Supporting Document for the Network Code on Operational Planning and Scheduling

26 March 2013

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

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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 consultation of the Network Code on Operational Planning and Scheduling (NC OPS) and should be read in conjunction with that document.

The document has been developed in recognition of the fact that the NC OPS, which will become a legally binding document after Comitology, inevitably cannot provide the level of explanation, which some parties may desire. Therefore, this document aims to provide interested parties with the background information and explanation for the requirements specified in the NC OPS, as well as the document outlines the following steps of the work.

1.2 STRUCTURE OF THE DOCUMENT

The Supporting Document is structured as all other supporting documents for the NCs developed in line with the Framework Guidelines on Electricity System Operation. This Supporting Document is therefore presented as follows:

Background:

- Chapter 2 introduces the legal framework within which the System Operation Network Codes have been developed.
- Chapter 3 explains the approach, which ENTSO-E has taken to develop the Network Code, outlines some of the challenges and opportunities ahead for System Operation and benefits of the NC OPS.

Explanatory notes:

- Chapter 4 deals with the requirements of the Framework Guidelines on Electricity System Operation (FG ESO) developed by the Agency for the Cooperation of Energy Regulators (ACER) and their implications regarding the NC OPS.
- Chapter 5 deals with the explanation of requirements of the NC OPS.
- Chapter 6 is dedicated to the clarification of key concepts used within the NC OPS.
- Chapter 7 is explaining how stakeholders' comments during public consultation were managed.
- Chapter 8 introduces the next steps in the process.

Appendices:

- Appendix 1: Baseline – purpose of Network Code.
- Appendix 2: Assessment of the Network Code on Operational Planning and Scheduling against the requirements of the Framework Guidelines.
- Appendix 3: Summary of comments received during public consultation and overview of the ENTSO-E responses.
- Appendix 4: Methodologies for determining the relevant assets and neighbouring assets to monitor and consider in Contingency Analysis.
- Appendix 5: Scheduling examples.
- Appendix 6: FAQs.
- Appendix 7: Impact analysis.
- Appendix 8: Glossary.

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1.3 LEGAL STATUS OF THE DOCUMENT

This document accompanies the Network Code on Operation Planning and Scheduling, but is provided for information only.

Therefore it has no legally binding status.

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2 PROCEDURAL ASPECTS

2.1 INTRODUCTION

This chapter provides an overview of the procedural aspects of the 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 NC OPS.

2.2 THE FRAMEWORK FOR DEVELOPING NETWORK CODES

The NC OPS has been developed in accordance with the process established within the Third Energy Package, in particular in Regulation (EC) N° 714/2009. The Third Energy Package legislation establishes ENTSO-E and ACER and gives them clear obligations in developing Network Codes. This is shown in Figure 1 below:

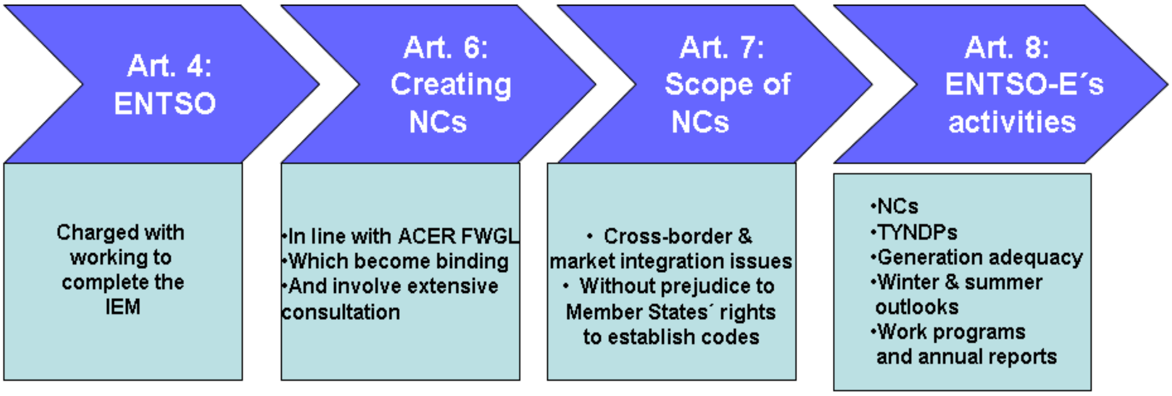

Figure 1: ENTSO-E's legal role in Network Code development according to Regulation (EC) N° 714/2009.

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

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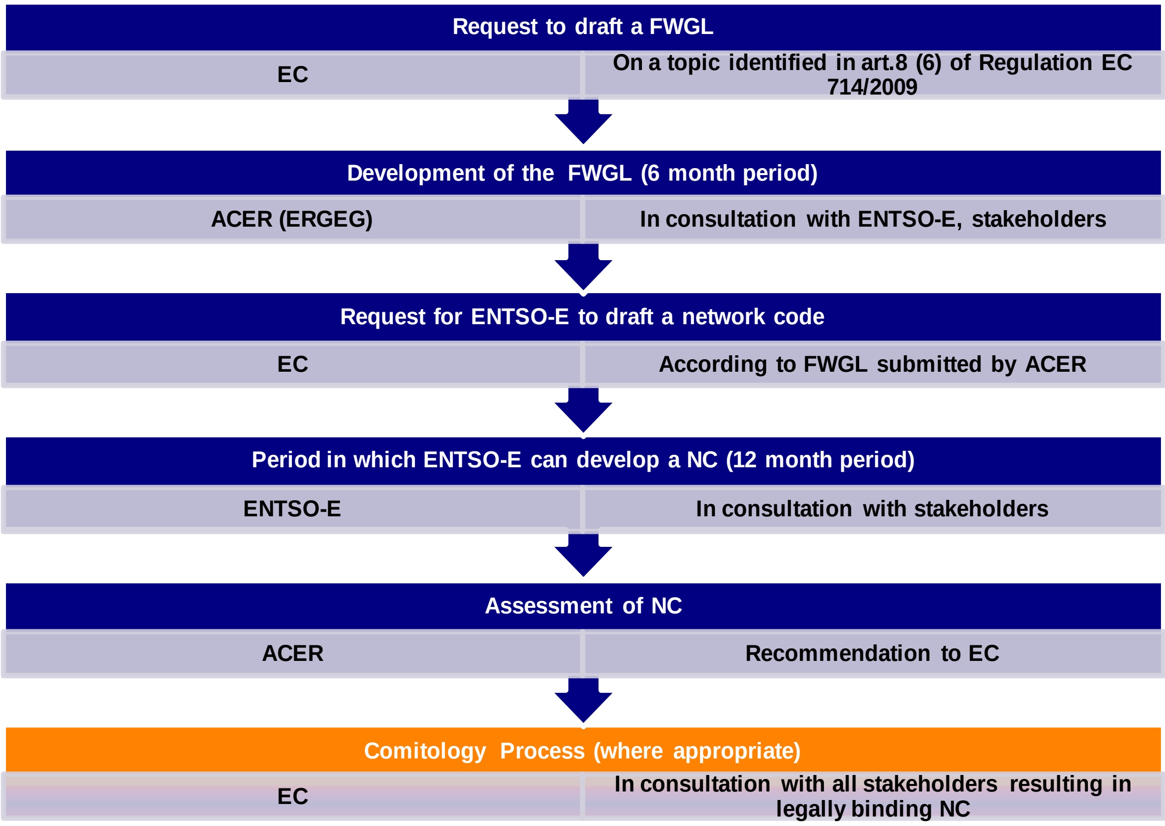

Figure 2: Network Codes' development process [Source: ENTSO-E]

The NC OPS has been developed by ENTSO-E to meet the requirements of the Framework Guidelines on Electricity System Operation (FG ESO) [1] published by ACER in December 2011. ACER has also conducted an Initial Impact Assessment associated with its consultation on its draft FG ESO in June 2011 [2].

ENTSO-E was formally requested by the European Commission to begin the development of the NC OPS on the 1st of April 2012. The deadline for the delivery of the code to ACER is the 1st of April 2013.

ENTSO-E held four workshops with stakeholders and launched a public consultation for two months from November 2012 until beginning of January 2013. Stakeholders and involved parties submitted comments and provided proposals for addressing the concerns they had with the draft of the code at that time. ENTSO-E carefully considered all comments which were provided and updated the Network Code in light of the proposed changes and comments. Results of this consultation are exposed in appendix 3 and were presented and discussed in the last Workshop held on the 14th of February 2013.

Following agreement and approval within ENTSO-E, the Network Code will be submitted to ACER in line with the defined deadline of 1 April 2013.

ACER is then expected to assess the NC OPS to ensure it complies with the FG ESO and will make a recommendation to the European Commission. When the European Commission agrees with the ACER recommendation, the European Commission can conduct the Comitology process which should transform the NC OPS into a legally binding integral component of Regulation (EC) N°714/2009.

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3 SCOPE, STRUCTURE & APPROACH TO DRAFTING THE NC OPS

3.1 INTRODUCTION

This chapter provides the overview of the background and place of the NC OPS, covering the guiding principles for the Drafting Team in developing the NC OPS, general structure and level of details of the code, challenges and opportunities ahead of system operation, interaction with other Network Codes, interaction with stakeholders during the network Code development process, describing how NRAs are involved and benefits of the NC OPS.

ENTSO-E has drafted the NC OPS to define the minimum operational planning and scheduling requirements for ensuring coherent and coordinated preparation of real-time operation of Transmission Systems in order to achieve and maintain a satisfactory level of Operational Security of the interconnected Transmission Systems in real time, to support the efficient functioning of the European Internal Electricity Market (IEM), and to allow the integration of electrical Renewable Energy Sources.

Based on the FG ESO and on the Initial Impact Assessment (IIA) provided by ACER, the NC OPS states the operational planning and scheduling principles in terms of technical needs, considering compatible market solutions and as such provides support to maintain the security of supply.

The NC OPS recognises there will be increased levels of RES within the European electricity Network in the coming years. This code has been drafted in a way to support this evolution without adversely impacting on system security.

3.2 GUIDING PRINCIPLES

The guiding principles of the NC OPS are to determine common Interconnected System operational planning principles, to ensure the conditions for maintaining Operational Security levels throughout the EU, to provide for the coordination of system operational planning, as well as to determine common requirements for DSOs, power generating facilities and demand facilities connected to Transmission and Distribution Systems, which are relevant for the operational planning of the Interconnected System. These principles are essential for the TSOs to manage their responsibilities for preparing a secure operation of the interconnected Transmission Systems with a high level of coordination, reliability, quality and stability.

A key goal of the NC OPS is to achieve a harmonised and solid technical framework for Interconnected System operational planning - including the implementation of all necessary processes required for it, taking into account the rapid growth of the (volatile) Renewable Energy Sources (RES) generation and their impact on system operation. Consequently, the requirements have been designed in order to ensure an operational planning that meets the objectives of a secure Interconnected System operation, taking into account the integration of the RES and the effective development of the IEM.

The requirements set out in the NC OPS are building on 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 1950s (ENTSO-E Regional Group Central Europe (RGCE), former Union for Coordination of (Production) and Transmission of Electricity (UC(P)TE)), 1960s (ENTSO-E North, former Nordel), and 1970s (TSO Associations of Great Britain and Republic of Ireland, UKTSOA and ITSOA), distinguishes the NC OPS and all other SO NCs from other Network Codes in following terms:

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- The work on the SO NCs does not start from "scratch" but builds upon a wide and deep range of requirements, policies and standards of the previous European Transmission System interconnections (Synchronous Areas), adapting and developing further these requirements in order to satisfy the requirements from the FG ESO, to meet the challenges of the energy "turnaround" - including the integration of RES and increasingly volatile and dynamic market operations - as well as to support the effective and efficient completion of the IEM;
- The subject matter – system operation 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 properly, efficiently and in favour of all Market Participants. 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" – TSOs 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, firm 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 regulating power/balancing.

3.3 STRUCTURE AND BACKGROUND OF THE NC OPS

Secure and efficient Transmission System operation can be made possible, only if there is an obligation for the Transmission System Operators (TSOs), Distribution System Operators (DSOs), power generating facility operators and demand facilities to cooperate and to meet the relevant minimum technical requirements for the operation of the interconnected Transmission Systems as one entity. Even though each TSO has one Responsibility Area, they are responsible for secure and efficient system operation as a common task:

- All systems are to some extent interconnected, and a Fault in one area will possibly affect another area. Hence, secure system operation requires close coordination and cooperation.
- Efficient system operation requires close collaboration between all stakeholders; the main purpose of the liberalisation, and therefore this harmonisation, of the electricity sector was efficiency, more specifically utilizing efficiently the resources for balancing the system. This requires close collaboration and coordination.

Secure and efficient Transmission System operation can be made possible only if there is a well-organized preparation of real time operation. This requires TSOs to have the necessary means to control the system in real time, either when the system is subject to normal changes of operation conditions or when it is facing incidents that affect generation, demand or Transmission equipment.

The NC OPS provides a basis for this preparation as it defines the minimum operational planning and scheduling requirements for ensuring a coherent and coordinated preparation of real-time operation of Transmission Systems. These minimum requirements will be applicable to all TSOs, DSOs and Grid Users of significance to the Transmission System.

The NC OPS resides under the umbrella of the Network Code on Operational Security, and therefore shares the principles of supporting the coordination of system operation across Europe. The NC OPS will also support the evolution of system operation methodologies to facilitate the expected increase of RES penetration across Europe.

The NC OPS covers all planning tasks and procedures required in Operational Planning timeframes. All stakeholders, including TSOs, should respect common requirements for the processes within these different time frames necessary to anticipate real-time operation conditions of the interconnected Transmission Systems and to develop relevant measures required to maintain the Operational Security, quality and stability of the interconnected Transmission System and to support the efficient functioning of the European Internal Electricity Market. These time frames and related processes are the basis for the structure, key elements and provisions of this Network Code, as illustrated in Figure 3 below:

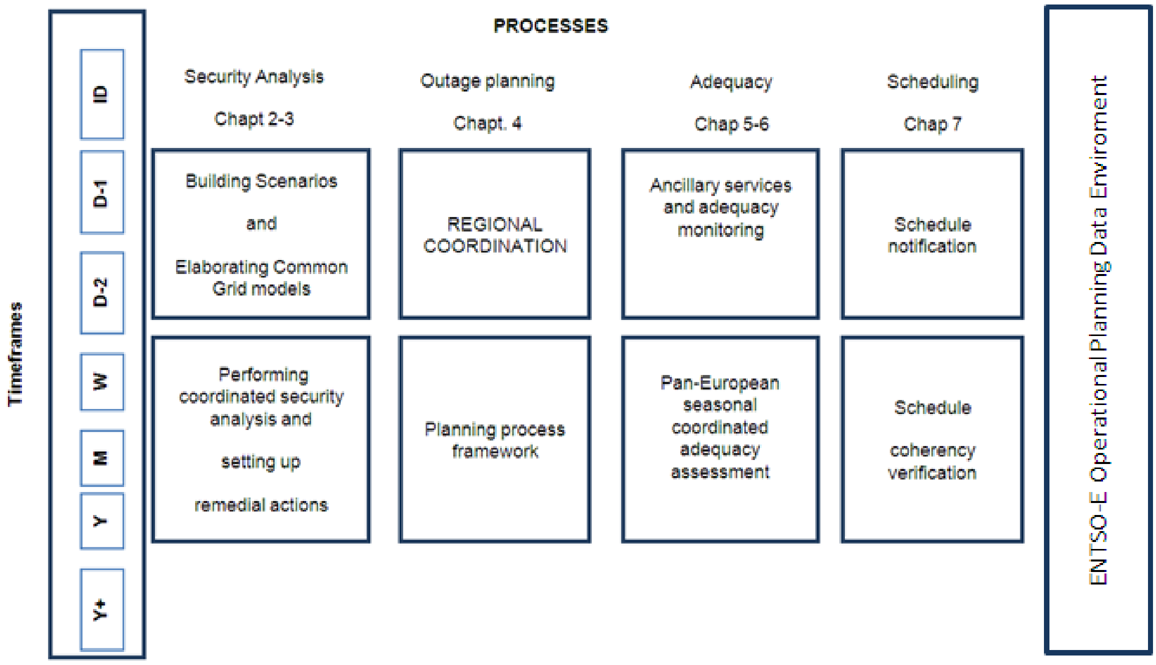

Figure 3: Structure and provisions of the Network Code on Operational Planning and Scheduling

The focus of the NC OPS is the following:

- **Building and collecting data for scenarios/models within the Responsibility Areas:** each TSO should implement processes to build scenarios representative of the upcoming operational environment, within each time frame. This should be based on information inputs provided by TSOs and, where necessary, DSOs and grid users, taking into account uncertainties of demand, classical generation, renewable, exchanges patterns etc.;
- **Building models assuring cross border or cross control area coordination:** each TSO should implement a process to build, within each time frame, common grid models fitting these scenarios. These should cover zones that allow a coordinated security analysis and congestion and power flow management, while taking into account relevant characteristics of the connected generation, consumption and distribution as well as Transmission equipment and planned outages;
- **Monitoring the system state at all times:** each TSO should implement processes to carry out, within each time frame, a Contingency Analysis. This should use simulation tools that allow for an assessment of the state of the system. This assessment will be the basis to prepare for contingencies as defined by the NC OS and to set up the required preventive and/or curative Remedial Actions;
- **Coordinating and monitoring planned outages:** each TSO should implement processes to elaborate and update, within each time frame, a coordinated outage plan. This should allow

TSOs, DSOs and grid users to perform and optimize their maintenance works without jeopardizing Operational Security or altering the functioning of the electricity market;

- **Monitoring Adequacy of power, and both monitoring and acquiring Ancillary services:** each TSO should implement processes, within each time frame, to elaborate a coordinated assessment between TSO's that the power generation capacities will allow to balance the demand as to have the required amount of Ancillary Services, taking into account:
    - planned outages, considering possible significant deviations in load or generation due to uncertain weather forecasts;
    - possible Forced Outages on classical generation;
    - the possibilities of cross border exchanges within available Transmission capacities.

  Each TSO should provide the systems and procedures to facilitate an adequate level of Ancillary Services according to security requirements and should also develop relevant preventive and/or curative measures to be involved timely and adequate data exchange;
- **Providing procedures for scheduling of cross-border energy exchanges and cross-border coordination of Ancillary services exchanges:** TSOs should implement processes allowing the acquisition and coherency verification of cross border scheduled energy exchanges. Furthermore, TSOs should agree on procedures for the coordination and exchange of Ancillary Services in order to use of the available resources in the systems effectively;
- **Providing the tools and procedures for the scheduling of generation and demand:** TSO's should set up procedures that ensure schedules of generation and demand are provided before real time. This is required in order to establish the most efficient basis for anticipating real-time Operational Security difficulties.

3.4 Level of Detail

The system operation NCs provide minimum standards and requirements related to system operation. The level of detail matches the purpose of the codes: harmonising security principles, clarifying and harmonising methods, roles and responsibilities of operators and grid users as well as to enable and ensure adequate data exchange in order to future proof the system for integrating innovative technologies and sustainable energy sources, operate the system in a safe, secure, effective and efficient manner and applying the same principles and procedures for different systems to establish a wider level playing field for Market Participants.

In order to achieve the necessary level of European harmonisation, ENTSO-E developed the SO NCs by taking a pan-European that focused on the most widely applicable requirements. This approach allowed at the same time more detailed provisions at the regional/national level where necessary, with the view of drafting Network Codes for electricity system operation that are open for future developments and new applications.

The FG ESO 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 taking into consideration a view of future industry trends, building up a coherent legal mechanism with the appropriate balance between level of detail and flexibility, which focuses on what-to-do, not so much on how-to-do.

Regarding NC OPS, harmonisation principles are handled through a global framework, consisting of three coherently addressed levels:

- **The European wide level** deals with building common data sets, that allow the sharing of data, common analyses and common processes defined for operational planning activities. This data sharing is articulated on common time frames, including common principals for assessing Operational Security referring to the NC OS;
- **The Synchronous Area level** refers to common methodologies for security analysis;
- **The Regional level** groups together areas presenting power flow patterns that influence each other. These areas deal with coordinated planning processes and coordinated Operational Security assessment. Consistency between different regions is ensured under the roof of the two former levels and by implementing a common design for each time frame of the main operational planning processes across regions. As such, the Regional level enforces strong coordination requirements.

With its strong coordination requirements, this three level framework will ensure a pragmatic and efficient harmonisation of operational planning practices as promoted by the FG.ESO.

Regarding methodologies, the approach adopted is to tune the provisions through a global framework giving high level principles and requirements for detailed specifications to be developed out of the code in a transparent process and leaving place to further evolutions and improvements.

3.5 CHALLENGES AND OPPORTUNITIES AHEAD OF SYSTEM OPERATION

Today, in line with the challenging objectives addressed in the FG ESO, 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.

In this context, the future challenges for System Operation, which are addressed in particular in the NC OPS, include:

- effects resulting from fast growth of (volatile) generation from Renewable Energy Sources (RES);
- needs resulting from the evolution (and completion) of the Internal Electricity Market (IEM).

As ENTSO-E means to achieve the integration of RES in the system and the implementation of the IEM, the following opportunities and risks have been identified as relevant for System Operation in a scenario with increasing complexity, where further challenges can be foreseen in the near future due to the new applications and developments on system operation.

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

These different issues are addressed below.

3.5.1 Generation from RES

The challenges of operating the European Transmission System are ever more influenced by the effects of the growing volume of generation from Renewable Energy Sources (RES). The characteristics of RES i.e. variability, intermittency and the challenges of accurate forecasting, cause the following issues for system operational planning:

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- RES increasingly replaces the feed-in from large power plants directly connected to the Transmission System. This leads to less certainty of energy volumes, system flows and to changing system dynamics (due to the different characteristics of RES).
- Over the last few years, RES generation has contributed significantly to the increase in volatility of cross-border power flows, creating new challenges to the requirements of balancing production and consumption.
- The influence of underlying production in distribution Networks leads to forecast complexity for the balances of transfers to/from distribution Networks and thus also for the prediction of load flows in the Transmission System.

These issues lead to concerns about how to maintain a stable system operation in an electricity Network with high penetration of RES. European best practice shows that the answer to this concern is to increase the controllability and the flexibility of all elements of the Transmission System. This in turn leads to a Transmission System which can react and cope better with the volatility of RES.

The NC OPS recognises these increased levels of RES within the European electricity Network in the coming years. This code has been drafted in way that supports this evolution by including several provisions regarding RES handling, particularly in security analysis, in Adequacy assessment and in scheduling.

3.5.2 Internal Electricity Market (IEM)

Cross border trades, daily and intraday, have significantly increased in the recent years, with the corresponding introduction of daily and intraday capacity allocation and the resulting short-term adjustments to the generating capacity of power plants. Due to this fact and in order to comply with the obligations under Regulation (EC) N°714/2009, a short-term update of generation forecasts has become indispensable a reliable system operation can only be established on the basis of reliable input values.

The NC OPS addresses these issues through coordination development through all operational planning processes with a special emphasis on the links with the NC CACM and developing requirements on scheduling.

3.5.3 HVDC, PST and Super Grids

Because of their connection to the pan-European Transmission System, the operation of HVDC-links requires a systematic approach towards their reliability. Therefore, the NC OPS provisions have been drafted in such a way that HVDC infrastructures are included systematically. For example Outage Coordination processes and particularities of HVDC-links operation have been addressed in the Scheduling processes.

Devices as PSTs (Phase-Shifting Transformers) and FACTS (Flexible Alternating Current Transmission Systems) provide TSOs with controllability opportunities because of the ability of PSTs to optimise cross border flows. Therefore TSOs have to coordinate the operation of PSTs ensuring coherent and coordinated power flows. The necessary coordination of PSTs has been addressed in Chapter 3 of the NC OS.

The following coordination measures are included in the NC OPS:

- establishing and using Common Grid Models for the relevant phases of operational planning system operation;

- exchanging and coordinating of relevant information and data between TSOs and between Relevant Grid Users, together with NC OS;

- ensuring the provisions and a firm basis for coordinated control actions of TSOs and Relevant Grid Users, in order to maintain the global and overall view, while allowing at the same time acting locally or regionally to achieve most efficient and effective results maintaining Operational Security.

This provides a robust and reliable framework for the incorporation of Super Grids, the prospected future system that encompasses massive, additional AC-lines and HVDC links enforcements.

3.5.4 Smart Grids and Demand Side Response

Smart grids and Demand Side Response technologies are already becoming a reality. Their development will increase the complexity of system operation, leading to new products, processes and services.

The consequences of their development on system operation will be an important challenge and opportunity in future years. In particular, TSOs will face higher uncertainties during the operational planning phase due to increasing variability of load and generation. There will also be a higher level of distributed facilities and Ancillary Services.

The NC OPS provides requirements and principles to harmoniously accompany this development and to handle some of the issues that will arise in the short term. For instance, the Operational Security Analysis is performed in Year-Ahead and Week-Ahead timeframes on the basis of scenarios. This offers a powerful tool to take into account distributed generation and consumption facilities, and the possible contribution of smart grids and DSR.

In the long term, the principles of operational rules set up by system operation NCs are compatible with the future implementation of such developments. However, beyond a certain level of development, new needs may arise and require the definition of new standards and new processes.

3.6 INTERACTION WITH OTHER NETWORK CODES

The NC OPS is being drafted in parallel with other related Network Codes. Several processes, methodologies and standards provided in NC OPS could be influenced by, or could influence these related Network Codes. ENTSO-E sees the coordination of these interactions as an important objective. The most important interactions with other Network Codes have been dealt within the following way:

- The Network Codes on *System Operation* – these codes consist of the Operational Security NC (NC OS), the Load-Frequency Control and Reserves NC (NC LFCR) and this Network Code (NC OPS). The NC OS is the ‘umbrella’ code of the System Operation Network Codes. It therefore sets the overall principles for system operation, describes data exchanges and reflects on the common issues with the NC LFCR and the NC OPS while these latter two will describe their specific processes in greater detail.

- The connection codes (e.g. NC RfG and NC DCC) establish the technical capabilities of the generation and Demand Units connected to the grid. The NC OPS references to them in those provisions in which information related to technical characteristics is required. The translation of technical capabilities described in connection codes to operational criteria is done in the OS NC.

- The Network Code on Capacity Calculation and Congestion Management (NC CACM) – was developed in advance of the NC OPS, enabling the interfaces between the capacity calculation process and system operation to be identified in the early drafting phase of this code. The following separation has been agreed upon: topics related to the physical operation of the power system are covered by the system operation Network Codes, topics related to the operation of the electricity market are covered by the CACM NC, taking into account the physical risks described in the SO NCs.

- The process required for building and implementing a Common Grid Model (CGM) is shared between the NC CACM and the system operation Network Codes (thus including NC OPS) due to the following reasons:

    - the same CGM before capacity calculation on the different market frameworks is used for the calculation of load-flows in order to carry out Network Security Analysis on the different timeframes of operational planning;

    - during the creation of Individual Grid Models (IGM), NC OPS takes into account updates of several input parameters: e.g. altered availability plans and agreed upon scheduled exchanges, the latter resulting from long term nominations, day-ahead market coupling, intraday activities and TSO cross border activities as described in the scheduling chapter of NC OPS;

    - Day-Ahead and possible Intraday IGMs and CGMs can be both considered as IGMs and CGMs for intraday capacity calculation.

- *Future Network Codes* – NCs on Electricity Balancing (NC EB) and on Forward Capacity Allocation (NC FCA) are being drafted and especially the latter will cover the capacity calculation and allocation in Year-Ahead and month-ahead timeframes; timeframes that are also relevant for activities covered in the NC OPS. The updates of the Year-Ahead CGM, as described in the NC OPS, would trigger a specific security analysis that could lead to updates of planned operational actions to be taken into account in month-ahead capacity calculation processes.

The goal of capacity calculation is to provide a Cross Zonal Capacity. Part of this process (for both the Flow based and NTC Capacity Calculation Approach) is to assess the available margin on all critical branches, based on a CGM (from D-2 to intraday: a single CGM shall be used per timeframe). As the real grid situation will be certainly different than the one anticipated by the capacity calculation, a margin has to be taken into account to cope with uncertainties described in Article 25.2 of NC CACM, to ensure that the calculated Cross Zonal Capacity will most of the time respect Operational Security Limits, in accordance with a target risk level.

The NC OPS also has to assess the capacity of the grid to withstand different events. The better way to consider these different events is to directly model them in the CGMs, by possibly producing various CGMs. Such an approach for capacity calculation is not the preferred one for short term (from D-2 to ID), where a single CGM is used, but will be the one used for long term time frames, since using a single CGM with Reliability Margin would give too rough results or high uncertainty from a system security perspective.

3.7 WORKING WITH STAKEHOLDERS & INVOLVED PARTIES

The legally binding nature of Network Codes, which is achieved through the Comitology process, means that they can have a fundamental bearing on stakeholders' businesses. As such, ENTSO-E recognises the importance of engaging with stakeholders at an early stage, involving all interested parties in the development of the code, in an open and transparent manner.

ENTSO-E's stakeholder involvement comprised of workshops with the DSO Technical Expert Group and 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 functioning of the Transmission System from an operational point of view that arose during the public consultation of the NC RfG, the first ENTSO-E stakeholder workshop on system operation was held on 19th March 2012 in Brussels. The 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 had the opportunity to express feedback and expectations.

In line with suggestions by stakeholders' organizations and following requests by the EC and ACER, ENTSO-E envisaged four workshops for NC OPS with the DSOs Technical Expert Group and with all stakeholders both prior to, during and after the public consultation:

- The aim of the first NC OPS Workshop, held on 23rd May was to present and discuss the scope of the draft NC OPS, which reflected the work completed by TSO experts as of 14 May 2012. The workshop addressed the scope of the Network Code, updated stakeholders on its 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 NC OPS Workshop (25 July 2012) was to present updates made to the Network Code and to present the main content of the first version of this Supporting Document, based on the stakeholders' feedback received in the first NC OPS 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 NC OPS Workshop (21st November 2012) during the public consultation was to present the draft NC OPS for the formal public consultation after updates have been made to the Network Code based on stakeholder feedback received in all workshops. The workshop provided stakeholders with the opportunity to discuss their views on the code and for a Q&A session.
- The aim of the fourth NC OPS Workshop (14th February 2013) after the public consultation was to present the updated NC OPS with a more detailed insight into the important changes resulting from stakeholder comments and suggestions provided during the public consultation. As the primary goals of this workshop were common understanding and maximum transparency, ENTSO-E looked forward to this meeting in order to answer all questions and provide all necessary explanations on an updated draft of the code following the public consultation.

3.8 Involvement of National Regulatory Authorities

The security of the Transmission System is the core business of the TSOs and often requires operational actions to be taken within a very short timeline. In that sense, the responsibility of adopting these measures cannot be shifted to the NRAs as it would otherwise lead to delays in the adoption of the necessary operational measures.

On the other hand, the involvement of the NRAs is foreseen for the approval of certain methodologies, listed in the Network Code (see Article 4). NRAs will thus have the opportunity to control a priori that these methodologies are compliant with the principles of transparency, proportionality and non-discrimination which the TSOs should respect.

NRAs will also always remain competent to act as a dispute settlement authority for any complaint that a party could raise against a TSO or DSO in relation to the TSO's or DSO's obligations.

Finally, the Network Code is without prejudice to the more stringent requirements which could be established in national legislation, as long as these requirements are not in contradiction with the provisions of this Network Code. In that sense, further involvement of the NRAs could be foreseen in national legislation as long as it does not go against the provisions of this Network Code.

3.8.1 NRA's approvals required

Task	Relevant Articles	M1	M2	M3	M4	M5	M6	M7	M8	M9	M10	M11	M12	M13	M14	M15	M16	M17	M18	M19	M20	M21	M22	M23	M24
No later than 12 months after applicability of this Article, TSOs shall have established a methodology standardized at least per Synchronous Area, for Operational Security Analysis	19(1)	TSOs per synchronous area establish												NRAs per synchronous area approve											
No later than 12 months after applicability of this Article, all TSOs shall have established a coordinated methodology, standardised at least per Synchronous Area, for assessing the relevance of Power Generating Modules, Demand Facilities, and grid elements located in a Transmission Network, in a Distribution Network, or in a Closed Distribution Network for the Outage Coordination Process	23(1)	TSOs per synchronous area establish																							
All TSOs shall establish pan-European annual summer and winter Generation Adequacy outlooks before 21 May and 21 November of each calendar year respectively, using a common methodology.	49(1)	All NRAs approve																							

Table 1: Methodologies in NC OPS that require NRAs approval

3.8.2 Applicability of the NC OPS

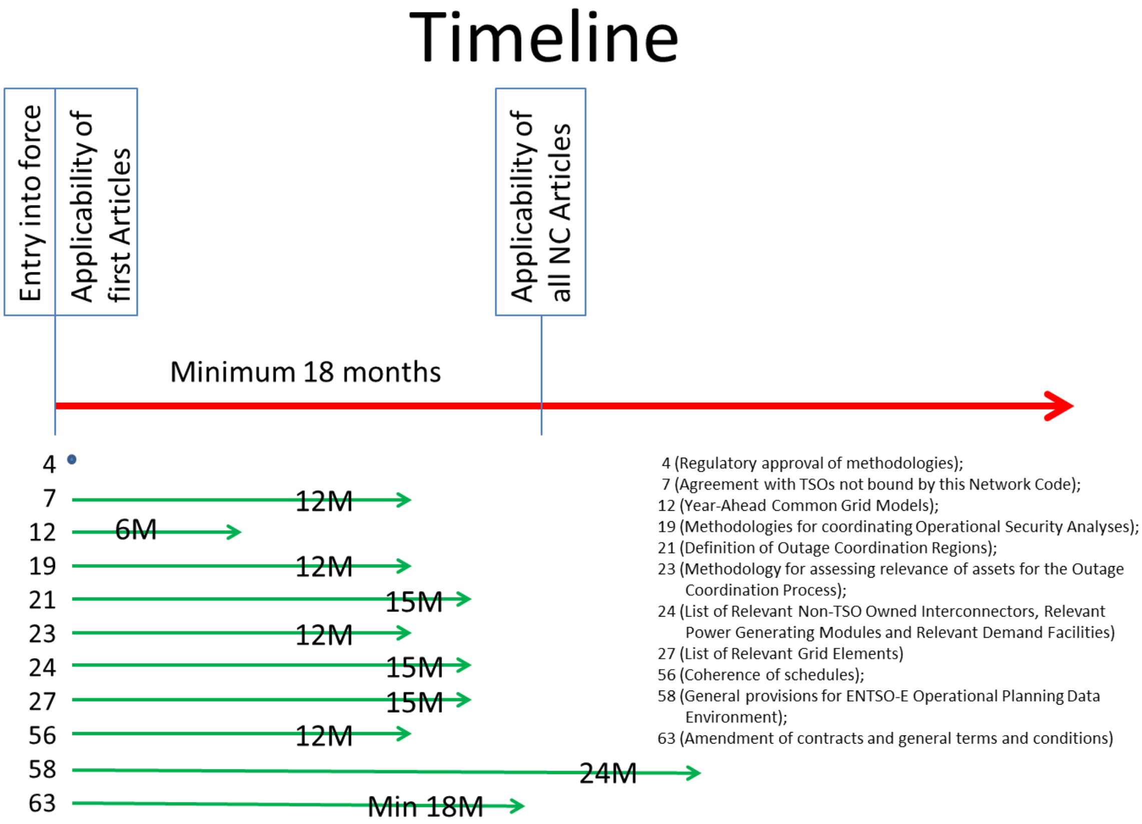

Figure 4: Timeline of NC OPS applicability

Entry into force:
This Network Code shall enter into force on the twentieth day following that of the publication in the Official Journal of the European Union of the Network Code OS, OPS, or LFCR, whichever is the latest. This date of entering into force is chosen to ensure that the three operational Network Codes are entering into force at the same time.

Date of applicability:
The Articles 4, 7, 12, 19, 21, 23, 24, 27, 56, 58 and 63 of the Network Code shall apply as from the date of entry into force.
The remaining Articles shall apply as from a date to be jointly defined with ACER and the European Commission and which should take place at minimum 18 months after the entry into force. The latter date should be the same as the one in the NC OS, to ensure that the three operational Network Codes are applicable at the same date.

Date of implementation:
The Articles 7, 12, 19, 21, 23, 24, 27, 56, 58 of the Network Code establish a time period within which methodologies have to be developed, MLA agreed upon or the ENTSO-E Operational Planning Data Environment has to be developed. These time periods run as from the date of applicability of the articles, which is also the date of entry into force of these articles.

3.8.3 Derogations

The code is in line with the framework guideline and evolution of existing practises does not need derogations.

3.9 BENEFITS OF THE NC OPS

During the process of scoping the objectives and topics to be included in the NC OPS, the objectives and topics defined by the FG ESO have been kept under careful consideration. The NC OPS addresses all activities dealing with the preparation of operation and as expressed in the previous paragraph, opportunity has been taken to strongly improve the coordination between the TSOs on a Pan-European, synchronous area and regional level, from which the following significant benefits are to be expected:

- Developing the same principles in which the best practices are incorporated will result in improving the efficiency of operational planning activities for key areas such as security and Adequacy analysis. This will in particular provide a common base for handling increasing uncertainties at the planning stage due to the strong development of RES and future development of distributed generation.
- Developing common scenarios will create a common basis to investigate the consequences of the different operational conditions the interconnected Transmission System on the security of the system. It will enable TSOs to evaluate the intermittent nature and volatility of RES, as well as to evaluate external parameters such as load level or generation availability in connection with the assessment of the system security. TSOs are able to develop relevant measures to maintain its security level and consequently maximising the output from intermittent generation of RES as facilitating their integration.
- Dealing with an outage coordination process on common time frames and procedures, will allow a coordinated incorporation of all the consequences of Relevant Planned Outages in the planning phase, while taking into account cross border issues. This will lead to less incompatibilities of outages between the different Responsibility Areas and thereby potentially decrease the number of unexpected Constraints leading to security problems, and the need for costly remedial measures.
- During the whole operational planning phase, the sharing of Common Grid Models, coordinated security analysis processes and setting up - when relevant - regional coordination initiatives will allow to develop the use of coordinated curative or preventive Remedial Actions and consequently:
    - maintain the required security level of the interconnected Transmission System while optimizing the cost of these actions;
    - have more opportunity to plan outages by finding new coordinated ways to solve upcoming problems in an early stage;
    - provide the TSO with the possibility to optimize the cross border capacities by reducing the impact of planned outages on the cross border capacities.
- Handling adequacy analysis in a coordinated Pan-European way will allow having more benefits from the different cross border reserves available in the Pan-European system. This analysis will also improve the coordination between TSOs and between TSOs, DSOs and Significant Grid Users (SGU); the detection of inadequacy in the transmission system and the treatment of these situations.
- Developing the coordination between Synchronous Areas for the key processes involved in operational planning activities will also allow fully utilizing the HVDC potential.

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Globally, the benefits mentioned above cover the ability to maintain the high system security standard as it is nowadays and as it is appreciated by European citizens. With these benefits the TSOs lay a robust basis for facing the new energy transition challenges. A quantification of the added values of implementing the requirements of the NC OPS would require complex studies subject to multiple factors and hypothesis that depend strongly on scenarios per region and are subject to numerous fluctuating parameters.

Apart from the beneficial effects described above, the coordinated principles in NC OPS also have positive side effects, such as:

- improved conditions for data collection, handling and exchange;
- provision of a framework for the compatibility of tools;
- optimizing the use of energy resources by enforcing greater cooperation amongst TSOs.

3.10 CONCLUSIONS

A key goal of the NC OPS is to achieve as much as possible harmonised and solid technical framework for Interconnected System operational planning taking into account the rapid growth of the (volatile) Renewable Energy Sources (RES) generation and their impact on system operation. Consequently, the requirements have been designed in order to ensure an operational planning that meets the objectives of a secure Interconnected System operation and the effective development of the IEM.

The requirements set out in the NC OPS are building on a long history of existing common and best practices, lessons learned and operational needs throughout the European Transmission Systems.

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4 NC OPS & FRAMEWORK GUIDELINES COMPLIANCE

This chapter aims to provide a short overview of the requirements of the Framework Guidelines on Electricity System Operation [1] issued by ACER on 2 December 2011.

The Framework Guidelines on Electricity System Operation (FG ESO) focuses on three key challenges, which shall be addressed by four objectives as Figure 5 shows.

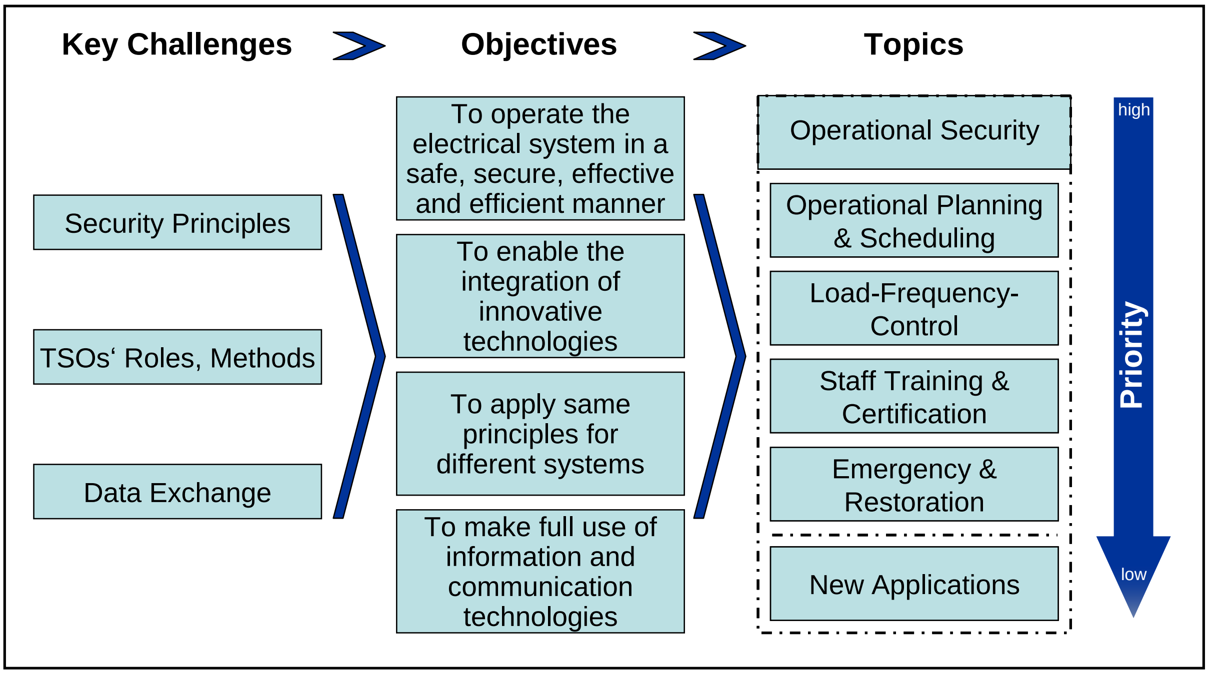

Figure 5: Structure and development flow of the Framework Guidelines on Electricity System Operation

The overall scope and objectives of the FG ESO is *"Achieving and maintaining normal functioning of the power system with a satisfactory level of security and quality of supply, as well as efficient utilisation of infrastructure and resources".* The FG ESO focuses on defining common principles, requirements, standards and procedures within Synchronous Areas throughout EU, especially regarding the roles of and the coordination/information exchange between the TSOs, DSOs and significant grid users.

The requirements described in the NC OPS have been formulated in line with the FG ESO and the new developments on system operation, with the aim to ensure a satisfactory level of Operational Security and an efficient utilisation of the power system and resources by providing a coherent and coordinated preparation of real-time operation.

The FG ESO establishes the following requirements:

1. Performing of security analyses (Contingency Analysis, voltage stability analysis, etc.) at each relevant stage of operational planning;
2. Implementation of State Estimation, as required for supporting the security control and maintaining the Operational Security, including periodical (with sufficiently short time periods) checks in order to ensure a consistent and accurate input data set for other computations like load-flows and security analyses;
3. Prevention and/or remediation of disturbances and blackouts on incidents which can affect neighbouring areas;

4. Scheduling of planned outages and relevant maintenance works of Transmission network, significant generation and DSOs' elements, including a coordinated and agreed (among the affected TSOs) scheduling process for long-term and short-term planning;
5. Ensuring of access to an adequate level of ancillary services (e.g. active and Reactive Power Reserves, balancing power) in real-time to meet security criteria and the requirements set at Synchronous Area level, for each operational planning timeframe;
6. Exchange of Ancillary Services across interconnections in terms of technical principles;
7. Coordination of Reactive Power control with significant cross-border impact;
8. Coordination of short circuit current between TSOs at interconnections;
9. Coordination of commissioning and entering into operation of active and Reactive Power control Network elements with significant cross-border impact. In particular, Reactive Power control elements installed at each end of cross-border lines shall be coordinated;
10. The principle for the different timeframes for exchange of all necessary information between system operators to handle the different planning and scheduling activities in a coordinated and cooperative manner. This includes all necessary data to construct a proper Synchronous Area-wide Common Grid Model;
11. The exchange of up-to-date information among TSOs and significant grid users on the development of grid components and configurations, especially with regards to planned and unplanned outages and technical ability to provide Ancillary Services.

The detailed requirements in the FG ESO are linked to the NC OPS requirements in Appendix 2.

The NC OPS was developed according to the principles defined in the ACER Framework Guidelines on Electricity System Operation of 2 December 2011.

5 NC OPS: EXPLANATION OF REQUIREMENTS

5.1 INTRODUCTION

This chapter aims at providing the reader a basis for understanding the requirements in the NC OPS and is based on the questions and concerns raised by the stakeholders at the workshops held during the NC OPS development process.

5.2 INVOLVEMENT OF NRA

In several topics a description has been included for a consultation or approval process by NRA(s) or ACER. These processes are mostly related to methodologies.

Cross Responsible Area Remedial Action (joint Remedial Actions)

NC CACM and NC OS define and describe all Remedial Actions and establish also the approval of relevant NRAs.

This is the reason why NC OPS is not covering additional (redundant) approval for methodologies or arrangements for establishing Remedial Actions.

Security Analyses Coordination

Performing Operational Security Analysis can only be achieved when TSOs coordinate this activity. Therefore a harmonization of the methodology for an Operational Security analyses in operational planning is foreseen. For this reason both ACER and ENTSO-E are involved: the latter proposing (adaptations to) methodologies and the former providing its opinion on them. It must be stated that it is not strictly necessary to have one pan-European methodology: a harmonised methodology per Synchronous Area is enough because the HVDC connections are limiting the possibility that AC incidents spread out from one synchronous system to another.

Updating Year Ahead Planning Process

The main feature of this important process is coordination between all stakeholders in order to make sure that all outages are aligned, after alterations to the agreed upon year outage plan. TSOs will propose a coordination process; because of the importance that also the other stakeholders (i.e. Relevant Power Generating Module, a Relevant Demand Facility or a Self-Planned Interconnector) are represented on a non-discriminatory basis, it is important that TSO's consult relevant NRAs for this coordination processes.

Pan European System Adequacy Season Ahead

Each TSO must check whether or not it is able to meet its demand via the production in its area and via import possibilities. Therefore a pan-European methodology must be in place, taking into account Transmission capacities for energy exchanges. Because of this, both ENTSO-E and ACER are involved: the latter will be consulted. Also the Stakeholders will be heavily involved by means of workshops, organised when the pan European Methodology is being updated, in which they can submit comments that need to be dealt with by ENTSO-E. The Methodology will be publicly available.

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5.3 INPUT DATA AND SECURITY ANALYSIS

Security analysis is required at relevant stages of the planning process to ensure that system operation is within the normal operating state of the Transmission System and that under n-1 conditions as described in the NC OS the frequency, Fault level, voltage and load flows etc. remain within predefined limits.

This NC OPS details the responsibilities on TSOs for security analysis, the levels of harmonisation required at the various stages, the framework for the grid modelling and the requirements for data exchange.

The first part of the security analysis chapter describes the principles for constructing and exchanging all necessary information between system operators to perform the necessary security analysis at the relevant timeframes as well as, when applicable, input data for capacity calculation processes.

The second part of the chapter describes provisions for security analysis in the different timescales (Year-Ahead, Day-Ahead, etc.) to be carried out by each TSO in a coordinated way and describes the general provisions for co-ordination of security analysis and Remedial Actions.

Timeframes contemplated have been the ones in which operational planning activities, other than capacity calculation, are carried out: Year-Ahead (Adequacy outlook, yearly outage plan) and its updates, Week-Ahead (typical timeframe for outages programming), Day-Ahead and Intraday.

The main objectives of the Chapter 2 and 3 are to detail:

- The requirements for data exchange, as with other parts of the NC OPS accurate and timely provisions of data is of the utmost importance.
  - Provisions to ensure pan-European harmonisation, with the construction and update of Year-Ahead Common Grid Models for the whole pan-European system, based on harmonised scenarios.
  - Provision of day-ahead and intraday Individual Grid Models, allowing harmonisation at least at Synchronous Area level as well as regional merging, when necessary, will include meaningful data from the market, predictions of uncertainties and results of scheduling activities performed by TSOs in order to ensure the accurate data needed to perform security analysis.
  - Regarding uncertainties:
    - IGMs should contain updated information on load and generation, differentiated per primary energy source.
    - TSOs shall assess uncertainties in load and renewable energy generation in accordance with established methodologies (Article 19), standardised at least per Synchronous Area.
- The requirements for performing security analysis, in line with methodologies standardised at least at Synchronous Area level, at each relevant stage of Operational planning, ensuring that the system operation meets security criteria under simulated operating conditions and the secure energy exchange between different Reponsibility Areas.
- Requirements for ensuring the coordination in operational planning, including contingencies, Constraints evaluation, Remedial Actions, covering Reactive Power control and short circuit coordination.

The majority of requirements in this topic are building upon existing best practices and lessons learned: data exchange and day-ahead congestion forecast models have already been developed and built in Continental Europe and that experience will be beneficial when developing the models described in this Network Code.

The integration of renewable energies and the assessment of the uncertainties associated with them which is detailed in this Network Code also builds on existing best practice and lessons learned. Existing practices in several areas, based on a combination of the establishment of appropriate requirements for renewable generation, together with the centralised and real time update of its forecasted production and the capability to be controlled, have demonstrate their efficiency.

The new and enhanced requirements under this topic in the NC OPS are:

- The procedures for constructing pan-European Year-Ahead Common Grid Models and relevant information.
- Improvement of quality of data used to construct the grid models, including specific attention to forecast of renewable energy production and distributed generation.
- Methodologies standardising the principles for Operational Security Analysis at least at Synchronous Area level (nevertheless Operational Handbooks do already exist in each Synchronous Area).

The NC OPS is compliant with the requirements placed on it by the FG ESO. It is to be mentioned that the basis for the determination of the harmonised methodology to calculate the necessary Reliability Margin to cope with uncertainties relevant to the system operation is not here developed, since all provisions for calculating Reliability Margin have been described in the NC CACM. Reliability Margin is related only to the capacity calculation and for allocation of capacities to the market. Security analysis is done within Operational Security Limits.

NRA approval has been provided for methodologies in those topics that required it, in particular:

- Principles of the coordination process to ensure the Availability Status of Relevant Assets in case of Forced Outages pursuant to Article 45(1).
- The methodology for establishing summer and winter Generation Adequacy outlooks pursuant to Article 49.
- The methodology set up pursuant to Article 19 for coordinating Operational Security Analysis.
- The methodology established pursuant to Article 23 for determining Relevant Assets for the Outage Coordination Process.

5.4 OUTAGE PLANNING

To prepare operation of the electricity grid, outages of Grid Elements, Power Generating Modules and Demand Facilities have to be planned. This chapter provides a common European framework to perform these planning activities with harmonized deadlines, data exchanges and coordination requirements.

5.4.1 Reasons for Coordinated Outage Planning Process

The Outage Coordination Process is all about coordinating the availabilities as well as the unavailability and testing periods of all elements that interact with the interconnected electricity system, including Power Generating Modules, Demand Facilities and Grid Elements alike; and that have a significant impact on cross-border operation of the Transmission Systems.

The need for such a coordinated process is mainly driven by three facts:

- The assets of which the Availability Status is coordinated do not belong to (are operated, planned or managed by) a single party. As a result of the unbundling, System Operators are separated from Power Generating Modules and Demand Facilities. Also the playing field of

Power Generating Modules is more and more dispersed with a multitude of companies owning sometimes only one or a few of physical generation assets, rendering the planning of the Availability Statuses more complex, and making extensive coordination between parties a necessity;

- A secure operation of the grid, hereby limiting the Constraints on renewable generation and market operation is only possible if the Availability Statuses are carefully coordinated. Both ensuring generation Adequacy and keeping the system within Operational Security Limits are crucial to avoid large-scale disturbances of the electricity system;
  Additionally specifically for the Network Codes, the Cross-Border issue arises. All involved parties are not located within the borders of one member state, but impact between parties located in multiple (two or even more) is present, especially for the Relevant Assets for which the Outage Coordination Process is established.

Some examples to illustrate the importance of coordination:

- For generation Adequacy reasons on a national or supra-national scale, it is necessary that a certain amount of Power Generating Modules are available for operation. Or in other words: not all Power Generating Modules can be unavailable at the same time. As these Power Generating Modules are possibly managed by different parties, a coordination process is necessary, as well as some commitment to the communicated plans (see below);
- In several situations, maintenance of certain Relevant Assets can only be executed while another Relevant Assets (managed by a different party) has a specific Unavailability Status (mostly unavailable, but can also be available);
- Due to the increasing amount of intermittent generation in the grids, and the consequently lowering level of inertia, it can be necessary for dynamic stability of the electricity system to have a minimal number of Power Generating Modules of a certain type available.

5.4.2 Most frequently arising levels of interaction between different parties

Different types of interaction between the Availability Statuses of Relevant Assets are possible. ENTSO-E will describe the most frequent interactions, dividing them into four main categories:

- generation Adequacy issues;
- (firmness of) cross-border exchange capacities;
- Operational Security issues not linked to the Availability Status of Relevant Grid Elements; and
- Operational Security issues linked to the Availability Status of Relevant Grid Elements.

5.4.2.1 GENERATION ADEQUACY ISSUES

The global level of generation Adequacy within a Responsibility Area is mainly governed by three variables affected by planned Availability Statuses:

- the number of Power Generating Modules that are unavailable;
- the number of Demand Facilities that are available;
- the cross-border capacities to exchange energy with other Responsibility Areas (which can be linked to the Availability Status of all Relevant Assets).

As it is a task of the TSO to detect potential generation Adequacy problems – preferably well ahead of real-time – and report these to the other TSOs, NRAs and market parties, the TSO needs at least to have a view on the most recent Availability Status information to perform these generation Adequacy assessments.

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5.4.2.2 Cross-border exchange capacities

On several time horizons cross-border exchange capacities are determined by the TSOs. These TSOs envision two main goals when executing this process:

- ensuring an adequate level of cross-border exchange capacities, thereby limiting the congestion experienced by the market; and
- determining beforehand a level of the cross-border exchange capacities that will be given to the market e.g. in Day-Ahead. (in other words limiting fluctuations of cross-border exchange capacities as much as possible).

As these cross-border exchange capacities are strongly linked with the Availability Status of Relevant Assets, for determining them a good view on these Availability Statuses is indispensable, as well as a certain level of stability of these planned Availability Statuses in time.

5.4.2.3 Operational Security issues not linked to Relevant Grid Element outages

The third main categories are problems with Operational Security without impact from the Availability Status of one or more Relevant Grid Elements. These issues are mostly linked to the **unavailability** of a Power Generating Module or the availability of a Demand Facility but the opposite could - however being rare - also be possible.

Examples of such issues are:

- multiple Power Generating Module unavailabilities in the same electrical region lead to structural overloads on Grid Elements feeding into this region;
- high renewables feed-in combined with low classical generation availability leads to a low level of inertia in the system, leading to issues with dynamic stability.

In the operational environment (medium to short term) these issues can only be solved by having more available Power Generating Modules (or sometimes less available Demand Facilities).

5.4.2.4 Operational Security issues linked to Relevant Grid Element outages

These issues are very similar to the previous category, except for the interaction with the planned Availability Status of Relevant Grid Elements. For solving these issues, next to Power Generating Modules or Demand Facilities adapting their Availability Statuses, the possibility of shifting/cancelling Grid Element outages is also available.

The same examples as in the previous section can apply here. However, in this category the situation where issues are linked with the available status of a Power Generating Module is much more likely: for planning a specific Relevant Grid Element, the unavailable status of a Power Generating Module can be necessary, and vice versa.

The solution to these issues is highly dependent on the specific nature of the problem and the circumstances which caused the issue. In general adapting the Availability Status of one or more Relevant Assets that caused the Outage Incompatibility solves the issues.

5.4.3 Commitment to a coordinated Availability Plan

As different parties are involved in this Outage Coordination Process, and decisions of one party might very well impact the feasibility of the Availability Plan of one or more other parties, some commitment to a coordinated Availability Plan is necessary. To allow all parties to organize their works, contract third parties, etc. they should know when to thrust that their envisioned planning for their own Relevant Assets is feasible, and can be executed with high probability. This reasoning holds for Generation owners, Demand Facility Owners and Grid Element owners alike.

Also, for enabling a good estimation of the TSO on the generation Adequacy of the pan-European system, as well as a good estimation/determination of cross-border exchange capacities, a certain level of stability of the Availability Plan is needed.

This need brings about two specific characteristics that should hold for the coordinated Availability Plans:

- At any point in time, the ensemble of coordinated Availability Plans should represent a feasible provisional situation. In other words, at every time point within the planning horizon, having Outage Incompatibilities in the coordinated Availability Plans has to be avoided; and
- When any party changes the Availability Plan for its Relevant Assets, a potential Outage Incompatibility can arise with the Availability Plans of other parties, and therefore a coordination process handling these changes is necessary.

5.4.4 Goals of this Network Code

The Network Code enforces:

- starting from Year-Ahead, and up to real-time, at every point in time having a common coordinated Availability Plan that is feasible for execution according to the best estimates of each party;
- coordination between parties (TSOs, DSOs and Outage Planning Agents) whenever Outage Incompatibilities have to be resolved, and this in a symmetrical and reciprocal way.

The Network Code does not envision to change current (and very different) best practices installed in the different systems. The way of coordinating, making decisions and possibly financially compensating parties is determined within the national regulatory framework.

5.4.5 Organization of Outage Coordination in the NC OPS

5.4.5.1 AN EU-WIDE HARMONIZED OUTAGE COORDINATION PROCESS

The general framework of the described Outage Coordination Process is based upon the current best practices installed in the EU.

The Outage Coordination Process as described is standardized EU-wide, with the same deadlines, data provision requirements and roles and responsibilities for every relevant party operating in the EU. To allow an efficient execution of the Year-Ahead process, at a Synchronous Area level, the deadlines of the process can be adjusted if there is no impact on the coordination process for other areas, and after approval of all relevant NRA’s.

A division into Outage Coordination Regions is made to organize the practical execution of the coordination processes. These Outage Coordination Regions are constructed to reflect clusters of systems with large mutual impact. In the situations where this is necessary, coordination between different Outage Coordination Regions is enforced. This division into Outage Coordination Regions is a current practice, and the currently used regions can therefore serve as a good basis for defining the

Outage Coordination Regions. The introduction of this Network Code however presents an opportunity for the TSOs to reconsider and optimize the definition of these Outage Coordination Regions.

It is worth noticing that the definition of Outage Coordination Regions is mainly guided from a practical point of view, to ensure efficiency of the Outage Coordination Process. It is therefore recognized to have no direct market impact, which justifies them being defined by the TSOs, and published for information to the general public.

Some of the existing Outage Coordination Regions are:

- TenneT NL, TenneT DE, Amprion, TransNetBW, Swissgrid, RTE, Elia, Creos, APG
- APG, MAVIR, SEPS, CEPS
- APG, Terna, MAVIR, HEP, ELES, BIH, SERBIA
- RTE, Swissgrid, Terna, APG, ELES
- PSE-O, 50 HzT, CEPS, SEPS, TenneT DE
- MAVIR, SEPS, Transelectrica (RO), Ukraine
- MAVIR, Bosnia, Serbia, Macedonia, Bulgaria, Greece, Albania, Turkey
- Energinet.dk, Fingrid OyJ, Statnett SF, Affärsverket svenska kraftnät

5.4.5.2 Timings of the Outage Coordination Process

The timings defined in this Network Code are based on current best practices as well as information requirements for different processes and assessments.

First, a point in time has to be defined when a first Availability Plan, coordinated between all parties, and assessed by all on its feasibility is established. An important trade-off has to be made here: the later this time point is set, the more and better information is available to all parties. However, as a view on these Availability Plans and their feasibility is necessary for executing several tasks (generation Adequacy assessments, cross-border exchange capacity calculations), for contracting third parties, and to serve as a basis for planning all other, non-Relevant Assets.

As in most systems, some kind of Year-Ahead coordination process is already established (e.g. in continental Europe an extensive Year-Ahead Outage Coordination Process already exists today), the Network Code also refers to this horizon for establishing a feasible starting point. After this Year-Ahead phase, a continuous process of updating and assessing the feasibility of the coordinated Availability Plans is introduced, to allow for a maximal flexibility of planning the Availability Status of Relevant Assets.

In this Year-Ahead coordination process, deadlines are set to ensure that relevant information on the Availability Status of Relevant Assets is available when it is needed for linked processes (for example Security Analysis, System Adequacy assessment and Capacity Calculation).

The sequence of tasks that are to be performed in the Year-Ahead coordination process, and that determine the time flow and deadlines of this process are depicted in the scheme below. Important to note is that the coordination process between all parties is very much condensed in this diagram to avoid unnecessary clutter and to focus on the time flow of the process.

The main driver for the deadlines set for the different tasks are the preliminary outage plans which need to be available at the beginning of September to be used as an input for the pan-European generation Adequacy assessment and for long-term Capacity Calculations.

Some deadlines reported in figure below are not reflected as requirements in the code and serve simply as an indication for the time flow of the process.

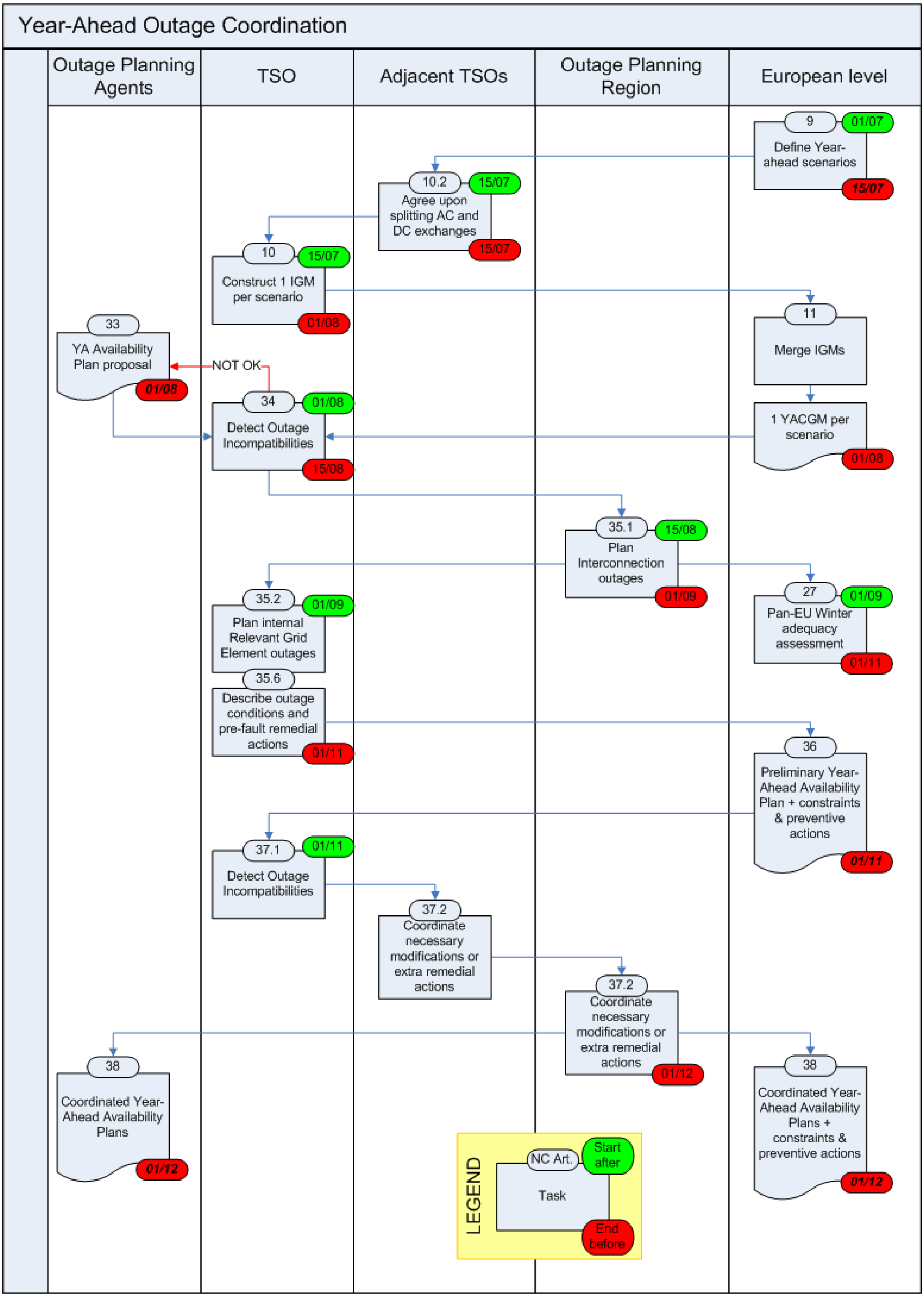

Figure 6: Condensed view on the Year-Ahead coordination process, focusing on the time flow and data links

5.4.5.3 Long-term Availability Plans

An additional phase in the coordination process has been established between three years ahead of real-time and the Year-Ahead process. As the Transparency Regulation requires all parties to publish information on their long-term Availability Plans, a process is envisioned where the TSO assesses these long-term plans on their feasibility, and can report in a transparent way to the impacted parties on potential difficulties regarding Operational Security.

As this is a purely informational process, every party can – if it wishes to – take this indicative assessment provided by the TSO into account when establishing its long-term Availability Plans.

5.4.5.4 The Year-Ahead outage coordination phase

To illustrate the Year-Ahead outage coordination described in Articles 35 to 39 of the Network Code, below a flowchart giving an overview of the coordination process is included.

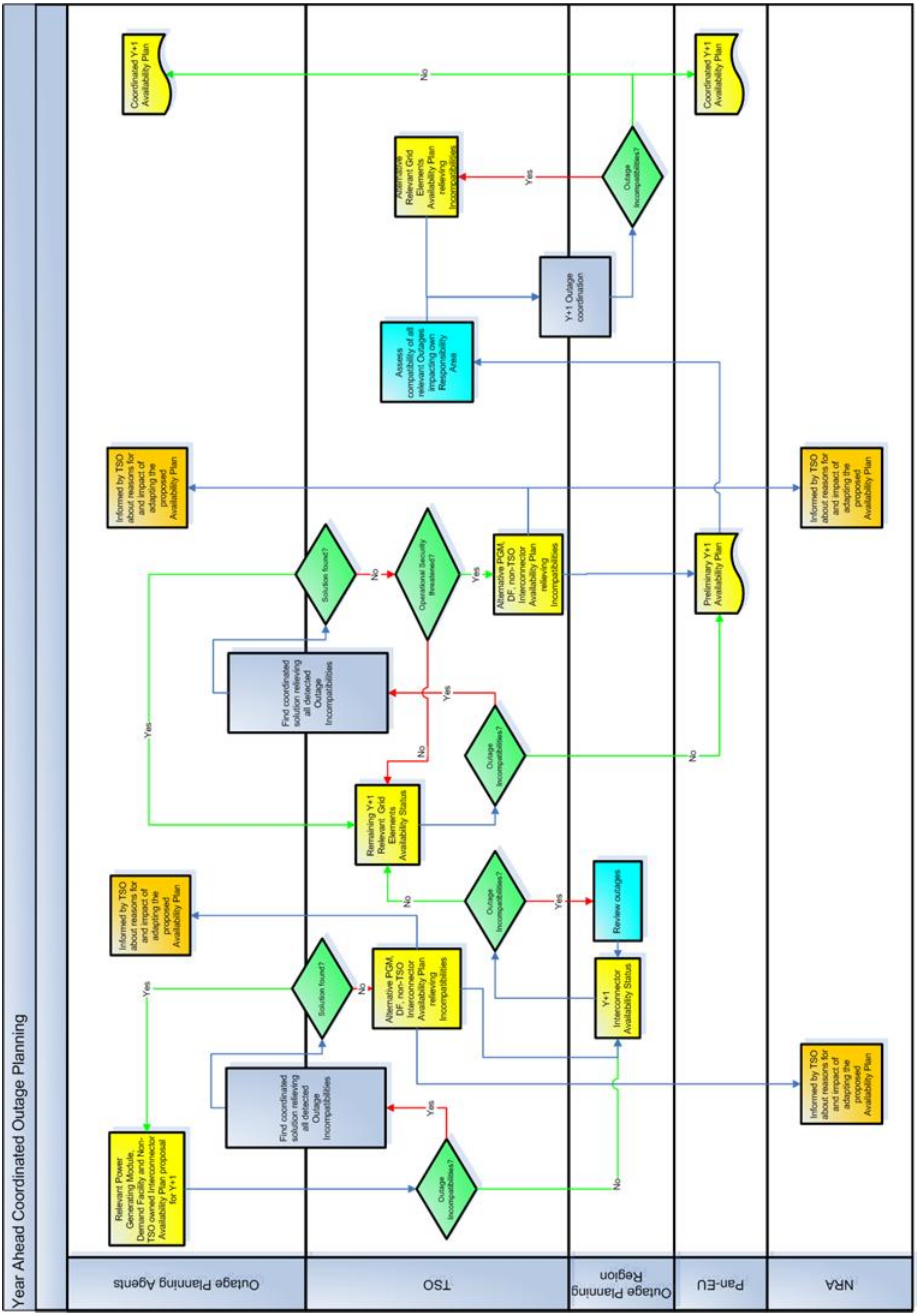

Figure 7: Overview of the Year-Ahead outage coordination phase

5.4.5.5 UPDATES TO THE YEAR-AHEAD AVAILABILITY PLAN

Article 41 of the Network Code describes how all parties can initiate a change to the coordinated Availability Plan. To clarify the described procedure Figure 8 and Figure 9 below present the procedure to be followed as a flowchart, for respectively changes initiated by an Outage Planning Agent, and changes initiated by a TSO.

Important to stress here is the meaning of the coordination process to be initiated when Outage Incompatibilities are detected. The exact implementation of this process is not described in this Network Code. This is done on purpose to allow the current best practices installed in the different systems to be honoured. To this end, Article 40 makes a specific reference to the applicable legal framework for elaborating this coordination process.

As an illustration, in the coordination process, it could happen that in order to allow accepting the initial change request, the Availability Plan of other parties must be modified. According to national legislation, bilateral contracts or any other agreed upon mechanism, this could lead to financial compensation from the change initiating party to the changing parties. This Network Code therefore does not oblige nor forbid the instalment of this kind of mechanism, and leaves it open to be regionally or nationally decided.

What is however enforced by this Network Code is that after this coordination process, a feasible coordinated Availability Plan must be achieved.

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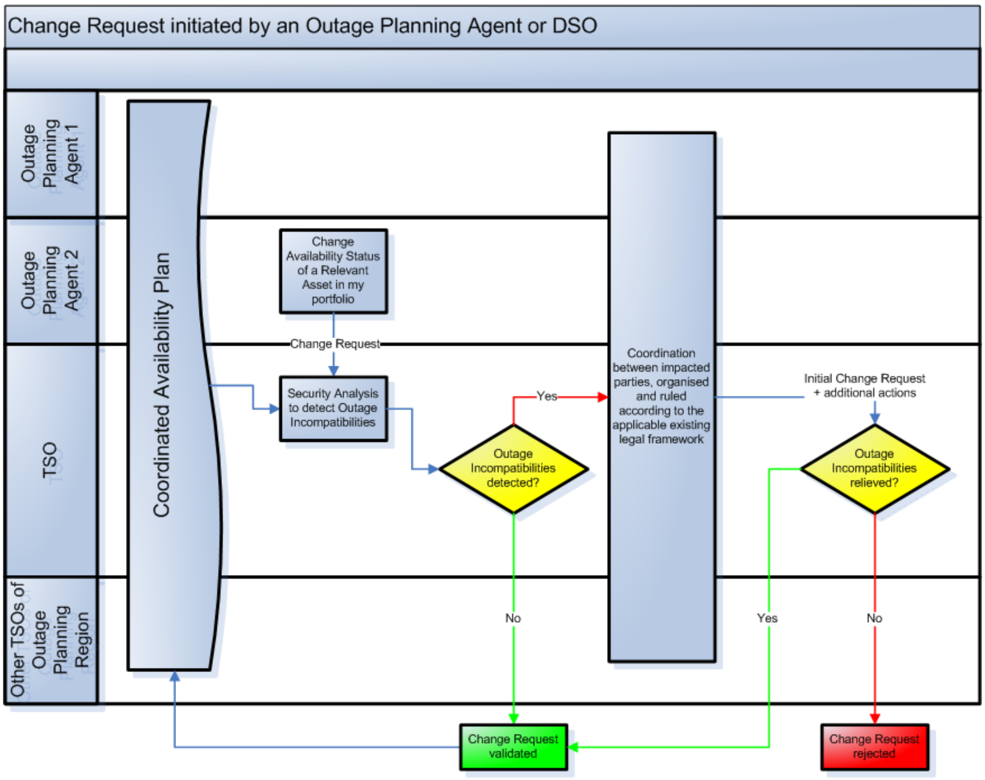


Figure 8: Update procedure for a change initiated by an Outage Planning Agent or DSO

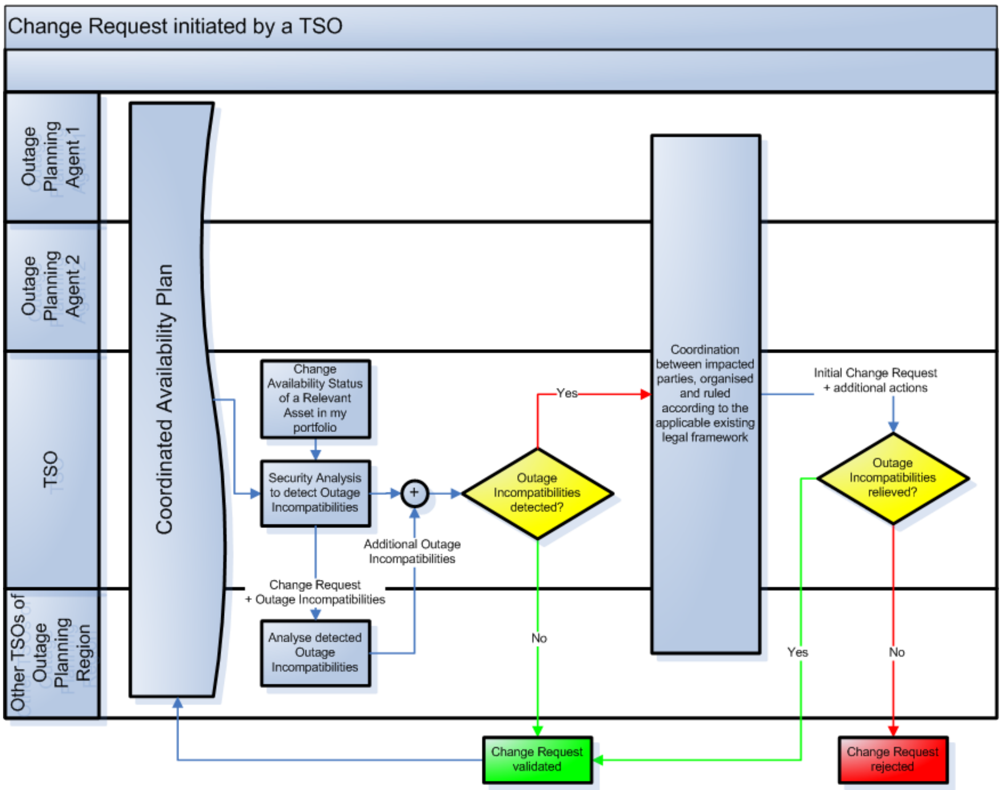


Figure 9: Update procedure for a change initiated by a TSO.

5.4.6 Availability of information

Relevant information is shared between TSOs not only on a regional level, but on the EU-wide scale through the means of an ENTSO-E Operational Planning Data Environment. Every TSO is obliged to put and update its data (regarding Availability Plans and other information necessary for Security Analysis and coordination) under a common format on this environment, where it is accessible by all EU TSOs (and RSCIs operating within this area). This principle allows a TSO to filter the data that is deemed relevant for its purpose, with the access to the full EU-wide dataset if desired.

Currently no such single centralized data environment exists for sharing relevant information concerning Availability Plans between TSOs. Having such a data environment should greatly ease and stimulate collaboration and coordination between TSOs, provides an environment where needed information can be found on request, and enforces TSOs in using common data formats, common timelines and – to a certain level – common methodologies.

5.4.7 Links with other Network Codes

The Outage Coordination Process – or more in particular the results thereof – support the real-time operation of the grid, and is therefore implicitly linked with all system operation NCs. A direct link with the NC CACM and the NC FCA can also be distinguished, as the Availability Status or Relevant Assets is a key factor in the determination of cross-border exchange capacities.

5.5 ADEQUACY

5.5.1 Introduction

Adequacy, the ability of Generation connected to an area to meet the demand of this area, deals with the ability of a power system to supply the demand in all the steady states that the power system may face. It is a function of the Topology of the grid as well as the Generation and demand both directly and indirectly connected to it. Both the situation where there is a lack of Generation within an area to meet the demand and the situation where there is an excess of Generation within an area that cannot reach demanding parties elsewhere, can be considered as situations in which Adequacy is not fulfilled. Adequacy can be assessed for any area, but within the NC OPS analyses are being done only on the level of the Responsibility Area, and on pan-European level.

Coordinated Adequacy analyses are already taking place on pan-European level. TSOs perform these analyses every two years within the framework of the TYNDP and twice a year in order to establish summer and winter Generation Adequacy outlooks, in line with Article 8 of Regulation (EC) N° 714/2009.

Especially with the introduction of more RES into the system and with the occurrence of larger fluctuations in Generation, demand, and cross border flows, it becomes more and more important to assess and forecast Adequacy. These problems can be detected when they present themselves, and the possibility of being caught unaware is limited.

For that reason the NC OPS sets out requirements for TSOs, asking them to perform regular Adequacy analyses. The requirements are based upon the pan-European summer and winter Generation Adequacy outlooks adopted by ENTSO-E in accordance with Article 8(3) of Regulation (EC) N° 714/2009 and upon existing best practices of bilateral coordination. The NC OPS also requires approval by all National Regulatory Authorities of the pan-European methodology used to perform the summer and winter Generation Adequacy outlooks. Aside from the summer and winter

Generation Adequacy outlooks, there are two other types of Adequacy analyses NC OPS requires TSOs to perform on their Responsibility Area, as will be explained in more detail below.

There are no requirements in addition to what is asked of stakeholders elsewhere in regards to the exchange of information in relation to the Adequacy analyses. Analyses on different timeframes use different information, which is provided in part through the NC OS, in part through the transparency guidelines, and in part through other parts of the NC OPS.

5.5.2 Summer and winter Generation Adequacy outlooks

In accordance with Article 8(3) of Regulation (EC) N°714/2009, ENTSO-E must adapt summer and winter Generation Adequacy outlooks. These Adequacy outlooks are harmonized on a Community level, and they are established by all TSOs through a methodology that is based around a shared set of scenarios.

Figure 10 shows schematically how Adequacy is currently being assessed to produce the summer and winter Generation Adequacy outlooks. It includes the terms currently in use, which may not be the same as terms used in the NC OPS. When the NC OPS comes into force, this methodology, or an updated version of it, will have to be approved by National Regulatory Authorities.

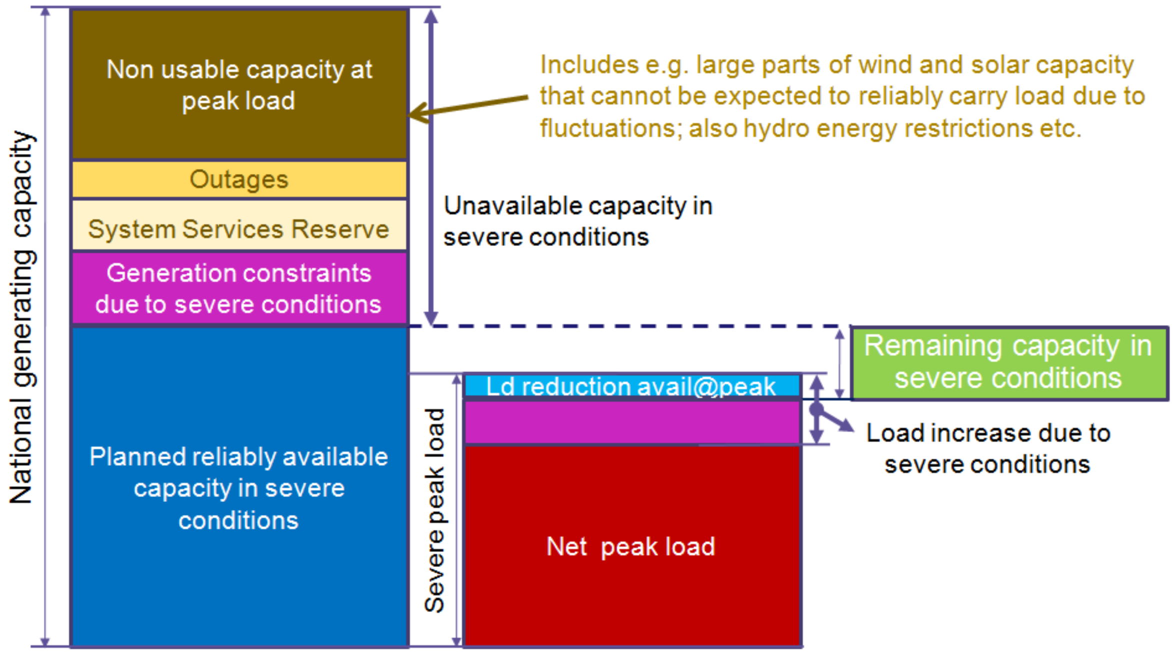


Figure 10: Assessing Adequacy

The current methodology assesses Adequacy using a deterministic method. The methodology is first applied to a situation referred to as “normal conditions”. The Net Generating Capacity of each country is determined under these conditions. For thermal plants "normal conditions" means average external conditions (weather, climate...) and full availability of fuels. For hydro and wind units, "normal conditions" refer to the usual maximum availability of primary energies, i.e. optimum water or wind conditions.

Aside from normal conditions, severe demand and generation conditions are also taken into account within the pan-European summer and winter Generation Adequacy outlooks. Severe conditions are related to what each TSO would expect under a one-in-ten-year scenario. These severe conditions could for instance arise at low temperatures and extreme weather, resulting in higher than usual demand and reduced generation output.

Under these sets of conditions the national generating capacity, the reliably available capacity, and the peak demand are determined for each individual country. The remaining capacity, as shown in Figure 10, is then determined.

Not only demand and generation are important in Adequacy analyses. Cross border capacities also play their role. Within the current methodology, they are taken into account in two different scenarios in order to come to the pan-European summer and winter Generation Adequacy outlooks:

- The first scenario is a copperplate scenario, which assumes there is an unlimited exchange capacity between countries. In this scenario all individual remaining capacities are simply added, and when the result is greater than zero, theoretically enough power is available in Europe to cover the needs of each country. Using this scenario the only thing that can be detected is a generation deficit on pan-European level.
- In the second scenario the exchange capacity between countries is not unlimited. The bilateral exchanges must respect the given NTC values, and the total simultaneous import and export should be lower than or equal to the given limits.

More details on the current methodology used to establish summer and winter Generation Adequacy outlooks can be found on the ENTSO-E website.

In order to perform this summer and winter Generation Adequacy outlooks, the TSOs make use of several different types of data. They use the Availability Statuses of Power Generating Modules, Demand Facilities, and grid elements that are available to them. For units larger than 100MW this information is delivered to them through the Transparency Guideline. For Relevant Assets this information is available to them in line with the chapter on Outage Coordination. The TSOs also make use of their knowledge of Generation capacities, in line with the requirements on generators as established in the NC RfG and of DSR in line with the NC DCC. This should not be taken as purely static information, as the availability of for instance solar and wind energy requires the use of weather forecast to estimate actual capacities.

Finally cross border capacities are needed. In the future it makes sense for cross border capacities to be evaluated in line with the capacity calculations that will be performed in the framework of FCA. However, this includes the caveat that, if capacities will be assessed through NC FCA as Cross Zonal Capacities, they will not always coincide with the cross border capacities based on the available capacity between different countries that are used for the summer and winter Generation Adequacy outlooks. However, the cross border capacities used should not be inconsistent with the capacities calculated through the NC FCA.

The summer and winter Generation Adequacy outlooks will be adopted and published by ENTSO-E. Whenever a situation is detected within a responsibility area where Adequacy is not fulfilled, affected stakeholders and DSOs will be informed.

5.5.3 Responsibility Area Adequacy analyses

Aside from the summer and winter Generation Adequacy outlooks, NC OPS also requires TSOs to perform regular Adequacy analyses within their Responsibility Area. These Responsibility Area Adequacy analyses are connected to the pan-European outlooks and can be seen as updates to them, and they are performed whenever the TSOs detect changes to generation, demand or cross border capacities that they believe to be significant in light of maintaining Adequacy.

TSOs will monitor changes to generation and demand in order to be able to detect significant changes that could lead to a reassessment of Adequacy. These significant changes could for example include the unexpected closure of a large nuclear power plant. For these updates TSOs will make use of the information available to them in relation to cross border capacities, demand including DSR in line with the NC DCC, and generation in line with the NC RfG.

Monitoring these changes and performing updates Adequacy analyses is a new requirement for TSOs. Part of its added value is the fact that when a situation is detected in which Adequacy is not fulfilled, affected parties will be informed not only of the existence of the situation, but also of its causes as detected by the TSO.

5.5.4 D-1 and intraday Adequacy analyses

Aside from the Adequacy forecasts performed by TSOs, Adequacy analyses also take place within the D-1 and intraday timeframes. For these Responsibility Area Adequacy analyses, TSOs shall make use of the D-1 and intraday data provided to them in the framework of the NC OS, as well as information on Market Participant Schedules provided to them through national legislation according to the requirements detailed within the Scheduling chapter of the NC OPS. Forecasts are used in order to assess weather conditions. Whenever a situation is detected in which Adequacy is not fulfilled, National Regulatory Authorities and affected market parties and DSOs will be informed immediately, and will be provided with an analysis of the causes as soon as is reasonably practicable.

5.6 ANCILLARY SERVICES

Ancillary Services are services provided by grid users to the TSO. In the NC OPS Ancillary Services refers to Active Power, Reactive Power and black start. The first two Ancillary Services enable the TSO to operate a secure and reliable power system, whereas the last enables the TSO to reset the system after a Fault. Focus is on active and Reactive Power, since black start will be included in more detail in emergency code.

In managing the Transmission Systems, the TSOs must be able to deal with unexpected changes of generation capacity, Interconnector flows or system demand. This is accomplished by maintaining a prudent level of Active Power Ancillary Services. The OPS NC puts the responsibility on the TSOs to ensure the correct procurement and management systems are put in place to ensure adequate/correct Ancillary Services.

The correct levels of Active Power Ancillary Services are set by calculations within the NC LFCR. The NC OPS recognizes the need to plan ahead to ensure the correct levels of Active Power Ancillary Services will be available once real time is reached. Updates to this plan will be required for any significant network or generation changes that impact on Operational Security. If when updating the plan a shortfall is detected, Remedial Action shall be taken. The NC OPS recognizes that if a TSO finds itself in a shortfall position (after Remedial Actions have been investigated), communication and cooperation with neighbouring TSOs is a priority.

For Reactive Power, the TSOs must maintain a voltage balance across the Transmission Systems in order to maintain a secure and stable power system and to avoid damage to connected equipment. To maintain the balance, the appropriate level of Reactive Power (leading and lagging) is required at appropriate locations in the Transmission System. The required level of Reactive Power varies in the operational timeframe. Reactive power is mainly provided by generator units and Transmission assets.

Generally, Reactive Power must be provided close to the location where it is needed. Overall, therefore, the requirement is for the flexible provision of Reactive Power at appropriate points across the Transmission Systems. The OPS NC developed requirements including relevant security analyses to ensure the correct level and location of Reactive Power Ancillary Services.

The NC OPS also recognizes that within the heavily interconnected networks of the EU, system operation is no longer a national issue. Secure and efficient system operation demands cross-border and cross-control area coordination. Hence, there is a need to share information on Ancillary Services across Interconnectors in the planning phase to ensure that everything reasonably practical has been done to ensure both Operational Security and an economically sound outcome.

The NC OPS does not cover the procurement of Ancillary Services, which will be dealt with in detail within other codes (market codes).

The code is applicable in all areas due to the high harmonization level.

The section adds general requirements concerning cross-border coordination of Ancillary Services in order to facilitate closer collaboration TSO-to-TSO.

Closer collaboration enables a more efficient and economic system operation, meaning maintaining the same system security at lower costs. This also future-proofs the system, making sure a high amounts of renewables can be integrated in the system to lowest possible costs.

The Ancillary Services section of NC OPS is closely linked to NC LFCR and NC EB.

5.7 Scheduling

Schedules are a tool for the TSO for planning system operation after market closure before real time. Schedules are agreed plans from generation and consumption units as well as internal and external commercial exchanges and exchanges between TSOs. Schedules provide the necessary information for the TSO to operate and balance the system as well to carry out security analysis. All Schedules in a Scheduling Area should sum up to zero within a time period to keep the system in balance, if no Faults occur and both consumption and production will be equal to the prognosis. This enables the TSO to balance its system in real time with a minimum level of reserves for balancing, compared to the extensive level of reserves necessary if no schedules are available.

Figure 11 shows the relations between Scheduling Area, Responsibility Area and Bidding Zone:

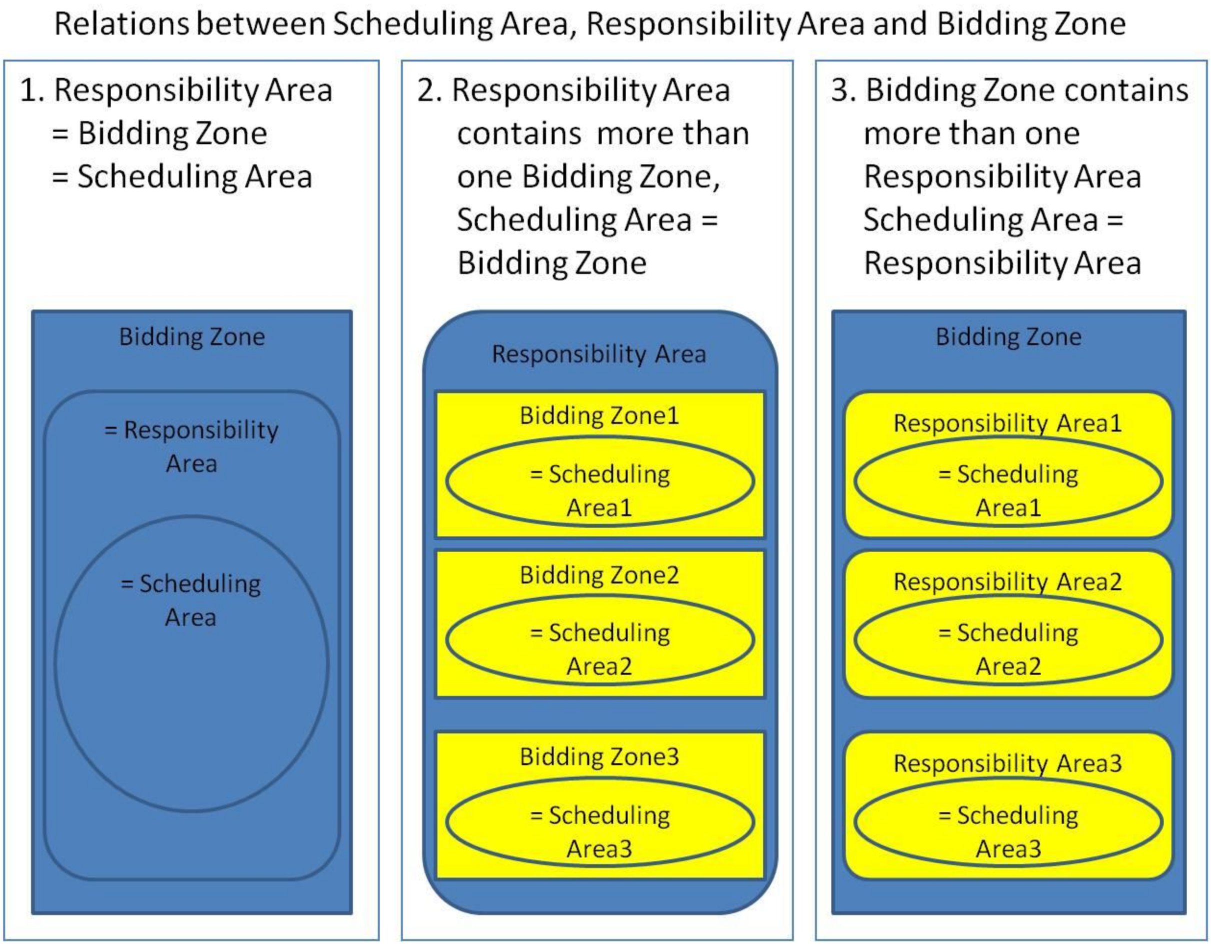


Figure 11: Relation between Scheduling Area, Responsibility Area and Bidding zone

Scheme of available schedules is given bellow:

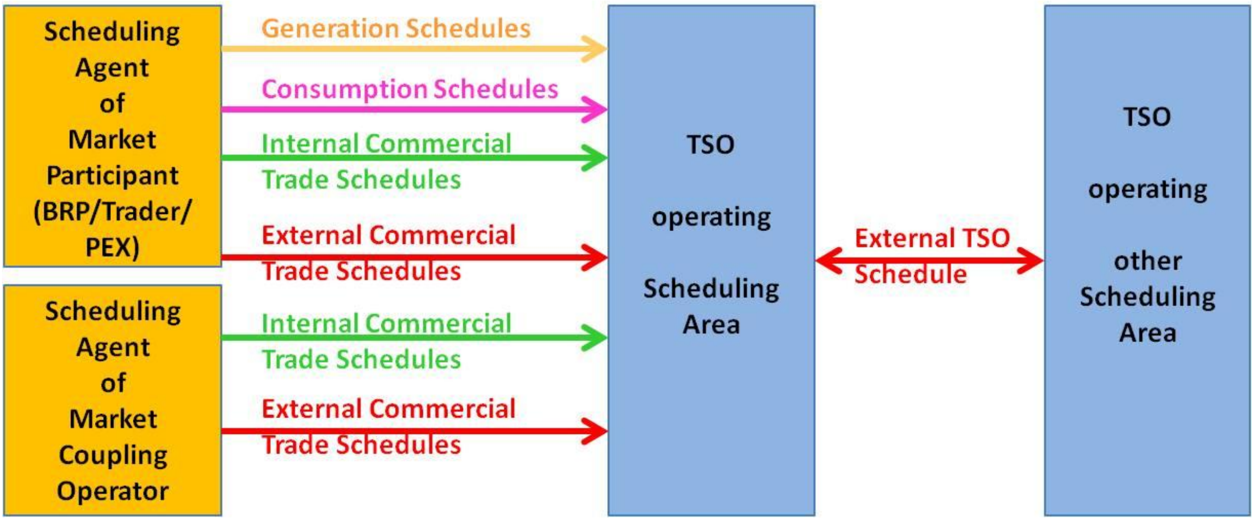
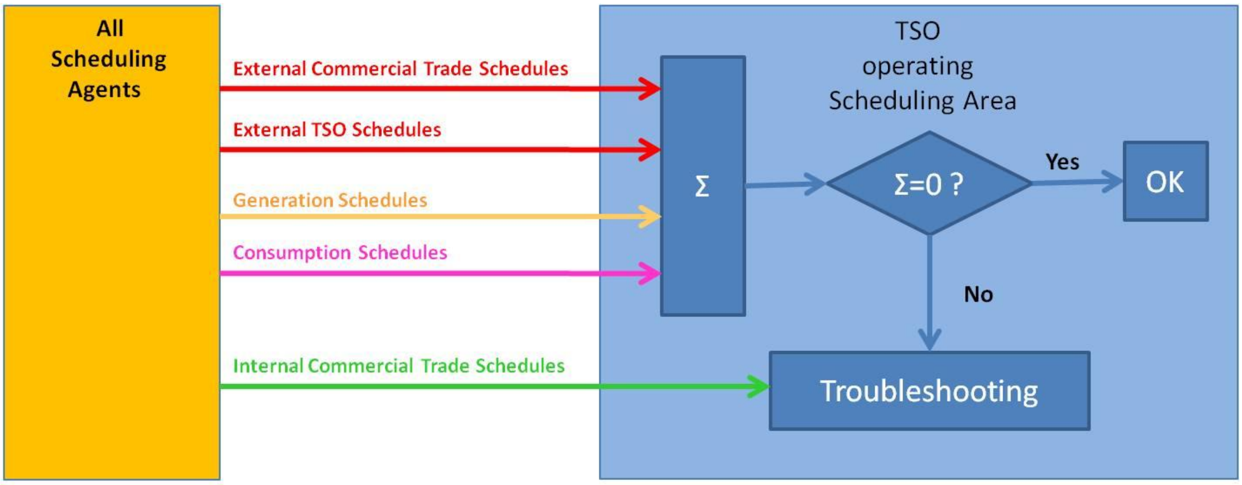


Figure 12: Scheme of available schedules

Schedules provide the TSO with valuable insight; if the schedules do not sum up to zero, the TSO will have time to inform proactively the market players of potential mistakes instead of experiencing potential enormous imbalances in real time. This increases security of supply and is more economical.

Figure 13 shows the verification of the area internal balance for Generation Schedules, Consumption Schedules, External Commercial Trade Schedules and External TSO Schedules (NC OPS Article 56(1)).



Troubleshooting:
e. g.:
- **Matching of Internal Commercial Trade Schedules**
- **Verification of the balance of Market Participants**

Figure 13: Verification of the area internal balance for Generation Schedules, Consumption Schedules, External Commercial Trade Schedules and External TSO Schedules

Requirements for scheduling between Market Participants/Power Generating Facilities/Demand Facilities/Market Coupling Operators and TSO operating Scheduling Area are very different in Europe and regulated in national legal framework.

The scheduling chapter of the NC OPS sets general requirements for scheduling processes:

- between Market Participants/Power Generating Facilities/Demand Facilities /Market Coupling Operators and TSOs; and
- between TSOs to ensure that TSOs receive the necessary data to run the system in a secure and efficient manner.

The NC OPS focuses on the use of the schedules submitted from the market players to the TSO and on inter-TSO scheduling issues.

The majority of requirements set out on TSOs in this topic are based on existing and best practice.

The requirements of scheduling of the NC OPS are applicable in all areas due to the high level of harmonization.

The output of a market coupling process, i.e. energy exchanges, results in new requirements for TSOs and Market Coupling Operators (scheduling “Net Positions”).

Scheduling “Net Positions” means a multilateral exchange between one Scheduling Area and a group of other Scheduling Areas involved in Market Coupling. “The group of other Scheduling Areas involved in Market Coupling“, will modelled as a specific Scheduling Area without generation or consumption and where the sum of all imports is equal to the sum of all exports. All involved Scheduling Areas in the Market Coupling have a border with the specific Scheduling Area, except if the local situation requires bilateral exchanges between two Scheduling Areas. The Scheduling Agent of the Market Coupling Operator acts as “Operator of this specific Scheduling Area”.

Market Coupling Operators shall support the process that ensures that all external schedules between Scheduling Areas are balanced.

Within market coupling process, multilateral exchanges between Scheduling Areas is the standard, but also bilateral exchanges may be required in order to allow for regional variations. Bilateral exchanges also take place if one of the Scheduling Areas does not participate in market coupling.

Figure 14 shows the bilateral agreement and verification process (NC OPS Article 56(2)):

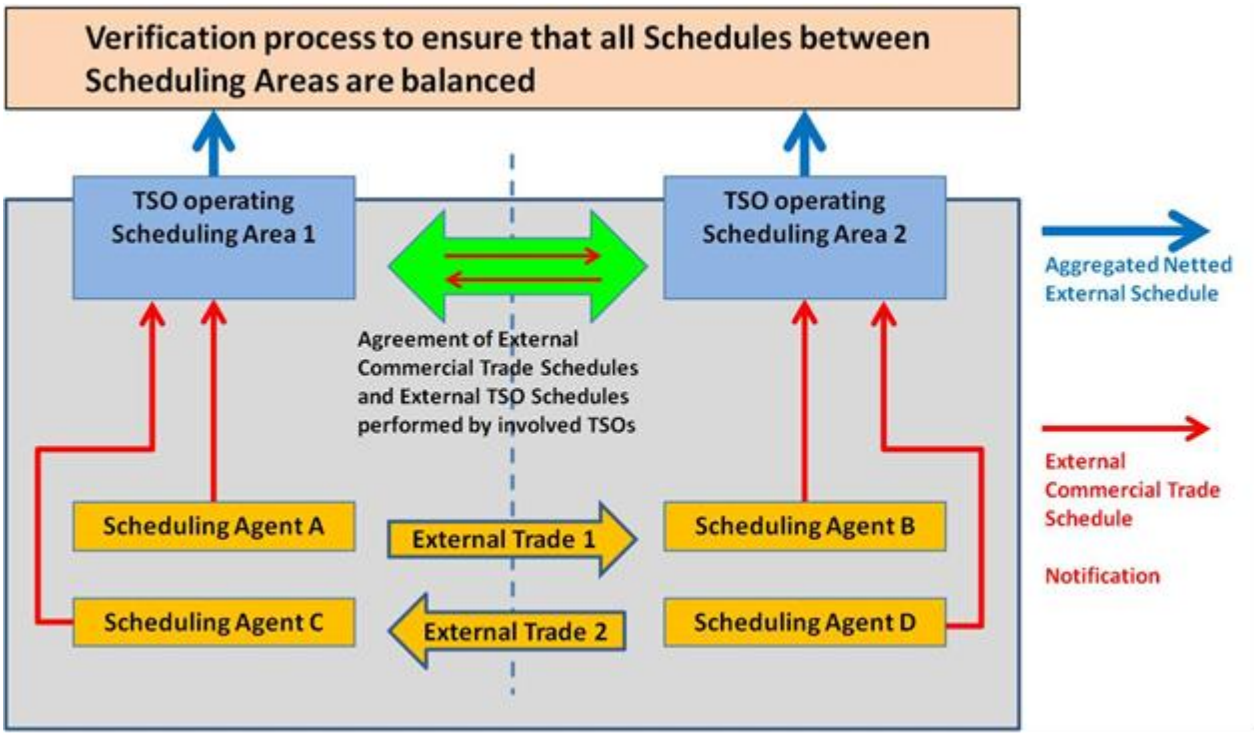


Figure 14: Bilateral agreement and verification process

Verification process to ensure that all Schedules between Scheduling Areas are balanced - see NC OP&S 56.2b

Agreement of External Commercial Trade Schedules and External TSO Schedules performed by involved TSOs - see NC OP&S 56.2a

Notification - see NC OP&S 55.1

Figure 15 below shows the multilateral verification process (NC OPS Article 56(3)):

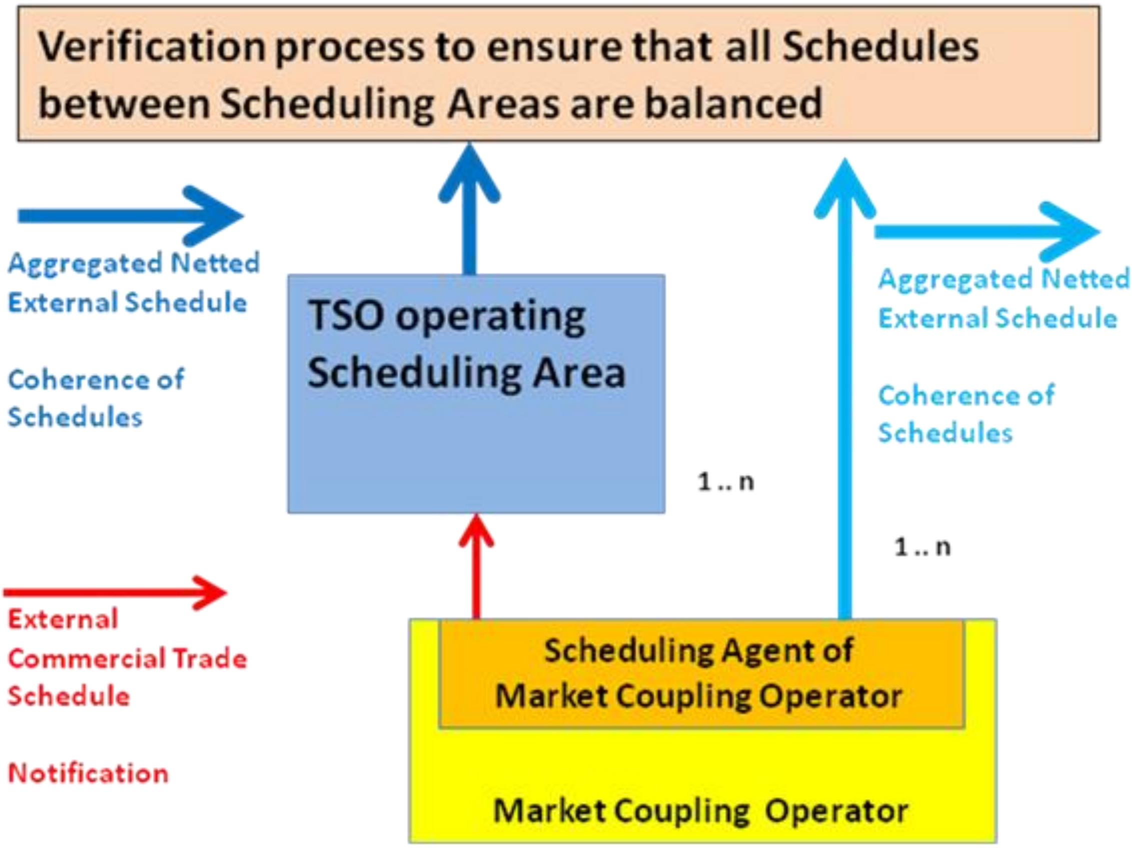


Figure 15: Multilateral verification process

Verification process to ensure that all Schedules between Scheduling Areas are balanced - see NC OP&S 56.2b

Notification - see NC OP&S 55.2

Coherence of Schedules (for TSO) - see NC OP&S 56.2

Coherence of Schedules (for Scheduling Agent of Market Coupling Operator) - see NC OP&S 56.3

The requirements set out in the NC OPS do not deviate from the requirements set out in the FG ESO. NC OPS describes the principles for exchange of all necessary information between system operators.

5.8 Conclusions

The NC OPS does not deviate from the best current practices and aims to make the European power transmission system more robust and competitive, to integrate significant volumes of renewable energy, to promote initiatives for regional cooperation and coordination among TSOs, to allow introducing innovative technologies to ensure the existing level of security of supply and support creating a single, competitive market across the continent.

6 CLARIFICATION ON CONCEPTS USED WITHIN THE NC OPS

6.1 INTRODUCTION

This chapter aims to provide additional information to the explanation of the requirements of the NC OPS above and to clarify in the Supporting Document various concepts of the operational planning and scheduling as a result of the comments and request for more detailed description raised by stakeholders in the 2nd, 3rd and 4th Workshops of the NC OPS (25 July and 21 November 2012, and 14 February 2013).

It has been considered convenient to explicitly clarify the following concepts of the NC OPS:

- Data for performing Operational security Analysis;
- Common grid model;
- Forecasts;
- Handling uncertainties;
- Remedial Actions;
- Agreements for Operational Security Analysis Coordination, including Regional Security Coordination Initiatives (RSCIs);
- Three folds harmonisation within NC OPS: Pan-EU, Synchronous Area and Regional;
- Outage Coordination structural choices;
- Significant Grid Users and Relevant Assets;
- Isolated Systems;
- Adequacy: structural choices;
- DSO involvement in NC OPS provisions;
- Delegation of tasks, subcontractors;
- Transparency Platform and ENTSO-E Operational Planning Environment.

6.2 DATA FOR PERFORMING OPERATIONAL SECURITY ANALYSIS

Chapter 2 of the NC OS as well as Chapter 3 of the NC OPS both address the topic of Operational Security Analysis from specific perspectives:

- The NC OS focuses on the common principles to be respected in order to ensure Operational Security with a special relevance regarding the monitoring of operational parameters for managing power flows, voltages, short-circuit currents and ensuring global balance between generation and demand. NC OS also establishes requirements for Contingency Analysis both: in operational planning and close to real-time.
- The NC OPS focuses on the processes to handle the Contingency Analysis and other relevant Operational Security Analysis (voltages, short-circuit coordination) to be performed in operational planning timeframes.

The NC OS also deals with other kinds of principles linked to the system design in order to ensure that means necessary to ensure Operational Security are in place, which are to some extent also linked to real-time operation and in some cases with operational planning activities. This is the case with requirements dealing with Transmission System protection, coordinated with Dynamic Stability Management as well as short circuit management.

The NC OS stipulates that if the Network is under N-Situation with respect to the Contingency List, Stability Limits are reached "before steady-state limits", the TSO shall perform a Dynamic Stability

Assessment (DSA) in all phases of operational planning. A DSA is an Operational Security Assessment in terms of Dynamic Stability, common term including the Rotor Angle Stability, Frequency Stability and Voltage Stability.

The NC OPS is in line with these provisions of the NC OS stating that each TSO shall perform Operational Security Analyses, including where applicable, breaches of Stability Limits of the Transmission System.

Exchange of data for DSA are both enforced within NC OS and NC OPS. The way to exchange these data is described below:

- **Data associated to power flow simulation needs**: where applicable, these data exchange could be supported by the CGM if they are affecting Operational Security over time in terms of generation, load, and exchange patterns. These data, used for DSA as power flows simulation are also a starting point for all dynamic simulations.
- **Specific data needed for DSA**: these data are numerous and very specific to control equipment models required for dynamics simulations. These data are fixed and don't change as data addressed through the CGM. Analyses are limited to regions and areas presenting dynamics vulnerability also taking into account that these phenomena need to be controlled locally. System monitoring and feedback analysis may reveal wide area dynamics phenomena. These situations can lead to the setting up of a grid model that adjusts the area-width of the simulation on a case y case to the appropriate size.

As a first idea, the principle followed in both NC OS and NC OPS is that requirements governing the exchange of information (structural, forecasted, real-time measurement) are drafted in the NC OS, while the NC OPS concentrates on processes for constructing models and sharing information between TSOs for ensuring the coordination of Operational Security Analysis in operational planning timeframes.

As a consequence, Chapter 2 of the NC OPS covers in particular the processes for establishing Individual and Common Grid Models as well as other relevant information (protection Set Points or System Protection Schemes, single line diagrams and substations configurations or others) allowing Operational Security Analyses to check power flows, voltages and at least three phases short-circuit currents remain on the established thresholds for the foreseen situations.

The NC OS deals with three topics related to Dynamic Stability Assessment:

- Rotor Angle Stability;
- Voltage Stability;
- Frequency Stability.

The first two kind of analyses: Angle Stability and Voltage Stability, which have in general local affection, will be performed, if applicable (this is the Nordic case, with very long axes of Transmission lines, in which Voltage and Angle Stability should be assessed in operational planning timeframes and in which these DSA are part of the analyses needed to calculate capacity), by data exchange supported by CGMs. In other cases, additional data exchanges are required to improve the steady state of the CGM. This is foreseen in the NC OPS at regional or bilateral level (Art 17(1) and Article 20(2)(f)).

Regarding Frequency Stability assessment (analysis and measures for solving inter-area oscillations), the NC OS requires that TSOs perform DSA studies (Article 15(3)), including Frequency Stability assessment, which for sure requires a model of the whole Synchronous Area. This Synchronous Area

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dynamic model for performing inter-area oscillations is not prevented to be covered by Chapter 2 of the NC OPS neither this inter-area oscillations analysis is prevented to be covered by Chapter 3 of the NC OPS if it is the case in the future.

Nevertheless, the current practice today is that inter-area oscillations analysis is linked with the system design and not with Operational Planning. Inter-area oscillation analysis is performed by off-line dynamic analysis, using models and tools different from the models for Operational Planning. Current practice is that Frequency Stability is analysed when assessing the synchronous Interconnected System in case of Contingencies, allowing to assess the modes of oscillation detected in long term and to design the adequate solutions to damp these oscillations.

6.3 COMMON GRID MODEL (CGM)

This section should be read in addition to the explanation in the Supporting Document for the NC OS and in the Supporting Document for the NC CACM.

The Common Grid Model is built by merging Individual Grid Models. An Individual Grid Model is defined as a grid model of the Responsibility Area of a single TSO.

Common Grid Models are Network models allowing the calculation of the values of the electrical parameters (voltage, active and Reactive Power flows…) on the elements of the electrical Network of a given area, according to a given scenario or best estimates of in-feeds and of withdrawals of active and Reactive Power.

The CGM is used to perform security analysis and capacity calculation. To perform the analysis, the whole Common Grid Model or the necessary part of it is used. CGM will be prepared in different timeframes for the different processes:

- For capacity calculation: CGMs are established two days before the energy is delivered, and for the intraday timeframe (NC CACM). Other timeframes for long term capacity calculation will be decided upon in the NC FCA.
- For assessing Operational Security as described in NC OPS: a Year-Ahead CGM is built and updated. For D-1, and where relevant intraday, CGMs are built. Complementary provisions, leaving room for regional agreements, addressing regional differences, have been drafted for Week-Ahead.

The NC OPS provides requirements in addition to the ones established in the NC CACM and the NC OS regarding the construction of CGMs.

The NC CACM establishes the requirement for building up CGMs as an input for capacity calculations at least at D-2 and Intraday.

The NC OS defines the basic characteristics of the Common Grid Model (at least the Transmission System of 220 kV and the 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 Network). Besides provisions in the NC OS, further characteristics of CGMs can be found in the NC OPS regarding the detail of equivalents: the need of clearly distinguishing in each IGM node (≥220 kV) the generation connected below 220 kV by their primary energy source.

The NC OS also establishes the way the TSOs receive the necessary information to prepare the Individual Grid Model. It is important to mention that the construction of IGMs established in OPS and NC OS does not imply any additional data provision process from stakeholders: for Year-Ahead, its

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updates and week ahead, TSOs should construct IGMs based on their best estimation. For D-1 and intraday timeframes data used will come from the results of the cleared markets and updated forecasts.

The NC OPS establishes further methodologies and principles for:

- Defining the scenarios in long term timeframes (Year-Ahead and updates) to be taken into account for building up IGMs:
    - In this sense, the establishment of Year-Ahead IGMs and CGMs will correspond to the important situations to be simulated because of their probability of occurrence and their potential for possible violations of Operational Security Limits. In that sense, the number of these scenarios are not determined by the yearly time granularity (e.g. one or several per month), but by specific situations (e.g. they could probably be determined by specified levels of demand and in-feed of RES.
    - Also, it is convenient to signal the need of establishing open provisions for Year-Ahead and updates of Year-Ahead CGMs, in order to allow enough flexibility for the NC FCA for further developing that process in line with the requirements of capacity calculation in long term timeframes.
- Defining the considered models at regional level (regional here means at the level of the regions defined in line with Article 20 of NC OPS) needed for the Week-Ahead usual processes in outages coordination:
    - As additional explanation, models within a region for such Week-Ahead processes can be defined e.g. as a sub-ensemble of CGMs established in certain periods of previous week.
- Building D-1 and intraday CGMs:
    - Capacity calculations need to be performed prior to the market to guarantee that the results from the market are secure. For D-2, NC CACM establishes CGMs based on estimations. For D-1 and Intraday, the Capacity Calculation Process and the Contingency Analysis described in both Network Codes (NC CACM and NC OPS) are intimately related. It is foreseen the same models could serve for both objectives.
    - Principles already establishes in the NC CACM are also applicable for the processes established in the NC OPS. In particular:
        - Approval of NRAs of methodologies to construct CGM.
        - Provisions regarding the perimeter of merging of IGMs into CGMs: single EU wide models for the whole pan-EU agreed timeframes, with possibility to merge at regional level for regionally agreed timeframes, considering certain conditions and covering zones to allow coordinated security analysis such as congestion and power flow management.
    - The NC OPS establishes the main conditions for each Individual Grid Model that they must comply with in order to be merged in a consistent way into the Common Grid Model:
        - In this context, preliminary power flow “net values” allowing to be consistent between borders are agreed in order to allow the operative merging of IGMs.

Those values do not constitute a pre-selected output of the Contingency Analysis and do not pre-condition the results.

- "Loop flows" are not input values for IGMs or CGMs, but on the contrary, they may be an outcome of the simulations performed with the CGMs.

The coherency of Common Grid Models in all NCs is ensured for all timeframes, since:

- All Common Grid Models comply with principles established in the NC OS.

- All CGMs comprise at least the Transmission System of 220 kV and the higher voltage Network, and an equivalent model of the lower voltage grid with influence and the sum of generation and consumption in the nodes of the Transmission Network, as described in Article 16(3) of the NC OS.

- All grid models use the same following data:

  - Demand pattern (active and Reactive Power withdrawals in the Network);
  - Availability of Power Generating Modules and their contribution;
  - RES generation;
  - Net Position for bidding zones and for Market Balance Areas.

  These data are collected by TSOs in all cases, on the basis of best estimates or information resulted from market, depending on the timeframe.

- On the basis of collected data, each TSO will build its IGM proposing for its own Responsibility Area a Topology, including planning outages, of its grid elements allowing a correct coordinated power flow calculation.

- To build a CGM from a set of IGMs, for all purposes and timeframes, IGMs must fulfil the following requirements:

  - All IGMs need to be consistent regarding their Net Position, their flows on DC links and the availability of interconnections between IGMs;
  - The data format of the concerned IGMs must be the same;
  - The provision of accurate and timely information by each TSO is essential to the building of the Common Grid Model.

While coherence is ensured some differences still exist between models constructed for Operational Security Analysis in the NC OPS and for the Capacity Calculation Process:

- The perimeter of merging:

  - CGM constructed for capacity calculation is considered pan-European in order to ensure non-discrimination and transparency allowing creating inputs for the regional or Synchronous Area processes of capacity calculation and allocation.
  - Performing Operational Security Analyses is in the first place an individual TSO responsibility, to be coordinated with the other TSOs following the requirements set forth in the NC OPS. This coordination implies in some cases the full merging of all TSOs IGMs (Year-Ahead and updates) and in others, for the sake of efficiency, merging at Synchronous Area (at least Day-Ahead) or even Regional (if so decided for Intraday) level. The NC OPS establishes provisions for the merging process at least at Synchronous Area level of Day-Ahead and Intraday models, in such a way to allow a CGM per Synchronous Area level containing updated schedules at least at D-1.

The NC OPS also includes requirements for the control of the plausibility and quality of the D-1 and intraday IGMs and CGMs. The plausibility control aims at ensuring that the data in the IGMs and CGMs datasets are realistic and don't contain implausible injections, withdrawals, topology leading to unrealistic power flows or voltage values. The quality control aims at verifying among others the respect of the requirements and principles developed for the building of IGMs and CGMs (format, timing of provision, respect of the "net values", etc.), the accuracy of the variables used to build its Individual Grid Models, comparing it with the realised values, the coherency of the connection status of interconnections. The NC OPS also includes some requirements for 'model improvement', based on the individual task of each TSO of monitoring the quality of D-1 and intraday IGMs and CGMs (in line with Article 15 of the NC OPS).

Besides CGMs, which should be used for performing Operational Security Analysis, additional information to the one exchanged at pan-EU level (described in Article 20(2)(.f)), could be covered by regional agreements.

6.4 FORECASTS

Within the NC OPS there are several implicit requirements for TSOs to produce or collect forecasts. These forecasts are used for Operational Security Analyses and for Adequacy assessments. Forecasts are mainly used for the D-1 and intraday timeframes. For other timeframes statistical scenarios are used instead. The difference between the use of forecasts and the use of scenarios is that forecasts are expectations of what will happen, while scenarios are examples of what could happen.

Forecasts used in Individual Grid Model scenarios are used at least for demand and for generation from Renewable Energy Sources. This is implicitly required in Article 14. For Adequacy assessments, forecasts are being used for demand, generation and generation from Renewable Energy Sources, as specified in Article 51.

The use of forecasts in the planning stages for Operational Security analyses is current practice for TSOs. The forecasts could be part of the input used for determining the scenarios for timeframes other than D-1 and intraday. Both for Operational Security Analyses and for Adequacy, statistical analyses are a more likely source of data. Furthermore, many forecasts come from sources other than the TSOs themselves, including DSOs and Market Participants, although some of the forecasts may be produced by the TSOs. Within the SO NCs, the sharing of information in relation to these forecasts is handled by the NC OS in the following Articles:

- Article 13(11) states that each DSO with a Connection Point directly to the Transmission System shall deliver all information for Contingency Analyses including forecast data, with possible data aggregation, to the TSO.
- Article 16(3) states that each TSO shall be entitled to gather information required for its own forecasts for use in a Common Grid Model.
- Article 17(3) states that TSOs shall share forecast data on node injections and withdrawals. It also states that it shall be based on the best forecast available and shall be as realistic as possible.

Specifically for the D-1 and intraday timeframes the following requirements of the NC OS relate to forecasts:

- Article 22(1) which states that TSOs shall be provided with forecasts of Active Power outputs for directly connected Power Generating Modules of type B, C and D on a D-1 and intraday basis.

- Article 25(1) which states that DSOs shall be provided with Active Power forecasts of Power Generating Modules within the Distribution Network. TSOs shall be able to receive this data according to Article 13(11) or 16(3).
- Article 28(2) which states that TSOs shall be provided with forecasts of Active Power consumption by Demand Facilities on a D-1 and intraday basis.

Aside from forecasts delivered by DSOs and Market Participants, it is of course possible for TSOs to use their own best estimates, for which NC OS provides the necessary data sharing requirements in Article 16(3). This is especially true for levels of Generation of Renewable Energy Sources and for levels of demand in relation to their dependencies on weather patterns in the Year-Ahead and Week-Ahead timeframes. As mentioned above, the NC OS requires TSOs to use best endeavours to ensure the quality of such estimations.

Sharing of data on forecasts is mostly being handled by the Transparency Guidelines, in Article 6 in relation to forecasts for demand, and Article 14 in relation to forecasts for Renewable Energy Generation. However, Article 47 of NC OPS requires TSOs to share with each other any forecasts used for performing Adequacy Analyses. This is handled within the NC OPS to ensure that TSOs are aware which of all available forecasts have been used, specifically, for performing these analyses.

6.5 HANDLING UNCERTAINTIES IN SHORT TERM OPERATIONAL PLANNING SECURITY ANALYSIS AND PROVIDING A RIGHT LEVEL OF OPERATIONAL TRANSMISSION RELIABILITY MARGINS

6.5.1 Making the link between Operational Security principles and operational Transmission Reliability Margins

Transmission Systems operation must be reliable, also in an uncertain environment, and cost effective. Uncertainties can be categorized in two main parts:

- Incidents that can affect both internal (e.g. transmission line) or external (e.g. generator) equipment.
- Uncertain forecast variables that can affect the Transmission System operation such as changes in weather conditions: variations of temperature affect the level of load, wind conditions affect wind generation level, solar conditions affect photovoltaic generation.

Uncertainties related to forecast states decrease while approaching real-time, nevertheless some decisions need time to be implemented (e.g. rescheduling of a maintenance program), hence TSOs are forced to take decision in an uncertain environment.

All these events change power flows patterns and may affect Operational Security of the interconnected power system.

To handle uncertainties, Transmission Systems can't be operated using the full loading or capabilities of all equipment. Both on the Transmission side and one the generation side, there is the need of physical margins, expressed as the difference between the online loading of equipment and its full capability. To ensure the availability of physical margins that allows maintaining the existing level of Operational Security, TSOs have developed Operational Security principles that must apply within operation and operational planning of the Transmission System. These security principles are set up by the NC OS. They define the types of events the Transmission System must be able to withstand when they occur without leading to uncontrolled situations (e.g. N-1 criteria).

Physical margins are delivered by applying these Operational Security principles throughout a global framework as exposed by the Figure 16 below:

- TSOs establish the state of the system.
- TSOs proceed to a security analysis examining the consequences of the events defined within security rules.
- If these rules are not fulfilled, TSOs need to take Remedial Actions in all timeframes allowing the Transmission System to cope with Operational Security principles and thus presenting the required level of physical margins.

It must be emphasized that the Operational Security principles are the result of years of TSOs practices and feedback experience. The application of these principles allows for providing the right level of physical margins to reach the high level of reliability for electrical energy that European citizens currently enjoy, with a frequency of major incident below one incident per 10 years on average. The right level of physical margins will evolve together with the new generation patterns of the near future, with how close systems are operated to their limits (stability) and with the introduction of new technologies to the Network (such as HVDC links in the meshed system).

In that context, feedback experience and monitoring reliability is a key point addressed by TSOs. This is achieved within the implementation of the ICS methodology and associated performance indicators; the NC OPS has established enhanced indicators to that purpose.

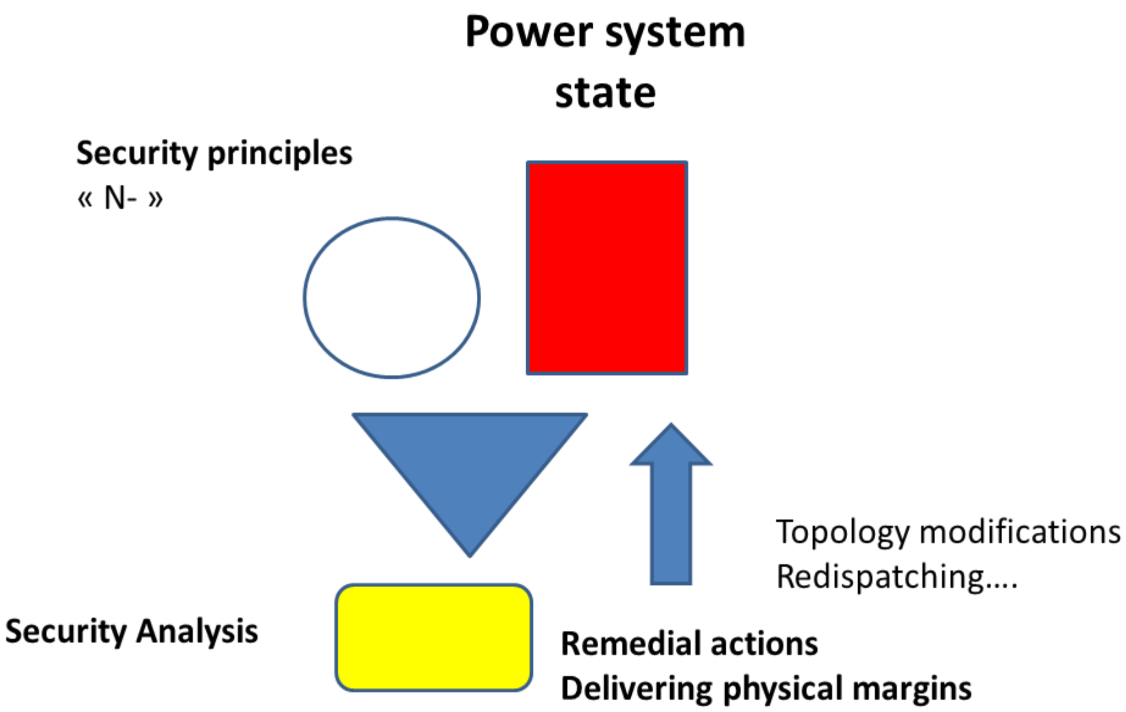

Figure 16: The link between Operational Security principles and physical limits

6.5.2 Making the link between Operational Security principles, operational Transmission Reliability Margins and physical limits on Network and generation equipment

The link between observance of security principles and physical margins on equipment (Transmission, generation, consumption) are handled throughout the global framework shown in Figure 17 below.

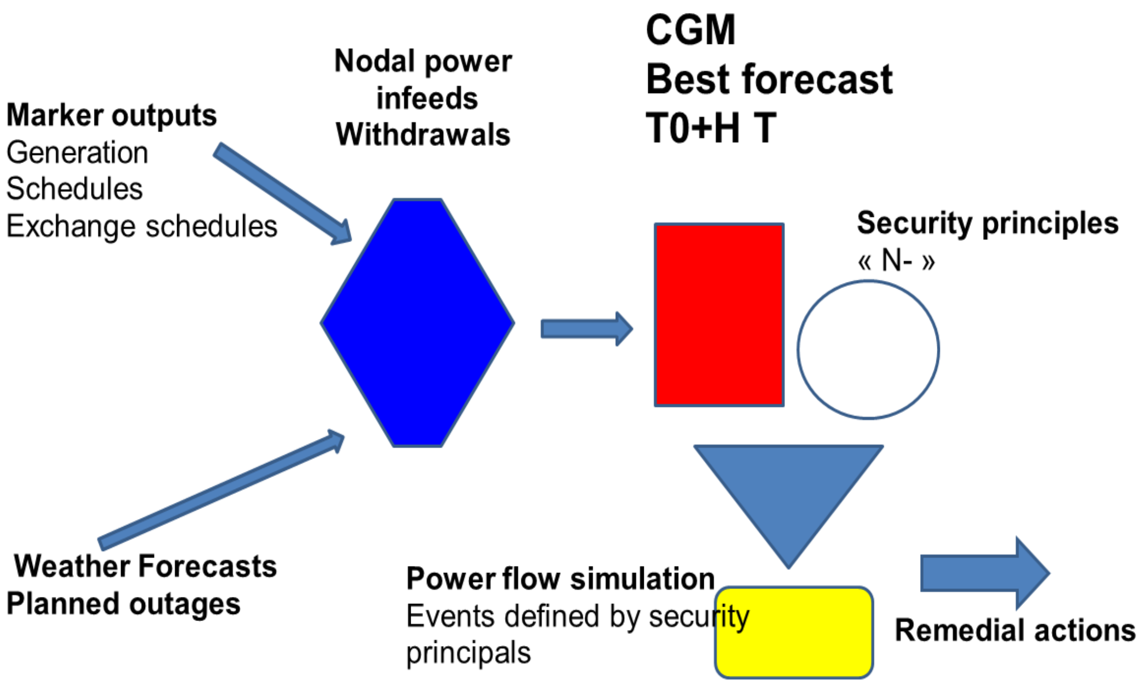

Figure 17: The link between Operational Security principles and physical margins on Network and generation equipment

To examine consequences of events, TSOs perform security analysis on a state of the Network provided, having Common Grid Model as main input. The currents, the voltages (angles, modules and frequency when performing time domain simulations) are compared with the maximal or minimal values as defined by ranges in Network Codes, or allowed by equipment within the power system. If these conditions are not fulfilled TSOs develop Remedial Actions and check their efficiency through simulation if needed. As tripping of generation units are handled by security principles, the Active Power reserves (FCR and FRR) activations are addressed within the corresponding security analysis.

Since the performed computations can never be perfectly accurate, it is necessary to take margins when comparing the result of the simulation with the maximal and minimal values admissible for equipment. This issue is referred to in the NC OPS within the security analysis methodology provisions. Provisions to monitor and ensure accuracy of models are also established.

6.5.3 Handling weather forecast uncertainties and providing a right level of physical margins in short term operational planning

Throughout the global framework explained above and specifically in relation to the method of providing physical margins, TSOs use weather forecasts:

- to determine the level of load and renewable generation;
- to provide for each node of the CGM the corresponding withdrawal and in-feed of electrical energy.

The NC OPS enforces the use of these forecasts, the delivery of a best estimate and the description of both load and generation with the distinction between wind and PV generation. The best guideline here seems to be to differentiate geographically to a level of detail that is useful for TSOs.

Short term changing weather conditions are not sudden (closer to real time forecasts are more accurate), as it is for a line tripping or faulty generation unit. Taking into account this characteristic, the

TSOs' practices in this domain are to get forecasts regularly updated, to monitor the discrepancies regarding the previous forecasts, to re-update security analysis if pertinent and to deliver, if needed, required Remedial Actions to comply with Operational Security principles.

Different current practices are applied today by TSOs for updating forecasts. A first classification of modes to calculate forecasts could be:

- forecasts made in a centralized way by the TSO; and
- forecasts made by responsible agents (balance parties, aggregators, etc.) and aggregated by TSOs.

Of utmost importance is that the continuous update of forecasts is taken into account by TSOs when performing operational security analysis, hence allowing to undertake Remedial Actions according to the evolution of the situation, as weather forecast updates become more accurate.

The NC OPS enforces this monitoring and continuously updated security analysis within the intraday time frame to face changing weather conditions, within a global framework supported by the security analysis methodology.

Uncertainties associated with a weather forecast are also provided by forecast tools. Specific situations with a high degree of uncertainty and a high level of possible deviation in generation or load level, are included in the TSOs' security analysis in order to deliver the required corresponding physical margins.

The NC OPS enforces the integration of such uncertainties.

6.5.4 Links with NC CACM, RM and operational Transmission Reliability Margin as addressed by this Network Code

The operational Reliability Margins (RM) addressed in NC CACM code is part of the the global framework described above. They take into account the following:

- The capacities to be offered on D-1 market are calculated in D-2. This calculation is based on a use of a Common Grid Model, using a best forecast, in order to assess the possible commercial exchanges between Bidding Zones. The goal of that capacity calculation is to maximize the commercial exchanges while remaining compliant with security principles.
- Two days ahead (D-2), weather forecasts are more uncertain.
- TSOs have no information of exchanges schedules, and neither of generation schedules, therefore reference days are used.

The RM defined in the NC CACM is a component of the operational Transmission Reliability Margins expressed as the part of the capacity that is not delivered to the market. This RM covers the impacts on power flows of all uncertainties explained above. The estimation of the required size of the RM is based on a statistical analysis of the deviations between forecasted power flows and observed power flows in real time.

The flow based Reliability Margin (FRM) includes:

- Wind, solar uncertainty;
- Outages (generation/Network);
- Load uncertainty;
- Redispatch (e.g. Remedial Action or operation of load frequency control);
- Topology and PST taps;

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- Intraday schedules; and
- Application of linear grid model inherent to Flow Based Market Coupling algorithm.

6.6 Remedial actions

Remedial Action means a measure that relieves or contributes to relieving Constraints on the Transmission Network. These Constraints can be for example overloads on Transmission lines, low or high voltages under or beyond the operational limits. TSOs must ensure that for all contingencies (for example Transmission line tripping) defined within the Operational Security rules, such Constraints are prevented or mitigated by utilizing dedicated Remedial Actions.

A Remedial Action can be implemented pre Fault (preventive) or post Fault (curative), can involve costs or not, can be internal or external to a TSO's Responsibility Area, and can be a grid related measure (change of Topology including PST tap position changes) or a market related measure (Redispatching of units, modifying cross borders exchanges using Countertrading).

The Remedial Actions TSOs can utilize are strongly linked to the timeframes considered. Several hours in advance, a TSO can, for example, contract the preheating of a given generation unit not required by the market. For short timeframes, TSOs have the possibility to act on balancing and emergency reserves, or control devices such as applying changes in Topology or activating PSTs.

A Remedial Action can be activated immediately (e.g. grid related measure) or need a certain period to be activated (e.g. Redispatching).

A Remedial Action can be applied manually or automatically.

In general TSO prefer to use post Fault Remedial Actions especially if they are costly. As such, they are only used if the contingency occurs.

Pre-Fault Remedial Actions will be implemented only if there is no possible delay to restore Operational Security after the contingency.

The Remedial Actions can be used in the capacity calculation in order to optimize the cross border capacity for each market timeframe and in security analyses to ensure Operational Security after the market results and to deal with all events occurring after the market closure.

The enhanced requirements under this topic in the NC OPS are:

- Coherency from year ahead to real time: this means ensuring that all Remedial Actions declared available or used in long term calculations are taken into account in the following calculations. It may nevertheless happen that a Remedial Action developed in the longer term timeframe may not be applicable due the discrepancy between the long term scenario and short term scenario.
- Coherency with the use of Remedial Actions in Capacity Calculation: the principle is the same as explained above.
- Methodology and Common Process in Security Analysis Coordination for defining the available Remedial Actions.
- Process for determining and selecting the most suitable ones;
- Process to coordinate the activation of those Remedial Actions.

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6.7 Agreements for Operational Security Analysis Coordination, including RSCIs

6.7.1 Need for Coordination

The operation of the electrical Transmission grids is becoming more and more complex due to the high volatility of renewable generation, the development of electricity markets which leads to an increase of cross-border transitions up to intraday and also the emergence of new Transmission technologies (PST, HVDC...). Moreover the development of the European grid and therefore the increase of cross-border flows make the influence and interdependency between distant electrical systems growing quickly.

Consequently the need for a coordinated management of flows at international level is now undeniable to guaranty security of supply in some highly meshed areas of the European grid but also to enhance social welfare through better integration and use of Renewable Energy Sources and higher availability and reliability of transfer capacities for the market.

The Table 2 below highlights the need for common security analyses and coordinated Remedial Actions implementation to maintain and enhance the operational level of security of a supply in the CWE area and CEE area with neighbour TSOs.

Estimated number of grid elements that can implies cross-border coordination when overloaded or tripped	50 \ over 100	
Highly stressed situations with a need of coordination (assessed by CORESO during day-ahead study process) (assessed by TSC-Operator during day-ahead study process)	in 2010	in 2011
	2 \ 2	4 \ 9
Stressed situations or situations with a need of coordination (assessed by CORESO during day-ahead study process) (assessed by TSC-Operator during day-ahead study process)	in 2010	in 2011
	15 \ 5	47 \ 63

Table 2: Illustration of a need for common security analyses and coordinated Remedial Actions implementation

In other Regions, like SWE, the strength of the coordinated security analysis is based on:

- the wide extension of the Observability Area to all those parts of neighboring systems with an sensitive influence on the Responsibility Area;
- information shared on the updated cleared markets;
- information exchanged on TSOs forecasts;
- agreements for identifying and activating Remedial Actions as well as for sharing Replacement Reserves.

There are more than 220 grid elements that can imply cross-border coordination when overloaded or tripped in SWE Region: more than 70 elements in France and in Portugal, and more than 80 elements in Spain.

However, the need for operational coordination can be different depending on the regions: number of interdependent TSOs in terms of cross-border influence, meshing level of the grid, variability of generation, market solutions etc.

Therefore the NC OPS introduces the notion of Multilateral Agreements which guarantee coordination between TSOs adapted to the operational needs of each region.

6.7.2 Geographical applicability of Multilateral Agreements

The coordination shall mainly be performed at regional level, where a region can be defined as a set of TSOs, presenting areas of their Network being connected together (either by DC and/or AC links), with strong electrical interdependencies (loop flows, PST and/or HVDC influencing each other). A region would cover such a number of TSOs areas that corresponds to the geographic scale of operational risks and of power flow effects from changes in generation patterns, and that leads to tasks performed at regional level efficiently and reliably:

- sharing information on external Contingencies;
- needed common view of uncertainties associated to Generation or demand;
- identification of Remedial Actions that are efficient and compliant with TSOs' operation security principles.

Only one Multilateral Agreement shall be defined for each region, but a TSO can be part of several regions and therefore TSO can have several Multilateral Agreements.

As expressed above, the definition of regions is based on practical approach of TSOs confronted to coordination needs to ensure Operational Security. Nevertheless some guiding principles can be exposed on the way these regions are constituted.

The synchronism could be one of the starting criteria for determining that regions. Nevertheless this criterion is much too wide for Synchronous Area Continental Europe. The need for pragmatic divisions of the Continental Europe leads to organize regions in line with interdependencies between Responsibility Areas.

As starting point, it can usefully be referred to two TSOs having a common border (see figure below). For this simple case, the coordination region can be seen as the merge of the Observability Areas of each TSO Responsibility Area. Indeed the Observability covers the part of the Transmission System of one TSO influencing the other and within which external contingencies must be handled.

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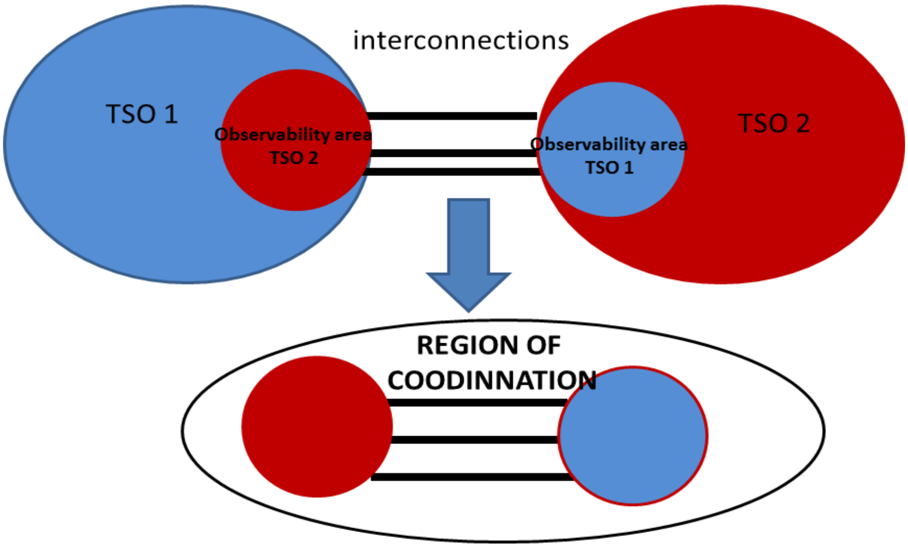

Figure 18: Illustration of region of coordination

The Figure 18 above makes clear that the region for coordination doesn't include the Responsibility Area of each TSO but address the relevant merge of Observability Areas of connected TSOs.

The reality is much more complex than this example involving just two TSOs. For the multilateral case, the coordination region must contain all Observability Areas considering the different borders between TSOs and ensuring that:

- for an External Contingency affecting two borders, these borders should be handled in the same coordination region; and
- for two external contingencies in a same Responsibility Area affecting the same borders in the Observability Area of these borders should belong to a same coordination region.

These considerations are not the only ones and other factors such as loop flows, effects of PST, effects of generation patterns have also to be taken into account so that a pragmatic approach referring to TSOs feedback experience is imperative.

6.7.3 Functional applicability of Multi-lateral Agreements

Multilateral Agreements shall guarantee a consistent and coordinated security assessment of the grid for operational planning timeframes as much as the search and implementation of optimized coordinated Remedial Actions.

To perform these tasks, Multilateral Agreements shall ensure the use of common hypotheses for grid studies. The Common Grid Model resulting from the Individual Grid Models merging is the main basis of this hypotheses sharing.

To enhance communication and cooperation, a common tool or at least compatible tools shall be used within a given region and even between several regions if required, within a global three level framework as exposed on Figure 19 and Figure 20 combining the European, synchronous and regional levels.

Common processes are then necessary to optimize the security assessment and Remedial Actions implementation phases. The common processes include but are not limited to:

- the definition of coordinated Remedial Actions, such as adapting Topology or phase-shifting transformers;
- the application of the coordinated Remedial Actions;
- the adaptation of outage scheduling;
- the implementation of Redispatching or Countertrading.

Multilateral Agreements shall include a process dedicated to the revision of its content.

To ensure the consistency between Multilateral Agreements specific provisions are drafted in order to trigger, when possible inconsistencies are detected, a process for affected regions to come to a consistent solution.

Functions covered by the Multilateral Agreement may be partly performed by a delegated entity.

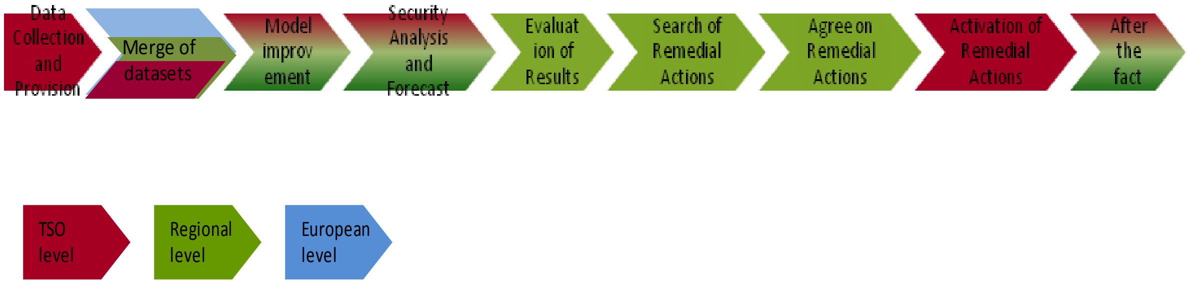

Figure 19: Activities coordinated at TSO, regional and European level

6.7.4 Regional Security Coordination Initiatives

Especially in highly meshed regions, the coordination needs to be multilateral with usually more than two TSOs at the same time. In that case, TSOs can attribute, through their multi-lateral agreement the common tasks to be performed to delegated entities considered as RSCIs. RSCIs should support the operational coordination, TSOs remaining sole to take the final operational decisions. Indeed in these regions a decentralised cooperation between TSOs can be insufficient to seek quickly enough the optimized coordinated Remedial Actions. This process implies an objective and global vision of the regional grids cooperation which is ensured by RSCIs, especially when organised as a physical centre gathering operators from different TSOs of the region.

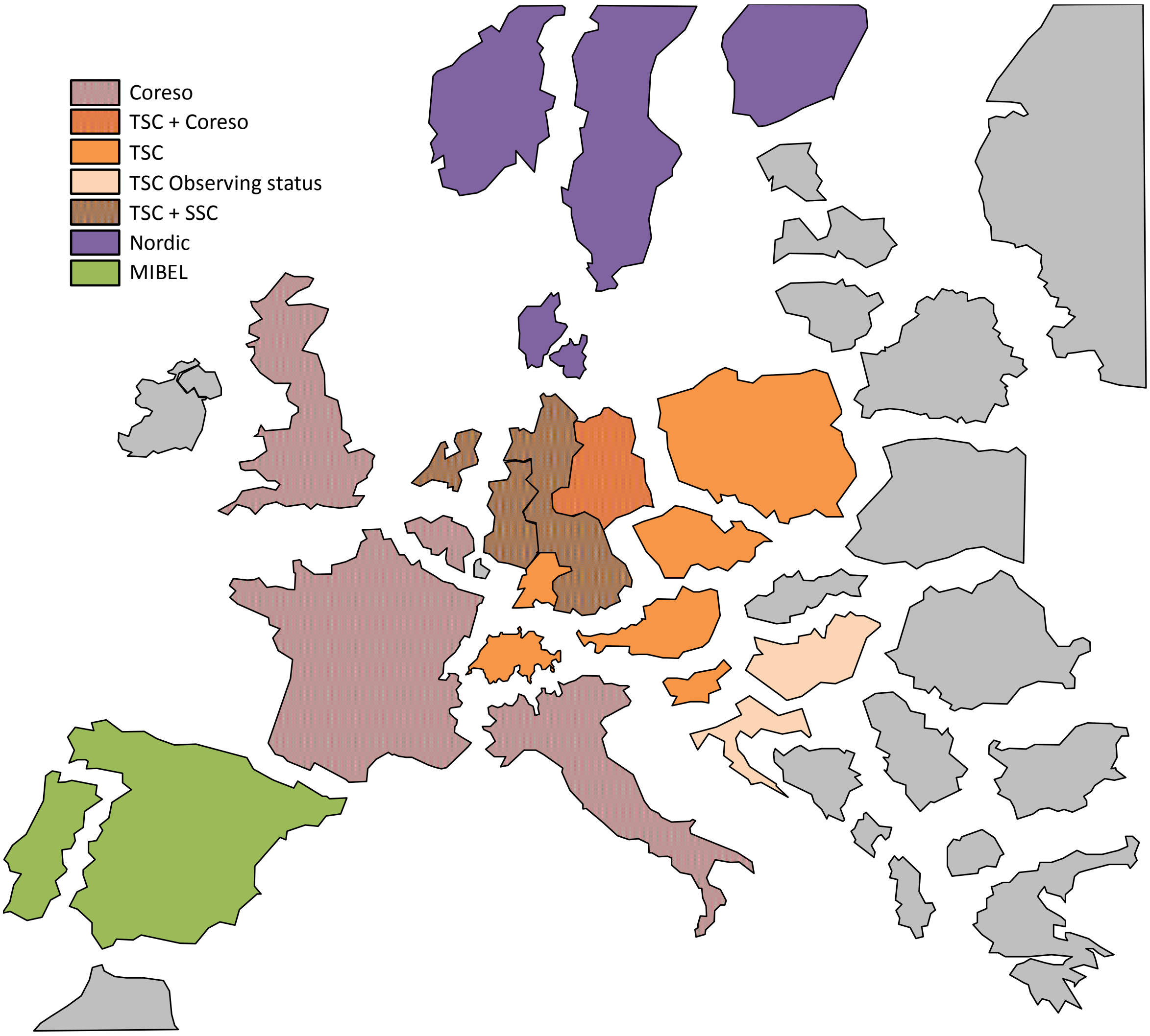

Figure 20: TSOs participation in Regional Security Coordination Initiatives in Europe

The main principles to be taken into account when creating a RSCI are described below:

- They can take the form of legal entities, but they have to be owned and administrated by TSOs.
- They must have the compliant delegation and legal authority for the functions described above, but it is of crucial importance that TSOs remain responsible for final operational decisions and stay completely responsible for security issues.
- Global and common governance shall be established between all TSOs and RSCIs involved.
- If a TSO from a given region refuse to join a RSCI, it should not be able to oppose its creation and shall be obliged to collaborate with this RSCI.
- A given RSCI can act in several regions.
- Several RSCIs can act for several TSOs in the same region, ensuring the necessary cooperation.

6.7.5 Geographical applicability of Multilateral Agreements and RSCIs

Participating TSOs in RSCIs as presented in the Figure 21 below is the present state of a process still developing.

ENTSO-E does not see a theoretical approach allowing designing the best regions. TSOs have to stay in a pragmatic approach taking into account their feed-back experience in the practical implementation of RSCIs and the different regions of the Transmission System subject to Constraints needing to be jointly addressed between them. These regions cover the zones of the respective TSOs Responsibility Area having cross-border influence.

Some TSO have different zones of their Responsibility Area which might belong to different regions (example: zones of France between CWE, SWE and CSE, parts of Germany between CWE and CEE).

There are two types of such situations to be considered:

- The first one deals with *two* different zones of a TSO Responsibility Area *belonging* to *two* different regions without overlapping – France between CWE and CSE: this case doesn't present any difficulty as there are no common processes between *these two* regions.
- The second one is when *two* regions are overlapping, the same zone of a TSO responsibility area possibly belonging to *two* different regions. In that case, the concerned TSO will have to belong to the *two* RSCIs and be part of *two MLAs* for his zone. In such a case, consistency of the *two* MLAs have to be ensured through common contractual principles regarding the interactions of MLAs on the following:
    - consistency of the CGMs (allowing to carry out coherent security analyses on the overlapping part);
    - timeframes of operational processes (presenting steps allowing coordination on the actions on the overlapping zone);
    - cross-checking of the actions taken on the overlapping zone.

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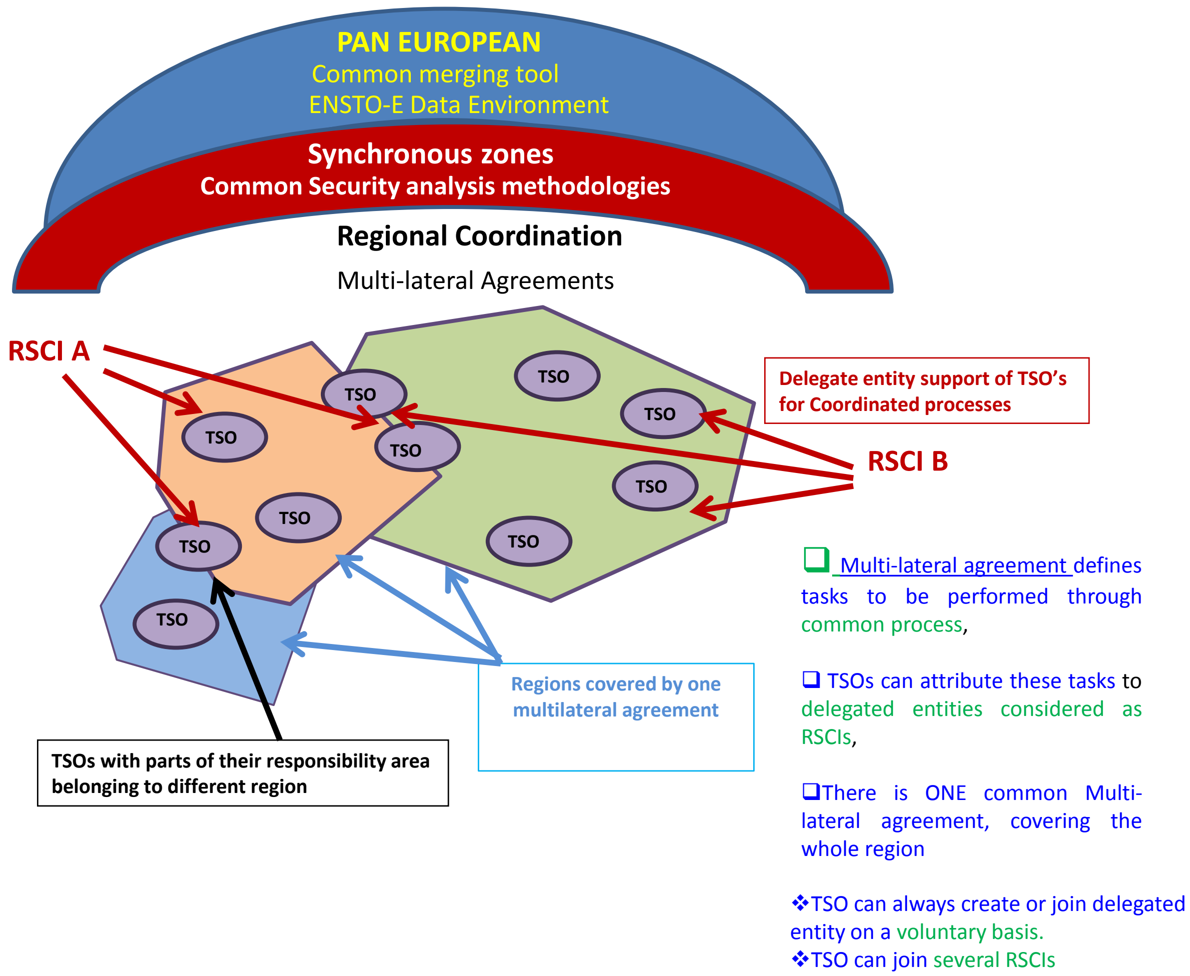

Figure 21: Present state of TSOs participation in RSCIs

6.7.6 Global added value of RSCIs

The existing RSCIs such as Coreso and TSC have proved their efficiency during the last years. The benefits brought are quite varied.

These initiatives contribute to enhance the Operational Security due to:

- an increase of communication between TSOs;
- a better awareness of the Constraints and risks identified in the neighboring TSOs;
- sharing of Remedial Actions with cross-border influence.

These initiatives also encourage the creation of common tools, common procedures, common trainings, etc.

There is also a tendency for gathering operators originally from different TSOs into the same physical entity. Where applicable, this brings to additional benefits such as:

- sharing of system operation experiences and good practices from different TSOs leading to a "global operational culture and understanding";

- the neutral point of view of the operators that will seek innovative and optimized cross-border Remedial Actions;
- speed up of coordination with a common entity seeking the best action and then discussing it with concerned TSOs supporting efficiently a multilateral research of the solution.

6.8 Three folds harmonisation within NC OPS: Pan-EU, Synchronous Area and Regional

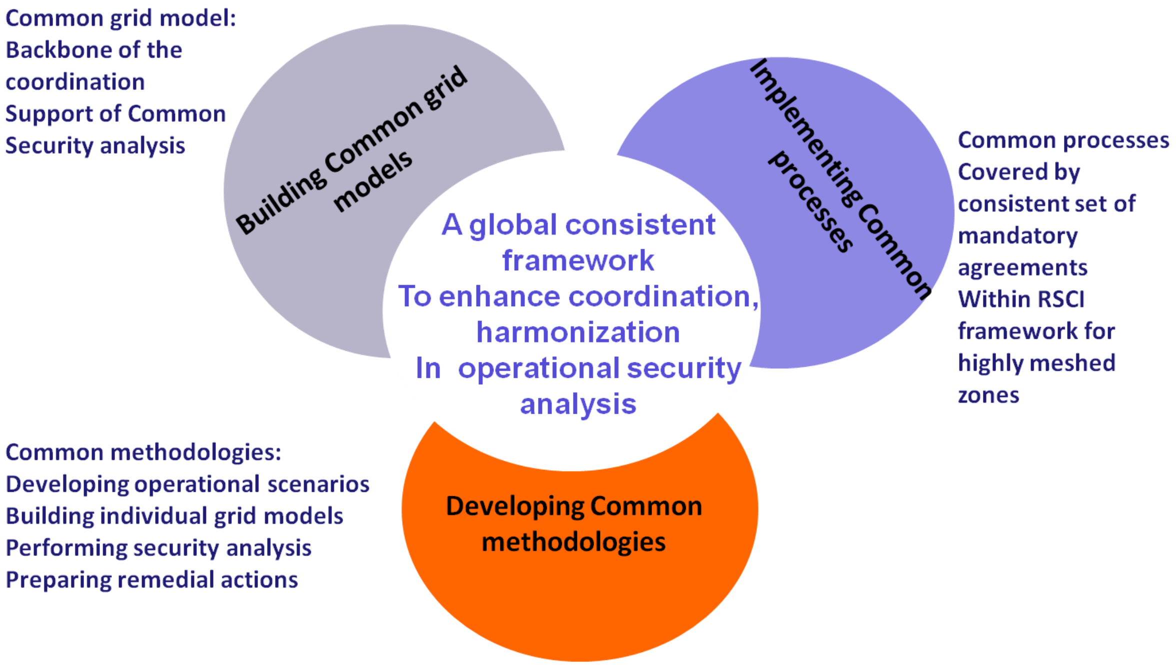

Figure 22: Framework to enhance coordination, harmonization in Operational Security Analysis

The Network Code on Operational Planning and Scheduling takes the first steps in the direction of pan-European harmonisation of operational practices while respecting current practices and the principles of subsidiarity and proportionality. In order to achieve the best results, different tasks are harmonised to a different degree.

6.8.1 Operational Security Analysis

Figure 22 above shows the concept of harmonisation as it relates to Operational Security Analysis. A distinction can be made between harmonisation at a pan-European level, Synchronous Area level and regional level.

First of all, Common Grid Models for the Year-Ahead, D-1 and Intraday timeframes are established on a pan-European level, with the required data being shared amongst all TSOs, in order to allow them to perform Operational Security Analyses.

Secondly, these Operational Security Analyses will be performed on different timeframes using a common methodology harmonised at the level of Synchronous Area. In line with FG ESO, since there are differences between Synchronous Areas, it is prudent to allow these areas some freedom in this respect.

The actual implementation of the procedures required for the Operational Security Analyses will be done at a regional level. For this purpose TSOs shall establish multilateral agreements within which the processes and tools used for the Operational Security Analyses are detailed. In some cases TSOs may decide to delegate the coordinated tasks to RSCIs.

6.8.2 Outage Coordination

Since there is a lot of interaction between the grids within different Responsibility Areas, it is important to coordinate outages of Network elements, Self-Planned Interconnectors, Power Generating Modules and Demand Facilities for as far as they impact other Responsibility Areas. This will help ensure Operational Security and will prevent unnecessary costs for TSOs, like Redispatching.

A certain level of harmonisation is therefore required and established in the Chapter 4 of the NC OPS. It would be unnecessary for purposes of Operational Security, and would be highly inefficient, to coordinate outages between Responsibility Areas that are quite far apart, for instance between Denmark and Spain. The elements for which the outages have to be coordinated need to have some level of influence on each other.

Therefore the NC OPS defines the Outage Coordination Region in order to establish an optimal Outage Coordination Process. This is in line with current practices, as outages of TSO owned elements are already being coordinated within specific regions, though the current regions may be changed as a result of the requirements within the NC OPS dependant on the assessment of which Responsibility Areas are significantly affected by specific assets or network elements. The use of Outage Coordination Regions allows for the most efficient way to harmonise the way outages are being handled by TSOs, while leaving enough room to prevent the current practices that are vastly different, to change unnecessarily.

A single Responsibility Area can in some cases belong to two or more Outage Coordination Regions. If this is the case, this TSO will be required to coordinate its Availability Plans within all of his Outage Coordination Regions.

6.8.3 Adequacy

Fulfilling Adequacy within its Responsibility Area is a responsibility of each TSO. In order to streamline this process and facilitate the development of the grid within the European level, such as for example through the TYNDP, it is important to use harmonised principles to perform Adequacy analyses. The NC OPS requires TSOs to establish pan-European summer and winter Generation Adequacy outlooks, in line with Article 8(3) of Regulation (EC) N° 714/2009, and ensuring that TSOs update this Adequacy analyses for their own Responsibility Area whenever significant changes occur to Generation or demand patterns or to cross border capacities.

Aside from these pan-European analyses, TSOs will also asses the Adequacy within their Responsibility Area on a Week-Ahead, D-1 and intraday basis, making use of for example the latest Market Participant Schedules.

6.8.4 Scheduling

The NC OPS takes the first step towards ensuring harmonisation of Schedules within the European Union. However, the direct link to the market and the scope of NC the NC OPS prevents the achievement of full harmonisation. Instead, the consistency of Schedules across the EU is ensured.

6.9 OUTAGE COORDINATION: STRUCTURAL CHOICES

The Network Code for Operational Planning and Scheduling makes a first attempt at harmonising the Outage Coordination Process between TSOs and with Relevant Assets. This is necessary to ensure that the system remains within the Operational Security Limits, because planned outages in one Responsibility influence the security of the system in another Responsibility Area.

Certain measures are required in the NC OPS to ensure that the influence on current practices is kept to a minimum. These measures include the following:

- **Relevant Assets.** A definition of Relevant Assets has been introduced to ensure that only those elements participate in the Outage Coordination Process whose individual Availability Statuses have a significant influence on another. Larger units that are closer to the border are more likely to be qualified as Relevant Assets than smaller units that are farther from the border.
- **No aggregation.** While for some purposes the capacities of units are aggregated, aggregation is not done in determining whether Power Generating Modules or Demand Facilities are Relevant Assets. The likelihood of enough outages being planned at the same time for this aggregation to have a significant cross border impact was estimated to be too small to justify including them in the process.
- **No coordination details.** While the NC OPS requires parties involved in a possible Outage Incompatibility to coordinate, it does not specify the details of this coordination process, and leaves options open for the wide range of measures that are currently being used in all Member States, not excluding for example the possibility of financial compensation if it exists in the applicable national legal framework.

Despite these measures, it can, however, not be prevented that in rare cases Outage Incompatibilities arise which lead to stakeholders incurring costs they would not have incurred without the applicability of the NC OPS. This can for instance happen when there is an Outage Incompatibility between a unit in one Responsibility Area, and the TSO of another Responsibility Area that cannot be resolved despite of coordination and existing legislation.

Since TSOs are, however, required to facilitate the coordination of outages to resolve Outage Incompatibilities, they will where possible move their own outages unless, for example, costs have been incurred by them in relation to those outages or if they have contracted obligations to third parties. Furthermore, a low threshold for the determination of Relevant Assets would lead to higher costs and additional work for the TSOs, which will help ensure the selection of sober but technically sound, NRA approved, criteria. The occurrence of situations in which extra costs are incurred has thus been kept to a minimum, and when it does occur, it will likely prevent costs to others.

The Outage Coordination Process has been defined with a maximum amount of freedom for stakeholders in mind, assuming no Outage Incompatibilities occur, and of course, without prejudice to the rights of Member States establishing more stringent conditions. This means that as long as no Outage Incompatibilities arise, stakeholders should be able to change their Availability Plans at will in order to adapt to changes in market conditions as long as national legislation does not prevent them from doing so.

Taking all these caveats into account, the minimum costs incurred by stakeholders as a result of the new obligations arising from the NC OPS are relatively small in relation to the gain of the requirements, which include lower costs for TSOs and for consumers as a result and a better security of a supply.

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6.10 SIGNIFICANT GRID USERS AND RELEVANT ASSETS

6.10.1 Relevant versus significant

According to the Framework Guidelines on Electricity System Operations, Significant Grid Users are defined by considering their impact (individual or aggregated) on the cross border system performance. The Framework Guidelines on Electricity Grid Connections uses similar definitions. Indeed, an aggregation of units with very small connection point voltages has an impact on the balancing of the system, and could have an impact on the power flows as well, leading to possible Constraints.

In line with this observation, the Network Code on Operational Security (NC OS) defines significance by considering the impact of a grid user in terms of the security of supply regardless of the connection point voltage. In order to include aggregation in the NC OPS as well, it refers to the role of aggregation in Article 3, where the Significant Grid Users for the purposes of the Network Code are listed.

Because different purposes lead to different grid users being of importance to Operational Security, NC OPS introduces a new definition alongside the definition of Significant Grid Users. For the Outage Coordination Process reference is made to Relevant Assets. These Relevant Assets are defined as those assets, whether they are Power Generating Modules, Demand Facilities, grid elements or Interconnectors, for which the individual Availability Status has an impact on the Operational Security of the Interconnected System. This definition implies that for as far as Power Generating Modules and Demand Facilities are Relevant Assets, they are always Significant Grid Users as well, which is reinforced by Article 24(3) of the NC OPS.

While the definition in NC OS implies that Power Generating Modules and Demand Facilities can be Significant Grid Users as part of an aggregated set of units, this is not the case for Relevant Assets, whose relevance for the Outage Coordination Process is based upon their individual Availability Statuses alone.

6.10.2 Determination of Relevant Assets

From the definitions of Significant Grid Users and Relevant Assets respectively, it follows that the group of Relevant Assets must be a subset of Significant Grid Users for as far as they are Power Generating Modules or Demand Facilities. For indeed whenever a change in the Availability Status of a grid user impacts the Operational Security of the Interconnected System in accordance with the definition of a Relevant Grid User, this implies that the grid user will also impact the Operational Security, in accordance with the definition of a Significant Grid User The Network Code further ensures that establishing requirements relating to Relevant Assets rather than Significant Grid Users for the Outage Coordination Process will therefore help ensure the proportionality of NC OPS.

In order to assess the relevance of a grid user, a methodology will be developed by all TSOs, which shall abide by the principles detailed in Article 23 of the NC OPS. This methodology shall be subject to approval by all NRAs. Example 1 shows a possible method of implementing this methodology. This example is consistent with the methodology already used in some Member States to assess the relevance of grid elements for purposes of coordinating outages across borders. As the insights of TSOs develop, it is possible that the methodology used will be different from this example.

EXAMPLE 1

A possible methodology to be used to assess whether a generator can be qualified as a Relevant Asset follows the following steps:

1. *a reference Common Grid Model in which every unit is available and connected is established;*
2. *for each branch the Permanently Admissible Transmission Loading (PATL) is determined. This is the loading in Amps or MVA that can be accepted on the branch for an unlimited time;*
3. *a deterministic method is used to assess the influence of an asset in the N-1 situation. In this method each of the branches within the interconnected network are considered to be disconnected, one by one;*
4. *the influence of a generator on another Responsibility Area is then determined. This is done by assessing for each of the branches within the Responsibility Area in question, how large the influence of disconnecting the generator is on the Active Power through the branch;*
5. *the ratio of this change in Active Power through the branch, and the PATL of the branch determines the influence on a particular branch. The influence on the Responsibility Area is then connected to that branch on which the influence is maximal;*
6. *when this influence is above a certain threshold, perhaps 5%-10%, the generator is qualified as a Relevant Asset.*

6.10.3 Relevant Assets within NC OPS

The concept of Relevant Assets is being used within the Outage Coordination chapter of NC OPS. Outage Planning Agents of Relevant Assets are being required to submit their plans for outages for the following calendar year before 1st August in order for the TSOs to assess whether Outage Incompatibilities arise.

All TSOs of an Outage Coordination Region will then analyse whether the proposed plans contain any Outage Incompatibilities. If so, they will work with the Outage Planning Agents involved to ensure the Outage Incompatibilities are relieved. This process is finalised before 1st December.

After the Year-Ahead outage coordination is finalised, the Outage Planning Agents of Relevant Assets are entitled to change their plans whenever they like. They are also able to submit changes to their plans between 1st August and 1st December. Those changes will not be assessed for the occurrence of Outage Incompatibilities until the process of Year-Ahead outage coordination is finalised.

There is always the possibility that a change of plans for the outages of Relevant Assets will not be acceptable without coordination, because if no other outage plans of other Market Participants or TSOs are changed an Outage Incompatibility will arise from the proposed change. In that case a solution will have to be found.

In order to adhere closely to current practice, the coordination between Outage Planning Agents of Relevant Assets and TSOs is not detailed within NC OPS. This means that for as far as possible, national legislation will still apply in relation to coordinating to resolve Outage Incompatibilities. In case the Outage Incompatibility is between the TSO of one Responsibility Area and an Outage Planning Agent whose asset is located within another Responsibility Area, the connecting TSO will play a role in the coordination process

6.10.4 Application of significance within the NC OPS

Aside from the topic of relevance, NC OPS also includes the aggregated integration of distributed Generation and demand when describing the provisions related to the development of Individual Grid Models, to the Adequacy analysis, to their contribution to the provision of Ancillary Services as well as of Generation schedules. The subject of Significant Grid Users is therefore not trivial within the NC OPS.

6.10.5 Self-Planned Interconnector: reason for introducing the definition and consistency within global framework of Outage Coordination

The Network Code addresses the variety of roles regarding coordination of outages of Interconnectors and the differences between them:

- The role of being responsible for providing an Availability Plan for each Relevant Grid Element linking Responsibility Areas; and
- The role of Connecting TSOs, i.e. TSOs whose Responsibility Areas connect all Relevant Assets. These TSOs are responsible of the compatibility of the whole Availability Plan taking into account operational security:
    - coordinating together per Outage Coordination Region to ensure compatibility of the whole Availability Plan per Outage Coordination Region;
    - entitled to request changes to the Availability Plans in coordination with Outage Planning Agents;
    - resolving Outage Incompatibilities in accordance with national regulations and with procedures available to each TSO.

For some Interconnectors the role of being responsible for providing an Availability Plan is not taken by the Connecting TSO. The definition of a Self-Planned Interconnector aims at identifying these situations. In this case, the Availability Plan is delivered by a separate entity responsible for the Interconnector at the Connection Point according to national regulation. In the framework of this Network Code this separate entity is addressed as the Outage Planning Agent of this Self-Planned Interconnector.

As such, the delivery of information and coordination between the Connecting TSOs and the Outage Planning Agents with regard to Availability Planning is ensured.

This type of situation is encountered for example for the Interconnector between Switzerland and Italy where there are more than one Self-Planned Interconnector (one Self-Planned Interconnector connects Campocolgna to Tirano, a second one connects Cagno to Mendrisio, further Self-Planned Interconnectors are in a planning stage).

Another example are the interconnections between Great Britain and France and Great Britain and The Netherlands where the Connecting TSO does not manage the Availability Status of those interconnectors, this is managed by the owners/operators of those assets (called the Outage Planning Agents of those assets), but the arrangements with the Connecting TSOs provide for a coordination process in outage planning.

6.11 ISOLATED SYSTEMS

According to Article 8(7) of Regulation EC N° 714/2009 the 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.

First is to mention, that this Network Code only applies within EU, Energy Community and third countries being Member of ENTSO-E as these third countries will also apply this Network Code. 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 Network Code.

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).

In many cases, it is obvious that such 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 a Transmission System would not possibly have cross border or market integration impact and therefore, would be out of the scope of the Code.

In several cases a system of an Island, belonging to the Responsibility Area of a TSO (like Balearic Islands) or having an 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 due to the fact of being connected to the mainland only through a DC link or for other technical reasons.

As a conclusion, National Network Code, respecting European legislation, apply to those systems and it is up to the respective TSO to assess if such a system as mentioned above under the scope of application of the Code.

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

6.12 ADEQUACY: STRUCTURAL CHOICES

Especially in light of the integration of an increasing amount of RES into the system, the subject of Adequacy within Europe is becoming more and more important. Ensuring Adequacy requires not only sufficient Generation to meet the demand, but also the capability of the system to deliver the energy to the end user. Although it was not mentioned explicitly within the Framework Guidelines on Electricity System Operation, the subject of Adequacy is closely related to Operational Security. It is clear that if Adequacy is not ensured, the security of supply is at stake, and because ensuring Adequacy is often related to the amount of energy that can be imported into the Responsibility Area, it is clearly a cross border issue as well.

While the most important measures that the TSOs could take to counteract Adequacy problems relate to investments into the Transmission System, and are therefore out of scope of the NC OPS, it is important for TSOs to monitor those situations that could lead to Adequacy problems, and to clearly communicate with concerned parties when these problems are detected. In order to achieve that, the Network Code imposes actions of TSOs that could not be in all cases in line with the current practices. In relation to the Framework Guidelines on Electricity System Operation this could be considered to be a part of preventing blackouts.

Where today all TSOs perform summer and winter Generation Adequacy outlooks, after the NC OPS comes into force they will be required to monitor changes in Generation, demand and cross border capacities and update the summer and winter outlooks for their own Responsibility Area when there are significant changes. An example of a situation that could lead to a significant change in the Adequacy assessment, even between the summer and winter Generation Adequacy outlooks of the same year, is a political decision such as the one taken in Germany to make haste with closing down all the nuclear power plants. Other examples include natural disasters which damage large facilities, and economical problems that lead to the closure of factories.

While these changes could constitute a deviation from the current practice, it is warranted because communicating on these threats is the only opportunity TSOs have to influence the future fulfilment of Adequacy. The same holds for the new requirement for TSOs to assess Adequacy on a D-1 and intraday basis. The application of existent or new procedures at TSOs' disposal would not represent significative added workload for TSOs, and nothing is being asked of other parties in addition to what they are already required to do from requirements elsewhere.

6.13 DSOs INVOLVEMENT IN NC OPS PROVISIONS

The introduction in general terms of DSOs in the outage planning processes is not foreseen in the NC OPS, since those processes are covering the necessary coordination activities between TSOs in order to carry out the outage plan of the elements and units with individual cross-border affection. Nevertheless, particular requirements have been drafted to cover those cases in which distribution assets in one Control Area affect the security limits of a different Control Area

The inclusion of aggregated values of the generation or demand in distribution levels for other processes (Adequacy and Ancillary Services monitoring or scheduling) is ensured in the NC OPS provisions, and performed under the national rules in place. Therefore, DSO activities, roles and responsibilities are not impacted by this Network Code.

The NC OS is defining the principles governing the data exchanges between TSOs and DSOs for Operational Security.

As a result of the points mentioned above, the details of the processes like information exchange, congestion management, voltage control, carried out within a Control Area and implying TSOs coordination with DSOs and Grid Users is considered not under the scope of NC OPS. In that sense, the Network Code would not intend to impose “one-size-fits-all” provisions that deviate from existing practices. But it pretends to establish the minimum harmonised requirements for coordinating the system, allowing national regulation to fix the details on the how and roles of responsibilities of the different system and network operators and ensuring adequate provisions for allowing “TSOs acting as one” in relation to the assessment of the Operational Security of the whole Interconnected System.

6.14 DELEGATION OF TASKS, SUBCONTRACTORS

All parties can outsource several tasks by itself or together with other parties. This right shall not be limited by this Network Code. Delegation to subcontractors, service providers or other third parties has no impact on the responsibility of the delegating party, the delegating party still remains responsible (liable) for its tasks according to its role (see also Article 8 and Article. 20).

6.15 TRANSPARENCY PLATFORM AND ENTSO-E OPERATIONAL PLANNING ENVIRONMENT

As defined in the Transparency Guidelines TSO is responsible for collecting and sending all relevant data on load in their control area to the central information platform. The consumption units, the generation units and the DSOs that are located within the TSOs’ control area shall provide the TSOs with all the relevant data that are required to fulfil the obligations of Transparency Guidelines.

TSOs are responsible for providing to the central information platform at least the following load data that are defined in the points from 4.1.3.1 till 4.1.3.8 of the Transparency Platform.

As defined in point 4.3 of the Transparency Platform Guidelines Generators are responsible for providing all relevant generation data.

The information on generation shall include at least the information which is defined in the points from 4.3.2.1 till 4.3.2.10 of the Transparency Platform.

ENTSO-E Operational Planning Environment described in Chapter 8 of the NC OPS is not intended to substitute or be implemented as Transparency Platform. It is established as a mean to exchange data

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between TSOs and RSCIs participating in the Operational Security and Adequacy Analysis and Outage Coordination as established in the Network Code.

ENTSO-E Operational Planning Environment contains data not only for the final result of the processes, but for the intermediate steps, which is considered sensitive information, provided to TSOs under confidentiality agreements. It is not either a platform for communicating with DSOs connecting Relevant Assets, being the information exchange at that level ruled by NC OS and by national legal framework.

6.16 CONCLUSIONS

The NC OPS constitutes a number of best current practices to make the European power transmission system more robust and competitive and to integrate significant volumes of renewable energy. The common rules it provides should provide a spur to extend existing initiatives across Europe and to ensure the existing level of security of supply and support creating a single, competitive market across the continent.

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7 RESPONSES TO PUBLIC CONSULTATION

7.1 INTRODUCTION

This chapter of the document provides a summary of the comments received as a result of publication, via workshops and in discussions 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 code. More detailed explanations are provided in an appendix 3 ''Network Code on Operational Planning and Scheduling - summary of comments received during public consultation and overview of the ENTSO-E responses'' of this document.

7.2 SUMMARY OF COMMENTS

In total ENTSO-E received just over 850 individual comments as part of the public consultation. Those comments were varied and, as shown in the diagram below, covered most parts of the Network Code. However, comments were focussed on security analysis and outage planning in particular.

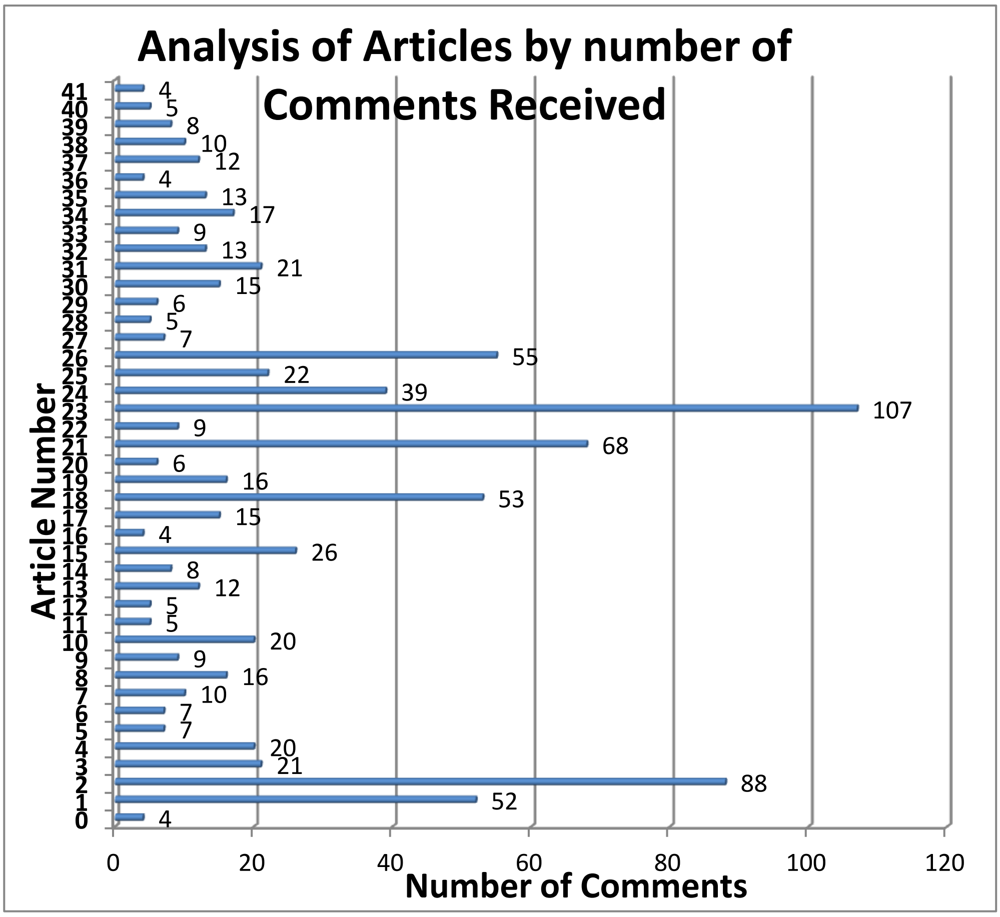

Figure 23: Analysis of Articles by number of comments received

As the summaries in appendix 3 demonstrate, each comment was considered and assessed and decisions were taken about whether there was a need to update the Network Code. Themes which occurred frequently in responses were:

- Consistency with other NCs;
- Clarification of definitions;

- Cost recovery;
- Information and data exchange;
- NRA involvement, stakeholder consultation;
- Transparency and ENTSO-E data environment;
- Common Grid Models and coordinated security analysis;
- DSOs involvement;
- Remedial actions;
- Criteria for relevance;
- Outage planning deadlines, priorities, flexibility, clarity of the process;
- Coordinated Adequacy;
- Scope of Ancillary Services;
- Harmonization and coherence of schedules.

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

7.3 STRUCTURAL CHANGES IN LIGHT OF COMMENTS

As mentioned above, many of the comments ENTSO-E received focused on the need to increase clarity and avoid duplication within the Network Code. ENTSO-E carefully considered these changes and made the following structural changes in the updated version:

- Created a new article dealing with Regulatory approvals;

- Created a new article on Common Grid Model general provisions;

- To improve readability and for clarification reasons the Article 21 ''Self-Planned Interconnectors, Relevant Power Generating Modules and relevant demand facilities'' is split into Articles 22-25 in new version, introducing Methodology for assessing relevance of assets for the Outage Coordination Process and providing more clarity and details on the list and re-assessment of the list of Self-Planned Interconnectors, Relevant Power Generating Modules and Relevant Demand Facilities;

- To improve readability and for clarification reasons the Article 22 ''Relevant Grid Elements with impact across borders'' is split into Articles 26-32 in new version, introducing more clarity and details concerning list and re-assessment of the list of Relevant Grid Elements, treatment of Relevant Assets located in the Distribution Network, variations to deadlines for the Year-Ahead coordination process, link with data to be provided according to requirements outside this Network Code, general provisions on Availability Plans and long-term indicative Availability Plans;

- To improve readability and for clarification reasons the Article 23 ''Year-ahead outage planning'' is split into Articles 33-39 and 41-43 in new version, introducing more clarity and details in Year-Ahead Availability Plan proposals and coordination of the Availability Status of Relevant Power Generating Modules, Relevant Demand Facilities and Self-Planned Interconnectors, Relevant Grid Elements, preliminary Year-Ahead Availability Plans, validation of Year-Ahead Availability Plans within Outage Coordination Regions, final Year-Ahead Availability Plans and Coordination processes in case of detected Outage Incompatibilities, detailing the testing status of Relevant Power Generating Modules, Relevant Demand Facilities and Self-Planned Interconnectors, Relevant Grid Elements located in the Transmission and the Distribution Network;

- Created new article on performance indicators requested by the FG.

7.4 Enhancing consistency

ENTSO-E has sought to respond to comments about inconsistencies in the Network Code and have made considerable efforts to ensure it reads like a single document. Particular focus has been given to the following:

- *Definitions* – Many respondents raised comments that the draft NC OPS was not consistent with the wider suite of Network Codes. Consistency across Network Codes being developed over a period of years is a considerable challenge. Nevertheless, ENTSO-E recognizes the importance of consistency and have taken steps to improve definitions, to align them with those used in other draft Network Codes (or already existing legislation), and to take steps to ensure the definitions in OPS can be used in future Network Codes.

- *Regulatory Approvals* – Several respondents and the regulatory authorities pointed out that ENTSO-E took a haphazard approach to regulatory approvals in the draft Network Code. In particular, there were inconsistencies in what was approved, in the timings in which approvals took place and in the powers to, for example, approve, consult or opinion which were given to regulators. Several parties also pointed out that these powers are set out in law (Directive 2009/72/EC, Articles 36 and 37). Given this concern ENTSO-E has developed a new article in the first section of the Network Code (Article 4). This directly 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. To add clarity ENTSO-E has listed explicitly all cases where Regulatory Approvals are foreseen and at what level the respective approval should take place (e.g. pan-European, Synchronous Area level or national regulatory authorities).

- *Consistency with other NCs* – Detailed analysis of the more advanced NCs (RfG, DCC, CACM, OS) helped to avoid overlapping and to make more precise references.

7.5 Additions since the previous version

ENTSO-E would particularly like to draw parties' attention to issues which have been added since the consultation version. This covers the methodology for assessing relevance of assets for the Outage Coordination Process, treatment of Relevant Assets located in the Distribution Network, variations to deadlines for the Year-Ahead coordination process, detailing the testing status and performance indicators as requested by the FG. Mainly clarifications were inserted follow the comments from the stakeholders during public consultation.

7.6 Conclusion

In our view, the changes discussed in this section have improved the overall consistency and readability of the Network Code and, as well as addressing a significant number of stakeholder concerns, have improved the overall quality of the Network Code and extent to which it complies with the framework guideline. We'd like to thank the parties that responded to the consultation for their helpful views.

8 NEXT STEPS

In this chapter ENTSO-E briefly summarises the main steps of the Network Code development process with a special focus on those that will occur between the submission of the Network Code to ACER and its application.

8.1 SUBMISSION TO ACER

Regulation (EC) N° 714/2009, and in particular its Article 6, 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) N° 714/2009 foresees the need for a NC. 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 guideline is intended to set clear and objective principles with which the Network Code should be in line.

The development by 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.

8.2 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 code if it’s satisfied that it meets the requirements of the framework guideline or can provide a negative opinion; effectively meaning the code is returned to ENTSO-E.

8.3 THE COMITOLOGY PROCEDURE

The NC 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. Our working assumption is that it will take about 12 months from the issuing of the ACER opinion (if positive) to the conclusion of the Comitology process.

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8.4 ENTSO-E STEPS DURING THIS PERIOD

Meeting the requirements of the NC OPS as soon as practicable is a significant challenge for ENTSO-E. During the period in which the 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.

8.5 ENTRY INTO FORCE

The Network Code will enter into force 20 days after its publication. However, due to the various consultations and approvals the application of different parts of the code will be triggered by the timing of regulatory decisions. Because of uncertainties about the ACER opinion, the timings of the Comitology process, the time needed to deliver parts of the code and the time needed to approve parts of the code (which could include a referral to ACER) it is not possible to say exactly when each part will apply. A close working relationship between ENTSO-E, ACER, national regulators and the Commission is, in our view, necessary to ensuring the OPS code can be implemented as quickly as possible.

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9 LITERATURE & LINKS

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[8] NationalGrid – Complete Grid Code http://www.nationalgrid.com/NR/rdonlyres/67374C36-1635-42E8-A2B8-B7B8B9AF2408/58810/00_GRID_CODE_FULL_I5R2.pdf

[9] EirGrid - Grid Code Version 4.0 http://www.eirgrid.com/media/Grid%20Code%20Version%204.pdf

[10] SONI – Grid Code http://www.soni.ltd.uk/upload/SONI%20Grid%20Code%20-%2020%20July%202012.pdf

10 APPENDICES

10.1 APPENDIX 1 BASELINE - PURPOSE OF THE NETWORK CODE

Purpose

This appendix provides a high level overview of the rationale for including particular articles in the Network Code. It is complemented by the more detailed assessment found in detailed analysis of responses found in appendix 3.

This Network Code defines the minimum Operational Planning and Scheduling requirements for ensuring coherent and coordinated operational planning processes of the Synchronous Areas applicable to all Significant Grid Users, all Transmission System Operators and all Distribution System Operators.

This Network Code aims at determining common time horizons, methodologies and principles allowing carrying out coordinated Operational Security Analysis and Adequacy analysis to maintain Operational Security and support the efficient functioning of the European internal electricity market and determining conditions to coordinate Availability Plans, allowing works required by Relevant Assets.

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. Cross-references with other ENTSO-E Network Codes: • NC RfG and NC 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; • NC CACM for establishing and delivering Individual Grid Models for merging into Common Grid Models • 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; 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. Cross-references with other ENTSO-E Network Codes: none (but using the definitions from all other ENTSO-E Network Codes) 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 NC OPS.
3	REGULATORY ASPECTS	Address the regulatory aspects of relevance for all Network Codes in the area of system operation in a common and coherent way. Cross-references with other ENTSO-E Network Codes: referring to the capabilities required in the NC RfG and NC 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. The principles to be respected in the whole code and by fulfilling the requirements of this Network Code needs to be appointed in one place.
4	REGULATORY APPROVALS	Provides 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. Required NRA approval: listed all articles in this Network Code which call for NRA approval. The issues listed for NRA approval include only those which are explicitly introduced and specified in this Network Code. Besides, a number of additional issues are implicitly under the oversight and approval by the NRA within the subsidiarity of EU legislation – e.g. in the form of market rules or other; these issues are presented in the Supporting Document. Finally, a number of issues where information to the NRA is provided in the scope of this Network Code, are also 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.
5	RECOVERY OF COSTS	Define provisions for recovery of costs related to the obligations from this Network Code, including assessment by NRA, recovery via Network tariffs, providing any necessary additional information by the TSOs. Required NRA approval: general NRA involvement and key role in costs assessment, recognition and recovery through the regulated Network tariffs 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 The provisions for confidentiality are important for TSOs and any other entities, e.g. common initiatives.
7	AGREEMENT WITH TSOS NOT BOUND BY THIS NETWORK CODE	Obligation to try to reach an agreement with TSOs in the same Synchronous Area to reach a cooperation with such TSOs to fulfil the obligation of this

		Network Code Cooperation of TSOs in a Synchronous Area is important to fulfil the requirements of this Network Code
8	ROLES IN OPERATIONAL PLANNING AND SCHEDULING AND DELEGATIONM	Accepts the possibility of delegation of tasks and ensuring that the delegated party fulfils the requirements and the confidentiality If a delegation takes place it is important, that the delegated party acts the same way as the delegating party would act to ensure the function of the system and the needed cooperation over the borders.
	CHAPTER 2 DATA FOR OPERATIONAL SECURITY ANALYSIS IN OPERATIONAL PLANNING	
9	INDUVIDUAL AND COMMON GRID MODEL GENERAL PROVISIONS	Detail general requirements for Common Grid Models as used in the framework of NC OPS: specify the timeframes for which the CGMs are established and specify the role of the European Merging Function in merging the IGMs in a way consistent with both NC CACM and NC OPS. Current practices dealing with the delivering, merging and sharing of Common Grid Models exit in the different Synchronous Areas and regions. Nevertheless, articles in Chapter 2 entrain an enhanced new view, since they extend this practice, following commonly agreed principles and provisions, to the whole Interconnected System, in line with NC CACM and to other timeframes, Year-Ahead provisions, drafted in Articles 9 to 12 could be considered new requirements for all TSOs.
10	YEAR-AHEAD SCENARIOS	Specify the requirements for Year-Ahead scenarios to be used in Common Grid Models in order to perform Operational Security Analyses on a Year-Ahead basis. These requirements take into account patterns for generation, including RES, demand and cross border exchanges.
11	YEAR-AHEAD INDIVIDUAL GRID MODELS	Detail the procedure by which each TSO shall construct Year-Ahead Individual Grid Models for merging into Common Grid Models by the European Merging Function. Focus specifically on coordination with neighbouring TSOs in order to allow the IGMs to be merged.
12	YEAR-AHEAD COMMON GRID MODELS	Specify the specific procedures to be developed by TSOs in order to facilitate the gathering, saving and merging of Year-Ahead Common Grid Models.
13	UPDATES OF YEAR-AHEAD COMMON GRID MODELS	Specify the procedure for updating Individual and Common Grid Models on the Year-Ahead timeframe.
14	WEEK-AHEAD INDUVIDUAL AND COMMON GRID MODELS	Specify the procedures for Week-Ahead Individual and Common Grid Models. This Article will not represent a completely new requirement for the regions that currently establish Common Grid Models, and its adoption is on a voluntary basis for the rest of the regions. In that sense, current (best) practices are formalised, with flexibility enough not to impact dramatically the TSOs processes.
15	D-1 AND INTRADAY GRID MODELS	Specify the requirements for D-1 and intraday Individual and Common Grid Models as established in accordance with NC CACM in order for TSOs to be able to perform Operational Security Analyses on them. Specify a way to monitor the quality of these CGMs. Currently D-1 models are merged by Synchronous Area (ex. for Continental Europe: DACF files, with a time granularity of 1 hour of D, ….). Intraday Common Grid Models are specified in NC CACM for capacity calculation processes. Intraday CGMs constitute a new activity formalized for some Synchronous Areas and for some of the regions within Synchronous Areas. The impact on the TSO current processes in relation with that task (building intraday CGMs) will be finally determined by the number of intraday sessions for capacity calculation.
	CHAPTER 3 OPERATIONAL SECURITY ANALYSIS IN OPERATIONAL PLANNING	

16	OPERATIONAL SECURITY ANALYSIS IN OPERATIONAL PLANNING	Detailing, for the Operational Planning timeframes, the general principles for Operational Security Analyses, having as main framework the NC OS and as main input the built Common Grid Models. This requirement formalises current practices. It establishes CGMs, where applicable, as input for Operational Security Analysis as new requirement allowing consistency of results.
17	YEAR-AHEAD UP TO AND INCLUDING WEEK-AHEAD OPERATIONAL SECURITY ANALYSIS	Requirement for performing and coordinating Operational Security Analyses from Year-Ahead up to Week-Ahead as well as identifying and preparing solutions to possible detected Constraints.
18	D-1, INTRADAY AND CLOSE TO REAL-TIME OPERATIONAL SECURITY ANALYSIS	Requirement for performing Operational Security Analyses and for evaluating and coordinating joint Remedial Actions to cope with possible detected Constraints, for D-1, intraday and Close to Real Time. The article makes the link with provisions drafted in NC OS and NC CACM and establishes the need to take into account for the coordinated analysis the updates of generation due to new market positions, updated forecasts or TSOs processes.
19	METODOLOGIES FOR COORDINATING OPERATIONAL SECURITY ANALYSIS	Contains of the methodologies, to be published on ENTSO-E website and applied by TSOs, which standardize Operational Security Analyses per Synchronous Area. In a certain extent, current practices include established methodologies (Operational Handbooks or similar) for the points described in the Article. A review of existent handbooks, containing principles and processes is to be made in order to formalize and adapt the existent principles and methodologies in line with the NC.
20	AGREEMENTS FOR COORDINATING OPERATIONAL SECURITY ANALYSIS	Requirement on the contents of the multilateral agreements to be established by TSOs to efficiently coordinate Operational Security Analyses, including provisions to ensure the coherences of processes and decisions between regions and the possibility to delegate particular tasks. TSOs shall review and adapt the today existent agreements in line with this Article.
	CHAPTER 4 OUTAGE COORDINATION	
21	DEFINITION OF OUTAGE COORDINATION REGIONS	The set of requirements ensures the formal installation of Outage Coordination Regions for ensuring the efficient and effective coordination of outages. In this framework, all interdependencies between Responsibility Areas with regard to Relevant Assets are taken into account, and sufficient coordination is guaranteed. Furthermore, the publication of the Outage Coordination Regions ensures the transparent coordination of outages. Initiatives for regional coordination of outages are extensively already in place. This set of requirements enables, however, a more systematic, formalized and transparent approach of the coordination among all parties.
22	REGIONAL COORDINATION PROCEDURE	The requirements set the framework for the coordination within the Outage Coordination Regions. They ensure the cooperation of all TSOs within an Outage Coordination Region and the information exchange of TSOs with other TSOs and connected DSOs and CDSOs. This is an existing practice. Nevertheless, the requirements set up a systematic and formalized framework for the regional coordination.
23	METHODOLOGY FOR ASSESSING RELEVANCE OF ASSETS FOR THE OUTAGE COORDINATION PROCESS	The set of requirements introduce the framework for the establishment of a methodology necessary to assess the impact of various assets within a Responsibility Area on another Responsibility Area. The methodology is vital for the outage coordination within the Outage Coordination Regions and defines

		the set of assets, whose outages are to be coordinated. Based upon the methodology, the effectiveness and efficiency of the coordination procedure is ensured. This approach is currently not established and will ensure a manageable and transparent way to coordinate outages.
24	LIST OF SELF-PLANNED INTERCONNECTORS, RELEVANT POWER GENERATING MODULES AND RELEVANT DEMAND FACILITIES	The set of requirements ensure the establishment of the list of Relevant Assets and the information exchange between TSOs, NRAs and all involved parties. Furthermore, the efficiency and effectiveness of the coordination procedures is ensured through the establishment of a single list within each Outage Coordination Region. The establishment of the list is based upon the methodology of Article 23.
25	RE-ASSESSMENT OF THE LIST OF SELF-PLANNED INTERCONNECTORS, RELEVANT POWER GENERATING MODULES AND RELEVANT DEMAND FACILITIES	The methodology for the establishment of the list of Relevant Assets is to be implemented periodically every year, in order to take into account the changes of the system and the assets and keep the coordination process up to date. Furthermore, the transparency is ensured through the publication of the updated list.
26	APPOINTING OUTAGE PLANNING AGENTS	The requirement ensures a single point of contact for each asset regarding to the outage planning, thus ensuring the effective and efficient communication and coordination of all responsible parties.
27	LIST OF RELEVANT GRID ELEMENTS	The set of requirements ensure the establishment of the list of Relevant Assets which are grid elements and the information exchange between TSOs, NRAs and all involved parties. Furthermore, the efficiency and effectiveness of the coordination procedures is ensured through the establishment of a single list within each Outage Coordination Region. The establishment of the list is based upon the methodology of Article 23.
28	RE-ASSESSMENT OF THE LIST OF RELEVANT GRID ELEMENTS	The methodology for the establishment of the list of Relevant Assets which are grid elements is to be implemented periodically every year, in order to take into account the changes of the system and the assets and keep the coordination process up to date. Furthermore, the transparency is ensured through the publication of the updated list.
29	TREATMENT OF RELEVANT ASSETS LOCATED IN A DISTRIBUTION NETWORK OR IN A CLOSED DISTRIBUTION NETWORK	The requirement ensures that when a Relevant Asset is connected to the Distribution Network, the concerned DSO is strongly involved by the TSO in the Outage Coordination Process related to this Relevant Asset. This principle is current practice in all Member States.
30	Variations to deadlines for the Year-Ahead coordination process	The requirement allows all the TSOs of a particular Synchronous Area to change the timeframe of the Outage Coordination Process from the one defined in the Network Code to a different one in order to cope with the specificity of the concerned Synchronous Area. This requirement will allow each Synchronous Area to adapt to the current practice as at this time, the timeframe may be different in different Member States.
31	LINK WITH DATA TO BE PROVIDED ACCORDING TO REQUIREMENTS OUTSIDE THIS NETWORK CODE	The requirement ensures that the Availability Plans resulting from the Outage Coordination Process are taken into account in all publication made by any party according to requirements outside this Network Code,
32	GENERAL PROVISIONS ON AVAILABILITY PLANS	Specify the requirements regarding the content of the Availability Plans: each Relevant Asset has a separate Availability Status which is either available, either unavailable either testing. The latter availability status “testing” is limited to specific time periods of operation of a Relevant Asset. This content and this granularity of Availability Plans are current practices in all members States.
33	LONG-TERM INDICATIVE AVAILABILITY PLANS	Specify the requirements regarding the assessment by the TSOs of a long-term indicative Availability Plans. On the basis of the data provided through the

		framework of the Transparency Regulation. TSOs provide their preliminary comments regarding Outage incompatibilities to the Outage Planning Agents. The requirement ensures that TSOs can detect Outage Incompatibilities two years before their occurrence, leaving more room to find a coordinated solution with the concerned Outage Planning Agents.
34	PROVISION OF YEAR-AHEAD AVAILABILITY PLAN PROPOSALS	Specify the requirements regarding the provision of the Availability Plans to the TSOs and if necessary DSOs by the Outage Planning Agents. The article also specifies the rules applied by TSOs to handle the change requests received. The requirements ensure that all Availability Plans are available at the same time in every Synchronous Area, allowing the TSOs to start the assessment of possible Outage Incompatibilities without advantaging any party.
35	YEAR-AHEAD COORDINATION OF THE AVAILABILITY STATUS OF RELEVANT POWER GENERATING MODULES, RELEVANT DEMAND FACILITIES AND SELF-PLANNED INTERCONNECTORS	Specify the requirements regarding the process of detecting and solving on a Year-Ahead horizon, the Outage Incompatibilities raised from the Availability Plans in coordination with the Outage Planning Agents. The requirements ensure that Outage Incompatibilities are detected by TSOs and that a solution is found in coordination with the impacted Outage Planning Agents or in the event that no coordinated solution is reached, that the lowest impact solution is proposed by the TSOs, informing the NRA of the not coordinated solution and of its technical and financial impacts for all parties. This requirement ensures that the conducted coordination processes are handled according to and in line with the current existing practices (regulations, law, contracts) as they are installed in the different Member States.
36	YEAR-AHEAD COORDINATION OF THE AVAILABILITY STATUS OF RELEVANT GRID ELEMENTS	Specify the requirements regarding the process of planning on a Year-Ahead horizon the Availability Statuses of Relevant Grid Elements. The requirements ensure that the Availability Plans provided by Outage Planning Agents are used as a basis by TSOs to plan the Availability Statuses of their Relevant Grid Elements and that the works on the Relevant Grid Elements are planned while minimizing their impact on the market. The availability Statuses of Relevant Grid elements interconnecting Transmission Systems are planned before the Availability Statuses of the other Relevant Grid Elements. The requirements ensure also that in case of Outage Incompatibilities, the TSO initiates coordination with the impacted parties in order to reach a solution. In the event that no coordinated solution is reached and that the delay in maintenance on the Relevant Grid Element threatens the Operational Security, the article aims at ensuring that the TSO takes all the necessary actions to plan the outage, while ensuring Operational Security and informs all impacted parties, including the NRA, of the technical and financial impacts of the actions taken.
37	PROVISION OF PRELIMINARY YEAR-AHEAD AVAILABILITY PLANS	Specify the requirements regarding the provision of preliminary Year-Ahead Availability Plans to all TSOs via the ENTSO-E Operational Planning Data Environment. The requirement ensures also that if a Relevant Asset is connected to a Distribution Network, the DSO operating this Network is provided with the Availability Plan of the Relevant Asset.
38	VALIDATION OF YEAR-AHEAD AVAILABILITY PLANS WITHIN OUTAGE COORDINATION REGIONS	Specify the requirements regarding the assessment and treatment by TSOs of the Outage Incompatibilities arisen when combining the Availability Plans of all the Relevant Assets within the Outage Coordination Regions. The requirement ensures that a solution is found for each Outage Incompatibility in coordination with all concerned TSOs and all concerned Outage Planning Agents within the concerned Outage Coordination Region.
39	FINAL YEAR-AHEAD AVAILABILITY PLANS	Specify the deadline for the provision of Year-Ahead Availability Plans by TSOs to all TSOs within ENTSO-E, to the concerned Outage Planning Agents and to the concerned DSOs. The requirement ensures that the Availability Plans are made available to the concerned entities (DSOs, TSO and Outage Planning Agents) by the TSOs respecting the same deadline in a given Synchronous Area. For confidentiality reasons, the information regarding the Availability Statuses of Relevant Assets

		is provided only to other TSOs, the concerned DSO if connected to the Distribution Network and the Outage Planning Agent which was appointed for.
40	COORDINATION PROCESSES IN CASE OF DETECTED OUTAGE INCOMPATIBILITIES	When a change to the coordinated Availability Plan is initiated by any party, and after assessment Outage Incompatibilities are detected, a coordination phase is set up. This coordination process shall be conducted by the connecting TSO(s) according to the applicable legal framework. This requirement ensures that the conducted coordination processes are handled according to and in line with the current existing practices (regulations, law, contracts) as they are installed in the different Member States.
41	UPDATES TO THE YEAR-AHEAD AVAILABILITY PLANS	After the Year-Ahead coordination process, the resulting coordinated Availability Plans of all Relevant Assets should be feasible and compatible. The purpose of this requirement is to ensure that all parties can update this Year-Ahead Availability Plan by describing the high-level process on how this should be done. The main goal of this Article is to ensure that after a change has been initiated, the impact on the overall Availability Plans is assessed, a coordination phase is set up according to the applicable legal framework and that after this coordination phase the resulting overall Availability Plans remain feasible and compatible. In every Member State, coordination processes exist for planning the Availability Status of Relevant Assets. These can be – depending on the country – described in national legislation, by bilateral contracts, etc. This Network Code does not envision changing these existing practices. The fact that a global Availability Plan for all Relevant Assets needs to be feasible and compatible at any point in time between Year-Ahead and Real-time might not be the case in all Member States. However, to ensure coordination between all affected parties being located in different Member States, and to make sure a suitable basis can be used for all related processes (e.g. capacity calculations, optimal planning of asset portfolio), a "reference" Availability Plan for Relevant Assets should be available to all TSOs, DSOs and Outage Planning Agents.
42	DETAILING THE TESTING STATUS OF RELEVANT POWER GENERATING MODULES, RELEVANT DEMAND FACILITIES AND SELF-PLANNED INTERCONNECTORS	The testing status is one of the three possible Availability Statuses, and is created to allow more flexibility in the status of a Relevant Assets during the limited time periods in which the correct functioning of the asset is tested. This basically means that when assessing the feasibility of the Availability Plans, for the Relevant Assets having the testing status, the possibility of them being both available or unavailable has to be taken into account, and neither of these statuses should lead to Outage Incompatibilities. When real-time operation is approached though, more detailed information on this testing period becomes available, and should be taken into account for a correct assessment of the feasibility and compatibility of the Availability Plans. This requirement ensures that the needed information is provided from the Outage Planning Agent to the connecting TSO, the connecting DSO and all other TSOs in the Outage Coordination Region. This principle is current practice in all Member States.
43	DETAILING THE TESTING STATUS OF RELEVANT GRID ELEMENTS LOCATED IN THE TRANSMISSION NETWORK	The testing status is one of the three possible Availability Statuses, and is created to allow more flexibility in the status of a Relevant Assets during the limited time periods in which the correct functioning of the asset is tested. This basically means that when assessing the feasibility of the Availability Plans, for the Relevant Assets having the testing status, the possibility of them being both available or unavailable has to be taken into account, and neither of these statuses should lead to Outage Incompatibilities. When real-time operation is approached though, more detailed information on this testing period becomes available, and should be taken into account for a correct assessment of the feasibility and compatibility of the Availability Plans. This requirement ensures that the needed information is provided from the TSO to all other TSOs in the Outage Coordination Region. This principle is current practice in all Member States.
44	DETAILING THE TESTING STATUS OF RELEVANT GRID ELEMENTS LOCATED IN THE DISTRIBUTION NETWORK	The testing status is one of the three possible Availability Statuses, and is created to allow more flexibility in the status of a Relevant Assets during the limited time periods in which the correct functioning of the asset is tested. This basically means that when assessing the feasibility of the Availability Plans, for the Relevant Assets having the testing status, the possibility of them being both

		available or unavailable has to be taken into account, and neither of these statuses should lead to Outage Incompatibilities. When real-time operation is approached though, more detailed information on this testing period becomes available, and should be taken into account for a correct assessment of the feasibility and compatibility of the Availability Plans. This requirement ensures that the needed information is provided from the DSO to its connecting TSO, and all other TSOs in the Outage Coordination Region. This principle is current practice in all Member States.
45	PROCESSES FOR HANDLING FORCED OUTAGES	Whenever a Forced Outage of a Relevant Asset occurs, the secure operation of the Transmission System could be jeopardized. The Transmission System should be able to withstand these Forced Outages for a certain time period thanks to the (N-1) planning principles. However, it is this "unplanned" nature of a Forced Outage that could result in the mentioned time period not being unlimited. To mitigate this risk, first requirements are installed to ensure timely information sharing from the Forced Outage experiencing party to all other affected parties. Second, information on the time period after which the Transmission System cannot be maintained in Normal State shall be provided from the TSO(s) to the Forced Outage experiencing party and this latter party shall endeavour to respect this time limit or justify its deviation. When, after this process, Operational Security is still endangered, a coordination process should be readily available to ensure that a solution can be found avoiding the risk for a Synchronous Area-wide system collapse. This emergency coordination process has to be set up by each TSO in advance and shall be approved by the relevant NRA.
46	REAL-TIME EXECUTION OF THE AVAILABILITY PLANS	Availability Plans have been established and coordinated to ensure a secure operation of the electricity system in Real-time, and to allow this real-time operation to be planned and assessed beforehand, based on these Availability Plans. It is therefore absolutely necessary that the coordinated Availability Plans of Relevant Assets are honored by all parties in real-time. As these Availability Plans only contain information on the Availability Status of a Relevant Asset this does not mean that the concerned party is restricted in its freedom to produce (for Power Generating Modules), transport (for Grid Elements) or consume (for Demand Facilities) energy with the concerned asset. This principle is current practice in all Member States.
	CHAPTER 5 ADEQUACY	
47	FORECASTS FOR ASSESSING ADEQUACY	Require TSOs to share the forecasts they use for assessing Adequacy. Forecasts are already shared through the Transparency Guidelines, however, this Article ensures that it is clear which forecasts in particular are used for Adequacy analyses.
48	RESPONSIBILITY AREA ADEQUACY ANALYSES	Specify the requirements for the Responsibility Area Adequacy analysis that each TSO will have to perform regularly.
49	SUMMER AND WINTER GENERATION ADEQUACY OUTLOOKS AND METHODOLOGY	Specify the requirements for TSOs for the establishment of the pan-European Generation Adequacy outlooks that ENTSO-E has to adopt under the requirement of Article 8(3)(f) of Regulation (EC) N° 714/2009. Specify the requirements for the update process of the NRA approved methodology used to establish these outlooks.
50	RESPONSIBILITY AREA ADEQUACY UP TO AND INCLUDING WEEK AHEAD	Specify the requirements for performing Responsibility Area Adequacy analyses whenever significant changes occur to Generation, demand, or cross border capacities. Changes are monitored for significance starting from the establishment of the summer and winter Generation Adequacy outlooks up to Week-Ahead.
51	RESPONSIBILITY AREA ADEQUACY D-1 AND INTRADAY	Specify the requirements for TSOs to perform Responsibility Area Adequacy analyses on a D-1 and intraday basis in order to predict when Adequacy is not fulfilled and take the necessary measures.

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	CHAPTER 6 ANCILLARY SERVICES	
52	ANCILLARY SERVICES	Specify the requirements for TSOs to assess and publish the required level of Ancillary Services, and to facilitate the procurement of these Ancillary Services.
53	REACTIVE POWER ANCILLARY SERVICES	Specify requirements for TSOs specifically dealing with assessing whether the levels of Reactive Power Ancillary Services are sufficient to ensure Operational Security and establishment and prioritisation of Remedial Actions should the level of Reactive Power Ancillary Services not be sufficient.
	CHAPTER 7 SCHEDULING	
54	ESTABLISHMENT OF SCHEDULING PROCESSES	Basic requirement to set up scheduling process between Market Participants and TSOs in accordance with the applicable national legal framework. This principle is current practice in all Member States.
55	NOTIFICATION OF SCHEDULES WITHIN SCHEDULING AREAS	This requirement ensures that the needed information is provided from the Market Participants to the TSO operating a Scheduling Area in accordance with the applicable national legal framework. This principle is current practice in all Member States.
56	COHERENCE OF SCHEDULES	All Schedules in a Scheduling Area should sum up to zero within a time period to keep the system in balance. All Schedules between all Scheduling Areas within a Synchronous Area should sum up to zero within a time period to keep the system in balance. This principle is current practice in all Member States.
57	PROVISION OF INFORMATION TO OTHER TSOS	TSOs shall provide Schedules to other TSOs to enable these TSOs to fulfil their operational tasks. This principle is current practice in all Member States.
	CHAPTER 8 ENTSO-E OPERATIONAL PLANNING DATA ENVIRONMENT	
58	GENERAL PROVISIONS FOR ENTSO-E OPERATIONAL PLANNING DATA ENVIRONMENT	To have a common data base for data exchange in operational planning between TSOs and RSCIs. At the moment there isn't an existing common data base for data exchange in operational planning. To have one defined data format, to get easier and faster the relevant information and an overview of the impact on each system, to increase the grid security
59	INDIVIDUAL GRID MODELS, COMMON GRID MODELS AND OPERATIONAL SECURITY ANALYSIS	To have an operational planning data environment that shall allow access to all Individual Grid Models and related relevant information for all relevant time horizons At the moment there are more different processes how to design Individual Grid Models and what kind of information they should include. To have defined data format, to get easier and faster the relevant information and an overview of the impact on each system, to increase the grid security
60	OUTAGE COORDINATION PROCESS	To have an operational planning data environment for storage and sharing of all relevant information for coordinated outage planning with access for all TSOs and RSCIs. At the moment the outage planning data exchange will be done via e.g. WOPT (weekly operational planning telephone conference)

		To have a common data base for data exchange To have one defined data format, to get easier and faster the relevant information and an overview of the impact on each system, to increase the grid security
61	SYSTEM ADEQUACY	To have an operational planning data environment for all relevant information for coordinated Adequacy analysis with access for all TSÖs and RSCIs. E.g. exchange WOPT (weekly operational planning telephone conference) reports with relevant information's for week ahead Possibility to provide all the time an update of Adequacy analysis and to make it quickly available for all TSO's and RSCIs

CHAPTER 9 PERFORMANCE INDICATORS

62	PERFORMANCE INDICATORS	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 Planning and Scheduling Performance Indicators in the ACER Framework Guidelines for Electricity System Operation. This methodology allows developing for OPS indicators focused on the results of OPS processes in terms of interconnected power Transmission System reliability. The ranking and explanation / analysis of reasons of incidents and events reported in the yearly ICS report allow to monitor to which extent processes dealing with operational planning are affecting reliability of the interconnected power system and are the part of the Operational Planning and Scheduling Performance Indicators approach developed in the NC OPS. They provide for a structured and transparent, to identify any necessary enhancements (those can even include changes in framework or even NC OPS itself if it is considered lacking any critical provisions) in order to maintain Operational Planning and Scheduling 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 will not allow to address the objectives of the Network Code which aims at developing cross border coordination in operational planning processes especially bearing in mind the rapidly growing degree of interleaved dependencies between the TSOs and their Responsibility Areas, 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, tit suffers also of limits 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 or powers flows patterns not in line with security principles). This means further that the scope for the assessment of the System Operational Planning and Scheduling will always have to retain a wide, view on the European interconnected Transmission Systems and that the identification of necessary enhancements – or new means – will always be case-by-case based. Nevertheless, the ex-post analysis after significant incidents or events 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 relevant Operational Planning and Scheduling coordinated processes in Europe.
	CHAPTER 10 FINAL PROVISIONS	
63	AMENDMENT OF CONTRACTS AND GENERAL TERMS AND CONDITIONS	Timeframes and final provisions for amendments.
64	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

10.2 Appendix 2 Assessment of the NC OPS against requirements of the Framework Guidelines

Purpose

Table: FG, NC OPS & other NCs. The NC OPS defines, according to the OS FG, the following requirements to be found in the table, which also lists the chapter that defines the requirement, followed by the link to other Network Codes.

	REQUIREMENT OF THE FRAMEWORK GUIDELINE	EXTENT TO WHICH THE PROVISION IS MET
1. General provisions		
Scope and Objectives	The Network Code(s) developed according to these Framework Guidelines will be applied by electricity system operators and significant grid users, taking into account possible public service obligations and without prejudice to the regulatory regime for cross-border issues pursuant to Article 38 of Directive 2009/72/EC (henceforth referred to as the "Electricity Directive") and to the responsibilities and powers of regulatory authorities established according to Article 37(6) of the Electricity Directive.	Regulatory issues and NRA scrutiny are covered in Article 3, 4, 5, 24(6), 27(6), 30(1)(b), 35(3)(c), 36(5)(c), 48(3), 51(3). The scrutiny level takes into account the responsibilities of TSOs regarding Operational Security as set up by the Directive 2009/72/EC.
	The Network Code(s) will be evaluated by ACER, taking into account their degree of compliance with these Framework Guidelines and the fulfilment of the following objectives: maintaining security of supply, supporting the completion and functioning of the internal market in electricity and cross-border trade, delivering benefits to the customers and facilitating the EU's targets for penetration of renewable generation.	The OPS supporting document develops extensively how the code contributes to the objectives addressed by the FGL in particular through a global coordinated security analysis framework, by promoting extensive use of Common Grid Models, developing common methodologies and developing RES handling.
	All Transmission System Operators' (TSOs) actions with regard to system operation within a Synchronous Area or between them could bear cross-border character due to law of physics. Rulebooks on system operation already exist in the different Synchronous Areas, but the debate with the Expert Group1 revealed problems that have not been tackled by these rules – prominent example is the event on 4 November 2006 – hence, a more coherent framework is needed.	Articles 9 to 15 establish a Common Grid Models (at least at Synchronous Area Level) from Year Ahead down to Intraday, support of coordinated analysis. Articles 16 to 20 oblige TSO's to undertake co-ordinate Operational Security Analysis from Year Ahead down to Intraday including cross control area Remedial Actions. TSO shall develop methodologies for assessing Operational Security standardised at least at Synchronous Area level. TSOs shall develop regional coordination to address electrical interdependencies with one unique agreement per region linking all concerned TSO's and delivering defined processes ensuring security analysis coordination. These agreements shall

		allow integrating RSCI's common entities within these processes.
	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.	TSOs, DSOs and relevant grid users participation is enforced through the different processes addressed by the code and in particular in co-ordinated outage planning. The methodology to achieve this is defined in Articles 21 to 46. TSO's coordination and co-operation is enforced for all processes involved in operational planning and developed through the code: producing Common Grid Models, performing coordinated security analysis, coordination per outage region to produce outage plans, performing Adequacy outlook, allowing exchange of Ancillary Services ensuring consistent cross-border schedules and developing a common ENTSO-E Data Environment.
	The Network Code(s) for System Operation shall ensure provision of an efficient functioning of the interconnected Transmission Systems to support all market activities.	Links with CACM are developed and the uses of CGM largely promoted in all time frames. Obligations on TSOs to harmonise Operational Security Analysis and Outage Coordination included in Chapters 3 and 4 respectively. Articles 54 to 57 oblige TSO's to implement a process to Schedule internal energy balance and between Responsibility Areas. Chapter 2 and 3 oblige TSOs to develop Remedial Actions with principles approved by NRA.
1.2 Structure	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.	The NC OPS obliges TSO's to produce harmonised security analysis principles in line with NC OS, within a detailed mandatory scope. The NC OPS defines role of TSO in all processes dealing with operational planning activities. The NC OPS promotes the development of an ENTSO-E data environment covering needs of data exchange for processes involved in operational planning. Data from grid users are provided within the framework established by NC OS.
	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.	By increasing the level of co-ordination between TSOs the code will facilitate increased cross border flows and enhance Operational Security. Obligations to apply common principles: • Scenarios to assess operation; • Methodologies for security analysis co-ordination at least at Synchronous Area level; • Coordinated Outage Planning; • Coordinated Adequacy Analysis taking into account possibilities of imports and exports within cross border transmission capacities; • monitoring availability of Ancillary Services including possibilities of Ancillary Services exchanges; • setting up an ENTSO-E data environment supporting data exchanges required by operational planning processes.

1.3 Links and dependencies	There is close interrelationship between issues related to System Operation, grid connection, cross-border capacity allocation and congestion management, grid development and maintenance, obligations for data provision and the functioning of balancing and reserve power markets. In drafting the Network Code(s) the European Network of Electricity Transmission Operators for Electricity (ENTSO-E) should take into consideration, at least, the following existing requirements and proposed separation of issues in drafting the Network Code(s)	Cross checking with other codes, e.g. NC OS and NC CACM have been carried out. Interrelationships are developed throughout the code and the supporting document, in particular with the other system operation codes, with NC CACM regarding Common Grid Models and operational margins, and with NC RfG considering characteristics and capabilities of grid users' equipment used for system simulations and analysing system security. Data requirements are referring NC OS as umbrella code defining all data addressed for system operation.
	Issues which are relevant to more than one Framework Guidelines are as a minimum mentioned in all the relevant Framework Guidelines and specified in more detail where necessary. This approach, in the interests of completeness and clarity on important issues, may result in some duplication amongst different Framework Guidelines. In drafting the relevant Network Code(s) ENTSO-E shall ensure that they are appropriately coherent and compatible.	Regarding NC RfG and NC DCC , NC OPS deals with operational planning processes and doesn't use directly capabilities of connected grid users. These capabilities are activated in real time, under NC OS requirements. NC OPS is using these capabilities for system security and Adequacy analysis referring NC OS which specifies the use in operation of these capabilities.
1.5 Application	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. The Network Codes on system operation shall be drafted with due attention to the Network Code amendment process. 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.	Level of details is specifically discussed within the supporting document pointing out the global three layers framework developed by the code addressing in a consistent way the pan European, synchronous zones and regions levels. In particular regarding methodologies the code is fixing a detailed scope of the methodologies, based on existing operational handbooks and leaving the details to be fixed outside the code in order to enable relevant flexibility and improvements of these in a changing environment.
	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.	Reference to national laws is developed in particular in Article 3.
	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	Impact assessment is being drafted. It doesn't involved additional cost for stakeholders. Regarding TSOs cost are related to new tools and processes supporting an increased coordination.

	ENTSO-E that justifies and demonstrates additional benefits from the proposed standard or requirement.	
	The cost-benefit analysis should be provided to stakeholders when ENTSO-E consults on the Network Code(s). The cost-benefit analysis should be submitted to ACER alongside the Network Code(s) and will be taken into consideration by ACER in providing its opinion on the Network Code(s).	Impact assessment being drafted.
1.6 Roles and responsibilities	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).	The NC OPS refers to significant grid users, aligned with NC OS. Relevance of significant grid users in the coordinated outage planning is covered through a common methodology explained in the supporting document.
	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.	DSO's in NC OPS are addressed consistently with NC OS. Appropriate requirements deal with their involvement in operational planning processes.
	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.	The NC OPS is aligned with NC OS.
1.7 Derogations	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.	The NC OPS is aligned with NC OS.
	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 NC OPS does not allow derogations for TSOs.
1.8 Adaptation of existing arrangement to the Network Code(s)	System operators and relevant significant grid users shall amend all relevant clauses in contracts and/or all relevant clauses in general terms and conditions in accordance with the terms of the Network Code(s) on System Operation. The relevant clauses shall be	Amendments of relevant clauses in contracts are treated in Article 63.

	amended within a fixed time limit after entry into force of the Network Code(s), defined in the Network Code(s), but not exceeding three years. This requirement shall apply regardless of whether the relevant contracts or general terms and conditions provide for such amendment.	
	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.	Implementation timescales are developed in Article 64 including time scales for methodologies implementation.
2. Minimum standards and requirements for system operation **General System Operation Characteristics**		
Scope and Objectives	Achieving and maintaining normal functioning of the power system with a satisfactory level of security and quality of supply, as well as efficient utilisation of infrastructure and resources.	The supporting document describes the key concepts developed by NC OPS to fulfil scope and objectives set up in Article 1.
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. 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 the NRAs and ACER.	Article 62 establishes indicators making the link between OPS processes and reliability of system operation per synchronous zones. Article 15 set up requirements on data quality for Common Grid Models.
Methodology and Tools	The Network Code(s) shall define common principles, requirements, standards and procedures within the Synchronous Areas throughout the EU.	The Network Code establishes common principles, requirements, standards and procedures for all time frames and key processes dealing with operational planning activities. Level of detail is specifically discussed within the supporting document pointing out the global three layers framework developed by the code

		addressing in a consistent way of the pan European, synchronous zones and regions levels. In particular regarding methodologies the code is fixing a detailed scope of the methodologies based on existing operational handbooks and leaving the details to be fixed outside the code in order to enable relevant flexibility and improvements of these in a changing environment. These methodologies are: methodology for summer and winter generation Adequacy outlooks pursuant to Article 49, the methodology set up pursuant to Article 19 for coordinating Operational Security Analysis, the methodology set up pursuant to Chapter 4 Article 23 for assessing relevance of assets for the outage coordination process, the provisions dealing with the gathering of the Year-Ahead Individual Grid Models, merging them into Common Grid Models and saving them pursuant Article 12, the provisions dealing with the gathering and merging of the D-1 and intraday Individual Grid Models into Common Grid Models at the level of at least the Synchronous Area pursuant Article 15, consistent with the methodology set up pursuant to Article 18, 20 and 21 of NC CACM.
	Network code(s) shall be in line with experiences, best known operational practices and lessons learnt from experiences.	Code has been drafted based on operational experienced and knowledge, with references exposed in the supporting document for each key process of operational process addressed by the code.
	No provision in the Network Code(s) shall prevent market arrangements being used for the provision and use of Ancillary Services.	Chapter 6 (Ancillary Services) takes into account the possibility of market arrangements and the exchange of Active Power Ancillary Services.
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).	Roles of TSOs and DSOs where relevant are defined within each process handled by the NC OPS.
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.	The NC OPS is aligned with NC OS regarding data procurement, timing being precised according to operational planning processes handled by NC OPS.
	The Network Code(s) shall set the requirement for DSOs to execute the instructions given by the TSOs.	Applies to real time operation.
	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,	Information exchange is defined in NC OS and NC OPS is referring to NC OS in Article 15(3)(b).

	• 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.	
	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.	Instructions are covered in NC OS and in NC OPS for outage planning when involving DSOs.
	Obligation for data delivery: 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.	Enforcement measures are covered by NC OS as umbrella code. Confidentiality is covered by Article 6.
	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.	Transparency guidelines address data delivered by operational planning. Besides these guidelines additional information and publication are required for all processes such as publication of common list of scenarios and their description, outage coordination regions, Adequacy outlooks, requirements of Active Power reserves, as the publication of methodologies. Non-discrimination is handled through a common methodology for relevance criterion to be applied to all grid users in outage planning coordination.
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.	The supporting document develops how the code fits with forthcoming changes and challenges in particular concerning RES increase by reinforcing coordinated security analysis, integrating RES forecast and concerning market developments with enforcing the use of Common Grid Models and making the links with NC CACM.
Topic 2 Operational Planning and Scheduling		
Scope and Objectives	Ensuring coherent and coordinated behaviour of Transmission Networks and power systems in preparation of real-time operation.	Scope is addressed through a global framework addressing time frames and processes required for operational planning.

	Achieving and maintaining a satisfactory level of Operational Security and efficient utilisation of the power system and resources.	The supporting document describes the key concepts developed by NC OPS to fulfil scope and objectives set up in Article 1.
Criteria	The Network Code(s) shall provide criteria (performance indicators) against which the Operational Planning and Scheduling can be monitored.	Article 62 establishes indicators making the link between NC OPS processes and reliability of system operation per synchronous zones. Article 15 sets up requirements on data quality for Common Grid Models.
Methodology and Tools		The Network Code establishes common principles, requirements, standards and procedures for all time frames and key processes dealing with operational planning activities. Level of detail is specifically discussed within the supporting document pointing out the global three layers framework developed by the code addressing in a consistent way of the pan European, synchronous zones and regional levels. In particular regarding methodologies the code is fixing a detailed scope of the methodologies, based on existing operational handbooks and leaving the details to be fixed outside the code in order to enable relevant flexibility and improvements of these in a changing environment. These methodologies are: methodology for summer and winter generation Adequacy outlooks pursuant to Article 49, the methodology set up pursuant to 19 for coordinating Operational Security Analysis, the methodology set up pursuant to Article 23 for assessing relevance of assets for the outage coordination process, the provisions dealing with the gathering of the Year-Ahead Individual Grid Models, merging them into Common Grid Models and saving them pursuant Article 12, the provisions dealing with the gathering and merging of the D-1 and intraday Individual Grid Models into Common Grid Models at the level of at least the Synchronous Area pursuant Article 15, consistent with the methodology set up pursuant to Article 18, 20, 21 of NC CACM.
F1	Performing security analyses (Contingency Analysis, voltage stability analysis, etc.) at each relevant stage of operational planning. The provisions shall ensure that System Operation meets security criteria under any simulated operating conditions consistent with security assessment, and that the operation of the interconnected control areas is not jeopardised;	Chapter 2 All TSO's define a common list of scenarios to allow Operational Security to be assessed including timescales and methodology for updating the list of scenarios. Also detailed in Chapter 2 is gathering and sharing data across TSO's required for producing both Individual Grid Models and Common Grid Models both at Outage Coordination Region and pan European level. Chapter 3 Details TSO obligations for timelines for performing Operational Security Analysis including detailed reference to relevant articles in the NC OS. Also detailed are the security analysis for Contingency Analysis, voltage stability and short circuit events.
F2	State Estimation, to be implemented as required for supporting the security control and maintaining the Operational Security, including	Article 18.5 establishes use of State Estimation to perform Operational Security Analysis close to real time on a time cycle not exceeding 15 minutes.

	periodical (with sufficiently short time periods) checks in order to ensure a consistent and errorless input data set for other computations like load-flows, security analyses, etc.;	Quality of D-1 and intraday Common Grid Models are covered by Articles 15.
F3	Determining the specific Reliability Margin, required to cope with uncertainties relevant to System Operation, and which uncertainties are covered by the Reliability Margin. Consistency between Reliability Margins for system operation and transmission capacity calculations shall be ensured	The NC OPS supporting document details the global framework for making the link between Operational Security principles, transmission Reliability Margins and handling uncertainties as the links with NC CACM. Article 19 establishes the corresponding principles and the consistency of Article 25 of NC CACM as part of the methodology for Operational Security Analysis.
F4	Prevention and/or remedy of disturbances and blackouts on incidents which can affect neighbouring control areas or the Synchronous Areas;	Prevention of disturbances and blackouts on incidents which can affect neighbouring control areas or the Synchronous Areas is covered in: ▪ Chapter 2 defines common scenarios and sharing of information across TSOs to identify disturbances in conjunction with the building of IGMs and CGM; ▪ Chapter 3 defines the time frames and actions necessary to detect disturbances and Remedial Actions including checking the validity of the Remedial Actions; Remedy of disturbances and blackouts and incidents which can affect neighbouring control areas or the Synchronous Areas is covered by: ▪ Chapter 3 Article 17 and 18 details process for neighbouring TSOs to agree and review Remedial Actions with Article 20 defining an ACER approved methodology defining coordinated Remedial Actions. Chapter 6 details actions necessary to monitor Ancillary Services such that they do not cause disturbances and blackouts with reference to the NC LFCR.
F5	Scheduling planned outages and relevant maintenance works of Transmission Network, significant generation and *DSOs*' elements, including a coordinated and agreed (among the affected *TSOs*) scheduling process for long-term and short-term planning;	This is covered in Chapter 4 which details: • The process to identify affected TSOs (Outage Coordination Regions) and sharing and co-ordinating the long and short term planning process (Articles 21, 22 and 23,); • The process to identify relevant grid users (Article 24 and 25); • The process to identify Relevant Grid Elements (Article 27, 28 and 29); • Year ahead outage planning and updating both planned and unplanned changes (Article 33-41) and real time execution of the plan (Article 46); • DSOs involvement in particular addressed though Article 29, 44).
F6	Ensuring access to an adequate level of Ancillary Services (e.g. active and Reactive Power Reserves, balancing power) in real-time to meet security criteria and the requirements set at Synchronous Area	Chapter 6 details the process for Ancillary Services: • Co-ordination up to Synchronous Area level;

	level, for each operational planning stage;	• Procurement of active and Reactive Power including exchange between TSOs; • Monitoring levels and locations of Ancillary Services; • Information provision and exchange. Chapter 5 details the Adequacy monitoring and in particular the process for seasonal pan-European analysis (Article 49).
F7	Calculation of requirements on different categories of control reserves with the aim to optimise these requirements within Synchronous Area to meet the security criteria with minimum costs;	Chapter 6 defines: • Monitoring of availability of Ancillary Services integrating exchange of Ancillary Services between TSOs (Article 52); • Level of Ancillary Services in accordance with NC LFCR and NC EB (Article 52).
F8	Exchange of Ancillary Services across interconnections in terms of technical principles;	Chapter 6 (Article 52) treats the exchange of Ancillary Services between TSOs aligned with technical principles detailed in NC LFCR and NC EB.
F9	Coordination of Reactive Power control with significant cross-border impact;	Article 53 establishes the requirements regarding consistency of Reactive Power sources to ensure Operational Security and the coordination with other TSOs.
F10	Coordination of short circuit current between TSOs at interconnections;	Chapter 3 details the requirement for co-ordination of short circuit currents (Article 17) in all planning timescales.
F11	Coordination of commissioning and entering into operation of active and Reactive Power control Network elements with significant cross-border impact. In particular, Reactive Power control elements installed at each end of cross-border lines shall be coordinated;	Chapter 4 (Article 32, 42-44) covers coordination of the entering into operation of the Relevant Grid Elements.

	Obligation for data delivery → See Information Exchange The Network Code(s) shall describe - for the different time frames - the principles for exchange of all necessary information between system operators to handle the different planning and scheduling activities in a coordinated and cooperative manner. This includes all necessary data to construct a proper Synchronous Area-wide Common Grid Model. TSOs shall be provided with up-to-date information on the development of grid components and configuration, also by significant grid users, especially as regards planned and unplanned outages and their technical ability to provide Ancillary Services;	Chapter 2 details a co-ordinated list of scenarios across TSOs (Article 10) and the creation and merging of Individual Grid Models (Article 10 and 13) across planning timescales to create a Common Grid Model along with requirements to update information (Article 13, 14, 15). Chapter 4 (Article 33 and 40) details the information exchange for TSO outage plan to be shared with all TSOs, including updates (Article 41, 45, 46) Chapter 8 details: • The provision of an operational planning environment to facilitate outage information exchange between TSOs (Article 60); • Details provision of data for the production of CGM for security analysis (Article 59).
F13	In relation to the CACM FG and the respective Network Code(s), principles and requirements for the implementation and operation of the Transmission capacity calculation methods at the different time frames. In this respect, the coherence between the preparation of a Common Grid Model and the assessment of relevant Reliability Margins shall be ensured. Specifically, Reliability Margin calculations shall take into consideration all pertinent assumptions made in due course of preparation of the Common Grid Model and Transmission capacity calculation in order to cope with model/method inaccuracies and relevant uncertainties efficiently.	The NC OPS Supporting Document details the consistency with NC CACM for building Common Grid Models, referring in particular to the European Merging Function. Article 9 of NC OPS sets up the general requirements to ensure this consistency with NC CACM. Articles 12 to 15 establish the requirements for elaborating Common Grid Model within each time frame, referring the European Merging Function and for D-1 and intraday, Article 20 and 21 of NC CACM. Article 18 establishes the corresponding principles and the consistency with Article 25 of CACM NC as part of the methodology for Operational Security Analysis.
Roles and Responsibilities	The Network Code(s) shall foresee that the TSOs coordinate their operational planning activities at regional, Synchronous Area and EU level – as technically necessary and within the most appropriate entities – in order to ensure meeting the objectives of secure System Operation and applying the most appropriate measures to prevent and/or remedy system disturbances.	The NC OPS establishes TSOs responsibilities for the different processes involved in their operational planning activities and corresponding coordination requirements at regional, Synchronous Area and EU level in order to ensure Operational Security of the Interconnected System.
Implementation Issues	The Network Code(s) for Operational Planning and Scheduling are related to the CACM FG and EB FG, and the respective Network Code(s); thence, the overlapping issues shall be harmonised.	Overlapping issues with other Networks code have been analysed and solved when establishing appropriate references and sharing common definitions.

2.1 New Applications		
	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. Forthcoming changes and challenges caused by further market integration and innovation in technology and organisation should be recognised and considered. 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, beyond 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).	The Supporting Document develops in Chapter 3.5 challenges and opportunities ahead of system operation addressing in particular the integration of RES in the system and implementation of the IEM, in a scenario with increasing complexity, where further challenges can be foreseen in the near future due to the new applications and developments on system operation: 1. High Voltage DC (HVDC) Links; 2. Demand Side Response (DSR); 3. Smart Grids; 4. Super Grids. The supporting document explains how the NC OPS provides requirements and principles to accompany harmoniously this development.

10.3 APPENDIX 3 NETWORK CODE ON OPERATIONAL PLANNING AND SCHEDULING - SUMMARY OF COMMENTS RECEIVED DURING PUBLIC CONSULTATION AND OVERVIEW OF THE ENTSO-E RESPONSES

Purpose

This third appendix provides ENTSO-E's assessment of comments provided as part of the web-based consultation on the draft Network Code on "Operational Planning and Scheduling" between 7 November 2012 to 7 January 2013. Rather than providing responses per individual comment received, an assessment of all input received has been undertaken on a clustered basis.

Comments are grouped by Article and are summarised in the interest of accessibility.

The Article numbering in this document refers to the Article numbering of the draft code published on 7 November 2012.

This document is not legally binding and aims only at clarifying the content of the final Network Code based on feedback provided during the formal consultation period.

ENTSO-E notes that many comments were not attributed to a specific article and gave general views or referred to cover letters. No specific responses are given on these comments in this document though they have been taken into account, to the extent possible, in our general assessment of comments.

Article by article summary

WHEREAS and Article 1 - SUBJECT MATTER AND SCOPE

Summary	4 comments were received on this Article regarding the item "Isolated systems''.
Changes made & explanation	The definition of Micro Isolated System and Small Isolated System is contained in Article 2 (26 and 27) of Directive 72/2009/EC. The rule to exclude them is stipulated in Article 8(7) of Regulation (EC) N°714/2009. An additional article has been added due to concerns of stakeholders about the relevance of human and nuclear safety.

Article 2 - DEFINITIONS

Summary	88 comments were received on this Article. Three themes emerged several times: 1. Consistency with other codes; 2. Clarification of the definitions related to the relevance of Grid Users; 3. Clarification or addition of the definitions related to availability (Outage, Availability …)
Changes made	In order to improve clarity and consistency of the definitions, 15 definitions are modified and few new definitions are added
Explanation for change or no change	All the definitions used in the NC OPS are not written down in the Article 2 following the decision taken at ENTSO-E level to ensure the coherency of definitions. It is important that, to the fullest extent possible, a single glossary exists for all Network Codes. Hence attempts to avoid overlap are needed and definitions need to be written in a way such that they are fit for purpose for other codes. Hence, they cannot be overly specific.

Article 3 – REGULATORY ASPECTS

(Added new Article 4 Regulatory approvals)

Summary	21 Comment was received on this article. Two themes emerged several times: 1) NRA involvement. 2) Transparency.
Changes made	A new article on Regulatory approvals has been added in the new version.
Explanation for change or no change	A new article has been added in the first section of the Network Code (Article 4). This directly refers to the powers of regulators as mentioned in the Third Energy Package and specifically in Directive 2009/72/EC. It presents a consistent set of timings and clarifies the role of regulatory authorities. To enhance clarity, ENTSO-E has explicitly listed all cases where Regulatory Approvals are foreseen and at which level the respective approval should take place (e.g. pan-European, Synchronous Area level or national regulatory authorities). Transparency market issue are dealt with in the European transparency guidelines. Not all information should be available close to real time. Even so, Article 3(1) imposes that all requirements under this Network Code are also to be established under the principle of transparency. Therefore, this principle - substantiated in the transparency guidelines - is fully respected.

Article 4 – RECOVERY OF COSTS

(Article 5 in new version)

Summary	18 comments were received on this Article. Three themes emerged several times: 1) that recovery of costs should be extended to DSOs and other Grid Users and 2) that costs of DSO and grid users need to be taken into account so decisions/optimisation of outages are not just to benefit of TSO and 3) need for provisions re principles on recovery of expenses of power generating facilities on a compulsory change in outage and 4) the language used on the TSOs obligations at Article 4(3) less onerous than language used at obligations on grid users
Changes made	All regulated Network Operators are now considered.
Explanation for change or no change	1. Reference to only regulated NOs is consistent with the approach in the NC OS (presumably on the basis that the NC mainly addresses TSOs and hence involves them in costs. RfG and DCC refer to regulated NOs (which includes DSOs). As such, including NOs in the definition of this article enhances consistency between these three Network Codes, even though the NC OS will incur very little obligation on DSOs. 2. Language used is consistent with the approach in other NCs.

Article 5 – CONFIDENTIALITY OBLIGATIONS

(Article 6 in new version)

Summary	7 comments were received on this Article. The following two themes emerged: 1) Information exchange, 2) Confidentiality of information
Changes made	
Explanation for change or no change	1. Information exchange between TSO, DSO and significant Grid Users is necessary to ensure System Security and fulfilment of the tasks of the NC. The information exchange has also to respect the transparency guidelines. The specifics about information exchange are explained in the Supporting Document. 2. 2) The risk of providing confidential information to third parties is known. On the one side everyone getting any information has to respect the confidentiality obligation of the NC and on the other hand TSO will mostly exchange aggregated information without the possibility to see the individual information.

Article 6 – ROLES IN OPERATIONAL PLANNING AND SCHEDULING AND DELEGATION

(Article 8 in new version)

Summary	7 comments were received on this Article. The following three themes emerged: 1. Outage planning; 2. Delegation; 3. NRA Involvement.
Changes made	Changes concerning detailed roles on outage coordination are done in Chapter 4. Provisions concerning delegation are clarified. NRA involvement is treated in Articles 3 and 4.
Explanation for change or no change	1. No new paragraph will be inserted here, as outage planning is treated in Chapter 4. As such, the process for information exchange in time, to hinder uncertainty of outage planning has to be described in Chapter 4. 2. Delegation of tasks must be possible. Delegation of tasks doesn't mean delegation of the whole business, since this would mean a player would no longer exercise its function. Delegation of tasks isn't the same as delegation of responsibility, which is explicitly written down in this Article. 3. NRA Involvement is treated in Article 3. A special norm to give competence to a NRA to monitor / survey TSOs and review the fulfilling of the tasks by the TSO is not necessary in this NC as this competence is already stipulated in Regulation (EC) N°714/2009 and Directive 72/2009/EC

Article 7 – YEAR-AHEAD SCENARIOS

(Articles 9 and 10 in new version)

(To improve readability and for clarification reasons the Article 7 is split into Articles 9 Individual and Common Grid Model general provisions and Article 10 Year-Ahead scenarios in new version)

Summary	There were 10 comments received on this Article, addressing the following key issues: 1. 2 comments were received on code consistency: both comments concerned perceived inconsistencies with NC CACM and NC OS, one of which suggested that parameters/requirements from NC OS could be changed by NC OPS. 2. 2 comments were received on data from stakeholders: both comments concerned the required data for the Year-Ahead scenarios, asking for the source of the data to be clarified. 3. 1 comment was received on reference to NC OS: It requested referencing to NC OS in regards to the parameters used to assess Operational Security 4. 4 comments were received on transparency: it requested adding a publication date to the requirement for ENTSO-E to publish the Year-Ahead scenarios. It also requested to require publication of the general description of the scenarios as well as the scenarios itself, to improve transparency. 5. 1 comment was received on TSO workload: it was suggested that the number of scenariosshould be limited in order to keep a check on TSO workload.
Changes made	Article 10 has been changed according to the suggestions, including the date of the requirement in Article 10(3) and asking for the full description of the scenarios to be included in the publication
Explanation for change or no change	1. No inconsistencies with other codes were detected, nor is it possible or intended for NC OS parameters to change. In order to prevent this misconception the word parameter has been changed to variable. 2. No further data will be required from stakeholders in order to establish the Year-Ahead scenarios because they will be based on TSOs best estimates, as will be further clarified in the Supporting Document. As a result, no change to the NC is required. 3. The suggested change will not be made, as the necessary reference is made already in the description of the security calculations, in Article 15. 4. The NC has been changed according to the suggestions, including the date of the requirement in Article 10(3) and asking for the full description of the scenarios to be included in the publication. 5. Although ENTSO-E agrees with the general principle of keeping the increase of TSO workload to a minimum, ENTSO-E believes in this case it is already as small as can managed in order to maintain Operational Security. Therefore the code should not be changed.

Article 8 – CONSTRUCTION OF YEAR-AHEAD INDIVIDUAL GRID MODELS

(Article 11 in new version)

Summary	There were 16 comments on this Article, all dealing with one key issue: grid models. The following topics were touched upon: 1. 4 comments were received on net exchanges: they were said to be an output rather than an input. 2. 5 comments were received on inconsistency with CACM: it was suggested that NC OPS should use the same models as NC CACM 3. 2 comments were received on wording: missing words and apparently inconsistent plurals were pointed out. 4. 1 comment was received on loop flows: it was suggested that loop flows be included in the grid model 5. 4 comments were received on grid models: it was suggested that grid models should be updated rather than created.
Changes made	Changes have been made to further clarify the code, including the addition of a new Article 9. The missing word 'interconnections' has been added.
Explanation for change or no change	1. The net exchanges referred to are required in order to merge the IGMs into the CGM. Using this input does not in any way limit the space of the market. It can be compared to Net Position as used in NC CACM, although it may apply to different borders. This issue will be further explained in the Supporting Document. 2. There is no inconsistency between NC CACM and NC OPS. However, there is some ambiguity contained within the way NC OPS was being formulated. Therefore some changes have been made to further clarify the code, including the addition of a new Article 9. Multiple CGMs exist because they deal with different timeframes. The timeframes in NC CACM are sometimes different from the ones used in NC OPS. The Year-Ahead timeframe this Article applies to is not part of NC CACM. 3. The missing word 'interconnections' has been added. Consistent with NC CACM, there is one IGM for each scenario, so that TSOs will indeed establish multiple IGMs. The plural therefore is acceptable. 4. Loop flows are not necessary as inputs for the EU-wide CGM. Instead, they should be outputs. 5. The Network Code should be flexible enough to allow IGMs to be only partially updated when for technical reasons this is needed instead of uploading an entire new model. This should be detailed within the provisions for the gathering, saving and merging of IGMs according to Article 11(1).

Article 9 – DISTRIBUTED GENERATION AND CONSUMPTION IN YEAR-AHEAD SCENARIOS

(Merged with Article 12 in new version)

Summary	Nine comments were received on Article 9. They addressed three key issues: 1. 1 comment asked for a definition of distributed generation. 2. 7 comments dealt with DSOs: a) there were some comments regarding the delivery of data to DSOs (6); b) there was a comment asking for clarification of the existence of Article 9, which was said to be unnecessary as its requirements belong in Article 7 instead. (1) 3. 1 comment concerned aggregated data: it was suggested that if the assessment of Article 9(2) required disaggregated data this would be extensive.
Changes made	Merged with Article 12 in new version.
Explanation for change or no change	1. There will be no definition of distributed generation in the Network Code as it is unnecessary for the correct understanding of the text, and it is too broad a subject to be easily covered in a single definition. 2. a) The delivery of data will be organized according to NC OS, or national law where applicable. This will be further explained in the Supporting Document. b) Although they partially represent a separate topic, the role of distributed generation, these requirements have been merged into Article 10 Year-ahead scenarios, and Article 11 Year-Ahead Individual Grid Models. NC OPS does not require disaggregated data, as Article 11(3) specifies it to be aggregated and differentiated according to the primary energy source. There will be further explanation in the Supporting Document.

Article 10 – YEAR-AHEAD COMMON GRID MODELS AND OUTAGES INFORMATION

(Article 12 Year-Ahead Common Grid Models in new version)

Summary	There were 20 comments regarding Article 10. They involved the following key issues: 1. 4 comments were received on data sharing with DSOs: it was suggested that the TSOs should share information with DSOs regarding changed Topology in times of an outage; 2. 2 comments were received on CGMs: it was asked that provisions regarding the gathering, merging and saving of the Year-Ahead IGMs should be directly included in the NC OPS; 3. 3 comments were received on consistency with NC CACM: a) it was suggested that the code presented inconsistencies with NC CACM, both in wording and conceptually, that NC OPS deals differently with CGMs than NC CACM does (5);b) it was suggested to add that deadlines for the CGM should be consistent with NC CACM; 4. 1 comment was received on definitions: it was suggested to change the word outage to availability in the Article title; 5. 1 comment was received on DSOs: it was asked if there were implications for DSOs resulting from Article 10(1)(a); 6. 4 comments were received on NRA approval: it was suggested that ACER or NRA approval was necessary in order to decide on the provisions in Article 10(1)(a).
Changes made	Some of the wording has been changed to clarify the consistency. The title has been changed in the new version.
Explanation for change or no change	1. The required data for DSOs to abide by the operational NCs should be delivered to them according to NC OS or national legislation. This will be further explained in the Supporting Document. 2. The CGM building procedures will not be part of NC OPS, both because there should be operational flexibility for TSOs, and because it is impossible to establish all necessary provisions in the timeframe available for the development of NC OPS. 3. a) Conceptually, there is no inconsistency between NC OPS and NC CACM. However, some of the wording has been changed to clarify the consistency. b) A reference to NC CACM here would be inconsistent because the reference would be made to CGMs of different timeframes. The capacity code dealing with longer timeframes such as the ones used in NC OPS is NC FCA, which has not yet been developed. 4. The title has been changed in the new version. 5. No change was made to the code in regards to this comment, as there are no implications for DSOs. 6. Approval by ACER or NRAs is under legal review. In this particular instance, ENTSO-E does not see a reason to include approval. More details on the rationale for when approval is required within NC OPS will be in the Supporting Document.

Article 11 – UPDATES OF YEAR-AHEAD COMMON GRID MODELS

(Article 13 in new version)

Summary	There were five comments on this article, dealing with two key issues: 1. 4 comments dealt with consistency with NC CACM 2. 1 comment dealt with the update of the CGM: it was suggested there should be an NRA approved maximum time period within which TSOs must update the grid models.
Changes made	The wording has been altered to clarify the code. A paragraph has been added to clarify when the CGM should be updated.
Explanation for change or no change	1. There is no inconsistency with NC CACM, so that a conceptual change is not needed. However, some of the wording has been altered to clarify the code. 2. A paragraph has been added to clarify when the CGM should be updated. It is not based on a set time period but on changes made in the IGMs, so there is no need for NRA approval.

Article 12 – WEEK-AHEAD GRID MODELS

(Article 14 in new version)

Summary	There were five comments on this Article. 1. Four of those dealt with data sharing with DSOs, asking for DSOs to be supplied with the information TSOs use to update their IGMs and for data to supplied to TSOs via DSOs where applicable. 2. The other one dealt with the inclusion of an NRA approved deadline for the deliverance of the necessary information.
Changes made	The wording has been altered to clarify the code
Explanation for change or no change	1. The required data for DSOs to abide by the operational NCs should be delivered to them according to NC OS. This will be explained further in the Supporting Document. 2. The inclusion of a specific deadline is not necessary. The text of the code has, however, been altered to ensure a timely delivery of data.

Article 13 – DAY-AHEAD AND INTRADAY GRID MODELS

(Article 15 in new version)

Summary	There were 12 comments on this Article, addressing the following key issues: 1. 7 comments were received on details and NRA approval: it was suggested that NC OPS should be more detailed regarding the creation of grid models, and that NRA approval was needed on these topics. 2. 1 comment was received on Intraday grid models: it was pointed out that intraday grid models were not mandatory within NC OPS. 3. 1 comment was received on Consistency with NC CACM: some concerns were voiced in relation to the consistency between NC OPS and NC CACM, especially in relation to the requirements asked of different parties. 4. 2 comments were received on DSOs: a) Data sharing: it was suggested data should be shared with DSOs; b) it was asked if Article 13(1)(a) had any implications for DSOs, and if so, to clarify. 5. 1 comment was on a legal issue: it was suggested that a dispute resolution mechanism was necessary to ensure that all TSOs would decide upon what they are required to decide upon.
Changes made	The code has been updated to make sure ID models are mandatory. The wording of NC OPS has been improved to clarify the consistency between the NC OPS and the NC CACM.
Explanation for change or no change	1. Details on creation of CGMs will not be part of the NC OPS, both because there should be operational flexibility for TSOs, and because it is impossible to establish all necessary provisions in the timeframe available for the development of NC OPS. 2. The code has been updated to make sure ID models are mandatory. 3. There is no inconsistency regarding CGMs between NC OPS and NC CACM. However, the wording of NC OPS has been improved to clarify the consistency. 4. a) The required data is being shared according to NC OS Articles 23 and 25; No change is necessary. b) There are no implications for DSOs regarding this article, so no change to the code is necessary. 5. There will be no mechanism for dispute resolution within NC OPS. However, ENTSO-E is investigating methods for dispute resolution.

Article 14 – OPERATIONAL SECURITY ANALYSIS IN OPERATIONAL PLANNING

(Article 16 in new version)

Summary	8 comments have been received, some of them repeated, 3 key topics have been identified: 1. 3 comments questioning references to the NC OS, as it is not jet approved. 2. 3 comments asking for inclusion of Operational Limits, which are already in the NC OS. 3. 2 comments questioning the delay in drafting methodology referring to in Art. 18.
Changes made	The delay to draft a harmonized methodology standardized per Synchronous Area has been shorten to 12 months reference to Article 19.
Explanation for change	1. In order to allow a coherent set of NCs, the principle agreed between drafting teams is that those NCs going through the Comitology process first are taken into account when

or no change	drafting the later. 2. Operational Limits are in NC OS. Not to be repeated. 3. The delay to draft a harmonized methodology standardized per Synchronous Area has been shorten to 12 months by reference to Article 19. In the meanwhile current practices will remain active. Current Handbooks and agreements shall be reviewed and update, taking into account the provisions drafted by NCs. For that, a 12 months period seems reasonable.

Article 15 – CROSS CONTROL AREA REMEDIAL ACTIONS

(Article deleted, as it is redundant with NC CACM)

Summary	26 comments have been received, some of them repeated, 4 key topics have been identified and other two were wording or topics repeated in other articles: 1. 6 comments in relation with the implication of NRAs and stakeholders in the tipification of Remedial Actions: NRA approval and stakeholders consultation has been asked, in line with the NC CACM provisions. 2. 5 comments mentioning that not only Cross-border but also Internal Remedial Actions should be treated. 3. 4 comments have been received in relation with the concretion in the NC of tipified Remedial Actions and transparency of the today existing Remedial Actions. 4. 3 comments in relation to include requirements for the calculation and distribution of financial compensations. 5. 2 comments in relation with the involvement of DSOs when setting up Remedial Actions in those cases where they are involved. 6. 5 comments were related to wording improvement and they have been considered in the new version. 7. Comment repeated in other articles, in relation to the reference to not approved NCs.
Changes made	The Article on Cross Control Area remedial Actions is deleted, as all Remedial Actions are covered by NC CACM.
Explanation for change or no change	1. Internal Remedial Actions are not under the scope of the NC. 2. Provisions for financial compensation calculation or distribution have not been included. In line with ACER direction, and since it seems a sensitive subject to be solved with NRA involvement.

Article 16 - YEAR-AHEAD AND UPDATED OPERATIONAL SECURITY ANALYSIS

(Article 17 in new version)

Summary	4 comments have been received, some of them repeated, 2 key topics have been identified: 1. 1 comment asked for the involvement of affected stakeholders in Remedial Actions. 2. 3 comments referred to the need to assess, if needed, dynamic stability analysis.
Changes made	1. Included the agreement of affected DSOs on the possible applicable Remedial Actions. 2. Stability analyses included in a more generic way.
Explanation for change or no change	All Stakeholders' comments are taken into account.

Article 17 - DAY-AHEAD, INTRADAY AND CLOSE TO REAL-TIME OPERATIONAL SECURITY ANALYSIS

(Article 18 D-1, intraday and Close to Real-Time Operational Security Analysis in new version)

Summary	15 comments have been received, some of them repeated, 6 key topics have been identified: 1. 5 comments referred to DSO involvement in analysis to assess Remedial Actions when they are affected. 2. 4 comments suggesting that TSOs shall perform the Security Analysis commonly (not an individual TSO task). 3. 3 comments asking for definition of State Estimation. 4. 1 comment asking for details about how data is obtained. 5. 1 comment related to the wording / definition of "distributed generation" 6. 1 comment suggesting that Intraday Security Analysis should only be performed on a

	voluntary basis.
Changes made	1. DSO involvement has been included in the assessment analysis of Remedial Actions, when they are affected. 2. Security analysis shall be carried out by each TSO, following common principles, in a coordinated way and ensuring coherence in the data all TSOs are considering. 3. State Estimation is defined in NC OS. 4. Details on how the data for performing Security Analysis are obtained are in OS or in national legislation. The NC OPS is not intended to cover or organize such detail aspects in a standardized way for the whole Pan-European system. 5. Wording referred to “distributed generation” has been improved. 6. Intraday analysis shall be covered in order to fulfill Framework Guidelines.
Explanation for change or no change	All Stakeholders’ comments are taken into account.

Article 18 - SECURITY ANALYSIS COORDINATION

(Article 19 and 20 in new version)

Summary	56 comments have been received, some of them repeated, only 11 differentiated comments have been identified: 1. 9 comments asking for higher involvement of NRAs: approval of methodology standardized per Synchronous Area level to set up more detailed principles for coordinated security analysis. 2. 9 comments asked for including Market Principles when establishing Remedial Actions. 3. 7 comments considering too long the delay of 24 months for the development of the methodology standardized per Synchronous Area level to set up more detailed principles for coordinated security analysis. 4. 5 comments asking for NRAs approval of the agreements covering RSCIs 5. 4 comments asking for including thresholds in the NC 6. 3 comments asking for including the methodology, or at least further details, in the NC 7. 4 different comments in relation with the agreements at Regional level for commonly evaluate deviations of Operational Limits: related to DSO information, to the observed Network by each TSO. 8. 3 comments considering that the requirements to set up agreements between TSOs for performing Security Analysis should be in the OS NC. 9. 1 comment giving the opinion that RSCIs shall be mandatory. 10. 1 comment asking for cost compensations in general terms. 11. 8 comments referring to wording: clarification on the kind of agreements (between TSOs), clarifications on Regional level.
Changes made	The wording of NC OPS has been improved. Delay for drafting the established methodology has been shortened to 12 months. Principles for establishing the thresholds referred to in Article 21(3) will be part of the methodology standardized per Synchronous Area. Topics addressed in methodology for Security Analysis have been further detailed.
Explanation for change or no change	1. NRA consultation and ACER opinion are more explained in Articles 3 and 4. 2. Remedial Actions are already ruled by the principle of minimizing costs and take into account the operation of the Market in which they are used. 3. Delay for drafting the established methodology has been shortened to 12 months. 4. No need for NRA approval when TSOs endorse RSCIs is foreseen, since RSCIs have been defined as specific TSO arrangement of processes. 5. The NC OPS has detailed that principles for establishing the thresholds referred to in Article 21(3) will be part of the methodology standardized per Synchronous Area and some reference examples are included in the Supporting Document. 6. Topics addressed in the methodology for performing Security Analysis have been further detailed. All the details of that methodology could not be included in the NC, because of the need for flexibility.. 7. Standardization of principles at Synchronous Area level shall be ensured, in line with Framework Guidelines, leaving room for Regional particularities and further coordination processes. 8. The NC OPS shall contain principles for coordination of security analysis in Operational Planning timeframes.

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	9. Endorsing RSCIs shall remain voluntary. More explanation could be found in the supporting document. 10. Cost compensation is out of the scope of this article.

Article 19 - OUTAGE PLANNING REGIONS

(Article 21 Definition of Outage Coordination Regions in new version)

Summary	16 comments were received on Article 19. There were 5 key-issues addressed: 1. Harmonization of the procedures. 2. DSO involvement. 3. Outage Planning Regions. 4. Stakeholder consultation. 5. NRA consultation.
Changes made	The wording of NC OPS has been improved. The deadline of 15 months after entry in force of this code concerning agreement on Outage Coordination Regions is set. Principles of the definition of the Outage Coordination Regions have been extended to guarantee the efficiency of the defined Regions.
Explanation for change or no change	• Harmonization of outage planning: The NC harmonizes principles and processes at Pan-European level. Details are left to be hamonized at regional level. • DSO involvement is treated in the NC but it is to be underlined that the NC is focused on cross-border impacts. The Outage Coordination Regions are therefore treated on a TSO-level. • Principles of the definition of the Outage Coordination Regions have been extended to guarantee the efficiency of the defined Regions. • NRA and Stakeholder consultation is not to be included in the definition of the Outage Coordination Regions, as this primarily deals with cross boarder issues and TSO activities. Nevertheless, all information is to be made public.

Article 20 - REGIONAL COORDINATION PROCEDURE

(Article 22 in new version)

Summary	6 comments were received on Article 20. There were 3 key-issues addressed: 1. DSO involvement. 2. Coordination meetings. 3. Sharing of information.
Changes made	In the Code the further clarification concerning coordination meetings has been introduced. Information from TSO to DSO is added concerning Transmission related projects.
Explanation for change or no change	1. Coordination meetings: The aim of the meetings is to improve and finalize the coordination process. Their scope shall be further clarified in the Supporting Document. In the Code the further clarification has been introduced. 2. DSOs with the Connection Point to the Transmission System shall be informed about Transmission related projects which impact their operation. 3. Sharing of information: Not all of the information can be provided, as confidentiality and discriminatory issues might arise.

Article 21 - RELEVANT NON-TSO OWNED INTERCONNECTORS, RELEVANT POWER GENERATING MODULES AND RELEVANT DEMAND FACILITIES

(To improve readability and for clarification reasons Article 21 is split into Articles 23-26 in the new version: Article 23 Methodology for assessing relevance of assets for the Outage Coordination Process, Article 24 List of Self-Planned Interconnectors, Relevant Power Generating Modules and Relevant Demand Facilities, Article 25 Re-assessment of the list of Self-Planned Interconnectors, Relevant Power Generating Modules and Relevant Demand Facilities, Article 26 Appointing Outage Planning Agents)

Summary	68 comments were received on Article 21. There were 7 key-issues addressed: 1. Criteria for relevance. 2. Single submission of data.

	3. Definition of Outage Planning Agent. 4. DSO involvement. 5. NRA – stakeholder consultation. 6. Relevant Generator. 7. Thresholds' definition for relevance.
Changes made	To improve readability and for clarification reasons Article 21 is split into Articles 23-26.
Explanation for change or no change	1. Data submission: Relevant facilities should send information directly to related TSO. Further clarification on the Outage Planning Agent of aggregated facilities to be included in the Supporting Document. 2. Postponing of deadlines: The deadlines after the entry into force of the code shall be harmonized. 3. Outage Planning Agent: Further clarification shall be provided in the Supporting Document. 4. DSO involvement: The DSO involvement in the definition of relevance is deemed as not necessary as it only refers to the Transmission System and to cross-border issues. 5. List updating process: This article referres only to cross-border impact (not to all impacts). The involvement of DSO in the connection of new power plants should be guarantee by connection code. 6. Relevant Generator: Generating Units supposed to be relevant should communicate their Availability Plan. 7. Single submission of data: This Article does not require any extra submission of data. 8. Thresholds' definition for relevance: a single threshold could not be defined for all Responsibility Areas: it depends on system design and market design. To be further explained in the Supporting Document.

Article 22 - RELEVANT GRID ELEMENTS WITH IMPACT ACROSS BORDERS

(To improve readability and for clarification reasons the Article 22 is split into Articles 27-33 in the new version: Article 27 List of Relevant Grid Elements, Article 28 Re-assessment of the list of Relevant Grid Elements, Article 29 Treatment of Relevant Assets located in the Distribution Network, Article 30 Variations to deadlines for the Year-Ahead coordination process, Article 31 Link with data to be provided according to requirements outside this Network Code, Article 32 General provisions on Availability Plans, Article 33 Long-term indicative Availability Plans)

Summary	9 comments were received on Article 22. There were 3 key-issues addressed: 1. Thresholds' definition for relevance. 2. Information. 3. Deadlines.
Changes made	To improve readability and for clarification reasons Article 22 is split into Articles 27-33.
Explanation for change or no change	1. Deadlines are to be harmonized. 2. Information: Information on reduction dates and reasons shall be provided. 3. Thresholds' definition for relevance: Not a single threshold could be defined for all Responsibility Areas: it depends on system design, market design. To be further explained in the Supporting Document.

Article 23 - YEAR-AHEAD OUTAGE PLANNING

(To improve readability and for clarification reasons the Article 23 is split into Articles 34-40 and 42-44 in the new version: Article 34 Provision of Year-Ahead Availability Plan proposals, Article 35 Year-Ahead coordination of the Availability Status of Relevant Power Generating Modules, Relevant Demand Facilities and Self-Planned Interconnectors, Article 36 Year-Ahead coordination of the Availability Status of Relevant Grid Elements, Article 37 Provision of preliminary Year-Ahead Availability Plans, Article 38 Validation of Year-Ahead Availability Plans within Outage Coordination Regions, Article 39 Final Year-Ahead Availability Plans, Article 40 Coordination processes in case of detected Outage Incompatibilities and Article 42 Detailing the testing status of Relevant Power Generating Modules, Relevant Demand Facilities and Self-Planned Interconnectors, Article 43 Detailing the testing status of Relevant Grid Elements located in the Transmission Network, Article 44 Detailing the testing status of Relevant Grid Elements located in the Distribution Network)

Summary	107 comments were received on Article 23. 9 themes emerged several times: • Outage planning process dates. • Outage incompatibilities management. • NRA involvement. • DSOs involvement. • Financial compensation. • Outage planning commitment. • Long-term commitment. • Coherency with REMIT, Transparency and the NC OS. • Priority of outages.
Changes made	To improve readability and for sake of clarity Article 23 is split into 10 articles: Articles 34-40 and 42-44. Flexibility has been introduced by allowing an update to the proposal of the Year-Ahead Availability Plans. Availability Statuses are defined. The involvement of DSOs and NRAs is foreseen in the coordination process. The establishment of long-term indicative Availability Plans is foreseen.
Explanation for change or no change	Flexibility has been introduced by allowing an update to the proposal of Year-Ahead Availability Plans between the 1st of August and the 1st of December. As this flexibility is introduced, the timeframe is left unchanged. Regarding financial compensation, the financial impacts on Market Participants are also to be reported to the NRA if no agreement can be reached with the Outage Planning Agents to relieve Outage Incompatibilities. Availability Statuses are defined and used instead of the words “availability”, “commissioning” and “outages” in order to clarify the meaning of the article. The involvement of DSOs is foreseen in the coordination process related to Relevant Assets connected to their Network. NRA’s involvement is foreseen when the coordination process failed to solve an Outage Incompatibility. The global process (Year-Ahead Availability Plan built from proposals by Outage Planning Agents, proposals by TSOs and validation by TSOs) is unchanged as it gives to the stakeholders a certainty about the feasibility of Availability Plans regarding Operational Security. The establishment of long-term indicative Availability Plans is foreseen in order to provide to Outage Planning Agents a preliminary impact assessment of their outages proposal by the TSOs. No priority is given to any type of Relevant Assets. A coordination process is set up in line with the applicable national framework.

Article 24 - UPDATES TO THE YEAR-AHEAD OUTAGE PLANNING

(Article 41 Updates to the Year-Ahead Availability Plans in new version)

Summary	39 comments were received on this Article of which 16 on paragraph 2. Three themes emerged several times: 1. Stakeholders ask for more flexibility, up to 3 months before real time instead of 12 months before real time, to update its outage schedules without being bothered by TSO approval. 2. TSO approval must be more conditional: (i.e. priority to GenCos with demand, approval based only on full Network, and include economical judgment). 3. To provide or update not the Availability plan, but the indicative Availability plan.
Changes made	Flexibility has been introduced as update of proposal of Year-Ahead Availability Plans.
Explanation for change or no change	ENTSO-E acknowledges the fact that stakeholders require maximum flexibility to economically optimize their portfolio assets to the maximum possible extent. Therefore the point of view of this article has been turned around; because the assets of both the stakeholders and TSOs are electrically connected, some restrictions have been introduced in order to secure security of supply or to respect necessary agreements. Prioritization of some stakeholders cannot be approved. The requirements of NC OPS have to be aligned with existing regulations and NC OS, but the coordinated availability planning process described in OPS is a part of the decision making process for stakeholder’s Availability Plans, as it gives to stakeholders elements about the feasibility of their plans regarding the Operational Security of the Interconnected System. As the needed information cannot be provided through REMIT or the Transparency Regulation, it has to

	be provided directly to the TSOs.

Article 25 - UPDATE OF YEAR-AHEAD OUTAGE PLANNING IN CASE OF FORCED OUTAGES

(Article 45 Processes for handling Forced Outages in new version)

Summary	22 comments were received on this Article. Three themes emerged several times: 1) Consistency with data provided by stakeholders in the framework of Transparency Regulations. 2) Involvement of DSOs as System Operators that can be impacted by Forced Outages. 3) The phrasing “jeopardizing Operational Security” is quite vague and could be improved.
Changes made	A new Article 29 was added to cover the general coordination needs with DSOs in the framework of outage coordination. The phrasing “jeopardizing Operational Security” is replaced by referring to the system states defined in the NC OS. A requirement is added to ensure the consistency between the data provided by the outage coordination process and those provided by the Transparency Regulation.
Explanation for change or no change	The Network Code lists all data that is necessary to implement its requirements. This is needed to ensure that all needed data will be provided to the impacted parties, and to avoid this Network Code being subjected to changes in other regulations. It is therefore possible that some of these data are also necessary to be provided by other regulations. It is however obvious that the implementation of data exchange processes will need to be governed by efficiency, but putting this as a requirement is out of the scope of this Network Code. The distinction needs to be made between: ○ Forced Outages (Article 45): cannot be foreseen, no flexibility: consequences have to be contained; ○ Change requests (Article 41): are foreseen, in case of Incompatibilities, coordination has to be initiated. The Transparency Regulation does not make this distinction, and therefore the Network Code requirements on data provision are consistent with the Transparency Regulation, but are not obsolete. A new Article 29 was added to cover the general coordination needs with DSOs in the framework of outage coordination. In this article, as DSOs indeed can be impacted, they are included at several instances to ensure their involvement. The phrasing “jeopardizing Operational Security” is acknowledged to be vague and therefore replaced by referring to the system states defined in the NC OS.

Article 26 - REAL-TIME EXECUTION OF THE OUTAGE PLANNING

(Article 46 Real-time execution of the Availability Plans in new version)

Summary	55 comments were received on this Article. Four themes emerged several times: 1. Earlier entering into service after overhaul of generator: the flexibility should be present to allow this freedom. 2. Involvement of DSOs. 3. Delaying of execution of planned outages: a. technical and safety limits should be respected, and b. a mechanism for financial compensation should be installed. 4. In case of deviations from the validated outage plan, only the **expected** duration of the deviation can be communicated.
Changes made	If a plant wants to come back into service early, the process is described in Article 41. More involvement of DSOs is ensured. Technical and safety aspects are covered and a mechanism for financial compensation should be installed. Communication of reasons of delay is deleted.
Explanation for change or no change	1. Earlier entering into service after overhaul of generator: the flexibility should be present to allow this. If a plant wants to come back into service early, the possibility exists (as in any other case) to send a change request to the coordinated Availability Plan in which the Availability Status of this unit is adapted. The process described in Article 41 shall be followed in this case. 2. As indeed Relevant Grid Assets can be located in the DSOs Network, their involvement in the requirements for this Article is added. 3. Delaying of execution of planned outages: technical and safety limits should be respected, and a mechanism for financial compensation should be installed.

	Requirements stating that technical and safety limits should be respected are added. Mechanisms for financial compensation could be installed in national legislation but this is out of the scope of this Network Code. 4. In case of deviations from the validated outage plan, only the **expected** duration of the deviation can be communicated.

Article 27 - CONTROL AREA ADEQUACY

(Article 47 Forecasts for assessing Adequacy and Article 48 Responsibility Area Adequacy analyses in new version)

Summary	7 comments were received on this Article. These 7 comments contained 3 unique comments, dealing with two key issues: 1. 4 comments dealt with control area Adequacy: it was suggested the control area Adequacy assessment should be performed commonly. 2. 3 comments dealt with transparency: a) It was asked to refer to the transparency guidelines in regards to the available data for the outage plan in order to prevent redundancy (2); b) It was also asked to ensure that redundancy is avoided by not monitoring the power generation twice, by referring to the transparency guideline in relation to the monitoring of power generation. For this comment there is a relationship with Article 29, where the monitoring of power generation is actually required. (1)
Changes made	The link between the Responsibility Area Adequacy Analysis and the seasonal Adequacy Analysis referred to in Article 48 is clarified. The wording concerning the latest available data is taken.
Explanation for change or no change - (Article numbers refer to the new version of the NC OPS)	1. A change has been made in regards to the Responsibility Area Adequacy Analysis, not to change the concept, but to clarify the link between the Responsibility Area Adequacy Analysis, which is to be performed by individual TSOs, and the seasonal Adequacy Analysis referred to in Article 48, which is to be performed on pan-European level. 2. a) ENTSO-E will not make a reference to the Transparency Guidelines here, because the data for units of less than 100MW are not included in the data submitted for the Transparency Guidelines, so it would be too limiting for our purposes. However, the wording that the latest available data should be used does not exclude TSOs for using the same data that is submitted in line with the Transparency Guideline where applicable; b) The change wasn't accepted, because there is no requirement in the Transparency Guideline for TSOs to monitor the changes, just to submit them, and because units smaller than 100MW are not included in the Transparency Guideline.

Article 28 - PAN-EUROPEAN SYSTEM ADEQUACY SEASON-AHEAD

(Article 49 Summer and winter Generation Adequacy outlooks in new version)

Summary	Five comments were received for this Article. Four of these were the same, requiring to not just consult ACER but to ask ACER's approval when updating the methodology for determining Adequacy. The other asked for another method of consulting stakeholders to be included, and not to limit stakeholder consultation to workshops.
Changes made	Approval of NRA is included in Article 4. The code has been adapted in order to collect comments from all stakeholders rather than hold workshops to collect these comments.
Explanation for change or no change	1. For the methodology used to establish the summer and winter generation Adequacy outlooks, NRA approval will be mandatory. This is now handled in Article 4. 2. The code has been adapted in order to collect comments from all stakeholders rather than hold workshops to collect these comments.

Article 29 - CONTROL AREA ADEQUACY UNTIL AND INCLUDING WEEK AHEAD

(Article 50 Responsibility Area Adequacy until and including Week Ahead in new version)

Summary	There were six comments on this article. They were all the same, asking for stakeholders to be informed of an inability to ensure Adequacy.
Changes made	The Network Code has been altered to allow all affected parties to be informed of a lack of Adequacy.
Explanation for change	The proposal by the stakeholders has been accepted, and the Network Code has been altered to allow all affected parties to be informed of a lack of Adequacy.

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or no change	

Article 30 - CONTROL AREA ADEQUACY DAY AHEAD AND INTRADAY

(Article 51 Responsibility Area Adequacy D-1 and intraday in new version)

Summary	There were fifteen comments on this Article, of which six were unique. These six comments were: 1. There was a wish to refer to adherence to all relevant confidentiality agreements in this article. (1) 2. There was a wish to delete the evaluation of the required load shedding. (1) 3. There was a worry that TSOs would gain unfair advantages in their role as traders due to them having more information than Market Participants. (1) 4. There was a wish to make sure the publication of the result of the Adequacy Analysis should be published for everyone. (5) 5. There was a wish to make the requirements apply to Week-Ahead as well as to day-ahead and intraday. (2) 6. Finally, there was a wish to make sure the data transfer would be consistent with other Network Codes, in particular NC OS and NC RfG. (5)
Changes made	The Article has been changed in order to make sure that the information shall be made available to NRAs. A reference to NC OS is included concerning data provision.
Explanation for change or no change (Article numbers are taken from the new version)	1. The Article has not been changed. ENTSO-E believes that the principle of confidentiality is sufficiently guarded. 2. The requirement to evaluate the level of energy not served shall not be deleted, as it is an inherent part of the process of determining Adequacy. 3. There will be no change in the Article to ensure confidentiality is being met, as that is already arranged in the code, where there are specific references to information being used only for operational purposes. TSOs by no means function as traders. In cases where energy is being bought or sold by the TSOs, these actions are being monitored and regulated. 4. The Article has been changed in order to make sure that the information shall be made available to NRAs. 5. The requirements for determining Week-Ahead Adequacy are detailed in Article 50. Article 50 now refers to Article 49, so there are sufficient requirements for this Adequacy analysis and no further changes will be necessary. The time horizon for the Week-Ahead analyses make them more closely related with the summer and winter generation Adequacy outlooks, than with D-1 and intraday Adequacy analyses. 6. In regards to the D-1 and Intraday Adequacy analyses, using the data provided in the framework of NC OS was a possibility, so a reference has been included to NC OS in order to ensure the codes are consistent.

Article 31 - ANCILLARY SERVICES

(Article 52 in new version)

Summary	There were 21 comments received on this Article. Seven key issues emerged: 1. Definition of Ancillary Services: it was said to be missing. (3) 2. Contract with GenCos: It was suggested that the paragraph requiring parties to abide by the contracts was redundant and should therefore be deleted. It was also suggested that it should also require the TSO to adhere to their part of the agreement, not just the other parties. (5) 3. Reference to NC LFCR: a) It was suggested no reference be made to NC LFCR at all, because it has not been approved. In one of the comments it was added that DSOs should be involved as well as no reference made to NC LFCR. b) It has also been suggested that a specific reference should be made to NC LFCR in regards to procurement of Ancillary Services, and that it should be done commonly by all TSOs.(8) 4. Data exchange with DSO: There was a suggestion that DSOs be informed about the availability of Ancillary Services. 5. Data exchange between TSOs: It was suggested that TSOs should only share information about Ancillary Services in case of emergency. 6. Other Ancillary Services than Active Power: It was suggested that the NC limit the applicability to active and Reactive Power Ancillary Services. (1) 7. Scope of NC OPS: it was suggested that the Active Power Ancillary Services were out of scope for the NC OPS. (2)

Changes made	The paragraph on abiding by contracts has been deleted.
Explanation for change or no change (Article numbers refer to the new version)	1. The definition from Directive 2009/72/EC shall apply for Ancillary Services. There is no inconsistency between that definition and our use of it within the Network Code, and ENTSO-E wants to make sure all Ancillary Services are included: not just existing ones, but also possible new products. 2. ENTSO-E acknowledges that the paragraph on abiding by contracts is redundant, so the proposed change has been accepted and the article has been deleted. 3. a) The reference to the NC LFCR is kept so general that this reference can be accepted. Because the procurement of Ancillary Services is a responsibility of the TSO, they will be responsible for the procurement process, and DSOs will participate in other ways, b) Assuring sufficient Ancillary Services for its own Responsibility Area is a specific responsibility of each TSO, therefore this process will not be performed commonly although coordination is foreseen. Because Article 52(2) is about the procurement process, a reference to NC LFCR is out of place here. 4. The required data for DSOs to abide by the operational NCs should be delivered to them according to NC OS. 5. The change was not accepted as TSOs require information about the Ancillary Services in order to take preventative measures. If data is only exchanged in case of emergency it would be too late. 6. The change was not accepted as the NC aims to include all Ancillary Services, not just Active Power and Reactive Power, but also, for example, black start facilities or future Ancillary Services developed as a response to emerging changes in the system operation. 7. The Framework Guidelines requires the NC OPS to contain requirements for the planning and scheduling of Active Power Ancillary Services.

Article 32 - REACTIVE POWER ANCILLARY SERVICES

(Article 53 in new version)

Summary	There were 13 comments on this Article. Of these, there were 7 unique comments. These seven comments addressed the following five key issues: 1. Dynamic stability Year-Ahead: It was asked that dynamic stability be ensured on a Year-Ahead basis. (3) 2. Reference to NC OS NC: It was suggested that non-approved NCs such as NC OS should not be mentioned in our code. (3) 3. Data Exchange with DSO: It was asked to include a method for DSOs to ensure the active/Reactive Power ratio at T/D connection point. (2) 4. Reference to NC RfG: a) wording; b) monitoring would only apply to new generating units; c) a reference to NC RfG is said to be duplicated; d) minimum/maximum values were said to be made the norm. (4) 5. NRA involvement: It was asked that the Contingency List be NRA approved. (1)
Changes made	Dynamic stability is treated in Article 19. DSO are now included in a new paragraph to ensure that the available Reactive Power of DSOs is identified. A reference to NC OS, where the capabilities of all facilities are described, is made instead of NC RfG.
Explanation for change or no change (Article numbers refer to the new version)	1. Operational Security Analysis to detect a breach of dynamic stability has been included in Article 19. 2. ENTSO-E will maintain all references to codes that are developed ahead of our own. This also helps ensure consistency between the codes. As they are submitted to ACER before ours, ENTSO-E will have the opportunity to adapt to any changes when necessary. 3. Article 53(2) has been amended. DSO are now included in new paragraph [c] to ensure that the available Reactive Power of DSOs is identified. Because the TSO is responsible for monitoring the ratio, DSOs are not otherwise mentioned here. 4. The textual problem has been solved; problems between existing facilities and new facilities have been avoided, as well as other consistency problems, by no longer referring to NC RfG and by making a reference to NC OS instead, where the capabilities of all facilities are described. The requirement stated in Article 53(2) is a requirement for TSOs only to ensure what their sources for Ancillary Services are. It should not be understood as duplicating requirements from NC RfG. 5. The Contingency List is being treated in NC OS.

Article 33 - ESTABLISHMENT OF SCHEDULING PROCESSES

(Article 54 in new version)

Summary	9 comments were received on this Article. All comments refer to the same issue – lack of harmonization of scheduling in Europe.
Changes made	Changes are only made to the definitions as to maintain consistency with NC RfG and NC DCC.
Explanation for change or no change	No changes will be made regarding harmonization of Scheduling in Europe since all necessary provisions and requirement for Scheduling are set according to the Framework Guidelines on Electricity System Operation. Requirements for Scheduling within Marked Balance Area are very different in Europe due to different national legal framework, therefore OPS focuses on inter-TSO scheduling issues.

Article 34 - NOTIFICATION OF SCHEDULES WITHIN MARKET BALANCE AREAS

(Article 55 Notification of schedules within Scheduling Areas in new version)

Summary	16 comments were received on this Article. They are mainly the same referring to the lack of harmonization of scheduling in Europe. Several comments were specific: 1. 34(1) – clarification if Generation Schedules requires schedules per machine or per unit. 2. 34(3) – proposal to include dispute procedure if no common agreement on External Schedule between TSOs is reached. 3. 34(3) - Significant DSO shall be informed of the schedules of units connected at its Network to prevent in advance possible restrictions at distribution Network.
Changes made	No changes were made
Explanation for change or no change	1. 34(1) – requirement for detail level of Generation Schedule is not specified in NC OPS, because there are different requirements for detail level of Generation Schedules in Europe due to different national legal frameworks: per machines, per units, per portfolio. NC OPS sets general requirement for Generation Schedule while TSO sets specific requirements for detail level according to their national legal framework. 2. 34 (3) – NC OPS sets requirement for TSOs to agree on the External Schedules, while the process of how two TSOs agree and any dispute procedures shall be define d in bilateral (multilateral) agreements between TSOs. 3. 34(3) - DSOs shall receive scheduled generation data from the Generating Facilities connected to the Distribution Network according to Article 23 of NC OS.

Article 35 - COHERENCE OF SCHEDULES

(Article 56 in new version)

Summary	13 comments were received on this Article. Three types of comments: 1. 35(1) - justification is required of 12 months of implementation of provisions to ensure its area internal balance for Generation Schedules, Consumption Schedules, External Commercial Trade Schedules and External TSO Schedules. Justification is also required for of 12 months of implementation of provisions in Synchronous Area 35(2) 2. 35(2) - lack of harmonization of scheduling in Europe. 3. 35 (2) - It is legally not correct to impose responsibility for operators of areas without any legal obligation towards NC OPS.
Changes made	No changes were made
Explanation for change or no change	1. Implementation delays for internal and Synchronous Area processes are the same since they are connected process and depend on each other. The process reffered to in article 56(2) is currently running in ENTSO-E Continental Europe, however in other Synchronous Areas this process will require some development in order to change processes between TSOs and possibly internal scheduling processes, therefore a 12 month implementation delay was introduced. 2. No changes will be made regarding harmonization of Scheduling in Europe since all necessary general principles and requirement for Scheduling are set according to Framework Guidelines on Electricity System Operation. Requirements for Scheduling within Marked Balance Areas are very different across Europe due to different national legal frameworks, therefore NC OPS focuses on inter-TSO scheduling issues. 3. NC OPS does not impose any legal responsibility for operators of areas without any legal obligation towards NC OPS, while NC OPS obliges operators in Synchronous Areas to implement procedures in order to fulfil the main requirement that all Schedules

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	between all Market Balance Areas within Synchronous Area are balanced.

Article 36 - PROVISION OF INFORMATION TO OTHER TSOs

(Article 57 in new version)

Summary	4 comments were received on this Article asking clarification on 36(1) - Why are the DC Interconnectors excluded?
Changes made	No changes were made.
Explanation for change or no change	Schedules of DC Interconnectors are included in 57(1) a) Aggregated Netted External Schedules Aggregated Netted External Schedules means a Schedule representing the netted aggregation of all External TSO Schedules and External Commercial Trade Schedules between two Market Balance Areas or between a Market Balance Area and a group of other Market Balance Areas.

Article 37 - GENERAL PROVISIONS

(Article 58 General provisions for ENTSO-E Operational Planning Data Environment in new version)

Summary	12 comments were received on this Article. Five themes emerged several times: 1) No later than 18 months after the entry into force of this Network Code, all TSOs shall agree upon and define a standardized data format for the data exchange taking place. ... 2) All TSOs shall define a standardized data format for the data exchanges taking place, there by consulting with owners and operators of the Relevant Non-TSO Owned Interconnectors, Relevant Power Generating Modules and Relevant Demand Facilities. The description of this data format shall be an integral part of the ENTSO-E Operational Planning Data Environment. 3) To add: Market Participants shall have a limited view on this data environment according to the transparency guidelines. 4) In case a DSO Network contains Relevant Power Generating Modules, Demand Facilities or Interconnectors, the DSO will have access to the data contained in the operational planning environment the model of TSO grid which directly affects to the grid it operates so that he can use them for Operational Planning and security analysis. 5) Each DSO shall be granted access to the content regarding outage planning contained in its common TSO platform which directly related to the grid it operates; subject to confidentiality guidelines.
Changes made	No changes were made
Explanation for change or no change	1. Agreement is not needed. TSO just define standards but do not need to agree. Only TSOs will provide information to the ENTSO-E Operational Planning Data Environment , while requirements for data formats for GenCos are defined in national framework. 2. The ENTSO-E Operational Planning Data Environment is intended for TSOs, Market Participants will get information via the Transparency platform according the Transparency Regulation. 3. TSOs performs operational planning and security analysis and are responsible for control areas, therefore it is not needed for TSOs to deliver the TSO grid model (or part of the model) to DSOs. Purpose of the ENTSO-E Operational Planning Data Environment is to increase cooperation between TSOs (systems), while DSOs will receive the outage data according NC RfG and this type of access to the data is not the purpose of this NC. 4. Purpose of ENTSO-E Operational Planning Data Environment is to increase cooperation between TSOs (systems), while DSOs will receive the outage data according to the NC RfG and this type of access to data is not the purpose of this NC.

Article 38 - GRID MODELS & SECURITY ANALYSIS

(Article 59 Individual Grid Models, Common Grid Models and Operational Security Analysis in new version)

Summary	10 comments were received on this Article. Four themes emerged several times: 1) This is the first mentioning of the Common Grid Model also being in CACM. It should be

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	explicit that this information is available to all Market Participants, and is in line with the EC's Fundamental Data Transparency Guideline. 2) All Common Grid Models shall be made available on the ENTSO-E Operational Planning Data Environment . The TSO's and the relevant DSOs should have access to the operational planning data environment and the relevant grid models. 3) All Common Grid Models shall be made available to all TSOs and Market Participants on the ENTSO-E Operational Planning Data Environment . 4) Information for Week-Ahead time horizon should be included in the new provision.
Changes made	The wording is changed for clarification.
Explanation for change or no change	1. Common Grid Models and Individual Grid Models are available only for TSOs. 2. Week-Ahead Common Grid Models won't be merged on pan-European level. So it isn't necessary to include it here.

Article 39 - OUTAGE PLANNING

(Article 60 Outage Coordination Process in new version)

Summary	8 comments were received on this Article. Two themes emerged several times: 1) The ENTSO-E Operational Planning Data Environment shall contain a module for the storage of all relevant information for coordinated outage planning. This information shall be shared to all Market Participants according to the transparency guidelines. 2) Why restitution time is only mentioned for Interconnectors and not for a) b) c).
Changes made	The wording is changed for clarification.
Explanation for change or no change	1. ENTSO-E Operational Planning Data Environment is intended for TSOs; market participants will get information via Transparency platform according to the Transparency Regulation. 2. For point a) the restitution time (the time required to restore) is defined in Article 27(4) of the new version.

Article 40 - SYSTEM ADEQUACY

(Article 61 in new version)

Summary	5 comments were received on this Article. Themes emerged several times: The ENTSO-E Operational Planning Data Environment shall allow the access and sharing of all relevant information for coordinated Adequacy analysis. This information shall be shared to all Market Participants according to the transparency guidelines.
Changes made	No changes were made.
Explanation for change or no change	ENTSO-E Operational Planning Data Environment is intended for TSOs, Market Participants will get information via the Transparency platform according to the Transparency Regulation.

Article 41 - AMENDMENT OF CONTRACTS AND GENERAL TERMS AND CONDITIONS

(Article 63 in new version. Additional Article 60 Performance indicators was included as it is required by FG)

Summary	4 comments were received on this Article questioning the need for the Article at all given NC OPS covers new units and will take the form of a Regulation.
Changes made	The reference to grid connection has been deleted.
Explanation for change or no change	1. The framework Guidelines on System Operation provide for this (para 1.8), hence it is necessary to include this to be consistent with the framework guidelines. 2. Significant Grid Users (and the Relevant Grid Users derived from these) are not necessarily only "new units", given the approach adopted in identifying significant users in the framework guidelines on Electricity Grid Connections and the NC s developed according to these. 3. Any provisions that apply retrospectively under the Grid Connections NC processes will

	be transparent and its necessity will be assessed by a Cost Benefit Analysis. 4. Whilst the Regulation supersedes national law, it does not in itself amend existing contracts etc. to be consistent with that Regulation and so place contractual (as distinct from statutory) obligations between parties. 5. Therefore the Article must remain but the reference to grid connection seems unnecessarily confusing.

Article 42 - ENTRY INTO FORCE

(Article 64 in new version)

Summary	No comments received
Changes made	
Explanation for change or no change	

10.4 APPENDIX 4 METHODOLOGIES FOR DETERMINING THE RELEVANT ASSETS AND NEIGHBOURING ASSETS TO MONITOR AND CONSIDER IN CONTINGENCY ANALYSIS

Purpose

This appendix clarifies the concerns from the stakeholders on the methodologies to be developed by TSOs for Operational Security Analysis and for assessing the relevance of Power Generating Modules, Demand Facilities, and grid elements located in a Transmission Network, in a Distribution Network, or in a Closed Distribution Network for the Outage Coordination Process.

General information

Articles 19 and 23 of NC OPS establish requirements for TSOs to develop:

- Methodology standardized at least per Synchronous Area for Operational Security Analysis, covering, among other topics, principles for defining the Observability Area and External Contingencies (including determining the Contingency Influence Threshold);
- Methodology standardized at least per Synchronous Area, for assessing the relevance of Power Generating Modules, Demand Facilities, and Transmission and distribution grid elements for the Outage Coordination Processes described in Chapter 4 of NC OPS.

Methodologies proposed in those articles are subject to approval of the relevant national authorities. As both methodologies are intended to obtain a list of assets located in neighbouring Responsibility Areas which have such an impact to necessitate them being included in the described processes (monitoring, Contingency Analysis and coordination of outages), their mutual consistency shall be ensured.

The application of a methodology for assessing the influence of external assets on each TSO's Responsibility Area would result in objective criteria under which the resulting flows in the Transmission System could be calculated. This will allow ranking assets of multiple systems in accordance with the effects they have on each TSOs' Responsibility Area, and this way, to establish the lists of Relevant Assets, the list of External Contingencies as well as the Observability Area.

Below a possible methodology for evaluating the cross-border influence offsets is described. This methodology uses the current Operation Handbook of Regional Group Continental Europe (Annex of Policy 3) as a basis, and is further extended in order to cover influence analysis for Power Generating Modules and Demand Facilities.

A possible methodology for ranking Grid Elements based on their cross-border influence

Taking as an input agreed reference (Common) Grid Model in which all Grid Elements are available and connected in a standard Topology.

Being defined Permanently Admissible Transmission Loading (PATL) as the loading in Amps or MVA that can be accepted by a branch for an unlimited duration.

The INFLUENCE FACTOR of a branch *r* on another RESPONSIBILITY AREA could be calculated according to the following formula:

$$In_r = \max_{\forall t}\left(\max_{\forall i \neq t} \frac{P_{i,r}^t - P_i^t}{PATL^t} \cdot \frac{PATL^r}{P^r} \cdot 100\right)$$

- In_r *:* Influence factor of an branch *r* on another Responsibility Area

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- *t*: Branch of another Responsibility Area where the Active Power difference is observed
- *i:* Branch of the interconnected Network within the Ordinary Contingency List considered disconnected from the Network when assessing the formula (simulating the N-1 situation)
- $P_{i,r}^{t}$: Active power through the branch *t* with both branches *r* (under planned outage) and *i* (N-1 contingency) disconnected from the Network.
- P_{i}^{t} : Active power through the branch *t* with the branch *i* (N-1 contingency) disconnected from the Network (and branch *r* is connected to the Network).
- P^{r} : Active power through the branch *r*, when connected to the Network (branch *i* is connected to the Network)
- $PATL^{t}$: PERMANENTLY ADMISSIBLE TRANSMISSION LOADING (PATL) of the branch *t* (in MVA)
- $PATL^{r}$: PERMANENTLY ADMISSIBLE TRANSMISSION LOADING (PATL) of the branch *r* (in MVA).

A possible methodology for ranking Power Generating Modules and Demand Facilities based on their cross-border influence. Taking as an input agreed reference (Common) Grid Model in which all Grid Elements are available and connected in a standard Topology. The Power Generating Modules of which the influence factor is calculated should be available and producing Active Power.

Being defined Permanently Admissible Transmission Loading (PATL) as the loading in Amps or MVA that can be accepted by a branch for an unlimited duration.

The INFLUENCE FACTOR of a generator *g* on another RESPONSIBILITY AREA could be calculated according to the following formula:

$$In_{g} = \max_{\forall t}\left(\max_{\forall i \neq t}\left|\frac{P_{i,g}^{t} - P_{i}^{t}}{PATL^{t}}\right| \cdot \frac{Pmax^{g}}{P^{g}} \cdot 100\right)$$

- In_{g} *:* Influence factor of an generator *g* on another Responsibility Area
- *t*: Relevant Grid Element of another Responsibility Area where the Active Power difference is observed
- *i:* Branch of the interconnected Network considered disconnected from the Network when assessing the formula (simulating the N-1 situation)
- $P_{i,g}^{t}$: Active power through the branch *t* with both generator *g* (under planned outage) and *i* (N-1 contingency) disconnected from the Network. The Active Power that was generated by generator *g* before disconnection is compensated by homothetically adapting all loads in the Responsibility Area where generator g is connected, or compensation on other running generators of the same Responsibility Area or compensating in the slack bus.
- P_{i}^{t} : Active power through the branch *t* with the branch *i* (N-1 contingency) disconnected from the Network (and generator *g* is connected to the Network).
- P^{g} : Active power infeed of generator *g*
- $PATL^{t}$: PERMANENTLY ADMISSIBLE TRANSMISSION LOADING (PATL) of the branch *t* (in MVA)
- $Pmax^{g}$: Maximum Active Power infeed of generator *g* (in MW).

The threshold value (%) above which the Influence Factor In_{r}or In_{g} of a branch *r* or a generator *g* is considered high enough to consider the asset as being relevant for the Outage Coordination Process is to be further defined after experimentation and simulation. Finally a threshold should be sought that will be included in the methodology and therefore is to be approved by NRAs.

10.5 APPENDIX 5 SCHEDULING EXAMPLES

Purpose

This appendix gives some examples to illustrate the existing Scheduling processes as asked by the stakeholders at the workshops.

All Scheduling examples refer to

Article 55: **Notification of schedules within Scheduling Areas**
Article 55.2: **Notification of Schedules of Scheduling Agent of Market Coupling Operator**

Internal Commercial Trade Schedules between Scheduling Agent of Market Coupling Operator and Scheduling Agent of Nominated Electricity Market Operator(s).

External Commercial Trade Schedules

-based on Net Positions related to the Scheduling Area using AC interconnections, when the Scheduling Area is interconnected to other Scheduling Area(s) via AC interconnection(s). These External Commercial Trade Schedules can describe a bilateral exchange between 2 Scheduling Areas or a multilateral exchange between 1 Scheduling Area and all other Scheduling Areas involved in the Market Coupling.

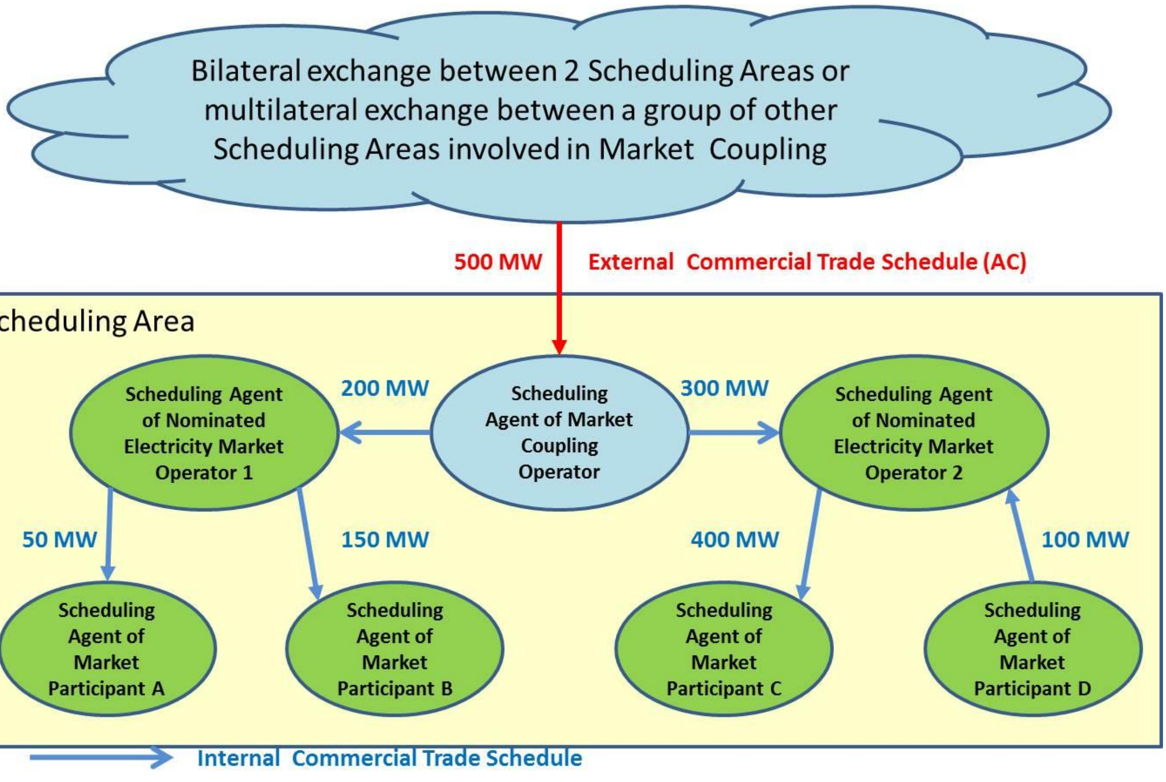
- based on Net Positions related to the Scheduling Area using DC interconnection(s), separate for each DC interconnection, when the Scheduling Area is interconnected to other Scheduling Area(s) via DC interconnection(s).

The next slide shows the situation where a Scheduling Area has to import 500 MW due to the Market Coupling. The energy is given to 2 different Nominated Electricity Market Operators (=Power Exchanges) that exchange energy with different market participants.

Notification of Schedules of Scheduling Agent of the Market Coupling to Scheduling Area:
- External Commercial Trade Schedules
  - Scheduling Area: Import 500MW
- Internal Commercial Trade Schedules
  - From Scheduling Agent of Market Coupling Operator to Scheduling Agent of Nominated Electricity Market Operator 1: 200MW
  - From Scheduling Agent of Market Coupling Operator to Scheduling Agent of Nominated Electricity Market Operator 2: 300MW

The Nominated Electricity Market Operators have to notify their
- Internal Commercial Trade Schedules from Scheduling Agent of Market Coupling Operator to Scheduling Agent of Nominated Electricity Market Operator; and their
- Internal Commercial Trade Schedules with the different market participants.

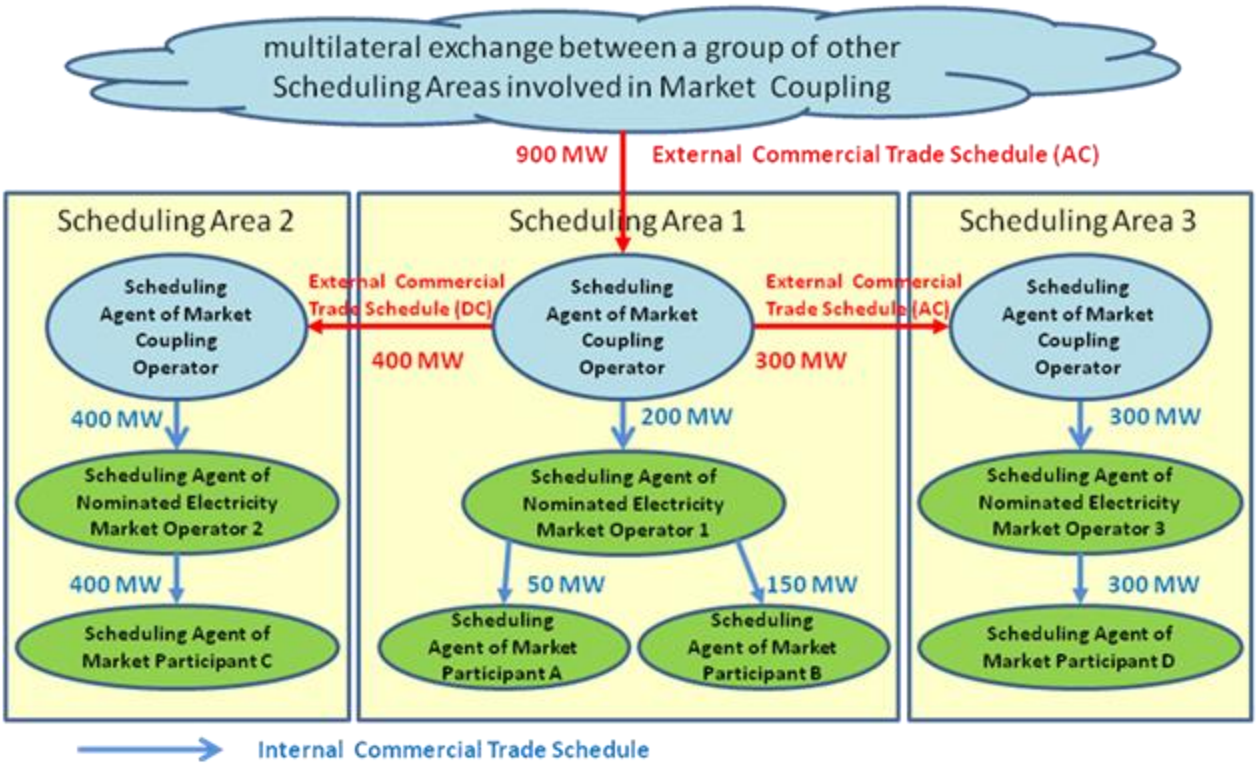
Remark: "a group of other Scheduling Areas involved in Market Coupling" will modelled as a specific Scheduling Area without generation or consumption and where the sum of all imports is equal to the sum of all exports. All Scheduling Areas involved in the Market Coupling have a border with the specific Scheduling Area, except if the local situation requires bilateral exchanges between 2 Scheduling Areas. The Scheduling Agent of the Market Coupling Operator acts as "Operator of this specific Scheduling Area".



The next slide shows a more complex situation where Scheduling Area 1 has a DC-Interconnection with Scheduling Area 2 and due to local situation the Notification of the Scheduling Agent of the Market Coupling Operator to Scheduling Area 3 must be based on a bilateral exchange between Scheduling Area 2 and Scheduling Area 3.

Market Coupling Results (Net Position) for that given timeframe:
- Scheduling Area 1: Import 200MW
- Scheduling Area 2: Import 400MW
- Scheduling Area 3: Import 300MW

Notification of Schedules of Scheduling Agent of the Market Coupling to Scheduling Area 1:
- External Commercial Trade Schedules
  - Scheduling Area 1: Import 900MW (scheduled as multilateral exchange between Scheduling Area 1 and all other Scheduling Areas involved in Market Coupling)
  - From Scheduling Area 1 to Scheduling Area 2: 400 MW
  - From Scheduling Area 1 to Scheduling Area 3: 300 MW
- Internal Commercial Trade Schedules
  - From Scheduling Agent of Market Coupling Operator to Scheduling Agent of Nominated Electricity Market Operator 1: 200MW



10.6 APPENDIX 6 FREQUENTLY ASKED QUESTIONS

Purpose

This appendix outlines the questions which ENTSO-E has been asked at various stages of the process of developing the NC OPS and provides answers to those questions. This appendix therefore aims at providing interested parties with additional information and explanation on specific concepts explained above in this document and issues related to the NC OPS.

10.6.1 General Provisions

a) Is the "whereas section" (Recitals) of the Network Code legally binding?

The "whereas section" (Recitals) of any piece of EU law and of this specific Network Code is not legally binding. The "whereas section" is designed to explain the general philosophy of the Network Code. It can be used to help interpreting the provisions of the Network Code, for instance by a judge in case of a claim in front of a court.

Only the Articles of the Network Code contain legally binding provisions.

b) Is the pan-EU character of the Network Codes preventing national legislation to go beyond the requirements of the Network Code?

After Comitology, Network Codes take the form of EU Regulations, 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) N° 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) Why is not environmental safety in the list of the objectives to be achieved by the Network Code? Does it mean that security of supply come above the environmental safety?

EU and national legislation have elaborated a complete set of rules and requirements to protect the environment. Referring or repeating these provisions in the Network Code would not add any value as it would only repeat these obligations without giving them any additional strength.

d) In case of conflict between the provisions of the Network Code and of national legislation, which one should prevail?

Once adopted, the Network Code will take the form of a EU Regulation, which is an act of EU law. In accordance with the principles of EU law, in case of conflict between the provisions of EU and national pieces of legislation, the provisions of the EU law act should prevail.

The provisions of the Network Code should thus prevail on any contradictory provision coming from national law. Nevertheless, this does not prevent national legislation to contain more stringent requirements than those in the Network Code if the former are not contradictory to the latter.

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e) The influence of the Availability Status of a Power Generating Module on the Operational Security is taken into account to determine if it qualifies as a Relevant Power Generating Module. How is such an influence assessed?

In accordance with Article 23 of the Network Code, TSOs have to establish a coordinated methodology for assessing the relevance of the Power Generating Modules, of the Demand Facilities and of the grid elements located in a Transmission Network, in a Distribution Network or in a Closed Distribution Network for the Outage Coordination Process.

To determine whether a Power Generating Module is considered as relevant, the influence of its Availability Status on the Operational Security will be taken into account in accordance with parameters developed further in the above-mentioned methodology.

f) In the case where several NRAs have to jointly approve a methodology, what would happen if they could not reach an agreement?

Article 4(6) of the Network Code states that, in case the NRAs cannot find an agreement within a period of six months from the submission of a methodology for approval, ACER should decide upon those regulatory issues.

This possibility is foreseen under Article 8 of Regulation (EC) N° 713/2009.

10.6.2 Definitions

a) Do criteria need to be added in the definitions of Relevant Power Generating Facility and Relevant Demand Facility?

The Relevant Power Generating Facilities and Demand Facilities are the Significant Grid Users impacting the Transmission System cross-border operation in such a way that the planning of their unavailability needs to be coordinated between their Outage Planning Agent and at least two different TSOs. The establishment of the list of Relevant Power Generating Facilities and Demand Facilities is not as simple as applying direct criteria. It implies to perform load-flows calculations and impact analyses, including Contingency Analysis, which may evolve due to new applications. This is the reason why the Network Code foresees the establishment of a dedicated methodology. Examples of this methodology are provided in this document.

b) Should the term of Commissioning be defined and should this definition be restricted to the phases of commissioning impacting the Transmission Network operation?

In the version published for consultation, Commissioning was defined as the process of assuring that all systems and components of a Power Generating Module, Demand Facility or non TSO owned Interconnector are designed, installed, tested, according to the operational requirements of the owner or final client. As the Network Code OPS aims at ensuring the Operational Security of Transmission System Operation, this definition goes beyond the scope of the Network Code as it also applies to commissioning activities without impact on the Network Operation. In the new version of the Network Code, the definition of Commissioning was thus deleted and replaced by an Availability Status termed as “testing”, allowing to take into account the impact on the Transmission Network operation of the tests performed before entering into operation of after maintenance of assets.

c) Should the terms TSO and DSO be defined within this Network Code as they might be differently interpreted in different countries?

The definitions of Transmission System Operator and of Distribution System Operators are available in the Article 2 of the Directive 2009/72/EC to which the Article 2 of the Network Code refers. It is therefore not possible for the Network Code to re-define the terms of TSO or DSO.
The definitions provided by the Directive 2009/72/EC can be implemented in national legislation in different ways, notably by establishing different thresholds between the activities of distribution and the Transmission.

10.6.3 Data for Operational Security Analysis in Operational Planning

a) How is a Common Grid Model created?

The European Merging Function establishes Common Grid Models through the merging of multiple Individual Grid Models. Because of the modular way the IGMs are built, it is possible to create Common Grid Models for different regions, such as Outage Coordination Regions or Synchronous Areas.

b) Why are multiple Common Grid Models needed?

The information contained within the Common Grid Models differs for the different timeframes for which the Common Grid Models are established. For that reason a separate Common Grid Model is needed for each different timeframe. Within NC OPS Common Grid Models are established for the Year-ahead, Week-Ahead, D-1 and intraday timeframes.

c) Why are new Common Grid Models established in NC OPS and aren't the Common Grid Models from NC CACM used here?

In order to prevent additional workload on TSOs, consistency between Common Grid Models is ensured wherever possible. For the D-1 and intraday timeframes there is an overlap with NC CACM. Therefore Common Grid Models required in NC OPS for those timeframes are supposed to be the same ones used in line with requirements in NC CACM.
However, NC OPS also requires the establishment of Common Grid Models for the Year-Ahead and possibly Week-Ahead timeframes. Since those timeframes are not included in NC CACM, new Common Grid Models are needed for those timeframes as defined in NC OPS. If these timeframes prove to be consistent with the ones used in NC FCA, the Common Grid Models used for Forward Capacity Allocation should be required to be consistent with NC OPS as well.

d) What is the source of the data included within the Common Grid Models?

For the D-1 and intraday timeframes the information within the Common Grid Models is delivered to TSOs in line with scheduling processes described in Chapter 7 (based on national market scheduling processes or as a result of the future Market Coupling) and according to the requirements in NC OS. The results of capacity calculations performed in line with NC CACM are an implicit input, since they are an input for D-1 markets. For the Week-Ahead and Year-Ahead timeframes data will be based on TSOs’ best estimates, so no additional data provision for stakeholders is foreseen.

e) How data exchange with DSOs and grid used is addressed in NC OPS?

NC OPS requirements are, with the exception of those in Chapter 4 (Outage Planning Coordination), based on data exchange procedures provided in:

- NC OS and other NCs (NC CACM, NC LFC&R);
- Transparency Guidelines;

- Applicable national framework.

Chapter 3 of NC OS extensively describes the sets of data to exchange between grid users and TSOs, grid users and DSOs as well as between DSOs and TSOs. Data exchange between DSOs and TSOs is addressed in NC OS in order to ensure the acquisition of necessary information to ensure the necessary inputs for coordinating cross border Operational Security Analysis between TSOs.

NC OS in Article 16(6) establishes also at least a minimum data exchange from TSOs to grid users and DSOs in relation to the transmission installations at the connection point in order to allow grid users and DSOs to perform their own analysis. Besides, in Article 16(5) NC OS establishes the requirement to TSOs to draft key organizational requirements, roles and responsibilities in relation to the data exchange. Further requirements for data exchanging between TSOs and grid users and DSOs can be addressed as necessary in applicable national legal framework, in particular the details regarding additional TSO data which is needed for DSOs to perform security analyses within their network..

10.6.4 Operational Security Analysis in Operational Planning

a) *Deadlines for creation of regions need clarification. What is the link with the creation of regions?*

Methodology for Relevant Assets will be approved by NRAs and the list of the Relevant Assets is the consequence. A Relevant Asset will be handled in only one Outage Planning Coordination Region.

b) *The security analysis is done not on regional level only, but within control area also. Coordination of outage planning is also important for internal security analysis.*

Since TSOs act not only in their control areas, but all together in one system, mainly coordination of interconnections on TSO level should be addressed by the code, which will not replace national legislation, which cover the internal security analysis and roles of grid users in different countries.

c) *How regional security coordination initiatives are defined?*

The regional security coordination initiatives are defined on the basis of expertise and practice. It depends on contingency analyses and how many TSOs are affected by one contingency. Methodologies for Operational Security Analysis will have to be developed.

d) *Could one TSO be in more than one regional security coordination initiative?*

A TSO can be in several regional security coordination initiatives because all TSOs are interconnected. Region is therefore well designed to cover group of TSOs and make Contingency Analysis.

10.6.5 Outage Coordination

a) *An outage process already exists in every country. Is there going to be a common process for outage planning at the EU level?*

It is not possible to harmonize all outage planning in Europe in short time. The NC OPS attempts to make a first step in this direction, i.e. to harmonize the coordination of outage planning on TSOs level.

b) *Are CACM regions the same as Outage Coordination Regions?*

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CACM and outage regions are not the same, but can coincide. The CACM regions are based on biding zones, and outage planning is based on physical influence.

c) *What is a process for the update of year ahead planning: the process could be understood that the principle of yes by default is not true and that every time coordination process will be initiated.*

The process will only be initiated if no solution in the hands of TSO exists.

d) *What size of units is involved in outage planning process?*

The size of the unit involved in outage planning depends on the characteristic of the system.

e) *Interconnection means no involvement of DSOs? Could DSOs outages impact cross borders?*

Yes. It depends on specific case and this coordination between TSO-DSO is foreseen in OPS code.

f) *What means testing?*

Only testing of equipment with impact on the grid is addressed.

g) *It is not clear what outage planning agent is. Are there any criteria for agent? The concern is related to confidentiality of information. In this case confidentiality requirements should be in the code.*

There are no criteria for outage planning agent. It could be generator itself. The term is introduced because of big variety of entities in Europe. Each grid user can nominate anybody as an agent or perform the agent functions itself. Confidentiality in this case is responsibility of grid user.

h) *What will happen, if outage planning coordination fails?*

The outage planning process covers such possibilities and foresees NRAs engagement.

10.6.6 Adequacy

a) *Why is generation Adequacy the only adequacy to be covered by the NC OPS and not, for instance, Transmission adequacy?*

After coordinated security analysis on the basis of CGM, new methodologies will take into account also Transmission Adequacy. This is already covered by TYNDP.

b) *Why weekly adequacy report is not published?*

Weekly adequacy report could influence and distort market.

10.6.7 Ancillary Services

a) *What precisely is the definition of Ancillary Services as used in the Network Code?*

The definition of "Ancillary Services" is coming from Directive 2009/72/EC which defines it as " *a service necessary for the operation of a Transmission or distribution system*".

b) *What are the products which are referred to when the NC OPS refers to Ancillary Services?*

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When reference is made to Ancillary Services, the Network Code actually refers to all currently available Ancillary Services and to those Ancillary Services to be developed in the future. The use of Ancillary Services within the scope of NC OPS is therefore not limited to Active Power or Reactive Power Ancillary Services, but also, for instance, to black start facilities.

c) How will information be shared when for some reason there are not enough available Ancillary Services?

In case there are insufficient Ancillary Services within a Responsibility Area, the TSO is required to inform neighbouring TSOs.

d) Is any communication foreseen between parties who deliver Ancillary services and TSOs?

Significant Grid Users and DSOs shall provide information to the TSO, to which they are connected, on their availability to provide Ancillary Services and related capacity. TSOs will publish their required levels of Active Power Ancillary Services.

e) Why are the tools for DSOs' control of voltage not covered in the Network Code?

Voltage control in DSOs Networks should be covered by national grid codes for distribution Networks. This Network Code is developed only for cross-borders issues and DSO voltage and Reactive Power control has a local character.

10.6.8 Scheduling

a) Why is scheduling referring only to the national market rules?

Requirements for scheduling between Market Participants/Power Generating Facilities/Demand Facilities/Market Coupling Operators and TSO operating Scheduling Area are very different in Europe and regulated in national legal framework.

b) The grid model is well defined and harmonized on pan European level, but on other hand the scheduling is not and refers only to national legal framework. The format for the schedules should be the same across all Europe.

The first step in the Network Code is to achieve consistency of schedules.

c) What is External TSO Schedule?

This is a Schedule of area where TSOs prepare schedules in order to perform load frequency control function. This is a summary of all import/export schedules on the borders of each TSO.

d) Why does the definition of ''Netted Area AC Position'' exclude DC lines from its scope of application?

This is a set value for load frequency control only in AC Network because DC set values are constant and controlled separately from load frequency control in Synchronous Area.

10.6.9 ENTSO-E Operational Planning and data Environment

a) What is the difference between the Transparency Platform and the ENTSO-E Operational Planning Data Environment? Will stakeholders have and access to ENTSO-E Operational Planning Data Environment?

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ENTSO-E Operational Planning Data Environment is a tool which is designed for the use of TSOs only. As it contains information which could prove sensitive for the market, it could not be made generally available. Information required for transparency will be published in Transparency platform and will be available to all Market Participants.

b) Who will have an access to the data collected by the TSOs?

ENTSO-E Operational Planning Data Environment will be only for TSOs. Data collected in the Common Grid Model is for the use of TSOs only. Only information required by transparency guidelines will be published.

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10.7 APPENDIX 7 IMPACT ANALYSIS

Purpose

This appendix aims to demonstrate the impact of the requirements of the NC OPS on the existing practices in UK, Continental Europe, Nordic and Baltic areas.

The main conclusions to draw in terms of impact are the following:

- concerning stakeholders, processes and information exchanges are not affected by NC OPS beyond what is already provided through the NCs on RfG, DCC, OS and CACM.
- concerning inter TSOs operational planning processes, NC OPS enforces coordination processes already existing, but significantly developed on the following aspects:
  - delivery and use of Common Grid Models within all timeframes;
  - setting up coordinated processes for Operational Security Analysis within RSCIs framework;
  - introducing systematic coordination outages procedure for all cross border relevant elements outages;
  - integration of cross-border capacities in Adequacy analysis;
  - upgrading scheduling processes to integrate new market coupling procedures;
  - implementing an ENTSO-E data environment for sharing operational planning data.

10.7.1 Impact on NationalGrid (UK)

Obligation	Code Ref	Existing Obligation	Current Practice	Impact NG	Impact User
Data for Operational Security Analysis in Operational Planning					
TSOs shall establish Individual Grid Models for the merging into Common Grid Models (a) Year-Ahead (b) Week-Ahead (c) D-1 (d) intraday	Art 9	None	Grid models produced for internal use.	Medium. National Grid are developing processes to convert models for merging. More scenarios may be required	Low

The European Merging Function shall establish Common Grid Models	Art 9	None;	Work in progress to send DACF to Coreso for merging	Medium. National Grid are developing processes to convert models for merging. More scenarios may be required	Low
All TSOs shall establish a common list of scenarios against which the operation of the Interconnected System shall be assessed. Individual Grid Models to be produced for each scenario.	Art 10 and 11	Implicit in Transmission Licence	A range of scenarios are studied but more may be required under the OP and S Code	Medium. National Grid are developing processes to convert models for merging. More scenarios may be required	Low
TSOs shall define the provisions dealing with the gathering of the Year-Ahead Individual Grid Models, merging them into Common Grid Models	Art 12	None.	Current proposals only cover D-1.	Medium. National Grid are developing processes to convert models for merging. More scenarios may be required	Low
When a group of TSOs considers it necessary for coordinating Operational Security Analysis, they shall define the most representative scenarios for analysing the Operational Security of the Transmission System for the Week-Ahead time horizons	Art 14	Implicit in Transmission Licence	A range of scenarios are studied more may be required under the Code	Medium. More scenarios may need to be studied	Low
All TSOs shall agree on the provisions dealing with the gathering and merging of the D-1 and Intraday Individual Grid Models into Common Grid Models.	Art 15	None	NG produce D-1 and intraday grid models for cardinal points. Process for conversion into DACF being developed.	Medium Processes being developed but may have to be amended to meet new obligations.	Low

Operational Security Analysis in Operational Planning					
Each TSO shall perform coordinated Operational Security Analysis at least at the following time horizons Year Ahead, Week Ahead, D-1 and Intraday. Analysis to assess the system under a range of defined scenarios for steady state and dynamic (frequency and voltage) security and short circuit infeed.	Art 16	Implicit in Transmission Licence		Medium. Co-ordination between TSOs may require more frequent and/or analysis at different time s to present.	Low
Year-Ahead and updated Operational Security Analysis. D-1, Intraday and close to Real-Time Operational Security Analysis. Agree with TSOs on use of Remedial Actions	Art 17 and 18	Implicit in Grid Code	Remedial Actions agreed with external interconnected TSOs	Low	Low
Security Analysis co-ordination. Principals for (a) defining contingencies which impact on security in a Control Area outside of the Control Area in which they occur, (b) common risk assessment © selecting Remedial Actions. Methodologies for co-ordinated Dynamic Stability Analysis	Art 19 and 20	GBSQSS does not require NG to secure system for Faults outside of GB. However loss of Interconnector due to a contingency outside of GB may be the largest credible loss for GB system			
Outage Co-ordination					

Outage co-ordination regions; establish and developing methodologies for co-ordination the availability of Relevant Assets	Art 21 and 22	No obligation but co-ordination could mitigate effect of the availability of Relevant Assets on Interconnector capacity. For example if unavailability of Gen A in France and Gen B in GB both limit capacity it would be expedient to align unavailability's.	None	Medium	Low
Assessment of Relevance	Art 23 to 25, 27 and 28	Grid Code uses the concept of size of Generator/ Demand to determine relevance to system operation. Generators and Demand relevant to cross border flows would be a subset of this.		Low	High, if being deemed to be Relevant impacts of freedom to take outages
Appointment of Outage Planning Agents	Art 26	Grid Code requires data to be provided by Licence Holder	Data provided by Licence holder	Medium may require Code change	Low. Outage Planning Agent could be the User; User decides
TSO to co-ordinate outages of Relevant Assets located in DSO Network with DSO	Art 29	Grid Code OC2 obligation		Low.	Low
Variations to deadlines for the Year-Ahead coordination process only by TSO agreement and NRA approval	Art 30			Low.	Low

General provisions on Availability Plans. At least daily granularity. Status Available/Unavailable or Testing	Art 32	>=Year Ahead down to 49 days ahead weekly resolution. 2 to 49 days ahead daily resolution.D-1 to gate closure 0.5 hour resolution. Generators provide availability and Output Useable i.e. MW available.		Medium More date will be required from Relevant Assets for period down to 49 days ahead. IS and process changes	Medium More date will be required from Relevant Assets for period down to 49 days ahead. IS and process changes
Two years prior to the start of the Year Ahead co-ordination process (August 1st Day Ahead) TSO to assess availability plans for incompatibility	Art 33	Aligns with current Grid Code OC2 process		Medium More date will be required from Relevant Assets for period down to 49 days ahead. IS and process changes	Medium More date will be required from Relevant Assets for period down to 49 days ahead. IS and process changes
Year Ahead availability plans to be submitted before 1st August and 1st December plans may be changed	Art 34 to 37	Grid Code OC 2 process outage co-ordination from early March to early December.		Low aligns with current process	Low aligns with current process
TSO to assess whether outage incompatibilities arise within Outage Co-ordination Regions	Art 38	No existing obligation. Co-ordination on availabilities which impact on Interconnector capacity		Low TSO to TSO data exchange on outage which limit capacity	Low

Final Year-Ahead Availability Plans finalised on 1st December. After this date changes will require TSO approval but will not be refused unless incompatibilities cannot be resolved. Outage Planning Agents and DSO to be informed of outages where availability status is critical. Proposal to state that where incompatibilities can be resolved through the market change will be allowed	Art 39	Outages can be changed up until gate closure		Process for dealing with outage incompatibilities will be in line with applicable legal framework	Low Relevant Generators will be able to change outages in line with existing arrangements.
Testing of Relevant Generating Modules, Relevant Demand Facilities and Self-Planned Interconnectors. Test plan to be provided no later than two months before the test date	Art 42	Under Grid Code reasonable advanced notification required		Low	High more stringent notice period for testing Generators.
Testing of Relevant Grid Elements TSO to inform TSOs in Outage Coordination Region of plans to test.	Art 43	No obligation.		Low	Low
Testing of Relevant Grid Elements Located in DSO Network	Art 44	Obligation on DSOs and SO to liaise in Grid Code and Distribution Code		Low	Low

Handing Forced Outages. TSO to be informed of Forced Outages on Relevant Assets as soon as possible. TSO to inform Outage Planning Agents when Operational Security will no longer be fulfilled (if at all). TSO/DSO to inform other impacted DSOs/TSOs outage planning agents Summarise this	Art 45	Obligations on Generators to inform TSO of Forced Outages in Physical Notification and OC2 data. Obligation on DSO's and TSO's to liaise on Forced Outages which impact on each other's Networks.		Low	Low
Generators obliged to ensure generators declared available are ready to produce electricity subject to Constraints e.g. start up delays. .	Art 46	Aligns with Grid Code BC obligations Notice to Deviate from Zero		Low	Low
Adequacy					
Responsibility Area Adequacy Up to week ahead and D-1 to Intraday	Art 47, 48, 50 and 51	Grid Code obligation to assess margin of generation over demand		Low	Low
Summer and winter outlooks Pan European)	Art 49	Obligation under Regulation (EC) N° 714/2009		Low	Low
Ancillary Services					
Ancillary Services monitor availability	Art 52	None	Contracts placed ahead of real time to ensure availability	Low	Low
Reactive power services assess availability and inform neighbouring TSOs of shortfalls	Art 53	None	Availability assessed in planning and control timescales. Neighbouring TSOs would be informed if Operational Security is at risk.	Low	Low
Scheduling					

Establish a scheduling process	Art 54	Grid Code Balancing Codes		Low	Low
Market Participants to provide schedules	Art 55	Grid Code and BSC obligations on Market Participants		Low	Low
Process to ensure that aggregated market schedules within a Synchronous Area balance.	Art 56	Grid Code obligation to monitor supply and demand and inform market.		Low	Low
Provision of information to other TSOs	Art 57	Grid Code. Explicit obligation to monitor supply and demand and inform externally interconnected TSOs of shortfalls. No obligation on i/c owners and TSOs to develop operating procedures	Operating Protocols established to exchange info	Low	Low
ENTSOE-E Operational Planning Data Environment , EOPDE					
Database to store data related to grid models and security analysis, outage co-ordination and system Adequacy	Arts 58 to 61	No obligation	None	Medium; Data is available but will require development of an interface to transfer data between NG systems and EOPDE	
Performance Indicators					
Yearly report and detailed analysis if performance is deteriorating	Art 62	No obligation	None	Medium Data collection and reporting process to be established.	
Final Provisions					
All contracts to be amended to ensure compliance with Code	Art 63	N/A	N/A	Unsure needs to be discussed internally	Unsure needs to be discussed internally
Entry into Force					

Timescales	Art 64			Medium	Medium

10.7.2 Impact on Continental Europe

Obligation	Code Ref	Existing Obligation	Current Practice	Impact Continental Europe	Impact User
Data for Operational Security Analysis in Operational Planning					
TSOs shall establish Individual Grid Models for the merging into Common Grid Models (a) Year-Ahead (b) Week-Ahead (c) D-1 (d) intraday. The European Merging Function shall establish Common Grid Models	Art 9	partially	Individual Grid models already delivered and merged for the whole Continental Europe for D-1 (DACF (Policy 4.C of Operational Handbook, P4.C of OH)). In some regions intraday IGM are delivered and merged for Week-Ahead and intraday. Regarding Year-ahead, currently data sets are exchanged and merged for the whole Continental Europe for two scenarios: Summer and Winter.	Medium-high. Limited number of established Year-ahead scenarios would not impose huge work-load. Week-Ahead remains on a voluntary basis. D-1 is currently being implemented for every hour of day D for the whole Continental Europe. Main impact of this requirement is in **intraday** CGMs, which will be finally determined by the number of intraday sessions for Capacity Calculation.	none
All TSOs shall establish a common list of scenarios against which the operation of the Interconnected System shall be assessed. Individual Grid Models to be produced for each scenario.	Art 10, 11, 12 and 13	partially	Current practices contemplate two Year-ahead scenarios (Summer and Winter) (Base-Case Exchange (BCE), according to Policy 4.B of OH) and the delivering of IGMs to be merged for the whole Synchronous Area.	Medium. Limited number of established Year-ahead scenarios would not impose huge work-load.	none

All TSOs of an Outage Coordination Region, shall define the most representative scenarios for analysing the Operational Security of the Transmission System for the Week-Ahead time horizons.	Art 14	yes, in some regions	Today this requirement is a (non binding) Guideline for the whole Continental Europe, in Policy 4.A.G1 of Operational Handbook (P4.A.G1 OH). Current practice only in some regions (SW).	Low, if any. Regional process, on a voluntary basis.	none
All TSOs shall agree on the provisions dealing with the gathering and merging of the D-1 and intraday Individual Grid Models into Common Grid Models, at least at Synchronous Area level	Art 15	partially	Already current practice for the whole Continental Europe for D-1 (DACF, P4.C OH). Not in place for the whole Continental Europe for intraday. Covered by (non-binding) Guidelines in P4.C.G1-5. Regional intraday merging is a current practice in some regions (CW, CE).	Medium / High, depending on the number of mandatory intradays for the whole Continental Europe.	none
Operational Security Analysis in Operational Planning					
Each TSO shall perform coordinated Operational Security Analysis at least at the following time horizons: Year Ahead, Week Ahead, D-1 and Intraday.	Art 16	yes (coordinated at regional level) (without considering CGMs as input for Operational Security Analyses)	P4.A of OH established ENTSO-E Continental Network planning deadlines on a general way, associated with outage scheduling iterative processes that starts in the second half of the preceding year and finishes on the day preceding actual operation (day-ahead).	Low-medium. The major impact comes from the associated task of building up Year-Ahead CGMs.	none

Year-Ahead and updated Operational Security Analysis. Analysis to assess the system under a range of defined scenarios for steady state and, where relevant, dynamic (frequency and voltage) security and short circuit infeed. Agree with TSOs on use of Remedial Actions	Art 17	yes	Principles covered by Policy 3 of Operational Handbook (P3: A1.S2,3,5; A2.S1-6; A3.S4; A4.S1, S4) for all timeframes and enforced in Year-Ahead (second half of the preceding year) and in other outage planning timeframes (notably Week-Ahead) by Policy 4.	Medium. Co-ordination between TSOs may require more analyses (as per CGMs established) and updates of previous analyses, at different time to present.	Low-medium, (Remedial Actions limited to topological measures in the Network and outages planning)
D-1, intraday and Close to Real-Time Operational Security Analysis, with the updated data regarding generation and demand, to detect possible Constraints and programe with TSOs and in coordination with DSOs and SGU necessary Remedial Actions.	Art 18	yes	For D-1, principles covered in Policy 4.C.S9,10. In all timeframes, covered by Policy 3.A1.S3; P3.A4.S1-2. Based on State Estimation and exchange of data sets between TSOs.	Medium. Co-ordination between TSOs may require more analysis (as per CGMs established) and create new processes.	Low-medium. Activation of Remedial Actions involving DSOs or SGU is today a current practice, not changed by the NC.
Methodologies for coordinating Operaitonal Security Analysis standardized per Synchronous Area.	Art 19	partially	Current standardize methodology for Operational Security Analysis in Continental Europe is mainly the Policy 3 of Operational Handbook.	High. A deep review of Policy 3 shall be done in order to cover the topics detailed in NC OPS.	none
Agreements (regional) for coordinating Operational Security.	Art 20	partially	Current agreements per region in Continental Europe exist.	Medium-High. A review of existing agreements shall be done in order to fit with requirements detailed in NC OPS.	none
Outage Co-ordination					
Definition of Outage Coordination Regions and Regional coordination procedure	Art 21 and 22	yes	Policy 4.A establishes Regions whose composition depends on the operational tasks to be performed in Outage Coordination.	Low. Details are now introduced in the NC OPS that should be formalised in reviewed versions of P4.A OH.	none

Methodology for assessing relevance of assets for the Outage Coordination Process and List of Relevant Assets per region.	Art 23, 24 and 25.	partially	Policy 3.A2.S3 establishes that the determination of the external Contingency List must be based on numerical Network analysis, leaving freedom to each TSO to select the most suitable method.(Non binding) Annexes of Policy 3 are an example of current (best) practices, formalised as Guidelines for the whole Continental Europe. Policy 4.A.S2 establishes the requirement for updating the List of Relevant Assets per region.	Medium. TSOs shall develop and agree on a common methodology. Additional impact comes from the requirement establishing the exchange of data through ENTSOE Operational Planning Data Environment.	Medium. If being deemed to be Relevant. In this case requirements in Chapter 4 for outages planning will became applicable and there is a different degree (depending on the national legal framework and the type of asset) of impact of these requirements on the current practices.
Appointment of Outage Planning Agents	Art 26	Different practices under national legal frameworks.	Different practices under national legal frameworks.	Low-medium. Depending on national legal framework. May require updates of national grid codes.	Low. Outage Planning Agent could be the Owner or the Operator (SGU decides).
List of Relevant Grid Elements	Art 27 and 28	partially	Policy 4.A establishes requirements for TSOs to collect and share information about planned outages of the Relevant Grid Elements within regional groups.	Low. The major impact comes from the requirement establishing the exchange of data through ENTSOE Operational Planning Data Environment.	none
Coordination of Relevant Assets in Distribution Networks.	Art 29	yes, under national legal framework	TSOs coordinate the outages processes involving, in line with national legal framework, possible affected DSOs and CDSO.	none	none
Variations to deadlines for the Year-Ahead coordination process only by TSO agreement and NRA approval	Art 30	--	This requirement has been drafted to allow non-dramatical changes of current practices for specific Synchronous Areas (in principle, not for Continental	none	none

			Europe).		
Link with data to be provided as described in other legal acts (notably Transparency Regulation)	Art 31	--	This requirement has been drafted to ensure the consistency of the data published in the Transparency Regulation with respect to the final approved outage plans.	Low. TSOs shall check the consistency of the data.	none
General provisions on Availability Plans. At least hourly granularity. Status Available/Unavailable or Testing	Art 32	depending on national legal framework	Granularity of Availability Plans depends on the national legal framework.	Medium. Different treatment of data sets.	Medium. Possible additional detail in data sets for Relevant Assets.
Long-term indicative assessment of three years-ahead availabiltiy statuses delivered in line with the Transparency Regulation.	Art 33	only in some national legal frameworks	Only in some national legal frameworks	Medium. Additional assessments to be done once per year.	Low
Year Ahead availability plans to be submitted before 1st August.	Art 34	depending on national legal framework	Current practices contemplate very different deadlines.	Medium. In some cases, advancement of current processes.	Medium. In some cases, anticipation of delivering proposals.
TSO to assess whether outage incompatibilities arise within Outage Co-ordination Regions, to initiate a coordination procedure in such a case and, if incompatibility remains, to establish an alternative Availability Plan.	Art 35 and 36	depending on national legal framework	Policy 4 requires establishing alternative outages plans in case of incompatibilities are detected. TSOs are entitled to perform proposals of alternative plans, with more or less binding character, depending on national legal framework.	Low-medium. In any case, Article 40 applies.	Low-medium. Depending on the national legal framework and in any case, Article 40 applies.

Preliminary Year-Ahead Availability Plans delivered by each TSO through ENTSOE Operational Planning Data Environment to the rest of TSOs before 1st of November.	Art 37	partially	P4.A.S4.1 establishes long term planning in the second half of the preceding year, not fixing a single common date to deliver preliminary plans. Also ENTSOE Operational Planning Data Environment as mean of sharing information is new.	Medium-high. Adaptation of processes and development of ENTSOE Operational Planning Data Environment.	none
Final Year-Ahead Availability Plans finalised on 1st December, after coordinating possible incompatibilities with affected DSOs and SGUs.	Art 38 and 39	depending on national legal framework	1st of December is a date quite repeated in national legal frameworks for finalising Year-Ahead Availability Plans	Low.	Low
Applicable national legal framework to rule coordination in case of detected Outages Incompatibilities.	Art 40	yes	The article refers to national legal framework, so it deals with current practices.	none	none
Requested changes of the Year-Ahead Availability Plan requested will require TSO approval but will not be refused unless incompatibilities cannot be resolved.	Art 41	depending on national legal framework	The degree of firmness of Year-Ahead Availability Plans is different depending on the national legal framework.	Medium.	Medium. Depending on the national legal framework and in any case, Article 40 applies.
Test plan of Relevant Assets to be provided no later than one month before the test date.	Art 42, 43 and 44	depending on national legal framework	Notice period in national legal framework.	Low	Medium. Depending on the notice period required in national legal framework.

TSO establishes Handing Forced Outages process, submitted to NRA approval. Informed of Forced Outages on Relevant Assets to be provided as soon as possible. TSO to inform Outage Planning Agents when Operational Security will no longer be fulfilled (if at all).	Art 45	under national legal framework	It is in a major extent a current practice covered by national legal framework.	Low	Low
Generators obliged to ensure generators declared available are ready to produce electricity subject to Constraints.	Art 46	under national legal framework	It is in a major extent a current practice covered by national legal framework.	Low	Low
Adequacy					
TSOs to make available the forecasts to the other TSOs through ENTSOE Operational Planning Data Environment.	Art 47	no	When performed, on a regional level on a voluntary basis.	Low. The major impact comes from the requirement establishing the exchange of data through ENTSOE Operational Planning Data Environment.	none
Responsibility Area Adequacy Up to week ahead and D-1 to Intraday	Art 48, 50 and 51	under national legal framework	Current practices cover this requirement in a great extent.	none	Low
Summer and winter outlooks Pan European)	Art 49	Obligation under Regulation (EC) N° 714/2009	already in place; although methodology is being improved	Low	Low
Ancillary Services					
Ancillary Services monitor availability and manage and set up procedures for Ancillary Services procurement.	Art 52	yes under national legal framework	Current practices cover this requirement in a great extent.	none	none (no change of current practices)

Reactive power assessment and inform neighbouring TSOs of shortfalls	Art 53	Already in place	Already in place	none	none (no change of current practices)
Scheduling					
Establish a scheduling process	Art 54	Already in place	Already in place	none	none
Market Participants to provide schedules	Art 55	Already in place	Already in place	none	none
Process to ensure that aggregated market schedules within a Synchronous Area balance.	Art 56	Already in place	Already in place	none	none
Provision of information to other TSOs	Art 57	Already in place	Already in place	none	none
ENTSOE-E Operational Planning Data Environment					
Database to store data related to grid models and security analysis, outage co-ordination and system Adequacy	Arts 58 to 61	no	Even if partially in place for the whole Continental Europe for some processes and for some regions for other processes, the scope of the requirements require a significant task.	High. Need for agreement, design, development and operation	none
Performance Indicators					
Yearly report and detailed analysis if performance is deteriorating	Art 62	partially	Partially dealt by Incident Classification Scale	Medium	none

10.7.3 Impact on Nordic

Obligation	Code Ref	Existing Obligation	Current Practice	Impact Nordic	Impact User
Data for Operational Security Analysis in Operational Planning					
TSOs shall establish Individual Grid Models for the merging into Common Grid Models (a) Year-Ahead (b) Week-Ahead (c) D-1 (d) intraday	Art 9	None	Grid models produced for internal use.	Medium. The Nordic region is developing processes to convert models for merging. More scenarios may be required. The complexity is dependent on NRA approval	Low
The European Merging Function shall establish Common Grid Models	Art 9	None	The idea (in Sweden) is to send IGM to the European Merging Function. This functionality is developed in the new SCADA/EMS system	Medium. National Grid are developing processes to convert models for merging. More scenarios may be required	Low
All TSOs shall establish a common list of scenarios against which the operation of the Interconnected System shall be assessed. Individual Grid Models to be produced for each scenario.	Art 10 and 11	None (Summer/winter outlook?)	A range of scenarios are studied but more may be required under the OP and S Code	Medium. Nordic TSOs are developing processes to convert models for merging. More scenarios may be required	Low
TSOs shall define the provisions dealing with the gathering of the Year-Ahead Individual Grid Models, merging them into Common Grid Models	Art 12	None	None	Medium.	Low

When a group of TSOs considers it necessary for coordinating Operational Security Analysis, they shall define the most representative scenarios for analysing the Operational Security of the Transmission System for the Week-Ahead time horizons	Art 14	None	A range of scenarios are studied more may be required under the Code	Medium. More scenarios may need to be studied	Low
All TSOs shall agree on the provisions dealing with the gathering and merging of the D-1 and Intraday Individual Grid Models into Common Grid Models.	Art 15	None	Not fully in practice. Sweden, being in the middle has a grid model that includes relevant parts of the adjacent areas. Input to this model is gathered from adjacent TSOs.	Medium Processes being developed but may have to be amended to meet new obligations.	Low
Operational Security Analysis in Operational Planning					
Each TSO shall perform coordinated Operational Security Analysis at least at the following time horizons Year Ahead, Week Ahead, D-1 and Intraday. Analysis to assess the system under a range of defined scenarios for steady state and dynamic (frequency and voltage) security and short circuit infeed.	Art 16	Fulfilment of system responsibility (National law)	Not fully in practice in a structured way. More event based.	Medium. Need for more Co-ordination between TSOs.	Low

Year-Ahead and updated Operational Security Analysis. D-1, Intraday and close to Real-Time Operational Security Analysis. Agree with TSOs on use of Remedial Actions	Art 17 and 18	Grid Code states the main principal, that Fault in one area should not affect power system in adjacent areas.	Remedial Actions is agreed to some extent with external interconnected TSOs	Low. More data and formal decisions probably required.	Low
Security Analysis co-ordination. Principals for (a) defining contingencies which impact on security in a Control Area outside of the Control Area in which they occur, (b) common risk assessment © selecting Remedial Actions. Methodologies for co-ordinated Dynamic Stability Analysis	Art 19 and 20	Grid Code states the main principal, that Fault in one area should not affect power system in adjacent areas.	This is managed in the Nordic Outage Team (NOT).	Low. More data and formal decisions probably required.	Low
Outage Co-ordination					
Outage co-ordination regions; establish and developing methodologies for co-ordination the availability of Relevant Assets	Art 21 and 22	Grid Code states the main principal, that Fault in one area should not affect power system in adjacent areas.	This is managed in the Nordic Outage Team (NOT).	Low. More data and formal decisions probably required.	Low
Assessment of Relevance	Art 23 to 25, 27 and 28	Grid Code uses the concept of size of Generator/ Demand to determine relevance to system operation. Generators and Demand relevant to cross border flows would be a subset of this. Also Reactive Power might be an issue.	This is managed in the Nordic Outage Team (NOT).	Low	Medium, if being deemed to be Relevant impacts of freedom to take outages

Appointment of Outage Planning Agents	Art 26	None	Data provided by Licence holder (Generator/DSO etc..)	Medium (may require change of "agreement to connect to grid")	Low.
TSO to co-ordinate outages of Relevant Assets located in DSO Network with DSO	Art 29	None	This is managed as a prerequisite to the work done in the Nordic Outage Team (NOT). So there is a national workflow to coordinate this.	Low.	Low
Variations to deadlines for the Year-Ahead coordination process only by TSO agreement and NRA approval	Art 30	none	This is managed in the Nordic Outage Team (NOT). So there is a national workflow to coordinate this.	Low.	Low
General provisions on Availability Plans. At least daily granularity. Status Available/Unavailable or Testing	Art 32	>=Year Ahead down to hour resolution. Via Urgent market message (UMM) the players inform of availability with impact larger than 100 MW and a duration over 1h.		Low. More data and formal decisions probably required.	Low. More data and formal decisions probably required.
Two years prior to the start of the Year Ahead co-ordination process (August 1st Day Ahead) TSO to assess availability plans for incompatibility	Art 33	Aligns with current practices		Low. More data and formal decisions probably required.	Low. More data and formal decisions probably required.
Year Ahead availability plans to be submitted before 1st August and 1st December plans may be changed	Art 34 to 37	Aligns with current practices		Low. More data and formal decisions probably required.	Low. More data and formal decisions probably required.
TSO to assess whether outage incompatibilities arise within Outage Co-ordination Regions	Art 38	Aligns with current practices		Low. More data and formal decisions probably required.	Low. More data and formal decisions probably required.

Final Year-Ahead Availability Plans finalised on 1st December. After this date changes will require TSO approval but will not be refused unless incompatibilities cannot be resolved. Outage Planning Agents and DSO to be informed of outages where availability status is critical. Proposal to state that where incompatibilities can be resolved through he market change will be allowed	Art 39	Aligns with current practices		Low. More data and formal decisions probably required.	Low. More data and formal decisions probably required.
Testing of Relevant Generating Modules, Relevant Demand Facilities and Self-Planned Interconnectors. Test plan to be provided no later than two months before the test date	Art 42	Aligns with current practices		Low	Low. More data and formal decisions probably required.
Testing of Relevant Grid Elements TSO to inform TSOs in Outage Coordination Region of plans to test.	Art 43	Aligns with current practices		Low	Low
Testing of Relevant Grid Elements Located in DSO Network	Art 44	The TSO (in Sweden)has responsibility for grid components to interact reliably. This includes testing…		Low	Low

Handing Forced Outages. TSO to be informed of Forced Outages on Relevant Assets as soon as possible. TSO to inform Outage Planning Agents when Operational Security will no longer be fulfilled (if at all). TSO/DSO to inform other impacted DSOs/TSOs outage planning agents Summarise this	Art 45	Market rules sets some requirement.(Via Urgent market message (UMM) the players inform of availability with impact larger than 100 MW and a duration over 1h.)		Low. More data and formal decisions probably required.	Low. More data and formal decisions probably required.
Generators obliged to ensure generators declared available are ready to produce electricity subject to Constraints e.g. start up delays. .	Art 46	Market rules sets some requirement.(Via Urgent market message (UMM) the players inform of availability with impact larger than 100 MW and a duration over 1h.)		Low. More data and formal decisions probably required.	Low. More data and formal decisions probably required.
Adequacy					
Responsibility Area Adequacy Up to week ahead and D-1 to Intraday	Art 47, 48, 50 and 51	Grid Code obligation to assess margin of generation over demand		Low. More data and formal decisions probably required.	Low. More data and formal decisions probably required.
Summer and winter outlooks Pan European	Art 49	Obligation under Regulation (EC) N° 714/2009		Low	Low
Ancillary Services					
Ancillary Services monitor availability	Art 52	None	Contracts placed ahead of real time to ensure availability	Medium. More data and formal decisions probably required.	Medium. More data and formal decisions probably required.
Reactive power services assess availability and inform neighbouring TSOs of shortfalls	Art 53	None	Availability assessed in planning and control timescales. Neighbouring TSOs would be informed if Operational Security is at risk.	Low. More data and formal decisions probably required.	Low. More data and formal decisions probably required.

Scheduling					
Establish a scheduling process	Art 54	Grid Code Balancing Codes		Low	Low
Market Participants to provide schedules	Art 55	Grid Code and Agreement of BRP sets obligations.		Low	Low
Process to ensure that aggregated market schedules within a Synchronous Area balance.	Art 56	Grid Code and Agreement of BRP sets obligations.		Low	Low
Provision of information to other TSOs	Art 57	Grid Code.	Information regarding Ancillary Services is exchanged (CMO etc.) via Nordic Operational Information System(NOIS). This is ATC based and not Flowbased so there will be some changes.	Low	Low
ENTSOE-E Operational Planning Data Environment , EOPDE					
Database to store data related to grid models and security analysis, outage co-ordination and system Adequacy	Arts 58 to 61	No obligation	None	Medium; Data is available but will require development of an interface to transfer data between Nordic systems and EOPDE	
Performance Indicators					
Yearly report and detailed analysis if performance is deteriorating	Art 62	No obligation	None	Medium Data collection and reporting process to be established. More data and formal decisions probably required.	
Final Provisions					

All contracts to be amended to ensure compliance with Code	Art 63	N/A	N/A	Unsure needs to be discussed internally	Unsure needs to be discussed internally
Entry into Force					
Timescales	Art 64			Medium	Medium

10.7.4 Impact on Baltics

Obligation	Code Ref	Existing Obligation	Current Practice	Impact Baltic	Impact User
Data for Operational Security Analysis in Operational Planning					
TSOs shall establish Individual Grid Models for the merging into Common Grid Models (a) Year-Ahead (b) Week-Ahead (c) D-1 (d) intraday	Art 9	Partly	Year ahead, Month ahead, week ahead, D-1 Individual Grid Model s are established, however not as detailed as defined in NC OPS. Currently no Intraday	Medium. IGMs for Intraday and improvement of detail and format are necessary.	None
The European Merging Function shall establish Common Grid Models	Art 9	Partly	Merging function is assigned to the Coordinator for specific timeframe (Y-1, M-1…) however not as detailed as defined in NC OPS.	Medium. Improvement of detail and formats for merging function is necessary.	None
All TSOs shall establish a common list of scenarios against which the operation of the Interconnected System shall be assessed. Individual Grid Models to be produced for each scenario.	Art 10 and 11	None	Only Min/max load scenarios are evaluated in some timeframes, while best estimate scenarios of each TSO is mostly used	Medium.	None
TSOs shall define the provisions dealing with the gathering of the Year-Ahead Individual Grid Models, merging them into Common Grid Models	Art 12	Partly	Current process of gathering IGMs and merging them into CGMs ins not as detailed as defined in NC OPS.	Medium. IGMs for Intraday and improvement of detail and format are necessary.	None

When a group of TSOs considers it necessary for coordinating Operational Security Analysis, they shall define the most representative scenarios for analysing the Operational Security of the Transmission System for the Week-Ahead time horizons	Art 14	none	No specific scenarios are defined, only best estimate scenarios of each TSO is used	Medium.	None
All TSOs shall agree on the provisions dealing with the gathering and merging of the D-1 and Intraday Individual Grid Models into Common Grid Models	Art 15	Partly	Some provisions for year ahead, Month ahead, week ahead, D-1 are in place, however not as detailed as defined in NC OPS. Currently no Intraday	Medium. Provisions regarding intraday and improvement of detail and format are necessary.	None
Operational Security Analysis in Operational Planning					
Each TSO shall perform coordinated Operational Security Analysis at least at the following time horizons Year Ahead, Week Ahead, D-1 and Intraday. Analysis to assess the system under a range of defined scenarios for steady state and dynamic (frequency and voltage) security and short circuit infeed.	Art 16	none on Baltic level, only national legislations.	No provisions regarding coordination of security analysis.	Medium. Coordination process is needed.	None

Year-Ahead and updated Operational Security Analysis. D-1, Intraday and close to Real-Time Operational Security Analysis. Agree with TSOs on use of Remedial Actions	Art 17 and 18	none	No provisions regarding evaluation of Remedial Actions during planning phase, only bilateral agreements for real-time operation.	High. Agreement on Remedial Actions and coordination between TSOs for all timeframes are needed.	None
Security Analysis co-ordination. Principals for (a) defining contingencies which impact on security in a Control Area outside of the Control Area in which they occur, (b) common risk assessment © selecting Remedial Actions. Methodologies for co-ordinated Dynamic Stability Analysis	Art 19 and 20	none on Baltic level, only national legislations.	No provisions regarding coordination of security analysis.	Medium. Coordination process is needed.	None
Outage Co-ordination					
Outage co-ordination regions; establish and developing methodologies for co-ordination the availability of Relevant Assets	Art 21 and 22	yes	Coordination process is in place	Low	Low
Assessment of Relevance	Art 23 to 25, 27 and 28	none	Currently no methodology is in place. Only agreement between TSO on defining Relevant Assets.	Medium	high
Appointment of Outage Planning Agents	Art 26	yes	National legislation and agreements with TSOs.	low	low

TSO to co-ordinate outages of Relevant Assets located in DSO Network with DSO	Art 29	none on Baltic level, only national legislations.	No Relevant Assets in DSOs Network	Low.	Low
Variations to deadlines for the Year-Ahead coordination process only by TSO agreement and NRA approval	Art 30	yes.	No variations to deadlines is needed.	Low.	Low
General provisions on Availability Plans. At least daily granularity. Status Available/Unavailable or Testing	Art 32	Yes	No requirements for status "Testing"	Low	Medium. Additional information regarding "testing" will be needed.
Two years prior to the start of the Year Ahead co-ordination process (August 1st Day Ahead) TSO to assess availability plans for incompatibility	Art 33	None	no process regarding two-years ahead coordination process.	Medium. New process shall be established.	Medium. Additional information regarding Y-2 availability plans will be needed.
Year Ahead availability plans to be submitted before 1st August and 1st December plans may be changed	Art 34 to 37	yes	before 1st August	Low aligns with current process	Low
TSO to assess whether outage incompatibilities arise within Outage Co-ordination Regions	Art 38	Yes	Incompatibilities are assesed while performing security analysis	Low	Low

Final Year-Ahead Availability Plans finalised on 1st December. After this date changes will require TSO approval but will not be refused unless incompatibilities cannot be resolved. Outage Planning Agents and DSO to be informed of outages where availability status is critical. Proposal to state that where incompatibilities can be resolved through he market change will be allowed	Art 39	Yes	Year-ahead plans are set before 1st December, however doesn't have status of "final"	Low	Medium. Theoretical restriction to move outage plans arises
Testing of Relevant Generating Modules, Relevant Demand Facilities and Self-Planned Interconnectors. Test plan to be provided no later than two months before the test date	Art 42	None	No requirements for status "Testing" nor for information provision no later than two months before	Low. Additional requirements for status "testing" shall be established.	Medium. Additional information regarding "testing" will be needed.
Testing of Relevant Grid Elements TSO to inform TSOs in Outage Coordination Region of plans to test.	Art 43	None	No requirements for status "Testing".	Low. Additional requirements for status "testing" shall be established.	Low
Testing of Relevant Grid Elements Located in DSO Network	Art 44	None on Baltic level, only national legislations.	No Relevant Assets in DSOs Network	Low.	Low

Handing Forced Outages. TSO to be informed of Forced Outages on Relevant Assets as soon as possible. TSO to inform Outage Planning Agents when Operational Security will no longer be fulfilled (if at all). TSO/DSO to inform other impacted DSOs/TSOs outage planning agents Summarise this	Art 45	Yes	Already in place	Low	Low
Generators obliged to ensure generators declared available are ready to produce electricity subject to Constraints e.g. start up delays. .	Art 46	none on Baltic level, only national legislations.		Low	Low
Adequacy					
Responsibility Area Adequacy Up to week ahead and D-1 to Intraday	Art 47, 48, 50 and 51	None on Baltic level, only national legislations.		Medium. New processes must be established	none
Summer and winter outlooks Pan European)	Art 49	Obligation under Regulation (EC) N° 714/2009	already in place; although methodology is being improved	Low	none
Ancillary Services					
Ancillary Services monitor availability	Art 52	none on Baltic level, only national legislations.		High. Common processes must be established	Low
Reactive power services assess availability and inform neighbouring TSOs of shortfalls	Art 53	none	no common process is in place	Medium. New process must be established	Low
Scheduling					
Establish a scheduling process	Art 54	None on Baltic level, only national legislations.	Already in place	none	none

Market Participants to provide schedules	Art 55	Yes	Already in place	none	none
Process to ensure that aggregated market schedules within a Synchronous Area balance.	Art 56	None		Medium. New process must be established	none
Provision of information to other TSOs	Art 57	yes	Already in place	none	none
ENTSOE-E Operational Planning Data Environment , EOPDE					
. Database to store data related to grid models and security analysis, outage co-ordination and system Adequacy	Arts 58 to 61	none		Medium; Data is available but will require development to provide information for ENTSO-E Database	none
Performance Indicators					
Yearly report and detailed analysis if performance is deteriorating	Art 62	none on Baltic level, only national legislations.		Medium. New process to deliver report must be established	none
Final Provisions					
All contracts to be amended to ensure compliance with Code	Art 63	-	-	high, since number of new processes and requirements must be set between Baltic TSOs	Medium
Entry into Force					
Timescales	Art 64	-	-	Medium	Medium

10.8 APPENDIX 8 GLOSSARY

Purpose

For the sake of convenience this appendix includes all definitions used in the OPS NC.

Significant attention has been given to refining and harmonising definitions. Concerning definitions of certain terms, there is no need to duplicate or make additional references to the other NCs, as the Article 2(1) in OPS NC is already referring to the definitions of more advanced codes.

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)) (from NC RfG)

Active Power Reserve means the Active Power which is available for maintaining the frequency (from NC OS)

Adequacy means the ability of Generation connected to an area to meet the demand in this area (from NC OPS)

Aggregated Netted External Schedule means a Schedule representing the netted aggregation of all External TSO Schedules and External Commercial Trade Schedules between two Scheduling Areas or between a Scheduling Area and a group of other Scheduling Areas (from NC OPS)

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 (from NC OS)

Ancillary Service means a service necessary for the operation of a Transmission or Distribution system (from Directive 2009/72/EC)

Availability Plan means the combination of all planned Availability Statuses for a Relevant Asset for a given time period (from NC OPS)

Availability Status means the capability for a given time period of a Power Generating Module, grid element, Demand Facility, Self-Planned Interconnector or another facility to provide service, whether or not it is in operation (from NC OPS)

Bidding Zone means the largest geographical area within which Market Participants are able to exchange energy without Capacity Allocation (from NC CACM)

Blackout State means the System State where the operation of part or all of the Transmission System is terminated (from NC OS)

Capacity Calculation Process means a process in which the capability of the Transmission Network to accommodate market transactions is assessed, it consists of calculation of the Cross Zonal Capacity. This assessment must be in line with Operational Security and optimization of Cross Zonal Capacity made available to market participants; (from NC CACM)

Close to Real-Time means a time interval before real-time in an order of magnitude of 15 minutes (from NC OPS)

Common Grid Model means European-wide or multiple-System Operator-wide data set, created by the European Merging Function, through the merging of relevant data (from NC CACM)

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Connecting DSO means the DSO to whose Network a Power Generating Module, Demand Facility, Self-Planned Interconnector, or grid element is located (from NC OPS)

Connecting CDSO means the CDSO to whose Network a Power Generating Module, Demand Facility, Self-Planned Interconnector, or grid element is located (from NC OPS)

Connecting TSO means the TSO in whose Responsibility Area a Power Generating Module, Demand Facility, Self-Planned Interconnector, or grid element is connected to the Network at any voltage level (from NC OPS)

Constraint means a situation in which to respect Operational Security Limits there is a need to implement Remedial Action (from NC OPS)

Consumption Schedule means a Schedule representing the consumption of a Demand Facility or the aggregation of Consumption Schedules of a group of Demand Facilities (from NC OPS)

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 with an Influence Factor higher than the Contingency Influence Threshold (from NC OS)

Contingency Analysis means computer based simulation of Contingencies (from NC OS)

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 (from NC OS)

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 before or after a Contingency took place (from NC OS)

Countertrading means a Cross Zonal energy exchange initiated by System Operators between two Bidding Zones to relieve a Physical Congestion (from NC CACM)

Critical Network Element means a network element either within a Bidding Zone or between Bidding Zones taken into account in the Capacity Calculation Process, limits the amount of power that be exchanged in order to maintain the System Security (from NC CACM)

D-1 means the day prior to the day on which the energy is delivered (from NC CACM)

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 (from NC DCC)

Demand Facility Operator means the natural or legal person who is the operator of a Demand Facility (from NC OPS)

Demand Facility Owner means the owner of the Demand Facility (from NC DCC)

Demand Side Response (DSR) means demand offered for the purposes of, but not restricted to, providing Active or Reactive Power management, Voltage and Frequency regulation and System Reserve (from NC DCC)

Demand Unit means an indivisible set of installations which can be actively controlled by a Demand Facility Owner or Distribution Network Operator to moderate its electrical energy demand. A storage device within a Demand Facility or Closed Distribution Network operating in electricity consumption mode is considered to be a Demand Unit. A hydro pump-storage unit with both generating and pumping operation mode is excluded. If there is more than one unit consuming power within a Demand Facility, that cannot be operated independently from each other or can reasonably be considered in a combined way, then each of the combinations of these units shall be considered as one Demand Unit (from NC DCC)

Distribution means the transport of electricity on high-voltage, medium-voltage and low-voltage distribution systems with a view to its delivery to customers, but does not include supply (from Directive 2009/72/EC)

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 (from NC DCC)

Distribution System Operator (DSO) means a natural or legal person responsible for operating, ensuring the maintenance of and, if necessary, developing the distribution system in a given area and, where applicable, its interconnections with other systems and for ensuring the long-term ability of the system to meet reasonable demands for the distribution of electricity (from Directive 2009/72/EC)

Dynamic Stability Assessment (DSA) means the Operational Security Assessment in terms of Rotor Angle Stability, Frequency Stability and Voltage Stability (from NC OS)

Emergency State means the System State where Operational Security Limits are not kept and at least one of the operational parameters is outside of the respective limits (from NC OS)

ENTSO-E Operational Planning Data Environment means the set of application programs and equipment developed in order to allow the storage, the exchange and the management of the data used within operational planning processes between TSOs (from NC OPS)

External Commercial Trade Schedule means a Schedule representing the commercial exchange of electricity between Market Participants in different Scheduling Areas (from NC OPS)

External Contingency means a Contingency with an Influence Factor higher than the Contingency Influence Threshold (from NC OS)

External TSO Schedule means a Schedule representing the exchange of electricity between TSOs in different Scheduling Areas (from NC OPS)

Fault means the event that could affect the Transmission System such as all kinds 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 (from NC OS)

Forced Outage means the unplanned removal from service of Relevant Assets for any urgency reason that is not under the operational control of the respective operator (from NC OPS)

Generation means the production of electricity (from Directive 2009/72/EC)

Generation Schedule means a Schedule representing the generation of electricity of a Power Generating Module or the aggregation of Generation Schedules of a group of Power Generating Modules (from NC OPS)

Individual Grid Model means a data set prepared by the responsible System Operator(s), to be merged with other Individual Grid Model components through the European Merging Function in order to create the Common Grid Model (from NC CACM)

Interconnected System means a number of Transmission and distribution systems linked together by means of one or more Interconnectors (from Directive 2009/72/EC)

Interconnector means a transmission line which crosses or spans a border between Member States and which connects the national Transmission Systems of the Member States (from Regulation (EC) N°714/2009)

Internal Commercial Trade Schedule means a Schedule representing the commercial exchange of electricity within a Scheduling Area between different Market Participants or between Nominated Electricity Market Operators and Market Coupling Operators (from NC OPS)

Market Coupling Operator means the role of Matching Orders for all Bidding Zones, taking into account Allocation Constraints and Cross Zonal Capacity and thereby implicitly allocating capacity for the Day Ahead and Intraday timeframes (from NC CACM)

Market Participant means market participant within the meaning of the Regulation (EU) No 1227/2011 of the European Parliament and of the Council of 25 October 2011 on wholesale energy market integrity and transparency (from NC CACM)

Micro Isolated System means any system with consumption less than 500 GWh in the year 1996, where there is no connection with other systems (from Directive 2009/72/EC)

National Regulatory Authority means a regulatory authority as referred to in Article 35 (1) of Directive 2009/72/EC (from Directive 2009/72/EC)

Net Position means the netted sum of electricity exports and imports for each Market Time Period for a given geographical area. In the context of this Network Code, geographical area is a Bidding Zone (from NC CACM)

Netted Area AC Position means the netted aggregation of all AC-External Schedules of an area (from NC OPS)

Network means plant and apparatus connected together in order to transmit or distribute electrical power (from NC RfG)

Network Code means a Network Code as referred to in Article 6 of Regulation (EC) N°714/2009 (from Regulation (EC) N°714/2009)

Nominated Electricity Market Operator means the role of interfacing between local markets and the Market Coupling Operator(s), including collecting and delivering Orders (from NC CACM)

Normal State means the operational 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 Remedial Actions available (from NC OS)

N-Situation means the situation where no element of the Transmission System is unavailable due to a Fault (from NC OS)

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Observability Area means the area of the relevant parts of the Transmission Systems, Distribution Networks and neighboring TSOs' Transmission Systems, on which TSO shall implement real-time monitoring and modeling to ensure Operational Security in its Responsibility Area (from NC OS)

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 thermal limits, voltage Constraints, short-circuit current, frequency limits and Stability Limits (from NC OS)

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, Dynamic Stability Assessment, real-time and offline short circuit calculations, System Frequency monitoring, Reactive Power and voltage assessment (from NC OS)

Operational Security Limits mean the acceptable operating boundaries: thermal, voltage, short-circuit current, frequency and Dynamic Stability Limits (from NC OS)

Outage Coordination Process means the process of coordinating the Availability Plans of all Relevant Assets (from NC OPS)

Outage Coordination Region means a combination of Responsibility Areas in which procedures are defined to monitor and where necessary coordinate Availability Statuses of Relevant Assets on all planning timescales (from NC OPS)

Outage Incompatibility means the state in which a combination of one or more Relevant Grid Elements, Relevant Power Generating Modules, Relevant Demand Facility and/or Self-Planned Interconnector outages and the best estimate of the forecasted electricity grid situation leads to violation of Operational Security Limits taking into account non-costly Remedial Actions at the TSO's disposal (from NC OPS)

Outage Planning Agent means the role of planning Availability Status of Relevant Power Generating Modules, Demand Facilities or Self-Planned Interconnectors (from NC OPS)

Out-of-Range Contingency means the simultaneous loss of several Transmission System elements such as, but not limited to two independent lines, a substation of more than one busbar, a tower with more than two circuits or a power swinging or oscillation event leading to the loss of one or more Power Generating Facilities with a total lost capacity exceeding the Reference Incident (from NC OS)

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 Connected Points (from NC RfG)

Power Generating Facility Operator means the natural or legal person who is the operator of a Power Generating Facility (from NC OPS)

Power Generating Facility Owner means a natural or legal entity owning a Power Generating Facility (from NC RfG)

Power Generating Module means either a

- Synchronous Power Generating Module

- a Power Park Module (from NC RfG)"

Reactive Power means the imaginary component of the Apparent Power at fundamental Frequency, usually expressed in kilovar (kvar) or megavar (Mvar) (from NC RfG)

Reactive Power Reserve means the Reactive Power which is available for maintaining voltage (from NC OS)

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 Network and relieve a Physical Congestion (from NC CACM)

Regional Security Coordination Initiative (RSCI) means regional unified scheme set up by TSOs in order to coordinate Operational Security Analysis in a determined geographic area (from NC OS)

Relevant Asset means any Relevant Demand Facility, Relevant Power Generating Module, Self-Planned Interconnector and Relevant Grid Element partaking in the Outage Coordination Process (from NC OPS)

Relevant Demand Facility means a Demand Facility which participates to the Outage Coordination Process as its Availability Status influences cross-border Operational Security (from NC OPS)

Relevant Grid Element means a grid element located in a Transmission Network, in a Distribution Network, or in a Closed Distribution Network which participates in the Outage Coordination Process as its Availability Status influences cross-border Operational Security (from NC OPS)

Relevant Power Generating Module means a Power Generating Module which participates in the Outage Coordination Process as its Availability Status influences cross-border Operational Security (from NC OPS)

Reliability Margin means the margin reserved on the permissible loading of a Critical Network Element or a Bidding Zone Border to cover against uncertainties between a capacity calculation timeframe and real time, taking into account the availability of Remedial Actions (from NC CACM)

Remedial Action means any measure applied by a TSO in order to maintain Operational Security. In particular, Remedial Actions serve to fulfill the N-1 Criterion and to maintain Operational Security Limits (from NC OS)

Renewable Energy Sources means renewable non-fossil energy sources (wind, solar, geothermal, wave, tidal, hydropower, biomass, landfill gas, sewage treatment plant gas and biogases) (from Directive 2009/72/EC)

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 (from NC OS)

Schedule means a reference set of values representing the generation, consumption or exchange of electricity between actors for a given time period (from NC OPS)

Scheduled Exchange means the transfer scheduled between geographic areas, for each Market Time Period and for a given direction (from NC CACM)

Scheduling Agent means the role of providing Schedules (from NC OPS)

Scheduling Area means Responsibility Area except if there are several Bidding Zones within this Responsibility Area. In the latter case, the Scheduling Area equals Bidding Zone (from NC OPS)

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Self-Planned Interconnector means a grid element used to link different Responsibility Areas whose planning of the Availability Status is not performed by a Connecting TSO(s) of these Responsibility Areas (from NC OPS)

Setpoint means a target value for any parameter typically used in control schemes (from NC RfG)

Significant Grid User means the existing and new Power Generating Facility and Demand Facility deemed by the TSO, while respecting provisions of Article 3(3), as significant because of their impact on the Transmission System in terms of the security of supply including provision of Ancillary Services; the criteria of significance for the Significant Grid Users are defined in Article 1(3) (from NC OS)

Small Isolated System means any system with consumption of less than 3 000 GWh in the year 1996, where less than5 % of annual consumption is obtained through interconnection with other systems (from Directive 2009/72/EC)

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 (from NC OS)

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 (from NC OS)

Synchronous Area means an area covered by interconnected TSOs with a common System Frequency in a steady operational state such as the Synchronous Areas Continental Europe (CE), Cyprus (CY), Great Britain (GB), Ireland (IRE), Northern Europe (NE) and the power systems of Lithuania, Latvia and Estonia (Baltic) as a part of a Synchronous Area (from NC OS)

System User means a natural or legal person supplying to, or being supplied by, a transmission or distribution system (from Directive 2009/72/EC)

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 (from NC OS)

Transitory Admissible Overloads mean the temporary overloads of Transmission System elements which are allowed for a limited period and which do not cause physical damage to the Transmission System elements and equipment as long as the defined duration and thresholds are respected (from NC OS)

Transmission means the transport of electricity on the extra high-voltage and high-voltage Interconnected System with a view to its delivery to final customers or to distributors, but does not include supply (from Directive 2009/72/EC)

Transmission Connected Demand Facility means a Demand Facility which has a Connection Point to a Transmission Network (from NC DCC)

Transmission Network means an electrical Network for the Transmission of electrical power from and to third party[s] connected to it, including Demand Facilities, Distribution Networks or other Transmission Networks. The extent of this Network is defined at a national level (from NC DCC)

Transmission System means the electric power network used to transmit electricity 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 (from NC CACM)

Transmission System Operator (TSO) means a natural or legal person responsible for operating, ensuring the maintenance of and, if necessary, developing the Transmission System in a given area and, where applicable, its interconnections with other systems, and for ensuring the long-term ability of the system to meet reasonable demands for the Transmission of electricity (from Directive 2009/72/EC)

Week-Ahead means the week before the calendar week of operation (from NC OPS)

Year-Ahead means the year before the calendar year of operation (from NC OPS)

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