Common Coordinated Capacity Calculation Methodology for Capacity Calculation Region Hansa in accordance with Article 20(2) of the Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a Guideline on Capacity Allocation and Congestion Management

26th of April 2021

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THE TRANSMISSION SYSTEM OPERATORS OF CAPACITY CALCULATION REGION HANSA, TAKING INTO ACCOUNT THE FOLLOWING:

WHEREAS

(1) This document is a common Methodology of the Transmission System Operators (hereafter referred to as "TSOs") of Capacity Calculation Region (hereafter referred to as "CCR") Hansa as described in the ACER decision[1].

(2) This Common Coordinated Capacity Calculation Methodology (hereafter referred to as "CCM") for the CCR Hansa takes into account the general principles and goals set in Commission Regulation (EU) 2015/1222, establishing a guideline on capacity allocation and congestion management (hereafter referred to as the "CACM Regulation"), Commission Regulation (EU) 2017/1485, establishing a guideline on electricity transmission system operation (hereafter referred to as the "SO Regulation"), Regulation (EU) 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 (EU) 2019/943") as well as the Commission Decision (EU) 2020/2123 of 11 November 2020 on the derogation for Kriegers Flak Combined Grid Solution (hereafter referred to as "KF CGS") following article 64 of Regulation (EU) 2019/943[2].

(3) The goal of the CACM Regulation is the coordination and harmonisation of capacity calculation and allocation in the day-ahead time frame and the intraday time frame.

(4) This CCM is required by Article 20(2) of the CACM Regulation:

"No later than 10 months after the approval of the Proposal for a capacity calculation region in accordance with Article 15(1), all TSOs in each capacity calculation region shall submit a Proposal for a common coordinated capacity calculation methodology within the respective region. ..."

This CCM is subject to consultation in accordance with Article 12 of the CACM Regulation.

(5) This CCM covers all requirements as given in Article 21(1), (2) and (3) of the CACM Regulation.

(6) According to Article 14(1) and 14(2) of the CACM Regulation, all CCR Hansa TSOs shall calculate cross-zonal capacity for at least the day-ahead time frame and intraday time frame. Furthermore, Articles 14(1) and 14(2) require that the cross-zonal capacity for each market-time unit shall be calculated.

(7) The CCM for the CCR Hansa contributes to, and does not in any way hinder, the achievement of the objectives of Article 3 of the CACM Regulation.

(8) The CCM for the CCR Hansa is based on a Coordinated Net Transfer Capacity[3] (CNTC) methodology with a strong link to adjacent CCRs[4]. As CCR Hansa bidding-zone borders, including the German – Western Danish Alternating Current (hereafter referred to as "AC") border, are radial interconnections, a CCM based on the flow-based methodology is not more efficient compared to the CNTC approach suggested, assuming the same level of operational security in the Hansa region. Following Article 20(7) of the CACM Regulation, the CCR Hansa TSOs have, in a separate request, motivated the efficiency of CNTC in comparison to the flow-based approach. The request is submitted for CCR Hansa National Regulatory Authorities (hereafter referred to as "CCR Hansa NRAs") approval together with this CCM.

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[1] ACER's definition of the Capacity Calculation Regions (CCRs) of 17 November 2016 (Annex I to CCR decision) http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/ANNEXES_CCR_DECISION/Annex%20I.pdf

[2] Commission Decision (EU) 2020/2123 of 11 November 2020 granting the Federal Republic of Germany and the Kingdom of Denmark a derogation of the Kriegers Flak combined grid solution pursuant to Article 64 of Regulation (EU) 2019/943 of the European Parliament and of the Council https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A32020D2123&qid=1608200554462

[3] CNTC is understood as a NTC methodology, where coordination is done through the use of the common grid model and the calculations carried out by the coordinated capacity calculator.

[4] Adjacent CCRs are understood as CCR Nordic and CCR Core from a CCR Hansa perspective for the purpose of this CCM.

(9) The CCM for the CCR Hansa secures optimal use of the transmission capacity as it takes advantage of the flow-based capacity calculation methodologies being developed simultaneously in CCR Nordic and CCR Core in order to represent the constraints in the AC grid. The use of CCR Hansa interconnector capacity and AC grid capacity is fully integrated in this way, thereby providing a fair competition for the scarce capacities in the system and an optimal system use. There is no predefined and static split of the capacities on critical network elements, and the flows through CCR Hansa interconnectors are optimised based on economic efficiency during the capacity allocation phase.

(10) The CCM for the CCR Hansa treats all bidding-zone borders in the CCR Hansa and adjacent CCRs equally and provides non-discriminatory access to cross-zonal capacity. It creates a basis for a fair and orderly market and a fair and orderly price formation by implementing a pragmatic CCM solution which is integrated with the methodologies of the adjacent CCRs.

(11) The CCM for the CCR Hansa will fully apply in a situation where Advanced Hybrid Coupling (hereafter referred to as "AHC") is implemented in a flow-based capacity calculation in CCR Nordic and CCR Core according to the flow-based CCMs of the two regions. The application of AHC ensures that CCR Hansa bidding-zone borders are treated equally to bidding-zone borders in the flow-based CCMs of adjacent CCRs.

(12) The CCM for the CCR Hansa takes advantage of the flow-based CCMs from adjacent CCRs while ensuring full transparency in the calculation of the cross-zonal capacity. This will in turn result in a better understanding for market participants and improve transparency and reliability of information compared to what is available today on the CCR Hansa bidding-zone borders.

(13) The CCM for the CCR Hansa foresees a stepwise implementation to the situation where both the CCR Nordic and CCR Core apply AHC. In case that AHC is not yet implemented in either of the adjacent CCRs, or the flow-based CCMs of the adjacent CCRs do not include a selection of Critical Network Elements (CNEs) relevant for CCR Hansa exchanges, the improved capacity calculation process for the CCR Hansa bidding-zone borders, as explained in Article 19(4), will continue until AHC and the selection of CCR Hansa relevant CNEs have been implemented in both adjacent CCRs. This implies that the improved capacity calculation process will also continue on the CCR Hansa bidding-zone borders when the CCR Core have implemented their Standard Hybrid Coupling (hereafter referred to as "SHC"). When applying SHC, the anticipated flows on CCR Hansa bidding-zone borders are taken into account in the available margins of CNEs in the flow-based methodology of CCR Core which is less efficient than applying AHC where this is not necessary.

(14) With the CCM for the CCR Hansa, the CCR Hansa TSOs are preconditioning the use of AHC in the adjacent CCRs Nordic and Core and there will, when implemented, be no undue discrimination between cross-zonal flows within CCR Hansa and adjacent CCRs. It will also ensure that there will be no undue discrimination between bidding-zone borders within CCR Hansa.

(15) The CCM for the CCR Hansa has no negative consequences on the development of CCMs in adjacent CCRs and can evolve dynamically with the development and merger of CCRs in the future. The CCM for the CCR Hansa therefore does not hinder an efficient long-term operation in CCR Hansa and/or adjacent CCRs, and the development of the transmission system in the European Union.

(16) With the CCM for the CCR Hansa being aligned with the flow-based CCMs in adjacent CCRs, the selection, inclusion and justification of relevant critical network elements and contingencies, the handling of adjustment of power flows on critical network elements due to remedial actions as well as the mathematical description for the calculation of power transfer distribution factors and the calculation of available margins on critical network elements for the adjacent AC grids are handled by the adjacent CCRs' CCMs.

(17) Article 27(2) of the CACM Regulation states that CCR Hansa shall set up a Coordinated Capacity Calculator (hereafter referred to as "CCC") no later than four months after the decision on the CCM referred to in Articles 20 and 21 of the CACM Regulation. The CCR Hansa CCC will be responsible for calculating the cross-zonal capacities stated in this CCM.

(18) The CCM for the CCR Hansa is aligned with Article 16 (8) of Regulation (EU) 2019/943 that sets out

that transmission system operators shall not limit the volume of interconnection capacity to be made available to market participants as a means of solving congestion inside their own bidding zone or as a means of managing flows resulting from transactions internal to bidding zones. This shall be considered to be complied when at least 70 % of the transmission capacity respecting operational security limits after deduction of contingencies, as determined in accordance with the CACM Regulation, are available for cross-zonal trade.
The Commission Decision (EU) 2020/2123 of 11 November 2020 on the derogation for KF CGS following article 64 of Regulation (EU) 2019/943 specifies that this minimum percentage should not apply to the overall transmission capacity respecting operational security limits after deduction of contingencies for KF CGS. Instead, it should apply only to the capacity remaining after all capacity expected to be required for the transmission of production from the wind farms connected to the KF system to shore has been deducted (hereafter referred to as ”residual capacity”). The exception for KF CGS is addressed throughout this CCM.

HEREBY SUBMIT THE FOLLOWING COMMON COORDINATED CAPACITY CALCULATION METHODOLOGY FOR THE CCR HANSA:

Article 1
Subject, Matter and Scope

1. As required under Article 20(2) of the CACM Regulation, all TSOs in each CCR shall submit a CCM within the respective region.

2. This document establishes a common coordinated CCM for all bidding-zone borders in CCR Hansa.

Article 2
Definitions

1. For the purpose of this CCM, the terms used will have the meaning of the definitions included in Article 2 of the CACM Regulation, of the Regulation (EU) 2019/943, of the Regulation (EU) No 543/2013 on submission and publication of data in electricity markets and in the Commission Decision (EU) 2020/2123 of 11 November 2020 on the derogation for KF CGS following Article 64 of Regulation (EU) 2019/943.

   In addition, in this CCM the following definitions shall apply:

   a. The Net Transfer Capacity (NTC) is the maximum total exchange program between two adjacent bidding zones complying with security standards, and taking into account the technical uncertainties on future network conditions: NTC = TTC - TRM. In case the Transmission Reliability Margin (TRM) equals zero, the NTC equals the Total Transfer Capacity (TTC).

   b. Advanced Hybrid Coupling (AHC) is an enhancement of the flow-based CCM, representing a more detailed modelling of the influence of the High Voltage Direct Current (HVDC) line on the AC network flows and allowing NTC bidding-zone borders to compete for the scarce capacity within the flow-based area and vice versa, thereby enabling the capacity allocation algorithm to make an economic optimisation of the flows on NTC bidding-zone borders on equal terms with the flows within the flow-based area. Advanced Hybrid Coupling is also to be used to represent the DK1-DE/LU bidding-zone exchanges, given its radial topology, in flow-based methodologies.

   c. The Available Transfer Capacity (ATC) is a measure of the transfer capability remaining in the physical transmission network for further commercial activity after already committed uses: ATC = NTC – AAC. In case the Already Allocated Capacity (AAC) equals zero, the ATC equals the NTC.

   d. CCR Hansa interconnector is either a radial DC line(s) or the combination of radial AC lines between the meshed AC grids on either side of the bidding-zone border.

   e. A critical network element (CNE) is a network element which is significantly impacted by cross-zonal trades. This element can be an overhead line, an underground cable or a transformer.

2. In this 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 the CCM.

   c. References to an “Article” are, unless otherwise stated, referring to an article of this CCM document.

   d. Any reference to legislation, regulations, directives, orders, instruments, codes or any other enactment includes any modification, extension or re-enactment of it when in force.

Article 3

Rules for Calculating Cross-Zonal Capacity

1. The capacity calculation approach for CCR Hansa shall follow the coordinated net transmission capacity (CNTC) approach.
2. The CCR Hansa TSOs shall provide the CCC, a list of CNEs in accordance with Article 5, sufficiently in advance of the day-ahead and the intraday firmness deadline.
3. The CCR Hansa TSOs shall provide the CCC, in accordance with Article 29(1) of CACM Regulation, sufficiently in advance of the day-ahead and the intraday firmness deadline, with the following information for each Market Time Unit (MTU):
    a. Input parameters, including an availability factor of equipment, thermal capacity of the CNEs and a loss factor to calculate the Total Transfer Capacity (TTC) in accordance with the mathematical description in Article 4 and Article 12;
    b. Operational security limits and contingencies in accordance with Article 7;
    c. Allocation constraints in accordance with Article 8;
    d. TRM in accordance with Article 6;
    e. Generation Shifts Key (GSKs) in accordance with Article 9; and
    f. Available remedial actions in accordance with Article 10.
4. The CCR Hansa TSOs, or an entity acting on their behalf, shall send for each MTU the already allocated and nominated capacities (AACs) to the CCC without undue delay, following Article 11 and Article 15.
5. Based on the inputs provided from the CCR Hansa TSOs, the CCC shall perform the capacity calculation for each bidding-zone border in both directions in accordance with the mathematical descriptions in Article 4 and Article 12.
6. Where a CCR Hansa bidding-zone border has more than one interconnector, the cross-zonal capacity of those interconnectors shall be summed up to determine the full cross-zonal capacity of the CCR Hansa bidding-zone border.
7. In case the capacity calculation cannot be performed by the CCR Hansa CCC, the fallback for capacity calculation in accordance with Article 18 applies.
8. The CCC shall submit the results of the capacity calculation to the CCR Hansa TSOs for validation, following the principles described in Article 16.
9. In accordance with CACM Regulation Articles 46 and 58, the CCC shall ensure that validated cross-zonal capacities and allocation constraints are provided to relevant NEMOs before the day-ahead and intraday firmness deadlines.

CHAPTER 1
Capacity Calculation Methodology for the Day-Ahead Time Frame

Article 4
Mathematical Description

1. The following mathematical description applies for the calculation of ATC on the DC lines between bidding zones. The capacity shall be calculated for both directions, A→B and B→A.

The $\mathrm{ATC}_{\mathrm{i,DC,A\rightarrow B}}$ on a DC line i in the direction A→B is calculated as follows:

$$\mathrm{ATC}_{\mathrm{i,DC,A\rightarrow B}} = \mathrm{TTC}_{\mathrm{i,A\rightarrow B}} - \mathrm{AAC}_{\mathrm{i,A\rightarrow B}} + \mathrm{AAC}_{\mathrm{i,B\rightarrow A}}$$

When the DC line is not in operation (TTC = 0) due to a planned or unplanned outage:

$$\mathrm{ATC}_{\mathrm{i,DC,A\rightarrow B}} = 0$$

Where

A	:=	Bidding zone A.
B	:=	Bidding zone B.
$\mathrm{ATC}_{\mathrm{i,DC,A\rightarrow B}}$	:=	Available Transfer Capacity on a DC line i in direction A→B provided to the day-ahead market.
$\mathrm{TTC}_{\mathrm{i,A\rightarrow B}}$	:=	Total Transfer Capacity (TTC) of a DC line i in direction A→B. The TTC corresponds only to the full capacity of the DC line, in case of no failure on the CCR Hansa interconnector, including converter stations. The TTC for a DC line i is defined as follows: $\mathrm{TTC}_{\mathrm{i,A\rightarrow B}} = \alpha_{\mathrm{i}} \cdot \mathrm{P}_{\mathrm{i,max\,thermal}} * \left(1 - \beta_{\mathrm{i,Loss,A\rightarrow B}}\right)$
$\mathrm{AAC}_{\mathrm{i,A\rightarrow B}}$	:=	Already Allocated and nominated Capacity for a DC line i in direction A→B in accordance with Article 11.
$\mathrm{AAC}_{\mathrm{i,B\rightarrow A}}$	:=	Already Allocated and nominated Capacity for a DC line i in direction B→A in accordance with Article 11.
α_{i}	:=	Availability factor of equipment defined through scheduled and unscheduled outages, α_{i}, being a real number in between and including 0 and 1.
$\mathrm{P}_{\mathrm{i,max\,thermal}}$	:=	Thermal capacity for a DC line i.
$\beta_{\mathrm{i.Loss,A\rightarrow B}}$	:=	Loss factor in case of explicit grid loss handling on a DC line i in direction A→B, can be a different value depending on α_{i}. In case of implicit loss handling, the loss factor is set to zero but taken into account as an allocation constraint in accordance with Article 8.

2. The following mathematical description applies for the calculation of ATC on the AC lines between bidding zones. The capacity shall be calculated for both directions, A→B and B→A.

   The $\mathrm{ATC}_{\mathrm{AC,A\rightarrow B}}$ on a bidding-zone border that is connected by AC lines in the direction A→B is calculated as follows:

$$\mathrm{ATC}_{\mathrm{AC,A\rightarrow B}} = \mathrm{TTC}_{\mathrm{A\rightarrow B}} - \mathrm{TRM}_{\mathrm{A\rightarrow B}} - \mathrm{AAC}_{\mathrm{A\rightarrow B}} + \mathrm{AAC}_{\mathrm{B\rightarrow A}}$$

   When the CCR Hansa AC interconnector is out of operation (TTC = 0) due to a planned or unplanned outage:

$$\mathrm{ATC}_{\mathrm{AC,A\rightarrow B}} = 0$$

   Where

A	:=	Bidding zone A.
B	:=	Bidding zone B.
$\mathrm{ATC}_{\mathrm{AC,A\rightarrow B}}$	:=	Available Transfer Capacity of a bidding-zone border in direction A→B, provided to the day-ahead market.

$TTC_{A\rightarrow B}$:= Total Transfer Capacity of a bidding-zone border in direction A→B.

The TTC is determined according to the following steps:

1. Performing load-flow calculation using the CGM and the GSKs according to Article 9.
2. When assessing the loading of the individual circuits of the CCR Hansa interconnector, and to take N-1 security criterion into account, the processes of point 3 and 4 are repeated with the outage of each of the individual circuits on the CCR Hansa interconnector where the minimum TTC for each CCR Hansa interconnector and in each direction is set as TTC in the given direction.
3. Using the GSK to increase the net position of bidding zone A while decreasing the net position of bidding zone B at equal amounts until a circuit or multiple circuits of the CCR Hansa interconnector reach their permanent admissible thermal loading. The TTC is then equal to the maximum exchange between the bidding zones.
4. The process of point 3 is repeated in the opposite direction to determine the TTC in the direction B to A.

$TRM_{A\rightarrow B}$:= Transmission Reliability Margin for a bidding-zone border in direction A→B, in accordance with Article 6.

$AAC_{A\rightarrow B}$:= Already Allocated and nominated Capacity for a bidding-zone border in direction A→B, in accordance with Article 11.

$AAC_{B\rightarrow A}$:= Already Allocated and nominated Capacity for a bidding-zone border in direction B→A, in accordance with Article 11.

3. The following mathematical description applies solely to the calculation of ATC on the KF CGS, being a hybrid interconnector and offshore wind farm (hereafter referred to as “OWF”) grid connection between DK2-DE/LU.

The $ATC_{KF\ CGS,DE\rightarrow DK}$ on KF CGS, in direction from DE/LU→DK2 is calculated as follows:

$$ATC_{KF\ CGS,DE\rightarrow DK} = \alpha_i \cdot \min\left(\min\left(\frac{P_{max\ thermal,DE}}{1+Loss_{DE}+Loss_{XB}} + \frac{\min\left(AAC_{DE}^{Wind}, P_{max\ thermal,DE} \times Loss_{DE}\right)}{1+Loss_{XB}}, P_{max\ thermal,DE}\right), \frac{P_{max\ thermal,XB}}{1+Loss_{XB}}, P_{max\ thermal,DK} - AAC_{DK}^{Wind}\right) - AAC_{KF\ CGS,DE\rightarrow DK} + AAC_{KF\ CGS,DK\rightarrow DE}$$

The $ATC_{KF\ CGS,DK\rightarrow DE}$ on KF CGS, in direction from DK2 → DE/LU is calculated as follows:

$$ATC_{KF\ CGS,DK\rightarrow DE} = \alpha_i \cdot \min(\min\left(\frac{P_{max\ thermal,DK}}{1+Loss_{DK}} + \min\left(AAC_{DK}^{Wind}, P_{max\ thermal,DK} \times Loss_{DK}\right), P_{max\ thermal,DK}\right), P_{max\ thermal,XB}, \frac{P_{max\ thermal,DE} - AAC_{DE}^{Wind}}{1-Loss_{XB}}, \frac{P_{max\ thermal,DE} - AAC_{DE}^{Wind}(1-Loss_{DE})}{1-Loss_{XB}-Loss_{DE}}) - AAC_{KF\ CGS,DK\rightarrow DE} + AAC_{KF\ CGS,DE\rightarrow DK}$$

When KF CGS is not in operation ($P_{\text{max thermal,DK}}$, $P_{\text{max thermal,DE}}$ or $P_{\text{max thermal,XB}}$ is equal to zero) due to a planned or unplanned outage:

$$\text{ATC}_{\text{KF CGS,DE}\to\text{DK}} = 0$$
$$\text{ATC}_{\text{KF CGS,DK}\to\text{DE}} = 0$$

Where:

DE	:= Bidding zone DE/LU.
DK	:= Bidding zone DK2.
$\text{ATC}_{\text{KF CGS,DE}\to\text{DK}}$	:= Available Transfer Capacity on KF CGS in direction DE/LU→DK2 provided to the day-ahead market.
$\text{AAC}_{\text{KF CGS,DE}\to\text{DK}}$	:= Already Allocated and nominated Capacity for KF CGS in direction DE/LU→DK2, in accordance with Article 11.
$\text{AAC}_{\text{KF CGS,DK}\to\text{DE}}$	:= Already Allocated and nominated Capacity for KF CGS in direction DK2→DE/LU, in accordance with Article 11.
$\text{AAC}_{\text{DE}}^{\text{Wind}}$	:= Expected wind generation on the OWF(s) from TSO forecast that is a part of bidding zone DE/LU and connected to the KF CGS, in accordance with Article 11.
$\text{AAC}_{\text{DK}}^{\text{Wind}}$	:= Expected wind generation on the OWF(s) from TSO forecast that is a part of bidding zone DK2 and connected to the KF CGS, in accordance with Article 11.
$CP_{\text{OWF, DE}}$	Connection Point of offshore windfarm connected in the bidding zone DE/LU to KF CGS.
$CP_{\text{OWF, DK}}$	Connection Point of offshore windfarm connected in the bidding zone DK2 to KF CGS.
Loss_{DE}	:= Electrical losses between the connection point of KF CGS in bidding zone DE/LU and $CP_{\text{OWF, DE}}$
Loss_{XB}	:= Electrical losses between the connection point in $CP_{\text{OWF, DK}}$ and $CP_{\text{OWF, DE}}$
Loss_{DK}	:= Electrical losses between the connection point of KF CGS in bidding zone DK2 and $CP_{\text{OWF, DK}}$
α_i	:= Availability factor of equipment defined through scheduled and unscheduled outages, α_i, being a real number in between and including 0 and 1.
$P_{\text{max thermal,DE}}$	:= Thermal capacity for line section from bidding zone DE/LU to $CP_{\text{OWF, DE}}$
$P_{\text{max thermal,XB}}$	:= Thermal capacity for line section from $CP_{\text{OWF, DK}}$ to $CP_{\text{OWF, DE}}$
$P_{\text{max thermal,DK}}$	:= Thermal capacity for line section from bidding zone DK2 to $CP_{\text{OWF, DK}}$

Article 5
Methodology for Critical Network Elements Selection and Rules for Avoiding Undue Discrimination Between Internal and Cross-Zonal Exchanges

1. Each CCR Hansa TSO shall provide a list of CNEs of its own control area based on operational experience and the topology of its grid. CNEs taken into account in the CCR Hansa capacity calculation shall be part of a CCR Hansa interconnector.

2. CNEs in the AC grids adjacent to the CCR Hansa interconnectors, reflecting the flow interactions between the CCR Hansa interconnectors and the AC grids, are determined in the flow-based parameters of CCR Nordic and CCR Core following their respective methodologies for critical network elements selection and rules for avoiding undue discrimination between internal and cross-zonal

exchanges.

3. Following Article 21(1)(b)(ii), the rule for avoiding undue discrimination is to only include CCR Hansa interconnectors in the CCR Hansa capacity calculation, whereby no discrimination between internal and cross-zonal exchanges is possible.

Article 6
Methodology for Determining the Transmission Reliability Margin

1. The methodology for determining the TRM applies solely to a border connected by AC lines in the CCR Hansa.
2. The methodology for the TRM is founded on 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, and subsequently specifies the uncertainties to be taken into account in the capacity calculation.
3. Following Article 22(2) of the CACM Regulation, the methodology for the TRM takes into account unintended deviations of physical electricity flows caused by the adjustment of electricity flows within and between control areas and unintended deviations of flows which could occur between the capacity calculation time frame and real time. The activation of remedial actions is not regarded as a source of uncertainty which needs to be taken into account in the TRM.
4. The TRM calculation consists of the following steps:
    a. Identification of sources of uncertainty for each TTC calculation. The TTC calculation is based on the CGM which includes assumptions of cross-border exchanges between third parties and forecasts for wind and solar infeed which impact the generation and load pattern as well as the grid topology;
    b. Derivation of independent time series for each uncertainty and determination of probability distributions (PD) of each time series. Generic time series from an already existing database are used as a starting point. The time series cover an appropriate timespan from the past in order to get a significant and representative amount of data;
    c. Convolution of the individual PDs and derivation of the TRM value from the convoluted PD. From the convoluted PD the 90th percentile is taken.
5. The inputs for the TRM calculation, as described in Article 6(4)(a), shall be coordinated and commonly agreed by the involved CCR Hansa TSOs to ensure a harmonised approach for deriving the reliability margin from the probability distribution following CACM Regulation Article 22(3).
6. The TRM shall be updated regularly and at least once a year by the CCR Hansa TSOs or by the appointed CCC.

Article 7
Methodology for Determining Operational Security Limits and Contingencies Relevant to Capacity Calculation

1. In accordance with Article 23(1) of the CACM Regulation, CCR Hansa TSOs shall respect the operational security limits used in operational security analysis in line with Article 72 of the SO Regulation. The operational security limits used in the common capacity calculation are the same as those used in operational security analysis, therefore any additional descriptions pursuant to Article 23(2) of the CACM Regulation are not needed. In particular, CCR Hansa TSOs shall respect the acceptable operating boundaries for secure grid operation such as thermal limits, voltage limits, short-circuit current limits, frequency and dynamic stability limits.
2. Thermal limits of the CCR Hansa CNEs are considered in the TTC calculation process described in Article 4 for the day-ahead time frame and Article 12 for the intraday time frame.
3. Operational security limits and contingencies of AC grid elements adjacent to the CCR Hansa CNEs,

reflecting the flow interactions between the CCR Hansa interconnectors and the AC grids, are expected to be considered in the flow-based parameters of CCR Nordic and CCR Core.

4. CCR Hansa TSOs can assess individually the operational security limits which cannot be reflected in the flow-based parameters of adjacent CCRs, including but not limited to: voltage stability limits, short-circuit limits and dynamic stability limits, following the provisions of Article 8(1).

Article 8
Methodology for Allocation Constraints

1. In accordance with Article 23(3)(a) or (b) of the CACM Regulation, CCR Hansa TSOs may, besides active power-flow limits on CCR Hansa interconnectors, apply allocation constraints during the capacity allocation phase that are needed to maintain the transmission system within operational security limits which cannot be transformed efficiently into maximum flows on critical network elements or constraints intended to increase economic surplus, to take into account:

    a. The production in a bidding zone shall be above a given minimum production level;

    b. The combined import or export from one bidding zone to other adjacent bidding zones shall be limited in order to ensure adequate level of generation reserves required for secure system operation;

    c. Maximum flow change on DC lines and KF CGS between MTUs (ramping restrictions);

    d. Implicit loss factors on DC lines.

2. Following Article 8(1)(a), a minimum production level may need to be assured in a bidding zone in order to guarantee a minimum number of generators running in the system that are able to supply reactive power needed for voltage support or to safeguard sufficient inertia to ensure dynamic stability.

3. Following Article 8(1)(b), a CCR Hansa TSO may use allocation constraints to ensure a minimum level of operational reserve for balancing in case of a central dispatch model. The allocation constraints introduced are bi-directional, with independent values for directions of import and export, depending on the foreseen balancing situation. The details, justifications for use, and the methodology for the calculation of this kind of allocation constraints are set forth in Annex 1.

4. Following Article 8(1)(c), a ramping restriction is an instrument of system operation to maintain system security for frequency management purposes. This sets the maximum change in DC flows and KF CGS market flows between MTUs (max. MW/MTU per CCR Hansa interconnector).

5. Following Article 8(1)(d), in case of implicit loss handling an implicit loss factor on DC lines during capacity allocation ensures that the DC line will not carry a flow unless the welfare gain exceeds the costs of the corresponding losses.

6. If one, several, or all CCR Hansa TSOs plan to apply one or more of the allocation constraints, referred to in Article 8(1), on Hansa bidding zone borders, the relevant CCR Hansa TSOs shall inform market participants, the other CCR Hansa TSOs, and the all CCR Hansa NRAs, on the planned allocation constraints, accompanied by detailed descriptions and justifications for the allocation constraints in question, at the latest 2 months prior to the planned application of those allocation constraints.

7. CCR Hansa TSOs report on statistical indicators of cross-zonal capacity, including allocation constraints where appropriate for each capacity calculation time frame as a part of a biennial report on capacity calculation and allocation according to Article 31 of the CACM Regulation. Upon request of the CCR Hansa NRAs, CCR Hansa TSOs shall provide additional information about allocation constraints.

8. The shadow prices of the applied allocation constraints in the capacity allocation shall be recorded and reported by the NEMOs to the CCR Hansa TSOs and CCR Hansa NRAs.

9. Allocation constraints are used for the purpose of allocating capacity in accordance with CACM Regulation Articles 46 and 58.

Article 9
Methodology for Determining Generation Shift Keys

1. For the TTC calculation of the radial AC lines, as described in Article 4(2), the GSKs of the relevant bidding zones are expected to be defined in the CCMs of adjacent CCRs applying a flow-based capacity calculation approach. These GSKs are applied to represent the distribution of the power flow on the CCR Hansa interconnectors in CCR Hansa.
2. Flow interactions between the CCR Hansa interconnectors and the adjacent AC grids are reflected in the corresponding flow-based parameters of adjacent CCRs.

Article 10
Methodology for Determining Remedial Actions to be Considered in Capacity Calculation

1. Non-costly remedial actions shall be used to optimise the TTC.
2. For KF CGS, all available remedial actions shall be used to ensure that operational security limits are not violated in cases where both of the following conditions are applicable:
    a. The expected production on one windfarm exceeds the anticipated day-ahead market outcome by the CCR Hansa TSOs.
    b. The full transmission capacity towards the corresponding bidding zone of this windfarm is used for the anticipated market outcome of this windfarm, nominated long-term transmission rights, day ahead and intraday exchanges.
3. Each CCR Hansa TSO shall individually define the remedial actions available to be exclusively taken into account in the CCR Hansa capacity calculation, following CACM Regulation Article 25(1), and shall be shared with the CCC and all other TSOs according to CACM Regulation Article 29(1).
4. Each CCR Hansa TSO shall ensure that remedial actions are taken into account in capacity calculation under the condition that the remaining available remedial actions, taken together with the reliability margin, are sufficient to ensure operational security, following CACM Article 25(4).
5. Each CCR Hansa TSO shall ensure that the remedial actions to be taken into account in capacity calculation for the day-ahead and intraday time frames are the same, following CACM Regulation Article 25(6), subject to technical availability for each capacity calculation time frame.
6. Following Articles 25(2) and 25(3) of the CACM Regulation, CCR Hansa TSOs shall coordinate any application of remedial actions used in capacity calculation with the CCR Hansa appointed CCC and any affected CCR Hansa TSOs. All CCR Hansa TSOs shall agree on the use of remedial actions that require the action of more than one CCR Hansa TSO.
7. The rule for adjustment of power flow is that the CCR Hansa CCC shall, when remedial actions are applied in accordance with the CCM, adjust the capacity on the CCR Hansa interconnectors where the remedial action has effect in either direction, following CACM Regulation 21(1)(b)(iv).

Article 11
Rules for Taking into Account Previously Allocated Cross-Zonal Capacity in the Day-Ahead Time Frame

1. In the day-ahead time frame, the CCR Hansa TSOs shall take into account the previously allocated cross-zonal capacity (AAC) as follows:

    a. Capacity allocated for nominated Physical Transmission Rights (PTRs).

    b. Capacity allocated for cross-zonal exchange of ancillary services, following Articles 40, 41 or 42 of the Commission Regulation (EU) 2017/2195, establishing a guideline on electricity balancing (EB Regulation), except those ancillary services in accordance with Article 22(2)(a) of the CACM Regulation.

c. For KF CGS, AAC^{Wind} is the expected wind generation on the OWF(s) based on the relevant CCR Hansa TSOs forecasts.

2. AAC shall be taken into account in the day-ahead market as described in the mathematical descriptions of Article 4.

CHAPTER 2
Capacity Calculation Methodology for the Intraday Time Frame

Article 12
Mathematical Description

1. The following mathematical description applies for the calculation of ATC on DC lines between bidding zones. The capacity shall be calculated for both directions, A→B and B→A.

   The $\mathrm{ATC}_{\mathrm{i,DC,A\to B}}$ on a DC line i in the direction A→B is calculated as follows:

$$\mathrm{ATC}_{\mathrm{i,DC,A\to B}} = \mathrm{TTC}_{\mathrm{i,A\to B}} - \mathrm{AAC}_{\mathrm{i,A\to B}} + \mathrm{AAC}_{\mathrm{i,B\to A}}$$

   When the DC line is not in operation (TTC = 0) due to a planned or unplanned outage:

$$\mathrm{ATC}_{\mathrm{i,DC,A\to B}} = 0$$

   Where

A	:=	Bidding zone A.
B	:=	Bidding zone B.
$\mathrm{ATC}_{\mathrm{i,DC,A\to B}}$	:=	Available Transfer Capacity on a DC line i in direction A→B provided to the intraday market.
$\mathrm{TTC}_{\mathrm{i,A\to B}}$	:=	Total Transfer Capacity of a DC line i in direction A→B,. The TTC corresponds to the full capacity of the DC line, in case of no failure on the CCR Hansa interconnector, including converter stations. The TTC for a DC line i is defined as follows: $\mathrm{TTC}_{\mathrm{i,A\to B}} = \alpha_{\mathrm{i}} \cdot \mathrm{P}_{\mathrm{i,max\ thermal}} * (1 - \beta_{\mathrm{i,Loss,A\to B}})$
$\mathrm{AAC}_{\mathrm{i,A\to B}}$	:=	Already Allocated and nominated Capacity for a DC line i in direction A→B, in accordance with Article 15.
$\mathrm{AAC}_{\mathrm{i,B\to A}}$	:=	Already Allocated and nominated Capacity for a DC line i in direction B→A, in accordance with Article 15.
α_{i}	:=	Availability factor of equipment defined through scheduled and unscheduled outages, α_{i}, being a real number in between and including 0 and 1.
$\mathrm{P}_{\mathrm{i,max\ thermal}}$	:=	Thermal capacity for a DC line i.
$\beta_{\mathrm{i.Loss,A\to B}}$	:=	Loss factor for explicit grid loss handling on a DC line i in direction A→B, can be a different value depending on α_{i}. In case of implicit loss handling, the loss factor is set to zero but taken into account as an allocation constraint in accordance with Article 14.

2. The following mathematical description applies for the calculation of available transfer capacity on the AC lines. The capacity shall be calculated for both directions, A→B and B→A.

   The $\mathrm{ATC}_{\mathrm{AC,A\to B}}$ on a bidding-zone border that is connected by AC lines in the direction A→B is calculated as follows:

$$\mathrm{ATC}_{\mathrm{AC,A\rightarrow B}} = \mathrm{TTC}_{\mathrm{A\rightarrow B}} - \mathrm{TRM}_{\mathrm{A\rightarrow B}} - \mathrm{AAC}_{\mathrm{A\rightarrow B}} + \mathrm{AAC}_{\mathrm{B\rightarrow A}}$$

When the CCR Hansa AC interconnector is not in operation (TTC = 0) due to a planned or unplanned outage:

$$\mathrm{ATC}_{\mathrm{AC,A\rightarrow B}} = 0$$

Where

A	:=	Bidding zone A.
B	:=	Bidding zone B.
$\mathrm{ATC}_{\mathrm{AC,A\rightarrow B}}$	:=	Available Transfer Capacity of a bidding zone border in direction A→B, provided to the intraday market.
$\mathrm{TTC}_{\mathrm{A\rightarrow B}}$	:=	Total Transfer Capacity of a bidding-zone border in direction A→B. The TTC is determined according to the following steps: 1. Performing load-flow calculation using the CGM and the GSKs according to Article 9. 2. When assessing the loading of the individual circuits of the CCR Hansa interconnector, and to take N-1 security criterion into account, the processes of point 3 and 4 are repeated with the outage of each of the individual circuits on the CCR Hansa interconnector where the minimum TTC for each CCR Hansa interconnector and in each direction is set as TTC in the given direction. 3. Using the GSK to increase the net position of bidding zone A while decreasing the net position of bidding zone B at equal amounts until a circuit or multiple circuits of the CCR Hansa interconnector reach their permanent admissible thermal loading. The TTC is then equal to the maximum exchange between the bidding zones. 4. The process of point 3 is repeated in the opposite direction to determine the TTC in the direction B to A.
$\mathrm{TRM}_{\mathrm{A\rightarrow B}}$	:=	Transmission Reliability Margin for a bidding-zone border in direction A→B, in accordance with Article 14.
$\mathrm{AAC}_{\mathrm{A\rightarrow B}}$	:=	Already Allocated and nominated Capacity for a bidding-zone border in direction A→B, in accordance with Article 15.
$\mathrm{AAC}_{\mathrm{B\rightarrow A}}$	:=	Already Allocated and nominated Capacity for a bidding-zone border in direction B→A, in accordance with Article 15.

3. The following mathematical description applies solely to the calculation of ATC on KF CGS. The capacity calculation following this will be the minimum capacity given to the market.

The $\mathrm{ATC}_{\mathrm{KF\ CGS,DE\rightarrow DK}}$ on KF CGS, in direction from DE/LU→DK2 is calculated as follows:

$$\mathrm{ATC}_{\mathrm{KF\ CGS,DE\rightarrow DK}} = \alpha_{\mathrm{i}} \cdot \min\Bigg(\min\bigg(\frac{\mathrm{P}_{\mathrm{max\ thermal,DE}}}{1+\mathrm{Loss}_{\mathrm{DE}}+\mathrm{Loss}_{\mathrm{XB}}} + \frac{\min\left(\mathrm{AAC}_{\mathrm{DE}}^{\mathrm{Wind}}, \mathrm{P}_{\mathrm{max\ thermal,DE}} \times \mathrm{Loss}_{\mathrm{DE}}\right)}{1+\mathrm{Loss}_{\mathrm{XB}}}, \mathrm{P}_{\mathrm{max\ thermal,DE}}\bigg), \frac{\mathrm{P}_{\mathrm{max\ thermal,XB}}}{1+\mathrm{Loss}_{\mathrm{XB}}}, \mathrm{P}_{\mathrm{max\ thermal,DK}} - \mathrm{AAC}_{\mathrm{DK}}^{\mathrm{Wind}}\Bigg) - \mathrm{AAC}_{\mathrm{KF\ CGS,DE\rightarrow DK}} + \mathrm{AAC}_{\mathrm{KF\ CGS,DK\rightarrow DE}}$$

The $\mathrm{ATC}_{\mathrm{KF\ CGS,DK\rightarrow DE}}$ on KF CGS, in direction from DK2 → DE/LU is calculated as follows:

$$\mathrm{ATC}_{\mathrm{KF\ CGS,DK\rightarrow DE}} = \alpha_i \cdot \min\Big(\min\Big(\frac{P_{\mathrm{max\ thermal,DK}}}{1+\mathrm{Loss}_{\mathrm{DK}}} + \min\big(\mathrm{AAC}_{\mathrm{DK}}^{\mathrm{Wind}}, P_{\mathrm{max\ thermal,DK}} \times \mathrm{Loss}_{\mathrm{DK}}\big), P_{\mathrm{max\ thermal,DK}}\Big), P_{\mathrm{max\ thermal,XB}}, \frac{P_{\mathrm{max\ thermal,DE}} - \mathrm{AAC}_{\mathrm{DE}}^{\mathrm{Wind}}}{1-\mathrm{Loss}_{\mathrm{XB}}}, \frac{P_{\mathrm{max\ thermal,DE}} - \mathrm{AAC}_{\mathrm{DE}}^{\mathrm{Wind}}(1-\mathrm{Loss}_{\mathrm{DE}})}{1-\mathrm{Loss}_{\mathrm{XB}}-\mathrm{Loss}_{\mathrm{DE}}}\Big) - \mathrm{AAC}_{\mathrm{KF\ CGS,DK\rightarrow DE}} + \mathrm{AAC}_{\mathrm{KF\ CGS,DE\rightarrow DK}}$$

When KF CGS is not in operation ($P_{\mathrm{max\ thermal,DK}}$, $P_{\mathrm{max\ thermal,DE}}$ or $P_{\mathrm{max\ thermal,XB}}$ is equal to zero) due to a planned or unplanned outage:

$$\mathrm{ATC}_{\mathrm{KF\ CGS,DE\rightarrow DK}} = 0$$
$$\mathrm{ATC}_{\mathrm{KF\ CGS,DK\rightarrow DE}} = 0$$

Where:

DE	:= Bidding zone DE/LU.
DK	:= Bidding zone DK2.
$\mathrm{ATC}_{\mathrm{KF\ CGS,DE\rightarrow DK}}$	:= Available Transfer Capacity on KF CGS in direction DE/LU→DK2 provided to the intraday market.
$\mathrm{AAC}_{\mathrm{KF\ CGS,DE\rightarrow DK}}$	:= Already Allocated and nominated Capacity for KF CGS in direction DE/LU→DK2, in accordance with Article 15.
$\mathrm{AAC}_{\mathrm{KF\ CGS,DK\rightarrow DE}}$	:= Already Allocated and nominated Capacity for KF CGS in direction DK2→DE/LU, in accordance with Article 15.
$\mathrm{AAC}_{\mathrm{DE}}^{\mathrm{Wind}}$	:= Expected wind generation on the OWF(s) from TSO forecast that is a part of bidding zone DE/LU and connected to the KF CGS, in accordance with Article 15.
$\mathrm{AAC}_{\mathrm{DK}}^{\mathrm{Wind}}$	:= Expected wind generation on the OWF(s) from TSO forecast that is a part of bidding zone DK2 and connected to the KF CGS, in accordance with Article 15.
$\mathrm{CP}_{\mathrm{OWF,\ DE}}$	Connection Point of offshore windfarm connected in the bidding zone DE/LU to KF CGS.
$\mathrm{CP}_{\mathrm{OWF,\ DK}}$	Connection Point of offshore windfarm connected in the bidding zone DK2 to KF CGS.
$\mathrm{Loss}_{\mathrm{DE}}$	:= Electrical losses between the connection point of KF CGS in bidding zone DE/LU and $\mathrm{CP}_{\mathrm{OWF,\ DE}}$
$\mathrm{Loss}_{\mathrm{XB}}$	:= Electrical losses between the connection point in $\mathrm{CP}_{\mathrm{OWF,\ DK}}$ and $\mathrm{CP}_{\mathrm{OWF,\ DE}}$
$\mathrm{Loss}_{\mathrm{DK}}$	:= Electrical losses between the connection point of KF CGS in bidding zone DK2 and $\mathrm{CP}_{\mathrm{OWF,\ DK}}$
α_i	:= Availability factor of equipment defined through scheduled and unscheduled outages, α_i, being a real number in between and including 0 and 1.
$P_{\mathrm{max\ thermal,DE}}$	:= Thermal capacity for line section from bidding zone DE/LU to $\mathrm{CP}_{\mathrm{OWF,\ DE}}$
$P_{\mathrm{max\ thermal,XB}}$	:= Thermal capacity for line section from $\mathrm{CP}_{\mathrm{OWF,\ DK}}$ to $\mathrm{CP}_{\mathrm{OWF,\ DE}}$
$P_{\mathrm{max\ thermal,DK}}$	:= Thermal capacity for line section from bidding zone DK2 to $\mathrm{CP}_{\mathrm{OWF,\ DK}}$

Article 13
Frequency of Reassessment of the Capacity in the Intraday Time Frame

1. The TTC for the intraday time frame will be reassessed by the CCC when updated intraday Common Grid Models are available, at least once during the intraday time frame.
2. In case of unexpected events on the CCR Hansa interconnectors, and if these would impact cross-zonal capacity, the capacity in the intraday time frame will be reassessed by the CCC.
3. The AAC, as defined in Article 15, is continuously updated.
4. By 30 days after the approval of this CCM for CCR Hansa, the CCR Hansa TSOs will inform the market about what time cross-zonal intraday capacity will be released. If the cross-zonal capacity is released after the cross-zonal gate opening time of the single intraday coupling (SIDC), the justification will be provided by the CCR Hansa TSOs.

Article 14
Methodologies for Critical Network Element Selection and Rules for Avoiding Undue Discrimination Between Internal and Cross-Zonal Exchanges, Determining the Reliability Margin, Operational Security Limits and Contingencies Relevant to Capacity Calculation and Allocation Constraints, Generation Shift Keys and Remedial Actions to be Considered in Capacity Calculation

The Articles 5 to 10 of this CCM for the day-ahead time frame also apply to the intraday time frame.

Article 15
Rules for Taking into Account Previously Allocated Cross-Zonal Capacity in the Intraday Time Frame

1. In the intraday time frame, the CCR Hansa TSOs shall take into account the AAC as follows:
   a. Capacity allocated for nominated Physical Transmission Rights (PTRs).
   b. Capacity allocated for cross-zonal exchange of ancillary services, following Articles 40, 41 or 42 of EB Regulation, except those ancillary services in accordance with Article 22(2)(a) of the CACM Regulation.
   c. Capacity nominated in the day-ahead market.
   d. For KF CGS, AAC^{Wind} is the expected wind generation on the OWF(s) based on the relevant CCR Hansa TSOs forecasts.
2. AAC shall be taken into account in the intraday market in accordance with the mathematical descriptions of Article 12.

CHAPTER 3
Common Provisions Applicable to both the Day-Ahead and Intraday Time Frames

Article 16
Methodology for the Validation of Cross-Zonal Capacity

1. In reference to the CACM Regulation Article 26(1), each CCR Hansa TSO shall validate and have the right to correct cross-zonal capacity provided by the CCC, for bidding-zone borders directly relevant to the CCR Hansa TSO.
2. As only CCR Hansa interconnectors are included as CNEs in CCR Hansa capacity calculation, following Article 5, a situation where an internal AC grid element requires a correction of available cross-zonal capacity is not applicable for CCR Hansa.

3. In reference to CACM Regulation Article 26(3) each CCR Hansa TSO may reduce cross-zonal capacity during the validation process referred to in Article 16(1) for reasons of operational security.
4. Each CCR Hansa TSO shall validate the cross-zonal capacity by checking that the correct input data, as sent by the CCR Hansa TSO as mentioned in Article 29(1) of the CACM Regulation, is used. CCR Hansa TSOs may employ validation tools and can perform its own calculations using a common grid model.
5. An increase of cross-zonal capacity proposed in the validation phase, shall be commonly agreed by the affected CCR Hansa TSOs.
6. Any information on increased or decreased cross-zonal capacity from adjacent CCCs will be provided by the CCR Hansa CCC to the CCR Hansa TSOs to be taken into account during the validation.
7. Each CCR Hansa TSO sends its capacity validation result to the CCR Hansa CCC and to the other CCR Hansa TSOs. In case a CCR Hansa TSO corrects capacity it shall provide a justification for this to be submitted to the CCC and to the other CCR Hansa TSOs.
8. The CCR Hansa CCC shall coordinate with adjacent CCCs during the validation process following CACM Regulation Article 26(4), where at least the corrections in cross-zonal capacity are shared among them.
9. In case capacities on a given bidding-zone border are regularly corrected by the CCR Hansa TSOs, the CCR Hansa TSOs shall evaluate the capacity calculation process including the CCM, and if possible adjust it to reduce the need for corrections in the future.
10. Every three months, the CCR Hansa CCC shall report on all reductions made during the validation of cross-zonal capacity to all CCR Hansa NRAs. The report shall include the location and amount of any reduction in cross-zonal capacity and shall give a justification for the reductions, following the requirements in CACM Regulation Article 26(5).

Article 17
Rules for Sharing the Power Flow Capabilities of Critical Network Elements

1. CCR Hansa interconnectors are the only CNEs taken into account in the capacity calculation. None of these elements, or their power flow capabilities, are shared between CCR Hansa bidding-zone borders, following CACM Regulation Article 21(1)(b)(vi), or between CCR Hansa and other CCRs bidding-zone borders in accordance with CACM Regulation Article 21(1)(b)(vii).

Article 18
Fallback for Capacity Calculation

1. In case the capacity calculation cannot be performed by the CCR Hansa CCC, the concerned CCR Hansa TSOs will bilaterally calculate and agree on cross-zonal capacities. The CCR Hansa TSOs shall individually apply the CCM and the final cross-zonal capacity will be determined by using the minimum value of the calculated capacities by CCR Hansa TSOs on the relevant bidding-zone border. The concerned CCR Hansa TSOs shall submit the capacities to the CCR Hansa CCC and to the other CCR Hansa TSOs.

CHAPTER 4
Final provisions

Article 19
Implementation

1. Implementation of this CCM will be a stepwise process with the following milestones:
    a. The CCR Hansa CCC is appointed and in operation pursuant to Article 27(2) of CACM Regulation.

b. Implementation of the methodology for the CGM.
c. The flow-based CCMs of CCR Core and of CCR Nordic have been implemented including AHC for the CCR Hansa interconnectors.
d. The day-ahead CCM is implemented. Pursuant to Article 20(8) a 6-month testing of the methodology shall be coordinated with CCR Nordic and CCR Core.
e. The Single Intraday Coupling (SIDC) solution can apply flow-based parameters and relevant TSOs and the Nominate Electricity Market Operators (NEMOs) processes have been adapted accordingly.
f. The CCM for the intraday time frame is implemented.

2. Following Article 19(1)(a), with the CCR Hansa CCC appointment and its entry into operation, CCR Hansa CCC will calculate the cross-zonal capacity while the CCR Hansa TSOs will send the results from their capacity calculations on the AC grid to the CCR Hansa CCC, based on current methodologies. The minimum capacity calculated will prevail and will be applied by the CCR Hansa CCC. The resulting cross-zonal capacities are subject to validation by each CCR Hansa TSO for its bidding-zone borders. The CCR Hansa CCC provides the validated cross-zonal capacities to the allocation mechanism.

3. Following Article 19(1)(b), with the implementation of the two-days ahead, day-ahead and intraday CGMs, CCR Hansa TSOs will use the same CGM input in their CCR Hansa related capacity calculation processes. This will ensure that the forecast of demand, generation and line availability are the same, thus increasing the coordination of the capacity calculation.

4. Following Article 19(1)(c), with the implementation of the flow-based CCMs of CCR Core and of CCR Nordic using AHC, the influence of the CCR Hansa interconnectors on the AC grid will be market driven, ensuring equal treatment of the CCR Hansa bidding-zone borders and bidding-zone borders in the adjacent CCRs. Until this full implementation of the CCR Hansa CCM for the day-ahead market is done, in the case that AHC is not yet implemented in an adjacent CCR, or the flow-based CCMs of the adjacent CCRs are not including a selection of CNEs relevant for CCR Hansa exchanges, the CCR Hansa TSOs will follow the capacity calculation as described in Article 19(3) towards this adjacent CCR. This implies that the capacity calculation process will continue on the CCR Hansa bidding zone borders even when the CCR Core has implemented the flow-based CCM using SHC. Before AHC will replace the NTC calculation applied by the CCR Hansa TSOs on each side of the CCR Hansa interconnectors, a testing phase of 6 months will be coordinated with the CCR Nordic and CCR Core respectively as required in CACM Regulation Article 20(8).

5. With the application of flow-based in SIDC and adaptation of the processes on relevant CCR Hansa TSOs and NEMOs side, there will be no need to translate flow-based parameters into ATC constraints for the intraday market and CCR Hansa CCM for intraday market can be fully implemented, after a required 6 months testing phase following CACM Regulation Article 20(8).

Article 20
Language

1. The reference language for this CCM is English.

2. To avoid any doubt, where CCR Hansa TSOs need to translate this CCM into their national language(s), in the event of inconsistencies between the English version published by the TSOs in accordance with Article 9(14) of the CACM Regulation and any version in another language, the concerned CCR Hansa TSOs shall, in accordance with national legislation, provide the relevant CCR Hansa NRAs with an updated translation of the CCM.

Annex 1
Justification of Usage and Methodology for Calculation of Allocation Constraints in PSE as Described in Article 8(3)

Allocation constraints in Poland are applied as stipulated in Article 8(3) of the CCM. These constraints reflect the ability of Polish generators to increase generation (potential constraints in export direction) or decrease generation (potential constraints in import direction) subject to technical characteristics of individual generating units as well as the necessity to maintain minimum generation reserves required in the whole Polish power system to ensure secure operation. This is explained further in subsequent parts of this Annex.

Rationale behind implementation of allocation constraints on PSE side

Implementation of allocation constraints as applied by PSE side is related to the fact that under the conditions of the integrated scheduling based market model applied in Poland (also called central dispatch system) the responsibility of the Polish TSO on system balance is significantly extended comparing to such standard responsibility of TSOs in so-called self-dispatch market models. The latter is usually defined up to hour-ahead time frame (including real time operations), while for PSE as Polish TSO this is extended to short (intraday and day-ahead). Thus, PSE bears the responsibility, which in self-dispatch markets is allocated to balance responsible parties (BRPs). That is why PSE needs to take care of back up generating reserves for the whole Polish power system, which leads to implementation of allocation constraints if this is necessary to ensure operational security of Polish power system in terms of available generating capacities for upward or downward regulation capacity and residual demand[5]. In self-dispatch markets BRPs are themselves supposed to take care about their generating reserves and load following, while TSO ensures them just for dealing with contingencies in the time frame of up to one hour ahead. In a central dispatch market, in order to provide generation and demand balance, the TSO dispatches generating units taking into account their operational constraints, transmission constraints and reserve requirements. This is realized in an integrated scheduling process as an optimization problem called security constrained unit commitment (SCUC) and security constrained economic dispatch (SCED). Thus these two approaches (i.e. self and central dispatch market) ensure similar level of feasibility of transfer capacities offered to the market from the generating capacities point of view.

It was noted above that systemic interpretation of all network codes is necessary to ensure their coherent application. In SO Regulation, the definitions of specific system states involve a role of significant grid users (generating modules and demand facilities). To be in the ‘normal’ state, a transmission system requires sufficient active and reactive power reserves to make up for occurring contingencies (Article 18) – the possible influence of such issues on cross-zonal trade has been mentioned above. Operational security limits as understood by SO Regulation are also not defined as a closed set, as Article 25 requires each TSO to specify the operational security limits for each element of its transmission system, taking into account at least the following physical characteristics (…). The CACM Regulation definition of contingency (identified and possible or already occurred fault of an element, including not only the transmission system elements, but also significant grid users and distribution network elements if relevant for the transmission system operational security) is therefore consistent with the abovementioned SO Regulation framework, and shows that CACM Regulation application should involve circumstances related to generation and load.

As regards the way PSE procures balancing reserves, it should be noted that the EB Regulation allows TSOs to apply integrated scheduling process in which energy and reserves are procured simultaneously (inherent feature of central dispatch systems). In such a case, ensuring sufficient reserves requires setting a limit to how much electricity can be imported or exported by the system as a whole (explained in more detail below). If CACM Regulation is interpreted as excluding such a solution and mandating that a TSO offers capacity even if it may lead to insufficient reserves, this would make the provisions of EB Regulation void, and make it impossible or at least much more difficult to comply with SO Regulation.

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5 Residual demand is the part of end users’ demand not covered by commercial contracts (generation self-schedules).

Specification of security limits violated if the allocation constraint is not applied

With regard to constraints used to ensure sufficient operational reserves, if one of interconnected systems suffers from insufficient reserves in case of unexpected outages or unplanned load change (applies to central dispatch systems), there may be a sustained deviation from scheduled exchanges of the TSOs in question. These deviations may lead to an imbalance in the whole synchronous area, causing the system frequency to depart from its nominal level. Even if frequency limits are not violated, as a result, deviation activates frequency containment reserves, which will thus not be available for other contingencies, if required as designed. If another contingency materializes, the frequency may in consequence easily go beyond its secure limits with all related negative consequences. This is why such a situation can lead to a breach of operational security limits and must be prevented by keeping necessary reserves within all bidding zones, so that no TSO deviates from its schedule in a sustained way (i.e. more than 15 minutes, within which frequency restoration reserve shall be fully deployed by any given TSO). Finally, the inability to maintain scheduled area balances resulting from insufficient operational reserves will lead to uncontrolled changes in power flows, which may trigger lines overload (i.e. exceeding the thermal limits) and as a consequence can lead to system splitting with different frequencies in each of the subsystems. The above issue affects PSE in a different way from other TSOs due to reasons explained in the subsequent paragraph.

PSE role in system balancing

PSE directly dispatches all major generating units in Poland taking into account their operational characteristics and transmission constraints in order to cover the load forecasted by PSE, having in mind adequate reserve requirements. To fulfil this task PSE runs the process of operational planning, which begins three years ahead with relevant overhaul (maintenance) coordination and is continued via yearly, monthly and weekly updates to day-ahead SCUD and SCED. The results of this day-ahead market are then updated continuously in intraday time frame up to real time operation.

In a yearly time frame PSE tries to distribute the maintenance overhauls requested by generators along the year in such a way that on average the minimum year ahead generation reserve margin[6] over forecasted demand including already allocated capacities on interconnections is kept on average in each month. The monthly and weekly updates aim to keep a certain reserve margin on each day[7], if possible. This process includes also network maintenance planning, so any constraints coming from the network operation are duly taken into account.

The day-ahead SCUC process aims to achieve a set value of spinning reserve[8] (or quickly activated, in current Polish reality only units in pumped storage plants) margin for each hour of the next day, enabling up and down regulation. This includes primary and secondary control power pre-contracted as an ancillary service. The rest of this reserve comes from usage of balancing bids, which are mandatory to be submitted by all centrally dispatched generating units (in practice all units connected to the transmission network and major ones connected to 110 kV, except Combined Heat and Power (CHP) plants as they operate mainly according to heat demand). The remaining generation is taken into account as scheduled by owners, which having in mind its stable character (CHPs, small thermal and hydro) is a workable solution. The only exception from this rule is wind generation, which due to its volatile character is forecasted by PSE. Thus, PSE has the right to use any available centrally dispatched generation in normal operation to balance the system. The negative reserve requirements during low load periods (night hours) are also respected and the potential pumping operation of pumped storage plants is taken into account, if feasible.

The further updates of SCUC/SCED during the operational day take into account any changes happening in the system (forced outages and any limitations of generating units and network elements, load and wind forecast updates, etc.). It allows to keep one hour ahead spinning reserve at the minimum level of 1000 MW, i.e. potential loss of the largest generating unit, currently 850 MW (subject to change as new units are commissioned) and ca. 150 MW of primary control reserve (frequency containment reserve) being PSE's share in RGCE.

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6 The generation reserve margin is regulated by the Polish grid code and currently set at 18% (point II.4.3.4.18). It is subject to change depending on the results of the development of operational planning processes.

7 The generation reserve margin for monthly and weekly coordination is also regulated by the Polish grid code (point II.4.3.4.18) and currently set at 17% and 14% respectively.

8 The set values are respectively: 9% over forecasted demand for up regulation and 500 MW for down regulation. These values are regulated by the Polish grid code (point 4.3.4.19) and subject to change.

Determination of allocation constraints in Poland

When determining the allocation constraints, the Polish TSO takes into account the most recent information on the aforementioned 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 horizons.

Allocation constraints are bidirectional, with independent values for each MTU, and separately for directions of import to Poland and export from Poland.

For each hour, the constraints are calculated according to the below equation:

$$\mathrm{EXPORT}_{constraint} = \mathrm{P}_{CD} - (\mathrm{P}_{NA} + \mathrm{P}_{ER}) + \mathrm{P}_{NCD} - (\mathrm{P}_{L} + \mathrm{P}_{UPres}) \quad (1)$$

$$\mathrm{IMPORT}_{constraint} = \mathrm{P}_{L} - \mathrm{P}_{DOWNres} - \mathrm{P}_{CD_{min}} - \mathrm{P}_{NCD} \quad (2)$$

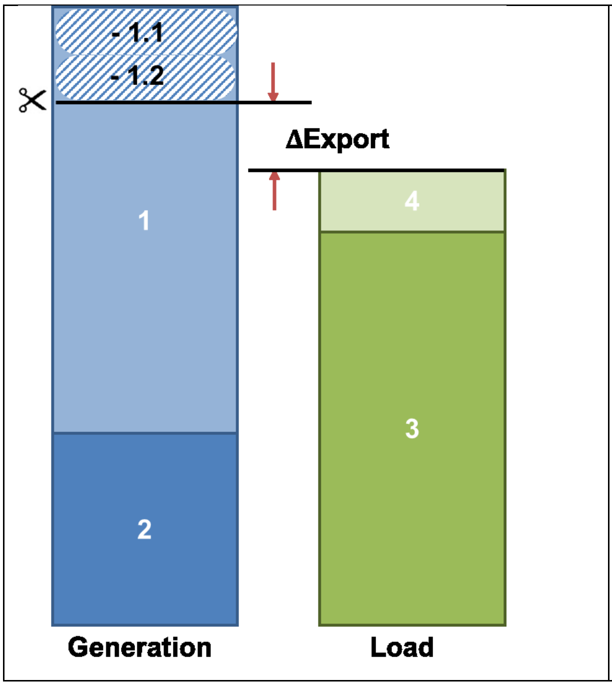
Where:

P_{CD}	Sum of available generating capacities of centrally dispatched units as declared by generators[9]
$\mathrm{P}_{CD_{min}}$	Sum of technical minima of centrally dispatched generating units in operation
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 up regulation
$\mathrm{P}_{DOWNres}$	Minimum reserve for down regulation

For illustrative purposes, the process of practical determination of allocation constraints in the framework of day-ahead transfer capacity calculation is illustrated below: figures 1 and 2. The figures illustrate how a forecast of the Polish power balance for each hour of the next day is developed by TSO day ahead in the morning in order to determine reserves in generating capacities available for potential exports and imports, respectively, for day ahead market. For the intraday market, the same method applies mutatis mutandis.

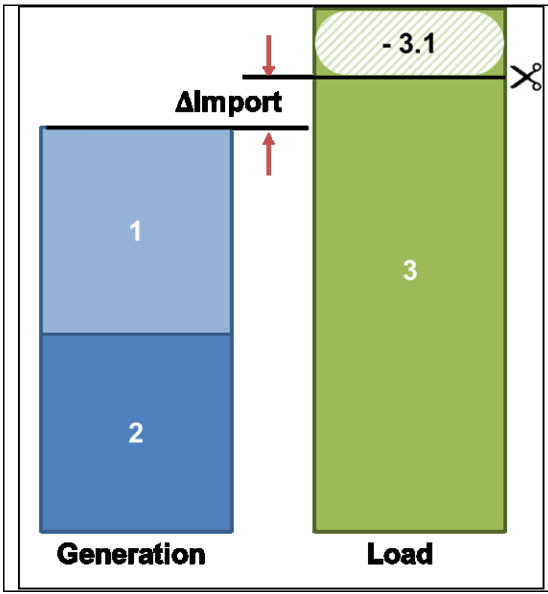
Allocation constraint in export direction is applicable if ΔExport is lower than the sum of transfer capacities on all Polish interconnections in export direction. Allocation constraint in import direction is applicable if ΔImport is lower than the sum of transfer capacities on all Polish interconnections in import direction.

9 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.



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 allocation constraints in export direction (generating capacities available for potential exports) in the framework of day-ahead transfer capacity calculation.



1 Sum of technical minima of centrally dispatched generating units in operation

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, reduced by:

3.1 Minimum necessary reserve for down regulation

Figure 2: Determination of allocation constraints in import direction (reserves in generating capacities available for potential imports) in the framework of day-ahead transfer capacity calculation.

Frequency of re-assessment

Allocation constraints are determined in a continuous process based on the most recent information, for each capacity allocation time horizon, from forward till day-ahead and intraday. In case of day-ahead process, these are calculated in the morning of D-1, resulting in independent values for each MTU, and separately for directions of import to Poland and export from Poland.

Impact of allocation constraints on single day-ahead coupling and single intraday coupling

Allocation constraints in form of allocation constraints as applied by PSE do not diminish the efficiency of day-ahead and intraday market coupling process. Given the need to ensure adequate availability of generation and generation reserves within Polish power system by PSE as TSO acting under central-dispatch market model, and the fact that PSE does not purchase operational reserves ahead of market coupling process, imposing constraints on maximum import and export in market coupling process – if necessary – is the most efficient manner of reconciling system security with trading opportunities. This approach results in at least the same level of generating capacities participating in cross border trade as it is the case in self-dispatch systems, where reserves are bought in advance by BRPs or TSO, so they do not participate in cross-border trade, either. Moreover, this allows to avoid competition between the TSO and market participants for generation resources.

It is to be underlined that allocation constraints applied in Poland will not affect the ability of any Hansa country to exchange energy, since these constraints only affect Polish export and/or import. Hence, transit via Poland will be possible in case of allocation constraints applied.

Impact of allocation constraints on adjacent CCRs

Allocation 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 border (i.e. Core, Baltic and Hansa).

It is to be underlined that this solution has been proven as the most efficient application of allocation constraints. Considering allocation constraints separately in each CCR would require PSE to split global allocation 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 generation requirements, or when Poland is unable to export any more power due to insufficient generation reserves in upward direction, Polish transmission infrastructure still can be – and indeed is - offered for transit, increasing thereby trading opportunities and social welfare in all concerned CCRs.

Time periods for which allocation constraints are applied

As described above, allocation constraints are determined in a continuous process for each capacity allocation time frame, so they are applicable for all MTUs (hours) of the respective allocation day.

Why the allocation constraints cannot be efficiently translated into capacities of individual borders offered to the market

Use of capacity allocation constraints aims to ensure economic efficiency of the market coupling mechanism on these interconnectors while meeting the security requirements of electricity supply to customers. If the generation conditions described above were to be reflected in cross-border capacities offered by PSE in form of an appropriate adjustments of border transmission capacities, this would imply that PSE would need to guess the most likely market direction (imports and/or exports on particular interconnectors) and accordingly reduce the cross-zonal capacities in these directions. In the CNTC approach, this would need to be done in a form of ATC reduction per border. However, from the point of view of market participants, due to the inherent uncertainties of market results, such an approach is burdened with the risk of suboptimal splitting of allocation constraints onto individual interconnections – overstated on one interconnection and underestimated on the other, or vice versa. Consequently, application of allocation constraints to tackle the overall Polish balancing constrains at the allocation phase allows for the most efficient use of transmission infrastructure, i.e. fully in line with price differences in individual markets.