Third amendment of the Day-Ahead Capacity Calculation Methodology of the Core Capacity Calculation Region

in accordance with Articles 20ff. of the Commission Regulation (EU) 2015/1222 of 24th July 2015 establishing a guideline on capacity allocation and congestion management

8th December 2023

Whereas

TSOs of the Core CCR ("Core TSOs"), taking into account the following:

(1) Owing to the complexity of the subject matter, the Day-Ahead Capacity Calculation Methodology of the Core Capacity Calculation Region (DA CCM) was initially formulated such that certain aspects were left for later refinement, while allowing for an early Go-Live of Core FB DA MC with respective interim solutions. This amendment addresses all aspects for which such refinement is due eighteen months after Go-Live;

(2) Eighteen months after Core FB DA MC Go-Live, Core TSO need to submit to Core NRAs a proposal for amendment of this methodology detailing the methodology for coordinated validation, a list of internal network elements (combined with the relevant contingencies) to be defined as CNECs, further harmonisation of the generation shift key methodology, an approach and justification for selecting FRM, and an approach for using allocation constraints;

(3) With this amendment, Core TSOs aim to detail the coordinated validation methodology and set a timeline for the technical readiness of the tools used in the Core FB DA CC process for the introduction of the coordinated validation. The proposed methodology makes it possible to include network elements not being CNECs pursuant to Article 15(1) as part of the coordinated validation. This is to enable a consistent use of all available RA potential to ensure operational security. At the same time, it is acknowledged that the impact of such network elements on cross-zonal capacities must be monitored pursuant to Article 20(15). Any CVA is capped to guarantee a minimum capacity floor in terms of the percentage of RAM_{biv} pursuant to Article 20(4g) in relation to the maximum admissible active power per CNEC (F_{max}) pursuant to Article 6(2)(d). The CVA shall be capped to respect this floor, such that any remaining operational security violations are left to the individual validation. The implementation of the coordinated validation is expected not earlier than forty-two months after Core FB DA MC Go-Live.

(4) The provision of a list of internal network elements is postponed to sixty months after Core FB DA MC Go-Live. In regard to the list of internal network elements, the German NRA BNetzA appealed again against a decision by the BoA on Article 5. Consequently, a new court ruling needs to be awaited before providing the list of internal network elements.

(5) The harmonisation of the generation shift key methodology is postponed to forty-two months after Core FB DA MC Go-Live.

(6) The approach and justification for selecting FRM is postponed to sixty months after Core FB DA MC Go-Live. However, the FRM values to be applied until then are set to 10% of Fmax.

(7) With this amendment, PSE aims at extending the period of using AC by additional two years. Operational experience gathered over the previous two years has proven that allocation constraints are an effective measure to maintain the transmission system within operational security limits and cannot be transferred efficiently into maximum flows on critical network elements, as prescribed by provisions of the CACM Art. 23(3). In absence of explicit reserve capacity procurement, allocation constraints allowed to avoid any cases of insecure operation in Poland that could not have been resolved by operational means. Moreover, no alternatives have been identified as plausible to be implemented until two years after implementing flow-based in Core that

would both have lower overall cost while maintaining the similar level of operational security and which would not require a major overhaul of the market design. Given the current legal framework in Poland, in particular responsibilities of PSE regarding dispatching generation units connected to the transmission grid while respecting their technical characteristics, allocation constraints is the only means of ensuring availability of sufficient balancing capacity reserves in Poland. Currently, the balancing market in Poland is undergoing a significant redesign, aiming at strengthening balancing energy price signals and creating stronger incentives for balanced positions of balancing responsible parties. In combination with the planned market-based process for procuring balancing capacity reserves, this should improve the ability of PSE to manage the secure operation of the Polish power system and potentially even alleviate the need for allocation constraints of the cross-border market coupling process. It is expected that the balancing market redesign will be implemented in mid 2024. This is a very significant change for the whole Polish market and such reform must be well prepared and tested against security requirements. For the above reasons, two years extension for using capacity allocation constraints is necessary in order to gather real-live operational experience from the ongoing market redesign after its successful completion.

(8) The following changes fulfil the objectives set out in Article 3 CACM. In particular, the coordinated validation will bring about improvements in relation to Article 3 (b), (c), (d) and (g) CACM. The coordinated validation contributes to reaching the minimum levels of available capacity for cross-zonal trade pursuant to Article 16(8) Regulation (EU) 2019/943. The aim of the coordinated validation is to maximize cross-zonal capacities while respecting operational security limits and thereby contribute to increased social welfare in the Single Day-Ahead Market Coupling and secure system operation.

(9) The evolved flow-based method described in Article 12 has been introduced with the commissioning of the ALEGrO HVDC link between Belgium and Germany. Operational experience over recent years has shown that the actual method turns out to come along with the undesired effect of very frequent circular flows in the nearby AC grid induced by the ALEGrO schedule after DA MC. The undesired behaviour is attributed to very distant network elements with a low sensitivity to ALEGrO exchanges in the context of the social welfare maximization in Market Coupling. A slight relief of a very distant limiting CNEC is achieved by scheduling ALEGrO against the market direction at the cost of circular flows and full loading of nearby CNECs leading to n-1 violations and application of costly remedial actions in real-time system operation. The circular flows have been observed mainly between the hubs BE, DE, NL and FR, counteracting operational security and reducing Intraday Capacities whilst only leading to a negligible social welfare increase in Day Ahead Market Coupling. In order to prevent such a behaviour of existing and future HVDC Interconnectors on Core bidding zone borders, Core TSOs aim to introduce a zone-to-zone PTDF threshold for internal virtual hubs in the context of the Evolved flow-based method. By introducing a threshold, this undesired impact can be prevented. The appearance of circular flows and the resulting high loading of nearby AC network elements can be significantly reduced by the PTDF threshold. This means that less congestion in the AC grid, less redispatch, less setpoint volatility and less need of real-time coordination and intervention would be needed which is beneficial for operational security. At the same time

higher capacities for ID Capacity Calculation are made available, as AC network elements around the HVDC link and the HVDC link itself are not fully occupied by DA MC for very limited welfare gain in DA. Thus, the overall transmission capacity across all time frames is maximized this way, which is supposed to come along with an increase in overall social welfare.

(10) For the purposes of this third amendment to the Core CCR TSOs' Day-Ahead Capacity Calculation Methodology, terms used in this document shall have the meaning of the definitions included in Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity, Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU (recast), Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management (CACM Regulation), Commission Regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation (FCA Regulation), Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing (EB Regulation) and Commission Regulation (EU) No 543/2013 of 14 June 2013 on submission and publication of data in electricity markets and amending Annex I to Regulation (EC) No 714/2009 of the European Parliament and of the Council and the definitions set out in Article 2 Annex I of the Decision No 02/2019 of the Agency for the Cooperation of the Energy Regulators of 21 February 2019 on the Core CCR TSOs' proposal for the regional design of the day-ahead and intraday common capacity calculation methodologies.

Article 1
Implementation of coordinated validation

1. Article 2. Definitions and interpretation shall be amended by introducing a new number 77:

   > "77. 'circumstance' means a combination of net positions which is feasible according to the CZC used for the respective validation phase. A circumstance comprises at least the Core bidding zones and, where AHC is applied, the respective external virtual hubs. It may additionally contain bidding zones of technical counterparties."

2. Article 4. Day-ahead capacity calculation process shall be amended by updating paragraph 8 step 8 accordingly:

   > "The Core TSOs and the CCC shall, according to Article 20, validate the RAM_{bv} with coordinated validation, calculate the RAM before individual validation (RAM_{biv}), validate the RAM_{biv} with individual validation, and decrease RAM when operational security is jeopardised, which results in the RAM before long-term nominations (RAM_{bn});"

3. Article 6. Methodology for operational security limits shall be amended accordingly:

Footnote 1 shall be replaced and be read accordingly:

> "[1] Uncertainties in capacity calculation are covered on each CNEC by the flow reliability margin (FRM) in accordance with Article 8 and adjustment values related to validation in accordance with Article 20."

Paragraph 2(f) shall be replaced and be read accordingly:

> "(f) the CCC shall, by default, set the power factor $\cos(\varphi)$ to 1 based on the assumption that the CNE is loaded only by active power and that the share reactive power is negligible (i.e. $\varphi = 0$). If the share of reactive power is not negligible, a TSO may consider this aspect during the individual validation phase in accordance with Article 20."

4. Article 10. Methodology for remedial actions in day-ahead capacity calculation shall be amended by updating paragraph 4 accordingly:

> "4. For the purpose of the NRAO, all Core TSOs shall provide to the CCC all expected available non-costly RAs and, for the purpose of coordinated capacity validation, all Core TSOs shall provide to the CCC all expected available costly and non-costly RAs."

5. Article 14. Initial flow-based calculation shall be amended by updating paragraph 3a accordingly:

> "3a. For network elements with contingencies from technical counterparties pursuant to Article 20(6a), the steps described in paragraphs 1 to 3 shall be carried out by the CCC in order to enable a potential submission, subject to Article 13(2), of the network elements with contingency by the technical counterparty to the final list of CNECs during coordinated and individual validation. Until then, the network elements with contingencies from technical counterparties shall not be considered as constraints to the formulation of flow-based domain, neither to the NRAO."

6. Article 17. Adjustment for minimum RAM shall be amended by updating paragraph 1 accordingly:

> "1. To address the requirement of Article 21(1)(b)(ii) of the CACM Regulation, the Core TSOs shall ensure that the RAM for each CNEC determining the cross-zonal capacity is never below a minimum RAM, except in cases of validation reductions as defined in Article 20."

7. Article 18. Long-term allocated capacities (LTA) inclusion shall be amended by updating paragraph 5a accordingly:

> "5a. In case the extended LTA approach is applied Core TSOs may additionally carry out the steps described in paragraphs 2 to 5 with the sole purpose to make available a flow-based domain with LTA inclusion as

input for the coordinated and individual validation as described in Articles 19 and 20.”

8. Article 20. Validation of flow-based parameters amended accordingly:

Paragraph 3 shall be replaced and be read accordingly:

> “3. In the process of cross-zonal capacity validation the Core TSOs shall exchange information on all expected available (non-costly and costly) RAs in the Core CCR, defined in accordance with Article 22 of the SO Regulation. In case the cross-zonal capacity could lead to violation of operational security, all Core TSOs in coordination with the CCC shall verify whether such violation can be avoided with the application of RAs. In this process, the CCC shall coordinate with neighbouring CCCs and optionally technical counterparties on the use of RAs having an impact on neighbouring CCRs and optionally on technical counterparties. For those CNECs where all available RAs are not sufficient to avoid the violation of operational security, the Core TSOs in coordination with the CCC may reduce the $RAM_{bv,LTAmargin}$ or $RAM_{bv,noLTAmargin}$ to the maximum value which avoids the violation of operational security. This reduction is called ‘coordinated validation adjustment’ (CVA) and the adjusted RAM is called ‘RAM before individual validation’ (RAM_{biv}).”

Paragraph 4 shall be replaced and be read accordingly:

> “4. The coordinated validation pursuant to paragraph 3 shall be implemented gradually. During the first forty-two months following the implementation of this methodology in accordance with Article 28(3), the coordinated validation may be limited to exchange of information on the available (non-costly and costly) RAs in the Core CCR and a CCC’s advice to individual TSOs based on its operational experience. After the forty-two months, the simplified process shall be replaced by a full analysis pursuant to paragraphs 4a until 4h.
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> 4a. The coordinated validation process step in the Core CCR as set out in paragraph 4 sentence 3 shall be performed by the CCC and the Core TSOs and optionally by the technical counterparties pursuant to Article 13(2) according to the following procedure:
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> > Step 1. The CCC shall use the inputs pursuant to paragraph 4b;
> >
> > Step 2. The CCC shall, pursuant to paragraph 4c, select the circumstances, being possible market outcomes, that shall be evaluated to determine whether the power system could accommodate them having regard to operational security requirements;
> >
> > Step 3. The CCC shall analyse the selected circumstances subject to the criteria pursuant to paragraph 4d and applying the remedial action optimisation method pursuant to paragraph 4e;

Step 4. The CCC shall, in coordination with the Core TSOs and optionally technical counterparties pursuant to Article 13(2), determine CVA pursuant to paragraph 4f;

Step 5. The CCC shall compute the RAM_biv pursuant to paragraph 4g;

Step 6. The CCC shall disseminate the results of steps 2, 3, 4 and 5 pursuant to paragraph 4h to enable Core TSOs and technical counterparties pursuant to Article 13(2) to consider them in the individual validation process step;

4b. The CCC shall base the full coordinated validation on the following inputs:

(a) the CZC domain based on the flow-based parameters before validation pursuant to Article 19 and, in case the extended LTA approach pursuant to Article 18(1a)(b) is applied, the LTA domain;

(b) the CGM;

(c) all expected available (non-costly and costly) RAs in the Core CCR and optionally in control areas of technical counterparties pursuant to Article 13(2), defined in accordance with Article 22 of the SO Regulation. These may comprise RAs from bidding zones outside the Core CCR, subject to alignment with the respective connecting TSOs. The probability of RAs being available under the modelling assumptions may be taken into consideration when providing RAs;

(d) a list of network elements and contingencies to consider when assessing operational security. Each Core TSO and optionally each technical counterparty pursuant to Article 13(2) shall provide such a list to the CCC. Any network element from the CGM with a voltage level higher than or equal to 220 kV may be considered. The standard properties of these network elements are that they shall not be overloaded after coordinated validation with respect to their operational security limits. Each Core TSO and optionally each technical counterparty pursuant to Article 13(2) may define two parameters to modify the properties of each network element. Firstly, the maximum flow of a network element may be increased. Secondly, a network element may be specified as scanned network element. Scanned network elements may not be overloaded, or not incur additional overloading, pursuant to the specifications in paragraph 4d.

Core TSOs may decide for the CCC to base the full coordinated validation on further input, as long as this is within the boundaries of Article 3 (b), (c) and (d) CACM. Core TSOs may alter the parameters and thresholds of the input where an input would have a significant impact on the resulting CZC, as long as this is within the boundaries of Article 3 (b), (c) and (d) CACM. The CCC shall report quarterly on the initial setup and any change in the input or its parameters and thresholds, together with its impact and a due justification. The CCC shall also publicly announce such change at least two working days before it takes effect.

4c. The CCC shall separately select at least one circumstance for each DA CC MTU, to be analysed in the coordinated validation as set out in paragraph 4 sentence 3. The number of circumstances shall be sufficiently large having regard to the time available for conducting the coordinated validation and the complexity of the analysis per circumstance pursuant to paragraph 4e. During the implementation of the coordinated validation as set out in paragraph 4 sentence 3, the Core TSOs and optionally the technical counterparties pursuant to Article 13(2) shall:

(a) make a justified trade-off between the complexity of the analysis and the number of circumstances;

(b) define criteria for the selection of circumstances. The Core TSOs may alter the criteria after implementation to cope with the evolution of technical or market conditions, as long as this is within the boundaries of Article 3 (b), (c) and (d) CACM. The CCC shall report quarterly on any change in the criteria, together with its impact and due justification

Exchanges on borders to non-Core bidding zones via AHC shall be treated equally to exchanges on Core borders when defining and selecting circumstances. Exchanges on borders with technical counterparties may optionally be taken into account in the selection of circumstances.

4d. When analysing a circumstance, the CCC shall use the CGM and apply load flow calculation and contingency analysis. The net positions of the BZs in the CGM shall be shifted towards the net positions of the circumstance. This shift shall, in principle, be done using the GSK pursuant to Article 9. A deviation from the GSK is allowed, insofar as the injection from generators is altered, to prevent a violation of technical generator bounds. The RA potential related to redispatch shall be adjusted to reflect the dispatch modifications between the CGM and the circumstance.

For each circumstance in each DA CC MTU, the maximum admissible flow on each scanned network element shall, if necessary, be increased such that the difference between the maximum admissible flow and the post-contingency flow in the circumstance prior to the remedial action optimisation pursuant to paragraph 4e is at least as large as a threshold, which shall be set according to the process described in paragraph 4b.

4e. The CCC shall perform an RA optimisation to determine for each circumstance in each DA CC MTU, to which extent this circumstance could be realised with respect to operational security. The circumstance can be realised entirely, if all operational security violations, which might occur after shifting the CGM to the circumstance pursuant to paragraph 4c, and having regard to the network elements, contingencies and properties as specified pursuant to paragraph 4b(d), can be completely eliminated by the application of RAs. In case the circumstance cannot be realised without violating operational security constraints, the RA optimisation shall determine the extent of this violation. The RA optimisation shall further determine an alternative circumstance that is as similar as possible to the original one but can be implemented without violating operational security constraints.

The RA optimisation shall consider the same types of RAs as used in the Core CCR ROSC process, which implements the methodology developed pursuant to Article 76(1) of the SO Regulation, or other congestion management planning processes of the Core TSOs or optionally technical counterparties. To limit the complexity of the RA optimisation and in accordance with the requirements and obligations set out in paragraph 4b, Core TSOs and optionally technical counterparties may adjust the inputs of the coordinated validation to reflect the estimated effect of congestion management planning procedures while adhering to operational security constraints. Such adjustments may comprise, but are not limited to, ignoring network elements or allowing a certain amount of overload. The RA optimisation shall consider preventive and curative RAs with full or partial sharing of the benefit of curative RAs.

The RA optimisation shall be specified such that use of RAs shall precede a reduction to the extent needed to which the circumstance can be realised. The RA optimisation shall be designed in consistency with the approach for determining the limitations of the CZC pursuant to paragraph 4f.

Core TSOs may apply the following means to relax or constrain the RA optimisation:

(a) To avoid unnecessarily strict limitations, Core TSOs may specify optimisation parameters. These may comprise, but are not limited to, ignoring low sensitivities of loadings on network elements with respect to RAs and/or cross-zonal exchanges;

(b) To take into account constraints of the Core CCR ROSC process, which implements the methodology developed pursuant to Article 76(1) of the SO Regulation, or other congestion management planning processes of the Core TSOs or optionally technical counterparties, Core TSOs and optionally technical counterparties may specify limits on the number of RAs and/or on the total redispatch amount that can be simultaneously applied. These limits may be specified on subsets of RAs.

(c) Core TSOs may define the objective function to minimise the extent of operational security violations and/or to maximise the extent to which the cross-zonal exchanges match the circumstance.

4f. If one or more circumstances for a DA CC MTU cannot be realised to their full extent, the CCC shall limit cross-zonal capacity such that the maximum line loading on network elements that would lead to operational security violations in any circumstance is reduced to comply with operational security limits. CNECs with applied CVA shall be sufficiently effective for reducing the loading of the network elements on which operational security limits would be violated in the circumstance without CVA.

If several circumstances lead to CVA in a given DA CC MTU, the final CVA per CNEC shall be the maximum across all circumstances.

The Core TSOs shall consider a minimum capacity floor in terms of the percentage of RAM_{biv} in relation to the maximum admissible active power per CNEC (F_{max}) pursuant to Article 6(2)(d). The CVA shall be capped to respect this floor, such that any remaining operational security violations are left to the individual validation.

Subject to a previous alignment with the other Core TSOs, the CCC and optionally technical counterparties in which an attempt was made to resolve the reasons for the rejection, a Core TSO may reject with justification all of the CVA resulting from one or several circumstances in one or several DA CC MTUs. In case of such rejection the final CVA shall be recomputed as if no CVA had resulted from the rejected circumstances.

4g. The CCC shall calculate for each CNEC:

(a) the RAM before individual validation as follows;

$$\overrightarrow{RAM}_{biv,LTAmargin} = \overrightarrow{RAM}_{bv,LTAmargin} - \overrightarrow{CVA}$$

Equation 19c

(b) in case the extended LTA approach pursuant to Article 18(1a)(b) is applied, the RAM before individual validation as follows;

$$\overrightarrow{RAM}_{biv,noLTAmargin} = \overrightarrow{RAM}_{bv,noLTAmargin} - \overrightarrow{CVA}$$

Equation 19d

4h. The CCC shall share with each Core TSO and technical counterparty pursuant to Article 13(2) all information that is necessary to support consistency of the subsequent individual validation with the coordinated validation. This information shall at least comprise the analysed circumstances, applied RAs and, if applicable, remaining operational security violations after coordinated validation."

Paragraph 5(b) shall be replaced and be read accordingly:

"(b) when all available costly and non-costly RAs are not sufficient to ensure operational security, taking the CCC's analysis pursuant to paragraph 4 into account, and coordinating with the CCC when necessary;"

Paragraph 14 shall be replaced and be read accordingly:

"14. The quarterly report shall also include at least the following aggregated information:

(a) statistics on the number, causes, volume and estimated loss of economic surplus of applied reductions by different TSOs;

(b) general measures to avoid cross-zonal capacity reductions in the future;
(c) changes to inputs, parameters or thresholds of the coordinated validation referred to in paragraph (4b)."

Paragraph 15 shall be replaced and be read accordingly:

"15. When capacity is reduced for operational security limits of a given Core TSO in more than 1% of DA CC MTUs of the analysed quarter, the concerned TSO shall provide to the CCC a detailed report and action plan describing how such deviations are expected to be alleviated and solved in the future. This report and action plan shall be included as an annex to the quarterly report."

9. Article 22. Day-ahead capacity calculation fallback procedure shall be amended by updating paragraph (b) accordingly:

"(b) when the day-ahead capacity calculation fails to provide the flow-based parameters for three or more consecutive hours, the Core TSOs shall define the missing parameters by calculating the default flow-based parameters. Such calculation shall also be applied in cases of impossibility to span the missing parameters pursuant to point (a) or in the situation as described in Article 20(9). The calculation of default flow-based parameters shall be based on long-term allocated capacities as provided by TSOs pursuant to Article 4(4(a). The capacities on the bilateral Core bidding zone borders and on AHC borders shall be defined based on the LTA capacity for each oriented bidding zone border:"

10. Article 25. Publication of data shall be amended adding paragraph 8 accordingly:

"8. Any change in the threshold according to Article 12(4) shall be publicly notified at least two weeks before its entry into force. The notification shall at least include:

a. the current threshold applied;

b. the day of entry into force of the new threshold;

c. the value of the new threshold; and

d. a due justification of the change."

11. Article 27. Monitoring, reporting and information to the Core regulatory authorities amended in paragraph 5 accordingly:

"5. The CCC, with the support of the Core TSOs where relevant, shall draft and publish a quarterly report satisfying the reporting obligations set in Articles 7, 12, 20, 25 and 28 of this methodology:
(a) according to Article 7(3)(b), the CCC shall collect all reports analysing the effectiveness of relevant allocation constraints, received from

the concerned TSOs during the period covered by the report, and annex those to the quarterly report.

(b) according to Article 20(13)f, the CCC shall provide all information on the reductions of cross-zonal capacity, with a supporting detailed analysis from the concerned TSOs where relevant.

(c) according to Article 28(3), during the implementation of this methodology, the Core TSOs shall report on their continuous monitoring of the effects and performance of the application of this methodology.

(d) according to Article 25(2) (g), Core TSOs shall report on flows resulting from net positions resulting from the SDAC on each CNEC and external constraint of the final flow-based parameters.

(e) according to Article 12(4), Core TSOs shall report on the economic social welfare deviation which was provoked by introducing a non-zero PTDF threshold."

Article 2
Amendment on harmonization of FRM approach

1. Article 8. Reliability margin methodology shall be amended accordingly:

Paragraph 7 shall be replaced and be read accordingly:

> "7. No later than sixty months after the implementation of this methodology in accordance with Article 28(3), the Core TSOs shall jointly perform the first FRM calculation pursuant to the methodology described above and based on the data covering at least the first year of operation of this methodology. By the same deadline, all Core TSOs shall submit to all Core regulatory authorities a proposal for amendment of this methodology in accordance with Article 9(13) of the CACM Regulation as well as the supporting document as referred to in paragraph 9 below. The proposal for amendment shall include an approach and justification for selecting the FRM from the range between the lower and upper estimates as well as next possible steps for improving the process to approach as much as possible the true FRM."

Paragraph 10 shall be replaced and be read accordingly:

> "10. Until the proposal for amendment of this methodology pursuant to paragraph 7 has been approved by all Core regulatory authorities, the Core TSOs shall use FRM values equal to 10% of F_{max} pursuant to Article 6(2)."

Article 3
Methodology for allocation constraints

1. Article 7. Methodology for allocation constraints shall be amended accordingly:

Paragraph 3 shall be replaced and be read accordingly:

"3. External constraints may be used by a Core TSO as listed in Annex 1 during a transition period of four years following the implementation of this methodology in accordance with Article 28(3) and in accordance with the reasons and the methodology for the calculation of external constraints as specified in Annex 1 to this methodology. During this transition period, the concerned Core TSOs shall:

(a) calculate the value of external constraints in accordance with Annex 1 and in any case at least on a quarterly basis and publish the results of the underlying analysis;

(b) in case the external constraint had a non-zero shadow price in more than 0.1% of hours in a quarter, provide to the CCC a report analysing: (i) for each DA CC MTU when the external constraint had a non-zero shadow price the loss in economic surplus due to external constraint and the effectiveness of the allocation constraint in preventing the violation of the underlying operational security limits and (ii) alternative solutions to address the underlying operational security limits. The CCC shall include this report as an annex in the quarterly report as defined in Article 27(5);

(c) if applicable and when more efficient, implement alternative solutions referred to in point (b)."

Paragraph 4 shall be replaced and be read accordingly:

"4. In case the concerned Core TSOs could not find and implement alternative solutions referred to in the previous paragraph, they may, by forty-two months after the implementation of this methodology in accordance with Article 28(3), together with all other Core TSOs, submit to all Core regulatory authorities a proposal for amendment of this methodology in accordance with Article 9(13) of CACM Regulation. Such a proposal shall include the following:"

Paragraph 9 shall be introduced and be read accordingly:

"9. If one or more Core TSOs plan to apply external constraints, referred to in Article 7 (1), the relevant Core TSOs shall, together with all other Core TSOs, submit to all Core regulatory authorities a proposal for amendment of this methodology in accordance with Article 9(13) of CACM Regulation. Such a proposal shall include the following:

(a) the technical and legal justification for the need to use an external constraint indicating the underlying operational security limits and why they cannot be transformed efficiently into I_{max} and F_{max};

(b) the methodology to calculate the value of external constraints including the frequency of recalculation."

2. Article 23. Calculation of ATCs for SDAC fallback procedure shall be amended in paragraph 3(c) accordingly:

"(c) if defined, the global allocation constraints shall be assumed to constrain the Core net positions pursuant to Article 7(6), and shall be described following the methodology described in Article 18(2). Such constraints shall be adjusted for offered cross-zonal capacities on the remaining non-Core bidding zone borders."

3. Annex 1: Justification of usage and methodology for calculation of external constraints should be amended accordingly

Title of Annex 1 shall be replaced and be read accordingly:

"Annex 1: List of Core TSOs and their justification of usage and methodology for calculation of external constraints"

Text of the Annex 1 shall be replaced and be read accordingly:

"External constraints may be used by the following Core TSOs:
1: Poland – PSE

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

1. Poland:
PSE may use an external constraint to limit the import and export of the Polish bidding zone.
Technical and legal justification
Implementation of external constraints as applied by PSE is related to Integrated Scheduling Process IPS applied in Poland (also called central dispatching model) and the way how reserve capacity is being ensured by PSE. Within the current legal framework in Poland, there is no explicit balancing capacity reserves procurement process – which makes for a significant difference between Poland and other Core CCR countries with respect to the approach to ensure availability of generation reserves. Therefore, for Poland, the only means of ensuring sufficient generation reserves is to use allocation constraints and thus set a limit to how much electricity can be imported or exported in the SDAC. Capacity allocation constraints are a legally prescribed means, defined by CACM Regulation (Art. 23(3) and art. 21(1)(a)(ii) CACM).
In a central dispatching model, in order to balance generation and demand and ensure secure energy delivery, the TSO dispatches generating units taking into account their operational constraints, transmission constraints and reserve capacity requirements. This is realised in an integrated scheduling process as a single optimisation problem called security constrained unit commitment (SCUC) and economic dispatch (SCED).

Integrated Scheduling Process starts after the day-ahead capacity calculation and SDAC and continues until real-time. This means that reserve capacity is not blocked by TSO in advance of SDAC and in effect not removed from the wholesale market and SDAC. However, if balancing service providers (generating units) would already sold too much energy in the day-ahead market because of high exports, they may not be able to provide sufficient upward or downward reserve capacity within the integrated scheduling process.[1]

Within aforementioned integrated scheduling process, generation units connected to the transmission grid are dispatched by PSE with the aim to respect power purchase agreement concluded between the market participants on the wholesale market, while minimizing overall costs of energy supply. When doing so, PSE is obliged to respect power system operation conditions, as well as the technical characteristics of generation units both on the level of individual generation units and on the level of power plants.

Allocation constraints serve thus as a means to limit balancing service providers to sell too much energy in the day-ahead market , so that to ensure and enforce that they will be able to provide sufficient reserve capacity in the integrated scheduling process that is run after the day-ahead market. This limitation cannot be efficiently expressed by translating it into transfer capacities of critical network elements offered to the market. If this limit was to be reflected in cross-zonal capacities offered by PSE in the form of an appropriate adjustment of cross-zonal 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 flow-based approach, this would need to be done on each CNEC in a form of reductions of the RAM. 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 – overestimated on one interconnection and underestimated on the other, or vice versa. Also, such reductions of the RAM would limit cross-zonal exchanges for all bidding zone borders having impact on Polish CNECs (i.e., transit flows), whereas the allocation constraint has an impact only on the import or export of the Polish bidding zone, whereas the trading of other bidding zones is unaffected.

Allocation constrains are applied in DA allocation process, with values determined in D-1, per each hour individually based on generation adequacy analysis for this hour. They are determined for the whole Polish power system, meaning that they are applicable simultaneously for all CCRs in which PSE has at least one bidding zone border (i.e., Core, Baltic and Hansa). This solution is the most efficient application of external constraints. Considering allocation constraints separately in each CCR would require PSE to split global external constraints into CCR-related sub-values, which would be less efficient than maintaining the global value. Moreover, in the hours when Poland is unable to absorb any more power from outside due to violated minimal downward reserve capacity requirements, or when Poland is unable to export any more power due to insufficient upward reserve capacity requirements, Polish transmission infrastructure is still available for cross-border trading between other bidding zones and between different CCRs.

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

Methodology to calculate the value of external constraints

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

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

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

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

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

Where:

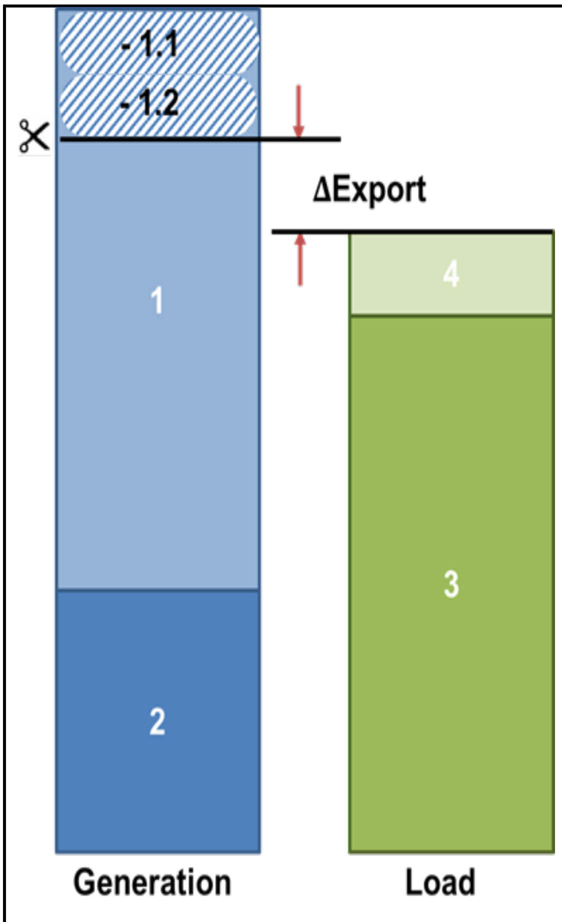
P_{CD}	Sum of available generating capacities of centrally dispatched units as declared by generators1
$P_{CD_{min}}$	Sum of technical minima of available centrally dispatched generating units
P_{NCD}	Sum of schedules of generating units that are not centrally dispatched, as provided by generators (for weather-dependent intermittent renewable generation: 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

[1] 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.

P_{UPres} Minimum reserve for upward regulation

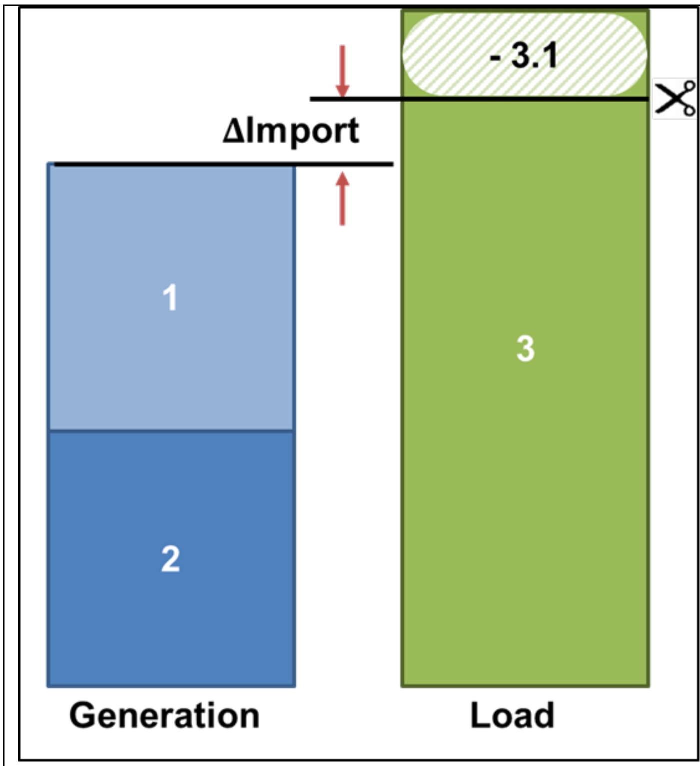
$P_{DOWNres}$ Minimum reserve for downward regulation

For illustrative purposes, the process of practical determination of external constraints in the framework of the day-ahead capacity calculation is illustrated below in Figures 1 and 2. The figures illustrate how a forecast of the Polish power balance for each hour of the delivery day is developed by PSE in the morning of D-1 in order to determine reserves in generating capacities available for potential exports and imports, respectively, for the day-ahead market.
External constraint in export direction is applicable if DExport is lower than the sum of cross-zonal capacities on all Polish interconnections in export direction. External constraint in import direction is applicable if DImport is lower than the sum of cross-zonal capacities on all Polish interconnections in import direction.



1. Sum of available generating capacities of centrally dispatched units as declared by generators, reduced by:
    1.1. Generation not available due to grid constraints
    1.2. Generation unavailability's adjustment resulting from issues not declared by generators, forecasted by PSE due to exceptional circumstances (e.g., cooling conditions or prolonged overhauls)
2. Sum of schedules of generating units that are not centrally dispatched, as provided by generators (for weather-dependent intermittent renewable generation: forecasted by PSE) Demand forecasted by PSE
3. Minimum necessary reserve for up regulation

Figure 1: Determination of external constraints in export direction (generating capacities available for potential exports) in the framework of the day-ahead 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 weather-dependent intermittent renewable generation: forecasted by PSE)
3. Demand forecasted by PSE, reduced by:
   3.1. Minimum necessary reserve for down regulation

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

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

Time periods for which external constraints are applied
As described above, external constraints are determined in a continuous process for each capacity allocation timeframe, so they are applicable for all DA CC MTUs of the respective allocation day."

Article 4
Amendments to postpone post go-live studies

1. Article 5. Definition of critical network elements and contingencies shall be amended accordingly:

Paragraph 5 shall be replaced and be read accordingly:

"5. No later than sixty months after the implementation of this methodology in accordance with Article 28(3), all Core TSOs shall jointly develop a list of internal network elements (combined with the relevant contingencies) to be defined as CNECs and submit it by the same deadline to all Core regulatory authorities as a proposal for amendment of this methodology in accordance with Article 9(13) of the CACM Regulation. After its approval in accordance with Article 9 of the CACM Regulation, the list of internal CNECs shall form an annex to this methodology."

2. Article 9. Generation shift key methodology shall be amended accordingly:

Paragraph 6 shall be replaced and be read accordingly:

"6. Within forty-two months after the implementation of this methodology in accordance with Article 28(3), all Core TSOs shall develop a proposal for further harmonisation of the generation shift key methodology and submit it by the same deadline to all Core regulatory authorities as a proposal for amendment of this methodology in accordance with Article 9(13) of the CACM Regulation. The proposal shall at least include:

(a) the criteria and metrics for defining the efficiency and performance of GSKs and allowing for quantitative comparison of different GSKs; and

(b) a harmonised generation shift key methodology combined with, where necessary, rules and criteria for TSOs to deviate from the harmonised generation shift key methodology."

Article 5
Amendment regarding Advanced Hybrid Coupling

1. Article 11. Calculation of power transfer distribution factors and reference flows shall be amended by updating the definition of parameter $PTDF_{H2,l}$ in equation 5 accordingly:

"$PTDF_{H2,l}$	zone-to-slack $PTDF$ of internal virtual hub H_2 on a CNEC l, with H_2 representing the converter station at the receiving end of the HVDC interconnector H located in bidding zone B"

2. Article 12. Integration of HVDC interconnectors on bidding zone borders of the Core CCR shall be amended by updating paragraph 2 accordingly:

"2. In order to calculate the impact of the cross-zonal exchange over a HVDC interconnector pursuant to paragraph 1 on the CNECs, the converter stations of the cross-zonal HVDC shall be modelled as two internal virtual hubs, which function equivalently as bidding zones. Then the impact of an exchange between A and B, each being either a bidding zone or an external virtual hub, over such HVDC interconnector shall be expressed as an exchange from the bidding zone or external virtual hub A to the internal virtual hub representing the sending end of the HVDC interconnector plus an exchange from the internal virtual hub representing the receiving end of the interconnector to the bidding zone or external virtual hub B:"

3. Article 13. Consideration of non-Core bidding zone borders shall be amended by updating paragraph 3(b) accordingly:

   "(b) In the AHC, the CNECs of the Core Day-ahead capacity calculation region shall not only limit the net positions of Core bidding zones due to exchanges on bidding zone borders of the Core CCR but also the exchanges on bidding zone borders between the Core CCR and respective adjacent bidding zones.
   Core TSOs applying AHC shall introduce at least one external virtual hub for each AHC border, meaning that multiple interconnectors (be it HVDC or AC interconnectors) at a single AHC border can be assigned to separate EVHs."

4. Article 17. Adjustment for minimum RAM shall be amended by updating equation 10 accordingly:

   "$\vec{F}_{0,Core}$ flow per CNEC in the situation without commercial exchanges within the Core CCR and without commercial exchanges on AHC borders"

Article 6
Amendment regarding circular flows challenge around HVDC interconnectors

1. Article 12. Integration of HVDC interconnectors on bidding zone borders of the Core CCR shall be amended by updating paragraph 4 accordingly:

   "4. The internal virtual hubs introduced by this methodology are only used for modelling the impact of an exchange through a HVDC interconnector and no orders shall be attached to these internal virtual hubs in the coupling algorithm. The two internal virtual hubs will have a combined net position of 0 MW, but their individual net position will reflect the exchanges over the interconnector. The flow-based net positions of these internal virtual hubs shall be of the same magnitude, but they will have an opposite sign. $PTDF_{VH\_1,l}$ and $PTDF_{VH\_2,l}$ of all or only a subset of CNECs can be set to zero before the DA market coupling if $\left|PTDF_{VH\_1,l} - PTDF_{VH\_2,l}\right|$ is below a certain threshold. The adjustment is to be done after the NRAO optimization described in Article 16 and before the validation steps described in Article 20. This PTDF threshold shall not exceed 1% and may be applied during the transition period preceding the Go-Live of Core CCR ROSC process, which implements the methodology developed pursuant to Article 76(1) of the SO Regulation. Core TSOs shall report quarterly on the initial setup and any change of this threshold together with the impact which entails from a non-zero threshold and a due justification."

Article 7
Amendment regarding DA FB MC go-live date

1. Article 28. Timescale for implementation shall be amended by updating paragraph 3 accordingly:

“3. The TSOs of the Core CCR shall implement this methodology no later than 8 June 2022. The implementation process, which shall start with the entry into force of this methodology and finish by 8 June 2022, shall consist of the following steps.”

Explanatory document to the third amendment of the Day-Ahead Capacity Calculation Methodology of the Core Capacity Calculation Region

in accordance with article 20ff. of the Commission Regulation (EU) 2015/1222 of 24th July 2015 establishing a guideline on capacity allocation and congestion management

8th December 2023

Table of Content

1. Introduction

The Commission Regulation (EU) 2015/1222 establishing a guideline on Capacity Calculation and Congestion Management ('CACM') requires the development and implementation of a common Day-Ahead Capacity Calculation Methodology ('DA CCM') per Capacity Calculation Region ('CCR').

Based on Article 5 (5), Article 7 (4), Article 8 (7), Article 9 (6) and Article 20 (4) of the currently effective DA CCM for the CCR Core ('Core DA CCM'), the Core TSOs must no later than eighteen months after the implementation of this methodology and in accordance with Article 28 (3), develop a proposal detailing the methodology for coordinated validation, a list of internal network elements (combined with the relevant contingencies) to be defined as CNECs, further harmonisation of the generation shift key methodology, an approach and justification for selecting FRM, and an approach for using allocation constraints, and submit them by the same deadline to all Core regulatory authorities as a proposal for amendment of said methodology in accordance with Article 9 (13) of the CACM Regulation.

In this explanatory document Core TSOs explain the background to the changes included in the proposal for amendment of the Core DA CCM. A track-change version of the Core DA CCM reflecting the proposed changes is shared for informative purpose.

2. Flow Reliability Margin

The implementation of the detailed FRM determination shall be postponed. Core TSOs will prioritize the improvement of data input quality mainly the quality of the common grid model used for DA capacity calculation.

To harmonize the FRM approach, 10% of Fmax shall be used for all CNECs considered during the Core DA capacity calculation. 10% FRM approach shall also reflect hourly changing Fmax values due to e.g., dynamic line rating.

3. Coordinated validation

3.1. Introduction

Coordinated Validation (CV) and Individual Validation (IV) are two complementary steps that coexist in the DACC process. While the IV has been in place since go-live of Core DA CC, the CV shall be gradually introduced. With this proposal for amendment, the "full analysis" as described in Article 20(4) is specified.

The Coordinated Validation takes place with the aim to assess the security of the grid in a coordinated manner. If available remedial actions (RAs) are not sufficient to solve any detected operational security violations, a Coordinated Validation Adjustment (CVA) will be applied. Thanks to its coordinated nature, the cross-zonal benefit of RAs for ensuring cross-zonal capacity (CZC) can be considered in the CV step of the DA CC, in alignment with closer to real-time operational planning processes.

The IV is performed by each TSO based on the outcome of the CV. The IV allows considering local specifics such as additional input data or the assessment of potential market outcomes (so-called circumstances) that have not yet been analysed in the CV but are relevant from a local perspective. The IV also serves as a back-up that enables Core TSOs to validate cross-zonal capacities in case the CV yields no or insufficient results.

In the DA CCM, the IV is specified on a high level. This has given Core TSOs the necessary degrees of freedom to develop and implement IV methods suited to their local or regional needs, while being based on the harmonised principles set out in the DA CCM. For the to-be-implemented CV, the proposal for amendment takes a different approach by specifying CV in a greater level of detail than the IV. This is necessary because in CV, which implements a single method executed centrally by the CCC, the inputs from each TSO have an increased impact on the CZC and operational security throughout the Core CCR. A more detailed specification is also possible because when drafting the proposal for amendment, Core TSOs could build upon their acquired experience from the application and evolution of their IV methods.

Owing to the complexity of a process such as CV, it is neither recommended nor possible to specify in the proposal every input parameter and threshold level that will be used in the CV. Core TSOs will determine the concrete values of such parameters and thresholds by means of experimentation during the implementation phase such that unnecessary capacity reductions are avoided. Based on experience from the application of IV it is also foreseeable that inputs and parameters may have to undergo further adjustment after the initial implementation of the CV. This can become necessary due to the evolution of external factors such as penetration of renewable energy sources, evolution of EU and national rules impacting operational processes, or learnings from practical application of the CV. Core TSOs are deeply convinced that the objectives of Article 3 CACM can be met best by allowing for adaptability, accompanied by transparency. Core TSOs are committed to a transparent process all around the CV, comprising the following elements:

- The initial choice of input and parameter settings will be justified and reported, as set out in Article 20(4b).
- Before the go-live of the CV, Core TSOs will communicate on the parameter settings together with a clear explanation for their initial choice. Core TSOs are looking into possibilities to provide such transparency through SPAICC and/or parallel run like activities, and are happy to further align on a suitable approach in the course of the development of CV prior to its application. Formally, this is covered by the obligation of quarterly reporting on initial settings pursuant to Article 20(4b).
- Changes of parameters will be communicated and justified both ex-ante and via quarterly reports. The relatively short lead time for ex-ante communication allows for sufficient flexibility when an urgent need for updates has been identified, while the ex-post reporting obligation ensures that only duly justifiable changes will be introduced.
- Day-by-day transparency of CV outcomes will be ensured via the already existing

obligations in Article 25 DA CCM.

3.2. Inputs

The scope of this section on inputs is limited to the **additional** process inputs required for the Coordinated Validation step. It is important to note that the section refrains from duplicating existing inputs already incorporated within the DA CC process, such as CGMs, intermediate flow-based domain or GLSKs and therefore also incorporates all initiatives started to improve the quality of those input files.

First, each Core TSO can additionally provide a list of XNEs and scanned Elements (as defined in the ROSC methodology) that should be considered during the coordinated validation step. The consideration of XNEs and scanned elements implies that non-CNECs can be added in the coordinated validation process. It should be noted that the overall objective of coordinated validation can differ in function of the network elements that are considered: for CNECs and XNEs the aim is to solve any overloads to ensure operational security limits are not violated, while for scanned elements the aim is not to create or worsen an already existing overload throughout the process. For all network elements, Core TSOs can increase the maximum permissible power flow compared to the value in the CGM. This, as well as the scanned elements concept, does not mean that higher flow and overloading are deemed physically feasible. Rather, a nominal increase of flow limits for the simulations undertaken during Coordinated Validation can increase the overall consistency of the Coordinated Validation with closer to real-time processes and operational security standards, see also section 3.5.

The possibility of considering network elements in the coordinated validation that are no CNEs is required to ensure operational security. Operational security is a condition of the power system as a whole. It is not possible to operate a part of the power system, e.g. the subset of lines and transformers that are CNEs, if operational security limits are breached on other lines or transformers. This holistic nature of operational security is a framework condition stemming from the laws of physics and thus unchangeable by human will or legislation. It is consequently acknowledged by the Core DA CCM, for instance in Article 20(1)f, containing references to operational security and operational security limits without any restrictions. Moreover, Core TSOs are required to reduce the RAM (by applying CVA) only if all available RAs are not sufficient to avoid the violation of operational security. It is obvious that using *all* RAs to avoid such violations only on *a part* of the power system would create a risk that insufficient RAs would be left to avoid violations on the other part, thus leading to a loss of operational security (as a whole, that is). The Core TSOs would like to point out that the ROSC methodology correctly acknowledges the need to be able and consider any network element to ensure operational security. The DA CC process, of which coordinated validation is a part, has the purpose to define boundaries to cross-zonal exchanges and thus to the range of operational situations that may materialise as input to the later congestion management processes such as ROSC. Therefore, the coordinated validation will anticipate the possibilities of these congestion management processes. Ignoring relevant network elements during coordinated validation could over-stretch the above boundaries such that the network situation arising from the utilisation of the cross-zonal capacities could make it infeasible for ROSC to resolve all operational security violations.

It is important to distinguish between the consideration of network elements which are no CNECs during coordinated validation and the consideration of only CNECs as part of the cross-zonal capacities. The proposed coordinated validation method does not foresee any systematic inclusion of additional CNECs to subsequent process steps and eventually to the cross-zonal capacities. This is an important difference to the chain of ROSC and subsequent ID CC, where it is foreseen to allow for inclusion of certain network elements identified in the former as CNECs to the latter. Although the coordinated validation as part of DA CC aims at mimicking ROSC, it is important to take into account the different framework conditions due to the different positions in the sequence of operational planning processes. During coordinated validation the market outcome is not known yet, such that several circumstances will be validated. At the same time, no RAs have been firmly activated yet. By contrast, later congestion management planning processes such as ROSC are based on the concrete outcome of previous capacity allocation stages and lead to concrete activation of RAs, which subsequent ID CC must take into consideration.

Finally, each Core TSO shall prepare a list of remedial actions (RAs) which can be considered during the coordinated validation. In accordance with Article 20(3) of the DA CCM the provided list shall at least include all expected available RAs. This means the considered RAs are deemed available in subsequent operational planning processes, such as the ROSC process or real time grid operation. The provided RAs shall at least include the categories defined in accordance with Article 22 of the SO Regulation.

In general, cross border relevant RAs like cross border redispatch shall only be considered if operational processes (e.g., reliable cross-border redispatch contracts) are in place that allow for a reliable usage of such RAs before real time grid operation. Also, RAs from non-Core bidding zones can be considered, to the extent these are aligned with the connecting TSO(s).

The real availability of the RAs is partly of stochastic nature, while the RAO is a deterministic model. To not overestimate the available RAs, the probability of RAs being available under the modelling assumptions should be taken into consideration. For example, there is no knowledge about reservoir content of small-scale pumped-hydro storage power plants ahead of real time. Therefore, using such a power plant to the full extent in the remedial action optimisation could endanger operational security. Hence, only a share of their capacity may be considered for coordinated validation. This is one possible example, but other examples might exist as well. Furthermore, time-coupled restrictions are not modelled. To not overstate the real RD potential, the modelled RD potential needs to properly reflect the limitations that exist in system operation.

3.3. Selection of circumstances

During coordinated validation, only the intermediate FB-domain with D-2 reference program and bilateral exchange restrictions domain, but no market results, are available yet. TSOs and the CCC must make sure that market coupling does not lead to infeasible flows in the transmission grid. To deal with the uncertainty imposed by the possible range of market outcomes, the CCC chooses an appropriate set of circumstances according to Article 2 CCM. The choice of circumstances will enable the CCC to conclude that TSOs are able to securely operate the grid in all plausible market outcomes, or otherwise limit the domain by applying CVAs. Therefore, a choice of circumstances must cover a sufficiently large part of the domain within which market results can be realized. On the other hand, the analysed circumstances also must be as close to likely market results as possible in order to infer that market results can be secured. At the same time, the choice of circumstances must make sure that CVAs can be applied effectively in case operational constraints are not met in a particular circumstance (see section 2.3).

Given these trade-offs, the selection of circumstances is expected to be based at least on the following criteria:

1. Each circumstance shall be a plausible market outcome having regard to forecasted Core net positions
2. Each circumstance shall be technically plausible having regard to the power generation potential and load consumption potential per Core bidding zone
3. Each circumstance shall be extreme but feasible in terms of being on or close to the edge of the CZC domain

Regarding 1., the likelihood will be assessed on the basis of the forecasted Core net positions (Net Position Forecast; NPF) using distance measures developed in the course of method implementation. For example, the Euclidian distance to the NPF, the angle difference to NPF, or statistical assessment of historical market outcomes may be used to identify circumstances that cover the range of likely market results sufficiently.

For a number of reasons, it is useful to analyse several circumstances.[1] These include, but are not limited to:

- NPF error;
- Setpoints of controllable network elements such as the ALEGrO DC link.

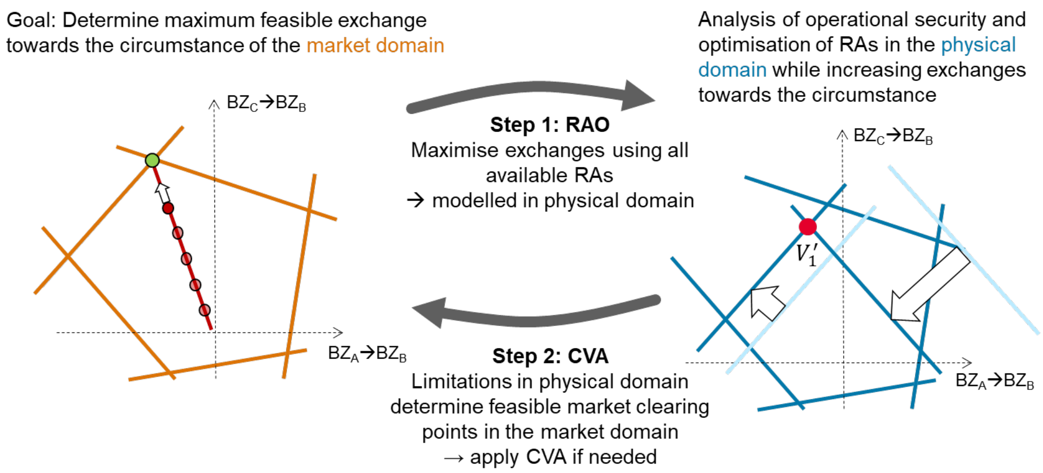
Regarding 2., the technical plausibility of circumstances is ensured by limiting generation shift in such a way that generator limits are respected. In order to prevent generator overload when moving from zero balance towards the circumstance, redispatching of power plants may be used.

Regarding 3., the extremeness of circumstances may be ensured by orienting the choice of circumstances towards the vertices of the CZC domain. However, in order to meet the other two criteria, vertices may be insufficient, and circumstances lying on the linear trajectory between vertex and zero balance might be chosen. Additionally, during the implementation phase, other methods may be evaluated.

[1] Note that if the market outcome was predictable enough to make it sufficient to analyse a single circumstance, no flow-based domain (offering different "market directions") would be needed in the first place.

3.4. Analysis of circumstances

When shifting the Core NPs towards the circumstance, generator limits need to be respected. Thereto, redispatching of generation units within the same bidding zone may be necessary to reach the desired circumstance. In essence, this means that the GLSK used to shift the net position towards the circumstance needs to reflect the physical realities and therefore may differ from the GLSK used to compute the flow-based domain ('the market domain') during capacity calculation. As a consequence of any change in the GLSK, the PTDFs in a quasi-nodal representation ('the physical domain') may differ from those from the CZC domain ('the market domain').



As a consequence of the shifting of net positions towards the circumstance, the redispatch potential of generators that are participating in the shifting must be adjusted. For example, one could consider a generator with $P_{RefProg}$ (injection in the CGM) of 100 MW, and P_{max} (maximum admissible injection) of 220 MW. The redispatch potential of this generator in positive (upward) direction is thus 220 – 100 = 120 MW in the situation modelled in the CGM. Now consider that this generator has a GSK factor of 10 %, and that the net position of the bidding zone where this generator is located changes from 1000 MW at RefProg (in the CGM) to 1300 MW in the considered circumstance. Consequently, the injection of the generator changes to 100 + 10% * (1300 - 1000) = 130 MW in the circumstance. The generator thus injects 30 MW more in the circumstance than in the RefProg (CGM) situation. But its maximum admissible injection is technically still at 220 MW. Therefore, its redispatch potential in positive direction must be decreased from 120 MW to 120 – 30 = 90 MW in the circumstance. Note that at the same time any redispatch potential in negative direction would increase by the same 30 MW.

A power flow and contingency analysis of the grid is necessary to check the loading of the elements in the base case and all relevant contingencies. However, the lists of XNEs, as described in chapter 3.2, may be adapted to exclude specific elements from further analysis.

The TSOs may define the list of scanned elements. The scanned elements shall be network elements (any possible element that is excluded from the CNEC list and is included in

CGM), which shall be monitored during the CV process and limit the additional (over)loading stemming from application of the remedial actions. The level of the additional loading shall be defined by threshold based on experimentation.

3.5. Remedial action optimisation

This section refers to Art. 20(4e)f of the amended DA CCM.

The remedial action optimisation (RAO) is executed subsequently for each considered circumstance. It serves to check if in the event the market outcome is equal to the considered circumstance, Core TSOs and optionally technical counterparties can facilitate cross-zonal exchange leading to these net positions by applying RAs in a coordinated manner to maintain operational security. In case this is not possible for a given circumstance, the CZC domain must be restricted to limit the set of realisable net positions. The objective of the RAO is to compute the least required reduction of the domain. This is achieved by determining a set of net positions as close as possible to the circumstance, using all available RAs, such that operational security is maintained. If the circumstance can be facilitated without operational security violations, the domain is not reduced.

The RAO simulates the impact of shifts in net positions in accordance with section 3.4. In addition, it models the impact of RAs on the flows on all considered network elements with contingencies. This allows to optimise the net positions (to make them as similar as possible, if not equal, to the circumstance) while selecting the most suitable set of RAs among the available RAs.

The choice of RAs for the RAO shall be consistent with what TSOs have at hand in close-to-real-time congestion management planning processes. This comprises in particular ROSC, but also other processes that are in place on a local or subregional level. In other words, the RAO of the coordinated validation mimics the processes used to identify the RAs that will be actually activated, to anticipate the beneficial effect that these processes (and thus the activated RAs) would have in the simulated situations.

One the one hand, the coordinated validation would overestimate the need for capacity reduction via CVA if it failed to consider the aforementioned benefits. On the other hand, it would underestimate the need for CVA if it assumed a higher degree of coordination than the one applied in practice. This has two implications. Firstly, the inputs and parameters will, therefore, evolve over time along with the evolution of the congestion management planning processes, in particular ROSC. Secondly, while for complexity and performance reasons it will not be possible to explicitly model every local process, it is important to at least implicitly consider their benefits. To achieve this, the TSOs shall have the possibility to adjust their inputs. For example, by ignoring branches or allowing a certain degree of overload on some branches, TSOs can implicitly reflect the benefit of their local procedures even if these are not explicitly modelled in the RAO.

The so-called sharing rules constitute another aspect by which TSOs can reflect their operational planning principles and/or the degree of cross-zonal coordination closer to real-time. When an RA of a given TSO is shared with other TSOs, this means that the benefit of the RA on the loading of the other TSOs' network elements is taken into account. While the physical effect of an RA always "happens" and by principle can never be ignored, sharing denotes if other TSOs are aware and rely on the activation of the RA from another TSO. An example of a lack of awareness is a local process, where a TSO applies an RA for the sake of its own grid while neighbouring TSOs are not involved (and thus not aware). An example of non-reliance on foreign RAs is when a TSO applies curative RAs, which are activated only after occurrence of a contingency, while its neighbouring TSO follows an operating principle by which RAs must be activated pre-fault (i.e., preventive RAs only). The RAO shall be able to model preventive and curative RAs including full or partial sharing of the latter, to cover the range of actual operating regimes.

The RAO implements a model of the real power system, which is by principle an abstraction from reality and, as every model, subject to imperfections. To reach the objective of maintaining operational security while avoiding CZC domain reduction as much as possible, the RAO will allow the setting of parameters that on the one hand help avoiding unnecessary reductions due to model restrictions and on the other hand help avoiding "too perfect" results that cannot be implemented in practice.

For example, an increase of net positions might have a very low but positive impact on the loading of a network element, which might lead to unreasonably large reduction of CZC for a small reduction of the loading. Such effect might be overcome by ignoring very low impacts (so-called sensitivities), especially when these are deemed to be insignificant with regards to the model and computation accuracy. Also, the selection of network elements, their possible designation as scanned elements and the possible adaptation of their maximum loading for the RAO (see sections 3.2 and 3.4) are means to bridge the gap between the imperfect RAO model and operational reality.

The RA potential is not only defined by the individual RAs, but might also be subject to practical limitations of the local operational processes, e.g., the number of RAs that can be activated in a constrained period of time close to real-time. For example, there may be 100 topological RAs and 100 redispatch resources available. However, "available" then only means that *any* of these can be activated, but not *all* of them at once. If the RAO was allowed to treat all RAs independently, the availability of RAs as a whole would be overstated. To avoid this, the optimisation can be constrained by imposing limits on the number of simultaneously activated RAs or on the total amount of redispatch. Such limitations could be differentiated per RA type, per bidding zone, per TSO, etc., in order to reflect the practical limitations that the TSOs are facing.

The objective of the RAO has been set out at the beginning of this section. This must be distinguished from the so-called objective function, which is the mathematical formula whose value shall be formally maximised or minimised by the RAO. In order to be able to determine if the circumstance can be realised while maintaining operational security and, if it cannot be entirely realised, determine a realisable set of net positions as close as possible to the circumstance, it is not sufficient to strictly model the cross-zonal exchanges of the circumstance and at the same time strictly require the fulfilment of operational security requirements. Namely, this could lead to infeasibility, i.e., yield a too simple yes/no result. A common way to overcome this is the introduction of so-called soft constraints, which are mathematically formulated as components of the objective function. Therefore, the objective function may be specified to minimize the extent of operational security violations and/or to maximize the extent to which the cross-zonal exchanges match the circumstance. With this approach one avoids a need for iterative "probing" of net positions at or close to the circumstance, since the optimisation yields the realisable net positions closest to the circumstance in a single run.

If a circumstance cannot be realised, CVA is needed. CVA is determined in a separate step after the RAO. This is because the RAO is performed in the realm of the physical domain. Overloads on network elements (in particular, on CNECs) in the physical domain are not equal to the required reduction of RAM in the market domain. The link between the two domains is achieved via the net positions: Those net positions that are feasible (as close as possible to the analysed circumstance) can be mapped as a potential market clearing point in the market domain (i.e., the CZC domain). The area "beyond" this point cannot be safely provided to the SDAC and must thus be eliminated from the domain. This can be achieved by imposing CVA on a suitable subset of CNECs. When doing so, a minimum capacity floor is always maintained, i.e., if CVA would push RAM below this floor, CVA is capped.

It might happen that a TSO, when checking the Coordinated Validation results, finds out that all or part of the results are of bad quality. For instance, bad input quality might have led to overestimation of CVA. Therefore, a TSO may reject parts or all of the Coordinated Validation results, however with clear rules and limitations. The TSO must present a justification for the rejection. It must align with the other TSOs and the CCC, and an attempt must be made to resolve the reason for the rejection. In any case, only the entire results of a circumstance (or of several circumstances) can be rejected. It is not allowed to reject a subset of CVA for a given circumstance, because all CVAs together protect the grid from operational security violations in that circumstance.

3.6. Dissemination of results

In the context of the validation processes (individual and coordinated), it is essential to execute individual validation subsequent to the coordinated validation process. This sequence ensures that the results of individual validation and coordinated validation remain distinct and coherent, without overlapping and/or contradicting each other. When coordinated validation identifies any remaining overload, for example when a coordinated validation adjustment is capped, it is crucial that this is known when individual validation starts. This ensures that individual validation can assess whether local measures should be taken into account, or if additional adjustments through the individual validation step are required.

Also, for efficiency purposes, coherence and well aligned processes are essential, to avoid any duplicate or obsolete checks.

Furthermore, it is important to continuously improve the efficiency of the validation process and its tools. Therefore, a feedback loop will be put in place to monitor and analyse the outcomes of coordinated validation by Core TSOs and/or the CCC. This includes a thorough examination of whether non-CNECs cause a coordinated validation adjustment.

Finally, when it comes to reporting, Core TSOs and the CCC shall provide transparent reporting to stakeholders, according Article 27. In this reporting, each CVA application will be published together with its relevant CNEC, the value of the CVA, the circumstance that led to the CVA application and the justification for the CVA application.

4. Allocation constraints

4.1. General changes in CCM

The scope of this section refers to a change in methodology for allocation constraints. Based on the information that ELIA and TTN will not utilize external constraints, they will be excluded from the CCM regarding both Article 7 and Annex 1.

On the other hand, PSE intends to continue using allocation constraints. Due to this fact and in order to make the provisions of Article 7 more general, the list of Core TSOs that can use allocation constraints has been removed and this list has been moved to Annex 1 which contains detailed technical and legal justification for the need to continue using allocation constraints. It is hence proposed to extend the transitional period for another two years. Moreover, minor changes in the detailed methodology for calculating the values for allocation constrains in a given MTU have been also introduced in Annex 1.

Additionally, provisions were proposed indicating to Core TSOs the conditions that must be met in order for a given Core TSO to apply for the possibility of using allocation constraints. It is proposed that a request to use allocation constraints by any Core TSO (other than those listed in Annex 1) should be preceded by the submission of a proposal for amendment of the methodology to all Core national regulatory authorities, along with the submission of an appropriate explanation of the need to use the AC and the frequency of its calculation.

4.2. Reasons why PSE intends to continue using allocation constraints

Disclaimer: *PSE maintains that allocation constraints is a critical means to ensure secure operation of the Polish power system. Core TSOs other than PSE are not able to validate the legitimacy of PSE's need for the allocation constraints.*

Operational experience gathered over the previous two years has proven that allocation constraints are an effective measure to maintain the transmission system within operational security limits and cannot be transferred efficiently into maximum flows on critical network elements, as prescribed by provisions of the CACM Art. 23(3). Allocation constraints allow to ensure availability of sufficient balancing capacity reserves in Poland, so that no case of insecure operation that could not have been resolved by operational means has been experienced in Poland.

Considering the fact, that Poland operates under Central Dispatch regime, the approach to ensure availability of generation reserves applied in Poland differs from the approach applied in other Core countries. Given current legal framework in Poland, PSE as a TSO is responsible for dispatching generation units connected to the transmission grid. When doing so, PSE is obliged to respect power system operation conditions, as well as the technical characteristics of generation units both on the level of individual generation units and on the level of power plants. Moreover, there is no explicit balancing capacity reserves procurement process in Poland, and hence the only means of ensuring sufficient reserves capacity is to use allocation constraints.

The impact of allocation constraints was analysed and described in “Core DA CC 2022 report”. The report shows that the largest social welfare impact concerns Poland (order of magnitude higher than for other Core countries), resulting in a loss of social welfare in Poland due to application of allocation constraints. However, as demonstrated in the report, this apparent loss of social welfare in Poland avoids much higher welfare losses when secure operation of the Polish power system is threatened and extraordinary measures must be applied to mitigate this threat (i.e. demand curtailment or RES curtailment). Due to the fact that no alternatives to using allocation constraints have been identified as plausible to be implemented until two years following implementation of flow-based in Core, which could both have lower overall cost while maintaining the similar level of operational security and which would not require a major overhaul of the market design, PSE aims at extending the period of using AC by additional two years.

Currently, balancing market in Poland is undergoing a significant redesign, aiming at strengthening balancing energy price signals and creating stronger incentives for balanced positions of balancing responsible parties. In combination with the planned market-based process for procuring balancing capacity reserves, this should improve the ability of Polish transmission system operator to manage the secure operation of the Polish power system and limit the need for allocation constraints of cross-border market coupling process.

PSE expects that these new Terms and Conditions for Balancing will be implemented mid 2024. NRA approval for the proposed Terms and Conditions for Balancing is expected to take place in Q3/Q4 2023, giving market participants and PSE the required time to introduce and test all needed changes in the IT systems. However, this is a very significant change for the whole Polish market and such reform must be well prepared and tested against security requirements. The steps undergone on legal side to pave the way for this are as follows (among other):

- Decree of the Ministry for Climate and Environment on the detailed conditions for power system operation has been adopted on 28 April 2023, after having been notified with the European Commission. This is the most significant reform of this comprehensive legal act since 2007 (https://www.gov.pl/web/klimat/rozporzadzenie-ministra-klimatu-i-srodowiska-ws-szczegolowych-warunkow-funkcjonowania-systemu-elektroenergetycznego-opublikowane).

- Based on the abovementioned updated legal act, PSE has launched public consultation of the new updated Terms and Conditions for Balancing ("Warunki Dotyczące Bilansowania" – WDB), stemming from EBGL. Consultation run from 22 February till 5 May 2023. On 30 June 2023, PSE provided a finalized proposal for updated Terms and Conditions for Balancing after public consultation. The process for approval of this document by Polish NRA is currently undergoing and its result is expected soon.
- Update of the Polish Grid Code, adjusting its text to the adopted Decree of the Ministry for Climate and Environment on the detailed conditions for power system operation as well as to the proposed Terms and Conditions for Balancing, has been already sent to Polish NRA for approval and it is planned to be introduced in force together with the new updated Terms and Conditions for Balancing.

Finally, it is very important to highlight, that after successful completion of the changes in the Polish balancing market, real-live operational experience from this market redesign must be collected. It is therefore impossible for PSE to make any firm commitment with respect to the future application of allocation constraints. PSE is unable to give up the only tool that is able to ensure secure operation of the Polish power system without having a proven and reliable alternative. Hence the period of 2 years is indeed necessary.

Technical and legal justification

Implementation of external constraints as applied by PSE is related to Integrated Scheduling Process ISP applied in Poland (also called central dispatching model) and the way how reserve capacity is being ensured by PSE. Within the current legal framework in Poland, there is no explicit balancing capacity reserves procurement process – which makes for a significant difference between Poland and other Core CCR countries with respect to the approach to ensure availability of generation reserves. Therefore, for Poland, the only means of ensuring sufficient generation reserves is to use allocation constraints and thus set a limit to how much electricity can be imported or exported in the SDAC. Capacity allocation constraints are a legally prescribed means, defined by CACM Regulation (Art. 23(3) and art. 21(1)(a)(ii) CACM).

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

Integrated Scheduling Process starts after the day-ahead capacity calculation and SDAC and continues until real-time. This means that reserve capacity is not blocked by TSO in advance of SDAC and in effect not removed from the wholesale market and SDAC.

However, if balancing service providers (generating units) would already sell too much energy in the day-ahead market because of high exports, they may not be able to provide sufficient upward or downward reserve capacity within the integrated scheduling process.[2]

Within aforementioned integrated scheduling process, generation units connected to the transmission grid are dispatched by PSE with the aim to respect power purchase agreement concluded between the market participants on the wholesale market, while minimizing overall costs of energy supply. When doing so, PSE is obliged to respect power system operation conditions, as well as the technical characteristics of generation units both on the level of individual generation units and on the level of power plants.

Allocation constraints serve thus as a means to limit balancing service providers to sell too much energy in the day-ahead market, so that to ensure and enforce that they will be able to provide sufficient reserve capacity in the integrated scheduling process that is run after the day-ahead market. This limitation cannot be efficiently expressed by translating it into transfer capacities of critical network elements offered to the market. If this limit was to be reflected in cross-zonal capacities offered by PSE in the form of an appropriate adjustment of cross-zonal 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 flow-based approach, this would need to be done on each CNEC in a form of reductions of the RAM. 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 – overestimated on one interconnection and underestimated on the other, or vice versa. Also, such reductions of the RAM would limit cross-zonal exchanges for all bidding zone borders having impact on Polish CNECs (i.e. transit flows), whereas the allocation constraint has an impact only on the import or export of the Polish bidding zone, whereas the trading of other bidding zones is unaffected.

Allocation constrains are applied in DA allocation process, with values determined in D-1, per each hour individually based on generation adequacy analysis for this hour. They are determined for the whole Polish power system, meaning that they are applicable simultaneously for all CCRs in which PSE has at least one bidding zone border (i.e., Core, Baltic and Hansa). This solution is the most efficient application of external constraints. Considering allocation constraints separately in each CCR would require PSE to split global external constraints into CCR-related sub-values, which would be less efficient than maintaining the global value. Moreover, in the hours when Poland is unable to absorb any more power from outside due to violated minimal downward reserve capacity requirements, or when Poland is unable to export any more power due to insufficient upward reserve capacity requirements, Polish transmission infrastructure is still available for cross-border trading between other bidding zones and between different CCRs.

Methodology to calculate the value of external constraints

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

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

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

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

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

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

Where:

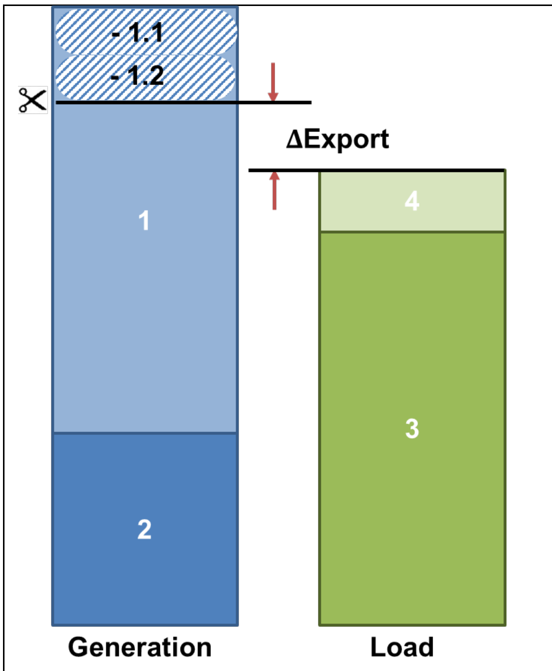
P_{CD}	Sum of available generating capacities of centrally dispatched units as declared by generators[3]
$P_{CD_{min}}$	Sum of technical minima of available centrally dispatched generating units
P_{NCD}	Sum of schedules of generating units that are not centrally dispatched, as provided by generators (for weather-dependent intermittent renewable generation: forecasted by PSE)
P_{NA}	Generation not available due to grid constraints (both planned outage and/or anticipated congestions)
P_{ER}	Generation unavailability's adjustment resulting from issues not declared by generators, forecasted by PSE due to exceptional circumstances (e.g., cooling conditions or prolonged overhauls)
P_L	Demand forecasted by PSE
P_{UPres}	Minimum reserve for upward regulation
$P_{DOWNres}$	Minimum reserve for downward regulation

For illustrative purposes, the process of practical determination of external constraints in the framework of the day-ahead capacity calculation is illustrated below in Figures 1 and 2. The figures illustrate how a forecast of the Polish power balance for each hour of the

[3] 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.

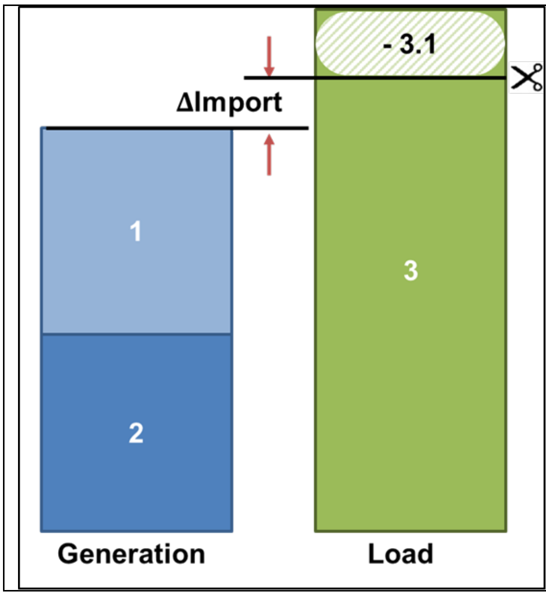
delivery day is developed by PSE in the morning of D-1 in order to determine reserves in generating capacities available for potential exports and imports, respectively, for the day-ahead market.

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



1. Sum of available generating capacities of centrally dispatched units as declared by generators, reduced by:
   1.1 Generation not available due to grid constraints
   1.2 Generation unavailability's adjustment resulting from issues not declared by generators, forecasted by PSE due to exceptional circumstances (e.g., cooling conditions or prolonged overhauls)
2. Sum of schedules of generating units that are not centrally dispatched, as provided by generators (for weather-dependent intermittent renewable generation: forecasted by PSE)
3. Demand forecasted by PSE
4. Minimum necessary reserve for up regulation

Figure 1: Determination of external constraints in export direction (generating capacities available for potential exports) in the framework of the day-ahead 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 weather-dependent intermittent renewable generation: forecasted by PSE)

3 Demand forecasted by PSE, reduced by:
3.1 Minimum necessary reserve for down regulation

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

Frequency of re-assessment

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

Time periods for which external constraints are applied

As described above, external constraints are determined in a continuous process for each capacity allocation timeframe, so they are applicable for all DA CC MTUs of the respective allocation day.

5. Circular flows around HVDC interconnectors

Disclaimer: *In general, Core TSOs do not see the usage of PTDF threshold as an adequate way forward as it implies neglecting some physical effects in the grid. Therefore, the PTDF-Threshold for the evolved flow-based Virtual Hubs shall only be applied if there is no adequate alternative solution to solve given issues of circular flows in the proximity of the evolved flow-based Virtual Hubs. A PTDF threshold is not considered for any other use case.*

The evolved flow-based method described in Article 12 has been introduced with the commissioning of the ALEGrO HVDC link between Belgium and Germany. The DA-schedule of the ALEGrO HVDC is determined during DA market coupling with the aim of maximizing the overall social welfare. This leads to very frequent undesired behaviour during real-time grid operation as the ALEGrO setpoint is chosen to relieve very distant network elements with a very low sensitivity to ALEGrO exchanges in order to maximize the social welfare during DA Market Coupling. The slight relief of a very distant market limiting CNEC is achieved by ALEGrO setpoint which lead to circular flows and full loading in the surrounding area of ALEGrO HVDC interconnector. In real-time grid operation the high loading of the surrounding area might lead to n-1 violations, application of (costly) remedial actions and can impact intraday capacity in a negative way.

In order to prevent such a behaviour of existing and future HVDC Interconnectors on Core bidding zone borders, Core TSOs aim to introduce a zone-to-zone PTDF threshold for virtual hubs in the context of the Evolved flow-based method. Analysis showed that introducing an ALEGrO PTDF-threshold of 0.5% prevent this undesired impact.

After approval of the RfA the PTDF threshold will get a start value of 0 which equates no threshold being implemented. Core TSOs may alter the threshold if they deem it necessary or after running a parameter study with the objective of finding the best trade-off between maximizing operational security and maximizing economical social welfare. However, the threshold shall not exceed 1%. Core TSOs shall report on a quarterly basis on any change of the threshold.

The quarterly report shall also include the economic social welfare deviation which was provoked by the above-described threshold.

A change of the ALEGrO setpoint after DA Market Coupling requires coordination between all affected TSOs namely TenneT NL, RTE, Elia and Amprion as the change of the setpoint impacts the loading in the surrounding AC grid. At the moment there is no coordinated process in place which would allow a frequent deviation from ALEGrO DA schedule. When Core CCR ROSC process will be in operation, a coordinated process between all affected TSOs will exist, and consequently the ALEGrO PTDF-threshold for virtual hubs is no longer required and will be removed.

6. Advanced Hybrid Coupling

Following the Core NRAs' decision on the 2nd amendment of the Core DA CCM on 29 November 2023, a few corrections are proposed as part of the 3rd request for amendment. These corrections refer to the following articles or paragraphs:

- Article 11(5), definition of $PTDF_{H2,l}$: Change of *'sending'* to *'receiving'* to clarify that $PTDF_{H2,l}$is the $PTDF$ on the receiving end of the internal virtual hub.
- Article 12(2) main paragraph: Remove *'A and B or external virtual hubs'* to streamline the sentence and avoid double-mentioning of A and B.
- Article 13(3)(b): rewording *', meaning that multiple interconnectors (be it HVDC or AC interconnectors) at a single AHC border can be assigned to separate EVHs.'* to not limit the concept by, e.g., to excluding the case, where there is HVDC interconnector(s) and AC interconnector(s) in parallel on the same AHC border.
- Article 17(2), definition of $\vec{F}_{0,Core}$: Add *'borders'* at the end of the sentence to make a complete and meaningful sentence.