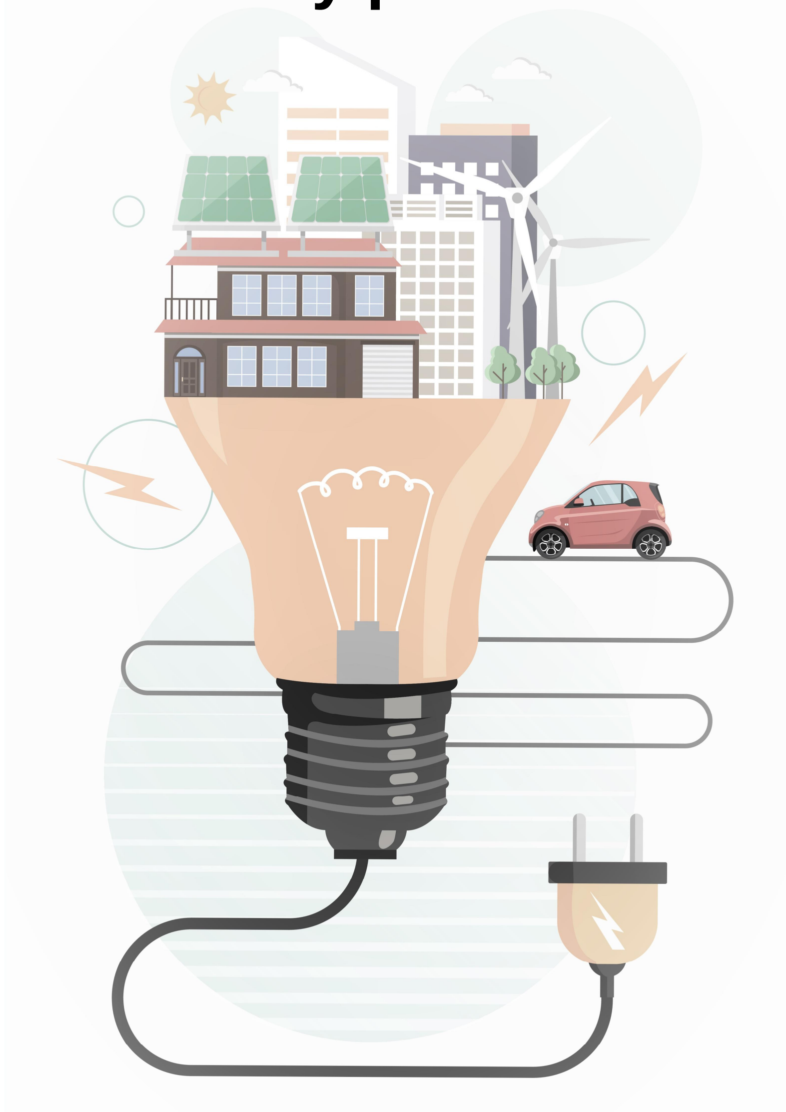
European Commission

ASSET STUDY on **Cross-border transmission capacity calculation: Analysis of the key parameters**



AUTHORS

Pierre Henneaux (Tractebel Impact),

Karim Karoui (Tractebel Impact),

Loïc Maudoux (Tractebel Impact)

EUROPEAN COMMISSION

Directorate-General for Energy
Directorate for Internal Energy Market
Unit B.2.: Wholesale markets, Electricity and Gas
Contact: Elaine O'Connell
E-mail: ENER-B2-SECRETARIAT@ec.europa.eu
European Commission
B-1049 Brussels

Legal Notice

Luxembourg: Publications Office of the European Union, 2020

PDF ISBN 978-92-76-24733-3 doi: 10.2833/461068 MJ-01-20-654-EN-N

About the ASSET project

The ASSET Project (Advanced System Studies for Energy Transition) aims at providing studies in support to EU policy making, research and innovation in the field of energy. Studies are in general focussed on the large-scale integration of renewable energy sources in the EU electricity system and consider, in particular, aspects related to consumer choices, demand-response, energy efficiency, smart meters and grids, storage, RES technologies, etc. Furthermore, connections between the electricity grid and other networks (gas, heating and cooling) as well as synergies between these networks are assessed.

The ASSET studies not only summarize the state-of-the-art in these domains, but also comprise detailed qualitative and quantitative analyses on the basis of recognized techniques in view of offering insights from a technology, policy (regulation, market design) and business point of view.

Disclaimer

The study is carried out for the European Commission and expresses the opinion of the organisation having undertaken them. To this end, it does not reflect the views of the European Commission, TSOs, project promoters and other stakeholders involved. The European Commission does not guarantee the accuracy of the information given in the study, nor does it accept responsibility for any use made thereof.

Authors

This study has been developed as part of the ASSET project by Tractebel Impact.

Authoring team: Pierre Henneaux, Karim Karoui, Loïc Maudoux (Tractebel Impact)

Executive summary

An efficient internal electricity market is of paramount importance in Europe to ensure that all consumers can purchase electricity at an affordable price while maintaining security of energy supply. The way the transmission capacity is allocated, and the way congestions are managed, play key roles in the functioning of the internal electricity market. In 2015, the European Commission established a "guideline on capacity allocation and congestion management" through the Commission Regulation (EU) 2015/1222. This guideline relies on the concept of bidding zones, that are geographical areas within which market participants can exchange energy without capacity allocation and recommends the use of the flow-based approach as the primary approach to calculate and allocate transmission capacity between bidding zones in both the day-ahead and the intraday market timeframes. Although the flow-based approach is currently only used in the Central West European (CWE) region (since May 2015), it will become a cornerstone of the internal electricity market in the near future. It will be thus of paramount importance to guarantee that the flow-based approach supports effectively an efficient electricity market. However, it does not seem to be yet fully the case in the CWE region. Indeed, the capacity of several critical network elements allocated to the market is still very low, mainly because internal flows from domestic trade and loop flows have priority access to the grid, and because large reliability margins are used. Furthermore, in the past, the available capacity was further reduced on several critical network elements due to the use of adjustment values supposed to represent complex grid constraints.

In that context, this study analyzes the key parameters currently used in the capacity calculation methodologies for some of the current European capacity calculation regions and provides an analysis about the trends driving their evolution. Although the information communicated by TSOs to market participants and regulators appears to be incomplete to fully understand key constraints impacting the electricity market, this study establishes two main key facts. First, in the Nordic countries the level of loop flows, internal flows and residual flows due to exchanges with countries outside that region is not negligible but appears to be much lower than the one in the CWE region. Second, although reliability margins taken in the CWE region appear to be in the upper range of European practices and are significantly above the Nordic region, they did not drastically increase with the introduction of the FB market coupling, but the level of risk used to compute these values is not always fully transparent and can also be questioned. Additionally, it must be emphasized that the FB market in the CWE region is strongly driven by the application of an LTA-patch aiming at including long-term cross-border transmission capacity rights in a FB domain, which initially considered that capacity allocation as unsafe. The lack of transparency about the process leads to an uncertainty about the capacity really allocated to the market on several key transmission elements. Similarly, the TSOs use final adjustment values to modify the capacity given to the market, but there is a lack of transparency about the way these values are obtained.

This study concludes on the expected future evolution of the capacity calculation methodologies and parameters. The capacity calculation methodology for the Core region, resulting from the merging of the CWE region with the Central East European (CEE) region exhibits major improvements compared to the current flow-based approach in the CWE region, in terms of transparency and for the design of the LTA patch. However, the calculation of the intraday capacity based on an updated model, which is a key to obtain an efficient market, will be implemented only in 2021. On the Nordic side, it is surprising that the use of negative RAMs is not seen as a problem. Furthermore, it is surprising to observe that the risk levels chosen in the different capacity calculation regions for the reliability margins are different. On a more positive tone, it must also be noted that the evolution of the maximum allowable power flow calculation methods should lead to an increased offered transmission capacity to the

market. For that purpose, flexible and dynamic line rating calculations should be implemented to limit too conservative Fmax ratings. Similarly, the update of the capacity that can be allocated to the market in the intraday timeframe will allow a reduction of reliability margins close to real-time.

Table of Contents

List of Acronyms

AAC	Already Allocated Capacity
ATC	Available Transfer Capacity
CACM	Capacity Allocation and Congestion Management
CB	Critical Branch
CBCO	Critical Branch with Critical Outage
CEE	Central and Eastern Europe
CCM	Capacity Calculation Methodology
CCR	Capacity Calculation Region
CO	Critical Outage
CNE	Critical Network Element
CNEC	Critical Network Element with Contingency
CWE	Central West Europe
FAV	Final Adjustment Value
FB	Flow-Based
FRM	Flow Reliability Margin
GSK	Generation Shift Key
IEM	Internal Electricity Market
LTA	Long Term Allocated capacity
NTC	Net Transfer Capacity
NP	Net Position
PTDF	Power Transfer Distribution Factor
RAM	Remaining Available Margin
TRM	Transmission Reliability Margin
TTC	Total Transfer Capacity
TSO	Transmission System Operator

Introduction

An efficient Internal Electricity Market (IEM) is of paramount importance in Europe to ensure that all consumers can purchase electricity at an affordable price while maintaining security of energy supply. The way the transmission capacity is allocated, and the way congestions are managed, play key roles in the functioning of the IEM. In 2015, the European Commission (EC) established a “guideline on capacity allocation and congestion management” through the Commission Regulation (EU) 2015/1222 [1], hereafter called the “CACM guideline”. The CACM relies on the concept of bidding zones, that are geographical areas within which market participants can exchange energy without capacity allocation. On the contrary, the exchange of energy between different bidding zones require capacity allocation. Two methods are used to couple markets of different bidding zones, and thus to compute and to allocate transmission capacity: the coordinated net transmission capacity approach and the flow-based approach. The coordinated net transmission capacity approach entails significant conservatism when bidding zones are connected in a meshed way. Therefore, the CACM recommends the flow-based approach as the primary approach for both day-ahead market coupling and intraday market coupling.

The Central West European (CWE) region was the first Capacity Calculation Region (CCR) in Europe to make use of a flow-based approach for day-ahead market coupling in May 2015. Compared to the coordinated net transmission capacity approach, the flow-based approach has the advantage of avoiding conservative assumptions in the calculation of the transmission capacity available for the market. However, the flow-based approach has the inconvenience to rely on a set of parameters to represent, in a simplified way, network constraints. Since its implementation, the flow-based approach in the CWE region did not deliver its promise to be significantly more efficient than the coordinated net transmission capacity approach due to the specific choices of parameters that have been made. Furthermore, there is some concern that the current implementation does not fully comply with the current regulatory framework, in particular because Regulation (EC) 714/2009 [2] requires that congestion management methodologies should “not limit interconnection capacity in order to solve congestion inside their own control area”. Indeed, the capacity of several critical network elements actually allocated to the market is still very low (e.g. less than 10% of the thermal capacity for a significant time period) for two main reasons: (i) internal flows from domestic trade and loop flows have priority access to the grid, and (ii) a large discrepancy exists between the forecasted flows during the determination of the flow-based domain and the actual flows, leading to large reliability margins. Furthermore, in the past, the available capacity was further reduced on several critical network elements due the use of adjustment values supposed to represent complex grid constraints. In the CWE region, in order to limit the reduction of interconnection capacity to solve internal congestions, a minimal RAM of 20% of their thermal capacity is imposed on each critical branch since April 2018. Such a measure might nevertheless lead to side-effects such as an impact on redispatch needs.

The flow-based approach for capacity calculation and allocation will become a cornerstone of the internal electricity market in a short-term future. Indeed, the CWE CCR is merging with the Central East European (CEE) CCR to form the Core CCR, and the flow-based approach is expected to be used for the overall Core CCR early 2020 for day-ahead market coupling [3] and early 2021 for intraday market coupling [4]. Similarly, the flow-based approach is expected to be used for the Nordic CCR late 2019 for day-ahead market coupling and early 2022 for intraday market coupling [5]. It will be thus of paramount importance to guarantee that power exchanges within bidding zones and reliability margins used to cover uncertainties do not excessively hamper cross-border exchanges.

In that context, this study aims at analyzing the key parameters currently used in the capacity calculation methodologies for some of the current European CCRs as well as providing an analysis about the trends driving their evolution. This report starts with a short explanation of the two capacity calculation methodologies in chapter 0. On that basis, chapter 0 presents the results of quantitative statistical analysis of key parameters used in the CWE CCR, in the SWE CCR and in the Nordic CCR. Then, the expected evolution of the capacity calculation methodologies and their key parameters is discussed in chapter 0. Finally, chapter 0 concludes.

Capacity calculation methodologies

Introduction

The CACM guideline allows two methodologies to compute and to allocate transmission capacity between bidding zones to the market: the “coordinated net transmission capacity approach” and the “flow-based approach”, referred afterwards in this document as the NTC approach and the FB approach, respectively. Although according to the CACM guideline, the FB approach should be the primary approach for both day-ahead market coupling and intraday market coupling, the NTC approach is still widely used. Consequently, the two approaches are briefly described in this chapter.

Coordinated net transfer capacity approach

In a nutshell
The NTC approach defines import and export active power limits between adjacent bidding zones, i.e. the Net Transfer Capacities between neighboring zones. The NTC is computed in two steps: (i) The maximum exchange of active power compatible with operational security standards applicable in both zones without considering the uncertainties on network conditions, i.e. the Total Transfer Capacity (TTC), is first computed. The computation of the TTC must satisfy the security constraints in N and N-1 situations, i.e. thermal, voltage and stability constraints. (ii) A security margin to cope with uncertainties, called the Transmission Reliability Margin (TRM), is then deducted à $\boldsymbol{NTC = TTC - TRM}$. The TRM is computed using a probabilistic approach and is used to cope with uncertainties induced by load-frequency controls and forecast errors. Note that market coupling algorithms make use of the Available Transfer Capacity (ATC), computed as the difference between the NTC and the capacity already allocated to the market à $\boldsymbol{ATC = NTC - AAC}$.

Introduction

According to the CACM guideline, the NTC approach is based on the principle of assessing and defining *ex ante* a maximum energy exchange between adjacent bidding zones. The so-called Net Transfer Capacity (NTC) from a bidding zone A to a bidding zone B is precisely the maximum exchange program of active power compatible with operational security standards applicable in both zones and considering the uncertainties on future network conditions. Note that NTCs can be asymmetric, i.e. the import and export limits of a country are not necessarily equal.

The computation of NTCs is usually performed in two steps: (i) the maximum exchange of active power compatible with operational security standards applicable in both zones without considering the uncertainties on network conditions (i.e. considering that network conditions, generation and load patterns are perfectly known), called the Total Transfer Capacity (TTC), is first computed and (ii) a security margin to cope with uncertainties, called the Transmission Reliability Margin (TRM), is then deducted. The NTC is thus given by $NTC = TTC - TRM$. Note that market coupling algorithms make use of the Available Transfer Capacity (ATC) to account for the capacity already allocated to the market. The ATC is then simply given by subtracting the Already Allocated Capacity (AAC) to the NTC: $ATC = NTC - AAC$. The following subsections summarize the main computation principles for the TTC and the TRM.

Computation of the TTC

The TTC corresponds to the maximum exchange of active power between two zones while satisfying operational limits in the normal (N) situation (i.e. the situation where no transmission system element is unavailable due to occurrence of a contingency) and after the occurrence of any single contingency (N-1 security criterion). Contingencies explicitly considered in the TTC computation (e.g. trip of a line, of a cable, of a transformer) are called Critical Outages (COs).

Major operational limits that must be satisfied are the thermal limitations of transmission elements (i.e. transmission lines and transformers). Indeed, the electric current that a transmission element can conduct over a specified period without sustaining damage is limited to a value called the maximum admissible current. In the N situation, the maximum admissible current corresponds to the permanent current limit. Under a N-1 situation, depending on the specific operational policy, the maximum admissible current can correspond either also to the permanent current limit, or to a temporary current limit higher than the permanent one when an overload is accepted for a certain finite duration. Note that thermal limitations of transmission elements can vary in function of weather conditions. Transmission elements having thermal limits explicitly considered in the TTC computation are called Critical Branches (CBs) or Critical Network Elements (CNEs).

Beyond thermal limitations of transmission elements, voltage limitations at each node (i.e. minimum and maximum admissible voltage) and stability limitations (voltage and angular stability) are other important operational limits that must also be satisfied.

TTCs are thus usually computed by determining how much power can be transferred between two bidding zones before thermal overloads, violation of voltage limits and/or instability in the N situation or after the occurrence of a single contingency. This is done using the linearized version of power flow equations, i.e. the DC power flow, providing a good approximation of active power flows in transmission elements, but unable to provide indications about voltage issues[1]. This is done in three main steps:

1. A base case specifying the grid configuration (topology), the initial production pattern (production level in each bidding zone and its geographical distribution) and the load pattern (load level in each bidding zone and its geographical distribution) is first defined. This base case must be such that operational limits are satisfied under N and N-1 conditions. Furthermore, assumptions used on the load and generation

[1] AC power flow and/or dynamic simulation are required to analyze voltage and stability issues.

patterns must reflect the expected conditions that will happen in the power system during the period for which the capacity calculation is made.

2. Generation Shift Keys (GSKs) to transform any change in the balance of a bidding zone into a change of injections of specific generators of that bidding zone, or, equivalently, into a change of injections in the nodes of that bidding zone, are then defined. For example, for a node N in a zone Z, the value $GSK_{N,Z}$ indicates the participation of the node N to the supply of an additional MW. A $GSK_{N,Z}$ equals to 0.5 means that the node N supplies 0.5 MW if the zonal balance of zone Z is increased by 1 MW.
3. Finally, the exchange of active power between the two bidding zones is progressively increased from the base case by increasing the balance of one bidding zone and reducing the balance of the other bidding zone by the same amount, until an operational limit is reached. The production pattern is changed according to the GSKs.

When there are more than two bidding zones in a network, assumptions must be taken about the net positions of other bidding zones and thus about the exchanges between other bidding zones. When bidding zones are connected radially, the TTC between two areas does not strongly depend on the assumptions taken for the exchanges between other areas. However, when bidding zones form a meshed system, the TTC between two areas is strongly dependent on the assumptions taken for the exchanges between other zones. The NTC approach requires thus to share the physical capacity between borders before the market clearing. If the assumptions used for this sharing are not aligned with the market needs, the allocation of transmission capacity to the market is suboptimal. This is the major limitation of the NTC approach.

Computation of the TRM

As described by the CACM guideline, TRMs must cover, in a probabilistic way, deviations between the expected power flows at the time of TTC calculation and realized power flows in real time. These flow deviations can be caused by

- The unexpected action of load-frequency controls (e.g. FCR, mFRR, aFRR),
- Forecast uncertainties on parameters used in the power flow computations at the time of TTC calculation (e.g. grid topology forecast, load forecast, production pattern in the base case including wind and solar generation forecast, GSKs).

The probability distribution of the deviations between the expected power flows at the time of TTC calculation and realized power flows in real time is usually estimated through statistical analysis of past data. Then, the TRM can be defined as a percentile of the probability distribution corresponding to the desired probability that the actual flows do not exceed the expected power flows at the time of TTC calculation, or, equivalently, the probability distribution can be fit by a normal distribution and the TRM is chosen as a multiple of the corresponding standard deviation. For example, a TRM chosen to 1, 2 or 3 standard deviations allows to reach a probability of 84.13%, 97.72% or 99.87%, respectively. Note that an empirical approach is still sometimes used instead of a probabilistic approach (e.g. TRM on the border between Netherlands and Germany for long-term transmission rights), but only probabilistic approaches are expected to be used following the implementation of regional Capacity Calculation Methodologies (CCMs) required by the CACM guideline.

Flow-based approach

In a nutshell

The flow-based approach is a capacity calculation method which represents explicitly the physical limits of the transmission elements in the market clearing process. By avoiding a spread of the physical capacity among borders before the market clearing, the flow-based approach can better account for the dynamics between several bidding zones during the market clearing mechanism and therefore offer more transmission capacity to the market. In other words, the domain accessible to the market (i.e. the set of net positions of the bidding zones for which the market can clear while operating the network safely) is wider compared to the NTC approach. To build up the domain accessible to the market:

(i) Each TSO identifies critical branches (CBs) and critical outages (COs) based on their knowledge of the network.

(ii) On each CB under the contingency of a given CO, the TSO computes the Remaining Available Margin (RAM), i.e. the capacity of a transmission element which can be safely allocated to the market for international exchanges, in N and N-1 situations. Starting from the total thermal limit Fmax of a transmission element, its RAM is obtained by subtracting estimations of internal and loop flows and security margins.

(iii) The most restricting network constraints shape the flow-based domain, which defines what can be the sets of net positions of the bidding zones.

The constraints defining the flow-based domain translate the physical limit of each CB under the contingency of a given CO, i.e. the flow due to cross-border exchanges beyond the long-term nominations on a CB must remain below the RAM computed by TSOs.

Introduction

The second method to compute and allocate transmission capacity to the electricity market between two biddings zones is the flow-based (FB) approach. According to the CACM guideline, a ‘flow-based approach’ means a capacity calculation method in which energy exchanges between bidding zones are limited by power transfer distribution factors and available margins on critical network elements. Contrarily to the NTC approach, the FB approach is thus not based on the *ex-ante* assessment of the maximum energy exchange between two adjacent bidding zones but aims at representing directly and explicitly in the market clearing process the main grid limitations constraining the energy exchanges between the different bidding zones.

A simplified representation of the network based on the linearized version of the power flow equations (i.e. DC power flow approximation) is used. Due to this simplification, only thermal limitations of transmission elements can be explicitly considered in the flow-based approach. Voltage and stability limitations can be implicitly considered through external constraints, or through the modification of the capacity of a transmission available for power exchanges. Like the NTC approach, transmission elements having thermal limits explicitly considered in the FB approach are called Critical Branches (CBs) or Critical Network Elements (CNEs)[2]. A CB is supposed to be a critical element with respect to cross-border electricity trades. Similarly, single contingencies explicitly considered in the FB approach to enforce the N-1 security rule (e.g. trip of a line, of a cable, of a transformer) are called Critical Outages (COs). Because the power flow on a transmission element after the occurrence of a contingency depends on the specific contingency, CBs/CNEs and COs are associated into couples called CBCOs or CNE Contingencies (CNECs)[3].

The consideration of a CBCO in the FB approach means that the thermal limit of the CB after the loss of the CO (N-1 security rule) is explicitly enforced through a dedicated equation. This a major difference between the NTC approach and the FB approach: the N-1 security rule is considered implicitly in the capacity allocated in the market in the NTC approach and no equation represents explicitly that rule in the market clearing process, while it is considered explicitly in the FB approach and equations modeling that rule are kept up to the market clearing process. However, because each bidding zone is represented in an aggregated way (i.e. single node representation), the impact of an energy exchange between two bidding zones on the power flows in the grid can only be represented in an approximate way, based on a set of parameters detailed hereafter.

Flow-based parameters

The flow-based calculation uses critical branches (CBs) and critical outages (COs) as in the NTC approach. Additionally, the flow-based approach uses, for each CBCO, a set of parameters to model the simplified network:

§ Power Transfer Distribution Factors (PTDFs): The PTDFs4 quantify the impact of a unit power transferred from a bidding zone to a reference hub. The computation of PTDFs is studied in the next section using GSKs.

§ Net Positions (NPs): Each bidding zone's net position is defined as the difference between its generation and consumption. In case of positive NP, the power surplus is exported to bidding zone with negative NP.

§ Remaining Available Margin (RAM): The RAM of a given line represents the capacity of the line that can be allocated to the market for commercial exchanges between bidding zones.

Note that a prerequisite of the FB capacity calculation is thus the selection of CBs. Currently, in the CWE region, a CB is considered to be significantly impacted by CWE cross-border trade and must thus be considered explicitly as CB in the FB capacity calculation, if its maximum CWE zone-to-zone PTDF is larger than a threshold value that is currently set at 5%.

Computation of the GSKs

Generation Shift Keys (GSKs) are used to compute the zonal PTDFs used in the flow-based calculation, starting from nodal representation of the network. GSKs provide the contribution of each node of a given zone to a change in zonal balance, similarly to the

---

[2] What is called "Critical Branch" in the FB capacity calculation methodology currently in used in the CWE region will be called "Critical Network Element" in the future according to the new capacity calculation methodologies.

[3] What is called "CBCO" in the FB capacity calculation methodology currently in used in the CWE region will be called "CNEC" in the future according to the new capacity calculation methodologies.

[4] In this section, only the zonal PTDFs are considered. The detailed mathematical development starting with the nodal PTDFs is available in appendix.

NTC approach. Therefore, GSKs translate the participation of power plants to the change of power balance inside their bidding zone. For a given power plant, a GSK of 0.01 means that this power plant increases its power output by 0.01 MW if the total power supplied by its bidding zone increases by 1 MW.
In practice, TSOs determine the values of the GSKs based on their knowledge of the power plants, their availability, and, to some extent, their anticipated market behavior. However, knowing which power plants will participate in the market requires the market clearing price and vice versa. Determining the GSKs is therefore a complicated task and relies thus usually on TSO experience and heuristic rules which may lead to a suboptimal solution of the optimization problem of the FB algorithm.

Computation of the RAM

The Remaining Available Margin (RAM) is the capacity of the line that can be allocated to the market. As mentioned before, power flow exchanges between nodes within a bidding zone usually contribute to a part of the loading of CBs (loop flows and internal/domestic flows). Furthermore, similarly to the NTC approach, a reliability margin covering uncertainties must be kept. Mathematically, the RAM of a given CBCO is thus expressed as follows:

$$\mathrm{RAM}_{\mathrm{CBCO}} = \mathrm{F}_{\mathrm{CB}}^{\max} - \mathrm{F}_{\mathrm{CBCO}}^{\mathrm{ref}} - \mathrm{FAV}_{\mathrm{CBCO}} - \mathrm{FRM}_{\mathrm{CB}} \tag{1}$$

where:

- § $\mathrm{F}_{\mathrm{CB}}^{\max}$ is the maximum admissible power flow [MW] of the CB (thermal limit of the transmission element, related to the maximum admissible current).
- § $\mathrm{F}_{\mathrm{CBCO}}^{\mathrm{ref}}$ is the estimated physical flow [MW] when there is no commercial exchange between bidding zones beyond long-term nominations i.e. the physical flow on the CB after the loss of the CO resulting from domestic trade within a bidding zone (loop flows and internal/domestic flows), from exchanges with countries external to the CCR5 and from nominations of long-term transmission rights.
- § $\mathrm{FRM}_{\mathrm{CB}}$ is the Flow Reliability Margin [MW] on a CB used to cover, in a probabilistic way, deviations between expected power flows at the time of the FB domain computation and realized power flows in real-time, like the TRM of the NTC approach.
- § FAV_{CBCO} represents the Final Adjustment Value [MW] on the CBCO, margin is used by TSOs to consider complex remedial actions or phenomena, based on their knowledge of the network.

These parameters are described in the next subsections. Note that a transmission element can transfer power in two directions. Consequently, there are two RAMs corresponding to each CBCO: the RAM in the forward direction and the RAM in the backward direction. Because the Fref is associated to a specific direction, the RAM is in general not the same in each direction. Indeed, if the Fref is positive in the forward direction and reduces then the RAM in that direction, it is negative in the backward direction and increases the RAM in that direction. *Figure 1* illustrates the computation of the RAM for a null FAV (which is the case on most CBCOs) and when the Fref is in the forward direction. If the Fref is positive or negative depending on the direction, the FRM is always positive and always decrease the RAM.

[5] Additional uncertainties on Fref are due to the residual flows in the considered region induced by exchanges with countries out of the region.

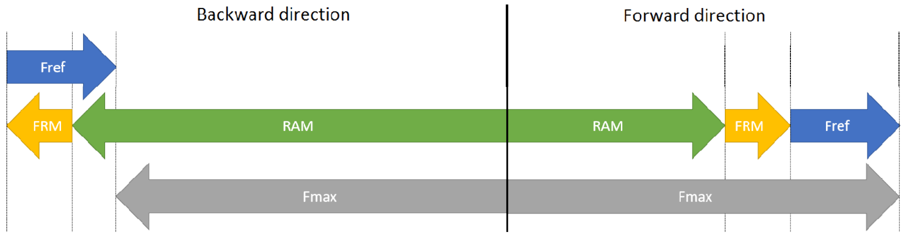


Figure 1: Illustration of the RAM computation for a null FAV and with Fref in the forward direction.

Thermal limit of the transmission element – Fmax

To avoid damage (e.g. insulation disruption, unacceptable ageing), a transmission element (e.g. overhead line, underground cable, transformer) must be kept below a specific temperature. The main origin of heating is resistive heating due to the electrical current. A transmission element can thus conduct over a specified period without sustaining damage only a limited electrical current called the maximum admissible current. This current is related to the way the transmission element is cooled, and thus to the weather conditions. As a consequence, each transmission element can carry only a maximum power flow, called thermal limit, related to both the maximum admissible current and its voltage. This maximum power flow is denoted Fmax.

Estimated reference flow – Fref

As stated previously, the value denoted Fref corresponds to the estimated reference flow, i.e. the flow when there is no commercial exchange between bidding zones beyond long-term nominations i.e. the physical flow on the CB after the loss of the CO resulting from domestic trade within a bidding zone (loop flows and internal/domestic flows), from exchanges with countries external to the CCR6 and from nominations of long-term transmission rights. A forecast of the power flows on the system by the TSOs (i.e. the "base case"), defined usually two days ahead, is used to estimate these reference flows. The reference flow for a CBCO is estimated from the base case with estimated commercial exchanges between bidding areas by subtracting the estimation of the flows due to exchanges between bidding areas to the computed total flow on the CBCO7. These flows are given by the product between the zonal PTDFs and the net positions used in the base case.

Flow reliability margin – FRM

As stated previously, the value denoted FRM corresponds to the flow reliability margin on a transmission element used to cover, in a probabilistic way, deviations between expected power flows at the time of the FB domain computation and realized power flows in real-time, like the TRM of the NTC approach. The need for a margin to hedge against uncertainties comes from several factors inherent to the FB algorithm, i.e. the use of a simplified and linearized grid model and of GSKs. The FRM also covers uncertainties related to the unintentional flow deviations due to load-frequency control

[6] Additional uncertainties on Fref are due to the residual flows in the considered region induced by exchanges with countries out of the region.
[7] Note that the total flow in the base case on a CBCO is sometimes called F^{ref}, while the physical flow when there is no commercial exchange between bidding zones beyond long-term nominations is called $F^{ref\prime}$. For the sake of clarity, only F^{ref} will be used in this document to denote the physical flow when there is no commercial exchange between bidding zones beyond long-term nominations

on one side and related to forecast errors of supply and demand (e.g. wind, solar, load, conventional generation) and of topology on the other side. The absence of spatial information of the accurate supply and demand inside a zone tends to increase the need for FRM as well. Like the TRM, the FRM determination is usually done by deriving a probabilistic distribution of the difference between the expected power flows and the actual power flows. The probability distribution is then fit by a normal distribution and the FRM is chosen as a multiple of the corresponding standard deviation based on the desired probability that the actual flows do not exceed the expected power flows. The estimation of the FRMs is key in the FB algorithm process as it directly impacts the results by lowering the RAM and consequently the social welfare value.

Final adjustment value – FAV

As stated previously, the value denoted FAV corresponds to the final adjustment value on a CBCO or on a CNEC and is used to consider complex remedial actions or phenomena. A negative FAV emulates a decrease of the power flow on a transmission element, and thus an increase of the capacity available to the market on that transmission element, due to remedial actions that cannot be modelled explicitly in the FB algorithm. Remedial actions include changing the tap position of phase shift transformers (PST), opening and closing of lines, cables, transformers, busbar couplers and changing generation infeed or load. On the other hand, a positive FAV reduces the RAM and is applied to prevent overloads or voltage issues detected in the validation phase with a more complex security analysis, i.e. based on AC power flow simulations. Note that, because the detailed grid model is not publicly available, the use of FAV in a given situation cannot be easily understood or challenged.

Typical process for capacity calculation in a FB approach

Figure 2 show a typical process for capacity calculation in a FB approach. The process starts with four parallel steps: the weather forecast, the load/generation forecast (dependent on the weather forecast), the definition of GSKs and the definition of FRMs (normally based on a statistical analysis). For transmission elements with dynamic line rating, the thermal limit depends on the weather forecast. Based on the load/generation forecast and the thermal limits of transmission elements, a base case is developed. Combined with the GSKs, the topology used in the base case leads to the zonal PTDFs. The base case is then mainly used to estimate the physical flow on transmission elements when there is no commercial exchange between bidding zones beyond long-term nominations together with the PTDFs (Fref). That base case is also typically used to define the FAVs, if relevant. For each CBCO, its Fmax, FAV, Fref and FRM are then combined to lead to the RAM. The RAMs and the PTDFs are the only values used finally in the flow-based market clearing process. In the FB approach currently in use in the CWE region for the DA market, this process starts two days before delivery with the definition of the base case, corresponding to the two-days ahead congestion forecast files (D2CF files). These files are provided by the participating TSOs for their grid two-days ahead and are their best estimate of the state of the CWE electric system for day D. The domain (and consequently the admissible exchanges between countries) is thus based on assumptions (e.g. on weather, on load, GSK) fixed 2 days before delivery. The day-ahead market algorithm uses then this hourly domain in D-1 to optimize the cross-border exchanges depending on the bids received. An example of this flow-based calculation process with real market data is given in appendix (section 0).

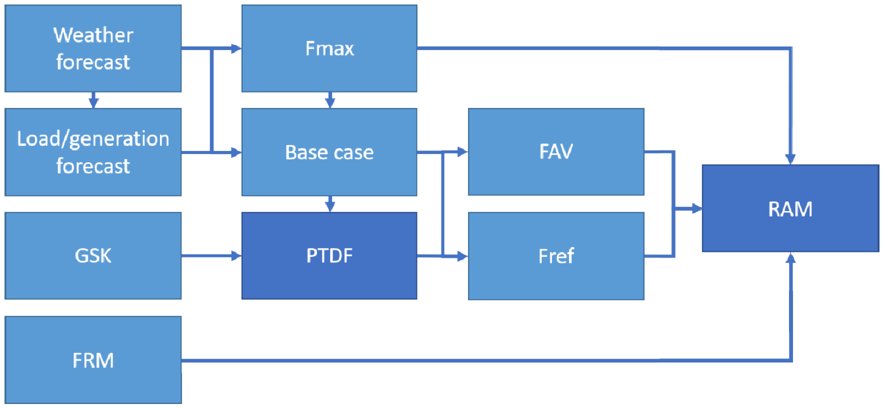


Figure 2: Typical process for capacity calculation in a FB approach.

Representation of grid constraints in the market clearing process

The goal of the processes described in the previous sections is to compute and allocate transmission capacity to the electricity market. These processes lead to an admissible domain, representing the possibilities of exchanges between the different zones. This admissible domain is then used in a market coupling algorithm such as EUPHEMIA to match demand and supply orders in a single market. The mathematical objective function of a market coupling algorithm is the maximization of the social welfare. The optimization problem is subject to constraints enforcing the limited transfer capability of the transmission grid. For borders based on an NTC approach, the exchange from one bidding zone to the other bidding zone is limited by the ATC given by the difference between the NTC and the AAC as described in section 0. For borders based on a FB approach, a specific constraint is enforced for each CBCO: the power flow on each CBCO must remain below the estimated value of the RAM. Mathematically, it is expressed as:

$$\sum_{Z} \mathrm{PTDF}_{\mathrm{zone-to-hub,CBCO}} \cdot \mathrm{NEX_Z} \leq \mathrm{RAM_{CBCO}}$$

with $\mathrm{NEX_Z}$ being the net export power of the zone Z, i.e. the power flowing from the zone Z to the reference hub. These constraints shape the flow-based domain and mean that the admissible power flow on a line, under the contingency of another element of the network, must remain below the RAM computed by the TSO. Note that only some CBCOs constraints are really delimiting the FB domain. The others, called redundant constraints, are removed by TSOs before the market coupling process through a so-called “presolve”.

Figure 3 depicts a theoretical flow-based domain for 3 countries[8]. If the market clears in any point (representing a position of the market) inside the domain, no network constraint is violated. Therefore, the clearing point is admissible from a network security perspective, i.e. the market clearing point does not lie beyond the network constraints represented by the straight lines.

[8] The sum of the net positions of all 3 countries must be zero. Therefore, only 2 independent variables are kept in the problem, leading to a 2-dimension problem as shown in *Figure 3*, because of the net positions depends on the two others. For example, the same principle applies to the CWE zone, with 4 countries and therefore 3 independent variables, leading to a 3-dimension flow-based domain.

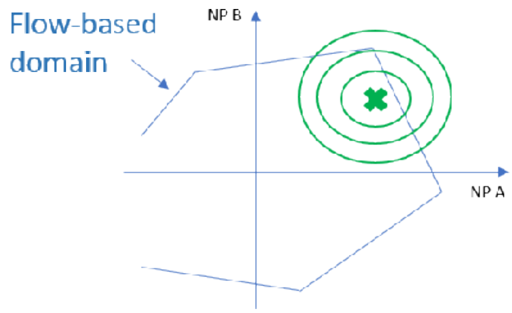


Figure 3: Flow-based domain illustration

As stated previously, the main goal of a market clearing algorithm is to maximize the social welfare while respecting the physical constraints of the network, i.e. the limits of the power flows on the CBCOs. In the example of *Figure 3*, the social welfare is maximized in the market clears at the point represented by the green cross. This clearing point is admissible since it lies inside the flow-based domain.

Statistical analysis

Introduction

The previous chapter summarized the capacity calculation methodologies in use in Europe, and defined the main factors and parameters used. However, it did not provide order of magnitude of these parameters and, consequently, did not indicate how much of the thermal capacity of transmission elements is really available to the market. The purpose of this chapter is precisely to provide a quantification of the main parameters used in the day-ahead timeframe, based on statistical analysis of the CWE CCR in section 0, of the Nordic CCR in section 0, and of the SWE CCR (i.e. Iberian Peninsula) in section 0. This quantification allows additionally a relative comparison of the different CCRs.

The CWE region

Data

Detailed data[9] related to the FB day-ahead market coupling are published by JAO[10]. They contain, for each CBCO, details about the parameters leading to the RAM (i.e. Fmax, Fref, FRM, FAV). The publication of market data by JAO allows a quantitative analysis of key factors impacting the FB approach in the CWE region, as well as their recent evolution.
The data used for the analysis of the latest trends in the CWE region cover the period 01/06/17 to 06/08/18 as JAO's market data are only available for one year on the website. Three types of critical branches are considered in this chapter: the internal branches, the interconnections and the external constraints[11].

[9] Data available at: http://www.jao.eu/marketdata/implicitallocation
[10] "The JAO is a joint service company of twenty-two Transmission System Operators (TSOs) from nineteen countries. It mainly performs the yearly, monthly and daily auctions of transmission rights on 29 borders in Europe and acts as a fall-back for the European Market Coupling." - http://www.jao.eu/aboutus/history/overview
[11] External constraints are artificial constraints introduced in the flow-based domain to limit the import/export of a bidding zone for stability reasons (which cannot be modelled with the DC load flow approximation used in the flow-based calculations). External constraints are a mathematical trick to consider more complex stability

In the data available, the following interconnections are identified (*Table 1*), i.e. their physical name is published in JAO's data.

Border	Interconnection line	Voltage level [kV]
BE – FR	Avelin – Avelgem (1, 2)	380
	Lonny – Achène (1)	380
	Mont St. Martin – Aubange (1, 2)	220
BE – NL	Zandvliet – Geertruidenberg (1, 2)	380
	Zandvliet – Borssele (1, 2)	380
	Van Eyck – Maasbracht (1, 2)	380
FR – DE	Vigy – Ensdorf (1, 2)	380
	Muhlbach – Eichstetten (1)	380
NL – DE	Maasbracht – Siesdorf (1, 2)	380
	Hengelo – Gronau (1, 2)	380
	Diele – Meeden (1, 2)	380

Table 1: Interconnections branches identified in the data set from 01/06/17 to 08/08/18

In this section, only CBCOs constraining the flow-based domain, i.e. non-redundant constraints, are considered[12]. Both real and virtual CBCOs[13] are studied together, unless stated otherwise.

Approaches used to calculate and allocate transmission capacity

The transmission capacity allocation process occurs in different time scales, i.e. in the long-term, day-ahead and intraday markets (Figure 4). For the long-term allocation, TSOs use an NTC approach in which bilateral exchanges of active power between two bidding zones are limited to a conservative value (Section 0). Long-term cross-border transmission capacity rights for those values are allocated explicitly to market participants through annual and monthly auctions. At that time, forecasts on available generation, load and renewable energy sources are such that the conservative approach is justified.

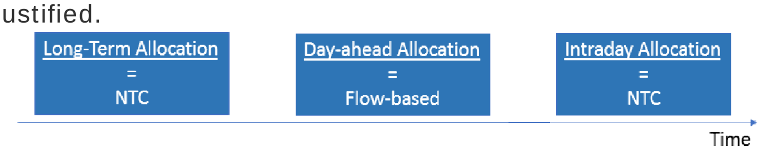


Figure 4: Transmission capacity allocation for long-term, day-ahead and intraday markets

The day-ahead capacity calculation is computed with a flow-based approach, i.e. considering a linear approximation of the electrical network to represent the thermal constraints of network elements. Currently, an NTC approach is used for the intraday market coupling. However, the domain available for the intraday market does not result from a complete capacity recalculation after the day-ahead market clearing but is simply obtained from the left-over capacities of the day-ahead market clearing point. TSOs maximize the intraday domain such that it is contained in the flow-based domain computed at the day-ahead stage, as shown in Figure 5, depicting the Long-Term Allocation (LTA), the Day-Ahead Flow-Based (DA FB) and the IntraDay (ID) domains. Note that, as it will be explained in section 0, a FB approach is expected to be used for intraday market starting from 2021, and the FB domain allocated to the intraday market will then result from a dedicated capacity recalculation after the day-ahead market clearing.

phenomena. They have a unitary PTDF value as they take the form NEXz ≤ RAM_CBCO.

[12] The non-redundant CBCOs have a "presolved" status at "true" in the JAO's data.

[13] As detailed in Section 0, virtual CBCOs are derived from the LTA-patch and replace real CBCO when the long-term allocated capacity does not lie in the initial flow-based domain.

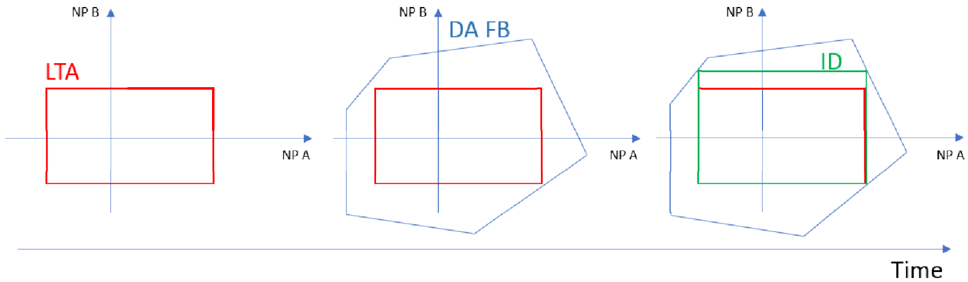


Figure 5: Illustration of the domains for long-term, day-ahead and intraday markets

Note that the long-term allocation NTC domain should be included in the day-ahead allocation FB domain, as in Figure 5. When this is not the case, an additional algorithm (LTA patch) is run in order to extend the flow-based domain to fully contain the Long-Term Allocation (LTA) domain, as explained in the next section.

LTA patch activation

Theoretical concept

As discussed in the previous section, the available long-term transmission capacity is computed through an NTC approach and has thus a different offer to the market i.e. a different shape compared to the FB domain. However, the FB domain must contain the Long Term Allocated capacity (LTA), i.e. the yearly and monthly auctions must lie in the FB domain. This is expected to be the case due to the different approaches (long-term allocation through NTC is generally more conservative) and the reduction in uncertainty when it comes to the day-ahead stage which means that the capacity offer to the market through FB can generally be expected to be higher. However, it is not always directly the case: the transmission capacity rights lie often outside the FB domain initially computed by TSOs, demonstrating an inconsistency between the two approaches. To correct this, the "LTA patch" is applied and enlarges FB domain by replacing the CBCOs violating the LTA by virtual CBCOs, as depicted with dashed lines in *Figure 6*. Note that virtual constraints do not have a physical significance, unlike real constraints which represent the physical limits and sensitivity of the network.

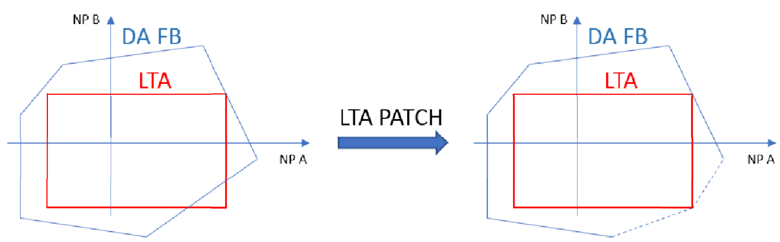


Figure 6: LTA patch illustration (dashed lines = virtual CBCOs)

The LTA patch activation guarantees in particular that a point describing a state without commercial exchanges between bidding zones is inside the FB domain and is thus an admissible market outcome from the transmission system point of view. Indeed, if the computed value of the RAM of a given CBCO is smaller than zero, the point describing a state without commercial exchanges between bidding zones is not inside the initial FB domain: cross-border power exchanges could be required to relieve an overload on CBCOs with a negative RAM. The flow-based domain extended by the LTA patch (allowing thus more admissible clearing points that the initial flow-based domain) is the final domain available to the day-ahead market[14]. Note that the exact algorithm used to perform the LTA inclusion is not published.

LTA activation statistics

The LTA patch activation implies the use of virtual CBCOs, which artificially increase the initial flow-based domain to include all LTAs inside it, as explained in the previous section. Table 2 summarizes the results of LTA patch activation during the studied period of 2017 and 2018. Note that the two periods do not deal with the same season. The common period for 2017 and 2018 available in the data sets is June-August. The percentage of active hours from June 2017 to August 2017 and from June 2018 to August 2018 are respectively 74% and 71%. The virtual rates are 47% and 37%, respectively.

Studied period	LTA [% of activated hours]	Virtual rate [% of virtual constraints]
P1: 01/06/17 à 31/12/17	75 %	46 %
P2: 01/01/18 à 08/08/18	59 %	33 %

Table 2: LTA patch activation statistics for the whole periods

The first column of Table 2 shows the percentage of hours during which the LTA patch was activated, i.e. the flow-based domain was not large enough to include the LTA during 75% of the time in period 1 and 59% in period 2. Note that an “active hour” is defined as an hour during which at least one CBCO constraint is active. The second column of Table 2 provides the percentage of virtual constraints compared to the total amount of constraints defining the FB domain over the year (i.e. non-redundant constraints). In period 1, the domains were shaped by 46% of virtual constraints, whereas this amount dropped to 33% in period 2. These number tend to show that the use of virtual CBCOs is decreasing between 2017 and 2018. A lower rate of activated hours means that the domain is less often artificially increased with virtual CBCOs. It seems however due to a reduction of the LTA domain in 2018 compared to 2017. Indeed, the long-term transmission capacity allocated to the market decreased in the first half of 2018 by 24% for the border Belgium → France and by 26% for the border Netherlands → Germany, compared to the first half of 2017.
Also, some constraints do not always respect the RAM equation derived in Section 0. Indeed, RAM is calculated as $\mathrm{RAM}_{\mathrm{CBCO}} = \mathrm{F}_{\mathrm{CB}}^{\max} - \mathrm{F}_{\mathrm{CBCO}}^{\mathrm{ref}} - \mathrm{FAV}_{\mathrm{CBCO}} - \mathrm{FRM}_{\mathrm{CB}}$, which confirms that the domain is artificially modified with virtual CBCOs. Note that the “amplitude” of the LTA patch activation is unknown because the initial flow-based domain, i.e. the flow-based domain without virtual constraints (before the LTA patch activation) is not published.
Results of Table 2 show that the LTA patch is often activated, and a deeper study of the virtual constraints show inconsistencies in the RAM calculations. To have a deeper understanding of the flow-based market design, a set of parameters (Fref, FRM, FAV, RAM) of the flow-based market are studied in the next sections. The statistical analysis of these parameters enables to identify the parameters limiting the RAM offered to the market on critical elements of the network.

In a nutshell

The LTA patch is a mathematical algorithm which ensures that the LTA domain is included in the flow-based domain i.e. if the LTA offer was more than the day-ahead calculation of capacity, the day-ahead capacity offer can be extended artificially to accommodate those long-term transmission rights. It

[14] For finding the optimal clearing point, the flow-based domain must be convex. The LTA patch enables to retrieve a convex domain.

also guarantees that a point describing a state without commercial exchanges between bidding zones is inside the FB domain and is thus an admissible market outcome from the transmission system point of view. The new constraints defining the flow-based domain after the LTA patch are called virtual constraints.
In the studied periods of 2017 and 2018, the LTA patch was activated during 75% and 59% of the hours respectively. In other words, in 75% and 59% of the studied hours of 2017 and 2018, the flow-based constraints (i.e. day-ahead calculations) were more restrictive than the LTA constraints, which is an unexpected trend that has emerged from the statistical analysis.

Internal flows and loop flows

Statistical observations

As stated in Section 0, F_{CBCO}^{ref} is the physical flow when there is no additional commercial exchange between bidding zones beyond long-term nominations[15] i.e. the physical flow [MW] on the CB after the CO resulting from domestic trade within a bidding zone (loop flows and internal/domestic flows), from exchanges with bidding zones in other CCRs and from nominations of long-term transmission rights. Fref is therefore the result of an estimate by TSOs of the power flows in their control area caused by exchanges out of the scope of the day-ahead market concerning that CCR. Nevertheless, for transmission elements not close to boundaries with other CCRs, the impact of power exchanges with external bidding zones has only a marginal impact on Fref. The exchanges between the CWE region and Denmark or Norway could impact transmission elements critical also for the capacity allocated to the day-ahead market within the CWE region. Nevertheless, the order of magnitude of the impact of exchanges with Denmark on the power flows on CBCOs constraining the FB market is expected to be below a few tens of MW[16]. Indeed, the calculation of PTDFs of 380kV lines of critical importance for the CWE FB market[17] in Germany, Netherlands, France and Belgium for an exchange between Denmark and Germany provides values below 4-5%[18] and the NTC between Germany and Denmark is typically between 1 and 1.5 GW. Furthermore, the analysis of the JAO data indicates that the long-term nominations are usually null (or very small) for the day-ahead market in the CWE region. Consequently, the value of Fref constitutes a good proxy to measure the sum of loop flows and internal/domestic flows in the CWE region[19].
The results of the statistical analysis of the ratio Fref/Fmax for CBCO delimiting the FB domain (i.e. non-redundant constraints) are presented in *Figure 7* and *Figure 8*

[15] As mentioned in section 0, the total flow in the base case on a CBCO is sometimes called Fref, while the physical flow when there is no commercial exchange between bidding zones beyond long-term nominations is called Fref', but only Fref is used in this document to denote the physical flow when there is no commercial exchange between bidding zones beyond long-term nominations

[16] Denmark is chosen as example as it is electrically close to most of the critical elements of CWE.

[17] Examples: Krimpen – Geertruidenberg, Vigy – Ensdorf, Aubange – Mont-Saint-Martin, Ens – Lelystad, Maasbracht – Rommerskirchen, Doel – Zandvliet

[18] It means that only 4-5% of the exchanges between Denmark and Germany will transit on the lines of critical importance for the CWE FB market.

[19] Note that, with the reinforcement of the interconnections between the CWE region and Great Britain, power exchanges with Great Britain could impact more the capacity calculation in the CWE region. This property might thus not hold everywhere.

showing the cumulative probability distributions for the positive Fref/Fmax for internal lines and interconnections in 2017 and 2018. According to equation (1), a negative Fref allocates a higher RAM to the market and a positive Fref allocates a lower RAM to the market (because there is less capacity left over to offer to the market due to high levels of loop flows and internal flows).

In 2017, in *Figure 7*, it appears that 80% of the interconnections have a Fref/Fmax ratio lower than 60%, whereas the ratio increases to values up to 90% for 80% of the internal lines. Therefore, in 2017, the RAM of internal lines is in average more impacted by Fref flows than interconnections.

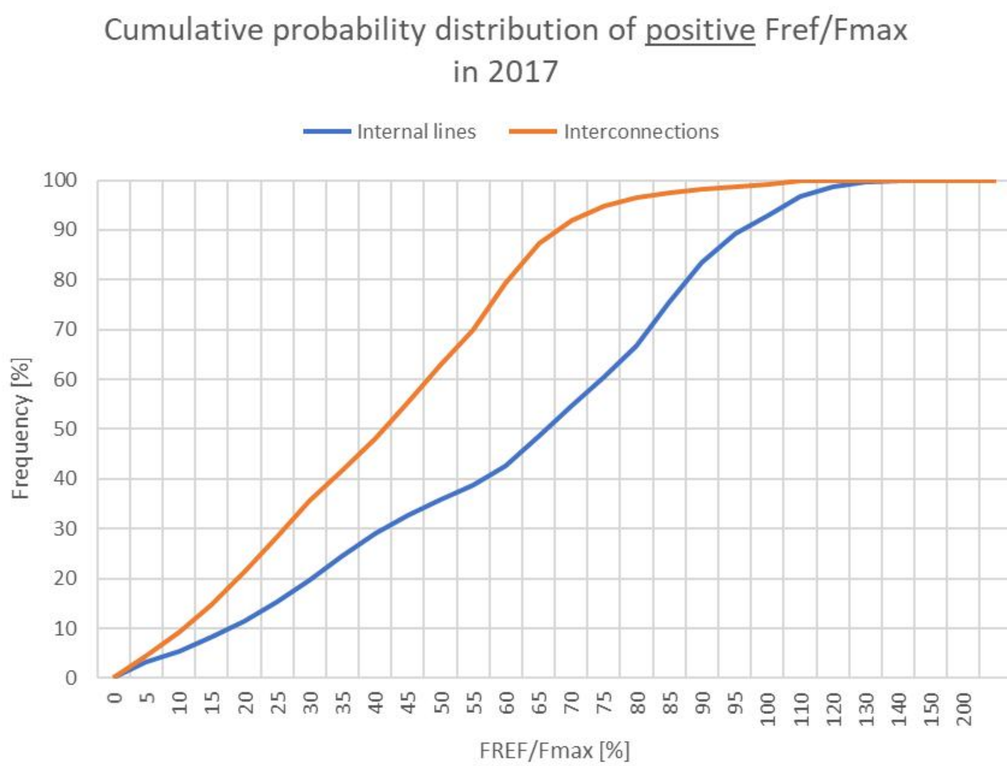


Figure 7: Cumulative probability distribution of positive Fref/Fmax in 2017 in CWE region

The opposite behavior is observed in 2018, in Figure 8. For information, cumulative probability distributions of negative Fref/Fmax are provided in appendix (section 0). Note that a negative Fref implies an increase of the available transmission capacity on the transmission element in the considered direction compared to the thermal rating, because internal flows and loop flows go in the other direction, as explained in section 0. The main observation with negative Fref/Fmax is that the average value of non-redundant CBCOs is smaller compared to non-redundant CBCOs with a positive Fref. It seems logical because CBCOs with a high negative Fref tend to be redundant (i.e. they do not tend to constraint the domain).

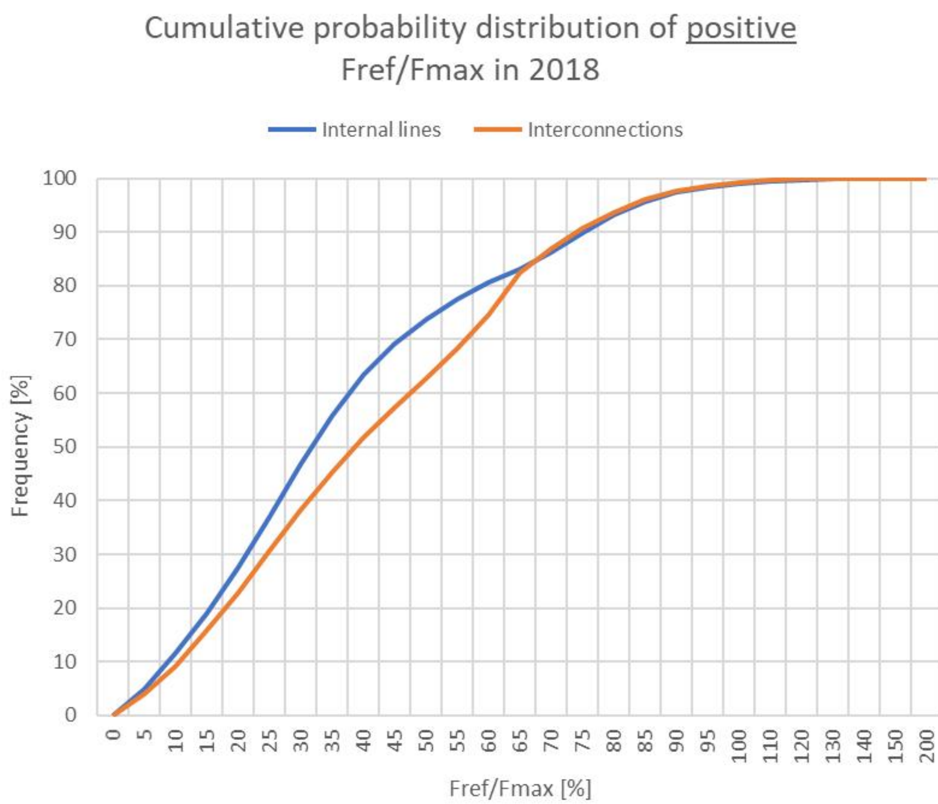


Figure 8: Cumulative probability distribution of positive Fref/Fmax in 2018 in CWE region

A summary of the results, including the external constraints, is given in *Table 3*. The mean values of internal branches show that internal and loop flows were reduced from 61.21% to 37.10% between the two periods. Values up to 40% are observed for interconnections.

Fref / Fmax [%]								
Type of branch	Studied period	Negative Fref			Positive Fref		
		Min	Max	Mean	Min	Max	Mean
Internal	P1: 01/06/17 à 31/12/17	-74.52 %	-0.06 %	-9.44 %	0 %	160.30 %	61.21 %
	P2: 01/01/18 à 08/08/18	-70.55 %	-0.04 %	-11.99 %	0 %	155.75 %	37.10 %
Interconnection	P1: 01/06/17 à 31/12/17	-78.25 %	-0.05 %	-12.66 %	0 %	121.37 %	40.73 %
	P2: 01/01/18 à 08/08/18	-72.55 %	-0.05 %	-13.65 %	0 %	133.90 %	41.22 %
External	P1: 01/06/17 à 31/12/17	-6.93 %	-0.41 %	-1.48 %	0 %	5.45 %	0.42 %
	P2: 01/01/18 à 08/08/18	-1.93 %	-0.42 %	-0.63 %	0 %	1.52 %	0.02 %

Table 3: Minimum, maximum and mean Fref/Fmax ratios for internal branches, interconnections and external constraints in CWE region

Extreme Fref values: violation of the RAM equation

In the available data set published by JAO, some branches have almost null RAM values, meaning that they strongly limit the market due to extreme values of positive Fref. For the branches with a RAM approaching zero, the procedure to determine the RAM value allocated to the market is unclear. Indeed, the equation (1) which should be used to determine the RAM of a given CBCO is violated for several CBCOs. Furthermore, the RAM of some CBCOs is set to small values, leading to minimal values of almost 0% in both studied periods[20].

In short, RAM values are artificially changed during the flow-based algorithm process, most probably during the LTA patch activation, as these modified RAMs appear for virtual constraints.

To give an order of magnitude of this violation issue, equation (1) was violated by more than 1 MW (i.e. $|\mathrm{RAM}_{\mathrm{CB}} - (\mathrm{F}_{\mathrm{CB}}^{\max} - \mathrm{F}_{\mathrm{CB}}^{\mathrm{ref}} - \mathrm{FAV}_{\mathrm{CB}} - \mathrm{FRM}_{\mathrm{CB}})| > 1\,MW$) for 53% of the CBCOs in 2017 and for almost 37% of the CBCOs in 2018, i.e. that the absolute value of the error was strictly larger than 1 MW for these CBCOs. Figure 9 and Figure 10 depict the distribution of errors as defined in this section for 2017 and 2018.

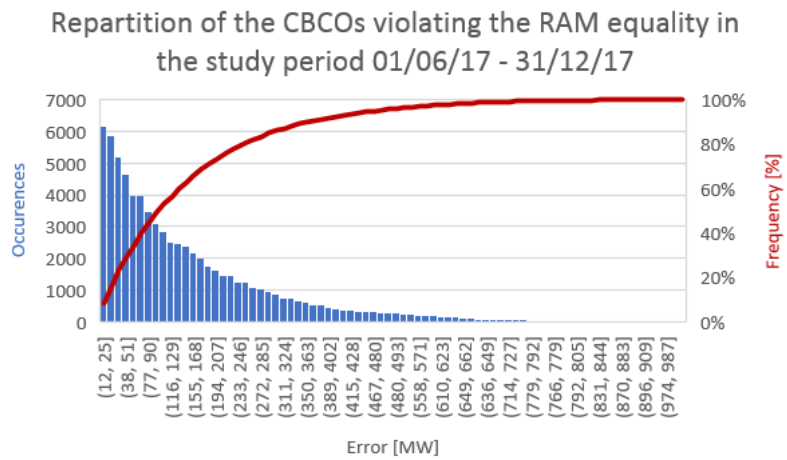


Figure 9: Repartition of the CBCOs violating the RAM equality in the study period 01/06/17 - 31/12/17 in CWE region

Both distributions show large numbers of occurrences for small absolute errors but also a non-negligible (more than 1300 in 2017 and 900 in 2018) number of occurrences for which the error is above 600 MW. Note that the intervals of both distributions are positive, i.e. the $\mathrm{RAM}_{\mathrm{CB}} > (\mathrm{F}_{\mathrm{CB}}^{\max} - \mathrm{F}_{\mathrm{CB}}^{\mathrm{ref}} - \mathrm{FAV}_{\mathrm{CB}} - \mathrm{FRM}_{\mathrm{CB}})$ when this correction is applied. A positive RAM error implies that the final offered RAM is greater than what it should be according to the equation of the RAM, most probably due to the LTA patch.

[20] The CBCO 1556664 linked to the CB "Niederlangen - Meppen EMSLD OW" on the 12/06/17 in period 17 can serve as an example of the violation of equation (1). The parameters are the following: $\mathrm{F}_{\mathrm{CB}}^{\max} = 1441\,MW$, $\mathrm{F}_{\mathrm{CB}}^{\mathrm{ref}} = 1592\,MW$, $\mathrm{FAV}_{\mathrm{CB}} = 0\,MW$ and $\mathrm{FRM}_{\mathrm{CB}} = 137\,MW$. These values should lead to a RAM value of 1441 – 1592 – 0 – 137 = -288 MW, which would lead to a 0 hub-position point out of the FB domain. The RAM value obtained in the JAO data set is equal to 44 MW, which violates the way the RAM is defined in this report. No additional information is explicitly published to figure out how the 44 MW are found.

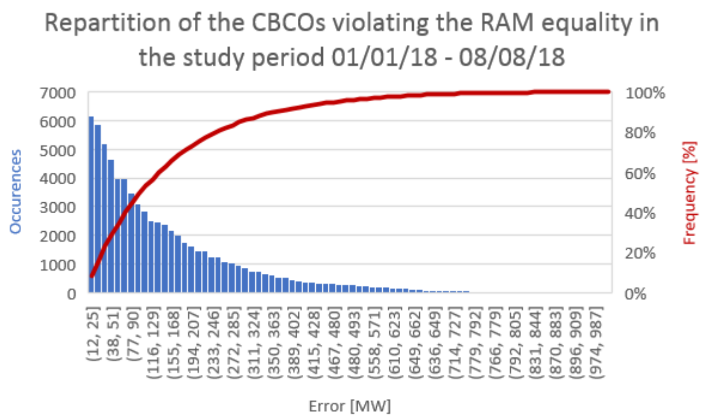


Figure 10: Repartition of the CBCOs violating the RAM equality in the study period 01/01/18 - 08/08/18 in CWE region

Reliability margins

The FRM of a critical branch is used as safety margin to compensate the uncertainties of the models and the potential flow deviations with respect to the forecasts. As explained in section 0, it is computed based on statistical distributions with a level of risk defined by TSOs. According to the study "CWE Flow Factor Competition Study" performed in 2017 by E-Bridge Consulting on behalf of CWE NRAs [6], "all TSOs except ELIA and TRANSNET apply a P90 percentile on the observed difference to determine FRM per CB". *Figure 11* and *Figure 12* depict the cumulative probability distributions of the relative reliability margins linked to the day-ahead capacity calculation for internal lines and interconnections in 2017 and 2018 in the CWE market. Although the distributions are not fully the same for the two years, they are very close, and the differences might be explained by seasonal effects.

Figure 11 shows that most of the FRM on internal lines in the CWE market range from 10% to 20% of the Fmax. For interconnections, a considerable number of branches are set to an FRM value of around 20%, whereas the rest is comprised between 10% and 18%. Details of minimum, maximum and average values are given in *Table 4* hereafter. Such values might be explained by the definition of the bidding zones and by the location of renewable energy sources. For instance, the uncertainty on generation from wind farms located in the north of the CWE region can lead to uncertainties on the level of internal flows and loop flows when they are expected to supply loads in the center and in the south of the region.

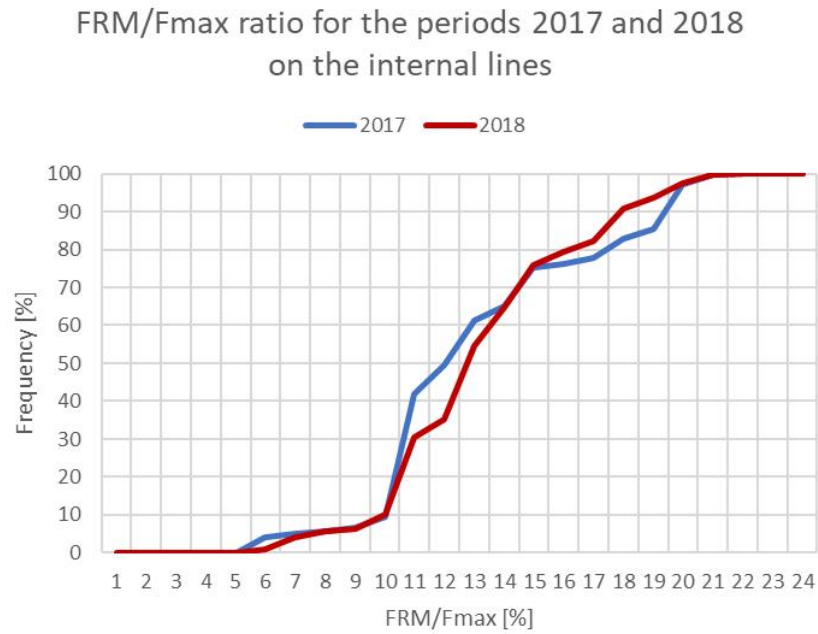


Figure 11: FRM/Fmax ratio for the periods 2017 and 2018 on the internal lines in CWE region

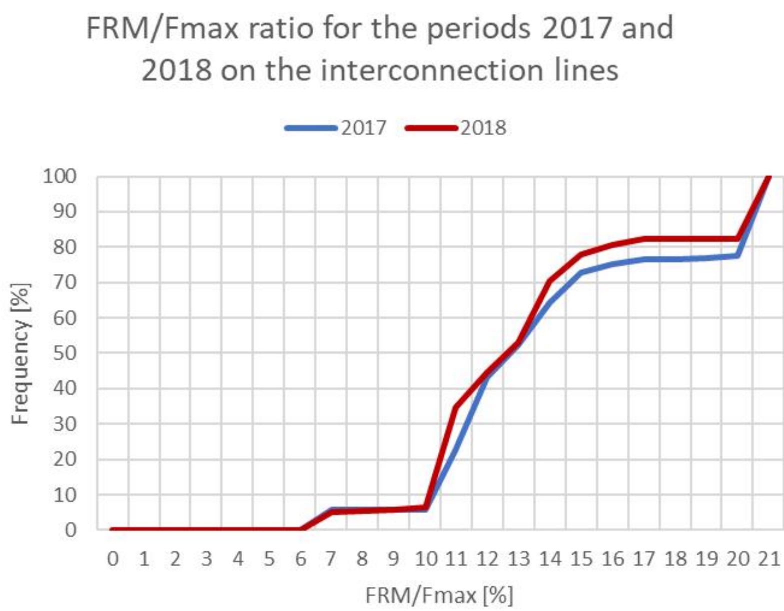


Figure 12: FRM/Fmax ratio for the periods 2017 and 2018 on the interconnection lines in CWE region

Table 4 shows the detailed figures obtained for the FRM in the studied periods P1 and P2. Note that external constraints being artificially implemented, no FRM is set on them, i.e. the RAM is directly set to a defined value. Results of *Table 4* show that:

§ For internal branches, the average value slightly increases between P1 (01/06/17 à 31/12/17) and P2 (01/01/18 à 08/08/18), with a mean value for both periods about 12%, in line with past data in CREG studies [7].

§ On interconnections, values are slightly higher, most likely due to a higher safety margin taken by TSOs for the interconnections between bidding zones.

FRM/Fmax [%]								
Studied period	Internal branches				Interconnections			
	P90	P95	P99	Mean	P90	P95	P99	Mean
P1: 01/06/17 à 31/12/17	18.09 %	18.09 %	19.98 %	12.11 %	20.04 %	20.04 %	20.04 %	13.78 %
P2: 01/01/18 à 08/08/18	16.98 %	18.09 %	19.98 %	12.31 %	20.04 %	20.04 %	20.04 %	13.23 %

Table 4: Minimum, maximum and mean FRM/Fmax ratios for internal branches and interconnections in CWE region

Before the go-live of the FB approach in May 2015, the market coupling in the CWE region was purely based on an NTC approach. It is thus of interest to compare the TRM that were taken just before (e.g. in 2013 and 2014) with the FRM used now. Just before the go-live of the FB approach, the TRM was 250 MW on the border between France and Belgium [8], 150 MW on the border between France and Germany [8], 250 MW on the border between Belgium and the Netherlands, and 250 MW on the border between the Netherlands and Germany. *Figure 13* shows then the relative reliability margins for the years 2013-2014, using the approach developed in Appendix 0. TRMs are globally between 6% and 14% with an average of 9.5%. Although Appendix 0 shows that TRMs and FRMs are not fully comparable, it must be noted that the relative FRMs of the current FB approach tends to be higher than the relative TRMs of the former NTC approach in the CWE region.

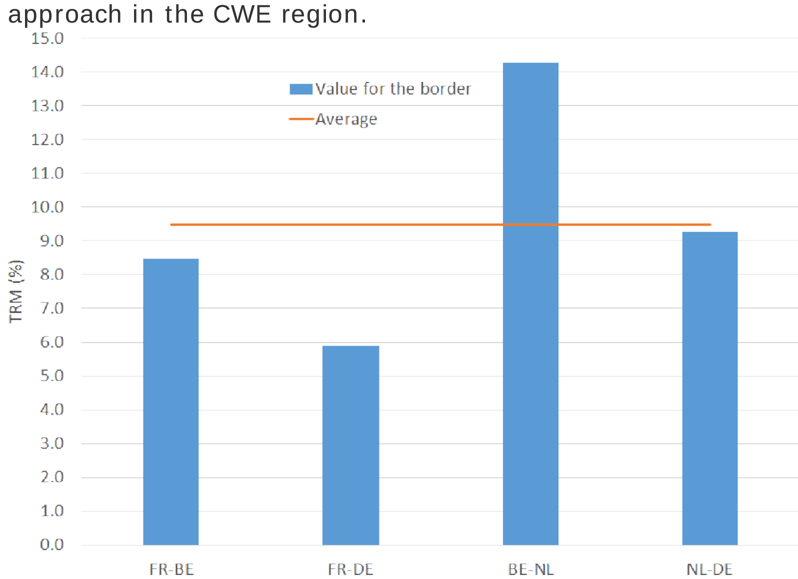


Figure 13: Relative reliability margins in the CWE countries in 2013-2014.

Final adjustment values

The FAV is a margin to cover remedial actions of the TSOs based on their knowledge of the network. A negative FAV simulates the effect of an additional margin due to a remedial action, i.e. a higher transmission capacity on the CBCO offered to the market. A positive FAV is used to prevent overloads detected earlier in the process and results in a reduction of the capacity offered to the market (RAM). *Table 5* provides the figures for the studied periods.

The main observation is that, in average, the FAV is negligible compared to the Fmax rating of the lines, i.e. around ± 1% for internal and interconnection lines. The 1.90% value appears as an upper limit in the data sets and is mainly applied to the critical branch Diele – Meeden. The largest negative values in 2018, down to – 56% of Fmax, are observed on the branches Diele – Meeden and Niederlangen – Meppen, both in the same region.

FAV / Fmax [%]									
Studied period	Internal branches			Interconnections			External constraints		
	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean
P1: 01/06/17 à 31/12/17	0 %	1.90 %	0.002 %	0 %	1.90 %	0.61 %	0 %	0 %	0 %
P2: 01/01/18 à 08/08/18	-56.43 %	1.90 %	-0.476 %	-55.96 %	1.90 %	-0.56 %	0 %	0 %	0 %

Table 5: Minimum, maximum and mean FAV/Fmax ratios for internal branches, interconnections and external constraints

The process behind the FAV value is unclear as no description of the remedial action taken by the TSOs are available in the data sets. Indeed, the critical branch and critical outage of the CBCO are published but the remedial action causing/enabling a decrease/increase of the RAM is unknown. Values of FAV down to -1100 MW are observed for internal branches in 2018 and suggest that corrective action plans are set up (e.g. use of phase-shifter transformers or modification of the grid topology) and quantified (accurate value of the negative FAV).

Finally, no negative FAV are observed in the studied period of 2017[21]. The reason behind these null values is unclear. The example of the CBCO "*1350127 Eemshaven-Meeden Z – Eemshaven-Meeden W*" shows that the RAM was mostly equal, in average, in 2017 and 2018, with 559 MW and 554 MW respectively. However, these similar values are without explicit FAV in 2017, i.e. the FAV column in 2017 in set to 0 MW. This suggests that the effect of the FAV on the RAM value was included in the other parameters (Fref, FRM). In 2018, the negative FAV value are explicitly displayed in the FAV columns of JAO's data, therefore the gain in RAM of the remedial action is known.

Remaining available margins

In the previous sections, the statistical analysis of Fref, FRM and FAV is discussed. What remains from the initial Fmax, when removing the Fref, FRM and FAV is the RAM allocated to the market.

The study of the RAM/Fmax is restricted to the real CBCOs as the virtual CBCOs lose their physical meaning. As previously mentioned, virtual CBCOs are computed to extend the initial flow-based domain. Therefore, the equations describing the virtual CBCOs are no longer associated to the real sensitivity of the power flows of the CBCOs (PTDF). Figure 14 and Figure 15 depict the cumulative probability distributions of the RAM/Fmax ratio for real CBCOs of internal lines and interconnections in 2017 and 2018. *Table 6* shows that the RAM/Fmax ratio is in average slightly higher in 2018 (56.40%) than in 2017 (49.51%). The extreme values up to 160% are observed for CBCOs with a highly negative Fref on the CB. Examples of such CBs are Horta – Mercator, Achène – Gramme, Aubange – Moulaine, Avelgem – Mastaing.

[21] From June to December 2017.

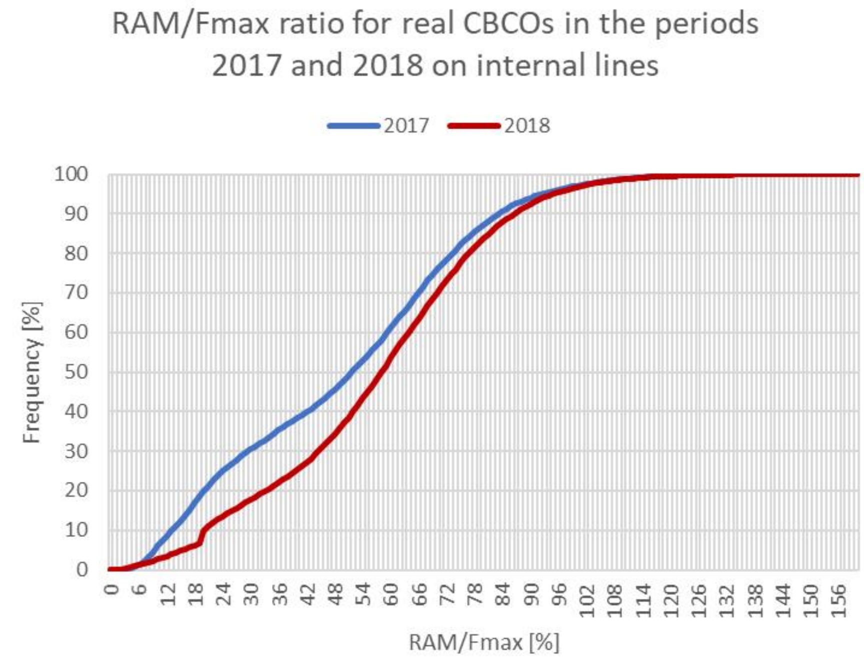


Figure 14: RAM/Fmax ratio for real CBCO in the periods 2017 and 2018 on internal lines in CWE region

Figure 15 depicts the RAM/Fmax ratio for interconnections. In this case, the cumulative probability functions are almost equal in 2017 and 2018. Average values are 68.14% and 67.72% in 2017 and 2018, respectively.

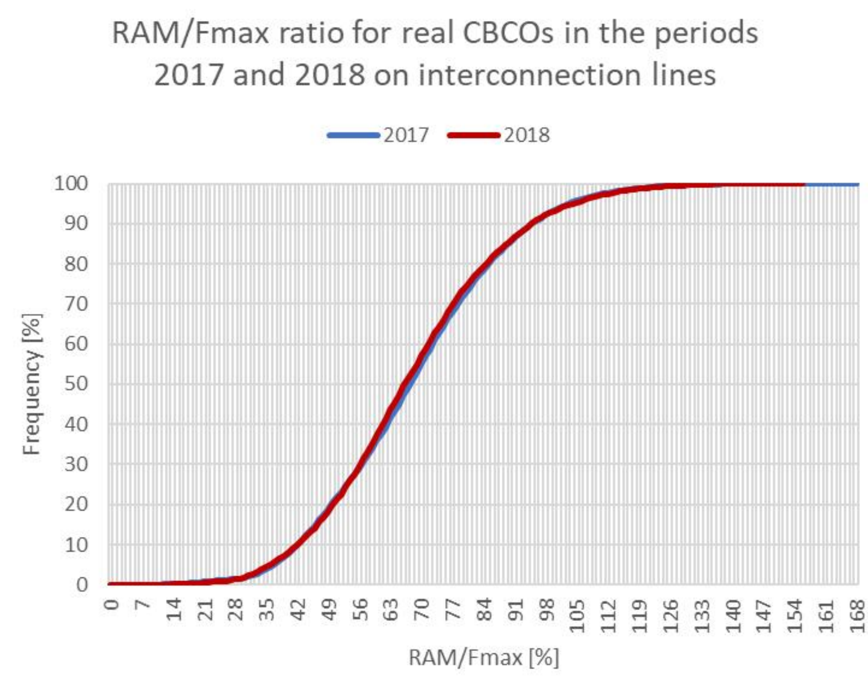


Figure 15: RAM/Fmax ratio for real CBCO in the periods 2017 and 2018 on interconnection lines in CWE region

Details of the results shown in Figure 14 and Figure 15 are provided in Table 6, including the percentiles 90 and 99[22]. The results mainly highlight the difference between internal and interconnections with respect to the RAM allocated to the market. Numbers show that, in average, internal lines have a lower RAM/Fmax ratio than the interconnection.

RAM/Fmax ratio for real CBCOs in the periods 2017 and 2018								
Studied period	Internal lines				Interconnections			
	Min	P90	P99	Mean	Min	P90	P99	Mean
P1: 01/06/17 à 31/12/17	0.62 %	83.32 %	112.27 %	49.51 %	6.65 %	95.05 %	120.55 %	68.14 %
P2: 01/01/18 à 08/08/18	1.43 %	86.74 %	112.61 %	56.40 %	6.36 %	94.92 %	121.76 %	67.72 %

Table 6: RAM/Fmax ratio for real CBCOs in the periods 2017 and 2018 in CWE region

Note that the lower RAM/Fmax ratio of internal lines does not mean necessarily that they limit the market more often, because they are less impacted by inter-area exchanges (i.e. they have smaller PTDFs). Indeed, the limitation of commercial exchanges between two areas by a CBCO is given by the ratio between the RAM and the difference of PTDFs between these two areas. To complement this analysis, Table 7 provides the repartition of the constraints shaping the flow-based domain in the studied periods of 2017 and 2018. Figures show that 26% and 36% of all constraints shaping the flow-based domain, respectively in 2017 and 2018, are internal lines. Interconnections account for 67% and 47% of the constraints for the studied periods[23]. It means that, although interconnection lines play a major role in the limitation of cross-border commercial exchanges, bidding zones are generally not a copper plate and internal congestions limit as well significantly the cross-border commercial exchanges.

Repartition of the types of constraints limiting the flow-based domain (PRESOLVED = TRUE) [%]		
	2017	2018
Internal lines	26 %	36 %
Interconnections	67 %	47 %
External constraints	7 %	17 %

Table 7: Repartition of the types of constraints limiting the flow-based domain in 2017 and 2018 in CWE region

Analysis including redundant constraints

In the analysis performed in the previous sections, only the constraints limiting the flow-based domain are analyzed in order to identify the parameters which limit cross-border commercial exchanges. For the sake of completeness, the analysis presented in this section includes redundant constraints, i.e. constraint which do not shape the flow-based domain. The studied period is the 19/06/18. In this period, the total number of constraints is 115 327, from which 114 720 are redundant and 607 are limiting constraints. Note that the proportion of limiting constraints compared to the total amount of constraints is discussed in appendix (section 0).

[22] Example: Percentile 90 = 83.32% for internal lines in 2017 means: 90% of the values have a RAM/Fmax ratio below 83.32%.

[23] The differences between 2017 and 2018 could come from the different periods studied, i.e. second part of the year in 2017, first part of the year in 2018. Also, values given are approximative as not all CBCO are identified by their physical name. Therefore, the percentages of constraining internal lines provided in this report should be higher than the real value. See Table 1 for the identification of interconnections.

Table 8 summarizes the results obtained for the studied period. The parameters discussed are the RAM/Fmax, the positive, negative and global Fref/Fmax, the FRM/Fmax and the FAV/Fmax. The column "FALSE" include the redundant constrains whereas the column "TRUE" includes the constraints limiting the flow-based domain.

	RAM/Fmax [%]		Positive FREF/Fmax [%]		Negative FREF/Fmax [%]		FREF/Fmax [%]		FRM/Fmax [%]		FAV/Fmax [%]	
	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE	FALSE	TRUE
Mean	88	63	20	33	-18	-14	1	27	11	12	0	-0.3
Min	20	20	0	0	-103	-70	-104	-70	0	0	-25	-24
Max	195	148	95	94	0	-0.2	95	94	21	20	2	2

Table 8: Statistical analysis of flow-based parameters for all CBCOs (including redundant) on the 19/06/2018

The results of Table 8 show that:

§ The RAM/Fmax ratio is slightly higher for the redundant constraints (88%) than for the limiting constraints (63%). This observation is in line with the fact that the RAM is the final capacity allocated to the day-ahead market. The minimum value of the RAM/Fmax corresponds to the minimal imposed RAM value (20%) applied since April 2018.

§ The difference in RAM/Fmax ratio between redundant and limiting constraints is mainly due to the higher positive Fref/Fmax values in limiting constraints (33%) compared to redundant constraints (20%).

§ The sum of means of RAM/Fmax + Fref/Fmax + FRM/Fmax + FAV/Fmax for limiting constraints is not 100% due to the LTA patch activation which changes the values of RAMs after the computation of the initial domain.

§ FRM and FAV of redundant and limiting constraints are mostly similar. Indeed, FRM are defined by critical branch, therefore it does not change the FRM/Fmax value if the critical branch belongs to a redundant or limiting CBCO.

Intermediate conclusions

The analyses performed in this section show that the FB market in the CWE region used for day-ahead market coupling is strongly driven by the application of an LTA-patch aiming at including long-term cross-border transmission capacity rights in a FB domain, which initially considered that capacity allocation as unsafe. Although the LTA-patch tends to increase the capacity allocated to the market, the RAM on key critical network elements is very low. In average, for CBCOs limiting the domain, the RAM is lower than 60% of the thermal capacity on internal lines and lower than 70% on interconnection lines. Furthermore, 37% of the internal lines had a RAM lower than 50% in 2018, and 20% of the interconnection lines. These low values can be mainly explained by high values of internal flows and loop flows (representing several tens of percent), but also, to some extent, to the reliability margin representing 10-20%.

The Nordic region

In the previous section, the CWE flow-based market example is analyzed. In this section, the Nordic power market is discussed. It is currently based on an NTC approach, but a FB approach should be implemented for the day-ahead market coupling in a short-term future (2019/2020) [5]. The analysis of the Nordic power market can bring two insights for the CWE region: the values of the TRM used so far [9] can be used to compare the FRM used in the CWE region, and the simulations performed for the impact assessment of the FB approach can be used as an interesting comparison for the level of internal flows and loop flows (Fref) in the CWE region.

Reliability margins

Figure 16 shows then the relative reliability margins (using the approach described in Appendix 0) for the year 2014. At the exception of NO2-NO5, most of the borders have a TRM below 10%. The average is 5%. Relative TRMs applied in the Nordic region appear thus to be approximately the half of the relative FRMs applied in the CWE region. Note that energy mixes are not the same in the two regions: the CWE region integrates higher amounts of variable energy sources (e.g. wind and solar) which may explain higher values for the TRM. For instance, in 2017, variable renewable energy sources represented 14.7% of the energy mix in the CWE region, while it represented 10.0% in the Nordic countries. Another factor explaining that difference is the size of the bidding zones in the considered system. For instance, in the extreme case in which each bidding zone contains only one node (nodal market), forecast uncertainties on parameters used in the flow-based approach are drastically reduced (i.e. GSKs are trivial and there is no uncertainty on the load and generation patterns within each zone for a specific load and generation levels). Consequently, in that case, reliability margins are essentially due to the unexpected action of load-frequency controls. Note that it does not mean that a small bidding zone will have small reliability margins, because that bidding zone is impacted from externalities coming from other bidding zones (e.g. a large bidding zone can induce uncertainty on the flows in a small bidding zone).

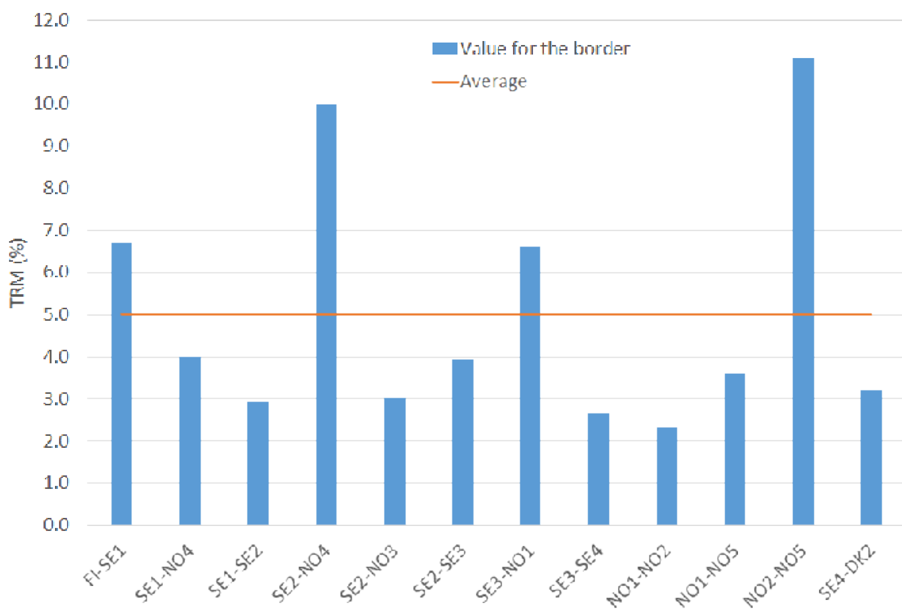


Figure 16: Relative reliability margins in the Nordic countries.

Internal flows and loop flows

Based on the publicly available simulation results linked to the impact assessment of the FB approach in the Nordic CCR[24], *Figure 17* shows the values obtained for the positive Fref'/Fmax ratio in 2016 and 2017.

[24] http://nordic-rsc.net/simulation-results/

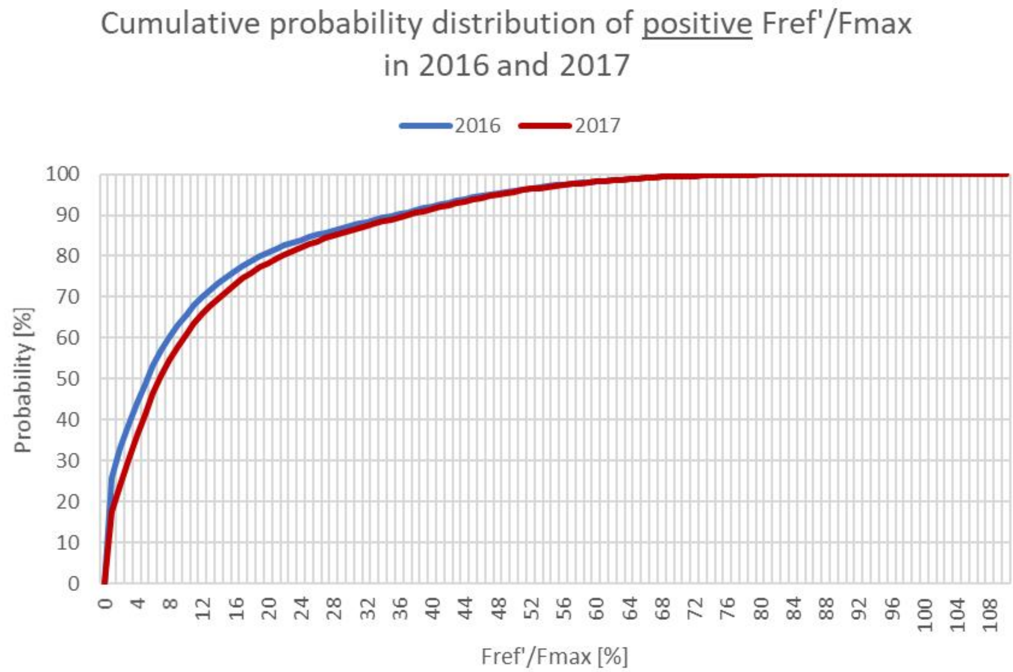


Figure 17: Cumulative probability distribution of positive Fref'/Fmax in 2016 and 2017 in Nordic countries

For CBCOs with a positive Fref, the average is much lower for the Nordic CCR (*Table 9*) than for the CWE CCR (*Table 3*). Indeed, Fref'/Fmax ratios in Nordic countries are close to 10%, in negative and positive[25], as shown in *Table 9* hereafter.

Fref / Fmax [%]						
Studied period	Negative Fref			Positive Fref		
	Min	Max	Mean	Min	Max	Mean
Period 2016	-94.61 %	0 %[26]	-9.24%	0 %	109.98 %	11.48 %
Period 2017	-109.75 %	0 %[26]	-10.79	0 %	93.13 %	12.47 %

Table 9: Fref/Fmax for the periods 2016 and 2017 in the Nordic countries

From *Figure 17* hereafter and values of *Table 9*, one can observe that the Fref'/Fmax is not only smaller in absolute value in Nordic countries but also more symmetrical, i.e. the internal power flows are as high as the positive power flows.

[25] A negative Fref implies an increase of the available transmission capacity on the transmission element in the considered direction compared to the thermal rating, because internal flows and loop flows go in the other direction, while a positive Fref implies a decrease of the available transmission capacity on the transmission element in the considered direction compared to the thermal rating, because internal flows and loop flows go in the same direction, as explained in section 0.

[26] The intervals are set as follows: negative FREF means FREF strictly lower than 0, whereas positive FREF means FREF greater than or equal to 0.

Nevertheless, values close to 100% and even higher are observed in both cases, i.e. in Nordic countries and CWE. Internal flows and loop flows on lines of critical importance for cross-border exchanges are thus not negligible.

Intermediate conclusions

Although an NTC approach is still used in the Nordic region, the relative capacity allocated to the market on critical network elements after the implementation of the FB approach is expected to be higher than in the current implementation of the FB approach in the CWE region for two reasons: the level of internal flow and loop flows appear to be much lower (a little bit more than 10%), and most of the borders have a reliability margin below 10%, with an average of 5% (i.e. approximately the half of the relative FRMs applied in the CWE region).

Iberian Peninsula

Border between Portugal and Spain

Between Portugal and Spain, the TRM is, since at least 2007, 10% of the TTC with a minimum of 100 MW [10] [11]. This relative TRM of 10% corresponds directly to a possible application of equation (16) shown in appendix 0. It is a little bit lower than the relative FRMs observed in the CWE region. In 2017, the ideal TTC computed through equation (12) was 7.7 GW (winter ratings). However, the maximum actual NTC corresponded to 42% (3.2 GW) of this ideal TTC in the direction Spain → Portugal and 52% (4.0 GW) in the direction Portugal → Spain. Important loop flows[27] might explain these low values [10].

Border between Spain and France

The electrical border between Spain and France changed drastically in 2015 with the commissioning of the INELFE HVDC system between Baixas and Santa Llogaia. In order to keep a benchmark with borders purely based on AC connections, the analysis is based on the situation just before the commissioning of that new interconnection, i.e. on the year 2014. The ideal TTC computed through equation (12) in appendix 0 was then 2.4 GW. However, the maximum actual NTC corresponded to 46% (1.1 GW) of this ideal TTC in the direction Spain → France and 54% (1.3 GW) in the direction France → Spain. If the TRM used is supposed to be 200 MW [8], an application of equation (16) similar to what was done in section 0 gives a relative TRM of 14.3%. This high value can be explained by the fact that all power imbalances of the Iberian Peninsula are compensated quasi-exclusively by that boundary. Note that now, with an increase of the NTC by approximately 2 GW with the INELFE HVDC system, the TRM is 7.5% of the TTC with a minimum of 200 MW [8].

Intermediate conclusions

The analysis of these two borders show that, although the reliability margins are limited to 10-15%, the capacity available for cross-border exchanges is well below the ideal capacity that would be obtained with a perfect balance of flows on cross-border lines and without loop flows.

---

[27] A loop flow can be defined as the physical flow on a line in one bidding zone due to internal power transfers in another bidding zone. Consequently, loop flows can already occur in a system with two bidding zones if these two bidding zones are connected in a meshed way, which is the case of Spain and Portugal.

Expected future evolution

Introduction

The previous chapter described the status-quo and the recent evolution of capacity calculation methodologies. However, as the CACM guideline is being implemented, major evolutions are expected in the upcoming years. Indeed, the FB approach will be extended in Continental Europe to the overall Core CCR for both day-ahead and intraday timeframes and is being revisited for that occasion. The FB approach will also be applied to the Nordic CCR. Even if other CCRs will keep for the moment an NTC approach, methodologies are also being revised and clarified to comply with the CACM guideline. In that context, this chapter aims at discussing the key factors impacting the efficiency of the capacity calculation and allocation. Section 0 and section 0 summarize first the future CCRs and CCMs, respectively. Then, section 0 elaborates on the evolution of key parameters.

Future CCRs

The bidding zones borders are being restructured in 10 CCRs: Nordic, Hansa, Core, Italy North, Greece-Italy, South-West Europe (SWE), Ireland and United Kingdom (IU), Channel, Baltic, and South-East Europe (SEE). *Figure 18* shows the Core CCR, resulting from the merging of the former CWE and CEE CCRs and being thus the largest one in terms of number of countries and TSOs involved.

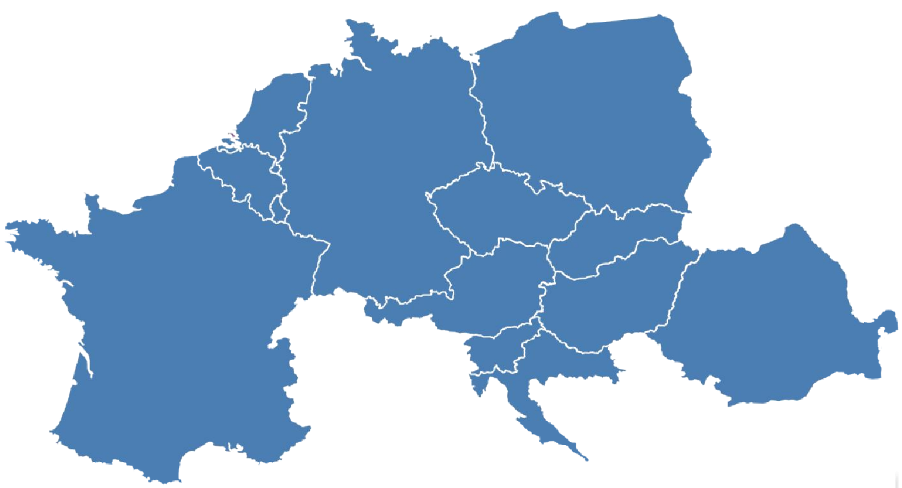


Figure 18: Core CCR.

Future CCMs for DA and ID timeframes

Core CCR

The Capacity Calculation Methodologies (CCMs) for the day-ahead and the intraday timeframes that will be used in the Core CCR are described in three documents published in June 2018 [3] [4] [12]. The CCMs are expected to be implemented early 2020 for the day-ahead timeframe, and early 2021 for the intraday timeframe. Compared to the current practices within the CWE region, the following key points are worth to be emphasized:

§ The risk level used to compute the FRMs is clarified and fixed to 10% in the new day-ahead and intraday CCMs published by the Core TSOs in June 2018 [3] [4]: the FRM values cover 90% of the historical errors (i.e. 1.38 standard deviation of the historical errors probability distribution), in line with the current practices of the CWE region [6]. It means that two probability distributions will be derived: one for forecast errors related to the day-ahead capacity calculation, and the other one for the forecast errors related to the intraday capacity calculation. Consequently, different FRMs are expected to be used in the day-ahead and in the intraday capacity calculations. In case there is a lack of statistical data for a critical network element, a standard value of 10% of the Fmax will be used for the FRM for both the intraday and the day-ahead timeframe.

§ An adjustment procedure to have a minimum RAM of 20% of Fmax will be applied for the day-ahead timeframe only (and thus not for the intraday timeframe), with the provision that a TSO may decide not to apply this adjustment procedure in certain circumstances on specific network elements.

§ The procedure to include long-term allocated capacities for the day-ahead timeframe will change and does not involve anymore the creation of virtual constraints. Indeed, instead of transforming the real constraints corresponding to problematic network elements into virtual constraints through both a modification of the PTDFs and a modification of the RAM in an opaque way, only the RAM of problematic network elements will be increased to meet the LTA. Figure 19 illustrates this change: the "Current LTA patch" uses virtual constraints to enlarge the domain. The "Future LTA patch" only increases the value of the RAM for problematic elements.

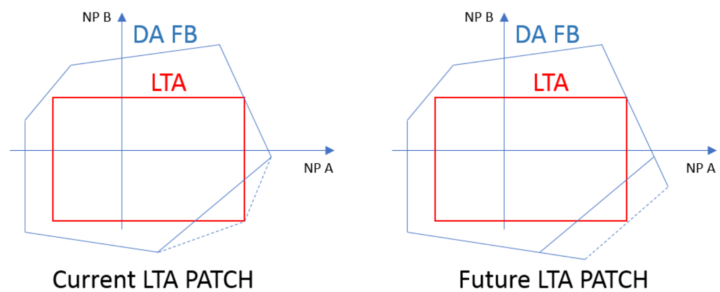


Figure 19: Comparison of current and future LTA patch methodologies

Because all the constraints will stay real (i.e. physical meaning associated to the PTDFs), it is expected to solve most of the problems emphasized in section 0. Nevertheless, the use of a margin for LTA inclusion will still mean that the FB approach is applied in a more conservative way that the NTC approach.

§ Once the capacity calculation methodology for the intraday timeframe will have been implemented, the available capacity for the intraday market will not be any more simply the left-over capacity from the day-ahead market clearing point. Indeed, a first intraday common capacity calculation will be performed in the end of the day before the delivery for all market time units and a second intraday capacity calculation will be performed during intraday (i.e. the day of delivery) for the remaining market time units of that day, each calculation being performed using the latest forecasts available. The final target is to have multiple (i.e. more than two) recalculations throughout the day, if it is feasible and of added value.

Nordic CCR

The Capacity Calculation Methodologies (CCMs) for the day-ahead and the intraday timeframes that will be used in the Nordic CCR for the day-ahead and the intraday timeframes are described in two documents [13] [5]. A FB approach will be eventually used for both the day-ahead and the intraday timeframes. However, in the beginning of the implementation in the end of 2019, an NTC approach will be used for the intraday timeframe. Nevertheless, capacities released for intraday market will not just be left-over capacities from the day-ahead market clearing point: one (or several) dedicated NTC calculation will be performed based on the latest forecasts available. The frequency of the intraday capacity calculation is not yet clear: "the frequency of the reassessment of intraday cross-zonal capacity shall be dependent on the availability of input data relevant for capacity calculation, as well as any events impacting the cross-zonal capacity" [13]. A FB approach is expected to be used for the intraday timeframe only in the beginning of 2022. Compared with the proposed CCM of the Core CCR, the following differences are worth to be emphasized:

§ In [13], it is noted that "TSOs shall use the predefined risk level of 95%" to compute the reliability margins. It means in that case that the reliability margins values will cover 95% of the historical errors in the SWE CCR (i.e. 1.64 standard deviation of the historical errors probability distribution).

§ No minimum RAM is envisaged "to the extent that the capacity allocation in the following timeframe will allow such negative values" [13]. A stakeholder consultation document published in 2017 [14] explicitly mentioned that negative RAMs could be used directly because it claims that "increasing the RAM would also not allow the market coupling process to determine the most efficient way to relieve a possible congestion". However, "when a negative RAM is calculated but not applied in capacity allocation, the RAM value shall be set to zero and the potential constraint shall be managed by RA" [13].

Other CCRs

At the moment of writing, only the SWE CCR [15] and Italy North have published its CCM. Nevertheless, consultation documents are available for the other CCRs. If the Core CCR and the Nordic CCR will use a FB approach, all other CCRs will continue to use an NTC approach to calculate and allocate the capacity. Two CCRs mentioned explicitly the risk level used to over the reliability margins: the TRM values will cover 95% of the historical errors in the SWE CCR (i.e. 1.64 standard deviation of the historical errors probability distribution) and the TRM values will cover 99.87% of the historical errors in the North Italy CCR (i.e. 3 standard deviations of the historical errors probability distribution). These percentiles are much higher than the ones used currently in the CWE region (i.e. 90%) which might thus lead to relative TRMs higher than the relative FRMs currently in use in the CWE region (i.e. higher than 10-20%). The discrepancy of practices between CCRs about the acceptable risk level is thus worth to be emphasized.

Evolution of key parameters

In the short run, three major key parameters impacting the capacity allocated to the market could evolve significantly: the maximum allowable power flows (Fmax), the reliability margins and the final adjustment values. The evolution of these parameters must also be put in perspective with the recalculation of the transmission capacity that can be allocated to the market for the intraday timeframe. The next subsection briefly discusses the expected evolution of these three parameters.

Maximum allowable power flows (Fmax)

Because the factor limiting the current in a transmission element is its temperature, the associated maximum admissible power flow varies in function of weather condition (e.g. air temperature, wind speed). When a unique maximum admissible power flow

(Fmax) is considered along the year for a specific element, its estimation is based on conservative assumptions about weather conditions (e.g. high air temperature, low wind speed). It would thus be inefficient to have such a unique value. The maximum allowable power flow is thus usually fixed per season. The seasonal ratings are based on conservative assumptions about weather conditions individually for each season, which allows the use of higher capacities in winter. To reduce further the conservatism about weather conditions assumptions, it is possible to use dynamic line ratings. In that case, the maximum admissible power flow depends on the forecasted weather conditions, and is, in average, higher than the corresponding static rating. In the past years, several TSOs started to implement dynamic line ratings leading to higher capacities in average. However, this is not yet systematic. If TSOs continue to implement dynamic line rating, the maximum allowable power flows will increase.

Reliability margins

Reliability margins are driven by two main factors: the action of load-frequency controls following unexpected generating unit outage, and forecast uncertainties on parameters used in capacity calculation, in particular parameters related to the load/generation pattern.

The impact on reliability margins of the first factor, i.e. the action of load-frequency controls following unexpected generating unit outage, is not expected to decrease in the intraday capacity calculation compared to the day-ahead capacity calculation (e.g. the unexpected outage of a generating unit cannot be forecasted at all, so the forecast does not improve between the day-ahead and the intraday timeframes). However, because there is a trend to integrate frequency reserve markets at a European level[28], it is expected to have an increase of the flow uncertainties due to the actions of load-frequency controls. Although the proposal for the implementation framework for the exchange of balancing energy from frequency restoration reserves with automatic activation [16] allows exchange of aFRR only if transmission capacity remains available after the closure of the cross-border ID market coupling, the actual activation of the aFRR will stay uncertain because it is linked to unexpected events. It is thus not clear how aFRR activation will be accounted for in the computation of reliability margins but, if they are not included in the forecasted flows (as they are by nature quite uncertain), it will tend to increase reliability margins. That increase should be marginal for countries strongly interconnected with their neighbors. For example, if Belgium contracts all its FRR (i.e. aFRR and mFRR) abroad, power flows in the importing direction after the deployment of FRR following the unexpected outage of a nuclear unit will increase by about 1 GW. It represents approximately 18.2% of the current maximum import capacity (5.5 GW), but it impacts in average approximately 0.1% of the hours in a year. Consequently, if the FRM aims at covering 90% of the deviation, the impact of this 0.1% is marginal. On the other hand, that increase might be more substantial for countries or regions weakly connected to the rest of the European electricity grid.

On the contrary, the impact on reliability margins of the second factor, i.e. forecast uncertainties on parameters used in capacity calculation, is expected to decrease significantly in the intraday capacity calculation compared to the day-ahead capacity calculation, if latest forecasts available are really used in the capacity calculation, and

[28] Markets for Frequency Containment Reserves (FCR) are already strongly integrated at a European level, but ongoing projects are under development at the European level to integrate Frequency Restoration Reserve (FRR) markets and to have thus exchange of FRR services between LFC areas. For the aFRR markets, the PICASSO project aims at designing, implementing and operating (by late 2020) a platform for the exchange of balancing energy from aFRR. For the mFRR markets, the MARI project aims at designing and implementing (in 2022) a platform for the exchange of balancing energy from mFRR.

if the intraday capacity is regularly recalculated. Indeed, data published by Elia show that forecast errors are, for wind generation, around 18.8%, 6.9% and 4.9%, a week ahead, a day ahead and during the day, respectively, and are, for PV generation, around 7.6%, 4.1% and 3.1%, a week ahead, a day ahead and during the day, respectively. Because the day-ahead capacity calculation is based on the two-day ahead congestion forecast, forecast errors related to wind generation and PV generation can be considered between the week-ahead and the day-ahead forecasts. Therefore, updating grid models for the intraday capacity calculation could substantially decrease the reliability margins. Nevertheless, looking only at the day-ahead timeframe, two opposite driving forces linked to forecast errors on renewable energy sources are impacting the reliability margins. On one hand, the integration of renewable energy sources will tend to increase the absolute forecast error on the generation pattern. On the other hand, the increasing regional cross-border cooperation between TSOs and the improvement of forecasting techniques for renewable energy sources will lead to lower relative forecast errors on the grid topology, on the load, and on the generation pattern. Beyond the forecasts of renewable energy sources, GSKs represent a crucial factor impacting the reliability margins. Indeed, because they are linking the change in net position of a bidding zone and the change in output of every generating unit inside the same bidding zone, they play a critical role in the prediction of flows on critical transmission elements. If GSKs are not properly estimated, reliability margins will have to cover the important deviation between expected and actual flows. The empirical rules currently used by TSOs in the CWE region without proof of their effectiveness (e.g. consideration that all units in operation will participate homothetically to the power shift) seem to be transposed in the Core CCM for both the day-ahead and the intraday timeframes [12]. There is thus room for improvement, and a better estimation of the GSKs, as well as an update of GSKs for the intraday capacity calculation, could help to reduce the reliability margins. However, without a quantitative analysis, the reduction of the magnitude of reliability margins that could be obtained by better GSKs is unclear and might be marginal. Note that the Nordic CCM proposes to define 9 generic strategies to define GSKs and to select the best one in each bidding zone such that the reliability margins are minimized. The operational feedback obtained from the yearly review of GSKs that will be performed by Nordic TSOs will clarify the benefits that could be expected from more accurate GSKs.

Final adjustment values

In a FB approach, FAVs are of paramount importance, because they can drastically impact the capacity allocated to the market. As shown in section 0, they were used to reduce significantly the capacity on several critical network elements in the CWE region, but that are now mainly use to increase the RAM on CBCOs in order to simulate corrective actions after the occurrence of a contingency (e.g. use of phase-shifter transformers, modification of the grid topology). The CCM of the Core CCR [3] and the stakeholder consultation document of the Nordic CCR [14] mention the use of FAVs, but without providing detailed explanations, except that the relevant TSO will have to provide the Core regulatory authorities with a clear description of the specific situation that led to the use of a FAV for the Core CCR. The reinforcement of regional cooperation between TSOs provides an opportunity for a better consideration of coordinated corrective actions such that FAVs can be used to increase the RAM. However, without clear transparency obligations on the grid model and actions that could be taken to alleviate overloads, no major change is expected.

Conclusions

The European internal electricity market will play a crucial role to accommodate higher amounts of renewable energy sources in the electricity mix while maintaining the security of supply at an affordable cost for consumers. In that context, the use of efficient cross-border capacity calculation methodologies allocating the maximum transmission capacity to the market while ensuring a secure operation of the power system is of paramount importance. This report summarized the two capacity calculation methodologies used in Europe, presented the results of a statistical analysis performed for the CWE CCR, for the Nordic CCR and for the SWE CCR (i.e. the Iberian Peninsula), and elaborated on the expected future evolution of the capacity calculation methodologies and parameters.

The statistical analysis presented in this report leads to the following key conclusions:

§ As general observation, it must be noted that information communicated by TSOs to market participants and regulators appears to be incomplete to fully understand key constraints impacting the electricity market.

§ The FB market in the CWE region is strongly driven by the application of an LTA-patch aiming at including long-term cross-border transmission capacity rights in a FB domain, which initially considered that capacity allocation as unsafe. The lack of transparency about the process leads to an uncertainty about the capacity really allocated to the market on several key transmission elements. Although lower volumes of long-term capacity was auctioned in 2018 compared to 2017, leading to a reduction of the LTA patch activation, if that allocation was deemed to be unsafe, it is not clear why urgent measures were not taken to much strongly reduce the need to LTA patches over the studied period.

§ Although Sweden and Norway are split into several bidding zones, and the comparison basis is not fully the same, the level of loop flows, internal flows and residual flows due to exchanges with countries outside the Nordic countries is not negligible. However, it appears to be much lower than the one in the CWE region.

§ Reliability margins taken in the CWE region appear to be in the upper range of European practices and are significantly above the Nordic region and although they did increase, it was not a dramatic increase with the introduction of the FB market coupling. High values can be explained partly by the combination of high amount of renewable energy sources at locations different from the ones of conventional generation (and of load) on one side, and of large bidding zones on the other side. However, the level of risk used to compute these values is not always fully transparent and can also be questioned. The reliability margins evolution will be driven by several factors. The evolution of the market towards an intraday recalculation of the transmission capacity should reduce forecast errors and therefore reduce the reliability margins necessary to cover uncertainties of variable renewable energy. Cooperation between TSOs at a region level coupled to improved forecast methods should reduce uncertainties on load, grid topology and generation patterns. A better estimation of GSKs should reduce the magnitude of reliability margins as well29.

§ In CWE, final adjustment values are used as a margin to cover remedial actions of the TSOs based on their knowledge of the network. Although the resulting RAM gain, i.e. the negative FAV value, of the remedial action is now explicitly published, the remedial action plan is still unknown by the market. More transparency

[29] Note that, without a quantitative analysis, the reduction of the magnitude of reliability margins that could be obtained by better GSKs is unclear and might be marginal.

regarding the description of the specific situation that led to the use of a FAV for the Core CCR is needed such that that FAV can be easily understood.

Concerning the expected future evolution of the capacity calculation methodologies and parameters, the Core CCM exhibits major improvements compared to the current CWE CCR, in terms of transparency and for the design of the LTA patch. However, the calculation of the intraday capacity based on an updated model, which is a key to obtain an efficient market, will be implemented only in 2021. On the Nordic side, it is surprising that the use of negative RAMs is not seen as a problem. Furthermore, it is surprising to observe that the risk levels chosen in the different CCRs for the reliability margins are different. On a more positive tone, it must also be noted that the evolution of the maximum allowable power flow calculation methods should lead to an increased offered transmission capacity to the market. For that purpose, flexible and dynamic line rating calculations should be implemented to limit too conservative Fmax ratings. Similarly, the update of the capacity that can be allocated to the market in the intraday timeframe will allow a reduction of reliability margins close to real-time.

References

[1] European Commission, "Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management".

[2] European Parliament and European Council, "Regulation (EC) No 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".

[3] 50Hertz, Amprion, APG, CREOS, CEPS, ELES, ELIA, HOPS, MAVIR, PSE, RTE, SEPS, TenneT GmbH, TenneT B.V., Transelectrica, TransnetBW, "Core CCR TSOs' regional design of the day-ahead common capacity calculation methodology in accordance with Article 20ff. of Commission Regulation (EU) 2015/1222 of 24 July 2015," 4th of June 2018.

[4] 50Hertz, Amprion, APG, CREOS, CEPS, ELES, ELIA, HOPS, MAVIR, PSE, RTE, SEPS, TenneT GmbH, TenneT B.V., Transelectrica, TransnetBW, "Core CCR TSOs' regional design of the intraday common capacity calculation methodology in accordance with Article 20ff. of Commission Regulation (EU) 2015/1222 of 24 July 2015," 4th of June 2015.

[5] Energinet, Svenska Kraftnät, Fingrid and Statnett, "Supporting document for the Nordic Capacity Calculation Region's proposal for capacity calculation methodology," 2018.

[6] R. Beune, S. C. Müller and O. Obert, "CWE Flow Factor Competition Study, part I: Qualitative Analysis," 2017.

[7] CREG, Functioning and design of the Central West European day-ahead flow based market coupling for electricity: Impact of TSOs Discretionary Actions, 2017.

[8] RTE, "Méthodologie de calcul des capacités d'échanges transfrontaliers d'électricité appliquée par RTE aux frontières françaises," 2014.

[9] ENTSO-E, "Principles for determining the transfer capacities in the Nordic power market," 2015.

[10] R. Pestana (REN), "Interchange Capacity between Portugal and Spain," in *2nd International Conference on Electrical Engineering*, Coimbra, 2007.

[11] REE, REN and RTE, "Explanatory Note of the Coordinated NTC methodology for SWE CCR," 2017.

[12] 50Hertz, Amprion, APG, CREOS, CEPS, ELES, ELIA, HOPS, MAVIR, PSE, RTE, SEPS, TenneT GmbH, TenneT B.V., Transelectrica, TransnetBW, "Explanatory note on the day-ahead and intraday common capacity calculation methodologies for the Core CCR," 4th of June 2018.

[13] Energinet, Svenska Kraftnät, Fingrid and Statnett, "All TSOs' of the Nordic Capacity Calculation Region proposal for capacity calculation methodology," 2018.

[14] Energinet, Svenska Kraftnät, Fingrid and Statnett, "Stakeholder consultation document and impact assessment for the capacity calculation methodology for the Nordic CCR," 2017.

[15] REE, REN and RTE, "South West Europe TSOs proposal of common capacity calculation methodology for the day-ahead and intraday market timeframe in accordance with Article 21 of Commission Regulation (EU) 2015/1222 of 24 July 2015," May 2018.

[16] ENTSO-E, "All TSOs' proposal for the implementation framework for the exchange of balancing energy from frequency restoration reserves with automatic activation in accordance with Article 21 of Commission Regulation (EU) 2017/2195," 2018.

Appendices

Flow-based approach: from zonal to nodal representation

When the linearized version of the power flow equations (i.e. the DC power flow approximation) is used, it can be shown that the power flow on a line depends, for a given topology, linearly and only on the net injection (i.e. difference between the generation and the load) of each node. Because under steady-state conditions the load must be equal to the generation, the sum of the net injections of all nodes must be equal to zero. Therefore, a slack node must be chosen to ensure that condition. The power flow F_{CB} on the transmission element CB can then be expressed mathematically by

$$F_{CB} - \sum_{n} \mathrm{PTDF}_{n\text{-to-slack,CB}} \cdot \mathrm{NEX}_n, \tag{2}$$

where NEX_n is the net injection of node n (positive when the node n exports power to the slack node) and $\mathrm{PTDF}_{n\text{-to-slack,CB}}$ is the Power Transfer Distribution Factor (PTDF) indicating the proportion of the power exchange between the node n and the slack node flowing on the transmission element CB (e.g. a PTDF of 10% indicates that 0.1 MW of a 1-MW exchange between the node n and the slack node flows on the considered transmission element). This equation can be extended to outages conditions: the power flow F_{CBCO} on the transmission element CB when there is the outage of the transmission element CO can then be expressed mathematically by

$$F_{CBCO} = \sum_{n} \mathrm{PTDF}_{n\text{-to-slack,CBCO}} \cdot \mathrm{NEX}_n, \tag{3}$$

where $\mathrm{PTDF}_{n\ \text{to}\ \text{slack,CBCO}}$ indicates the proportion of the power exchange between the node n and the slack node flowing on the transmission element CB when there is the outage of the transmission element CO.

Because nodes are clustered in bidding zones in a zonal market, nodal power flow equations cannot be directly used. Nevertheless, by assuming the way nodal net positions change when the zonal net positions change, zonal power flow equations very similar to the nodal power flow equations can be derived.

The purpose of Generation Shift Keys (GSKs) is precisely to make the bridge between nodal and zonal power flow equations. Indeed, they provide the contribution of each node of a given zone to a change in zonal balance, similarly to the NTC approach. In practice, TSOs determine the values of the GSKs, based on their knowledge of the power plants and their availability. However, knowing which power plants will participate in the market requires the market clearing price and vice versa. Determining the GSKs is therefore a complicated task and may lead to a suboptimal solution of the optimization problem of the FB algorithm.

Zonal PTDFs translate then the increase of power flow on a given line when the supply is increased by 1 MW in a given zone and consumed in a reference hub, playing a role similar to the slack node in the nodal approach. The PTDF associated to a given CBCO provides the increase of power flow on the CB for an addition MW in a given zone, consumed in the reference hub, considering that the CO is no longer available (N-1 situation). The zonal PTDFs can be derived from the nodal PTDFs, which translate the effect of an additional MW supplied by a given node and consumed at the hub node, by using the GSKs:

$$\mathrm{PTDF}_{z\text{-to-hub,CBCO}} = \frac{\sum_{n\in z} \mathrm{PTDF}_{n\text{-to-slack,CBCO}} \cdot GSK_n}{\sum_{n\in z} GSK_n} - \frac{\sum_{n\in hub} \mathrm{PTDF}_{n\text{-to-slack,CBCO}} \cdot GSK_n}{\sum_{n\in hub} GSK_n} \tag{4}$$

The flow on a transmission element CB due to cross-border electricity trades can then be expressed mathematically by

$$F_{CBCO}^{Cross-border} = \sum_{z} \mathrm{PTDF}_{z\text{-to-hub,CBCO}} \cdot \mathrm{NEX}_z, \tag{5}$$

where $\mathrm{PTDF}_{z\text{-to-hub,CBCO}}$ is the PTDF associated to the transmission element the transmission element CB when there is the outage of the transmission element CO, and where NEX_z is the net export power of the zone z, i.e. the power flowing from the zone z to the reference hub. Note that the total flow on a transmission element is the sum of the flow due to cross-border electricity trades and of the flow due to electricity exchanges between nodes within a bidding zone (often called F^{ref} or $F^{ref\prime}$). Therefore, not all the capacity of a transmission element (maximum allowable power flow, i.e. F^{max}) can be allocated to cross-border electricity trades. The actual capacity of a transmission element allocated to cross-border electricity trades is called the Remaining Available Margin (RAM).

Practical example of flow-based calculation process

To illustrate the flow-based calculation process on a real line, the example of the critical branch Van Eyck – Maasbracht is discussed for the period 1 of January 17th 2018. The critical outage considered is the line Borssele – Zandvliet.

- Knowing that the period is a winter and offpeak period, TSOs are able to provide an estimated Fmax for the critical branch (2009 MW in this case) and a load/generation forecast based on the set of available units and knowledge of the past.
- The PTDFs corresponding to the CBCO are computed based on the topology of the network and based on the GSKs. The values for this example are: BE = -0.13755, DE = -0.00489, FR = -0.06461, NL = 0.00492.
- The power flow Fref on the critical branch Van Eyck – Maasbracht under the contingency of the critical outage Borssele – Zandvliet is computed using the base case and the PTDF values. The value of Fref = 321 MW in this example.
- With a FAV = 0 MW and a FRM = 174 MW, the RAM of the CBCO is given by RAM = 2009 – 321 – 174 = 1514 MW.

Comparison of FRM and TRM

This section derives a way to compare FRM and TRM based on a two-zone system where each zone contains a single node. This is the simplest case to compare the NTC approach and FB approach. *Figure 20* shows such a system with L interconnection lines between zone A and zone B.

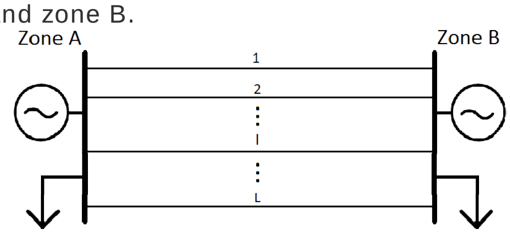


Figure 20: Two-zone & two-node system.

If all the lines are identical, the TTC is simply given, considering the N-1 security criterion, by

$$TTC_{A\to B} = TTC_{B\to A} = (\mathrm{L}-1)F^{max} \quad (6)$$

where F^{max} is the thermal capacity of any single transmission line. The NTC is then simply given by

$$NTC_{A\to B} = NTC_{B\to A} = (\mathrm{L}-1)F^{max} - TRM \quad (7)$$

In an NTC approach, the constraint on the net position of zone A, NEX_A (opposite of the net position of zone B), is thus

$$-\big((\mathrm{L}-1)F^{max} - TRM\big) \le \mathrm{NEX_A} \le (\mathrm{L}-1)F^{max} - TRM \quad (8)$$

In a FB approach, if all the lines are identical, the PTDFs on CBs for any CO (outage of a single line) are the same and are given by

$$\mathrm{PTDF}_{A\rightarrow B} = \frac{1}{L-1} \tag{9}$$

because the power flow is equally split between the remaining $L-1$ lines after a single outage. Due to the nature of the system, there is no loop flow and no transit flow. Therefore, $F^{ref} = 0$. In a FB approach, the constraint for each CBCO on the net position of zone A is then given by

$$-(F^{max} - FRM) \leq \frac{1}{L-1}\mathrm{NEX_A} \leq F^{max} - FRM \tag{10}$$

Equation (8) is equivalent to equation (10) if

$$TRM = (L-1) \times FRM \tag{11}$$

This result can be generalized to the case with different lines connecting two zones A and B, if the power flow is shared between lines proportionally to their ratings. This is not true in practice and corresponds thus more to an ideal case, but it can be used as a reasonable assumption if the system is planned and operated in an efficient way. In that case, the TTC is simply given, considering the N-1 security criterion, by

$$TTC_{A\rightarrow B} = TTC_{B\rightarrow A} = \sum_{l=1}^{L} F_l^{max} - \max_l F_l^{max} \tag{12}$$

In a FB approach, binding contingencies occur when the outage of the line with the highest capacity occurs. Under the ideal assumption of perfect power sharing between remaining lines, we have, considering that outage,

$$\mathrm{PTDF}_{A\rightarrow B,k} = \frac{F_k^{max}}{\sum_{l=1}^{L} F_l^{max} - \max_l F_l^{max}} \tag{13}$$

and the corresponding constraint on the net position of zone A is given by

$$-(F_k^{max} - FRM_k) \leq \frac{F_k^{max}}{\sum_{l=1}^{L} F_l^{max} - \max_l F_l^{max}}\mathrm{NEX_A} \leq F_k^{max} - FRM_k \tag{14}$$

Consequently, the NTC approach and the FB approach are equivalent if

$$FRM_k = \frac{F_k^{max}}{\sum_{l=1}^{L} F_l^{max} - \max_l F_l^{max}} \times TRM = F_k^{max}\frac{TRM}{TTC} \tag{15}$$

or, if

$$\frac{FRM_k}{F_k^{max}} = \frac{TRM}{\sum_{l=1}^{L} F_l^{max} - \max_l F_l^{max}} = \frac{TRM}{TTC} = \frac{TRM}{NTC + TRM} = \frac{TTC - NTC}{TTC} \tag{16}$$

These relations will also be used to benchmark the current values of the FRM used in the CWE region. However, a real two-zone system will differ from such an ideal two-zone system for two main reasons: each zone does not contain only one node and power flows on the cross-border lines are not perfectly distributed. It entails the following issues: loop-flows can occur, internal lines can limit the cross-border trade (and not only the cross-border lines), and a cross-border lines can hit its limit while there is still significant room on the others. Consequently, equation (12), (15) and (16) do not apply for real two-zone systems. Nevertheless, they can be used to quantify the distance to optimality. Furthermore, Equation (16) gives the correspondence between the FRM and the TRM in ideal two-zone systems. In a real system, its application is not unambiguous because the TTC is not simply given by equation (12), is not symmetric and varies with the operational conditions. A choice must thus be made about the way to compute the relative TRM to benchmark the FB approach against the former NTC approach in the CWE region. It is proposed to compute it as follows for the border between a zone A and a zone B.

$$TRM_{A-B}(\%) = \frac{TRM_{A-B}}{\frac{\max(NTC_{A\rightarrow B}) + \max(NTC_{B\rightarrow A})}{2} + TRM_{A-B}} \tag{17}$$

where the maximum of the NTC values is taken over the period of time considered. Consequently, although the correspondence between the TRMs and the FRMs is not unambiguous, a comparison can reasonably be made.

LTA patch activation statistics

Table 10 compares the common months between both 2017 and 2018 datasets, i.e. June and July. Results confirm the decrease of virtual CBCOs between 2017 and 2018. Nevertheless, the rate of LTA patch activation and the level of virtual constraints defining the FB domain stay high. However, the “amplitude” of the LTA patch activation is unknown because the initial flow-based domain, i.e. the flow-based domain without virtual constraints (before the LTA patch activation) is not published.

Studied period	LTA [% of active hours]	Virtual rate [% of virtual constraints]
P3: 01/06/17 à 31/07/17	74 %	47 %
P4: 01/06/18 à 31/07/18	71 %	37 %

Table 10: LTA patch activation statistics for June and July

Redundant and limiting constraints

In this section, the number of limiting constraints (shaping the final flow-based domain) is compared to total number of constraints in order to provide an order of magnitude of their proportion.

- In CWE, results show that, for an average day, the total amount of constraints (CBCOs) ranges from 110 000 to 150 000. From these constraints, 0.4% to 0.6% are not redundant and therefore limit the flow-based domain.
- In Nordic countries, the same analysis is performed. Per hour, the total amount of constraints observed in a set of hours in 2016 and 2017 in the published data ranges between approximately 300 and 450. The number of dimensions of the system is higher in this case (27 PTDFs) and the limiting constraints represent 40% to 50% of the total amount of constraints.

Negative Fref

CWE

For both years, interconnections lines have slightly more extreme negative Fref/Fmax (Figure 21 and Figure 22). Also, very few negative Fref/Fmax value above 40% are observed, i.e. the negative Fref just slightly increases the RAM, in average. Some extreme cases of negative Fref/Fmax ratios up to 40-50%.

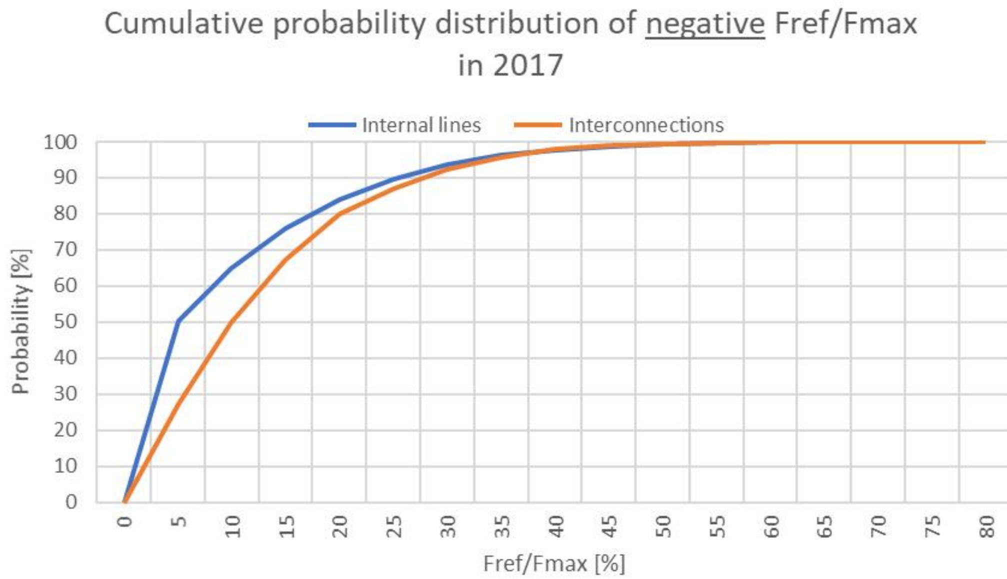


Figure 21: Cumulative probability distribution of negative Fref/Fmax in 2017

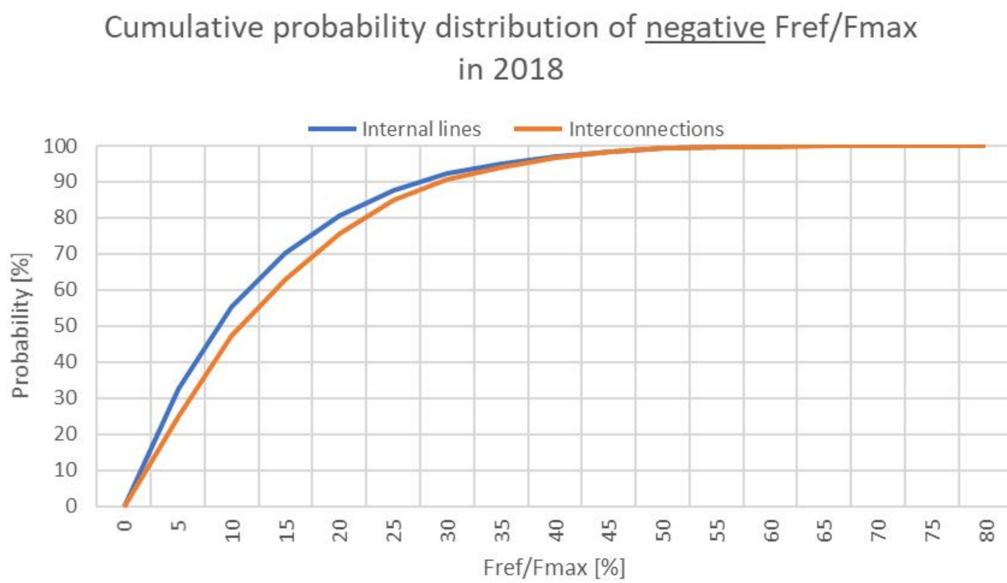


Figure 22: Cumulative probability distribution of negative Fref/Fmax in 2018

Nordic countries

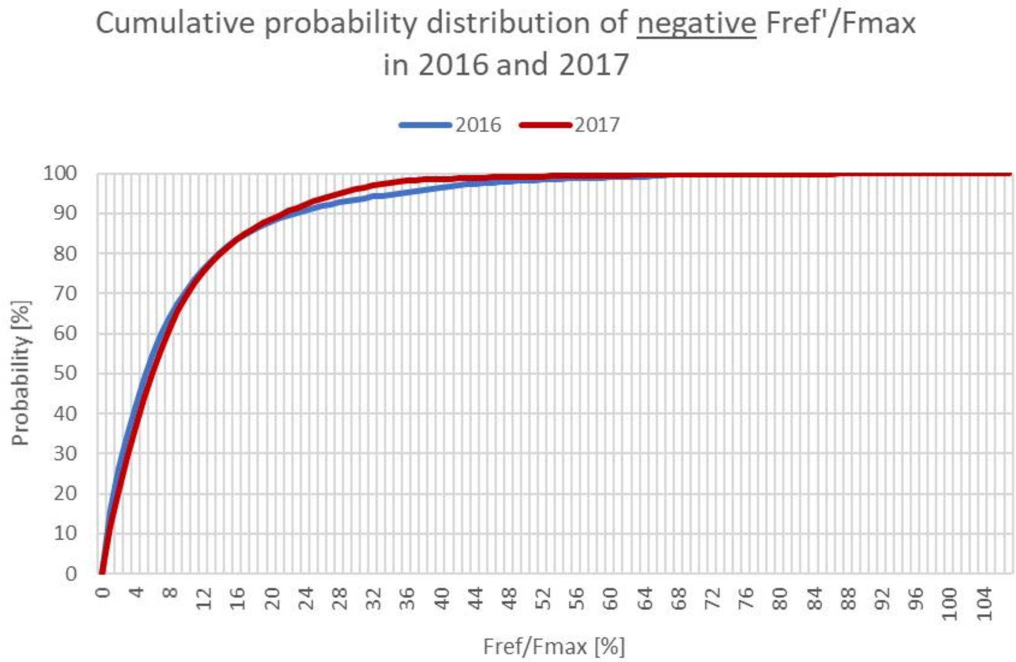


Figure 23: Cumulative probability distribution of negative Fref'/Fmax in 2016 and 2017 in Nordic countries

GETTING IN TOUCH WITH THE EU

In person

All over the European Union there are hundreds of Europe Direct information centres. You can find the address of the centre nearest you at: https://europa.eu/european-union/contact_en

On the phone or by email

Europe Direct is a service that answers your questions about the European Union. You can contact this service:

– by freephone: 00 800 6 7 8 9 10 11 (certain operators may charge for these calls),

– at the following standard number: +32 22999696 or

– by email via: https://europa.eu/european-union/contact_en

FINDING INFORMATION ABOUT THE EU

Online

Information about the European Union in all the official languages of the EU is available on the Europa website at: https://europa.eu/european-union/index_en

EU publications

You can download or order free and priced EU publications at: https://publications.europa.eu/en/publications. Multiple copies of free publications may be obtained by contacting Europe Direct or your local information centre (see https://europa.eu/european-union/contact_en).

EU law and related documents

For access to legal information from the EU, including all EU law since 1952 in all the official language versions, go to EUR-Lex at: http://eur-lex.europa.eu

Open data from the EU

The EU Open Data Portal (http://data.europa.eu/euodp/en) provides access to datasets from the EU. Data can be downloaded and reused for free, for both commercial and non-commercial purposes.

Publications Office
of the European Union