entsoe

Reliable Sustainable Connected

Supporting Document for the Network Code on Operational Security

24 September 2013
2nd Edition Final

TABLE OF CONTENTS

1 Purpose and Objectives of this document ... 8
1.1 Purpose of the document ... 8
1.2 Structure of the document ... 8
1.3 Legal status of the document ... 9
2 Procedural aspects ... 9
2.1 Introduction ... 9
2.2 The framework for developing Network Codes ... 9
3 Scope, structure & approach to drafting the OS NC ... 10
3.1 Background ... 10
3.2 Guiding Principles ... 10
3.3 Structure ... 11
3.4 Level of Detail ... 12
3.5 Field of Applicability of the OS NC ... 12
3.6 Future Challenges and Opportunities for System Operation ... 14
3.6.1 Challenges for System Operation ... 14
3.6.2 Risks and Opportunities ... 15
3.7 Current Frequency Management and related New Issues: Inertia, Load and Power Generating Module Sensitivity to Frequency ... 17
3.7.1 Frequency response: theory ... 17
3.7.2 Causes of current frequency deviations ... 19
3.7.3 New risks identified ... 20
3.7.4 New opportunities identified ... 21
3.8 The Link of the OS NC with the ENTSO-E R&D Plan ... 22
3.9 Interaction with other Network Codes ... 23
3.10 Working with Stakeholders & Involved Parties ... 26
4 Relationship between the OS NC & Framework Guidelines ... 27
5 Provisions of the OS NC ... 29
5.1 System States ... 29
5.2 Frequency Control Management ... 30
5.3 Voltage Control and Reactive Power Management ... 30
5.4 Short-Circuit Current Management ... 31
5.5 Power Flows Management ... 31
5.6 Contingency Analysis and Handling ... 32
5.7 Protection ... 33
5.8 Dynamic Stability Management ... 33
5.9 Operational Training and Certification ... 33
6 Necessary Data and Information for safeguarding the Operational System Security ... 35

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

6.1 Introduction 35
6.2 Tasks of the Transmission System Operators 35
6.3 The OS NC as a Place for Centralized Data Exchange Provisions for Operational Purpose 37
6.4 The Two ways of exchanging data with the TSO set by the OS NC 37
6.5 Data exchange with the Significant Grid Users 37
6.6 Different needs of Data for the TSO from the Transmission System and the Distribution Network 40
6.7 Current practices of data and information provision to TSOs 41
6.7.1 Current practise of data provision by Power Generating Modules of type A to TSOs 42
6.7.2 Current practice of scheduled and real-time data provision by Power Generating Modules (PGM) of Type B to TSOs 42
6.7.3 Current practice of data provision by Demand Facilities 45
6.7.4 Examples on current practices of Data and Information Exchange for operational purposes 47
6.7.4.1 The Cascading Structure: the case of Germany 48
6.7.5 Examples of situations or services in which there needs to be direct communication channels between the TSO and a Significant Grid User connected to the network of a DSO 49
7 Compliance, testing and investigation in the framework of the OS NC 51
7.1 Common Testing and Incident Analysis Responsibilities 51
7.1.1 The goal of Operational Testing and Monitoring 51
7.1.2 Common Testing and Incident Analysis Responsibilities in the framework of the OS NC 51
7.1.3 Some Examples on Compliance Testing 52
7.1.4 Information and documents in the Compliance Context 52
7.2 The incidents Classification Scale 53
7.2.1 Geographical vs. Electrical Scope 57
8 Fundamental Concepts & Processes of the OS NC 58
8.1 Common Grid Model (CGM) 58
8.1.1 What is the CGM? 58
8.1.2 What does the CGM comprise and how is it formed? 58
8.1.3 Overview of the building of the CGM 58
8.1.4 Interface of the CGM for operational purposes with the CGM for capacity calculation purposes 59
8.2 Significant Grid User (SGU) 60
8.2.1 SGU: a unique concept of the System Operation Codes 61
8.3 LFC Area, Responsibility Area, Observability area, ... 62
8.3.1 Explanation of the different concepts 62
8.3.2 Illustrative examples for the distinction between LFC Area and Responsibility Area 63
8.3.1 Algorithms for evaluating the influence of external elements on the Responsibility Area. 64

8.4 N-1 principle ... 66
8.4.1 The "philosophy" of the (N-1)-Principle in Transmission System Operation ... 66
8.4.2 (N-1)-assessment: classification of Contingencies as a function of probability of occurrence ... 67
8.4.3 (N-1)-assessment: distinction between Internal Contingency and External Contingency. 67
8.5 System States ... 68
8.5.1 Real-time monitoring of the Transmission System: Control Facilities, Security Telecommunication Network and Telecontrol System. ... 68
8.5.2 European Awareness System ... 69
8.5.3 Remedial Actions ... 72
8.5.4 System Defence Plan in case of Emergency State ... 73
8.6 Dynamic Stability Assessment (DSA) ... 74
8.6.1 Motivation of the DSA in the context of the OS NC ... 74
8.6.2 The relevance of inertia in the coming operational future scenario ... 75
8.7 System Protection ... 76
8.7.1 System Protection Functions. Difference to System Defence Plan. Fault clearing times. 76
8.8 Short-circuit Current Management ... 76
8.8.1 The three parts of the short-circuit current ... 76
8.8.2 The need of harmonisation in the framework of short-circuit current calculation and its related data exchange ... 76
8.9 TSO Co-ordination for Operational Purpose ... 77
8.9.1 The role of Regional Security Cooperation Initiatives (RSCIs) ... 77
9 Added values of the OS NC ... 79
10 Summary of changes to the draft Network Code ... 81
10.1 Introduction ... 81
10.2 Summary of comments ... 81
10.3 Structural changes in light of comments ... 82
10.4 Enhancing Consistency ... 82
10.5 Most Significant Content Related Changes of the OS NC ... 83
10.6 Conclusion ... 83
11 Next Steps ... 84
12 References ... 86
Annex I – Purpose of the Operational Security Network Code ... 87
Annex II- Assessment of the final OS NC against the Requirements of the Framework Guidelines on System Operation ... 102
Annex III - National Regulatory Authorities´ Involvement in the Framework of the OS NC ... 125
National Regulatory Authorities´ Involvement for Information Purposes in the Framework of the OS NC ... 125
Annex IV - Operational Security Network Code ... 127

Summary of comments received during public consultation and overview of the ENTSO-E response ... 127

Attention is drawn to the following definitions which require more explanation on the basis of stakeholder suggestions: ... 128

Annex V – Frequently Asked Questions ... 153

Introduction and Overview ... 153

General - Objectives ... 153

Legal Issues ... 153

Requirements ... 154

Terminology & Concepts used ... 160

Annex VI – Link of the OS NC with the future NC ER ... 163

Annex VII – Assessment of the OS NC against the Requirements set in the NC RfG and DCC ... 164

General overview: Interaction between the Codes covering System Operation and System Development ... 164

Interaction between the OS NC and the Grid Connection Codes (NC RfG, DCC) ... 164

Mapping of the NC OS against the Requirements set in the NC RfG and DCC ... 170

Annex VIII-Definitions in the framework of the OS NC ... 247

INDEX OF TABLES AND FIGURES

Figure 1: ENTSO-E's legal role in Network Code development according to Regulation (EC) No 714/2009 (Source: ENTSO-E) ... 9
Figure 2: Network Codes' development process (Source: ENTSO-E) ... 10
Figure 3: Current operational frequency behaviour in Continental Europe (Source: University of Stuttgart) ... 18
Figure 4: Impact of PV penetration on island networks in case of loss of generation (Source: EDF) . 20
Figure 5: Structure and development flow of the Framework Guidelines on Electricity System Operation (Source: [1]) ... 27
Figure 6: Structure and key provisions of the Operational Security Network Code (Source: ENTSO-E) ... 29
Figure 7: System States in the framework of the OS NC (Source: ENTSO-E) ... 30
Figure 8: Schematic representation of a LFC area (Source: [6]) ... 36
Figure 9: Comparison of the electric connection and the flow of information (Source: ENTSO-E) ... 39
Figure 10: Illustration of the different levels considered by the chapter data Exchange for the information providence to the TSO (Source: ENTSO-E) ... 40
Figure 11: Main Principle for the data- and information exchange between Grid Operators ... 47
Figure 12: Communication system of an interruptible load scheme used to achieve response times of 5 minutes with high penalties for providers in case of non-compliance with the TSO instructions. ... 50
Figure 13: Real-time communication channels in the case of REE in order to directly issue automatic or semi-automatic real-time instructions to the control centres of renewable energy generators depending on the real-time scenario. ... 50
Figure 14: Coordination of tests between TSOs, DSOs and System Users (Source: ENTSO-E) ... 51
Figure 15: Operational Security Performance Indicators (Source: ENTSO-E) ... 55
Figure 16: Simulated yearly ICS reporting (Source: ENTSO-E) ... 57
Figure 17: Individual Grid Models versus Common Grid Model (Source: ENTSO-E) ... 58
Figure 18: Overview of CGM building process: data and information exchange (Source: ENTSO-E) 59
Figure 19: SGUs in the framework of the OS NC (Source: ENTSO-E) ... 60
Figure 20: Definitions on Observability Area and Responsibility Area of a TSO (source: [20]) ... 63
Figure 21: Two LFC Areas and one Responsibility Area: the case of Energinet DK (Source: ENTSO-E) ... 63
Figure 22: Two Responsibility Areas within one LFC Area: the case of Creos and Amprion and methodology for determining the Observability Area (Source: ENTSO-E) ... 64
Figure 23: Observability Area and Responsibility Area of the German TSO 50Hertz (Source: 50Hertz) ... 65
Figure 24: European Awareness System (EAS) (Source: ENTSO-E) ... 71
Figure 25: Operational constraints by thermal resp. Stability Limits (source: [13]) ... 75
Figure 26: TSOs participating at the RSCI Coreso (Source: [16]) ... 78

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

Figure 27: TSOs participating at the RSCI TSC (Source: [15]) 78
Figure 28: Analysis of articles by number of comments received (Source: ENTSO-E) 81
Figure 29: Key challenges in the framework of System Operation (Source: ENTSO-E) 87
Figure 30: Structural interfaces and dependencies in System Operation (Source: ENTSO-E) 88
Figure 31: Illustration of the mandatory gross pool in Ireland (Source: [18]) 159

Table 1: Thresholds for Type B, C and D Power Generating Modules (source: [9]) 25

Table 2: Current practices of the Power Generating Modules (PGM) of Type B that have to provide.....

scheduled and real-time information to their respective TSOs (Source: ENTSO-E) 44

Table 3: Current practises of data provision by Demand Facilities to TSOs (Source: ENTSO-E) 46

Table 4: Added values with related articles in OS NC 80

Table 5: Exhaustive requirements according to the classification of the NC RfG 165

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

1 PURPOSE AND OBJECTIVES OF THIS DOCUMENT

1.1 PURPOSE OF THE DOCUMENT

This document has been developed by the European Network of Transmission System Operators for Electricity (ENTSO-E) to accompany the Operational Security Network Code (OS NC) and should be read in conjunction with that Network Code.

It aims to provide interested parties with information about the rationale for the approach set out in the OS NC, outlining the reasons that led to the requirements specified in it. The document has been developed in recognition of the fact that the OS NC, which will become a legally binding document after Comitology, inevitably cannot provide the level of detailed explanation which some parties may desire.

1.2 STRUCTURE OF THE DOCUMENT

This document is structured as follows:

- Section 2 introduces the legal framework within which the OS NC has been developed;
- Section 3 explains the approach which ENTSO-E has taken to develop the OS NC, outlining the challenges and opportunities ahead for System Operation, the link between the OS NC and the ENTSO-E R&D Plan and the interactions of the OS NC with other Network Codes;
- Section 4 describes how this Network Code complies with the requirements of the Framework Guidelines on System Operation (SO FG) developed by the Agency for the Cooperation of Energy Regulators (ACER);
- Section 5 focuses on the Requirements of the OS NC by topic;
- Section 6 focuses on the topic of necessary data and information for safeguarding the Operational Security;
- Section 7 treats the topics compliance, testing and investigation in the framework of the OS NC;
- Section 8 presents the fundamental concepts of the OS NC;
- Section 9 presents the added values of implementing the principles set by the OS NC;
- Section 10 includes a summary of changes to the draft Network Code upon public consultation and workshops with stakeholders;
- Section 11 summarises the next steps;
- Section 12 mentions the references that have been used for developing the supporting document.

In addition, eight annexes are attached to this supporting document:

- Annex I provides a high level overview of the rationale for including particular articles in the OS NC;
- Annex II contains an assessment of the final OS NC against the requirements of the SO FG;
- Annex III gives an overview of the NRA involvement in the framework of the OS NC;
- Annex IV presents a summary of the comments received during public consultation and its responses;
- Annex V presents the Frequently Asked Questions (FAQs);

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

- Annex VI establishes a link between the OS NC and the future Emergency and Restoration Network Code NC ER;
- Annex VII performs an Assessment of the OS NC against the requirements set in the NC RFG and DCC;
- Annex VIII contains the Definitions in the framework of the OS NC.

1.3 LEGAL STATUS OF THE DOCUMENT

This document accompanies the OS NC and is provided for information purposes. Consequently, this document has no legally binding status.

2 PROCEDURAL ASPECTS

2.1 INTRODUCTION

This section provides an overview of the procedural aspects of Network Codes' development. It explains the legal framework within which Network Codes are developed and focuses on ENTSO-E's legally defined roles and responsibilities. It also explains the next steps in the process of developing the OS NC.

2.2 THE FRAMEWORK FOR DEVELOPING NETWORK CODES

This OS NC has been developed in accordance with the process established within the Third Package, in particular adhering to the Regulation (EC) No 714/2009. The Third Package establishes ENTSO-E and ACER and gives them clear obligations in developing Network Codes. This is shown in Figure 1.

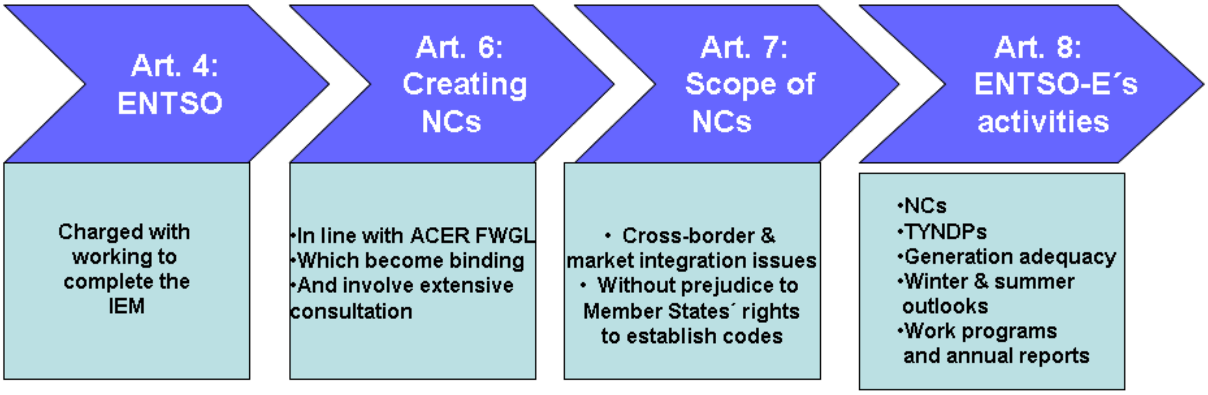

Figure 1: ENTSO-E's legal role in Network Code development according to Regulation (EC) No 714/ 2009 (Source: ENTSO-E)

Moreover, this framework defines the process for developing Network Codes involving ACER, ENTSO-E and the European Commission, as shown in Figure 2.

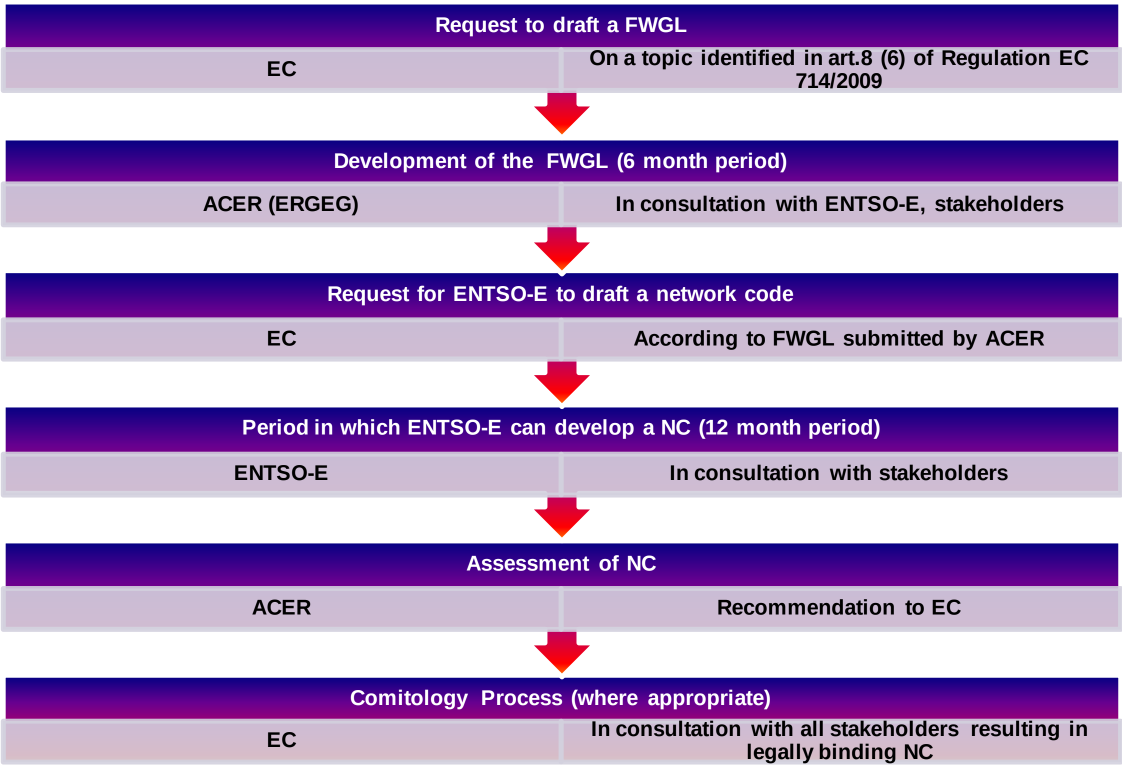

Figure 2: Network Codes' development process (Source: ENTSO-E)

The OS NC has been developed by ENTSO-E to meet the requirements of the SO FG [1] published by ACER in December 2011. ACER has also conducted an Initial Impact Assessment associated with the consultation on its draft SO FG in June 2011 [2].

ENTSO-E was formally requested by European Commission to begin the development of the OS NC on 1st March 2012. The deadline for the delivery of the Network Code to ACER is the 1st March 2013.

3 SCOPE, STRUCTURE & APPROACH TO DRAFTING THE OS NC

3.1 BACKGROUND

ENTSO-E has drafted the OS NC to set out clear and objective minimum requirements for real-time Operational Security and achieving the main goal of keeping the European interconnected Transmission Systems in continuous operation, in order to contribute to a harmonised framework for completion of the EU Internal Electricity Market (IEM) and to ensure non-discrimination, effective competition and the efficient functioning of the IEM.

Based on the SO FG and on the Initial Impact Assessment provided by ACER, the OS NC states the Operational Security principles in terms of technical needs, considering market solutions compatible with and supporting security of supply.

3.2 GUIDING PRINCIPLES

The guiding principles of the OS NC are to determine common Operational Security requirements and principles, to ensure the conditions for maintaining Operational Security throughout the EU and to promote coordination of system operation. These Operational Security principles are essential for the

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

TSOs to manage their responsibilities for operating the interconnected Transmission Systems with a high level of coordination, reliability, quality and stability.

A key goal of the OS NC is to achieve a harmonised and solid technical framework - including the implementation of all necessary processes required for Operational Security, considering present and expected challenges including rapid growth of Renewable Energy Sources (RES) generation and their impact on System Operation. Consequently, the requirements have been designed in order to ensure secure System Operation, taking into account the integration of RES and the effective development of the IEM.

The requirements set out in OS NC on TSOs, DSOs and Significant Grid Users are building upon a long history of existing common and best practices, lessons learned and operational needs throughout the European Transmission Systems. This, together with the fact that the European experience of interconnected Transmission Systems operation dates back to the 1950-ies (Union for Coordination of (Production) and Transmission of Electricity (UC(P)TE)), 1960-ies (Nordel), and 1970-ies (TSO Associations of Great Britain and Republic of Ireland, UKTSOA and ITSOA), distinguishes the OS NC and other System Operation Network Codes (SO NCs) from other Network Codes in the following terms:

- The work on the SO NCs has not started from “scratch” but builds upon a wide and deep range of requirements, policies and standards of the previous European Transmission System organisations. These practices have been adapted and developed in order to satisfy the requirements of the SO FG, to meet the challenges of changes and evolution in the energy sector including RES and increasing volatility and dynamics of market operations and to support effective and efficient completion of the IEM.

- The subject matter – Operational Security of the interconnected Transmission Systems of Europe – is vital not just for the continuous and secure supply of European citizens with electricity but also for the electricity market to function at all; therefore, any changes, adjustments and developments based on the new (legally binding after Comitology) SO NC’s framework must acknowledge and respect the fact that System Operation cannot be interrupted and “restarted” – we are working on a “living grid”.

- By their nature and because of the level of technical detail involving all aspects of Transmission System operations, the SO NCs are mainly addressing the TSOs and ENTSO-E; nevertheless, links and cross-references, as well as practical dependencies and explanations are established in relation to other NCs, most notably those addressing grid connection, market and balancing / regulating power.

- Finally, whereas the aim in the OS NC is always to be as specific and exhaustive as possible, due to the fact that different Synchronous Areas exist in Europe, each with different electrical “past” and geographical/technical background and conditions, it is inevitably that the level of detail end exhaustiveness in the OS NC must be aligned with the need to retain flexibility, ensuring thus applicability throughout all of Europe.

3.3 STRUCTURE

Ensuring Operational Security, reliability and quality implies providing a common Security Level within the interconnected Transmission Systems of Europe, requiring the close cooperation of TSOs, DSOs, and Significant Grid Users.

In order to set out clear and objective requirements, the following categories have been established in the OS NC:

- System States;
- Frequency control management;
- Voltage control and Reactive Power management;
- Short-circuit current management;
- Power flows management;
- Contingency Analysis and handling;
- Protection;
- Dynamic Stability management;
- Data Exchange;
- Operational training and certification;
- Compliance testing and incident analysis responsibilities.

3.4 LEVEL OF DETAIL

In order to achieve the necessary level of European harmonisation, allowing at the same time more detailed provisions at the regional/national level where necessary, and with the view of drafting an OS NC open for future developments and new applications, an approach focusing on a pan-European view and the most widely applicable Operational Security requirements has been pursued throughout the development of the OS NC. The SO FG[1] provided further clarification concerning the issue of European-wide applicability, while pointing out that *"… ENTSO-E shall, where possible, ensure that the rules are sufficiently generic to facilitate incremental innovation in technologies and approaches to system operation being covered without requiring code amendments"*.

Thus, the requirements have been drafted considering a period of approximately 5 years as a reasonable cycle within which changes to the OS NC could be needed and implemented, building up a coherent legal mechanism with the appropriate balance between level of detail and flexibility.

Whereas this OS NC picks up as much input from involved parties as possible in order to enable a high level of Operational Security, regional requirements concerning the different Synchronous Areas, regions or even single TSOs may lead to further and more detailed provisions. In any case, compatibility and coherence must be ensured for all provisions defined at the level of Synchronous Area, region or a single TSO.

3.5 FIELD OF APPLICABILITY OF THE OS NC

According to Article 8(7) of Regulation (EC) No 714/2009 this Network Code is developed for cross-border network issues and market integration issues. The right of the Member States to establish national Network Codes which do not affect cross-border network issues and market integration issues is not limited.

[1] Article 1.5 Application, Framework Guidelines on System Operation, ACER, December 2011 [1]

This Network Code applies within EU, Energy Community and third countries whose TSOs are Members of ENTSO-E. For this reason neither cross-border network issues to third countries outside ENTSO-E nor market integration with such third countries are in the scope of this NC.

In light of the above, this Network Code shall not apply to those systems which do not present any cross-border network issues or market integration issues.

Articles 2(26) and 2(27) of Directive 2009/72/EC define Small and Micro isolated systems referring to consumption in 1996 and level of interconnection of those systems. These terms have been defined in the Directive with the sole purpose of applying Article 44 which allows the systems that comply with those criteria to request and obtain derogation from the application of certain provisions of the Directive. The provisions of the Directive from which those systems could get derogation are not of technical nature but rather linked to the unbundling obligations and third party access to the system (chapters IV, VI, VII and VIII). Small or Micro isolated systems (like Canary islands, Cyprus and Malta) as well as other systems not being classified as Micro or Small isolated systems that have no link to any other Transmission System would not have cross border or market integration impact and therefore, would be out of the scope of the Operational Security Network Code. In several cases a system on an island, belonging to the Responsibility Area of a TSO (like Balearic Islands) or having its own TSO Responsibility Area (like Aland) not fulfilling the criteria of a system as mentioned in the previous paragraph has no impact or only a very small and negligible impact on cross-border network issues or market integration issues. This might be because of connection to the mainland through a DC link or for other technical reasons. As transmission systems or part of transmission systems do not affect cross-border network issues as long as they are not operating synchronously with a Synchronous Area, they are for this time out of the scope of this Network Code. This is clarified with Article 1(4) of the Network Code. As a conclusion, National Network Codes, respecting European legislation, apply to those systems.

Consequently, network codes of the Member States shall apply to those systems and it is up to the responsible TSO to assess if such a system as mentioned above falls under the scope of application of the Operational Security Network Code.

Each National Regulatory Authority has to monitor the correct implementation of EU-legislation and therefore of the OS NC. If a TSO considers that a system or part of a system of its Responsibility Area does not fall under the scope of application of the OS NC, the reasoning for this has to be given by the TSO. The monitoring of implementation by NRA will ensure the correct application of the OS NC.

The TSOs of Estonia, Latvia and Lithuania operate under the synchronous mode in the IPS/UPS Synchronous Area where more than 97% of the TSOs are not bound by the EU legislation. Frequency and dynamic behaviour depend on the physical and technical nature of frequency regulation implemented in the whole Synchronous Area and wide area dynamic phenomena which depend on all Synchronous Area design details. The Baltic systems represent less than 3 % of all the whole IPS/UPS Synchronous Area. Therefore the physical influence of the Baltic systems on the frequency management and dynamic processes is limited.

This situation is reflected in the specific legal framework for the Baltic TSOs who, in accordance with the Article 1(6) of the OS NC, have to comply with the provisions on frequency control management of Article 9 only to the extent that those provisions could be duly applied and implemented within the entire Synchronous Area, taking into account the physical and technical nature of frequency regulation. As an example, the provisions of the Article 15(2) and 15(8) of the OS NC do not apply to those TSOs.

In addition, the provisions of Article 7 which normally foresee the conclusion and implementation of a Synchronous Area Agreement, also establishes that, in case such Agreement cannot be concluded, the TSOs should adopt the necessary processes to nevertheless aim at complying with the requirements of the NC. This provision aims therefore at ensuring to the greatest extent possible the implementation of the NC requirements all over Europe.

3.6 Future Challenges and Opportunities for System Operation

In line with the challenging objectives set out in the SO FG, System Operation goes beyond just operating the electric power system in a safe, secure, effective and efficient manner. Aspects such as enabling the integration of innovative technologies and making use of information and communication technologies must be fully integrated, while applying the same principles for the different Transmission Systems of Europe.

3.6.1 Challenges for System Operation

In this context, the particularly important future challenges for System Operation which needs to be addressed more specifically include:

- Effects resulting from the fast growth of intermittent generation from RES;
- Needs resulting from the evolution (and intended completion) of the IEM.

Generation from RES

The transmission tasks and challenges within the Transmission Systems of the European TSOs are ever more driven and influenced by the effects of the growing generation from RES. RES generation predominately varies with weather conditions, times of day/night, etc. The volatility of RES generation, being difficult to forecast accurately until close to real-time, causes the following consequences for System Operation:

- Renewable energy increasingly replaces the feed-in from large power plants directly connected to the Transmission System;
- During the past several years RES generation has contributed significantly to the increase and volatility of planned and unplanned cross-border power flows, therefore posing new challenges to maintaining the required balance between production and consumption, and to the management of physical flows over the borders;
- The influence of underlying production leads to a high forecast complexity for the balance of transfers into the Distribution Network and thus also for the prediction of load flows in the Transmission System.

This leads to concerns about how to maintain stable System Operation in the electric power system with high penetration of RES. The general answer to this is to increase the controllability and the flexibility of all elements of the Transmission System. This can in turn lead to a Transmission System which can react and cope better with the intermittency of RES.

Internal Electricity Market (IEM)

Cross border trades and Intraday markets have significantly increased in recent years, with the corresponding introduction of Intraday capacity allocation and the resulting short-term adjustments to the generating capacity of Power Generating Facilities. Due to this fact and in order to comply with the obligations under Regulation (EC) No 714/2009, a short-term update of generation forecasts has

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

become indispensable, and reliable System Operation can only be established on the basis of reliable input values.

In addition to the consequences for power flows, large changes on generation programs with different ramp rates (especially non-synchronous ramps) lead to temporary imbalances and can create a frequency deviation; this phenomenon is observed throughout ENTSO-E Regional Group Continental Europe (former UCTE), with an increasing trend in the number, duration, and the amplitudes of these frequency deviations, especially during the ramping periods in the morning and in the evening[2]. Another observed reason for longer periods with large frequency deviations is the persistent imbalance in one or more LFC Areas which cannot be restored due to insufficient Frequency Restoration Reserve and/or Replacement Reserve.

These frequency deviations activate a significant share of the Frequency Containment Reserve in the system, which is intended and dimensioned for coping with predictable (in terms of quantity and risk) sudden generation or load outages. Consequently these frequency deviations endanger secure System Operation by depleting the required containment reserves for significant periods.

Another factor that has accentuated these frequency deviations is the already mentioned rapid growth in generation from RES, where the Power Generating Modules used (mainly asynchronous by technology, or e.g. recently synchronous but with variable speed and lightweight rotors with permanent magnets) provide insufficient inertia. Inertia is however essential for maintaining frequency stability and ensuring adequate frequency response in case of major losses of generation.

3.6.2 Risks and Opportunities

In view of achieving the integration of RES and implementation of the IEM, the following opportunities and challenges with their associated risks, have been identified as relevant for System Operation. These changes create a scenario with increasing complexity, where further challenges can be foreseen in the near future due to the new applications and developments of System Operation, such as:

- High Voltage DC (HVDC) Links;
- Demand Side Response (DSR);
- Smart Grids;
- Super Grids.

HVDC Links

The operation of HVDC links has to be ensured by TSOs. This requires a systematic approach to their reliability when connected to the AC grid and the consideration of the effects of connecting large amounts of bi-directional power, in-feed/out-feed to single points, on the operation of the Transmission Systems. In addition, the operational impacts of HVDC links also need to be accounted for, with their filter banks, zero fault level in-feed and very fast ramping rates.

The common features of devices such as PST (Phase-Shifting Transformers) or FACTS (Flexible Alternating Current Transmission Systems) are their controllability and the large impact they can have on cross-border power flows, also in conjunction with HVDC.

[2] [7]

Nevertheless, these also provide opportunities for TSOs to optimise flows and voltages and have to be considered as such. It follows that TSOs have to coordinate the application and operation of PSTs and HVDC lines for coherent and coordinated power flows' control.

Demand Side Response

Demand Side Response is already a reality and common System Operational practice in several Transmission Systems, increasing the complexity of System Operation due to its corrective control approach. Technical requirements, information provision and co-ordination are therefore needed in order to facilitate DSR resources to support Transmission System Operational Security and to give Demand Facilities access to markets for ancillary services required by TSOs.

Smart Grids

Smart Grids will provide a competitive edge for the IEM focusing particularly on the Distribution Networks, leading to new products, processes and services. At the same time they will require a transformation of the functionality of the current Transmission Systems and Distribution Networks to support achieving the energy policy targets and to guarantee high security, quality and economic efficiency of electricity supply. Moreover, new developments related to aspects such as communication, especially between DSOs and TSOs, IT-infrastructure and new applications must be foreseen.

Super Grids

The term Super Grids stands for the developments almost exclusively affecting the TSOs and Transmission Systems. Whereas the first ideas on a pan-European Super Grid date back to the early 1950-ies, the real needs (i.e. "collecting" and delivering wind power from the North and solar power from the South, while fostering evolution of the IEM at the same time) emerge only with the current evolution of the power systems, as a consequence of the energy turnaround/transformation. While initially perceived as a future prospect, Super Grids – building upon additional and substantial AC-lines re-enforcements, as well as greater integration of HVDC technology – are already becoming a reality today.

The OS NC provisions therefore also account for the relevant aspects of the Super Grids, which are additionally determining the System Operation and Operational Security of the European Transmission Systems:

- Establishment and usage of the Common Grid Models for all phases of Operational Planning and real-time System Operation;
- Exchange and coordination of all relevant information and data, both between the TSOs and also between the TSOs, DSOs and Significant Grid Users. This is an issue which is addressed in detail in Chapter 3 of the OS NC;
- Ensuring the provisions and a firm basis for coordinated control actions of TSOs, DSOs and Significant Grid Users, in order to maintain the global and overall view, while at the same time acting locally or regionally to achieve the most efficient and effective results – maintaining Operational Security and maximizing the welfare from well utilised Transmission System capacities.

Taking into consideration the new developments described in this section and the associated opportunities and challenges for System Operation, the OS NC principles set the base for operational rules and for a technical-operational coordination between TSOs, DSOs and Significant Grid Users in order to deal with issues such as the intermittent generation, low predictability until closer to real-time,

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

massive growth of cross-border trade and transits, generation allocation changing close to real-time and high forecast complexities.

3.7 CURRENT FREQUENCY MANAGEMENT AND RELATED NEW ISSUES: INERTIA, LOAD AND POWER GENERATING MODULE SENSITIVITY TO FREQUENCY

Frequency is the sole parameter in the Synchronous Area common to all TSOs and System Users, who are all concerned with its quality. Frequency permanently reflects the balance between supply and demand. Deviations from the nominal value[3] signal either a generation surplus or a generation deficit within the Synchronous Area.

Frequency response is defined as the automatic corrective response provided for balancing load and generation. Based on the different response time, frequency response can be classified into three different categories: Inertial Frequency Response[4], Frequency Containment Response and Frequency Restoration Response.

In the last few years, practically all ENTSO-E Synchronous Areas have been experiencing increasing frequency variations at hour boundaries, multiple times per day, mainly during the ramping periods in the morning and the evening[5]. Furthermore, lasting frequency deviations (generally high frequency) can more often also be observed not only at boundaries hours: statistics shows an increase of the system frequency variations, in respect to number, duration and size.

3.7.1 Frequency response: theory

Inertial Frequency Response is defined as:

"*The power delivered by the Interconnection in response to any change in frequency due to the rotating mass of machines synchronously connected to the bulk Power System, including both load and generation*".

System Frequency drops whenever there is shortage of generation to supply demand and frequency increases whenever there is excess of energy. Frequency at its nominal value reflects balance in supply and demand. Sudden loss of supply or demand will result in frequency deviation from equilibrium. The rate of change in frequency due to imbalance depends partly on the system inertia.

System inertia is directly proportional to synchronously rotating mass in the system (includes synchronous generation and motor load). The general equation for calculating rate of change of frequency using system inertia constant (H) is:

$$\frac{df}{dt}=\frac{\Delta P}{tI}*f_0$$

[3] E.g. 50Hz in the RG Continental Europe Synchronous Area

4 For further details, see section 3.7.1

5 See Figure 3 (frequency behaviour)

where

- tl = system start time (in s): time needed by the governor to reach its nominal speed when starting from 0 and fed by the nominal mechanical power;

- f_0 = Frequency at the time of disturbance (Hz);

- df/dt = Rate of change of frequency (Hz/s);

- ΔP = (PL-PG)/PG, Power change (per unit in system load base), with PL = Load prior to generation Loss in (MW) and PG = System Generation after Loss in (MW);

- Load dampening is assumed to be zero.

A typical frequency response during unit trip is shown in Figure 3 (Frequency drop). In normal conditions, system frequency is controlled close to nominal frequency. Immediately after a disturbance, as frequency starts to decay, Inertial Frequency Response will determine how fast the frequency falls. Then the Frequency Containment Response (i.e. Governor Response) will act to arrest the frequency decay. Full Frequency Containment Response and Frequency Restoration Response will eventually restore the frequency back to nominal value.

In Figure 3:

- Point A represents the system frequency immediately before the disturbance;
- Point C represents the system frequency at its maximum deviation due to loss of rotating kinetic energy from the system;
- Point B represents the System Frequency at the point immediately after the frequency stabilizes due to primary governor action before the automatic part of Frequency Restoration Response in the area where the outage happens starts corrective action. This Frequency Restoration Response will aim at getting the frequency back to its nominal value and restoring the Frequency Containment Reserve.

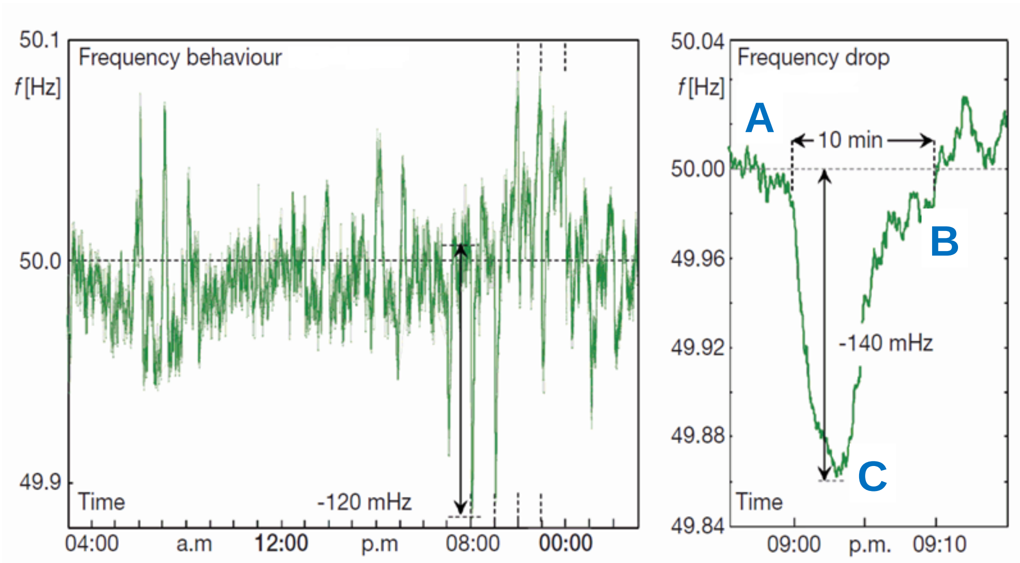

Figure 3: Current operational frequency behaviour in Continental Europe (Source: University of Stuttgart)

The *Inertial Frequency Response* is the frequency response between point A and C. This is also called the dynamic frequency deviation (Δfdyn.max), magnitude which is mainly governed by:

- the amplitude and development over time of the disturbance affecting the balance between power output and consumption (ΔP);
- the kinetic energy of rotating machines in the system which is a function of the System Frequency at the starting time of the incident (tl);
- the number of generators subject to Primary Frequency Control, the primary control reserve and its distribution between these generators;
- the dynamic characteristics of the machines (including controllers);
- the dynamic characteristics of loads, particularly the self-regulating effect of loads ("*load response with frequency*").

The *quasi-steady-state frequency deviation* (Δf) is the resulting frequency deviation between point A and point B, which is mainly governed by:

- the amplitude of the disturbance;
- the Frequency Containment Reserve and the droop of all generators subject to primary control in the Synchronous Area;
- the sensitivity of consumption (end consumers) and also production (e.g: renewable energy) to variations in System Frequency.

3.7.2 Causes of current frequency deviations

The last study of Eurelectric & ENTSOE [7] shows that recent significant frequency deviations are not caused by critical events such as power plant or load tripping. The variations with peak-to-peak values up to 150 mHz and even more are observed mainly within a time window of 10 minutes centred on the change of the hour, corresponding with the standardized time interval for cross border (international) schedule changes.

These frequency deviations activate a significant share of the Frequency Containment Reserve which is initially intended and dimensioned for large generation and load outages and consequently endanger the Operational Security by limiting the required control reserves for longer time periods in case of the loss of a Power Generating Module or Demand Facility. A further increase in size of the frequency deviations will result in the activation of the whole available Frequency Containment Reserve without any critical incidents having occurred.

Furthermore, another phenomenon can accentuate these frequency differences: the development of renewable energies. The solar panels or wind turbine technologies provide little or no natural Inertial Frequency Response to the system compared to conventional synchronous generators because of decoupling through power electronic devices. In this situation, larger transient frequency deviation can also possibly occur during mid or off-peak period with large wind or solar power penetration in the system. Figure 4 shows the Frequency Inertial Response with different rates of PV generation in case of tripping of a Power Generating Module in an island network, illustrating the impact of PV penetration on island networks in case of loss of generation:

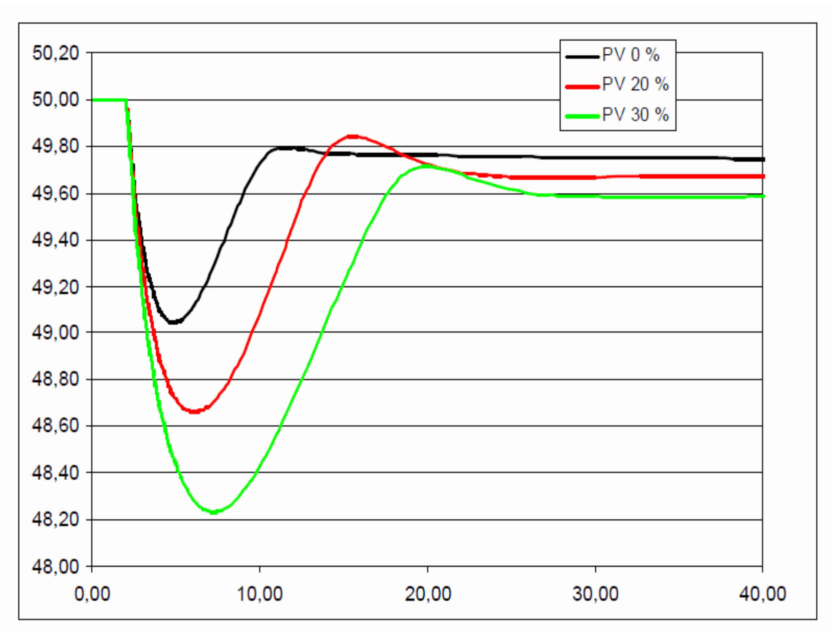

Figure 4: Impact of PV penetration on island networks in case of loss of generation (Source: EDF)

3.7.3 New risks identified

Lower system inertia is observed specially during off-peak periods compared to peak periods because of less synchronously rotating mass online. The phenomenon is increased by a global demand with fewer directly coupled motors connected through inverters. The impact of higher penetration of renewable resources on frequency control can be extreme during low loads / off-peak periods. The condition can be more complicated for the system with high penetration of renewable energy. Greater penetration of intermittent resources can potentially displace conventional generation from economic perspective, and the TSOs would face more challenges in real-time operations with the increased integration of intermittent renewable resources.

System Defence Plan and Protection Concepts are generally built considering conservative assumption on the dynamic behaviour of the Transmission System and considering that some Power Generating or Demand Facilities can be disconnected above these thresholds[6]. Conservative assumptions do not mean the worst possible situation; it is important to be able to minimize the probability that the Transmission System could be in a worst situation than the one which has been considered when developing the System Defence Plan and System Protection Concepts, avoiding big

[6] Jolt of frequency or regulation problems – e.g.: PV panels on LV grid can have trigger relays set to 49.8/50.2Hz instead of 47.5/51.5Hz.

imbalances and also to maintain adequate Inertial Frequency Response in the ENTSO-E Synchronous Areas.

Development of HVDC interconnectors between Synchronous Areas (Continental Europe, Baltic, Nordic, UK, etc.) with a total capacity progressively increasing may contribute to impact on frequency issues. Indeed, this kind of technology provides no inertia either.

3.7.4 New opportunities identified

As explained in section 3.7.1, the dynamic behaviour of the frequency directly depends on the inertia of the system and the frequency sensitivity of the load. Synthetic Inertia Provider, rotating mass and Automatic Frequency Demand Side Response will in the future be important means for TSOs to manage the dynamic behaviour of the system within the Operational Security Limits, in the situations where the system situation is worse than the assumptions taken when dimensioning Frequency Reserves, protection concepts and System Defence Plan, and this at a lower costs than having to cover these worst situations by default.

Development of HVDC interconnectors between Synchronous Areas is also an opportunity to allow emergency help among Synchronous Areas in case of frequency issues.

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

3.8 THE LINK OF THE OS NC WITH THE ENTSO-E R&D PLAN

TSOs shall establish the terms, conditions and actions necessary to ensure Operational Security in a way not to be detrimental to the innovation and forthcoming changes in electric power system operation, maintenance and control, in market design, in grid architecture or technologies development, but shall instead foster their development and integration with the existing systems and solutions.

This is closely linked to the requirement on "*New applications*" of the SO FG [1]. Moreover, achieving this is closely related to the so-called "*Six R&D Roadmap Targets for 2050*" defined by ENTSO-E:

1) To facilitate development of pan-European grid architecture that fulfills the low-carbon requirements of Energy Roadmap 2050 and enables effective power delivery throughout Europe;
2) To demonstrate, understand and appraise the impact and potential benefits of state-of-the-art power technologies and offshore solutions;
3) To design and validate novel ICT-based methodologies for network operation that meet today's and tomorrow's reliability targets;
4) To develop the market designs for the IEM that are most beneficial for system operators, market participants and consumers;
5) To determine and develop an optimal asset management strategy for equipment on a cost-effectiveness basis;
6) To strengthen collaborations between TSOs and DSOs in their efforts to integrate distributed energy resources.

The OS NC explicitly states the necessity and obligation of all entities and actors affected by the Code, that "… *no action in fulfilment of this Network Code shall hinder the implementation of new applications* …" in Article 1(8) of the Code.

The following issues addressed by specific requirements of the OS NC are possible areas in which New Applications are anticipated and will emerge in the coming years and decades:

- Voltage control and Reactive Power management;
    - Active / automatic voltage control and Reactive Power management in the Distribution Network, within the scope of Smart Grids could influence and enhance the voltage control and Reactive Power management at the Connection Point to the Transmission System;
    - Larger involvement of the new Power Generating Modules – especially wind and solar power – in the voltage control and Reactive Power management will have to be ensured as these generation technologies significantly grow and replace the conventional ones.

- Short circuit-current management;
    - New methodologies and IT solutions

- Power flow management;
    - Coordinated operation of Phase Shifting Transformers;
    - Coordinated and coherent interaction of market and Operational Security in terms of flow-based capacity calculation and allocation in the EU within the Target Model.

- Contingency Analysis and handling
    - Dynamic and probabilistic-based approaches.

- Protection;

- Dynamic stability assessment;
    - Methodologies and solutions for ensuring minimum required inertia in the Transmission System for maintaining frequency stability;
    - Development and common deployment by the European TSOs, of the Wide Area Monitoring Systems (WAMS) and Wide Area Protection Systems (WAPS).

- Common testing and incident analysis
    - The incident analysis on the basis of the common ENTSO-E Incident Classification Scale pursuant to Article 8(3) of the Regulation (EC) No 714/2009 will enable transparent identification of necessary enhancements in the Transmission System and of new Ancillary Services, which are required in order to maintain Operational Security in the future.

3.9 Interaction with other Network Codes

The Network Codes Development Process carried out by ENTSO-E addresses the interaction during drafting of several Network Codes in parallel. That these codes are at the same time both interfacing and influencing each other is an important issue with significant impact. While recognising this issue in the early drafting phases of the OS NC, internal coordination has been held between the convenors and drafting teams (regular meetings, workshops with different drafting teams, etc.) to treat the key cross-issues and therefore reach the coherence and consistency of all the different and related Network Codes.

The major cross-issues have been dealt among the different Network Codes in the following way:

- The Network Codes on *System Operation* - The OS NC can be viewed as the 'umbrella' code for all the System Operation Network Codes. It therefore sets the overall principles for System Operation and reflects on the common high level issues for the Network Codes for Load-Frequency Control and Reserves (NC LFCR), and for Operational Planning and Scheduling (NC OPS). The NC LFCR and NC OPS will describe their specific processes in greater detail. Moreover, regarding issues to be covered in the future Emergency and Restoration Network Code (NC ER), an overview of the areas interfacing with the OS NC and which will be treated in more detail in the NC ER has been created in Annex VI of this document.

- The Network Code on *Capacity Calculation and Congestion Management* (NC CACM) was developed in advance of the OS NC, enabling the interfaces between the Capacity Calculation Process and System Operation to be identified in the early drafting phase of this Network Code.

  The common work between the Capacity Calculation Drafting Team and the Operational Security Drafting Team led to the classification of topics treated among both codes based on the following reasoning: while topics related to the physical operation of the power system - where physical scenarios are hypothesised and physical risks are involved - are covered by the System Operation Network Codes, topics related to the operation of the electricity market - where market scenarios are hypothesised and financial risks are involved - are covered by the NC CACM, taking into account the physical risks described in the System Operation Network Codes.

  A data list containing the information required as an input for building and implementing a Common Grid Model (CGM) has been shared among the NC CACM, the OS NC and the NC OPS for the following reason: while the Common Grid Model is to be used for capacity calculation, it shares the same technical data that TSOs require for the calculation of load-flows in order to carry out Operational Security Analysis, taking into account the fulfilment of the (N-1)-Criterion.

In order to ensure the coherency and compatibility and to reach the common legal approach of the different Network Codes, an internal ENTSO-E Workshop on Capacity Calculation and System Operation Network Codes was organised in December 2011.

- The Grid Connection Codes: *Network Code on Requirements for Grid Connection Applicable for All Generating Facilities (NC RfG) and the Demand Connection Code DCC).*

  Transmission System Operators are responsible for defining operational practices and operational requirements for Significant Grid Users, in order to maintain Operational Security, make the best use of the available infrastructure and to foster achieving of European energy policy targets. It is a common practice for TSOs to review these operating practices periodically even if fundamental changes are not frequent. Operating practices have to be adapted to the system evolution, with the load and the generation mix (type and location of Power Generating Modules) as major drivers, but must at the same time be within reach of the Significant Grid User's technical capabilities.

  Since Significant Grid User's installations are built to operate for a few decades. It is essential that the Connection Network Codes are designed to anticipate the operational needs of the future electric power systems of Europe. Having this perspective in mind, the NC RfG and DCC set out requirements for the technical capabilities of generation and demand to ensure Operational Security and safety.

  Thus, the objectives of the NC RfG and DCC Network Codes are to define the requirements for the connection of new Power Generating Modules or new Demand Facilities regarding their capability to remain connected to the grid or to control their Active and/or Reactive Power outputs or to provide information in function of the frequency or voltage behavior of the system.

  These capabilities are crucial to allow TSOs to operate the system in Normal State. But these capabilities are even more important to allow TSOs to develop appropriate System Defense and Restoration Plans in Emergency State or Blackout, where for a limited period of time frequency and/or voltage are out of their range determined by the Operational Security Limits.

  The System Operation Network Codes develop the needed provisions for an efficient functioning of the interconnected Transmission Systems in Normal State and efficient coordination of the development and application of the System Defense and Restoration Plans. The efficiency of these provisions and plans will highly depend on the evolution of the load and generation patterns and their application will be subject to the capability of Significant Grid Users to withstand exceptional situations and participate in the Restoration to Normal State.

  There is then a need of high flexibility in the way these provisions and plans can be applied and adapted. Usual life time of such provision or plans is between 5 to 10 years. In the opposite, when connected to the Transmission System or a Distribution Network, Power Generating Modules a life time up to 40 years.

  In consequence, the requirements which are developed in the RfG and DCC Network Codes also aim at providing capabilities to anticipate future needs in the System Operation related to the evolution of the load and generation patterns and system design (e.g. longer distance between generation consumption, development of off-shore DC grids, reduced inertia and related needs for ensuring minimum inertia in the Transmission System, higher degree of microprocessor driven solutions and technologies, etc.).

An assessment of the relation of the OS NC with the technical capabilities of the RfG and DCCs is performed in order to clarify in detail the interaction of the OS NC with the Grid Connection Codes.

Differentiation by type of Power Generating Facilities

For a systematic and consistent addressing of the Power Generating Facilities in the requirements, and in order to reach consistency in the terminology used and appropriate cross referencing between the OS NC and the NC RfG, the OS NC has adopted the differentiation by type of Power Generating Facilities defined in the NC RfG in the following manner:

a) A Synchronous Power Generating Unit or Power Park Module is of Type A if its Connection Point is below 110 kV and its Maximum Capacity is 0.8 kW or more;

b) A Synchronous Power Generating Unit or Power Park Module is of Type B if its Connection Point is below 110 kV and its Maximum Capacity is at or above a threshold defined by each Relevant TSO This threshold shall not be above the threshold for Type B Power Generating Modules according to Table 1;

c) A Synchronous Power Generating Unit or Power Park Module is of Type C if its Connection Point is below 110 kV and its Maximum Capacity is at or above a threshold defined by each Relevant TSO. This threshold shall not be above the threshold for Type C Power Generating Modules according to Table 1;d) A Synchronous Power Generating Unit or Power Park Module is of Type D if its Connection Point is at 110 kV or above; a Synchronous Power Generating Module or Power Park Module is of Type D as well if its Connection Point is below 110 kV and its Maximum Capacity is at or above a threshold defined by each Relevant TSO. This threshold shall not be above the threshold for Type D Power Generating Modules according to Table 1: Thresholds for Type B, C and D Power Generating Modules (source: [9])

Synchronous Area	Maximum capacity threshold from which on a Power Generating Module is of Type B	Maximum capacity threshold from which on a Power Generating Module is of Type C	Maximum capacity threshold from which on a Power Generating Module is of Type D
Continental Europe	1 MW	50 MW	75 MW
Nordic	1.5 MW	10 MW	30 MW
Great Britain	1 MW	10 MW	30 MW
Ireland	0.1 MW	5 MW	10 MW
Baltic	0.5 MW	10 MW	15 MW

Table 1: Thresholds for Type B, C and D Power Generating Modules (source: [9])

3.10 WORKING WITH STAKEHOLDERS & INVOLVED PARTIES

The legally binding nature of Network Codes achieved through the Comitology process implies that they can have a fundamental bearing on stakeholders businesses. As such, the ENTSO-E recognised the importance of engaging with stakeholders at an early stage, involving all interested parties at the earliest possible phases in the development of the Operational Security Network Code, in an open and transparent manner.

ENTSO-E's stakeholder involvement comprised workshops with the DSO Technical Expert Group, public stakeholder workshops, as well as ad-hoc meetings and exchange of views with all interested parties as necessary.

Due to the many questions concerning the function of the Transmission System from an operational point of view that arose during the public consultation of the NC RfG, the first "unofficial" ENTSO-E stakeholder workshop on System Operation was held on 19th March 2012 in Brussels with an aim of explaining the key concepts in and around System Operation. A further aim of the workshop was to present information focusing on the operation of an interconnected Transmission System, and the physical basis for scoping and drafting the System Operation Network Codes. Stakeholders have also had the opportunity to raise questions, express feedback and expectations.

In line with suggestions by stakeholder organizations and following requests by the EC and ACER, ENTSO-E has scheduled four official workshops with the DSO Technical Expert Group and four official public workshops with all stakeholders before, during and after the public consultation:

- The aim of the first OS NC Workshops (20th April 2012) was to present and discuss the scope of the draft OS NC, which reflected the work completed by TSO experts as of 5 April 2012. The workshop addressed the scope of the Network Code, provided an update on the present state and allowed for discussion and a Q&A session. Stakeholders in attendance included DSOs, industrial electricity consumers, generators, energy traders and turbine suppliers.

- The aim of the second OS NC Workshops (2nd July 2012) was to present updates made to the Network Code in line with the discussion at the first OS NC Workshop and to present the main content of the first version of this supporting document based on the stakeholder feedback received in the first OS NC workshop. The workshop was an opportunity for stakeholders, including DSOs, industrial electricity consumers, generators, energy traders and turbine suppliers, to provide feedback on the current status of the Network Code.

- The aim of the third OS NC Workshops during the public consultation was to discuss in detail the remarks by the respondents in the consultation and to explain any outstanding issue or questions on System Operation or Operational Security, which might be raised by the respondents. As such, this third Workshop was also an opportunity for all stakeholders to clarify any outstanding question regarding the detailed contents of the OS NC.

- The aim of the fourth OS NC Workshop of the 20th December 2012 was to present the final version of the OS NC including the relevant amendments resulting from the public consultation and to identify any important changes that the stakeholders still considered to be necessary in the OS NC – those have been taken into account in the final OS NC version.

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

4 RELATIONSHIP BETWEEN THE OS NC & FRAMEWORK GUIDELINES

The OS NC sets the pan-European basis for ensuring on a high level secure and coordinated System Operation, facing the three key challenges identified by the SO FG [1]:

- To define harmonised Security Criteria.
- To clarify and harmonise TSOs' roles, responsibilities and methods.
- To enable and ensure adequate data exchange.

The requirements described in the OS NC have been formulated in line with the SO FG and the new developments on System Operation, with the aim of maintaining the Operational Security. The OS NC can therefore be regarded as the implementation of the objectives and resolution of the key challenges addressed in the SO FG: the Operational Security issues raised by the SO FG are addressed in eleven categories of requirements and these are further described in Section 5 of this document.

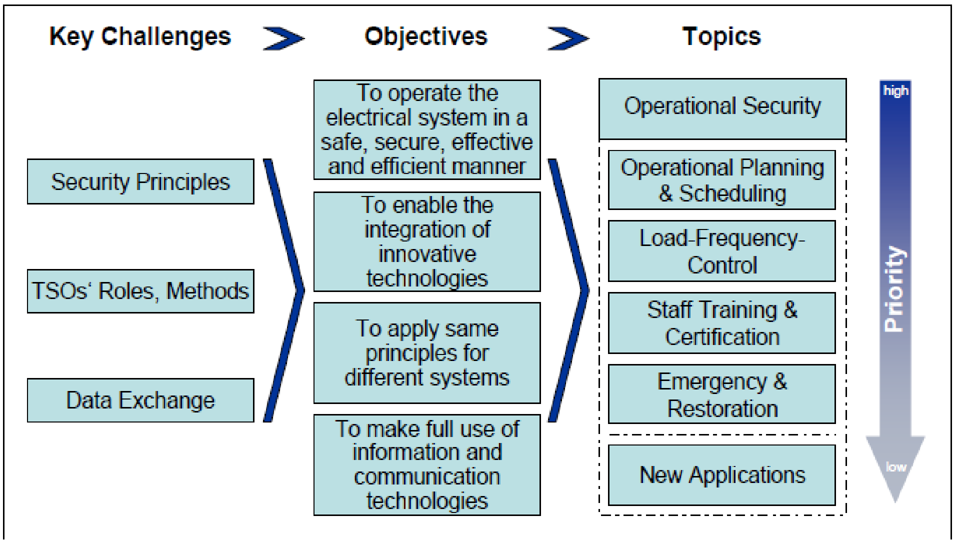

Figure 5: Structure and development flow of the Framework Guidelines on Electricity System Operation (Source: [1])

The OS NC reflects the common issues described in detail in the NC OPS and the NC LFCR with the following reasoning:

- The basics of Operational Planning and Scheduling, including all the principles, key tasks and activities conducted prior to the real-time operation are set out in the Operational Security Network Code, whereas the detailed provisions and description of specific requirements are part of the NC OPS.
- Article 9 of the Operational Security Network Code sets the general framework for the Frequency Control Management, but it is in the NC LFCR where concrete issues are described in full detail and the related requirements quantified.

As an instrument required for the maintenance and further improvement of System Operation and whose importance was emphasised in the ERGEG Guidelines of Good Practice for Operational

Security [4], it has been considered appropriate to address the topic of Operational Training and Certification in the OS NC with a general focus within its own Article. More details regarding Training could be developed within a separate NC on Operational Training and Certification if it is decided to develop such a Network Code.

Emergency and Restoration, as an issue focusing on defence plans and restoration of the system after a major disturbance or a blackout, but also analysing events afterwards, has been considered to be beyond the framework of a "regular" System Operation with focus on Normal and Alert State. Emergency and Restoration will therefore be addressed in detail in a later NC ER.

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

5 PROVISIONS OF THE OS NC

This chapter describes for each provision of OS NC the objectives that the OS NC sets out to achieve by means of the defined standards and requirements. The Articles with key provisions structured into the six chapters of the OS are shown in Figure 6.

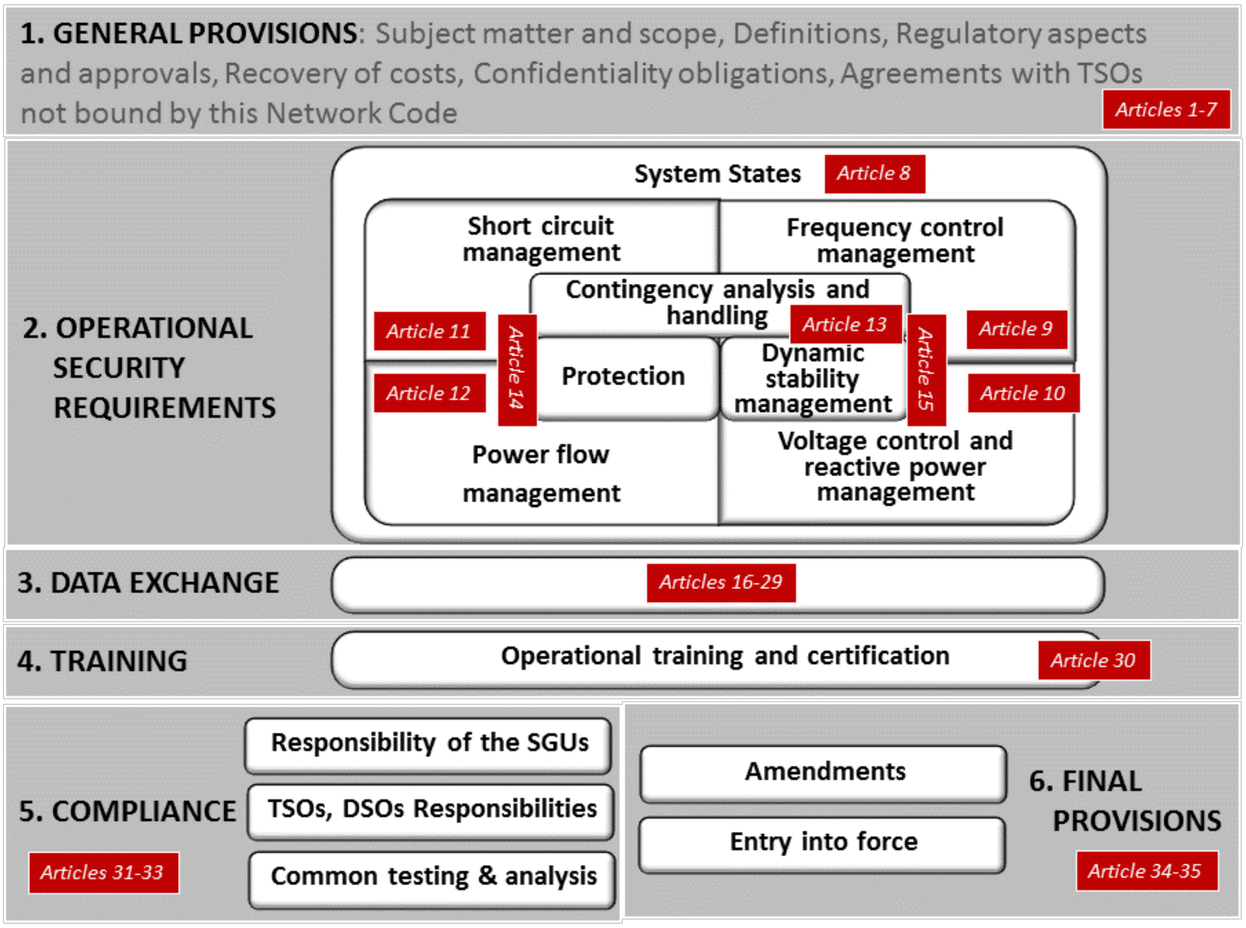

Figure 6: Structure and key provisions of the Operational Security Network Code (Source: ENTSO-E)

5.1 SYSTEM STATES

A continuous monitoring of the System State, based on the real-time measured values of operational parameters with permanent online mutual information about the System State among the affected TSOs and with a common set of definitions for the System States across all TSOs, provides for effective State Estimation and for preparation of Remedial Actions in order to keep the system in a Normal State or return to it as soon and close as possible in case of disturbances.

The increased system coordination achieved by monitoring the System State contributes to a coherent and coordinated behaviour of the interconnected Transmission Systems, both in each TSO's Responsibility Area and between Responsibility Areas.

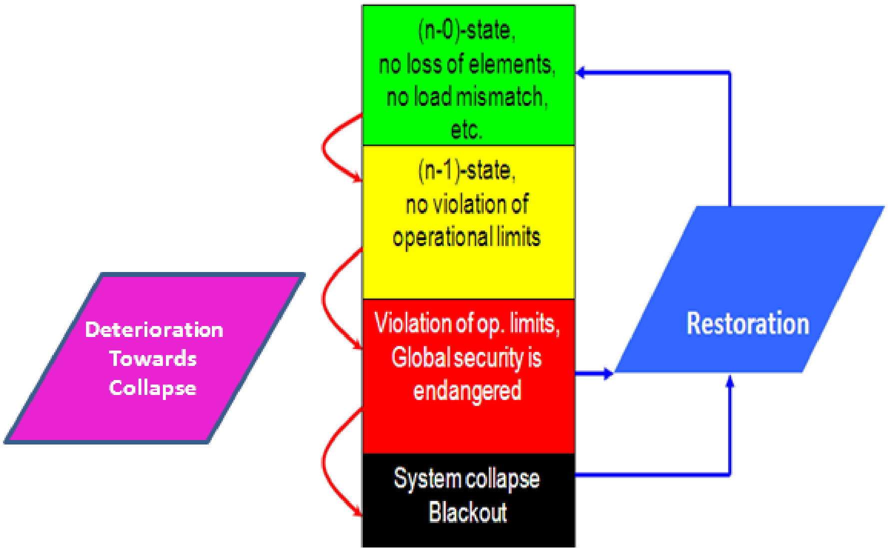

Figure 7: System States in the framework of the OS NC (Source: ENTSO-E)

5.2 Frequency Control Management

The scope of frequency control management is to maintain a continuous balance between generation and demand, ensuring frequency quality and stability within each Synchronous Area. For this purpose, TSOs shall procure adequate upward and downward Active Power Reserve and shall define criteria, according to which the quality of the frequency shall be assessed. Furthermore, in line with the NC LFCR and the NC on Balancing, common criteria are set for the dimensioning and establishment of these reserves.

TSOs should be aware of parameters that can lead to frequency deviations and check them in order to undertake joint measures to limit the effects on the balance of their Transmission System. Increasing power exchanges between LFC areas, the intermittent nature of the RES generation and, the difficulties in forecasting load/generation variations due to normal operation evolution and/or disturbances, market driven imbalances (e.g. ramping at the end of each hour) impose heavy challenges on the TSOs for balancing demand and generation. Furthermore, the robustness of the Transmission System in terms of stability is deteriorating, as the increasing volume of power stemming from RES still not contribute to the required inertia of the Transmission System. To the contrary, RES replaces synchronous generators and therefore alters the principles and well established practices of the current operation of the European Transmission Systems.

5.3 Voltage Control and Reactive Power Management

Voltage conditions in a Transmission System are directly related to the Reactive Power situation at the system nodes. In order to compensate for an excessive consumption of Reactive Power, TSOs must make sure that the most efficient and effective producers feed / absorb sufficient Reactive Power in addition to the Reactive Power from other sources installed in the Transmission System or at Demand Facilities. TSOs must further ensure a continuous and locally sufficient Reactive Power balance to be able in turn to maintain adequate voltage levels.

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

In this context, the goal of voltage control and Reactive Power management is to ensure that:

- Voltage levels, Reactive Power flows and Reactive Power resources are monitored, controlled and maintained in real-time within the Operational Security Limits, in order to protect the equipment of the Transmission System and ensure its Voltage Stability.

- Adequate instantaneous Reactive Power reserve is available in spinning generators, reactors and capacitors in order to secure the technical functioning of the whole electric power system and to be able to restore the Normal State after disturbances.

For this purpose, permanent online monitoring and information exchange that takes place with the TSOs from the TSO's defined Observability Area is established.

5.4 Short-Circuit Current Management

Short-circuit current management is required to prevent all types of Generating Facilities, Transmission System elements and related equipment from damage and to provide safety for persons, through the fast and selective disconnection of short-circuit Faults.

The objective of short-circuit current management is therefore to keep the impact of short-circuit currents at a level that provides secure functioning of the Transmission System with system protection and its set-points. This implies:

- Enabling an accurate short-circuit current calculation by TSOs while following standardised principles and ensuring the required data provision from neighbouring TSOs, DSOs and Significant Grid Users.

- Monitoring the short-circuit currents and taking preventive and curative Remedial Actions if the Operational Security Limits are, or tend to be violated.

- Provision of information and communication to affected TSOs, DSOs and Significant Grid Users in order to be able to consider the effect of other Transmission Systems and Distribution Networks.

5.5 Power Flows Management

Each Transmission System element has Operational Security Limits in terms of power flow. These limits are relevant for protecting the equipment and the humans in the vicinity of a given Transmission System element, taking into account the technical constraints of the used materials in order to avoid damage or premature ageing.

The scope of power flow management provisions is therefore to establish the operational means to maintain power flows within Operational Security Limits on every element of the Transmission System.

To be able to monitor and control operational parameters it is necessary to have precise information on System States and an accurate State Estimation. For this, each TSO has to control operational parameters inside its own Responsibility Area and, in a coordinated way, take into account operational parameters from the Observability Area of other TSOs. This implies structural and real-time data and information exchange between the TSOs in the TSOs' Observability Area and between TSO and DSOs in the TSO's Responsibility Area. In order to be able to cope with disturbances in System Operation, individual and coordinated Remedial Actions are prepared and applied when needed, to prevent violation of Operational Security Limits and to support return to Normal State in case of disturbance and Alert or Emergency State.

5.6 CONTINGENCY ANALYSIS AND HANDLING

Article 13 of the OS NC covers the (N-1)-Criterion, a long established and proven operational standard which is common amongst TSOs. With the aim of maintaining the Operational Security of the Transmission System, Contingency Analysis means simulating the tripping of Transmission System elements. This analysis is conducted based on the Observability Areas of the TSOs, respecting Operational Security Limits whilst preparing and carrying out pre-fault and post-fault Remedial Actions where required.

The key principles to be followed in relation to Contingency Analysis, which also outline the overall goals and objectives of Contingency Analysis in real-time and in operational planning phase are:

One goal

"*No cascading with impact outside my border*".

Two obligations

1 - Obligation for each TSO to monitor the consequences of the events defined in its Contingency List (= Normal + Exceptional Contingencies) and warn its neighbours when its own system is at risk at any operational planning stage and in real-time.

2 - Mandatory coordination by bilateral, multilateral or regional actions in order to better assess the consequences of any domestic TSO's decision.

Three behaviours

1 - "*Be aware of the risks*", even if not sufficiently covered by Remedial Action due to too high costs (potential emergency situations).

2 - "*Best efforts*" to set-up Remedial Actions, that is not always possible or sufficiently efficient by one single TSO to cover Exceptional Contingencies.

3 – Be aware of impacts of domestic operational decisions (switching, Redispatching, outage planning, capacity assessment) on neighbouring systems.

Risk assessment: a concern

Each TSO is only responsible for the operation of its own Transmission System. But it is required to inform relevant neighbours in case it assumes some risks to come from outside or to come from inside to be propagated abroad.

Inter-TSO coordination

Bilateral, multi-lateral or regional coordination is requested to assess risks.

Thus, the objectives of Contingency Analysis and handling in the OS NC are:

- To ensure prevention and/or remedy in terms of Remedial Actions required to maintain Operational Security, for all credible Contingencies affecting the Transmission System.
- To coordinate both analysis and Remedial Actions, wherever it is necessary, to ensure the desired result – maintaining Operational Security of the own and the interconnected Transmission Systems.

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

- To rely on adequate data and information: real-time and forecast based, Common Grid Model and exchange of all necessary data and information between TSOs and from DSOs and Significant Grid Users to the TSO.

- To support elaboration of the pan-European standard provisions for Contingency Analysis in order to maintain Operational Security while maximizing system utilisation.

5.7 PROTECTION

Equipment protection is used to protect Transmission System assets from Faults. System Protection Schemes are used to detect abnormal system conditions and take predetermined, corrective actions to preserve system integrity and provide acceptable system performance, in a coordinated way. System Protection Schemes are nowadays widely used by TSOs in most Synchronous Areas.

System protection functions shall be analysed relying on network calculations, considering correct and incorrect functioning. If unacceptable consequences are forecast, functionality and redundancy of the System Protection Scheme have to be accordingly adjusted to fulfil Operational Security requirements. The functionality and System State status have to be monitored, communicated and coordinated between neighbouring TSO and other parties affected by the system protection.

5.8 DYNAMIC STABILITY MANAGEMENT

The goal of the Dynamic Stability Assessment (DSA) is to ensure awareness of the TSO staff regarding the current and future forecast System State of the Transmission System with respect to stability, in the N-Situation and in the possible (N-1)-Situation. In addition, DSA supports the decisions towards the most effective and efficient Remedial Actions, for preventing disturbances or correcting their consequences if disturbances occur.

The extensive use of DSA allows different applications, not only in real-time, but also in operational planning phases. An emphasis is put on training of TSO staff operating and making use of DSA as well as on the continuous maintenance of models and simulation engines via on site tests and validations.

The OS NC focuses on the different scopes defined for the DSA, depending on the characteristics of the given Transmission System.

Presently DSA is an issue of high priority only in a few Transmission Systems where closer to real-time DSAs are required (e.g. TSOs in the Nordic countries, due to a system characterised by longer transmission lines). The future evolution of DSA will focus on its relation to Special Protection Schemes and Wide Area Measurement Systems, in order to face operating conditions for which fast automatic Remedial Actions will be introduced because manual intervention by the human is too slow. In this framework, Dynamic Security Analysis will indicate, in relation to automatic protection systems, the most suitable adaptive logics to be triggered in case of critical Contingencies, calling for fast automatic Remedial Actions.

5.9 OPERATIONAL TRAINING AND CERTIFICATION

In line with SO FG and the Guidelines of Good Practice for Operational Security [4], operational training is required in order to guarantee that System Operators and other operational staff are skilled, well trained and that the System Operator Employees in real-time operation are certified to operate the Transmission System in a secure way during all operational situations.

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

In this context, the OS NC sets up the goal of implementing a wide training and certification process, which will enable recognising and responding to abnormal operating conditions in appropriate timescales and, where appropriate, in a coordinated manner with other TSOs. What's more, the application of operational standards can be ensured by the development of programmes involving initial training, continuous staff development and regular certification re-assessment.

The OS NC strengthens and formalises existing best practice amongst TSOs in training and certification thereby ensuring minimum standards are applied across all TSOs in ENTSO-E.

The OS NC sets up the obligation on TSOs to have in place continuous development programmes for their control room staff and to co-ordinate and co-operate on inter-TSO training for wide area transmission issues. Highly trained TSO staff are able to operate efficiently in the balancing of the Transmission System, whilst maximising the opportunity for cross-border transfers both of which deliver real economic benefits to customers, significantly in excess of the incremental costs of investing more in the training of TSO control room staff.

In addition, an on-going commitment to continuous development programme for control room staff will ensure TSOs can maximise the output from intermittent generation whilst maintaining security of the transmission system operation in an ever increasingly dynamic and changing future.

Furthermore, investing in TSO control room staff training will reduce the probability of widespread disturbances and disruption to supplies from unplanned events that if they occur can last for many hours or even days and for which the costs to the wider economic and social activity can be measured in billions of Euros.

The requirements set out on TSOs, DSO and Significant Grid Users in this topic are building upon the existing best practice and identified needs.

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

6 NECESSARY DATA AND INFORMATION FOR SAFEGUARDING THE OPERATIONAL SYSTEM SECURITY

This chapter serves to justify the requirements set in the OS NC with regards to data exchange while bearing in mind the tasks of the TSOs for safeguarding the Operational Security. The needs of establishing a coordinated information flow between TSOs, DSOs and Significant Grid Users are described too.

6.1 INTRODUCTION

As a consequence of the new developments of System Operation described in Section 3.6, the increase of volume and dynamics of power flows has significantly affected the Operational Security. This tendency is set to further increase in the near and longer term future. Moreover, the increased variable and dispersed generation from RES on medium and low voltage levels replaces conventional generation in operation and this increases the TSOs challenges in operating the Transmission System in a safe and secure manner.

To underpin the Operational Security, it is essential to assess the expected power flow in the Transmission System as accurately as possible and to estimate the System State in order to avoid dangerous situations in real-time and to plan Remedial Actions. The required access by TSOs to data from DSOs and Significant Grid Users is mandatory to facilitate this process. Additionally, the OS NC covers the required access by DSOs to data from Significant Grid Users connected to its Distribution Network.

It is essential to be able to accurately forecast all relevant operational parameters of the Transmission System and to accurately build the Common Grid Model in order to ensure Operational Security, while at the same time utilizing maximum capacity for the market. While the TSO carries out the topology forecast on its own, the power balance creation requires both, its own Transmission System information and that from the connected Distribution Networks. The accuracy of variable generation forecasts can be significantly improved closer to real-time operation, which heightens the focus on the data and information to be provided by TSOs, DSOs and Significant Grid Users.

Due to the full unbundling achieved by the 3rd Energy Package, there is no reason for the avoidance of data provision to a TSO due to confidentiality concerns.

The focus is therefore on fast and effective data provision by DSOs and Grid Users necessary for detecting, forecasting and thus for carrying out Operational Security Analysis of a Transmission System ahead of and in real-time, supporting the coordination in System Operation between TSOs, DSOs and Significant Grid Users. The question of which partners have to provide which data for the Transmission System Operation in the respective Responsibility Area has not been clearly and consistently answered yet in the European context. The requirement of a binding answer, which is provided in the OS NC, is evident taking into account the emerging system development of the European electric power systems and the associated risks or disturbances that need to be handled by TSOs in order to ensure the conditions for maintaining Operational Security throughout the EU.

6.2 TASKS OF THE TRANSMISSION SYSTEM OPERATORS

The risks or disturbances that need to be handled by TSOs in order to maintain the Operational Security include the following aspects:

- Continued power supply to the Demand Facilities connected to the Transmission System;
- Power flow control to avoid congestion;

- Frequency Stability;
- Voltage Stability;
- System Stability; and
- Emergency control and restoration.

With regards to the exclusive responsibility of the TSO for Operational Security and liability for its own actions, TSOs work on the principle that they must have full control over the tools used and a complete overview of the data quality of the in-house and externally-supplied information.

Since mere trust in the accuracy of information without an appropriate level of assurance and control is not acceptable for technical and for reasons of liability, the OS NC establishes the right of the TSOs to receive the required data with the aim of enabling the adequate performance of Operational Security Analysis and, at the same time, establishes the obligation on all involved parties to provide the therefore required data with an adequate level of quality and precision.

With regards to the assumption of the system responsibility and herewith to the detection and prevention of short-term risks and disturbances, the Operational Planning and System Operation processes seem to be particularly important.

With regards to the task of maintaining the Frequency Stability, it is important to note that the responsibility of the TSOs includes their own Transmission System, as well as the LFC Area as a whole, including thus the underlying network. This is of particular importance in Transmission Systems where a cascading structure of Transmission and Distribution Network levels exists, like e.g. in Transmission Systems of Germany or Austria:

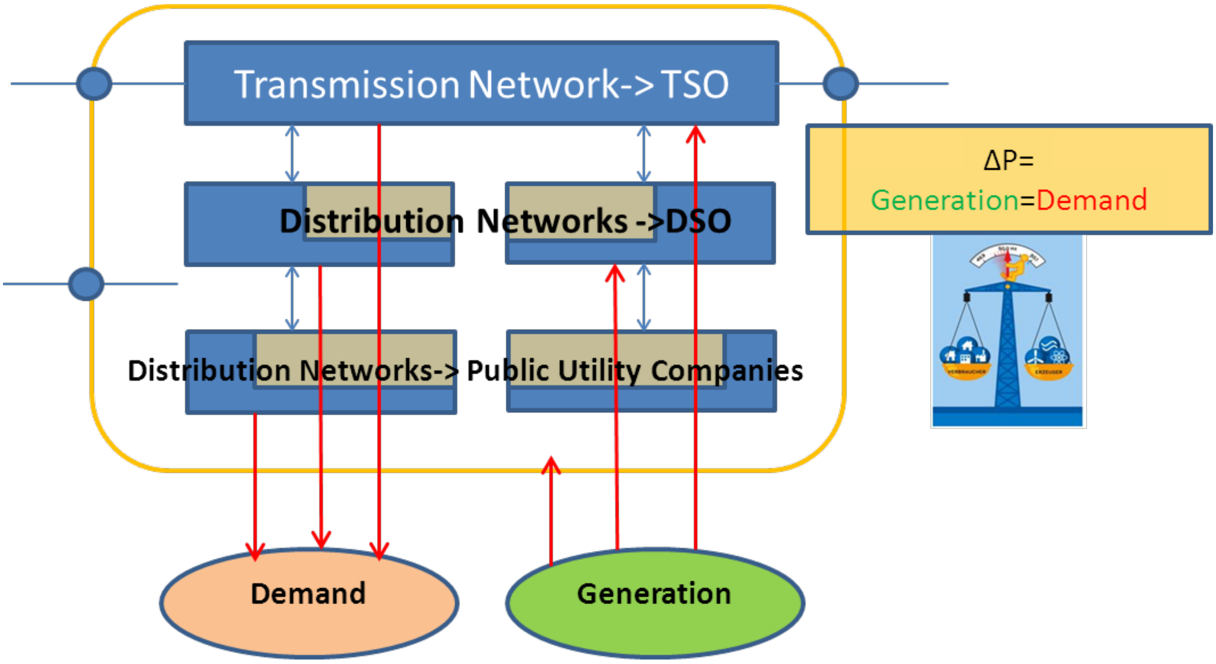

Figure 8: Schematic representation of a LFC area (Source: [6])

The TSO responsibility linked to the task of maintaining the frequency control extends to the entire balancing of the LFC Area at all grid levels, especially since effects leading to the imbalance are generally not caused from within the own Transmission System operation but by the behaviour of the Significant Grid Users.

Interventions by DSOs in the operation of Demand Facilities represent an exception to the latter, e.g. regarding the avoidance of congestions in the Distribution Network. These interventions are complex in terms of their impacts on the Transmission System operation and can extend their effect on the system balance and load flows of other LFC Areas.

It is essential that the TSO is informed in an appropriate manner about the current and planned Significant Grid User behaviour and participates in the interventions by DSOs in the whole LFC Area.

Since the TSOs work closely together on a horizontal level, each TSO has to ensure in its LFC Area that effects with negative consequences on Operational Security do not lead to impacts on other Transmission Systems due to the high degree of interconnection in Europe.

6.3 THE OS NC AS A PLACE FOR CENTRALIZED DATA EXCHANGE PROVISIONS FOR OPERATIONAL PURPOSE

The central purpose of the Data Exchange Articles of the OS NC is to define the data and information required by the TSO to perform its tasks described in the OS NC. The OS NC is the umbrella code of the SO NCs. Therefore, it has to consider all the possible data and information required to maintain the Operational Security in the Transmission System. This includes: real-time data, schedules, structural data and other data needed for analysis.

Part of this data may also coincide with data required in other Network Codes like the NC CACM. This is due to the fact that Operational Security is strongly inherent to the Transmission System. For example, the capacity calculation is a specific kind of Operational Security Analysis, considering different values of interchange between Responsibility Areas.

6.4 THE TWO WAYS OF EXCHANGING DATA WITH THE TSO SET BY THE OS NC

The OS NC allows different possibilities for the TSO to receive data from Significant Grid Users, connected to the Distribution Network. Two of them are already well known and implemented processes within the European TSOs: one is that SGU send the data directly to the TSO, the other is that SGUs send the data to the DSO who, at the same time, will forward them to the respective TSO.

The first option makes communication between TSO and SGU faster and more reliable as it is direct between both agents. The second one is simpler for SGU as sometime they would only need one communication link instead of two. This will only apply in those cases were the SGU do not need or do not already have a communication link with the TSO.

As the two options conceived by the OS NC are already in use and properly working, allowing both of them is the simplest and economically most viable option. Reducing the possibilities will oblige Significant Grid Users in some places to modify their installations. That would mean new costs.

6.5 DATA EXCHANGE WITH THE SIGNIFICANT GRID USERS

Data requested are divided in three types: structural data, scheduled data and real-time data.

- The structural data refer to the general information about the facility needed for the models used to perform Operational Security Analysis in any timeframe.

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

- The scheduled data refer to the information from the facilities for day ahead and intra-day used for Operational Security Analysis during this timeframes of Operational Planning.
- The real-time data refer to the actual information from the facilities needed to know the real situation of the Transmission System to perform real-time analysis.

To maintain the Operational Security, it is necessary to know the situation of the Transmission System in a precise way so the follow-up analyses are reliable. To achieve this, the TSO needs information from its Responsibility Area or from another TSO's Responsibility Area. Data from its Responsibility Area may come from the Distribution Networks and Significant Grid Users, so the TSOs rely on the information from the Significant Grid Users to perform its tasks.

Lack of accurate information to the TSO has significant impact on the Operational Security as it makes it difficult to know the demand and calculate reserves in an adequate way. This also leads to higher costs as more reserves are required to face the uncertainties due to insufficient or inaccurate information. Taking into account the present and expected future evolution of the electric power systems in Europe, the requirements of information for the TSO become especially important. With the growth of RES Power Generating Modules, connected at Transmission and Distribution level, their requirements for data provisions shall also increase.

The Data Exchange Chapter is organised taking into consideration who has to provide the information.

The information from other Responsibility Areas is always provided by the TSO of that Responsibility Area.

Articles 17 and 18 describe the data exchanged by TSOs.

The information from the own Responsibility Area is provided by DSOs or the Significant Grid Users, both Power Generating Facilities and Demand Facilities. The information about Distribution Networks shall be provided by the DSO. The information from Significant Grid Users may be provided by the owner of the Facility or by the operator of the network where the Significant Grid User is connected. It shall be decided at national level how to respect current detailed practices in different countries.

Figure 9 shows the flow of information between different agents within a Responsibility Area:

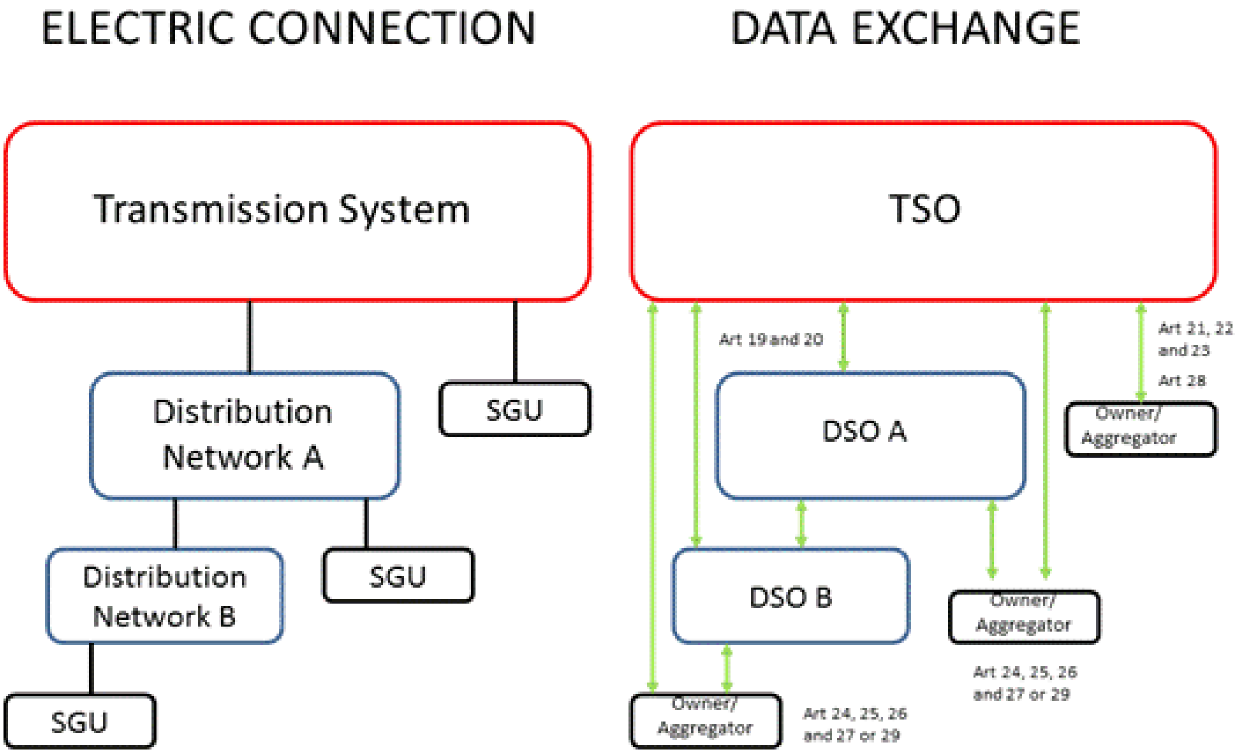

Figure 9: Comparison of the electric connection and the flow of information (Source: ENTSO-E)

Articles 19 and 20 describe the information from the Distribution Networks needed by the TSO. This data is always provided by the DSO.

Articles 21, 22 and 23 describe the data that owners of Power Generating Modules directly connected to the Transmission system have to provide to the TSO.

In a similar way, Articles 24, 25, 26 and 27 refer to the data that the SGU which are owners of Power Generating Facilities connected to the Distribution Network have to provide to the DSOs. Article 27 states that the TSO has to exchange the data with the DSO when and to the extent requested by the TSO, or respectively by the DSO.

In the cases where an SGU is connected to the DSO network, the decision to have a direct communication link from the TSO to the SGU or indirect communication through the DSO will depend on the services the SGU will provide to TSO or on its obligations due to the needs of the specific Synchronous Area, LFC Block or LFC Area. For some of services like primary or secondary reserve, black start, defence plan actions, etc. direct links are needed to ensure effectiveness of the service. For other services or obligations like redispatching, reactive power instructions, etc. it might be mandatory or not depending on the system.

Modalities of how the data flows will be organized (whether e.g. the owner of the Power Generating Module or the DSO has to send the data to the TSO) have to be decided at the national level in line with the principles of efficiency and proportionality, taking into account that (in particular in networks with high shares of distributed generation) DSOs will also need the access to this data in order to fulfil their tasks as defined in article 25 of Directive 2009/72/EC.

Article 28 defines the information required by the TSO from Demand Facilities directly connected to the Transmission System and the Article 29 refers to the information provided by Demand Facilities

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

connected at distribution level. For the latter, it has to be decided at national level whether the owner of the Demand Facility or the DSO has to send the data to the TSO or a DSO will do that in an aggregated form.

The Article 29 only refers to Aggregators of demand facilities connected to distribution system and according to Article 1(5) where SGUs are categorized, those Aggregators are only those providing DSR directly to TSO.

So, it means that the quality/accuracy/frequency of exchange of information defined in Article 29, including real time one, will depend on the service the Aggregator will provide to the TSO and will be further described in the contract he will have with the TSO. This is the main reason why we don't have to specify more details in the code. In this case, the resolution of the real-time information may be e.g. sub-hourly, hourly, etc., depending on the service of the users included in the Aggregator, the size of the users and the variability of their active or reactive power output.

6.6 DIFFERENT NEEDS OF DATA FOR THE TSO FROM THE TRANSMISSION SYSTEM AND THE DISTRIBUTION NETWORK

The Data Exchange Chapter has been developed considering the different needs of information for the TSO to maintain Operational Security. For this purpose, three different levels are considered within a Responsibility Area: The Transmission System, the Observability Area in the Distribution Network and the rest of the Distribution network. Figure 10 shows the different levels:

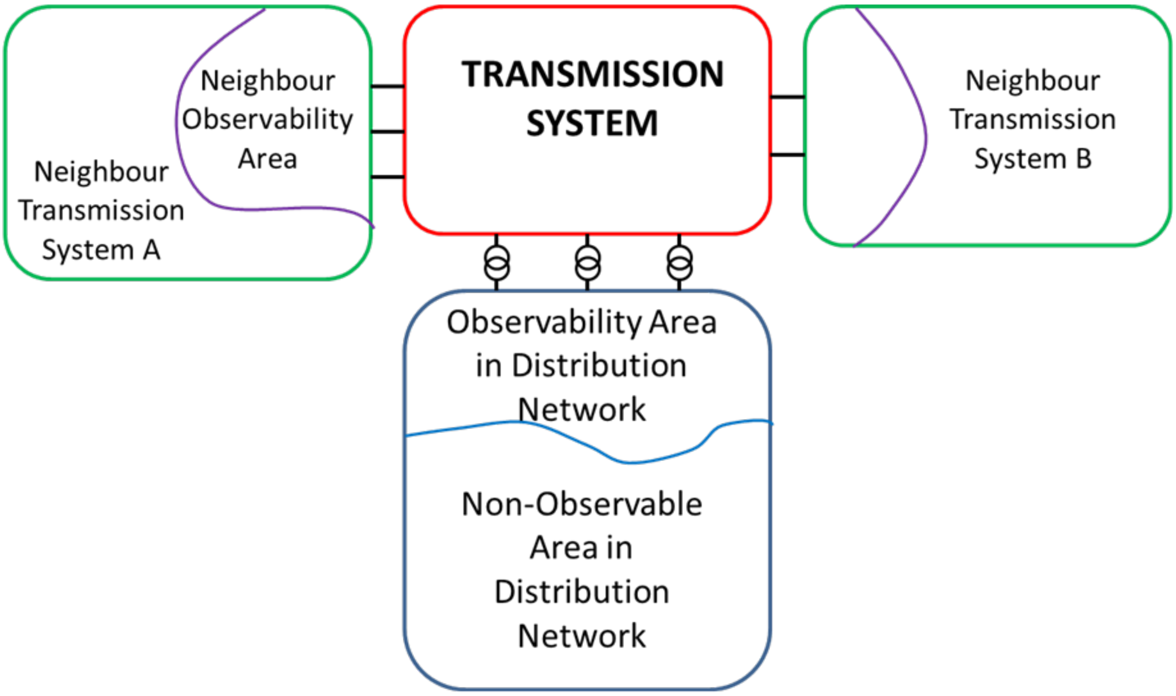

Figure 10: Illustration of the different levels considered by the chapter data Exchange for the information providence to the TSO (Source: ENTSO-E)

- The data requirements for the Transmission System reflect on the needs for the Transmission System Operation including network operation:

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

The Transmission System is the part of the electric power system directly operated by the TSO. At this level, the TSO is the System Operator and also the Network Operator so it needs the higher level of information to exactly assess the situation. This implies to have data from its own Transmission System and from the Significant Grid Users directly connected to the Transmission System so the situation can be precisely evaluated. Also, as the TSO operates the Transmission System, the data requirements for Significant Grid Users at this level are high in relation to the Active and Reactive Power control capability. It must be taken into account that Significant Grid Users directly connected to the Transmission System are large ones, so their influence on the Transmission System is large too.

- The Distribution Network is the part of the electric power system where the TSO is the System Operator and the DSO is the Network Operator. For Operational Security – including data requirements – the Distribution Network view is divided in two parts: the Observable and the Non-Observable:

    - The data requirements for the Observability Area in the Distribution Network shall cover the needs for the System Operation and the Observability Area:

      The Observability Area in the Distribution Network is electrically close to the Transmission System so it has influence on it. The requirements of information from this level are not as detailed as in the Transmission System. To perform the duties as System Operator, the TSO needs information about Significant Grid Users with regard to their Active Power capability as it has relation to the balance between generation and demand. On the other hand, as the Observability Area has influence on the Transmission System, the TSO needs certain information about the Topology of the Distribution Network for the proper functioning of the State Estimation. The requirements of data are moderate at this level. The requirements of information about Reactive Power control are not as detailed as for the Transmission System because the DSO is the Network Operator but some requirements have been kept after taking into consideration the comments and needs of the DSOs Technical Experts Group. The Significant Grid Users are usually smaller than those connected to the Transmission system.

    - The data requirements for the Non-Observable Area in the Distribution Network shall cover the needs for the System Operation:

      The Non-Observability Area from the perspective of the Transmission System in the Distribution Network are the lower voltage levels of the Distribution Grids. This part of the Distribution Grid has none or very small effect on the Transmission System. Usually it also does not need to be modelled; only occasionally an equivalent is needed to have a coherent Observability Area. The TSO is the System Operator so information about Active Power is required as it affects the generation-demand balance. Requirements like voltage control are not needed for the TSO. Many Grid Users are connected at this level. Some of them are Significant Grid Users, but most would become Significant only in an aggregated way.

6.7 CURRENT PRACTICES OF DATA AND INFORMATION PROVISION TO TSOS

6.7.1 Current practise of data provision by Power Generating Modules of type A to TSOs

The OS NC does not introduce any new requirement in addition to the NC RfG for type A Power Generating Modules.

6.7.2 Current practice of scheduled and real-time data provision by Power Generating Modules (PGM) of Type B to TSOs

The following table shows examples for the current practices of the Power Generating Modules (PGM) of Type B[7] that have to provide scheduled and real-time information to their respective TSOs:

Country	Scheduled data provision	Real-time data provision	Max. capacity of a type B PGM according to NC RfG
Finland	• Balance Responsible Parties have to send production plans from all Power Generating Facility larger than 1 MVA. Aggregated plan is allowed for Power Generating Facility within 1 MVA to 100 MVA. Larger than 100 MVA have to send separate schedules.	• PGM larger than 10 MVA: active and reactive power and circuit breaker status • PGM between 1 and 10 MVA: aggregated value by Power Generating Facility Owner, separate aggregated value from wind power.	Up to 10 MW
France	• Every PGM over 5 MW; some smaller PGM are also affected if they represent more than 25% of the Active Power of the substation they are connected to.	• Every PGM over 5 MW; some smaller PGM are also affected if they represent more than 25% of the Active Power of the substation they are connected to.	Up to 50 MW
Germany	• Power Generating Facilities (according to Grid Connection Contract between power plant and TSO) deliver Day Ahead a first schedule for each quarter hour, which has to be updated each time a	• Power Generating Facilities directly connected to the TSO have to deliver: set point, power reserved for reserve power market and for own reserves, real output of active and reactive power. In addition, Power	Up to 50 MW

[7] A Synchronous Power Generating Unit or Power Park Module is of Type B if its Connection Point is below 110 kV and its Maximum Capacity is at or above a threshold defined by each Relevant TSO This threshold shall not be above the threshold for Type B Power Generating Modules according to Table 1.

	change occurs during Intraday. • Balance Responsible Parties have to deliver power plant schedules used in their portfolio (at least as a sum of all Power. Generating Facilities).	Generating Facilities have to deliver all status information of circuit breaker, insulators, earthing equipment, house load if the transformer is connected on the Power Generating Facilities line. • Power Generating Facilities not directly connected to the TSO do not deliver anything to TSOs due to missing contracts. • In some cases TSOs also have information from Power Generating Facilities connected to the Distribution Network.	
Great Britain	• Power Generating Modules connected to the Distribution System which are: >50MW in England and Wales, >30MW in South of Scotland or >10MW in North of Scotland can be asked to supply half hour schedules if reasonably required.	• Power Generating Modules connected to the Distribution System which are: >50MW in England and Wales, >30MW in South of Scotland or >10MW in North of Scotland. • Power Generating Modules connected to the Distribution System who are >3MW and providing commercial balancing service to the TSO.	Up to 10MW
Ireland	• PGM ≥10 MW (<10 MW voluntary) and • Demand Facilities, (≥4 MW) registered in the Single Electricity Market and • Interconnection trades provided by the Single Electricity Market Operator • Shall provide in Day Ahead and Intraday the following data: • Technical offer data and Commercial offer data, under test requests at D-2, availability, re-declarations, fuel type, scheduled outages and • Ancillary Service Capabilities in Northern	• Transmission System • PGM connected to the Transmission System (the Grid Code is applicable to all PGM and different sections of the Grid Code put requirements related to size). • PGM with a registered capacity greater than 2MW (transmission system)(LV switch gear positions, kV at transformer LV terminals, MW, ±Mvar and kV at generator terminals, PGM transformer tap position, MW on each fuel, remaining secondary fuel capability). • Transmission connected controllable Wind Farm and	Up to 5 MW

	Ireland.	extensions (MWs, ±Mvar and kV, available active power, Transformer tap positions, voltage set point, on/off status of reactive power devices(>5MWs), CB and disconnect position, active power control set. point and on/off and frequency response mode signal and on/off. Greater than 10MWs meteorological data, availability data. • Distribution Network • Wind farms over 2 MW (MW, ±Mvar, and kV), and additional requirements depending on size and connection voltage for wind farms≥2, ≥5 and ≥ 10 MW.	
Spain	• Provided from Day Ahead and Intraday markets.	• Power Generating Modules over 1 MW or aggregation of Power Generating Modules individually below 1MW but aggregated over 1 MW.	Up to 50 MW
Switzerland	• Power Generating Modules connected to the Transmission System deliver their planned production scheduled. • Power Generating Modules providing Ancillary Services. Only information about Ancillary Services, i.e. provision of active power reserves.	• Power Generating Modules connected to the Transmission System deliver their power output. • Power Generating Modules providing Ancillary Services. Only information about Ancillary Services.	Up to 50 MW

Table 2: Current practices of the Power Generating Modules (PGM) of Type B that have to provide scheduled and real-time information to their respective TSOs (Source: ENTSO-E)

The schedules from Significant Grid Users which are Power Generating Facilities connected to Distribution Networks are required in Article 25(1). In some countries at the moment the small Power Generating Facility schedules can be aggregated. According to Article 16(4) TSO can adjust the scope of data provision of scheduled data and thus have the possibility to continue aggregation.

Conclusions on scheduled and real-time information to be provided by type B Power Generating Modules to TSOs:

As shown in the table above, Power Generating Modules within the range defined in RfG for type B are already providing scheduled and real-time data in some countries like France, Ireland or Spain.

This exchange is made directly or via market results but shows that they are already considered as Significant Grid Users. This fact means that the criteria to define Significant Grid Users in OS NC are in line with current practices in an important part of ENTSO-E Member TSOs. Therefore, the requirements set within the OS NC in the framework of real-time information provision are not considered to be a significant deviation from current practice.

Furthermore, Article 26(2) foresees the possibility for the Significant Grid Users according to Article 1(3)(a) and Article 1(3)(d) to deliver the real-time information to DSOs / TSOs in an aggregated form. Thus, the OS NC sets a framework that takes into account the flexibility required for the different current practices within the EU, while guaranteeing at the same time, accurate calculations, starting from a harmonised set of information and by following common principles for handling the exchanged data.

6.7.3 Current practice of data provision by Demand Facilities

Country	Current Practice	Demand Facility
Finland	Fingrid makes the Day Ahead and Intraday forecast of the total consumption in Finland with own forecast tools and therefore no schedule or forecast information from consumption is needed nor requested. If the Demand Facility sells reserves or other service to TSO then they have to provide schedule of that Demand Facility.	All Demand Facilities
France	• Demand Facilities connected to the Transmission system have to provide their structural data at the moment of their connection. • Demand Facilities > 120 MW have to be connected to the French safeguard system, and must be able to receive orders for safeguard actions (e.g. load-shedding) within 10" and to implement them within 10'. • Demand Facilities who are connected at a T-point have to provide real time data for P and Q. • If the Demand Facility sells reserves or other service to TSO then they have to provide schedule of that Demand Facility.	
Germany	Demand Facilities do not deliver any data to the TSO (neither load on each node nor as a sum of all). Only balance responsible parties deliver their total balance as schedules in Day Ahead and in Intraday. Load can be changed each quarter hour in accordance to electricity market.	
Great Britain	All Demand Facilities directly connected to the Transmission System are required to provide forecast scheduled consumption (Physical Notifications) for market rules purposes.	Directly connected to TSO
Ireland	Transmission connected Demand Customers and Dispatchable Demand Facilities. • for both, LV switch gear positions, kV at transformer LV	All Demand Facilities and Dispatchable

	terminals; • for Demand Facilities MW, ±Mvar at HV terminals of transformer and tap position; • for Dispatchable Demand Facilities measured or derived MW output for each PGM and demand side unit MW response; • for Dispatchable Demand Facilities who represent a demand side unit which consists on an Aggregated Demand Site, the aggregated, measured or derived loss adjusted MW output for each individual demand site, control facility of the dispatchable demand customer and the aggregated demand side unit MW response aggregated at the HV control facility of the dispatchable demand customer. Demand Side Units At Day Ahead and Intraday stage provides: Technical offer data and Commercial offer data, under test requests at D-2, availability, re-declarations, fuel type and scheduled outages. Where applicable, Ancillary Service Capabilities in Northern Ireland.	Demand Facilities

Spain	• Demand Facilities directly connected to the Transmission System provide real-time P and Q.
	• Demand Facilities over 5 MW providing Demand Side Response are required to provide:
	  o Real-time P and Q
	  o 15 minutes Active Power consumed in the last hour
	  o Hourly forecast consumption for the next two months. Updated every months
	  o Forecast outage program for the next two months.	

Switzerland	Demand Facilities do not deliver any data to the TSO. Only Balance Group Responsible deliver their total balance as schedules in day ahead and the schedules may be updated in intraday.	

Table 3: Current practises of data provision by Demand Facilities to TSOs (Source: ENTSO-E)

Conclusions on information to be provided by Demand Facilities to TSOs

TSOs may require data from Demand Facilities directly connected to the Transmission System or from Demand Facilities providing Demand Side Response.

Information from Demand Facilities directly connected to the Transmission System is taken into account as it is needed to operate the Network. In the Article 28(2) the active and reactive schedules are required from each Demand Facility with Connection Point directly to the Transmission System. In some countries existing market and balance settlement rules don't require schedules to be provided to the TSO by Demand Facilities. To avoid the provision of data which may be not currently needed, the TSO can, according to Article 16(4), adjust the scope of data provision and reduce the requested amount of data. The situation may change when the market rules evolve and in the future there may be a need of wider data exchange need and use for the 26(2) requirement in the OS NC.

Information from Demand Facilities providing Demand Side Response, independently of their Connection Point, is required to maintain the generation-demand balance and to determine the amount of load that can be curtailed if required. In some TSOs, this information is provided indirectly via Balance Group Responsible Parties like in Germany or Switzerland, or directly from the Demand Facility Owners like in France or Ireland. Further development of Demand Side Response will need these data to be delivered in an even more secure manner. The requirements of the OS NC have been defined in line with present needs but aiming to cover future ones.

6.7.4 Examples on current practices of Data and Information Exchange for operational purposes

In the framework of System Operation, the whole data exchange covers all voltage levels of the power system. Figure 11 shows a schematic overall constellation of the different actors involved.

For the proper interpretation of Figure 11, it should be noted that the relevant area for the network operation management is always located in the vicinity of each network area, whereas the relevant area for the system balance management is the entire LFC Area of the TSO.

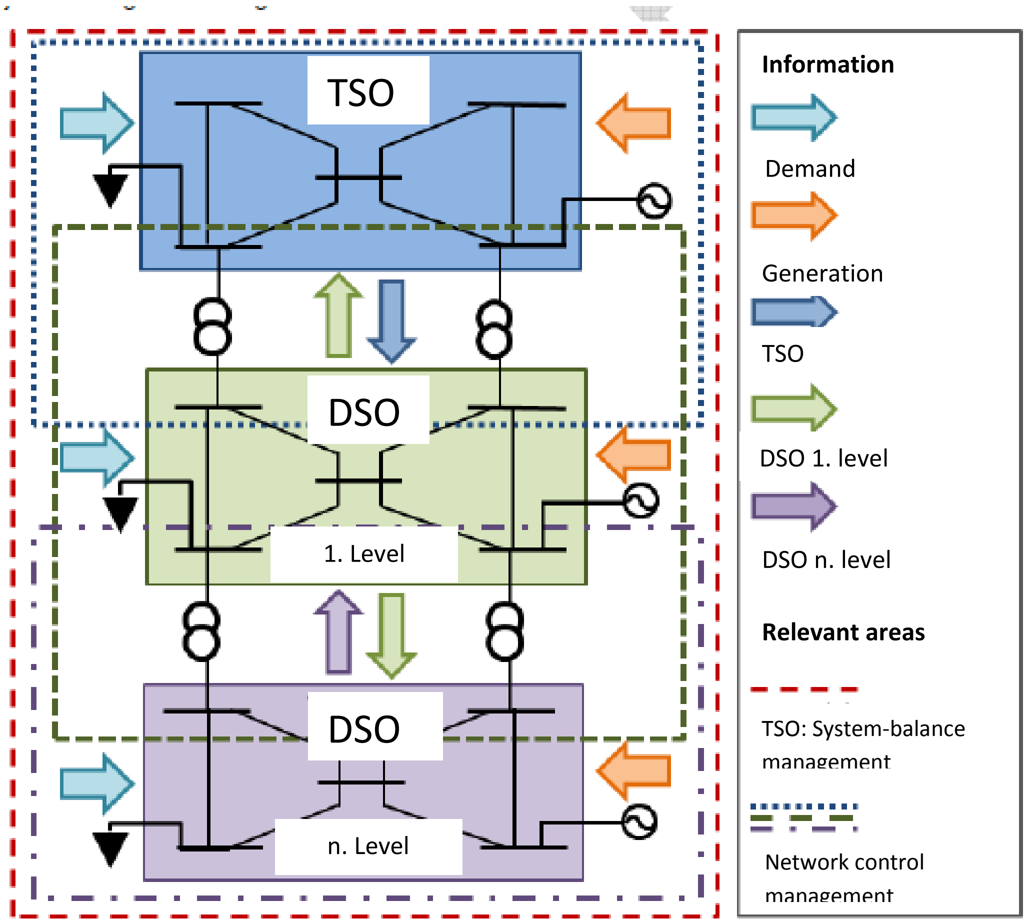

Figure 11 : Main Principle for the data- and information exchange between Grid Operators

The requirements of the OS NC define the data and information that the TSO has to receive without imposing how the information has to be exchanged. The way this data exchange is to be implemented will be defined via the key organizational requirements, roles and responsibilities to be proposed by all TSOs within 6 months after entry into force of the Network Code according to Article 16(5).

In order to respect the varieties of current practices established within the European Member States section 6.4 describes the two ways conceived by the OS NC for the SGUs connected to the Distribution Network in order to exchange data with the TSO, The following section goes a bit further while describing concrete current practices on the way of exchanging data and information for operational purpose.

6.7.4.1 The Cascading Structure: the case of Germany

The aim of the data- and information exchange is that Operators of Power Generating Facilities, DSOs, Closed Distribution Networks, Demand Facilities and Owners of interconnectors or other lines provide to TSOs and upstream DSOs the necessary information to ensure the safe and reliable operation, maintenance and expansion of the Transmission System. In this sense, the information provided should enable TSOs to create a report informing about the power balance forecast and statistics in the Responsibility Area of the TSO.

In the framework of the implemented Cascading Structure in Germany, following conditions are assumed for the practical implementation of the data exchange:

a) The delivery of data (structural-, scheduling and forecast -, real-time data) from Power Generating Facilities is generally performed by Power Generating Facilities Operators to its Connecting Network Operator. If the Network Operator is a DSO, the data transfer takes place via a “cascading flow” until reaching the TSO. Therefore, the transfer of the information to the TSO is preferably its direct downstream DSO.

b) Whereas Power Generating Facilities Operators are generally the source of structural- and scheduling data for Power Generating Facilities, the respective Connecting Network Operator of the Power Generating Facility collects operational information in the form of metered- and counter values at the point of supply of a Power Generating Facility and defines the required network operation conditions. In the latter case, the Connecting DSO is the source of information, forwarding it at the same time to the upstream Network Operator.

c) The facts described in a) and b) do also apply to withdrawals by large Demand Facilities with atypical consumption behaviour.

d) Scheduling- and real-time values as well as counter values of Power Generating Facilities or large Demand Facilities in Distribution Networks can be transmitted in an aggregated form if so agreed with the upstream Network Operator.

e) The aggregation of data of individual Power Generating Facilities or large Demand Facilities performed by the downstream Network Operator is performed for a grid node at the upstream network or a group of topologically meaningful combined grid nodes of a certain local network area with respect to existing balancing groups and further aspects agreed between directly connected Network Operators.

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

6.7.5 Examples of situations or services in which there needs to be direct communication channels between the TSO and a Significant Grid User connected to the network of a DSO

- A) *Participation by the Significant Grid User in Load-Frequency Control*.

In order to fulfil the requirements of Frequency Containment Reserves, Frequency Restoration Reserves or Replacement Reserves for monitoring or issuing real-time instructions as due to the critical nature of these reserves for system balancing there needs to be high reliability in the communication channels only achievable by a direct channel. For example, automatic Frequency Restoration Reserves are often based in continuously changing real-time set-points where very small delays and rapid response by the provider are required.

- *B) System restoration*.

For some TSOs, the emergency procedures during the Restoration state include issuing instructions which shall be followed and monitored closely in order to achieve a fast and efficient restoration process during these critical situations. It is of the utmost importance that these communication channels with the Significant Grid Users are direct and that they have a high reliability. Examples of such instructions to be given through these communication channels are orders to switch on or ramp up or down units with black-start capabilities or units that assume temporarily the frequency regulation of a restoration island.

- *C) Special real-time operating measures*.

Some Significant Grid Users connected to the DSO network may be providers to the TSO of a special critical service which needs to be activated rapidly and with high confidence and thus the need for direct communication channels. An example of such schemes are emergency or very fast operational reserves involving hydro pump-storage units or interruptible loads that are switched on or tripped rapidly after a certain event detected by the TSO or automatically has occurred.

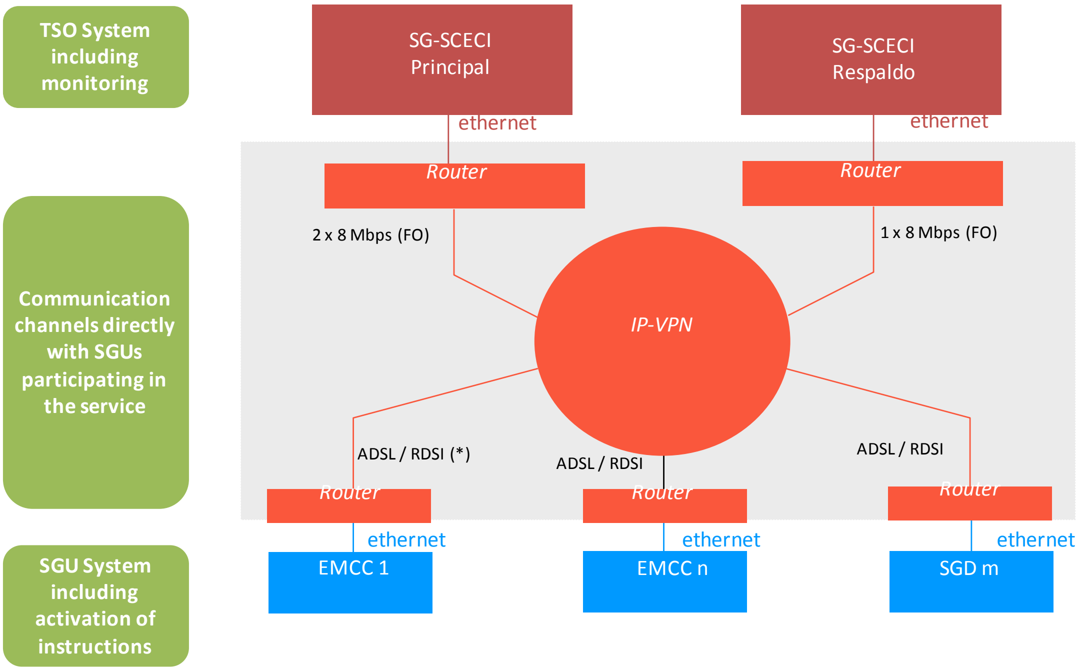

Figure 12 Communication system of an interruptible load scheme used to achieve response times of 5 minutes with high penalties for providers in case of non-compliance with the TSO instructions.

- *D) Real-time last resort operating set-points to renewable energy generators*.

As a specific example of special real-time operating measures involving a large number of units are set-points that are used by some TSOs to maintain system balancing by means of controlling the output of renewable energy sources. These instructions are usually last resort instructions and need to be executed as fast as possible and with high reliability as otherwise the LFC-Area or Block may reach large imbalances. In order to reach such requirements the communication channel may need to be direct.

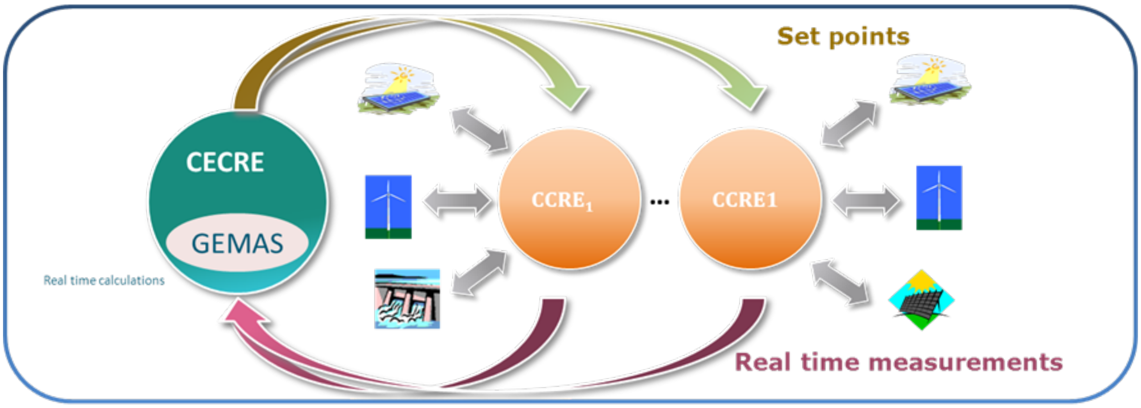

Figure 13: Real-time communication channels in the case of REE in order to directly issue automatic or semi-automatic real-time instructions to the control centres of renewable energy generators depending on the real-time scenario.

7 COMPLIANCE, TESTING AND INVESTIGATION IN THE FRAMEWORK OF THE OS NC

7.1 COMMON TESTING AND INCIDENT ANALYSIS RESPONSIBILITIES

7.1.1 The goal of Operational Testing and Monitoring

Operational testing and monitoring aims to ensure correct functioning of elements of the Transmission System and Distribution Network and Grid User's equipment; to ensure Power Generating Facilities and Demand Facilities continue to meet connection requirements, their declared capability and supply of ancillary services; to maintain and develop operational procedures; to train staff and to acquire information in respect of power system or equipment behaviour under abnormal system conditions.

Planning for and coordination of operational tests is necessary to minimise disruption to the stability, operation and economic efficiency of the interconnected system. For the efficient planning, coordination and implementation of tests, the TSOs require the cooperation of Significant Grid Users in the provision of the necessary data. As the power system is subject to various disturbances that could lead to a widespread incident, the TSOs will have to undertake investigations to determine the main causes and learning points of disturbances in order to avoid, if possible, their recurrence.

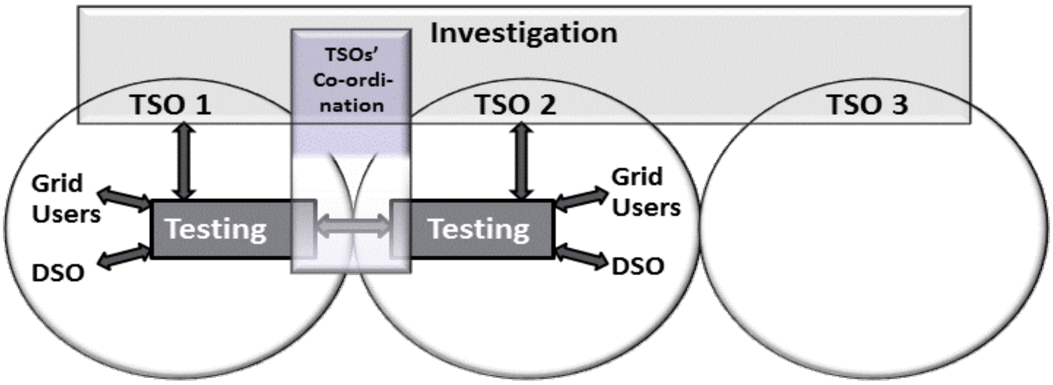

Figure 14: Coordination of tests between TSOs, DSOs and System Users (Source: ENTSO-E)

7.1.2 Common Testing and Incident Analysis Responsibilities in the framework of the OS NC

The Article 33 of the OS NC on common testing and incident analysis is not replacing or made redundant by, the NC RfG. It should be noted that the tests required in the NC RfG have the particular purpose of certifying and are much more exhaustive due to their nature.

From the operational point of view, the tests required in the OS NC should be seen as complementary to the NC RfG: the OS NC deals with disturbances, Faults and any other issue that can happen during the lifetime of the facility. The only one exception when the tests are repeated is in case of significant changes where it necessary to repeat the compliance tests of those technical requirements set by the NC RfG.

7.1.3 Some Examples on Compliance Testing

In the following, concrete procedures that can be seen as examples for illustrating the framework of the compliance testing in the OS NC are described:

a) *Test 1: Change of power system stabilizers in a Power Generating Facility*

Different stabilizers are used to stabilize possible oscillations after disturbances in Transmission System. The stabilizers can be installed in the controls systems of Power Generating Modules or in control systems of HVDC links. With correct parameters these stabilizers can increase the dynamically limited transmission capacity. In order to ensure the correct function of stabilizing functions and Transmission System Operational Security they shall be tested and tuned-up after changes in the power generating unit or HVDC parameters. Tests impulse can be caused by weakening the network e.g. by changing the topology in order to create a strobe signal for stabilizers.

b) *Test 2: Review of nuclear units: does the process work as planned?*

Nuclear Power Generating Facilities have safety and security regulations, which require periodical testing of their protection systems. The tests may include partial load trips every few months or full load trip to house-load operation or heat run (P-Q-diagram) tests after major changes of the plant components.

c) *Test 3: Deep voltage transient caused by short circuit in the grid*

When commissioning new Power Generating Modules their Fault Ride Through capabilities shall be tested by deep voltage transient test created by short circuit, if the test arrangements can be done without endangering other Significant Grid Users. Otherwise the test can be based on calculations The Power Generating Modules with their auxiliary systems shall be designed so that they can withstand the grid voltage variations according to the NC RfG Fault Ride Through definitions at their Connection Point.

d) *Test 4: Changeover to house load operation and house load operation predefined time*

All Power Generating Modules shall be designed to safely change over to house load operation. In house load operation the unit is only loaded by its own auxiliary supply system. The house load operation shall be possible for each generation type for predefined duration.

7.1.4 Information and documents in the Compliance Context

The OS NC sets the requirement for TSO or DSO for making publicly available the list of information and documents to be provided as well as the requirements to be fulfilled by the Significant Grid User in the framework of the compliance testing. This information and documentation is the same as that required by the NC RfG, updated as necessary over the lifetime of the Significant Grid User. This requirement is not about making publicly available data of a Significant Grid User, but the publication of the description of the compliance procedure by the relevant TSO or DSO.

The concerned list of information and documents shall at least cover the following information, documents and requirements:

a) All documentation and certificates to be provided by the Significant Grid User;

b) Details of the technical data of the Significant Grid User facility with relevance for the system operation;

c) Requirements for models for steady-state and Dynamic Stability Assessment;

d) Studies by the Significant Grid Users demonstrating expected steady-state performance and Dynamic Stability Assessment outcome.

7.2 THE INCIDENTS CLASSIFICATION SCALE

The Incidents Classification Scale developed by ENTSO-E [8] provides the procedures for incident classification, analysis and reporting with the aim of monitoring system security levels and identification of improvements to reduce the risk of reoccurrence. The incidents classification scale ranks disturbances into four levels of severity, ranging from:

- Local events the consequences of which are limited to one TSO (Level 0);
- Noteworthy disturbances covering national events the consequences of which are manageable by one TSO (Level 1);
- Extensive and major incidents covering regional events (Level 2);
- Widespread incident and major incident for one TSO such as massive loss of load for one TSO, isolated system or regional Blackout (Level 3).

To identify the incident level, the following five general system reliability criteria have been defined:

- Transmission System equipment events (tripping of Transmission System equipment);
- Generation events (tripping of generators);
- Load events;
- Degradation in system operating conditions leading to non-fulfillment of the Operational Security criteria or violation of standards;
- System disturbance leading to reliability degradation.

Different thresholds have been defined to take into account differences in the Synchronous Areas. Specific thresholds are defined for:

- The definition of loss of generation;
- The definition of loss of load;
- Frequency deviation; and
- Percentage of peak load affected by Blackout.

For example, for a Level 2 incident any of the following criteria apply:

- Transmission System equipment events: tripping with consequences at regional level (exchange capability and social consequences);
- Generation events: loss of generation in a time period of 30 minutes leading to a degradation of system adequacy, e.g. for Continental Europe >3000 MWs;
- Load events: all regions except isolated systems, disconnection of load on one TSO area of 10 to 50% of the load at the time of the incident;
- Degradation in system operating conditions: Emergency State transmitted by the ENTSO-E wide awareness system;
- System disturbance leading to a reliability degradation:
    - Sustained frequency deviation below the last step of automatic load shedding, for Continental Europe 800 mHz – 2 Hz;
    - Separation of a significant part of the interconnected Transmission Systems (at least one TSO);
    - Regional (synchronous area) collapse.

The level of detail of the investigation/analysis will vary depending on their impact on the integrity of the interconnected Transmission System:

- For local or national incidents which have limited consequences with a low effect on reliability there will be no obligation to carry out specific analysis. These events will be reported to allow statistical analysis and TSO's to report events for internal purposes.

- For national incidents which have noticeable consequences (high security and/or market influence or cause violation of standards for at least two TSOs) and are manageable by one TSO, analysis will be carried out if decided by a TSO, coordinated system operation or any type of working group dedicated to operational issues, ENTSO-E Regional Group or the ENTSO-E System Operations Committee. The relevant information will be shared among TSOs using the reporting tool and the analysis will be prepared by the impacted TSO covering the facts, actions, anomalies and learning points.

- For an extensive incident at a regional level (violation of standards, degradation of system adequacy, or important social consequences) not manageable by one TSO and Wide Area events such as massive loss of load (50% / 70%) on one TSO or regional Blackout a detailed report will be prepared by an ENTSO-E Regional Group team. An expert panel is appointed to perform the analysis based on a TSO's (or a working group dedicated to operational issues) proposal, and approved by the ENTSO-E Regional Group. The analysis will be performed in two steps. After collecting the data the expert panel will produce a factual (or preliminary) report. The aim of this report is to provide a clear understanding of the main causes, a clear description of the disturbance (situation before and after), preliminary evaluation of actions taken and functioning of equipment. The analysis (or final) report will include conclusions and recommendations (an action plan and lessons learned).

In addition to the data received via the SCADA system, the following information may be needed to fully investigate a major system incident:

- State of Transmission System pre-fault/disturbance including details on any large angular differences open due to a line being out of service;
- Fault records from Disturbance Recorders and Relays;
- Relay Annunciation records;
- Event recordings from Transmission substations/Significant Grid Users;
- Weather including any lightning activity (lightning locator);
- Information on action of Under Voltage Load Shedding/Under Frequency Load Shedding schemes and System Protection Schemes;
- Information from generators as to cause of generator tripping (e.g. flame out);
- Information from equipment manufacturer on cause of Fault (e.g. bushing failure results, moisture ingress results etc.);
- Interviews with System Operator Employees;
- Customer load lost from DSO.

Figure 15 illustrates the high-level process from the identification and definition of the Operational Security Performance Indicators, over the yearly reporting according to the ENTSO-E Incidents Classification Scale, to the identification of the necessary enhancements in order to maintain Operational Security in a sustainable, effective and efficient way.

Figure 15: Operational Security Performance Indicators (Source: ENTSO-E)

The decision to rely on the ENTSO-E Incidents Classification Scale as the basis for the Operational Security Performance Indicators is made following the framework for that described in the ACER Framework Guidelines on Electricity System Operation: "*General System Operation Characteristics*

… The network code(s) shall provide criteria (performance indicators) against which the quality of System Operation can be monitored. In particular, adequate criteria should be proposed for security of supply, quality of supply and for the quality of the data delivered as input for congestion management in comparison with the effective use of the transmission system represented by real-time data. The network code(s) shall foresee the publication of a yearly report by ENTSO-E on the evolution of system operation performance. This report shall provide a detailed assessment of the performance per country, including the selected performance criteria and their evolution over time. The format and content of the report shall be approved by ACER …

> *Topic 1: Operational Security*
>
> *… The network code(s) shall provide criteria (performance indicators) against which the Operational Security can be monitored…*"

As the Incidents Classification Scale Methodology puts it, Transmission System is subjected to various contingencies (grid disturbances, system disturbances) that may potentially, regardless of where they occur, lead to widespread incident over a large part of interconnected systems. The knowledge of main causes and most important sources of disturbance and the learning from recent incidents are necessary for TSOs to avoid their recurrence. The ENTSO-E Incidents Classification Scale is designed pursuant to Article 8(3) of the Regulation (EC) No 714/2009 and is subject to monitoring by ACER and reporting by ACER to the EU Commission, pursuant to Article 9(1) of the Regulation (EC) No 714/2009.

The implementation of the ENTSO-E Incidents Classification Scale:

- Describes the principles of classification with full explanations about the methodology used to establish correspondence between events and level of importance with regard to security;

- Defines the process each TSO will have to apply in order to analyze classified events;
- Defines reporting and analyses procedures at ENTSO-E level;
- Permits to follow the number of events;
- Permits to follow the status of security level by analyzing the violations of preset thresholds;
- Puts into evidence needs to perform feedback analyses and, possibly, facilitate the identification of ways of progress to improve grid codes in order to avoid the reproduction of known situations.

The European-wide Incidents Classification Scale will allow ENTSO-E and Transmission System Operators to draw up a yearly report reflecting the level of Operational Security all over Europe. It will represent a real opportunity for Transmission System Operators to characterize main issues and to identify ways of progress. It is against this background that the ENTSO-E with its Methodology and Guidelines is considered an adequate match to the mentioned requirements for Operational Security Performance Indicators in the ACER Framework Guidelines for Electricity System Operation.

In the first step – definitions – of Figure 10, the key concepts around Operational Security Performance Indicators are introduced and their relation with the Operational Security Network Code established. The reasoning behind the ranking is explained and the basis laid down for the later on introduced yearly reporting by TSOs and compilation of the common report.

In the second step – Article 32(1)(a) and 32(1)(b) – first the TSOs obligation to maintain Operational Security is structured in terms of utilization of all available means within own Responsibility Area and the means through cooperation with other stakeholders, in the form of congestion management and ancillary services. Then, the yearly reporting obligation in compliance with the ENTSO-E ICS in its current version is introduced in Article 32(1)(c) and Article 32(2).

Finally and in the third step, Articles 32(1)(d) and 32(1)(e) specify the TSOs obligation for identification, evaluation and implementation of necessary enhancements of the existing means according to Articles 32(1)(a) and 32(1)(b), as well as the development – where necessary - of any new means within the scope of the Articles 32(1)(a) and 32(1)(b).

The ranking and explanation / analysis of reasons of incidents and events reported in the yearly Incidents Classification Scale report are the essential part of the Operational Security Performance Indicators approach developed in the Operational Security Network Code. They provide for a structured and transparent way to monitor the overall health and Operational Security of the European interconnected Transmission Systems, to identify any necessary enhancements (those can even include changes in framework or even Operational Security Network Code itself if it is considered lacking any critical provisions) in order to maintain Operational Security in an effective and sustainable way throughout Europe.

An example of a simulated yearly Incidents Classification Scale reporting, based on only three months and not fully complete data, is shown in Figure 16: Simulated yearly ICS reporting (Source: ENTSO-E).

	Level 1	Level 2	Level 3
Number of tripped grid equipment, leading to overload, violation of N-1, limitation of transfer capacity	79	0	N/A
Disconnected generation per year, MWh	0 MMh	0 MWh	N/A
Disconnected load per year, MWh	0 MWh	0 MWh	0 MWh
Time of being in different states (alert, emergency, black-out), h	267 h	0 h	0 h
Time of lack of reserves (> 20%), h	92 h	N/A	N/A
Voltage deviation	0	N/A	N/A
Frequency deviation (frequency curves of the different synchronous areas)	2	0	0
Number of separation of the system and/or local black-outs (1 TSO)	N/A	0	N/A
Number of regional black-outs	N/A	N/A	0

Figure 16: Simulated yearly ICS reporting (Source: ENTSO-E)

7.2.1 Geographical vs. Electrical Scope

The SO FG call for "… *a detailed assessment of the system operation performance per country…*". Whereas this framework provision is simple enough and sufficient from a formal perspective, it is not practically applicable in the today's system operational practice and growing degree of interleaved dependencies between the TSOs and their Responsibility Areas in terms of Operational Security. This means that eventually, the scope for a particular incident – depending on its character and ranking – could be a Synchronous Area (e.g. for frequency), or even beyond the Synchronous Area (e.g. for lack of reserves in case of exchange of reserves beyond the Synchronous Area borders), as well as a part of a Synchronous Area with several TSOs (e.g. in case of regional Blackouts).

This means further that the scope for the assessment of the System Operation in general and Operational Security in particular will always have to retain the wide, holistic view at the European interconnected Transmission Systems and that the identification of necessary enhancements – or even new means – according to the obligations pursuant to Article 32(1)(d) and 32(1)(e) will always be case-by-case based. This means nevertheless also that the ex-post analysis after any significant incident will be carried on at the right level of detail and with high scrutiny, relying on the agreed criteria to decide specific ex-post analysis, the data needed to run ex-post analysis, the items to be dealt with, the organization performing the analysis and main milestones of it. Eventually, the results of such ex-post analyses, subject of yearly incidents classification scale reporting, will be the main driver for any necessary enhancements and further developments of TSOs own means and of any further means in cooperation with other stakeholders, with a common goal to maintain Operational Security in Europe.

Concluding, the scope for a detailed assessment shall not be limited by political borders of a country but shall, following the formulation in Article 32(2), always be based on the geographical scope of the incidents reported, according to the electrical interdependencies between the TSOs' Responsibility Areas and relevant historical information of similar incidents from the past.

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

8 Fundamental Concepts & Processes of the OS NC

This section presents the fundamental concepts used in the framework of the OS NC while clarifying at the same time resulting comments of stakeholders during the OS Network Code Development Process.

8.1 Common Grid Model (CGM)

8.1.1 What is the CGM?

The CGM is an ENTSO-E wide data set used to prepare a model used to analyse different scenarios. These scenarios are valid to enable Operational Security Analysis and capacity calculation to be performed. To perform the analysis, the whole Common Grid Model or the necessary part of it is used. The scenarios are prepared for different time frames: Year ahead, Week ahead, Day ahead and Intraday. All of them are used for Contingency Analysis. The Day ahead and Intraday ones are also used for Capacity Calculation.

8.1.2 What does the CGM comprise and how is it formed?

The CGM comprises at least the transmission system of 220 kV and higher voltage network, an equivalent model of the lower voltage grid with influence and the sum of generation and withdrawals in the nodes of the Transmission System. It is formed by merging the individual data sets provided by every TSO as stated in the Article 17(3) of the OS NC. The individual data provided by each TSO comes from its own observability models. The Individual data sets, so-called individual grid models, are part of the Common Grid Model, as reflected in the figure below:

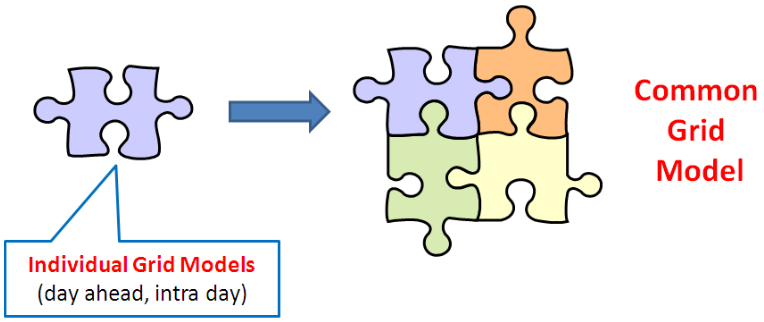

Figure 17: Individual Grid Models versus Common Grid Model (Source: ENTSO-E)

Whereas the NC OPS describes the procedure to prepare the CGM scenarios in each time frame for Contingency Analysis, it is in the NC CACM where the requirements for building the CGM scenarios for Capacity Calculation purposes are set.

8.1.3 Overview of the building of the CGM

The next figure gives an overview of the building of the CGM and whether the respective actions are performed on TSO level or coordinated on a regional level:

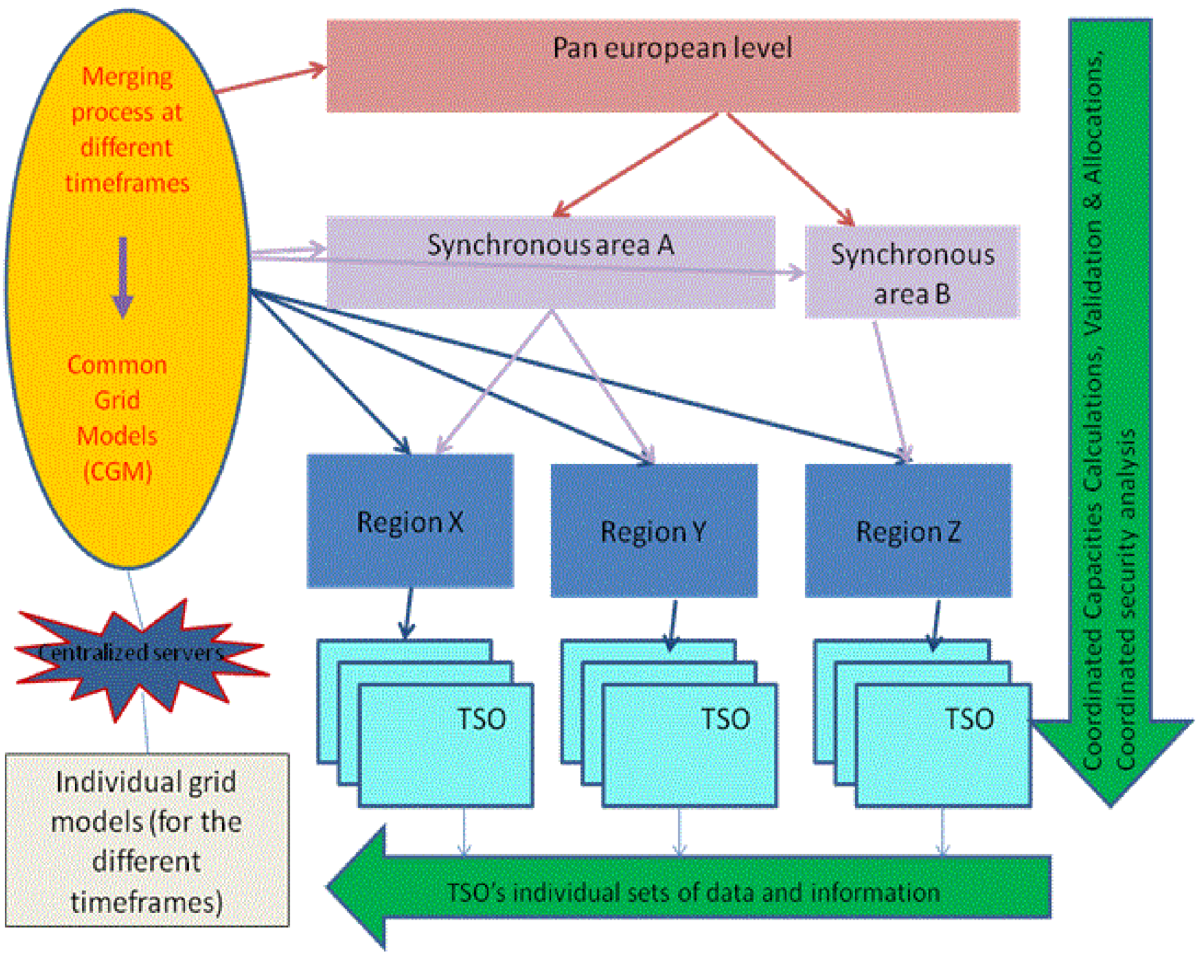

Figure 18: Overview of CGM building process: data and information exchange (Source: ENTSO-E)

The OS NC focuses on the Common Grid Model scenarios relevant for the purpose of Operational Security Analysis; each TSO uses the data from its Observability Area to build, within each relevant time frame, the individual data set for the Common Grid Model. This process is carried out considering certain conditions and covering zones to allow coordinated Operational Security Analysis resulting e.g. in actions on power flow management. It has to include relevant characteristics of the connected Power Generating and Demand Facilities and of the Transmission System and Distribution Network elements, taking into account planned outages.

The data from its Observability Area within the relevant timeframe permits the TSO to monitor its Transmission System and to perform the Contingency Analysis in order to assess the System State for Contingencies and to set up the required Remedial Actions.

8.1.4 Interface of the CGM for operational purposes with the CGM for capacity calculation purposes

Different Network Codes deal with different aspects of the Common Grid Model. For example: CACM refers to Capacity Calculation, OS refers to Contingency Analysis and OPS to outage planning. All of these issues are the components of the wider Operational Security Analysis, general or specific ones, considering different values of exchange between Responsibility Areas. Network Codes establish the detailed requirements to perform these specific analysis but the generally applicable criteria are the same for all of them.

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

OS NC defines the basic characteristics of the Common Grid Model and entitles the TSO to receive the necessary information to prepare the Individual Grid Model. The NC OPS states the general criteria to merge the Individual Grid Models into the Common Grid Model. NC CACM defines the merging function.

The different scenarios are related to each other. Capacity Calculations need to be performed prior to the market to guarantee that the results from the market are secure. NC CACM defines the Capacity Calculation Timeframes in Day-Ahead and Intraday so a scenario of the Common Grid Model has to be merged in D-2 based in estimations. The results of this Capacity Calculation Analysis, done according to NC CACM, are used in the Day-Ahead to perform Security Analysis according to the OPS.

8.2 SIGNIFICANT GRID USER (SGU)

According to the SO FG [1], Significant Grid User is defined as "*pre-existing grid users and new grid users which are deemed significant on the basis of their impact on the cross border system performances via influence on the LFC Area's security of supply including provision of ancillary services*". This has been the approach followed by the OS NC, i.e. defining the significance by considering the impact of a grid user on the Transmission System performance, regardless of the voltage at its Connection Point.

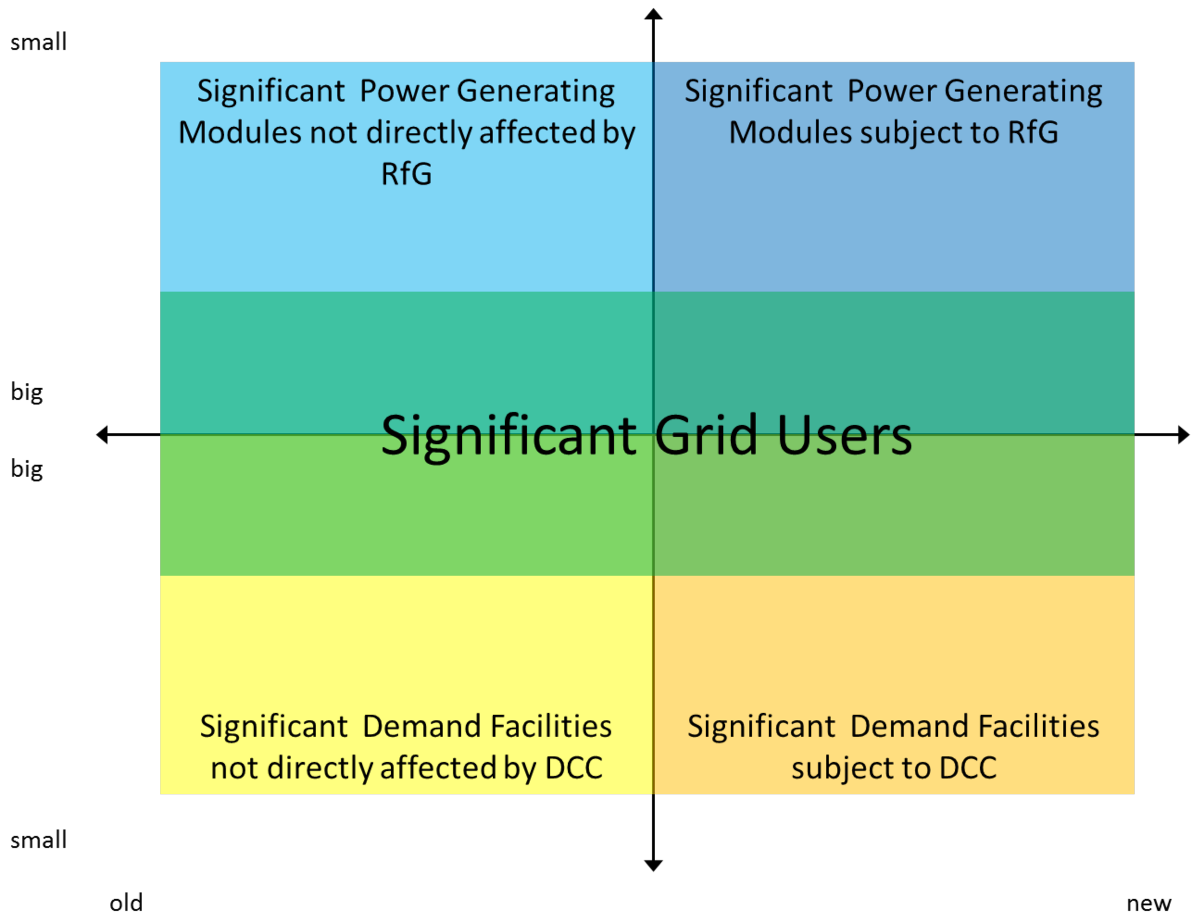

Figure 19: SGUs in the framework of the OS NC (Source: ENTSO-E)

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

Indeed, the Article 1(5) of the OS NC specifies, the following to be considered Significant Grid Users:

a) *Existing and New Power Generating Modules of type B, C and D according to the criteria defined in [Article 3(6) of RfG NC];*

b) *Existing and New Transmission Connected Demand Facilities according to the criteria defined in Article 5 and Article 8 of [DCC] and all Existing and New Transmission Connected Closed Distribution Networks;*

c) *Significant Demand Facilities, Closed Distribution Networks and Aggregators according to the [NC DC], in case that they provide Demand Side Response directly to the TSO;*

d) *Redispatching Aggregators and Providers of Active Power Reserve according to provisions of [NC LFCR].*

8.2.1 SGU: a unique concept of the System Operation Codes

Significant Grid User is significant for the important System Operation matters such as the provision to the TSO or DSO of structural data, forecast output or consumption data, provision of real-time data and other obligations such as to follow a TSOs instruction to protect Operational Security.

The term SGU is unique to the System Operation Codes and differs from the terms Significant Generating Module used in the NC RfG or Significant Demand Facility used in DCC, which primarily sets out the design and build capability requirements for different sizes. The definition of SGU clearly specifies that PGMs which are not type B, C, D will never be considered as SGU. Only their Aggregator providing services directly to TSO is SGU. The intention is not and there is no reason to hinder market development by putting limits with a minimum value for level of aggregation to participate in services to TSO. When needed harmonised minimum technical requirements are further defined in the respective network codes (like in NC LFCR for active power reserves or NC EB for balancing purpose).

The criteria to establish the significance of Grid Users relies on the following main aspects:

a) Grid Users directly connected to the Transmission System;
b) Influence of the Grid Users on the Generation-Demand Balance.
c) Grid Users providing services directly to the TSO.

Grid Users directly connected to the Transmission System are significant for two reasons: they are big Power Generating Facilities and big Demand Facilities so they have significant influence on the Transmission System. As they are directly connected to the Transmission System, they shall be accordingly taken into account in the System Operation. Type D Power Generating Modules, both old and new ones, and Demand Facilities directly connected to the Transmission System are included in this category.

All Grid Users that provide Ancillary Services directly to the TSO are also considered Significant Grid Users. Demand Facilities, Closed Distribution Networks and Aggregators according to Article 1(5)(b) and Aggregated Power Generating Modules according to Article 1(5)(d) are included in this category. This Significant Grid Users have influence on the Generation-Demand Balance via DSR, Redispatching or providing Active Reserve and doing so they are direct clients to the TSO. All Grid Users providing a service directly to the TSO need to be considered as Significant so the TSO can take into account and verify the provision of that service irrespective of their size. Provision of Service by SGU to TSO is always subject to contract and those contracts will define fulfilment of minimum technical requirements and pre-qualification tests.

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

Type B and C Power Generating Modules shall also be included in the group of SGUs. These Power Generating Modules generate up to 50 and 75 MW in Continental Europe. This is a noticeable size, particularly for smaller TSOs. It should be taken into account that the development of generation from RES has increased and will keep increasing the amount of small and medium Power Generating Facilities that cannot be aggregated due to their geographical dispersion; some examples are Denmark, Germany or Spain.

8.3 LFC AREA, RESPONSIBILITY AREA, OBSERVABILITY AREA,

8.3.1 Explanation of the different concepts

Load-Frequency Control Area (LFC Area)

From a functional point of view, the term LFC Area is related to load-frequency control, aiming at balancing the LFC Area in terms of Frequency, including loads and generation. Therefore, a LFC Area fulfils the following functions:

- Being responsible for the Frequency Containment Process;
- Being able to maintain power interchange at the scheduled value;
- Cooperating to restore Frequency to its set value following a perturbation;
- Being responsible for accounting inadvertent energy deviations within its territory;

Therefore, in the framework of the LFC NC, LFC Area appears defined as follows:

"*A part of the Synchronous Area physically demarcated by points of measurement of Tie-Lines to other LFC Areas fulfilling the Area Process Obligations of a Control Area*;"

Responsibility Area

Defined as follows in the OS NC:

"*A coherent part of the interconnected Transmission System including Interconnectors, operated by a single TSO with connected Demand Facilities, or Power Generating Modules , if any*;",

The term Responsibility Area covers a different part of the System than the term LFC Area: the TSO is responsible for maintaining the (N-1)-Criterion of its own grid and all the interconnectors to adjacent TSOs. The components comprising this network are together called Responsibility Area.

Observability Area

Due to the increase of the degree of interconnections between TSOs, market operations, volatility of generation, etc. Operational Security Assessment has become more and more interdependent. As a consequence, the TSO has to take into account the influence of the surrounding grid on its Responsibility Area by analysing the external Transmission System which has influence on its Responsibility Area. This introduces the concept of Observability Area, which includes the Responsibility Area, and is defined as follows by the OS NC:

"*Observability Area means the own Transmission System and the relevant parts Distribution Networks and neighbouring TSOs' Transmission Systems, on which TSO implements real-time monitoring and modelling to ensure Operational Security in its Responsibility Area*; "

Figure 20 presents in a schematic way the concepts of Responsibility Area and Observability Area with the purpose of clarifying what is exactly meant under each term and how those terms are linked:

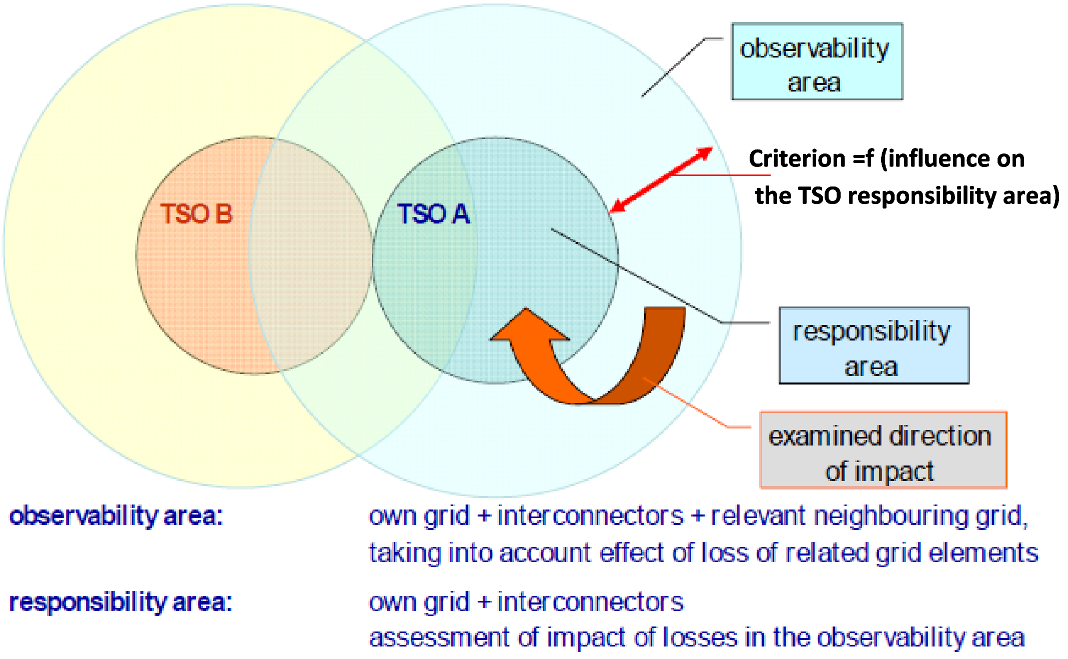

Figure 20: Definitions on Observability Area and Responsibility Area of a TSO (source: [20])

8.3.2 Illustrative examples for the distinction between LFC Area and Responsibility Area

The following examples provide a visual explanation about the distinction between the concept of LFC Area and the concept of Responsibility Area:

- *One Responsibility Area and two LFC Areas: the case of Energinet DK*

The Danish TSO is Energinet DK, the Transmission System Operator for the whole country. In Denmark there are two Synchronous Areas, one is part of the Continental Europe Synchronous Area and another one in the islands, connected to the Nordic Synchronous Area. The load-frequency control has to be done independently in each Synchronous Area. Therefore, Energinet DK operates one Responsibility Area and two LFC Areas.

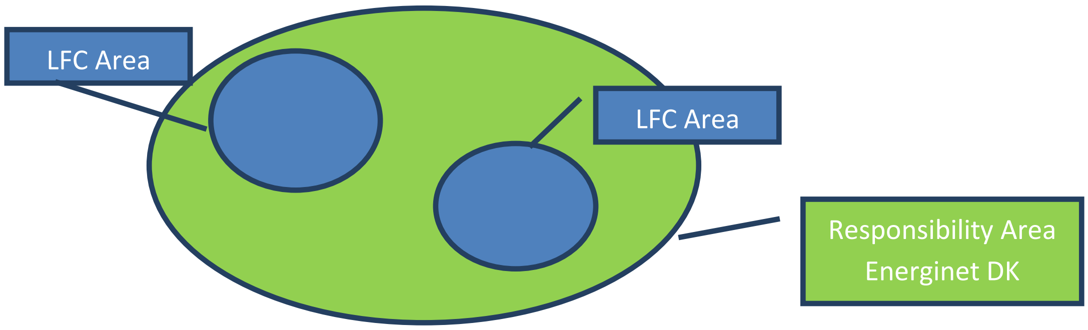

Figure 21: Two LFC Areas and one Responsibility Area: the case of Energinet DK (Source: ENTSO-E)

- *Two Responsibility Areas within one LFC Area: the case of Creos & Amprion.*

Creos is the TSO in Luxembourg and represents the opposite example of Energinet DK. It operates the Transmission System in Luxembourg but the load-frequency control is performed by Amprion, one of the four German TSOs. In this case, Creos and Amprion do represent two Responsibility Areas but only constitute one LFC Area as follows:

- o On the one hand, Creos and Amprion are responsible for the system operation management of the Transmission System within their respective grid areas (Responsibility Areas) and for the common Ínterconnectors. The responsibility comprises the internal LFC Area supervision and management of the Transmission System aiming at remaining (N-1)-secure by monitoring the Operational Security Limits. Therefore, Creos constitutes a Responsibility Area independent from the Responsibility Area of Amprion.

- o On the other hand, the LFC Area of Creos is located within the LFC Area of Amprion, who performs the load-frequency control for Creos and Amprion by continuously monitoring the Frequency Restoration Control Error of the LFC Area. Therefore, the (Amprion+Creos)-LFC Area is one region physically demarcated by points of measurement of Interconnectors to the other LFC Areas.

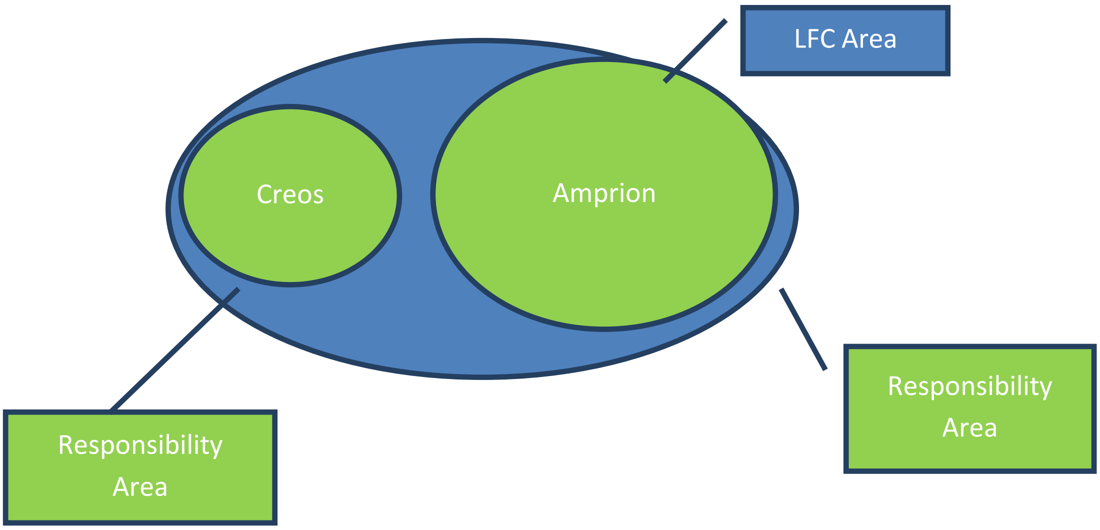

Figure 22: Two Responsibility Areas within one LFC Area: the case of Creos and Amprion and methodology for determining the Observability Area (Source: ENTSO-E)

8.3.1 Algorithms for evaluating the influence of external elements on the Responsibility Area

The Observability Area has to be precisely defined in terms of Topology and measurement acquisition has to be as complete as possible. Following guidelines should be taken into account for its determination, bearing in mind also the necessary redundancy for the sake of ensuring a complete dataset:

- It is desirable to have voltage measurements from all buses and Active and Reactive Power measurements from both ends of all branches.

- It may be acceptable to have some branches that are metered at only one end but then the bus on the unmetered end must have fully metered injection (or be a zero injection bus).
- Radial branches can be omitted, under the condition that they themselves do not connect elements of the Contingency List from the Observability Area and replaced with telemetered fictitious loads in the connecting grid bus.

In the Regional Group Continental Europe, the Operation Handbook[8] foresees two algorithms for the evaluation of the impact of external outages on the Responsibility Area and, therefore, offering support in the determination of the Observability Area:

- Influence factor and
- Influence factor linked with influence thresholds.

Figure 23 illustrates the Observability Area (purple colour) and the Responsibility Area (red colour) of the German TSO 50Hertz, who applies the methodology of the Influence factor according to Policy 3 of the Operation Handbook:

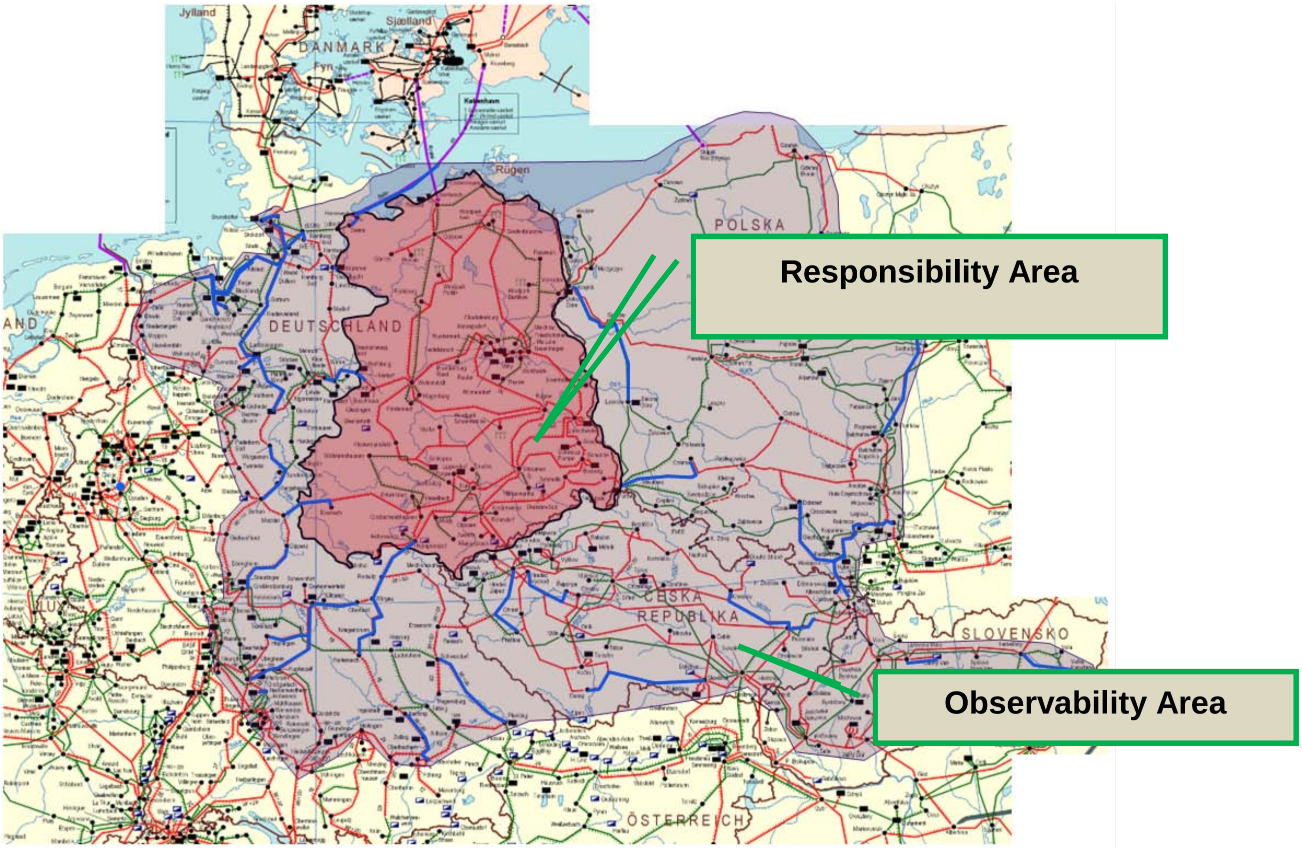

Figure 23: Observability Area and Responsibility Area of the German TSO 50Hertz (Source: 50Hertz)

In the framework of the System Operation Network Codes, the OS NC sets the high-level principles for these concepts while defining:

Contingency Influence Threshold as "a numerical limit value against which the Influence Factors must be checked. The outage of e.g. an external Transmission System element with an Influence

---

8 [10]

Factor higher than the Contingency Influence Threshold is considered having a significant impact on the TSO's Responsibility Area. The value of the Contingency Influence Threshold is based on the risk assessment of each TSO."

and

Influence Factor as "a numerical value used to quantify the highest effect of the outage of an external Transmission System element on any Transmission System branch. The worse the effect, the higher the influence factor value is."

It is in the NC OPS where the procedure for setting concrete methodologies for the Observability Area determination is set.

8.4 N-1 PRINCIPLE

8.4.1 The "philosophy" of the (N-1)-Principle in Transmission System Operation

The operation of the interconnected Transmission System is founded on the principle that each partner is responsible for its own System, provided the interference of national and the corresponding inter-TSO coordination that requests more and more coordination at regional level. Within this context, the (N-1)-Principle is a well-established practice among TSOs, documented in numerous existing regional grid codes and operation handbooks, which ensures the Operational Security, by foreseeing that any Contingency from the Contingency List (Normal and Exceptional types of Contingencies considered in the Contingency List) must not endanger the Operational Security of the interconnected operation. After any of these Contingencies, the operational conditions within the TSO´s Responsibility Area must not lead to the triggering of an uncontrollable cascading outage propagating across the Transmission System borders or have an impact outside these borders.

In line with this principle, each TSO is responsible of procedures for reliable operation over a reasonable future time period in view of real-time conditions and of their preparation. Therefore the (N-1)-Principle has been developed with the goal for each TSO to prevent any propagation of one incident with the meaning of "*no cascading with impact outside my borders*". (N-1)-Principle application purpose is then to prevent emergency or critical conditions that appear as a result of a combination of events. Coordination between TSOs contributes to enhance the common solidarity to cope with risks, resulting from the operation of interconnected Transmission Systems, to prevent disturbances, to provide assistance in the event of failures with a view to reduce their impact and to provide resetting strategies after a Blackout. This coordination is intensively developed covering aspects related to market mechanisms.

The detailed definition of (N-1)-Criterion is based upon:

- The risk assessment by each TSO;
- The Contingencies and their gravity in terms of consequences for the System to be considered in the Operational Security Analysis whose goal is to detect constraints of the Transmission System;
- The area to observe by each TSO in order to get the best survey of expected constraints or violations to come;
- The Operational Security Limits to be respected in order to maintain minimum risks for the Transmission System;

- The Remedial Actions to cope with and relieve constraints in due time with simulations of their efficiency in advance;
- The strengthened coordination between TSOs to implement such stronger commitments.

The (N-1)-Principle guarantees that the loss of any any event of the Contingency List of the network is compatible with the Operational Security Criteria, taking into account available Remedial Actions.

8.4.2 (N-1)-assessment: classification of Contingencies as a function of probability of occurrence

The classification of the Contingencies in Ordinary, Exceptional and Out-of-Range for the purpose of Contingency Analysis is based upon the probability of occurrence of each Contingency. Thus, Contingencies with a high probability of occurrence are characterised as Ordinary, the ones with a low probability are characterised as Exceptional and those with an extremely low probability are characterised as Out-of-Range. For example, the single loss of a line has a high probability of occurrence and therefore belongs to the Ordinary Contingencies. On the other hand, the simultaneous loss of multiple elements is considered to be of lower probability and is therefore either in the Exceptional or in the Out-of-Range Contingency category. Factors such as the severity of the incident and the resulting duration of the unavailability of the element due to the Contingency are not taken into account in the preparation of the Contingency List.

One such example is the tripping and damage of one or more Power Generating Facilities due to the occurrence of a resonant Frequency in the Synchronous Area. Such an incident is highly severe, as it damages the turbine-generator system and results in a prolonged period of unavailability of the Power Generating Facilities due to demanding repair works. However, such a Contingency is considered as highly improbable, as each generator is equipped with automatic protection systems, which disconnect the Power Generating Facility before the deteriorating Frequency reaches the resonant Frequency.

The assessment of the probability of occurrence and the related severity of a Contingency is based upon existing practices of the TSOs and has its foundation on TSOs continuous assessment, statistical analysis and operational experience.

8.4.3 (N-1)-assessment: distinction between Internal Contingency and External Contingency

The nature of the interconnected Transmission Systems and the given physical interdependencies of Transmission System elements imply that the (N-1)-Principle cannot be limited to the Responsibility Area of each TSO. On the contrary, each TSO is bound to take into account the influence of Transmission System elements outside of its own Responsibility Area on its Transmission System, assess their impact and accordingly coordinate Remedial Actions with the interconnected TSOs in order to ensure the secure and reliable system operation. The Transmission System elements which are taken into account in a TSOs Contingency Analysis, while not belonging to its own Responsibility Area comprise the External Contingencies, whereas the elements which are part of its own Area are considered within the scope of Internal Contingencies.

The aforementioned principle encompasses the philosophy that TSOs are aware of the risk in their own Responsibility Area due to Internal or External Contingencies, that they accordingly inform or are informed by neighbouring Transmission Systems and prepare coordinated Remedial Actions in order to avoid uncontrolled cascading. Furthermore, all TSOs are aware that their decisions and can have an influence on neighbouring Transmission Systems and, therefore, coordination is an obligation.

8.5 SYSTEM STATES

8.5.1 Real-time monitoring of the Transmission System: Control Facilities, Security Telecommunication Network and Telecontrol System.

CONTROL FACILITIES

All the Transmission System control centers are equipped with complex computing systems ensuring the acquisition and processing of data from facilities (substations and Power Generating Facilities). Their availability relies on the redundancy of their hardware and software components, as well as their data bases. They also benefit from a high-quality, guaranteed power supply (including by autonomous generating facilities).

The control centers are equipped with a control computing system which carries out the following main functions:

- Acquisition, processing, display and archiving of remote data;
- Systematic Operational Security Analysis in real-time and in study mode;
- Load-frequency control;
- Voltage control.

Additional computing systems are also included, such as:

- Specialist tools for Operational Security Analysis;
- Mimic board providing the nodal display of the grid, voltage and overload states, flows in the lines and transformers.

These tools allow the System Operator Employees to monitor the System State and state of the Transmission System elements, display the status of a substation or an area (topology, flows and voltages) and, if necessary, to remotely control the equipment.

SECURITY TELECOMMUNICATION NETWORK

The security telecommunication network is a telecommunication-transmission network which is devoted to the exclusive use of power network operation. Its infrastructure can be based on different supports: switched network links rented from a telecom operator, private microwave relay links or those rented from a telecom operator, power-line carrier links, fiber optics deployed on the public Transmission System, as well as radio links currently being replaced.

The security telecommunication network enables the operating personnel at the different control levels and between the control centers of European TSOs to exchange commands and information via a security telephone system, made up of private branch exchanges installed in the connected control centers.

It ensures the conveyance of signals intended for the operation of protection systems on electrical facilities or for remote actions performed by local automatic control devices.
The smooth operation of the security telecommunication network is vital for system operation and Operational Security and implies the redundancy of telecommunication transmission channels on the telecommunication security network and the absence of common modes between these channels.
This is ensured by the use of different supports between 2 points of concentration with duplication of routing equipment.

TELECONTROL SYSTEM

The control equipment and security network constitute the so-called telecontrol system. This system must:

- Guarantee the observability of the Transmission System by providing the System Operator Employees with the means of keeping track, at all times, of the state of flows, of the Topology and value of electrical magnitudes (Frequency and Voltage) characteristic of system operation. This observability must take into account data from the other European TSOs, information serving to manage the complexity of the exchanges in the best possible way while ensuring the operating reliability of the European interconnected Transmission Systems;

- Guarantee the controllability of the Transmission System by providing the System Operator Employees and the automatic control devices with the means of controlling the operation through the telecontrol of circuit-breaking equipment and through the automatic centralized control of Frequency and (if used) Voltage;

- Supply reliable information to the complex functions of Operational Security Analysis which enable the System Operator Employees:

    - To anticipate the consequences of events, such as tripping of Power Generating Facilities or Transmission System elements or short-circuits Faults on Transmission System flows, voltage or stability,
    - To prepare Remedial Actions.

The telecontrol system is vital for Transmission System reliability and Operational Security. Measures are therefore taken to ensure the permanence of all its related features:

- The security telecommunication network is dedicated to operation and consequently its capacities cannot be altered by a saturation of the public telecommunication networks; each national control center has a reserve / backup control center connected to the security telecommunication network and equipped with control facilities;
- All of the remote data on the Transmission System and on Power Generating Facilities are acquired and processed twice by different channels;
- Partial overlapping of the Observability Areas of TSOs (i.e. between their control centers) is provided by the exchange of data on the Observability Area;
- Calculation and transmission of the centralized frequency control level are ensured by an independent channel;
- Finally, uninterrupted power supply to the telecontrol and telecommunication equipment of the control centers is provided by mixed and independent external sources and internal sources.

8.5.2 European Awareness System

Article 8 (11) of the NC OS inserts the use of an IT-tool for real-time data exchange at pan-European level. This tool is currently known as European Awareness System (EAS), which was implemented in April 2013 within the TSOs which are members of ENTSO-E.

This section of the OS NC Supporting Document explains the origin and scope of the EAS. Furthermore, the range of data exchanged via this EAS is described, being in line with the requirement set in Article 18 (1) of the NC OS.

The origin of the European Awareness System: UCTE incident report 04/11/2006

– ***Conclusions***:

"During the first minutes of disturbances, dispatchers should focus their actions on the restoration of normal conditions. On the other hand, the information about localisation of the source of the disturbance and overall system conditions is necessary for other TSOs in order to act accordingly and efficiently. On November 4, this was true more than ever - the information about the split of the system into three areas was available to some operators with significant delay. This issue might be solved via a dedicated central server collecting the real-time data and making them available to all UCTE TSOs. In this way, each TSO will obtain within a few minutes essential information about disturbances, beyond their own control area."

– ***Recommendation #4***: *"information platform allowing TSOs to observe in real-time the actual state of the whole UCTE system in order to quickly react during large disturbances".*

What is an awareness system?

The awareness system is a tool whose objectives are:

- *In case of a stressed situation*: to provide automatic or manual information to enable the TSOs to apprehend globally an endangered situation;
- *In case of disturbance*: to provide information to the TSOs to help them to identify its origin, borders and to be helpful during solving this disturbance.

In both cases, this shall enable the TSOs to enhance their assessment of, the nature and the size of the disturbance, to make decision to react (or not) without engraving the situation and, if possible, contribute to its securing and to seek for cross-border co-operations.

As the effects of a disturbance or a stressed situation can be seen throughout the whole interconnected Transmission System, an awareness system should cover this whole area. As the area is extended, it is necessary to limit the amount of information to be shared to ease their interpretation. There are two types of information:

- *Automatic real-time measurements or data*: providing an objective overview of the physics of the networks;
- *Manual indications providing*:
    - o Factual or first step analysis from one TSO: system states (traffic lights) and/or preformatted messages);
    - o And/or short free messages.

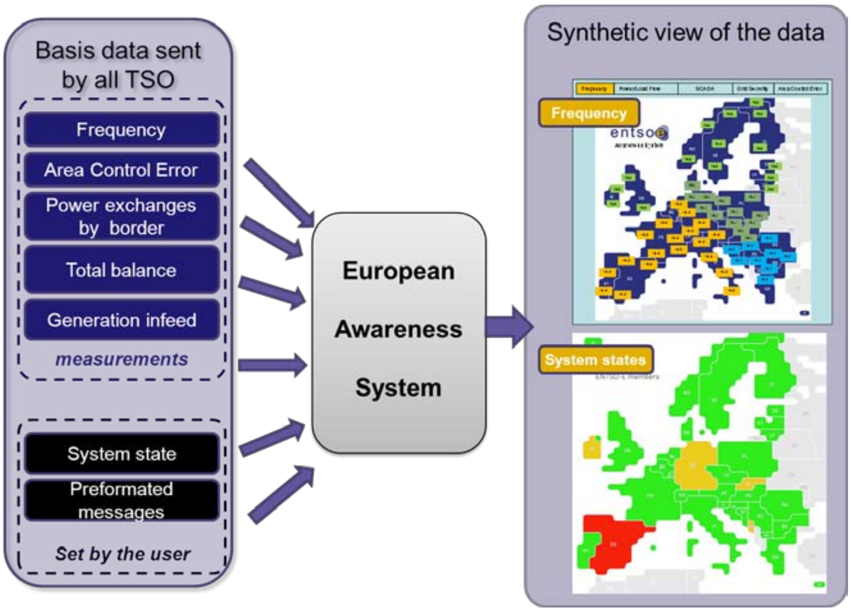

Figure 24: European Awareness System (EAS) (Source: ENTSO-E)

Data available in the European Awareness System (EAS)

In the following, the parameters available in the EAS are presented. For each of those parameters, the indications aimed to achieve by the EAS are briefly summarised.

- *Frequency measurement on different locations in the Synchronous Area:*
  - Indication for actual overall Active Power balances in different Synchronous Areas / regions;
  - Indication for synchronism in the transmission grid regions;
  - Indication of possible existence of different asynchronous grid sections in one region (e.g. by identification of different frequencies in case of network split in the Transmission System).

- *Area Control Error*
  - Indication of sudden or persisting Active Power imbalances during normal operation and after incidents;
  - Indication if and for how long certain values:
    - Have not changed their sign;
    - Are in a certain range or exceed a certain limit;
    - Have a certain mean value for the last 15 minutes or fulfill other numerical conditions.

- *Scheduled and measured power exchanges:*
  - Indication of sudden or persisting Active Power imbalances during normal operation and after incidents;
  - Indication if and for how long certain values:
    - Have not changed their sign;
    - Are in a certain range or exceed a certain limit;
    - Have a certain mean value for the last 15 minutes or fulfill other numerical conditions.

- *Generation in feed*
  - o Provide a common geographical ENTSO-E wide real-time overview of the actual generation in-feed in the ENTSO-E area;
  - o The view will especially depict information about amount of renewable generated energy strongly dependable on weather conditions, especially in case of unexpected weather changes, what has direct influence on Transmission System operation.

Manual indications from the operator

System States

- Detailed definition of each System State to be set in the usage procedure of the EAS is defined in Article 8 of the OS NC.

8.5.3 Remedial Actions

Remedial Actions are any measures applied by a TSO in order to maintain Operational Security. In particular, Remedial Actions serve to fulfil the (N-1)-Criterion and to maintain Operational Security Limits. They can be categorized to pre-fault (i.e. preventive) or post-fault (i.e. corrective or curative) Remedial Actions within one TSO area or between interconnected TSOs.

Preventive Remedial Actions are used normally in Operational Planning or Scheduling stage to maintain system in Normal State in the coming operational situation and to prevent propagation of disturbance outside the TSO´s Responsibility Area. Preventive Remedial Actions may include, but are not limited to the following:

- re-dispatching or counter trade actions;
- topology changes in the network;
- adjusting flows by phase shifters and other flow controlling devices;
- manual switching of reactive power devices (tap-changers, reactors, capacitor banks, SVC, etc.) or changing the set-point level of their controllers;
- request (or control if available) additional voltage/reactive support from power plants;
- enabling available System Protection Schemes.

Corrective Remedial Actions are actions, which will be implemented immediately or relatively soon after an occurrence of a Contingency, which leads to a state differing from Normal State. With the corrective Remedial Action the system will be returned back to Normal State. Corrective Remedial Actions may include, but are not limited to the following:

- re-dispatching or counter trade actions including activation of TSO reserves;
- control of reactive power devices (tap-changers, reactors, capacitor banks, SVC, etc.);
- activation of additional voltage/reactive support from power plants;
- emergency power control of HVDC links of other power controlling devices;
- System Protection Schemes actions e.g. change of network topology, trip of production or trip load depending on protection specification.

8.5.4 System Defence Plan in case of Emergency State

The Operational Security implies the capability to assure normal functioning of the Transmission System, to limit the duration and number of disturbances, to prevent large disturbances, and to limit the consequences of a large disturbance in case it occurs with also the view to ease the Restoration of the Transmission System after such a large disturbance (Blackout) back to normal operation.

The System Defense Plan is related to Emergency State with the associated information process and Remedial Actions and consists of a set of coordinated measures, which aim to keep the integrity of the Transmission System in case of system conditions resulting from extreme disturbances.
The procedures and related actions under the survey of the control centers and the needed coordination between TSOs in real-time operation will be part of the future NC ER.

Measures of the System Defence Plan

Remedial Actions are classified by TSOs under their individual approach in accordance with their grid codes. TSOs consider in all cases an escalation of measures - post event/curative and preventive.
In the framework of the OS NC, measures of the System Defence Plan can be understood as emergency Remedial Actions.

In the following, examples of applicable measures of the System Defence Plan for load, Frequency, power flows and Voltage constraints are presented. It should be noted that all those measures are not always available, depending on the national legal and regulatory frameworks.

Load/Frequency constraints

- Start or stop Power Generation Modules;
- Start or stop pump storage units;
- Increase or decrease (automatically or on request) production level of Power Generating Modules or pumps;
- Adapt active LFC control mode;
- Use of manual or automatic load shedding;
- Changes of Voltage regulator set points on transformers at distribution level.

Power Flow Constraints

- Cancellation of maintenance (grid elements urgently backed to operational service);
- Changes in the pattern of reactive power flow within the own TSO grid or with the support of neighboring TSOs;
- Automatic unit trip triggered by line outage;
- Counter-trading with neighboring Responsibility Areas;
- Intervention in scheduling;
- Freezing of scheduled exchanges;
- Schedule of exchange reduction;
- Reduction of interconnection capacities;
- Pump trip;
- Manual load shedding of interruptible Demand Facilities;
- Automatic shedding of interruptible Demand facilities triggered by line outages;
- Manual load shedding of domestic Demand Facilities;
- Automatic shedding of Demand Facilities.

Voltage Constraints

- Requesting maximum or minimum values of generation for Active and Reactive Power;
- Reduction of Active Power in favor of additional Reactive Power output;
- Preventive start of units with provision of additional Reactive Power;
- Stop of Voltage and Reactive Power optimization;
- Stop of maintenance, switching-on of all elements previously in maintenance;
- Limitation of Intraday trade (influence on transits);
- Blocking of on load tap changers of transformer.

8.6 Dynamic Stability Assessment (DSA)

Depending on the structure of the Transmission System, there might be different phenomena endangering Operational Security during (N-1)-Contingencies. In Transmission Systems with relatively long transmission paths (lines), dynamic Voltage Stability or Rotor Angle Stability may require limiting the power flows in order to secure the system against (N-1)-Contingencies. This is the case for example in the Nordic Synchronous Area, where many of the longest lines are series compensated, but the thermal Operational Security Limits have not yet been reached before Dynamic Stability Operational Security Limits.

In more meshed Transmission Systems with relatively short lines like e.g. in the Synchronous Area of Continental Europe the thermal Operational Security Limits are in most cases prevailing over the Dynamic Stability ones, but there might be e.g. dynamic Voltage Stability limitations after contingencies, if tap-changers of the transformers connecting Transmission System with the Distribution Network are not blocked.

Frequency Stability can become a problem in a Synchronous Area loses exceptionally large amount of generation or demand e.g. in situation where the interconnected Transmission Systems break to separate subsystems.

DSA shall be made in order to identify the Stability Limits and potential stability problems. DSA studies shall be coordinated between the TSOs within each Synchronous Area and shall be done for the whole or relevant parts of the Synchronous Area. These studies can be offline.

8.6.1 Motivation of the DSA in the context of the OS NC

The tendency to increase the loading of transmission lines and to facilitate electrical energy trades across wide areas reduces the natural stability margin of the Transmission System. If the consequences of the (N-1)-Contingency on stability are expected to be more severe than on the thermal limits, an online DSA becomes mandatory. In lightly meshed systems, the stability of the system might be the limiting factor.

Measures like Transmission Line Monitoring or High Temperature Low Sag (HTLS) lines increase the thermal limits, but not the Stability Limits.

Further use of the existing network stresses the load ability of the Transmission System, constrained by static and dynamic limits, and requires a more optimum calculation these limits. This fact might require commissioning and utilization of the online DSA tools.

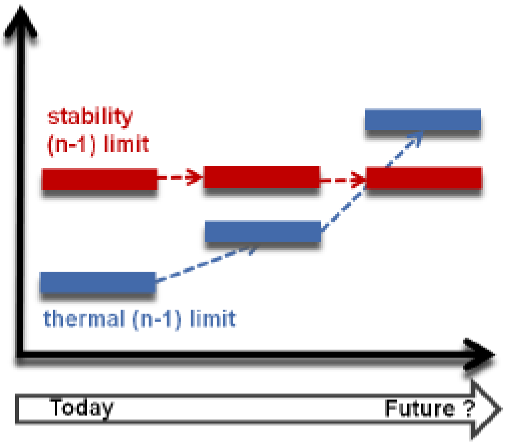

Figure 25: Operational constraints by thermal resp. Stability Limits (source: [13])

8.6.2 The relevance of inertia in the coming operational future scenario

In the Transmission Systems most of the power is generated by synchronous generators, where their inertia – "rotating masses" – provide for system stabilizing in case of disturbances such as loss of generation. This is an essential feature in order to maintain Frequency Stability.

In the Transmission Systems where the synchronous generators are gradually replaced by other power generation technologies which do not possess large and heavy rotating masses, the system sensibility to a sudden disturbance and e.g. loss of generation is higher and the danger of jeopardizing system stability greater.

The issue of inertia is not a new one per se, but its significance has been raised massively with the growing installed capacity of wind and solar generation. Even though the recent wind power generators do have a capability of synchronous operation with variable rotor speed, due to the light-weight rotor construction (with permanent magnets) the rotating masses remain relatively low and lack of inertia persists.

The ways to ensure sufficient inertia in the future operational scenario in Europe vary: from "*must-run*" synchronous generators, over Active Power Frequency Response (like e.g. "*Delta Control*" in Danish wind parks) to the provision of "*synthetic*" inertia by coordinated response of many wind power converters to the system disturbance. Whereas this later method is a promising one in terms of theoretical gain (by coordinated response of many thousands of converters the system stability could be retained, if such a response is fast enough) the arising new challenges are possible inter-area oscillation due to communicating energy storages throughout the systems; this might be in turn soluble by power system stabilisers, but the whole approach has not yet been analysed for feasibility and practical applicability in Europe.

This is the reason why the issue of inertia – with all its crucial importance for the Operational Security of the future – has been dealt with in the OS NC in three steps (Article 15(8)): identification of any possible need for the definition of required minimum inertia in the interconnected Transmission Systems; based on the identified needs, development of methodology for the deployment of minimum inertia; definition and practical deployment of the minimum inertia according to the developed methodology.

8.7 SYSTEM PROTECTION

8.7.1 System Protection Functions. Difference to System Defence Plan. Fault clearing times.

System protection is an automatic protection function, which is designed to make predefined trip actions in most of the cases by using telecommunication links. System protection is used to maintain Operational Security after triggering faults. System protection functions shall be designed to keep system in Normal or Alert State after the Faults, for which they have been deployed. In that respect system protection and System Defence Plans are comparable functions, but System Defence Plans are not designed to be activated before being in Emergency State e.g. by using load shedding functions.

Short-Fault clearing time is very critical in order to maintain Transmission System stability. During short-circuit Faults the Voltage in the Transmission System will drop in wide areas and resulted low Voltage at Connection Points of Power Generating Modules will cause the electrical output of Power Generating Module to decrease suddenly. At that moment, full mechanical power in the turbine will still speed up the Power Generating Module, which may after some time cause instability to the Power Generating Facility and finally loss of synchronism with the Transmission System. In order to avoid trips of Power Generating Facility during Faults, the Fault clearing time shall not be longer than the Fault Ride Through time of the large units. The longest Fault clearing time will occur during breaker failure, when the breaker failure protection will take over the Fault clearing, but there is always a time delay in the protection system, which will extend the normal Fault clearing time.

8.8 SHORT-CIRCUIT CURRENT MANAGEMENT

8.8.1 The three parts of the short-circuit current

The short-circuit current is usually divided into three parts:

- *Sub transient* current: this is the value of the current that will appear at the beginning of the Fault and during the first cycles (during the first 100 ms after the fault);
- T*ransient* current: this is the value of the current that will appear after a few cycles (from 100 ms till 500 ms);
- *Permanent* current: this is the value of the current that will appear after stabilisation of these sub transient and transient phenomena.

8.8.2 The need of harmonisation in the framework of short-circuit current calculation and its related data exchange

While dealing with the short-circuit behaviour in a meshed system with a lot of rotating masses, it has to be considered that the short-circuit current will evolve in time.

On the one hand, when looking at the capability of Transmission System elements and equipment to withstand short-circuit or capability of protection to eliminate short circuit in EHV meshed system, TSOs generally refer to the sub transient current. Therefore, the data to be used should allow representing this current. Nevertheless, in some Transmission Systems, the transient current is still used as reference.

On the other hand, when exchanging data allowing computing short circuit current, different ways of doing this can be considered:

- Exchange of the detailed parameters of the equipment: impedances or equivalent impedances of lines (Zline), transformers (Ztfo), rotating machines (Z"d, Z'd, Zd), option which provides the highest flexibility.

- Exchange of the short circuit in feed at each bus bar, what can depend on the Topology.

Therefore, if there are no common principles which are clearly defined and followed, the risk of mixing up different components by using at the same time e.g. data based on sub transient impedances and data based on transient impedances, or data based on e.g. a fixed topology with detailed equipment parameters arises, what would lead to imprecise calculation of short-circuit currents.

Therefore, short-circuit calculation and the related data exchange needs harmonisation and a common level of understanding, to ensure that the results are representative.

8.9 TSO Co-ordination for Operational Purpose

During the last 10 years the operational context for electricity transmission in Europe has significantly changed and the pace and degree of this change is set to increase in the next ten years. The drivers of this change are increased levels of interconnection, increased levels of intermittent renewable generation, increased levels of cross-border trading and increased use of controllable transmission devices such as Phase Shifting Transformers. There is now an ever larger degree of interdependency between TSOs for Operational Security and this leads to a fundament need for ever closer co-ordination between TSOs. Good examples of this requirement for TSO co-ordination set out in the OS NC are the establishment of Regional Security Co-ordination Initiatives (RSCI) such as Coreso and TSC and the ability of TSOs to share information with the RSCI, the use of a Common Grid Model,[9] the EAS[10] and common definition and understanding of the System States and incident classification. More established requirements for TSO co-ordination are also covered by the OS NC such as load-frequency control across all the TSOs in a Synchronous Area and the co-ordination of protection settings across Interconnectors.

8.9.1 The role of Regional Security Cooperation Initiatives (RSCIs)

The aim of RSCIs is to help European TSOs to enhance the Operational Security and in general level of security of supply by bringing them a wide view of electricity flows complementary to their individual view. As a new step for an enhancement of the European security of electricity supply, European TSOs have set up RSCIs, which provide TSOs with a wide vision of electricity flows complementary to their individual vision. In this framework, projects such as Coreso and TSC should be mentioned:

- *Coreso*, the RSCI set by 5 TSOs in Europe (50Hertz, Elia, National Grid, RTE and Terna), completes its operational coordination services with a service of support to TSOs in case of potential large disturbance: the main services provided by Coreso consist in Day-ahead and Intraday Operational Security Analyses and Remedial Actions coordination management.

[9] See Section 8.1for further details,

[10] See Section 8.5.2 for further details.

Figure 26: TSOs participating at the RSCI Coreso (Source: [16])

- The *TSC* initiative comprises eleven TSOs in Europe (Amprion, PSE, CEPS, Swissgrid, TransnetBW, TenneT BV, TenneT GmbH, 50Hertz, APG, ELES and HEP OPS) that have implemented a shared IT-platform for exchanging data and assessing mutual security needs, with the goal of developing coordinated procedures and multilateral Remedial Actions and thus achieve a high Operational Security standard for the European interconnected Transmission Systems. In this context, following activities should be mentioned:
  - Exchange of experiences on inter-TSO Remedial Actions using state-of-the-art data flows;
  - Share knowledge and expertise gleaned through system monitoring;
  - Development and implementation of new multilateral procedures and Remedial Actions, and thus maintain high system security levels;
  - Development of proposals for improving the functionality of the new, shared IT-platform.

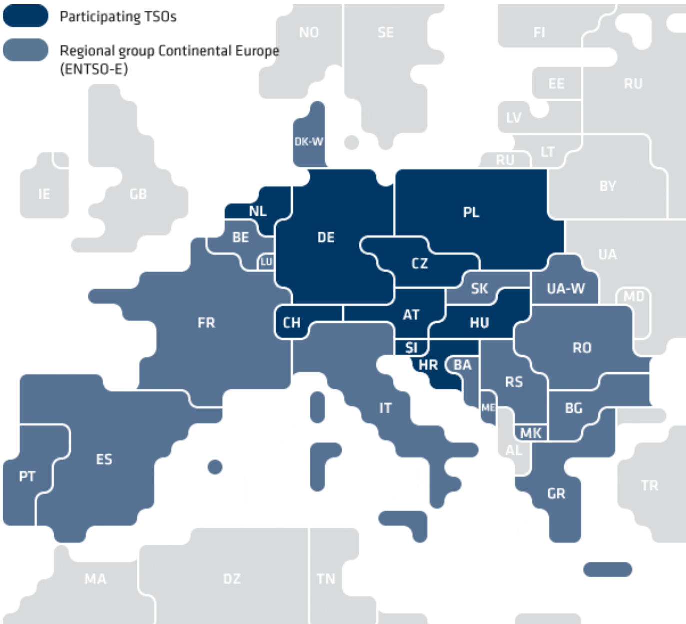

Figure 27: TSOs participating at the RSCI TSC (Source: [15])

9 ADDED VALUES OF THE OS NC

While deciding on the objectives and major topics to be included in the OS NC, a constant screening process with the objectives defined by the SO FG has been carried out. The analytic approach taken for drafting the OS NC resulted in the current Network Code structure. Reaching this point and by recognising that the added values of the Network Code are inherently linked to its provisions, the following benefits are to be expected by implementing the requirements defined in the OS NC:

Added value	Related article of the OS NC
Apply the same Operational Security principles for System Operation among European TSOs.	- The whole Network Code
Improve the interconnected system safety and security.	- Articles 8 to 15
Optimise the detection of constraints in the Transmission System by enforcing coordination between TSOs and between TSOs, DSOs and Significant Grid Users.	- Articles 8, 13 - Chapter 3: Data Exchange
Reduce the risk of system-wide disturbances and the number of critical incidents, avoiding major incidents and limiting their consequences if they occur.	- Articles 8 to 15
Enhance uniform treatment of Significant Grid Users across Europe.	- Articles 8, 10, 13, 15 - Chapter 3: Data Exchange
Enable the integration of RES, maximising the output from intermittent generation whilst maintaining security of the Transmission System operation in an increasingly dynamic and changing future.	- Article 13 - Chapter 3: Data Exchange
Increase the potential for greater volumes of cross-border exchanges, whilst ensuring existing levels of reliability are not reduced alongside ever increasing levels of RES intermittent output.	- Article 13 - Chapter 3: Data Exchange
Prepare the Transmission System for integrating distributed generation.	- Article 13 - Chapter 3: Data Exchange
Make efficient and effective use of Smart Grid applications.	- Chapter 3: Data Exchange
Provide the adequate conditions for exploiting the demand-side potential and integrating advanced power electronic systems.	- Article 34 - Chapter 3: Data Exchange
Improve conditions for data collection, handling and exchange.	- Article 6 - Chapter 3: Data Exchange
Provide a framework for the compatibility of tools.	- Chapter 3: Data Exchange,

	but mainly in NC OPS
Enhance the coordination of the tests between involved parties in order to ensure the correct functioning of all elements connected to the Transmission System.	- Article 34
Provide a common framework for the training of System Operation Employees.	- Article 31

Table 4: Added values with related articles in OS NC

Whereas the benefits mentioned above cover the improvement of Operational Security and therefore the ultimate goal of preventing Blackouts, concrete numbers depend strongly on the underlying disturbance scenario and the region. Moreover, the probability of such events must be taken into account.

It is evident that a quantitative analysis of the added values of implementing the requirements of the OS NC would require an assessment, of the implementation and additional operation costs, to be conducted in cooperation by the TSOs, DSOs and Significant Grid Users,

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

10 SUMMARY OF CHANGES TO THE DRAFT NETWORK CODE

10.1 INTRODUCTION

This section of the document provides a summary of the comments received as a result of publication, via workshops and in discussion with stakeholders and regulatory authorities. It is intended to provide interested parties with an explanation of the most significant changes which have been made to the Network Code. More detailed explanations are provided in Annex IV of this document.

10.2 SUMMARY OF COMMENTS

In total just over 1200 individual comments on the OS NC were received within the public consultation. Those comments varied and, as shown in the diagram below, covering most parts of the Network Code. Most of the comments were mainly focused on definitions, consistency with NC RfG, System States and data exchange.

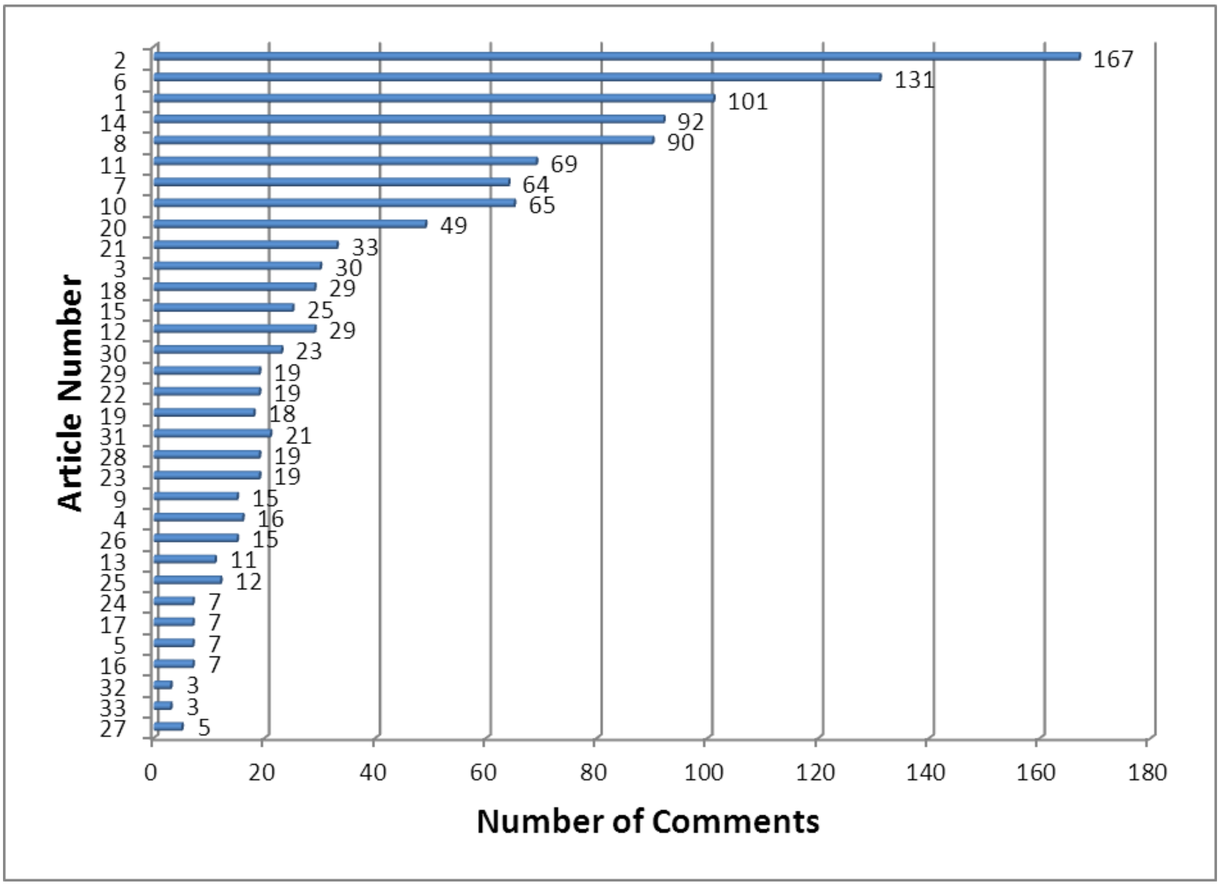

Figure 28: Analysis of articles by number of comments received (Source: ENTSO-E)

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

As the summaries of public consultation outcome demonstrate, each comment was considered and assessed, and decisions were taken about whether there was a need to update the OS NC. Themes which occurred frequently in responses were:

- There needs for more transparency and consultation;
- Asking for more NRAs involvement;
- Asking for cost recovery issues for all stakeholders;
- Provision to take into account human and nuclear safety;
- More clarification on information exchange;
- More Remedial Actions and involvement of DSOs;
- Consistency with NC RfG and DCC concerning disconnection of Grid Users at specified Frequencies and Voltages, and with other System Operation NCs;
- There is a new definition of Significant Grid Users than that in NC RfG and DCC and requirements to existing Power Generating Facilities;
- On technical issues related to Operational Security, e.g. ramping, reactive power, non-compliance with (N-1)-Criterion, clearance time, Connection Point, minimum inertia;
- TSOs decision process details; Cost-benefit analysis for significant changes;

This list is by no means exhaustive and does not reflect the views of all respondents. However, these are points where we ENTSO-E was particularly encouraged to focus on, during the stakeholder workshops which were held during and immediately after the public consultation.

10.3 STRUCTURAL CHANGES IN LIGHT OF COMMENTS

Many of the comments received, focused on the need to increase clarity and avoid duplication within the OS NC. The following structural changes were made in the final OS NC version:

- Moving the Article 14 to the Chapter 5 Compliance as a new Article 34 Common testing and incident analysis responsibilities;
- New articles on cost recovery, incident analysis and publication, and relevant information exchange for analysis of quality of the grid connection point;
- Clarification was made concerning TSO and DSO providing information for Significant Grid User investigation;
- Removal of articles already covered by the NC RfG and the DCC.

10.4 ENHANCING CONSISTENCY

Particular focus has been given to the following:

- Using Voltage limits defined in NC RfG and DCC in system operation and maintaining consistency with load-frequency control in NC LFCR;
- Involvement of NRAs is coherent through all System Operation Network Codes. Several parties pointed out that these powers are set out in law (Directive 2009/72/EC, Articles 36 and 37). Given this concern we have updated the Article 3 and added Article 4 in the first section of the Network Code. This refers to the powers of regulators from Directive 2009/72/EC and from the third energy package. It also presents a consistent set of timings and makes it clear where regulatory authorities have a role;

- Significant Grid Users are consistent with the significant users defined by NC RfG and DCC and includes criteria of significance for existing users;
- Description of CGM is consistent with requirements of NC CACM and NC OPS;
- Concerning transparency, a number of comments are asking us to make the TSOs decision process more open and clear. All information required by the new European Transparency Guidelines will be published;
- Definitions are reviewed. Consistency across Network Codes being developed over a period of years is a considerable challenge. Nevertheless, we recognize the importance of consistency and have taken steps to improve definitions, to align them with those used in other Network Codes (or already existing legislation), and to take steps to ensure the definitions in OS NC can be used in future Network Codes.

10.5 Most Significant Content Related Changes of the OS NC

The points presented in section 10.4 have improved the clarity; though have not introduced substantial changes relative to the draft Network Code. Those key changes are summarized below:

Regulatory Aspects – provision harmonized among System Operation Network Codes and with all other Network Codes;

Frequency Control Management and Voltage Control and Reactive Power Management – adding Voltage operational limits and ensuring consistency with the NC LFCR;

Data Exchange – Reviewed all articles to optimize the data exchange, avoiding duplication of data provision and to be consistent with the other NCs.

10.6 Conclusion

The changes discussed in this section have improved the overall consistency and readability of the OS NC, as well as addressing a significant number of stakeholder concerns, have improved the overall quality and the extent to which the OS NC complies with the SO FG.

11 NEXT STEPS

The main steps of the Network Code Development Process with a special focus on those which will between the submission of the OS NC to ACER and its application are summarized.

Submission to ACER

Article 6 of the Regulation (EC) No 714/2009 defines a clear Network Code Development Process.

The process begins with the set up by the Commission of an annual list of priorities amongst the 12 areas where Article 8(2) of Regulation (EC) No 714/2009 foresees the need for a Network Code. The annual priority list must be adopted after consultation with the relevant stakeholders.

Once a priority list is established, the Commission shall request ACER to develop and submit to it a non-binding framework guideline. The Framework Guidelines are intended to set clear and objective principles with which the Network Code should be in line.

The development of a Framework Guideline is followed by a request from the Commission for ENTSO-E to develop a Network Code within a twelve month period. The Network Code to be developed by ENTSO-E within that period shall be subject to an extensive consultation, taking place at an early stage in an open and transparent manner.

At the end of these 12 months ENTSO-E delivers a Network Code and set of explanatory documents to ACER for its assessment.

The ACER opinion

ACER has three months to assess the draft prepared by ENTSO-E and deliver a reasoned opinion. In doing so, ACER may decide to seek the views of the relevant stakeholders.

ACER can decide to recommend to the Commission that it adopts the Network Code if it is satisfied that it meets the requirements of the SO FG or can provide a negative opinion; effectively meaning the Network Code is returned to ENTSO-E.

The Comitology Procedure

The Network Code prepared by ENTSO-E shall only become binding if, after being recommended to the Commission by ACER, it is adopted via the Comitology procedure.

The Comitology process will be led by the Commission who will present the draft text to representatives of Member States organized in so-called “committee”. The Comitology procedure used for the Network Codes (called regulatory procedure with scrutiny) grants the European Parliament and the Council important powers of control and oversight over the measure adopted by the committee.

For that reason, it is unclear how much time the process can take in practice. The working assumption based on the previous experiences with comparable Comitologies is that it will take about 12 months from the issuing of the ACER opinion (if positive) to the conclusion of the Comitology process.

Meeting the requirements of the OS NC is a significant challenge for ENTSO-E. During the period in which the Network Code is being considered by ACER and the Commission, ENTSO-E will continue work to prepare for the delivery of the requirements of the Network Code. Some of these requirements are particularly challenging and beginning work in the near term is necessary to delivering them on time.

Entry into Force

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

The OS NC will enter into force 20 days after its publication. All provisions of the Network Code shall apply as from the date to be jointly agreed with EC, ACER and ENTSO-E.

Because of uncertainties about the ACER opinion, the timings of the Comitology process, the time needed to deliver parts of the Network Code (the timings are “no later than”) and the time needed to approve parts of the Network Code (which could include a referral to ACER), it is not possible to specify exactly when each requirement of the OS NC will exactly apply. A continued close working relationship between ENTSO-E, ACER, NRAs and the Commission is necessary for ensuring the implementation of the OS NC as soon as possible.

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

12 REFERENCES

[1] "Framework Guidelines on System Operation" (SO FG), ACER December 2011.

[2] "Initial Impact Assessment", ACER June 2011.

[3] "Necessary data and information for safeguarding the operational system security by the German Transmission System Operators according to Section 12(4) of the EnWG", August 2011.

[4] "Guidelines of Good Practice for Operational Security", ERGEG November 2008.

[6] "Developing Balancing Systems to Facilitate the Achievement of Renewable Energy Goals, Position Paper Prepared by WG Renewables and WG Ancillary Services", ENTSO-E November 2011.

[7] "Deterministic frequency deviations – root causes and proposals for potential solutions", a joint EURELECTRIC – ENTSO-E response paper.

[8] "Incident Classification Scale Guidelines", ENTSO-E.

[9] "Network Code "Requirements for Generators" in view of the future European electricity system and the Third Package network codes", ENTSO-E.

[10] "Operation Handbook of the Regional Group Continental Europe", ENTSO-E.

[11] "Transforming Power Systems", Philipp Strauss, 5th International Conference on Integration of renewable Energy and Distributed Energy Reserves, Berlin 2012.

[12] "All Island TSO Facilitation of Renewables Studies", Eirgrid and SONI.

[13] "Dynamic Security Assessment", ENTSO-E Regional Group Continental Europe Subgroup "System Protection and Dynamics".

[14] "Network Code "Requirements for Generators" in view of the future European electricity system and the Third Package network codes", ENTSO-E.

[15] www.tso-security-cooperation.net

[16] www.coreso.eu

[17] http://www.conference-on-integration-2012.com/conference-presentations-materials/speaker-presentations.htm

[18] „Guide to the Single Electricity Market", Single Electricity Market Operator (SEMO).

[19] „Ensuring a Secure, Reliable and Efficient Power System in a Changing Environment" EirGrid/SONI.

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

ANNEX I – PURPOSE OF THE OPERATIONAL SECURITY NETWORK CODE

OVERVIEW

This Annex provides a high level overview of the rationale for including particular articles in this Network Code. It is complemented by the more detailed assessment found in Annex IV - Operational Security Network Code

This Network Code embodies the core aspects of Operational Security and serves as an "umbrella" code covering high level principles, procedures and relations overarching the more detailed issues which will be dealt with in other dedicated System Operation Network Codes: Operational Planning & Scheduling, Load-Frequency Control & Reserves, Emergency and Restoration. This Network Code contains also provisions for training and certification of the System Operator Employees, addressing the related area from the SO FG. If deemed necessary and decided so by the European Commission, ACER and ENTSO-E, a dedicated network code covering the aspects of training and certification may be developed at a later stage.

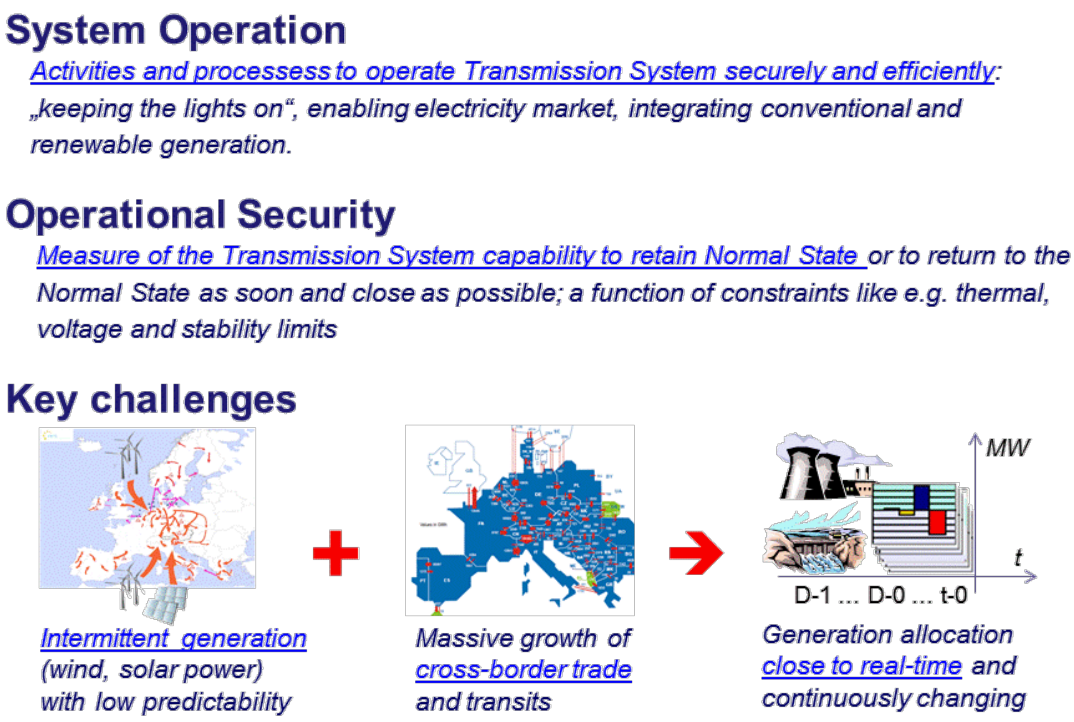

Figure 29: Key challenges in the framework of System Operation (Source: ENTSO-E)

The key challenges of System Operation are shown in the Figure 29 above. The structural interfaces and dependencies are shown in the Figure 30 below.

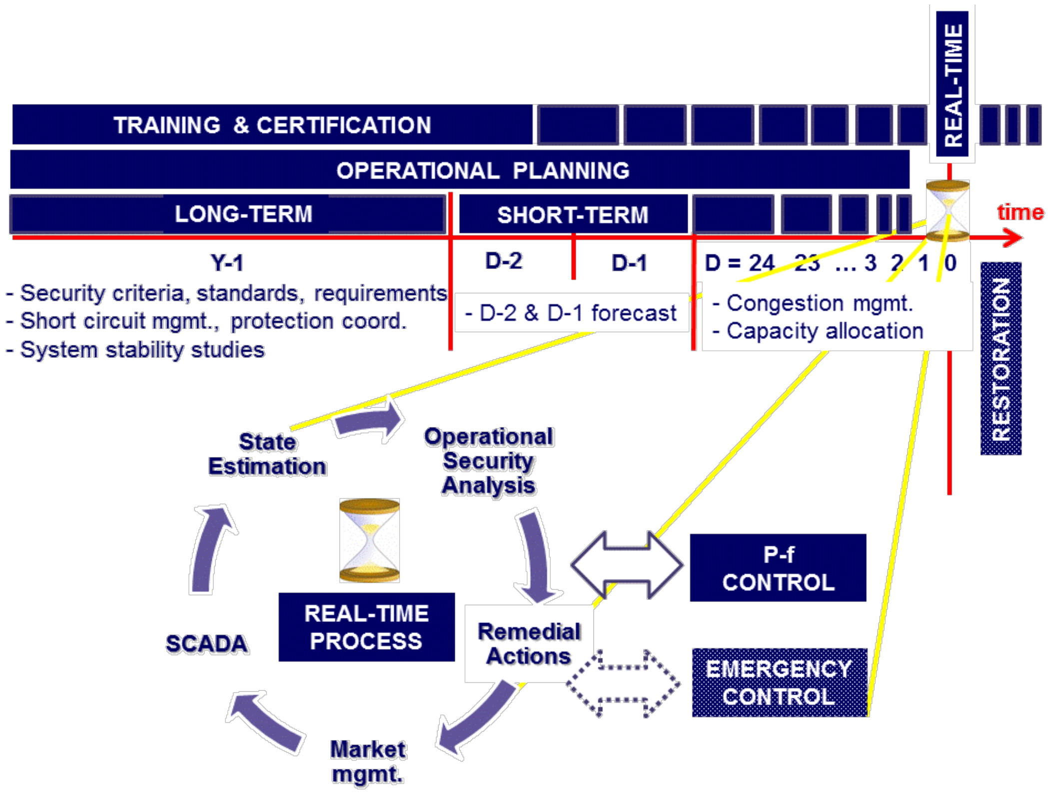

Figure 30: Structural interfaces and dependencies in System Operation (Source: ENTSO-E)

It is important to emphasize that the Operational Security Network Code as an “umbrella” Code forms an interrelated whole with the other System Operation Network Codes: Operational Planning and Scheduling NC, Load Frequency Control and Reserves NC and Emergency and Restoration NC which will be developed at a later stage. Defining the key provisions for all areas of System Operation, this Network Code has a number of interfaces and interdependencies with the Network Codes from other areas:

- Requirements for Grid Connection Applicable to All Generators NC RfG;
- Demand Connection Network Code DCC;
- Capacity Allocation and Congestion Management Network Code;
- Electricity Balancing Markets Integration Network Code, to be developed at a later stage.

Due to the large number and complexity of interdependencies, indicating and justifying the related cross-references in the firm and specific, but at the same time flexible and future-proof manner (especially bearing in mind the on-going development of all the Network Codes in parallel) is of high importance for the Operational Security Network Code. In the baseline argumentation presented in this Annex I, the references to other Network Codes including a summary of cross-references to other Network Codes, reference to the NRA involvement and a justification are presented for each article where they appear.

EU-wide harmonization with a focus on Operational Security and achieving a strong platform for the more detailed System Operation topics is a high priority of this Network Code. Because of the large number, width and fundamental significance of the System Operation aspects in general and Operational Security issues in particular, a number of methodologies and solutions are introduced in such a way that their development and implementation requires involvement of National Regulatory Authorities at a later stage, after entering into force of this Network Code. This is particularly important for the sake of stable and sustainable system operation and the Operational Security framework which must be able to meet the current and the future needs.

This Network Code is a result of intensive cooperation and coordination with all stakeholders of the European Internal Electricity Market and the interconnected Transmission Systems of Europe, with the representatives of the European Commission and ACER who are the first recipients and evaluators of this Network Code. While ENTSO-E had to take into account many different interests and views, which introduced thus a number of constructive and helpful compromise solutions where necessary, a number of specific System Operation issues had to be defined in a strictly specific and strongly determined way.

ENTSO-E has invested all necessary care and effort to ensure justification for each important provision of this Network Code both in the OS NC itself where it was legally possible and in the OS NC Supporting Document where more detailed explanations and examples were required.

Article Number	Article Name	Purpose of & need for the article
	CHAPTER 1 GENERAL PROVISIONS	
1	SUBJECT MATTER & SCOPE	Explain the boundaries of this Network Code summarize its key objectives and clarify those affected by it. Define precisely the concept of Significant Grid User for this Network Code and introduce the necessary cross-references with all other affected Network Codes in order to have fully consistent approach to this key concept. <u>Cross-references with other ENTSO-E Network Codes:</u> • NC RfG and DCC for common approach to the definition of Significant Grid Users in this Network Code, applicable to the existing and new ones; • NC LFCR for addressing Providers of Active Power Reserve in the scope of Significant Grid Users; • Whereas no dedicated code for new applications has been developed or planned yet, Article 1 introduces the provision ensuring that no actions in fulfilment of this Network Code shall hinder the implementation of new applications; this is particularly important in relation to the intended development and implementation in the scope of ENTSO-E R&D plan; <u>Required NRA approval</u>: none <u>Justification</u> As in all other Network Codes, the subject matter and scope of this System Operation Code are defined in terms target audience and Significant Grid Users, dependencies with other Network Codes and goals are defined in this Article.
2	DEFINITIONS	Explain the terms used in this Network Code, while ensuring the same terms are used in existing EU law and other ENTSO-E Network Codes. The definitions have been introduced according to the following principle (i) first use definitions from the EU Directives and Regulations if existing; (ii) second use existing definitions from the other ENTSO-E Network Codes the development of which is in a more advanced phase than this Network Code; (iii) only if no definitions from (i) and (ii) can be applied introduce a new definition in this Network Code. <u>Cross-references with other ENTSO-E Network Codes</u>: none (but using the

		definitions from all other ENTSO-E Network Codes) Required NRA approval: none Justification The definitions applicable specifically in this Network Code are introduced in this Article 2; the definitions from the Directive, Regulation and those which are already introduced in other Network Codes are used as they are, except for the very few exemptions which are redefined for the purpose of the OS NC:
3 and 4	REGULATORY ASPECTS AND APPROVALS	Address the regulatory aspects of relevance for all Network Codes in the area of system operation in a common and coherent way; provide a comprehensive overview with detailed list of all articles in this Network Code, which contain provisions for the specific terms, conditions and methodologies to be developed after the entry into force of this Network Code, requiring thus approval by NRA or other relevant national authority. Cross-references with other ENTSO-E Network Codes: referring to the capabilities required in the NC RfG and DCC for the Power Generating Facilities, Demand Facilities an HVDC links and the conditions for those which are not a subject of relevant provisions – binding them to those technical requirements applying to them pursuant to the Member State national legislation. Required NRA approval: the articles in this Network Code which call for NRA approval are listed. Justification The issues listed for NRA approval are specified in Articles 4(2) and 4(3).Moreover, a number of issues where information to the NRA is provided in the scope of this Network Code, are listed in the supporting document for the sake of completeness and meeting the needs and wishes of the stakeholders expressed during the workshops and Public Consultation - those issues do not call for an explicit provision either, because the NRA have access and can obtain any necessary information from the regulated TSOs within the scope of their regular activity and the defined EU and Member States' national legal framework.
5	RECOVERY OF COSTS	Define provisions for recovery of costs related to the obligations from this Network Code. Cross-references with other ENTSO-E Network Codes: none Required NRA approval: methodology for recovering the costs of tests of compliance with this Network Code pursuant to Article 5(4). Justification The issues related to the recovery of costs in relation with this Network Code are introduced in line with the equivalent provisions of the other Network Codes.
6	CONFIDENTIALITY OBLIGATIONS	Ensuring that obligations for confidentiality are specified in a clear and unique way, applicable to all TSOs and respective other entities, most notable RCSIs Cross-references with other ENTSO-E Network Codes: none Required NRA approval: none Justification The provisions for confidentiality are important for TSOs and other entities like

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

		e.g. .
7	AGREEMENT WITH TSOS NOT BOUND BY THIS NETWORK CODE	Clauses introducing the obligation for Agreement with TSOs not bound by this Network Code shall be implemented to guarantee that they also cooperate to fulfil the requirements under this Network Code. Required NRA approval: none
	CHAPTER 2 OPERATIONAL SECURITY REQUIREMENTS	
8	SYSTEM STATES	Define precisely the key concepts and criteria for the System States as the main framework for evaluation, assessment and information, as well as the application of all relevant Operational Security Analysis applications, by the TSOs and where applicable reflecting on the affected DSOs and Significant Grid Users, in order to maintain Operational Security. The Article 8 relates closely to the Article 13 on Contingency Analysis and Handling especially in terms of common criteria for the Remedial Actions and specific issues in relation to frequency, voltage and other operational parameters. Cross-references with other ENTSO-E Network Codes: NC LFCR, NC RfG, DCC, OP&S, NC CACM Required NRA approval: none Justification In Continental Europe Policy 5 of the Operation Handbook already defines criteria to classify System States (Normal, Alert, Emergency and Blackout); the Nordic Grid code also defines System States, while adding the Restoration state. With this Network Code it was chosen to enlarge the definition to the scope of all European Transmission Systems, in order to share the same criteria to estimate the System State. To ensure a common classification of the System States across the Synchronous Area and between the Synchronous Areas is a pre-requisite for communications to be managed in a coordinated manner between the TSOs. Sharing a common appreciation of the System States is necessary for efficient coordination. This Network Code also defines the obligations of each TSO in terms of communication on the status of its system between TSOs and among different Significant Grid Users, as this was one of the lessons learned during the large disturbances of the past (e.g. system split on 04th November 2006). A common awareness system like EAS will allow all TSOs to get a view in real-time on the System States all over Europe, and with a common understanding of what it means for all TSOs.
9	FREQUENCY CONTROL MANAGEMENT	Provide (within the scope of the OS NC as the umbrella code for all other Network Codes in the area of System Operation) the most important key provisions for the detailed requirements and provisions on frequency control management in NC LFCR; a special emphasis is put to the interaction and coherence with other Network Codes, to the necessary management of reserves (for load-frequency control) and to the frequency quality; introduce the obligation for the TSOs to contribute to the Load-Frequency Control Structure -> Article 9(1); specifying the obligation for the TSOs to maintain frequency within the defined ranges and times according to the detailed specification in the NC RfG and DCC; defining high level requirements for the emergency and restoration measures in relation to the frequency control management, which will be detailed further in the NC ER, to be developed at a later stage. Cross-references with other ENTSO-E Network Codes: NC LFCR -> the most

		important code for this Article 9, NC RfG, DCC Required NRA approval: Modifications of the Power Generating Module Capabilities required by the TSO pursuant to Article 9(4). Justification Frequency is a vital parameter of the synchronous System Operation, which is common to all parties of the same Synchronous Area and comprises a clear indicator of the Operational Security of the system and of the power quality. It is therefore of extreme significance to define the minimum requirements to be fulfilled by all involved parties at least on the Synchronous Area level, so as to ensure the secure and reliable operation. Due to its common nature it is impossible to adopt an approach of local definition and organization of the overall Frequency Control Structure, i.e. on the LFC Area or the LFC Block level, as this would lead to great discrepancies within the same Synchronous Area and would make it impossible to have an efficient and effective control of the frequency. Therefore, a wide approach of this issue is necessary. Within this context, all TSOs must contribute to the Load Frequency Control Structure of their Synchronous Area, by controlling certain parameters like the Frequency Restoration Control Error and by providing Active Power Reserves in line with the requirements in place for their Synchronous Area. Not complying with these requirements can have an impact on all TSOs of the same Synchronous Area. Thus, and as frequency problems can be generally characterized as wide area events, it is absolutely necessary to have a clearly defined minimum set of requirements which are harmonized at least on the Synchronous Area level, which guarantee the system security. Furthermore, Significant Grid Users play a decisive role in the Frequency Control Management. It is therefore important for TSOs, who are responsible for the overall frequency, to have full information of the frequency behaviour of Significant Grid Users in normal and abnormal situations. The Network Code makes use of the frequency capabilities of the Significant Grid Users provided within the NC RfG and DCC. For Significant Grid Users not subject to or derogated from these to Codes, the only requirement imposed is to inform the TSO of their behaviour compared to the frequency requirements of the two connection codes. If this information is not at the disposal of the TSOs, the TSOs are not able to predict the system behaviour and therefore they are not able to plan and secure the system. Article 9 sets out the framework of the Frequency Control Management with the purpose of maintaining the Operational Security of the system. The [NC LFC&R] builds upon this minimum framework, by specifying the necessary technical and organisational requirements for ensuring a well-functioning frequency control.
10	VOLTAGE CONTROL AND REACTIVE POWER MANAGEMENT	Specifying the provisions for the TSO to use its best endeavour to maintain the steady-state voltage at the Transmission System Connection Points within the specified ranges -> Tables 8.1 and 8.2; prescribing best endeavour to coordinate all provisions at the level of Synchronous Area -> Article 10(7); defining high level requirements for the emergency and restoration measures in relation to the voltage control and Reactive Power management; specifying the TSO entitlement to apply all necessary measures in case of threat of voltage collapse, including also all Significant Grid Users, Distribution Networks and Closed Distribution Networks -> Article 10(17). Cross-references with other ENTSO-E Network Codes: NC RfG, DCC and [NC OP&S -> for the coordinated Operational Security Analysis in relation to the voltage Operational Security Limits within the TSO Responsibility Area and coordinating with the actions in the Responsibility Area of the other TSOs]; Required NRA approval: Modifications of the Power Generating Module

		Capabilities required by the TSO pursuant to Article 10(3). Justification The two extreme options for Voltage Control and reactive power management are to go back to the past approach where the voltage control was done strictly within the scope of one TSO and its responsibility Area, or to apply one single voltage control for the whole Europe. The first option would mean neglecting the needs and lessons learned about the fact that voltage constraint is not only a local issue, and that in this field also coordination between TSO is necessary. The second option would mean a huge and unnecessary process to be set up. Moreover the second option would also be against the present EU-wide legal framework, which foresees the respective responsibility and liability for voltage control and reactive power management assigned to the single TSOs. The approach chosen in Article 10 for voltage control and Reactive Power management is therefore an optimized, middle-way, complementing the local process (TSO coordination with DSO and SGU in order to maintain the voltage within the ranges defined taking into account the equipment protection, the SGU's capabilities and the Voltage Stability), with the deployment of necessary coordination between TSOs on the Interconnectors, in order to use the Reactive Power resources in the most effective way and ensure adequate voltage control.
11	SHORT CIRCUIT MANAGEMENT	Set out harmonized, EU-wide applicable provisions for the maximum/minimum short-circuit definition, maintain those limits, cooperating when necessary with the other TSOs and DSOs in short-circuit calculations. Cross-references with other ENTSO-E Network Codes: none Required NRA approval: none Justification While setting the limits for short-circuit current, the two extreme options are to leave the setting of the limits for short-circuit current to be individually defined by each TSO or to completely harmonise those limits by prescribing concrete parameters to be followed by each TSO. The first option would imply the risk of not accomplishing the requirement of the SO FG for harmonising the framework for short-circuit current calculations. The second option would mean the imposition of prescribed limits, what would not necessarily fit to the particular characteristic of the TSO´s Transmission System as this option does not respect the existing differences between Synchronous Areas. While calculating short-circuit current and power, the two extreme options are to go back to the previous approach, where this calculation was performed by the TSO´s own approach, or to completely harmonise the short-circuit current and power calculation according to a prescribed standard. The first option would imply the risk of mixing up different components of the short-circuit current[11], which would lead to an imprecise calculation of short-circuit currents. The second option would mean the imposition of a prescribed standard that would not necessarily fit to the particular characteristic of the TSOs transmission system within the Europe as this option does not respect the existing differences between Synchronous Areas. The approach chosen in Article 11 for short-circuit current management is therefore a middle-way, complementing the local and regional concepts while taking at the same time the existing differences between Synchronous Areas into account. This is implemented by introducing clearly defined common

[11] See Section 8.8 for further details.

		principles in a sufficient flexible way in order to achieve a harmonised and standardised framework through the EU for short-circuit current management. Besides, from the point of view of the practical implementation of those requirements, Article 11 achieves a common level of understanding within the TSOs while establishing the necessary common minimum requirements for short-circuit current management and, consequently ensuring a coherent and coordinated behaviour of interconnected Transmission Systems and power systems in each and between Responsibility Areas .
12	POWER FLOWS MANAGEMENT	Set out harmonized, EU-wide applicable provisions for the power flow management Operational Security Limits, coordination among TSOs, Remedial Actions and Redispatching (the later in close relation with the NC CACM). <u>Cross-references with other ENTSO-E Network Codes</u>: [NC OP&S <u>Required NRA approval</u>: none. Justification Transmission System elements have thermal limits that shall be respected to avoid damage to the installations or the people in the vicinity. For Operational Security, thermal limits represent an admissible current that the equipment can withstand for an indefinite or a definite time. Defining Operational Security Limits for Power Flows, including temporary overloads, according to the thermal limits is current practice in all TSOs. To verify the respecting of Operational Security Limits it is necessary to monitor Power Flows. In the interconnected Transmission Systems, it is not sufficient to monitor the Power Flows only within ones own TSO Responsibility Area but also to take into consideration the influence of neighbouring Transmission System, so analysis shall be performed taking into account Observability Area to take into account the influence of external elements on own Transmission System. To avoid violations of Operational Security Limits, Remedial Actions are needed. These Remedial Actions can be non-costly or costly ones. Included in the costly ones is Redispatching. The TSOs shall be entitled to Redispatching of Power Generating Facilities or Demand Facilities within its own Responsibility Area. Not considering Redispatching as a Remedial Action at hand for the TSO will endanger the Operational Security as it will be much more difficult to remove overloads.
13	CONTINGENCY ANALYSIS AND HANDLING	Set out EU-wide applicable harmonized provisions for a central application in the area of Operational Security – Contingency Analysis; this Article 13 is also in the “core” of this Network Code; the issues addressed include Contingency and Contingency List definition, criteria for the different categories of Contingencies, Remedial Actions, relation between real-time and operational planning application of Contingency Analysis, involvement (in Contingency Analysis computation) of the necessary Significant Grid Users and finally building and usage of the Common Grid Model. <u>Cross-references with other ENTSO-E Network Codes</u>: [NC OP&S], NC CACM <u>Required NRA approval</u>: none. <u>Justification</u> The two extreme options for Contingency Analysis are to go back to the past approach where the Contingency Analysis was done strictly within the scope of one TSO and its Control Area, or to apply one single Contingency Analysis for the whole Europe. The first option would mean significant drawback and neglecting the needs and lessons learned during the large disturbances of the past – indeed, the key concepts of the Contingency Analysis and Handling are building upon these experiences and lessons learned. The second option would

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

		mean one huge application and monolithic database, with high risks and poor transparency, not practical for the implementation and deployment of necessary Remedial Actions which must be done at the regional or TSO/local level. Moreover the second option would also be against the present EU-wide legal framework, which foresees the respective responsibility and liability for Contingency Analysis and Operational Security assigned to the single TSOs. The approach chosen in Article 13 for Contingency Analysis and Handling is therefore an optimized, middle-way, complementing the local and regional concepts (TSO Responsibility Area, TSO Observability Area), with the local deployment of necessary Remedial Actions and with the Synchronous Area wide coordination and implementation of Contingency Analysis and Handling approaches and methodologies in a common and coherent way. Furthermore, as the aim of the OS NC is to be applicable for the whole EU and all countries of the Energy Community who have committed to the EU common Acquis Communitaire on Energy, the provisions for the Contingency Analysis and Handling are defined also in a sufficiently flexible way, so as to allow for their detailed implementation with least necessary effort in and between all Synchronous Areas of Europe. The concepts of Ordinary, Exceptional and Out-of-Range Contingencies and the concepts of Internal and External Contingencies build also upon the good operational practice, allowing at the same time for the TSO-performed risk analysis and decision making on when to include which Contingencies in the Contingency List. This sets the framework for the future dynamically changing Contingency Lists, depending on the actual Operational Security and System State. Finally, the reaffirmed, well known concept of (N-1)-Criterion is defined in such a way that it allows for more stringent application on one hand (e.g. on island Synchronous Area with a weaker interconnection towards other Synchronous Areas, where (N-2) or (N-m) criteria might be necessary), as well as for temporary deviation from it during switching, Remedial Actions deployment or if it is certain that there are only local consequences of the given Contingency.
14	PROTECTION	Set out the harmonized criteria and provisions for the protection concepts, coordination and System Protection Schemes, to be applied in a harmonized way throughout the EU. <u>Cross-references with other ENTSO-E Network Codes</u>: DCC, NC RfG <u>Required NRA approval</u>: none at the level of EU (remark: measures for over- and under frequency are to be detailed further and their implementation specified in the NC ER which will be developed at a later stage. <u>Justification</u> Protection is a core function to maintain Operational Security during Faults. Because of its important role protection shall be planned, installed and operated in a way which ensures reliable, selective and fast functioning of the protection in order to keep fault clearing times as short as possible in transmission systems. Protection coordination between interconnected TSOs, DSOs and Significant Grid Users is needed to ensure correct protection functions and to protect connected equipment from damage during the faults. System Protection functions while used shall have same reliability, speed and coordination requirement as normal equipment protection. Low Frequency Demand Disconnection schemes and over-frequency actions are used during extreme situations to protect the whole Transmission System and the Synchronous Area from collapse after an Exceptional or Out-of-Range

		Contingency happened.
15	DYNAMIC STABILITY MANAGEMENT	Set out the harmonized concepts and provisions for the DSA throughout Europe, allowing for the TSO-based or when applicable regional DSA and deployment of respective measures; set out the obligations on the TSO to exchange data (e.g. WAMS measurements) and engage in common, EU-wide stability analyses if this is beneficial or technically required. Cross-references with other ENTSO-E Network Codes: none Required NRA approval: methodology developed by the TSO for the definition of minimum inertia required for maintaining Operational Security at the level of Synchronous Area and to prevent violation of Stability Limits pursuant to Article 15(3) and 15(8). Justification: The power flows in Transmission System are continuously increasing due to changes in the market and increasing amount of intermittent generation. These changes together with long distance transmission paths from generation to load centres can increase the risk of wide area oscillations or other dynamic stability problems in transmission systems. To ensure that the dynamic limits are known in TSOs control centres in all situations Dynamic Stability Analysis (DSA) have to be implemented in cooperation with all TSOs in each synchronous area. When Voltage, Rotor Angle or Frequency stability are found to be limiting factors before the steady-state limits are reached the DSA calculations shall be re-assessed as soon as reasonably practical after a significant change in conditions is detected. New technologies like wide-area measurement systems may in the future give possibilities to monitor or calculate the dynamic stability limits even closer to real-time. Inertia adequacy will have an important role in order to ensure system stability after major disturbances in future, when intermittent generation having relatively small amount of inertia is in increasing. There is need to make studies to identify the needed minimum amount of inertia in each Synchronous Area and based on that study develop methodologies to fulfil this minimum inertia requirement.
	CHAPTER 3 DATA EXCHANGE	
16	GENERAL REQUIREMENTS	Specify the most important and harmonized throughout the EU, requirements which apply generally to all aspects of data exchange which are subject of the subsequent Articles 16 to 29. Cross-references with other ENTSO-E Network Codes: [NC OP&S] Required NRA approval: none at the EU level Justification To maintain Operational Security, it is necessary to know the general situation and specific characteristics of the System States in a precise way so the analyses done are reliable and accurate at all times. To achieve this, the TSO needs information from the Transmission System, the Distribution Network, the Power Generating and Demand Facilities. In Chapter 3, the amount and types of information needed by the TSO is defined. The basis for that was evaluating all information required in order to enable the TSO to comply with its duties. Lack of accurate information for the TSO has significant impact on the

		Operational Security as it makes it impossible to forecast the demand and calculate necessary reserves in an adequate way. This also leads to higher costs as more reserves required to face the uncertainties due to short or inaccurate information. Taking into account the present and expected evolution of the interconnected Transmission Systems of Europe, the requirements of information for the TSO becomes even more important.
17	STRUCTURAL AND FORECAST DATA EXCHANGE BETWEEN TSOs	Specify in an exhaustive and complete way all the structural (“off-line”) data to be exchanged among the TSOs to ensure sound and sufficient inputs and basis for all kinds of Operational Security Analyses and related activities. Cross-references with other ENTSO-E Network Codes: [NC OP&S] Required NRA approval: none Justification: see justification provided for Article 16.
18	REAL-TIME DATA EXCHANGE BETWEEN TSOs	Specify in an exhaustive and complete way all the real-time data to be exchanged among the TSOs to ensure sound and sufficient inputs and basis for all kinds of Operational Security Analyses and related activities in real-time in relation to any critical systems and applications in the System Operation. Cross-references with other ENTSO-E Network Codes: none Required NRA approval: none Justification: see justification provided for Article 16.
19	STRUCTURAL AND FORECAST DATA EXCHANGE BETWEEN TSOs AND DSOs WITHIN THE TSO's RESPONSIBILITY AREA	Define provisions for all necessary structural data exchange between all stakeholders involved within the TSO's Responsibility Area. Cross-references with other ENTSO-E Network Codes: NC RfG Required NRA approval: none Justification: see justification provided for Article 16.
20	REAL-TIME DATA EXCHANGE BETWEEN TSOs AND DSOs WITHIN THE TSO's RESPONSIBILITY AREA	Specify all relevant real-time data exchanged between TSO and DSOs within its Responsibility Area. Cross-references with other ENTSO-E Network Codes: none Required NRA approval: none Justification: see justification provided for Article 16.
21	STRUCTURAL DATA EXCHANGE BETWEEN TSOs, OWNERS OF INTERCONNECTORS OR OTHER LINES AND POWER GENERATING MODULES DIRECTLY CONNECTED TO THE TRANSMISSION SYSTEM	Specify all relevant structural data exchanged between TSOs and directly connected Significant Grid User that are Power Generating Modules. Cross-references with other ENTSO-E Network Codes: [NC LFC&R] Required NRA approval: none. Justification: see justification provided for Article 16.
22	SCHEDULED DATA EXCHANGE BETWEEN TSOs, OWNERS OF INTERCONNECTOR OR OTHER LINES AND POWER GENERATING MODULES DIRECTLY CONNECTED TO THE TRANSMISSION SYSTEM	Specify all relevant scheduled data exchanged between TSOs and directly connected Significant Grid User that are Power Generating Modules. Cross-references with other ENTSO-E Network Codes: none Required NRA approval: none Justification: see justification provided for Article 16.

23	REAL-TIME DATA EXCHANGE BETWEEN TSOs, OWNERS OF INTERCONNECTOR OR OTHER LINES AND POWER GENERATING MODULES DIRECTLY CONNECTED TO THE TRANSMISSION SYSTEM	Specify all relevant real-time data exchanged between TSOs and directly connected Significant Grid User that are Power Generating Modules. Cross-references with other ENTSO-E Network Codes: none Required NRA approval: none Justification: see justification provided for Article 16.
24	STRUCTURAL DATA EXCHANGE BETWEEN DSOs AND SIGNIFICANT GRID USERS ACCORDING TO ARTICLE 1(3)(a) AND ARTICLE 1(3)(d) CONNECTED TO THE DISTRIBUTION NETWORK	Specify all relevant structural data exchanged between DSOs and Significant Grid Users that are Power Generating Modules connected to that DSO. Cross-references with other ENTSO-E Network Codes: NC RfG Required NRA approval: none. Justification: see justification provided for Article 16.
25	SCHEDULED DATA EXCHANGE BETWEEN DSOs AND SIGNIFICANT GRID USERS ACCORDING TO ARTICLE 1(3)(a) AND ARTICLE 1(3)(d) CONNECTED TO THE DISTRIBUTION NETWORK	Specify all relevant scheduled data exchanged between DSOs and Significant Grid Users that are Power Generating Modules connected to that DSO. Cross-references with other ENTSO-E Network Codes: none Required NRA approval: none Justification: see justification provided for Article 16.
26	REAL-TIME DATA EXCHANGE BETWEEN DSOs AND SIGNIFICANT GRID USERS ACCORDING TO ARTICLE 1(3)(A) AND ARTICLE 1(3)(D), CONNECTED TO THE DISTRIBUTION NETWORK	Specify all relevant real-time data exchanged between DSOs and Significant Grid Users that are Power Generating Modules connected to that DSO. Cross-references with other ENTSO-E Network Codes: none Required NRA approval: decision on exempted Significant Grid Users, to which the provisions in this Network Code would not apply. Justification: see justification provided for Article 16.
27	DATA EXCHANGE BETWEEN TSOs AND SIGNIFICANT GRID USER ACCORDING TO ARTICLE 1(3)(A) AND ARTICLE 1(3)(D) CONNECTED TO THE DISTRIBUTION NETWORK	Specify all relevant data exchanged between TSOs and Significant Grid Users that are Power Generating Modules connected to the Distribution Network. Cross-references with other ENTSO-E Network Codes: none Required NRA approval: Requirements by TSO for provision of data and information, as well as provision of further data to the TSO -> Article 27 Justification: see justification provided for Article 16.
28	DATA EXCHANGE BETWEEN TSOs AND DEMAND FACILITIES DIRECTLY CONNECTED TO THE TRANSMISSION SYSTEM	Specify data exchange between TSOs and Demand Facilities directly connected to the Transmission System. Cross-references with other ENTSO-E Network Codes: none Required NRA approval: none Justification: see justification provided for Article 16.
29	DATA EXCHANGE BETWEEN TSOs AND DEMAND FACILITIES CONNECTED TO THE DISTRIBUTION NETWORK OR AGGREGATORS	Specify data exchange between TSOs and Significant Grid Users that are Demand Facilities connected to the Distribution Network. Cross-references with other ENTSO-E Network Codes: none Required NRA approval: none Justification: see justification provided for Article 16.

CHAPTER 4 TRAINING		
30	TRAINING	Define specific and EU-wide applicable provisions for System Operator Employees training and certification. Cross-references with other ENTSO-E Network Codes: none Required NRA approval: none Justification Training is one of the required areas for provisions in the System Operation Network Codes according to the SO FG. Following a common agreement and understanding of ENTSO-E, ACER and EC, the Article 30 on Training and Certification has been introduced in the Operational Security Network Code in order to have early availability of the necessary training provisions – whereas training as a subject is foreseen for a dedicated code in the SO FG, due to the importance of this issue and to the need to have well defined, coordinated and coherent training provisions throughout the EU for all TSOs, this training provisions are intended to serve as the training and certification framework for the time being. This does not preclude any possible future training and certification Network Code which might be decided upon.
CHAPTER 5 COMPLIANCE		
31	RESPONSIBILITY OF THE SIGNIFCANT GRID USERS	Defining the necessary obligations and responsibilities – most notably on data exchange - for the of Significant Grid Users. Cross-references with other ENTSO-E Network Codes: none Required NRA approval: none Operational Security Justification For the TSO to meet its obligation to ensure Operational Security of the Transmission System it relies on the availability of the required services from Significant Grid Users. To maintain an up to date awareness of the Operational Security of the Transmission System the TSO needs to know if these services are available. To achieve this requirement the OS NC places an obligation on Significant Grid Users and DSOs to ensure compliance with the OS NC. It also gives the TSO the ability to evaluate the provision of the services Significant Grid Users are required or have agreed to provide. This combination of self-assessed compliance with an ability to test by the TSO or DSO provides a practical and reasonable approach to compliance, consistent with current practices of a number of TSOs. Significant Grid Users not meeting the expected performance and capability standards create uncertainty in system service delivery, which manifests itself today in increased costs in the System Operation, and in the long run may compromise Operational Security.
32	RESPONSIBILITIES OF THE TSOs AND DSOs	Define relevant responsibilities of the TSOs and DSOs, with a particularly important emphasize on the Operational Security Performance Indicators and ENTSO-E incidents classification scale with detailed definition and provisions for that. Cross-references with other ENTSO-E Network Codes: [OP&S]

		Required NRA approval: Enhancements of the means from Article 32(1)(a)-(e) pursuant to Article 32(1); Justification – Operational Security Performance Indicators (Articles 32(1), 32(2)) The European-wide incidents classification scale (ICS) will allow ENTSO-E and Transmission System Operators to draw up a yearly report reflecting the level of Operational Security all over Europe. It will represent a real opportunity for Transmission System Operators to characterize main issues and to identify ways of progress. It is against this background that the ENTSO-E with its methodology and guidelines is considered an adequate match to the mentioned requirements for Operational Security Performance Indicators in the ACER Framework Guidelines for Electricity System Operation. The ranking and explanation / analysis of reasons of incidents and events reported in the yearly ICS report are the essential part of the Operational Security Performance Indicators approach developed in the OS NC. They provide for a structured and transparent way to monitor the overall health and Operational Security of the European interconnected Transmission Systems, to identify any necessary enhancements (those can even include changes in framework or even OS NC itself if it is considered lacking any critical provisions) in order to maintain Operational Security in an effective and sustainable way throughout the Europe. The SO FG call for *"… a detailed assessment of the system operation performance per country …".* Whereas this framework provision is simple enough and sufficient from a formal perspective, it is not practically applicable in the today's System Operation practice, especially bearing in mind the rapidly growing degree of interleaved dependencies between the TSOs and their Responsibility Areas in terms of Operational Security. Moreover, it is also not well applicable to and reflecting of the ever more globally visible intermittent generation from wind and solar power in Europe. Finally, this is also a too narrow approach from the perspective of the EU Internal Electricity Market which aims at reducing the significance of political borders in the common EU market. This means further that eventually the scope for a particular incident – depending on its character and ranking – could be a Synchronous Area (e.g. for frequency), or even beyond the Synchronous Area (e.g. for lack of reserves in case of exchange of reserves beyond the Synchronous Area borders), as well as a part of a Synchronous Area with several TSOs (e.g. in case of regional blackouts). This means further that the scope for the assessment of the System Operation in general and Operational Security in particular will always have to retain a wide, holistic view on the European interconnected Transmission Systems and that the identification of necessary enhancements – or new means – according to the obligations pursuant to Article 32(1)(d) and 32(1)(e) will always be case-by-case based. Nevertheless, the ex-post analysis after significant incidents will be carried on at the right level of detail and with high scrutiny, aiming agreed criteria to decide specific ex-post analysis, the data needed to run ex-post analysis, the items to be dealt with, the organization performing the analysis and main milestones of it. Eventually, the results of such ex-post analyses, subject of yearly ICS reporting, will be the main driver for any necessary enhancements and further developments of TSOs own means and of any further means in cooperation with other stakeholders, with a common goal to maintain Operational Security in Europe.
33	COMMON TESTING AND INCIDENT ANALYSIS RESPONSIBILITIES	Cross-references with other ENTSO-E Network Codes: none Required NRA approval: none

		Operational Security Justification This Article aims to facilitate the significant development which will take place in the coming years by ensuring that the testing and analysis which this will require are consistent with Operational Security. To ensure Operational Security and safety of personnel and equipment TSOs, DSOs and Significant Grid Users must have an ability to postpone or interrupt testing. To ensure the full benefit to and continued development of the Transmission System the relevant outputs of compliance testing and incident analysis must be exchanged, incorporated into training and development, used to update procedures and used as inputs to research and development.
		CHAPTER 6 FINAL PROVISIONS
34	AMENDMENTS OF CONTRACTS AND GENERAL TERMS AND CONDITIONS	Time frames and final provisions for amendments. Cross-references with other ENTSO-E Network Codes: none Required NRA approval: none
35	ENTRY INTO FORCE	Final provisions for entering into force of this Network Code.

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

ANNEX II- ASSESSMENT OF THE FINAL OS NC AGAINST THE REQUIREMENTS OF THE FRAMEWORK GUIDELINES ON SYSTEM OPERATION

	REQUIREMENT OF THE FRAMEWORK GUIDELINES	EXTENT TO WHICH THE PROVISION IS MET
1.	**General provisions**	
1.1	**Scope**	
1.1	The Network Code(s) developed according to these Framework Guidelines will be applied by electricity system operators and significant grid users.	Article 1 defines the Significant Grid users and shall be applicable to all TSOs, DSO and Significant Grid Users. Article 8 is to be applied by TSOs and to be taken into account where necessary by DSOs and Significant Grid Users. Article 8(14) and (15) are to be applied by DSOs and Significant Grid Users. Article 9 is to be applied by TSOs, whereas Articles 9(4) and 9(6) are to be applied by Significant Grid User and Articles 9(7) and 9(8) are to be taken into account by DSOs. Article 10 is to be applied by TSOs and to be taken into account where necessary by DSOs and Significant Grid Users. Articles 10(3) and 10(9) are to be applied by Significant Grid Users. Article 11 is to be applied by TSOs and to be taken into account where necessary by DSOs and Significant Grid Users. Article 12 is to be applied by TSOs. Article 13 is to be applied primarily by the TSO as it deals with Contingency Analysis and Handling; nevertheless, it requires also necessary input data from SGUs (dealt with in Chapter 3). Article 14 is to be applied by all TSOs and coordinated with connected DSOs and Significant Grid Users. Article 15 is to be applied by TSOs and to be taken into account where necessary by DSOs and Significant Grid Users. Chapter 3 is to be applied by TSOs, DSOs and Significant Grid Users. Chapter 5 is to be applied by TSOs, DSOs and Significant Grid Users.
1.1	The Network Code(s) for System Operation shall elaborate on relevant subjects that should be coordinated between TSOs, as well as between TSOs and Distribution System Operators (DSOs); and with significant grid users, where applicable.	Article 1 is to be applied by all TSOs, DSO and Significant Grid Users. Article 8(8) describes coordination among TSOs around Operational Security Limits on the Interconnectors. Articles 8(9) and 8(10) and 8(11) describe coordination to be set up when the system is not in Normal State. Articles 8(12), 8(13) and 8(14) describe coordination for Remedial

		Actions preparation and implementation. Article 8(15) describes coordination between TSOs, DOSs and SGUs for ensuring the availability, the reliability and redundancy of the critical tools and facilities which are required for System Operation. Article 9 foresees the coordination among TSOs with respect to the frequency control management at least on the Synchronous Area level, whereas Articles 9(4)-9(8) describe the coordination between TSOs, DSOs and Significant Grid Users. Article 10(10) describes coordination between TSOs in order to use Reactive Power resources in the most effective way and ensure adequate voltage control. Article 10(11) is about coordination of Security Analysis for voltage management. Article 10(15) defines the coordination needed between TSOs and SGU directly connected to the Transmission System and with neighbouring TSOs. Article 12 will require coordination between TSOs. Article 13 elaborates in detail the coordination and collaboration of TSOs in common Contingency Analysis throughout the EU and Synchronous Areas, reflecting in particular on the specific provisions in NC OPS which are related to the RSCI's. It includes further considerations of involvement of DSOs and SGUs (especially in relation to the concepts of Responsibility and Observability Areas which are extensively used in determination of Contingency Lists). Article 14 will require protection coordination between all parties using protection systems, which have impact to system security. Article 15 elaborates requirements on coordination concerning Dynamic Stability of the system. Chapter 3 provides the necessary information required by the TSO to securely operate the System. That information shall be provided by other TSOs, DSOs and SGU. Chapter 5 includes coordination between TSOs, DSOs and Significant Grid Users on testing and incident analysis.
1.2	**Structure**	
1.2	Therefore, focus is to be laid on the three key challenges: • To define harmonised security principles; • To clarify and harmonise TSOs' roles, responsibilities and methods; and • To enable and ensure adequate data exchange.	Article 8 sets a harmonised framework for: - The classification of the System State (parameters to monitor and common criteria); - Definition of Operational Security Limits; - TSO's responsibilities when the System State is not Normal; - TSO's and DSO's role in Remedial Action preparation and implementation; - Availability, redundancy and reliability of critical tools for System Operation; - Principles for Business Continuity Plan and Security Plan; - High level principles for Operational Security Analysis (to be detailed in NC OPS). Article 9 sets out a harmonised framework at least on the Synchronous Area level concerning: - The contribution of each TSO to the Load-Frequency Control Structure and the frequency quality defining parameters in line with the NC LFCR; - Procedures in emergency situations due to frequency excursions to be coordinated among

TSOs;
- The parameters to be monitored by each TSO;
- The control parameters to be maintained by each TSO in order to achieve the desired frequency quality;

The provisions of Article 9 shall be further detailed in the NC LFCR as they concern the frequency control management.

Article 10 sets a harmonised framework for:
- The definition of min. and max. limits for voltages and time duration at Connection Points;
- The coordination of voltages and Reactive Power flow limits on the interconnections;
- The coordination of Operational Security analysis with all affected TSOs;
- The coordination of voltage control actions with all affected significant grid users and TSOs.

Article 11 sets a harmonised framework for:
- The definition of min. and max. limits for Short-circuit current;
- The Short-circuit current and – power calculation;
- Applying operational measures to prevent or relieve a deviation from Short-circuit current limits in the transmission system.

Article 12:
- TSOs define Operational Security Limits of the power flows on the elements of the Transmission System;
- Necessary data exchange is considered in Chapter 3.

Article 13: sets a harmonized framework for Contingency Analysis as one of the central activities in System Operation, providing for the definition of TSO roles and using the data exchange provisions from Chapter 3:
- Each TSO shall define Contingency Lists including Internal and External Contingencies as well as Ordinary, Exceptional and Out of Range Contingencies based on the common methodology according to the provisions in NC OPS and using the common principles in Article 13(5);
- All TSOs must contribute to the establishment of the Common Grid Model in Article 13(13);
- Real-time system operation parameters are used for Contingency Analysis, which is also performed in operational planning; the detailed data specification is contained in Chapter 3.

Article 14 defines harmonized principles for reliable protection systems, responsibilities for parties coordinating the protection and enables adequate information exchange related to protection systems.

Article 15 defines harmonized principles, responsibilities and methods for Dynamic Stability Management.

Chapter 3 defines the common information that shall be received by TSOs. Information has to be shared by other TSOs or sent by DSOs and SGU.

Chapter 5 Compliance focuses on harmonising principles, roles and responsibilities related to testing and incident analysis. Data exchange is covered in Article 31(2), (3) and (4), 32 (6), (7) and (9) and Article 33 (4), (5).

1.2	The following objectives for these Framework Guidelines were set out, to address the identified challenges: • To operate the electric power system in a safe, secure, effective and efficient manner; • To enable the integration of innovative technologies; • To apply same principles for different systems; • To make full use of information and communication technologies.	Article 8 aims to monitor the system state and detect as soon as possible risky situations, in order to take the adequate measures to return to a secure state of the system. Principles are shared within all European systems. Article 9 aims at maintaining the frequency of the interconnected systems within the permissible frequency ranges, thus keeping the system stable and protecting facilities of all parties from damages. Frequency control management principles are shared within all European systems on the Synchronous Area level. Article 10 aims to prevent damage to all types of SGUs, network elements and related equipment and to prevent voltage collapse through uniform voltage limits in each synchronous area. Article 11 aims to prevent damage to all types of SGUs; network elements and related equipment and to provide safety for persons, through the fast and selective disconnection of short-circuit Faults. Article 12 states harmonised principles for defining Operational Security limits. The objective is to avoid damage due to operating the system over the thermal capabilities of the equipment. Article 13 states principles for ensuring Contingency Analysis recognises sufficiently in advance possible endangering of Operational Security; it sets out the TSOs obligations in a uniform way, to coordinate and apply Remedial Actions when required; the information and communication solution for the Common Grid Model will be applied in a uniform way in line with the methodology to be developed pursuant to the NC OPS. Article 14 defines the principles for selective and reliable protection, which is basic fundament for ensuring secure operation of transmission systems. The security, reliability and redundancy principles in protection systems shall be the same when having cross-border impact. New protection systems and especially System Protection Schemes enable the usage of new and innovative technologies and information and communication technologies. Article 15 defines principles to operate the Transmission System in a safe, secure, effective and efficient manner with innovative dynamic management technologies and to make full use of information and communication technologies. Chapter 3 provides the necessary information required by the TSO to securely operate the System. The chapter states the same principles for all systems and allows integration of innovative technologies. Chapter 5 Compliance aims to facilitate safe, secure and efficient operation of the Transmission System by ensuring the necessary analysis is carried out prior to testing, allowing for the postponement of test in deteriorating system conditions or due to safety. It also requires incident analysis, publication of results and requires feedback into training, research and development and system operation. It applies the same principles for different Transmission Systems.
1.5	**Application**	

1.5	The Network Code(s) shall establish minimum standards and requirements related to System Operation. In developing the Network Code(s) ENTSO-E should take into consideration the rulebooks on System Operation that already exist for each synchronous area. In particular, ENTSO-E shall ensure that the level of detail in the code is sufficiently high level to facilitate incremental innovation in technologies and approaches to system operation without requiring code amendments.	Article 1 is the general basis for these requirements; it aims to determining common Operational Security requirements and principles, ensuring conditions for maintaining Operational Security throughout the EU and providing for coordination of system operation. Principles for System state classification described in the Article 8 are based on those existing in Nordic and CE's policies. Requirements of Article 8 describe the objectives to be reached but not the detail of technologies to be used, so it can remain valuable even when technologies will progress. Article 9 sets out a harmonised framework for frequency control management and is based on best practices of the European synchronous areas. Furthermore, Article 9 describes the high level process to ensure system security, while the implementation is left open leaving space for new technologies to emerge. Article 10 sets a harmonised and standardised framework for the voltage and Reactive Power management. Article 11 sets a harmonised and standardised framework for the short-circuit current management. Article 12 sets a harmonised and standardised framework for power flow management. Article 13 relies largely on the existing RGCE (former UCTE) Operational Handbook, most notably its Policy 3 with the respective Annex, but it is sufficiently flexible so as to be applicable throughout EU and in all TSOs and Synchronous Areas; any specifics of local or regional character are possible to be implemented at the level of MS or when necessary through detailed agreements among the TSOs of a Synchronous Area. Article 14 Protection defines the minimum standards for protection systems taking into account the existing protection systems and principles. Article 15 shall establish minimum standards and requirements related to dynamic stability management. Chapter 3 has been written taking into account existing practices in different TSOs. It defines on a high level the required data to facilitate innovation without requiring code amendments.
1.5	The Network Code(s) shall take precedence over the relevant national codes and international standards and regulations, without prejudice to the Member States' right to establish national rules which do not affect cross-border trade. Where there are proven benefits, and if compatible with the provisions of the Network Code(s), any national codes, standards and regulations which are more detailed or more stringent than the Network Code(s) should retain their applicability.	Principles respected in all Article 8. Regarding Security Plan, Article 8 gives high level principles, but each Member State keeps a responsibility in the threat scenarios' definition. Article 9 defines the frequency control management and takes precedence over the relevant national codes. Article 10 takes precedence over the relevant national codes for the Transmission System voltage levels 400 to 110 kV.

		Article 11 takes precedence over the relevant national codes while following agreed international standards or by the TSO using the best available data and its own practice approaches. Article 12 takes precedence over national regulations. Article 13 specifies high level principles for Contingency Analysis and introduces TSOs obligations especially in relation to Contingencies handling; nevertheless, although especially provisions on Remedial Actions and Contingency List definition set common principles and rules, the detailed implementation will remain at the level of Synchronous Area and single TSOs, respectively. The provisions of the Article 13 are formulated in such a way that they always precede any national rules, without compromising or jeopardizing good operational practices. Article 14 requires same criteria for national and international protection systems when they have cross-border impact. Article 15 takes precedence over national codes when defining the wide area stability management principles in each synchronous area. Chapter 3 defines required data and takes precedence over national regulation. The compliance testing principles in Chapter 5 are high level enough for the European common approach, allowing therefore for more detailed or stringent requirements in national codes.
1.5	Where the minimum standards and requirements, introduced by the Network Code(s) deviate significantly from the current standards and requirements, there should be a cost-benefit analysis performed by ENTSO-E that justifies and demonstrates additional benefits from the proposed standard or requirement.	There is no significant deviation from existing practices, but a number of improvements, amendments and provisions for coherence, consistency and common approaches. Chapter 3 defines the necessary information required by the TSO to securely operate the Transmission System. It has been written taking into account existing practices in different TSOs so different parts of the Chapter may reflect current practices in different TSOs. In Article 13, the only significant deviation from the current practice is the relying on the Common Grid Model in the wider sense, as it is introduced and specified in detail according to the contents and timeframes of Chapter 3 (data exchanges) and provisions in NC OPS and NC CACM.
1.6	**Roles and Responsibilities**	
1.6	The Network Code(s) shall apply to system operators and all significant grid users already, or to be, connected to the transmission or distribution network. Any grid user not deemed to be a significant grid user shall not fall under the requirements of the Network Code(s).	Article 1 defines the Significant Grid User for the OS NC and the other System Operations NCs. Article 8 is to be applied by TSOs and to be taken into account where necessary by DSOs and Significant Grid Users. Article 8(14) and (15) are to be applied by DSOs and Significant Grid Users as defined in article 1(3). Article 9 is to be applied by TSOs and to be taken into account where necessary by DSOs and Significant Grid Users. Articles 7(4) and 7(6)-7(8) is to be applied by Significant Grid Users and to be considered by TSOs and DSOs. Article 10 is to be applied by TSOs and to be taken into account where necessary by DSOs and Significant Grid Users. Articles 8(3) and 8(9) are to be applied by Significant Grid Users as defined in Article 1(3).

		Article 11 is to be applied by TSOs and to be taken into account where necessary by DSOs and Significant Grid Users. Article 12 is to be applied by TSOs and to be taken into account where necessary by DSOs and Significant Grid Users affected by redispatch. Article 13 addresses in the first line TSOs as the main actors, defining where applicable relations to the Significant Grid Users – most notable in data exchange in Article 13(11). Article 14 is to be applied by TSOs and coordinated with connected DSOs and Significant Grid Users. Article 15 is to be applied by TSOs and coordinated with connected DSOs and Significant Grid Users. Chapter 3 applies to TSOs, DSOs and SGU. SGU are defined according to the criteria in Article 1(3) taking into account NC RfG and DCC. Chapter 5 applies to TSOs, DSOs and Significant Grid Users. No differentiation is made between existing and new Significant Grid Users.
1.6	For the purpose of these Framework Guidelines DSOs shall be treated as grid users where they have to comply with the TSO's requirements in the Network Code(s). They are treated as system operators where they implement Network Code(s) provisions with respect to significant grid users connected to the distribution system or in undertaking system operation actions. Unless otherwise stated, reference to DSO implied DSO as grid user.	Articles 8(9) and 8(10) describe communication from TSOs to DSOs in case of situations that can lead to emergency measures involving Significant Grid Users connected to Distribution Network. Articles 8(13) and 8(14) describe coordination between TSOs and DSOs when Remedial Actions can have an impact on Distribution Networks. In the other requirements, DSOs are considered as grid users. Article 9(4) and 9(7) regards DSOs as System Operators responsible for gathering information on deviations from the permissible disconnection frequencies from Significant Grid Users connected to their network and responsible for adopting the criteria and conditions for disconnection of Significant Grid Users connected to their network. Furthermore, Article 9(8) sets out the conditions for resynchronization on the DSOs' network according to the conditions of the TSOs. Article 10 treats DSOs as grid users excepted in Article 10(9) (conditions for disconnection of SGU connected to the Distribution network), Article 10(15) (coordination with TSO for directing SGU connected to the Distribution Network with voltage instruction), and Article 10(17) (Demand Facilities disconnection if needed to avoid voltage collapse). Article 11 treats DSOs as grid users. In Article 13 the DSOs are mainly concerned for the exchange and delivery to TSO of necessary information for Contingency Analysis. In Article 14 the DSOs are treated as Significant Grid Users in protection systems coordination with TSO. When dealing with Low Frequency Demand Disconnection DSOs are treated as

		system operators as opposed to system users connected to distribution networks. Article 15 dynamic stability requirements don't apply to DSOs, because dynamic stability is wide area phenomena and DSOs activity is more regional than system wide. According to Chapter 3 DSOs shall send information about their networks to its TSO and shall receive information from SGU connected to their networks. DSOs are treated as system operators in Chapter 5 except in Article 31(1).
1.6	The approach to establishing significant grid users is set out in the Framework Guidelines on Electricity Grid Connections, and relevant details shall be set out in the Network Code(s) developed according to the Framework Guideline on Electricity Grid Connections.	Article 1(3) states the Significant Grid Users who are subject to this Network Code.
1.7	**Derogations**	
1.7	For minimum standards and requirements that impact on significant grid users, the derogation process set out in the Framework Guidelines on Electricity Grid Connections, and to be established in the Network Code(s) developed accordingly, shall apply.	Existing and new significant grid users shall apply this NC. Significant grid users for system operation are stated in Article 1 and consistent with the NC RfG and DCC.
1.7	For system operators there shall be no possibility for derogation from the requirements of the Network Code(s) developed according to these Framework Guidelines.	The requirements set in this Network Code do not introduce the possibility of derogation.
1.7	The Network Code(s) may state that the provided requirements are not applicable for a specific system operator (e.g. isolated system or a synchronous area). These cases must be duly justified by ENTSO-E	Article 1 sets the legal framework for this requirement. Exemptions are foreseen for Baltic systems. Exceptions for Baltic TSOs are related to frequency management and dynamic assessment of synchronous area, so detailed justification for Baltic TSOs will be in supporting paper on NC LFCR.
1.8	**Adaptation of existing arrangements to the Network Code(s)**	
1.8	The Network Code(s) shall provide a transition time within which system operators and relevant significant grid users have to apply the new standards and requirements. The transition period shall be consulted on with relevant stakeholders. In general the transition period should not exceed two years. Different transition periods for compliance can be set for new grid users and for pre-existing grid users and also for different minimum standards and requirements.	Chapter 6 is in line with this requirement.
2	**Minimum Standards and Requirements for System Operation**	
	General System Operation Characteristics	
Criteria	The Network Code(s) shall provide criteria (performance indicators) against which the quality of System Operation can be monitored. In particular, adequate criteria should be proposed for security of supply, quality of supply and for the quality of the data delivered as input for congestion management in comparison with the effective use of the transmission system represented by real-time data.	Articles 10 and 32 define the provisions on Operational Security Performance Indicators. Articles 32 (2) and (3) contain all the relevant provisions, including a dynamic reference to the ENTSO-E incidents classification scale which is the basis for the annual reporting of the Operational Security Performance Indicators and for the related enhancements of existing solutions and apporaches.

	The Network Code(s) shall foresee the publication of a yearly report by ENTSO-E on the evolution of system operation performance. This report shall provide a detailed assessment of the performance per country, including the selected performance criteria and their evolution over time. The format and content of the report shall be approved by ACER.	Articles 32 (1)(d) and (e), 32 (2) contain provisions on the yearly report. The Operational Security Indicators are defined in the Article 32(2).
Methodology and Tools	The Network Code(s) shall define common principles, requirements, standards and procedures within the synchronous areas throughout the EU.	Article 3 defines the common principles that are basis of this Network Code. Article 8 sets a harmonised framework for: - The classification of the System State (parameters to monitor and common criteria); - Definition of Operational Security Limits; - TSO's responsibilities when the System State is not Normal; - TSO's and DSO's role in Remedial Action preparation and implementation; - Availability, redundancy and reliability of critical tools for System Operation; - Principles for Business Continuity Plan and Security Plan; - High level principles for Security Analysis (to be detailed in NC OPS). Article 9 sets out a harmonised framework for: - Procedures in emergency situations due to frequency excursions to be coordinated among TSOs; - The parameters to be monitored by each TSO; - The control parameters to be maintained by each TSO in order to achieve the desired frequency quality; - The contribution of each TSO to the Load-Frequency Control Structure and the frequency quality defining parameters in line with the NC LFCR; The provisions of Article 9 shall be further detailed in the NC LFCR as they concern the frequency control management. Article 10 sets a harmonised framework for: - The definition of min. and max. limits for voltages and time duration at Connection Points; - The coordination of voltages and reactive flow limits on the interconnections; - The coordination of Operational Security analysis with all affected TSOs; - The coordination of voltage control actions with all affected significant grid users and TSOs. Article 11 sets a harmonised framework for: - The definition of min. and max. limits for short-circuit current; - The Short-circuit current and – power calculation; - Applying operational measures to prevent or relieve a deviation from Short-circuit current limits in the Transmission System. Article 12 states harmonised principles for defining Operational Security Limits according to Thermal capability of the equipment. Article 13 defines common principles for Contingency Analysis and handling per Synchronous Area and throughout the EU.

		Article 14 requires common protection principles throughout the EU. Article 15 requires common Dynamic Stability principles throughout the EU. Chapter 3 define the necessary information required by the TSO to securely operate the Transmission System. Chapter 5 is applicable within each of the Synchronous Areas. It describes common principles, requirements, standards and procedures.
	Network code(s) shall be in line with experiences, best known operational practices and lessons learnt from experiences.	The requirements set in Article 8, 9,10, 11, 12, 14, 15 are based upon existing practices and lessons learned. Article 13 takes in particular into account the lessons learned from the previous large disturbances (most notably UCTE system split on 04th November 2006) in the way of the definition of Contingencies, in the concept of Observability Area and further detailed concepts which are explained further in the supporting document. It relies in its provisions on the best existing and proven practices in relation to the Contingencies risks and Remedial Actions strategies of the EU TSOs. Chapter 3 has been written taking into account existing practices in different TSOs so different parts of the Chapter may reflect current practices in different TSOs.
	No provision in the Network Code(s) shall prevent market arrangements being used for the provision and use of ancillary services.	Article 12 states the possibility for the TSO to redispatch Significant Grid Users but no provision forbids market agreements. Other articles do not include any provisions that prohibit the proper functioning of the ancillary services markets or prevent market arrangement.
Roles and Responsibilities	In addition to provisions set out in Chapter 1.6 the Network Code(s) should further clarify the roles and responsibilities related to System Operation, especially considering differences in the tasks of TSOs and DSOs (e.g. caused by national obligations).	Articles 6(13) and 6(14) describe respective responsibilities for TSO and DSO on the preparation and in the implementation of Remedial Actions when they have an impact on distribution networks. The frequency control management described in Article 9 lies within the responsibility of the TSOs. According to the provision of Article 9(4) and 9(7) DSOs are responsible for gathering information concerning deviations from disconnection frequencies of Significant Grid Users connected to their network and for implementing the criteria and conditions set out by the TSO for re-synchronization of Significant Grid Users connected to their network. Voltage control described in Article 10 is done mainly by TSOs. The collaboration of DSOs is required in order to: - To define the terms and settings for automatic disconnection; - To coordinate voltage control actions; - To maintain reactive power flows at connection points; - To disconnect Demand Facilities if needed to avoid Voltage collapse. The topic treated within Article 11 (short-circuit current management) is considered a

		transmission issue within the OS NC. The collaboration of DSOs is required in order to: - Be able to consider the short-circuit contributions from Distribution Networks and Closed Distribution Networks by the TSOs; - Model the Distribution Network and the Closed Distribution Networks in the transmission short-circuit calculations with the level of detail needed by the TSOs. Article 12 defines that respecting Power Flow Security Limits in the Transmission System is carried out by TSOs. Redispatching is also done by TSOs. Article 13 focuses on TSOs as the main actors in Contingency Analysis, DSOs and SGUs are primarily the supplier of the required data and information. Article 14 Protection defines the roles and responsibilities of TSOs and DSO related to protection systems. Article 15 defines the roles and responsibilities of TSOs and DSO related to Dynamic Stability Management. According to Chapter 3 DSOs shall send information about their networks to its TSO and shall receive information from SGU connected to their networks.
Information Exchange	The Network Code(s) shall define a harmonised standard for timing and content of information (real-time and other) between TSOs and/or DSOs within ENTSO-E as well as outside of ENTSO-E, where applicable.	Article 14 defines the information exchange needed for protection coordination between TSOs and DSOs. Framework is set in Chapter Data Exchange of the OS NC Chapter 3 on sufficiently high level and to facilitate innovation without requiring code amendments. NRA involvement is considered to define detailed content and timing of information. In Chapter 5 data exchange for compliance tests and analysis is covered in Article 31(2), (3) and (4), 32 (6), (7) and (9) and Article 33 (4), (5).
	The Network Code(s) shall set the requirement for DSOs to execute the instructions given by the TSOs.	Article 8 sets the obligation to DSO to follow instructions form TSO for Remedial Action implementation in real-time. Article 10 sets the obligation to DSO to follow Voltage Control instructions from TSO. Article 14 Protection set requirements for DSOs to execute the protection instructions given by the TSOs. Framework is set in Chapter 3 Data Exchange of the OS NC. DSOs shall provide information to the TSO as stated in Articles 19 and 20.

	Further, the Network Code(s) shall define for every significant grid user: • which information it is obliged to provide to the TSO or DSO that, it is connected to, and how this data shall be provided, • requirements to be able to receive and to execute the instructions sent by the TSO and/or DSO to ensure the Operational Security of the system.	Article 9(4) defines the information to be provided by Grid Users deemed Significant within [OS NC] and not subject to or derogated from the requirements of NC RfG to the TSO or DSO if connected to the Distribution Network Article 14 defines the information which is needed for protection coordination between TSOs and DSOs. Necessary data to be provided by DSOs and Significant Grid Users for the System State monitoring, to follow Voltage Control instructions from TSO, to facilitate frequency control management, active power flow management, short-circuit current and power calculation are specified in the Chapter 3 Data Exchange of the OS NC. SGU shall provide information stated in Articles 21 to 29. In Chapter 5 data exchange for compliance tests is covered in Article 31(2), (3) and (4).
	The TSO and the DSO shall agree how these instructions are delivered in practice. This applies also for those DSOs connected to another DSO's network.	Articles 10, 12, 14 cover these provisions as different practices already exist. According to Chapter 3 DSOs shall send information about their networks to its TSO and shall receive information from SGU connected to their networks.
	The significant grid users are obliged to provide the TSOs with information required for System Operation. The Network Code(s) should lay down the necessary enforcement measures in case of non-compliance of the significant grid users with this obligation. The TSOs are obliged and entitled to exchange the information provided by significant grid users with other TSOs for reasons of Operational Security. In doing that, the TSOs should fully respect data protection laws and regulation, most notably the requirement of not disclosing the received data to any market participant but only to the affected and responsible TSOs. System operators should be allowed to establish an equally reliable and credible information exchange regime by considering other data sources in a more efficient way.	Framework of data exchange is set in Chapter 3 Data Exchange of the OS NC. SGU, including DSOs, shall provide information stated in Articles 21 to 29. TSOs shall exchange information defined in Articles 17 and 18. Article 6 with its confidentiality obligations sets the legal framework for data protection in this NC. Article 14 Protection defines the information that DSOs have to deliver to TSOs related to protection systems.
	Network codes shall set out the transparency requirements for TSO's actions with a significant impact to market functioning and to ensure non-discrimination between grid users.	Article 3 defines the common principles that are basis of the OS NC. Article 9(2), (3) requires publishing of frequency management procedures. Chapter 3 defines general provisions stated in Article 16. Agreements between TSOs about data Exchange shall be published according to Article 16(5).
Implementation issues	The Network Code(s) shall be elaborated and be modified in a coherent and coordinated way, taking into account forthcoming changes and challenges caused by increasing cross-border exchanges, changes in technology and socio-economic developments.	General issue. The Network Code is elaborated in a coherent and coordinated way.
	Topic 1: Operational Security	
Scope and Objectives	Ensuring – on a high level – coherent and coordinated behaviour of interconnected transmission networks and power systems in each	Article 8 sets common requirements for: - The classification of the System State (parameters to monitor and common criteria);

	control area and between control areas under normal operation state, in alert as well as in critical operating states.	- Definition of Operational Security Limits; - TSO's responsibilities when the system state is not normal; - TSO's and DSO's role in Remedial Action preparation and implementation; - Availability, redundancy and reliability of critical tools for system operation; - Principles for Business Continuity Plan and Security Plan; - High level principles for Security Analysis (to be detailed in NC OPS). Article 8 aims to ensure a coherent and coordinated behaviour of interconnected transmission systems and power systems in each and between control areas. Article 9 sets out a harmonised framework for: - Procedures in emergency situations due to frequency excursions to be coordinated among TSOs; - The parameters to be monitored by each TSO; - The control parameters to be maintained by each TSO in order to achieve the desired frequency quality; - The contribution of each TSO to the Load-Frequency Control Structure and the frequency quality defining parameters in line with the NC LFCR. The provisions of Article 9 shall be further detailed in the NC LFCR as they concern the frequency control management. Article 10 sets a harmonised framework for: - The definition of min. and max. limits for voltages and time duration at connection points; - The coordination of voltages and reactive flow limits on the interconnections; - The coordination of Operational Security analysis with all affected TSOs; - The coordination of voltage control actions with all affected significant grid users and TSOs. Article 11 sets common requirements for: - The definition of min. and max. limits for short-circuit current; - The Short-circuit Current and power calculation; - The application of operational measures to prevent or relieve a deviation from short-circuits limits in the transmission system. Article 11 aims to ensure a coherent and coordinated behaviour of interconnected transmission systems and power systems in each and between Responsibility Areas. Article 12 states harmonised principles for defining Operational Security limits. Security Limits of interconnections are defined in a coordinated way. Article 13 aims at coherent and coordinated behaviour of all TSOs in the definition and implementation of main Contingency Analysis principles and solutions. It unifies the key principles for the deployment of Remedial Actions and sets the TSOs obligation towards preventing System State deterioration in case of Contingencies identified which would provoke this deterioration. Article 14 defines the security and redundancy principles of protection systems, which are fundaments for Operational Security. Article 15 defines the principles for TSOs in order to detect and analyse dynamic stability

		situation in the transmission system and make necessary actions to release instability. Chapter 3 provides the necessary information required by the TSO to securely operate the System and effectively define the System State. Article 32 (8) requires the necessary analysis and planning to be carried out using the common grid model. Article 32 (9) requires information exchange between TSOs. Article 33 (3) ensures coordination under non-Normal System States.
	Achieving and maintaining a satisfactory level of Operational Security allowing for efficient utilisation of the power system and resources, including, but not limited to, the necessary inputs to congestion management and balancing.	Article 8 sets common requirements for: - The classification of the System State (parameters to monitor and common criteria); - Definition of Operational Security Limits; - TSO's responsibilities when the system state is not normal; - TSO's and DSO's role in Remedial Action preparation and implementation; - Availability, redundancy and reliability of critical tools for system operation; - Principles for Business Continuity Plan and Security Plan; - High level principles for Security Analysis (to be detailed in NC OPS); Article 8 aims to achieve and maintain a satisfactory level of Operational Security. Article 9 sets out a harmonised framework for: - Procedures in emergency situations due to frequency excursions to be coordinated among TSOs; - The parameters to be monitored by each TSO; - The control parameters to be maintained by each TSO in order to achieve the desired frequency quality; - The contribution of each TSO to the Load-Frequency Control Structure and the frequency quality defining parameters in line with the NC LFCR. The provisions of Article 9 shall be further detailed in the NC LFCR as they concern the frequency control management. The balancing market shall be considered in the [NC Balancing]. Article 10 sets a harmonised framework for: - The definition of min. and max. limits for voltages and time duration in connection points; - The coordination of voltages and reactive flow limits on the interconnections; - The coordination of Operational Security analysis with all affected TSOs; - The coordination of voltage control actions with all affected significant grid users and TSOs. Article 11 sets common requirements for: - The definition of min. and max. limits for short-circuit current; - The Short-circuit Current and power calculation; - The application of operational measures to prevent or relief a deviation from short-circuits limits in the transmission system. Article 11 aims to achieve and maintain a satisfactory level of Operational Security. Article 12 states the necessity of carrying Security Analysis to respect (N-1)-Criterion. Contingency Analysis and handling in Article 13 is one of the essential tools and solutions for maintaining Operational Security, providing thus also a basis for the inputs for congestion

		management (i.e. capacity calculation and its constraints) and balancing. Article 14 defines the security and redundancy principles of protection systems, which are fundaments for Operational Security. Article 15 defines the principles for dynamic stability analysis and needed protection in order to maintain system security. Chapter 3 The information shall be provided in every operational State by other TSOs, DSOs or SGU. The information is needed to efficiently monitor the System in Real-Time. Operating the electric power system in a safe, secure, effective and efficient manner is covered in Articles 31(4), 32(8) and (9), 33(2) and (3). Article 32(8) requires the necessary analysis and planning to be carried out using the common grid model.
	Avoiding further deterioration of Operational Security in cases, where security constraints are violated and systems are not in normal operating state.	Articles 8(9), 8(10) and 8(11) describe actions to be undertaken by TSOs to prevent the spread of non-Normal States and to return to Normal State. The provisions in Article 9 are based on current best practices which aim at the coordination of the TSOs and maintenance of the Operational Security and, in case of occurrence of security constraints' violations, the avoidance of deterioration of the Operational Security. The conditions set in Article 10 are based on current practises of the TSOs and designed to avoid further deterioration of the Operational Security in the power system. The conditions set in Articles 11(1) – 11(5) are based on current practises of the TSOs and designed to avoid further deterioration of the Operational Security in the transmission system. Article 12 Allows the use of Redispatching measures. Article 13 calls for respective Remedial actions wherever a possible deterioration by a Contingency is identified. Article 14 defines the security and redundancy principles of protection systems, which are fundaments for Operational Security. Article 15 defines the principles for Dynamic Stability Analysis and needed protection in order to maintain Operational Security. According to Chapter 3 the information shall be provided in every operational State by other TSOs, DSOs or SGU. The information is needed to efficiently monitor the System in Real-Time. Article 33(2) allows a TSO to postpone or interrupt testing if system conditions require. Article 33(3) allows for testing to be interrupted in the event of a non-normal system state in the TSO's system or that of another TSO's system.
Criteria	The Network Code(s) shall provide criteria (performance indicators)	Considered in Article 32.

	against which the Operational Security can be monitored.	
Methodology and Tools	Coherent minimum security criteria, which are mandatory within a synchronous area;	Article 8 sets the necessary common criteria for monitoring operational parameters and determining the System States, and also the minimum requirements in terms of organization for ensuring the availability, redundancy and reliability of the critical tools which are required for system operation. Article 9 sets the necessary common minimum requirements in terms of contribution to the Load-Frequency Control Structure, parameters to be monitored and necessary coordination among TSOs, as well as among TSOs, DSOs and Significant Grid Users. Article 10 sets a harmonised framework for: - The definition of min. and max. limits for voltages and time duration in Connection Points; - The coordination of voltages and reactive flow limits on the interconnections. Article 11 sets the necessary common minimum requirements in terms of: - The definition of min. and max. limits for short-circuit current Article 11(1); - The Short-circuit Current and power calculation Article 11(3). Article 12 considers the definition of and respect for Power Flow Security Limits in N and N-1 situation. Article 13 defines minimum criteria for Contingency Analysis mandatory within a Synchronous area concerning definition of Contingencies, Contingency Analysis actions, Remedial Actions, but also exemptions from (N-1)-Criterion in Article 13(9). Article 14 defines coherent security criteria for protection systems. Article 15 defines the principles for Dynamic Stability Analysis and needed protection in order to maintain system security. Chapter 3 provides the necessary information required by the TSO to securely operate the Transmission System in any Synchronous Area.
	Operational security rules, which shall be aligned as far as technically possible and economically beneficial throughout the EU, irrespective of synchronous area borders;	Article 8 sets Operational Security rules in terms of actions to be undertaken by TSOs to prevent the spread of non-Normal states and to return to Normal State. Article 9 sets a harmonised framework concerning the processes to be followed by the TSOs for frequency control management. Article 10 sets the necessary common minimum requirements in terms of the definition of min. and max. limits for Transmission System voltages in Article 10(1), and coordination for voltage ranges and Reactive Power flows among the Interconnectors in Article 10(10); Article 11 sets the necessary common minimum requirements in terms of the definition of min. and max. limits for Short-circuit Current in Article 11(1). The Short-circuit Current and power calculation in Article 11(3).

		Article 12 considers the definition of and respect for Power Flow Security Limits in N and N-1 situation. Article 13 unifies the key Operational Security for Contingency Analysis for each TSO throughout the EU. Article 14 defines provisions for the protection systems throughout the EU. Article 15 defines provisions for the Dynamic Stability management throughout the EU. Chapter 3 provides the necessary information required by the TSO to securely operate the Transmission System in any Synchronous Area. Chapter 5 Compliance is applicable within each of the Synchronous areas. It describes common principles, requirements, standards and procedures.
	Appropriate minimum technical and organisational standards and requirements applicable for Operational Security, covering e.g. aspects of state estimation; security analyses, data exchange and SCADA (Supervisory Control and Data Acquisition) systems;	Article 8 sets the necessary common minimum requirements in terms of : - Availability, reliability and redundancy of critical tools and facilities in Article 8(15); - Business Continuity Plan in Article 8(16); - Security Plan in Article 8(17). Article 9 sets the necessary common minimum requirements in terms of: - Real time frequency and Frequency Restoration Control Error monitoring in Article 9(10); - Monitoring of generation and consumption schedules, injections and withdrawals, power flows and other parameters which might influence the frequency. Article 10(11) sets the necessary common minimum requirements in terms of coordinated security analysis between TSOs to ensure the respecting of voltage ranges. Article 11 sets the necessary common minimum requirements in terms of : - The definition of min. and max. limits for short-circuit current in Article 11(1); - The Short-circuit Current and power calculation in Article 11(3). Article 12 states the obligation to monitor Power Flows and perform Security Analysis based on real-time telemetry. Article 13 defines the Contingency Analysis common principles in a harmonized way, which represents a significant part of the overall Operational Security Analyses. Article 14 defines minimum technical and organizational standards for protection systems. Article 15 defines minimum technical and organizational standards for Dynamic Stability management. Chapter 3 defines the data necessary for the SCADA and State Estimation.
	Roles and responsibilities of TSOs and Significant Grid Users in all	Articles 8(9) and 8(10) describe communication from TSOs to DSOs in case of situations that

	operating states, including actions to be taken;	can lead to emergency measures involving grid users connected to Distribution Network. Articles 8(13) and 8(14) describe coordination between TSOs and DSOs when Remedial Actions can have an impact on Distribution Networks. In the other requirements, DSOs are considered as Significant Grid Users. Article 9 sets obligations to TSOs concerning the contribution to Load-Frequency Control Structure and foresees the coordination among TSOs, DSOs and Significant Grid Users concerning the terms and conditions for actions taken in all System States. Article 10 sets the obligations mainly to TSOs. Article 10 treats DSOs as grid users excepted in Article 10(9) (conditions for disconnection of SGU connected to the Distribution network). Article 10(15) (coordination with TSO for directing SGU connected to the Distribution Network with voltage instruction), and Article 10(17) (Demand Facilities disconnection if needed to avoid voltage collapse). Article 11 defines the responsibilities of the TSOs in terms of the Short-circuit Current management. Article 12 defines that respecting of Power Flow Security Limits in the Transmission System is carried out by TSOs. Redispacthing is also done by TSOs. Article 13 defines these roles and responsibilities accordingly, with a focus on TSOs. Article 14 defines the requirements for protection systems, which shall be in place in all System States. Article 15 sets obligations mainly to TSOs. Chapter 3 defines what data has to be shared between TSOs and what data has to be sent by DSOs and SGU. Data has to be provided in every System State. Chapter 5 sets out the responsibilities of TSOs, DSOs and Significant Grid Users in relation to compliance testing.
	Coordination requirements with other TSOs and other SGU;	Articles 8(9), 8(10), and 8(11) describe communication and coordination between TSOs in case of non-Normal states. Security Limits of interconnections are defined in a coordinated way in Article 8. Defining Remedial Actions has to be done in coordination with the DSOs but when implementing them, DSOs have to execute instructions given by the TSOs. Article 9(4) sets the obligation to the Significant Grid Users to inform their respective System Operator if they deviated from the required disconnection frequencies according to NC RfG. Article 10 sets the obligations for coordination with other TSOs in relation to: - Maintaining voltages at Connection Points; - Operational Security Analysis. Article 13 defines to one of the most important coordination aspects in terms of the Common

		Grid Model, referring also to the related methodologies in NC OPS. Article 14 defines the coordination principles of protection functions and settings for all parties having protection systems. Article 15 defines the coordination principles for wide area Dynamic Stability management. DSOs and SGU shall provide information stated in Articles 21 to 29. TSOs shall exchange information defined in Articles 17 and 18. Article 32(8) requires the necessary analysis and planning to be carried out using the Common Grid Model. Article 32(9) requires information exchange between TSOs. Article 33(3) ensures coordination under non-Normal System States.
	Requirements in relation to the relevant system parameters, criteria and technical aspects in order to contribute to Operational Security, in particular referring to: - Security criteria (e.g. Contingency Analysis); - Normal vs. Alert vs. critical operating state; - Frequency and voltage parameters; - Requirements for voltage and Reactive Power management; - Short-circuit Current requirements, provisions and coordination; - Rotor angle stability requirements, provisions and coordination; - Requirements for coordination and information on protection settings.	Article 8 sets the necessary common criteria for determining the System States. Article 9 refers to the frequency quality defining parameters defined in NC LFCR to be pursued by each TSO. Article 10 sets the requirements for voltage and Reactive Power management and the necessary common minimum requirements in terms of the definition of min. and max. limits for Transmission System voltages in Article 10(1). Article 11 sets the Short-circuit Current requirements. Article 12 considers the definition and respect of Power Flow Security Limits in N and N-1 situation. Article 13 defines the key actions in relation to the definition of (N-1)-Criterion, possible violation of this criterion and necessary Remedial Actions for prevention / remedy, relating them to the key concepts of TSO Responsibility and Observability Areas within which the Contingency Analysis setup and operation is implemented. Article 14 defines the coordination principles of protection functions and settings for all parties having protection systems. Article 15 defines Rotor Angle Stability requirements, provisions and coordination. No Operational Security Limits are defined in Chapter 3 but Information defined in Chapter 3 is necessary for Security Analysis. Article 33(2) allows a TSO to postpone or interrupt testing if system conditions require. Article 33(3) allows for testing to be interrupted in the event of a non-Normal System State in the TSO's system or that of another TSO's system.
	The definitions of Operational Security requirements shall always include the essential aspect of need for security of persons and goods.	Article 1(5) is general requirement asking always respect relevant provisions for human safety and nuclear safety.

		Article 9 sets requirements on the contribution of each TSO to the Load-Frequency Control Structure aiming at preventing damage to all Transmission System elements SGUs and related equipment and providing safety for persons and goods. The requirements set in Articles 10 and 11 aims to prevent damage to all types of SGUs, network elements and related equipment and to provide safety for persons, through the maintaining of nominal voltages. Article 12 states harmonised principles for defining Operational Security Limits. The objective is to avoid damage due to operating the system over the thermal capabilities of the equipment. In Article 14 the aspect of security of persons and goods is always present. Article 33(2) allows tests to be interrupted or postponed due to safety of personnel or equipment.
	In order to perform efficient and effective operational planning and transmission capacity calculation, it is essential that the Network Code(s) provide for a unique timing and contents of the common grid model and harmonised schedule for individual TSO data exchange.	Considered in Chapter 3, Data exchange. Defined in general provisions stated in Article 16.
	The Network Code(s) shall also contain all the necessary provisions applicable to significant grid users that are connected to distribution networks, so far as they affect the Operational Security of the network. These provisions shall be agreed upon by the TSOs and the concerned DSOs (i.e. in order to ensure applicability for the significant grid users connected at DSO level, in which case the DSOs has an obligation to submit the positive results of the conducted compliance tests to the TSOs).	Article 8(14) describe obligations for SGU and DSOs in implementing Remedial Actions asked by the TSO, and DSO's role between TSO and SGU connected to distribution network. Article 9(4) sets the requirement for the Significant Grid Users to inform their respective Transmission or Distribution System Operator if deviations from the requirements described in NC RfG concerning disconnection frequencies exist. Article 10 sets the requirement to Significant Grid Users to disconnect if it is required by a TSO. Article 13 specifies provisions for SGUs to deliver necessary data and information, with a possibility of data aggregation if this is justified according to Article 27(2). Article 14 defines protection coordination principles between TSOs, DSOs and Significant Grid Users. Article 15 defines the Dynamic Stability requirement for Significant Grid Users where relevant. Considered in Chapter 3 Data exchange, SGU connected to Distribution Networks shall provide data defined in Articles 25, 26, 27 and 29. TSOs, DSOs and Significant Grid Users are included in Chapter 5 on compliance.
	To achieve coherent and coordinated behaviour of, particularly but not limited to, each Synchronous Area under Alert Operating States as well as in emergency operating states the Network Code(s) shall provide for TSOs` coordination in terms of joint Remedial and Restoration Action plans.	Articles 8(9), 8(10), and 8(11) describe actions to be undertaken by TSOs to prevent the spread of non-Normal states and to return to normal state. Article 9(2) and 9(3) defines the requirements for coordinated actions of TSOs at least on the Synchronous Area level in case of significant frequency excursions.

		Article 14 defines protection coordination principles between TSOs and DSOs. Chapter 3 defines the data that has to be shared to know Operational States of neighbouring TSOs. Data shared between TSO is stated in Articles 16 to 18. Article 33(2) allows a TSO to postpone or interrupt testing if system conditions require. Article 33(3) allows for testing to be interrupted in the event of a non-Normal System State in the TSO's Responsibility Area or that of another TSO.
Roles and Responsibilities	The Network Code(s) should aim at a minimum set of Operational Security provisions that must be met by any affected TSO, DSOs or SGU.	Article 1 sets the legal framework for this requirement. Article 8 sets a minimum set of Operational Security provisions for: - The classification of the System State (parameters to monitor and common criteria); - Definition of Operational Security Limits; - TSO's responsibilities when the System State is not normal; - TSO's and DSO's role in Remedial Action preparation and implementation; - Availability, redundancy and reliability of critical tools for system operation; - Principles for Business Continuity Plan and Security Plan. High level principles for Security Analysis (to be detailed in NC OPS) Article 9 sets minimum requirements for the TSOs concerning the contribution of each TSO to the Load-Frequency Control Structure, the provision of active power reserves and continuous monitoring of parameters which affect the Operational Security of the system in terms of frequency. Article 10 sets minimum requirements in the framework of the maintaining voltages at Connection Points and define voltage control actions. Article 11 sets minimum requirements in the framework of the Short-circuit Current management. Article 12 defines that respecting of Power Flow Security Limits in the Transmission System is carried out by TSOs. Redispacthing is also done by TSOs. Article 13 defines minimum set of requirements on Contingency Analysis with main focus on TSOs and their cooperation and coordination. Article 14 defines minimum set of criteria for protection systems. Article 15 defines minimum set of criteria for Dynamic Stability management. Chapter 3 provides the necessary information required by the TSO to securely operate the System. That information shall be provided by other TSOs, DSOs or SGU.
	TSOs' coordinated Remedial Action plans including cost sharing principles shall be submitted to national regulatory authorities (NRAs) for approval.	Article 3 enables the NRAs to be involved where involvement is foreseen either by EU or by national law.

		In Article 14 this has been taken into account in requirement of Low Frequency Demand Disconnection.
Information exchange	The Network Code(s) shall define the timing and content of data exchange between TSOs, among TSOs and DSOs, between TSOs/DSOs and significant users and among adjacent DSOs for: • The common grid model; • Issues related to secure system operation, such as detection of security criteria violation; • Real-time information on network configuration and the status of significant grid users; • Matters of significance for the security of supply, such as information from TSOs regarding when they can no longer comply with an Operational Security provision (i.e. real-time and mid-term).	Framework is set in Chapter 3 Data Exchange. Considered in Articles 16 to 18. In Chapter 5 data exchange for compliance tests and analysis is covered in Article 31(2), (3) and (4), 32(6), (7) and (9) and Article 33(4), (5).
Implementation Issues	The Network Code(s) must consider existing differences in Operational Security requirements between the synchronous areas and hence, define the procedure for smooth and undisturbed transition to a harmonised state. The Network Code(s) shall list all links necessary from Operational Security perspective to other relevant Network Code(s).	The requirements set in Article 9 take into account the existing differences between Synchronous Areas by setting a common framework for the frequency control but leaving, at the same time, concrete values to be defined by each Synchronous Area. The requirements set in Article 10 take into account the existing differences between Synchronous Areas by setting a common framework for the voltage control but leaving, at the same time, concrete values to be defined by each Synchronous Area. The requirements set in Article 11 take the existing differences between Synchronous Areas into account by setting a common framework for the Short-circuit Current management but leaving, at the same time, concrete values to be defined by each TSO depending on the System characteristics. Article 12 affects all Synchronous Areas equally. Article 13 establishes the flexible and EU-wide applicable framework for Contingency Analysis, providing at the same time all required references to the other relevant Codes. Article 14 Protection defines harmonized criteria for all Synchronous Areas. Chapter 3 provides the necessary information required by the TSO to securely operate the System in any Synchronous Area.
	Topic 4: Training and Certification	
Scope and Objectives	Staff working in control rooms to be properly trained, with common Training principles and Certification. Leading to better co-operation and co-ordination at European level, with TSOs inviting DSO and other SGUs to participate in training.	Article 30 sets out a clear obligation on TSO to ensure System Operator Employees are trained and that the System Operator Employees in real-time operation also Certified. Training underpins safe, secure and economic operations. There is a common set of requirements for Training and Certification between and within Synchronous Areas, which involves users.
Criteria	The TSO have sufficient skills to maintain security under different network conditions, knowledge of market effects and sufficient knowledge of English to carry out tasks in co-operation with neighbours.	Article 30 requires initial and continuous training under all System States, together with training in market arrangements and for inter-TSO language training in English, unless agreed otherwise between the TSOs.

Methodology and Tools	Necessary qualifications are defined, together with roles and responsibilities. A defined training process with minimum content and inter TSO training. An assessment by the TSO of the candidate's ability to perform the necessary tasks with criteria that ensures a high degree of quality, objectivity, independence and transparency. A validity period for the Certification. A train the trainer programme. Models, tools and databases at a sufficient level including neighbours network. Monitoring of training effectiveness and adjusting procedures and processes. Retaining evidence of training.	Article 30 requires TSO to define qualifications for its System Operator Employees, to set out a complete Training process and requires Certification of the System Operator Employees in real-time operation only after formal assessment to a predefined level of competence. Inter TSO Training requirements are set out, as is a continuous Training programme and a maximum period before renewal of the Certification. Article 30 requires TSO to have training in teaching and mentoring skills and defined level of competency for on-job trainers, with models for training at comprehensive level nationally and with neighbour's network data, it also requires TSO to review Training programmes at least annually. Article 30 requires TSO to keep records of an individual training.
Roles & Responsibilities	TSO responsible for selection, assessment and assignment of their staff, ENTSO-E shall co-ordinate Training and Certification	Article 30 of the ENTSO-E developed OS NC sets out a clear obligation on TSOs for assessment of their Operators suitability for the roles they perform.
Information Exchange	TSO exchange operational experience within Regular joint training between neighbouring TSOs	Article 30 requires sharing between TSOs on operational experience and regular joint training between relevant neighbouring TSOs.
2.1	**New Applications**	
2.1	The Network Code(s) shall be elaborated in such a way not to be detrimental to innovation in electric power system operation, maintenance and control. Where, forthcoming changes and challenges caused by further market integration and innovation in technology and organization can be foreseen, they should be recognized and considered in Network Code(s) so as to ensure that system operation rules are in place to accommodate their integration.	The code leaves flexibility for the development of new applications in Article 1. All principles through the code are based on existing practices. Requirements describe the objectives to be reached but not the detail of technologies to be used, so it remains valuable even when technologies will progress.
2.1	Among such future trends the following issues should be taken into account: • Integration and operation of a DC power-transport lines, used for "collecting" the massive wind power generation in the North and solar-thermal generation (CSP) in the South of Europe; • Methods and tools enabling high-level and efficient TSO coordination during the operational planning and scheduling and real-time system operation. In particular, the adequate operational observability and control of electric power system, during the transition to low carbon society; • Dynamic rating of power cables and overhead transmission lines; • Close interaction of the future integrated electricity balancing markets of Europe with the intraday trade and manually activated (tertiary) reserves; • Coordinated usage of FACTS for active load flow control and system stability augmentation; • Advanced storage technologies; • Smart applications (e.g. pooling of distributed generation, storage and demand response).	OS NC leaves flexibility for the development of new applications in Article 1. All principles through the OS NC are based on existing practices. Requirements describe the objectives to be reached but not the detail of technologies to be used, so it remains applicable even when new solutions are developed and technologies progress.

ANNEX III - NATIONAL REGULATORY AUTHORITIES´ INVOLVEMENT IN THE FRAMEWORK OF THE OS NC

NATIONAL REGULATORY AUTHORITIES´ INVOLVEMENT FOR INFORMATION PURPOSES IN THE FRAMEWORK OF THE OS NC

The National Regulator Authorities or, when explicitly foreseen in national law, other relevant national authorities are mandated with regulatory oversight over the regulated Transmission System Operators and have within this mandate the access to all the necessary information.

The following list of items, referred to in the OS NC within the respective Articles, are provided to the NRA or other authority if explicitly foreseen in national law, is enclosed here for the sake of completeness and for ensuring that the interests and suggestions of stakeholders raised during public consultation and workshops are duly taken into account. It is important to emphasize that the necessary legal basis for providing this information to the NRAs or other relevant authorities if explicitly foreseen in national law, already exists within the scope of the Directive and its implementation into the national laws of the Member States.

a) Operational Security Limits and other parameters of Interconnectors pursuant to Articles 8(6), 8(8), 10(10);

b) Operational Security Limits pursuant to Article 8(6);

c) Business Continuity Plan pursuant to Article 8(16);

d) Confidential Security Plan pursuant to Article 8(17);

e) Provisions in relation to frequency management pursuant to Articles 9(2), 9(3), 9(10) and 9(12);

f) Criteria and conditions for manual or automatic re-synchronization for SGUs and DSOs by the TSO pursuant to Article 9(6) and by the DSO pursuant to Article 9(7);

g) Predefined active power steps for automatic disconnection at specified frequencies by the TSO pursuant to Article 9(8);

h) Information on coordination of TSOs within Synchronous Area and coordination with involved DSOs pursuant to Article 9(9);

i) Active Power Reserves at different time-frames according to the provisions of the NC LFCR pursuant to Article 9(12);

j) Restrictions on the Active Power Ramping Rates of the Significant Grid Users by the TSO pursuant to Article 9(14);

k) Voltage ranges for reference voltages defined by TSOs between 110 kV to 300 kV (excluding) and between 300 kV and 400 kV pursuant to Article 10(1);

l) Wider voltage ranges by the TSO pursuant to Article 10(2);

m) Voltage and/or reactive power flow limits on the Interconnectors pursuant to Article 10(10);

n) Reactive Power set-points, power factor ranges or voltage set-points defined by the TSO pursuant to Article 10(12);

o) Voltage control actions defined by the TSO with the Significant Grid Users, DSOs and neighboring TSOs pursuant to Article 10(15);

p) Measures for blocking of automatic voltage/Reactive Power control of transformers or other voltage control instructions by the TSO pursuant to Article 10(17);

q) Operational Security Limits for power flows pursuant to Article 12(1);

r) Contingency List by the TSO pursuant to Article 13(1);

s) Decision by the TSO not to apply Costly Remedial Actions pursuant to Article 13(3);

t) Criteria for coordination and harmonization of Contingency Lists across the Synchronous Areas pursuant to Article 13(5)(f);

u) Results of Dynamic Stability Analysis (DSA) pursuant to Article 15(2) and 15(3);

v) Measures to keep the Transmission System stable involving Significant Grid Users which are Power Generating Modules pursuant to Article 15(6);

w) Decision by the TSO to receive information from Significant Grid Users connected to the Distribution Network directly or via the DSO pursuant to Article 27 and Article 29.

x) Training and certification information pursuant to Article 30(1), Article 30(13) and Article 30(14).

y) Request of compliance testing results from SGU connected to DSO, if this is relevant for the Operational Security of the Transmission System pursuant to Article 31(7).

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

ANNEX IV - OPERATIONAL SECURITY NETWORK CODE

SUMMARY OF COMMENTS RECEIVED DURING PUBLIC CONSULTATION AND OVERVIEW OF THE ENTSO-E RESPONSE

Purpose

This annex briefly summarises the comments received during public consultation and outlines the way in which those proposals have been taken into account in the updated Operational Security Network Code. Comments are grouped by Article and are summarised for the sake of better readability and comprehensiveness.

Comments Received

Whereas and Article 1 – Subject Matter and Scope

Summary	101 comments (of which 52 were considered to be of a legal nature) were received on either Article 1 or the whereas section. Four themes emerged several times in relation to Article 1: 1) The coherence of the definition of Significant Grid User across Network Codes; 2) A need for greater clarity regarding DSO Involvement; 3) The need for an exemption for Isolated Systems; 4) TSO decision process In addition, significant comments were received on the whereas section due to the inability, which we are seeking to address, for general comments or comments related to the whereas section to be submitted via the consultation tool.
Changes made & explanation	The point regarding coherence with RfG and DCC definitions of Significant Grid Users is important and has been the focus of much attention. It is now defined more precisely in the new Article 1(3). The OS NC version after public consultation defines objective criteria to determine which Grid Users are considered Significant. These criteria rely in two main aspects: their connection to the Transmission System and their impact in System Operation through the Generation-Demand Balance; for example providing Ancillary Services. The concept of SGU is explained in supporting document. The exemption for isolated systems has been deleted because the Network Code, by definition, applies to cross border and market integration issues. However, an exception for Baltic systems has been added. Article 1(5) on nuclear safety is included to reflect concerns of stakeholders the relevance of human and nuclear safety. The main requests on whereas section were to change ''should'' to ''shall'', but as this is not a binding part of the document it was done according to the practice of EU legislation focussing on the binding requirements in the OS NC.

Article 2 - Definitions

Summary	167 Comments were received on Article 2. 77 comments included requests to add to or to change definitions which already exist in EU legislation or in Network Codes which have previously been submitted to the Agency. As such, and in the interests of consistency, it has not been possible to make changes in light of these comments. 33 comments which asked for refinements and improvements in definitions have been incorporated in the Network Code in order to improve clarity. 57 comments were partially accepted because they ask for more definitions. In deciding on which terms to include we tried to be mindful that: the objective is to create a single set of definitions applicable to all Network Codes; to ensure simplicity as far as possible and to avoid very specific definitions. Some suggestions would have limited the ability to use a term elsewhere.
Changes made	Significant attention has been given to refining and harmonising definitions. A group of dedicated experts from ENTSO-E's System Operation Network Codes' drafting teams were assigned with resolving of definitions and liaising with representatives from all other drafting teams (for the other Network Codes being developed) to align definitions. In doing this, they drew mainly on comments from public consultation respondents and on always ensuring maximum possible consistency and coherence.
Explanation for change or no change	As noted above, it is important that, to the highest extent possible, a single glossary is established for all Network Codes. Avoiding overlaps is essential and definitions need to be written in a way such that they are fit for purpose for other Network Codes. Hence, they cannot be overly specific. Attention is drawn to the following definitions which require more explanation on the basis of stakeholder suggestions: Extension of *Observability Area* to the level of Distribution Network - the scope becomes too deep and not covering cross border issues. Explanation of ASAP - asap doesn't mean any strict period, because it depends on the reasons, which are not possible to harmonize by any classification. Additional definition on *Real Time*, *Element* - real time period is different for different purposes, so common definition is not possible and Element is too general term and may cover all equipment needed. The new term could limit the new technologies. More information on *Contingency* - additional information as time of repair is usually provided as common practice asap as it is known. It seems too detailed for definition. Explanations of Areas - Different areas for System Operation are used only by TSOs - LFC Area, Responsibility Area and Observability Area. There are different functions and responsibilities of TSOs, but grid users are connected to TSO and do not have any obligation concerning different areas. Extension of responsibilities - TSOs are not responsible for quality, reliability and security in the Distribution Network.

	Limitation of transmission system voltages - transmission system is very different in Europe. Definition should include all voltages. Definition of *(N-1)-Criterion* - it concerns only transmission. In transmission system N-1 should be fulfilled even in maintenance period. Outage is already taken into account in N-situation Concerning busbars in *Ordinary Contingency* - it depends on the importance of the substation and is assessed by TSOs each case individually. *Significant Grid Users* - RfG covers only new grid users, OS code covers existing users also. SGUs are defined in more details in Article 1(3). *Contingency Analysis* - TSOs are doing Contingency Analysis only for Transmission System, it doesn't mean that TSOs are doing security analysis in DSOs network by taking into account element of DSO network. *Active Power Reserves* - general definition is needed, NC LFCR deals with different kinds of Active Power reserves. OS NC covers on general level. Concerning of using the definitions - the formulation “for the avoidance of doubt” is really contractual and does not fit for an EU regulation. The current wording seems to reverse the principle that the definitions of a previous NC shall prevail over the definitions of a subsequent NC. *System Operator Employee* - in this case definition is correct. For DSOs the DSO operator could be defined. *N-Situation* - it concerns only transmission. Generation is treated from TSOs point of view, to cope with loss of generation. In transmission system (N-1) should be fulfilled even in maintenance period. Planned outage is already taken into account in N-situation. No need to define significant or relevant TSO, or relevant DSO. All TSOs are equal and all DSOs connected to transmission grid are equal. In *Operational Security Limits* - acceptable means taking into account physical limits of each equipment. The range of existing equipment is too wide to specify. High priority Demand Facilities is a national issue and should be defined in cooperation with NRA and Government. It is a matter of national legislation.

Article 3 – Regulatory Aspects and Approvals > new Article 3 Regulatory Aspects and Article 4 Regulatory Approvals

Summary	30 comments (of which 14 were of a legal nature) were received on this Article. Three themes emerged several times: 1) NRA involvement; 2) Safety (including nuclear and human safety); 3) Transparency.
Changes made	Article 3 is split into two articles - 3 Regulatory Aspects and 4 Regulatory Approvals Article 3(3) concerning NRA involvement has been removed and replaced

	after consultation by Articles concerning direct NRA involvement in specific approvals. An additional article has been added due to concerns of stakeholders about the relevance of human and nuclear safety. Finally, the references to the NRA involvement in Articles which are explicitly covered by the Member States national legal frameworks are removed from the OS NC but listed in Annex III for completeness and for fulfilment of the needs expressed by the stakeholders.
Explanation for change or no change	Article 3(3) concerning NRA involvement has been removed and replaced by specific NRA involvements for the following reasons: a) Article 37 of Directive 2009/72/EC sets out the roles and responsibilities of NRAs regarding issues of system operation; b) the goal of the Generic Clause which will be included in all the operational Network Codes is to provide an opportunity, consistent with the provisions of the Directive, for NRAs to comment and express concerns. Article 4(1) aims to reassure Power Generating Facilities which could be afraid of being asked more in this code than the capabilities they are obliged to have in application of the connection code. Transparency market issues are dealt in the Transparency Guidelines. Not all information should be open close to real time. The scope of the OS NC is only addressed to network connected parties. Even though, Article 3(1) imposes that all requirements under this Network Code are established also under the principle of transparency. Therefore, this principle - substantiated in the Transparency Guidelines - is fully respected.

Article 4 – Recovery of Costs > new Article 6

Summary	16 comments (of which 9 were of legal nature). All focussed on including stakeholders' costs within the scope of the provision.
Changes made	Article 5(1) covers the costs of all regulated network operators. New Article 5(4) asks for methodology for recovering the costs of test of compliance in order to reflect the existing practices of national regulatory frameworks.
Explanation for change or no change	Following discussions with regulators, it is considered that the issue of stakeholder cost recovery is a matter of national legal framework.

Article 5 – Confidentiality Obligations > new Article 6

Summary	7 comments were received on this Article. Topics focussed on: 1) The need for consistency with other NC, i.e. DCC; and 2) Information exchange.
Changes made	Article 6 (3) has been harmonised with Article 5 of the draft NC OPS.

	Comments concerning data exchange have been accepted.
Explanation for change or no change	Article 6 (3) has been harmonised not with DCC as proposed, but with Art. 5 of NC OPS. Comments concerning data exchange were beneficial to the clarity of the code and can be accepted, but they don't require changes. The data exchange between TSO's, DSOs and significant grid users is treated in the data exchange chapter.

Article 6 – System states > new Article 8

Summary	130 comments were received on this Article. The main themes emerging several times were: 1) There is a need for more common principles and values which can be used in defining system states; 2) Information is needed on the consequences of the system states for grid users; Parties wished to understand how the monitoring of the number of alert states would be undertaken; How communication to grid users about non normal states would take place; 3) What would be the priority used in the re-energizing process; 4) There is a need for more figures and more obligations for TSOs; 5) There is a need to more clearly demonstrate links with frequency and voltage ranges defined in NC RfG and DCC; 6) There should be greater and clearer stakeholders and NRA involvement in the definition of Operational Security Limits; 7) PGFs and DSOs should be involvement in coordination; 8) There should be clearer links with contractual agreements in place; 9) The code should cover cost recovery for SGU participating in a Remedial Action; 10) Links between the OS NC and the NC OPS and NC CACM should be more carefully and thoroughly managed.
Changes made	A large number of changes have been made in light of these concerns, with most important ones summarized below: Article 8(1) gives common criteria and values to define System States, so that each TSO evaluates the state of its system using the same set of criteria. Articles 7, 8 and 10 have been improved with more figures and more precise arrangements for TSOs. More precise criteria have been added in System State definition. Consistency with SGU capabilities defined in NC RfG, DCC or national laws has been described and is outlined further in the earlier parts of this supporting document. Regarding coordination: more precision and differentiation has been made in Article 8 about the coordination of the actions taken in the preparation, and implementation of Remedial Actions in real time. NRA involvement is explained in the summary relating to Article 3. Consistency with the Incident Classification Scale (ICS) has been improved, so that the ICS annual report can serve to monitor the number of alert or

	emergency states. Article 32(10) has been added, specifying that each TSO shall elaborate a list of high priority Significant Grid Users in terms of the conditions for their disconnection and re-energizing. Article 34 defines the process of amendments of contractual agreements in place. Links with the NC OPS and NC CACM have been added regarding coordination and security analysis. The earlier parts of the supporting paper have provided information regarding: 1) The consequences of the System States for Significant Grid Users; 2) How the ICS allows monitoring the level of Operational Security of the Transmission System.
Explanation for change or no change	The article gives precise criteria to characterize the System State in a coherent way in every part of the grid; Articles 7 and 8 contain more precise figures for Operational Security limits for voltage and frequency, and Article 13 gives common principles regarding contingencies to take into account for State Estimation. The codes provisions relating to information provision are aligned with the EU Transparency Guidelines and reflect the obligations set in that Regulation. A precise definition of the impact on grid users in case of emergency state cannot be provided through the OS NC, since it can be very different depending of the succession of events that have occurred. Thresholds for declaring a Blackout state are in line with criteria of the Incident Classification Scale. Cost recovery is dealt in the Article 5 of this NC. The content of system defence actions and plans, coordination in emergency and restoration processes will be described in the NC Emergency. A definition of Reactive Power Reserve has been added. The Reactive Power Reserve can be derived from the current maximum capability of the Power Generating Facility and the value provided at the time t. TSOs need to know system capabilities in real-time so the availability of reserves is important to evaluate e.g. available Remedial Actions. TSOs are not the only body that influences the parameters of the system, so they will do their best but cannot guarantee that a normal state will be maintained in all circumstances. An Alert State only has consequence for the Significant Grid User performing compliance tests and the probability that the Alert State degrades to Emergency State may be low. Warning Significant Grid Users at each Alert State could be harmful because of loss of credibility and significance of such warnings. The first priority is to recover the Transmission System as fast as possible, so information will be delivered first to those who are involved in restoration plans. Further steps in communication and coordination in case of a Blackout will be

	defined in NC Emergency and Restoration. In accordance with the Incident Classification Scale, the number of Alert or Emergency States will be counted and the evolution of their number will be analysed. Remedial Actions are indeed covered in both the CACM Network Code and the OS Network Code. The crucial difference is that CACM Network Code considers the Remedial Actions when calculating capacities, while OS Network Code considers actions to maintain Operational Security at all times. These are related but different. They also involve a different set of conditions and consequences which need to be weighed against each other, e.g., – with one leading to a potentially larger amount of capacity being made available to the market and the other potentially mitigating a serious Operational Security issue. The new version of the OS NC deals with the preparation and the implementation phase of Remedial Actions in two different articles. DSOs shall be part of the coordination ex-ante, so as the Remedial Actions can be validated before real-time and set up without delay when needed. The OS NC defines the needs for Operational Security and contractual agreements shall be in line with these needs, otherwise they must be adapted. Whereas concerning redundancy of communication only Significant Grid Users should be concerned, new communication means should be compliant with these needs and OS NC requirements from their very fists usage. The NC OPS supporting document explains links and differences with Common Grid Model for capacity calculation.

Article 7 – Frequency control management > new Article 9

Summary	61 comments were received on this Article. The following topics emerged several times: 1) Consistency among the provisions of NC RfG, DCC and OS NC (17 comments); 2) DSO involvement (8 comments); 3) Frequency Performance Indicators (7 comments); 4) Links with the NC LFCR (5 comments); 5) Ramping rates of PGF (4 comments); 6) Provisions for over-frequency incidents (3 comments); 7) Provisions for high priority customers (3 comments); 8) Load shedding harmonization on the level of Synchronous Area (3 comments); 9) Significant Grid Users (2 comments).
Changes made	Reference in Article 9(1) has been made to the frequency quality defining parameters in NC LFCR. Furthermore, reference to the NC LFCR has also been included in the provisions of Article 9(10), 9(12) and 9(13) in order to link NC OS with the detailed requirements of NC LFCR. Requirements in Article 9(2) and 9(3) are included ensuring the harmonization of the Remedial Actions measures and procedures of the System Defence Plan such as Low Frequency Demand Disconnection scheme at least at the Synchronous Area level, while respecting the frequency and time ranges of

	NC RfG and DCC - the key issue here is consistency among the network codes. Requirements have been included in Articles 7(4) and 7(5) which are in line and reinforcing in a clear and transparent way provisions of NC RfG and DCC. The requirement of Article 9(14) which has been included provides the framework for the definition of Ramping Rates of Power Generating Facilities by each TSO. The provision for high priority customers has been treated in Article 32(10).
Explanation for change or no change	For the sake of not repeating requirements, parameters from NC LFCR have not been included in the OS NC. Furthermore, frequency excursion events are reported within the incident Classification scale (Frequency Performance Indicators). The involvement of the DSOs is provided in case the Significant Grid Users are connected to their network. Furthermore, provisions for Significant Grid Users which are not subject to or are derogated from the NC RfG and DCC are also included for the sake of completeness (consistency among the Network Codes, DSO involvement, Significant Grid Users). The frequency related Remedial Actions are described in a generic way with no differentiation between over-frequency and under-frequency measures, which is a subject of NC LFCR.

Article 8 – Voltage control and Reactive Power management > new Article 10

Summary	82 comments were received on this Article. The most comments were to Articles: 1) 8(4) (Reactive Power Operational Security Limits at the Connection Point) and 6 (disconnection at the specified voltages) - each of these 15 comments; 2) 8(5) (Power Generating Facilities remaining connected) - 10 comments; 3) 8(12) (maintaining voltage and Reactive Power flows at Connection Points by TSOs and DSOs) - 7 comments; 4) 8(7) (using of all available Reactive Power resources) and 8 (preparing Remedial Actions) - each 5 comments; 5) 8(9) (monitoring of respecting of operational voltage limits) - 4 comments; 6) 8(1) (maintaining the voltage and Reactive Power flows), 8(2) (defining voltage and Reactive Power flow Operational Security Limits), and 8(10) (operation of Reactive Power resources) - each 3 comments; 7) 8(11) (coordination of voltage control actions) - 2 comments; and 8) 8(3) (coordination of Operational Security Analysis) - 1 comment. The remaining comments proposed new paragraphs related mainly to the issue of registration of occurrences of voltages outside the ranges in 8(1).
Changes made	Concrete values for voltage ranges have been added in Article 10(1). Links with NC RfG and DCC have been explained, and the case of SGU who are not subject to or have derogation from these NCs has been described in Articles 8(3), 8(4), 8(5), 8(6) and 8(16). Obligations for TSOs have been added in Articles 8(4), 8(7), 8(8) and 8(14).

	Links with other NCs (RfG, DCC, OPS) have been made in Articles 8(4), 8(5), 8(9) and 8(12) Coordination with DSOs and SGU has been defined in more detail in Articles 8(12), 8(15), 8(16), 8(17). Coordination between TSOs has been defined in more detail in Articles 8(10) and 8(11).
Explanation for change or no change	Consistency with the incidents classification scale has been improved, so that the ICS annual report can serve to monitor situation where Operational Security Parameters are out of the ranges. More specific values for Operational Security Limits have been added. Wording has been streamlined and references with other Network Code made consistent. As described in Article 3(4) the OS NC relies on the capabilities required in the NC RfG and DCC, and no other capabilities. Power Generating Modules, Demand Facilities and HVDC links that are not a subject of the provisions in [NC RfG] and [DCC NC, shall continue to be bound by those technical requirements that apply to them pursuant to legislation in force in the respective Member States or contractual arrangements in force.

Article 9 – Short-circuit current management > new Article 11

Summary	15 comments were received on this Article. Four themes emerged several times: 1) NRA involvement; 2) The distinction (or lack of it) between the terms Control Area and Responsibility Area; 3) Observability Area Network; 4) Minimum limits of Short-circuit current. Several remarks have been repeated by different respondents.
Changes made	A consistent distinction between the definition of Short-circuit current limits in Article 11(1) and the maintenance of those limits in Article 11(2) by the TSO has been drawn. The minimum short-circuit current for correct operation of protection equipment has been included as well as the maximum short-circuit current at which the rated capability of circuit breakers and other equipment is exceeded for the definition of limits within the short-circuit current should be maintained. In Article 11(2) the proposed reference of operation according to national safety legislation (Article 1(5)) has been added In Article 11(3) OS NC establishes a harmonised framework for short-circuit current calculation. The aim is not to rewrite in detail existing international standards. In Articles 9(4) and 9(5) the impact of Closed Distribution Networks has been considered in the requirement.
Explanation for change or no	The term “Observability Area network” leads to confusion with the term

change	"Observability Area" and does not add any additional value. Articles 5 and 12 of the Directive 2009/72/EC do not directly impose a strict obligation to TSOs to ensure the short circuit management. Therefore, TSOs can only commit to "use its best endeavour". The following topics have been explained in the OS NC supporting document: 1) The distinction between Load Frequency Control Area and Responsibility Area; 2) That Article 5 and 12 of the Directive 2009/72/EC does not directly impose a strict obligation to TSOs to ensure the short circuit management; 3) The added value of harmonization for short-circuits current calculations established by Article 11(3). 4) The term "shall endeavour" in the framework of short-circuit management is explained in Annex V (Legal Issues), of the OS NC supporting document.

Article 10 – Power flow management > new Article 12

Summary	63 comments were received on this Article. The following themes emerged several times: 1) The obligation for the TSO to define the Operational Security Limits and to comply with (N-1) Criterion; 2) Suggestions to refer to power flow instead of Active Power flow to include also Reactive Power; 3) Suggestions to refer to Significant Grid Users instead of Grid Users, Generating Facilities or Demand Facilities; 4) A call to explain the difference between Responsibility Area and Control Area; 5) Comments to Include NRA involvement in the Redispatching measures; 6) A desire to see coordination between TSOs in accordance with CACM; 7) Request for greater coordination with DSOs and Significant Grid Users during the definition of Redispatching measures; 8) A call to avoid redundancy and respect existing information delivery concepts.
Changes made	All references in Article 12 have been modified to refer to power flow instead to Active Power flow. Coordination between TSOs, DSOs and Significant Grid Users has been moved to new Article 8. A reference to market procedures has been included in the recitals (Whereas) and the necessary references to NC CACM have been added. Paragraphs about Redispatching have been deleted, but updated Article 8 concerning Remedial Actions including Redispatching and Countertrading. Further explanation has been provided in the Supporting Document about the communication between TSOs and Significant Grid Users connected to the Distribution Network.
Explanation for change or no change	[NC CACM] defines Redispatching as "the measures activated by one or several System Operators by altering the generation and/or load pattern, in order to change physical flows in the Transmission System and relieve physical congestion". In CACM and OS NC scope, Redispatching is understood as a costly Remedial Action to relieve violation of Operational

	Security Limits detected in the security analysis. The security analysis performed on the basis of [NC CACM] and OS NC, although have its own distinctive features (i.e. timeframes), are in essence the same. Explanation of the difference between Responsibility Area and LFC Area has been included in the supporting document.

Article 11 – Contingency Analysis and handling > new Article 13

Summary	69 comments were received on this Article. The following themes emerged several times: 1) Referring to all Significant Grid Users connected to the Distribution Network; 2) TSO option of using the Remedial Actions; 3) Harmonization of key principles in the establishment of the Contingency List; 4) Involving DSOs in Contingency Analysis; 5) Avoiding redundancy and respecting existing information delivery concepts; 6) Ensuring CGM consistency with the [NC CACM]; 7) Including obligations on TSOs and DSOs to inform Significant Grid User prior to re-synchronization.
Changes made	Referring to all Significant Grid Users connected to the Distribution Network and not just to Generating Facilities (Article 27(1) where change was actually done). Generalizing the TSO option not to use Remedial Actions if consequences are only local and not endangering Operational Security of interconnected Transmission System. Harmonization of key principles in establishment of Contingency List. Involving DSOs in Contingency Analysis in which Significant Grid Users are addressed which are connected to the Distribution Network. Coordination and as far as reasonable practical and economically justified harmonization of the criteria for Contingency List establishment. Avoid redundancy and respect existing information delivery concepts. Article 13(13) ensuring CGM consistency with [NC CACM] definitions in Article 2. General Article 13 is always referring to the TSO Responsibility Area when talking about Contingency. There is only one – “the” CGM. More explanation is provided in the supporting document for NC OPS. Adjusted the formulation in former 11(19) and 11(20) to include the obligation on TSOs and DSOs also to inform Significant Grid User prior to re-synchronization, merged both paragraphs into one and moved to the Article on protection. Moreover, a number of simplifications, clarifications and improvements in the text have been conducted in order to raise clarity and understanding.

Explanation for change or no change	Regarding Significant Grid Users, a new definition has been included in Article 1(3) of the OS NC, consistent with all other Network Codes and appropriate to resolve the remark above. The TSO option not to use Remedial Actions refer to the costly ones, the respective approval (in the Code) and information (in the supporting document) to the NRA has been amended. The Contingency List provisions have been reworked and now present a harmonized approach. The involvement of DSOs and Significant Grid Users is mainly focused on the necessary data to be delivered and, where applicable, the parts of the Distribution Network which are relevant for the Operational Security of the Transmission System; no further involvement is considered necessary, bearing in mind that the primary focus of this Network Code is the Transmission System and the cross border influence.

Article 12 – Protection > new Article 14

Summary	27 comments were received on this Article. The following themes emerged several times: 1) Vague formulation "TSOs shall endeavour"; 2) Critical Fault Clearing Time; 3) More precise definition of protection; 4) Involvement of DSOs. Moreover, a number of simplifications, clarifications and improvements in the text were suggested and have been implemented to enhance clarity and understanding.
Changes made	Vague formulation "TSOs shall endeavour" was changed to a mandatory formulation in order to stress the TSOs responsibility of protection functions when ensuring system security. In respect of the Critical Fault Clearing Time - in order to clear Faults before wide area instability occurs was inserted and moved to Article 15(7). This will clarify the importance of deployment of fast and reliable protection system and to have coordination with requirements in NC RfG. A more precise definition was inserted concerning protection functions e.g. protection against over-frequencies and coordination with Significant Grid Users against faults in Transmission System e.g. synchronism (vector angle shift) check during reconnection after Faults. DSOs were added where they are affected or responsible parties in coordination of protection functions, which have impact to Operational Security.
Explanation for change or no change	The comments were taken into account by new formulation of the Article 14 Protection and partly in formulation of Article 15(7). Changes were made to clearly define the responsibility to TSOs to ensure the high quality, effective and selective protection system taking into account coordination between DSOs and Significant Grid Users e.g. coordinated set-points and synchronism check during reconnection. High quality principles of

	secure system protection were also defined. Critical Fault Clearing Time was defined in order to ensure that generating facilities don't lose stability during Faults causing deep voltage drop at the Connection Points of the Power Generating Facilities.

Article 13 – Dynamic stability management > new Article 15

Summary	11 comments were received on this Article 15 (one of the comments was actually a comment on Article 13(12)). The following themes emerged several times: 1) NRA involvement; 2) Inertia.
Changes made	NRA approval was added to the establishment of the methodology for the definition of minimum inertia. The amount of inertia shall be based on the result of studies done by all TSOs in each Synchronous Area. Moreover, a number of simplifications, clarifications and improvements in the text have been conducted in order to raise clarity and understanding.
Explanation for change or no change	In summary, it is considered that all suggestions and comments have been dealt with so that they were positively considered and integrated in the final version of this Network Code. Clear requirement for establishment of the methodology of the definition of the minimum inertia based on studies to be done by the TSOs was defined. The defined methodology shall be approved by NRAs.

Article 14 – Testing and investigation – (this article has been moved to the Compliance chapter and is now Article 33)

Summary	92 comments were received on this Article 14. The following themes emerged several times: 1) A suggestion to move it to the Compliance Chapter; 2) Continuous monitoring and inability of ageing plant; 3) Involvement of DSO and the impact on Significant Grid Users; 4) TSO obligations and timeframes; 5) Limited to required relevant information; 6) Consistency with the NC RfG and the DCC; 7) Cost recovery; 8) Non-discrimination and transparency; 9) Risk and Remedial Actions; 10) There were 4 requests for additional Articles.
Changes made	Article 14 has been removed and incorporated into Chapter 5 on compliance and is now in Article 33. It remains referred to as Article 14 in supporting document, for avoiding ambiguity as this was the Article commented on by DSOs and stakeholders. The criteria for the significance of Significant Grid User are without “small” grid users. Directive 2009/72/EC contains a definition of Ancillary Service. A Grid

	User will not be required to do anything that it has not declared itself capability of. continuous monitoring removed as it may not be appropriate in all situations. The following paragraphs have been removed 14(2), 14(5), 14(6), 14(7), 14(11), 14(13), 14(15), 14(16) removed Additional provisions have been added on cost recovery and information exchange from TSOs. Publication will ensure transparency.
Explanation for change or no change	Article 14(2) has been removed, because it was felt that this requirement was duplication. For the TSO to meet its obligation to ensure Operational Security of the Transmission System, it should have the ability to evaluate the provision of services by Significant Grid Users which they are required or have agreed to provide. Article 14(5) has been removed, because it was felt that there was duplication with Article 32(2) and 32(3). Article 14(6) has been removed. In general we agree with DSOs and stakeholders, however if services are provided to another system operator, that system operator should be able to confirm compliance. Article 14(7) removed. Agree with DSOs and stakeholders up to a point. There should be a test plan developed. It is covered by two other requirements, provision of information to the TSO and the TSO analysis and planning. The criteria for the significance of Significant Grid User will remove “small” grid users. The TSO will have to consider the influence or impact of testing on Significant Grid Users operation and ensure minimum impact on Operational Security and economic operation. We agree with DSOs and stakeholders on safety. A requirement on cost recovery has been added and the ability of a DSO or Significant Grid User to postpone or interrupt a test has been added. The requirement 14(13) has been deleted as it was duplicated in the Compliance Chapter. It is difficult to put an exact time frame on the provision of test information. More complex test will require more time to plan for whereas less complex test may require very little time. If required we can specify a time frame that covers all tests. Publication of the system state may only be of benefit for short notice within day tests and there were concerns that it could lead to increased system operational difficulties. Article 14(15) was removed due to duplication with the new Articles on Operational Security performance which foresees the publication of an annual report. Article 14(16) was removed due to duplication with a more general Article in the compliance Chapter. The more specific information requirements are probably too detailed for a pan-European Network Code and are probably best covered at national level. DSOs are included in data exchange and the level of detail can be set out in agreements.

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

Article 15 – General requirements > new Article 16

Summary	26 comments were received on this Article. The following themes emerged several times: 1) To include NRA involvement in relation with further implementation regarding detailed content and timescales for data provisions; 2) To include some provisions about the data required by DSOs and Significant Grid Users; 3) To explain the impact of the NC on previous agreements; 4) To ensure consistency with the NC CACM in respect of coordination.
Changes made	Relevant paragraphs of Article 16 have been redrafted to refer to further agreements between TSOs in relation to the detailed content and the timescales of data provisions. The agreements shall be done respecting other Network Codes. A new paragraph was included to provide data to DSOs and Significant Grid Users about the Transmission System at its Connection Point. An explanation about the impact of the Network Code on previous agreements is included in supporting document.
Explanation for change or no change	The changes increase clarity what was the key criterion for their including into the OS NC. To guarantee the Operational Security, it is necessary to know the situation of the Transmission System in a precise way so the analyses done are reliable and accurate. To achieve this, the TSO needs information from the Transmission System, the Distribution Network, the Power Generating Facilities and the Demand Facilities, so the TSOs relies on the information from the Significant Grid Users to perform its tasks. Lack of accurate information to the TSO has significant impact in the Operational Security as it makes difficult to know the demand and calculate reserves in an adequate way. This also leads to higher costs as more reserves are required to face the uncertainties due to short or inaccurate information. Taking into account the present and expected evolution of the Transmission Systems of Europe, the requirements of information for the TSO becomes especially important. Information from the TSOs to the DSOs and Significant Grid Users is considered in new Article 16(6). Information about the Connection Point allows the DSOs, Power Generating Facilities or Demand Facilities to know the possible demand supply or generation. As DSOs may have several Connection Points to the Transmission System, they will have more complete information about power flows in the Transmission System. The drafting of this paragraph does not prevent further TSO-DSO agreements in accordance with NRA for more information exchange from the Transmission System. As, according to the SO FG, the data provisions addressed in the OS NC mainly focus on the needs ensuring an efficient functioning of the interconnected Transmission System, no symmetrical data provisions have been drafted for TSOs and DSOs because, due to the specificities of the Distribution Network, the additional provisions of data from TSOs or Significant Grid Users to DSOs shall be defined in a more appropriate manner at national level.

Article 16 – Structural and forecast data exchange between TSOs > new Article 17

Summary	8 comments were received on this Article. The following themes emerged several times: 1) To take into account NRA involvement in relation to the further definition of the Observability Area; 2) Coordination between TSOs in accordance with other Network Codes. To include some provisions about data required by DSOs and Significant Grid Users.
Changes made	Explanation about the Observability Area included in the supporting document. Relevant paragraphs of Article 16 have been redrafted to refer to further agreements between TSOs in relation to the detailed content and the timescales of data provisions. The agreements shall be done respecting other Network Codes and be public. NRA involvement is considered in this provision. The exchange of information between TSO shall respect confidentiality obligations and Power Generating Modules owners will be informed.
Explanation for change or no change	The new criteria for Significant Grid Users clarify which ones shall be included in the Observability Area in neighbouring Responsibility Areas but that information shall be exchanged as it is important for Operational Security.

Article 17 – Real-time data exchange between TSOs > new Article 18

Summary	6 comments were received on this Article. The following themes emerged several times: 1) To include NRA involvement in relation with further definition of the Observability Area; 2) Coordination between TSOs in accordance with other Network Codes; 3) To include some provisions about data required by DSOs and Significant Grid Users.
Changes made	An explanation of the Observability Area is included in the supporting document. Relevant paragraphs of Article 16 have been redrafted to refer to further agreements between TSOs in relation to the detailed content and the timescales of data provisions. The agreements shall be done respecting other Network Codes and be public. A definition of Virtual Line has been added.
Explanation for change or no change	This Article refers to information exchanged between TSOs and focuses to data from the Observability Areas in neighbouring Responsibly Areas.

Article 18 – Structural and forecast data exchange between TSOs and DSOs within the TSO's Responsibility Area > new Article 19

Summary	29 comments were received on this Article. The following themes emerged several times: 1) To define the DSOs affected by the OS NC; 2) To include some provisions about data required by DSOs; 3) To include NRA involvement in relation with further implementation regarding detailed content and timescales for data provisions and the definition of the Observability Area; 4) To delete the provision about historical data.
Changes made	The relevant paragraphs of Article 16 have been redrafted to refer to further agreements between TSOs in relation to the detailed content and the timescales for data provision. The agreements shall be done respecting other Network Codes and be public. Explanation about the Observability Area included in the supporting document. A new paragraph was included in Article 16 to provide data to DSOs about the Transmission System at its Connection Point. Explanation about the DSOs affected by the OS NC included in the supporting document. Deleted the paragraph dealing with provision of historical data.
Explanation for change or no change	As, according to the SO FG, the data provisions addressed in the OS NC mainly focus on the needs ensuring an efficient functioning of the interconnected transmission system. no symmetrical data provisions have been drafted for TSOs and DSOs because, due to the specificities of the Distribution Network, the additional provisions of data from TSOs or grid users to DSOs shall be defined in a more appropriate manner at national level.

Article 19 – Real-Time data exchange between TSOs and DSOs within the TSO's Responsibility Area > new Article 20

Summary	17 comments were received on this Article. The following themes emerged several times: 1) To define the DSOs affected by the OS NC; 2) To include some provisions about data required by DSOs; 3) To include NRA involvement in relation with further implementation regarding detailed content and timescales for data provisions and the definition of the Observability Area.
Changes made	The relevant paragraphs of Article 16 have been redrafted to refer to further agreements between TSOs in relation to the detailed content and the timescales for data provision. An explanation about the Observability Area has been included in the supporting document. A new paragraph has been included in Article 16 to provide data to DSOs and Significant Grid Users about the Transmission System at its Connection Point. An explanation about the DSOs affected by the OS NC has been included in the Supporting Document.
Explanation for change or no	As, according to the SO FG, the data provisions addressed in the OS NC mainly focus on the needs ensuring an efficient functioning of the

change	interconnected transmission system. no symmetrical data provisions have been drafted for TSOs and DSOs because, due to the specificities of the Distribution Network, the additional provisions of data from TSOs or grid users to DSOs shall be defined in a more appropriate manner at national level.

Article 20 – Structural data exchange between TSOs, owners of Interconnectors or other lines and Power Generating Modules directly connected to the Transmission System > new Article 21

Summary	50 comments were received on this Article. The following themes emerged several times: 1) Definition of the Significant Grid Users affected by the OS NC 2) To include some provisions about data required by Significant Grid Users 3) To include NRA involvement in relation with implementation regarding detailed content, timescales and further data provisions.
Changes made	The criteria to identify Significant Grid Users have been defined in Article 1(3). The relevant paragraphs of Article 16 have been redrafted to refer to further agreements between TSOs in relation to the detailed content and the timescales of data provisions. A new paragraph was included in Article 16 to provide data to Significant Grid Users about the Transmission System at its Connection Point.
Explanation for change or no change	Redrafted Article 16(5) covers the agreements between TSOs to define the detailed content and format for the data that has to be delivered by Power Generating Facilities. The data shall be coordinated with data requested in other Network Codes so they do not have to be provided twice. The information is necessary for the TSO to operate the Transmission System so it has to be provided. An explanation of the necessity of information is given in the response for Article 16.

Article 21 – Scheduled data exchange between TSOs, owners of Interconnector or other lines and Power Generating Modules directly connected to the Transmission System > new Article 22

Summary	33 comments were received on this Article. The following themes emerged several times: 1) Coordination between TSOs in accordance with other Network Codes; 2) To include some provisions about data required by Significant Grid Users; 3) To include NRA involvement in relation with implementation regarding detailed content and timescales of data provisions.
Changes made	The relevant paragraphs have been redrafted to add clarity in relation to the timeframes for schedules provisions. The relevant paragraphs of Article 16 have been redrafted to refer to further agreements between TSOs in relation to the detailed content and the timescales of data provisions. The agreements shall be done respecting other Network Codes and be public. A new paragraph has been included in Article 16 to provide data to Significant

	Grid Users about the Transmission System at its Connection Point.
Explanation for change or no change	Scheduled data is necessary to perform Operational Security Analysis in Operational Planning and the requested data shall be coordinated with other Network Codes so they do not have to be provided twice. The information is necessary for the TSO to operate the Transmission System so it has to be provided. An explanation of the necessity of information is given in the response for Article 16. It seemed to be an incorrect understanding of the word Interconnector (formerly Interconnection), which links the Responsibility Areas of two TSOs, and is not owned by DSOs.

Article 22 – Real-Time data exchanged between TSOs, owners of Interconnector or other lines and Power Generating Modules directly connected to the Transmission System > new Article 23

Summary	22 comments were received on this Article. The following themes emerged several times: 1) Coordination between TSOs in accordance with other Network Codes; 2) To include some provisions about data required by Significant Grid Users; 3) To include NRA involvement in relation with implementation regarding detailed content and timescales of data provisions.
Changes made	Relevant paragraphs have been redrafted to add clarity in relation to the requirements of reserves. Relevant paragraphs of Article 16 have been redrafted to refer to further agreements between TSOs in relation to the detailed content and the timescales of data provisions. The agreements shall be done respecting other Network Codes and be public. A new paragraph was included in Article 16 to provide data to Significant Grid Users about the Transmission System at its Connection Point.
Explanation for change or no change	Redrafted Article 16(5) covers the agreements between TSOs to define the time stamping for the data that has to be delivered by Power Generating Facilities. The information is necessary for the TSO to operate the Transmission System so it has to be provided by type B, C and D because all are considered Significant. An explanation of the necessity of information is given in the response for Article 16.

Article 23 – Structural data exchange between DSOs and Significant Grid Users according to Article 1(3)(a) and Article 1(3)(d)connected to the Distribution Network > new Article 24

Summary	23 comments were received on this Article. The following themes emerged several times: 1) Definition of the Significant Grid Users affected by the Network Code; 2) Coordination between TSOs in accordance with other Network Codes; 3) To include NRA involvement in relation with implementation regarding detailed content and timescales of data provisions.

Changes made	The criteria to identify the Significant Grid Users have been defined in Article 1(3). The relevant paragraphs of Article 16 have been redrafted to refer to further agreements between TSOs in relation to the detailed content and the timescales of data provisions.
Explanation for change or no change	The new criteria for Significant Grid Users clarify which ones shall be affected. The data requirements of this Article shall be coordinated with data required in other Network Codes so they do not have to be provided twice. The information is necessary for the TSO to operate the Transmission System so it has to be provided. An explanation of the necessity of information is given in the response for Article 16.

Article 24 – Scheduled data exchange between DSOs and Significant Grid Users according to Article 1(3)(a) and Article 1(3)(d) connected to the Distribution Network > new Article 25

Summary	7 comments were received on this Article. The following themes emerged several times: 1) Definition of the Significant Grid Users affected by the OS NC; 2) To include NRA involvement in relation with implementation regarding detailed content and timescales of data provisions.
Changes made	The criteria to identify Significant Grid Users have been defined in Article 1(3). The relevant paragraphs have been redrafted to add clarity in relation to the timeframes for schedules provisions. The relevant paragraphs of Article 16 have been redrafted to refer to further agreements between TSOs in relation to the detailed content and the timescales of data provisions. The agreements shall be done respecting other Network Codes and be public.
Explanation for change or no change	The new criteria for Significant Grid Users clarify which ones shall be affected. Scheduled data in necessary to perform Operational Security Analysis in Operational Planning and the required data shall be coordinated with other Network Codes so they do not have to be provided twice. The information is necessary for the TSO to operate the Transmission System so it has to be provided. An explanation of the necessity of information is given in the response for Article 16.

Article 25 – Real-Time Data exchange Between DSOs and Significant Grid Users according to Article 1(3)(a) and Article 1(3)(d)connected to the Distribution Network > new Article 26

Summary	12 comments were received on this Article. The following themes emerged several times: 1) To define the Significant Grid Users and DSOs affected by the OS NC; 2) To include NRA involvement in relation with implementation regarding detailed content and timescales of data provisions and communication between TSOs and Significant Grid Users connected to the Distribution Network;

	3) Consider possible of data aggregation.
Changes made	The criteria to identify the Significant Grid Users have been defined in Article 1(3). Aggregation of Grid Users is considered. The relevant paragraphs of Article 16 have been redrafted to refer to further agreements between TSOs in relation to the detailed content and the timescales of data provisions. The agreements shall be done respecting other Network Codes and be public. NRA involvement is considered regarding the two possibilities of communication between TSOs and Significant Grid Users connected to the Distribution Network and the possibility for Power Generating Modules to provide aggregated data. An explanation about the DSOs affected by the OS NC is included in the supporting document
Explanation for change or no change	Real time information is necessary for the TSO to operate the Transmission System as it has impact in the Generation-Demand Balance so it has to be provided by type B, C and D because all are considered significant. An explanation of the necessity of information is given in the response for Article 16.

Article 26 – Data Exchange Between TSOs and Significant Grid User according to Article 1(3)(a) and Article 1(3)(d) connected to the Distribution Network > new Article 27

Summary	15 comments were received on this Article. The following themes emerged several times: 1) To define the DSOs affected by the OS NC; 2) To include NRA involvement in relation with implementation regarding detailed content and timescales of data provisions and communication between TSOs and Significant Grid Users connected to the Distribution Network.
Changes made	The criteria to identify Significant Grid Users have been defined in Article 1(3). The relevant paragraphs of Article 16 have been redrafted to refer to further agreements between TSOs in relation to the detailed content and the timescales of data provisions. The agreements shall be done respecting other Network Codes and be public. NRA involvement is subsidiary considered regarding the two possibilities of communication between TSOS and Significant Grid Users connected to the Distribution Network. An explanation about the DSOs affected by the network Code is included in the supporting document
Explanation for change or no change	For the data exchange between Significant Grid Users and TSOs, the NRA involvement is considered too, in the definition at the national level, of how the information is exchanged, directly or via DSOs.

Article 27 – Data Exchange between TSOs and Demand Facilities directly connected to the Transmission System > new Article 28

Summary	5 comments were received on this Article. The following themes emerged several times: 1) To include NRA involvement in relation with implementation regarding detailed content and timescales of data provisions; 2) Coordination between TSOs in accordance with other Network Codes.
Changes made	The relevant paragraphs have been redrafted to add clarity in relation to the provisions regarding Reactive Power provisions. A reference to the Connection Point has been added. The relevant paragraphs of Article 16 have been redrafted to refer to further agreements between TSOs in relation to the detailed content and the timescales of data provisions. The agreements shall be done respecting other Network Codes and be public.
Explanation for change or no change	The data requirement of this Article allows the TSO to know the impact of consumers directly connected to the Transmission System. It is necessary for TSO to operate the Transmission System so it has to be provided. An explanation of the necessity of information is given in the response for Article 16.

Article 28 – Data Exchange between TSOs and Demand Facilities connected to the Distribution Network or Aggregators > new Article 29

Summary	19 comments were received on this Article. The following themes emerged several times: 1) To define the Significant Grid Users and DSOs affected by the OS NC; 2) To include NRA involvement in relation with implementation regarding detailed content and timescales of data provisions and communication between TSOs and Significant Grid Users connected to the Distribution Network; 3) Coordination between TSOs in accordance with other Network Codes.
Changes made	The criteria to identify the Significant Grid Users have been defined in Article 1(3). Aggregation of Grid Users is considered. The relevant paragraphs of Article 16 have been redrafted to refer to further agreements between TSOs in relation to the detailed content and the timescales of data provisions. NRA involvement is subsidiary considered regarding the two possibilities of communication between TSOs and Significant Grid Users connected to the Distribution Network. An explanation about the DSOs affected by the OS NC is included in the supporting document
Explanation for change or no change	For the data exchange between Significant Grid Users and TSOs, the NRA involvement is considered too within the scope of the definition at national level how the information is exchanged, directly or via DSOs. DCC provisions with regards to Aggregators have been taken into account while defining the criteria for Significant Grid Users.

Article 29 – Operational training and certification > new Article 30

Summary	18 comments were received on this Article. The main themes are below and emerged several times: 1) NRA involvement in approving training plans and certification extensions, 2) Providing more specific requirements for the certification assessment; 3) Explicitly set out that training includes System States such as Blackout, Restoration, Emergency or all System States; 4) Strengthen the wording on shared training with DSO and Significant Grid Users staff.
Changes made	All of the comments received on this Article were helpful and all but the comments involving direct NRA involvement were adopted. The OS NC Article 31 has been updated to reflect themes (2) and (3) above, as well as theme (1) in part through more specific requirements for the certification assessment. In addition a small number of comments from ACER were also adopted, including references to training programs outside of the control room.
Explanation for change or no change	NRA direct approval of the competencies and the direct involvement in the extension of the certification period of a System Operator employee is not regarded as appropriate decision for a NRA.

Article 30 – Responsibility of the Significant Grid Users > new Article 31

Summary	23 comments were received on this Article. Three themes emerged several times: 1) Obscurities, who should be included and who is relevant/significant, what kind of modification; 2) The authority of TSOs/DSOs; 3) Costs for the Significant Grid Users.
Changes made	Approval of the test by TSO or DSO has been added. A compliance test, if required by a TSO or DSO, shall be carried out by the Significant Grid User.
Explanation for change or no change	The criteria for the significance of Significant Grid User will clarify who is included and relevant / significant. Modifications which affect a Significant Grid Users ability to meet the requirements of this code e.g. frequency or voltage control capability or data exchange capability. For the TSO to meet its obligation to ensure Operational Security of the transmission system, it should have the ability to evaluate the provision of services by Significant Grid Users which they are required or have agreed to provide. Article 5(4) has been included requiring the development of a methodology for recovering the costs of compliance tests. There have already been several changes removing obscurities and making it clear who is included. Cost recovery should be done according to Article 5(4).

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

Article 31 – Responsibilities of TSOs and DSOs > new Article 32

Summary	21 comments were received on this Article. Three themes emerged several times: 1) Restrictions in TSOs/DSOs according to compliance tests and simulations; 2) The article should be deleted because the NC RfG and DCC cover the issues addressed it; 3) More involvement from NRA.
Changes made	The details of the responsibility of TSO have been added. Operational Security performance indicators concepts and methodology have been added and specified in detail. Transparency issues are more detailed. Elaboration of a list of high priority Significant Grid Users according to national legislation and criteria has been added.
Explanation for change or no change	From the System Operation point of view, the tests required in the OS NC should be seen as complementary to the NC RfG: the OS NC deals with disturbances, faults and any other issue that can happen during the lifetime of the facility. The only one exception when the tests are repeated is in case of significant changes where it arises as necessary to repeat the compliance of those technical requirements set by the NC RfG. For the TSO to meet its obligation to ensure Operational Security of the Transmission System, it should have the ability to evaluate the provision of services by Significant Grid Users which they are required or have agreed to provide. NRA involvement is explained in Article 3.

New Article 33 Common Testing and Incident Analysis Responsibilities > the old Article 14 (see the explanation above)

Article 34 – Amendments of contracts and general terms and conditions

Summary	Four (4) comments were received on this Article and, in general, its removal was recommended due to overlap with Article 57 of the NC RfG. According to the received comments, the same provisions in different NCs harm the legal and regulatory certainty and are out of the scope of the OS NC.
Changes made	The sentence "relating to the grid connection of new Power Generating Modules" has been deleted; All relevant clauses of terms and conditions shall be amended.

Article 31 – Responsibilities of TSOs and DSOs > new Article 32

Summary	21 comments were received on this Article. Three themes emerged several times: 4) Restrictions in TSOs/DSOs according to compliance tests and simulations; 5) The article should be deleted because the NC RfG and DCC cover the issues addressed it;

	6) More involvement from NRA.
Changes made	The details of the responsibility of TSO have been added. Operational Security Performance Indicators concepts and methodology have been added and specified in detail. Transparency issues are more detailed. Elaboration of a list of high priority Significant Grid Users according to national legislation and criteria has been added.
Explanation for change or no change	From the System Operation point of view, the tests required in the OS NC should be seen as complementary to the NC RfG: the OS NC deals with disturbances, faults and any other issue that can happen during the lifetime of the facility. The only one exception when the tests are repeated is in case of significant changes where it arises as necessary to repeat the compliance of those technical requirements set by the NC RfG. For the TSO to meet its obligation to ensure Operational Security of the Transmission System, it should have the ability to evaluate the provision of services by Significant Grid Users which they are required or have agreed to provide. NRA involvement is explained in Article 3.

New Article 33 Common Testing and Incident Analysis Responsibilities > the old Article 14 (see the explanation above)

Article 34 – Amendments of contracts and general terms and conditions

Summary	Four (4) comments were received on this Article and, in general, its removal was recommended due to overlap with Article 57 of the NC RfG. According to the received comments, the same provisions in different NCs harm the legal and regulatory certainty and are out of the scope of the OS NC.
Changes made	The sentence “relating to the grid connection of New Power Generating Modules” has been deleted; All relevant clauses of terms and conditions shall be amended.
Explanation for change or no change	

Article 35 – Entry into force

Summary	Three (3) comments were received on this Article. It was requested to set two (2) years transition period for applicability of the OS NC with the three (3) years period set for the amendment of contracts under Article 34 of the OS NC. It was, further referred to NC RfG which sets a three (3) years transition period as a justification to change the set transition period to three (3) years.
Changes made	Transition period for applicability was replaced by an exact date of entry into force, allowing a simultaneous entry into force of all three System Operation

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

	Network Codes.
Explanation for change or no change	The article is based on the SO FG, according to which, the OS NC shall provide a transition period for Transmission System Operators, Distribution System Operators and Significant Grid Users and that, *in general,* the transition period should not exceed two years. According to the SO FG, the transition period is to be consulted with stakeholders. Based on the stakeholder consultation and the requests received as a result, the amendment proposal could, for consistency reasons (with Article 34 and other NCs), be accepted. Further, the amendment would not, as such, be against the applicable SO FG. It is the aim of all DTs of SO NCs to have the entry into force simultaneously, thus respecting the necessary consistence of the 3 SO NCs. Therefore, the new wording allots an exact date of entry into force to be defined.

ANNEX V – FREQUENTLY ASKED QUESTIONS

INTRODUCTION AND OVERVIEW

This Annex outlines the questions which ENTSO-E has been asked at various stages of the process of developing the OS NC and provides answers to those questions. The aim is here to provide interested parties with additional information and help in further explanation of specific concepts and issues in the OS NC.

GENERAL - OBJECTIVES

a) *Why there is no full reciprocity in the obligations between the NC RfG and DCC (for SGU the term "shall" is used) and the OS NC (for TSO the term "shall endeavour")?*

There will be situations when Operational Security of the Transmission System will be subject to abnormal levels of risk outside the control of the System Operator Employee, for example during major lightning storms. To deal with these situations the TSO puts in place systems and procedures designed to ensure the Operational Security. These systems and procedures rely on the services provided by Significant Grid Users and their ability to operate within certain limits. For a stable and secure System Operation it is necessary to require that certain minimum technical, design and operational criteria are met by the Significant Grid User's equipment. It is due to the limited influence the TSO can bring to bear on many of the operational parameters, weather, demand and actual performance of SGUs equipment, that impact the System Operation of the Transmission System and determine the TSO's ability to maintain continuous System Operation within Operational Security Limits.

b) *Every requirement being part of OH, etc. is applicable unless it is dealt with it in NCs.*

The Operational Security Network Code sets out a harmonized framework for the System Operation, towards contributing to non-discrimination and facilitating the Internal Electricity Market. However, while taking into account the existing differences among the Synchronous Areas, the OS NC orientates towards adopting high level principles without hindering their smooth functioning in view or their special characteristics and differences, such as Transmission System size, degree of various technical developments, etc. Therefore, the OS NC is applicable for all Synchronous Areas as an "umbrella" framework of common harmonized practices and principles, while their detailed specification is left to be defined at the national level, building upon existing best practices which are already documented in existing grid codes and operation handbooks.

LEGAL ISSUES

a) *The term "shall endeavour" in the framework of short-circuit management (Article 11);*

Directive 2009/72/EC, in particular Articles 5 and 12, do not impose a strict obligation for TSOs to ensure the short circuit management. There is therefore no legal basis to formulate a strict obligation on this, as a proposal surged during public consultation.

As a practical example within the framework of the OS NC in Article 8(5) each TSO shall define the Operational Security Limits for admissible short-circuit current ranges in terms of equipment capacity and impedance. From a legal perspective, this seems to be the range of obligation the TSO have to deal with.

b) The pan-EU character of the Network Codes, going beyond national legislation.

After comitology, Network Codes become part of EU Regulation, becoming thus also directly legally binding acts for all EU Member States. As such, Network Codes will prevail over national legislation in case of conflicting provisions. Nevertheless, it is always possible for national legislation to provide more stringent requirements if the latter are not in contradiction with the requirements of the EU Regulation / Network Code. Article 8(7) of Regulation (EC) No 714/2009 provides further details on that. The national law continues to apply for the issues which are not within the scope of the EU Regulation / Network Code and which do not affect cross-border trade.

c) Regulations (safety, nuclear, environmental, etc.) should not be overruled while applying the requirements of the OS NC;

Article 1(5) of the OS NC provides that TSOs and DSOs shall always respect relevant provisions for human safety and nuclear safety. This provision shall guarantee that there will be no harm to other relevant regulations and that they shall not be overruled by the OS NC.

REQUIREMENTS

In the following text, organized by OS NC requirements, the most frequently raised questions and comments are addressed.

Article 1: Subject matter and scope

a) Who are the Significant Grid Users?

Significant Grid Users are those Grid Users whose influence on the Transmission System needs to be taken into account for Operational Security. The impact on the Transmission System can have different causes: Grid User directly connected to the Transmission System are considered to be Significant because they are large Power Generating Facilities or Demand Facilities; Grid Users providing Ancillary Services are also considered Significant because they influence the Generation-Demand Balance. Besides, other large Power Generating Facilities connected to the Distribution Network can have significant impact to the Transmission System so they also need to be considered as Significant Grid Users.

b) What relation do Significant Grid users have with Connection Codes?

Connection Codes define the technical requirements that Significant Grid Users shall comply with to connect to the Transmission System. These requirements apply mainly to new Grid Users but cover a very broad range of them, from big to small ones. OS NC was developed after Connection Codes and it takes them into account but needs to apply different significance thresholds. From Operational Security perspective the criteria shall be applied to Grid Users independently of the date of their connection to the System, but only to those with direct impact in the Transmission System due to their size or the services they are providing. This includes those Grid Users not individually significant, but that become significant when aggregated.

It follows that the criteria for Significant Grid Users are a combination of the criteria for Significant Power Generating Modules and Significant Demand Facilities, applied to both new and pre-existing ones.

c) Which are the DSOs affected in the framework of the OS NC and why there is no distinction concerning "relevant DSOs" is made?

DSOs are not included in Article 1(3) with the criteria to define the Significant Grid Users because according to the SO FG, DSOs can be treated as Grid Users or not. In the OS NC each relevant Article states if it affects DSOs or not.

In general, DSOs have to comply with the requirements of OS NC if they are directly connected to the Transmission System so the Distribution Network they operate has impact on the Transmission System, or if they have Significant Grid Users connected to their Distribution Network.

Article 8: System States

a) What are the consequences of the System States for Grid Users?

The first aim of a common definition for System State is to give to TSOs a common understanding of the situation, and of the coordination they must have to undertake. The principles for System State classification aims at differentiating when the system is N- and (N-1) compliant (Normal State), N compliant but not (N-1) compliant (Alert State), or not N- compliant (Emergency State). That means that in both Normal and Alert State, there is no significant violation of the Operational Security Limits.

When the Transmission System is in Alert State, although all Operational Security Limits are respected, there is at least one Contingency which is reasonably probable and which is part of the Contingency List, for which, in case of occurrence, at least one of the operational parameters will not remain within the Operational Security Limits. It's therefore important to mitigate the risk of occurrence of such Contingency, and this is the reason why TSO can ask for stopping actions which can increase the probability of Contingency.

1. In Emergency State, at least one of the operational parameters is outside of the Operational Security Limits, so it affects the quality and security of the electricity supply towards Significant Grid Users. Nevertheless, a precise definition of the impact on Grid Users in case of Emergency State cannot be done in the OS NC, since it varies depending on the sequence of events that have occurred: impact on frequency in case of big imbalance without sufficient amount of active reserves, impact on voltage in case of insufficient of Reactive Power reserves, etc.;

2. In Alert State the system is secure in N- situation, so there is no direct consequence for Grid Users, except for those currently conducting a test;

A precise definition of the impact on Significant Grid Users in case of Emergency State cannot be done in the OS NC, since it varies depending of the sequence of events that have occurred.

Article 10: Voltage and Reactive Power Management

a) Why generation remaining connected is important for the Operational Security?

The Operational Security of the Transmission System is closely coupled with the voltage profile. For the maintenance of a good and viable operational voltage profile sufficient Reactive Power resources are needed. The main resources of Reactive Power are the Power Generating Facilities and compensation devices. In cases of voltage degradation where the Transmission System is in danger and the voltages are outside the ranges for the Normal or Alert State, the Power Generating Facilities are mostly needed to stay connected to the Transmission System, supporting the system voltages and providing Reactive Power for keeping the Transmission System intact and reinstating the Normal State.

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

b) Why do the TSOs require the observability of generation connected to the Distribution Network?

The Observability Area of a TSO is built upon the principle that each TSO must have sufficient horizontal and vertical data of the networks and network elements connected to and having an influence on its own Transmission System, in order to be able to reliably determine and assess the System State and safely operate its Responsibility Area. Generation connected to the Distribution Network has a limited impact on the Transmission System in terms of voltage and Reactive Power. Nevertheless, the Reactive Power output together with the Active Power output of Power Generating Facilities within a TSO's Observability Area are vital, in order to correctly calculate the Active and Reactive Power flows. In the absence of the Reactive Power output of Power Generating Facilities, the result of the TSOs' State Estimation would be false and unreliable, especially in terms of Reactive Power flow, voltages and load of elements

c) Voltage management: a transmission issue in the framework of the OS NC.

Voltage and Reactive Power management have mainly a local character. Therefore, in the framework of the Operational Security Network Code this issue is treated in such a way, that the focus lies on the TSO responsibility for the effective and efficient management and the coordination among interconnected TSOs. Nevertheless, Distribution Networks and Demand Facilities are directly coupled with Transmission System, they play a significant role for the Reactive Power management. For this reason, the Connection Points of TSOs, DSOs and Demand Facilities with regard to Reactive Power have to be managed with requirements which ensure the reliable and secure System Operation.

d) DSOs and TSOs won't go outside the capabilities of Significant Grid Users and contractual agreements shall be in line with the needs for Operational Security.

The requirements of the Operational Security Network Code set out the minimum requirements necessary to ensure the reliable, efficient and secure System Operation. The Network Code uses as a starting point and makes use of the requirements of the NC RfG and DCC, which both take into account existing practices and capabilities. For the Significant Grid Users derogated from or not subject to the requirements of the aforementioned Network Codes the exchange of information on their capabilities and performance with voltage and Reactive Power management from Significant Grid Users towards the TSOs and DSOs if connected to the Distribution Network is solely required, so as to ensure the full information for the System Operators. The purpose of this requirement is to enable System Operators to correctly, efficiently and effectively operate the Transmission System taking into account the behaviour of all involved parties.

e) The volatile character of voltage as the cause for the TSO for "using its best endeavour".

Voltage and Reactive Power, unlike frequency, are local parameters, which under certain conditions like topology and system configuration do not influence the overall Transmission System Operational Security and Stability. TSOs ensure the overall viable voltage profile of their Transmission System which enables the secure and safe System Operation. Nevertheless local voltage excursions might arise, which however do not endanger the Transmission System as a whole, its elements, or the Grid Users and are therefore considered to be acceptable.

f) Why the TSO has the right of defining wider voltage ranges in the framework of the OS NC? (i.e. within the scope of System Operation and not only within the scope of capability as is the case within the framework of the NC RfG)

Because of the distinctive regional features of the Transmission Systems regarding coordination of insulation and existing equipment, existing supplies and load conditions, it is necessary to allow different voltage thresholds.

This approach takes into account the need for an operational practice that has been used in various regions of the Transmission System.

g) Why Base values for voltage cannot be the same for all TSOs?

Because of the different installed equipment with different corresponding levels of insulation in several regions of the Transmission System, the Base values for voltage are not the same for all TSO.

Nevertheless the usual Base values for e.g. voltages between 300-400 kV are 330, 380 or 400kV.

Article 11: Short-circuit management

a) What is the added value of harmonization with regards to Article 11(3) of the OS NC?

For a precise explanation of the added value of the concerned requirement of Article 11(3) and the need of harmonisation level in the framework of short-circuit current calculation and its related data exchange, Section 8.8.2 of the supporting document shall be consulted.

Article 15: Dynamic stability assessment

a) Why does the approach of the DSA defer from Responsibility Area to Responsibility Area?

If the distance from generation to load is large, Voltage Stability or Rotor Angle Stability is often limiting factor during occurred Contingencies, before the power flow reaches thermal limits. On the contrary, in meshed Transmission Systems with shorter distances from generation to load the thermal limits are the limiting factors. In both cases DSA calculation has to be made, but in the first one they have to be made closer to real-time.

DATA EXCHANGE

a) What is the role of DSOs when they are recipients of information from the TSO in the framework of the OS NC?

The information from the respective TSOs to be provided to DSOs and Significant Grid Users is considered in Article 16(6) of the OS NC.

In concrete terms, information about the Connection Point allows DSOs, Power Generating Modules or Demand Facilities to know the possibility of feeding the demand or evacuating the generation. As DSOs may have several Connection Points to the Transmission System, this exchange of information of the TSOs with the DSOs will enable DSOs to have a more complete information about Power Flows in the Transmission System. It should also be noted that the drafting of Article 16(6) does not prevent further TSO-DSO agreements involving NRA for more information exchange from the Transmission System.

Therefore, by the framework set in the OS NC, each DSO directly connected to the Transmission System can become a recipient of information from the TSO if data (structural, forecast and real-time data) from the Transmission System of their respective TSO are necessary for the calculation of the security of the Distribution Network.

b) Articles 20, 23, 26: justification of the purpose of the data requirements for Transmission Systems with Central Dispatching of Generation

In the OS NC, specific requirements (Article 28) apply to regions with central dispatching with regards to:

- Scheduled data exchange between TSOs, owners of Interconnector or other lines and Power Generating Modules directly connected to the Transmission System according to Article 22 of the OS NC;
- Scheduled data exchange between DSOs and Significant Grid Users connected to the Distribution Network according to Article 25 of the OS NC;
- Data exchange between TSOs and Demand Facilities directly connected to the Transmission System according to Article 28 of the OS NC.

This is due to the market structure of the Systems with Central Dispatching, which is the case of countries such as Ireland or Poland.

For example, in the Irish electricity market:

1) The Power Generating Facilities only submit technical and commercial offer data;
2) The Market Operator, using this data, produces an indicative market schedule on a day D-1 before the trading day D. This schedule is unconstrained; it does not take into account transmission constraints, voltage and reserve requirements.
3) The TSOs, using the generator data and the Interconnector data from the market schedule, produce an indicative operations schedule D-1. This schedule takes into account transmission constraints, voltage and reserve requirements.

It should be noted that these two schedules, described respectively in steps 2 and 3 above are indicative and not binding: they only give the generators an indication of their likely running in the trading day D.

As a question raised during public consultation and for the purpose of clarification, in the following the key features of the electricity market in Ireland are described as an illustrative example of a System with Central Dispatching.

Key features of the Single Electricity Market on the island of Ireland

The *key features of the Single Electricity Market on the island of Ireland* are the following:

- Mandatory gross Pool;
- Day Ahead and an additional Intraday complex bidding;
- Ex-post System Marginal Price (SMP) pricing (which excludes transmission, reserve and other constraints), with a single island-wide price for each Trading Period;
- Central dispatch.

Mandatory gross pool

Participation in the pool is mandatory for licensed generators and suppliers, save for generators which have a maximum export capacity of less than 10MW (the minimum threshold) for whom direct participation is voluntary. As a consequence, almost all electricity generated has to be sold into/purchased from the pool. Under the pool arrangements, the sale and purchase of electricity is conducted on a gross basis, with all generators/suppliers receiving/paying the same price for the electricity sold into/bought via the pool.

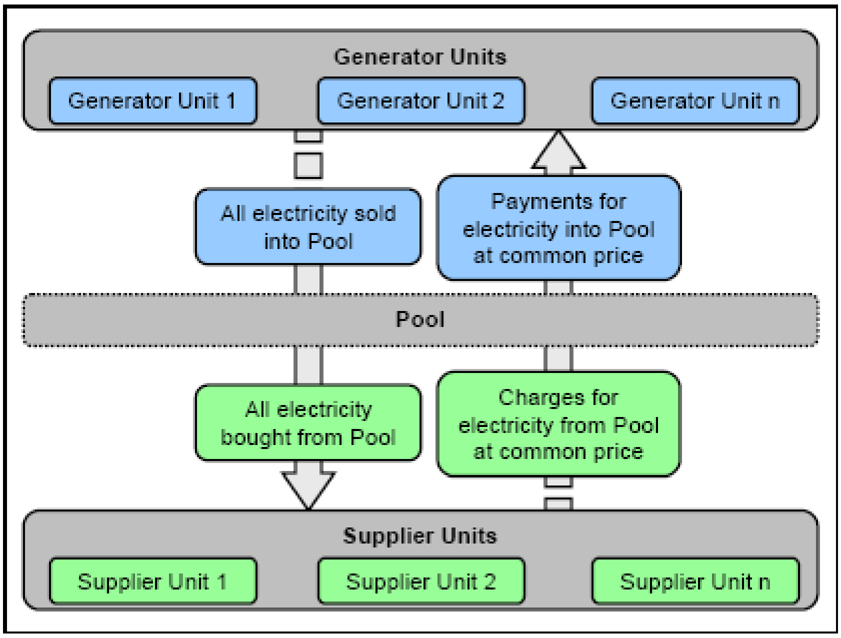

Figure 31: Illustration of the mandatory gross pool in Ireland (Source: [18])

Participants are required to submit offers[12], technical and commercial, into the pool in respect of each Generator or Demand Unit for each Trading Day with an additional intra-day gate opening. The data contained within Offers applies equally for all Trading Periods within the relevant Trading Day (Interconnector Units are an exception to this rule. Interconnector Units are able to submit individual Offers to apply for each Trading Period in order to enable effective interaction with interconnected markets).

Central Dispatch

Under the Single Electricity Market, dispatchable Generator and Demand Units are dispatched centrally by the TSOs, rather than autonomously through self-dispatch by the Generator Unit operator. The TSO produces a schedule for each half hour based on the technical and commercial offer data submitted by the market participants, using a unit commitment and economic dispatch tool.

As for the market schedule determined by the MSP Software, actual dispatch patterns are in principle based upon economics, and it is a reasonable expectation that the cheapest generation will be scheduled to run first, whilst respecting the technical capabilities of the Generator or Demand Units. However, while the MSP Software produces a market schedule on the assumption of an unconstrained system, ignoring the impact of, for example, transmission constraints, voltage and reserve requirements, the TSOs must dispatch Generator and Demand Units taking system constraints and reserve requirements into account (and must also consider real-time issues on the system such as unplanned outages). Therefore, the actual dispatch schedule followed is likely to deviate from the market schedule produced by the MSP Software.

The Reserve Constrained Unit Commitment (RCUC) package is normally run three times, but can be run as required, with in the relevant trading day to account for any changes such as unit trips or changes in system demand or wind output.

---

[12] Technical Offer Data relates to the technical capabilities of the Generator or Demand Unit and consists of parameters such as ramp rates, start-up times.Commercial Offer Data consists of No load data, start-up costs, MW price up to 10 price quantity pairs).

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

The output of the RCUC is:

- A Unit Commitment schedule;
- A set of discrete MW set points for each unit at 30 minute intervals;
- A reserve schedule for each jurisdiction; and
- A tie-line flow schedule.

The control room operators use the output of the RCUC package to guide them in the real time dispatch of the generation units.

Actual dispatch is achieved through the issue of Dispatch Instructions throughout the Trading Day [18].

TERMINOLOGY & CONCEPTS USED

The definition of Transmission Network in the framework of the OS NC

In the OS NC, Transmission System is not the full system that can be operated by a TSO, but the Transmission System which is above a given voltage threshold according to national rules. An illustrative example is the case of Belgium: whereas the Transmission System is defined above a voltage level of 70 kV according to national rules, the Belgium TSO ELIA operates 90% of the system down to a voltage level of 20 kV.

The definition of Operational Security and Remedial Actions, as terms already defined in the NC CACM, but which require a specific meaning in the framework of the OS NC

The deviation from the definitions in NC CACM for the terms Operational Security and Remedial Actions was necessary to take into account the point of view of the online operation in real-time.

The approach of NC CACM refers primarily to the offline view, planning and general terms and conditions.

Interpretation of real-time operation

The NC OS makes use of term real-time operation. Whereas this notion is a fundamental one and in daily use in the control center of a TSO, in order to bring this term closer to stakeholders, in the following lines the terms “real-time” and “real-time assessment” are explained based on the US NERC glossary, what coincides well with the interpretation and application made by the NC OS:

Real-time: “present time as opposed to future time”.[13]

Real-time Assessment: “an examination of existing and expected system conditions, conducted by collecting and reviewing immediately available data”.

The meaning of ‘’as soon as reasonably practicable’’

The task to be performed must be done soon, but it is permissible to begin or complete other tasks first if the delay can be justifiable. Acceptable reasons for a delay in completing the task can be other

---

[13] From Interconnection Reliability Operating Limits standard.

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

higher priority tasks need to be completed first or the additional costs that would be incurred to complete the tasks as soon as possible are high or disproportionate to the benefits achieved.

The role of the Demand Side Response Aggregator (DSR Aggregator) in the framework of the OS NC

The DSR Aggregator is a third party company specializing in electricity demand side participation. The DSR Aggregator will contract with the individual demand sites (industrial, commercial or residential consumers) and aggregate them together to operate as a single DSR provider to the TSO, a Balance Responsible Party or to a DSO. The individual demand sites can use a combination of increasing on-site generation and/or process shutdown or reduction to deliver the active power demand reduction service. The DSR Aggregator receives a percentage of the value created by the avoided consumption to reduce peak demands, balance intermittent generation, provide a balancing service or increase security of supply.

Business Continuity Plan. Differences between Business Continuity Plan, Security plan and System Defence Plan in the framework of the OS NC.

Business Continuity Plan

A Business Continuity Plan:

"*identifies an organization's exposure to internal and external threats and synthesizes hard and soft assets to provide effective prevention and recovery for the organization, while maintaining competitive advantage and value system integrity*".

It is also called business continuity and resiliency planning (BCRP). A Business Continuity Plan is a roadmap for continuing operations under adverse conditions such as a storm, fire, earthquake, sabotage or cyber-attacks.

Any event that could impact operations is included, such as loss of or damage to critical infrastructure (major tool or computing/network resource). As such, risk management must be incorporated as part of BCP.

The analysis phase consists of impact analysis, threat analysis and impact scenarios.

- A Business Impact Analysis (BIA) differentiates critical (urgent) and non-critical (non-urgent) organization functions/activities. Critical functions are those whose disruption is regarded as unacceptable. Perceptions of acceptability are affected by the cost of recovery solutions. A function may also be considered critical if dictated by law. For each critical function, the objectives are: To ensure that the maximum tolerable data loss for each activity is not exceeded; To ensure that the maximum tolerable period of disruption for each activity is not exceeded.

Next, the impact analysis results in the recovery requirements for each critical function.

After defining threats, impact scenarios form the basis of the business recovery plan. A typical impact scenario such as "building loss" encompasses most critical business functions. After the analysis phase, business and technical recovery requirements precede the solutions phase.

The purpose of the testing phase is to achieve organizational acceptance that the solution satisfies the recovery requirements. Plans may fail to meet expectations due to insufficient or inaccurate recovery requirements, solution design flaws or solution implementation errors.

Security plan

The aim of a Security plan is to prepare an overall strategy to strengthen the protection of critical infrastructure against major physical or cyber threat scenarios.

As the potential for catastrophic terrorist attacks that affect critical infrastructure is increasing, the consequences of an attack on the control systems of critical infrastructure could vary widely. It is commonly assumed that a successful cyber-attack would cause few, if any, casualties but might result in the loss of vital infrastructure service. For example, a successful cyber-attack on the public telephone switching network might deprive customers of telephone services while technicians reset and repair the switching network. An attack on the control systems of a chemical or liquid gas facility might lead to more widespread loss of life as well as significant physical damage.

The failure of part of the infrastructure could lead to failures in other sectors, causing a cascade effect because of the synergistic effect of infrastructure industries on each other. An example might be an attack on electrical utilities where electricity distribution is disrupted; sewage treatment plants and waterworks could also fail as the turbines and other electrical apparatuses in those facilities might shut down.

Virtual Tie-line

The NC OS defines the term of Virtual Tie-Line as follows:

“Virtual Tie-Line means an additional input of the controllers of the involved areas that has the same effect as a measuring value of a physical Tie-Line and allows exchange of electric energy between the respective areas. “

The usage of this term and the concept of Virtual Tie-Line is relevant in particular in the netting of imbalances of controllers (e.g. for Frequency Restoration Reserve) – in that context, Virtual Tie-Line is a telemetered reading which is used as a “real tie line flow” in the AGC/ACE equation, but for which no physical metering or exchange really exists. Such integrated value is used as a metered MWh value for interexchange accounting purposes.

ANNEX VI – LINK OF THE OS NC WITH THE FUTURE NC ER

The following list refers to items that have been referred to in the OS NC, but whose detailed requirements will be described in the Network Code for Emergency and Restoration NC ER, The NC ER will cover detailed provisions for the Emergency System State, Blackout and Restoration and will be developed at a later stage according to the requirements specified in the SO FG.

Initially the NC ER was directly referenced in the OS NC, but this is not correct from a legal point of view due to the following reasons:

> With a reference to a clause in another Network Code, it is intended that the content of this clause becomes part of the referencing Network Code.
>
> When the Network Code to which reference is made to has already entered into force, such a reference is uncomplicated. Nevertheless, in case a reference is made to a non-existing act, as is the case of the NC ER, the reference and the clause in the referencing Network Code would be lacking in content. The referencing Network Code (OS NC in this case) would therefore be incomplete and thus would cause an ambiguity and uncertainty.

Thus, Annex VI is enclosed in the OS NC supporting document for the sake of completeness and in order to ensure that the following items are taken into account by the future NC ER.

a) The System Defense Plan defined in Article 2 of the OS NC will be elaborated in detail in the NC ER;

b) The actions to be undertaken by the TSO in case of Blackout referred to in Article 8(1) will be elaborated in detail in the NC ER;

c) The measures of the System Defence Plan to be implemented according to the [OPS NC] agreed TSOs and with the DSOs and SGUs involved in system defence and Restoration referred to in Article 8(10) will be elaborated in detail in the NC ER;

d) The NC ER should further precise the conditions for preparing and implementing a Remedial Action or a measure of the System Defence Plan by the TSO in real time or in operational planning phase which has an effect on other TSOs as referred to in Article 8(12);

e) The NC ER should precise also the cooperation procedures, in case of mutual influences between TSOs and SGUs and DSOs directly connected to the Transmission System, for preparing and implementing a Remedial Action or a measure of the System Defence Plan as referred to in Article 8(13);

f) The measures of the System Defence Plan to be applied by the TSO in line with the coordinated procedures agreed among all TSOs of each Synchronous Area referred to in Article 9(3) will be elaborated in detail in the NC ER;

g) The details of the Low Frequency Demand Disconnection Scheme including its implementation and operational coordination referred to in Article 14(7) are a subject of the NC ER;

ANNEX VII – ASSESSMENT OF THE OS NC AGAINST THE REQUIREMENTS SET IN THE NC RFG AND DCC

GENERAL OVERVIEW: INTERACTION BETWEEN THE CODES COVERING SYSTEM OPERATION AND SYSTEM DEVELOPMENT

The OS NC, as an umbrella for the NC LFCR and the NC OPS, has been developed taking into account the required capabilities for Power Generating and Demand Facilities established in the NC RfG and DCC. The goal of the OS NC is to establish the Operational Security principles for System Operation with a forward-looking approach, based upon which TSOs shall be able to detect and cover Operational Security needs in the medium- and long-term. The future perspective encompasses a "smart" electrical power system, understanding a "Smart Grid" as the process "*to transform the functionality of the present electricity transmission and distribution grids so that they are able to provide a user-oriented service, enabling the achievement of the 20/20/20 targets and guaranteeing, in an electricity market environment, high security, quality and economic efficiency of electricity supply*". This new context presents significant challenges for TSOs: to operate the Transmission System with increasing distributed RES calls for providing the TSOs the ability of having visibility and management capability of a myriad of new installations, developing the tools for being able to manage the new uncertainties that may arise (such as forecasts) and tackling the new features of the system: "active" Distribution Networks and an "active" Demand Side Response. And all of this with increasingly interconnected Transmission Systems, with increasing multi-TSOs influence, where coordination has become an cornerstone of System Operation. The forward-looking approach of the OS NC can be found throughout all the Articles: data exchanges articles have been developed to ensure the abovementioned visibility and controllability for present and future needs, requirements of minimum inertia have also been taken into account and extensive coordination principles are introduced in all relevant parts of the OS NC.

INTERACTION BETWEEN THE OS NC AND THE GRID CONNECTION CODES (NC RFG, DCC)

In the framework of the development of the NC RfG, the following fact was stated with regards to its interaction with the OS NC:

"[…] The OS NC builds primarily on the 12 exhaustive requirements as a basis for the future picture of the system that is envisaged (what generators can provide). The definition of these requirements can be seen as the first step in the development of this code. Building on those requirements, as well as a definition of the Operational Security principles, the OS NC proposes new measures for coordinating System Operation and complements the overall picture provided by the NC RfG. […] The System Operation Network Codes are looking into the medium term only as operational tools need be adapted continuously to address rising challenges […]"

The exhaustive requirements classified by the NC RfG are listed in the following table:

Article, NC RfG	Requirement
8.1.a	Frequency ranges
8.1.c	Limited Frequency sensitive mode-over frequency
8.1.d	Constant output at target Active Power
8.1.f	Remote switch on/off

9.2.a	Active Power reduction
9.5.c	Priority ranking of protection and control
10.2.b	Limited frequency sensitive mode-under frequency
10.2.c	Frequency sensitive mode
10.2.e	Low frequency load disconnection
10.4.a	Steady-state stability
11.2.a	Voltage ranges
11.2.b	Voltage control system (simple)

Table 5: Exhaustive requirements according to the classification of the NC RfG

While expressing these 12 exhaustive requirements of the NC RfG as the part of the "backbone" of the OS NC, the RfG was aiming at the fact that the System Operation NCs would set the framework for coordination and define the security principles on the basis of exhaustive requirements in NC RfG and DCC. Nevertheless, it should be noted that the aim was not to make the System Operation NCs introduce concrete values by using the exhaustive requirements defined for Power Generating Facilities. This is due to the nature of the Grid User's installations, which are built to operate for a few decades, making it essential that the Connection Network Codes anticipate the System Operation needs of the future Transmission System. On the contrary, the System Operation NCs require the necessary flexibility to be able to adapt the operational practices to the dynamic environment and its continuous challenges.

Starting from this framework:

- While taking into account the fundamental requirements of the NC RfG (Frequency ranges, Voltage ranges, Reactive Power, Fault-ride-through); and

- While following the key issues, arising from the increasing levels of non-synchronous RES generation being connected to the European Transmission Systems addressed in the NC RfG (Fault Ride Through, Frequency Stability, Voltage stability, Remote Control of distributed generation units).

The NC RfG -related issues have been "translated" to the Operational Security perspective.
Thus, the following topics have been further precised in the framework of the OS NC:

- Remote switch on/off;
- Fault Ride Through (FRT);
- Inertia;
- Low frequency demand disconnection;
- Justification of NC RfG capabilities with regards to data & information.

In the following, a brief description of the topics mentioned above is provided from the perspective of the OS NC:

__Remote switch on/off__

The amount of installed power of photovoltaic (PV) panels is continuously increasing, which may during low load on sunny days create a power surplus in the interconnected Transmission Systems of Europe and may cause overfrequency or congestions and voltage problems in the areas where the transmission capacity is limited. In order to handle these situations there shall be measures to control the output of PV panels in order to relieve over-frequency as defined in OS NC Article 14(8) The requirement of remote switch on/off in NC RfG Article 8(1)(f) will be used for that purpose. In the future possibilities supported by mobile and Smart Grid technologies might be utilized for that too.

Fault Ride Through

The Transmission System experiences voltage and frequency disturbances, during which it is essential that Power Generating Facilities remain connected avoid widespread disturbances and Blackouts. The (N-1)-Criterion, upon which the important provisions in Article 13 of the OS NC are based, is underpinned by the requirement for an appropriate Fault Ride Through capability of Power Generating Facilities. For example, during a transmission line Fault, the voltage near the Fault will be close to zero for a certain time period (e.g. 140 ms at 400kV) until the fault is cleared. Without an appropriate Fault Ride Through capability, as required in the NC RfG, and in case the line is part of the interconnected Transmission System (i.e. not a radial circuit) then at the same time as the transmission circuit trips, all generation in the vicinity of the fault will also be tripping. (N-1)-Criterion is based upon Ordinary or Exceptional Contingencies. The Fault and tripping of the line or a double line is an Ordinary or Exceptional Contingency respectively, as is a single Power Generating Facility tripout. The tripping of multiple or even single Power Generating Facility sites at the same time as a transmission circuit (other than for radial circuits) would be an Out-of-Range Contingency for which there would or could be widespread shut-down or cascade tripping. Whilst the OS NC does not directly refer to Fault Ride Through capability the (N-1)-Criterion would be violated without it and the probability of widespread disturbances and Blackouts would be significantly higher.

Inertia

The NC RfG and DCC require frequency stability capabilities including frequency sensitive mode and a capability of providing synthetic inertia. The following paragraphs, extracted from two EirGrid/SONI reports, try to provide a background as to why the Operational Security Network Code requires TSOs to conduct studies, develop and implement methodologies and deploy the necessary resources in relation to the minimum inertia required for their Synchronous Area. The two reports from which the following extracts are taken are, the “Facilitation of Renewables” report and the “Ensuring a Secure, Reliable and Efficient Power System in a Changing Environment” report.

Ireland and Northern Ireland have set ambitious renewable energy targets up to 2020 and wind power is expected to form the largest component of these targets. Indeed, it has been estimated that at least 6000 MW of wind farms will need to be installed by 2020 to ensure our targets are achieved. This amount of wind farms will at times represent well in excess of 50% of the generation of the total power system in real time.

In 2009, EirGrid and SONI initiated a suite of studies – entitled the Facilitation of Renewables – designed to examine the technical challenges with integrating significant volumes of windfarms onto the power system of Ireland and Northern Ireland.

The technical characteristics of wind generation mean that this level of instantaneous penetration will alter the dynamic characteristics of the electricity power system. Understanding these changes therefore is fundamental to developing the operational strategies needed to manage the power system in a secure, reliable and consistent manner in the years ahead. These studies provide the first significant modelling of power system behaviour at these unprecedented instantaneous penetrations of wind, and the findings are a key element towards meeting our renewable energy targets.

The main findings of the study indicate that the integrity of the frequency response and the dynamic stability of the power system are compromised at high instantaneous penetrations of wind. The modelling used in the studies also suggests that the voltage and reactive behaviour of the system is directly related to the performance of all generators on the island as well as how the network is developed, and will require significant management over the coming years. Finally, the studies indicate that voltage disturbances could result in the temporary loss of wind farm output. Nevertheless, the core message from the studies is positive. The findings indicate that subject to the fulfilment of a number of technical and operational criteria, Ireland and Northern Ireland can achieve our renewable energy targets securely and effectively by 2020. These technical and operational criteria are:

- That the use of standard protection relays on the Distribution Network and the capability of all generators to ride through high rates of change of frequency is reviewed;
- That compliance with the Grid Code standards is consistent and in particular conventional generators meet the standards of primary reserve that the dynamic models provided suggest; and
- That all wind farms have the appropriate control, capability and response, particularly for voltage reactive support during disturbances that the Grid Code requires.

Understanding the implications of these findings and working towards their implementation will require the full engagement and support of all stakeholders in the electricity sector. [18] [Facilitation of Renewables, EirGrid/SONI]

With the publication of the EirGrid and SONI “Facilitation of Renewables” report a significant step was taken in understanding the system needs of the future power system.

Following on from this report a report entitled “Ensuring a Secure, Reliable and Efficient Power System in a Changing Environment” was commissioned which takes the findings of the FoR study and combines this with an hour-by-hour assessment of the needs of the power system in 2020 across three key operational criteria:

- Frequency Response;
- Ramping Services; and
- Voltage Control.

The “Ensuring a Secure, Reliable and Efficient Power System in a Changing Environment” report augments the results of the “Facilitation of Renewables” with additional analysis quantifying the level of change required over a range of key operational and plant portfolio metrics. It also considers the implications of the current levels of performance. From this analysis the key challenges and solutions are grouped into four areas:

System Frequency Response

New operational practices are required to ensure system frequency response remains adequate with increasing penetrations of wind. In particular, as the average level of synchronous inertia will potentially fall by 25% in 2020, power imbalances will have a greater impact on the minimum frequency reached and the rate of change of frequency experienced following a disturbance. There will be an increased reliance on fast acting reserve provision from all plant to ensure that system security is not compromised and significant additional curtailment of wind farms is avoided.

The laws of physics demand that generation and consumption of electricity is balanced at all times. Variations in electricity demand or generation results in fluctuations in frequency. Control of these fluctuations is effected via two mechanisms: inertia, the inherent electro-mechanical response of the synchronous system; and operating reserve, the rapid, active control of power output.

All rotating machines have stored kinetic energy due to their inertia. In the case of synchronous generators, the mechanical stored energy of each generator is coupled together via the electrical power system. This stored energy increases or decreases in response to frequency changes that arise due to power imbalances and acts to damp out or slow down these frequency fluctuations. This response is an intrinsic capability of synchronous generators and, as such, is entirely automatic.

System inertia, which is analogous to the “momentum”, is a key determinant in how rapidly the system frequency will change in response to a disturbance. In particular, the maximum rate of change of frequency is directly proportional to the system inertia. Based on the Facilitation of Renewables studies, it is known that, due to the RoCoF (rate of change of frequency) relays that are used to provide protection functions to distribution generation, a maximum rate of change of frequency greater than 0.5 Hz / s could result in loss of generation which could lead to system instability. For a largest infeed of 450 MW, a minimum system inertia level of 25,000 MW s results in a maximum rate a change of frequency of 0.45 Hz/s, which allows a prudent margin of safety.

It should be noted that there is a link between inertia and primary operating reserve: inertia determines the rate of change of frequency; reserve arrests the falling frequency and then restores it towards its nominal value. The lower the system inertia, the faster the frequency will fall following the loss of a generator and hence the faster the primary reserve response needs to be; conversely, at high inertia levels (such as for larger interconnected systems) slower-acting primary reserve is adequate to cope with generation loss. Thus the minimum system inertia level suggested here is only achievable provided there is an adequate amount of sufficiently fast-acting reserve to arrest the frequency fall before load shedding occurs.

Ramping Services

New operational policies are needed to manage the increased variability and uncertainty that intermittent (wind and solar power) generation will bring. These policies will need to ensure that there is sufficient ramping capability over multiple time horizons to meet the ramping needs of the system. The effectiveness of these policies will be dependent on the level of controllability of all windfarms, the accuracy of wind forecasts, and the portfolio ramping capability and performance.

Voltage Control

A co-ordinated approach to voltage control across the Transmission System and Distribution Networks is required to allow for the changing nature and location of Reactive Power sources. This approach will need to consider a number of factors: a potential decrease of over 25% on-line synchronous reactive capability; that windfarms reactive capability and their control will be a key requirement to manage voltage; and that the nature of windfarms reactive behaviour during voltage disturbances has implications for the stability of the Transmission System.

Portfolio performance

The current experience is that not all Power Generating Facilities are reliably and at all times the expected performance and capability standards. This creates uncertainty in system service delivery, which manifests itself today in increased costs in the operation of the Transmission System, and in the long run may compromise Operational Security.

To deliver the solutions to the key operational challenges of frequency response, ramping services, voltage control and unreliable portfolio performance, EirGrid and SONI are putting in place a three-year multi-stakeholder “Programme for a Secure, Sustainable Power System”. This programme will systematically address the challenges identified, by consistently monitoring plant performance and using the information gained to determine the performance needs of the future system, and by developing the necessary operational policies and tools to manage the increased system operational complexity, [19]

Low frequency demand disconnection

The Low Frequency Demand Disconnection is a system defence measure defined in detail in DCC Article 20, and it is used to shed load in situations of Active Power imbalances. In the implementation of Low Frequency Demand Disconnection the triggering frequencies have to be coordinated in each Synchronous Area between the TSOs, but the technical implementation may vary in different countries. Most often Low Frequency Demand Disconnection is implemented within Distribution Networks in preselected feeders but there may also be circulation between the feeders having the lowest negative impact during shedding. In some Transmission Systems Low Frequency Demand Disconnection is also implemented by the TSO in 110 kV network feeders in order to have continuously more accurate supervision and remote control of the amount to be shed in the TSO's control centre. Low Frequency Demand Disconnection will typically start functioning at frequencies of 49.0 Hz and lower in several predefined steps. In the future, when new Smart Grid solutions for Demand Side Response have been widely implemented the Low Frequency Demand Disconnection may utilize those functions and thus be able to select for this purpose only consumption, which has very low impact to Demand Facilities, e.g. electrical heating or cooling or refrigerators etc.

Justification of NC RfG capabilities with regards to data & information

The requirements on Data Exchange of the OS NC for type B, C and D Power Generating Facilities are established according to the information exchange capabilities requirements established in Article 9(5)(d)(1) of the NC RfG. The requirements are also in line with the possibility to exchange data directly with the TSO or to do this via the DSO:

“*Power Generating Facilities shall be capable of exchanging information between the Power Generating Facility Owner and the Relevant Network Operator and/or the Relevant TSO in real time or periodically with the time stamping as defined by the Relevant Network Operator and/or the Relevant TSO while respecting the provisions of Article 4(3)*.”

MAPPING OF THE NC OS AGAINST THE REQUIREMENTS SET IN THE NC RFG AND DCC

In the following table, an exhaustive mapping has been performed in order to clearly identify how the requirements set in terms of capability in the NC RfG and DCC have been applied in the NC OS for operational purpose.

OS NC		NC RfG		DCC	
Article		Article		Article	
8(1) (b)(ii)(a)	Active Power Reserve requirements are not fulfilled with lack of more than 20% of the required amount of any of the following: FCR, FRR and RR according to the dimensioning in the [NC LFCR], for more than 30 minutes and with no means to replace them;	10(2) (f)	Type ‘C’ & ‘D’ With regard to real-time monitoring of FSM: 1) To monitor the operation of Active Power Frequency Response the communication interface shall be equipped to transfer on-line from the Power Generating Facility to the Network control centre of the Relevant Network Operator and/or the Relevant TSO on request by the Relevant Network Operator and/or the Relevant TSO at least the following signals: - status signal of FSM (on/off); - scheduled Active Power output; - actual value of the Active Power output; - actual parameter settings for Active Power Frequency Response; and - Droop and dead band. 2) The Relevant Network Operator and the Relevant TSO shall define while respecting the provisions of Article 4(3) additional signals to be provided by the Power Generating Facility for monitoring and/or recording devices in order to verify the performance of the Active Power Frequency Response provision of participating		

OS NC		NC RfG		DCC	
Article		Article		Article	
			Power Generating Modules.		
8(1) (e)(i)	Restoration: Procedures are implemented to bring frequency, voltage and other operational parameters within the Operational Security Limits defined according to Articles 9, 10 and 12 in accordance with Article 8(5);	10(5) (a)&(b)	Type ‘C’ & ‘D’ Type C Power Generating Modules shall fulfil the following requirements referring to system restoration: a) With regard to Black Start Capability: 1) Black Start Capability is not mandatory. If the Relevant TSO deems system security to be at risk due to a lack of Black Start Capability in a Control Area, the Relevant TSO shall have the right to obtain a quote for Black Start Capability from Power Generating Facility Owners. 2) A Power Generating Module with a Black Start Capability shall be able to start from shut down within a timeframe decided by the Relevant Network Operator in coordination with the Relevant TSO while respecting the provisions of Article 4(3), without any external energy supply. The Power Generating Module shall be able to synchronise within the Frequency limits defined in Article 8(1) and Voltage limits defined by the Relevant Network Operator or defined by Article 11(2) where applicable. 3) The Power Generating Module Voltage regulation shall be capable of regulating load connections causing dips of Voltage automatically. The Power Generating Module shall: - be capable of regulating load connections in		

OS NC		NC RfG		DCC	
Article		Article		Article	
			block load; - control Frequency in case of over-frequency and under-frequency within the whole Active Power output range between Minimum Regulating Level and Maximum Capacity as well as at house load level; b) With regard to capability to take part in Island Operation: 1) The capability to take part in Island Operation, if required by the Relevant Network Operator in coordination with the Relevant TSO while respecting the provisions of Article 4(3), shall be possible within the Frequency limits defined in Article 8(1) and Voltage limits according to Article 10(3) or Article 11(2) where applicable. 2) If required, the Power Generating Module shall be able to operate in FSM during Island Operation, as defined in Article 10(2) (b). In the case of a power surplus, it shall be possible to reduce the Active Power Output of the Power Generating Module from its previous operating point to any new operating point within the P-Q-Capability Diagram as much as inherently technically feasible, but at least a Active Power output reduction to 55 % of its Maximum Capacity shall be possible. 3) Detection of change from interconnected system operation to Island Operation shall not rely solely on the Network Operator's switchgear position signals. The detection method shall be agreed between the Power Generating Facility Owner and the Relevant Network Operator in coordination with the Relevant TSO while		

OS NC		NC RfG		DCC	
Article		Article		Article	
			respecting the provisions of Article 4(3).		
8(3)	Each TSO shall monitor in real-time the following parameters within its Responsibility Area based on real-time telemetry and measurements from its Observability Area, taking into account the structural and real-time data defined in Chapter 3: a) active and reactive power flows; b) busbar voltages; c) frequency and Frequency Restoration Control Error of its LFC Area; d) Active and Reactive power reserves; and e) generation and consumption.	9(5) (d) And 10(2) (f)	Type 'B', 'C' and 'D' Type B Power Generating Modules shall fulfil the following general system management requirements: d) With regard to information exchange: 1) Power Generating Facilities shall be capable of exchanging information between the Power Generating Facility Owner and the Relevant Network Operator and/or the Relevant TSO in real time or periodically with time stamping as defined by the Relevant Network Operator and/or the Relevant TSO while respecting the provisions of Article 4(3). 2) The Relevant Network Operator in coordination with the Relevant TSO shall define while respecting the provisions of Article 4(3) the contents of information exchanges and the precise list and time of data to be facilitated. Type 'C' & 'D' Type C Power Generating Modules shall fulfil the following requirements referring to Frequency stability: f) With regard to real-time monitoring of FSM: 1) To monitor the operation of Active Power Frequency Response the communication interface shall be equipped to transfer on-line from the Power Generating Facility to the Network control centre of the Relevant Network Operator and/or the Relevant TSO on request by the Relevant	18	INFORMATION EXCHANGE 1. All Transmission Connected Demand Facilities and Transmission Connected Distribution Networks, deemed significant pursuant to the provisions of this Network Code, shall fulfil the following requirements related to the information exchange: a) Transmission Connected Demand Facilities shall be equipped according to the standard defined by the Relevant TSO, while respecting the provisions of Article 9(3), to transfer information between the Relevant TSO and the Transmission Connected Demand Facility with the defined time stamping. The defined standard shall be made publically available by the Relevant TSO. b) Transmission Connected Distribution Networks shall be equipped according to the standard defined by the Relevant TSO, while respecting the provisions of Article 9(3) to transfer information between the Relevant TSO and the Transmission Connected Distribution Network with the defined time stamping. The defined standard shall be made publically available by the Relevant TSO. c) The Relevant TSO shall define the information exchange standards while respecting the provisions of Article 9(3). The precise list of data required shall be made publically available by the Relevant TSO.

OS NC		NC RfG		DCC	
Article		Article		Article	
			Network Operator and/or the Relevant TSO at least the following signals: - status signal of FSM (on/off); - scheduled Active Power output; - actual value of the Active Power output; - actual parameter settings for Active Power Frequency Response; and - Droop and dead band. 2) The Relevant Network Operator and the Relevant TSO shall define while respecting the provisions of Article 4(3) additional signals to be provided by the Power Generating Facility for monitoring and/or recording devices in order to verify the performance of the Active Power Frequency Response provision of participating Power Generating Modules.		
8(6)	When defining the Operational Security Limits, each TSO shall take into account the capabilities required for Significant Grid Users which are Power Generating Modules in NC RfG, for Significant Grid Users which are Demand Facilities and Closed Distribution Networks in DCC and the capabilities required in the national grid codes for those Significant grid Users who are not subject or are derogated from NC RfG and DCC, in order to ensure that voltage and frequency ranges in Normal and Alert States do not lead to their	8(11)(a) (1)&(2) And 11(2) (a)(1)	Type 'B', 'C' and 'D' Type A[14] Power Generating Modules shall fulfil the following requirements referring to Frequency stability: a) With regard to Frequency ranges: 1) A Power Generating Module shall be capable of staying connected to the Network and operating	13 And 14(1) (a)(i)	GENERAL FREQUENCY REQUIREMENTS 1. All Transmission Connected Demand Facilities, and all Distribution Networks, shall fulfil the following Frequency stability requirements: a) With regard to Frequency ranges: i. A Transmission Connected Demand Facility Owner and Distribution Network Operator shall use their best endeavours in the design of its Transmission Connected Demand Facility and Distribution Network

[14] This reference is made because Power Generating Modules type B, C and D shall comply with requirements defined for Power Generating Modules type A.

OS NC		NC RfG		DCC	
Article		Article		Article	
	disconnection.		within the Frequency ranges and time periods specified by table 2 [RfG]. 2) While respecting the provisions of Article 4(3), wider Frequency ranges or longer minimum times for operation can be agreed between the Relevant Network Operator in coordination with the Relevant TSO and the Power Generating Facility Owner to ensure the best use of the technical capabilities of a Power Generating Module if needed to preserve or to restore system security. If wider Frequency ranges or longer minimum times for operation are economically and technically feasible, the consent of the Power Generating Facility Owner shall not be unreasonably withheld. Type 'D' Type D Power Generating Modules shall fulfil the following requirements referring to Voltage stability: a) With regard to Voltage ranges: 1) While still respecting the provisions according to Articles 9(3) (a) and 11(3) (a), a Power Generating Module shall be capable of staying connected to the Network and operating within the ranges of the Network Voltage at the Connection Point, expressed by the Voltage at the Connection Point related to nominal Voltage (per unit), and the time periods specified by tables 6.1 and 6.2 [RfG]. 2) While respecting the provisions of Article 4(3), wider Voltage ranges or longer minimum times for operation can be agreed between the Relevant Network Operator in coordination with the Relevant TSO and the Power Generating Facility		respectively for it to cope with the Frequency ranges and time periods specified in Table 1. ii. Wider Frequency ranges or longer minimum times for operation can be agreed between the Relevant Network Operator and the Distribution Network Operator or Transmission Connected Demand Facility Owner, in coordination with the Relevant TSO, while respecting the provisions of Article 9(3). If wider Frequency ranges or longer minimum times for operation are technically feasible, the consent of the Distribution Network Operator or Transmission Connected Demand Facility Owner shall not be unreasonably withheld. GENERAL VOLTAGE REQUIREMENTS 1. All Transmission Connected Demand Facilities and all Transmission Connected Distribution Networks, deemed significant pursuant to the provisions of this Network Code, shall fulfil the following Voltage stability requirements: a) With regard to Voltage ranges: i. In case of a deviation of the Network Voltage at the Connection Point from its nominal value, any Transmission Connected Demand Facility Owner or Transmission Connected Distribution Network Operator with a Connection Point at 110 kV or above, shall ensure its equipment at the Connection Point site is capable of withstanding without damage the Voltage range at the Connection Point, expressed by the Voltage at the Connection Point related to nominal per unit Voltage, within the time periods specified by Table 2.1 and Table 2.2. The establishment of the reference nominal Voltage shall be subject to coordination between the adjacent TSOs.

OS NC		NC RfG		DCC	
Article		Article		Article	
			Owner to ensure the best use of the technical capabilities of a Power Generating Module if needed to preserve or to restore system security. If wider Voltage ranges or longer minimum times for operation are economically and technically feasible, the consent of the Power Generating Facility Owner shall not be unreasonably withheld.		
8 (14)	When implementing a Remedial Action or a measure of the System Defence Plan, each Significant Grid User or DSO with Connection Point directly to the Transmission System shall execute the instructions given by the TSO to maintain Operational Security of the Transmission System, without undue delay. Unless decided otherwise by the TSO, DSOs shall communicate the instructions of the TSO to the Significant Grid Users if they are connected to the Distribution Network.	8(1)(f), 9(2)(a), 10(2)(a), 12(2) (a)&(b), 15(2)(a), 13(2) (b)&(c), And 16(3) (b)&(c)	Type 'B', 'C' and 'D' Type A[15] Power Generating Modules shall fulfil the following requirements referring to Frequency stability: f) The Power Generating Module shall be equipped with a logic interface (input port) in order to cease Active Power output within less than 5 seconds following an Instruction from the Relevant Network Operator. The Relevant Network Operator shall have the right to define while respecting the provisions of Article 4(3) the requirements for further equipment to make this facility operable remotely. Type 'B' Type B Power Generating Modules shall fulfil the following requirements referring to Frequency stability: a) In order to be able to control Active Power output, the Power Generating Module shall be equipped with a interface (input port) in order to be	22	DEMAND SIDE RESPONSE - ACTIVE POWER CONTROL, REACTIVE POWER CONTROL AND TRANSMISSION CONSTRAINT MANAGEMENT 1. With regard to either Demand Side Response Active Power Control, Reactive Power Control, or Transmission Constraint Management, Demand Facilities and Closed Distribution Networks may voluntarily offer this service. The requirements below shall be mandatory only for Demand Facilities or Closed Distribution Networks whom offer these services, either individually or as part of Demand Aggregation:

[15] This reference is made because Power Generating Modules type B, C and D shall comply with requirements defined for Power Generating Modules type A.

OS NC		NC RfG		DCC	
Article		Article		Article	
			able to reduce Active Power output as instructed by the Relevant Network Operator and/or the Relevant TSO. The Relevant Network Operator shall have the right to define while respecting the provisions of Article 4(3) the requirements for further equipment to make this facility operable remotely. Type 'C' & 'D' 2. Type C Power Generating Modules shall fulfil the following requirements referring to Frequency stability: a) With regard to Active Power controllability and control range, the Power Generating Module control system shall be capable of adjusting an Active Power Setpoint as instructed by the Relevant Network Operator or the Relevant TSO to the Power Generating Facility Owner. It shall be capable of implementing the Setpoint within a period specified in the above Instruction and within a tolerance defined by the Relevant Network Operator or the Relevant TSO (subject to the availability of the prime mover resource). Manual, local measures shall be possible in the case that any automatic remote control devices are out of service. Type 'B' 2. Type B Synchronous Power Generating Modules shall fulfil the following requirements referring to Voltage stability: a) With regard to Reactive Power capability the Relevant Network Operator shall have the right to define while respecting the provisions of Article 4(3) the capability of a Synchronous Power		

OS NC		NC RfG		DCC	
Article		Article		Article	
			Generating Module to provide Reactive Power. b) With regard to the Voltage control system, a Synchronous Power Generating Module shall be equipped with a permanent automatic excitation control system in order to provide constant Alternator terminal Voltage at a selectable Setpoint without instability over the entire operating range of the Synchronous Power Generating Module. Type B Power Park Modules shall fulfil the following requirement referring to Voltage stability: a) With regard to Reactive Power capability the Relevant Network Operator shall have the right to define while respecting the provisions of Article 4(3) the capability of a Power Park Module to provide Reactive Power. Type ‘C’ & ‘D’ Type C Synchronous Power Generating Modules shall fulfil the following requirements referring to Voltage stability: 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/Pmax-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		

OS NC		NC RfG		DCC	
Article		Article		Article	
			Maximum Capacity. 2) The U-Q/Pmax-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/Pmax-profile shall not exceed the U-Q/Pmax-profile envelope, represented by the inner envelope in figure 7 [RfG]; - the dimensions of the U-Q/Pmax-profile envelope (Q/Pmax range and Voltage range) are defined for each Synchronous Area in table 8 [RfG]; and - the position of the U-Q/Pmax-profile envelope within the limits of the fixed outer envelope in figure 7 [RfG]. 3) The Reactive Power provision capability requirement applies at the Connection Point. For profile shapes other than rectangular, the Voltage range represents the highest and lowest values. The full Reactive Power range is therefore not expected to be available across the range of steady-state Voltages. 4) The Synchronous Power Generating Module shall be capable of moving to any operating point within its U-Q/Pmax profile in appropriate timescales to target values requested by the Relevant Network Operator. c) With regard to Reactive Power capability below Maximum Capacity, when operating at an Active Power output below the Maximum Capacity (P<Pmax), the Synchronous Power Generating		

OS NC		NC RfG		DCC	
Article		Article		Article	
			Modules shall be capable of operating in every possible operating point in the P-Q Capability Diagram of the Alternator of this Synchronous Power Generating Module at least down to Minimum Stable Operating Level. Even at reduced Active Power output, Reactive Power supply at the Connection Point shall fully correspond to the P-Q-Capability Diagram of the Alternator of this Synchronous Power Generating Module, taking the auxiliary supply power and the Active and Reactive Power losses of the step-up transformer, if applicable, into account. Type C Power Park Modules shall fulfil the following requirements referring to Voltage stability: 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/Pmax-profile that shall take any shape within the boundaries of which the Power Park Module shall be capable of providing Reactive Power at its Maximum Capacity. 2) The U-Q/Pmax-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/Pmax-profile shall not exceed the U-Q/Pmax-profile envelope, represented by the inner envelope in figure 8 [RfG], its shape does not		

OS NC		NC RfG		DCC	
Article		Article		Article	
			need to be rectangular; - the dimensions of the U-Q/Pmax-profile envelope (Q/Pmax range and Voltage range) are defined for each Synchronous Area in table 9 [RfG]; and - the position of the U-Q/Pmax-profile envelope within the limits of the fixed outer envelope in figure 8 [RfG]. 3) The Reactive Power provision capability requirement applies at the Connection Point. For profile shapes other than rectangular, the Voltage range represents the highest and lowest values. The full Reactive Power range is therefore not expected to be available across the range of steady-state Voltages. c) With regard to Reactive Power capability below 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. For doing so, it shall define a P-Q/Pmax-profile that shall take any shape within the boundaries of which the Power Park Module shall be capable of providing Reactive Power below Maximum Capacity. 2) The P-Q/Pmax-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/Pmax-profile shall not exceed the P-		

OS NC		NC RfG		DCC	
Article		Article		Article	
			Q/Pmax-profile envelope, represented by the inner envelope in figure 9; - the Q/Pmax range of the P-Q/Pmax-profile envelope is defined for each Synchronous Area in table 9; - the Active Power range of the P-Q/Pmax-profile envelope at zero Reactive Power shall be 1 pu; - the P-Q/Pmax-profile can be of any shape and shall include conditions for Reactive Power capability at zero Active Power; and - the position of the P-Q/Pmax-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<Pmax), the Power Park Module shall be capable of providing Reactive Power at any operating point inside its P-Q/Pmax-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. 4) The Power Park Module shall be capable of moving to any operating point within its P-Q/Pmax profile in appropriate timescales to target values requested by the Relevant Network Operator.		

OS NC		NC RfG		DCC	
Article		Article		Article	
9(2) And 9(3)	In case the frequency is beyond the Maximum Steady-state Frequency Deviation, but within the range 49 – 51 Hz, all TSOs of the Synchronous Area shall apply commonly agreed Remedial Actions following coordinated procedures agreed among all TSOs of that Synchronous Area in order to recover frequency back within the range of Maximum Steady-state Frequency Deviation. The description of such coordinated procedures shall be published at the ENTSO-E website 12 months after entry into force of this Network Code. In case the frequency is outside of the range 49 – 51 Hz, all TSOs of the Synchronous Area shall apply commonly agreed measures of the System Defence Plan following coordinated procedures agreed among all TSOs of that Synchronous Area in order to recover and restore frequency within the time ranges specified in NC RfG and Article 13 of DCC. These coordinated procedures shall be published on the ENTSO-E website 12 months after entry into force of this Network Code.	8(1)(f), 9(2)(a) and 10(2)(a)	Type 'B', 'C' and 'D' Type A[16] Power Generating Modules shall fulfil the following requirements referring to Frequency stability: f) The Power Generating Module shall be equipped with a logic interface (input port) in order to cease Active Power output within less than 5 seconds following an Instruction from the Relevant Network Operator. The Relevant Network Operator shall have the right to define while respecting the provisions of Article 4(3) the requirements for further equipment to make this facility operable remotely. Type 'B' Type B Power Generating Modules shall fulfil the following requirements referring to Frequency stability: a) In order to be able to control Active Power output, the Power Generating Module shall be equipped with a interface (input port) in order to be able to reduce Active Power output as instructed by the Relevant Network Operator and/or the Relevant TSO. The Relevant Network Operator shall have the right to define while respecting the provisions of Article 4(3) the requirements for further equipment to make this facility operable remotely.	22	DEMAND SIDE RESPONSE - ACTIVE POWER CONTROL, REACTIVE POWER CONTROL AND TRANSMISSION CONSTRAINT MANAGEMENT 1. With regard to either Demand Side Response Active Power Control, Reactive Power Control, or Transmission Constraint Management, Demand Facilities and Closed Distribution Networks may voluntarily offer this service. The requirements below shall be mandatory only for Demand Facilities or Closed Distribution Networks whom offer these services, either individually or as part of Demand Aggregation:

[16] This reference is made because Power Generating Modules type B, C and D shall comply with requirements defined for Power Generating Modules type A.

OS NC		NC RfG		DCC	
Article		Article		Article	
			Type 'C' & 'D' 2. Type C Power Generating Modules shall fulfil the following requirements referring to Frequency stability: a) With regard to Active Power controllability and control range, the Power Generating Module control system shall be capable of adjusting an Active Power Setpoint as instructed by the Relevant Network Operator or the Relevant TSO to the Power Generating Facility Owner. It shall be capable of implementing the Setpoint within a period specified in the above Instruction and within a tolerance defined by the Relevant Network Operator or the Relevant TSO (subject to the availability of the prime mover resource). Manual, local measures shall be possible in the case that any automatic remote control devices are out of service.		
9(4) And 9(5)	Significant Grid Users which are Power Generating Modules subject to the requirements of the [NC RfG] shall remain connected at least within the frequency and time ranges defined in the Article 8 of [NC RfG] when generating electrical power. All Significant Grid Users which are Power Generating Modules which are not subject to or derogated from the requirements of the [NC RfG] shall inform their TSOs and DSOs if connected to the Distribution Network, about their performance in comparison with the frequency requirements in [NC RfG] and in so doing they shall within 12 months after the	8(1) (a)&(b)	Type 'B', 'C' & 'D' Type A[17] Power Generating Modules shall fulfil the following requirements referring to Frequency stability: a) With regard to Frequency ranges: 1) A Power Generating Module shall be capable of staying connected to the Network and operating within the Frequency ranges and time periods	13	GENERAL FREQUENCY REQUIREMENTS 1. All Transmission Connected Demand Facilities, and all Distribution Networks, shall fulfil the following Frequency stability requirements: a) With regard to Frequency ranges: i. A Transmission Connected Demand Facility Owner and Distribution Network Operator shall use their best endeavours in the design of its Transmission Connected Demand Facility and Distribution Network respectively for it to cope with the Frequency ranges and time periods

[17] This reference is made because Power Generating Modules type B, C and D shall comply with requirements defined for Power Generating Modules type A.

OS NC		NC RfG		DCC	
Article		Article		Article	
	entry into force of this Network Code declare the frequencies and time ranges they can withstand without disconnection. Where the TSO requires modifications by a Power Generating Module not subject to or derogated from the requirements of [NC RfG] to improve its performance then this requirement shall be done according to the Article 33 of the NC RfG and shall be approved by NRA. . While being in Emergency State, the system frequency can exceed the range of 49 – 51 Hz. TSOs shall take into account that Significant Grid Users which are Power Generating Modules and Demand Facilities subject to NC RfG and DCC can disconnect after the time periods required in NC RfG and DCC and take this into account in planning of Remedial Actions and measures of the System Defence Plan. For Significant Grid Users which are Power Generating Modules not subject to or derogated from the requirements of the NC RfG, the TSOs shall take into account the frequency values at which each of these system users will disconnect.		specified by table 2 [RfG]. 2) While respecting the provisions of Article 4(3), wider Frequency ranges or longer minimum times for operation can be agreed between the Relevant Network Operator in coordination with the Relevant TSO and the Power Generating Facility Owner to ensure the best use of the technical capabilities of a Power Generating Module if needed to preserve or to restore system security. If wider Frequency ranges or longer minimum times for operation are economically and technically feasible, the consent of the Power Generating Facility Owner shall not be unreasonably withheld. 3) While respecting the provisions of Article 8(1) (a) point 1) a Power Generating Module shall be capable of automatic disconnection at specified frequencies, if required by the Relevant Network Operator. While respecting the provisions of Article 4(3), Terms and settings for automatic disconnection shall be agreed between the Relevant Network Operator and the Power Generating Facility Owner. b) With regard to the rate of change of Frequency withstand capability, a Power Generating Module shall be capable of staying connected to the Network and operating at rates of change of Frequency up to a value defined by the Relevant TSO while respecting the provisions of Article 4(3) other than triggered by rate-of-change-of-Frequency-type of loss of mains protection. This rate-of-change-of-Frequency-type of loss of mains protection will be defined by the Relevant Network Operator in coordination with the Relevant TSO.		specified in Table 1. ii. Wider Frequency ranges or longer minimum times for operation can be agreed between the Relevant Network Operator and the Distribution Network Operator or Transmission Connected Demand Facility Owner, in coordination with the Relevant TSO, while respecting the provisions of Article 9(3). If wider Frequency ranges or longer minimum times for operation are technically feasible, the consent of the Distribution Network Operator or Transmission Connected Demand Facility Owner shall not be unreasonably withheld.

OS NC		NC RfG		DCC	
Article		Article		Article	
9(6) and 9(7)	6. Each Significant Grid User with Connection Point directly to the Transmission System shall adopt the criteria and conditions including requirements for permission to re-synchronize, defined by the TSO for re-synchronization. Each DSO with Connection Point directly to the Transmission System shall adopt the criteria and conditions including requirements for permission to re-synchronize, defined by the TSO for re-synchronization of the Significant Grid Users with Connection Point to its Distribution Network. Each DSO with Connection Point directly to the Transmission System shall in turn ensure that those criteria and conditions are agreed upon with the Significant Grid Users with Connection Point directly to the Distribution Network.	8(1)(g), 9(4)(a), 10(5)(c) and 11(4)(a)	Type 'B', 'C' and 'D' Type A[18] Power Generating Modules shall fulfil the following requirements referring to Frequency stability: g) The Relevant TSO shall define while respecting the provisions of Article 4(3) the conditions under which a Power Generating Module shall be capable of connecting automatically to the Network. These conditions shall include: - Frequency ranges, within which an automatic connection is admissible, and a corresponding delay time - maximum admissible gradient of increase of Active Power output Automatic connection is allowed unless determined otherwise by the Relevant Network Operator in coordination with the Relevant TSO. Type 'B' Type B Power Generating Modules shall fulfil the following requirement referring to system restoration: a) With regard to capability of reconnection after an incidental disconnection due to a Network disturbance, the Relevant TSO shall adopt a decision while respecting the provisions of Article	20(5)	DEMAND DISCONNECTION FOR SYSTEM DEFENCE AND DEMAND RECONNECTION 5. Transmission Connected Demand Facilities and Transmission Connected Distribution Networks shall fulfil the following requirement referring to disconnection or reconnection of a Transmission Connected Demand Facility or Transmission Connected Distribution Network: a) With regard to capability of reconnection after a disconnection, the Relevant TSO shall define, while respecting the provisions of Article 9(3), the conditions under which a Transmission Connected Demand Facility and Transmission Connected Distribution Network is entitled to reconnect to the Transmission Network. Installation of automatic reconnection systems shall be subject to prior authorization by the Relevant TSO. b) With regards to reconnection of a Transmission Connected Demand Facility or Transmission Connected Distribution Network, the Transmission Connected Demand Facility and Transmission Connected Distribution Network shall be capable of synchronisation for Frequencies within the ranges set out in Article 13(1)(a)(i). The Relevant TSO and the Transmission Connected Demand Facility Owner or Transmission Connected Distribution Network Operator shall agree on the settings of synchronization devices prior to connection of the Transmission Connected Demand Facility or Transmission Connected Distribution Network, including: Voltage, Frequency, phase angle range, deviation of Voltage and Frequency.

[18] This reference is made because Power Generating Modules type B, C and D shall comply with requirements defined for Power Generating Modules type A.

OS NC		NC RfG		DCC	
Article		Article		Article	
			4(3) defining the conditions under which a Power Generating Module shall be capable of reconnecting to the Network after an incidental disconnection has taken place due to a Network disturbance. Installation of automatic reconnection systems shall be subject to prior authorization by the Relevant Network Operator subject to reconnection conditions specified by the Relevant TSO. Type 'C' Type C Power Generating Modules shall fulfil the following requirements referring to system restoration: c) With regard to quick re-synchronization capability: 1) Quick re-synchronization capability is required in case of disconnection of the Power Generating Module from the Network in line with the protection strategy agreed between the Relevant Network Operator in coordination with the Relevant TSO and the Power Generation Facility Owner in the event of disturbances to the system. 2) The Power Generating Module whose minimum re-synchronization time after its disconnection from any external power supply exceeds 15 minutes shall be designed for tripping to houseload from any operating point in its P-Q-Capability Diagram. For identifying houseload operation any Network Operator's switchgear position signals may be used only as additional information which cannot be solely relied on. 3) Power Generating Modules shall be capable of continuing operation following tripping to		

OS NC		NC RfG		DCC	
Article		Article		Article	
			houseload, irrespective of any auxiliary connection to the external Network. The minimum operation time shall be defined by the Relevant Network Operator in coordination with the Relevant TSO taking into consideration the specific characteristics of the prime mover technology. Type 'D' Type D Power Generating Modules shall fulfil the following general system management requirements: a) With regard to synchronization, when starting a Power Generating Module, synchronization shall be performed by the Power Generating Facility Owner after authorization by the Relevant Network Operator. The Power Generating Module shall be equipped with the necessary synchronization facilities. Synchronization of Power Generating Modules shall be possible for frequencies within the ranges set out in table 2. While respecting the provisions of Article 4(3), the Relevant Network Operator and the Power Generating Facility Owner shall agree on the settings of synchronization devices to be concluded prior to operation of the Power Generating Module. An agreement shall cover the following matters: Voltage, Frequency, phase angle range, phase sequence, deviation of Voltage and Frequency.		
9(8)	Notwithstanding the provisions of Article 10(6) and 10(7), each DSO with Connection Point directly to the Transmission System shall automatically disconnect at specified frequencies and in predefined Active Power steps, defined by the TSO. Notwithstanding the provisions of Article 9(6) and 9(7), each	10(2)(e)	Type 'C' & 'D' Type C Power Generating Modules shall fulfil the following requirements referring to Frequency stability:	20 (1)&(2)	DEMAND DISCONNECTION FOR SYSTEM DEFENCE AND DEMAND RECONNECTION 1. All Transmission Connected Demand Facilities and Transmission Connected Distribution Networks, deemed significant pursuant to the provisions of this Network Code, shall fulfil the following requirements

OS NC		NC RfG		DCC	
Article		Article		Article	
	Significant Grid User which is a Power Generating Module shall automatically disconnect at specified frequencies, defined by the TSO.		e) With regard to disconnection due to underfrequency, any Power Generating Facility being capable of acting as a load except for auxiliary supply, including hydro Pump-Storage Power Generating Facilities, shall be capable of disconnecting its load in case of underfrequency.		related to Low Frequency Demand Disconnection schemes: a) Each Transmission Connected Distribution Network Operator and as specified by the TSO, Transmission Connected Demand Facility Owner, shall provide capabilities that shall enable automatic low Frequency (or alternatively if specified by the TSO combined with rate-of change-of-Frequency) disconnection of a percentage of their demand. The percentage of the demand shall be specified by the TSO, in coordination with all TSOs in the Synchronous Area. This specification shall be based on a rule set defined by the TSO while respecting the provisions of Article 9(3). b) The Low Frequency Demand Disconnection schemes shall be capable of disconnecting demand in stages for a range of operational frequencies. The number of stages and their respective operational frequencies shall be defined by the TSO, while respecting the provisions of Article 9(3). c) The percentage of the demand disconnection at each Frequency shall be defined by the TSO while respecting the provisions of Article 9(3). d) The geographical distribution of this demand disconnection shall be provided by the Transmission Connected Distribution Network Operator or Transmission Connected Demand Facility Owner and approved by the TSO. In cases of nested Distribution Networks the geographical distribution shall be equitable to all the associated Distribution Network Operators. e) Each Distribution Network Operator and Transmission Connected Demand Facility Owner shall notify the TSO in writing of the details of the automatic Low Frequency Demand Disconnection on its Network. This notification shall be made every year and shall identify, for each Connection Point to the Transmission Network, the Frequency settings at which demand disconnection shall be initiated and the percentage of demand disconnected at every such setting. f) The Low Frequency Demand Disconnection scheme shall be suitable

OS NC		NC RfG		DCC	
Article		Article		Article	
					for operation from a nominal AC input to be defined by the Relevant Network Operator, while respecting the provisions of Article 9(3), and shall have the following functional capability: i. Frequency Range: at least between 47-50Hz, adjustable in steps of 0.05Hz; ii. Operating time: no more than 150 ms after triggering the Frequency set-point; iii. Voltage lock-out: blocking of the scheme should be possible when the voltage is within a range of 30 to 90% of nominal Voltage; and iv. Direction of Active Power flow at the point of disconnection. 2. With regard to Low Frequency Demand Disconnection schemes AC Voltage supply: a) The voltage supply to the Low Frequency Demand Disconnection schemes shall be derived from the Network at the Frequency signal measuring point, as defined in the Low Frequency Demand Disconnection scheme in paragraph 1(f), so that the Frequency of the Low Frequency Demand Disconnection schemes supply Voltage is the same as that of the Network.
9(10)	Each TSO shall operate its LFC Area with sufficient upward and downward Active Power Reserve, which may include shared or exchanged reserves, to face imbalances of demand and supply within its LFC Area. Each TSO shall control the Frequency Restoration Control Error as defined in the NC LFCR in order to reach the required frequency quality within the Synchronous Area in cooperation with the TSOs in the same Synchronous Area. All TSOs within a Synchronous Area shall establish the methodology used within this Synchronous Area to determine the required upward and downward Active Power reserve in accordance with the provisions of the NC	10(2)(c)	Type C Power Generating Modules shall fulfil the following requirements referring to Frequency stability: c) In addition to Article 10(2) (b) the following shall apply accumulatively, when operating in Frequency Sensitive Mode (FSM): 1) The Power Generating Module shall be capable of providing Active Power Frequency Response with respect to figure 5 and in accordance with the parameters specified by each TSO within the ranges shown in table 4.		

OS NC		NC RfG		DCC	
Article		Article		Article	
	LFCR.		2) In case of overfrequency the Active Power Frequency Response is limited by the Minimum Regulating Level. 3) In case of underfrequency the Active Power Frequency Response is limited by Maximum Capacity. The actual delivery of Active Power Frequency Response depends on the operating and ambient conditions of the Power Generating Module when this response is triggered, in particular limitations on operation near Maximum Capacity at low frequencies according to Article 8(1) (e) and available primary energy sources. 4) 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. 5) As a result of a frequency step change, the Power Generating Module shall be capable of activating full Active Power Frequency Response, at or above the full line according to figure 6 in accordance with the parameters specified by each TSO (aiming at avoiding Active Power oscillations for the Power Generating Module) within the ranges according to table 5. The combination of choice of the parameters according to table 5 shall take into account possible technology dependent limitations. The initial delay of activation shall be as short as possible and reasonably justified by the Power Generating Facility Owner to the Relevant TSO, by providing technical evidence for why a longer time is needed, if greater than 2 seconds or a shorter time if specified by the Relevant TSO while respecting the provisions of Article 4(3) for generation technologies without		

OS NC		NC RfG		DCC	
Article		Article		Article	
			Inertia. 6) 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. 7) As long as a Frequency deviation continues Active Power control shall not have any adverse impact on the Frequency response within the time limits of Article 10(2) (c) point 6).		
9(11)	Each TSO shall monitor close to real-time generation and exchange schedules, power flows, node injections and withdrawals and other parameters within its LFC Area relevant for anticipating a risk of a frequency deviation and when needed take joint measures to limit their negative effects on the balance between generation and demand in coordination with other TSOs of its Synchronous Area.	9(5) (d) And 10(2) (f)	Type 'B', 'C' and 'D' Type B Power Generating Modules shall fulfil the following general system management requirements: d) With regard to information exchange: 1) Power Generating Facilities shall be capable of exchanging information between the Power Generating Facility Owner and the Relevant Network Operator and/or the Relevant TSO in real time or periodically with time stamping as defined by the Relevant Network Operator and/or the Relevant TSO while respecting the provisions of Article 4(3). 2) The Relevant Network Operator in coordination with the Relevant TSO shall define while respecting the provisions of Article 4(3) the contents of information exchanges and the precise list and time of data to be facilitated.	18	INFORMATION EXCHANGE 1. All Transmission Connected Demand Facilities and Transmission Connected Distribution Networks, deemed significant pursuant to the provisions of this Network Code, shall fulfil the following requirements related to the information exchange: a) Transmission Connected Demand Facilities shall be equipped according to the standard defined by the Relevant TSO, while respecting the provisions of Article 9(3), to transfer information between the Relevant TSO and the Transmission Connected Demand Facility with the defined time stamping. The defined standard shall be made publically available by the Relevant TSO. b) Transmission Connected Distribution Networks shall be equipped according to the standard defined by the Relevant TSO, while respecting the provisions of Article 9(3) to transfer information between the Relevant TSO and the Transmission Connected Distribution Network with the defined time stamping. The defined standard shall be made publically available by the Relevant TSO. c) The Relevant TSO shall define the information exchange standards while respecting the provisions of Article 9(3). The precise list of data

OS NC		NC RfG		DCC	
Article		Article		Article	
			Type 'C' & 'D' Type C Power Generating Modules shall fulfil the following requirements referring to Frequency stability: f) With regard to real-time monitoring of FSM: 1) To monitor the operation of Active Power Frequency Response the communication interface shall be equipped to transfer on-line from the Power Generating Facility to the Network control centre of the Relevant Network Operator and/or the Relevant TSO on request by the Relevant Network Operator and/or the Relevant TSO at least the following signals: - status signal of FSM (on/off); - scheduled Active Power output; - actual value of the Active Power output; - actual parameter settings for Active Power Frequency Response; and - Droop and dead band. 2) The Relevant Network Operator and the Relevant TSO shall define while respecting the provisions of Article 4(3) additional signals to be provided by the Power Generating Facility for monitoring and/or recording devices in order to verify the performance of the Active Power Frequency Response provision of participating Power Generating Modules.		required shall be made publically available by the Relevant TSO.
9(14)	Each TSO shall be entitled to use actions to improve System Frequency quality as defined	10(6)	Type 'C' & 'D'	23(1)(b)	DEMAND SIDE RESPONSE SYSTEM FREQUENCY CONTROL

OS NC		NC RfG		DCC	
Article		Article		Article	
	in [NC LFCR]. These actions can include restrictions on the Ramping Rates of Significant Grid Users and HVDC interconnectors.	(d)&(e)	Type C Power Generating Modules shall fulfil the following general system management requirements: d) With regard to the installation of devices for system operation and/or security, if the Relevant Network Operator or the Relevant TSO considers additional devices necessary to be installed in a Power Generating Facility in order to preserve or restore system operation or security, the Relevant Network Operator or Relevant TSO and the Power Generating Facility Owner shall investigate this request and, while respecting the provisions of Article 4(3), agree on an appropriate solution . e) The Relevant Network Operator in coordination with the Relevant TSO shall define while respecting the provisions of Article 4(3) minimum and maximum limits on rates of change of Active Power output (ramping limits) in both up and down direction for a Power Generating Module taking into consideration the specific characteristics of the prime mover technology.		1. With Regard to Demand Side Response System Frequency Control on Temperature Controlled Devices: b) The control system shall be designed with a logic interface (input port) in order that a communication signal may be fitted into the system to inhibit operation as part of a Demand Side Response system within the facility. The Relevant Network Operator shall have the right to define while respecting the provisions of Article 9(3) the requirements for further equipment to make use of this logical interface.
10(3)	Significant Grid Users which are Power Generating Modules of type D subject to the requirements of the [NC RfG] shall remain connected at least within the voltage and time ranges defined according to Article 11 of [NC RfG]. All Significant Grid Users which are Power Generating Modules with Connection Point directly to the Transmission System who are not subjected to or derogated from the [NC RfG] shall inform their TSO about their capabilities compared to the voltage requirements in [NC RfG] and in so doing they shall declare the voltages and time they can withstand without disconnection. Each TSO can	11(2)(a) (1)&(2) and 10(6) (d)	Type 'D' Type D Power Generating Modules shall fulfil the following requirements referring to Voltage stability: a) With regard to Voltage ranges: 1) While still respecting the provisions according to Articles 9(3) (a) and 11(3) (a), a Power Generating Module shall be capable of staying connected to the Network and operating within the ranges of the Network Voltage at the Connection	14(1) (a)(i)	GENERAL VOLTAGE REQUIREMENTS 1. All Transmission Connected Demand Facilities and all Transmission Connected Distribution Networks, deemed significant pursuant to the provisions of this Network Code, shall fulfil the following Voltage stability requirements: a) With regard to Voltage ranges: i. In case of a deviation of the Network Voltage at the Connection Point from its nominal value, any Transmission Connected Demand Facility Owner or Transmission Connected Distribution Network Operator with a Connection Point at 110 kV or above, shall ensure its equipment at the

OS NC		NC RfG		DCC	
Article		Article		Article	
	require modifications of the capability of such Significant Grid User which is a Power Generating Module if this is necessary for maintaining Operational Security and then this requirement shall be done according to the Article 33 of [NC RfG] and shall be approved by NRA.		Point, expressed by the Voltage at the Connection Point related to nominal Voltage (per unit), and the time periods specified by tables 6.1 and 6.2. 2) While respecting the provisions of Article 4(3), wider Voltage ranges or longer minimum times for operation can be agreed between the Relevant Network Operator in coordination with the Relevant TSO and the Power Generating Facility Owner to ensure the best use of the technical capabilities of a Power Generating Module if needed to preserve or to restore system security. If wider Voltage ranges or longer minimum times for operation are economically and technically feasible, the consent of the Power Generating Facility Owner shall not be unreasonably withheld. Type 'C' & 'D' Type C Power Generating Modules shall fulfil the following general system management requirements: d) With regard to the installation of devices for system operation and/or security, if the Relevant Network Operator or the Relevant TSO considers additional devices necessary to be installed in a Power Generating Facility in order to preserve or restore system operation or security, the Relevant Network Operator or Relevant TSO and the Power Generating Facility Owner shall investigate this request and, while respecting the provisions of Article 4(3), agree on an appropriate solution .		Connection Point site is capable of withstanding without damage the Voltage range at the Connection Point, expressed by the Voltage at the Connection Point related to nominal per unit Voltage, within the time periods specified by Table 2.1 and Table 2.2. The establishment of the reference nominal Voltage shall be subject to coordination between the adjacent TSOs.
10(5), 10(14)	If voltages at Connection Point to the Transmission System are outside the ranges from Tables 8.1 and 8.2, each TSO shall apply voltage control and Reactive Power management measures in order to restore	12(2) (a)&(b)	Type 'B' Type B Synchronous Power Generating Modules shall fulfil the following requirements referring to	16(1)(b) And	REACTIVE POWER REQUIREMENTS b) Without prejudice to the provisions of paragraph 1(a) of this article, the Relevant TSO shall have the right to require, while respecting the provisions of Article 9(3), the ability of the Transmission Connected

OS NC		NC RfG		DCC	
Article		Article		Article	
And 10(18)	voltages within the ranges from Tables 8.1 and 8.2 and within the time ranges specified according to Article 11 of [NC RfG] and Article 14 of [DCC]. Each TSO shall be entitled to use all available Reactive Power resources with Connection Point to the Transmission System within its Responsibility Area to ensure effective Reactive Power management and maintaining the ranges of voltage Operational Security Limits defined in this Network Code. If voltage deterioration jeopardizes Operational Security or threatens to develop into a voltage collapse in either N or (N-1)-Situation the TSO shall be entitled to instruct the DSOs, Closed Distribution Networks and Significant Grid Users with Connection Point directly to the Transmission System, to block automatic voltage and Reactive Power control of transformers or to follow other voltage control instructions. As a consequence of these measures directed by the TSO, the DSO may have to disconnect Significant Grid Users which are Demand Facilities in order to avoid jeopardising the Transmission System. This is part of the Defence Plan. .	13(2) (b)&(c) and 14(2)(a)	Voltage stability: a) With regard to Reactive Power capability the Relevant Network Operator shall have the right to define while respecting the provisions of Article 4(3) the capability of a Synchronous Power Generating Module to provide Reactive Power. b) With regard to the Voltage control system, a Synchronous Power Generating Module shall be equipped with a permanent automatic excitation control system in order to provide constant Alternator terminal Voltage at a selectable Setpoint without instability over the entire operating range of the Synchronous Power Generating Module. Type 'C' & 'D' Type C Synchronous Power Generating Modules shall fulfil the following requirements referring to Voltage stability: 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/Pmax-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/Pmax-profile is defined by the Relevant Network Operator in coordination with	22	Distribution Network to actively control the exchange of Reactive Power at the Connection Point as part of a wider common concept for management of Reactive Power capabilities for the benefit of the entire Network. The method of this control shall be agreed between the Relevant TSO and the Transmission Connected Distribution Network Operator to ensure the justified level of security of supply for both parties. The justification shall include a roadmap in which the steps and the timeline for fulfilling the requirement are specified. DEMAND SIDE RESPONSE - ACTIVE POWER CONTROL, REACTIVE POWER CONTROL AND TRANSMISSION CONSTRAINT MANAGEMENT 1. With regard to either Demand Side Response Active Power Control, Reactive Power Control, or Transmission Constraint Management, Demand Facilities and Closed Distribution Networks may voluntarily offer this service. The requirements below shall be mandatory only for Demand Facilities or Closed Distribution Networks whom offer these services, either individually or as part of Demand Aggregation:

OS NC		NC RfG		DCC	
Article		Article		Article	
			the Relevant TSO while respecting the provisions of Article 4(3) in conformity with the following principles: - the U-Q/Pmax-profile shall not exceed the U-Q/Pmax-profile envelope, represented by the inner envelope in figure 7; - the dimensions of the U-Q/Pmax-profile envelope (Q/Pmax range and Voltage range) are defined for each Synchronous Area in table 8; and - the position of the U-Q/Pmax-profile envelope within the limits of the fixed outer envelope in figure 7. 3) The Reactive Power provision capability requirement applies at the Connection Point. For profile shapes other than rectangular, the Voltage range represents the highest and lowest values. The full Reactive Power range is therefore not expected to be available across the range of steady-state Voltages. 4) The Synchronous Power Generating Module shall be capable of moving to any operating point within its U-Q/Pmax profile in appropriate timescales to target values requested by the Relevant Network Operator. c) With regard to Reactive Power capability below Maximum Capacity, when operating at an Active Power output below the Maximum Capacity (P<Pmax), the Synchronous Power Generating Modules shall be capable of operating in every possible operating point in the P-Q Capability Diagram of the Alternator of this Synchronous Power Generating Module at least down to Minimum Stable Operating Level. Even at reduced		

OS NC		NC RfG		DCC	
Article		Article		Article	
			Active Power output, Reactive Power supply at the Connection Point shall fully correspond to the P-Q-Capability Diagram of the Alternator of this Synchronous Power Generating Module, taking the auxiliary supply power and the Active and Reactive Power losses of the step-up transformer, if applicable, into account. Type 'D' Type D Synchronous Power Generating Modules shall fulfil the following requirements referring to Voltage stability: a) While respecting the provisions of Article 4(3), the parameters and settings of the components of the Voltage control system shall be agreed between the Power Generating Facility Owner and the Relevant Network Operator in coordination with the Relevant TSO Such agreement shall include: - specifications and performance of an Automatic Voltage Regulator (AVR) with regards to steady-state Voltage and transient Voltage control; and - specifications and performance of the Excitation System: ☐ bandwidth limitation of the output signal to ensure that the highest Frequency of response cannot excite torsional oscillations on other Power Generating Modules connected to the Network; ☐ an Underexcitation Limiter to prevent the Automatic Voltage Regulator from reducing the Alternator excitation to a level which would endanger synchronous stability;		

OS NC		NC RfG		DCC	
Article		Article		Article	
			☐ an Overexcitation Limiter to ensure that the Alternator excitation is not limited to less than the maximum value that can be achieved whilst ensuring the Synchronous Power Generating Module is operating within its design limits; ☐ a stator Current limiter; and ☐ a PSS function to attenuate power oscillations, if the Synchronous Power Generating Module size is above a value of Maximum Capacity defined by the Relevant TSO while respecting the provisions of Article 4(3).		
10(6)	In Emergency State, if voltages at Connection Points of Power generating Modules of type D to the Transmission System exceed the ranges from Tables 8.1 and 8.2, TSOs shall take into account that Significant Grid Users connected to the Transmission System and who are affected by [NC RfG] and [DCC] might disconnect after the time periods required in Article 11 of [NC RfG] or Article 14 of [DCC] and take this into account in defining Remedial Actions and measures of the System Defence Plan.	11(2)(a), 9(3)(a) And 11(3)(a)	Type ‘D’ Type D Power Generating Modules shall fulfil the following requirements referring to Voltage stability: a) With regard to Voltage ranges: 1) While still respecting the provisions according to Articles 9(3) (a) and 11(3) (a), a Power Generating Module shall be capable of staying connected to the Network and operating within the ranges of the Network Voltage at the Connection Point, expressed by the Voltage at the Connection Point related to nominal Voltage (per unit), and the time periods specified by tables 6.1 and 6.2. 2) While respecting the provisions of Article 4(3), wider Voltage ranges or longer minimum times for operation can be agreed between the Relevant Network Operator in coordination with the Relevant TSO and the Power Generating Facility Owner to ensure the best use of the technical capabilities of a Power Generating Module if needed to preserve or to restore system security.		

OS NC		NC RfG		DCC	
Article		Article		Article	
			If wider Voltage ranges or longer minimum times for operation are economically and technically feasible, the consent of the Power Generating Facility Owner shall not be unreasonably withheld. 3) While still respecting the provisions of Article 11(2) (a) point 1), the Relevant Network Operator in coordination with the Relevant TSO shall have the right to specify while respecting the provisions of Article 4(3) Voltages at the Connection Point at which a Power Generating Module shall be capable of automatic disconnection. The terms and settings for automatic disconnection shall be agreed between the Relevant Network Operator and the Power Generating Facility Owner, while respecting the provisions of Article 4(3). Type ‘B’, ‘C’ &’D’ 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) Each TSO shall define while respecting the provisions of Article 4(3) a voltage-against-time-profile according to figure 3 at the Connection Point for fault conditions which describes the conditions in which the Power Generating Module shall be capable of staying connected to the Network and continuing stable operation after the power system has been disturbed by Secured Faults on the Network. 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		

OS NC		NC RfG		DCC	
Article		Article		Article	
			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 using parameters in figure 3 according to tables 3.1 and 3.2. 3) Each TSO shall define and make publicly available while respecting the provisions of Article 4(3) defining the pre-fault and post-fault conditions for the fault-ride-through capability in terms of: - conditions for the calculation of the pre-fault minimum short circuit capacity at the Connection Point; - conditions for pre-fault active and Reactive Power operating point of the Power Generating Module at the Connection Point and Voltage at the Connection Point; and - conditions for the calculation of the post-fault minimum short circuit capacity at the Connection Point. 4) Each Relevant Network Operator shall provide on request by the Power Generating Facility Owner the pre-fault and post-fault conditions to be considered for fault-ride-through capability as an outcome of the calculations at the Connection Point as defined in Article 9 (3) (a) point 3) regarding: - pre-fault minimum short circuit capacity at each Connection Point expressed in MVA; - pre-fault operating point of the Power Generating Module expressed in Active Power output and Reactive Power output at the Connection Point		

OS NC		NC RfG		DCC	
Article		Article		Article	
			and Voltage at the Connection Point; and - post-fault minimum short circuit capacity at each Connection Point expressed in MVA. Alternatively generic values for the above conditions derived from typical cases may be provided by the Relevant Network Operator. 5) The Power Generating Module shall be capable of staying connected to the Network and continue stable operation when the actual course of the phase-to-phase Voltages on the Network Voltage level at the Connection Point during a symmetrical fault, given the pre-fault and post-fault conditions according to Article 9(3) (a) points 3) and 4), remains above the lower limit defined in Article 9(3) (a) point 2), unless the protection scheme for internal electrical faults requires the disconnection of the Power Generating Module from the Network. The protection schemes and settings for internal electrical faults shall be designed not to jeopardize fault-ride-through performance. 6) While still respecting Article 9(3) (a) point 5), undervoltage protection (either fault-ride-through capability or minimum Voltage defined at the connection point Voltage) shall be set by the Power Generating Facility Owner to the widest possible technical capability of the Power Generating Module unless the Relevant Network Operator requires less wide settings according to Article 9(5) (b). The settings shall be justified by the Power Generating Facility Owner in accordance with this principle. 7) Fault-ride-through capabilities in case of asymmetrical faults shall be defined by each TSO		

OS NC		NC RfG		DCC	
Article		Article		Article	
			while respecting the provisions of Article 4(3). Type 'D' Type D 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) 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). 3) Each Relevant Network Operator shall provide on request by the Power Generating Facility Owner the pre-fault and post-fault conditions to be considered for fault-ride-through capability as an outcome of the calculations at the Connection Point as defined in Article 9 (3) (a) point 3) regarding: - pre-fault minimum short circuit capacity at each Connection Point expressed in MVA; - pre-fault operating point of the Power Generating Module expressed in Active Power output and Reactive Power output at the Connection Point and Voltage at the Connection Point; and - post-fault minimum short circuit capacity at each		

OS NC		NC RfG		DCC	
Article		Article		Article	
			Connection Point expressed in MVA. 4) Fault-ride-through capabilities in case of asymmetrical faults shall be defined by each TSO while respecting the provisions of Article 4(3).		
10(8)	Each TSO shall use its best endeavour to implement the provisions from the Article 10(1) to Article 10(6) in a coordinated way at the level of Synchronous Area.	11(2)(a) (1)&(2)	Type 'D' Type D Power Generating Modules shall fulfil the following requirements referring to Voltage stability: a) With regard to Voltage ranges: 1) While still respecting the provisions according to Articles 9(3) (a) and 11(3) (a), a Power Generating Module shall be capable of staying connected to the Network and operating within the ranges of the Network Voltage at the Connection Point, expressed by the Voltage at the Connection Point related to nominal Voltage (per unit), and the time periods specified by tables 6.1 and 6.2. 2) While respecting the provisions of Article 4(3), wider Voltage ranges or longer minimum times for operation can be agreed between the Relevant Network Operator in coordination with the Relevant TSO and the Power Generating Facility Owner to ensure the best use of the technical capabilities of a Power Generating Module if needed to preserve or to restore system security. If wider Voltage ranges or longer minimum times for operation are economically and technically feasible, the consent of the Power Generating Facility Owner shall not be unreasonably withheld.	14(1) (a)(i)	GENERAL VOLTAGE REQUIREMENTS 1. All Transmission Connected Demand Facilities and all Transmission Connected Distribution Networks, deemed significant pursuant to the provisions of this Network Code, shall fulfil the following Voltage stability requirements: a) With regard to Voltage ranges: i. In case of a deviation of the Network Voltage at the Connection Point from its nominal value, any Transmission Connected Demand Facility Owner or Transmission Connected Distribution Network Operator with a Connection Point at 110 kV or above, shall ensure its equipment at the Connection Point site is capable of withstanding without damage the Voltage range at the Connection Point, expressed by the Voltage at the Connection Point related to nominal per unit Voltage, within the time periods specified by Table 2.1 and Table 2.2. The establishment of the reference nominal Voltage shall be subject to coordination between the adjacent TSOs.
10(9)	Each TSO shall ensure Reactive Power reserve, with adequate volume and time response, in order to keep the voltages within	9(5)	Type 'B', 'C' and 'D' Type B Power Generating Modules shall fulfil the	18	INFORMATION EXCHANGE 1. All Transmission Connected Demand Facilities and Transmission

OS NC		NC RfG		DCC	
Article		Article		Article	
	its Responsibility Area within the Operational Security Limits ranges defined in Tables 8.1 and 8.2.	(d)	following general system management requirements: d) With regard to information exchange: 1) Power Generating Facilities shall be capable of exchanging information between the Power Generating Facility Owner and the Relevant Network Operator and/or the Relevant TSO in real time or periodically with time stamping as defined by the Relevant Network Operator and/or the Relevant TSO while respecting the provisions of Article 4(3). 2) The Relevant Network Operator in coordination with the Relevant TSO shall define while respecting the provisions of Article 4(3) the contents of information exchanges and the precise list and time of data to be facilitated.		Connected Distribution Networks, deemed significant pursuant to the provisions of this Network Code, shall fulfil the following requirements related to the information exchange: a) Transmission Connected Demand Facilities shall be equipped according to the standard defined by the Relevant TSO, while respecting the provisions of Article 9(3), to transfer information between the Relevant TSO and the Transmission Connected Demand Facility with the defined time stamping. The defined standard shall be made publically available by the Relevant TSO. b) Transmission Connected Distribution Networks shall be equipped according to the standard defined by the Relevant TSO, while respecting the provisions of Article 9(3) to transfer information between the Relevant TSO and the Transmission Connected Distribution Network with the defined time stamping. The defined standard shall be made publically available by the Relevant TSO. c) The Relevant TSO shall define the information exchange standards while respecting the provisions of Article 9(3). The precise list of data required shall be made publically available by the Relevant TSO.
10(10)	A Significant Grid User which is a Demand Facility shall automatically or manually, disconnect at specified voltages in the specified timeframe, defined by the TSO or by the DSO if this Demand Facility has Connection Point to the Distribution Network. Each TSO making use of the provision in Article 10(9) shall respect agreements with other TSOs pursuant to NC OPS and shall ensure the coordination with involved DSOs.			14(1) (a)(ii), 20(3) And 20(5)(c)	GENERAL VOLTAGE REQUIREMENTS ii. Notwithstanding the provisions of paragraph (1)(a)(i), a Transmission Connected Demand Facility and Transmission Connected Distribution Network shall be capable of automatic disconnection at specified Voltages, if required by the Relevant TSO. The terms and settings for automatic disconnection shall be agreed between the Relevant TSO and the Transmission Connected Demand Facility Owner or the Transmission Connected Distribution Network Operator, while respecting the provisions of Article 9(3). DEMAND DISCONNECTION FOR SYSTEM DEFENCE AND DEMAND RECONNECTION 3. With regard to Low Voltage Demand Disconnection schemes: a) Low Voltage Demand Disconnection schemes for Transmission

OS NC		NC RfG		DCC	
Article		Article		Article	
					Connected Distribution Networks shall be defined by the Relevant TSO, while respecting the provisions of Article 9(3), in coordination with Transmission Connected Distribution Network Operators. In cases of nested Distribution Networks the geographical distribution shall be equitable to all the associated Distribution Network Operators. b) Low Voltage Demand Disconnection schemes for a Transmission Connected Demand Facility shall be defined by the Relevant TSO, while respecting the provisions of Article 9(3), in coordination with the Transmission Connected Demand Facility Owner. c) Based on the TSO assessment of system security the implementation of On Load Tap Changer Blocking and Low Voltage Demand Disconnection shall be binding for Transmission Connected Distribution Network Operators. d) If the Relevant TSO decides to implement a Low Voltage Demand Disconnection scheme, both On Load Tap Changer Blocking and Low Voltage Demand Disconnection shall be fitted in a coordinated way led by the TSO. e) The method of Low Voltage Demand Disconnection shall be implemented by relay or Control Room initiation. f) The Low Voltage Demand Disconnection schemes shall have the following functional capability: i. The Low Voltage Demand Disconnection scheme shall monitor the Voltage by measuring all three phases. ii. Blocking of the relays operation shall be based on direction of either Active Power or Reactive Power flow. DEMAND DISCONNECTION FOR SYSTEM DEFENCE AND DEMAND RECONNECTION c) A Transmission Connected Demand Facility and Transmission Connected Distribution Network shall be capable of being remotely disconnected from the Transmission Network when required by the

OS NC		NC RfG		DCC	
Article		Article		Article	
					Relevant TSO. Where automated disconnection equipment is required (for reconfiguration of the Network in preparation for Block Loading) these shall be defined by the Relevant TSO while respecting the provisions of Article 9(3). The time taken for remote disconnection shall be defined by the Relevant TSO while respecting the provisions of Article 9(3).
10(13)	Each TSO shall define the Reactive Power set-points, power factor ranges and voltage set-points for voltage control in accordance with [DCC], which shall be maintained by the Significant Grid Users or DSOs with Connection Point directly to the Transmission System, while respecting the provisions of Article 8(13). DSOs shall in turn be able to define voltage control instructions to Significant Grid Users connected to the Distribution Network in order to respect the instructions of the TSO.			16(1)(a)	REACTIVE POWER REQUIREMENTS 1. All Transmission Connected Demand Facilities and all Transmission Connected Distribution Networks, deemed significant pursuant to the provisions of this Network Code, shall fulfil the following requirements referring to Reactive Power exchange and control: a) With regard to Reactive Power ranges: i. Transmission Connected Distribution Networks and Transmission Connected Demand Facilities shall be capable to maintain their steady-state operation at their Connection Point in a Reactive Power range specified by the Relevant TSO, while respecting the provisions of Article 9(3) and the following conditions: - For Transmission Connected Demand Facilities without onsite generation, the actual Reactive Power range specified by the Relevant TSO for importing reactive power shall not be wider than 0.9 to 1 Power Factor of their Maximum Import Capability, except in situations where either technical or financial system benefits are demonstrated and accepted by the Relevant TSO, while respecting the provisions of Article 9(3); - For Transmission Connected Demand Facilities with onsite generation, the actual Reactive Power range specified by the Relevant TSO shall not be wider than 0.9 Power Factor of the larger of their Maximum Import Capability or Maximum Export Capability in import to 0.9 Power Factor of their Maximum Export Capability in export, except in situations where either technical or financial system benefits are demonstrated and accepted by the Relevant TSO, while respecting the provisions of Article

OS NC		NC RfG		DCC	
Article		Article		Article	
					9(3); - For Transmission Connected Distribution Networks, the actual Reactive Power range specified by the Relevant Network Operator shall not be wider than 0.9 Power Factor of the larger of their Maximum Import Capability or Maximum Export Capability in import to 0.9 Power Factor of their Maximum Export Capability in export, except in situations where either technical or financial system benefits are demonstrated by the Relevant TSO and the Distribution Network Operator through joint analysis. The scope of the analysis shall be agreed between the Relevant TSO and Distribution Network Operator and will consider the possible solutions and determine the optimal solution for reactive power exchange between their Networks taking adequately in consideration the specific Network characteristics, variable structure of power exchange, bidirectional flows and the Reactive Power capabilities in the Distribution Network, while respecting the provisions of Article 9(3); - The use of other metrics than Power Factor to define equivalent Reactive Power capability ranges can be specified by the Relevant TSO. - The Reactive Power range requirement shall apply at the Connection Point. ii. Transmission Connected Distribution Networks shall have the capability at the Connection Point to not export Reactive Power (at nominal Voltage) at an Active Power flow of less than 25% of the Maximum Import Capability, except in situations where either technical or financial system benefits are demonstrated by the Relevant TSO and the Distribution Network Operator through joint analyse, while respecting the provisions of Article 9(3). iii. The scope of the analysis will be agreed between the Relevant TSO and Distribution Network Operator and will consider the possible solutions and determine the optimal solution for reactive power exchange between their Networks taking adequately in consideration the specific Network characteristics, variable structure of power exchange, bidirectional flows and the reactive capabilities in the Distribution Network, while respecting

OS NC		NC RfG		DCC	
Article		Article		Article	
					the provisions of Article 9(3);
10(17)	Each TSO shall maintain voltage ranges and each DSO and Significant Grid User which is a Transmission Connected Demand Facility shall maintain the power factor or Reactive Power flows at Connection Points within the ranges specified in Article 10(12) and in Article 16 of [DCC], unless an agreement is defined between the TSO and the DSO foreseeing the active voltage control by the DSO in accordance with Article 16(1)(c) of [DCC], or unless another value is defined in accordance with national legislation for Significant Grid Users which are Transmission Connected Demand Facilities who are not subject to or are derogated from [DCC].			16(1) (a)&(b), 20(4) And 20(5)(c)	REACTIVE POWER REQUIREMENTS 1. All Transmission Connected Demand Facilities and all Transmission Connected Distribution Networks, deemed significant pursuant to the provisions of this Network Code, shall fulfil the following requirements referring to Reactive Power exchange and control: a) With regard to Reactive Power ranges: i. Transmission Connected Distribution Networks and Transmission Connected Demand Facilities shall be capable to maintain their steady-state operation at their Connection Point in a Reactive Power range specified by the Relevant TSO, while respecting the provisions of Article 9(3) and the following conditions: - For Transmission Connected Demand Facilities without onsite generation, the actual Reactive Power range specified by the Relevant TSO for importing reactive power shall not be wider than 0.9 to 1 Power Factor of their Maximum Import Capability, except in situations where either technical or financial system benefits are demonstrated and accepted by the Relevant TSO, while respecting the provisions of Article 9(3); - For Transmission Connected Demand Facilities with onsite generation, the actual Reactive Power range specified by the Relevant TSO shall not be wider than 0.9 Power Factor of the larger of their Maximum Import Capability or Maximum Export Capability in import to 0.9 Power Factor of their Maximum Export Capability in export, except in situations where either technical or financial system benefits are demonstrated and accepted by the Relevant TSO, while respecting the provisions of Article 9(3); - For Transmission Connected Distribution Networks, the actual Reactive Power range specified by the Relevant Network Operator shall not be wider than 0.9 Power Factor of the larger of their Maximum Import

OS NC		NC RfG		DCC	
Article		Article		Article	
					Capability or Maximum Export Capability in import to 0.9 Power Factor of their Maximum Export Capability in export, except in situations where either technical or financial system benefits are demonstrated by the Relevant TSO and the Distribution Network Operator through joint analysis. The scope of the analysis shall be agreed between the Relevant TSO and Distribution Network Operator and will consider the possible solutions and determine the optimal solution for reactive power exchange between their Networks taking adequately in consideration the specific Network characteristics, variable structure of power exchange, bidirectional flows and the Reactive Power capabilities in the Distribution Network, while respecting the provisions of Article 9(3); - The use of other metrics than Power Factor to define equivalent Reactive Power capability ranges can be specified by the Relevant TSO. - The Reactive Power range requirement shall apply at the Connection Point. ii. Transmission Connected Distribution Networks shall have the capability at the Connection Point to not export Reactive Power (at nominal Voltage) at an Active Power flow of less than 25% of the Maximum Import Capability, except in situations where either technical or financial system benefits are demonstrated by the Relevant TSO and the Distribution Network Operator through joint analyse, while respecting the provisions of Article 9(3). iii. The scope of the analysis will be agreed between the Relevant TSO and Distribution Network Operator and will consider the possible solutions and determine the optimal solution for reactive power exchange between their Networks taking adequately in consideration the specific Network characteristics, variable structure of power exchange, bidirectional flows and the reactive capabilities in the Distribution Network, while respecting the provisions of Article 9(3); b) Without prejudice to the provisions of paragraph 1(a) of this article, the Relevant TSO shall have the right to require, while respecting the provisions of Article 9(3), the ability of the Transmission Connected

OS NC		NC RfG		DCC	
Article		Article		Article	
					Distribution Network to actively control the exchange of Reactive Power at the Connection Point as part of a wider common concept for management of Reactive Power capabilities for the benefit of the entire Network. The method of this control shall be agreed between the Relevant TSO and the Transmission Connected Distribution Network Operator to ensure the justified level of security of supply for both parties. The justification shall include a roadmap in which the steps and the timeline for fulfilling the requirement are specified. DEMAND DISCONNECTION FOR SYSTEM DEFENCE AND DEMAND RECONNECTION 4. With regard to blocking of On Load Tap Changers: a) The transformer at the Transmission Connected Distribution Network Connection Point to the Transmission Network shall be capable of automatic or manual On Load Tap Changer Blocking, if required by the Relevant TSO. b) The automatic On Load Tap Changer Blocking scheme shall be specified by the Relevant TSO, while respecting the provisions of Article 9(3). c) A Transmission Connected Demand Facility and Transmission Connected Distribution Network shall be capable of being remotely disconnected from the Transmission Network when required by the Relevant TSO. Where automated disconnection equipment is required (for reconfiguration of the Network in preparation for Block Loading) these shall be defined by the Relevant TSO while respecting the provisions of Article 9(3). The time taken for remote disconnection shall be defined by the Relevant TSO while respecting the provisions ofArticle 9(3).
11(5)	Each TSO shall perform short-circuit calculations in order to evaluate the impact of directly interconnected TSOs, Transmission	9(5)	Type ‘B’, ‘C’ and ‘D’ Type B Power Generating Modules shall fulfil the	18 And	INFORMATION EXCHANGE 1. All Transmission Connected Demand Facilities and Transmission

OS NC		NC RfG		DCC	
Article		Article		Article	
	Connected Distribution Networks and Transmission Connected Closed Distribution Networks, on the short-circuit current level. Where a Transmission Connected Distribution Network or Transmission Connected Closed Distribution Network has an impact on short-circuit current levels it has to be modelled in the Transmission System short-circuit calculations.	(d), 10(6)(c) And 10(6)(f)	following general system management requirements: d) With regard to information exchange: 1) Power Generating Facilities shall be capable of exchanging information between the Power Generating Facility Owner and the Relevant Network Operator and/or the Relevant TSO in real time or periodically with time stamping as defined by the Relevant Network Operator and/or the Relevant TSO while respecting the provisions of Article 4(3). 2) The Relevant Network Operator in coordination with the Relevant TSO shall define while respecting the provisions of Article 4(3) the contents of information exchanges and the precise list and time of data to be facilitated Type 'C' and 'D' Type C Power Generating Modules shall fulfil the following general system management requirements: c) With regard to the simulation models: 1) The Relevant Network Operator in coordination with the Relevant TSO shall have the right to require while respecting the provisions of Article 4(3) the Power Generating Facility Owner to provide simulation models, that shall properly reflect the behaviour of the Power Generating Module in both steady-state and dynamic simulations (50 Hz component) and, where appropriate and justified, in electromagnetic transient simulations.	15(1) (f)&(g)	Connected Distribution Networks, deemed significant pursuant to the provisions of this Network Code, shall fulfil the following requirements related to the information exchange: a) Transmission Connected Demand Facilities shall be equipped according to the standard defined by the Relevant TSO, while respecting the provisions of Article 9(3), to transfer information between the Relevant TSO and the Transmission Connected Demand Facility with the defined time stamping. The defined standard shall be made publically available by the Relevant TSO. b) Transmission Connected Distribution Networks shall be equipped according to the standard defined by the Relevant TSO, while respecting the provisions of Article 9(3) to transfer information between the Relevant TSO and the Transmission Connected Distribution Network with the defined time stamping. The defined standard shall be made publically available by the Relevant TSO. c) The Relevant TSO shall define the information exchange standards while respecting the provisions of Article 9(3). The precise list of data required shall be made publically available by the Relevant TSO. SHORT-CIRCUIT REQUIREMENTS f) The Transmission Connected Demand Facility Owner and Transmission Connected Distribution Network Operator shall inform the Relevant TSO as soon as practicable, but no later than one week after an unplanned event, of the changes in short-circuit contribution above a threshold set by the Relevant TSO, while respecting the provisions of Article 9(3), from its Demand Facility or Distribution Network in paragraph 1(e). g) The Transmission Connected Demand Facility Owner and Transmission Connected Distribution Network Operator shall inform the Relevant TSO as soon as practicable before a planned event of changes in short-circuit contribution above a threshold set by the Relevant TSO, while respecting the provisions of Article 9(3), from its Demand Facility or Distribution Network in paragraph 1(e).

OS NC		NC RfG		DCC	
Article		Article		Article	
			The decision shall include: - the format in which models shall be provided - the provision of documentation of models structure and block diagrams The models shall be verified against the results of compliance tests as of Title 4 Chapters 2, 3 and 4. They shall then be used for the purpose of verifying the requirements of this Network Code including but not limited to Compliance Simulations as of Title 4 Chapters 5, 6 and 7 and for use in studies for continuous evaluation in system planning and operation. 2) For the purpose of dynamic simulations, the models provided shall contain the following sub-models, depending on the existence of the mentioned components: - Alternator and prime mover; - Speed and power control; - Voltage control, including, if applicable, Power System Stabilizer (PSS) function and excitation system; - Power Generating Module protection models as agreed between the Relevant Network Operator and the Power Generating Facility Owner, while respecting the provisions of Article 4(3); and - Converter models for Power Park Modules. 3) The Relevant Network Operator shall deliver to the Power Generating Facility Owner an estimate of the minimum and maximum short circuit		

OS NC		NC RfG		DCC	
Article		Article		Article	
			capacity at the connection point, expressed in MVA, as an equivalent of the Network. 4) The Relevant Network Operator or Relevant TSO shall have the right to require while respecting the provisions of Article 4(3) Power Generating Module recordings in order to compare the response of the models with these recordings. f) With regard to earthing arrangement of the neutral-point at the Network side of step-up transformers, it shall be in accordance with the specifications of the Relevant Network Operator.		
12(4), And 13(6)	Each TSO shall be entitled to use Redispatching of available Significant Grid users with Connection Point directly to the Transmission System or to the Distribution Network to maintain Operational Security. Each TSO shall prepare Remedial Actions including Redispatching pursuant to Article 8(12) and 8(13), or Countertrading to cope with any Contingency from its Contingency List for which potential deviation from Operational Security Limits is identified in accordance with Article 8(5).	8(1)(f), 9(2)(a), 10(2)(a), 12(2) (a)&(b), 15(2)(a), 13(2) (b)&(c), And	Type 'B', 'C' and 'D' Type A[19] Power Generating Modules shall fulfil the following requirements referring to Frequency stability: f) The Power Generating Module shall be equipped with a logic interface (input port) in order to cease Active Power output within less than 5 seconds following an Instruction from the Relevant Network Operator. The Relevant Network Operator shall have the right to define while respecting the provisions of Article 4(3) the requirements for further equipment to make this facility operable remotely.	22	DEMAND SIDE RESPONSE - ACTIVE POWER CONTROL, REACTIVE POWER CONTROL AND TRANSMISSION CONSTRAINT MANAGEMENT 1. With regard to either Demand Side Response Active Power Control, Reactive Power Control, or Transmission Constraint Management, Demand Facilities and Closed Distribution Networks may voluntarily offer this service. The requirements below shall be mandatory only for Demand Facilities or Closed Distribution Networks whom offer these services, either individually or as part of Demand Aggregation:

[19] This reference is made because Power Generating Modules type B, C and D shall comply with requirements defined for Power Generating Modules type A.

OS NC		NC RfG		DCC	
Article		Article		Article	
		16(3) (b)&(c)	Type 'B' Type B Power Generating Modules shall fulfil the following requirements referring to Frequency stability: a) In order to be able to control Active Power output, the Power Generating Module shall be equipped with a interface (input port) in order to be able to reduce Active Power output as instructed by the Relevant Network Operator and/or the Relevant TSO. The Relevant Network Operator shall have the right to define while respecting the provisions of Article 4(3) the requirements for further equipment to make this facility operable remotely. Type 'C' & 'D' 2. Type C Power Generating Modules shall fulfil the following requirements referring to Frequency stability: a) With regard to Active Power controllability and control range, the Power Generating Module control system shall be capable of adjusting an Active Power Setpoint as instructed by the Relevant Network Operator or the Relevant TSO to the Power Generating Facility Owner. It shall be capable of implementing the Setpoint within a period specified in the above Instruction and within a tolerance defined by the Relevant Network Operator or the Relevant TSO (subject to the availability of the prime mover resource). Manual, local measures shall be possible in the case that any automatic remote control devices are out of service.		

OS NC		NC RfG		DCC	
Article		Article		Article	
			Type 'B' 2. Type B Synchronous Power Generating Modules shall fulfil the following requirements referring to Voltage stability: a) With regard to Reactive Power capability the Relevant Network Operator shall have the right to define while respecting the provisions of Article 4(3) the capability of a Synchronous Power Generating Module to provide Reactive Power. b) With regard to the Voltage control system, a Synchronous Power Generating Module shall be equipped with a permanent automatic excitation control system in order to provide constant Alternator terminal Voltage at a selectable Setpoint without instability over the entire operating range of the Synchronous Power Generating Module. Type B Power Park Modules shall fulfil the following requirement referring to Voltage stability: a) With regard to Reactive Power capability the Relevant Network Operator shall have the right to define while respecting the provisions of Article 4(3) the capability of a Power Park Module to provide Reactive Power. Type 'C' & 'D' Type C Synchronous Power Generating Modules shall fulfil the following requirements referring to Voltage stability: b) With regard to Reactive Power capability at Maximum Capacity:		

OS NC		NC RfG		DCC	
Article		Article		Article	
			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/Pmax-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/Pmax-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/Pmax-profile shall not exceed the U-Q/Pmax-profile envelope, represented by the inner envelope in figure 7 [RfG]; - the dimensions of the U-Q/Pmax-profile envelope (Q/Pmax range and Voltage range) are defined for each Synchronous Area in table 8 [RfG]; and - the position of the U-Q/Pmax-profile envelope within the limits of the fixed outer envelope in figure 7 [RfG]. 3) The Reactive Power provision capability requirement applies at the Connection Point. For profile shapes other than rectangular, the Voltage range represents the highest and lowest values. The full Reactive Power range is therefore not expected to be available across the range of steady-state Voltages. 4) The Synchronous Power Generating Module		

OS NC		NC RfG		DCC	
Article		Article		Article	
			shall be capable of moving to any operating point within its U-Q/Pmax profile in appropriate timescales to target values requested by the Relevant Network Operator. c) With regard to Reactive Power capability below Maximum Capacity, when operating at an Active Power output below the Maximum Capacity (P<Pmax), the Synchronous Power Generating Modules shall be capable of operating in every possible operating point in the P-Q Capability Diagram of the Alternator of this Synchronous Power Generating Module at least down to Minimum Stable Operating Level. Even at reduced Active Power output, Reactive Power supply at the Connection Point shall fully correspond to the P-Q-Capability Diagram of the Alternator of this Synchronous Power Generating Module, taking the auxiliary supply power and the Active and Reactive Power losses of the step-up transformer, if applicable, into account. Type C Power Park Modules shall fulfil the following requirements referring to Voltage stability: 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/Pmax-profile that shall take any shape within the boundaries of which the Power Park Module shall be capable of providing Reactive Power at its Maximum Capacity.		

OS NC		NC RfG		DCC	
Article		Article		Article	
			2) The U-Q/Pmax-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/Pmax-profile shall not exceed the U-Q/Pmax-profile envelope, represented by the inner envelope in figure 8 [RfG], its shape does not need to be rectangular; - the dimensions of the U-Q/Pmax-profile envelope (Q/Pmax range and Voltage range) are defined for each Synchronous Area in table 9 [RfG]; and - the position of the U-Q/Pmax-profile envelope within the limits of the fixed outer envelope in figure 8 [RfG]. 3) The Reactive Power provision capability requirement applies at the Connection Point. For profile shapes other than rectangular, the Voltage range represents the highest and lowest values. The full Reactive Power range is therefore not expected to be available across the range of steady-state Voltages. c) With regard to Reactive Power capability below 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. For doing so, it shall define a P-Q/Pmax-profile that shall take any shape within the boundaries of which the Power Park Module shall be capable of providing Reactive Power below Maximum		

OS NC		NC RfG		DCC	
Article		Article		Article	
			Capacity. 2) The P-Q/Pmax-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/Pmax-profile shall not exceed the P-Q/Pmax-profile envelope, represented by the inner envelope in figure 9; - the Q/Pmax range of the P-Q/Pmax-profile envelope is defined for each Synchronous Area in table 9; - the Active Power range of the P-Q/Pmax-profile envelope at zero Reactive Power shall be 1 pu; - the P-Q/Pmax-profile can be of any shape and shall include conditions for Reactive Power capability at zero Active Power; and - the position of the P-Q/Pmax-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<Pmax), the Power Park Module shall be capable of providing Reactive Power at any operating point inside its P-Q/Pmax-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. 4) The Power Park Module shall be capable of		

OS NC		NC RfG		DCC	
Article		Article		Article	
			moving to any operating point within its P-Q/Pmax profile in appropriate timescales to target values requested by the Relevant Network Operator.		
13(3)	Each TSO shall perform Contingency Analysis on the basis of the real-time system operation parameters periodically, according to Article 8(2) and in operational planning according to the provisions defined in the NC OPS. Each TSO shall ensure that potential deviations from the Operational Security Limits in its Responsibility Area which are identified by the Contingency Analysis do not endanger the Operational Security of its Transmission System or of the interconnected Transmission Systems. In accordance with its own rules and procedures, a TSO can decide not to apply costly Remedial Actions if the effects of the Contingencies are Local and they do not impact Operational Security of the interconnected Transmission Systems.	9(5)(d), 10(2)(f) 9(3)(a) And 11(3)(a)	Type 'B', 'C' and 'D' Type B Power Generating Modules shall fulfil the following general system management requirements: d) With regard to information exchange: 1) Power Generating Facilities shall be capable of exchanging information between the Power Generating Facility Owner and the Relevant Network Operator and/or the Relevant TSO in real time or periodically with time stamping as defined by the Relevant Network Operator and/or the Relevant TSO while respecting the provisions of Article 4(3). 2) The Relevant Network Operator in coordination with the Relevant TSO shall define while respecting the provisions of Article 4(3) the contents of information exchanges and the precise list and time of data to be facilitated. Type 'C' & 'D' Type C Power Generating Modules shall fulfil the following requirements referring to Frequency stability: f) With regard to real-time monitoring of FSM: 1) To monitor the operation of Active Power Frequency Response the communication interface shall be equipped to transfer on-line from the Power Generating Facility to the Network control		INFORMATION EXCHANGE 1. All Transmission Connected Demand Facilities and Transmission Connected Distribution Networks, deemed significant pursuant to the provisions of this Network Code, shall fulfil the following requirements related to the information exchange: a) Transmission Connected Demand Facilities shall be equipped according to the standard defined by the Relevant TSO, while respecting the provisions of Article 9(3), to transfer information between the Relevant TSO and the Transmission Connected Demand Facility with the defined time stamping. The defined standard shall be made publically available by the Relevant TSO. b) Transmission Connected Distribution Networks shall be equipped according to the standard defined by the Relevant TSO, while respecting the provisions of Article 9(3) to transfer information between the Relevant TSO and the Transmission Connected Distribution Network with the defined time stamping. The defined standard shall be made publically available by the Relevant TSO. c) The Relevant TSO shall define the information exchange standards while respecting the provisions of Article 9(3). The precise list of data required shall be made publically available by the Relevant TSO.

OS NC		NC RfG		DCC	
Article		Article		Article	
			centre of the Relevant Network Operator and/or the Relevant TSO on request by the Relevant Network Operator and/or the Relevant TSO at least the following signals: - status signal of FSM (on/off); - scheduled Active Power output; - actual value of the Active Power output; - actual parameter settings for Active Power Frequency Response; and - Droop and dead band. 2) The Relevant Network Operator and the Relevant TSO shall define while respecting the provisions of Article 4(3) additional signals to be provided by the Power Generating Facility for monitoring and/or recording devices in order to verify the performance of the Active Power Frequency Response provision of participating Power Generating Modules. Type ‘B’, ‘C’ &’D’ 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) Each TSO shall define while respecting the provisions of Article 4(3) a voltage-against-time-profile according to figure 3 at the Connection		

OS NC		NC RfG		DCC	
Article		Article		Article	
			Point for fault conditions which describes the conditions in which the Power Generating Module shall be capable of staying connected to the Network and continuing stable operation after the power system has been disturbed by Secured Faults on the Network. 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 using parameters in figure 3 according to tables 3.1 and 3.2. 3) Each TSO shall define and make publicly available while respecting the provisions of Article 4(3) defining the pre-fault and post-fault conditions for the fault-ride-through capability in terms of: - conditions for the calculation of the pre-fault minimum short circuit capacity at the Connection Point; - conditions for pre-fault active and Reactive Power operating point of the Power Generating Module at the Connection Point and Voltage at the Connection Point; and - conditions for the calculation of the post-fault minimum short circuit capacity at the Connection Point. 4) Each Relevant Network Operator shall provide on request by the Power Generating Facility Owner the pre-fault and post-fault conditions to be considered for fault-ride-through capability as an outcome of the calculations at the Connection		

OS NC		NC RfG		DCC	
Article		Article		Article	
			Point as defined in Article 9 (3) (a) point 3) regarding: - pre-fault minimum short circuit capacity at each Connection Point expressed in MVA; - pre-fault operating point of the Power Generating Module expressed in Active Power output and Reactive Power output at the Connection Point and Voltage at the Connection Point; and - post-fault minimum short circuit capacity at each Connection Point expressed in MVA. Alternatively generic values for the above conditions derived from typical cases may be provided by the Relevant Network Operator. 5) The Power Generating Module shall be capable of staying connected to the Network and continue stable operation when the actual course of the phase-to-phase Voltages on the Network Voltage level at the Connection Point during a symmetrical fault, given the pre-fault and post-fault conditions according to Article 9(3) (a) points 3) and 4), remains above the lower limit defined in Article 9(3) (a) point 2), unless the protection scheme for internal electrical faults requires the disconnection of the Power Generating Module from the Network. The protection schemes and settings for internal electrical faults shall be designed not to jeopardize fault-ride-through performance. 6) While still respecting Article 9(3) (a) point 5), undervoltage protection (either fault-ride-through capability or minimum Voltage defined at the connection point Voltage) shall be set by the Power Generating Facility Owner to the widest possible technical capability of the Power		

OS NC		NC RfG		DCC	
Article		Article		Article	
			Generating Module unless the Relevant Network Operator requires less wide settings according to Article 9(5) (b). The settings shall be justified by the Power Generating Facility Owner in accordance with this principle. 7) Fault-ride-through capabilities in case of asymmetrical faults shall be defined by each TSO while respecting the provisions of Article 4(3). Type 'D' Type D 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) 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). 3) Each Relevant Network Operator shall provide on request by the Power Generating Facility Owner the pre-fault and post-fault conditions to be considered for fault-ride-through capability as an outcome of the calculations at the Connection Point as defined in Article 9 (3) (a) point 3) regarding: - pre-fault minimum short circuit capacity at each		

OS NC		NC RfG		DCC	
Article		Article		Article	
			Connection Point expressed in MVA; - pre-fault operating point of the Power Generating Module expressed in Active Power output and Reactive Power output at the Connection Point and Voltage at the Connection Point; and - post-fault minimum short circuit capacity at each Connection Point expressed in MVA. 4) Fault-ride-through capabilities in case of asymmetrical faults shall be defined by each TSO while respecting the provisions of Article 4(3).		
13(10) And 13(13)	Each TSO shall ensure that its Observability Area used for Contingency Analysis is based upon a sufficient amount of accurate real-time data. Each TSO shall contribute to establishing the Common Grid Model. This contribution shall include the data for the Common Grid Model according to the defined contents and timeframes according to the provisions in Chapter 3 consistent with the NC OPS and NC CACM.	9(5) (d) And 10(2) (f)	Type 'B', 'C' and 'D' Type B Power Generating Modules shall fulfil the following general system management requirements: d) With regard to information exchange: 1) Power Generating Facilities shall be capable of exchanging information between the Power Generating Facility Owner and the Relevant Network Operator and/or the Relevant TSO in real time or periodically with time stamping as defined by the Relevant Network Operator and/or the Relevant TSO while respecting the provisions of Article 4(3). 2) The Relevant Network Operator in coordination with the Relevant TSO shall define while respecting the provisions of Article 4(3) the contents of information exchanges and the precise list and time of data to be facilitated. Type 'C' & 'D'	18	INFORMATION EXCHANGE 1. All Transmission Connected Demand Facilities and Transmission Connected Distribution Networks, deemed significant pursuant to the provisions of this Network Code, shall fulfil the following requirements related to the information exchange: a) Transmission Connected Demand Facilities shall be equipped according to the standard defined by the Relevant TSO, while respecting the provisions of Article 9(3), to transfer information between the Relevant TSO and the Transmission Connected Demand Facility with the defined time stamping. The defined standard shall be made publically available by the Relevant TSO. b) Transmission Connected Distribution Networks shall be equipped according to the standard defined by the Relevant TSO, while respecting the provisions of Article 9(3) to transfer information between the Relevant TSO and the Transmission Connected Distribution Network with the defined time stamping. The defined standard shall be made publically available by the Relevant TSO. c) The Relevant TSO shall define the information exchange standards while respecting the provisions of Article 9(3). The precise list of data required shall be made publically available by the Relevant TSO.

OS NC		NC RfG		DCC	
Article		Article		Article	
			Type C Power Generating Modules shall fulfil the following requirements referring to Frequency stability: f) With regard to real-time monitoring of FSM: 1) To monitor the operation of Active Power Frequency Response the communication interface shall be equipped to transfer on-line from the Power Generating Facility to the Network control centre of the Relevant Network Operator and/or the Relevant TSO on request by the Relevant Network Operator and/or the Relevant TSO at least the following signals: - status signal of FSM (on/off); - scheduled Active Power output; - actual value of the Active Power output; - actual parameter settings for Active Power Frequency Response; and - Droop and dead band. 2) The Relevant Network Operator and the Relevant TSO shall define while respecting the provisions of Article 4(3) additional signals to be provided by the Power Generating Facility for monitoring and/or recording devices in order to verify the performance of the Active Power Frequency Response provision of participating Power Generating Modules.		
14(1)	Each TSO shall install the necessary protection and backup protection equipment within its	9(5)	Type 'B', 'C' & 'D'	17	PROTECTION AND CONTROL

OS NC		NC RfG		DCC	
Article		Article		Article	
	Transmission System in order to efficiently and effectively protect Transmission System elements and to coordinate with the protection of the equipment of Significant Grid Users, from effects of Faults in Transmission System.	(a)&(b)	5. Type B Power Generating Modules shall fulfil the following general system management requirements: a) With regard to control schemes and settings 1) While respecting the provisions of Article 4(3), schemes and settings of the different control devices of the Power Generating Module relevant for transmission system stability and to enable emergency actions shall be coordinated and agreed between the Relevant TSO, the Relevant Network Operator and the Power Generating Facility Owner. 2) While respecting the provisions of Article 4(3), any changes to the schemes and settings of the different control devices of the Power Generating Module, relevant for transmission system stability and to enable emergency actions, shall be coordinated and agreed between the Relevant TSO, the Relevant Network Operator and the Power Generating Facility Owner, especially if they concern the circumstances referred to under Article 9(5) (a) point 1). b) With regard to electrical protection schemes and settings: 1) The Relevant Network Operator shall define the schemes and settings necessary to protect the Network taking into account the characteristics of the Power Generating Module. While respecting the provisions of Article 4(3), protection schemes relevant for the Power Generating Module and the Network and settings relevant for the Power Generating Module shall be coordinated and agreed between the Relevant Network Operator and the Power Generating Facility Owner. The	(1)&(2)	1. All Transmission Connected Demand Facilities and all Transmission Connected Distribution Networks, deemed significant pursuant to the provisions of this Network Code, shall fulfil the following requirements referring to the protection and control: a) With regard to electrical protection schemes and settings: i. The Relevant TSO shall define the settings necessary to protect the Network while respecting the characteristics of the Transmission Connected Demand Facility or Transmission Connected Distribution Network. Protection schemes as well as settings relevant for the Transmission Connected Demand Facility or Transmission Connected Distribution Network shall be agreed between the Relevant TSO and the Transmission Connected Demand Facility Owner or Transmission Connected Distribution Network Operator while respecting the provisions of Article 9(3). ii. Electrical protection of the Transmission Connected Demand Facility or Transmission Connected Distribution Network shall take precedence over operational controls while respecting system security, health and safety of staff and the public as well as mitigation of the damage to the Transmission Connected Demand Facility or Transmission Connected Distribution Network. b) Protection scheme devices may cover the following aspects: i. external and internal short circuit; ii. over- and under-voltage at the Connection Point; iii. over- and under-frequency; iv. demand circuit protection; v. unit transformer protection; and vi. backup schemes against protection and switchgear malfunction. c) The Relevant TSO shall define the mandatory devices while respecting

OS NC		NC RfG		DCC	
Article		Article		Article	
			protection schemes and settings for internal electrical faults shall be designed not to jeopardize the performance of a Power Generating Module according to this Network Code requirements otherwise. 2) Electrical protection of the Power Generating Module shall take precedence over operational controls taking into account system security, health and safety of staff and the public and mitigation of the damage to the Power Generating Module. 3) Protection schemes can protect against the following aspects: - external and internal short circuit; - asymmetric load (Negative Phase Sequence); - stator and rotor overload; - over-/underexcitation; - over-/undervoltage at the Connection Point; - over-/undervoltage at the Alternator terminals; - inter-area oscillations; - inrush Current; - asynchronous operation (pole slip); - protection against inadmissible shaft torsions (for example, subsynchronous resonance); - Power Generating Module line protection;		the provisions of Article 9(3). d) Any changes to the protection schemes, relevant for the Transmission Connected Demand Facility or Transmission Connected Distribution Network and the Network, as well as to the setting relevant for the Transmission Connected Demand Facility or Transmission Connected Distribution Network, shall be agreed between the Relevant TSO and the Transmission Connected Demand Facility Owner or Transmission Connected Distribution Network Operator, while respecting the provisions of Article 9(3). 2. With regard to control schemes and settings: a) Schemes and settings of the different control devices of the Transmission Connected Demand Facility or Transmission Connected Distribution Network, relevant for system security, shall be agreed between the Relevant TSO, and the Transmission Connected Demand Facility Owner or Transmission Connected Distribution Network Operator, while respecting the provisions of Article 9(3). This agreement shall cover the following aspects: i. isolated (Network) operation; ii. damping of oscillations; iii. disturbances to the Network; iv. automatic switching to emergency supply and come-back to normal topology; and v. automatic circuit-breaker re-closure (on 1-phase faults). b) Any changes to the schemes and settings of the different control devices of the Transmission Connected Demand Facility or Transmission Connected Distribution Network, relevant for system security, shall be agreed between the Relevant TSO, and the Transmission Connected Demand Facility Owner or Transmission Connected Distribution Network

OS NC		NC RfG		DCC	
Article		Article		Article	
			- unit transformer protection; - backup schemes against protection and switchgear malfunction; - overfluxing (U/f); - inverse power; - rate of change of Frequency; and - neutral Voltage displacement. 4) While respecting the provisions of Article 4(3), any changes to the protection schemes relevant for the Power Generating Module and the Network and to the setting relevant for the Power Generating Module shall be agreed between the Network Operator and the Power Generating Facility Owner and be concluded prior to the introduction of changes. c) With regard to priority ranking of protection and control, the Power Generating Facility Owner shall organize its protections and control devices in compliance with the following priority ranking, organized in decreasing order of importance: - Network system and Power Generating Module protection; - Synthetic Inertia, if applicable; - Frequency control (Active Power adjustment); - Power Restriction; and - Power gradient constraint.		Operator, while respecting the provisions of Article 9(3).

OS NC		NC RfG		DCC	
Article		Article		Article	
14(7)	While respecting the provisions of the DCC, each TSO shall define a Low Frequency Demand Disconnection Scheme with common principles and in coordination with the respective DSOs and the TSOs of its Synchronous Area. Each DSO or where relevant TSO shall implement the Low Frequency Demand Disconnection scheme in its area of responsibility and shall inform the TSOs of a Synchronous Area in case of change of the conditions and settings.			20 (1)&(2)	DEMAND DISCONNECTION FOR SYSTEM DEFENCE AND DEMAND RECONNECTION 1. All Transmission Connected Demand Facilities and Transmission Connected Distribution Networks, deemed significant pursuant to the provisions of this Network Code, shall fulfil the following requirements related to Low Frequency Demand Disconnection schemes: a) Each Transmission Connected Distribution Network Operator and as specified by the TSO, Transmission Connected Demand Facility Owner, shall provide capabilities that shall enable automatic low Frequency (or alternatively if specified by the TSO combined with rate-ofchange-of-Frequency) disconnection of a percentage of their demand. The percentage of the demand shall be specified by the TSO, in coordination with all TSOs in the Synchronous Area. This specification shall be based on a rule set defined by the TSO while respecting the provisions of Article 9(3). b) The Low Frequency Demand Disconnection schemes shall be capable of disconnecting demand in stages for a range of operational frequencies. The number of stages and their respective operational frequencies shall be defined by the TSO, while respecting the provisions of Article 9(3). c) The percentage of the demand disconnection at each Frequency shall be defined by the TSO while respecting the provisions of Article 9(3). d) The geographical distribution of this demand disconnection shall be provided by the Transmission Connected Distribution Network Operator or Transmission Connected Demand Facility Owner and approved by the TSO. In cases of nested Distribution Networks the geographical distribution shall be equitable to all the associated Distribution Network Operators. e) Each Distribution Network Operator and Transmission Connected Demand Facility Owner shall notify the TSO in writing of the details of the automatic Low Frequency Demand Disconnection on its Network. This notification shall be made every year and shall identify, for each Connection Point to the Transmission Network, the Frequency settings at

OS NC		NC RfG		DCC	
Article		Article		Article	
					which demand disconnection shall be initiated and the percentage of demand disconnected at every such setting. f) The Low Frequency Demand Disconnection scheme shall be suitable for operation from a nominal AC input to be defined by the Relevant Network Operator, while respecting the provisions of Article 9(3), and shall have the following functional capability: i. Frequency Range: at least between 47-50Hz, adjustable in steps of 0.05Hz; ii. Operating time: no more than 150 ms after triggering the Frequency setpoint; iii. Voltage lock-out: blocking of the scheme should be possible when the voltage is within a range of 30 to 90% of nominal Voltage; and iv. Direction of Active Power flow at the point of disconnection. 2. With regard to Low Frequency Demand Disconnection schemes AC Voltage supply: a) The voltage supply to the Low Frequency Demand Disconnection schemes shall be derived from the Network at the Frequency signal measuring point, as defined in the Low Frequency Demand Disconnection scheme in paragraph 1(f), so that the Frequency of the Low Frequency Demand Disconnection schemes supply Voltage is the same as that of the Network.
14(8)	While respecting the provisions of the NC RfG, each TSO shall define and implement actions for over-frequency in cooperation with Significant Grid Users which are Power Generating Facility Owners and in coordination	8(1)(c)	Type 'B', 'C' & 'D' Type A[20] Power Generating Modules shall fulfil the following requirements referring to Frequency		

[20] This reference is made because Power Generating Modules type B, C and D shall comply with requirements defined for Power Generating Modules type A.

OS NC		NC RfG		DCC	
Article		Article		Article	
	with the TSOs of its Synchronous Area.		stability: c) With regard to the Limited Frequency Sensitive Mode - Overfrequency (LFSM-O) the following shall apply: 1) The Power Generating Module shall be capable of activating the provision of Active Power Frequency Response according to figure 1 at a Frequency threshold between and including 50.2 Hz and 50.5 Hz with a Droop in a range of 2 – 12 %. The actual Frequency threshold and Droop settings shall be determined by the Relevant TSO. The Power Generating Module shall be capable of activating Active Power Frequency Response as fast as technically feasible with an initial delay that shall be as short as possible and reasonably justified by the Power Generating Facility Owner to the Relevant TSO if greater than 2 seconds. The Power Generating Module shall be capable of either continuing operation at Minimum Regulating Level when reaching it or further decreasing Active Power output in this case, as defined by the Relevant TSO while respecting the provisions of Article 4(3). 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.		
15(1)	Each TSO shall monitor the dynamic state of the Transmission System in terms of Voltage, Frequency and Rotor Angle Stability by off-line studies, wide area measurements, or other approaches according to Article 15(5) including the exchange of relevant data with other TSOs if necessary, in order to be able to take the	10(4)(a), 10(6) (b)&(c),	Type ‘C’ & ‘D’ 4. Type C Power Generating Modules shall fulfil the following requirements referring to robustness of Power Generating Modules	26	SIMULATION MODELS 1. All Transmission Connected Demand Facilities, Demand Facilities or Closed Distribution Network providing DSR (excluding DSR SFC), and Transmission Connected Distribution Networks, shall fulfil the following requirements related with regard to the simulation models or equivalent

OS NC		NC RfG		DCC	
Article		Article		Article	
	necessary Remedial Actions when Transmission System Operational Security is at a risk.	14(3)(a) And 9(5)(a)	a) In case of power oscillations, Steady-state Stability of a Power Generating Module is required when operating at any operating point of the P-Q-Capability Diagram. A Power Generating Module shall be capable of staying connected to the Network and operating without power reduction notwithstanding the provisions of Article 8(1) (e), as long as Voltage and Frequency remain within the admissible limits pursuant to this Network Code. Type C Power Generating Modules shall fulfil the following general system management requirements: b) With regard to instrumentation: 1) Power Generating Facilities shall be equipped with a facility to provide fault recording and dynamic system behaviour monitoring of the following parameters: - Voltage; - Active Power; - Reactive Power; and - Frequency. The Relevant Network Operator shall have the right to define while respecting the provisions of Article 4(3) quality of supply parameters to be complied with provided a reasonable prior notice is given. 2) While respecting the provisions of Article 4 (3), the settings of the fault recording equipment, including triggering criteria and the sampling rates		information: a) Each TSO shall have the right to require the simulation models or equivalent information showing the behaviour of the Demand Facility, Closed Distribution Network providing DSR (excluding DSR SFC) and/or Transmission Connected Distribution Network in both steady and dynamic states. Each TSO shall define, while respecting the provisions of Article 9(3), the content and format of those simulation models or equivalent information. The content and format defined may include but is not restricted to: i. steady and dynamic states, including 50 Hz component; ii. electromagnetic transient simulations at the Connection Point ; iii. structure and block diagrams. b) For the purpose of dynamic simulations, the simulation model or equivalent information provided shall as defined in paragraph 1(a) contain the following sub-models or equivalent information: i. Power control; ii. Voltage control; iii. Demand Facility and Transmission Connected Distribution Network protection models; iv. The constituent demand types, i.e. electro technical characteristics of the demand; and v. Converter models. c) Each Relevant Network Operator or Relevant TSO shall define, while respecting the provisions of Article 9(3), requirements for Transmission Connected Demand Facilities and/or Transmission Connected Distribution Network recordings in order to compare the response of the model with

OS NC		NC RfG		DCC	
Article		Article		Article	
			shall be agreed between the Power Generating Facility Owner and the Relevant Network Operator in coordination with the Relevant TSO. 3) The dynamic system behaviour monitoring shall include an oscillation trigger, specified by the Relevant Network Operator in coordination with the Relevant TSO, detecting poorly damped power oscillations. 4) The facilities for quality of supply and dynamic system behaviour monitoring shall include arrangements for the Power Generating Facility Owner, the Relevant Network Operator and/or the Relevant TSO to access the information. While respecting the provisions of Article 4 (3) the communications protocols for recorded data shall be agreed between the Power Generating Facility Owner and the Relevant Network Operator and Relevant TSO. c) With regard to the simulation models: 1) The Relevant Network Operator in coordination with the Relevant TSO shall have the right to require while respecting the provisions of Article 4(3) the Power Generating Facility Owner to provide simulation models, that shall properly reflect the behaviour of the Power Generating Module in both steady-state and dynamic simulations (50 Hz component) and, where appropriate and justified, in electromagnetic transient simulations. The decision shall include: - the format in which models shall be provided - the provision of documentation of models		these recordings.

OS NC		NC RfG		DCC	
Article		Article		Article	
			structure and block diagrams The models shall be verified against the results of compliance tests as of Title 4 Chapters 2, 3 and 4. They shall then be used for the purpose of verifying the requirements of this Network Code including but not limited to Compliance Simulations as of Title 4 Chapters 5, 6 and 7 and for use in studies for continuous evaluation in system planning and operation. 2) For the purpose of dynamic simulations, the models provided shall contain the following sub-models, depending on the existence of the mentioned components: - Alternator and prime mover; - Speed and power control; - Voltage control, including, if applicable, Power System Stabilizer (PSS) function and excitation system; - Power Generating Module protection models as agreed between the Relevant Network Operator and the Power Generating Facility Owner, while respecting the provisions of Article 4(3); and - Converter models for Power Park Modules. 3) The Relevant Network Operator shall deliver to the Power Generating Facility Owner an estimate of the minimum and maximum short circuit capacity at the connection point, expressed in MVA, as an equivalent of the Network. 4) The Relevant Network Operator or Relevant TSO shall have the right to require while		

OS NC		NC RfG		DCC	
Article		Article		Article	
			respecting the provisions of Article 4(3) Power Generating Module recordings in order to compare the response of the models with these recordings. Type ‘D’ Type D Synchronous Power Generating Modules shall fulfil the following requirements referring to robustness of Power Generating Modules: a) Technical capabilities in order to aid angular stability under fault conditions (e. g. fast valving or braking resistor) shall be implemented if allowed or requested by the Relevant TSO. While respecting the provisions of Article 4 (3), the specifications shall be agreed between the TSO and the Power Generating Facility Owner. Type ‘B’ Type B Power Generating Modules shall fulfil the following general system management requirements: a) With regard to control schemes and settings 1) While respecting the provisions of Article 4(3), schemes and settings of the different control devices of the Power Generating Module relevant for transmission system stability and to enable emergency actions shall be coordinated and agreed between the Relevant TSO, the Relevant Network Operator and the Power Generating Facility Owner. 2) While respecting the provisions of Article 4(3), any changes to the schemes and settings of the different control devices of the Power Generating Module, relevant for transmission system stability		

OS NC		NC RfG		DCC	
Article		Article		Article	
			and to enable emergency actions, shall be coordinated and agreed between the Relevant TSO, the Relevant Network Operator and the Power Generating Facility Owner, especially if they concern the circumstances referred to under Article 9(5) (a) point 1).		
15(8)	In relation to the minimum inertia required for the Synchronous Area: a) all TSOs of that Synchronous Area shall conduct the studies to identify if a need exists for the definition of the minimum required inertia, not later than two years after entering into force of this Network Code and shall conduct a periodic review and update of these studies every two years; b) based on the results of the studies from Article 15(8)(a) all TSOs from a Synchronous Area shall develop and implement the methodology for the definition of minimum inertia required to maintain Operational Security and to prevent violation of Stability Limits identified pursuant to Article 15(3); this methodology shall be developed not later than six months after first completion of the studies from Article 15(8)(a) which showed the need for the definition of a required minimum inertia and shall be regularly updated not later than six months after each new update of the studies from Article 15(8)(a) is available; and c) Each TSO shall be entitled to define and deploy in operation the minimum inertia in its own Responsibility Area, according to the defined methodology and obtained results in Article 15(8)(b).	16(2)(a)	Type ‘C’ & ‘D’ Type C Power Park Modules shall fulfil the following requirements referring to Frequency stability: a) With regard to the capability of providing Synthetic Inertia to a low Frequency event: 1) The Relevant TSO shall have the right to require while respecting the provisions of Article 4(3), in co-operation with other TSOs in the relevant Synchronous Area, a Power Park Module, which is not inherently capable of supplying additional Active Power to the Network by its Inertia and which is greater than a MW size to be specified by the Relevant TSO, to install a feature in the control system which operates the Power Park Module so as to supply additional Active Power to the Network in order to limit the rate of change of Frequency following a sudden loss of infeed. 2) The operating principle of this control system and the associated performance parameters shall be defined by the Relevant TSO while respecting the provisions of Article 4(3).	24	DEMAND SIDE RESPONSE VERY FAST ACTIVE POWER CONTROL 1. The facilitation of a Demand Facility or Closed Distribution Network to voluntarily deliver Demand Side Response Very Fast Active Power Control by a change of Active Power related to the rate-of-change-of-Frequency for that portion of its demand, shall be agreed between the Relevant TSO and Demand Facility Owner or operator of a Closed Distribution Network, in coordination with the Relevant Network Operator, while respecting the provisions of Article 9(3). 2. The operating principle of this control system and the associated performance parameters shall be defined by the Relevant TSO, in agreement with the Relevant Network Operator, while respecting the provisions of Article 9(3). 3. The response time for Very Fast Active Power Control will be defined by Relevant TSO but will not be more than 2 seconds.

OS NC		NC RfG		DCC	
Article		Article		Article	
Chap. 3	CHAPTER 3 DATA EXCHANGE	9(5) (d) And 10(2) (f)	Type ‘B’, ‘C’ and ‘D’ Type B Power Generating Modules shall fulfil the following general system management requirements: d) With regard to information exchange: 1) Power Generating Facilities shall be capable of exchanging information between the Power Generating Facility Owner and the Relevant Network Operator and/or the Relevant TSO in real time or periodically with time stamping as defined by the Relevant Network Operator and/or the Relevant TSO while respecting the provisions of Article 4(3). 2) The Relevant Network Operator in coordination with the Relevant TSO shall define while respecting the provisions of Article 4(3) the contents of information exchanges and the precise list and time of data to be facilitated. Type ‘C’ & ‘D’ Type C Power Generating Modules shall fulfil the following requirements referring to Frequency stability: f) With regard to real-time monitoring of FSM: 1) To monitor the operation of Active Power Frequency Response the communication interface shall be equipped to transfer on-line from the Power Generating Facility to the Network control centre of the Relevant Network Operator and/or the Relevant TSO on request by the Relevant Network Operator and/or the Relevant TSO at	18	INFORMATION EXCHANGE 1. All Transmission Connected Demand Facilities and Transmission Connected Distribution Networks, deemed significant pursuant to the provisions of this Network Code, shall fulfil the following requirements related to the information exchange: a) Transmission Connected Demand Facilities shall be equipped according to the standard defined by the Relevant TSO, while respecting the provisions of Article 9(3), to transfer information between the Relevant TSO and the Transmission Connected Demand Facility with the defined time stamping. The defined standard shall be made publically available by the Relevant TSO. b) Transmission Connected Distribution Networks shall be equipped according to the standard defined by the Relevant TSO, while respecting the provisions of Article 9(3) to transfer information between the Relevant TSO and the Transmission Connected Distribution Network with the defined time stamping. The defined standard shall be made publically available by the Relevant TSO. c) The Relevant TSO shall define the information exchange standards while respecting the provisions of Article 9(3). The precise list of data required shall be made publically available by the Relevant TSO.

OS NC		NC RfG		DCC	
Article		Article		Article	
			least the following signals: - status signal of FSM (on/off); - scheduled Active Power output; - actual value of the Active Power output; - actual parameter settings for Active Power Frequency Response; and - Droop and dead band. 2) The Relevant Network Operator and the Relevant TSO shall define while respecting the provisions of Article 4(3) additional signals to be provided by the Power Generating Facility for monitoring and/or recording devices in order to verify the performance of the Active Power Frequency Response provision of participating Power Generating Modules.		
31(2)	Before initiating any modification, each Significant Grid User shall notify the TSO or DSO to which it has Connection Point, about any planned modification of its technical capabilities which could have an impact on its compliance with the requirements of this Network Code.	10(6)(g)	Type 'C' and 'D' Type C Power Generating Modules shall fulfil the following general system management requirements: g) With regard to changes to, modernization of or replacement 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),	19 (1)&(2)	DEVELOPMENT, MODERNIZATION AND EQUIPMENT REPLACEMENT 1. All Existing Distribution Network Connections, Existing Transmission Connected Demand Facilities, Existing Demand Facilities providing DSR and Existing Closed Distribution Networks providing DSR, deemed significant pursuant to the provisions of this Network Code, shall fulfil the following requirements related to equipment development: a) A Demand Facility Owner or Distribution Network Operator intending to develop, increasing plant and equipment, of the Existing Demand Facility or Existing Distribution Network Connection in a way that may have an impact on its performance and ability to meet the requirements of this Network Code shall notify the Relevant Network Operator directly or indirectly (including but not restricted to via an Aggregator). The

OS NC		NC RfG		DCC	
Article		Article		Article	
			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 be affected by the 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. In case of modernisation or replacement of equipment in existing Power Generating Modules the new equipment shall comply with the respective requirements which are relevant to the planned work. While respecting the provisions of Article 4 (3), the use of existing spare components that do not comply with the requirements has to be agreed with the Relevant Network Operator in coordination with the Relevant TSO in each case.		notification shall take place in advance to the national timescales defined, while respecting the provisions of Article 9 (3). This equipment development may include high-voltage equipment, protection and control systems, including hardware and software. b) The developed equipment shall comply with the respective Network Code requirements which are relevant to the planned work. 2. All Existing Distribution Network Connections, Existing Transmission Connected Demand Facilities, Existing Demand Facilities providing DSR and Existing Closed Distribution Networks providing DSR, deemed significant pursuant to the provisions of this Network Code, shall fulfil the following requirements related to modernization and equipment replacement: a) A Demand Facility Owner or Distribution Network Operator intending to modernize and replace the equipment of the Existing Demand Facility or Existing Distribution Network in a way that may have an impact on its performance and ability to meet the requirements of this Network Code shall notify to the Relevant Network Operator directly or indirectly (including but not restricted to via an Aggregator). The notification shall take place in advance to the national timescales defined, while respecting the provisions of Article 9(3). This modernization and equipment replacement may include high-voltage equipment, protection and control systems, including hardware and software. b) The modernized and replaced equipment shall comply with the respective Network Code requirements which are relevant to the planned work.
32(2) And 33(4)	Each TSO shall contribute to the annual reporting developed pursuant to the common incidents classification scale, adopted by ENTSO-E in accordance with Article 8(3)(a) of the Regulation (EC) 714/2009. The format and contents of this annual report, including the specific geographical and electrical scope of the incidents reported and including relevant historical information of similar incidents from the past, shall be approved by ACER. The	10(6) (b)&(c), 9(5) (d)	Type ‘C’ and ‘D’ Type C Power Generating Modules shall fulfil the following general system management requirements: b) With regard to instrumentation: 1) Power Generating Facilities shall be equipped	18(1)	INFORMATION EXCHANGE 1. All Transmission Connected Demand Facilities and Transmission Connected Distribution Networks, deemed significant pursuant to the provisions of this Network Code, shall fulfil the following requirements related to the information exchange: a) Transmission Connected Demand Facilities shall be equipped according to the standard defined by the Relevant TSO, while respecting

OS NC		NC RfG		DCC	
Article		Article		Article	
	annual report shall contain the Operational Security Performance Indicators on scale 1-3: a. number of tripped Transmission System elements per year; b. number of tripped Power Generation Facilities per year; c. energy of disconnected Demand Facilities per year; d. time duration of being in Operational States other than Normal State; e. time duration and number within which there was a lack of reserves identified; f. voltage deviation exceeding the voltage thresholds for Emergency State; g. frequency deviation per Synchronous Area; h. number of system-split separations or local blackouts; and i. number of blackouts involving two or more TSOs. The yearly report developed pursuant to the Article 8(3)(a) of the Regulation (EC) 714/2009 shall contain explanation of reasons of incidents at the Operational Security Ranking Scales 2 and 3 according to Article 32(3). TSOs, DSOs and Significant Grid Users shall exchange any relevant data, necessary to fully analyse both Local and Wide Area system incidents and facilitate system analysis.	And 10(2) (f)	with a facility to provide fault recording and dynamic system behaviour monitoring of the following parameters: - Voltage; - Active Power; - Reactive Power; and - Frequency. The Relevant Network Operator shall have the right to define while respecting the provisions of Article 4(3) quality of supply parameters to be complied with provided a reasonable prior notice is given. 2) While respecting the provisions of Article 4 (3), the settings of the fault recording equipment, including triggering criteria and the sampling rates shall be agreed between the Power Generating Facility Owner and the Relevant Network Operator in coordination with the Relevant TSO. 3) The dynamic system behaviour monitoring shall include an oscillation trigger, specified by the Relevant Network Operator in coordination with the Relevant TSO, detecting poorly damped power oscillations. 4) The facilities for quality of supply and dynamic system behaviour monitoring shall include arrangements for the Power Generating Facility Owner, the Relevant Network Operator and/or the Relevant TSO to access the information. While respecting the provisions of Article 4 (3) the communications protocols for recorded data shall be agreed between the Power Generating Facility		the provisions of Article 9(3), to transfer information between the Relevant TSO and the Transmission Connected Demand Facility with the defined time stamping. The defined standard shall be made publically available by the Relevant TSO. b) Transmission Connected Distribution Networks shall be equipped according to the standard defined by the Relevant TSO, while respecting the provisions of Article 9(3) to transfer information between the Relevant TSO and the Transmission Connected Distribution Network with the defined time stamping. The defined standard shall be made publically available by the Relevant TSO. c) The Relevant TSO shall define the information exchange standards while respecting the provisions of Article 9(3). The precise list of data required shall be made publically available by the Relevant TSO.

OS NC		NC RfG		DCC	
Article		Article		Article	
			Owner and the Relevant Network Operator and Relevant TSO. c) With regard to the simulation models: 1) The Relevant Network Operator in coordination with the Relevant TSO shall have the right to require while respecting the provisions of Article 4(3) the Power Generating Facility Owner to provide simulation models, that shall properly reflect the behaviour of the Power Generating Module in both steady-state and dynamic simulations (50 Hz component) and, where appropriate and justified, in electromagnetic transient simulations. The decision shall include: - the format in which models shall be provided - the provision of documentation of models structure and block diagrams The models shall be verified against the results of compliance tests as of Title 4 Chapters 2, 3 and 4. They shall then be used for the purpose of verifying the requirements of this Network Code including but not limited to Compliance Simulations as of Title 4 Chapters 5, 6 and 7 and for use in studies for continuous evaluation in system planning and operation. 2) For the purpose of dynamic simulations, the models provided shall contain the following sub-models, depending on the existence of the mentioned components: - Alternator and prime mover;		

OS NC		NC RfG		DCC	
Article		Article		Article	
			- Speed and power control; - Voltage control, including, if applicable, Power System Stabilizer (PSS) function and excitation system; - Power Generating Module protection models as agreed between the Relevant Network Operator and the Power Generating Facility Owner, while respecting the provisions of Article 4(3); and - Converter models for Power Park Modules. 3) The Relevant Network Operator shall deliver to the Power Generating Facility Owner an estimate of the minimum and maximum short circuit capacity at the connection point, expressed in MVA, as an equivalent of the Network. 4) The Relevant Network Operator or Relevant TSO shall have the right to require while respecting the provisions of Article 4(3) Power Generating Module recordings in order to compare the response of the models with these recordings. Type ‘B’, ‘C’ and ‘D’ Type B Power Generating Modules shall fulfil the following general system management requirements: d) With regard to information exchange: 1) Power Generating Facilities shall be capable of exchanging information between the Power Generating Facility Owner and the Relevant Network Operator and/or the Relevant TSO in real time or periodically with time stamping as defined by the Relevant Network Operator and/or the		

OS NC		NC RfG		DCC	
Article		Article		Article	
			Relevant TSO while respecting the provisions of Article 4(3). 2) The Relevant Network Operator in coordination with the Relevant TSO shall define while respecting the provisions of Article 4(3) the contents of information exchanges and the precise list and time of data to be facilitated. Type ‘C’ & ‘D’ Type C Power Generating Modules shall fulfil the following requirements referring to Frequency stability: f) With regard to real-time monitoring of FSM: 1) To monitor the operation of Active Power Frequency Response the communication interface shall be equipped to transfer on-line from the Power Generating Facility to the Network control centre of the Relevant Network Operator and/or the Relevant TSO on request by the Relevant Network Operator and/or the Relevant TSO at least the following signals: - status signal of FSM (on/off); - scheduled Active Power output; - actual value of the Active Power output; - actual parameter settings for Active Power Frequency Response; and - Droop and dead band. 2) The Relevant Network Operator and the Relevant TSO shall define while respecting the		

OS NC		NC RfG		DCC	
Article		Article		Article	
			provisions of Article 4(3) additional signals to be provided by the Power Generating Facility for monitoring and/or recording devices in order to verify the performance of the Active Power Frequency Response provision of participating Power Generating Modules.		

ANNEX VIII-DEFINITIONS IN THE FRAMEWORK OF THE OS NC

(N-1)-Criterion means the rule according to which elements remaining in operation within TSO's Responsibility Area after a Contingency from the Contingency List must be capable of accommodating the new operational situation without violating Operational Security Limits *(definition from OS NC)*;

(N-1)-Situation means the situation in the transmission system in which a Contingency from the Contingency List has happened *(definition from OS NC)*;

Active Power - is the real component of the Apparent Power at fundamental Frequency, expressed in watts or multiples thereof (e.g. kilowatts (kW) or megawatts (MW)). (definition from NC RfG)

Active Power Reserve means the Active Power which is available for maintaining the frequency *(definition from OS NC)*;

Alert State means the System State where the system is within Operational Security Limits, but a Contingency from the Contingency List has been detected, for which in case of occurrence, the available Remedial Actions are not sufficient to keep the Normal State *(definition from OS NC)*;

Ancillary Services means services necessary to support transmission of electric power between generation and load, maintaining a satisfactory level of Operational Security and with a satisfactory quality of supply*(definition from Directive 2003/54/EC)*;

Area Control Error (ACE) – means the sum of the instantaneous difference between the actual and the set-point value for the power interchange of a LFC Area or a LFC Block and the frequency bias given by the product of the K-Factor of the LFC Area or the LFC Block and the Frequency Deviation. (Definition from LFC NC – now in OS NC)

Automatic Voltage Control means the automatic control actions at the generation node, at the end nodes of the AC lines or High-Voltage DC lines, on transformers, or other means, designed to maintain the set voltage level or the set value of Reactive Power *(definition from OS NC)*;

Blackout State means the System State where the operation of part or all of the Transmission System is terminated *(definition from OS NC)*;

Common Grid Model (CGM) means the European-wide or multiple-TSOs-wide data set, created by the European Merging Function, through the merging of relevant data *(definition from NC CACM)*;

Connection Point is the interface at which the Power Generating Module, Demand Facility, Distribution Network or Closed Distribution Network is connected to a Transmission System, Distribution Network or Closed Distribution Network *(definition from OS NC);*

Contingency Analysis means computer based simulation of Contingencies *(definition from OS NC)*;

Contingency Influence Threshold means a numerical limit value against which the Influence Factors must be checked. The outage of an external Transmission System element with an Influence Factor higher than the Contingency Influence Threshold is considered having a significant impact on the TSO's Responsibility Area. The value of the Contingency Influence Threshold is based on the risk assessment of each TSO *(definition from OS NC)*;

Contingency List means the list of Contingencies to be simulated in the Contingency Analysis in order to test the compliance with the Operational Security Limits a priori or a posteriori after a Contingency took place *(definition from OS NC)*;

Contingency means the identified and possible or already occurred Fault of an element within or outside a TSO's Responsibility Area, including not only the Transmission System elements, but also Significant Grid Users and Distribution Network elements if relevant for the Transmission System Operational Security. Internal Contingency is a Contingency within the TSO's Responsibility Area. External Contingency is a Contingency outside the TSO's Responsibility Area, with an Influence Factor higher than the Contingency Influence Threshold *(definition from OS NC)*;

Control Program means the set-point value, also called schedule, for the netted power interchange of a LFC Area over Interconnectors*(definition from OS NC)*;

Critical Fault Clearing Time means the maximum Fault duration for which the electric power system remains transiently stable *(definition from OS NC)*;

Declared Availability means declaration and notice prepared in respect of a Significant Grid User, submitted to the TSO setting out the values and times applicable to those values of availability and Ancillary Services capability (definition from OS NC);

Demand Facility means a facility which consumes electrical energy and is connected at one or more Connection Points to the Network. For the avoidance of doubt a Distribution Network and/or auxiliary supplies of a Power Generating Module are not to be considered a Demand Facility (definition from DCC);

Distribution Network means an electrical Network, including Closed Distribution Networks, for the distribution of electrical power from and to third party[s] connected to it, a Transmission or another Distribution Network (definition from DCC);

Distribution System Operator (DSO) means a natural or legal person responsible for operating, ensuring the maintenance of and developing the distribution system in its Responsibility Area and its interconnections with other systems and for ensuring the long-term ability of the system to meet reasonable demands for distribution of electricity (definition from Directive 2009/72/EC);

Disturbance means an unplanned event that may cause the Transmission System to divert from Normal State (definition from OS NC);

Dynamic Stability Assessment (DSA) means the Operational Security Assessment in terms of Dynamic Stability (definition from OS NC);

Dynamic Stability is a common term including the Rotor Angle Stability, Frequency Stability and Voltage Stability (definition from OS NC);

Emergency State means the System State where Operational Security Limits are violated and at least one of the operational parameters is outside of the respective limits (definition from OS NC);

ENTSO-E means the European Network of Transmission System Operators for Electricity as established in the Regulation (EC) No 714/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the network for cross-border exchanges in electricity and repealing Regulation (EC) No 1228/2003[21];

Exceptional Contingency means the loss of a busbar, or more than one element such as, but not limited to: a common mode Fault with the loss of more than one Power Generating Module, a common mode Fault with the loss of more than one AC or DC line, a common mode Fault with the loss of more than one transformer; (definition from OS NC);

Fault means all types of short-circuits: single-, double- and triple-phase, with and without earth contact. It means further a broken conductor, interrupted circuit, or an intermittent connection, resulting in a permanent non-availability of the affected Transmission System element; *(definition from OS NC)*;

Frequency Containment Reserves (FCR) means the Operational Reserves activated to contain System Frequency after the occurrence of an imbalance *(definition from OS NC)*;

Frequency Deviation means the difference between the actual System Frequency and the Nominal Frequency of the Synchronous Area which can be negative or positive *(definition from OS NC)*;

[21] *OJ L 211, 14.8.2009, p. 15–35*

Frequency Restoration Control Error means the control error for the FRP which is equal to the ACE of a LFC Area or is equal to the Frequency Deviation where the LFC Area geographically corresponds to the Synchronous Area *(definition from OS NC)*;

Frequency Stability means the ability of the Transmission System to maintain stable frequency in N-Situation and after being subjected to a disturbance *(definition from OS NC)*;

System user means a natural or legal person supplying to, or being supplied by, a transmission or distribution system Directive 2009/72/EC;

Influence Factor means a numerical value used to quantify the highest effect of the outage of an external Transmission System element on any Transmission System branch. The worse the effect, the higher the influence factor value is *(definition from OS NC);*

K-Factor means a factor used to calculate the frequency bias component of the ACE of a LFC Area or a LFC Block (definition from OS NC);

Load-Frequency Control Area (LFC Area) means a part of a Synchronous Area or an entire Synchronous Area, physically demarcated by points of measurement of Interconnectors to other LFC Areas, operated by one or more TSOs fulfilling the obligations of a LFC Area *(definition from OS NC)*;

Load-Frequency Control Block (LFC Block) means a part of a Synchronous Area or an entire Synchronous Area, physically demarcated by points of measurement of Interconnectors to other LFC Blocks, consisting of one or more LFC Areas, operated by one or more TSOs fulfilling the obligations of a LFC Block *(definition from OS NC)*;

Local means the qualification of an Alert, Emergency or Blackout State when there is no risk of extension of the consequences outside of the Responsibility Area of a single TSO (definition from OS NC);

Maximum Steady-State Frequency Deviation means the maximum expected Frequency Deviation after the occurrence of an imbalance equal or less than the Reference Incident at which the System Frequency is designed to be stabilized (definition from OS NC);

Nominal Frequency means the rated value of the System Frequency (definition from OS NC);

Normal State means the System State where the system is within Operational Security Limits in the N-Situation and after the occurrence of any Contingency from the Contingency List, taking into account the effect of the available Remedial Actions; state in which there is a low risk for Operational Security of the Transmission System (definition from OS NC);

N-Situation means the situation where no element of the Transmission System is made unavailable due to a Fault (definition from OS NC);

Observability Area means the own Transmission System and the relevant parts Distribution Networks and neighbouring TSOs' Transmission Systems, on which TSO implements real-time monitoring and modelling to ensure Operational Security in its Responsibility Area (definition from OS NC);

Operational Reserves means the spinning and non-spinning reserves that are accessible to at least one TSO (definition from OS NC);

Operational Security means the Transmission System capability to retain a Normal State or to return to a Normal State as soon and as close as possible, and is characterized by its thermal limits, voltage constraints, short-circuit current, frequency reference value and stability limits (definition from OS NC);

Operational Security Analysis means the entire scope of the computer based, manual and combined activities performed in order to assess Operational Security of the Transmission System, including but not limited to: processing of telemetered real-time data through State Estimation, real-time load flows calculation, load flows calculation during operational planning, Contingency Analysis in real-time and during operational planning, Dynamic Stability Assessment, real-time and offline short circuit calculations, System Frequency monitoring, Reactive Power and voltage assessment (definition from OS NC);

Operational Security Limits means the acceptable operating boundaries: thermal limits, voltage limits, short-circuit current limits, frequency and Dynamic Stability limits (definition from OS NC);

Operational Security Performance Indicators are used for monitoring of the Operational Security in terms of Faults, incidents, disturbances and other events which influence Operational Security, as specified in the ENTSO-E incidents classification scale developed pursuant to the Article 8(3)(a) of the Regulation (EC) No 714/2009 (definition from OS NC);

Operational Security Ranking is used for monitoring of the Operational Security on the basis of the Operational Security Performance Indicators, according to the ENTSO-E incidents classification scale developed pursuant to the Article 8(3)(a) of the Regulation (EC) No 714/2009 (definition from OS NC);

Ordinary Contingency means the loss of a Transmission System element such as, but not limited to: a single line, a single transformer, a single phase-shifting transformer, a voltage compensation installation connected directly to the Transmission System; it means further also the loss of a single Power Generating Module connected directly to the Transmission System, the loss of a single Demand Facility connected directly to the Transmission System, or the loss of a single DC line (definition from OS NC);

Out-of-Range Contingency means the simultaneous loss, without a common mode Fault, of several Transmission System elements such as, but not limited to: two independent lines, a substation with more than one busbar, a tower with more than two circuits, one or more Power Generating Facilities with a total lost capacity exceeding the Reference Incident; (definition from OS NC);

Power Generating Facility means a facility to convert primary energy to electrical energy which consists of one or more Power Generating Modules connected to a Network at one or more Connection Points (definition from NC RfG);

Power Generating Module means either a Synchronous Power Generating Module or a Power Park Module (definition from NC RfG);

Ramping Rate means the rate of change of Active Power by a Power Generating Module, Demand Facility or DC interconnection(definition from OS NC);

Redispatching means a measure activated by one or several System Operators by altering the generation and/ or load pattern, in order to change physical flows in the Transmission System and relieve a physical congestion; (definition from NC CACM)

Redispatching Aggregator means a legal entity which is responsible for the operation of a number of Power Generating Modules by means of generation aggregation for the purpose of offering Redispatching (definition from OS NC);

Reference Incident means the maximum instantaneously occurring power deviation between generation and demand in a Synchronous Area in both positive and negative direction, considered in the FCR dimensioning (definition from OS NC);

Remedial Action means any measure applied by a TSO in order to maintain Operational Security. In particular, Remedial Actions serve to fulfil the (N-1)-Criterion and to maintain Operational Security Limits. (definition from OS NC);

Reactive Power - is the imaginary component of the Apparent Power at fundamental Frequency, usually expressed in kilovar (kvar) or megavar (Mvar) (definition from NC RfG);

Reactive Power Reserve means the Reactive Power which is available for maintaining voltage (definition from OS NC);

Regional Security Coordination Initiative (RSCI)- means regional unified scheme set up by TSOs in order to coordinate Operational Security analysis on a determined geographic area (definition from NC OPS);

Responsibility Area means a coherent part of the interconnected Transmission System including Interconnectors, operated by a single TSO with connected Demand Facilities, or Power Generating Modules , if any (definition from OS NC) (definition from OS NC);

Restoration means the System State in which the objective of all activities in Transmission System is to re-establish the system operation and maintain Operational Security after a Blackout (definition from OS NC) ;

Rotor Angle Stability means the ability of synchronous machines to remain in synchronism under N-Situation and after being subjected to a disturbance (definition from OS NC);

Schedule means a reference set of values representing the Generation, consumption or exchange of electricity between actors for a given time period (definition from NC OPS);

Security Plan means the plan containing a risk assessment of critical TSO's assets to major physical- and cyber-threat scenarios with an assessment of the potential impacts (definition from OS NC);

Significant Grid User means the existing and new Power Generating Facility and Demand Facility deemed by the TSO as significant because of their impact on the Transmission System in terms of the security of supply including provision of Ancillary Services (definition from OS NC) ;

Stability Limits means the permitted operating boundaries of the Transmission System in terms of respecting the constraints of Voltage Stability, Rotor Angle Stability and Frequency Stability (definition from OS NC) ;

State Estimation means the methodology and algorithms used to calculate a reliable set of measurements defining the state of the Transmission System out of the redundant set of measurements (definition from OS NC);

Synchronous Area means an area covered by interconnected TSOs with a common System Frequency in a steady-state such as the Synchronous Areas Continental Europe (CE), Great Britain (GB), Ireland (IRE) and Northern Europe (NE);

Synchronous Area Agreement means a multi-party agreement between all TSOs of a Synchronous Area if the Synchronous Area consists of more than one TSO. If a Synchronous Area consists of only one TSO, the Synchronous Area Agreement means a formal declaration of the obligations defined in this Network Code;

System Defence Plan means the summary of all technical and organisational measures to be undertaken to prevent the propagation or deterioration of an incident in the Transmission System, in order to avoid a widespread disturbance and Blackout State (definition from OS NC);

System Frequency means the electric frequency of the system that can be measured in all parts of the Synchronous Area under the assumption of a coherent value for the system in the time frame of seconds, with only minor differences between different measurement locations (definition from OS NC);

System Operator Employee means the person who is a TSO employee in charge of system operation and control of the Transmission System in real-time, or the person who is a TSO employee in charge of operational planning locations (definition from OS NC);

System Protection Scheme (SyPS) means the set of coordinated and automatic measures designed to ensure fast reaction to Disturbances and to avoid the propagation of Disturbances in the Transmission System; (definition from OS NC);

System State means the operational state of the Transmission System in relation to the Operational Security Limits: Normal, Alert, Emergency, Blackout and Restoration System States are defined (definition from OS NC);

System user means the natural or legal person supplying active and/or reactive power to a TSO or DSO grid, or being supplied with active and/or reactive power from a TSO or DSO grid(definition from the Directive *2003/54/EC*);

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

Topology means necessary data about the connectivity of the different Transmission System or Distribution Network elements in a substation. It includes the electrical configuration and the position of circuit breakers and isolators (definition from OS NC);

Transitory Admissible Overloads means the temporary overloads of Transmission System elements or secondary equipment which are allowed for a limited period and which do not cause physical damage to the elements and equipment as long as the defined duration and thresholds are respected (definition from OS NC);

Transmission System means the electric power network used to transmit electric power over long distances within and between Member States. The Transmission System is usually operated at the 220 kV and above for AC or HVDC, but may also include lower voltages (definition from NC CACM);

Virtual Tie-Line means an additional input of the controllers of the involved areas that has the same effect as a measuring value of a physical Tie-Line and allows exchange of electric energy between the respective areas (definition from OS NC);

Voltage Stability means the ability of a Transmission System to maintain acceptable voltages at all buses in the Transmission System under N-Situation and after being subjected to a Disturbance (definition from OS NC);

Wide Area means the qualification of an Alert, Emergency or Blackout State when there is a risk of propagation to the interconnected Transmission Systems (definition from OS NC)

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