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

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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 development of the common capacity calculation methodology in accordance with Article 20 ff. 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 “intraday common capacity calculation methodology”.
2. The intraday common capacity calculation methodology takes into account the general principles and goals set in the CACM Regulation as well as 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 intraday cross-zonal markets. It sets for this purpose requirements to develop an intraday 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 intraday common capacity calculation methodology on the objectives of the CACM Regulation has to be described and is presented below. The proposed intraday common capacity calculation methodology generally contributes to the achievement of the objectives of Article 3 of the CACM Regulation.
4. The intraday 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 intraday common 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 intraday allocation, at the same time and in a transparent way.
5. The intraday common capacity calculation methodology contributes to the optimal use of transmission infrastructure and operational security (Article 3(b) and (c) of the CACM Regulation) since the flow-based mechanism aims at providing the maximum available capacity to market participants on the intraday timeframe within the operational security limits.
6. The intraday 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 is using the flow-based approach which provides optimal cross-zonal capacities to market participants.
7. The intraday common capacity calculation methodology is designed to ensure a fair and non-discriminatory treatment of TSOs, NEMOs, the Agency, regulatory authorities and market participants (Article 3(e) of the CACM Regulation) since the intraday common capacity calculation methodology is performed with transparent rules that are approved by the relevant national regulatory authorities.
8. Regarding the objective of transparency and reliability of information (Article 3(f) of the CACM Regulation), the intraday common capacity calculation methodology determines the main principles and main processes for the intraday timeframe. The proposed intraday common capacity calculation methodology enables TSOs to provide market participants with the same reliable information on

cross-zonal capacities and allocation constraints for intraday allocation in a transparent way and at the same time.

9. The intraday common 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 cross-zonal capacity to be released in the market.
10. When preparing the intraday common capacity calculation methodology, TSOs took careful consideration of the objective of creating a level playing field for NEMOs (Article 3(i) of the CACM Regulation) since all NEMOs and all their market participants will have the same rules and non-discriminatory treatment (including timings, data exchanges, results formats etc.) within the Core CCR.
11. Finally, the intraday 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.
12. In conclusion, the intraday common capacity calculation methodology contributes to the general objectives of the CACM Regulation to the benefit of all market participants and electricity end consumers.

SUBMIT THE FOLLOWING INTRADAY COMMON CAPACITY CALCULATION METHODOLOGY TO REGULATORY AUTHORITIES OF THE CORE CCR:

GENERAL PROVISION

Article 1 Subject matter and scope

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

Article 2 Definitions and interpretation

1. For the purposes of the intraday 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 and Commission Regulation (EU) 543/2013. In addition, the following definitions, abbreviations and notations shall apply:
    1. 'AAC' is the already allocated capacity which has been allocated as an outcome of the latest common capacity calculation in the Core CCR;
    2. ‘advanced hybrid coupling’ (hereinafter ‘AHC’) means a solution to fully take into account the influences of the adjacent capacity calculation regions during the capacity allocation;
    3. ‘available transmission capacity’ (hereinafter ‘ATC’) means the transmission capacity that remains available after allocation procedure and which respects the physical conditions of the transmission system;
    4. ‘CCC’ is coordinated capacity calculator, as defined in Article 2(11) of the CACM Regulation;
    5. ‘CCR’ is the capacity calculation region as defined in Article 2(3) of the CACM Regulation;
    6. ‘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;

7. ‘CGM’ is the common grid model as defined in Article 2(2) of the CACM Regulation;
8. ‘CGMM’ is the common grid model methodology, pursuant to Article 17 of the CACM regulation;
9. ‘CNE’ is a critical network element;
10. ‘CNEC’ is a critical network element with a contingency;
11. ‘Core CCR’ is the Core capacity calculation region as given by the Agency for the cooperation of energy regulators No. 06/2016 on 17 November 2016;
12. 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”);
13. ‘cross-zonal network element’ means in general only those transmission lines which cross a 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 connected;
14. ‘D-1’ means day-ahead;
15. ‘external constraint’ means the maximum import and/or export constraints of given bidding zone;
16. ‘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;
17. ‘FAV’ is the final adjustment value;
18. ‘flow-based domain’ means the set of constraints that limits the cross-zonal capacity calculated with a flow-based approach;
19. ‘F_{max}’ is the maximum admissible power flow;
20. ‘F_i’ is the expected flow in commercial situation i;
21. ‘F_{ref}’ is the reference flow;
22. ‘flow reliability margin’ (hereinafter ‘FRM’) means the reliability margin as defined in Article 2(14) of the CACM Regulation applied to a CNE in a flow-based approach;
23. ‘GSK’ is the generation shift key as defined in Article 2(12) of the CACM Regulation;
24. ‘HVDC’ is a high voltage direct current transmission system;
25. ‘IGM’ is the individual grid model as defined in Article 2(1) of the CACM Regulation;
26. ‘I_{max}’ is the maximum admissible current;
27. ‘merging agent’ as defined in Article 20 of the CGMM;
28. ‘neighbouring bidding zone pairs’ means the bidding zones which have a common commercial border;
29. ‘MTU’ is the market time unit;
30. ‘MP’ is the market participant;
31. ‘NP’ is the net position;
32. ‘presolved domain’ means the final set of binding constraints for capacity allocation after pre-solving process;

33. ‘presolving process’ means that the redundant constraints are identified and removed from flow-based domain by CCC;
34. ‘PST’ is a phase-shifting transformer;
35. ‘$PTDF$’ is the power transfer distribution factor;
36. ‘RA’ means a remedial action as defined in Article 2(13) of the CACM Regulation;
37. ‘RAM’ is the remaining available margin;
38. ‘RAO’ is the remedial action optimization;
39. ‘slack node’ means the reference node used for determination of the $\boldsymbol{PTDF}$ matrix, i.e. shifting the power infeed of generators up results in absorption of the power shift in the slack node;
40. ‘SO Regulation’ is the System Operation Guideline (Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation);
41. ‘standard hybrid coupling’ means a solution to capture the influence of exchanges with non-Core bidding zones on CNECs that are not explicitly taken into account during the capacity allocation phase;
42. ‘static grid model’ is a list of relevant grid elements of the transmission system, including their electrical parameters;
43. ‘U’ is the reference voltage;
44. ‘vertical load’ means the total amount of electricity which exits the national transmission system to connected distribution systems, end consumers connected to transmission system and to electricity producers for consumption in the generation of electricity;
45. ‘zone-to-slack $PTDF$’ means the power transfer distribution factor of a commercial exchange between a bidding zone and slack node;
46. ‘zone-to-zone $PTDF$’ means the power transfer distribution factor of a commercial exchange between two bidding zones;
47. ‘preventive’ remedial action means a remedial action which is applied before a contingency occurs;
48. ‘curative’ remedial action means a remedial action which is applied after a contingency occurs;
49. the notation x denotes a scalar;
50. the notation $\vec{x}$ denotes a vector;
51. the notation $\boldsymbol{x}$ denotes a matrix.

2. In this intraday common capacity calculation methodology, unless the context requires otherwise:
   a. the singular indicates the plural and vice versa;
   b. the table of contents and headings are inserted for convenience only and do not affect the interpretation of this intraday common capacity calculation methodology; and
   c. any reference to legislation, regulations, directive, order, instrument, code or any other enactment shall include any modification, extension or re-enactment of it then in force.

Article 3 Application of this methodology

This intraday common capacity methodology solely applies to the intraday capacity calculation within the Core CCR. Common capacity calculation methodologies within other capacity calculation regions (CCRs) or other time frames are outside the scope of this methodology.

Article 4 Cross-zonal capacities for the intraday market

1. For the intraday market time-frame, individual values for cross-zonal capacity for each remaining intraday market time unit (MTU) shall be calculated using the flow-based approach as defined in the intraday common capacity calculation methodology, as set forth in Article 14 and 20(ff) of the CACM Regulation.
2. The capacity calculation process can be started as soon as necessary proceeding processes (i.e. single day-ahead coupling and all data preparations for a coordinating operational security analysis, as referred to in Article 75 of SO Regulation, have been finalized.
3. The TSOs of the Core CCR shall provide the coordinated capacity calculator (CCC) without undue delay the following initial inputs for the first intraday capacity calculation and subsequent re-calculations of intraday cross-zonal capacity:
    a. D-1 and Intraday IGMs respecting the methodology developed in accordance with Article 19 of the CACM Regulation;
    b. critical network elements (CNEs) and contingencies in accordance with Article 6;
    c. operational security limits in accordance with Article 7;
    d. allocation constraints in accordance with Article 9;
    e. flow reliability margin (FRM) in accordance with Article 10;
    f. generation shift key (GSK) in accordance with Article 11; and
    g. remedial actions (RAs) in accordance with Article 12.
4. Core TSOs, or an entity on behalf of the Core TSOs, shall send for each MTU the already allocated capacities (AAC) to the CCC.
5. When providing the inputs, the TSOs of the Core CCR shall respect the formats commonly agreed between the TSOs and the CCC of the Core CCR, while respecting the requirements and guidance defined in the CGMM.
6. Once D-1 or intraday IGMs have been received, the merging agent shall merge the IGMs to create the D-1 or intraday CGMs respecting the methodology developed in accordance with Article 17 of the CACM Regulation.
7. For the intraday common capacity calculation in the Core CCR, performed by the CCC, the high-level process flow includes six steps until the final flow-based domain for the single intraday coupling process is set:
    a. First, the provided inputs as defined in Article 4(3) are taken for the initial flow-based computation as defined in Article 13, taking into account the reference commercial situation, leading to preliminary results of capacity calculation;
    b. 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 6;
    c. after the determination of relevant CNECs, the third process step selects RAs resulting from the remedial action optimization (RAO) as defined in Article 14;
    d. the fourth process step is the intermediate flow-based computation where a new flow-based computation is performed as defined in Article 13, taking into account the already nominated capacity as the commercial situation and the updated inputs resulting from steps described in Article 4(7)(b) and Article 4(7)(c);
    e. after the intermediate flow-based computation the resulting cross-zonal capacities are validated by the TSOs of the Core CCR as defined in Article 19. During this validation process the CCC shall coordinate with CCCs of neighbouring CCRs as defined in Article 19(7);
    f. the final process step is the final flow-based computation where:

i. a new flow-based computation is performed as defined in Article 17(1)(b), taking into account the already nominated capacity as the commercial situation and the updated inputs resulting from steps described in Article 4(7)(d) and Article 4(7)(e);
ii. the last step is performing the presolve process as defined in Article 17(1)(c).

8. The CCC of the Core CCR or the Core TSOs shall provide the NEMOs with the final flow-based parameters of the Core CCR and the external constrains in accordance with Article 9. In case the capacity allocation mechanism expects ATCs for each bidding-zone border, the CCC or the Core TSOs shall derive these from the final flow-based parameters and provide it to the NEMOs.
9. In accordance with Article 58(1) of CACM Regulation, the CCC and TSOs of the Core CCR shall provide cross-zonal capacity to relevant NEMOs no later than 15 minutes before the intraday cross-zonal gate opening time. However, Core TSOs may refrain from providing any cross-zonal capacity until the intraday common capacity calculation as described in Article 4(7) has been finalized or an ultimate deadline of 22:00 CE(S)T D-1, whichever is earlier.

Article 5 Intraday capacity re-calculation

1. A first intraday common capacity calculation is performed in the end of D-1 for all MTUs of day D, and a second intraday capacity calculation is performed during intraday (i.e. day D), for the remaining MTUs of day D.
   a. in case, during the project implementation phase, it turns out feasible and of added value, in terms of increased social welfare and/or increased grid security, additional re-calculations of intraday cross-zonal capacity shall be performed during intraday.
   b. target for the intraday common capacity calculation methodology is to have multiple (i.e. more than two) re-calculations throughout the day.
2. The Core TSOs shall review the frequency of re-calculations two years after the implementation of the common capacity calculation methodology for the intraday market timeframe.

METHODOLOGIES FOR CALCULATION OF THE INPUTS

Article 6 Methodology for critical network elements and contingencies selection

1. Each Core TSO shall provide a list of 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 20. 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:
   - a cross-zonal network element; or
   - an internal network element.

   Those network elements can be an overhead line, an underground cable or a transformer.
2. In accordance with Article 23(1) of CACM Regulation, Core TSOs shall provide a list of contingencies used in operational security analysis in line with Article 33 of the SO Regulation, limited to their relevance for the set of CNEs as defined in Article 6(1) and pursuant to Article 23(2) of the CACM Regulation. 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 20.

   A contingency can be a trip of:
   - a line, a cable or a transformer;
   - a busbar;
   - a generating unit;

- a load; or
- a set of the aforementioned contingencies.

3. The association of contingencies to CNEs shall be done from the list of CNEs established in Article 6(1) and from the list of contingencies established in Article 6(2). It shall follow the rules established in Article 75 of SO Regulation.
4. Until a compliant methodology for SO Regulation Article 75 enters into force, and pursuant to Article 23(2) of the CACM regulation, the association of contingencies to CNEs 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.
5. The result of the process according to Article 6(3) or Article 6(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 can be reviewed before the initial flow-based computation pursuant to Article 6(6).
6. Core TSOs shall distinguish between:
    a. 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 Power Transfer Distribution Factor ($PTDF$), as described in Article 13, higher than a common threshold of 5 percent. The value of this threshold is defined in coherence with the threshold defined for the day-ahead common capacity calculation.

       The CNECs of this category shall be taken into account in all the subsequent steps of the common capacity calculation and will determine the cross-zonal capacity;
    b. the CNECs of the initial pool that, based on experience are expected to be influenced by the RAs defined in Article 12, but are not significantly influenced by the changes in bidding zone net positions, pursuant to Article6(6)a. The CNECs of this category may only be monitored during the RAO and shall not limit the cross-zonal capacity.

       In accordance with Article 14(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.

       The differentiation of the 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-zonal 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;
    c. the CNECs of the initial pool not mentioned in Article 6(6)(a) or Article 6(6)(b). The CNECs of this category shall not be taken into account in the intraday common capacity calculation.
7. 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 6(6)(a) for one or several MTUs covering the expected period of presence of the exceptional situation.
    a. In case a TSO decides, in an exceptional situation, to keep a CNEC within the list described in Article 6(6)(a) which is not 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 22, a clear description of the

specific situation, providing detailed information such as the specific grid topology or grid situation, that lead to this decision.

   b. In case a TSO decides, in an exceptional situation, to exclude a CNEC from the list described in Article 6(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 22, a clear description of the specific situation, providing detailed information such as the specific grid topology or grid situation, that lead to this decision.

8. Core TSOs shall study the added value for ensuring a minimum Remaining Available Margin (RAM) for the CNECs determining the cross-zonal capacity before allocating commercial exchanges, in addition to applying the common threshold set in Article 6(6)(a), 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.
9. Core TSOs shall further study the value of the common threshold referred to in Article 6(6)(a) and the value for a minimum RAM referred to in Article 6(8), including social welfare based analysis, and potentially adapt in accordance with the results of the internal parallel run pursuant to Article 23(2).
10. Core TSOs shall review and update methodologies for determining CNECs in accordance with Article 20.

Article 7 Methodology for operational security limits

1. In accordance with Article 23(1) of the CACM Regulation, Core TSOs shall determine the operational security limits used in operational security analysis carried out in line with Article 72 of the SO Regulation. The operational security limits used in the common capacity calculation are the same as those used in operational security analysis, therefore any additional descriptions pursuant to Article 23(2) of the CACM Regulation are not needed. In particular:
   a. Core TSOs shall respect the maximum admissible current (I_{max}) which is the physical limit of a CNE according to the operational security policy in line with Article 25 of the SO Regulation. The I_{max} can be defined with:
      i. fixed limits for all MTUs in the case of transformers and certain types of conductors which are not sensitive to ambient conditions. This is applicable for all Core TSOs.
      ii. fixed limits for all MTUs 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.
      iii. a value per MTU depending on the weather forecast. This is applicable for ČEPS, PSE, ELIA, TenneT GmbH, TenneT B.V., APG, ELES, 50Hertz, Amprion, and RTE.
      iv. fixed limits for all MTUs, in case of specific situations where the physical limit reflects the capability of substation equipment (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.
   b. when applicable, I_{max} shall be defined as a temporary current limit of the CNE in accordance with Article 25 of the SO Regulation. A temporary current limit means that an overload is only allowed for a certain finite duration.
   c. I_{max} is not reduced by any security margin, as all uncertainties in the common capacity calculation are covered on each CNEC by the FRM in accordance with Article 10 and final adjustment value (FAV) in accordance with Article 8.

d. the value F_{max} in MW, describes the maximum admissible power flow on a CNE. F_{max} is calculated by the CCC from I_{max} by the given formula:

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

Equation 1

where I_{max} is the maximum admissible current in kA of a CNE, U is a fixed reference voltage in kV for each CNE, and $\cos(\varphi)$ the power factor. Core TSOs shall assume that the share of the CNE loading by reactive power is negligible (i.e. the angle $\varphi = 0$). Thus, factor $\cos(\varphi)$ equals 1, which means that the element is assumed to be loaded only by active power. Any significant deviation from this assumption shall be covered by FAV pursuant to Article 19(1)(d).

2. Core TSOs shall aim towards determining the I_{max} using at least seasonal limits pursuant to Article 7(1)(a)(ii) and ideally dynamic line rating pursuant to Article 7(1)(a)(iii), save for cases where the conditions pursuant to Article 7(1)(a)(i) or Article 7(1)(a)(iv) apply.
3. TSOs shall review and update operational security limits in accordance with Article 20.

Article 8 Final Adjustment Value

1. The RAM on a CNE may be increased or decreased by the FAV, where:
   a. positive values of FAV (given in MW) reduce the available margin on a CNE while negative values increase it;
   b. FAV can be set by the responsible TSO during the validation process in accordance with Article 19;
   c. in case a TSO decides to use FAV during the intraday common capacity calculation, the respective TSO shall provide to Core regulatory authorities a clear description of the specific situation that lead to this decision in the monitoring report defined in Article 22.

Article 9 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, depend on production and consumption in a given system and can therefore 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 the intraday common capacity calculation expressed as maximum import and export constraints of the respective bidding zones. These kind of allocation constraints are called external constraints.
2. External constraints are determined by Core TSOs and taken into account during the single intraday coupling in addition to the active power flow limits on CNECs.
3. These external constraints shall be modelled as a constraint on the global net position (the sum of all cross border exchanges for a certain bidding zone in the single intraday coupling), thus limiting the net position of the respective bidding zone with regards to all CCRs which are part of the single intraday coupling.

4. In case implementation of an external constraint on the global net position in the single intraday coupling is technically unfeasible, the external constraints shall be modelled as a constraint within the Core cross-zonal capacity calculation as described in Article 17(2), thus limiting the Core net position of the respective bidding zone.
5. A TSO may use external constraints in order to avoid situations which 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.
6. 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-1 or intraday CGMs, 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.
7. A TSO may use external constraints in case of a central dispatch model that needs a minimum level of operational reserve for balancing. The external constraint 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.
8. The details, justifications for use, and the methodology for the calculation of external constraints as described in Article 9(5), 9(6), and 9(7) are set forth in Appendix 1 of the Core TSOs day-ahead common capacity calculation methodology.
9. A TSO may discontinue the usage of an external constraint as described in Article 9(5), 9(6), and 9(7). The concerned TSO shall communicate this change to the Core regulatory authorities and to the market participants at least one month before its implementation.
10. TSOs shall review and update allocation constraints in accordance with Article 20.

Article 10 Reliability margin methodology

1. The intraday common capacity calculation methodology is based on forecast models of the transmission system. The inputs are created the day before or on 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:
    a. in a first step, for each MTU of the observatory period, the CGMs used in the intraday common capacity calculation are updated in order to take into account the real-time situation of at least the RAs that are considered in the common capacity calculation and defined in Article 12. These RAs are controlled by Core TSOs and thus not considered as an uncertainty. This step is undertaken by copying the real-time configuration of these RAs and applying them into the historical CGM. The power flows of the latter modified 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 CGM according to the methodology as described in Article 13. Consequently, the same commercial exchanges in the Core CCR are taken into account when comparing the power flows based on the intraday common capacity calculation with flows in the real-time situation. These flows are called expected flows (F_{exp}), see Equation 2.

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

Equation 2

with

$\vec{F}_{exp}$	expected flow per CNEC in the realised commercial situation
$\vec{F}_{ref}$	flow per CNEC in the CGM (reference flow)
$\boldsymbol{PTDF}$	power transfer distribution factor matrix
$\overrightarrow{NP}_{real}$	Core net position per bidding zone in the realised commercial situation
$\overrightarrow{NP}_{ref}$	Core net position per bidding zone in the CGM

The power flows on each CNEC of the Core CCR, as expected with the intraday common capacity calculation methodology are then compared with the real time flows observed on the same CNEC, by means of a contingency analysis. All differences for all MTUs of a one-year observation period are statistically assessed and a probability distribution is obtained;

b. 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 90^{th} 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:
    i. directly take the 90^{th} 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 B.V., and TransnetBW;
    ii. only take the 90^{th} 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;

c. a possible third step is to undertake an operational adjustment on the values derived from Article 10(2)(b)(i) or 10(2)(b)(ii), which can applied to reduce the computed FRM values to a value within the range between 5% and 20% of the F_{max} calculated under normal weather conditions.

d. TSOs shall further study the value of the common risk level referred to in Article 10(2)(b) and potentially adapt it in accordance with the results of the internal parallel run pursuant to Article 23(2).

3. The FRM values shall be updated every year based upon an observatory period of one year such that seasonal effects can be reflected in the values. The FRM values remain fixed until the next update.
4. 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 initiatives. In case these values are not available, Core TSOs shall determine the FRM values as 10% of the F_{max} calculated under normal weather conditions.
5. In accordance with Article 22(2) and (4) of the CACM Regulation, the FRMs 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 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; and
g. flow-based capacity calculation assumptions including linearity and modelling of external (non-Core) TSOs' areas.

6. Core TSOs shall assess the possible improvements of the inputs of the intraday common capacity calculation in the annual review as defined in Article 20.
7. 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 intraday common capacity calculation.

Article 11 Generation shift keys methodology

1. In accordance with Article 24 of the CACM Regulation, Core TSOs developed the following methodology to determine the common GSK:
   a. Core TSOs shall take into account the available information on generation or load available in the CGM for each scenario developed in accordance with Article 18 of the CACM Regulation in order to select the nodes that will contribute to the GSK;
   b. Each Core TSO shall aim to apply a GSK that resembles the dispatch and the corresponding flow pattern, thereby contributing to minimizing the $FRMs$;
   c. Core TSOs shall define a constant GSK per MTU;
   d. 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 CGM.
2. For the application of the methodology, Core TSOs shall define, for the capacity calculation process, GSKs with fixed values, impacted by the actual generation and/or load present in the D-1 or intraday CGM, for each MTU.
3. Core TSOs have harmonized their GSK determination methodologies while including some dedicated features to take into account specific production patterns within their grids.
   a. Common rules to establish GSKs shared by all Core TSOs:
      i. 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 the CGM).
      ii. Units unavailable due to outage or maintenance are not included.
      iii. GSK is reviewed on a daily basis.
   b. Specific methodologies have been developed by some TSOs that are facing 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.
      i. For Belgium, the GSK is defined in such 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.
      ii. 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.

   iii. 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.

   c. Germany and Luxembourg

      i. The German and Luxembourgian TSOs provide one single GSK for the whole German-Luxembourgian bidding zone.

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

      iii. the TSO-specific GSKs are combined into a single GSK by assigning relative weights to each TSO-specific GSK. These weights reflect the distribution of the total market-driven generation among TSOs.

4. TSOs shall further study the GSK methodology referred to in Article 11(2) and Article 11(3) and potentially adapt it in accordance with the results of the internal parallel run pursuant to Article 23(2). Potential improvements shall be done in a progressively harmonized way.
5. TSOs shall review and update the application of the methodology for determining the GSK in accordance with Article 20.

Article 12 Methodology for remedial actions in capacity calculation

1. In accordance with Article 25(1) of the CACM Regulation and Article 20(2) of the SO Regulation, Core TSOs shall individually define Remedial Actions (RAs) to be taken into account in the intraday common capacity calculation.
2. In case a RA made available for the capacity calculation in the Core CCR is also made available in another CCR, the TSO taking control of the RA shall take care, when defining it, of a consistent use in its potential application in both regions to ensure a secure power system operation.
3. In accordance with Article 25(2) and (3) of the CACM Regulation, these RAs will be used for coordinated optimization of cross-zonal capacities while ensuring secure power system operation in real time.
4. In accordance with Article 25(4) of the CACM Regulation, a TSO may refrain from considering a particular RA in capacity calculation in order to ensure that the remaining RAs are sufficient to ensure operational security.
5. In accordance with Article 25(5) of the CACM Regulation, the intraday common capacity calculation takes only non-costly RAs into account which can be explicitly modelled in the used CGMs. These RAs can be:
   a. changing the tap position of a phase-shifting transformer (PST);
   b. topological measure: 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. 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. The RAs can be preventive or curative, i.e. affecting all CNECs or only pre-defined contingency cases, respectively.
8. The optimized application of RAs in the intraday common capacity calculation is performed in accordance with Article 14.
9. TSOs shall review and update RAs taken into account in capacity calculation in accordance with Article 20.

DETAILED DESCRIPTION OF THE CAPACITY CALCULATION APPROACH

Article 13 Mathematical description of the capacity calculation approach

1. The flow-based computation is a centralized calculation which delivers two main classes of parameters needed for the definition of the flow-based domain: the $PTDFs$ and the $RAMs$.
2. In accordance with Article 21(b)(i) of the CACM Regulation, for each CNEC defined in Article 6(5), Core TSOs shall calculate the influence of the bidding zone net position changes on its power flow. This influence is called the zone-to-slack $PTDF$. This calculation is performed using the D-1 or Intraday CGM used in the intraday common capacity calculation and the GSK defined in accordance with Article 11.
3. The nodal $PTDFs$ can be first calculated by subsequently varying the injection of each node defined in the GSK in D-1 or Intraday CGM used in the intraday common capacity calculation. For every single nodal variation, the effect on every CNE's or CNEC's loading is monitored and calculated as a percentage. The GSK shall translate these node-to-slack $PTDFs$ into zone-to-slack $PTDFs$ as it converts the bidding zone net position variation into an increase of generation in specific nodes as follows:

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

Equation 3

with

$\boldsymbol{PTDF}_{zone-to-slack}$	matrix of zone-to-slack $PTDFs$ (columns: bidding zones, rows: CNECs)
$\boldsymbol{PTDF}_{node-to-slack}$	matrix of node-to-slack $PTDFs$ (columns: nodes, rows: CNECs)
$\boldsymbol{GSK}_{node-to-zone}$	matrix containing the $GSKs$ of all bidding zones (columns: bidding zones, rows: nodes, sum of each column equal to one)

4. $PTDFs$ may be defined as zone-to-slack $PTDFs$ or 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. A zone-to-zone $PTDF_{A\to B,l}$ 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 $PTDF_{A\to B,l}$ can be linked to zone-to-slack $PTDFs$ as follows:

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

Equation 4

5. A low value of the zone-to-zone $PTDF_{A\to B,l}$ as defined 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 single intraday coupling, 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 22. In case

of an undesirable impact, the TSOs shall take appropriate actions to investigate the mitigation of those effects.

6. The $PTDF$ for an exchange between two bidding zones A and B over a HVDC interconnector within the Core CCR following the Evolved Flow-Based (EFB) methodology pursuant to Article 15 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:

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

Equation 5

with

$PTDF_{VH\_1,l}$	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
$PTDF_{VH\_2,l}$	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

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 15.

7. The maximum zone-to-zone $PTDF$ of a CNE or a CNEC ($PTDF_{z2zmax,l}$) is the maximum influence that a Core exchange can have on the respective CNE or CNEC:

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

Equation 6

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

8. The reference flow (F_{ref}) is the active power flow on a CNE or a CNEC based on the D-1 or Intraday CGM. In case of a CNE, F_{ref} is directly simulated from the CGM whereas in case of a CNEC, F_{ref} is simulated with the specified contingency.

9. 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-1 or Intraday CGM (reference commercial situation) and the commercial situation i:

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

Equation 7

with

$\vec{F}_i$	expected flow per CNEC in the commercial situation i
$\vec{F}_{ref}$	flow per CNEC in the CGM (reference flow)
$\boldsymbol{PTDF}$	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

10. The 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 reliability margin (FRM), the final adjustment value (FAV), and the expected flow (F_i) with the following equation:

$$RAM_i = F_{max} - FRM - FAV - F_i$$

Equation 8

Article 14 Rules on adjustment of power flows on critical network elements due to remedial actions

1. In accordance with Article 21(1)(b)(iv) of the CACM Regulation, this intraday common capacity calculation methodology shall describe the rules on the adjustment of power flows on CNEs due to RAs:
    a. An exchange of foreseen RAs in each CCR, with sufficient impact on the 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;
    b. 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 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 starting from the AAC.
    c. the RAO shall be an automated, coordinated and reproducible process, performed by the CCC, that applies RAs defined in accordance with Article 12; and
    d. the applied RAs should be transparent to all TSOs, also of adjacent CCRs.
2. The RAO methodology contains a set of pre-defined characteristics such as an objective function, constraints and optimization variables:
    a. The RAO objective is to enlarge the capacity domain starting from the AAC, with the objective function $\min(RAM_{rel}) \rightarrow max$, i.e. maximizing the minimum relative RAM of all optimized CNECs in accordance with Article 6(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 9.

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

Equation 9

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 6(6)(a), until all CNECs have a RAM equal to or larger than zero.

b. The constraints, in accordance with Article 25(4) of the CACM Regulation, are:
   - operational security limits of optimized CNECs in accordance with Article 6(6)(a);
   - the provided range of tap positions of each PST as preventive or curative RAs;
   - minimum impact on objective function value for use of RAs;
   - equal tap positions for pre-defined parallel PSTs;
   - limitations on the number of activated curative RAs;
   - maximum loading of monitored (i.e. not optimized) CNECs in accordance with Article 6(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.

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

Article 15 Integration of HVDC interconnectors located within the Core

1. Core TSOs shall apply EFB methodology when including cross-border HVDC interconnectors within the flow-based Core CCR.
2. 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.
3. Core TSOs shall distinguish between Advanced Hybrid Coupling (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 CCRs. 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.
4. The main adaptations to the intraday common capacity calculation process introduced by the concept of EFB are twofold:
   a. the impact of an exchange over the cross-border HVDC interconnector is considered for all relevant CNECs;
   b. 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.
5. 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 will 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 13(6) are only used to model 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 flow-based 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.

6. 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 an 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.

Article 16 Consideration of non-Core CCR borders

1. In accordance with Article 21(1)(b)(vii) of the CACM Regulation, Core TSOs will 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 CGMM.
2. The assumptions of non-Core exchanges are implicitly captured in the 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 13). 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.
3. In contrast, AHC would enable Core TSOs to explicitly model the exchange situations of adjacent CCRs within the flow-based domain and thus in the single intraday coupling. This would reduce uncertainties in the CGM regarding forecast of non-Core exchanges, and increase the degree of freedom for the single intraday market coupling in terms of optimal allocation of capacities. The feasibility of AHC will be studied in accordance with Article 23(6).
4. AHC is considered to be the target solution to explicitly model the exchange situations of adjacent CCRs within the Core flow-based domain.
5. Core TSOs shall monitor the accuracy of non-Core exchanges in the CGM. Core TSOs shall report on at least an annual basis.

Article 17 Calculation of the final flow-based domain

1. 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:
   a. application of a possible FAV in accordance with Article 19;
   b. final calculation of the RAM for the single intraday coupling in accordance to Article 13, taking into account the already nominated capacity in the commercial situation.
   c. only the constraints that are most limiting the exchanges need to be respected in the single intraday 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 other constraints;

2. In case an external constraint is modelled as a constraint within the Core cross-zonal capacity calculation according to Article 9(4), it shall be added as an additional row to the final flow-based domain as follows:
   a. 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;
   b. the $PTDF$ values for all other bidding zones are set to zero;
   c. the RAM value is set to the amount of the external constraint and adjusted such that the limits provided to the single intraday coupling mechanism refer to the increments or decrements of the net positions with respect to the already nominated capacity.
3. In case costly RAs are needed to maintain the calculated cross-zonal capacity, coordination of these RAs shall occur.

Article 18 Backup procedures

1. 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, a technical failure in the tools, an error in the communication infrastructure, or corrupted or missing input data.
2. In case the CCC is unable to produce results, the CCC or TSOs of Core CCR, where applicable, shall provide the NEMOs of the Core CCR with the latest cross-zonal capacities calculated within the Core CCR for the MTU considered.
3. In case the allocation mechanism expects ATCs for each bidding-zone border, the CCC or the Core TSOs, where applicable, shall derive these from the latest cross-zonal capacities calculated within the Core CCR and provide them to the NEMOs for the MTU considered.

Article 19 Capacity validation methodology

1. 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:
   a. an occurrence of an exceptional contingency or forced outage as defined in Article 3 of SO Regulation;
   b. when costly RAs and non-costly RAs, pursuant to Article 11, that are needed to ensure the calculated capacity pursuant to Article 4(7)(d) on all CNECs, are not sufficient;
   c. a mistake in input data, that leads to an overestimation of cross-zonal capacity from an operational security perspective;
   d. a potential need to cover reactive power flows on certain CNECs.
2. 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 employ verification tools not available to the CCC.
3. In case of a required reduction due to situations as defined in Article 19(1)(a), a TSO may use a positive value for FAV for its own CNECs or adapt their external constraints to reduce the cross-zonal capacity for his market area.

4. In case of a required reduction due to situations as defined in Article 19(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 19(1)(c), a TSO may also request a common decision to launch the back-up procedure as defined in Article 18.
5. In case the allocation mechanism requires ATC values, the validation shall be performed based on ATCs. In this case, a reduction of ATC in the relevant amount is applied.
6. Any reduction of cross-zonal capacities during the validation process shall be communicated to market participants and justified to the Core national regulatory authorities in accordance with Article 21 and Article 22, 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 19(1)(c) the report shall contain measures to prevent similar mistakes.
7. The CCC shall coordinate with neighbouring CCCs 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 CCCs shall be provided to Core TSOs. Core TSOs may then apply the appropriate reductions of cross-zonal capacities as described in Article 19(3).

UPDATES AND DATA PROVISION

Article 20 Reviews and updates

1. Based on Article 3(f) of the CACM Regulation and in accordance with Article 27(4) of the CACM 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.
    a. If the operational security limits, CNEs, contingencies and allocation constraints used for the common capacity calculation need to be updated based on this review, Core TSOs shall publish the changes at least one week before the implementation.
    b. Core TSOs shall include the re-assessment of the further need of allocation constraints.
2. In case the review proves the need of an update of the reliability margins, Core TSOs shall publish the changes at least one month before the implementation.
3. The review of the common list of RAs taken into account in capacity calculation shall include at least an evaluation of the efficiency of specific PSTs and the topological RAs considered during RAO.
4. In case the review proves the need for updating the application of the methodologies for determining GSKs, CNEs, and contingencies referred to in Articles 22 to 24 of the CACM Regulation, changes have to be published at least three months before the final implementation.
5. Any changes of parameters listed in Article 27(4) of the CACM Regulation have to be communicated to market participants and Core NRAs.
6. The impact of any changes of allocation constraints and parameters listed in Article 27(4)(d) of the CACM Regulation have to be communicated to market participants and Core NRAs. If any change leads to an adaption of the methodology, Core TSOs will amend the methodology according to Article 9(13) of the CACM Regulation.

Article 21 Publication of data

1. The data as set forth in Article 21(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

published data, a handbook will be prepared by Core TSOs and published on this communication platform.

2. 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 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. final flow-based parameters shall be published for each MTU, comprising the zone-to-slack $PTDFs$ and the RAM for each "presolved" CNEC;
    b. additionally, the following data items shall be published for each MTU:
        i. maximum and minimum net position of each bidding zone;
        ii. maximum bilateral exchanges between all Core bidding zones;
    c. the following information may be published:
        i. real names of CNEC and external constraint;
        ii. CNE EIC code and Contingency EIC code;
        iii. detailed breakdown of RAM per CNEC:
            - F_{max}, including information if it is based on permanent or temporary limits;
            - I_{max};
            - F_i;
            - FRM;
            - FAV.
        iv. detailed breakdown of RAM per external constraint:
            - F_{max};
            - F_i.
        v. For each RA resulting from the RAO:
            - Type of RA;
            - Location of RA.
    d. the following information of the used CGMs for each MTU, for each Core bidding zone and each TSO may be published ex-post:
        i. vertical load;
        ii. production;
        iii. best forecast of net position.
    e. publication of the static grid model.
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 day-ahead 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 23(4).

Article 22 Monitoring and information to regulatory authorities

1. With reference to the Whereas and Article 26(5) of the CACM Regulation, monitoring data shall be provided towards the Core regulatory authorities as basis for supervising a non-discriminatory and efficient congestion management in the Core CCR.

2. 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.
3. 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:
    a. maximum zone-to-zone $PTDF$ check;
    b. hourly Min/Max Net Positions per bidding zone;
    c. maximum bilateral exchanges for each Core bidding zone border (hourly);
    d. usage of the FAV;
    e. external constraints;
    f. overview of MTUs for which the backup procedure was triggered;
    g. hourly non-anonymized presolved CNECs, disclosing $PTDF$, F_{max}, FRM, FAV, RAM, and F_i;
    h. hourly non-anonymized active CNECs, disclosing associated net positions;
    i. key aggregated figures per bidding zone, for each MTU:
        - number of presolved CNECs;
        - if the RAM after initial computation, pursuant to Article 4(7)(a), on at least one CNEC is less than zero;
        - number of presolved CNECs with RAs applied;
        - number of presolved CNECs without RAs applied;
        - number of presolved CNECs, breaching the max zone-to-zone $PTDF$ threshold;
        - number of presolved CNECs, breaching the max zone-to-zone $PTDF$ threshold due to the application of RAO;
        - number of presolved CNECs using the FAV;
        - if a backup procedure, according to Article 18, was applied;
    j. the impact of small zone-to-zone PTDFs;
    k. in case of occurrence: justification when FAV is applied;
    l. in case of occurrence: justification when the max zone-to-zone $PTDF$ threshold is breached of presolved CNECs due to decisions pursuant to Article 6(7);
    m. reductions made during the validation of cross-zonal capacity in accordance with Article 26(5) of the CACM Regulation;
    n. the list of CNEs with the I_{max} definitions used and a justification for that, in accordance to Article 7(1);
    o. new CNEs and contingencies that have been added to the lists, in accordance to Article 6(1) and Article 6(2), provided by the TSOs to the capacity calculation, including a justification.
4. The final, exhaustive and binding list of all monitoring items, respective templates and 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 23(4).

IMPLEMENTATION

Article 23 Timescale for implementation of the Core flow-based intraday capacity calculation methodology

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

1. The TSOs of the Core CCR shall publish the 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) to (12) of the CACM Regulation.
2. TSOs shall continue to monitor the effects and the performance of the proposed intraday 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.
3. 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 21 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 21) shall be done in accordance to these national analysis.
4. The TSOs of the Core CCR aim to implement the intraday capacity calculation methodology in order to be operationally ready for launching an external parallel run together with the Core NEMOs, no later than S2-2020 in accordance with Article 20(8) of CACM Regulation. The external parallel run will be followed by a single intraday coupling integration phase and go live preparations aiming for S1-2021 as the go-live window for the market.
5. Until the intraday common capacity calculation is operational, the Core intraday capacities will be produced based on the left over capacity from the Core day-ahead common capacity calculation process or the available capacity resulting from the intraday cross-zonal capacity calculation in the CWE region, if applicable.
6. After the implementation of the intraday common capacity calculation methodology, 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 AHC concept, in close cooperation with adjacent involved CCRs. A decision will be taken based on a study to be delivered two (2) years after the go-live of the common intraday capacity calculation.
7. The deadlines defined in the above Article 23(4) 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.

LANGUAGE

Article 24 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 regulatory authorities with an updated translation of the methodology.