CWE Flow Factor Competition Study, part I: Qualitative Analysis

By order of ACM, BNetzA, CRE, CREG, ILR and e-Control

29 September 2017

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<u>Disclaimer</u>: The outcomes of the study are only supported by CWE NRAs and have not been reviewed yet by CWE Partners.

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CWE FLOW FACTOR COMPETITION STUDY, PART I: QUALITATIVE ANALYSIS

IMPACTS OF LOCAL DIFFRENCES AND CONSEQUENCES FOR FFC INDICATORS

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CONTENT

LIST OF FIGURES AND TABLES

Glossary

Acronym	Description
50Hz	50 Hertz Transmission GmbH
AC	Alternating Current
ACM	Dutch NRA - Autoriteit Consument en Market
APG	Austrian Power Grid
ATC	Available Transfer Capability
BE	Belgian bidding zone
BNetzA	Bundesnetzagentur
CB	Critical Branche
CBCO	Critical Branche/Critical Outage combination
CO	Critical Outage
CRE	French NRA - Commision du Régulation de l'Énergie
CREG	Belgian NRA - Commision du Régulation de l'Électricité et du Gaz
CWE	Central-West Europe
DAM	Day Ahead Market
D-2CF / D2CF	Two days ahead (D-2) Congestion Forecast
DACF	Day Ahead Congestion Forecast
DC	Direct Current
DE	Germany German/ Luxembourgian/Austrian bidding zone
EC	European Commission
e-Control	Austrian NRA
FAV	Final Adjustment Values
FB	Flow-Based
FBMC	Flow-Based Market Coupling
FBI	Flow-Based Intuitive
FBP	Flow-Based Plain
FFC	Flow Factor Competition

Acronym	Description
Fmax	Maximum allowed active power flow
Fref	Reference flow, i.e. the flow on a line in a reference situation
FR	French bidding zone
FTR	Financial Transmission Rights
FRM	Flow Reliability Margin
GSK	Generation Shift Keys
ILR	Institut Luxembourgeois de Régulation
Imax	Maximum electric current on a line
LTA	Long Term Allocation
LTN	Long Term Nomination
MC	Market Coupling
NL	Dutch bidding zone
NP	Net Position
NRA	National Regulatory Authority
OPF	Optimal Power Flow
PST	Phase-Shifting Transformer
PTDF	Power Transfer Distribution Factor
PX	Power Exchange
RA	Remedial Action
RAM	Remaining Available Margin
RTE	French TSO - Réseau de Transport d'Electricité
TSO	Transmission System Operator
U	Voltage on a line
UIOSI	Use It Or Sell It

Introduction

This report is the first part of the reporting on the study that CWE NRAs have requested to assess the fairness of flow-factor competition.

Following the approval by CWE National Regulatory Authorities (NRAs) on April 23rd, 2015 the CWE project partners launched the CWE Flow-Based Market Coupling (CWE FBMC) on May 20th, 2015[1] with the first trading day using Flow-Based parameters for market coupling.

The main objective of the CWE FBMC is to make the maximum capacity of the interconnections affecting cross-border flows available to market players, while taking into account the physical limits imposed by the transmission network. The CWE NRAs and the CWE project partners encompassing the CWE Transmission System Operators (TSO) and Power Exchanges (PX) are committed to monitoring and, if needed, improving the CWE FBMC methodology. In particular the CWE NRAs have agreed upon to monitor the impact of the "flow factor competition" phenomenon (in the following referred to as "FFC") linked to the implementation of CWE FMBC on the fairness of competition in the electricity market.

After one year of CWE FBMC operation the FFC and the fairness of FFC is now investigated in a study. The first step of the study focused on the investigation of fairness of FFC. The objectives of this first step are the development of indicators to quantify the extent of the FFC and analyzing the fairness of the FFC. The results of the first step shall help the NRAs in their assessment of the fairness respectively unfairness of the current FFC.

Assessing the fairness of flow factor competition is a challenge because already the definition of fairness in this context is not trivial. There are several perspectives on how to look at fairness, e.g., from an economic point of view it could be argued that the market situation is fair as long as the market participants had transparent information on the future market design and market procedures, and that they could base their economic decisions on reliable information on the framework (regardless of potential weaknesses of the framework). For this study, we will follow the definition provided by the NRAs) which defines flow factor competition as fair as long as it is "based on the true impact of commercial exchanges on the network". In particular, the relative impact between competing cross-zonal trades by the FB methodology should not be systematically biased due to assumptions linked to the modelling of the system and to the FB parameters.

On the basis of the results of this first step the NRAs will decide on the second step, i.e. to recommend structural solutions to avoid or mitigate possible unfairness or discrimination. Any proposed solutions should be reliable for the CWE FBMC mechanism in general and shall not be limited to only some border(s). These solutions shall be developed and implemented by the TSOs and PXs at a later stage and are not in scope of this study.

The general methodical approach is summarized in Figure 1.

[1] Start of TSO's operational process for Flow-Based capacity calculation was on May 19th, 2015

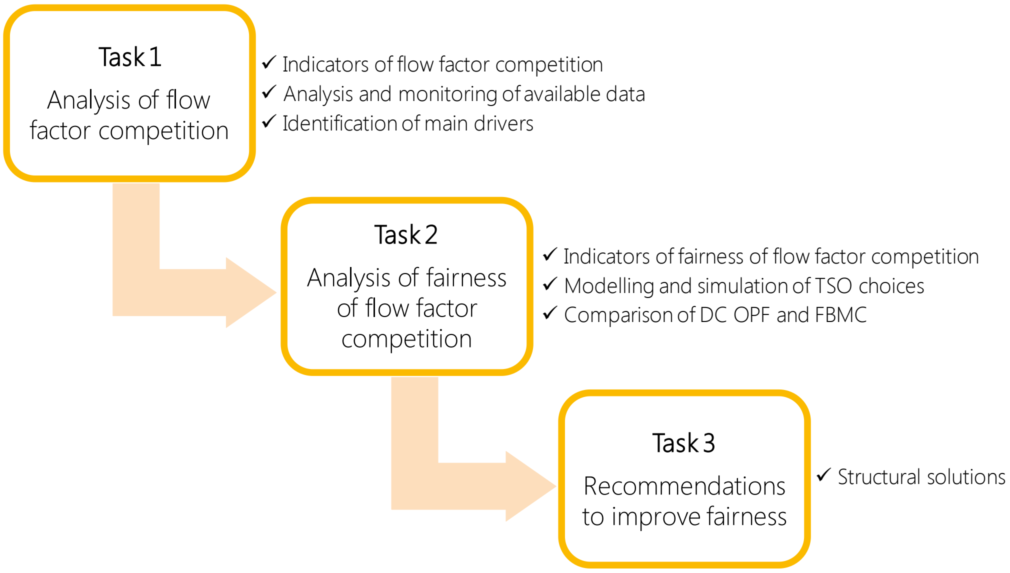

Figure 1: Overview of the methodology for analyzing flow factor competition and its fairness

Task 1 is split into 4 subtasks as follows:

Figure 2: Overview of task 1

The first subtask is the qualitative analysis of flow factor competition which should lead to the selection of items to be monitored, so-called FFC influencing parameters. The other subtasks are of a more quantitative nature and are covered in part II of the report. Part III of the report covers task 2 and if a task 3 is decided, this will be covered by a part IV of the report.

This leads to the following structure of the reporting:

- CWE Flow Factor Competition Part I: Qualitative Analysis
- CWE Flow Factor Competition Part II: Quantitative Analysis
- CWE Flow Factor Competition Part III: Fairness Assessment
- CWE Flow Factor Competition Part IV: Recommendations

This document is Part I.

The goals of this part of the study are:

- To understand which parameters influence Flow Factor Competition (FFC) and how they influence it
- To identify what and when functional changes have been implemented that may have impacted FFC
- To identify differences in design choices between the TSOs that could be a potential source for „unfair" FFC

- To select alternative design choices that could improve fair FFC and that will be studied as a reference in task 2

Chapter 1 focuses on identification of the main drivers for flow factor competition. Chapter 2 analyzes the CWE TSOs' flow-based capacity calculation process in detail to identify differences between TSOs in modeling approaches as these may be an important driver for different accuracies in the flow modeling to represent the real flows. Chapter 3 summarizes the influencing factors for FFC and the potential alternative modeling scenarios to assess the fairness impacts of the different modeling approaches. The final selection of alternative scenarios to assess fairness of FFC is covered in part II of the report.

1 Key drivers for Flow Factor Competition

The resulting flow-based network constraints in the market coupling all have the form:

$$\sum_{z} \mathrm{PTDF}_{z,j,t} . NP_{z,t} \leq \mathrm{RAM}_{j,t}, \forall_{j,t}$$

Where:

- z = bidding zone
- t = hour
- j = CBCO (Critical Branche/Critical Outage combination) or virtual CB (due to LTA inclusion) or an External Constraint)
- $NP_{z,t}$ = Net position = the sum of DA exchanges on all AC interconnectors of a bidding zone z
- $\mathrm{PTDF}_{z,j}$= Power Transfer Distribution factor, determines the contribution of the net position of zone z to the total flow on a given CBCO j
- $\mathrm{RAM}_{j,t}$ = Remaining Available Margin. This is the remaining margin on a CBCO that is available for additional flows to be offered to the flow-based market coupling before the total flow on the CBCO leads to overloading and therefore breach of operational security

j represents a real CBCO(/RA) combination, a virtual CB (due to long term allocation adjustments) or an external constraint, z represents a bidding zone and t represents a time step.

From this equation we can derive that all bidding zones are competing for the same capacity (RAM), but their competitive position is determined by the zonal PTDFs. If there is an impact on RAM, this creates more or less capacity to compete for, but it does not influence the mutual competition for that capacity between bidding zones. An impact on RAM can however influence the location and frequency of occurrence of competition for scarce capacity, i.e. congestion. If there is an impact on the PTDFs, this can change the bidding zones' relative share in the competition and therefore this potentially impacts fairness of the competition. This means that although RAM does not directly influence fairness of FFC, it does influence when, where and how often FFC occurs. As the location, where FFC occurs, also determines the PTDFs that compete, RAM indirectly also has an impact on fairness.

The CBCOs that are selected are subject to congestion management by the market coupling. Congestions that may occur on CBCOs that are not selected must be managed by internal re-dispatch or congestion management on external CWE borders (DC interconnectors, exchanges with ATC coupled synchronous areas). In this sense, the choice of including a CBCO or not also includes a choice of using the CWE FBMC as a congestion management measure for that CBCO or not. CBCOs thus determine the scope of the network for which CWE MC is applied as a congestion management measure.

Therefore we need to distinguish impact on RAM as this may change frequency of scarce capacity and severity of scarcity from the impact on PTDF which may change the "competitive" position of a bidding zone in cases where the capacity is scarce. Although CBCOs, similar to RAMs, determine occurrence of FFC, there is also a "fairness" issue on selection of CBCOs related to welfare distribution. Is the total welfare effect including all congestion management costs fairly distributed between all users of the network, including non-domestic users? This fairness question is out of scope of this study.

2 Description and assessment of CWE FB CC methodologies

This chapter describes the flow-based parameters in order to assess their influence on fairness and discusses possible alternative designs that could be considered as a reference scenario in the fairness assessment. Throughout this chapter differences between TSOs will be qualitatively described, whereas in part II of this report the observed differences on selected parameters are monitored. More detailed information on details of differences and similarities between the TSOs can be found in the CWE FB MC approval package and is not repeated here.

This chapter is structured according to the high level business process of the FB capacity calculation and allocation which is described in section 2.1. Section 3.2 covers the changes in this process that took place since the go-live of FB MC. The rest of this chapter is structured according to the different phases of the high level business process.

2.1 High level business process

The high level business process for FB capacity calculation for the CWE region is shown in figure below and is taken from the document 20151017_CWE_FB_Business_Process_Doc_V3_1_TH.

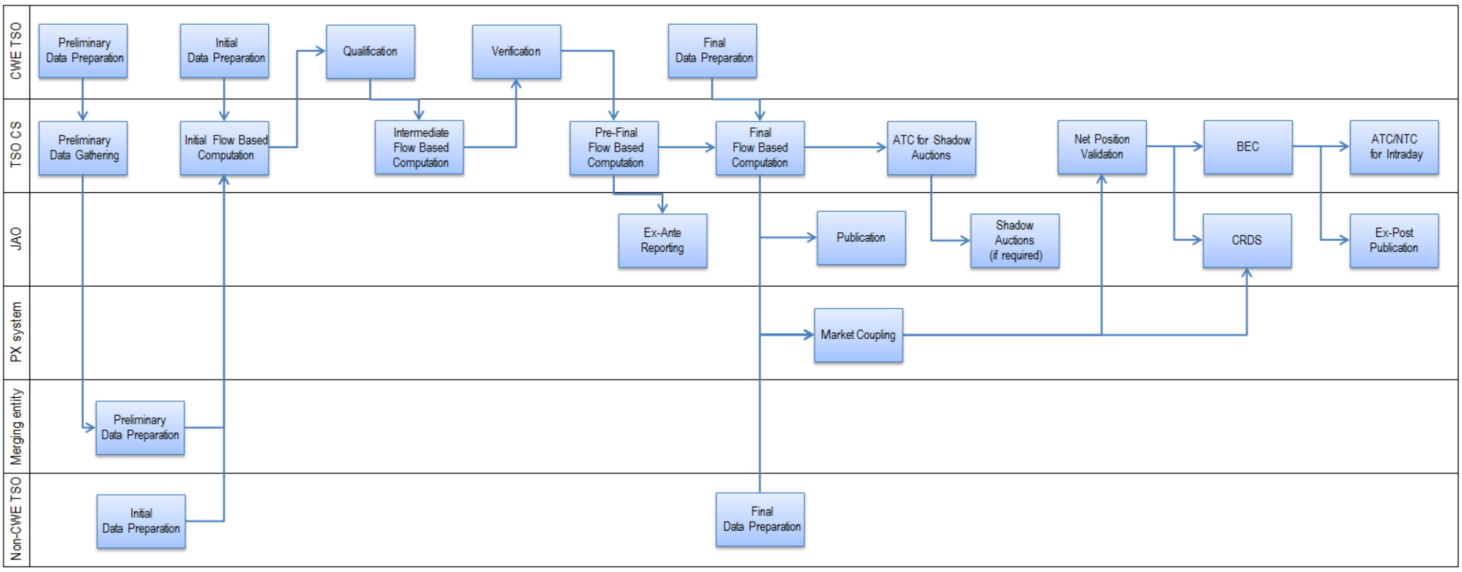

Figure 3: CWE FB MC Business process

Differences between CWE TSOs in modelling approaches are only supposed to occur in the local CWE TSO processes. Therefore, the following local business processes are scrutinized on differences and their potential impact on set of flow-based network constraints that enter the market coupling business process.

1. Preliminary data preparation
2. Initial data preparation
3. Qualification
4. Verification
5. Final data preparation

In addition, the following "sub-process" must be distinguished that can be applied during any of the business processes 2. - 5.

6. Pre-qualification

2.2 Changes since go-live of the CWE Flow-based Market Coupling

The following changes may have impacted FFC and are therefore notable to take into account in the monitoring process.

- On 1 January 2015, long term PTRs on all Belgian borders were replaced by FTRs. As a consequence, long term nomination volumes almost decreased to zero.
- Although FAVs were initially only applied with negative values (complex RAs), positive FAVs have been applied on the German-Dutch border since the summer of 2015. At the end of Q3 2016, positive FAVs were gradually reduced until the end of the studied period (May 2015 – November 2016, can be observed by the FBMC Monitoring Tool)
- Since go-live coordination efforts have increased and all applied RAs are either commonly determined or at least commonly verified to not impact security in other bidding zones.
- As a part of this increased coordination effort, the LTA inclusion was moved from pre-final flow-based computation to the point in time, where remedial actions are determined in a coordinated way, i.e. before the qualification process. This allows the necessary coordination of remedial actions to make the resulting vertices of the flow-based domain secure and to have them verified during the verification step.
- After go-live it turned out that scenarios of net positions became viable that were not experienced in the ATC world. This made CBCO combinations critical which were not experienced as critical under ATC market coupling. The initial CBCO set was enlarged accordingly[2].
- The Austrian grid was embedded in the FB MC with a D-2CF network model since 2 December 2015 for delivery date 4 December 2015. Before that time the Austrian grid was included just

[2] Note that after go-live of the FBMC order books may have been changed to employ the wider feasible exchange domain provided by the FBMC. This might be one reason for why these CBCOs did not become visible during parallel run. However, this is out of scope of this study.

like the other non-CWE grids with a DACF (of D-2 from D-3) instead of a D-2CF. It was not until November 2016 before APG also provided CBCOs.

2.3 Preliminary data preparation

During this local business process, CWE TSOs individually prepare an external constraints file and a GSK file. These are not needed for the merging but for the flow-based parameter calculation. Both sets of information require a daily intervention, while the set of information prepared with initial data preparation does not (see 2.4).

2.3.1 External constraints

Besides thermal limitations on electrical critical branches, other specific limitations may be necessary to guarantee a secure and stable grid operation. These additional constraints are justified, if voltage and stability limits become more restrictive than thermal limits. They are expressed as virtual critical branches, usually representing an import or export limit, in order to guarantee that the market outcome does not exceed these limits.

Application of an external constraint would make a critical situation that TSOs try to catch, subject to the CWE FB MC congestion management measure.

There can be several reasons for a TSO to use external constraints. The main reasons are:

- Avoid market results which lead to stability problems in the network, detected by system dynamics studies (these are initial external constraints)
- Avoid market results which are too far away from the reference flows going through the network in the base case and which in exceptional cases would induce extreme additional flows on grid elements, leading to an exchange situation on internal CWE borders, which could not be verified as secure[3] and for which other measures (internal re-dispatch, congestion management on external CWE borders) are disproportionate, ineffective or simply not available.

For NL and BE there are off-line studies done; for Belgium at certain import levels, for the Netherlands besides for import also for export. For the French and German grid (which are much bigger) the assumption is that the linear approximation of the flow-based model is not valid beyond a certain NP range (even where inaccuracies would be caught by FRM, which is currently under discussion with the regulators).

Conclusion: there are differences between the TSOs which are basically explained by differences in grid characteristics. This is currently being validated under regulatory pressure by different studies. Nevertheless, these differences may explain some of the indicator differences that we will find later.

We will classify FFCs according to whether an external constraint is active or not.

Alternative design:

External constraints are needed to catch security issues which are not caused by thermal overloads. It does not make much sense to define a reference methodology for the determination

[3] This could also be for other reasons than thermal overloads of lines, e.g. voltage and stability problems

of external constraints here as this would require an in-depth benchmark of the efficiency of the congestion management processes of each TSO including transmission network investment planning and stability analyses. However, we will compare in part II between the TSOs how often FFC occurrences are caused by external constraints.

2.3.2 Generation Shift Keys

This section provides a summary of the GSK modelling by the different TSOs of Belgium, France, Germany and the Netherlands. For Luxemburg, no GSKs are applied, as there is no significant production within the control area of the Luxembourgian TSO CREOS. APG is has started providing GSKs after go-live.

TSOs use different methods to determine Generation Shift Keys (GSKs). GSKs are nodal parameters that represent how much a nodal net position changes with a change in a zonal net position. The zonal PTDFs, which are input to the market coupling, are determined by the sum of the products of nodal PTDFs with their nodal GSKs. The GSKs are also used to correct the nodal positions belonging to the D-2CF forecasted zonal net positions to the zonal net positions in the reference programs.

Elia uses a method leading to a fixed GSK per node for all hours of the day, but possibly different for each day. German TSOs have two GSKs per node per day, one for peak, one for off-peak. RTE uses a method that leads to different GSKs per node per hour of the day. TenneT NL applies a method with an hourly selection of generating units based on a weekly varying merit order list, where GSKs are determined on an hourly basis[4].

The basic philosophy for TenneT NL and Elia is as follows: at maximum import all units should be at P_{min}, at maximum export, all units should be at P_{max}. The difference between Elia and TenneT NL is that TenneT NL applies merit order corrections (but fixed over the whole week) and hourly GSKs.

The French GSK is computed by the following formula: $GSK_i = P_i/sum(P_i)$. The power output P_i for each hour is taken from the reference schedule of generation unit i in the reference program.

In Germany, separate values for peak and off-peak hours are used (they correspond to average values determined from experience). GSKs are determined depending on technology and TSO. Merging for the German bidding zone is done on a pro-rata basis in relation to the remaining grid load. The process is based on ATC experience of assessing the situations at 3h30 and at 10h30.

In the real world, the market conditions that determine which of the dispatchable generator units are running and to what extent and which ones are not may well vary per hour according to the zonal net position. Also, nodal positions may contain elements that are invariant to the zone’s net position: non-dispatchable generation and demand. TSOs apply different methodologies for this. As a consequence, accuracies of the GSK modelling will be different per TSO.

GSKs are initially determined, not taking generator availabilities into account. This is corrected in the flow-based parameter calculation, where it is checked from the D-2CF information, which units are out and which are not.

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[4] See: Glismann, de Almeida de Graaff: “Selective Generation Shift Key determination”, Cigré C2-207, CIGRÉ 2016

At the end, inaccuracies in GSK modelling will be accumulated in the so-called flow reliability margin (FRM).

Alternative design:

GSKs have two effects. Firstly, they are used to determine the zonal PTDFs from the nodal PTDFs. Secondly, they are used to adjust the nodal net positions from the forecasted zonal net position in the D-2CF to the reference programs in the base case. Hence, they influence the reference flow (Fref) and therefore also the RAM on each CBCO:

$$RAM_{NEX=ref\ prog} = Fmax\text{-}FRM\text{-}FAV\text{-}Fref$$

$$RAM_{NEX=0} = RAM_{NEX=ref\ prog} + PTDFz*NEX_{ref\ prog}$$

$$RAM_{NEX=\Sigma LTN} = RAM_{NEX=0}\text{-}PTDFz*\ \Sigma LTN$$

Where NEX is the net export position of the zone, PTDFz is the zonal PTDF of the CBCO, ΣLTN is the net value of long term nominations of the zone and RAM and PTDF are CBCO specific.

In the CWE flow-based design, a GSK represents the change in output of dispatchable generation at each node relative to the change of a bidding zone net position. GSKs are a linear factor applied to the whole range of possible changes of zonal net positions whereas in practice nodal generation will not vary linearly with the zonal net position due to non-linear production costs curves and merit order effects. This inaccuracy could be partially overcome by applying piece-wise linear GSKs.

Ideally, one could perform a unit commitment and dispatch algorithm over all bidding zones to establish the correct “optimal” generation levels per node given the forecasted net positions per hour where the forecasted net positions should come from a coordinated forecasting model rather than the currently individual forecasting. TSOs are currently working on a common forecasting.

Neither of the two alternative designs are in scope of task 2. Feasibility of piece-wise linear GSKs is questionable as for each piece in the piece-wise curve a different set of PTDFs and RAMs must be generated. Besides, EUPHEMIA will have to deal with more integer decision variables to select the optimal piece in the curve which could dramatically increase computation time. A common unit commitment and dispatch model would require a tremendous coordination effort of the TSOs, where the results of this study should provide an indication of the fairness benefits that could be reached with such an approach. Therefore, we will approximate in task 2 ideal GSKs from the CWE DACF files. These DACFs contain schedules for day D submitted by market parties after inclusion of the market coupling results for day D and updated demand and non-dispatchable forecasts from the TSOs matching with the net positions resulting from the long term nomination for day D and the day ahead allocation for day D.

2.4 Initial data preparation

This step covers the initial data preparation for the TSO common system. The following information is prepared for each bidding zone by the responsible TSO(s) and send to the common TSO system:

1. A CB file (Critical Branches file) with

a. Critical Branches/Critical Outages (CBCOs)
b. Maximum current on each Critical Branches (Imax)
c. Maximum flow on each Critical Branch (Fmax, determined by Imax and U)
d. Explicit remedial actions (explicit RAs)
e. Final Adjustment Values for non-explicit remedial actions (FAV)
f. Flow Reliability Margin (FRM)

2. External constraints: specific limitations not associated with Critical Branches

3. D-2CF files and reference programs

4. Reference values for qualification (the zone-to-zone PTDF threshold values per CB)

2.4.1 CB file

General TSO philosophy here is to start with initial CBCOs, then add RAs or remove insignificant CBCOs to increase the flow-based domain. Also, CBCOs can be added during the process, e.g. to catch security violations under specific circumstances, which the existing set of CBCOs does not cover (simply because the specific circumstances did not happen before) CBCOs and reference values for qualification

All initially selected CBCOs are at 380 kV level, except the FR-BE tie-lines, which are at 220 kV. Selected CBCOs are limited to cross-border lines and internal transmission lines, which are considered by the TSOs to be highly influenced by cross-border exchanges.

At initial data preparation, the initial list of CBCOs is created. The CBCOs define the scarcity situations. The TSOs have defined a common threshold value of 5% for the maximum of the zone to zone PTDFs on each CBCO that must be superseded in order for this CBCO to be maintained. This would fulfil the criterion of "highly influenced by cross-border exchanges". Exceptions must be commonly discussed and agreed between the TSOs but can lead to situations, where exchanges between some bidding zones are more restricted than between others because of these exceptions. The resulting CBCOs are called significant CBCOs in the remaining of this document.

The threshold value determines in principle the separation between congestions that are managed by the CWE market coupling and those that must be managed otherwise. For any CBCO not retained as significant, allocated capacities can create overloads, which then can only be relieved by internal re-dispatch, cross-border congestion management on other borders or other remedial actions not affecting CWE cross-border flows. Each TSO may decide to retain CBCOs that fall below the threshold criterion. Hence, it can happen that a CBCO retained as significant that falls below the threshold value makes the capacity of that CBCO situation subject to congestion management on internal CWE borders, whereas CBCOs with a similar low threshold value in other bidding zones would be excluded from CWE cross-border congestion management. This potentially impacts the welfare of CWE MC and the distribution of welfare caused by the exchanges on all CWE borders. We can observe the zone to zone PTDFs per bidding zone and we will classify FFC accordingly.

Alternative design choice:

As the threshold basically determines, which congestions will be managed by the CWE MC and which ones will not, an alternative would be to have a very small threshold (one that falls within an accuracy bandwidth) or no threshold at all. This would create equal treatment of all congestions.

On the other hand, it then may happen that remote congestions (far away from internal CWE borders) are managed by CWE MC, whereas it may be more efficient to manage them by other congestion management measures.

Theoretical fair thresholds would be thresholds that maximize overall welfare including costs of all congestions. These costs and therefore the thresholds may vary from TSO to TSO or even from congestion to congestion. Such alternative design would require a tremendous common effort of all TSOs, not just the CWE TSOs.

We will conclude on the results of task 1 if it makes sense to model alternative designs in task 2.

2.4.1.1 COs

Critical outages can be one or more events of the following list and the ones that are applied can vary from TSO to TSO (especially with respect to a difference in parallel events considered):

- Trip of a line, cable or transformer
- Trip of a busbar
- Trip of a generating unit
- Trip of a (significant) load
- Trip of k elements

The same applies here as mentioned under CBCOs above: if one TSO applies (n-2) monitoring where the other would only apply (n-1) monitoring, cross-border exchanges would be used by one TSO to manage (n-2) outages while not by the other (that TSO must use other measures for critical n-2 situations like internal congestion management or congestion management on non-CWE borders). This would not lead to a difference in PTDFs and thus fairness of competition on defined CBCOs would not be impacted. However, it will impact occurrence of FFC. We can observe differences in applied COs and classify FFC accordingly.

Alternative design choices:

In case a specific scenario of COs is not added to the CB file, this means that a congestion occurring due to the specific CO scenario cannot be managed by the CWE market coupling. Alternatively such scenarios must be covered by internal measures (re-dispatch, reactive remedial actions) or by congestion management on external CWE borders, e.g. reducing ATC or applying cross-border re-dispatch on that borders. If this must be covered by internal measures, the local TSO pays, if covered by congestion management on external CWE borders the concerned interconnector owners pay and there is a shift of welfare effect from CWE external borders to CWE internal borders, This changes the welfare distribution between CWE countries and non-CWE countries, but it may also impact the total welfare effect of all countries involved.

A completely “fair” solution in this respect can only be accomplished, if all cross-border capacities of the European interconnected grid are flow-based allocated, including DC interconnector capacities. In this case congestion anywhere in the transmission network would be managed equally by the market coupling, although there could still be differences between bidding zones in accuracy of the PTDF modelling. One of the potential implications could be that the whole European interconnected system would need to become one CCR.

Keeping it to CWE alone, the best proxy for a "fair" solution would be that exchanges on all CWE borders including the ones with non-CWE countries (AC and DC) are treated "flow-based". This is also referred to as advanced hybrid coupling (today's method is called standard hybrid coupling).

An alternative design choice for COs would be to select all scenarios of COs with a probability exceeding a common threshold value. As this requires a common assessment of probability of occurrence of COs, this will not be practical within this study. An alternative to be considered then is a scenario where all TSOs apply the same CO selection criteria, e.g. all of the following COs (to be discussed what makes sense with the TSOs):

- Trip of a single line, cable or transformer, for each line, cable and transformer
- Trip of a single busbar for each busbar
- Trip of a single generating unit, for each generating unit larger than ... (250 MW?)
- Trip of a (significant) load, for each load larger than ... (250 MW?)
- Trip of k elements, for k=2 only and not including busbars

We will investigate during task 1 if it makes sense to consider an alternative design for the selection of COs. This would be the case if we find that a certain CO scenario is binding in one bidding zone while the same CO scenario is not applied elsewhere.

2.4.1.2 Fmax

The maximum allowed total active power flow Fmax on a line is expressed in MW by the formula:

$$\mathrm{Fmax} = \sqrt{3} * \mathrm{Imax} * \mathrm{U} * \cos(\varphi)/1000$$

Here Imax is in Ampères and U is in kV.

Fmax, Fref and FAV together determine the remaining available margin RAM which represents the maximum allowable power flow caused by internal CWE DAM exchanges. Besides Imax, which is described in the next section, Fmax is influenced by the voltage *U* and the phase angle φ. Both voltage and phase angle are set to standard values for all bidding zones. In practice, the operational values for the voltage level may differ according to local operating policies. This leads to a similar observation for Fmax as for Imax. In case of Fmax, standard values may be replaced by values calculated from an AC load flow.

Alternative design choice:

As a reference, the operational values for U and cos(φ) could be determined by a common AC load flow calculation of the base case. This requires the setup and fine-tuning of an AC load flow which is out of scope of this study.

2.4.1.3 Imax

The maximum current on a line Imax is influenced by weather conditions. At given voltage, current times duration together with the weather conditions determine how much a line heats up. From all TSOs, only RTE distinguishes three different Imax values, depending on the duration of CO (for COs with duration between 1 and 5 minutes they require preventive RAs, for COs that last 20 minutes they allow corrective RAs). RTE does its own initial flow based calculation.

As Imax in practice changes with weather conditions (air temperature, wind), TSOs apply different policies to take this into account. Corrections for seasonal and time of day influences vary between the TSOs. This leads to a flow-based constraint potentially becoming binding for one bidding zone where it would not become binding for another bidding zone under otherwise identical circumstances. The differences in applied TSO policies are not of influence on PTDFs, only on available capacities and thus on location, frequency and severity of flow factor competition.

Alternative design choice

An alternative for Imax would be that Imax is varied per season, day and night per TSO according to average weather conditions for the day and for the night per season and per TSO. Also, the RTE approach of distinguishing COs of different duration could be considered in a common approach.

We will conclude at the end of task 1 if an alternative design for task 2 makes sense here or not. This would only be the case if we find a high sensitivity on Imax in the FFC indicators which are treated in part II of the report.

2.4.1.4 Explicit remedial actions

These are remedial actions that can be modelled in the CB file directly. It concerns topology changes, change of phase shifter settings and change of output of some generators or load (re-dispatch) that may be applied when a given CB becomes overloaded in one or more predefined outage situations (the COs). This would reduce the reference flow of such a CB and thus increase RAM.

A possible explicit remedial action applied in one bidding zone but not in another bidding zone due to a difference in operational security policy would influence location, frequency and severity of scarcity. While we can observe the explicit remedial actions defined in the CB-file, we cannot observe all possible explicit remedial actions on CBCOs in a bidding zone (and thus we cannot observe differences in the ones that are applied) as this falls outside the scope of the available data. However, we can differentiate active CBCOs (FFC occurrence) without explicit RAs from active CBCOs with explicit RAs.

Alternative design choice:

In the current set-up TSOs decide on preventive remedial actions a priori to the market coupling. An alternative design would be to capture the RAs as decision variables in the MC optimization as part of the TSO network constraints. This may only include generator re-dispatch and PST settings as topological changes would require the re-computation of topological information and PTDFs in the algorithm. Generator re-dispatch would alter the nodal net positions and hence the zonal PTDFs and the RAMs, change of PST settings can be approximated with balanced nodal injections and take-offs around the PST but change of topology alter the nodal PTDFs in a complex way that requires more complex topological modelling and integer variables.

Such alternative designs for explicit remedial actions are out of scope of this study.

2.4.1.5 Final adjustment values for non-explicit RAs (negative FAVs)

Implicit RAs can be used when it is not possible to explicitly express a set of conditional remedial actions into a concrete change in the D-2CF. For example, this could be a topology change and/or a re-dispatch at a voltage level which is not represented in the D-2CF. In such case a negative FAV will be used as RA.

Negative FAVs directly increase RAM, which could make some CBs less binding than others. Where implicit RAs are potentially available but not applied, a CBCO congestion is managed by CWE exchanges and not by such RA. In case local policies lead to a different application of implicit RAs, this influences occurrence, location and severity of congestion. We can only categorize congestions (FFCs) according to whether an implicit RA is applied or not and for which CBs, we cannot classify them according to different local RA policies.

Alternative design choices:

Any alternative design would require to make implicit RAs explicit. This may increase the complexity of the grid modelling to a disproportionate level. In any case, it is out of scope of our study. However, we will monitor the influence of implicit RAs on FFC.

2.4.1.6 Flow reliability margin

In the end, all inaccuracies in the flow-based model are accumulated in the observed difference between calculated flows (i.e. the flows that can be calculated from a base case adjusted for the net positions resulting from the day-ahead and intraday market coupling) and observed flows (snapshots).

TSOs have structurally calculated this difference during parallel run and continue to do so since go-live of the FB MC. The resulting information is statistically analysed and a predefined risk level, different per TSO, is applied to determine the FRM bandwidth that is needed to cover for these differences. As different risk level policies exist between the TSOs, the FRMs that are applied relative to the Fmax may vary from TSO to TSO. This could be observed from the indicators. Again, as FRM impacts RAM, but not the PTDFs, this does not impact competition between bidding zones on a congested line, but it does impact the occurrence of congestion.

<u>Similarities and differences:</u>

For each tie-line the same FRM is applied on both sides of the border. For internal lines, TSOs each apply their own FRM policies. All TSOs except ELIA and TRANSNET apply a P90 percentile on the observed difference to determine FRM per CB. ELIA and TRANSNET are each using a different method. ELIA considers the timestamps where expected flow was high but real flow was even higher. These timestamps are weighted higher in the FRM determination than others. TRANSNET applies a similar method.

The goal is to update FRMs at least once a year, but the tools to do it are somewhat behind.

Alternative design choice

An evident alternative would be to apply a common predefined percentile risk level. As we do not have access to the FRM statistical data, this alternative is not available. We will conclude at the end of task 1 if it makes sense to look for an alternative FRM design in task 2. For this, we will monitor if there is a significant difference in FRM/Fmax ratio between FFC situations or not.

2.4.2 External constraints

See section 2.3.1.

2.4.3 D-2CF

With D-2CF each TSO makes two days ahead a best effort forecast of the expected grid situation for day D. This was during parallel run changed from the initial approach where each TSO provided a D-2CF based on the reference programs. The use of reference programs for the individual D-2CFs proofed to aggravate inaccuracies because they deviated too much from the MC results with a higher Fref inaccuracy as a consequence.

Generally, D-2CFs are built according to the following process

- For topology:
  - Snapshots form the basis for the grid topology model. Differences can exist in the granularity of snapshots (one for each hour or one for a typical hour representative for all hours in a predefined time-of day period)
  - Topology adaptations according to expected topology changes for day D

- For physical feed-ins and take-offs on each node of the grid for day D (as the snapshots only represent day D-2): this requires per bidding zone a forecast for day D of
  - the net position of each bidding zone
  - the demand and demand pattern (not supposed to vary with prices)
  - the renewable generation and generation pattern (not supposed to vary with prices)
  - the remaining dispatchable generation and distribution of dispatchable generation over the nodes (these are the only generators which can make the net position, given demand and renewable generation)

All TSOs provide a complete model of their 220 and 380 kV network in their grid topology. ELIA also includes the 150 kV network. RTE and the German TSOs provide an equivalent network for the lower voltages. CREOS' data is merged with Amprion's. CBCOs are only modelled at 380 and 220 kV level. Differences in topology representation may lead to different accuracies in PTDFs (given all other input parameters remain the same).

The D-2CF provides two key inputs to the flow-based parameter calculation: the nodal net positions and the topology.

The nodal net positions depend on three parameters:

1. how much demand is off-taken at or behind the node

2. how much non-dispatchable generation is fed-in at or behind the node

3. how much dispatchable generation is fed-in at or behind the node

Of those three only the dispatchable generation is assumed to vary with the net position of the bidding zone. The other parameters would only vary with the day and the hour of the day. There is little or no information available on how each TSO determines the net nodal position as a result of these three parameters. The approval package only mentions an aggregate forecast of the first two parameters but not the nodal distribution. Consequentially, there may be differences and therefore also differences in accuracy. For the third parameter, the forecasted zonal net position and the forecasted zonal demand and non-dispatchable generation are used to determine the forecasted zonal dispatchable generation. The GSKs are then applied to the forecasted zonal dispatchable generation to determine the dispatchable generation at each node.

Alternative design choice: We will focus on design alternatives for the GSKs rather than on alternatives for the D-2CF (see 2.3.2).

2.4.4 Reference programs

Reference programs are the scheduled net positions of the reference days, which are already standardized:

- for Tuesday to Friday: D-1 (most recent program)
- for Monday: D-3 (previous Friday)
- For Saturday and Sunday: D-7 (previous week)
- For bank holidays and specific outages, a reference day is determined and fixed in a separate calendar approved by all CWE TSOs.

Alternative design choice:

The reason that reference programs are needed is because the forecasted net positions from each TSO may not sum up to a balanced CWE net position. TSOs could apply a common forecast model to derive balanced net position forecasts. To our understanding, TSOs are currently working on this.

2.4.5 Pre-qualification

Pre-qualification was described as an option in the approval document, but was never used in reality. Pre-qualification is a local TSO process which is not coordinated with other TSOs and which can be applied prior to any flow-based calculation process. Only if a TSO identifies that an RA has a cross-border impact, he may request a coordination.

Before the start of any of the flow-based parameter calculation processes executed by the TSO common system, TSOs can individually review the CBs and RAs by a special tool. This tool allows them to validate CBs and RAs according to the latest operational developments since the start of the capacity calculation process. The result of this pre-qualification is an adapted CB-file, which contains the latest explicit RAs and FAV values from implicit RAs of that RA with other TSOs. Prequalification influences the size and the form of the resulting flow-based MC solution space (or flow-based domain) and may thus also influence the MC welfare and MC welfare distribution.

The qualification process (see 2.5) today only uses coordinated RAs.

Alternative design:

As pre-qualification is not used, it does not make sense to define an alternative reference design.

2.5 Initial flow-based calculation

This step is done for France by RTE and for the other countries by the TSO common system. Therefore, the TSO common system will not have at this stage a CBCO file as input from RTE.

2.6 LTA inclusion

LTA inclusion is a step between initial flow-based calculation and qualification.

The step to adjust the flow-based domain to envelop the long-term allocation domain is an automated harmonized common algorithm applied by the TSO common system, based on the allocated long term transmission rights submitted by JAO. This step is not to be confused with long term nomination adjustments, which is performed during pre-final flow-based calculations. After inclusion of the long term allocation domain, complex coordinated remedial actions may be required and this belongs to the qualification process.

LTA inclusion can be done in two ways:

1. Shifting the binding CB by a negative FAV or LTA margin, TSOs can individually specify a limit on this negative FAV
2. If the FAV limit is reached, LTA point will be included by replacing binding CBCO with virtual CBCOs

Note that the change from PTRs to FTRs on the Belgian borders did not change the need for LTA inclusion.

Alternative design:

As there are no physical implications on the grid from the allocation of FTRs one alternative would be to remove FTRs from the LTA inclusion. Another alternative would be to remove LTA inclusion completely. Although both alternatives may imply an increased financial risks to the TSOs, which is not in scope of this study, the fairness impact of LTA inclusion is in scope.

2.7 Qualification

The qualification process is intended to include as many remedial actions as possible in the CB file that would extend the limiting CBCO constraints space (flow-based solution space) to the maximum extent possible.

The RA selection has been moved from an individual process (pre-qualification) to a coordinated process. As a result, the scope of RAs that can be applied was reduced and positive FAVs have been reduced. The qualification process today only uses coordinated RAs. This also means that the RAs have been harmonized. Today all RAs are either determined through coordination or (for topological changes) they are verified to be safe for other TSOs.

For the qualification process, first a clean load flow analysis is carried out on the base case in the initial flow-based calculation process to determine the flows per CBCO, excluding any RAs (explicit or implicit). During this process, LTA inclusion is automatically performed based on a harmonized methodology (see section 2.6 below).

Then, all CBCOs that do not meet the PTDF threshold value are removed (see 2.4.1).

Then the corners of the limiting flow-based domain are shared between the TSOs: one set for the peak period of the day, one set for the off-peak period of the day.

Next, each TSO checks if any preventive PST tap changes could reduce flows on the corners and applies them after coordination and agreement with other TSOs. Secondly, other RAs from the commonly agreed list of RAs that impact flows from CWE cross-border exchanges are evaluated on reduction of flows in the corners and applied after coordination and common agreement.

The results of this coordination and common agreement process are the RAs to be applied, after which the intermediate flow based calculation takes place.

Alternative design

As the domain maximizing RAs are already determined today in a coordinated process, there is no need to study an alternative design for the qualification process.

2.8 Verification

After the qualification step where the purpose is to enlarge the resulting flow-based domain with RAs to the maximum extent possible, the flow-based domain must be calculated again and this is done by the TSO common system during the intermediate flow-based calculation process. The result is a flow based domain with new limiting corners.

The purpose of the verification step is two-fold. First, each TSO can verify the impact of the RAs applied by all other TSOs. Secondly, the TSOs can verify, if the resulting flow-based domain is operationally secure by applying full AC load flow analysis or other studies on selected points (vertices) of the flow-based domain:

- They can customize the generation pattern to the commonly observed one for D-1 (from the DACF on D-2) for the corresponding vertex instead of using the linear GSK (this verifies a selected vertex on security with a generation pattern more realistically belonging to that vertex situation)
- Full load flow analysis taking reactive power flow and voltage limits into account
- Perform voltage stability study on the vertex point (voltage collapse)
- Investigate extreme net positions belonging to the vertex

In case a breach of security is found, TSOs can add CBCOs that were not perceived upfront as being limiting (combined or unusual outages), adapt or introduce positive FAVs or adapt the External Constraints according to the findings.

After this step, there will in principle not be any more adjustments to the flow-based domain by individual TSOs.

Alternative design:

Not considered.

2.9 Final data preparation

During this step, long term capacity nominations and ATCs on external CWE borders are provided by the TSOs. There are no local policies which could lead to different outcomes under otherwise equal circumstances here other than for ATCs agreed on synchronous external CWE borders. DACFs of synchronous bidding zones with a CWE interconnection have determined the part of the reference flows within CWE that are caused by the net position of those synchronously interconnected adjacent bidding zones. However, ATCs with those bidding zones may lead to a net position of these bidding zones that differs from the one applied in the DACF. Such deviations over time are contained in the FRM, just like any other modelling or forecasting inaccuracies.

For the flow-based parameters, the only change here is a shift of the origin of the flow-based domain towards the long term nominations.

Alternative design:

See section on LTA.

3 Influential factors and alternative designs

From the previous analyses, the table below summarizes the parameters that are TSO specific and how they influence FFC.

Parameter	PTDF	RAM	congestions in scope	other
Applied COs and scenarios			CBCOs	
CBCOs (initial)			CBCOs	
CBCOs (significant)			CBCOs	
D-2CF (nodal positions)		Fref[1)]		
D-2CF (topology)	nodal PTDFs			
DC exchange program forecast		Fref		
External constraints				Direct
FAVs (negative)		Direct		
FAVs (positive)		Direct		
Fmax		Direct		
FRMs		Direct		
GSKs	zonal PTDFs	Fref		
Imax		Fmax		
hourly load forecast	GSKs	Fref		
net exchange program (AC) forecast		Fref		
non-dispatchable production forecast		Fref		
production forecast per dispatchable generating unit	GSKs			
PTDF thresholds			CBCOs	
RAs (explicit)		Fref		
RAs (implicit)		FAV (negative)		
[1)] **Fref* which is the pre-loading at net positions 0, is calculated from this by subtracting zonal PTDF * Reference program**				

Table 1: TSO specific parameters and their influence on the flow-based domain

The following table provides an overview of alternative design options for critical parameters, following the qualitative analysis. The final choice on alternative design options that are assessed in task 2 is determined on the basis of the quantitative analyses that is covered in part II of the report.

Parameter	Alternative design options	Relevant for task 2?
Applied COs and scenarios	Apply common standard list of COs	To be determined later
CBCOs (initial)	All branches in the D-2CF	No. TSOs have included new CBCOs from FB experience
DC exchange program forecast	Make DC exchanges flow-based (instead of ATC based), now they have a reserved capacity through Fref and thus priority above AC exchanges	No. Out of scope
Fmax	Calculate U and cos(phi) with AC load flow	No. Out of scope
FRMs	Common percentile value (out of scope)	To be determined later
GSKs	1)Derive GSKs from optimal unit commitment and dispatch over the whole region with common forecasts 2)Iterative FBMC clearing until perfect GSK is reached 3) Introduce demand GSKs 4) Piece-wise linear GSKs	Yes, we will approximate perfect GSKs from DACFs
Imax	Commonly make Imax dependent on average weather conditions per season and time of day	To be determined later
LTN	Only use FTRs for LTTRs (this would reduce all LTNs to zero)	No, we will differentiate in task 1 between FFC before and after FTR introduction
PTDF thresholds	Common significance threshold without exceptions	To be determined later
RAs (explicit)	Include PST settings and generator re-dispatch as decision variables in the FBMC clearing. Including topology changes as decision variables in FBMC is considered practically infeasible (algorithm performance, TSO modelling effort)	No
RAs (implicit)	Difficult as this may require extension of the scope of the network modelled in D-2CF	No
nodal demand, non-dispatchables and dispatchables	Model a perfect base case	Yes. We will approximate perfect base case by DACFs

Table 2: Alternative designs for critical parameters and relevancy for task 2

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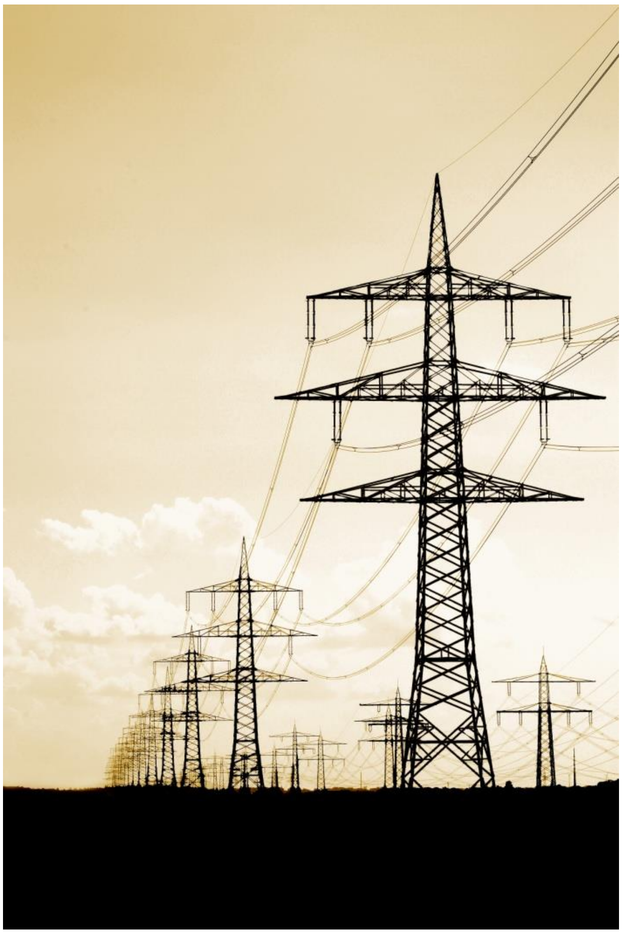

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