Stakeholder consultation document and Impact Assessment for the Capacity Calculation Methodology Proposal for the Nordic CCR

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Table of content:

Abbreviations:

AC	Alternating Current
ATC	Available Transfer Capacity
CACM	Capacity Allocation and Congestion Management
CCC	Coordinated Capacity Calculator
CCM	Capacity Calculation Methodology
CCR	Capacity Calculation Region
CGM	Common Grid Model
CNE	Critical Network Element
CNTC	Coordinated Net Transfer Capacity
CO	Critical Outage
DA	Day Ahead
DC	Direct Current
FAV	Final Adjustment Value
FB	Flow-Based
FCA	Forward Capacity Allocation
Fmax	Max Capacity on a CNE
Fref	Flow on a CNE in the base case
Fref'	Flow on a CNE at zero net position
FRM	Flow Reliability Margin
GSK	Generation Shift Key
ID	Intraday
IGM	Individual Grid Model
MCO	Market Coupling Operator
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
N-CGM	Nordic Common Grid Model
NEMO	Nominated Electricity Market Operator
NP	Net position
NTC	Net Transfer Capacity
PSIA	Power System Impact Analysis
PTDF	Power Transfer Distribution Factor
PTR	Physical Transmission Right
PX	Power Exchange
RA	Remedial Action
RAM	Remaining Available Margin

RSC	Regional Security Coordinator
TSO	Transmission System Operator

1 Introduction and executive summary

This document is the consultation document provided to the Stakeholders for the Nordic Capacity Calculation Methodology (CCM) proposal. The consultation document describes the proposal for the CCM for day ahead and intraday capacity calculation for the Nordic Capacity Calculation Region (CCR), and provides an impact assessment of the proposed methodology. The intention of this document is to give the Stakeholders the opportunity to comment on the proposed methodologies.

The CCM proposal for the Nordic CCR is required by Article 20 (2) of the Commission Regulation (EU) 2015/1222 establishing a guideline on capacity allocation and congestion management (CACM Regulation).

1.1 Proposal for the Capacity Calculation Methodology

With regard to the CACM Regulation Article 20.2, the Nordic TSOs are proposing to introduce new Capacity Calculation Methodologies for the day ahead, and intraday market. 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 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 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 coordinated net transmission capacity approach and assuming the same level of operational security in the concerned region.

1.1.1 Proposed approaches for the day ahead and intraday timeframes

For the Day Ahead timeframe: The Nordic TSOs propose to implement a Flow Based capacity calculation approach for the day ahead Market timeframe.

For the Intraday timeframe: As the long-term solution, the Nordic TSOs proposes to implement a Flow Based approach for the intraday timeframe as soon as the intraday market platform is technically able to utilize flow-based capacities.

As an interim solution, the Nordic TSOs propose to implement a coordinated net transmission capacity approach for the intraday market timeframe.

The current Nordic TSO proposal is based on quantitative and qualitative assessments, which has provided no evidence to support a hypothesis of the coordinated net transmission capacity approach being as efficient as the flow based approach. The assessment has been based on a comparison between Flow Based and the current net transmission capacity approach, where the current approach serves as a proxy for a coordinated net transmission capacity approach. Thus, all grid limitations introduced in the flow based simulations are the operational limitations used in daily operation. A prerequisite for implementing a flow based day ahead approach in the Nordics, is that the European day ahead market platform is technically able to manage flow based capacities.

The long term solution for the intraday market is proposed to be a flow based approach. This might however not be implemented until the intraday market platform are technically able to utilize flow based market capacities. As an interim solution, the Nordic TSOs proposes to implement a coordinated net transmission approach in the intraday market until the flow based approach becomes technically feasible.

The Nordic TSOs acknowledge that further work is needed to implement all CACM-required features in the capacity calculation; to apply proper Common Grid Model (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 Content of this document and guideline for the reader

This consultation document consists of four parts in addition to this introductory chapter.

Firstly*,* chapter 2 provides an interpretation of the relevant articles in CACM. Only the content and the wording of CACM articles where some interpretation seems needed, has been interpreted.

Secondly**,** chapter 3 gives a high-level introduction to the FB and CNTC capacity calculation approach. This is not required by CACM, but it allows the reader to learn about the different CCMs relevant for the proposal.

Thirdly**,** the actual Capacity Calculation Methodology proposal is presented in Chapters 5 to 9. These chapters are the response to the CACM Regulation article 12.2:

> *"TSOs and NEMOs responsible for submitting proposals for terms and conditions or methodologies or their amendments in accordance with this Regulation shall consult stakeholders, including the relevant authorities of each Member State, on the draft proposals for terms and conditions or methodologies where explicitly set out in this Regulation. The consultation shall last for a period of not less than one month."*

Chapters 5 to 7 are organized in order to facilitate the reader to check with the requirements in CACM. Thus, in the first level chapters, a distinction has been made between day ahead, intraday, and input parameters to the calculation process. In the second level subchapters, a distinction is made between flow based and CNTC, and in chapter 7, between different input to the capacity calculation. In the third level subchapters, we refer to each individual paragraph of CACM. Figure 1-1 below is an illustration of the organization of these chapters.

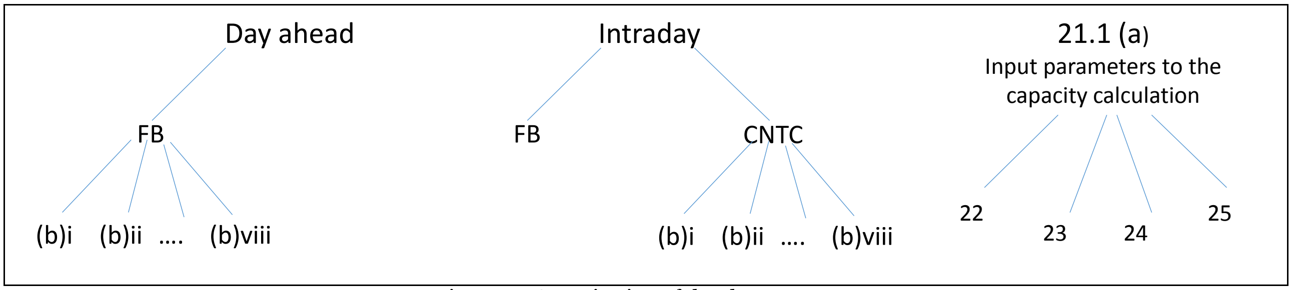

Figure 1-1 Organisation of the chapters 5 to 7

Chapter 8 and 9 are a response to the CACM articles 21.3 and 26.

Fourthly, in chapter 10 the impact of implementing FB in the day ahead market is assessed. The chapter consists of a quantitative part and a qualitative part. The quantitative part is presenting the impact on social welfare and prices/volumes, based on market simulation for a number of weeks in 2016. In the qualitative part, the impact of FB on selected issues is presented. These issues have been selected, based on feedback from stakeholders and what the Nordic TSOs find relevant.

The legal context of this stakeholder consultation document is captured in Box 1.

Box 1: Legal context of the stakeholder consultation document

Name of the Network Code/Guideline: Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management ("CACM Regulation")

Region and involved TSOs within the region: Nordic Capacity Calculation Region (Nordic CCR) as defined in Article 3 of Decision of the Agency for the cooperation of energy regulators No 06/2016 of 17 November 2016 on the electricity transmission system operators' proposal for the determination of capacity calculation regions, Annex 1 Definition of the Capacity Calculation Regions (CCRs) in accordance with Article 15(1) of the Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a Guideline on Capacity Allocation and Congestion Management (CACM Regulation)

Neighbouring regions: Hansa and Baltic Capacity Calculation Regions as defined in Article 4 and 11 of Decision of the Agency for the cooperation of energy regulators No 06/2016 of 17 November 2016 on the electricity transmission system operators' proposal for the determination of capacity calculation regions, Annex 1 Definition of the Capacity Calculation Regions (CCRs) in accordance with Article 15(1) of the Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a Guideline on Capacity Allocation and Congestion Management (CACM Regulation)

Articles referred from CACM Regulation: Articles 2, 3, 9(9), 14, 20, 21, 22, 23, 24, 25 and 26, and preambles 4, 6 and 7

Approval process: The proposal for common capacity calculation methodology in accordance with Article 20(2) of CACM Regulation drafted based on this supporting document shall be subject to approval by all regulatory authorities (NRAs) of the Nordic CCR in accordance with Article 9(7) of CACM Regulation. NRAs shall take decisions concerning the submitted capacity calculation methodology in accordance with Article 9(7), within six months following the receipt of the methodology by the last NRA concerned. In accordance with Article 9(12) of CACM Regulation, in the event that NRAs request an amendment to approve the methodology submitted in accordance with Article 9(7), the relevant TSOs shall submit a proposal for amended methodology for approval within two months following the requirement from the NRAs. The competent NRAs shall decide on the amended methodology within two months following the submission. Where the competent NRAs have not been able to reach an agreement on methodology pursuant to Article 9(7) within the two-month deadline or deadline referred to in Article 9(10), or upon their joint request, the Agency shall adopt a decision concerning the methodology or its amendment within six months, in accordance with Article 8(1) of Regulation (EC) No 713/2009. For Norway a parallel decision will have to be adopted by the EFTA Surveillance Authority according to adaptions when incorporating the Third Energy package into the EEA Agreement.

Amendment process: In accordance with Article 9(13), TSOs of Nordic CCR or NRAs responsible for their adoption in accordance with Article 9(7), may request amendments of the capacity calculation methodology. The proposal for amendment to adopted capacity calculation methodology shall be submitted to consultation in accordance with the procedure set out in Article 12 of CACM Regulation and approved in accordance with the procedure set out in Article 9 of CAC Regulation.

Responsibilities: All TSOs of Nordic CCR are responsible for developing a draft proposal for the capacity calculation methodology, submit the draft proposal for consultation, revise the draft proposal taking into account responses from the consultation, submit the proposal for NRAs' approval and, if requested, amend the proposal requested by the NRAs. All NRAs of Nordic CCR are responsible to approve the methodology and, if requested, to ask amendments to the proposed capacity calculation methodology.

1.3 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 makes use of 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 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 1-2 shows this coordinated capacity calculation process.

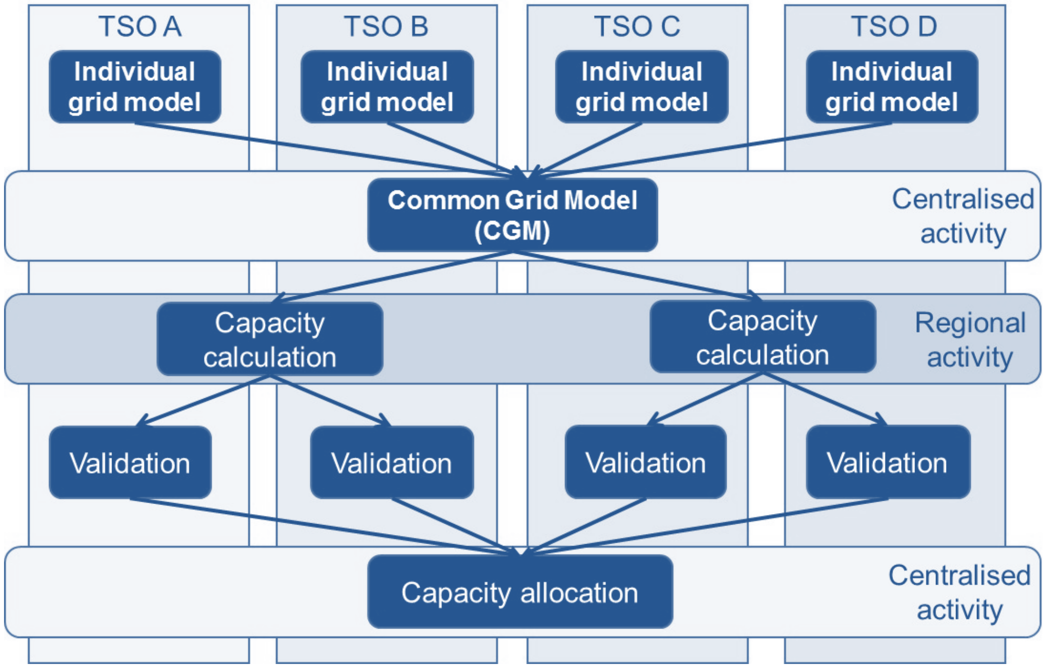

Figure 1-2 Coordinated capacity calculation process

Figure 1-2 illustrates whether the respective actions are performed on a TSO, a CCR region, or a 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.

Individual grid models 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 the Guideline on Capacity Calculation and Congestion Management (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 capacity calculation methodology for the day-ahead and intraday timeframes, in 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 capacity calculation methodology 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 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 <u>undue</u> discrimination between internal and cross-zonal exchanges, implies that unless for reasons of either operational security or 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 for 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 or 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 does not apply, limitations on internal network elements will not be considered in the cross-zonal capacity calculation methods.

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, 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 or of cross-zonal capacity due to remedial actions in accordance with Article 25. Article 25 requires that at least remedial actions 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 remedial actions, and application of remedial actions with costs agreed with market participants – such as countertrading and redispatch –, shall be taken into account. For the FB approach, this means adjustments of the remaining available margins of the critical network elements, 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 critical network elements 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 capacity calculation. The FB 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.

Article 21(1)(b)(vii) requires, in cases where the power flows on critical network elements are influenced by cross-zonal power exchanges in different capacity calculation regions, to set the rules for sharing the power flow capabilities of critical network elements among different capacity calculation regions in order to accommodate these flows. Generally, the CCRs have been configured to minimize the influence of different CCRs to critical network elements in a CCR. This influence can occur especially in CCRs, which reside at the same synchronous area requiring cooperation between neighboring 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 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. Article 14(4) requires that all TSOs in each capacity calculation region 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 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 capacity calculation timeframes.

Article 22 of the CACM Regulation sets requirements to the reliability margin 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 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 and TSOs have to be transparent on the application of these limits. These security limits will be applied to define maximum flows across critical network elements, bidding zone borders or limiting cuts within a bidding zone.

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, 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 DC interconnectors.

Article 24 of the CACM Regulation sets requirements to the generation shift key 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."

Generation shift key 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 common grid model.

A common generation shift key shall be developed for each bidding zone and scenario. Generation shift keys will be used to translate a change in net positions into specific nodal injections in the common grid model 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 remedial actions 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."

Remedial action 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. Remedial actions can be applied also in the capacity calculation phase, where each TSO shall individually define the available remedial actions to be taken into account to meet the objectives under Article 3 of the CACM Regulation.

Remedial actions without costs (such as grid topology change, phase shifter actions, system protection schemes[1]) shall be taken into account in the capacity calculation.

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

The remedial actions to be taken into account in capacity calculation shall be the same for all capacity calculation time-frames (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.*
>
> *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."*

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[1] *Please note that system protection schemes might bring a cost when they need to activated.*

3 Introduction to Flow Based and CNTC methodologies

The purpose of the chapter is to present the capacity calculation approaches Flow Based and CNTC, before moving into the more technical descriptions in the subsequent chapters. This chapter starts out by explaining why and how grid constraints are taken into account in the electricity market. In section 3.2, a motivation for proposing a new methodology, firstly in the day ahead market and later on in the intraday market, is provided.

3.1 Limited capacity in the electric transmission grid

To facilitate an economic efficient dispatch of generation units, it is also necessary to transmit electric power over longer distances. For example, on a day of high wind power output in Denmark, Germany and Southern Sweden, it may be beneficial to transmit this surplus power to consumers in Finland, Norway and Northern Sweden. Energy stored in the hydro reservoirs can be saved for days with lower wind output, when the power flows would be reversed.

Like all transport infrastructure, the transmission grid has a limited capacity for transporting electrical power. The limitations are due to reasons of safety, quality and dependability of the electricity supply. High power flows will increase the temperature of transmission lines beyond the safe range, equipment like circuit breakers and transformers will fail if used beyond the intended range, the quality of the supplied electricity will decline, and the totality of the grid will itself lose the ability to transmit sufficient power if pushed too hard.

Limitations on transmission capacity will endure, as it would not be economically efficient to construct a transmission grid of practically unlimited capacity due to the high capital costs of constructing new infrastructure. The Nordic power grid is illustrated in Figure 3-1.

Figure 3-1 Map showing the transmission grid in the Nordics (ENTSO-E, 2016). The transmission grid is needed to transport electric power from sites of generation to sites of consumption, but has a limited capacity to transmit electric power

The power system, as modeled in detail in power system analysis software, is a non-linear and complex system with thousands of interacting components. However, the algorithm calculating the electricity prices is only able to manage capacity limitations formulated as linear constraints, where any interconnections are modeled by fixed numbers. Thus, capacity calculation process is a process of simplifications: the TSOs must supply accurate information on the limitations in the transmission grid, while respecting the simplified format requested by the price coupling algorithms.

The *structure* of the electricity markets is also much simplified compared to the real power system. Large numbers of nodes in the power system are grouped into bidding zones, and the interconnecting transmission grid is simplified into a set of borders connecting the bidding zones. The real limiting grid elements however, might geographically speaking be located anywhere in the grid and not necessarily on the bidding zone borders.

To sum up, the capacity constraints as provided by the TSOs today to the electricity markets are highly simplified versions of the actual grid constraints.

3.2 Why introduce a new Methodology for Capacity Calculation

The purpose of capacity calculation is to "map" the physical abilities of the power grid, to transmit electric power from generation to end consumption, and to translate the physical abilities into constraints that can be used by the market algorithm. Currently, the capacity calculation is done by the individual TSOs using their own calculations and tools. The lowest value is used on the joint bidding zone borders between different TSOs, and the final grid limitations are reflected as Available Transmission Capacities (ATC) values used by the market algorithm (also referred to as Net Transmission Capacities, NTC). In the future, the calculation of transmission capacities for the power market will be done by a Coordinated Capacity Calculator (CCC) using a common calculation platform/tool and a Common Grid Model (CGM). The process will be based on input from the TSOs.

In recent years, we have seen several new developments within the Nordic and European energy sector that pose new challenges to both operation and operational security. Possibly most pronounced is the rapid development of wind power generation. The intermittent nature of wind power, and other renewable generation, increases uncertainty of both delivery, and delivery time.

Several new Direct Current (DC) interconnectors between the Nordics and Continental Europe have been installed over the last ten years, and several new ones will be installed within the next five to ten years. These have been, and will continue, to increase the import and export capacity from the Nordic power market by several thousands of MW per year. The DC connections have a large impact on the flows in the internal Nordic Alternating Current (AC) grid, and the direction of the power flow changes from hour to hour. Not only DC connections, but also the Nordic AC grid has been strengthened over the recent years. New and refurbished AC connections have been installed, and new ones will continue to be added in the future.

All new grid connections, both DCs and ACs, will have a tendency to increase the interdependency of the combined power system. At the same time, the development within renewables is adding uncertainty. Thus, the complexity of capacity calculation has increased, making it more difficult to decide on how to share exchange capacity for different bidding zone borders within the current capacity calculation approach.

According to the CACM, the future capacity calculation and market design for the European and Nordic DA and ID market might be either a Flow-Based (FB) or a Coordinated Net Transmission Capacity approach (CNTC). 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 coordinated net transmission capacity approach and assuming the same level of operational security in the concerned region".* The CACM Regulation also describes basic requirements to which the approaches have to comply, as explained earlier in this document.

Thus, both because of the requirements in the CACM Regulation, and because the increasing complexity which is challenging for the current capacity calculation approach, there is a need to develop a better capacity calculation approach based on more formal calculations and more automated procedures. Both methodologies prescribed by the CACM Regulation (FB and CNTC) are relevant candidates for this, but so far there are no theoretical or empirical evidence to support CNTC as being as efficient as the FB approach.

To illustrate the complexity and challenges within the current capacity calculation, the interdependencies in the Nordic power grid are illustrated in Figure 3-2. The figure illustrates a situation with a generation increase in NO3 that is "consumed" in SE2 (yellow arrows). In the current NTC market, this would generate a commercial trade between the two areas, as illustrated by the orange arrow.

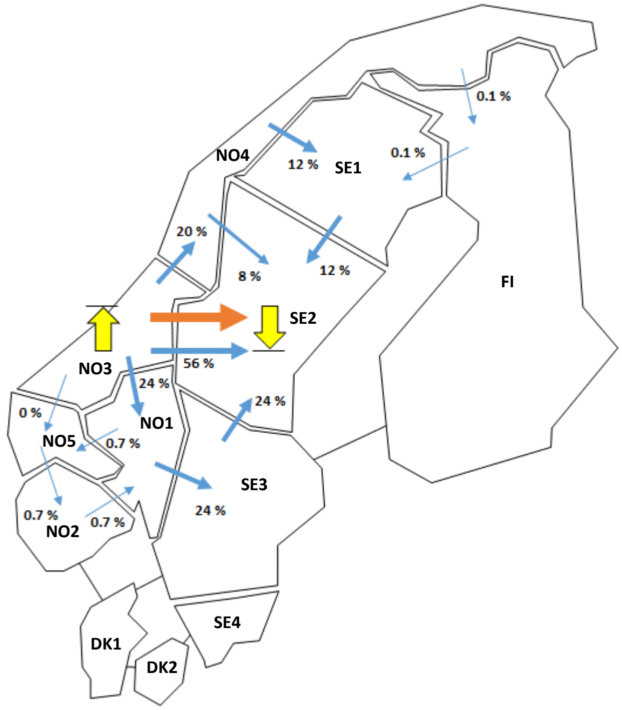

Figure 3-2 Contractual flows vs physical flows in the Nordic Grid. Power is injected in NO3 and consumed in SE2

In reality, the physical flow from this trade would follow the blue arrows in the figure, some large flows in the central area, and many tiny flows all over the system. All these transit flows are disregarded by the relevant market players, but they are using available capacity elsewhere in the system. Within Economics, this is called an external effect, and it has a negative impact on all other market players who will face less transmission capacity due to the illustrated trade.

Thus, when the TSOs are providing CNTC or NTC day ahead capacity for the illustrated commercial trade between NO3 and SE2, they are also considering the transit flows, reducing the exchange capacity "everywhere else". This however, has the drawback that if the forecasted trade between NO3 and SE2 is not realized, all other capacity reductions due to the expected transit flows are wasted. Thus, the TSOs' forecast going into capacity calculation, and prioritizing between different borders, is very important for the efficiency of the system.

The FB approach is managing the transit flows differently by internalizing them into the market. All exchanges have to compete for transmission capacity, including transit flows. By internalizing an external effect, the FB approach provides a more economic efficient congestion management system.

Loop flows, which are flows on bidding zone borders induced by trades within one bidding area, are however not managed by the FB approach. Loop flows, which does not exist in a nodal pricing system, is an inefficiency caused by the FB approach keeping the bidding zones structure. The benefit of keeping the zonal structure in FB however, is that all other markets and infrastructure remains intact. The only influence on other markets and infrastructure caused by FB is changes in price, net positions and flows, which is a familiar consequence of changes in transmission capacity.

3.3 Description of FB and CNTC

The Nordic Day Ahead (DA) power market is a part of the larger European power market. Market participants submit supply and demand bids to the Nominated Electricity Market Operator (NEMO) who forwards the bids to the joint European market coupling function where the European market algorithm, Euphemia[2], solves a European-wide market equilibrium based on explicit economic welfare optimization.

The organization of the Intra-Day (ID) power market is slightly different from the DA market. Market participants submit bids to the NEMO who forward the bids to the ID market platform. However, there is no explicit welfare optimization, rather a continuous matching of bids. The process may look different from the DA process, but in essence, the outcome will be an implicit optimization of economic welfare.

The market outcome, in both timeframes, has to respect the physical limitations of the power grid. For this purpose, the TSOs provide exchange capacities between bidding zones to the market. The exchange capacities act as constraints for the market-coupling algorithm, limiting the potential exchanges between bidding zones. In reality, the exchange capacities are translations of non-linear physical grid limits into linearized exchange constraints that "can be understood" by the market algorithm. The "full" available exchange capacity is initially provided for the DA market, and the "left over" capacity is at later provided for the ID market.

Currently, the Nordic market is based on a bilaterally Net Transmission Capacity approach[3] (NTC), although not compliant to the CACM Regulation requirements. Thus, the current Nordic market receives simultaneously available exchange capacities for each bidding zone border. *The current approach is hereafter referred to as NTC, while the CACM Regulation compliant version will be referred to as CNTC. The current NTC methodology is described in: https://www.nordpoolspot.com/globalassets/download-center/tso/principles-for-determining-the-transfer-capacities.pdf*

The European region of "Central Western Europe" (CWE – Germany, France, The Netherlands, and Belgium) has implemented an alternative market design, the Flow Based market coupling (FB). Thus, the

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[2] *The common market algorithm used in Northwestern Europe is called Euphemia. In principle, Euphemia is doing what is described in the generic model in Section 3.3.1. In essence, Euphemia is calculating the welfare maximum, but due to the stepwise nature of real world bids, several "optimum" price/volume combinations may exist. Euphemia uses a heuristic to choose a solution when steps are overlapping. This implies that the interpretation of shadow prices in Euphemia might not necessarily be in line with theory, which requires smooth continuous curves.*

[3] *Coordinated Net Transmission Capacity means the capacity calculation method based on the principle of assessing and defining ex-ante a maximum energy exchange between adjacent bidding zones (CACM def.).*

CWE market receives linear constraints in the form of FB parameters, being the Power Transfer Distribution Factors (PTDF) and Remaining Available Margins (RAM), rather than exchange capacities between bidding zone borders. Both Available Transmission Capacities (ATC), delivered by the CNTC and the NTC approach, and FB parameters, delivered by the FB approach, provide a solution domain (market domain) for the power market algorithm. The solution domain sets the boundaries for valid market solutions in terms of maximum and minimum net positions for each of the bidding zones. The solutions are "valid" in the sense of respecting the operational security limits defined by the TSOs.

The requirement in the CACM Regulation is that the linearized market constraints are calculated in a coordinated manner within a Capacity Calculating Region (CCR). For this purpose, CNTC values, RAMs and PTDFs shall be calculated by a Coordinated Capacity Calculator (CCC, or in practice the Nordic RSC in CCR Nordic) using a Common Grid Model, Operational Security Limits from the TSOs, generation shift keys (GSKs), and Remedial Actions (RAs).

3.3.1 The solution domain for the market optimization in FB and CNTC

The market optimization is executed by the European-wide market algorithm "Euphemia" for the DA market. The generic market optimization problem may be formulated in two different ways depending on FB or CNTC (the formulation for NTC and CNTC is equal):

CNTC:	Objective function:	Maximize "Welfare economic surplus"	
		Subject to:	
	- Balance constraint:	$\sum_i NP^i = 0$	$\forall\ Areas\ i$
	- Grid constraints:	$\partial^{ij} F^{ij} \leq ATC^{ij}$	$\forall\ Areas\ i, j$
FB:	Objective function:	Maximize "Welfare economic surplus"	
		Subject to:	
	- Balance constraint:	$\sum_i NP^i = 0$	$\forall\ Areas\ i$
	- Grid constraints:	$\sum_i PTDF_n^i * NP^i \leq RAM_n$	$\forall\ Areas\ i, \forall\ CNE\ \&\ Cut\ n$

Welfare Economic Surplus	= Producer surplus + Consumer surplus + Congestion income
NP^i	= Net Position in bidding zone (i) (Generation + Net Import – Consumption)
∂^{ij}	= 1 if there is an exchange border between zone (i) and (j), 0 if not
F^{ij}	= Exchange between bidding zone (i) and (j)
ATC^{ij}	= Available Transmission Capacity on border (i) to (j)
$PTDF_n^i$	= Power Transfer Distribution Factor on CNE or Cut (n) from bidding zone (i)

CNE	= Critical Network Element, a network element with a thermal limit to the scheduled power flow during an outage (Critical Branch : Critical Outage, see chapter 7.2.1)
Cut	= A set of grid components that in-sum (with or without an outage) limits the scheduled power flow in order to maintain operational security. Cuts are defined by either dynamic or voltage stability limits (See Chapter 7.2.1)
RAM_n	= Remaining Available Margin on CNE or Cut (n)

The objective function in both solutions is to maximize total welfare economic surplus. External effects, like emissions, environmental impacts or distributional effects are not considered part of the welfare economic surplus in this regard, as these are assumed to be internalized in the power price.

Because both the objective function and the balancing constraint[4] are the same for CNTC and FB, the difference between the approaches is how grid constraints enter into the optimization. There are two basic groups of grid constraints considered in the capacity calculation, CNEs and Cuts. CNEs is a class of grid constraints covering thermal limits, while Cuts are a class of grid constraints covering dynamic and voltage stability limits. These limits are described more closely in chapter 7.2. In the remainder of this document, the term "Grid Constraints" will be used to include both CNEs and Cuts.

The function of the grid constraints is to provide a solution domain, which provides limits for valid and non-valid market solutions. Thus, CNTC and FB are distinguished by the differences in the solution domains. Note that both the FB and CNTC grid constraints are linear formulations, which is required by the market algorithm.

In CNTC, each "cross-border exchange capacity" (or ATC), provides a single value indicating how much power can be exchanged between any two bidding zone borders *independent* on the distribution of generation and flows in and between all other bidding zones.

In FB, the PTDF is a factor telling how much power is flowing on a particular grid constraint (CNE or cut) when injecting one additional MW in a particular bidding zone. The RAM is limiting the power that may in sum flow on that particular grid constraint coming from all bidding zones at once. Thus, in FB, the maximum power flow on any particular bidding zone border *depends* on the distribution of generation and flows in and between all other bidding zones. This difference in flexibility to the solution domain allows FB to provide a broader range of valid market solutions compared to CNTC.

In sum, in CNTC the cross border capacities itself are the market constraints, while in FB, the Cross Border capacities are implicitly defined by the RAMs and PTDFs. In CNTC, each individual Cross Border capacity is simultaneously feasible, independent on the flow on all other borders, while in FB, the

[4] *Balance constraint is understood as the sum of net exports between all bidding zones in the market shall be zero – if a bidding zone is exporting it must - by definition - be imported in another bidding zone.*

resulting Cross Border capacity on each individual border is not uniquely defined, but depends on all other flows in the system.

3.3.2 The relation between the CNTC and FB solution domain

We can illustrate the difference between FB and CNTC graphically by using the simple three-zone grid in Figure 3-3. In this example, there are no internal constraints within the bidding zones, or no complex grid limitations or outages being considered. Thus, the only limiting grid elements are the connecting lines between the bidding zones[5]. All lines have a thermal capacity of 1000 MW and equal impedance (equal "electrical distance"). Zone C is a consumption zone and the zones A and B are generation zones. The question faced by the TSO, is how much capacity can be provided for the market for each line.

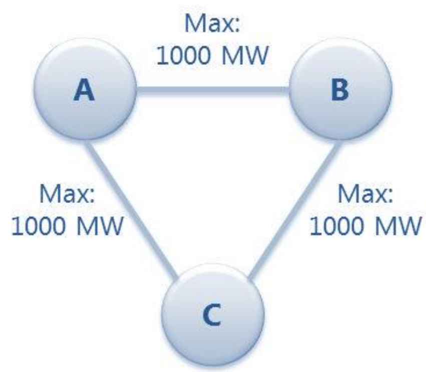


Figure 3-3 Grid with three Zones

At the time of capacity calculation (D-1)[6], the TSO does not know the final net position in zone A, B, or C, only the physical property of the grid is known. Due to the grid topology, one MW produced in A will induce a flow of 2/3 MW on the line AC, 1/3 MW on the line AB, and 1/3 MW on the line BC. The same holds for generation in B of which -1/3 appears on AB (the line from A to B), 1/3 on AC and 2/3 on BC. These sensitivity factors are commonly referred to as PTDFs. Zone C is the "slack node", meaning all power injected in A and B is (mathematically) absorbed in C. The same holds for Zone C itself, all power injected in C is absorbed in C. Thus, C individually has no influence on the flows in the grid. The flow influence of each zone to each line defines the PTDF matrix in Table 3-1.

Table 3-1 PTDF matrix of the grid in Figure 3-3

[5] In reality, not all CNEs or Cuts are located on the borders itself, but might be located anywhere on the borders or within the bidding zones

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

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 PTDF factors, translating the change in net positions into physical flows on the limiting grid elements (lines in figure 5), are not provided to the market algorithm under CNTC. Within the CNTC market coupling, transit flows (e.g. flows going from A to C via B) are ignored, and the algorithm only relates to the total provided exchange capacity on each border. This implies that one MW produced in A and consumed in C, will bring a contractual flow of (for example) 0.5 MW on the lines AB and BC, and 0.5 MW on AC. Thus, bluntly setting the CNTCs to thermal limit values would allow the CNTC market algorithm to carry 2000 MW of trade from A to C, or from B to C even though it is not physically feasible, and will create an overload.

The physical reality in the three-zone example, reflected by the PTDFs, is that 2000 MW generated in A will load A→C with 2/3*2000 = 1333 MW, which is above the thermal capacity of that line. The maximum generation (net position) in each of A and B that is possible in order to avoid overloads, is 1500 MW (however not simultaneously). The operator (TSO) has to limit the total export from A and B to this level under the CNTC approach. One possible set of ATC capacities is thus 750 MW on AC, BC and AB, which gives a secure CNTC solution domain. This is also the maximum simultaneous set of ATC capacities that are obtainable within a secure grid operation. Other alternative ATC capacities are 1500 MW on AC, and 0 on BC, or vice versa. Many different CNTC domains are in fact possible, and the goal of the CNTC capacity calculation is to pick the most relevant domain (described by ATC capacities for each border) for the market. The specific CNTC domain of 750 MW on all lines is illustrated in Figure 3-4.

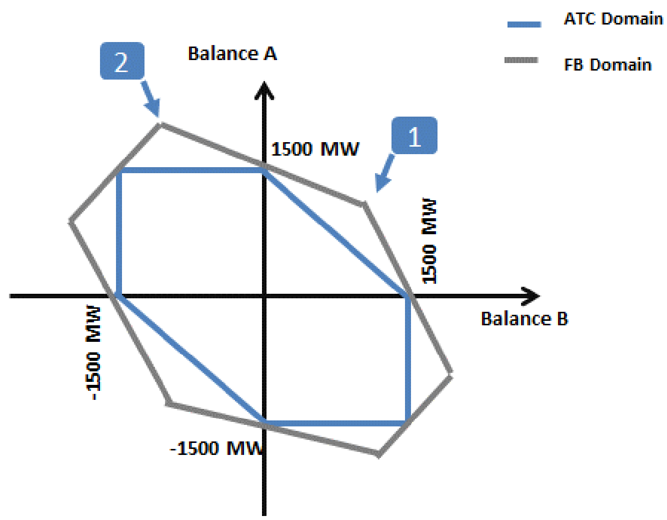


Figure 3-4 CNTC and FB domains

Both FB and CNTC have to obey the same physical grid limitations and provide a solution domain that will limit the net positions to be physically safe within a particular grid topology. What the CNTC market coupling boils down to, is to find the optimum market position inside the CNTC market domain (the blue lines in Figure 3-4).

Providing FB constraints will change the solution domain. FB constraints consist of two types of information, factors for monitoring flows induced on the grid constraints by the injection of power in each bidding zone, PTDFs, and the available capacity on each grid constraint. In our three-zone example, the RAM is 1000 MW on each line. In a more real life and complex grid configuration, the RAM will also reflect Reliability Margins (RM), loop flows from internal trades (MW at Zero net-position) and Remedial Actions (RA) (more on this later).

As with CNTC, a net position of 1500 MW for each of A and B is still feasible within FB. However, the larger maximum simultaneous net position of 1000 MW for A and B also becomes possible with FB. This corresponds to the net positions of A=1000, B=1000, C=-2000 (point 1 in Figure 3-4). The flow induced on AB is 1000*(2/3) + 1000*(1/3) = 1000, the flow on BC is 1000*(1/3) + 1000*(2/3) = 1000, and the flow on AB is 1000*(1/3)+1000*(-1/3)=0.

Another market position accessible in FB but not in CNTC, is a net position of 2000 MW for A or B (i.e. not simultaneously), illustrated for A as point 2 in Figure 3-4. This corresponds to the net positions A=2000, B=-1000, C=-1000, and the flow induced on line AB is 2000*1/3 -1000*(-)1/3 -1000*0=1000.

If all such "extra" points are added to the former CNTC domain, we have the FB domain shown in grey in Figure 3-4. In all situations where the optimal solution is found within the grey area, but outside the blue area, the FB solution is a better solution in terms of welfare economics than the CNTC solution.

Figure 3-4 shows a safe CNTC and FB domain derived from the grid in Figure 3-3 with the same level of system security. All points on the FB boundaries reflect congestions somewhere in the grid that will induce price differences in all nodes, without implying that all lines are congested simultaneously. These market positions are however not possible in CNTC due to the fact that the CNTC algorithm doesn't know the real physical flows (the PTDFs) between bidding zones.

With CNTC, only commercial exchanges between bidding zones are considered by the market algorithm. Real physical flows, including transit flows, are left to the TSO to manage in operation. Congestions are solved on a "border by border" basis by regulating the net positions on each side of the congested border. In order to manage the real physical flows in an effective manner, the TSOs have to prioritize and allocate capacity to certain borders in order to manage the effect of transit flows and internal congestions. As transit-flows are hard to predict, capacity calculation in meshed grid becomes more complex.

FB does things differently. The transmission capacities provided to the market come together with information on the physical flows (linearized as such) on all grid constraints (CNEs and Cuts), induced by a change in the net position in every bidding zone[7]. Transit flows are then monitored and overloads are managed directly by the market algorithm. The TSO can provide maximum capacity to the market, and the market algorithm will find the optimal welfare economic flow on all grid components by itself.

Because the TSO, by using FB, does not have to prioritize capacity on certain borders in advance, more solutions are available to the market algorithm. This implies (at least theoretically) that the solution domain, given to the market by a FB Capacity Calculation, is as large as or larger than the CNTC domain. All CNTC market solutions are also available in the FB market solution, but the FB domain provides access to solutions outside the CNTC domain. Whenever the optimal solution is within the CNTC domain, both market designs will find it, but the FB market may find an optimum outside of what is available to the CNTC. In theory, the FB has to be more efficient than the CNTC at the same level of system security, while practical implementation may sometimes prove otherwise.

The Nordic power system is far more complex than illustrated in the simple three-zone grid in Figure 3-3. Thus, the complexity of assigning exchange capacity is also far more complex. This is illustrated in Figure 3-5, with the real bidding zones and connections in the Nordic system.

There are currently twelve bidding zones within the Nordics and five connected external bidding zones in the CCRs of Core, Hansa and the Baltic. Altogether, there are 26 connections between bidding zones

[7] *Bidding Zones may differ from price areas in that one price area may contain several bidding zones.*

within the Nordics and between the Nordics and the external areas in other CCRs. For each connection, there is one exchange capacity in each direction for each hour of the day, and thus, the Nordic TSOs provides 1248 hourly exchange capacities per day, and 455 520 hourly exchange capacities per year.

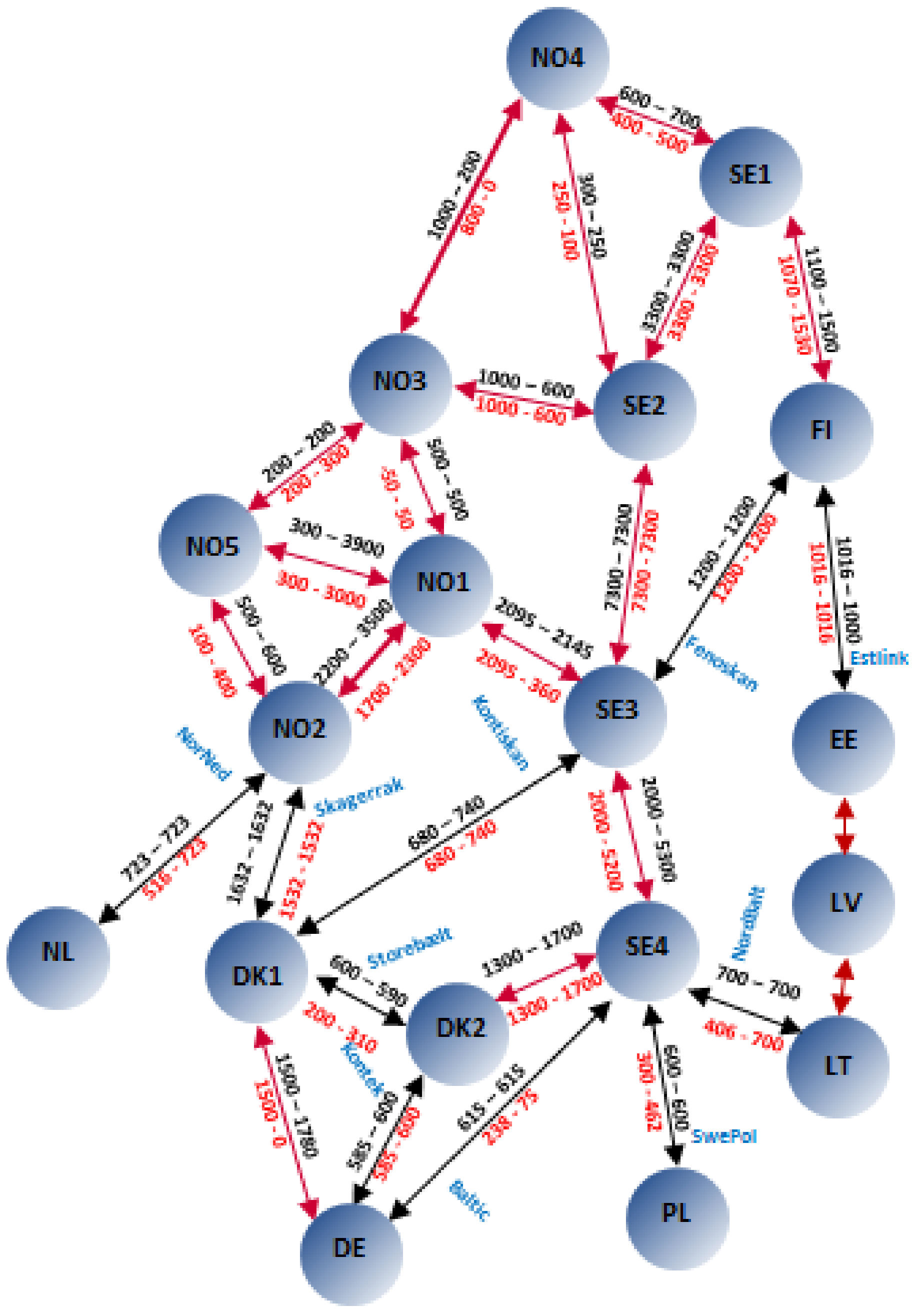


Figure 3-5 The Nordic power system.
This figure gives a schematic overview of the Nordic power system. AC connections are illustrated by red arrows and DC connections by black arrows. The Max exchange values for each connection is shown in black numbers, together with the provided exchange capacities 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 system is interdependent and influenced by loop flows.

4 ACER recommendation on Capacity Calculation

ACER launched a recommendation on capacity calculation and re-dispatching and countertrading cost sharing methodologies on 11 November 2016. In the ACER Recommendation "*On the common capacity calculation and re-dispatching and countertrading cost sharing methodologies*", the Agency proposes three general principles to guide the TSOs in developing and the Regulators in approving the Capacity Calculation Methodology. The ACER recommendation is a non-binding advice. Two of the principles relate to the CCM. In line with the binding rules for capacity calculation, as laid down in Regulation 714/2009 and its Annex 1, both recommended principles are subordinate to reasons of operational security and economic efficiency. This chapter describes how the ACER recommendation is foreseen to be included in the Nordic CCM.

The ACER guidance, subject to the restrictions following from operational security and economic efficiency, are the following:

1) As a general principle, limitations on internal network elements' should not be considered in the cross-zonal capacity calculation methods
2) As a general principle, the capacity of the cross-zonal network elements considered in the common capacity calculation methodologies should not be reduced in order to accommodate loop flows

4.1 The influence of the first ACER recommendation on the proposed CCM

The first principle relates to the selection of which grid constraints that will enter the capacity calculation. This choice is however not essential or relevant for the capacity calculation approaches itself, or the choice between FB end CNTC. Neither CNTC, nor FB distinguishes between internal and external constraints, and any number of grid constraints might enter the two approaches. Thus, both FB and CNTC will work independently of which network constraints are considered relevant in the market domain.

In the Nordic power system, a high share of the grid constraints is located inside bidding zones, not on the border. At further, most borders are bidirectional with different grid constraints limiting in different directions. As such, it is not possible to fully adopt the ACER Recommendation without compromising operational security, unless a nodal pricing system is introduced. However, a large part of the grid constraints today considered as relevant in capacity calculation is either dynamic-, or voltage limits. These limitations are exempted from the ACER recommendation:

> *"In few specific cases the cross-zonal exchanges may be limited by other operational security limits than thermal limits (e.g. voltage stability, dynamic stability etc.). In these cases, the capacity of the cross-zonal network elements may be reduced below the level of the full thermal capacity reduced by reliability margin"*

This leaves the remaining "market relevant" grid constraints, which are of a thermal nature, to consider whether they might be exempted from the ACER recommendation based on operation security or economic efficiency.

According to the ACER Recommendation, the proposed remedy for managing internal grid constraints is described as:

> *"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"*

Currently, some of these measures are being utilized in the Nordic in order to minimize the impact from any type of grid constraints on the provided XB capacity. These measures will also be present in FB and CNTC:

- All available non costly Remedial Actions are by default provided to all grid constraints;
- Grid constraints with small influence on cross-border flows are disregarded in the Capacity Calculation;
- Bidding Zone Delimitation is in use effectively in the Nordics (Currently 12 Biding Areas).

These measures have a significant impact on the provided cross-border capacities in the Nordics, but are not sufficient to manage all loop flows or the remaining internal thermal grid constraints. This leaves three measures to be utilized:

- Investments;
- Planned Counter trade (or re-dispatch);
- Exemption from the ACER recommendations.

The current investment criteria in the Nordics is to invest if the welfare economic effect is positive. However, there are no relation between this criteria and the requirement to remove grid constraints to satisfy the ACER recommendation. Thus, in order to utilize the grid investments arrangement in this manner, the investment criteria needs to be changed to "always invest in the most limiting grid component". However, this criteria is not in line welfare economic efficiency, nor is it foreseen to be adopted by the Nordic TSOs.

The next measure available is to disregard internal grid constraints and loop flows in capacity calculation and "solve" any overloads in operation, e.g. planned countertrade or re-dispatch. The implication of this is that physical capacity is "offered twice", which is not possible without having a high probability for overloads. In other words, the TSOs are offering more capacity to the market than is physically safe, e.g. "virtual capacity".

In this situation, the market clears on unrealistically high transmission capacity, and market prices are distorted with adverse effect on the dispatch planning. If the market actually moves into a position where all provided capacity are used, the TSOs face overloads and will eventually have to move the market "back" to a secure position by countertrade or re-dispatch, at best at the same prices as offered in the DA market. The approach boils down to introducing financial trade in the day ahead market, and thus generate a need for a new physical market after the spot clearing. **It is extremely unlikely that this solution will promotes welfare economic efficiency**.

The only viable measure to adapt to the ACER recommendations is for the TSOs to obtain exemptions for considering internal grid constraints in capacity calculation based on reasons of operational security and economic efficiency. However, the approach for managing internal grid constraints could deviate between the Nordic TSO, yet without changing the basic capacity calculation methodology as e.g.:

- One Nordic TSO could decide to employ remedial actions (planned counter trade) in a short term perspective, while
- Another Nordic TSO could opt for exemption by justifying the inclusion of relevant CNE's in the capacity calculation for the particular time frame

Both these approaches will (in principle) result in the same flow on a particular CNE and cross border as the basic calculation of Fmax is the same.

4.2 The influence of the second ACER recommendation on the proposed CCM

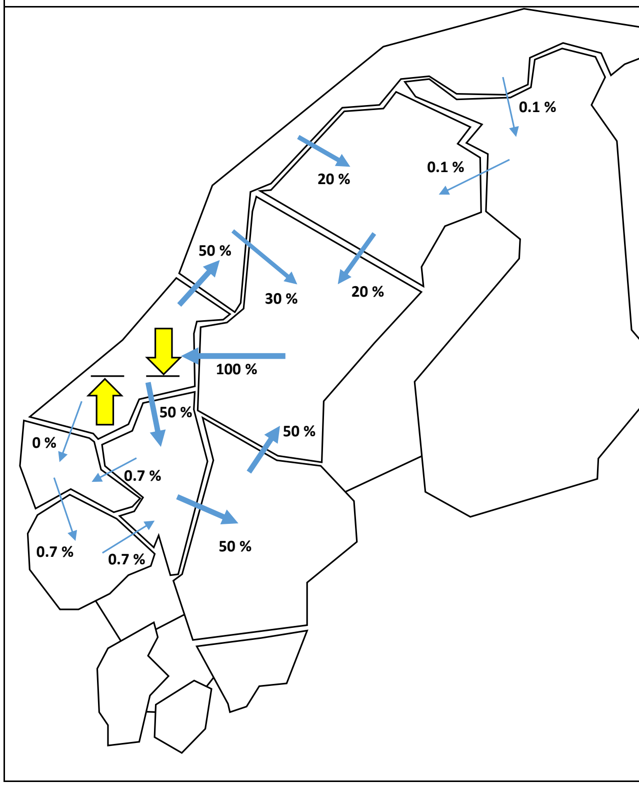
The second principle does have an impact for the FB and CNTC approach. The impact is however larger the CNTC approach. The reason for this being that the FB approach is managing transit flows directly in the market mechanism by the use of the PTDF's allocating flows on different CNE's. Only loop flows are external in the FB approach. In CNTC , neither loop flows nor transit flows are managed by the market mechanism. Thus, CNTC has a significantly higher degree of external flows that needs to be managed by the operators during capacity calculation. External flows are due to:

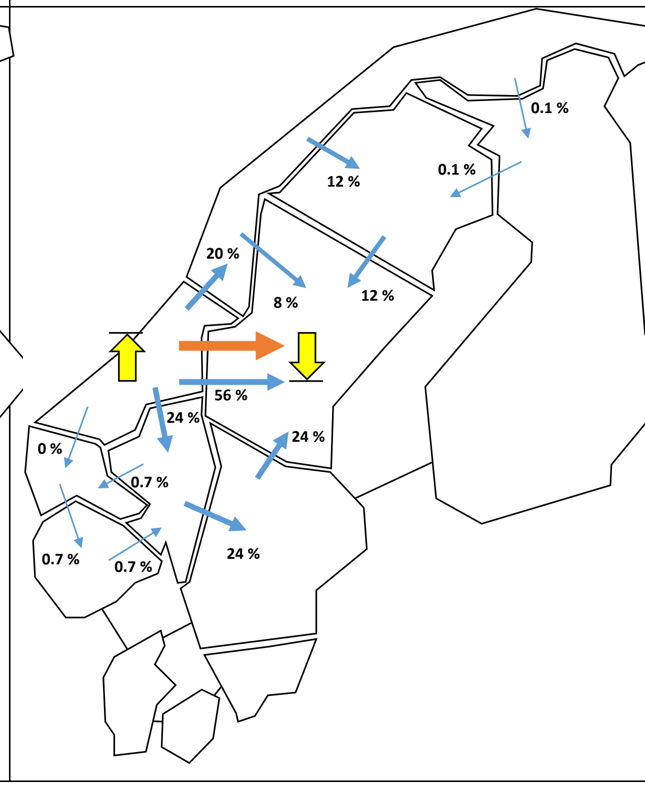
- Loop flows, which are flows on a border resulting from trades *within* a bidding zone, hence the flow starts and ends in the same bidding zone, but utilizes the grid in one or more adjacent bidding zone
- Transit flows, which are flows on a border resulting from trades *between* bidding zone, hence the flow starts and ends in different bidding zone, but utilizes the grid in one or more adjacent bidding zones

In the Figure 4-1: The difference between the concepts of loop and transit flows are illustrated the difference between loop – and transit flows. The yellow arrow illustrate the flow, which in the left panel starts and ends in same bidding zone and in the right panel starts and ends in different bidding zones.

Figure 4-1: The difference between the concepts of loop and transit flows

Loop flows; starting and ending in same bidding zone	**Transit flows;** starting and ending in different bidding zones





Flows not managed by the market mechanism are external effects to the market. In order to maintain operational security, these are normally considered within capacity calculation, directly limiting the provided XB capacity (see also section 10.2.4). Thus, in FB, external flows (i.e. the transit flows) are internalized and creating a level playing field for internal and external flow, hence undue discrimination between internal and cross-zonal flow are avoided

The chosen approach in order to cope with loop flows is to implement proper bidding zone delineation, in principle dividing one bidding zone into two, hence loop flows are turned into transit flows. In this way FB can internalize external flows. However, it is not part of the CCM proposal to suggest amendments of bidding zone delineation as this is part of the bidding zone study, cf. the procedure sat up in CACM chapter 2, yet this document still contains and impact assessment on bidding zone delineation in the Nordics from FB implementation, cf. 10.2.4.

5 DA Capacity calculation methodology

This chapter presents the capacity calculation methodologies of flow based.

Article 21(1b) requires the proposal for a common capacity calculation methodology to contain a mathematical description of the approach:

"(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;"

The following sections provide these descriptions of the methodologies.

5.1 Detailed description of the FB capacity calculation approach

5.1.1 Mathematical description of the capacity calculation approach

The flow-based approach provides constraints to the market coupling algorithm, and maintains the essential physical properties of a meshed AC grid. Transmission of electrical power between two bidding zones will spread throughout the electrical network in accordance to the impedance of the different paths.

Because the market coupling process only accepts linear grid constraints, the capacity calculation includes a methodology for creating a simplified representation of the grid constraints that adhere to this requirement. Within FB, the result of this simplification is the power transfer distribution factors (PTDFs) that applies for both CNEs and Cuts.

The MW limit for each grid constraint is termed the remaining available margin (RAM), which is the amount of grid capacity available to the market coupling process. The value of the RAM is determined, after various deductions, from the total available margin of the grid constraint. These deductions include at least the flow reliability margin (FRM), nominations of long term transmission rights (LTTR), and internal loop flows in the bidding zones.

For each flow-based constraint provided by the TSOs, the market coupling process will apply the constraint in the capacity allocation as shown in (1).

$$\text{NP} \cdot \text{PTDF} \leq \text{RAM} \tag{1}$$

NP refers to the vector of bidding zone market net positions within the flow based region, PTDF refers to the matrix of PTDFs for the bidding zones in the flow based region calculated for the specific constraint, and RAM refers to the available margin on the constraint. The "·" sign refers to the dot product of the vector NP and matrix PTDF.

The PTDFs and RAMs together form the set of flow based parameters describing the available transmission capacity between a set of bidding zones.

The set of bidding zones covered by a set of flow based parameters is naturally limited by DC links, such as the Skagerrak (between DK1 and NO2) and KontiSkan (between DK1 and SE3) interconnectors. This is because the transition between the AC grid and the DC links do not allow for the calculation of fixed PTDFs. The implication is that a set of flow-based parameters is limited to a synchronous region, and that two separate sets of flow-based parameters will be provided for the Nordic capacity calculation region since Jutland is a separate synchronous region from the rest of the Nordic CCR.

5.1.2 Mathematical description of the calculation of power transfer distribution factors and of the calculation of available margins on critical network elements

The power transfer distribution factors (PTDFs) will be calculated from an AC load flow model (the common grid model), applying the simplifications necessary to create a linear approximation. This section starts with a short introduction of the basics of the AC power flow equations and shows how the PTDFs are calculated.

For a grid constraint that includes either a contingency or a remedial action, requiring the disconnection of grid components, generators, or loads, the PTDFs will be calculated to represent the system state after the disconnections. This will minimize the errors, but means that the full set of PTDFs for all grid constraints do not represent the same grid state / model. Instead, the PTDFs for each grid constraint will represent the correct state of the power system after the disconnection.

The calculation of the PTDFs will start from an AC power flow model for the forecasted state of the electricity system[8]. The active and reactive power flows in steady state can be described by the power flow equations (2) and (3)).

$$P_i = V_i \sum_{k=1}^{n} V_k (G_{ik} \cos(\delta_i - \delta_k) + B_{ik} \sin(\delta_i - \delta_k)) \tag{2}$$

[8] *The calculations leading up to equations (2) & (3) is found in Grainger, J. & Stevenson, W. (1994). "Power System Analysis", New York: McGraw–Hill. ISBN 0-07-061293-5.*

$$Q_i = V_i \sum_{k=1}^{n} V_k (G_{ik} \sin(\delta_i - \delta_k) - B_{ik} \cos(\delta_i - \delta_k)) \tag{3}$$

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 branches 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[9] 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:

$$P_i = \sum_{k=1}^{n} B_{ik} (\delta_i - \delta_k) \tag{4}$$

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

$$Q_i = \sum_{k=1}^{n} -B_{ik} \tag{5}$$

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

$$[\delta] = \begin{bmatrix} \delta_1 \\ \delta_2 \\ \delta_3 \end{bmatrix} = \begin{bmatrix} 1 + B_{12} + B_{13} & -B_{12} & -B_{13} \\ -B_{21} & B_{21} + B_{23} & -B_{23} \\ -B_{31} & -B_{32} & B_{31} + B_{32} \end{bmatrix}^{-1} \begin{bmatrix} P_1 \\ P_2 \\ P_3 \end{bmatrix} = [Zbus][P] \tag{6}$$

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

$$PTDF_{ik,n} = B_{ik}(Zbus_{in} - Zbus_{kn}) \tag{7}$$

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

From nodal PTDFs to bidding zone PTDFs using generation shift keys

Capacity allocation using the flow-based approach employs PTDFs that describe how a change in bidding zone net position would impact the grid constraints. The initial calculation of the PTDFs as shown above is performed on a nodal basis, and each node within a bidding zone has a unique influence on each grid constraint. The nodal PTDFs must therefore be aggregated into zone values to be used by the capacity allocation process.

The generation shift keys provide weights to each node in a bidding zone reflecting how much of the PTDF for the bidding zone shall be attributed to the node. Nodes with a large GSK value will form a larger part of the PTDF for the bidding zone, and vice versa for the nodes with a small GSK value. The GSKs therefore allow the aggregation of the nodal PTDFs into bidding zone PTDFs in a controlled manner.

The aggregation of nodal PTDF values into a PTDF value for the bidding zone can be formally expressed as shown in (8).

$$PTDF_{i,j}^{A} = \sum\nolimits_{\forall\alpha} GSK^{\alpha} PTDF_{i,j}^{\alpha}\ , \quad \text{and} \quad \sum\nolimits_{\forall\alpha} GSK^{\alpha} = 1 \tag{8}$$

$\mathrm{PTDF}_{\mathrm{i,j}}^{\mathrm{A}}$ = Sensitivity of line i,j to injection in zone "A"

$\mathrm{PTDF}_{\mathrm{i,j}}^{\alpha}$ = Sensitivity of line i,j of injection in node "α"

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

The calculation of Remaining Available Margins on critical network elements and Cuts

With the flow-based approach the PTDFs describe how the net position in each bidding zone impacts the flow on the grid constraints, while the Remaining Available Margin (RAM) provides the available capacity to be allocated. The RAM is calculated from the total technical margin of the grid constraints, taking into account the necessary deductions as shown in (9). The various deductions are described below.

$$RAM = F_{max} - FRM + RA - F_{ref}' \text{- } FAV \tag{9}$$

Fmax= Maximum flow on the grid constraint
Fref'= Reference flow at zero net positions (when using the computed PTDF)
FRM= Flow Reliability Margin
FAV = Final Adjustment Value
RA= Remedial actions

F_{max} is the technical capacity of the grid constraint. This is a value in MW calculated either based on the technical characteristics of the grid components, or based on AC load flow analysis using a grid model.

FRM is the flow reliability margin, which is intended to cover the uncertainty between the forecasted flow and the realized flow in real time. The methodology for calculating the FRM is described in section 0.

RA includes information of the availability of remedial actions (non-costly and costly), which would increase the RAM if not already included in the calculation of F_{max}

F_{ref}' is the reference flow of the grid constraint when all bidding zones have a zero net position, as calculated by the PTDFs (shown in (10)). As such, F_{ref}' represents the loop flows resulting from internal trades between generators and consumers inside the same bidding zone. F_{ref}' can both be positive (will subtract from the RAM) or negative (will add to the RAM).

F_{ref} is the forecasted flow on the grid constraint, NP^{BC} is a vector of the forecasted zone net positions, and PTDF is the vector of PTDF values for this grid constraint. In order for the linearized flow, to act as accurate as possible compared to the real flow, the linearization is done at F_{ref}. Thus, the linearized grid flow described by the PTDF will be the tangent to the real flow in this point, as illustrated in Figure 5-1. As such, opposed to CNTC, the FB design does not distinguish between transit flows or "other flows". All flows (besides internal loop flows) are monitored.

$$Fref' = Fref - PTDF \cdot NP^{BC} \tag{10}$$

The relation between the net position, flow and RAM is illustrated in Figure 5-1.

Finally, RAM may be adjusted by applying final adjustment value (FAV) to be used to take into account relevant information such as last minute update of temperature or wind forecasts, which would increase the RAM and is not included in other RAM terms. This FAV may be taken into account when RAM is defined or during the validation of capacity calculation results. Important in this application is that a TSO applying FAV is transparent towards CCC and other TSOs about the information applied in FAV.

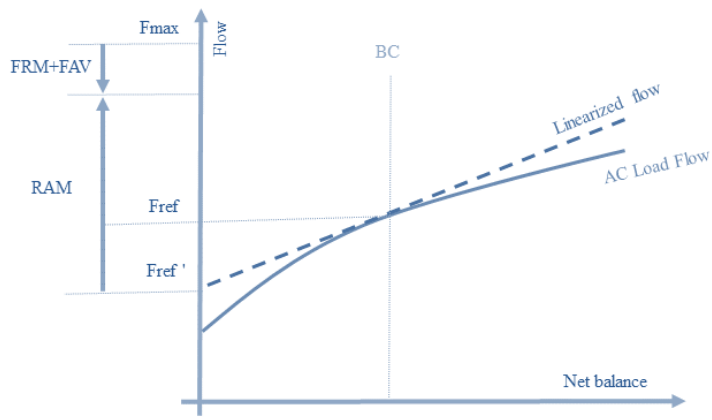


Figure 5-1 Relation between flow, net position and RAM

Negative available margins on critical network elements

In some cases the RAM for a grid constraint can be negative. This would imply that the market situation where all bidding zones have a net position of zero is not a feasible market outcome, and that the capacity allocation process is required to relieve the initial grid constraints. But the market outcome where all bidding zones have a net position of zero remains highly unlikely in the Nordic power system (there were no such market outcomes in 2016), so this may not represent a real possibility or downside to negative RAMs.

The option for eliminating negative RAMs, by increasing the value to at least zero would represent a real risk of grid overloads as this increase would also allow for overloads in more probable market outcomes close to the forecasted net positions. Increasing the RAM would also not allow the market coupling process to determine the most efficient way to relieve a possible congestion.

The flow-based approach will therefore allow for negative RAMs, to the extent that the capacity allocation process will allow such negative values.

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

This section covers the requirement in CACM Regulation Article 21(1)(b)(ii), that the proposal for capacity calculation methodology provides:

"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;"

Point 1.7 of Annex I to Regulation (EC) No 714/2009 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 (1). If such a situation 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."

(1) Operational security means 'keeping the transmission system within agreed security limits'.

The rules are provided in the next subsections.

Periodic review of grid constraints

The TSOs will periodically review the grid constraints applied in the market coupling that are found to be limiting the market exchange of power, to determine if including the grid constraints fulfills the requirements in CACM Regulation Article 21(1)(b)(ii).

Bidding zone delimitation

If the same internal grid constraint is limiting cross-zonal exchanges recurrently, it shall be studied whether dividing the bidding zone where the grid constraint is located into several bidding zones would bring benefits to the market. In addition to benefits also costs related to changing bidding zone delimitation should be evaluated. This kind of evaluation shall be done on a regular basis.

Selection criteria's for grid constraints

To avoid undue discrimination between internal and cross-zonal exchanges, only those critical network elements or cuts that are significantly influenced by cross-border exchanges will be included in the capacity calculation, as described in Section 5.2.

This will ensure that internal critical network elements, which are not significantly impacted by cross border trades, will not limit cross-border trade.

Advanced hybrid coupling for direct-current interconnectors

An exchange determined by the allocation mechanism on an AC-border, is not translated into the physical flow that will be realized. In an AC grid, the physical flows rather fans out in accordance to the laws of physics (which are approximated by the PTDFs).

An HVDC link on the other hand, is fully controllable by the operator. Thus, the DC flows determined by the allocation mechanism, will be the flows that the TSOs assign the link to transport. In essence, the HVDC link is a physical counterpart to an 'NTC' border, where a commercial exchange corresponds one-to-one to the physical flow.

In a mixed AC-DC grid, the NTC properties of the HVDC links must coexist with the FB methodology of the AC grid. This relation is referred to as "hybrid coupling" (between FB *and* NTC). In particular, the Nordic capacity calculation methodology includes an "advanced hybrid coupling" approach for cross-border exchanges for HVDC interconnectors.

Within the "advanced hybrid coupling" approach, the converter stations of the HVDC link are implemented as 'virtual' bidding zones in the FB system (a bidding zone, without order books though). PTDF factors, reflecting how the flow from the HVDC link will fan out in AC grid, are calculated for the virtual bidding zone and implemented in the PTDF matrix like other PTDF factors. No priority is given to the flows from the HVDC link in the AC grid, and thus these flows will have to compete for the capacity in the AC grid like exchanges from any other Nordic bidding zones (SE1, SE2, NO1, FI, and so on). Radial AC connections are managed in the same way.

Due to the advanced hybrid coupling, all bidding zones, also those not part of the flow-based capacity calculation region, will have equal access to the capacity in the Nordic AC grid, thereby avoiding undue discrimination.

The alternative "standard hybrid coupling" approach, where the cross-border flow from the HVDC link is prioritized in the AC grid, would mask the unique influence from the HVDC cross-border flow, increase uncertainty, reduce economic efficiency, and make the cross-border exchanges liable to undue discrimination.

Figure 5-2 illustrates the principle of "advanced hybrid coupling" where the terminal points of the direct-current interconnectors between the Nordic synchronous area and the Continental synchronous area (including the DK1 bidding zone) are placed in virtual bidding zones. This will ensure that the impact from the cross-border flow on the grid constraint is as precise as possible. DK1 is a separate flow-based region since it belongs to the Continental synchronous area. The virtual bidding zones are DK1_GE, DK1_Skagerrak, DK1_KontiSkan, DK1_Storebælt, NO2_Skagerrak, NO2_NorNed, SE3_KontiSkan, DK2_Storebælt, DK2_Kontek, and SE4_Baltic; the normal bidding zones are DK1, DK2, NO1, NO2, NO3, NO4, SE1, SE2, SE3, SE4, Germany, and the Netherlands.

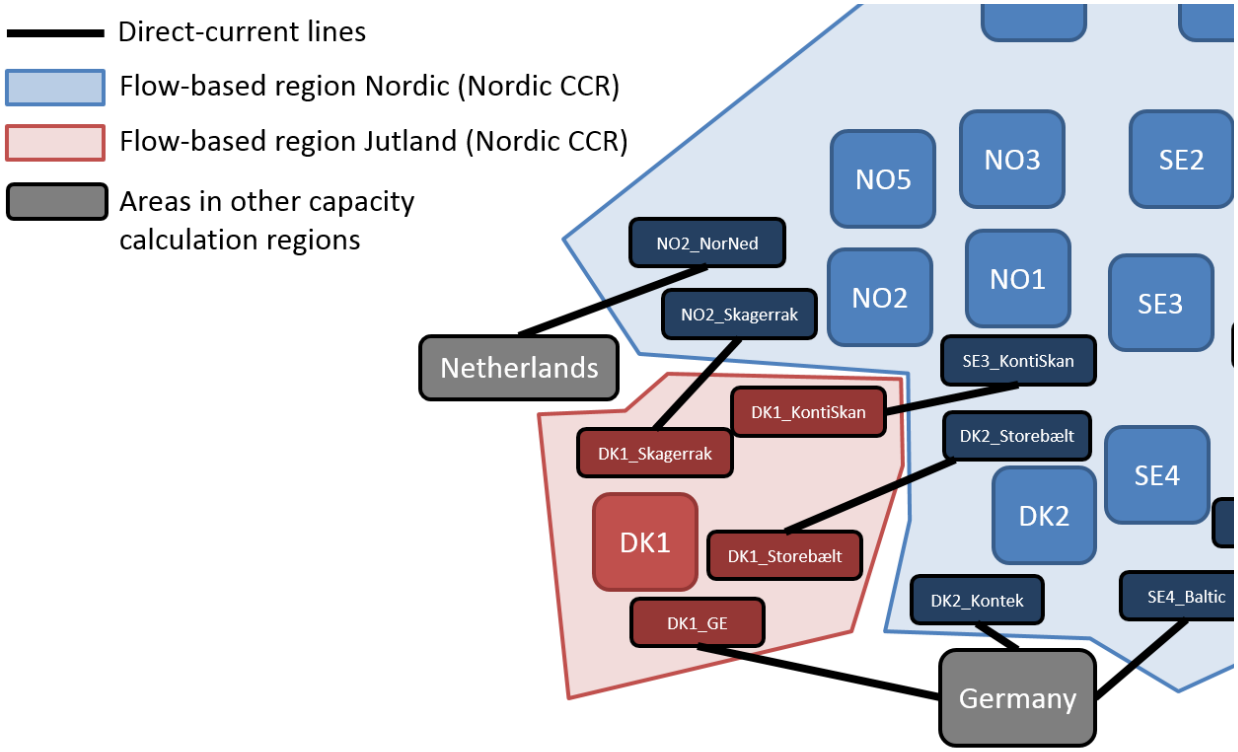


Figure 5-2 Illustration of the Advanced Hybrid Coupling approach in the HVDC modelling

5.1.4 Rules for taking into account previously allocated capacity

The CACM Regulation does not indicate for which purposes grid capacity can be previously allocated[10], only that previously allocated cross-zonal capacity should be taken into account in capacity calculation. The purpose of reservations are however stated in the draft Electricity Balancing Regulation and Forward Capacity Allocation Regulation respectively. This section explains how previously allocated (or reserved capacity) is taken into account in the proposed CCM. Grid capacity can be allocated ex ante of day-ahead capacity calculation and allocation, reducing the available day ahead capacity for two reasons:

- Existence of physical transmission right (PTR) *and* nominated for use
- Cross-zonal exchange of ancillary services, cf. Article 22(2) of the CACM regulation.

The impact of previously allocated capacity gives reduced capacity for day ahead or intraday market.

[10] *This is referred to as 'reservation' in the following text.*

In CNTC, and in NTC, reservation is reflected on the relevant bidding zone borders directly. This is, however, not possible in FB due to the formulation of grid constraints in the form of PTDFs and RAMs. Thus, a reservation in FB must relate directly to the relevant grid constraints influenced by a reservation.

In FB, a reservation must be specified by the areas of origin and consumption, and the MW target, i.e. the amount of MW that is previously allocated for PTRs or ancillary services. The necessary reservations on the relevant grid constraints is calculated by the use of the PTDF matrix. The necessary reservations on each individual grid constraint, calculated by the PTDFs, will be subtracted from the RAM of each relevant grid constraint. The calculation is illustrated in the figure below:

$$\begin{bmatrix} \Delta NP_1 \\ \Delta NP_2 \end{bmatrix} \rightarrow \begin{bmatrix} \text{PTDF} \\ \text{matrix} \end{bmatrix} \rightarrow \begin{bmatrix} \Delta Flow\_CNE_1 \\ \Delta Flow\_CNE_2 \\ \dots \\ \Delta Flow\_CNE_m \end{bmatrix}$$

Figure 5-3 Additional margin ΔFlow needed for each grid constraint for reserving capacity

The required reservation is specified as a change in the net position in the two areas ΔNP_1 and ΔNP_2. One is a buy volume, the other a sell volume. The net position changes are inserted in the PTDF matrix, and the resulting flows on the relevant grid constraints ($\Delta Flow\_CNE_m$) are computed. This flow will be subtracted from the RAM of the grid constraints.

In addition to these requirements, it is necessary to reserve the allocated capacity for the realization of the day ahead market solution in the intraday capacities.

5.1.5 Rules on the adjustment of power flows on critical network elements or of cross-zonal capacity due to remedial actions

This includes information on available non-costly remedial actions, that would increase the RAM. Whenever accessible, non-costly remedial actions will be provided for increasing the flow capability on grid constraints. Currently there are three types of non-costly RAs in use in the Nordics:

1. System Protection Schemes
2. Grid Splitting
3. Emergency power on DC connections

5.1.6 Rules for sharing the power flow capabilities of critical network elements among different capacity calculation regions

These are the same as the "Rules for avoiding undue discrimination between internal and cross-zonal exchanges" in chapter5.1.3, and thus not repeated here.

5.2 Selection of relevant grid constraints for the market domain

According to the CACM Regulation Article 29.3

> *"When calculating cross-zonal capacity, each coordinated capacity calculator shall (b) ignore those critical network elements that are not significantly influenced by the changes in bidding zone net positions according to the methodology set out in Article 21"*

On any given time, there are numerous constraints in in the electrical grid that needs to be managed in order to ensure safe operation. Some of these constraints are influenced by changes in bidding zones net positions (as in cross border trades), and some are not. Due to the zonal market structure (in contrast to a nodal pricing structure), only bidding zone net positions (and prices) are decided by the power market. Thus, capacity calculation cannot consider those constraints that does not respond to changes in bidding zones net positions.

One can say there are two broad categories of grid constraints, those influenced by cross border exchanges, and those not influenced by cross border exchanges. Only the first category are relevant candidates for entering the capacity calculation for the day ahead and intraday market.

Within the category of grid constraints influenced by cross border trades however, some are highly influenced, and some are hardly influenced by cross border trade. Thus, if the influence on a grid constraint from cross border trade are close to, but not actually zero, it is relevant to ask whether it is efficiently managed by the market or not.

As an example, one could imagine a grid constraint that is influenced by a cross border trade by 1%. This means that a cross border exchange of 100 MW, will induce a flow of 1 MW on that constraint. The implication of this relation will be that in order for the market to reduce the flow on that grid constraint by 1 MW, the cross border trade will have to be reduced by 100 MW. Leaving these "hardly influenced" grid constraints to be managed by the market, will severely reduce the capacities that can be provided for the market. Thus,

The CACM Regulation does require the TSOs to remove "not significantly influenced grid constraints" without defining what would constitute a "significant influence", which is the topic of the rest of this chapter. But as a point of departure, it shall be realized that each grid constraint under consideration normally will be influenced by several different cross border exchanges at the same timeframe. Thus, when referring to the level of influence on a grid constraint, we are referring to the particular cross border trade with the highest influence on that particular grid constraint.

We define:

> Not significantly influenced grid constraints are those with a maximum influence from any cross border trade below a certain threshold (that will be evaluated at least once a year).

Calculation of the maximum influence on grid constraints from cross border exchange

The influence of a grid constraint by cross border exchanges might be calculated by the use of PTDFs. A "normal" PTDF, described so far in the document, prescribes the change of flow on a grid constraint when injecting power in a particular bidding zone with the assumption that the injection is absorbed in "the slack node". Thus, to find the influence on any grid constraint from any cross border exchange, we may trace the route between the two bidding zones by PTDFs. For example if we like to find the influence on constraint "n" by a cross border trade from zone "A" to zone "B", we can calculate:

$$PTDF_n^{AB} = PTDF_n^A - PTDF_n^B$$

$PTDF_n^{AB}$ = The influence of cross border trade from zone "A" to zone "B" on constraint "n"

$PTDF_n^A$ = The "normal" PTDF of zone "A" on constraint "n"

$PTDF_n^B$ = The "normal" PTDF of zone "B" on constraint "n"

Generally, we would like to find the largest $PTDF_n^{ij}$ between any bidding zones (i,j) on each grid constraint "n" and evaluate if this is above chosen threshold. This might be found directly by calculating:

$$Max\ PTDF_n^{ij} = PTDF_{n,Max} - PTDF_{n,Min}$$

If this value is below the threshold, the grid constraint is removed from the PTDF matrix.

There are no theoretical sound guidance for defining a threshold value. Thus, we will initially start by a value of 15% and monitor this over time to find a suitable threshold. The threshold is defined as the share of power from a given exchange that “crosses” a particular CNE. If 100MW is exchanged between two bidding zones but less than 15MW “crosses” a particular CNE located anywhere in the Nordic power system, it is not included in the capacity calculation. The threshold value might also change from location to location, between TSO control areas and over time.

Exceptions

There might be instances where a grid constraint has a low cross border PTDF, but where there are no good alternative ways off managing the congestion. In such instances, one should be allowed an exemption to the general rule of a minimum threshold value. Such cases are few and by requiring the TSO to give an argument as to why the grid constraint in question needs to be part of the market clearing, it creates transparency as to what is a transmission issue.

6 ID Capacity calculation methodology

The CNTC methodology is proposed for intraday as a temporary solution until the XBID solution is able to facilitate FB. This section covers the proposal for both the long term solution of FB and the interim solution with CNTC.

6.1 Description of the FB capacity calculation approach

6.1.1 Mathematical description of the capacity calculation approach

The capacity calculation process is starting with the physical electricity grid and its limitations, and ends with the delivery of linear constraints to the market coupling function. The capacity calculation process for the ID market is the same as for the DA market. This is described in chapter 5.1.1, and not repeated here.

6.1.2 Mathematical description of the calculation of power transfer distribution factors and of the calculation of available margins on critical network elements

The mathematical description of the calculation of PTDFs and RAMs for the ID market is the same for the ID and the DA market. This is described in chapter 5.1.2, and not repeated here.

However, one important difference in the ID calculation is the use of a dedicated ID CGM rather than the DA CGM for this particular purpose. It is also worth noting that a particular FRM calculation will be maintained for the ID timeframe. It is expected that the ID FRMs will be smaller than the DA FRMs due to reduced uncertainty while moving closer to the operational hour. This will provide for some extra available capacity (RAM) in the ID timeframe.

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

The rules for avoiding undue discrimination between internal and cross-zonal exchanges are the same for ID and DA. These are described in chapter 5.1.3, and not repeated here.

6.1.4 Rules for taking into account previously allocated capacity

The rules for taking into account previously allocated capacity are the same for ID and DA. These are described in chapter 5.1.4, and not repeated here. However, for the intraday coupling, this also includes the flows already allocated by the day-ahead coupling.

6.1.5 Rules on the adjustment of power flows on critical network elements or of cross-zonal capacity due to remedial actions

The rules for adjusting power flow on critical network elements and Cuts are the same for the ID and the DA timeframe. This is described in chapter 5.1.5, and not repeated here.

6.1.6 Rules for sharing the power flow capabilities of critical network elements among different capacity calculation regions

The rules for sharing the power flow capabilities of critical network elements and Cuts among different CCRs are the same for the ID and the DA timeframe. This is described in chapter 5.1.6, and not repeated here.

6.2 Detailed description of the CNTC capacity calculation approach

This chapter describes the CNTC approach for the intraday time frame according to the Art.21(1) (b) of the CACM Regulation.

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

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

6.2.1 Mathematical description of the capacity calculation approach

Cross-zonal capacity which can be provided to the market is calculated as follows:

CNTC = TTC (adjusted using remedial actions, applying rules for undue discrimination, applying capacity sharing rules) - AAC - TRM, where TTC refers to total transmission capacity, AAC refers to already allocated capacity and TRM refers to transmission reliability margin.

The CNTC approach is based on basic AC load flow analysis. Inputs to the capacity calculation are a common grid model (CGM), which presents the forecasted state of the power system, generation shift keys (GSKs), contingencies, and operational security limits. Load flow analysis reveals the voltages in different nodes (magnitude and angle), power flows (active and reactive power), and losses on different lines. Voltages and power flows in the 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:

$$\underline{S}_i = P_i + \mathrm{j}Q_i = (P_{\mathrm{G}i} - P_{\mathrm{L}i} - P_{\mathrm{T}i}) + \mathrm{j}(Q_{\mathrm{G}i} - Q_{\mathrm{L}i} - Q_{\mathrm{T}i}) \qquad (3)$$

$\underline{S}_i$ 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 maximum exchange on a bidding zone border (i.e. total transmission capacity (TTC)) is the maximum allowed transmission of active power between bidding zones in accordance with the system security criteria (i.e. respecting N-1 criteria and operational security limits). Rules for avoiding undue discrimination, rules for taking into account previously allocated capacity (AAC), rules for taking into account remedial actions, rules for calculating total transmission capacity (TTC), and cross-zonal capacity given to the market, as well as the capacity sharing rules are discussed in more detail in the following sections.

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

Internal grid constraints are monitored in the capacity calculation process. If internal grid constraints are limiting cross-zonal exchanges, analysis shall be performed to determine if including the grid constraints fulfill the requirements in CACM Regulation Article 21(1)(b)(ii) (e.g. cost of countertrading compared to the loss of socio-economic welfare due to the limitation in cross-zonal capacity caused by the internal grid constraint shall be studied). If the same internal grid constraint is limiting cross-zonal exchanges recurrently, it shall be studied whether dividing the bidding zone where the grid constraint is located into several bidding zones would bring benefits to the market. In addition to benefits also costs related to changing bidding zone delimitation should be evaluated. This kind of evaluation shall be done on a regular basis.

6.2.3 Rules for taking into account previously allocated capacity

Cross-zonal capacities are reduced, where appropriate, by the amount of previously allocated capacities. In case of the intraday timeframe, the already allocated capacities for the day-ahead market shall be taken into account by reducing the cross-zonal capacity accordingly. In case already allocated capacity is bigger than CNTC capacity, zero capacity (0 MW) shall be provided the market.

6.2.4 Rules on the adjustment of power flows on critical network elements or of cross-zonal capacity due to remedial actions

Remedial actions are taken into account as a part of the capacity calculation. After calculating the maximum exchange between bidding zones without remedial actions, necessary adjustments related to remedial actions are done in the common grid model, and the calculation is continued until the maximum cross-zonal exchange - taking into account remedial actions - is found.

6.2.5 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

CNTC calculations follow the process described in CACM Regulation Art. 29(8):

a) use common grid model, generation shift keys and contingences to calculate maximum power exchange on bidding zone borders, which shall equal the maximum calculated exchange between two bidding zones on either side of the bidding zone border respecting operational security limits;
b) adjust maximum power exchange using remedial actions taken into account in capacity calculation;
c) adjust maximum power exchange, applying rules for avoiding undue discrimination between internal and cross-zonal exchanges;
d) apply the rules for efficiently sharing the power flow capabilities of different critical network elements among different bidding zone borders;
e) calculate cross-zonal capacity, which shall equal to maximum power exchange adjusted for the reliability margin and previously allocated cross-zonal capacity.

Step a)

The calculation of the maximum power exchange on a bidding zone border consists of two parts: load flow analysis and dynamic analysis. As long as there are no European CGMs that allow for dynamic simulations, offline dynamic simulations applying Nordic CGMs are performed (i.e. existing dynamic models are modified to be CGM compliant and dynamic simulations are performed using existing tools) and pre-calculated dynamic limits in MW are included in the European CGMs.

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). When calculating the maximum exchange, generation on both sides of the studied border is scaled stepwise according to the GSKs defined, in order to increase the flow on the studied bidding zone border.

The first approximation is done using AC load flow (ACLF) analysis. In ACLF analysis, generation on both sides of the studied border is scaled stepwise in order to increase the flow on the studied bidding zone border. After each step (i.e. after each increase in power exchange), contingency analysis (N-1 criteria) is performed and it is checked that operational security limits are not violated. The flow between the zones can be increased as long as there are no violations of the operational security limits. The load flow analysis is completed, when the maximum power exchange, that still respects operational security limits, is found.

After the load flow analysis, dynamic simulations are performed. The starting point for dynamic simulations is the maximum exchange case from ACLF analysis (i.e. the case with maximum acceptable flow, respecting the security limits in the ACLF analysis). Contingency analysis is performed also in the dynamic analysis part of the calculations. If the maximum exchange case from the ACLF analysis passes the dynamic analysis (i.e. does not violate dynamic limits), the exchange in that case is considered to be the maximum exchange for the studied border. If the dynamic limits are violated, the exchange on the studied border needs to be decreased. This can be done by backtracking the scaling done in the ACLF part. This backtracking is done until a case is found that passes the dynamic stability criteria.

Steps b) and c)

The maximum power exchange is adjusted by using remedial actions and by applying rules for undue discrimination between internal and cross-zonal exchanges. Remedial actions are taken into account as it is described in section 6.2.4. Rules for avoiding undue discrimination are described in section 6.2.2.

Step d)

The next step is to apply sharing rules. Sharing rules are needed in CNTC for interdependent bidding zone borders, in order to take into account the deviations between market flows and physical flows and to share capacities efficiently among the different bidding zone borders. Zone-to-zone PTDF matrices shall be used to evaluate in which borders sharing rules are needed and the need for sharing rules shall be reevaluated on a regular basis (e.g. once a year). The approach described below shall only be used for sharing the capacities among the most interdependent bidding zone borders, where sharing rules are needed.

Sharing rules are based on a linearized security domain that is calculated by using PTDFs and RAMs as in the FB approach (described in section 5.1). In CNTC, the main principle is that only cross-zonal capacities are considered in the sharing process when calculating the PTDF matrixes. Cross-zonal capacities are calculated described under steps (a)-(c) above. However, in bidding zones where interdependencies between bidding zone borders are high, also internal CNEs may be taken into account in the sharing process in order to ensure operational security. Figure 6-1 illustrates the relations between the linearized security domain, maximum simultaneously feasible CNTC values, and maximum physical flows allowed by the CNTC values respecting the linearized security domain.

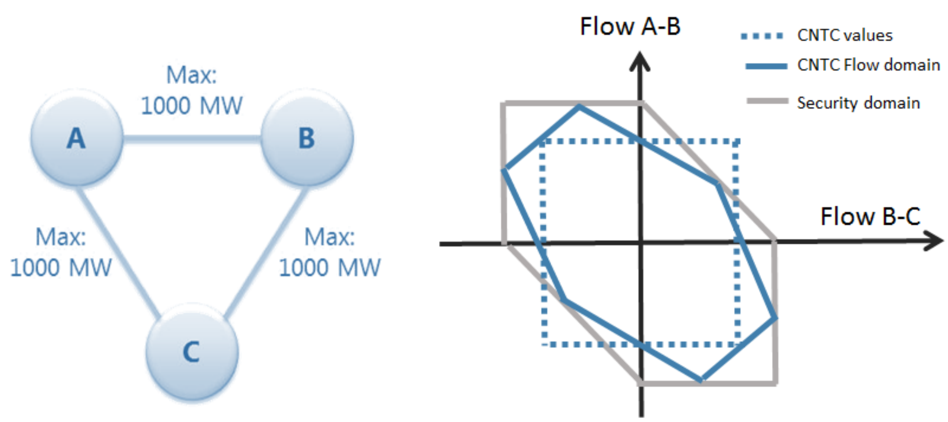


Figure 6-1 Illustration of the relation between security domains

The aim when sharing capacities among different bidding zone borders is to have a CNTC flow domain that is inside the linearized security domain, and at the same time provides as much welfare to the market as possible.

Step e)

Finally, the reliability margin and the previously-allocated cross-zonal capacity are taken into account. It means that cross-zonal capacities are reduced by the amount of reliability margin as described in section 7.1, and previously allocated capacity as described in section 6.2.3.

6.2.6 Rules for sharing the power flow capabilities of critical network elements among different capacity calculation regions

Bidding zones in neighboring capacity calculation regions (CCR Baltic, CCR Hansa) that are connected to bidding zones in CCR Nordic shall be taken into account in the capacity calculation in the Nordic CCR. Capacities for interconnections going out of CCR Nordic shall also be calculated in the Nordic CCR by using the CGMs, and be coordinated with the CCR Hansa and CCR Baltic. If there is a difference in the capacities calculated in the different CCRs (e.g. an internal congestion limits the capacity for the interconnector), the lower value shall be used.

6.3 Frequency of the ID capacity calculation

Capacity recalculation taking into account updated information will depend on updated common grid models with updated scenarios. Therefore, the frequency of intraday capacity recalculation will be decided by the Coordinated Capacity Calculator when the frequency of new scenario creation has been decided, and is likely to be aligned with this frequency.

7 Input parameters to the capacity calculation

This section presents the proposal for the input parameters in line with the requirement in CACM Regulation article 21.1(a) and 22 to 25.

7.1 Reliability Margin (RM)

One fundamental element in managing uncertainty in capacity calculation is the reliability margin (RM), more specifically Flow Reliability Margin (FRM) for a FB approach and Transmission Reliability Margin (TRM) for a CNTC approach. 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 grid constraint, or cross-zonal border for a certain hour day D given the information available at D-2 or intraday. There will always be prediction errors. The uncertainty originates from the ex-ante capacity calculation, and boils down to market-, model- and calculation method-uncertainties. The flow may be larger or smaller than anticipated, and if the 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 capacity on each grid constraint or cross-zonal border will be retained from the market as RM, reducing the RAM or cross-zonal capacity provided to the market to facilitate cross-border trading.

The RM value is normally defined in MW, but can also be presented as a percentage of the grid constraints or cross-zonal capacity's maximum limit. The value is individually quantified for each grid constraint and cross-zonal border and is based on a probability distribution of the prediction error of the flow.

The outline of this section is as follows. First a general description of the RM method is presented, describing the overall methodology. This is followed by a more thorough 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, and TRM in CNTC, is described and the update periodicity is defined.

7.1.1 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 realised power flows in real time. Second, the reliability margin shall be calculated by deriving a value from the probability distribution."*

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

The two steps in the requirement form the basis for the proposed RM method. Figure 7-1 shows a general overview of the proposed methodology, which applies both for the CNEs, cuts, and cross-zonal borders. Cuts are introduced in the Nordics in order to manage voltage or dynamic stability limits. A "cut" is a flow limit spanning several lines or other grid components which is not possible to manage in a "Critical Branch / Critical Outage" setup.

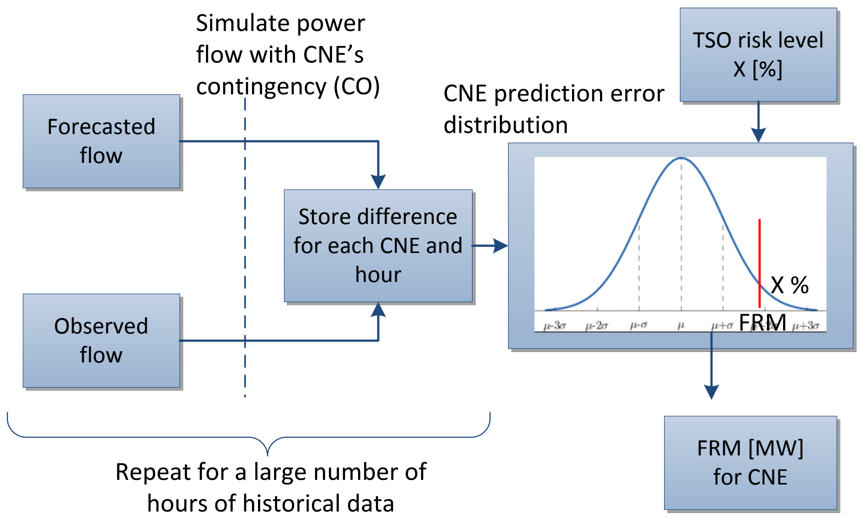


Figure 7-1. A schematic overview of the proposed RM methodology with its two steps; first a probability distribution is established based on historical data, then the RM value is derived from this distribution based on the set risk level.
The figure shows how the prediction error probability distribution is deduced for the grid constraint, 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 borders 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 grid constraint or cross-zonal border, based on a large number of historical snapshots[11] of the CGM for different hours. The grid constraint flows are calculated with a power flow simulation with the contingency for the grid constraint tripped[12]. The AC load flow calculation method is normally used, with the DC load flow method as a fallback in case of non-convergence. A large number of observed differences (in MW) form the prediction error distribution for the grid constraint or cross-zonal border.[13] The prediction error data is then fitted to a statistical

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

[12] Hereby, the difference in 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 cuts with no contingency included, the forecasted and observed power flows are calculated for the intact grid (N grid state).

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

distribution that minimizes the model error. This can be the normal distribution or any other suitable distribution.

In the second step of the method, 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.[14] 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 grid constraint or cross-zonal border.[15] A low risk level results in high RMs and vice versa. A TSO may use different risk levels for different grid constraints and cross-zonal borders.

With the above proposal the requirements in paragraph 1, Article 22 in CACM Regulation are fulfilled.

7.1.2 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 methodology, as defined in paragraph 2 in Article 22 in 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 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."*

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

As previously shown in Figure 7-1, the basic idea behind the RM determination is to quantify the flow uncertainty by comparing the forecasted flow with the observed flow in the corresponding snapshot of the CGM. Figure 7-2 shows a more detailed picture of the proposed method for deducing the distribution for each grid constraint and cross-zonal border. The forecasted flow in the base case is compared with the realized flow observed in a snapshot in the transmission system model. In order to compare the observed flows from the snapshot with the predicted flows in a coherent way, the forecasted grid constraint and cross-zonal border flows are adjusted with the realized schedules

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

[15] *See Figure 7-1. With a risk level of 10%, 90% of the cumulative probability (area) in the distribution is left of the FRM value.*

corresponding to the instant of time that the snapshot was created. In this way the realized net positions are taken into account when comparing the forecast flows with the observed ones. The reason for this model adjustment is that the intraday and bilateral trade as well as imbalances and reserve activation is reflected in the observed flows and need to be reflected in the predicted flows as well for a correct comparison. For FRM, the uncertainty from the FB linearization and GSK strategy is included by using the PTDF when the forecasted flows are adjusted. The highlighted blocks in Figure 7-2 show how the grid constraint flow is adjusted based on the PTDF matrix and the realized net positions.

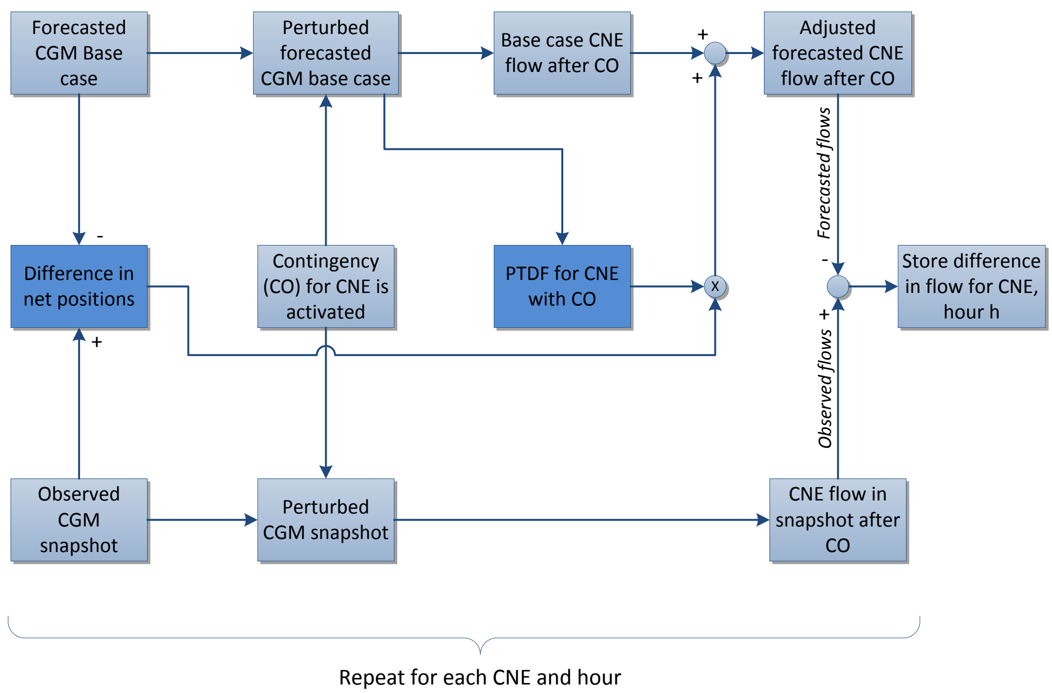


Figure 7-2. Process chart for evaluating the difference between the forecasted and observed flow in the proposed FRM methodology for FB approach. The uncertainty that originates from the FB method (e.g. linearization and GSK strategy) is captured in the PTDF matrix, which is used to adjust the forecasted grid constraint flows with the observed net positions.

As shown in Figure 7-2 the flow difference for the grid constraint is studied when its contingency is tripped in the CGM. In this way a higher accuracy in the FRM is achieved than if only the grid constraint flow difference were calculated on the intact grid. Furthermore, the PTDF for the grid constraint is calculated with the system state for which the contingency has occurred and hence it is beneficial to also calculate the FRM on the same grid state as this increases the accuracy of the method.

The observed grid constraint and cross-zonal border flows include the unintended deviations caused by the inherent random system behavior. Imbalances and adjustments made by the TSO will to some extent be included both in the observed and forecasted flow and hence also be included in the RM given necessary large amount of historical data for the grid constraint or cross-zonal border flow probability distribution. However, in order improve the accuracy of the margin caused by the activation of the frequency control reserve (FCR) this margin is proposed to be modelled separately and then merged with the FRM. A detailed method description of the capacity reservation for FCR is not within the scope of this proposal, but in general the following approach is proposed. First the FCR power flow impact is deduced for each grid constraint and cross-zonal border for a large number of historical hours, forming an FCR distribution. This distribution is then combined with the prediction error distribution, from which the FRM then is selected as earlier described. If the FCR distribution is too complex to establish for the TSO, the maximum FCR impact is instead assessed, giving an absolute FCR margin for the grid constraint or cross-zonal border. The final margin is then set by the largest of the two; the FRM or the FCR margin.

With the above description the requirements in paragraph 2, Article 22 in CACM Regulation are considered to be fulfilled.

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

The differences between the observations and predictions are stored in a database that allows the TSOs to make a statistical analysis on a significant amount of data. Based on a predefined risk level, the RM value can be computed from the prediction error distribution.

The TSO risk level determines how the RM is derived from the probability distribution. This is the proposed harmonized principle for all TSOs in the methodology, cf. 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."*

Each TSO will individually determine a suitable risk level for their grid constraints and cross-zonal borders in the RM methodology. The challenge is to find a balanced risk level that suits the TSO's system requirements. A too low level results in high RMs that constrain the market, whereas a too high level leads to small RMs that may jeopardize system security. With small RMs there is a higher need (and cost) to mitigate problems in operation with available remedial actions.

In the proposed method the risk level is determined by the TSO given the operational security limits, the system uncertainties and the available remedial actions in the system for specific grid constraints and cross-zonal borders. The uncertainties in the probability distribution are further described in the following section.

With the above description the requirements in paragraph 3, Article 22 in CACM Regulation are considered to be fulfilled.

7.1.4 RM in respect to operational security limits given uncertainty and remedial actions

As described earlier the RM for each grid constraint and cross-zonal border is determined based on the uncertainties for the timeframe between the forecast and the actual operation hour for which the agreed operational security limits shall be fulfilled. 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 method described in the previous sections the subsequent effects and uncertainties are covered by the RM values:

- Uncertainty in load forecast
- Uncertainty in generation forecasts (generation dispatch, wind prognosis, etc.)
- Assumptions inherent in the GSK strategy
- External trades to adjacent synchronous areas
- Application of a linear grid model (with the PTDFs), constant voltage profile and reactive power
- The prediction error is calculated based on the operational security limits (N-1 state) which give individual distributions for each grid constraint or cross-zonal border, providing lower uncertainties
- Unintentional flow deviations due to activation of frequency reserves (FCR and FRRa) is included in the methodology
- Topology changes due to e.g. unplanned line outages
- Internal trade in each bidding zone (i.e. working point of the linear model)
- Intraday trade
- mFRR activation
- Grid model errors, assumptions and simplifications.

Due to the complexity of modelling all types of remedial actions in the CGM model, the uncertainty of many of these are not included in the FRM. Instead this uncertainty is included individually in the grid constraint RA which is assigned for modelling remedial actions in the grid.

With the above description the requirements in paragraph 4, Article 22 in CACM Regulation are considered to be fulfilled.

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

In the last paragraph of Article 22 the actual requirement for RM in the day-ahead and intraday market 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."*

In both CNTC and FB the probability distribution and TRM (for CNTC) and FRM (for FB) value is reported in a standardized data sheet for each cross-zonal border or grid contraints, 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.[16]

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

7.1.6 RM update periodicity

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

> *"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 re-calculation and revision will be initiated at least once a year.

7.2 Operational security limits, contingencies, and allocation constraints

According to the CACM Regulation Article 21.1(a) (ii), operational security limits, contingencies and allocation constraints are three features described as key ingredients 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 text will continue to give more details as to how these issues enter into the actual capacity calculation process.

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

7.2.1 Operational security limits

In the CACM Regulation Article 2 (7), operational security limits are defined as the acceptable operating boundaries for secure grid operation:

> *"'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 capacity calculation methodology is CNTC or FB.

Within the capacity calculation process, the acceptable operating boundaries for secure grid operation are based on thermal limits, voltage limits, short-circuit current limits, frequency and dynamic stability limits.

The list of operational security limits consists of limits applied currently 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 greener energy system.

Thermal limits are limits on the maximum power carried by transmission equipment due to heating effect of electricity current flowing through these 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 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 System Operation Guideline. 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 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 a **Maximum flow on grid elements or sets of grid elements** (F_{max}), defined as a MW limit for maintaining the voltage and short circuit current level, frequency and dynamic stability within its limits. Figure 7-3 shows example how F_{max} will be defined.

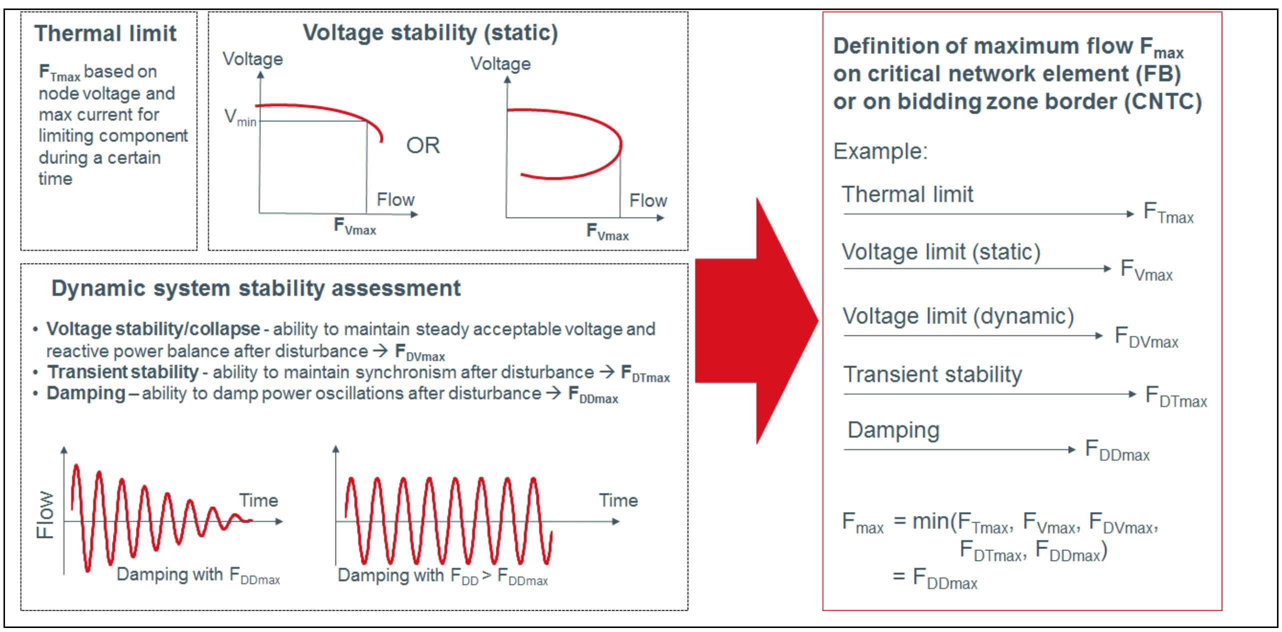


Figure 7-3: Definition of maximum flow (F_{max}) for grid elements

Generally, the F_{max} for Cuts are found by performing a network analyses on a relevant grid model, currently the TSOs local "Planning Grid Models" adjusted by the relevant grid topology, and considering an N-1 situation. (The CGM is intended to be used when sufficient data quality and performance is secured within this model.). Thermal limits are not considered in definition of the F_{max} for Cuts. Thermal limits are implemented as Critical Network Elements with or without an associated contingency.

7.2.2 Contingencies

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 the end-user noticing. For this to be the case, a certain amount of redundancy must be built into the system design. If you can withstand one error without the loss of system functionality we term the design to be in line with the N-1 criterion. If you can have two simultaneous errors, without affecting the end-user it is a N-2 design. When doing capacity calculation, one normally does not model all possible contingencies, but a relevant set for the cross zonal trade is chosen. In this context, contingencies are grid constraints which satisfy the selection criteria described in section5.2. These are grid components of the transmission system that are significantly influenced by cross zonal trade. It is the responsibility of the TSOs to specify which contingencies shall be considered by the CCC.

7.2.3 Allocation constraints

There are some trade restrictions that are not addressed by the abovementioned physical restrictions. These are termed allocation constraints and mentioned in CACM Regulation Article 23.3:

> *"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."*

Allocation constraints are defined in CACM Regulation Article 2 as:

> *"'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."*

Allocation constraints are a way of efficiently describing restrictions in the electricity market that cannot be, or are poorly, defined by flows on CNEs. The allocation constraints will be provided by the TSOs to the CCC. There are a number of such cases, which include - but are not limited by - the following examples:

- The production in a bidding zone must be above a given minimum level.

- The combined import or export from one bidding zone to several other neighboring zones must be limited to a threshold value.
- Maximum flow change on DC-links between MTUs (ramping restrictions).

Current implementation in parallel simulations

- Operational security limits are currently 'external' inputs from the TSOs to the capacity calculation method
- Contingencies are defined by the TSOs to model grid restrictions in the transmission grid and subject to the selection criteria described in section 5.2.
- Allocation constraints are used both to handle ramping restrictions, and the total flow from several bidding zones into another.

7.3 Generation Shift Key (GSK)

The generation shift keys (GSK) define how a net position (NP) change in a bidding zone should be distributed to each generator unit and load point in the CGM. This data is essential in capacity calculation. To illustrate this, Figure 7-4 provides an example of the GSK for a small system with three bidding zones (A-C) each with five interconnected electric nodes (1-5) with load and generation.

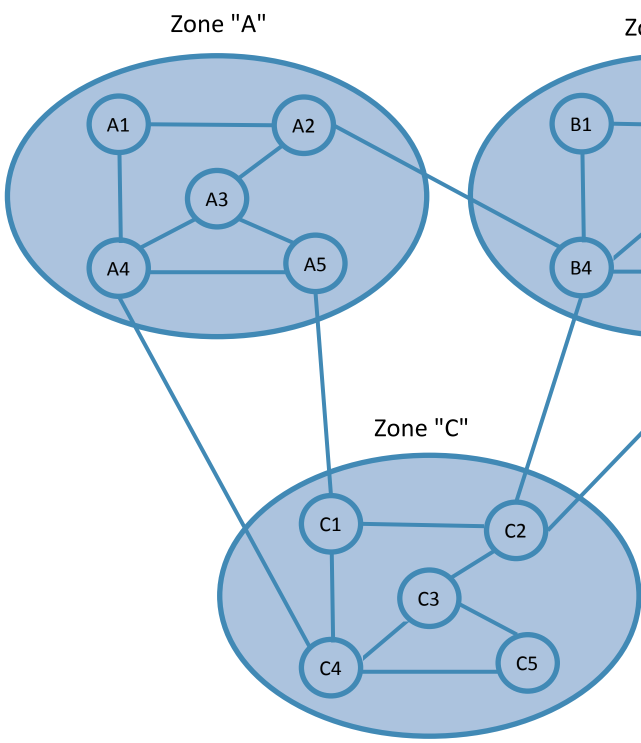


Figure 7-4 Illustrative example for GSK strategy

Figure 7-4 shows a small system to illustrate the GSK. Assume that for a specific hour only node A1 and A2 include generators that are sensitive to changes in the NP. Hence, one GSK strategy for zone A could be to distribute a NP change evenly to A1 and A2. If the NP in zone A increase with 1 MW then A1 and A2 are increased with 0.5 MW each, being close to zone B. Now assume that for the next system hour everything is exactly the same except that sensitive generators only are present in node A4 and A5, which now handle all NP changes. This calls for a different GSK strategy compared to the previous hour for the zone, i.e. A4 and A5 are increased with 0.5 MW, being closer to zone C. It is clear that, depending on the GSK strategy, there will be differences in power flows of the lines and since the PTDFs are calculated based on the marginal line flows given a NP change, the GSK will have an impact on the accuracy of the PTDFs.
The GSKs also provide the opposite transformation; how a nodal injection change affects the bidding zone net position. This information is essential when the zone-to-grid constraint PTDFs are calculated based on the node-to-grid constraint PTDFs.

Different GSK configurations will provide different PTDFs and hence influence the market domain and solution. A thoroughly worked out GSK strategy will improve the accuracy of capacity calculation and decrease the RM values.

When designing the GSK method, 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 cannot be considered by this approach it is important that the best available forecast is used for the CGM.

There are different shift keys related to generation and load (i.e. load shift keys, LSKs).[17] In this context however, the general term generation shift keys (GSK) is generally used for both.

7.3.1 GSK methodology

Article 24, paragraph 1 in the CACM Regulation provides the requirements for a GSK methodology:

> *"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."*

In the method proposal, eight different GSK strategies (1-8) have been developed, each modelling different zone characteristics. The TSO may select one of these strategies for each zone, or provide a custom GSK with individual participation factors for each load and generator unit in the CGM model. The

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[17] *In zones with little or no generation, the GSK strategy includes load shift keys for load points in the zone. A NP change in the zone is then handled by scaling these load points in the CGM.*

ENERGINET SVENSKA KRAFTNÄT FINGRID Statnett custom GSK strategy is always used if this is defined for the hour; otherwise a predefined default strategy (1-8) is used for the zone.

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

Table 7-1 shows the properties of the eight proposed GSK strategies 1-8 along with the custom GSK which here is denoted strategy 0. Each of the strategies may be applicable for a bidding zone, either during all hours for a year or for a single hour.

The participation factors are normalized per zone and then defined in a dimension-less unit. For example, one unit may have a participation 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 zones.

Table 7-1 GSK strategies in method proposal

Strategy number	GSK	LSK	Comment
0	k_g	k_l	Custom TSO GSK strategy with individual set of participating factors for each generator unit and load for the hour.
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 participation 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 participation of all loads, independently of size of load

k_g : Participation factor [-] for generator *g*

k_l : Participation factor [-] 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 power load for load *l*

With the above proposal the requirements in paragraph 1, Article 24 in the CACM Regulation are fulfilled.

7.3.2 Finding optimal GSK in forecast

Article 24, paragraph 2 in the CACM Regulation provides the requirements of the GSK forecast:

"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."

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

In order to test different GSK strategies a heuristic optimization method has been developed. The objective function is a weighted norm 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 set that minimizes the overall RM for the study period. Based on the results and on experience a default GSK strategy is selected for each zone.

With the above proposal the requirements in paragraph 2, Article 24 in the CACM Regulation are fulfilled.

7.4 Remedial Actions

The focal point of this text is not to elaborate on what remedial actions are, and how they are used, but on how they affect capacity calculation. In the preamble of the CACM Regulation it is stated in (10) that:

"*TSOs should use a common set of remedial actions such as countertrading or redispatching to deal with both internal and cross-zonal congestion. In order to facilitate more efficient capacity allocation and to avoid unnecessary curtailments of cross-border capacities, TSOs should coordinate the use of remedial actions in capacity calculation*."

In CACM Regulation Article 21 and Article 25 it is stated to include:

- In 21.1(a)(iv) - the methodology for determining remedial actions to be considered in capacity calculation. Whereas Article 25.1 defines this task to be the individual task of each TSO.
- In 21.1(b)(iv) - the rules on the adjustment of power flows on critical network elements or of cross-zonal capacity due to remedial actions.
- 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.

Most of the remedial action responsibility lies with the TSOs but the outcome must be clearly described, coordinated and communicated. Only non-costly remedial actions are a prerequisite in the cross zonal capacity calculation methodology, whereas the costly remedial actions are used according to the draft System Operation Guideline Article 20 to depend on *the time and resources needed for their activation.*

When costly remedial actions are used however, one needs to be in line with CACM Regulation Article 74.5(b) to monitor their use. There is no systematic record today on the use of costly or non-costly remedial actions.

Remedial actions allow for an increase in RAM on grid constraints. This is not done by adjusting the operational security limit of the grid constraints, but by adding a Remedial Actions (RA) in the calculation of the RAM. The RA element can be used to account for the effect of remedial actions to adjust the capacity. It also provides a transparent way of doing so. Each TSO is responsible for the remedial actions installed in their bidding zones and for setting the correct RA values, reflecting the impact of the remedial actions, on the relevant grid constraints.

RAs such as HVDC runback, and trip of generation or load, depend on the dispatch which is not known prior to the capacity calculation. Considering such RAs may introduce a risk that the capacity is over estimated.

8 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 coordinated capacity calculator can send the 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 capacity calculation methodology, 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."*

8.1 Methodology for the validation of cross-zonal capacity according to 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 allocation process will respect operational security requirements. The regional coordinated capacity calculator will coordinate with neighboring coordinated capacity calculators during the validation process. The TSOs will also assess whether any additional cross-zonal capacity can be made available without risk to operational security.

The relation between the CGM, the physical grid constraints and the XB capacity is provided in the form of a matrix of PTDF factors and RAMS (PTDF matrix). The PTDF matrix (>28 columns and >80 rows) contains the necessary data for maintaining safe transmissions in the grid. The data embedded in the matrix takes the form of numbers, and as such is difficult to comprehend. Thus, it is necessary to translate the data in the PTDF matrix into recognizable information.

A few examples on information that that is possible to extract from the data matrix is; Allowed maximum and minimum net position for each bidding area, allowed maximum and minimum flows on each grid constraint or bidding zone border, relations between allowed flow on a bidding zone border provided the flow on other borders.

Such information, and more, is extracted from the PTDF matrix by a validating tool developed for the purpose. The tool is able to read multiple PTDF matrixes and provide graphical information based on the numbers, for example time series for XB capacities for 24 hours (or more).

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

Article 26 paragraph 2 reads:

> *"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."*

The rules for splitting the corrections of cross-zonal capacity will follow the same methodology as described in the methodology for Article 21b(vi).

Article 26 paragraph 3 reads:

> *"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 capacities would allow the capacity allocation process to create a result that could put operational security at risk. The TSOs will reduce the cross-zonal capacity in a manner that would minimize any negative impact on the market by applying the same rules for splitting the cross-zonal capacity as is described in the methodology for Article 21b(vi).

Article 26 paragraph 4 reads:

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

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

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.

9 Fallback

Modern society needs continuous supply of electric power. Well functioning electricity markets are the means to meet that need, and they require valid information on transmission capacity in order to operate. If the primary transmission capacity calculation fails partially or as a whole there shall be fallback measures producing replacements for any missing data.

According to CACM Regulation Article 21.3 "The capacity calculation methodology shall include a fallback procedure for the case where the initial capacity calculation does not lead to any results".

It is assumed here that fallback procedures will be implemented separately for different parts of the capacity calculation (including capacity validation and publication) and will cover missing or erroneous

CGMs, GSKs and grid constraint definitions and communication channel failures. The fallback procedures will cover both long and short durations of system problems.

Detailed descriptions of fallback procedures can be created only after the primary capacity calculation and allocation process has been designed in detail.

10 Impact assessment

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

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

Finally, the costs for developing and implementing the different methodologies are compared and assessed.

10.1 Quantitative impact assessment

At the time of composing this document, it is not possible to test the FB methodology with industrial tools, operational processes, and the target CGM. Based on the existing prototype tools though, 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 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 capacity calculation are listed.

- Reliability margin
  For the (thermal) CNEs an FRM = 0 has been applied. The (voltage and dynamic stability) cuts in the Nordic system – they are computed by the local TSOs in their local tools, by using their local grid models – are provided as an input to the FB capacity calculation, like they are to the local NTC capacity calculation. This holds true for the TRMs on those cuts as well: the same value is applied in both the FB capacity calculation as well as in the operational NTC capacity calculation. The difference for cuts (compared to the operational NTC capacity calculation) only comes into play when the FB capacity calculation assesses the PTDF factors for the cuts, and takes into account the reference flows, to assess the RAMs on the cuts. As the Nordic system is mainly limited by those (voltage and dynamic stability) cuts, the assumption of having an FRM = 0 on the (thermal) CNEs is not expected to severely impact the quantitative results.
- Operational security limits

Please note that the FB capacity calculation is not an operational procedure yet. Although operators are consulted in the review stage, they are not personally involved in the FB capacity calculation process yet. The operational security limits applied in the FB capacity calculation, are the same as the ones applied in the current NTC capacity calculation, and are likely to be the ones to be applied in the FB operational process as well.

- Contingencies
  n-1 outages are taken into account for the thermal limits (CNEs) , and are the ones to be applied in the FB operational process as well.
- Allocation constraints
  The allocation constraints applied are the same as applied under the operational NTC capacity calculation and allocation. The allocation constraints consist of the implicit loss factors of DC links only (ensuring that the DC link will not flow unless the welfare gain of flowing exceeds the costs of the corresponding losses), for those DC links where this has been implemented, and maximum flow change on DC-links between MTUs (ramping restrictions).
- Generation shift keys
  One common GSK strategy has been applied for all bidding zones in the FB capacity calculation. This is strategy number 6, as mentioned in Table 7-1.
- Remedial actions
  Remedial actions have been applied in the form of FAV values, which might also include additional adjustment values in addition to RAs.
  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 both to cuts and CBCOs
- Undue discrimination between internal and cross-zonal exchanges
  The grid constraint selection process, as described in Section 5.2, is applied with a threshold value of 15%.
- Previously allocated cross-zonal capacity
  No previously allocated capacity has been considered in the DA FB capacity calculations.
- PTDF distribution factors
  The FB parameters are computed in a commercial software tool, that has been set up by the Nordic TSOs, and enhanced by scripts, for the FB capacity calculation purposes. Both the PTDF factors for cuts and CNEs are computed by this prototype tool.
- Remaining available margins on critical network elements
  The remaining available margins are computed in a stepwise manner: RAM = Fmax – FRM – Fref' – FAV. The Fmax values are set by the TSOs: they are physical properties for the grid constraints, whereas they are computed for the (voltage and dynamic stability) cuts in the Nordic system (by the local TSOs in their local tools, by using their local grid models). The FRMs are set by the TSOs as well (see the first bullet on reliability margin).The Fref (being the basis for the Fref') is

computed from the prototype common grid model (CGM) in the same software that computes the PTDF factors. The FAV is set by the TSOs, depending on the application of remedial actions.

- CGM
  The prototype CGM is used for the computation of the PTDFs, and the Fref (being the basis for the Fref'). The quality of the prototype grid models is the best we can have at this moment in time; they do not allow for dynamic analysis and detailed voltage/reactive power analysis though
- Sharing of power flows between CCRs
  No sharing of power flows between CCRs is applied. Indeed, the so-called advanced hybrid coupling is being applied in the FB capacity calculation and allocation. The converter stations of the DC interconnectors are modelled as 'virtual' bidding zones in the FB system (a bidding zone, without order books though), having their own PTDF factors reflecting how the exchange on the DC link is impacting the AC grid elements. Or in other words: the flows on the DC links are competing for the scarce capacity on the Nordic AC grid, like the exchanges from any of the other CCRs.
- Failures in the FB capacity calculation
  Mainly because the prototype CGM poses some challenges, for some of the hours (~6 %) in the FB capacity calculation no FB parameters can be computed. For these hours, in the capacity allocation simulation, the FB parameters are replaced with the operational NTC values of those hours. The future operational CGM and FB process are more robust. In the rare case that no FB parameters can be computed a proper fallback solution needs to 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 operational NTC mechanism). Furthermore, the geographical scope of the FB market coupling simulations is limited to the Nordics + CWE + GB + Baltics.

10.1.1 Socioeconomic welfare of FB per country/per bidding zone per element (PS, CS, CR)

In this section we present the results from the market simulations where we compare the FB with the NTC approach. The market results are simulated with Euphemia, the current DA market coupling algorithm, in the Simulation Facility.

Objective function of the algorithm

The algorithm aims to maximize the welfare in the whole region taking into account grid constraints. The welfare consists of Consumer surplus, producer surplus and congestion revenues, see Figure 10-1.

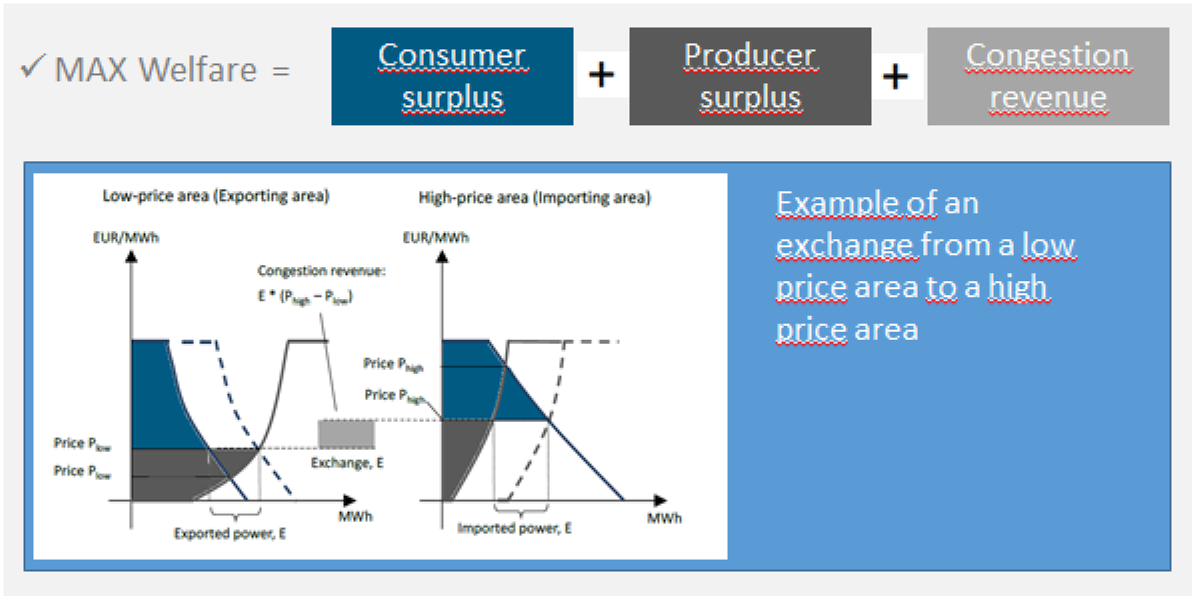


Figure 10-1 Objective function of the market coupling algorithm

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 revenue is equal to the product of the cross-border price spread and the implicit flow obtained by the market algorithm. The congestion revenues are assumed to be shared on a 50/50 basis between the involved TSOs on each side of the borders.

The order books used for the market simulations are the ones available in Simulation Facility, i.e. historical NTC order booksfor Northern Europe. The difference between the approaches is in how the grid constraints are represented in the algorithm. In FB, the grid constraints consist of PTDFs and RAMs for all limiting grid constraints, and in CNTC/NTC the grid constraints consist of capacity values for each bidding zone border.

Some of the hours in the FB results lack FB parameters; these hours are replaced with NTC values. We have simulated 16 weeks in total and compared the welfare results in the FB approach and the current NTC approach. The selection of which weeks are simulated is based on the availability of data and the availability of operators. Due to lack of grid models, some weeks have been disregarded from the simulations.

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

FB can potentially increase the available capacity for cross border trade. This impacts the prices in the 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 16 simulated weeks FB increases the welfare in the Nordic countries with 3900 k€ compared to the NTC approach, see Figure 10-2. Furthermore, we observe a welfare redistribution. The Nordic consumer surplus increases with 58 MEUR compared to the consumer surplus in the NTC approach. The congestion rent in the Nordic area drops with 17 MEUR and the producer surplus decreases with 38 MEUR compared to the NTC approach.

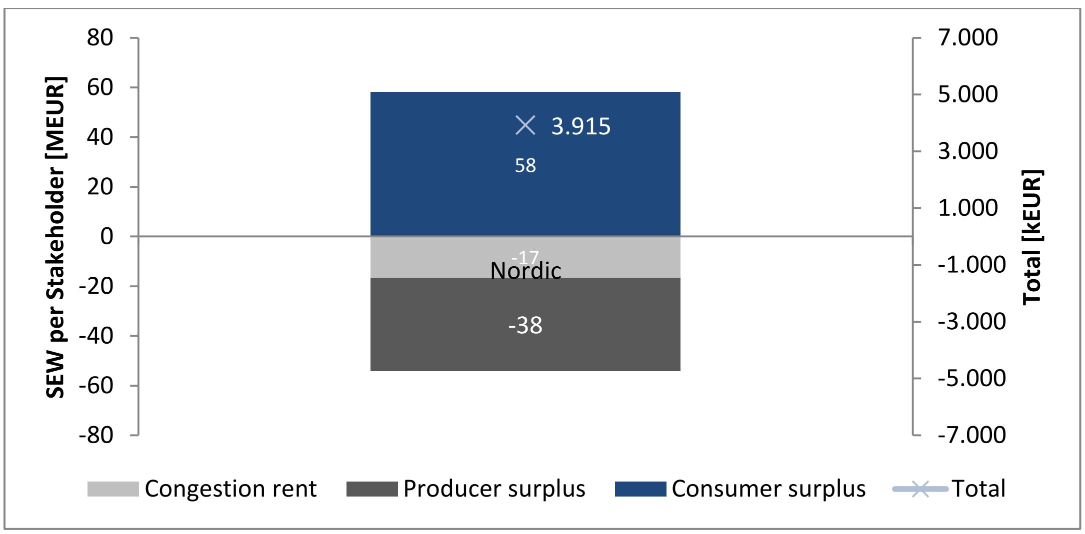


Figure 10-2 Nordic socio-economic welfare, FB compared to NTC for all simulated weeks

This indicates that FB manages to lower the prices and congestion rents by improving the capacity allocation. When looking at the results on a weekly basis in Figure 10-3 we can see that most welfare increase was generated during a few weeks. Most welfare was gained in week 3 and 43 followed by week 2, 41, 44 and 46.

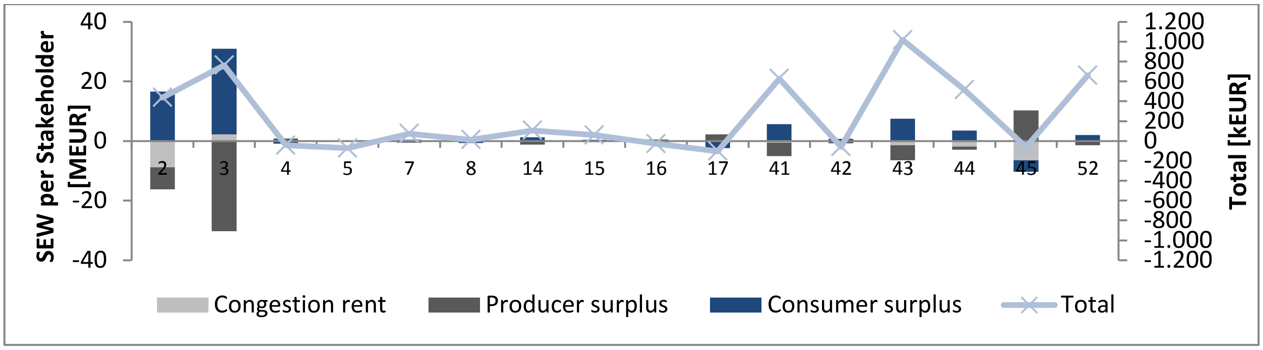


Figure 10-3 Nordic socio-economic welfare per week

The welfare gain in week 3 and 43 is driven by a drop in the average prices in most of the Nordic areas. For the other weeks there were no large differences between FB and NTC. None of the weeks shows a substantial welfare gain for NTC.Average bidding zone prices

As mentioned above the welfare results indicate that FB lowers the prices in the Nordic region. Figure 10-4 shows the average prices in the Nordic bidding zones. FB manages to lower the prices in most bidding zones compared to the NTC approach.

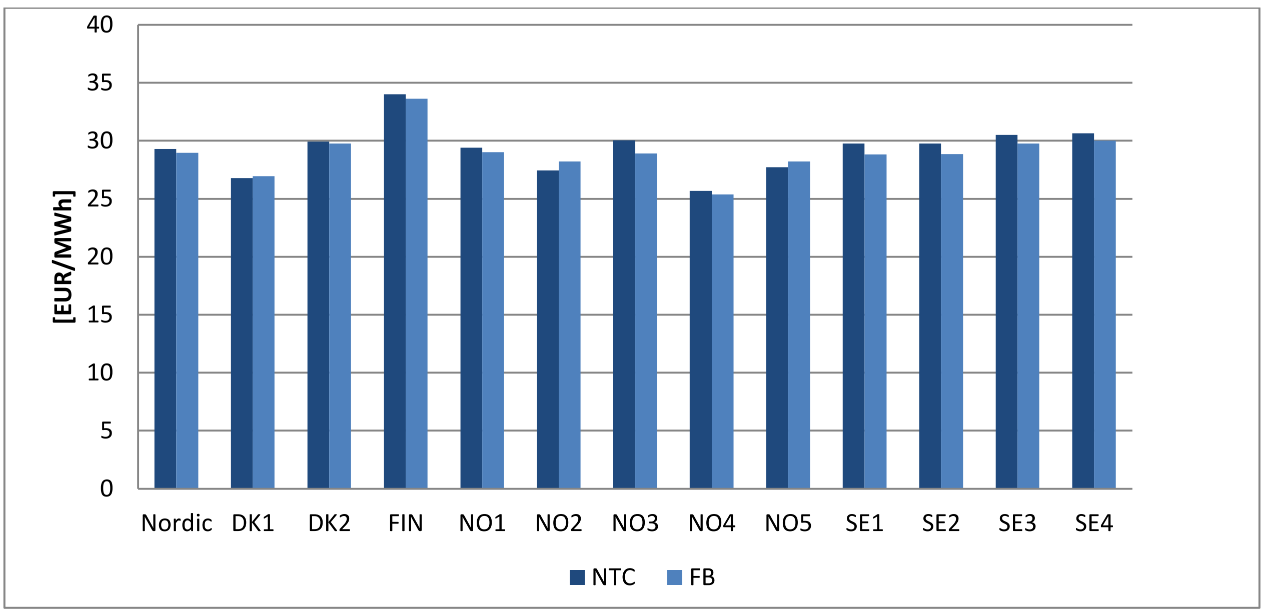


Figure 10-4 Average prices in the Nordic bidding zones in [EUR/MWh]

The average price difference between the FB and the NTC approach is below 1 EUR/MWh in most bidding zones, see Figure 10-5. The Nordic average price drops -0,3 EUR/MWh in FB compared to the

NTC approach. In DK1, NO2 and NO5 the prices increase on average, while the rest of the bidding zones face lower prices on average.

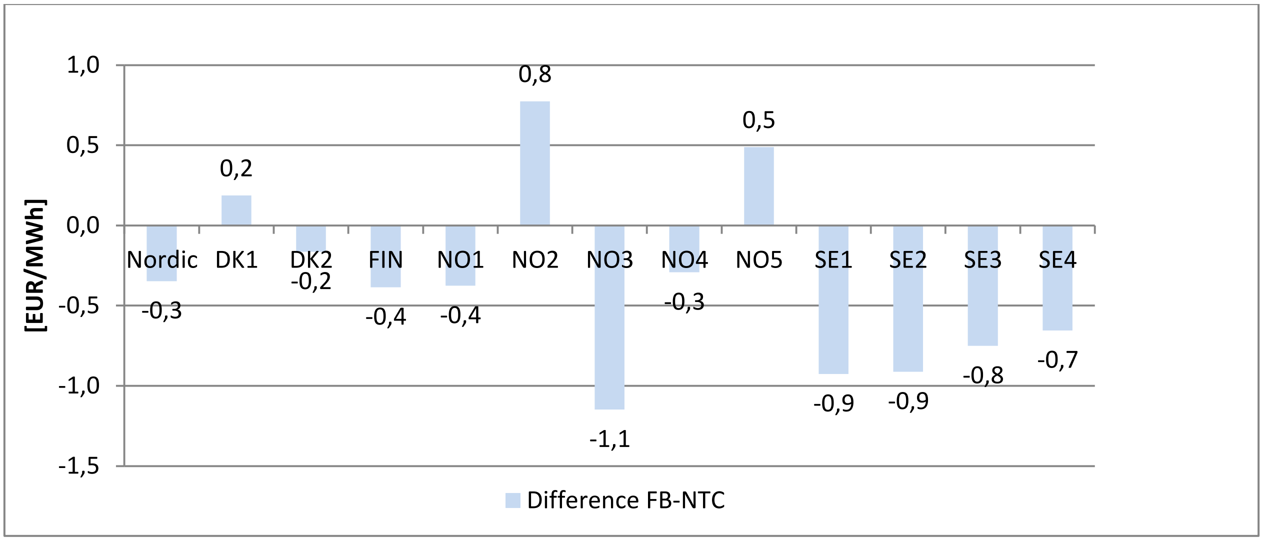
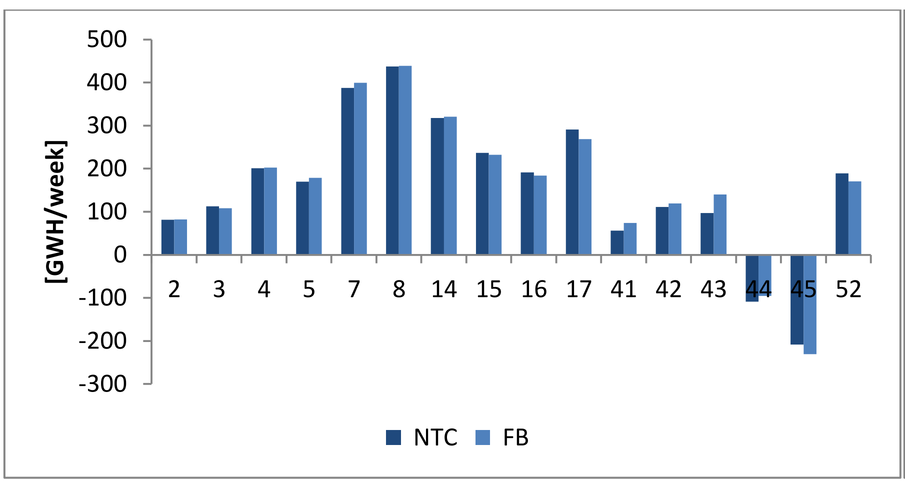


Figure 10-5 Difference average prices between FB and NTC in all Nordic bidding zones

Net positions

Figure 10-6 shows the nordic net position during the simulated weeks for the FB and NTC approach. As expected, the net position is more positive on average, i.e. more export from the Nordic region, in FB. The average weekly Nordic net position is 144 GWh in FB and 139 GWh in NTC for the simulated weeks.



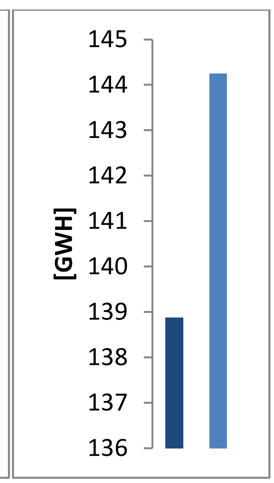


Figure 10-6 Nordic net position per week 2-5, 7-8, 14-17, 41-46 and average. The figure to the left is the weekly net position in [GWH/week]. The figure to the right is the average weekly Nordic net position in[GWh]

Figure 10-7 shows the hourly average net position in the Nordic bidding zones for the simulated weeks. FI, N01 and SE4 are the bidding zones with highest import in both NTC and FB. The bidding zones with most positive hourly average net position are NO2 and SE2 in both NTC and FB.

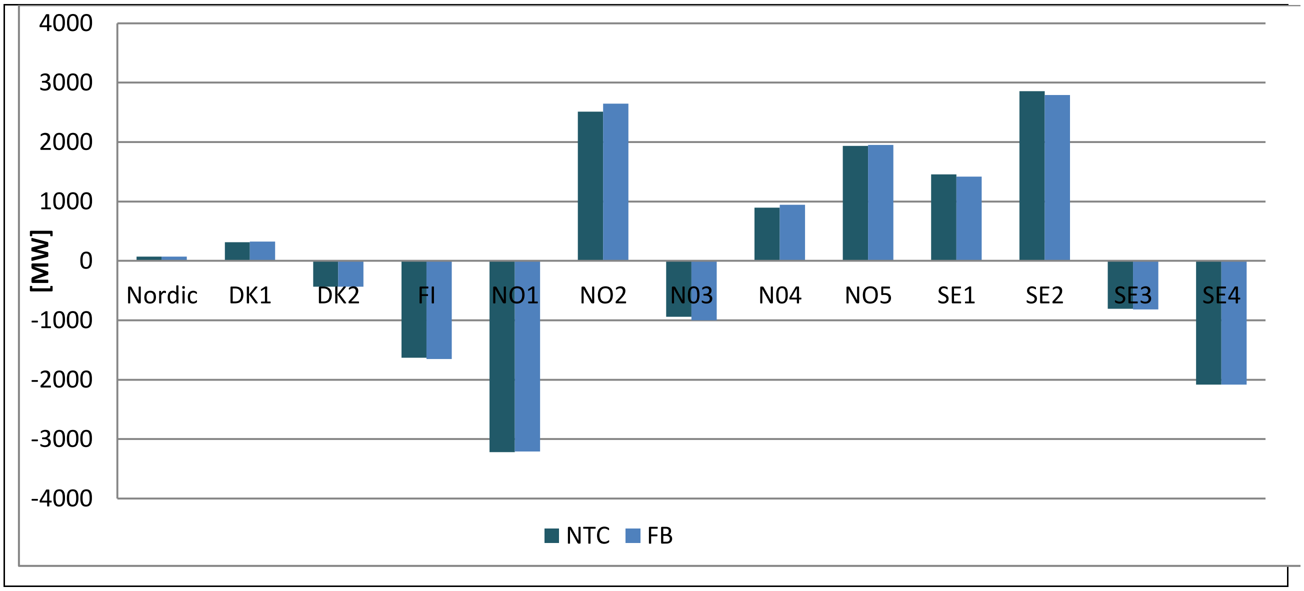


Figure 10-7 the hourly average net position in the Nordic bidding zones

Figure 10-8 shows the difference average hourly net position in the Nordic bidding zones between FB and NTC for the simulated weeks. The hourly average net position increases most in NO2 and NO4 during the simulated weeks. The hourly average net position decreases the most in NO3, SE1 and SE2. On an aggregated Nordic level the average hourly net position increases marginally in the FB solution for the simulated weeks.

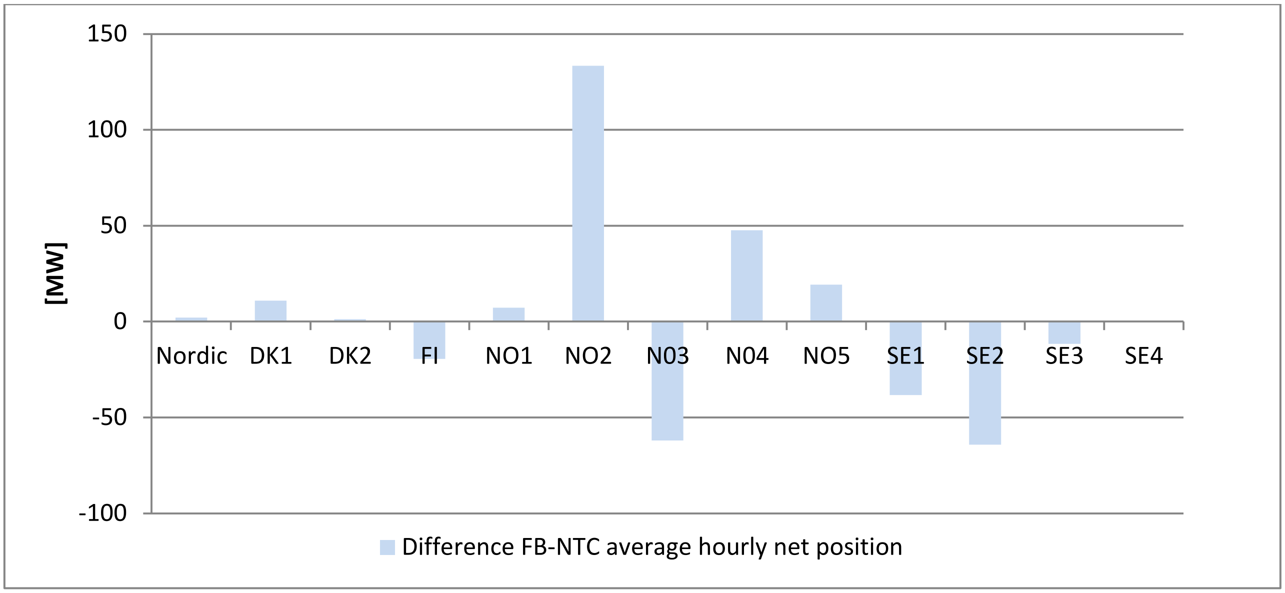


Figure 10-8: Difference between FB average hourly net position and the NTC average hourly net position in the Nordic Bidding zones for the simulated weeks

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 NTC order books are used as an input. If the export increases in FB during the first part of the weeks this is not reflected in the order books for the coming weeks.

10.1.2 Impact on capacity domains and cross bidding zone exchange

Because the allocation methodologies used in FB and NTC are different, the market results and the resulting power flows are also different depending on whether FB or NTC is used. An overload arises when the grid constraint flow resulting from the market results is higher than the RAM of this grid constraint.

The power system impact analysis presented in this section compares overloads, measured in MWh/h, resulting from the FB and the NTC allocation methodologies. The same 16 weeks as in the previous section are used.

Overloads in NTC

A number of different reasons can cause the overloads seen in the NTC market outcome. An important reason is that the NTC capacities are too high compared to the identified grid constraints. This means that NTC price coupling 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 will require the use of remedial actions to reduce the flow on these grid constraints. It can also happen if the NTC market outcome is significantly different from the forecasted market outcome 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 components such as lines, cables and transformers or planned outages where the connections and disconnections do not follow the planned schedule.

Overloads in FB

Forecasted overloads in the FB market outcome can occur on the grid constraints that were not considered in the capacity calculation process because they are not market relevant.

The number of grid constraints considered in the capacity calculation process differs between areas and hours. One grid constraint can be considered in one hour but not the next. The reason for changing from one hour to the next can be caused of topology changes which can have an impact on the PTDF that for one hour will have a big enough impact of the market flow and therefore be monitored, but in the next hour with different topology the market impact on the PTDF is to small and the CNE will therefore not be monitored. Also the TSOs can change the values of monitored CNEs between hours which also will impact the number of CNEs.

The reason for different number of grid constraints in the areas depends on net topology and operational aspects. The TSOs have different security criteria's and includes CNEs from different voltage levels and therefore the number of CNEs and different between areas. Figure 10-9 shows the average number of grid constraints provided to the power exchange for the simulated hours. The total number of grid constraints considered in the capacity calculation, and monitored for overloads is much higher.

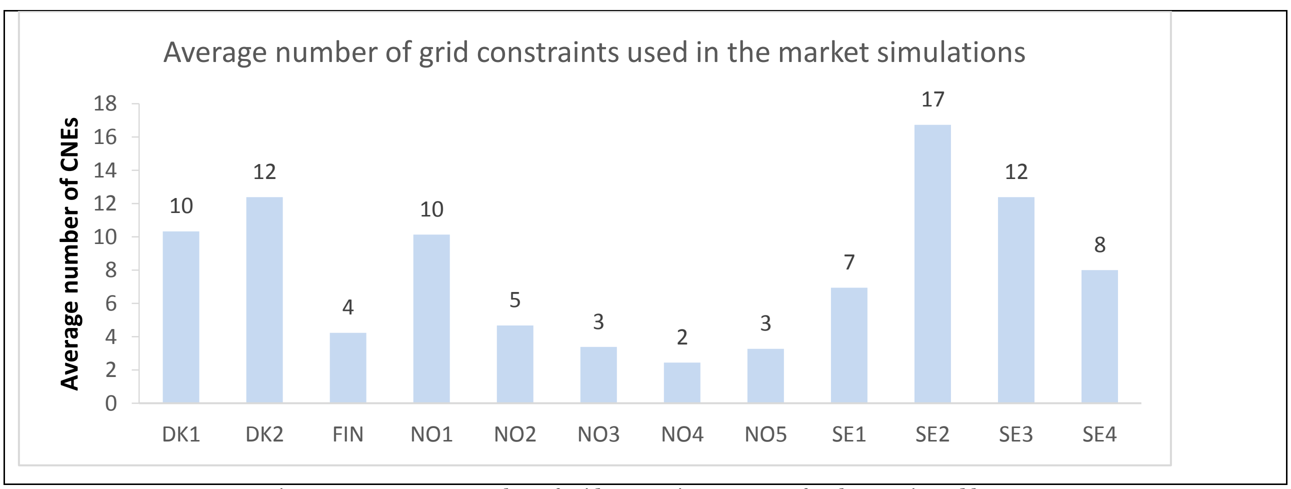


Figure 10-9 Average number of grid constraints per area for the monitored hours

Results: average overloads in FB and NTC

A comparison of the average overloads is shown in Figure 10-10. The values present the average system-wide overloads summarized for all the grid constraints. The results show a lot more overloads measured in NTC than in FB. Hours with missing FB data are removed from the NTC and FB results.

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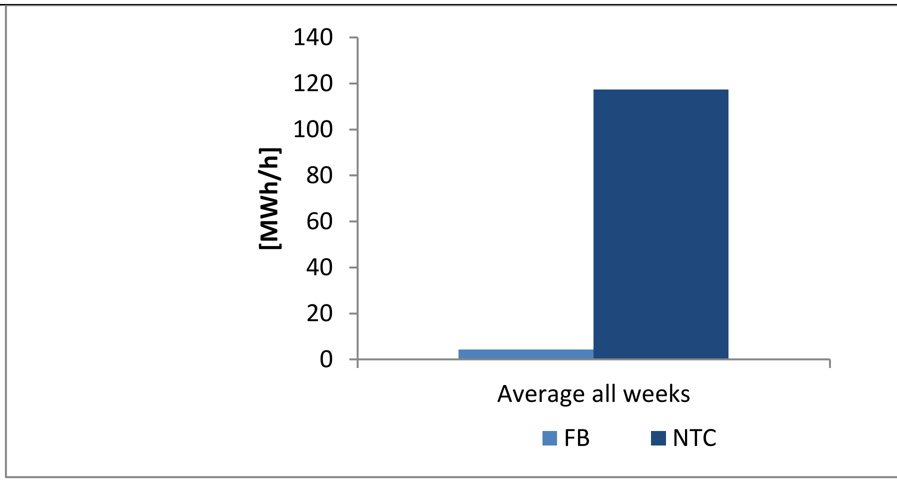


Figure 10-10 A comparison of the average overloads

The average overloads per week are shown in Figure 10-11.

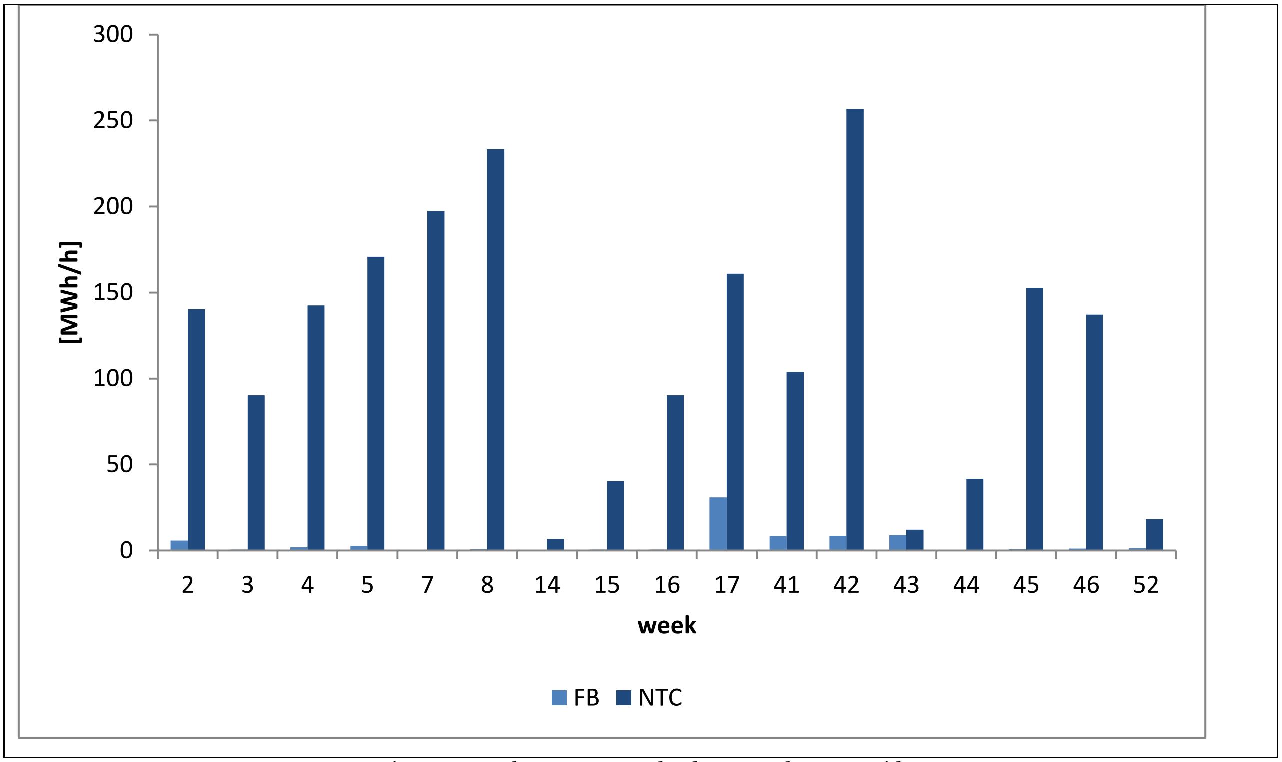


Figure 10-11 The average overloads per week systemwide

The comparison of the hourly average overloads per area is shown in Figure 10-12. The results indicate that most of the overloads measured in NTC are found in DK2, SE1 and NO4. These overloads decrease significantly in FB. The measured overloads are dependent on the number of grid constraints in the areas. A high number of grid constraints will easier lead to a high value of overload in an area. The point of the figure is to show the difference between FB and NTC. The grid constraints and the attached Fmax are the same in FB and NTC.

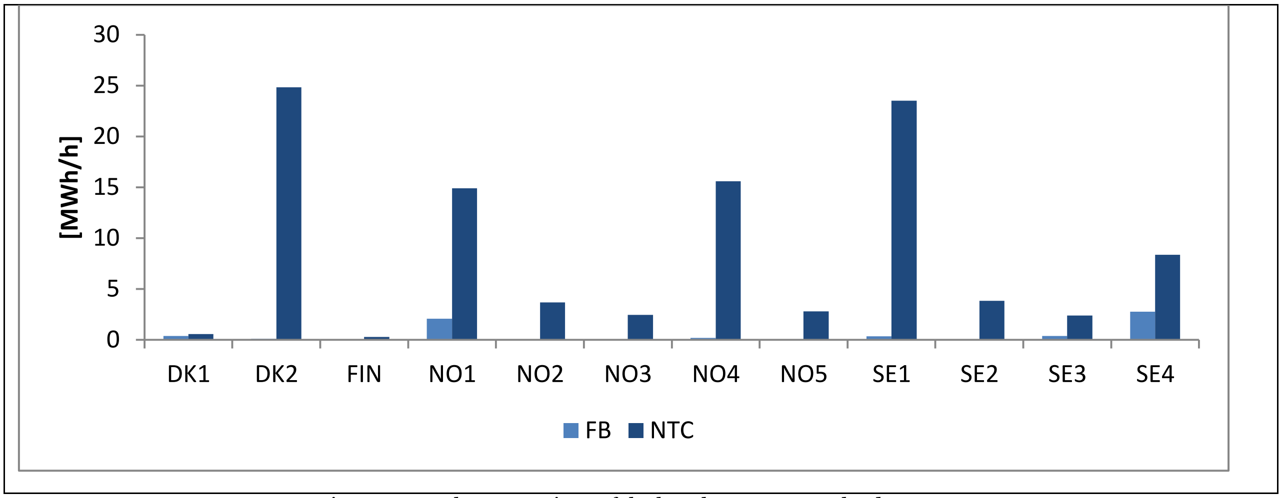


Figure 10-12 The comparison of the hourly average overloads per area

Results: Economic gain VS grid overloads

The total welfare and the net reduction in overloads are plotted in Figure 10-13. Each of the blue dots represents one hour of the 16-week period used in the power system impact analysis. In contrast, the results presented before in Figures 25 and 26 are average results per area or per week..

Values above the x-axis are representing a positive total welfare in FB compared to NTC and the values under the x-axis are representing a negative total welfare in FB compared to NTC. The values to the right of the y-axis are representing the reduction of overloads in FB compared to NTC. The values to the left of the y-axis are representing the increase of overloads instead. Therefore the values in the upper corner to the right are representing a positive total welfare and reduction of overloads in FB compared to NTC. The values in the lower corner to the left are representing a negative total welfare and increase of overloads in FB compared NTC.

The figure also shows the proportion of hours in each quadrant. For example is the upper right corner including 48.3 percent of all hours and the lower right corner 38.3 percent. The upper and lower left corner includes 9.0 percent and 1.7 percent respectively. The hours that are placed exactly on an axis are not included in a corner. The hours placed on the x-axis contain no difference in total welfare for FB compared NTC. Same goes for the hours placed on the y-axis since these hours contains no difference in net reduction in overloads. In Figure 10-14, that shows a zoom of Figure 10-13, we see that the majority of the hours are in the upper right corner.

The average and median values are in that same corner. In the 16-week period used in the impact analysis, FB resulted in an average gain in welfare of 1404 €/h and an average reduction in overloads of 118 MWh/h, compared to NTC. Therefore, for this 16-week period, FB performed better both in terms of market welfare and avoided overloads.

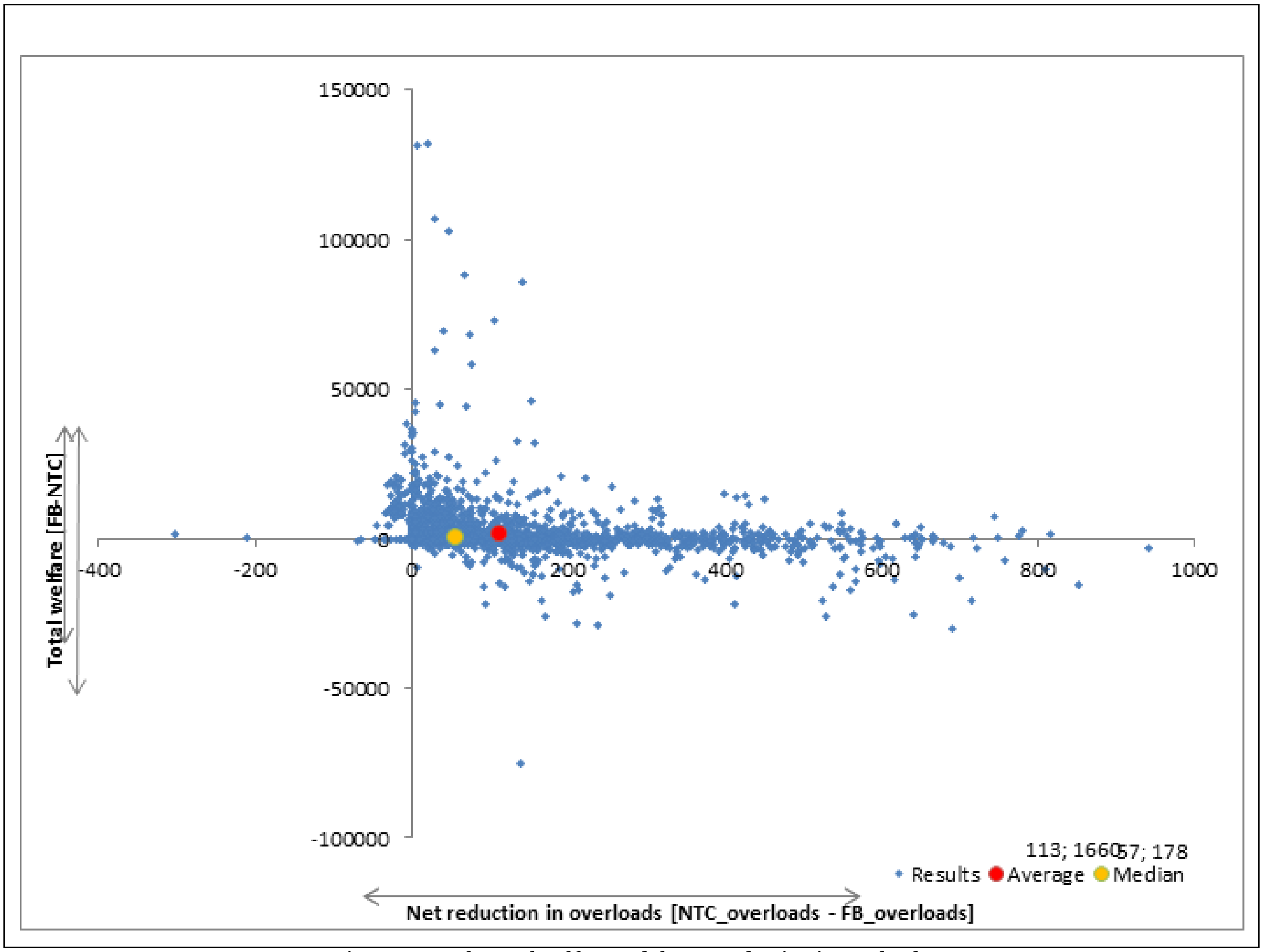


Figure 10-13 The total welfare and the net reduction in overloads

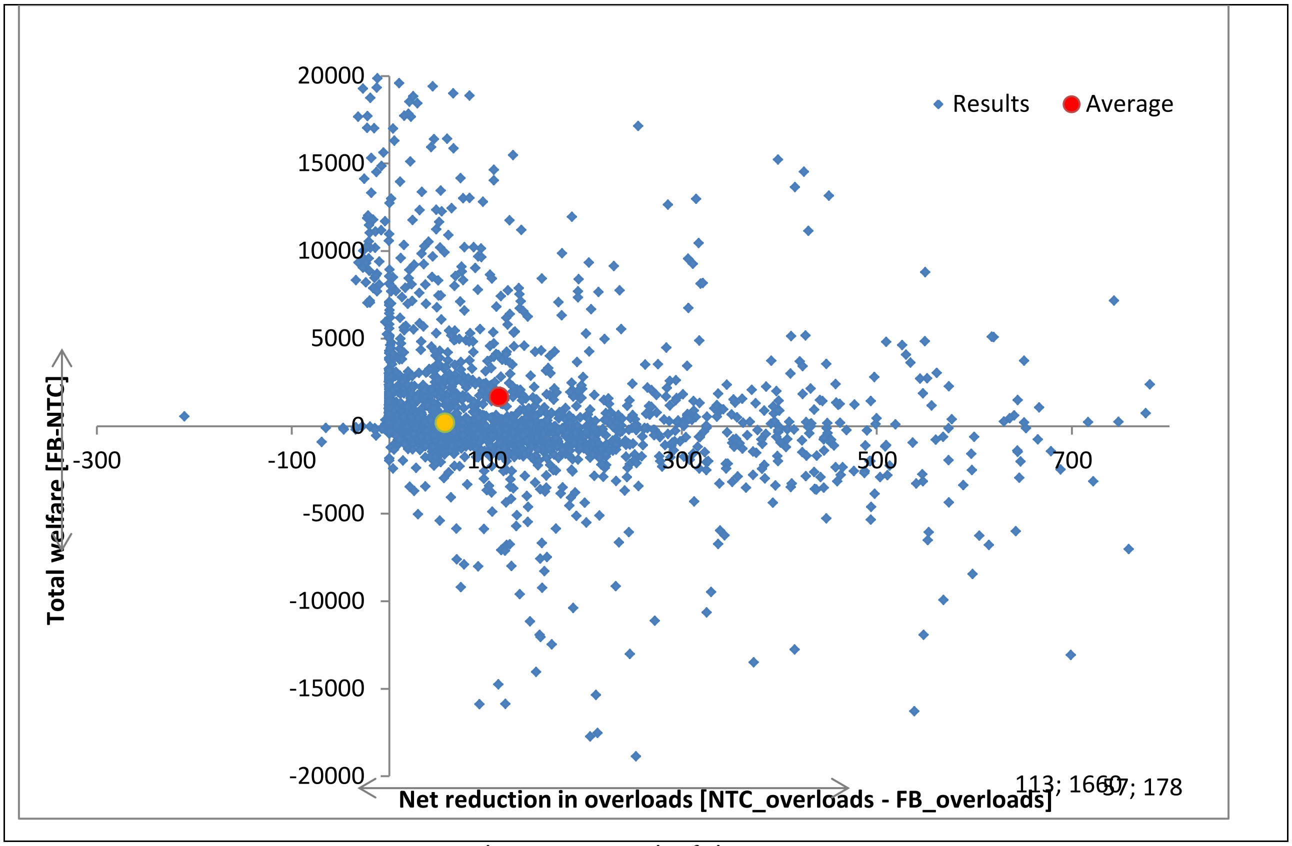


Figure 10-14 Zoom in of Figure 10-13

10.1.3 Selected cases illustrating FB benefit (in detail)

The objective of this section is to provide a more in-depth understanding of the difference of FB compared to (C)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 capacity on a new line between bidding zones NO3 and NO5
- Better management of the West Coast cut in Sweden

One case of non-intuitive flow

In this case we show how non-intuitive flows can occur in FB and enable a larger flow between SE1 and SE2. In Figure 10-15, we show a simplified example of an hour with high consumption and low wind production in the Nordic countries. The bidding zone prices are highly affected by a grid constraint with a high shadow price (see also section 10.2.5) between SE2 and SE3. To relieve this congestion, the FB solution reduces the flow on the border between SE2 and SE3 and increases the flow on the border between SE1 and SE2. The increased transaction between SE1 and SE2 has a relieving impact on the limiting grid constraint, i.e. the PTDF-margin is negative for trade between SE1 and SE2.

In the NTC approach EE, DK2, FI, NO1, NO3, NO4, SE1-4 constitute one price area and NO2, NO5 and DK1 constitute one price area. 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.

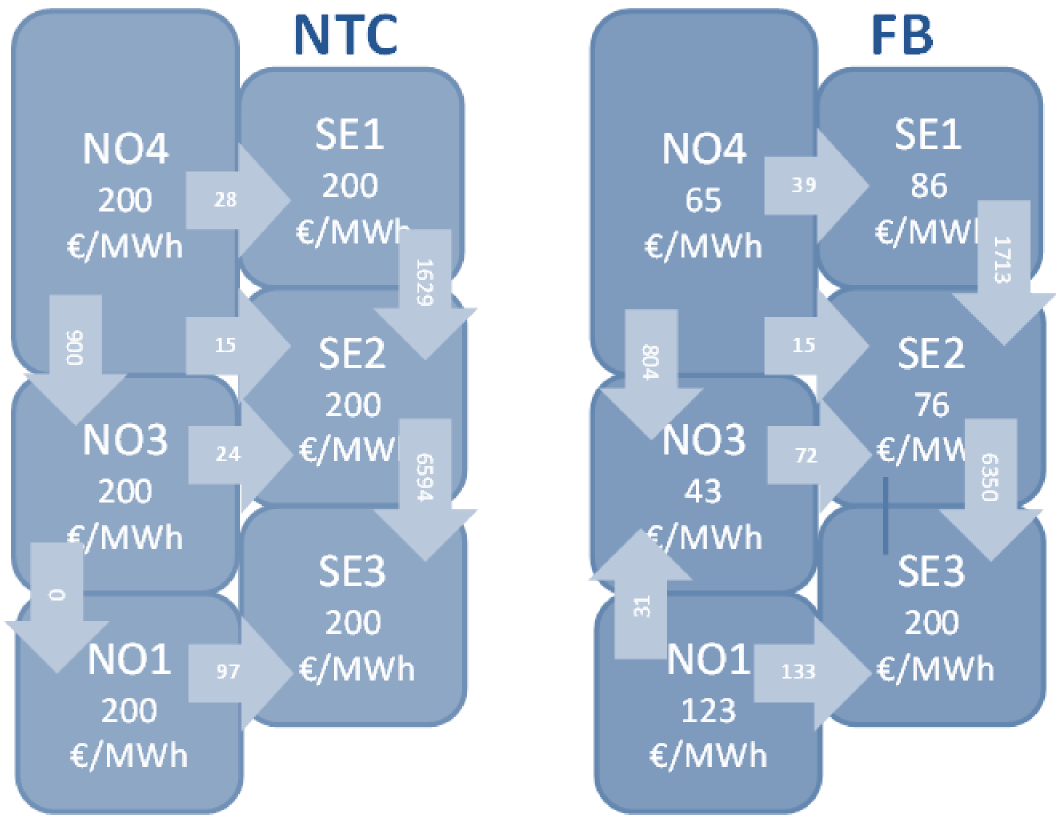


Figure 10-15 Simplified example with non-intuitive flow between SE1 and SE2

Case study NO3-NO5 (Ørskog-Sogndal)

During 2016, Statnett has taken a new transmission line - connecting the bidding zones NO5 and NO3 - in operation, see Figure 10-16. 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.

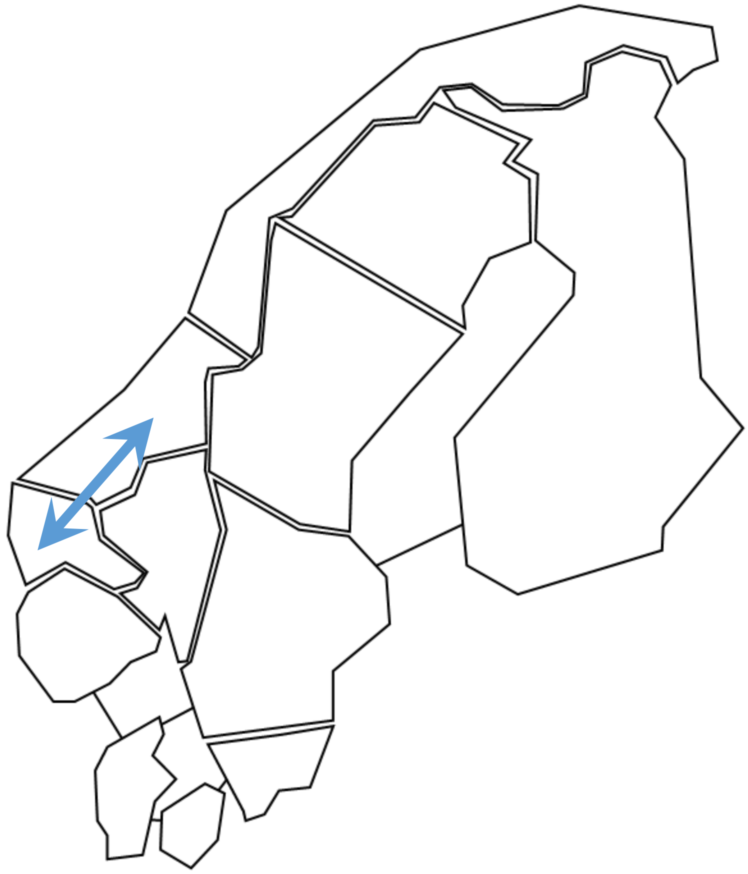


Figure 10-16 The line Ørskog-Sogndal (NO3-NO5)

The new line will provide 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.

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

How can FB capacity allocation improve the situation?

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.

More information regarding the model set up and assumptions are given in the Annex section

We have, as a starting point, made the assumption that the market flows on the borders that were congested in the historical market outcome were not allowed to increase, while the rest of the borders were considered open for additional trade. In the initial NTC solution, NO3, NO4 and the Swedish bidding zones constitute one price area with a lower price, whereas NO1, NO2 and NO5 constitute one price area with a higher price, see Figure 10-17.

The effect of adding 100 MW NTC 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 NTC market outcome.

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

The figure below shows the realized physical flows resulting from the commercial NTC exchanges, referenced to the original market outcome in the NTC approach.

From Figure 10-17, one can tell that 100 MW additional capacity for commercial exchange between NO3 and NO5, leads to a 74 MW increased load on the already-congested line NO1-SE3, while 9 MW goes from NO3 to NO1. Only 16 MW of the 100 MW additional commercial exchange appears as physical flow on the new interconnector between NO3 and NO5. The price in NO3, NO4 and the Swedish bidding zones increases marginally and the price in NO1, NO2 and NO5 decreases slightly.

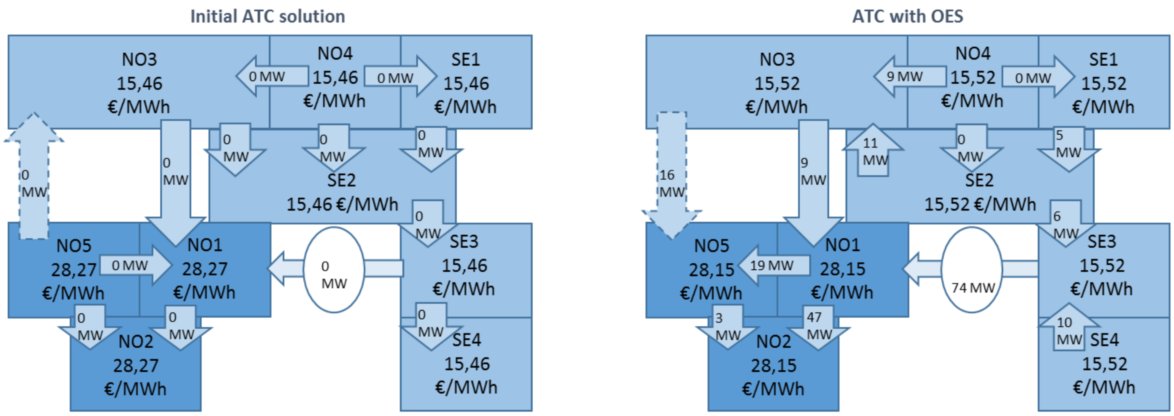


Figure 10-17 CNTC results for hour 4 on 25.12.2013. The prices are shown inside the boxes, and the colors indicate the price level. The physical flows resulting from the commercial exchanges are shown referenced to the initial market outcome.

The FB market solution for the same hour is shown below, in Figure 10-18. The flows are referenced to the same historical market outcome, and it's clear from the figures that there is no increased load on the line NO1-SE3, even though the market outcome has improved significantly in terms of socio-economic surplus. The improvement is due to a significant increase in the flow between the low-price areas (Sweden and Northern Norway) and the high-price areas (Southern Norway). FB manages to increase the flow on NO3-NO5 and NO3-NO1, while avoiding increased load on NO1-SE3, by increasing the NP in the north-west and reducing the NP in the south-east. The NPs in all areas are adjusted to maximize the flow into Southern Norway, and thus to create a better market outcome.

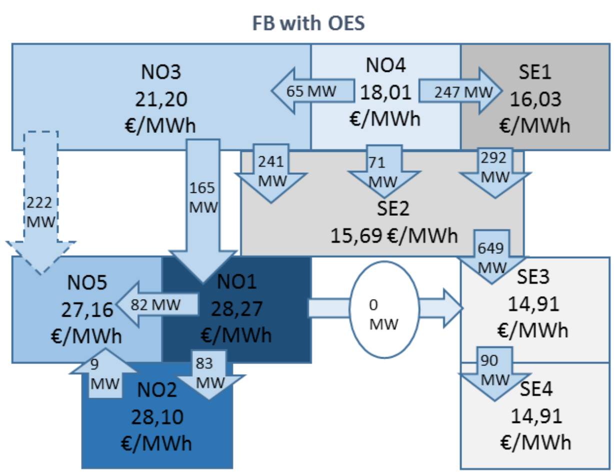


Figure 10-18 The prices are shown inside the boxes, and the colors indicate the price level. The physical flows resulting from the commercial exchange are shown referenced to the initial market outcome.

West-coast cut

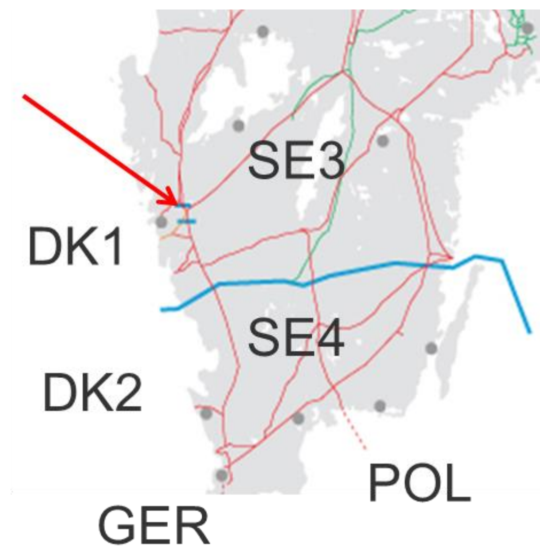
The current congestion management routine for the West Coast Corridor (see Figure 10-19) is based on a pro-rata approach where the trading capacity is limited on relevant interconnectors, in order not to overload the West coast corridor. The trading capacity is limited in proportion to a pre-defined dimensioned capacity for each interconnection. Today the capacity is limited on the following interconnections:

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

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 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 I 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 border to 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 flow over the west coast corridor. Hence, it is difficult to treat this congestion with the same principles as for the rest of the corridors, i.e. bidding zones.

Figure 10-19 The arrow shows the location of the West coast corridor

How can FB capacity allocation improve the situation?

By applying FB capacity allocation to the West coast corridor the flexibility would increase. Instead of the TSO deciding ex ante how much each interconnector should be limited based on a pro rata principle (CNTC), it is the capacity allocation mechanism that manages the congestion on the West coast corridor while maximizing social welfare (FB). This means, that the 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 have a market outcome that better takes into account the real physical flows in the grid. By applying PTDFs to all bidding zones and DC interconnectors, the FB approach would take into account how an increased flow on a specific DC interconnector would impact the West coast corridor. Instead of treating all the flows as they would have the same impact on the West coast corridor, the market algorithm can allocate more capacity to bidding zones and DC interconnections with lower impact on the West coast corridor, and reduce the allocated capacity to the bidding zones and interconnections with the highest impact, if this increases the total social welfare.

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

In Table 10-1, the results are presented for an hour where the west coast corridor severely limited the import capacity on the interconnectors. In the table the available capacities in the NTC approach are presented.

Table 10-1 The available capacities on the interconnectors 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 10-20 shows the result when the present congestion management method (NTC) and FB are used in the west coast corridor. In NTC, 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.

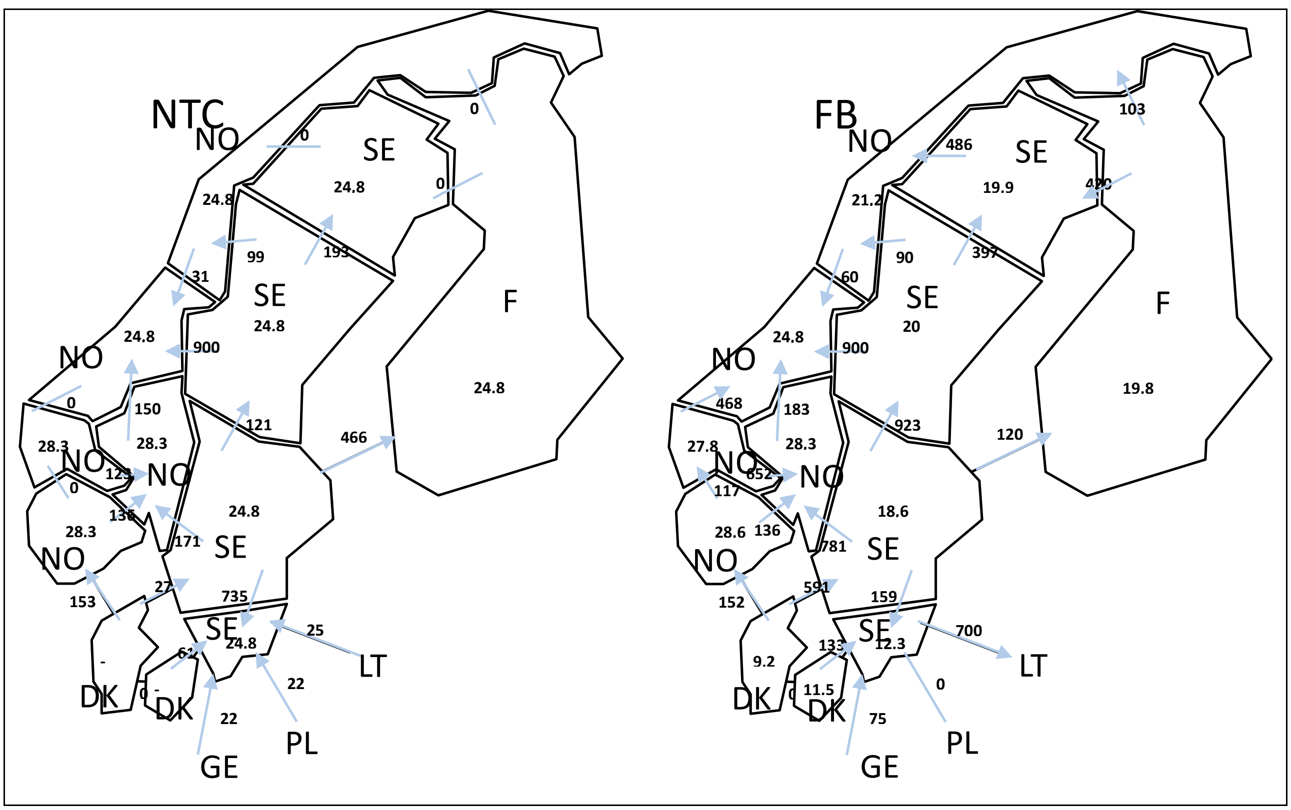


Figure 10-20 Management of congestion in the west coast corridor in NTC and FB. Results from hour 2016-12-26 23:00:00. Prices are shown in €/MWh and flows (arrows) are shown in MW.

In the FB solution there is no ex-ante capacity split between different interconnections. Instead, the market algorithm can choose to which interconnections the flow should be allocated based on the least generation cost for the whole system. Sweden gets a lower price compared to the CNTC solution in all zones, but now the prices differ between the bidding zones, see Figure 10-20. The flows from Denmark and Germany have increased and SE4 has an export flow on NordBalt. Denmark gets higher prices because of the increased export flows to Sweden.

10.2 Qualitative impact assessment

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

10.2.1 Impact on other electricity markets

According to the CACM regulation, the FB approach should, if implemented, be applied in the Day-ahead and Intraday markets. Other electricity markets, i.e. the balancing market and financial market are not in the scope of FB implementation. The implementation of FB 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. Indeed, the day-ahead market is the main market for power trade and the outcome 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 section the impact in terms of mainly the efficient functioning of these markets, by implementing FB in the day ahead marked, 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 players to forecast future System and spot prices*. The objective of the market for risk management is to hedge against future unexpected price volatility. The task is therefore to assess, whether market players are able to do a proper assessment of the future prices by implementing FB 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.

Regulating power 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 FB in the day ahead market distort the possibility for efficient regulation.

In addition, for the regulating power market it will be explained that in some situations the adverse balancing flows and the associated costs will be impacted by the more frequent occurrence of so-called non-intuitive flows (flows from high price to low price in the Day-ahead market) in the FB approach.

10.2.2 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 spot price future. The spot price future or Electricity Price Area Differential (EPAD) is to hedge an unexpected future difference between the system price and the spot price. These instruments are traded through Nasdaq OMX with a time horizon up to ten years. Assessing the impact on pricing of these instruments by FB has to be done assessing how the new management of grid constraints and flow (NTC→FB) may impact the transparency, hence impacting the possibility of put a "true" value on a future system price/spot price.

For the forecasting of system price futures it is concluded that implementing FB does not have any impact on transparency on forecasting as the grid contraints in the Nordic power system does not have any impact on the system price. However, FB might provide more capacity on the interconnectors between the Nordic CCR and Core CCR, hence it might have an impact on price level compared to a reference of CNTC, but not on the ability of market players to do a forecasting of the future system price. The impact from external interconnectors on the future system price cannot be expected to be more difficult to assess compared to todays situation.

For the forecasting of spot prices or bidding zone price it is concluded that FB probaly 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 spot 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 task for the market players (as it is today) is to forecast the netposition of the bidding zone, in order to identify the marginal generator. For that reason and to comply with CACM article 20.9, the TSOs will provide a tool that enables market participants to evaluate the interaction between cross-zonal capacities and cross-zonal exchanges between bidding zones. A draft version of such a tool has been provided by the Nordic TSO called the Stakeholder Information Tool[18].

10.2.3 The Balancing market

In this section, we describe the impact on the balancing market by introducing FB in DA market. As mention in the introduction, the Nordic balancing market will not be in scope for the implementation of FB. This implies that the basic fundamentals of the balancing market will be the same as today, i.e. an NTC like method will be used as capacity calculation method regardless of the chosen method in DA (FB or C-NTC). The capacity calculation will remain as today where the operators in the control centers will continue to assess the available capacity in the grid based on the grid utilization. The Total Transfer Capacity may differ from DA and ID since the conditions may have changed between forecast and operational hour. The operational staff will continue to monitor that the capacity limits are not exceeded and in case that occurs market splitting in the balancing market or counter trade measures are used.

The implementation of FB may, however, have some impact on the pricing principles in the balancing market since there is a close financial and physical link between the DA and ID market and the balancing market. In the balancing market, the day-ahead bidding zone prices are used as reference for the prices in the balancing market. In the present NTC system, two bidding zones get the same price when there is no congestion between them. If congestion occurs between bidding zones it leads to different prices in the bidding zones. The up-regulation price cannot be lower than the DA area price (the bid can be lower but will be adjusted) and the down-regulation price cannot be higher than the DA area price (the bid can be higher but will be adjusted). Special regulations are used to manage bottlenecks in the transmission network within bidding zones or to guarantee the allocated capacity. These measures do not have a direct impact on the balancing price as they are settled as bilateral trade between the TSO and asset owner.

The balancing market doesn´t rely on the same capacity calculation method as applied for the DA and the ID time frame. The TSOs are obliged to operate the power system in a secure manner and this is fulfilled by performing capacity calculation when needed. This means that the results of capacity calculation can change for each market time frame and that there may still be capacity to use for balancing regulations although all available transmission capacity provided to the DA and ID time frame has been allocated.

The main differences between FB and (C)NTC for the balancing market, is the potential more frequently occurrence of non-intuitive flows from a high-price to low-price area, and that two areas can have different prices although the capacity between them are not fully utilized in FB. This may have an impact

[18] *See also section 10.2.7.*

on the pricing principles of the adverse imbalance flow as well as how the power system is operated, as explained below.

Impact on pricing principles in the Balancing market

If FB is implemented in the day-ahead market, some of the principles that are in place today need to change, e.g. there may be different regulation "reference" prices in two bidding zones although there is no congested critical network element on the border between them, but instead somewhere else in the Nordic grid. The different "reference" regulation prices depend on that the areas have a different impact on the critical network element. This is illustrated in the simplified example in Figure 10-21, and it will be explained how this leads to a situation where cheaper bids cannot be activated.

In the example, we have a congested grid constraint in SE3 and a market-induced congestion, i.e. price difference between SE1 and SE2. There is no congested critical network element between SE1 and SE2 in the DA market, but SE1 and SE2 have a different impact on the grid constraint, which leads to different area prices.

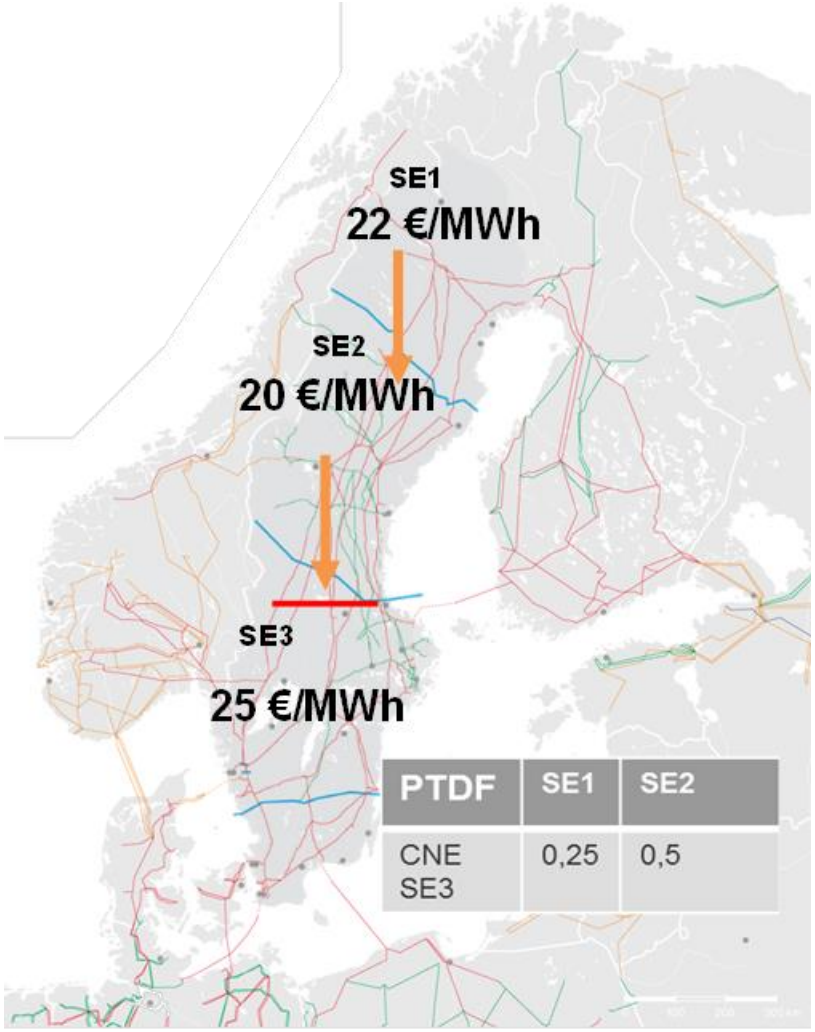


Figure 10-21 Example of impact on balancing pricing principles

If the system is in balance, the imbalances in each bidding zone will be settled on the reference price, i.e. Day-ahead price if the system is balanced. If changes in the system between DA and balancing market relieve the congestion on the grid constraint, SE1, SE2 and SE3 will get the same regulation price. All the bids are merged into the same merit order list and can be activated based on price. The bids in each bidding zone are adjusted in line with current pricing principles. This implies that the up-regulation price cannot be lower than the DA area price (the bid can be lower but will be adjusted) and the down-regulation price cannot be higher than the DA area price (the bid can be higher but will be adjusted).

If we assume that the system is under balanced (production shortage) and we need to activate up-regulation bids in order to balance the system. In Table 10-2 we show the available bids.

Table 10-2 Available balancing regulation bids

Bidding zone	Available up-regulation bids
SE1	23 €/MWh
SE2	21 €/MWh

The same grid constraint that is congested in the DA market coupling is congested in real time and there is no congested critical network element between SE1 and SE2. If SE2 is under balanced, a regulation can take place in SE2 to the price of 21 €/MWh, i.e. SE2 gets up regulation price (21 €/MWh) and SE1 gets 22 €/MWh (in balance and reference price from DA used) even though cut 1 is not fully utilized. If SE1 is under balanced, a regulation cannot take place in SE2. Instead a more expensive regulation is activated in SE1 instead of the cheaper bid in SE2.

In the current NTC market SE1 and SE2 would - in this specific case - get the same price in the DA market since there is no congestion between SE1 and SE2. The price in SE3 may be higher in CNTC than in FB. For the balancing market it means that the TSO could choose whether to activate the bid in SE1 or the bid in SE2. When activating the bid the TSO needs to take into consideration that this activation does not cause overloads in other parts of the Nordic system.

Operational tools
In the light of a more detailed capacity calculation method that has a resolution on individual grid constraint level, there may also be a need for operational tools that can monitor how potential activation of location specific bids in the balancing market affect individual grid constraints. This may be required as two bids in the same bidding zone may have a different impact on the critical grid constraint. The risk is otherwise that the activated balancing regulations need to be supplemented with additional remedial actions in order to manage the congestions created by the activation of bids in the balancing market.

10.2.4 Bidding zone delimitation

This chapter describes the potential impact of choosing a flow-based approach on the Nordic bidding zone delineation. As described above, FB differs from CNTC by the explicit use of PTDFs in the price/quantity calculation at the PX: FB interlinks the contractual path to the physical path. In this way all commercial exchanges – that are subject to the allocation mechanism - compete for the scarce capacity in the AC grid. As it is the bidding zone definition that defines which exchanges are subject to the allocation mechanism, the interlink between the two topics "bidding zone delineation" and "FB" surfaces. In this section it will firstly, by the use of a generic model, be shown that, while implementing a flow based capacity calculation method does not necessarily require to change the number - or delineation - of bidding zones, it might in some cases be beneficial to do so in order to increase the overall socioeconomic welfare in the region. Secondly, some reflections will be provided on the question to what extent the observations made for the generic model are applicable to the Nordic region.

Why FB implementation might alter bidding zone configuration

In FB, exchanges that are subject to the allocation mechanism are all competing for the scarce capacity made available within the allocation mechanism. Exchanges that are outside the allocation mechanism are all exchanges of which the impact is taken into account before the allocation mechanism itself, i.e. exchanges that can be said to enjoy a 'priority access' and that are exempted from the competition element within the allocation mechanism.

Consider the example in Figure 10-22, where the surplus and shortage areas are indicated, and a commercial exchange internally in bidding zone C (and therefore not subject to an allocation mechanism), 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 illustrated in Figure 10-22, where the yellow arrows correspond to flows that are caused by exchanges that are not subject to an allocation mechanism (unallocated flows). The grey arrows correspond to flows that are caused by exchanges that are subject to an allocation mechanism (allocated flows).

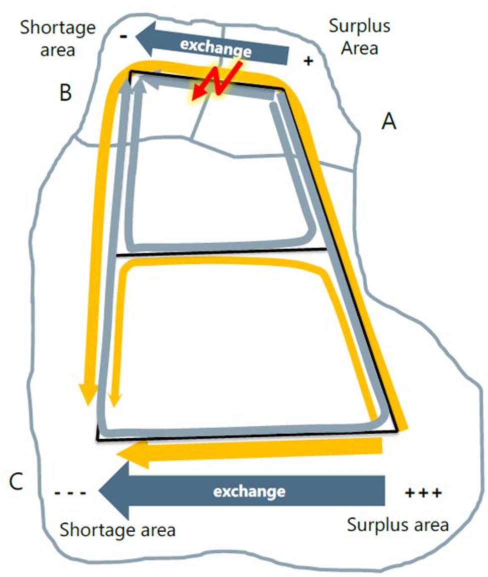


Figure 10-22 Non-allocated flows (yellow arrows) resulting from an internal exchange in bidding zone C

The example in Figure 10-22 shows that the flows resulting from the commercial exchanges (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 (coordinated) FB capacity calculation stage of this three-zone region, the flows that result from all unallocated exchanges, i.e. the exchanges that are not subject to the regional allocation mechanism, are forecasted (in the common grid model) in order to assess the capacity that can be given to the allocation mechanism and used by the market. The exchange within zone C is an intrazonal one, and is not subject to the allocation mechanism. This means that in the capacity calculation stage, the (forecasted) impact of this exchange needs to be taken into account. As such, the flows resulting from this intrazonal exchange receive a priority access to the grid and reduce the capacity available on the border between A and B that can be given to the allocation mechanism. The exchange between zone A and B is subject to the regional allocation mechanism. It is this exchange that will be reduced in order to prevent the congestion on the border between A and B.

When in country C a new bidding zone would be introduced, zone D, which separates the source and the sink of the former intrazonal exchange within zone C, the former unallocated exchange is turned into an allocated one as it is made subject to the regional FB allocation mechanism, as shown in Figure 10-23.

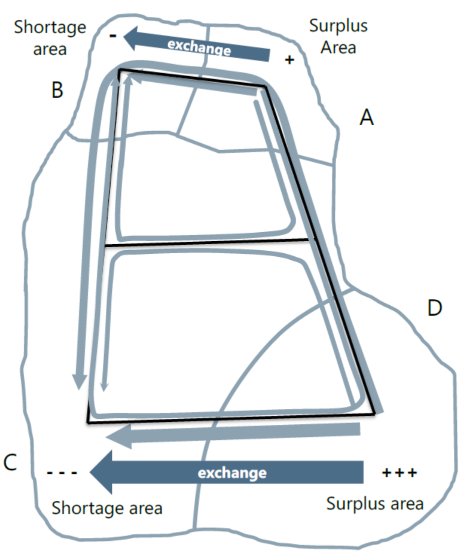


Figure 10-23: The unallocated flows in Figure 10-22 (yellow arrows) have been translated into allocated flows (grey arrows) by splitting the former bidding zone C into two bidding zones: C and D.C

In this situation, both the exchanges between zone A and B, and between zone D and C compete with one another to make use of the scarce 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*NetPosition(A) – 0.6*NetPosition(B) + 0.3*NetPosition(D) – 0.3*NetPosition(C) ⩽ 1000 MW. This formula illustrates that all exchanges within the allocation region compete for the scarce capacity as the NetPositions are defined by the net exchanges of the bidding zones. It is now an outcome of the regional Day-Ahead market welfare optimization, i.e. a market driven mechanism, which exchange will be reduced and to what extent. In principle both exchanges might be reduced in order to prevent the congestion on the border between A and B.

Note that in an NTC allocation mechanism 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 exchange without any problems, the NTC between zones C and D might be so large, that it does not limit the exchange 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 an allocation mechanism. In combination with a FB capacity calculation and allocation mechanism, where all exchanges that are subject to the allocation mechanism compete with one another to make use of the scarce capacity, an efficient allocation can be achieved.

Can implementation of FB be expected to have an impact on the Nordic BZ delineation?

Regardless of which capacity calculation methodology that is chosen in the Nordic CCR, 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 capacity calculation methodology. One of the major differences between (C)NTC and FB is the ability to include internal constraints directly in the capacity allocation. In FB, in difference to the CNTC approach, these constraints can be included directly as critical network elements in the capacity allocation, if they are significantly impacted by cross-border trade. If FB is implemented, it will provide more detailed information, such as shadow prices, and which critical network elements are (most) limiting the market. This information may be useful when answering the question how the bidding zones should be configured.

The Nordic system already has – especially in the meshed part of the Nordic grid – multiple, comparably-sized, bidding zones. As such, the reasoning that we followed in the generic example above, is not automatically applicable to the Nordics. This is demonstrated in the following reasoning. The FB capacity calculation is based on a common grid model. In this common grid model, the expected situation for the respective hour of Day D is reflected, including the generation and consumption in the different bidding zones. As explained in Section 5.1.2, the flows on the grid constraints are taken from the grid model (Fref) and translated into the Fref', being the flows on the grid constraints when all bidding zones have a zero net position, by means of the PTDFs. In Figure 10-24, the flows on the AC borders in the Nordic grid are shown when all bidding zones have a zero net position. As expected, the non-allocated flows on the AC 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 border), and do not provide a direct reason to reconsider the bidding zones.

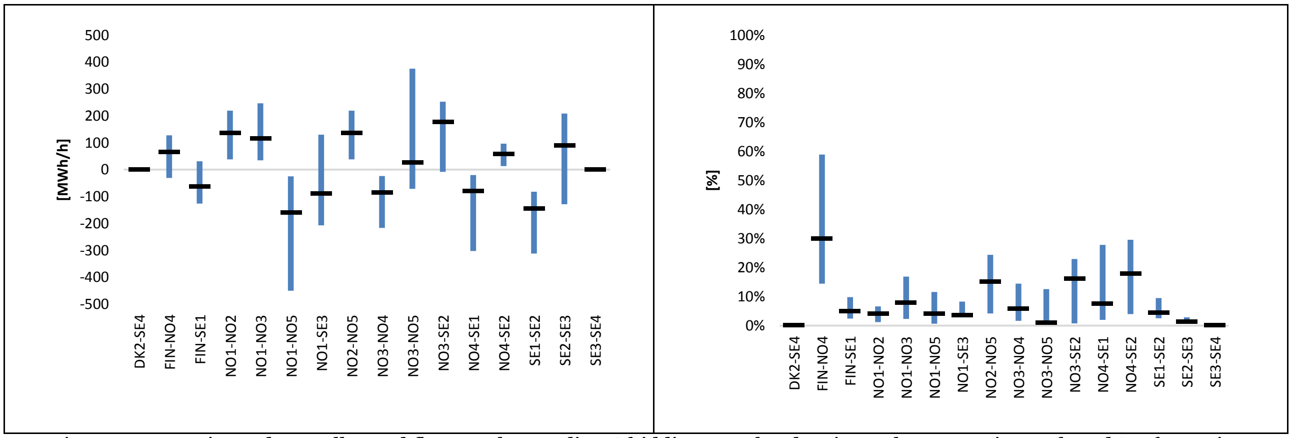


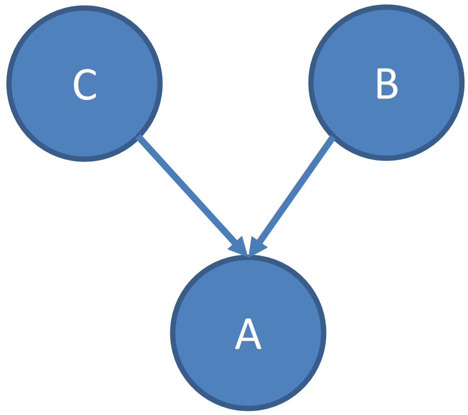
Figure 10-24 Estimated non-allocated flows at the Nordic AC bidding zone borders in week 52, 2017 in MWh and % of capacity

10.2.5 Non-intuitive flows

This chapter describes non-intuitive flows and the price formation that might happen in FB. In FB, flows from a high price area to a low price area, so called non-intuitive flows, occur more often compared to NTC and CNTC in the results from the market coupling algorithm. The market coupling algorithm aims to maximize the social welfare over the whole system. Non-intuitive flows relieve the congestion on the constrained grid element and enable more flows between other bidding zones, that brings more social welfare to the whole system welfare compared to a situation where they are not allowed. With CNTC constraints, the market coupling algorithm cannot take into account how trades in all bidding zones affect the critical network elements. It is only the two concerned bidding zones with the interconnection that can have an impact on the flow on the border.

With FB constraints the market coupling algorithm allows all transactions to compete for the scarce capacity on the critical network elements. How the transactions affect the critical network element is shown by the PTDF-matrix.

In the example below (see Figure 10-25) we show how the critical network element is affected by a trade from bidding zone C to bidding zone A and from bidding zone B to bidding zone A. Each MW that is traded from bidding zone B to bidding zone A relieves the congestion on the critical network element inside bidding zone A. Each 1 MW between bidding zone B to bidding zone A enables 0,3 MW exchange from bidding zone C to bidding zone A.



PTDF matrix	Bidding zone A	Bidding zone B	Bidding zone C	RAM
Critical Network Element inside bidding zone A	**0,11**	**0,098**	**0,15**	**15**

- An exchange of 1 MW from C to A uses (0,15 – 0,11)= 0,04 MW

→15/0,04= 355 MW can be exchanged

- An exchange of 1 MW from B to A uses (0,098 -0,11)= - 0,012 MW

→relieves the congestion on line X with 0,012 MW → Each 1 MW between B to A enables 0,3 MW (0,012/0,04) exchange from C to A

Figure 10-25 Example on how the usage of the margin on the critical network element can be calculated

By using the shadow price, i.e. the overall market value of an incremental MW of capacity on the congested critical network element, the price difference between the bidding zones can be calculated. This relationship between the shadow prices, the PTDFs and price differences is shown in the (11) below.

$$\text{Marginal Price A} - \text{Marginal Price B} = (\text{PTDF}_B - \text{PTDF}_A) * \text{Shadow price} \qquad (11)$$

In Figure 10-26, we show the price differences if we assume a shadow price of 100 €/MW on the critical grid constraint. The exchange from bidding zone B to bidding zone A relieves the congestion on the critical network X, i.e. the difference between the PTDFs is negative. Hence we will have a negative price difference between bidding zone A and bidding zone B, i.e. a non-intuitive flow.

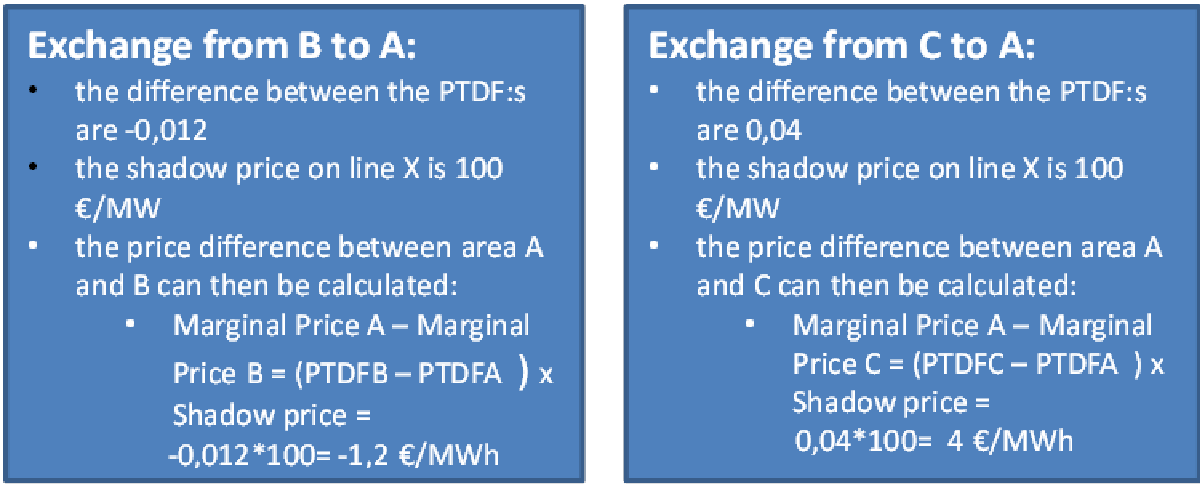


Figure 10-26 Example on how the price differences between bidding zones can be calculated by using the difference between PTDFs and the shadow price.

10.2.6 Congestion income distribution

Congestions in the electricity grid generates congestion income (CI) to the TSOs. Congestions generate spot price differences which, multiplied by the day ahead flow across the congested interconnector, gives the CI. Today the CI is shared among the TSO typically in accordance with ownership of the particular interconnector and often based on a sharing key of 50/50.

Several characteristics of the FB approach make it necessary, not only to use the default sharing (50/50) of the CI but to develop specific sharing keys. The main difference using a Flow-Based approach is, that non-intuitive flows (going from a higher-price area to a lower-price area) not just happen in rare cases[19] but happen more often in order to maximize the total economic surplus for the whole region. Also cross-border capacities are not as fixed in FB as in a NTC setup which must be considered when LTTRs are issued. This chapter describes two main issues of the flow-based approach:

- What happens with the Congestion Income on borders where there is a non-intuitive flow?
- How are Long Term Transmission Rights (LTTR) handled in a flow-based setup?

A first suggestion of how the above items can be handled is presented.

Avoidance of non-intuitive flows

Market algorithms, using a flow-based approach, result from time to time in solutions where the flow on some borders are going from the higher price area to the lower price area. Flow-based algorithms allow these "non-intuitive" flows in cases where they allow higher total socioeconomic benefits for the whole

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[19] *Where ramping requirements slow down the optimal distribution of power.*

system. At the specific borders however, where non-intuitive flows occur, negative CI is generated. This would cause a loss for the TSOs at both sides of these borders. Three different options of handling this are possible:

- Do nothing. The TSOs of both sides of a border with a non-intuitive flow take the loss.
- Avoid non-intuitive flows. Prevent the market algorithm from finding solutions with non-intuitive flows.
- Compensate negative congestion income by taking a little share of all the other borders, where a positive CI is generated.

The first option would be the easiest one to implement but would also not be fair – to have some TSOs pay for the overall increased regional benefits. The second option would also be easy to implement but the maximum feasible socioeconomic welfare would not be achieved. The last option requires a slightly more complicated calculation of the CI per border. It allows however to find a market clearing solution with optimal socioeconomic welfare while, at the same time, no borders generate negative CI.

If the third option is chosen, the following generic approach can be used:

1. Calculate the total CI of the region for a specific hour
   The total CI of the region is the sum of all border flows multiplied with the price difference of the two bidding zones connected by each border.
2. Calculate the adjusted CI for each border
   Some borders might, in a flow-based setup, give a negative CI which will reduce the total CI. However, non-intuitive flows are still optimizing the total CI of the region. Therefore negative CIs will be adjusted so that there are no losses for the TSOs on the affected borders. The adjustments will be paid by reducing the CI on the other borders.
3. Distribute the adjusted CI of each border to the right receivers
   Typically 50/50 to the TSOs on both ends of the border. Other, specific agreements might however be made for some borders.

The total Congestion Income of a region is calculated by the following equation:

$$CI = \sum_{i=1}^{NB} F_i \cdot |\Delta CPB_i| \tag{12}$$

Where:

- NB: total number of internal borders in the region
- F_i: flow at border *i* in the direction from low price area to high price area
- ΔCPB_i: delta clearing price between the two areas connected to border *i*

The adjusted Congestion Income on each border can be calculated by assigning a part of the above calculated total regional CI to each border.

Example

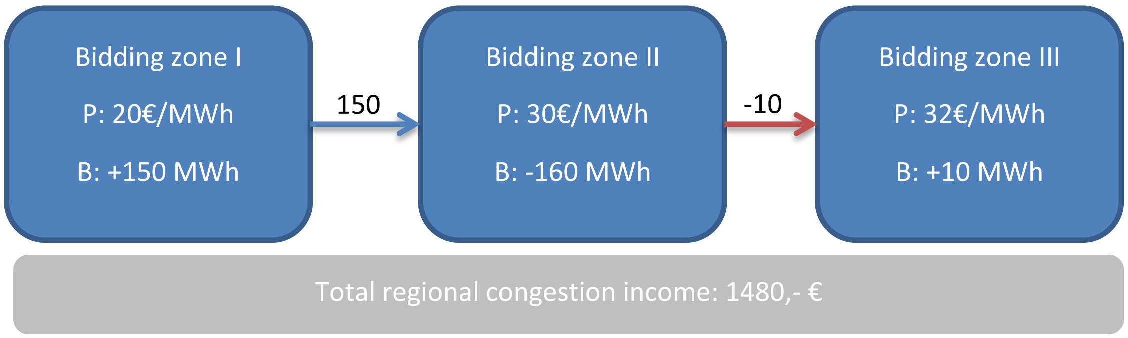


Figure 10-27 Example 1 – Calculation of regional congestion income

Handling of Long Term Transmission Rights (LTTR)

The European Guideline for Forward Capacity Allocation (FCA) states, that TSOs must make sure "[..] that other long-term cross-zonal hedging products are made available to support the functioning of wholesale electricity markets." Currently LTTRs are only offered on a one border of the Nordic CCR. This might however change in the future and therefore one possible approach of how LTTRs could be handled is explained below. Once a specific approach is chosen, it might be necessary to investigate additional details (like handling of LTTRs on external borders).

One question that must be answered in relation to the congestion income distribution methodology (CID), cf. FCA article 57 is whether the LTTR remuneration to the LTTR holder simply can be calculated by price difference multiplied by flow on a border or should the LTTR contribute to cover negative CI on borders with non-intuitive flows before remuneration.

10.2.7 Transparency

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

Up until now NTC values have secured a transparent Nordic power market where the link between capacities, flows and prices are easy to understand. As such, the NTC values are in the minds of the people active in this market, from the operators at the TSOs that are actually performing the capacity calculation, to the market participants that are placing the bids on the day-ahead market, and the NRAs. Nordic stakeholders are used to the 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 common grid model, a change compared to today's NTC values will be introduced. In the case of the CNTC methodology, although the cross-border capacity values are published in the same format, the values are likely to change, as is the reliability margin. Under a FB capacity calculation, the cross-border capacity values will be published in a different format compared to today. Under FB, the capacity constraints are not only located on bidding zone borders, but can also be within the bidding zone, while the capacity (the RAM) will vary hour by hour, in line with the loading and usage of the grid. In addition, the FB methodology provides PTDF matrices, which indicate the impact of a change in bidding zone net positions on the grid constraints. This concept is rather new and is to be used explicitly in the price calculation, where today this is used "behind the curtains" by the TSO operators. As such, FB increases the transparency, as the market players are no longer exposed to the TSO operators' subjective assessment on the (C)NTC domain, which is not visible to the market players. Indeed, in (C)NTC the TSO operators may have to decide between several NTC domains within the secure domain, as shown in Figure 10-28, which under FB is left to the market players.

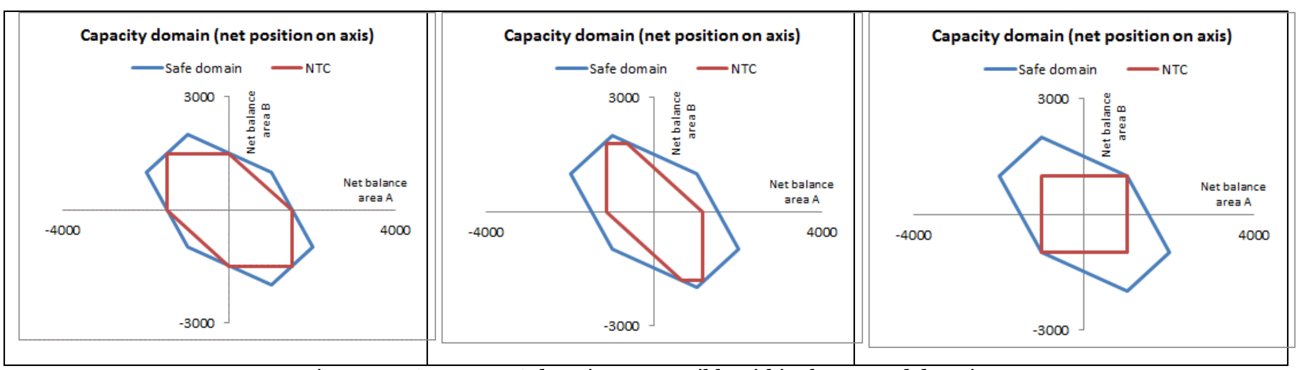


Figure 10-28 More NTC domains are possible within the secured domain

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 commercial exchange between the two bidding zones. With each aggregation made, grid details and a link with the physical reality are lost. In this sense, the FB approach is a step forward in terms of transparency. Individual grid elements are taken into account as such, whether they are tie lines or 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 cuts or grid elements that are limiting the Nordic power market on a regular base and with a social welfare loss tagged to it. In FB, it is the shadow prices of those individual grid element and cuts that are computed and available with an hourly resolution: a valuable source of information for both TSOs and NRAs.

The Nordic TSOs do, however, acknowledge that understanding the FB methodology and the impact thereof needs some training. The TSOs have therefore started some initiatives aiming at enhancing the understanding among stakeholders before go live with FB. 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 capacity calculation methodologies. 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 power exchanges 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 capacity calculation methodologies. In addition, the Nordic TSOs also issue newsletters in order to keep the stakeholders up to date with regard to the Nordic capacity calculation methodology 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 Nordics, such as on the maximum import and export positions of the bidding zones for example, given the FB constraints. It provides an insight as well on the physical cross border flows in the Nordic system and the (limiting) anonymized grid constraints. This functionality already meets the requirement postulated in Article 20.9 of the CACM GL:

"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 - is shown in Figure 10-29.

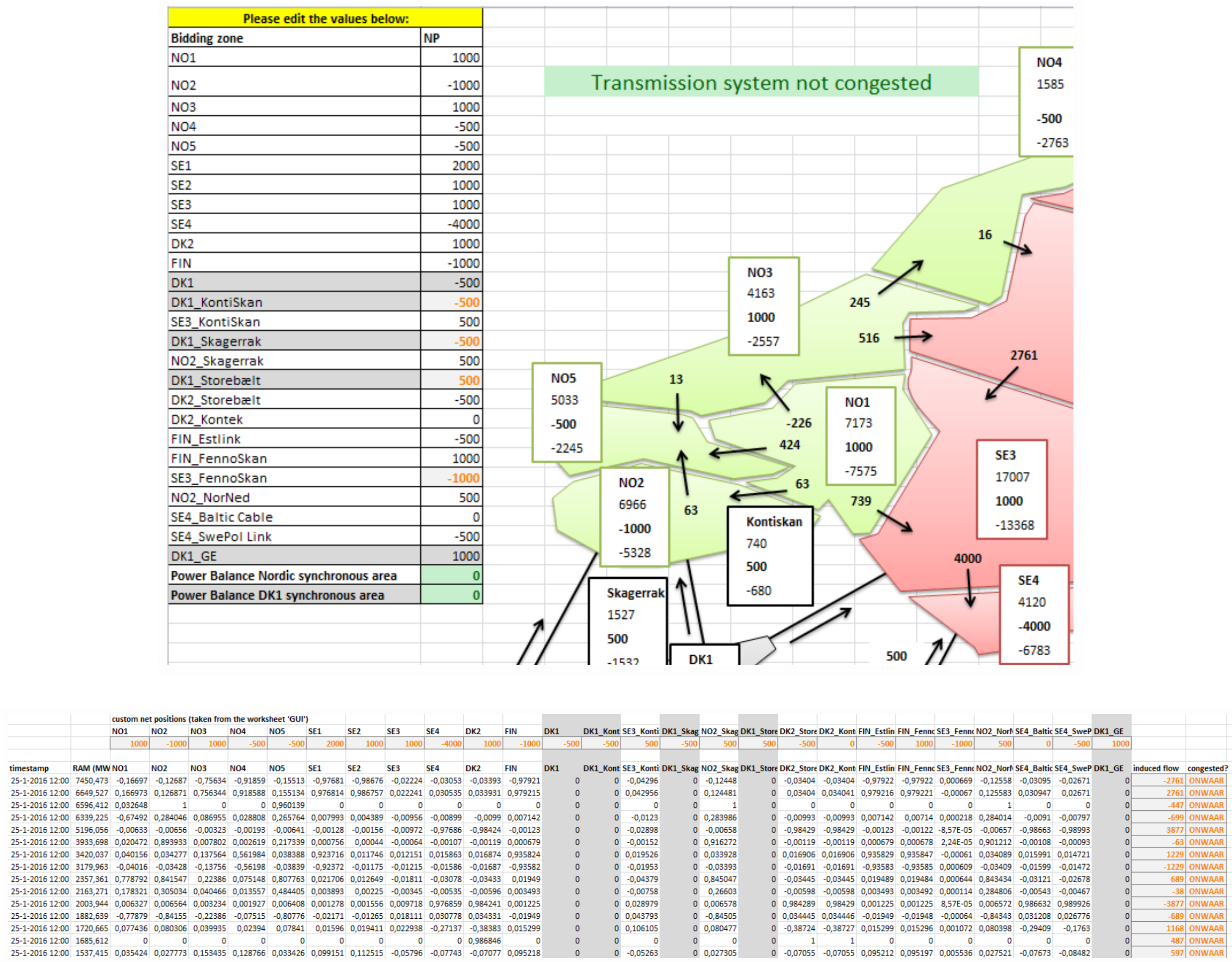


Figure 10-29 Two screenshots of the market information tool (that is under development)

Parallel run. As the implementation of FB introduces market constraints in a different format than what is used today, whereas the CNTC is likely to introduce different values than today's ones, an (at least) six-month parallel run period will be performed. While the current NTC mechanism is in operation to serve the day-ahead market, the TSOs run a second capacity calculation in parallel, being FB, in order to assess what would have been the capacity if the coordinated capacity calculation approach would have been applied. In addition, the actual order books at the PXs will be used to assess what would have been the market outcome in this case. This is a learning period for TSOs, NRAs, and market actors. After this period of parallel run, the new capacity calculation and allocation mechanism should have started to root in the minds and the IT systems, ready to step into this next evolution of the Nordic power market.

10.2.8 Long-term investment decisions

In this chapter we describe how the long-term investment analysis might be impacted when choosing FB as the capacity calculation methodology in the Nordic CCR.

One of the advantages of employing FB is that the capacity utilization of lines can potentially be increased, hence providing more capacity without any grid investments. Not only in operation, but also in the grid planning and investment analysis phase, implementing FB may have an impact. Using the FB algorithm to study grid constrains might give a more precise result on which grid constraints are limiting the market flows, and this can give a more direct indication on where constraints and bottlenecks might occur, as compared to the CNTC methodology. 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 in operation reveals, is the (true) costs of grid constraints. This is called the shadow price of capacity. The shadow price shows the market value of an incremental MW of 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 capacity. However, due to (C)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 FB.

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

To provide understanding on the concept of shadow prices in the light of the current CNTC capacity calculation method, an example with a simple radial grid is provided (Figure 10-30). In case of such a simple power system there is no difference between CNTC and FB in terms of capacity assessment. The shadow price is equal to the resulting spot 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 areas.

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

Figure 10-30 Example on CNTC 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:

$$P_i - P_j = \sum_{k=1}^{K} \delta_k \times \left(PTDF_{j,k} - PTDF_{i,k}\right)$$

Where:

P_i: Price in area *i*

K: Number of constraints

δ_k: Shadow price of constraint *k*

$PTDF_{i,\,k}$: Influence from area *i* on constraint *k*

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

$45 – 50 = \delta_{AC}(0 - 1)$

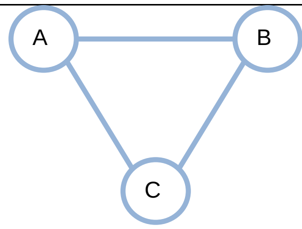
$-5/(0-1) = \delta_{AC}$

$5 = \delta_{AC}$

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

In case of CNTC, the shadow prices are always equal to the price differences between the bidding areas. In a meshed network that is managed by FB, we expect to see shadow prices that deviate from the CNTC (current method) shadow prices. An example is introduced in Figure 10-31 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

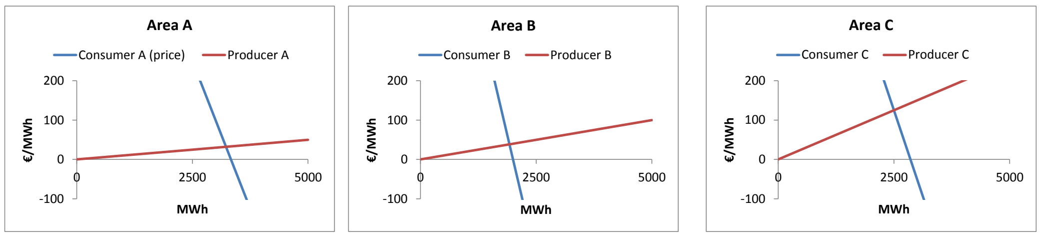


Figure 10-31 Example reflecting a grid and market situation.
The bid curves show an equilibrium before capacites have been taking into consideration

Based on the situation depicted in the example in Figure 10-31, the market outcome for CNTC and FB is illustrated in Figure 10-32.

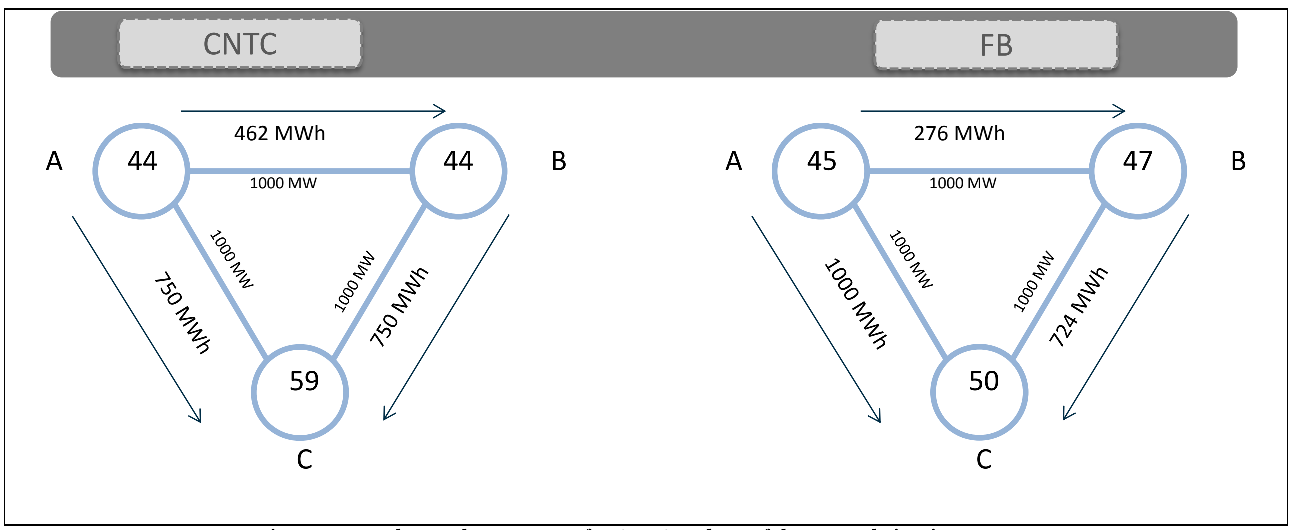


Figure 10-32 The market outcome for CNTC and FB of the example in Figure 10-31

It is easy to see that the shadow prices of Line A→B and B→C equal 0 in the FB situation. 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:

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

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

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

$$\delta_{AC} = 7{,}50\ €$$

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 CNTC, where the price difference is 15 €/MW.

10.2.9 Impact on management of extreme price situations from FB implementation

In FB capacity is allocated to the flows that provides most social economic welfare. In extreme situations curtailment occurs when market clearing price hit the maximum or minimum allowed price in the bidding zone and the offered quantity at these maximum or minimum prices is not fully accepted. This can occur both when there is abundance of generation capacity in e.g. high wind output and generation shortage to meet demand e.g. during cold winter days.

If several bidding zones end up at maximum (minimum) price and buy (sell) orders need to be curtailed the default solution in the FB solution is to allocate the flows that provides most social economic welfare. This could lead to that one bidding zone is totally curtailed while all the available energy is given to another market which is not necessarily at maximum price. This is not the case in the current NTC approach where the bidding zone that are not curtailed will be exporting or importing from the bidding zone with curtailment.

In the market algorithm, Euphemia, a mechanism that enables a fairer distribution of the curtailment between all the bidding zones in a Flow-based domain is implemented. This is done by penalizing non-acceptance of price taking orders before looking for the optimal solution. This functionality aims at harmonize the curtailment ratios across the curtailed bidding zones. Hence , Euphemia allows both to prevent sharing of curtailment and sharing of curtailment.This is also an all TSO requirement on the algorithm to be able to handle these two different apporaches. As such, the curtailment sharing rules are part of the capacity allocation and not the capacity calculation. As a consequence it is not a part of the capacity calculation methodology for the Nordic CCR.

10.3 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 costs, stakeholder costs, and TSO operational costs and maintenance costs. They will be discussed in more detail in the following.

10.3.1 Nordic CCM project costs

The Nordic CCM project is responsible for developing a CACM compliant capacity calculation methodology 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 is assumed to be same when it comes to the CCM project costs.

TSO training costs and changes in procedures

Introduction of a new capacity calculation methodology 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 methodology and procedures. Both CNTC and FB will induce a need to change procedures, although in the case of CNTC the change is not as remarkable as in the case of FB. The TSO training costs are more significant for FB compared to CNTC. However, to some degree it only holds for the short run, where "NTC thinking" has become the second nature. In the long run when new operators are trained and FB 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 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 RSC 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 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 10-3 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 10-3 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		

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11 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 latest deadline for implementing a harmonized CCM within a Capacity Calculation Region is called for in article 21(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 following section provides the description of the planned implementation timeline for the Nordic capacity calculation methodology.

11.1 Timeline for implementation of the CCM

Prerequisites

When the new Capacity Calculation (CC) goes live, the calculations will not be done by the local TSOs anymore, rather by the Regional Security Coordinator (RSC), based on input from the TSOs, and finally validated by the TSOs. Two crucial ingredients in this process are the Common Grid Model (CGM) and the Industrialized Capacity Calculation Tool, neither of them being developed by the Nordic CCM project. The CGM is being developed by a coordinated project from the TSOs, and the industrialized tool is being developed by the RSC. Both elements need to be in place before the "go-live" of the CCM.

In order to test the CC functionality, a preliminary CGM has been developed and operationalized within the CCM project. However, this model does not provide an operational data quality. Before the project may publish parallel calculation results to the public, the final CGM has to be available as basis for the calculations.

As for the preliminary CGM, a prototype tool for capacity calculation has been developed within the project. The prototype is not suited for operational use within the RSC environment, but the calculations are correct and could be used even for the first phase of public parallel runs. The industrialized tool should however be available for testing purposes in a suitable time until the final go-live date.

In order to apply a Flow Based Market Coupling, the NEMO market platform must be able to manage market constraints based on FB parameters. The Day Ahead Market algorithm, Euphemia, is developed for this purpose, and it is believed that by the go-live date, the current computational limitations are resolved. The new Intraday platform, XBID, is however currently not suited for using FB parameters. It is not yet clear when this can be developed. The FB approach is thus currently not foreseen to be a viable option for the Intraday market at the go-live date for the FB approach in the day ahead market. The initial solution for the intraday market will therefore be a CNTC approach.

Timeline

An indicative high-level timeline for implementing the new CCM is visualized in Figure 11-1: it shows a go-live date of the FB DA CCM and the intermediate ID CNTC CCM in Q4 2019 **at the earliest**.

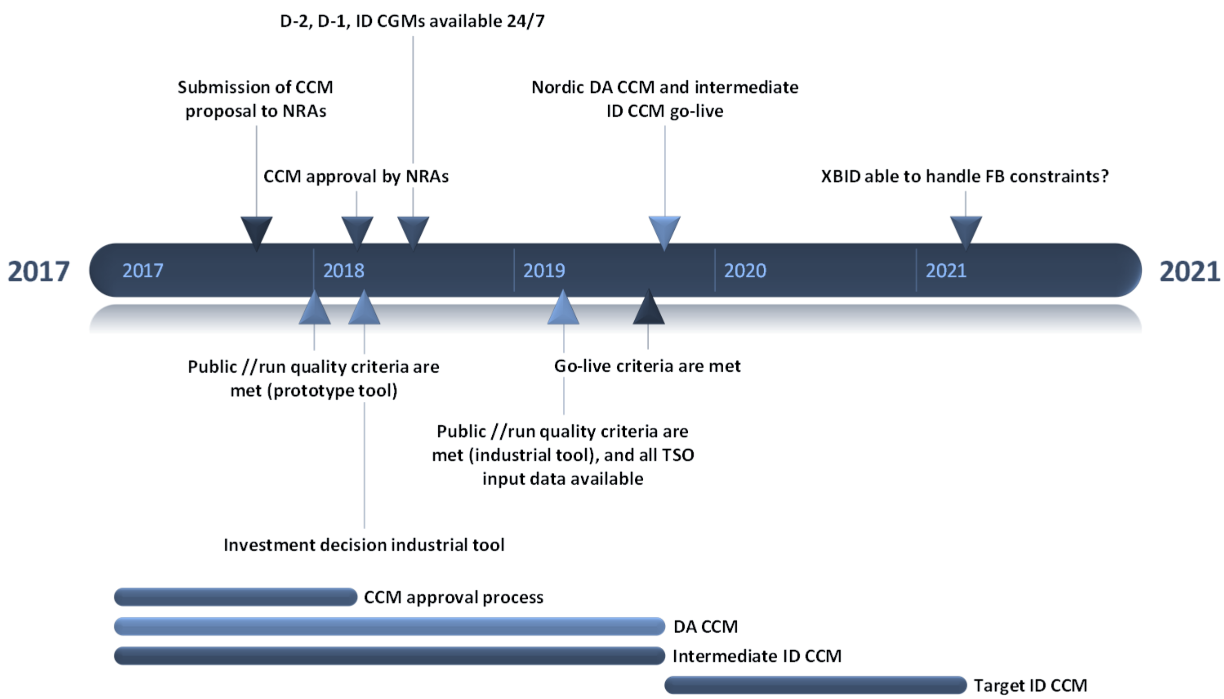

Figure 11-1 Planned timeline for implementing the new CCM

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12 ANNEX I: Results from the public consultation

13 ANNEX II: Example calculation of nodal PTDFs

Figure 13-1 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.

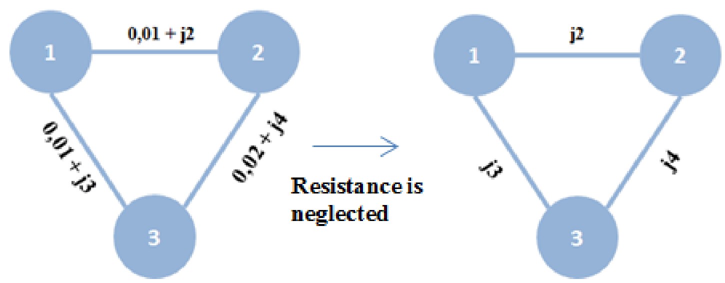

Figure 13-1 Example grid with three nodes. The node and line parameters used in the power flow equations are illustrated in the figure.

The $Ybus$ matrix is defined by the data in Figure 13-1. Recall that the susceptance between two nodes equals the inverse of the reactance for the line, since the resistance was neglected.

$$Ybus = \begin{bmatrix} 1/2 + 1/3 & -1/2 & -1/3 \\ -1/2 & 1/2 + 1/4 & -1/4 \\ -1/3 & -1/4 & 1/3 + 1/4 \end{bmatrix} \tag{13}$$

The $Zbus$ matrix is then constructed by adding "+1" to the diagonal element corresponding to the slack-node in the $Ybus$ matrix in (13), followed by an inverse operation. Node 3 is in this example selected as slack node.

$$Zbus = \begin{bmatrix} 1/2 + 1/3 & -1/2 & -1/3 \\ -1/2 & 1/2 + 1/4 & -1/4 \\ -1/3 & -1/4 & 1/3 + 1/4 + 1 \end{bmatrix}^{-1} = \begin{bmatrix} 3{,}00 & 2{,}33 & 1{,}00 \\ 2{,}33 & 3{,}22 & 1{,}00 \\ 1{,}00 & 1{,}00 & 1{,}00 \end{bmatrix} \tag{14}$$

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

$$PTDF_{ik,n} = B_{ik}(Zbus_{in} - Zbus_{kn}) \tag{15}$$

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

$$PTDF_{12,1} = B_{12}(Zbus_{11} - Zbus_{21}) = \left(\frac{1}{2}\right)(3{,}00 - 2{,}33) = 0{,}33 = 33\% \tag{16}$$

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:

$$\mathrm{PTDF} = \text{Line}\quad \begin{array}{c} \\ 1-2 \\ 1-2 \\ 2-3 \end{array} \begin{array}{c} \textbf{Node} \\ \begin{array}{ccc} \textbf{1} & \textbf{2} & \textbf{3} \end{array} \\ \begin{bmatrix} 0{,}33 & -0{,}44 & 0 \\ 0.67 & 0.44 & 0 \\ 0{,}33 & 0{,}56 & 0 \end{bmatrix} \end{array} \tag{17}$$

14 ANNEX III: 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 14-1, 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.

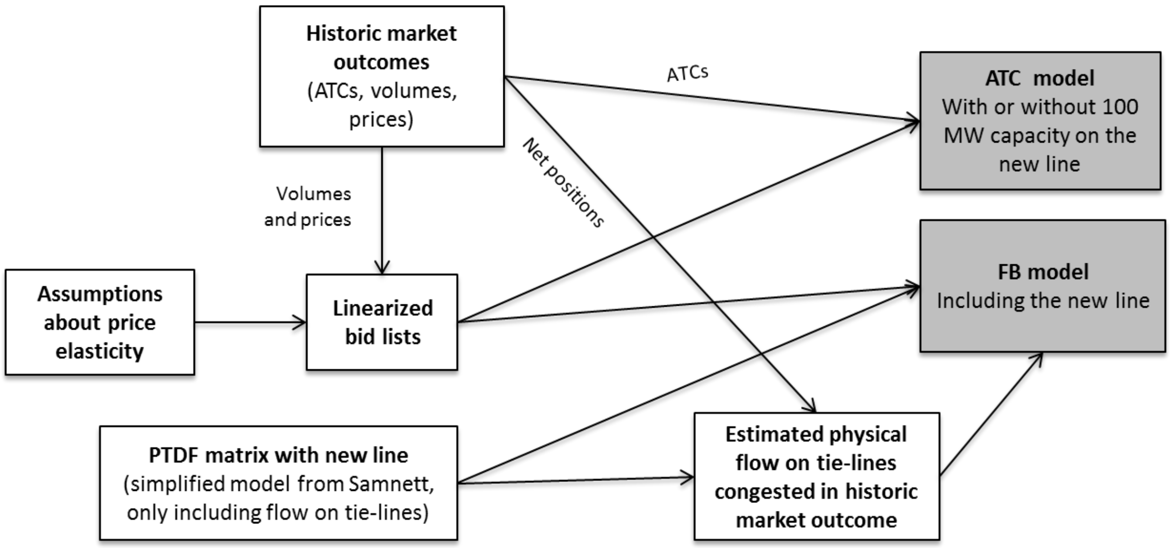

Figure 14-1 The model set-up

Figure 14-2 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.

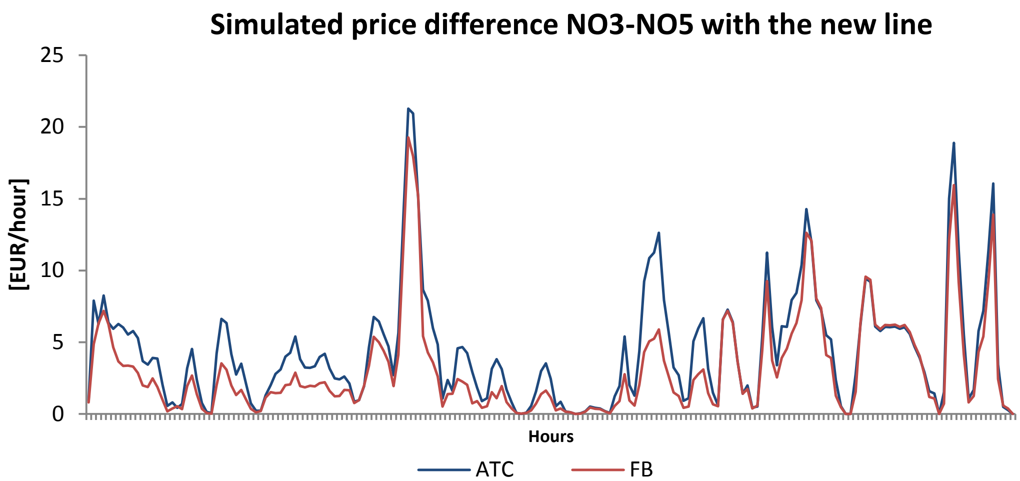

Figure 14-2 Simulation results for all historical hours with significant price differences in the Nordic system from 2.12.2013 and 15.1.2014

15 ANNEX IV: 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.

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

$$[\underline{I}] = [\underline{Y}][\underline{U}] \quad (2)$$

$[\underline{Y}]$ 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:

$$\underline{S}_i = P_i + \mathrm{j}Q_i = (P_{\mathrm{G}i} - P_{\mathrm{L}i} - P_{\mathrm{T}i}) + \mathrm{j}(Q_{\mathrm{G}i} - Q_{\mathrm{L}i} - Q_{\mathrm{T}i}) \quad (3)$$

$\underline{S}_i$ 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.

$$\underline{S}_i = \underline{U}_i \underline{I}^*_i = P_i + \mathrm{j}Q_i \Leftrightarrow$$

$$\left(\frac{\underline{S}_i}{\underline{U}_i}\right) = \underline{I}^*_i = \frac{P_i + \mathrm{j}Q_i}{\underline{U}_i} \Leftrightarrow$$

$$\left(\frac{\underline{S}_i}{\underline{U}_i}\right)^* = \left(\frac{\underline{S}^*_i}{\underline{U}^*_i}\right) = \underline{I}_i = \frac{P_i - \mathrm{j}Q_i}{\underline{U}^*_i}$$

Equation (1) can also be written as follows.

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

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

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

$$\frac{\underline{S}_1^*}{\underline{U}_1^*} = \frac{P_1 - \mathrm{j}Q_1}{\underline{U}_1^*} = \underline{Y}_{11}\underline{U}_1 + \underline{Y}_{12}\underline{U}_2 + \underline{Y}_{13}\underline{U}_3$$

$$\frac{\underline{S}_2^*}{\underline{U}_2^*} = \frac{P_2 - \mathrm{j}Q_2}{\underline{U}_2^*} = \underline{Y}_{21}\underline{U}_1 + \underline{Y}_{22}\underline{U}_2 + \underline{Y}_{23}\underline{U}_3 \qquad (5)$$

$$\frac{\underline{S}_3^*}{\underline{U}_3^*} = \frac{P_3 - \mathrm{j}Q_3}{\underline{U}_3^*} = \underline{Y}_{31}\underline{U}_1 + \underline{Y}_{32}\underline{U}_2 + \underline{Y}_{33}\underline{U}_3$$

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

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

$$\underline{S}_1^* = P_1 - \mathrm{j}Q_1 = \underline{Y}_{11}\underline{U}_1^*\underline{U}_1 + \underline{Y}_{12}\underline{U}_1^*\underline{U}_2 + \underline{Y}_{13}\underline{U}_1^*\underline{U}_3$$

$$\underline{S}_2^* = P_2 - \mathrm{j}Q_2 = \underline{Y}_{21}\underline{U}_2^*\underline{U}_1 + \underline{Y}_{22}\underline{U}_2^*\underline{U}_2 + \underline{Y}_{23}\underline{U}_2^*\underline{U}_3 \qquad (6)$$

$$\underline{S}_3^* = P_3 - \mathrm{j}Q_3 = \underline{Y}_{31}\underline{U}_3^*\underline{U}_1 + \underline{Y}_{32}\underline{U}_3^*\underline{U}_2 + \underline{Y}_{33}\underline{U}_3^*\underline{U}_3$$