# Day-Ahead Capacity Calculation Methodology of the Central Europe Capacity Calculation Region

in accordance with article 20ff. of the Commission Regulation (EU) 2015/1222 of 24th July 2015 establishing a guideline on capacity allocation and congestion management as amended by Commission implementing Regulation (EU) 2021/280 of 22 February 2021

# Clean version

**September 2025**

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# Contents

## Whereas

(1) 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 as amended by Commission implementing Regulation (EU) 2021/280 of 22 February 2021 (hereafter referred to as the "CACM Regulation"). This methodology is hereafter referred to as the "day-ahead capacity calculation methodology".

(2) The day-ahead capacity calculation methodology takes into account the general principles and goals set in the CACM Regulation as well as in Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (Electricity Regulation). 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 establish a day-ahead 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 capacity calculation methodology on the objectives of the CACM Regulation has to be described and is presented below.

(4) The day-ahead 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 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 Central Europe CCR, thereby ensuring a level playing field amongst 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 CACM Regulation aims at harmonizing capacity calculation of CCR, this includes the possibility to merge CCRs in case this is deemed most efficient. Therefore, on 19 March 2024 ACER approved the amendment on the determination of capacity calculation regions (Decision No 04/2024). This decision includes the merger of Core CCR and Italy North CCR, forming Central Europe CCR. For the time being only this day-ahead capacity calculation methodology will be implemented in Central Europe CCR.

(6) The day-ahead 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 approach aims at providing the maximum available capacity to market participants on the day-ahead timeframe within the operational security limits.

(7) The day-ahead 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 under which the network elements located inside bidding zones can be considered as limiting for capacity calculation, and (ii) ensuring that a minimum share of the capacity is made available for commercial exchanges while ensuring operational security (Article 3(a) to (c) of the CACM Regulation) and Electricity Regulation

(8) The day-ahead capacity calculation methodology serves the objective of optimising the allocation of cross-zonal capacity (Article 3(d) of the CACM Regulation), since it is using the flow-based approach, which 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.

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

(10) The day-ahead capacity calculation methodology determines the main principles and main processes for the day-ahead timeframe. It requires that the Central Europe TSOs provide market participants with 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).

(11) 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).

(12) 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 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.

(13) The day-ahead capacity calculation methodology facilitates a level playing field for NEMOs (Article 3(i) of the CACM Regulation) since all NEMOs and all their market participants will face the same rules and non-discriminatory treatment (including timings, data exchanges, results formats etc.) within the Central Europe CCR.

(14) Finally, the day-ahead 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.

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

(16) The day-ahead capacity calculation methodology is structured into three stages: (i) the definition and provision of capacity calculation inputs by the Central Europe 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 Central Europe TSOs, and (iii) the capacity validation by the Central Europe TSOs in coordination with the coordinated capacity calculator. The roles and responsibilities of the Central Europe TSOs and of the coordinated capacity calculator need to be clearly defined.

(17) 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.

(18) 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.

(19) 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* margins,frequency control, voltage and dynamic stability) 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 or from/to a set of interconnectors .

(20) 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.

(21) 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 Central Europe 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.

(22) 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.

(23) 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.

(24) 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.

(25) Cross-zonal capacities determined by the day-ahead capacity calculation shall ensure that all combinations of net positions that could result from previously-allocated cross-zonal capacity – Long Term Allocations (LTA) – can be accommodated. For that purpose, the TSOs proceeded to the LTA inclusion which consists in providing a single flow-based domain including LTAs for the single day-ahead coupling. The extended LTA inclusion approach differs by providing the single day-ahead coupling with LTAs and the flow-based domain without LTA inclusion separately. The market coupling algorithm then chooses which union of both domains creates most welfare.

(26) To enable a more accurate and efficient representation of connections with neighbouring CCRs, the advanced hybrid coupling (AHC) is foreseen in the Central Europe DA CCM to replace the standard hybrid coupling and provide efficiency gains in the capacity calculation and allocation phase on the borders where AHC is applied. AHC principles can also rather efficiently be applied to a lowly meshed alternating current (AC) border between a Central Europe and a non-Central Europe bidding zone, while its efficiency and accuracy of network representation diminishes with the increased meshness of AC borders. Implementation of AHC is foreseen on all borders linking Central Europe bidding zones and bidding zones of neighbouring CCRs and which are part of SDAC, except for the common borders with GRIT CCR, where only a low efficiency gain is expected in comparison with the challenges imposed by AHC.

(27) A high interdependency of the capacity calculation with Switzerland with the regions Italy North and Core exists. The merger of Core and Italy North CCRs enables CE TSOs to maximally include and coordinate Swiss borders in the capacity calculation process, thus providing the most efficient capacity calculation for the whole Central Europe CCR among all viable alternatives and hence contributing to the objectives of the CACM Regulation and the Electricity Regulation. Through a contractual framework, Swissgrid shall be included as an integrated technical counterparty (iTCP).

(28) CE TSOs and Integrated Technical Counterparty(ies) are developing and implementing processes for day-ahead capacity calculation. In order to for this methodology to become effective and obligatory for the Integrated Technical Counterparty(ies) a contractual framework is needed. An Integrated Technical Counterparty Agreement, which shall be concluded separately between the Parties, is needed to enable coordination between the Integrated Technical Counterparty(ies) and CE TSOs with regard to the processes, operations and obligations as described in the methodology.

(29) Core TSOs are working on amending the Core Day-Ahead Capacity Calculation Methodology (Core DA CCM). Upon approval of such an amendment to Core DA CCM, the CE TSOs shall, without undue delay, submit a corresponding amendment to the CE DA CCM.

# TITLE 1 - General provisions

## Article 1. Subject matter and scope

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

## Article 2. Definitions and interpretation

For the purposes of the day-ahead capacity calculation methodology, terms used in this document shall have the meaning of the definitions included in Article 2 of the CACM Regulation, of Electricity Regulation, Directive 2019/944, 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. 'Affected element' means an element of network (i. e. overhead lines, cables or substation) where the maximum thermal limit is increased for considering the effect of additional exchanges of the not modelled lines on the same border (see Annex 2).

2. 'AHC' means the advanced hybrid coupling which is a solution to take fully into account the influences of the adjacent CCRs during the capacity allocation;

3. 'AHC border' means a border between a bidding zone within and outside of the Central Europe CCR where both bidding zones are part of Single-Day-Ahead Coupling and the AHC is applied;

4. 'Allocation Constraints' means constraints as listed in Art 7(2) of this methodology to be respected during capacity allocation to maintain the transmission system within operational security limits and have not been translated into cross-zonal capacity or that are needed to increase the efficiency of capacity allocation (Art. 2(6) Reg.(EU) 2015/1222-CACM);

5. 'AMR' means the adjustment for the minimum remaining available margin;

6. 'annual report' means the report issued on an annual basis by the CCC and the Central Europe TSOs on the day-ahead capacity calculation;

7. 'ATC' means the available transmission capacity, which is the transmission capacity that remains available after the allocation procedure and which respects the physical conditions of the transmission system;

8. 'CCC' means the coordinated capacity calculator, as defined in Article 2(11) of the CACM Regulation, of the Central Europe CCR, unless stated otherwise;

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

10. 'CE' means Central Europe;

11. 'CE CCR' means the Central Europe capacity calculation region as established by the Determination of capacity calculation regions pursuant to Article 15 of the CACM Regulation;

12. ‘CGM’ means the common grid model as defined in Article 2(2) of the CACM Regulation and means a D-2 CGM established in accordance with the CGMM;

13. ‘CGMM’ means the common grid model methodology, pursuant to Article 17 of the CACM Regulation;

14. ‘CNE’ means a critical network element;

15. ‘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;

16. ‘CE net position’ means a net position of a bidding zone in CE CCR or of a VH resulting from the allocation of cross-zonal capacities within the CE CCR and on AHC borders;

17. CE TSOs are 50Hertz Transmission GmbH (“50Hertz”), Amprion GmbH (“Amprion”), Austrian Power Grid AG (“APG”), CREOS Luxembourg S.A. (“CREOS”), ČEPS, a.s. (“ČEPS”), EirGrid PLC (“EirGrid”), Eles d.o.o., operater kombiniranega prenosnega in distribucijskega elektroenergetskega omrežja (“ELES”), Elia System Operator S.A. (“ELIA”), Croatian Transmission System Operator Plc (“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”), System Operator for Northern Ireland Ltd. (SONI), TenneT TSO GmbH (“TenneT GmbH”), TenneT TSO B.V. (“TenneT B.V.”), TERNA - Rete Elettrica Nazionale S.p.A. (“TERNA”), National Power Grid Company Transelectrica S.A. (“Transelectrica”), TransnetBW GmbH (“TransnetBW”);

18. ‘cross-zonal CNEC’ means a CNEC of which a CNE is located on the bidding zone border or connected in series to such network element transferring the same power (without considering the network losses);

19. ‘curative remedial action’ means a remedial action which is only applied after a given contingency occurs;

20. ‘D-1’ means the day before electricity delivery;

21. ‘D-2’ means the day two-days before electricity delivery;

22. ‘DA CC TU’ is the day-ahead capacity calculation time unit, which means the time unit for the day-ahead capacity calculation and is equal to 60 minutes;

23. ‘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;

24. ‘external virtual hub (EVH)’ means a virtual bidding zone without any buy and sell orders, used to represent the imports and exports on an AHC border as specified in Article 13 of this Methodology;

25. ‘$F_{0,CE}$’ means the flow per CNEC in the situation without commercial exchanges within the CE CCR including iTCP and with EVH;

26. '$F_{0,all}$' 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;

27. '$F_i$' means the expected flow in commercial situation $i$;

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

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

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

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

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

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

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

35. "GRIT CCR" means Greece-Italy Capacity Calculation Region.

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

37. 'HVDC' means a high voltage direct current network element with reference to the interconnections within the CE CCR;

38. 'ID CC TU' is the intraday capacity calculation time unit, which means the time unit for the intraday capacity calculation and is equal to 15 minutes;

39. 'IGM' means the D-2 individual grid model as defined in Article 2(1) of the CACM Regulation;

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

41. 'internal virtual hub (IVH)' means a virtual bidding zone without any buy and sell orders, used to represent the commercial exchanges on an internal CE HVDC interconnector, where the evolved flow-based approach is applied as specified in Article 12 of this Methodology;

42. '$I_{max}$' means the maximum admissible current;

43. 'LTA' means the long-term allocated capacity;

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

45. 'LTN' means the long-term nomination, which is the nomination of the long-term allocated capacity;

46. ‘merging agent’ means an entity entrusted by the CE TSOs to perform the merging of individual grid models into a common grid model as referred to in Article 20ff of the CGMM;
47. ‘MNEC’ means a monitored network element with a contingency;
48. ‘Non-modelled lines’ means tie-lines below 220 kV on Italy North border not modelled in the CGM;
49. ‘NP’ or ‘$NP$’ means a net position of a bidding zone, which is the net value of generation and consumption in a bidding zone;
50. ‘NRAO’ means the non-costly remedial action optimisation;
51. ‘oriented bidding zone border’ means a given direction of a bidding zone border (e.g. from Germany to France);
52. ‘pre-solved domain’ means the final set of binding constraints for capacity allocation after the pre-solving process;
53. ‘pre-solving process’ means the identification and removal of redundant constraints from the flow-based domain;
54. ‘preventive remedial action’ means a remedial action which is applied on the network before any contingency occurs;
55. ‘previously-allocated capacities’ means the long-term capacities which have already been allocated in previous (yearly and/or monthly) time frames;
56. ‘PST’ means a phase-shifting transformer;
57. ‘PTDF’ or ‘$PTDF$’ means a power transfer distribution factor;
58. ‘$\mathbf{PTDF}_{init}$’ means a matrix of power transfer distribution factors resulting from the initial flow-based calculation;
59. ‘$\mathbf{PTDF}_{nrao}$’means a matrix of power transfer distribution factors used during the NRAO;
60. ‘$\mathbf{PTDF}_{f}$’ means a matrix of power transfer distribution factors describing the final flow-based domain;
61. ‘PTR’ means a physical transmission right;
62. ‘quarterly report’ means a report on the day-ahead capacity calculation issued by the CCC and the CE TSOs on a quarterly basis;
63. ‘Ramping Constraints’ means the constraints to be respected during capacity allocation to limit the variation of the net position or import/export from/to a set of interconnectors from one MTU to the next
64. ‘RA’ means a remedial action as defined in Article 2(13) of the CACM Regulation;
65. ‘RAM’ or ‘$RAM$’ means a remaining available margin;

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

67. ‘SDAC’ means the single day-ahead coupling;

68. ‘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;

69. ‘slack node’ means the single reference node used for determination of the 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 for each DA CC TU;

70. ‘spanning’ means the pre-coupling backup solution in situations when the day-ahead capacity calculation fails to provide the flow-based parameters for strictly less than three consecutive hours. This calculation is based on the intersection of previous and sub-sequent available flow-based parameters;

71. ‘SO Regulation’ means Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation;

72. ‘standard hybrid coupling’ means a solution to capture the influence of exchanges with non- CE bidding zones on CNECs that is not explicitly taken into account during the capacity allocation phase;

73. ‘static grid model’ means a list of relevant grid elements of the transmission system, including their electrical parameters;

74. ‘U’ is the reference voltage;

75. ‘UAF’ is an unscheduled allocated flow;

76. ‘vertical load’ means the total amount of electricity which exits the 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;

77. ‘virtual hub’ (VH) means external or internal virtual hub.

78. ‘zone-to-slack $PTDF$’ means the PTDF of a commercial exchange between a bidding zone and the slack node or between a VH and the slack node;

79. ‘zone-to-zone $PTDF$’ means the PTDF of a commercial exchange between two bidding zones, between two VHs or between a VH and a bidding zone;

80. the notation $x$ denotes a scalar;

81. the notation $\vec{x}$ denotes a vector;

82. the notation $\mathbf{x}$ denotes a matrix;

83. ‘CZC’ means cross-zonal capacity whereas this capacity is to be understood as an union of “flow-based parameters” (flow-based domain) and “LTA values” (LTA domain);

84. ‘LTA domain’ means a set of bilateral exchange restrictions covering the previously allocated cross-zonal capacities;

85. ‘third-country TSO’ means a TSO which is not a CE TSO and operates in a country which is not a Member State of the European Union;

86. ‘integrated technical counterparty’ (iTCP) means a TSO which is not a CE TSO and operates in a country which is not a Member State of the European Union, but is included in the CE day-ahead capacity calculation pursuant to Article 13(2) and (3);

87. ‘integrated technical counterparty bidding-zone’ (iTCP bidding-zone) means the bidding-zone of a country which is not a Member State of the European Union and in which the iTCP operates;

88. ‘integrated technical counterparty agreement’ means the agreement between all CE TSOs and the iTCP to jointly apply the CE day-ahead capacity calculation methodology at the borders between the relevant CE TSOs and the iTCP and contractually settled between all CE TSOs and the iTCP as described in Article 13 of this methodology;

89. ‘CGMES’ means the common grid model exchange specification that is developed by ENTSO-E pursuant to the CGMM;

90. ‘circumstance’ means a combination of net positions which is feasible according to the CZC used for the respective validation phase. A circumstance comprises at least the CE bidding zones and, where AHC is applied, the respective external virtual hubs. It may additionally contain bidding zones of iTCPs.

91. ‘MTU’ is the day-ahead and intraday market time unit, which means the time unit for capacity allocation during the day-ahead and intraday market and is equal to 15 minutes.

1. In this day-ahead 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 capacity calculation methodology;

   (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 CE TSOs and iTCP in a common and coordinated way on all bidding zone borders of the CE CCR; and

   (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. Application of this methodology

This day-ahead capacity calculation methodology applies to the day-ahead capacity calculation within the CE CCR. The relevant provisions of this methodology apply to the iTCP, by virtue of the integrated technical counterparty agreement. Capacity calculation methodologies within other CCRs or for other time frames, except for an update of the remaining cross-zonal capacities after SDAC to be used for intraday, as stipulated in Article 25, are not in the scope of this methodology.

# TITLE 2 - General description of the day-ahead capacity calculation methodology

## Article 4. Day-ahead capacity calculation process

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

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

   (a) the creation of capacity calculation inputs by the CE TSOs and iTCP;

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

   (c) the capacity validation by the CE TSOs and iTCP in coordination with the CCC.

3. Each CE TSO and iTCP 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) Allocation 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.

4. In addition to the capacity calculation inputs pursuant to paragraph 3, the CE TSOs and iTCP, or an entity delegated by the CE TSOs, shall send to the CCC, for each DA CC TU 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 CE bidding zone border and for each AHC 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).

5. When providing the capacity calculation inputs pursuant to paragraphs 3 and 4, the CE TSOs and iTCP shall respect the formats commonly agreed between the CE TSOs and the CCC while fulfilling the requirements and guidance defined in the CGMM. No later than three months after the implementation of the common grid model methodology according to Article 17 CACM Regulation and the implementation of this methodology according to Article 30, CE TSOs and iTCP shall deliver an assessment for the application of CGMES in the capacity calculation, including a planning proposal with clear milestones for each implementation step.

6. No later than six months before the implementation of this methodology in accordance with Article 30 the CE TSOs and iTCP shall jointly establish a process description document as referred to in paragraphs 3 and 4 and publish it on the online communication platform as referred to in Article 27. 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.

7. Once the merging agent receives all the IGMs established pursuant to the CGMM and iTCP IGM, it shall merge them to create the CGM in accordance with the CGMM and deliver the CGM to the CCC.

8. The day-ahead capacity calculation process and validation shall be performed by the CCC, the CE TSOs and iTCP according to the following procedure:

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

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

Step 8a. The CCC shall, according to Article 23, calculate the capacities for iTCPs, subject to Article 13(2).

Step 9. The CCC shall, according to Article 21, consider the capacities for iTCPs, subject to Article 13(2), and remove the redundant CNECs and redundant allocation constraints from final $PTDF_f$ and $RAM_{bn}$ and publish these as initial flow-based parameters in accordance with Article 27;

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 27and provide them to NEMOs for capacity allocation in accordance with Article 21.

# TITLE 3 – Capacity calculation inputs

## Article 5. Definition of critical network elements and contingencies

1. Each CE TSO and iTCP 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. Internal network elements may be defined as CNEs and additionally have to be published pursuant to paragraph 6 and 7.

2. CNEs pursuant to paragraph 1 shall additionally include those elements on AHC borders. In case the capacity constraints resulting from cross-zonal network elements on an AHC border are already considered in another CCR, a CE TSO or iTCP may decide not to define such network elements as CNE in CE. Such a CNE on an AHC border shall generally be included only in a single CCR. Any deviation from this rule shall be subject to a sound justification.

3. Each CE TSO and iTCP shall define a list of proposed contingencies used in operational security analysis in accordance with Article 33 of the SO Regulation, limited to their relevance for the set of CNEs as defined in paragraph 1 and pursuant to Article 23(2) of the CACM Regulation. The contingencies of a CE TSO or iTCP shall be located within the observability area of that CE TSO or iTCP. This list shall be updated at least on a yearly basis and in case of topology changes in the grid of the CE TSO or iTCP, pursuant to Article 26. A contingency can be an unplanned outage 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 elements.

4. Each CE TSO and iTCP shall establish a list of CNECs by associating the contingencies established pursuant to paragraph 3 with the CNEs established pursuant to paragraph 1 following the rules established in accordance with Article 75 of the SO Regulation. Until such rules are established and enter into force, the association of contingencies to CNEs shall be based on each TSO's operational experience. An individual CNEC may also be established without a contingency.

5. Each CE TSO and iTCP shall provide to the CCC a list of CNECs established pursuant to paragraph 4. Each CE TSO and iTCP may also provide to the CCC a list of monitored network elements with contingency (MNEC), which need to be monitored during the capacity calculation.

6. No later than 18 months after the implementation of this methodology in accordance with Article 30(2), all CE TSOs and iTCP shall publish a list of internal network elements (combined with the relevant contingencies) defined as CNECs on a dedicated online communication platform.

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

   a. a list of internal CNECs with the associated maximum zone-to-zone PTDFs calculated as time-average over the last twelve months or over the period since its inclusion in the capacity calculation whichever is the shortest duration;

   b. an impact assessment of increasing the threshold of the maximum zone-to-zone PTDF for exclusion of internal CNECs referred to in Article 15(1) equal to 10% or above.

8. The list pursuant to paragraph 7(a) shall be updated every year.

9. The CE TSOs and iTCP shall regularly review and update the application of the methodology for determining CNECs as defined in Article 26.

10. The CE TSOs and iTCP shall submit an amendment proposal reconsidering the list of internal CNECs, in order to comply with the legal findings of the General Court in the Case BNetzA v ACER (T-600/23) in so far as those legal findings are applicable to the day-ahead capacity calculation methodology of the Central Europe capacity calculation region. In case this methodology is already compliant with the legal findings of the General Court, no such amendment proposal is required.

## Article 6. Methodology for operational security limits

1. The CE TSOs and iTCP shall use in the day-ahead capacity calculation the same operational security limits as those used in the operational security analysis carried out in accordance with Article 72 of the SO Regulation.

2. To take into account the thermal limits of CNEs, the CE TSOs and iTCP shall use the maximum admissible current limit ($I_{max}$), which is the physical limit of a CNE according to the operational security limits in accordance with Article 25 of the SO Regulation. The maximum admissible current shall be defined as follows:

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

      i. Seasonal limit, which means a fixed limit for all DA CC TUs of each of the four seasons.

      ii. Dynamic limit, which means a value per DA CC TU reflecting the varying ambient conditions.

      iii. Fixed limits for all DA CC TUs, 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, or disconnector) 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 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) $I_{max}$ shall represent only real physical properties of the CNE and shall not be reduced by any security margin.[1]

   (d) the CCC shall use the $I_{max}$ of each CNEC to calculate $F_{max}$ for each CNEC, which describes the maximum admissible active power flow on a CNEC. $F_{max}$ shall be calculated by the given formula:

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

*Equation 1*

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

[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.

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

3. The CE TSOs and iTCP 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. Each CE TSOs and iCTP shall provide annually the status of operational limits in place. No later than 24 months after the implementation of this methodology in accordance with Article 30(2), CE TSOs and iTCP shall conduct an analysis on the efficiency of implementing dynamic limits for the maximum admissible current. This analysis shall include an identification of the CNECs where dynamic limits would bring the most value and possible solution to implement more granular operational security limits. Every two years after the end of the calendar year, all CE TSOs and iTCP shall analyse all CNEs which jointly collected 99% of cumulative shadow price in the period of last two calendar years.

4. Specific network elements, defined in Annex 2 are excluded from paragraph 1 and 2.

5. TSOs shall regularly review and update operational security limits in accordance with Article 26.

## Article 7. Methodology for allocation constraints

1. In case operational security limits cannot be transformed efficiently into $I_{max}$ and $F_{max}$ pursuant to Article 6, the CE TSOs or iTCP may transform them into allocation constraints.

2. The CE TSOs or iTCP may apply allocation constraints as one or more of the following four options:

   (a) a constraint on the CE net position (the sum of cross-zonal exchanges within the CE CCR and on AHC borders 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 CE CCR. This option shall be applied until option (b) can be applied.

   (b) a constraint on the global net position (the sum of all cross-zonal exchanges for a certain bidding zone in the SDAC), thus limiting the net position of the respective bidding zone with regards to all CCRs, which are part of the 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.

   (c) a constraint limiting the sum of import/export from/to a set of interconnectors. This option shall be applied when: (i) the respective solution is implemented within the SDAC algorithm and (ii) the respective bidding zone borders are participating in SDAC.

   (d) a ramping constraint (flow ramping limit) limiting the maximum variation of the CE net position (or import/export from/to a set of interconnectors) from one MTU to the next.

3. For iTCP bidding zone borders with the CE CCR, that are not included in SDAC, allocation constraints used by Terna are directly applied in the calculation performed by the CCC pursuant to Article 23.

4. Allocation constraints may be used by PSE and Terna, ramping constraints only by Terna, as listed in Annex 1 during a transitional period of two years following the implementation of this methodology in accordance with Article 30(2) in accordance with the reasons and the methodology

for the calculation of allocation constraints as specified in Annex 1 to this methodology. During this transition period, the concerned CE TSOs shall:

a) calculate the value of allocation constraints in accordance with Annex 1 and on a half-yearly basis publish the results of the analysis pursuant to paragraph 4(b);

b) in case the allocation constraint had a non-zero shadow price in more than 0.1% of hours in the half-year period, provide to the CCC a report containing:

   i) an analysis for each MTU when the allocation constraint had a non-zero shadow price the loss in economic surplus due to allocation constraint and the effectiveness of the allocation constraint in preventing the violation of the underlying operational security limits. The CCC shall include this analysis in the half-yearly report and;

   ii) alternative solutions to address the underlying operational security limits.

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

5. In case the concerned CE TSOs or iTCP will not find and implement alternative solutions to the use of allocation constraints by twenty-four months after the implementation of this Day-ahead capacity calculation methodology of the CE capacity calculation region in accordance with Article 30(2), they may together with all other CE TSOs and iTCP submit to all CE 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 allocation 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 allocation constraints including the frequency of recalculation.

6. For the SDAC fallback procedure, pursuant to Article 24, allocation constraints shall be modelled as the same type of constraints referred to in paragraphs 2(a), (b) and (c).

7. If CE TSO or iTCP may discontinue the use of an allocation constraint., the concerned CE TSO or iTCP shall communicate this change to all CE and iTCP regulatory authorities and to the market participants at least one month before discontinuation.

8. The CE TSOs or iTCP shall review and update allocation constraints in accordance with Article 26.

9. If one or more CE TSOs or iTCP plan to apply allocation constraints, referred to in Article 7 (2), the relevant CE TSOs or iTCP shall, together with all other CE TSOs, submit to all CE and iTCP regulatory authorities a proposal for amendment of this methodology in accordance with Article 9(13) of CACM Regulation. Such a proposal shall include the following:

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

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

## Article 8. Reliability margin methodology

1. The $FRM$s shall cover the following forecast uncertainties:

   (a) Cross-zonal exchanges on bidding zone borders outside the CE CCR excluding AHC borders;

   (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 frequency containment process; and

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

2. The CE TSOs and iTCP shall aim at reducing uncertainties by studying and tackling the drivers of uncertainty.

3. 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 and the realised power flows in real time shall be calculated. To calculate the expected power flows ($F_{exp}$), for each DA CC TU 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 CE TSOs' and iTCP's actions (including at least the RAs considered during the capacity calculation) that have been applied in the relevant DA CC TU[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 CE CCR and on AHC borders. 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 CE CCR and on AHC borders 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 CE CCR |
| $\vec{F}_{ref}$ | flow per CNEC in the CGM updated to take deliberate TSO actions into account |
| $\mathbf{PTDF}$ | power transfer distribution factor matrix calculated with updated CGM |
| $\overrightarrow{NP}_{real}$ | CE net positions in the realised commercial situation |

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

$\overrightarrow{NP}_{ref}$ CE net positions in the updated CGM

4. The expected power flows on each CNEC of the CE 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 TUs 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;

5. In the second step, the 90th percentiles of the probability distributions of all CNECs shall be calculated[3]. This means that the CE TSOs and iTCP 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.

6. The CE TSOs and iTCP shall repeat steps one and two pursuant to paragraphs 3 to 5 with two different implementation approaches for the recalculation of $F_{ref}$, where one implementation leads to an upper estimate and the other implementation leads to a lower estimate of the true $FRM$.

   (a) For the determination of the upper estimate, the historical CGMs shall be updated such that only the RAs considered during the day-ahead capacity calculation are considered as deliberated CE TSOs'or iTCP's actions. This will yield an upper estimate of the FRM because some deliberated CE TSOs' or iTCP's actions, in particular re-dispatching, will not be considered and thus treated as source of FRM.

   (b) For the determination of the lower estimate, the historical CGMs shall additionally be updated such that also the entire generation pattern of the CE CCR is considered as deliberated CE TSOs' or iTCP's actions. This will yield a lower estimate of the FRM because only a part of the entire generation dispatch is the result of deliberated CE TSOs' actions in the form of re-dispatching.

7. 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.

8. No later than 36 months after the implementation of this methodology in accordance with Article 30, the CE TSOs and iTCP 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 CE TSOs and iTCP shall submit to all CE and iTCP 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 10 below. The proposal for amendment shall include an approach and justification for selecting the $FRM$ from the range between the lower and upper estimates as well as next possible steps for improving the process to approach as much as possible the true $FRM$. CE TSOs shall reuse as much as possible of any similar activity already carried out in the Core region and thus potentially shorten the time needed for submitting the proposal for amendment.

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

9. 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.

10. The supporting document for the proposal for amendment of this methodology pursuant to paragraph 8 above shall include at least the following:

    (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.

11. Until the proposal for amendment of this methodology pursuant to paragraph 8 has been approved by all CE and iTCP regulatory authorities, the CE TSOs and iTCP shall use $FRM$ values equal to 10% of $F_{max}$ pursuant to Article 6(2).

12. After the proposal for amendment of this methodology pursuant to paragraph 8 has been approved by all CE and iTCP 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 CE TSO and iTCP shall define for its bidding zone and for each DA CC TU 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 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 TU, the GSK shall only include actual generation and/or load[4] present in the CGM for that DA CC TU. The CE TSOs and iTCP shall take into account the available information on generation or load available in the CGM in order to select the nodes that will contribute to the GSK.

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 CE TSOs and iTCP shall review and update the application of the generation shift key methodology in accordance with Article 26.

5. The CE TSOs belonging to the same bidding zone shall jointly define a common GSK for that bidding zone and shall agree on a methodology for such coordination. For Germany and Luxembourg, each TSO shall calculate its individual GSK and the CCC shall combine them into a single GSK for the whole German-Luxembourgian bidding zone, by assigning relative weights to

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

each TSO's GSK. The German and Luxembourgian TSOs shall agree on these weights, based on the share of the generation in each TSO's control area that is responsive to changes in net position, and provide them to the CCC.

6. The CCC shall define GSKs for the EVHs according to Article 9 (1) as follows:

    (a) In case an EVH represents only HVDC interconnectors, the GSK shall be defined by all converter stations of the HVDC interconnectors, weighted based on the respective transmission capacity.

    (b) In case an EVH represents only AC interconnectors, the CCC shall use the GSK of the adjacent bidding zone provided by the TSOs of that bidding zone. If this GSK is not available, the CCC shall define a GSK based on all positive injections in the IGM of the adjacent bidding zone.

    (c) In case an EVH represents both HVDC interconnectors and AC interconnectors, the respective CE TSO or iTCP shall define a single combined GSK based on the GSK for the HVDC and the GSK for the AC interconnectors.

7. Within 24 months after the implementation of this methodology in accordance with Article 30, all CE TSOs and iTCP shall develop a proposal for further harmonisation of the generation shift key methodology and submit it by the same deadline to all CE and iTCP regulatory authorities as a proposal for amendment of this methodology in accordance with Article 9(13) of the CACM Regulation. CE TSOs and iTCP shall reuse as much as possible of any similar activity already carried out in the Core region and thus potentially shorten the time needed for submitting the proposal for amendment. The proposal shall at least include:

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

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

### Article 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 Regulation, the CE TSOs and iTCP shall individually define the RAs to be taken into account in the day-ahead capacity calculation.

2. In case a RA made available for the day-ahead capacity calculation in the CE CCR is also made available in another CCR, the TSO having control on this RA shall take care, when defining it, of a consistent use in its potential application in both CCRs to ensure operational security.

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

4. For the purpose of the NRAO, all CE TSOs and iTCP shall provide to the CCC all expected available non-costly RAs and, for the purpose of coordinated capacity validation, all CE TSOs and iTCP 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 CE TSO or iTCP 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.

6. In accordance with Article 25(4) of the CACM Regulation, a TSO may 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 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.

7. The day-ahead capacity calculation may only take into account those non-costly RAs which can be modelled. 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 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.

    (c) Changing the set point of an HVDC line

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 capacity calculation, depending on their technical availability.

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

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

11. TSOs shall review and update the RAs taken into account in the day-ahead capacity calculation in accordance with Article 26.

## TITLE 4 - Description of the day-ahead capacity calculation process

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

1. The flow-based calculation is a 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 29(3)(a) of the CACM Regulation, the CCC shall calculate the impact of a change in the net positions of bidding zones and of VHs on the power flow on each CNEC (determined in accordance with the rules defined in Article 5). This influence is called the zone-to-slack $PTDF$. This calculation is performed from the CGM and the $GSK$ defined in accordance with Article 9.

3. The zone-to-slack $PTDFs$ are calculated by first calculating the node-to-slack $PTDFs$ for each node defined in the $GSK$. These nodal PTDFs are derived by varying the injection of a relevant node in the CGM and recording the difference in power flow on every CNEC (expressed as a percentage of the change in injection). These node-to-slack $PTDFs$ are translated into zone-to-slack $PTDFs$ 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:

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

*Equation 3*

with

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

4. The zone-to-slack $PTDFs$ 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 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 CNEC $l$. The zone-to-zone $PTDF_{A\rightarrow B,l}$ can be derived from the zone-to-slack $PTDFs$ as follows:

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

*Equation 4*

5. The maximum zone-to-zone $PTDF$ of a CNEC ($PTDF_{z2zmax,l}$) is the maximum influence that any CE and iTCP exchanges has on the respective CNEC, including the exchanges with the virtual hubs, i.e. the exchanges over HVDC interconnectors which are integrated pursuant to Article 12 and the exchanges on AHC borders which are modelled through EVH pursuant to Article 13:

$$\begin{aligned} PTDF_{z2zmax,l} = max\Bigg( & \max_{X\in\{BZ\cup EVH\}}\left(PTDF_{X,l}\right) \\ & - \min_{X\in\{BZ\cup EVH\}}\left(PTDF_{X,l}\right), \max_{H_1,H_2\in IVH}\Big(\big|\left(PTDF_{A,l} - PTDF_{H_1,l}\right) \\ & - \left(PTDF_{B,l} - PTDF_{H_2,l}\right)\big|, \left|PTDF_{H_1,l} - PTDF_{H_2,l}\right|\Big)\Bigg) \end{aligned}$$

*Equation 5*

with

| | |
|---|---|
| $PTDF_{X,l}$ | zone-to-slack $PTDF$ of bidding zone or external virtual hub X on a CNEC $l$ |
| BZ | set of allCE and iTCP bidding zones |
| $EVH$ | set of all external virtual hubs |

| | |
|---|---|
| $\max_{X \in \{BZ \cup EVH\}}(PTDF_{X,l})$ | maximum zone-to-slack PTDF of CE and iTCP bidding zones or EVHs on a CNEC $l$ |
| $\min_{X \in \{BZ \cup EVH\}}(PTDF_{X,l})$ | minimum zone-to-slack PTDF of CE and iTCP bidding zones or EVHs on a CNEC $l$ |
| $PTDF_{H1,l}$ | zone-to-slack $PTDF$ of internal virtual hub $H_1$ on a CNEC $l$, with $H_1$ representing the converter station at the sending end of the HVDC interconnector H located in bidding zone A |
| $PTDF_{H2,l}$ | zone-to-slack $PTDF$ of internal virtual hub $H_2$ on a CNEC $l$, with $H_2$ representing the converter station at the receiving end of the HVDC interconnector H located in bidding zone B |

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

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

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

*Equation 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) |
| **PTDF** | power transfer distribution factor matrix |
| $\overrightarrow{NP_i}$ | CE and iTCP net positions in the commercial situation $i$ |
| $\overrightarrow{NP}_{ref}$ | CE and iTCP net positions in the reference commercial situation |

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

1. The CE TSOs shall apply the evolved flow-based (EFB) methodology when including HVDC interconnectors on the bidding zone borders of the CE CCR[5]. According to this methodology, a cross-zonal exchange over an HVDC interconnector on the bidding zone borders of the CE CCR is

[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.

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 and constraints modelling the maximum possible exchange of the HVDC interconnector.

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

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

*Equation 7*

with

| | |
|---|---|
| $PTDF_{IVH\_1,l}$ | zone-to-slack $PTDF$ of internal virtual hub 1 on a CNEC $l$, with internal virtual hub 1 representing the converter station at the sending end of the internal CE HVDC interconnector |
| $PTDF_{IVH\_2,l}$ | zone-to-slack $PTDF$ of internal virtual hub 2 on a CNEC $l$, with internal virtual hub 2 representing the converter station at the receiving end of the internal CE HVDC interconnector |

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

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

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

1. Where critical network elements within the CE CCR are also impacted by electricity exchanges outside the CE CCR, the CE TSOs shall take such impact into account.

2. Where CE TSOs consider it essential to integrate a third-country TSO in day-ahead capacity calculation, such integration shall be based on this methodology and mutual obligations and responsibilities for CE TSOs and the third-country TSO during the day-ahead capacity calculation steps pursuant to Article 4. An integrated technical counterparty agreement shall be jointly reached between all CE TSOs and the third-country TSO. It shall establish the third-country TSO as iTCP and shall ensure that the iTCP is contractually bound to this methodology and by the same obligations as the ones binding upon CE TSOs by virtue of EU regulations. All CE regulatory authorities and the iTCP regulatory authority shall regularly monitor the application of the current methodology by the iTCP.

3. When the third-country TSO operates in a country that applies the legal framework of the European Energy Market or has concluded an intergovernmental agreement on electricity markets with the European Union, the following provisions of Article 13(3) do not apply. The integrated technical counterparty agreement is subject to the unanimous validation by all CE regulatory authorities and the iTCP regulatory authority. The integrated technical counterparty agreement and all its amendments shall enter into force only if and insofar as they are validated by all CE regulatory authorities and the iTCP regulatory authority. Where the integrated technical counterparty agreement has not been validated by all CE regulatory authorities and the iTCP regulatory authority, the CE TSOs shall not integrate the third-country TSO as iTCP in day-ahead capacity calculation.

4. In other cases, the CE TSOs shall consider using a standard hybrid coupling (SHC) or an advanced hybrid coupling (AHC).

    (a) In the standard hybrid coupling, the CE TSOs shall consider the electricity exchanges on bidding zone borders outside the CE 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 CE 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.

    (b) In the AHC, the CNECs of the CE Day-ahead capacity calculation region shall not only limit the net positions of CE bidding zones due to exchanges on bidding zone borders of the CE CCR but also the exchanges on bidding zone borders between the CE CCR and respective adjacent bidding zones. CE TSOs applying AHC shall introduce at least one external virtual hub for each AHC border, meaning that multiple interconnectors (be it HVDC or AC interconnectors) at a single AHC border can be assigned to separate EVHs. Implementation of AHC is foreseen on all borders linking Central Europe bidding zones and bidding zones of neighbouring CCRs and which are part of SDAC, except for the common borders with GRIT CCR, where only a low efficiency gain is expected in comparison with the challenges imposed by AHC.

5. CE TSOs may impose a limit to the net position of the external virtual hubs:

    (a) for HVDC interconnectors, the limit takes into account the physical limitations of the HVDC cables on the border, and the converter stations on the CE side;

    (b) CE TSOs may consider a limit in the form of an NTC value as an outcome of the capacity calculation from the neighbouring CCR.

6. CE TSOs shall monitor the accuracy of non-CE and non-iTCP exchanges in the CGM which are not handled through AHC. The CE TSOs shall report in the annual report to all CE and iTCP regulatory authorities the accuracy of such forecasts.

7. CE TSOs shall publish the list of the bidding borders on which AHC is used on a dedicated online communication platform.

## 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 CE TSOs and iTCP 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 TU.

3. The initial flow-based parameters shall be calculated pursuant to Article 11 and shall consist of the $\mathbf{PTDF}_{\boldsymbol{init}}$ 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 below 5%. The remaining CNECs shall constitute the final list of CNECs.

2. CE TSOs and iTCP may add network elements with a voltage level of 110kV and above to the final list of CNECs provided that the maximum zone-to-zone PTDF is equal to or above the threshold of 5% referred to in paragraph 1.

3. The CCC shall use the lists of MNECs submitted by the CE TSOs and iTCP and merge them into a common list of MNECs, which shall be monitored during the NRAO process, based on information provided by the CE TSOs and iTCP 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. Allocation 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, range of setpoints of each HVDC line 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.

(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) |

$$RAM_{rel} = \frac{RAM_{nrao}}{\sum_{(A,B)\,\in\, neighbou\ \ pairs} \left|PTDF_{A\to B,nrao}\right|}\ if\ RAM_{nrao} \geq 0$$

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

*Equation 9*

with

| | |
|---|---|
| $neighbour\ pairs$ | Set of two neighbouring CE bidding zones or set of a CE bidding zone and a neighbouring EVH |
| $PTDF_{A\to B,nrao}$ | 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. the available range of setpoints of each HVDC line

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[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.

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

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

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

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

vii. 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;

viii. 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:
   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);
   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) $\mathbf{PTDF}_{\boldsymbol{f}} = \mathbf{PTDF}_{\boldsymbol{nrao}}$ 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 CE 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.

4. 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 CE CCR;

5. Every year after the implementation of this methodology in accordance with Article 30(2), the CCC, in coordination with the CE TSOs and iTCP, 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 CE TSOs and iTCP, including the average number of non-costly RAs provided by each CE TSO and iTCP;

   (b) for the CE TSOs or iTCP 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.)

6. Based on the conclusion of the analysis mentioned in paragraph 5, the CE TSOs or iTCP may propose changes to the NRAO by submitting to all CE and iTCP regulatory authorities a proposal for amendment of this methodology in accordance with Article 9(13) of the CACM Regulation.

## Article 17. Adjustment for minimum RAM

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

2. In order to determine the adjustment for minimum $RAM$ for a CNEC, the flow in the situation without commercial exchanges within the CE CCR and on AHC borders is first calculated by setting the net positions $\overrightarrow{NP_i}$ in Equation 6 to zero for all CE bidding zones and for all VHs, leading to the following equation:

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

*Equation 10*

with

| | |
|---|---|
| $\vec{F}_{0,CE}$ | flow per CNEC in the situation without commercial exchanges within the CE CCR including iTCP and without commercial exchanges on AHC borders |
| $\vec{F}_{ref}$ | flow per CNEC in the CGM after the NRAO |
| $\mathbf{PTDF}_{\boldsymbol{f}}$ | power transfer distribution factor matrix for the CE CCR, including VHs and including iTCP |
| $\overrightarrow{NP}_{ref,CE}$ | CE net positions including iTCP 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 $\mathrm{F}_{0,\mathrm{all}}$ 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 |

| | |
|---|---|
| $\mathbf{PTDF}_{all}$ | power transfer distribution factor matrix for all bidding zones in Continental Europe and all CE 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 CE CCR ($F_{uaf}$) is then calculated for each CNEC as follows:

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

*Equation 12*

with

| | |
|---|---|
| $\vec{F}_{uaf}$ | flow per CNEC assumed to result from commercial exchanges outside CE CCR including iTCP excluding flows resulting from commercial exchanges on AHC borders |

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 CE CCR. This means that the sum of $RAM$ (capacity offered within the CE CCR and on the AHC borders) and $F_{uaf}$ (capacity offered outside the CE CCR except the AHC borders) on the CE 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:

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

*Equation 14*

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

8. Combining the previous requirements, the $AMR$ for a CNEC is finally determined with the following equation:

$$AMR = max\begin{pmatrix} R_{amr} \cdot F_{max} - F_{uaf} - \left(F_{max} - FRM - F_{0,CE}\right), \\ 0.2 \cdot F_{max} - \left(F_{max} - FRM - F_{0,CE}\right), 0 \end{pmatrix}$$

*Equation 15*

with

| | |
|---|---|
| $F_{max}$ | maximum admissible flow |
| $FRM$ | flow reliability margin |
| $F_{uaf}$ | flow per CNEC resulting from assumed commercial exchanges outside the CE CCR including iTCP, but excluding flows resulting from commercial exchanges on AHC borders |
| $F_{0,\mathrm{CE}}$ | flow in the situation without commercial exchanges within the CE CCR including iTCP, and without commercial exchanges on AHC borders |
| $R_{amr}$ | 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 in accordance with the relevant Union legislation. In case of such a derogation, the $R_{amr}$ shall be defined by the decisions on derogations. In the latter case, the TSO(s) affected by such derogations shall inform all CE and iTCP regulatory authorities and the Agency about the values of $R_{amr}$ applicable during the period for which the derogation has been granted.

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

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

    (a) the rules ensure that cross-zonal capacities can accommodate all combinations of net positions that could result from previously-allocated cross-zonal capacity.

    (b) previously-allocated capacities on all bidding zone borders of the CE CCR and on the AHC borders are the long-term allocated capacities (LTA) calculated and allocated pursuant to the FCA Regulation.

    (c) until the implementation of long-term capacity calculation 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 and agreed by all CE TSOs with the support of the CCC.

2. From the go-live of the implementation of this methodology in accordance with Article 30, all CE TSOs shall implement the rules set out in paragraph 1 by extended LTA inclusion.

3. If CE TSOs conclude that the implementation of extended LTA inclusion is not feasible from the go-live of the implementation of this methodology in accordance with Article 30, CE TSOs may propose to CE NRAs for consent to jointly implement the rules set out in paragraph 1 by the LTA margin approach as a temporary solution for a limited period in time. CE TSOs shall provide a sound justification to CE NRAs.

4. When extended LTA inclusion is operational, CE TSOs may apply the LTAmargin approach as a rollback solution, for a limited period in time. CE TSOs shall provide a sound justification to CE NRAs.

5. CE TSOs shall regularly review the choice for the Extended LTA inclusion approach against the alternative LTAmargin approach and propose to CE NRAs to change the approach if considered appropriate.

    (a) The LTAmargin approach pursuant to paragraphs 6 to 9 ensures that the $RAM$ of each CNEC remains non-negative in all combinations of net positions that could result from previously allocated cross-zonal capacity. The cross-zonal capacities consist of a flow-based domain.

(b) When applying extended LTA inclusion, the cross-zonal capacities consist of a flow-based domain without LTA inclusion and a LTA domain.

6. In case an allocation constraint restricts the CE net positions pursuant to Article 7(2), 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 allocation 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 the allocation constraint;

   (d) the $F_{ref}$ value is set to the CE net position in the CGM of the bidding zone or EVH applying the allocation constraint, i.e. $NP_{ref}$ in the equation below; and

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

7. The first step in the LTA inclusion is to calculate the flow for each CNEC (including allocation constraints) in each combination of net positions resulting from the full utilisation of previously-allocated capacities on all bidding zone borders of the CE CCR and on AHC borders, based on Equation 16:

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

*Equation 16*

with

| | |
|---|---|
| $\vec{F}_{LTAi}$ | flow per CNEC in LTA capacity utilisation combination $i$ |
| $\vec{F}_{ref}$ | flow per CNEC in the CGM after the NRAO |
| $\mathbf{PTDF}_f$ | zone-to-slack power transfer distribution factor matrix |
| $\overrightarrow{NP}_{LTAi}$ | CE net positions in LTA capacity utilisation combination $i$ |
| $\overrightarrow{NP}_{ref}$ | CE net positions in the CGM |

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

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

*Equation 17*

9. The adjustment for the LTA inclusion is finally:

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

*Equation 18*

10. In case the extended LTA approach is applied CE TSOs may additionally carry out the steps described in paragraphs 6 to 9 with the sole purpose to make available a flow-based domain with LTA inclusion as input for the coordinated and individual validation as described in Articles 19 and 20.

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

1. 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:

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

*Equation 19a*

with

| | |
|---|---|
| $\vec{F}_{max}$ | Maximum active power flow pursuant to Article 6 |
| $\overrightarrow{FRM}$ | Flow reliability margin pursuant to Article 8 |
| $\vec{F}_{0,CE}$ | Flow without commercial exchanges in the CE CCR including iTCP and without commercial exchanges on AHC borders, described in Equation 10. For allocation constraints, in line with Article 18(2), this flow is equal to zero.[8] |
| $\overrightarrow{AMR}$ | Adjustment for minimum RAM pursuant to Article 17 |
| $\overrightarrow{LTA}_{margin}$ | Flow margin for LTA inclusion, pursuant to Article 18 |
| $\overrightarrow{RAM}_{bv,LTAmargin}$ | Remaining available margin before validation with application of the flow margin for LTA inclusion pursuant to Article 18 |

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

(e) in case the extended LTA approach pursuant to Article 18(5)(b) is applied the calculation of $RAM$ before validation as follows;

$$\overrightarrow{RAM}_{bv,noLTAmargin} = \vec{F}_{max} - \overrightarrow{FRM} - \vec{F}_{0,CE} + \overrightarrow{AMR}$$

*Equation 19b*

with

| | |
|---|---|
| $\overrightarrow{RAM}_{bv,noLTAmargin}$ | Remaining available margin before validation without application of the flow margin for LTA inclusion pursuant to Article 18 |

2. NTCs in market non-likely direction for iTCP pursuant to Article 23(6) shall be considered based on the probability of an incorrect forecast of the market direction on iTCP bidding-zone borders with CE CCR.

## Article 20. Validation of flow-based parameters

1. The CE TSOs and iTCP shall validate and have the right to correct cross-zonal capacity for reasons of operational security during the validation process individually and in a coordinated way.

2. Capacity validation shall consist of two steps. In the first step, the CE TSOs and iTCP shall analyse in a coordinated manner whether the cross-zonal capacity could violate operational security limits, and whether they have sufficient RAs to avoid such violations. In the second step, each CE TSO and iTCP shall individually analyse whether the cross-zonal capacity could violate operational security limits in its own control area.

3. In case CE TSOs and iTCP apply the LTAmargin approach according to Article 18(5)(a), the capacity validation shall be based on the flow-based domain with $RAM_{bv,LTAmargin}$. In case CE TSOs and iTCP apply the extended LTA inclusion approach according to Article 18(5)(b), the capacity validation shall be based on the convex hull of the flow-based domain with $RAM_{bv,noLTAmargin}$ and the LTA domain, but for individual validation according to paragraph 21 each CE TSO and iTCP may decide to base it on $RAM_{bv,LTAmargin}$ instead.

4. In the process of cross-zonal capacity validation the CE TSOs and iTCP shall exchange information on all expected available (non-costly and costly) RAs in the CE CCR, defined in accordance with Article 22 of the SO Regulation. In case the cross-zonal capacity could lead to violation of operational security, all CE TSOs and iTCP 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 CE TSOs and iTCP in coordination with the CCC may reduce the $RAM_{bv,LTAmargin}$ or $RAM_{bv,noLTAmargin}$ to the maximum value which avoids the violation of operational security. This reduction is called 'coordinated validation adjustment' ($CVA$) and the adjusted $RAM$ is called '$RAM$ before individual validation' ($RAM_{biv}$).

5. CE TSOs and iTCP shall reuse as much as possible of any development already carried out in the Core region. The coordinated validation process in the CE CCR shall be performed by the CCC the CE TSOs and iTCP pursuant to Article 13(2) according to the following procedure:

Step 1 The CCC shall use the inputs pursuant to paragraph 6;

Step 2 The CCC shall, pursuant to paragraph 8, select the circumstances, being possible market outcomes, that shall be evaluated to determine whether the power system could accommodate them having regard to operational security requirements;

Step 3 The CCC shall analyse the selected circumstances subject to the criteria pursuant to paragraph 10 and 11 and applying the remedial action optimisation method pursuant to paragraph 12;

Step 4 The CCC shall, in coordination with the CE TSOs and iTCP , determine $CVA$ pursuant to paragraph 16;

Step 5 The CCC shall compute the $RAM_{biv}$ pursuant to paragraph 19;

Step 6 The CCC shall disseminate the results of steps 2, 3, 4 and 5 pursuant to paragraph 20 to enable CE TSOs and iTCP pursuant to Article 13(2) to consider them in the individual validation process step;

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

   (a) the CZC domain based on the flow-based parameters before validation pursuant to Article 19 and, in case the extended LTA approach pursuant to Article 18(5b) is applied, the LTA domain;

   (b) the CGM;

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

   (d) a list of network elements and contingencies to consider when assessing operational security. Each CE TSO and iTCP pursuant to Article 13(2) shall provide such a list to the CCC. Any network element from the CGM with a voltage level higher than or equal to 220 kV may be considered. The standard properties of these network elements are that they shall not be overloaded after coordinated validation with respect to their operational security limits. Each CE TSO and iTCP pursuant to Article 13(2) may define two parameters to modify the properties of each network element. Firstly, the maximum flow of a network element may be increased. Secondly, a network element may be specified as scanned network element. Scanned network elements may not be overloaded, or not incur additional overloading, pursuant to the specifications in paragraph 11.

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

8. The CCC shall separately select at least one circumstance for each DA CC TU, to be analysed in the coordinated validation. The number of circumstances shall be sufficiently large having regard to the time available for conducting the coordinated validation and the complexity of the analysis per circumstance pursuant to paragraph 12. During the implementation of the coordinated validation, the CE TSOs and iTCP shall:

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

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

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

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

11. For each circumstance in each DA CC TU, the maximum admissible flow on each scanned network element shall, if necessary, be increased such that the difference between the maximum admissible flow and the post-contingency flow in the circumstance prior to the remedial action optimisation pursuant to paragraph 12 is at least as large as a threshold, which shall be set according to the process described in paragraph 7.

12. The CCC shall perform an RA optimisation to determine for each circumstance in each DA CC TU, to which extent this circumstance could be realised with respect to operational security. The circumstance can be realised entirely, if all operational security violations, which might occur after shifting the CGM to the circumstance pursuant to paragraph 10, and having regard to the network elements, contingencies and properties as specified pursuant to paragraph 6(d), can be completely eliminated by the application of RAs. In case the circumstance cannot be realised without violating operational security constraints, the RA optimisation shall determine the extent of this violation. The RA optimisation shall further determine an alternative circumstance that is as similar as possible to the original one but can be implemented without violating operational security constraints.

13. The RA optimisation shall consider the same types of RAs as used in relevant ROSC processes, which implements the methodology developed pursuant to Article 76(1) of the SO Regulation, or other congestion management planning processes of the CE TSOs and iTCP. To limit the complexity of the RA optimisation and in accordance with the requirements and obligations set out in paragraph 6, CE TSOs and iTCP may adjust the inputs of the coordinated validation to reflect the estimated effect of congestion management planning procedures while adhering to operational security constraints. Such adjustments may comprise, but are not limited to, ignoring network elements or allowing a certain amount of overload. The RA optimisation shall consider preventive and curative RAs with full or partial sharing of the benefit of curative RAs.

14. The RA optimisation shall be specified such that use of RAs shall precede a reduction to the extent needed to which the circumstance can be realised. The RA optimisation shall be designed in consistency with the approach for determining the limitations of the cross-zonal capacities pursuant to paragraph 16 and 17.

15. CE TSOs and iTCP may apply the following means to relax or constrain the RA optimisation:

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

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

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

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

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

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

19. The CCC shall calculate for each CNEC:

(a) the $RAM$ before individual validation as follows;

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

*Equation 19c*

(b) in case the extended LTA approach pursuant to Article 18(5)(b) is applied, the $RAM$ before individual validation as follows;

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

*Equation 19d*

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

21. After coordinated validation, each CE TSO and iTCP 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 5 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.

22. 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 CE TSO and iTCP 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. $PTDF_{init}$ according to Article 14(3) shall be used to determine if the PTDF of the additional CNEC is above the PTDF threshold. When considering the additional CNEC during the computation of the final flow-based parameters, the $PTDF_f$ value from the NRAO according to Article 16 shall be considered.

23. When performing the validation, the CE TSOs and iTCP 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 CE TSOs and iTCP shall use the tools developed by the CCC for analysis, but may also employ verification tools not available to the CCC.

24. In case of a required reduction due to situations as defined in paragraph 21(a), a CE TSO or iTCP may use a positive value for $IVA$ for its own CNECs or adapt the allocation constraints, pursuant to Article 7, to reduce the cross-zonal capacity for its bidding zone.

25. In case of a required reduction due to situations as defined in paragraph 21(b), (c) and (d), a CE TSO or iCTP may use a positive value for $IVA$ for its own CNECs. In case of a situation as defined in paragraph 21(c), a CE TSO or iTCP may, as a last resort measure, request a common decision to launch the default flow-based parameters pursuant to Article 22.

26. 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 allocation constraint according to Equation 20a, if the LTAmargin approach is applied, and according to Equation 20b if the extended LTA inclusion is applied :

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

*Equation 20a*

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

*Equation 20b*

with

| | |
|---|---|
| $\overrightarrow{RAM}_{bn}$ | remaining available margin before adjustment for long-term nominations |
| $\overrightarrow{RAM}_{bv,LTAmargin}$ | remaining available margin before validation pursuant to Article 19(d) |
| $\overrightarrow{RAM}_{bv,noLTAmargin}$ | remaining available margin before validation pursuant to Article 19(e) Article 19 |
| $\overrightarrow{CVA}$ | coordinated validation adjustment |
| $\overrightarrow{IVA}$ | individual validation adjustment |

27. 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 CE and iTCP regulatory authorities in accordance with Article 27 and Article 29, respectively.

28. Only when CE TSOs apply the LTAmargin approach pursuant to Article 18(5)(a), capacity reductions through $CVA$ and $IVA$ shall ensure that the $RAM_{bn}$ remains non-negative in all combinations of nominations resulting from LTA, in order to fulfil the requirement pursuant to Article 18 (5)(a). Such a constraint is described for each CNEC, including allocation constraints, by the following equation:

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

*Equation 21*

with

| | |
|---|---|
| $CVA$ | coordinated validation adjustment |
| $IVA$ | individual validation adjustment |
| $F_{LTA,max}$ | maximum oriented flow from LTA inclusion pursuant to Equation 17 |

29. 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 TU:

    (a) the identification of the CNEC;

    (b) all the corresponding flow components pursuant to Article 27(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) 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 TUs for which the internal network elements with a specific contingency was added to the list and the information referred to in points (b) and (c) above;

(f) the remedial actions included in the CGM before the day-ahead capacity calculation;

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

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

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

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

(b) general measures to avoid cross-zonal capacity reductions in the future;

(c) changes to inputs, parameters or thresholds of the coordinated validation referred to in paragraph 6.

31. When capacity is reduced for operational security limits of a given CE TSO or iTCP in more than 1% of DA CC TUs 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. In order to determine the capacities for the CE bidding zone borders, the capacities calculated for the iTCP bidding-zone borders pursuant to Article 23 shall be deducted as follows

$$\overrightarrow{RAM'}_{bn} = \overrightarrow{RAM}_{bn} - \mathbf{pPTDF}_{\boldsymbol{zone-to-zone}}\,\overrightarrow{NTC}_{iTCP}$$

*Equation 22*

with

| | |
|---|---|
| $\overrightarrow{RAM'}_{bn}$ | Remaining available margin after deduction of iTCP bidding zone borders capacity and before adjustment for long-term nominations |
| $\mathbf{pPTDF}_{\boldsymbol{zone-to-zone}}$ | Positive zone-to-zone power transfer distribution factor matrix |
| $\overrightarrow{NTC}_{iTCP}$ | NTCs for the iTCP bidding-zone borders with CE CCR |

2. No later than 8:00 market time day-ahead, the CCC shall publish for each DA CC TU 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 allocation constraints on CE bidding zone

borders. 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 allocation constraints shall thus ensure that the capacity allocation do not exceed any limiting CNEC or allocation constraint. In addition, the CCC shall publish the LTA domain.

3. After the CCC receives all nominations of allocated long-term cross-zonal capacity (long-term nominations) on CE bidding zone borders, it shall calculate for each CNEC and allocation constraint the flow resulting from these 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 :

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

*Equation 23*

with

| | |
|---|---|
| $\vec{F}_{LTN}$ | flow resulting from CE LTN |
| $\mathbf{PTDF}_f$ | power transfer distribution factor matrix |
| $\overrightarrow{NP}_{LTN}$ | CE net positions resulting from LTN |

4. CE DA flow-based capacity calculation final flow-based parameters are computed with Equation 24:

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

*Equation 23*

with

| | |
|---|---|
| $\overrightarrow{RAM}_f$ | final CE remaining available margin |

5. After the CCC receives all nominations of allocated long-term cross-zonal capacity (long-term nominations), it shall also adjust the LTA domain for long-term nominations.

6. The final flow-based parameters shall consist of $\mathbf{PTDF}_f$ and $RAM_f$ for pre-solved CNECs and allocation constraints. In accordance with Article 46 of the CACM Regulation, the CCC shall ensure that, for each DA CC TU, the final flow-based parameters and the LTA domain adjusted for long-term nominations be provided to the relevant NEMOs as soon as they are available and no later than 10:30 market time day-ahead. If DA CC TU is different than MTU used by the relevant NEMOs, then CCC shall convert them before sending, by applying duplication of all DA CC TU. The CCC shall also publish these flow-based parameters for each DA CC TU of the following day no later than 10:30 market time day-ahead.

7. 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.

8. 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

1. According to Article 21(3) of the CACM Regulation, when the day-ahead capacity calculation for specific DA CC TUs 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 CE TSOs, iTCP and the CCC shall calculate the missing results by using the results of the initial flow-based calculation to directly run the computation of the final flow-based parameters according to Article 21. In case this does not lead to the final flow-based parameters either, the CE TSOs, iTCP and the CCC shall calculate the remaining missing results by using one of the following two capacity calculation fallback procedures:

   (a) when the day-ahead capacity calculation fails to provide the flow-based parameters for strictly less than three consecutive hours, the CCC shall calculate the missing flow-based parameters with the spanning method. The spanning method is based on the union of the previous and subsequent available flow-based parameters (resulting in the intersection of the two flow-based domains), adjusted to zero CE net positions (to delete the impact of the reference net positions of the CE bidding zones and VHs). All flow-based constraints from the previous and subsequent data sets are first converted into zero CE 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. In case the extended LTA inclusion approach is applied, the LTA domain for missing hours contains for each CE border and each AHC border the minimum of the long-term allocated capacities values of the hours for which the previous and subsequent flow-based parameters are available.

   (b) when the day-ahead capacity calculation fails to provide the flow-based parameters for three or more consecutive hours, the CE TSOs and iTCP 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(25). The calculation of default flow-based parameters shall be based on long-term allocated capacities as provided by TSOs pursuant to Article 4(4)(a). The capacities on the bilateral CE bidding zone borders and on AHC borders shall be defined based on the LTA capacity on that specific oriented bidding zone border:

      i. increased by the minimum of the two adjustments provided by the TSO(s) on each side of the CE bidding zone border, pursuant to Article 4(4)(b) and

      ii. adapted by the adjustment provided by the CE TSO on its adjacent AHC border, pursuant to Article 4(4)(b).

   These capacities are then adjusted for long-term nominations pursuant to Article 21, to obtain the final parameters.

   (c) The default NTC values for iTCP bidding-zone borders with CE CCR shall be agreed among CE TSOs and iTCP. The agreed default NTC values on each oriented iTCP bidding zone border with CE CCR, may be increased by the minimum of the two adjustments provided by the TSO(s) sharing an iTCP bidding-zone border.

## Article 23. Calculation of capacities for iTCP

1. Validated flow-based parameters of the final list of CNECs shall be split into a separate set of flow-based parameters according to a sharing key principle. The separated flow-based parameters and

the sharing key used for the split shall be computed for each CNEC in the final list as defined in Equation 25 and Equation 26.

$$\overrightarrow{RAM_s} = \overrightarrow{RAM_{bn}} \cdot \overrightarrow{RSK}$$

*Equation 24*

$$\overrightarrow{RSK} = \frac{\sum_b F_{max,b} \cdot pPTDF_{zone-to-zone,b}}{\sum_b F_{max,b} \cdot pPTDF_{zone-to-zone,b} + \sum_c F_{max,c} \cdot pPTDF_{zone-to-zone,c}}$$

*Equation 25*

| | |
|---|---|
| $\overrightarrow{RAM_{bn}}$ | remaining available margin before CE LTN adjustment |
| $\overrightarrow{RAM_s}$ | Separated remaining available margin for calculation of capacities for iTCP |
| $\overrightarrow{RSK}$ | Relative sharing key |
| $b$ | iTCP bidding-zone borders with CE CCR |
| $c$ | Bidding-zone borders of CE CCR |
| $F_{max,i}$ | Sum of maximum admissible flow over all tie-lines in service of a bidding-zone border i |
| $PTDF_{zone-to-zone,i}$ | Zone to Zone PTDF for bidding-zone border i |

CE TSOs and iTCP may define upper and lower boundaries for the sharing keys.

2. To enable the calculation of cross-border capacities for the iTCP bidding-zone borders with CE CCR a positive zone-to-zone PTDF matrix ($\mathbf{pPTDF_{zone-to-zone}}$) for oriented iTCP bidding zone borders with CE CCR shall be calculated from $\mathbf{PTDF_{f.}}$ as follows:

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

*Equation 226*

with

| | |
|---|---|
| $pPTDF_{zone-to-zone,A\rightarrow B}$ | positive zone-to-zone $PTDFs$ for the oriented iTCP bidding zone borders with CE CCR $A$ to $B$ |
| $PTDF_{zone-to-slack,m}$ | zone-to-slack $PTDF$ for CE and iTCP bidding-zones |

3. The CCC shall convert flow-based parameters, into net transmission capacities for each iTCP bidding-zone border with CE CCR and each DA CC TU pursuant to paragraph 4. The CE TSOs may delegate this responsibility to a third party.

4. The calculation of the NTCs for iTCP bidding-zone borders with CE CCR is an iterative procedure, which gradually calculates NTCs for each DA CC TU in the forecasted market direction for the iTCP bidding-zone borders with CE CCR, while respecting the constraints of the separated flow-based parameters calculated pursuant to paragraph 1:

   (a) The initial NTCs $\overrightarrow{NTC_{k=0}}$ for the iterative approach shall be defined in alignment between CE TSOs and the iTCP.

(b) The iterative method applied to calculate the NTCs for the iTCP bidding-zone borders with CE CCR consists of the following actions for each iteration step *k*:

i. for each CNEC and allocation constraint of the separated flow-based parameters, calculate the remaining available margin based on NTCs at iteration *k*-1:

$$\overrightarrow{RAM}_{NTC}(k) = \overrightarrow{RAM}_s - \mathbf{pPTDF}_{\boldsymbol{zone-to-zone}} \overrightarrow{NTC}_{k-1}$$

*Equation 27*

with

| | |
|---|---|
| $\overrightarrow{RAM}_{NTC}(k)$ | remaining available margin for NTC calculation at iteration *k* |
| $\overrightarrow{RAM}_s$ | Separated remaining available margin as starting point for NTC calculation |
| $\overrightarrow{RAM}_{NTC}(k)$ | remaining available margin for NTC calculation at iteration *k* |
| $\overrightarrow{NTC}_{k-1}$ | NTCs at iteration *k*-1 |
| $\mathbf{pPTDF}_{\boldsymbol{zone-to-zone}}$ | positive zone-to-zone power transfer distribution factor matrix |

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

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

iv. for each iTCP bidding-zone border CE CCR, $\overrightarrow{NTC}_k$ is calculated by adding to $\overrightarrow{NTC}_{k-1}$ the minimum of all maximum additional bilateral oriented exchanges for this border obtained over all CNECs and allocation constraints as calculated in the previous step;

v. adjust the RSK on CNECs with no remaining available margin left, until average deviation of RSK utilization by the calculated $NTC_k$ among pre-solved CNECs in the forecasted market direction of the separated flow-based parameters from RSK pursuant to paragraph 1 is close to 0. CE TSOs and iTCP may define limits for the maximum adjustment of RSK;

vi. go back to step i;

vii. iterate until the difference between the sum of NTCs of iterations *k* and *k*-1 is smaller than 1kW;

viii. the resulting NTCs for iTCP bidding-zone borders with CE CCR stem from the NTC values determined in iteration *k*, after rounding down to integer values and from which LTN are subtracted;

ix. at the end of the calculation, there are some CNECs and allocation constraints with no remaining available margin left. These are the limiting constraints for the calculation of NTCs for iTCPs.

5. Ramping constraints pursuant to Article 7(3) shall limit the maximum variation of the calculated NTCs between consecutive MTUs for the respective iTCP bidding-zone border with CE CCR not included in the SDAC.

6. The NTCs in market non-likely direction shall be constant values agreed between the CE TSOs and iTCP. These default values shall be published on an online communication platform and reassessed at least every year.

7. A reassessment of all the parameters defined in Article 23 concerning the sharing of capacities and NTC extraction approach shall be performed during both parallel run steps outlined in Article 30 of this methodology. Specifically, CE TSOs and iTCP will assess the relative sharing key principle and consideration of a potential relieving effect of NTCs.

## Article 24. Calculation of ATCs for SDAC fallback procedure for CE bidding borders

1. In the event that the SDAC process is unable to produce results, a fallback procedure established in accordance with Article 44 of the CACM Regulation shall be applied. This process requires the determination of available transmission capacities (ATCs) (hereafter referred as "ATCs for SDAC fallback procedure") for each CE oriented bidding zone border and each DA CC TU.

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

3. The following inputs are required to calculate ATCs for SDAC fallback procedure, respecting the allocation constraints, for each DA CC TU:

   (a) the CE LTA values;

   (b) the flow-based parameters $\mathbf{PTDF_{\mathit{f}}}$ and $\overrightarrow{RAM'}_{bn}$ in accordance with Article 16 and Article 20 respectively; and

   (c) if defined, the allocation constraints pursuant to Article 7(2).

   (d) if defined, the global allocation constraints pursuant to Article 7(2)(a) and Article 7(2)(b) shall be assumed to constrain the CE net positions pursuant to Article 7(4), and shall be described following the methodology described in Article 18(2). Such constraints shall be adjusted for offered cross-zonal capacities on the remaining non-CE bidding zone borders.

4. The following outputs are the outcomes of the calculation for each DA CC TU:

   (a) ATCs for SDAC fallback procedure; and

   (b) constraints with zero margin after the calculation of ATCs for SDAC fallback procedure.

5. The calculation of the ATCs for SDAC fallback procedure is an iterative procedure, which gradually calculates ATCs for each DA CC TU, while respecting the constraints of the final flow-based parameters pursuant to paragraph 3:

(a) The initial ATCs are set equal to LTAs for each CE and AHC oriented bidding zone border, i.e.:

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

*Equation 29*

with

| | |
|---|---|
| $\overrightarrow{ATC}_{k=0}$ | the initial ATCs before the first iteration |
| $\overrightarrow{LTA}$ | the LTA on CE and AHC 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 allocation constraint of the flow-based parameters pursuant to paragraph 3, calculate the remaining available margin based on ATCs at iteration *k*-1:

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

*Equation 28*

with

| | |
|---|---|
| $\overrightarrow{RAM}_{ATC}(k)$ | remaining available margin for ATC calculation at iteration *k* |
| $\overrightarrow{RAM'}_{bn}$ | Remaining available margin after deduction of iTCP bidding zone borders capacity and before adjustment for CE long-term nominations |
| $\overrightarrow{ATC}_{k-1}$ | ATCs at iteration *k*-1 |
| $\mathbf{pPTDF}_{\boldsymbol{zone-to-zone}}$ | positive zone-to-zone power transfer distribution factor matrix |

ii. for each CNEC, share $RAM_{ATC}(k)$ with equal shares among the CE and AHC 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 CE and AHC oriented bidding zone border by the respective positive zone-to-zone PTDF;

iv. for each CE and AHC 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 constraints as calculated in the previous step;

v. go back to step i;

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

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 LTN are subtracted;

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

ix. at the end of the calculation, in order to take into account the allocation constraints pursuant to Article 7(2)(c), the relevant ATCs shall be equal or minor to the allocation constraints split among impacted CE bidding zone borders (Article 24(3)(c).

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

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

*Equation 31*

with

| | |
|---|---|
| $pPTDF_{zone-to-zone,A \to B}$ | positive zone-to-zone $PTDFs$ for CE and AHC oriented bidding zone border $A$ to $B$ |
| $PTDF_{zone-to-slack,m}$ | zone-to-slack $PTDF$ for CE bidding zone or virtual hub m |

6. In case extended LTA inclusion approach is applied the ATCs for SDAC fallback procedure are set equal to the LTAs for each CE and AHC oriented bidding zone border, reduced by LTN, i.e.:

$$\overrightarrow{ATC} = \overrightarrow{LTA} - \overrightarrow{LTN}$$

*Equation 29*

with

| | |
|---|---|
| $\overrightarrow{ATC}$ | the ATC for SDAC fallback procedure |
| $\overrightarrow{LTA}$ | the LTA on CE and AHC oriented bidding zone borders |
| $\overrightarrow{LTN}$ | the nomination of the long-term allocated capacity on CE and AHC oriented bidding zone borders |

## Article 25. Update of remaining cross-zonal capacities after SDAC to be used for intraday

1. This article is applicable by CE TSOs until the implementation of a CE ID CCM.

2. The update of cross-zonal capacities remaining after the SDAC to be used for intraday solely applies within the CE CCR. Capacity calculation processes within other CCRs or for other time frames are not in the scope of this methodology.

3. The update of cross-zonal capacities remaining after SDAC to be used for intraday shall be performed as follows:

   IDCC(a): The cross-zonal capacities remaining after SDAC shall be updated for all ID CC TUs between 00:00 and 24:00 of day D and providing them as intraday cross-zonal capacities to relevant NEMOs no later than 15 minutes before the intraday cross-zonal gate opening time, at 15:00 market time of day D-1. This shall be calculated using the flow-based approach as defined in this article.

4. Further cross-zonal intraday capacities can be subsequently recalculated for relevant borders as defined in Core ID CCM and Italy North ID CCM.

5. The calculation of cross-zonal capacities remaining after SDAC for all ID CC TUs shall consist of three main stages:

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

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

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

   In addition to the cross-zonal capacities remaining after SDAC pursuant to paragraph 5(a), the CE TSOs, or an entity delegated by the CE TSOs, shall send to the CCC, for each ID CC TU of the delivery day, the following additional input by the times established in the process description document: the CE net positions or, alternatively, the already allocated capacities on the CE bidding zone borders resulting from the SDAC.

6. If the CE TSOs provided to the CCC the already allocated capacities on bidding zone borders instead of the net positions, the CCC shall convert them into net positions. All capacity updates, calculations and re-calculations pursuant to paragraph 4, including all steps pursuant to paragraph 3, shall be performed per ID CC TU. Cross-zonal capacities shall be provided to the NEMOs for each ID CC TU, but for capacity allocation they may be converted into a higher time resolution in accordance with the market time unit applicable on specific bidding zone border(s).

7. In case operational security limits cannot be transformed efficiently into $Imax$ and $Fmax$ pursuant to Article 6, the CE TSOs may transform them into allocation constraints.

8. PSE and Terna may apply allocation constraints as one <u>or more</u> of the following four options:

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

   (b) a constraint on the global net position (the sum of all cross-zonal exchanges for a certain bidding zone in the SIDC), thus limiting the net position of the respective bidding zone with regards to all CCRs, which are part of the SIDC. 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 SIDC algorithm and (iii) the respective bidding zone borders are participating in SIDC.

(c) a constraint limiting the sum of import/export from/to a set of interconnectors. This option shall be applied when: (i) the respective solution is implemented within the SIDC algorithm and (ii) the respective bidding zone borders are participating in SIDC.

(d) a ramping constraint (flow ramping limit) limiting the maximum variation of the CE net position (or import/export from/to a set of interconnectors) from one MTU to the next.

9. The CCC shall use the flow-based parameters resulting from CE day-ahead capacity calculation and the net positions or scheduled exchanges resulting from already allocated capacities on CE CNECs in SDAC to calculate the updated day-ahead cross-zonal capacities, in the form of flow-based parameters, to be used as intraday cross-zonal capacities at the intraday cross-zonal gate opening time.

10. For the updated CE intraday flow-based parameters, the PTDF values shall be the final PTDFs resulting from the day-ahead capacity calculation, and the RAM shall be derived as:

$$\overrightarrow{RAM}_{UID} = \overrightarrow{RAM}_{f,DA} - \boldsymbol{PTDF_f}\,\overrightarrow{NP}_{AAC,DA}$$

*Equation 30*

with

| | |
|---|---|
| $\overrightarrow{RAM}_{UID}$ | updated remaining available margin for intraday cross-zonal capacities on CE bidding zone borders |
| $\overrightarrow{RAM}_{f,DA}$ | final remaining available margin resulting from the day-ahead capacity calculation on CE bidding zone borders |
| $\boldsymbol{PTDF_f}$ | final power transfer distribution factor matrix resulting from the day-ahead capacity calculation on CE CNECs |
| $\overrightarrow{NP}_{AAC,DA}$ | net positions resulting from already allocated capacities in SDAC on CE bidding zone borders |

11. For each CNEC, each CE TSO may decrease the $RAM_{\mathrm{f,DA}}$ by decreasing the $AMR_{DA}$ and $LTA_{margin,\mathrm{DA}}$, while ensuring that there is no undue discrimination between internal and cross-zonal exchanges in line with Article 21(1)(b)(ii) of the CACM Regulation.

12. For each CNEC, each CE TSO may decrease the $RAM_{\mathrm{UID}}$ by excluding any margins reserved for cross-zonal capacity allocations (CZCA) for the exchange of balancing capacity or sharing of reserves, according to the methodology developed pursuant to article 38(3) of EB Regulation.

13. Irrespective of the options provided to each TSO pursuant to this paragraph, each TSO shall ensure that on each bidding zone border, the long-term capacities that are in effect taken into account in the $LTA_{margin,DA}$, are between 0.001 MW and 1500 MW.

14. The final $\mathbf{PTDF_f}$ of all or only a subset of CE CNECs can be adjusted before the ATC extraction by setting the positive zone-to-zone PTDFs below a certain threshold to zero. The following outputs are the outcomes of the calculation for each ID CC TU:

(a) ATCs; and

(b) constraints with zero margin after the calculation of ATCs.

(c) An ATC limitation on specific borders as set by relevant TSOs as output of the local validation as defined in Annex 4: $ATC_{A \rightarrow B\ validated}$

15. In case of a required reduction due to situations as defined in Annex 3 paragraph 3(a), (b), (c), and (d), a TSO may use a positive value for $IVA$ for its own CNECs.

After individual validation adjustments, the final remaining available margin for intraday cross-zonal capacity ($\overrightarrow{RAM}_{f,ID}$) shall be calculated by the CCC for each CE CNEC and allocation constraint as follows:

$$\overrightarrow{RAM}_{f,ID} = \overrightarrow{RAM}_{UID} - \overrightarrow{IVA}_{ID}$$

*Equation 314*

with

| | |
|---|---|
| $\overrightarrow{RAM}_{f,ID}$ | final remaining available margin for CE intraday cross-zonal capacity |
| $\overrightarrow{RAM}_{UID}$ | updated remaining available margin for CE intraday cross-zonal capacities |
| $\overrightarrow{IVA}_{ID}$ | intraday individual validation adjustment |

16. In case the SIDC is unable to accommodate flow-based parameters, the CCC shall convert them into available transmission capacities for each CE oriented bidding zone border and each ID CC TU. The CE TSOs may delegate this responsibility to a third party.

17. In parallel to IVA validation pursuant to Annex 3 and as long as SIDC is not able to directly apply flow-based parameters, the CE TSOs may also perform ATC based individual validation pursuant to Annex 4.

18. The calculation of the ATCs is an iterative procedure, which gradually calculates ATCs for each ID CC TU, while respecting the constraints of the final flow-based parameters pursuant to paragraph 9 and 14:

(a) The initial ATCs are set equal to zero for each CE oriented bidding zone border, i.e.:

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

*Equation 32*

with

| | |
|---|---|
| $\overrightarrow{ATC}_{k=0}$ | the initial ATCs before the first iteration |

(b) The remaining available margin at iteration zero is equal to the updated remaining available margin for intraday cross-zonal capacities according to paragraph 14.

(c) Before starting the iterative method applied to calculate the positive ATCs, all the remaining available margins for ATC calculation at iteration k=0( $\overrightarrow{RAM}_{ATC}(0)$) shall be adjusted to be non-negative:

$$\overrightarrow{RAM}_{ATC}(0) = \max\left(0; \overrightarrow{RAM}_{f,ID}\right)$$

*Equation 33*

with

| | |
|---|---|
| $\overrightarrow{RAM}_{ATC}(0)$ | Remaining available margin for ATC calculation at iteration $k = 0$ |
| $\overrightarrow{RAM}_{f,ID}$ | final remaining available margin for intraday cross-zonal capacity |

(d) The iterative method applied to calculate the ATCs for intraday cross-zonal capacity procedure consists of the following actions for each iteration step *k*:

i. for each CNEC and allocation constraint of the flow-based parameters pursuant to paragraph 1, calculate the remaining available margin based on ATCs at iteration *k*-1:

$$\overrightarrow{RAM}_{ATC}(k) = \overrightarrow{RAM}_{ATC}(0) - \mathbf{pPTDF}_{\boldsymbol{zone-to-zone}}\, \overrightarrow{ATC}_{k-1}$$

*Equation 34*

with

| | |
|---|---|
| $\overrightarrow{RAM}_{ATC}(k)$ | remaining available margin for ATC calculation at iteration *k* |
| $\overrightarrow{RAM}_{ATC}(0)$ | Remaining available margin for ATC calculation at iteration $k = 0$ |
| $\overrightarrow{ATC}_{k-1}$ | ATCs at iteration *k*-1 |
| $\mathbf{pPTDF}_{\boldsymbol{zone-to-zone}}$ | positive zone-to-zone power transfer distribution factor matrix |

ii. for each CNEC, share $RAM_{ATC}(k)$ with equal shares among the CE 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 CE oriented bidding zone border by the respective positive zone-to-zone PTDF;

iv. for each CE 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 constraints as calculated in the previous step;

v. $\overrightarrow{ATC_k}$ is limited to a maximum value of $ATC_{A\rightarrow B\ validated}$ if such value has been introduced by TSOs on the border A→B as a result of the ATC validation phase as described in Annex 4. Then go back to step i;

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

vii. the resulting ATCs after day-ahead market coupling stem from the ATC values determined in iteration $k$, after rounding down to integer values.

viii. at the end of the calculation, there are some CNECs and allocation constraints with no remaining available margin left. These are the limiting constraints for the calculation of ATCs after day-ahead market coupling.

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

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

*Equation 35*

with

| | |
|---|---|
| $pPTDF_{zone-to-zone,A\rightarrow B}$ | positive zone-to-zone $PTDFs$ for CE oriented bidding zone border $A$ to $B$ |
| $PTDF_{zone-to-slack,m}$ | zone-to-slack $PTDF$ for CE bidding zone or virtual hub m |

19. CE TSOs and the CCC shall publish at least the following information and data items for each IDCC TU:

i. Initial NTC and ATC before validation
ii. Final NTC and ATCs (after validation) for SIDC;
iii. value of each allocation constraint before pre-solving;
iv. information about the validation reductions:
   - the identification of the CNEC;
   - the TSO invoking the reduction;
   - the volume of reduction ($IVA$);
   - the detailed reason(s) for reduction in accordance with Article 18(2) and 18(3), including the operational security limit(s) that would have been violated without reductions, and under which circumstances they would have been violated;

The CCC shall include in its quarterly report as defined in Article 27(5) the flows resulting from net positions resulting from intraday auctions on each CNEC and allocation constraint of the final flow-based parameters. This requirement is valid after the SIDC will directly apply the flow-based parameters.

20. CE TSOs shall review and amend this Article 18 months after submission of this methodology to CE regulatory authorities to address any incompatibility with SIDC, Core ID CCM and Italy North ID CCM.

## TITLE 5 – Updates and data provision

### Article 26. Reviews and updates

1. Based on Article 3(f) of the CACM Regulation and in accordance with Article 27(4) of the 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 day-ahead capacity calculation inputs pursuant to Article 5 and Article 7 need to be updated based on this review, the CE TSOs and iTCP shall publish the changes at least 1 week before their implementation.

3. In case the review proves the need for an update of the reliability margins, the CE TSOs and iTCP shall publish the changes at least one month before their implementation.

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

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

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

7. The CE TSOs and iTCP shall communicate the impact of any change of allocation constraints and parameters listed in Article 27(4)(d) of the CACM Regulation to market participants, all CE and iTCP regulatory authorities and the Agency. If any change leads to an adaption of the methodology, the CE TSOs shall make a proposal for amendment of this methodology according to Article 9(13) of the CACM Regulation.

8. The CE TSOs shall coordinate with iTCP when they review the methodology or its parameters.

### Article 27. Publication of data

1. In accordance with Article 3(f) of the CACM Regulation aiming at ensuring and enhancing the transparency and reliability of information to all regulatory authorities and market participants, all CE TSOs, iTCP 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 CE CCR shall be published. To enable market participants to have a clear understanding of the published data, all CE TSOs, iTCP 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 CE TSOs, iTCP 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) flow-based parameters before long term nominations pursuant to Article 21(1), which shall be published no later than 8:00 market time of D-1 for each DA CC TU of the following day;

   (b) the long term nominations for each CE and iTCP bidding zone border where PTRs are allocated, including those regarding long term contracts, which shall be published no later than 10:30 market time of D-1 for each DA CC TU of the following day;

   (c) final flow-based parameters pursuant to Article 21(4), which shall be published no later than 10:30 market time of D-1 for each DA CC TU of the following day;

   (d) the following information, which shall be published no later than 10:30 market time of D-1 for each DA CC TU of the following day:

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

      ii. maximum possible bilateral exchanges between all pairs of two CE bidding zones, pairs of two EVHs and pairs of one CE bidding zone and one EVH;

      iii. ATCs for SDAC fallback procedure;

      iv. names of CNECs (with geographical names of substations where relevant and separately for CNE and contingency) and allocation 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);

      vii. detailed breakdown of $RAM$ for each CNEC of the final flow-based parameters before pre-solving: $I_{max}$, $U$, $F_{max}$, $FRM$, $F_{ref,init}$, $F_{nrao}$, $F_{ref}$, $F_{0,\mathrm{CE}}$, $F_{0,\mathrm{all}}$, $F_{uaf}$, $AMR$, $LTA_{margin}$ (not applicable for the parameter LTAmargin in case extended LTA inclusion approach is applied), $CVA$, $IVA$, $F_{LTN}$;

      viii. detailed breakdown of the $RAM$ for each allocation 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(16) and (21),) 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 in accordance with Article 20(22): (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 CE and iTCP bidding zone and each TSO;

- production for each CE and iTCP bidding zone and each TSO;

- CE net position including iTCP for each CE and iTCP 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

xiv. information about the calculation of capacities for integrated counterparties pursuant to Article 23:

- the sharing key of each CNEC from the final list : $\overrightarrow{RSK}$

- indication of whether a CNEC is a pre-solved element of the separated flow-based domain

- the forecasted market direction for the bidding-zone borders of the iTCP

- the list of limiting constraints for the calculation of NTCs for iTCPs

- the NTCs for the bidding-zone borders of the iTCP

(e) the information pursuant to paragraph 2(d)(vii) shall be complemented by 14:00 market time of D-1 with the following information for each CNEC and allocation constraint of the final flow-based parameters:

i. shadow prices;

(f) every six months, the publication of an up-to-date static grid model by each CE TSO and iTCP.

(g) The CCC shall include in its quarterly report as defined in Article 29(5) the flows resulting from net positions resulting from the SDAC on each CNEC and allocation constraint of the final flow-based parameters.

(h) a list of internal network elements (combined with the relevant contingencies) defined as CNECs, as defined in Article 5(6).

(i) the list of AHC bidding zone borders in line with Article 13(7).

3. Individual CE TSO or iTCP may withhold the information referred to in paragraph 2(d)iv), 2(d)v) and 2(f) 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 TUs. 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 2(f) 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 CE 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 CE and iTCP regulatory authorities and updated or improved when needed.

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

7. CE TSOs and iTCP shall provide CE and iTCP regulatory authorities on a monthly basis the underlying capacity calculation and market coupling data related to the quarterly reports. The reporting framework shall be developed in coordination with CE and iTCP regulatory authorities and updated and improved when needed.

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

    (a) the current threshold applied;

    (b) the day of entry into force of the new threshold;

    (c) the value of the new threshold; and

    (d) a due justification of the change.

## Article 28. Quality of the data published

1. No later than six months before the implementation of this methodology in accordance with Article 30, the CE TSOs and iTCP 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 27. When doing so, they shall consult with relevant stakeholders and all CE and iTCP 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 CE CCR and iTCP 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, CE and iTCP 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 CE and iTCP regulatory authorities; and

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

4. The CE TSOs and iTCP 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 29. Monitoring, reporting and information to the CE regulatory authorities

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

2. At least, the information on non-anonymized names of CNECs for final flow-based parameters before pre-solving as referred to in Article 27(2)(d)(iv) and (v) shall be provided to all CE and iTCP regulatory authorities on a monthly basis for each CNEC and each DA CC TU. This information shall be in a format that allows easily to combine the CNEC names with the information published in accordance with Article 27(2).

3. CE and iTCP regulatory authorities may request additional information to be provided by the TSOs. For this purpose, all CE and iTCP regulatory authorities shall coordinate their requests among themselves. Each CE TSO or iTCP 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 CE TSOs and iTCP 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 CE TSOs and iTCP 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(6), the CE TSOs and iTCP shall monitor the accuracy of non-CE exchanges in the CGM which are not handled through AHC. The CE TSOs and iTCP shall report in the annual report to all CE and iTCP regulatory authorities the accuracy of such forecasts.

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

   (d) according to Article 28(2), the CCC shall monitor and report on the quality of the data published on the dedicated online communication platform as referred to in Article 27, with supporting detailed analysis of a failure to achieve sufficient data quality standards by the concerned TSOs, where relevant.

   (e) according to Article 30 (2), after the implementation of this methodology, the CE TSOs and iTCP 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 CE TSOs and iTCP where relevant, shall draft and publish a quarterly report satisfying the reporting obligations set in Articles 12, 20, 27 and 30 of this methodology:

   (a) according to Article 20(30f), the CCC shall provide all information on the reductions of cross-zonal capacity, with a supporting detailed analysis from the concerned TSOs where relevant.

(b) according to Article 30(3) during the implementation of this methodology, the CE TSOs and iTCP shall report on their continuous monitoring of the effects and performance of the application of this methodology.

(c) according to Article 27(2) (g), CE TSOs and iTCP shall report on flows resulting from net positions resulting from the SDAC on each CNEC and allocation constraint of the final flow-based parameters.

(d) according to Article 12(4), CE TSOs shall report quarterly on the initial setup and any change of this threshold together with the impact which entails from a non-zero threshold and a due justification.

6. The CCC, with the support of the CE TSOs and iTCP where relevant, shall draft and publish a half-yearly report satisfying the reporting obligations set in Articles 7(4) of this methodology.

7. The published annual and quarterly reports may withhold commercially sensitive information or sensitive critical infrastructure protection related information as referred to in Article 27(3). In such a case, the CE TSOs and iTCP shall provide the CE and iTCP regulatory authorities with a complete version where no such information is withheld.

# TITLE 6 - Implementation

## Article 30. Timescale for implementation

1. The TSOs of the CE CCR shall publish this methodology without undue delay after the decision has been taken by the CE NRAs or by the Agency in accordance with Article 9 of the CACM Regulation.

2. The TSOs of the CE CCR shall implement this methodology no later than 15 January 2028. The implementation process, which shall start with the entry into force of this methodology, shall consist of the following steps:

   (a) internal parallel run, during which the TSOs shall test the operational processes for the day-ahead capacity calculation inputs, the day-ahead capacity calculation process and the day-ahead capacity validation and develop the appropriate IT tools and infrastructure;

   (b) external parallel run, during which the TSOs will continue testing their internal processes and IT tools and infrastructure. In addition, the CE TSOs will involve the CE 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 internal and external parallel runs, the CE TSOs and iTCP shall continuously monitor the effects and the performance of the application of this methodology. For this purpose, they shall develop, in coordination with the CE and iTCP regulatory authorities, the Agency and stakeholders, the monitoring and performance criteria and report on the outcome of this monitoring on a quarterly basis in a quarterly report. After the implementation of this methodology, the outcome of this monitoring shall be reported in the annual report.

4. The CE TSOs shall implement the day-ahead capacity calculation methodology on a CE bidding zone border only if this bidding zone border participates in the SDAC or is border between a CE CCR TSO bidding zone and an iTCP bidding zone.

# TITLE 7 - Final provisions

## Article 31. 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 CE and iTCP regulatory authorities with an updated translation of the methodology.

## Annex 1: Justification of usage and methodology for calculation of allocation constraints

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

### 1- Poland

PSE may use an allocation constraint to limit the import and export of the Polish bidding zone.

**Technical and legal justification**

Capacity allocation constraints are a legally prescribed means, defined by Capacity Allocation and Congestion Management Regulation (Art. 23(3) and art. 21(1)(a)(ii) CACM).

These constraints limit the global net position of Polish zone and 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 Polish power system to ensure secure operation. This is explained further in subsequent parts of this Annex.

**Rationale behind implementation of allocation constraints on PSE side**

Implementation of allocation constraints as applied by PSE is related to the fact that under the conditions of the integrated scheduling-based market model applied in Poland (also called central dispatching model) the responsibility of the Polish TSO on system balance is significantly extended comparing to such responsibility of TSOs in so-called self-dispatch market models. Central dispatching is one of the two dispatching models authorized by EU Commission Regulation 2017/2195. In self-dispatch markets, balance responsible parties (BRPs) are themselves supposed to take care about their generating reserves and load following, while TSO ensures them just for dealing with contingencies in the timeframe of up to one hour ahead. In a central dispatching model, it is the TSO who dispatches generating units taking into account their: operational constraints, transmission constraints and reserve capacity requirements, with the aim to balance national generation, demand and cross-border exchanges while ensuring secure operation of the transmission system. When TSO is preparing generation dispatch plans for the operational day, energy and reserves in the central dispatching model are ensured simultaneously (inherent feature of central dispatching systems with accordance to EU Commission Regulation 2017/2195). Results of the wholesale market together with the results of the balancing capacity reserves market serve as a basis for the generation dispatch performed under integrated scheduling process.

In central dispatching systems, the above process is realised within an Integrated Scheduling Process (ISP) run as a single optimisation problem called security constrained unit commitment (SCUC – where generation units are being dispatch on and off) and economic dispatch (SCED – where generation output for all dispatched generation units is determined). Integrated Scheduling Process starts in the late afternoon of D-1, already well after the day-ahead capacity calculation and SDAC, and continues iteratively by recalculating the future dispatch plans for each particular hour of day D until its real-time execution (new recalculation at least every hour). Within aforementioned integrated scheduling process, generation units connected to the transmission grid are dispatched by PSE with the aim to respect power purchase agreements concluded between market participants on the wholesale market, while minimizing overall costs of dispatch adjustments and balancing energy activation to cover the residual demand (being the part of end users demand not covered by commercial contracts). When doing so, PSE is obliged to respect power system operating conditions, as well as the technical characteristics of generation units both on the level of individual generation units and on the level of power plants. Unit capabilities, considering their inter-temporal limitations (ramping rates), are also considered in this process.

According to the national legislation, PSE is legally obliged ensure availability of sufficient level of generating reserves for the whole Polish power system in order to safeguard its secure operation in case of contingency, as well as in case of insufficient and ineffective balancing activities performed by market participants in Poland. However, if balancing service providers (generating units) would already sold too much energy in the day-ahead market in form of high exports, they may not be able to provide sufficient upward reserve capacity within the integrated scheduling process as required by national legislation. This conclusion equally applies for the case when market participants import significant amount of energy, as it could result in balancing service providers being unable to provide downward regulation capabilities due to not securing enough generation levels in the day-ahead market. The strength of the imbalance settlement pricing is also important in this process, together with the maturity and the ability market participants to maintain balanced portfolios under objectively high RES and demand uncertainties and underdeveloped intra-day markets.

This leads to implementation of allocation constraints, being the necessary means to ensure operational security of Polish power system in terms of securing generating capacities for upward or downward regulation, as well as in order to cover the national imbalances in the direction of shortage (i.e. cover the residual demand) and surplus (i.e. manage and regulate down the surplus of power during periods of oversupply). Excluding such a solution and depriving TSOs under central dispatching systems from the usage of allocation constraints to set appropriate limits to how much electricity can be imported or exported by the system as a whole may lead to insufficient balancing capacity reserves, making the provisions of Electricity Balancing Guideline void, and making it impossible or at least much more difficult to comply with System Operation Guideline.

The impact of allocation constraints is analysed and described in Quarterly and Annual CCR Reports. The reports shows that the largest social welfare impact concerns Poland (order of magnitude higher than for other countries of the CCR), resulting in a loss of social welfare in Poland due to application of allocation constraints. However, as demonstrated in the reports time after time, this apparent loss of social welfare in Poland avoids much higher welfare losses when secure operation of the Polish power system is threatened and extraordinary measures must be applied to mitigate this threat (e.g. demand curtailment or RES curtailment).

It needs to be highlighted that despite implementation of explicit balancing capacity procurement in Poland as per 14 June 2024, and despite maintaining the use of Allocation Constraints, PSE still has to apply remedial measures at large scale in order to ensure equilibrium between demand and supply in the Polish power system. These measures are mostly the non-market-based curtailment of RES (in case of energy surplus) and emergency exchanges with neighbouring TSOs (in case of energy surplus or shortage). Both aforementioned measures have severe negative consequences, such as difficulties for TSO and DSO dispatching teams to manage hundreds of operational commands issued to dispersed RES facilities in very short time, difficulties of RES facility owners to respond to dispatching commands issued with short notice, as well as depletion of operational reserves of neighbouring TSOs when asked for emergency exchanges, reducing overall European power system resilience. In many instances of time, neighbouring TSOs are unable to provide the requested support.

Balancing market reform executed on 14 June 2024 has significantly improved market price signals, so that balancing responsible parties are better reacting to dynamically changing power system situation. Nonetheless, the observed levels of balancing energy that needs to be activated by PSE under ISP is still very high, often exceeding the procured balancing capacity. This implies that the new improved balancing market prices are still unable to convey sufficient incentives for market participants to improve generation and demand planning as BRPs still do not balance their portfolios earlier on more attractive day-ahead and intraday markets. Moreover, new balancing capacity reserves procurement process is still immature and suffers from lack of liquidity, low supply and low competition. Both aforementioned items are a subject of intensive analysis on PSE side with the aim to prepare improvements and increase effectiveness of price signals.

Due to the fact that no alternatives to using allocation constraints have been identified as plausible to be implemented until two years following implementation of flow-based in Central Europe, which could both have lower overall cost while maintaining the similar level of operational security and which would not require a major overhaul of the whole market design, PSE aims at using allocation constraints AC in the Central Europe region.

**The reason why allocation constraints can't be expressed by maximum admissible power flow**

This limitation cannot be efficiently expressed by translating it into transfer capacities of critical network elements offered to the market. If this limit was to be reflected in cross-zonal capacities offered by PSE in the form of an appropriate adjustment of cross-zonal capacities, this would imply that PSE would need to guess the most likely market direction (imports and/or exports on particular interconnectors) and accordingly reduce the cross-zonal capacities in these directions. In the flow-based approach, this would need to be done on each CNEC in a form of reductions of the RAM. However, from the point of view of market participants, due to the inherent uncertainties of market results, such an approach is burdened with the risk of suboptimal splitting of allocation constraints onto individual interconnections – overestimated on one interconnection and underestimated on the other, or vice versa. Also, such reductions of the RAM would limit cross-zonal exchanges for all bidding zone borders having impact on Polish CNECs (i.e. transit flows), whereas the allocation constraint has an impact only on the import or export of the Polish bidding zone, while the trading of other bidding zones is unaffected.

**Determination of allocation constraints in Poland**

Allocation constrains are applied in day-ahead allocation process, with values determined day before energy delivery, per each hour individually based on expected generation adequacy analysis for this hour as well as power system operation conditions and technical characteristics of generation units both on the level of individual generation units and on the level of power plants. Allocation constrains 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.

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

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

For each hour, the constraints are calculated according to the below 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[9] |
| $P_{CD_{min}}$ | Sum of technical minima of available centrally dispatched generating units |
| $P_{NCD}$ | Sum of schedules of generating units that are not centrally dispatched, as provided by generators (for weather-dependent intermittent renewable generation: forecasted by PSE) |
| $P_{NA}$ | Generation not available due to grid constraints (both planned outage and/or anticipated congestions) |
| $P_{ER}$ | Generation unavailability's adjustment resulting from issues not declared by generators, forecasted by PSE due to exceptional circumstances (e.g. cooling conditions or prolonged overhauls) |
| $P_L$ | Demand forecasted by PSE |
| $P_{UPres}$ | Minimum reserve for upward regulation |
| $P_{DOWNres}$ | Minimum reserve for downward regulation |

Equation (1) stems from requirement for system operators to maintain upward reserves to cover part of forecasted load with accordance to Polish grid codes. These reserves are a critical aspect of ensuring system reliability and stability, particularly in balancing supply and demand during unexpected events such as generation outages or sudden demand spikes. During periods of high energy demand combined with limited additional capacity from renewable sources, it becomes challenging to maintain adequate upward reserves. In such scenarios, the only viable solution to address the balancing challenge is to set the export capacity to zero.

Equation (2) refers to the need of securing the capacity that can be quickly reduced to balance supply and demand when there is an excess of power in the grid e.g. in case of loss of significant load.

For illustrative purposes, the process of practical determination of allocation constraints in the framework of the day-ahead capacity calculation is illustrated below in Figures 1 and 2. The figures illustrate how a forecast of the Polish power balance for each hour of the delivery day is developed by PSE in the morning of D-1 in order to determine reserves in generating capacities available for potential exports and imports, respectively, for the day-ahead market.

| | |
|---|---|
| Allocation constraint in export direction is applicable if ΔExport is lower than the sum of cross-zonal capacities on all Polish interconnections in export direction. Allocation constraint in import direction is applicable if ΔImport is lower than the sum of cross-zonal capacities on all Polish interconnections in | 1. Sum of available generating capacities of centrally dispatched units as declared by generators, reduced by:<br>1.1 Generation not available due to grid constraints<br>1.2 Generation unavailability's adjustment resulting from issues not declared by |

[9] Note that generating units which are kept out of the market on the basis of strategic reserve contracts with the TSO are not taken into account in this calculation.

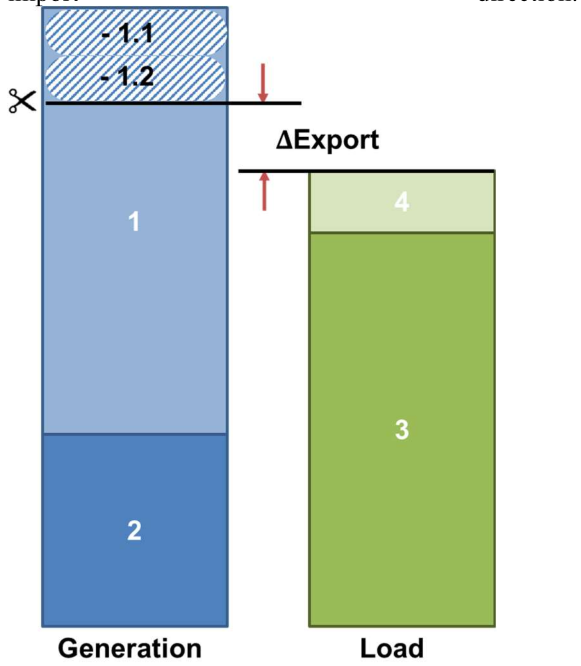
<table>
<tr>
<td>import direction.<br></td>
<td>generators, forecasted by PSE due to exceptional circumstances (e.g. cooling conditions or prolonged overhauls)<br>2. Sum of schedules of generating units that are not centrally dispatched, as provided by generators (for weather-dependent intermittent renewable generation: forecasted by PSE)<br>3. Demand forecasted by PSE<br>4. Minimum necessary reserve for up regulation</td>
</tr>
</table>

Figure 1: Determination of allocation constraints in export direction (generating capacities available for potential exports) in the framework of the day-ahead capacity calculation.

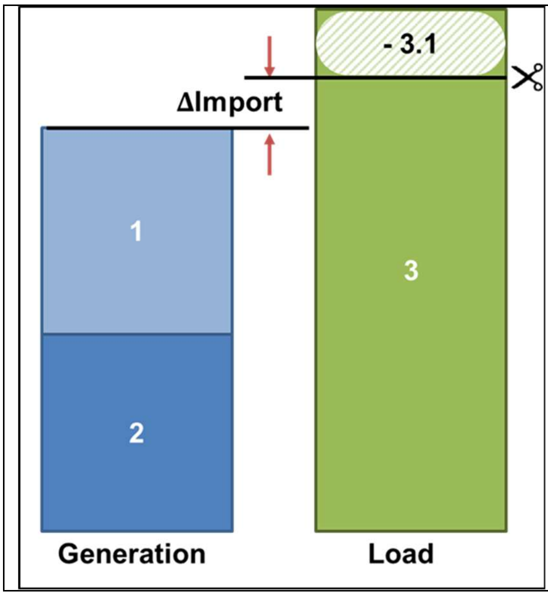
<table>
<tr>
<td></td>
<td>1 Sum of technical minima of centrally dispatched generating units in operation<br><br>2 Sum of schedules of generating units that are not centrally dispatched, as provided by generators (for weather-dependent intermittent renewable generation: forecasted by PSE)<br><br>3 Demand forecasted by PSE, reduced by:<br>3.1 Minimum necessary reserve for down regulation</td>
</tr>
</table>

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

**Frequency of re-assessment**

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

**Time periods for which allocation constraints are applied**

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

## 2- Italy

TERNA may use allocation constraints to limit the import from the Northern Italian interconnectors.

**Technical and legal justification**

**Allocation constraints** are defined by the Italian TSO and shared with the other TSOs and CCC as a maximum value of acceptable import from the whole Northern Italian Interconnection. Capacity allocation constraints are a legally prescribed means, defined by CACM Regulation (Art. 23(3) and art. 21(1)(a)(ii) CACM).

Allocation constraints are used by Terna to take into account operational security constraints related to margins, voltage control and dynamic system stability within the Italian grid, in particular during low demand/high renewable infeed periods.

These three kinds of constraints are needed to maintain the transmission system within secure operations, but cannot be translated efficiently in form of maximum flows on critical network elements. Hence the constraints above shall be expressed via allocation constraints in the market coupling algorithms.

If this constraint was implemented as a reduction in the cross-zonal capacities, it would mean that TERNA would have to guess the most probable direction of the market (imports and/or exports on particular interconnectors) and consequently estimate the reductions on the different interconnectors. In the flow based approach, this would mean estimating the RAM reduction on each CNEC, with the consequent risk of not distributing the constraint, in an optimal way, on the individual interconnections, overestimating the constraint on one interconnection and underestimating it on the other, or vice versa.

On the other hand, the use of allocation constraints ensures that the market decides how to allocate capacity in the most efficient way among the different Northern Italian Interconnections, considering that the allocation constraint is provided to the market as a constraint limiting the import at the Northern Italian Border.

The scope of Allocation Constraint is to make the Italian TSO able to activate the needed set of power plants, applying redispatching actions at national level.

The minimum set of dispatchable power plants to be activated in order to provide system services according to the criteria of System Operation Guidelines (e.g. voltage regulation, primary reserve…), is quantified performing steady-state security analysis and dynamic assessments on several scenarios considered representative of the expected system conditions

**Ramping constraints** (known also as ‘flow ramping limits’) are used for limiting the maximum variation of import/export from/to a set of interconnectors from one MTU to the next. Due to the peculiar structure of the Italian network as a long peninsula AC-meshed with the European bulk system only on the northern borders, large variations of exchange programs between one MTU and the next may endanger the grid security during real time operations leading to challenging management of the voltage and frequency profiles. In fact, the transient variations induced by the exchange control program may require such a relevant reserve margin that could lead to technical unfeasibility both in terms of active and reactive power.

Furthermore, the growing trend of production from renewable sources makes the issue even more critical due to the uncertainty of the actual production from renewable sources.

### Methodology to calculate the value of allocation constraints

The allocation constraint, defined as the maximum value of acceptable import from the Northern Italian interconnectors, is computed according to the following formula:

$$Import_{max}^{h} = [L^h - DR^h] - [ND^h + VRI^h] + P^h$$

Where:

*L: hourly load forecast*
*DR: downward reserve defined according to the uncertainties related to load and RES forecasts*
*ND: infeed expected from non-dispatchable power plants*
*VRI: is the infeed from the minimum set of dispatchable power plants*
*P: available pumping capacity*

When determining the allocation constraints, TERNA considers the most recent information on the technical characteristics of generation units, forecasted power system load as well as downward reserve defined according to the uncertainties related to load and RES forecasts. The available pumping capacity helps mitigate the effect of allocation constraint.

Allocation constraints are determined in the evening of D-2 for all the MTUs concerning both the DA and Intra-Day processes.

In order to take into account the allocation constraints, pursuant to Article (7)(2)(c) in case of SDAC fallback procedure, at the end of the calculation, the ATC for AT->IT, SI->IT and FR->IT borders shall be minor or equal to the Allocation constraints split among AT->IT, SI->IT and FR->IT borders, respectively:

$$Final\ ATC_{AT\rightarrow IT} = \min\,(AC_{AT\rightarrow IT}\ ;\ ATC_{k,AT\rightarrow IT})$$

$$Final\ ATC_{SI\rightarrow IT} = \min\,(AC_{SI\rightarrow IT}\ ;\ ATC_{k,SI\rightarrow IT})$$

$$Final\ ATC_{FR\rightarrow IT} = \min\,(AC_{FR\rightarrow IT}\ ;\ ATC_{k,FR\rightarrow IT})$$

The AC values (for AT->IT, SI->IT, FR->IT borders) are calculated splitting the allocation constraint per border, based on the splitting factors calculated by using the $\overrightarrow{ATC_k}$ values (Article (24)(5)(vii)).

$$AC_{x\rightarrow IT} = AC * SF_{x\rightarrow IT}; \qquad \textit{where x in (FR,AT,SI)}$$

$$SF_{x\rightarrow IT} = ATC_{k,x\rightarrow IT} / \sum_{x=1}^{3} ATC_{k,x\rightarrow IT}$$

### Methodology to calculate the value of ramping constraints

The ramping constraint is defined as the maximum value of variation of exchange (import/export) from/to a set of interconnectors from one MTU to the next from the Northern Italian interconnectors:

$$Exchange_{max}^{MTU} - Exchange_{max}^{MTU-1} \leq Max_{value}$$

When determining the ramping constraints, TERNA considers the most recent information on the reserve margin considering the technical feasibility, both in terms of active and reactive power as well as RES forecasts.

Ramping constraints are determined for all the MTUs concerning both the DA and Intra-Day markets.

As this process is going to be implemented by Terna together with the 15'minutes go-live in SDAC on 2025 and to be applied in Italy North CCR processes (e.g. Day-ahead and Intra-Day), further improvement of the methodological approach (both on calculation and frequency of recalculation) might be required. Indeed, gains from the experience of Terna in the usage of ramping constraints in the first period are necessary in order to adapt it properly. Therefore, an update concerning the methodological calculation approach for ramping constraints applied by Terna will be performed at latest 18 months after the first submission of this methodology.

## Annex 2: List of network elements excluded from Article 6 paragraph 1 and 2

The following grid elements are excluded from Article 6 paragraph 1 and 2 and are hereafter referred to as ''affected elements'':

- [AT-IT] Lienz-Auronzo 220 kV
- [AT-IT] Nauders – Glorenza 220 kV
- [CH-IT] Lavorgo – Musignano 380 kV
- [CH-IT] Soazza – Bulciago 380 kV
- [CH-IT] Robbia – S. Fiorano 380 kV
- [CH-IT] Robbia – Gorlago 380 kV
- [CH-IT] Riddes – Avise 220 kV
- [CH-IT] Riddes – Valpelline 220 kV
- [CH-IT] Serra – Pallanzeno 220 kV
- [CH-IT] Y All'Acqua – Ponte 220 kV
- [CH-CH] Sils-Soazza 380 kV
- [CH-CH] Filisur-Sils 380 kV
- [CH-CH] Filisur-Robbia 380 kV

**Technical reasoning**

The exclusion from Article 6 paragraph 1 and 2 is related to the fact that on the bidding-zone border between Austria and Italy North and between Switzerland and Italy North tie-lines below 220 kV exist, which are not modelled in the common grid model on both sides of the bidding-zone border. In order to consider the physical capacity of these tie-lines, parameters of modelled grid elements in the same bidding-zone are adjusted such that the capacity of these non-modelled tie-lines can be considered in the CE day-ahead capacity calculation.

The following tie-lines are currently not modelled in the common grid model:

- Interconnection AT – IT 'Tarvisio – Greuth' 132 kV
- Interconnection CH – IT 'Villa di Tirano – Campocologno' 132 kV
- Interconnection CH – IT 'Tirano – Campocologno' 150 kV

The above list of tie-lines currently not modelled might be extended to include, but not limited to, the future interconnection AT-IT 'Stainach – Prati di Vizze' 110 kV, a tie-line estimated to be in operation before the implementation of CGMES.

In fact, as the Italian network relevant for transmission includes network elements having voltage of 220 kV and over, the transmission network below 220 kV (i.e. network elements of 150/132/110 kV) can be considered decoupled from the relevant network*. Based on this consideration, with purposes of the CC process, the above mentioned existing tie-lines having voltage under 220 KV are not modelled in the CGM. As a consequence, when events diverging from the normal state of the transmission network operation occur in the 132/150 kV network, such as disturbances and fluctuations, they do not influence behaviour of the relevant network. Conversely, disturbances occurring in the relevant network do not influence these non-modelled lines due to the presence of PSTs. In fact, these non-modelled lines are run by fixed flows (impressed energy flows) and the injection of their flows is regulated by a PST put at one of the extremes of each line:

- for interconnection AT – IT 'Tarvisio – Greuth' 132 kV, a PST is present in Greuth substation;

- for interconnection CH – IT ‘Tirano – Campocologno’ 132 kV, a PST is present in Tirano substation;
- for interconnection CH – IT ‘Villa di Tirano – Campocologno’ 150 kV, a PST is present in Villa di Tirano substation

Based on the explanation above, these tie-lines shall be excluded from the CGM for CE day-ahead capacity calculation until CGMES implementation.

**Methodology to calculate the value of additional Fmax for affected elements**

Calculation of the additional capacity for the affected elements is done by evaluating the effect of an additional exchange over the bidding-zone border on the affected elements. The maximum additional exchange on these lines is the thermal limit of these not modelled lines.

$$\Delta F_{max,l} = \sum_{nML} F_{max,nML} \cdot pPTDF_{z2z,l}$$

| | |
|---|---|
| $\Delta F_{max,l}$ | Additional Fmax for affected element l |
| $F_{max,nML}$ | Fmax of the non-modelled Line |
| $pPTDF_{z2z,l}$ | Positive Zone to Zone PTDF of affected element l |

Fmax of the affected lines is then increased by the additional Fmax calculated above.

$$F'_{max,l} = F_{max,l} + \Delta F_{max,l}$$

| | |
|---|---|
| $F'_{max,l}$ | Adjusted Fmax of affected element l |
| $F_{max,l}$ | Fmax of affected element l |
| $\Delta F_{max,l}$ | Additional Fmax for affected element l |

* Definition from the SO GL Article (3)(85), where: ‘relevant grid element’ means any component of a transmission system, including interconnectors, or of a distribution system, including a closed distribution system, such as a single line, a single circuit, a single transformer, a single phase-shifting transformer, or a voltage compensation installation, which participates in the outage coordination and the availability status of which influences cross-border operational security

## Annex 3: IVA validation process for updated intraday capacities

1. The CE TSOs shall validate and have the right to correct cross-zonal capacity for reasons of operational security during the validation process.
2. Each CE 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, and only after all the expected available costly and non-costly remedial actions pursuant to Article 22 of the SO Regulation are considered.
3. 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 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.

4. When performing the validation, the CE 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 CE TSOs shall use the tools developed by the CCC for analysis, but may also employ verification tools not available to the CCC.

5. In case of a required reduction due to situations as defined in paragraph 3(a), a TSO may use a positive value for $IVA$ for its own CNECs or adapt the allocation constraints, pursuant to Article 25(8), to reduce the cross-zonal capacity for its bidding zone.

6. In case of a required reduction due to situations as defined in paragraph 3(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 3(c), a CE TSO may, as a last resort measure, request a common decision to launch the default flow-based parameters pursuant to Article 22.

## Annex 4: ATC based validation process for updated intraday capacities

1. Each CE TSO has the right to perform an ATC based validation in order to ensure operational security. This is an additional process, next to the existing validation process described in Annex 3 as IVA validation. Pursuant to this validation, each CE TSO can set a maximum ATC value for its own oriented bidding zone borders.

2. The ATC on a bidding zone border shall always be the lowest value of all ATCs set by all TSOs for this bidding-zone border.

$$ATC_{A\rightarrow B\ validated} = \min\left(\overrightarrow{ATC}_{A\rightarrow B\ validated,TSO\ 1}, \overrightarrow{ATC}_{A\rightarrow B\ validated,TSO\ 2}, \overrightarrow{ATC}_{A\rightarrow B\ validated,TSO\ x}\right)$$

*Equation 16*

with

| | |
|---|---|
| $ATC_{A\rightarrow B\ validated}$ | Minimum of validated ATCs for border A→B by all CE TSOs adjacent to this bidding zone border |
| $\overrightarrow{ATC}_{A\rightarrow B\ validated,TSO\ x}$ | Validated ATC for border A→B by TSO x |

3. The ATC limitation may be done only in the following situations:

   (a) an occurrence of an unexpected contingency impacting a CNE after the beginning of the process;

   (b) as a fallback, in case IVA validation cannot be performed fully in time or if it faces IT issue; or

   (c) a mistake in input data that leads to an overestimation of cross-zonal capacity from an operational system security perspective.

4. In addition to the publication described in Article 27, CE TSOs and the CCC shall publish at least the following information and data items with regard to the ATC based validation for each ID CC TU:

   (a) The TSO invoking the limitation;

   (b) The ATC limitation per border;

   (c) The situation applicable as per the previous paragraph; and

   (d) The detailed reason for the limitation of the ATC with the same level of information as IVA validation following the reasonings developed in Annex 3, including the operational security limits (when relevant) that would have been violated without the reductions, and under which circumstances they would have been violated. Every three months, the CCC, with the support of CE TSOs where relevant, shall provide in the quarterly report the data items given under paragraph 4(a), 4(b), 4(c) and 4(d), with regard to the ATC based validation.