Principle Approach for Assessing Nordic Welfare under Flow-based methodology

Abbreviations:

AC	Alternating Current
CNTC	Coordinated Net Transmission Capacity
CNE	Critical Network Element
CR	Congestion Rent
CS	Consumer Surplus
DC	Direct Current
ENTSO-E	European Network of Transmission System Operators for Electricity
EPAD	Electricity Price Area Differentials
FB	Flow-Based
GSK	Generation Shift Key
ID	Intraday
MW	Megawatt
NC CACM	Network Code on Capacity Allocation and Congestion Management
NP	Net Position
TSO	Transmission System Operator
PTDF	Power Transfer Distribution Factor
PS	Producer Surplus
PX	Power Exchange
RPM	Regulating Power Market
TRM	Transmission Reliability Margin
TTC	Total Transmission Capacity

Table of Content

1. Introduction and executive summary

This report is part of the Nordic flow based (FB) feasibility study part I. The objective of the report is to outline how to understand and assess the potential benefit of implementing flow based in the Nordic power system. The objective is not to do an actual quantification of potential benefit.

The report contains 3 chapters. The first chapter describes the way in which flow based provides a more accurate description of the grid and why this is important in order to maximise economic welfare and the functioning of the power market. It is argued that FB allows the flow, calculated by the market operator, to be more in line with the physical properties of the transmission grid. Chapter 2 outlines the understanding of economic benefit and shows that the economic gain is defined as the change in consumer, producer surplus and TSO congestions rent. In addition it is shown that FB provides the grid owners with explicit info on the location of grid investments with the highest economic benefit, by the use of shadow prices of grid constraints. In the last chapter, an outline of the market simulation approach is provided, as well as a list of concrete indicators to monitor the FB performance when simulations are conducted in the later part of the project.

The report has a mainly theoretical approach to these topics, and focusses on the potential benefits of FB compared to the current CNTC approach. Potential downsides, especially concerning implementation, is not taken into account, partly due to fact that is expected to be minor compared to potential benefit, partly due to the fact that is difficult to estimate and only relevant to estimate if there is any benefit at all. It is also worth noting that the outlined market simulations will be based on the current power system, not the one we expect when FB might be implemented.

2. Improved utilization of transmission capacity

2.1 Introduction to FB and CNTC

Flow based (FB) and Coordinated Net Transmission Capacity (CNTC) refer in this report to alternate methods for calculating transmission capacity between bidding areas. The CNTC method is the current basis of the day-ahead and intra-day markets at Nord Pool Spot.

The FB method aims to improve the capacity allocation at the power exchange (PX) without changing the fundamentals of the current market design, which includes the use of bidding areas covering large geographical areas where all market participants within one area receive the same access to the transmission capacity, and the same price for electrical power.

The improvements of FB compared to the CNTC method is due to more flexibility in describing the grid restrictions that limit the transmission of electric power between the bidding areas. This flexibility allows the FB method to be more in line with the physical properties of the transmission grid. From a theoretical perspective, the FB method is able to replicate all the properties and market outcomes of the CNTC method, while the reverse is not true.

Please refer to the Technical Report for a more thorough technical description of the FB method of capacity calculation and allocation as compared to the CNTC method.

2.2 Simplified example of FB and CNTC

FB is fundamentally different from CNTC in that it includes information on how electrical power actually flows in the transmission grid. This example aims to show how this may impact both the market outcome and the security of supply.

In normal grid operations the electrical power being transmitted between two nodes will be distributed in a fixed manner, according to the properties of the grid components. This is illustrated in Figure 1.

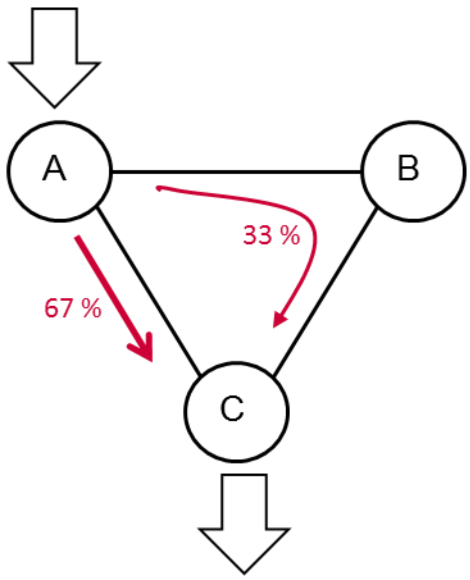

Figure 1 The power flows between two areas have a fixed distribution

The FB approach describes these relationships as part of the market information that is provided to the PX. An example of such market information is shown below in Table 1. In this case the grid is able to handle a physical flow of 1000 MW on each line. Using the FB approach, the PX is able to predict the physical flows in the grid, and will adjust the net positions (NP) so that the grid is optimally used in any situation.

Table 1 Example of market information when using the FB approach

Line	Remaining available margin	Influence from area A	Influence from area B
A -> B	1000 MW	33 %	- 33 %
B -> C	1000 MW	33 %	67 %
A -> C	1000 MW	67 %	33 %

With the CNTC approach, the TSO provides capacity for each line, but not the matrix describing how NPs are translated into physical flows. The PX is therefore not able to predict the flows correctly. If, in the example above, the TSO provides an CNTC capacity of 1000 MW on each line there is a risk for an overload as shown in the figure below. Notice that all the market flows comply with the CNTC limits of 1000 MW, but that the physical flows turn out differently. The blue arrows show the commercial exchanges, while the red arrows show the resulting physical flows.

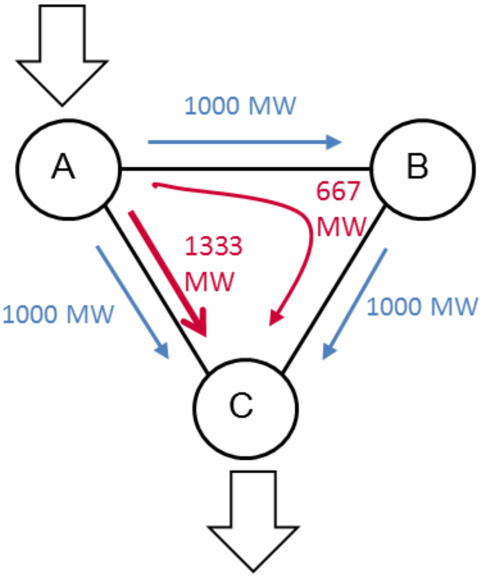

Figure 2 With CNTC the market flows may be different from the physical flows

To correct for this possibility of overloads, the TSO needs to withhold some capacity. The CNTC limits below are one possible set of values that ensure that overloads will never happen. But it comes at a cost, as not all grid capacity is available in most situations.

Table 2 Example of CNTC market information always providing a secure market outcome

Line	**Max CNTC**
A -> B	750 MW
B -> C	750 MW
A -> C	750 MW

If areas A and B have equal surplus of production, while area C is importing this surplus, the FB approach would allow an import in area C of 2000 MW, while the CNTC limits above would only allow an import of 1500 MW. This is shown in Figure 3.

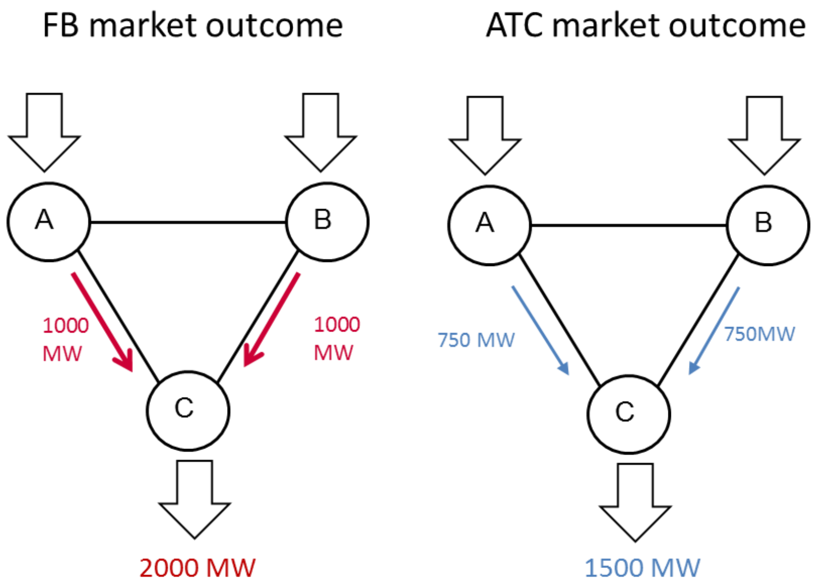

Figure 3 CNTC is not able to fully utilize the grid capacity when the generation is evenly distributed between areas A and B

In this simplified grid, the FB approach will always allow full grid utilization, and the FB market information requires no TSO assumptions about market outcome. For CNTC, no matter how the TSO sets the CNTC capacities, there will always be a possibility that the market is not able to access all the grid capacity if the market turns out differently than the TSO expected.

2.3 Increased accuracy in grid representation

The FB approach can give a better description of the physical grid constraints of the transmission grid to be used by the PX compared to the CNTC approach. This increased accuracy may translate into a more efficient market outcome, as market participants in all bidding areas compete for the scarce transmission capacity in relation to their relative contribution to the potential congestions.

The chapters 2.3.1 - 2.3.3 describe the theoretical benefit in terms of (1) the ability to predict the power flows in the transmission grid, (2) the ability to include grid constraints that reside within bidding areas, and (3) the reduced importance of TSO predictions in determining the market outcome.

Increased accuracy may also allow grid constraints to be included in the market coupling, that is currently handled treated using costly remedial actions, leading to an improved operation of the power system as a whole, as described in chapter 2.3.4.

2.3.1 Flow based offers improved grid representation in price calculation at the PX

The transmission of electric power in the AC grid is governed by a set of physical laws that dictate how the power flows are distributed along the different paths. The flow of power between two nodes in the grid is distributed along all paths connecting the two nodes by what may be considered a constant distribution in the normal operating conditions of the transmission grid.

The fixed distribution of power flows between pairs of bidding areas can be described by using the FB parameters, while the CNTC method does not include this information. The FB method is therefore more accurate in predicting the flows on the critical grid components than the CNTC approach. The difference is shown in Figure 4. The CNTC approach gives no indication of the physical distribution of power flows (only one of a number of possible market flows is shown).

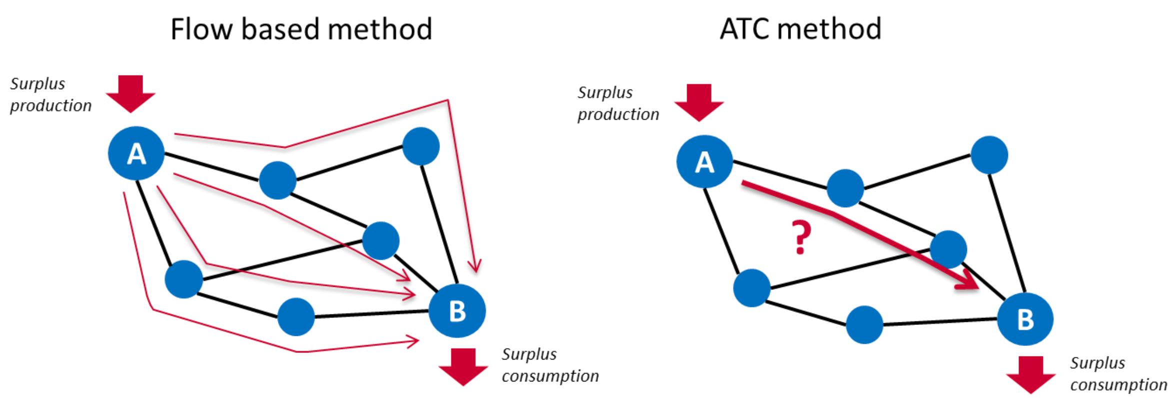

Figure 4 Difference in calculated power flows between bidding areas using the FB and CNTC methods

The constraints on the transmission of power between bidding areas in the day-ahead and intra-day markets are due to flow limitations on individual components, or sets of components. The ability to accurately describe how the NP of each bidding area contributes to the flow on these components means that FB can consider the contribution from all bidding areas in managing a potential grid congestion. This includes the property of FB being able to relieve congestions by increasing trades which increase the flow in the direction opposed to the congested direction. In short: FB can increase the available grid capacity for the most profitable trades by taking a small loss at other (less-profitable) trades, thereby leading to a better overall market outcome compared to CNTC.

The consequence of the limitations of the CNTC method is illustrated in Figure 5, showing the possible NPs in the day-ahead market for areas A and B (same areas as shown in the Figure 4). All market positions within the boundaries are possible outcomes at the PX, while the net positions outside the boundaries are not possible at the PX. Note that in this case the solution space for the market must be a square when using the CNTC approach (given that areas A and B are not neighbours), while the FB approach allows for any convex shape.

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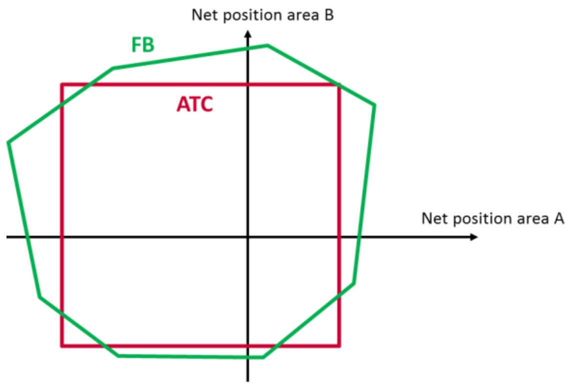


Figure 5 FB allows for a more flexible description of the constraints in the day-ahead market, illustrated here by the more complex shape of the FB area solution space compared to CNTC.

The parts of the FB area that are outside the CNTC area in the Figure 5 represent a major potential benefit of FB. The corners of the CNTC area that are outside the FB area may be considered to violate security of supply (before corrective action), as a market outcome would violate the flow limits on the constraints representing the closest edge of the FB area. These areas represent a theoretical risk that can be avoided by using the FB method, but the corners may also represent completely unrealistic market outcomes, in which case there is no real risk for the system security.

2.3.2 Constraints may be more accurately described in flow based market coupling than in CNTC

A limitation of the CNTC method is the inability to accurately describe the flows on constraining grid components. This includes both the influence from the NP of a bidding area on constraints on the borders between the bidding areas, constraints within itself, and on constraints inside other bidding areas.

To correct for this deficiency the TSOs may solve the congestions by costly remedial actions, such as counter trade. Anotheroption would be to restrict the CNTC capacities on the Elspot corridors, but this CNTCmay have detrimental effects for the utilization of the transmission grid, as commercial exchanges that do not affect the congestion are also limited.

The FB method can take into account the internal constraints directly, as the flow on the constraining grid component is modelled by the FB parameters. The knowledge on how each area influences the internal constraints also ensures that the constraints are handled in an efficient manner, where market participants in each bidding area are allocated transmission capacity based on both their relative contribution to the flows and their willingness to pay.

The different ability of FB and CNTC to handle an internal constraint is shown in Figure 6. FB is able to model the constraint (shown inside area A) directly, and to provide an efficient market solution regardless of the actual willingness-to-pay of the market participants. With CNTC there are multiple options available to the TSO, none of which will provide an optimal allocation of the available transmission capacity. The TSO may however also be able to create new bidding areas to improve on the CNTC market set up (not shown), but will never attain the precision of the FB approach, using an equal number of bidding areas.

In practice, the CNTC approaches shown below all give priority access to some areas, as the NPs of the bidding areas are not constrained according to their relative contribution to the congestions. For example, the first CNTC approach shown below gives priority access to area B and C, as the market is only limited at the border A-B, while the second approach gives priority access to area A and B etc.

The FB method does not give any priority, and allows all areas to compete for the scarce capacity according to how each trade influences the critical grid components. This means that a more efficient market outcome may be available in FB.

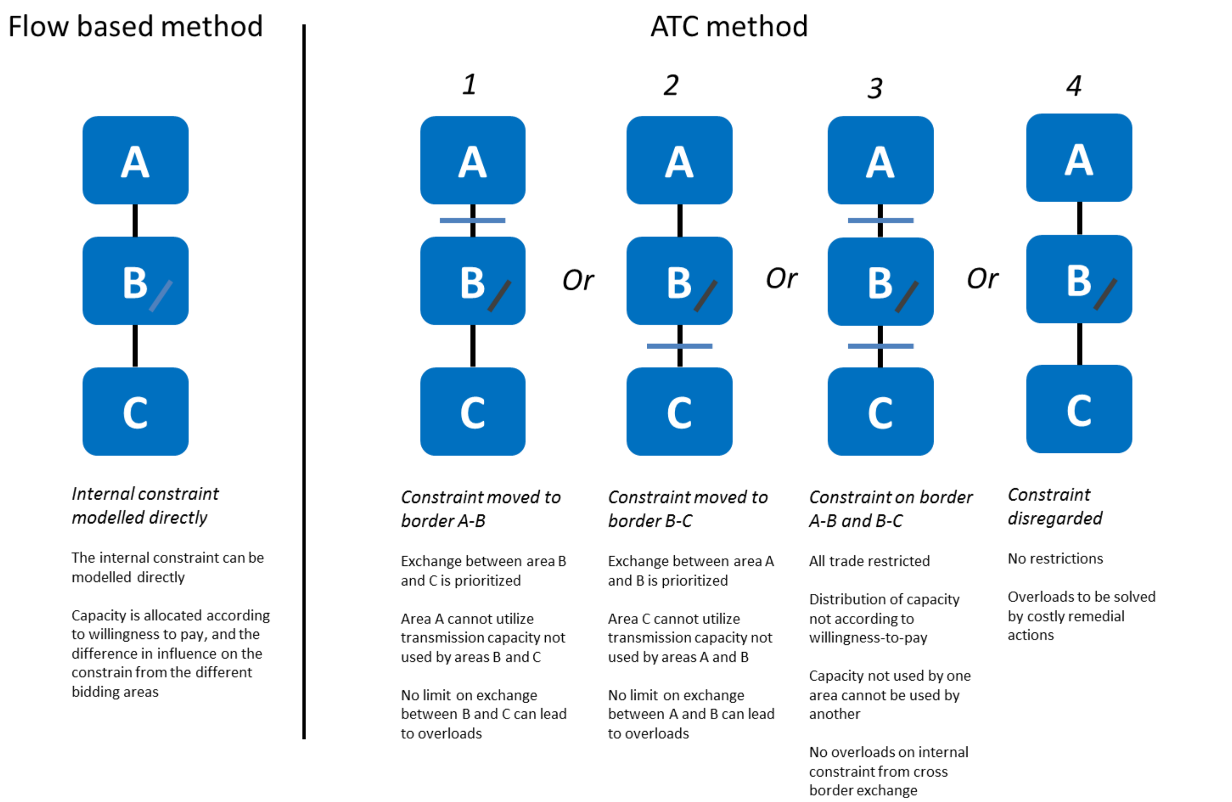


Figure 6 Showing how an internal constraint in bidding area B may be included in the day-ahead market under FB and CNTC

2.3.3 Reduced importance of uncertainty in FB compared to CNTC

. In order to provide as much grid capacity to the day-ahead market as possible the TSOs need to make predictions on the future load and generation in the system. But these prediction are necessarily not always accurate, and this uncertainty will impact the amount of grid capacity that can be made available to the market.

FB will provide the day ahead market with more flexibility in how to handle the grid constraints, as the net position in all areas may be used to relieve congestions. This added flexibility might reduce the importance of uncertainty in the TSO predictions.

Figure 7 shows an example of the variation in NPs between comparable hours. The flows to and from adjacent power systems can also be highly uncertain, and the market participation, and actual bid prices, of the market participants are not available to the TSO. Note these values are not the difference between the predicted and observed values, but indicate the importance of good predictions.

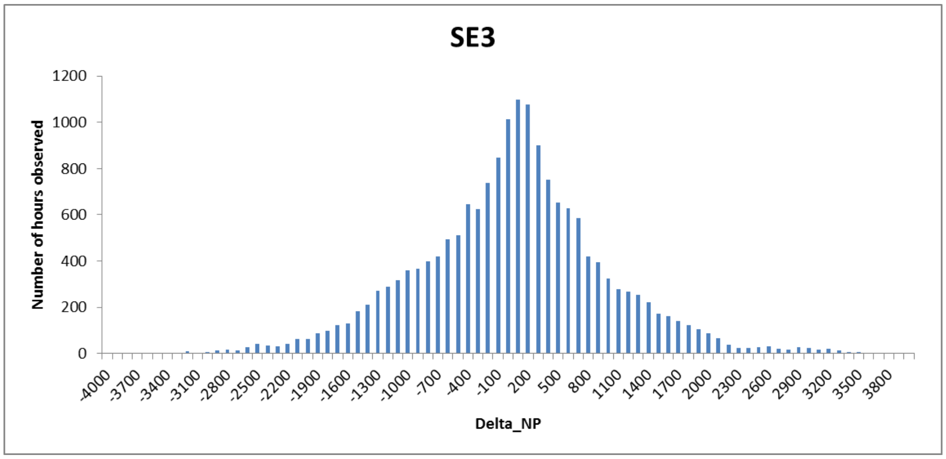


Figure 7 The distribution of difference in the NP (Delta_NP) of SE3 in MWh/h between two comparable[1] hours.

2.3.4 More of the grid constraints may be handled by the market coupling

In addition to the benefits described above, the FB approach may allow more of the potential grid constraints to be handled by the day-ahead market compared to CNTC. These critical grid components may for example be located far from area borders, or be significantly affected by trade between pairs of bidding areas other than the local area.

Including these constraints under the CNTC approach may not provide a cost efficient handling of the constraint, compared to countertrade or other remedial actions. With FB the grid constraints may be described accurately, so that the potential congestions can be handled efficiently by the market coupling

[1] For each hour on Saturdays the value is compared with the same hour on the previous Saturday, Sundays are compared with previous Sunday, Mondays and Tuesdays are compared with previous Friday, and Wednesdays, Thursdays and Fridays are compared with the NP two days before. The time period analyzed is 21.11.2011 to 1.12.2013 CNTC.

at the PX. While the inclusion in FB of grid components not considered in the CNTC approach might benefit the operation of the power system as a whole, the benefit of the FB market coupling compared to CNTC might be reduced, or even be negative, if the day-ahead market is seen without considering the costs associated with ensuring security of supply.

3. Methodology for impact assessment

In this section the core of the methodology for impact assessment of FB implementation in the Nordics is presented. The section entails both a presentation of the approach used for impact assessment later on in the project, but also some issues related to possible impact on adjacent markets and transparency of the FB method.

3.1 Welfare economics (Basics on economic benefit of trade)

In feasibility study part 2 of the FB project an impact assessment will be accomplished by the use of Nord Pool Spot market simulations. The potential gain from implementing FB will be evaluated using the standard methods from cost-benefit analysis; the welfare economic tools.

The gain will be assessed as the sum of change in consumer surplus (CS), producer surplus (PS) and congestion rent (CR).

The expected gain is driven by potential improved capacity utilization as described in chapter 2, due to better grid representation (PTDFs) in the day ahead price/quantity calculations at the power exchange (e.g. Nord Pool Spot), hence more low-cost generation and high willingness-to-pay consumers get access to the market. The basic idea of a gain can be illustrated by a very simple example for a two bidding zone, radial grid, power system. The example illustrates the welfare economic gain of increasing capacity from zero to E. The gain is measured as the sum of changes in CS, PS and CR, illustrated by the light blue and grey areas in Figure 8.

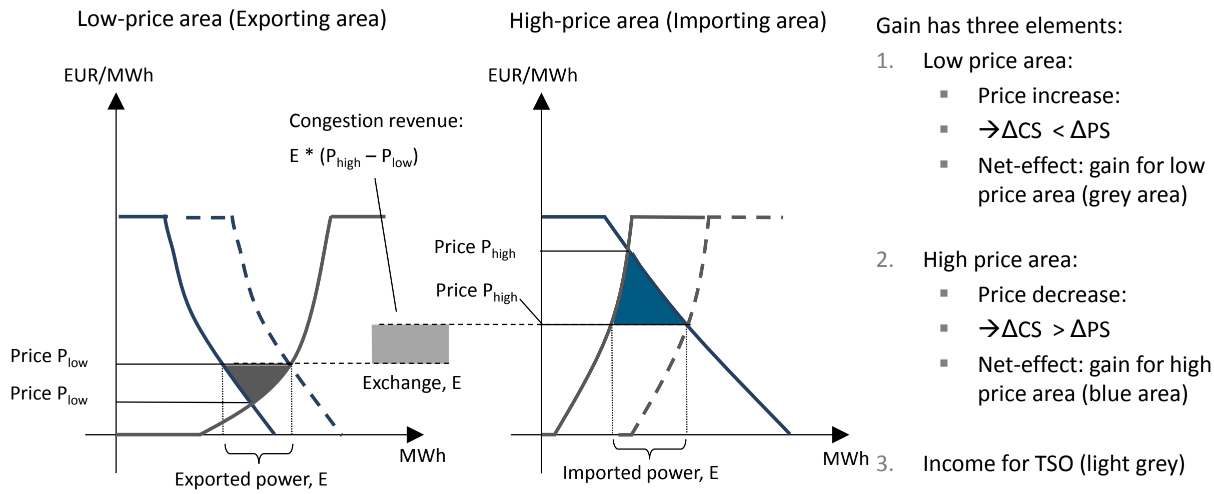


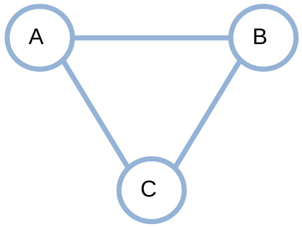
Figure 8 The gain from increased capacity is measured using standard welfare economics

In principle should all benefits and costs be taken into account in an impact assessment. This will not be done within this project. The assessment will only qualify and quantify increased benefit of better utilization of capacity in the day-ahead market. As such, modelling of welfare costs outside this market is not in scope (i.e. grid operation costs – if variable under different exchange scenarios, e.g. redispCNTCh costs, grid losses, DC cable losses), and impacts on adjacent markets (financial, ID, RPM) is also not quantified (only qualitatively addressed in Section 3.3). It is not considered a risk that these simplifications will lead to erroneous welfare estimates, as the majority of power is traded in the day-ahead market, and the majority of welfare is related to this market.

3.1.1 Local versus global effects

From an overall perspective, i.e. taking the welfare effects of all parties into account , FB will in theory create at least the same amount of welfare compared to CNTC, but probably more, provided that the level of security of supply does not change. However, looking at each bidding zone individually, the welfare of one bidding zone might decrease going FB compared to CNTC. There exist two possibilities. *Firstly* the negative effect is due to changes in CR combined with the chosen CR allocation method between bidding zones. *Secondly* capacity on some lines might decrease compared to the CNTC approach, in order to increase on other lines: for a bidding area, which is in an export situation in the majority of hours, this may cause an overall loss. A numerical example is provided to illustrate this first welfare effect, the global vs. the local welfare effect, in a simple 3-node meshed network.

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

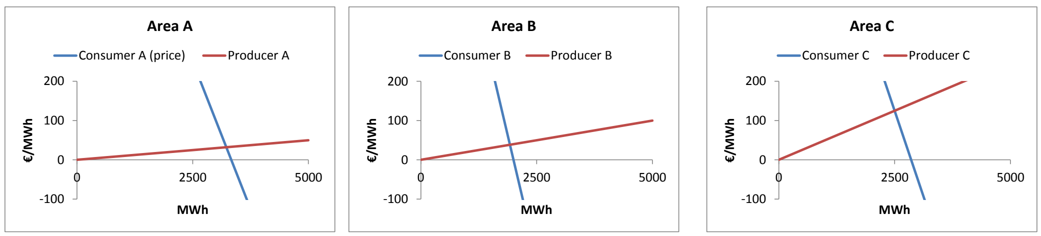


Figure 9 The basics of the market and the power system in the numerical example

The intersection between demand and supply in the three market areas in Figure 9 illustrates an equilibrium situation where no exchange is taking place, i.e. the prices that would balance each market area with no interconnection capacity (i.e. isolated markets). If we allow for exchange of power on interconnectors with a capacity of 1000 MW each, the market outcome for CNTC and FB capacity allocation is illustrated in Figure 10. Using CNTC only 750 MW of capacity can be allow cf. section 2.2, with the result that the physical flow will reflect the ex ante capacity limitation to 750 MW .

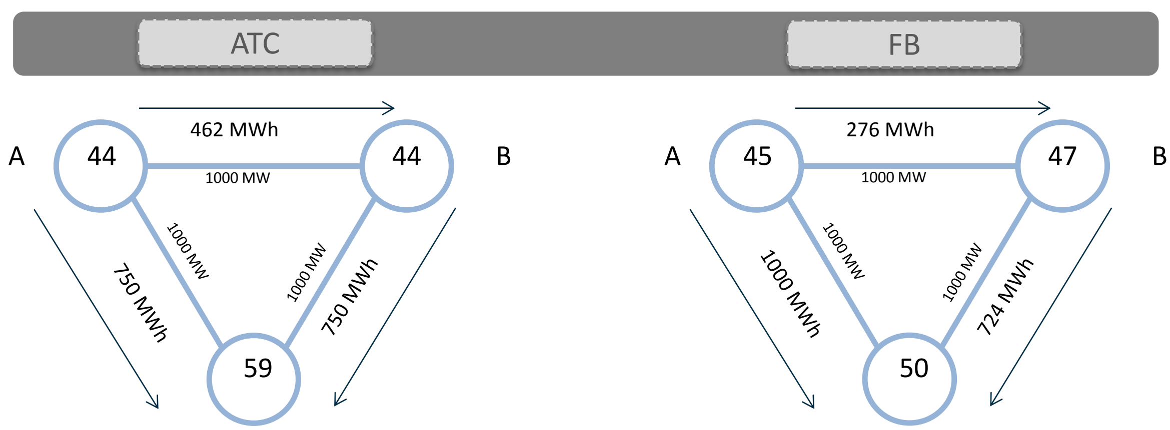


Figure 10 Market outcome differ using FB or CNTC

Note. All monetary numbers are in euros. Arrows indicate flow direction. The numbers in MWh indicate market flows from the price calculation on the PX

Based on the market outcome, the computation of welfare effects can be performed as is illustrated in the tables below. Please note that all areas gain looking only at changes in PS+CS by going FB. However, taking the effect on CR into account, the overall decrease in CR from 23,000 to 7,400 entails a welfare loss in area A and B of 2 and 3 respectively.

ATC

Bidding zone	*Consumer surplus*	*Producer surplus*	*PS+CS*	*Share of congestion rent*	*Total surplus*
A	1.523	97	1.620	5,8	1.626
B	914	48	962	5,8	968
C	1.264	35	1.299	11,5	1.311
Sum	3.701	180	3.881	23	3.905

FB

Bidding zone	*Consumer surplus*	*Producer surplus*	*PS+CS*	*Share of congestion rent*	*Total surplus*
A	1.521	99	1.621	2,8	1.624
B	908	55	963	1,2	965
C	1.290	26	1.315	3,4	1.318
Sum	3.720	179	3.899	7,4	3.907

Figure 11 Area A and B loose, although the overall welfare gain is positive

Note. All numbers are in 1 000 euros. Due to rounding the CR and total surplus might not exactly reflect the sum or difference of the input numbers

So, changes in CR can make the difference between welfare loss and welfare gain for a bidding zone. In the example ½ of the CR on a particular interconnector is allocated to the bidding zone from where the interconnector departs or arrives (both under CNTC and FB). This allocation method reflects the current Nordic approach (under CNTC). The CR sharing key in a meshed network managed by FB is subject to design in the Nordic FB feasibility study part 2.

3.2 Investment signal

Shadow prices are computed finding the solution to any constrained optimization problem, so also for the optimal mCNTChing of orders with given network constraints. 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. 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 5, being equal to the price difference between the bidding areas.

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

Figure 12 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

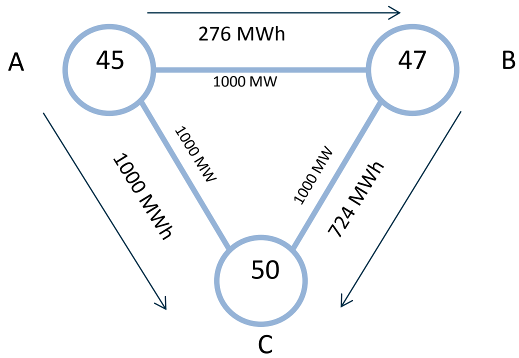
$45 - 50 = \delta_{AC}(0-1)$

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

$5 = \delta_{AC}$

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. The numerical example below provides an insight to this result. The example is based on the same market and grid assumptions as outlined in Figure 9 and Figure 10 above.



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

Figure 13 Market outcome

It is easy to see that shadow prices at Line A→B and B→C equal 0. The value added of increasing capacity marginally of these lines is 0 as the binding constraint is located at Line A→C.

By applying the formula for 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.

3.3 Impact on adjacent markets of FB in the day-ahead market

In this report the focus is on the qualification and quantification of the increased benefit of better utilization of capacity in the day-ahead market when implementing FB. Adjacent electricity markets, i.e. the intraday (ID) market, balancing market and financial market are not in the scope of this economic impact assessment. The implementation of FB may, however, have some impact[2] 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, see Figure 14. As such, a qualitative reasoning on the impact of introducing FB on the DA market on the intraday (ID) market, balancing market and financial market is given in this section.

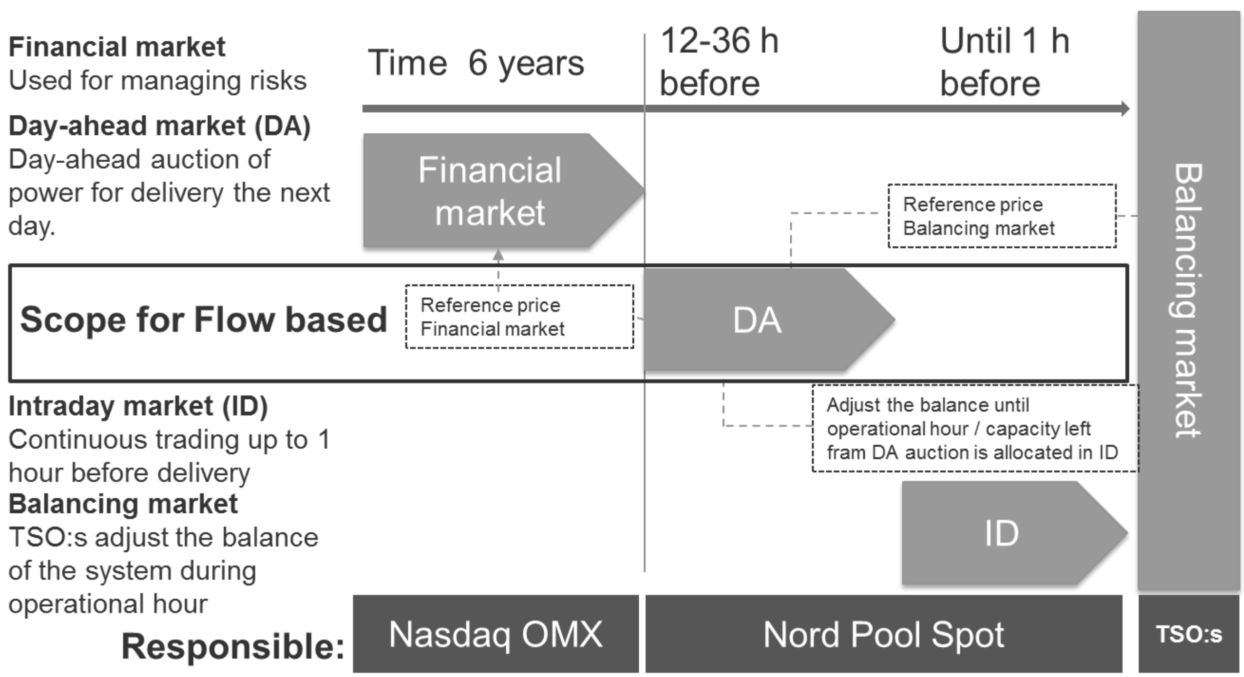


Figure 14: The dependencies between the different Nordic markets

The purpose of this chapter is to make a first attempt to map some of the impacts on the adjacent markets and identify issues that need to be further assessed, if FB would be implemented in the Nordic day-ahead market. In addition, the issues mentioned below should all be subject to a market consultation before a FB implementation can take place.

3.3.1 Intraday market

The Nordic ID market is a continuous market where energy is traded until one hour before the delivery hour. Trade is done on a first-come first-served principle where the highest buy price and the lowest sell

[2] E.g. on pricing principles, possibilities to trade, TSOs operation of the balancing markets etc.

price get served first. Implementation of FB capacity allocation in the day-ahead market may lead to more occasions with price differences between bidding zones compared to CNTC. It relates to the fact that the FB approach allows all transactions to compete for the scarce grid capacity and that different transactions between bidding areas have a different influence on the CNEs. The difference in influence on the CNEs may lead to area price differences between bidding areas.

ID trade can take place within bidding areas and between bidding areas when there still is capacity available after the day-ahead market ('left-over' capacity). If FB would be implemented in the day-ahead market while the ID market is still served by means of CNTCs, the FB domain from the day-ahead market could be translated into an ID CNTC-domain, as shown in Figure 15.

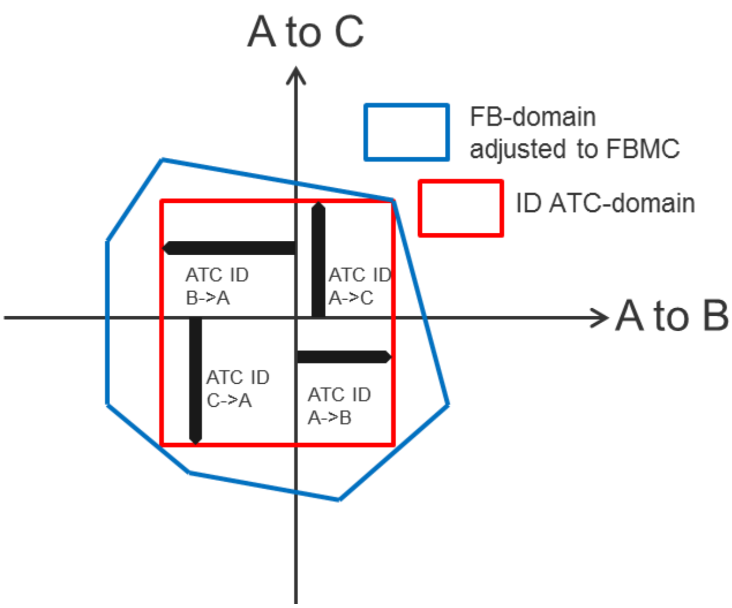


Figure 15 Translation of the Day-Ahead FB domain into an ID CNTC domain

When the ID CNTCs are assessed from the DA FB domain, it implies that these ID CNTCs reflect the left-over capacity from a FB point of view, as illustrated in the example below. In Figure 16 below there is a flow from north to south and a CNE in SE3 that limits the flow. There is no physical congestion between SE1 and SE2 but they have different prices because they have a different impact (PTDF factor) on the CNE.

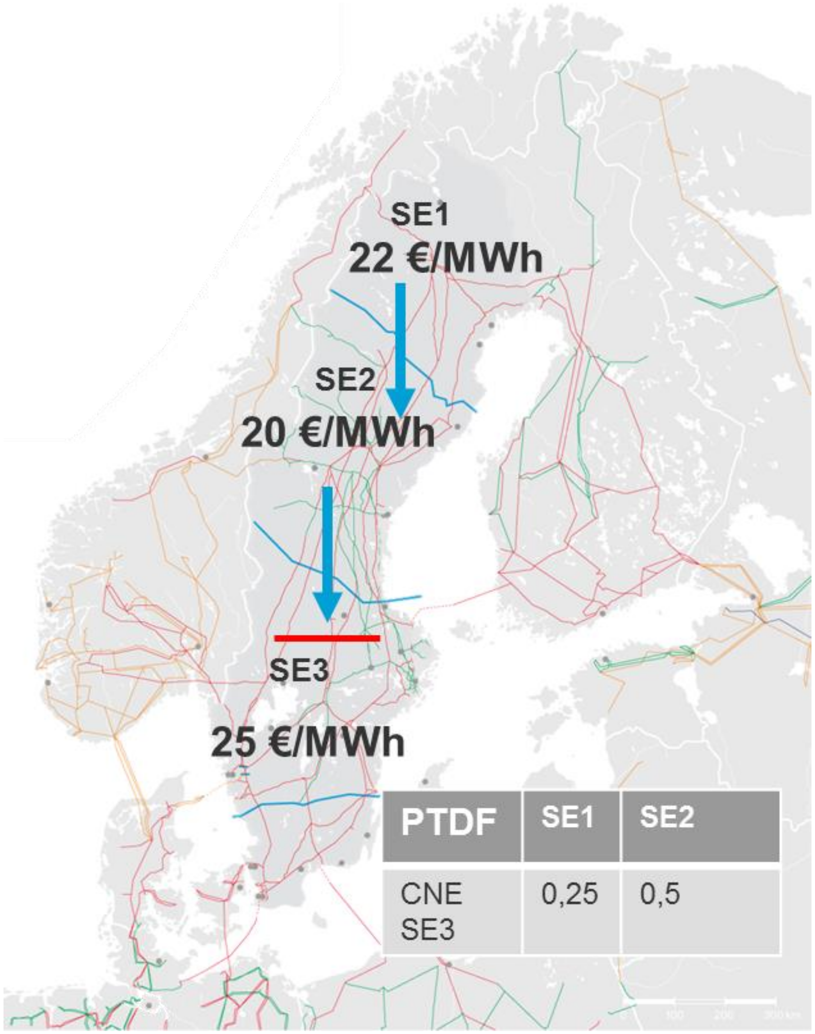


Figure 16 Example where ID trade between SE1 and SE2 is not possible due to a CNE in SE 3

In today’s CNTC world, ID trade would have been possible between SE1 and SE2 when there is no physical congestion between these two bidding zones. In the FB solution it is not possible for market actors to sell in SE2 and buy in SE1 since an increased NP in SE2 would lead to an overload on the CNE in SE3. As such, the CNTC value between SE1 and SE2 will be zero although the flow on the border between SE1 and SE2 is lower than the present NTC capacity.

3.3.2 Balancing market

In the balancing market, the day-ahead area prices are used as reference for the regulation prices. In the present system two bidding zones get the same price when there is no physical congestion between them. The balancing market doesn´t rely on the same capacity calculation as for the day-ahead 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 day-ahead and ID time frame has been allocated.

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 physical congestion between them. The different “reference” regulation prices depend on that the areas have different impact on the critical branch. The impact on the balancing market needs to be further assessed in feasibility study part 2 with respect to:

- Flowing balancing power costs
- Special regulations
- Bidding behaviour
- Principles for pricing balancing power
- Differences in flow between base case and operational hour

3.3.3 Financial market

In the Nordic financial market, financial contracts are traded through Nasdaq OMX with a time horizon up to six years. The implementation of FB would not change the fundamentals of the Nordic financial market. The Nordic system price, which is used as a reference price for the financial market, is calculated assuming no transmission constraints between the bidding zones and would as such remain the same regardless of FB or not. The bidding behaviour in the day-ahead market may change though and will impact the prices. The altered bidding behaviour and the new method for solving congestion may have an impact on the area prices and the prices of Electricity Price Area Differentials (EPADs). This could increase the uncertainty, and hence the risk premium for EPADs in some bidding zones, if it becomes more difficult for market actors to predict the area prices.

3.4 Market information

The market participants of the electricity markets need sufficient information in order to take efficient production, consumption, and trading decisions. The information on forecasted generation and consumption and available network capacity, including interconnections between bidding areas, is relevant to make these decisions.

At the moment, there is an ongoing process of implementing EU regulations related to cross-border capacity allocation and transparency issues. In this section we point out this regulation and discuss how it will affect the TSOs' actions in the future. Some of the changes will take place regardless of the capacity calculation method applied. After this we discuss the challenges in the publication and interpretation of market information if the FB approach is chosen.

3.4.1 Changes due to regulation

EU regulation 714/2009 on conditions for access to the network for cross-border exchanges in electricity is the origin for the ENTSO-E Network Code on Capacity Allocation and Congestion Management (NC CACM). At the moment NC CACM is at the comitology stage after which the network code will enter into force.

Regulation 543/2013 complements regulation 714/2009 in issues related to transparency (in particular article 15 and point 5 of Annex I). Regulation 543/2013 sets out the data which is to be made public and orders ENTSO-E to establish a public platform where the market participants can find the relevant data. The platform defined in 543/2013 will replace the current ENTSO-E platform. The Article 5 of 543/2013 states that ENTSO-E shall develop a Manual of Procedures (MoP) which specifies the data to be published and describes the technical specifications for the information exchange.

The most relevant implications of the regulation regarding market information and implementing FB approach are listed below (based on the January 2014 version of the NC CACM draft). TSOs need to

Regardless of the applied capacity calculation methodology

- consult the market participants on a proposal of the capacity calculation methodology (including a detailed description) on a European level (NC CACM draft, Articles 5 and 22)
- on request by the Agency (of regulators); in every second subsequent year, to prepare a report on capacity calculation including statistical and quality indicators and proposed improvement measures (The Agency shall decide whether to publish all or part of the report; NC CACM draft Article 36)
- every three months, report to the regulators all reductions made to the available cross-zonal capacities by an individual TSO due to system security reasons (The regulators shall decide whether to publish all or part of the report; NC CACM draft, Article 31)

For FB methodology only

- publish a tool which enables the market participants to evaluate how generation, consumption and grid configuration influence the feasible cross-border flows between bidding zones (NC CACM draft, Article 6)
- publish the relevant FB parameters, i.e. the non-redundant PTDFs associated to the anonymous CNEs including the physical margins available to the market, per market time unit (MoP, Detailed Data Descriptions)

3.4.2 Identified challenges in FB methodology

The current approach for calculating capacities is a fairly simple methodology for non-meshed grids. The Total Transmission Capacity (TTC) is the maximum exchange between two areas compatible with operational security. The Transmission Reliability Margin (TRM) is a security margin that copes with uncertainties of the future.

The Net Transfer Capacity NTC (trading capacity for the market) is defined as:

NTC = TTC - TRM

NTC is the maximum exchange program between two areas compatible with security standards applicable in both areas and taking into account the technical uncertainties on future network conditions. An example of hourly NTC values is presented in Figure 17 below.

	SE2 > SE3	SE3 > SE2	SE3 > SE4	SE4 > SE3	DK2 > SE4	SE4 > DK2
19-06-2014						
Max NTC	7 300	7 300	5 300	2 000	1 700	1 300
00 - 01	5 500	7 300	4 400	2 000	1 700	1 300
01 - 02	5 500	7 300	4 400	2 000	1 700	1 300
02 - 03	5 500	7 300	4 400	2 000	1 700	1 300
03 - 04	5 500	7 300	4 400	2 000	1 700	1 300
04 - 05	5 500	7 300	4 400	2 000	1 700	1 300
05 - 06	5 500	7 300	4 400	2 000	1 700	1 300
06 - 07	5 500	7 300	4 400	2 000	1 700	1 300
07 - 08	5 500	7 300	4 400	2 000	1 700	1 300
08 - 09	5 500	7 300	4 400	2 000	1 700	1 300

Figure 17 Example of hourly NTC figures for Elspot Capacity on Nord Pool Spot (www.nordpoolspot.com)

In contrast to the current capacity calculation approach, some challenges might arise when implementing the FB market coupling. The TSOs would be giving to the PX a PTDF-matrix per market time unit (one hour), potentially containing thousands of values. An example of a PTDF-matrix for the CWE region (with only four bidding zones), for a single hour, can be seen in the Figure 18 below. In the figure the ID column contains the anonymous CNE, the four subsequent columns contain the PTDF-values related to each bidding area, and the RAM column shows the remaining available margin.

	ID	BE-hub	DE-hub	FR-hub	NL-hub	RAM (MW)
hour 1	CB623	-0.00919	-0.09341	-0.04472	0.052	710
	CB625	0.02428	0.26172	0.17825	-0.00487	1069
	CB666	0.03693	-0.1232	0.09443	-0.08695	810
	CB667	0.0238	0.12224	0.06634	-0.03321	645
	CB668	-0.0238	-0.12224	-0.06634	-0.34572	1178
	CB669	0.09764	-0.15473	-0.21451	-0.09635	1021
	CB670	-0.07449	0.15941	0.06274	0.19062	977
	CB671	0.11946	0.38694	0.26366	0.5424	1355
	CB672	0.07615	-0.08117	-0.00745	-0.11123	658
	CB673	0.13337	-0.07247	-0.15455	-0.015	912
	CB674	0.03501	-0.16836	-0.28478	-0.07899	979
	CB675	0.044	0.1991	0.32575	0.11539	988
	CB676	-1	0	0	0	3612
	CB677	0	0	0	-1	3944
	CB678	0	0	0	1	4556
	CB679	0	0	1	0	5358
	CB680	0	0	-1	0	5312
	CB681	0	-1	0	0	4883
	CB682	0	1	0	0	6517

Figure 18 Example of a PTDF matrix from the CWE excel tool (available at www.casc.eu/en/Resource-center/CWE-Flow-Based-MC)

When a PTDF-matrix is compared to NTC-values, it can be easily justified that the market participants need a tool to interpret the FB values. Furthermore, as the FB market coupling price setting and price properties differ from those of the current well-known NTC-method, it takes time and effort to fully understand, for example, the prices in each bidding area. Even if the FB approach would be implemented, there will probably be a need for TSOs to publish NTC-values of cross-border capacities for the longer capacity calculation timeframes.

With regard to transparency, there are currently publicly available[3] harmonized Nordic rules for capacity calculation, and the FB approach will not bring a change to this. It is hard to argue whether the FB increases or decreases transparency compared to NTC, but regardless of the choice between NTC and FB, the network code NC CACM puts pressure on TSOs to consult the market participants on their capacity calculation methodology. This implies that the transparency is to increase regardless of which approach is chosen.

Central West Europe region has been developing FB methodology for quite some time, and they have already discovered solutions to some challenges. For example, an Excel tool has been published, which illustrates the potential cross-border flows resulting from the NPs of each bidding area. More information can be found at http://www.casc.eu/en/Resource-center/CWE-Flow-Based-MC

4. Market Simulations in Euphemia

4.1 Introduction

A set of market simulations is planned for the next phase (feasibility study part 2) of the project, pending a decision to continue the Nordic FB feasibility study. The simulations would involve the testing of the FB parameters derived with the prototype tool developed within this project against the order books at Nord Pool Spot referenced the same date. The output will be market results that can be compared both against the historical CNTC market outcome, and against the assumptions that were made when computing the FB parameters.

Although the results may provide (in)valuable input to the project, caution is needed when comparing these simulated FB market results with the historical CNTC market outcome, and especially when comparing the total socio-economic welfare, due to the reasons outlined below.

Firstly the order books at NPS are referenced the existing (CNTC) day-ahead market, and might have been different if FB were already implemented. This is especially due to different water values of the Nordic hydropower, as the expectations for future prices would be different.

[3] http://www.nordpoolspot.com/Global/Download%20Center/TSO/entsoe_Principles-for-determining-the-transfer-capacities-2013-12-02.pdf

Secondly, the market simulations only look at historical situations, which may not be relevant when assessing the future potential value and impact of implementing FB. This is due to both the planned changes to the Nordic transmission grid and generation capacity, any future developments of the CNTC model, and changes to the ability to predict the market outcome.

Thirdly, the CNTC and FB parameters are the output of completely different processes, and may not have the same level of security of supply.

The simulations aim to cover as broad an area as possible. The NPS area will be included in full, while the remaining European markets will either be estimated by net export curves, or fully included in the simulations.

4.1.1 Scenarios under which FB market coupling can provide a different market outcome compared to CNTC

The FB approach will only be able to improve the market outcome in cases where there were congestions (price differences) in the historical CNTC outcome, and where the FB solution space is larger than the CNTC space.

Conversely, there are some reasons to why the FB market simulations might provide a worse market outcome, such as more critical grid components being considered in the market coupling, non-optimal FB parameters, CNTCor the CNTC market outcome not fulfilling the requirements for security of supply used when computing the FB parameters.

A major aim of the study is to improve on the FB capacity calculation process developed by WP1, so some negative welfare (compared to CNTC) is expected during the simulations.

4.2 Simulation set-up

4.2.1 Description of the simulation process that we are setting-up

The simulation is set up as shown in Figure 19; there are two FB areas covering the two synchronous areas in the Nordic power system. The bidding areas are the same as in the current CNTC market coupling. The DC interconnectors are set up using the advanced hybrid coupling method [ref. WP1 report], by introducing a virtual area at all the terminal points at the Nordic side. For the DC interconnector SE3-FI this involves creating two virtual areas inside the same FB area.

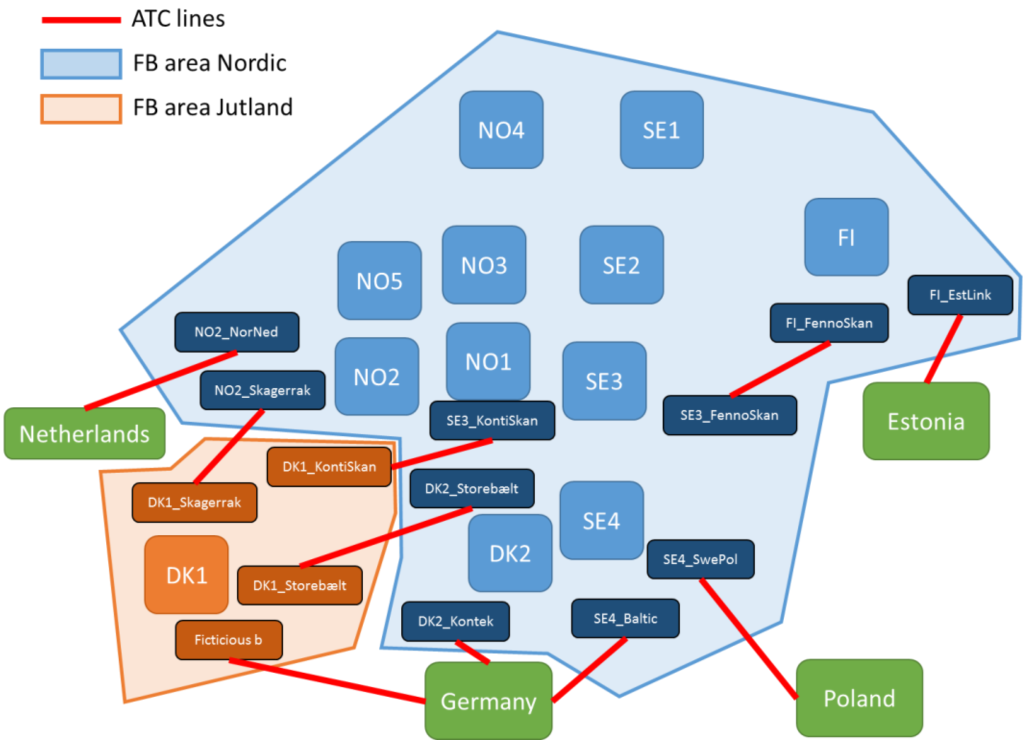


Figure 19 FB set up in the Nordics

4.3 Economic indicators

The table below shows the proposed indicators to be used when comparing the FB market simulations with the actual CNTC market results. The total welfare is the main indicator, and the one to show if FB can bring additional benefits compared to CNTC. The rest of the indicators are used to assess the redistribution effects, and to help explain any difference in total welfare.

The indicator 'energy balance' can show to what extent FB would require changes to the water value calculations. As such it is also an indicator as to what extent the total welfare deviates from what would actually be expected using FB.

Aim of study	*Indicator (change to …)*	*Relation to output from NPS*
Benefit of FB compared to CNTC	Total welfare	Sum of Nordic welfare and welfare of external areas
Redistribution effects	Nordic welfare	Sum of : 1. consumer and producer surplus in all Nordic areas 2. congestion rent on all Nordic interconnectors 3. 50 % of CR on interconnectors to other areas
	Welfare of external areas	50% of CR on interconnectors between Nordic areas and other areas

	Nordic congestion rent (CR)	Flow on each interconnector times price difference
	Consumer and producer surplus per area	Consumer and producer surplus per area
	National welfare	For each country the sum of: 1. consumer and producer surplus in all national areas 2. congestion rent on all internal interconnectors 3. 50 % of CR on interconnectors to other countries
Price effects	Volume weighed price for the Nordic region	Sum_for _all_areas_of(area_price * (area_buy_volume + area_sell_volume)) Divided by Sum_for_all_areas_of(area_buy_volume + area_sell_volume)
	Average sell and buy price	Same as above with only buy_volume or sell_volume respectively Per bidding area, groups of areas and for all areas
	Area prices	Area prices
	Price convergence	Proportion of hours with equal prices in all areas, or groups of areas
	Price volatility	Standard deviation of area prices
	Price convergence between neighbouring areas	Proportion of hours with equal prices in two neighboring areas
	Average price difference between neighbouring areas in hour with a price difference	Price difference between neighbouring areas, excluding hours with equal prices
Volume effects	Nordic volume	Sum of buy and sell volume in all areas
	National volume	For each country: sum of buy and sell volume in all national areas
	Area volumes	Buy and sell volumes in each area
	Total exchange	Sum of flow on all interconnectors
Validity of the results	Energy balance (related to energy constraint of hydro power)	Sum of production for all simulated days for the hydro areas (NO1 to NO5, SE1 and SE2)
Effect of the intuitive pCNTCh[4]	Difference in total welfare between comparable FB and FBI runs	Total welfare is sum of Nordic welfare and welfare of external areas

[4] The intuitive pCNTCh is a possible constraint imposed on the market coupling that would prohibit power to flow from high price areas to low price areas on any interconnector. This may have detrimental effects on the total welfare of the Nordic market.

Impact on social welfare from Hydro?

In the study of market welfare of FB market coupling, there is an additional limitation regarding the welfare results related to hydro production. As the historical bids submitted to Nord Pool Spot are used for simulating the FB market welfare, it is assumed that these bids correspond to actual marginal production cost. For hydro production in particular, this assumption is not correct. The marginal cost of hydropower production can be said to be very low, or almost zero. The bids instead correspond to the marginal water value of each reservoir. The water value is calculated by each hydropower producer and depends on factors such as reservoir filling, expected inflow and, not least, the cost of alternative power production.

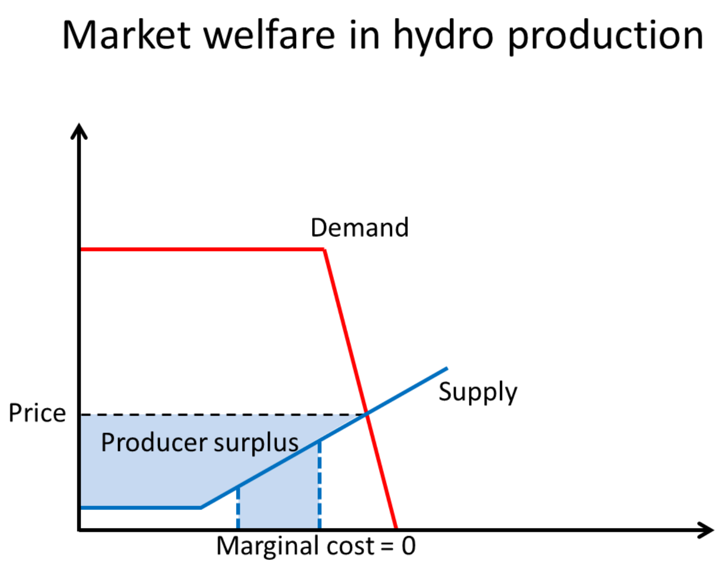


Figure 20 Traditionally, production bids are used to make up the supply curve when calculating market welfare. The producer surplus (PS) is part of the market welfare and is made up from the difference between the equilibrium price and the supply curve. The idea is that this represents the economic value for the power producers. However, for hydro production, the real marginal cost for production is almost zero, and there is therefore a "hidden" producer surplus not included in market welfare calculations (the area beneath the supply curve in the figure).

The result of this limitation in the market welfare assessment is an underestimation of the total welfare. Ideally, one would correct the bids from hydropower producers to reflect that the market welfare should be based on the actual marginal cost of production. As the production bids used for this study are anonymous, such a correction is not possible. This problem of course emerges in both the CNTC market welfare calculation as well as in the FB approach.

In the study of FB compared to CNTC, this becomes an issue if FB changes the price of hydro production bids. If the bids would not change, the error (underestimation) of market welfare would be the same for FB market coupling as for the CNTC approach. It is however possible that FB would enable a significantly larger exchange on interconnectors ("increasing the capacity") of some market areas, especially under flood periods, and that this would lead to changed supply curves. In the case of increased capacity out of hydro production intensive areas, this would mean an increase in "hidden" producers surplus and that the total market welfare is further underestimated.