Supporting document for the Nordic Capacity Calculation Region's proposal for 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

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Abbreviations:

AHC	Advanced hybrid coupling
CCC	Coordinated capacity calculator
CCM	Capacity calculation methodology
CCR	Capacity calculation region
CGM	Common grid model
CNE	Critical network element
CNTC	Coordinated net transmission capacity
FAV	Final adjustment value
FB	Flow-based
FCR	Frequency containment reserve
aFRR	Automatic frequency restoration reserve
mFRR	Manual frequency restoration reserve
F_{max}	Maximum flow on a CNE
F_{ref}	Flow on a CNE in the base case
F_{ref}'	Flow on a CNE at zero net position
FRM	Flow reliability margin
GSK	Generation shift key
IGM	Individual grid model
MCO	Market coupling operator
NEMO	Nominated electricity market operator
NTC	Net transfer capacity
PTDF	Power transfer distribution factor
PTR	Physical transmission right
RA	Remedial action
RAM	Remaining available margin
RM	Reliability margin
RSC	Regional security coordinator
SHC	Standard hybrid coupling
TRM	Transmission reliability margin
TSO	Transmission system operator
Legal documents:	
CACM Regulation	Commission regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management Guideline
FCA Regulation	Commission regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation
SO Regulation	Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation
Balancing Regulation	Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing

Regulation (EC) 714/2009	Regulation (EC) 714/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the network for cross-border exchanges in electricity and repealing Regulation (EC) no 1228/2003
Transparency Regulation	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

1 Introduction and executive summary

This document is the supporting document for the Nordic Capacity Calculation Methodology (CCM). The document describes the CCM proposal for the day-ahead and intraday market timeframe for the Nordic Capacity Calculation Region (CCR), and provides an impact assessment of the proposed methodology. The intention of this document is to provide explanation, background, and motivation on the proposed legal text on CCM.

On 17 September 2017, the Transmission System Operators (TSOs) of the CCR Nordic[1] and the Norwegian TSO submitted after consultation with stakeholders a common proposal for the CCM in accordance with Article 20 of the Commission Regulation (EU) 2015/1222 establishing a guideline on capacity calculation and congestion management (CACM Regulation) to the Regulatory Authorities (NRAs) of the CCR Nordic[2] and the Norwegian Regulatory Authority[3].

According to Article 9 (7) (e) of the CACM GL, the proposal is subject to approval by all the NRAs of CCR Nordic[4].

On 16 March 2018 the Nordic NRAs requested the Nordic TSOs to submit an amended proposal.

The amended proposal dated 16 May 2018 reflects the request for amendments received from NRAs.

1.1 Proposal for the Capacity Calculation Methodology

With regard to the CACM Regulation Article 20(2), the Nordic TSOs are proposing to introduce a new CCM for the day-ahead and intraday market timeframes. In accordance to CACM Regulation Article 20(1), the capacity calculation approach for the day-ahead and intraday market timeframe shall be a flow-based (FB) approach unless the requirements in CACM Regulation Article 20(7) are met.

The CACM Regulation article 20(7) states that the TSOs may jointly apply for a coordinated net transmission capacity (CNTC) approach if the TSOs concerned are able to demonstrate that the application of the CCM using the FB approach would not yet be more efficient compared to the CNTC approach and assuming the same level of operational security in the concerned region.

1 *Svenska kraftnät, Fingrid, and Energinet.*

2 *The Swedish Energy Markets Inspectorate (Ei), The Danish Energy Regulatory Authority (DERA) and The Finnish Energy Authority (EV).*

3 *The Norwegian Water Resources and Energy Directorate (NVE).*

4 *Until Regulation 2015/1222 applies in Norway, NVE and Statnett are not formally part of the process. NVE, will however follow the process and may approve the proposed CCM from Statnett according to national legislation.*

Proposed approaches for the day-ahead and intraday market timeframes

For the day-ahead market timeframe: The Nordic TSOs propose to implement a FB approach for the day-ahead market timeframe.

For the intraday market timeframe: As the long-term solution, the Nordic TSOs proposes to implement a FB approach for the intraday timeframe as soon as the intraday market platform is technically able to utilize FB parameters.

As an interim solution, the Nordic TSOs propose to implement a CNTC approach for the intraday market timeframe.

The current Nordic TSO proposal is based on preliminary quantitative and qualitative assessments, which has provided no evidence to support a hypothesis of the CNTC approach being as efficient as the FB approach. The assessment has been based on a comparison between FB and the current net transmission capacity (NTC) approach, where the current approach serves as a proxy for a CNTC approach. A prerequisite for implementing a FB approach for day-ahead market timeframe in the Nordics, is that the European day-ahead market platform is technically able to manage FB parameters.

The long term solution for the intraday market is proposed to be a FB approach. This approach cannot be implemented until the intraday market platform is technically able to utilize FB parameters. As an interim solution, the Nordic TSOs propose to implement a CNTC approach in the intraday market timeframe until the FB approach becomes technically feasible.

The Nordic TSOs acknowledge that further work is needed to implement all features in capacity calculation required by CACM Regulation; to apply proper Common Grid Models (CGM) in calculations, to make the CCM robust and reliable before go-live, and to confirm that the implemented CCM approach can deliver results in line with the preliminary quantitative assessments, showing benefits of the CCM approach. During this process, the transparency towards stakeholder will be ensured.

1.2 Capacity calculation process

The day-ahead and intraday electricity markets facilitate efficient matching of consumers and producers of electrical power. The sites of production and consumption of electric power are often located far apart, and the transfer of power between the two occurs through the electric transmission grid. Thus, the relevant physical limitations in the electricity grid must be calculated, simplified and communicated to the electricity market in order to maintain operational security. This is known as the capacity calculation process. The capacity calculation process has to be distinguished from the capacity allocation process, which takes place for e.g. day-ahead at the power exchanges. The result of the capacity calculation process is to be used as an input to the capacity allocation process. This document is a detailed proposal covering the capacity calculation process. How this process relates to the adjacent processes before ending up with an actual allocation of capacity, is described in this section.

The capacity calculation process will be coordinated among TSOs. This means that individual grid models (IGMs) prepared by each TSO will be merged into a single European grid model. This Common Grid Model (CGM) will include relevant parts of European grids with forecasted production and consumption patterns for each market time unit. For the day-ahead timeframe this currently implies 24 scenarios, where the capacities will be defined. Capacities will be calculated at the CCR level by applying the CGM. Each TSO will validate the results of the capacity calculation before the capacities are sent to the day-ahead and intraday market platforms. Figure 1 shows this coordinated capacity calculation process.

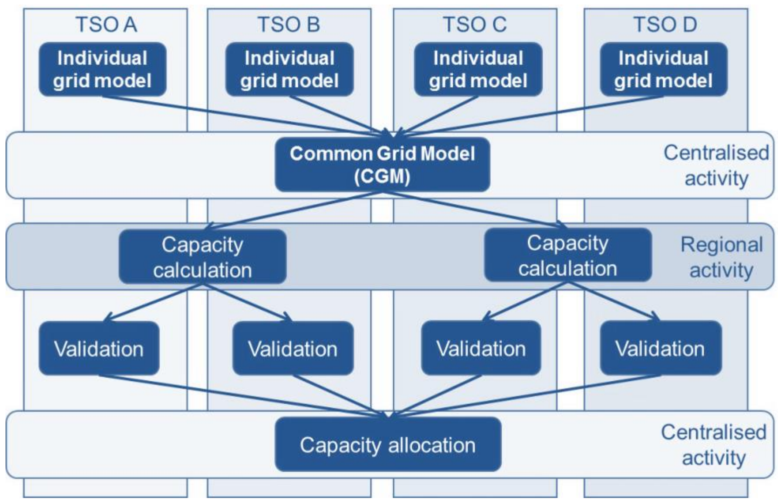

Figure 1 Coordinated capacity calculation process

Figure 1 illustrates whether the respective actions are performed on a TSO, a CCR region, or an European level. The actions requiring the most coordination and harmonization are the building of the CGM followed by the actual capacity calculation and the allocation. Capacity calculation shall be done on a CCR level.

IGMs are built on a TSO level using grid information, and input from market participants. Furthermore, the validation of capacity calculation results is performed at the TSO level, as the TSOs are the responsible parties for network security and can best assess the quality and correctness of the capacity calculation results and they are liable for the power system operation.

2 Legal requirements and their interpretation

This chapter contains a description of the relevant legal references in CACM Regulation including some interpretative guidance.

The legal framework also needs to be interpreted in order to formulate a legally sound proposal on the CCM, to define the scope of this proposal, and to make the proposal implementable.

A number of relevant passages of **the preamble of the CACM Regulation** are cited, that should be taken into account to properly interpret the articles stated further below:

> *"(4) To implement single day-ahead and intraday coupling, the available cross-border capacity needs to be calculated in a coordinated manner by the Transmission System Operators (hereinafter 'TSOs'). For this purpose, they should establish a common grid model including estimates on generation, load and network status for each hour. The available capacity should normally be calculated according to the so-called flow-based calculation method, a method that takes into account that electricity can flow via different paths and optimises the available capacity in highly interdependent grids. The available cross-border capacity should be one of the key inputs into the further calculation process, in which all Union bids and offers, collected by power exchanges, are matched, taking into account available cross-border capacity in an economically optimal manner. Single day-ahead and intraday coupling ensures that power usually flows from low-price to high-price areas.*
>
> *(6) Capacity calculation for the day-ahead and intraday market time-frames should be coordinated at least at regional level to ensure that capacity calculation is reliable and that optimal capacity is made available to the market. Common regional capacity calculation methodologies should be established to define inputs, calculation approach and validation requirements. Information on available capacity should be updated in a timely manner based on latest information through an efficient capacity calculation process.*
>
> *(7) There are two permissible approaches when calculating cross-zonal capacity: flow-based or based on coordinated net transmission capacity. The flow-based approach should be used as a primary approach for day-ahead and intraday capacity calculation where cross-zonal capacity between bidding zones is highly interdependent. The flow-based approach should only be introduced after market participants have been consulted and given sufficient preparation time to allow for a smooth transition. The coordinated net transmission capacity approach should only be applied in regions where cross-zonal capacity is less interdependent and it can be shown that the flow-based approach would not bring added value."*

The most important definitions for the CCM, extracted from **Article 2 of the CACM Regulation**, are as follows:

“6. ‘allocation constraints’ means the constraints to be respected during capacity allocation to maintain the transmission system within operational security limits and have not been translated into cross-zonal capacity or that are needed to increase the efficiency of capacity allocation;

7. ‘operational security limits’ means the acceptable operating boundaries for secure grid operation such as thermal limits, voltage limits, short-circuit current limits, frequency and dynamic stability limits;

8. ‘coordinated net transmission capacity approach’ means the capacity calculation method based on the principle of assessing and defining ex ante a maximum energy exchange between adjacent bidding zones;

9. ‘flow-based approach’ means a capacity calculation method in which energy exchanges between bidding zones are limited by power transfer distribution factors and available margins on critical network elements;

10. ‘contingency’ means the identified and possible or already occurred fault of an element, including not only the transmission system elements, but also significant grid users and distribution network elements if relevant for the transmission system operational security;

11. ‘coordinated capacity calculator’ means the entity or entities with the task of calculating transmission capacity, at regional level or above;

12. ‘generation shift key’ means a method of translating a net position change of a given bidding zone into estimated specific injection increases or decreases in the common grid model;

13. ‘remedial action’ means any measure applied by a TSO or several TSOs, manually or automatically, in order to maintain operational security;

14. ‘reliability margin’ means the reduction of cross-zonal capacity to cover the uncertainties within capacity calculation;”

Furthermore, each proposal shall meet the general objectives of the CACM Regulation as outlined in **Article 3**:

“This Regulation aims at:

(a) promoting effective competition in the generation, trading and supply of electricity;

(b) ensuring optimal use of the transmission infrastructure;

(c) ensuring operational security;

(d) optimising the calculation and allocation of cross-zonal capacity;

(e) ensuring fair and non-discriminatory treatment of TSOs, NEMOs, the Agency, regulatory authorities and market participants;

(f) ensuring and enhancing the transparency and reliability of information;

(g) contributing to the efficient long-term operation and development of the electricity transmission system and electricity sector in the Union;

(h) respecting the need for a fair and orderly market and fair and orderly price formation;

(i) creating a level playing field for NEMOs;

(j) providing non-discriminatory access to cross-zonal capacity."

As a general point, all methodologies and proposals developed under the CACM Regulation should align with the objectives of the CACM Regulation as set out in Article 3. More specifically, **Article 9(9) of the CACM Regulation** requires that:

"The proposal for terms and conditions or methodologies shall include a proposed timescale for their implementation and a description of their expected impact on the objectives of this Regulation."

Article 14 of the CACM Regulation sets requirements for market timeframes to be followed in drafting the CCM:

"1. All TSOs shall calculate cross-zonal capacity for at least the following time-frames:

(a) day-ahead, for the day-ahead market;

(b) intraday, for the intraday market.

2. For the day-ahead market time-frame, individual values for cross-zonal capacity for each day-ahead market time unit shall be calculated. For the intraday market time-frame, individual values for cross-zonal capacity for each remaining intraday market time unit shall be calculated.

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

4. All TSOs in each capacity calculation region shall ensure that cross-zonal capacity is recalculated within the intraday market time-frame based on the latest available information. The frequency of this recalculation shall take into consideration efficiency and operational security."

Article 20 of the CACM Regulation sets deadlines for the CCM proposal and defines several specific requirements that the CCM Proposal for CCR Nordic should take into account:

"1. For the day-ahead market time-frame and intraday market time-frame the approach used in the common capacity calculation methodologies shall be a flow-based approach, except where the requirement under paragraph 7 is met.

2. No later than 10 months after the approval of the proposal for a capacity calculation region in accordance with Article 15(1), all TSOs in each capacity calculation region shall submit a proposal for a common coordinated capacity calculation methodology within the respective region. The proposal shall be subject to consultation in accordance with Article 12. […]

7. TSOs may jointly request the competent regulatory authorities to apply the coordinated net transmission capacity approach in regions and bidding zone borders other than those referred to in paragraphs 2 to 4, if the TSOs concerned are able to demonstrate that the application of the capacity calculation methodology using the flow-based approach would not yet be more efficient compared to the coordinated net transmission capacity approach and assuming the same level of operational security in the concerned region.

8. To enable market participants to adapt to any change in the capacity calculation approach, the TSOs concerned shall test the new approach alongside the existing approach and involve market participants for at least six months before implementing a proposal for changing their capacity calculation approach.

9. The TSOs of each capacity calculation region applying the flow-based approach shall establish and make available a tool which enables market participants to evaluate the interaction between cross-zonal capacities and cross-zonal exchanges between bidding zones."

The FB approach shall be the approach used in the common CCM for the day-ahead and intraday market timeframes, in CCR regions specified in Article 20(2), Article 20(3) and Article 20(4) of the CACM Regulation. For the Nordic CCR, the CACM Regulation (Article 20(1)) gives the possibility, instead of the FB approach, to apply the CNTC approach if the Nordic TSOs are able to demonstrate that the application of the CCM using the FB approach would not yet be more efficient compared to the CNTC approach and given the same level of operational security in the Nordic CCR. Here the efficiency should be defined in the context of the capacity allocation and operational security. Thus for the day-ahead market timeframe, a more efficient approach is the one, which maximizes the social welfare, i.e. the total market value of the day-ahead implicit auctions, and/or increases operational security. Social welfare is computed as the sum of the consumer surplus, the producer surplus, and the congestion income.

Article 21 of the CACM Regulation defines the minimum content for the CCM proposal, including methodologies for the calculation of the inputs to the capacity calculation, a detailed description of the capacity calculation approach, and a methodology for cross-zonal capacity. Besides this, Article 21 requests to define the frequency to reassess capacity for the intraday capacity calculation timeframe, a fallback procedure, and a future harmonization of inputs and methodology across CCRs:

"1. The proposal for a common capacity calculation methodology for a capacity calculation region determined in accordance with Article 20(2) shall include at least the following items for each capacity calculation time-frame:

(a) methodologies for the calculation of the inputs to capacity calculation, which shall include the following parameters:

(i) a methodology for determining the reliability margin in accordance with Article 22;

(ii) the methodologies for determining operational security limits, contingencies relevant to capacity calculation and allocation constraints that may be applied in accordance with Article 23;

(iii) the methodology for determining the generation shift keys in accordance with Article 24;

(iv) the methodology for determining remedial actions to be considered in capacity calculation in accordance with Article 25.

(b) a detailed description of the capacity calculation approach which shall include the following:

(i) a mathematical description of the applied capacity calculation approach with different capacity calculation inputs;

(ii) rules for avoiding undue discrimination between internal and cross-zonal exchanges to ensure compliance with point 1.7 of Annex I to Regulation (EC) No 714/2009;

(iii) rules for taking into account, where appropriate, previously allocated cross-zonal capacity;

(iv) rules on the adjustment of power flows on critical network elements or of cross-zonal capacity due to remedial actions in accordance with Article 25;

(v) for the flow-based approach, a mathematical description of the calculation of power transfer distribution factors and of the calculation of available margins on critical network elements;

(vi) for the coordinated net transmission capacity approach, the rules for calculating cross-zonal capacity, including the rules for efficiently sharing the power flow capabilities of critical network elements among different bidding zone borders;

(vii) where the power flows on critical network elements are influenced by cross-zonal power exchanges in different capacity calculation regions, the rules for sharing the power flow capabilities of critical network elements among different capacity calculation regions in order to accommodate these flows.

(c) a methodology for the validation of cross-zonal capacity in accordance with Article 26.

2. For the intraday capacity calculation time-frame, the capacity calculation methodology shall also state the frequency at which capacity will be reassessed in accordance with Article 14(4), giving reasons for the chosen frequency.

3. The capacity calculation methodology shall include a fallback procedure for the case where the initial capacity calculation does not lead to any results.

4. All TSOs in each capacity calculation region shall, as far as possible, use harmonised capacity calculation inputs. By 31 December 2020, all regions shall use a harmonised capacity calculation methodology which shall in particular provide for a harmonised capacity calculation methodology for the flow-based and for the coordinated net transmission capacity approach. The harmonisation of capacity calculation methodology shall be subject to an efficiency assessment concerning the harmonisation of the flow-based methodologies and the coordinated net transmission capacity methodologies that provide for the same level of operational security. All TSOs shall submit the assessment with a proposal for the transition towards a harmonised capacity calculation methodology to all regulatory authorities within 12 months after at least two capacity calculation regions have implemented common capacity calculation methodology in accordance with Article 20(5).”

According to Article 21 of the CACM Regulation, the proposal shall define methodologies for the calculation of the inputs to the capacity calculation, a detailed description of the capacity calculation approach, and a methodology for the validation of cross-zonal capacity. Cross-zonal is understood to refer to cross bidding zone borders, regardless of whether these borders are within a Member State or between Member States.

The requirement under Article 21(1) (b) (ii), to set rules to avoid undue discrimination between internal and cross-zonal exchanges, implies that unless for reasons of either operational security and economic efficiency, neither internal nor cross-zonal exchanges can be given priority access to transmission capacity within bidding zones. However, due to the zonal approach in the congestion management, it is not possible to expose internal trades to prices competition. This implies that internal trades might be prioritized due to the existence of internal grid limitations when the above-mentioned reasons on operational security and economic efficiency apply. If so, the requests for internal exchanges will get priority access to the scarce network capacity, whereas the requests for cross-zonal exchanges can access only that part of the scarce network capacity that is not already used by internal exchanges. On occasions where the above-mentioned reasons do not apply, limitations on internal network elements will not be considered in the cross-zonal capacity calculation.

Generally, all cross-zonal capacities in CCR Nordic are allocated in day-ahead and intraday market couplings; only on one border PTRs for a forward timeframe are allocated. This implies that for the day-ahead timeframe there are no previously allocated cross-zonal capacities, except for one bidding zone border, where the effect of nominated PTRs to the cross-zonal capacity has to be taken into account when providing cross-zonal capacity to the allocation in the day-ahead timeframe. For the intraday timeframe there are allocated cross-zonal capacities from the day-ahead timeframe and these allocated capacities have to be taken into account when providing cross-zonal capacity to the allocation in the intraday timeframe. Besides this, if there are capacity reservations in the long-term, day-ahead, and intraday timeframe, such as reservations for FRR, these reservations have to be taken into account in the relevant timeframes to define previously allocated cross-zonal capacities. Rules for taking into account previously allocated cross-zonal capacity have to be defined for all bidding zone borders in the intraday and day-ahead timeframe.

Article 21(1)(b)(iv) requires to set rules on the adjustment of power flows on critical network elements (CNEs) or of cross-zonal capacity due to remedial actions (RAs) in accordance with Article 25. Article 25 requires that at least RAs without cost – such as change of grid topology or other measures under TSOs' control – have to be taken into account in the capacity calculation. The effects of the application of these RAs, and application of RAs with costs agreed with market participants – such as countertrading and redispatching – shall be taken into account. For the FB approach, this means adjustments of the remaining available margins (RAMs) of the CNEs, and for the CNTC approach it boils down to an adjustment of the cross-zonal capacity.

Article 21(1)(b)(vi) requires to set the rules for calculating cross-zonal capacity including the rules for efficiently sharing the power flow capabilities of CNEs among the different bidding zones for the CNTC approach. The CNTC approach may be applied in CCRs, where cross-zonal capacity between bidding zones is less interdependent and each bidding zone border can be treated separately during the capacity calculation. However, if interdependency exists, the rules to model this interdependency have to be defined and then applied in the CNTC approach. The FB approach should be used as a primary approach for day-ahead and intraday market timeframe, where cross-zonal capacity between bidding zones is highly interdependent.

Article 21(1)(b)(vii) requires, in cases where the power flows on CNEs are influenced by cross-zonal power exchanges in different CCRs, to set the rules for sharing the power flow capabilities of CNEs among different CCRs in order to accommodate these flows. Generally, the CCRs have been configured to minimize the influence of different CCRs to CNEs in a CCR. This influence can occur especially in CCRs, which reside at the same synchronous area requiring cooperation between neighboring coordinated capacity calculators (CCCs) regarding exchanging and confirming information on interdependency with the relevant regional CCCs and defining together rules to take these interdependencies into account.

Article 21(2) requires that the CCM shall also state the frequency at which capacity will be reassessed in accordance with Article 14(4), giving reasons for the chosen frequency. Article 14(4) requires that all TSOs in each CCR shall ensure that cross-zonal capacity is recalculated within the intraday market timeframe based on the latest available information. In accordance with Article 14(4) the frequency of this recalculation shall take into consideration efficiency and operational security. The frequency of reassessment depends on updates made to the CGM and regional/national updates during the calculation process. Currently it is foreseen that there will be one dedicated European CGM model for each market time unit of the intraday timeframe. However, it is possible to make capacity reassessment based on national/regional updates to the CGMs and to increase the frequency of national/regional capacity reassessments during the intraday market timeframe to ensure operational security while still having an efficient calculation process.

Article 21(3) requires that the CCM shall include a fallback procedure for the case when the initial capacity calculation does not lead to any results. This fallback procedure shall be developed for both the day-ahead and intraday market timeframes.

Article 22 of the CACM Regulation sets requirements to the reliability margin (RM) methodology, which is part of the CCM in accordance with Article 21(1)(a)(i):

> *"1. The proposal for a common capacity calculation methodology shall include a methodology to determine the reliability margin. The methodology to determine the reliability margin shall consist of two steps. First, the relevant TSOs shall estimate the probability distribution of deviations between the expected power flows at the time of the capacity calculation and realised power flows in real time. Second, the reliability margin shall be calculated by deriving a value from the probability distribution.*
>
> *2. The methodology to determine the reliability margin shall set out the principles for calculating the probability distribution of the deviations between the expected power flows at the time of the capacity calculation and realised power flows in real time, and specify the uncertainties to be taken into account in the calculation. To determine those uncertainties, the methodology shall in particular take into account:*
>
> *(a) unintended deviations of 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;*
>
> *(b) uncertainties which could affect capacity calculation and which could occur between the capacity calculation time-frame and real time, for the market time unit being considered.*
>
> *3. In the methodology to determine the reliability margin, TSOs shall also set out common harmonised principles for deriving the reliability margin from the probability distribution.*
>
> *4. On the basis of the methodology adopted in accordance with paragraph 1, TSOs shall determine the reliability margin respecting the operational security limits and taking into account uncertainties between the capacity calculation time-frame and real time, and the remedial actions available after capacity calculation.*
>
> *5. For each capacity calculation time-frame, the TSOs concerned shall determine the reliability margin for critical network elements, where the flow-based approach is applied, and for cross-zonal capacity, where the coordinated net transmission capacity approach is applied."*

Article 23 of the CACM Regulation sets requirements to the methodologies for operational security limits and contingencies and allocation constraints, which is part of the CCM in accordance with Article 21(1)(a)(ii):

> *"1. Each TSO shall respect the operational security limits and contingencies used in operational security analysis.*
>
> *2. If the operational security limits and contingencies used in capacity calculation are not the same as those used in operational security analysis, TSOs shall describe in the proposal for the common capacity calculation methodology the particular method and criteria they have used to determine the operational security limits and contingencies used for capacity calculation.*
>
> *3. If TSOs apply allocation constraints, they can only be determined using:*
>
> *(a) constraints that are needed to maintain the transmission system within operational security limits and that cannot be transformed efficiently into maximum flows on critical network elements; or*
>
> *(b) constraints intended to increase the economic surplus for single day-ahead or intraday coupling."*

Operational security limits mean, in accordance with Article 2(7), the acceptable operating boundaries for secure grid operation such as thermal limits, voltage limits, short-circuit current limits, frequency and dynamic stability limits. The list consists of the limits applied currently in the operational security analysis. Operational security limits are the same for CGM scenarios (e.g. minimum and maximum voltage and frequency limits, damping limits for voltage or rotor angle stability) and may be updated when ambient conditions (e.g. temperatures) or voltage/current ranges of devices connected to the grid (e.g. maximum currents, lowest voltages) change. Furthermore, guiding principles are needed to ensure that all TSOs in the CCR Nordic are using the same definitions when submitting operational security limits to the CCC. TSOs have to be transparent on the application of these operational security limits. These operational security limits will be applied to define maximum flows across CNEs or bidding zone borders.

Contingency means, in accordance with Article 2(10), the identified and possible or already occurred fault of an element, including not only the transmission system elements, but also significant grid users and distribution network elements if relevant for the transmission system operational security.

The contingencies shall be the same as those for the security analysis in accordance with the SO Regulation, generally meeting all N-1 situations, and thus there is no need to describe the particular method and criteria to be used to determine contingencies used in the capacity calculation.

Allocation constraints mean, in accordance with Article 2(6), the constraints to be respected during the capacity allocation to maintain the transmission system within operational security limits and that have not been translated into cross-zonal capacity or that are needed to increase the efficiency of capacity allocation.

TSOs may use these constraints in two occasions and they can be only used in the allocation phase, not in the capacity calculation phase. First usage of the allocation constraints is to maintain operational security in case where such constraints cannot be efficiently transformed to maximum flows on critical network elements. These constraints can be e.g. minimum production capacity or reserves within a bidding zone, or ramping constraints between market time units. Second usage of the allocation constraints is to increase economic surplus for single day-ahead or intraday coupling. These constraints can be e.g. losses on HVDC interconnections.

Article 24 of the CACM Regulation sets requirements to the generation shift key (GSK) methodology, which is part of the CCM in accordance with Article 21(1)(a)(iii):

> *"1. The proposal for a common capacity calculation methodology shall include a proposal for a methodology to determine a common generation shift key for each bidding zone and scenario developed in accordance with Article 18.*
>
> *2. The generation shift keys 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 common grid model. That forecast shall notably take into account the information from the generation and load data provision methodology."*

GSK means, in accordance with Article 2(12), a method of translating a net position change of a given bidding zone into estimated specific injection increases or decreases in the CGM.

A common GSK shall be developed for each bidding zone and scenario. GSKs will be used to translate a change in net positions into specific nodal injections in the CGM to reflect best the forecasted change in generation or load within a bidding zone.

Article 25 of the CACM Regulation sets requirements to the methodology for RAs in capacity calculation, which is part of the CCM in accordance with Article 21(1)(a)(iv):

> *"1. Each TSO within each capacity calculation region shall individually define the available remedial actions to be taken into account in capacity calculation to meet the objectives of this Regulation.*
>
> *2. Each TSO within each capacity calculation region shall coordinate with the other TSOs in that region the use of remedial actions to be taken into account in capacity calculation and their actual application in real time operation.*
>
> *3. To enable remedial actions to be taken into account in capacity calculation, all TSOs in each capacity calculation region shall agree on the use of remedial actions that require the action of more than one TSO.*
>
> *4. Each TSO shall ensure that remedial actions are taken into account in capacity calculation under the condition that the available remedial actions remaining after calculation, taken*

together with the reliability margin referred to in Article 22, are sufficient to ensure operational security.

5. Each TSO shall take into account remedial actions without costs in capacity calculation.

6. Each TSO shall ensure that the remedial actions to be taken into account in capacity calculation are the same for all capacity calculation time-frames, taking into account their technical availabilities for each capacity calculation time-frame."

RA means, in accordance with Article 2(13), any measure applied by a TSO or several TSOs, manually or automatically, in order to maintain operational security. RAs can be applied also in the capacity calculation phase, where each TSO shall individually define the available RAs to be taken into account to meet the objectives under Article 3 of the CACM Regulation.

RAs without costs (such as grid topology change, phase shifter actions, system protection schemes[5]) shall be taken into account in the capacity calculation and costly RA will be taking into account if available, but only if the EU-wide economic efficiency of applying the costly RA compared to the option of limiting cross border exchanges can be demonstrated

Each TSO has to coordinate the use of RAs, to be taken into account in the capacity calculation, with other TSOs in the same CCR. RAs can be taken into account in the capacity calculation on the condition that the RAs available after the capacity calculation are sufficient to ensure operational security.

The RAs to be taken into account in capacity calculation shall be the same for all capacity calculation timeframes (from day-ahead to intraday timeframe), taking into account their technical availabilities for each capacity calculation timeframe.

Article 26 of the CACM Regulation sets requirements to a cross-zonal capacity validation methodology, which is part of the CCM in accordance with Article 21(1)(c):

"1. Each TSO shall validate and have the right to correct cross-zonal capacity relevant to the TSO's bidding zone borders or critical network elements provided by the coordinated capacity calculators in accordance with Articles 27 to 31.

2. Where a coordinated net transmission capacity approach is applied, all TSOs in the capacity calculation region shall include in the capacity calculation methodology referred to in Article 21 a rule for splitting the correction of cross-zonal capacity between the different bidding zone borders.

3. Each TSO may reduce cross-zonal capacity during the validation of cross-zonal capacity referred to in paragraph 1 for reasons of operational security.

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[5] *Please note that system protection schemes might bring a cost when they are activated.*

4. Each coordinated capacity calculator shall coordinate with the neighbouring coordinated capacity calculators during capacity calculation and validation.

5. Each coordinated capacity calculator shall, every three months, report all reductions made during the validation of cross-zonal capacity in accordance with paragraph 3 to all regulatory authorities of the capacity calculation region. This report shall include the location and amount of any reduction in cross-zonal capacity and shall give reasons for the reductions.

6. All the regulatory authorities of the capacity calculation region shall decide whether to publish all or part of the report referred to in paragraph 5."

3 Introduction to FB capacity calculation methodology

The purpose of this chapter is to introduce the FB approach and highlight the differences compared to CNTC. The introduction will be relatively high level and aims at giving the overall understanding of FB approach and the motivation behind using the approach before more technical descriptions in the subsequent chapters.

3.1 Motivation behind introducing FB approach in the CCR Nordic

In the electricity markets, the transmission grid constrains how much electricity can be transferred between any two points in the grid. Even if these limitations can be removed by new investments, investments in transmission capacity is capital intensive and has a diminishing marginal value. Thus unlimited expansion of the transmission grid is unrealistic due to economics. This limiting nature of the transmission grid creates a need to have a methodology to optimize the utilization of the transmission grid according to the demand for electric power, and the complex physical limits of the grid must be expressed in a simplified manner to be communicated and understood by the electricity market.

Renewable energy is also a factor that creates a need for focusing of optimizing the scarce transmission capacity. When renewable energy is integrated into an electricity system, the location of the renewable energy can often be concentrated due to advantageous geographical areas, and weather patterns like wind that moves across geographical areas, which creates large differences in production volumes. To accommodate the difference in production there is a need to transport large quantities of electrical power across geographical areas. An example of this could be a windy day in the south west of Scandinavia. In such situations, Denmark has excessive wind production at a low marginal cost. This excess power could be moved to Sweden and Norway at higher prices, thus optimizing the value of the renewable production. In turn on a day with low wind, Denmark can benefit from the hydro production in Norway. To illustrate the current Nordic power system, see Figure 2.

Figure 2 Map showing the Nordic power system (ENTSO-E, 2016). The transmission grid is needed to transport electric power from sites of generation to sites of consumption, but this grid has a limited capacity to transmit electric power.

In reality, a power system is a non-linear system with endless complexities. However, the algorithms used to calculate the electricity prices and volumes are simplified in order to meet operational requirements. One of the simplifications is the representation of transmission grid capacities. In the price calculation algorithm, transmission capacities are represented as linear constraints where all constraints are modeled as fixed numbers. This gives the TSOs the task of supplying accurate information to the algorithm while respecting the constraints on linearity. Another of the simplifications is the representation of bidding zones. In reality, a power system consists of nodes that are geographically be located. In the simplification a large set of nodes are clustered together in a bidding zone, and the transmission grid is represented by bidding zone borders, thus congestions occurs on these borders in the electricity market, but in reality these congestions could be caused by any internal node and/or line not only at the bidding zone borders.

The better the representation of the transmission grid is in the electricity market, the more accurate the TSO can feed physical constraints into the price calculation algorithm. The motivation behind introducing the FB approach, is that the FB approach has the potential to better take into account the physical flow and constraints compared to the current NTC method. A better representation gives a better chance of optimizing the utilization of the scarce transmission capacity, which should lead to more accurate price signals and increased social economic welfare.

Over the last ten years several new HVDC interconnections have been commissioned across Europe, and in the coming years we expect further development of the transmission grid in terms of interconnections. Europe has also seen a sharp increase in the amount of renewable energy in the power system, and in order to fulfill emission reduction targets it is expected to increase further. This development has increased the interdependency as well as the complexity of the power system, and has increased volatility in production patterns. This has made it difficult to decide how to share transmission capacity for different bidding zone borders within the current NTC approach.

According to the CACM, the future capacity calculation methodology for the European day-ahead and intraday markets may be either FB or a CNTC approach. However the CACM Regulation requires that "*TSOs may jointly request the competent regulatory authorities to apply the coordinated net transmission capacity approach if the TSOs concerned are able to demonstrate that the application of the capacity calculation methodology using the flow based approach would not yet be more efficient compared to the net transmission capacity approach and assuming the same level of operational security in the concerned region*". It is not assumed that the CNTC method is as efficient as FB approach in the CCR Nordic. This is due to the presence of high levels of renewables and the relatively large number of bidding zones and interconnections between these bidding zones. This assumption effectively means that the CCR Nordic has to develop FB approach as the capacity calculation methodology in the future.

To illustrate the complexity and challenges within the CCR Nordic, the interdependencies in the power grid are illustrated in Figure 3 Commercial flows vs physical flows in the Nordic grid. Power is injected in bidding zone NO3 and consumed in bidding zone SE2. The figure illustrates a situation with a generation increase in bidding zone NO3 that is “consumed“ in bidding zone SE2 (yellow arrows). With the current NTC approach, this would generate a commercial trade between the two areas, as illustrated by the orange arrow.

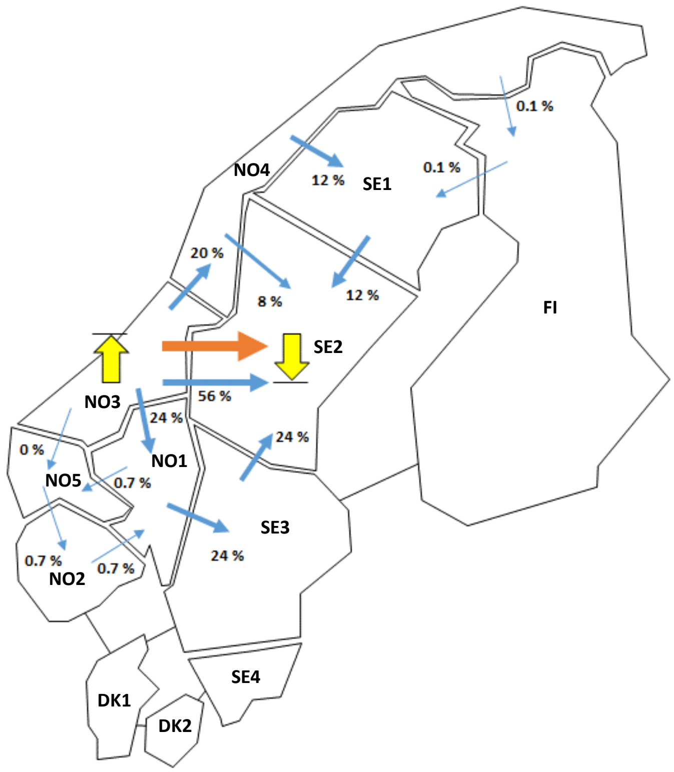

Figure 3 Commercial flows vs physical flows in the Nordic grid. Power is injected in bidding zone NO3 and consumed in bidding zone SE2

In reality, the physical flow from this trade would fan out in the transmission grid and follow the blue arrows in Figure 3. The largest flows are in the central area, but many tiny flows arise all over the power system as a consequence of the trade. All smaller transit flows are disregarded by the market, but in reality these flows are using available transmission capacity in other parts of the power system. This is called an external effect, and it has a negative impact on other market participants, who will face less transmission capacity due to this trade.

In the current NTC based capacity allocation method, the TSOs take the transit flows into account when calculating the amount of transmission capacity to be allocated on each bidding zone border in the day-ahead and intraday markets. If the forecasted trade is not realized, then the reductions due to transit flows are useless. This makes the accuracy of the TSO forecasts very important for the efficiency of the system, as these forecasts affect the capacity calculation and its outcome.

In the FB approach, the transit flows are internalized into the market. This means that all commercial exchanges have to compete for the transmission capacity, including transit flows. This internalization should in theory make the FB approach more efficient at managing congestions of the transmission grid.

3.2 Description of FB approach

In order to understand the FB approach this section will to some extent compare the differences of FB and (C)NTC approaches, this is to help the reader understand the changes in the capacity calculation once the approach is switched from the current NTC approach to FB approach. It is important to note that NTC is not CACM compliant, which means that some changes have to be made even if FB approach didn't have additional benefits compared to CNTC approach, although changes are in this case smaller and not affecting the output format of the results to market participants.

The Nordic day-ahead electricity market is part of the larger European electricity market. Market participants submit orders to the Nominated Electricity Market Operator[6] (NEMO). The NEMO forwards the orders to the joint European market coupling function (MCO) where the price coupling algorithm, Euphemia, solves an European-wide equilibrium, based on explicit economic welfare optimization. The organization of the intraday market is slightly different from the day-ahead market. In the intraday market, market participants submit orders to the NEMO, who forwards the orders to the intraday market platform. However, there is no explicit welfare optimization, rather a continuous matching of bids taking into account the transmission grid constraints. The process looks different from the day-ahead process, but in essence the outcome will be an implicit optimization of economic welfare taking into account the transmission grid constraints.

The market results of the intraday and day-ahead allocation process have to respect the physical limitations of the transmission grid. For this purpose, the TSOs currently provide transmission capacities between bidding zones to the market. These transmission capacities act as constraints in the day-ahead and intraday market coupling algorithms.

In the FB approach the market coupling algorithm receives constraints in the format of power transfer distribution factors (PTDF) and remaining available margins (RAM), rather than transmission capacity between bidding zone borders. Essentially RAM can be understood as the transmission capacity given to the market. To understand what PTDFs are, it is useful to illustrate the difference between FB and CNTC approaches using a simple three bidding zone grid shown in Figure 4.

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[6] *There may be more than one NEMO in an area, but this does not change the procedure, the market participant just chooses one of the approved NEMOs.*

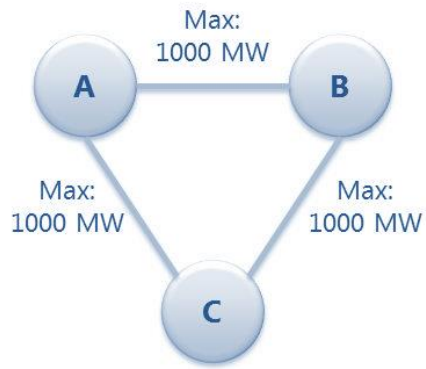

Figure 4 Transmission grid with three bidding zones.

In this example there are no internal constraints within the bidding zones, complex grid limitations or outages being considered. This means that the only limiting grid elements are the connecting transmission lines between the bidding zones[7]. All lines have a thermal capacity of 1000 MW and equal impedance (equal "electrical distance"). This thermal capacity of 1000 MW is referred to as RAM. RAM is the factor limiting the sum of power flows coming from all bidding zones that may flow on a particular connecting line at one point of time. Bidding zone C is a consumption bidding zone while bidding zones A and B are generation zones. At the time of capacity calculation (D-1)[8], the TSO does not know the final net position in the bidding zones, only the physical properties of the transmission grid. Due to the transmission grid topology, one MW produced in bidding zone A will induce a flow of 2/3 MW on the connecting line AC, 1/3 MW on the connecting line AB and 1/3 MW on the connecting line BC. The same holds true for generation in bidding zone B of which -1/3 appears on AB, 1/3 on AC and 2/3 on BC. These factors are known as PTDFs. PTDFs are parameters, which show how much power is flowing on a particular transmission grid element when injecting one additional MW in a particular bidding zone.

In this example bidding zone C is a "slack node", this means that all power injected in bidding zones A and B is (mathematically) absorbed in bidding zone C. The same holds true for bidding zone C itself, all power injected in bidding zone C is absorbed in C. The flow influence of each bidding zone to each connecting line defines the PTDF matrix in Table 1.

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[7] *This is a simplification – in reality constraints in the form of CNEs can be anywhere inside the bidding zone.*

[8] *The capacity calculation starts at D-2. Final values are provided to the market at D-1*

Table 1 PTDF matrix of the transmission grid in Figure 4

Line	RAM	A	B	C
A->B	1000	1/3	-1/3	0
A->C	1000	2/3	1/3	0
B->C	1000	1/3	2/3	0

The main difference between FB and CNTC approach is that in the CNTC approach the parameters above (PTDFs and RAMs) would not be provided to the NEMO, which means that only FB approach has a built-in representation of the actual power flows. In CNTC approach an example could be that it is assumed that one MW produced in bidding zone A flows with an equal distribution between connecting lines AC and AB/BC. This would allow the market coupling algorithm to carry 2000 MW from bidding zone A to bidding zone C, as this would create a flow of 1000 MW on connecting line AC and 1000 MW on connecting lines AB/BC. In reality this would create an overload as the PTDFs show that 2000 MW injected in bidding zone A would create a physical flow of 2/3*2000 = 1333 MW on connecting line AC which is in breach of the thermal limits. In this case a possible way to solve the issue in the CNTC approach is to limit the exchange capacity to 750 MW on connecting lines AC and AB/BC, other solutions are also feasible e.g. setting connecting line AC to 1500 MW and connecting lines AB/BC to 0 MW.

The FB approach will yield a larger set of possibilities, as this method will take the PTDF matrix into account. An example of this would be a situation where the following injection is made A=2000, B=-1000 and C=-1000, this would induce a flow of 2000*1/3-1000*(-) 1/3-1000*0=1000 on connecting line AB.

The solution domains for CNTC and FB approaches are illustrated in Figure 5.

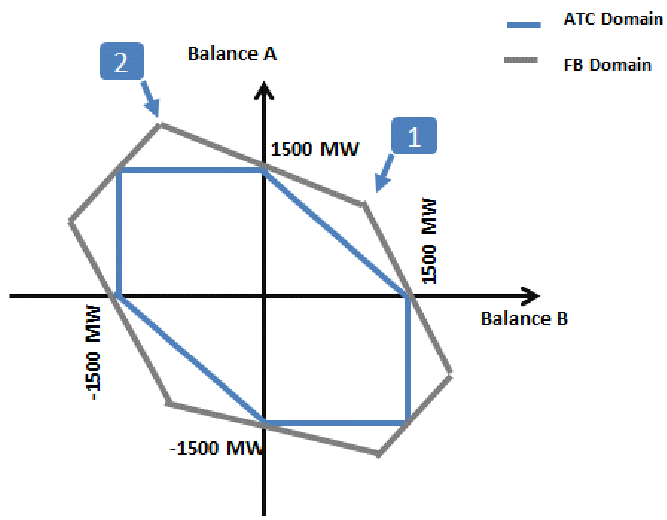

Figure 5 Solution domains for CNTC and FB approaches

As it is shown in Figure 5, all CNTC solutions are contained in the FB solution domain. This means that the FB approach has at least the same amount of possible solutions, and theoretically more. All points on the FB boundaries reflect transmission capacity limits in the grid that will induce price differences in all nodes, without implying that all transmission lines are congested simultaneously. This market solution is, however, not possible in the CNTC approach due to the fact that in CNTC allocation the real physical flows (the PTDF matrix) are not known between bidding zones.

It is important to note some simplifications of the FB approach. As mentioned earlier in this chapter multiple nodes are combined into one bidding zone. In the pure version of FB approach, called nodal pricing, each node would constitute its own bidding zone having its own price. In the FB approach applied in Europe, nodes are combined into bidding zones. This is done to satisfy the practicality in keeping the number of bidding zones relatively low – in the Nordic countries there are altogether 12 bidding zones. A new issue arises when combining nodes into bidding zones; how to secure a balance between generation and consumption in each node if the price – in contrast to nodal pricing – cannot be used as the balancing mechanism?

This issue is solved using GSKs. The GSK is a value which is used in the translation from node-to-CNE PTDFs to zone-to-CNE PTDFs. The relation is formally expressed as:

$$PTDF_j^A = \sum_\alpha GSK^\alpha * PTDF_j^\alpha, \qquad \text{and} \qquad \sum_\alpha GSK^\alpha = 1 \qquad (1)$$

$PTDF_j^A$ = Sensitivity of CNE "j" to injection of 1MW in bidding area "A"

$PTDF_j^{\alpha}$ = Sensitivity of CNE"j" to injection of 1MW in bidding area "α"

GSK^{α} = Weight of node "α" on the PTDFs of bidding zone "A"

The FB approach makes use of GSKs to describe how the net position of one node changes with the net position of the bidding zone it is a part of, hence the GSKs for a particular bidding zone shall sum to 1.

There is an infinite amount of different ways, or strategies, for how to generate GSKs, and none of the GSK strategies are theoretically right or wrong. However, it is important to understand that the choice of GSK strategy will influence the market. A poor choice might result in a large adverse market influence, thus making GSKs and the GSK strategy one of the biggest sources of inaccuracies in the calculation of the FB parameters (PTDFs and RAMs). The perfect strategy would mimic the market outcome of nodal pricing, but this is not possible as this would require perfect foresight of the TSO, which might not be possible in current liberalized electricity markets.

The GSK parameters (or GSK factors) are a linear representation of a complex non-linear process, and the simplest form of a GSK strategy is flat participation. This means that each node inside a bidding area will have an equal impact on a particular zone-to-CNE PTDF for that bidding zone, which theoretically might require more generation from a node than the maximum installed generation capacity at that node. However, the strength of GSK strategies is that the design is not limited to using the same strategy for all bidding zones. It is possible that the optimal strategy for each bidding zone and time stamp might differ. Luckily, it is possible in the FB approach (or in CNTC approach) to take into account differences in optimal GSK strategies, but identifying the optimal GSK strategy for each bidding zone and each time stamp is demanding. It is, however, a requirement in the CACM Regulation, that the rules guiding GSK strategies are harmonized across TSOs as they have such a large impact on capacity allocation.

In the initial version of the Nordic FB approach, the flat GSK strategy has been applied. However, outcomes from other GSK strategies will be monitored to provide an empirical basis for further development of the Nordic FB approach.

Another imperfection of the FB approach is loop flows. Loop flows arise when a commercial trade within a bidding zone creates flows that run through other bidding zones to end back in the original bidding zone. Loop flows do not exist in a nodal pricing system; in the FB approach they arise as a consequence of keeping the existing bidding zone structure. In the ACER recommendations “On the common capacity calculation and re-dispatching and countertrading cost sharing methodologies” it is specified as a general principle that cross zonal capacities should not be lowered as a consequence of loop flows. In the short run, loop flows have to be handled by RAs such as counter trading and redispatching. In the medium term, loop flows should be handled by reconfiguring bidding zones, and in the long run they should be handled by investments in the transmission grid.

The Nordic power system is far more complex than illustrated in the simple three bidding zone transmission grid in Figure 4. Thus, the complexity of assigning exchange capacity is also far more complex. This is illustrated in Figure 6, with the real bidding zones and connections in the Nordic system.

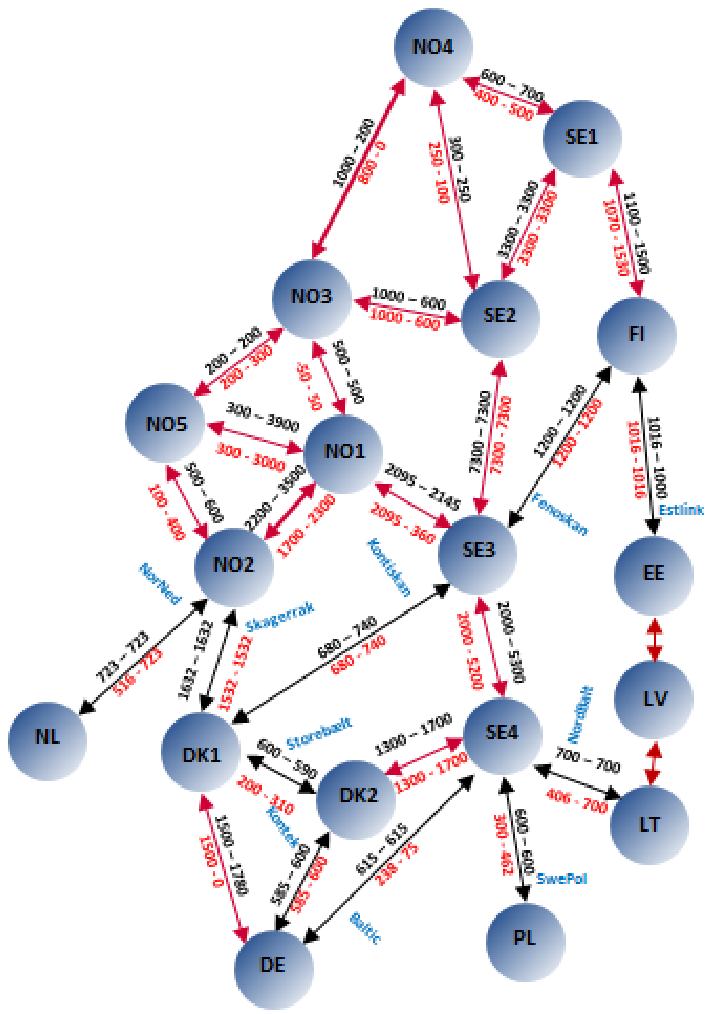

Figure 6 The Nordic power system and its connections to neighboring power systems.
This figure gives a schematic overview of the Nordic power system. AC interconnections are illustrated by red arrows and DC interconnections by black arrows. The maximum power exchange values for each interconnection is shown in black numbers, together with the provided transmission capacities for Jan 6'th 2017 at hour 10:00 – 11:00 in red numbers. The differences are due to both loop flow considerations and the outage situation on the relevant day. The Nordic bidding zones DK1, DK2, SE4 and FI are radially connected to the rest of the Nordic AC system, and thus not influenced by loop flows. The rest of the Nordic power system is interdependent and influenced by loop flows.

There are currently twelve bidding zones within the Nordic countries and five connected external bidding zones in the CCRs of Core, Hansa, and the Baltic. Altogether, there are 26 connections between bidding zones within the Nordic countries and between the Nordic countries and the external areas in other CCRs. For each interconnection, there is one transmission capacity in each direction for each hour of the day, and thus, the Nordic TSOs provides 1248 hourly transmission capacities per day, and 455 520 hourly transmission capacities per year.

4 Motivation for the articles in the CCM proposal

This chapter presents explanations of the proposed CCM articles. The aim of the chapter is to provide for a motivation for the content of each of the articles and the thinking that lies behind.

4.1 Article 2: Definitions and interpretation

"Advanced Hybrid Coupling"

The term "hybrid coupling" refers to the integration of the two capacity calculation methodologies, the CNTC and the FB approach.

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 CNTC 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 (or nodal) approach is the only one of the two which is able to manage real physical power flows.

In the Nordic countries, all interconnections to adjacent synchronous areas are either HVDC or radial interconnections. These parts of the Nordic transmission grid area by definition a physical embodiment of CNTC, and it doesn't make sense to implement an FB approach on these parts of the transmission grid (an FB approach would anyhow behave as a CNTC approach). With this realization in mind, the Nordic CCM have to apply a hybrid coupling to integrate the HVDC and radial AC interconnections in the meshed AC grid.

The "hybrid coupling" might be either the standard hybrid coupling (SHC) or the advanced hybrid coupling (AHC). Before entering into the explanation of SHC and AHC, it is important to bear in mind that when the power flows from an HVDC or a radial AC interconnection enters the meshed AC transmission grid, the power flow will fan out in the AC transmission grid and use the scarce transmission capacity like all other power flows in the transmission grid.

The distinction between SHC and AHC is the difference in how power flows coming from a radial AC or HVDC interconnection are managed by the market coupling in the meshed AC transmission grid. On a high level, the SHC 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 AHC, these power flows are subjected to competition for transmission capacity with all other power flows in the transmission system.

In the rest of this chapter, the term HVDC interconnection means both radial AC and HVDC interconnections. Both SHC and AHC are based on CGMs. In SHC, an expected flow on the HVDC interconnection is at first calculated for the base case net positions. In order to guarantee the estimated power flow on HVDC interconnection, the resulting power flows in the meshed AC grid must be granted priority access on the relevant grid limitations. This can be done by applying the nodal PTDF matrix on all limiting CNEs from the "access point node" of the relevant HVDC interconnection to calculate the amount of MWs the estimated HVDC flow puts on all CNEs in the meshed AC power system. The calculated amount of MW for each CNE is removed from the relevant RAMs to make room for the estimated flow from the HVDC interconnection. The adjusted RAMs are provided for allocation to the market coupling for all other power flows.

If the realized HVDC power flow falls below the estimated power flow, the SHC process might thus leave "unused" transmission capacity on CNEs, even with excess demand for that transmission capacity by other power flows. The SHC is by the same mechanism neither able to optimize the distribution of transmission capacity between different HVDC interconnections or between HVDC interconnections and other potential efficient power flows in the system. Thus, the SHC is clearly not able to ensure optimal use of transmission infrastructure.

In the AHC, the nodal PTDFs from the "access point node" is provided directly to the market coupling for allocation, and the RAMs for the affected CNEs in the AC transmission grid are left intact without reductions caused by the HVDC power flows. The "access point node" is established as a "virtual bidding zone" in the market coupling. This "virtual bidding zone", which is a bidding zone without any orders from market participants, is "only seen" by the market coupling during capacity allocation, in the sense it will obtain a unique price in the market equilibrium, while the actual power traded on the HVDC, will receiving the market price of in the surrounding bidding zone. In the AHC, each HVDC interconnection is provided with its own virtual bidding zone with unique PTDFs.

With the AHC, the power flows from the HVDC interconnections become a part of the FB approach within a CCR, and are thus treated as all other power flows in competing for transmission capacity. Transmission capacity in the meshed AC grid will be assigned for the power flows from each individual HVDC interconnection due to price differences and impact on CNEs in the AC transmission grid based on the competitiveness of the power flows coming from the individual HVDC interconnection.

By utilizing the AHC, there is no priority for HVDC power flows on any interconnection, and by utilizing the market coupling, the allocation of power flows between different HVDC interconnections will be optimized, as will the allocation of power flows between HVDC interconnections and all other power flows in the power system. This leaves no unused transmission capacity with excess demand. The AHC is thus a more flexible approach than the SHC in managing power flows on/from HVDC interconnections in the meshed AC transmission grid, and also the welfare economic more efficient congestion management approach.

"Base Case"

The "base case" (BC) is the forecasted state of the power system for a specific capacity calculation timeframe. For the day-ahead and intraday market timeframe, the BC is the forecasted state of the power system for a specific hour of a specific day of the year. Looking at one specific hour, the BC might be updated as moving from the day-ahead to the intraday market timeframe due to new information that serves the purpose of improving the quality of the BC.

Each BC for each market timeframe contains information on the expected transmission grid topology and on the expected net positions of bidding zones. The net position of each bidding zone is further distributed to nodal net positions by the use of the chosen GSK strategy, and thus, the BC will contain the expected flows on all transmission elements to the level of details embedded in the CGM.

The construction of the day-ahead BC for day D will start at D-2 based on the D-2 net positions from the D-2 market solution and planned outages for day D. The BC may be updated during the time until final day-ahead transmission capacities are released to the market at D-1 at 11 CET. Updates might for example be due to better wind or temperature forecasts, unplanned outages or other relevant information to improve the quality of the BC. After the day-ahead transmission capacities are released at D-1, the BC may be further updated for the intraday market timeframe due to similar information. In the FB approach, the BC is of importance as a linearization point for the PTDF matrix calculation, and thus implicitly for the calculation of F'_{ref} and RAMs. In CNTC, the BC also carries important information for the application of the rules for sharing transmission capacities of CNEs on the different bidding zone borders.

“Network element”

Network element means a component or several components, such as power transfer corridor (PTC), in the power system. PTC is a set of several transmission lines or other grid components imposing a MW limit for operational security reasons.

4.2 Article 3: Methodology for determining reliability margin (RM)

Reliability margin (RM), more specifically flow reliability margin (FRM) for a FB approach and transmission reliability margin (TRM) for a CNTC approach, is a fundamental element in managing uncertainty in capacity calculation. The RM is defined in Article 2 in CACM Regulation as: ‘*reliability margin’ means the reduction of cross-zonal capacity to cover the uncertainties within capacity calculation*. Due to uncertainties, the power system operator cannot fully predict what power flow will be realized on each CNE or cross-zonal border for a certain hour in day D given the information available at D-2 (or correspondingly for intraday market timeframe). There will always be prediction errors. The uncertainty originates from the ex-ante capacity calculation, and boils down to uncertainties for market, model and calculation method. The power flow may be larger or smaller than anticipated, and if the power flow turns out to be larger, there may be a risk for an overload which needs to be mitigated by the TSO. In order to reduce the risk of physical overloads, a part of the transmission capacity on each CNE or cross-zonal border shall be retained from the market as RM, reducing the RAM or cross-zonal capacity provided to the market coupling for allocation to facilitate cross-border trading.

The RM value is normally defined in MW, but can also be presented as a percentage of the Fmax on CNEs or the maximum cross-zonal capacity value for CNTC. The value is individually quantified for each cross-zonal capacity and is based on a probability distribution of the prediction error of the power flow.

The outline of this section is as follows. First a general description of the RM methodology is presented, describing the overall methodology on a high level. This is followed by a more detailed description of the actual method implementation. The two following sections describe the harmonized principles for the method and the uncertainties taken into account. Finally, the implementation of FRM in FB approach, and TRM in CNTC approach, is described and the update periodicity is defined.

Proposed RM methodology

CACM Regulation Article 22, "Reliability margin methodology", paragraph 1 states that:

> *"[…] The methodology to determine the reliability margin shall consist of two steps. First, the relevant TSOs shall estimate the probability distribution of deviations between the expected power flows at the time of the capacity calculation and realized power flows in real time. Second, the reliability margin shall be calculated by deriving a value from the probability distribution."*

The RM methodology for the FB approach and CNTC approach is similar, the only difference being that in the FB approach the FRM is calculated for CNEs and in the CNTC approach the TRM is calculated for cross-zonal capacities.

The two steps in the requirement form the basis for the proposed RM methodology. Figure 7 shows a general overview of the proposed RM methodology, which applies both for the CNEs and cross-zonal network elements.

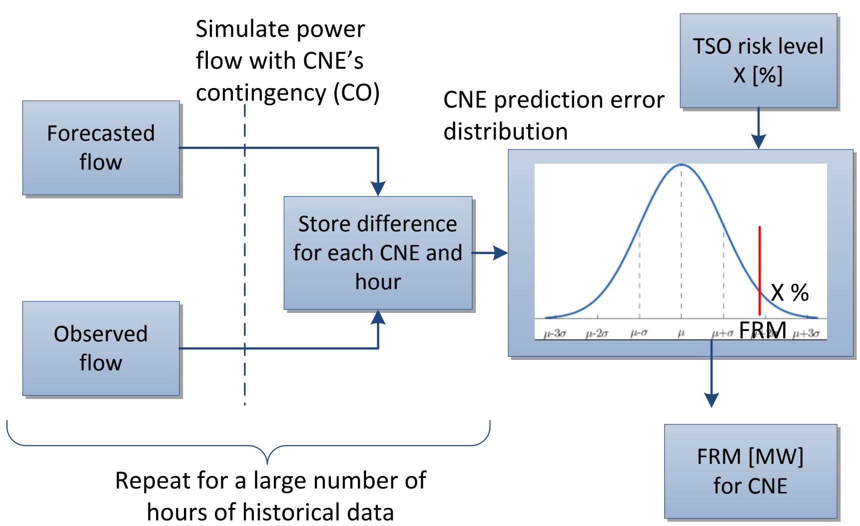

Figure 7. A schematic overview of the proposed RM methodology with its two steps; first a probability distribution is established based on historical data, then the RM value is derived from this distribution based on the set risk level.
The figure shows how the prediction error probability distribution is deduced for the CNE, given a power flow simulation with the

contingency activated for the observed and forecasted system state. The same fundamental technique applies for the cross-zonal network elements with the exception that these do normally not include a contingency in its definition.

In the first step a probability distribution of the deviation between the forecasted and realized (observed) power flows is determined for each CNE or cross-zonal network element, based on a large number of historical snapshots[9] of the CGM for different hours. The power flows of CNEs are calculated with a power flow simulation tool with the contingency for the CNE tripped[10]. The AC load flow simulation is normally used, with the DC load flow simulation as a fallback in case of non-convergence. A large number of observed differences (in MW) form the prediction error distribution for the CNE or cross-zonal network element.[11] The prediction error data is then fitted to a statistical distribution that minimizes the model error. This can be the normal distribution or any other suitable distribution.

In the second step of the methodology, the RM value is calculated by deriving a value from the probability distribution based on the TSOs risk level value [%]. The risk level is here defined as the area (cumulative probability) right of the RM value in the prediction error probability distribution.[12] With a risk level of *X* %, the likelihood of having a prediction error greater than the RM value is *X* %, based on the historical observations for the CNE or cross-zonal network element.[13] A low risk level results in high RM values and vice versa. A TSO may use different risk levels for different CNEs and cross-zonal network elements.

As an initial value, the TSOs have agreed to use a 95% risk level.

Principles for calculating the error distribution and the uncertainties

The principles for calculating the probability distribution should be described, together with the uncertainties taken into account by the RM methodology, as defined in paragraph 2 in Article 22 in the CACM Regulation:

> *"The methodology to determine the reliability margin shall set out the principles for calculating the probability distribution of the deviations between the expected power flows at the time of the*

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[9] A snapshot is like a photo of a TSO's transmission system state taken from the TSOs' control system, showing the voltages, currents, and power flows in the power system at the time of taking the photo.

[10] Hereby, the difference in power flows for the forecasted and observed flow for the CNE is calculated for the "N-1" grid state where this is applicable for the CNE. For CNEs or cross-zonal network elements with no contingency included, the forecasted and observed power flows are calculated for the intact transmission grid (N grid state).

[11] Note that e.g. a line monitored with five CNEs, each with different contingencies, will have five different prediction error distributions and FRM values.

[12] The risk level can also be defined as 1.0 subtracted with the percentile at the RM value in the probability distribution.

[13] See Figure 7. With a risk level of 10%, 90% of the cumulative probability (area) in the distribution is left of the FRM value.

capacity calculation and realized power flows in real time, and specify the uncertainties to be taken into account in the calculation. To determine those uncertainties, the methodology shall in particular take into account:

(a) unintended deviations of 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;

(b) uncertainties which could affect capacity calculation and which could occur between the capacity calculation time- frame and real time, for the market time unit being considered."

This subsection describes the principles for establishing the probability distribution and the uncertainties that are taken into account.

As previously shown in Figure 7, the basic idea behind the RM determination is to quantify the power flow uncertainty by comparing the forecasted power flow with the observed power flow in the corresponding snapshot of the CGM. Figure 8 shows a more detailed picture of the proposed method for deducing the distribution for each CNE and cross-zonal network element. The forecasted power flow in the base case is compared with the realized power flow observed in a snapshot taken from the TSOs' control system. In order to compare the observed power flows from the snapshot with the predicted flows in a coherent way, the forecasted CNE and cross-zonal network element power flows are adjusted by using the realized net positions from the snapshot, as illustrated in Figure 8. The reason for this model adjustment is that the intraday and bilateral trades as well as imbalances and reserve activations are reflected in the observed power flows and need to be reflected in the predicted power flows as well for a correct comparison. Indeed, in this way, only the following element of the RM is being covered:

(b) uncertainties which could affect capacity calculation and which could occur between the capacity calculation time- frame and real time, for the market time unit being considered."

For the FRM methodology, the uncertainty from the FB approach linearization and GSK strategy is included by using the PTDF when the forecasted power flows are adjusted. The highlighted blocks in Figure 8 show how the CNE power flow is adjusted based on the PTDF matrix and the realized net positions.

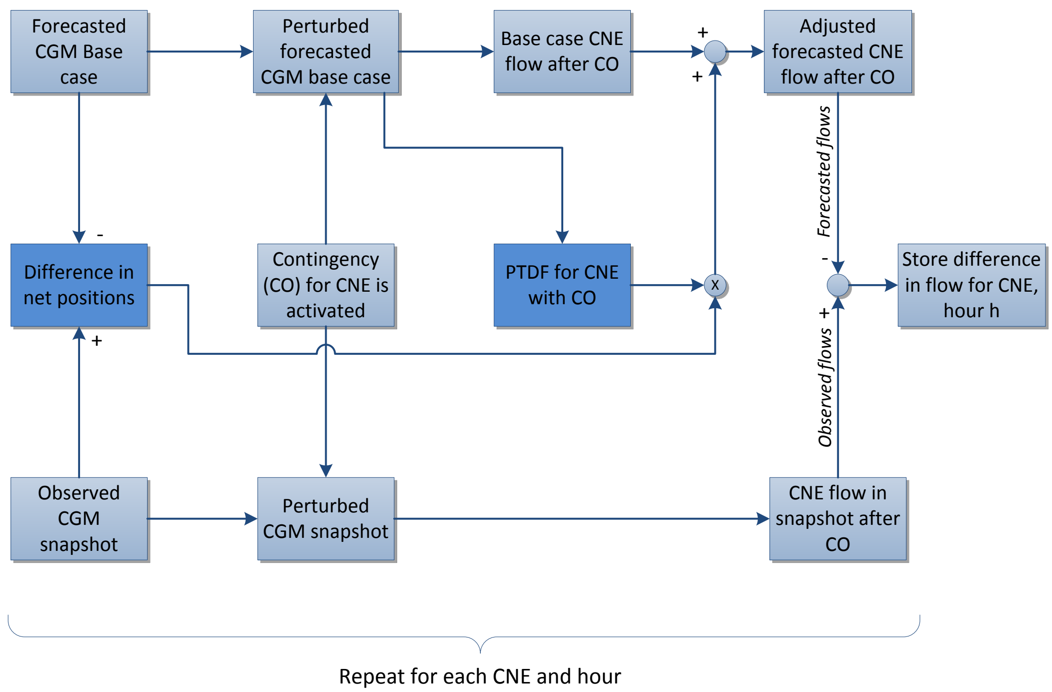

Figure 8. Process chart for evaluating the difference between the forecasted and observed power flow in the proposed FRM methodology for the FB approach. The uncertainty that originates from the FB approach (e.g. linearization and GSK strategy) is captured in the PTDF matrix, which is used to adjust the forecasted CNE power flows with the observed net positions.

As shown in Figure 8, the power flow difference for the CNE is studied when its contingency is tripped in the CGM. In this way a higher accuracy in the FRM value is achieved than if only the CNE power flow difference were calculated on the intact grid. Furthermore, the PTDF for the CNE is calculated with the system state for which the contingency has occurred and hence it is beneficial to also calculate the FRM value on the same grid state as this increases the accuracy of the methodology.

The power flows induced on each CNE or cross-zonal network element for all timestamps under consideration form a probability distribution. The "RM margin" for each CNE and cross-zonal network element is calculated by deriving a value from the probability distribution based on a 95% risk level value.

The second element of the RM:

> *(a) unintended deviations of 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;*

the so-called "frequency containment reserve (FCR) margin", is modelled separately as described below.

The net positions, resulting from the imbalances and the FCR activation, are determined from historical data. The net positions are used in combination with the FB approach of the corresponding timestamp, in order to derive the power flows induced by those net positions. The power flows induced on each CNE and cross-zonal network element for all timestamps under consideration form a probability distribution. The “FCR margin” for each CNE and cross-zonal network element, is calculated by deriving a value from the probability distribution based on a 95% risk level value.

The final RM value for each CNE and cross-zonal network element, is obtained by adding “RM margin” and “FCR margin”.

Common harmonized principles for deriving RM value (TSO risk level)

The TSO risk level determines how the RM value is derived from the probability distributions. This is the proposed harmonized principle for all TSOs in the RM methodology, as the requirement in paragraph 3:

> *“In the methodology to determine the reliability margin, TSOs shall also set out common harmonised principles for deriving the reliability margin from the probability distribution.”*

The challenge is to find a balanced risk level that suits the TSO’s power system requirements. A too low level results in high RMs that constrains the cross-border market, whereas a too high level leads to small RMs that may jeopardize system operational security. With small RMs there is a higher need (and cost) to mitigate security problems in operation with available RAs. As an initial value, the TSOs have agreed to use a 95% risk level.

RM in respect to operational security limits given uncertainty and remedial actions (RAs)

As described earlier the RM value for each CNE and cross-zonal network element is determined based on the uncertainties for the timeframe between the forecast and the actual operational hour for which the agreed operational security limits shall be fulfilled. The prediction error is calculated based on the operational security limits (N-1 situation) which give individual distributions for each CNE or cross-zonal network element, providing lower uncertainties. This requirement is also further defined in paragraph 4 in Article 22 in CACM Regulation:

> *“On the basis of the methodology adopted in accordance with paragraph 1, TSOs shall determine the reliability margin respecting the operational security limits and taking into account uncertainties between the capacity calculation time-frame and real time, and the remedial actions available after capacity calculation.”*

With the proposed RM methodology described in the previous sections the subsequent effects and uncertainties are covered by the RM values:

“RM margin”

- Uncertainty in load forecast

- Uncertainty in generation forecasts (generation dispatch, wind prognosis, etc.)
- Assumptions inherent in the GSK strategy
- External trades to adjacent CCRs
- Application of a linear grid model (with the PTDFs), constant voltage profile and reactive power in FB approach
- Topology changes due to e.g. unplanned transmission line outages
- Internal trade in each bidding zone (i.e. working point of the linear model)
- Grid model errors, assumptions and simplifications.

"FCR margin"

- Unintentional flow deviations due to activation of frequency reserves (FCR)

Set the RM value for FB approach (FRM) or CNTC approach (TRM)

In the last paragraph of Article 22 the actual requirement for RM in the day-ahead and intraday market timeframe is stated for FB and CNTC.

> *"For each capacity calculation time-frame, the TSOs concerned shall determine the reliability margin for critical network elements, where the flow-based approach is applied, and for cross-zonal capacity, where the coordinated net transmission capacity approach is applied."*

Separate distributions are formed for cross-zonal capacities that are calculated based on D-2, D-1, and intraday CGMs. Indeed, the uncertainty - and thus the RM value - is expected to reduce, the closer we get to real time.

In the CNTC and FB approach the probability distribution and TRM (for CNTC) and FRM (for FB) value is reported in a standardized data sheet for each cross-zonal network element or CNE, and each TRM/FRM value is assessed before being implemented. Obvious model or measurement errors are filtered from the data set, but they need to be monitored and justified.[14]

In its base format the TRM/FRM value is always defined and stored in its absolute value, in MW. It may then be converted to a percentage of the Fmax for each CNE in the FB approach or cross-zonal capacity in the CNTC approach for comparison.

RM update periodicity

The requirements on FRM update periodicity is specified in paragraph 4(b) in Article 27 in CACM Regulation:

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[14] *An obvious error can be a CGM model failure with abnormal net positons or CNE power flows compared to historical data. E.g. if the net position is twice the highest recorded value ever this indicates a model failure that needs to be investigated.*

"Using the latest available information, all TSOs shall regularly and at least once a year review and update: […] (b) the probability distribution of the deviations between expected power flows at the time of capacity calculation and realized power flows in real time used for calculation of reliability margins; […]"

In the proposed method, the RM calculation is performed on a regular basis in order to keep the RM updated as the system and market evolve. A recalculation and revision will be initiated at least once a year.

4.3 Article 4: Methodology for determining operational security limits

According to the CACM Regulation Article 21.1(a) (ii), operational security limits, contingencies and allocation constraints are three features described as part of in capacity calculation:

"*the methodologies for determining operational security limits, contingencies relevant to capacity calculation and allocation constraints that may be applied in accordance with Article 23".*

The following subsections give more details how these issues are taken into account in the capacity calculation.

Operational security limits

In the CACM Regulation Article 2 (7), operational security limits are defined as follows:

"'operational security limits' means the acceptable operating boundaries for secure grid operation such as thermal limits, voltage limits, short-circuit current limits, frequency and dynamic stability limits."

Boundaries for secure grid operation are independent of whether the CNTC or FB approach is applied.

The list of operational security limits consists of limits applied in the operational security analysis. All operational security limits shall, however, be respected both during the normal operation and in application of the N-1 criterion when defining allowed power flows across the power system. The list of operational security limits may change in the future when the characteristics of the power system will change due to foreseen change towards sustainable electricity system.

Thermal limits are limits on the maximum power carried by transmission equipment due to heating effect of electricity current flowing through the equipment, and depend on the physical structure of the equipment and the voltage level. Ambient conditions like temperature, wind and the duration of overload will influence the limit. Larger power flows may be allowed for a short period of time. Thermal limits define the maximum allowed power flow on the specific equipment, unless other more restricting limits (e.g. voltage or dynamic stability limits) exist.

Voltage limits for each substation and its equipment are defined in kVs. Both maximum and minimum limits for voltages are defined. The voltage limits are based on voltage ranges as defined in the connection network codes. Power flows across the power system have an effect on the voltages; increasing power flows decrease voltages. The minimum voltage limit defines for each operational situation the maximum allowed power flows in the transmission grid to avoid too low voltages and the disconnection of the equipment by the protection systems.

Short-circuit current limits are defined for each substation and its equipment in kAs. Both minimum and maximum limits for short-circuit currents are defined. The minimum limit is important for selective operation of protection devices, so that faults can be timely and selectively cleared. The maximum limit is set to ensure that devices connected to the grid can withstand induced fault currents. These limits do not influence the allowed power flows in the AC grid, but are there to ensure the functioning of protection systems and that devices connected to the grid can withstand fault currents and that the probability of cascading faults beyond the N-1 criterion is minimized.

Frequency stability limits are based on frequency ranges set in the connection network codes and in the SO Regulation. Frequency stability limits are taken into account during dynamic stability studies to see if the limits would have affected the allowed power flows on the transmission grid. It is foreseen that these limits will have more effect in the future system operation, due to changes in the generation mix.

Dynamic stability limits consist of voltage and rotor angle stability limits. For voltage stability studies, the voltage limits during the fault in the power system and after clearance of the fault shall be studied to define the allowed power flows within the power system, respecting the voltage limits. For rotor angle stability studies, the power flow and generator rotor angle oscillations are studied for each operational situation to define the allowed power flows within the power system with predefined damping coefficients for power and rotor angle oscillations. The magnitude of oscillations and their damping depends on the structure of the power system and the power flows across the power system.

The acceptable operating boundary for secure grid operation is defined by a maximum flow on a CNE ($F_{u,max}$, $u \in \{T,V,DV,DD\}$), that is monitored in the operational security analyses and in real time operation defined as a MW limit for maintaining the voltage and short circuit current level, frequency and dynamic stability within its limits.

T = Thermal
V = Voltage, Static
DV = Voltage, dynamic
DT = Transient stability
DD = Damping

Figure 9 shows an example of how $F_{u,max}$ will be defined and how it relates to the F_{max} on a CNE.

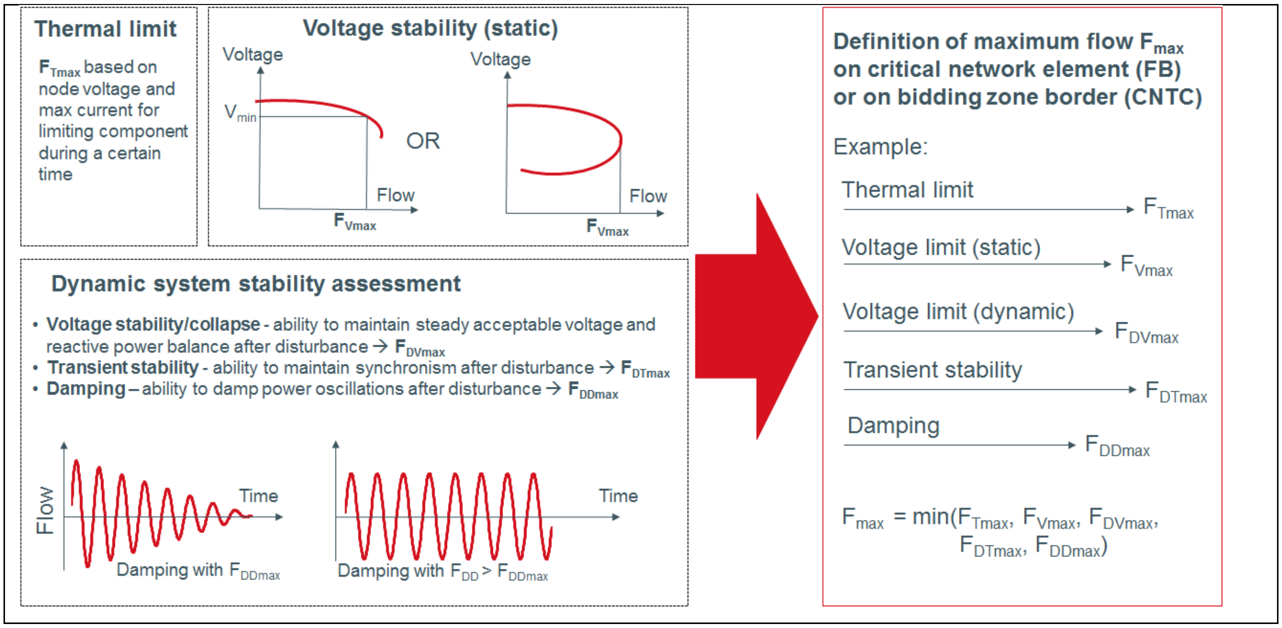

Figure 9: Definition of maximum flow (F_{max}) for CNEs

Generally, the $F_{u,max}$ are found by performing a network analyses on a relevant grid model, currently the TSOs' local grid models adjusted by the relevant grid topology, and considering an N-1 situation. The CGM will be used when sufficient data quality and performance is secured within this model.

4.4 Article 5: Methodology for determining contingencies relevant to capacity calculation

A contingency is commonly understood to be something that might possibly happen in the future that causes problems or makes further arrangements necessary. In the electricity system, contingencies are usually understood to be incidents in the shape of faults in the system that we would like to be able to manage without generation or consumption noticing. For this to be the case, a certain amount of redundancy must be built into the power system. If power system can withstand one error without the loss of system functionality, the power system is compliant with the N-1 criterion. If two simultaneous errors occur in the power system, without affecting the users of transmission grid it fulfills the N-2 criterion. When doing capacity calculation, one normally does not model all possible contingencies, but a relevant set having cross-zonal relevance is chosen. It is the responsibility of the TSOs to specify which contingencies shall be considered by the CCC during the capacity calculation.

4.5 Article 6: Methodology for determining allocation constraints

Allocation constraints are constraints for the market optimization that cannot be transformed efficiently into power flows on a CNE or that are intended to increase the economic surplus in market coupling in capacity calculation. The allocation constraints are embedded in the market coupling algorithm as constraints, meaning that the constraints are not part of capacity calculation as such.

There are three relevant allocation constraints considered in the Nordics:

a) The combined import or export from one bidding zone to other neighbouring bidding zones shall be limited to a threshold value,
b) Ramping rates for the HVDC interconnections, and
c) Implicit loss factors for the HVDC interconnections

a) Combined import or export limitations from one bidding zone to other neighboring bidding zones may be used to take into account operational security limits, e.g. situations where there is a risk for island operation for a bidding zone in order to define the amount of generation and reserves within that bidding zone. Combined import or export power flow limits are taken into account efficiently as allocation constraints. This enables allocation of cross-zonal capacities to different borders from/to the bidding zone in the most optimal way from the market point of view, and there is no need for the TSO to share the capacities for different bidding zone borders during the capacity calculation phase.

b) Between market time units, the HVDC interconnections are changing the power flows to the agreed level for the next market time unit. This change cannot be realized instantaneously due to technical characteristics of HVDC interconnections. Thus the ramping (i.e. changing of the power flow on the HVDC interconnection) creates imbalances in the power system due to the delayed power flow change of the HVDC interconnections compared to the instantaneous power flow change of the AC power system. In order to maintain the systems integrity, the ramping of HVDC interconnections cannot exceed the ability of the power system to maintain the balance. Thus, the availability of balancing reserves in the Nordics dictates an upper threshold to the potential ramping rates of the individual HVDC interconnection. The minimum requirement of balancing reserves are distributed across the Nordic synchronous area. It has been decided that the maximum ramping rate allowed for any HVDC interconnection in the Nordic synchronous area is 600 MW/hour.

c) When power is sent over a HVDC interconnection, less power is received than what is sent. This energy loss is due to a heating effect in the HVDC cable, and the amount of energy loss will vary by technology and the volume of the power flow compared to the transfer capacity of the HVDC cable. The implicit loss factor is a linear factor applied in the market coupling to account for these losses (which in reality is a non-linear/convex function of the flow).

On many Nordic HVDC interconnectors, losses are procured by the TSOs from the day-ahead market. When managing losses in that manner, the losses are external to the market participants, giving them no incentives to consider the losses their trades induce to the system. This embodies a negative external effect in the electricity market, and thus a welfare loss which is easily observed as electricity is frequently traded on an HVDC interconnection at a lower value (price difference) than the cost of the occurred losses. In line with economic theory, losses could be most efficiently managed by internalizing them in the market coupling. This is done by including a loss factor on the HVDC interconnections by including the relation in the market coupling algorithm:

Export quantity = (1 – "Loss Factor") * Import quantity

When this relation is implemented, electricity trade is not allowed on an HVDC interconnection unless the price difference is higher than the cost of losses.

The loss factor will be calculated based on two considerations:

1. A statistical assessment of the average or median flow of the HVDC interconnection
2. Calculation of the loss factor at the estimated average or median flow on the relevant DC interconnection. Calculation can either be based on a statistical model for measured losses, or by a component-based computation.

4.6 Article 7: Methodology for determining generation shift keys (GSK)

The GSKs define how a net position change, both positive and negative, in a bidding zone is distributed to each node (generator unit or load point) in the CGM during the capacity calculation. In this context the general term GSKs is used for both generation and load, as load is perceived as a negative generation.

As the GSKs are applied in translating nodal PTDFs to bidding zone PTDFs, the formulation of GSKs is a critical element for the quality of the PTDFs, and a central issue is whether a node responds to a price change or not. When a price change occurs in a bidding zone, only price responsive nodes will respond to the price and participate in the net position change in that bidding zone. Price independent nodes will not respond. This fact should be reflected in the formulation of GSKs.

Another important consideration in formulating the GSKs, is which attributes of the nodes that will be the basis for the GSK factors. More than several options are possible, and as a few examples it is easy to point to max generation/consumption capacity, generation/consumption in D-2, and excess generation/consumption capacity in the base case.

The set of principles used for calculating the GSK factors for a bidding zone is in general referred to as a GSK strategy, and as indicated, different GSK strategies will provide different PTDFs and hence influence capacity allocation and thus ultimately the market results. A thoroughly worked out GSK strategy will improve the accuracy of capacity calculation and decrease the RM values.

When designing the GSK strategy, it is important to be aware that this is a linear approximation of a non-linear relation. No matter what shifts are imposed to the net positions by the market, the linear relation is assumed to hold. As generator limits might not necessarily be a part of the selected approach, it is important that the best available forecast is used for the CGM.

Eight different GSK strategies (1-8), plus one custom strategy (0), have been developed for the CCR Nordic, each providing different bidding zone characteristics. The TSO may select one of the eight strategies for each bidding zone, or provide a custom GSK strategy with individual GSK factors for each load and generator unit in the CGM. The custom GSK strategy is always used if this is defined for one particular hour; otherwise a predefined default strategy (1-8) is used for the bidding zone.

In general, the GSK strategies include power plants and loads that are sensitive to market changes and flexible in changing the electrical power output/input. This mainly includes hydro, coal, oil, and gas units. Generators and loads that are likely to be shifted receive a high GSK factor. Non-flexible units, such as e.g. nuclear, wind, solar or run-of-river, are added to an ignore list and receive a GSK factor of zero. These are not included at all in the GSK and in the following description.

Table 2 shows the properties of the eight proposed GSK strategies 1-8 along with the custom GSK which here is denoted as strategy 0. Each of the GSK strategies may be applicable for a bidding zone and applied from a single hour until all hours of the year.

The GSK factors are normalized for each bidding zone and then defined in a dimensionless factor. For example, one production unit may have a GSK factor corresponding to its installed capacity (MW) and, normalized, this factor may equal 0.03. This means that 3% of the total NP change is handled by the unit.

Different strategies may be optimal for different bidding zones, countries or hours. This is something that can be discovered during the ex-post analysis of the capacity calculation and allocation. Reasons why this could happen is for example that the generation technology mixture varies between bidding zones or that the geographical distribution of generation and generation technologies varies significantly between bidding zones.

Table 2 GSK strategies in method proposal

Strategy number	Generation	Load	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	Flat GSK factors of 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 power generation or load (MW)
7	0	P_l	Loads participate relative to their power loading (MW)
8	0	1.0	Flat GSK factors for all loads, independently of size of load

k_g : GSK factor [pu] for generator *g*

k_l : GSK factor [pu] for load *l*

P_g : Current active generation [MW] for generator *g*

P_{min} : Minimum active power generator output [MW] for generator *g*

P_{max} : Maximum active power generator output [MW] for generator *g*

P_{load}: Current active load [MW] for load *l*

The TSOs provide the GSK strategy to be used in the capacity calculation process for each bidding zone and the time period for which it is valid. The TSO should aim to find a GSK strategy that minimizes the prediction error between the forecasted and observed power flows for all generator units and loads in each bidding zone for a certain time span.

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In order to test different GSK strategies a heuristic optimization method can be developed. The objective function is a weighted normal distribution of all RMs, providing a quantitative value of the GSK quality. Based on a large historical data set (observed and forecasted CGM) it is possible to find the GSK strategy that minimizes the overall RM for the studied period. Based on the results and on experience a default GSK strategy is selected for each bidding zone.

The applied GSK strategy in capacity calculation will be reviewed (and changed accordingly) at least once a year and if a significant change occurs in the Nordic power system.

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

This section describes how the rules set out in article 8 secure a minimum of undue discrimination between internal and external exchanges (power flows). The requirement is set out in CACM Regulation Article 21(1)(b):

a detailed description of the capacity calculation approach which shall include the following:

(ii) rules for avoiding undue discrimination between internal and cross-zonal exchanges to ensure compliance with point 1.7 of Annex I to Regulation (EC) No 714/2009;

Initially the article explicitly specifies what is implicitly understood when the CACM Regulation is talking about undue discrimination of internal and external power flows. It is about *undue discrimination* of *access* to the transmissions grid. And this is relevant as the transmission grid is the "market place".

The relevance of access to the market is founded / has been well recognized within modern micro economics for many years, where no (or minimum of) barriers for entry to the market is one of the core elements if market dynamics (invisible hand in the words of Adam Smith) shall lead to a welfare optimal/economic efficient allocation of supply and demand. Or in other words, a least cost allocation of supply and demand. This insight has also found its way to electricity market design and thus has been implemented in Regulation 714 and the CACM Regulation. In the context of the CCM proposal it is therefore important to allow for equal access and treatment of all power flows, otherwise a least cost allocation cannot be assured.

However, “no barriers” for entry or equal access to the market does not imply that “the physics” and capacity constraints of the power system can be repealed. This is basically why the mathematical method of constrained optimization is applied within economics. The reason for this is that capacity (in whatever market) is actually limiting at some level and exceeding this level can lead to broken machinery and a non-least cost allocation of resources. In the context of a power system this means that in the market operation, the constraints should be taken into account. A power system does have limiting transmission capacity during operation. Not respecting these limitation will ultimately lead to black-out due to unsecure operation and probably also to a not welfare optimal capacity allocation in the market coupling.

It is therefore recognized in the Nordic CCM project that *undue discrimination* to the market shall be defined as a situation where power flows are denied access to the transmission system because of reasons that cannot be justified based on operational security and economic efficiency. The latter is sometimes denoted social welfare on a European level, but the meaning is essentially the same as economic efficiency.

Undue discrimination is thus defined as *a situation where some flows are given priority access to grid capacity on grounds which cannot be justified by reasons of economic efficiency and operational security*. It is important to notice one important issue.

Undue discrimination and *discrimination* is not the same. Market participants are discriminated for many good reasons, where price is the foremost discriminating mechanism in any market based system, and insufficient, missing or non-existing infrastructure another. Following this logic, the fact that Australian generators and Danish generation are discriminated in terms of access to the Danish market is not considered undue discrimination.

Therefore, and in accordance with the objectives in the CACM Regulation, the CCM for the CCR Nordic states that

> "*Internal and cross-zonal flows shall be given access to transmission capacity on equal and fair conditions. Deviations from this principle can only be justified by reasons of economic efficiency and operational security*".

The rules that are set out in the CCM proposal to avoid undue discrimination are:

1. To consider whether a limiting internal CNE could be more efficiently managed by redispatching or countertrading in the operational time frame
2. To consider bidding zone reconfiguration to avoid structural congestions inside a bidding zone
3. To consider economical efficient investments to remove congestions

The methodology for assessing bidding zones reconfiguration is described in CACM article 32-34 and the assessment of efficient grid investments are based on traditional cost-benefit methodologies described in standard economic text books.

On the first rule however, the question is whether any trade might be declined by the market constraints due to grid constraints that are not needed (undue) based on operational security, or might be more economically efficient managed in the operational time frame:

a) Should a particular CNE be provided to the market coupling or managed in operation by countertrading or redispatching?
b) Is the transmission capacity provided for cross-zonal trade on each CNE, which is the RAM, set at the efficient level?

The methodology for assessing whether, and to what extent an internal CNE shall be provided for the market coupling or managed by countertrading or redispatching in operation, is outlined in Article 11 of the CCM proposal. The Nordic TSO assumes that the proposed methodology avoids undue discrimination as exactly the criteria of *economic efficiency and operational security* are used.

Operational security and the role of F'_{ref} in the FB approach

Whether RAM is calculated at the optimal level is based on how the different components of RAM are calculated. The RAM is defined by the following equation:

$$RAM = F_{max} - FRM + RA - F'_{ref} - FAV - AAC \quad (2)$$

F_{max} is defined by the operational security limits described in Article 4 of the CCM proposal. The methodology for calculating the *FRM* is described in the Article 3 in the CCM proposal, and the calculation of the *RA* is described in Article 9 of the CCM proposal. The *AAC* is the already allocated capacity (previously allocated capacity) and *FAV*, which might receive a positive or a negative number, is an adjustment factor for last minute changes in the power system to be assessed during the final validation of the cross-zonal capacities.

The last ingredient in the calculation of RAM, is the F'_{ref}. This component is essentially a part of the linearization of the power flows from the CGM, and is the fixed component in the linear formulation of the power flow in the base case, as seen in the equation and in Figure 10 below:

$$F_{ref} = F'_{ref} + \sum_{A} PTDF^{A} \cdot NP^{A} \quad (3)$$

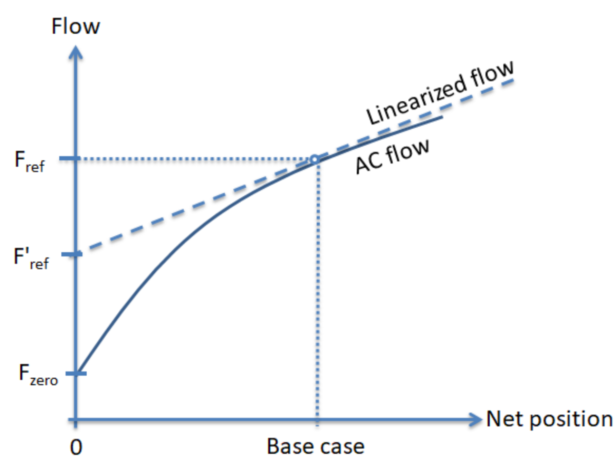

Figure 10 Linearization in the FB methodology

The concave solid line, "AC flow", in Figure 10 depicts an example of a real physical flow. This is a non-linear function of net positions for all bidding zones with an influence on the relevant (unspecified) transmission grid element. The real AC flow must, however, be represented by an equivalent linearized power flow in the market coupling, as described by the equation above.

However, in order to have a linearized power flow as accurately as possible to represent the real AC flow close to the base case, the linear flow equation is derived as a tangent to the reference power flow (in the base case) F_{ref}. The F'_{ref}, often referred to as "flow at zero net position", is thus in reality the intersection between the linearized power flow and the vertical power flow axes. The real "flow at zero net position" is depicted in Figure 10 as F_{zero}. Due to the naming convention, the two elements are easily confused. The F_{zero} consists essentially of power flows that start and end in the same bidding zone while traversing a CNE either within the same bidding zone, or in an adjacent bidding zone. These flows cannot be managed by the market coupling algorithm due to the fact that the sending and receiving end for the power flow is within the same bidding area, and thus are exposed to the same prices. The only way to remove these internal flows and loop flows and at the same time maintain operational security, is a further split into smaller bidding zones, and ultimately obtain a nodal pricing system. However, it should be noted that a further split of the market into further numbers of bidding zones does not lead to increased capacities to be allocated to the market. The effect is rather that the power flows will be managed by the market coupling algorithm (and potentially more efficient).

The RAM component F'_{ref}, is thus an element of the linearization, and does not represent real power flows. However, from an operational security point of view, the F'_{ref} is a necessary mathematical construction in order to have a sufficiently accurate prediction of real power flows in the market algorithm without compromising the integrity of the power system. Both F_{zero} and F'_{ref} is a consequence of the zonal structure essential in the FB approach.

F_{zero} is put into perspective in a numerical study in Section 5.1.

How do the proposed rules for undue discrimination fulfill the ACER deviation criteria´s?

The ACER recommendation sets out two high level principles for capacity calculation. According to ACER these are the default principles to follow and *Any deviation from the general principle, by limiting cross-zonal capacity in order to solve congestion inside bidding zones, should only be temporarily applied and in those situations when it is:*

(a) needed to ensure operational security; and

(b) economically more efficient than other available remedies (taking into account the EU-wide welfare effects of the reduction of cross-zonal capacity) and minimises the negative impacts on the internal market in electricity.

In this section we outline how the methods for RA (article 9), CNE selection (article 11) and calculations of F'_{ref}, meet the four conditions as outlined in the ACER recommendation. The four conditions are assessed in the following:

1 . Any deviation from the general principle should not induce undue discrimination between internal and cross-zonal exchanges, as required by Article 21(l)(b)(ii) of the CACM Regulation'. For this purpose, they should define, for those internal network elements which are considered in cross-zonal capacity calculation, a maximum portion of their capacity that may be reduced to accommodate loop flows and internal flows.

TSO Assessment: The Articles 9 and 11 are developed based on the definition of undue discrimination. Employing the test as outlined in these articles will ensure no undue discrimination. The Nordic TSOs do, however, not define an (arbitrary) maximum for loop flows and internal flows but instead the TSOs opt for a minimization of these power flows by securing the best possible accuracy of the RAM and a bidding zone configuration in line with structural congestions.

2. Any deviation from the general principle should be well justified with respect to the conditions referred to above. This justification should be regularly re-evaluated to account for changes in the actual situation.

TSO Assessment: Articles 9 and 11 are developed based on the criteria of operational security and economic efficiency.

3. During the period of deviation, the TSOs should develop mid-term and long-term solutions, including the projects and related methodologies to implement them. The purpose of these solutions should be to discontinue the deviations.

TSO Assessment: The Nordic TSOs are frequently assessing the existing bidding zone configuration and new and potentially efficient investment opportunities, which are the mid-term and long-term solutions put forward in the ACER recommendation.

4. The deviations should be of a temporary nature. However, in cases where deviations from the general principle are more efficient than any other available mid-term and long-term solution, TSOs may propose to NRAs to continue applying the deviations.

TSO Assessment: the CNEs selected by the method outlined in article 11 are due to outage situations and thus temporary in nature. If the test shows that it is operationally secure to increase the transmission capacity of internal CNEs and it is economic efficient to do so, the deviation will not be applied. Moreover it is assessed whether the selection test in article 11 shall be applied or the available mid-term and long-term solution should be applied.

4.8 Article 9: Methodology for determining remedial actions (RAs) to be considered in capacity calculation

The CACM Regulation requires that RAs are taken into account in capacity calculation in both market timeframes covered by the CACM Regulation. In CACM Regulation Article 21 and Article 25 it is stated to include RAs:

- In 21.1(a)(iv): *the methodology for determining remedial actions to be considered in capacity calculation in accordance with Article 25*. Whereas Article 25.1 defines this task to be the individual task of each TSO.
- In 21.1(b)(iv): *rules on the adjustment of power flows on critical network elements or of cross-zonal capacity due to remedial actions in accordance with Article 25*.
- 25.2: *Each TSO (…) shall coordinate with the other TSOs (…) the use of remedial actions to be taken into account in capacity calculation and their actual application in real time operation*.
- 25.5: *Each TSO shall take into account remedial actions without costs in capacity calculation*.

Moreover the inclusion of RAs shall also be seen in relation to Article 21.1(b)(ii) of the CACM Regulation, which reads: *rules for avoiding undue discrimination between internal and cross-zonal exchanges to ensure compliance with point 1.7 of Annex I to Regulation (EC) No 714/2009.*

This section outlines the motivation for Article 9 and explains the content of the Article. Article 9 shall be read in close connection with Article 11 on the Impact of remedial actions (RAs) on CNEs, and Article 8 on rules for avoiding undue discrimination between internal and cross-zonal exchanges. The objective of Article 9 is to state which RAs to apply and how to determine availability of costly RAs. Article 11 outlines the tests that shall be applied, in order to decide which level of RAM will be attached to an internal CNE in the day-ahead or intraday market timeframe, when it enters into capacity allocation. If RAM for allocation of an internal constraint is higher than the “physical” RAM it is due to the fact that the potential overload can be managed by costly RAs. As input into the first of these tests is the availability of costly RAs as identified by applying the approach outlined in Article 9.

The motivation for taking RAs into account in capacity calculation

Taking non-costly RAs into account is straight forward; it increases the available transmission capacity for the market participants at no cost. Non-costly RAs will therefore by default be taken into account if available.

Costly RAs might improve economic efficiency whenever re-dispatching of generation and consumption is able to secure least cost generation and consumption (on a European wide level) at a lower welfare economic cost compared to the allocation outcome from the day-ahead market coupling. This situation might occur in a day-ahead market coupling with zonal pricing, as the zonal “price”, compared to nodal pricing, does not automatically guarantee internal efficiency within a bidding area. In nodal pricing all CNEs will be taken efficiently into account in capacity allocation as the scarce transmission capacity of all

CNEs will be exposed to scarcity pricing, not only cross-bidding zone CNEs as in zonal pricing. This includes CNEs which are denoted internal CNEs in the context of zonal pricing.

Moreover, it shall be emphasized that Articles 8, 10, and 11 are taking into account the ACER Recommendation High Level principle 1 (HL#1) On the treatment of internal congestion. HL#1 reads:

As a general principle, limitations on internal network elements' should not be considered in the cross-zonal capacity calculation methods. If congestion appears on internal network elements, it should in principle be resolved with remedial actions in the short term, with the reconfiguration of bidding zones in the mid-term and with efficient network investments in the long term.

Any deviation from the general principle, by limiting cross-zonal capacity in order to solve congestion inside bidding zones, should only be temporarily applied and in those situations when it is:

- *a) needed to ensure operational security; and*
- *b) economically more efficient than other available remedies (taking into account the EU-wide welfare effects of the reduction of cross-zonal capacity) and minimises the negative impacts on the internal market in electricity.*

The ACER recommendation states that internal CNEs should not be considered in the cross-zonal capacity calculation and to avoid this, the TSOs shall apply RAs as a remedy in a short term perspective. However, to follow the general principle and apply costly RAs, this relies on the existence and availability of RAs and especially costly RAs. If costly RAs are not available, and not taking internal CNEs into account in capacity calculation, this would compromise operational security, hence operational security cannot be ensured. Following this, the motivation for Article 9 (and 11) in the CCM proposal, is to set up an ongoing (weekly or more often) process that can identify the availability of primarily costly RAs. This process shall be managed by the individual TSO and the results shall be communicated to the CCC (the Nordic RSC in the CCR Nordic).

Which RAs to apply

The CACM Regulation distinguishes between costly RAs and RAs without costs. Costly RA is here understood as a RA with a positive short run variable costs of being applied in capacity calculation and/or activated in real time – and will only apply for RAs to increase the RAM for internal CNEs in capacity calculation.

Article 9(2) implicitly states that non-costly RAs shall always be taken into account in capacity calculation. All RAs have a positive cost attached in a long run perspective, but the key issue here is whether a cost element is potentially activated by the application of the RA in capacity calculation. If so this defines it as costly RA. On the other hand, e.g. a system protection scheme is non-costly in the context of capacity calculation, as the cost is the same whether it is taken into account in capacity calculation or not.

Article 9 mainly deals with costly RAs, as non-costly is straight forward. On the other hand, costly RAs will only be taken into account if they are available and it is economic efficient to do so.

The overall purpose of considering costly RAs in capacity calculation is to enhance the social benefit (or economic efficiency) by potentially redispatching resources in order to obtain a merit order on both the generation and the consumptions side. RAs allow for an increase in RAM on internal CNEs. This is not done by adjusting the operational security limit of the CNEs, but by adding a RA in the calculation of the RAM. It is shown in the equation of Article 15.

Costly RAs in capacity calculations will only be applied for internal CNEs as cross-zonal CNEs are managed by market coupling, meaning that these CNEs will be most efficiently managed by the day-ahead and intraday market coupling. There are therefore no arguments in terms of economic efficiency of applying costly RAs for cross-zonal capacity calculation; it will only lead to a lower social welfare if more cross-zonal capacity is allocated to the market than available, as without RAs the prices on adjoining bidding zones correctly reflect the scarcity of cross-zonal capacity.

Article 9(3) and 9(4) are based on the consideration in the above sections. In these paragraphs the different types of RAs that can be applied are listed. Article 9(4) is based on the thinking that even though costly RAs as countertrading is not applied in capacity calculation it can still be applied when the firmness of cross-zonal capacity shall be ensured in real time by actually activating some RAs. It should be noted that the capacity calculation for the day-ahead market timeframe in D-2 is based on a forecast of the market in D. When the actual need for – and availability of – costly RAs are known, it might turn out that the most efficient way to maintain cross-zonal capacity is to activate the RA in another bidding zone by countertrading.

How to assess availability of costly RAs

As stated above, costly RA may potentially remedy the down sides of zonal pricing in terms of efficiency. However, adding costly RAs cannot be expected to fully remedy the down sides of zonal pricing in practice, as this would in the day-ahead market timeframe in D-2 require 100% knowledge on:

- Marginal costs of the resource used for RAs in order to secure a merit order allocation
- Availability of costly RAs in advance (in D-2) for capacity calculation
- A (grid) model that establishes an exact relationship between all available resources and the CNEs.

The challenge in terms of costly RAs is to assess how much MW is available for redispatching at least two days in advance of activation on the actual day D of operation. The assessment has to take place no later than D-2 as the transmission capacity (RAM) on each internal CNE has to be submitted to the NEMOs on D-1. Assessment of the availability will be based on a best guess of what might be available on a voluntary basis, without providing an explicit payment for being available.

Normally when TSOs secure availability of resources for e.g. reserves, this is done by offering a capacity payment – or option payment – and by this there follows an obligation to be ready for supplying if called upon by the TSO. In the case of managing internal CNEs there are no plans to establish a separate option market for redispatching resources. The reason for this is that it will drain the day-ahead market coupling by pushing for more resources to be allocated/reserved for this purpose and hereby creating a vicious spiral.

The assessment of availability will therefore be based on a best (unsecure) estimate of availability of re-dispatching resources. The overall approach for such a best estimate is described in Article 9(4). The point of departure for such an estimate is to list all known flexible resources on both the generation and consumption side in each bidding zone. Each TSO may use the resources that are available at the merit order list for balancing market (currently the NOIS list) and the IGM as a starting point. From this starting point, the goal is to produce a short list with available resources, by deducting all the resources that are known not be available for different reasons, e.g. ancillary reserves, sold in day-ahead market, forced or planned outage. The short list shall also include resources that are known to be available, but were not at the NOIS list in the relevant period. Each TSO is responsible for the RAs located in their bidding zone(s) and for setting the availability of the RAs.

Review of RAs taken into account in capacity calculation

CACM article 27(4) states that:

Using the latest available information, all TSOs shall regularly and at least once a year review and update:

(…..)

(c) the remedial actions taken into account in capacity calculation;

In order to make sure that the costly and non-costly RAs are applied in the best way, the TSOs will at least once a year review the application of RAs in capacity calculation in order to identify potential need for improvement. This is stated in Article 9(5) of the legal proposal.

4.9 Article 10: Mathematical description of the applied capacity calculation approach with different capacity calculation inputs

This Article elaborates on the relationship between the market optimization process, the calculation of FB constraints, and delivery of input to the calculation of the FB constraints. The relation between the Article 3 - 7, 9, 11, and 31 is made in this Article.

4.10 Article 11: Impact of remedial actions (RAs) on CNEs

This section describes the rules set out in Article 11 on the impact of RAs on internal CNEs, more specifically outlining how costly and non-costly RAs potentially can be applied to increase the RAM of internal CNEs in order to increase possible cross-zonal power exchange.

The objective of the Article 11 is to provide a short term solution to the requirement set out in the CACM Regulation Article 21(1)(b)(ii) and the ACER Recommendation on Capacity Calculation and Congestion Management on internal congestions. The mid and long term solutions, which are bidding zone reconfiguration and efficient investments, are not covered here.

According to the ACER recommendation on Capacity Calculation and Congestion Management on internal congestions:

"As a general principle, limitations on internal network elements' should not be considered in the cross-zonal capacity calculation methods (….). Any deviation from the general principle, by limiting cross-zonal capacity in order to solve congestion inside bidding zones, should only be temporarily applied and in those situations when it is:

> *(a) needed to ensure operational security; and*
>
> *(b) economically more efficient than other available remedies (taking into account the EU-wide welfare effects of the reduction of cross-zonal capacity) and minimises the negative impacts on the internal market in electricity."*

This is interpreted to mean that internal CNEs considered in capacity calculation can only be those that are relevant for cross-zonal trade for a strictly limiting time period (for example in outage situations), and only if the TSOs can justify that they are necessary for operational security reasons and are more economically efficient solved by the market coupling algorithm than by costly RAs (redispatching). Thus, internal CNEs that are relevant in intact grid situations and being continuously limiting to cross-zonal trade, shall be managed by redispatching.

On the reverse side, this implies that the TSOs do not have to justify "not taking internal CNEs into consideration" in capacity calculation, and rather manage them by costly RAs (redispatching), even when the option of limiting the cross-zonal trade is more economically efficient than applying costly RAs.

However, this is not a binary choice of whether or not to take an internal CNE into account, but rather a choice of how much the transmission capacity on internal CNE may be increased by taking available redispatching resources into account. The headline for Article 11 is therefore *Impact of remedial actions (RAs) on internal CNEs*, and thus Article 11 outlines the foreseen steps to manage the following issues:

1. Which CNEs shall be considered in capacity calculation;
2. To what extent might the RAM of a CNE be increased by the application of costly and/or non-costly RA (operational security test);

3. Will the application of costly RA to increase the capacity of internal CNEs improve economy efficiency (economic efficiency test)?

The first step is to identify those CNEs that potentially are limiting cross-zonal trade. The relevant CNEs are identified by testing different scenarios by the AC load flow simulations using a relevant CGM (operational security analysis). The outcome of this step is a list of internal CNEs and CNEs located on the bidding zone border that potentially might limit cross-zonal trade. (The actually limiting CNEs are identified later during capacity calculation based on this list.)

In the second step, the available RAs identified by the methodology described in Article 9 is combined with the list of CNEs to reveal the influence of the RA on each CNE. The "influence" is defined as the percentage of a MW of RA that is actually relieving the flow on a particular CNE (%MW relieved on a CNE per MW of RA). This assessment is done by testing the RA by the AC load flow simulations using the relevant CGM.

The influence of non-costly RA will always be added to the RAM if the RA is expected to be available in real time. This is due to the assumption that the application of non-costly RA always will add a welfare benefit to the power system. The application of costly RA to relieve internal CNEs, however, requires one further step in the assessment process.

Costly RA is normally recognized as redispatching. Thus, the third step outlines the test to be applied in order to decide whether social welfare is increased by applying redispatching in capacity calculation. The social welfare (or economic efficiency) is assessed by comparing the expected marginal social cost of applying redispatching, with the expected marginal social cost of limiting cross-zonal trade (by providing the CNE to the capacity calculation without any increase in RAM). If the expected social cost of applying redispatching is lower than the expected social costs of limiting cross-border trade, the amount of available redispatching will be applied in capacity calculation in order to increase the RAM.

The expected marginal social cost of redispatching, is based on three components, the difference in the price of up and down regulation on each side of the limiting CNE[15], the influence of the up and down regulation in terms of %MW per MW redispatching on the CNE, and a risk premium related to the uncertainty of whether the redispatching resources is actually available in real time.

Expected Social cost of RA = $\frac{P^r}{T^r} * (1 + R^r)$

Where:

P^r = Expected price of the RA (In general the price difference for up and down regulation)

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15 *In operation, only the down regulation will be applied in the capacity calculation phase. The up regulation on the other side of the limiting CNE will be applied if needed during the operational phase.*

T^r = Expected technical efficiency of the RA (% MW that appear on the CNE for each MW RA, which equals the node to node PTDF on the relevant CNE)

R^r = Estimated risk premium for the RA – will initially be set at zero until sufficient data is available for a reliable estimate to be calculated

The expected marginal social cost of limiting cross-zonal trade is based on two components, the price difference at the "cheapest" border at the bidding zone where the CNE is located, and the influence on the CNE from a flow on that border (%MW on the CNE per MW change in the cross-border flow). There are no uncertainty as the market coupling will obey the limit on the CNE.

Expected Social cost of RA = $\frac{P^{cb}}{T^{cb}}$

Where:

P^{cb} = Expected price difference at the "cheapest" border

T^{cb} = Expected technical efficiency of limiting the cross-border flow, which is equal to the zone to zone PTDF on the relevant CNE

If the equation $\frac{P^r}{T^r} * (1 + R^r) < \frac{P^{cb}}{T^{cb}}$ holds, the RAM of the internal CNE will be increased by the calculated influence from applying the available redispatching in the capacity calculation. The influence is provided by a node-to-node-PTDF which is calculated as the difference between the two relevant node-to-slack-PTDFs. The node-to-node PTDF is denoted *Expected technical efficiency of the RAs (T^r)* in the equations above.

The risk premium, R^r, in the above equations reflects the probability of the identified available redispatching resources of not being available. The higher the risk of not being available, the higher R^r. The risk taken into account here is the risk associated with resources which were assessed to be available. Resources that are assessed not to be available are not taken into account here (in order to avoid double counting). Currently, and by the time the parallel run starts, this estimate for R^r is not known. Therefore the risk is default set to zero and when data allows, the number will be updated with a calculated estimate. The risk level will be calculated by comparing actual availability for resources with expected availability in D-2. If all resources for RAs that were expected to be available D-2 actually are available in real time, R^r is set to zero.

The process outlined in Article 11 does not describe the foreseen TSO and RSC activities regarding internal CNEs in detail. The main reason is that by the time of submitting the CCM proposal, the process of managing internal CNEs are still under development in the RSC. Outlining these in detail will follow the project timeline as outlined in the RSC, which goes beyond the date for resubmission of the amended CCM proposal.

4.11 Article 12: Rules on the adjustment of power flows on critical network elements or of cross-zonal capacity due to remedial actions

RAs as defined in Article 9 shall be taken into account in the capacity calculation to increase cross-zonal capacity in day-ahead market timeframe. These RAs shall be translated to resulting power flows on each CNE applying rules set in Article 11 and added to the RAM of relevant CNEs in accordance with Article 15(1).

4.12 Article 13: Rules for taking into account previously allocated cross-zonal capacity

TSOs shall take into account capacities allocated already before the day-ahead market timeframe when calculating day-ahead cross-zonal capacities. Thus capacity allocated for nominated Physical Transmission Rights (PTRs) or capacity allocated for cross-zonal power exchange of ancillary services, where appropriate, have to be subtracted from the RAMs of affected CNEs. This will be done by translating already allocated cross-zonal capacity into resulting power flows on each CNE by applying PTDFs. The resulting flows will be included in the RAM equation defined in Article 15(1) to take into account the previously allocated cross-zonal capacity.

4.13 Article 14: A mathematical description of the calculation of power transfer distribution factors (PTDFs) for the FB approach

The PTDFs will be calculated applying CGM and an AC load flow analysis (applying CGM) with the simplifications necessary to create a linear approximation. This subsection starts with a short introduction of the basics of the AC power flow analysis and shows how the PTDFs are calculated.

For a CNE that includes either a contingency or a RA, requiring the disconnection of network elements, generators, or loads, the PTDFs are calculated to represent the system state after the disconnections. This will minimize the errors, but means that the full set of PTDFs for all CNEs do not represent the same transmission grid state / model. Instead, the PTDFs for each CNE will represent the correct state of the power system after the disconnection.

The calculation of the PTDFs will start from an AC power flow analysis for the forecasted state of the electricity power system[16]. The active and reactive power flows in steady state can be described by the power flow equations () and (5).

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[16] *The calculations leading up to equations and () is found in Grainger, J. & Stevenson, W. (1994). "Power System Analysis", New York: McGraw–Hill. ISBN 0-07-061293-5.*

$$P_i = V_i \sum_{k=1}^{n} V_k (G_{ik} \cos(\delta_i - \delta_k) + B_{ik} \sin(\delta_i - \delta_k)) \quad (4)$$

$$Q_i = V_i \sum_{k=1}^{n} V_k (G_{ik} \sin(\delta_i - \delta_k) - B_{ik} \cos(\delta_i - \delta_k)) \quad (5)$$

Where:

P_i	=	Active power balance in node *i* (per unit MW)
Q_i	=	Reactive power balance in node *i* (per unit Mvar)
i, k	=	Node number
n	=	Number of nodes
V_i	=	Voltage magnitude in node *i*
δ_i	=	Voltage angle of node *i*
δ_k	=	Voltage angle of node *k*
G_{ik}	=	Conductance between node *i* and *k* with negative sign
G_{ii}	=	Sum of all conductances connected to node *i*
B_{ik}	=	Susceptance between node *i* and *k* with negative sign
B_{ii}	=	Sum of all susceptances connected to node *i*

The two equations above show the balance of each node in the AC network as the sum of the flow on transmission lines and shunts connected to the node. The aim of these power flow equations is to determine the voltages (magnitude and angle) at all buses. If the voltages are known, it is possible to determine the power flows, losses, and currents.

Linearizing the power flow equations

Calculation of the PTDFs are based on standard DC linearization[17] including the following simplifications:

- Node voltage magnitude is 1 pu
- The resistance of the transmission lines are neglected
- The difference between the voltage angles are small

The power flow equations now become:

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[17] *See for example Schavemaker and van der Sluis (2009): "Electrical Power System Essentials", John Wiley & Sons Ltd, ISBN 978-0470-51027-8, Chapter 6.2.4.*

$$P_i = \sum_{k=1}^{n} B_{ik}(\delta_i - \delta_k) \tag{6}$$

$$Q_i = \sum_{k=1}^{n} -B_{ik} \tag{7}$$

Adding +1 to the diagonal elements representing the slack node, the voltage angles can be calculated as:

$$[\delta] = \begin{bmatrix} \delta_1 \\ \delta_2 \\ \delta_3 \end{bmatrix} = \begin{bmatrix} 1 + B_{12} + B_{13} & -B_{12} & -B_{13} \\ -B_{21} & B_{21} + B_{23} & -B_{23} \\ -B_{31} & -B_{32} & B_{31} + B_{32} \end{bmatrix}^{-1} \begin{bmatrix} P_1 \\ P_2 \\ P_3 \end{bmatrix} = [Zbus][P] \tag{8}$$

In a generic form, the PTDF can now be expressed as

$$PTDF_{ik,n} = B_{ik}(Zbus_{in} - Zbus_{kn}) \tag{9}$$

The $PTDF_{ik,n}$ is the sensitivity for the transmission grid element "ik" for power injection in bidding zone n. By repeating this procedure for all nodes and all transmission lines, the PTDF matrix can be computed. The matrix describes how the net balance of the nodes influences the power transfers on the transmission lines.

4.14 Article 15: A mathematical description of RAMs on CNEs for the FB approach

The mathematical description of the RAM is explained in Section 4.7 of this document on Article 8: "Rules for avoiding undue discrimination between internal and cross-zonal exchanges" -, subsection "Operational security and the role of F'_{ref} in FB capacity calculation".

4.15 Article 16: Rules for sharing the power flow capabilities of CNEs among different CCRs

The AHC is explained in Section 4.1 of this document on Article 2: Definitions "Advanced Hybrid Coupling".

4.16 Article 17: Methodology for the validation of cross-zonal capacity

The TSOs are legally responsible for the cross-zonal capacities and they have to validate the calculated cross-zonal capacities before the CCC can send the cross-zonal capacities for allocation. This section describes the methodology for validating cross-zonal capacity in line with Article 21(c) and 26 of the CACM Regulation. Article 21 paragraph 1 specifies the items to be included in the CCM, and subparagraph c) reads:

"The proposal for a common capacity calculation methodology for a capacity calculation region determined in accordance with Article 20(2) shall include (c) a methodology for the validation of cross-zonal capacity in accordance with Article 26."

Article 26 paragraph 1 reads:

"Each TSO shall validate and have the right to correct cross-zonal capacity relevant to the TSO's bidding zone borders or critical network elements provided by the coordinated capacity calculators in accordance with Articles 27 to 31."

The validation of cross-zonal capacities will be performed by each TSO to ensure the results of the capacity calculation process – executed by the CCC - will respect operational security requirements. The CCC will coordinate with neighboring CCC during the validation process.

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. The TSOs will consider the operational security limits and the CGM to perform the validation, but may also consider additional CNEs, grid models, and other relevant information. The TSOs may use, but are not limited to use, the tools developed by the CCC for operational security analysis. The TSOs might also employ validation tools not available to the CCC.

During the validation of cross-zonal capacity, each TSO may change the FB parameters on any CNE. The RAM may be adjusted during the validation by applying FAV to take into account relevant information known at the time of validation:

- A positive FAV value will decrease the RAM
- A negative FAV value will increase the RAM

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

Article 26 paragraph 2 states:

"Where a coordinated net transmission capacity approach is applied, all TSOs in the capacity calculation region shall include in the capacity calculation methodology referred to in Article 21 a rule for splitting the correction of cross- zonal capacity between the different bidding zone borders."

Under CNTC, the rules for splitting the corrections of cross-zonal capacity will follow the same methodology as described in Article 21(1)(b)(vi) of the CACM Regulation.

Article 26 paragraph 3 states:

"Each TSO may reduce cross-zonal capacity during the validation of cross-zonal capacity referred to in paragraph 1 for reasons of operational security."

The TSOs will reduce the cross-border capacity if the calculated cross-zonal capacities would allow the capacity allocation process to create a result that could put operational security at risk.

Article 26 paragraph 4 states:

> *"Each coordinated capacity calculator shall coordinate with the neighboring coordinated capacity calculators during capacity calculation and validation."*

The CCC will provide information on reductions or increases in cross-zonal capacity to the neighboring CCC.

Any information on increased or decreased cross-zonal capacity from neighboring coordinated capacity calculators will be provided to the TSOs. The TSOs may then apply the appropriate reductions or increases of cross-zonal capacities according to Article 26 of the CACM Regulation.

4.17 Article 18: Target capacity calculation approach

FB approach is the target capacity calculation approach for the intraday market timeframe. Main obstacle for the implementation of this target approach is that the current intraday market coupling (XBID) does not support the FB approach, and major developments are needed in the intraday market coupling algorithm to facilitate the FB approach. The CNTC approach shall be used in the intraday market timeframe until the application of the FB approach is realized.

4.18 Article 19: Mathematical description of the applied capacity calculation approach with different capacity calculation inputs

The procedure applied with CNTC is as follows:

- Inputs for the CNTC approach are defined
- AC load flow analysis is applied to the CGM to calculate voltages on each node of the CGM and power flows on each serial element of the CGM to define maximum power exchange across the transmission grid
- Cross-zonal capacity is defined from maximum power exchange by subtracting already allocated cross-zonal capacity and reliability margin

The mathematical formulation of the CNTC is captured in Section 4.23.

Cross-zonal capacity shall be calculated as follows:

$CZC = TTC - AAC - RM$,

where TTC is the maximum allowed power exchange of active power between adjoining bidding zones respecting the N-1 criteria and operational security limits taking into account RAs, rules for undue discrimination and rules for efficiently sharing the power flow capabilities of CNEs among different bidding zone borders, AAC refers to previously allocated capacity, and RM refers to reliability margin.

4.19 Article 20: Rules for taking into account previously allocated cross-zonal capacity

TSOs shall take into account capacities allocated already before intraday market timeframe when calculating intraday cross-zonal capacities. This will be done like for the day-ahead timeframe taking into account Physical Transmission Rights (PTRs), cross-zonal capacity allocated for ancillary services and cross-zonal capacity allocated for the day-ahead market timeframe (see Section 4.12 in this document on Article 13). If the previously allocated cross-zonal capacity is larger than the calculated cross-zonal capacity for intraday market timeframe, TSOs shall provide zero cross-zonal capacity for allocation in the market coupling and use RAs to manage operational security.

4.20 Article 21: Rules on the adjustment of power flows on CNEs or of cross-zonal capacity due to RAs

TSOs shall take into account in the capacity calculation RAs to increase the cross-zonal capacity for the intraday timeframe. RAs are listed in Article 9. After calculating the maximum power exchanges between bidding zones without RAs, necessary adjustments taking into account RAs are executed in the CGM and maximum power exchanges between bidding zones taking into account RAs shall be recalculated.

4.21 Article 22: A mathematical description of the calculation of PTDFs for the FB approach

The intra-day market timeframe applies the same calculation of PTDFs as for the day-ahead market timeframe. The explanation given for the day-ahead market timeframe is valid for the intraday market timeframe as well.

4.22 Article 23: A mathematical description of RAMs on CNEs for the FB approach

The intra-day market timeframe applies the same calculation of RAMs for CNEs as for the day-ahead market timeframe. The explanation given for the day-ahead market timeframe is valid for the intraday market timeframe as well.

4.23 Article 24: Rules for calculating cross-zonal capacity, including the rules for efficiently sharing the power flow capabilities of CNEs among different bidding zone borders for the CNTC approach

The CNTC approach is built on the current NTC approach, aiming to develop the current NTC approach further in order to fulfill the requirements laid down in the CACM Regulation. The main difference between the current NTC and CNTC approach is that CGMs are applied in the CNTC approach. The CNTC approach is using basic AC load flow and dynamic simulations as a point of departure. In CNTC, the cross-zonal capacities on bidding zone borders are calculated border by border to both directions using CGMs. The following inputs are needed for the calculations:

- CGMs;
- GSKs;
- Contingencies;
- Operational security limits.

Mathematical description of the capacity calculation approach

The AC load flow analysis forms the basis for the CNTC approach. Inputs to the capacity calculation are a CGM, which presents the forecasted state of the power system, GSKs, contingencies, and operational security limits. The AC load flow analysis reveals the voltages in different nodes (magnitude and angle), power flows (active and reactive power) and losses on different transmission lines. Voltages and power flows in the transmission system can be calculated when load and generation in different nodes are known.

Active and reactive power flows in steady state can be calculated using the following equation:

$$\underline{S}_i = P_i + \mathrm{j}Q_i = (P_{\mathrm{G}i} - P_{\mathrm{L}i} - P_{\mathrm{T}i}) + \mathrm{j}(Q_{\mathrm{G}i} - Q_{\mathrm{L}i} - Q_{\mathrm{T}i})$$

$\underline{S}_i$ is the net apparent power coming to node *i*

P_i is the net active power coming to node *i*

Q_i is the net reactive power coming to node *i*

$P_{\mathrm{G}i}$ is the active power coming to node *i* from the connected generators

$P_{\mathrm{L}i}$ is the active power from node *i* to the connected load

$P_{\mathrm{T}i}$ is the active power going from node *i* to the connected transmission lines

$Q_{\mathrm{G}i}$ is the reactive power coming to node *i* from the connected generators

$Q_{\mathrm{L}i}$ is the reactive power from node *i* to the connected load

$Q_{\mathrm{T}i}$ is the reactive power going from node *i* to the connected transmission lines

Background on the power flow equations is presented in more detail in Annex IV.

The TTC is the maximum allowed power exchange of active power between adjoining bidding zones respecting N-1 criteria and operational security limits taking into account remedial actions, rules for undue discrimination and rules for efficiently sharing the power flow capabilities of CNEs among different bidding zone borders.

Rules for calculating cross-zonal capacity, including the rules for efficiently sharing the power flow capabilities of CNEs among different bidding zone borders

The CNTC approach shall, in accordance with Article 29(8) of the CACM Regulation:

a) use CGM, GSKs and contingences to calculate maximum power exchange on bidding zone borders, which shall equal the maximum calculated power exchange between two bidding zones on either side of the bidding zone border respecting operational security limits;
b) adjust maximum power exchange using RAs taken into account in capacity calculation;
c) adjust maximum power exchange, applying rules for avoiding undue discrimination between internal and cross-zonal power exchanges;
d) apply the rules for efficiently sharing the power flow capabilities of different CNEs among different bidding zone borders;
e) calculate cross-zonal capacity, which shall equal to maximum power exchange adjusted according to b), c), and d), and taking into account RM and previously allocated cross-zonal capacity.

Point a)

The calculation of the maximum power exchange on a bidding zone border consists of AC load flow analysis and, where appropriate, dynamic analysis. As long as there are no European CGMs that allow for dynamic simulations, offline dynamic simulations applying Nordic CGMs are performed.

The calculation of maximum power exchanges is an iterative process, where the starting point is the CGM for the studied hour (i.e. the CGM includes the forecasted state of the power system). The calculation of the maximum power exchanges on bidding zone borders consists of contingency analyses taking into account relevant operational security limits. Generation on both sides of the studied borders is scaled stepwise in order to increase the power flow on the studied bidding zone border. After each step (i.e. after each increase in power exchange), contingency analysis (N-1 criterion) is performed and it is checked that operational security limits are not violated. The power flow between the bidding zones can be increased as long as there are no violations of the operational security limits. The analysis is completed, when the maximum power exchange, that still respects operational security limits, is found. Dynamic simulations are performed, where appropriate, in order to take into account dynamic limits and to ensure operational security.

Point b) and c)

The maximum power exchange is adjusted by using RAs and by applying rules for undue discrimination between internal and cross-zonal power exchanges.

Point d)

Sharing rules may be applied for interdependent bidding zone borders to share cross-zonal capacities efficiently among the different bidding zone borders in situations where full cross-zonal capacity cannot be given to all bidding zone borders simultaneously due to operational security reasons. The zone-to-zone PTDF matrix may be used to evaluate on which bidding zone borders sharing rules may be applied.

The guiding principle in the application of sharing rules is that the sharing rules applied shall ensure the maximization of cross-zonal trading possibilities. Sharing rules are defined by an iterative method adjusting the power flows on interdependent cross-zonal borders in order to find simultaneously feasible maximum power exchanges on those borders for each CGM scenario. Sharing rules are defined separately for each CGM scenario in order to take into account the forecasted state of the power system and share the cross-zonal capacities for interdependent borders in the most optimal and efficient way.

Re-evaluation of the interdependencies between bidding zones borders shall be carried out regularly in accordance with the timeframe set in Article 31 of the CACM Regulation, and shall be made available by the CCC together with a justification for the applied sharing rules.

Point e)

Finally, the RM and the previously-allocated cross-zonal capacity are taken into account. It means that cross-zonal capacities are reduced by the amount of RM, and previously allocated capacity.

4.24 Article 25: Rules for sharing the power flow capabilities of CNEs among different CCRs

Cross-zonal capacities on bidding zone borders between CCR Nordic and neighbouring CCRs shall be calculated using CGMs and relevant information from these adjoining bidding zones in coordination with the neighbouring CCC(s). If there is difference in the cross-zonal capacity on the bidding zone border to the neighbouring CCR, the lower value of the cross-zonal capacity shall be used for the capacity allocation.

4.25 Article 26: Methodology for the validation of cross-zonal capacity

Each TSO shall perform the validation of cross-zonal capacities on its bidding zone border(s) in the same way as for the day-ahead market timeframe.

For the CNTC approach, the rules for splitting the corrections of cross-zonal capacity shall follow the same sharing rules as described for calculating cross-zonal capacity for the CNTC approach. The TSOs shall reduce the cross-zonal capacity in a manner that minimizes the negative impact on the market by applying these same rules.

4.26 Article 27: Reassessment frequency of cross-zonal capacity for the intraday timeframe

Due to the fact that the intraday gate opening takes place before CGMs for the intraday market timeframe are available, the first assessment of intraday cross-zonal capacity shall be done based on CGMs for the day-ahead market timeframe and the results of the single day-ahead coupling. The cross-zonal capacity shall be released to the intraday market without undue delay. As soon as CGMs for the intraday market timeframe are available, the cross-zonal capacities shall be reassessed. The frequency of the reassessment of the intraday cross-zonal capacity is dependent on the availability of input data relevant for capacity calculation (e.g. CGMs), as well as any events impacting the cross-zonal capacity.

4.27 Article 28: Fallback procedure for the case where the initial capacity calculation does not lead to any results

In case the initial capacity calculation does not lead to any results, cross-zonal capacities calculated using long-term (i.e. annual, monthly, or more recent) CGMs are provided for allocation.

4.28 Article 29: Monitoring data to the national regulatory authorities

Monitoring data shall be provided to the national regulatory authorities in CCR Nordic as a basis for supervising a non-discriminatory and efficient Nordic capacity calculation and congestion management. Any data requirements mentioned in this article should be managed in line with confidentiality requirements pursuant to national legislation, if applicable.

4.29 Article 30: Publication of data

The TSOs are legally responsible for aiming at ensuring and enhancing the transparency and reliability of information to the national regulatory authorities and market participants. This article describes what shall be published in accordance with Article 3(f) of the CACM Regulation and in addition to the data items and definitions in accordance with Transparency Regulation.

Article 3(f) of the CACM Regulation specifies: why the information should be published, and the subparagraph c) states:

> *"ensuring and enhancing the transparency and reliability of information to the regulatory authorities and market participants".*

The purpose of publishing data is to give market participants and other stakeholders relevant and appropriate information on transmission capacity and its dependencies. With such information the market participants are supposed to be able to act rationally in the markets. This is done by publishing the following items on a regular basis and as soon as possible:

a) A list of all CNEs that are considered and used in the capacity allocation for each market time unit. Each CNE shall be presented with a unique identifier, and it shall be clear on which bidding zone border or in which bidding zone the CNE is located;
b) Information for each market time unit which shall include the following:
    i. all components of the RAM, i.e. FRM, Fmax, Fref´, RA, AAC, and FAV, for each CNE that are provided to capacity allocation;
    ii. allocation constraints and CNEs having impact on the cross-zonal capacity;
    iii. zone-to-slack PTDF matrix;

iv. The base case power flows (Fref) for each CNE that are provided to capacity allocation, on an ex-post weekly basis;

Any data requirements mentioned above should be managed in line with confidentiality requirements pursuant to national legislation, if applicable.

The final, exhaustive and binding list of all publication items, metrics and indicators etc. may be adjusted by the national regulatory authorities in CCR Nordic based on dialogue with TSOs and Nordic stakeholders and concluded in due time before go-live.

Publication of data during the parallel runs

In order to help market participants to compare the two capacity calculation approaches (FB and NTC), data will be published to the market participants on a regular basis through the parallel runs. The TSOs will engage stakeholders in a dialogue to specify necessary and useful data to this effect. The transparency towards stakeholders shall be ensured.

Indicators and metrics will be published showing the difference between the FB approach and the NTC approach in terms of available cross-zonal capacity to the market.

Based on the experience from the parallel runs and after dialogue between Nordic TSOs, stakeholders, and the national regulatory authorities in CCR Nordic, a final, exhaustive and binding list of all publication items, metrics and indicators etc. can be adjusted in due time before go-live.

4.30 Article 31: Capacity calculation process

This Article present a graphical overview that depicts the roles and entities involved, and the input and output data in the capacity calculation process for the day-ahead market timeframe. The same process applies for the capacity calculation process for the intraday market timeframe.

4.31 Article 32: Publication and Implementation

Parallel run means that the FB approach is run in parallel with the current NTC approach in NEMO systems (single day-ahead coupling).

- Both FB and NTC capacity calculation will be performed
    - NTC capacities are sent to the single day-ahead coupling
    - FB parameters are sent to the NEMOs for FB market coupling simulations using the NTC order books, and published daily together with the NTC capacities
    - FB results and other relevant information are published as described in the CCM proposal
- CGMs and industrial capacity calculation tools are applied in the capacity calculations

- TSOs are involved in input data provision to the CCC, and validation of the capacity calculation results

5 Impact assessment

In this section the impacts of the proposed CCM are assessed. First, the quantitative impact of the proposed CCM is assessed by analyzing and comparing the outcome, both in terms of economics and operational parameters, of the market simulations for FB and NTC approaches. In addition, some cases that have been identified, where the FB approach potentially can provide additional benefits, are shown. The NTC approach is used as a proxy for the CNTC approach due to the lack of CGMs with sufficient quality for calculations with the CNTC approach. The NTC approach is the current capacity calculation approach and well-understood by market participants.

Secondly, the qualitative impact of the proposed CCM is assessed by analyzing the impact on electricity markets in other timeframes, bidding zone delineation, congestion income distribution, non-intuitive flows, transparency, and long-term investment decisions.

Finally, the costs for developing and implementing the proposed CCM are assessed.

5.1 Quantitative impact assessment

At the time of writing this document, it is not possible to test the FB approach with industrial tools, operational processes of capacity calculation and allocation, and the CGM. Based on the existing prototype tools and results achieved by using these prototype tools, there is sufficient comfort at the TSOs to enter into the next stages of development. This is what is captured in this document.

This implies though, that the quantitative simulations that are presented in this section are based on - amongst others - prototype tools, non-operational processes, and prototype Nordic CGMs. This may have an impact on the quantitative results as they are presented, though it is hard to assess their impact. Nevertheless, in the following, an overview of the currently-used assumptions in the FB approach are listed.

- Reliability margin
  Currently the FRM is not explicitly defined and implemented as described in the CCM proposal for each CNE. TSOs apply their local tools and criteria to define RM for each CNE, based on the current TRM values. The impact of the FRM assessment as described in CCM proposal is not yet known but it is assumed to have some impact on the quantitative results.
- Operational security limits
  The operational security limits applied in the FB approach are the same as the ones applied in the current NTC approach, and are likely to be the ones to be applied in the operational process of the FB approach as well. The FB approach is not an operational procedure yet. Although the TSOs’ control room staff are consulted in the review stage, they are not personally involved in the FB capacity calculation process yet.
- Contingencies

N-1 contingencies are taken into account for the CNEs with thermal limits, and are the ones to be applied in the operational process of the FB approach as well.

- Allocation constraints
  The allocation constraints applied are the same as applied under the operational NTC approach during capacity allocation. The allocation constraints consist of the implicit loss factors of HVDC interconnections only (ensuring that the HVDC interconnection will not flow unless the welfare gain of flowing exceeds the costs of the corresponding losses), for those HVDC interconnections where this has been implemented, and maximum flow change on HVDC interconnections between market time units (ramping restrictions).
- Generation shift keys
  One common GSK strategy has been applied for all bidding zones in the FB approach. This is strategy number 6, as mentioned in Table 2.
- Remedial actions
  At the stage where the simulations have been performed, RAs have been applied in the form of FAV values, which might also include additional adjustment values (resulting from the validation stage) in addition to RAs. Indeed, this has been adjusted in the CCM proposal: RAs are now captured by their own parameter in the equation for the RAM.
  For Norway, automatic response systems where load, generation, HVDCs or other grid components are automatically disconnected or adjusted, are reflected by the FAV values. The FAVs are applied for CNEs
- Undue discrimination between internal and cross-zonal exchanges
  At the stage where the simulations were performed, the CNE selection process has been applied with a threshold value of 15% on the zone-to-zone PTDF. This approach has been abandoned in the current CCM proposal.
- Previously allocated cross-zonal capacity
  No previously allocated capacity has been considered in the FB approach for day-ahead market timeframe.
- PTDF matrix
  The PTDF matrix is computed in a commercial software tool that has been set up by the Nordic TSOs and enhanced by scripts, for the FB approach purposes.
- Remaining available margins on CNEs
  The remaining available margins are computed in a stepwise manner: RAM = F_{max} – FRM – F_{ref}’ – FAV + RA – AAC. The F_{max} values are calculated by the TSOs applying their local tools and by using their local grid models. The FRMs are set by the TSOs as well. F_{ref} (being the basis for the F_{ref}’) is computed from the prototype Nordic CGM in the same software that computes the PTDF matrix. At the stage where the simulations have been performed, RAs have been applied in the form of FAV values, so that for the simulation results the RA = 0, and possible use of RA is captured by

the FAV. No previously allocated capacity has been considered in the FB approach for the day-ahead market timeframe (AAC = 0).

- CGM
  The prototype Nordic CGM is used for the computation of the PTDFs, and the F_{ref} (being the basis for the F_{ref}'). The quality of the prototype Nordic CGMs is the best we can have at this moment in time but not adequate for a full-fledged industrial application, e.g. they do not allow for dynamic analysis and detailed voltage/reactive power analysis
- Sharing of power flows between CCRs
  No sharing of power flows between CCRs is applied. The advanced hybrid coupling is being applied in the FB approach for capacity calculation and allocation. The converter stations of the HVDC interconnections are modelled as 'virtual' bidding zones (a bidding zone without order books) in the FB approach, having their own PTDF reflecting how the power exchange on the HVDC interconnection is impacting the adjoining AC transmission grid elements. Or in other words: the power flows on the HVDC interconnections are competing for the scarce transmission capacity on the Nordic AC grid, like the power exchanges from any of the other CCR.
- Failures in capacity calculation with FB approach
  Mainly because the prototype CGM poses some challenges, no FB parameters can be computed for some market time units (hours). For these market time units, in the capacity allocation, the FB parameters are replaced with the NTC values of those market time units. In the future the operational CGM and FB processes shall be more robust. In the rare case that no FB parameters can be computed a proper fallback solution shall be in place.
- Market simulations
  The FB market coupling simulations are done in the European Power Exchanges' Simulation Facility by using historical order books (being order books from the current operational NTC approach). Furthermore, the geographical scope of the FB market coupling simulations is limited to the Nordic countries + CWE region + Great Britain + Baltic countries.

Socioeconomic welfare analysis

In this subsection the results from the market simulations to compare the FB approach with the NTC approach are presented. The market results are simulated with Euphemia - the current day-ahead market coupling algorithm - in the Simulation Facility. 4 weeks has been simulated.

Objective function of the algorithm

The algorithm aims to maximize the welfare in the simulated region taking into account grid constraints. The welfare consists of consumer surplus, producer surplus and congestion income, see Figure 11.

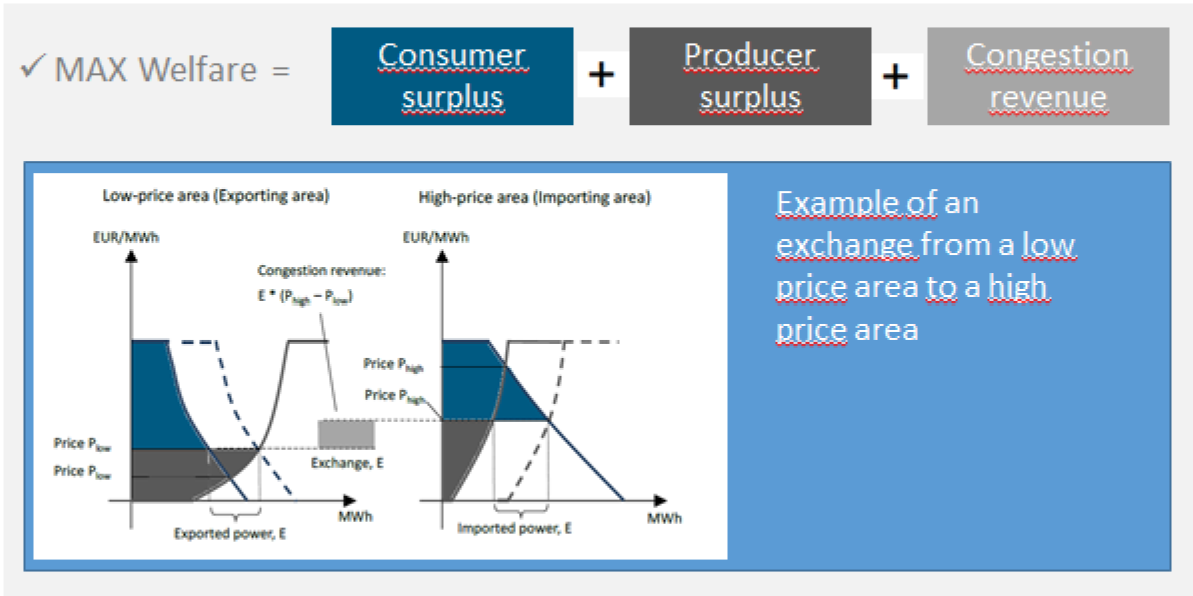


Figure 11 Objective function of the market coupling algorithm

The producer surplus measures for the sellers, whose orders are executed, the difference between the minimum amount of money they are requesting and the amount of money they will effectively receive. The consumer surplus measures for the buyers, whose orders are executed, the difference between the maximum amount of money they are offering and the amount of money they will effectively pay. The congestion income is equal to the product of the cross-zonal price spread and the implicit power flow obtained by the market coupling algorithm. The congestion income is assumed to be shared on a 50/50 basis between the involved TSOs on each side of the bidding zone border. In the current market simulations the socialization of non-intuitive flows has not been taken into account, which means that congestion income might shift from one TSO to another. However, this does not change the welfare gains in total generated in the CCR Nordic.

The order books used for the market simulations are the ones available in the Simulation Facility, i.e. historical order books for the studied area (North-Western Europe and CCR Baltic). The difference between the approaches is in how the cross-zonal capacities are represented in the market coupling algorithm. In the FB approach, the cross-zonal capacities are presented by PTDFs and RAMs for CNEs, and in the CNTC/NTC approach the cross-zonal capacities are presented with transmission capacity values for each bidding zone border.

Some of the market time units in the FB results lack FB parameters. As stated above, for these market time units, in the capacity allocation, the FB parameters are replaced with the NTC values of those market time units. These market time units are left out of the analysis below. We have simulated 4 weeks in total for 2017 and compared the welfare results in the FB approach and the current NTC approach. The weeks are the first 4 weeks of 2017, where the TSOs have been able to qualify the input to the simulations to a satisfactory level. The simulations will continue after the CCM proposal is submitted, and released to the market participants continuously as the TSOs are able to verify the results.

A general observation and starting point is that when there is no congestion in the power system, the result from the FB and NTC approach are expected to be similar. It is when the power system is stressed, with significant congestions, that the result is expected to differ between the two approaches.

The FB approach can potentially increase the available transmission capacity for cross-zonal trade. This impacts the prices in various bidding zones. If the price drops in one bidding zone the consumer surplus increases and the producer surplus decreases. Depending on the slope of the supply and demand curve and the amount of supply and the demand orders in the bidding zone, the change in price leads to a welfare increase or loss, e.g. a bidding zone with a lot of supply orders and a small amount of demand orders will face a welfare loss if the price drops and vice versa.

Impact on socio-economic welfare

For all 4 simulated weeks, the FB approach increases the welfare in the Nordic countries with a total of 544 k€ compared to the NTC approach, see Figure 12. Furthermore, we observe a welfare redistribution. The Nordic consumer surplus decreases with 2,844 KEUR compared to the consumer surplus in the NTC approach. The congestion income in the Nordic countries drops with 117 KEUR and the producer surplus increases with 3,505 KEUR compared to the NTC approach.

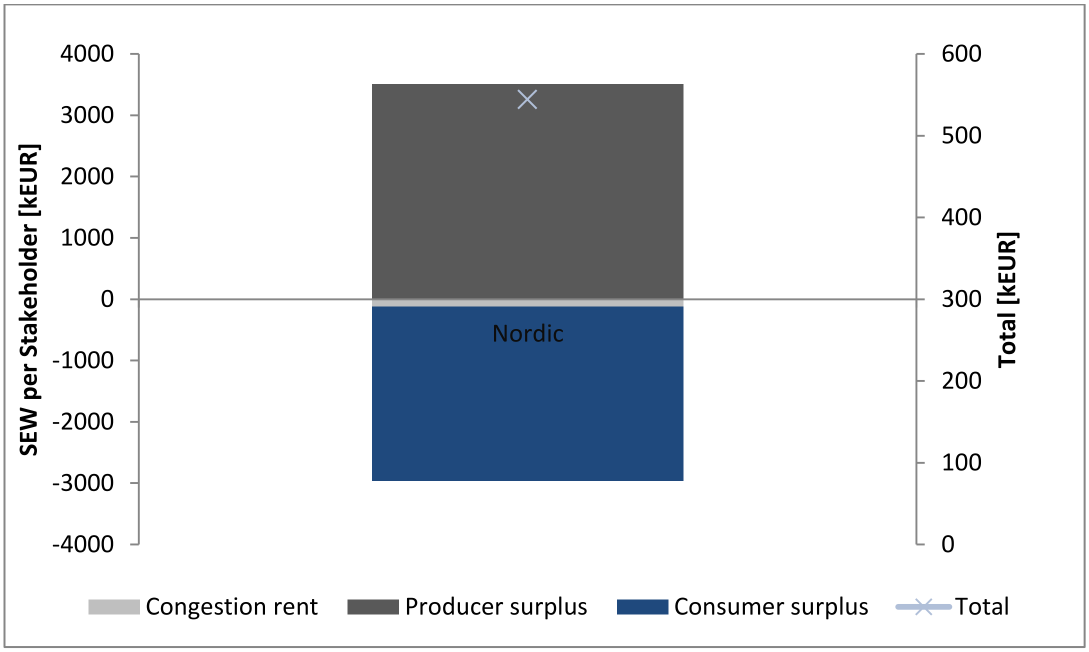


Figure 12 Nordic socio-economic welfare by stakeholder, FB approach compared to NTC approach for all simulated weeks. Stakeholders are understood as a stakeholder group consisting of consumers, producers and TSOs.

This indicates that the FB approach manages to increase prices and to reduce the congestion income by improving the capacity allocation, and thus better distribute the electricity in the system.

When looking at the results on a weekly basis in Figure 13 we can see that most welfare increase was generated during the first week.

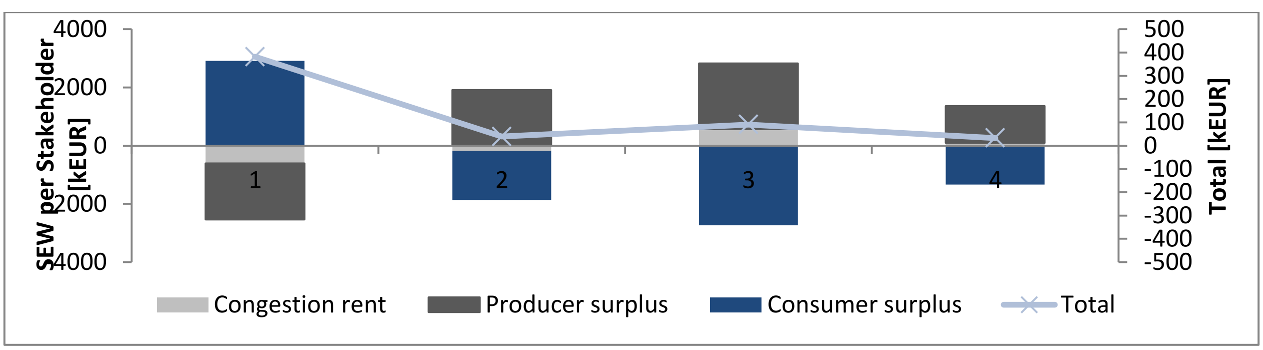


Figure 13 Nordic socio-economic welfare per week, FB approach compared to NTC approach

The welfare gain in week one is driven primarily by very windy morning hours, where the wind energy is distributed better in the Nordic system, thus increasing prices for producers in the windy area, and lowering prices for consumers in other areas.

Figure 14 shows the impact on socio-economic welfare in each Nordic country, where the FB approach is compared to the NTC approach. In this figure it is seen that all countries benefit from implementing the FB approach. During these four weeks it is Norway that has a higher gain than the other Nordic countries. However, this (i.e. that Norway gains most) should not be taken as a given, since this is only data for 4 weeks. The important point is that all countries in the Nordics benefit from a shift in capacity calculation methodology.

For Denmark it is the increase in producer surplus that drives the added socio-economic welfare, which is due to better utilization of interconnections on windy days. In Finland it is the consumer surplus that drives the main increase in socio-economic welfare. Finland is able to import more electricity in the FB approach compared to the NTC approach, which lowers prices for consumers. For Norway it is the producer surplus driving the main positive development in socio-economic welfare. Norway is able to export more electricity in the FB approach compared to the NTC approach, which leads to higher prices for producers. In Sweden the main driver for socio-economic welfare is the consumer surplus. In Sweden the FB approach utilizes transmission capacity to transport more electricity to the Swedish southern areas where a lot of the consumption is situated. This means that prices are lower in the FB approach for the consumers, which gives added welfare.

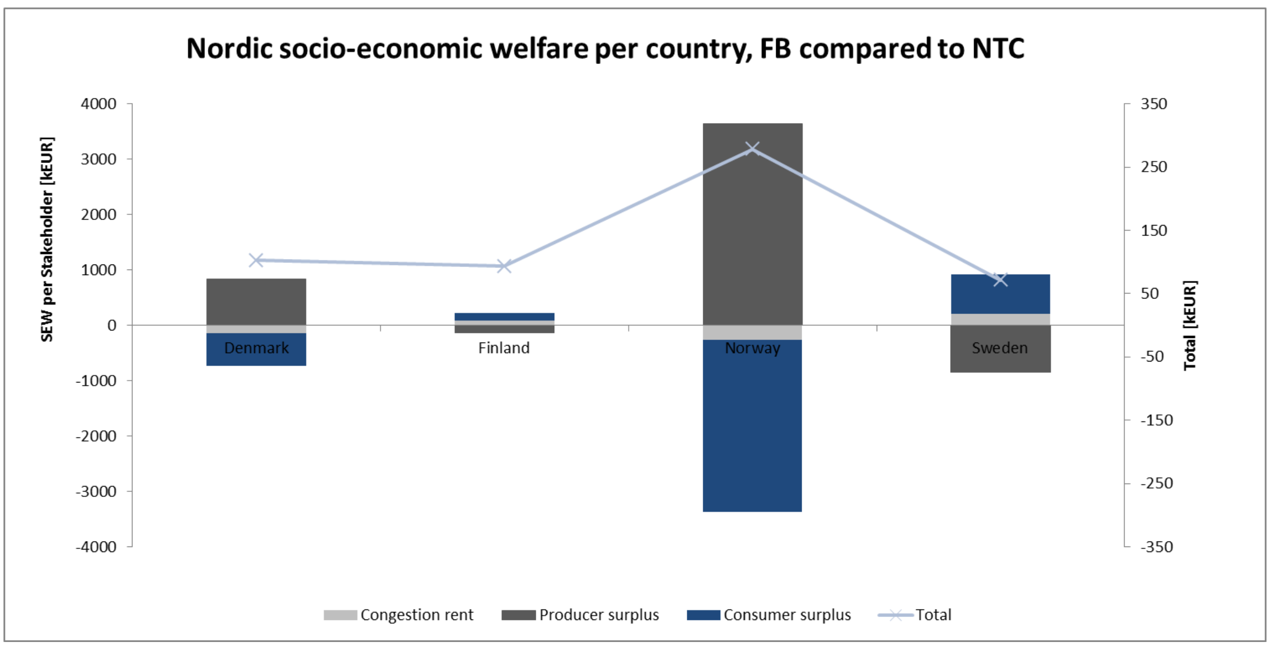


Figure 14 Nordic socio-economic welfare per country, FB approach compared to NTC approach for all 4 simulated weeks

Average bidding zone prices

As mentioned above the welfare results indicate that the FB approach increases the prices in the Nordic countries. Figure 15 shows the average prices in the Nordic bidding zones. The increase in prices especially happens in the Danish and Norwegian areas, while prices in Sweden tend to fall. This has an overall effect of slightly higher prices in the entire Nordic region on average.

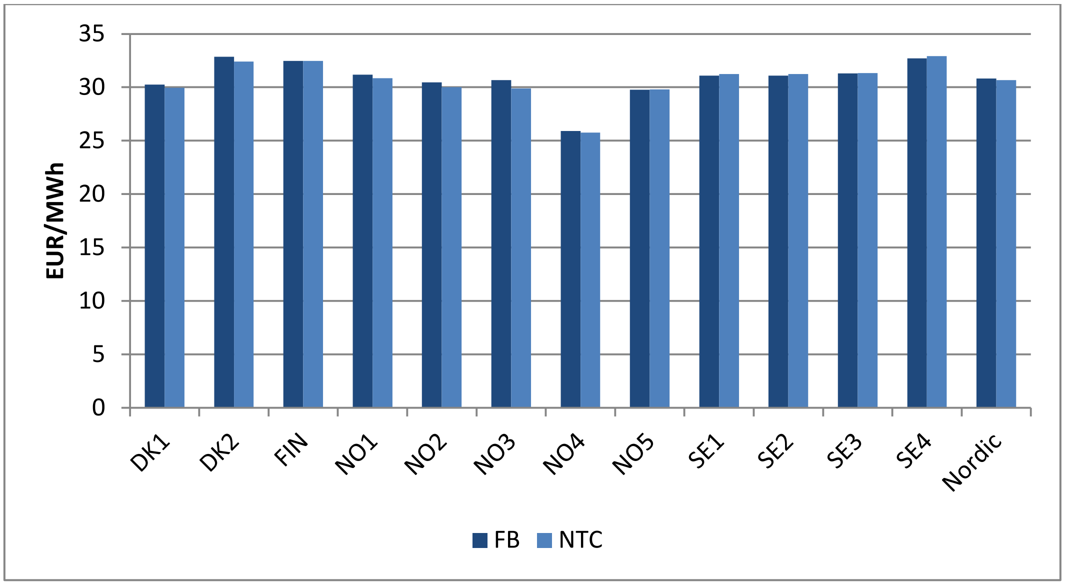


Figure 15 Average prices in the Nordic bidding zones in [EUR/MWh], FB approach compared to NTC approach for all 4 simulated weeks

The average price difference between the FB approach and the NTC approach is below 1 EUR/MWh in all bidding zones, see Figure 16. The Nordic average price increases 0.16 EUR/MWh in the FB approach compared to the NTC approach. The highest increase in price is in NO3, while SE4 has the highest decrease in prices.

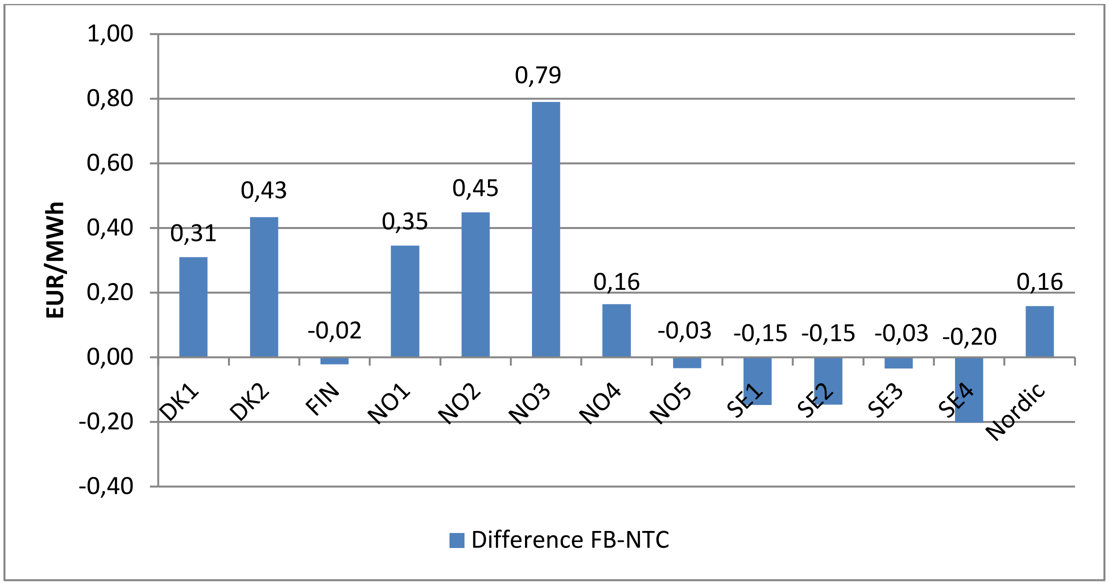


Figure 16 Difference average prices between FB approach and NTC approach in all Nordic bidding zones for all 4 simulated weeks. Note: the overall Nordic average price increase of 0.16 EUR/MWh is a simple average. If the a weighted averaged was calculated, with the market equilibrium as weights, the overall Nordic average price increase would be negative.

Net positions

Figure 17 shows the Nordic net positions during the simulated weeks for the FB approach and NTC approach. During these weeks there is slightly less export from the Nordic region in FB approach compared to NTC approach. On average the weekly Nordic net position is 281 GWh in FB approach compared to 284 in NTC appraoch. The reason for this, is that the Nordic is better at distributing production internally in the Nordic region compared to NTC approach, which in turn leaves less for export from the Nordic countries.

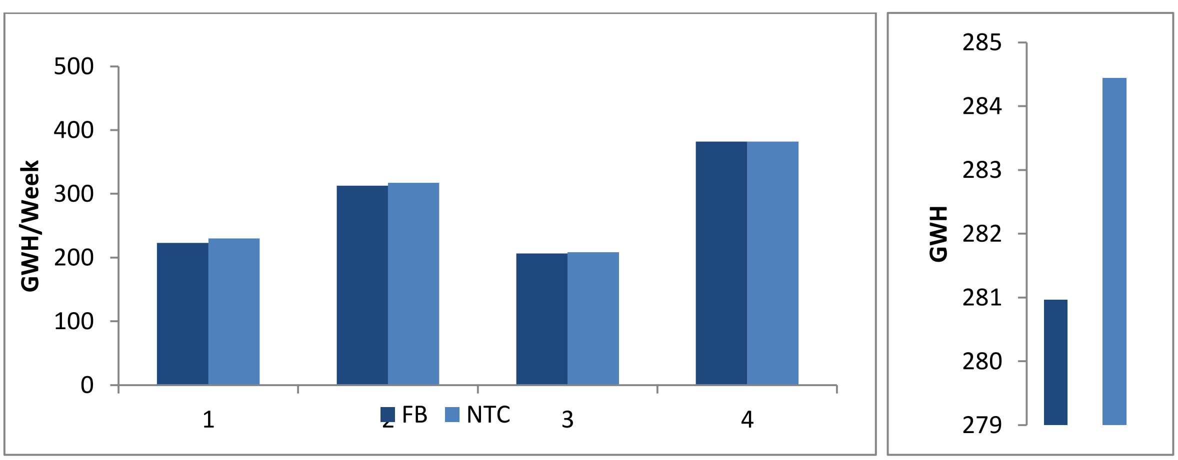


Figure 17 Nordic net position for the four simulated weeks and average. The figure to the left is the weekly net position in [GWh/week]. The figure to the right is the average weekly Nordic net position in [GWh]

Figure 18 shows the hourly average net position in the Nordic bidding zones for the simulated weeks. FI, NO1 and SE4 are the bidding zones with highest import in the NTC approach and FB approach. The bidding zones with the most positive hourly average net position are NO2 and SE2 in the NTC approach and FB approach.

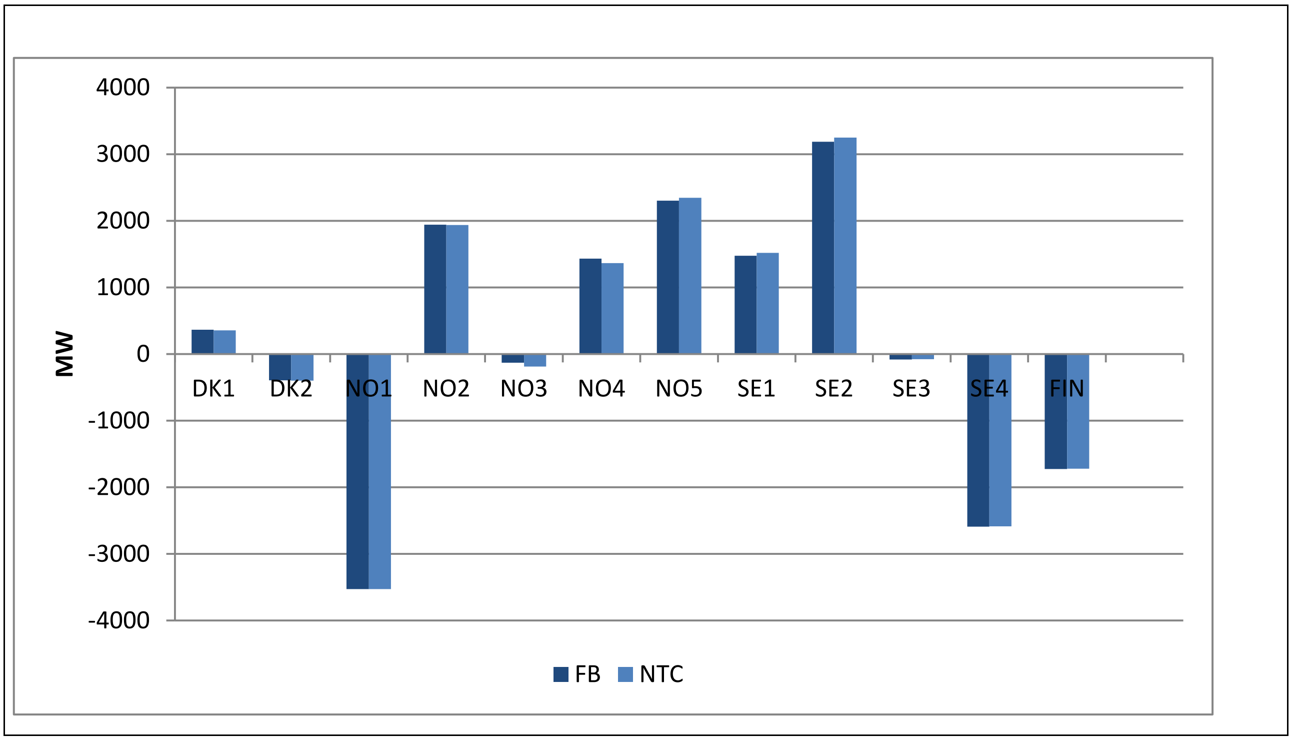


Figure 18 The hourly average net position in the Nordic bidding zones, FB approach compared to NTC approach for all 4 simulated weeks

Figure 19 shows the difference in average hourly net positions in the Nordic bidding zones between FB and NTC approach for the simulated weeks. The hourly average net position increases most in NO3 and NO4 during the simulated weeks. The hourly average net position decreases the most in NO5, SE1 and SE2.

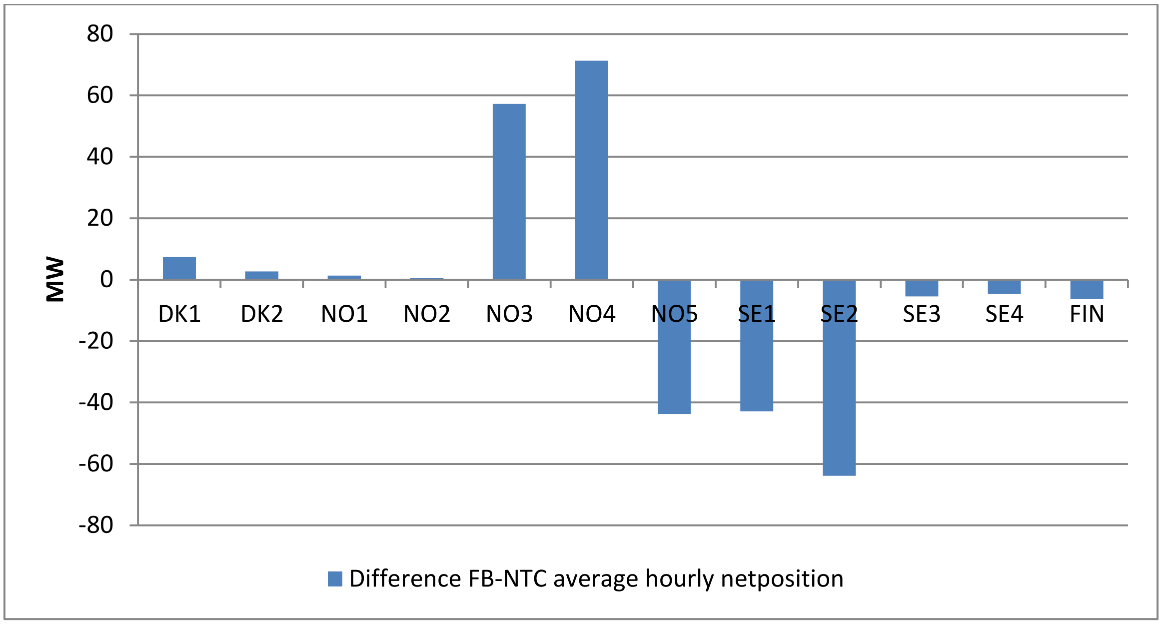


Figure 19 Difference between FB average hourly net position and the NTC average hourly net position in the Nordic Bidding zones for the simulated weeks

However, there is a risk to overestimate the possibility to increase the net position in the different Nordic bidding zones due to limitations in the amount of water available in the hydro reservoirs. In the market simulations, the order books for the NTC approach are used as an input. If the export increases in the FB approach during the first part of the weeks, this change is not reflected in the order books for the coming weeks.

When looking at the results for the four weeks there might seem to be inconsistencies at first glance. It is seen that the net positions are lower for FB than NTC, yet the overall Nordic price level increase by 0.16 EUR/MWh, cf. Figure 16. The more detailed results of the simulations downloadable at the RSC also show that the continental Europe has a large welfare increase. The price results are made as simple averages on a very special situation in the grid. During this time France had to shut down nuclear production, which stained the grid and created very high prices. In hours where the Nordics were able to export more because of flow based this created a very high increase in socio-economic welfare. Even if the Nordics on average did not export more under flow based the hours were this happened caused high welfare for the continent. In the hours where the export is not higher then power from especially Norway and windy days in Denmark is distributed better within the Nordics which causes lower prices. All this means that the average then distorts the picture and leads one to assume that the results are inconsistent, which they are not, they just cover a great variance in scenarios.

Impact on transmission capacity domains and cross-zonal power exchange

This subsection intends to highlight and summarize some important aspects observed during the simulations which were carried out for comparing the FB approach and NTC approach. It is important to emphasize, that the current NTC approach is not the future CNTC approach, where not only input data and the used CGMs cover a wider region but also calculations and decisions are taken on a regional level in a coordinated way (and not on a local TSO level).

In this sense, to describe these phenomena, Figure 20 illustrates a comparison example of the computed transmission capacity domains by both approaches for the Norwegian-Swedish border between NO1 and SE3 (the Hasle border) during week 4 of 2017.

As a matter of clarification, the legend of this figure can be interpreted as following. The orange line represents the physical base case flow on the border in the prototype Nordic CGM and the thick bold blue line the calculated power flow using the historical market results applying the NTC approach. The green line shows the maximum power flow that can be realized on the bidding zone border considering the FB approach and similarly does the thin light blue line for the NTC approach. The green pattern represents the maximum "realistic" power flow that can be realizable on the bidding zone border considering the FB approach by constraining the bidding zone net position to historical values. The blue pattern represents the same for the NTC approach.

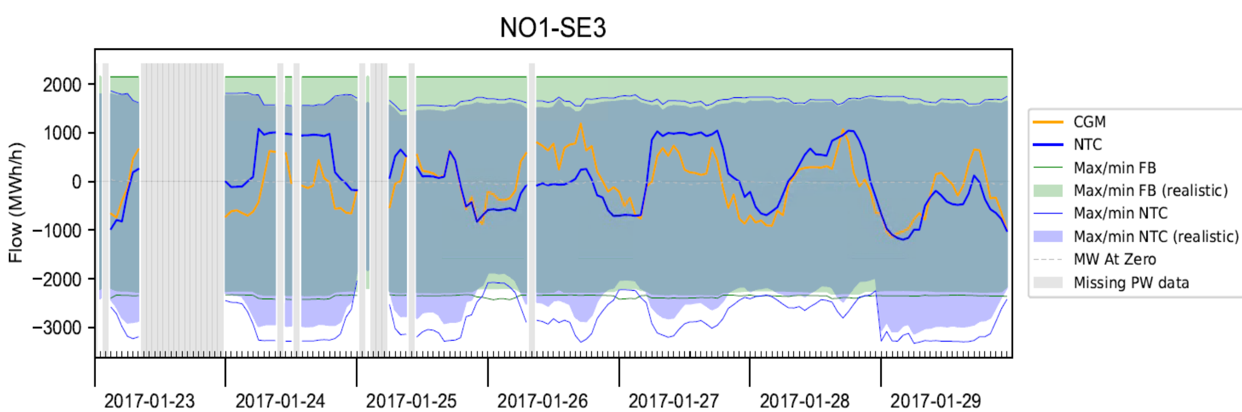


Figure 20 Comparison of the calculated FB and NTC domains for the Norwegian -Swedish border between NO1 and SE3 (Hasle) during week 4 in 2017

Two mains aspects can be derived from the picture above. First, something interesting happens on the 29 of January 2017, where the NTC domain defined for the backward direction becomes larger than the FB domain for most of the day. This can be explained as a consequence of having an NTC of which the security level is not equally restrictive as the one provided by a FB, which could lead to releasing a higher cross-zonal capacity to the market, as shown. This is quite a relevant fact, especially when considering that normally the input data, models and information that TSOs have when performing the current NTC calculations, is more or less limited to the area under their control. In the FB and CNTC approach instead, the data and the analysis itself is extended to the CCR level, thereby bringing a greater level of detail. For example, with the current NTC approach the loop flows are either not considered or considered in a simplified manner, mainly because there are no existing tools supporting that. In this sense, the cross-zonal capacities computed with the current NTC capacity calculation and delivered for allocation to the market coupling might in some cases be overestimated.

The other relevant aspect to mention is when the opposite of the explained above happens; the cross-zonal capacity becomes higher in FB approach than in NTC approach. As mentioned before, in an NTC approach the TSO is responsible to compute the cross-zonal capacity and deliver it for allocation in the market coupling. In a FB approach instead, all relies on how optimal the market framework is, limiting the TSO participation to delivering the constraints (including FB parameters) only without interfering with how the market solution is found. As a consequence, all hours from 23 to 29 of January the cross-zonal capacity for FB approach becomes larger than in the NTC approach in the direction from NO1 to SE3.

Power system impact analysis

Because the capacity allocation used in the FB approach and the NTC approach is different, the day-ahead market results and the resulting power flows are also different depending on whether the FB or NTC approach is used. An overload arises when the power flow on a CNE resulting from the market results is higher than the RAM of this CNE.

The power system impact analysis presented in this subsection compares overloads, measured in MWh/h, resulting from the FB approach and the NTC approach. The comparison is based on the FB security domain, which is used as a yardstick for revealing overloads. The same 4 weeks of simulations as in the previous sections are used for comparison.

Overloads in NTC approach

A number of different reasons can cause the overloads seen in the NTC market results. An important reason is that the cross-zonal capacities in the NTC approach are too high compared to the identified CNEs. This means that the day-ahead market coupling with the NTC approach allows for market solutions outside the FB security domain. This can be due to the TSOs allowing for overloads to enhance the market efficiency, knowing that this might require the use of RAs to reduce the power flows on these CNEs if security violations are occurring in real time. It can also happen if the NTC market results are significantly different from the forecasted market results used when the NTC capacities were calculated.

Another reason is related to the network topology being used in the prototype capacity calculation process. This network topology is from the real operational measurements for the relevant timeframe, and can contain changes compared to the forecasted network model. Some examples of differences that can affect the result are unplanned disconnections of elements such as transmission lines, HVDC interconnections or transformers or planned outages where the connections and disconnections do not follow the planned time schedule.

Overloads in FB approach

Forecasted overloads in the FB market results can occur on the CNEs that were not considered in the capacity calculation because they are not market relevant, either because their zone-to-zone PTDF is below the 15% threshold or because CNEs are included in the analysis for monitoring purposes only. This phenomenon is presented in the following figures by the FB market non-relevant overloads.

The number of CNEs considered in the capacity calculation differs between bidding zones and market time units. One CNE can be considered in one market time unit but not in the next one. The reason for changing from one market time unit to the next one can be caused by topology changes, which can have a big enough impact on the PTDF so the CNE will be considered, but in the next market time unit with a different topology the impact on the PTDF is small and the CNE will therefore not be considered.

The reason for having a different number of CNEs in the bidding zones depends on network topology and operational aspects. The TSOs have different security criteria, and include CNEs from different voltage levels, and therefore the number of CNEs is different between bidding zones. Figure 21 shows the average number of CNEs used to create the FB domain, i.e. those CNEs whose PTDF is above the 15% threshold. The total number of CNEs considered in the capacity calculation, and monitored for overloads is much higher.

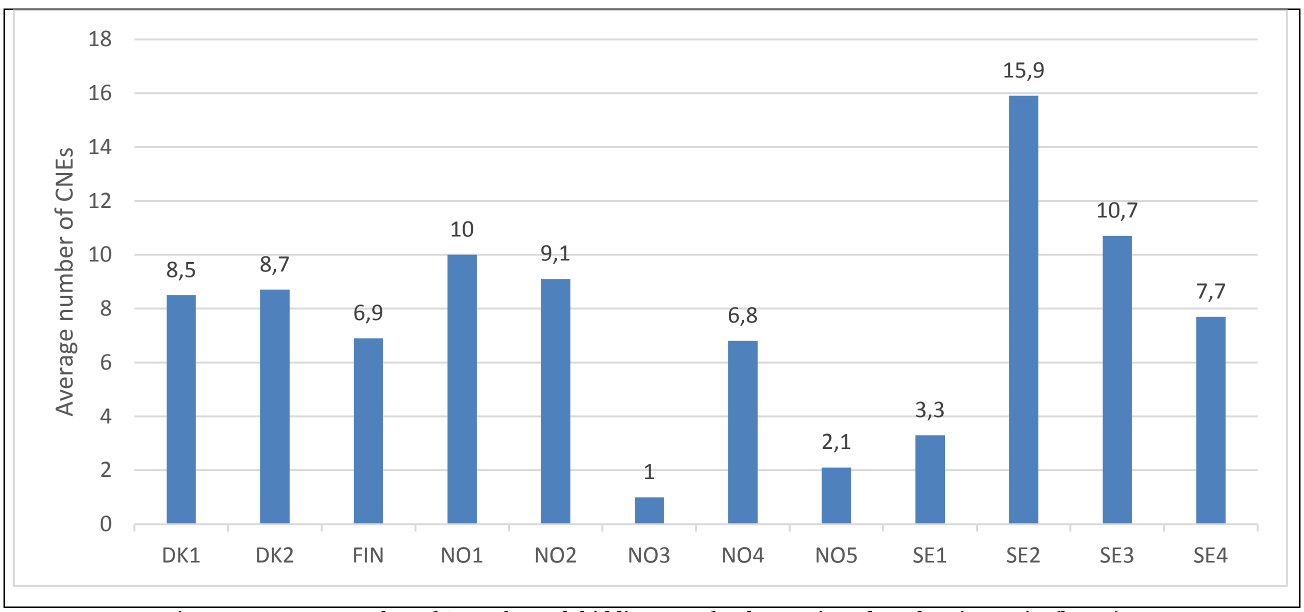


Figure 21 Average number of CNEs for each bidding zone for the monitored market time units (hours).

Results: average overloads in FB approach and NTC approach

A comparison of the average overloads is shown in Figure 22. The values present the average system-wide overloads summarized for both market relevant and market non-relevant CNEs. The results show a lot more overloads measured on the market relevant CNEs in the NTC approach than in the FB approach. Market time units with missing FB data are removed from the NTC and FB results.

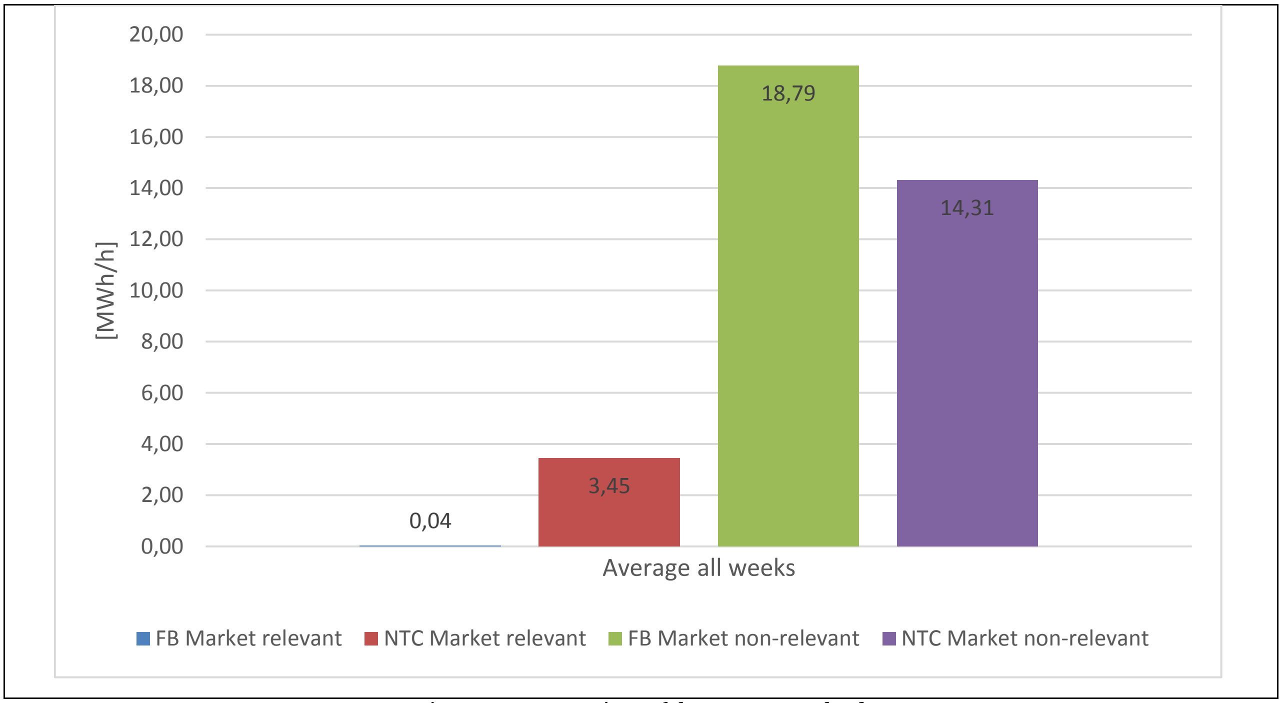


Figure 22 A comparison of the average overloads

The average overloads per week are shown in Figure 23.

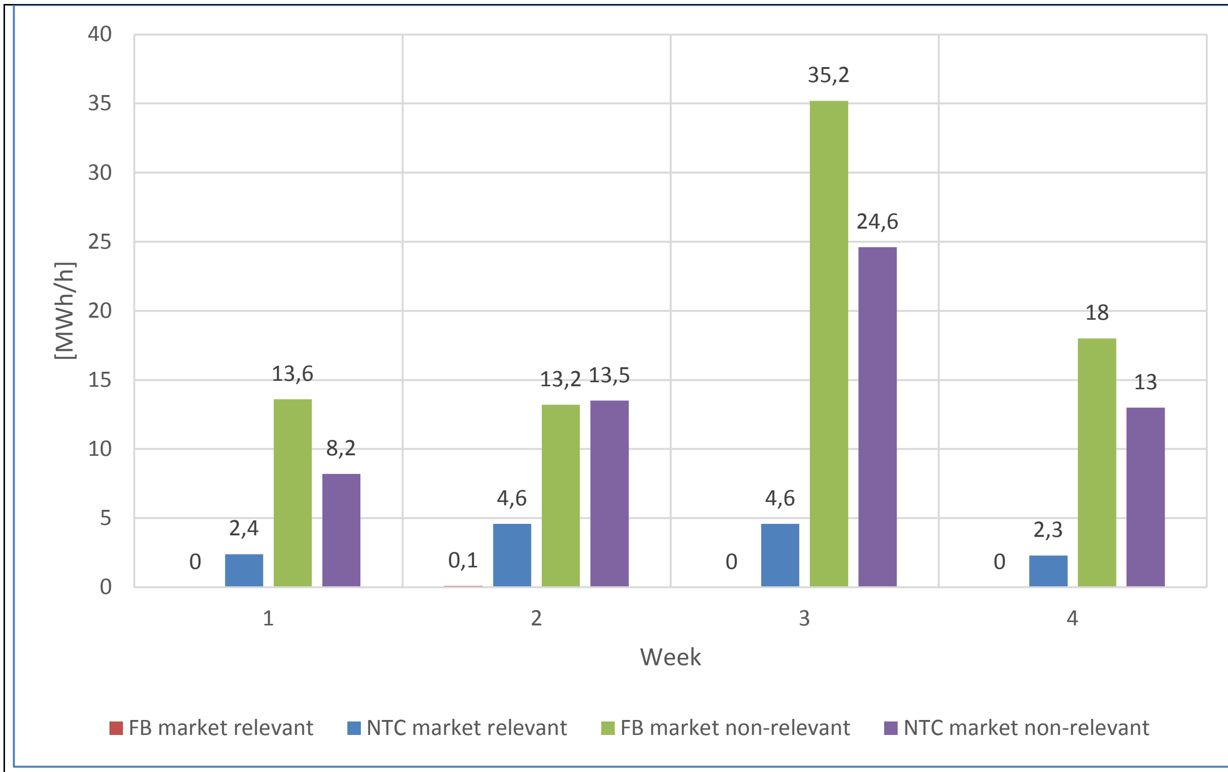


Figure 23 The average overloads per week for Nordic power system.

The comparison of the hourly (i.e. applied market time unit) average overloads per bidding zone is shown in Figure 24. The results indicate that most of the overloads measured in the NTC approach on market relevant CNEs are found in SE1, SE2, and NO1. These overloads decrease significantly in the FB approach. The measured overloads are dependent on the number of CNEs in the bidding zones. A high number of CNEs will more easily lead to a high number of overloads in a bidding zone. The point of the figure is to show the difference between the FB and NTC approach. The CNEs and the attached F_{max} are the same in the FB and NTC approach.

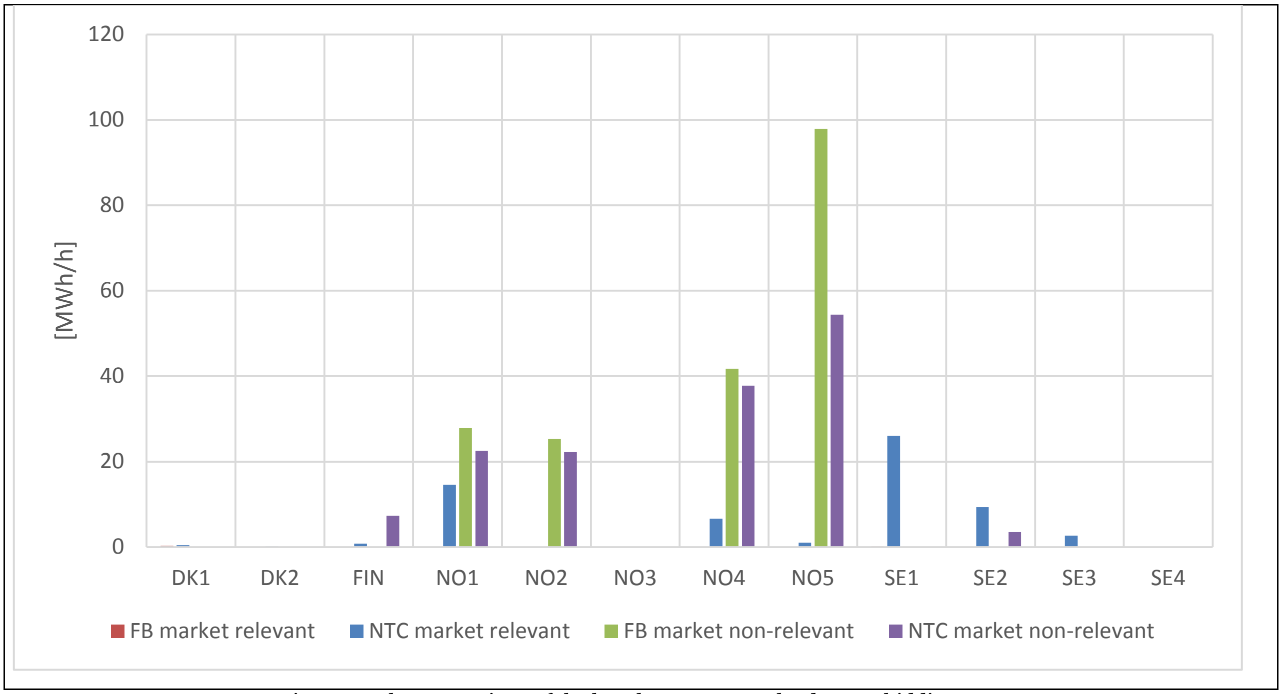


Figure 24 The comparison of the hourly average overloads per a bidding zone.

Results: Economic gain against transmission grid overloads

The total welfare and the net reduction in overloads are shown in Figure 25. Each dot represents one hour of the 4-week period of 2017 used in the previous analyses. In contrast, the results presented before in Figure 23 and Figure 24 are average results per bidding zone or per week.

The points can be located in any of the four quadrants Q1, Q2, Q3 and Q4. Values above the x-axis are representing a positive total welfare in the FB approach compared to the NTC approach and the values under the x-axis are representing a negative total welfare in the FB approach compared to the NTC approach. The values to the right of the y-axis are representing the reduction of overloads in the FB approach compared to the NTC approach. The values to the left of the y-axis are representing the increase of overloads instead.

Figure 26 shows the proportion of hours in each quadrant where it can be seen that the majority of the hours is in the quadrants Q1 and Q2, corresponding to a higher socio-economic welfare with the FB approach.

The hours in the quadrants Q1 and Q4 have larger overloads with the FB approach than with the NTC approach on the monitored CNEs. Not all monitored CNEs are considered in capacity calculations though. Indeed, the monitored CNEs considered in the capacity allocation do not receive any overloads with the FB approach. The overloads on the CNEs not considered in capacity calculation and allocation must be dealt with in some other way, for example during the coordinated security assessment or during real-time operations.

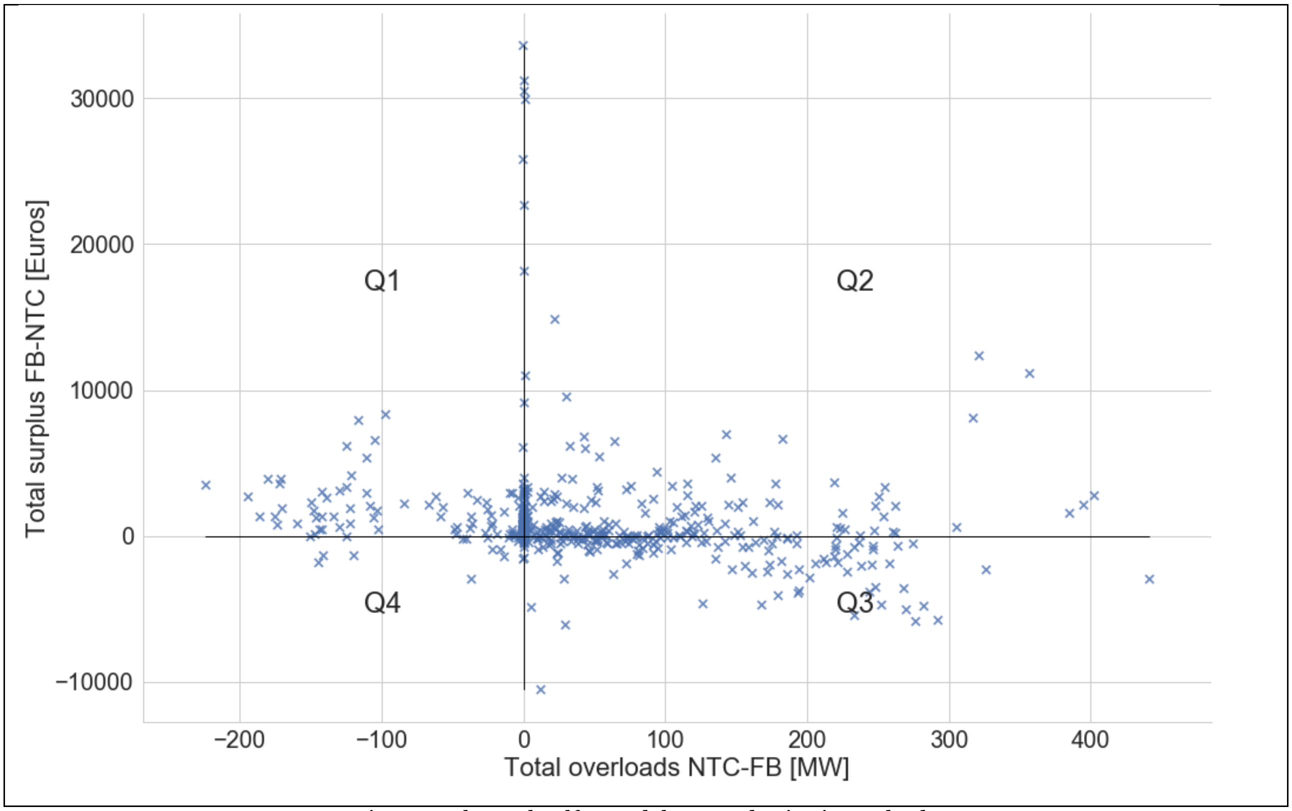


Figure 25 The total welfare and the net reduction in overloads

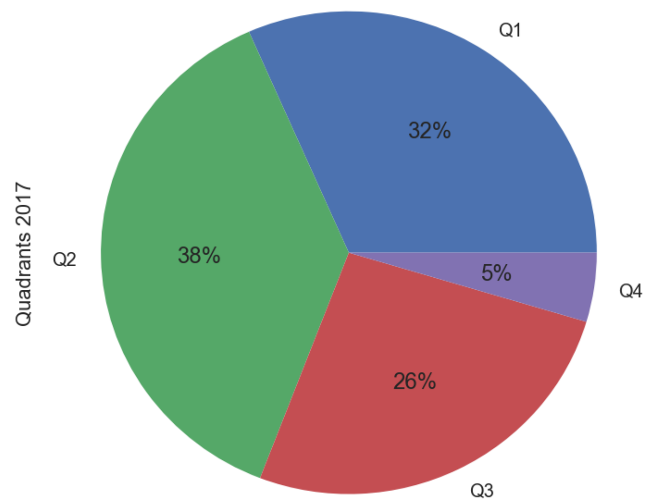


Figure 26: Proportions of simulated hours in each quadrant

The average and median values of all hours are presented in Table 3. FB approach performed better both in terms of market welfare and avoided overloads.

Table 3 Average and median values of reduction of overloads and welfare gains

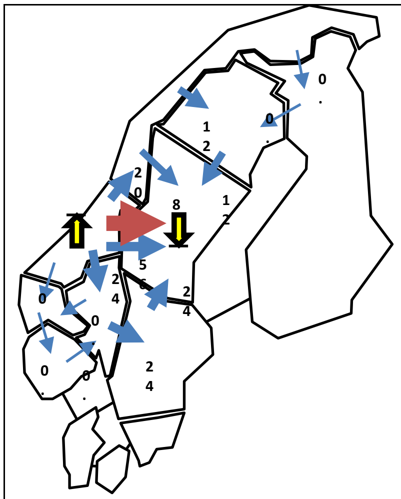
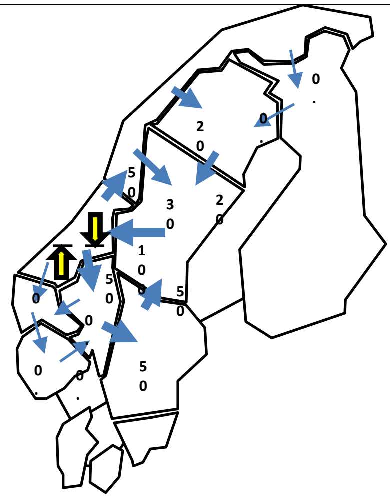
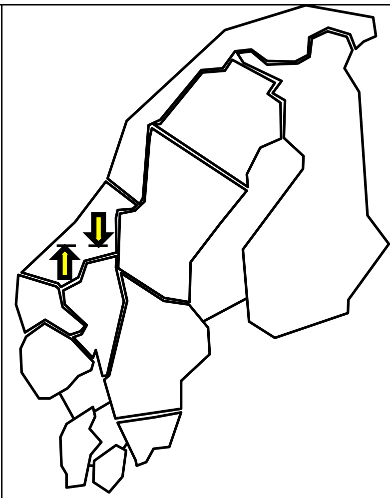
Average overloads NTC-FB [MW]	Average surplus FB-NTC [Euros]	Median overloads NTC-FB [MW]	Median surplus FB-NTC [Euros]
47	1047	14	369

Study of internal and loop flows

Background

In Table 4, transit flows, loop flows and internal flows are defined.

Table 4 Definition of transit flows, loop flows, and internal flows

		
Transit flows The power flow starts in one bidding zone and ends in another. The flow does not just flow on the border between these two bidding zones but spreads according to Kirchhoff's laws in the transmission grid. Considering a trade between two bidding zones, transit flows are defined as the flows on the bidding zone borders (others than the border between these two bidding zones) originating from this trade.	**Loop flows** The power flow starts and ends in the same bidding zone. The flow does not stay within the bidding zone but spreads according to Kirchhoff's laws in the transmission grid. Considering a trade within one bidding zone, loop flows are the flows on all borders originating from this trade.	**Internal flows** Internal flows are the power flows on the internal transmission lines of a bidding zone originating from the trades within that bidding zone.

Hypothetically, it is possible to consider the power system with zero trade between the bidding zones. This is achieved by setting the net positions to zero in each bidding zone. In a power system with zero net positions, all power flows will be either loop flows or internal flows and it is therefore possible to quantify the sum of these two kinds of power flows. Note that it is not possible to differentiate between these two kinds of power flows. A study of this kind was performed for one day in the Nordic system.

Setup

The input data to this study consists of: 24 CGMs and 24 sets of CNEs. The sum of internal and loop flows is recorded for these CNEs.

The net positions in the CGMs are in general not zero. The following strategy was used to scale the net positions to zero:

- For bidding zones with net export (production > load), the production is scaled down to the load level.
- For bidding zones with net import (production < load), the load is scaled down to the production level.

This results in "adjusted" CGMs in which all bidding zones have zero net positions. It is important to note that such a power system with zero net positions is a very hypothetical power system. Many bidding zones in the Nordic system are either export or import areas and will never receive a zero net position.

In these CGMs, the flows on the CNEs are the sum of internal flows and loop flows. It is then possible to compute the ratio of this sum and F_{max}, F_{max} being the maximum capacity of the CNEs.

Results

Figure 27 shows the cumulative distribution function of the ratio of the sum of internal and loop flows to F_{max}. From the figure, the overall results is that for 95% of the CNEs the sum of internal and loop flows is smaller than 25% of F_{max}.

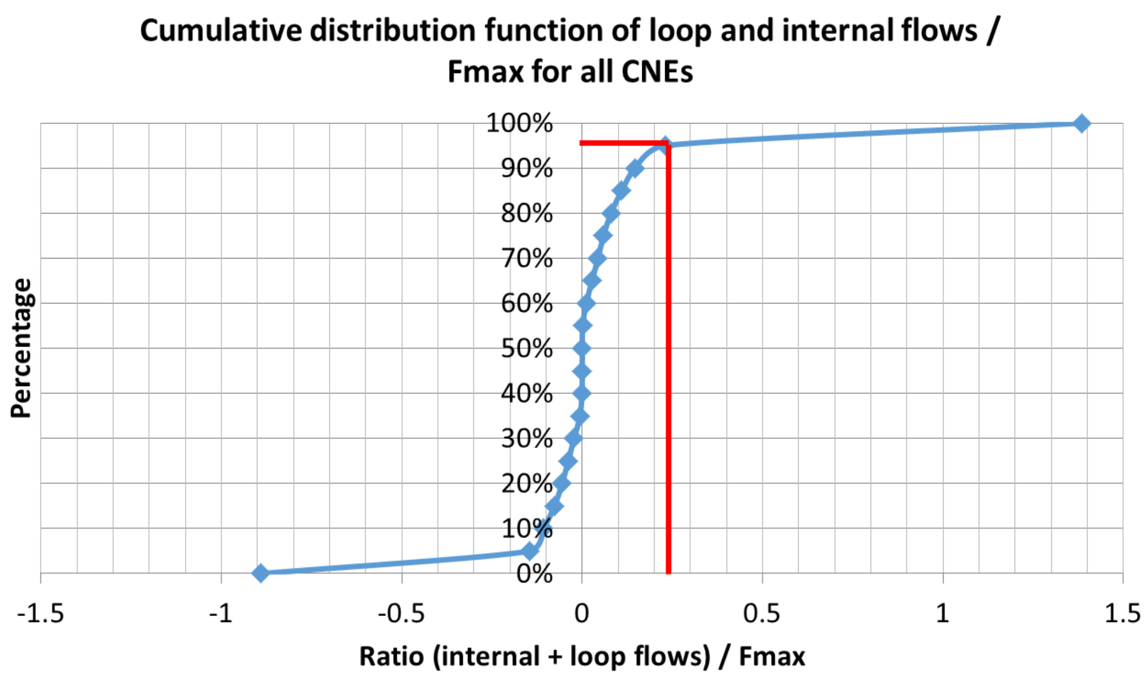


Figure 27 The cumulative distribution function of the ratio of the sum of internal and loop flows to Fmax

The sum of loop and internal flows are related to, but not equal to, F_{zero} introduced in Section 4.7. F_{zero} is computed by using the PTDFs obtained from the computations with the FB approach. The sum of loop flows and internal flows presented in the study above is computed by scaling the net positions to zero using the strategy described in the subsection “Setup”.

It is also important to note that a large ratio of internal and loop flows to F_{max} does not necessary imply that these internal and loop flows will limit the cross-zonal trades. For example, the internal and loop flows may go against the relevant market direction and, therefore, actually increase the RAM by relieving the CNEs in the market relevant direction.

Selected cases illustrating benefits (in detail) of FB approach

The objective of this subsection is to provide a more in-depth understanding of the difference of FB compared to NTC. This is done by presenting a selection of concrete situations in the Nordic power system. The section provides three cases:

- The existence of non-intuitive flows
- Better utilization of transmission capacity on a new transmission line between bidding zones NO3 and NO5
- Better management of the west-coast corridor in Sweden

One case of non-intuitive flow

In this case we show how non-intuitive flows can occur in the FB approach and enable a larger power flow between SE1 and SE2. In Figure 28, we show a simplified example of an hour with a high consumption and low wind production in the Nordic countries. The bidding zone prices are highly affected by a CNE with a high shadow price (see subsection “Long-term investment decisions – role of shadow price” on page 117 for more explanation on shadow prices) between SE2 and SE3. To relieve this congestion, the FB approach reduces the power flow on the bidding zone border between SE2 and SE3 and increases the power flow on the bidding zone border between SE1 and SE2. The increased transaction between bidding zones SE1 and SE2 has a relieving impact on the limiting CNE.

In the NTC approach bidding zones NO1, NO3, NO4, SE1-3 have the same price, and the bidding zones NO2, NO5 and DK1 have the same price. The FB approach manages to lower the prices compared to the NTC approach in most bidding zones due to a different way of managing the congestion.

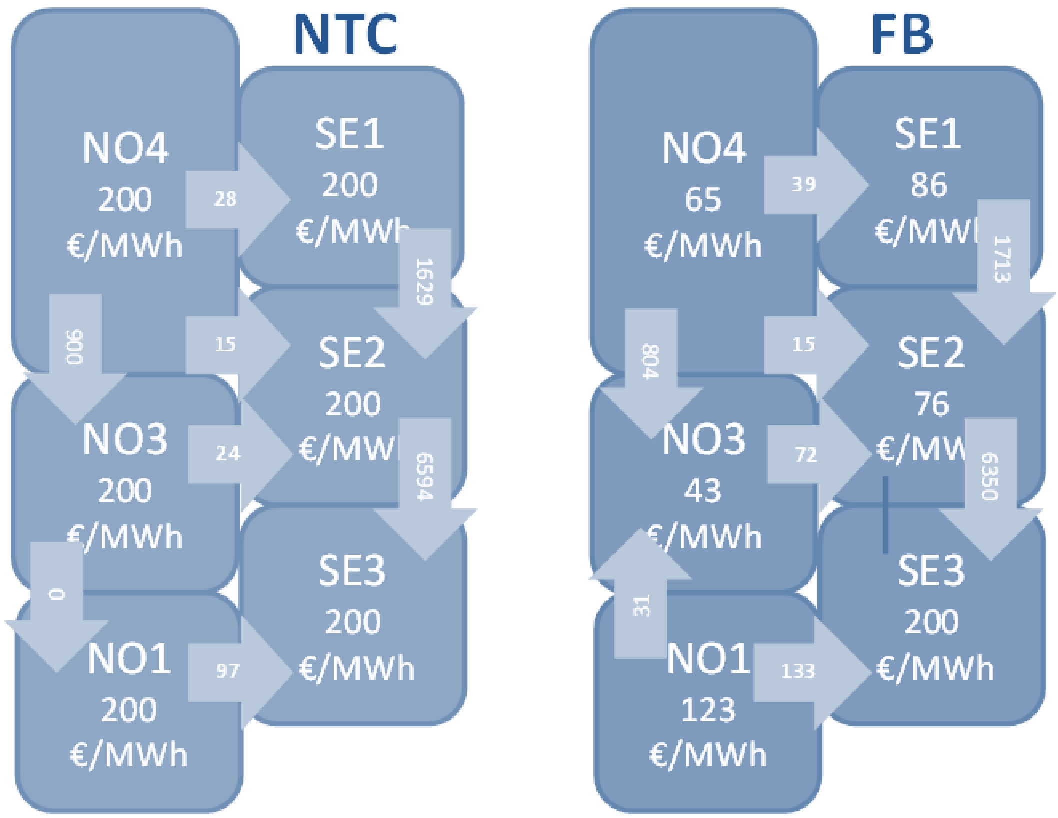


Figure 28 Simplified example with non-intuitive flow between bidding zones SE1 and SE2

Case study bidding zone border NO3-NO5 (Ørskog-Sogndal)
During 2016, Statnett has taken a new transmission line - connecting the bidding zones NO5 and NO3 - in operation, see Figure 29. The new line contributes significantly to the transmission capacity connecting Southern and Middle Norway, and thus increases the North-South transmission capacity in the Nordic power system.

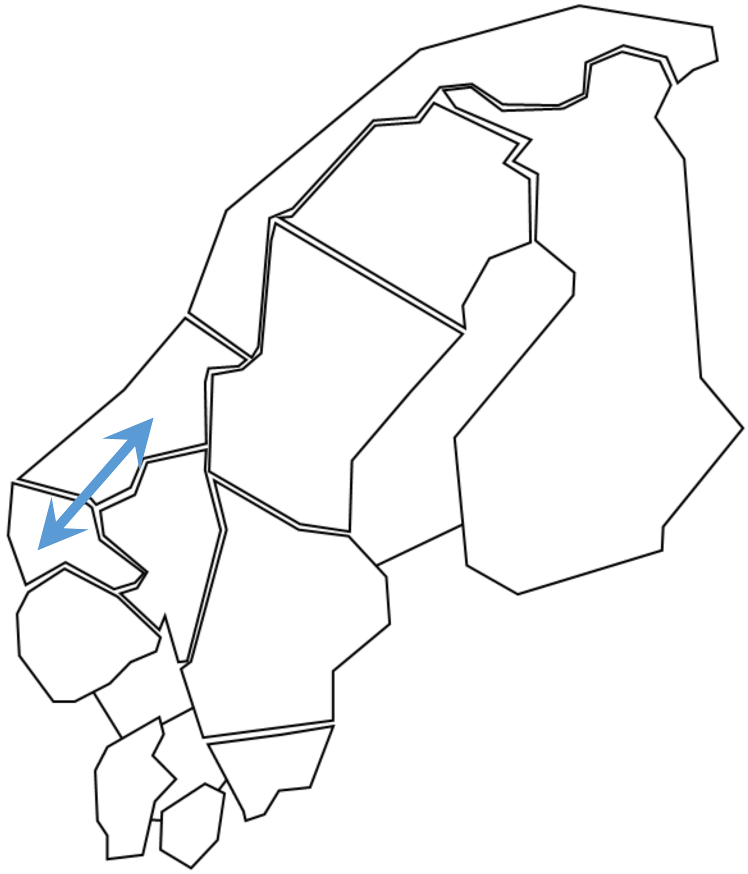


Figure 29 The line Ørskog-Sogndal (NO3-NO5)

The new transmission line will provide a parallel path to the existing north - south interconnections NO1-NO3 and SE2-SE3, which means that any trade between northern and southern Scandinavia will induce power flows on all three interconnections. This makes it challenging to determine the optimal transmission capacities as all three interconnections are influenced by transit flows from commercial trades. The transit flows are disproportionately greater for the Norwegian transmission lines due to the much greater transmission capacity on the Swedish side.

The existing interconnection NO1-NO3, which has the same issue on a smaller scale, is currently handled by limiting the available transmission capacity given to the market coupling to zero, as Statnett decides ex ante the exchanges on the interconnector. Zero or reduced transmission capacity at the new transmission line would incur a large cost as not all of the new transmission capacity becomes available to the market coupling.

How can FB approach improve the situation?

The FB approach has the potential to provide a better solution to this challenge by significantly reducing the uncertainty that accompanies the discrepancy between resulting power exchanges with the NTC approach and the realized physical power flows.

The challenge described above, and the potential of FB approach to improve the situation, was explored using empirical data: a simplified PTDF matrix from the Samnett simulation model, and the optimization engine in the Excel spreadsheet application. The approach was to do a simplified price calculation (simulating the allocation mechanism) using both the NTC and FB approach for individual hours, using historical net positions and prices as a starting point.

More information regarding the model set up and assumptions are given in the Annex, Section 8.

We have, as a starting point, made the assumption that the power exchanges on the bidding zone borders that were congested in the historical market results were not allowed to increase, while the rest of the bidding zone borders were considered open for additional cross-zonal trade. In the initial NTC approach, NO3, NO4 and the Swedish bidding zones have the same price (with a lower price), whereas NO1, NO2 and NO5 have the same price (with a higher price), see Figure 30.

The effect of adding 100 MW cross-zonal capacity with the NTC approach on the new transmission line was compared to the FB approach (with no limit on the new transmission line), and both were compared to the original market results applying the NTC approach. An important effect of the FB approach set up was that the power exchange on the bidding zone border NO1-NO3 was no longer determined ex ante, but the power exchange was not allowed to increase compared to the market results with NTC approach.

The results show that any power exchange on the new transmission line using the NTC approach would create physical overloads in other parts of the Nordic transmission grid. The results also show that the FB approach can provide a better solution than the NTC approach, without creating the same overloads.

Figure 30 shows the realized physical flows resulting from the power exchanges with NTC approach, referenced to the original market results in the NTC approach.

From Figure 30, one can see that 100 MW additional transmission capacity for power exchange between bidding zones NO3 and NO5, leads to a 74 MW increased load on the already-congested transmission line on the bidding zone border NO1-SE3, while 9 MW goes from biding zone NO3 to bidding zone NO1. Only 16 MW of the 100 MW additional power exchange appears as physical flow on the new interconnection between bidding zones NO3 and NO5. The price in NO3, NO4 and the Swedish bidding zones increases marginally and the price in the bidding zones NO1, NO2 and NO5 decreases slightly.

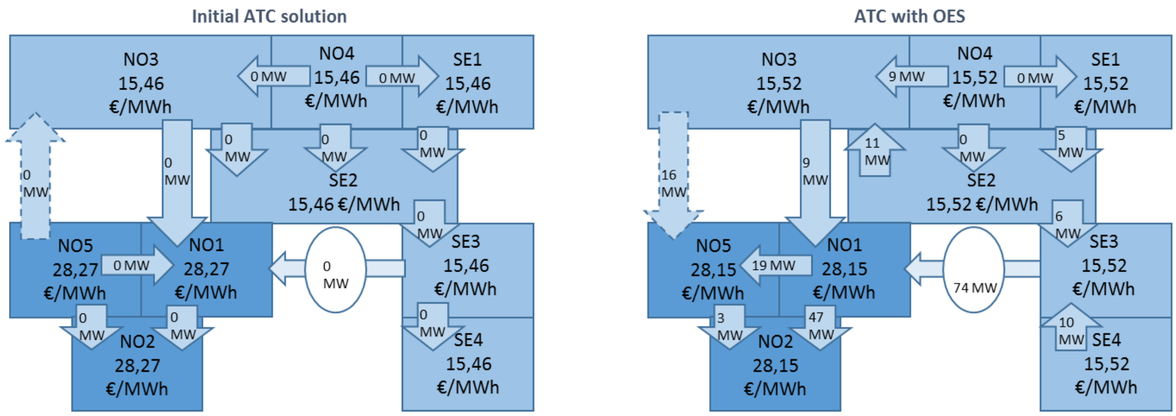


Figure 30 NTC results for hour 4 on 25.12.2013. The prices are shown inside the boxes, and the colors indicate the price level. The physical flows resulting from the power exchanges are shown referenced to the initial market results.

The market results with the FB approach for the same hour is shown in Figure 31. The flows are referenced to the same historical market results, and it's clear from the values that there is no increased load on the transmission line on bidding zone border NO1-SE3, even though the market results have improved significantly in terms of socio-economic surplus. The improvement is due to a significant increase in the flow between the bidding zones with low price (Sweden and Northern Norway) and the bidding zones with high price (Southern Norway). The FB approach manages to increase the power flow on the bidding zone borders NO3-NO5 and NO3-NO1, while avoiding increased load on the bidding zone border NO1-SE3, by increasing the net position in the north-west and reducing the net position in the south-east. The net positions in all bidding zones are adjusted to maximize the power flow into Southern Norway, and thus to create a better market results.

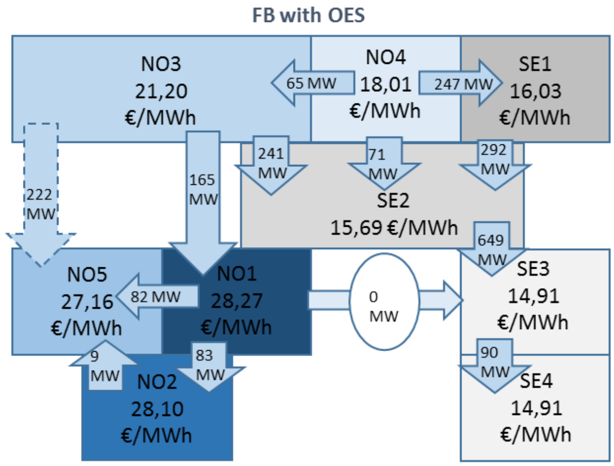


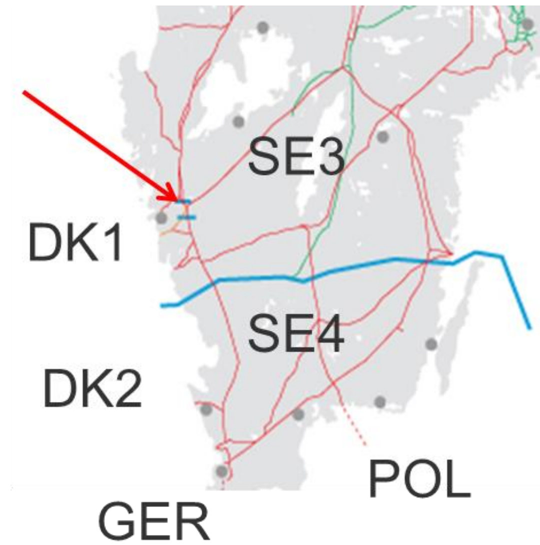
Figure 31 The prices are shown inside the boxes, and the colors indicate the price level. The physical flows resulting from the power exchange are shown referenced to the initial market results.

West-coast corridor

The current congestion management routine for the West-coast corridor (see Figure 32) is based on a pro-rata approach where the cross-zonal capacity is limited on relevant interconnections, in order not to overload the West-coast corridor. The cross-zonal capacity is limited in proportion to a pre-defined dimensioned capacity for each interconnection. Today the capacity is limited on the following interconnections:

- The Hasle interconnection to southern Norway (bidding zone NO1)
- Konti-Skan to Western Denmark (bidding zone DK1)
- Zealand interconnection to Eastern Denmark (bidding zone DK2)
- Baltic Cable to Germany (bidding zone DE)
- SwePol Link to Poland (bidding zone PL)
- NordBalt to Lithuania (bidding zone LT)

The West-coast corridor



The West-coast corridor is a section in the Swedish high voltage grid that cuts through three 400 kV lines in western Sweden, close to Gothenburg. During periods where there is import from Poland, Germany and Denmark, export to Norway and low load in the Gothenburg area, congestion can occur in the West-coast corridor.

To ensure system security, i.e. transient stability and thermal capacity, the power flow in the West-coast corridor then may need to be limited in a northerly direction. These conditions occur mostly during nights and weekends due to the fact that the prices in Norway are higher than in Denmark and Germany (hydro storage vs. wind)

Compared to other corridors in the Swedish high voltage grid, the West-coast corridor does not cut across the country from bidding zone border to another border. In addition, in the West-coast corridor case it would not be possible to define an area with sufficient amount of controllable generation capacity. The absence of fast adjustable generation resources close to the West-coast corridor implies that larger regulations must be activated in more distant locations. These measures are very inefficient as it has only a limited impact on the power flow over the West-coast corridor. Hence, it is difficult to treat this congestion with the same principles as for bidding zone borders.

Figure 32 The arrow shows the location of the West-coast corridor

How can FB approach improve the situation?

By applying FB approach to the West-coast corridor the flexibility would increase. Instead of the TSO deciding ex ante how much each interconnection should be limited based on a pro rata principle (NTC), the FB approach manages the congestion on the West-coast corridor while maximizing social welfare. This means, that the power flow between two bidding zones with a higher price difference, everything else being equal, would get priority over a flow between two bidding zones with a lower price difference.

The FB approach would also lead to market results that better take into account the real physical flows in the transmission grid. By applying PTDFs to all bidding zones and HVDC interconnections, the FB approach would take into account how an increased power flow on a specific HVDC interconnection would impact the West-coast corridor. Instead of treating all the power flows as they would have the same impact on the West-coast corridor, the market coupling algorithm can allocate more cross-zonal capacity to bidding zone borders and HVDC interconnections with lower impact on the West-coast corridor, and reduce the allocated cross-zonal capacity to the bidding zone borders and HVDC interconnections with the highest impact, if this increases the total social welfare.

Thus, the most efficient action can be used to reduce the power flow on the West-coast corridor.

In Table 5, the results are presented for an hour where the West-coast corridor severely limited the import capacity on the interconnections. In the table the available cross-zonal capacities in the NTC approach are presented.

Table 5 The available capacities on the interconnections involved in the congestion management in the West-coast corridor for hour 23-00 the 26th of December 2016. The max NTC are shown in the parenthesis.

2016-12-26 23:00	MW
DK2>SE4	61 (1700)
SE3>NO1	171 (2095)
DK1>SE3	27 (740)
PL>SE4	22 (600)
LT>SE4	25 (700)
DE>SE4	23 (615)

Figure 33 shows the result when the present NTC approach and FB approach are used in the West-coast corridor. In the NTC approach, all bidding zones in Sweden, Finland, NO3 and NO4 get the same price, while the price is higher in NO1, NO2 and NO5 and lower in Denmark due to congestion. The available capacities on the interconnections to Southern Norway (NO1), Denmark (DK1 and DK2), Germany and Poland have been limited ex ante to manage the congestion in the West-coast corridor.

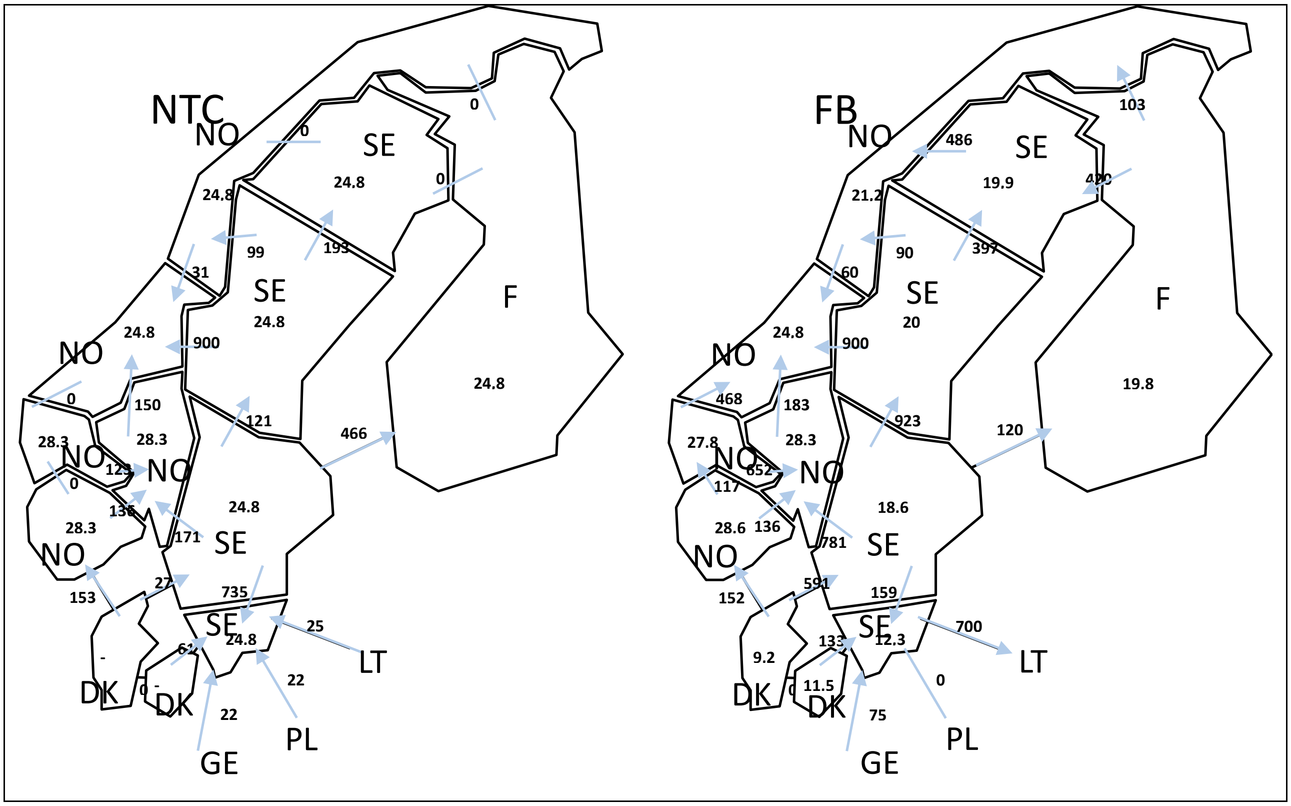


Figure 33 Management of congestion in the west coast corridor in NTC and FB approach. Results from hour 2016-12-26 23:00:00. Prices are shown in €/MWh and power flows (arrows) are shown in MW.

In the FB approach there is no ex-ante cross-zonal capacity split between different interconnections. Instead, the market coupling algorithm can choose to which interconnections the power flow should be allocated based on the least generation cost for the whole power system. Sweden gets a lower price compared to the NTC approach in all bidding zones, but now the prices differ between the bidding zones as shown in Figure 33. The power flows from Denmark and Germany have increased and bidding zone SE4 has an export power flow on NordBalt. Denmark gets higher prices because of the increased export power flows to Sweden.

5.2 Qualitative impact assessment

Implementing FB in the Nordic power system is a significant change compared to the current NTC approach. Therefore a qualitative impact assessment has been conducted on issues relevant for the Nordic stakeholders. This section contains the outcome of this assessment. Each subsection starts out by defining and explaining the focus or the criteria to be used for the qualitative impact assessment.

Impact on other electricity markets

According to the CACM Regulation, the FB approach should, if implemented, be applied in the day-ahead and intraday market timeframes. Other electricity markets, i.e. the balancing market and financial market are not in the scope of this FB implementation. The implementation of the FB approach may, however, have some impact on the operations and the functioning of these markets since there is a close financial and physical link between them. Currently the day-ahead market is the main market for electricity trading and the results from the day-ahead market serves as input to the other markets.

Today the Nordic market for risk management (operated by Nasdaq) and the Nordic regulating power market (operated by the TSOs) are functioning highly efficient. In this subsection the impact in terms of mainly the efficient functioning of these markets, by implementing the FB approach in the day-ahead market, are assessed. Economic efficiency is defined and understood for each of the markets as the following:

Market for risk management:

- *Impact on the possibility for market participant to forecast future system price and prices for each bidding zone*. The objective of the market for risk management is to hedge against future unexpected price volatility. The task is therefore to assess, whether market participants are able to do a proper assessment of the future prices when the FB approach is implemented in the day-ahead market. Or put more concretely, to forecast the future average marginal cost for a given period (month, quarters, years). In addition, the need for forecasting prices are also used by hydro producers to calculate the water value of the storage.

Balancing market:

- *Impact on the dispatch of up and down regulation of generators*. When doing regulation the criteria for efficient up-regulation is to ramp up generators (down-regulate consumption) by the use of the cheapest sources, given the grid constraints and for down-regulation to ramp down the most expensive generators (low value consumption), given the grid constraints. The question to answer is therefore whether the FB approach in the day-ahead market distorts the possibility for efficient regulation.

Nordic electricity market for risk management (hedging of market risk)

Risk management in the Nordic market is performed by utilizing two kinds of instruments, a system price future and a day-ahead price future. The day-ahead price future or Electricity Price Area Differential (EPAD) is to hedge an unexpected future difference between the system price and the day-ahead price. These instruments are traded through Nasdaq OMX with a time horizon up to several years. Assessing the impact on pricing of these instruments by the FB approach has to be done assessing how the new management of grid constraints and flow (NTC→FB) may impact the transparency, hence impacting the possibility to put a “true” value on a future system price/day-ahead price.

The Nordic system price is calculated assuming that there are no transmission constraints between the bidding zones in the Nordic synchronous area. The market coupling results, e.g. the net positions and scheduled flows between bidding zones may differ between the FB approach and the NTC approach due to a different way of allocating cross-zonal capacity. The scheduled flows from the market coupling between the Nordic synchronous area and the CWE region are used as an input in the system price calculation. This is managed by inserting the volume of the scheduled flow as price independent buy or sell order, depending on the flow direction. Baltic countries and Poland are configured as one zone each and the same limitations as in the market coupling are used. The main principles for calculation would as such remain the same regardless of the FB approach or NTC approach. However, the system price may be affected due to different scheduled flows in the FB approach and the NTC approach between the Nordic synchronous area and continental Europe and the Baltic countries.

For the forecasting of system price futures it is concluded that implementing FB approach does not have any impact on transparency on forecasting as the grid contraints in the Nordic power system do not have any impact on the system price. However, the FB approach might provide more cross-zonal capacity on the interconnections between the CCR Nordic and CCRs Hansa/Core, hence it might have an impact on the price level compared to a reference of NTC, but not on the ability of market participants to do a forecasting of the future system price. The impact from external interconnections on the future system price cannot be expected to be more difficult to assess compared to today's situation.

For the forecasting of day-ahead prices on bidding zones it is concluded that the FB approach probably will have an impact on the price level of some bidding zones (otherwise the increase in welfare by FB will not exist), but the ability to forecast the future day-ahead prices on bidding zones is not expected to change significantly. The price of an EPAD is based on expectation of the marginal cost of the marginal generator, averaged over a given period, in a given bidding zone. The FB approach is another method for including grid constraints and solving congestions in the grid, compared to the NTC approach. The market coupling simulations with the FB approach have shown that price differences between bidding zones occur more frequently, although the magnitudes of these differences often are small. In the light of these changes, the market participants' bidding behavior in the day-ahead market may change and have an impact on bidding zone prices and the prices of Electricity Price Area Differentials (EPADs).

The task for the market participants (as it is today) is to forecast the net position of the bidding zone, in order to identify the marginal generator. For that reason and to comply with Article 20(9) of the CACM Regulation, the TSOs will provide a tool that enables market participants to evaluate the interaction between cross-zonal capacities and cross-zonal power exchanges between bidding zones. A draft version of such a tool has been provided by the Nordic TSO called the Stakeholder Information Tool[18].

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[18] *See also subsection "Transparency" on page 114 for more explanation*

In the CCR Nordic, there is also Physical Transmission Rights (PTR) available for hedging of price differences on the border between West and East Denmark (The Great Belt). The holder of a PTR can choose to nominate the PTR and use the assigned cross-zonal capacity or to reallocate the PTR and sell the assigned cross-zonal capacity to the day-ahead market.

If the holder nominates the PTR it will be taken into account in capacity calculation as already allocated cross-zonal capacity according to the description in section 4.12. When market coupling exists it is probably not an advantage to nominate the PTR, thus the nomination possibility is more or less theoretical. If the cross-zonal capacity is reallocated to the day-ahead market, the PTR holder will be remunerated in accordance with the Harmonized Allocation Rules[19].

In the risk hedging timeframe – up to one year – TSOs are obliged to calculate cross-zonal capacities at least for the annual and monthly timeframes[20]. The CNTC approach is the default, but the FB approach may be applied on the following conditions:

- FB approach leads to an increase of economic efficiency in the CCR with the same level of system security;
- the transparency and accuracy of the FB results have been confirmed in the CCR; and
- TSOs provide market participants with six months to adapt their processes.

The implementation of a CCM in the risk hedging timeframe (annual and monthly calculations) help market participants in their forecasting.

Balancing market

The balancing market (or regulating power market[21]) is the TSO tool to secure the balance between demand and supply during the operational hour. Currently the Nordic TSOs activate bids from a common Nordic resource pool (the NOIS list), securing a merit order dispatch of resources in the balancing timeframe. When activating the bids, possible constraints between bidding zones are taken into account. Introducing the FB approach in the day-ahead market timeframe and later in the intraday market timeframe is not expected to have a significant impact on the market in terms of efficiency, as the FB approach is not expected to interfere with the merit order dispatching.

The Balancing Regulation states that TSOs may allocate cross-zonal capacity for the exchange of balancing capacity or sharing of balancing reserves only if cross-zonal capacity is calculated in accordance with the CCM developed pursuant to the CACM and FCA Regulations. TSOs shall include cross-zonal

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19 According to the Forward Capacity Allocation Regulation, all TSOs (except those having exemption in accordance with Article 30 of the FCA Regulation) have to deliver a set of Harmonised Allocation Rules (HAR) for long-term transmission rights.

20 *Article 10 of the FCA Regulation.*

21 *Regulating power market has been used in Nordic synchronous area and it covers resources used for manual frequency restoration reserves (mFRR)*

capacity allocated for the exchange of balancing capacity or sharing of reserves as already allocated cross-zonal capacity in the calculations of cross-zonal capacity in the day-ahead and intraday market timeframes if these cross-zonal capacities have been reserved before the day-ahead or intraday market timeframe. These reservations may affect the available cross-zonal capacities in these timeframes as it is expected that wider markets for balancing capacity need more cross-zonal capacity. Thus it is vital to ensure that scarce cross-zonal capacity is utilized most efficiently although FB and NTC approaches are used for consecutive timeframes.

The significant impact is expected to be on the volumes activated in the balancing market (for both automatic and manual reserves). The TSOs expect an increase in volumes. Not directly as a consequence of the FB approach, but due to the guidelines on management of internal constraints laid down in the ACER Recommendation.

Bidding zone configuration

This subsection describes the potential impact of choosing a FB approach on the Nordic bidding zone configuration. As described above, the FB approach differs from (C)NTC by the explicit use of PTDFs in the price/quantity calculation at the market coupling algorithm: the FB approach is foreseen to provide a closer link between the scheduled flow and the physical flow. For the reason of explicit utilization of the PTDFs new bidding zone configuration might be relevant as the *FB approach (and generally capacity calculation and allocation) and bidding zone (re)configuration are complementary components in proper congestion management*. Introducing the FB approach with the PTDFs, in power systems with structural congestions, while maintaining large bidding zone(s), does not exploit the full potential of the FB approach. And vice versa: having a lot of bidding zones but keeping the NTC approach will not exploit the full benefit of many bidding zones. Below is illustrated that the FB approach might give rise to a gain of introducing more bidding zones, whereas that gain would not be realized by the NTC approach.

By utilizing PTDFs and bidding zones in combination, all orders from market participants - that are subject to the capacity allocation - compete for the scarce transmission capacity in the AC transmission grid. As it is the bidding zone configuration that defines which orders are subject to the capacity allocation, the interlink between the two topics “bidding zone configuration” and “FB approach” surfaces. In this subsection it will firstly, by the use of a generic model, be shown that, while implementing a FB approach in capacity calculation does not necessarily require to change the number - or configuration - of bidding zones, it might in some cases be beneficial to do so in order to increase the overall socioeconomic welfare in the CCR. Secondly, some reflections will be provided on the question to what extent the observations made for the generic model are applicable to the CCR Nordic.

Why implementation of FB approach might alter bidding zone configuration

In the FB approach, orders from market participants that are subject to the capacity allocation are all competing for the scarce transmission capacity made available within the capacity allocation in market coupling. Some of these orders may introduce flows that are outside the capacity allocation and are flows of which the impact is taken into account before the capacity allocation, i.e. flows that can be said to enjoy a ‘priority access’ on a bidding zone border and that are exempted from the competition element within the capacity allocation. These are loop flows and internal flows.

Consider the example in Figure 34, where the surplus and shortage areas are indicated, and a commercial flow internally in bidding zone C (and therefore not subject to capacity allocation), and one between bidding zones A and B, and their physical flows are depicted. Some of the physical flow, induced by the commercial exchange within bidding zone C, might – due to the Kirchoff´s law of physics – take a detour through the networks of bidding zones A and B; this is a loop flow. This is illustrated in Figure 34, where the yellow arrows correspond to flows that are caused by exchanges that are not subject to a capacity allocation (unallocated flows). The grey arrows correspond to flows that are caused by flows that are subject to a capacity allocation (allocated flows).

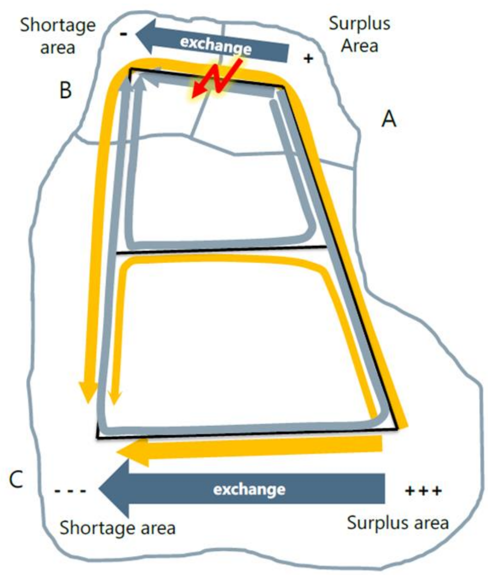


Figure 34 Non-allocated flows (yellow arrows) resulting from an internal flows in bidding zone C

The example in Figure 34 shows that the flows resulting from the commercial flows (the thick blue arrows, labeled with ‘exchange’) would lead to a congested situation on the border between the two zones A and B. As such, this situation is not a feasible one. In the capacity calculation with the FB approach for this three-zone region, the flows that result from all unallocated flows, i.e. the flows that are not subject to the regional capacity allocation, are forecasted (in the CGM) in order to assess the cross-zonal capacity that can be given to the capacity allocation in the market coupling. The flow within zone C is an intrazonal one, and is not subject to the capacity allocation. This means that in the capacity calculation stage, the (forecasted) impact of this flow needs to be taken into account. As such, the flows resulting from this intrazonal flows receive a priority access to the transmission grid and reduce the capacity available on the border between A and B that can be given to the capacity allocation. The flow between zone A and B is subject to the regional capacity allocation. It is this flow that will be reduced in order to prevent the congestion on the border between A and B.

When in zone C a new bidding zone would be introduced, zone D, which separates the source and the sink of the former intrazonal flow within zone C, the former unallocated flow is turned into an allocated one as it is made subject to the regional capacity allocation with the FB approach, as shown in Figure 35.

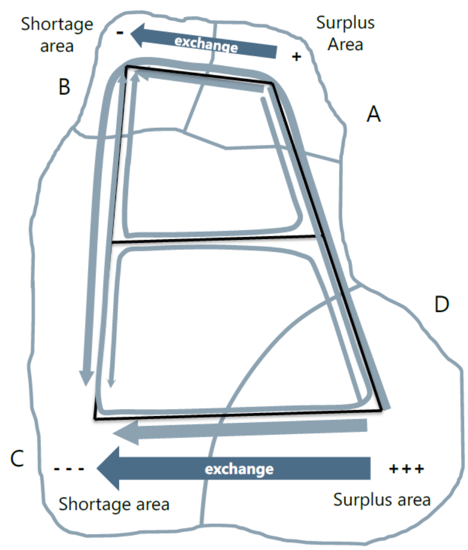


Figure 35 The unallocated flows in Figure 34 (yellow arrows) have been translated into allocated flows (grey arrows) by splitting the former bidding zone C into two bidding zones: C and D.

In this situation, both the flows between zone A and B, and between zone D and C compete with one another to make use of the scarce cross-zonal capacity on the border between zone A and B, that is expressed by a FB constraint that for example may look as follows: Induced flow = 0.6*Net Position(A) – 0.6*Net Position(B) + 0.3*Net Position(D) – 0.3*Net Position(C) ≤ 1000 MW. This formula illustrates that all flows within the capacity allocation region compete for the scarce cross-zonal capacity as the Net Positions are defined as the net flows on the bidding zone borders. It is now an outcome of the regional day-ahead market welfare optimization, i.e. a market driven mechanism, which flow will be reduced and to what extent. In principle both flows might be reduced in order to prevent the congestion on the border between A and B.

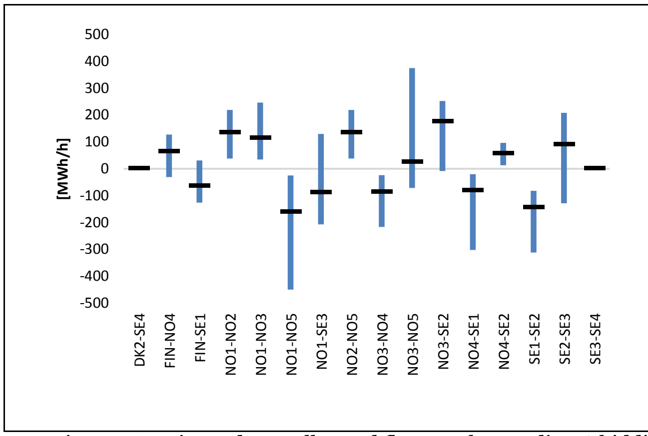
Note that in the capacity allocation with the NTC approach, the situation would not by definition be solved by introducing the new bidding zone D. Given the fact that zone C was one single bidding zone that could handle the large intrazonal flow without any problems, the NTC between zones C and D might be so large, that it does not limit the flow between C and D. Indeed, it is then the NTC between A and B that should be reduced in the capacity calculation stage to prevent the congestion on the border between A and B. Anyhow, this decision is not market driven and does not by definition lead to the most efficient solution.

The intention of the fictive example above is to illustrate that bidding zone delimitation provides an instrument to make exchanges subject to the capacity allocation in market coupling. In combination with the capacity calculation and allocation with FB approach, where all flows that are subject to the capacity allocation compete with one another to make use of the scarce cross-zonal capacity, an efficient capacity allocation can be achieved.

Can implementation of FB approach be expected to have an impact on the Nordic bidding zone delineation?

Regardless of which CCM that is chosen in the CCR Nordic, the bidding zone configuration may need a review but this will in that case be triggered in accordance with the provisions in the CACM Regulation and not only be dependent on the implementation of a new CCM. One of the major differences between CNTC and FB is the ability to include internal CNEs directly in the capacity allocation. In the FB approach, in difference to the CNTC approach, these constraints can be included directly as CNEs in the capacity allocation, if they are significantly impacted by cross-border trade. If the FB approach is implemented, it will provide more detailed information, such as shadow prices, and which CNEs are (most) limiting the market. This information may be useful when answering the question how the bidding zones should be configured.

The Nordic power system already has – especially in the meshed part of the Nordic transmission grid – multiple, comparably-sized, bidding zones. As such, the reasoning that we followed in the generic example above, is not automatically applicable to the Nordic countries. This is demonstrated in the following reasoning. The FB approach is based on a CGM. In this CGM, the expected situation for the respective hour of day D is reflected, including the generation and consumption in the different bidding zones. In Figure 36, the flows on the AC bidding zone borders in the Nordic transmission grid are shown when all bidding zones have a zero net position. As expected, the non-allocated flows on the AC bidding zone borders are not zero. Nevertheless, their relative values - meaning the amount of non-allocated flow in relation to the total capacity of the border - seem to be limited to 20% (with an exception to the FIN-NO4 bidding zone border), and do not provide a direct reason to reconsider the bidding zones configuration.



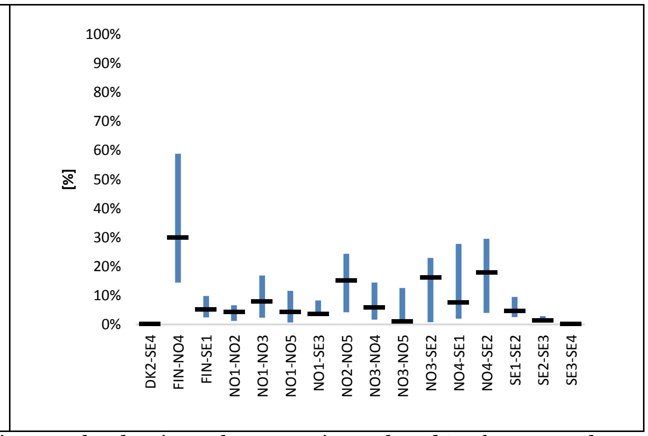


Figure 36 Estimated non-allocated flows at the Nordic AC bidding zone borders in week 52, 2017 in MWh and % of cross zonal capacity. Input data based on former simulations

Non-intuitive flows

Flows from a high to low price bidding zone is a natural consequence of implementing an FB approach. These are the so-called non-intuitive flows. These flows are not due to some lack of functioning of the FB approach, but welfare enhancing comparing to the NTC approach or FB approach where these flows are suppressed. The first go-live version of CWE FB capacity calculation and allocation did not allow for non-intuitive flows, yet with the NRA requirement that the impact should be assessed after a period of operation. The emergence of non-intuitive flows in the FB approach compared to the NTC approach has raised discussion among Nordic stakeholders requiring that the 'FB intuitive' (FBI) should be implemented in the CCR Nordic or at least part of the parallel run. The Nordic TSOs are not in favor of implementing FBI, nor to apply FBI during the parallel run. This section motivates the position of the Nordic TSOs.

As a point of departure, it should be mentioned that FBI is basically not part of capacity calculation, but the capacity allocation within market coupling, thus it is out of scope for TSO/CCC capacity calculation. The capacity calculation approach and the daily FB parameters is not impacted by going FBI – only the outcome: prices, quantities and social welfare.

However, it is the assessment of the Nordic TSOs that FBI is not in line with legislation and decreases the welfare generated in the day-ahead market. The Nordic TSOs put the following main argument forward to support this assessment: to suppress non-intuitive flows, FB-intuitive decreases the capacity domain below what can be justified based on arguments of operational security and economic efficiency, hence FBI is not compliant with Regulation (EC) No 714/2009, point 1.7 of Annex I and as such it must be concluded that FBI leads to undue discrimination. Restricting the FB domain below the secure domain leads to a lower social welfare.

FBI is not complaint with the EU Regulation 714 and leads to lower welfare
The market coupling algorithm - Euphemia - used by the NEMOs to operate the day-ahead market coupling, integrates a mechanism to suppress non-intuitive flows. This mechanism seeks "flows" between bidding zones which match the net positions. Rather than imposing the PTDF constraints directly on the net positions, an intuitive mode can be applied to these "flows". In case a PTDF constraint is detected that leads to a non-intuitive situation, all of its relieving effects of the non-intuitive flow are discarded: the impact of a "flow" from *i* to *j* actually is $PTDF_i - PTDF_j$, but is replaced by max($PTDF_i$-$PTDF_j$, 0). Meaning that if a non-intuitive flow is detected, the zone-to-zone PTDF is replaced by a 0.

Graphically this can be illustrated by the use of the figures from the report *CWE Enhanced Flow-Based MC intuitiveness report*[22] p. 15. The figure employs the 3 node/line power system to illustrate the way FBI works. Figure 37 below shows the FB domain with the segments corresponding to potential non-intuitive situations highlighted in red.

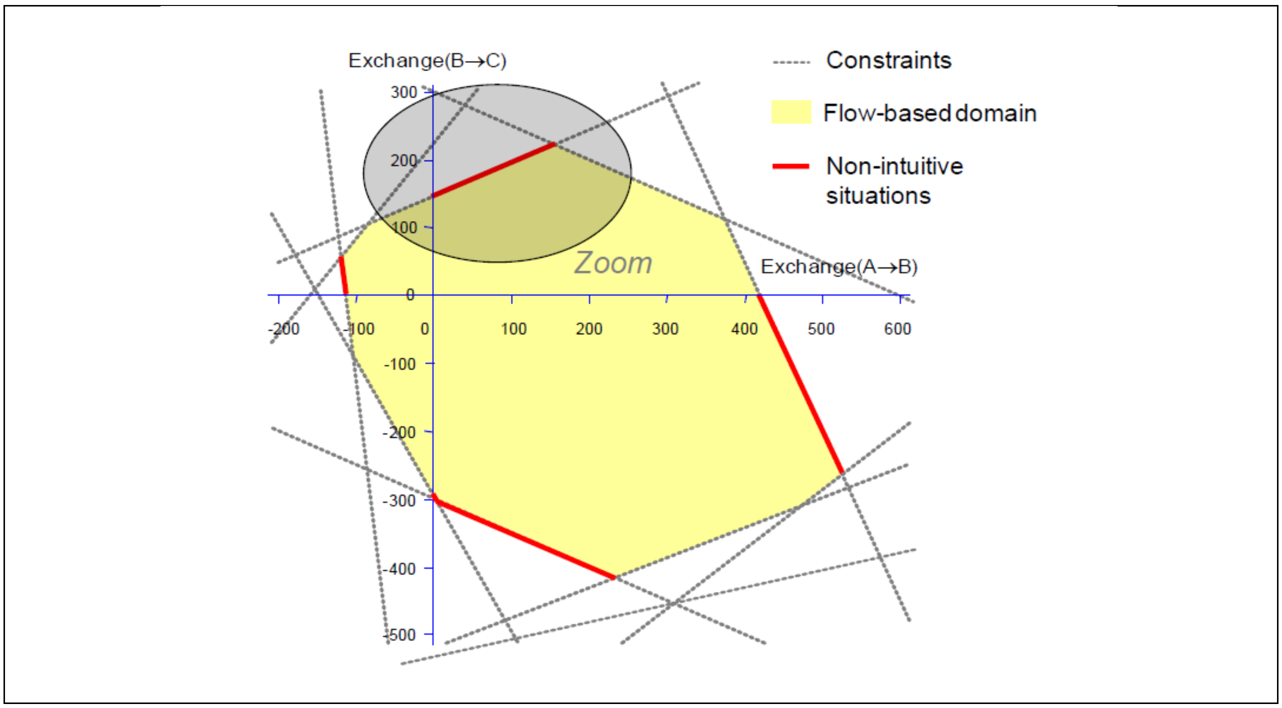


Figure 37 FB Domain with potential non-intuitive solutions

Figure 38 represents a closer look on the upper right non-intuitive segment of the FB domain. An alternative constraint (the green line), is added under FB "intuitive" MC when the "intuitive patch" is

22 *https://www.bundesnetzagentur.de/SharedDocs/Downloads/DE/Sachgebiete/Energie/Unternehmen_Institutionen/NetzzugangUndMesswesen/Marktkopllung/Annex%2016_12%20Intuitiveness%20Report.pdf?__blob=publicationFile&v=2*

triggered and the FB "plain" market coupling result yielded a non-intuitive situation because of a congestion corresponding to the upper right non-intuitive segment[23]. The resulting intuitive situation is clearly not on the boundary of the FB domain while prices are still different between bidding zones. Therefore, there is a congestion but without any saturation of capacity at any transmission line.

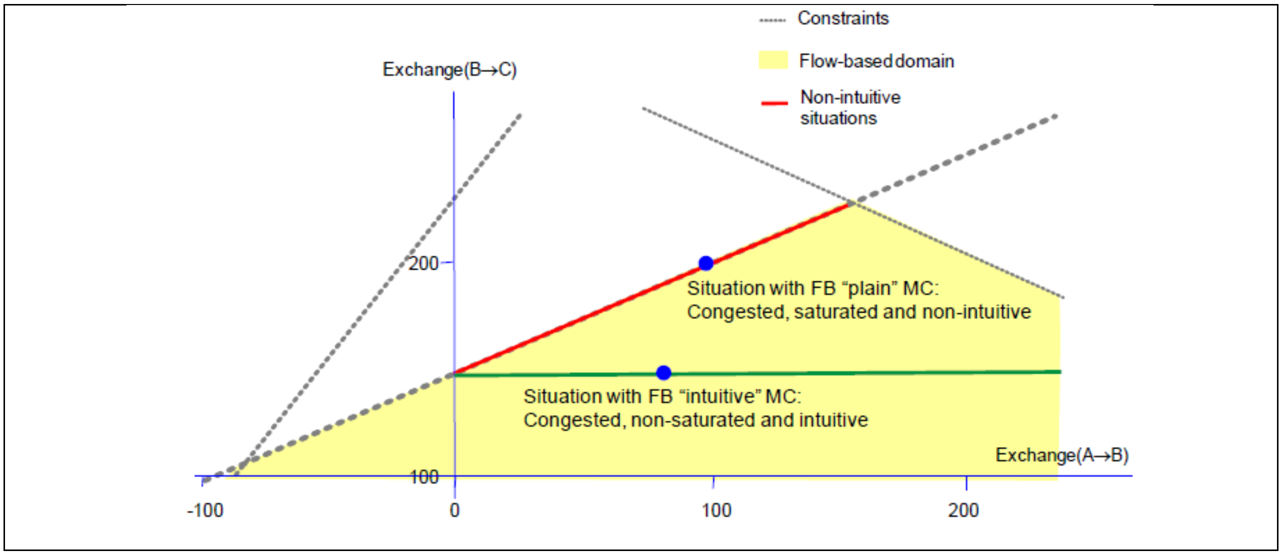


Figure 38 FB Domain with FBI

FBI is clearly not in compliance with Regulation (EC) No 714/2009, point 1.7 of Annex I. This reads:

When defining appropriate network areas in and between which congestion management is to apply, TSOs shall be guided by the principles of cost-effectiveness and minimisation of negative impacts on the internal market in electricity. Specifically, TSOs shall not limit interconnection capacity in order to solve congestion inside their own control area, save for the abovementioned reasons and reasons of operational security. I such a situations occurs, this shall be described and transparently presented by the TSOs to all the system users. Such a situation shall be tolerated only until a long-term solution is found. The methodology and projects for achieving the long-term solution shall be described and transparently presented by the TSOs to all the system users.

The text says that, *if* the TSO shall limit interconnection capacity it can only be done by reasons of cost-effectiveness and operational security. The assessment of the Nordic TSOs is that FBI is not compliant with the legislation, as the reduction in the domain cannot be justified based on operational security and economic efficiency.

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23 *FB «Plain» is flow based that allows for possible counter-intuitive flows.*

When grid capacity is decreased, by suppressing non-intuitive flows, it leads to another allocation of generation and consumption than the merit order dispatch. The consequence is higher generation cost/lower producer surplus and lower consumer surplus, hence a lower social surplus.

Congestion income distribution of implementing FB approach

In this subsection an assessment of the impact on congestion income is provided by implementing the FB approach. When implementing the FB approach it is expected that there will be more price differences, however, these price differences will be lower. In total congestion income will decrease for the CCR Nordic.

In week 2 2017 the total congestion income for the NTC approach is 5.816.523 EUR while the total congestion income for the FB approach is 5.640.426 EUR. This pattern of slightly lower congestion income is persistent throughout the simulations for the 4 weeks in the beginning of 2017. The congestion income will be distributed to the different TSOs based on the methodology developed for day-ahead timeframe under Article 73 of the CACM Regulation and for long-term timeframe under Article 57 of the FCA Regulation.

Currently and as a default solution going forward, congestion income will be distributed according to ownership share, mostly 50/50. However, in the FB approach there will emerge situations where some bidding zone borders generate a negative income, due to non-intuitive flows. This negative income has to be treated in a way that secures TSO incentives for efficient planning and operation of the interconnections. When implementing the FB approach, the methodology pursuant to Article 73 of the CACM Regulation as decided by ACER[24] states that all non-intuitive flows must be socialized; this is done by distributing congestion income generated by scheduled flows within a CCR based on the absolute value of the product of the scheduled flow and the market spread. In case the congestion income attributed to all bidding zone borders within a CCR is not equal to the total congestion income generated by the electricity income within the CCR, the congestion income will be adjusted proportionally in order to match the total congestion income generated by the electricity flows with in the CCR. In order to illustrate what this means let's assume that we have a three node system like illustrated in Figure 39.

[24] *https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions/ACER%20Decision%2007-2017%20on%20CIDM.pdf*

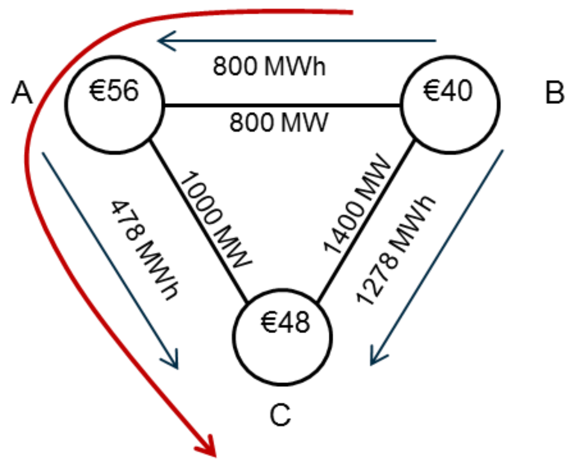


Figure 39 Non-intuitive flows

In the example above we assume that there are three TSOs A, B, and C with a 50/50 ownership share of the interconnections. In this case the congestion income will be distributed as follows:

First the absolute value of the flow is calculated:

- TSO A: (56-40)*800*0,5+(56-48)*478*0,5 = 8 312 EUR
- TSO B: (56-40)*800*0,5+(48-40)*1 278*0,5 = 11 512 EUR
- TSO C: (56-48)*478*0,5+(48-40)*1 278*0,5 = 7 024 EUR

Which gives a total of 26 848 EUR to be distributed as congestion income. However, due to the non-intuitive flow on bidding zone border AC the actual collected congestion income by the NEMOs/CCPs is only 19 200 EUR due to the negative congestion income collected on border AC. This means that TSOs' congestion income needs to be proportionally adjusted. Since the collected congestion income is 28,5 % lower than the absolute value of the congestion income, the congestion income will be adjusted as follows:

- TSO A: 8 312*(1-0.2849) = 5 944 EUR
- TSO B: 11 512*(1-0.2849) = 8 233 EUR
- TSO C: 7 024*(1-0.2849) = 5 023 EUR

The new total of the distributed congestion income is 19 200 EUR, which is also the value that NEMOs/CCPs have collected from the market participants[25]. This means that the cost of non-intuitive flows will be distributed to all TSOs in the CCR and not just the ones benefiting from the non-intuitive flows.

[25] *In this example there are small rounding errors, however this does not change the principle.*

Handling of Long Term Transmission Rights (LTTR)

Some of the congestion income is also distributed as LTTRs on the bidding zone borders where LTTRs are issued. With the introduction of the FB approach this will not change. The market participants will still be able to buy LTTRs on selected Nordic bidding zone borders, and the payout will still be in line with the Harmonized Allocation Rules (HAR) developed under Article 51 of the FCA Regulation. However, with the introduction of the FB approach the risk for the TSOs when issuing LTTRs might change. This is due to the fact that the FB approach, at the moment of writing this document, is not expected to be applied for the long term timeframe. However, a CCM will be developed at a later stage under Article 10 of the FCA Regulation. The potential changed risk from issuing LTTRs arises because two different allocation methods potentially are used in the day-ahead and long-term timeframe. It could then happen that the scheduled flow resulting from the day-ahead FB approach is smaller than the long term allocated (LTA) values. Although the LTA values were included in the FB approach, i.e. all combinations of LTA were feasible in the day-ahead market timeframe.

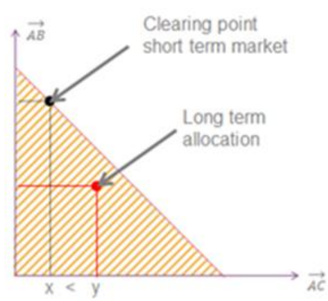


Figure 40 Scheduled flows on bidding zone borders AB and AC

The result would be that the remuneration of LTTRs to the market is higher than the congestion income generated on the day-ahead FB approach over a specific border within the CCR. A potential solution to this could be to adjust the day-ahead FB congestion income before distributing the day-ahead FB congestion income to the bidding zone borders of the TSOs of the relevant CCRs, so that the negative net border income is shared proportionally between the TSOs.

In the example given in Figure 40, the value of day-ahead FB allocated capacity on border AC (X) is lower than the LTA value for this border (Y). As a result, the day-ahead FB congestion income generated on this border will not be sufficient to cover the remuneration of LTTRs to the market, giving rise to a negative net congestion income. For the other bidding zone border AB, the inverse is true; the allocated capacity from the day-ahead market exceeds the long term allocated volume. Hence the net congestion income on bidding zone border AB will be positive. Since the day-ahead FB domain includes the volume of LTTRs, it can be proven that in the region (all borders applying the FB principle), the total congestion income will always exceed the cost for the remuneration of LTTRs. Therefore, the socialisation principle will ensure a non-negative congestion income on all bidding zone borders within a CCR with FB approach.

However, how to handle this potential issue will be developed under the Article 57 and 61 of the FCA Regulation. These articles have at the time of writing this document not yet been submitted to the National Regulatory Authorities (NRA), and are expected to be submitted to the NRAs after the submission of the amended CCM proposal, which is why the Nordic TSOs are unable to describe the effects of introducing the FB approach on the congestion income in the long term timeframe at the time of writing.

Additionally some bidding zone borders in CCR Nordic have been exempted issuing LTTRs and thus also exempted applying provisions for congestion income in Article 57 and 61 of the FCA Regulation.

Transparency

In this subsection an assessment is provided of implementing the FB approach in terms of transparency of the CNEs (and changes here in) and hence the link to the electricity price formation. Firstly it is described how an implementation of the FB approach may be perceived to decrease simplicity / increase complexity due to the more detailed CNEs, while - at the same time - increasing transparency as the FB parameters are not aggregated to one single value on a bidding zone border and are directly represented in the market coupling performed by the Market Coupling Operator (MCO). Secondly it is described how to cope with the challenges foreseen by having higher complexity.

Up until now NTC values have secured a transparent Nordic electricity market where the link between cross-zonal capacities, scheduled flows and prices on bidding zones are easy to understand. As such, the NTC values are in the minds of the stakeholders, from the operators at the TSOs that are actually performing the capacity calculation, to the market participants that are placing the orders on the day-ahead market, and the NRAs. Nordic stakeholders are used to the NTC values and, as such, they can easily be interpreted. With the introduction of a coordinated – and more formalized - capacity calculation methodology that is based on a CGM, a change compared to today’s NTC values will be introduced. In the case of the CNTC approach, although the cross-border capacity values are published in the same format, the values are likely to change, as is also the reliability margin. Under a FB approach, the cross-border capacity will be published in a different format compared to today. Under a FB approach, the constraints are not only located on bidding zone borders, but can also be within the bidding zone, while the transmission capacity (the RAM) will vary from market time unit to another, in line with the loading and usage of the transmission grid. In addition, the FB approach provides the PTDF matrix, which indicate the impact of a change in bidding zone net positions on the CNEs. This concept is rather new and is to be used explicitly in the market coupling algorithm, where today this is used “behind the curtains” by the TSO operators. As such, the FB approach increases the transparency, as the market participants are no longer exposed to the TSO operators’ subjective assessment on the NTC values, which is not visible to the market participants. Indeed, in the NTC approach the TSO operators may have to decide between several NTC domains within the secure domain, as shown in Figure 41, which under the FB approach is left to the market participants as part of market coupling.

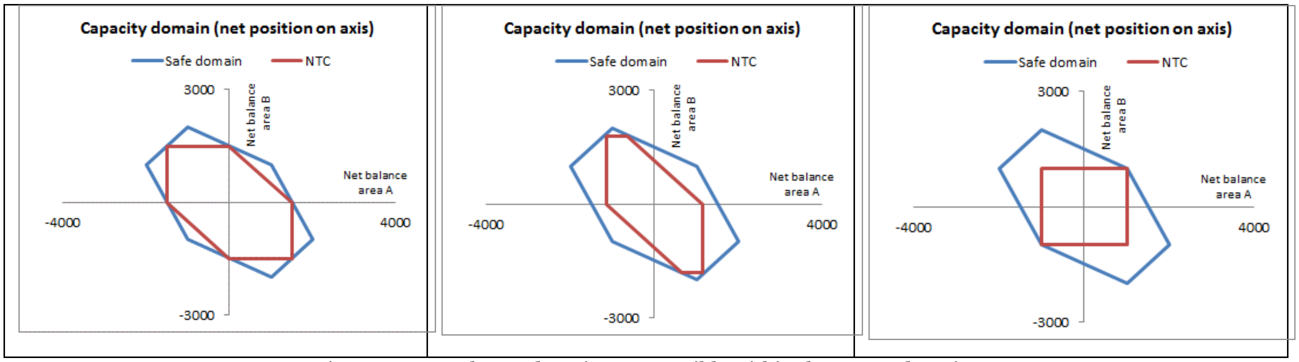


Figure 41 Several NTC domains are possible within the secure domain.

On a high-level, one can say that the more detailed the approach, the more *information* it contains and the more transparent it gets: less aggregation is required, and the number of assumptions reduces. In the case of a CTNC and FB approach, we can clearly see a level of aggregation in the CNTC approach that is not required in the FB approach. In the CNTC approach, the capacity calculation boils down into one 'aggregated' value between two bidding zones, that puts a limit on the scheduled flows between the two bidding zones. With each aggregation made, grid details and a link with the physical reality are decreased. In this sense, the FB approach is a step forward in terms of transparency. Individual transmission grid elements are taken into account as such, whether they are interconnections between bidding zones or transmission lines that are located within the bidding zone. This level of transparency brings many advantages, especially linked to the discussion on bidding zone delineation and the notion of "moving internal congestions to the border". It is this level of transparency that is actually required to properly assess the hot spots in the grid, being those CNEs that are limiting the electricity market in CCR Nordic regularly and with a social welfare loss tagged to it. In the FB approach, it is the shadow prices of CNEs that are computed and available with a market time unit resolution: a valuable source of information for both TSOs and NRAs.

The Nordic TSOs do, however, acknowledge that understanding the FB approach and the impact thereof needs some training and expertise. The TSOs have therefore started some initiatives aiming at enhancing the understanding among stakeholders before go live with the FB approach. These are described below.

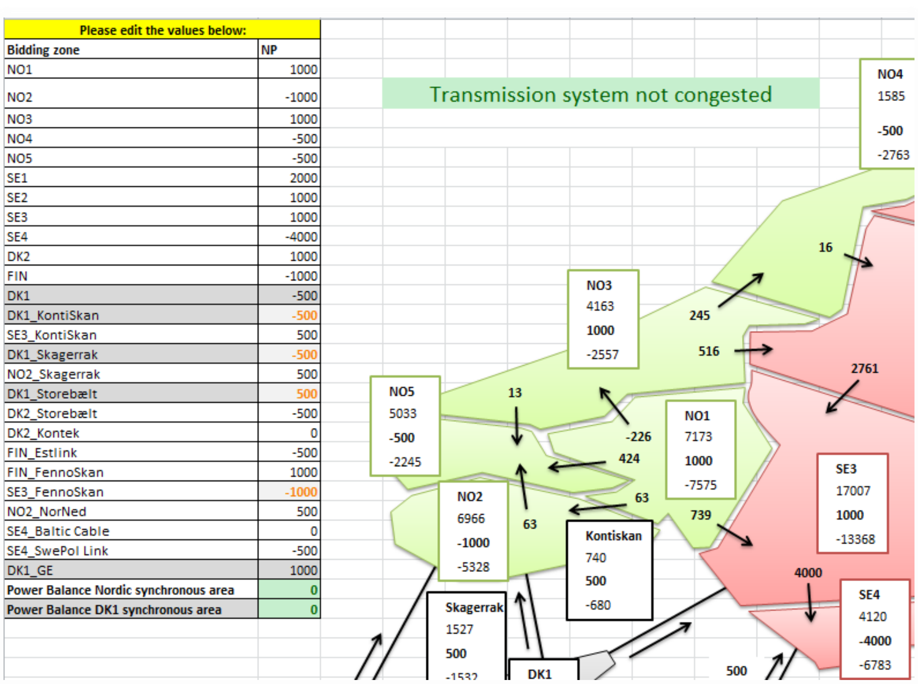
Stakeholder dialogue. In order to facilitate this dialogue, the Nordic TSOs have established two different settings to meet and discuss questions related to the CCM. In the Stakeholder Forum, all stakeholders are welcome to join the meetings. The other setting for stakeholder dialogue is the Stakeholder Group meeting, where the industry organizations, national regulatory authorities, and NEMOs have nominated representatives that meet and discuss issues together with representatives from the Nordic TSOs. This smaller setting allows for more intense and in-depth discussions.

Stakeholder information platform. The TSOs have also established a stakeholder information platform where materials are uploaded and where the stakeholders can post questions regarding the CCM. In addition, the Nordic TSOs also issue newsletters in order to keep the stakeholders up to date with regard to the Nordic CCM developments.

An example of the information provided to the stakeholders, is the early-stage development of the market information tool. Based on experiences in the CWE region, this tool has been developed to provide an insight into the trade possibilities in the Nordic countries, such as on the maximum import and export positions of the bidding zones for example, given the FB parameters. It provides an insight as well on the physical cross-zonal flows in the Nordic power system and the (limiting) anonymized CNEs. This functionality already meets the requirement postulated in Article 20(9) of the CACM Regulation:

"The TSOs of each capacity calculation region applying the flow-based approach shall establish and make available a tool which enables market participants to evaluate the interaction between cross-zonal capacities and cross-zonal exchanges between bidding zones."

Two screen shots of the market information tool - that is under development in correspondence with the stakeholders - are shown in Figure 42.



Please edit the values below:	
Bidding zone	NP
NO1	1000
NO2	-1000
NO3	1000
NO4	-500
NO5	-500
SE1	2000
SE2	1000
SE3	1000
SE4	-4000
DK2	1000
FIN	-1000
DK1	-500
DK1_KontiSkan	-500
SE3_KontiSkan	500
DK1_Skagerrak	-500
NO2_Skagerrak	500
DK1_Storebælt	500
DK2_Storebælt	-500
DK2_Kontek	0
FIN_Estlink	-500
FIN_FennoSkan	1000
SE3_FennoSkan	-1000
NO2_NorNed	500
SE4_Baltic Cable	0
SE4_SwePol Link	-500
DK1_GE	1000
Power Balance Nordic synchronous area	0
Power Balance DK1 synchronous area	0

custom net positions (taken from the worksheet 'GUI')

NO1	NO2	NO3	NO4	NO5	SE1	SE2	SE3	SE4	DK2	FIN	DK1	DK1_Kont	SE3_Konti	DK1_Skag	NO2_Skag	DK1_Store	DK2_Store	DK2_Kont	FIN_Estlin	FIN_Fennc	SE3_Fennc	NO2_NorN	SE4_Baltic	SE4_SweP	DK1_GE
1000	-1000	1000	-500	-500	2000	1000	1000	-4000	1000	-1000	-500	-500	500	-500	500	500	-500	0	-500	1000	-1000	500	0	-500	1000

timestamp	RAM (MW	NO1	NO2	NO3	NO4	NO5	SE1	SE2	SE3	SE4	DK2	FIN
25-1-2016 12:00	7450,473	-0,16697	-0,12687	-0,75634	-0,91859	-0,15513	-0,97681	-0,98676	-0,02224	-0,03053	-0,03393	-0,97921
25-1-2016 12:00	6649,527	0,166973	0,126871	0,756344	0,918588	0,155134	0,976814	0,986757	0,022241	0,030535	0,033931	0,979215
25-1-2016 12:00	6596,412	0,032648	1	0	0	0,960139	0	0	0	0	0	0
25-1-2016 12:00	6339,225	-0,67492	0,284046	0,086955	0,028808	0,265764	0,007993	0,004389	-0,00956	-0,00899	-0,0099	0,007142
25-1-2016 12:00	5196,056	-0,00633	-0,00656	-0,00323	-0,00193	-0,00641	-0,00128	-0,00156	-0,00972	-0,97686	-0,98424	-0,00123
25-1-2016 12:00	3933,698	0,020472	0,893933	0,007802	0,002619	0,217339	0,000756	0,00044	-0,00064	-0,00107	-0,00119	0,000679
25-1-2016 12:00	3420,037	0,040156	0,034277	0,137564	0,561984	0,038388	0,923716	0,011746	0,012151	0,015863	0,016874	0,935824
25-1-2016 12:00	3179,963	-0,04016	-0,03428	-0,13756	-0,56198	-0,03839	-0,92372	-0,01175	-0,01215	-0,01586	-0,01687	-0,93582
25-1-2016 12:00	2357,361	0,778792	0,841547	0,22386	0,075148	0,807763	0,021706	0,012649	-0,01811	-0,03078	-0,03433	0,01949
25-1-2016 12:00	2163,271	0,178321	0,305034	0,040466	0,013557	0,484405	0,003893	0,00225	-0,00345	-0,00535	-0,00596	0,003493
25-1-2016 12:00	2003,944	0,006327	0,006564	0,003234	0,001927	0,006408	0,001278	0,001556	0,009718	0,976859	0,984241	0,001225
25-1-2016 12:00	1882,639	-0,77879	-0,84155	-0,22386	-0,07515	-0,80776	-0,02171	-0,01265	0,018111	0,030778	0,034331	-0,01949
25-1-2016 12:00	1720,665	0,077436	0,080306	0,039935	0,02394	0,07841	0,01596	0,019411	0,022938	-0,27137	-0,38383	0,015299
25-1-2016 12:00	1685,612	0	0	0	0	0	0	0	0	0	0,986846	0
25-1-2016 12:00	1537,415	0,035424	0,027773	0,153435	0,128766	0,033426	0,099151	0,112515	-0,05796	-0,07743	-0,07077	0,095218

timestamp	DK1	DK1_Kont	SE3_Konti	DK1_Skag	NO2_Skag	DK1_Store	DK2_Store	DK2_Kont	FIN_Estlin	FIN_Fennc	SE3_Fennc	NO2_NorN	SE4_Baltic	SE4_SweP	DK1_GE	induced flow	congested?
25-1-2016 12:00	0	0	-0,04296	0	-0,12448	0	-0,03404	-0,03404	-0,97922	-0,97922	0,000669	-0,12558	-0,03095	-0,02671	0	-2761	ONWAAR
25-1-2016 12:00	0	0	0,042956	0	0,124481	0	0,03404	0,034041	0,979216	0,979221	-0,00067	0,125583	0,030947	0,02671	0	2761	ONWAAR
25-1-2016 12:00	0	0	0	0	1	0	0	0	0	0	0	1	0	0	0	-447	ONWAAR
25-1-2016 12:00	0	0	-0,0123	0	0,283986	0	-0,00993	-0,00993	0,007142	0,00714	0,000218	0,284014	-0,0091	-0,00797	0	-699	ONWAAR
25-1-2016 12:00	0	0	-0,02898	0	-0,00658	0	-0,98429	-0,98429	-0,00123	-0,00122	-8,57E-05	-0,00657	-0,98663	-0,98993	0	3877	ONWAAR
25-1-2016 12:00	0	0	-0,00152	0	0,916272	0	-0,00119	-0,00119	0,000679	0,000678	2,24E-05	0,901212	-0,00108	-0,00093	0	-63	ONWAAR
25-1-2016 12:00	0	0	0,019526	0	0,033928	0	0,016906	0,016906	0,935829	0,935847	-0,00061	0,034089	0,015991	0,014721	0	1229	ONWAAR
25-1-2016 12:00	0	0	-0,01953	0	-0,03393	0	-0,01691	-0,01691	-0,93583	-0,93585	0,000609	-0,03409	-0,01599	-0,01472	0	-1229	ONWAAR
25-1-2016 12:00	0	0	-0,04379	0	0,845047	0	-0,03445	-0,03445	0,019489	0,019484	0,000644	0,843434	-0,03121	-0,02678	0	689	ONWAAR
25-1-2016 12:00	0	0	-0,00758	0	0,26603	0	-0,00598	-0,00598	0,003493	0,003492	0,000114	0,284806	-0,00543	-0,00467	0	-38	ONWAAR
25-1-2016 12:00	0	0	0,028979	0	0,006578	0	0,984289	0,98429	0,001225	0,001225	8,57E-05	0,006572	0,986632	0,989926	0	-3877	ONWAAR
25-1-2016 12:00	0	0	0,043793	0	-0,84505	0	0,034445	0,034446	-0,01949	-0,01948	-0,00064	-0,84343	0,031208	0,026776	0	-689	ONWAAR
25-1-2016 12:00	0	0	0,106105	0	0,080477	0	-0,38724	-0,38727	0,015299	0,015296	0,001072	0,080398	-0,29409	-0,1763	0	1168	ONWAAR
25-1-2016 12:00	0	0	0	0	0	0	1	1	0	0	0	0	0	0	0	487	ONWAAR
25-1-2016 12:00	0	0	-0,05263	0	0,027305	0	-0,07055	-0,07055	0,095212	0,095197	0,005536	0,027521	-0,07673	-0,08482	0	597	ONWAAR

Figure 42 Two screenshots of the market information tool (that is under development)

Parallel run. As the implementation of the FB approach introduces constraints in a different format than what is used today, whereas the CNTC approach is likely to introduce different values than today's ones, an (at least) twelve-month parallel run period will be performed on a daily basis by using the industrial tools and a close-to-operational process. While the current NTC approach is in operation to serve the day-ahead market, the TSOs run a second capacity calculation in parallel, being the FB approach, in order to assess what would have been the cross-zonal capacity if the FB approach would have been applied. In addition, the actual order books at the NEMOs will be used to assess what would have been the market results in this case. This is a learning period for TSOs, NRAs, and market participants. After the period of parallel run, the new capacity calculation and allocation should have started to root in the minds and the IT systems, ready to step into this next evolution of the electricity market in CCR Nordic. Indeed, the objective of the parallel run is twofold:

- provide comfort to stakeholders
- secure a proper operation of the electricity market and power system for both TSOs and market participants

For stakeholders to get acquainted with the new FB approach, the Nordic TSOs are planning to share the results of capacity calculation and allocation applying the FB approach already well before the abovementioned parallel run, though these "parallel runs" are not based on industrial tools nor on close-to-operational processes.

Long-term investment decisions – role of shadow price

In this subsection it is described how the long-term investment analysis might be impacted when choosing the FB approach as the CCM in the CCR Nordic.

One of the advantages of applying the FB approach is that the capacity utilization of transmission lines can potentially be increased, hence providing more cross-zonal capacity without new grid investments. Not only in operation, but also in the grid planning and investment analysis phase, implementing the FB approach may have an impact. Using the FB approach to study CNEs might give a more precise result on which CNEs are limiting the flows in the transmission grid, and this can give a more direct indication on where congestions might occur, as compared to the CNTC approach. Therefore it could potentially also show limitations that one might not have found without an in-depth analysis.

One piece of new information that FB approach reveals in operation, is the (true) costs of transmission grid constraints. This is called the shadow price of transmission capacity. The shadow price shows the market value of an incremental MW of added transmission capacity on that specific grid constraint. This too can be used for a first screening of grid constraints that are in need of investments. Shadow prices do emerge today as the price difference between bidding zones reveals the need for more cross-zonal capacity. However, due to NTC potentially not reflecting true physics, this information might be a bit misleading, e.g. the true grid constraint is often not located at the bidding zone border, but within the bidding zone. Below an explanation is provided on the shadow prices under the FB approach.

Shadow prices are computed by finding the solution to any constrained optimization problem. It is relevant to compute as it indicates where to increase transmission capacity with a maximum socioeconomic impact. Shadow prices in the NTC model represent the effect on market welfare of a marginal increase of NTC values, which is equivalent to the resulting price difference between the bidding zones concerned. Shadow prices in the FB approach represent the effect on market welfare of a marginal increase of physical capacity of real network elements. In a FB approach, price differences between bidding zones are the result of shadow prices on all congested physical network elements. In other words, in a FB approach, the shadow price is calculated for any physical network element which is in the CGM, and it represents the overall market value of an incremental MW of additional capacity on that physical network element.

To provide understanding on the concept of shadow prices in the light of the current NTC approach, an example with a simple radial grid is provided (Figure 43). In case of such a simple power system there is no difference between the NTC and FB approach in terms of capacity assessment. The shadow price is equal to the resulting day-ahead price difference when relaxing the capacity constraint marginally (ΔMW = 1). If the equilibrium prices are 45 and 50 respectively, the shadow price can be computed to be 5, being equal to the price difference between the bidding zones.

Line	Input area A	Input area C (Slack)
A -> C	100 %	0

Figure 43 Example on NTC and FB shadow pricing

The shadow price can more formally be calculated as in the formula below. This is the approach used in a FB set-up:

$$P_i - P_n = \sum_{j=1}^{J} \delta_j \times \left(PTDF_{n,j} - PTDF_{i,j}\right) \quad (10)$$

Where:

P_i: Price in bidding zone *i*

P_n: Price in bidding zone n

J: Number of CNEs

δ_j: Shadow price of CNE*j*

$PTDF_{i,j}$: Influence from bidding zone *i* on CNEj

$PTDF_{n,j}$: Influence from bidding zone *n* on CNEj

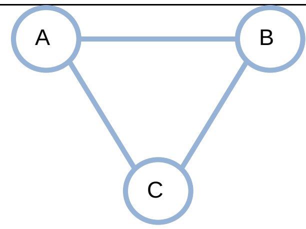
Applying this formula for the example above, the shadow price can be calculated to be

$$45 - 50 = \delta_{AC}(0-1)$$
$$-5/(0-1) = \delta_{AC} \quad (11)$$
$$5 = \delta_{AC}$$

This result is equal to the price difference between the bidding zones.

In case of the NTC approach, the shadow prices are always equal to the price differences between the bidding zones. In a meshed network that is managed by the FB approach, we expect to see shadow prices that deviate from the shadow prices with the current NTC approach. An example is introduced in Figure 44 to demonstrate this.

The grid



Line	Max exchange	Input area A	Input area B	Input area C (Slack)
A -> B	1000 MW	33 %	- 33 %	0
B -> C	1000 MW	33 %	67 %	0
A -> C	1000 MW	67 %	33 %	0

The market

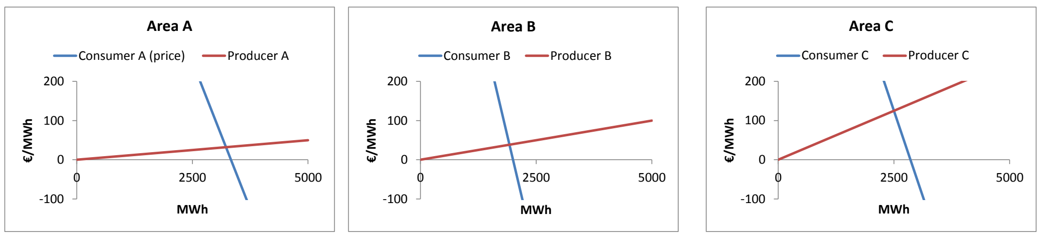


Figure 44 Example reflecting a transmission grid and market situation.
The order curves show an equilibrium before capacities have been taking into consideration

Based on the situation depicted in the example in Figure 44, the market outcome for the NTC and FB approach is illustrated in Figure 45.

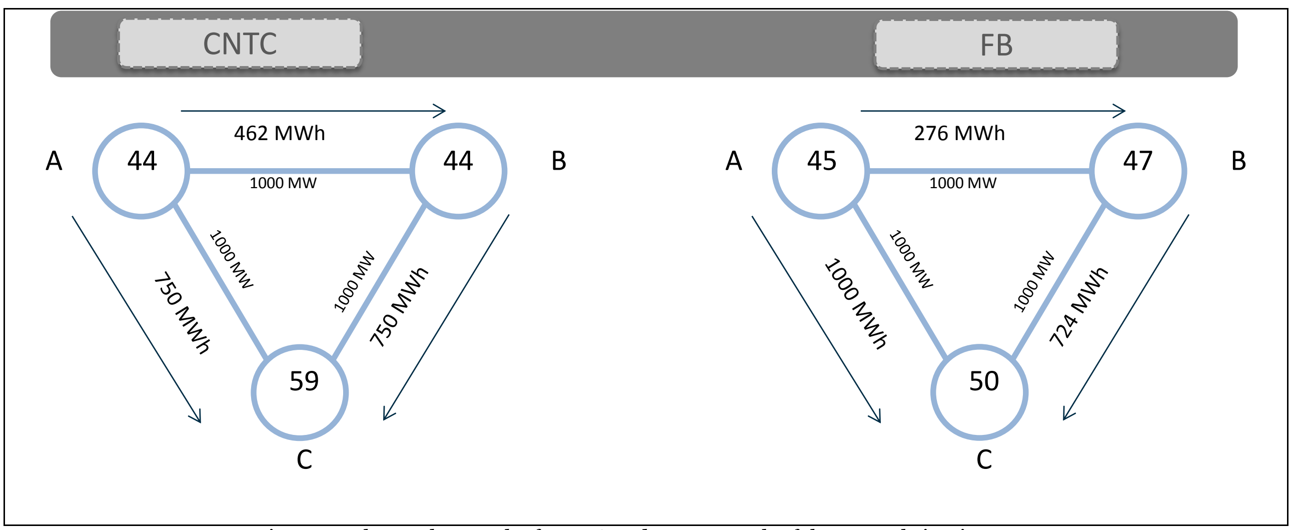


Figure 45 The market results for NTC and FB approach of the example in Figure 44

It is easy to see that the shadow prices of Line A→B and B→C equal 0 in the FB approach. The value added when increasing capacity marginally of these lines is 0, as the binding constraint is located at the Line A→C. By applying the formula for the shadow price calculation, the shadow price for line A→C can be computed as follows:

$$P_A - P_C = \delta_{AC} \times \left(PTDF_{C,AC} - PTDF_{A,AC}\right) + \qquad (12)$$

$$\delta_{BC} \times (PTDF_{C,BC} - PTDF_{A,BC}) +$$
$$\delta_{AB} \times (PTDF_{C,AB} - PTDF_{A,AB})$$

$$45 - 50 = \delta_{AC} \times (0 - 0{,}67) +$$
$$0 \times (0 - 0{,}33) +$$
$$0 \times (0 - 0{,}33) \quad (13)$$
$$\delta_{AC} = 7{,}50\ €$$

This means that the added value of increasing the capacity of line A→C equals 7,50 €/MW. This is only half the value as reflected by NTC approach, where the price difference is 15 €/MW.

5.3 Cost of implementation and operation

The aim of this section is to discuss the costs of implementation and operation of the CACM compliant capacity calculation approach. Five cost categories have been identified: Nordic CCM project costs, TSO training costs and changes in procedures, IT development costs, stakeholder costs, and TSO operational costs and maintenance costs. They will be discussed in more detail in the following.

Nordic CCM project costs

The Nordic CCM project is responsible for developing a CACM compliant CCM for the day-ahead and intraday timeframes. Both the FB approach and the CNTC approach are in the scope of the project. Since both approaches are to be developed, the cost for FB and CNTC approach is assumed to be same when it comes to the CCM project costs.

TSO training costs and changes in procedures

Introduction of a new CCM requires changes in procedures at the TSOs. New procedures need to be defined and the TSO personnel needs to be trained to learn and understand the new CCM and procedures. Both CNTC and FB approach will induce a need to change procedures, although in the case of CNTC approach the change is not as remarkable as in the case of FB approach. The TSO training costs are more significant for the FB approach compared to the CNTC approach. However, to some degree it only holds for the short run, where the “NTC thinking” has become the second nature. In the long run when new operators are trained and the FB approach is the reference CCM, the training cost cannot be expected to be significantly higher compared to the alternative.

IT development costs

IT development costs refer to the capacity calculation related IT costs in the Nordic RSC (CCC) as well as the IT development costs in the TSO systems. IT development costs consist of software, hardware and

TSO manpower costs. IT development costs are assumed to be quite similar for the FB and CNTC approach.

TSO operational costs and maintenance costs

TSO operational costs and maintenance costs are Nordic RSC (CCC) and TSO costs, which are most likely not dependent on the selected CCM.

Stakeholder costs

Introducing a new CCM is likely to cause some costs for stakeholders. In order to be able to estimate the costs for stakeholders, the Nordic TSOs sent a survey to the Nordic CCM project stakeholder group members. Cost estimates provided by the stakeholder group members are used as input here (5 stakeholder group members provided their answers).

The Nordic CCM project had an assumption that there would be no difference between current NTC and CNTC when it comes to costs for stakeholders. In CNTC, capacities might vary more from hour to hour but otherwise there is no difference seen from the stakeholders' perspective. The stakeholders confirmed this assumption to be in line with their own view.

The following cost categories related to introducing FB approach were identified by stakeholders:

- Software costs
- Hardware costs
- Costs related to changes in procedures
- Costs related to training of personnel
- Costs related to increased uncertainty
- Costs related to a change in level playing field

Based on answers provided by stakeholders, the estimate of total costs related to the above mentioned categories is on average above 500 k€ per stakeholder. However, as indicated by the stakeholders, there are major uncertainties related to the cost estimates. The biggest uncertainties are related to the costs of changes in procedures, training of personnel, increased uncertainty, and change in level playing field.

Summary of the costs

Table 6 shows a summary of the CCM related costs. Different cost categories are listed in the left column. The grey color indicates that there is no difference in costs between the FB approach and the CNTC approach. The red color indicates that the costs for the approach are higher compared to the alternative approach, which is marked with a green color. In conclusion, the total costs for the FB approach are higher compared to the CNTC approach.

Table 6 Summary of the costs related to implementation and operation

	FB	CNTC
Nordic CCM project		
TSO training and changes in procedures (short run)		
IT development costs		
TSO operational costs and maintenance costs		
Stakeholder costs		

5.4 Impact assessment in accordance with CACM article 3

Article 9 (9) of the CACM Regulation requires that the expected impact of the CCM Proposal on the objectives of the CACM Regulation is described. The objectives of CACM are listed in Article 3 of the CACM Regulation. The impact is presented below. The content is also included in the whereas section in the legal document.

The CCM contributes to and does not in any way hamper the achievement of the objectives of Article 3 of the CACM Regulation. In particular, the CCM serves the objectives of promoting effective competition in the generation, trading and supply of electricity (Article 3(a) of the CACM Regulation), ensuring optimal use of the transmission infrastructure (Article 3(b) of the CACM Regulation), ensuring operational security (Article 3(c) of the CACM Regulation), optimising the calculation and allocation of cross-zonal capacity (Article 3(d) of the CACM Regulation), ensuring and enhancing the transparency and reliability of information (Article 3(f) of the CACM Regulation), contributing to the efficient long-term operation and development of the electricity transmission system and electricity sector in the Union (Article 3(g) of the CACM Regulation), respecting the need for a fair and orderly market and fair and orderly price formation (Article 3(h) of the CACM Regulation) and providing non-discriminatory access to cross-zonal capacity (Article 3(j) of the CACM Regulation).

The CCM promotes effective competition in the generation, trading and supply of electricity (Article 3(a) of the CACM Regulation) since the CCM supports fair and equal access to the transmission system as it applies to all market participants on all bidding zone borders in CCR Nordic. Market participants will have access to the same reliable information on cross-zonal capacities and allocation constraints for day-ahead allocation, in a transparent way. The FB approach does not implicitly pre-select or exclude bids from market players and, hence the competitiveness of bidding is the only criteria on which bids of market players 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 CNEs in order to improve effective competition between internal and cross-zonal trades, taking operational security and economic efficiency into account.

The CCM 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. There is no predefined and static split of the capacities on critical network elements (hereafter referred to as "CNE"), and the flows within CCR Nordic and between CCR Nordic and adjacent CCRs are decided based on economic efficiency during the capacity allocation phase. The CCM treats all bidding zone borders within the CCR Nordic and adjacent CCRs equally, and provides non-discriminatory access to cross-zonal capacity. The CCM applies Advanced Hybrid Coupling (hereafter referred to as "AHC") for the efficient integration of HVDC interconnections into the FB CCM. The approaches aim at providing the maximum available capacity to market participants within the operational security limits. For the intraday timeframe, a CNTC approach ensures better use of transmission capacity compared to the currently-applied method until the FB approach is implemented. Non-costly RAs are taken into account if they are available.

The CCM 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 available costly RAs. 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.

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

The CCM 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 should publish data to the market on a regular basis to help market participants to evaluate the capacity calculation process. The TSOs should engage stakeholders in dialogue to specify necessary and useful data to this effect. The publication requirements are without prejudice to confidentiality requirements pursuant to national legislation.

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

The CCM 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.

The CCM provides non-discriminatory access to cross-zonal capacity (Article 3(j) of the CACM Regulation). Application of RAs to increase capacity on internal constraints - based on operational security and economic efficiency - contributes to avoiding undue discrimination between internal and cross-zonal power exchanges. The CCM includes two tests to be fulfilled in order to increase the available margin on internal CNEs. The test for operational security aims at quantifying available costly RAs in order to increase the available margin of internal CNEs, without compromising operational security. The available margin of internal CNEs will only be increased if costly RAs can be expected to be available and to have impact on the internal CNEs (by applying node-to-line PTDF matrices). The test for economic efficiency aims at assessing if adding more available margin to an internal CNE, will increase social welfare. Both tests have to be fulfilled simultaneously in order to increase the available margin. The CCM also ensures a transparent and non-discriminatory approach to facilitate cross-zonal capacity allocation.

In conclusion, the CCM contributes to the general objectives of the CACM Regulation to the benefit of market participants and electricity end consumers.

6 Timescale for the CCM implementation

Article 9(9) of the CACM Regulation requires that:

> *"The proposal for terms and conditions or methodologies shall include a proposed timescale for their implementation and a description of their expected impact on the objectives of this Regulation."*

The following section provides the description of the planned implementation timeline for the Nordic capacity calculation methodology.

6.1 Timeline for implementation of the CCM

An indicative high-level timeline for implementing the new CCM is visualized in Figure 46: it shows a go-live date of the FB approach CCM for the day-ahead timeframe and the intermediate CNTC approach CCM for the intraday timeframe in Q1 2021 at the earliest.

As indicated in the legal document, the different milestones are dependent on criteria being met.

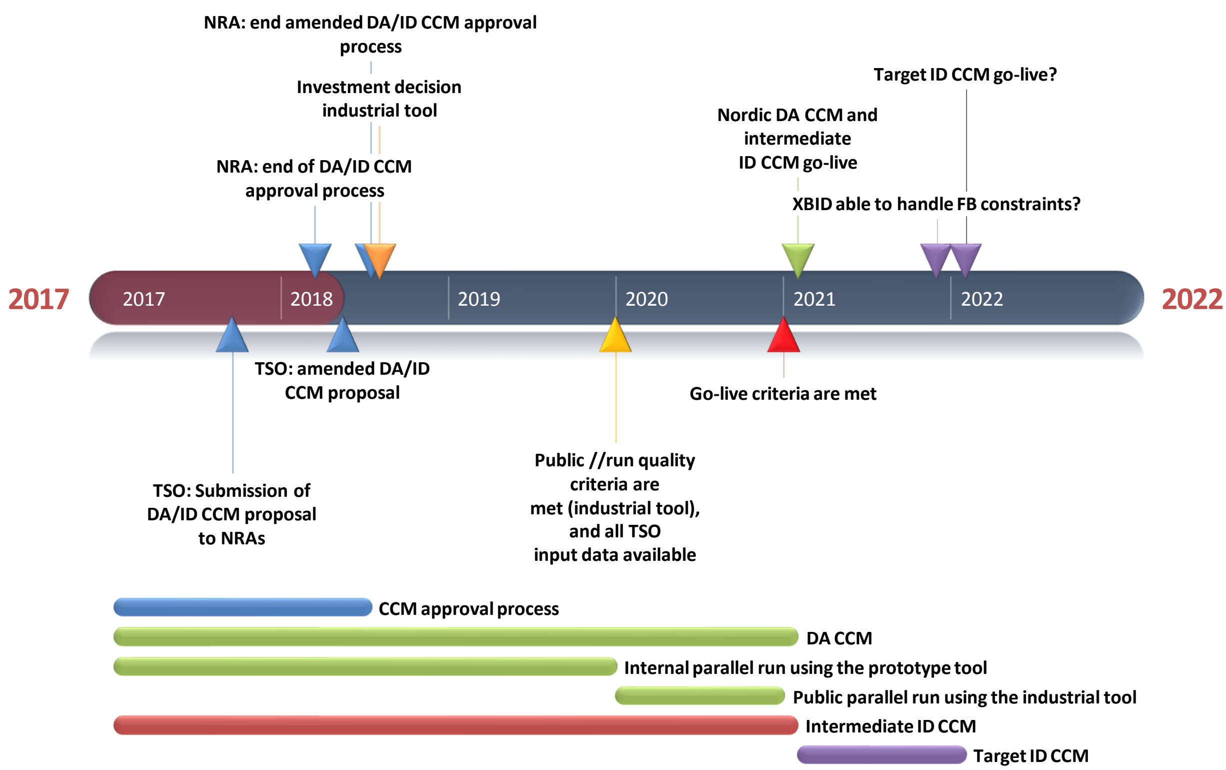


Figure 46 Indicative timeline for implementing the new CCM

7 ANNEX I: Example calculation of nodal PTDFs

Figure 47 below shows a three-node network where the nodal transfer PTDFs are going to be calculated. The impedances of the lines are included in the figure, being the sum of resistance and reactance. The slack node is located in node 3 in this example.

The line resistance is considered negligible compared to the reactance (e.g. line 1-2 has a 2/0.01=200 times higher reactance) and the DC power flow approximation is applied.

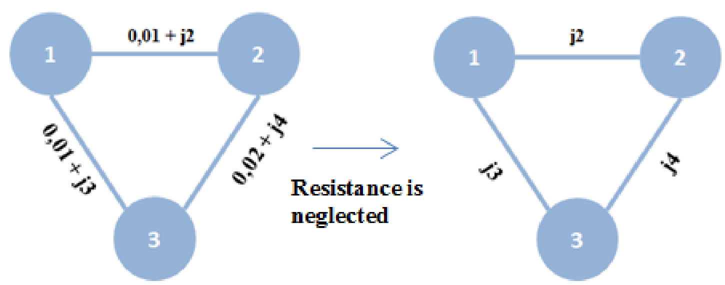


Figure 47 Example grid with three nodes. The node and line parameters used in the power flow equations are illustrated in the figure.

The $Ybus$ matrix is defined by the data in Figure 47. Recall that the susceptance between two nodes equals the inverse of the reactance for the line, since the resistance was neglected.

$$Ybus = \begin{bmatrix} 1/2+1/3 & -1/2 & -1/3 \\ -1/2 & 1/2+1/4 & -1/4 \\ -1/3 & -1/4 & 1/3+1/4 \end{bmatrix} \tag{14}$$

The $Zbus$ matrix is then constructed by adding "+1" to the diagonal element corresponding to the slack-node in the $Ybus$ matrix in (14), followed by an inverse operation. Node 3 is in this example selected as slack node.

$$Zbus = \begin{bmatrix} 1/2+1/3 & -1/2 & -1/3 \\ -1/2 & 1/2+1/4 & -1/4 \\ -1/3 & -1/4 & 1/3+1/4+1 \end{bmatrix}^{-1} = \begin{bmatrix} 3{,}00 & 2{,}33 & 1{,}00 \\ 2{,}33 & 3{,}22 & 1{,}00 \\ 1{,}00 & 1{,}00 & 1{,}00 \end{bmatrix} \tag{15}$$

The PTDF value from node n for the line between nodes i and k can then be calculated as

$$PTDF_{ik,n} = B_{ik}(Zbus_{in} - Zbus_{kn}) \tag{16}$$

For example, the PTDF value from node 1 to the line between node 1 and 2 can be calculated as

$$PTDF_{12,1} = B_{12}(Zbus_{11} - Zbus_{21}) = \left(\frac{1}{2}\right)(3{,}00 - 2{,}33) = 0{,}33 = 33\% \tag{17}$$

For production in node 1, 33% of the power will flow on the line 1 to 2. For consumption (which is the negative production) the effect will be the reverse, i.e. the line is loaded in the opposite direction.

For each line ik (row) and node n (column) the $PTDF_{ik,n}$ is calculated, resulting in the following PTDF matrix (nodal transfer PTDF matrix to be precise) with node 3 being the slack-node:

$$PTDF = \begin{array}{c c} & \textbf{Node} \\ & \begin{array}{ccc} \textbf{1} & \textbf{2} & \textbf{3} \end{array} \\ \textbf{Line} \begin{array}{c} 1-2 \\ 1-2 \\ 2-3 \end{array} & \begin{bmatrix} 0{,}33 & -0{,}44 & 0 \\ 0.67 & 0.44 & 0 \\ 0{,}33 & 0{,}56 & 0 \end{bmatrix} \end{array} \tag{18}$$

8 ANNEX II: Model set-up for the Case study NO3-NO5

The new line will between NO3 and NO5 provides a parallel path to the existing North – South interconnectors NO1-NO3 and SE2-SE3, which means that any trade between Northern and Southern Scandinavia will induce flows on all three interconnectors. This makes it challenging to determine the optimal capacities as all lines are influenced by transit flows from commercial exchanges on the other lines. The transit flows are disproportionately greater for the Norwegian lines due to the much greater transmission capacity on the Swedish side. FB has the potential to provide a better solution to this challenge by significantly reducing the uncertainty that accompanies the discrepancy between NTC market exchange and the realized physical flows.

The challenge described above, and the potential of FB to improve the situation, was explored using empirical data: a simplified PTDF matrix from the Samnett simulation model, and the optimization engine in Excel. The approach was to do a simplified price calculation (simulating the allocation mechanism) using both NTC and FB for individual hours, using historical NPs and prices as a starting point. The market flows on the borders congested in the historical market outcome were not allowed to increase, while the rest of the borders were considered open for additional trade. The effect of adding 100 MW CNTC capacity on the new line was compared to the FB solution (with no limit on the new line), and both were compared to the original market outcome.

An important effect of the FB set up was that the commercial flow on NO1-NO3 was no longer determined ex ante, but the flow was not allowed to increase compared to the CNTC market outcome.

The model set-up is illustrated in Figure 48, showing the data that went into the FB and CNTC models. All hours with significant price differences between 2.12.2013 and 15.1.2014 were analyzed individually, and the geographical scope was limited to Norway and Sweden.

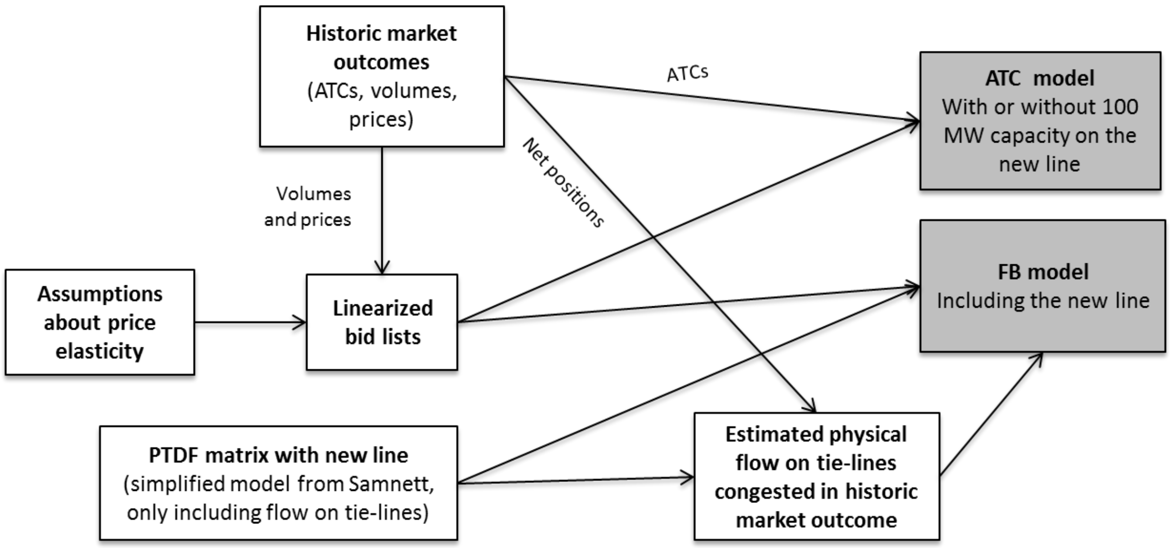


Figure 48 The model set-up

Figure 49 shows the simulated price difference between NO3 and NO5 (across the new line) using CNTC and FB. In most situations FB reduces the price difference compared to CNTC, which indicates a better utilization of the transmission capacity. FB provided an equal or better market outcome, measured as increased Nordic economic welfare, in every simulated hour.

The fact that the FB model had no limit on the flow NO3-NO5 seems not to be very significant as the maximum flow on the line was lower with FB than with CNTC, and since the average flow on this line increased barely 10 %. In fact the flow on the line NO3-NO5 was smallest with FB in 32 % of the hours, even though the Nordic welfare was higher in every case.

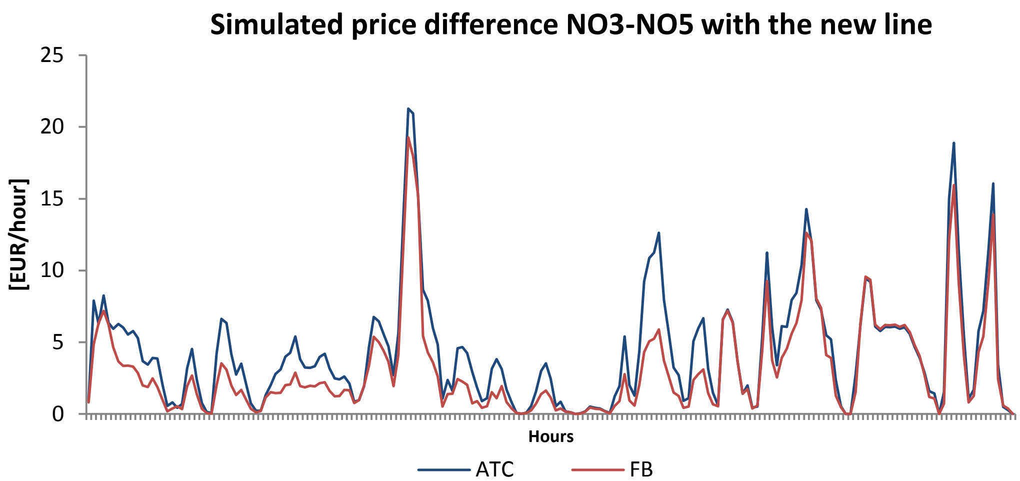


Figure 49 Simulation results for all historical hours with significant price differences in the Nordic system from 2.12.2013 and 15.1.2014

9 ANNEX III: Detailed mathematical descriptions of power flow equations

Four parameters are related to each node in a power system: voltage magnitude U, voltage angle δ, active power P, and reactive power Q. A node is defined when all those parameters are known. In load flow analysis, nodes can be categorized in the following way, based on the parameters that are known:

- PQ node: P and Q are known, U and δ are calculated
  - usually load, can also be a generator with constant reactive power
- PU node: P and U are known, Q and δ are calculated
  - generator/generators
- Uδ node: U and δ are known, P and Q are calculated
  - reference node (also called slack bus or swing bus)
  - voltage angle in reference node is the reference angle
  - needed to balance the load flow analysis in a way that generation equals load plus grid losses (losses are not known beforehand)

In a system with N nodes, the amount of known parameters is 2N. Other parameters have to be calculated. Calculations can be done utilizing the node equations.

$$\begin{bmatrix} \underline{I}_1 \\ \cdots \\ \underline{I}_i \\ \underline{I}_N \end{bmatrix} = \begin{bmatrix} \underline{Y}_{11} & \cdots & Y_{1i} & Y_{1N} \\ \cdots & \cdots & \cdots & \cdots \\ Y_{i1} & \cdots & Y_{ii} & Y_{iN} \\ Y_{N1} & \cdots & Y_{Ni} & Y_{NN} \end{bmatrix} \begin{bmatrix} \underline{U}_1 \\ \\ \underline{U}_i \\ \underline{U}_N \end{bmatrix} \tag{19}$$

$$[\underline{I}] = [\underline{Y}][\underline{U}] \tag{20}$$

$[\underline{Y}]$ is a node admittance matrix

$[\underline{I}]$ is a node current matrix

$[\underline{U}]$ is a node voltage matrix

Active and reactive power flows in steady state can be calculated using the following equation:

$$\underline{S}_i = P_i + \mathrm{j}Q_i = (P_{\mathrm{G}i} - P_{\mathrm{L}i} - P_{\mathrm{T}i}) + \mathrm{j}(Q_{\mathrm{G}i} - Q_{\mathrm{L}i} - Q_{\mathrm{T}i}) \tag{21}$$

$\underline{S}_i$ is the net apparent power coming to node *i*

P_i is the net active power coming to node *i*

Q_i is the net reactive power coming to node *i*

P_{Gi} is the active power coming to node *i* from the connected generators

P_{Li} is the active power from node *i* to the connected load

P_{Ti} is the active power going from node *i* to the connected transmission lines

Q_{Gi} is the reactive power coming to node *i* from the connected generators

Q_{Li} is the reactive power from node *i* to the connected load

Q_{Ti} is the reactive power going from node *i* to the connected transmission lines

For three nodes, the following equations can be developed.

$$\begin{aligned}
&\underline{S}_i = \underline{U}_i \underline{I}_i^* = P_i + \mathrm{j}Q_i \Leftrightarrow \\
&\left(\frac{\underline{S}_i}{\underline{U}_i}\right) = \underline{I}_i^* = \frac{P_i + \mathrm{j}Q_i}{\underline{U}_i} \Leftrightarrow \\
&\left(\frac{\underline{S}_i}{\underline{U}_i}\right)^* = \left(\frac{\underline{S}_i^*}{\underline{U}_i^*}\right) = \underline{I}_i = \frac{P_i - \mathrm{j}Q_i}{\underline{U}_i^*}
\end{aligned} \tag{22}$$

Equation (20) can also be written as follows.

$$\begin{aligned}
\underline{I}_1 &= \underline{Y}_{11}\underline{U}_1 + \underline{Y}_{12}\underline{U}_2 + \underline{Y}_{13}\underline{U}_3 \\
\underline{I}_2 &= \underline{Y}_{21}\underline{U}_1 + \underline{Y}_{22}\underline{U}_2 + \underline{Y}_{23}\underline{U}_3 \\
\underline{I}_3 &= \underline{Y}_{31}\underline{U}_1 + \underline{Y}_{32}\underline{U}_2 + \underline{Y}_{33}\underline{U}_3
\end{aligned} \tag{23}$$

By using this in the previous equation, we will have the following three-node example:

$$\begin{bmatrix} \dfrac{\underline{S}_1^*}{\underline{U}_1^*} \\ \dfrac{\underline{S}_2^*}{\underline{U}_2^*} \\ \dfrac{\underline{S}_3^*}{\underline{U}_3^*} \end{bmatrix} = \begin{bmatrix} \dfrac{P_1 - \mathrm{j}Q_1}{\underline{U}_1^*} \\ \dfrac{P_2 - \mathrm{j}Q_2}{\underline{U}_2^*} \\ \dfrac{P_3 - \mathrm{j}Q_3}{\underline{U}_3^*} \end{bmatrix} = \begin{bmatrix} \underline{Y}_{11} & \underline{Y}_{12} & \underline{Y}_{13} \\ \underline{Y}_{21} & \underline{Y}_{22} & \underline{Y}_{23} \\ \underline{Y}_{31} & \underline{Y}_{32} & \underline{Y}_{33} \end{bmatrix} \begin{bmatrix} \underline{U}_1 \\ \underline{U}_2 \\ \underline{U}_3 \end{bmatrix} \tag{24}$$

$$\begin{aligned}
\frac{\underline{S}_1^*}{\underline{U}_1^*} &= \frac{P_1 - \mathrm{j}Q_1}{\underline{U}_1^*} = \underline{Y}_{11}\underline{U}_1 + \underline{Y}_{12}\underline{U}_2 + \underline{Y}_{13}\underline{U}_3 \\
\frac{\underline{S}_2^*}{\underline{U}_2^*} &= \frac{P_2 - \mathrm{j}Q_2}{\underline{U}_2^*} = \underline{Y}_{21}\underline{U}_1 + \underline{Y}_{22}\underline{U}_2 + \underline{Y}_{23}\underline{U}_3 \\
\frac{\underline{S}_3^*}{\underline{U}_3^*} &= \frac{P_3 - \mathrm{j}Q_3}{\underline{U}_3^*} = \underline{Y}_{31}\underline{U}_1 + \underline{Y}_{32}\underline{U}_2 + \underline{Y}_{33}\underline{U}_3
\end{aligned} \tag{25}$$

Finally, the power flow equations for the three nodes will look as follows.

$$\begin{aligned}
&\begin{bmatrix} \underline{S}_1^* \\ \underline{S}_2^* \\ \underline{S}_3^* \end{bmatrix} = \begin{bmatrix} P_1 - \mathrm{j}Q_1 \\ P_2 - \mathrm{j}Q_2 \\ P_3 - \mathrm{j}Q_3 \end{bmatrix} = \begin{bmatrix} \underline{U}_1^*\underline{Y}_{11} & \underline{U}_1^*\underline{Y}_{12} & \underline{U}_1^*\underline{Y}_{13} \\ \underline{U}_2^*\underline{Y}_{21} & \underline{U}_2^*\underline{Y}_{22} & \underline{U}_2^*\underline{Y}_{23} \\ \underline{U}_3^*\underline{Y}_{31} & \underline{U}_3^*\underline{Y}_{32} & \underline{U}_3^*\underline{Y}_{33} \end{bmatrix} \begin{bmatrix} \underline{U}_1 \\ \underline{U}_2 \\ \underline{U}_3 \end{bmatrix} \Leftrightarrow \\
&\underline{S}_1^* = P_1 - \mathrm{j}Q_1 = \underline{Y}_{11}\underline{U}_1^*\underline{U}_1 + \underline{Y}_{12}\underline{U}_1^*\underline{U}_2 + \underline{Y}_{13}\underline{U}_1^*\underline{U}_3 \\
&\underline{S}_2^* = P_2 - \mathrm{j}Q_2 = \underline{Y}_{21}\underline{U}_2^*\underline{U}_1 + \underline{Y}_{22}\underline{U}_2^*\underline{U}_2 + \underline{Y}_{23}\underline{U}_2^*\underline{U}_3 \\
&\underline{S}_3^* = P_3 - \mathrm{j}Q_3 = \underline{Y}_{31}\underline{U}_3^*\underline{U}_1 + \underline{Y}_{32}\underline{U}_3^*\underline{U}_2 + \underline{Y}_{33}\underline{U}_3^*\underline{U}_3
\end{aligned} \tag{26}$$