose behind the RfG Network Code much better than an initial delay of up to 2 seconds. I am confident this point was made clear in past discussions as well as in the comments ENTSO-E provided on the recent EN50438 and TS50549 drafts.

Extensive discussions with manufacturers in the past development of the NC RfG have proven that an LFSM capability can easily be provided by the majority of technologies. Exceptional cases (and I acknowledge we discussed these as well) of specific types of generation that cannot deliver this capability could be covered by derogation or by classification as emerging technologies, which the NC RfG both provides for. The case of some micro-generation brands has been well understood in constructive discussions we had to date.

We do believe standards are an essential tool in ensuring compliance of mass market generation units, and are as such a valuable complement to European Network Codes. I hope continuing and even an increasing number of interactions (like we have seen in the past weeks) can ensure an efficient synchronization of standards and network codes in future.

Best regards
Edwin

Edwin Haesen
Planning Methods Senior Advisor

ENTSO-E
European Network of Transmission System Operators for Electricity

Experts position

Gunnar Kaestle [gunnar.kaestle@tu-clausthal.de]

Sent: 06 November 2013 16:40

To: Edwin Haesen [edwin.haesen@entsoe.eu]

Cc: Nicola Cammalleri [nicola.cammalleri@enel.com]; McVean, Robert; Marcus Merkel [marcus.merkel@ewe.de]; Catherine Vigneron [cvigneron@cencenelec.eu]; Hervé Rochereau [herve.rochereau@edf.fr]; Simone Botton [simone.botton@enel.com]; Thomas Schaupp [thomas.schaupp@kaco-newenergy.de]; Wouter Vancoetsem [wouter.vancoetsem@laborelec.com]

Dear Edwin,

Thank you for your note which has been forwarded within the WG03 Collaboration Area. I assume that CENELEC and ENTSO-E are working the same way: the organisation is fed with knowledge and initiatives by its members. Here is an overview on the working groups of TC8X which have been founded in the past to work on new standards or to maintain existing ones.
http://www.cenelec.eu/dyn/www/f?p=104:29:281672561209535::::FSP_ORG_ID,FSP_LANG_ID:1077,25#1
TC8X usually only meets only once a year and can be regarded as the steering committee assingning tasks to volunteering specialists.

Could you please help me out and tell me which experts from ENTSO-E member firms say that it is not acceptable to loose power in an overfrequency situation? I'd like to discuss personally the situation of ~6 GW of wind parks disconnecting within 200 ms at 50,5 Hz and if or if not this might have saved the night of several million people in the north eastern zone during the system split in November 2006 and preventing a blackout in this area which had to cope with a ~10 GW surplus.

From my basic understanding of control technology, the need for reconnection after a surplus of active power and the resulting frequency increase followed by a frequency decrease (overshooting) only comes from a massive delay in frequency response. Usually, you see this effect in the RG CE in a nadir after ca 10s in the case a loss of active power. This is caused by the slow activation (within several seconds) of primary power. The situation with a surplus of active power should be similar: if there is a delay in the reduction of power, then there will be an overshoot of frequency and after that the frequency declines again.

But if and only if, the delay in the reaction on over-frequency can be minimized, no overshoot will occur and therefore no fast declining frequency will be observed after the overshoot. An exponential curve with an aperiodic time constant will evolve f(t) = 1-exp^(-t/T) as a step response behaviour. This is what theory tells me and I am happy to learn more about this theory in practical applications. I'd like to share my thoughts and reasoning with those experts who still believe that fast active power reductions is harmful for grid stability and the following active power increase is immediately needed.

By the way, it's not only about microCHP. As you may know, even larger thermal plants may need some seconds to reduce active power. I believe that was the reason for the new draft for HV connections in Germany allowing up to 5 seconds for so called type 2 generators as a step response time. The difference between step response time and settling time is explained here:
http://www.electropedia.org/iev/iev.nsf/display?openform&ievref=351-24-28

Best regards,

Gunnar

H. Notes of Stakeholder Meeting

Project: Technical Report on ENTSO-E Network Code – Requirements for Generators

Stakeholder Meeting: 16 September 2013

Location: European Commission, DG ENER Rue de Mot 24, Brussels

Present:

> **Registration was conducted by EC who advised that everyone who had registered also attended. The representatives from ACER Ljubljana attended by video link. The meeting was chaired by Tadhg O'Briain.**

The purpose of the meeting was to discuss the main technical issues that were outstanding in the review of the NC RfG, the proposals included in the COWI Belgium/DNV KEMA Preliminary Report and alternative approaches that may be proposed by Stakeholders.

It was agreed that these issues were correctly identified in the Preliminary Report and were:

- Frequency Ranges;
- Active Power Output with Falling Frequency;
- LFSM-O and LFSM-U;
- Voltage Ranges;
- Potential Requirement for the use of On Load Tap Changers;
- Reactive Power Capability;
- Provision of Reactive Power as a Means of Voltage Control;
- Fault Ride through – Duration of Fault Clearing Time;
- Fast Reactive Current Injection and Active Power Recovery by Power Park modules B, C and D;
- Fault Ride Through on LV Networks; and
- Effects for DSOs.

Following a short introduction to the review by Bob McVean representing DNV KEMA, Ralph Pfeiffer responded on behalf of ENTSO-E. The technical issues were discussed with Bob McVean introducing the issue and the proposal submitted by DNV KEMA and Ralph Pfeiffer responding where appropriate with a description of ENTSO-E's objectives and rationale for the initial drafting. A full discussion by stakeholders followed and for several issues an agreed position was reached.

Frequency Ranges	Stakeholders repeated their concerns regarding the (as they see them) excessive safety margins applied and this was noted. It was determined that frequency ranges should follow IEC standards recognising that the requirement is to remain connected which should not be interpreted as normal operation where the operation of mechanical plant has an impact.
Active Power with Falling Frequency	The need for greater definition was acknowledged and drafting requiring that NRAs take account of ambient temperatures and the technical capabilities of existing technologies should be introduced.
LFSM-O and LFSM-U	It was accepted that derogations based on safety cases should be given where technology so required. The genuine issues related to industrial CHP should be addressed. COGEN Europe argued the case for randomised disconnection which ENTSO-E could not see operating. The reconnection issue was recognised and no action on this proposed.
Voltage Ranges	Time periods in the range 20 – 40 mins and 40 – 80 mins were proposed in place of both previous proposals. The form of IEC standards should be followed choosing outside ranges to fit. Drafting to be introduced permitting an opt out where required for network configuration reasons as approved by the NRA provided it is not detrimental to operation of the power system or the internal market.
OLTCs and reactive power provision	Drafting would be introduced making clear that where OLTCs are required, this must be specified not left to be inferred. Where OLTCs are required, figure 7 would follow ENTSO-E arrangement. Where OLTCs are not required, figure 7 would follow the arrangement in the DNV KEMA proposal.
FRT – Clearing Times	Where generic values are quoted, they shall be distinguished by voltage level and, at 400 kV by synchronous area, except where alternative arrangements are required for network configuration reasons as approved by the NRA provided it is not detrimental to operation of the power system or the internal market.

Fast Reactive Current Injection and Active Power Recovery by Power Park modules B, C and D	Active power requirements should be specified with greater precision; fast reactive current injection should be specified with less precision recognising the current state of technology. The effect of the combination of these requirements should be recognised. EWEA and EPIA are working on this issue and will propose a resolution.
FRT at LV	The DNV KEMA proposal was accepted
Effect for DSOs	It was acknowledged that DSOs must be free to set values as required for safety.
	The power system protection issues should be dealt with after the results of current trials are known. To allow this, provisions should allow NRAs, operating in conjunction with other NRAs, to apply appropriate standards.
	The impact of DSOs operating 110 kV (+) networks should be addressed by allowing overlaps between application of T and D rules. *POST MEETING NOTE: One part may be not to make it automatic that a unit is type D just because it is connected to a 110kV distribution network.*
	The ability for CDSOs to obtain derogations is required with responsibilities then falling on connecting RNO.
	Compliance issues were not resolved. *POST MEETING NOTE: one solution may be to require the TSO to establish detailed rules that must be subject to NRA approval. Requirement for NRAs to establish best practice guidelines may also be appropriate.*

Bob McVean
DNV KEMA
19 September 2013

[*End of Document*]