ENTSO-E Draft Network Code for Operational Planning and Scheduling

18 July 2012

Notice
This document contains a draft Network Code for Operational Planning and Scheduling, prepared by the Drafting Team of the Operational Planning and Scheduling Network Code as of 18 July 2012, in line with the ACER Framework Guidelines on System Operation published on 2 December 2011. It is intended for the discussion at the second public Workshop with DSOs' technical experts and all other stakeholders, taking place on 25 July 2012. **The document does not in any case represent a firm, binding or definitive ENTSO-E position on the contents, the structure, or the prerogatives of the Network Code for Operational Planning and Scheduling. Such position will be released for public consultation following the procedure according to the provisions of the 3rd Legislative Package.**

PURPOSE AND OBJECTIVES

THE EUROPEAN COMMISSION,

Having regard to the Treaty on the Functioning of the European Union,

Having regard to Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC;

Having regard to Regulation (EC) 714/2009 of the European parliament and of the Council of 13 July 2009 and in particular Article 6;

Having regard to the priority list issued by the European Commission on 22 December 2010;

Having regard to the Framework Guidelines on Electricity System Operation issued by ACER on 2. December 2011;

Whereas:

(1) Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC and Regulation (EC) N° 714/2009 of the European parliament and of the Council of 13 July 2009 underline the need for an increased cooperation and coordination among Transmission System Operators within a European Network of Transmission System Operators for Electricity (ENTSO-E) to create Network Codes for providing and managing effective and transparent access to the Transmission Systems across borders, and to ensure coordinated and sufficiently forward-looking planning and sound technical evolution of the Transmission System in the European Union, including the creation of Interconnection capacities, with due regard to the environment;

(2) Directive 2009/72/EC stresses that a secure supply of electricity is of vital importance for the development of European society, the implementation of a sustainable climate change policy, and the fostering of competitiveness within the internal market;

(3) Transmission System Operators (TSOs) are according to Article 12 of Directive 2009/72/EC responsible for providing and operating high and extra-high voltage networks for long-distance transmission of electricity. Besides this transmission and supply task it is also the TSOs' responsibility to ensure the Operational Security of their Control Areas and together in the whole Synchronous Areas and the European Union, with a high level of reliability and quality;

(4) Secure Transmission System operation can be made possible only if there is an obligation for the TSOs, Distribution System Operators (DSOs), Power Generating Facility Operators and Demand Facilities to cooperate and to meet the relevant minimum technical requirements for the operation of the interconnected Transmission Systems as one entity;

(5) To ensure the Operational Security of the interconnected Transmission Systems and to provide a common Security Level it is essential that a common set of minimum requirements regarding the processes necessary to prepare real time operation is defined to meet European Union-wide Operational Security principles as required in the Network Code for Operational security in the Chapter 2, for both the cross-border cooperation between the TSOs and for taking into account where relevant characteristics of the connected generation, consumption and distribution systems;

(6) Transmission System Operators should respect common requirements for the processes within the different time frames necessary to anticipate real time operation conditions of the interconnected Transmission Systems in order 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 times frames and related processes are the basis for the key elements, structure and provisions of this Network Code;

(7) Each Transmission System Operator should implement processes to build scenarios representatives of coming operation environment, within each time frame, based on information inputs between Transmission System Operators and where necessary with Distribution System Operators and Grid Users, taking into account uncertainties on demand, classical generation; renewable exchanges patterns;

(8) Each Transmission System Operator should implement process to build, within each time frame, common Grid models fitting with these scenarios, covering zones allowing coordinated security analysis as congestion and power flow management, including where relevant characteristics of the connected generation, consumption and distribution as transmission equipments and taking into account planned outages;

(9) Each transmission System Operator should implement process to carry out, within each time frames, on these common grid models, contingency analysis, using simulation tools allowing to assess the state of the system for contingencies as defined by Operational Security network code and to set up required preventive and/or remedial actions;

(10) Each transmission system operator should implement process to elaborate and update, within each time frame, a coordinated outages plan allowing Transmission system operators, distributions system operators and grid users to perform and optimise their maintenance works without jeopardizing the Operational security of the transmission system and altering the functioning of the electricity market;

(11) Each transmission system operator should implement processes within each time frame to elaborate a coordinated assessment that the generation capacities will allow to balance the demand as to have the required amount of ancillary services, taking into account planned outages, uncertainties on demand, classical generation and renewables, as the possibilities of cross border exchanges within available transmission capacities;

(12) On shortest time scales, starting the day before Transmission Systems Operators should implement process allowing the acquisition and coherency verification of cross border scheduled energies exchanges;

(13) The operational and scheduling processes required to anticipate real time Operational Security difficulties and develop relevant preventive and /or curative measures involve timely and adequate data exchange which should therefore not encounter any barrier between the different actors involved;

HAS ADOPTED THIS NETWORK CODE:

Chapter 1

GENERAL PROVISIONS

Article 1

SUBJECT MATTER AND SCOPE

1. This Network Code defines the minimum Operational Planning and Scheduling requirements for ensuring coherent and coordinated preparation of real-time operation of Transmission Systems applicable to all TSOs, Relevant DSOs, Power Generating Facility Operators and Demand Facilities of significance for the Transmission System. in order to achieve and maintain a satisfactory level of Operational Security of the interconnected Transmission Systems and to support the efficient functioning of the European Internal Electricity Market.

2. This Network code aims at:
   a) Determining common time frames, methodologies and principles allowing to carry out coordinated Operational Security and Adequacy analysis in preparation of real time operation to maintain Operational Security and support the efficient functioning of the European Internal Electricity Market;
   b) Determining conditions to plan outages allowing works required by Power Generating Facility operators, Distribution System operators, by Demand Facilities of significance for the Transmission System and Transmission System Operators.

3. In the small Isolated Systems for which a derogation has been granted in application of Article 44 of Directive 2009/72/EC, in the absence of Transmission System, the provisions of this Network Code shall not apply.

4. In the Spanish Isolated Systems (SEIE), the references to market rules in this Network Code shall not apply and shall be replaced by references to SEIE rules.

Article 2

DEFINITIONS

The following definitions shall apply:

The definitions contained in Article 2 of Directive 2009/72/EC and in Article 2 of Regulation (EC) N°714/2009.

(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;

Active Power Reserves – means the operational reserves available for maintaining the planned power exchange and for guaranteeing secure operation of the Transmission System;

Adequacy - Ability of generation connected to an area to meet the load of this area;

Ancillary Services –means the services identified as necessary by a TSO to effect a secure transfer of electricity between purchasing and selling entities;

Availability – 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;

Balance Control Area – the smallest geographic area for which the imbalance on the border of the area, between the sum of physical flows and of scheduled flows, is continuously monitored and controlled;

Bidding Zone –the largest geographical area within which Market Participants are able to exchange energy without Capacity Allocation;

Capacity Allocation – the attribution of Cross Zonal Capacity;

Capacity Calculation Process – a process in which the capability of the 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 capacity made available to Market Participants;

Close to Real-Time – Time interval before real-time within the System State can be considered as stable excepted in case of unforeseen events. This time interval is usually around 15 minutes;

Commissioning – 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;

Common Grid Model (CGM) – European-wide or multiple-TSOs-wide data set created by the TSOs and coordinated within the ENTSO-E created through merging of relevant data;

Congestion – a situation in which a Transmission System element cannot accommodate all physical flows resulting from international trade requested by Market Participants, because of a lack of capacity of the Interconnections and/or the national Transmission Systems concerned, without endangering Operational Security Limits;

Connection Point – the interface at which the Demand Facility or Power Generating Facility is connected to a Transmission or Distribution Network, or at which the Distribution Network is connected to a Transmission Network according to Article 28 of Directive 2009/72/EC and as identified in the connection agreement;

Constraint – a situation, either described in a Common Grid Model, or occurring in real time, where Operational Security Limits are not respected;

Contingency – is 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(s) of Neighbouring TSO(s), having effects in the Control Area of the TSO;

Contingency List – 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;

Countertrading – a Cross Zonal exchange initiated by Transmission or Distribution System Operators between two Bidding Zones to relieve a Congestion;

Control Area – a part of the interconnected Transmission System controlled by a single TSO;

Cross-Border – For the purpose of this Network Code, Cross-Border when used as an adjective means "beyond the limits of a single Control Area";

Cross Zonal Capacity – The capability of the interconnected electricity transmission network to accommodate energy transfer between Bidding Zones. It takes into account Operational Security Limits;

Day-Ahead – The day before the calendar day of operation;

Demand Facility – 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 Facility are not a Demand Facility;

Demand Facility Operator – the natural or legal person which is the operator of a Demand Facility;

Distribution Network – the electrical network for the distribution of electrical power from and to third parties connected to it, a Transmission or another Distribution Network;

Distribution System Operator (DSO) – the natural person or legal person responsible for operating, ensuring the maintenance of and developing the distribution system in its Responsibility Area and its interconnections with other systems and for ensuring the long-term ability of the system to meet reasonable demands for distribution of electricity;

Fault – the event occurring on the primary equipment in a Transmission System or in a Distribution Network such as all kinds of short circuits: single-, double- and triple-phase, with and without earth contact. It means further a broken conductor, open circuit, or an intermittent connection, resulting in a permanent non-availability of the affected Transmission System or Distribution Network element;

Forced Outage – 1. The removal from service Availability of a Power Generating Module, Transmission Line, or other facility for emergency reasons. 2. The condition in which the equipment is unavailable due to unanticipated failure;

Grid element – Element of the Transmission System;

Grid User – means the natural or legal person supplying to, or being supplied with active and/or reactive power by a TSO or DSO;

Individual Grid Model – 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;

Intraday – The period of time within the day of operation before the momentary operational situation;

Isolated System – A System which is designed to operate as a stand-alone system for a definite or indefinite time. It includes systems that bear DC or a single AC Interconnection to other synchronous areas;

Interconnection – a transmission link (AC or DC line, circuit or transformer) which connects two Control Areas or Market Balance Areas;

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

Market Balance Area – the smallest geographical area between the Bidding Zone and the Balance Control Area. Market Balance Area is the smallest area on which a scheduled Net Position is known;

Market Participant – an entity taking part in the electricity market. In Operational Planning and Scheduling Network Code, TSOs and PXs and their designated entity(ies) are considered as Market Participant;

N-Situation – the situation in the Transmission System where no element of the Transmission System is made unavailable due to a Fault;

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

Neighbouring TSOs – 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;

Netted Area AC-Position – The netted aggregation of all AC-External Schedules of an area;

Netted Area Global Position – The netted aggregation of all External Schedules of an area;

Normal State – the operational state in which there is a low risk for Operational Security of Transmission System;

Observability Area – An area of the relevant parts of the Transmission System, relevant DSOs and Neighbouring TSOs, on which TSO shall implement a real-time monitoring and modelling to ensure reliability of the respective Responsibility Area;

Operational Security – of Transmission System means the measure of the Transmission System capability to retain Normal State or to return to Normal State as soon and close as possible; it is characterized by the thermal limits, voltage constraints, short-circuit current, frequency reference value and stability limits; the concepts and meaning of the Term;

Operational Security Limits – the acceptable operating boundaries: thermal, voltage, frequency, Fault levels and stability limits;

Outage Incompatibility – the state in which a combination of two or more Grid Element, Power Generating Modules, 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;

Outage Planning Region – a combination of Responsibility Areas in which processes are defined to coordinate outage planning on all planning timescales;

Power Generating Facility – a facility to convert primary energy to electrical energy which consists of one or more Power Generating Modules connected to a Transmission or Distribution Network at one or more Connection Points;

Power Generating Module – is either a Synchronous Power Generating Module or a Power Park Module;

Power Generating Facility Operator – the natural or legal person which is the operator a Power Generating Facility;

Power Park Module – is 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;

Redispatch – means the measure taken by Transmission or Distribution System Operators by altering the generation pattern in order to change physical flows in the grid and relieve Congestion;

Regional Security Coordination Initiative (RSCI) – Regional unified scheme set up by TSOs in order to coordinate Operational Security analysis on a determined geographic area;

Relevant Demand Facility – a Demand Facility which participates to the coordinated outage planning process;

Relevant Grid Element – a Grid Element which participates to the coordinated outage planning process;

Relevant Power Generating Module – a Power Generating Module which participates to the coordinated outage planning process;

Relevant Third-party Owned Tie-line – a Third-party Owned Tie-Line which participates to the coordinated outage planning process;

Remedial Action – 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;

Responsibility Area – a coherent part of the interconnected system operated by a single TSO with physical loads and generation units connected within the area;

Restitution Time – the time required to restore service in a Grid Element which is currently under planned outage;

Schedule – a reference set of values of energy or power expressed as a time serie with a time interval or resolution within a future time period or horizon. Schedules refer to:

a) An Internal Commercial Trade Schedule: Commercial exchange between different Market Participants in a Market Balance Area;

b) An External Commercial Trade Schedule: Commercial exchange between Market Participants in different Market Balance Areas;

c) A Generation Schedule: the Schedule of a particular Power Generating Module or the aggregation of Schedules of a group of Power Generating Modules;

d) A Consumption Schedule: the Schedule of a particular Demand Facility or the aggregation of Schedules of a group of Demand Facilities;

e) An External Schedule: planned exchange of energy between Market Balance Areas;

f) Aggregated Netted External Schedules: netted aggregation of all External Schedules between Market Balance Areas;

Scheduling Agent – an entity in charge according to local market rules to provide Schedules;

Significant Grid Users – the Grid User that is able to influence transmission flow patterns beyond the thresholds defined by its TSO as a consequence of the events or actions taken in relation with the equipment under its own responsibilities;

State Estimation – 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;

Synchronous Area - an area covered by interconnected TSOs with the common system frequency in a steady operational state;

Synchronous Power Generating Module – is 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

b) 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

c) 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

d) a single synchronous storage device operating in electricity generation mode directly connected to a transmission, distribution or closed distribution network; or

e) 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;

System State – the operational state of the Transmission System in relation to the Operational Security Limits;

Third-party Owned Tie-Line – An Interconnection whose owner is not a TSO;

Transmission – 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;

Transmission Circuit – the system of three-phase alternating current conductors with, where relevant, accompanying earth wire and other hardware of the AC transmission or a direct-current conductor with accompanying hardware of the DC transmission;

Transmission Line – a 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;

Transmission Network – the electrical network for the transmission of electric power from and to third party(s) connected to it, including Demand Facilities, Distribution Networks or other Transmission Networks;

Transmission System – the electric power network used to transmit electric power over long distances within and between the Control Areas. Transmission systems are usually operated at the 220 kV and above for AC or HVDC, but may also include lower voltages;

Transmission System Operator (TSO) – 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;

Voltage Control – the balancing of the reactive power needs of the network and the Grid Users in order to maintain permitted voltage profile;

Voltage Stability of the Transmission System – 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;

Week-Ahead – The week before the calendar week of operation;

Year-Ahead – The year before the calendar year of operation.

Article 3

REGULATORY ASPECTS

1. The requirements established in this Network Code and their applications are based on the principle of non-discrimination and transparency as well as the principle of optimisation between the highest overall efficiency and lowest total cost for all involved parties.

2. Notwithstanding the above, the application of non-discrimination principle and the principle of optimization between the highest overall efficiency and lowest total costs while maintaining Operational Security as the highest priority for all involved parties, shall be balanced with the aim of achieving the maximum transparency in issues of interest for the market and the assignment to the real originator of the costs.

3. Where reference is made to this paragraph, any decision by a Relevant DSO and/or a Relevant TSO or any agreement between, on the one hand, a Relevant Network Operator or a Relevant TSO and, on the other, a Power Generating Facility Operator,

DSO or TSO shall be performed under the conditions of the applicable national legal framework and in accordance with the principles of transparency in issues of interest for the market, proportionality and non-discrimination and, as the case may be, with the involvement of the National Regulatory Authority.

Article 4

RECOVERY OF COSTS

1. The costs related to the obligations referred to in this Network Code which have to be borne by regulated Transmission System Operators shall be assessed by National Regulatory Authorities.

2. Costs assessed as reasonable and proportionate shall be recovered in a timely manner via network tariffs or appropriate mechanisms as determined by National Regulatory Authorities.

3. If requested to do so by National Regulatory Authorities, regulated Transmission System Operators shall, within three months of such a request, use best endeavours to provide such additional information as reasonably requested by National Regulatory Authorities to facilitate the assessment of the costs incurred.

Article 5

CONFIDENTIALITY OBLIGATIONS

1. Each TSO, DSO, Power Generating Facility Operator or Demand Facility Operator shall preserve the confidentiality of the information and data submitted to them in connection with this Network Code and shall use them exclusively for the purpose they have been submitted in compliance with the Network Code.

2. Without prejudice to the obligation to preserve the confidentiality of commercially sensitive information obtained in the course of carrying out its activities, each TSO shall provide to the operator of any other system with which its system is interconnected, sufficient information to ensure the secure and efficient operation, coordinated development and interoperability of the interconnected system.

3. The Regional Security Coordination Initiatives which are taking the form of a legal entity shall preserve the confidentiality of the information and data submitted to them in connection with this Network Code and shall use them exclusively for the purpose they have been submitted, in compliance with this Network Code.

Article 6

RELATIONSHIP WITH NATIONAL LAW PROVISIONS

1. This Network Code shall be without prejudice to the rights of Member States to maintain or introduce measures that contain more detailed or more stringent provisions than those set out herein, provided that these measures are compatible with the principles set forth in this Network Code.

Chapter 2

DATA FOR OPERATIONAL SECURITY ANALYSIS IN OPERATIONAL PLANNING

Article 7

GENERAL PROVISIONS

1. Each and all TSOs shall carry out the processes required to support the following functions for each relevant timeframe:
   a) All TSOs in a coordinated way define, as applicable, appropriate Pan-European or Regional scenarios, as described in Article 8.1 and Article 8.2;
   b) Each TSO performs the collection and delivery of data in accordance with the defined scenarios, as described in Article 8.2 and Article 8.4, or in accordance with the regionally agreed scenarios, as described in Article 9 and Article 10;
   c) All TSOs define a Pan-European procedure for merging the datasets and assuring quality of the so constructed Common Grid Models, as described in Article 8.4 and Article 8.5, which, together with the information related to outages of Relevant Power Generating Modules, Demand Facilities, Third-party Owned Tie-Lines and Grid Elements is gathered in the common TSO platform for operational planning defined in Chapter 8, ensuring Year-ahead and updated input data for Operational Security analysis.

Article 8

YEAR-AHEAD SCENARIOS AND COMMON GRID MODEL

Article 8.1

DEFINITION OF YEAR-AHEAD SCENARIOS

1. All TSOs together shall define by July 15th of every year one list of common scenarios covering the most representative Year Ahead conditions of the European Transmission System. These scenarios should cover, not being limited to, the next parameters, in such a way to ensure that the impact of the different sources of uncertainty are clearly identified and parameterized:
   a) Load;
   b) Conditions in relation with renewable energies contribution;
   c) Defined import/export positions (including agreed reference values allowing the merging task);
   d) Standard generation pattern given a fully available production park.

2. These scenarios shall be defined taking into account their probability of occurrence and historical experience by the TSOs in order to detect possible deviations from Operational Security Limits.

3. The last version of the list of common scenarios shall be made publicly available.

Article 8.2

CONSTRUCTION OF YEAR-AHEAD INDIVIDUAL GRID MODELS

1. Each TSO shall construct and provide in line with Article 8.4.1 its respective Individual Grid Model in the agreed format and time and obeying the scenarios defined in Article 8.1, enabling the coherent merge of its Individual Grid Model into the Common Grid Model.

2. When constructing Individual Grid Models, each TSO shall comply with the following requirements:
   a) The net exchanges on AC shall be agreed among the relevant TSOs;
   b) The estimated power flow on DC interconnections shall be agreed upon by the relevant TSOs;
   c) For each scenario, the following sum shall be balanced: net exchanges, estimated power flows on DC Interconnections, load (including losses estimation) and generation.

Article 8.3

CONSIDERATION OF DISPERSED GENERATION AND CONSUMPTION IN YEAR-AHEAD SCENARIOS

1. Each TSO shall take into account in the scenarios the power generated and consumed by the Power Generating Facilities and Demand Facilities connected to DSOs within their Responsibility Areas.

2. Each TSO shall in line with Article 3.3 define in relation with DSOs if applicable, the methodology used to assess the aggregated power outputs of the Dispersed Power Generating and Demand Facilities connected to DSOs within its Responsibility Area in the Individual Grid Model.

3. For Dispersed Power Generating Facilities connected to DSOs, the aggregated active power output shall comply at least with the following requirements:
   a) It shall be consistent with the scenarios defined in Article 8.1;
   b) Aggregated power outputs shall be differentiated according to the type of primary energy source (i.e. PV, wind, hydro,…).

Article 8.4

YEAR-AHEAD COMMON GRID MODELS AND OUTAGES INFORMATION

1. All TSOs shall decide, no later than 6 months after the entry into force of this Network Code, on the provisions dealing with the gathering, merging and saving of the Individual Grid Models, including the possibility of subcontracting an entity that will perform the tasks of gathering and merging. These provisions shall cover the following elements:
   a) Data Format;
   b) Deadlines;
   c) Quality control of datasets;
   d) Tasks to be performed at Pan-European level;
   e) Specifications of the common TSO platform for operational planning as described in Chapter 8.

2. Each TSO shall deliver to the Neighbouring TSOs on their request further detailed information containing the topology modifications or operational arrangements issued as a consequence of an outage, in such a way that an accurate representation of the system is provided for performing complete Operational Security analysis.

Article 8.5

UPDATES OF YEAR-AHEAD COMMON GRID MODELS

1. Taking into account changes in TSOs’ best estimations, TSOs shall update – as necessary – Individual Grid Models in accordance with the newly identified conditions.

Article 9

WEEK-AHEAD GRID MODELS

1. At least on the level of Outage Planning Regions, each and all TSOs shall define the most representative scenarios for analysing the Operational Security of the Transmission System for the Week-Ahead timeframe.

2. Each TSO shall provide information to the TSOs in its Outage Planning Region in order to allow these TSOs to update their Individual Grid Model in accordance with the scenarios defined in this article.

Article 10

DAY-AHEAD AND INTRADAY GRID MODELS

1. All TSOs shall decide, no later than 6 months after the entry into force of this Network Code, on the provisions dealing with the gathering and merging of the Individual Grid Models representing the system, at least at Synchronous Area level, including the possibility of subcontracting an entity that will perform the tasks of gathering and merging. These provisions shall cover the following elements:
   a) Data Format;
   b) Time granularity;
   c) Deadlines compatible with setting up Remedial Actions and Capacity Calculation,
   d) Quality control of datasets;
   e) Tasks to be performed at the regional, Synchronous Area and Pan-European level including time schedules for the different tasks in all timeframes;
   f) Specifications of the common TSO platform for operational planning as described in Chapter 8.

2. Each TSO shall create and deliver Individual Grid Models in accordance with Article 10.1, as an input for the Day-Ahead and Intraday Operational Security analysis. As a result, at least Day-ahead grid models shall be available, including next information:
   a) The Schedules received from Scheduling Agents according to Article 31.1 and Article 31.2;
   b) Updated information on demand and renewable generation – if applicable – in line with Article 3.3;
   c) Expected grid topology;
   d) Internal Remedial Actions taken for congestion management.

3. Each TSO shall check the accuracy of its Individual Grid Models as necessary and adapt the process for creating Individual Grid Models by comparing its results with State Estimation results and real-time measurements. The Individual Grid Model shall for this purpose be upgraded with the events that occurred between the time of creating the Individual Grid Model and the time of the State Estimation. The comparison shall assess the discrepancies regarding voltages, active and reactive power flows.

Chapter 3

OPERATIONAL SECURITY ANALYSIS IN OPERATIONAL PLANNING

Article 11

GENERAL PROVISIONS FOR OPERATIONAL SECURITY ANALYSIS IN OPERATIONAL PLANNING

1. Each TSO shall perform coordinated Operational Security analysis at least at the following timeframes, in order to assess the Operational Security in line with the Operational Security Network Code:
   a) Year-Ahead and updates;
   b) Week-Ahead;
   c) Day Ahead;
   d) Intraday.

2. Operational Security analyses shall be performed at the timeframes specified in Article 11.1 in N-situation, simulating each Contingency from the TSO's Contingency List as referred in Operational Security Network Code, thus checking that the Operational Security Limits as defined in Operational Security Network Code in the (N-1) Situation are fulfilled.

3. Each TSO shall coordinate its Operational Security analyses in accordance with the requirements set forth in Operational Security Network Code, regarding Voltage Control and Reactive Power Management, Short Circuit Current Management and Congestion and Power Flow Management, and in line with Article 14 of this NC, in order to verify the respect of the Operational Security Limits affecting the own and the Responsibility Areas of other TSOs.

4. Each TSO shall use Common Grid Models described in Article 8.4 and Article 8.5 (Year-Ahead and updates), Article 9 (Week-Ahead) and Article 10 (Day-Ahead) to perform Operational Security analyses referred to in Article 11.1 and Article 11.2.

5. Each TSO shall assess as necessary bilateral or regional coordination of actions in line with the requirements on short-circuits current and dynamic stability management of Operational Security NC, regarding:
   a) Short-circuit current;
   b) Dynamic stability.

Article 11.2

CROSS BORDER REMEDIAL ACTIONS

1. Each TSO shall prepare and check cross border Remedial Actions in a coordinated way with affected TSOs to be implemented in due time to cope with Contingencies detected in the different Timeframes in which Operational Security analysis are performed. Principles for categorisation of and applicable methodology governing Remedial Actions shall be approved by NRAs.

2. When setting up these cross border Remedial Actions, TSOs shall check, not limited to:
   a) The technical-economical efficiency of the Remedial Action;
   b) That the Remedial Action does not jeopardise the Operational Security of the Transmission System in which the Remedial Action is executed;
   c) The agreement of the TSO that executes the Remedial Action;
   d) The Remedial Action is in line with the methodological principles and categorisations approved by NRAs.

3. Each TSO shall report on the Remedial Actions in accordance with the Regulation on Transparency on Fundamental Electricity Data.

4. Costs of Remedial Actions shall be recovered in accordance with the principles approved by NRAs and in compliance with EC Regulation 714/2009, Art. 16(6).

Article 12

PROVISIONS FOR YEAR-AHEAD AND UPDATED OPERATIONAL SECURITY ANALYSIS

1. Each TSO shall perform Operational Security analysis on its Observability Area as defined in Operational Security Network Code, taking as an input the updates of the Common Grid Model and relevant information (outages of relevant elements) described in Article 8.4 and Article 9, in order to detect possible Constraints and agree upon Remedial Actions with the impacted neighbouring TSOs.

2. The Operational Security analysis referred to in the previous paragraph, performed in accordance with coordination methodology described in Article 14.3, shall ensure to detect at least the following network constraints:
   a) Power flows over Operational Security Limits;
   b) Breach of Voltage Stability of the Transmission System;
   c) That the impact of short circuit events remains at a level that provides correct functioning of transmission facilities and protection.

3. Each TSO shall prepare Remedial Actions in a coordinated way with affected TSOs to be implemented in due time to cope with any Cross-Border Contingency detected in Year-Ahead Operational Security analysis in line with Article 12 of this Network Code. The efficiency of a Remedial Action shall be checked by load-flow calculations.

Article 13

PROVISIONS FOR DAY-AHEAD, INTRADAY AND CLOSE TO REAL-TIME OPERATIONAL SECURITY ANALYSIS

1. On a Day-Ahead basis and within the intraday periods, each TSO shall perform Operational Security analysis on its Responsibility Area, taking into account all the elements contained in its Contingency List as defined in Operational Security Network Code, in order to detect possible Constraints and agree upon Remedial Actions with the impacted Neighbouring TSOs.

2. For these analyses and in order to finally assess Operational Security, the TSO shall consider updates of generation or load patterns, the results of the Day-Ahead and Intraday market processes as well as the results of the Scheduling tasks described in Chapter 7 of this Network Code.

3. In order to perform Operational Security analysis established in the previous paragraph, TSOs shall use the Day-Ahead forecast of renewable and distributed generation in line with Article 3.3, and update Intraday in line with Article 3.3 this forecast with real time measurements received as established in Operational Security Network Code. This information shall be published in accordance with Transparency Rules.

4. On the Day-ahead and intraday, each TSO shall evaluate in a coordinated way, in line with provisions in Article 14, the effectiveness of the Remedial Actions in line with provisions defined in Article 12.7 of Operational Security Network Code.

5. Close to real-time, each TSO shall perform Operational Security analysis from using State Estimation. This analysis shall be performed on a time cycle basis not exceeding 15 minutes and shall be executed on request in case of changes significantly affecting voltages or power flows.

Article 14

COORDINATION, INCLUDING PREVENTION AND REMEDIAL ACTIONS

1. Each TSO as individual company is responsible for Operational Security analysis, no matter what cooperation rules they commit to.

2. At least at synchronous level, TSOs shall at least on a yearly basis, analyse the mutual impact between the interconnected Control Areas in terms of flows and voltage.

3. 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 in operational planning.

4. As a result of the coordinated analysis described in Article 14.3, TSOs shall propose to ACER, if necessary, adaptations of the methodology described in the previous paragraph.

5. As a result of the analysis described in Article 14.3, TSOs shall establish if necessary bilateral or regional agreements, covering, but not limited to, next points:
   a) Possible required additional scenarios and datasets to the ones described in Article 8;
   b) Processes for the evaluation of deviations from Operational Security Limits, in accordance with the methodology referred to in Article 14.3 and Article 14.4;
   c) Agreements on the following appropriate preventative and curative measures, not limited to:
      i. Defining coordinated Remedial Actions (eg. adapting topology, phase-shifter transformers), in line with Article 11.2;
      ii. Processes for the applicability of the Remedial Actions;
      iii. Adopting dedicated solutions concerning planned outages;
      iv. Utilizing Redispatch or Countertrade in order to prevent violations of the Operational Limits between the Responsibility Areas, in line with Article 11.2.

6. TSOs shall, at least at regional level, commonly evaluate the consequences and probability of occurrence of the forecast situation, sharing the Operational Security Limits applied in their area.

7. TSOs shall agree on appropriate curative or preventive measures, not limited to:
   a) Preparing coordinated Remedial Actions: adapting topology, phase shifting transformers, etc;
   b) Adopting dedicated solutions concerning planned outages;
   c) Utilizing Redispatch or Countertrade in order to prevent Constraints between their Responsibility Area.

8. When, as a result of Security Analysis, a Contingency is detected whose consequences affect other TSO(s), the detecting TSO shall share the information with the relevant TSO(s).

9. Led by the high level of interdependency of certain areas in the European Transmission System, TSOs may decide to coordinate Operational Security analysis in a regional unified scheme termed as Regional Security Coordination Initiatives, and in such a case:
   a) TSOs shall sign specific multilateral agreements for the realization of joint regional security including the possibility to establish a single entity to perform all or part of the necessary functions requested for the regional Operational Security analysis;
   b) These multilateral agreements shall cover, but not limited to:
      i. The compatible or common tools and processes to deliver these functions;
      ii. The processes to set up common Remedial Actions;
      iii. Where applicable, the functions covered by single entities.

Chapter 4

REQUIREMENTS FOR OUTAGE PLANNING

Article 15

DETERMINATION OF OUTAGE PLANNING REGIONS

1. No later than 6 months after the entry into force of this regulation, all TSOs shall define the Outage Planning Regions within which coordinated outage planning shall be performed. The outage planning coordinating process, as described in this Network Code, enters into force at the same time.

2. The definition of the outage planning regions shall comply with the following:
   a) Each Control Area shall be attributed to at least one Outage Planning Region; and
   b) Each border between Control Areas shall be attributed to exactly one Outage Planning Region; and
   c) The definition of Outage Planning Regions shall be based on an assessment against the cross-border impact on Operational Security of a planned outage in a Control Area. Control Areas with a major mutual impact will preferentially be attributed to a common Outage Planning Region; and
   d) For each Outage Planning Region one coordinating TSO shall be appointed. This coordinating role can cycle between TSOs over the years; and
   e) A procedure for making changes to the defined Outage Planning Regions shall be included in the definition.

3. The preliminary definition of Outage Planning Regions shall be published by all TSOs one month in advance of the final publication date. All Power Generating Facility, Demand Facility, Third-party Owned Tie-Line Operators and DSOs shall have the opportunity to comment on this definition until two weeks before the final publication data. If deemed relevant, these comments will be taken into account in the final definition of Outage Planning Regions. The same procedure shall apply for making changes to the defined Outage Planning Regions, as required by Article 15.2.e).

4. The definition of the Outage Planning Regions, together with all other information required by Article 15.2 shall be published by the TSOs according to transparency guidelines.

Article 16

REQUIREMENTS FOR REGIONAL COORDINATION

1. The practical organisation of the coordination process for outage planning shall be managed by the coordinating TSO(s) for each Outage Planning Region according to the provisions agreed upon by all TSOs of the concerned Outage Planning Region.

2. Each TSO shall participate to the installed outage planning coordination process(es) for the Outage Planning Regions of which he is a member.

3. Regional Security Coordination Initiatives operating in a certain Outage Planning Region and/or TSOs operating Control Areas in another Outage Planning Region shall be invited to participate to the relevant coordination process at least for the phases in which these parties are involved.

4. Coordination meetings shall be held within the coordination process to allow coordination of outages, information sharing about past, current and future of the Transmission System, and validating outages plans relevant to the concerned time horizon.

5. Coordination meetings shall be organized at least on the following time frames:
   a) Year ahead;
   b) Week ahead.

   The modalities of these coordination meeting shall be defined in the coordination process, and can differ depending on the concerned timeframe.

6. If incompatibilities arise between outages planned in different Outage Planning Regions, coordination between the affected TSOs shall be initiated to relieve these incompatibilities.

7. Each TSO shall provide on a best effort basis all relevant information at its disposal to the relevant TSO's regarding grid-, Power Generating or Demand Facility-related projects that impact the operation of Neighbouring TSO's grids.

Article 17

LIST OF RELEVANT THIRD-PARTY OWNED TIE-LINES, POWER GENERATING MODULES AND DEMAND FACILITIES

1. No later than 3 months after the entry into force of this regulation, each TSO shall submit a proposal to the Relevant National Authority, according to the applicable national legislation, regarding:
   a) The Power Generating Modules, Demand Facilities and Third-Party Owned Tie-Lines which shall participate to the coordinated outage planning process as described in this Network Code;

b) The types of information to be submitted. This information shall include, but not be limited to:
   i. Information related to technical characteristics;
   ii. Information related to Availability.

This proposal shall respect the principles of transparency, proportionality and non-discrimination.

2. Each TSO shall consult the other TSOs in its Outage Planning Region on the necessity to include specific Power Generating Modules or Demand Facilities in the proposed list.

3. The proposed list will contain at least:
   a) All Power Generating Modules and Demand Facilities of which their availability status influences cross-border Operational Security beyond the thresholds defined by the concerned TSOs;
   b) All combinations of Power Generating Modules and Demand Facilities feeding into the electricity grid through a single grid element of which their aggregated availability status influences cross-border Operational Security beyond the thresholds defined by the concerned TSOs;
   c) All Third-Party Owned Tie-Lines.

4. If applicable, the Relevant National Authority shall approve or reject the proposal submitted by the TSO within 3 months of the date of receipt.

5. Following a decision by the Relevant National Authority, and according to local regulations regarding transparency and confidentiality, the following shall be published:
   a) A list of parties required to provide information; and
   b) A list of information to be provided.

6. Each TSO shall reassess the list of Relevant Third-Party Owned Tie-Lines, Power Generating Modules and Demand Facilities on a regular basis. In case significant changes occur in the installed units in its Control Area, the TSO shall consult all other TSOs of the relevant Outage Planning Region(s) on the need to adapt the list of relevant units.

7. In the event that a need to change the list of Relevant Third-Party Owned Tie-Lines, Power Generating Modules or Demand Facilities is identified, the relevant TSO will submit a request for change to the Relevant National Authority for approval. Within 2 months, the National Authority shall approve or reject the request. If approved, the resulting list will be published according to Article 17.5. Reasons for a reassessment include the commissioning of new Third-Party Owned Tie-Lines, Power Generating Modules or Demand Facilities.

Article 18

LIST OF RELEVANT GRID ELEMENTS WITH IMPACT ACROSS BORDERS

1. No later than 6 months after the entry into force of this regulation, for all Outage Planning Regions, a list of Relevant Grid Elements shall be set up for coordinated Outage Planning. This shall be achieved through a coordinated process involving all TSOs of the concerned Outage Planning Region.

2. The list of Relevant Grid Elements shall contain at least:
   a) All Grid Elements interconnecting Control Areas;
   b) All Grid Elements of which their planned outage brings about an impact across Control Area borders;
   c) All Grid Elements contained in the External Contingency List of at least one TSO;
   d) All Grid Elements which induces a limit upon the Cross-Border Capacities.

3. The types of information that are to be provided by each TSO are described together with the list of Relevant Grid Elements. This shall include, but not be limited to:
   a) Outage dates;
   b) Outage reason (maintenance, grid development, reparation or combined works);
   c) Specific conditions for execution of the outage;
   d) Restitution Time information.

4. The list of Relevant Grid Elements shall be published according to transparency guidelines and respecting all relevant confidentiality requirements.

5. Prior to the start of the year ahead planning process, each TSO shall examine the list of Relevant Grid Elements in order to identify the need to add or subtract Grid Elements from this list.

6. The coordinating TSO of each Outage Planning Region shall collect all change requests to the list of Relevant Grid Elements, and – if appropriate – organize a meeting between all relevant TSOs to update the list of Relevant Grid Elements.

Article 19

REQUIREMENTS FOR YEAR AHEAD OUTAGE PLANNING

1. A proposal of the Relevant Power Generating Module, Demand Facility and Third-Party Owned Tie-Line Availability (see Article 17 and Article 18) shall be submitted by its Operator or its delegate for the following year to the relevant TSO. This information shall be provided before August 1st.

2. Relevant Power Generating Modules or Demand Facilities and Third-Party Owned Tie-Lines that are considered to be in Commissioning the following year will be declared as such by their Operator or its delegate:
   a) An estimated Commissioning period will be provided to the relevant TSO;

b) Before this Commissioning period the respective asset will be declared as unavailable;
c) After this Commissioning period a proposal regarding Availability will be provided as per Article 19.1.

3. Each TSO shall assess if Operational Security can be fulfilled without Load-Shedding taking into account the Relevant Power Generating Modules, Demand Facilities and Third-Party Owned Tie-Line outage proposals. If Outage Incompatibilities arise, all affected parties shall coordinate with the goal of establishing a feasible alternative outage plan. If Operational Security cannot be guaranteed, the Relevant Third-Party Owned Tie-line, Power Generating Modules or Demand Facilities Operator or its delegate shall propose to the relevant TSO an alternative outage plan relieving the detected incompatibilities.

4. Grid elements interconnecting different Control Areas shall be planned in a coordinated manner within the defined Outage Planning Regions according to the principles:
   a) Planned outages shall be combined as much as possible, hereby minimizing market impact while maintaining Operational Security;
   b) TSOs shall take into account all received Relevant Power Generating Modules, Demand Facilities and Third-Party Owned Tie-Line outage proposals as per Article 19.1.

5. Each TSO shall plan outages of all remaining Relevant Grid Elements (cf. Article 18) taking into account Relevant Third-Party Owned Tie-Lines, Power Generating Modules and Demand Facilities outage proposals and outages of Control Area Interconnection Grid Elements. If Operational Security cannot be guaranteed due to the combination of grid and Relevant Power Generating Module/Demand Facility outages, the TSO can request a change of the Relevant Power Generating Module/Demand Facility outage proposal, and coordination with the concerned Relevant Power Generating Module/Demand Facility Operator or its delegate shall be initiated by the TSO.

6. Information about grid-related conditions and planned Pre-Fault Remedial Actions for executing specific planned Relevant Grid Element outages shall be included by the TSO in the grid outage plans published on the common TSO platform for operational planning.

7. If the TSO is not able to plan Relevant Grid Element outages within the reasonable delays and normal practices, which might lead to the inability to guarantee Operational Security, the TSO together with the Relevant Power Generating Facility Operators and Demand Facility Operators or their delegates shall find a solution to allow these critical grid outages to be planned. If no such solution can be found, the TSO will report being unable to plan these critical grid outages to the relevant NRA.

8. If an NRA is informed according to Article 19.7, he will ensure that a solution will be established between all affected parties, taking into account risk and impact assessed by these affected parties and avoiding to jeopardize Operational Security.

9. Each TSO shall publish Relevant Third-Party Owned Tie-Line, Power Generating Modules and Demand Facilities preliminary outage plans for the following year before November 1st to the Relevant Power Generating Facility and Demand Facility Operators, their delegates or Significant Grid Users – whichever is appropriate.

10. Each TSO shall provide its preliminary outage plans for all Relevant Grid Elements and its Relevant Power Generating Modules, Demand Facilities and Third-Party Owned Tie-Line outage plans for the following year to other TSOs before November 1st. This shall be achieved by means of the common TSO platform for operational planning. These plans shall contain at least the types of information listed in Article 18.3.

11. Each TSO shall analyse the compatibility of all preliminary outage plans impacting its Responsibility Area, coordinating and resolving issues should they arise with their Neighbouring TSOs. When all conflicts are resolved, a final coordination step is initiated per Outage Planning Region, where all member TSOs shall validate the year-ahead grid outage plans.

12. Before December 1st, outage plans for the following year will be finalized. Each TSO will publish the validated outage plans on the common TSO platform for operational planning which will serve as the reference up to real time. Every change to this plan that is requested by any party (barring the results of Forced Outages) can be subject to approval of all concerned parties according to the requirements set forth in Article 20.

13. Each TSO shall publish Relevant Third-Party Owned Tie-Line, Power Generating Modules and Demand Facilities final outage plans for the following year before November 1st to the Relevant Power Generating and Demand Facility Operators, their delegates or Significant Grid Users – whichever is appropriate.

Article 20

REQUIREMENTS FOR PLANNED UPDATES TO THE YEAR-AHEAD OUTAGE PLANNING

1. After the Year-Ahead outage planning process is finalized, and before real-time execution, all concerned parties can initiate an adaptation of the validated outage plan. Each TSO, Power Generating or Demand Facility Operator or Third-Party Owned Tie-Line operator – whichever is relevant – shall handle this request according to the requirements set forth in the remainder of this article.

2. Each Relevant Power Generating and Demand Facility Operator or its delegate wanting to initiate an adaptation of the validated outage plan shall send a change request to the relevant TSO. The following procedure shall be followed:
   a) The TSO shall assess the impact on Operational Security taking into account all previously validated Relevant Grid, Power Generating Module and Demand Facility outages;
   b) If Outage Incompatibilities are detected, a coordination step between all impacted parties shall be initiated;

c) If no feasible solution can be reached, the TSO can deny the requested change if Operational Security is at stake or if Article 19.7 applies. In this case, the TSO will motivate this decision towards all impacted parties;
d) If the change is approved by the TSO or if no other parties are impacted, it is incorporated in the validated outage plan and published to all relevant parties and on the common TSO platform for operational planning.

3. Each TSO wanting to initiate an adaptation of the validated outage plan shall follow the following procedure:
   a) The initiating TSO shall determine which parties are impacted through an analysis of Operational Security taking into account all previously validated Relevant Grid, Power Generating Module and Demand Facility outages;
   b) The TSO shall send a change request to all other TSOs of the Outage Planning Region(s) of which it is a member, combined with the results of the performed impact assessment;
   c) All other TSOs shall amend this impact assessment if deemed necessary;
   d) If Outage incompatibilities are identified, a coordination step between all affected parties will be initiated;
   e) If no feasible solution can be reached, the requested change can be denied unless Operational Security is at stake or Article 19.7 applies. In this case, the relevant party shall motivate this decision towards the requesting TSO;
   f) If the change is approved by all impacted parties or if no other parties are impacted, the change is incorporated in the validated outage plan and published to all relevant parties and on the common TSO platform.

4. For Relevant Power Generating Modules or Demand Facilities or Third-Party Owned Tie-Lines that are declared to be in Commissioning, the relevant Operator or its delegate shall provide the relevant TSO with a detailed availability and test plan as soon as it is available, and no later than two months before the start of the declared Commissioning period.

5. For Relevant Power Generating Modules or Demand Facilities or Third-Party Owned Tie-Lines that are declared to be in Commissioning and in case of an update of the availability and test plan, the relevant Operator shall provide this information, as soon as it is available, to the relevant TSO.

Article 21

REQUIREMENTS FOR UNPLANNED UPDATES TO THE YEAR-AHEAD OUTAGE PLANNING

1. Each TSO shall set up and manage a coordination process, approved by the relevant NRA, allowing to achieve the Availability or Unavailability of Third-Party Owned Tie-Lines, Power Generating Modules and/or Demand Facilities in its Control Area in case of unforeseen events and when Operational Security is at stake, hereby:
   a) Respecting technical limits and feasibility;
   b) Motivating this decision to all affected parties;

c) First using all means that are reasonably at its disposal to come to a fulfilling negotiated solution.

2. In case of unforeseen Forced Outages of Relevant Power Generating Modules and/or Demand Facilities or Third-Party Owned Tie-Lines, the concerning Operator or its delegate shall inform the relevant TSO(s) as soon as possible, hereby declaring:
   a) The reason of the event;
   b) The expected duration;
   c) The impact on the availability of other assets under his responsibility.

3. In case the unforeseen Forced Outage jeopardizes Operational Security of the European electricity grid, the TSO will provide the motivated limit in the duration above which Operational Security will no longer be fulfilled without Load Shedding. The Relevant Power Generating and Demand Facilities and/or Third-Party Owned Tie-line Operator(s) shall do their utmost to respect this limit. If not respected, the relevant Operator(s) shall provide a motivation for this non-compliance to the relevant TSO.

4. In case of unforeseen Forced Outages of Relevant Grid Elements, the relevant TSO shall inform all other impacted TSOs as soon as possible, hereby declaring:
   a) The reason of the event;
   b) The expected duration;
   c) The impact on the availability of other Grid Elements.

5. In case the unforeseen Forced Outage jeopardizes Operational Security of the European electricity grid, the impacted TSO(s) will provide the motivated limit in the duration above which Operational Security will no longer be fulfilled without Load Shedding. The relevant TSO shall do its utmost to respect this limit. If not respected, the relevant TSO shall provide a motivation for this non-compliance to the impacted TSO(s).

6. Following all unplanned updates to the outage planning, and within the time delays established by the transparency guidelines, the relevant TSO shall update the common TSO platform for operational planning to contain the most up to date information.

Article 22

REQUIREMENTS FOR REAL-TIME EXECUTION OF THE OUTAGE PLANNING

1. Each Relevant Power Generating Facility Operator or its delegate shall ensure that all Relevant Power Generating Modules that were declared as being available are ready to produce energy pursuant to their declared technical capabilities when necessary to maintain Operational Security without Load Shedding, being restricted to possible constraints as for example start-up delays, and barring Forced Outages.

2. Each Relevant Power Generating and Demand Facility Operator or its delegate shall ensure that all Relevant Generating Modules and Demand Facilities that were declared as being unavailable cannot produce resp. consume energy.

3. Each TSO and Third-Party Owned Tie-Line Operator or its delegate shall ensure that all Relevant Grid Elements including Third-Party Owned Tie-Lines that were declared as being available have to be ready to transport energy pursuant to their declared technical capabilities when necessary to maintain Operational Security without Load Shedding, being restricted to possible constraints as for example switching delays, and barring Forced Outages.

4. If specific grid-related Constraints apply for the execution of a planned grid outage, the relevant TSO shall assess if these Constraints are met before real-time execution of the outage. If not, the planned outage, or a part thereof, shall not be executed.

5. Before executing planned Relevant Grid Element or Power Generating Modules outages infringing Operational Security, and on the request of a TSO, each concerned party shall delay the corresponding outage according to the conditions defined by the TSO.

6. Before executing a planned test during the Commissioning period of Relevant Grid Element, Power Generating Modules or Demand Facilities infringing Operational Security, and on the request of a TSO, each concerned party shall delay the corresponding test according to the conditions defined by the TSO.

7. Each Relevant Power Generating Facility, Demand Facility or Third-Party Owned Tie-Line Operator shall inform the TSO in case of a deviation from the validated outage planning, at least including the reason for and the duration of the deviation.

8. Each TSO shall inform all impacted parties in case of a deviation from the validated outage planning, at least including the reason for and the duration of the deviation.

Chapter 5

REQUIREMENTS FOR ADEQUACY

Article 23

REQUIREMENTS FOR CONTROL AREA ADEQUACY IN GENERAL

1. Each TSO shall monitor, in line with provisions in Article 3.3 of this Network Code, whether or not its Control Area Adequacy is fulfilled while:
   a) Checking for a set of operational scenarios, with a level of probability in accordance with applicable national legal framework, that the connected generation and import capabilities allow the load to be met;
   b) Using the last available data for:
      i. Generation capacities and their Availability;
      ii. Available import/export Cross-Border Capacities;
      iii. The relevant outage plan.
   c) Taking into account at least the uncertainties assessed through statistical analysis for:
      i. Power Generating Modules;
      ii. Renewable generation;
      iii. Load.
   d) Taking into account limitation on the level of import issued and motivated by Neighbouring TSO's if the operational security of their responsibility is at stake;
   e) Assessing, in case of breaching Adequacy, the expected duration and undelivered energy.

2. Each TSO shall inform:
   a) Its NRA in case it estimates its Control Area Adequacy is not fulfilled without Load Shedding;
   b) Neighbouring TSO's if imports are needed to satisfy its Control Area Adequacy.

3. Each TSO shall publish Control Area Adequacy analysis results and related information according to the transparency rules as mentioned in Regulation EC/714/2009.

Article 24

REQUIREMENTS FOR PAN-EUROPEAN SYSTEM ADEQUACY SEASON-AHEAD

1. No later than 12 months after the entry into force of this regulation, all TSOs shall set up a detailed methodology subject to public consultation and approval by NRAs and associated procedures, for performing seasonal Pan-European System Adequacy

outlook for at least summer and winter period, in line with the framework in Article 231 and precise:

a) Criteria used to define the set of operational scenarios by Control Area, taking into account their probability of occurrence;
b) Criteria used to combine these operational scenarios by Control Area to build an set of Pan-European scenarios, taking into account their probability of occurrence;
c) Methods to assess Adequacy of each Control Area taking into account Pan-European scenarios taking into account available Cross Border Capacities for exchanges of energy;
d) Data to be exchanged between TSO's;
e) Provisions for reviewing the procedure concerning in particular (but not limited to) the periodicity of the analysis.

2. Following the approval by the NRAs, all TSO's shall publish this methodology and implement it within 6 months.

Article 25

REQUIREMENTS FOR CONTROL AREA ADEQUACY UNTIL AND INCLUDING WEEK AHEAD

1. Each TSO shall monitor changes on power generation Availability and/or on load estimations and perform as necessary an updated Adequacy and provide updated information to the Neighbouring TSO's.

Article 26

REQUIREMENTS FOR CONTROL AREA ADEQUACY DAY AHEAD AND INTRADAY

1. Only for Day ahead and Intraday, each TSO shall perform Adequacy analysis using:
   a) Market Participant Schedules according to Local market rules;
   b) Forecast for load;
   c) Renewable generation forecast;
   d) Required Active Power Reserves;
   e) Allocated Cross Border Capacities;
   f) Power Generating Modules Availability and capabilities.

2. Each TSO shall assess the maximum level of import or export Capacity compatible with its Control Area Adequacy, and estimate the following knowledge upon potential lack of Adequacy:
   a) The expected duration;
   b) The level of load shedding required.

3. Each TSO shall publish Adequacy results and related information according to transparency guidelines.

Chapter 6

REQUIREMENTS FOR ANCILLARY SERVICES

Article 27

REQUIREMENTS FOR ANCILLARY SERVICES IN GENERAL

1. Each TSO shall do everything reasonable practical to prevent disturbances and blackouts, which can affect neighbouring control areas or the Synchronous Areas by monitoring and using sufficient Ancillary Services in real-time to meet Operational Security and the requirements set by LFC&R Network Code.

2. Each TSO shall ensure access to a level and location of Ancillary Services in real-time, assessing they fulfil Operational Security for its Control Area either alone or in coordination with other TSOs. Ensuring here means that each TSO shall:
   a) Design and set up procedures, under Article 3.3, for the procurement of Ancillary Services;
   b) Monitor that the level and location of available capacity of Ancillary Services allows to fulfil operational security;
   c) Manage the designed procedures and do everything reasonable practical to procure, under Article 3.3, the level of Ancillary Services required.

3. Each TSO shall ensure, in accordance with Article 27.2, at least the following Ancillary Services according to Operational Security Network Code and LFC&R Network Code:
   a) Active power Ancillary Services;
   b) Reactive power Ancillary Services;
   c) Black-start Ancillary Services.

4. Each TSO shall publish, according to transparency guidelines and respecting all relevant confidentiality requirements, the level of Ancillary Services required, at least but not limited to active power Ancillary Services.

5. Each TSO shall agree and establish a procedure with Neighbouring TSOs for allowing the exchange of at least active power Ancillary Services Cross Border, in accordance with LFC&R Network Code and Balancing Network Code.

6. Each Significant Grid User and DSO shall provide information to the TSO, to which they are connected, on their availability to provide Ancillary Services and related capacity in accordance with Requirements for Grid Connection Network Code and with local market rules.

7. Power Generating and Demand Facility Operators or their delegates shall provide the relevant Ancillary Services as agreed upon with the relevant TSO in time, with the

agreed upon quantities per product and in the correct format. For regulating power this applies both to contracted and voluntary bids.

Article 28

REQUIREMENTS FOR ENSURING ACTIVE POWER ANCILLARY SERVICES

1. Each TSO shall verify that the available capacities of active power Ancillary Services will allow to meet the level set up by LFC&R Network Codes.

2. Each TSO shall deliver information about their available level of active power Ancillary Services to Neighbouring TSOs and on request from other TSOs.

3. Each TSO (A) shall require prior consent from an affected TSO (B), if A procures active power Ancillary Services in the Control Area of TSO B and the procurement of reserves shall be coordinated between TSOs (A and B).

4. If a TSO is sharing or procuring Ancillary Services Cross Border, this TSO shall ensure that Cross-Border Capacity corresponding to the amount of the shared or the procured Cross Border Ancillary Services will be available between the involved areas in accordance with Balancing Network Code and LFC&R Network Code or he shall have Remedial Actions corresponding to the required Ancillary Services.

Article 29

REQUIREMENTS FOR ENSURING REACTIVE POWER ANCILLARY SERVICES

1. Each TSO shall asses, from Year-Ahead stage until real time, if available reactive power sources will allow to fulfil Operational Security as referred in Chapter 3.

2. Each TSO shall define:
   a) Available reactive power capacities on generation facilities referenced by RfG Network Code;
   b) Available transmission compensators dedicated to deliver or absorb reactive power;
   c) The ratio of active/reactive power at the border between Transmission and Distribution Networks.

3. Each TSO shall ensure by this assessment that the Voltage Control of the Transmission System is fulfilled for all events included in its Contingency List and for Year-Ahead scenarios covering at least:
   a) Peak and off peak loads situations;
   b) Situation with high and low level of RES;
   c) Generation patterns affecting voltage profiles.

4. Each TSO, in case the level of reactive power Ancillary Services are not adequate to ensure Operational Security, shall inform the Neighbouring TSO(s) and shall set up

internal or Cross-Border Remedial Actions, prioritized on economic and effectiveness basis.

Chapter 7

REQUIREMENTS FOR SCHEDULING

Article 30

GENERAL PROVISIONS

1. No later than 6 months after entry into force of this Network Code, each TSO operating a Market Balance Area shall set up and implement the relevant process(es) necessary to handle the Schedules in accordance with the local market rules and shall establish to that purpose:
   a) A list of Power Generating Modules and Demand Facilities directly connected to the Transmission Network to which these requirements for scheduling apply;
   b) A list of Market Participants to which these requirements for scheduling apply;
   c) A definition of the time resolution of the Schedules;
   d) Rules of how Power Generating Modules and Demand Facilities connected to the Distribution Network must be handled and how DSOs are involved.

2. Each Power Generating Facilities Operator, Demand Facilities Operator and Market Participant of the lists defined in the previous paragraph must appoint a Scheduling Agent in accordance with local market rules.

Article 31

REQUIREMENTS FOR NOTIFICATION OF SCHEDULES WITHIN MARKET BALANCE AREAS

1. Each Scheduling Agent, according to the lists set forth in Article 30.1 within a Market Balance Area shall submit Schedules to the correspondent TSO operating the Market Balance Area in accordance with the local market rules. These Schedules include (where applicable):
   a) Generation Schedules;
   b) Consumption Schedules;
   c) Internal Commercial Trade Schedules;
   d) External Commercial Trade Schedules using AC-Interconnections;
   e) External Commercial Trade Schedules using DC-Interconnections.

2. Each Market Coupling Operator in its role of Scheduling Agent shall submit Schedules to the relevant TSO(s) operating a Market Balance Area in accordance with the local market rules. These schedules include:
   a) Net Position related to the Market Balance Area;

b) External Commercial Trade Schedules, representing the part of the Net Position related to the Market Balance Area using AC-Interconnections (where applicable);
c) External Commercial Trade Schedules, representing the part of the Net Position related to the Market Balance Area using DC-Interconnections, separate for each DC- Interconnection (where applicable).

3. In case TSOs need to introduce External Schedules to ensure Operational Security, the corresponding External TSO-related Schedules:
   a) Have to be agreed between concerned TSOs before setting them into force;
   b) Can be set into force without delay;
   c) Shall be reconciled, maybe ex post.

4. External TSO-related Schedules include (not being limited to):
   a) Countertrading;
   b) Balancing energy exchanges;
   c) Energy due to Emergency reserves activation.

Article 32

REQUIREMENTS FOR COHERENCY OF SCHEDULES

1. Each TSO operating the Market Balance Area shall implement rules and processes to ensure the agreement of all External Schedules between their own Market Balance Area and other Market Balance Areas.

2. Each TSO operating the Market Balance Area shall ensure its area internal balance for Generation Schedules, Consumption Schedules and External Schedules.

3. Each and all TSOs operating Market Balance Areas shall implement a process to ensure that all Schedules between Market Balance Areas are balanced, including areas whose operators have no legal obligation to respect this Network Code.

4. Each Market Coupling Operator in its role of Scheduling Agent shall support the process that ensures that all External Schedules between Market Balance Areas are balanced according to Article 32.3. They shall submit to TSOs coordinating this process on their request for each Market Balance Area:
   a) Schedules representing the part of the Net Position related to the Market Balance Area using AC-Interconnections (where applicable);
   b) Schedules representing the part of the Net Position related to the Market Balance Area using DC-Interconnections, separate for each DC- Interconnection (where applicable).

Article 33

REQUIREMENTS FOR PROVIDING INFORMATION TO OTHER TSOs, REQUIRED FOR FURTHER PROCESSING

1. In order to allow further processing by TSOs, including at least performing Load Frequency Control and creating Common Grid Models, each TSO operating a Market Balance Area shall calculate and exchange with other TSOs using the common TSO platform for operational planning referred to in Chapter 8:
   a) Aggregated Netted External Schedules (per border / DC-Interconnection (where applicable));
   b) Netted Area AC Position (where applicable);
   c) Netted Area Global Position.

2. For the purposes of creating Common Grid Models, each TSO operating a Market Balance Area shall provide in accordance with Article 10.2 on request of another TSO this TSO with its
   a) Generation Schedules;
   b) Consumption Schedules.

Chapter 8

COMMON TSO OPERATIONAL PLANNING PLATFORM

Article 34

GENERAL PROVISIONS

1. No later than 24 months after the entry into force of this regulation, all TSOs together shall develop one common pan-European platform that contains all relevant information for operational planning.

2. Each TSO is responsible to provide and update the relevant information to the common TSO platform.

3. All data exchanges with the common TSO platform shall be based on a standardized data format defined by all TSOs together. The description of this data format shall be an integral part of the common platform description.

4. All TSOs and RSCIs in the form of a legal entity shall have access to all information contained in this common TSO platform.

5. Each DSO shall be granted access to the content regarding outage planning contained in this common TSO platform which directly relates to the grid it operates; subject to confidentiality guidelines.

Article 35

CONTENT REGARDING GRID MODELS & SECURITY ANALYSIS

1. The common TSO platform shall store all Individual Grid Models and related relevant information for all relevant timeframes defined in this network code and CACM code.

2. All merged Common Grid Models shall be made available on the common TSO platform.

3. For the Year-Ahead time horizon, the following information has to be included:
   a) A description of the commonly defined scenarios as described in Article 8.1;
   b) A Year-Ahead Individual Grid Model per TSO and per scenario defined (Article 8.2);
   c) A Year-Ahead Common Grid Model per scenario defined (Article 8.4).

4. For the Day-Ahead and Intraday time horizons, the following information has to be included:

a) A Day-Ahead/Intraday Individual Grid Model(s) per TSO and per forecast time period as described in Article 10;
b) The Scheduled Exchanges at the relevant time instances per Control Area or per Control Area Border – whichever is deemed relevant by the TSOs – and per DC Interconnection;
c) A Day-Ahead/Intraday Common Grid Model(s) per forecast time period as described in Article 10;
d) A list of the prepared and agreed upon pre-fault and post-fault Remedial Actions identified to cope with Cross-Border Constraints according to Article 11.2.

Article 36

CONTENT REGARDING OUTAGE PLANNING

1. The Common TSO Platform shall contain a module for the storage and sharing of all relevant information for coordinated outage planning.

2. This information encompasses at least:
   a) Planned outages of Relevant Grid Elements including at least all information described in Article 18.3;
   b) Planned outages of Relevant Power Generating Modules including, but not limited to outage period, eventual commissioning period and lost generation capacity;
   c) Planned outages of Relevant Demand Facilities including, but not limited to outage period, eventual commissioning period and lost load;
   d) Planned outages of Third-Party Owned Tie-Lines including, but not limited to outage period, specific conditions for execution of the outage and restitution time.

Article 37

CONTENT REGARDING SYSTEM ADEQUACY

1. The common TSO platform shall contain a module for the storage and sharing of all relevant information for coordinated Adequacy analysis.

2. This information encompasses at least:
   a) The season ahead System Adequacy data provided by the individual TSOs;
   b) The season ahead Pan-European System Adequacy assessment report.

Chapter 9

FINAL PROVISIONS

Article 38

ENTRY INTO FORCE

1. This Network Code shall enter into force on the twentieth day following that of its publication in the Official Journal of the European Union.

2. It shall apply as from the day of expiration of a 3 year period following its publication.