Capacity Calculation Methodology for the Balancing Time Frame for Capacity Calculation Region Hansa in accordance with Article 37(3) of the Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing

17th of August 2022

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

CHAPTER 1
General provisions

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) 2017/2195, establishing a guideline on electricity balancing (hereafter referred to as the "EB 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 13 July 2009 on conditions for access to the network for cross-bidding-zone border exchanges in 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 (KF CGS) following article 64 of Regulation [2].

(3) The goal of this CCM is the coordination and harmonisation of capacity calculation and allocation in the balancing time frame.

(4) This CCM is required by article 37(3) of the EB Regulation:

"By five years after entry into force of this Regulation, all TSOs of a capacity calculation region shall develop a methodology for cross-zonal capacity calculation within the balancing timeframe for the exchange of balancing energy or for operating the imbalance netting process. Such methodology shall avoid market distortions and shall be consistent with the cross-zonal capacity calculation methodology applied in the intraday timeframe established under Regulation (EU) 2015/1222"

This CCM is subject to consultation in accordance with article 10 of the EB Regulation.

(5) Article 37 of the EB Regulation states that this CCM shall be consistent with the methodology applied by the CCM for intraday for the CCR Hansa that was established under CACM Regulation. Therefore, this CCM will follow the principle established under CACM.

(6) 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 or article 3 of the EBGL Regulation.

(7) Each CCR Hansa TSO shall use a list of CNEs of its own control area from the ID capacity calculation process. CNEs taken into account in the CCR Hansa capacity calculation shall be part of a CCR Hansa interconnector.

(8) 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 flow-based parameters of CCR Nordic and CCR Core following their respective balancing time frame methodologies for critical network elements selection and rules for avoiding undue discrimination between internal and cross-zonal exchanges.

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[1] ACER's definition of the Capacity Calculation Regions (CCRs) of 7 May 2021 (Annex I to CCR decision) https://documents.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions%20Annexes/ACER%20Decision%20No%2004-2021_Annexes/ACER%20Decision%2004-2021%20on%20the%20CCR%20-%20Annex%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

(9) The CCM for the CCR Hansa treats all bidding-zone borders in the Hansa CCR and adjacent CCRs[3] 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.

(10) 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.

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

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

Article 1
Subject, Matter and Scope

1. As required under article 37(3) of the EBGL Regulation, all TSOs in each CCR shall within the respective region submit a CCM for the exchange of balancing energy or operating the imbalance netting process.

2. This document establishes a common coordinated CCM for all bidding-zone borders in the 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 EBGL Regulation, of the Regulation (EU) 2017/2195, 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.

   b. The Already Allocated Capacity (AAC) is the capacity nominated for a line in a specific direction in previous market time frames.

   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.

   d. A 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.

   f. 'Balancing Platforms' means European platforms for the exchange of balancing energy from frequency restoration reserves with manual and automatic activation as well as from replacements reserves and the imbalancing netting process

   g. 'CMM' means the Capacity Management Module refers to a centralised solution for management of cross-zonal capacities between the balancing platforms for the exchange of balancing energy, or the imbalance netting process.

   h. 'CCC' means the Coordinated Capacity Calculator.

   i. 'CNTC' means Coordinated Net Transfer Capacity.

   j. 'KF CGS' means Kriegers Flak Combined Grid Solution, which is one of the interconnectors of Hansa CCR.

   k. 'MTU' means Market Time Unit.

   l. 'OWF' means Offshore Wind Farm.

   m. 'PTR' means Physical Transmission Rights.

   n. 'ROSC' means Regional Operational Security Coordination within Hansa CCR.

   o. 'TRM' means Transmission Reliability Margin.

p. 'TTC' means Total Transfer Capacity.

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 CCR Hansa TSOs or an entity acting on their behalf shall provide the CMM in advance of the CMM firmness deadline with the following information for each MTU:

   a. NTC shall be retrieved from XBID, reflecting the minimum value principle from Hansa CCR and the adjacent CCRs, unless a recomputation is needed and performed. Recomputations within Hansa CCR shall be in accordance with Article 4.

   b. AAC in accordance with Article 8;

   c. Allocation constraints shall be delivered in accordance with Article 6; and

   d. Capacity allocated for cross-zonal exchange of ancillary services with Article 7.

2. Where a CCR Hansa bidding-zone border has more than one interconnector, the NTC and AAC-values of those interconnectors shall be summed up to a total NTC and AAC of the CCR Hansa bidding-zone border.

3. In case the ATC calculation cannot be performed by the CMM the fallback for capacity calculation in accordance with Article 10(3) applies.

CHAPTER 2
Capacity Calculation Methodology for the Balancing Time Frame

Article 4
Mathematical Description

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

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

$$NTC_{\mathrm{i,A\rightarrow B}} = \alpha_{\mathrm{i}} \cdot \mathrm{P}_{\mathrm{i,max\,thermal}} * \left(1 - \beta_{\mathrm{i,Loss,A\rightarrow B}}\right)$$

   Where

A	:=	Bidding zone A.
B	:=	Bidding zone B.
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.

$\beta_{i.Loss,A\to B}$	:=	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 6.

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

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

$$\mathrm{NTC}_{AC,A\to B} = \mathrm{TTC}_{A\to B} - \mathrm{TRM}_{A\to B}$$

   Where

A	:=	Bidding zone A.
B	:=	Bidding zone B.
$\mathrm{TTC}_{A\to B}$	:=	Total Transfer Capacity of a bidding-zone border in direction A→B. The TTC is determined according to the last available CGM.
$\mathrm{TRM}_{A\to B}$	:=	Transmission Reliability Margin for a bidding-zone border in direction A→B, in accordance with article 14 of the CCR Hansa ID/DA CCM.

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

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

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

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

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

Planned or unplanned outages can lead to a reduction (partial reduction or full reduction to zero) of one or more of the following parameters: $P_{max\ thermal,DK}$, $P_{max\ thermal,DE}$ or $P_{max\ thermal,XB}$.

Where:

DE	:= Bidding zone DE/LU.
DK	:= Bidding zone DK2.
AAC_{DE}^{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 8.
AAC_{DK}^{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 8.
$CP_{OWF, DE}$	Connection Point of offshore windfarm connected in the bidding zone DE/LU to KF CGS.
$CP_{OWF, DK}$	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 $CP_{OWF, DE}$
$Loss_{XB}$	:= Electrical losses between the connection point in $CP_{OWF, DK}$ and $CP_{OWF, DE}$
$Loss_{DK}$	:= Electrical losses between the connection point of KF CGS in bidding zone DK2 and $CP_{OWF, DK}$
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.
$P_{max\,thermal,DE}$	:= Thermal capacity for line section from bidding zone DE/LU to $CP_{OWF, DE}$
$P_{max\,thermal,XB}$	:= Thermal capacity for line section from $CP_{OWF, DK}$ to $CP_{OWF, DE}$
$P_{max\,thermal,DK}$	:= Thermal capacity for line section from bidding zone DK2 to $CP_{OWF, DK}$

Article 5
Reassessment & Validation of Capacity in the Balancing Time Frame

1. The NTC for the balancing time frame may be reassessed by the CCR Hansa TSOs or an entity acting on their behalf.
2. In case of unexpected events on the CCR Hansa interconnectors or on close proximity to this interconnectors, or obtaining new information with impact on cross-zonal capacity, the capacity in the balancing time frame can be recalculated by the involved TSO.
3. The AAC, as defined in Article 2 and 8, will be fixed after the intraday gate closing time.
4. As only CCR Hansa interconnectors are included as CNEs in the CCR Hansa capacity calculation, a situation where an internal AC grid element requires a correction of available cross-zonal capacity is not applicable for CCR Hansa.
5. Each CCR Hansa TSO may perform a validation which can be done either locally or commonly in the CCR Hansa.
6. Each CCR Hansa TSO may adjust cross-zonal capacity during the validation process for reasons of operational security.
7. Any information on increased or decreased cross-zonal capacity from adjacent CCCs to the CCR Hansa TSOs shall be taken into account during the validation.
8. In case a calculation is performed in the balancing time frame, a CCR Hansa TSO may perform a validation step and send the result of the validation to the other CCR Hansa TSOs. In case a CCR Hansa TSO corrects capacity it shall provide a justification for this to be submitted later to the other CCR Hansa TSOs.

Article 6

Methodology for Allocation Constraints

1. In accordance with article 58(4)(a) and (b) of the EB Regulation, all algorithms operated by the activation optimisation functions, imbalance netting process functions and capacity procurement optimisation functions shall respect operational security constraints, take into account technical and network constraints and, if applicable, take into account the available cross-zonal capacity. In order to ensure consistency with the cross-zonal CCM applied in the intraday time frame in accordance with article 37(3) of the EB Regulation, CCR Hansa TSOs may apply these constraints as allocation constraints during the capacity allocation phase, 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;
    e. Minimum flow on DC lines;
    f. Limitations of amount of polarity reversals (zero-crossings) on DC lines for a given period of time;
    g. Limitation of maximum flow on DC lines dependent on cable temperature and pressure.
2. Following Article 6(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 6(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 6(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 6(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. Following Article 6(1)(e), considering a minimum flow on each DC line during capacity allocation ensures that the DC line won't be operated outside its technical capabilities.
7. Following Article 6(1)(f), in systems with line commutated converters polarity reversals cause increased electrical stress in the cable insulation. An allocation constraint might be used to limit polarity reversals on each DC line to not negatively influence the ageing of the cable and its service life.
8. Following Article 6(1)(g), a maximum flow might be limited on some DC line technologies which are sensitive to cable temperature and pressure. In this case lower voltage mode is triggered when cable temperature and pressure thresholds are exceeded and limits the maximum flow of the DC line, e.g. in case of polarity reversal or ramp-up of the DC line.
9. If one, more, or all CCR Hansa TSOs plan to apply one or more of the allocation constraints, referred to in Article 6(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 regulatory authorities, 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.

Article 7
Cross-Zonal Exchange of Ancillary Services

1. Capacity reserved or allocated for cross-zonal exchange of ancillary services following article 40, 41 or 42 of the EB Regulation shall be provided by the CCR Hansa TSOs or an entity acting on their behalf on product level to the CMM, so each balancing platform can use the capacity allocated for reserves.

Article 8
Rules for Taking into Account Already Allocated Cross-Zonal Capacity in the Balancing Time Frame

1. In the balancing time frame, the CCR Hansa TSOs or an entity acting on their behalf shall take into account the latest AAC for each MTU after the ID GCT which is a result of:
    a. Capacity allocated for nominated PTR.
    b. Capacity nominated in the day-ahead market.
    c. For KF CGS, AACWind is the expected wind generation on the OWF(s) based on the relevant CCR Hansa TSOs forecasts.
    d. Capacity nominated in the intraday market, including the consideration of cross-border redispatch and countertrade and future ROSC processes.

Article 9
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.

3. Other operational security limits relevant for the balancing time frame in Hansa CCR are provided in Article 6, which defines the allocation constraints.

4. 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.

Article 10
Fallback for Capacity Calculation

1. In case the remaining capacities after the IDCZGCT are not available, 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 other CCR Hansa TSOs.

2. The Hansa TSOs shall have the possibility to validate the aforementioned capacities pursuant to Article 5.

3. In case the CMM does not receive any capacity or cannot perform the ATC calculation, the available capacities for the balancing platforms should be adjusted to respect the system security.

CHAPTER 3
Final provisions

Article 11
Implementation

1. Implementation of this CCM will be a stepwise process with the following milestones:
    a. The CCR Hansa TSOs go-live on the balancing platforms;
    b. The CMM platform is implemented;
    c. The implementation of allocation constraints, either by the CMM or balancing platforms shall be in place.
    d. The CCM for the balancing time frame is implemented.

2. Following article 5(5) of the EB Regulation, the implementation timescale of the CCR Hansa EB CCM shall not be longer than 12 months after the approval by the relevant regulatory authorities, except where all relevant regulatory authorities agree to extend the implementation timescale or where different timescales are stipulated in the EB Regulation and given the condition that the milestones from Article 11(1)(a,b,c) are implemented.

Article 12
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 English version prevails.

Annex 1
Justification of Usage and Methodology for Calculation of Allocation Constraints in PSE as Described in Article 6(3)

Allocation constraints in Poland are applied as stipulated in Article 6(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 (balancing time frame, 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[4]. 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.

4 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, balancing 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[5] 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[6], 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[7] (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.

5 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.

6 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.

7 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:

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

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

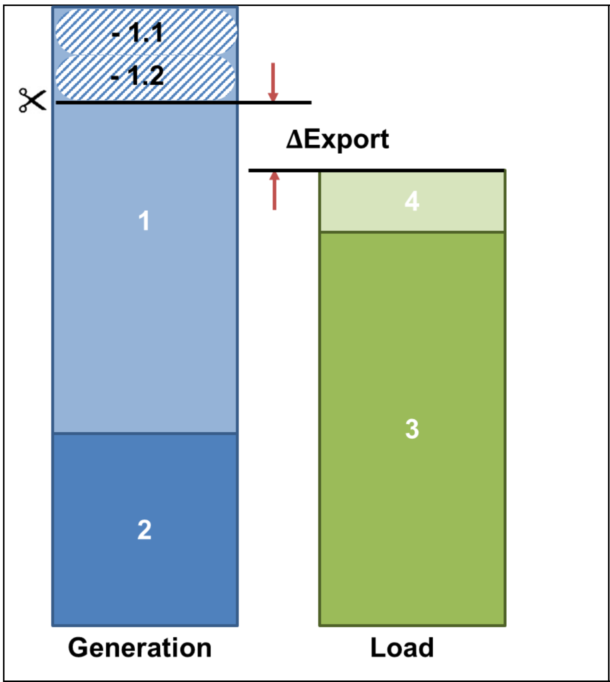
Where:

P_{CD}	Sum of available generating capacities of centrally dispatched units as declared by generators[8]
$\mathrm{P}_{CD_{min}}$	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 and balancing time frame market, the same method applies mutatis mutandis.

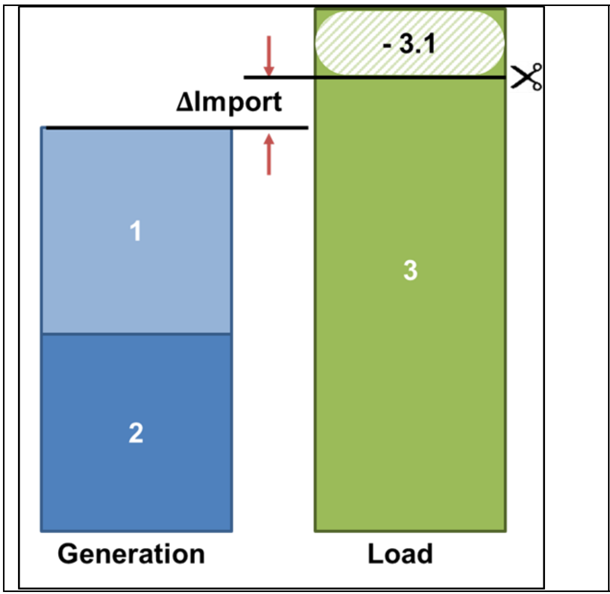
Allocation constraint in export direction is applicable if ΔExport is lower than the sum of transfer capacities on all Polish interconnections in export direction. Allocation constraint in import direction is applicable if ΔImport is lower than the sum of transfer capacities on all Polish interconnections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

8 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,intraday and balancing time frame. 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,intraday and balancing time frame 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.