SUPPORTING PAPER FOR THE OPERATIONAL PLANNING AND SCHEDULING NETWORK CODE

17.10.2012

DRAFT V4

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 system operation network codes supporting papers as follows:

Background:

- Section 2 introduces the legal framework within which the system operation network codes 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

1.3 LEGAL STATUS OF THE DOCUMENT

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

1.4 RESPONDING TO THE CONSULTATION

Responses to the public consultation on the OPS NC are requested by 7 January 2013. All responses should be submitted electronically via the ENTSO-E consultation tool, explained at https://www.entsoe.eu/resources/consultations/ .

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:

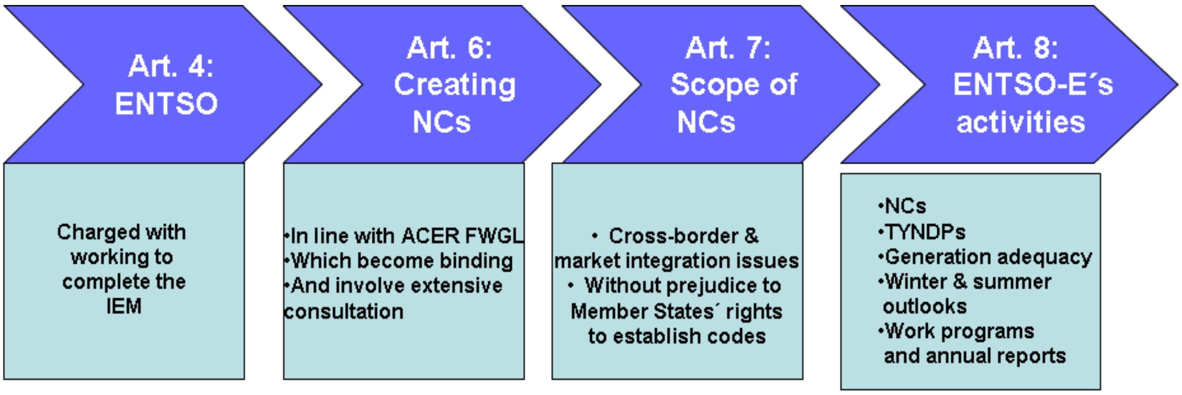

Figure 1: ENTSO-E's legal role in network code development according to Regulation (EC) 714/2009.

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

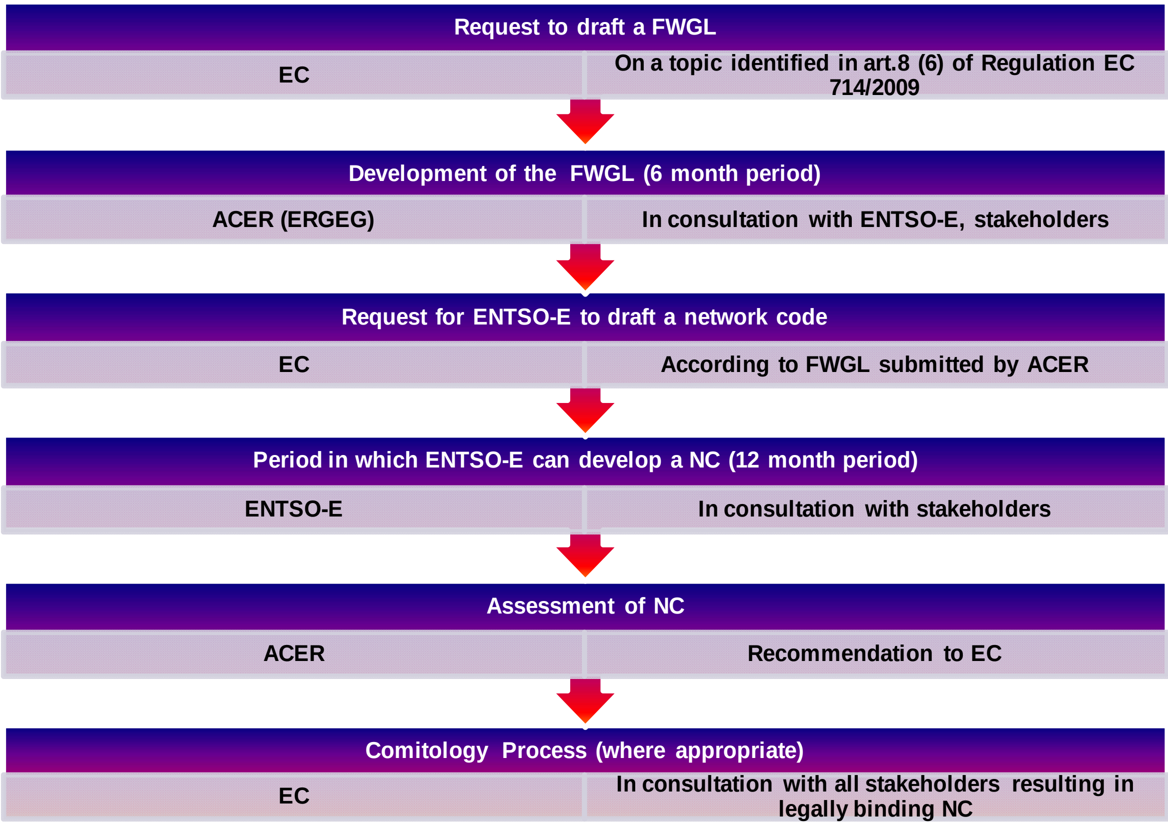

Figure 2: Network codes' development process [Source: ENTSO-E]

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. A workshop with the DSOs Technical Expert Group and a public stakeholder's workshop will be held on 20th-21st November 2012, in order to present the updates done in the draft OPS NC, taking into account comments from the stakeholders after 1st and 2nd workshops respectively 23 May and 25 July 2012. We encourage stakeholders and involved parties to submit comments and to provide proposals for addressing any concerns they have with the current draft to the public consultation tool, available on ENTSO-E webpage https://www.entsoe.eu/resources/consultations/. 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 4th Workshop on the OPS NC planned for the end of January 2013. 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;

- Article 8.1, Definition of Year-Ahead Scenarios.
- Article 10, Day-Ahead and Intraday Grid Models.
- Article 13, Day Ahead, Intraday and Close To Real Time Operational Security Analysis.
- Article 23, Requirements for Control Area Adequacy in General.
- Article 26, Requirements for Control Area Adequacy Day Ahead and Intraday.

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 preparing 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 network codes from other network codes in following terms:

- The work on the system operation network codes 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 network codes' 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 network codes 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 network codes, 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 facility operators 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 of Operational Security Network Code (OS NC), 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:

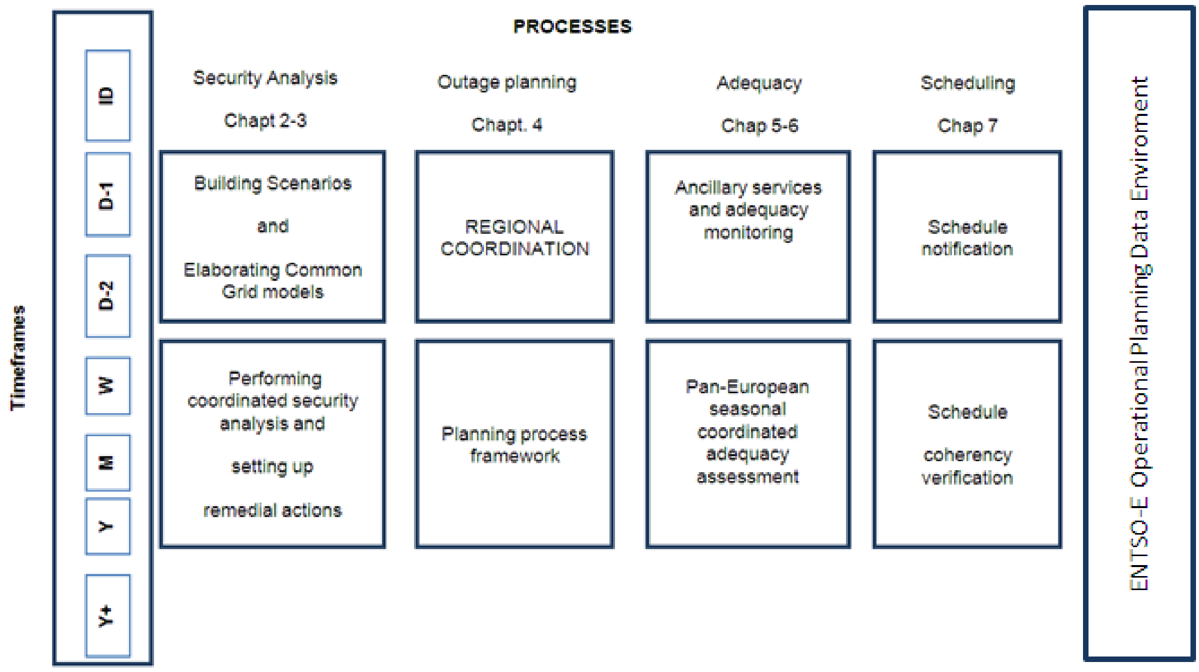

Figure 3: Structure and provisions of the Operational Planning and Scheduling Network Code

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:** each TSO should implement processes within each time frame to elaborate a coordinated assessment between TSO's that the power generation capacities will allow to balance the demand as to have the required amount of ancillary services, taking into account planned outages, 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 network codes 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.

3.5.1 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.

3.5.2 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, 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.

3.5.3 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 NC addresses these issues through coordination trough all operational planning processes with a special emphasis on the links with the Capacity Allocation and Congestion Management Network Code (CACM NC) and developing requirements on scheduling.

3.5.4 HVDC, PST and Super Grids

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.

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 Significant Grid Users;
- Ensuring the provisions and a firm basis for coordinated control actions of all concerned TSOs and Significant 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.

3.5.5 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 network codes 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.

3.6 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 NC 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 Allocation 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 – for the calculation of load-flows the same CGM is used before capacity calculation on the different market frameworks 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 network codes 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 NC, 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 Reliability Margin (RM) would give too rough results or high uncertainty on security level.

3.7 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 supporting documents for system operation network codes. The following concepts are described below:

- Common grid model;
- Relevant Grid User;
- DSO involvement ;
- NRA involvement;
- Delegation of tasks, sub contractors.

3.7.1 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 (network) models are allowing calculating the values of the electrical parameters (e.g. voltage, active, 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.

The coherency in Grid Models in all network codes 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 planned outages, of its grid elements allowing a correct coordinated power flow calculation.

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

  - All IGMs 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 is ensured, but some differences between models constructed for security analysis in OPS NC and for capacity calculation in CACM NC 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 to contain 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.

3.7.2 Significant and Relevant Grid Users

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 outage planning the TSOs coordinate in Chapter 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 18(1).

Nevertheless, the OPS NC 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. 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.

3.7.3 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 the other Control Area(s).

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 network code.

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.

3.7.4 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 OPS NC.

3.7.5 Delegation of tasks, subcontractors

All parties can outsource several tasks by itself or together with other parties. This right shall not be limited by this network code. Delegation to subcontractors, service providers or other third parties has no impact on the responsibility of the delegating party, the delegating party still remains responsible (liable) for its tasks according to its role (see also art. 6 and art. 18(8)).

3.8 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. Material is available in ENTSO-E webpage under link https://www.entsoe.eu/events/system-operation/ .

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 prior to, during and after the public consultation.

- The aim of the first OPS NC Workshop, held on 23rd May 2012 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 held on 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.

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.

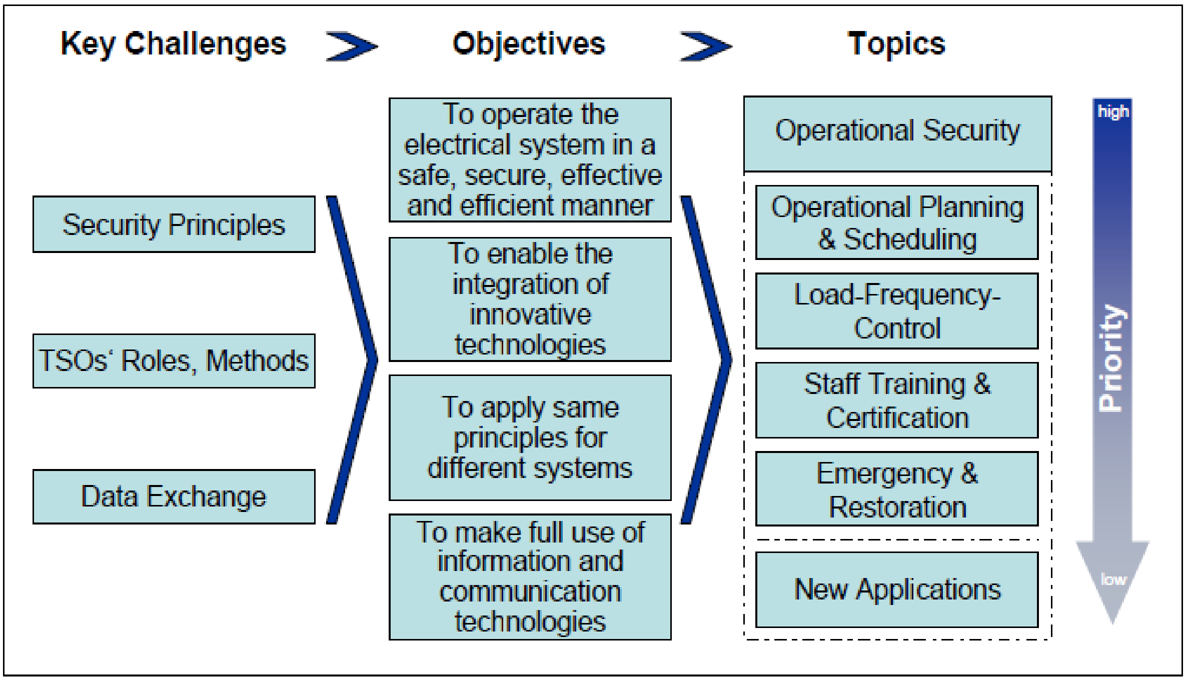


Figure 4: Structure and development flow of the Framework Guidelines on Electricity System Operation.

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

5 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 1 is given showing the processes as ENTSO-E sees them. Every process is provided with an explanation:

	(Article) **Methodologies/ Process**	**ACER** **involvement**	**NRA involvement**	**Stakeholder involvement**	**ENTSO-E role**
1	(15.1; 15.2) *Cross control area remedial action*	OPS addresses technical coordination No involvement of ACER foreseen	Yes	No	No
2	(18.1; 18.2) *Security analyses coordination*	Yes	No	No	Yes
3	(25.1) *Updating Year Ahead Outage planning process*	No	Yes	Yes	No
4	(28.1) *Pan European system adequacy season ahead*	Yes	No	Yes	Yes

Table 1

1. Cross Control Area 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, etc.) 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 Outage 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 coordination process where 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.

5.1 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.) 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 NC 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, harmonised at least at synchronous area level, 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.
- 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 network code.

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

The new and enhanced requirements under this topic in the 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 OS FG. 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 CACM NC. 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 or ACER approval and consultation has been provided for methodologies in those topics that required it, in particular:

- NRA’s shall be consulted with on the principles of remedial actions and the methodologies governing remedial actions.

- All TSOs shall submit, not later than 24 months after the entry into force of this network code, to ACER a methodology, harmonised at least per synchronous area, for operational security analysis.

5.2 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.

The outage planning process starts on the year-ahead timeframe, where the basis for the coming year is established. After being finalized, the year-ahead outage plan can be updated by all parties up to real-time. Once real-time operations are reached, agreed upon outage plans should be honoured by all parties, and Forced Outages are to be handled.

The described outage planning process is reciprocal for all parties, enforcing transparency between parties to allow preparation for a safe operation of the grid and an optimal functioning of the electricity market.

Important to notice is that all requirements set forth in this chapter of the OPS NC only apply to assets of which the unavailability has a significant impact across Responsibility Area borders. The concerned Relevant Elements are identified in articles 21 and 22.

5.2.1 An EU-wide coordinated outage planning

The general framework of the described planning process is based upon the current best practices installed in the EU.

The coordinated outage planning 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.

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

It is worth noticing that the definition of Outage Planning Regions is mainly guided from a practical point of view, to ensure efficiency of the coordinated planning process. It is therefore recognized to have little direct market impact, which justifies them being defined by the TSOs, and published for information to the general public.

Some of the existing Outage Planning Regions are as follows:

- TenneT NL, TenneT DE, Amprion, TransNetBW, Swissgrid, RTE, Elia, Creos, APG;
- APG, MAVIR, SEPS, CEPS;
- APG, Terna, MAVIR, HEP, ELES, NOSBiH, EMS;
- RTE, Swissgrid, Terna, APG, ELES;
- PSEO, 50HzT, CEPS, SEPS, TenneT DE ;
- MAVIR, SEPS, Transelectrica, Ukraine;
- MAVIR, NOSBiH, EMS, MEPSO, ESO EAD, IPTO, Albania, Turkey;
- Energinet.dk, Fingrid, Statnett, Svenska Kraftnät;
- Elering, AST, Litgrid.

The OPS NC gives the opportunity to develop optimal outage planning regions.

5.2.2 The outage planning process

The outage planning process, with its deadlines, responsibilities, data exchanges and coordination actions is established in several requirements. Currently there is no such harmonized basis on the European level, and differences exist between countries and/or regions. To provide a common, uniform basis is however necessary in creating a level playing field for the European electricity market.

Currently, in different countries, the process of establishing the year-ahead up to day-ahead availability plans for Relevant Power Generating Modules and Relevant Demand Facilities greatly differs. How the TSO intervenes in this process varies between the extremes of being a mere observer to being capable of fully steering these outage plans. As one of the main objectives is to stimulate the functioning of the European electricity market as much as possible meanwhile guaranteeing Security of Supply; the way the process is drafted ensures the following:

- In the year-ahead planning stage, Outage Planning Agents are free to plan (un-)availabilities according to their desires and to optimize their portfolio of assets;
- The concerned TSOs will assess, if an issue arises with these combined proposals regarding Operational Security (so-called Outage Incompatibilities). At this point in time no Grid Element outages are planned, so they do not interfere with Relevant Power Generation Module and Relevant Demand Facility outage proposals;
- If Outage Incompatibilities arise, all affected parties enter into a coordination step. If no feasible alternative can be decided upon, the only option to guarantee Operational Security is by modifying the proposed outage plan. The affected Outage Planning Agents will be asked to provide the TSO with an alternative outage plan relieving the detected Outage Incompatibilities;
- After this step, Relevant Grid Element outages are planned by the TSOs. In case of Outage Incompatibilities with Relevant Power Generating Module and/or Relevant Demand Facility outages, the TSOs shall coordinate with the relevant parties to find a negotiated solution;
- After the year-ahead outage plan is finalized, all parties can request changes to this outage plan. These changes will be accepted by other parties unless Operational Security cannot be guaranteed under the combination of the requested change and the already existing outage plans. In case there is some impact on the plans from other parties, the opportunity is left open for all parties to coordinate and come to a negotiated solution (see also the section “Changing the year-ahead outage plan”);
- Next to these updates, Forced Outages can occur. If so, the relevant party should inform all impacted parties as soon as possible, and do its utmost to limit the consequences for the electricity market as much as possible.

Except in case of Force Majeure or if Security of Supply is at stake, the established outage plan should be honoured in real-time by all parties.

Important to stress is the fact that outage planning only refers to:

a) Relevant elements: this holds for Grid Elements, Power Generating Modules and Demand Facilities equally. Relevant is here related to cross-border impact, and is described in Articles 21 and 22 of the Network Code;
b) The Availability and non-Availability of assets. This means only the capability of producing, consuming and transporting energy is planned in this process. If and how much the asset produces, consumes or grids are not directly impacted by these rules (except for assets being unavailable) and is governed by market or other rules (whichever is applicable).

5.2.3 The year-ahead outage planning phase

To illustrate the year-ahead outage planning described in Article 22 of the Network Code, below a flowchart depicting the coordination process is included.

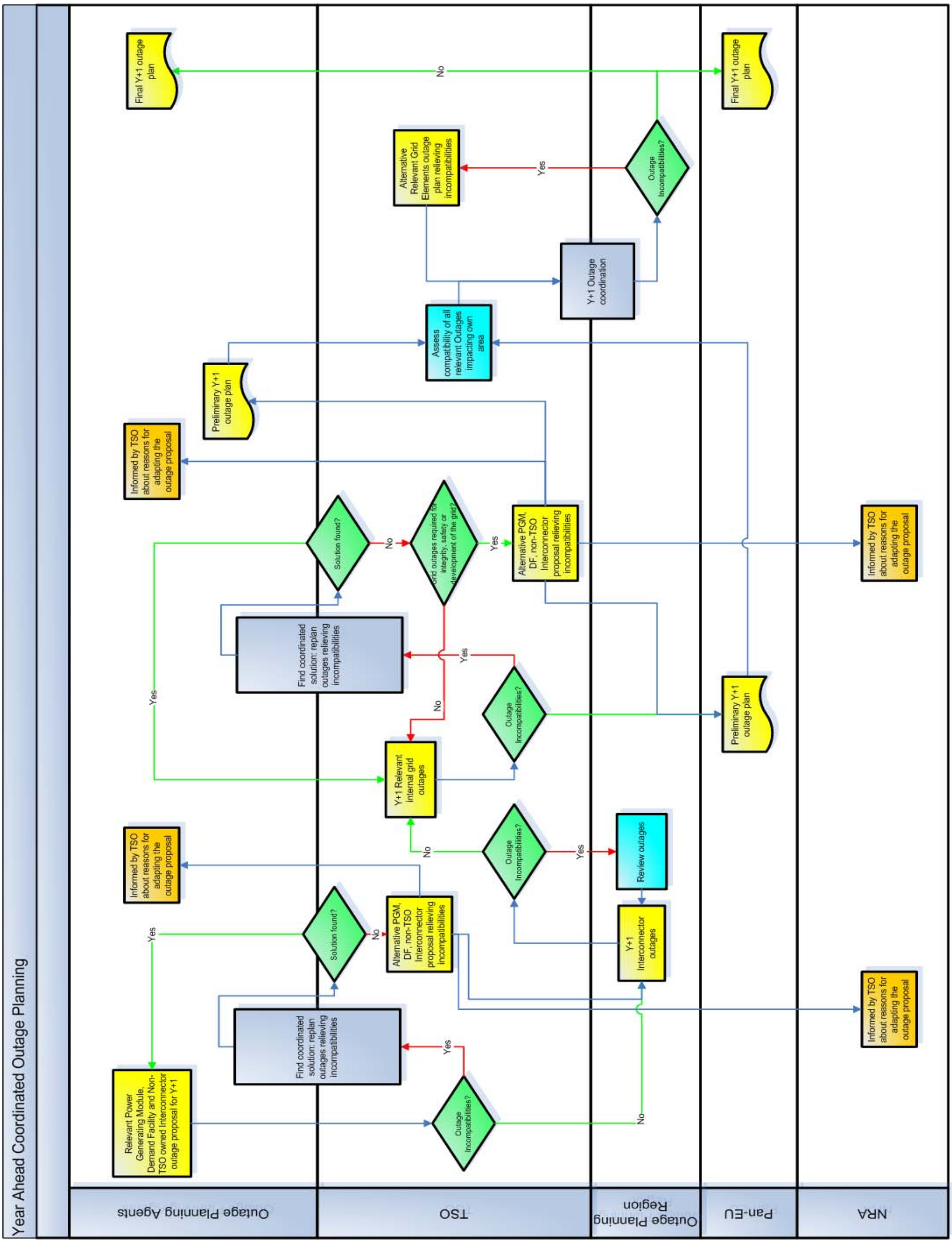

Year Ahead Coordinated Outage Planning
Outage Planning Agents
TSO
Outage Planning Region
Pan-EU
NRA
Relevant Power Generating Module, Demand Facility and Non-TSO owned Interconnector outage proposal for Y+1
Outage Incompatibilities?
Find coordinated solution: replan outages relieving incompatibilities
Solution found?
Alternative PGM, DF, non-TSO Interconnector proposal relieving incompatibilities
Informed by TSO about reasons for adapting the outage proposal
Y+1 Interconnector outages
Review outages
Y+1 Relevant internal grid outages
Grid outages required for integrity, safety or development of the grid?
Preliminary Y+1 outage plan
Assess compatibility of all relevant Outages impacting own area
Y+1 Outage coordination
Alternative Relevant Grid Elements outage plan relieving incompatibilities
Final Y+1 outage plan
Yes
No

Figure 5:

5.2.4 Changing the year-ahead outage plan

Article 24 of the Network Code describes how all parties can initiate a change to the validated outage 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 note that the outcome of the coordination step between all parties which are asked to change their outage plan could be that in order to allow accepting the initial change request, already planned outages of other parties are 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 does not oblige nor forbid the instalment of this kind of mechanism, and leaves it open to be regionally or nationally decided.

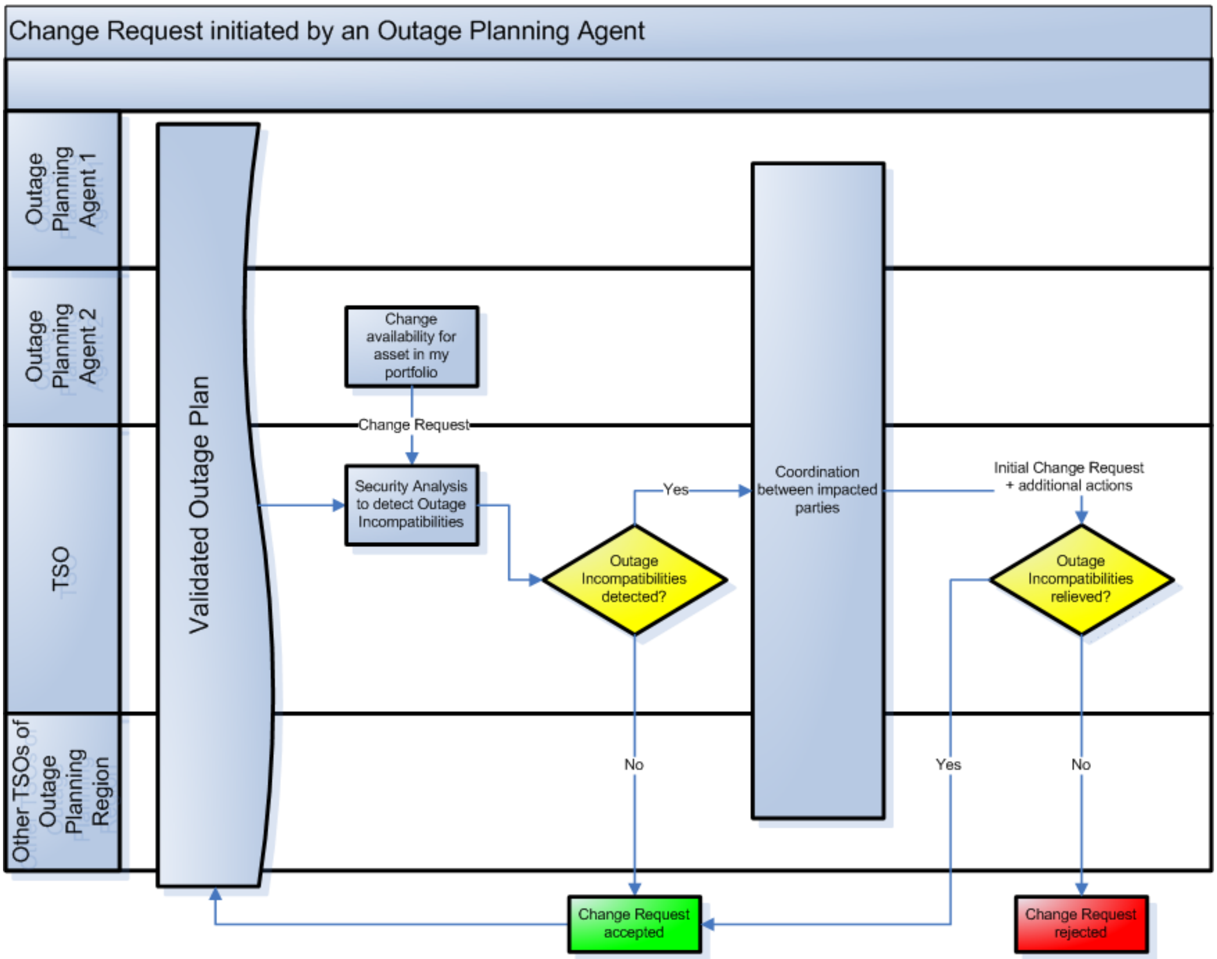


Figure 6:

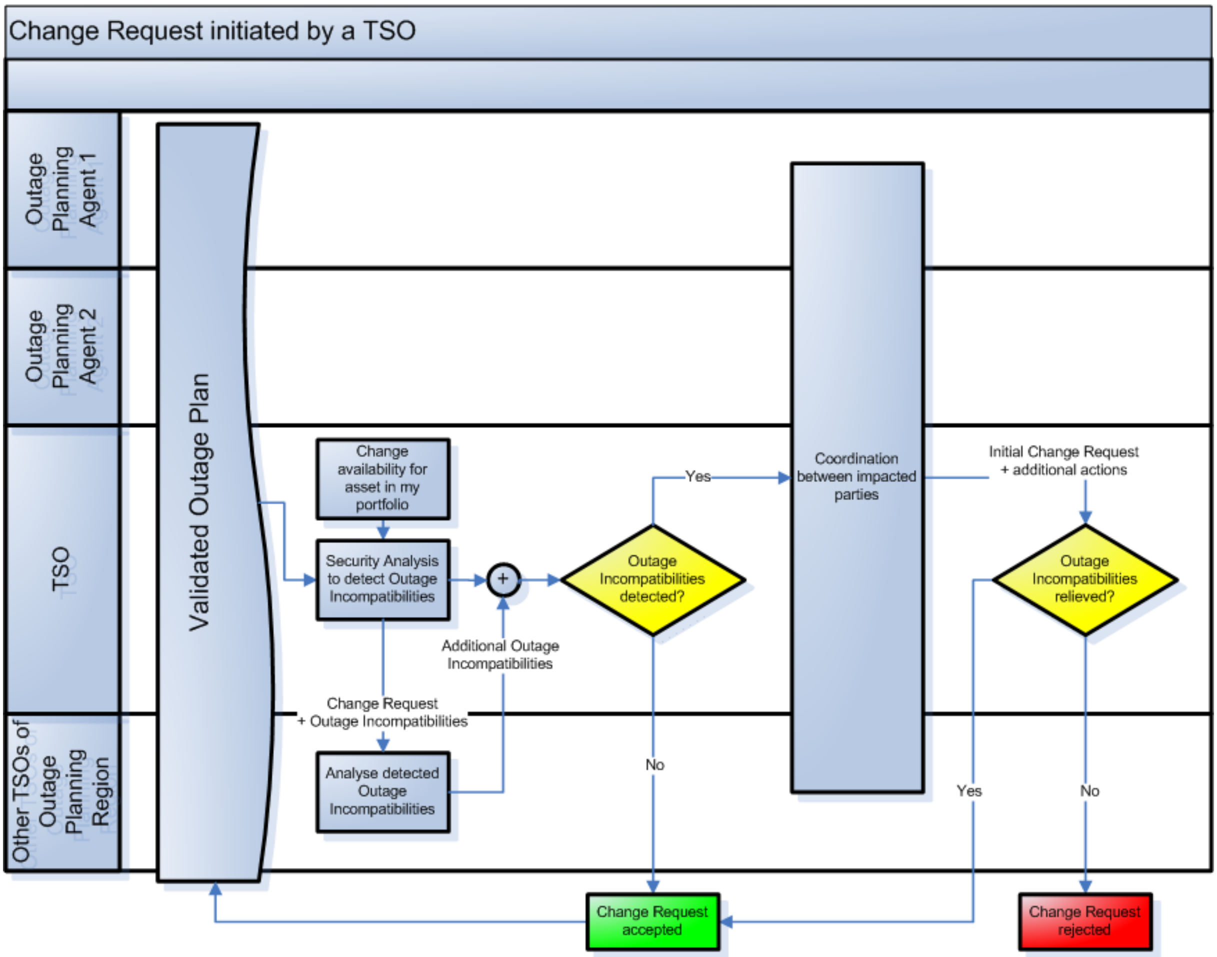


Figure 7:

5.2.5 Outage Planning deadlines

In the year-ahead outage planning process, deadlines are set to ensure that relevant and necessary information about planned outages 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 planning 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 impacted 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 adequacy assessment.

Some deadlines reported in Figure 8 are not in the code and are therefore indicative.

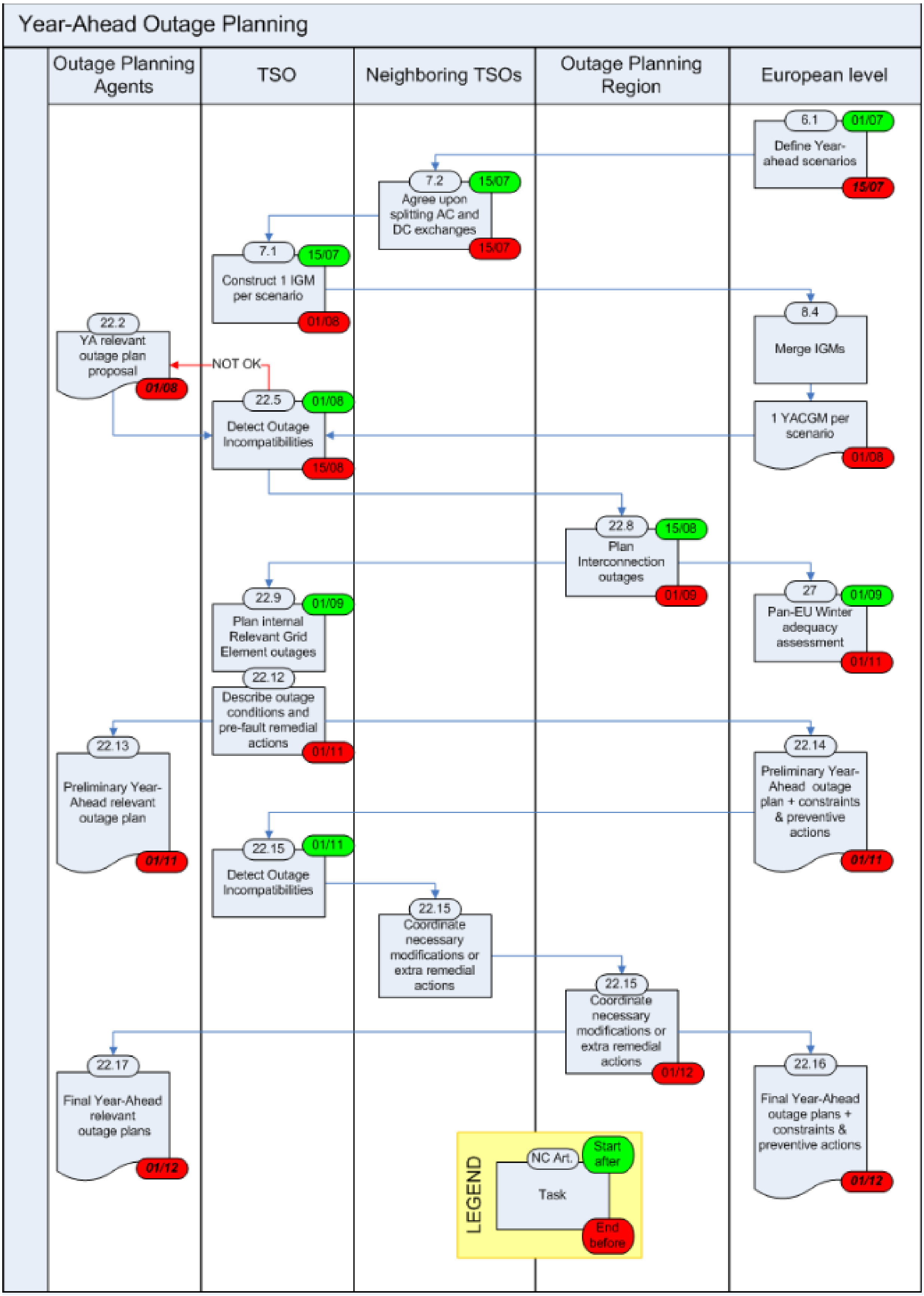

Year-Ahead Outage Planning
Outage Planning Agents
TSO
Neighboring TSOs
Outage Planning Region
European level
6.1
01/07
Define Year-ahead scenarios
15/07
7.2
15/07
Agree upon splitting AC and DC exchanges
15/07
7.1
15/07
Construct 1 IGM per scenario
01/08
8.4
Merge IGMs
22.2
YA relevant outage plan proposal
01/08
NOT OK
22.5
01/08
Detect Outage Incompatibilities
15/08
1 YACGM per scenario
01/08
22.8
15/08
Plan Interconnection outages
01/09
22.9
01/09
Plan internal Relevant Grid Element outages
27
01/09
Pan-EU Winter adequacy assessment
01/11
22.12
Describe outage conditions and pre-fault remedial actions
01/11
22.13
Preliminary Year-Ahead relevant outage plan
01/11
22.14
Preliminary Year-Ahead outage plan + constraints & preventive actions
01/11
22.15
01/11
Detect Outage Incompatibilities
22.15
Coordinate necessary modifications or extra remedial actions
22.15
Coordinate necessary modifications or extra remedial actions
01/12
22.17
Final Year-Ahead relevant outage plans
01/12
22.16
Final Year-Ahead outage plans + constraints & preventive actions
01/12
LEGEND
NC Art.
Start after
Task
End before

Figure 8:

5.2.6 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 his data (regarding outages and other information necessary for Security Analysis) under a common format on this environment, where it is accessible by all EU TSOs (and RSCIs operating on 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 outage planning between TSOs. Having such a data environment should greatly ease and stimulate collaboration and coordination between TSOs, provides an environment where needed information can be found on request, and enforces TSOs in using common data formats, common timelines and – to a certain level – common methodologies.

5.2.7 Links with other Network Codes

The outage planning 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 planned outages are a key factor in the determination of cross-border exchange capacities.

5.3 ADEQUACY

System adequacy deals with the ability of a power system to supply the load in all the steady states that the power system may face.

The majority of requirements set out for TSOs, DSOs and grid users in this topic are currently bases upon pan-European system adequacy outlook and existing best practice of bilateral coordination.

Specific requirements for pan-European adequacy analysis are foreseen to be set by all TSO in methodology.

The OPS NC harmonizes a pan-European adequacy analysis season ahead. All other analyses are an update to this season adequacy and are performed on a responsibility area level, whereby, if applicable, neighbouring TSO's are taken into account. This twofold approach is sufficient to cover current pan-European operational needs.

The added value of these new requirements are that each TSO will be able up to real time to, in a coordinated way, review and monitor the adequacy status of its system taking thereby imports/exports into account.

The aim of adequacy analysis is identifying the ability of generation to meet demand by calculating the “remaining capacity” for both normal and severe conditions.

The Methodology is shown in the figure below:

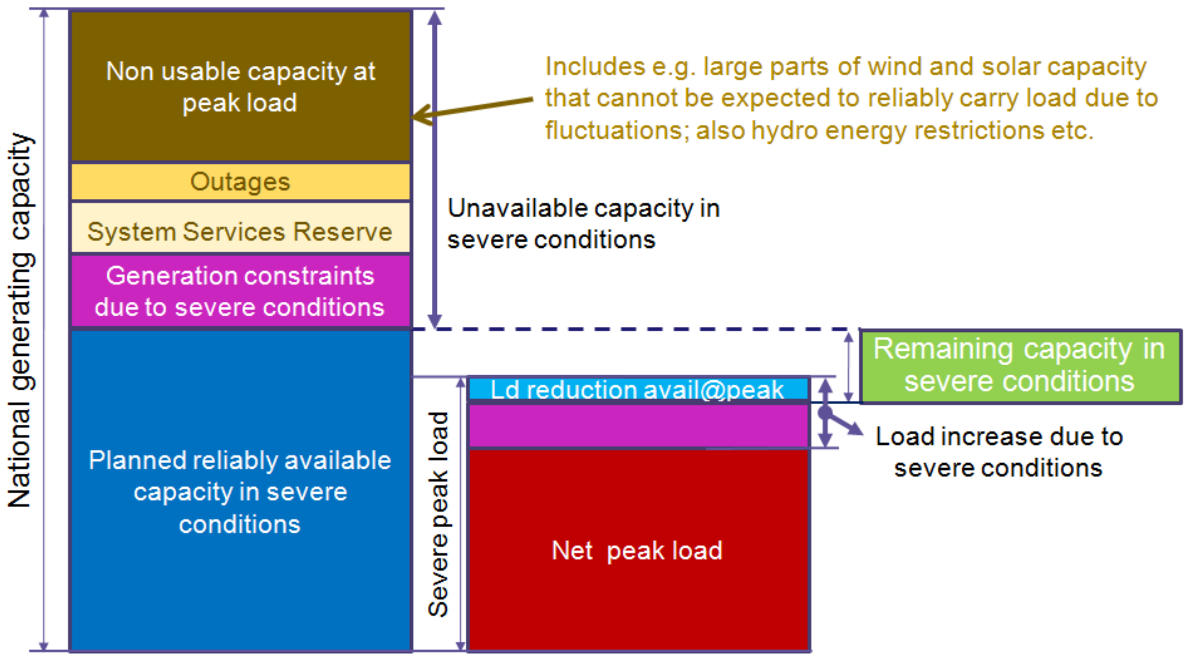


Figure 9:

The basis of the analysis is the situation called “normal conditions”. Normal conditions are defined as conditions that correspond to normal demand on the system, due to 'normal' weather conditions, wind or hydro output and outages.

A severe scenario was also built showing the sensitivity of the generation-load balance to low temperature and extreme weather conditions. The severe conditions relate to what each TSO would expect: higher demand than in normal conditions and reduced generation output (i.e. severe conditions resulting in lower wind or restrictions in generation power plants).

The figures of the individual country responses show the “National Generating Capacity”, the “Reliably Available Capacity” and the “peak load” under normal and severe conditions. The remaining capacity is calculated for normal conditions. The remaining capacity is also evaluated with firm import / export contracts and for severe conditions.

The regional analysis comprises a twofold scenario:

1. Is in a “copperplate” scenario (i.e. unlimited exchange capacity between countries) enough power that can be produced to meet the demand? 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 country needs. It must be stated that with this scenario only a risk of shortage on the European level can be detected; it will not show which countries will have a generation deficit.
2. In this scenario the exchange capacity between countries is not unlimited, but the bilateral exchanges must respect the given NTC values; also the total simultaneous import and export should be lower or equal to the given limits.

The OPS NC foresees updating this existing Methodology in consultation with stakeholders.

5.4 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 LFCR 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.

5.5 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 Market Balance 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.

Scheme of available schedules is given bellow:

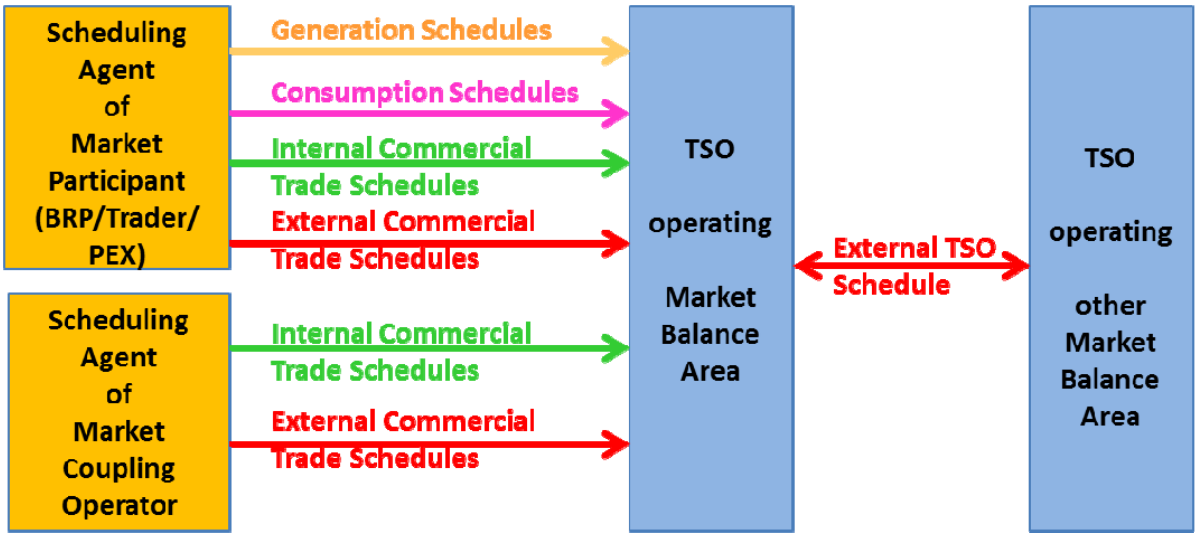


Figure 10:

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.

The scheduling chapter of OPS NC sets the 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.

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

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

Within market coupling process, multilateral exchanges between Market Balance 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 Market Balance Areas do not participate in market coupling.

Figure 11 shows the bilateral agreement and verification process (OPS NC Art.35.2):

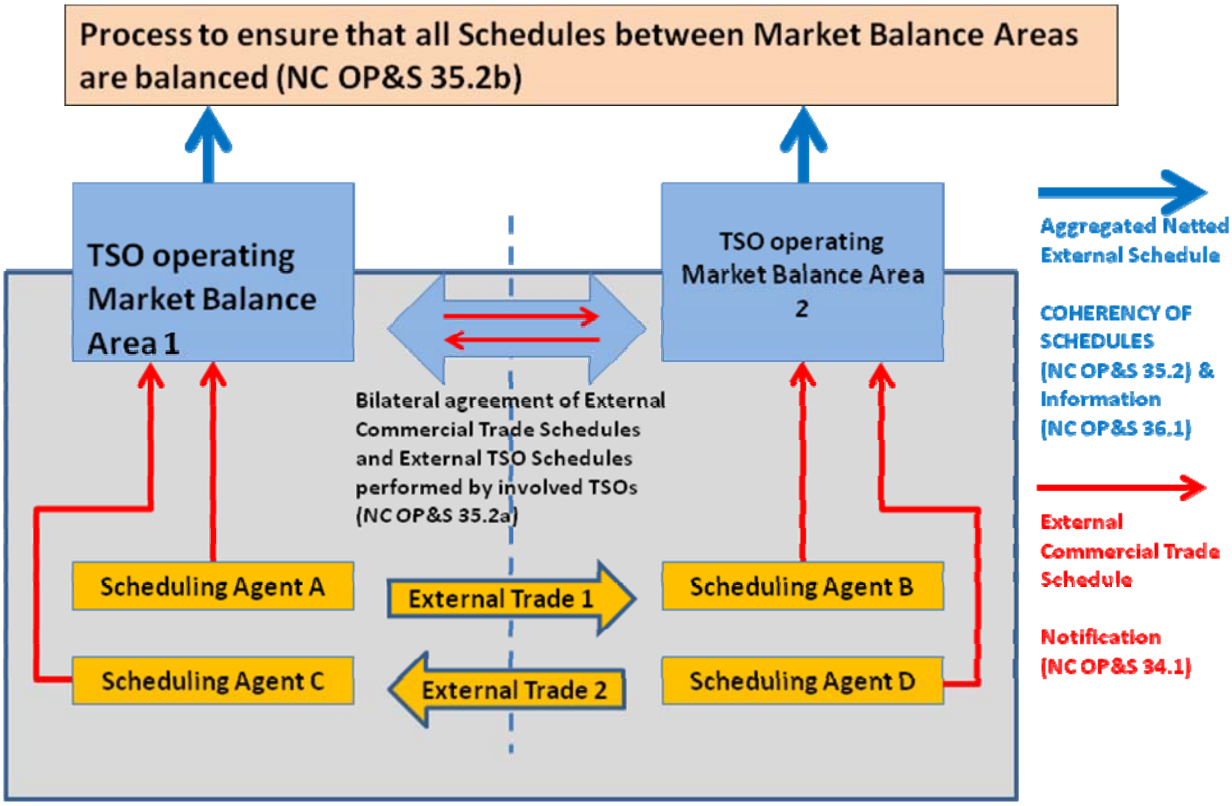


Figure 11

Figure 12 below shows the multilateral verification process (OPS NC Article 35.3):

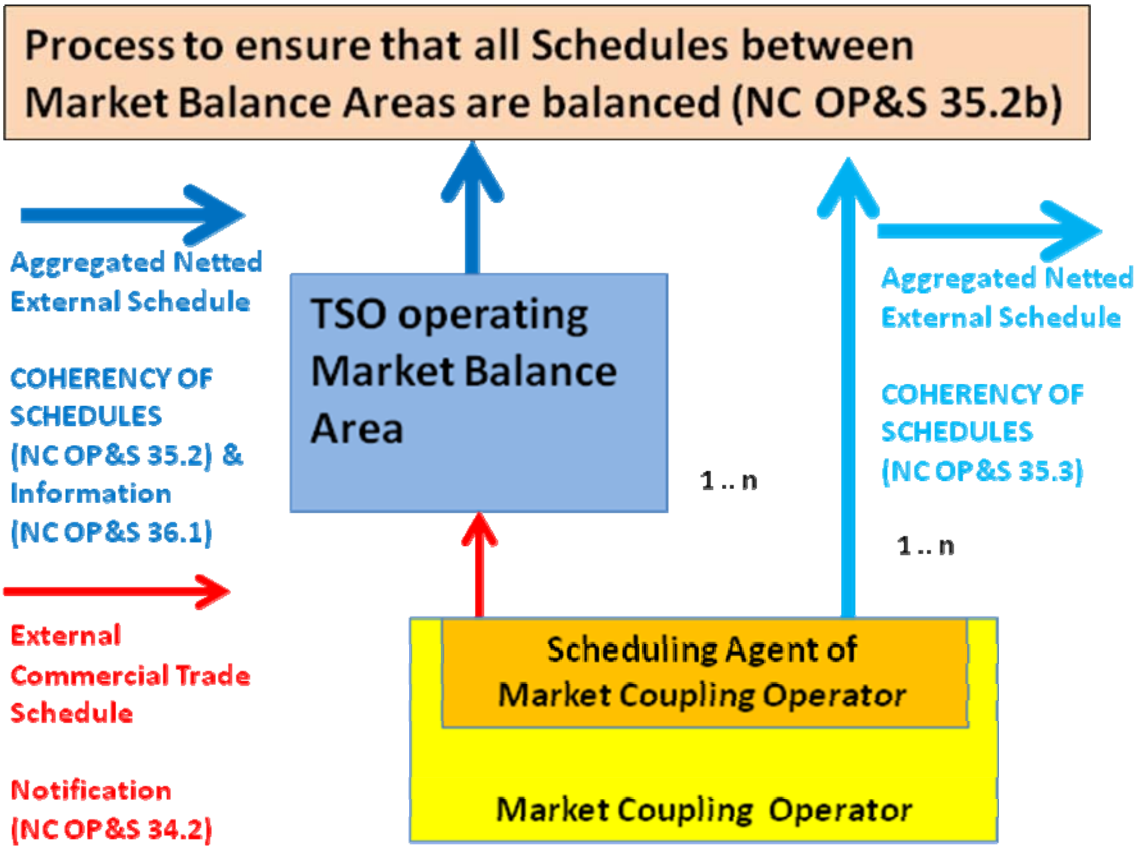


Figure 12

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

6 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 of common grid models during the whole operational planning phase, 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 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 while integrating more efficiently all transmission and generation capacities, 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, as 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.

7 Responses and Next Steps

7.1 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.

7.2 Submission of Responses

Responses to the public consultation on the OPS NC are requested by 7 January 2013. All responses should be submitted electronically via the ENTSO-E consultation tool, explained at https://www.entsoe.eu/resources/consultations/ .

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 21st November 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 Pilar.Munoz-Elena@entsoe.eu.

7.3 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.

7.4 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 NC 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 at the end of January 2013, as the result of public consultation, the major comments received and the therefore amendments made in the Code will be presented.

8 LITERATURE & LINKS

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

[2] “Initial Impact Assessment”, ACER, June 2011.

9 APPENDICES

9.1 APPENDIX 1 ALIGNMENT WITH FRAMEWORK GUIDELINES

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

No.	The network code(s) shall define (according to SO FG):	Chapter in OPS NC	Article number [to come]	Link to other NCs
FG1	Performing security analyses (contingency analysis, voltage stability analysis, etc.) at each relevant stage of operational planning. The provisions shall ensure that System Operation meet security criteria under any simulated operating conditions consistent with security assessment, and that the operation of the interconnected control area is not jeopardised;	Security analysis		Capacity Allocation and Congestion Management network code (CACM) OS
FG2	State estimation, to be implemented 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 errorless input data set for other computations like load-flows, security analyses, etc.;	Security analysis		
FG3	Determining the specific reliability margin, required to cope with uncertainties relevant to System Operation, and which uncertainties are covered by the reliability margin. Consistency between reliability margins for system operation and transmission capacity calculations shall be ensured;	Security analysis		OS CACM
FG4	Prevention and/or remedy of disturbances and blackouts on incidents which can affect neighbouring areas or the synchronous areas;	Security analysis Adequacy Ancillary services Scheduling		OS CACM
FG5	Scheduling planned outages and relevant maintenance works of transmission network, significant generation and DSOs' elements, including a coordinated and agreed (among the affected TSOs) scheduling process for long-term and short-term planning;	Outage planning Scheduling		

FG6	Ensuring access to an adequate level of ancillary services (e.g. active and reactive power reserves, balancing power) in real-time to meet security criteria and the requirements set at synchronous area level, for each operational planning stage;	Ancillary services		LFC Network Code for Requirements for Grid Connection Applicable to all Generators (RfG)
FG7	Calculation of requirements on different categories of control reserves with the aim to optimise these requirements within synchronous area to meet the security criteria with minimum costs;	Ancillary services		LFC Balancing
FG8	Exchange of ancillary services across interconnections in terms of technical principles;	Ancillary services		Balancing
FG9	Coordination of reactive power control with significant cross-border impact;	Ancillary services		OS
FG10	Coordination of short circuit current between TSOs at interconnections;	Ancillary services		OS
FG11	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;	Ancillary services		
FG12	Obligation for data delivery -> See Information Exchange: The network code(s) shall describe – for the different timeframes – the principle 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. TSO shall be provided with up-to-date information on the development of grid components and configurations, also by significant grid users, especially as regards planned and unplanned outages and their technical ability to provide ancillary services.	Security analysis Outage planning		LFC RfG
FG13	In relation to the CACM FG and the respective network code(s), principles and requirements for the implementation and operation of the *transmission capacity calculation* method at the different time frames. In this respect, the coherence between the preparation of a *common grid model* and the assessment of relevant	Data for Operational Security Analysis		CACM

	reliability margins shall be ensured. Specifically, reliability margin calculations shall take into consideration all pertinent assumptions made in due course of preparation of the *common grid model* and *transmission capacity calculation* in order to cope with model/method inaccuracies and relevant uncertainties efficiently.			
FG14 General	General: Roles and Responsibilities The network code(s) shall foresee that the TSOs coordinate their operational planning activities at regional, synchronous area and EU level – as technically necessary and within the most appropriate entities – in order to ensure meeting the objectives of secure System Operation and applying the most appropriate measures to prevent and/or remedy system disturbances.	All		
FG15 General	General: Information Exchange (I) The network code(s) shall describe – for the different time frames – the principles for exchange of all necessary information between system operators to handle the different planning and scheduling activities in a coordinated and cooperative manner, including all necessary data to construct a proper synchronous area-wide common grid model.	All		
FG16 General	General: Information Exchange (II) TSOs shall be provided with up-to-date information on the development of grid components and configuration, also by significant grid users, especially as regards planned and unplanned outages and their technical ability to provide ancillary services.	ENTSO-E operational planning data environment		

9.2 APPENDIX 2 SCHEDULING EXAMPLES

Article 34: NOTIFICATION OF SCHEDULES WITHIN MARKET BALANCE AREAS
Article 34.2: 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 Market Balance Area using AC interconnections, when the Market Balance Area is interconnected to other Market Balance Area(s) via AC interconnection(s).
  These External Commercial Trade Schedules can describe a bilateral exchange between 2 Market Balance Areas or a multilateral exchange between 1 Market Balance Area and a group of other Market Balance Areas involved in the Market Coupling.
  The use of bilateral or multilateral exchanges is dependent on the request from concerned TSOs.
  "A group of other Market Balance Areas involved in Market Coupling" will be modelled as a specific Market Balance Area without generation or consumption and where the sum of all imports is equal to the sum of all exports. All Market Balance Areas involved in the Market Coupling have a border with the specific Market Balance Area, except if the local situation requires bilateral exchanges between 2 Market Balance Areas. The Scheduling Agent of the Market Coupling Operator acts as "Operator of this specific MBA".

- based on Net Positions related to the Market Balance Area using DC interconnection(s), separate for each DC interconnection (if requested by concerned TSOs), when the Market Balance Area is interconnected to other Market Balance Area(s) via DC interconnection(s).

Article 34: NOTIFICATION OF SCHEDULES WITHIN MARKET BALANCE AREAS
Article 34.2: NOTIFICATION OF SCHEDULES OF SCHEDULING AGENT OF MARKET COUPLING OPERATOR

The next slide shows the situation where a Market Balance 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.

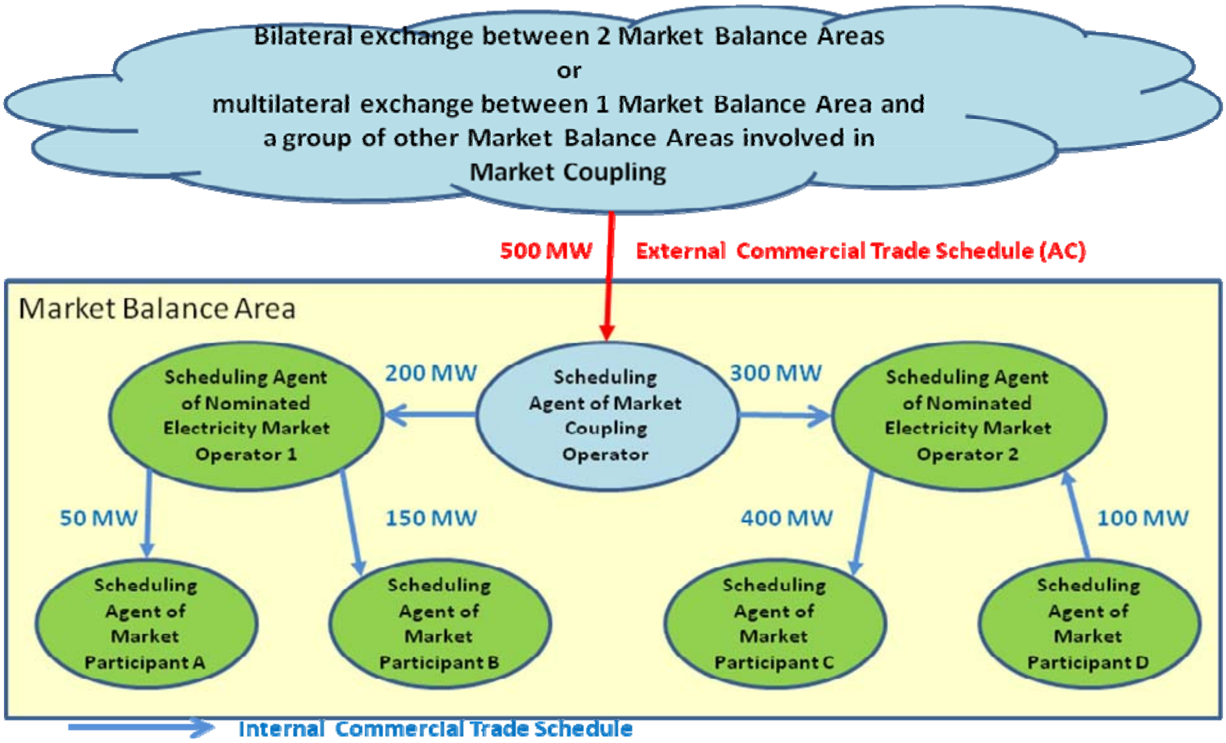
Notification of Schedules of Scheduling Agent of the Market Coupling to Market Balance Area:

- External Commercial Trade Schedules
  - Market Balance 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

Notification of Schedules of Scheduling Agents of Nominated Electricity Market Operators:

- 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.

Article 34: NOTIFICATION OF SCHEDULES WITHIN MARKET BALANCE AREAS
Article 34.2: NOTIFICATION OF SCHEDULES OF SCHEDULING AGENT OF MARKET COUPLING OPERATOR



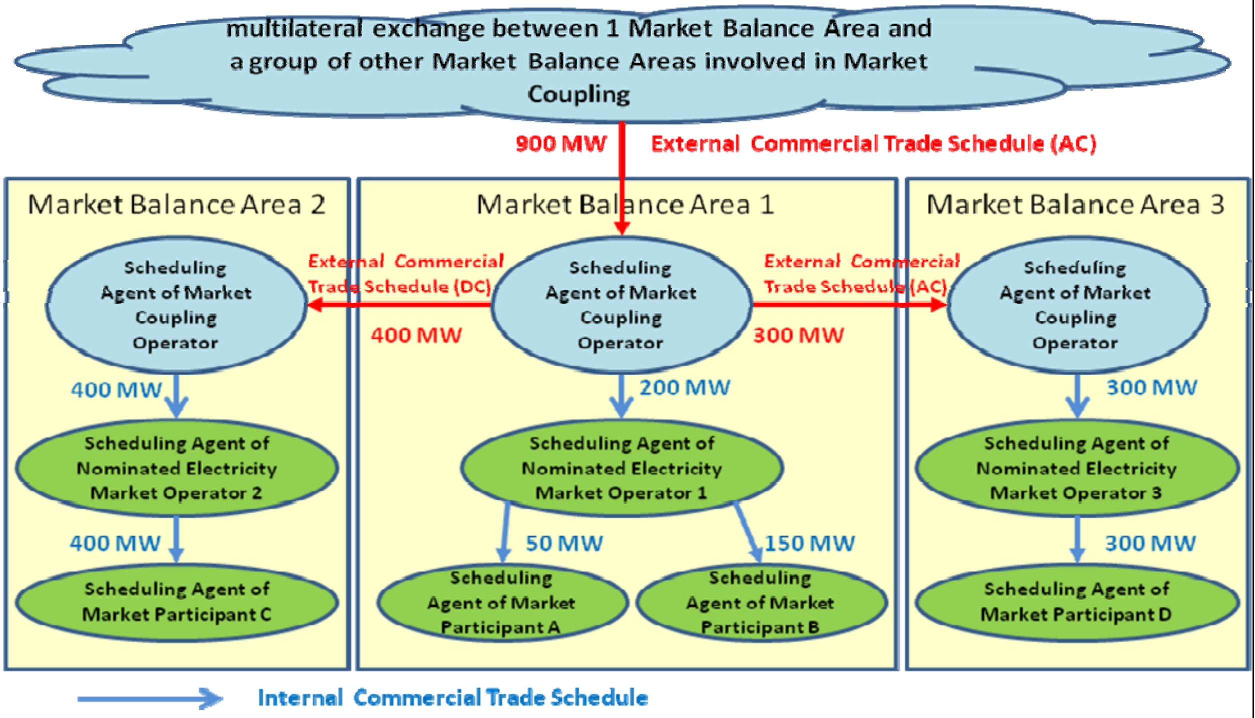
Article 34: NOTIFICATION OF SCHEDULES WITHIN MARKET BALANCE AREAS
Article 34.2: NOTIFICATION OF SCHEDULES OF SCHEDULING AGENT OF MARKET COUPLING OPERATOR

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

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

Notification of Schedules of Scheduling Agent of the Market Coupling to Market Balance Area 1:
- External Commercial Trade Schedules
  - Market Balance Area 1: Import 900MW (scheduled as multilateral exchange between Market Balance Area 1 and all other Market Balance Areas involved in Market Coupling)
  - From Market Balance Area 1 to Market Balance Area 2: 400 MW
  - From Market Balance Area 1 to Market Balance 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 34: NOTIFICATION OF SCHEDULES WITHIN MARKET BALANCE AREAS
Article 34.2: NOTIFICATION OF SCHEDULES OF SCHEDULING AGENT OF MARKET COUPLING OPERATOR



9.3 APPENDIX 3 GLOSSARY

(N-1)-Situation means the situation in the Transmission System in which a Fault on an element of Transmission System or a Power Generating Facility Operator has happened (definition from NC OS);

Active Power Reserve means the operational reserves available for maintaining the planned power exchange and for guaranteeing secure operation of the Transmission System (definition from NC OS);

Adequacy means ability of generation connected to an area to meet the load of this area (definition from NC OPS);

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

Ancillary Service means a service necessary for the operation of a transmission or distribution system (definition from Directive 2009/72/EC);

Availability means state of a Power Generating Module, Transmission Line, Ancillary Service, Demand Facility, Third-party Owned Tie-Line or another facility is capable of providing service, whether or not it actually is in service (definition from NC OPS);

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

Capacity Allocation means the attribution of Cross Zonal Capacity (definition from NC CACM);

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 optimisation of Cross Zonal Capacity made available to market participants (definition from NC CACM);

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

Commissioning means the process of assuring that all systems and components of a Power Generating Module, Demand Facility or Third-party Owned Tie-line are designed, installed, tested, according to the operational requirements of the owner or final client (definition from NC OPS);;

Common Grid Model (CGM) means European-wide or multiple-TSOs-wide data set created, by the TSOs and coordinated within the ENTSO-E, created through merging of relevant data (definition from NC OS);

Congestion means a situation in which an interconnection linking national transmission networks cannot accommodate all physical flows resulting from international trade requested by market participants, because of a lack of capacity of the interconnectors and/or the national transmission systems concerned (definition from Regulation EC 714/2009);

Connection Point means the interface at which the Power Generating Module is connected to a transmission, distribution or closed distribution Network according to Article 28 of Directive 2009/72/CE as identified in the Connection Agreement (definition from NC RfG);

Constraint means a situation, either described in a Common Grid Model, or occurring in real time, where Operational Security Limits are not respected (definition from NC OPS);

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

Contingency means the identified and possible or already occurred Fault of an element within the TSO’s Control Area, including not only the transmission but also the distribution networks of DSOs on lower voltage levels. Internal Contingency is a Contingency within the TSO’s Control Area. External Contingency is a Contingency within the Control Area of neighboring TSO having effects in the Control Area of the TSO (definition 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 a priori or a posteriori after a Contingency took place (definition from NC OS);

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

Control Area means a part of the interconnected Transmission System controlled by a single TSO (definition from NC OS);

Cross Zonal Capacity means the capability of the interconnected Transmission System to accommodate energy transfer between Bidding Zones. It can be expressed either as a Coordinated Net Transmission Capacity value or Flow Based parameters, and takes into account Operational Security Constraints (definition from NC CACM);

Day-Ahead means the day before the calendar day of operation (definition from NC OPS);

Demand Facility means a facility which consumes electrical energy and is connected at one or more Connection Points to the Network. For the purpose of avoidance of doubt a Distribution Network and/or Auxiliary Supplies of a Power Generating Modules are not a Demand Facility (definition from NC DCC);

Demand Facility Operator means the entity (usually the owner) that is responsible for the operation of the Demand Facility (definition from NC DCC);

Direct Current Line (DC Line) means a transmission link between two MBA using direct current technology (definition from NC CACM adapted to NC OPS context);

Distributed Generation means generation plants connected to the distribution system (definition from Directive 2009/72/EC);

Distribution Network means is an electrical Network for the distribution of electrical power from and to third party[s] connected to it, a Transmission or another Distribution Network, including Closed Distribution Networks (definition 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 (definition from Directive 2009/72/EC);

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

External TSO Schedule means a Schedule representing the exchange of electricity between TSO in different Market Balance Areas (definition from NC OPS);

Fault means the event occurring on the primary equipment in a 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 (definition from NC OS);

Forced Outage means the unplanned removal from service Availability of a Power Generating Module, Transmission Line, or other facility for emergency reasons (definition from NC OPS);

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 (definition from NC OPS);

Grid Element means element of the Transmission System (definition from NC OPS);

Grid User means the natural or legal person supplying to, or being supplied with active and/or reactive power by a TSO or DSO (definition from NC OS);

Individual Grid Model means Control Area-wide dataset created by a TSO for Operational Security analysis purpose, to be merged with other Individual Grid Model components in order to create the Common Grid Model (definition from NC OPS);

Intraday means the period of time within the day of operation before the momentary operational situation (definition from NC OPS);

Interconnection means a transmission link - AC or DC line, circuit or transformer - which connects two Control Areas (definition from NC OS);

Load Shedding means the disconnection of load from the synchronous electric power system, performed automatically or manually, to control the system frequency, to avoid voltage deterioration, or prevent another disturbance and deterioration of Operational Security (definition from NC OS);

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

Market Balance Area means the smallest geographical area between the Bidding Zone and the Responsibility Area (definition from NC OPS);

Market Coupling Operator(s) 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 (definition 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 (definition from NC CACM);

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

Neighboring TSOs means regarding a given TSO and events or decisions within its Responsibility Area, refers to the TSOs operating the Responsibility Areas potentially subject to operational parameters variation resulting of these events or decisions, having an impact on their Operational Security (definition from NC OPS);

Net Position means the netted sum of electricity exports and imports for each Market Time Period for a given geographical area (definition from NC CACM adapted to NC OPS context);

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

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

Normal State means the operational state in which there is a low risk for deterioration of Operational Security of the transmission system (definition from NC OS);

Observability Area means the area of the relevant parts of the transmission systems, relevant DSOs and neighboring TSOs, on which TSO shall implement a real-time monitoring and modeling to ensure reliability of the respective Responsibility Area (definition 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 reference value and stability limits (definition from NC OS);

Operational Security Limits means the acceptable operating boundaries: thermal, voltage, Fault levels, frequency and stability limits (definition from NC OS);

Outage Incompatibility means the state in which a combination of two or more Relevant Grid Element, Relevant Power Generating Modules, Relevant Demand Facility and/or Third Party Owned Tie-Line outages leads to the impossibility to maintain Operational Security without Load Shedding under the best estimate of the forecasted electricity grid situation (definition from NC OPS);

Outage Planning Agent means a legal entity which has the task of planning Availabilities of Relevant Power Generating Modules, Demand Facilities or interconnectors (definition from NC OPS);

Outage Planning Region means a combination of Responsibility Areas in which processes are defined to coordinate outage planning on all planning timescales (definition from NC OPS);

Power Generating Facility means a facility to convert primary energy to electrical energy which consists of one or more Power Generating Modules connected to a Network at one or more Connection Points (definition from NC RfG);

Power Generating Module means either a Synchronous Power Generating Module or a Power Park Module (definition from NC RfG);

Power Generating Facility Operator means the natural or legal person which is the operator a Power Generating Facility (definition from NC OPS);

Power Park Module means a unit or ensemble of units generating electricity, which is connected to the Network non-synchronously or through power electronics, and has a single Connection Point to a Transmission, Distribution or closed distribution Network (definition from NC RfG);

Redispatch means the measures taken by System Operator Employee to alter the generation or demand pattern in order to change physical flows in the grid and relieve congestion (definition from NC OS);

Regional Security Coordination Initiative (RSCI) means regional unified scheme set up by TSOs in order to coordinate Operational Security analysis on a determined geographic area (definition from NC OPS);

Relevant Demand Facility means a Demand Facility which participates to the coordinated outage planning process (definition from NC OPS);

Relevant Grid Element means a Grid Element which participates to the coordinated outage planning process (definition from NC OPS);

Relevant Power Generating Module means a Power Generating Module which participates to the coordinated outage planning process (definition from NC OPS);;

Relevant Third-party Owned Tie-line means a Third-party Owned Tie-Line which participates to the coordinated outage planning process (definition from NC OPS);

Remedial Action means the measure activated by the TSO manually or automatically to relieve consequences of disturbances and maintain Normal State or move towards Normal State, which can be applied pre-fault or post-fault and may involve costs (definition from NC OS);

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

Responsibility Area means a coherent part of the interconnected system operated by a single TSO with physical loads and generation units connected within the area (definition from NC OS);

Restitution Time means the time required to restore service in a Grid Element which is currently under planned outage (definition from NC OPS);

Schedule means a reference set of values representing the generation, consumption or exchange of electricity between actors for a given time period expressed as a time series with a time interval and resolution (definition from NC OPS);

Scheduling Agent means an entity in charge to provide Schedules in accordance with the applicable national legal framework (definition from NC OPS);

Significant Grid Users means the pre-existing Grid Users and new Grid Users which are deemed significant on the basis of their impact on the cross border system performances via influence on the Control Area's security of supply including provision of ancillary services (definition 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 which might contain faulty and inaccurate values or where some measurement values are missing (definition from NC OS);

Synchronous Area means an area covered by interconnected TSOs with the common system frequency in a steady operational state (definition from NC OS);

Synchronous Power Generating Module means an indivisible set of installations which can generate electrical energy. It is either a:

- a single synchronous unit generating power within a Power Generating Facility directly connected to a transmission, distribution or closed distribution Network, or
- an ensemble of synchronous units generating power within a Power Generating Facility directly connected to a transmission, distribution or closed distribution Network with a common Connection Point, or
- an ensemble of synchronous units generating power within a Power Generating Facility directly connected to a transmission, distribution or closed distribution Network that cannot be operated independently from each other (e. g. units generating in a combined-cycle gas turbine facility), or
- a single synchronous storage device operating in electricity generation mode directly connected to a transmission, distribution or closed distribution Network, or
- an ensemble of synchronous storage devices operating in electricity generation mode directly connected to a transmission, distribution or closed distribution Network with a common Connection Point. (definition from NC RfG);

System State means the operational state of the Transmission System in relation to the Operational Security Limits (definition from NC OS);

Third-party Owned Tie-Line means an Interconnection whose owner is not a TSO (definition from NC OPS);

Transmission means the transport of electricity on the extra high or high voltage interconnected system with a view to its delivery to final customers or to distributors, but does not include supply (definition from Directive 2009/72/EC);

Transmission Circuit means the system of three-phase alternating current conductors with, where relevant, accompanying earth wire and other AC transmission hardware, or a direct-current conductor(s) with accompanying DC transmission hardware (definition from NC OS);

Transmission Line means the system of structures, wires, insulators and associated hardware that carry electric energy from one point to another in an electric power system. Transmission Lines are operated at voltages varying from 50 kV up to 765 kV. One Transmission Line can have one or more Transmission Circuits (definition from NC OS);

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. This extent of this Network is defined at a national level (definition 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 (definition 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 (definition from Directive 2009/72/EC);

Voltage Control means the balancing of the reactive power needs of the network and the Grid Users in order to maintain permitted voltage profile (definition from NC OS);

Voltage Stability means the ability of a Transmission System to maintain acceptable voltages at all buses in the system under N-Situation and after being subjected to a disturbance in (N-1)-Situation (definition from NC OS);

Week-Ahead means the week before the calendar week of operation (definition from NC OPS);

Year-Ahead means the year before the calendar year of operation (definition from NC OPS).