DRAFT V4

European Network of
Transmission System Operators
for Electricity

SUPPORTING PAPER FOR OPERATIONAL PLANNING AND SCHEDULING NETWORK CODE

06.02.2013

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

The document has been developed in recognition of the fact that the OPS NC, 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 OPS NC, as well as the document outlines the following steps of the work.

1.2 STRUCTURE OF THE DOCUMENT

The supporting paper is structured within the framework for all SO NCs supporting papers as follows:

Background:

- Section 2 introduces the legal framework within which the SO NCs have been developed as well as the next steps in the process.
- Section 3 explains the approach, which ENTSO-E has taken to develop the network code, outlines some of the challenges and opportunities ahead of System Operation as well as concepts used in the OPS NC are clarified in this section.

Explanatory notes:

- Section 4 complies with the requirements of the Framework Guidelines on System Operation (SO FG) regarding OPS NC developed by the Agency for the Cooperation of Energy Regulators (ACER).
- Section 5 focuses on the objectives of the OPS NC by topic, identifying the enhancement of technical requirements with an assessment of their associated benefits. Choices appearing in the code will be justified in this section.
- Section 6 describes the added value of implementing the operational principles set by the OPS NC.

Next steps:

- Section 7 summarises next steps in the development of the OPS NC.

Appendices:

- Appendix 1; links the SO FG to OPS NC as well as the interaction between the OPS NC and other codes is illustrated.
- Appendix 2; Scheduling examples
- Appendix 3; Glossary

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1.3 LEGAL STATUS OF THE DOCUMENT

This document accompanies the network code on OPS, but is provided for information only and therefore it has no binding legal status.

1.4 RESPONDING TO THE CONSULTATION

Responses to the consultation on the OPS NC are requested by **[XX]** All responses should be submitted electronically via the ENTSO-E consultation tool, explained at www.entsoe.eu.

2 PROCEDURAL ASPECTS

2.1 INTRODUCTION

This section 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 OPS NC.

2.2 THE FRAMEWORK FOR DEVELOPING NETWORK CODES

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

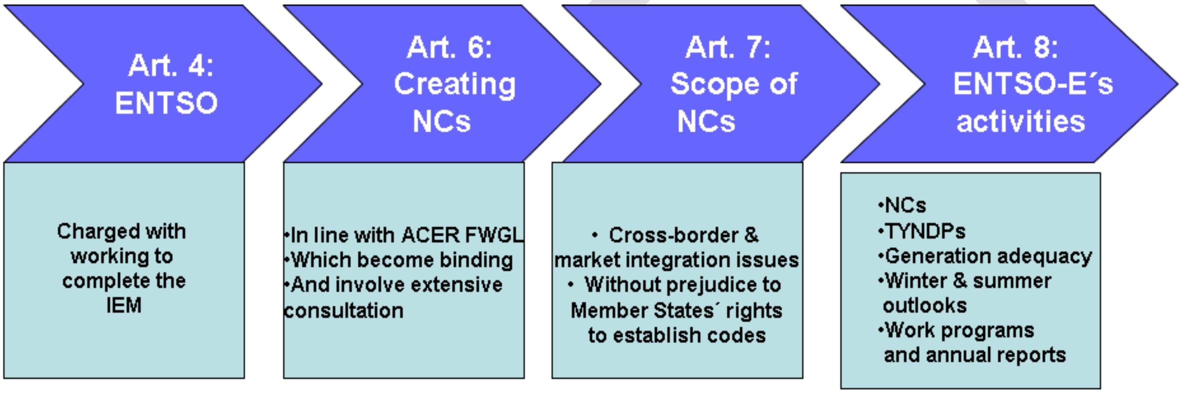

Figure 1: ENTSO-E's legal role in network code development according to Regulation (EC) 714/2009.

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

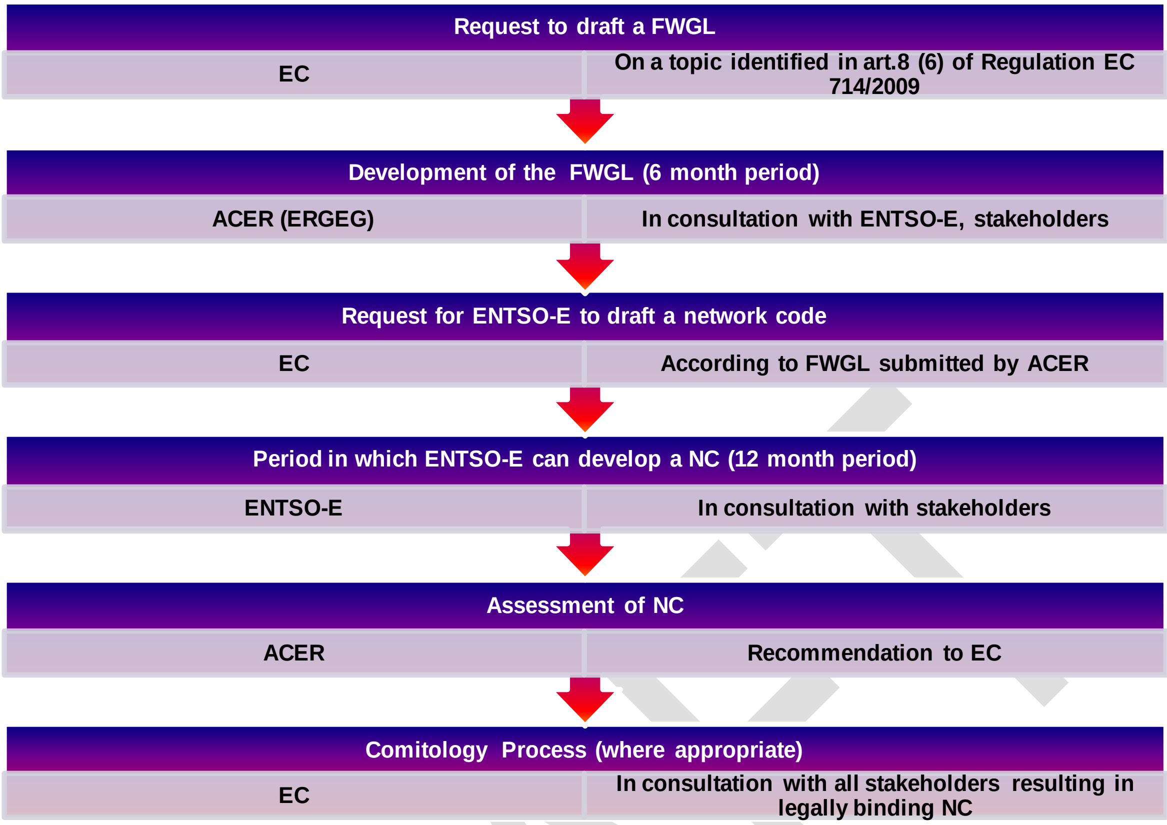

Figure 2: Network codes' development process [Source: ENTSO-E]

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

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

2.3 Next steps in the process

ENTSO-E is now consulting on the OPS NC. We encourage stakeholders and involved parties to submit comments and to provide proposals for addressing any concerns they have with the current draft. ENTSO-E will carefully consider all comments which are provided and will update the network code in light of them. The way in which we intend to finally amend the code will be outlined in the 4. Workshop on the OPS NC planned for the 20th-21st November 2012. Following agreement and approval within ENTSO-E, the network code will be submitted to ACER in line with the defined deadline of 1st April 2012.

ACER is then expected to assess the OPS NC to ensure it complies with the SO FG 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 will eventually transform the OPS NC into a legally binding integral component of the Regulation (EC) 714/2009.

3 SCOPE, STRUCTURE & APPROACH TO DRAFTING THE OPS NC

3.1 BACKGROUND

ENTSO-E has drafted the OPS NC 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 and to support the efficient functioning of the European Internal Electricity Market (IEM), to non-discrimination, effective competition and the efficient functioning of the IEM.

Based on the SO FG and on the Initial Impact Assessment (IIA) provided by ACER, the OPS NC states the operational planning and scheduling principles in terms of technical needs, considering market solutions compatible and supporting to maintaining the security of supply.

OPS NC recognises there will be increased levels of RES within the European electricity network in the coming years. This code has been drafted in way to support this evolution without adversely impacting on system security. Renewables integration is cover within the following articles;

3.2 GUIDING PRINCIPLES

The guiding principles of the OPS NC are to determine common interconnected system operational planning principles, to ensure the conditions for maintaining operational security level throughout the EU, to provide for coordination of system operational planning, as well as to determine common requirements to DSOs, power generating facilities and demand facilities connected to transmission and distribution systems, which are relevant for operational planning of the interconnected system. These principles are essential for the TSOs to manage their responsibilities for preaparing a secure operation of the interconnected transmission systems with a high level of coordination, reliability, quality and stability.

A key goal of the OPS NC 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 meeting 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 OPS NC are building upon a long history of existing common and best practices, lessons learned and operational needs throughout the European transmission systems. This, together with the fact that the European experience of interconnected transmission systems operation dates back to the 1950-ies (ENTSO-E Regional Group Central Europe (RGCE), former Union for Coordination of (Production) and Transmission of Electricity (UC(P)TE)), 1960-ies (ENTSO-E North, former Nordel), and 1970-ies (TSO Associations of Great Britain and Republic of Ireland, UKTSOA and ITSOA), distinguishes the OPS NC and all other System Operation NCs from other Network Codes in following terms:

- 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 SO FG, to meet the challenges of the energy turnaround” including RES and increasing volatility and dynamics of market operations as well as to support 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 at all. Therefore, any changes, adjustments and developments based on the new (legally binding after comitology) system operation NC’s framework must acknowledge and respect the fact that system operation cannot be interrupted and “restarted” – we are working on a “living grid”;
- By their nature and because of the level of technical detail involving all aspects of transmission system operations, the system operation 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 Background and Structure of OPS NC

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 have 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 liberalizing and therefore this harmonizing of the electricity sector was efficiency, and utilizing the resources for balancing the system efficient 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 allowing to have all means necessary to control the system in real time at disposal of the TSO, when it is either subject to normal changes of operation conditions or facing incidents affecting generation, demand or transmission equipment.

OPS NC provides a basis for the 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 applicable to all TSOs and DSOs and Grid Users of significance to the transmission system.

The OPS NC resides under the umbrella network code of Operational Security, and therefore shares the principles of supporting coordination of system operation across Europe, determining common requirements for DSO’s, Generating facilities and Demand facilities. The OPS NC will also support the evolution of system operation methodologies to facilitate increases of RES penetration across Europe.

OPS NC covers all planning tasks and procedures required from year ahead to just before real-time. 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 key elements, structure and provisions of this Network Code, as illustrated in Figure 3 below:

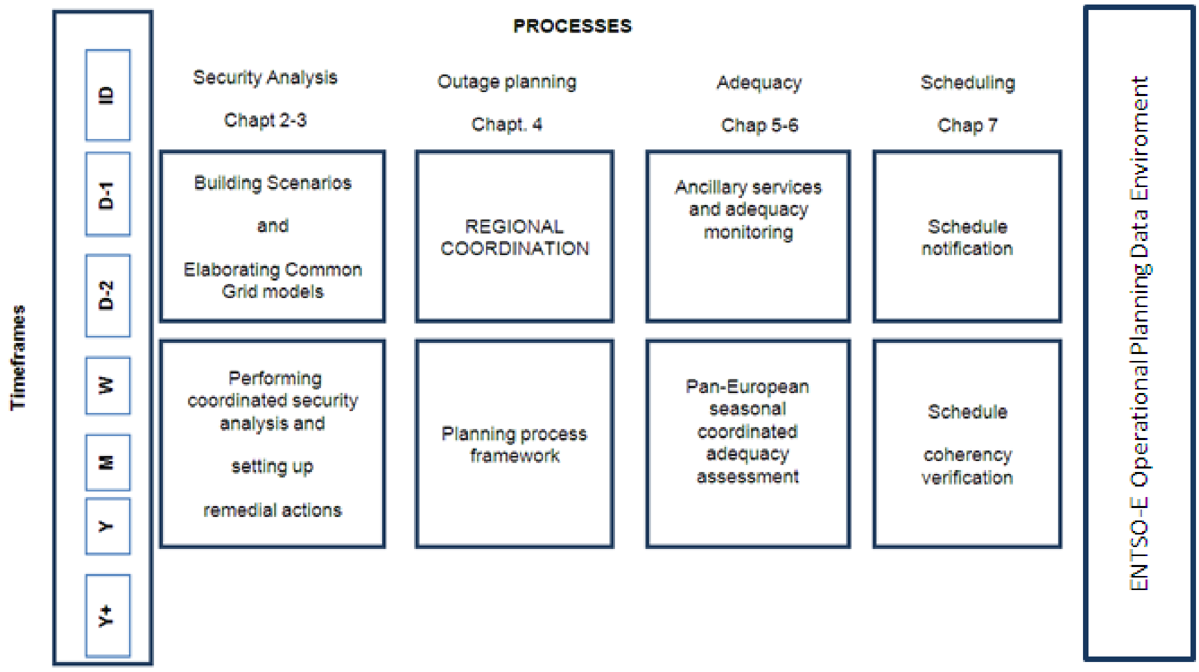

Figure 3: Structure and provisions of the Operational Planning and Scheduling Network Code

The focus of the OPS NC is the following:

- **Building and collecting data for scenarios/models within the responsibility areas:** each TSO should implement processes to build scenarios representatives of coming operation environment, within each time frame, based on information inputs between TSOs and, where necessary, DSOs and grid users, taking into account uncertainties on 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, covering zones allowing coordinated security analysis as congestion and power flow management, including relevant characteristics of the connected generation, consumption and distribution as transmission equipment and taking into account planned outages;
- **Monitoring the system state at all times:** each TSO should implement processes to carry out, within each time frame, on these common grid models, contingency analysis, using simulation tools allowing to assess the state of the system for contingencies as defined by OS NC and to set up 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 allowing TSOs, DSOs and grid users to perform and optimize their maintenance works without jeopardizing operational security nor altering the functioning of the electricity market;

- **Monitoring adequacy of power, and both monitoring and acquiring ancillary services: e**ach 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, performing prognosis on uncertainties on demand, classical generation and renewables, as well as 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 involve 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 energies exchanges as well as agreed procedures for coordination and exchange of ancillary services in order to use the available resources in the systems effectively;
- **Providing the tools and procedures for scheduling of generation and demand:** TSO's should set up procedures to ensure schedules of generation and demand are provided before real time in order to provide the most efficient basis to allow 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, allowing at the same time more detailed provisions at the regional/national level where necessary, and with the view of drafting network codes for electricity system operation that are open for future developments and new applications, an approach focusing on pan-European view and most widely applicable requirements has been pursued throughout all the development phases.

The SO FG 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 how-to-do.

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

- **European wide level** dealing with building common data set allowing sharing of data, common analyses and common processes defined for operational planning activities articulated on common time frames, including common principals for assessing operational security referring to OS NC;

- **Synchronous areas level** referring to LFC Network code principles;
- **Regional level** for areas presenting power flow patterns influencing each other, dealing with coordinate planning processes and coordinated operational security assessment.

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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.

Whereas the first OPS NC picks up as much input from involved parties as possible in order to enable a high level of system security, regional requirements concerning the different synchronous areas, regions or even single TSOs may lead to further and more detailed provisions.

3.5 FIELD OF APPLICABILITY OF THE OPS NC

Whereas the requirements of the OPS NC are directly applicable in all Member States, it should be noticed that the provisions set in the OPS NC should not apply in the following cases:

- In the small isolated systems for which a derogation has been granted in application of Article 44 of Directive 2009/72/EC;
- In the isolated systems which do not present any cross-border network issues nor market integration issues, in the absence of transmission system.

3.6 CHALLENGES AND OPPORTUNITIES AHEAD OF SYSTEM OPERATION

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

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

1. Effects resulting from fast growth of (volatile) generation from Renewable Energy Sources (RES);
2. Needs resulting from the evolution (and completion) of the Internal Electricity Market (IEM).

As we mean to achieve the integration of RES in the system and 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.

3. High Voltage DC (HVDC) Links;
4. Demand Side Response (DSR);
5. Smart Grids;
6. Super Grids.

These different issues are addressed below;

3.6.1 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:

- RES increasingly replaces the feed-in from large power plants directly connected to the transmission system leading to less certainty of energy volumes, system flows and 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 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.

OPS NC recognises these increased levels of RES within the European electricity network in the coming years. This code has been drafted in way to support this evolution with several provisions regarding RES handling, particularly in security analysis, in adequacy assessment and in scheduling.

3.6.2 Internal Electricity Market (IEM)

The increasing cross border trades, daily and intraday markets 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) 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.

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

3.6.3 HVDC, PST and SuperGrids

Because of its connection to the pan-European transmission system, the operation of HVDC-links requires a systematic approach of their reliability.. OPS NC provisions have been drafted in such a way that HVDC infrastructures are included in a systematic way. For example; when coordinating Outage Planning processes, particularities of HVDC-links operation have been addressed in the Scheduling processes.

Devices as PST (Phase-Shifting Transformers; but also FACS – Flexible Alternating Current Systems – is such a device) provides 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 PST has been addresses in the Operational Security Chapter.

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, The following coordination features in the OPS NC:

- Establishing and using common grid models for the relevant phases of operational planning and real-time system operation;
- Exchanging and coordinating of relevant information and data between TSOs and between Relevant Grid Users;
- Ensuring the provisions and a firm basis for coordinated control actions of all relevant 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 does provide 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.

3.6.4 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 at 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 OPS NC provides requirements and principles to accompany harmoniously this development and to handle some of the issues it will raise in the short term. For instance, the Operational Security analysis is performed in Year-ahead and week-ahead on the basis of scenarios offering 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 but beyond a certain level of development, new needs may arise and require the definition of new standards and new processes.

3.7 Interaction with other Network Codes

The OPS NC is being drafted in parallel with other related network codes. Several processes, methodologies and standards provided in OPS NC could be influenced by, or could influence these related network codes and the coordination of the interactions is an important objective of ENTSO-E. The principal cross-issues with other network codes have been dealt with in the following way:

- The Network Codes on *System Operation* – these codes consist of the Operational Security NC (OS NC), the Load-Frequency Control and Reserves NC (LFCR NC) and the OPS NC. The OS NC 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 LFCR NC and the OPS NC while those will describe their specific processes in greater detail.

- The connection codes (RfG NC and DCC) – connection codes establish the technical capabilities of the generation and demand units connected to the grid. OPS references to them in those provisions in which information related to technical characteristics are 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* (CACM NC) – The CACM NC was developed in advance of the OPS NC, enabling the interfaces between the capacity calculation process and system operation to be identified in the early drafting phase of this code. The following separations have 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 system operation. A data list containing the information required for building and implementing a Common Grid Model (CGM) has been shared among the CACM NC and the system operation network codes (thus including OPS NC) 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), OPS NC takes into account updates of several input parameters: e.g. altered outage 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 OPS NC. Also provisions for constructing 2 days-ahead CGM to calculate capacity, described in CACM NC, are inputs for the construction of day-ahead IGM in order to check in advance its security and to prepare, when applicable, necessary actions.

- *Future network codes* –: the forthcoming NC's on Balancing (BAL NC) and on Forward Markets are under scoping discussions 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 OPS NC: the updates of year-ahead CGM, as described in OPS NC, would trigger 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 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 for the capacity calculation, a margin has to be taken into account to cope with uncertainties described in article 25.2 of 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.

OPS NC 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 CGMs, by possibly producing variants of CGMs. Such 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 also be the one used for long term time frames as using a single CGM with RM would give too rough results or high uncertainty on security level.

3.8 CLARIFICATION ON CONCEPTS USED WITHIN THE OPS NC

As a result of the comments raised by stakeholders in the 2nd Workshop of the OPS NC (25th July 2012), it has been considered convenient to explicitly clarify various concepts of the OPS NC in the SO NC Supporting Documents. The following concepts are described below:

- Common grid model
- Remedial actions
- Relevant Grid User
- DSO involvement
- NRA involvement
- Regional Security Coordination Initiatives (RSCIs)
- Delegation of tasks, sub contractors

3.8.1 Common Grid Model (CGM)

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

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

Grid models are a network model allowing to calculate 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 is prepared in different time frames for the different processes:

- For capacity calculation: Year-Ahead and Month-Ahead (Forwards NC), 2-Days-Ahead and Intraday (CACM NC).

- For assessing Operational Security as referred in OPS NC: for Year-Ahead and updates CGM at Pan-European level is built. For Day-Ahead, CGM at least at Synchronous Area Level is built, Complementary provisions, leaving room for regional agreements, addressing regional differences have been drafted for Week ahead and Intraday.

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

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

NC OS defines the basic characteristics of the Common Grid Model (at least the transmission system of 220 kV and higher voltage network, an equivalent model of the lower voltage grid with influence and the sum of generation and withdrawals in the nodes of the transmission network). Besides provisions in NC OS, further characteristics of CGMs can be found in OPS NC 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.

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 OS NC

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does not imply any additional data provision process from stakeholders: for Year-ahead, its 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.

OPS NC 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 the typified situations (e.g. they could probably being determined by typified consumption levels and contribution of renewable energies production).
    - Also, it is convenient to signalise the need of establishing open provisions for Year-ahead and updates of Year-ahead CGMs, in order to allow flexibility enough to NC Forwards for further developing that processed in line with the requirements of capacity calculation in long term timeframes.
- Defining the considered models at Regional level (Regional here means at 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 up 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 processes of capacity calculation and 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 NC CACM are also applicable for the processes established in 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 for 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.
    - NC OPS establishes the main criteria to merge Individual Grid Models into the Common Grid Model:
        - In this context, preliminary “instrumental” net values 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 flow" are not input values for IGMs or CGMs, but on the contrary, they will be a result of the simulations performed with the CGMs.

The coherency in Grid Models in all NCs is ensured for all Timeframes, since:

- All Grid models are built following Operational Security Principles established in OS NC.

- All CGMs comprise at least the transmission system of 220 kV and 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 OS NC.

- All Grid models use the same following data:

    - Load pattern (active and reactive power withdrawals in the network)
    - Availability of generation power modules and their contribution
    - RES generation
    - Net position for bidding zones and for Market Balance Area

    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 fulfill the following requirements:

    - All IGMs are consistent together, regarding their Net Position, their flows on DC links and the availability of interconnections between IGMs.
    - 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.

The coherency ensured, some differences between models constructed for security analysis in OPS NC and for capacity calculation exist:

- 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 first an individual TSO responsibility, to be coordinated with the other TSOs following the requirements set forth in the OPS NC. 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). OPS NC establishes provisions for the merging process at least at Synchronous Area level of

Day-ahead and Intraday models, in such a way to allow CGM per Synchronous Area level containing updated schedules at least at Day-ahead.

- Because of differences in Timeframes and occurrence of the market in CACM NC and OPS NC, some differences for Timeframes and data sources for building models exist:
    - Capacity calculation processes are preliminary to the related market processes. Therefore, data included in models are previous to the next Market session. For 2-Days-Ahead is based on estimations.
    - The models used in Operational Security Analyses in Day-Ahead in OPS NC are built after the market processes that result in firm schedules. Therefore, data are the output of the wholesale market and other relevant TSO-managed processes (constraints resolution, balancing, others) and under the applicable national regulation. This could also be the case for Intraday.

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 14 Of NC OPS).

Besides CGMs, which should be used for performing Operational Security Analysis, other information additional to the one exchanged at Pan-EU level (described in Article 19.5.f), could be covered by regional agreements.

3.8.2 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 rule such constraints will not occur or should be released by using dedicated remedial actions.
A remedial action can be implemented pre fault (preventive) or post fault (curative), involve cost or not, be internal or external to a TSO's responsibility area, be a grid related measure (change of topology including PST tap position changes) or market related measure (redispatching of units, modifying cross borders exchanges using countertrading).
The remedial actions on which TSOs can act are strongly linked to the timeframes considered. Several hours in advance, a TSO can for example contract the pre heat of given generation not asked by the market. For short timeframes TSOs have the possibility to act on balancing, emergency reserves, control devices such changes in topology or PST…

A remedial action can be activated immediately (ex grid related measure) or need a certain period to be activated (ex redispatching).
A remedial action can be applied manually or automatically (ex automatons).
In general TSO prefer to use post fault remedial actions especially if they are costly. They will be used only if the contingency occurs.
Pre fault remedial actions will be implemented only if there is not enough delay allowed 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 new and enhanced requirements under this topic in the OPS NC are:

- Coherency from year ahead to real time: to ensure that all remedial actions declared available or used in long term calculations are taken into account in following calculations. It may nevertheless happen that remedial action developed in longer term 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 than exposed 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.

3.8.3 Handling uncertainties and operational transmission margins

1) Making the link between operational security principles and operational transmission reliability margins

Transmission systems are faced to unforeseen events. These events are for example transmission lines or generation units tripping. These events are also related to changes in weather conditions: variations of temperatures affect the level of load, wind conditions affect wind generation level, solar conditions affect Photovoltaic generation too.

To face these events transmission systems need operational reliability margins. To that end, TSOs have developed operational security principles they must apply within operation and operational planning of the transmission system. These security principles are set up by the OS network code. They define the types of events the transmission system must withstand when they occur without leading to uncontrolled situation.

Operational margins are delivered by applying these operational security principles throughout a global framework as exposed by the figure below:

- TSos establish the state of the system

- TSO's 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 (as exposed in chapter XX) allowing the transmission system to cope with operational security principles and thus presenting the required level of operational margins.

It must been noticed that the operational security principles are the result of years of TSOs practices and feedback experience. The application of these principles allow to provide a right level of operational margins to reach the high level of reliability for electricity energy that European citizens benefits, with a fequency of major incident below one incident per 10 years in average.

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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 OPS Network Code having establish enhanced indicators to that purpose as exposed in chapter (TT)

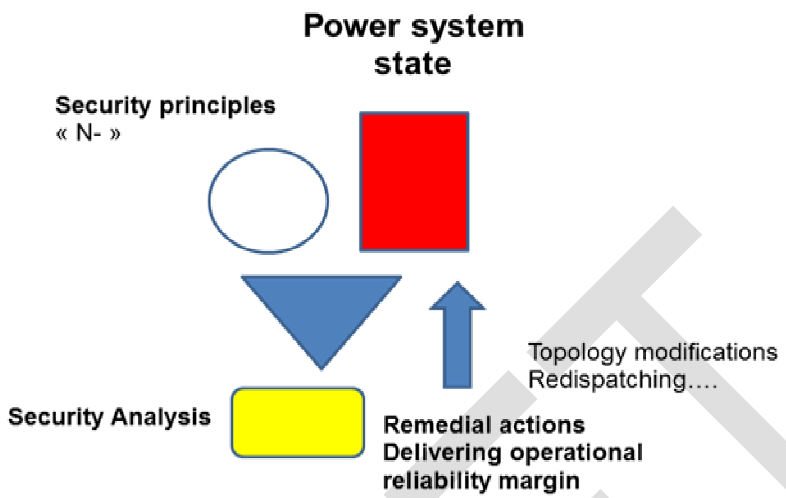

Figure 4

2) Making the link between operational security principles, operational transmission reliability margins and physical limits on network and generation equipment

The link between operational transmission reliability margin and physical limits on equipments (transmission, generation, consumption) are handled throughout the global framework shown below.

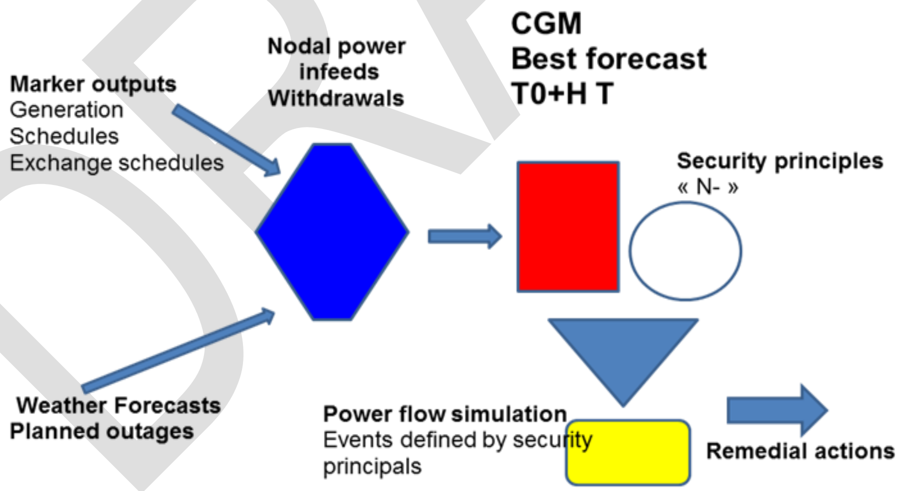

Figure 5

To examine consequences of events, TSOs perform power flows simulation on a state of the network provided through a common grid model. The current, voltages (angles and frequency when performing dynamic security analysis) are compared with the maximal or minimal values allowed by equipments within the power system (according, for grid users, to capabilities as defined in connecting codes). 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 FCR and FRR activations are addressed within the corresponding security analysis.

As the computations performed have not a perfect accuracy, it is necessary to take physical margins considering the maximal and minimal values admissible for equipment. **This issue is referred by the OPS Network Code within the security analysis methodology provisions. Provisions to monitor and ensure models accuracy are also established.**

3) Handling weather forecast uncertainties and providing a right level of operational transmission reliability margins in short term operational planning

Considering the global framework exposed here above and the way of providing operational transmission margins, weather forecast are used:

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

  The OPS network code 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.

Short term changing weather conditions are not sudden, as it is for a line tripping or generation unit. Taking into account this characteristic, the TSOs' practices in that 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. It should be noticed that this way to proceed by continuous intraday updating allow to engage remedial actions according to the evolution of the situation as weather forecast updates become more accurate.

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

Uncertainties associated with a weather forecast are also provided by forecast tools. For specific situations with a high degree of uncertainty and a high level of possible deviation in generation or load level, TSOs include in their security analysis this event to be possibly faced in order to deliver corresponding margin as necessary.

The OPS Network Code enforces the integration of such uncertainties.

4) Links with CACM, RM and operational transmission reliability margin as addressed by this Network Code.

The operational reliability margins addressed in CACM network code fits within the global framework described above taking into account the following:

- Capacity calculation aims at delivering the maximum level of energy exchanges compliant with security principles.
- Two days (D-2) in advance, weather forecast are more uncertain
- Generation schedules are not known and there are uncertainties in the generation dispatch.

The RM defined in CACM expresses the part of the capacity not delivered to the market as component of the operational transmission reliability margins. The RM allows taking into account the impacts on power flows of residual uncertainties not covered by the security analysis frame work applied to the best forecast. The RM sizing is based on statistical analysis of the deviations between forecasted power flows and observed power flows in real time.

3.8.4 Significant Grid Users and Relevant Assets

3.8.4.1 RELEVANT VERSUS SIGNIFICANT

According to the Framework Guidelines on System Operations, Significant Grid Users are defined by considering their impact (individual or aggregated) on the cross border system performance. 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. Since NC OS is an umbrella code, the Network Code on Operational Planning and Scheduling refers to the definition within NC OS for significance. 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 be 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 also Significant Grid Users.

While the definition in NC OS also 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.

3.8.4.2 DETERMINATION OF RELEVANT ASSETS

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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.

Establishing requirements relating to Relevant Assets rather than Significant Grid Users where possible, will therefore help ensure the proportionality of NC OPS, as further explained in 5.1.1.

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 22 of 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.*

3.8.4.3 APPLICATION OF RELEVANCE 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 1 August in order for the TSOs to assess whether Outage Incompatibilities arise.

All TSOs of an Outage Coordination Region will then analyze 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 1 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 1 August and 1 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. This includes, for example, the possibility of financial compensation. 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.

3.8.4.4 APPLICATION OF SIGNIFICANCE WITHIN 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 NC OPS.

According to the SO FG, Significant Grid User is defined by considering their impact (individual or aggregated) on the cross border system performance, Indeed, the aggregation of very small units has impact on the balancing of the system, as well as it could have it in the flows and create possible constraints.

In line with that, the OS NC defines the significance by considering the impact of a grid user on the cross border system performance, regardless of the connection point voltage. OPS NC refers to the OS NC definition as OS NC is an umbrella code.

The OPS NC introduces a new definition: Relevant Grid Users are grid users whose individual availability status has an impact on the Operational Security of the interconnected system. In that sense, the significance of the aggregated performance of the distributed generation or demand is differentiated from the individual distributed generation or demand unit, relevant for the analyses the TSOs coordinate in Chapter 3 and 4 of the OPS NC.

In order to assess this relevance, a specific mention of harmonisation at least at Synchronous Area level methodology is made in article 17(1).

Nevertheless, the OPS NC includes, as it is logical, 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. A reference to national applicable legal framework in this regards is made in order to establish the way this aggregation is done and the roles and responsibilities of TSOs, DSOs or Grid Users in performing such aggregation.

3.8.5 DSOs involvement in OPS NC provisions

The introduction in general terms of DSOs in the outage planning processes is not foreseen in OPS NC, 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 OPS NC provisions, and performed under the national rules in place. Therefore, DSO activities, roles and responsibilities are not impacted by this NC.

OS NC 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 OPS NC. In that sense, the NC would not intend to impose "one-size-fits-all" provisions that deviates 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.

3.8.6 Involving of National Regulatory Authorities

The involvement of NRA’s is foreseen in several articles for consultation or information. Further involvement is not foreseen as grid operation is one of the main tasks of TSO. A further involvement would lead to liabilities of NRA’s as they would have to take decisions instead of the TSO. A shifting of liability from TSO to NRA is not wanted.

As far as national regulation stipulates a further involvement of NRA, this will stay in force as long as this regulation complies with the rules of the NC OPS.

3.8.7 Regional Security Coordination Initiatives RSCIs

NEED FOR COORDINATION

The operation of the electrical transmission grids is becoming more and more complex due to the high variability of renewable generation, the development of electricity markets which leads to an increase of cross-border transactions 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 makes the influence and interdependency between distant electrical systems growing quickly.

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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 figures below highlight the need for common security analyses and coordinated remedial actions implementation to maintain and enhance the operational level of security of 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

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, production mix, market solutions...

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

Geographical applicability of Multi-lateral 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:

possible common view and understanding of risk analyses,

possible identification of remedial actions that are efficient and compliant with s TSOs' operation security principles.

One and only one Multi-lateral Agreement shall be defined for each region, but a TSO can be part of several regions and therefore several Multi-lateral Agreements.

Functional applicability of Multi-lateral Agreements

Multi-lateral Agreements shall guarantee a consistent and coordinated security assessment of the grid from the outage scheduling phase up to close to real-time operations as much as the search and implementation of optimized coordinated remedial actions.

To perform this tasks, Multi-lateral Agreements shall ensure the use of common hypotheses for grid studies. The Common Grid Model resulting from the Individual Grid Models merging is the 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 thee level framework as exposed on figure 1 and figure 2 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-shifter transformers,
- the application of the coordinated Remedial Actions,
- the adaptation of outage schedulling,
- the implementation of Redispatching or Countertrading.

Multi-lateral Agreements shall include a process dedicated to the revision of its content.

Functions covered by the Multi-lateral Agreement shall be partly performed by a delegated entity.

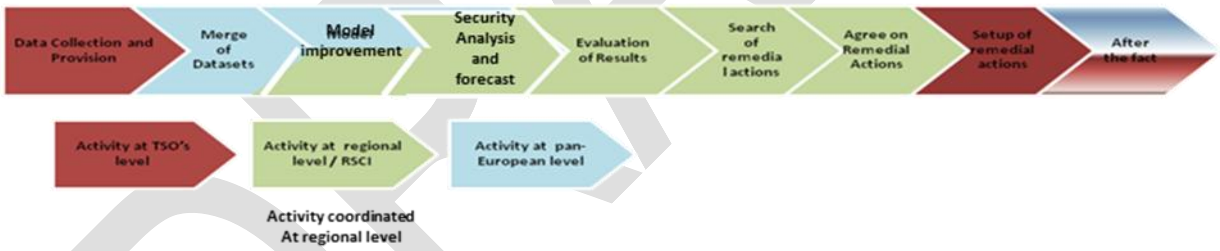

Figure 6

Regional Security Coordination Initiatives

Especially in highly meshed regions, the coordination needs to be multilateral with usually more than two TSO's at the same time. In that case, TSO's 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 grid which is only available in RSCIs, especially when organised as a physical centre gathering operators from different TSOs of the region.

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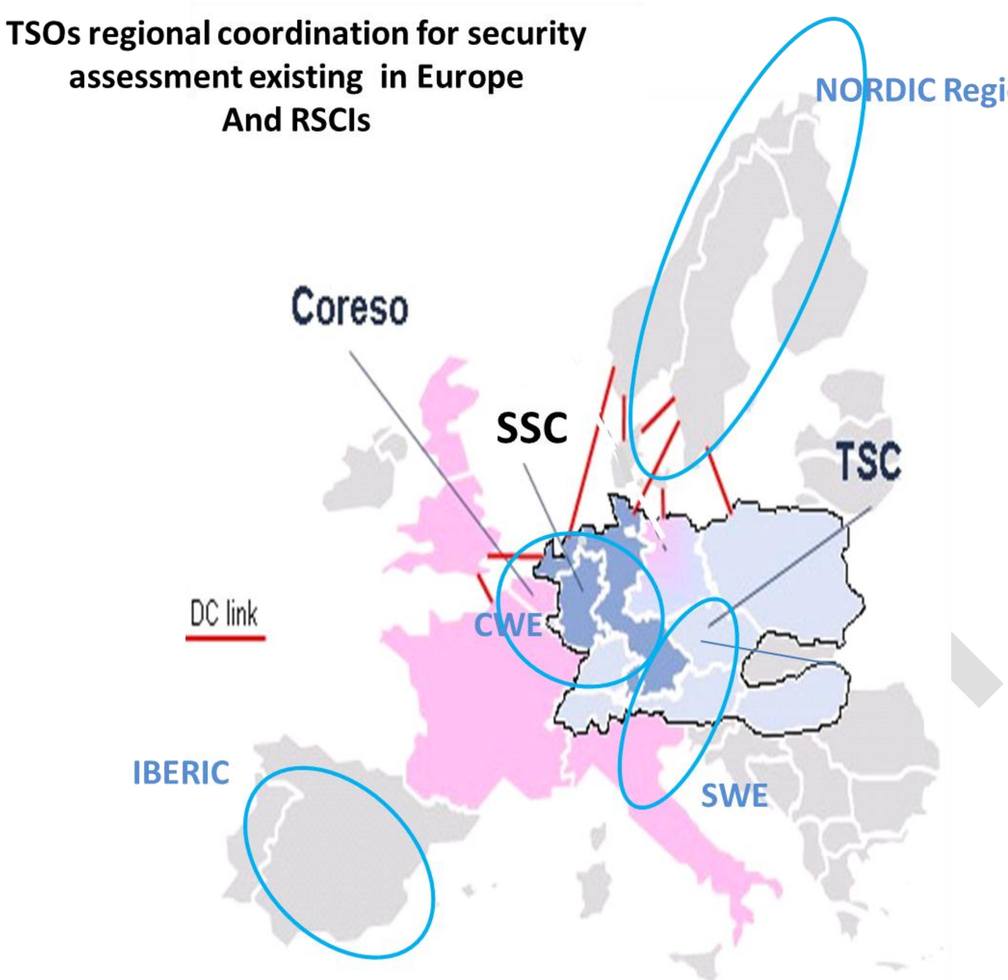

Figure 7: Regional Security Coordination Initiatives in Europe

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 involved in 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 on several regions.
- Several RSCIs can act for several TSO'sin the same region, ensuring the necessary cooperation.

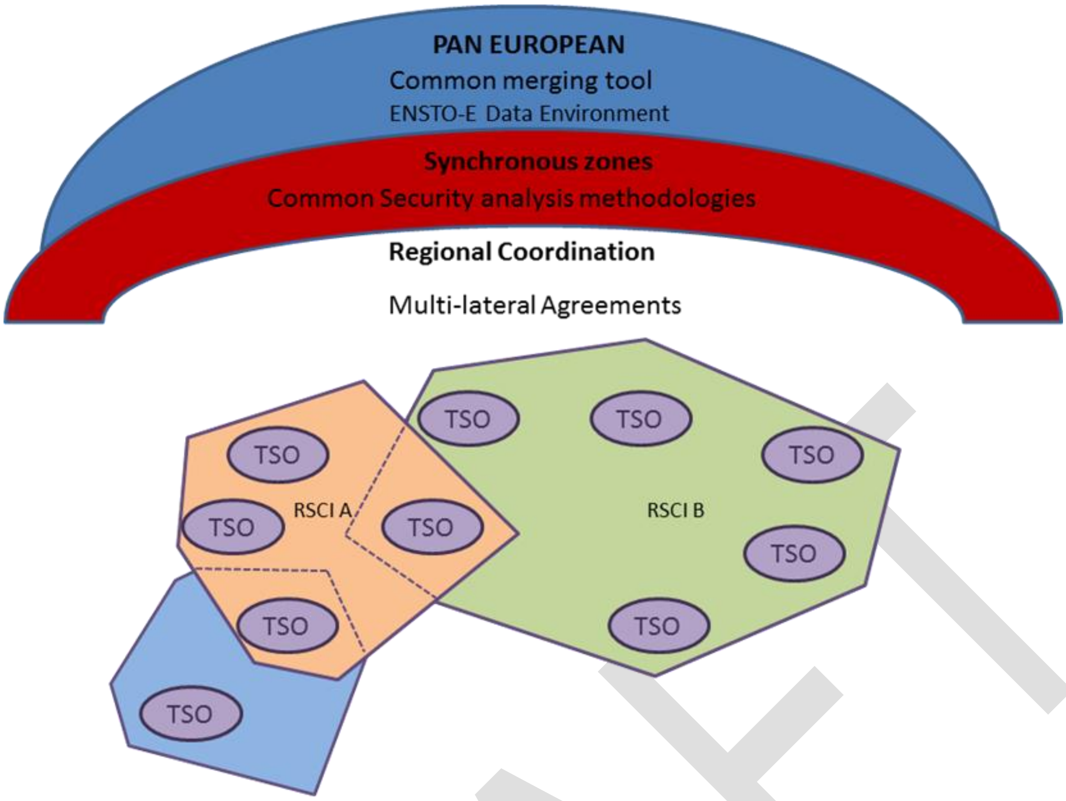

Figure 8

3.8.8 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 NC. 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 art. 6 and art. 18(8)).

3.9 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, the 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 function of the transmission system from an operational point of view that arose during the public consultation of the RfG NC, the first ENTSO-E stakeholder workshop on system operation was held on 19 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 also had the opportunity to express feedback and expectations.

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

- The aim of the first OPS NC Workshop, held on the 23rd May was to present and discuss the scope of the draft OPS NC, which reflected the work completed by TSO experts as of 14 May 2012. The workshop addressed the scope of the network code, updated on the present state and allowed for discussion and a Q&A session. Stakeholders in attendance included DSOs, industrial electricity consumers, generators, energy traders and turbine suppliers.
- The aim of the second OPS NC Workshop (25th 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 stakeholder feedback received in the first OPS NC workshop. The workshop was an opportunity for stakeholders, including DSOs, industrial electricity consumers, generators, energy traders and turbine suppliers, to provide feedback on the current status of the network code.

3.10 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
All TSOs shall define the provisions dealing with the gathering of the Year-Ahead Individual Grid Models, merging them into Common Grid Models and saving them.	11(1)	TSOs develop						TSOs agreement																	
In line with Article 18 of [NC CACM], 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.	14(1)	TSOs agree						TSOs agreement																	
Within 6 months after the entry into force of this Network Code, each TSO shall establish the principles for the categorisation of Remedial Actions.	16(2)	Each TSO establish						Each NRA approve																	
No later than 12 months after the entry into force of this Network Code, TSOs shall establish a methodology standardized at least per Synchronous Area, for Operational Security Analysis.	19(1)	TSOs per synchronous area establish												NRAs per synchronous area approve											
All TSOs shall adopt an agreement defining Coordination Regions within which the Availability Status of Relevant Assets shall be monitored and coordinated.	20(1)	TSOs develop						TSOs agreement																	
All TSOs shall establish a coordinated methodology, standardised 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 Process.	22(1)	TSOs per synchronous area establish												NRAs per synchronous area approve											
All TSOs shall perform Pan-European annual summer and winter generation Adequacy outlooks before 21 May and 21 November respectively, using a common methodology .	47(1)	All NRAs approve																							
No later than 12 months after the entry into force of this Network Code, each TSO operating a Scheduling Area shall develop and implement a process to ensure its area internal balance for Generation Schedules, Consumption Schedules, External Commercial Trade Schedules and External TSO Schedules.	54(1)	TSOs develop												TSOs agreement											
ENTSO-E shall implement and administer an ENTSO-E Operational Planning Data Environment for the storage of all relevant information for operational planning.	56(1)	ENTSO-E implement																							
No later than 12 months after entry into force of this Network Code all TSOs shall define a standardised data format for the data exchanges taking place. The description of this data format shall be an integral part of the ENTSO-E Operational Planning Data Environment.	56(2)	12 months												TSOs agreement											

4 RELATIONSHIP BETWEEN THE OPS NC & FRAMEWORK GUIDELINES

The SO FG focuses on three key challenges, which shall be addressed by four objectives as Figure 4 shows.

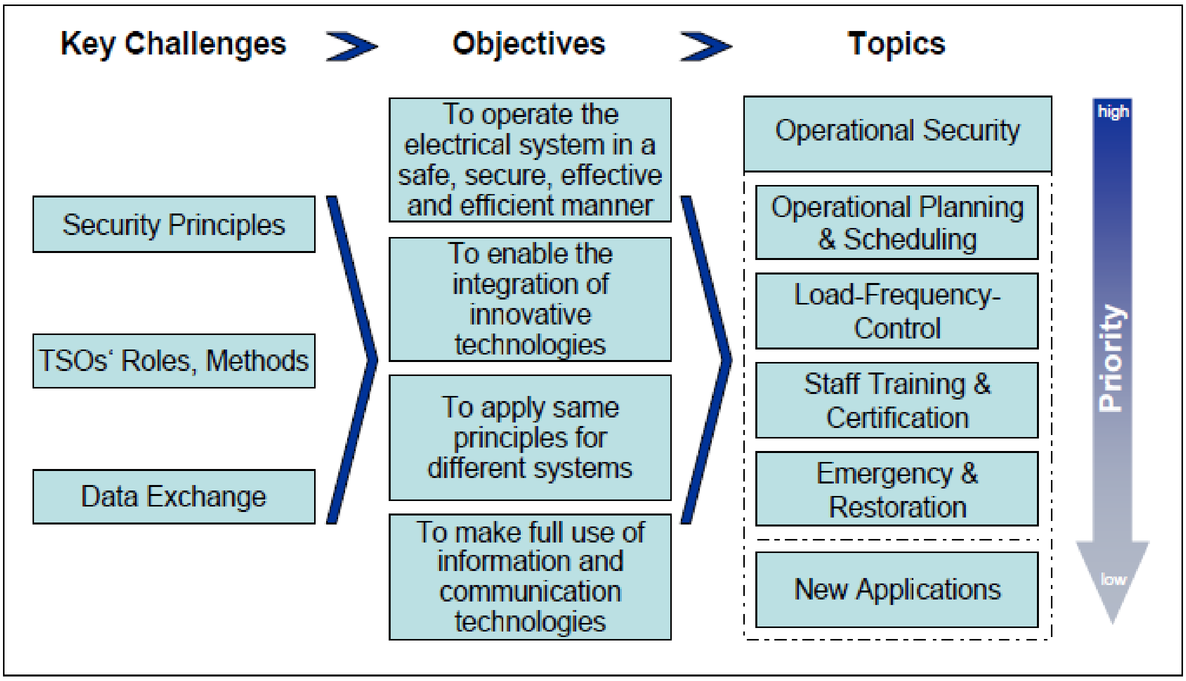

Figure 9: Structure and development flow of the Framework Guidelines on Electricity System Operation.

The overall scope and objectives of the SO FG 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 SO FG 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 OPS NC have been formulated in line with the SO FG 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 coherent and coordinated preparation of real-time operation.

The OPS FG sets 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 maintain 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, security analyses;

3. Prevention and/or remedy 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 planned and unplanned outages and technical ability to provide ancillary services.

The requirements in the FG OPS are linked to the OPS NC requirements in Appendix 1.

5 CURRENT PRACTISES & IMPACT ASSESSMENT

5.1 JUSTIFICATION OF CHOICES MADE IN THE OPS NC

5.1.1 Outage Coordination

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 have been taken within NC OPS to ensure that the influence on current practices is kept to a minimum. These measures include the following:

1. **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.
2. **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.

3. **No coordination details.** While 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.

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 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. The occurrence of situations in which extra costs are incurred has thus be kept to a minimum, and when it does occur, it will likely prevent costs to others.

Taking all these caveats into account, the minimum costs incurred by stakeholders as a result of the new obligations arising from 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 supply.

5.1.2 Adequacy

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. 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 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 in addition to the current practices.

Where today all TSOs perform summer and winter generation Adequacy outlooks, after 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 this change constitutes a deviation from current practice, it is warranted because communicating on these threats is the only opportunity TSOs have to influence the future fulfilment of Adequacy. Furthermore, it helps provide stakeholders with extra information on the causes of any situation in which Adequacy is not fulfilled. The same holds for the new requirement for TSOs to assess Adequacy on a D-1 and intraday basis. Aside from the establishment of new procedures, the added workload for TSOs is not very large, and nothing is being asked of other parties in addition to what they are already required to do from requirements elsewhere.

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6 OPS NC: OBJECTIVES, REQUIREMENTS

This chapter aims at providing the reader the basis for understanding the requirements in the OPS NC, i.e. security analysis (chapter 5.1), outage planning), adequacy (chapter 5.3), ancillary services (chapter 5.4) and scheduling (chapter 5.5) in that document below.

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. Below a table is given showing the processes as ENTSO-E sees them. Every process is provided with an explanation:

1. ***Cross Control Remedial Action*.**

   Due to the country specific nature of putting in place cross border remedial actions, ENTSO-E considers it not useful to introduce a technical methodology that need harmonisation on a broader scale (i.e. regional, synchronous or Pan-European). Indeed, each TSO could set up different priorities for putting into effect remedial action depending on the nature of its technical system(i.e. production mix, PSTs..) and depending on this nature of its neighbour.

2. **Security Analyses Coordination.**

   Performing operational security analysis can only be achieved when TSOs coordinate this activity. Therefore a harmonization of the methodology for a 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..

3. **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 Relevant Non-TSO Owned Interconnector) are represented on a non-discriminatory basis, it is important that TSO's consult relevant NRAs for this coordination processes.

4. **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.

6.1 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 OS NC the frequency, fault level, voltage and load flows etc. remain within predefined limits.

This OPS NC details the responsibilities on TSO's 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 TSOs 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 OPS network code 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 control 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 NC.

The integration of renewable energies and the assessment of the uncertainties associated with them which is detailed in this NC 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 OPS NC 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 OPS NC is compliant with the requirements placed on it by the FWGL. 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:

- on the principles of remedial actions and the methodologies governing remedial actions.

  a methodology, harmonised at least per synchronous area, for operational security analysis.

6.2 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.

6.2.1 Why a Coordinated Outage Planning Process?

The Outage Coordination Process is all about coordinating the availabilities as well as the unavailabilities 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

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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;

6.2.2 Which are the most frequently arising levels of interaction between different parties?

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

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

6.2.2.1 Generation Adequacy issues

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

I. the number of Power Generating Modules that are unavailable;
II. the number of Demand Facilities that are available;
III. 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.

6.2.2.2 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.

6.2.2.3 Operational Security issues not linked to Relevant Grid Element outages

The third main category 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).

6.2.2.4 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.

6.2.3 Why is some commitment to a coordinated Availability Plan necessary?

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

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Assets is feasible, and can be executed with high probability. This reasoning holds for Generation owners, Consumption 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:

I. 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
II. 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.

Fictional illustration of a situation in a coordination process without commitment to the coordinated Availability Plans

Let's say Generator A owned by company A and Generator B owned by company B cannot be unavailable at the same time (the reason is not important here; this could be generation Adequacy, dynamic stability or static Operational Security Limit violations). Both A and B have to perform maintenance works somewhere during the next year. A and B provide Year-Ahead Availability Plans which are compatible, having planned their maintenance in separate time periods. B starts contracting third parties to execute its maintenance after its Availability Plans are coordinated with all parties.

Two months in advance of B's maintenance, company A shifts its maintenance to the same period where B planned its maintenance. As this is not feasible, some coordinated solution has to be found. Without any commitment to a coordinated Availability Plan, a possibility (depending on the rules installed at the concerned national level) could be that the TSO buys off company A or company B to ensure the availability of its generator. Let's say company B shifts its maintenance and is compensated for this. B will re-contract the third parties for executing the maintenance during the newly defined time window. Up to here this is a perfectly realistic situation, with a correct solution for relieving Outage Incompatibilities.

However, one month in advance of the concerned maintenance period, A unilaterally shifts its maintenance again. This results in B having received financial compensation for moving its maintenance, while finally no Outage Incompatibility would have existed. From a social welfare point of view this is sub-optimal at least.

6.2.4 What is and what is not the goal of this Network Code?

The Network Code enforces:

1. 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;

2. 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 financially compensating parties is determined within the national regulatory framework.

6.2.5 How is Outage Coordination organized in this Network Code?

6.2.5.1 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

6.2.5.2 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 8 are not reflected as requirements in the code and serve simply as an indication for the time flow of the process.

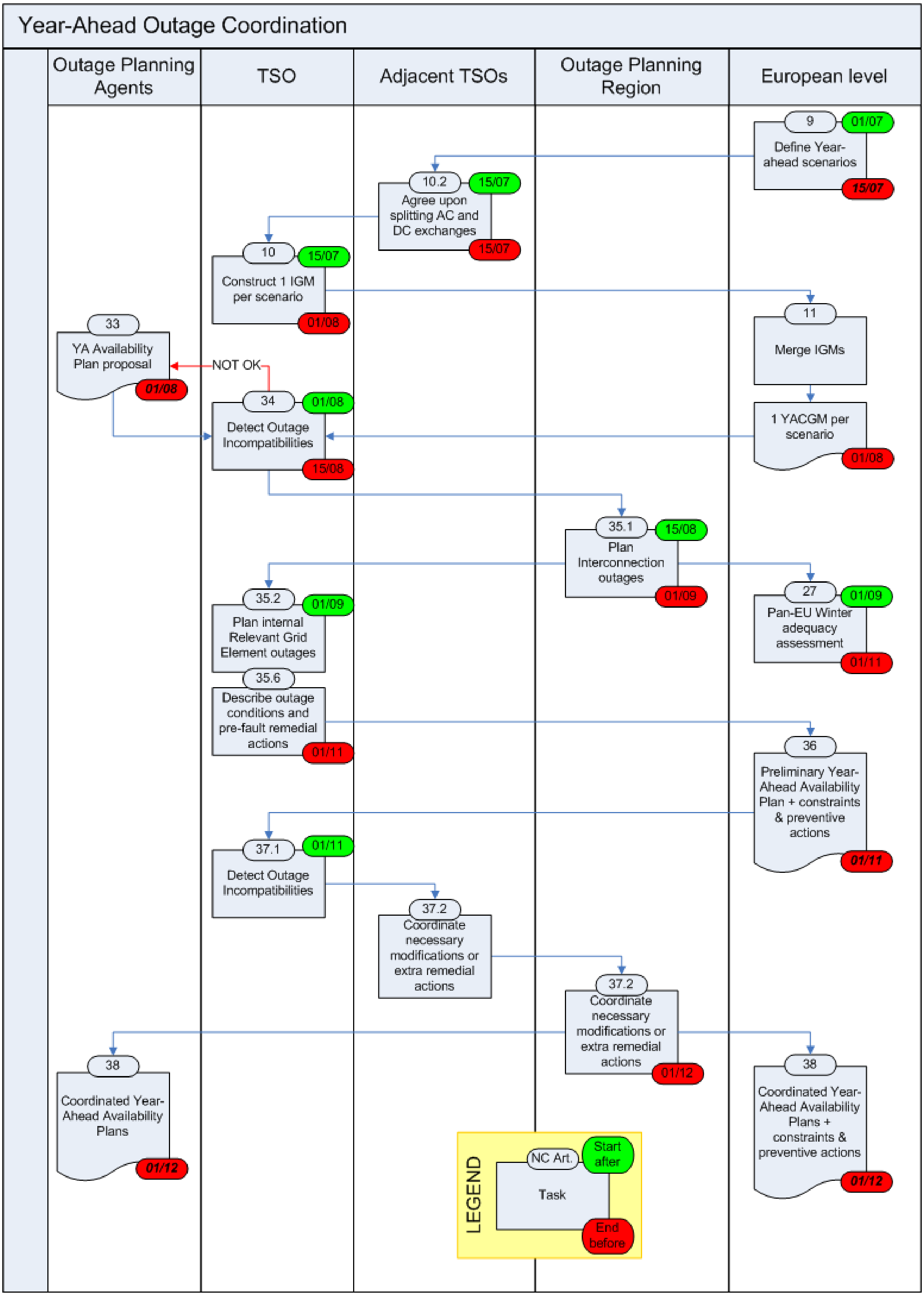


Figure 10: Condensed view on the Year-Ahead coordination process, focusing on the time flow and data links.

6.2.5.3 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 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.

6.2.5.4 The Year-Ahead outage coordination phase

To illustrate the Year-Ahead outage coordination described in Articles 34 to 38 of the Network Code, below a flowchart giving an overview of the coordination process is included.

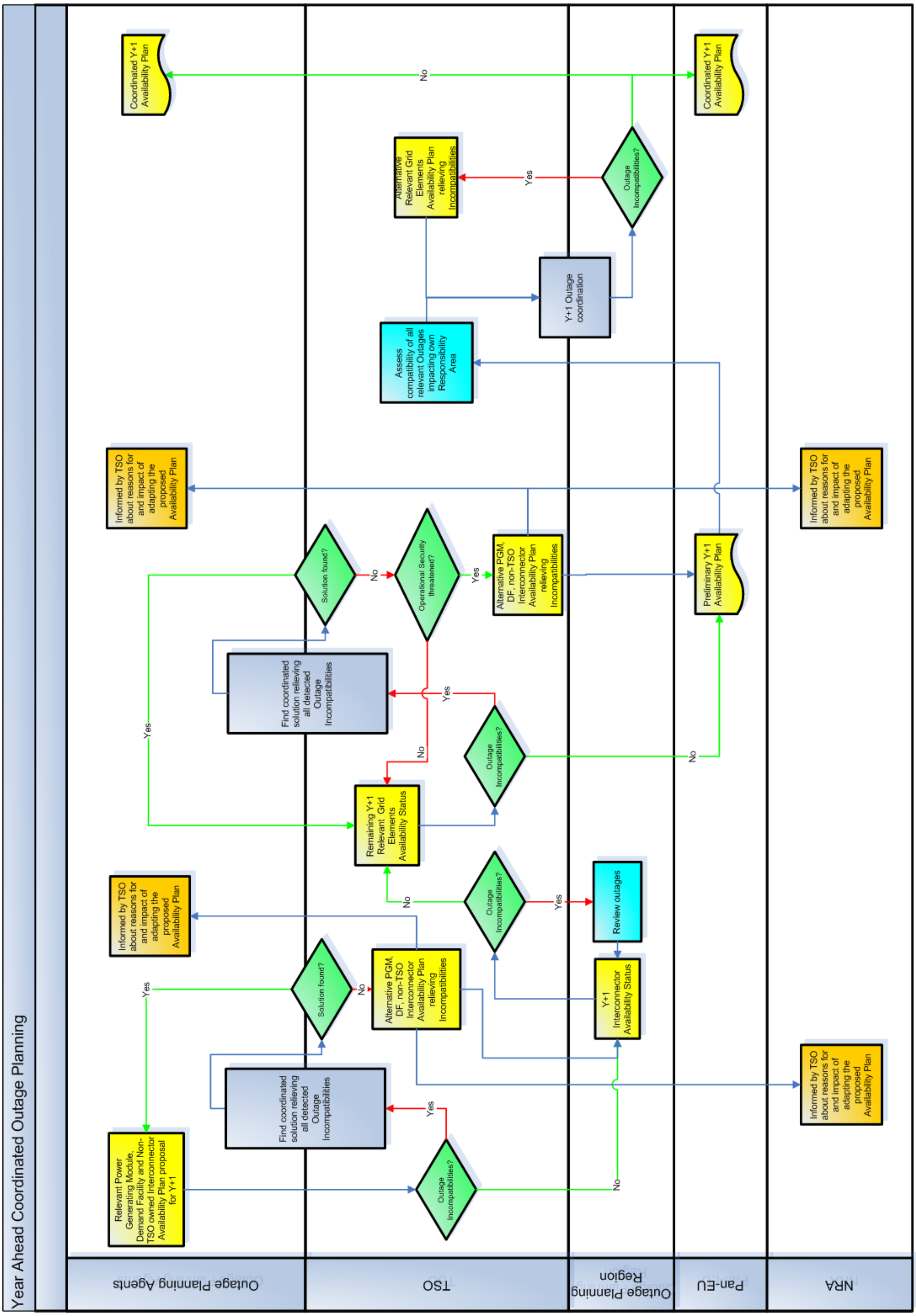


Figure 11: Overview of the Year-Ahead outage coordination phase.

6.2.5.5 Updates to the Year-Ahead Availability Plan

Article 40 of the Network Code describes how all parties can initiate a change to the coordinated Availability Plan. To clarify the described procedure, Figures 6 and 7 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 39 makes a specific reference to the applicable legal framework for elaborating this coordination process. It is exactly in this existing framework where for example rules for financial compensation can be described.

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 regulations, 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.

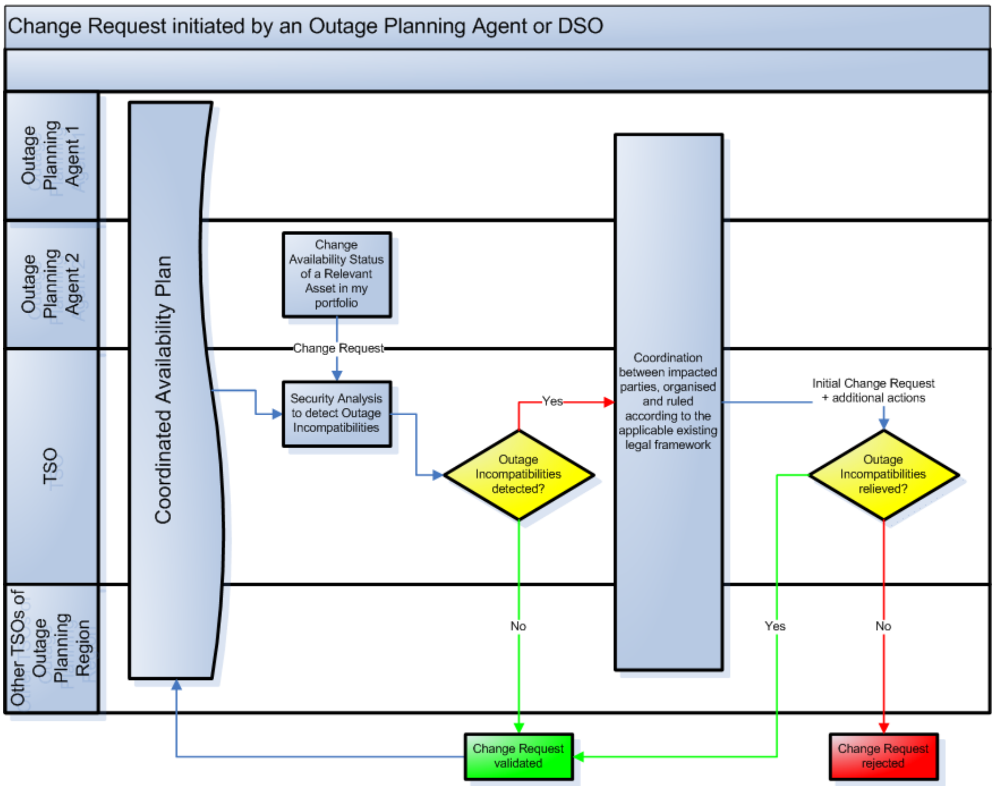


Figure 12: Update procedure for a change initiated by an Outage Planning Agent or DSO

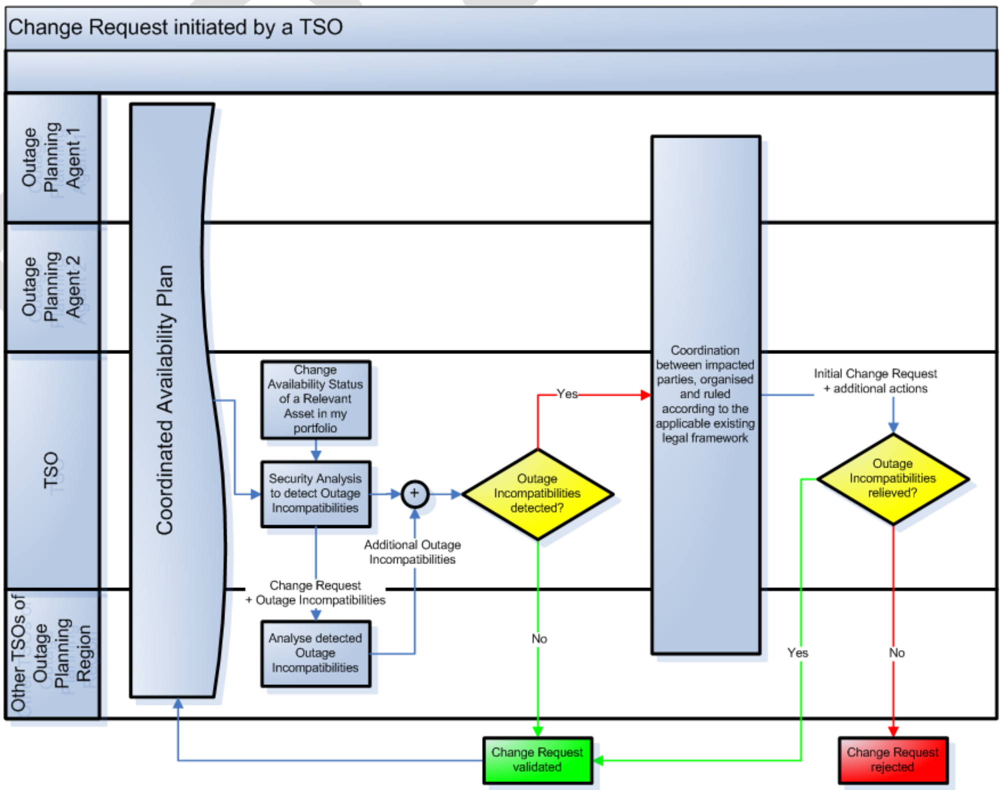


Figure 13: Update procedure for a change initiated by a TSO.

6.2.6 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.

6.2.7 Links with other Network Codes

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

6.3 ADEQUACY

6.3.1 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, can be considered as situations in which Adequacy is not fulfilled. Adequacy can be assessed for any area, but within NC OPS analyses are being done only on the level of the Responsibility Area, and on pan-European level.

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. This way problems can be detected when they present themselves, and the possibility of being caught unaware is limited.

For that reason 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. 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 NC OS, in part through the transparency guidelines, and in part through other parts of NC OPS.

6.3.1.1 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.

Error! Reference source not found. 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 NC OPS. When NC OPS comes into force, this methodology, or an updated version of it, will have to be approved by National Regulatory Authorities.

The Methodology is shown in the figure below:

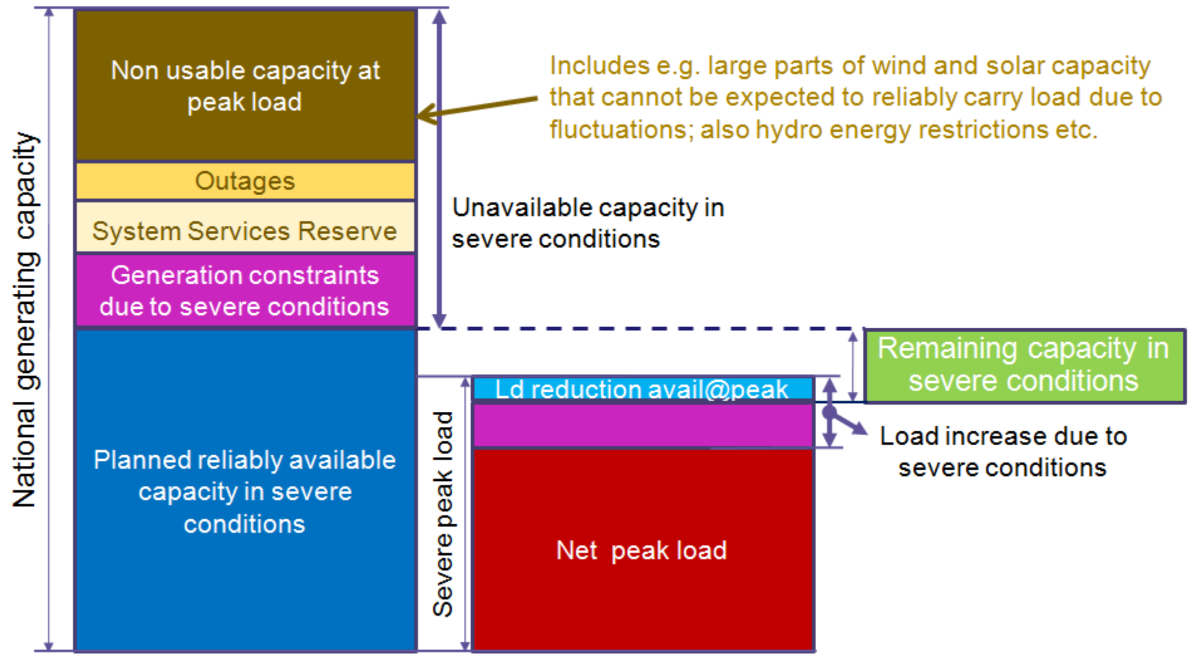


Figure 14: Assessing Adequacy

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 load 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 load are determined for each individual country. The remaining capacity, as shown in **Error! Reference source not found.**, 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:

1. 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
2. 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 these summer and winter Adequacy outlooks, the TSOs make use 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. 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 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 performed

6.3.1.2 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 they 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 changes. Significant changes that could lead to a reassessment of Adequacy include for example, the unexpected closure of a large nuclear power plant.

This is a new requirement on 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.

6.3.1.3 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 NC OS, as well as information on Market Participant Schedules provided to them through national legislation. 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.

6.4 ANCILLARY SERVICES

Ancillary services are services provided by grid users to the TSO. In the OPS NC ancillary services refers to active power, reactive power and black start. The two former ancillary services enable the TSO to operate a secure and reliable power system, whereas the latter 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 TSO's 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 LFC NC. The OPS NC 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. OPS NC recognizes that if a TSO finds itself in a shortfall position (after remedial actions have been investigated), communication and cooperation with neighbouring TSO's 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 OPS NC 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 majority of requirements set on TSO's, DSO and grid users in this topic are based on best practises and lessons learned.

The OPS NC 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 service section of OPS NC is closely linked to LFCR NC and NC on Balancing.

6.5 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 15 shows the relations between Scheduling Area, Responsibility Area and Bidding Zone

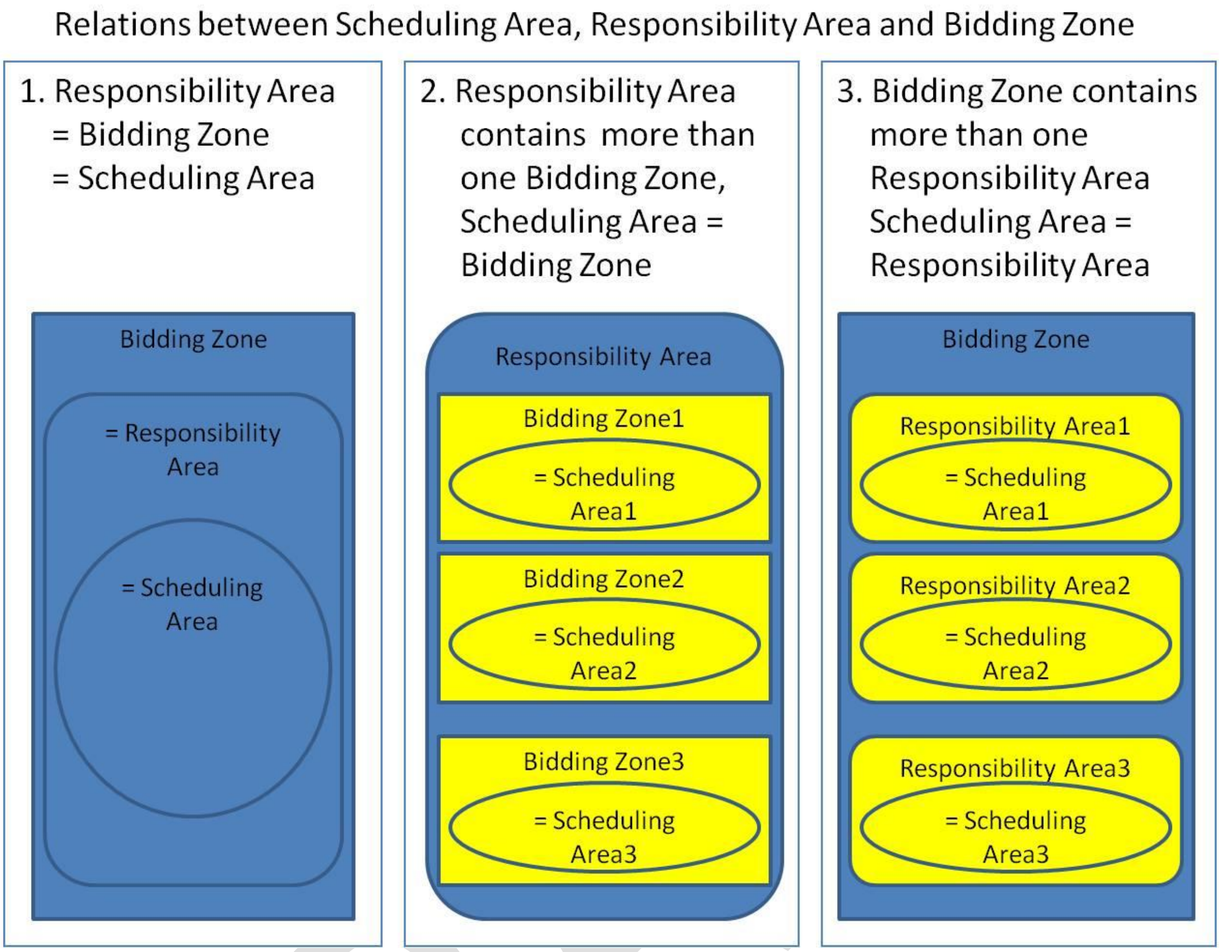


Figure 15

Scheme of available schedules is given bellow:

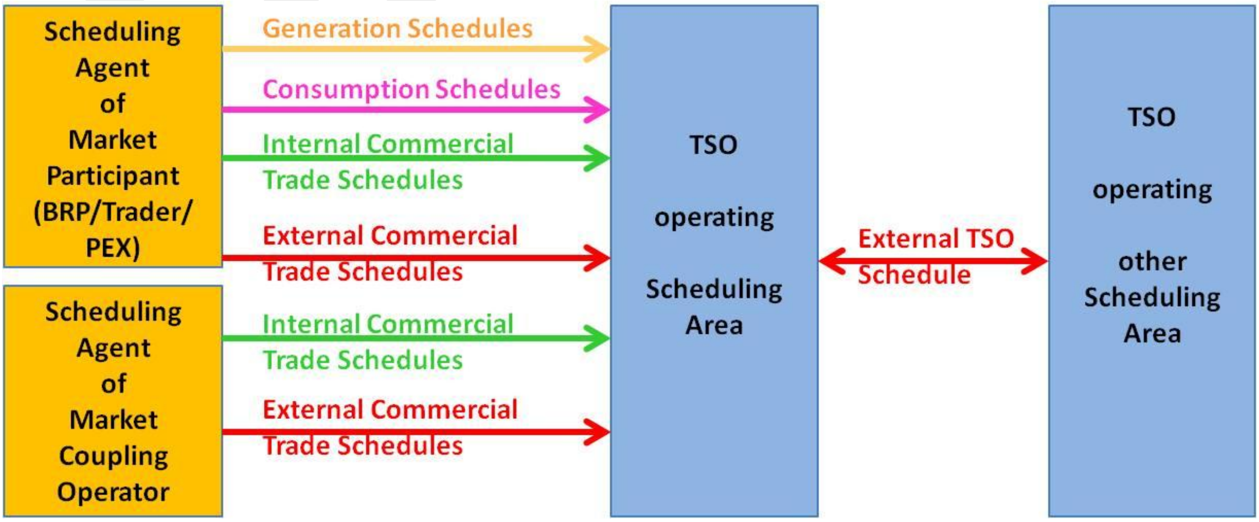
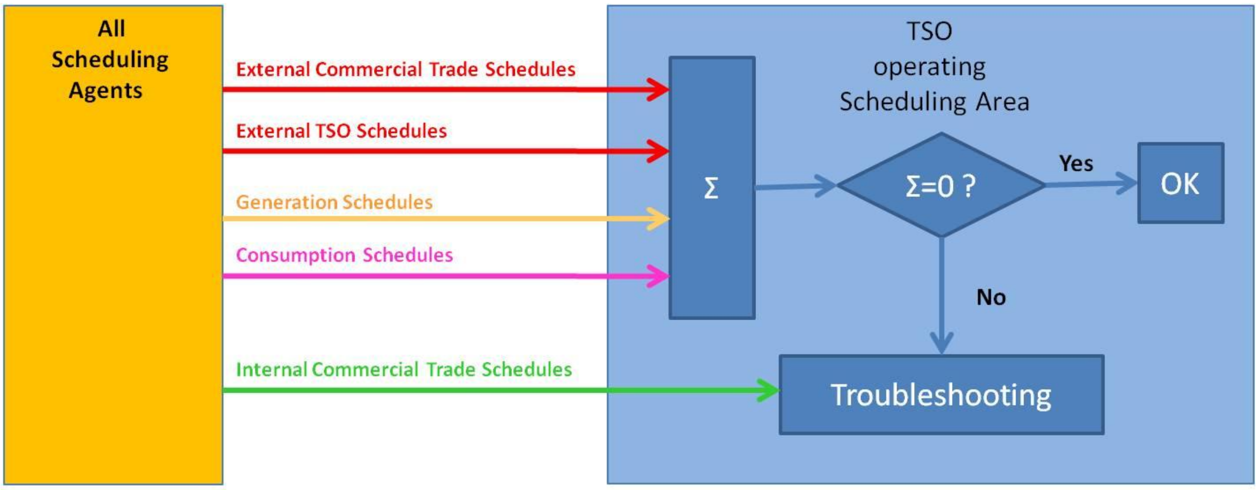


Figure 16

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 17 shows the verification of the area internal balance for Generation Schedules, Consumption Schedules, External Commercial Trade Schedules and External TSO Schedules (OPS NC Art.54.1):



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

Figure 17

The scheduling chapter of OPS NC sets general requirements for scheduling processes between market participants and TSOs and scheduling processes between TSOs to ensure that TSOs receive the necessary data to run the system in a secure and efficient manner. 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. OP&S NC focuses on inter-TSO scheduling issues that use the schedules of Market Participants, Power Generating Facilities, Demand Facilities and Market Coupling Operators.

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

OPS NC focuses on inter-TSO scheduling issues, leaving to local market rules the scheduling processes design between market participants and TSOs

The requirements of scheduling of OPS NC 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 do not participate in market coupling.

Figure 17 shows the bilateral agreement and verification process (OPS NC Art.56.2):

Figure 18:

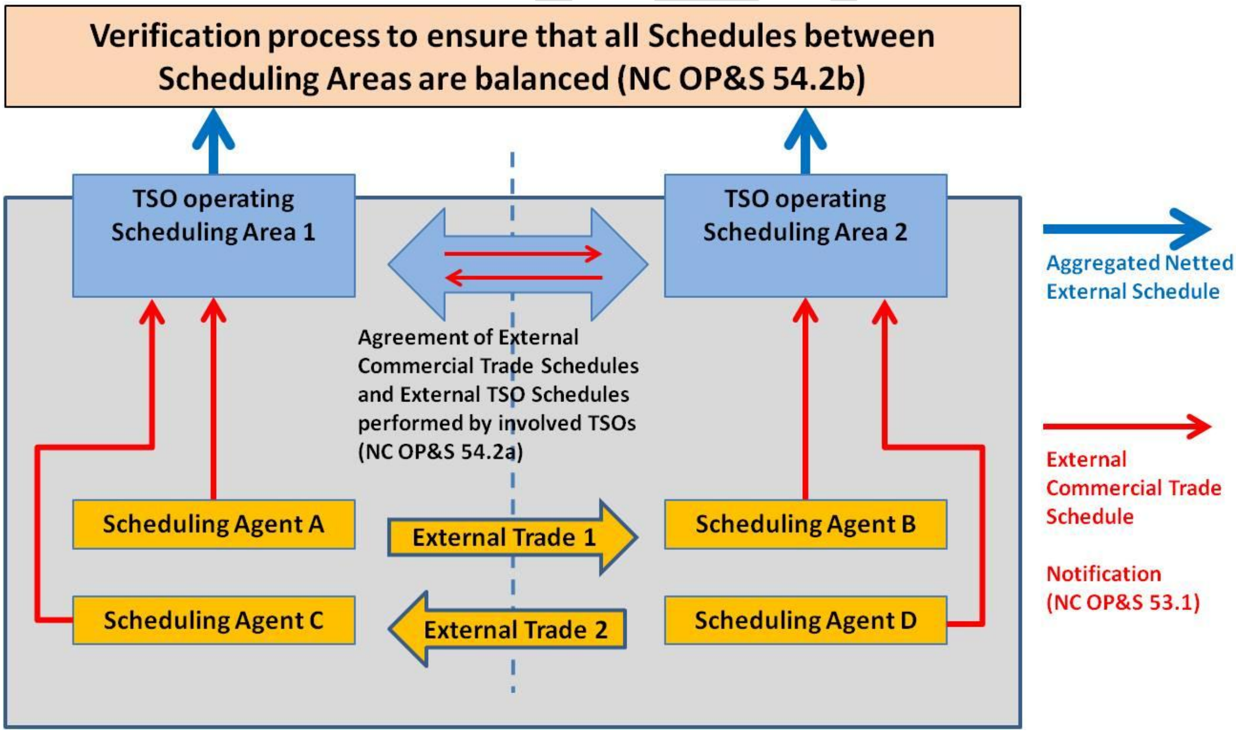
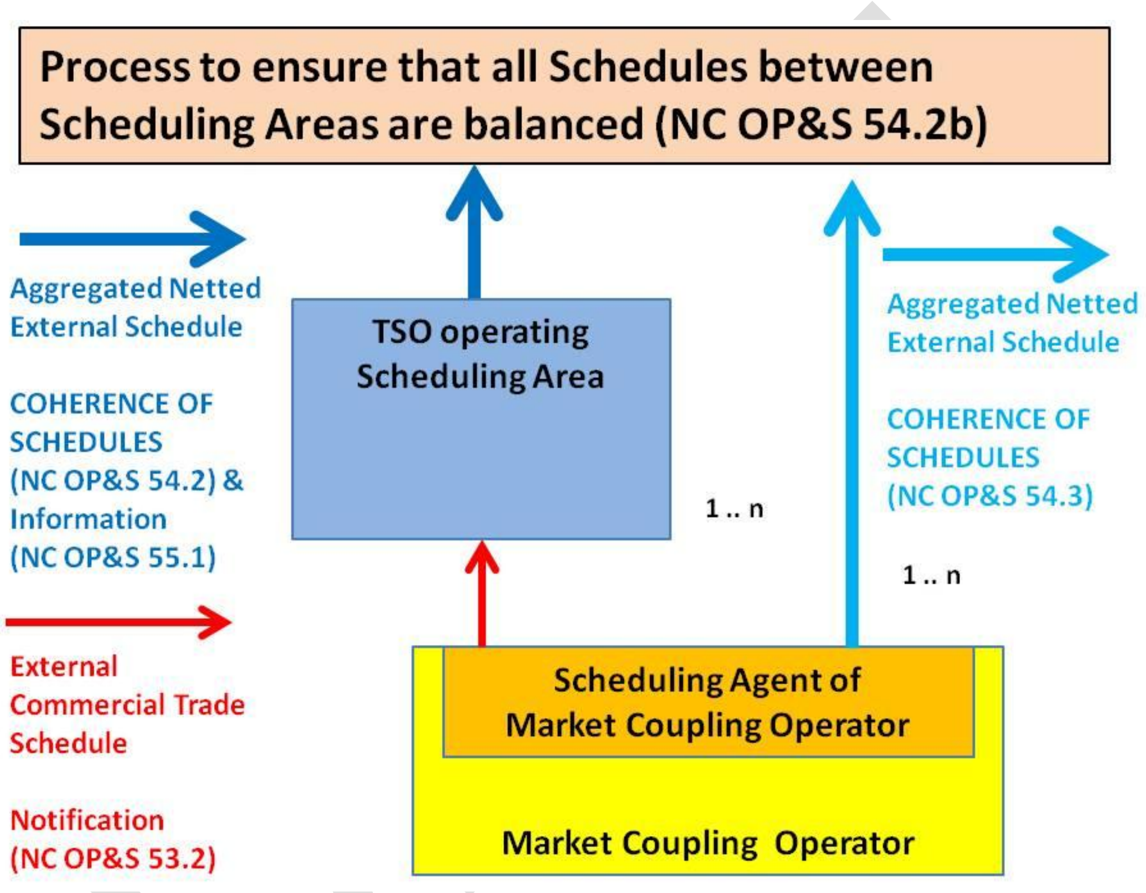


Figure 18 below shows the multilateral verification process (OPS NC Art.54.3):

Figure 19:



The requirements set out in the OPS NC do not deviate from the requirements set out in the Framework Guidelines on System Operation. OPS NC describes the principles for exchange of all necessary information between system operators.

7 ADDED VALUE OF THE OPS NC

During the process of scoping the objectives and topics to be included in the OPS NC, the objectives and topics defined by the SO FG have been kept under careful consideration. The OPS NC addresses all activities dealing with the preparation of Operation. Thereby the opportunity has been taken to improve strongly the coordination between the TSOs on a Pan-European, Synchronous 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, giving in particular common bases for handling increasing uncertainties at the planning stage due to the strong development of RES and future development of distributed generation..
- Developing in particular common scenarios allow investigating on a common basis the consequences for the security of the system the different operational conditions the interconnected transmission system may face. 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 security of the system. 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 a coordinated outage planning process, on common time frames and procedures will allow incorporating in the planning phase all the consequences of Relevant Planned Outages in a coordinated way, taking into account cross border issues. This will lead to less incompatibilities of outages between the different control areas and thereby potentially decrease the number of unexpected constraints leading to security problems, and needing costly remedial measures;
- Sharing during the whole operational planning phase 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 and 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, thereby integrating in that analysis transmission capacities more efficiently, 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; 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 to fully utilize the HVDC potentials.

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 energetic transitional challenges. A quantification of the added values of implementing the requirements of the OPS NC would require complex studies subject to multiple factors and hypothesis for they depend strongly on scenarios per region and are subject to numerous fluctuating parameters.

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

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

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8 RESPONSES AND NEXT STEPS

8.1 OVERVIEW

This chapter provides information on how to respond to the consultation on the OPS NC and provides an overview of the processes which ENTSO-E intends to follow in developing a final version of the OPS NC for submission to ACER.

8.2 SUBMISSION OF RESPONSES

We ask that all responses are provided on or before the **[XX].**

In order to allow similar comments to be considered and appropriately responded to, we ask that all responses are submitted via the ENTSO-E consultation tool. A brief submission guide can be found at https://www.entsoe.eu/resources/consultations/submission-guide/. Opportunities to discuss further issues

We appreciate that many stakeholders and involved parties may wish to discuss issues raised in this document. For this reason ENTSO-E has scheduled a workshop for the 19th September 2012 at the ENTSO-E premises. We will structure the workshop in a way which enables parties with an opportunity to provide their views. Should you wish to attend, please contact**[XX]@entsoe.eu.**

8.3 RESPONDING TO COMMENTS

ENTSO-E will endeavour to respond to comments raised by stakeholders, indicating how a comment has been taken into account or indicating the reasons for not doing so, via the consultation tool. This document seeks to answer some of the questions which we have been repeatedly asked during the process of developing the code up to date.

8.4 NEXT STEPS

As a consequence of the 12 month timescale, this is the only formal consultation by ENTSO-E on the OPS NC. We should urge parties to provide comments and views. Following the closure of the consultation ENTSO-E will begin the process of considering comments and reflecting them in text. It will be the responsibility of the OPS drafting team, which contributed to the development of this code to process comments, provide feedback and make changes as necessary. An updated code will be subject to internal approval and will be sent to ACER ahead deadline. As indicated above, parties will see answers to their individual comments via the consultation tool as soon as we are able to provide them.

As mentioned in section 2.3. of this document, in the public workshop for the OPS NC, , as the result of public consultation, the major comments received and the therefore amendments made in the Code will be presented.

9 LITERATURE & LINKS

[1] "Framework Guidelines on System Operation" (FG SO), ACER, 2 December 2011.

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

10 APPENDICES

10.1 APPENDIX 2 SCHEDULING EXAMPLES

Article 53: **Notification of schedules within Scheduling Areas**

Article 53.2: **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).**

Article 53: Notification of schedules within Scheduling Areas

Article 53.2: Notification of Schedules of Scheduling Agent of Market Coupling Operator

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

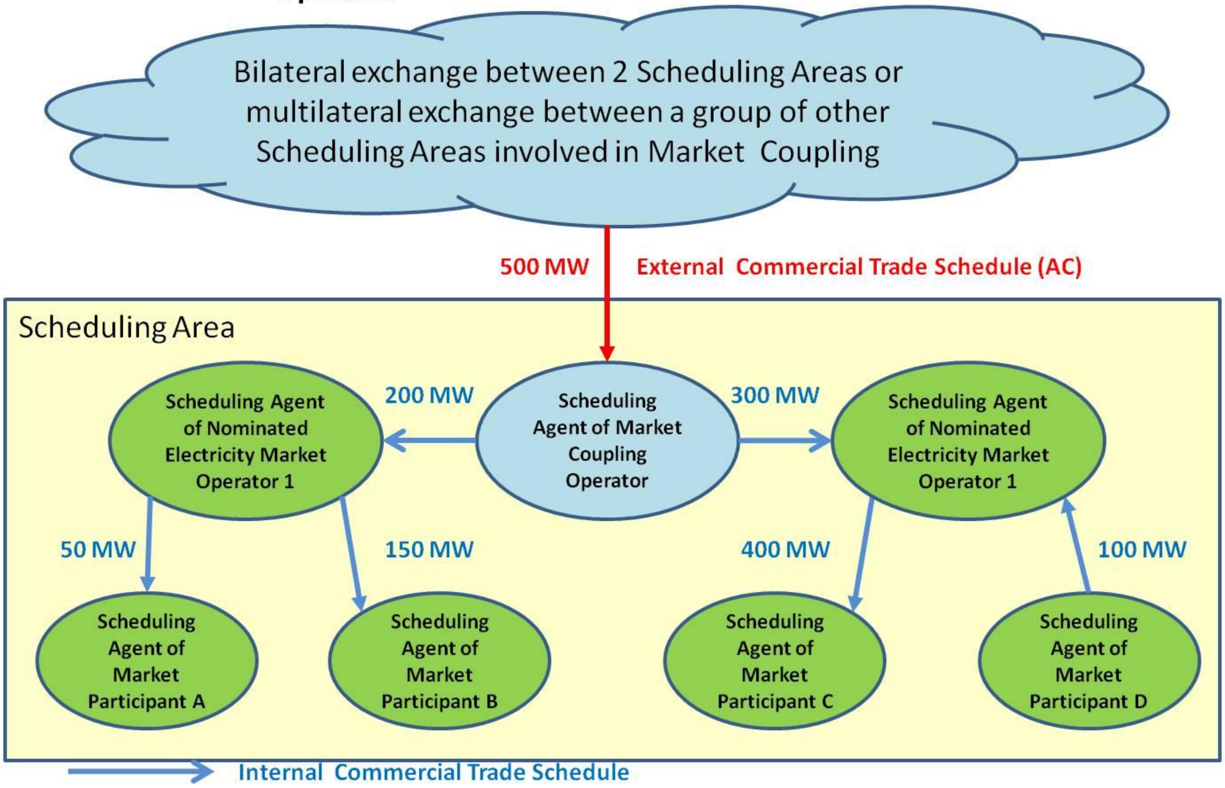
The Nominated Electricity Market Operators have to notify their

- 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”.

Article 53: **Notification of schedules within Scheduling Areas**

Article 53.2: **Notification of Schedules of Scheduling Agent of Market Coupling Operator**



Article 53: Notification of schedules within Scheduling Areas
Article 53.2: Notification of Schedules of Scheduling Agent of Market Coupling Operator

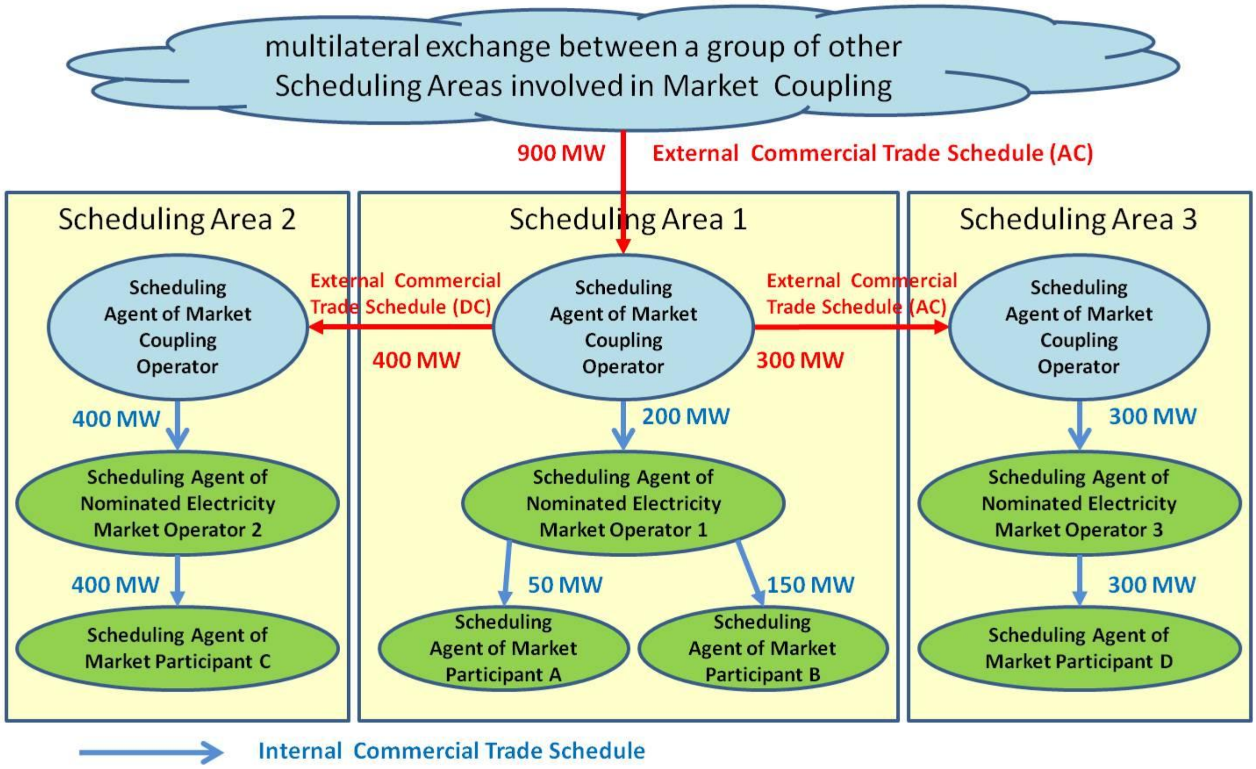
The next slide shows a more complex situation where Scheduling Area 1 has a DC-Interconnection with Scheduling Area 2 and due to local situation the Notification of the Scheduling Agent of the Market Coupling Operator to Scheduling Area 3 must be based on a bilateral exchange between Scheduling Area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

Article 53: Notification of schedules within Scheduling Areas

Article 53.2: Notification of Schedules of Scheduling Agent of Market Coupling Operator



10.2 APPENDIX 3 GLOSSARY

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 load of this area (from [NC OP&S])

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 OP&S])

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 2009-072-EC)

Availability Plan means the combination of all planned Availability Statuses for a Relevant Asset for a given time period (from [NC OP&S])

Availability Status means the capability for a given time period of a Power Generating Module, Transmission line, Ancillary Service, Demand Facility, non-TSO owned interconnector or another facility to provide service, whether or not it is in operation (from [NC OP&S])

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 time interval before real-time in an order of magnitude of 15 minutes (from [NC OP&S])

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])

Constraint means a situation in which to respect Operational Security Limits there is a need to implement Remedial Action (from [NC OP&S])

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 OP&S])

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 OP&S])

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 2009-072-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 2009-072-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 equipments 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 OP&S])

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 OP&S])

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 emergency reasons (from [NC OP&S])

Generation means the production of electricity (from Directive 2009-072-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 OP&S])

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 2009-072-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 OP&S])

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 2009-072-EC)

National Regulatory Authority means a regulatory authority as referred to in Article 35 (1) of Directive 2009/72/EC (from Directive 2009-072-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 OP&S])

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])

Observability Area means the area of the relevant parts of the Transmission Systems, Distribution Networks and neighbouring 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 OP&S])

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 OP&S])

Outage Incompatibility means the state in which a combination of one or more Relevant Grid Element, Relevant Power Generating Modules, Relevant Demand Facility and/or non-TSO owned Interconnector outages and the best estimate of the forecasted electricity grid situation leads to violation of Operational Security Limits (from [NC OP&S])

Outage Planning Agent means the role of planning Availability Status of Relevant Power Generating Modules, Demand Facilities or Relevant Non-TSO Owned Interconnectors (from [NC OP&S])

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 OP&S])

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, Relevant Non-TSO Owned Interconnector and Relevant Grid Element partaking in the Outage Coordination Process (from [NC OP&S])

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 OP&S])

Relevant Grid Element means a transmission or distribution grid element which participates in the Outage Coordination Process as its Availability Status influences cross-border Operational Security (from [NC OP&S])

Relevant Non-TSO Owned Interconnector means a non-TSO owned interconnector which participates in the Outage Coordination Process as its Availability Status influences cross-border Operational Security (from [NC OP&S])

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 OP&S])

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 2009-072-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 OP&S])

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 in accordance with the applicable national legal framework (from [NC OP&S])

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 OP&S])

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 2009-072-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 2009-072-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 2009-072-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 2009-072-EC)

Week-Ahead means the week before the calendar week of operation (from [NC OP&S])

Year-Ahead means the year before the calendar year of operation (from [NC OP&S])

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