# 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

9 February 2026

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

## Whereas

(1) This document is a common proposal for the third amendment (hereafter referred to as "This Amendment") developed by 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 15 of Commission Regulation (EU) 2015/1222 establishing a guideline on Capacity Allocation and Congestion Management (hereafter referred to as the "CACM Regulation") regarding a methodology for Capacity Calculation (hereafter referred to as "CCM") in accordance with Article 20 and Article 21 of the CACM Regulation.

(2) All regulatory authorities of Nordic CCR (hereafter referred to as the "Nordic regulatory authorities") approved the first CCM in July 2018. These regulatory authorities sent a request for amendment (hereafter referred to as "RfA") to all TSOs in December 2018 in accordance with Article 9(13) of the CACM Regulation. All TSOs submitted to all Nordic regulatory authorities a first proposal for amendment (hereafter referred to as the "First Amendment) regarding methodology for Capacity Calculation in accordance with Article 20(2) and Article 21 of the CACM Regulation. The First Amendment was approved by all Nordic regulatory authorities in autumn 2019.

(3) The First Amendment took into account the requested changes to the capacity calculation methodology listed in the RfA. It expanded Article 4(1) of the approved methodology to state that each TSO is required to provide the operational security limits to the CCC in an appropriate format compliant with the RfA. The First Amendment included a capacity calculation process in a written format clarifying the roles and responsibilities of TSOs and the CCC. In addition, the First Amendment took into account the request that the TSOs start to develop an appropriate grid model in coordination with each other, in order for the CCC to handle dynamic stability in capacity calculation.

(4) The Second Amendment took into account the general principles and goals set in the CACM Regulation as well as Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market of electricity (hereafter referred to as "Regulation (EU) 2019/943"). 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, and it sets requirements for the TSOs to co-operate on the level of CCR for coordinated capacity calculation.

(5) The Second Amendment, which substituted entirely the First Amendment, aligned the CCM for day-ahead and intraday timeframe with the capacity calculation methodology for the long-term timeframe as decided by ACER in the decision No 16/2019.

(6) The Second Amendment provided a transition period for the allocation of intraday cross-zonal capacities based on flow-based (hereafter referred to as "FB") parameters. Until the single intraday coupling was able to allocate cross-zonal capacities using the FB parameters, the TSOs may convert the FB parameters resulting from the application of the FB approach into available transfer capacities ('ATC') for each bidding zone border to be used for intraday capacity allocation by the single intraday coupling.

(7) This third amendment aligns with the required updates forwarded in article 5.5, 6.3, 7.4 and 20.4 in the second amendment. This third amendment aligns Article 24 in the second amendment, the process of publishing input data for capacity calculation, with Article 14.3 in the CACM Regulation. This third amendment removes the explicit requirement to develop, deliver and apply dynamic CGMs for capacity calculation. This third amendment includes updates to the FRM methodology.

(8) According to Article 9(9) of the CACM Regulation, the expected impact of the proposal on the objectives of the CACM Regulation shall be described. This amendment contributes to and does not in any way hamper the achievement of the objectives of Article 3 of the CACM Regulation. In particular this Amendment serves the same objectives as the approved CCM. In addition, this amendment harmonises the CCM across long-term, day-ahead and intraday timeframes defining the same transitional solution for intraday timeframe as defined for the long-term timeframe.

(9) This amendment promotes effective competition in the generation, trading and supply of electricity (Article 3(a) of the CACM Regulation) by supporting fair and equal access to the transmission system as it applies to all market participants on all bidding zone borders in Nordic CCR. Market participants will have access to the same reliable information on cross-zonal capacities and allocation constraints for the day-ahead and the intraday allocation, in a transparent way. The FB approach does not implicitly pre-select or exclude bids from market participants and, hence the competitiveness of bidding is the only criteria on which bids of market participants are selected during the matching, yet taking the significant grid constraints into consideration. The CCM applies remedial actions (hereafter referred to as “RAs”), increasing cross-zonal capacity and capacity on internal critical network elements (hereafter referred to as “CNE”) in order to improve effective competition between internal and cross-zonal trades, taking operational security and economic efficiency into account.

(10) This amendment secures optimal use of the transmission capacity (Article 3(b) of the CACM Regulation) as it takes advantage of the FB approach, representing the limitations in the alternating current (hereafter referred to as “AC”) grids. The approach aims at providing the maximum available capacity to market participants within the operational security limits. There is no predefined and static split of the capacities on CNEs. The flows within the Nordic CCR and between the Nordic CCR and adjacent CCRs are decided based on economic efficiency during the capacity allocation phase. The CCM treats all bidding zone borders within the Nordic CCR and adjacent CCRs equally and provides non-discriminatory access to the cross-zonal capacity. For the intraday timeframe, the transitional solution ensures better use of transmission capacity compared to the currently applied method until the FB approach is implemented.

(11) This amendment secures operational security (Article 3(c) of the CACM Regulation) as the grid constraints are taken into account in the day-ahead and intraday timeframe providing the maximum available capacity to market participants within the operational security limits, hereby not allowing for more cross-zonal exchange possibilities than can be supported by the DA FB domain and ID ATC capacity. This supports operational security in a short time perspective, where bidding zone re-configuration will be used in a mid-term perspective and grid investments in the long-term perspective. Furthermore, the TSOs shall include the description of the format used for the provision of operational security limits to the coordinated capacity calculator (hereafter referred to as "CCC"). In addition, operational security is ensured by the development of appropriate grid models and processes in order for the CCC to handle dynamic stability in capacity calculation.

(12) This amendment serves the objective of optimising the calculation and allocation of cross-zonal capacity in accordance with Article 3(d) of the CACM Regulation since the CCM is using the FB approach for the day-ahead timeframe and also for the intraday timeframe - when the

conditions for implementation have been fulfilled - providing optimal cross-zonal capacities to market participants. Better optimisation in the intraday timeframe, compared to the current method, can be achieved with a transitional solution until a FB approach is implemented. Moreover, optimisation of capacity calculation is secured based on coordination between the TSOs, hereby applying a CGM and a CCC.

(13) This amendment serves the objective of transparency and reliability of information (Article 3(f) of the CACM Regulation) as the CCM determines the main principles and main processes for the day-ahead and intraday timeframes. The CCM enables TSOs to provide market participants with the same reliable information on cross-zonal capacities and allocation constraints for day-ahead and intraday allocation in a transparent way. To facilitate transparency, the TSOs publish data to the market on a regular basis to help market participants to evaluate the capacity calculation process.

(14) This amendment does not hinder an efficient long-term operation in the Nordic CCR and adjacent CCRs, and the development of the transmission system in the European Union (Article 3(g) of the CACM Regulation). This amendment, by taking most important grid constraints into consideration, will support efficient pricing in the market, providing the right signals from a long-term perspective.

(15) This amendment contributes to the objective of respecting the need for a fair and orderly market and price formation (Article 3(h) of the CACM Regulation) by making available in due time the cross-zonal capacity to be released in the day-ahead and intraday market.

(16) This amendment provides non-discriminatory access to cross-zonal capacity (Article 3(j) of the CACM Regulation) in accordance with Article 16(8) of Regulation 2019/943.

(17) In conclusion, this amendment contributes to the general objectives of the CACM Regulation to the benefit of market participants and electricity end consumers.

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

# TITLE I
# General

## Article 1
## Subject matter and scope

1. This amendment substitutes entirely the CCM approved by the Nordic regulatory authorities in October 2020.

2. The CCM is the common methodology of all TSOs in Nordic CCR in accordance with Article 20(2) and Article 21 of the CACM Regulation.

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

4. The CCM covers the capacity calculation methodologies for the day-ahead and intraday timeframes.

## 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 Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation (hereafter referred to as "SO Regulation"), Article 2 of the Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing (hereafter referred to as "Balancing 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 a reliability margin and 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. 'cross-zonal network element' means a network element located on the bidding zone border. Any network element whose connecting nodes lie in different bidding zones is considered a cross-zonal network element;
    9. '$F_0$' means the linear approximation of a flow on a CNEC or combined dynamic constraint when all bidding zone net positions are zero;
    10. '$F_{max}$' or '$F_{max}$' means the maximum admissible flow on a CNEC or combined dynamic constraint;
    11. '$F_{RA}$'means the additional flow for increasing the RAM on a CNEC or combined dynamic constraint due to RAs taken into account in capacity calculation;
    12. '$F_{RM}$' or 'FRM' means the combined effect of the RM and FCR margin for all CNECs and combined dynamic constraints;
    13. '$F_{ref}$' means the reference flow on a CNEC or combined dynamic constraint;
    14. 'FCR margin' means the margin needed to cope with the activation of the frequency containment reserves;
    15. 'FCR-N' means Frequency Containment Reserve for Normal operation and aims to maintain the grid frequency within the normal range of 49.9–50.1 Hz;
    16. 'GSK' means the generation shift key as defined in Article 2(12) of the CACM Regulation;

17. ‘HVDC network element’ means a high voltage direct current network element;
18. ‘IGM’ means the individual grid model as defined in Article 2(1) of the CACM Regulation;
19. ‘$I_{max}$’ means the maximum admissible current of a CNE or a CNEC;
20. ‘internal network element’ means a network element, which is not cross-zonal;
21. ‘LFC area’ or ‘load-frequency control area’ means a part of a synchronous area or an entire synchronous area, physically demarcated by points of measurement at interconnectors to other LFC areas, operated by one or more TSOs fulfilling the obligations of load-frequency control;
22. ‘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;
23. ‘NP’ or ‘$NP$’ means a net position of a bidding zone, which is the net value of generation and consumption in a bidding zone;
24. ‘Nordic CCR’ means the Nordic capacity calculation region as determined pursuant to Article 15 of the CACM Regulation;
25. ‘PATL’ means the Permanent Admissible Transmission Loading; the loading in Amps, MVA or MW that can be accepted by a network element for an unlimited duration without any risk for the material;
26. ‘polarity reversal’ means an event on an HVDC interconnection where the power flow is reversed;
27. ‘previously allocated cross-zonal capacities’ means the capacities which have already been allocated;
28. ‘PTDF’ or ‘$PTDF$’ means a power transfer distribution factor;
29. ‘RA’ means a remedial action as defined in Article 2(13) of the CACM Regulation;
30. ‘RAM’ or ‘$RAM$’ means a remaining available margin on a CNEC or a combined dynamic constraint;
31. ‘reference net position’ or ‘reference exchange’ means a position of a bidding zone or an exchange over HVDC interconnection assumed within the CGM;
32. ‘reliability margin’ or ‘RM’ means the reliability margin as defined in Article 2(14) of the CACM Regulation;
33. ‘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;
34. ‘snapshot’ means like a photo of a TSO’s power system state taken from the TSOs’ control system, showing the voltage, currents, and power flows in the power system at the time of taking the photo;
35. ‘TATL’ means the Temporary Admissible Transmission Loading; the loading in Amps, MVA or MW that can be accepted by a network element for a certain limited duration;
36. ‘virtual bidding zone’ means a bidding zone without any buy and sell orders from market participants;
37. ‘zone-to-slack $PTDF$’ means the PTDF of a commercial exchange between a bidding zone and the slack node;
38. ‘zone-to-zone $PTDF$’ means the PTDF of a commercial exchange between two bidding zones;
39. the notation $x$ denotes a scalar;
40. the notation $\vec{x}$ denotes a vector; and

41. 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 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 CACM Regulation, where applicable. However, the delegating TSO shall remain responsible for ensuring compliance with the obligations under the CACM Regulation.

## TITLE 2
## Description of capacity calculation input for day-ahead and intraday timeframe

### 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 realized (observed) and expected 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. Until the observed state CGMs are available, the TSOs may use their observed state IGMs. 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 FRM value is the sum of the RM value and the FCR margin; the TSO shall send this FRM 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 FCR margin shall take into account unintended deviations of physical electricity flows within and between control areas within a market time unit that follow from FCR-N reserve activations within the Nordic LFC areas. The FCR margin shall take into account FCR exchange between the Nordic TSOs to fulfil requirements of Article 163(5) of the SO Regulation and Article 38(4) of the Balancing Regulation. The FCR margin shall be calculated as follows:
   a) Historical data shall be used to determine FCR-N reserve net position for each LFC area. The data shall consist of at least imbalance data and approximated FCR-N reserve activations for each LFC area. The approximation of the FCR-N reserve activation shall take into account FCR-N reserve technical requirements defined in accordance with Article 154(2) of the SO Regulation. The sampling rate of the data shall be at minimum 1 minute and it shall consist of consecutive timestamps over a period of 1 year not ending earlier than 6 months before calculation date.
   b) FCR-N reserve net positions pursuant to paragraph (a) shall be used together with zone-to-slack PTDF to calculate FCR-N flow distribution for each CNEC. The PTDF shall be calculated using a long-term capacity calculation grid model and available information about locations of prequalified FCR-N providing units in the grid at the time of calculation.
   c) The FCR margin value for each CNEC shall be calculated from the FCR-N flow distribution based on the risk level defined in paragraph 5 of this article.

   Until the FCR margin has been assessed, the TSOs will set the FCR margin to zero.

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. These risk levels 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) left of the RM value and

FCR margin value in their probability distribution. The TSOs may not use a greater risk level than 95%. The TSOs shall use a risk level value of 95% for each CNEC or combined dynamic constraint, unless this results in an overly conservative FRM value, in which case the TSO may set a risk level < 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 FRM value for each CNEC and combined dynamic constraint shall be defined and stored as a 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 FRM 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.

9. In case new CNECs or combined dynamic constraints are introduced, and insufficient historical data are available, TSOs can set an FRM value for those CNECs or combined dynamic constraints of no more than 10% of Fmax.

10. For operational security purposes, the TSOs may perform an additional calculation of the FRM. Such assessment shall at least be based on a two-week period of data. The resulting values may be temporarily used, in line with Art 24(3), instead of the FRM values following paragraph 1-9 in this article.

## 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 time frame 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 limits 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, if applicable; and

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

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 (PATL).
   (b) 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.

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 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. 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 time frame and each scenario a list of CNECs established pursuant to paragraph 3.

5. 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. TSOs may apply 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 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:

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

*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 it can be demonstrated, to the Nordic NRAs, that it will not lead to significant external flows, thus increasing the power losses in the transmission grid in the Nordic power system compared to a situation without an implicit loss factor.

(c) Limit on polarity reversals, which defines a maximum amount of polarity reversals on a specific HVDC interconnection per time interval applied. A limit on the polarity reversals may be applied to any HVDC if it is justified by the technical specifications or physical condition of the HVDC interconnection.

(d) The total import or export from one virtual bidding zone to other neighbouring bidding zones may be limited to a specified value equal to the operational capacity of the HVDC interconnector.

2. Each TSO applying the allocation constraints according to paragraph 1 shall communicate and justify application of those constraints to the NRAs and market participants.

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

## Article 7
## Combined dynamic constraints

1. In case dynamic stability limits cannot be transformed efficiently into maximum flow on specific CNECs pursuant to article 4, TSOs may use combined dynamic constraints.

2. Combined dynamic constraints may be used for the purpose of respecting either of the following dynamic stability limits:
    a. voltage stability;
    b. rotor angle stability;
    c. frequency stability.

3. TSOs applying combined dynamic constraints in accordance with paragraph 2 or 5 shall provide to the CCC for each combined dynamic constraint a specification on which network elements are combined into the combined dynamic constraint.

4. The Fmax is determined by a scenario-based assessment, supported by dedicated dynamic tools, and local grid expertise. The resulting Fmax value sets a limit to the secure system operations given the various dynamic effects that may occur in the system.

5. In addition to paragraph 2, without justification of any of the paragraph 2 options, TSOs may also use combined dynamic constraints to represent a border of bidding zones.

6. TSOs applying the combined dynamic constraint shall perform the calculation and provide Fmax for each combined dynamic constraint to the CCC.

## Article 8
## 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 time frame 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<br><br>$k_g$ : GSK factor [pu] for generator g<br><br>$k_l$ : GSK factor [pu] for load l<br><br>$P_g$ : Active power generation [MW] for generator *g* contained in CGM<br><br>$P_{min}$ : Minimum active generator output [MW] for generator g | | | |

| |
|---|
| $P_{max}$ : Maximum active generator output [MW] for generator $g$<br>$P_l$ :Active power load [MW] for load l contained in CGM |

4. TSOs shall perform a comparative study with different GSK strategies applied in their bidding zones. The objective of this study is to identify the GSK strategy for a specific bidding zone that on average shows the lowest RM value over the same period of time. The TSO shall apply this GSK strategy for the specific bidding zone in the capacity calculation process.

5. Performing the study as described in paragraph 4 requires the RM assessment and therefore the observed state CGM to be available. Until the observed state CGMs are available, the TSOs may choose a GSK strategy based on qualitative assessments.

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

## Article 9
## Rules for avoiding undue discrimination between internal and cross-zonal exchanges

1. The Danish, Finnish, and Swedish TSO 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. The Danish, Finnish, and Swedish TSO may apply RA to avoid undue discrimination while ensuring operational security.

2. The Norwegian TSO shall take actions to avoid undue discrimination between internal and cross-zonal exchanges in accordance with Article 21(1)(b)(2) of the CACM Regulation. The Norwegian TSO may apply RA to avoid undue discrimination while ensuring operational security.

## Article 10
## Methodology for determining remedial actions (RAs) to be considered in capacity calculation

1. Each TSO shall define all available non-costly RAs to be taken into account in capacity calculation and provide them to CCC for each day-ahead and intraday market time unit:
    (a) System protection schemes, being an automatic tripping of generation, consumption or grid elements, or changing setpoints of HVDCs, in case of transmission system faults;
    (b) Topology changes, being any changes in grid topology in order to minimise the effect of transmission system faults.

2. Each TSO may define costly RAs to be taken into account in capacity calculation and provide them to CCC for each day-ahead and intraday market time unit:
    (a) To comply to applicable regulatory requirements;
    (b) To manage temporary grid outages or grid investment delays;
    (c) To allow for the application of TATL.

3. Each TSO applies costly RAs to secure the firmness of the capacities:
    (a) Redispatching; and
    (b) Countertrading.

4. Each TSO shall quantify the RAs foreseen to be available in its own control area and to apply them in the capacity calculation. Outage information shall be considered when assessing the availability of costly and non-costly RAs.

5. When a TSO is unable to define explicitly the RAs to be taken into account in capacity calculation and to secure firmness of capacity, due to uncertainty of their actual availability in real-time, but is able to evaluate the approximate adjustment of flows on critical network elements or combined dynamic constraints due to RAs by taking into account the statistics and probability of the availability of RAs, it may provide to the CCC the minimum $F_{RA}$ that needs to be respected when calculating the $F_{RA}$ in accordance with Article 15. When determining this minimum $F_{RA}$, TSOs may also take into account other (non-costly) RAs.

6. The TSO shall coordinate the application of RA to be taken into account in capacity calculation. If applicable, the coordination may be performed bilaterally between TSOs before RAs are provided to the CCC.

7. The TSOs shall regularly review and update the application of RAs taken into account in the capacity calculation in accordance with Article 24.

## Article 11
## Previously allocated cross-zonal capacities

For each Nordic bidding zone border and for day-ahead and intraday capacity calculation time frame, the previously allocated cross-zonal capacities are to be taken into account.

# TITLE 3
# Description of the capacity calculation process for day-ahead and intraday timeframe

## 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.

2. 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.
      i. Until the Common Grid Model is available with a sufficient level of quality and reliability at Union level, the coordinated capacity calculator shall merge at least the individual grid models provided by each TSO of the Nordic capacity calculation region. The CCC shall follow the principles and standards in accordance with article 17 of CACM Regulation.

   (b) The merging agent shall send the CGM to the CCC;

   (c) Each TSO shall send GSK strategies as defined in Article 8 to the CCC;

   (d) Each TSO shall send operational security limits, determined in accordance with Article 4, and combined dynamic constraints, determined in accordance with Article 7, for its bidding zone(s) to the CCC;

(e) 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;

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

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

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

(i) The CCC shall apply the AAC for each CNEC determined in accordance with Article 16 for calculation of RAMs;

(j) 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 and third countries in accordance with Article 18;

(k) 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;

(l) Each TSO shall send validated FB parameters to the CCC;

(m) Each TSO shall send allocation constraints determined in accordance with Article 6(1) to the CCC;

(n) 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;

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

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

3. 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.

4. 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 13
## Description of the calculation of power transfer distribution factors

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

2. In accordance with Article 29(3)(a) of the CACM Regulation, the CCC shall calculate the impact of a change in the bidding zones' net position on the power flow on each CNEC of the initial list of CNECs and on each combined dynamic constraint. This influence is called the zone-to-slack $PTDF$ (i.e. $PTDF_{z2s}$). This calculation is performed by applying the CGM and the GSKs defined in accordance with Article 8.

3. The zone-to-slack $PTDFs$ are calculated by first calculating the node-to-slack $PTDFs$ (i.e. $PTDF_{n2s}$) for each node defined in the GSKs. These node-to-slack $PTDFs$ 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) or on combination of network elements in case of combined dynamic constraint. 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 node-to-slack $PTDFs$ and summing up these products per bidding zone. This calculation is mathematically described as follows:

$$\mathbf{PTDF}_{\mathrm{z2s}} = \mathbf{PTDF}_{\mathrm{n2s}}\, \mathbf{GSK}_{\mathrm{n2z}}$$

*Equation 2*

with

| | |
|---|---|
| $\mathbf{PTDF}_{z2s}$ | matrix of zone-to-slack PTDFs (columns: bidding zones; rows: CNECs and combined dynamic constraints) |
| $\mathbf{PTDF}_{n2s}$ | matrix of node-to-slack PTDFs (columns: nodes; rows: CNECs and combined dynamic constraints) |
| $\mathbf{GSK}_{n2z}$ | GSK in a form of matrix containing the shares of each node in the net positions of the corresponding bidding zones (columns: bidding zones; rows: nodes; sum of each column equal to one) |

4. The impact of HVDC network elements on the bidding zone borders within the Nordic CCR shall be taken into account by defining the connecting nodes of such HVDC network element as separate virtual bidding zones. The zone-to-slack PTDFs calculated for these virtual bidding zones are equal to node-to-slack $PTDFs$ for the connecting nodes of the HVDC network element, whereas these nodes are not included in the summing up of products for real bidding zones as referred to in paragraph 3.

5. The zone-to-slack $PTDFs$ as calculated above can also be expressed as zone-to-zone $PTDFs$ (i.e. $PTDF_{z2z}$). 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:

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

*Equation 3*

6. The cross-zonal exchange over HVDC network elements on the bidding zone borders of the Nordic CCR is modelled 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 FB domain used in capacity allocation.

7. The maximum zone-to-zone $PTDF$ of a CNEC (i.e. $PTDF_{z2zmax,l}$) is the maximum influence that any cross-zonal exchange in the Nordic CCR has on the respective CNEC, including exchanges over HVDC network elements:

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

*Equation 4*

with

| | |
|---|---|
| $PTDF_{A,l}$ | zone-to-slack $PTDF$ of bidding zone A on a CNEC $l$ |
| $BZ$ | set of all Nordic bidding zones (including virtual bidding zones) |
| $\max_{A\in BZ}(PTDF_{A,l})$ | maximum zone-to-slack PTDF of Nordic bidding zones on a CNEC $l$ |
| $\min_{A\in BZ}(PTDF_{A,l})$ | minimum zone-to-slack PTDF of Nordic bidding zones on a CNEC $l$ |

## Article 14
## Definition of the final list of CNECs for day-ahead and intraday capacity calculation

After the calculation of maximum zone-to-zone $PTDFs$ calculated in accordance with Article 13(7), the CCC shall remove from the initial list of CNECs at least those CNECs for which the maximum zone-to-zone $PTDF$ is not higher than 5% to meet CACM Art 29(3)(b). This removal shall / may not apply for CNECs or combined dynamic constraints which are defined as cross-zonal network elements. The remaining CNECs shall constitute the final list of CNECs.

## Article 15
## Rules on the adjustment of power flows on critical network elements due to RAs

1. The RAs taken into account in capacity calculation aim to increase RAM in accordance to Article 17. These RAs are not interdependent in the sense that they would increase cross-zonal capacity on some CNECs or combined dynamic constraints and decrease it on others. For these reasons, all RAs provided by the TSOs in accordance to Article 10 shall be applied and no optimisation of RAs is necessary.

2. As the outcome of the application of RA, the CCC shall calculate for each CNEC of the final list of CNECs and for each combined dynamic constraint the increase of flow on such CNEC or combined dynamic constraint due to the application of RA. This flow for increasing the RAM on each CNEC and combined dynamic constraint shall be expressed as $F_{RA}$. In case TSO(s) provided to CCC a

minimum $F_{RA}$ pursuant to Article 10(5), the CCC shall adjust the calculated $F_{RA}$ such that it is not lower than the minimum value provided by the TSO(s).

## 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 and capacity allocated for the intraday timeframe where applicable.

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 17
## Description of the calculation of available margins on critical network elements before validation

1. The CCC shall use voltage limits, frequency limits and dynamic stability limits provided by TSOs to calculate for each relevant CNEC the respective $I_{max}$ representing these limits. Subsequently, the CCC shall calculate the final $I_{max}$ for each CNEC which shall be the lowest of all values of $I_{max}$ calculated by the CCC or provided by TSOs for each specific CNEC.

2. The CCC shall use the final $I_{max}$ of each CNEC calculated pursuant to paragraph 1 to calculate $F_{max}$ for each CNEC, which describes the maximum admissible active power flow on a CNEC. $F_{max}$ of a CNEC shall be calculated by the given formula:

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

*Equation 8*

with

| | |
|---|---|
| $F_{max}$ | maximum admissible flow of a CNE |
| $I_{max}$ | maximum admissible current of a CNE |
| $U$ | voltage for a CNE as defined in paragraph 3 |
| $cos(\varphi)$ | power factor as defined in paragraph 3 |

3. The voltage $U$ referred to in paragraph 2 shall be the average voltage on two connecting nodes of a CNE included in a CNEC resulting from the AC load-flow calculation on the CGM and shall not be lower than the 95% of the reference voltage of that CNE. The power factor $\cos(\varphi)$ referred to in paragraph 2 shall be the average power factor on two connecting nodes of a CNE included in a CNEC resulting from the load-flow calculation on the CGM and shall not be lower than 0.95.

4. The CCC shall calculate the reference flow ($F_{ref}$) for each CNEC and combined dynamic constraint, which is the active power flow on a CNEC or combined dynamic constraint calculated with the CGM. In case of a CNEC or combined dynamic constraint without contingency, $F_{ref}$ is simulated by directly performing the load-flow calculation on the CGM, whereas in case of a CNEC with contingency or combined dynamic constraint, $F_{ref}$ of such CNEC or combined dynamic constraint is simulated by first applying the contingency of this CNEC or combined dynamic constraint, and then performing the load-flow calculation.

5. The CCC shall calculate for each CNEC and combined dynamic constraint the linear approximation of a flow in a situation without any cross-zonal exchanges ($F_0$) as follows:

$$\vec{F}_0 = \vec{F}_{ref} - \boldsymbol{PTDF} \cdot \overrightarrow{NP}_{ref}$$

*Equation 9*

with

| | |
|---|---|
| $\vec{F}_0$ | 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 |
| $\vec{F}_{ref}$ | reference flows on all CNECs and combined dynamic constraints |
| $\boldsymbol{PTDF}$ | matrix of power transfer distribution factors |
| $\overrightarrow{NP}_{ref}$ | net position of bidding zone (including virtual bidding zones) in the reference commercial situation |

The net positions ($\overrightarrow{NP}_{ref}$) of virtual bidding zone include injections of the connecting nodes of the HVDC network elements, whereas the net positions of real bidding zones are excluding the injections of those connecting nodes.

6. Subsequently, the CCC shall calculate the RAM before validation for each CNEC and combined dynamic constraint as follows:

$$\overrightarrow{RAM}_{bv} = \vec{F}_{max} + \vec{F}_{RA} - \vec{F}_{RM} - \vec{F}_0 - \vec{F}_{AAC}$$

*Equation 10*

with

| | |
|---|---|
| $\overrightarrow{RAM}_{bv}$ | remaining available margin before validation |
| $\vec{F}_{max}$ | maximum flow on all CNECs and combined dynamic constraints |
| $\vec{F}_{RA}$ | flow impact of RAs on a CNEC or combined dynamic constraint |

| | |
|---|---|
| $\vec{F}_{RM}$ | flow for reliability margin for all CNECs and combined dynamic constraints |
| $\vec{F}_{0}$ | 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 |
| $\vec{F}_{AAC}$ | flows resulting from previously allocated cross-zonal capacities for all CNECs and combined dynamic constraints |

7. When the RAM value calculated pursuant to paragraph 6 is negative it shall be set to zero for day-ahead timeframe and the potential congestion resulting from negative RAM shall be managed by the application of RAs, which may include other RAs than the ones defined pursuant to Article 10. For the intraday timeframe, the RAM value calculated pursuant to paragraph 6 shall be sent as input to the allocation mechanism also in case the value is negative.

## Article 18
## Rules for sharing the power flow capabilities of CNECs among different CCRs and third countries

1. The power flow capabilities are shared with different CCRs by means of Advanced Hybrid Coupling. In Advanced Hybrid Coupling, the impact of HVDC interconnection power exchanges on the CNECs and combined dynamic constraints in the AC grid in the FB model are taken into account during the allocation stage by means of Power Transfer Distribution Factors (PTDFs) that reflect the impact of the HVDC interconnection power exchanges on the CNECs and combined dynamic constraints.

2. The power flow capabilities are shared with third countries by taking the impact of HVDC interconnection exchanges on the CNECs and combined dynamic constraints in the AC grid in the FB model into account during the capacity calculation stage by means of a forecasted exchange on the HVDC interconnection in the CGM. As such, capacity on the CNECs and combined dynamic constraints in the AC grid is reserved to facilitate for this forecasted exchange on the HVDC interconnection.

3. The CCC shall submit FB parameters, or the ATC values in case of the transitional solution pursuant to Article 20, calculated for bidding zone borders of neighbouring CCRs to the CCCs of these CCRs. The FB parameters or the ATC values may limit capacity allocation on the bidding zone borders of those CCRs if such limitations are allowed within the day-ahead and intraday CCM governing capacity calculation within those CCRs.

# TITLE 4
# Description of capacity validation for day-ahead and intraday timeframe

## Article 19
## Methodology for the validation of cross-zonal capacity

1. Each TSO shall perform the 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 and allocation 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 17(6) may be adjusted during the validation by applying individual validation adjustment ($IVA$) to take into account relevant information known at the time of validation in accordance with paragraph 1. $IVA$ can be a positive value indicating reduction of cross-zonal capacities or a negative value indicating increase of cross-zonal capacities.

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) an error in input data, that leads to a wrong estimation of cross-zonal capacity from an operational security perspective; and/or

   (c) when TSO(s) is unable to define exact RAs to be taken into account in capacity calculation due to uncertainty of their actual availability in real-time, but is able to evaluate the approximate adjustment of flows on CNECs or combined dynamic constraints due to RAs by taking into account the statistics and probability of the availability of RAs.

4. The final FB parameters available for capacity allocation shall be the PTDF calculated pursuant to Article 13 and the RAM calculated as follows:

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

*Equation 11*

with

| | |
|---|---|
| $\overrightarrow{RAM}$ | final remaining available margin |
| $\overrightarrow{RAM}_{bv}$ | remaining available margin before validation |
| $\overrightarrow{IVA}$ | individual validation adjustment |

Each application of $IVA$ needs to be justified by the TSOs applying it, by reporting on the need to apply $IVA$, and the rationale behind the value of $IVA$, towards the CCC and other TSOs.

5. Each CCC shall report all reductions made during the validation of cross-zonal capacity to all Nordic regulatory authorities in accordance with Article 26(5) of the CACM Regulation. This report shall include the location and amount of any reduction of cross-zonal capacities and shall give reasons for the reductions.

6. The CCC shall ensure coordination with the neighbouring CCCs during the validation.

## TITLE 5
## Miscellaneous

### Article 20
### Transitional solution for calculation of intraday cross-zonal capacities in the Intraday timeframe

1. Until the single intraday coupling 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 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 $ATC^{n,a\rightarrow b}$ (for bidding zone border $n$, with a separate value for each direction $a \rightarrow b$ or $b \rightarrow a$) shall be calculated as:

$$Maximize \prod_{n}(ATC^{n,a\rightarrow b} + ATC^{n,b\rightarrow a})$$

$$subject\ to$$

$$\sum_{n}[(ATC^{n,a\rightarrow b}) * \max\left(0, PTDF_j^{n,a\rightarrow b}\right) + \left(ATC^{n,b\rightarrow a}\right) * \max\left(0, PTDF_j^{n,b\rightarrow a}\right)] \leq ID\_RAM_j \quad \forall j$$

*Equation 12*

with

| | |
|---|---|
| $ATC^{n,a\rightarrow b}$ | available transfer capacity on border $n$ in direction $a \rightarrow b$ |
| $PTDF_j^{n,a\rightarrow b}$ | zone-to-zone PTDF for constraint $j$ and border $n$ in direction $a \rightarrow b$ |
| $ID\_RAM_j$ | remaining RAM for constraint $j$ for intra-day trade after the day-ahead allocation, and is computed by $ID\_RAM_j = DA\_RAM_j - DA\_AAF_j$ |
| $DA\_AAF_j$ | already allocated flow for constraint $j$ |

3. Before applying the optimization described in paragraph 2, the CCC may apply either or both of the following domain relaxations:
   a) Each RAM value may be increased by a prespecified MW amount; and
   b) Each zone-to-zone PTDF below a prespecified value may be rounded down to zero.

4. The Nordic TSOs shall maintain a public description of this transitional solution, including additional details about the optimization described in paragraph 2, and the domain relaxation described in paragraph 3.

## Article 21
## Reassessment frequency of cross-zonal capacity for the intraday timeframe

1. First assessment of intraday cross-zonal capacity shall be done based on CGMs for the day-ahead capacity calculation timeframe, the results of the single day-ahead coupling, and may include other updated information.
2. Reassessment of intraday cross-zonal capacity shall be done at least at the frequency the CGM for the intraday timeframe is made available in accordance with the CGM methodology developed in line with Article 17 of the CACM Regulation. The latest available CGM, potentially including updated information, is applied in a reassessment of cross-zonal capacities.

## Article 22
## Fallback procedure if the initial capacity calculation does not lead to any results

1. When day-ahead or intraday capacity calculation fails to provide the FB parameters for two or less consecutive calculation time units, the CCC shall calculate the missing FB parameters as being the

minimum of the FB parameters, which have been successfully calculated for adjoining calculation time units.

2. When day-ahead or intraday capacity calculation fails to provide the FB parameters for three or more consecutive calculation time units, the CCC shall apply the default FB parameters. These default FB parameters shall be based on latest calculated FB parameters for the same calculation time unit and market time frame taken from daily, weekly, monthly or yearly capacity calculation.

## Article 23
## Monitoring data to the Nordic regulatory authorities

1. All technical and statistical information related to this CCM shall be made available upon request to the Nordic regulatory authorities.

2. Any data requirements mentioned above shall be managed in line with confidentiality requirements pursuant to national legislation.

## Article 24
## Reviews and updates

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

2. Any of the day-ahead and intraday calculation inputs pursuant to Articles 4, 5, 6, 7 and 10 shall be updated and published in accordance with the CACM Regulation, Article 14(3).

3. Any adjustment of the day-ahead and intraday calculation inputs pursuant to Articles 3 and 8 shall be published to the market participants one month before their implementation. In case of an incident and if justifiable, adjustment and publication of inputs pursuant to Article 3 and 8 might be performed according to the CACM Regulation, Article 14(3). As soon as the incident has passed, the original input parameters pursuant to article 3 and 8 shall be reinstated.

4. The TSOs shall communicate any change of parameters listed in Article 24.2 and 24.3 to market participants, all Nordic regulatory authorities and the Agency. The parameters in Article 4, 5, 7 and 10 shall be published as part of the day ahead and intraday parameters prior to day ahead and intraday allocation. If any change leads to an adaption of the methodology, the TSOs shall make a proposal for amendment of this methodology according to Article 9(13) of the CACM Regulation.

## Article 25
## 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 Nordic regulatory authorities and market participants, all TSOs and the CCC shall regularly publish the data on the day-ahead and intraday 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 Nordic CCR shall be published. To enable market participants to have a clear understanding of the published data, all TSOs and the CCC shall develop a handbook and publish it on this communication platform. This handbook shall include at least a description of each data item, including its unit and underlying convention.

2. The 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 market time unit pursuant to Article 19(4);
   b) in case of application of the transitional solution pursuant to Article 20 for each market time unit, the ATC values for all bidding zone borders in Nordic CCR calculated pursuant to Article 20;
   c) the following additional information for market time unit:
      i. maximum and minimum possible net position of each bidding zone;
      ii. maximum possible bilateral exchanges on all Nordic bidding zone borders;
      iii. names of CNECs (with geographical names of substations where relevant and separately for CNE and contingency) and combined dynamic constraints of the final FB parameters and the TSO defining them;
      iv. for each CNEC of the final FB parameters, the EIC code of CNE and Contingency;
      v. for each CNEC of the final FB parameters, the method for determining $I_{max}$ in accordance with Article 4(3);
      vi. detailed breakdown of $RAM$ for each CNEC of the final FB parameters: final $I_{max}$, $U$, $F_{max}$, $F_{RA}$, $F_{RM}$, $F_{ref}$, $F_0$, $F_{AAC}$ and $IVA$;
      vii. detailed breakdown of the $RAM$ for each combined dynamic constraint: $F_{max}$, $F_{RA}$, $F_{RM}$, $F_{ref}$, $F_0$, $F_{AAC}$ and $IVA$;
      viii. information about the individual validation adjustments:
         - the identification of the CNEC;
         - in case of adjustment due to individual validation, the TSO invoking the adjustment;
         - the volume of adjustment ($IVA$);
         - the detailed reason(s) for reduction;
      ix. for each RA taken into account in day-ahead and intraday calculation:
         - 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;
         - the provided minimum $F_{RA}$ pursuant Article 10(5)
      x. the forecast information contained in the CGM:
         - vertical load for each Nordic bidding zone and each TSO;
         - production for each Nordic bidding zone and each TSO;
         - for each Nordic bidding zone and each TSO;
         - reference net positions of all bidding zones in CCR Nordic and reference exchanges for all HVDC network elements within CCR Nordic and between CCR Nordic and other synchronous areas.

3. Individual Nordic TSO may choose not to identify the CNEC concerned and specify its location when publishing the information referred to in paragraph 2(c) 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 withheld information shall be replaced with an anonymous identifier, which shall be stable for each CNEC across day-ahead and intraday capacity calculation time frames, as well as all long-term capacity calculation time frames. The anonymous identifier shall also be used in the other TSO communications related to the CNEC 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 shall be publicly notified at least one month before its publication.

5. If a TSO provides evidence to its regulatory authority that the provision of anonymised stable identifiers is not sufficient to prevent the identification of network elements, and is therefore not compliant with its national legislation, they can be exempted from the requirements of stable identifiers pursuant to paragraphs 3 and 4.

6. The data shall be published as soon as available and no later than:

   (a) for day-ahead capacity calculation, one hour before single day-ahead coupling gate closure time, for each market time unit; and

   (b) for intraday capacity calculation, at least 15 minutes before the first single intraday allocation.

7. 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 26
### Publication and Implementation

1. The TSOs shall publish this capacity calculation methodology without undue delay after an approval from all Nordic regulatory authorities or a decision has been taken by the Agency for the Cooperation of Energy Regulators in accordance with Article 9(10), Article 9(11) and 9(12) of the CACM Regulation.

2. The TSOs shall implement this capacity calculation methodology on all bidding zone borders within the Nordic CCR according to the CGM methodology developed in accordance with Article 17 of the CACM Regulation, the market coupling operator function developed in accordance with Article 7(3) of the CACM Regulation, the relevant requirements set in the algorithm methodology in accordance with Article 37(5), and the Nordic CCR established in accordance with Article 27 of the CACM Regulation, and at the latest 18 months after approval of this CCM by all relevant regulatory authorities.

## Article 27
## Language

The reference language for this Second Amendment shall be English. For the avoidance of doubt, where TSOs need to translate this Second Amendment 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 TSOs shall be obliged to dispel any inconsistencies by providing a revised translation of this Second Amendment to their relevant national regulatory authorities.