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

October 6, 2022

Table of Contents

All TSOs of the Nordic Capacity Calculation Region, taking into account the following:

Whereas

(1) This document describes a common methodology for all Transmission System Operators (hereafter referred to as “TSOs”) of the Nordic Capacity Calculation Region (hereafter referred to as “Nordic CCR”) as defined in accordance with Article 37(3) of Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing (hereafter referred to as the “EB Regulation”).

(2) This capacity calculation methodology (hereafter referred to as the “CCM”) takes into account the general principles, goals and other methodologies set in the EB Regulation, Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management (hereafter referred to as the “CACM Regulation”), Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation (hereafter referred to as "SO Regulation") and Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (hereafter referred to as “Regulation (EU) 2019/943”).

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

(4) According to article 37(3) of the EB Regulation, this CCM shall be consistent with the capacity calculation methodology applied in the intraday timeframe for the Nordic CCR established under the CACM Regulation. Therefore, this CCM will follow the principle established under the CACM Regulation.

(5) The CCM - by building on the intraday CCM fundaments as described in the “Nordic Capacity Calculation Region capacity calculation methodology in accordance with Article 20(2) of Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management” approved by Nordic regulatory authorities and dated 14 October 2020 (hereafter referred to as “Nordic ID CCM”) - contributes to the general objectives of the EB Regulation and the CACM Regulation to the benefit of market participants and electricity end consumers.

(6) The CCM makes use of the Nordic capacity calculation process implemented for the intraday timeframe. The flow-based (hereafter referred to as the “FB”) parameters computed for the intraday timeframe, by using dedicated intraday common grid models (hereafter referred to as the “CGMs”), will be updated for the balancing timeframe, by taking into account the already-allocated capacities from the intraday and balancing timeframes and transmission capacity already reserved for the balancing timeframe. As such, the left-over capacity – being the capacity remaining after the intraday timeframe with the addition of capacity already reserved for the balancing timeframe – can be provided to the balancing timeframe for the exchange of balancing energy or for operating the imbalance netting process.

(7) This CCM provides a transition period for the capacity calculation of cross-zonal capacity for the exchange of balancing energy: until the European platforms for the exchange of balancing energy from frequency restoration reserves with manual and automatic activation (MARI and Picasso platform) are able to support the allocation of cross-zonal capacity based on FB parameters, the coordinated capacity calculator (hereafter referred to as “CCC”) transforms the FB parameters

into available transmission capacity (hereafter referred to as “ATCE”) values on bidding zone borders of the Nordic CCR.

(8) This CCM is based on the assumption that HVDC ramping restrictions are defined as allocation constraints and will be handled by the European balancing platforms and/or the capacity management module (hereafter referred to as “CMM”) of these European platforms.

SUBMIT THE FOLLOWING CCM TO ALL REGULATORY AUTHORITIES OF THE NORDIC CCR:

TITLE I
General

Article 1
Subject matter and scope

1. The CCM is the common methodology of all TSOs in the Nordic CCR in accordance with Article 37(3) of the EB Regulation.

2. The CCM applies solely to the Nordic CCR as defined in accordance with Article 15 of the CACM Regulation.

3. The CCM covers the capacity calculation methodology for the balancing timeframe.

Article 2
Definitions and interpretation

1. For the purposes of the Proposal, the terms used shall have the meaning given to them in Article 2 of the Regulation (EU) 2019/943, Article 2 of the CACM Regulation, Article 3 of the SO Regulation, Article 2 of the EB Regulation”), and Article 2 of Commission Regulation (EU) No 543/2013 of 14 June 2013 on submission and publication of data in electricity markets and amending Annex I to Regulation (EC) No 714/2009 of the European Parliament and of the Council (hereafter referred to as “Transparency Regulation”).
2. In addition, in this CCM, the following terms shall have the meaning below:
    1. ‘ATC’ means the available transmission capacity on bidding zone borders, which is the transmission capacity that remains available after the deduction of eventual previously allocated capacities and which respects the physical conditions of the transmission system;
    2. ‘CCC’ means the coordinated capacity calculator, as defined in Article 2(11) of the CACM Regulation, of the Nordic CCR, unless stated otherwise;
    3. ‘CCR’ means the capacity calculation region as defined in Article 2(3) of the CACM Regulation;
    4. ‘CGM’ means the common grid model as defined in Article 2(2) of the CACM Regulation and means a CGM established in accordance with the common grid model methodology, pursuant to Article 17 of the CACM Regulation;
    5. ‘CNE’ means a critical network element;
    6. ‘CNEC’ means a critical network element monitored under a contingency;
    7. ‘combined dynamic constraint’ means a limit on the sum of power flows on a set of network elements or partial flows on a set of network elements for the purpose to respect dynamic stability limits;

8. 'F_0' means the linear approximation of a flow in the reference net position on a CNEC or combined dynamic constraint in a situation without any cross-zonal exchanges;
9. 'F_{max}' or 'F_{max}' means the maximum flow on a CNEC or combined dynamic constraint;
10. 'F_{RA}' means the flow for increasing the RAM on a CNEC or combined dynamic constraint due to RAs taken into account in capacity calculation;
11. 'F_{RM}' means flow for reliability margin for all CNECs and combined dynamic constraints
12. 'F_{ref}' means the reference flow on a CNEC or combined dynamic constraint;
13. 'GSK' means the generation shift key as defined in Article 2(12) of the CACM Regulation;
14. 'HVDC network element' means a high voltage direct current network element;
15. 'IGM' means the individual grid model as defined in Article 2(1) of the CACM Regulation;
16. 'I_{max}' means the maximum admissible current of a CNE or a CNEC;
17. 'Nordic CCR' means the Nordic capacity calculation region as determined pursuant to Article 15 of the CACM Regulation;
18. 'internal CNE' means a critical network element (CNE) that is located inside a bidding zone and that is limiting the amount of power that can be exchanged between bidding zones;
19. 'merging agent' means a party, which builds the CGM from IGMs sent by each TSO and sends the CGM to the CCC for capacity calculation;
20. 'NP' or 'NP' means a net position of a bidding zone, which is the net value of generation and consumption in a bidding zone;
21. 'previously allocated cross-zonal capacities' means the capacities which have already been allocated;
22. 'PTDF' or '$PTDF$' means a power transfer distribution factor;
23. 'RA' means a remedial action as defined in Article 2(13) of the CACM Regulation;
24. 'RAM' or 'RAM' means a remaining available margin on a CNEC or a combined dynamic constraint;
25. 'reference net position' or 'reference exchange' means a position of a bidding zone or an exchange over HVDC interconnection assumed within the CGM;
26. 'reliability margin' or 'RM' means the reliability margin as defined in Article 2(14) of the CACM Regulation;
27. 'slack node' means the single reference node per synchronous area 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 scenario;
28. 'zone-to-slack $PTDF$' means the PTDF of a commercial exchange between a bidding zone and the slack node;
29. 'zone-to-zone $PTDF$' means the PTDF of a commercial exchange between two bidding zones;
30. the notation x denotes a scalar;
31. the notation $\vec{x}$ denotes a vector; and
32. the notation **x** denotes a matrix.

3. In this CCM, unless the context requires otherwise:

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

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

(c) the table of contents and the headings are inserted for convenience only and do not affect the interpretation of this CCM; and

(d) any reference to legislation, regulations, directives, orders, instruments, codes or any other enactment shall include any modifications, extensions or re-enactment of it when in force.

4. For the sake of clarity this CCM does not affect TSOs' right to delegate their task in accordance with the Article 13 of the EB Regulation and Article 81 of the CACM Regulation. In this CCM the reference to a TSO shall mean Transmission System Operator or to a third party, whom the TSO has delegated task(s) to, in accordance with the EB Regulation and CACM Regulation, where applicable. However, the delegating TSO shall remain responsible for ensuring compliance with the obligations under the EB Regulation and CACM Regulation.

TITLE 2
Description of capacity calculation input for balancing timeframe

Article 3
Methodology for determining reliability margin

The reliability margin shall be the reliability margin as determined in the intraday capacity calculation process and described in Article 3 of the Nordic ID CCM.

Article 4
Methodology for determining operational security limits

The operational security limits considered and applied in the intraday capacity calculation process, and described in Article 4 of the Nordic ID CCM, are valid for the balancing timeframe. Additionally, the CCM shall take into account the specific technical limits for the HVDC links.

Article 5
Methodology for determining critical network elements and contingencies relevant to capacity calculation

The critical network elements and contingencies considered and applied in the intraday capacity calculation process, and described in Article 5 of the Nordic ID CCM, are valid for the balancing timeframe. No additional critical network elements and contingencies are applied.

Article 6
Methodology for allocation constraints

The allocation constraints considered and applied in the intraday capacity calculation process, and described in Article 6 of the Nordic ID CCM, are equally valid for the balancing timeframe. Ramping limitations, as defined in the methodology in accordance with Article 176 of the SO regulation, for HVDC links shall be treated as allocation constraints. In addition, the following allocation constraints apply in the balancing timeframe:

(a) Limitations of amount of polarity reversals (zero-crossings) on HVDC links for a given period of time; and

(b) Minimum flow on HVDC links.

Article 7
Methodology for determining generation shift keys (GSKs)

The generation shift keys (hereafter referred to as “GSKs”) considered and applied in the intraday capacity calculation process, and described in Article 7 of the Nordic ID CCM, are equally valid for the balancing timeframe.

Article 8
Methodology for determining remedial actions (RAs) to be considered in capacity calculation

The remedial actions (hereafter referred to as “RAs”) reflected in the FB parameters resulting from the intraday capacity calculation process, following from the Nordic regional operational security coordination (hereafter referred to as “ROSC”) process and described in Article 8 of the Nordic ID CCM, are the starting point for the validation process in the balancing timeframe. During the validation process the RAs applied for the intraday timeframe can be reconsidered for the balancing timeframe.

Article 9
Already allocated cross-zonal capacities

On the balancing timeframe, capacity has already been allocated on the long term (hereafter referred to as “LT”), day ahead (hereafter referred to as “DA”), and intraday (hereafter referred to as “ID”) timeframes. This is considered in the Already Allocated Capacity (hereafter referred to as “AAC”) as described in Article 11.

TITLE 3
Description of the capacity calculation process for the balancing timeframe

Article 10
Rules for calculating Cross-Zonal Capacity

The capacity calculation process for the balancing timeframe and for each market time unit within this timeframe is as follows:

a) The single intraday coupling (hereafter referred to as “SIDC”) shall send the latest available AAC in the intraday timeframe to the CCC.
b) If the CGM is updated after the intraday timeframe, the merging agent shall provide the latest available CGM to the CCC for the calculation of FB parameters in accordance with Article 12 of the ID CCM.
c) The CCC shall apply the latest available FB parameters, or the FB parameters resulting from the capacity calculation in b) for the balancing timeframe.
d) The CCC shall send the FB parameters for the balancing timeframe to each TSO for validation.
e) Each TSO has the right to adjust the FB parameters before sending the final validated FB parameters, together with allocation constraints, to the CMM in accordance with the deadlines set by the CMM.

Article 11
Rules for taking into account previously allocated cross-zonal capacity

1. The TSOs shall take into account the previously allocated capacity as follows for the balancing timeframe:

    (a) Capacity allocated for nominated Physical Transmission Rights (PTRs);

    (b) Capacity allocated in the DA and ID markets

    (c) Capacity reserved for cross-zonal exchange of balancing services, except those balancing services in accordance with Article 22(2)(a) of the CACM Regulation.

2. The CCC shall take into account the previously allocated cross-zonal capacities such that the calculation of the RAM takes into account the flows resulting from previously allocated cross-zonal capacities in accordance with Article 29(7)(c) of the CACM Regulation.

3. The flows resulting from allocated cross-zonal capacities for the DA and ID timeframes, and reserved for the balancing timeframes, in accordance with Article 29(7)(c) of the CACM Regulation shall be calculated for each CNEC and combined dynamic constraint in accordance with the Article 16(5) of the Nordic ID CCM.

Article 12
Description of the calculation of available margins on critical network elements before validation

1. The FB parameters that result from the intraday capacity calculation process describe a RAM after validation that contains a capacity reservation for balancing services:

$$\overrightarrow{RAM}_{IDCC} = \vec{F}_{max} + \vec{F}_{RA} - \vec{F}_{RM} - \vec{F}_0 - \vec{F}_{AAC\ (DA+ID)} - \vec{F}_{AAC\ (BT)} - IVA_{ID}$$

Equation 1

2. The CCC shall calculate the RAM before validation for each CNEC and combined dynamic constraint for the balancing timeframe as follows:

$$\overrightarrow{RAM}_{bv} = \overrightarrow{RAM}_{IDCC} + \vec{F}_{AAC\ (BT)}$$

Equation 2

with

$\overrightarrow{RAM}_{IDCC}$	final remaining available margin for the intraday timeframe
$\overrightarrow{RAM}_{bv}$	remaining available margin before validation for the balancing timeframe
$\vec{F}_{max}$	maximum flow on all CNECs and combined dynamic constraints, as resulting from the intraday capacity calculation
$\vec{F}_{RA}$	flow for increasing the RAM on a CNEC or combined dynamic constraints due to RAs taken into account in capacity calculation, as resulting from the intraday capacity calculation

$\vec{F}_{RM}$	flow for reliability margin for all CNECs and combined dynamic constraints, as resulting from the intraday capacity calculation
$\vec{F}_0$	linear approximation of a flow in the reference net position on a CNEC or combined dynamic constraint in a situation without any cross-zonal exchanges, as resulting from the intraday capacity calculation
$\vec{F}_{AAC(DA+ID)}$	flows resulting from previously allocated, or reserved cross-zonal, capacities for all CNECs and combined dynamic constraints for day-ahead and intraday timeframe
$\vec{F}_{AAC(BT)}$	flows resulting from previously allocated, or reserved cross-zonal, capacities for all CNECs and combined dynamic constraints for balancing timeframe
IVA_{ID}	individual validation adjustment for the intraday timeframe

3. When the RAM value calculated pursuant to paragraph 2 is negative it shall be applied as is.

Article 13
Rules for sharing the power flow capabilities of CNECs among different CCRs

The FB parameters calculated for bidding zone borders outside the Nordic CCR are part of the intraday FB parameters that serve as the basis for the balancing timeframe.

TITLE 4
Description of capacity validation for the balancing timeframe

Article 14
Methodology for the validation of cross-zonal capacity

1. Each TSO may perform a validation of cross-zonal capacities on its bidding zone border(s), defined by the FB parameters on its CNECs and combined dynamic constraints, to ensure that the results of regional calculation of cross-zonal capacity will ensure operational security. When performing the validation, the TSOs shall consider operational security, taking into account new and relevant information obtained during or after the most recent capacity calculation.

2. RAM_{bv} calculated in accordance with Article 12(2) may be adjusted during the validation by applying individual validation adjustment (IVA_{BT}) to take into account relevant information known at the time of validation in accordance with paragraph 1. IVA_{BT} can only be a positive value indicating a reduction of cross-zonal capacities.

3. The final FB parameters available for capacity allocation shall be the latest PTDF calculated in the capacity calculation and the RAM calculated as follows:

$$\overrightarrow{RAM} = \overrightarrow{RAM}_{bv} - \overrightarrow{IVA}_{BT}$$

Equation 3

with

$\overrightarrow{RAM}$	final remaining available margin
$\overrightarrow{RAM}_{bv}$	remaining available margin before validation

$\overrightarrow{IVA}_{BT}$	individual validation adjustment at the balancing timeframe

TITLE 5
Miscellaneous

Article 15
Transitional solution for calculation and allocation of balancing timeframe cross-zonal capacities

Until the European balancing platforms are able to support the allocation of cross-zonal capacity based on FB parameters, the CCC shall transform the final FB parameters as referred to in Article 14 into available transmission capacity (‘ATCE’) values on bidding zone borders of the Nordic CCR and bidding zone borders of neighbouring CCRs if the latter are included in the capacity calculation pursuant to Article 13. For each balancing market time unit, one set of ATCE values shall be calculated in accordance with Article 20 of the Nordic ID CCM.

Article 16
Fallback procedure if the initial capacity calculation does not lead to any results

The FB parameters computed for the intraday timeframe, by using dedicated intraday CGMs, will be updated for the balancing timeframe, by taking into account the already allocated capacities from the intraday and balancing timeframes. As such, the left-over capacity – being the capacity remaining after the intraday timeframe – can be provided to the balancing timeframe for the exchange of balancing energy or for operating the imbalance netting process. If this process does not lead to a result, the capacity reserved for the cross-zonal exchange of balancing services will be released as fallback capacity for the balancing timeframe.

Article 17
Publication of data

1. In accordance with Article 12 of the EB Regulation aiming at ensuring and enhancing the transparency and reliability of information to all Nordic regulatory authorities and market participants, all TSOs and the CCC shall regularly publish the data on the balancing timeframe capacity calculation process pursuant to this methodology as set forth in paragraph 2 on a dedicated online communication platform.

2. The TSOs 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) final FB parameters for each balancing market time unit pursuant to Article 14; and
    b) in case of application of transitional solution pursuant to Article 15 for each balancing market time unit the ATCE values for all bidding zone borders in Nordic CCR calculated pursuant to Article 15;

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

TITLE 6
Final Provisions

Article 18
Publication and Implementation

1. The TSOs shall publish the CCM without undue delay after all Nordic regulatory authorities have approved the CCM or a decision has been taken by the Agency for the Cooperation of Energy Regulators in accordance with Article 5(6), Article 5(7) and Article 6 of the EB Regulation.

2. Following Article 5(5) of the EB Regulation, the implementation timescale of this CCM shall not be longer than 12 months after the approval by the relevant regulatory authorities, except where all relevant regulatory authorities agree to extend the implementation timescale. The implementation will follow a stepwise approach, where in the first step intraday left-over capacities are shared with the balancing platforms as ATCE values, followed by the second step in which FB parameters are shared with the balancing platforms when these platforms are capable to handle the FB parameters.

Article 19
Language

The reference language for this CCM shall be English. For the avoidance of doubt, where TSOs need to translate this CCM into their national language(s), in the event of inconsistencies between the English version published by TSOs in accordance with Article 7 of the EB Regulation and any version in another language, the relevant TSOs shall be obliged to dispel any inconsistencies by providing a revised translation of this CCM to their relevant national regulatory authorities.

Annex 1 – Relevant articles from the intraday CCM approved by Nordic regulatory authorities (dated 14 October 2020)

Article 3
Methodology for determining reliability margin

1. The TSOs shall determine the reliability margin as follows:
   (a) The reliability margin (hereafter referred to as "RM") is determined for AC grid elements only.
   (b) A probability distribution of the deviation between the expected and realized (observed) power flows is determined at least annually for each AC CNEC and combined dynamic constraint, based on historical snapshots of the CGM for different market time units. The realized (observed) power flows for each CNEC and combined dynamic constraint are obtained from the snapshot, where also the potential contingencies associated with this CNEC and combined dynamic constraint are taken into account. The net positions from the snapshot are used with the FB parameters or in the CGM to compute the expected power flows. The differences between the realized and expected power flows (in MW) form the prediction error distribution for each CNEC and combined dynamic constraint. The prediction errors shall be fitted to a statistical distribution that minimizes the modelling error.
   (c) The reliability margin value shall be calculated by deriving a value from the probability distribution based on the TSOs risk level value as defined in paragraph 5.
   (d) The unintended deviations of the physical electricity flows within a market time unit, caused by the adjustment of electricity flows within and between control areas, to maintain a constant frequency (frequency containment reserve), are not part of the reliability margin described in paragraphs 1(a) – 1(c) and need to be assessed separately (hereafter referred to as "FCR margin"). The final RM value is the sum of the RM value and the FCR margin; the TSO shall send this RM values as input data to the CCC.

2. The principles for calculating the probability distribution of the deviations between the expected power flows at the time of the capacity calculation and realized power flows in real time are as follows:
   (a) The methodology for RM determination described in paragraphs 1(a) – 1(c) is applied on all CNECs and combined dynamic constraints; and
   (b) Separate distributions are formed for capacities that are calculated based on CGMs for day-ahead and intraday capacity calculation timeframes.

3. The uncertainties covered by the RM values, described in the paragraph 1 originate from various elements, such as:
   (a) Uncertainty in load forecast;
   (b) Uncertainty in generation forecasts (generation dispatch, wind prognosis, etc.);
   (c) Assumptions inherent in the generation shift key (hereafter referred to as "GSK") strategy;
   (d) Uncertainty in external trades to adjacent synchronous areas;
   (e) Application of a linear grid model (with the power transfer distribution factors (hereafter referred to as the "PTDFs")), constant voltage profile and reactive power;
   (f) Topology changes due to e.g. unplanned outages of network elements;
   (g) Internal trade in each bidding zone; and
   (h) Grid model errors, assumptions and simplifications.

4. The margin caused by the activation of the frequency containment reserve (hereafter referred to as "FCR") shall be modelled separately and added to the RM, pursuant to paragraph 1(d). The following approach shall be applied:

   (a) The FCR power flow impact shall be computed for each CNEC and combined dynamic constraint based on historical information, forming FCR power flow distributions; and

   (b) The FCR margin value for each CNEC and combined dynamic constraint shall be calculated by deriving a value from the probability distribution based on the TSOs risk level value as defined in paragraph 5.

5. The TSOs shall take into account the operational security limits, the power system uncertainties and the available RAs when determining the risk level for their CNECs and combined dynamic constraints to ensure the system security and efficient system operation. This risk level shall determine how the RM value and FCR margin value shall be derived from their probability distributions. The risk level is defined as the area (cumulative probability) right of the RM value and FCR margin value in their probability distribution. The TSOs shall use the predefined risk level of 95%.

6. The TSOs shall store the differences between the realized and expected flows in a database that allows the TSOs to make statistical analyses.

7. The probability distributions, RM values, and FCR margin values, shall be stored in a standardized data format for each CNEC and combined dynamic constraint. The RM value shall be defined and stored as an absolute value (in MW). It may be converted for comparison purposes to a percentage of the CNEC's or combined dynamic constraint's maximum flow (hereinafter referred to as "F_{max}").

8. The TSOs shall perform the calculation of the RM regularly and at least once a year applying the latest information, for the same period of analysis for the RM and FCR margins, on the probability distribution of the deviations between expected power flows at the time of capacity calculation and realized power flows in real time.

Article 4
Methodology for determining operational security limits

1. Each Nordic TSO shall provide to the CCC for each CNEC, day-ahead and intraday capacity calculation timeframe and each scenario the operational security limits, which are needed by the CCC to calculate the maximum flow on CNECs in accordance with Article 29(7)(c) of the CACM Regulation. For each of the operational security limit defined pursuant to paragraph 2, the concerned TSO shall specify the CNEC(s) to which these limits should be applied and translated into maximum flow on CNECs.

2. Each TSO shall apply the same operational security limits as in the operational security analysis. These limits shall be defined in accordance with Article 25 of the SO Regulation. The TSOs shall provide these operational security limits to the CCC in the following format describing a specific power system physical property:

   (a) thermal limits shall be expressed in maximum admissible current (I_{max}) with the unit of Ampere;

   (b) voltage limits shall be expressed in nominal voltage (per unit);

   (c) frequency limits shall be expressed in Hertz; and

   (d) dynamic stability limits shall be expressed in (i) per unit for voltage stability and (ii) damping for electromechanical oscillations.

3. The maximum admissible current representing thermal limit according to paragraph 2(a) shall be defined as follows:
    (a) the maximum admissible current representing thermal limits shall be defined as fixed limit for each scenario representing the ambient conditions of this scenario.
    (b) when applicable, the maximum admissible current representing thermal limits 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) the maximum admissible current representing thermal limits shall represent only real physical properties of the CNE and shall not be reduced by any security margin.

4. TSOs shall regularly review and update operational security limits in accordance with Article 24.

Article 5
Methodology for determining critical network elements and contingencies relevant to capacity calculation

1. Each Nordic TSO shall define a list of CNEs, which are fully or partly located in its own control area, and which can be, *inter alia*, overhead lines, underground cables and transformers. All cross-zonal network elements shall be defined as CNEs, whereas only those internal network elements, which are defined pursuant to paragraphs 5 to 7 shall be defined as CNEs. Until 30 days after the approval of the proposal pursuant to paragraph 5, all internal network elements may be defined as CNEs.

2. Each Nordic TSO 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 Nordic TSO shall be located within the observability area (as defined in Article 3(2)(48) of the SO Regulation) of that Nordic TSO. This list shall be updated at least on a yearly basis and in case of topology changes in the grid of the Nordic TSO, pursuant to Article 24. A contingency can be, inter alia, 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 such network elements.

3. Each Nordic TSO shall establish a list of CNEs associated with a contingency (CNECs) by associating the contingencies established pursuant to paragraph 2 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.

4. Each TSO shall provide to the CCC for day-ahead and intraday timeframe and each scenario a list of CNECs established pursuant to paragraph 3.

5. No later than eighteen months after the implementation of this methodology in accordance with Article 26(2), all TSOs shall jointly develop a proposal for amendment of this methodology in accordance with Article 9(13) of the CACM Regulation, which shall improve this methodology by including a method for assessing the economic efficiency of increasing margin on internal network elements (combined with the relevant contingencies) in the day-ahead and intraday capacity calculation. This proposal shall be submitted by the same deadline to Nordic regulatory authorities for approval.

6. The methodology referred to in paragraph 5 shall define a process by which TSOs regularly, at least annually, analyse and identify internal network elements on which congestions are most efficiently addressed with day-ahead and intraday capacity calculation, taking into account other alternative measures for managing congestions on internal network elements, such as:

   (a) application of RA;

   (b) reconfiguration of bidding zones;

   (c) investments in network infrastructure combined with one or the two above; or

   (d) any combination of (a), (b) and (c).

7. The methodology referred to in paragraphs 5 and 6 shall also ensure that TSOs take into account different timescales needed to implement alternative solutions such that including internal network elements in capacity calculation is allowed only until the alternative solution(s), which are identified as more efficient, can be implemented.

8. The TSOs shall regularly review and update the application of the methodology for determining CNECs as defined in Article 24.

Article 6
Methodology for allocation constraints

1. In case operational security limits cannot be transformed efficiently into maximum flow on specific CNECs pursuant to Article 4, the TSOs may transform them into allocation constraints and provide them to the CCC to be used in the day-ahead and intraday capacity calculation. For this purpose, the TSOs may use the combined dynamic constraint, which limits the sum of power flows on a set of network elements, for the purpose to respect the dynamic stability limits. These TSOs shall provide to the CCC the F_{max} for each defined combined dynamic constraint and the information on which network elements are combined into such combined dynamic constraint.

2. Allocation constraints pursuant to paragraph 1 may be used during a transition period of two years following the implementation of this methodology in accordance with Article 26(2). During this transition period, the concerned TSOs shall calculate the value of each combined dynamic constraint by performing a dynamic stability analysis in accordance with Article 38 of the SO Regulation at least on an annual basis and updated on a monthly basis, if relevant. The concerned TSOs shall publish the results and the underlying analysis.

3. In case the concerned TSOs cannot find and implement a more efficient solution than the applied combined dynamic constraint, they may, by eighteen months after the implementation of this methodology in accordance with Article 26(2), together with all other TSOs, submit to the Nordic 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 combined dynamic constraint indicating the underlying operational security limits and why they cannot be transformed efficiently into maximum flow on specific CNECs; and

(b) a detailed methodology to calculate the values of the combined dynamic constraints.

In case such a proposal has been submitted by all TSOs, the transition period referred to in paragraph 2 shall be extended until the decision on the proposal is taken by the Nordic regulatory authorities.

4. TSOs applying allocation constraints shall regularly review and update the application of allocation constraints in accordance with Article 24.

5. In addition, TSOs may apply other allocation constraints in day-ahead and intraday timeframe in accordance with Article 23(3) of the CACM Regulation. The relevant TSOs shall provide these allocation constraints to the CCC. The TSOs may apply either of the following allocation constraints:

   (a) Ramping rates: Ramping rates define the maximum flow changes on HVDC interconnections between market time units. Due to imbalances generated by flows on HVDC interconnections between market time units, ramping rates are needed in order to maintain the stability of the power system. Ramping rates ensure that the maximum flow change on HVDC interconnections between market time units is kept within the available balancing power reserves or within the technical limits of HVDC interconnections.

   (b) Implicit loss factors: The implicit loss factors on HVDC interconnections account for the power loss on HVDC interconnections by the following equation:

$$\textit{Export quantity} = (1 - \textit{"Loss Factor"}) * \textit{Import quantity}$$

Equation 1

The implicit loss factor is a correction mechanism for a negative external effect incentivising the market to respect the cost of electricity losses on HVDC interconnections in the market coupling. The implicit loss factor may be applied on an HVDC interconnection if an EU-wide welfare economic benefit can be demonstrated to the NRAs.

6. Each TSO applying the allocation constraints according to paragraph 5 shall communicate and justify application of those constraints to the market participants.

Article 7
Methodology for determining generation shift keys (GSKs)

1. Each Nordic TSO shall provide to the CCC for each of the bidding zone under its responsibility, day-ahead and intraday capacity calculation timeframe and each scenario, the GSK to be used in the day-ahead and intraday capacity calculation.

2. GSKs shall define how a net position change in a given bidding zone shall be distributed to each production and load unit on that bidding zone in the CGM. These GSKs shall represent the best forecast of the relation of a change in the net position of a bidding zone to a specific change of generation or load in the CGM for each scenario. The forecast shall take into account the information received in accordance with Article 10 and Article 12 of the generation and load data provision methodology developed by all TSOs in accordance with Article 16 of the CACM Regulation.

3. Each TSO shall apply for a given bidding zone and the given scenario one of the GSK strategies listed below:

Strategy number	Generation	Load	Description/comment

0	k_g	k_l	Custom GSK strategy with individual set of GSK factors for each generator unit and load for each market time unit for a TSO
1	$\max\{P_g - P_{min}, 0\}$	0	Generators participate relative to their margin to the generation minimum (MW) for the unit
2	$\max\{P_{max} - P_g, 0\}$	0	Generators participate relative to their margin to the installed capacity (MW) for the unit
3	P_{max}	0	Generators participate relative to their maximum (installed) capacity (MW)
4	1.0	0	Equal GSK factors for all generators, independently of the size of the generator unit
5	P_g	0	Generators participate relative to their current power generation (MW)
6	P_g	P_l	Generators and loads participate relative to their current expected power generation or loading power (MW)
7	0	P_l	Loads participate relative to their expected loading power (MW)
8	0	1.0	Equal GSK factors for all loads, independently of their expected size of loading power

where

k_g : GSK factor [pu] for generator g

k_l : GSK factor [pu] for load l

P_g : Active power generation [MW] for generator *g* contained in CGM

P_{min} : Minimum active generator output [MW] for generator g
P_{max} : Maximum active generator output [MW] for generator *g*
P_l :Active power load [MW] for load l contained in CGM

4. Within eighteen months after the implementation of this methodology in accordance with Article 26(2), all TSOs shall develop a proposal for amendment of this methodology in accordance with Article 9(13) of the CACM Regulation, which shall further harmonise the generation shift key methodology. This proposal shall be submitted by the same deadline to the Nordic regulatory authorities for approval. 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 GSK methodology.

5. TSOs shall regularly review and update the application of the GSKs in accordance with Article 24.

Article 8
Rules for avoiding undue discrimination between internal and cross-zonal exchanges

1. The TSOs shall take actions to avoid undue discrimination between internal and cross-zonal exchanges in accordance with Article 16(8) of the Regulation (EU) 2019/943.

2. In a short-term perspective the TSOs shall apply RAs in accordance with Article 17 based on the assessment according to Article 9 and 10.

3. In a mid-term perspective, the TSOs shall review the existing bidding-zone configuration in accordance with Article 32 of the CACM Regulation. In this review, the TSOs shall study whether a reconfiguration of bidding zones would bring benefits in accordance with Article 33 of the CACM Regulation.

4. In a long-term perspective, the TSOs shall consider efficient investments.

Article 12
Description of the applied capacity calculation approach with different capacity calculation inputs

1. The capacity calculation process for the day-ahead and intraday timeframe shall use the FB process.

   The capacity calculation process for the day-ahead and intraday timeframe and for each market time unit within these timeframes is as follows:

   (a) Each TSO shall create an IGM for its bidding zone(s) and send it to the merging agent for merging IGMs to build the CGM in accordance with Article 17 of the CACM Regulation. The IGM shall include dynamic data for the CCC to facilitate dynamic stability analysis in capacity calculation in accordance with Table 1 of Article 26;

   (b) The merging agent shall send the CGM to the CCC for calculation of F_{max};

   (c) Each TSO shall send GSK strategies as defined in Article 7 to the CCC for calculation of F_{max};

   (d) Each TSO shall send contingencies for its bidding zone(s) determined in accordance with Article 5 to the CCC for calculation of F_{max};

   (e) Each TSO shall send operational security limits for its bidding zone(s) determined in accordance with Article 4 to the CCC for calculation of $F_{max.}$ A TSO may transform operational security limits for dynamic stability into allocation constraints and send these as combined dynamic constraints defined in accordance with Article 6(1) to the CCC for calculation of F_{max};

   (f) Each TSO shall send CNECs for its bidding zone(s) determined in accordance with Article 5 to the CCC to be considered in capacity calculation;

   (g) The CCC shall calculate F_{max} for each CNEC in accordance with Article 17 applying the CGM, GSKs, contingencies, operational security limits, combined dynamic constraints, and CNECs submitted by each TSO;

   (h) Each TSO shall send RM for each CNEC determined in accordance with Article 3 to the CCC for calculation of RAMs;

   (i) Each TSO shall send AAC for each CNEC determined in accordance with Article 16 to the CCC for calculation of RAMs;

   (j) Each TSO shall send RA for each CNEC determined in accordance with Article 9 and Article 10 to the CCC for calculation of RAMs;

   (k) The CCC shall calculate RAM for each CNEC and combined dynamic constraint determined in accordance with Article 17 and PTDFs in accordance with Article 13 taking into account rules for sharing the power flow capabilities of CNECs among different CCRs in accordance with Article 18;

   (l) The CCC shall send FB parameters calculated in accordance with Article 13 and Article 17 to each TSO for validation in accordance with Article 19;

(m) Each TSO shall send validated FB parameters, including adjustments to FB parameters, to the CCC;

(n) Each TSO shall send allocation constraints determined in accordance with Article 6(5) to the CCC;

(o) The CCC shall send the validated FB parameters and allocation constraints to relevant NEMOs for the purpose of allocating cross-zonal capacity by MCO in accordance with the CACM Regulation;

(p) Relevant NEMOs shall publish validated FB parameters and allocation constraints to the market in accordance with Article 46(1) of the CACM Regulation; and

(q) The CCC shall publish validated FB parameters, allocation constraints and other information requested in accordance with Article 25.

2. The capacity calculation process shall be performed by the CCC and shall provide the following capacity calculation results to be validated by each TSO:

   (a) Calculation of the PTDF matrix, where each factor in the matrix, $PTDF_j^A$, represents the percentage of 1 MW injected in bidding zone A, and extracted from a defined slack node, that will appear on the CNEC or combined dynamic constraint j in accordance with Article 13; and

   (b) Calculation of the RAM for each CNEC and combined dynamic constraint, which shall be the amount of transmission capacity available for capacity validation and determined in accordance with Article 17.

3. The PTDF matrix and RAM vector shall form FB parameters describing the available transmission capacity between relevant bidding zones to be validated by capacity validation in accordance with Article 19.

Article 16
Rules for taking into account previously allocated cross-zonal capacity

1. The TSOs shall take into account the previously allocated capacity as follows:

   (a) For day-ahead and intraday timeframe, capacity allocated for nominated Physical Transmission Rights (PTRs);

   (b) For day-ahead and intraday timeframe, capacity allocated for cross-zonal exchange of balancing services, except those balancing services in accordance with Article 22(2)(a) of the CACM Regulation; and

   (c) For intraday timeframe, capacity allocated for day-ahead timeframe.

2. The CCC shall take into account the previously allocated cross-zonal capacities such that the calculation of the RAM takes into account the flows resulting from previously allocated cross-zonal capacities in accordance with Article 29(7)(c) of the CACM Regulation.

3. Previously allocated cross-zonal capacities, applied for balancing capacity purposes, in accordance with Article 29(7)(c) of the CACM Regulation shall be calculated for each CNEC and combined dynamic constraint by multiplying the volumes of previously allocated cross-zonal capacities with the positive zone-to-zone $PTDFs$, i.e:

$$F_{AAC} = max\ (0, PTDF_{z2z}) \cdot \overrightarrow{AAC}$$

Equation 5

with

F_{AAC}	flows resulting from previously allocated cross-zonal capacities for each CNEC and combined dynamic constraint
$PTDF_{z2z}$	zone-to-zone PTDFs calculated in accordance with Article 13(5)
$\overrightarrow{AAC}$	previously allocated cross-zonal capacities

4. The flows resulting from nominated previously allocated cross-zonal capacities for long-term timeframes, in accordance with Article 29(7)(c) of the CACM Regulation shall be calculated for each CNEC and combined dynamic constraint by multiplying the volumes of previously allocated cross-zonal capacities with the zone-to-zone $PTDFs$, i.e:

$$F_{AAC} = PTDF_{z2z} \cdot \overrightarrow{AAC}$$

Equation 6

with

F_{AAC}	flows resulting from previously allocated cross-zonal capacities for each CNEC and combined dynamic constraint
$PTDF_{z2z}$	zone-to-zone PTDFs calculated in accordance with Article 13(5)
$\overrightarrow{AAC}$	previously allocated cross-zonal capacities

5. For the intraday timeframe, the flows resulting from nominated cross-zonal capacities for the previous timeframes, in accordance with Article 29(7)(c) of the CACM Regulation shall be calculated for each CNEC and combined dynamic constraint by multiplying the net positions of previously allocated cross-zonal capacities with the zone-to-slack $PTDFs$, i.e:

$$F_{AAC} = PTDF_{z2s} \cdot \overrightarrow{NP_{AAC}}$$

Equation 7

with

F_{AAC}	flows resulting from previously allocated cross-zonal capacities for each CNEC and combined dynamic constraint
$PTDF_{z2s}$	zone-to-slack PTDFs calculated in accordance with Article 13(3)
$\overrightarrow{NP_{AAC}}$	Net positions of previously allocated cross-zonal capacities

Article 20
Transitional solution for calculation and allocation of intraday cross-zonal capacities for continuous trading in the Intraday timeframe

1. Until the single intraday coupling in accordance with Article 51 of the CACM Regulation is able to support the allocation of cross-zonal capacities based on FB parameters, the CCC shall transform the final FB parameters as referred to in Article 19 into available transmission capacity ('ATC') values on bidding zone borders of the Nordic CCR and bidding zone borders of neighbouring CCRs if the latter are included in capacity calculation pursuant to Article 18. For each market time unit, one set of ATC values shall be calculated.

2. The available transfer capacity ATC^n (where $ATC^n \in ATC$, and ATC is a vector of maximum allowed power exchange on all bidding zone borders) shall be calculated as:

$$\text{Maximize } f(\overrightarrow{ATC})$$

$$\text{Subject to}$$

$$g_j\Big(\sum_n ATC^n * PTDF_j^n\Big) \leq h_j(RAM_j) \qquad \forall j \in \{All\ CNEs\ and\ allocation\ constraints\}$$

Equation 12

with

f	a function defining the weight for each border in the optimisation
g_j	a function defining the weight of each trade in the total flow on CNE j
h_j	a function defining the scaling of CNEs in non-relevant market directions
ATC^n	maximum available power exchange on bidding zone border n
$\overrightarrow{ATC}$	a vector of maximum available power exchanges for all borders
$PTDF_j^n$	zone-to-zone PTDF for bidding zone border n

3. Two months before the application of this transitional solution, the Nordic TSOs shall publish the exact values and parameters of the functions f, g and h, including their description, purpose and effect. During the development process of the functions f, g and h, Nordic regulatory authorities and stakeholders will be informed, and they may provide comments duly to be taken into account in development work.

4. No later than eighteen months after the implementation of this methodology in accordance with Article 26(2), all TSOs shall jointly develop a proposal for amendment of this methodology in accordance with Article 9(13) of the CACM Regulation, which shall improve this methodology by including the description and definition of the functions referred to in paragraph 3. This proposal shall be submitted by the same deadline to all Nordic regulatory authorities for approval.

5. Any update to the transitional solution, affecting the results of the calculation pursuant to paragraph 2, shall be done in accordance to Article 20(3) and 20(4).