Nordic TSO proposal for amendment of the October 2020 Nordic DA/ID CCM – supporting document

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1 Introduction

This is the supporting document of the Nordic TSO proposal for the amendment of the Nordic DA/ID CCM. The latest version of the CCM was approved in October 2020, and the intention of the amendment proposal is to replace this version. The supporting document explains the motivation for the proposed amendments in the legal text of the CCM.

The amendment of the CCM will not alter the main building blocks of the CCM, which are:

- Application of the Flow Based methodology for the DA time frame and ATCE for the ID time frame in a short-term perspective and Flow Based methodology for all time frames when allocation systems are ready for this;
- The daily coordination between Nordic TSOs and the Nordic RCC; the daily procedures will basically be the same as of today.

The main motivation for the proposed amended CCM is:

- In the 2020 version some elements were not entirely spelled out into detailed methodologies, but were left for further detailing no later than 18 months after go live of Flow Based in the DA market.
- During a TSO review process, it was identified that some articles would benefit from greater clarity to enhance the transparency.
- Due to an internal TSO assessment of application of costly remedial actions (e.g. counter trade) and a decision by the Court of Justice of the European Union it has been decided not to apply costly RAs to allocate capacity more than 100% of physical Fmax or beyond what is required to comply with the Regulation 2019/943, Article 16(8).
- To bring the boundaries in daily operation and practice related to capacity calculation, in line with the legal CCM and also the CACM. This is mainly related to input data to be applied in capacity calculation, where the 2020 version of the CCM only allows for a change with a one-month notification. This is problematic because some elements of data are not known with a level of certainty more than two days in advance, and because this is not in line with Article 14 in the CACM.

In the supporting document those articles that have been amended are explained in a chronological order, thus it should be possible to read the amended CCM in parallel with the explanations provided in this supporting document. Only substantial changes are elaborated upon in this supporting document.

2 Articles

2.1 Article 2: Definitions and interpretation

The amended CCM introduces the following new definitions: FCR margin, FCR-N, LFC area, PATL, polarity reversal, and TATL.

2.2 Article 3: Methodology for determining reliability margin

The articles related to the FCR margin have been improved by clearly defining what should be included in the FCR margin and how it should be calculated in a consistent and transparent way. The draft proposal explicitly defines the scope of the FCR margin, linking it to FCR-N activations within the Nordic LFC areas and to cross-border FCR exchange between the Nordic TSOs. In addition, it sets minimum data requirements (e.g., at least one year of consecutive data, a minimum 1-minute sampling rate, and constraints on how recent the data must be). It also specifies a structured calculation method (FCR-N net positions → PTDF-based flow distribution → risk-level quantile). Finally, the draft proposal adds practical fallback options and operational flexibility by temporarily setting the margin to zero until it has been assessed and allowing TSOs to calculate an alternative FRM based on a shorter data period (two weeks) for operational security purposes.

The historical snapshots, which are the bases for the observed state CGMs which is to be applied for the RM-calculations, are not expected to be available for some time yet. Until they are, it is necessary for the TSOs to apply an intermediate solution to calculate the RM-values in a coherent way other than deciding on a fixed value. The proposed solution in Article 3(1)(b) is for each TSO to apply their individual observed state IGM for this task.

When using the observed state IGMs, the level of accuracy of the predicted flows is less than what is foreseen by the observed state CGMs. This might lead to excessive RM-values well above a realistic RM-level with a risk assessment based on 95% in the observed state CGM. To mitigate this, the TSOs may set a risk level below the maximum level of 95% when applying the observed state IGMs. By lowering the risk level, the value drawn from the distribution of deviations will be lower than the application of 95% will imply.

2.3 Article 4: Methodology for determining operational security limits

The main update of Article 4 is related to a change in how thermal limits are reflected in the capacity calculation. In general, there are two types of thermal limits for many network elements:

1. The permanent admissible transmission loading (PATL) provides the highest loading that a network element can handle for an unlimited amount of time.

2. The temporary admissible transmission loading (TATL) provides the highest loading that a network element can withstand for a short duration of time. This limit is higher than the PATL limit.

In other words, the PATL limit may be exceeded, up to the TATL limit, but only for a short duration (e.g. 15 minutes).

Paragraph 4(3) of the 2020 version of the CCM states that the thermal limit (Imax) shall be defined as a temporary current limit “when applicable”. However, it does not explicitly state when this is applicable.

Applying TATL instead of PATL may be applicable for a CNEC (with a contingency) if sufficient remedial actions can be expected to be available during operations, should the contingency occur. The applicability of TATL therefore depends on the expected availability of remedial actions.

Therefore, the amended CCM removes paragraph 4(3) and specifies that Imax shall be based on PATL. When sufficient remedial actions are expected to be available and the TATL limit can be applied, this shall instead be captured as an increase in capacity due to remedial actions in accordance with Article 10. This is further described in the section for Article 10 below.

This change clarifies the impact of remedial actions in capacity calculation. Since this update shifts capacity from Fmax to F_{RA}, the resulting RAM remains unchanged.

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

In this article the methodology for determining CNECs including contingencies is outlined. The 2020 version of the CCM includes methodologies for determining an increase in the capacity offered to the DA and ID market, by means of RA, if it can be shown that it will increase economic efficiency. Essentially, it says that the TSOs should provide virtual capacity if a social gain can be demonstrated. In addition to this, the CCM also includes that efficient congestion management shall include consideration on re-configured bidding zones and investment.

The paragraphs on economic efficiency, bidding zone re-configuration and grid investment have been taken out for the following reasons:

- Based on TSO considerations, it is concluded that it is not possible to show that an increase in virtual capacity is followed by a social gain. The reason is data, methodology and tools to do this do not exist and that virtual capacity – meaning capacity that does not exist – cannot “produce” a social real gain.
- Consideration on bidding zones and investment is not relevant for CCM that should act as framework for daily operation of DA and ID markets. Considerations are relevant, but are already included in other regulations.

- The General Court of the European Union has decided that issues beyond Article 16(8) of regulation 943/2019 is not relevant in terms of capacity calculation, cf.: [The General Court annuls a decision of ACER concerning the management of electricity markets.]() This decision essentially says that if the TSO has provided 70% of Fmax on CNECs there are no legal obligations to move even further. The introduction of Regulation 943/2019 basically created a situation where the previously legal obligation of offering 100% of (cross-zonal capacity) was reduced to 70%.

2.5 Article 6: Methodology for allocation constraints

The amended CCM introduces the possibility for TSOs to apply a limit on polarity reversals as an allocation constraint on HVDCs. Polarity reversals refer to situations where the direction of electrical flow changes direction on an HVDC cable. It is notable that polarity reversals generally occur on interconnectors when the total flow on the border changes direction. However, on non-symmetric HVDC interconnectors, polarity reversals may occur on non-zero flow crossings as the cables have different capacities.

Older HVDC systems were designed for stable operating conditions. In systems using line-commutated converters, changing power flow direction requires reversing voltage polarity. These polarity reversals cause rapid electrical field changes and put extra electrical stress on the cable insulation and can reduce cable lifetime.

Several ongoing developments and trends in European electricity markets, such as increased price volatility, and the introduction of 15-minute MTUs and flow-based with advanced hybrid coupling (AHC), cause, or are foreseen to cause, increased polarity reversals. It is therefore foreseen to be necessary to introduce allocation constraints to avoid excessive wear and tear. Polarity reversals as an allocation constraint align with CACM Art. 23(3) and when implemented would have to be justified by the technical specifications or physical condition of the HVDC.

The amended CCM does not specify exactly how an allocation constraint for polarity reversals shall be implemented. The inclusion of this allocation constraint would be a novel feature for the day-ahead and intraday markets, and the exact specifications need to take into account practical implications for the day-ahead and intraday market algorithms, as well as weighing the benefits of maintaining the life expectancy of the cables against the socioeconomic costs of constraining market allocations. One important aspect of this will be to express the polarity reversal limitation at a time-granularity suitable for day-ahead and intraday timeframes. For example, X amount of polarity reversals per hours or day. Alternatively, each polarity reversal could be penalized [EUR per reversal] in the objective function. When the welfare gain due to the reversal is greater than the penalty, it will be actualized.

The amended CCM introduces the possibility for TSOs to apply an allocation constraint which represents the capacity of virtual bidding zones. Specifically, this means translating a specific HVDC interconnector's import/export capacity as total maximum import or export capacity from the virtual bidding zone to other neighbouring bidding zones.

2.6 Article 7: Combined dynamic constraints

A combined dynamic constraint (CDC) is a type of constraint that limits the sum of power flows on a set of network elements. From a market allocation point-of-view, a CDC is similar to a CNEC in the sense that it is modelled using PTDFs and RAMs. The main difference is that a CDC limits the combined flow on multiple network elements, while a CNEC limits the flow on one single network element.

The motivation for using CDCs is that some operational security limits cannot be captured efficiently by restricting the flow on only one network element. This is especially the case for dynamic stability limits, as described in more detail below.

Legal justification for the use of CDC

Since combined dynamic constraints do not limit the flow on individual critical network elements, they can be considered a type of allocation constraint according to CACM.

Article 23(3)(a) in CACM states that TSOs may apply allocation constraints if they are "[…] needed to maintain the transmission system within operational security limits and that cannot be transformed efficiently into maximum flows on critical network elements".

As described in the technical justification below, CDCs are needed to maintain the transmission system within operational limits, and these constraints cannot be transformed efficiently into maximum flows on individual CNEs. Hence, TSOs may apply this form of allocation constraint.

Technical justification for the use of CDC

Voltage stability

Voltage stability refers to the ability of a power system to maintain acceptable voltage levels across the network, under both normal and contingency (N-1) conditions. It is primarily governed by the balance between reactive power supply and demand within the network.

As real power transfers between areas increase, the transmission system experiences higher loading, which in turn raises reactive power losses and causes progressive voltage drops along a power transmission corridor. Beyond a certain transfer level, the system may be unable to supply sufficient reactive power to support the receiving-end voltages. This condition can lead to a voltage instability phenomenon, where voltages decline uncontrollably, potentially resulting in a voltage collapse and widespread outages.

To prevent such conditions, it is necessary to impose limits on total power transfers along a transmission corridor to ensure that voltages remain stable.

Voltage collapse occurs across a section of lines (often, but not limited to, on a bidding zone border), not on a single line. Therefore, voltage stability can be managed much more efficiently by limiting the power flow across a set of network elements, rather than linking voltage collapse to a specific CNEC.

Rotor angle stability

Rotor angle stability refers to the power system's ability to keep generators spinning in synchronism. If stressed conditions cause the angles of their rotating magnetic fields to drift too far apart, leading to loss of generation and potential blackout. Rotor angle stability hence represents the system's ability to maintain a coherent angular relationship between generating units and thereby preserve synchronized operation across the transmission network.

Transient stability refers to the power system's capability to maintain synchronism following a large, sudden disturbance, such as a short circuit, line fault, or abrupt loss of generation or load. During such events, generator rotor angles may experience rapid acceleration or deceleration, and the system must absorb and damp these swings to avoid loss of synchronism. Oscillations, on the other hand, are the periodic variations in rotor angles and power flows that occur as the system attempts to return to equilibrium. These oscillations can be local—affecting a small group of generators—or inter-area, involving coherent groups of machines across different regions. The nature and damping of these oscillations are key indicators of the system's dynamic stability.

Transient stability and oscillations correlate with the transmission, either on a single line or a set of lines (power transmission corridor), depending on whether it is a local phenomenon or a phenomenon that affects the whole system. An inter-area oscillation often has no or little correlation with a flow on a single line, while the correlation with a power transmission corridor is often good.

To manage rotor angle stability, it may therefore be necessary to impose limits on the power flow across a set of network elements to ensure that the synchronous operation of all generating units is maintained.

Frequency stability

Frequency stability refers to the power system's ability to maintain system frequency within acceptable limits following disturbances, such as generation loss, load changes, or network faults. Stable frequency is essential for secure system operation, as large or sustained deviations can lead to generator disconnections, load shedding, or cascading outages. To ensure frequency stability, it may be necessary to impose limits on the power flow across a set of network elements. In the Nordic power system, it has been needed to introduce operational security limits to ensure that any incident (e.g. trip of a single large generator) does not exceed the existing dimensioning incident in the Nordic synchronous area.

Paragraph 5

The following paragraph allows TSOs to define CDCs based on operational reasons:

“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.”.

The technical reasons are based on operational needs, mainly in the case where there is a need to change the capacity reflecting cross-zonal power exchange close to the validation phase: adjusting border capacities is easier using a combined dynamic constraint than with a set of specific CNECs. As so called “border_CNECs” are not used for operational purposes (monitoring purposes only), the Nordic TSOs may have a need for such a combined dynamic constraint, on which they can apply individual validation adjustments.

Additionally, sometimes any of the above-mentioned other technical justifications are not valid for every day, every MTU. Thus, for smooth handling of the constraints used in the capacity calculation, it is convenient to have the CDCs constantly in the list of monitored critical network elements, as they can be used for operational purposes as described above. Naturally, the actual capacity on the specific CDC needs to be justified, regardless of the technical or operational justification.

Method for calculating maximum flow

Both for voltage, frequency, and rotor angle stability, the maximum flow (Fmax) on a CDC is determined using offline dynamic load flow tools. These tools contain more advanced network models, compared to those used for other aspects of capacity calculation.

Using these more advanced tools, it is possible to estimate at which flow on the relevant power transmission corridor dynamic violations are deemed to occur. This flow level can then be used as Fmax on the CDC.

Local TSO calculation

Nordic RCC does not have the ability to perform the calculations and analysis described above for defining the maximum flow on CDCs. These calculations are therefore performed locally by the TSOs.

However, other components of the CDCs (such as PTDFs, F0, Fref and the final RAM calculation) are calculated by the Nordic RCC applying the same methods as for CNECs.

Why is this amendment needed?

Article 6 of the 2020 version of the CCM allows for the use of CDCs for a period of two years after FB go-live in the day-ahead market. Article 6(3) further states:

“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."

As is explained in this document, the TSOs believe that a continued use of combined dynamic constraints is the most efficient available method for managing dynamic stability limits. The amendment, in combination with this explanatory document, aims to satisfy the requirements of Article 6(3).

For increased clarity, the provisions concerning CDCs are removed from Article 6 and instead provided in a new and dedicated Article 7.

2.7 Article 8: Methodology for determining generation shift keys (GSKs)

The application of a GSK-strategy has a significant impact on the PTDFs for each bidding zone and CNEC. Depending on the GSK-strategy, the relation between net positions and aggregated flows on the CNECs predicted by the market algorithm might be more or less accurate. Such inaccuracies can potentially cause large overloads to appear in real-time or be excessively constraining to the market.

It may, due to local geographical and technological differences in supply and demand, be necessary for the TSOs to apply different GSK-strategies for different bidding zones, seasons and years. Thus, there is a need for a consistent methodology to compute PTDFs based on local conditions. The proposed solution in Article 8(4) is to compute RMs following the application of different GSK-strategies, and to choose the strategy that minimizes the RM.

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

Referring to CACM Article 21(1)(b)(ii) the CCM shall describe actions to take in order to avoid undue discrimination between internal and cross zonal exchanges. To understand the proposed rules in the CCM we firstly need to define "undue" *and* "discrimination" in a market context and then, secondly, the rules proposed in CCM shall refer to current higher ranking relevant legislation.

Discrimination is related to the access to the marketplace, thus within economics it is well understood that in order to fulfill the goal of market operation of least cost and maximization of value, (undue) discrimination of access shall not take place. In this case, discrimination is about access to the market (the network) to supply electricity and access to purchase electricity.

As the word "undue" is applied in legislation, it means that there must exist a counter party as "due discrimination". To define undue is therefore worthwhile to understand what "due" is. As all resources of the economy/society can be characterized as scarce, so can the network of the electricity industry. “Scarce” means that the demand for access to the grid by consumers and producers is larger than the capacity if the price for access to the network was zero (or too low), thus some kind of rationing mechanism must be established. This rationing mechanism is “due” discrimination via the “network access price” designed as implicit capacity auctions in Europe. Those producers with lowest short-term cost of generation and those consumers with highest willingness to pay are assumed to have the highest willingness to pay for access to the network and hereby the social surplus is assumed to be maximized. This auction will lead to some settlement prices above zero – in this case 96 prices per BZ per day in the DA market. The idea of “due discrimination” is therefore related to the price of access to the network, thus the role of the DA and ID market operators (NEMOs) are to calculate prices that balance the supply of network with the demand for network capacity.

As a point of departure, the objective of non-discrimination of market access is basically supported by moving from NTC to flow based and by implementing a coordinated capacity calculation (through the Nordic RCC). This will support the access of most efficient market players. On the other hand, undue discrimination of access to the network or a certain part of the network, or a particular bidding zone, towards some market players, may be related to other barriers than price to be paid for access. A well-known example of this, in the context of the European electricity market, can be said to be the TSO restriction of cross zonal exchanges by supplying less amount than Fmax on one or more CNEs. Those restrictions can be explained (but without justifications) for (at least) two reasons:

1. To apply the price signal to fully balance demand and supply of the network requires a market design of nodal pricing where all CNEs of the network can be individually balanced by the price mechanism. As the European electricity market is managed by (large) bidding zones and not nodal pricing, Europe does experience a significant amount of so-called loop flows and internal trade which takes up some of the capacity outside the market mechanism. To cope with this, TSOs may have to restrict available capacity on some CNEs below Fmax.
2. The IT algorithm applied for operation of the electricity market (Euphemia) can only handle a linear functional relation between changes in net position of a certain physical area (in this case a bidding zone) and the incident on a CNE. This will lead to “un-expected” deviations in flows. To handle those deviations, a FRM is part of CC, thus leading to a restriction in capacity available.

As those two reasons currently are facts of life and not to be changed in the foreseen future, a legal solution has been introduced in EU legislation. This solution has been laid down in EU Regulation 2019/943 Article 16(8) and it states that the TSOs shall at least provide 70% of Fmax of a CNE to be allocated in the market. The remaining 30% can be applied for FRM and internal trade. In other words, the Article 16(8) is the legal solution to avoid undue discrimination by restricting access to certain bidding zones for market players located outside the bidding zone in focus.

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

The TSOs have realized that the application and quantification of costly RA is likely to provide a socio-economic loss, and this has been reflected in the amended version of the CCM. The approach to non-costly RA has not changed. Article 9(2) of the October 2020 version mentions:

- *The RAs referred to in paragraph 1 shall be used for increasing the day-ahead and intraday cross-zonal capacities while ensuring operational security.*

This paragraph indicates that costly RA shall be applied to increase capacity on CNEs to a level above 100% of not only RAM but also Fmax. In other words, the capacity to be offered for the market can be higher than what is physically available if operational security is not compromised. In Article 10 of the 2020 version the CCM it is further stated that RA shall be added to RAM if economic efficiency can be demonstrated. Thus, the 2020 version of the CCM operates with a requirement to offer so-called virtual capacity to the DA (and ID) market, if found economically efficient. Please see the explanation in relation to the changes in Article 5 above.

The proposed new approach to costly RAs is in line with the decision taken by General Court in the case BNetzA and Germany vs ACER. The General Court concluded that if the TSOs in capacity calculation comply with the minimum capacity of 70% available for cross-zonal trade, the TSOs do comply with the relevant regulation. Furthermore, virtual capacity is unlikely to lead to an increase in social welfare, as explained in the box below.

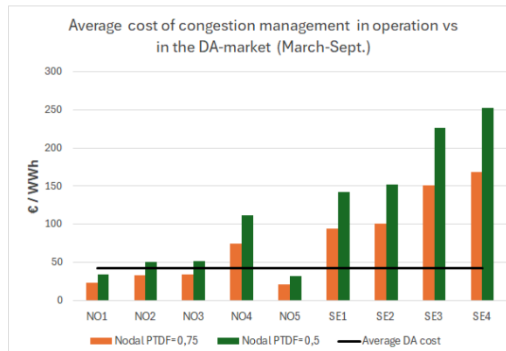
Cf.: The General Court annuls a decision of ACER concerning the management of electricity markets

It is not likely that virtual capacity will bring a welfare economic benefit for the Nordic region where many smaller bidding zones are applied to reflect the physical features of the power grid. Providing virtual capacity might cause physical overloads in real time, and due to the high costs of balancing timeframe activations, this is likely to cause a welfare economic loss in the Nordics.

Capacity is computed by Regional Coordination Centers based on a methodology requiring the use of grid models and formal equations. This accommodates a framework for forecasting the maximum operationally safe transmission capacity that can be made available to the electricity market. However, due to internal trades in bidding zones, loop-flows and internal flows cause the available cross border capacity to be less than the maximum physical capacity. This is present also in small bidding zones and will in fact not disappear before moving all the way to nodal pricing.

It is possible to provide additional capacity for the electricity market above the physically safe capacity. Such added capacity is virtual and cannot be used to transport physical energy. If virtual capacity is allocated for cross border trade, the TSOs will have to redispatch the system in the balancing time frame to bring the system into a safe state. For this to be a welfare economic efficient solution, congestion management in the balancing timeframe will have to be less costly than congestion management in the day ahead and intraday market.

There are however claims that it is possible to obtain welfare economic benefits from providing virtual capacity. The argument is that balancing timeframe redispatch can be made in a nodal setting which provides more accurate congestion management than dispatches between bidding zones in the day ahead and intraday market. However, available reserves for balancing timeframe time activations are scarce and significantly more costly than resources available in the day ahead time frame, even when taking the lower accuracy of congestion management in the day ahead market into consideration. This is illustrated in the figure below, where the expected average congestion management cost in the day ahead market is compared to the average redispatch cost in the balancing time frame for the two least-costly parts of the Nordics (Norway and Sweden).



The expected average day-ahead congestion management cost is computed by zone-to-zone PTDFs for one representative MTU, and the average day-ahead price differences for seven months in 2025. For each CNEC in the matrix, the most efficient combination of zone-to-zone PTDF and related price spread have been used. The average balancing time frame activation costs have been computed for node-to-node PTDFs of 0,75 and 0,5. These are coupled with average activation prices for up- and down regulations in each bidding zone for the time-period March-September 2025 (procurement cost for reserves is not considered.)

In some of the Norwegian bidding zones, depending on the accuracy (node-to-node PTDF) of redispatches in the balancing time frame, it might be argued that the cost of real time redispatch can be less expensive than congestion management in the day-ahead market. However, availability to reserves is not guaranteed without increasing procurement of reserves above the current level, causing a significant increase in procurement cost. And when looking at the even higher redispatch cost in Sweden, it is clear that a general application of the 70% requirement will likely provide a more costly solution for the Nordic electricity market as a whole and thus is most likely to provide both a welfare economic loss and an operational security issue. In a longer time frame, there will also be further significant welfare economic issues in terms of price-distortions and income redistribution from tariff customers to market participants.

The impact of this is that costly RA can be applied in the following situations:

- To comply with regulation, such as Regulation 943/2019 Article 16.
- To be able to offer an amount of TATL capacity in N-1 setting, in case of a forced outage, some amount of RA must be activated bringing the flow into a PATL level on this/those CNECs affected by the outage.

Moreover, there might be situations of short duration where TSOs would prefer to increase grid capacity due to temporary outages by applying costly RA.

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

In the amended CCM it is specified that a regional grid model is used until the pan-European CGM can be used. The quality of the pan-European CGM has to be of sufficient quality to be used as a basis for capacity calculation in order to ensure a realistic outcome and secure system operation without security violations. The process also has to deliver a reliable performance to ensure a stable capacity calculation process. Both are not in place at the moment.

Instead the CCC shall merge a regional grid model on the basis of at least IGMs from TSOs of the Nordic CCR. The observability area can be increased further if deemed relevant.

This process has been used since DA FB go-live and delivers reliable and high-quality results.

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

The idea of the original article remains the same. However, one additional specification has been added in the amended CCM, allowing some exceptions, for which the impact of trading possibilities of including PTDFs lower than 5% has not been simulated, however the impact can be roughly estimated by using operational tools available. In addition, the estimated impact has not been presented to any participants - TSOs or market. Reasonings for the exceptions, and the following sentence alternatives are shown below:
"*This removal shall / may* not apply for CNECs or combined dynamic constraints reflecting bidding zone borders.*"

*In parallel with the public consultation an expert evaluation will be made to clarify the possible impacts of the alternatives

The wording "may" in the sentence originates from the reasoning below.
This sentence is added because for some cross-zonal CNECs the zone-to-zone PTDF is often lower than 5 % and may pose an operational issue. Such low PTDFs will however limit the trade possibilities from certain BZs, e.g. NO4 in the case of the FI-NO4 CNEC, and thus removing these CNECs must be balanced against the negative impact on the trading opportunities of the impacted BZs and the availability of RAs.

The wording "shall" in the sentence originates from the reasoning below.
By using 'shall', the implementation of the exception becomes independent of any bilateral TSO alignment, which makes the requirement considerably clearer from the stakeholders' perspective. The implementation of the exception ensures that no additional CDCs (explained in detail further down) are needed to ensure operationally secure capacities of the NO4-FI-border in DA-market allocation.

It should be noted that further assessment regarding the impact and measures to manage the impact of different implementation options are needed to properly justify the selection between shall/may. It seems that solid measures to manage and limit the impacts are available in both cases.

The following sentence: "*This removal shall not apply for CNECs or combined dynamic constraints reflecting bidding zone borders.*", originates from the reasoning below.

This sentence is added because for some cross-zonal CNECs the zone-to-zone PTDF is often lower than 5%. This is a problem because if the cross-zonal CNEC is removed according to the original rule, capacity on underlying border between bidding zones is not limited, as it should be for operational security reasons. So far, this has been an issue on FI-NO4-border, where it has been mitigated by introducing two additional CDCs:
FI_PTC_SE1-FI_NO4-FI

FI_PTC_FI-SE1_FI-NO4

This ensures that FI-NO4 capacity/operational security limit is considered in the capacity calculation, regardless of the zone-to-zone PTDF of the FI_PTC_NO4-FI or FI_PTC_FI-NO4.

Note that this concept shall not be mixed up with border CNECs, which are made up in the CCC-process for monitoring purposes only:

"*For each bidding-zone border and direction is a system-defined border CNEC. These may be identified by the CNEC name that follows the naming convention: "Border_CNEC_[BZfrom]-[BZto]". The border CNECs do not represent constraints of the operational security of the power system, and they have been assigned an arbitrarily high value of Fmax to ensure that they are redundant and do not impact trading capacities. The Border_CNECs are used for monitoring purposes only. E.g. the Fref of a border CNEC indicates what flows are assumed on the bidding-zone border in the CGM base-case. Furthermore, the zone-slack PTDFs of Border CNECs may be used to assess cross zonal power flows resulting from a given set of net positions. Border CNECs for borders between real and virtual bidding zones will have zero zone-slack PTDFs for all bidding-zones, except for the adjacent virtual bidding zone, where the PTDF is +1 or -1. For the interconnectors to Great Britain, VikingLink (DK1_VL) and NorthSeaLink (NO2_NSL) are defined Border_CNECs in the same way. The F0 value represents the forecasted flow on each interconnector. These non-market borders are not included in the FB domain used for market coupling. They are introduced for monitoring and reporting purposes and serve as the first step toward enabling broader publication of impacts from non-market borders, which is expected in 2026*."[1]

[1] Nordic_PublicationTool_Handbook_v1.4.pdf

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

The following text and figure are taken from the EU MC handbook, Chapter 12, Day-Ahead Flow-Based Capacity Calculation in CCR Nordic[2].

The Nordic region is strongly interconnected with other synchronous areas through HVDC interconnections. Therefore, the proper modeling of the HVDC interconnections within the FB capacity calculation and allocation is key. This modeling approach should ensure that the commercial exchange over a HVDC interconnection competes for the scarce capacity both on the HVDC interconnection, as well as in the AC grid where the converter stations are located.

Power flows on HVDC interconnections are by nature fully manageable, and a radial AC transmission grid has no meshed structure for the power to fan out. Thus, in a pure HVDC network, or in a radial AC transmission grid, both the NTC and FB perception of the power flows corresponds fully to the real physics of the power system. However, in a meshed AC network, the FB approach is the only one of the two which can manage real physical power flows.

In the Nordic countries, all interconnections to adjacent CCRs are either HVDC or radial interconnections. These parts of the Nordic transmission grid are by definition a physical embodiment of NTC, and it doesn't make sense to implement a FB approach on these parts of the transmission grid. With this realization in mind, the Nordic CCR must apply a hybrid coupling, i.e. both NTC and FB constraints to be considered in the allocation mechanism, to integrate with the other CCRs.

The hybrid coupling might be either the standard hybrid coupling or the advanced hybrid coupling. Before discussing standard hybrid coupling and advanced hybrid coupling in the Nordic CCR, it is important to bear in mind that when the power flow from another CCR (originating from a HVDC or a radial AC interconnection) enters the meshed AC transmission grid, the power flow will fan out in the AC transmission grid and will use the scarce transmission capacity like all other power flows in the AC transmission grid.

The distinction between standard hybrid coupling and advanced hybrid coupling is the difference in how power flows from another CCR (originating from a radial AC or HVDC interconnection) are managed by the market coupling algorithm in the meshed AC transmission grid. At a high level, the standard hybrid coupling is granting priority access in the meshed AC transmission grid for power flows coming from a radial AC or a HVDC interconnection, while in the advanced hybrid coupling, these power flows are subject to competition for transmission capacity with all other power flows in the transmission system:

[2] European Electricity Market Coupling - A Practitioner's Guide: https://link.springer.com/book/10.1007/978-3-031-86315-8

- Standard hybrid coupling: Reserves MWs (margin) in the AC grid for the HVDC cable exchanges and Available Transfer Capacity (ATC) exchanges with the other CCRs: i.e. ATC exchanges as well as HVDC cable exchanges receive a priority access to the grid;
- Advanced hybrid coupling: The influence of HVDC cable exchanges and ATC exchanges on the MWs (margins) in the AC grid in the FB model are taken into account during the allocation stage: i.e. Power Transfer Distribution Factors (PTDFs) need to be computed that reflect the impact of the ATC exchanges and HVDC cable exchanges on the margins of the FB constraints.

These two approaches are illustrated in the figure below.

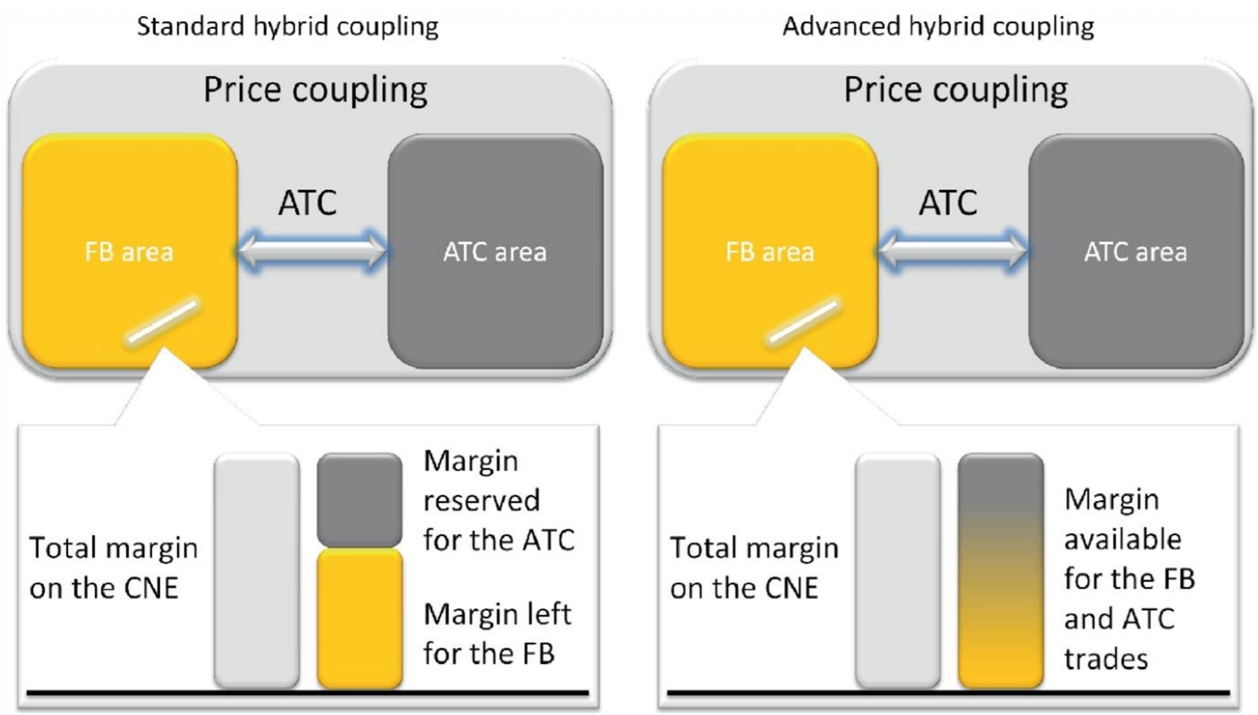


Figure: Standard and advanced hybrid coupling.

Under the standard hybrid coupling, the TSO needs to apply a capacity split: capacity is reserved ex-ante for the flows induced in the AC grid by the HVDC cable exchanges. If it turns out, during the allocation process, that not all this reserved capacity is used by the energy exchange over the HVDC link, it cannot be used anymore to allow for more exchanges in the AC grid. This implies an efficiency loss, as scarce capacity cannot always be fully used in this timeframe. This issue is mitigated in the advanced hybrid coupling approach.

The advanced hybrid coupling fits perfectly well with the FB capacity calculation and allocation and establishes true competition between all relevant exchanges, including the ones on the HVDC interconnections, for the scarce capacity. The Nordic CCR applies the so-called advanced hybrid coupling on the HVDCs and radial AC connections to neighbouring CCRs that are subject to the single day-ahead coupling.

In the advanced hybrid coupling approach, a virtual bidding zone—a bidding zone without any demand or supply—is introduced at the converter station on the Nordic side of the HVDC interconnection. Like for any other bidding zone, the impact of an import or export from the virtual bidding zone on the AC network elements is assessed and captured in the form of PTDFs. In this way, any commercial exchange of power over the HVDC interconnection is competing to make use of the scarce capacity in the Nordic AC grid. This implies that the HVDC interconnection becomes subject to FB properties. Or in other words: a price differential can occur over a HVDC link, while the transmission capacity of the interconnection is not fully utilized.

Description of current capacity calculation and allocation on Viking Link and North Sea Link

In addition to the interconnectors connecting the Nordic CCR to other CCRs, there are currently two interconnectors connecting the Nordic CCR with third countries:

- Viking Link (VL): HVDC interconnection between DK1 and UK
- North Sea Link (NSL): HVDC interconnection between NO2 and UK.

The UK is a third country in this regard because, due to Brexit, the UK no longer participates in the European market coupling. Capacity on VL and NSL is therefore not allocated by SDAC and SIDC. Instead, capacity for these interconnectors is allocated using separate dedicated auctions. The auction arrangements differ somewhat, with NSL applying an implicit capacity auction and VL applying an explicit capacity auction.

Although the day-ahead NSL and VL auctions take place before the SDAC auction, the outcomes of the NSL and VL auctions are not available on time to enable an inclusion of the market results as an input to the common Nordic D-2 capacity calculation process.

Nevertheless, the flows from and to NSL and VL need to be accounted for in the Nordic capacity calculation. This is achieved by applying the standard hybrid coupling approach described above (keeping in mind that the term “hybrid coupling” may be a bit misleading in this case, since the NSL and VL auctions are not part of the common European market coupling). As a result, capacity is reserved on Nordic CNECs and CDCs based on the forecasted flows.

Since VL is connected to DK1, which is part of the continental European synchronous area, the capacity reservations for VL will only affect CNECs and CDCs in DK1. Capacity reservations for NSL can affect all CNECs and CDCs within the Nordic synchronous grid, but since the reservations are based on a forecasted flow between NSL and the rest of NO2, the impact will be largest for CNECs and CDCs within NO2.

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

The intraday market allocation process is not yet able to handle flow-based capacities. The left-over flow-based capacities after the day-ahead market therefore needs to be translated to ATC capacities for the intraday market.

Article 20 in the 2020 version of the CCM describes how the Nordic flow-based domain shall be converted to ATC capacities using an optimization approach. However, in the 2020 version of the CCM, the objective function and constraints for this optimization problem are specified using generic functions, without specifying functional form or parameters.

In accordance with Article 20(3) of the 2020 version of the CCM, the Nordic TSOs have published a document (the ATC Extraction Description) on the Nordic RCC website, describing the applied transitional solution in more detail[3].

Article 20(4) of the 2020 version of the CCM requires that the CCM, no later than 18 months after the implementation of flow-based in the day-ahead market, shall be updated with a description and definition of the generic functions used. The amended article intends to satisfy this requirement by describing the transitional solution as it is currently applied.

Paragraph 2 in the amended article describes the optimization problem. The objective of the optimization is to maximize the product of all capacities at border-level, where each border-level capacity equals the sum of the capacity in each direction across the border. This is already described in the ATC Extraction Description, and the amended article does not imply any implementation changes compared to the current solution.

Further, the currently applied solution includes a feature called “relaxation”, where the FB-domain is somewhat expanded before the ATC capacities are extracted. This relaxation is also described in detail in the ATC Extraction Description. The relaxation feature was not explicitly mentioned in the 2020 version of the CCM but is now described in paragraph 3.

Even though the amended article provides a more precise description of the transitional solution compared to the 2020 version of the CCM, it does not provide as much detail and reasoning as the ATC Extraction Description document. Paragraph 4 of the amended article therefore requires the TSOs to continue maintaining a detailed public description of the transitional solution.

[3] The ATC Extraction Description can be found here: https://nordic-rcc.net/flow-based/methodology/

2.14 Article 24: Reviews and updates

Capacity calculation for the Day Ahead (DA) market is a daily process based on recent conditions and the latest available information. This is recognized in CACM Article 14(3):

"For the day-ahead market timeframe, the capacity calculation shall be based on the latest available information. The information update for the day-ahead market timeframe shall not start before 15:00 market time two days before the day of delivery."

Besides the IGMs, input to the daily capacity calculation are Reliability Margin (RM), Operational Security Limits (OSL), Critical Network Elements and Contingencies (CNEC), Allocation Constraints (AC), Combined Dynamic Constraints (CDC), GSK-strategy, and Remedial Actions (RA).

The RM and the GSK-strategy are based on time series assessments and do not depend on the current state of the system. These inputs will not change frequently, and it is, in normal conditions, feasible to publish any changes in parameter value one month before implementation. However, in specific situations, either of those inputs might be needed as a short-term operational tool in lack of better alternatives. In such situations, the value might be changed on a shorter note to be changed back to its original value when the situation has passed.

The other 5 input parameters are case specific. That implies that it is not possible to define these parameter values until the current grid-situation and forecasted generation and consumption is known. This will be in D-1 as recognized by CACM Article 14(3).

2.15 Article 26: Publication and Implementation

The table 1 present in the October 2020 version of the DA/ID CCM, which captured "milestones and criteria for implementation of FB approach for the day ahead timeframe" has been removed from the amended legal document. Indeed, all relevant milestones have been achieved in the meantime, making the table redundant. With the removal of the table, one milestone has been removed that has not been realized: the establishment of a common dynamic security assessment, based on a common dynamic CGM, and common tools, as part of the daily capacity calculation process. Though there was no date tagged to the realization of this very ambitious objective, the Nordic TSOs are of the opinion that a common dynamic security assessment is not needed for, and does not contribute to, a well-functioning daily capacity calculation process. Indeed, the effort to put in place a common dynamic security assessment, based on a common dynamic CGM, and common tools, is unprecedented, extremely complex, depending on very scarce TSO resources, and much larger than the implementation of the DA FB has been. This effort cannot be justified; there are more urgent developments and implementations where the resources are needed.

The Nordic TSOs do build a common dynamic grid model once a year, for dedicated dynamic studies.