ACER Decision on Core CCM: Annex Ia

# Day-ahead capacity calculation methodology of the Core capacity calculation region

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

**21 February 2019**

Inserted Cells

# ~~Core CCR TSOs' regional design of the day-ahead common capacity calculation methodology in accordance with Article 20ff. of Commission Regulation (EU) 2015/1222 of 24 July 2015~~

~~4th of June 2018~~

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~~TSOs OF THE CORE CCR, TAKING INTO ACCOUNT THE FOLLOWING,~~

## Whereas

(1) ~~This document is the methodology developed by the transmission system operators of the Core CCR (hereafter referred to as "Core TSOs") regarding the common~~This document sets out the capacity calculation methodology in accordance with Article 20ff. of Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on Capacity Allocation and Congestion Management (hereafter referred to as the "CACM Regulation"). This methodology is hereafter referred to as the "day-ahead ~~common~~ capacity calculation methodology".

(2) The day-ahead ~~common~~ capacity calculation methodology takes into account the general principles and goals set in the CACM Regulation as well as in Regulation (EC) No 714/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the network for cross-border exchanges in electricity (hereafter referred to as "Regulation (EC) No 714/2009"). The goal of the CACM Regulation is the coordination and harmonisation of capacity calculation and allocation in the day-ahead and intraday cross-border markets. It sets, for this purpose, the requirements to ~~develop~~establish a day-ahead ~~common~~ capacity calculation methodology to ensure efficient, transparent and non-discriminatory capacity allocation.

(3) According to Article 9(9) of the CACM Regulation, the expected impact of the day-ahead ~~common~~ capacity calculation methodology on the objectives of the CACM Regulation has to be described and is presented below. ~~The proposed day-ahead common capacity calculation methodology generally contributes to the achievement of the objectives of Article 3 of the CACM Regulation.~~

(4) The day-ahead ~~common~~ capacity calculation methodology serves the objective of promoting effective competition in the generation, trading and supply of electricity (Article 3(a) of the CACM Regulation) since ~~the same day-ahead common~~it ensures that the cross-zonal capacity is calculated in a way that avoids undue discrimination between market participants and since the same day-ahead capacity calculation methodology will apply to all market participants on all respective bidding zone borders in the Core CCR, thereby ensuring a level playing field amongst ~~respective~~ market participants. Market participants will have access to the same reliable information on cross-zonal capacities and allocation constraints for day-ahead allocation, at the same time and in a transparent way.

(5) The day-ahead ~~common~~ capacity calculation methodology contributes to the optimal use of transmission infrastructure and to operational security (Article 3(b) and (c) of the CACM Regulation) since the flow-based ~~mechanism~~approach aims at providing the maximum available capacity to market participants on the day-ahead timeframe within the operational security limits.

(6) The day-ahead ~~common~~ capacity calculation methodology contributes to avoiding that cross-zonal capacity is limited in order to solve congestion inside control areas by (i) defining clear criteria ~~for cross-zonal relevance of critical~~under which the network elements located inside bidding zones can be considered as limiting for capacity calculation, and ~~contingencies and~~(ii) ensuring that a minimum ~~margin~~share of the capacity is made available for commercial exchanges while ensuring operational security (Article 3(a) to (c) of the CACM ~~regulation~~Regulation and ~~Article~~Point 1~~.~~(7) of Annex I to the Regulation (EC) 714/2009).

(7) The day-ahead ~~common~~ capacity calculation methodology serves the objective of optimising the allocation of cross-zonal capacity ~~in accordance with~~ (Article 3(d) of the CACM Regulation), since ~~the common capacity calculation methodology~~it is using the flow-based approach, which ~~provides optimal~~optimises the way in which the cross-zonal capacities are allocated to market participants, and since it facilitates the efficiency of congestion management by comparing the capacity allocation

with other congestion management alternatives, such as the application of remedial actions, bidding zone reconfiguration and network investments.

(8) The day-ahead~~ common~~ capacity calculation methodology is designed to ensure a fair and non-discriminatory treatment of TSOs, ~~NEMOs,~~nominated electricity market operators ('NEMOs'), the Agency, regulatory authorities~~,~~ and market participants (Article 3(e) of the CACM Regulation) since the day-ahead ~~common ~~capacity calculation methodology ~~is performed with transparent rules~~has been developed and adopted within a process that ~~are approved by~~ensures the involvement of all relevant ~~national regulatory authorities~~stakeholders and independence of the approving process.

(9) ~~Regarding the objective of transparency and reliability of information (Article 3(f) of the CACM Regulation), the day-ahead common~~The day-ahead capacity calculation methodology determines the main principles and main processes for the day-ahead timeframe. ~~The day-ahead common capacity calculation methodology enables ~~It requires that the Core TSOs ~~to ~~provide market participants with~~ the same~~ reliable information on cross-zonal capacities and allocation constraints for day-ahead allocation in a transparent way and at the same time. This includes information on all steps of capacity calculation and regular reporting on specific processes within capacity calculation. The day-ahead capacity calculation methodology therefore contributes to the objective of transparency and reliability of information (Article 3(f) of the CACM Regulation).

(10) ~~The day-ahead common~~The day-ahead capacity calculation methodology provides requirements for efficient use of existing electricity infrastructure and facilitates competitive and equal access to transmission infrastructure in particular in case of congestions. This provides a long-term signal for efficient investments in transmission, generation and consumption, and thereby contributes to the efficient long-term operation and development of the electricity transmission system and electricity sector in the Union (Article 3(g) of the CACM Regulation).

~~(10)~~(11) The day-ahead capacity calculation methodology also contributes to the objective of respecting the need for a fair and orderly market and price formation (Article 3(h) of the CACM Regulation) by making available in due time the information about cross-zonal ~~capacity~~capacities to be released in the market, by maximising the available cross-zonal capacities and by ensuring a backup solution for the cases where capacity calculation fails to provide flow-based parameters.

~~(11)~~(12) ~~When preparing the~~The day-ahead ~~common ~~capacity calculation methodology~~, Core TSOs took careful consideration of the objective of creating~~ facilitates a level playing field for NEMOs (Article 3(i) of the CACM Regulation) since all NEMOs and all their market participants will ~~have~~face the same rules and non-discriminatory treatment (including timings, data exchanges, results formats etc.) within the Core CCR.

~~(12)~~(13) Finally, the day-ahead~~ common~~ capacity calculation methodology contributes to the objective of providing non-discriminatory access to cross-zonal capacity (Article 3(j) of the CACM Regulation) by ensuring a transparent and non-discriminatory approach towards facilitating cross-zonal capacity allocation.

~~(13)~~(14) In conclusion, the day-ahead ~~common ~~capacity calculation methodology contributes to the general objectives of the CACM Regulation to the benefit of all market participants and electricity end consumers.

(15) The day-ahead capacity calculation methodology is structured into three stages: (i) the definition and provision of capacity calculation inputs by the Core TSOs, including the underlying principles and calculation methods for these inputs, (ii), the capacity calculation process by the coordinated capacity calculator in coordination with the Core TSOs, and (iii) the capacity validation by the Core TSOs in coordination with the coordinated capacity calculator. The roles and responsibilities of the Core TSOs and of the coordinated capacity calculator need to be clearly defined.

~~(14)~~ The day-ahead capacity calculation methodology is based on forecast models of the transmission system. The inputs are created two days before the electricity delivery date with the available knowledge at that time. Therefore, the outcomes are subject to inaccuracies and uncertainties. The aim of the reliability margin is to cover a level of risk induced by these forecast errors.

~~(15) SUBMIT THE FOLLOWING DAY-AHEAD COMMON CAPACITY CALCULATION METHODOLOGY TO REGULATORY AUTHORITIES OF THE CORE CCR:~~

~~(16)~~

(16)

(17) The methodology applies temporary solutions for reliability margins, generation shift keys and allocation constraints. As regards reliability margins, the first real calculation can only be done after some operational experience is gained with the application of this methodology. For generation shift keys, TSOs also need some operational experience in order to be able to improve them. The final definition of these capacity calculation inputs should therefore be reviewed and redefined if needed after the effective implementation of this methodology.

(18) Some operational security limits can be transformed into limitations on active power flows on critical network elements, whereas some other cannot and may be modelled as allocation constraints. Some of the operational security limits (*inter alia* frequency, voltage and dynamic stability) depend on the level of production and consumption in a given bidding zone, and these cannot be controlled by active power flow on critical network elements. Thus, specific limitations on production and consumption are needed, and these are expressed as maximum import and export constraints of bidding zones. External constraints are therefore a type of allocation constraints limiting the total import and export of a bidding zone. Nevertheless, given the lack of proper legal and technical justification for these allocation constraints, their application is considered in this methodology as a temporary solution in order to allow TSOs to explore alternative solutions to the underlying problems. If none of the alternative solutions is more efficient to tackle the underlying problems, the concerned TSOs may propose to continue applying them.

(19) To avoid undue discrimination between internal and cross-zonal exchanges (and the underlying discrimination between market participants trading inside or between bidding zones), this methodology introduces two important measures. The first measure aims to limit the situations where cross-zonal exchanges are limited by congestions inside bidding zones. The second measure aims to minimise the degree to which the flows resulting from exchanges inside a bidding zone on network elements located inside that zone (i.e. internal flows) or on network elements on the borders of bidding zones and inside neighbouring bidding zones (i.e. loop flows) are reducing the available cross-zonal capacity.

(20) In the zonal congestion management model established by the CACM Regulation, bidding zones should be established such that physical congestions occur only on network elements located on the borders of such bidding zones. The network elements located within bidding zones should therefore *a priori* not limit cross-zonal capacity and should therefore not be considered in capacity calculation. Nevertheless, at the time of adoption of this methodology, some network elements located inside the Core bidding zones are often congested and therefore TSOs need some transition period to shift gradually from limiting cross-zonal capacity, as the main method to address these internal congestions, to other methods in which internal congestions limit cross-zonal capacity only when this is the most efficient solution considering other alternatives (such as remedial actions, reconfiguration of bidding zones or network investments). Only in case those alternatives are proven inefficient, TSOs should be able to continue addressing internal congestions by limiting cross-zonal capacity beyond the transition period.

(21) In highly meshed electricity networks, exchanges inside bidding zones create flows through other bidding zones (i.e. loop flows) which can significantly reduce the capacity for trading between

bidding zones. To avoid undue discrimination between internal and cross-zonal exchanges, this methodology aims to minimise the negative impact of these loop flows. This is first achieved by allowing TSOs to define initial settings of remedial actions with the aim to reduce the loop flows on their interconnectors. These remedial actions are then further coordinated within capacity calculation process with a constraint not to increase loop flows beyond a defined threshold. This measure is needed to avoid undue discrimination in situations where coordination of remedial actions would significantly increase loop flows in order to address congestions within bidding zones. Since this first measure is optional for TSOs, the second measure aims to ensure that the final outcome of the capacity calculation meets the agreed thresholds for available cross-zonal capacities, where such thresholds are established by limiting the number and size of variables which reduce cross-zonal capacities. For this purpose, at least 70% of the technical capacity of critical network elements considered in capacity calculation should be available for cross-zonal trade in all CCRs in the day-ahead timeframe. Nevertheless, in case of exceptions or deviations granted in accordance with the relevant Union legislation, the target value of 70% may temporally be replaced by a linear trajectory.

(22) Despite coordinated application of capacity calculation, TSOs remain responsible for maintaining operational security. For this reason they need to validate the calculated cross-zonal capacities to ensure that they do not violate operational security limits. This validation is first performed in a coordinated way to verify whether a coordinated application of remedial actions can address possible operational security issues. Finally, each TSO may individually validate cross-zonal capacities. Both validation steps may lead to reductions of cross-zonal capacities below the values needed to avoid undue discrimination. Thus transparency, monitoring and reporting, as well as the exploration of alternative solutions are needed in case of reductions of cross-zonal capacities.

(23) Transparency and monitoring of capacity calculation are essential for ensuring its efficiency and understanding. This methodology establishes significant requirements on TSOs to publish the information required by stakeholders to analyse the impact of capacity calculation on the market functioning. Furthermore, additional information is required to allow regulatory authorities to perform their monitoring duties. Finally, the methodology establishes significant reporting requirements in order for stakeholders, regulatory authorities and other interested parties to verify whether the transmission infrastructure is operated efficiently and in the interest of consumers.

# TITLE 1 - General ~~Provision~~provisions

## Article 1. ~~Article 1~~ Subject matter and scope

The day-ahead ~~common~~ capacity calculation methodology shall be considered as a Core ~~TSOs~~TSOs' methodology in accordance with Article 20ff. of the CACM Regulation and shall cover the day-ahead ~~common~~ capacity calculation methodology for the Core CCR bidding zone borders.

## Article 2. ~~Article 2~~ Definitions and interpretation

1. For the purposes of the day-ahead ~~common~~ capacity calculation methodology, terms used in this document shall have the meaning of the definitions included in Article 2 of the CACM Regulation, of Regulation (EC) 714/2009, Directive 2009/72/EC, Commission Regulation (EU) 2016/1719 (hereafter referred to as the 'FCA Regulation'), Commission Regulation (EU) 2017/2195 and Commission Regulation (EU) 543/2013. In addition, the following definitions, abbreviations and notations shall apply:

    1. ~~'~~'AHC' means the advanced hybrid ~~coupling' (hereinafter 'AHC') means~~ coupling which is a solution to take fully ~~take~~ into account the influences of the adjacent ~~capacity calculation regions~~CCRs during the capacity allocation;

    2. '$AMR$' ~~is the adjustment for minimum $RAM$, i.e.~~means the adjustment for the minimum remaining available margin;

    3. ~~'~~'annual report' means the report issued on an annual basis by the CCC and the Core TSOs on the day-ahead capacity calculation;

    ~~3.~~4. 'ATC' means the available transmission ~~capacity' (hereinafter 'ATC') means~~capacity, which is the transmission capacity that remains available after the allocation procedure and which respects the physical conditions of the transmission system;

    ~~1. 'balance responsible party' (hereinafter 'BRP') means a market participant or its chosen representative responsible for its imbalances;~~

    ~~4.~~5. 'CCC' ~~is~~means the coordinated capacity calculator, as defined in Article 2(11) of the CACM Regulation, of the Core CCR, unless stated otherwise;

    ~~5.~~6. 'CCR' ~~is~~means the capacity calculation region as defined in Article 2(3) of the CACM Regulation;

    ~~2. 'central dispatch model' means a scheduling and dispatching model where the generation schedules and consumption schedules as well as dispatching of power generating facilities and demand facilities, in reference to dispatchable facilities, are determined by a TSO within the integrated scheduling process;~~

    ~~3.~~ 'CGM' ~~is~~means the common grid model as defined in Article 2(2) of the CACM Regulation~~;~~

    ~~6.~~7. ~~'CGMAM' is~~ and means a D-2 CGM established in accordance with the ~~the common grid model alignment methodology~~CGMM;

    ~~7.~~8. 'CGMM' ~~is~~means the common grid model methodology, pursuant to Article 17 of the CACM ~~regulation;~~ Regulation;

    ~~8.~~9. 'CNE' ~~is~~means a critical network element;

~~4. 'CNEC' is a critical network element with a contingency;~~

10. 'CNEC' means a CNE associated with a contingency used in capacity calculation. For the purpose of this methodology, the term CNEC also cover the case where a CNE is used in capacity calculation without a specified contingency;

11. 'Core CCR' ~~is~~means the Core capacity calculation region as ~~given by the Agency for the cooperation of energy regulators No 06/2016 on 17 November 2016~~established by the Determination of capacity calculation regions pursuant to Article 15 of the CACM Regulation;

~~9.~~12. 'Core net position' means a net position of a bidding zone in Core CCR resulting from the allocation of cross-zonal capacities within the Core CCR;

~~10.~~13. Core TSOs are 50Hertz Transmission GmbH ("50Hertz"), Amprion GmbH ("Amprion"), Austrian Power Grid AG ("APG"), CREOS Luxembourg S.A. ("CREOS"), ČEPS, a.s. ("ČEPS"), Eles d.o.o. sistemski operater prenosnega elektroenergetskega omrežja ("ELES"), Elia System Operator S.A. ("ELIA"), Croatian Transmission System Operator Ltd. (HOPS d.o.o.) ("HOPS"), MAVIR Hungarian Independent Transmission Operator Company Ltd. ("MAVIR"), Polskie Sieci Elektroenergetyczne S.A. ("PSE"), RTE Réseau de transport d'électricité ("RTE"), Slovenská elektrizačná prenosová sústava, a.s. ("SEPS"), TenneT TSO GmbH ("TenneT GmbH"), TenneT TSO B.V. ("TenneT B.V."), National Power Grid Company Transelectrica S.A. ("Transelectrica"), TransnetBW GmbH ("TransnetBW");

~~11.~~14. 'cross-zonal ~~network element'~~CNEC' means ~~in general only those transmission lines~~ a CNEC of which ~~cross a~~ a CNE is located on the bidding zone border~~. However, the term 'cross-zonal network elements' is enhanced to also include the network elements between the interconnector and the first substation to which at least two internal transmission lines are~~ or connected~~;~~ in series to such network element transferring the same power (without considering the network losses);

~~5. 'default flow-based parameters' means the precoupling backup values computed in situations when inputs for flow-based parameters are missing for more than two consecutive hours. This computation is done based on existing long term bilateral capacities;~~

~~6. 'external constraint' (hereinafter 'EC') means the maximum import and/or export constraints of a given bidding zone;~~

~~7. 'evolved flow-based' (hereinafter 'EFB') means a solution that takes into account exchanges over all cross-border HVDC interconnectors within a single CCR applying the flow-based method of that CCR;~~

15. 'curative remedial action' means a remedial action which is only applied after a given contingency occurs;

~~12.~~16. 'D-1' means ~~day-ahead~~the day before electricity delivery;

~~13.~~17. 'D-2' means the day two-days ~~ahead~~before electricity delivery;

~~8. '*FAV*' is the final adjustment value;~~

18. ~~'flow-based domain' means the set~~'DA CC MTU' is the day-ahead capacity calculation market time unit, which means the time unit for the day-ahead capacity calculation and is equal to 60 minutes;

19. 'default flow-based parameters' means the pre-coupling backup values calculated in situations when the day-ahead capacity calculation fails to provide the flow-based

parameters in three or more consecutive hours. These flow-based parameters are based on long-term allocated capacities;

~~9.~~ 'external constraint' means a type of ~~constraints~~allocation constraint that limits the ~~cross-zonal capacity calculated with a flow-based approach;~~

~~14.~~20. ~~'$F_{max}$' is the~~ maximum ~~admissible power flow~~import and/or export of a given bidding zone;

~~10. '$F_i$' is the expected flow in commercial situation i;~~

~~15.~~21. ~~'$F_0$' is~~'$F_{0,Core}$' means the flow per CNEC in the situation without commercial exchanges within the Core CCR;

~~11. '$F_{ref}$' is the reference flow;~~

22. '$F_{0,all}$' means the flow per CNEC in a situation without any commercial exchange between bidding zones within Continental Europe and between bidding zones within Continental Europe and bidding zones of other synchronous areas;

~~16.~~23. '~~$F_{LTN}$~~$F_i$' ~~is~~means the expected flow ~~after long-term nominations~~in commercial situation $i$;

24. 'flow-based domain' means a set of constraints that limit the cross-zonal capacity calculated with a flow-based approach;

25. 'FRM' or '$FRM$' means the flow reliability ~~margin' (hereinafter '$FRM$') means the~~ margin, which is the reliability margin as defined in Article 2(14) of the CACM Regulation applied to a ~~critical network element in a~~ CNE;

26. '$F_{LTN}$' means the expected flow after long-term nominations;

27. '$F_{max}$' means the maximum admissible power flow;

28. '$F_{nrao}$' means the expected flow change due to non-costly remedial actions optimisation;

29. '$F_{ref}$' means the reference flow;

~~17.~~30. '$F_{ref,init}$' means the reference flow calculated during the initial flow-based ~~approach;~~calculation pursuant to Article 14;

~~18.~~31. 'GSK' or '$GSK$' ~~is~~means the generation shift key as defined in Article 2(12) of the CACM Regulation;

~~19.~~32. 'HVDC' ~~is~~means a high voltage direct current ~~transmission system~~network element;

~~20.~~33. 'IGM' ~~is~~means the D-2 individual grid model as ~~described~~defined in Article 2(1) of the CACM Regulation;

34. 'internal CNEC' means a CNEC, which is not cross-zonal;

~~21.~~35. '$I_{max}$' ~~is~~means the maximum admissible current;

~~22.~~36. 'LTA' ~~are~~means the long-term allocated ~~capacities~~capacity;

~~12. $LTA_{margin}$ is the margin for LTA inclusion;~~

37. $LTA_{margin}$ means the adjustment of remaining available margin to incorporate long-term allocated capacities;

~~23.~~38. 'LTN' ~~are~~means the long-term ~~nominations submitted by market participants based on LTA~~nomination, which is the nomination of the long-term allocated capacity;

~~24.~~39. 'merging agent' ~~as defined in Article 20~~means an entity entrusted by the Core TSOs to perform the merging of individual grid models into a common grid model as referred to in Article 20ff of the CGMM;

40. '~~neighbouring~~MNEC' means a monitored network element with a contingency;

41. 'NP' or '$NP$' means a net position of a bidding zone~~ pairs' means the~~, which is the net value of generation and consumption in a bidding ~~zones which have a common commercial~~zone;

42. 'NRAO' means the non-costly remedial action optimisation;

~~25.~~43. 'oriented bidding zone border' means a given direction of a bidding zone border~~;~~ (e.g. from Germany to France);

~~13. 'MTU' is the market time unit;~~

~~14. 'MP' is the market party;~~

~~15. 'NP' is the net position;~~

~~26.~~44. ~~'presolved~~'pre-solved domain' means the final set of binding constraints for capacity allocation after the pre-solving process;

45. '~~presolving~~pre-solving process' means ~~that~~ the identification and removal of redundant constraints ~~are identified and removed~~ from the flow-based domain~~ by~~;

~~27.~~46. 'preventive remedial action' means a remedial action which is applied on the ~~CCC~~network before any contingency occurs;

~~28.~~47. 'previously-allocated capacities' means the long-term capacities which have already been allocated in previous (yearly and/or monthly) time frames;

~~29.~~48. 'PST' ~~is~~means a phase-shifting transformer;

~~30.~~49. 'PTDF' or '$PTDF$' ~~is the~~means a power transfer distribution factor;

50. '$\mathbf{PTDF}_{init}$' means a matrix of power transfer distribution factors resulting from the initial flow-based calculation;

51. '$\mathbf{PTDF}_{nrao}$'means a matrix of power transfer distribution factors used during the NRAO;

52. '$\mathbf{PTDF}_{f}$' means a matrix of power transfer distribution factors describing the final flow-based domain;

~~31.~~53. 'PTR' ~~is the~~means a physical transmission right;

54. 'quarterly report' means a report on the day-ahead capacity calculation issued by the CCC and the Core TSOs on a quarterly basis;

~~32.~~55. 'RA' means a remedial action as defined in Article 2(13) of the CACM Regulation;

~~33.~~56. 'RAM' or '$RAM$' ~~is the~~means a remaining available margin;

~~16. 'RAO' is the remedial action optimization;~~

57. 'reference net position or exchange' means a position of a bidding zone or an exchange over HVDC interconnector assumed within the CGM;

~~34.~~58. 'SDAC' means the single day-ahead coupling;

59. 'shadow price' means the dual price of a CNEC or allocation constraint representing the increase in the economic surplus if a constraint is increased by one MW;

~~35.~~60. 'slack node' means the single reference node used for determination of the ~~$PTDF$~~PTDF matrix, i.e. shifting the power infeed of generators up results in absorption of the power shift in the slack node. A slack node remains constant ~~per~~for each DA CC MTU ~~calculation~~;

~~36.~~61. 'spanning' means the ~~precoupling~~pre-coupling backup solution in situations when ~~inputs for~~ the day-ahead capacity calculation fails to provide the flow-based parameters ~~are missing~~ for strictly less than three consecutive hours. This ~~computation~~calculation is based on the intersection of previous and sub-sequent available flow-based ~~domains~~parameters;

~~37.~~62. ~~'SO GL' is the System Operation Guideline (~~'SO Regulation' means Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation~~);~~;

~~38.~~63. 'standard hybrid coupling' means a solution to capture the influence of exchanges with non-Core bidding zones on CNECs that is not explicitly taken into account during the capacity allocation phase;

~~39.~~64. 'static grid model' ~~is~~means a list of relevant grid elements of the transmission system, including their electrical parameters;

~~40.~~65. '~~$U$'~~U' is the reference voltage;

66. 'UAF' is an unscheduled allocated flow;

~~41.~~67. 'vertical load' means the total amount of electricity which exits ~~in~~ the ~~national~~ transmission system of a given bidding zone to connected distribution systems, end consumers connected to the transmission system, and to electricity producers for consumption in the generation of electricity;

~~42.~~68. 'zone-to-slack $PTDF$' means the ~~power transfer distribution factor~~PTDF of a commercial exchange between a bidding zone and the slack node;

~~43.~~69. 'zone-to-zone $PTDF$' means the ~~power transfer distribution factor~~PTDF of a commercial exchange between two bidding zones;

~~17. 'preventive' remedial action means a remedial action which is applied before a contingency occurs;~~

~~18. 'curative' remedial action means a remedial action which is applied after a contingency occurs;~~

~~44.~~70. the notation $x$ denotes a scalar;

~~45.~~71. the notation $\vec{x}$ denotes a vector;

~~46.~~72. the notation ~~$x$~~ $\mathbf{x}$ denotes a matrix.

2. In this day-ahead ~~common~~ capacity calculation methodology unless the context requires otherwise:

   (a) the singular indicates the plural and vice versa;

   (b) the acronyms used both in regular and italic font represent respectively the term used and the respective variable;

   (c) the table of contents and the headings are inserted for convenience only and do not affect the interpretation of this day-ahead ~~common~~ capacity calculation methodology;

   ~~(b)~~(d) any reference to the day-ahead capacity calculation, day-ahead capacity calculation process or the day-ahead capacity calculation methodology shall mean a common day-ahead capacity calculation, common day-ahead capacity calculation process and common day-ahead capacity calculation methodology respectively, which is applied by all Core TSOs in a common and coordinated way on all bidding zone borders of the Core CCR; and

   ~~(c)~~(e) any reference to legislation, regulations, directive, order, instrument, code, or any other enactment shall include any modification, extension or re-enactment of it when in force.

### Article 3. ~~Article 3~~ Application of this methodology

This day-ahead ~~common~~ capacity calculation methodology solely applies to the day-ahead capacity calculation within the Core CCR. ~~Common capacity~~Capacity calculation methodologies within other ~~capacity calculation regions~~CCRs or for other time frames are not in the scope of this methodology.

## ~~Article 4 Cross-zonal capacities for~~TITLE 2 - General description of the day-ahead ~~market~~capacity calculation methodology

### Article 4. Day-ahead capacity calculation process

1. For the day-ahead market time~~-~~ frame, ~~individual values for~~ the cross-zonal ~~capacity~~capacities for each ~~day-ahead market time unit~~DA CC MTU shall be calculated using the flow-based approach as defined in ~~the~~this methodology.

2. The day-ahead ~~common~~ capacity calculation ~~methodology,~~process shall consist of three main stages:

   (a) the creation of capacity calculation inputs by the Core TSOs;

   (b) the capacity calculation process by the CCC; and

   (c) the capacity validation by the Core TSOs in coordination with the CCC.

3. Each Core TSO shall provide the CCC the following capacity calculation inputs by the times established in the process description document:

   (a) individual list of CNECs in accordance with Article 5;

   (b) operational security limits in accordance with Article 6;

   (c) external constraints in accordance with Article 7;

   (d) FRMs in accordance with Article 8;

(e) GSKs in accordance with Article 9; and

(f) non-costly and costly RAs in accordance with Article 10.

1. In addition to the capacity calculation inputs pursuant to paragraph 3, the Core TSOs, or an entity delegated by the Core TSOs, shall send to the CCC, for each DA CC MTU of the delivery day, the following additional inputs by the times established in the process description document:

   (a) the long-term allocated capacities (LTA);

   (b) the adjustment values for long-term allocated capacities for each Core bidding zone border to enlarge the default flow-based domain beyond the long-term allocated capacities for the purpose of calculating the default flow-based parameters; and

   (c) the long-term nominated capacities (LTN).

2. When providing the capacity calculation inputs pursuant to paragraphs 3 and 4, the Core TSOs shall respect the formats commonly agreed between the Core TSOs and the CCC while fulfilling the requirements and guidance defined in the CGMM.

~~1.~~3. No later than six months before the implementation of this methodology in accordance with Article 28(3), the Core TSOs shall jointly establish a process description document as ~~set forth in Article 20ff of the CACM Regulation.~~ referred to in paragraphs 3 and 4 and publish it on the online communication platform as referred to in Article 25. This document shall reflect an up to date detailed process description of all capacity calculation steps including the timeline of each step of the day-ahead capacity calculation.

4. ~~The TSOs of~~Once the ~~Core CCR shall provide~~merging agent receives all the ~~coordinated capacity calculator (CCC) sufficiently in advance of the day-ahead firmness deadline as defined~~IGMs established pursuant to the CGMM, it shall merge them to create the CGM in accordance with ~~Article 69 of CACM Regulation~~the CGMM and deliver the CGM to the CCC.

5. The day-ahead capacity calculation process and validation in the Core CCR shall be performed by the CCC and the Core TSOs according to the following procedure:

Step 1. The CCC shall define the initial ~~inputs:~~list of CNECs pursuant to Article 14;

~~1. D-2 IGMs respecting the methodology developed in accordance with Article 19 of the CACM Regulation;~~

Step 2. The CCC shall calculate the first flow-based parameters ($PTDF_{init}$ and $F_{ref,init}$) for each initial CNEC pursuant to Article 14;

Step 3. The CCC shall determine the final list of CNECs and MNECs for subsequent steps of the day-ahead capacity calculation pursuant to Article 15;

Step 4. The CCC shall perform the non-costly remedial actions optimisation (NRAO) according to Article 16 and, as a result, obtain the applied non-costly RAs, along with the final $PTDF_f$ and $F_{ref}$ adjusted for the applied RAs;

Step 5. The CCC shall calculate the adjustment for minimum $RAM$ ($AMR$) according to Article 17;

Step 6. The CCC shall calculate the adjustment for LTA inclusion according to Article 18;

Step 7. The CCC shall calculate the $RAM$ before validation ($RAM_{bv}$) based on the results of the previous processes pursuant to Article 19;

Step 8. The Core TSOs and the CCC shall, according to Article 20, validate the $RAM_{bv}$ with coordinated and individual validations, and decrease RAM when operational security is jeopardised, which results in the $RAM$ before long-term nominations ($RAM_{bn}$);

Step 9. The CCC shall, according to Article 21, remove the redundant CNECs and redundant external constraints from final $PTDF_f$ and $RAM_{bn}$ and publish these as initial flow-based parameters in accordance with Article 25;

Step 10. The CCC shall calculate the flows resulting from long-term nominations ($F_{LTN}$) and derive the final $RAM$ ($RAM_f$) according to Article 21;

Step 11. The CCC shall publish the $PTDF_f$ and $RAM_f$ values in accordance with Article 25 and provide them to NEMOs for capacity allocation in accordance with Article 21.

## TITLE 3 – Capacity calculation inputs

### ~~Article 4.~~Article 5. Definition of critical network elements ~~(CNEs)~~ and contingencies ~~in accordance with Article 5;~~

~~1. operational security limits in accordance with Article 6;~~

~~2. allocation constraints in accordance with Article 8;~~

~~3. flow reliability margin ($FRM$) in accordance with Article 9;~~

~~4. generation shift key (GSK) in accordance with Article 10; and~~

~~5. remedial actions in accordance with Article 11.~~

~~6. Core TSOs, or an entity acting on behalf of Core TSOs, shall send for each market time unit of the day the long term allocated capacities (LTA) and nominated capacities (LTN) to the coordinated capacity calculator, without undue delay.~~

~~7.~~

~~8. When providing the inputs, the TSOs of the Core CCR shall respect the formats commonly agreed between the TSOs and the coordinated capacity calculators of the Core CCR, while respecting the requirements and guidance defined in the CGMM.~~

~~9. Once D-2 IGMs have been received, the merging agent shall merge the D-2 IGMs to create the D-2 CGMs respecting the methodology developed in accordance with Article 17 of the CACM Regulation.~~

~~10. For the day-ahead common capacity calculation in the Core CCR, performed by the CCC, the high-level process flow includes seven steps until the final flow-based domain for the single day-ahead coupling process is set:~~

~~11. First, the provided inputs as defined in Article 4(2) are taken for the inital flow-based computation as defined in Article 12, taking into account the reference commercial situation, leading to preliminary results of capacity calculation;~~

~~12. after the initial flow-based computation, the second process step is to determine the relevant CNECs for subsequent steps of the common capacity calculation based on the preliminary results as defined in Article 5;~~

~~13. after the determination of relevant CNECs, the third process step selects remedial actions (RAs) resulting from the remedial action optimization as defined in Article 15;~~

~~14. the fourth process step is the intermediate flow-based computation where:~~

~~15. a new flow-based computation is performed as defined in Article 12, taking into account the reference commercial situation and the updated inputs resulting from steps described in Article 4(6)(b) and Article 4(6)(c);~~

~~16. the following step is the determination of the adjustment for minimum *RAM* (*AMR*) as defined in Article 13;~~

~~17. and finally the execution of the rules for previously-allocated capacities from long-term auctions (LTA) are taken into account as defined in Article 14.~~

~~18. after the intermediate flow-based computation the resulting cross-zonal capacities are validated by the TSOs of the Core CCR as defined in Article 21. During this validation process the CCC shall coordinate with CCCs of neighbouring CCRs as defined in Article 21(6);~~

~~19. the sixth process step is the pre-final flow-based computation where:~~

~~20. a new flow-based computation is performed as defined in Article 18, taking into account no commercial exchange for the Core region and the updated inputs resulting from steps described Article 4(6)(d) and Article 4(6)(e);~~

~~21. the following step is performing the presolve process as defined in Article 18(1)(d);~~

~~22. the next step is to remove the reference commercial situation as defined in in Article 18(1)(e);~~

~~23. as a final step the remaining available margin is calculated as defined in Article 12(10).~~

~~24. the seventh and final process step is the final flow-based computation where:~~

6. Each Core TSO shall define a list of CNEs, which are fully or partly located in its own control area, and which can be overhead lines, underground cables, or transformers. All cross-zonal network elements shall be defined as CNEs, whereas only those internal network elements, which are defined pursuant to paragraph 6 or 7 shall be defined as CNEs. Until 30 days after the approval of the proposal pursuant to paragraph 6, all internal network elements may be defined as CNEs.

~~25.~~ Each Core TSO shall define a ~~new flow-based computation is performed as defined in Article 18, taking into account no commercial exchange for the Core region and the updated inputs resulting from steps described Article 4(6)(d) and Article 4(6)(e);~~

~~26. the following step is performing the presolve process as defined in Article 18(1)(d);~~

~~27. the next step is to remove the reference commercial situation as defined in in Article 18(1)(e);~~

~~28. afterwards the LTN adjustment is performed as defined in Article 18(1)(f);~~

~~29. as a next step the external constraints are adjusted with respect to the net positions resulting from LTN, as defined in Article 18 (2)(c);~~

~~30. finally, the remaining available margins for the day-ahead single coupling are calculated as defined in Article 18(1)(g).~~

~~31. In accordance with Article 46~~list of ~~CACM Regulation, the CCC and TSOs of the Core CCR shall ensure that cross-zonal capacity shall be provided to relevant NEMOs before the day-ahead firmness deadline as defined in accordance with Article 69 of CACM Regulation.~~

~~32.~~

## ~~33. Methodologies for calculation of the inputs~~

### ~~34. Article 5 Methodology for critical network elements and contingencies selection~~

~~35. Each Core TSO shall provide a list of critical network elements (CNEs) of its own control area based on operational experience. This list shall be updated at least on a yearly basis and in case of topology changes in the grid of the TSO, pursuant to Article 22. A CNE is a network element, significantly impacted by Core cross-zonal trades, which are supervised under certain operational conditions, the so-called contingencies. A CNE can be:~~

~~36. a cross-zonal network element; or~~

~~37. an internal network element.~~

38. ~~Those elements can be an overhead line, an underground cable, or a transformer.~~

~~39.~~7. ~~In accordance with Article 23(1) of CACM Regulation, Core TSOs shall provide a list of~~ proposed contingencies used in operational security analysis in ~~line~~accordance with Article 33 of the SO ~~GL~~Regulation, limited to their relevance for the set of CNEs as defined in ~~Article 5(~~paragraph 1~~)~~ and pursuant to Article 23(2) of the CACM Regulation. The contingencies of a Core TSO shall be located within the observability area of that Core TSO. This list shall be updated at least on a yearly basis and in case of topology changes in the grid of the Core TSO, pursuant to ~~Article 22.~~Article 24. A contingency can be an unplanned outage of:

~~A contingency can be a trip of:~~

(a) a line, a cable, or a transformer;

(b) a busbar;

(c) a generating unit;

(d) a load; or

(e) a set of the aforementioned ~~contingencies~~elements.

40. ~~The association of contingencies to CNEs shall be done from the~~ Each Core TSO shall establish a list of ~~CNEs~~ CNECs by associating the contingencies established ~~in Article 5(1) and from the list of contingencies~~ pursuant to paragraph 2 with the CNEs established ~~in Article 5(2). It shall follow~~ pursuant to paragraph 1 following the rules established in accordance with Article 75 of the SO ~~GL.~~

41. Regulation. Until ~~a compliant methodology for Article 75 SO GL enters~~such rules are established and enter into force, ~~and pursuant to Article 23(2) of the CACM regulation,~~ the association of contingencies to CNEs ~~will~~shall be based on each TSO's ~~needs and~~ operational experience. ~~The contingencies of a TSO will be associated to the CNEs of that TSO, and each TSO will individually associate contingencies within its observability area to its own CNEs.~~

42. ~~The result of the process according to Article 5(3) or Article 5(4) will be an initial pool of CNECs to be used for RAO and in all subsequent steps of the common capacity calculation. This pool shall remain fixed during the computation. The initial pool of CNECs will be reviewed on a daily basis before the initial flow-based computation pursuant to Article 5(6).~~

43. ~~Core TSOs shall distinguish between:~~

44. ~~the CNECs of the initial pool that are marked by the CCC to be significantly influenced by the changes in bidding zone net positions in accordance with Article 29(3) of the CACM Regulation. A cross-zonal network element is always considered as significantly influenced. The other CNECs shall have a maximum zone-to-zone~~ $\cancel{PTDF}$~~, as described in Article 12, higher than a common threshold of 5 percent. The value of this threshold is defined in conjunction with the adjustment for minimum~~ $\cancel{RAM}$ ~~according to Article 13, both being a measure to mitigate possible discrimination between the treatment of internal and cross-zonal transactions, in response to Article 21(1)(b)(ii) of the CACM Regulation and Article 1.7 of Annex I to the Regulation (EC) 714/2009 and in line with Article 3(a), 3(b) and 3(e) of the CACM Regulation, with the aim to promote social welfare.~~

45. ~~The CNECs of this category will be taken into account in all the subsequent steps of the common capacity calculation and will determine the cross-zonal capacity;~~

46. ~~the CNECs of the initial pool that, based on experience are expected to be influenced by the RAs defined in Article 11, but are not significantly influenced by the changes in bidding zone net positions, pursuant to~~

~~Article 5(6)(a). The CNECs of this category may only be monitored during the RAO and shall not limit the cross-zonal capacity.~~

~~47.~~ ~~In accordance with Article 15(2)(b) the additional loading, resulting from the application of RAs, of CNECs of this category may be limited during the RAO, while ensuring that a certain additional loading up to the defined threshold is always accepted.~~

~~48.~~ ~~The differentiation of the~~An individual CNEC ~~selection between the two sub-processes (RAO and the subsequent steps of the common capacity calculation) is needed to monitor the impact of RAO on certain CNECs which are strongly impacted by RAs while only being weakly impacted by cross-border exchanges, in line with Article 3(c) of the CACM Regulation. The pool of CNECs for RAO and for subsequent steps of the common capacity calculation may differ. However, the pool of CNECs for the subsequent steps of the common capacity calculation shall be a subset of the CNECs considered for RAO;~~

~~49.~~ ~~the CNECs of the initial pool not mentioned in Article 5(6)(a) or Article 5(6)(b). The CNECs of this category shall not be taken into account in the day-ahead common capacity calculation.~~

~~50.~~ ~~In an exceptional situation, such as extreme weather conditions, untypical flow conditions or topology or grid situation, a TSO may decide to modify the CNEC list described in Article 5(6)(a) for one or several market time units covering the expected period of presence of the exceptional situation.~~

~~51.~~8. ~~In case a TSO decides, in an exceptional situation, to keep a CNEC within the list described in Article 5(6)(a) which is not significantly influenced by the changes in bidding zone net positions, the respective TSO shall inform Core national regulatory authorities~~ may also be established without ~~undue delay and provide in the monitoring report defined in Article 24 a clear description of the specific situation providing detailed information such as the specific topology or grid situation that led to this decision.~~ a contingency.

~~52.~~ ~~In case a TSO decides, in an exceptional situation, to exclude a CNEC from the list described in Article 5(6)(a) which is significantly influenced by the changes in bidding zone net positions, the respective TSO shall inform Core national regulatory authorities without undue delay and provide in the monitoring report defined in Article 24 a clear description of the specific situation providing detailed information such as the specific topological or grid situation that led to this decision.~~

~~53.~~ ~~TSOs shall further study the value of the common threshold referred to in Article 5(6)(a), including social welfare based analysis, and potentially adapt it in accordance with the results of the internal parallel run pursuant to Article 25.~~

9. ~~TSOs shall~~ Each Core TSO shall provide to the CCC a list of CNECs established pursuant to paragraph 3. Each Core TSO may also provide to the CCC a list of monitored network elements with contingency (MNEC), which need to be monitored during the capacity calculation.

10. No later than eighteen 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.

11. The list pursuant to the previous paragraph shall be updated every two years. For this purpose, no later than eighteen months after the approval by all Core regulatory authorities of the proposal for amendment of this methodology pursuant to previous paragraph and this paragraph, all Core TSOs shall jointly develop a new proposal for the list of internal 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 replace the relevant annex to this methodology.

12. The proposed list of internal CNECs pursuant to paragraph 5 and 6 shall not include any internal network element with contingency with a maximum zone-to-zone PTDF below 5%, calculated as the time-average over the last twelve months.

13. The proposal pursuant to paragraphs 5 and 6 shall include at least the following:

    (a) a list of proposed internal CNECs with the associated maximum zone-to-zone PTDFs referred to in paragraph 7;

    (b) an impact assessment of increasing the threshold of the maximum zone-to-zone PTDF for exclusion of internal CNECs referred to in paragraph 7 to 10% or higher; and

    (c) for each proposed internal CNEC, an analysis demonstrating that including the concerned internal network element in capacity calculation is economically the most efficient solution to address the congestions on the concerned internal network element, considering, for example, the following alternatives:

        i. application of remedial actions;

        ii. reconfiguration of bidding zones;

        iii. investments in network infrastructure combined with one or the two above; or

        iv. a combination of the above.

    Before performing the analysis pursuant to point (c), the Core TSOs shall jointly coordinate and consult with all Core regulatory authorities on the methodology, assumptions and criteria for this analysis.

14. The proposals pursuant to paragraphs 5 and 6 shall also demonstrate that the concerned Core TSOs have diligently explored the alternatives referred to in paragraph 8 sufficiently in advance taking into account their required implementation time, such that they could be applied or implemented by the time that the decisions of the Core regulatory authorities on the proposal pursuant to paragraphs 5 and 6 are taken.

~~54.~~15. The Core TSOs shall regularly review and update ~~methodologies~~the application of the methodology for determining CNECs ~~in accordance with Article 22.~~ as defined in Article 24.

## ~~Article 5.~~Article 6. ~~Article 6~~ Methodology for operational security limits

1. ~~In accordance with Article 23(1) of the CACM Regulation,~~The Core TSOs shall ~~respect~~use in the day-ahead capacity calculation the same operational security limits as those used in the operational security analysis carried out in ~~line~~accordance with Article 72 of the SO ~~GL. The operational security~~Regulation.

~~55.~~ To take into account the thermal limits ~~used in the common capacity calculation are the same as those used in operational security analysis, therefore any additional descriptions pursuant to Article 23(2) of the CACM Regulation are not needed. In particular:~~

2. ~~Core TSOs shall respect~~of CNEs, the Core TSOs shall use the maximum admissible current limit ($I_{max}$~~)~~), which is the physical limit of a CNE according to the operational security ~~policy~~limits in ~~line~~accordance with Article 25 of the SO ~~GL~~Regulation. The maximum admissible current shall be defined as follows:

    (a) the maximum admissible current can be defined ~~with~~as:

i. Seasonal limit, which means a fixed ~~limits~~limit for all ~~market time units in the case~~DA CC MTUs of ~~transformers and certain types~~each of ~~conductors which are not sensitive to~~the four seasons.

~~i.~~ii. Dynamic limit, which means a value per DA CC MTU reflecting the varying ambient conditions.~~This is applicable for all Core TSOs;~~

~~1.~~ ~~fixed~~Fixed limits for all ~~market time units of a specific season; This is applicable for Amprion, APG, CREOS, ČEPS, ELIA, HOPS, MAVIR, RTE, SEPS, TenneT GmbH, TenneT B.V., Transelectrica, and TransnetBW;~~

~~2. a value per market time unit depending on the weather forecast. This is applicable for ČEPS, PSE, ELIA, TenneT GmbH, TenneT B.V., APG, ELES, 50Hertz, Amprion, and RTE;~~

~~ii.~~iii. ~~fixed limits for all market time units~~DA CC MTUs, in case of specific situations where the physical limit reflects the capability of overhead lines, cables or substation equipment installed in the primary power circuit (such as circuit-breaker, ~~current transformer,~~ or disconnector~~). This is applicable for a subset of lines of the following TSOs: MAVIR, Transelectrica, PSE, SEPS, ČEPS, TransnetBW, APG, ELES, Amprion, HOPS,TenneT GmbH, TenneT B.V., and 50Hertz~~) with limits not sensitive to ambient conditions.

(b) when applicable, $I_{max}$ shall be defined as a temporary current limit of the CNE in accordance with Article 25 of the SO ~~GL~~Regulation. A temporary current limit means that an overload is only allowed for a certain finite duration. As a result, various CNECs associated with the same CNE may have different $I_{max}$ values.

(c) $I_{max}$ ~~is~~shall represent only real physical properties of the CNE and shall not be reduced by any security margin~~, as all uncertainties in the common capacity calculation are covered on~~.[1]

~~2.~~ the CCC shall use the $I_{max}$ of each CNEC ~~by the flow reliability margin ($FRM$) in accordance with Article 9 and final adjustment value ($FAV$) in accordance with Article 7.~~

~~(c)~~(d) ~~the value~~to calculate $F_{max}$ ~~in MW,~~for each CNEC, which describes the maximum admissible active power flow on a ~~CNE~~CNEC. $F_{max}$ ~~is~~shall be calculated by the ~~CCC from $I_{max}$ by the~~ given formula:

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

*Equation ~~1~~1*

(e) where $I_{max}$ is the maximum admissible current ~~in kA~~ of a critical network element (CNE), $U$ is a fixed reference voltage ~~in kV~~ for each CNE, and $\cos(\varphi)$ is the power factor.~~Core TSOs~~

~~(d)~~(f) the CCC shall~~assume~~, 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 ~~of the CNE loading by~~ reactive power is negligible (i.e. ~~the angle~~ $\varphi = 0$). ~~Thus, factor cos(φ) equals 1, which means that the element is assumed to be loaded only by active power. Any significant deviation from~~ If the share of reactive power is not negligible, a TSO may

[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.

consider this ~~assumption shall be covered by $FAV$ pursuant to Article 21(1)(d);~~aspect during the validation phase in accordance with Article 20.

1. ~~Core TSOs shall aim towards determining the maximum admissible current using at least seasonal limits pursuant to Article 6(1)(a)(ii) and ideally dynamic line rating pursuant to Article 6(1)(a)(iii), save for cases where the conditions pursuant to Article 6(1)(a)(i) or Article 6(1)(a)(iv) apply.~~
1. ~~TSOs shall~~ The Core TSOs shall aim at gradually phasing out the use of seasonal limits pursuant to paragraph 2(a)(i) and replace them with dynamic limits pursuant to paragraph 2(a)(ii), when the benefits are greater than the costs. After the end of each calendar year, each TSO shall analyse for all its CNEs for which seasonal limits are applied and have a non-zero shadow price at least in 0.1% of DA CC MTUs in the previous calendar year, the expected increase in the economic surplus in the next 10 years resulting from the implementation of dynamic limits, and compare it with the cost of implementing dynamic limits. Each TSOs shall provide this analysis to Core regulatory authorities. If the cost benefit analysis, taking into account other planned investments, is positive, the concerned TSO shall implement the dynamic limits within three years after the end of the analysed calendar year. In case of interconnectors, the concerned TSOs shall cooperate in performing this analysis and implementation when applicable.

2. TSOs shall regularly review and update operational security limits in accordance with ~~Article 22.~~Article 24.

~~1.1 Article 7 Final Adjustment Value~~

1. ~~The remaining available margin ($RAM$) on a CNE may be increased or decreased by the final adjustment value ($FAV$), where:~~
   1. ~~positive values of $FAV$ (given in MW) reduce the available margin on a CNE while negative values increase it;~~
   2. ~~$FAV$ can be set by the responsible TSO during the validation process in accordance with Article 21;~~
   3. ~~in case a TSO decides to use $FAV$ during the day-ahead common capacity calculation, the respective TSO shall provide the Core regulatory authorities with a clear description of the specific situation that led to this decision in the monitoring report defined in Article 24.~~

## ~~Article 6.~~Article 7. ~~Article 8~~ Methodology for allocation constraints

1. ~~In accordance with Article 23(3)(a), and respecting the objectives described in Article 3 of the CACM Regulation, besides active power flow limits on CNEs, allocation constraints may be necessary to maintain a secure grid operation. As defined in Article 2(6) of the CACM Regulation, allocation constraints constitute measures defined to the purpose of keeping the transmission system within operational security limits. Some of the transmission system parameters, defined in Article 2(7) of CACM Regulation, used for expressing operational security limits (*inter alia* frequency, voltage and dynamic stability) depend on production and consumption in a given system, and these specific limitations can be related to generation and load. Since such specific limitations cannot be efficiently transformed into maximum active power flows on individual CNEs, these have to be included as allocation constraints in capacity calculation expressed as maximum import and export constraints of bidding zones. These kinds of allocation constraints are called external constraints.~~
2. ~~External constraints are determined by Core TSOs and taken into account during the single day-ahead coupling in addition to the active power flow limits on CNECs.~~
3. ~~These~~In case operational security limits cannot be transformed efficiently into $I_{max}$ and $F_{max}$ pursuant to Article 6, the Core TSOs may transform them into allocation constraints. For this

purpose, the Core TSOs may only use external constraints as a specific type of allocation constraint that limits the maximum import and/or export of a given Core bidding zone within the SDAC.

4. The Core TSOs may apply external constraints ~~shall be modelled as~~ as one of the following two options:

   (a) a constraint on the Core net position (the sum of cross-zonal exchanges within the Core CCR for a certain bidding zone in the SDAC), thus limiting the net position of the respective bidding zone with regards to its imports and/or exports to other bidding zones in the Core CCR. This option shall be applied until option (b) can be applied.

   ~~(a)~~(b) a constraint on the global net position (the sum of all cross-zonal exchanges for a certain bidding zone in the ~~single day-ahead coupling~~SDAC), thus limiting the net position of the respective bidding zone with regards to all CCRs, which are part of the ~~single day-ahead coupling.~~ SDAC. This option shall be applied when: (i) such a constraint is approved within all day-ahead capacity calculation methodologies of the respective CCRs, (ii) the respective solution is implemented within the SDAC algorithm and (iii) the respective bidding zone borders are participating in SDAC.

5. ~~In case~~ External constraints may be used by ELIA, TenneT B.V. and PSE during a transition period of two years following the implementation of ~~an~~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 on a daily basis for each DA CC MTU (for PSE only) or at least on a quarterly basis and publish the results of the underlying analysis (this obligation is for ELIA and TenneT B.V. only);

   (b) in case the external constraint ~~on the global net position in the single day-ahead coupling is technically unfeasible,~~ 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 ~~shall be implemented by constraining the cross-zonal capacity calculation in the Core CCR as described in Article 18(2), thus limiting the Core net position of the respective bidding zone.~~ 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).

6. In case the concerned Core TSOs could not find and implement alternative solutions referred to in the previous paragraph, they may, by eighteen 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:

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

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

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

~~3.~~7. For the SDAC fallback ~~process~~procedure, pursuant to ~~Article 20, the allocation constraints, being~~Article 23, all external constraints~~,~~ shall be modelled as constraints limiting the Core net position~~.~~ as referred to in paragraph 2(a).

~~4. A TSO may use external constraints in order to avoid situations that lead to stability problems in the network, detected by at least yearly reviewed system dynamics studies. This is applicable for ELIA and TenneT B.V., for all MTUs.~~

~~5. A TSO may use external constraints in order to avoid situations which are too far away from the reference flows going through the network in the D-2 CGM, and which, in exceptional cases, would induce extreme additional flows on grid elements resulting from the use of a linearized GSK, leading to a situation which could not be validated as safe by the concerned TSO. This is applicable for TenneT B.V., for all MTUs.~~

~~6. A TSO may use external constraints in case of a central dispatch model for ensuring a minimum level of operational reserve for balancing. The external constraints introduced are bi-directional, with independent values for directions of import and export, depending on the foreseen balancing situation. This is applicable for PSE, for all MTUs.~~

~~7. The details, justifications for use, and the methodology for the calculation of external constraints as described in Article 8(6), 8(7), and 8(8) are set forth in Appendix 1.~~

8. ~~A~~Core TSO may discontinue the ~~usage~~use of an external constraint ~~as described in Article 8(6), 8(7), and 8(8).~~. The concerned Core TSO shall communicate this change to ~~the~~all Core regulatory authorities and to the market participants at least one month before ~~its implementation.~~ discontinuation.

9. The Core TSOs shall review and update allocation constraints in accordance with ~~Article 22.~~ Article 24.

## ~~Article 7.~~Article 8. ~~Article 9~~ Reliability margin methodology

~~1.~~ The ~~day-ahead common capacity calculation methodology is based on forecast models of the transmission system. The inputs are created two days before the delivery date of energy with available knowledge. Therefore, the outcomes are subject to inaccuracies and uncertainties. The aim of the reliability margin is to cover a level of risk induced by these forecast errors.~~

~~2. In accordance with Article 22(1) of the CACM Regulation, the reliability margins for critical elements (hereafter referred to as "$FRM$") are calculated in a three-step approach:~~

~~3. in a first step, for each market time unit of the observatory period, the D-2 common grid model (CGM) are updated in order to take into account the real-time situation of at least the remedial actions that are considered in the common capacity calculation and defined in Article 11. These remedial actions are controlled by Core TSOs and thus not considered as an uncertainty. This step is undertaken by copying the real-time configuration of these remedial actions and applying them into the historical D-2 CGM. The power flows of the latter modified D-2 CGM are re-computed ($F_{ref}$) and then adjusted to realised commercial exchanges inside the Core CCR with the $PTDF$s calculated based on the historical GSK and the modified D-2 CGM according to the methodology as described in Article 12. Consequently, the same commercial exchanges in the Core CCR are taken into account when comparing the power flows based on the day-ahead common capacity calculation with flows in the real-time situation. These flows are called expected flows ($F_{exp}$), see Equation 2.~~

~~4.~~

~~5.~~ $$\cancel{\vec{F}_{exp} = \vec{F}_{ref} + \boldsymbol{PTDF} \times \left(\overrightarrow{NP}_{real} - \overrightarrow{NP}_{ref}\right)}$$

~~6. *Equation 2*~~

~~7. with~~

| | |
|---|---|
| ~~8.~~ $\cancel{\vec{F}_{exp}}$ | ~~9. expected flow per CNEC in the realised commercial situation~~ |
| ~~10.~~ $\cancel{\vec{F}_{ref}}$ | ~~11. flow per CNEC in the CGM (reference flow)~~ |
| ~~**12. *PTDF***~~ | ~~13. power transfer distribution factor matrix~~ |
| ~~14.~~1. $\overrightarrow{NP}_{rea}$ | ~~15.~~1. ~~Core net position per bidding zone in the realised commercial situation~~ |
| ~~16.~~ $\cancel{\overrightarrow{NP}_{ref}}$ | ~~17. Core net position per bidding zone in the CGM~~ |

~~18.~~

~~19.~~

~~20. The power flows on each CNEC of the Core CCR, as expected with the day ahead common capacity calculation methodology are then compared with the real time flows observed on the same CNEC. All differences for all market time units of a one-year observation period are statistically assessed and a probability distribution is obtained;~~

~~21. in a second step and in accordance with Article 22(3) of the CACM Regulation, based on experience in existing flow-based market coupling initiatives, the 90th percentiles of the probability distributions of all CNECs are calculated. This means that the Core TSOs apply a common risk level of 10% i.e. the *FRM* values cover 90% of the historical errors. Core TSOs can then either:~~

~~22. directly take the 90th percentile of the probability distributions to determine the *FRM* of each CNEC. This means that a CNE can have different *FRM* values depending on the associated contingency; this principle will be applied by the following Core TSOs: 50Hertz, Amprion, APG, CEPS, MAVIR, PSE, SEPS, Transelectrica, TenneT GmbH, TenneT BV, and TransnetBW;~~

~~23. only take the 90th percentile of the probability distributions calculated on CNEs without contingency. This means that a CNE will have the same *FRM* for all associated contingencies; this principle will be applied by the following Core TSOs: ELES, Elia, CREOS, HOPS, and RTE;~~

~~24.~~1. ~~a possible third step is to undertake an operational adjustment on the values derived from Article 9(2)(b)(i) or 9(2)(b)(ii), which can be applied to reduce the computed *FRM* values to a range between 5% and 20% of the~~ $\cancel{F_{max}}$ ~~calculated under normal weather conditions.~~

~~25. TSOs shall further study the value of the common risk level referred to in Article 9(2)(b) and potentially adapt it pursuant to Article 25.~~

~~26. The *FRM* values will be updated every year based upon an observatory period of one year so that seasonality effects can be reflected in the values. The *FRM* values are then fixed until the next update.~~

~~27. Before the first operational calculation of the *FRM* values, Core TSOs shall use the *FRM* values already in operation in existing flow-based market coupling initatives. In case these values are not available, Core TSOs shall determine the *FRM* values as 10% of the~~ $\cancel{F_{max}}$ ~~calculated under normal weather conditions.~~

~~28.~~10. ~~In accordance with Article 22(2) and (4) of the CACM Regulation, the~~ $FRM$s shall cover the following forecast uncertainties:

(a) ~~Core external transactions (out of Core CCR control: both between Core CCR and other CCRs as well as among TSOs~~cross-zonal exchanges on bidding zone borders outside the Core CCR~~);~~;

(b) generation pattern including specific wind and solar generation forecast;

(c) generation shift key;

(d) load forecast;

(e) topology forecast;

(f) unintentional flow deviation due to ~~the operation of~~ frequency containment ~~reserves~~process; and

(g) flow-based capacity calculation assumptions including linearity and modelling of external (non-Core) TSOs' areas.

11. The Core TSOs shall ~~assess~~aim at reducing uncertainties by studying and tackling the ~~possible improvements~~drivers of ~~the inputs of the day-ahead common~~ uncertainty.

~~29.~~12. The $FRM$s shall be calculated in two main steps. In the first step, the probability distribution of deviations between the expected power flows at the time of the capacity calculation ~~in the annual review as defined in Article 22.~~and the realised power flows in real time shall be calculated. To calculate the expected power flows ($F_{exp}$), for each DA CC MTU of the observation period, the historical CGMs and GSKs used in capacity calculation shall be used. The historical CGMs shall be updated with the deliberated Core TSOs' actions (including at least the RAs considered during the capacity calculation) that have been applied in the relevant DA CC MTU[2]. The power flows of such modified CGMs shall be recalculated ($F_{ref}$) and then adjusted to take into account the realised commercial exchanges inside the Core CCR. The latter adjustment shall be performed by calculating $PTDF$s according to the methodology as described in Article 11, but using the modified CGMs and the historical GSKs. The expected power flows at the time of the capacity calculation shall therefore be calculated using the final realised commercial exchanges in the Core CCR which are reflected in realised power flows. This above calculation of expected power flows ($F_{exp}$) is described with Equation 2.

$$\vec{F}_{exp} = \vec{F}_{ref} + \mathbf{PTDF}\left(\overrightarrow{NP}_{real} - \overrightarrow{NP}_{ref}\right)$$

*Equation 2*

with

$\vec{F}_{exp}$ expected power flow per CNEC in the realised commercial situation in Core CCR

$\vec{F}_{ref}$ flow per CNEC in the CGM updated to take deliberate TSO actions into account

**PTDF** power transfer distribution factor matrix calculated with updated CGM

$\overrightarrow{NP}_{real}$ Core net position per bidding zone in the realised commercial situation

[2] These actions are controlled by the Core TSOs and thus not considered as an uncertainty.

~~2. Core TSOs shall publish a study, based on the first and second annual FRM assessments and the quality improvements on the input data and process of the flow-based capacity calculation, two and a half years after the go-live of the Core flow-based day-ahead capacity calculation.~~

## ~~1.2 Article 10 Generation shift keys methodology~~

~~In accordance with Article 24 of the CACM Regulation, Core TSOs developed~~ $\overrightarrow{NP}_{ref}$ Core net position per bidding zone in the updated CGM

13. The expected power flows on each CNEC of the Core CCR shall then be compared with the realised power flows observed on the same CNEC. When calculating the expected (respectively realised) flows for CNECs, the expected (resp. realised) flows shall be the best estimate of the expected (resp. realised) power flow which would have occurred, should the outage have taken place. Such estimate shall take curative remedial actions into account where relevant. All differences between these two flows for all DA CC MTUs of the observation period shall be used to define the probability distribution of deviations between the expected power flows at the time of the capacity calculation and the realised power flows;

14. In the second step, the 90th percentiles of the probability distributions of all CNECs shall be calculated[3]. This means that the Core TSOs apply a common risk level of 10% and thereby the $FRM$ values cover 90% of the historical forecast errors within the observation period. Subject to the proposal pursuant to paragraph 6, the $FRM$ value for each CNEC shall either be:

    (a) the 90th percentile of the probability distributions calculated for such CNEC;

    (b) the 90th percentile of the probability distributions calculated for the CNEs underlying such CNEC.

15. Each TSO may reduce the $FRM$ values resulting from the second step for its own CNECs if it considers that the underlying uncertainties have been over-estimated.

16. No later than eighteen 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.

17. The proposal for amendment of this methodology pursuant to the previous paragraph shall specify whether the $FRM$ value shall be calculated for each CNEC based on the underlying probability distribution, or whether all CNECs with the same underlying CNE shall have the same $FRM$ value calculated based on the probability distribution calculated for the underlying CNE. In case the proposal suggests calculating the FRMs at CNEC level, the proposal shall describe in detail how to estimate the expected and realised flows adequately, including the RAs that would have been triggered in order to manage the contingency when relevant.

18. The supporting document for the proposal for amendment of this methodology pursuant to paragraph 7 above shall include at least the following:

[3] This value is derived based on experience in existing flow-based market coupling initiatives.

(a) the FRM values for all CNECs calculated at the level of CNE and CNEC; and

(b) an assessment of the benefits and drawbacks of calculating the FRM at the level of CNE or CNEC.

19. 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 the following $FRM$ values:

(a) for CNECs already used in existing flow-based capacity calculation initiatives, the $FRM$ values shall be equal to the $FRM$ values used in these initiatives at the time of adoption of this methodology; and

(b) for CNECs not already used in existing flow-based capacity calculation initiatives, the $FRM$ values shall be equal to 10% of the $F_{max}$ calculated under normal weather conditions.

20. ~~methodology to determine the common~~ After the proposal for amendment of this methodology pursuant to paragraph 7 has been approved by all Core regulatory authorities, the $FRM$ values shall be updated at least once every year based on an observation period of one year in order to reflect the seasonality effects. The $FRM$ values shall then remain fixed until the next update.

## Article 9. Generation shift key methodology

1. Each Core TSO shall define for its bidding zone and for each DA CC MTU a GSK, which translates a change in a bidding zone net position into a specific change of injection or withdrawal in the CGM. A GSK shall have fixed values, which means that the relative contribution of generation ~~shift key:~~or load to the change in the bidding zone net position shall remain the same, regardless of the volume of the change.

2. For a given DA CC MTU, the GSK shall only include actual generation and/or load[4] present in the CGM for that DA CC MTU. The Core TSOs shall take into account the available information on generation or load available in the ~~common grid model for each scenario developed in accordance with Article 18 of the CACM Regulation~~CGM in order to select the nodes that will contribute to the ~~generation shift key;~~GSK.

~~3. Each Core TSO shall aim to apply a GSK that resembles the dispatch and the corresponding flow pattern, thereby contributing to minimizing the flow reliability margins;~~

~~4. Core TSOs shall define a constant generation shift key per market time unit;~~

3. The GSKs shall describe the expected response of generation and/or load units to changes in the net positions. This expectation shall be based on the observed historical response of generation and/or load units to changes in net positions, clearing prices and other fundamental factors, thereby contributing to minimising the FRM.

4. The GSKs shall be updated and reviewed on a daily basis or whenever the expectations referred to in paragraph 3 change. The Core TSOs shall review and update the application of the generation shift key methodology in accordance with Article 24.

~~5.~~ The Core TSOs belonging to the same bidding zone shall ~~determine a common methodology that translates a change in the bidding zone net position to a specific change of generation or load in the common grid model.~~

[4] And other elements connected to the network, such as storage equipment.

~~6. For the application of the methodology, Core TSOs shall define, for the capacity calculation process, generation shift keys with fixed values, impacted by the actual generation and/or load present in the D-2 CGM, for each market time unit.~~

~~7. Core TSOs have harmonized their GSK determination methodologies whilst including some dedicated features to take into account specific production patterns within their grids.~~

~~8. Common rules to establish generation shift keys shared by all Core TSOs~~

~~9. In its GSK, each TSO shall use flexible and controllable production units which are available inside the TSO grid (they can be running or not within D-2 CGM).~~

~~10. Units unavailable due to outage or maintenance are not included.~~

~~11. GSK is reviewed on a daily basis~~

~~12. Specific methodologies have been developed by some TSOs that are facing~~jointly define a ~~limited amount of flexible production and consumption units within their grid. These methodologies are applied to avoid unrealistic under- and overloading of the units in extreme import or export scenarios.~~

~~13. For Belgium, the~~ common GSK ~~is defined in such~~ for that bidding zone and shall agree on a ~~way that for high levels of import into the Belgian bidding zone all GSK units are, at the same time, either at 0 MW or at their minimum production level (including a margin for reserves). For high levels of export from the Belgian bidding zone all GSK units are at their maximum production level (including a margin for reserves) at the same time.~~

~~14. For the Netherlands, all GSK units are redispatched pro rata on the basis of predefined maximum and minimum production levels for each active unit to prevent infeasible production levels at foreseen extreme import and export scenarios.~~

~~15. For Croatia, Hungary, Slovakia, and Slovenia, small dispersed units connected to lower voltage levels are considered in the GSK in order to achieve more realistic flow patterns when the net position shifts.~~

~~16.~~ methodology for such coordination. For Germany and Luxembourg

~~17. The German and Luxembourgian TSOs provide one~~, each TSO shall calculate its individual GSK and the CCC shall combine them into a single GSK for the whole German-Luxembourgian bidding zone~~;~~

~~18. Each single TSO provides GSKs that respect the specific characteristics of the generation in their own grid;~~

~~19.~~5. ~~the TSO-specific GSKs are combined into a single GSK,~~ by assigning relative weights to each ~~TSO-specific GSK. These~~TSO's GSK. The German and Luxembourgian TSOs shall agree on these weights~~ reflect~~, based on the ~~distribution~~share of the ~~total market-driven~~ generation ~~among TSOs~~in each TSO's control area that is responsive to changes in net position, and provide them to the CCC.

~~20. TSOs shall further study~~Within eighteen months after the ~~GSK~~implementation of this methodology ~~referred to in Article 10(2) and Article 10(3) and potentially adapt it~~ in accordance with ~~the results of the internal parallel run pursuant to~~ Article ~~25. Potential improvements~~28(3), all Core TSOs shall ~~be done in~~develop a ~~progressively harmonized way.~~

~~21.~~6. ~~TSOs shall review and update the application~~proposal for further harmonisation of the generation shift key methodology ~~for determining GSK~~and submit it by the same deadline to all Core regulatory authorities as a proposal for amendment of this methodology in accordance with Article ~~22.~~9(13) of the CACM Regulation. The proposal shall at least include:

(a) ~~Article 11~~ 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 8.~~Article 10. Methodology for remedial actions in day-ahead capacity calculation

1. In accordance with Article 25(1) of the CACM Regulation and Article 20(2) of the SO ~~GL,~~ Regulation, the Core TSOs shall individually define ~~Remedial Actions (~~the RAs~~)~~ to be taken into account in the day-ahead ~~common~~ capacity calculation.

2. In case a ~~remedial action~~RA made available for the day-ahead capacity calculation in the Core CCR is also ~~one which is~~ made available in another ~~capacity calculation region~~CCR, the TSO ~~taking~~having control ~~of the remedial action~~on this RA shall take care, when defining it, of a consistent use in its potential application in both ~~regions~~CCRs to ensure ~~a secure power system operation.~~operational security.

3. In accordance with Article 25(2) and (3) of the CACM Regulation, these RAs will be used for the coordinated ~~optimization~~optimisation of cross-zonal capacities while ensuring ~~secure power system operation~~operational security in real~~-~~time.

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 capacity validation, all Core TSOs shall provide to the CCC all expected available costly and non-costly RAs.

5. In order to avoid undue discrimination and with the aim to reduce the amount of expected loop flows, each Core TSO may individually define the initial setting of its own non-costly and costly RAs, based on the best forecast of their application and with the aim to reduce the total loop flows on its cross-zonal CNECs below a loop flow threshold that avoids undue discrimination. This threshold shall be consistent with the assumptions made about the loop flows when defining the minimum RAM factor pursuant to Article 17(9), and shall be equal to 30% of the $F_{max}$ of these CNECs reduced by the *FRM* when a TSO applies a minimum RAM factor equal to 0.7. Each TSO shall provide the CCC with the loop flow threshold for its cross-zonal CNECs to be used in the NRAO.

~~4.~~6. In accordance with Article 25(4) of the CACM Regulation, a TSO may ~~refrain from considering a particular remedial action in~~ withhold only those RAs, which are needed to ensure operational security in real-time operation and for which no other (costly) RAs are available, or those offered to the day-ahead capacity calculation in ~~order to ensure that the remaining remedial actions are sufficient~~other CCRs in which the concerned TSO also participates. The CCC shall monitor and report in the annual report on systematic withholdings, which were not essential to ensure operational security~~;~~ in real-time operation.

~~5.~~7. ~~In accordance with Article 25(5) of the CACM Regulation, the~~The day-ahead ~~common~~ capacity calculation ~~takes~~may only ~~non-costly RAs~~take into account those non-costly RAs which can be ~~explicitly~~ modelled ~~in the D-2 CGM.~~. These non-costly RAs can be, but are not limited to:

(a) changing the tap position of a phase-shifting transformer (PST); and

(b) a topological ~~measure~~action: opening or closing of one or more line(s), cable(s), transformer(s), bus bar coupler(s), or switching of one or more network element(s) from one bus bar to another.

~~6.~~8. In accordance with Article 25(6) of the CACM Regulation, the RAs taken into account are the same for day-ahead and intra-day ~~common~~ capacity calculation, depending on their technical availability.

~~7.~~9. The RAs can be preventive or curative, i.e. affecting all CNECs or only pre-defined contingency cases, respectively.

~~8.~~10. The ~~optimized~~optimised application of non-costly RAs in the day-ahead ~~common~~ capacity calculation is performed in accordance with ~~Article 15.~~Article 16.

~~9.~~11. TSOs shall review and update ~~remedial actions~~the RAs taken into account in the day-ahead capacity calculation in accordance with ~~Article 22.~~Article 24.

## ~~Detailed description~~TITLE 4 - Description of the day-ahead capacity calculation ~~approach~~process

~~1.3 Article 12 Mathematical description of the capacity calculation approach~~

### Article 11. Calculation of power transfer distribution factors and reference flows

1. The flow-based ~~computation~~calculation is a ~~centralized~~centralised calculation, which delivers two main classes of parameters needed for the definition of the flow-based domain: the power transfer distribution factors ($PTDFs$) and the remaining available margins ($RAMs$).

2. In accordance with Article ~~21(b)(i~~29(3)(a) of the CACM Regulation, ~~for each CNEC defined in Article 5(5), Core TSOs~~the CCC shall calculate the ~~influence~~impact of a change in the bidding ~~zone~~zones net position ~~changes~~ on ~~its~~the power flow~~.~~ on each CNEC (determined in accordance with the rules defined in Article 5). This influence is called the zone-to-slack ~~power transfer distribution factor (~~$PTDF$~~)~~. This calculation is performed from the ~~D-2~~ CGM and the $GSK$ defined in accordance with ~~Article 10.~~ Article 9.

3. The ~~nodal~~ zone-to-slack $PTDFs$ ~~can be first~~are calculated by ~~subsequently~~first calculating the node-to-slack $PTDFs$ for each node defined in the $GSK$. These nodal PTDFs are derived by varying the injection of ~~each~~a relevant node ~~defined~~ in the ~~$GSK$ in D-2~~ CGM~~. For~~ and recording the difference in power flow on every ~~single nodal variation, the effect on every CNE's or CNEC's loading is monitored and calculated~~CNEC (expressed as a percentage~~. The $GSK$ shall translate these~~ of the change in injection). These node-to-slack $PTDFs$ are translated into zone-to-slack $PTDFs$ ~~as it converts the bidding zone net position variation into an increase of generation in specific nodes~~by multiplying the share of each node in the GSK with the corresponding nodal PTDF and summing up these products. This calculation is mathematically described as follows:

$$\cancel{\boldsymbol{PTDF}_{zone-to-slack} = \boldsymbol{PTDF}_{node-to-slack} \cdot \boldsymbol{GSK}_{node-to-zone}}$$

$$\mathbf{PTDF}_{\mathrm{zone-to-slack}} = \mathbf{PTDF}_{\mathrm{node-to-slack}}\ \mathbf{GSK}_{\mathrm{node-to-zone}}$$

*Equation ~~3~~3*

with

| | |
|---|---|
| ~~$\boldsymbol{PTDF}_{zone-to-slack}$~~$\mathbf{PTDF}_{zone-to-slack}$ | matrix of zone-to-slack $PTDFs$ (columns: bidding zones~~,~~; rows: CNECs) |
| ~~$\boldsymbol{PTDF}_{node-to-slack}$~~$\mathbf{PTDF}_{node-to-slack}$ | matrix of node-to-slack $PTDFs$ (columns: nodes~~,~~; rows: CNECs) |

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

~~4.~~

~~5.~~4. ~~$PTDFs$ may be defined as~~ The zone-to-slack $PTDFs$ ~~or~~as calculated above can also be expressed as zone-to-zone $PTDFs$. A zone-to-slack $PTDF_{A,l}$ represents the influence of a variation of a net position of bidding zone A on a ~~CNE or CNEC $l$.~~CNEC $l$ and assumes a commercial exchange between a bidding zone and a slack node. A zone-to-zone $PTDF_{A\rightarrow B,l}$ represents the influence of a variation of a commercial exchange from bidding zone A to bidding zone B on ~~a CNE or~~ CNEC $l$. The zone-to-zone $PTDF_{A\rightarrow B,l}$ can be ~~linked to~~derived from the zone-to-slack $PTDFs$ as follows:

$$\cancel{PTDF_{A\rightarrow B,l} = PTDF_{A,l} - PTDF_{B,l}}$$

$$PTDF_{A\rightarrow B,l} = PTDF_{A,l} - PTDF_{B,l}$$

*Equation ~~4~~4*

~~6. A low value of the zone-to-zone value $PTDF_{A\rightarrow B,l}$ as in Equation 4, being a value close to zero percent, means that a commercial exchange between the bidding zone A and bidding zone B does impact the flow on the CNE or CNEC $l$, yet not to a large extent. In a flow-based SDAC, all commercial exchanges that do have an impact on the flow of CNE or CNEC $l$, even when it is low, are competing to make use of its capacity. When it is this CNE or CNEC $l$ that is congested, it implies that the commercial exchange between the bidding zones A and B is restricted as well. TSOs shall monitor the impact of small zone-to-zone PTDFs, as defined in Article 24. In case of an undesireable impact, the TSOs shall take appropriate actions to investigate the mitigation of those effects.~~

~~7.~~

~~8. The PTDF for an exchange between two bidding zones A and B over a HVDC interconnector within the Core CCR following the EFB methodology pursuant to Article 16 shall be expressed as an exchange from bidding zone A to the sending end of the HVDC interconnector plus an exchange from the receiving end of the interconnector to bidding zone B:~~

~~9.~~1. $\cancel{PTDF_{A\rightarrow B,l} = (PTDF_{A,l} - PTDF_{VH\_1,l}) +} (PTDF_{VH\_2,l} - PTDF_{B,l})$

~~10. *Equation 5*~~

~~11.~~

~~12.~~1. ~~with~~

| | |
|---|---|
| ~~13. $PTDF_{VH\_1,l}$~~ | ~~14. zone-to-slack $PTDF$ of Virtual hub 1 on a CNE or CNEC $l$. With Virtual hub 1 representing the converter station at the sending end of the HVDC interconnector located in bidding zone A~~ <br> ~~15.~~ |
| ~~16. $PTDF_{VH\_2,l}$~~ | ~~17. zone-to-slack $PTDF$ of Virtual hub 2 on a CNE or CNEC $l$. With Virtual hub 2 representing the converter station at the receiving end of the HVDC interconnector located in bidding zone B~~ <br> ~~18.~~ |

~~19. The impact of the exchange over the HVDC interconnector on the flow of the CNEs and CNECs can hence be computed as a function of the net positions of the virtual hubs and the corresponding zone-to-slack PTDFs, in accordance to Article 16.~~

~~20.~~

~~21.~~5. The maximum zone-to-zone $PTDF$ of a ~~CNE or a~~ CNEC ($PTDF_{z2zmax,l}$) is the maximum influence that any Core exchange ~~can have~~has on the respective ~~CNE or CNEC~~CNEC, including exchanges over HVDC interconnectors which are integrated pursuant to Article 12:

$$\cancel{PTDF_{z2zmax,l} = \max_{A \in BZ}(PTDF_{A,l}) - \min_{A \in BZ}(PTDF_{A,l})}$$

$$PTDF_{z2zmax,l} = max\left(\max_{A \in BZ}(PTDF_{A,l}) - \min_{A \in BZ}(PTDF_{A,l}), \max_{B \in HVDC}(PTDF_{B,l})\right)$$

*Equation ~~6~~5*

with

| | |
|---|---|
| ~~$PTDF_{A,l}$~~ | ~~zone-to-slack $PTDF$ of bidding zone A on a CNE or CNEC $l$~~ |
| ~~$BZ$~~ | ~~set of all Core bidding zones~~ |
| ~~$\max_{A \in BZ}(PTDF_{A,l})$~~ | ~~maximum zone-to-slack PTDF of Core bidding zones on a CNE or CNEC $l$~~ |
| ~~$\min_{A \in BZ}(PTDF_{A,l})$~~ | ~~minimum zone-to-slack PTDF of Core bidding zones on a CNE or CNEC $l$~~ |
| $PTDF_{A,l}$ | zone-to-slack $PTDF$ of bidding zone A on a CNEC $l$ |
| HVDC | set of HVDC interconnectors integrated pursuant to Article 12 |
| $BZ$ | set of all Core bidding zones |
| $\max_{A \in BZ}(PTDF_{A,l})$ | maximum zone-to-slack PTDF of Core bidding zones on a CNEC $l$ |
| $\min_{A \in BZ}(PTDF_{A,l})$ | minimum zone-to-slack PTDF of Core bidding zones on a CNEC $l$ |

~~22.~~6. The reference flow ($F_{ref}$) is the active power flow on a ~~CNE or a~~ CNEC based on the ~~D-2~~ CGM. In case of a ~~CNE~~CNEC without contingency, $F_{ref}$ is simulated by directly ~~simulated from the D-2~~ performing the direct current load-flow calculation on the CGM~~,~~ whereas in case of a CNEC with contingency, $F_{ref}$ is simulated ~~with~~by first applying the specified contingency, and then performing the direct current load-flow calculation.

~~23.~~7. The expected flow $F_i$ in the commercial situation $i$ is the active power flow of a ~~CNE or~~ CNEC based on the flow $F_{ref}$ and the deviation ~~of commercial exchanges~~ between the ~~D-2~~commercial situation considered in the CGM (reference commercial situation) and the commercial situation $i$:

$$\vec{F_i} = \vec{F}_{ref} + \cancel{\boldsymbol{PTDF} \times (\vec{NP_i} - \vec{NP}_{ref})}\mathbf{PTDF}\left(\vec{NP_i} - \vec{NP}_{ref}\right)$$

*Equation ~~7~~6*

with

| | |
|---|---|
| $\vec{F_i}$ | expected flow per CNEC in the commercial situation $i$ |
| $\vec{F}_{ref}$ | flow per CNEC in the CGM (reference flow) |

| | |
|---|---|
| ~~$\mathbf{PTDF}$~~PTDF | power transfer distribution factor matrix |
| $\overrightarrow{NP_i}$ | Core net position per bidding zone in the commercial situation $i$ |
| $\overrightarrow{NP_{ref}}$ | Core net position per bidding zone in the ~~CGM~~reference commercial situation |

## Article 12. Integration of HVDC interconnectors on bidding zone borders of the Core CCR

1. The Core TSOs shall apply the evolved flow-based (EFB) methodology when including HVDC interconnectors on the bidding zone borders of the Core CCR[5]. According to this methodology, a cross-zonal exchange over an HVDC interconnector on the bidding zone borders of the Core CCR is modelled and optimised explicitly as a bilateral exchange in capacity allocation, and is constrained by the physical impact that this exchange has on all CNECs considered in the final flow-based domain used in capacity allocation.

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

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

~~3. The remaining available margin ($RAM$) of a CNE or a CNEC in a commercial situation $i$ is the remaining capacity that can be given to the market taking into account the already allocated capacity in the situation $i$. This $RAM_i$ is then calculated from the maximum admissible power flow ($F_{max}$), the adjustment for minimum $RAM$ ($AMR$), the margin for LTA inclusion ($LTA_{margin}$), the reliability margin ($FRM$), the final adjustment value ($FAV$), and the expected flow ($F_i$) with the following equation:~~

$$\cancel{RAM_i = F_{max} + AMR + LTA_{margin} - FRM - FAV - F_i}$$

*Equation ~~8~~7*

with

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

[5] EFB is different from AHC. AHC imposes the capacity constraints of one CCR on the cross-zonal exchanges of another CCR by considering the impact of exchanges between two capacity calculation regions. E.g. the influence of exchanges of a bidding zone which is part of a CCR applying a coordinated net transmission capacity approach is taken into account in a bidding zone which is part of a CCR applying a flow-based approach. EFB takes into account commercial exchanges over the cross-border HVDC interconnector within a single CCR applying the flow-based method of that CCR.

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

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

4. The 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 virtual hubs in the coupling algorithm. The two 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 virtual hubs shall be of the same magnitude, but they will have an opposite sign.

## Article 13. Consideration of non-Core bidding zone borders

1. Where critical network elements within the Core CCR are also impacted by electricity exchanges outside the Core CCR, the Core TSOs shall take such impact into account with a standard hybrid coupling (SHC) and where possible also with an advanced hybrid coupling (AHC).

2. In the standard hybrid coupling, the Core TSOs shall consider the electricity exchanges on bidding zone borders outside the Core CCR as fixed input to the day-ahead capacity calculation. These electricity exchanges, defined as best forecasts of net positions and flows for HVDC lines, are defined and agreed pursuant to Article 19 of the CGMM and are incorporated in each CGM. They impact the $F_{ref}$ and $F_{0,Core}$ on all CNECs and thereby increase or decrease the $RAM$ of the Core CNECs in order for those CNECs to accommodate the flows resulting from those exchanges. Uncertainties related to the electricity exchanges forecasts are implicitly integrated within the $FRM$ of each CNEC.

3. In the AHC, the CNECs of the day-ahead capacity calculation methodology shall limit not only the net positions of the Core bidding zone borders, but also the electricity exchanges on bidding zone borders of adjacent CCRs.

4. No later than eighteen months after the implementation of this methodology in accordance with Article 28(3), the Core TSOs shall jointly develop a proposal for the implementation of the AHC 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 for the implementation of the AHC shall aim to reduce the volume of unscheduled allocated flows on the CNECs of the Core CCR resulting from electricity exchanges on the bidding zone borders of adjacent CCRs. If before the implementation of this methodology, the AHC has been implemented on some bidding zone borders in existing flow-based capacity calculation initiatives, it may continue to be applied on those bidding zone borders as part of the day-ahead capacity calculation carried out according to this methodology until the amendments pursuant to this paragraph are implemented.

5. Until the AHC is implemented, the Core TSOs shall monitor the accuracy of non-Core exchanges in the CGM. The Core TSOs shall report in the annual report to all Core regulatory authorities the accuracy of such forecasts.

## Article 14. Initial flow-based calculation

1. As a first step in the day-ahead capacity calculation process, the CCC shall merge the individual lists of CNECs provided by all Core TSOs in accordance with Article 5(4) into a single list, which shall constitute the initial list of CNECs.

2. Subsequently, the CCC shall use the initial list of CNECs pursuant to paragraph 1, the CGM pursuant to Article 4(7) and the GSK for each bidding zone in accordance with Article 9 to calculate the initial flow-based parameters for each DA CC MTU.

3. The initial flow-based parameters shall be calculated pursuant to Article 11 and shall consist of the $\mathbf{PTDF}_{init}$ and $\vec{F}_{ref,init}$ values for each initial CNEC.

## Article 15. Definition of final list of CNECs and MNECs for day-ahead capacity calculation

1. The CCC shall use the initial list of CNECs determined pursuant to Article 14 and remove those CNECs for which the maximum zone-to-zone $PTDF_{init}$ is not higher than 5%. The remaining CNECs shall constitute the final list of CNECs.

2. The CCC shall use the lists of MNECs submitted by the Core TSOs and merge them into a common list of MNECs, which shall be monitored during the NRAO process, based on information provided by the Core TSOs pursuant to Article 5. In accordance with Article 16(3)(d)(vi), the additional loading resulting from the application of the NRAO process on the MNECs may be limited during the NRAO process, while ensuring that a certain additional loading up to the defined threshold is always accepted.

## Article 16. Non-costly remedial actions optimisation

1. The NRAO process coordinates and optimises the use and application of non-costly RAs pursuant to Article 10, with the aim of enlarging and securing the flow-based domain around the expected operating point of the grid, represented by the reference net positions and exchanges.

2. The NRAO shall be an automated, coordinated and reproducible optimisation process performed by the CCC that applies non-costly RAs defined in accordance with Article 10. Before the start of the NRAO, the CCC shall apply the initial setting of non-costly and costly RAs as determined and provided by individual TSOs pursuant to Article 10(4) and (5).

3. The NRAO shall consist of the following objective function, variables and constraints:

   (a) the objective function of the NRAO is to maximise the smallest relative RAM of all limiting CNECs. External constraints shall not be included in this objective function.

$$\min_{limiting\ CNECs}(RAM_{rel}) \rightarrow to\ be\ maximised$$

   (b) the optimisation process iterates[6] over switching states (i.e. activated or not-activated) of topological measures and PST tap positions in order to maximise this objective. Preventive RAs may jointly be associated with all CNECs, whereas curative RAs may be optimised independently for each contingency.

[6] A global optimisation finding the optimal solution in one iteration would also be acceptable, as long as the final optimisation result is at least as good as the one obtained through the described iterative process, i.e. would lead to a higher value of the objective function while fulfilling all constraints.

(c) for a given state of the optimisation, the $RAM_{nrao}$ of a CNEC takes into account flows coming from reference net positions and exchanges as well as switching states of RAs. As a result, the $PTDF_{nrao}$ and $F_{nrao}$ are updated for each CNEC during each optimisation iteration. The calculations of $RAM_{nrao}$ and relative $RAM_{nrao}$ for a given CNEC are expressed in Equation 8 and Equation 9, and rely on $F_{max}$, $FRM$ and $F_{ref,init}$.

$$\overrightarrow{RAM}_{nrao} = \vec{F}_{max} - \overrightarrow{FRM} - \vec{F}_{ref,init} + \vec{F}_{nrao}$$

*Equation 8*

with

| | |
|---|---|
| $\overrightarrow{RAM}_{nrao}$ | RAM per CNEC during the NRAO optimisation process |
| $\vec{F}_{ref,init}$ | Reference flow per CNEC in the CGM in the initial flow-based calculation |
| $\vec{F}_{nrao}$ | Flow change per CNEC due to preventive and/or curative RAs, derived from simulations conducted on the CGM (and initially zero) |

$$RAM_{rel} = \frac{RAM_{nrao}}{\sum_{(A,B)\,\in\, neighbouring\ Core\ bidding\ zones\ pairs} |PTDF_{A\rightarrow B,nrao}|}\ if\ RAM_{nrao} \geq 0$$

$$RAM_{rel} = RAM_{nrao}\ if\ RAM_{nrao} < 0$$ [7]

*Equation 9*

with

~~Article 13~~

| | |
|---|---|
| $PTDF_{A\rightarrow B,nrao}$ | The zone-to-zone PTDFs for the current optimisation iteration |

(d) The constraints of the NRAO are:

i. $F_{max}$, $FRM$ and $F_{ref,init}$ per CNEC;

ii. the available range of tap positions of each PST;

iii. parallel PSTs, as defined by TSOs, shall have equal tap positions;

iv. a RA may only be associated with a CNEC, if it has a minimum positive impact on the objective function or constraint;

v. the maximum number of activated curative non-costly remedial actions per CNEC (with contingency);

vi. the $RAM_{nrao}$ of the MNECs shall be positive. A minimum initial $RAM_{nrao}$ (at reference point, without RAs) of 50 MW shall be applied for MNECs;

[7] $RAM_{rel}$ ignores PTDFs for overloaded CNECs, in order to solve the largest absolute overloads first.

vii. the loop flow on each cross-zonal CNEC, which is equal to $F_{0,all}$ calculated pursuant to Article 17(3), shall not increase above either:

d.vii.1. the initial value of $F_{0,all}$ of the considered CNEC before the NRAO in case this value is higher than or equal to the loop flow threshold as defined in Article 10(5);

d.vii.2. the loop flow threshold as defined in Article 10(5) in case the initial value of $F_{0,all}$ of the considered CNEC before the NRAO is lower than the loop flow threshold as defined in Article 10(5);

4. As a result of the NRAO, a set of RAs is associated with each CNEC. $PTDF$ and $F_{ref}$ are updated as follows:

(a) $\mathbf{PTDF}_f = \mathbf{PTDF}_{nrao}$ directly from the optimisation results;

(b) $\vec{F}_{ref} = \vec{F}_{ref,init} - \vec{F}_{nrao}$, based on the RAs associated with each CNEC by the NRAO.

5. The non-costly RAs applied at the end of the NRAO shall be transparent to all TSOs of the Core CCR, and also of adjacent CCRs, and shall be taken as an input to the coordinated operational security analysis established pursuant to Article 75 of the SO Regulation.

6. An exchange of foreseen RAs in each CCR, with sufficient impact on the cross-zonal capacity in other CCRs, shall be coordinated among CCCs. The CCC shall take this information into account for the coordinated application of RAs in the Core CCR;

7. Every year after the implementation of this methodology in accordance with Article 28(3), the CCC, in coordination with the Core TSOs, shall analyse the efficiency of the NRAO and present the results of this analysis in the annual report. This analysis shall contain an ex-post analysis on whether the NRAO effectively increased cross-zonal capacity in the most valuable market direction. The analysis shall focus on data from the last year of operation, and shall include at least the following information:

(a) an assessment of the availability of non-costly RAs provided by the Core TSOs, including the average number of non-costly RAs provided by each Core TSO;

(b) for the Core TSOs which did not provide non-costly RAs, a justification why they did not do so;

(c) for each CNEC with non-zero shadow price: $\overrightarrow{PTDF}_{init}$, $\overrightarrow{PTDF}_f$, $F_{ref,init}$ and $F_{nrao}$; and

(d) an estimate of the market clearing point (and related market welfare) which may have occurred, should the NRAO not have taken place (but including other capacity calculation steps such as minRAM, LTA inclusion and an estimate of the validation phase).

8. Based on the conclusion of the analysis mentioned in the previous paragraph, the Core TSOs may propose changes to the NRAO by submitting to all Core regulatory authorities a proposal for amendment of this methodology in accordance with Article 9(13) of the CACM Regulation.

## ~~Article 9.~~Article 17. Adjustment for minimum ~~*RAM*~~RAM

1. ~~In response to~~To address the requirement of Article 21(1)(b)(ii) of the CACM Regulation, ~~in addition to applying the common maximum zone-to-zone *PTDF* threshold set in Article 5(6)(a),~~the Core TSOs shall ensure ~~a minimum~~that the $RAM$ for ~~the CNECs~~each CNEC determining the cross-

zonal capacity ~~before allocating commercial exchanges, save for reasons of operational security.~~is never below a minimum $RAM$, except in cases of validation reductions as defined in Article 20.

~~2. The margin made available on each CNEC for flows stemming from the sum of all commercial exchanges within the Core CCR shall not be lower than 20 percent of the maximum admissible power flow $F_{max}$, without prejudice to the right for exclusion of specific CNECs according to Article 13(5) and for adjustment of cross-zonal capacity during validation in accordance with Article 21.~~

2. In order to determine the adjustment for minimum $RAM$~~,~~ for a CNEC, the flow in the situation without commercial exchanges within the Core CCR is ~~considered. The flows on all CNECs in this commercial situation are determined by setting $\overrightarrow{NP_i}$ to zero in~~ first calculated by setting the Core net positions $\overrightarrow{NP_i}$ in Equation 6 to zero for all Core bidding zones, leading to the following equation:

$$\vec{F}_{0,Core} = \vec{F}_{ref} - \mathbf{PTDF}_{\boldsymbol{f}}\ \overrightarrow{NP}_{ref,Core}$$

*Equation 10*

with

| | |
|---|---|
| $\vec{F}_{0,Core}$ | flow per CNEC in the situation without commercial exchanges within the Core CCR |
| $\vec{F}_{ref}$ | flow per CNEC in the CGM after the NRAO |
| $\mathbf{PTDF}_{\boldsymbol{f}}$ | power transfer distribution factor matrix for the Core CCR |
| $\overrightarrow{NP}_{ref,Core}$ | Core net position per bidding zone included in the CGM |

3. Then, the CCC shall calculate $F_{0,all}$, which is the flow on each CNEC in a situation without any commercial exchange between bidding zones within Continental Europe, and between bidding zones within Continental Europe and bidding zones from other synchronous areas. For this calculation, the CCC shall set all exchanges on DC interconnectors between Continental Europe and other synchronous areas to zero, and then calculate the zonal PTDFs for all bidding zones within the synchronous area Continental Europe for each CNEC. For this calculation, the CCC shall use the GSKs provided by the concerned TSOs to the Common Grid Model platform, and when these are not available, the CCC shall use a GSK where all nodes with positive injections participate to shifting in proportion to their injection. Subsequently the CCC shall calculate $F_{0,all}$ with the following Equation 11.

$$\vec{F}_{0,all} = \vec{F}_{ref} - \mathbf{PTDF}_{\boldsymbol{all}}\ \overrightarrow{NP}_{ref,all}$$

*Equation 11*

with

| | |
|---|---|
| $\vec{F}_{0,all}$ | flow per CNEC in a situation without any commercial exchange between bidding zones within Continental Europe and between bidding zones within Continental Europe and bidding zones of other synchronous areas |
| $\mathbf{PTDF}_{\boldsymbol{all}}$ | power transfer distribution factor matrix for all bidding zones in Continental Europe and all Core CNECs |
| $\overrightarrow{NP}_{ref,all}$ | total net positions per bidding zone in Continental Europe included in the CGM |

4. The flow assumed to result from commercial exchanges outside the Core CCR ($F_{uaf}$) is then calculated for each CNEC as follows:

$$\vec{F}_{uaf} = \vec{F}_{0,Core} - \vec{F}_{0,all}$$

*Equation 12*

with

| | |
|---|---|
| $\vec{F}_{uaf}$ | flow per CNEC assumed to result from commercial exchanges outside Core CCR |

5. The main objective of the adjustment of the minimum RAM is to ensure that at least a specific percentage, as defined in paragraph 9, of $F_{max}$ is reserved for commercial exchanges on all bidding zone borders, including those outside the Core CCR. This means that the sum of $RAM$ (capacity offered within the Core CCR) and $F_{uaf}$ (capacity offered outside the Core CCR) on the Core CNECs shall be equal or higher than the specific percentage, defined in paragraph 9, of $F_{max}$. If the specific percentage, defined in paragraph 9, is expressed generally as a minimum RAM factor ($R_{amr}$), then it follows:

$$RAM + F_{uaf} \geq R_{amr} \cdot F_{max}$$

*Equation 13*

6. The adjustment of minimum RAM aims to ensure that the previous inequality is always fulfilled, therefore $AMR$ is added as follows:

$$RAM + F_{uaf} + AMR = R_{amr} \cdot F_{max}$$
$$RAM = F_{max} - FRM - F_{0,Core}$$

*Equation 14*

7. The minimum RAM available for trade on each CNEC of the Core CCR shall not be below 20% of $F_{max}$.

~~3.~~8. Combining the previous requirements, the $AMR$ for a CNEC is finally determined with the following equation~~7, which leads to the following equation:~~:

$$\cancel{\vec{F}_0} AMR = \max\begin{pmatrix} R_{amr} \cdot F_{max} - F_{uaf} - (F_{max} - FRM - F_{0,Core}), \\ 0.2 \cdot F_{max} - (F_{max} - FRM - F_{0,Core}), 0 \end{pmatrix}$$

$$= \vec{F}_{ref} \cancel{- \mathbf{PTDF} \cdot \overrightarrow{NP}_{ref}}$$

*Equation ~~9~~15*

with

| | |
|---|---|
| ~~$\vec{F}_0$~~ | ~~flow per CNEC in the situation without commercial exchanges within the Core CCR~~ |
| ~~$\vec{F}_{ref}$~~ | ~~flow per CNEC in the CGM (reference flow)~~ |
| ~~$\mathbf{PTDF}$~~ | ~~power transfer distribution factor matrix~~ |

| | |
|---|---|
| ~~$\overrightarrow{NP}_{ref}$~~ | ~~Core net position per bidding zone in the CGM~~ |

~~4. The adjustment for minimum $RAM$ ($AMR$) per CNEC is determined with the following equation:~~

$$\cancel{AMR = max(0.2F_{max} - (F_{max} - FRM - F_0); 0)}$$

~~*Equation 10*~~

~~with~~

| | |
|---|---|
| ~~$F_{max}$~~ | ~~Maximimum admissible flow~~ |
| ~~$FRM$~~ | ~~Flow reliability margin~~ |
| ~~$F_0$~~ | ~~Flow in the situation without commercial exchanges within the Core CCR~~ |

~~5. A TSO may decide to not apply the $AMR$ in certain circumstances on specific CNECs, justified to regulatory authorities pursuant to Article 24(3)(o). The exclusion can be performed:~~

~~1. before the initial flow based parameter computation when the TSO identifies the necessity when providing the CNEC list, pursuant to Article 4(2); or~~
~~2. during the validation process as described in Article 21, and pursuant Article 4(6)(e).~~

~~6. The exclusion of the application of $AMR$ for a given CNEC as described in Article 13(5) can be triggered in situations when there are insufficient available remedial actions, costly or not, in order to ensure the security of supply and system security.~~

~~Article 14~~

| | |
|---|---|
| $F_{max}$ | maximum admissible flow |
| $FRM$ | flow reliability margin |
| $F_{uaf}$ | flow per CNEC resulting from assumed commercial exchanges outside the Core CCR |
| $F_{0,\mathrm{Core}}$ | flow in the situation without commercial exchanges within the Core CCR |
| $R_{amr}$ | minimum RAM factor |

9. The minimum RAM factor $R_{amr}$ shall be equal to 0.7 for all CNECs, except those for which a derogation has been granted or an action plan to address structural congestions has been set in accordance with the relevant Union legislation. In case of such a derogation or action plan, the $R_{amr}$ shall be defined by means of a linear trajectory as defined in Annex II to this methodology, unless otherwise defined by the decisions on derogations or action plans in accordance with the relevant Union legislation. In the latter case, the TSO(s) affected by such derogations or action plans shall inform all Core regulatory authorities and the Agency about the values of $R_{amr}$ applicable during the period for which the derogation has been granted or action plan has been set.

## ~~Article 10.~~Article 18. Long-term allocated capacities (LTA) inclusion

1. In accordance with Article 21(1)(b)(iii) of the CACM Regulation, the Core TSOs shall apply the following rules for taking into account the previously-allocated cross-zonal capacity:

(a) ~~The objective of~~ the rules ~~is to verify~~ensure that the $RAM$ of each ~~CNE or~~ CNEC remains non-negative in all combinations of net positions that could result from previously-allocated ~~commercial net positions~~cross-zonal capacity.

(b) ~~"Previously~~previously-allocated capacities~~"~~ on all ~~commercial~~bidding zone borders of the Core CCR are the long-term allocated capacities (LTA~~). LTA shall be~~) calculated ~~under~~ and allocated pursuant to the ~~framework of Commission~~FCA Regulation ~~(EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation in accordance with the therein foreseen respective timelines~~.

(c) ~~As long as~~until the implementation of long-term capacity calculation ~~according to Article 14(1)(b) has not been established, LTA will be~~ as referred to in paragraph 1(b), LTA shall be based on historical values of long-term allocated capacities and any change shall be commonly coordinated ~~on an annual basis during an~~ and agreed by all Core TSOs ~~meeting. Core TSOs will commonly coordinate on any proposed deviation from~~ with the support of the ~~historical values on~~CCC.

2. In case an external constraint restricts the ~~basis~~Core net positions pursuant to Article 7(2(a), it shall be added as an additional row to the $\mathbf{PTDF}_f$ matrix and to the $\vec{F}_{max}$, $\vec{F}_{ref}$, $\overrightarrow{FRM}$, and $\overrightarrow{AMR}$ vectors as follows:

(a) the $PTDF$ value in the column related to the bidding zone applying the concerned external constraint is set to 1 for an export limit and -1 for an import limit, respectively;

(b) the $PTDF$ values in the columns related to all other bidding zones are set to zero;

(c) the $F_{max}$ value is set to the amount of ~~security assessment.~~the external constraint;

(d) ~~The following~~the $F_{ref}$ value is set to the Core net position in the CGM of the bidding zone applying the external constraint, i.e. $NP_{ref}$ in the equation ~~shall be applied to all possible combinations~~below; and

(e) the $FRM$ and $AMR$ values are set to zero;

~~2.~~3. The first step in the LTA inclusion is to calculate the flow for each CNEC (including external constraints) in each combination of net positions resulting from the full ~~utilization~~utilisation of previously-allocated capacities on all ~~commercial~~bidding zone borders~~:~~ of the Core CCR, based on Equation 6:

$$\cancel{\vec{F}_{LTA_i} = \vec{F}_{ref} + \boldsymbol{PTDF} \times \left(\overrightarrow{NP}_{LTA_i} - \overrightarrow{NP}_{ref}\right)}$$

$$\vec{F}_{LTAi} = \vec{F}_{ref} + \mathbf{PTDF}_f \left(\overrightarrow{NP}_{LTAi} - \overrightarrow{NP}_{ref}\right)$$

*Equation ~~11~~16*

with

| | |
|---|---|
| $\cancel{\vec{F}_{LTA_i}}\vec{F}_{LTAi}$ | flow per CNEC in LTA capacity ~~utilization~~utilisation combination $i$ |
| $\vec{F}_{ref}$ | flow per CNEC in the CGM ~~(reference flow)~~after the NRAO |

| | |
|---|---|
| $\cancel{\boldsymbol{PTDF}}\mathbf{PTDF}_f$ | zone-to-slack power transfer distribution factor matrix |
| $\cancel{\overrightarrow{NP}_{LTA_i}}\overrightarrow{NP}_{LTAi}$ | Core net position per bidding zone in LTA capacity ~~utilization~~utilisation combination $i$ |
| $\overrightarrow{NP}_{ref}$ | Core net position per bidding zone in the CGM |

~~3.~~

~~4. Then the following equation shall be checked:~~

~~5.~~

~~6.~~ $\cancel{RAM_{LTA_i} = F_{max} + AMR + LTA_{margin} - FRM - FAV - F_{LTA_i}}$

~~7. *Equation 12*~~

4. For a given CNEC, the maximum oriented flow from the LTA inclusion is then

$$F_{LTA,max} = \max_i F_{LTAi}$$

*Equation 17*

5. The adjustment for the LTA inclusion is finally:

$$LTA_{margin} = \max(F_{LTA,max} + FRM - AMR - F_{max}; 0)$$

*Equation 18*

## Article 19. Calculation of flow-based parameters before validation

Based on the initial flow-based domain and on the final list of CNECs, the CCC shall calculate for each CNEC the RAM before validation, relying on the following sequential steps:

(a) the calculation of $F_{ref}$ and $PTDF_f$ through the NRAO according to Article 16;

(b) the calculation[8] of the adjustment for minimum $RAM$ ($AMR$) according to Article 17;

(c) the calculation of the adjustment for the LTA inclusion according to Article 18;

(d) the calculation of $RAM$ before validation as follows:

$$\overrightarrow{RAM}_{bv} = \vec{F}_{max} - \overrightarrow{FRM} - \vec{F}_{0,Core} + \overrightarrow{AMR} + \overrightarrow{LTA}_{margin}$$

*Equation 19*

with

| | |
|---|---|
| $\vec{F}_{max}$ | Maximum active power flow pursuant to Article 6 |
| $\overrightarrow{FRM}$ | Flow reliability margin pursuant to Article 8 |

[8] $AMR$, $F_{0,Core}$ and $FRM$ do not apply to external constraints, and shall be zero for such constraints.

| | |
|---|---|
| $\cancel{RAM_{LTA_i}}\vec{F}_{0,Core}$ | ~~$RAM$ per CNEC in LTA capacity utilization combination $i$~~ Flow without commercial exchanges in the Core CCR, described in Equation 10. For external constraints, in line with Article 18(2), this flow is equal to zero. |
| $\overrightarrow{AMR}$ | Adjustment for minimum RAM pursuant to Article 17 |
| $\cancel{LTA_{margin}}\overrightarrow{LTA}_{margin}$ | ~~the~~Flow margin for LTA inclusion, pursuant to Article 18 |
| $\overrightarrow{RAM}_{bv}$ | Remaining available margin before validation |

~~7. If at least one of the remaining available margins $RAM_{LTA_i}$ is smaller than zero, it implies that the previously-allocated capacities are not fully covered by the flow-based domain. In this case the $RAM$ of limiting CNEs shall be increased using the $LTA_{margin}$ parameter to compensate the negative $RAM_{LTA_i}$.~~

~~1.4 Article 15 Rules on adjustment of power flows on critical network elements due to remedial actions~~

~~8. In accordance with Article 21(1)(b)(iv) of the CACM Regulation, this day-ahead common capacity calculation methodology shall describe the rules on the adjustment of power flows on critical network elements due to remedial actions:~~

## Article 20.~~An exchange of foreseen remedial actions in each CCR, with sufficient impact on the~~ Validation of flow-based parameters

~~1.~~ The Core TSOs shall validate and have the right to correct cross-zonal capacity ~~in other CCRs, should be coordinated among CCCs. The Core CCC shall take this information into account~~ for ~~the coordinated application of RAs in the Core CCR;~~

~~2. the coordinated application of RAs shall aim at optimizing cross-zonal capacity in the Core CCR in accordance with Article 29(4) of the CACM Regulation. The remedial action optimization (RAO) itself consists of a coordinated optimization of cross-zonal capacity within the Core CCR by means of securing and enlarging the flow-based domain in the foreseen operating point of the grid. The foreseen operating point of the grid shall be expressed by the balanced net positions for each bidding zone obtained from the Common Grid Model Alignment process, pursuant to the Common Grid Model Alignment Methodology.~~

~~3. The RAO shall be an automated, coordinated, and reproducible process, performed by the CCC, that applies RAs defined in accordance with Article 11; and~~

~~4.~~1. ~~the applied RAs should be transparent to all TSOs, also of adjacent CCRs, and shall be an input to the coordinated~~ reasons of operational security ~~analysis established under SO GL Article 75~~during the validation process individually and in a coordinated way.

~~5. The RAO methodology contains a set of pre-defined characteristics such as an objective function, constraints, and optimization variables:~~

~~6. The RAO objective is to enlarge the capacity domain around the balanced net positions of the Common Grid Model Alignment process, with the objective function $\min(RAM_{rel}) \rightarrow max$, i.e. maximizing the minimum relative $RAM$ of all optimized CNECs in accordance with Article 5(6)(a). The term relative refers to a~~

~~weighting of $RAM$ determined by the reciprocal of the sum of all absolute zone-to-zone $PTDFs$ on Core bidding zone borders, see Equation 13.~~

~~7.~~

~~8.~~ $$\cancel{RAM_{rel} = \frac{RAM}{\sum_{(A,B)\in Pairs\ of\ Core\ bidding\ zones\ with\ commercial\ border}|PTDF_{A\rightarrow B}|}}$$

~~9. *Equation 13*~~

~~10.~~

~~11. As long as the $RAM$ on at least one CNEC is less than zero, the objective function changes to the maximization of the minimum *absolute* margin of all optimized CNECs in accordance with Article 5(6)(a), until all CNECs have a $RAM$ equal to or larger than zero.~~

~~12. The constraints, in accordance with Article 25(4) of the CACM Regulation, are:~~

~~13. operational security limits of optimized CNECs in accordance with Article 6;~~

~~14. the provided range of tap positions of each PST as preventive or curative remedial actions;~~

~~15. minimum impact on objective function value for use of remedial actions;~~

~~16. equal tap positions for pre-defined parallel PSTs;~~

~~17. limitations on the number of activated curative remedial actions;~~

~~18. maximum loading of monitored (i.e. not optimized) CNECs in accordance with Article 5(6)(b), limiting the additional flow due to the RAO to the maximum of 50 MW and the CNEC's $RAM$ prior to the RAO.~~

~~19. The optimization variables are the switching states of topological measures and PST tap positions.~~

## ~~20. Article 16 Integration of cross-border HVDC interconnectors located within the Core CCR~~

~~21. Core TSOs shall apply the evolved flow-based (EFB) methodology when including cross-border HVDC interconnectors within the Core CCR.~~

~~22. Core TSOs shall take into account the impact of an exchange over a cross-border HVDC interconnector located within the Core CCR on all CNECs within the process of capacity calculation and allocation. The flow-based properties and constraints of the Core CCR (in contrast to an NTC approach) and at the same time optimal allocation of capacity on the interconnector in terms of market welfare shall be taken into account.~~

~~23. Core TSOs shall distinguish between AHC and EFB. AHC imposes the capacity constraints of one CCR on the cross-zonal exchanges of another CCR by considering the impact of exchanges between two capacity calculation regions. E.g. the influence of exchanges of a bidding zone which is part of a CCR applying a coordinated net transmission capacity approach is taken into account in a bidding zone which is part of a CCR applying a flow-based approach. EFB takes into account commercial exchanges over the cross-border HVDC interconnector within a single CCR applying the flow-based method of that CCR.~~

~~24. The main adaptations to the day-ahead common capacity calculation process introduced by the concept of EFB are twofold:~~

~~25. the impact of an exchange over the cross-border HVDC interconnector is considered for all relevant CNECs;~~

~~26. the outage of the HVDC interconnector is considered as a contingency for all relevant CNEs in order to simulate no flow over the interconnector, since this is becoming the N-1 state.~~

~~27. In order to achieve the integration of the cross-border HVDC interconnector into the flow-based process, two virtual hubs at the converter stations of the cross-border HVDC shall be added. These virtual hubs represent the impact of an exchange over the cross-border HVDC interconnector on the relevant CNECs. By placing a GSK value of 1 at the location of each converter station, the impact of a commercial exchange can be translated into a $PTDF$ value. This action adds two columns to the existing $PTDF$ matrix, one for each~~

~~virtual hub. The virtual hubs introduced by this process in Article 12(6) are only used for the modelisation of the impact of an exchange, and do not contain any bids during market coupling. As a result, the virtual hubs will have a global net position of 0 MW, but their FB net position will reflect the exchanges over the interconnector. The flow-based net positions of these virtual hubs will be the same value, but they will have an opposite sign.~~

28. ~~The list of contingencies considered in the capacity calculation will be extended to include the cross-border HVDC interconnector. Therefore, the outage of the interconnector has to be modelled as a N-1 state and the consideration of the outage of the HVDC interconnector creates additional CNEC combinations for all relevant CNEs during the process of capacity calculation and allocation.~~

## 29. ~~Article 17 Consideration of non-Core CCR borders~~

30. ~~In accordance with Article 21(1)(b)(vii) of the CACM Regulation, Core TSOs take into account the influences of other CCRs by making assumptions on what will be the future non-Core exchanges in accordance with Article 18(3) of the CACM Regulation and Article 19 of the Common Grid Model Methodology.~~
31. ~~The assumptions of non-Core exchanges are implicitly captured in the D-2 CGM by the non-Core TSOs' best forecasts of net positions and flows for HVDC lines, according to Article 18(3) of CACM Regulation, which are used as the basis for the common capacity calculation. In Core CCR, this constitutes the rule for sharing power flow capabilities of Core CNECs among different CCRs. The expected exchanges are thus captured implicitly in the~~ $RAM$ ~~via the reference flow~~ $F_{ref}$ ~~over all CNECs (see also Equations 7 and 8 of Article 12). As such, these assumptions will impact (increase or decrease) the~~ $RAMs$ ~~of Core CNECs. Resulting uncertainties linked to the aforementioned assumptions are implicitly integrated within each CNEC's~~ $FRM$. ~~This concept is usually referred to as standard hybrid coupling.~~
32. ~~In contrast, advanced hybrid coupling (AHC) would enable Core TSOs to explicitly model the exchange situations of adjacent CCRs within the flow-based domain and thus in the single day-ahead coupling. This would reduce uncertainties in the D-2 CGM regarding forecast of non-Core exchanges, and increase the degree of freedom for the single day-ahead coupling in terms of optimal allocation of capacities. The feasibility of AHC will be studied in accordance with Article 25(7).~~
33. ~~AHC is considered to be the target soluton to explicitly model the exchange situations of adjacent CCRs within the Core flow-based domain and will be discussed with adjacent involved CCRs.~~
34. ~~Core TSOs shall monitor the accuracy of non-Core exchanges in the D-2 CGM. Core TSOs shall report on at least an annual basis.~~

## 35. ~~Article 18 Calculation of the final flow-based domain~~

36. ~~After the determination of the optimal preventive and curative RAs, the RAs are explicitly associated to the respective Core CNECs (thus altering their reference flow~~ $F_{ref}$ ~~and~~ $PTDF$ ~~values) and the final flow-based parameters are computed in the following sequential steps:~~
37. ~~determination of the adjustment for minimum~~ $RAM$ ($AMR$) ~~according to Article 13;~~
38. ~~execution of the rules for previously-allocated capacity in Article 14;~~
39. ~~application of a possible~~ $FAV$ ~~in accordance with Article 21;~~
40. ~~only the constraints that are most limiting the exchanges need to be respected in the single day-ahead coupling: the non-redundant constraints (or the "presolved" domain). The redundant constraints are identified and removed by the CCC by means of the so-called "presolve" process. The principle of the "presolve" is to give, one after the other, each flow-based constraint a very high RAM and check whether the flow on this line can be higher than its original RAM value by changing the net position values and taking all the other~~

~~constraints into account. If the flow on this line is able to exceed the original RAM value, by a certain set of net positions without violating any of the other constraints, the flow-based constraint is not redundant and remains with its original RAM. If the flow on this line remains below the original RAM value, the flow is limited by other constraints and the flow-based constraint is redundant and will be removed ("presolved") from the flow-based domain. By respecting this "presolved" domain, the commercial exchanges also respect all the redundant constraints;~~

~~41. as the reference flow ($F_{ref}$) is the physical flow computed from the D-2 CGM, it reflects the loading of the CNEs and CNECs given the forecast commercial exchanges. Therefore, this reference flow has to be adjusted firstly to remove the effect of these commercial exchanges. The $PTDFs$ remain identical in this step. Consequently, the effect on the flow-based capacity domain is a shift in the solution space. It is computed using equation 7 pursuant to Article 12(9) for the commercial situation without Core commercial exchanges:~~

~~42.~~

~~43.~~ $\vec{F}_0 = \vec{F}_{ref} + \boldsymbol{PTDF} \cdot (\vec{0} - \overrightarrow{NP}_{ref})$

~~44. *Equation 14*~~

2. Capacity validation shall consist of two steps. In the first step, the Core TSOs shall analyse in a coordinated manner whether the cross-zonal capacity (i.e. the $RAM_{bv}$) could violate operational security limits, and whether they have sufficient RAs to avoid such violations. In the second step, each Core TSO shall individually analyse whether the cross-zonal capacity could violate operational security limits in its own control area.

3. In the first step, the CCC in coordination with all Core TSOs shall validate the $RAM_{bv}$. In this process they 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 $RAM_{bv}$ on individual CNECs 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 on the use of RAs having an impact on neighbouring CCRs. 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 $RAM_{bv}$ to the maximum value which avoids the violation of operational security. This reduction of the $RAM_{bv}$ is called 'coordinated validation adjustment' ($CVA$) and the adjusted $RAM$ is called '$RAM$ after coordinated validation'.

4. The coordinated validation pursuant to paragraph 3 shall be implemented gradually. During the first year 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. Subsequently, the simplified process shall gradually be replaced by a full analysis by twenty four months after the implementation of this methodology. Within eighteen months after the implementation of this methodology in accordance with Article 28(3), 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, further specifying the process and requirements for coordinated validation. The proposal shall at least include:

   (a) the CCC role in assessing and communicating available remedial actions; and

   (b) a process for assessing in a coordinated manner (between the Core TSOs and the CCC) whether there are enough RAs to avoid capacity reductions.

5. After coordinated validation, each Core TSO shall validate and have the right to decrease the $RAM$ for reasons of operational security during the individual validation. The adjustment due to

individual validation is called ‘individual validation adjustment’ ($IVA$) and it shall have a positive value, i.e. it may only reduce the $RAM$. $IVA$ may reduce the $RAM$ only to the minimum degree that is needed to ensure operational security considering all expected available costly and non-costly RAs, in accordance with Article 22 of the SO Regulation. The individual validation adjustment may be done in the following situations:

(a) an occurrence of an exceptional contingency or forced outage as defined in Article 3(39) and Article 3(77) of the SO Regulation;

(b) when all available costly and non-costly RAs are not sufficient to ensure operational security, taking the CCC’s analysis pursuant to paragraph 3 into account, and coordinating with the CCC when necessary;

(c) a mistake in input data, that leads to an overestimation of cross-zonal capacity from an operational security perspective; and/or

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

6. If all available costly and non-costly RAs are not sufficient to ensure operational security on an internal network element with a specific contingency, which is not defined as CNEC and for which the maximum zone-to-zone PTDF is above the PTDF threshold referred to in Article 15(1), the competent Core TSO may exceptionally add such internal network element with associated contingency to the final list of CNECs. The RAM on this exceptional CNEC shall be the highest RAM ensuring operational security considering all available costly and non-costly RAs.

7. When performing the validation, the Core TSOs shall consider the operational security limits pursuant to Article 6(1). While considering such limits, they may consider additional grid models, and other relevant information. Therefore, the Core TSOs shall use the tools developed by the CCC for analysis, but may also employ verification tools not available to the CCC.

8. In case of a required reduction due to situations as defined in paragraph 1(a), a TSO may use a positive value for $IVA$ for its own CNECs or adapt the external constraints, pursuant to Article 7, to reduce the cross-zonal capacity for its bidding zone.

9. In case of a required reduction due to situations as defined in paragraph 1(b), (c), and (d), a TSO may use a positive value for $IVA$ for its own CNECs. In case of a situation as defined in paragraph 1(c), a Core TSO may, as a last resort measure, request a common decision to launch the default flow-based parameters pursuant to Article 22.

10. After coordinated and individual validation adjustments, the $RAM_{bn}$ before adjustment for long-term nominations shall be calculated by the CCC for each CNEC and external constraint according to Equation 20:

$$\overrightarrow{RAM}_{bn} = \overrightarrow{RAM}_{bv} - \overrightarrow{CVA} - \overrightarrow{IVA}$$

*Equation 20*

with

| | |
|---|---|
| $\cancel{\vec{F}_0}\overrightarrow{RAM}_{bn}$ | ~~flow per CNEC in the commercial situation without Core commercial exchanges~~ remaining available margin before adjustment for long-term nominations |

| | |
|---|---|
| ~~$\vec{F}_{ref}$~~ $\overrightarrow{RAM}_{bv}$ | ~~flow per CNEC in the CGM (reference flow)~~ remaining available margin before validation |
| ~~$\boldsymbol{PTDF}$~~ $\overrightarrow{CVA}$ | ~~power transfer distribution factor matrix~~ coordinated validation adjustment |
| ~~$\vec{0}$~~ $\overrightarrow{IVA}$ | ~~Zero vector~~ individual validation adjustment |
| ~~45. $\overrightarrow{NP}_{ref}$~~ | ~~46. Core net position per bidding zone in the CGM~~ |

~~47.~~

~~48. next, the flow has to be adjusted to take into account the effect of the LTN (Long-Term Nominations) of the market time unit. The $PTDFs$ remain identical in this step. Consequently, the effect on the flow-based capacity domain is another shift in the solution space:~~

~~49.~~

~~50. $\vec{F}_{LTN} = \vec{F}_0 + \boldsymbol{PTDF} \cdot \overrightarrow{NP}_{LTN}$~~

11. Any reduction of cross-zonal capacities during the validation process, separately for coordinated and individual validation, shall be communicated and justified to market participants and to all Core regulatory authorities in accordance with Article 25 and Article 27, respectively.

12. Pursuant to Article 18(1(a), capacity reductions through $CVA$ and $IVA$ shall ensure that the $RAM_{bn}$ remains non-negative in all combinations of nominations resulting from LTA. Such a constraint is described for each CNEC, including external constraints, by the following equation:

$$CVA + IVA \leq F_{max} - FRM + AMR + LTA_{margin} - F_{LTA,max}$$

*Equation ~~15~~21*

with

| | |
|---|---|
| ~~$\vec{F}_{LTN}$~~ $CVA$ | ~~flow per CNEC after consideration of LTN~~ coordinated validation adjustment |
| ~~$\vec{F}_0$~~ $IVA$ | ~~flow per CNEC in the commercial situation without Core commercial exchanges~~ individual validation adjustment |
| ~~$\boldsymbol{PTDF}$~~ | ~~power transfer distribution factor matrix~~ |
| ~~$\overrightarrow{NP}_{LTN}$~~ $F_{LTA,max}$ | ~~Core net position per bidding zone resulting from LTN~~ maximum oriented flow from LTA inclusion pursuant to Equation 17 |

~~51.~~

~~52. Finally, the remaining available margin for the single day-ahead coupling shall be calculated as follows:~~

~~53. $RAM_{LTN} = F_{max} + AMR + LTA_{margin} - FRM - FAV - F_{LTN}$~~

~~54. *Equation 16*~~

~~55. In case an external constraint is modelled as a constraint within the Core cross-zonal capacity calculation according to Article 8(4), it shall be added as an additional row to the final flow-based domain as follows:~~

~~56. The $PTDF$ value in the column relating to the concerned bidding zone is set to 1 for an export limit and -1 for an import limit, respectively;~~

~~57. the $PTDF$ values for all other bidding zones are set to zero;~~

~~58. the $RAM$ value is set to the amount of the external constraint and adjusted such that the limits provided to the single day-ahead coupling mechanism refer to the increments or decrements of the net positions with respect to the net positions resulting from LTN.~~

13. ~~In case costly~~Every three months, the CCC shall provide in the quarterly report all the information on the reductions of cross-zonal capacity, separately for coordinated and individual validations. The quarterly report shall include at least the following information for each CNEC of the pre-solved domain affected by a reduction and for each DA CC MTU:

   (a) the identification of the CNEC;

   (b) all the corresponding flow components pursuant to Article 25(2)(d)(vii);

   (c) the volume of reduction, the shadow price of the CNEC resulting from the SDAC and the estimated market loss of economic surplus due to the reduction;

   (d) the detailed reason(s) for reduction, including the operational security limit(s) that would have been violated without reductions, and under which circumstances they would have been violated;

   (e) the forecasted flow in the CGM, in the D-1 CGM, and the realised flow, before (and when relevant after) contingency;

   (f) if an internal network elements with a specific contingency was exceptionally added to the final list of CNECs during validation: a justification why adding the network elements with a specific contingency to the list was the only way to ensure operational security, the name or the identifier of the internal network elements with a specific contingency, the DA CC MTUs for which the internal network elements with a specific contingency was added to the list and the information referred to in points (b), (c) and (e) above;

   (g) the remedial actions ~~are needed to maintain the calculated~~included in the CGM before the day-ahead capacity calculation;

   (h) in case of reduction due to individual validation, the TSO invoking the reduction; and

   (i) the proposed measures to avoid similar reductions in the future.

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; and

   (b) general measures to avoid cross-zonal capacity~~,~~ reductions in the future.

15. When a given Core TSO reduces capacity for its CNECs 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.

## Article 21. Calculation and publication of final flow-based parameters

1. No later than 8:00 market time day-ahead, the CCC shall publish for each DA CC MTU of the following day the flow-based parameters before long-term nominations. These parameters are the $PTDF_f$ and $RAM_{bn}$ of pre-solved CNECs and external constraints. The CCC shall remove those $RAM_{bn}$ and $PTDF_f$ values which are redundant, and therefore may be removed without impacting

the possible allocation of cross-zonal capacity. The pre-solved CNECs and external constraints shall thus ensure that the capacity allocation do not exceed any limiting CNEC or external constraint.

~~1.~~2. After the CCC receives all nominations of allocated long-term cross-zonal capacity (long-term nominations), it shall calculate for each CNEC and external constraint the flow resulting from these ~~remedial actions shall be coordinated.~~nominations ($F_{LTN}$). This is done by multiplying the net positions reflecting the long-term nominations with the $\mathbf{PTDF}_f$. This step is described with Equation 22:

~~1.5 Article 19 Precoupling backup and default processes~~

~~In accordance with Article 21(3) of the CACM Regulation, this methodology includes a fallback procedure for the case where the initial capacity calculation does not lead to any results. Possible causes can be linked, but are not limited, to~~

$$\vec{F}_{LTN} = \mathbf{PTDF}_f \, \overrightarrow{NP}_{LTN}$$

*Equation 22*

with

| | |
|---|---|
| $\vec{F}_{LTN}$ | flow after consideration of LTN |
| $\mathbf{PTDF}_f$ | power transfer distribution factor matrix |
| $\overrightarrow{NP}_{LTN}$ | Core net position per bidding zone resulting from LTN |

3. The CCC shall calculate the final $RAM_f$ for each CNEC and external constraint as follows:

$$\overrightarrow{RAM}_f = \overrightarrow{RAM}_{bn} - \vec{F}_{LTN}$$

*Equation 23*

with

| | |
|---|---|
| $\overrightarrow{RAM}_{bn}$ | remaining available margin before LTN adjustment |
| $\vec{F}_{LTN}$ | flow after consideration of LTN |
| $\overrightarrow{RAM}_f$ | final remaining available margin |

4. The final flow-based parameters shall consist of $\mathbf{PTDF}_f$ and $RAM_f$ for pre-solved CNECs and external constraints. In accordance with Article 46 of the CACM Regulation, the CCC shall ensure that, for each DA CC MTU, the final flow-based parameters be provided to the relevant NEMOs as soon as they are available and no later than 10:30 market time day-ahead. The CCC shall also publish these flow-based parameters for each DA CC MTU of the following day no later than 10:30 market time day-ahead.

5. When missing data prevented the calculation of the final flow-based parameters, the final flow-based domain shall be the flow-based domain resulting from the day-ahead capacity calculation fallback procedure in accordance with Article 22.

6. If the CCC is unable to provide the final flow based parameters to NEMOs by 10:30 market time day-ahead, that coordinated capacity calculator shall notify the relevant NEMOs. In such cases, the CCC shall provide the final flow based parameters to NEMOs no later than 30 minutes before the day-ahead market gate closure time.

## Article 22. Day-ahead capacity calculation fallback procedure

According to Article 21(3) of the CACM Regulation, when the day-ahead capacity calculation for specific DA CC MTUs does not lead to the final flow-based parameters due to, *inter alia*, a technical failure in the tools, an error in the communication infrastructure, or corrupted or missing input data~~.~~, the Core TSOs and the CCC shall calculate the missing results by using one of the following two capacity calculation fallback procedures:

(a) ~~When inputs for~~when the ~~flow-based~~day-ahead capacity calculation ~~are missing for~~ fails to provide the flow-based parameters for strictly less than three consecutive hours, ~~it is possible to compute spanned~~ the CCC shall calculate the missing flow-based parameters with ~~an acceptable risk level, by the so-called~~ the spanning method. The spanning method is based on ~~an intersection~~the union of the previous and ~~sub-sequent~~subsequent available flow-based parameters (resulting in the intersection of the two flow based domains~~,~~), adjusted to zero ~~balance~~Core net positions (to delete the impact of the reference ~~program). For each TSO, the CNEs and CNECs~~ net positions). All flow-based constraints from the previous and ~~sub-sequent timestamps are gathered and only the most constraining ones of both timestamps are taken into consideration (intersection).~~subsequent data sets are first converted into zero Core net positions. Then all previous and subsequent constraints are combined, the redundant constraints are removed, and the pre-solved constraints are adjusted for the long term nominations in accordance with Article 21.

~~(b) In case of impossibility to span the missing parameters or in the situation as described in Article 21(1)(c), Core TSOs can deploy the computation of "Default flow-based parameters". This computation shall be based on existing Long-Term bilateral capacities. These capacities can be converted into flow-based cross-zonal capacities, via a simple linear operation. In order to optimize the capacities provided in this case to the allocation system, involved TSOs shall adjust the long-term capacities during the capacity calculation process. Eventually, delivered capacities will be equal to "LTA value + n" for each border and each direction, transformed into flow-based constraints, "n" being positive or null and computed during the capacity calculation process.~~

(b) ~~Article 20~~ 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). An external constraint on the Core bidding zones' net positions shall be defined based on the LTA capacity for each Core oriented bidding zone border. The external constraint shall be the LTA value, increased by the minimum of the two adjustments provided by the TSO(s) on each side of the bidding zone border, pursuant to Article 4(4(b). These external constraints are then combined, and adjusted for long-term nominations pursuant to Article 21, to obtain the final flow-based domain.

## ~~Article 11.~~Article 23. Calculation of ATCs for SDAC fallback ~~process~~procedure

1. ~~According to Article 21(3) of the CACM Regulation, in~~ In the event that the ~~single day ahead coupling~~SDAC process is unable to produce results, a fallback ~~solution will be applied.~~procedure established in accordance with Article 44 of the CACM Regulation shall be applied. This process requires the determination of ~~bilateral~~ available transmission capacities (ATCs) (hereafter referred as "ATCs for SDAC fallback ~~process~~procedure") for each Core oriented bidding zone border and

each ~~market time unit, in line with the "Core TSOs' Proposal for Fallback Procedures"[9] as requested in Article 44 of the CACM Regulation~~DA CC MTU.

2. The flow-based ~~domains will~~parameters shall serve as the basis for the determination of the ATCs for SDAC fallback ~~process~~procedure. As the selection of a set of ATCs from the flow-based ~~domain~~parameters leads to an infinite set of choices, an algorithm ~~was designed that~~ determines the ATCs for SDAC fallback ~~process~~procedure in a systematic way.

3. The following ~~input data~~inputs are required to calculate ATCs for SDAC fallback procedure for each ~~market time unit~~DA CC MTU:

   (a) the LTA values;

   (b) the ~~final~~ flow-based ~~domain as described~~ parameters $\mathbf{PTDF}_f$ and $\overrightarrow{RAM}_{bn}$ in accordance with Article ~~18;~~16 and 20 respectively; and

   ~~1. the allocation constraints pursuant to Article 8(5).~~

   (c) if defined, the global allocation constraints shall be assumed to constrain the Core net positions pursuant to Article 7(5), and shall be described following the methodology described in Article 18(2). Such constraints shall be adjusted for offered cross-zonal capacities on the non-Core bidding zone borders.

4. The following outputs are the outcomes of the ~~computation~~calculation for each ~~market time unit~~DA CC MTU:

   (a) ATCs for SDAC fallback ~~process;~~procedure; and

   ~~(b)~~ constraints with zero margin after the ~~ATCs for fallback process computation.~~

   ~~(c)~~(b) ~~The computation~~calculation of ~~the~~ ATCs for SDAC fallback ~~process is part of the final flow-based computation step as described in Article 4 and thus is realised for each market time unit~~procedure.

~~5. In the computation~~The calculation of the ATCs for SDAC fallback ~~process each allocation constraint pursuant to Article 20(3)(c) is modelled as an additional row to the final flow-based domain as follows:~~

~~6. The $PTDF$ value in the column relating to the concerned bidding zone is set to 1 for an export limit and -1 for an import limit, respectively;~~

~~7. the $PTDF$ values for all other bidding zones are set to zero;~~

~~8. the $RAM$ value is set to the amount of the allocation constraint, reduced by the sum of the ATCs on the non-Core CCR borders of the respective bidding zone.~~

~~9.~~5. ~~The computation of the ATCs for fallback process~~procedure is an iterative procedure, which ~~aims at increasing the LTA domain~~gradually calculates ATCs for each DA CC MTU, while respecting the constraints of the final flow-based ~~domain calculated for each market time unit as described in Article 18.~~parameters pursuant to paragraph 3:

   (a) ~~first,~~The initial ATCs are set equal to LTAs for each Core oriented bidding zone border, i.e.:

$$\overrightarrow{ATC}_{k=0} = \overrightarrow{LTA}$$

[9] ~~Submitted to the Core regulatory authorities on the 26th of January 2018.~~

with

| | |
|---|---|
| $\overrightarrow{ATC}_{k=0}$ | the initial ATCs before the first iteration |
| $\overrightarrow{LTA}$ | the LTA on Core oriented bidding zone borders |

(b) The iterative method applied to calculate the ATCs for SDAC fallback procedure consists of the following actions for each iteration step *k*:

i. for each CNEC and external constraint of the flow-based parameters pursuant to paragraph 3, calculate the remaining available ~~margins ($RAM$) of the final flow-based domain (CNEs,~~margin based on ATCs at iteration *k*-1:

$$\overrightarrow{RAM}_{ATC}(k) = \overrightarrow{RAM}_{bn} - \mathbf{pPTDF}_{zone-to-zone}\,\overrightarrow{ATC}_{k-1}$$

with

| | |
|---|---|
| $\overrightarrow{RAM}_{ATC}(k)$ | remaining available margin for ATC calculation at iteration *k* |
| $\overrightarrow{ATC}_{k-1}$ | ATCs at iteration *k*-1 |
| $\mathbf{pPTDF}_{zone-to-zone}$ | positive zone-to-zone power transfer distribution factor matrix |

ii. for each CNEC, share $RAM_{ATC}(k)$ with equal shares among the Core oriented bidding zone borders with strictly positive zone-to-zone power transfer distribution factors on this CNEC;

iii. from those shares of $RAM_{ATC}(k)$, the maximum additional bilateral oriented exchanges are calculated by dividing the share of each Core oriented bidding zone border by the respective positive zone-to-zone PTDF;

iv. for each Core oriented bidding zone border, $\overrightarrow{ATC}_k$ is calculated by adding to $\overrightarrow{ATC}_{k-1}$ the minimum of all maximum additional bilateral oriented exchanges for this border obtained over all CNECs~~,~~ and ~~allocation~~external constraints~~) have to be adjusted to take into account~~ as calculated in the ~~starting point~~previous step;

v. go back to step i;

vi. iterate until the difference between the sum of ~~the~~ ATCs of iterations *k* and *k*-1 is smaller than 1kW;

~~i.~~vii. the resulting ATCs for SDAC fallback procedure stem from the ATC values determined in iteration *k*, after rounding down to integer values and from which ~~is the LTA domain:~~LTN are subtracted;

~~ii. from the zone-to-slack $PTDFs$ ($PTDF_{zone-to-slack}$), one computes zone-to-zone $PTDFs$ ($pPTDF_{zone-to-zone}$), where only the positive numbers are stored:~~

~~iii.~~

viii. at the end of the calculation, there are some CNECs and external constraints with no remaining available margin left. These are the limiting constraints for the calculation of ATCs for SDAC fallback procedure.

(c) positive zone-to-zone PTDF matrix ($\mathbf{pPTDF}_{zone-to-zone}$) for each Core oriented bidding zone border shall be calculated from the $\mathbf{PTDF}_f$ as follows (for HVDC interconnectors integrated pursuant to Article 12, Equation 7 shall be used):

$$pPTDF_{zone-to-zone,A\to B} = \max\left(0, PTDF_{zone-to-slack,A} - PTDF_{zone-to-slack,B}\right)$$

*Equation ~~17~~24*

with

| | |
|---|---|
| $pPTDF_{zone-to-zone,A\to B}$ | positive zone-to-zone ~~$PTDF$ of a CNE, CNEC or allocation constraint with respect to exchange from~~ $PTDFs$ for Core oriented bidding zone ~~$A$ to $B$, only taking into account positive values~~ border $A$ to $B$ |
| ~~$PTDF_{zone-to-slack,k}$~~ $PTDF_{zone-to-slack,m}$ | zone-to-slack $PTDF$ ~~of the CNE, CNEC or allocation constraint with respect to~~ for Core bidding zone ~~$k$~~ border m |

~~Only zone-to-zone $PTDFs$ of Core internal borders i.e. of neighbouring bidding zone pairs are needed.~~

1. ~~the iterative procedure to determine the ATCs for fallback process starts from the LTA domain. As such, with the impact of the LTN already reflected in the $RAMs$, the $RAMs$ need to be adjusted in the following way:~~

$$\cancel{\overrightarrow{Margin}(0) = \overrightarrow{RAM}_{LTN} - \mathbf{pPTDF}_{zone-to-zone} * \left(\overrightarrow{LTA} - \overrightarrow{LTN}\right)}$$

~~*Equation 18*~~

~~with~~

| | |
|---|---|
| ~~$\overrightarrow{Margin}(0)$~~ | ~~Margin at the starting point, being iteration 0~~ |
| ~~$\overrightarrow{RAM}_{LTN}$~~ | ~~Remaining available margins after the LTN, pursuant to Article 18(1)(g)~~ |
| ~~$\mathbf{pPTDF}_{zone-to-zone}$~~ | ~~matrix of zone-to-zone PTDFs of all CNEs, CNECs and allocation constraints with respect to exchange between all pairs of neighbouring Core bidding zones, only taking into account positive values~~ |

2. ~~The iterative method applied to compute the ATCs for fallback process comes down to the following actions for each iteration step i:~~
   1. ~~for each CNE, CNEC and allocation constraint of the final flow-based domain, share the remaining margin between the Core internal borders that are positively influenced with equal shares;~~

2. ~~from those shares of margin, maximum bilateral exchanges are computed by dividing each share by the positive zone-to-zone $PTDF$;~~
3. ~~the bilateral exchanges are updated by adding the minimum values obtained over all CNEs, CNECs, and allocation constraints.~~
4. ~~Update the margins on the CNEs, CNECs, and allocation constraints using new bilateral exchanges from step iii and go back to step i;~~
5. ~~iterations continue until the maximum value over all constraints of the absolute difference between the margin of iterations i+1 and i is smaller than a stop criterion;~~
6. ~~the resulting ATCs for fallback process get the values that have been determined for the maximum Core internal bilateral exchanges obtained in iteration i+1 after rounding down to integer values;~~
7. ~~After algorithm execution, there are some CNEs, CNECs, and allocation constraints with no remaining available margin left. These are the limiting constraints of the ATCs for fallback process computation.~~

## ~~1.6 Article 21 Capacity validation methodology~~

9. ~~Each TSO shall, in accordance with Article 26(1) and 26(3) of the CACM Regulation, validate and have the right to correct cross-zonal capacity relevant to the TSO's bidding zone borders for reasons of operational security during the validation process. In exceptional situations cross-zonal capacities can be decreased by TSOs. These situations are:~~
    1. ~~an occurrence of an exceptional contingency or forced outage as defined in Article 3 of SO GL;~~
    2. ~~when costly remedial actions and non-costly remedial actions, pursuant to Article 11, that are needed to ensure the calculated capacity pursuant to Article 4(6)(d) on all CNECs, are not sufficient;~~
    3. ~~a mistake in input data, that leads to an overestimation of cross-zonal capacity from an operational security perspective;~~
    4. ~~a potential need to cover reactive power flows on certain CNECs;~~
10. ~~When performing the validation, Core TSOs may consider the operational security limits, but may also consider additional grid constraints, grid models, and other relevant information. Therefore Core TSOs may use, but are not limited to, the tools developed by the CCC for analysis and might also e mploy verification tools not available to the CCC.~~
11. ~~In case of a required reduction due to situations as defined in Article 21(1)(a), a TSO may use a positive value for $FAV$ for its own CNECs or adapt the external constraints to reduce the cross-zonal capacity for its market area.~~
12. ~~In case of a required reduction due to situations as defined in Article 21(1)(b), (c), and (d), a TSO may use a positive value for $FAV$ for its own CNECs. In case of a situation as defined in Article 21(1)(c), a TSO may also request a common decision to launch the default flow-based parameters. In case of a situation as defined in Article 21(1)(b), a TSO may also decide not to apply the $AMR$ on specific CNECs pursuant to Article 13(5).~~
13. ~~Any reduction of cross-zonal capacities during the validation process shall be communicated to market participants and justified to regulatory authorities in accordance with Article 23 and Article 24, respectively. The CCC shall issue a three-monthly report for regulatory authorities that shall include the amount of reduction in cross-zonal capacity, location, and reason for reduction, pursuant to Article 26(5) of CACM. In cases of reduction due to situations as defined in Article 21(1)(c) the report shall contain measures to prevent similar mistakes.~~

## ~~The regional coordinated capacity calculator shall coordinate~~ TITLE 5 – Updates and data provision

~~14. with neighbouring coordinated capacity calculators during the validation process, where at least the reductions in cross-zonal capacity are shared among them. Any information on decreased cross-zonal capacity from neighbouring coordinated capacity calculators shall be provided to Core TSOs. Core TSOs may then apply the appropriate reductions of cross-zonal capacities as decribed in Article 21(3).~~

### ~~Article 12.Updates and data provision~~

### ~~Article 13.~~Article 24. ~~Article 22~~ Reviews and updates

1. Based on Article 3(f) of the CACM Regulation and in accordance with Article 27(4) of the ~~CACM~~same Regulation, all TSOs shall regularly and at least once a year review and update the key input and output parameters listed in Article 27(4)(a) to (d) of the CACM Regulation.

2. If the operational security limits, critical network elements, contingencies and allocation constraints used for ~~the common~~day-ahead capacity calculation inputs pursuant to Article 5 and Article 7 need to be updated based on this review, the Core TSOs shall publish the changes at least 1 week before ~~the~~their implementation.

~~3. Core TSOs shall include the re-assessment of the further need of allocation constraints.~~

~~4.~~3. In case the review proves the need ~~of~~for an update of the reliability margins, the Core TSOs shall publish the changes at least ~~1~~one month before ~~the~~their implementation.

~~5.~~4. The review of the common list of ~~remedial actions~~RAs taken into account in the day-ahead capacity calculation shall include at least an evaluation of the efficiency of specific PSTs and the topological RAs considered during the RAO.

~~6.~~5. In case the review proves the need for updating the application of the methodologies for determining ~~generation shift keys~~GSKs, critical network elements~~,~~ and contingencies referred to in Articles 22 to 24 of the CACM Regulation, changes have to be published at least ~~3~~three months before ~~the final~~their implementation.

~~7.~~6. Any changes of parameters listed in Article 27(4) of the CACM Regulation ~~have to~~shall be communicated to market participants, all Core regulatory authorities and ~~Core NRAs.~~ the Agency.

~~8.~~7. The Core TSOs shall communicate the impact of any ~~changes~~change of allocation constraints and parameters listed in Article 27(4)(d) of the CACM Regulation ~~have to be communicated~~ to market participants, all Core regulatory authorities and ~~Core NRAs~~the Agency. If any change leads to an adaption of the methodology, the Core TSOs ~~will amend the~~shall make a proposal for amendment of this methodology according to Article 9(13) of the CACM Regulation.

### ~~Article 14.~~Article 25. ~~Article 23~~ Publication of data

~~1. The data as set forth in Article 23(2) will be published on a dedicated online communication platform representing all Core TSOs. To enable market participants to have a clear understanding of the publicated data, a handbook will be prepared by Core TSOs and published on this communication platform.~~

1. In accordance with Article 3(f) of the CACM Regulation aiming at ensuring and enhancing the transparency and reliability of information to ~~the regulatory authorities and market participants, at least the following data items shall be published~~ all regulatory authorities and market participants, all Core TSOs and the CCC shall regularly publish the data on the day-ahead capacity calculation process pursuant to this methodology as set forth in paragraph 2 on a dedicated online communication platform where capacity calculation data for the whole Core CCR shall be published. To enable market participants to have a clear understanding of the published data, all Core TSOs and the CCC shall develop a handbook and publish it on this communication platform. This handbook shall include at least a description of each data item, including its unit and underlying convention.

2. The Core TSOs and the CCC shall publish at least the following data items (in addition to the data items and definitions of Commission Regulation (EU) No 543/2013 on submission and publication of data in electricity markets~~:~~):

   (a) ~~initial~~ flow-based parameters ~~(without LTN)~~ before long term nominations pursuant to Article 21(1), which shall be published ~~at D-1 before the nominations of long-term rights for each~~ no later than 8:00 market time ~~unit~~of D-1 for each DA CC MTU of the following day~~. For this set of initial flow-based parameters all~~ ;

   ~~(a)~~ the long~~-~~ term nominations ~~at all Core bidding zone borders are assumed as zero (LTN=0);~~

   (b) ~~the LTN~~ for each Core bidding zone border where PTRs are ~~applied~~allocated, which shall be published ~~at~~ no later than 10:30 market time of D-1 ~~(10:30 target time)[10]~~ for each ~~market time unit~~DA CC MTU of the following day;

   (c) final flow-based parameters pursuant to Article 21(4), which shall be published ~~at D-1~~ (no later than 10:30 ~~target~~market time~~)~~ of D-1 for each ~~market time unit~~DA CC MTU of the following day~~, comprising the zone-to-slack *PTDFs* and the *RAM* for each "presolved" CNEC;~~ ;

   (d) ~~additionally, at D-1 (10:30 target time),~~ the following ~~data items~~information, which shall be published ~~for each~~ no later than 10:30 market time ~~unit~~of D-1 for each DA CC MTU of the following day:

      i. maximum and minimum possible net position of each bidding zone;

      ii. maximum possible bilateral exchanges between all pairs of Core bidding zones;

      iii. ATCs for SDAC fallback ~~process.~~procedure;

      iv. names of CNECs (with geographical names of substations where relevant and separately for CNE and contingency) and external constraints of the final flow-based parameters before pre-solving and the TSO defining them;

      v. for each CNEC of the final flow-based parameters before pre-solving, the EIC code of CNE and Contingency;

      vi. for each CNEC of the final flow-based parameters before pre-solving, the method for determining $I_{max}$ in accordance with Article 6(2)(a);

~~[10] This is CET during the winter period and CEST during the summer period.~~

vii. detailed breakdown of $RAM$ for each CNEC of the final flow-based parameters before pre-solving: $I_{max}$, $U$, $F_{max}$, $FRM$, $F_{ref,init}$, $F_{nrao}$, $F_{ref}$, $F_{0,\text{core}}$, $F_{0,\text{all}}$, $F_{uaf}$, $AMR$, $LTA_{margin}$, $CVA$, $IVA$, $F_{LTN}$;

viii. detailed breakdown of the $RAM$ for each external constraint before pre-solving: $F_{max}$, $F_{LTN}$;

ix. indication of whether spanning and/or default flow-based parameters were applied;

x. indication of whether a CNEC is redundant or not;

xi. information about the validation reductions:

- the identification of the CNEC;
- in case of reduction due to individual validation, the TSO invoking the reduction;
- the volume of reduction ($CVA$ or $IVA$);
- the detailed reason(s) for reduction in accordance with Article 20(5), including the operational security limit(s) that would have been violated without reductions, and under which circumstances they would have been violated;
- if an internal network elements with a specific contingency was exceptionally added to the final list of CNECs during validation: (i) a justification of the reasons of why adding the internal network elements with a specific contingency to the list was the only way to ensure operational security, (i) the name or identifier of the internal network elements with a specific contingency;

xii. for each RA resulting from the NRAO:

- type of RA;
- location of RA;
- whether the RA was curative or preventive;
- if the RA was curative, a list of CNEC identifiers describing the CNECs to which the RA was associated;

xiii. the forecast information contained in the CGM:

- vertical load for each Core bidding zone and each TSO;
- production for each Core bidding zone and each TSO;
- Core net position for each Core bidding zone and each TSO;
- reference net positions of all bidding zones in synchronous area Continental Europe and reference exchanges for all HVDC interconnectors within synchronous area Continental Europe and between synchronous area Continental Europe and other synchronous areas; and

~~(e)~~ the information pursuant to paragraph 2(d)(vii) shall be complemented by 14:00 market time of D-1 with the following information ~~may be published at D-1 (10:30 target time):~~

~~(f) real names of~~for each CNEC and ~~external constraint;~~

~~(g) CNE EIC code and Contingency EIC code;~~

~~(h) detailed breakdown of $RAM$ per CNEC:~~

~~(i) $F_{max}$, including information if it is based on permanent or temporary limits;~~

~~(j) $F_{LTN}$;~~

~~(k) $I_{max}$;~~

~~(l) $FRM$;~~

~~(m) $AMR$;~~

~~(n) $LTA_{margin}$;~~

~~(o) $FAV$.~~

~~(p)~~(e) ~~detailed breakdown of $RAM$ per~~ external constraint of the final flow-based parameters:

~~i. $F_{max}$;~~

~~ii. $F_{LTN}$.~~

i. ~~For each RA~~shadow prices;

~~iii.~~ii. flows resulting from net positions resulting from the ~~RAO:~~SDAC.

~~(q) Type of RA;~~

~~(r) Location of RA.~~

~~(s) the following information of the D-2 CGM for each market time unit, for each Core bidding zone and each TSO may be published ex-post at D+2:~~

~~(t) vertical load;~~

~~(u) production;~~

~~(v) best forecast of net position.~~

~~(w)~~(f) every six months, the publication of ~~the~~ an up-to-date static grid model by each Core TSO.

~~3. The final, exhaustive and binding list of all publication items, respective templates and the data-access points shall be developed in dedicated workshops with the Core Stakeholders and regulatory authorities. The refinement shall keep at least the transparency level reached in the operational CWE flow-based market coupling. An agreement between Stakeholders, Core regulatory authorities and Core TSOs shall be reached not later than three months before the go-live window as described in Article 25(4).~~

3. ~~Article 24~~ Individual Core TSO may withhold the information referred to in paragraph 2(d)iv), 2(d)v) and 1(a) if it is classified as sensitive critical infrastructure protection related information in their Member States as provided for in point (d) of Article 2 of Council Directive 2008/114/EC of 8 December 2008 on the identification and designation of European critical infrastructures and the assessment of the need to improve their protection. In such a case, the information referred to in paragraph 2(d)iv) and 2(d)v) shall be replaced with an anonymous identifier which shall be stable for each CNEC across all DA CC MTUs. The anonymous identifier shall also be used in the other TSO communications related to the CNEC, including the static grid model pursuant to paragraph 2(f) and when communicating about an outage or an investment in infrastructure. The information about which information has been withheld pursuant to this paragraph shall be published on the communication platform referred to in paragraph 1.

4. Any change in the identifiers used in paragraphs 2(d)iv), 2(d)v) and 1(a) shall be publicly notified at least one month before its entry into force. The notification shall at least include:

(a) the day of entry into force of the new identifiers; and

(b) the correspondence between the old and the new identifier for each CNEC.

5. Pursuant to Article 20(9) of the CACM Regulation, the Core TSOs shall establish and make available a tool which enables market participants to evaluate the interaction between cross-zonal capacities and cross-zonal exchanges between bidding zones. The tool shall be developed in coordination with stakeholders and all Core regulatory authorities and updated or improved when needed.

6. The Core regulatory authorities may request additional information to be published by the TSOs. For this purpose, all Core regulatory authorities shall coordinate their requests among themselves and consult it with stakeholders and the Agency. Each Core TSO may decide not to publish the additional information, which was not requested by its competent regulatory authority.

## Article 26. Quality of the data published

1. No later than six months before the implementation of this methodology in accordance with Article 28(3), the Core TSOs shall jointly establish and publish a common procedure for monitoring and ensuring the quality and availability of the data on the dedicated online communication platform as referred to in Article 25. When doing so, they shall consult with relevant stakeholders and all Core regulatory authorities.

2. The procedure pursuant to paragraph 1 shall be applied by the CCC, and shall consist of continuous monitoring process and reporting in the annual report. The continuous monitoring process shall include the following elements:

   (a) individually for each TSO and for the Core CCR as a whole: data quality indicators, describing the precision, accuracy, representativeness, data completeness, comparability and sensitivity of the data;

   (b) the ease-of-use of manual and automated data retrieval;

   (c) automated data checks, which shall be conducted in order automatically to accept or reject individual data items before publication based on required data attributes (e.g. data type, lower/upper value bound, etc.); and

   (d) satisfaction survey performed annually with stakeholders and the Core regulatory authorities.

   The quality indicators shall be monitored in daily operation and shall be made available on the platform for each dataset and data provider such that users are able to take this information into account when accessing and using the data.

3. The CCC shall provide in the annual report at least the following:

   (a) the summary of the quality of the data provided by each data provider;

   (b) the assessment of the ease-of-use of data retrieval (both manual and automated);

   (c) the results of the satisfaction survey performed annually with stakeholders and all Core regulatory authorities; and

   (d) suggestions for improving the quality of the provided data and/or the ease-of-use of data retrieval.

4. The Core TSOs shall commit to a minimum value for at least some of the indicators mentioned in paragraph 2, to be achieved by each TSO individually on average on a monthly basis. Should a TSO fail to fulfil at least one of the data quality requirements, this TSO shall provide to the CCC within one month following the failure to fulfil the data quality requirement, detailed reasons for the failure to fulfil data quality requirements, as well as an action plan to correct past failures and prevent future failures. No later than three months after the failure, this action plan shall be fully implemented and the issue resolved. This information shall be published on the online communication platform and in the annual report.

## ~~Article 15.~~Article 27. Monitoring, reporting and information to the Core regulatory authorities

1. ~~With reference~~The Core TSOs shall provide to Core regulatory authorities data on day-ahead capacity calculation for the ~~Whereas~~purpose of monitoring its compliance with this methodology and other relevant legislation.

~~4.~~2. At least, the information on non-anonymized names of CNECs for final flow-based parameters before pre-solving as referred to in Article ~~26(5) of the CACM Regulation, monitoring data~~ 25(2)(d)(iv) and (v) shall be provided ~~towards~~to all Core regulatory authorities on a monthly basis for each CNEC and each DA CC MTU. This information shall be in a format that allows easily to combine the ~~Core regulatory authorities as basis for supervising a non-discriminatory and efficient Core congestion management.~~CNEC names with the information published in accordance with Article 25(2).

~~5. The provided monitoring data shall also be the basis for the biennial report to be provided according to Article 27(3) of the CACM Regulation.~~

~~6. At least, the following monitoring items related to the Core common capacity calculation shall be provided to the Core regulatory authorities on a monthly basis:~~

~~7. results of the hourly LTA checks;~~

~~8. maximum zone-to-zone~~ $\cancel{PTDF}$ ~~check;~~

~~9. hourly Min/Max Net Positions per bidding zone;~~

~~10. maximum bilateral exchanges for each Core bidding zone border (hourly);~~

~~11. usage of the final adjustment value~~ $\cancel{FAV}$~~;~~

~~12. external constraints;~~

~~13. hourly ATCs for the fallback process for all Core-borders;~~

~~14. overview of timestamps where spanning is applied (per month);~~

~~15. overview of timestamps for which default flow-based parameters were applied (per month);~~

~~16. hourly non-anonymized presolved CNECs, disclosing~~ $\cancel{PTDF, F_{max}, FRM, AMR, LTA_{margin}, FAV, RAM}$ ~~and~~ $\cancel{F_{ref}}$~~;~~

~~17. hourly non-anonymized active CNECs, disclosing associated net positions and shadow prices;~~

~~18. key aggregated figures per bidding zone, for each MTU:~~

~~19. number of presolved CNECs;~~

~~20. if the~~ $\cancel{RAM}$ ~~after initial computation, pursuant to Article 4(6)(a), on at least one CNEC is less than zero;~~

~~21. number of CNECs impacted by LTA inclusion;~~

~~22. number of presolved CNECs with RAs applied;~~

~~23. number of presolved CNECs without RAs applied;~~

~~24. number of presolved CNECs, breaching the max zone-to-zone~~ $\cancel{PTDF}$ ~~threshold;~~

~~25. number of presolved CNECs, breaching the max zone-to-zone $PTDF$ threshold due to the application of RAO;~~

~~26. number of presolved CNECs using the $FAV$;~~

~~27. number of presolved CNECs where $AMR$ has not been applied, pursuant to Article 13(5);~~

~~28. if spanning technology was applied;~~

~~29. if default flow-based parameters were applied;~~

~~30. the impact of small zone-to-zone PTDFs;~~

~~31. in case of occurrence: justification when $FAV$ is applied;~~

~~32. in case of occurrence: justification when $AMR$ is not applied;~~

~~33. in case of occurrence: justification when the max zone-to-zone $PTDF$ threshold of presolved CNECs is breached due to decisions pursuant to Article 5(7);~~

3. ~~reductions made during the validation~~ Core regulatory authorities may request additional information to be provided by the TSOs. For this purpose, all Core regulatory authorities shall coordinate their requests among themselves. Each Core TSO may decide not to provide the additional information, which was not requested by its competent regulatory authority.

4. The CCC, with the support of the Core TSOs where relevant, shall draft and publish an annual report satisfying the reporting obligations set in Articles 10, 13, 16, 26 and 28 of this methodology:

   (a) according to Article 10(6), the Core TSOs shall report to the CCC on systematic withholdings which were not essential to ensure operational security in real-time operation.

   (b) according to Article 13(5), the Core TSOs shall monitor the accuracy of non-Core exchanges in the CGM.

   (c) according to Article 16(6), the CCC shall monitor the efficiency of the NRAO.

   (d) according to Article 26(3), the CCC shall monitor and report on the quality of the data published on the dedicated online communication platform as referred to in Article 25, with supporting detailed analysis of a failure to achieve sufficient data quality standards by the concerned TSOs, where relevant.

   (e) according to Article 28(3), after 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.

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, 20 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), 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.

6. The published annual and quarterly reports may withhold commercially sensitive information or sensitive critical infrastructure protection related information as referred to in Article 25(3). In such a case, the Core TSOs shall provide the Core regulatory authorities with a complete version where no such information is withheld.

## TITLE 6 - Implementation

### Article 28.Timescale for implementation

1. The TSOs of the Core CCR shall publish this methodology without undue delay after the decision has been taken by the Agency in accordance with Article ~~26(5~~9(12) of the CACM Regulation.

~~1.~~2. No later than four months after the decision has been taken by the Agency in accordance with Article 9(12) of the CACM Regulation~~;~~, all Core TSOs shall jointly set up the coordinated capacity calculator for the Core CCR and establish rules governing its operation.

~~2. the list of CNEs with the Imax definitions used and a justification for that, in accordance to Article 6(1);~~

3. ~~new CNEs and contingencies that have been added to the lists, in accordance to Article 5(1) and Article 5(2), provided by~~ The TSOs of the Core CCR shall implement this methodology no later than 1 December 2020. The implementation process, which shall start with the entry into force of this methodology and finish by 1 December 2020, shall consist of the following steps:

   ~~1.~~ internal parallel run, during which the TSOs ~~to~~shall test the ~~capacity calculation, including a justification.~~

~~15. The final, exhaustive and binding list of all monitoring items, respective templates and~~ operational processes for the ~~data access point shall be developed in dedicated workshops with the regulatory authorities. An agreement between the Core regulatory authorities and Core TSOs shall be reached not later than three months before the go-live window as described in Article 25(4).~~

### ~~Article 16.Implementation~~

(a) ~~Article 25 Timescale for implementation of the Core flow based~~ day-ahead capacity calculation ~~methodology~~inputs, the day-ahead capacity calculation process and the day-ahead capacity validation and develop the appropriate IT tools and infrastructure;

~~(b) Below, in accordance with Article 9(9) of the CACM Regulation, a proposed timescale for implementation is presented:~~

(b) ~~The TSOs of the Core CCR shall publish the day ahead common capacity calculation methodology without undue delay after all national regulatory authorities have approved the proposed methodology or a decision has been taken by the Agency for the Cooperation of Energy Regulators in accordance with Article 9(10), (11), and (12) of~~external parallel run, during which the TSOs will continue testing their internal processes and IT tools and infrastructure. In addition, the Core TSOs will involve the Core NEMOs to test the implementation of this methodology within the SDAC, and market participants to test the effects of applying this methodology on the market. In accordance with Article 20(8) of CACM Regulation, this phase shall not be shorter than 6 months.

~~3.~~ During the ~~CACM Regulation.~~

~~4.~~ internal and external parallel runs, the Core TSOs shall ~~continue to~~continuously monitor the effects and the performance of the ~~proposed day-ahead flow-based methodology. This will be done under dedicated internal and external parallel run as well as in continuous manner once the methodology is operational. Monitoring~~application of this methodology. For this purpose, they shall develop, in coordination with the Core regulatory authorities, the Agency and stakeholders, the monitoring and performance criteria ~~/ KPIs will be defined in alignment with Core NRAs and other stakeholders (see also Table 1 – Appendix 2).~~

~~5. Before implementation of the CCM an analysis shall be made of information required to be published for each country, that sees a conflict of Article 23 with national as well as international regulations or directives (e.g. EU 114/2008, EU 1227/2011, EU 72/2009). The results of this conducted analysis by respective TSO(s) in cooperation with respective national regulatory authorities shall be presented to all Core NRAs and data publication (Article 23) shall be done in accordance to these national analysis.~~

~~6. The TSOs of the Core CCR aim to implement the day-ahead common capacity calculation methodology in order to be operationally ready for launching an external parallel run together with Core NEMOs no later than S1-2019 in accordance with Article 20(8) of CACM Regulation, except the execution of the methodology for *FRM* in line with Article 22 of the CACM Regulation. The external parallel run will be followed by an SDAC integration phase and go live preparations aiming for S1-2020 as the go-live window for the market. The milestones and the criteria for implementing the CCM are presented in Table 1 – Appendix 2. The duration of the external parallel run will be depending on the market experiences, economic welfare results, as well as the duration of the NRA approval process.~~

~~7. For the day-ahead common capacity calculation, the FRM defined in accordance with Article 9 shall be implemented 3 months after collecting 1 year of data since the Core flow-based day-ahead market coupling go-live.~~

~~8. For this transitional period, according to Article 25(4), the *FRM* shall be determined in accordance with Article 9.~~

4. and report on the outcome of this monitoring on a quarterly basis in a quarterly report. After the implementation of ~~the day-ahead common capacity calculation~~this methodology, the outcome of this monitoring shall be reported in the annual report.

~~9.~~ The Core TSOs ~~are willing to work on supporting a solution, in addition to standard hybrid coupling, that fully takes into account the influences of the adjacent CCRs during the capacity allocation i.e. the so called advanced hybrid coupling (AHC) concept, in close cooperation with adjacent involved CCRs. Core TSOs aim to be operationally compatible two (2) years after the Core flow-based day-ahead market coupling go live for the market. The implementation of the AHC concept will be decided together with the adjacent involved CCRs.~~

~~10. The deadlines defined in the above Article 25(), Article 25(4), and Article 25(5) can be modified on request of all TSOs of the Core CCR to their national regulatory authorities, where testing period does not meet necessary conditions for implementation.~~

~~11.~~

~~12.~~5. ~~Core TSOs will~~ shall implement the day-ahead ~~common~~ capacity calculation methodology on a Core bidding zone border only if this bidding zone border ~~is operated in implicit allocation sessions together with all other bidding zone borders of the Core CCR.~~ participates in the SDAC.

## ~~Article 17. Language~~

~~Article 26~~

# TITLE 7 - Final provisions

## ~~Article 18.~~Article 29. Language

The reference language for this methodology shall be English. For the avoidance of doubt, where TSOs need to translate this methodology into their national language(s), in the event of inconsistencies between the English version published by TSOs in accordance with Article 9(14) of the CACM Regulation and any version in another language, the relevant TSO shall, in accordance with national legislation, provide the relevant ~~national~~Core regulatory authorities with an updated translation of the methodology.

## ~~APPENDIX~~Annex 1~~ – ~~: Justification of usage and methodology for calculation of external constraints

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 ~~CACM~~the objectives of the CACM Regulation is included in the Explanatory Note.

~~1.~~

~~2. Austria:~~

~~3. APG does currently not apply external constraints. Due to lack of operational experience this section is subject to changes and further amendments at a later stage.~~

### ~~4.~~1. Belgium:

~~Elia uses~~ELIA may use an ~~import limit~~external constraint ~~which is related~~ to limit the ~~dynamic stability~~ import of the ~~network. This limitation is estimated with offline studies which are performed on a regular basis. The offline study includes a voltage collapse analysis and a stability analysis performed in line with Article 38 of SO GL. Indeed, as a small hub, Elia~~Belgian bidding zone.

**Technical and legal justification**

ELIA is facing voltage constraints and voltage collapse risks in case of low generation within the Belgium grid. Therefore ~~Elia~~ELIA requires to maintain a certain amount of power to be generated within Belgium to prevent violation of voltage constraints (i.e. to prevent voltage dropping below the lower safety limit). The risks of dynamic instability are also analysed to assess the amount of machines requested within ~~Elia~~the Belgium grid to provide a minimal dynamic stability to avoid transient phenomena. These ~~analysis~~analyses and results lead to the use of a maximum import ~~position~~constraint.

~~Croatia:~~

~~HOPS does not apply~~ **Methodology to calculate the value of external constraints**~~. Due to lack of operational experience this section is subject to change, and further amendments at a later stage.~~

~~Czech Republic:~~

~~CEPS does not apply external constraints. Due to lack of operational experience, this section is subject to change, and further amendments at a later stage.~~

~~France:~~

~~RTE does not apply external constraints.~~

~~Germany and Luxembourg:~~

The ~~German and Luxembourgian TSOs do not apply external constraints for the German-Luxembourgian bidding zone~~value of maximum import constraint for the Belgian bidding zone shall be estimated with studies performed on a regular basis. The studies shall include a voltage collapse analysis and a stability analysis performed in line with Article 38 of the SO Regulation. The studies shall be performed and published at least on an annual basis and updated every time this external constraint had a non-zero shadow price in more than 0.1% of hours in a given quarter.

~~5. Hungary:~~

~~6. MAVIR does not apply external constraints.~~

## ~~7.~~2. Netherlands:

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

**Technical and legal justification**

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

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

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

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

**Methodology to calculate the value of external constraints**

TenneT ~~TSO~~ B.V. determines the maximum import and export constraints for the Netherlands based on ~~an off-line study~~studies, which ~~combines~~combine a voltage collapse analysis, stability analysis and an analysis on the increased uncertainty introduced by the (linear) GSK during different extreme import and export situations in accordance to Article 38 of the SO ~~GL~~Regulation. The ~~study takes several months to be performed,~~studies shall be ~~repeated when necessary (e.g. on the introduction of a new interconnector) but~~performed and published at least ~~once a year and may result in~~ on an ~~update of the applied values for the~~annual basis and updated every time this external ~~constraints of the Dutch network~~constraint had a non-zero shadow price in more than 0.1% of hours in a given quarter.

### ~~8.~~3. Poland:

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

~~Rationale behind implementation of external constraints on PSE side~~

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 ~~side~~ is related to ~~the fact that under the conditions of~~ integrated scheduling ~~based market model~~process applied in Poland (also called central ~~dispatch system) responsibility of Polish TSO on system balance is significantly extended comparing to such standard responsibility of TSO in so-called self-dispatch market models. The latter is usually defined up to hour-ahead time frame (including real time operations), while for PSE as Polish TSO this is extended to short (intraday and day-ahead). Thus, PSE bears the responsibility, which in self-dispatch markets is allocated to balance responsible parties (BRPs). That is why PSE needs to take care of back up generating reserves for the whole Polish power system, which leads to implementation of external constraints if this is necessary to ensure operational security of Polish power system in terms of available generating capacities for upward or downward regulation capacity and residual demand[11]. In self-dispatch markets BRPs are themselves supposed to take care about their generating reserves~~dispatching model) and ~~load following, while TSO ensures them just for dealing with contingencies in~~ the ~~time frame of up to one hour ahead.~~way how reserve capacity is being procured by PSE. In a central ~~dispatch market~~dispatching model, in order to ~~provide~~balance generation and demand ~~balance~~and ensure secure energy delivery, the TSO dispatches generating units taking into account their operational constraints, transmission constraints and reserve capacity requirements. This is ~~realized~~realised in an integrated scheduling process as ~~an optimization~~a single optimisation problem called security constrained unit commitment (SCUC) and economic dispatch (SCED). ~~Thus these two~~

~~[11] Residual demand is the part of end users' demand not covered by commercial contracts (generation self-schedules).~~

~~approaches (i.e. self and central dispatch market) ensure similar level of feasibility of transfer capacities offered to the market from the generating capacities point of view.~~

The integrated scheduling process starts after the day-ahead capacity calculation and SDAC and continues until real-time. This means that reserve capacity is not blocked by TSO in advance of SDAC and in effect not removed from the wholesale market and SDAC. However, if balancing service providers (generating units) would already sold too much energy in the day-ahead market because of high exports, they may not be able to provide sufficient upward reserve capacity within the integrated scheduling process.[12] Therefore, one way to ensure sufficient reserve capacity within integrated scheduling process is to set a limit to how much electricity can be imported or exported in the SDAC.

The objective to limit balancing service providers to sell too much energy in the day-ahead market in order to be able to provide sufficient reserve capacity in the integrated scheduling process cannot be efficiently met by translating this limit into 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, 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.

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

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

~~Specification of security limits violated if the external constraint is not applied~~

~~With regard to constraints used to ensure sufficient operational reserves, if one of interconnected systems suffers from insufficient reserves in case of unexpected outages or unplanned load change (applies to central dispatch~~

[12] 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.

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

~~PSE role in system balancing~~

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

~~In a yearly timeframe PSE tries to distribute the maintenance overhauls requested by generators along the year in such a way that on average the minimum year ahead generation reserve margin[13] over forecasted demand including already allocated capacities on interconnections is kept on average in each month. The monthly and weekly updates aim to keep a certain reserve margin on each day[14], if possible. This process includes also network maintenance planning, so any constraints coming from the network operation are duly taken into account.~~

~~The day-ahead SCUC process aims to achieve a set value of spinning reserve[15] (or quickly activated, in current Polish reality only units in pumped storage plants) margin for each hour of the next day, enabling up and down regulation. This includes primary and secondary control power pre-contracted as an ancillary service. The rest of this reserve comes from usage of balancing bids, which are mandatory to be submitted by all centrally dispatched generating units (in practice all units connected to the transmission network and major ones connected to 110 kV, except CHP plants as they operate mainly according to heat demand). The remaining generation is taken into account as scheduled by owners, which having in mind its stable character (CHPs, small thermal and hydro) is a workable solution. The only exception from this rule is wind generation, which due to its volatile character is forecasted by PSE. Thus, PSE has the right to use any available centrally dispatched generation in normal operation to balance the system. The negative reserve requirements during low load periods (night hours) are also respected and the potential pumping operation of pumped storage plants is taken into account, if feasible.~~

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

~~Determination~~ 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

~~[13] The generation reserve margin is regulated by the Polish grid code and currently set at 18% (point II.4.3.4.18). It is subject to change depending on the results of the development of operational planning processes.~~

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

~~[15] The set values are respectively: 9% over forecasted demand for up regulation and 500 MW for down regulation. These values are regulated by the Polish grid code (point 4.3.4.19) and subject to change – see footnote 2.~~

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 ~~in Poland~~**

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

External constraints are bidirectional, with independent values for each ~~market time unit~~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 ~~equation~~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:

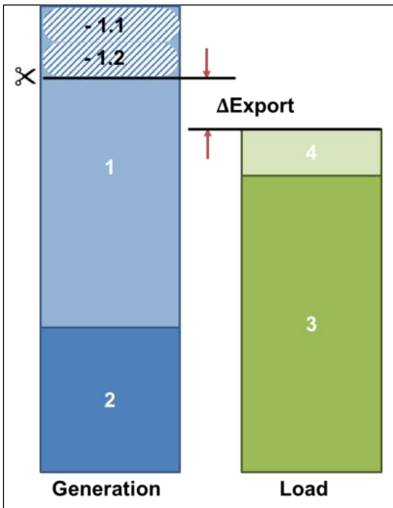
| | |
|---|---|
| $P_{CD}$ | Sum of available generating capacities of centrally dispatched units as declared by generators[16] |
| $P_{CD_{min}}$ | Sum of technical minima of available centrally dispatched generating units ~~in operation~~ |
| $P_{NCD}$ | Sum of schedules of generating units that are not centrally dispatched, as provided by generators (for wind farms: forecasted by PSE) |
| $P_{NA}$ | Generation not available due to grid constraints (both planned outage and/or anticipated congestions) |
| $P_{ER}$ | Generation unavailability's adjustment resulting from issues not declared by generators, forecasted by PSE due to exceptional circumstances (e.g. cooling conditions or prolonged overhauls) |
| $P_L$ | Demand forecasted by PSE |

[16] 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.

| | |
|---|---|
| $\cancel{P_{UPres}}P_{UPres}$ | Minimum reserve for ~~up~~upward regulation |
| $\cancel{P_{DOWNres}}P_{DOWNres}$ | Minimum reserve for ~~down~~downward regulation |

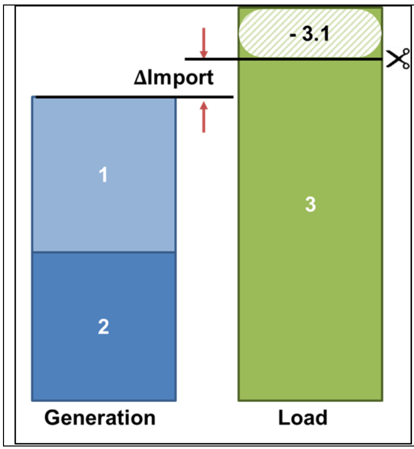
For illustrative purposes, the process of practical determination of external constraints in the framework of the day-ahead ~~transfer~~ capacity calculation is illustrated below~~: figures~~ in Figures 1 and 2. The figures illustrate how a forecast of the Polish power balance for each hour of the ~~next~~delivery day is developed by ~~TSO day ahead~~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~~. For the intraday market, the same method applies *mutatis mutandis*~~.

External constraint in export direction is applicable if ΔExport is lower than the sum of ~~transfer~~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 ~~transfer~~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 wind farms: 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~~ transfer~~ capacity calculation.




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

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

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

Figure 2: Determination of external constraints in import direction (reserves in generating capacities available for potential imports) in the framework of the day-ahead ~~transfer~~ 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 ~~horizon~~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 ~~market time unit~~DA CC MTU, and separately for directions of import to Poland and export from Poland.

~~Impact of external constraints on single day-ahead coupling and single intraday coupling~~

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

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

~~Impact of external constraints on neighboring CCRs~~

~~External constraints are determined for the whole Polish power system, meaning that they are applicable simultaneously for all CCRs in which PSE has at least one border (i.e. Core, Baltic and Hansa).~~

~~It is to be underlined that this solution has been proven as the most efficient application of allocation constraints. Considering allocation constraints separately in each CCR would require PSE to split global allocation constraints into CCR-related sub-values, which would be less efficient than maintaining the global value. Moreover, in the hours when Poland is unable to absorb any more power from outside due to violated minimal downward generation requirements, or when Poland is unable to export any more power due to insufficient generation reserves in upward direction, Polish transmission infrastructure still can be – and indeed is - offered for transit, increasing thereby trading opportunities and social welfare in all concerned CCRs.~~

### Time periods for which 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 ~~market time units (hours)~~DA CC MTUs of the respective allocation day.

~~Why the allocation constraints cannot be efficiently translated into capacities of critical network elements offered to the market~~

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

~~Romania:~~

~~Transelectrica does not apply external constraints.~~

~~Slovakia:~~

~~SEPS does currently not apply external constraints. Due to lack of operational experience this section is subject to changes and further amendments at a later stage.~~

~~Slovenia:~~

~~ELES does not apply external constraints.~~

# ~~APPENDIX 1 - Implementation milestones and criteria for implementation of the day-ahead CCM~~

~~Table 1. Implementation milestones and criteria for implementation of the day-ahead CCM.~~

## Annex 2: Application of linear trajectory for calculation of minimum RAM factor

1. One linear trajectory for calculation of minimum RAM factor shall be calculated per Member State and shall apply for all CNECs defined by TSO(s) of such Member State.[17]

2. The linear trajectory for calculation of minimum RAM factor shall define yearly values to be applied for each year between the start year and the end year. The start year shall be 2020, and the end year shall be 2026. For each year between 2020 and 2026, the minimum RAM factor $R_{amr}$ pursuant to Article 17(9) shall be defined as follows

$$R_{amr}(year) = R_{amr,start} + \frac{year - 2020}{2026 - 2020} * (R_{amr,end} - R_{amr,start})$$

with

| ~~#~~ | ~~Milestone~~ | ~~Criteria to be met before moving to the next milestone~~ |
|---|---|---|
| ~~1~~ | ~~Internal parallel run~~ | ~~1. Industrial tool is ready to be used;~~ ~~2. The flow-based capacity calculation process is a close-to-operational process, that will be performed by TSO operators;~~ ~~3. Market simulation results can be published for the stakeholders on a daily basis.~~ |
| ~~2~~$R_{amr,start}$ | ~~External parallel run~~ | ~~1.~~ Minimum ~~of six months of external parallel runs, wh~~ ~~flow-based is reliable~~RAM factor in ~~producing capacity calculation parameters and results.~~year 2020 |
| ~~3~~ | ~~Day-ahead CCM go-live~~ | ~~1. Operational readiness to introduce advanced hybrid coupling in the daily capacity calculation and allocation process;~~ ~~2. Alignment and agreement among the relevant CCRs.~~ |
| ~~4~~$R_{amr,end}$ | ~~Day-ahead CCM compatibility with Advanced Hybrid Coupling~~ | ~~Go live is to be decided in alignment with CCRs~~Minimum RAM factor in year 2026 which is equal to 0.7 |

3. The minimum RAM factor in year 2020, $R_{amr,start}$ is the average total capacity allocated on all CNECs[18] defined by the TSO(s) of a Member State in the year 2019 or the average total capacity allocated on all CNECs defined by the TSO(s) of a Member State in the years 2017, 2018 and 2019, whatever is higher:

$$R_{amr,start} = \max(RAM_{rel,avg}\ (2019), RAM_{rel,avg}\ (2017 - 2019))$$

with

| | |
|---|---|
| $RAM_{rel,avg}\ (2019)$ | average relative total RAM ($RAM_{t,rel}$) calculated over all CNECs defined by the TSO(s) of a Member State and all market time units of 2019 |

[17] In case a bidding zone covers a territory of more than one Member State, the common trajectory shall be applied for such bidding zone

[18] This includes all cross-zonal capacities from all bidding zones in all CCRs impacting the flow on this CNEC

| | |
|---|---|
| $RAM_{rel,avg}\ (2017-2019)$ | average relative RAM ($RAM_{t,rel}$) calculated over all CNECs defined by the TSO(s) of a Member State and all market time units of 2017, 2018 and 2019 |

The selection of CNECs for this analysis shall be defined pursuant to paragraph 8.

4. The relative total RAM ($RAM_{t,rel}$) for each CNEC and market time unit available for cross-zonal trade over all bidding zone borders of all CCRs is the ratio of the total RAM available for trade over all bidding zone borders of all CCRs to $F_{max}$ as defined pursuant to paragraph 8.

$$RAM_{rel}(CNEC, MTU) = \frac{RAM_t(CNEC, MTU)}{F_{max}}$$

with

| | |
|---|---|
| $RAM_{rel}(CNEC, MTU)$ | Relative total RAM ($RAM_{t,rel}$) calculated of a specific CNEC in a specific market time unit |
| $RAM_t(CNEC, MTU)$ | Total RAM ($RAM_{t,rel}$) calculated of a specific CNEC in a specific market time unit |
| $F_{max}$ | Maximum admissible flow of a specific CNEC in a specific market time unit |

5. For each CNEC and market time unit, the total RAM available for cross-zonal trade over all CCRs is then the sum of contributions from bidding zone borders applying the flow-based approach and contributions from bidding zone borders applying the NTC approach:

$$RAM_t(CNEC, MTU) = RAM_{FB}(CNEC, MTU) + RAM_{NTC}(CNEC, MTU)$$

with

| | |
|---|---|
| $RAM_{FB}(CNEC, MTU)$ | The capacity (or RAM) of a CNEC available for cross-zonal trade on bidding zone borders applying the flow-based approach |
| $RAM_{NTC}(CNEC, MTU)$ | The capacity of a CNEC available for cross-zonal trade on bidding zone borders applying the NTC approach |

6. The capacity (or RAM) of a CNEC available for cross-zonal trade on bidding zone borders applying the flow-based approach ($RAM_{FB}(CNEC, MTU)$) shall be defined as follows:

   a) For CNECs which are already used in existing flow-based capacity calculation initiatives, $RAM_{FB}(CNEC, MTU)$ shall be equal to the historical DA RAM values calculated in these initiatives and offered for cross-zonal trading, without the adjustment for long-term nominations;

   b) For CNECs, which are not yet used in existing flow-based capacity calculation initiatives $RAM_{FB}(CNEC, MTU)$ shall be calculated as follows:

$$\overrightarrow{RAM}_{FB}(CNEC, MTU) = \mathbf{pPTDF_{zone-to-zone}}(CNEC, \mathrm{MTU})\ \overrightarrow{NTC}_{fallback}(MTU)$$

with

| | |
|---|---|
| $\mathbf{pPTDF}_{\mathbf{zone-to-zone}}(\mathrm{CNEC}, \mathrm{MTU})$ | Positive zone-to-zone power transfer distribution factor matrix for a given CNEC, bidding zone border and market time unit, pursuant to Equation 24. |
| $\overrightarrow{NTC}_{fallback}(MTU)$ | The NTCs used for the DA fallback procedure on all oriented bidding zone borders in implemented flow-based capacity calculation initiatives for a given market time unit |

7. The capacity of a CNEC available for cross-zonal trade resulting from bidding zone borders applying the NTC approach ($RAM_{NTC}(CNEC, MTU)$) shall be defined by converting for each market time unit the day-ahead NTC values on all oriented bidding zone borders applying the NTC approach with the corresponding zone-to-zone PTDFs (if positive) for the given CNEC:

$$\overrightarrow{RAM}_{NTC}(CNEC, MTU) = \mathbf{pPTDF}_{\mathbf{zone-to-zone}}(CNEC, \mathrm{MTU})\ \overrightarrow{NTC}_{DA}(MTU)$$

with

| | |
|---|---|
| $\overrightarrow{NTC}_{DA}(MTU)$ | The day-ahead NTCs of all oriented bidding zone borders for a given market time unit |

8. For the calculation of the above variables, the following assumptions shall be used:

(a) The selection of CNECs to be used in the analysis shall be equal to the selection of CNECs that TSOs expect to use in the Core day-ahead capacity calculation.

(b) $\vec{F}_{max}$ and **PTDF** for CNECs which are the same as the ones used in existing flow based capacity calculation initiative shall be equal to the historical values used in these initiatives. For CNECs, which have not been used in implemented flow-based capacity calculation initiatives during 2017 – 2019, $\vec{F}_{max}$ and **PTDF** shall be calculated by the concerned TSOs based on Article 6 and Article 11 respectively. When doing so, the TSOs may use representative values for more than one market time unit.

(c) The $\overrightarrow{NTC}_{fallback}$ as referred to in paragraph 6 shall be the ATC values used for fallback procedures on the borders for which the flow-based capacity calculation approach was already implemented during the analysed period of 2017 – 2019.

(d) The $\overrightarrow{NTC}_{DA}$ as referred to in paragraph 6 shall be the day-ahead NTC values on the borders which have been applying the NTC approach during the analysed period of 2017 – 2019.