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Core TSOs common coordinated long-term capacity calculation methodology in accordance with article 10 of Commission Regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation

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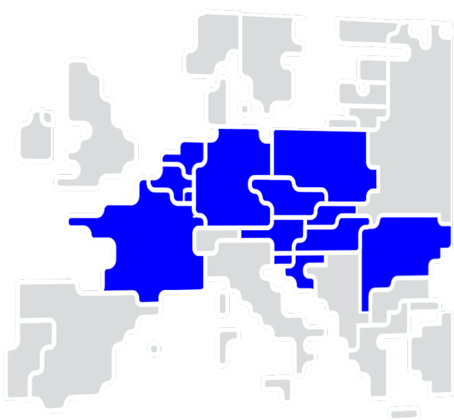


Table of Contents

ALL TSOS OF THE CORE CCR TAKING INTO ACCOUNT THE FOLLOWING,

Whereas

1. This document sets out the common coordinated capacity calculation methodology in accordance with article 10 seq. of Commission Regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on Forward Capacity Allocation (hereafter referred to as the “FCA Regulation”). This methodology is hereafter referred to as the "Long-Term Capacity Calculation Methodology" (LT CCM).
2. The LT CCM takes into account the general principles and goals set in the FCA Regulation as well as Regulation (EC) No 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (hereafter referred to as "Regulation (EC) No 2019/943”.
3. The LT CCM serves the objective of promoting effective long-term cross-zonal trade with long-term cross-zonal hedging opportunities for market participants (article 3(a) of the FCA Regulation) by taking into account the hedging needs of market participants by calculating reliable capacities at an early stage and making them available to market participants, which makes long-term planning possible.
4. The LT CCM contributes to the optimal calculation of long-term capacity (article 3(b) of the FCA Regulation) since it takes into account all critical network elements, coordinates the timings of delivery of inputs, provides a calculation approach and coordinates validation requirements of the capacity calculation between Core TSOs and the Coordinated Capacity Calculator of Core (Core CCC). The optimal calculation is a result of close cooperation and establishment of a smooth interface between capacity calculation by Core TSOs and allocation of the capacity for market parties.
5. The LT CCM contributes to the objective of providing non-discriminatory access to long-term cross-zonal capacity (article 3(c) of the FCA Regulation) by allowing each market participants to access and participate to Long-Term (LT) Auctions organized transparently by the Singe Allocation Platform (SAP) operator. The Core TSOs ensure that the cross-zonal capacity is calculated in such a way that the same LT CCM will apply to all market participants on all respective bidding zone borders in the Core CCR, thereby framing a non-discriminatory playing field amongst market participants.
6. The LT CCM is designed to ensure a fair and non-discriminatory treatment of Core TSOs, ACER, regulatory authorities and market participants (article 3(d) of the FCA Regulation) since it has been developed and adopted within a process that ensures the involvement of all relevant stakeholders and independence of the approving process. Transparency and monitoring of capacity calculation are essential for ensuring its efficiency and understanding. This methodology establishes significant requirements for Core TSOs to publish the information required by market participants, to report the information to regulatory authorities and to analyse the impact of capacity calculation on the market functioning.
7. This LT CCM also contributes to the objective of respecting the need for a fair and orderly forward capacity allocation and orderly price formation (article 3(e) of the FCA Regulation) by making available in due time the information about cross-zonal capacities to be released in the market, and by ensuring a backup solution when capacity calculation fails to provide results.

8. The LT CCM requires Core TSOs to provide market participants with reliable information on cross-zonal capacities and import/export limits for year and month ahead allocation in a transparent and continuous way by publication of the validated results at the Transparency Platform. This includes regular reporting on specific processes within capacity calculation. The LT CCM therefore contributes to the objective of transparency and reliability of information (article 3(f) of the FCA Regulation).

9. Finally, the LT CCM provides a long-term signal for efficient investments in transmission, generation and consumption, and thereby contributes to the efficient long-term operation and development of the electricity transmission system and electricity sector in the Union (article 3 (g) of the FCA Regulation).

10. The LT CCM covers the annual and monthly long-term time frames pursuant to article 9 of the FCA Regulation.

11. In August 2019, the Core TSOs reached the situation described on the article 4(4) of the FCA Regulation. Starting from this date, an iterative process took place, involving Core TSOs, National Regulatory Authorities (NRAs), ACER, the European Commission (EC) for designing an acceptable methodology for all parties. Following the guidance of ACER, this LT CCM considers the flow-based calculation as a target.

12. The LT CCM for the Core CCR is composed of a flow-based (FB) approach in accordance with article 10(5) of the FCA Regulation. In accordance with article 10(5)(a) of the FCA Regulation the FB approach leads to an increase of economic efficiency in the capacity calculation region with the same level of system security. The LT CCM calculates the annual and monthly cross-zonal capacities based on selected timestamps corresponding to different scenarios. Each timestamp delivers for each Critical Network Element and Contingency (CNEC), aside its Power Transfer Distribution Factors (PTDFs) for each of the Core Bidding Zone Borders (BZBs), the Remaining Available Margin (RAM) respecting the operational security limits (in accordance with Article 5 subject to Article 4 describing the Flow Reliability Margin). Those PTDFs and RAM values form identical inputs to perform either a coordinated Net Transfer Capacity (cNTC) extraction or a FB allocation. Therefore, a FB approach clearly respects the same level of security for the grid. Additionally, a FB approach will allocate the cross-zonal capacities by putting the different BZBs in competition with each other in order to receive a portion of the RAM of the CNEC and therefore lead to a better economic efficiency. In opposite, a cNTC extraction is based on a fixed and predefined formula to distribute the RAM of each CNEC over the interdependent borders before converting them into NTC values for each border. Consequently, these NTCs are allocated independently on each interdependent border which essentially limits the competition between interdependent borders. Lack of competition between borders for the capacity of network elements, which these borders are significantly impacting inevitably, leads to loss of economic efficiency in allocating the capacity of such network elements. In accordance with article 10(5)(b) of the FCA Regulation the transparency and accuracy of the flow-based results shall have been confirmed in the capacity calculation region. The LT CC Methodology foresees the reporting and publication of the FB results in accordance with Article 19 and Article 20 in order to obtain a full transparency and accuracy. In accordance with article 10(5)(c) of the FCA Regulation Core TSOs will provide market participants with at least six months to adapt their processes.

13. The LT CCM is structured in three consecutive stages: (i) the definition and provision of capacity calculation inputs by the Core TSOs, (ii) the capacity calculation process by the Core CCC in coordination with the Core TSOs, and (iii) the capacity validation by the Core TSOs in coordination with the Core CCC.

14. Core TSOs determine the final capacity values to meet the form of product regulated in the Core Design of Long-Term Transmission Rights (in accordance with article 31(3) of the FCA Regulation). Those capacity values are subject to the Core Methodology for splitting long-term cross-zonal capacity (in accordance with article 16 of the FCA regulation).

15. The LT CCM is based on forecast models of the transmission system. The inputs of the LT CCM are determined more than a year, respectively more than a month, before the electricity delivery date taking into account the available knowledge at that time. Therefore, the outcomes are subject to inaccuracies and uncertainties that are higher than the inaccuracies and uncertainties of the Day-Ahead (DA) capacity calculation methodology (CCM). The aim of the reliability margin is to cover the risk induced by these forecast errors.

16. Core TSOs remain responsible for maintaining operational security regardless of whether there is a coordinated application of capacity calculation or not. For this reason, they need to validate the calculated capacities to ensure that they do not violate operational security limits. This step may lead to reductions of the values given by the LT CC process. In order to avoid undue discrimination these measures of reduction have to be performed in a coordinated way. In case of missing coordination, the results might be that a Core TSO might have more capacities to the detrimental effect (operational security issues) of another Core TSO.

SUBMIT THE FOLLOWING LT CCM TO THE NATIONAL REGULATORY AUTHORITIES OF THE CORE CCR:

TITLE 1: GENERAL PROVISIONS

Article 1 Subject, Matter and Scope

1. The long-term common capacity calculation methodology as determined in this LT CCM is the common proposal of all Core Transmission System Operators (hereafter referred to as “Core TSOs”) in accordance with article 10 seq. of the FCA Regulation and shall cover the BZBs of the Capacity Calculation Region Core (hereafter referred to as “the Core CCR” – as established by the determination of capacity calculation regions pursuant to article 15 of the CACM Regulation).
2. This LT CCM applies solely to the long-term capacity calculations within the Core CCR and covers the annual and monthly long-term time frames pursuant to article 9 of the FCA Regulation and in line with the Regional Design for LTTR in the Core CCR. Common capacity calculation methodologies within other capacity calculation regions or other timeframes are outside the scope of this proposal.
3. The methodology for splitting long-term capacity is out of scope of this LT CCM, but in the scope of the methodology pursuant to article 16 of the FCA Regulation.

Article 2 Definitions and Interpretation

1. For the purposes of the LT CCM, the terms used shall have the meaning given to them in article 2 of Regulation (EC) 2019/943, article 2 of Regulation (EC) 2013/543 of 14 June 2013 on submission and publication of data in electricity markets, article 2 of Regulation (EC) 2015/1222 establishing a guideline on Capacity Allocation and Congestion Management (hereafter referred to as the “CACM Regulation”) and article 2 of the FCA Regulation.
2. In addition, the following definitions, abbreviations and notations shall apply:

ACER	Agency for the Cooperation of Energy Regulators
AHC	Advanced Hybrid Coupling
AMR	Adjustment of Minimum RAM
BZBs	Bidding Zone Border standing also for set of BZBs
C	Contingency
CACM Regulation	Capacity Allocation and Congestion Management Regulation
CC	Capacity Calculation
CCC	Coordinated Capacity Calculator, as defined in article 2(11) of the CACM Regulation
CCM	Capacity Calculation Methodology
CCR	Capacity Calculation Region, as defined in article 2(3) of the CACM Regulation
CHP	Combined Heat and Power plant
CGM	Common Grid Model, as defined in article 2(2) of the CACM Regulation
CGMM	Common Grid Model Methodology
CNE	Critical Network Element
CNEC	Critical Network Element and Contingency
cNTC	Coordinated Net Transfer Capacity

DA	Day-Ahead, as defined in article 2(34) of the CACM Regulation
DA CCM	Day-Ahead Capacity Calculation Methodology
EC	European Commission
EIC	Energy Identification Code
ENTSO-E	European Network of Transmission System Operators for Electricity
EU	European Union
FCA Regulation	Forward Capacity Allocation Regulation
FB	Flow Based
F_{max}	Maximum Admissible Power Flow
F_{ref}	Reference Flow
$F_{0, Core}$	Flow without commercial exchanges within Core CCR
FRM	Flow Reliability Margin
GSK	Generation Shift Key, as defined in article 2(12) of the CACM Regulation
HVDC	High-Voltage Direct Current
IGM	Individual Grid Model, as defined in article 2(1) of the CACM Regulation
$I_{\max}$	Maximum Admissible Current
LT	Long-Term
LTCC	Long-Term Capacity Calculation
LT CCM	Common Coordinated Long-Term Capacity Calculation Methodology
kA	Kilo Ampère
kV	Kilo Volt
minRAM	Minimum Remaining Available Margin
MPTC	The Maximum Permanent Technical Capacity represents the maximum continuous active power an HVDC element is capable of transmitting, taking into account potential reduced availability due to planned outages of the interconnector asset. This parameter is defined by the interconnector's asset operators.
MTU	Market Time Unit
MW	Megawatt
NP	Net Position
NRA	National Regulatory Authority
NTC	Net Transfer Capacity
OPC	Outage Planning Coordination
OPDE	Operational Planning Data Environment, as defined in article 3(74) of the SO GL Regulation
PTDF	Power Transfer Distribution Factor
PST	Phase-Shifting Transformer
R_{amr}	Minimum RAM factor
RA	Remedial Action, as defined in article 2(13) of the CACM Regulation
RAM	Remaining Available Margin
RG CE	Regional Group Continental Europe
RM	Reliability Margin
SAP	Single Allocation Platform
SCED	Security Constrained Economic Dispatch

SCUC	Security Constrained Unit Commitment
SO GL Regulation	Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation.

3. In this LT CCM, unless the context requires otherwise:
    a. the singular indicates the plural and vice versa;
    b. headings are inserted for convenience only and do not affect the interpretation of this LT CCM; and
    c. any reference to legislation, regulations, directives, orders, instruments, codes or any other enactment shall include any modification, extension or re-enactment of it when in force.

Article 3 Long-Term Capacity Calculation Process

1. The capacity calculation process for the long-term time frame in Core CCR shall apply the FB approach.
2. The year-ahead and month-ahead capacity calculation process shall consist of three main stages:
    a. the creation of capacity calculation inputs by the Core TSOs, in accordance with Title 2;
    b. the capacity calculation process by the Core CCC, in accordance with Title 3; and
    c. the capacity validation by the Core TSOs in coordination with the Core CCC, in accordance with Title 4.
3. In accordance with article 24 of the FCA Regulation, each Core TSOs shall validate the results.

TITLE 2: TREATMENT OF INPUT

Article 4 Reliability Margin Methodology

1. The Core TSOs shall use the latest available Flow- Reliability Margin (FRM) from the DA timeframe. The latest available FRMs are the yearly updated FRMs as defined per CNEC in article 8(11) of the DA CCM and in accordance with article 22 of the CACM Regulation. They are applied for all yearly and monthly capacity calculations. In case the FRM considered in the DA CC have been updated between the yearly and the monthly capacity calculation, the latest FRM is considered in the monthly capacity calculation.
2. As stated in article 8 of the Core DA CCM, the FRM is a percentage of Fmax which covers the uncertainties.
3. Referring to Article 18(1)(2), Core TSOs shall regularly review the FRMs following Article 4(1)(2) and if needed change the FRMs for LT timeframe in order to ensure at least the consistency with their neighbouring CCRs and to ensure an adequate consideration of the uncertainties in the capacity calculation for the long-term timeframes.

Article 5 Methodologies for Operational Security Limits

1. In accordance with article 12 of the FCA Regulation, referring to article 23 of the CACM Regulation, Core TSOs shall respect in the LT CCM the operational security limits in line with article 72 of the SO GL Regulation. The operational security limits used in the LT CCM are the same as those used in operational security analysis. In particular:
   a. to take into account the thermal limits of Critical Network Elements (CNEs), the Core TSOs shall use the maximum admissible current limit (I_{max}) which is the physical limit of a CNE according to the operational security limits in line with article 25 of the SO GL Regulation. The maximum admissible current can be defined by:
      i. fixed limits for all timestamps in the case of transformers and certain types of conductors which are not sensitive to ambient conditions;
      ii. fixed limits for all timestamps of a specific season. Fixed limits are determined separately for each of the seasons.
   b. when applicable, I_{max} shall be defined as a temporary current limit of the CNE in accordance with article 25 of the SO GL Regulation. A temporary current limit means that an overload is only allowed for a certain finite duration.
   c. I_{max} is not reduced by any security margin, as all uncertainties in the LT CCM are covered on each CNEC by the reliability margin in accordance with Article 4.
   d. the value F_{max} in MW, describes the maximum admissible active power flow on a CNE. F_{max} is calculated by the Core CCC from I_{max} by the given formula:

   $$\mathrm{F_{max}} = \sqrt{3} \cdot \mathrm{I_{max}} \cdot \mathrm{U} \cdot \cos(\varphi) \qquad (1)$$

   where I_{max} is the maximum admissible current in kA of a CNE, U is a fixed reference voltage in kV for each CNE, and $\cos(\varphi)$ the power factor. Core CCC shall assume that the share of the CNE loading by reactive power is negligible (i.e. the angle $\varphi = 0$). Thus, factor $\cos\varphi$ equals 1, which means that the element is assumed to be loaded only by active power.

2. Core TSOs shall aim towards determining the maximum admissible current using seasonal limits pursuant to Article 5(1)(a)(ii). If a Core TSO uses the seasonal limits of Imax, this Core TSO has to insert this information into the list of CNECs where I_{max} of CNE is defined.
3. For each CNEC the respective I_{max} and the respective F_{max} of the CNE is used.
4. The Core TSOs shall review and update the methodology for operational security limits in accordance with Article 18.

Article 6 Methodology for Allocation Constraints

1. In case operational security limits cannot be transformed into I_{max} pursuant to Article 5, the Core TSOs may transform them into allocation constraints. For this purpose, the Core TSOs may only use external constraints as a specific type of allocation constraint that limits the maximum import and/or export of a given Core bidding zone.

2. For the implementation of the LT CCM, external constraints are applied by TenneT TSO B.V. and PSE during a transition period of two years following the implementation of this LT CCM in accordance with Article 21(2), as specified in Annex 1 to this LT CCM, explaining the reasons and the methodology for the calculation of external constraints. During the transition period for allocation constraints, the concerned Core TSOs shall calculate the value of external constraints on a yearly and monthly basis for all allocation periods (for PSE only) or at least on a quarterly basis and publish the results as described in Article 19 of the underlying analysis (this obligation is for TenneT TSO B.V. only).

3. In case Core TSOs could not find and implement alternative solutions referred to in the previous paragraphs, they may, by eighteen months after the implementation of this LT CCM in accordance with Article 21(2), together with all other Core TSOs, submit to all Core NRAs a proposal for amendment of this LT CCM in accordance with article 4(12) of FCA Regulation. Such a proposal shall include the following:

   a. the technical and legal justification for the need to continue using the external constraints or introducing external constraints indicating the underlying operational security limits and why they cannot be transformed efficiently into I_{max} and F_{max};
   b. the methodology to calculate the value of external constraints including the frequency of recalculation.

   In case such a proposal has been submitted by all Core TSOs, the transition period for allocation constraints referred to in paragraph 3 shall be extended until the decision on the proposal is taken by all Core NRAs.

4. A Core TSO may discontinue the use of an external constraint. The concerned Core TSO shall communicate this change to the other Core TSOs, to all Core NRAs, and to the market participants at least one month before discontinuation.

5. The Core TSOs shall review and update the methodology for allocation constraints in accordance with Article 18.

Article 7 Methodology for Critical Network Elements and Contingencies Selection

1. Each Core TSO shall provide a list of CNEs, including by default all cross zonal network elements and a list of associated contingencies (Cs) of its own control area based on operational experience to the Core CCC. The result of the process will be an initial pool of CNECs in all subsequent steps of the common Long-Term Capacity Calculation (LTCC).
2. Only those CNECs of the initial pool are considered by each Core TSO for the common LTCC that are marked by the Core CCC to be significantly influenced by the changes in bidding zone Net Positions (NPs) in accordance with article 23(2) of the FCA Regulation.
3. The CNECs shall have a maximum zone-to-zone PTDF higher than a common threshold of 5%. The CNECs of this category will be taken into account by the Core TSOs in all subsequent steps of the common capacity calculation and will determine the long-term capacity.
4. The list of CNEs and the associated Cs can be updated monthly by the respective Core TSOs and published in accordance with Article 19(2).

Article 8 Generation Shift Keys Methodology

1. In accordance with article 13 of the FCA Regulation, Core TSOs developed the following methodology to determine the common Generation Shift Key (GSK):

    a. each Core TSO shall define for its bidding zone and for each timestamp a GSK, which translates a NP change of a given bidding zone into estimated specific injection increases or decreases in the Common Grid Model (CGM). A GSK shall have fixed values, which means that the relative contribution of generation or load to the change in the bidding zone NP shall remain the same, regardless of the volume of the change;

    b. Core TSOs shall take into account the actual information on generation and/or load available in the CGM for each scenario developed in accordance with article 19 of the FCA Regulation in order to select the nodes that will contribute to the GSK;

    c. each Core TSO shall aim to apply a GSK that resembles the dispatch and the corresponding flow pattern, thereby contributing to minimizing the FRMs;

    d. Core TSOs shall define GSK for the calculation period. This GSK created by each Core TSO can be different for each timestamp or can be same for all timestamps;

    e. the Core TSOs belonging to the same bidding zone shall jointly define a common GSK for that bidding zone and shall agree on a methodology for such coordination. For Germany and Luxembourg, each TSO shall calculate its individual GSK and the Core CCC shall combine them into a single GSK for the whole German-Luxembourgian bidding zone, by assigning relative weights to each Core TSO’s GSK. The German and Luxembourgian TSOs shall agree on these weights, based on the share of the generation in each Core TSO’s control area that is responsive to changes in NP, and provide them to the Core CCC.

2. When the proposal for further harmonization of the GSK methodology as listed in article 9(6) of the Core DA CCM is implemented, then no later than twelve months after, the Core TSOs shall use this GSK methodology as a basis to submit to all Core NRAs a proposal for amendment of this LT CCM in accordance with article 4(12) of FCA Regulation. The proposal shall at least include:

a. the criteria and metrics for defining the efficiency and performance of GSKs and allowing for quantitative comparison of different GSKs; and
b. a harmonised GSK methodology combined with, where necessary, rules and criteria for TSOs to deviate from the harmonised GSK methodology.

Article 9 Methodology for Remedial Actions in Capacity Calculation

1. Each Core TSO may define a set of available Remedial Actions (RAs), which is located in its control area. For transparency reasons, all Core TSOs have to be informed about this set of RAs in advance.
2. Only the following RAs are considered:
   - opening or closing of one or more line(s), cable(s), transformer(s), bus bar coupler(s);
   - switching of one or more network element(s) from one bus bar to another;
   - transformer and Phase-Shifting Transformer (PST) tap adjustment.
3. During the implementation timeline as described in Article 21(2), all Core TSOs with the support of the Core CCC will define a common procedure to handle the use of RAs defined in Article 9(1).

Article 10 Scenarios and Calculation Timestamps

1. In accordance with article 19 of the FCA Regulation, referring to article 10(4)(a) of the FCA Regulation, all TSOs in the CCRs shall jointly develop a common set of scenarios to be used in the CGM for each LTCC time frame.

2. In order to meet the above requirements, for each LTCC time frame the Core TSOs shall use the annually created ENTSO-E year-ahead reference scenarios (i.e. default scenarios), in accordance with article 3(1) of CGMM for FCA Regulation in conjunction with article 65 of the SO GL Regulation. This Pan-European process is based on the CGMM as developed in accordance with article 18 of the FCA Regulation and respecting the merging and alignment processes developed in accordance with article 27 of the CACM Regulation.

3. For the month-ahead capacity calculation timeframe, in case of a considerable change such as for example a change in generation pattern following untypical climate and hydrological conditions, compared to the Individual Grid Model (IGM) for the ENTSO-E year-ahead reference scenario, in the grid of a Core TSO, this Core TSO shall update its IGM by incorporating the latest available information as regard to the generation pattern and topology (due to grid element commissioning or decommissioning), while the NP of the bidding zone is maintained unchanged when changing the generation pattern/topology. Therefore, the described updating process with the latest available data does not imply creation of a new scenario for the monthly timeframe and hence does not require approval process specified in article 3(5) of CGMM for FCA Regulation.

4. For each calculation timestamp the Core CCC shall implement the latest available outage plans on the (updated) ENTSO-E CGM by applying the relevant planned outages together with the associated topological switches related to a planned outage using the Outage Planning Coordination (OPC) database (foreseen to be replaced by the Operational Planning Data Environment (OPDE) in accordance with Title 7 of the SO GL Regulation), where all ENTSO-E RG CE TSOs' planned outages and the associated topological switches are stored and regularly updated pursuant to the articles 99 and 100 of the SO GL Regulation.

5. Based on the database mentioned in the previous paragraph the selection of calculation timestamp is as follows:
   a. two timestamps will be selected per granularity of the concerned period, one peak and one valley. This granularity is fixed in advance and is as following:
      i. 1 month for the year-ahead timeframe;
      ii. 1 week for the month-ahead timeframe.
   b. the selected timestamps are the ones with the biggest simultaneous amount of planned relevant grid element outages within the Core CCR.
6. Core TSO may require to include additional planned outages to the calculation process if they are critical and not contained within the set of outages selected based on the Article 10(4)(5).
7. The Core CCC shall generate, after each long-term calculation, a reporting of the base case quality of the CGM for each calculation timestamp after the application of the planned outages pursuant Article 10(4) and Article 10(6). This report shall consist of and include at least the following CNECs per calculated timestamp:
      i. the overloaded CNE(C)s and its level of overload in base case before the application of Minimum Available Remaining Margin (minRAM), i.e. the negative RAM occurred pursuant Article 14 but before application of minRAM pursuant Article 14(4);
      ii. the pre-solved branches that were not subject to minRAM.
8. Following the report specified in Article 10(7), Core TSOs shall commonly take necessary actions in a timely manner to improve the base case quality.
9. This improvement of this base case may be achieved by adjusting among others the following settings in Article 10(9) (i-iv), based on a unanimous agreement among Core TSOs:
      i. the minRAM threshold pursuant to Article 14;
      ii. the application of RA pursuant to Article 9;
      iii. the sensitivity threshold pursuant to Article 13(3);
      iv. the topological switches related to a planned outage pursuant Article 10(4).

   The aforementioned measures influence the size of FB domain without impact on NPs and therefore increase the available margin for trading.
10. Core CCC will report on base case quality of each calculated timestamp pursuant to Article 20(4)(5).

Article 11 Integration of Cross-Zonal HVDC Interconnectors Located within the Core CCR

1. Core TSOs shall provide information on the capacity of their High-Voltage Direct Current (HVDC) interconnector located within the Core CCR at long-term timeframe, the so called maximum permanent technical capacity (MPTC).

2. In order to calculate the impact of the cross-zonal exchange over a HVDC interconnector on the CNECs, the evolved flow-based concept is applied as a basis. Due to this concept, the converter stations of the cross-zonal HVDC shall be modelled as two virtual hubs, which function equivalently as bidding zones. Then the impact of an exchange between two bidding zones A and B over such HVDC interconnector shall be expressed as an exchange from the bidding zone A to the virtual hub representing the sending end of the HVDC interconnector plus an exchange from the virtual hub representing the receiving end of the interconnector to the bidding zone B:

$$PTDF_{A\rightarrow B,l} = (PTDF_{A,l} - PTDF_{VH\_1,l}) + (PTDF_{VH\_2,l} - PTDF_{B,l}) \qquad (2)$$

   With:

$PTDF_{VH\_1,l}$	zone-to-slack $PTDF$ of Virtual hub 1 on a CNEC l, with virtual hub 1 representing the converter station at the sending end of the HVDC interconnector located in bidding zone A
$PTDF_{VH\_2,l}$	zone-to-slack $PTDF$ of Virtual hub 2 on a CNEC l, with virtual hub 2 representing the converter station at the receiving end of the HVDC interconnector located in bidding zone B

3. The PTDFs for the two virtual hubs $PTDF_{VH\_1,l}$ and $PTDF_{VH\_2,l}$ are calculated for each CNEC considered during the calculation and they are added as two additional columns (representing two additional virtual bidding zones) to the existing PTDF matrix, one for each virtual hub.

4. In case of a planned outage of the respective HVDC interconnector, the MPTC will be set to zero.

TITLE 3: DESCRIPTION OF THE CAPACITY CALCULATION PROCESS

Article 12 Description of the CC inputs and outputs

1. For each calculation timestamp the Core TSOs shall provide the Core CCC with the following inputs:

   a. GSKs in accordance with Article 8;

   b. MPTC of HVDC inside the Core CCR in accordance with Article 11;

   c. CNEs and C(s) in accordance with Article 7;

   d. reliability margin in accordance with Article 4;

   e. $Imax$ per CNE in accordance with Article 5(1)(a);

   f. RAs in accordance with Article 9;

   g. allocation constraints in accordance with Article 6.

2. For each calculation timestamp the Core CCC shall provide the following inputs:

   a. CGMs for each selected timestamp and the outage planning from OPC in accordance with Article 10;

   b. the already allocated capacities from the SAP operator of previous timeframes;

   c. the F_{max} per CNE pursuant to Article 5(1)(d).

3. For each calculation timestamp the Core CCC shall use the following calculation parameters:
   a. the minRAM threshold pursuant to Article 14;
   b. the sensitivity threshold pursuant to Article 13(3).

4. When providing the capacity calculation inputs pursuant to Article 12(1), the Core TSOs shall respect the formats commonly agreed between the Core TSOs and the Core CCC while fulfilling the requirements and guidance defined in the CGMM developed in accordance with Section 2 of the FCA Regulation.

5. For each calculation timestamp the Core CCC shall provide the FB parameters, RAM and PTDFs computed in accordance with Article 13 and Article 14 respectively, for TSOs validation in accordance with Article 17.

Article 13 Computation of Power Transfer Distribution Factors

1. For each calculation timestamp using the associated CGM, CNECs and GSKs, the Core CCC shall calculate for each CNEC its PTDFs for each Core BZB representing the influence of a variation of a commercial exchange between bidding zones on a CNEC. The calculation process is mathematically described below. Firstly, zone-to-slack PTDFs shall be derived as follows:

$$\mathbf{PTDF}_{\text{zone-to-slack}} = \mathbf{PTDF}_{\text{node-to-slack}} * \mathbf{GSK}_{\text{node-to-zone}} \quad (3)$$

With:

$\mathbf{PTDF}_{zone-to-slack}$ matrix of zone-to-slack $PTDFs$ (columns: bidding zones; rows: CNECs)

$\mathbf{PTDF}_{node-to-slack}$ matrix of node-to-slack $PTDFs$ (columns: nodes; rows: CNECs)

$\mathbf{GSK}_{node-to-zone}$ matrix containing the $GSKs$ of all bidding zones (columns: bidding zones; rows: nodes; sum of each column equal to one).

The zone-to-slack $PTDFs$ as calculated above can also be expressed as zone-to-zone $PTDFs$. A zone-to-slack $PTDF_{A,l}$ represents the influence of a variation of a NP of bidding zone A on a CNEC l and assumes a commercial exchange between a bidding zone and a slack node. A zone-to-zone $PTDF_{A \to B,l}$ represents the influence of a variation of a commercial exchange from bidding zone A to bidding zone B on CNEC l. The zone-to-zone $PTDF_{A \to B,l}$ can be derived from the zone-to-slack $PTDFs$ as follows:

$$PTDF_{A \to B,l} = PTDF_{A,l} - PTDF_{B,l} \quad (4)$$

2. Using zone-to-zone PTDFs, the Core CCC shall determine flow on a CNEC in the situation without commercial exchanges within the Core CCR as follows:

$$\vec{F}_{0,Core} = \vec{F}_{ref} - \mathbf{PTDF_f} \ \overrightarrow{Exchanges}_{ref,Core} \quad (5)$$

With:

$\vec{F}_{0,Core}$	flow per CNEC in the situation without commercial exchanges within the Core CCR
$\vec{F}_{ref}$	flow per CNEC in the CGM with commercial exchanges obtained using DC load flow for the calculation timestamp
$\mathbf{PTDF_f}$	zone-to zone power transfer distribution factor matrix for CNECs of the Core CCR
$\overrightarrow{Exchanges}_{ref,Core}$	Core commercial exchanges between the bidding zones as mentioned in the reference program associated with the CGMs of the ENTSO-E scenarios

3. The Core CCC may apply the common threshold for minimum sensitivity of CNECs using the following formula:

If $PTDF_{A \to B,l} \leq threshold$ then the $PTDF_{A \to B,l}$ is set to zero before starting the calculation process.

Article 14 Computation of the available margins on critical network elements

1. Following the PTDFs' computation of Article 13, the Core CCC shall compute the RAM based on CNEC maximum admissible power flow in accordance with Article 5 at Core zero-balance situation. The uncertainties of flows by using an FRM in accordance with Article 4 should be taken into account. The RAM calculation is mathematically described as follows:

$$RAM_l^+ = Fmax_l - FRM_l^+ - \vec{F}_{0,Core} \quad (6)$$

$$RAM_l^- = Fmax_l - FRM_l^- + \vec{F}_{0,Core} \quad (7)$$

With:

RAM_l^+ and FRM_l^+	RAM and FRM of CNEC l in one direction of monitoring (direction is defined by TSO)
RAM_l^- and FRM_l^-	RAM and FRM of CNEC l in direction of monitoring opposite to the previous direction (direction is defined by TSO).

2. To calculate the minRAM in accordance with Article 14(4), the minRAM factor (R_{amr}) is defined as 20% and will be subject to a review by all Core TSOs 2 years after the LT CCM go live.

3. The Core CCC shall check if the RAM for each CNEC determining the cross-zonal capacity is not below the defined minRAM.

4. In case the RAM determined according to Article 14(1) is below the minRAM, the Core CCC shall increase the RAM according to the following process:

   a. The main objective of the minRAM is to ensure that at least a specific percentage of F_{max}, a minRAM factor (R_{amr}) as defined in Article 14(4)(c), of F_{max} is reserved for the commercial exchanges. Therefore, the following equation needs to apply for each CNEC l:

$$RAM_l \geq R_{amr} * F_{max_l} \quad (8)$$

   b. The Adjustment of Minimum RAM (AMR) aims to ensure that the previous inequality is always fulfilled; therefore, AMR is added as follows:

$$RAM_l + AMR = R_{amr} * F_{max_l} \quad (9)$$

   c. The AMR for a CNEC is determined with the following equation:

$$AMR = \max\left(R_{amr} * F_{max_l} - \left(F_{max_l} - FRM - F_{0,Core}\right),\ 0\right) \quad (10)$$

   d. Finally, the RAM will be adjusted due to the following equation:

$$RAM_l = F_{max_l} - FRM - F_{0,Core} + AMR \quad (11)$$

Article 15 Consideration of Non-Core CCR Bidding Zone Borders

1. Where CNEs within the Core CCR are impacted by electricity exchanges outside the Core CCR, Core TSOs shall take this impact into account.
2. Core TSOs shall consider the electricity exchanges on BZBs outside the Core CCR as fixed input to the LT CCM, as prepared in the common set of ENTSO-E year-ahead reference scenarios, with unchanged NPs. These electricity exchanges, defined as best forecasts of NPs and flows in the LTCC models, are defined and agreed based on the CGMM as developed in accordance with article 18 of the FCA Regulation and are incorporated in the CGM. Uncertainties related to the electricity exchanges forecasts are implicitly considered within the FRM.
3. Treatment of non-Core CCR BZBs with adjacent CCRs in the LT CCM will be studied by the Core TSOs in order to take into account non-Core CCR influence and to heed article 21(1)(b)(vii) of the CACM Regulation. The Core TSOs will start to study solutions for considering influence of non-Core CCR BZBs immediately after implementation of Advanced Hybrid Coupling (AHC) in the Core DA CCM.

Article 16 Fallback Procedures

1. Taking into account the requirements stipulated in article 10(7) of the FCA Regulation, and referring to article 21(3) of the CACM Regulation, in the event that a LTCC process is unable to produce results, a fallback procedure shall be applied.
2. In case the initial capacity calculation does not lead to any results, the Core CCC shall try to solve the problem and perform the LTCC again within a new agreed timeframe to make such calculation.
3. If the Core CCC is not able to deliver the long-term FB parameters to the SAP within the new timeframe in accordance with Article 19(2), Core TSOs shall bilaterally agree on NTC values for the relevant time frame(s). The Core TSOs shall commonly coordinate and validate these bilaterally agreed NTC values.
4. The Core CCC shall send the NTC values following Article 19(3) to the SAP.

TITLE 4: VALIDATION PROCESS

Article 17 Validation Methodology

1. In accordance with article 15 and article 24 of the FCA Regulation, referring to article 26 of the CACM Regulation, the Core TSOs shall have the right to correct long-term capacity relevant to the Core TSO's BZBs for reasons of operational security during the validation process. In exceptional situations long-term capacities can be reduced by all Core TSOs. These potential situations are at least:
    a. an occurrence of an exceptional contingency or forced outage as defined in article 3 of the SO GL Regulation;
    b. when RAs, pursuant to Article 9, that are needed to ensure the calculated capacity on all CNECs, are not sufficient;
    c. a mistake in the input data, that leads to an overestimation of long-term capacity from an operational security perspective, occurred;
    d. a potential need to cover reactive power flows on certain CNECs.
2. The validation process refers to the outcomes of the long-term capacity calculation process within the Core CCR. The validation process is composed of two parts and explained in more detail in Article 17(3)(4):
    a. individual verification of the calculated capacities for each calculated timestamp after the change of input parameters in accordance with Article 17(3);
    b. coordinated validation of the final capacities.
3. The Core TSOs shall analyse individually whether the calculated capacity could violate operational security limits, and whether they have sufficient measures to avoid such violations. The verification is performed as follows:
    a. in case of a required reduction due to situations as defined in Article 17(1)(a), (b) and (d), a Core TSO may correct its initial FRM in accordance with Article 4; or decrease RAM, even below the minRAM threshold in accordance with Article 14(2) if necessary, for its own CNECs;
    b. in case of a situation as defined in Article 17(1)(a), Core TSOs using external constraints may also request to adapt the external constraints to reduce the capacity for its BZBs;
    c. in case of a situation as defined in Article 17(1)(c), Core TSOs may also request a common decision to calculate capacities with the correct input data.
4. When the process of individual verification of the calculated capacities is completed, then the final capacity validation process takes place in a coordinated way, whereby Core TSOs may require a reduction in calculated capacities for reasons of operational security.

TITLE 5: UPDATES

Article 18 Review and Updates

1. Based on article 3(f) of the FCA Regulation and in accordance with article 21(3) of the FCA Regulation, referring to article 27 of the CACM Regulation, all Core TSOs shall regularly and at least once a year review and update the key input and output parameters listed in article 27(4)(a) to (d) of the CACM Regulation. Should the operational security limits, CNEs, Cs and import/export limits used for the common capacity calculation need to be updated based on this review, Core TSOs shall publish the changes simultaneously with the update and publication as mentioned in article 24 of the Core DA CCM.
2. In case the review proves the need of an update of the reliability margins, Core TSOs shall publish the updated values of reliability margin at least one month before their implementation.
3. The review of the methodology for allocation constraints by the Core TSOs shall take place before the start of each LT capacity calculation timeframe.
4. The review by the Core TSOs of the set of RAs taken into account in capacity calculation, in accordance with Article 9 shall include at least an evaluation of the efficiency of the RAs applied.
5. In case the review proves the need for updating the application of the methodologies for determining GSKs, CNEs, and Cs referred to in articles 12 and 13 of the FCA Regulation, referring respectively to the articles 23 to 24 of the CACM Regulation, article 4(12) of the FCA Regulation applies. After approval by the Core NRAs, Core TSOs shall publish changes made in the methodologies at least three months before their implementation.
6. Any changes of parameters listed in article 27(4) of the CACM Regulation have to be communicated to market participants, ACER and Core NRAs.
7. The impacts of any changes of parameters listed in article 27(4)(d) of the CACM Regulation and of import/export limits have to be communicated to market participants, ACER and Core NRAs. If any change leads to an adaption of the methodology, the Core TSOs shall make a proposal for amendment of this methodology according to article 4(12) of the FCA Regulation and submit it for approval to the Core NRAs.
8. In case the following calculation parameters are subject to change, the Core TSOs will publish and implement the updated calculation parameters after approval by the Core NRAs:
   a. minRAM factor according to Article 14(2);
   b. PTDF threshold according to Article 7(3).
9. Core TSOs shall publish updated set of calculation parameters three months before their application.

TITLE 6: REPORT

Article 19 Publication of Data

1. The data as set forth in Article 19(2) shall be published regularly by the Core CCC on a dedicated online communication platform representing all Core TSOs. To enable market participants to have a clear understanding of the published data, the handbook that has been prepared and published by Core TSOs on this communication platform in the framework of article 25(1) of the DA CCM, shall be extended with the information related to the LTCC, using the same format and data platform.
2. In accordance with article 3(f) of the FCA Regulation, at least the following data items shall be published after each LTCC by the Core CCC in addition to the data items and definitions of Commission Regulation (EU) No 543/2013 on submission and publication of data in electricity markets:
    a. CNECs names;
    b. CNECs EIC codes;
    c. detailed breakdown of the final FB parameters per CNEC: RAM, Fmax, Fref, $F_{0,Core}$, respective reliability margin, zone-to-slack PTDFs;
    d. allocation constraints;
    e. NTC values in case of activation of the fallback procedure in accordance with Article 16(3).
3. Any change in the identifiers used in paragraphs 2(a) and 2(b) of Article 19 shall be publicly notified at least one month before its entry into force.
4. An individual Core TSO may withhold the information referred to in paragraph 2(a) and 2(b) of Article 19 if it is classified as sensitive critical infrastructure protection related information in their Member States as provided for in point (d) of Article 2 of Council Directive 2008/114/EC of 8 December 2008 on the identification and designation of European critical infrastructures and the assessment of the need to improve their protection. In such a case, the information referred to in paragraph 2(a) and 2(b) of Article 19 shall be replaced with an anonymous identifier which shall be stable for each CNEC across all LTCC timeframes. The anonymous identifier shall also be used in the other TSO communications related to the CNEC and when communicating about an outage or an investment in infrastructure. The information about which information has been withheld pursuant to this paragraph shall be published on the communication platform referred to in Article 19(1).
5. The Core NRAs may request additional information to be published by the Core TSOs. For this purpose, all Core NRAs shall coordinate their requests among themselves and consult it with stakeholders and ACER. Each Core TSO may decide not to publish the additional information, which was not requested by its competent NRA.

Article 20 Monitoring and Information to Regulatory Authorities

1. The Core TSOs shall provide to Core NRAs data on LTCC for the purpose of monitoring its compliance with this methodology and other relevant legislation. The reporting framework shall be developed in coordination with Core NRAs and updated and improved when needed.
2. At least, the information on non-anonymized names of CNECs as referred to Article 19(2)(a)(b) shall be provided to Core NRAs on a yearly basis for each CNEC after the yearly calculations and on a monthly basis for each CNEC after each monthly calculation. This information shall be in a format

that allows easily to combine the CNEC names with the information published in accordance with Article 19(2).

3. Core NRAs may request additional information to be provided by Core TSOs. For this purpose, Core NRAs shall coordinate their requests and forward the coordinated request to Core TSOs. Individual not coordinated requests of one NRA are not in scope of this methodology and shall be dealt with on a national level.

4. The Core CCC, with the support and after approval of the Core TSOs where relevant, shall submit an annual monitoring report containing:
   a. the RAs in accordance with Article 9 on capacity calculation and in accordance with Article 10 on increasing base case quality;
   b. additional planned outages with requesting Core TSO names applied in accordance with Article 10(6);
   c. the quality of the data published on the dedicated online communication platform as referred to in Article 19, with a supporting detailed analysis of a failure to achieve sufficient data quality standards by the concerned Core TSOs, where relevant;
   d. the Core TSOs´ report on their continuous monitoring of the effects and performance of the application of this methodology;
   e. the monitoring of the accuracy of non-Core exchanges in the CGM.

5. The Core CCC shall submit a quarterly monitoring report on capacity validation to the Core NRAs after approval by the Core TSOs. In each quarterly monitoring report, the Core CCC shall provide all the information on the reductions of calculated capacity after individual validation and coordinated validation of capacities according to Article 17(3)(4). The quarterly monitoring report shall include at least the following information for each reduced capacity and for each timestamp:
   a. the identification of the CNEC;
   b. the volume of reduction of capacity;
   c. the detailed reason(s) for reduction, including the operational security limit(s) that would have been violated without reductions, and under which circumstances they would have been violated;
   d. the proposed measures to avoid similar reductions in the future.

6. The quarterly monitoring report of the Core CCC shall also include at least the following aggregated information:
   a. statistics on the number, causes, volume and estimated loss of economic surplus of applied reductions by different Core TSOs; and
   b. general measures to avoid capacity reductions in the future.

7. Core TSOs shall report to the Core NRAs in the situation when no capacity is offered by the Core TSOs via the monthly timeframe. This report shall contain a justification for the difference between the predicted monthly capacity in the yearly timeframe and the actual allocated monthly capacity.

TITLE 7: IMPLEMENTATION AND LANGUAGE

Article 21 Timescale for Implementation

1. Core TSOs shall publish this methodology without undue delay after it has been approved by the relevant NRAs or a decision has been taken by ACER in accordance with article 4(9) of the FCA Regulation.
2. Core TSOs shall implement this FB capacity calculation methodology allowing a FB allocation for LT timeframe within 5 years after approval of this methodology. The implementation process shall start on the date of approval of this methodology. The Core coordinated LT capacities are the ones resulting from the FB capacity calculation process after the implementation of this methodology.
3. The implementation process shall consist of the following steps:
    a. internal parallel run, during which the Core TSOs shall test the operational processes for the LTCC inputs, the LTCC process and the long-term capacity validation and develop the appropriate IT tools and infrastructure;
    b. external parallel run, during which the Core TSOs will continue testing their internal processes and IT tools and infrastructure. In addition, the Core TSOs will involve the SAP operator to test the implementation of this methodology and market participants to test the effects of applying this methodology on the market. In accordance with article 10(5)(c) of FCA Regulation this phase shall not be shorter than 6 months.

4. During the internal parallel run, the Core TSOs shall continuously monitor the effects and the performance of the application of this methodology. During the external parallel run Core TSOs shall publish the monitoring and performance criteria without undue delay. For this purpose, Core TSOs will develop in coordination with the Core NRAs the monitoring and performance criteria. After the implementation of this methodology, the outcome of this monitoring shall be summarized in an annual report.
5. Until the implementation of this FB methodology, the Core TSOs will continue the NTC allocation and will improve the coordination at Core CCR level.

Article 22 Language

1. The reference language for this LT CCM shall be English.

2. For the avoidance of doubt, where Core TSOs need to translate this LT CCM into their national language(s), in the event of inconsistencies between the English version published by Core TSOs in accordance with article 4(13) of the FCA Regulation and any version in another language, the relevant Core TSOs shall be obliged to dispel any inconsistencies by providing a revised translation of this LT CCM to their relevant Core NRAs.

ANNEX 1: JUSTIFICATION FOR CALCULATION OF EXTERNAL CONSTRAINTS AND ITS APPLICATION

The following section depicts in detail the justification of usage and methodology currently used by each Core TSO to design and implement external constraints, if applicable. The legal interpretation on eligibility of using external constraints and the description of their contribution to the objectives of the FCA Regulation is included in the Explanatory Document.

1. **Netherlands:**

TenneT TSO B.V. may use an external constraint to limit the import and export of the Dutch bidding zone.

Technical and legal justification

The combination of voltage constraints and limitations following from using a linearized GSK make it necessary for TenneT TSO B.V. to apply external constraints. Voltage constraints justify the use of a maximum import constraint, because a certain amount of power needs to be generated within the Netherlands to prevent violation of voltage constraints (i.e. to prevent voltage dropping below the lower safety limit). To prevent the deviations between forecasted and realised values of generation in-feed following from the linear GSK to reach unacceptable levels, it is necessary to limit the feasible net position range for the Dutch import and export net position. This last point is explained in more detail below.

The long-term capacity calculation methodology uses a Generator Shift Key (GSK) to determine how a change in net position is mapped to the generating units in a specific bidding zone. The algorithm requires that the GSK is linear and that by applying the GSK the minimum and maximum net position ('the feasibility range') of a bidding zone can be reached. TenneT TSO B.V. applies a GSK method that aims at establishing a realistic generator schedule for every hour and which is applicable to every possible net position within the flow-based domain. In order to realise this, generators can be divided in three groups based on a merit order: (i) rigid generators that always produce at maximum power output, (ii) idle generators that are out-of-service and (iii) 'swing generators' that provide the 'swing capacity' to reach all intermediate net positions required by the algorithm for a specific grid situation. To reach the maximum net position, all 'swing generators' shall produce at maximum power. To reach the minimum net position, all 'swing generators' shall produce at minimum power. The absolute difference between the minimum and maximum net position thus determines the amount of required 'swing capacity', i.e. the total capacity required from 'swing generators'.

If TenneT TSO B.V. would not apply this limitations and higher import and export net positions would be possible, several generators that in practice operate as rigid generators (e.g. CHPs, coal fired power plants etc.) would need to be modelled as 'swing generators'. In some cases, a switch of a generator from 'idle' to 'swing' or from 'rigid' to 'swing' could mean a jump of roughly 50% in the power output of such a power plant, which in turn has significant impact on the forecasted power flows on the CNECs close to that power plant. This results in a reduced accuracy of the GSK as the generation of these plants is modelled less accurately and the deviations between the forecasted and realised flows on particular CNECs increase to unacceptable levels with significant impact on the capacity domain. The consequence of this would be that higher FRMs need to be applied to partly cover these deviations, which will constantly limit the available capacity for the market. To prevent too large deviations in generation in-feed, the total feasibility range, which should be covered by the GSK, thus needs to be limited with external constraints.

The Netherlands is a small bidding zone with, in comparison to other bidding zones, a lot of interconnection capacity which implies a very large feasibility range compared to the total installed capacity. E.g. TenneT TSO B.V. has applied limit of 5 GW for both the import and export position in the past, already implying a feasibility range of 10 GW on a total of roughly 15 GW generation capacity included in the GSK at that point in time. For other bidding zones with a much higher amount of installed capacity or relatively less interconnection capacity, the relative amount of 'swing capacity' in their GSK is much lower and therefore also the deviations between forecasted and realised generation are lower. Or in other words, the maximum feasibility range which can be covered by the GSK without increasing deviations between forecasted and realised generation to unacceptable levels, is larger than the total installed interconnection capacity for these bidding zones, making it not necessary to use external constraints as a measure to limit these deviations.

Methodology to calculate the value of external constraints

TenneT TSO B.V. determines the maximum import and export constraints for the Netherlands based on studies, which combine a voltage collapse analysis, stability analysis and an analysis on the increased uncertainty introduced by the (linear) GSK during different extreme import and export situations in accordance to Article 38 of the SO GL Regulation. The studies shall be performed and published at least on an annual basis and updated every time this external constraint had a non-zero shadow price in more than 0.1% of hours in a given quarter.

2. **Poland:**

PSE may use an external constraint to limit the import and export of the Polish bidding zone.

Technical and legal justification

Implementation of external constraints as applied by PSE is related to integrated scheduling process applied in Poland (also called central dispatching model) and the way how reserve capacity is being procured by PSE. In a central dispatching model, in order to balance generation and demand and ensure secure energy delivery, the TSO dispatches generating units taking into account their operational constraints, transmission constraints and reserve capacity requirements. This is realised in an integrated scheduling process as a single optimisation problem called security constrained unit commitment (SCUC) and economic dispatch (SCED).

The integrated scheduling process starts after the day-ahead capacity calculation and SDAC and continues until real-time. This means that reserve capacity is not blocked by TSO in advance of SDAC and in effect not removed from the wholesale market and SDAC. However, if balancing service providers (generating units) would already sell too much energy in the day-ahead market because of high exports, they may not be able to provide sufficient upward reserve capacity within the integrated scheduling process1. Therefore, one way to ensure sufficient reserve capacity within integrated scheduling process is to set a limit to how much electricity can be imported or exported in the SDAC.

[1] This conclusion equally applies for the case of lack of downward balancing capacity, which would be endangered if balancing service providers (generating units) sell too little energy in the day-ahead market, because of too high imports.

External constraints are determined for the whole Polish power system, meaning that they are applicable simultaneously for all CCRs in which PSE has at least one bidding zone border (i.e. Core, Baltic and Hansa). This solution is the most efficient. Considering such constraints separately in each CCR would require PSE to split global constraints into CCR-related sub-values, which would be less efficient than maintaining the global value. Moreover, in the hours when Poland is unable to absorb any more power from outside due to violated minimal downward reserve capacity requirements, or when Poland is unable to export any more power due to insufficient upward reserve capacity requirements, Polish transmission infrastructure is still available for cross-border trading between other bidding zones and between different CCRs.

Methodology to calculate the value of external constraints

When determining the external constraints, PSE takes into account the most recent information on the technical characteristics of generation units, forecasted power system load as well as minimum reserve margins required in the whole Polish power system to ensure secure operation and forward import/export contracts that need to be respected from previous capacity allocation time frames.

The constraints are calculated according to the below equations:

$$EXPORT_{constraint} = P_{CD} - (P_{NA} + P_{ER}) + P_{NCD} - (P_L + P_{UPres}) \quad (1)$$

$$IMPORT_{constraint} = P_L - P_{DOWNres} - P_{CD_{min}} - P_{NCD} \quad (2)$$

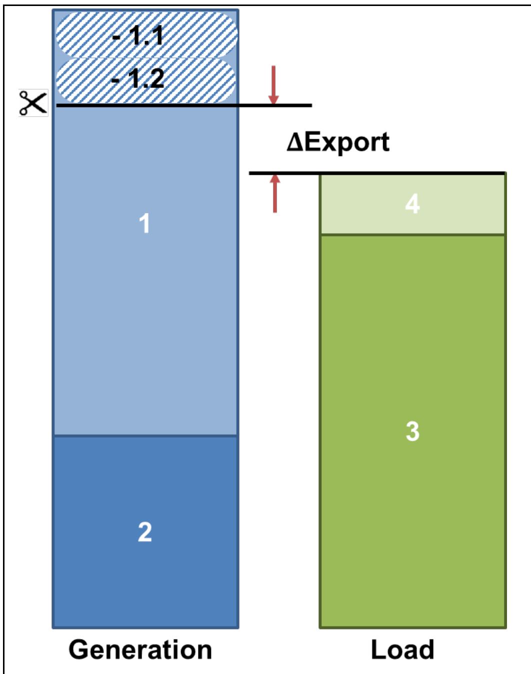
Where:

P_{CD}	Sum of available generating capacities of centrally dispatched units as declared by generators2
$P_{CD_{min}}$	Sum of technical minima of available centrally dispatched generating units
P_{NCD}	Sum of schedules of generating units that are not centrally dispatched, as provided by generators (for wind farms: forecasted by PSE)
P_{NA}	Generation not available due to grid constraints (both planned outage and/or anticipated congestions)
P_{ER}	Generation unavailability's adjustment resulting from issues not declared by generators, forecasted by PSE due to exceptional circumstances (e.g. cooling conditions or prolonged overhauls)
P_L	Demand forecasted by PSE
P_{UPres}	Minimum reserve for upward regulation
$P_{DOWNres}$	Minimum reserve for downward regulation

[2] Note that generating units which are kept out of the market on the basis of strategic reserve contracts with the TSO are not taken into account in this calculation.

For illustrative purposes, the process of practical determination of external constraints in export direction in the framework of the long-term capacity calculation is illustrated below in Figure 1. The figure illustrate how a forecast of the Polish power balance for the delivery period is developed by PSE in order to determine reserves in generating capacities available for potential exports, for the long-term market.

External constraint in export direction is applicable if Export is lower than the sum of cross-zonal capacities on all Polish interconnections in export direction.



1 Sum of available generating capacities of centrally dispatched units as declared by generators, reduced by:
  - 1.1 Generation not available due to grid constraints
  - 1.2 Generation unavailability's adjustment resulting from issues not declared by generators, forecasted by PSE due to exceptional circumstances (e.g. cooling conditions or prolonged overhauls)

2 Sum of schedules of generating units that are not centrally dispatched, as provided by generators (for wind farms: forecasted by PSE)

3 Demand forecasted by PSE

4 Minimum necessary reserve for up regulation

Figure 1 Determination of External constraint in export direction (generating capacities available for potential exports) in the framework of the long-term capacity calculation.

Frequency of review

External constraints are determined in a continuous process based on the most recent information, for each capacity allocation time frame.

Explanatory document to the Core CCR TSOs common coordinated long-term capacity calculation methodology in accordance with article 10 of Commission Regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation

November 2020

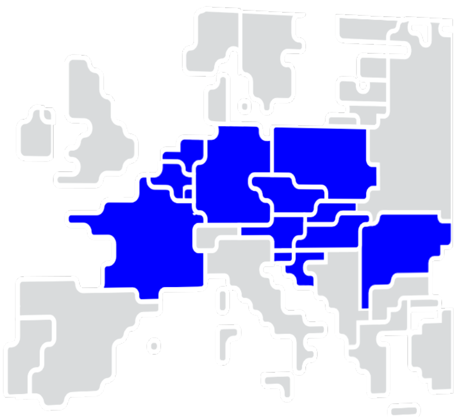


Table of Contents

1. INTRODUCTION

Sixteen Transmission System Operators (TSOs) follow a decision of the Agency for the Cooperation of Energy Regulators (ACER) to combine the existing regional initiatives of former Central Eastern Europe and Central Western Europe to the enlarged European Core CCR (Decision 06/2016 of November 17, 2016). The countries within the Core CCR are located in the center of Europe which is why the Core CCR Project has a substantial importance for the further European market integration.

In accordance with article 10 of the FCA Regulation, the Core TSOs have developed a common long-term capacity calculation methodology proposal (hereafter Core LT CCM or Proposal).

The aim of this explanatory document is to provide a detailed description of the Core LT CCM and relevant processes. This paper considers the main elements of the relevant legal framework (i.e. FCA and CACM Regulation, 2019/943, 543/2013).

Title 2 of this document covers the input aspects, Title 3 describes the capacity calculation process, Title 4 details the validation methodology, Titles 5 deals with updates and publication and Title 6 mentions the implementation timeline.

1.1 Approach for Finalization of the Core LT CCM

Although the Core TSOs started the development of the required Core LT CCM in an early stage, it is highly challenging for the 16 TSOs (13 countries) in the Core CCR to deliver a final CCM.

Therefore, the Core TSOs follow the approach for finalization of the Core LT CCM mentioned hereafter:

1. The publication of the first draft of the Approval Package accompanying the public consultation from September 16, 2020 to October 16, 2020. This first draft contains the Core LT CCM and its accompanying explanatory document, including a high level description of all the steps mentioned in the High Level Business Process (HLBP) on how to determine the final values and methods for e.g. Scenarios, CNEC selection, GSK methodology and the treatment of RAs and Scenarios (including outages).
2. Submission of the final Approval Package for Core NRA approval of the Core LT CCM Proposal ultimately by November 2020.
3. This final package contains:
   - Core LT CCM, including updates based upon Core NRAs' and stakeholders' comments, if any;
   - explanatory document, including a description of all the steps mentioned in the HLBP on how to determine the final values and methods for e.g. CNEC selection, GSK methodology and the treatment of RAs and Scenarios (including outages), as well as updates based upon Core NRAs' and stakeholders' comments, if any.

Main reasons for Core TSOs to propose this approach:

- to be able to develop a Core LT CCM that meets stakeholders' and Core NRAs' expectations as reflected in feedback, if any, received after public consultation.

1.2 Core TSO Deliverable Report

Currently no deliverable reports are foreseen.

1.3 High Level Business Process

This section refers to Article 3 of the Core LT CCM.

See below Figure 1 depicting the Core Long-Term Capacity Calculation (LTCC) HLBP:

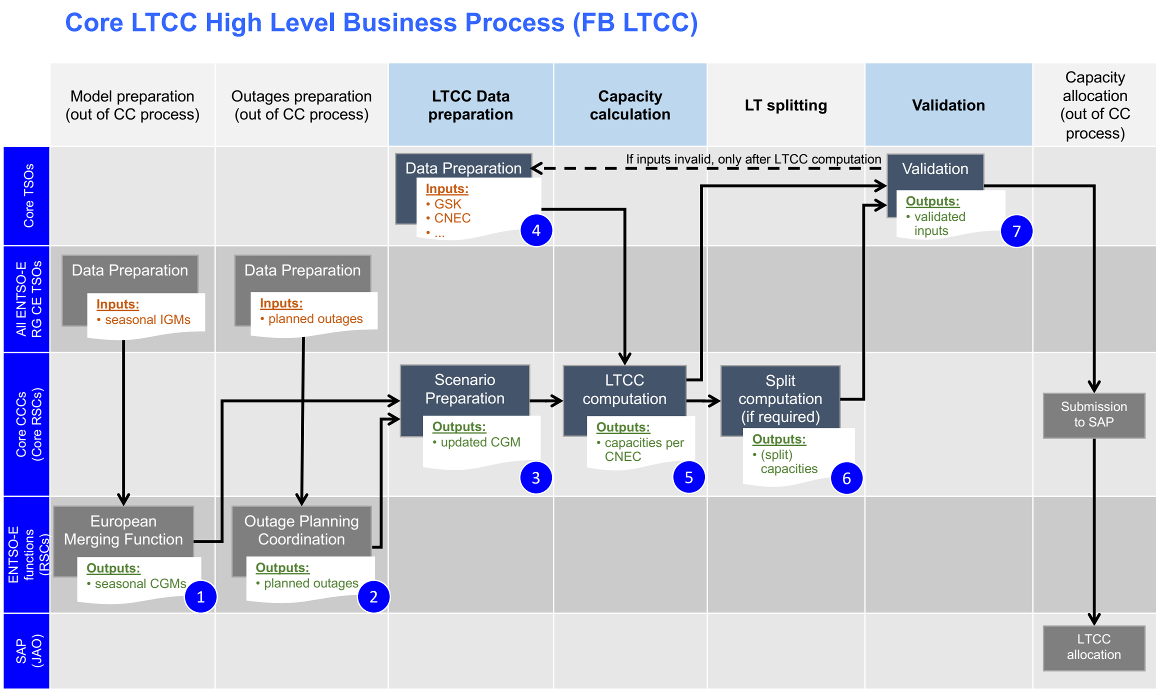


Figure 1: High Level Business Process

There are 6 steps shown (numbered); the steps dedicated to the Core LTCC process are shown in the three columns, marked light blue (LTCC Data preparation, Capacity calculation and Validation). The rows indicate which role is responsible for the process.

Data preparation for Core LTCC relies on all TSOs' European Network of Transmission System Operators for Electricity (ENTSO-E) processes. These all TSOs' data preparation steps are shown in the first two columns.

Herewith follows a description of the 6 steps:

1. The step 1 is related to an all TSOs' ENTSO-E process (article 67 of the SO GL Regulation and the FCA-CGMM). Each Core TSO provides an IGM for each seasonal CGM. IGMs are merged into seasonal default CGMs by the Core CCC each year for the next calendar year.
2. The step 2 is also related to an all TSOs´ ENTSO-E process (Title 3 of the SO GL Regulation). Availability plans (outage plans) are provided by each Core TSO to a common database. This database and the communication between the database and the Core TSOs are managed by the Core CCC. Preliminary outage plans of ENTSO-E TSOs are available in the OPC database from 1 November for the next calendar year (article 97 of the SO GL Regulation).

Planned Core processes:

3. Based on default CGMs (see step 1) and the preliminary outage plans of all Core TSOs for the whole year (see step 2), in the step 3 the Core CCC shall create the forecasted network models for any of the selected time stamps; this is achieved by incorporating the relevant outages (see Article 10 on Scenarios) in the CGMs.

4. In the step 4, each Core TSO provides to the Core CCC the necessary input data: these are e.g. GSK and CNEC files (see Article 12(1) presenting all relevant inputs for calculation).
5. During the step 5, the Core CCC performs the actual capacity calculation based on the Core LT CCM. This step represents all necessary calculations performed by the Core CCC and is described in Title 3: the step delivers results of FB CC (RAM per CNEC).
6. In the step 6, the capacity calculation outcomes can be subject to LT Splitting Rules Methodology pursuant to article 16 of FCA Regulation. For further details, please see the LT Splitting Rules Methodology.
7. During the 7th step, the Core TSOs validate the capacity calculation results obtained before and after splitting (see Article 17 on Validation), upon which the (splitted) results of the step 6 are submitted to the SA) by the Core CCC. This procedure is set in accordance with the article 24 of FCA Regulation. In case a Core TSO declares CC results obtained before splitting as invalid, a new calculation round could be triggered with necessary adjustment of input data.

These briefly described relevant steps and related methodologies are explained more in detail in the next sections.

2 TREATMENT OF INPUT

2.1 Reliability Margin Methodology

This section refers to Article 4 of the Core LT CCM.

Article 11 of the FCA Regulation requires a methodology for reliability margin (RM), meeting the requirements set out in article 22 of the CACM Regulation.

In article 2(14) of the CACM Regulation the following definition is given:

"Reliability Margin means the reduction of cross-zonal capacity to cover the uncertainties within capacity calculation". FRM means the margin reserved on the permissible loading of a CNE or cross zonal capacity to cover uncertainties of power flows in the period between the capacity calculation and real time, taking into account the availability of RA.

The uncertainties covered by the FRM values are among others:

a. Core external transactions (out of Core CCR control: both between Core region and other CCRs as well as among TSOs outside the Core CCR);

b. generation pattern including specific wind and solar generation forecast;

c. GSK;

d. load forecast;

e. topology forecast;

f. unintentional flow deviation due to the operation of load frequency controls.

Compared to the DA time frame, there are further uncertainties in the LT timeframe which are not explicitly mentioned in the list above. These are in particular the knowledge about the availability of topological measures or redispatch measures. Such further LT uncertainties cannot be considered in the FRMs calculated for the DA timeframe. Yet, taking into account the complexity of determining such additional uncertainties (whose determination is in fact also subject to a certain level of uncertainty), Core TSOs decided to cover these additional uncertainties approximately by the the consideration of several selected scenarios, which shall be the annually created ENTSO-E year-ahead reference scenarios (those scenarios are created in accordance to article 65 of the SO GL Regulation, see the paragraph on scenarios).

Therefore, considering that the additional uncertainty in the LT timeframes can approximately be adressed by the consideration of different scenarios, Core TSOs use the same FRMs in the LTCC as defined in article 8(11) of the DA CCM. Yet, if Core TSOs note after implementation of the Core LT CCM, that the described simplified approach is not sufficient to adequately cover the uncertainties in the Core LT CCM, they will review the applied approach and might request a Request for Amendment (RfA) for Core NRAs' approval.

The values technically applied in the LT capacity calculation are the FRMs (as defined in article 8(11) of the DA CCM). By referring to the DA CCM in this LT CCM, all the relevant stipulations therein, e.g. that the FRM is a percentage of the maximum admissible power flow (Fmax), apply for the Core LT CCM as well.

The reliability margin methodology shall be reviewed and if necessary, updated in order to keep full consistency with the methodology and its evolution in the Core CCR and, as aforementioned, to ensure that the higher uncertainties in the capacity calculation for the LT time frames is adequately considered.

Since a DC interconnection is not a critical branch, a reliability margin is not applicable here.

2.2 Methodologies for Operational Security Limits

This section refers to Article 5 of the Core LT CCM.

According to article 12 of the FCA Regulation the proposal for a Core LT CCM shall include methodologies for operational security limits and contingencies and it shall meet the requirements set out in articles 23(1) and 23(2) of the CACM Regulation. This methodology for operational security limits is in accordance with article 25 on operational security limits of the SO GL Regulation and with article 72 on operational security analysis in operational planning of the SO GL Regulation.

According to Article 5, the maximum admissible current ($I_{\max}$) is the physical limit of a CNE determined by each Core TSO in line with its operational security policy. The physical limit reflects the capability of a transmission element (e.g. line, circuit-breaker, current transformer or disconnector). This $I_{\max}$ is the same for all the CNECs referring to the same CNE. $I_{\max}$ is defined as a permanent or temporary physical (thermal) current limit of the CNE in kilo ampère (kA).

A temporary current limit represents a loading that is allowed for a certain finite duration only (e.g. 115% of permanent physical limit can be accepted during 15 minutes). Each individual Core TSO is responsible for deciding, in line with their operational security policy, if a temporary limit can be used. All Core TSOs will use seasonal limits or constant limits depending on the assets for LT capacity calculations. Seasonal limits are fixed limits in accordance with article 25 on operational security limits of the SO GL Regulation. The calculation of yearly capacities is carried out using 4 (winter, spring, summer, autumn) seasonal CGMs. In function of the selected timestamp the seasonal criteria will be applied conform per each Core TSO policy. No dynamic rating will be used in Core CCR for LT capacity calculations due to absence of the required forecast parameter. It is not possible in the LT capacity calculation timeframe to sufficiently forecast weather conditions like it can be done in the DA and intraday time frames. This fact is not a restriction to the use of dynamic limits in DA and ID time frames and will allow maximal available capacity utilization in short term capacity calculations.The most reliable possibility to forecast weather conditions in LT capacity calculation is by application of seasonal limits.

Generally, the methodology for operational security limits and contingencies for LT included in the proposal for a common capacity calculation methodology shall:

- meet the requirement of respecting the operational security limits used in operational security analysis (as foreseen in article 23(1) of the CACM Regulation);
- describe the particular method and criteria that are used to determine the operational security limits used for capacity calculation (in case the operational security limits used in capacity calculation are not the same as those used in operational security analysis), as foreseen in article 23(2) of the CACM Regulation.

Article 75 of the SO GL Regulation foresees development of a proposal for a methodology for coordinating operational security analysis that is applicable by Core TSO when performing a coordinated operational security analysis (article 72 of the SO GL Regulation). This methodology shall aim at the standardization of operational security analysis at least per synchronous area and shall include in the light of article 75(1) of the SO GL Regulation at least (inter alia):

- principles for common risk assessment, covering at least, for the contingencies referred to in article 33 of the SO GL Regulation: (i) associated probability; (ii) transitory admissible overloads; and (iii) impact of contingencies;
- principles for assessing and dealing with uncertainties of generation and load, taking into account a reliability margin in line with article 22 of the CACM Regulation.

2.3 Allocation Constraints

This section refers to Article 6 of the Core LT CCM.

In case operational security limits cannot be transformed efficiently into I_{max} and F_{max}, the Core TSOs may transform them into allocation constraints as foreseen in article 29(1) of the CACM Regulation, which article 23(2) of the FCA Regulation refers to. For this purpose, the Core TSOs may only use external constraints as a specific type of Allocation Constraints pursuant to Article 6 that limits the maximum import and/or export of a given Core bidding zone. Reasons and the methodology for the calculation of external constraints is specified in detail in Annex 1 to the Core LT CCM.

2.4 Critical Network Elements and Contingencies

This section refers to Article 7 of the Core LT CCM.

In the Central Western European Region (CWE), CNEs are known as Critical Branches (CBs), while contingencies are called Critical Outages (COs). Yet, in the Core CCR, the combination of a CB and a CO (in CWE known as CBCO) is referred to as a CNEC (in line with the nomenclature applied in the Core DA CCM).

The list of CNEs is determined by each Core TSO for his own bidding zone/ control area and the respective scenarios used in the Core LT CCM. A CNE is a network element, significantly impacted by Core cross-zonal trades, which is supervised under certain operational conditions, the so-called contingencies (see below). A CNE can be a cross-zonal or internal network element. Those elements can be an overhead line, an underground cable, or a transformer.

For each CNE within a certain scenario, Core TSOs provide a list of contingencies limited to their relevance for the respective CNE. A contingency can be a trip of a line, a cable, or a transformer; a busbar; a generating unit; a load; or a set of the aforementioned contingencies.

The cross-zonal sensitivity is the criterion for selecting the CNECs that are significantly impacted by cross-zonal trade and shall therefore be considered in the LTCC. Cross-zonal network elements are by definition considered to be significantly impacted. All other (i.e. non-cross-zonal) CNECs shall have at least one zone-to-zone $PTDF$ that exceeds the threshold of 5%. Due to the high complexity of LT capacity calculation and the strong interdependencies between different methodological parameters, it is difficult to derive conclusions on specific values of single methodology parameters. Given this and the general acknowledgement, that the uncertainty in the LT time frame is higher than in the short-term (like DA), Core TSOs agree on a threshold of 5%. If the operational experience after the go-live of DA CCM in Core CCR for the LTCC shows that a different threshold would be more appropriate, this will be forwarded to the Core NRAs as a RfA for their approval.

The mechanism of the CNEC selection is illustrated in Figure 2 below.

Zone to zone PTDFs				
CNEC	A→B	A→C	B→C	Max z2z
CNEC 1	0,1 %	8,8 %	8,7 %	**8,8 %**
CNEC 2	28,7 %	15,8 %	-12,9 %	**28,7 %**
CNEC 3	17,3 %	24,6 %	7,3 %	**24,6 %**
CNEC 4	2,7 %	1,7 %	-1,0 %	**2,7 %**

Figure 2: CNEC Selection Threshold Example

In the last column of Figure 2 the maximum zone-to-zone PTDF per CNEC is shown. Investigating the sensitivity of CNEC 1 for instance, out of three cross-border exchanges, exchange A →C holds the maximum zone-to-zone PTDF by 8.8%, indicating that 1 MW of A →C exchange imposes 0.088 MW on CNEC 1. When considering the maximum zone-to-zone PTDF of CNEC 4, it is clear that this CNEC 4 does not meet the 5% threshold criterion. This implies that the branch (CNEC 4) will not be considered for the calculation of LT capacities.

The impact of this CNEC selection threshold can only be assessed in conjunction with the notion of RAM, according to Article 14 of the Core LT CCM. This is clarified in the following example.

A CNEC 1 with a maximum zone-to-zone $PTDF$ of 5% and a Remaining Available Margin (RAM) of 200 MW (being 20% of an F_{max} = 1000 MW), is able to allow for a commercial exchange of at least 200/0.05 = 4000 MW. The wording “at least” refers to the exchange for which the maximum zone-to-zone $PTDF$ holds, i.e. for other exchanges even higher exchanges would be feasible.

A CNEC 2 with a maximum zone-to-zone $PTDF$ of 10% and an identical RAM of 200 MW (being 20% of an F_{max} = 1000 MW), is able to allow for a commercial exchange of at least 200/0.10 = 2000 MW.

Assuming that we are referring to the same pair of bidding zones for the two CNECs, the example shows that CNEC 2 is more restrictive for the potential exchange between those two bidding zones. Or in other words: CNEC 1 cannot be limiting for the exchange between the two bidding zones in the presence of CNEC 2. Increasing the maximum zone-to-zone $PTDF$ threshold value would essentially imply setting the RAM of those CNECs, which then fall below the threshold, to an infinite value.

As described in Article 7 of the Core LT CCM, the Core TSOs have adopted the following method to select the CNEC list to be used during capacity calculation.

Firstly, each Core TSO provides a list of critical network elements and a list of associated contingencies of its own control area. Core TSOs make their decision based on their operational experience. Operation experience refers here to the experience of grid dispatchers that, when a specific contingency is relevant for a specific critical network element as in case of an outage (i.e. contingency) the specific critical network element would be considerably impacted (i.e. by a higher loading).

Secondly, based on this initial pool of CNECs, the Core CCC selects a final list of CNECs to be used in the LTCC, based on the principle that a CNEC in the final list must meet the criterion to be significantly influenced by changes in the net position. This is in accordance with article 29(3) of the CACM Regulation. It must be stated that a cross-zonal critical network element is always considered as being significantly influenced. As defined in Article 7 of the Core LT CCM, the threshold for the CNEC selection shall be a at least one zone-to-zone PTDF of 5%. Finally, the Core TSOs can update both the initial and the final list of CNECs on a monthly basis. By this possibility, Core TSOs are able to update the list with updated information before the start of a monthly capacity calculation e.g. with an updated outage planning. The publication requirements are to be found in Article 19(2).

The Core TSOs did not harmonise the methodology of the CNEC selection with the CNEC selection methodology in the Core DA CCM, due to the fact that there are significant differences between LT and DA capacity calculation. The reliability of information available one year ahead of the real-time situation is considerably lower than the information available on DA. As explained before, this is also the reason why Core TSOs foresee the possibility to update the information considered in the month-ahead capacity calculation (e.g. by consideration of the updated outage planning). In light of the considerable uncertainty one-year ahead, Core TSOs do not see it justified to limit the CNEC selection for the LT capacity calculation as foreseen in the DA CC, as the latter one requires to limit the amount of CNECs mainly to cross-zonal network elements.

2.5 Generation Shift Keys

This section refers to Article 8 of the Core LT CCM.

Article 8(2) mentions specific situations that Core TSOs can face. An example is having hardly any hydro power due to an extraordinary dry season. It must be explicitly stated that since the generation pattern (locations) is unique for each Core TSO and the range of the NP shift is also different, there is no unique formula for all Core TSOs for the creation of the GSK: the GSKs in the Core CCR are determined by each Core TSO individually on the basis of the latest available information about the generating units and loads; to be calculated for each scenario seperately. Each TSO assesses a GSK for its control area taking into account the characteristics of its system. Individual GSKs can be merged if a bidding zone contains several control areas. The GSK created by each Core TSO can be different for each timestamp or can be same for all timestamps. If only a reference GSK file is provided, it is used for all scenarios. If no GSK file is provided, a proportional shift is implicitly applied to all generating nodes (load nodes will not be included). The GSK values are given in dimensionless units. For instance, a value of 0.05 for one unit means that 5% of the change of the NP of the bidding zone will be realized by this unit. Technically, the GSK values are allocated to units in the CGM. In cases where a generation unit contained in the GSK is not directly connected to a node of the CGM (e.g. because it is connected to a voltage level not contained in the CGM), its share of the GSK will be allocated to one or more nodes of the CGM in order to appropriately model its technical impact on the transmission system.

Appendix 1 describes the GSK creation per Core TSO.

2.6 Methodology for Remedial Actions in Capacity Calculation

This section refers to Article 9 of the Core LT CCM.

The use of RAs during capacity calculation is not obligatory. The purpose of RA application is to alleviate possible local constraints and not to optimize capacities.

After first capacity calculation results are available, Core TSOs may draw a conclusion that the capacity values are not in line with Core TSO's best practice and experience. In order to improve calculation results, the Core TSOs will create a common set of coordinated RAs to be applied in accordance with predefined criteria. The set will be validated and approved by each Core TSO based on coordinated capacity calculation results. The Core TSOs can initiate updates of the set.

Each Core TSO assesses the impact of RAs proposed by other Core TSOs on its grid. In case of negative influence to capacity or the (n-1) criteria is violated, then a Core TSO may refuse the proposed RA.

During the calculation process the Core CCC will apply the RAs based on the predefined criteria and deliver results to the Core TSOs. Both the application of RAs and the final capacity calculation during the validation phase has to be confirmed by all Core TSOs.

For the LTCC within the Core CCR, only the following RAs are considered:

- opening or closing of one or more line(s), cable(s), transformer(s), bus bar coupler(s);
- switching of one or more network element(s) from one bus bar to another;
- transformer and Phase-Shifting Transformer (PST) tap adjustment.

The Core TSOs shall not apply RAs optimization, because the optimization with the aim of enlarging and securing the long-term capacity around the expected operating point of the grid is not possible so far in advance of the real time grid situation.

2.7 Scenarios and Calculation Timestamps

This section refers to Article 10 of the Core LT CCM.

In accordance with article 19 of the FCA Regulation, the Core TSOs shall jointly develop a common set of scenarios to be used in the CGM for each LT capacity calculation timeframe; this applies for the situation where security analysis based on multiple scenarios pursuant to article 10(4)(a) of the FCA Regulation is applied, which is the case for the Core CCR.

For the LTCC for both timeframes, the Core TSOs shall use the annually created ENTSO-E year-ahead reference scenarios (i.e. default scenarios), in accordance with article 3(1) of Common Grid Model Methodology (CGMM) for FCA in conjunction with article 65 of the SO GL Regulation. This Pan-European process is based on the common grid methodology as developed in accordance with article 18 of the FCA Regulation[1]. The description of these scenarios is available ultimately 15 July each year; the accompanying CGMs are available ultimately 15 September each year[2]. The creation of the year-ahead scenarios are bound by the stipulations in article 65 of the SO GL Regulation and article 3(1) of the CGMM for FCA Regulation, which is an ENTSO-E responsibility. When Core TSOs use the resulting ENTSO-E CGMs and only apply on these CGMs the relevant outage information, the Core TSOs are not bound by the CGMM for FCA Regulation. The SO GL Regulation does not require the creation of monthly scenarios and accompanying CGMs. Therefore, ENTSO-E does not create monthly scenarios that could be used by the Core TSOs.

The current CGMM for FCA Regulation differentiates for the four seasons; for each season a scenario is created for peak and valley, hence resulting in 8 final scenarios for each year. This is based on the assumption that ENTSO-E provides 8 CGMs. Please be reminded that ENTSO-E decides annually how many CGMs are created.

The ENTSO-E OPC process also uses these scenarios (CGMs) as starting points for security assessments. Therefore, the main quality issues in the CGMs are solved by the Core CCC, on request of the Core TSOs. The main issues of preliminary year-ahead availability plans provided by all TSOs before

[1] The Common Grid Model Methodology ("CGMM") of article 18 of the FCA Regulation has been approved by all NRAs on 04.07.2018 (*All TSOs' proposal for a common grid model methodology in accordance with Article 18 of Commission Regulation EU 2016/1719 of 26 September 2016 establishing a Guideline on forward capacity allocation*).

[2] Article 22(1)g CGMM SO GL Regulation: 1 September + 10 business days.

1st November (pursuant to article 97 of the SO GL Regulation), are solved by ENTSO-E and the relevant CCCs early November each year (4-5 November).

The Core TSOs use these pieces of information and the accompanied updated CGMs for the LT capacity calculation process for the yearly timeframe.

The related year-ahead seasonal scenarios used for yearly capacity calculation may be updated for monthly capacity calculation. Core TSOs may initiate a scenario update for any predictable change, compared to the year-ahead seasonal scenarios, associated with a specific measure concerning the grid topology or generation pattern, such as for example a change in generation pattern following untypical climate and hydrological conditions.

If this is the case, the Core TSOs may update:

- the generation pattern; and/or
- the topology due to grid element commissioning or decommissioning;

in its own IGM, and may provide one updated IGM for each default seasonal scenario for the referred calculation time-frame, while the NPs in the IGMs shall remain the same as given in the year ahead CGMs.

Accordingly, the Core CCC updates the CGM by replacing the initial IGM with the newly updated single Core TSOs' IGM: the Core CCC does this when a Core TSO provides a new monthly IGM that respects the NP of the respective default seasonal scenario; all in accordance with timing described in the beginning of this paragraph.

The Core CCC applies the planned outages for the monthly capacity calculations for the selected timestamps on the above mentioned updated CGM. Also for the monthly capacity calculations the Core TSOs will work in coordination with the OPC project group on the OPC process.

2.7.1 Outage Selection and Resulting Capacity Products

All ENTSO-E Regional Group Continental Europe (RG CE) TSOs' planned outages and the associated topological switches are stored and regularly updated in the OPC database (foreseen to be replaced by OPDE). The Core CCC will use this database for downloading the most actual set of planned outages not only for the Core CCR, but for the whole synchronous area. According to the SO GL Regulation, preliminary year-ahead availability plans, i.e. planned outages of all TSOs', are available in OPC database as from 1st November for the next year, and final year-ahead availability plans as from 1st December.

According to the OPC process time schedule, the quality check of preliminary availability plans regarding tie-line inconsistencies is first performed by the Core CCC, upon which the availability plans are corrected by the Core TSOs ultimately on 4 November of each year. The year-ahead capacity calculation shall be performed using the latest outage data amended in OPC data base.

Month-ahead capacity calculation shall be performed using the latest outage data updated by Core TSOs in the OPC database. Theoretically, any timestamp with the planned outages can be selected for LTCC. In order to keep the regular workload of Core TSOs and Core CCC within a reasonable boundary the selection of planned outages for scenarios of year-ahead and month-ahead capacity calculation is determined as follows.

Year-ahead:

For each month of the year two timestamps are selected: one valley timestamp and one peak timestamp, resulting in 24 timestamps. The following selection criterion is applied on these timestamps: the largest number of simultaneously planned outages in Core CCR in the respective valley and peak periods of the month. Then all planned outages available in the OPC database for the selected timestamps of the synchronous area of Continental Europe are applied on the related default seasonal scenarios: the outages of the valley timestamp for the default valley scenario and the outages of the peak timestamp for the default peak scenario.

Note: OPC database may store planned outages of any grid element of TSOs. TSOs may mark any other TSO's grid element in OPC database as relevant for outage coordination according to SO GL Regulation. Timestamp selection considers and counts only relevant grid element outages of Core TSOs, but then all planned outages available in OPC database in the selected timestamp are applied on CGM for CC.

If any of the Core TSOs considers that a selected timestamp with all its planned outages does not represent the most critical network condition in the related period, such TSO may require to add any of the planned outages from the related period to the related set of outages. This may happen if the timestamp with the largest number of e.g. peak period outages in January does not include a certain outage (considered by a Core TSO as critical), that is planned in other peak timestamp(s) in January, as that outage is simultaneous with less other planned outages. Therefore, a critical outage may fall out from the automatic selection. Simply adding any further planned outage to the related set of outages, as decribed above, does not increase the calculation cases.

Added outages considered as critical by a TSO are individual considerations of single TSOs, and intend to serve for avoiding high cross-zonal capacities jeopardizing the system security.

Based on the 24 timestamps (i.e. the network models including the planned outages), capacity calculations are performed (as described in following sections), upon which the lowest capacity of the two capacity calculations of each month are selected, resulting in 12 values per. This is the calculated year-ahead capacity for the related monthly subperiod as the grey columns (#1) in Figure 3 below.

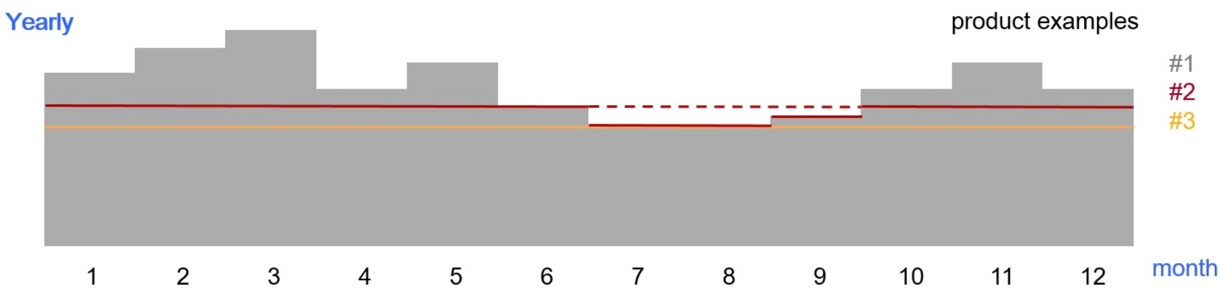


Figure 3

Based on this so-called profile different year-ahead capacity products (e.g. year-ahead capacity with 12 monthly subperiods represented by #2 or a stable bound year-ahead capacity adjusted to the lowest calculated capacity represented by #3) can be defined upon which forms of products could be applied. As the allocation algorithm is still under development, the definition of yearly products is to be confirmed by all parties.

Month-ahead:

Analogue to the monthly granularity approach for year-ahead outage selection and capacity product possibility, a weekly granularity is applied for the month-ahead CC process, resulting in 4 or 5 times 2 timestamps (valley and peak). Hence, 8-10 timestamps are selected, and 8-10 calculations are performed using the most actual planned outages information available in the OPC database. Similarly to the year-ahead process, further planned outages can be added to the related set of outages at any Core TSO's request. Resulting calculated capacities look like the grey columns in Figure 4 below. As the allocation algorithm is still under development, the definition of monthly products is to be confirmed by all parties.

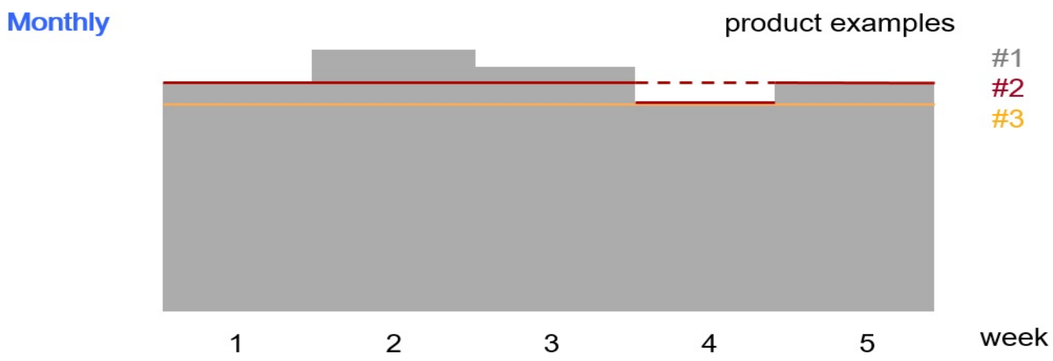


Figure 4

Also for this profile different month-ahead capacity products (e.g. month-ahead capacity with 4-5 weekly subperiods or a stable bound month-ahead capacity adjusted to the lowest calculated capacity) can be defined.

Summary

The Core TSOs use the ENTSO-E year-ahead scenarios for both long-term capacity calculation time frames as starting points. Assuming that ENTSO-E creates 8 CGMs for a specific year (4 seasons; 2 timestamps (peak and valley) per season), the Core TSOs plan to use these CGMs for LTCC. Based on these CGMs, the Core TSOs create the so-called timestamps: this is the year-ahead CGMs *plus* the selected outages as described above. For the monthly time-frame the latest available information for a TSO IGM could be incorporated under specific conditions explained above.

For the yearly calculation, the Core TSOs select per month 2 timestamps: one peak and one valley, resulting in 24 timestamps. Capacity calculation is performed based on these 24 timestamps.

For the monthly calculation, the Core TSOs select per week 2 timestamps: one peak and one valley, resulting in 8-10 timestamps. The capacity calculation is performed based on these 8 timestamps.

Based on these results, the final set of FB parameters are chosen after the validation process taking into account the product requirements pursuant to the Regional Design of Long-Term Transmission Rights (LTTRs) in accordance with article 31 of the FCA Regulation.

Based on later experiences, Core TSOs in coordination with Core CCC may modify the above selection approach, in accordance with the existing legislation.

2.7.2 Base Case Quality

Upon receiving the yearly CGMs and before the actual capacity calculation process, the Core LT CCM foresees two additional process steps yielding the necessity to check the base case quality:

1. Mapping of the planned outages against CGMs before LTCC computation

For each timestamp for which the capacity will be calculated, the grid elements that are in planned outage are searched in the CGM and the planned outages of the found elements are applied (see previous paragraph). The outage of the grid element combined with the eventual topological switches will lead to different loading of the elements compared to the loading of those elements in seasonal CGMs. It is expected that all LTCC planned outages could be found in seasonal CGMs to properly simulate system loading.

2. Congestion Check in CGMs with zero balance net position in the Core CCR

While it can be expected that overloading of the grid elements will be avoided in the year-ahead reference scenarios, it is still possible that certain grid elements after planned outages application and transition of CGM net position to zero balance, will be loaded to such an extent (e.g. 99.9%) that results will end in low capacities.

Therefore the condition for minRAM on each CNEC can be verified and imposed as the first step of capacity calculation for each timestamp as described in Article 14(3) and Article 14(4).
Yet, in order to systematically improve the base case quality on the long run, the Core TSOs will constantly monitor the base case quality pursuant to Article 10(7). Improvement of the base case may be achieved by adjusting the following settings, based on a coordinated agreement among Core TSOs:

i. the minRAM threshold pursuant to Article 14(2);
ii. the application of RA pursuant to Article 9;
iii. the sensitivity threshold pursuant to Article 13(3);
iv. the topological switches related to a planned outage pursuant Article 10(4).

Finally, after each long-term calculation an overview of the base case quality shall be provided by Core CCC to Core TSOs in a corresponding report. This report shall consist of and include at least the following CNECs per calculated timestamp:

i. the overloaded CNE(C)s and its level of overload in base case before the application of minRAM, i.e. the negative RAM occurred pursuant Article 14 but before application of minRAM pursuant Article 14(4);

ii. the pre-solved branches that were not subject to minRAM, where pre-solved branches represent the final set of binding constraints for capacity allocation after identification and removal of redundant constraints from the FB domain (based on definitions of the DA CCM).

Core CCC will also reflect the measures related to improvement of base case quality of each calculated timestamp pursuant to Article 20(4)(5).

2.8 Integration of Cross-Border HVDC Interconnectors Located within the Core CCR

This section refers to Article 15 of the Core LT CCM.

This document details the methodology for the integration of the High-Voltage Direct Current (HVDC) interconnector in the Core LT CCM. In fact, this document describes the general integration of a HVDC grid element.

2.8.1 Introduction

The integration of a HVDC grid element in an alternating current (AC) meshed grid is very particular as its flow is constant and independent of the situation on the surrounding AC meshed grid, contrasting AC elements that are directly impacted by the situation on the surrounding HVDC grid element(s).

Nevertheless, the goal is to integrate the HVDC grid elements in such a way that they are compatible with the existing calculation methodologies for an AC grid. The case of Alegro is also particular because the DE <> BE border is the only fully DC interconnector within the Core CCR.

2.8.2 Philosophy

In the Core LT CCM for the Core region, an AC-line is characterized by its zone-to-zone PTDFs and its RAM. An AC-line can be a CNEC. The idea is to give the same parameters to a HVDC element so it can be integrated in the calculation tool.

RAM

The available margin on an HVDC element is defined in the same way as on an AC-line, being the difference between the Fmax – Reference flow (Fref). The Fmax of the HVDC will be equal to the MPTC (Maximum Permanent Transfer Capability).

PTDF

An HVDC element has no zone-to-zone PTDF except between the two virtual hubs to which it is connected.

Contingency (C)

An HVDC element is a C, this means that the impact on other AC elements on the loss of an HVDC element has to be taken into account.

Critical Network Element (CNEC)

An HVDC element is not a critical branch because the flow on an HVDC is not influenced by the surrounding grid situation (e.g. exchanges on other BZBs). Consequently, Alegro will not have any FRM (see Reliability Margins section).

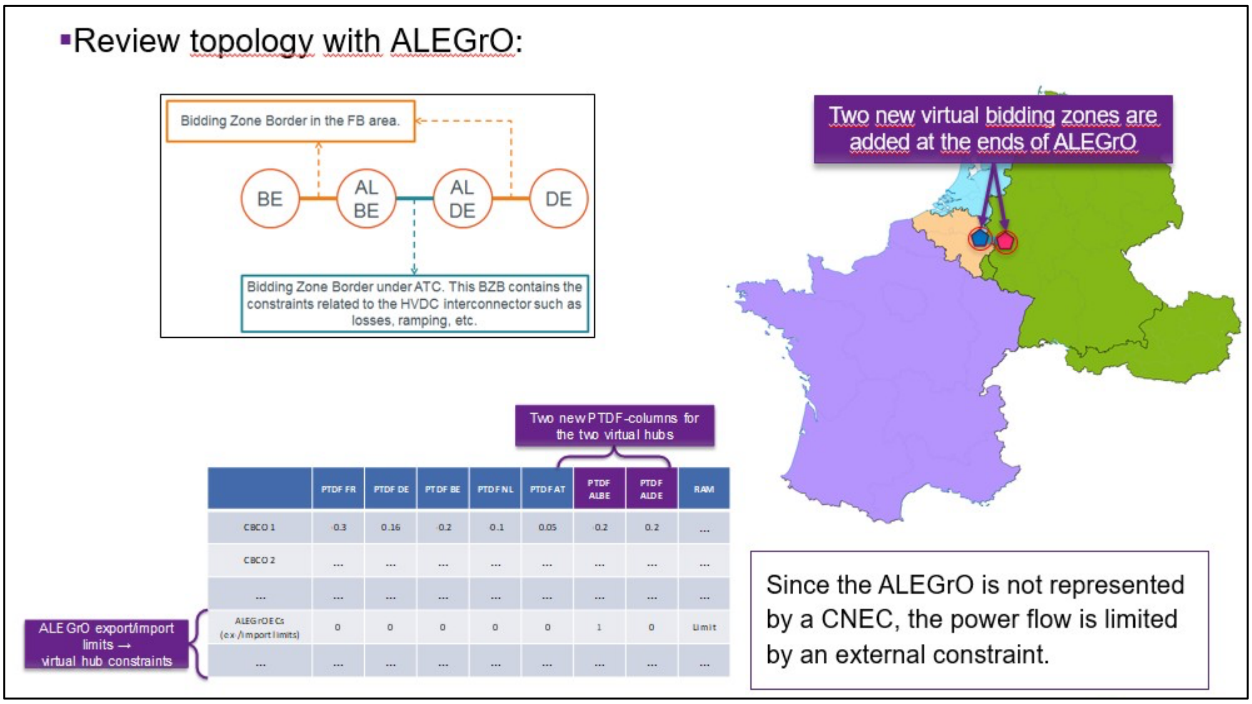
Operation of the HVDC

The HVDC will be operated with fixed flows (set point), which would be equal to the commercial flows. The adjustment of the flow for the base case improvement will not be considered, due to the fact that the starting position of the calculation is zero-balance.

Methodology

Amprion and Elia foresee to integrate the HVDC interconnector Alegro by adding two virtual hubs in order to represent the exchange over the DC link. Each virtual hub is modelled as one load/generation node. The PTDFs of the CNECs concerning the virtual hubs can be calculated and integrated in the Core LT CCM.

The HVDC interconnector Alegro will be considered in the inputs of Core TSOs as a CO, but not as a CB according to the particularities of the HVDC technology (fixed flows so no change in flow due to exchanges on other BZB, no overload possible). In addition, the MPTC, for which the BE <> DE long-term capacity will be capped in any case, will be an input provided by Core TSOs for the computation. This method is general and could also be applied for any other future HVDC interconnector within the Core CCR.



	PTDF FR	PTDF DE	PTDF BE	PTDF NL	PTDF AT	PTDF ALBE	PTDF ALDE	RAM
CBCO 1	0.3	0.16	0.2	0.1	0.05	0.2	0.2	...
CBCO 2	...	...	...	...	...	...	...	...
...	...	...	...	...	...	...	...	...
ALEGrOECs (ex-/import limits)	0	0	0	0	0	1	0	Limit
...	...	...	...	...	...	...	...	...

Figure 5

Some consequences:

- the long-term capacity on the BE <> DE border will be limited by the Alegro MPTC or by a limiting AC CNEC;
- the long-term capacity on AC BZB will never been limited due to an overload on an HVDC.

2.8.3 Additional Remarks

- This proposal is meant to be used only for any cross border HVDC connection within the Core Region. Therefore, if an AC connection exists on the same border as the HVDC interconnector, then the general AC calculation, as described in Article 12(5) will be used for this AC connection.

3 DESCRIPTION OF THE CAPACITY CALCULATION PROCESS

3.1 Technical Description of the Capacity Calculation Method

This section refers to Title 3 of the Core LT CCM.
The principles under which the calculation algorithm has been developed are the following:

- full compliance with the FCA Regulation – the algorithm offers a clear, transparent and scenario based methodology with FB approach. It has been developed with the objective to benefit from Core TSOs' experiences in both LT and DA capacity calculations;
- network security – the calculated figures must allow Core TSOs to effectively limit cross-border power exchanges in such a way that the relevant network security criteria are fulfilled;
- coordination and maximization of trade opportunities – within the limits of network security and taking into consideration of Core TSOs experience and best practice in internal capacity calculation risks policies, the procedure shall allow for a high utilization of the grid infrastructure by the network users;
- transparency – the procedure shall be highly transparent, i.e. with a comprehensive methodology as well as clear information on the input and the output side:
    - input: the provided data and assumptions made by each Core TSO shall be transparent to all other Core TSOs;
    - output: the procedure shall allow for the identification of input parameters necessary for the FB allocation;
- non-discriminatory and common – the LT capacity calculations for each BZB are done by the Core CCC considering the same grid model, the same scenario and applying the same calculation method.

3.1.1 Main Characteristics of the LTCC Algorithm

Before the calculation algorithm is explained in more technical detail the following set of characteristics, that are forming the basis of the LTCC algorithm, need to be introduced:

- all Core TSOs apply a commonly agreed threshold for making CNECs insensitive for "enough far away" electrical distance between the CNECs and the BZB: the so called common threshold for minimum sensitivity of CNECs or "Rule No 1". Further analysis will be performed both on the volume and on whether it could be an individual Core TSO threshold. As this is an important parameter on which the Core TSOs do not have much experience yet, the Core TSOs will review and agree on this threshold before the start of each LT capacity calculation;
- the algorithm uses a concept of positive contributors that represents Core internal borders that are positively influenced (PTDF>0) to avoid netting effect in LT CC;
- the algorithm will apply a minimum RAM threshold for each CNEC.

In order to calculate the long-term capacity respecting the system security, the following parameters are to be calculated for each CNEC **for each timestamp**:

- zone-to-zone PTDFs for each bilateral exchange direction;
- RAMs.

In accordance with Article 12 these parameters should be provided as flow based domain for allocation. Detailed explanation on how to obtain these parameters is given below.

3.1.2 PTDF Calculation

In accordance with article 29(3)(a) of the CACM Regulation, the Core CCC shall calculate the impact of a change in the bidding zones NP on the power flow on each CNEC (determined in accordance with the rules defined in Article 7 on CNEC). This influence is called the zone-to-slack $PTDF$. This calculation is performed with the CGM and the GSK defined in accordance with Article 8 on GSK.

The zone-to-slack $PTDFs$ are calculated by first calculating the node-to-slack $PTDFs$ for each node defined in the GSK. These nodal PTDFs are derived by varying the injection of a relevant node in the CGM and recording the difference in power flow on every CNEC (expressed as a percentage of the change in injection). These node-to-slack $PTDFs$ are translated into zone-to-slack $PTDFs$ by multiplying the share of each node in the GSK with the corresponding nodal PTDF and summing up these products. This calculation is mathematically described as follows:

$$\mathbf{PTDF}_{\text{zone-to-slack}} = \mathbf{PTDF}_{\text{node-to-slack}}\,\mathbf{GSK}_{\text{node-to-zone}} \qquad (1)$$

with

$\mathbf{PTDF}_{zone-to-slack}$	matrix of zone-to-slack $PTDFs$ (columns: bidding zones; rows: CNECs)
$\mathbf{PTDF}_{node-to-slack}$	matrix of node-to-slack $PTDFs$ (columns: nodes; rows: CNECs)
$\mathbf{GSK}_{node-to-zone}$	matrix containing the $GSKs$ of all bidding zones (columns: bidding zones; rows: nodes; sum of each column equal to one).

The zone-to-slack $PTDFs$ as calculated above can also be expressed as zone-to-zone $PTDFs$. A zone-to-slack $PTDF_{A,l}$ represents the influence of a variation of a NP of bidding zone A on a CNEC l and assumes a commercial exchange between a bidding zone and a slack node. A zone-to-zone $PTDF_{A\rightarrow B,l}$ represents the influence of a variation of a commercial exchange from bidding zone A to bidding zone B on CNEC l. The zone-to-zone $PTDF_{A\rightarrow B,l}$ can be derived from the zone-to-slack $PTDFs$ as follows:

$$PTDF_{A\rightarrow B,l} = PTDF_{A,l} - PTDF_{B,l} \qquad (2)$$

In order to determine the flow on a CNEC in the situation without commercial exchanges within the Core CCR the following equation is used:

$$\vec{F}_{0,Core} = \vec{F}_{ref} - \mathbf{PTDF}_{\boldsymbol{f}}\ \overrightarrow{Exchanges}_{ref,Core} \qquad (3)$$

with

$\vec{F}_{0,Core}$	flow per CNEC in the situation without commercial exchanges within the Core CCR
$\vec{F}_{ref}$	flow per CNEC in the CGM with commercial exchanges obtained using DC load flow for the calculation timestamp
$\mathbf{PTDF}_{\boldsymbol{f}}$	zone-to zone power transfer distribution factor matrix for CNECs of the Core CCR
$\overrightarrow{Exchanges}_{ref,Core}$	Core commercial exchanges between the bidding zones as mentioned in the reference program associated with the CGMs of the ENTSO-E scenarios

In order to ensure consistency with DA CC, DC loadflow is used to compute $\vec{F}_{ref}$. The slack reaction of the grid is compensated by adjusting the load. Usage of DC loadlow allows a consistent use of variables in Formula 3 above (with PTDFs and exchanges) and in the RAM computation in Formula 4 and 5 in section

3.1.3. Moreover, the DC loadlflow provides a stable convergance of loadflow and enhances the computation time.

Additionally, the use of DC loadflow will ensure the fact that:

- Core TSOs will be compatible with the DA CC methodology to manage load flow investigations and improvements if any, and to ensure the compatibility between LT CC and DA CC;
- The implementation of the LT CCM requires stable assumptions in order to achieve a process fulfilling all TSO obligations.

Further investigations can be launched after Go Live in order to assess the need to include AC load flows at this step of the process.

CNEC selection described in the section 2.4 is also applied to the CNECs based on their PTDFs.

A common threshold for minimum sensitivity of CNECs in accordance with Article 13(3) may be applied to the computed zone-to-zone PTDFs using the following formula:

If $PTDF_{A\rightarrow B,l} \leq threshold$ then the $PTDF_{A\rightarrow B,l}$ is set to zero.

As a starting point the threshold will be set as 0%. Core TSOs can jointly change the value of the threshold if it is supposed to increase economic efficiency and does not harm the system security. The threshold allows to discard influence of electrically distant CNECs on exchange directions.

3.1.3 RAM Calculation

Based on the definition of PTDF described above, the RAM of a CNEC l is calculated in accordance with the definition of Fmax in Article 13 and in accordance with the definition of FRM in Article 4 on Reliability Margins as follows:

$$RAM_l^+ = Fmax_l - FRM_l^+ - F_{0,Core} \qquad (4)$$

$$RAM_l^- = Fmax_l - FRM_l^- + F_{0,Core} \qquad (5)$$

with

RAM_l^+ and FRM_l^+	RAM and FRM of CNEC l in one direction of monitoring (direction is defined by TSO)
RAM_l^- and FRM_l^-	RAM and FRM of CNEC l in direction of monitoring opposite to the previous direction (direction is defined by TSO)

The non-Core BZB exchanges should be maintained in accordance with the Article 15 on Consideration of non-Core CCR bidding zone borders.

Assuming that the procedures for RAM and PTDF calculations have been used, a set of values has been created for an educative grid that contains a set of 3 CNECs: Table 1 gives an overview of the mentioned values.

Input CNECs	PTDF (A>B)	PTDF (A>C)	PTDF (D>B)	PTDF (D>C)	initial RAM
CNEC1	-0,5	0,18	-0,06	0,09	1200
CNEC2	0,27	0,05	0,13	-0,1	600
CNEC3	0,12	0,27	-0,12	0,05	2000

Table 1

Applying the CNEC selection threshold of 5% and threshold for minimum sensitivity of 5% provides the following PTDFs:

Input CNECs	PTDF (A>B)	PTDF (A>C)	PTDF (D>B)	PTDF (D>C)	initial RAM
CNEC1	0	0,18	0	0,09	1200
CNEC2	0,27	0,05	0,13	0	600
CNEC3	0,12	0,27	0	0,05	2000

Table 2

These vaues will be used for the purpose of explanation of LTCC algorithm described in the next section.

3.1.4 Application of minimum RAM

This is referring to the Article 14 of the CCM and explains how and why the TSOs of Core CCR apply a threshold in order to retrieve a minimum value of RAM.

To avoid insufficient value of RAM after computation, all TSOs have agreed on a minimum value R_{amr} which is a percentage of F_{max} that allows to retrieve a minimum RAM above this specific threshold:

$$RAM \geq R_{amr} * F_{max}$$

The previous equation can be fulfilled by adding a new parameter AMR which describe the amount of artificial RAM added to the initial RAM (defined in eq. 4-5) in the following equation:

$$RAM + AMR = R_{amr} * F_{max}$$

In order to retrieve a final value of AMR for each CNEC the following equation is used:

$$AMR = \max\left(R_{amr} * F_{max} - \left(F_{max} - FRM - F_{0,Core}\right),\ 0\right)$$

The final RAM of a CNEC l is therefore corrected by AMR value as follows:

$$RAM = F_{max} - FRM - F_{0,Core} + AMR$$

The minRAM factor is set on the level of 20% as a working assumption based on performed experimentations and will be subject to a review according to Article 14 of the LTCCM 2 years after Go Live of the methodology. The two first yearly auctions will be performend based on FB parameters computed using a 20% minRAM factor, while for the third yearly auction after Go Live, Core TSOs will use a reviewed minRAM factor. The review will take into consideration the lessons learned during all the yearly and monthly computations occurred during these 2 years.

3.2 Form of products

In accordance with article 31 of the FCA Regulation, the Core TSOs developed a proposal for the Regional Design of LTTRs to be issued on each BZB within the CCR. The application of form of products is taking into account a foreseen specific network situation (e.g. planned maintenance, long-term outages).

The harmonised allocation rules (HAR) for LTTRs developed in accordance with article 51 of the FCA Regulation, also supports the use of form of products.

In accordance with article 48 of the FCA Regulation, all TSOs established the SAP. The SAP requires that the SAP Operator shall receive the amount of LT capacity to be offered in the respective auction directly from the TSOs or the coordinated capacity calculator where relevant. The SAP Operator shall publish the offered capacity including form of products (if applicable) in accordance with the HAR.

The application of form of products is legally possible for each individual hour, which ensures that a minimum amount of capacity will be reduced. However, from a LTCC perspective, this level of detail is very challenging indeed, because in that case all timestamps representing outages causing reduction need to be considered (see Article 10 on Scenarios).

In order for the Core TSOs to facilitate the LT capacity calculation process, reduction hours are considered in default timestamps as follows:

- for the yearly long-term calculations, a monthly timestamp is chosen;
- for the monthly long-term calculation, a weekly timestamp is chosen.

As a result of this approach, capacities would be reduced for the whole respective period represented by timestamp. The results of the yearly calculation in monthly timestamps, is shown in Figure 6 below:

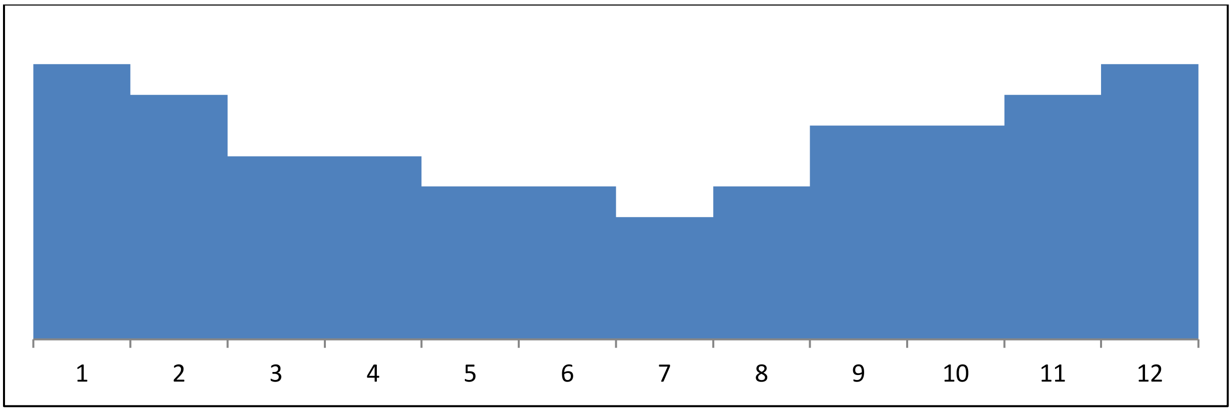


Figure 6

Analogue results can be imagined for monthly calculation, using weekly timestamps. Based on these results as a next step the coordinated long-term capacity for the respective yearly and monthly products need to be determined.

The form of any product as regulated in the regional market design pursuant to article 31 of the FCA Regulation, gives the possibility to use calculated results in order to offer capacities to the maximum amount possible. This maximum amount is represented by the red line in Figure 7.

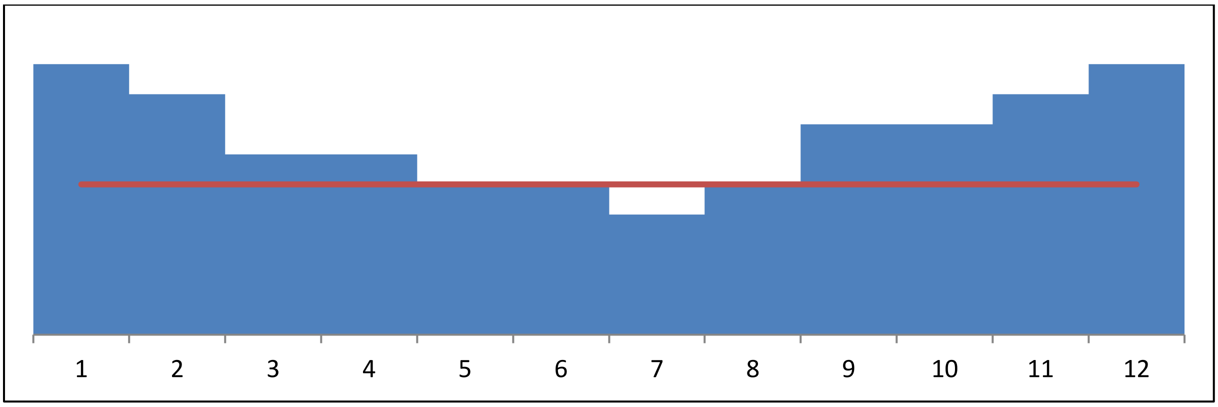


Figure 7

Core TSOs will finalize calculation results to meet the form of product regulated in the Regional Design of LTTR including reduction periods if applicable. The outcome results can vary amongst BZBs. Therefore it is inefficient to set fixed rules how to come from the calculation result to capacity products. On the one hand Core TSOs are striving to offer maximum available capacity, but on the other hand the form of product regulated in the Regional Design of LTTRs, established based on article 31 of FCA Regulation, needs to be respected. To balance those two requirements, flexibility is needed on Core TSO side in order to meet market participants expectations to the extent possible.

3.3 Consideration of non-Core Bidding Zone Borders

This section refers to Article 15 of the Core LT CCM.

Capacity calculation on non-Core borders is out of the scope of Core LT CCM. Based on approved methodologies from the relevant capacity calculation regions, JAO auctions the provided long-term capacities on Core to non-Core borders.

However, the impact of exchanges between CCRs physically exists and needs to be taken into account to ensure viable secure grid assessments, and this is done implicitly as is explained in the following lines.

As a basis or starting point for LTCC, the prepared scenarios (CGMs) include assumptions on the exchanges on non-Core BZBs. During the capacity calculation process, these exchanges are untouched and remain fixed. This is done as this is in line and compatible with the DA CCM. The expected exchanges with the Core CCR are captured implicitly (in the RAM over all CNECs). The resulting uncertainties to the aforementioned assumptions are implicitly integrated within the reliability margin (see section 2.1 in this document). As such, these assumptions will impact the available margins of Core CNECs, and consequently long-term capacity. It must be noted that it is called implicit. An explicit integration would mean incorporating exchanges between Core and non-Core bidding zones in a dedicated, seperated calculation step, which is not the case. At this stage, during the calculation step, relevant CNECs between Core and non-Core zones will be included in LTCC for the purpose of Core TSOs security of the long-term capacities (exchanges within the Core CCR).

The Core TSOs work on a target solution, in close cooperation with the adjacent involved CCRs, that fully takes into account the influences of the adjecent CCRs during the long-term capacity calcuation process and therefore less reliance on Core TSOs assumptions on non-Core exchanges. The base for non-Core approach in the Core LT CCM will be article 21(1)(b)(vii) of the CACM Regulation.

The proposal is that the Core LT CCM can update its method when the Core DA CCM fulfill article 13(4) of the DA CCM. This article 13(4) of the DA CCM deals with the implementation of Advanced Hybrid Coupling (AHC); unfortunately it is not possible to give a deadline for this implemention as the AHC is not mature enough yet. It should be noted that the final DA CCM method is considered to be the target solution to explicitly model the exchange situations of adjacent CCRs within the Core flow-based domain which will be discussed with adjacent involved CCRs, according to article 17(4) of the DA CCM. How this would impact the Core LT CCM must be explored and decided upon when the DA target solution is finalized.

3.4 Fallback Procedures

This section refers to Article 16 of the Core LT CCM.

In accordance with article 10(7) of the FCA Regulation, referring to article 21(3) of CACM Regulation, a fallback procedure needs to be in place in case the initial capacity calculation does not lead to any results.

First of all the Core TSOs would like to emphasize that the LT capacity calculation process is not under such time pressure as the DA capacity calculation process. This means that the Core TSOs have some leeway to deal with any issue that could delay the calculation process.

In case of force majeur situations, the Core TSOs will firstly, together with JAO, to the extend possible for JAO, postpone the relevant yearly or monthly auction for which the Core TSOs can not provide results. In this situation, the Core TSOs and JAO will agree on a new deadline for the submission of the results.

Secondly, in case the postponement of the auction is not possible, or the new deadline has been reached, the Core TSOs foresees the following fallback process:

1. The Core TSOs shall bilaterally agree on NTC values for the relevant timeframe.
2. The Core TSOs shall commonly coordinate, validate these bilaterally agreed NTC values and send it to the Core CCC.
3. The Core CCC shall send the NTC values to the SAP.

4 VALIDATION

4.1 Validation Methodology

This section refers to Article 17 of the Core LT CCM.

The Core TSOs are legally responsible for the long-term capacities and therefore have to validate the calculated values, in accordance with article 15 of the FCA Regulation, before the coordinated capacity calculator can send them to SAP for allocation. The Core TSOs have the right to correct their set of FB parameters provided by the Core CCC and then the Core CCC shall coordinate the validation.

After the first LT CC computation a re-assessment might be necessary to respect operational security requirements:

a. an occurrence of an exceptional contingency or forced outage as defined in article 3 of the SO GL Regulation;

b. when RAs, pursuant to Article 9, that are needed to ensure the calculated capacity on all CNECs, are not sufficient;

c. a mistake in the input data, that leads to an overestimation of long-term capacity from an operational security perspective, occurred;

d. a potential need to cover reactive power flows on certain CNECs;

and imply changes in the CGM used in calculation for that timeframe.

If one of the above situations occur, then the relevant Core TSO will send new input data and may request based on a common decision the Core CCC to launch a new calculation.

Each Core TSO may reduce the long-term capacity for reasons of operational security as soon as it is justified. The reduction and justification will be monitored according to Article 20(5).

Hence, the splitting of the correction of long-term capacity between the different BZBs is always ensured and that is why Core TSOs do not explicitly refer to article 26(2) of the CACM Regulation.

Each reduction of the capacity has to be monitored with at least an identification of the limiting CNEC and the explanation of the unforseen event. Article 15 of the FCA Regulation refers to article 26 of the CACM

Regulation, where it is stipulated that any reduction during the validation stage shall be reported to the Core NRAs every three months.

It must be clarified that the iterations on the results are not part of the final validation process, but they are part of the calculation process.

5 UPDATES AND PUBLICATION

5.1 Review and Updates

This section refers to Article 18 of the Core LT CCM.

The Core TSOs foresee to review and update the necessary parameters in conjunction with the same process as for the Core DA CCM.

5.2 Publication of Data

This section refers to Article 19 of the Core LT CCM.

The Core TSOs foresee to publish the information as described in Article 19(2). This enhances transparency for market parties and also facilitates the Core NRAs need for monitoring compliance.

5.3 Monitoring and Information to Regulatory Authorities

This section refers to Article 20 of the Core LT CCM.

The Core TSOs consider that the transparency framework as provided in this section on reporting in general to the Core NRAs, provides all necessary information to the Core NRAs enabling them to monitor compliance with this Core LT CCM and other relevant legislation.

The Core TSOs and Core CCC foresee to send the information described in Article 20 to the Core NRAs for the purpose of monitoring compliance.

6 IMPLEMENTATION

6.1 Timescale for Implementation of the methodology

This section refers to Article 21 of the Core LT CCM.

In accordance with article 10ff. of the FCA Regulation, the Core TSOs are working on the implementation of the Core LT CCM. The Core LT CCM may go-live either with yearly or monthly calculation and allocation.

Core TSOs will implement the approach described in the LT CCM within a maximum period of 5 years after approval of this methodology. Such a timescale for implementation would give Core TSOs and RSCs the chance to deal with all obligations and projects within Core CCR. There are numerous projects running in parallel (e.g. short-term flow-based capacity calculcation, redispatch and countertrading, regional operational security coordination). The simultaneous implementation of these methodologies requires a high amount of resources both from Core TSOs and RSCs and makes a priorisation of projects inevitable.

As allocation will change from NTC to FB, the implementation of this LT CCM requires the amendment of different other methodologies and IT developments:

- amendments to other methodologies, such as but not limited to HAR, LTTR and LT Splitting, and their respective approval through NRAs;
- adaptation by market parties;
- implementation of the new FB allocation platform at the SAP, which is currently not existing.

Having said this, the above mentioned timeline for implementation of LT CCM assumes a timely amendment and approval of the other methodologies. Nevertheless, the Core TSOs will try to shorten the implementation timeline as much as possible in order to achieve an earlier go-live date.

The implementation process of the FB approach shall include an internal test, during which the Core TSOs shall test the operational processes for the long-term capacity calculation inputs, the long-term capacity calculation process and the long-term capacity validation and develop the appropriate IT tools and infrastructure. The implementation process of the FB calculation and allocation approach shall also include an external parallel run, to allow all market participants to adapt and develop appropriate IT tools to be able to proceed to FB allocations for long term time frames. This step requires an already finished implementation of an explicit FB allocation at the SAP operator.

During the internal parallel run, the Core TSOs shall continuously monitor the effects and the performance of the application of this methodology. During the external parallel run TSOs shall publish the monitoring and performance criteria. After the implementation of this methodology, the outcome of this monitoring shall be summarized in an annual report.

The Core coordinated Long Term capacities are the ones resulting from the FB capacity calculation process after the implementation of this methodology. Until the implementation of this FB methodology, Core TSOs will continue the NTC allocation and will improve the coordination at Core CCR level.

APPENDIX 1 - METHODS FOR GSKS PER BIDDING ZONE

The following section depicts in detail the method currently used by each Core TSO to design and implement GSKs.

Austria:

APG's method only considers market driven power plants in the GSK file which was done with statistical analysis of the market behaviour of the power plants. This means that only pump storages and thermal units are considered. Power plants which generate base load (river power plants) are not considered. Only river plants with daily water storage are also taken into account in the GSK file. The list of relevant power plants is updated regularly in order to consider maintenance or outages.

Belgium:

Elia will use in its GSK flexible and controllable production units which are available inside the Elia grid (they can be running or not). Units unavailable due to outage or maintenance are not included.

The GSK is tuned in such a way that for high levels of import into the Belgian bidding zone all units are, at the same time, either at 0 MW or at Pmin (including a margin for reserves) depending on whether the units have to run or not (specifically for instance for delivery of primary or secondary reserves). For high levels of export from the Belgian bidding zone all units are at Pmax (including a margin for reserves) at the same time.

After producing the GSK, Elia will adjust production levels in all datasets to match the linearised level of production to the exchange programs of the reference day

Croatia:

HOPS will use in its GSK all flexible and controllable production units which are available inside the HOPS' grid (mostly hydro units). Units unavailable due to outage and maintenance are not included, but units that aren't currently running are included in GSK. In addition also load nodes that shall contribute to the shift are part of the list in order to take into account the contribution of generators connected to lower voltage levels (implicitly contained in the load figures of the nodes connected to the 220 and 400 kV grid). All mentioned nodes are considered in shifting the net position in a proportional way.

Czech Republic:

The Czech GSK considers all production units which are available inside CEPS´s grid and were foreseen to be in operation. Units planned for the maintenance and nuclear units are not included in the GSK file. The units inside the GSK will follow the change of the Czech net position proportionally to the share of their production. In other words, if one unit represents n% of the total generation on the Czech bidding zone, n% of the shift of the Czech net position will be attributed to this unit.

The current approach of creation GSKs is regularly analysed and can be adapted to reflect situation in CEPS´s grid.

France:

The French GSK is composed of all the flexible and controllable production units connected to RTE's network in the D-2 CGM.

The variation of the generation pattern inside the GSK is the following: all the units which are in operation in the D-2 CGM will follow the change of the French net position based on the share of their productions in the D-2 CGM. In other words, if one unit represents n% of the total generation on the French bidding zone in the D-2 CGM, n% of the shift of the French net position will be attributed to this unit.

Germany:

The four German TSOs provide one single GSK for the whole German bidding zone. Since the structure of the generation differs for each German TSO, an approach has been developed, which allows the single TSO to provide GSKs that respect the specific character of the generation in their own grid while ultimately yielding a comprehensive single German GSK.

In a first step, each German TSO creates a TSO-specific GSK with respect to its own control area based on its local expertise. The TSO-specific GSK denotes how a change of the net position in the forecasted market clearing point of the respective TSO's control area is distributed among the nodes of this area. This means that the nodal factors of each TSO-specific GSK sum up to 1. Details of the creation of the TSO-specific GSKs are given below per TSO.

In a second step, the four TSO-specific GSK are combined into a single German GSK by assigning relative weights to each TSO-specific GSK. These weights reflect the distribution of the total market driven generation among German TSOs. The weights sums up to 1 as well.

With this method, the knowledge and experience of each German TSO can be brought into the process to obtain a representative GSK. As a result, the nodes in the GSK are distributed over whole Germany in a realistic way, and the individual factors per node are relatively small.

Both the TSO-specific GSKs and the TSOs' weights are time variant and updated on a regular basis. Clustering of time periods (e.g. peak hours, off-peak hours, week days, weekend days) may be applied for transparency and efficiency reasons.

Individual distribution per German TSO:

50Hertz:

The GSK for the control area of 50Hertz is based on a regular statistical assessment of the behaviour of the generation park for various market clearing points. In addition to the information on generator availability, the interdependence with fundamental data such as date and time, season, wind infeed etc. is taken into account. Based on these, the GSK for every market time unit (MTU) is created.

Amprion:

Amprion established a regular process in order to keep the GSK as close as possible to the reality. In this process Amprion checks for example whether there are new power plants in the grid or whether there is a block out of service. According to these monthly changes in the grid Amprion updates its GSK.

If needed Amprion adapts the GSK in meantime during the month.

In general Amprion only considers middle and peak load power plants as GSK relevant. With other words base load power plants like nuclear and lignite power plants are excluded to be a GSK relevant node.

From this it follows that Amprion only takes the following types of power plants: hard coal, gas and hydro power plants. In the view of Amprion only these types of power plants are taking part of changes in the production.

TenneT Germany:

Similar to Amprion, TTG considers middle and peak load power plants as potential candidates for the GSK. This includes the following type of production units: coal, gas, oil and hydro. Nuclear power plants are excluded upfront.

In order to determine the TTG GSK, a statistical analysis on the behaviour of the non-nuclear power plants in the TTG control area has been made with the target to characterize the units. Only those power plants, which are characterized as market-driven, are put in the GSK. This list is updated regularly.

TransnetBW:

To determine relevant generation units, TransnetBW takes into account the power plant availability and the most recent available information from the independent power producer at the time when the individual GSK-file needs to be created.

The GSK for every considered generation node i is determined as:

$$\mathrm{GSKi} = \frac{\mathrm{Pmax,i} - \mathrm{Pmin,i}}{\sum_{i=1}^{n}(\mathrm{Pmax,i} - \mathrm{Pmin,i})}$$

Where n is the number of power plants, which are considered for the generation shift within TransnetBW's control area.

Only those power plants which are characterized to be market-driven, are used in the GSK if their availability for the MTU is known.

Hungary:

MAVIR uses general GSK file listing all possible nodes to be considered in shifting the net position in a proportional way, i.e. in the ratio of the actual generation at the respective nodes. All dispatchable units, including actually not running ones connected to the transmission grid are represented in the list. Furthermore, as the Hungarian power system has generally considerable import, not only big generation units directly connected to the transmission grid are represented, but small, dispersed ones connected to lower voltage levels as well. Therefore, all 120 kV nodes being modelled in the IGM are also listed representing this kind of generation in a proportional way, too. Ratio of generation connected to the transmission grid and to lower voltage levels is set to 50-50% at present.

Netherlands:

TenneT TSO B.V. will dispatch controllable generators in such a way as to avoid extensive and not realistic under- and overloading of the units for foreseen extreme import or export scenarios. Unavailability due to outages are considered in the GSK. Also the GSK is directly adjusted in case of new power plants.

All GSK units (including available GSK units with no production in de D2CF file) are redispatched pro rata on the basis of predefined maximum and minimum production levels for each active unit in order to prevent unfeasible production levels.

The maximum production level is the contribution of the unit in a foreseen extreme maximum production scenario. The minimum production level is the contribution of the unit in a foreseen extreme minimum production scenario. Base-load units will have a smaller difference between their maximum and minimum production levels than start-stop units.

TenneT TSO B.V. will continue fine-tuning their GSK within the methodology shown above.

Poland:

PSE present in GSK file all dispatchable units which are foreseen to be in operation in day of operation. Units planned for the maintenance are not included on the list. The list is created for each hour. The units inside the GSK will follow the change of the Polish net position proportionally to the share of their production in the D-2 CGM. In other words, if one unit represents n% of the dispatchable generation on the Polish bidding zone in the D-2 CGM, n% of the shift of the Polish net position will be attributed to this unit.

Romania:

The Transelectrica GSK file contains flexible and controllable units which are available in the scenario. The units planned for maintenance and nuclear units are not included in the list. The fixed participation factors of GSK are impacted by the generation present in the IGM.

Slovak Republic:

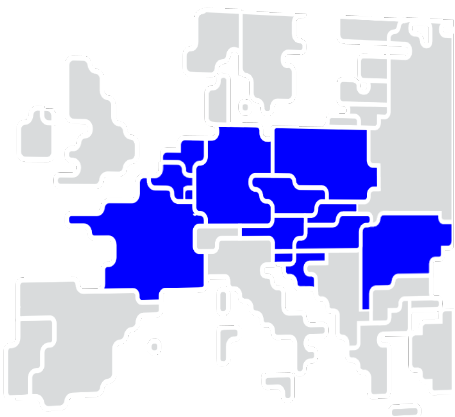
In GSK file of SEPS are given all dispatchable units which are in operation in respective time frame which the list is created for. The units planned for maintenance and nuclear units are not included in the list. In addition also load nodes that shall contribute to the shift are part of the list in order to take into account the contribution of generators connected to lower voltage levels (implicitly contained in the load figures of the nodes connected to the 220 and 400 kV grid). All mentioned nodes to be considered in shifting the net position in a proportional way.

Slovenia:

GSK file of ELES consists of all the generation nodes specifying those generators that are likely to contribute to the shift. Nuclear units are not included in the list. In addition also load nodes that shall contribute to the shift are part of the list in order to take into account the contribution of generators connected to lower voltage levels (implicitly contained in the load figures of the nodes connected to the 220 and 400 kV grid). At the moment GSK file is designed according to the participation factors, which are the result of statistical assessment of the behaviour of the generation units infeeds.

Consultation Report on Core CCR TSOs' methodology for long-term capacity calculation in accordance with article 10 of the Commission Regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation

November 2020



CONTENT

GLOSSARY

All definitions and abbreviations of the Core Long-Term Capacity Calculation Methodology apply accordingly.

1. INTRODUCTION

This document is the consultation report for the Core CCR TSOs' methodology for long-term capacity calculation. The Core CCR TSOs' methodology for long-term capacity calculation is based on article 10 of the FCA Regulation.

Core TSOs would like to thank all participants of the public consultation for their interest in the Core CCR TSOs' long-term capacity calculation methodology.

Via the ENTSO-E Consultation Platform, the public consultation document for the Core CCR TSOs' long-term capacity calculation methodology was available to Core stakeholders from the 16th of September 2020 until the 16th of October 2020. In total, 7 stakeholders submitted their responses in time.

Since the public consultation results should be processed in an anonymised manner, the identity of the respondents is not disclosed in this consultation report. Please note that all responses were, however, shared with the Core National Regulatory Authorities (NRAs) in a non-anonymised manner.

Main views and recurring comments have been summarized in this report. The Core TSOs wish to clarify that the content of this document is intended to summarize the results obtained in the public consultation. The Core TSOs did their best to reply to all comments and concerns.

2. RECEIVED RESPONSES

In this chapter, a summary is provided of all stakeholder responses received via the ENTSO-E Consultation Platform. All contributions can be found in the Annex. All responses are structured in a table showing the stakeholder response, the number of stakeholders asking for a specific adaptation, the action taken by Core TSOs and in addition a Core TSOs answer to the stakeholders' response.

2.1. General Feedback

The following general feedback was received:

Stakeholder response		Number of stakeholder requesting	Action taken	Core TSOs' answer
1.	Three stakeholders argue that the LT CCM should be as realistic as manageable and comprise various situations that may occur in DA/Spot market timeframe. This includes various weather scenarios, outages/revisions of power lines and plants and different developments of renewables and thermal capacities. Calculation should be performed within these different scenarios and the resulting LT capacity should reflect the expected value across all scenarios.	3	See Core TSOs' answer	Core TSOs explain that the different scenarios are covered by the procedure on 8 Yearly Reference Scenarios from ENTSO-E as described in Article 10. The uncertainties of these scenarios will be tackled by the FRM as described in Article 4.
2.	One stakeholder explains that it understood from discussions at Core Consultative Group meetings that the objective is also to use the flow-based approach for the allocation of capacity by 3 to 5 years. In the meantime, an NTC extraction would be performed to allocate capacity at each border. Considering the uncertainties about the capacity calculation model already – and the worries the stakeholder has that a flow-based calculation may not yield very high level of cross-zonal capacity in the forward timeframe – the lack of clear idea how capacity will be allocated in the future significantly adds to market participants concerns with the overall proposal. The stakeholder calls on the TSOs to engage in a dialogue with market participants to help us understand how the future capacity calculation and allocation processes will play out. This should also include all the elements in the new processes that would require an adaptation of tools and systems on market participants' side. On a side note, the stakeholder would like to underline that political agreements on pre-determined levels of capacity at given borders, such as bilateral agreements, are detrimental to the efficiency of capacity	1	See Core TSOs' answer	Core TSOs suggest to all stakeholders to read the minutes of the last CCG meeting (LINK). The LTCCM is a methodology that focuses on the flow-based approach, there is no plan to perform a cNTC extraction by the Core TSOs. Core TSOs will continue the dialogue with market parties during the CCG meetings. The LT CCM that will be submitted to Core NRAs does not allow for any political agreements on pre-determined levels of capacity at given borders.

	calculation and the maximisation of welfare at regional level. The treatment of such agreements, as they exist today, is not ruled in the LTCCM proposal. Should they be allowed to be maintained once the LTCCM comes into force, they should at the very least be listed in the capacity calculation methodology and their impact thoroughly assessed.			
3.	Two stakeholders invite Core TSOs to strive for maximum market integration by applying the 70% minRAM obligation (Regulation 2019/943, article 16) as early as possible, i.e. already in the framework of the long-term capacity calculation and allocation process.	2	See Core TSOs' answer	Core TSOs explain that the 70% rule is not applicable to the long-term timeframe and FCA methodologies.
4.	One stakeholder has underlined at numerous occasions in the past, re-iterates its view that interconnector capacity is paid for by grid users, who therefore are entitled to expect a maximum of cross-border capacity to be made available for the electricity market as soon as possible. The stakeholder therefore strongly invite Core TSOs to make sure the methodology maximizes capacity made available for the market in every timeframe (in this proposal, annually and subsequently monthly). Capacity limitation/withholding for shorter term time frames will reduce the liquidity and the level of market integration in the Core region and therefore go against the principles of European electricity market legislation.	1	See Core TSOs' answer	Core TSOs answer that maximization of cross-zonal capacity is the target of the LTCCM and therefore any limitation to the capacity is subject to a well coordinated process.

2.2. Specific Feedback

The following feedback on specific articles was received:

2.2.1. Whereas

Stakeholder response		Number of stakeholder requesting	Action taken	Core TSOs' answer
1.	Two stakeholder argues that the flow-based approach does not 'by default' lead to an increase of economic efficiency	2	See Core TSOs' answer, Proposal updated	Core TSOs thank the stakeholder for the feedback. The flow-based approach will be implemented following the clearly defined guidance of ACER. Core TSOs acknowledge the challenges of the flow-based approach and have deleted the wording 'by default' in Recital 9.

2.	One stakeholder argues that Core TSOs should have the mandate to provide reliable information to the market participants.	1	See Core TSOs' answer, Proposal updated	Core TSOs agree with this comment and have changed the word 'enables' to 'requires' in Recitcal 11 of the Whereas.
3.	One stakeholder argues that the LT CCM has to be compatible with the DA and ID CCMs approved by ACER in February 2019.	1	See Core TSOs' answer	Core TSOs explain that the recital shows the reference to FCA. The Whereas section provides the framework of the methodology and Core TSOs remind on the requirements of the FCA.

2.2.2. Article 3 Long-Term Capacity Calculation Process

Stakeholder response		Number of stakeholder requesting	Action taken	Core TSOs' answer
1.	One stakeholder comments that article 3(3) seems to be an unnecessary repetition of article 3.2(c)	1	See Core TSOs' answer	Core TSOs explain that article 3.2(c) makes a reference to article 15 of the FCA Regulation (via Article 17 of the LTCCM). The purpose of article 3.3 is to refer to article 24 of the FCA Regulation.

2.2.3. Article 4 Reliability Margin Methodology

Stakeholder response		Number of stakeholder requesting	Action taken	Core TSOs' answer
1.	One stakeholder comments that using the same methodology to determine reliability margins in DA and forward timeframes would be welcome, but using the same exact margins does not seem appropriate: a specific calculation should be performed for each timeframe.	1	See Core TSOs' answer	Core TSOs explain that in the Long-Term timeframe there is not enough statistical data to perform a calculation. There is a different purpose of the timeframes as well because the Long-Term timeframe only wants to show the extreme grid situations and is therefore barely reached in realtime in order to perform the comparison.
2.	Three stakeholders comment that Article 4 (2) should not only focus on higher uncertainties but should also consider the possibility that the level of uncertainty decreases, hence, the stakeholders propose the following amendment: "[...] and to ensure an adequate consideration of the uncertainties in the capacity calculation for the long-term timeframes."	3	See Core TSOs' answer	Core TSOs agree and remove the word 'higher' from Article 4(2).
3.	On article 4 of the proposal, one stakeholder insists on the need to take also into account the thermal or nominal capacity of the different CNEs, not only	1	See Core TSOs' answer	Core TSOs explain that the FRM is a percentage of the Fmax, and the Fmax covers the thermal or nominal capacity.

	historic FRMs, for calculating future reliability margins.			

2.2.4. Article 6 Methodology for Allocation Constraints

Stakeholder response		Number of stakeholder requesting	Action taken	Core TSOs' answer
1.	Four stakeholders oppose external constraints without proper justification.	4	See Core TSOs' answer	Core TSOs need the allocation constraints to maintain system security and the justification is explained in Annex 1 of the methodology.
2.	One stakeholder invites Core TSOs to thoroughly justify all allocation constraints and qualifications as CNEs, and submit them to NRA approval.	1	See Core TSOs' answer	Core TSOs answer that allocation constraints cannot be translated to CNE(s) by definition. All justification for using them are explained in Annex 1 of the methdolology.

2.2.5. Article 7 Methodology For Critical Network Elements and Contingencies

Stakeholder response		Number of stakeholder requesting	Action taken	Core TSOs' answer
1.	Four stakeholders comment that Article 7 (1) The methodology does not provide any condition/methodology for the CNEC selection. Article 7 (3) mentions that zone-to-zone PTDF should be higher than a threshold of 5% while it is 10% for the DA and additionally, it has never been proven that this threshold was optimal. Article 7 (4) mentions that the list of CNE can be updated once a month. Is this a realistic development or rather reasonable approach?	4	See Core TSOs' answer; Proposal updated	Core TSOs acknowledge the comment, Core TSOs shall provide a list of CNEs which will be subject to the CNEC filtering according to Article 7(3). Core TSOs answer that the DA CCM as decided by ACER included a CNEC selection threshold of 5%. Core TSOs question why market parties mention 10%? Due to the fact that the risk level is not the same between LT and DA timeframe, Core TSOs decided to not make a direct reference to the DA CCM CNEC selection and to apply its own CNEC selection process. Core TSOs explain that for each calculation timestamp a new list of CNECs can be provided.
2	One stakeholder comments list of CNE can be updated once a month: the stakeholder opposes this possibility and considers that the list should be validated by all Core NRAs and TSOs.	1	See Core TSOs' answer	Each CNEC will respect the sensitivity threshold that has been validated by Core NRAs. The list of CNECs withhold from the initial pool might change before each computation and the NRA validation is not possible in such short timeframe. Furthermore, this is a coordinated methodology and the

				CNECs considered during computation is coordination between Core TSOs.
3	The stakeholder acknowledges that the PTDF threshold of 5% proposed in the LTCCM is consistent with that of the DA and ID CCMs, and the current practice in CWE flow-based. However, although this 5% criterion is apparently currently being applied, it has never been approved. On the contrary, it was identified as one of the open issues that still need to be resolved. In their Position Paper on CWE Flow-Based Market Coupling of March 2015, the CWE NRAs write the following (in paragraph 9.12 CBCO selection): "The project has proposed the rule of 5% to identify a critical branch (the 5% criterion means that a CBCO, to be selected, has to have at least one zone-to-zone PTDF which exceeds 5%). It is stated in the Approval Package that this rule was assessed inside the project to be efficient. This has nevertheless not been demonstrated to CWE NRAs. If there is room for improving this CB selection rule, this could lead to a higher global welfare. As a matter of fact, a network element not considered as a CB in the Flow-Based methodology cannot limit cross-border exchanges. If an overload is expected on this line, the relevant TSO(s) may have to activate potentially costly remedial actions such as re-dispatching. Moreover, the current rule does not prevent the fact that constraints with very low PTDF are active and may have huge impact on prices. Therefore, CWE NRAs consider that the project has to demonstrate, at the latest when applying for a capacity calculation methodology in the frame of the CACM Regulation, whether the 5% rule is optimal, or what other rule could lead to such optimality. The Flow-Based methodology would have to be adapted consequently." Five years later, this demonstration of the optimality of the 5% criterion has not been provided, and is still not detailed in the proposed LTCCM or its explanatory document.	1	See Core TSOs' answer	Core TSOs answer that this methodology handles the Core LT CCM and cannot answer for the position paper prepared by CWE TSOs.

2.2.6. Article 8 Generation Shift Key Methodology

Stakeholder response		Number of stakeholder requesting	Action taken	Core TSOs' answer
1.	One stakeholder comments that Article 8(1) does not provide a harmonised methodology for GSKs, as required under article 13 FCA Regulation.	1	See Core TSOs' answer	The Core TSOs acknowledge this comment: the GSK method is taken from the Agency's Day-Ahead methodology. Article 8(2) explains that further harmonisation could be possible in line with DA CCM, at this moment the methodologies are harmonised to the extent possible.

2.2.7. Article 9 Methodology for Remedial Actions in Capacity Calculation

Stakeholder response		Number of stakeholder requesting	Action taken	Core TSOs' answer
1.	One stakeholder comments that the process as described in this version of the methodology does not give a role to the coordinated capacity calculator (CCC), contrary to the previous version of the methodology. The stakeholder welcome clarification by the TSOs whether this step has now been abandoned, and why.	1	See Core TSOs' answer; Proposal updated	Core TSOs explain that the application of minRAM is made to consider remedial actions (each kind of remedial action). Usage of remedial actions is not mandatory according to the FCA Regulation. The role of the CCC and application of remedial actions will be detailed during the implention phase.

2.2.8. Article 10 Scenarios and Calculation Timestamps

Stakeholder response		Number of stakeholder requesting	Action taken	Core TSOs' answer
1.	One stakeholder comments on Article 10(3) that scenarios to be used in the common grid model for the monthly capacity calculation should always be updated – i.e. not only in case of “considerable change”, a concept that is not defined and would likely be applied differently by each TSO. This would allow reflecting the latest changes in market fundamentals and topology, and hence improve the efficiency of monthly capacity calculation.	1	See Core TSOs' answer	Core TSOs mantain the fact that such update should only be performed in case of a considerable changes such as change in gernation pattern following untypical climate and hydrological conditions. Generation pattern is not to be confused by the availablity of an individual power plant which is taken into account each month via the OPC process. Structural updates in the CGM is not supported by operational deparments due to lack of added value as in Long-Term timeframe the goal is to represent limiting conditions. Additionally, Core TSOs highlight that the format of reference scenarios is not part of the methodology and will be defined in the implementation phase.

2.2.9. Article 13 Computation of Power Transfer Distribution Factors

Stakeholder response		Number of stakeholder requesting	Action taken	Core TSOs' answer
1.	Article 13 (3) together with 3.1.1. Explanatory Document mention “the algorithm uses a concept of positive contributors that represents Core internal borders that are positively influenced (PTDF>0)”. What is the reason for dropping negative contributors? Is the procedure coherent with DA CCM?	3	See Core TSOs' answer	Core TSOs explain that netting is not applied in the LT timeframe due to the fact that the relieving flows are not guarenteed over the long time horizon. Consideration of negative PTDFs would allow netting, which is not compatible with the hedging nature of Long Term products (i.e. obtaining rights for both directions on one bidding zone border).

2.2.10. Article 14 Computation of the Available Margins on Critical Network Elements

Stakeholder response		Number of stakeholder requesting	Action taken	Core TSOs' answer
1.	One stakeholder welcome the adoption of a minRAM concept in the LTCCM. The stakeholder nonetheless insists that the definition of the minRAM factor (and its reviews) is approved by the Core NRAs.	1	See Core TSOs' answer	Core TSOs agree and do not have additional comments.
2.	One stakeholder finds that the methodology gives the possibility to have a minRAM imposed to CNECs but does not precise how it would be determined and what would be the governance. The stakeholder welcomes the idea to have an imposed minRAM but considers it should be further clarified and be binding, similarly to the day-ahead timeframe.	1	See Core TSOs' answer; Explanatory document updated	Core TSOs answer that the minRAM factor is to be detailed during implementation and is subject to regular review as described in Article 14. The methodology is designed as such to provide more room for improvement of the minRAM factor.

2.2.11. Article 17 Validation Methodology

Stakeholder response		Number of stakeholder requesting	Action taken	Core TSOs' answer
1.	Five stakeholders oppose the possibility to add constraints and oppose the possibility to correct results individually without proper, detailed justification and disclosure. The LT CCM has to be consistent and transparent. Any deviation from this principle has to be precisely defined, justified and disclosed.	5	See Core TSOs' answer; Proposal updated	Core TSOs answer that this information is provided in the quarterly report. Core TSOs will fulfill the requirements of the transperency platform as described in Article 19(2). Core TSOs agree to delete from Article 17(4) "When performing the steps of the validation, Core TSOs shall consider the operational security limits, but may also consider additional grid

				constraints, grid models, and other relevant information. Therefore, Core TSOs shall use the tools developed by the Core CCC for analysis but may also employ verification tools not available to the Core CCC".
2.	One stakeholder argues that considering that the use of costly remedial actions is excluded from the methodology, it is likely that the validation process will quite often restrict the capacity initially calculated. The "exceptional situations" mentioned in article 15.1 are likely to occur very frequently.	1	See Core TSOs' answer; Explanatory document updated	Core TSOs explain that costly remedial actions are not excluded due to the application of minRAM. Core TSOs want to avoid that the validation step might reduce the cross-zonal capacity by defining the boundaries in which such reduction can be applied.

2.2.12. Article 19 Publication of Data

Stakeholder response		Number of stakeholder requesting	Action taken	Core TSOs' answer
1.	For transparency and coherence reasons, publication structure and detail of LT CCM, all parameters and results, should correspond to DA CCM (e.g. DA CCM Art 22).	2	See Core TSOs' answer	Core TSOs explain that due to different calculation steps, some of the DA calculation parameters are not part of the LT CC and therefore cannot be published.
2.	One stakeholder proposes that the TSO's annually should publish a report on the efficiency and economic results of the long term transmission auctions and its impact on the utilization and development of transmission capacity. This report should be publicly available	1	See Core TSOs' answer	Core TSOs answer that such report is not foreseen by the FCA Regulation, Core TSOs will put available all relevant input data for third parties to perform such analysis.

2.2.13. Article 20 Monitoring and Information to Regulatory Authorities

Stakeholder response		Number of stakeholder requesting	Action taken	Core TSOs' answer
1.	One stakeholder argues that the report for all reductions made during the validation of cross-zonal capacity available to the public as well, for transparency reasons.	1	See Core TSOs' answer	Core TSOs understand this recommendation, yet the FCA Regulation stipulates that the reports are to be shared with Core NRAs and the Agency.

2.2.14. Article 22 Timescale for Implementation

Stakeholder response	Number of stakeholder requesting	Action taken	Core TSOs' answer

1.	Five stakeholders argue that an implementation timeline between 3.5 to 5 years is too long for LT CCM.	5	See Core TSOs' answer	Core TSOs will do their best to minimize the implementation timeline. Yet, there is a dependency on external developments such as: - LT CCM is a new methodology to implemented by all Core TSOs and CCC. The implementation timeline is required for development and implementation at all parties; - FB explicit allocation for LT timeframe is new for all parties for which new IT developments are needed; - Design and development of a new allocation platform is needed at JAO; - Adaptation is needed at market parties side as well; - To allow such changes at Market parties and JAO, // runs will be organized by Core TSOs. To conclude, Core TSOs estimate a timeperiod maximum of 5 years for all parties to adapt themselves to this new explicit Long Term Flow Based Allocation.
2.	One stakeholder opposes the establishment of a new TSO committee during the implementation phase as there already exists a proven allocation method which is also valid during the implementation phase, id est NTC allocation. Any modification of allocation (rules) - if any at all - has to be defined accurately and approved by Core regulators, notably as futures and forwards at least for the year 2023 are already traded and thus any modification constitutes a severe market intervention which distorts price formation.	1	See Core TSOs' answer; Proposal updated	Core TSOs do not foresee the comittee to change any rules on the allocation. The current NTC allocation will remain the norm. The TSO committee has been removed from the methodology.

2.2.15. FB allocation/LTTR/Hedging

Stakeholder response		Number of stakeholder requesting	Action taken	Core TSOs' answer
1.	One stakeholder would like to stress how important long-term transmission rights are for the market integration. They allow market participants to hedge against price spreads, especially for the risks related to the bidding zones with lower liquidity. Basically, DA CCM and LT CCM must lead	1	See Core TSOs' answer	Core TSOs acknowledge the importance of the long-term transmission rights and their role from the aspect of market integration via hedging strategy of market participants. The current LTCC methodology focuses to the Capacity

	to equal levels of capacities in order to obtain reasonable price signals. As long-term markets are to predict the future fulfilment in DA/Spot markets, an appropriate relation between LT and DA capacities is crucial.			Calculation only, but Core TSOs will endeavour to incorporate the market participants views and proposals during the redesigning process of cross border long-term market. The forms of products will be compatible with the LTTR Regional Design (including reduction periods). But this methodology together with other relevant methodologies (e.g. EU HAR) shall be modified in line with the LTCC method, all those shall go through the formal Public Consultation required by FCA, where all the market participants' feedbacks and views will be properly discussed and taken into consideration at the largest possible extent. Moreover Core TSOs plan to consult the status of the development with market participants on a regular basis via the CCG forums.
2.	One stakeholder comments that forward capacity calculation and allocation is critical to allow market participants to hedge their long-term positions across borders and make sure that they are not exposed to short-term price volatility and imbalance costs. Hence, it is vital that the calculation methodology for the forward timeframe is robust. As the stakeholder sees it for the moment, the draft proposal does not show a clear commitment to the first objective listed in article 3 of the Forward Capacity Allocation (FCA) Regulation, i.e. "promoting effective long-term cross-zonal trade with long-term cross-zonal hedging opportunities for market participants".	1	See Core TSOs' answer	Core TSOs acknowledge the importance of the long-term transmission rights and their role from the aspect of market integration via hedging strategy of market participants. The current LTCC methodology focuses to the Capacity Calculation only, but Core TSOs will endeavour to incorporate the market participants views and proposals during the redesigning process of cross border long-term market. The forms of products will be compatible with the LTTR Regional Design (including reduction periods). But this methodology together with other relevant methodologies (e.g. EU HAR) shall be modified in line with the LTCC method, all those shall go through the formal Public Consultation required by FCA, where all the market participants' feedbacks and views will be properly discussed and taken into consideration at the largest possible extent. Moreover Core TSOs plan to consult the status of the development with market participants on a regular basis via the CCG forums.
3.	One stakeholder finds that the proposal lacks details about the allocation process. The target model of this proposal, which we understand as including also flow-based capacity allocation, would require significant adaptation on market participants' side from an operational standpoint. In light of all these	1	See Core TSOs' answer	Core TSOs explain that the flow-based approach will be implemented following the clearly defined guidance of ACER. Core TSOs acknowledge the challenges of the flow-based approach. With the Flow Based approach the capacity might be bigger at CCR level and the distribution to the

	uncertainties, some modelling of flow-based capacity calculation and allocation in the Core region could have helped to confirm or refute the assertion of Recital 9. The TSOs have not provided such information to the market. Therefore, we believe that Recital 9 is only aspirational, and fails to provide a justification to the application of a flow-based approach to LTCCM in the Core region, as required by article 10(5) FCA Regulation.			borders is depending on market demand. Core TSOs will elaborate the Flow Based allocation, there is a sufficient time foreseen to develop and implement proper allocation mechanisms to be used by SAP.
4	The proposal for the allocation of capacity is not described in the proposed methodology, however we understand that the LT Capacity Calculation and the LT Capacity Allocation should be consid-ered as a whole. We also understand that there is no certainty yet on how to allocate cross-border rights (how to extract NTC from the previously calculated FB domain). In any case, the stakeholder would like to share the following remark regarding this issue: • The flow-based allocation has merit on a theoretical perspective: having the market interests determining the most optimal NTC extraction is indeed an interesting idea. However, this process would require very important operational and structural changes with respect to the current situation. • Given the reserves we have on the capacity calculation, the stakeholder wonders whether this is not too early to envisage such a solution. This could however be a nice target solution, pro-vided that all the issues/unclarity of the capacity calculation process are solved. As next steps, stakeholder sees the following actions: a) The methodology for allocation therefore needs to be further developed/refined. b) The stakeholder would welcome a recurrent and constructive dialogue with the various stakeholders to refine/discuss the flow-based allocation.	1	See Core TSOs' answer	Core TSOs explain that this LTCCM is a methodology for capacity calculation. The flow based allocation will be designed but not written in this methodology. Core TSOs will consult on a regular basis with market participants during the CCG forums.
5	Forward capacity calculation and allocation is critical to allow market participants to hedge their long-term positions across borders and make sure that they are not exposed to short-term price volatility and imbalance costs. Hence, it is vital that the calculation methodology for the forward timeframe is robust.	1	See Core TSOs' answer	Core TSOs acknowledge the importance of the long-term transmission rights and their role from the aspect of market integration via hedging strategy of market participants. The current LTCC methodology focuses to the Capacity Calculation only, but Core TSOs will endeavour to incorporate the market

	Methodology must be transparent, predictable, not discriminating smaller bidding zones and allocating at least the existing volumes of cross-border capacity for market participants. Any decrease in the volume would lead to detrimental effects on the market. As we see it for the moment, the draft proposal does not show a clear commitment to the first objective listed in article 3 of the Forward Capacity Allocation (FCA) Regulation, i.e. "promoting effective long-term cross-zonal trade with long-term cross-zonal hedging opportunities for market participants". In particular, the choice of a flow-based approach for the calculation (and possibly the allocation) of long-term capacity in the Core CCR – instead of the default coordinated net transfer capacity (cNTC) approach – is not justified in the methodology or the explanatory document, as required by article 10(5) FCA Regulation.			participants views and proposals during the redesigning process of cross border long-term market. The forms of products will be compatible with the LTTR Regional Design (including reduction periods). But this methodology together with other relevant methodologies (e.g. EU HAR) shall be modified in line with the LTCC method, all those shall go through the formal Public Consultation required by FCA, where all the market participants' feedbacks and views will be properly discussed and taken into consideration at the largest possible extent. Moreover Core TSOs plan to consult the status of the development with market participants on a regular basis via the CCG forums.
6	The proposed methodology is extremely complex, and requires an in-depth knowledge and understanding of numerous parameters and procedures applied by the different concerned TSO's. The stakeholder does not have access to all this information and thus cannot provide an overall assessment of all the elements of the proposed methodology. We find it important that the TSOs provide a correct analysis of future transmission capacities and balance the sale of Long Term Transmission rights with the interests of the transmission customers.	1	See Core TSOs' answer	Core TSOs acknowledge the importance of the long-term transmission rights and their role from the aspect of market integration via hedging strategy of market participants. The current LTCC methodology focuses to the Capacity Calculation only, but Core TSOs will endeavour to incorporate the market participants views and proposals during the redesigning process of cross border long-term market. The forms of products will be compatible with the LTTR Regional Design (including reduction periods). But this methodology together with other relevant methodologies (e.g. EU HAR) shall be modified in line with the LTCC method, all those shall go through the formal Public Consultation required by FCA, where all the market participants' feedbacks and views will be properly discussed and taken into consideration at the largest possible extent. Moreover Core TSOs plan to consult the status of the development with market participants on a regular basis via the CCG forums.
7	Long-term transmission rights are very important for the market integration as they allow market participants to hedge against price spreads, especially for the risks related to the bidding zones with	1	See Core TSOs' answer	Core TSOs acknowledge the importance of the long-term transmission rights and their role from the aspect of market integration via hedging strategy of market

	lower liquidity. Basically, DA CCM and LT CCM must lead to equal levels of capacities in order to obtain reasonable price signals. As long-term markets are to predict the future fulfilment in DA/Spot markets, an appropriate relation between LT and DA capacities is crucial.			participants. The current LTCC methodology focuses to the Capacity Calculation only, but Core TSOs will endeavour to incorporate the market participants views and proposals during the redesigning process of cross border long-term market. The forms of products will be compatible with the LTTR Regional Design (including reduction periods). But this methodology together with other relevant methodologies (e.g. EU HAR) shall be modified in line with the LTCC method, all those shall go through the formal Public Consultation required by FCA, where all the market participants' feedbacks and views will be properly discussed and taken into consideration at the largest possible extent. Moreover Core TSOs plan to consult the status of the development with market participants on a regular basis via the CCG forums.

ANNEX

Stakeholder responses	
1.	Long-term transmission rights are very important for the market integration as they allow market participants to hedge against price spreads, especially for the risks related to the bidding zones with lower liquidity. Basically, DA CCM and LT CCM must lead to equal levels of capacities in order to obtain reasonable price signals. As long-term markets are to predict the future fulfilment in DA/Spot markets, an appropriate relation between LT and DA capacities is crucial. Furthermore, LT CCM should be as realistic as manageable and comprise various situations that may occur in DA/Spot market timeframe. This includes various weather scenarios, outages/revisions of power lines and plants and different developments of renewables and thermal capacities. Calculation should be performed within these different scenarios and the resulting LT capacity should reflect the expected value across all scenarios. The methodology mentions the possibility for TSOs to apply “additional grid constraints, grid models and other relevant information” but those elements are not defined in the methodology. We oppose such a vague possibility. External constraints for and individual corrections of the CC results have to be prevented; any exemption has to be justified and disclosed. For transparency and coherence reasons, publication structure and detail of LT CCM, all parameters and results, should correspond to DA CCM (e.g. DA CCM Art 22). In detail: Article 4 (2) should not only focus on higher uncertainties but also consider the possibility that the level of uncertainty decreases, hence, we propose the following amendment: “[...] and to ensure an adequate consideration of the uncertainties in the capacity calculation for the long-term timeframes.” Article 6 (1) We oppose the possibility to add external constraints without proper justification and disclosure. Article 7 (1) The methodology does not provide any condition/methodology for the CNEC selection. Article 7 (3) mentions that zone-to-zone PTDF should be higher than a threshold of 5% while it is 10% for the DA and additionally – it has never been proven that this threshold was optimal. Article 13 (3) together with 3.1.1. Explanatory Document mention “the algorithm uses a concept of positive contributors that represents Core internal borders that are positively influenced (PTDF>0)”. What is the reason for dropping negative contributors? Is the procedure coherent with DA CCM? Article 17 (1) and 17 (4) We oppose the possibility to add constraints and we oppose the possibility to correct results individually without proper, detailed justification and disclosure. The LT CCM has to be consistent and transparent. Any deviation from this principle has to be precisely defined, justified and disclosed. Article 22 (2) mentions an implementation period of 3.5 to 5 years which is too vague and too long. 3 years should be the maximum implementation timeframe. Article 22 (3) We oppose the establishment of a new TSO committee during the implementation phase as there already exists a proven allocation method which is also valid during the implementation phase, id est NTC allocation. Any modification of allocation (rules) - if any at all - has to be defined accurately and approved by Core regulators, notably as futures and forwards at least for the year 2023 are already traded and thus any modification constitutes a severe market intervention which distorts price formation.
2	The stakeholder would like to stress how important long-term transmission rights are for the market integration. They allow market participants to hedge against price spreads, especially for the risks related to the bidding zones with lower liquidity. Basically, DA CCM and LT CCM must lead to equal levels of capacities in order to obtain reasonable price signals. As long-term markets are to predict the future fulfilment in DA/Spot markets, an appropriate relation between LT and DA capacities is crucial. Furthermore, LT CCM should be as realistic as manageable and comprise various situations that may occur in DA/Spot market timeframe. This includes various weather scenarios, outages/revisions of power lines and plants and different developments of renewables and thermal capacities. Calculation should be performed within these different scenarios and the resulting LT capacity should reflect the expected value across all scenarios. The methodology mentions the possibility for TSOs to apply “additional grid constraints, grid models and other relevant information” but those elements are not defined in the methodology. We oppose such a vague possibility.

	External constraints for and individual corrections of the CC results have to be prevented; any exemption has to be justified and disclosed. For transparency and coherence reasons, publication structure and detail of LT CCM, all parameters and results, should correspond to DA CCM (e.g. DA CCM Art 22). In detail: Article 4 (2) should not only focus on higher uncertainties but also consider the possibility that the level of uncertainty decreases, hence, we propose the following amendment: "[...] and to ensure an adequate consideration of the uncertainties in the capacity calculation for the long-term timeframes." Article 6 (1) We oppose the possibility to add external constraints without proper justification and disclosure. Article 7 (1) The methodology does not provide any condition/methodology for the CNEC selection. Article 7 (3) mentions that zone-to-zone PTDF should be higher than a threshold of 5% while it is 10% for the DA and additionally, it has never been proven that this threshold was optimal. Article 7 (4) mentions that the list of CNE can be updated once a month. Is this a realistic development or rather reasonable approach? Article 13 (3) together with 3.1.1. Explanatory Document mention "the algorithm uses a concept of positive contributors that represents Core internal borders that are positively influenced (PTDF>0);". What is the reason for dropping negative contributors? Is the procedure coherent with DA CCM? Article 17 (1) and 17 (4) We oppose the possibility to add constraints and we oppose the possibility to correct results individually without proper, detailed justification and disclosure. The LT CCM has to be consistent and transparent. Any deviation from this principle has to be precisely defined, justified and disclosed. Article 22 (2) mentions an implementation period of 3.5 to 5 years which is too vague and too long. 3 years should be the maximum implementation timeframe. Article 22 (3) We oppose the establishment of a new TSO committee during the implementation phase as there already exists a proven allocation method which is also valid during the implementation phase, id est NTC allocation. Any modification of allocation (rules) - if any at all - has to be defined accurately and approved by Core regulators, notably as futures and forwards at least for the year 2023 are already traded and thus any modification constitutes a severe market intervention which distorts price formation.
3.	The stakeholdder welcomes the opportunity to provide comments on the updated draft methodology for long-term capacity calculation (LTCCM) proposed by the TSOs of the Core capacity calculation region (Core CCR). As previously mentioned in stakeholder responses to the Core and other CCRs' LTCCM proposals (*) , forward capacity calculation and allocation is critical to allow market participants to hedge their long-term positions across borders and make sure that they are not exposed to short-term price volatility and imbalance costs. Hence, it is vital that the calculation methodology for the forward timeframe is robust. As we see it for the moment, the draft proposal does not show a clear commitment to the first objective listed in article 3 of the Forward Capacity Allocation (FCA) Regulation, i.e. "promoting effective long-term cross-zonal trade with long-term cross-zonal hedging opportunities for market participants". In particular, the choice of a flow-based approach for the calculation (and possibly the allocation) of long-term capacity in the Core CCR – instead of the default coordinated net transfer capacity (cNTC) approach – is not justified in the methodology or the explanatory document, as required by article 10(5) FCA Regulation. Besides, the proposal lacks sufficient details in the description of the capacity calculation methodology itself. This is especially when it comes to the selection of CNE(C)s, but also for the determination of GSKs or the definition of remedial actions. Finally, it is currently unclear how the allocation process will take place. Beyond calculation, we understood from discussions at Core Consultative Group meetings that the objective is also to use the flow-based approach for the allocation of capacity by 3 to 5 years. In the meantime, an NTC extraction would be performed to allocate capacity at each border. Considering the uncertainties about the capacity calculation model already – and the worries we have that a flow-based calculation may not yield very high level of cross-zonal capacity in the forward timeframe – the lack of clear idea how capacity will be allocated in the future significantly adds to market participants concerns with the overall proposal. We call on the TSOs to engage in a dialogue with market participants to help us

	understand how the future capacity calculation and allocation processes will play out. This should also include all the elements in the new processes that would require an adaptation of tools and systems on market participants' side. On a side note, we would like to underline that political agreements on pre-determined levels of capacity at given borders, such as bilateral agreements, are detrimental to the efficiency of capacity calculation and the maximisation of welfare at regional level. The treatment of such agreements, as they exist today, is not ruled in the LTCCM proposal. Should they be allowed to be maintained once the LTCCM comes into force, they should at the very least be listed in the capacity calculation methodology and their impact thoroughly assessed. You will find below our detailed comments on individual articles of the draft methodology. Comments on individual articles: • Recital 9: In accordance with article 10(5) of the FCA Regulation, the CCM applies the flow-based approach to capacity calculation. In capacity calculation regions characterised by meshed networks and physically interdependent bidding zone borders, the flow-based approach by default leads to an increase in economic efficiency with the same level of system security. This is because, when a network element, which is considered in capacity calculation as critical network element is significantly impacted by cross-zonal exchanges on two or more bidding zone borders (which makes those borders interdependent), then it is by default more efficient that requests for cross-zonal exchanges on these interdependent borders equally compete for the capacity of such critical network element. This competition between borders is the intrinsic advantage of the flow-based approach compared to the coordinated net transmission capacity ('NTC') approach. In the latter approach, the capacity of such critical network elements needs to be first split into portions reserved for each of the interdependent borders and then converted into NTC values for each border. These NTCs are then allocated independently on each interdependent border, which essentially limits the competition between interdependent borders for the capacity of such critical network elements. Lack of competition between borders for the capacity of network elements, which these borders are significantly impacting inevitably, leads to loss of economic efficiency in allocating the capacity of such network elements. Recital 9 considers that the flow-based approach to capacity calculation leads "by default" to an increase in economic efficiency with the same level of system security. Should this necessarily be the case, we wonder why the legislator would have put this element as the first condition to the implementation of a flow-based approach in the forward timeframe in article 10(5) FCA Regulation. While the flow-based approach may indeed linked to improved economic efficiency in theory, the practice may be quite different. This is already the case in day-ahead – as shown by the economic indicators in CWE, which show much lower efficiency gains in practice than modelled ex-ante in theory. This would be even truer in the forward timeframe, where significant uncertainties will be taken into account in a flow-based model. Grid models will be much less precise than in day-ahead, and elements like reliability margins or allocation constraints will likely be much more limiting. Finally, the validation process may lead to significant gaps between theoretically calculated and actually allocated capacities. All in all, it is far from certain that with such levels of uncertainty, a flow-based approach to capacity calculation will "by default" yield more economic efficiency than a cNTC approach. Finally, as noted in our introduction, the proposal lacks details about the allocation process. The target model of this proposal, which we understand as including also flow-based capacity allocation, would require significant adaptation on market participants' side from an operational standpoint. In light of all these uncertainties, some modelling of flow-based capacity calculation and allocation in the Core region could have helped to confirm or refute the assertion of Recital 9. The TSOs have not provided such information to the market. Therefore, we believe that Recital 9 is only aspirational, and fails to provide a justification to the application of a flow-based approach to LTCCM in the Core region, as required by article 10(5) FCA Regulation. • Recital 11: The LT CCM enables Core TSOs to provide market participants with reliable information on cross-zonal capacities and import/export limits for year and month ahead allocation in a transparent way and at the same time. This includes regular reporting on specific processes within capacity calculation. The LT CCM therefore contributes to the objective of transparency and reliability of information (article 3(f) of the FCA Regulation). A binding methodology should mandate TSOs to provide reliable information to market participants, not enable them to do so.

• Recital 18: The LT CCM shall be compatible with the day-ahead and intraday capacity calculation methodologies (article 10 (3) of the FCA Regulation).

This recital is a copy-paste of article 10(3) FCA Regulation. When proposing a draft LTTCM – i.e. the document currently under consultation – this document has to be (not shall be) compatible with the day-ahead (DA) and intraday (ID) CCMs approved by ACER in February 2019. The TSOs should prove now, in this methodology and the explanatory document, that all Core CCMs (LT, DA and ID) are compatible.

• Article 3.2: The year-ahead and month-ahead capacity calculation process shall consist of three main stages: a. the creation of capacity calculation inputs by the Core TSOs, in accordance with Title 2;

b. the capacity calculation process by the CCC, in accordance with Title 3;

c. the capacity validation by the Core TSOs in coordination with the CCC, in accordance with Title 4.

and article 3.3: In accordance with article 24 of the FCA Regulation, each Core TSOs shall validate the results.

It looks like article 3.3 is an unnecessary repetition of article 3.2(c). See more details on the validation process in our reaction to article 17.

• Article 4.1: The Core TSOs shall use the latest available FRM from the DA timeframe.

The proposal is to use the same reliability margins in the forward timeframe as those of the day-ahead timeframe. According to article 22(2) of the CACM Regulation, referred to in article 11 of the FCA Regulation, “The methodology to determine the reliability margin shall set out the principles for calculating the probability distribution of the deviations between the expected power flows at the time of the capacity calculation and realised power flows in real time.” This means that reliability margins serve to cover uncertainty between the time of calculation and the time of delivery. Hence, using the same methodology to determine reliability margins in DA and forward timeframes would be welcome, but using the same exact margins does not seem appropriate: a specific calculation should be performed for each timeframe.

• Article 6.1: In case operational security limits cannot be transformed efficiently into ■■max and ■■max pursuant to Article 5, the Core TSOs may transform them into allocation constraints. For this purpose, the Core TSOs may only use external constraints as a specific type of allocation constraint that limits the maximum import and/or export of a given Core bidding zone.

and the rest of article 6.

We oppose the inclusion in the methodology of a provision opening the possibility for TSOs to include import/export limits in the forward timeframe without proper justification, consultation of other Core TSOs and market participants, and approval by all Core regulators.

• Article 7.1: Each Core TSO shall provide a list of critical network elements (CNEs), including by default all cross-zonal network elements and a list of associated contingencies (Cs) of its own control area based on operational experience. The result of the process will be an initial pool of CNECs in all subsequent steps of the common long-term capacity calculation.

The article does not include the methodology for the CNE(C) selection, which will therefore remain at national level if the methodology is approved as is. This approach is not coherent with the CNE(C) selection methodology for day-ahead and intraday (article 5), which is harmonised at CCR level for the Core region.

German-Luxembourgian bidding zone, by assigning relative weights to each Core TSO’s GSK. The German and Luxembourgian TSOs shall agree on these weights, based on the share of the generation in each Core TSO’s control area that is responsive to changes in net position, and provide them to the Core CCC.

Article 8.1 does not provide a harmonised methodology for GSKs, as required under article 13 FCA Regulation. Should TSOs think that local specificities prevent harmonisation of principles and methodologies, these specificities should be clearly explained. The addition of article 8.2 foreseeing a harmonisation of the methodology for GSKs in the future is not sufficient in relation to the FCA Regulation.

The addition of specifications for the determinations of GSKs in Germany and Luxembourg – basically allowing the TSOs or Germany on the one side, and Luxembourg on the other side, to unilaterally define their GSKs – contradicts the principle of article 8.1.e which initially states that the GSK in bidding zones

covering multiple TSO areas shall be defined jointly. Considering that the German-Luxembourg bidding zone is the only one covering multiple TSOs, the principle of article 8.1.e seems void.

	• Article 9.1: Each Core TSO may define a set of available RAs, which is located in its control area. For transparency reasons, all Core TSOs have to be informed about this set of RAs in advance. and article 9.2: Only the following RAs are considered: - opening or closing of one or more line(s), cable(s), transformer(s), bus bar coupler(s); - switching of one or more network element(s) from one bus bar to another; - transformer and PST tap adjustment. Article 9.1 leaves entire room to TSOs to define the set of available RAs in their control area, and article 9.2 openly excludes the consideration of costly remedial actions. We believe that costly remedial actions should be systematically considered in the capacity calculation, to the same extent that they are considered in the coordinated security assessment. Where economically efficient, costly remedial actions should be taken in order to allocate the maximum of cross-zonal capacity to the market. Congestion “rents” and redispatch “costs” are both financial redistributions elements that should be considered on an equal footing in order to optimise regional welfare. • Article 9.5: The initial step of the common procedure is a comparison of calculation results by each Core TSO based on its best practice and experience on the combination of the results and the contingencies. This step is followed by improvement of calculation results based on a common set of coordinated remedial actions, in case a Core TSO decides in the initial step that the result is not in line with its best practice and experience. The process as described in this version of the methodology does not give a role to the coordinated capacity calculator (CCC), contrary to the previous version of the methodology. We welcome clarification by the TSOs whether this step has now been abandoned, and why. If not, all the steps should be clearly detailed in the methodology. • Article 10.3: In case of a considerable change, compared to the IGM for the ENTSO-E year-ahead reference scenario, in the grid of a Core TSO, this Core TSO shall update its IGM by incorporating the latest available information as regard to the generation pattern and topology (due to grid element commissioning or decommissioning), while the net position of the bidding zone is maintained unchanged when changing the generation pattern/topology. This updating process with the latest available data is performed in the month-ahead capacity calculation timeframe by Core TSOs as there is no such a process at ENTSO-E level. We think the scenarios to be used in the common grid model for the monthly capacity calculation should always be updated – i.e. not only in case of “considerable change”, a concept that is not defined and would likely be applied differently by each TSO. This would allow reflecting the latest changes in market fundamentals and topology, and hence improve the efficiency of monthly capacity calculation. • Article 14.2: The Core TSOs shall commonly define the minimum RAM factor (Ramr), i.e. a specific percentage value for calculation of minimum RAM in accordance with paragraph 4. The minRAM factor is subject to a regular review by all Core TSOs. We welcome the adoption of a minRAM concept in the LTCCM. We nonetheless insist that the definition of the minRAM factor (and its reviews) is approved by the Core NRAs. • Article 17.1.b: In accordance with article 15 of the FCA Regulation, referring to article 26 of the CACM Regulation, the Core TSOs shall have the right to correct long-term capacity relevant to the Core TSO’s BZBs for reasons of operational security during the validation process. In exceptional situations long-term capacities can be reduced by all Core TSOs. These potential situations are at least: [...] b. when RAs, pursuant to TITLE 2:Article 9, that are needed to ensure the calculated capacity on all CNECs, are not sufficient; See our comments to article 9.1 and 9.2. Considering that the use of costly remedial actions is excluded from the methodology, it is likely that the validation process will quite often restrict the capacity initially calculated. The “exceptional situations” mentioned in article 15.1 are likely to occur very frequently.

	• Article 17.4: When the process of individual verification of the calculated capacities is completed, then the final capacity validation process takes place in a coordinated way, whereby Core TSOs may require a reduction in calculated capacities for reasons of operational security. When performing the steps of the validation, Core TSOs shall consider the operational security limits, but may also consider additional grid constraints, grid models, and other relevant information. Therefore, Core TSOs shall use the tools developed by the Core CCC for analysis but may also employ verification tools not available to the Core CCC. The possible application by individual TSOs of "additional grid constraints, grid models and other relevant information" – none of them defined in this methodology – as part of the validation process leaves far too much room to the TSOs for further restricting capacity. Elements that can restrict capacity should be included in the methodology, not left open for discretionary application at the end of the process by the TSOs. Coming back to our initial comment on Recital 9 and the application of a flow-based methodology: by the time we have reached article 17 of the methodology, we are particularly doubtful that a flow-based approach would be "by default" more efficient than a cNTC approach. Indeed, the theoretical model sees the imposition of the following elements that are likely to skew a calculation that may have "by default" led to mathematical ideal results: - Non-coordinated selection of CNE(C)s - sensitivity threshold for PTDFs set at 5% without justification - imposition of import and export limits - non-harmonised methodology for GSKs - exclusion of costly remedial actions - uncertain grid models that are not updated frequently enough - potential application of "additional grid constraints, grid models, and other relevant information" as part of the validation process • Article 20.5: The Core CCC shall issue a quarterly report on capacity validation to the Core NRAs after approval by the Core TSOs. In each quarterly report, the Core CCC shall provide all the information on the reductions of calculated capacity after coordinated validation of capacities according to Article 17(4). and article 20.6. We recommend making the report for all reductions made during the validation of cross-zonal capacity available to the public as well, for transparency reasons. (*) See the stakeholder responses to consultations on the SWE LTCCM proposal (dated 15 April 2019, available at: https://efet.org/Files/Documents/Downloads/EFET_ENTSO-E%20consult%20SWE%20LTCC_15042019.pdf), the Hansa LTCCM proposal (dated 15 May 2019, available at: https://efet.org/Files/Documents/Downloads/EFET_Hansa_CCM_15052019_final.pdf), the Core LTCCM proposal (dated 10 July 2019, available at: https://efet.org/Files/Documents/Downloads/EFET-MPP_TSOs%20consult%20CORE%20LTCC_10072019-2.pdf), the SEE LTCCM proposal (dated 2 September 2019, available at: https://efet.org/Files/Documents/Downloads/EFET_TSOs%20consult%20SEE%20LTCC_02092019.pdf), the Italy North LTCCM proposal (dated 13 March 2020, available at: https://efet.org/Files/Documents/Downloads/EFET%20response%20to%20Italy%20north%20TSO%20on%20a%20forward%20capacity%20calculation%20methodology.pd and the Baltic LTCCM proposal (dated 24 August 2020, available at: https://efet.org/Files/Documents/Electricity%20Market/Forward%20markets/EFET_response_ACER_consultation_Baltic_CCR_LT_CCM_24082020_final.pdf).
4.	In principle the CA CCM and the LT CCM should be as identical as possible. Long term markets try to predict the situation of the future fulfilment in DA/Spot market, therefore they need a stable, consistent and transparent framework. The LT CCM should be as realistic as possible and represent various situations that may occur in the DA/Spot market timeframe. This includes various weather scenarios, outages/revisions of power lines and plants and different development paths of renewable and thermal capacities.

	The calculation should be performed in different variations/scenarios and the resulting LT capacity should mirror the expectation value across all these scenarios (and not be biased). Article 4 (2.) should not only focus on higher uncertainties but also consider the possibility that the uncertainty may evolve to lower levels, hence we propose to change the sentence to "[...] and to ensure an adequate con-sideration of the uncertainties in the capacity calculation for the long-term timeframes." (delete: higher) Article 7 (3.) What is the argumentation behind the agreed CNEC threshold of significance of 5%? We would have welcomed more explanation and derivation of the threshold in the explanatory document. Is the methodology consistent to the DA CCM? For reasons of transparency and coherence between DA CCM and LT CCM, we think that the frame publication of data like in the DA CCM (e.g. DA CCM Art 22) should be followed in this methodology as well. The parameters and results of the LT CCM should be completely disclosed to public in a useful and transparent form. Regarding Art. 13 (3) of the LT CCM and 3.1.1. (Expl. Doc.) "the algorithm uses a concept of positive contributors that represents Core internal borders that are positively influenced (PTDF>0);". What is the reason for dropping negative contributors? Is the procedure coherent with DA CCM? Article 17 (1) and 17 (4) We oppose the possibility to add constraints and we oppose the possibility to correct results individually without proper, detailed justification and disclosure. The LT CCM has to be consistent and transparent. Article 22 (3) We oppose the establishment of a new TSO committee during the implementation phase as there already exists a proven allocation method which is also valid during the implementation phase, id est NTC allocation. Any modification of allocation (rules) - if any at all - has to be defined accurately and approved by Core regulators, notably as futures and forwards at least for the year 2023 are already traded and thus any modification constitutes a severe market intervention which distorts price formation.
5.	The stakeholder welcomes the opportunity to provide comments on the Core CCR TSOs' amendment proposal to the Core long-term capacity calculation methodology (CCM). Long-term transmission rights are indeed key when it comes to market integration, insofar as they allow market participants to hedge against price spreads, especially for the risks related to the bidding zones with lower liquidity. Overall and as detailed below, the stakeholder considers that the Core TSOs' proposal has merit since it brings new ideas that are in theory interesting in terms of increasing the social welfare but lacks clarity, for instance regarding the CNECs selection. It also lacks justification on the proposed choices, in particular regarding the justification of the choice to opt for a flow-based approach for both the calculation and the allocation of capacity. Finally, the stakeholder observes that no explanation is provided regarding the treatment of political agreements. 1/ Regarding the choice to opt for a flow-based approach for the calculation Recital 9 mentions that in a meshed network, flow-based approach leads by default to an increase in the economic efficiency. As experience in day-ahead capacity calculation conversely shows that the welfare benefits are lower in reality than expected, the stakeholder wonders about the rationale of such a statement and would therefore welcome more information on the elements underlying it. This especially in the light of the 70% rule: the room to find flow based solutions seems limited with that in mind. 2/ Regarding the choice to opt for a flow-based approach for the allocation of capacity The proposal for the allocation of capacity is not described in the proposed methodology, however we understand that the LT Capacity Calculation and the LT Capacity Allocation should be consid-ered as a whole. We also understand that there is no certainty yet on how to allocate cross-border rights (how to extract NTC from the previously calculated FB domain). In any case, stakeholder would like to share the following remark regarding this issue: • The flow-based allocation has merit on a theoretical perspective: having the market interests determining the most optimal NTC extraction is indeed an interesting idea. However, this process would require very important operational and structural changes with respect to the current situation. • Given the reserves we have on the capacity calculation, the stakeholder wonders whether this is not too early to envisage such a solution. This could however be a nice target solution, pro-vided that all the issues/unclarity of the capacity calculation process are solved. As next steps, stakeholder sees the following actions: a) The methodology for allocation therefore needs to be further developed/refined.

	b) The stakeholder would welcome a recurrent and constructive dialogue with the various stakeholders to refine/discuss the flow-based allocation. 3/ Regarding the application of external constraints (article 6.1) The stakeholder opposes the possibility to apply external constraints without proper justification. 4/ Regarding the CNECs selection (article 7.1) The methodology does not provide any condition/methodology for the CNEC selection. • Article 7.3 mentions that zone-to-zone PTDF should be higher than a threshold of 5% while it is 10% for the DA. Such a threshold has additionally never proven to be optimal. • Article 7.4 mentions that the list of CNE can be updated once a month: the MPP opposes this possibility and considers that the list should be validated by all Core NRAs and TSOs. 5/ Regarding the minRAM The methodology gives the possibility to have a minRAM imposed to CNECs but does not precise how it would be determined and what would be the governance. The stakeholder welcomes the idea to have an imposed minRAM but considers it should be further clarified and be binding, similarly to the day-ahead timeframe. 6/ Regarding the application of additional elements The methodology mentions the possibility for TSOs to apply “additional grid constraints, grid models and other relevant information” but those elements are not defined in the methodology. The stakeholder opposes such a vague possibility. 7/ Regarding the foreseen implementation timeline and the transitory measures The stakeholder observes that article 22.2 of the methodology foresees an implementation timeline spreading over a period of 3.5 to 5 years after approval and considers such a range to be too imprecise and too long. Moreover, given the uncertainty on the method for the allocation (included or not?), the period is even more vague. The stakeholder would also like to stress the need to establish clear transitory measures until the full implementation of the new long-term capacity calculation. To that extent, the stakeholder acknowledges that the Core TSOs will pursue the NTC allocation, which in the stakeholder’s view questions the need for an ad hoc TSO committee dedicated to settle disputes among TSOs regarding the coordination of long-term capacities. Any modification of allocation rules should anyway be defined and approved by Core regulators, notably as futures and forwards – at least for the year 2023 – are already traded.
6.	The stakeholder would like to support the other stakeholder’s position paper on the long-term capacity calculation methodology, which reflects our views on the matter an on specific Articles in detail (as there is limited space to express our views here). Forward capacity calculation and allocation is critical to allow market participants to hedge their long-term positions across borders and make sure that they are not exposed to short-term price volatility and imbalance costs. Hence, it is vital that the calculation methodology for the forward timeframe is robust. Methodology must be transparent, predictable, not discriminating smaller bidding zones and allocating at least the existing volumes of cross-border capacity for market participants. Any decrease in the volume would lead to detrimental effects on the market. As we see it for the moment, the draft proposal does not show a clear commitment to the first objective listed in article 3 of the Forward Capacity Allocation (FCA) Regulation, i.e. “promoting effective long-term cross-zonal trade with long-term cross-zonal hedging opportunities for market participants”. In particular, the choice of a flow-based approach for the calculation (and possibly the allocation) of long-term capacity in the Core CCR – instead of the default coordinated net transfer capacity (cNTC) approach – is not justified in the methodology or the explanatory document, as required by article 10(5) FCA Regulation. Besides, the proposal lacks sufficient details in the description of the capacity calculation methodology itself, especially when it comes to the selection of CNE(C)s. The LTCCM proposal does not take account of the requirements laid down by ACER in its decision on the DA and ID CCMs for the Core region concerning the removal of internal CNE(C)s from the DA and ID capacity calculation within two years unless properly justified by the TSOs and approved by all CCR NRAs. For consistency reasons once again, we believe the same provision should apply to the LTCC.

	We would like to underline that political agreements on pre-determined levels of capacity at given borders, such as bilateral agreements, are detrimental to the efficiency of capacity calculation and the maximisation of welfare at regional level. The treatment of such agreements, as they exist today, is not ruled in the LTCCM proposal. The possible application by individual TSOs of “additional grid constraints, grid models and other relevant information” – none of them defined in this methodology – as part of the validation process leaves far too much room to the TSOs for further restricting capacity. Elements that can restrict capacity should be included in the methodology, not left open for discretionary application at the end of the process by the TSOs. In a nutshell, we are doubtful that a flow-based approach would be “by default” more efficient than a cNTC approach. Indeed, the theoretical model sees the imposition of the following elements that are likely to skew a calculation that may have “by default” led to mathematical ideal results: - Non-coordinated selection of CNE(C)s - sensitivity threshold for PTDFs set at 5% without justification - imposition of import and export limits - non-harmonised methodology for GSKs - exclusion of costly remedial actions - uncertain grid models that are not updated frequently enough - potential application of “additional grid constraints, grid models, and other relevant information” as part of the validation process
7.	1. The stakeholder thanks the CORE TSOs for being given the opportunity to respond to this proposal. The proposed methodology is extremely complex, and requires an in-depth knowledge and understanding of numerous parameters and procedures applied by the different concerned TSO’s. The stakeholder does not have access to all this information and thus cannot provide an overall assessment of all the elements of the proposed methodology. We find it important that the TSOs provide a correct analysis of future transmission capacities and balance the sale of Long Term Transmission rights with the interests of the transmission customers. 2. The stakeholder, as underlined at numerous occasions in the past, re-iterates its view that interconnector capacity is paid for by grid users, who therefor are entitled to expect a maximum of cross-border capacity to be made available for the electricity market as soon as possible. We therefor strongly invite CORE TSOs make sure the methodology maximizes capacity made available for the market in every timeframe (in this proposal, annually and subsequently monthly). Capacity limitation/withholding for shorter term time frames will reduce the liquidity and the level of market integration in the CORE region and therefore go against the principles of European electricity market legislation. 3. The stakeholder particularly invites CORE TSOs to strive for maximum market integration by applying the 70%minRAM obligation (Regulation 2019/943, article 16) as early as possible, i.e. already in the framework of the long-term capacity calculation and allocation process. 4. On article 4 of the proposal, the stakeholder insists on the need to take also into account the thermal or nominal capacity of the different CNEs, not only historic FRMs, for calculating future reliability margins. 5. On article 6 and 7 of the proposal, the stakeholder strongly invites CORE TSOs to thoroughly justify all allocation constraints and qualifications as CNEs, and submit them to NRA approval. 6. On article 19 and 20 of the proposal, the stakeholder proposes that the TSO’s annually should publish a report on the efficiency and economic results of the long term transmission auctions and its impact on the utilization and development of transmission capacity. This report should be publicly available 7. On article 22 of the proposal, the stakeholder is deeply disappointed by the implementation timeframe proposed by CORE TSOs (3,5 to 5 years). This is far longer than the “normal” implementation time of European legislation or network codes/guidelines. The stakeholder invites CORE TSOs to apply the methodology, once approved by NRS’s, within 1 or 2 years.