

# Explanatory Note of the day-ahead and intraday common capacity calculation methodology for the SEE CCR

Version August 2018

## Contents

<b>1.</b>	<b>Introduction .....</b>	<b>3</b>
<b>2.</b>	<b>Coordinated NTC calculation methodology.....</b>	<b>3</b>
<b>2.1.</b>	<b>Inputs.....</b>	<b>3</b>
2.1.1.	Operational security limits, contingencies and allocation constraints .....	3
2.1.2.	Reliability Margin (RM) .....	4
2.1.3.	Base Case - Individual Grid Model (BC-IGM) .....	5
2.1.4.	Generation Load Shift Key (GLSK) .....	6
2.1.5.	Remedial Action (RA).....	7
2.1.6.	Mathematical description of the CNTC approach .....	8
2.1.7.	Cross-zonal capacity validation .....	13
<b>2.2.</b>	<b>Backup &amp; Fallback processes.....</b>	<b>14</b>
2.2.1.	Backups and replacement process .....	14
2.2.2.	Fallback NTC values .....	14
<b>3.</b>	<b>Transparency .....</b>	<b>14</b>
<b>4.</b>	<b>Timescale for the CCM implementation .....</b>	<b>14</b>
<b>4.1.</b>	<b>Prerequisites.....</b>	<b>15</b>
<b>4.2.</b>	<b>Timeline for implementation of the CCM.....</b>	<b>15</b>

## 1. Introduction

This technical document sets out the main principles for the common capacity calculation methodology for the day-ahead and intraday market time-frames (hereafter SEE day-ahead and intraday CCM) applied in the SEE CCR. It contains a description of both methodologies in compliance with the Capacity Allocation and Congestion Management guideline (hereafter referred to us “CACM Regulation”).

The participating TSOs for the calculations are ADMIE (GR), ESO EAD (BG), Transelectrica (RO) and the following borders are considered GR-BG and BG-RO.

## 2. Coordinated NTC calculation methodology

### 2.1. Inputs

In order to allow the Coordinated Capacity Calculator (CCC) to perform the relevant Capacity Calculation (CC) processes, each TSO for the SEE CCR shall provide the following relevant input data:

- Operational security limits, contingencies and allocation constraints;
- Reliability Margins;
- Base Case – Individual Grid Models;
- Generation shift keys;
- Remedial actions.

In this chapter details about the previous data are described.

#### 2.1.1. Operational security limits, contingencies and allocation constraints

This section refers to Article 7 of the CCM.

A Critical Network Element (CNE) is a network element either within a bidding zone or between bidding zones impacted by cross-border trades and monitored during the CC process under certain operational conditions. The CNEC (Critical Network Element and Contingency) is a CNE limiting the amount of power that can be exchanged, potentially associated to a contingency. They are determined by each SEE TSO according to agreed rules, described below.

The CNECs are defined by:

- A CNE: a line or a transformer that is significantly impacted by cross-border exchanges;
- An “operational situation”: base case (N) or contingency cases (N-1, N-2, busbar faults, depending on the TSO risk policies).

A contingency is defined as the trip of one single or several network elements. A scheduled outage is not a contingency. A contingency can be a trip of:

- a line, a cable or a transformer (including phase shifter transformer);
- a generating unit;
- a load;
- a set of the aforementioned contingencies.

SEE TSOs may provide a list of nodes in order to verify the voltage level during coordinated NTC calculation process based on each TSO operational experience. The CCM use Sensitivity factor as the criterion for selecting the CNECs and nodes that are significantly impacted by cross-zonal trade. Cross-zonal network elements are by definition considered to be significantly impacted. The other CNECs and the nodes shall have a sensitivity factor that exceeds the threshold of 5% to be taken into account in all

of the steps of the common capacity calculation and will determine the cross-zonal capacity. The assessment of sensitivity factors calculated as a percentage is performed from the relevant CGM and GSK in order to determine the effect on additional flow for each CNEC and voltage level for each node.

The maximum permanent admissible current/power limit means the maximum loading that can be sustained on a transmission line, cable or transformer for an unlimited duration without risk to the equipment, determined by each TSO in line with its operational security policy. The temporary current/power limit means the maximum loading that can be sustained for a limited duration without risk to the equipment (e.g. 120% of permanent physical limit can be accepted during 20 minutes). Each SEE TSO is responsible for deciding, in line with their operational security policy, if temporary limit should be used. As thermal limits and protection settings can vary in function of weather conditions, different values are calculated and set for the different seasons within a year. These values can be also adapted by the concerned TSO if a specific weather condition is forecasted to highly deviate from the seasonal values. The maximum admissible limit is not reduced by any security margin, as all uncertainties in capacity calculations are covered by reliability margin.

SEE TSOs will not apply allocation constraints.

### 2.1.2. Reliability Margin (RM)

This section refers to Article 6 of the CCM.

The day-ahead and intraday common capacity calculation methodologies are based on forecast models of the transmission system. Therefore, the outcomes are subject to inaccuracies and uncertainties. The aim of the reliability margin is to cover a level of risk induced by these forecast errors.

In accordance with Article 22(2) and (4) of the CACM Regulation, the Reliability Margins (*RM*s) cover the following forecast uncertainties:

- a. SEE external transactions (out of SEE CCR control: both between SEE CCR and other CCRs as well as among TSOs outside the SEE CCR);
- b. generation pattern including specific wind and solar generation forecast;
- c. generation shift key;
- d. load forecast;
- e. topology forecast;
- f. unintentional flow deviation due to the operation of frequency containment reserves.

The reliability margin can be considered as an indirect input to the CC process since it refers to the difference where the TTC and the NTC limits are reached for the constraint under investigation.

RMs computation is based on the analysis of the following data:

- unintended deviations of physical electricity flows within a market time unit caused by the adjustment of electricity flows within and between control areas, to maintain a constant frequency;
- uncertainties which could affect capacity calculation and which could occur between the time of capacity calculation and real time, for the market time unit being considered.

Regarding the unintended deviation (UD), for control-related reasons, deviations occur between the scheduled values and the actual values during the exchange of energy between neighboring control areas. This implies that at any moment the exchange between two control areas can be significantly

higher than the scheduled exchanged, endangering the security of supply.

Regarding the uncertainties (UN) the coordinated NTC calculation methodology is based on different inputs provided by TSOs, they are based on best available forecast at the time of the capacity calculation for renewable energy sources, consumption, generation or available network elements and those could differ from the real-time situation.

The RMs determination is based on a probability distribution function of the deviations between the expected power flows at the time of the capacity calculation and realized power flows in real time. The RMs on the SEE CCR borders are calculated in a three-step approach:

- a. in a first step, for each market time unit of the observatory period, the relevant common grid models (CGM) are updated in order to take into account the real-time situation of the remedial actions that are considered in the common capacity calculation. This step is undertaken by copying the real-time configuration of these remedial actions and applying them into the historical CGM where the capacity calculation was performed. The exchange on BG-RO and BG-GR borders of the SEE CCR, as expected with the common capacity calculation methodology is then compared with the real time exchange observed on the same borders. All differences for all market time units of a one-year observation period are statistically assessed and a probability distribution is obtained;
- b. in a second step and in accordance with Article 22(3) of the CACM Regulation the 95th percentiles of the probability distributions for the BG-RO and BG-GR borders of the SEE CCR are calculated. This means that the TSOs apply a common risk level of 5% i.e. the RM values cover 95% of the historical errors;
- c. a possible third step is to undertake an operational adjustment on the values derived previously, which can applied to adjust the computed RM values to a value within the range between 1% and 20% of the TTC calculated under normal weather conditions.

Before the first operational calculation of the *RMs* values, SEE CCR TSOs shall use the RM values already in operation in the existing capacity calculation initiatives. The *RMs* before the first operational calculation for the BG-RO and BG-GR borders shall be 100 MW for each direction.

### **2.1.3. Base Case - Individual Grid Model (BC-IGM)**

Basis for the Individual Grid Model (IGM), adopted in the CC process, is a scenario assumed to be representative of the expected conditions for the market time unit under assessment. The scenarios contain structural data, topology and forecast (obtaining the so called “Base Case – Individual Grid Model”) of:

- Grid topology: outages of grid elements is adapted according to the approved outages plans;
- Load conditions: most recently updated load forecast is implemented;
- Conventional generation sheet:
  - for the day-ahead CC process, the best available forecast is adopted,
  - for the intraday CC process, the last available market results are adopted;
- Renewable generation infeed: the best available forecasts are adopted;
- Net positions and initial cross-border exchanges, accordingly to the approach described in the following paragraph.

### Day-Ahead time-frame

Forecasting of the net positions two days before the delivery day is based on a common process established in ENTSO-E: the Common Grid Model Alignment (CGMA). This centrally operated process ensures the grid balance of the models used for the CC across Europe. The process is described in the Common Grid Model Alignment Methodology (CGMAM), which was approved by all TSOs in ENTSO-E.

Main concept of the CGMAM is presented in Figure 1 below:

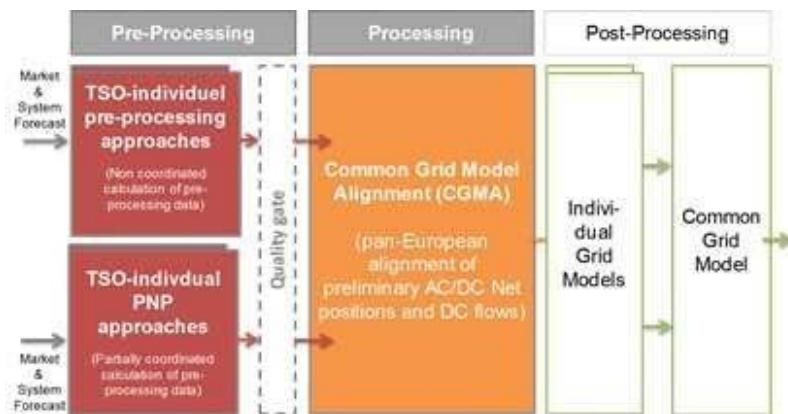


Figure 1: Main concept of the CGMAM

The CGMAM input data are created in the pre-processing phase, which shall be based on the best available forecast of the market behavior and Renewable Energy Source (RES) generation.

Pre-Processing Data (PPD) of CGMA are based on either an individually or regionally coordinated forecast. Basically the coordinated approach shall yield a better indicator about the final net position than an individual forecast. Therefore, TSOs in SEE CCR agreed to prepare the PPD in a coordinated way.

The main concept of the coordinated approach intends to use statistical data as well as linear relationships between forecasted NP and input variables. The data shall represent the market characteristic and the grid conditions in the given time horizon. The coefficients of the linear model will be tuned by archive data.

The result of the process is the “Balanced Net Position” (BNP) for each control area and for each market time unit.

The TSOs of the SEE CCR will adopt the net position of their control area as the result of the CGMA process, based on which the net positions on each relevant border can be defined and used at the relevant IGM models.

### Intra-Day timeframe

The net position of each bidding zone of the SEE CCR and the cross-border exchanges on each border are defined according to the latest available market results.

#### 2.1.4. Generation Load Shift Key (GLSK)

This section refers to Article 8 of the CCM.

GLSKs are needed to transform any change in the balance of one bidding zone into a change of injections in the nodes of that bidding zone. GLSKs are elaborated on the basis of the forecast information about the generating units and, if necessary, the loads.

GLSK file is defined for each:

- control area: GLSK is computed for each relevant network node in the same control area;
- and time interval: GLSK is dedicated to individual market time unit in order to model differences between different system conditions.

In order to avoid newly formed unrealistic congestions caused by the process of generation shift, TSOs should be able to define generation shift key (GSK) and, if necessary, load shift key (LSK):

- Generation shift: GSK constitute a list specifying those generators that shall contribute to the shift;
- Load shift: LSK constitute a list specifying those load that shall contribute to the shift in order to take into account the contribution of generators connected to lower voltage levels.

If GSK and LSK are defined, a participation factor is also given:

- G(a) Participation factor for generation nodes;
- L(a) Participation factor for load nodes.

The sum of G(a) and L(a) for each area has to be to 1 (i.e. 100%).

SEE TSOs have harmonized their GSK determination methodologies:

- a. In its GSK, each TSO shall use flexible and controllable production units which are available inside the TSO grid
- b. Units unavailable due to outage or maintenance are not included.
- c. GSK is reviewed on a daily basis.

For the Greek bidding zone a proportional representation of the generation variation to the remaining capacity, based on ADMIE's best estimate of the initial generation profile, ensure the best modeling of the Greek system.

For the Bulgarian bidding zone a proportional representation of the generation variation to the remaining capacity respecting the limits of the generating units, based on ESO EAD's best estimate of the initial generation profile, ensure the best modeling of the Bulgarian system. The nuclear units are not included in the list.

The Transelectrica GSK file contains dispatchable units which are available in the day of operation. The nuclear units are not included in the list. The fixed participation factors of GSK are impacted by the actual generation present in the D-2 CGM.

### **2.1.5. Remedial Action (RA)**

This section refers to Article 9 of the CCM.

During coordinated NTC calculation, SEE TSOs will take into account Remedial Actions (RAs), that refers to any measure applied in due time by a TSO in order to respect security principles under maximum allowed cross border exchanges of the transmission power system regarding power flows and voltage constraints.

The general purpose of the application of RAs is to maintain the transmission system within the operational security limits during the CC process, where maximum power exchanges are reached. The application of proper RAs in the context of the capacity calculation can allow an increase of NTC values released to the markets, with subsequent benefits for the system.

RAs can be classified in the following two categories:

- Preventive Remedial Actions (PRAs) are those launched to anticipate a need that may occur, due to the lack of certainty to cope efficiently and in due time with the resulting constraints once they have occurred;
- Curative Remedial Actions (CRAs) are those needed to cope with and to relieve rapidly

constraints with an implementation delay of time for full effectiveness compatible with the Temporary Admissible Transmission Loading. They are implemented after the occurrence of the contingencies.

The possible types of RAs considered in the CC process are the following:

- Changing the tap position of a phase shifting transformer (PST);
- Topological measure: opening or closing of one or more line(s), cable(s), transformer(s), bus bar coupler(s) or switching of one or more network element(s) from one bus bar to another, connection/disconnection of reactor(s), capacitor(s).

In accordance with Article 25(5) of the CACM Regulation, the day-ahead and intraday common capacity calculation take non-costly RAs into account which can be explicitly modelled in the CGM.

The RAs coordination (RAC) in the day-ahead and intraday common capacity calculation is performed in accordance with a set of pre-defined characteristics such as an objective function, constraints and variables:

- a. The RAC objective is to enlarge the capacity domain around the balanced net position of the Common Grid Model Alignment process, with the objective function to minimize the overload of the CNECs and/or the violation of the nodes voltage;
- b. The constraints are the operational security limits in accordance with Article 7, minimum impact on objective function value for use RAs and without negative impact on the TTC values calculated according with Article 11.
- c. The variables are the switching states of the topological measures and tap positions.

#### **2.1.6. Mathematical description of the CNTC approach**

This section refers to Article 11 of the CCM.

For the day-ahead and intraday market time-frames, individual values for cross-zonal capacity for each market time unit shall be calculated using the Coordinated Net Transmission Capacity (CNTC) approach as defined in the common capacity calculation methodology, as set forth in Article 14 and Article 21 of the CACM Regulation. This approach has been selected since a flow-based approach is effective only when is applied to a large number of borders which are in a closed-loop formulation, on contrary the GR-BG-RO connection is like a single path connection, where bidding zones are connected through a single root.

The Coordinated Net Transmission Capacity (CNTC) computation is a centralized calculation based on AC load flow which delivers the main parameter needed for the definition of CNTC domain: Total Transmission Capacity (TTC). The TTC represent the maximum power exchange on a bidding zone border.

During the day-ahead and the intraday CC processes, the Total Transfer Capacity (TTC) for the south RO borders, BG-RO border, north Greek borders and BG-GR border shall be assessed in both border directions:

- Using Alternate Current (AC) load-flow algorithm in order to assess network security of the relevant CNECs, taking also into consideration the beneficial effects of remedial actions coordination;
- Based on:
  - merged two-days ahead CGMs (D2CF merged models) for day-ahead CC process;



- merged day ahead or intraday CGMs (DACF or IDCF merged models) for intraday CC process;
- Applying modification of cross-zonal exchanges according to GLSK files.

The *TTC* on the BG-GR direction is a ratio of the total *TTC* value calculated from all north Greek systems (power systems of Albania, FYROM, Bulgaria and Turkey) to the Greek system:

$$TTC_{BG-GR} = k_{BG-GR} \cdot TTC_{north\ GR\ systems-GR}$$

with

$TTC_{BG-GR}$	<i>TTC</i> on the BG-GR direction
$k_{BG-GR}$	splitting factor for BG-GR direction
$TTC_{north\ GR\ systems-GR}$	<i>TTC</i> from all north Greek systems to the Greek system

The *TTC* on the GR-BG direction is a ratio of the total *TTC* value calculated from the Greek system to all north Greek systems (power systems of Albania, FYROM, Bulgaria and Turkey):

$$TTC_{GR-BG} = k_{GR-BG} \cdot TTC_{GR-north\ GR\ systems}$$

with

$TTC_{GR-BG}$	<i>TTC</i> on the GR-BG direction
$k_{GR-BG}$	splitting factor for GR-BG direction
$TTC_{GR-north\ GR\ systems}$	<i>TTC</i> from the Greek system to all north Greek systems

The *TTC* on the BG-RO direction is a ratio of the total *TTC* value calculated from all south Romanian systems (power systems of Bulgaria and Serbia) to the Romanian system:

$$TTC_{BG-RO} = k_{BG-RO} \cdot TTC_{south\ RO\ systems-RO}$$

with

$TTC_{BG-RO}$	<i>TTC</i> on the BG-RO direction
$k_{BG-RO}$	splitting factor for BG-RO direction
$TTC_{south\ RO\ systems-RO}$	<i>TTC</i> from all south Romanian systems to the Romanian system

The *TTC* on the RO-BG direction is a ratio of the total *TTC* value calculated from the Romanian system to all south Romanian systems (power systems of Bulgaria and Serbia):

$$TTC_{RO-BG} = k_{RO-BG} \cdot TTC_{RO-south\ RO\ systems}$$

with

$TTC_{RO-BG}$	<i>TTC</i> on the RO-BG direction
$k_{RO-BG}$	splitting factor for RO-BG direction
$TTC_{RO-south\ RO\ systems}$	<i>TTC</i> from the Romanian system to all south Romania systems

The splitting factor used for day-ahead and intraday capacity calculation in the year *Y* will be based on the NTC values from the last two years. This approach is based on the Article 3(h) of the CACM Regulation that contributes to the objective of respecting the need for a fair and orderly market and price formation and ensures a fair distribution of costs and benefits between the involved TSOs. Moreover the approach is in line with the distribution of the congestion income (as defined in the Article 73 of CACM Regulation and Article 57 of FCA Regulation) collected by the TSOs, and thus do not alter the signals for investments to TSOs given by the congestion income. The splitting factors used at the NTC computation will comply with the security operation in accordance with Article 3(c) of the CACM Regulation, will not

alter the signals for investments to TSOs given by the congestion income and allow reasonable financial planning according with Article 73 of the CACM Regulation.

The splitting factor for BG-GR direction is determined with the following equation:

$$k_{BG-GR} = NTC_{BG-GR} / NTC_{north\ GR\ systems-GR}$$

where:

$k_{BG-GR}$	splitting factor as percentage to be applied for BG-GR direction for day-ahead and intraday capacity calculation in the year Y
$NTC_{BG-GR}$	Average value of the NTC for the direction BG-GR (excluding the period when the tie-line BG-GR was out of operation for maintenance) in the last two years
$NTC_{north\ GR\ systems-GR}$	Average value of the total NTC for the direction north GR systems -GR (excluding the period when the tie-line BG-GR was out of operation for maintenance) in the last two years

The splitting factor for GR-BG direction is determined with the following equation:

$$k_{GR-BG} = NTC_{GR-BG} / NTC_{GR-north\ GR\ systems}$$

where:

$k_{GR-BG}$	splitting factor as percentage to be applied for GR-BG direction for day-ahead and intraday capacity calculation in the year Y
$NTC_{GR-BG}$	average value of the NTC for the direction GR-BG (excluding the period when the tie-line BG-GR was out of operation for maintenance) in the last two years
$NTC_{GR-north\ GR\ systems}$	average value of the total NTC for the direction GR-north GR systems (excluding the period when the tie-line BG-GR was out of operation for maintenance) in the last two years

The splitting factor for BG-RO direction is determined with the following equation:

$$k_{BG-RO} = NTC_{BG-RO} / NTC_{south\ RO\ systems-RO}$$

where:

$k_{BG-RO}$	splitting factor as percentage to be applied for BG-RO direction for day-ahead and intraday capacity calculation in the year Y
$NTC_{BG-RO}$	Average value of the NTC for the direction BG-RO in the last two years
$NTC_{south\ RO\ systems-RO}$	Average value of the total NTC for the direction south RO systems-RO in the last two years

The splitting factor for RO-BG direction is determined with the following equation:

$$k_{RO-BG} = NTC_{RO-BG} / NTC_{RO-south\ RO\ systems}$$

where:

$k_{RO-BG}$	splitting factor as percentage to be applied for RO-BG direction for day-ahead and intraday capacity calculation in the year Y
$NTC_{RO-BG}$	Average value of the NTC for the direction RO-BG in the last two years
$NTC_{RO-south\ RO\ systems}$	Average value of the total NTC for the direction RO-south RO systems in the last two years

The CCC of the SEE CCR shall provide to the SEE TSOs with the validated NTCs values after

The Net Transmission Capacity (NTC) on the BG-GR border is determined with the following equations:

$$NTC_{BG-GR} = TTC_{BG-GR} - RM_{BG-GR}$$

$$NTC_{GR-BG} = TTC_{GR-BG} - RM_{GR-BG}$$

with

$NTC_{BG-GR}$	<i>NTC</i> on the BG-GR direction
$NTC_{GR-BG}$	<i>NTC</i> on the GR-BG direction
$TTC_{BG-GR}$	<i>TTC</i> on the BG-GR direction
$TTC_{GR-BG}$	<i>TTC</i> on the GR-BG direction
$RM_{BG-GR}$	<i>RM</i> on the BG-GR direction
$RM_{GR-BG}$	<i>RM</i> on the GR-BG direction

The Net Transmission Capacity (NTC) on the BG-RO border is determined with the following equations:

$$NTC_{BG-RO} = TTC_{BG-RO} - RM_{BG-RO}$$

$$NTC_{RO-BG} = TTC_{RO-BG} - RM_{RO-BG}$$

with

$NTC_{BG-RO}$	<i>NTC</i> on the BG-RO direction
$NTC_{RO-BG} =$	<i>NTC</i> on the RO-BG direction
$TTC_{BG-RO}$	<i>TTC</i> on the BG-RO direction
$TTC_{RO-BG}$	<i>TTC</i> on the RO-BG direction
$RM_{BG-RO}$	<i>RM</i> on the BG-RO direction
$RM_{RO-BG}$	<i>RM</i> on the RO-BG direction

In accordance with Article 21(1)(b)(iii) of the CACM Regulation, SEE TSOs shall apply the rules for taking into account the previously-allocated cross-zonal capacity. The objective of the rules is to verify that the Available Transmission Capacity (*ATC*) value of each border and direction of the SEE CCR remains non-negative in case of previously-allocated commercial capacity.

The Available Transmission Capacity (*ATC*) taking into consideration the Already Allocated Capacities (*AAC*) is determined with the following equations in case of BG – GR border:

$$ATC_{BG-GR} = NTC_{BG-GR} - AAC_{BG-GR} + AAC_{GR-BG}$$

$$ATC_{GR-BG} = NTC_{GR-BG} - AAC_{GR-BG} + AAC_{BG-GR}$$

with

$ATC_{BG-GR}$	<i>ATC</i> on the BG-GR direction
$NTC_{BG-GR}$	<i>NTC</i> on the BG-GR direction
$AAC_{BG-GR}$	<i>AAC</i> on the BG-GR direction
$AAC_{GR-BG}$	<i>AAC</i> on the GR-BG direction
$ATC_{GR-BG}$	<i>ATC</i> on the GR-BG direction
$NTC_{GR-BG}$	<i>NTC</i> on the GR-BG direction

The Available Transmission Capacity (*ATC*) taking into consideration the Already Allocated Capacities (*AAC*) is determined with the following equations in case of BG – RO border:

$$ATC_{BG-RO} = NTC_{BG-RO} - AAC_{BG-RO} + AAC_{RO-BG}$$

$$ATC_{RO-BG} = NTC_{RO-BG} - AAC_{RO-BG} + AAC_{BG-RO}$$

with

$ATC_{BG-RO}$	<i>ATC</i> on the BG-RO direction
$NTC_{BG-RO}$	<i>NTC</i> on the BG-RO direction
$AAC_{BG-RO}$	<i>AAC</i> on the BG-RO direction
$AAC_{RO-BG}$	<i>AAC</i> on the RO-BG direction
$ATC_{RO-BG}$	<i>ATC</i> on the RO-BG direction
$NTC_{RO-BG}$	<i>NTC</i> on the RO-BG direction

The Available Transmission Capacity (*ATC*) for day-ahead market time-frame and also for the intraday market time-frame is determined with the following equations in case of BG – GR border, taking into account the *NTC* values calculated before and Already Nominated Capacity (*ANC*):

$$ATC_{BG-GR} = NTC_{BG-GR} - ANC_{BG-GR} + ANC_{GR-BG}$$

$$ATC_{GR-BG} = NTC_{GR-BG} - ANC_{GR-BG} + ANC_{BG-GR}$$

with

$ATC_{BG-GR}$	<i>ATC</i> on the BG-GR direction
$NTC_{BG-GR}$	<i>NTC</i> on the BG-GR direction
$ANC_{BG-GR}$	<i>ANC</i> on the BG-GR direction
$ANC_{GR-BG}$	<i>ANC</i> on the GR-BG direction
$ATC_{GR-BG}$	<i>ATC</i> on the GR-BG direction
$NTC_{GR-BG}$	<i>NTC</i> on the GR-BG direction

The Available Transmission Capacity (*ATC*) for day-ahead market time-frame and also for the intraday market time-frame is determined with the following equations in case of BG – RO border, taking into account the *NTC* values calculated before and Already Nominated Capacity (*ANC*):

$$ATC_{BG-RO} = NTC_{BG-RO} - ANC_{BG-RO} + ANC_{RO-BG}$$

$$ATC_{RO-BG} = NTC_{RO-BG} - ANC_{RO-BG} + ANC_{BG-RO}$$

with

$ATC_{BG-RO}$	<i>ATC</i> on the BG-RO direction
$NTC_{BG-RO}$	<i>NTC</i> on the BG-RO direction
$ANC_{BG-RO}$	<i>ANC</i> on the BG-RO direction
$ANC_{RO-BG}$	<i>ANC</i> on the RO-BG direction
$ATC_{RO-BG}$	<i>ATC</i> on the RO-BG direction
$NTC_{RO-BG}$	<i>NTC</i> on the RO-BG direction

If the *ATC* values calculated for day-ahead or intraday market time-frames are negative, no capacity will be made available for day-ahead, respectively intraday market time-frame.

For the day-ahead and intraday capacity calculation the processes are depicted in Figure 2 and Figure 3. It shows the various processes performed by entities involved.

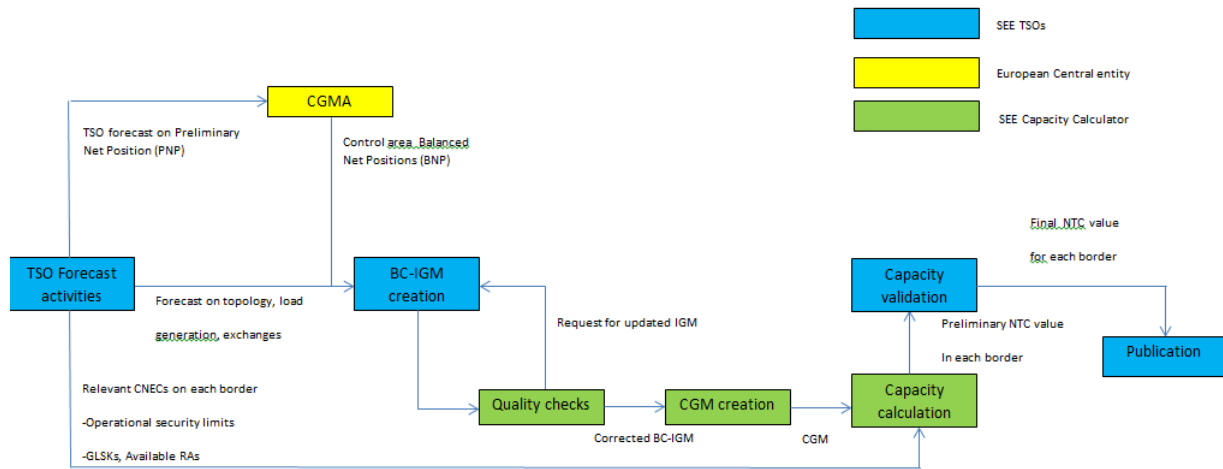


Figure 2: CNTC day-ahead CC process

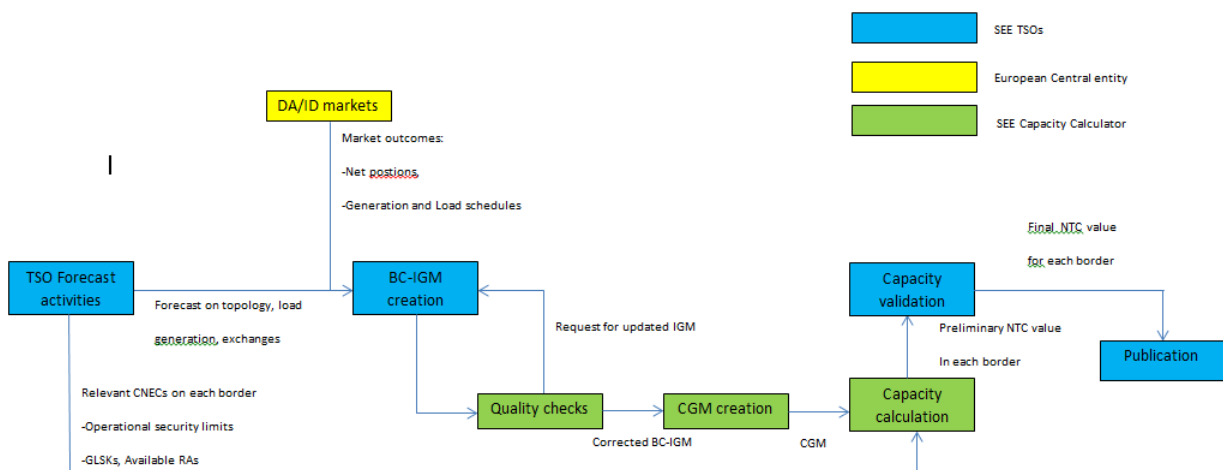


Figure 3: CNTC intraday CC process

### 2.1.7. Cross-zonal capacity validation

This section refers to Article 10 of the CCM.

Regarding the final validation process, once the coordinated capacity calculator has calculated the TTC, it provides the concerned TSOs with these values. Each TSO then has the opportunity to validate the TTC value calculated centrally or can reduce the value in exceptional situations. These situations are:

- a. A forced outage as defined in Article 3 of SO GL;
- b. when remedial actions, that are needed to ensure the calculated capacity, are not sufficient;
- c. extremely low demand of a TSO which leads to low system inertia and high voltage conditions and so require a minimum number of power plants on the grid;
- d. a mistake in input data, that leads to an overestimation of cross-zonal capacity from an operational security perspective.

The TSO requesting a capacity reduction is required to provide a reason for this reduction, its location and the amount of MW to be reduced in accordance with article 26.5 of CACM Regulation.

Where the two TSOs of a bidding zone border request a capacity reduction on their common border, the coordinated capacity calculator will select the minimum value provided by the TSOs. The reason associated to this value will be the one taken into account in all report required by relevant legislation.

## **2.2. Backup & Fallback processes**

### **2.2.1. Backups and replacement process**

For all inputs related to the capacity calculation, standard backup communication process has to be defined among SEE TSOs and the coordinated capacity calculator. Where inputs are not available for one of the parties at the expected time, back up procedures are applied until a critical deadline is reached, in order to get the associated inputs and carry on with the original process.

Where a critical deadline is reached and the inputs could not be provided to the concerned party on time, then fallbacks are applied, meaning that SEE TSOs and the coordinated capacity calculator could use other inputs to perform their tasks. As an example, inputs from the day before, since network situations are usually stable from one day to another and could be re-used in order to complete the CC process.

### **2.2.2. Fallback NTC values**

If the SEE TSOs and the coordinated capacity calculator could not complete a CC process within the agreed time for calculation, the last coordinated cross-zonal capacity calculated within the long-term time-frame is then used as an input for validation of cross-zonal capacities for day-ahead market time-frame. For intraday market time-frame the cross-zonal capacities calculated within the day-ahead time-frame are used as fallback NTC values.

## **3. Transparency**

In accordance with Article 3(f) of the CACM Regulation aiming at ensuring and enhancing the transparency and reliability of information to the regulatory authorities and market participants, the following data items shall be published in addition to the data items and definitions of Commission Regulation (EU) No 543/2013 on submission and publication of data in electricity markets:

- NTC values computed for the day-ahead and intraday CC processes;
- Reliability margins applied;
- Remedial actions applied;
- Limiting CNECs.

SEE TSOs will participate in the elaboration of the ENTSO-E biennial report on capacity calculation and allocation, which will be provided each two years and updated under request of the relevant authorities, according to Article 31 of CACM Regulation. For SEE CCR, this report will contain the capacity calculation approach used, statistical indicators of cross-zonal capacity, and, if appropriate, proposed measures to improve capacity calculation.

The Agency shall decide whether to publish all or part of this report.

## **4. Timescale for the CCM implementation**

Article 9(9) of the CACM Regulation requires that:

*“The proposal for terms and conditions or methodologies shall include a proposed timescale for their*

implementation and a description of their expected impact on the objectives of this Regulation.”

The deadline for implementing a harmonized CCM within a Capacity Calculation Region is defined in article 21(4):

*"All TSOs in each capacity calculation region shall, as far as possible, use harmonized capacity calculation inputs. By 31 December 2020, all regions shall use a harmonized capacity calculation methodology which shall in particular provide for a harmonized capacity calculation methodology for the flow-based and for the coordinated net transmission capacity approach."*

The following section provides the description of the planned implementation timeline for the SEE capacity calculation methodology.

#### 4.1. Prerequisites

When the new Capacity Calculation (CC) goes live, the calculation will be performed by the coordinated capacity calculator based on input provided by the TSOs, and finally validated by the TSOs. Two crucial elements in this process are the Common Grid Model (CGM) and the Industrialized Capacity Calculation Tool. The CGM is being developed by a coordinated project of all EU TSOs, and the industrialized capacity calculation tool is being developed by the coordinated capacity calculator. Both shall be implemented before the "go-live" of the CCM.

#### 4.2. Timeline for implementation of the CCM

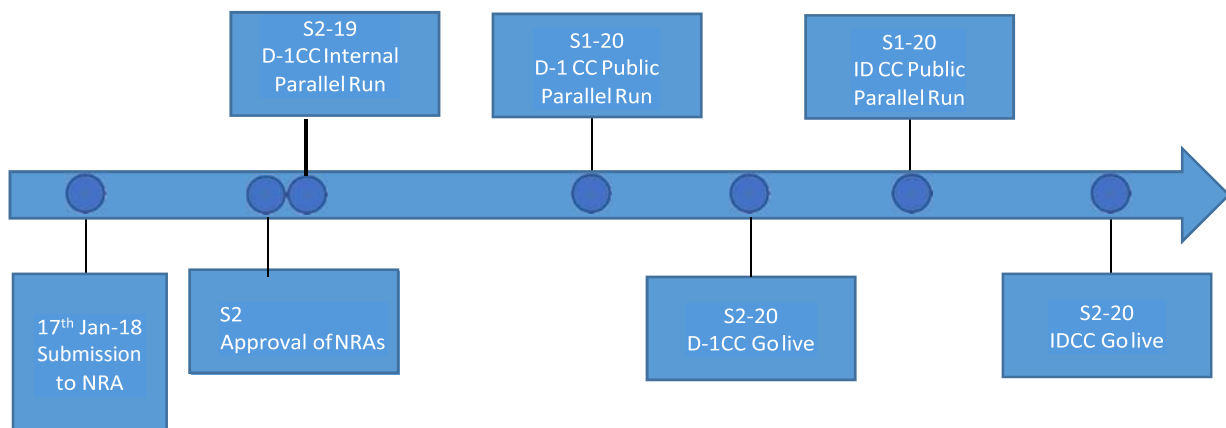


Figure 6: Timeline

##### Main dates:

- 17th of January 2018: Submission of the methodology for approval;
- S2 2018: Approval of the CCM by the SEE NRAs;
- S2 2019: Start of Internal parallel run;
- S1 2020: Start of the capacity calculation for the day-ahead market time-frame, External parallel run;
- 1st July 2020: Go-Live criteria of the Capacity Calculation for the day-ahead market time-frame are met;
- S1 2020: Start of the capacity calculation for the intraday market time-frame, External parallel run;
- 1st October 2020: Go-Live criteria of the Capacity Calculation for the intraday market time-frame are met.