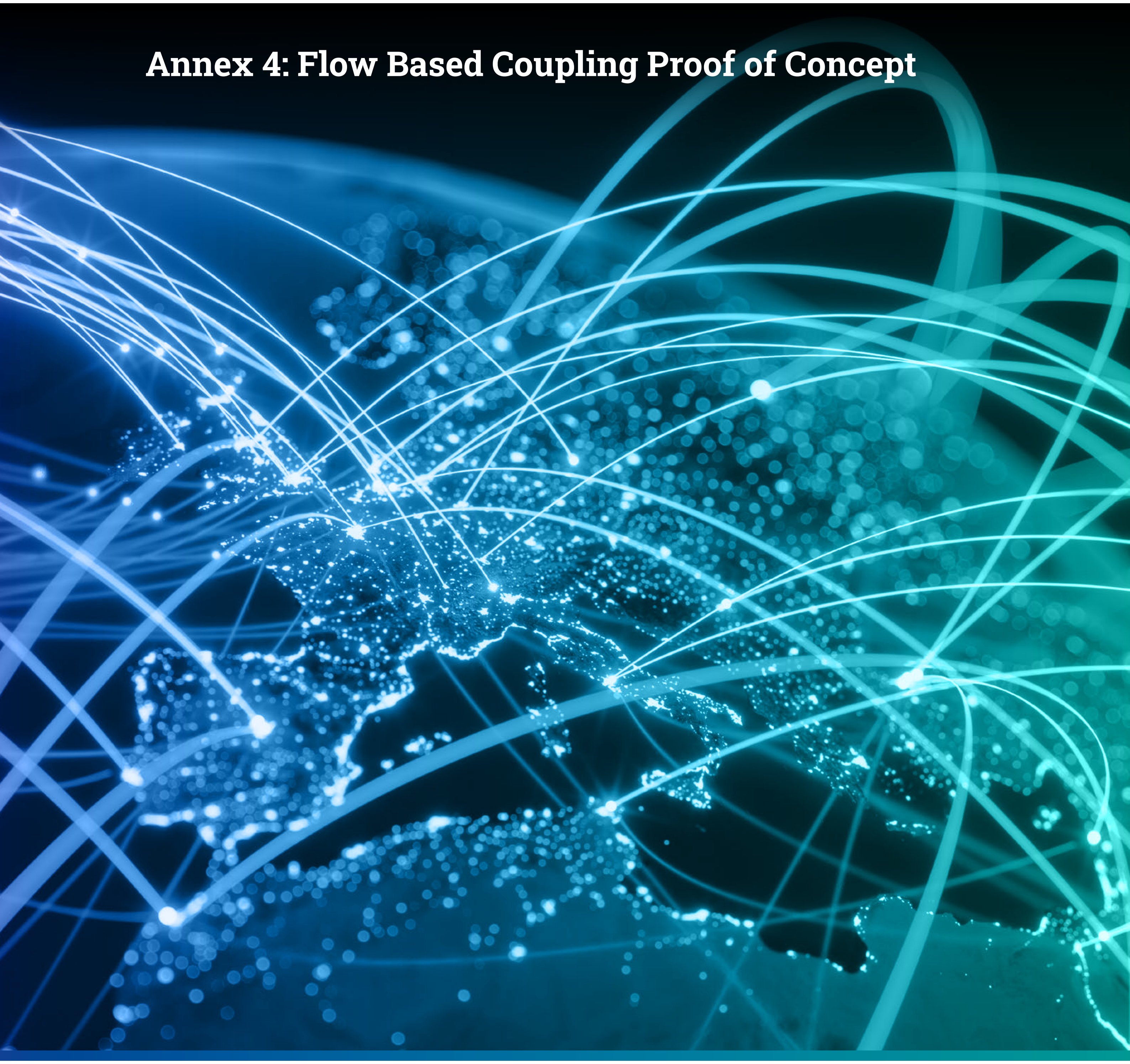
European Resource Adequacy Assessment

2021 Edition

Annex 4: Flow Based Coupling Proof of Concept



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1 Introduction

The ERAA target Methodology requires to implement, where applicable, a flow-based (FB) capacity calculation methodology (CCM) for cross-zonal trade. In the European day-ahead (DA) market for electricity, energy is traded within and across bidding zones. Although the market assumes no grid restrictions within a bidding zone, there are limitations to the amount of energy that can be traded across bidding zone borders. One approach to consider those limitations is market coupling by net transfer capacity (NTC). In this approach, the trades across any given border and market time unit do not affect trading capacities of other borders in the market clearing process for the same market time unit. As a more advanced approach, flow-based market coupling (FBMC) considers the power flow on individual critical network elements and contingencies (CNECs) and, therefore, takes better into account the physical reality of the grid. The MC approach is currently defined by so-called capacity calculation regions (CCRs). In prospective studies such as the ERAA, it is important to represent the CCRs and the underlying power system accurately and, when relevant, to consider expected evolutions in their configuration with respect to the present one.

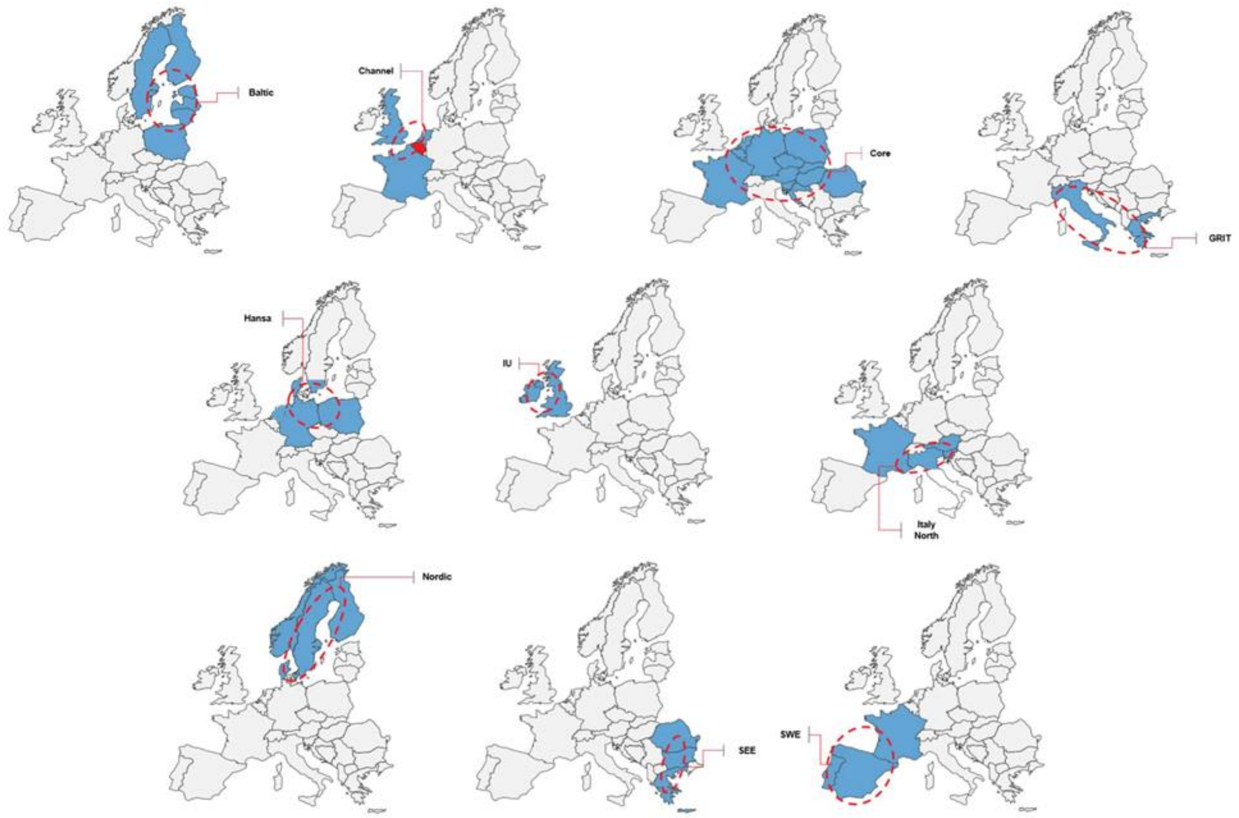

Figure 1 Capacity Calculation Regions in Europe.

Currently (2021), only the Central-Western Europe region (CWE; subregion of Core CCR consisting of France, Germany, Austria and the Benelux) applies FBMC. However, FBMC implementation in the whole Core region (c.f. Figure 1) is expected to be finalised in the first quarter of 2022. Furthermore, the Nordic CCR (c.f. Figure 1) also develops a framework for FBMC with its implementation to be expected by late 2022. Hence, the ERAA 2021 represented a Core region through FBMC as a POC and plans to apply FB for the Nordic region in future ERAA publications. The present Annex describes the tested methodology for computing and allocating FB domains, as well as the adequacy assessment results using these FB domains.

2 FB methodology

Framework description:

Due to their high methodological and modelling complexity, the FB CCM and probabilistic FB capacity allocation have been tested before in a larger implementation within ERAA scenarios. The ERAA 2021 covers the year 2025 for its POC study, with a geographical scope corresponding to CCR, as visualised in Figure 2. This CCR is expected to introduce (FBMC at the beginning of 2022. The Core perimeter includes the following bidding zones: Austria, Belgium, Croatia, the Czech Republic, France, Germany (+Luxembourg), Hungary, the Netherlands, Poland, Romania, Slovakia and Slovenia.

In 2025 (assessed year in this report) FBMC is also expected to be operational in the Nordic CCR covering Denmark, Sweden, Norway and Finland. Although the Nordic CCR is still modelled with the NTC approach in the ERAA 2021, a qualitative assessment of the effects of FB on adequacy in this region is given in in section 5 (FBMC implementation in Nordics – qualitative impact assessment).

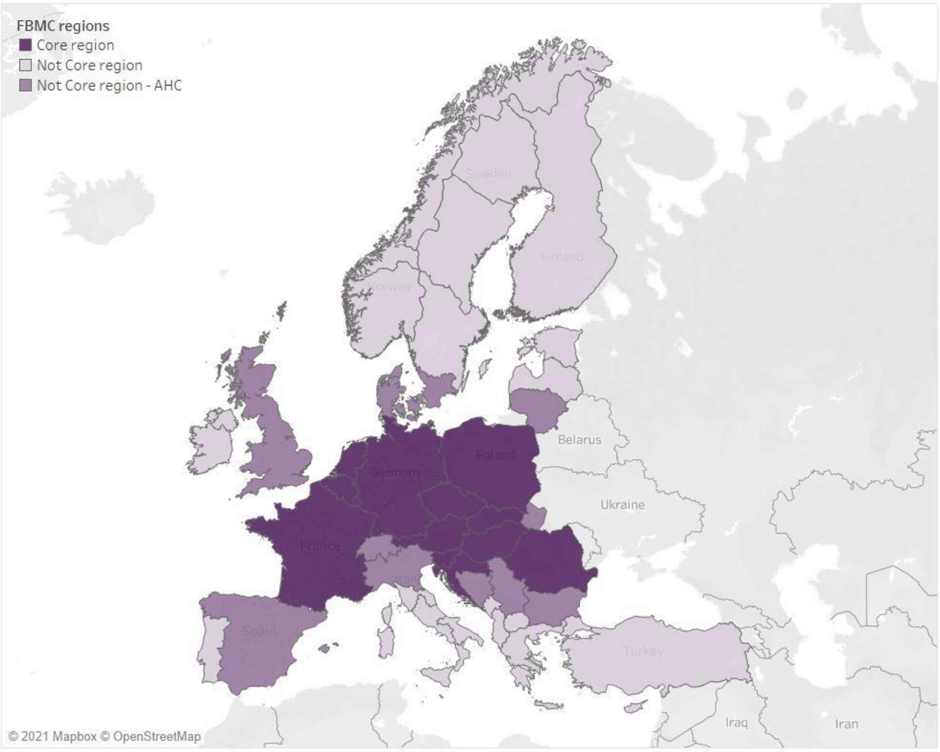

Figure 2: Core Capacity Calculation Region

The FB capacity calculation and allocation methodology within the ERAA needs to be designed while addressing the following objectives:

1. To be consistent with the short-term operational flow-based framework applied in the DA market[1].
2. To serve as a flexible modelling framework for short- (one to three years ahead), mid- (up to five years ahead) and long-term (up to ten years ahead) FB assessments following the ERAA target methodology[2].

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[1] ACER Decision on Core CCM Annex I: Day-ahead capacity calculation methodology of the Core capacity calculation region

[2] ACER Decision on the ERAA methodology: Annex I - Methodology for the European resource adequacy assessment

3. To be suitable for application in probabilistic Monte-Carlo simulations. This feature is referred to as probabilistic FB capacity allocation.

Especially because of the requirement to assess long-term scenarios, it is not possible to use historical FB domains from system operations. The reasons are the foreseen grid expansions and the changes in the location and source of electricity generation[3]. Instead, the ERAA needs to mimic the operational FB CCM workflow by basing itself on planning datasets and models.

FB domain concept description:

In broad terms, a FB domain describes the solution space for net positions of individual bidding zones in a given CCR as a result of the capacity calculation. In addition, external flows or the flow on internal DC lines can be represented by additional variables. The FB domain therefore defines the limitation for exchanges between bidding zones in that CCR.

A FB domain is defined by a set of linear constraints derived from linearised equations for the power flow across monitored network elements. A change in bidding zone net positions directly translates into the change of power flow on the respective network element. This relation is represented by power transfer distribution factors (PTDF). Please refer to Appendix 5Appendix 5

Monitored network elements considered as critical network elements (CNEs)[4] in the capacity calculation can be both within and across bidding zone borders. Specific requirements apply for the consideration of internal network elements. By including relevant contingencies, the N-1 security constraints of the grid can be represented. This results in a list of CNECs, i.e. a list of CNEs combined with relevant contingencies under which particular CNEs are monitored. For each CNEC, a margin available for cross-zonal trade (MACZT) is defined that restricts the power flow on the CNEC, which in turn will be the limiting factor for net positions of bidding zones in the form of FB domains.

As explained above, the constraints of a FB domain are given by the CNEC power flow definition on the left-hand side and their respective capacity margin on the right-hand side. Thus, a FB domain consists of linear constraints in the form of inequalities. In the conceptual FB domain given in **Fehler! Verweisquelle konnte nicht gefunden werden.**, for example, the first row with CNEC 1 corresponds to the following linear constraint:

$$-0.3A + 0.25B + 0.1C \leq 150 \text{ MW}$$

Here *A, B* and *C* correspond to the net positions of bidding zones A, B and C in MW.

[3] European Power System 2040 - Completing the map: System Needs Analysis, part of ENTSO-E's 2025, 2030, 2040 Network Development Plan 2018
[4] ACER Decision on tge Core CCR TSOs' proposals for the regional design of the day-ahead and intraday common capacity calculation methodologies

Table 1: Conceptual FB domain example

Critical network element	Contingency	Critical network element and contingency	Influence of the net position on the flow on each line (PTDF matrix)			MACZT (MW)
			A	B	C	
Line 1	None	CNEC 1	-30%	25%	10%	150
	Contingency 1	CNEC 2	-17%	35%	-18%	120
	Contingency 2	CNEC 3	15%	30%	12%	100
Line 2	None	CNEC 4	60%	25%	25%	150
	Contingency 3	CNEC 5	4%	-15%	4%	50
...	...	...	...	...	...	...

The so-called 'convex hull' of these linear constraints therefore forms an n-dimensional polytope. The dimensions correspond to the columns of the FB domain matrix. In the example of Table 1 above, the dimensions are given by A, B and C and can generally refer either to net positions of bidding zones or flows and/or set points of selected external flows to the CCR, internal HVDCs and selected phase-shifting transformers (PST) within the CCR. For visualisation of a domain or the comparison between different domains, it can be useful to project the polytope onto a two-dimensional plane. This is comparable to the concept of casting the shadow of a three-dimensional object onto a wall. However, the computational complexity of creating the projection increases with the number of dimensions as it requires enumerating the vertices of the full polytope. In the current calculation considered in the ERAA 2021 with up to 44 dimensions, it is practically impossible to compute full 2D projections of the FB domain. Instead, for visualisation purposes, it was necessary to select some relevant dimensions for each chosen projection, while fixing the variables referring to other dimensions being less relevant for each chosen projection, fixing them to the relevant 'reference' values. Of course, this reduction is only applied for illustrational purposes and, in the adequacy simulation, all dimensions are considered in full and not fixed to any pre-determined value.

When referring to the 2D projection of a FB domain, it is important to mention that although the displayed polygon does show all admissible values for the considered two dimensions, it does not show the implication of these values on the variables of the remaining dimensions. As an example, we assume a simplified three-dimensional domain with the shape of a cube as described in **Fehler! Verweisquelle konnte nicht gefunden werden.**. Its projection onto the dimensions A and B is shown in **Fehler! Verweisquelle konnte nicht gefunden werden.**. From the projection, we see that the balance of A and B can adopt e.g. values of 0.5 each. However, only from the complete domain definition in **Fehler! Verweisquelle konnte nicht gefunden werden.** does it become clear that this assignment forces C to adopt a balance of 0.

Table 2: Cube-shaped domain

CNEC	A	B	C	RAM
CNEC 1	1	1	1	1
CNEC 2	1	1	-1	1
CNEC 3	1	-1	1	1
CNEC 4	-1	1	1	1
CNEC 5	1	-1	-1	1
CNEC 6	-1	-1	1	1
CNEC 7	-1	1	-1	1
CNEC 8	-1	-1	-1	1

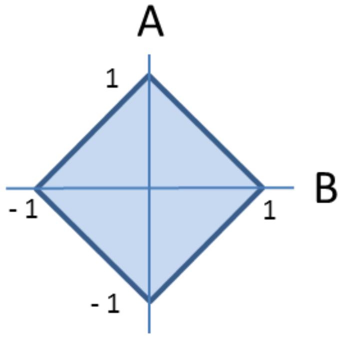

Figure 3: 2D projection of cube-shaped domain

Methodology description:

The process of computing the FB domains can be described in five steps (see Figure 4) and is explained in the following paragraphs.

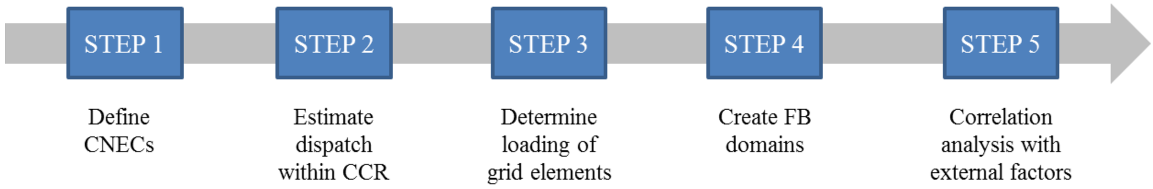

Figure 4: Steps of ERAA FB methodology

In the first step, a list of CNECs which potentially limit cross-zonal trade is defined. As mentioned above, a CNEC is a combination of a CNE with a contingency that refers, for example, to overhead lines, transformers or underground cables. Refer to the section on CNEC selection in Chapter 3 for a more detailed description of the used CNEC sets.

The second step requires an estimation of the dispatch within the CCR as well as exchanges with neighbouring CCRs. This is achieved with an initial market simulation, starting from the market model from MAF 2020[5]. The market model from the ERAA 2021 was created in parallel to the FB domain calculation process and was therefore not available yet. In addition, the market model from the MAF 2020 for the TY 2025 was reasonably close to the ERAA 2021 national estimate input data.

Following Step 2 with the market outcome estimation in the CCR, Step 3 determines the reference loading of grid elements. This step can be covered by performing a load flow calculation on a relevant grid model. For the ERAA 2021, the National Trends 2025 grid model from TYNDP 2020 was chosen. Another option for retrieving the reference loading of grid elements would be to apply linear power flow constraints directly within the initial market simulation, considering the thermal limits of each CNEC as right-hand side of the inequality.

Step 4 describes the computation of the FB domains. The FB domain calculation begins with the power transfer distribution factor (PTDF) matrix, which is derived from the grid model and allows for linear power flow calculations. This PTDF matrix provides nodal granularity and incorporates all network nodes represented by columns. To allow for a zonal representation in accordance with the European bidding zone

[5] MAF 2020 – Appendix 2v

configuration, a generation shift key (GSK) is required. The GSK is a matrix that carries the information of how the nodal power injection changes if the net position of a bidding zone moves up or down. Multiplying the nodal PTDF and GSK matrices results in a zonal PTDF matrix. Finally, the matrix is augmented by columns representing either DC links or exchanges with external CCRs that are modelled as advanced hybrid coupling (AHC). This step concludes the left-hand side of the FB domain constraints. To establish the right-hand side of the constraints, the amount of transmission capacity available on each CNEC must be known. This margin is also referred to as the margin available for cross-zonal trade (MACZT). Its size depends on the physical active power transmission capacity, the base or 'reference-flow' loading and the flow reliability margin of the CNEC on the one hand and on the minimum legal requirements for cross-zonal trade on the other hand. Step 4 also includes a non-costly remedial action optimisation through PSTs, which aims to increase the size of the domain in its narrower dimensions. The outcome of this step may therefore differ depending on the actual constraining CNECs, which are linked to the CNEC list used to build the domain. See Appendix for more details.

As final part of Step 4, a post-processing to the FB domains can be adopted for better handling. First, a pre-solving algorithm identifies the convex hull of the domains, i.e. the linear constraints that shape the FB domain. Any remaining constraints (outside of FB domains) are then filtered out, resulting in a smaller set of constraints. Last, the left-hand side equations that differ for each FB domain are reduced to one set and kept static. In contrast, the MACZT values on the right-hand side are adapted to respect the changes in the PTDF by shifting the linear constraints and thereby defining the resulting FB domain size and shape in accordance with the original PTDF matrices. In this manner, the data handling is reduced to one PTDF matrix overall and to one right-hand side vector per FB domain.

Step 5 defines the last part of the FB methodology and describes how the identified FB domains can be applied in the probabilistic Monte-Carlo (MC) simulations. In the ERAA 2021, six clusters have been identified by a k-medoids algorithm with one representative FB domain at its centre. Next, the correlation between the hours of the year belonging to the specific clusters and external factors such as weather dependent variables are analysed. Based on the resulting correlation matrix, a probability matrix is created, which maps the representative FB domains to the individual hours of the MC years for the probabilistic adequacy simulations. In the following adequacy simulation, the FB domains will then be applied accordingly.

3 CNEC selection and computed FB domains

CNEC selection

The definition of CNECs in the capacity calculation has a considerable influence on the resulting FB domain. Because every CNEC implies an additional linear constraint, the resulting FB domain becomes potentially more restrictive when more CNECs are included. To assess the influence of the CNEC selection in FB CC on the adequacy assessment, three different sets of CNECs are included in this proof of concept.

Regarding the rules and principles in place[6] related to the definition of CNECs relevant for day-ahead capacity calculation, the current legislation does not exclude the inclusion of grid elements internal to a bidding zone in the CNE list. However, a condition aims to demonstrate, through a cost benefit analysis),that adding the internal grid element is a more economically efficient solution in comparison to other solutions such as remedial actions, the reconfiguration of bidding zones or network investments.

[6] ACER Decision on Core CCM Annex I: Day-ahead capacity calculation methodology of the Core capacity calculation region

The FB domains calculated in this ERAA study are based on CNEC data submitted by each Core-TSO. These data actually contain CNE corresponding to both cross-border and internal network elements, i.e. cross-zonal (bidding zone) network elements as well as network elements located within bidding zones.

To reflect the current regulation framework with respect to the relevant CNECs for DA capacity calculation, 3 sets of CNECs were considered in the calculation of FB domains for the ERAA 2021.

These 3 CNEC sets, referred to as sets A, B and C, have been defined based on the following criteria:

- Set A includes only cross-border CNEs with a rated voltage level of 380 kV or higher in combination with relevant contingencies. Cross-border in this context refers to network elements that connect two bidding zones. This selection leads to the most relaxed set of constraints with respect to the data provided by the TSO.
- Set B includes only cross-border CNEs with a rated voltage level of 220 kV or higher in combination with relevant contingencies. This selection leads to a slightly more constraining set of constraints with respect to the previous one, Set A, and thus includes all cross-border elements provided by the Core-TSO.
- Set C includes all CNECs (~1900) submitted by Core-TSOs based on their outlook for the year 2025 in this proof of concept. This selection includes all cross-border and some internal network elements at rated voltage levels of 220 kV or higher. Therefore, Set C describes the most extensive CNEC set in this assessment and leads to the most restrictive FB domain.

The described CNEC sets are included in the published data set of the ERAA 2021.

Computed FB domains

In this section, the information for a particular domain is presented. This information is presented only for a conceptual comparison of domains computed using different set of CNECs. No conclusions should be made about domains (or domain sets) from the figures presented below. To draw any quantitative conclusions, we invite readers who are interested to check the FB domain sets published in the ERAA 2021 themselves.

Using the methodology described in Section 2 and for each of the three sets of CNEC described above, six types of FB domains were calculated, each of which is used for a relevant period of the simulation. For example, a particular domain could be used for a day in winter with high demand; whereas another domain could be used for a summer day with low demand. In the domain creation process, domains are prepared so that they could be used for a given conditions in the adequacy assessment.

Below is presented, for conceptual comparison, the projections of three FB domains projections which were built using different CNEC lists. All of them refer to domains to be used under the same operational conditions. Figure 5 shows that FB domains within set A (black line) tend to provide the highest relative volume for commercial exchanges, whereas FB domains within set C (yellow line) tend to provide the lowest relative volume for commercial exchanges.

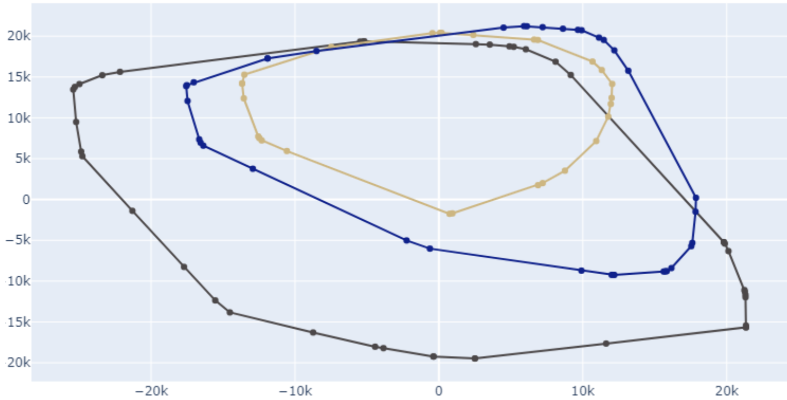

Figure 5 projections of FB domains.

Readers may expect that more constrained domains would be positioned within a more relaxed domain (i.e. FB set C would be within FB set A). This is typically observed only when the power system is represented with linear functions, which is the foundation of FB domain computation. However, PSTs are non-linear elements and can contribute notably to creating extra space for commercial exchanges and hence to moving some 'vertices' of the domain when looking for optimal FB domains. Thus, PSTs have been used in the FB domain calculation to maximise the space for commercial exchanges, following the current practice in operational CC foreseen within the Core CCR. PSTs are used to modify the extreme points of the cross-sections when different CNEC sets are being used, as observed in Figure 5. In summary:

- All FB vertices remain unchanged when one constraining CNEC vertex is removed if only linear elements are considered during FB domain computations (e.g. only lines generators and load).
- FB vertices can change their angle (and hence position) when one constraining CNEC vertex is removed when non-linear elements (e.g. PSTs) are considered during FB domain computations.

Figure 6 also helps to compare FB domain sets. It presents the highest theoretical imports and exports[7] for given 'Study Zones' in the ERAA study. Highest theoretical exports are equivalent to Maximum Net Position used in some technical documentations (e.g. JAO), whereas the highest theoretical imports is equivalent to Minimum Net Positions (which is highest negative value of net position).

[7] Theoretical import and export capabilities reflect only exchanges through Core CCR and ignore possible contribution of exchanges via borders which are modelled as AHC (c.f. Figure 2).

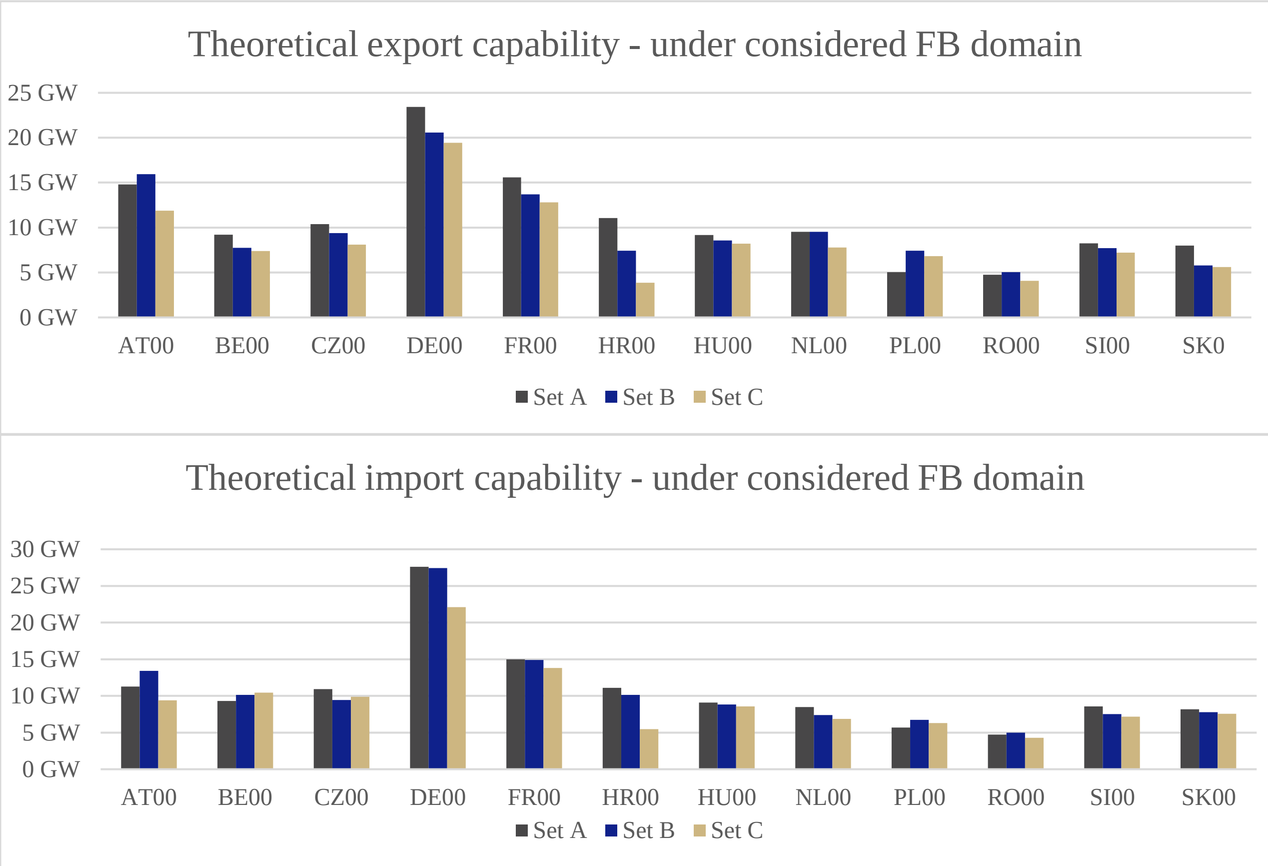

Figure 6 Theoretical highest import and exports: a conceptual comparison

For the specific case of presented domains, Figure 6 displays the theoretical highest imports and exports in each of the Core CCR bidding zones. For the sake of completeness, it should be mentioned that each value is the result of an optimisation problem[8], thus the highest imports and exports, respectively, of a bidding zone implies specific values for the net positions of all other hubs, which are, however, not part of this graph. That means that it should not be expected that all Study Zones are capable of importing (or exporting) highest theoretical values simultaneously as some values might be technically infeasible in practice. Furthermore, this figure presents only import and export capabilities considering borders within CCR and excluding exchanges on borders with bidding zones outside of Core CCR. Hence, Figure 6 should be only used for domain set comparison purposes and not to make statements regarding export/import capabilities of zones in market allocation.

We refer below to the definition of this KPI[9]:
5.11 Max Net Positions
These [..] display the minimum and maximum Core net positions in MW of each hub for each MTU of the day. These indicators are extracted from the vertices of the final FB domain given for market coupling.

[8] Essentially, the point in the FB domain with the highest import/export value is taken for a concerned bidding zone, assuming other bidding zones do whatever they need to maximise import/export in the concerned bidding zone.
[9] JAO publication handbook.

4 Adequacy results

To evaluate how different FB domains impact European adequacy, several adequacy simulations have been carried out. Each simulation considers a different feasible space in the energy dispatch problem, stemming from one of the FB domains detailed in the previous section. The rest of the simulation assumptions remained unchanged and were based on the Post EVA without CM scenario.
Adequacy assessments implementing the above mentioned FB domain sets consider market economic aware dispatch algorithm[10], which mitigates flow factor competition phenomena[11] and introduces fair sharing of ENS. This is done by integrating local matching constraints and curtailment sharing algorithms. *Any comparisons and result interpretation should be performed in light of this information*.

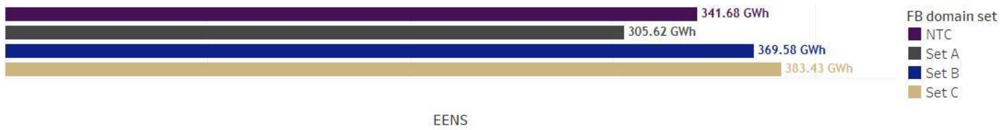

Figure 7 System EENS

The simulation results are aligned with the observations on the size of the feasible space discussed in the previous section. Figure 7 depicts the total EENS (computed by summing the EENS of all countries) obtained applying different FB domains. FB Domain Set A enlarges the global feasible space if compared to the NTC model. In other words, it allows for greater power transfer between neighbour countries compared to the NTC model, thus reducing the total EENS. It should be noted, however, that this global trend does not necessarily imply that the adequacy indicators for all bidding zones would be lower when comparing adequacy results with FB Domain Set A and the NTC data. In the same manner, FB Domain Sets B and C reduce the feasible space if compared to the NTC model, leading to an increase in total EENS.

[10] Description can be found in Appendix 7
[11] CWE Flow Factor Competition Study (accessible on JAO website: Part I; Part II; Part II (Appendix); Part III)

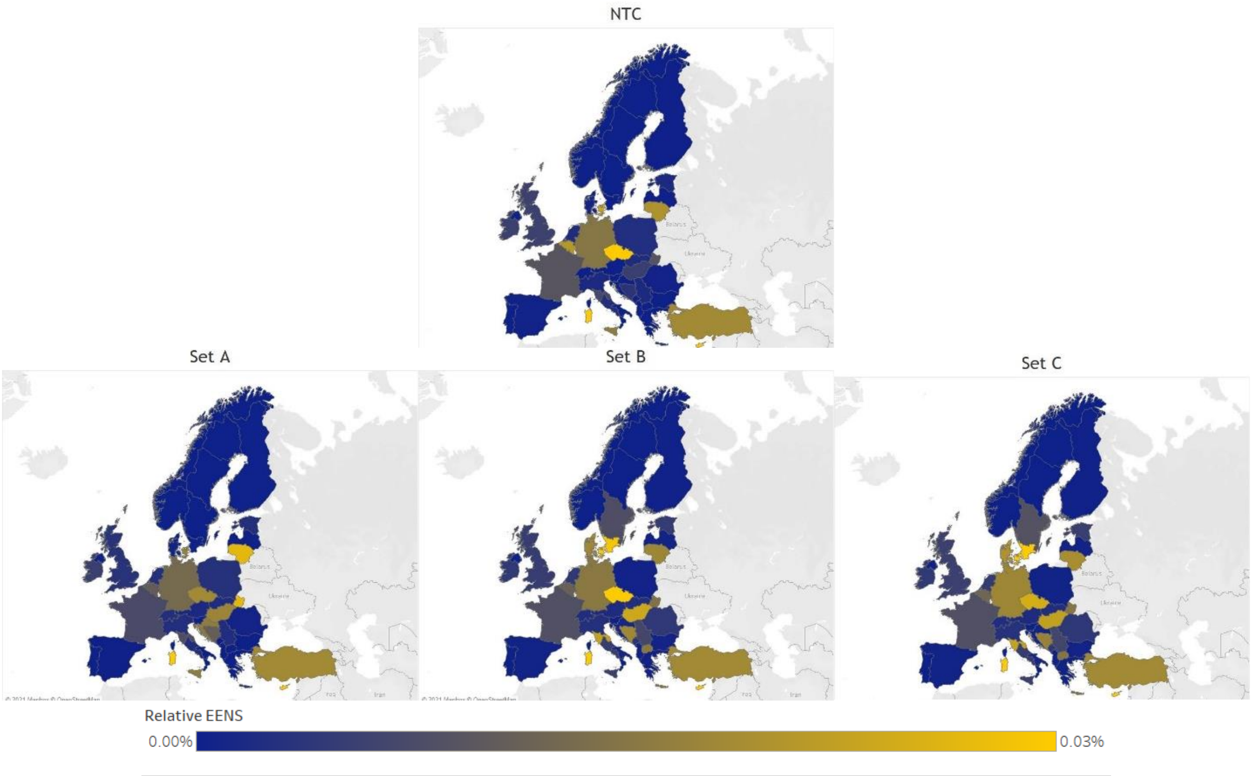

Figure 8 Relative EENS graph[12]

This general trend holds not only from a system perspective but also at a country-level when examining the different FB sets. Figure 8 illustrates the ratio between EENS and total demand per country. It can be observed that, for most countries, the EENS grows with 'shrinking' FB domains sets, i.e., going from FB Domain Set A to B and from FB Domain Set B to C. NTC modelling stands between FB Domains Set A and B, as already observed examining total EENS. Note that this trend is also confirmed for countries with a greater maximum/minimum net position with FB Domain Set C than with Domain A (e.g. Poland, see previous Section): their EENS slightly decreases from FB Domain Set A to C.

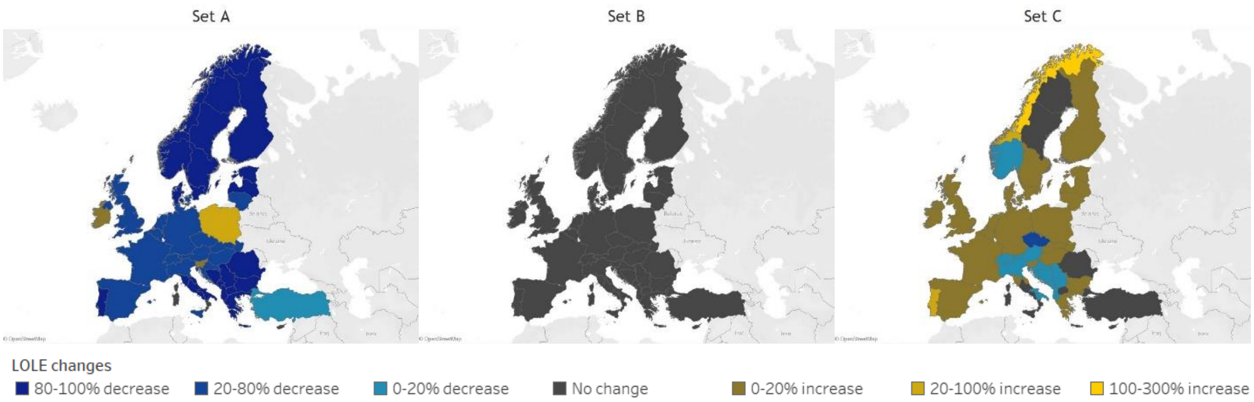

Figure 9 CNEC selection impact on LOLE[13]

The choice of the FB domain sets has an even greater effect on LOLE. Considering the simulation based on FB Domain set B as reference, Figure 9 shows how LOLE changes with an increased (FB Domain set A, on the left) or reduced (FB Domain set C, on the right) feasible space. At first glance, LOLE exhibits the same

[12] Detailed numbers are available in **Fehler! Verweisquelle konnte nicht gefunden werden.**

[13] Detailed LOLE results can be accessed in Appendix 3.

trend already observed for EENS: the larger the domain, lower the LOLE. However, the rate of change differs from the EENS trend: moving from FB Domain set A to FB Domain set B implies a greater increase in LOLE than moving from FB Domain set B to FB Domain set C. The non-linear relation between EENS and LOLE is the main cause of this difference, which in some bidding zones could be amplified due to the implementation of the market aware dispatch algorithm (which ensures the fair sharing of ENS; c.f. footnote 10) Note that the correlation between LOLE and size of the feasible space is also confirmed by countries where FB Domain set B corresponds to the smallest/highest net position. For example, LOLE reaches its lowest level in Poland with Domain B, allowing the highest import of power for that country. At the same time, the results indicate that the highest value of LOLE for the Czech Republic is achieved considering FB Domain set B, with the lowest import of power for that country.

5 FBMC implementation in Nordics – qualitative impact assessment on Nordic adequacy

Introduction

In the ERAA, grid representation for zones within FBMC and the relevant grid constraints shall be captured by the FB approach, where this is applicable[14]. In light of FBMC developments in the Nordic CCR, a qualitative analysis was performed to assess the impact of such market coupling change.

The scope of this section is to provide a qualitative assessment of the impact of FBMC on the Nordic region which complements the assessment performed on the Core CCR. ENTSO-E is planning in the future assessments to include the Nordic countries in the FB calculations. At the time of this assessment, however, the FBMC in the Nordic CCR was still in the development phase and, therefore, a quantitative analysis was not possible. Instead, the Nordic TSOs provide their expectations with respect to the implementation of FBMC in the sections below. Note that the comments in this document are solely TSOs' expectations based on currently available data and experience.

Expected impact of FBMC in the Nordic CCR on adequacy

Key messages

1. Nordics overall – adequacy could be expected to improve marginally.
2. Short-term impact – more exchanges should be facilitated, and price should converge more.
3. Long-term impact – investments on supply side are impacted due to increased interconnection availability.

As the market becomes more in tune with the physical grid, area prices will, to a larger extent, reflect real physical locational information to the market.

- As a long-term consequence, future investments in generation, consumption and transmission should improve the geographical location of assets in the system in relation to both local needs and in relation to the system-wide ability to manage adequacy.
- In the short run, as the market gains more flexibility to utilise the current power-system, the ability to manage adequacy situations improves. That is because the (D-1) dispatch will likely be more in tune with the physical reality of the power system at an early stage during the day. This has the

[14] ERAA methodology and based on Article 23 (5) of the electricity regulation 2019/943

potential to provide fewer strained situations in general, and a longer lead time for system operators to manage potentially strained situations.

General impact on adequacy

Finland

The current expectation is that the impacts of FBMC on adequacy in Finland will be minor. The Finnish power system is synchronously connected to the rest of the Nordic power system via two, and in the future three, 400 kV HVAC lines. The connections are situated between bidding zones SE1 (ERAA terminology SE01) and Finland, and through a relatively weak 220 kV AC connection to bidding zone NO4 (ERAA terminology NON1) in Northern Norway. In addition to these connections, there is an HVDC connection between bidding zone SE3 (ERAA terminology SE03) and Finland. Consequently, the major benefits FBMC has over meshed AC grids are not expected to materialise in Finnish borders.

In theory, FBMC should result in equal or higher cross-border capacity and, hence, the higher availability of imports during periods of scarcity. If it materialises, the possible impact is expected to be indirect as changes in adequacy levels, particularly in SE1 and SE3, would impact exchanges in cross-border connections between Finland and these zones.

Sweden

The introduction of FBMC in the Nordics is expected to improve the general adequacy situation due to higher capacities given to the bidding zone borders that would allow for more trades and, hence, higher socio-economic welfare.

Norway

Compared to the rest of the Nordic CCR, the Norwegian power system is highly meshed, contains four bidding zones, and is a geographically long and stretched system covering large distances. Thus, due to the composition of the power system, it is likely that the FB approach will be particularly important in relation to adequacy in Norway. Providing efficient NTC is increasingly difficult due to the many bidding zones being increasingly more interconnected, also toward Europe (new AC and DC lines). In FB, market flows are better aligned with the physical reality, thus market prices become better vessels for forwarding locational information to the market participants. This applies to both short-term and long-term behavior.

Denmark

The expected impact of FBMC on adequacy can be divided into two time horizons. In the long term, the question is whether FBMC creates an incentive for investments in dispatchable generation units. As FBMC allows for better utilisation of the grid in general, all else equal it leads to slightly more equal prices across bidding zones. Therefore, additional investments in generation units as a direct consequence are unlikely.

In the shorter term, the question is whether FBMC will affect which and how many plants are started in a given time span due to the equalising effect of FBMC on prices. Again, as the effect on prices is expected to be quite small, the expected effect on adequacy due to fewer or more plants being started at any given time is expected to be small as well.

In the end, the physics of the system remains the same, and as markets applying FBMC will end at the latest one hour before real-time when FBMC is introduced in the intraday market, then it will ultimately be the control centres of the TSOs that will manage the last balancing of the system. In the event of an imbalance, the control centres will do their upmost to ensure that consumption can be covered by applying all means available. This is applied regardless of whether FBMC or NTC is used.

Impact on exchanges within Nordic CCR during scarcity

Finland
The impact during scarcity is not expected to differ from the general impact on adequacy and is expected to be minor. In theory, FBMC should result in equal or higher cross-border capacity and hence a higher availability of imports during periods of scarcity. If it materialises, the possible impact is expected to be indirect as changes in adequacy levels, particularly in SE1 and SE3, would impact exchanges in cross-border connections between Finland and these zones.

Sweden
Same expectation as given in the section on general impact on adequacy in Nordics.

Norway
Same expectation as given in the section on general impact on adequacy in Nordics.

Denmark
The impact is expected to be low. However, FBMC should in theory allow for marginally more or at least the same capacity on HVAC borders to be made available in scarcity situations with high prices and consequently have a positive effect on exchanges. For HVDC borders, the impact of progressing from an NTC approach to FBMC should be negligible as maximum capacity is conventionally made available to the market for HVDC interconnectors.

During loss of load events, as in CWE, it may be the case that a country with sufficient supply sheds load to maximise the social welfare of the system as a whole. In such an event, the true socio-economic optimum will be chosen to the extent that the Value of Lost Load is known. If the value is not known, the Nordic countries will have procedures for load shedding in place.

Simultaneous scarcity

During the simultaneity of loss of load events in the Nordic CCR, the true optimal solution will be taken in the event that the Value of Lost Load is known. If this is not known, the Nordic Countries will have procedures for load shedding in place. These procedures might differ from country to country.

Impact on imports from non-Nordic power systems during scarcity

Finland
Outside Nordics, the Finnish power system is connected to Estonia and Russia via DC interconnections. FBMC is not expected to alter the availability of imports from these countries.

Sweden
Sweden has the following borders to non-Nordic countries; SE4-LT, SE4-PL and SE4-DE. In theory, FBMC should allow for trades that relieve the scarcity situations. However, as today's capacity allocation rarely limits the import capacity on these borders, the effect is expected to be negligible.

Norway
In NO2, four DC interconnectors exist with Denmark, Germany, the Netherlands and the UK, with a combined capacity of approximately 5000 MW (Denmark being a part of the Nordic). This is a considerable amount of transmission capacity compared to the size of the bidding zone. However, all the DC connections will be managed by AHC, meaning the flows will be an integrated part of the Nordic FBMC. The FB approach in itself, and the AHC in particular, will greatly improve the ability to manage import on the DC capacity in NO2 by optimising the distribution of flows between the DCs, and also in relation to all other flows in Norway and in the Nordics. The positive effects are expected because the Norwegian grid is more meshed compared to other Nordic countries. In addition, the North–South flow in Norway is strongly dependent of the North–

South flow in Sweden, and it is important to monitor the total North–South flow in Norway and Sweden together. For DC cables, the effect is more difficult to predict, but it is expected to be positive as well.

Denmark
As for the impact during scarcity, it is possible that FBMC will have a positive but marginal effect on import on HVAC borders. The effect on HVDC borders will be negligible.

Impact on exports to non-Nordic power systems during scarcity

Finland
Outside the Nordic CCR, the Finnish power system is connected to Estonia and Russia via DC interconnections. FBMC is not expected to alter the availability of exports to these countries.

Sweden
Sweden has the following borders to non-Nordic countries: SE4-LT, SE4-PL and SE4-DE. In theory, FBMC should allow for trades that relieve the scarcity situations, and it is expected to increase the export capacities to some extent during scarcity events outside the Nordic CCR.

Norway
Same as in 2.3.3. We do not expect any differences between exports and imports.

Denmark
As for the impact during scarcity, it is possible that the FBMC will have a positive but marginal effect on export on HVAC borders. The effect on HVDC borders will be negligible.

Expected timeframe of FBMC implementation in the Nordic CCR and reflection in adequacy studies

During the preparation of the ERAA 2021, FBMC in the Nordic CCR was in the implementation phase. Parallel market clearing with FB domains was tested by TSOs in summer 2021. In autumn 2021, parallel market clearing will start to test the robustness of FBMC in the Nordic CCR, which shall last for at least one year. Eventually, FBMC in Nordics is expected to be operational in the second half of 2022.

The ERAA will investigate in which manner the FBMC can be reflected in the adequacy assessment. This includes whether the FB methodology currently under development for Core CCR is suitable for Nordics; whether the necessary data are available; and the impact of Nordic FB domain computation and their use in adequacy models on the process timeline.

6 Conclusion

FB market coupling is an established capacity calculation and allocation method for cross-zonal trade in the European energy market for electricity in the CWE region. With its introduction in Core CCR, the method becomes even more relevant to the whole European market and requires a proper representation in short-, mid- and long-term studies. Therefore, FB capacity calculation and allocation will be an essential part of the final ERAA framework. In the ERAA 2021, FB has been introduced as a proof of concept, with the results being reported in the present Annex. The methodology is both applicable to short-, mid- and long-term studies as well as probabilistic simulations, and it is based on the general FB CCM description for Core. By covering all bidding zones in the Core CCR with FB, a major milestone has been reached for future ERAA editions.

As a key outcome, it was shown that the CNEC selection has a large impact on the commercial exchange capacities and therefore greatly influences the simulation results (EENS and LOLE). In general, a higher degree of relaxation in the CNEC selection leads to a lower likelihood of simulation results with considerable EENS and LOLE. Changes in EENS and LOLE per bidding zone are consistent with the respective exchanges allowed by the FB domains.

FBMC implementation in Nordics is expected to improve adequacy in Nordics marginally as more exchanges should be facilitated. Nevertheless, its possible impact on investments and adequacy shall be monitored.

For the next ERAA editions, it is planned to agree on a single consistent selection criteria for CNECs. This will result in one set of CNECs per target year and scenario. Another target is to implement FB for the Nordic CCR in cooperation with the Nordic TSOs. Furthermore, updated market and grid model databases will be included in the domain calculations and market simulations.

7 Appendices

Appendix 1 – Detailed EENS result tables

Set A

Study Zone	EENS	Relative EENS
AL00	0.00 GWh	0.0000%
AT00	1.27 GWh	0.0019%
BA00	1.37 GWh	0.0113%
BE00	9.50 GWh	0.0116%
BG00	0.00 GWh	0.0000%
CH00	1.86 GWh	0.0031%
CY00	3.98 GWh	0.0765%
CZ00	13.29 GWh	0.0206%
DE00	72.30 GWh	0.0136%
DKE1	2.77 GWh	0.0215%
DKW1	0.20 GWh	0.0009%
EE00	0.24 GWh	0.0032%
ES00	0.58 GWh	0.0002%
FI00	0.17 GWh	0.0002%
FR00	35.14 GWh	0.0087%
GR00	0.01 GWh	0.0000%
GR03	0.11 GWh	0.0032%
HR00	2.91 GWh	0.0167%
HU00	8.45 GWh	0.0181%
IE00	2.08 GWh	0.0068%
ITCA	0.00 GWh	0.0000%
ITCN	2.38 GWh	0.0086%
ITCS	1.49 GWh	0.0028%
ITN1	4.87 GWh	0.0029%
ITS1	0.02 GWh	0.0001%
ITSA	25.67 GWh	0.2775%
ITSI	3.29 GWh	0.0168%
LT00	3.67 GWh	0.0327%
LV00	0.02 GWh	0.0004%
ME00	0.00 GWh	0.0001%
MK00	0.03 GWh	0.0004%
MT00	16.74 GWh	0.5677%
NL00	4.07 GWh	0.0034%
NOM1	0.00 GWh	0.0000%
NON1	0.00 GWh	0.0000%
NOS0	0.00 GWh	0.0000%
PL00	5.33 GWh	0.0034%
PT00	0.00 GWh	0.0000%
RO00	0.40 GWh	0.0007%
RS00	1.00 GWh	0.0027%
SE01	0.00 GWh	0.0000%
SE02	0.00 GWh	0.0000%
SE03	0.00 GWh	0.0000%
SE04	0.08 GWh	0.0004%
SI00	0.05 GWh	0.0003%
SK00	0.63 GWh	0.0020%
TR00	67.82 GWh	0.0193%
UA01	1.90 GWh	0.0342%
UK00	9.92 GWh	0.0044%
UKNI	0.02 GWh	0.0002%

Set B

Study Zone	EENS	Relative EENS
AL00	0.03 GWh	0.0004%
AT00	1.47 GWh	0.0022%
BA00	2.30 GWh	0.0190%
BE00	10.17 GWh	0.0124%
BG00	0.21 GWh	0.0007%
CH00	1.46 GWh	0.0025%
CY00	3.98 GWh	0.0765%
CZ00	23.41 GWh	0.0363%
DE00	86.57 GWh	0.0163%
DKE1	5.94 GWh	0.0460%
DKW1	5.05 GWh	0.0236%
EE00	0.43 GWh	0.0059%
ES00	1.43 GWh	0.0005%
FI00	0.30 GWh	0.0004%
FR00	38.79 GWh	0.0096%
GR00	0.27 GWh	0.0005%
GR03	0.51 GWh	0.0146%
HR00	0.23 GWh	0.0013%
HU00	11.31 GWh	0.0243%
IE00	1.70 GWh	0.0056%
ITCA	0.00 GWh	0.0000%
ITCN	6.60 GWh	0.0240%
ITCS	2.94 GWh	0.0055%
ITN1	5.39 GWh	0.0032%
ITS1	0.25 GWh	0.0012%
ITSA	25.65 GWh	0.2772%
ITSI	1.16 GWh	0.0059%
LT00	2.47 GWh	0.0220%
LV00	0.05 GWh	0.0007%
ME00	0.16 GWh	0.0044%
MK00	1.24 GWh	0.0170%
MT00	16.74 GWh	0.5678%
NL00	6.00 GWh	0.0050%
NOM1	0.02 GWh	0.0001%
NON1	0.00 GWh	0.0000%
NOS0	0.04 GWh	0.0000%
PL00	0.89 GWh	0.0006%
PT00	0.00 GWh	0.0000%
RO00	2.65 GWh	0.0048%
RS00	2.91 GWh	0.0079%
SE01	0.00 GWh	0.0000%
SE02	0.00 GWh	0.0000%
SE03	7.14 GWh	0.0096%
SE04	7.50 GWh	0.0360%
SI00	0.05 GWh	0.0004%
SK00	0.75 GWh	0.0024%
TR00	67.81 GWh	0.0193%
UA01	1.02 GWh	0.0184%
UK00	14.61 GWh	0.0065%
UKNI	0.02 GWh	0.0002%

Set C

Study Zone	EENS	Relative EENS
AL00	0.02 GWh	0.0003%
AT00	1.50 GWh	0.0022%
BA00	2.17 GWh	0.0179%
BE00	11.03 GWh	0.0135%
BG00	0.22 GWh	0.0007%
CH00	1.43 GWh	0.0024%
CY00	3.98 GWh	0.0765%
CZ00	17.79 GWh	0.0276%
DE00	100.00 GWh	0.0188%
DKE1	6.54 GWh	0.0507%
DKW1	5.57 GWh	0.0260%
EE00	0.47 GWh	0.0064%
ES00	1.44 GWh	0.0006%
FI00	0.31 GWh	0.0004%
FR00	39.22 GWh	0.0097%
GR00	0.29 GWh	0.0005%
GR03	0.48 GWh	0.0139%
HR00	0.18 GWh	0.0010%
HU00	10.69 GWh	0.0230%
IE00	1.71 GWh	0.0056%
ITCA	0.00 GWh	0.0000%
ITCN	6.70 GWh	0.0243%
ITCS	2.86 GWh	0.0053%
ITN1	5.88 GWh	0.0035%
ITS1	0.24 GWh	0.0012%
ITSA	25.64 GWh	0.2771%
ITSI	1.14 GWh	0.0058%
LT00	2.65 GWh	0.0237%
LV00	0.05 GWh	0.0008%
ME00	0.17 GWh	0.0046%
MK00	1.20 GWh	0.0165%
MT00	16.74 GWh	0.5678%
NL00	6.86 GWh	0.0057%
NOM1	0.02 GWh	0.0001%
NON1	0.00 GWh	0.0000%
NOS0	0.03 GWh	0.0000%
PL00	0.91 GWh	0.0006%
PT00	0.01 GWh	0.0000%
RO00	2.55 GWh	0.0047%
RS00	2.81 GWh	0.0077%
SE01	0.00 GWh	0.0000%
SE02	0.00 GWh	0.0000%
SE03	7.77 GWh	0.0104%
SE04	8.18 GWh	0.0393%
SI00	0.07 GWh	0.0005%
SK00	0.80 GWh	0.0025%
TR00	67.82 GWh	0.0193%
UA01	1.08 GWh	0.0194%
UK00	16.22 GWh	0.0072%
UKNI	0.02 GWh	0.0002%

Appendix 3 – Detailed LOLE results

	FB domain set		
	Set A	Set B	Set C
AL00	0.0 h	0.8 h	0.7 h
AT00	2.5 h	6.5 h	6.1 h
BA00	2.7 h	21.0 h	20.4 h
BE00	9.9 h	23.0 h	25.2 h
BG00	0.0 h	1.6 h	1.7 h
CH00	1.7 h	6.6 h	6.3 h
CY00	63.9 h	63.9 h	63.9 h
CZ00	11.1 h	48.6 h	38.1 h
DE00	11.3 h	32.5 h	34.3 h
DKE1	6.8 h	29.0 h	31.2 h
DKW1	1.0 h	21.1 h	23.1 h
EE00	0.9 h	8.0 h	9.1 h
ES00	0.5 h	2.0 h	2.3 h
FI00	0.4 h	2.3 h	2.4 h
FR00	9.3 h	13.7 h	14.1 h
GR00	0.0 h	2.3 h	2.4 h
GR03	0.4 h	9.9 h	9.9 h
HR00	1.5 h	3.0 h	2.6 h
HU00	11.0 h	35.5 h	36.9 h
IE00	7.7 h	7.0 h	7.1 h
ITCA	0.0 h	0.0 h	0.0 h
ITCN	1.8 h	28.9 h	30.0 h
ITCS	2.2 h	14.6 h	14.5 h
ITN1	4.6 h	15.9 h	15.5 h
ITS1	0.1 h	3.2 h	3.1 h
ITSA	146.6 h	146.5 h	146.5 h
ITSI	8.9 h	12.5 h	12.5 h
LT00	7.4 h	24.7 h	26.3 h
LV00	0.1 h	1.2 h	1.4 h
ME00	0.0 h	3.7 h	3.6 h
MK00	0.1 h	14.5 h	14.5 h
MT00	324.2 h	324.2 h	324.2 h
NL00	5.2 h	13.3 h	14.6 h
NOM1	0.0 h	0.6 h	0.7 h
NON1	0.0 h	0.0 h	0.0 h
NOS0	0.0 h	0.8 h	0.8 h
PL00	3.4 h	2.4 h	2.8 h
PT00	0.0 h	0.2 h	0.3 h
RO00	0.5 h	13.6 h	13.6 h
RS00	1.8 h	14.6 h	14.5 h
SE01	0.0 h	0.2 h	0.2 h
SE02	0.0 h	0.0 h	0.0 h
SE03	0.0 h	23.6 h	24.8 h
SE04	0.5 h	29.0 h	30.6 h
SI00	1.1 h	1.0 h	1.2 h
SK00	5.0 h	7.4 h	7.9 h
TR00	25.6 h	25.9 h	25.9 h
UA01	8.2 h	17.5 h	18.7 h
UK00	4.9 h	12.9 h	14.1 h
UKNI	0.2 h	0.5 h	0.5 h

Figure 10: LOLE results – absolute values

Appendix 4 - Curtailment sharing description

Independent of the FB domain calculation, a special focus is set on scarcity situations in FB CCRs. Due to flow factor competition, FB market simulations require post-treatment in line with the EUPHEMIA algorithm, which is used in the operational electricity market of Core. Therefore, a local matching and curtailment sharing algorithm (also referred to as 'adequacy patch' in some national or regional adequacy assessments) is included in the ERAA FB simulations, which follows the principles described in the following paragraphs.

IMPLEMENTATION IN EUPHEMIA

Within the EUPHEMIA algorithm[15], a mitigation measure has been implemented to prevent price-taking orders (orders submitted at the price bounds set in the market coupling framework) to be curtailed because of 'flow factor competition'. The solution implemented in EUPHEMIA within flow-based market coupling (FBMC) follows the curtailment sharing principles that already existed under NTC. The objective is to equalise the ratio of curtailment (~Energy Not Served [ENS]) between bidding zones as much as possible.

FLOW FACTOR COMPETITION

If two possible market transactions generate the same welfare, the one with the lowest impact on the scarce transmission capacity will be selected first. It also means that, to optimise the use of the grid and to maximise the market welfare, some sell (/buy) bids with lower (/higher) prices than other sell (/buy) bids might not be selected within the flow-based allocation. This is a well-known and intrinsic property of flow-based referred to as 'flow factor competition'.

FLOW FACTOR COMPETITION AND PRICE TAKING ORDERS

Under normal FBMC circumstances, 'flow factor competition' is accepted as it leads to maximal overall welfare. However, for the special case where the situation is exceptionally stressed e.g. due to scarcity in one particular zone, 'flow factor competition' could lead to a situation where order curtailment takes place non-intuitively. This could mean, for example, that some buyers which are ready to pay any price to import energy would be rejected whereas lower buy bids in other bidding areas are selected instead, due to 'flow factor competition'. These 'pay-any-price' orders are also referred to as 'Price Taking Orders', which are valued at the market price cap in the market coupling. This would lead to the situation where one bidding area is curtailed while the clearing prices in the other bidding areas are lower or equal to the market price cap. This is the situation that the local matching and curtailment sharing algorithm seeks to mitigate by 'by-passing' flow factor competition in such cases and ensuring maximal imports for zones experiencing curtailment.

CURTAILMENT SHARING

The situation becomes more complex when two or more markets are simultaneously in curtailment, i.e. facing a scarcity situation. For these situations, the implemented mechanism aims to 'fairly' distribute the curtailments across the involved markets by equalising the curtailed price-taking orders to total price-taking orders ratio between the curtailed zones. The curtailment sharing is implemented by adding a large penalty term into the primal problem plus solving a sub-optimisation problem for the minimisation and sharing of curtailment, whereby all network constraints are enforced, but only the acceptance of the price taking volume is considered in the objective function. The curtailment ratios weighted by the volumes of price taking orders are therefore minimised (see EUPHEMIA public description[15]). The results of this study consider these curtailment minimisation and sharing rules by applying those after the optimisation found by the modelling tool.

[15] Euphemia public description

Appendix 5 – Nodal and zonal FB domain computation generic methodology description

Nodal distribution factor matrices

The active power flow P_L through a lossless line L between node N and Q is described by

$$P_L = \frac{|V_N||V_Q|}{X_L}\sin(\delta_N - \delta_Q), \tag{1.1}$$

with X_L being the line reactance and δ_N and δ_Q being the voltage angles at node N and Q, respectively. As $\sin(\delta_N - \delta_Q) \approx \delta_N - \delta_Q$ for small angle differences and assuming voltage magnitude of one at each node, eq. (1.1) simplifies to

$$P_L = B_L(\delta_N - \delta_Q), \tag{1.2}$$

where B_L is the line susceptance. The power flow vector $\boldsymbol{p}_\mathrm{L}$ for all lines in the power system can also be expressed in matrix form by

$$\boldsymbol{p}_\mathrm{L} = \boldsymbol{B}_\mathrm{d} \cdot \boldsymbol{A} \cdot \boldsymbol{\delta}_\mathrm{N}, \tag{1.3}$$

with $\boldsymbol{B}_\mathrm{d}$ being the line susceptances stated as a diagonal matrix, $\boldsymbol{A}$ being the incidence matrix that describes the network topology and vector $\boldsymbol{\delta}_\mathrm{N}$ representing the nodal voltage angles. The nodal active power balance P_N for node N can, in turn, be expressed as the sum of power flows on lines between node N and neighbouring nodes Q.

$$P_N = \sum_Q B_L(\delta_N - \delta_Q), \tag{1.4}$$

or in matrix form for all nodes as

$$\boldsymbol{p}_\mathrm{N} = \boldsymbol{A}^\mathrm{T} \cdot \boldsymbol{B}_\mathrm{d} \cdot \boldsymbol{A} \cdot \boldsymbol{\delta}_\mathrm{N} \tag{1.5}$$

From eq. (1.3) and eq. (1.5) follows:

$$\boldsymbol{p}_\mathrm{L} = \left((\boldsymbol{B} \cdot \boldsymbol{A}) \cdot \left(\boldsymbol{A}^\mathrm{T} \cdot \boldsymbol{B}_\mathrm{d} \cdot \boldsymbol{A}\right)^{-1}\right) \cdot \boldsymbol{p}_\mathrm{N} \tag{1.6}$$

where $\boldsymbol{B}$ is the vector of line susceptances. By defining the nodal PTDF matrix as

$$\boldsymbol{PTDF} = (\boldsymbol{B} \cdot \boldsymbol{A}) \cdot \left(\boldsymbol{A}^\mathrm{T} \cdot \boldsymbol{B}_\mathrm{d} \cdot \boldsymbol{A}\right)^{-1}, \tag{1.7}$$

Eq. (1.6) can be expressed as:

$$\boldsymbol{p}_\mathrm{L} = \boldsymbol{PTDF} \cdot \boldsymbol{p}_\mathrm{N} \tag{1.8}$$

The matrix entry $ptdf_{L,N}$ states how much power in [p.u.] injected at node N flows on line L. As the matrix $\boldsymbol{A}^\mathrm{T} \cdot \boldsymbol{B}_\mathrm{d} \cdot \boldsymbol{A}$ is singular, it is not possible to build the inverse. To make the power equations linearly independent and enable the inverse, one slack node must first be chosen for each connected AC grid in the power system. The respective rows and columns referring to these slack nodes in matrices $\boldsymbol{B} \cdot \boldsymbol{A}$ and $\boldsymbol{A}^\mathrm{T} \cdot$

$\boldsymbol{B}_{\mathrm{d}} \cdot \boldsymbol{A}$ will then be removed. Having calculated the product $(\boldsymbol{B} \cdot \boldsymbol{A}) \cdot \left(\boldsymbol{A}^{\mathrm{T}} \cdot \boldsymbol{B}_{\mathrm{d}} \cdot \boldsymbol{A}\right)^{-1}$, one column containing zeros will be inserted for each slack node, resulting in the final nodal PTDF matrix.

From eq. (1.1), it is evident that the active power flow can be changed by either altering line reactance or the voltage angle difference between two nodes. It is not possible to change the voltage magnitude because of grid safety. The two power flow controlling devices regarded in the following are PSTs and high-voltage direct current (HVDC) lines. Whereas PSTs can alter the voltage angle difference between two nodes, the converters of HVDC lines directly change the power injections at the corresponding nodes. The principle of considering the linearised power flow equations of power flow controlling devices in market models is also referred to as AHC.
To include the effect of PSTs in the power flow formulation of eq. (1.2), the change in voltage angles must be added. A PST introduces a change in the difference of voltage angles between node N and Q connected by line L, notated by α_L.

$$P_L = B_L\left(\delta_N - \delta_Q + \alpha_L\right) \tag{1.9}$$

The matrix form of eq. (1.9) for all lines translates to

$$\boldsymbol{p}_{\mathrm{L}} = \boldsymbol{B} \cdot \boldsymbol{A} \cdot \boldsymbol{\delta}_{\mathrm{N}} + \boldsymbol{B} \cdot \boldsymbol{\alpha}_{\mathrm{L}} \tag{1.10}$$

From eq. (1.9) the nodal active power injection P_N at node N is expressed as

$$P_N = \sum_{Q} B_L\left(\delta_N - \delta_Q + \alpha_L\right) \tag{1.11}$$

The matrix form of eq. (1.11) for all nodes is given by

$$\boldsymbol{p}_{\mathrm{N}} = \boldsymbol{A}^{\mathrm{T}} \cdot \boldsymbol{B}_{\mathrm{d}} \cdot \boldsymbol{A} \cdot \boldsymbol{\delta}_{\mathrm{N}} + (\boldsymbol{B} \cdot \boldsymbol{A})^{\mathrm{T}} \cdot \boldsymbol{\alpha}_{\mathrm{L}} \tag{1.12}$$

When combining eq. (1.10) and eq. (1.12) it can be concluded that

$$\begin{aligned}\boldsymbol{p}_{\mathrm{L}} = &\left((\boldsymbol{B} \cdot \boldsymbol{A}) \cdot \left(\boldsymbol{A}^{\mathrm{T}} \cdot \boldsymbol{B}_{\mathrm{d}} \cdot \boldsymbol{A}\right)^{-1}\right) \cdot \boldsymbol{p}_{\mathrm{N}} \\ &+ \left(\boldsymbol{B}_{\mathrm{d}} - (\boldsymbol{B} \cdot \boldsymbol{A}) \cdot \left(\boldsymbol{A}^{\mathrm{T}} \cdot \boldsymbol{B}_{\mathrm{d}} \cdot \boldsymbol{A}\right)^{-1} \cdot (\boldsymbol{B} \cdot \boldsymbol{A})^{\mathrm{T}}\right) \cdot \boldsymbol{\alpha}_{\mathrm{L}}\end{aligned} \tag{1.13}$$

By defining the phase shifter distribution factors (PSDF) matrix analogous to the PTDF matrix as

$$\boldsymbol{PSDF} = \boldsymbol{B}_{\mathrm{d}} - (\boldsymbol{B} \cdot \boldsymbol{A}) \cdot \left(\boldsymbol{A}^{\mathrm{T}} \cdot \boldsymbol{B}_{\mathrm{d}} \cdot \boldsymbol{A}\right)^{-1} \cdot (\boldsymbol{B} \cdot \boldsymbol{A})^{\mathrm{T}}, \tag{1.14}$$

it follows from eq. (1.7), eq. (1.13) and eq. (1.14):

$$\boldsymbol{p}_{\mathrm{L}} = \boldsymbol{PTDF} \cdot \boldsymbol{p}_{\mathrm{N}} + \boldsymbol{PSDF} \cdot \boldsymbol{\alpha}_{\mathrm{L}} \tag{1.15}$$

For the calculation of the PSDF matrix, it is again necessary to choose a slack node analogous to the procedure explained for the PTDF matrix. The matrix entry $psdf_{L,N}$ then states by how much the power flow in [p.u.] increases on line L when increasing α_L by one radian.
So far, only active power flows and injections in the alternating current (AC) grid have been considered. In the next step, direct current (DC) transmission lines will be included as well. To be able to differentiate between power flows on AC and DC elements, eq. (1.15) will first be extended by the subscript AC.

$$\boldsymbol{p}_{\mathrm{L}_{\mathrm{AC}}} = \boldsymbol{PTDF} \cdot \boldsymbol{p}_{\mathrm{N}_{\mathrm{AC}}} + \boldsymbol{PSDF} \cdot \boldsymbol{\alpha}_{\mathrm{L}_{\mathrm{AC}}} \tag{1.16}$$

The power injection $\boldsymbol{p}_{\mathrm{N_{AC}}}$ can be expressed as part of the total power injection $\boldsymbol{p}_{\mathrm{N}}$ that splits up into flows on AC or DC lines in the grid:

$$\boldsymbol{p}_{\mathrm{N}} = \boldsymbol{p}_{\mathrm{N_{AC}}} + \boldsymbol{p}_{\mathrm{N_{DC}}} \tag{1.17}$$

The injections on DC nodes, $\boldsymbol{p}_{\mathrm{N_{DC}}}$, is defined by

$$\boldsymbol{p}_{\mathrm{N_{DC}}} = \boldsymbol{A}_{\mathrm{DC}}^{\mathrm{T}} \cdot \boldsymbol{p}_{\mathrm{L_{DC}}}, \tag{1.18}$$

where $\boldsymbol{A}_{\mathrm{DC}}^{\mathrm{T}}$ is the transposed incidence matrix of the DC grid and $\boldsymbol{p}_{\mathrm{L_{DC}}}$ are the active power flows on DC lines. With eq. (1.17) and eq. (1.18), the expression for the power flow on AC lines in eq. (1.16) can be rearranged as

$$\boldsymbol{p}_{\mathrm{L_{AC}}} = \boldsymbol{PTDF} \cdot \left(\boldsymbol{p}_{\mathrm{N}} - \boldsymbol{A}_{\mathrm{DC}}^{\mathrm{T}} \cdot \boldsymbol{p}_{\mathrm{L_{DC}}}\right) + \boldsymbol{PSDF} \cdot \boldsymbol{\alpha}_{\mathrm{L_{AC}}} \tag{1.19}$$

Introducing the definition of the DC power flow distribution factors (DCDF) matrix as

$$\boldsymbol{DCDF} = -\boldsymbol{PTDF} \cdot \boldsymbol{A}_{\mathrm{DC}}^{\mathrm{T}} \tag{1.20}$$

the matrix entry $dcdf_{L_{\mathrm{AC}},L_{\mathrm{DC}}}$ then states by how much the power flow in [p.u.] increases on the AC line L_{AC} when increasing the power flow on the DC line L_{DC} by one p.u. With eq. (1.20), eq. (1.19) results in the final formulation for the active power flow on AC lines in the power system in eq. (1.21) as a function of total nodal active power injection $\boldsymbol{p}_{\mathrm{N}}$, the phase shift angles $\boldsymbol{\alpha}_{\mathrm{L_{AC}}}$ and the active power flow on DC lines $\boldsymbol{p}_{\mathrm{L_{DC}}}$.

$$\boldsymbol{p}_{\mathrm{L_{AC}}} = \boldsymbol{PTDF} \cdot \boldsymbol{p}_{\mathrm{N}} + \boldsymbol{PSDF} \cdot \boldsymbol{\alpha}_{\mathrm{L_{AC}}} + \boldsymbol{DCDF} \cdot \boldsymbol{p}_{\mathrm{L_{DC}}} \tag{1.21}$$

Zonal distribution factor matrices

The PTDF matrix introduced in the previous section considers all nodes and their power injections in the power system. Depending on the use case, it is necessary to cluster the N nodes of a grid into Z zones and to reduce the nodal PTDF matrix into a zonal matrix. This is, for example, the case in the European DA market where the grid is split into bidding zones. An example for grouping nodes into zones is given in **Fehler! Verweisquelle konnte nicht gefunden werden.** where a grid with five nodes is grouped into three zones. Note that in this context, the lines do not get reduced to equivalent lines between or within zones, meaning that the PSDF and DCDF matrices do not have to be reduced. As will be shown in the following paragraphs, the node-to-line PTDF matrix is going to be transformed to a zone-to-line matrix. For the remainder of this report, the terms ‘zone-to-line’ and ‘zonal’ are used as equivalents when referring to the PTDF matrix.

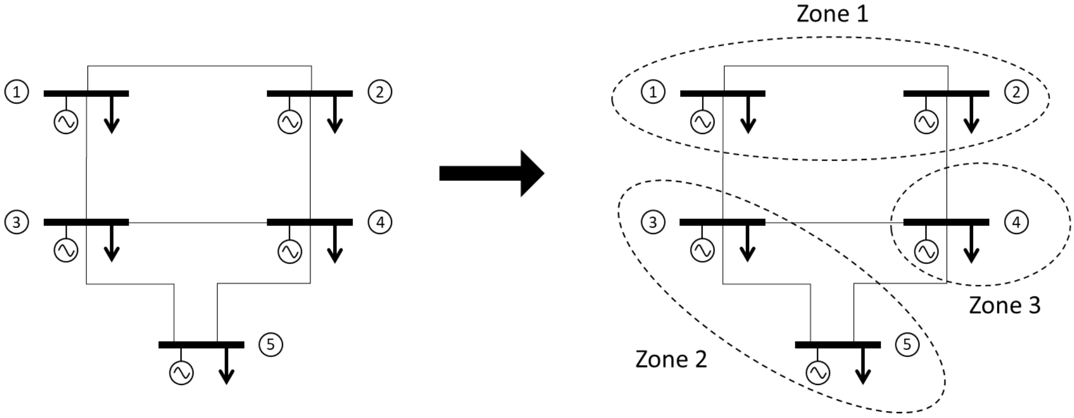

Figure 11: Zonal reduction of a five-node grid into three zones

As a first step, the GSK of the power system must be known. The GSK is a NxZ matrix that carries the information of how changing the zonal power injection by 1 p.u. is distributed among the nodes within the zone. Here, the sum of each column equals 1 as the power system is assumed to be lossless. The GSK strongly depends on the types and distribution of power plants in the system and generally reflects the marginal costs of the dispatchable generating units. With the GSK and nodal PTDF matrix, it is then possible to form the zonal PTDF matrix as

$$\boldsymbol{PTDF}_{\mathrm{zonal}} = \boldsymbol{PTDF}_{\mathrm{nodal}} \cdot \boldsymbol{GSK} \tag{1.22}$$

Consequently, with eq. (1.21) and eq. (1.22) the power flow on AC lines results in

$$\boldsymbol{p}_{\mathrm{L_{AC}}} = \boldsymbol{PTDF}_{\mathrm{zonal}} \cdot \boldsymbol{p}_{\mathrm{Z}} + \boldsymbol{PSDF} \cdot \boldsymbol{\alpha}_{\mathrm{L_{AC}}} + \boldsymbol{DCDF} \cdot \boldsymbol{p}_{\mathrm{L_{DC}}}, \tag{1.23}$$

where $\boldsymbol{p}_{\mathrm{Z}}$ is the zonal active power injection.

Use of distribution factor matrices in linear constraints

Eq. (1.22) describes a set of linear equations that can be integrated as the left-hand side of a set of linear constraints that restrict the allowable power flow $\boldsymbol{p}_{\mathrm{L_{AC}}}$ by the remaining available margin (RAM) allocated to trade. Introducing the RAM as the right-hand side (RHS), the set of constraints can be expressed as

$$\boldsymbol{PTDF}_{\mathrm{zonal}} \cdot \boldsymbol{p}_{\mathrm{Z}} + \boldsymbol{PSDF} \cdot \boldsymbol{\alpha}_{\mathrm{L_{AC}}} + \boldsymbol{DCDF} \cdot \boldsymbol{p}_{\mathrm{L_{DC}}} = \boldsymbol{p}_{\mathrm{L_{AC}}} \leq \boldsymbol{RAM}_{\mathrm{L_{AC}}} \tag{1.24}$$

Here, $\boldsymbol{RAM}_{\mathrm{L_{AC}}}$ denotes the RAM of AC lines in vector format. For further reading on how to define RAM values, refer to [2]. The set of linear constraints defined by eq. (1.24) is the basic format for the FB CCM and sets up the FB domain.

In the basic form of eq. (1.24), all lines and other network elements are included. When investigating a large power system such as the pan-European transmission grid, there are thousands of network elements with a corresponding linear constraint for each element. Furthermore, power grid analyses usually include n-1 cases for security reasons, resulting in a vast number of constraints. For this reason, it is relevant to choose only CNEs for which the power flow on these elements needs monitoring. Per default, all cross-zonal elements are considered as CNEs, but intra-zonal elements can be as well if it can be economically justified [2]. In addition to the n-0 case, it is also possible to include contingencies representing n-1 cases in the set of constraints. A contingency potentially alters the values for PTDF, PSDF, DCDF and / or RAM and can have a large impact on the resulting FB domain. The combination of CNEs and relevant contingencies result in the term CNECs. The linear constraints corresponding to all CNECs then form the final FB domain.