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

November 2020

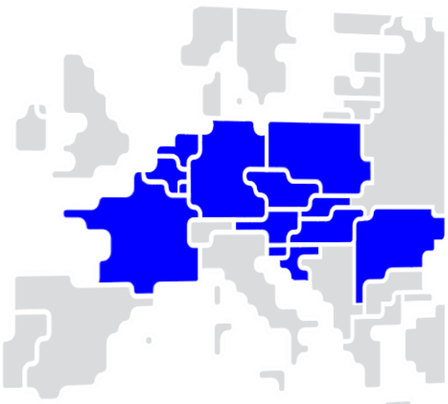


Table of Contents

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:

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

   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:

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

<u>With</u>:

$PTDF_{VH\_1,l}$	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 $PTDF_{A\rightarrow B,l}$ 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:

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

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:

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

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
$\mathbf{PTDF}_{\boldsymbol{f}}$	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

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

If $PTDF_{A\rightarrow B,l} \leq threshold$ then the $PTDF_{A\rightarrow B,l}$ 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:

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

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

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:

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

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

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

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

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

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

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

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:

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

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

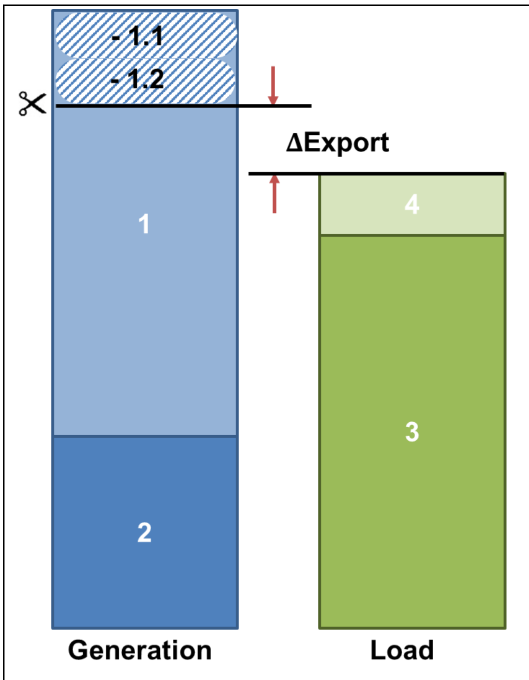
Where:

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.