Supporting document for the second amendment of the Nordic Capacity Calculation Region's proposal for capacity calculation methodology in accordance with Article 20(2) of Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management

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Abbreviations:

AAC	Already allocated capacity
AC	Alternating current
ACER	Agency for the Cooperation of Energy Regulators
AHC	Advanced hybrid coupling
ATC	Available transmission capacity
CACM GL	Capacity Allocation and Congestion Management Guideline
CCC	Coordinated capacity calculator
CCM	Capacity calculation methodology
CCR	Capacity calculation region
CGM	Common grid model
CNE	Critical network element
CNEC	Critical network element monitored under a contingency
CNTC	Coordinated net transmission capacity
DA	Day ahead
DC	Direct current
$\mathrm{F_0}$ or F_0	Linear approximation of a flow in the reference net position on a CNEC or combined dynamic constraint in a situation without any cross-zonal exchanges
$\mathrm{F_0}'$ or F_0'	Real flow on a CNEC or combined dynamic constraint in a situation without any cross-zonal exchanges
$\mathrm{F_{AAC}}$ or F_{AAC}	Flows resulting from previously allocated cross-zonal capacities for all CNECs and combined dynamic constraints
$\mathrm{F_{max}}$ or F_{max}	Maximum flow on all CNECs and combined dynamic constraints
$\mathrm{F_{ref}}$ or F_{ref}	Reference flows on all CNECs and combined dynamic constraints
$\mathrm{F_{RA}}$ or F_{RA}	Flow for increasing the RAM on a CNEC or combined dynamic constraint due to RAs taken into account in capacity calculation
$\mathrm{F_{RM}}$ or F_{RM}	Flow for reliability margin for all CNECs and combined dynamic constraints
FB	Flow-based
FCA GL	Forward Capacity Allocation Guideline
FCR	Frequency containment reserve
FRM	Flow reliability margin
GSK	Generation shift key
HVDC	High-voltage direct current
ID	Intraday
IGM	Individual grid model
IVA	Individual validation adjustment
KPI	Key performance indicators
LT	Long term
MC	Market coupling
MCO	Market coupling operator
MTU	Market time unit

NEMO	Nominated electricity market operator
NP	Net position
NRA	National Regulatory Authority
NTC	Net transfer capacity
PTDF or *PTDF*	Power transfer distribution factor
PTR	Physical transmission right
RA	Remedial action
RAM or *RAM*	Remaining available margin
RM	Reliability margin
RSC	Regional security coordinator
SHC	Standard hybrid coupling
SO GL	System Operation Guideline
TSO	Transmission system operator

Legal documents:

CACM Regulation	Commission regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management Guideline
FCA Regulation	Commission regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation
SO Regulation	Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation
Balancing Regulation	Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing
Regulation (EC) 714/2009	Regulation (EC) 714/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the network for cross-border exchanges in electricity and repealing Regulation (EC) no 1228/2003
Regulation (EC) 943/2019	Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast)
Transparency Regulation	Commission Regulation (EU) No 543/2013 of 14 June 2013 on submission and publication of data in electricity markets and amending Annex I to Regulation (EC) No 714/2009 of the European Parliament and of the Council

1 Introduction and executive summary

This document is the supporting document for the Nordic Capacity Calculation Methodology (CCM) for the Day-Ahead (DA), and Intraday (ID) timeframes for the Nordic Capacity Calculation Region (CCR). The intention of this document is to provide explanation, and background on the proposed legal text in the CCM.

The Nordic Capacity Calculation Methodology (CCM) for the Long-Term (LT), Day-Ahead (DA), and Intraday (ID) timeframes are to be developed in line with the requirements from the Forward Capacity Allocation Guideline (FCA GL)[1] and Capacity Allocation and Congestion Management Guideline (CACM GL)[2], and to be approved by the National Regulatory Authorities (NRAs). If NRAs are not able to approve the methodology proposed by the TSOs, they have to refer the methodology to the Agency for the Cooperation of Energy Regulators (ACER). ACER will then amend, and decide on, the methodology.

Below, an overview is provided of the Nordic LT and DA/ID CCM developments.

LT CCM

- January 16, 2019 – The Nordic TSOs submitted the LT CCM to the Nordic NRAs
- May 15, 2019 – Nordic NRAs referred the LT CCM to ACER
- October 30, 2019 – ACER decision to approve the Nordic LT CCM (Decision 16/2019)

DA/ID CCM

- July 16, 2018 – The Nordic NRAs approved the DA/ID CCM
- December 20, 2018 – The Danish, Finnish, and Swedish NRA issued a request for amendment for the DA/ID CCM
- June 20, 2019 – Amended DA/ID CCM (“first amendment”) submitted by Energinet, Fingrid, and Svenska kraftnät
- October / November 2019 – The Danish, Finnish, and Swedish NRA have agreed to approve the amended DA/ID CCM (“first amendment”)
- November 2019 – The TSOs of the CCR Nordic initiated the process of amending the DA/ID CCM (“second amendment”), in line with ACER’s decision on the LT CCM. This second amendment of the DA/ID CCM is intended to replace fully all earlier legal documents.

This document is the supporting document of the second amendment of the DA/ID CCM.

[1] *Commission regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation*

[2] *Commission regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management Guideline*

1.1 Proposal for the Capacity Calculation Methodology

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

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

Proposed approaches for the day-ahead and intraday market timeframes

For the day-ahead market timeframe:

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

For the intraday market timeframe:

The Nordic TSOs propose to implement a FB approach for the intraday timeframe. Until the time that the intraday market platform is technically able to utilize FB parameters, ATC capacity will be extracted from the ID FB domain as a transitional solution for calculation and allocation of intraday cross-zonal capacities.

2 Introduction to FB capacity calculation methodology

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

2.1 Motivation behind introducing FB approach in the CCR Nordic

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

Renewable energy is also a factor that creates a need for focusing on optimizing the scarce transmission capacity. When renewable energy is integrated into an electricity system, the location of the renewable energy can often be concentrated due to advantageous geographical areas, and weather patterns like wind that moves across geographical areas, which creates large differences in production volumes. To accommodate the difference in production there is a need to transport large quantities of electrical power across geographical areas. An example of this could be a windy day in the south west of Scandinavia. In such situations, Denmark has excessive wind production at a low marginal cost. This excess power could be moved to Sweden and Norway at higher prices, thus optimizing the value of the renewable production. In turn on a day with low wind, Denmark can benefit from the hydro production in Norway. To illustrate the current Nordic power system, see Figure 1.

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

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

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

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

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

To illustrate the complexity and challenges within the CCR Nordic, the interdependencies in the power grid are illustrated in Figure 2. The figure illustrates a situation with a generation increase in bidding zone

NO3 that is “consumed“ in bidding zone SE2 (yellow arrows). With the current NTC approach, this would generate a commercial trade between the two areas, as illustrated by the orange arrow.

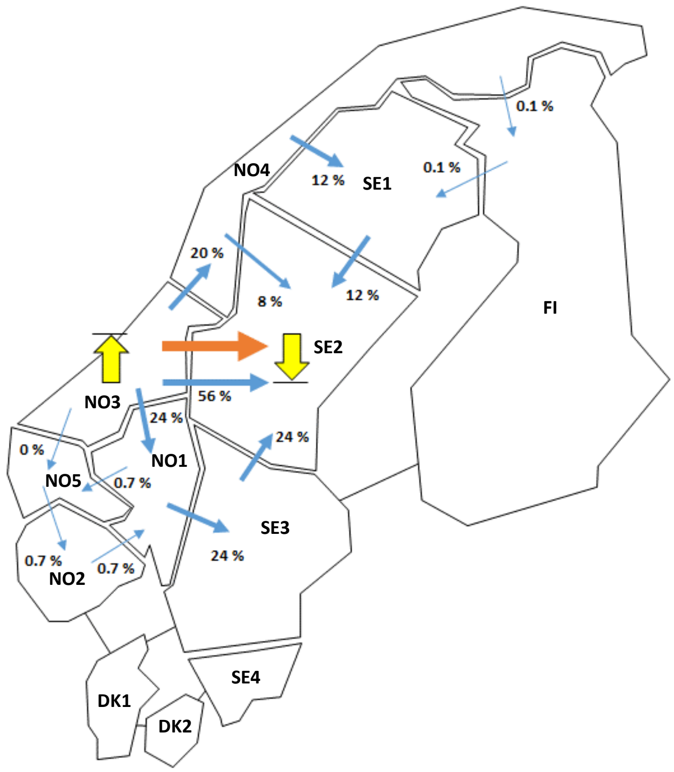

Figure 2 Commercial flows vs physical flows in the Nordic grid. Power is injected in bidding zone NO3 and consumed in bidding zone SE2

In reality, the physical flow from this trade would fan out in the transmission grid and follow the blue arrows in Figure 2. The largest flows are in the central area, but many tiny flows arise all over the power system as a consequence of the trade. All smaller transit flows are disregarded by the market, but in reality these flows are using available transmission capacity in other parts of the power system. This is called an external effect, and it has a negative impact on other market participants, who will face less transmission capacity due to this trade.

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

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

ACER – in its DECISION No 16/2019 OF THE EUROPEAN UNION AGENCY FOR THE COOPERATION OF ENERGY REGULATORS of 30 October 2019 approving the Nordic CCR TSOs' proposal for the long-term capacity calculation methodology – states:

> (35) According to the CACM Regulation, the CNTC approach was never meant to be applied in a meshed transmission network, because it is extremely difficult efficiently to define simultaneously feasible NTC values for highly interdependent borders as is the case for the Nordic CCR. Therefore, the Nordic CCR should ideally apply a flow-based approach,

2.2 Description of FB approach

In order to understand the FB approach, this section will to some extent compare the differences of FB and NTC approaches, this is to help the reader understand the changes in the capacity calculation once the approach is switched from the current NTC approach to FB approach. It is important to note that NTC is not CACM compliant, which means that some changes have to be made.

The Nordic day-ahead electricity market is part of the larger European electricity market. Market participants submit orders to the Nominated Electricity Market Operator[3] (NEMO). The NEMO forwards the orders to the joint European market coupling function (MCO) where the price coupling algorithm, Euphemia, solves an European-wide equilibrium, based on explicit economic welfare optimization. The organization of the intraday market is slightly different from the day-ahead market. In the intraday market, market participants submit orders to the NEMO, who forwards the orders to the intraday market platform. However, there is no explicit welfare optimization, rather a continuous matching of bids taking into account the transmission grid constraints. The process looks different from the day-ahead process, but in essence the outcome will be an implicit optimization of economic welfare taking into account the transmission grid constraints.

The market results of the intraday and day-ahead allocation process have to respect the physical limitations of the transmission grid. For this purpose, the TSOs currently provide transmission capacities

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

between bidding zones to the market. These transmission capacities act as constraints in the day-ahead and intraday market coupling algorithms.

In the FB approach the market coupling algorithm receives constraints in the format of power transfer distribution factors (PTDF) and remaining available margins (RAM), rather than transmission capacity between bidding zone borders. Essentially RAM can be understood as the transmission capacity given to the market. To understand what PTDFs are, it is useful to illustrate the difference between FB and NTC approaches using a simple three bidding zone grid shown in Figure 3.

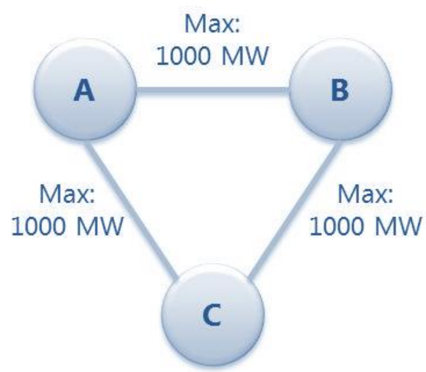

Figure 3 Transmission grid with three bidding zones.

In this example there are no internal constraints within the bidding zones, complex grid limitations or outages being considered. This means that the only limiting grid elements are the connecting transmission lines between the bidding zones[4]. All lines have a thermal capacity of 1000 MW and equal impedance (equal "electrical distance"). This thermal capacity of 1000 MW is referred to as RAM. RAM is the factor limiting the sum of power flows coming from all bidding zones that may flow on a particular connecting line at one point in time. Bidding zone C is a consumption bidding zone while bidding zones A and B are generation zones. At the time of capacity calculation (D-1)[5], the TSO does not know the final net position in the bidding zones, only the physical properties of the transmission grid. Due to the transmission grid topology, one MW produced in bidding zone A will induce a flow of 2/3 MW on the connecting line AC, 1/3 MW on the connecting line AB and 1/3 MW on the connecting line BC (when consumed in bidding zone C). The same holds true for generation in bidding zone B of which -1/3 appears on AB, 1/3 on AC and 2/3 on BC. These factors are known as PTDFs. PTDFs are parameters,

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

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

which show how much power is flowing on a particular transmission grid element when injecting one additional MW in a particular bidding zone.

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

Table 1 PTDF matrix of the transmission grid in Figure 3

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

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

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

The solution domains for the NTC and FB approaches are illustrated in Figure 4.

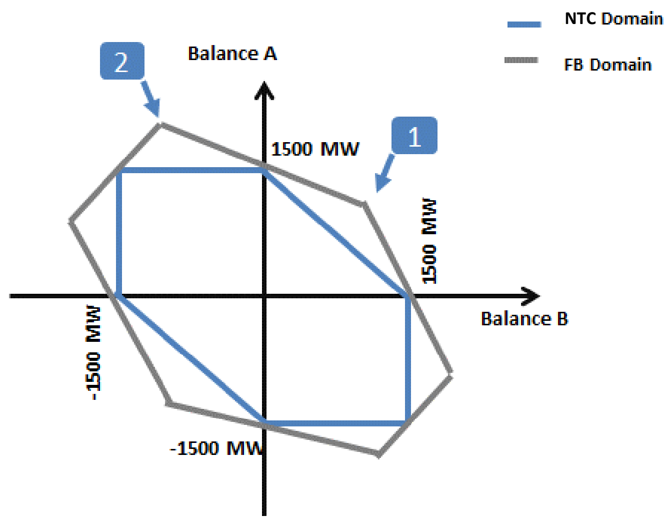

Figure 4 Solution domains for NTC and FB approaches

As it is shown in Figure 4, all NTC solutions are contained in the FB solution domain. This means that the FB approach has at least the same amount of possible solutions, and theoretically more. All points on the FB boundaries reflect transmission capacity limits in the grid that will induce price differences in all nodes, without implying that all transmission lines are congested simultaneously. This market solution is, however, not possible in the NTC approach due to the fact that in NTC allocation the real physical flows (the PTDF matrix) are not known between bidding zones.

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

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

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

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

ENERGINET SVENSKA KRAFTNÄT FINGRID Statnett

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

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

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

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

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

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

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

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

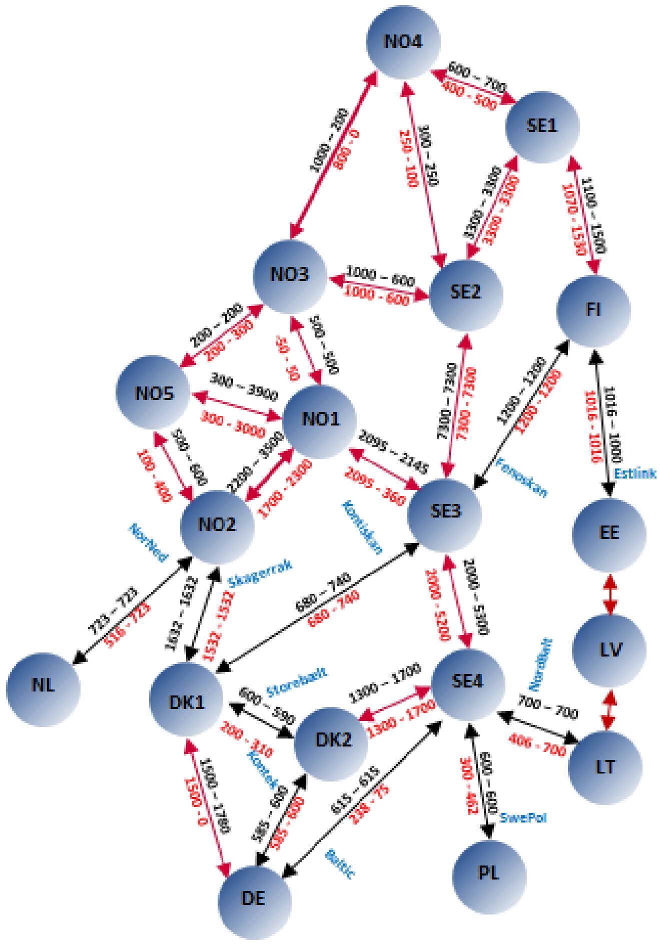

Figure 5 The Nordic power system and its connections to neighboring power systems.
This figure gives a schematic overview of the Nordic power system. AC interconnections are illustrated by red arrows and DC interconnections by black arrows. The maximum power exchange values for each interconnection is shown in black numbers, together with the provided transmission capacities for Jan 6'th 2017 at hour 10:00 – 11:00 in red numbers. The differences are due to both loop flow considerations and the outage situation on the relevant day. The Nordic bidding zones DK1, DK2, SE4 and FI are radially connected to the rest of the Nordic AC system, and thus not influenced by loop flows. The rest of the Nordic power system is interdependent and influenced by loop flows.

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

3 Motivation for the articles in the CCM proposal

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

3.1 Article 2: Definitions and interpretation

"virtual bidding zone" and "advanced hybrid coupling"

The term "virtual bidding zone" is linked to the application of the so-called "advanced hybrid coupling"-concept, which refers to the integration of the two capacity calculation methodologies, the NTC and the FB approach.

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

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

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

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

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

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

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

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

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

3.2 Article 3: Methodology for determining reliability margin

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

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

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

Proposed RM methodology

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

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

The two steps in the requirement form the basis for the proposed RM methodology. Figure 6 shows a general overview of the proposed RM methodology.

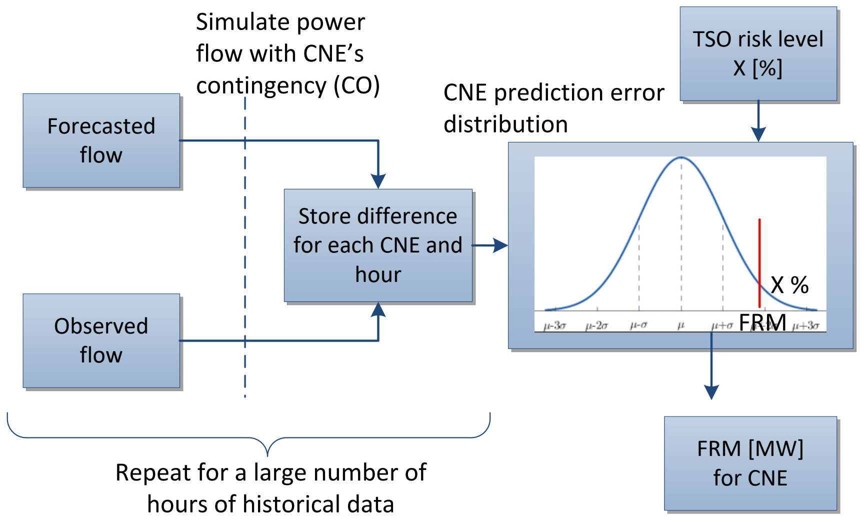

Figure 6. A schematic overview of the proposed RM methodology with its two steps; first a probability distribution is established based on historical data, then the RM value is derived from this distribution based on the set risk level.
The figure shows how the prediction error probability distribution is deduced for the CNE, given a power flow simulation with the contingency activated for the observed and forecasted system state.

In the first step a probability distribution of the deviation between the forecasted and realized (observed) power flows is determined for each CNE and combined dynamic constraint, based on a large number of historical snapshots[6] of the CGM for different hours. The power flows of CNEs and combined dynamic constraints are calculated with a power flow simulation tool with the contingency for the CNE tripped[7]. The AC load flow simulation is normally used, with the DC load flow simulation as a fallback in case of non-convergence. A large number of observed differences (in MW) form the prediction error distribution for the CNE or combined dynamic constraint.[8] The prediction error data is then fitted to a statistical distribution that minimizes the model error. This can be the normal distribution or any other suitable distribution.

In the second step of the methodology, the RM value is calculated by deriving a value from the probability distribution based on the TSOs risk level value [%]. The risk level is here defined as the area

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

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

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

(cumulative probability) right of the RM value in the prediction error probability distribution.[9] With a risk level of *X* %, the likelihood of having a prediction error greater than the RM value is *X* %, based on the historical observations for the CNE or combined dynamic constraint.[10] A low risk level results in high RM values and vice versa. A TSO may use different risk levels for different CNEs and combined dynamic constraints.

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

Principles for calculating the error distribution and the uncertainties

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

> *"The methodology to determine the reliability margin shall set out the principles for calculating the probability distribution of the deviations between the expected power flows at the time of the capacity calculation and realized power flows in real time, and specify the uncertainties to be taken into account in the calculation. To determine those uncertainties, the methodology shall in particular take into account:*
>
> *(a) unintended deviations of physical electricity flows within a market time unit caused by the adjustment of electricity flows within and between control areas, to maintain a constant frequency;*
>
> *(b) uncertainties which could affect capacity calculation and which could occur between the capacity calculation time- frame and real time, for the market time unit being considered."*

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

As previously shown in Figure 6, the basic idea behind the RM determination is to quantify the power flow uncertainty by comparing the forecasted power flow with the observed power flow in the corresponding snapshot of the CGM. Figure 7 shows a more detailed picture of the proposed method for deducing the distribution for each CNE and combined dynamic constraint. The forecasted power flow in the base case is compared with the realized power flow observed in a snapshot taken from the TSOs' control system. In order to compare the observed power flows from the snapshot with the predicted flows in a coherent way, the forecasted CNE and combined dynamic constraint power flows are adjusted by using the realized net positions from the snapshot, as illustrated in Figure 7. The reason for this model

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

[10] See Figure 6. With a risk level of 10%, 90% of the cumulative probability (area) in the distribution is left of the FRM value.

adjustment is that the intraday and bilateral trades as well as imbalances and reserve activations are reflected in the observed power flows and need to be reflected in the predicted power flows as well for a correct comparison. Indeed, in this way, only the following element of the RM is being covered:

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

For the FRM methodology, the uncertainty from the FB approach linearization and GSK strategy is included by using the PTDF when the forecasted power flows are adjusted. The highlighted blocks in Figure 7 show how the CNE power flow is adjusted based on the PTDF matrix and the realized net positions.

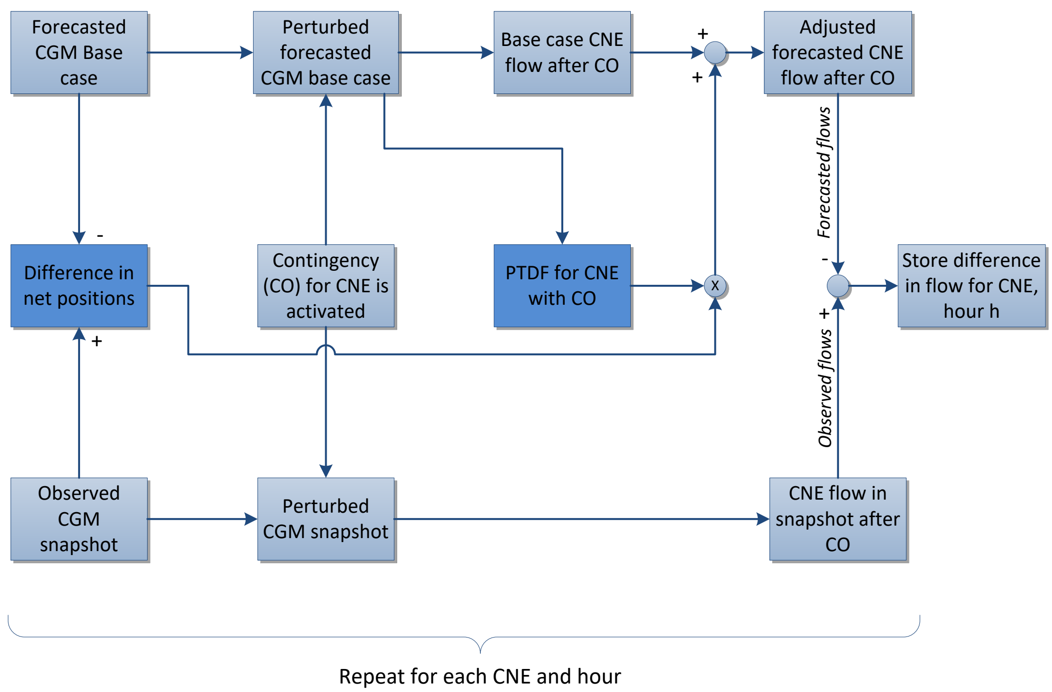

Figure 7. Process chart for evaluating the difference between the forecasted and observed power flow in the proposed FRM methodology for the FB approach. The uncertainty that originates from the FB approach (e.g. linearization and GSK strategy) is captured in the PTDF matrix, which is used to adjust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

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

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

The second element of the RM:

> *(a) unintended deviations of physical electricity flows within a market time unit caused by the adjustment of electricity flows within and between control areas, to maintain a constant frequency;*

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

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

The final RM value for each CNE and combined dynamic constraint, is obtained by adding “RM margin” and “FCR margin”.

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

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

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

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

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

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

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

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

"RM margin"

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

"FCR margin"

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

Set the RM value for FB approach (FRM)

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

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

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

In its base format the FRM value is always defined and stored in its absolute value, in MW. It may then be converted to a percentage of the Fmax for each CNE or combined dynamic constraint for comparison.

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 recalculation and revision will be initiated at least once a year.

3.3 Article 4: Methodology for determining operational security limits

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

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

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

Operational security limits

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

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

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

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

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

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

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

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

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

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

Figure 8 shows an example of how $F_{u,max}$ will be defined and how it relates to the F_{max} on a CNE.

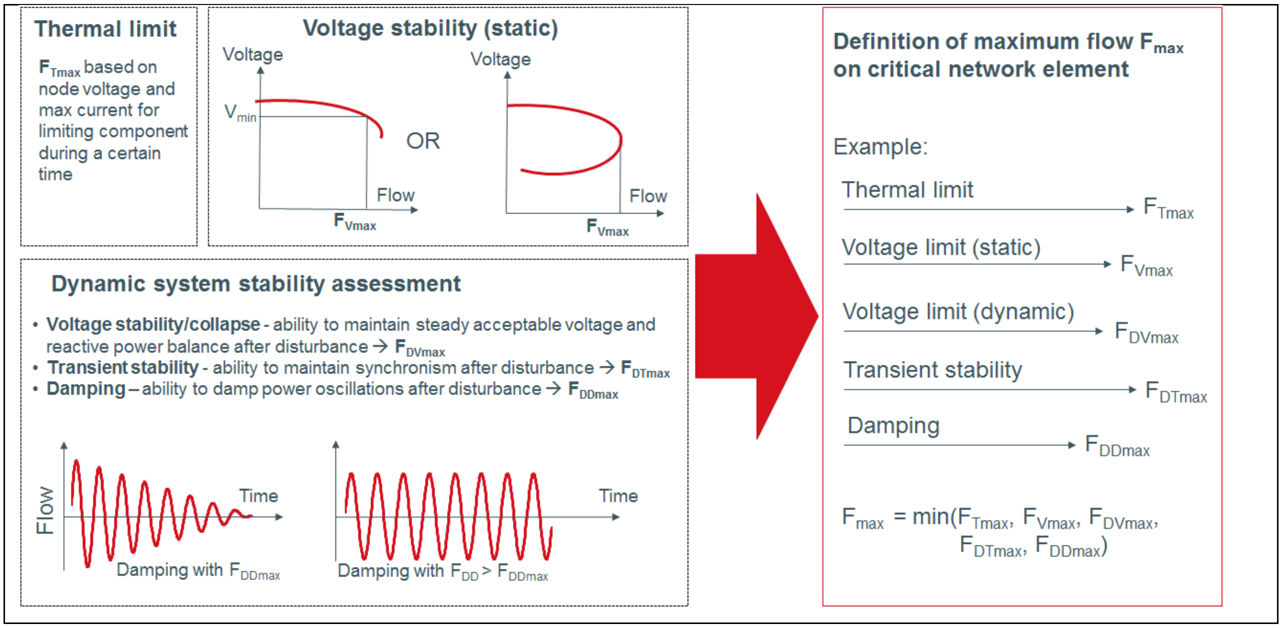

Figure 8: Definition of maximum flow (F_{max}) for CNEs

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

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

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

3.5 Article 6: Methodology for allocation constraints

Allocation constraints are constraints for the market optimization that cannot be transformed efficiently into power flows on a CNE or that are intended to increase the economic surplus in market coupling in capacity calculation.

There are three relevant allocation constraints considered in the Nordics:

a) The combined dynamic constraint, which limits the sum of power flows on a set of network elements, for the purpose to respect the dynamic stability limits.
b) Ramping rates for the HVDC interconnections, and
c) Implicit loss factors for the HVDC interconnections

a) The combined dynamic constraint limits the sum of power flows on a set of network elements, for the purpose to respect the dynamic stability limits. The TSO shall provide to the CCC the Fmax for each defined combined dynamic constraint and the information on which network elements are combined into such combined dynamic constraint.

Operational security limits are thermal limits, voltage limits, short-circuit current limits, frequency and dynamic stability limits. The thermal limits of network elements are easily monitored during capacity calculation and system operation. The restrictions are mainly given by the ambient temperature and the design of the network elements, whereas the loading after a contingency is relatively easily calculated. The assumption in such calculations is that the electricity system remains relatively stable after the contingency.

However, operational security is also impacted by the dynamic stability of the electricity system, which includes voltage stability and electromechanical oscillations. This affects the power system as a whole, not just one or a few network elements. The Nordic CCR needs to consider dynamic stability closely, mainly due to the electrical distances in the Nordic CCR being large which increase the likelihood of both voltage collapse and electromechanical oscillations.

In the south-west part of Norway there are a lot of production units in remote areas. These are connected with the eastern part (Oslo) where the consumption is high, especially during winter. The transmission lines between the production and the consumption area can be very long. When a contingency (N-1 situation) occurs, this can cause electromechanical oscillations on the remaining lines. In this example, there are more than 2 lines in parallel serving the Oslo region. In some dynamical limitations, there are up to 4 to 5 lines in which oscillations can occur. It is not possible to single out these stability problems to one or two network elements, due to the production being so distributed and spread over a large area. The dynamic limitations are therefore best described as a sum of flow through several lines. It also depends on which generators are in operation at a given time, which is impacted by many factors such as price in the neighboring areas and legal limitations regarding hydrological considerations in the water ways.

Another example which is closely monitored in Sweden is related to voltages in the network. Large amounts of electricity transferred through long transmission lines consumes significant amount of reactive power, which is mostly compensated by generators. This is the case in Sweden where most of the production is located in the north, and consumption in the south. Large transmission lines from SE1 and SE2 transfer power to SE3 and SE4. Eleven lines are connecting SE3 (Stockholm area) and SE2 and these are referred to as CUT2.

The voltage limit on CUT2 can vary depending on the dispatch situation (i.e. which generators are in operation) and planned outages. Generators operate in different operation modes and with varying reactive power producing capabilities and they contribute to voltage control differently. In case of a contingency where reactive power consumption increases or reactive power producing capabilities are reduced, the electricity system may end up in situation where reactive power sources are depleted. This could further reduce the voltage and result in a voltage collapse. Voltage collapses can lead to large-scale blackouts, such as those which occurred in Sweden in 1983 and 2003. To prevent this, the power flow through the corridor (CUT2) and possible contingencies need to be studied together. The variables used to monitor the voltage limits are the active power flow through the north-south corridors. From these, the maximum possible flow that can be transferred on all the lines together without leading to a voltage collapse after a contingency is calculated and used as an operational security limit in the dispatch centre. It is not possible to study the voltage problems by only looking at a subset of the 11 lines connecting SE2 and SE3. They must be monitored together.

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

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

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

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

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

The loss factor will be calculated based on two considerations:

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

3.6 Article 7: Methodology for determining generation shift keys (GSKs)

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

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

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

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

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

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

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

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

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

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

Table 2 GSK strategies in method proposal

Strategy number	Generation	Load	Description/comment
0	k_g	k_l	Custom GSK strategy with individual set of GSK factors for each generator unit and load for each market time unit for a TSO
1	$\max\{P_g - P_{min}, 0\}$	0	Generators participate relative to their margin to the generation minimum (MW) for the unit
2	$\max\{P_{max} - P_g, 0\}$	0	Generators participate relative to their margin to the installed capacity (MW) for the unit
3	P_{max}	0	Generators participate relative to their maximum (installed) capacity (MW)
4	1.0	0	Equal GSK factors 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 expected power generation or loading power (MW)
7	0	P_l	Loads participate relative to their expected loading power (MW)
8	0	1.0	Equal GSK factors for all loads, independently of their expected size of loading power

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

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

P_g : Active power generation [MW] for generator *g* contained in CGM

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

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

P_{load}: Active power load [MW] for load *l* contained in CGM

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

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

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

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

Undue discrimination has been explicitly defined in the clean energy package, more precisely in article 16(8) of Regulation 943, which states that TSOs shall allocate at least 70% of Fmax of cross border CNECs and (binding) internal CNECs to be compliant with legislation and not to undue discriminate between internal and external flows. It is about *undue discrimination* of *access* to the transmissions grid. And this is relevant as the transmission grid is the "market place".

The relevance of access to the market is founded / has been well recognized within modern micro economics for many years, where no (or minimum of) barriers for entry to the market is one of the core elements if market dynamics (invisible hand in the words of Adam Smith) shall lead to a welfare optimal / economic efficient allocation of supply and demand. Or in other words, a least-cost allocation of supply and demand. This insight has also found its way to electricity market design and thus has been implemented firstly in Regulation 714 and the CACM Regulation, and secondly has been explicitly defined in Regulation 943 (replacing 714). In the context of the CCM proposal it is therefore important to allow for equal access and treatment of all power flows, otherwise a least-cost allocation cannot be assured.

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

It is therefore recognized in the Nordic CCM project that *undue discrimination* to the market shall be defined as a situation where power flows are denied access to the transmission system because of reasons that cannot be justified based on operational security up to 70% of Fmax and economic efficiency, only for RAM beyond 70% of Fmax. The latter is sometimes denoted as social welfare on a European level, but the meaning is essentially the same as economic efficiency.

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

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

1. To apply RA at whatever cost, securing that 70% of Fmax on all CNECs and combined dynamic constraints, can be allocated to the market
2. To consider whether a limiting internal CNEC or internal combined dynamic constraint could be more efficiently managed by redispatching or countertrading (cross-border redispatch) in the operational time frame in order to allocate more than 70% of Fmax
3. To consider bidding zone reconfiguration to avoid structural congestions inside a bidding zone
4. To consider economical efficient investments to remove congestions

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

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

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

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

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

This section outlines the motivation for Article 9 and explains the content of the Article. Article 9 shall be read in close connection with Article 10 on the Impact of remedial actions (RAs) on CNEs, and Article 8 on rules for avoiding undue discrimination between internal and cross-zonal exchanges. The objective of Article 9 is to state which RAs to apply and how to determine availability of costly RAs.

The motivation for taking RAs into account in capacity calculation

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

The motivation for taking costly RA into account can be explained from a legal point and an economic point. From a legal point, it is a way to support the 70% obligation. From an economic point, it is an attempt to increase economic efficiency. Costly RAs might in theory improve economic efficiency whenever re-dispatching of generation and consumption is able to secure least-cost generation and consumption (on a European-wide level) at a lower welfare economic cost compared to the allocation outcome from the day-ahead market coupling. This situation might occur in a day-ahead market coupling with zonal pricing, as the zonal "price", compared to nodal pricing, does not automatically guarantee internal efficiency within a bidding area. In nodal pricing all CNEs will be taken efficiently into account in capacity allocation as the scarce transmission capacity of all CNEs will be exposed to scarcity pricing, not only cross-bidding zone CNEs as in zonal pricing. This includes CNEs which are denoted internal CNEs in the context of zonal pricing. On the other hand, it does not increase economic efficiency, if the only impact is a (virtual) increase in capacity. In such a situation the day ahead schedule leads to overloads of CNE(s), creating a need for re-dispatch and "moving the market" back to a balance that would have been in case of no virtual capacity.

Which RAs to apply

The CACM Regulation distinguishes between costly RAs and RAs without costs. Costly RA is here understood as a RA with a positive short run variable costs of being applied in capacity calculation and/or activated in real time. Costly RAs will only be applied to increase the RAM for internal CNEs and internal combined dynamic constraints in capacity calculation, if they are available and it is economic efficient to do so.

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

The overall purpose of considering costly RAs in capacity calculation is to enhance the social benefit (or economic efficiency) by potentially redispatching resources in order to obtain a merit order on both the generation and the consumptions side. RAs allow for an increase in RAM on internal CNECs and internal combined dynamic constraints, as denoted in the equation in Article 17(6).

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

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

How to assess availability of costly RAs

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

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

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

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

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

Review of RAs taken into account in capacity calculation

CACM article 27(4) states that:

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

(…..)

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

In order to make sure that the costly and non-costly RAs are applied in the best way, the TSOs will at least once a year review the application of RAs in capacity calculation in order to identify potential need for improvement. This is stated in Article 9(7) of the legal proposal.

3.9 Article 10: Impact of remedial actions (RAs) on critical network elements

This section describes the rules set out in Article 10 on the impact of RAs on internal CNEs, more specifically outlining how costly and non-costly RAs potentially can be applied to increase the RAM of internal CNECs and internal combined dynamic constraints in order to increase possible cross-zonal power exchange.

The objective of the Article 10 is to provide a short-term solution to the requirement set out in the Regulation 943, article 16(8), i.e. the 70% requirement. The mid- and long-term solutions, which are bidding zone reconfiguration and efficient investments, are not covered here.

According to regulation 943, article 16(8):

"Transmission system operators shall not limit the volume of interconnection capacity to be made available to market participants as a means of solving congestion inside their own bidding zone or as a means of managing flows resulting from transactions internal to bidding zones. Without prejudice to the application of the derogations under paragraphs 3 and 9 of this Article and to the application of Article 15(2), this paragraph shall be considered to be complied with where the following minimum levels of available capacity for cross-zonal trade are reached:

(a) (…)

(b) for borders using a flow-based approach, the minimum capacity shall be a margin set in the capacity calculation process as available for flows induced by cross-zonal exchange. The margin shall be 70 % of the capacity respecting operational security limits of internal and cross-zonal critical network elements, taking into account contingencies, as determined in accordance with the capacity allocation and congestion management guideline adopted on the basis of Article 18(5) of Regulation (EC) No 714/2009."

The headline for Article 10 is therefore *Impact of remedial actions (RAs) on critical network elements*, and thus Article 10 outlines the foreseen steps to manage the following issues:

1. Which CNECs shall be considered in capacity calculation;
2. To what extent can the RAM of a CNEC or combined dynamic constraint be increased to meet the 70% requirement by the application of non-costly and/or costly RA (operational security test);
3. Will the application of costly RA, to increase the capacity of internal CNECs and internal combined dynamic constraints beyond the 70% requirement, improve economy efficiency (economic efficiency test)? Note: this test needs to be developed within 18 months after go-live as stated in Article 5(5).

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

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

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

Costly RA is normally recognized as redispatching. Thus, the third step outlines the test to be applied in order to decide whether social welfare is increased by applying redispatching in capacity calculation. The social welfare (or economic efficiency) is assessed by comparing the expected marginal social cost of applying redispatching, with the expected marginal social cost of limiting cross-zonal trade (by providing the CNEC and combined dynamic constraint to the capacity calculation without any increase in RAM). If the expected social cost of applying redispatching is lower than the expected social costs of limiting cross-border trade, the amount of available redispatching will be applied in capacity calculation in order to increase the RAM. How this test shall be conducted in practice is yet to be develop, cf. article 5(5) of the proposed CCM.

3.10 Article 11: Previously allocated cross-zonal capacities

TSOs shall take into account capacities allocated already before the day-ahead market timeframe when calculating day-ahead cross-zonal capacities. Thus capacity allocated for nominated Physical Transmission Rights (PTRs) or capacity reserved for cross-zonal power exchange of ancillary services, where appropriate, have to be subtracted from the RAMs of affected CNECs and combined dynamic constraints. This will be done by translating already allocated cross-zonal capacity into resulting power flows on each CNEC and combined dynamic constraint by applying PTDFs. This is explained in Article 16. The resulting flows will be included in the RAM equation defined in Article 17(6) to take into account the previously allocated cross-zonal capacity.

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

This article describes the capacity calculation process, and the entity responsible, while referring to the relevant articles in the CCM.

3.12 Article 13: Description of the calculation of power transfer distribution factors

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

For a CNEC and combined dynamic constraint that includes either a contingency or a RA, requiring the disconnection of network elements, generators, or loads, the PTDFs are calculated to represent the system state after the disconnections. This will minimize the errors, but means that the full set of PTDFs for all CNECs and combined dynamic constraints do not represent the same transmission grid state / model. Instead, the PTDFs for each CNEC and combined dynamic 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 analysis for the forecasted state of the electricity power system[11]. The active and reactive power flows in steady state can be described by the power flow equations:

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

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

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 transmission lines and shunts connected to the node. The aim of these power flow equations is to determine the voltages (magnitude and angle) at all buses. If the voltages are known, it is possible to determine the power flows, losses, and currents.

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

Linearizing the power flow equations

Calculation of the PTDFs is based on standard DC linearization[12] including the following simplifications:

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

The power flow equations now become:

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

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

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

The zone-to-slack PTDFs indicate how much the flow on a CNEC or combined dynamic constraint changes when the injection in a bidding zone increases while this additional injection is being absorbed in the slack node. As all commercial exchanges take place from one bidding zone to the other, the zone-to-slack PTDF can (easily) be converted into a zone-to-zone PTDF, by subtracting the “to” bidding zone PTDF from the “from” bidding zone PTDF, as demonstrated in the example below.

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

$$\begin{array}{c} \boldsymbol{PTDF}_{z2s} \\ \begin{array}{c c} & \begin{array}{ccc} \mathrm{A} & \mathrm{B} & \mathrm{C} \end{array} \\ \begin{array}{c} \mathrm{CNEC1} \\ \mathrm{CNEC2} \\ \mathrm{CNEC3} \end{array} & \begin{bmatrix} -0.2 & 0.4 & 0.25 \\ 0.04 & -0.03 & -0.1 \\ 0.05 & 0.15 & -0.4 \end{bmatrix} \end{array} \end{array} \Rightarrow \begin{array}{c} \boldsymbol{PTDF}_{z2z} \\ \begin{array}{c c} & \begin{array}{ccc} \mathrm{A>B} & \mathrm{A>C} & \mathrm{B>C} \end{array} \\ \begin{array}{c} \mathrm{CNEC1} \\ \mathrm{CNEC2} \\ \mathrm{CNEC3} \end{array} & \begin{bmatrix} -0.6 & -0.45 & 0.15 \\ 0.07 & 0.14 & 0.07 \\ -0.1 & 0.45 & 0.55 \end{bmatrix} \end{array} \end{array} \quad (8)$$

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

Only the CNECs that are significantly impacted by cross-border trade are maintained in the capacity calculation and allocation process. Or in other words: the CNECs with a maximum zone-to-zone PTDF smaller than (at least) 5% are removed from the initial list with CNECs.

For the example above, the maximum zone-to-zone PTDFs are as follows: $PTDF_{z2zmax}$(CNEC1) = 0.15 – (–0.6) = 0.75, $PTDF_{z2zmax}$(CNEC2) = 0.07, $PTDF_{z2zmax}$(CNEC3) = 0.65. This implies that with a threshold of 5%, all CNECs are maintained in the capacity calculation and allocation process. With a threshold of 15%, the CNEC2 is removed from the initial list with CNECs.

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

The RAs provided by the TSOs, to be taken into account in the capacity calculation by the CCC, are not interdependent. As such, the RAs do not need to be coordinated / optimized. The effect of the RA – i.e the increase of the RAM of the CNEC or the combined dynamic constraint (F_{RA}) – is computed and the RAM is adjusted accordingly (as defined in Article 17(6)).

3.15 Article 16: Rules for taking into account previously allocated cross-zonal capacity

TSOs shall take into account capacities allocated already before the day-ahead market timeframe when calculating day-ahead cross-zonal capacities. Thus capacity allocated for nominated Physical Transmission Rights (PTRs) or capacity reserved for cross-zonal power exchange of ancillary services, where appropriate, have to be subtracted from the RAMs of affected CNECs and combined dynamic constraints. This will be done by translating already allocated cross-zonal capacity into resulting power flows on each CNEC and combined dynamic constraint by applying PTDFs. The resulting flows will be included in the RAM equation defined in Article 17(6) to take into account the previously allocated cross-zonal capacity.

There is a difference between how capacity options (like the capacity that is reserved for cross-zonal exchange of ancillary services) is taken into account, and how capacity nominations are considered. Indeed, in the case of capacity options only the loading effect of the capacity reservation can be taken into account, as it is not sure to what extent the relieving effect will occur. As such, only the positive zone-to-zone PTDF factors are used when assessing the flows resulting from capacity options. In case of nominated capacity, both the loading and relieving effect need to be assessed, and the full PTDF matrix is used to compute the corresponding flows.

3.16 Article 17: Description of the calculation of available margins on critical network elements before validation

The mathematical description of the RAM is explained in this article. The F_{max} for the combined dynamic constraints are computed by the TSOs and provided to the CCC. For the CNECs it is the maximum current limit I_{max}, as provided by the TSOs, that is translated into the F_{max} based on the voltages and cos(φ) computed from the CGM by means of an AC load flow computation.

The *RAM* is defined by the following equation:

$$\overrightarrow{RAM}_{bv} = \vec{F}_{max} + \vec{F}_{RA} - \vec{F}_{RM} - \vec{F}_0 - \vec{F}_{AAC} \tag{9}$$

$\overrightarrow{RAM}_{bv}$	remaining available margin before validation
$\vec{F}_{max}$	maximum flow on all CNECs and combined dynamic constraints
$\vec{F}_{RA}$	flow for increasing the RAM on a CNEC or combined dynamic constraint due to RAs taken into account in capacity calculation
$\vec{F}_{RM}$	flow for reliability margin for all CNECs and combined dynamic constraints
$\vec{F}_0$	linear approximation of a flow in the reference net position on a CNEC or combined dynamic constraint in a situation without any cross-zonal exchanges
$\vec{F}_{AAC}$	flows resulting from previously allocated cross-zonal capacities for all CNECs and combined dynamic constraints

F_{max} is defined by the operational security limits described in Article 4 of the CCM proposal. The methodology for calculating the F_{RM} is described in the Article 3 in the CCM proposal, and the calculation of the F_{RA} is described in Article 9 of the CCM proposal. The F_{AAC} is the already allocated capacity (previously allocated capacity), as explained in Article 16.

The last ingredient in the calculation of *RAM* is the F_0, being a linear approximation of a flow in a situation without any cross-zonal exchanges:

$$\vec{F}_0 = \vec{F}_{ref} - \boldsymbol{PTDF} \cdot \overrightarrow{NP}_{ref} \tag{10}$$

with

$\vec{F}_0$	linear approximation of a flow in the reference net position on a CNEC or combined dynamic constraint in a situation without any cross-zonal exchanges

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

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

The F_0 component is essentially a part of the linearization of the power flows from the CGM, and is the fixed component in the linear formulation of the power flow in the reference commercial situation, as can be seen in Figure 9 below.

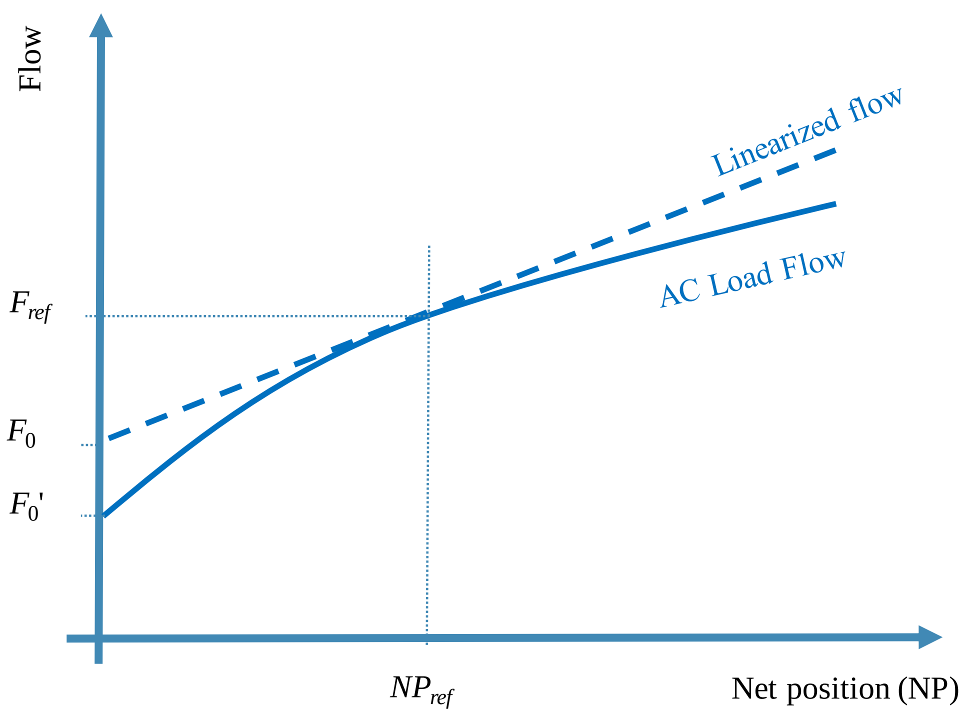


Figure 9 Linearization in the FB methodology

The concave solid line, "AC flow", in Figure 9 depicts an example of a real physical flow. This is a non-linear function of net positions for all bidding zones with an influence on the relevant (unspecified) transmission grid element. The real AC flow must, however, be represented by an equivalent linearized power flow in the market coupling.

In order to have a linearized power flow as accurately as possible to represent the real AC flow close to the reference commercial situation, the linear flow equation is derived as a tangent to the reference power flow F_{ref}. The F_0, often referred to as "flow at zero net position", is thus in reality the intersection between the linearized power flow and the vertical power flow axes. The real "flow at zero net position" is depicted in Figure 9 as F_0'. The F_0' consists essentially of power flows that start and end in the same bidding zone while traversing a CNE either within the same bidding zone, or in an adjacent bidding zone. These flows cannot be managed by the market coupling algorithm due to the fact that the sending and receiving end for the power flow is within the same bidding area, and thus are exposed to the same prices. The only way to remove these internal flows and loop flows and at the same time maintain operational security, is a further split into smaller bidding zones, and ultimately obtain a nodal pricing system.

The RAM component F_0, is thus an element of the linearization, and does not represent real power flows. However, from an operational security point of view, the F_0 is a necessary mathematical construction in order to have a sufficiently accurate prediction of real power flows in the market algorithm without compromising the integrity of the power system. Both F_0 and F_0' are a consequence of the zonal structure in the FB approach.

3.17 Article 18: Rules for sharing the power flow capabilities of CNECs among different CCRs

In this article the AHC is being described without naming at such though. Indeed, by the application of AHC, all exchanges in the grid (including the ones on the DC links towards different CCRs) are competing for the scarce capacity on the Nordic AC network elements on an equal footing. The AHC is introduced and described in Section 3.1 of this document under the definitions of "virtual bidding zone".

3.18 Article 19: Methodology for the validation of cross-zonal capacity

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

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

Article 26 paragraph 1 reads:

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

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

When performing the validation, the TSOs shall consider operational security, taking into account new and relevant information obtained during or after the most recent capacity calculation. The TSOs will consider the operational security limits and the CGM to perform the validation, but may also consider additional CNECs, grid models, and other relevant information. The TSOs may use, but are not limited to use, the tools developed by the CCC for operational security analysis. The TSOs might also employ validation tools not available to the CCC.

The *RAM* may be adjusted during the validation by applying *IVA* (individual validation adjustment) to take into account relevant information known at the time of validation:

- A positive *IVA* value will decrease the *RAM*
- A negative *IVA* value will increase the *RAM*

Each application of *IVA* – restricted to the situations mentioned in Article 19(3) - needs to be justified by the TSOs applying it, by reporting on the need to apply *IVA*, and the rationale behind the *IVA* value, towards the CCC and other TSOs. The CCC will provide information on reductions or increases in cross-zonal capacity to the neighboring CCCs.

3.19 Article 20: Transitional solution for calculation and allocation of intraday cross-zonal capacities for continuous trading in the Intraday timeframe

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

Until the single intraday coupling is able to support the allocation of cross-zonal capacities based on flow-based parameters, the CCC shall transform the final flow-based parameters (PTDF and RAM) into available transmission capacity ('ATC') values on bidding zone borders of the Nordic CCR and bidding zone borders of neighboring CCRs.

Example

Imagine a grid component (CNEC) being impacted with 25% by an exchange from bidding zone A to B. Or in other words, if we exchange 100 MW from bidding zone A to B, the CNEC would be loaded with

25 MW.

If the RAM (Remaining Available Margin; the capacity available for the market) on this CNEC equals 200 MW, and we would assign the full 200 MW to be used by a commercial exchange from bidding zone A to B, this would imply an ATC(A->B) = 200/0.25 = 800 MW.

If we would assign the 200 MW to be used by commercial exchanges on several bidding zone borders, a rule is needed to do this, as explained in the text below.

Graphically, this could be visualized as the determination of a box within the FB domain, as depicted in Figure 10.

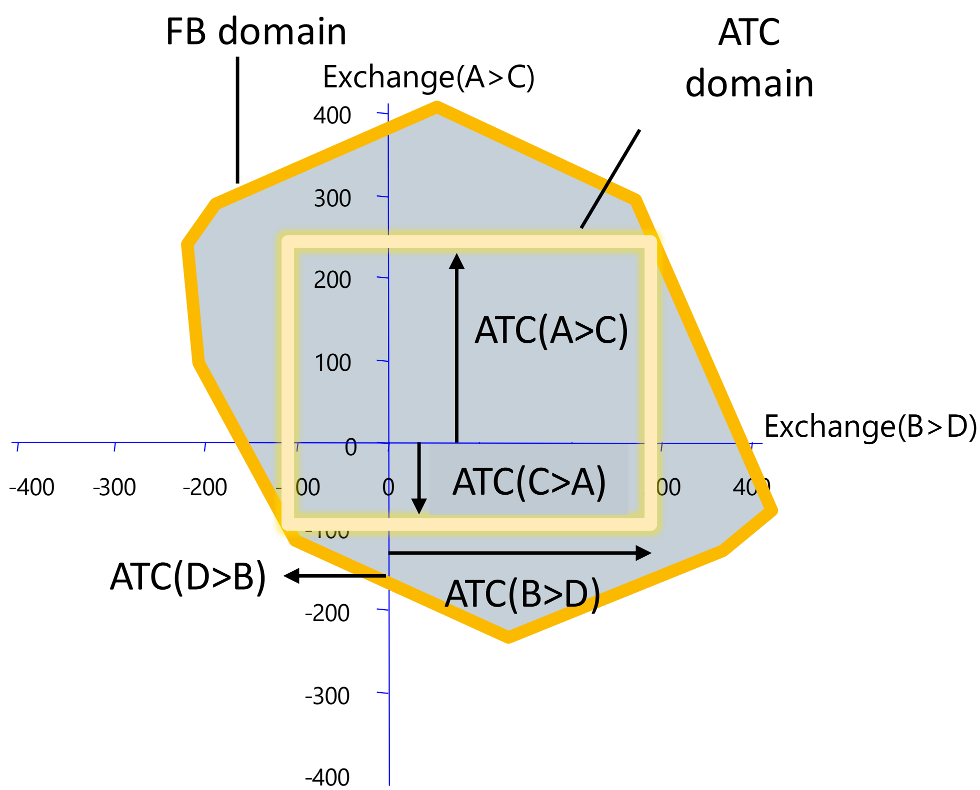


Figure 10 ATC domain extracted from the FB domain

It is clear from Figure 10, that the ATC domain depicted is not the only box that fits within the FB domain; one can "draw" many that would fit in the FB domain. Therefore a rule needs to be determined to do so.

In the CWE region - where this approach is applied to extract ATC values from the FB domain - the rule is based on an equal sharing of a CNEC's RAM between the electrical borders that are loading the CNEC. In the Nordics, an optimization-based approach is being developed to determine the ATC values. The optimization is formulated in the legal document as follows.

$$\text{Maximize } f(\overrightarrow{ATC}) \qquad (11)$$
$$\text{Subject to}$$
$$g_j(\sum_n ATC^n * PTDF_j^n) \leq h_j(RAM_j) \qquad \forall j \in \{All\ CNEs\ and\ allocation\ constraints\}$$

with

f	a function defining the weight for each border in the optimisation
g_j	a function defining the weight of each trade in the total flow on CNE j
h_j	a function defining the scaling of CNEs in non-relevant market directions
ATC^n	maximum available power exchange on bidding zone border n
$\overrightarrow{ATC}$	a vector of maximum available power exchanges for all borders
$PTDF_j^n$	zone-to-zone PTDF for bidding zone border n

The objective function is a maximization of a function of the ATC values to be computed (e.g. a product of the ATC values). The inequality constraints of the optimization indicate that the ATCs need to be determined in such a way that no overloads in the system are created (i.e. to determine a box within the FB domain). The inequality constraints are however formulated in a way that both the left-hand and right-hand side of the constraint are functions as well. Indeed, this is to build in some flexibility in the optimization (the problem is ”relaxed”), for example to allow for overloads in those directions where the market is not expected to end up (i.e. to allow the box to stick out of the linear security domain), as depicted in Figure 11. This with the objective to assess the largest ATC values possible, without jeopardizing the operational security.

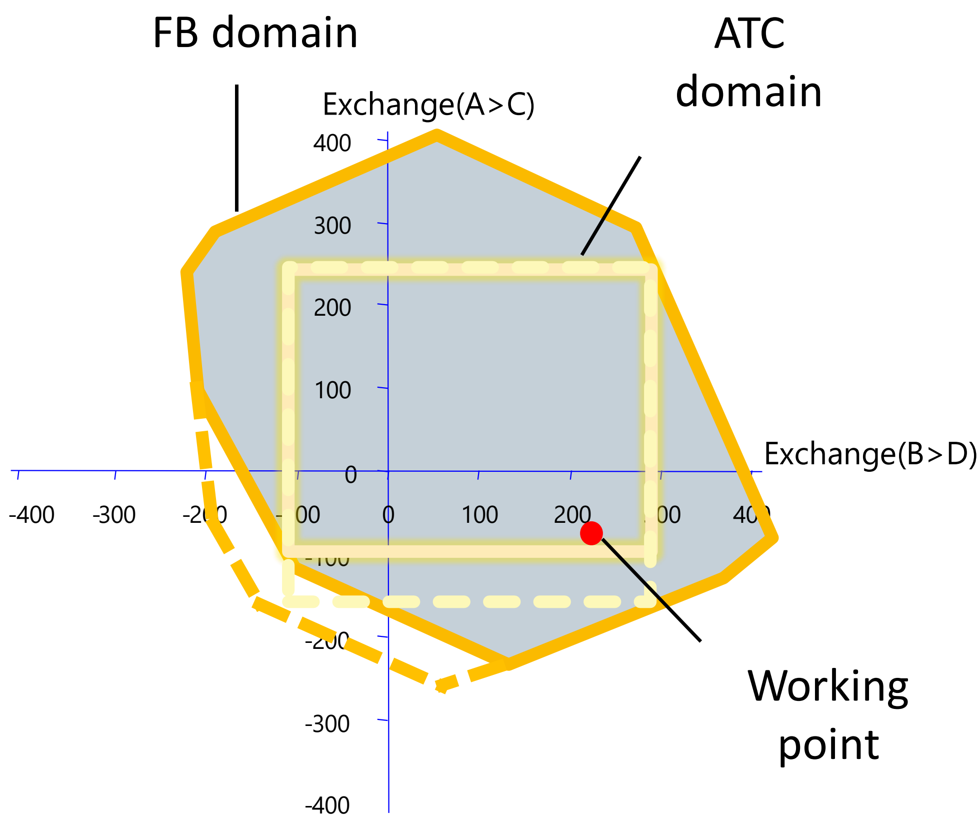
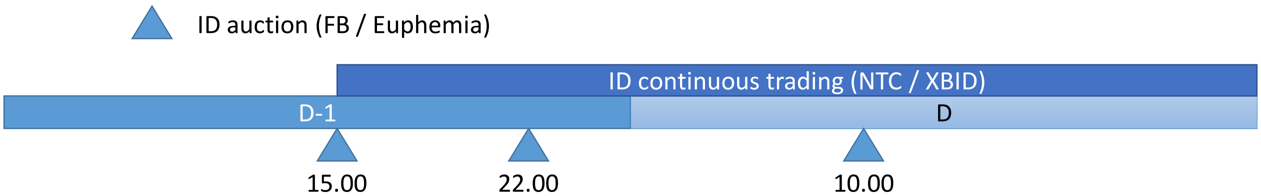


Figure 11 The optimization problem can be relaxed to make the ATC domain larger, e.g. by allowing the ATC domain to exceed the FB domain in those "corners" where the market is not expected to end up

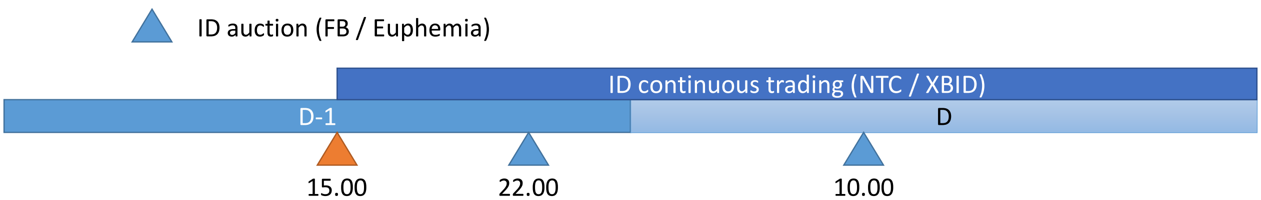
3.20 Article 21: Reassessment frequency of cross-zonal capacity for the intraday timeframe

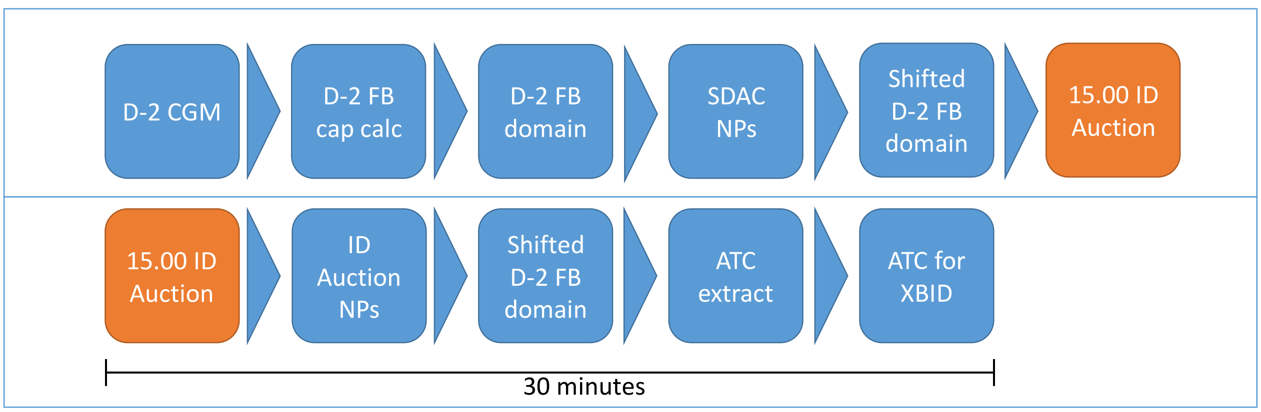
Due to the fact that the intraday gate opening takes place before CGMs for the intraday market timeframe are available, the first assessment of intraday cross-zonal capacity shall be done based on the left-over capacity after the day-ahead coupling. The cross-zonal capacity shall be released to the intraday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

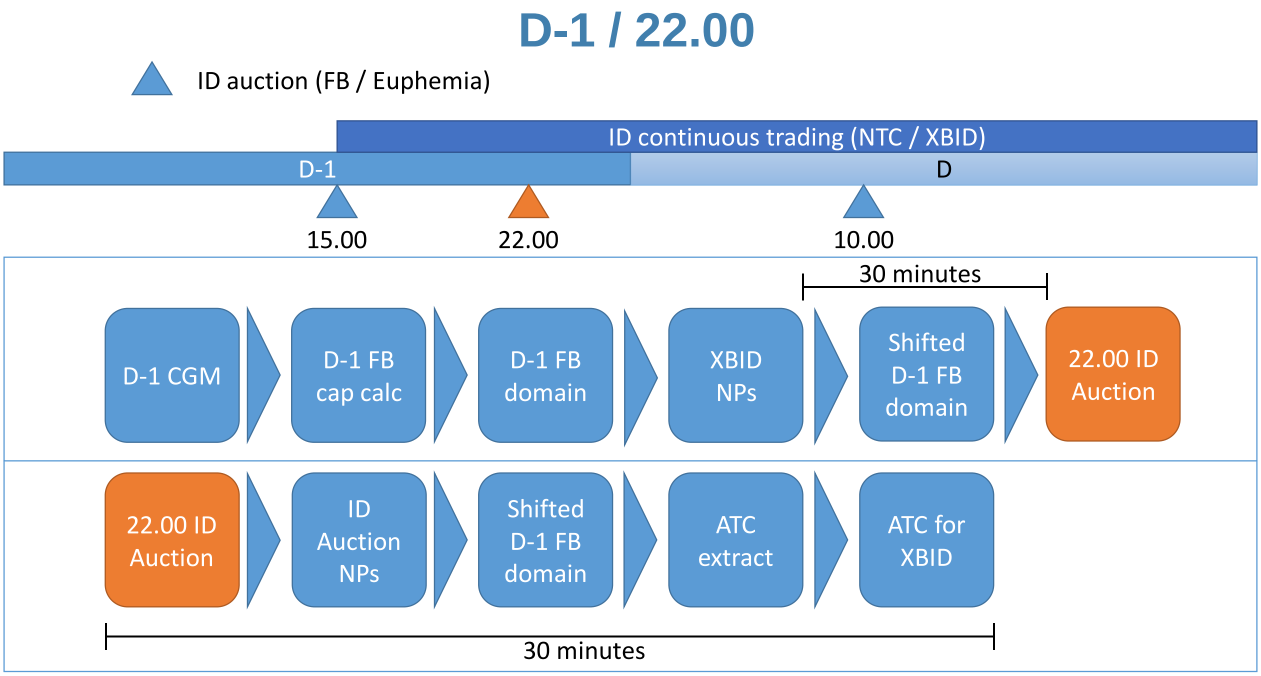
A possible overview for the ID timeframe is depicted in the images below.


ID auction (FB / Euphemia)
ID continuous trading (NTC / XBID)
D-1
D
15.00
22.00
10.00

D-1 / 15.00


ID auction (FB / Euphemia)
ID continuous trading (NTC / XBID)
D-1
D
15.00
22.00
10.00


D-2 CGM
D-2 FB cap calc
D-2 FB domain
SDAC NPs
Shifted D-2 FB domain
15.00 ID Auction
15.00 ID Auction
ID Auction NPs
Shifted D-2 FB domain
ATC extract
ATC for XBID
30 minutes



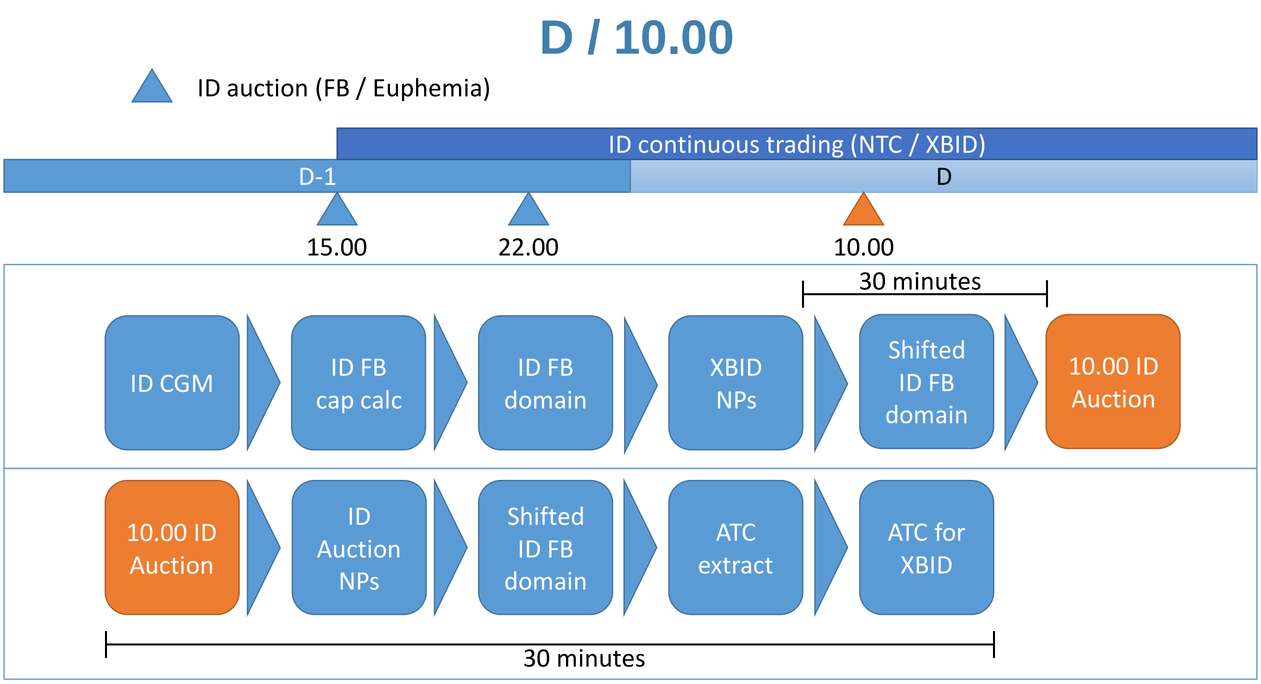


Figure 12 A possible overview of the ID capacity calculation

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

In case the initial capacity calculation does not lead to any results for two or less consecutive MTUs, the CCC shall calculate the missing FB parameters as being the minimum of the adjoining MTUs' FB parameters, as illustrated in Figure 13.

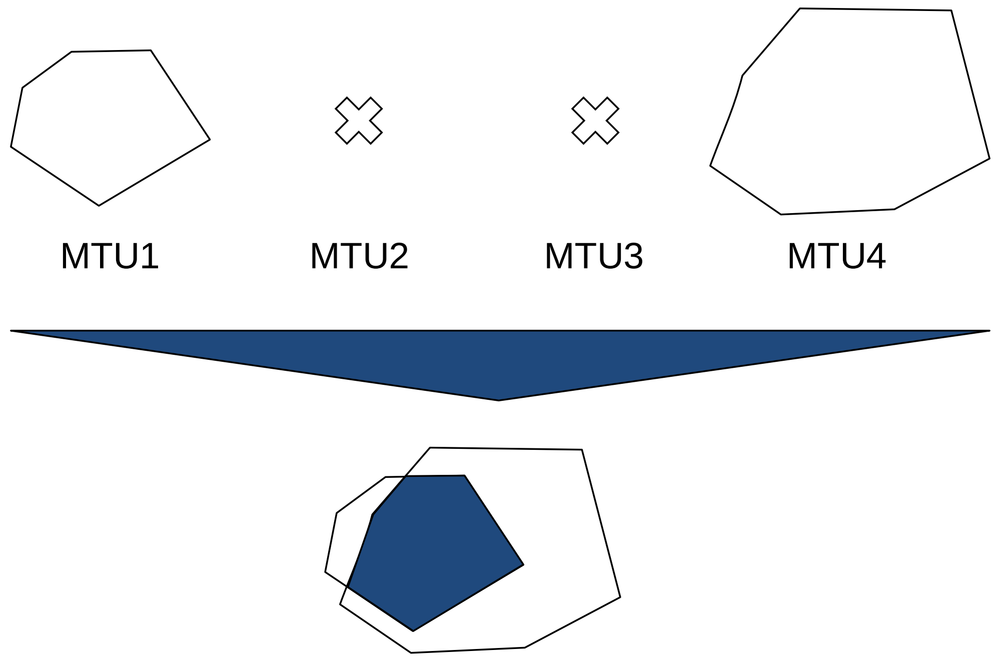


Figure 13 For missing MTUs, the FB parameters will be the minimum of the adjoining MTU's FB parameters. In this example, the dark blue FB domain will be applied for MTU2 and MTU3.

In case the initial capacity calculation does not lead to any results for three or more consecutive MTUs, the CCC will apply default FB parameters that are based on the latest available FB parameters for the same MTU taken from daily, weekly, monthly or yearly capacity calculation.

3.22 Article 23: Monitoring data to the Nordic regulatory authorities

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

3.23 Article 24: Reviews and updates

The application of the CCM is subject to review and potential updates, as explained in the Article 24.

3.24 Article 25: Publication of data

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

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

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

The purpose of publishing data is to give market participants and other stakeholders relevant and appropriate information on transmission capacity and its dependencies. With such information the market participants are supposed to be able to act rationally in the markets. This is done by publishing the items in Article 25 on a regular basis and as soon as possible.

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

3.25 Article 26: Publication and Implementation

The Article 26 provides a conditional implementation timeline. Before the go-live of the DA/ID CCM, a parallel run will be performed for at least a one-year period, such to facilitate a learning process for all involved stakeholders. Parallel run means that the FB approach is run in parallel with the current NTC approach in NEMO systems (single day-ahead coupling).

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

In the Table 1 in the legal document (Milestones and criteria for implementation of FB approach for day-ahead timeframe), a conditional implementation timeline is provided where certain criteria need to be met before a next milestone can be reached.
Before the start of the external parallel run, KPIs for a go-live of the FB approach need to be specified, in dialogue with Nordic regulatory authorities and stakeholders. At the time of writing this document, this process is ongoing.
By defining the KPIs for a go-live of the FB approach this early in the process, the KPIs can be monitored during the external parallel run and the go-live readiness can be measured.
The KPIs have been divided into the following two categories:

- FB capacity calculation process, to assess the stability of the process and the ability to run the process in a timely manner and to deliver the required results in time
- FB capacity allocation results, to assess the market results obtained with the FB MC simulations performed by the NEMOs, e.g. by comparison with the operational NTC market coupling results.

4 Timescale for the CCM implementation

An indicative high-level timeline for implementing the new CCM is visualized in Figure 14.

The NorCap project at the Nordic RSC is implementing the Nordic DA/ID CCM, being a FB capacity calculation. The start of the Parallel run has been communicated to happen late summer 2020. At this point in time Nordic RSC/NorCap implementation project cannot be more specific about this date, as the NorCap IT Application including the FB tool, which is the foundation of the parallel run, has not yet been delivered. The first delivery* from the Supplier is expected in February/March 2020, and the dialog and alignment with the NEMOs will take place during Q1 2020. Consequently the Norcap implementation project expects to be able to publish a more specific start of parallel run by the end of March 2020. At the moment the project has a working assumption, that the Parallel run cannot start before September 2020, meaning the go-live date cannot be before September 2021.

*First full release including a first version of the FB tool.

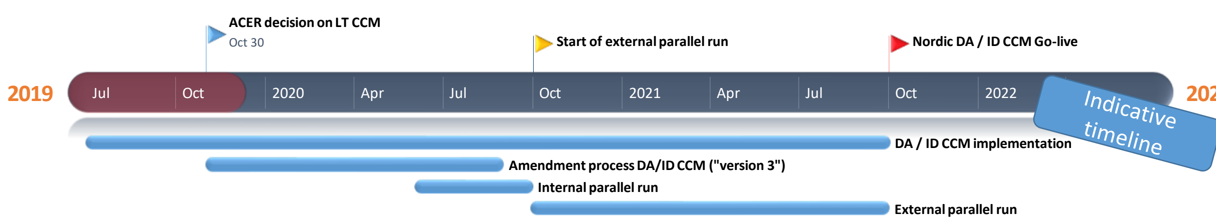


Figure 14 Indicative timeline for implementing the new CCM

5 ANNEX I: Example calculation of nodal PTDFs

Figure 15 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.

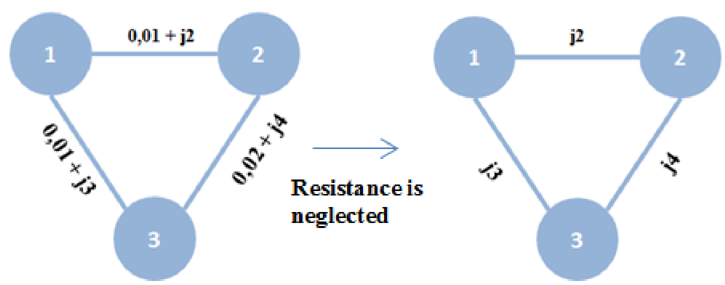


Figure 15 Example grid with three nodes. The node and line parameters used in the power flow equations are illustrated in the figure.

The $Ybus$ matrix is defined by the data in Figure 15. Recall that the susceptance between two nodes equals the inverse of the reactance for the line, since the resistance was neglected.

$$Ybus = \begin{bmatrix} 1/2+1/3 & -1/2 & -1/3 \\ -1/2 & 1/2+1/4 & -1/4 \\ -1/3 & -1/4 & 1/3+1/4 \end{bmatrix} \tag{12}$$

The $Zbus$ matrix is then constructed by adding "+1" to the diagonal element corresponding to the slack-node in the $Ybus$ matrix in (12), followed by an inverse operation. Node 3 is in this example selected as slack node.

$$Zbus = \begin{bmatrix} 1/2+1/3 & -1/2 & -1/3 \\ -1/2 & 1/2+1/4 & -1/4 \\ -1/3 & -1/4 & 1/3+1/4+1 \end{bmatrix}^{-1} = \begin{bmatrix} 3{,}00 & 2{,}33 & 1{,}00 \\ 2{,}33 & 3{,}22 & 1{,}00 \\ 1{,}00 & 1{,}00 & 1{,}00 \end{bmatrix} \tag{13}$$

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

$$PTDF_{ik,n} = B_{ik}(Zbus_{in} - Zbus_{kn}) \tag{14}$$

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

$$PTDF_{12,1} = B_{12}(Zbus_{11} - Zbus_{21}) = \left(\frac{1}{2}\right)(3{,}00 - 2{,}33) = 0{,}33 = 33\% \tag{15}$$

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

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

$$PTDF = \quad \textbf{Line} \quad \begin{array}{c} \\ \\ 1-2 \\ 1-2 \\ 2-3 \end{array} \begin{array}{c} \textbf{Node} \\ \begin{array}{ccc} \textbf{1} & \textbf{2} & \textbf{3} \end{array} \\ \begin{bmatrix} 0{,}33 & -0{,}44 & 0 \\ 0.67 & 0.44 & 0 \\ 0{,}33 & 0{,}56 & 0 \end{bmatrix} \end{array} \tag{16}$$