
Explanatory note for Channel TSOs proposal of common capacity calculation methodology for the day-ahead and intraday market timeframe in accordance with Article 20 of Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management

September 15th, 2017

Disclaimer

This explanatory document is submitted by all TSOs of the Channel Region to all NRAs of the Channel Region for information and clarification purposes only accompanying the proposal for common capacity calculation methodology for the day-ahead and intraday market timeframe in accordance with Article 20 of Commission Regulation (EU) 2015/1222 of 24 July 2015.

Contents

1 Introduction	5
1.1 Purpose of the document.....	5
1.2 Explanation of the main choices of the proposed methodology	5
1.3 Planning for implementation	8
2 General principles of Channel DA&ID Capacity Calculation	10
2.1 High level process.....	10
2.1.1 Day-ahead cross-zonal capacity calculation.....	10
2.1.2 Intraday cross-zonal capacity calculation	10
2.2 Inputs gathering phase	11
2.2.1 Definition of a Critical Network Element and a Contingency (CNEC)11	
2.2.2 Flow Reliability Margin.....	13
2.2.3 Maximum current on a Critical Network Element (I_{max}) / Maximum allowable power flow (F_{max}).....	15
2.2.4 IGMS and CGMs	16
2.2.5 External Constraints	17
2.2.6 Generation shift keys	18
2.2.7 Remedial actions	19
2.3 Qualification phase : Coordinated NTC approach.....	21
2.3.1 NTC calculation : Mathematical description	21
2.3.2 Remedial Action optimization	21
2.3.3 How to implement a reduction of the import/export	23
2.3.4 How to implement a shift of import/export	24
2.3.5 How to perform the N-1 security assessment of the maximum import/export for the 24h of the business day	24
2.3.6 CNTC Process.....	25
2.4 Validation Phase	26
2.4.1 Day Ahead cross-zonal capacity validation	27
2.4.2 Intraday cross-zonal capacity validation – initial calculation and within day recalculation	27
2.5 Intraday reassessment frequency	28
2.6 Allocation constraints	28
2.7 Fallback procedure.....	28
3 Channel DA&ID Experimentation Results	30
3.1 Approach of the experimentation	30
3.2 Assessment results and learnings	30
4 Criteria for an operational process	31
4.1 Criteria for the process operation.....	31
4.2 Criteria for the computed capacity	31

Annex 132

List of elements for which a planned or unplanned outage may trigger a detailed day-ahead capacity calculation32

1 Introduction

1.1 Purpose of the document

As required under Article 20 of the CACM Regulation, all TSOs in each capacity calculation region shall, within 10 months after the approval of the Capacity Calculation Regions, submit a proposal for a common coordinated capacity calculation methodology within the respective region. This document provides further explanation on the concepts and different inputs used for day-ahead (DA) and intraday (ID) capacity calculation for the Channel region. Where deemed necessary, the document explains differences in the proposed Channel CC Methodology between the DA and ID timeframes and between the different TSOs of the Channel Region.

Following topics are out of scope of this document:

- Capacity calculation methodology for the long term timeframe
- Allocation of cross-zonal capacity in the DA and ID timeframes
- Any compensation payable to an interconnector in the event that its capacity is restricted

The capacity calculation methodology for the Channel CCR is based on the Coordinated Net Transmission Capacity (or C-NTC) methodology.

1.2 Explanation of the main choices of the proposed methodology

The Channel Capacity Calculation Region consists of following bidding zone borders:

- France – Great Britain (FR - GB);
- Netherlands – Great Britain (NL – GB); and
- Belgium – Great Britain¹ (BE – GB).

Figure 1 provides the lay-out of the Channel CCR bidding zone borders:

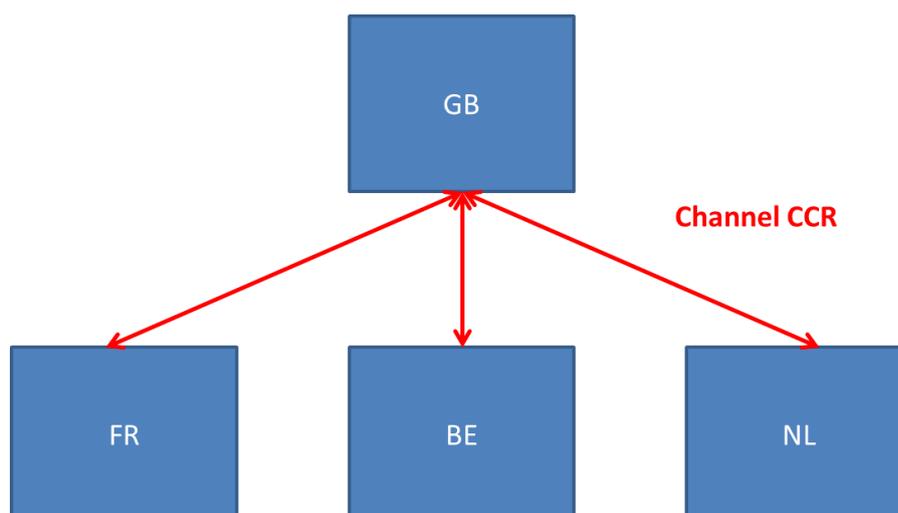


Figure 1: Lay-out of the Channel CCR bidding zone borders

The Channel day-ahead and intraday capacity calculation methodologies need to define cross-zonal capacities and allocation constraints for the different HVDC interconnectors between Great-Britain and the continent.

The capacity calculation for the BE-FR and BE-NL bidding zones borders is to take place in the Core CCR, as decided by ACER in its decision 06/2016.

¹ All TSOs introduced a request for amendment in accordance with Article 9(13) of Regulation 2015/1222 to include this border in the Channel CCR.

The Great-Britain and Continental European grids belong to different synchronous areas (i.e. having different frequencies). All bidding zone borders in the Channel Region consist of controllable HVDC interconnectors. From technical point of view each of the HVDC interconnectors in the Channel Region can be controlled in an independent way.

Regulation 2015/1222 requires that the available capacity normally should be calculated by a flow-based calculation method that takes into account that electricity can flow via different paths and optimises the available capacity in highly interdependent meshed grids, where cross-zonal capacity between bidding zones is highly interdependent.

According to Regulation 2015/1222 a coordinated net transmission capacity approach should only be applied in regions where cross-zonal capacity is less interdependent and it can be shown that the flow-based approach would not bring added value.

The Channel Region consists of HVDC interconnectors that can be operated in an independent way. The proposed capacity calculation methodology for the day-ahead timeframe provides that the maximum permanent technical capacity (MPTC) of the interconnectors is given to the market, except in the event planned or unplanned outages on the interconnector cables, or in case a planned or unplanned outage with significant impact on the interconnector exists in one of the bidding zones to which that interconnector is connected.

The reason for this is that, under normal operating conditions, the grid is considered sufficiently strong to accommodate the full MPTC of the interconnectors in the day-ahead timeframe. The MPTC is, for the relevant market time unit(s), the maximum permanent technical capacity which is the maximum continuous active power which a cross-zonal network element (interconnector/HVDC system) is capable of transmitting (taking into account potential reduced availability due to planned and unplanned outages of the interconnector asset). This parameter is defined by the interconnector's asset operators, and only considers the interconnector asset availability. In case a planned or unplanned outage with significant impact on the interconnector exists in one of the bidding zones to which that interconnector is connected, the cross-zonal capacity is calculated in a detailed and coordinated way.

Annex 1 of this explanatory note provides for each TSO of the Channel region an illustrative list of network elements that, given their significant impact on the interconnectors, may trigger a more detailed DA capacity calculation in case of planned or unplanned outage. This list is non-exhaustive as combined planned and unplanned outages on other elements may also force a TSO to trigger such detailed DA calculation. In any case, the considered TSO who triggers a calculation shall provide transparency on the conditions which triggered a more detailed DA calculation.

In such circumstances the advantages of a flow-based approach are less evident. Therefore the Channel TSOs decided to implement a CNTC approach. Other arguments for not developing a flow-based approach are:

- Annex 2 of ACER decision suggest that three years after said decision, the efficiency of the CCR configuration is to be re-evaluated, with specific attention on a potential merger of the Core and Channel CCRs;
- With regards to such potential merger, Channel TSOs prefer not to develop a flow-based approach in parallel with the flow-based approach being developed in the Core CCR; furthermore it is doubtful whether there would be any benefits in applying independent flow-based calculations for the Channel and the Core CCR;
- As already explained the benefits for a flow-based approach are unclear for the specific situation of the Channel CCR. A Coordinated Net Transmission Capacity calculation can be considered as a significant step forward compared to the current situation without any coordinated calculation. It therefore increases operational security.
- The feasibility of implementing a flow-based approach for the GB system must be further investigated to ensure it takes into account all operational security issues experienced in GB. In particular, it is noted that there are operational security issues seen within the smaller GB synchronous area are not experienced within the larger continental Europe synchronous area. For example, National Grid Electricity Transmission (NGET) manages low inertia and ROCOF (Rate of Change of Frequency) risks not currently seen on continental Europe. Implementing a Coordinated Net Transmission Capacity approach based on common TSO inputs will provide TSOs with

greater operational experience of how such dynamic operational security issues can be taken into account.

The interface between the flow-based approach of the Core CCR and the Channel CNTC methodology can be managed in two different ways in the Core flow-based mechanism:

- Standard Hybrid Coupling:
 - In such case the interconnectors are considered as an offtake (positive or negative infeed) in the flow-based mechanism;
 - The D-2 forecasted flow over the HVDC interconnector (as a results of market coupling) is considered as a starting point for performing the Core flow-based grid calculations.
- Advanced Hybrid Coupling:
 - In such case the Core flow-based constraints are imposed on the Channel HVDC interconnectors;
 - Each of the Channel HVDC interconnectors is connected to a specific Virtual Hub in the Core CCR, which in next step is connected to respectively the French, Belgian and Dutch bidding zones; and
 - The Core flow-based capacity allocation process takes fully into account the impact of exchanges over the Channel HVDC interconnectors on the Core CNECs during the allocation phase.

The Channel TSOs are committed to investigate in a next stage the Advanced Hybrid Coupling model as a potential target model. The Channel TSOs will perform a study and experimentations to investigate impacts of applying an Advanced Hybrid Coupling mechanism no later than 2 years after the implementation of the Channel CC Methodology.

The results of the study will be consulted with all stakeholders before taking a decision on an Advanced Hybrid Coupling approach. Channel TSOs are of the opinion that further experimentations are needed to assess the impact of applying Core FB constraints upon the Channel HVDC interconnectors. One particular point that needs to be investigated is to check to which extent Core CNECs (with potentially low sensitivity to exchanges over the HVDC interconnectors) would limit exchanges over the Channel interconnectors. These experimentations cannot be performed at this stage since the Core FB methodology is under development and doesn't support an Advanced Hybrid Coupling methodology at this stage.

As a result a Standard Hybrid Coupling methodology will be applied for the Channel HVDC interconnectors. This has following impacts on the proposed CNTC methodology for the Channel Region:

- Day-ahead timeframe:
 - The D-2 forecasted position of the HVDC interconnector as a result of the day-ahead market coupling is used as a starting point for the Core flow-based calculation;
 - In case the realized position of the HVDC interconnector deviates from the D-2 forecasted position, there is a risk for limited overloads in the Core CCR due to imperfections in the way how the exchanges over the interconnectors are taken into account in the flow-based region. Indeed, the exchange of an HVDC interconnector is taken into account in the Core flow-based mechanism as a change of net position of the bidding zone with the GSK of that bidding zone. The Channel TSOs consider that, especially for the day-ahead timeframe, there are sufficient resources and time available to cope with such limited overloads in a safe way.
 - This, in combination with the fact that Channel TSOs consider that the grid is sufficiently strong to accommodate the full MPTC of the HVDC interconnectors, makes that a CNTC calculation is applied for the day-ahead timeframe in which the MPTC of the Channel HVDC interconnectors is given to the market under normal operating conditions; a more detailed calculation for an interconnector being performed in case a specific planned or unplanned outage exists with significant impact on the interconnector in one of the bidding zones to which the interconnector is connected with significant impact on the HVDC interconnectors.

- Intraday timeframe:
 - Also for the intraday timeframe the forecasted flow of the HVDC interconnector, i.e. the flow resulting from previous market timeframes, will be used as a starting point for Core intraday flow-based calculation;
 - In absence of flow-based allocation in the intraday timeframe (not foreseen in first releases of the XBID mechanism), capacity is allocated independently on the Channel and Core bidding zone borders. Hence in contrast to the day-ahead timeframe, an exchange over the Channel HVDC interconnectors is not considered by a change in the net position with the GSK of the bidding zone in the Core intraday capacity allocation (thereby increasing the magnitude of potential overloads in case of flow reversal in the ID timeframe compared to the DA timeframe). This increases the risks for overloads in case the flows over the interconnectors deviated from the forecasted position (especially in case of full flow reversal over the HVDC interconnectors).
 - Given the higher risk for overloads in the Core region in the intraday timeframe due to flow reversal, and the more limited time (and scarcer resources) to resolve such overloads, Channel TSOs require a detailed CNTC calculation in the intraday timeframe in all situations in order to avoid issues with operational security stemming from flow reversal in intraday. Therefore a binary approach is used (see further).

1.3 Planning for implementation

Figure 2 illustrates an indicative planning for the implementation process of the capacity calculation methodology.

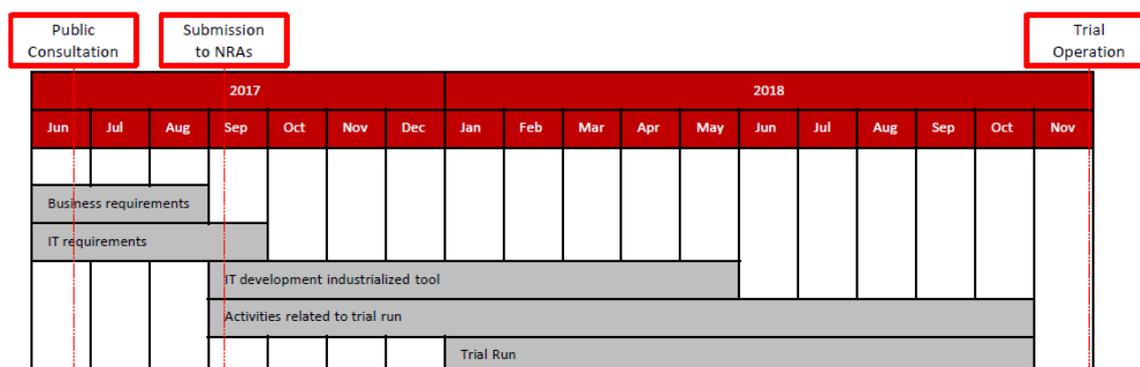


Figure 2. Indicative planning for implementation.

The implementation will be prepared by interactions with TSOs and coordinated capacity calculator(s) ("CCCs").

The first step will aim at defining the IT requirements based on the High Level Business Process and requirements resulting from the proposed methodologies and developed by the TSOs. This shall cover identification of formats, AS IS model, TO BE model, performance... IT development shall then follow.

In parallel with the IT development, TSOs shall organise trial runs, where possible failure can be detected and feedback from end-user will lead to improvements. The trial run is expected to start not sooner than Q1-2018 and will continue until the go-live.

The capacity calculation process is expected to go-live in Q4-2018. FRM values will be computed no later than 18 months after the end of the implementation of the Channel capacity calculation methodology.

2 General principles of Channel DA&ID Capacity Calculation

2.1 High level process

2.1.1 Day-ahead cross-zonal capacity calculation

On an abstract level, the day-ahead cross-zonal Capacity Calculation process can be described by the following flow chart in Figure 3.

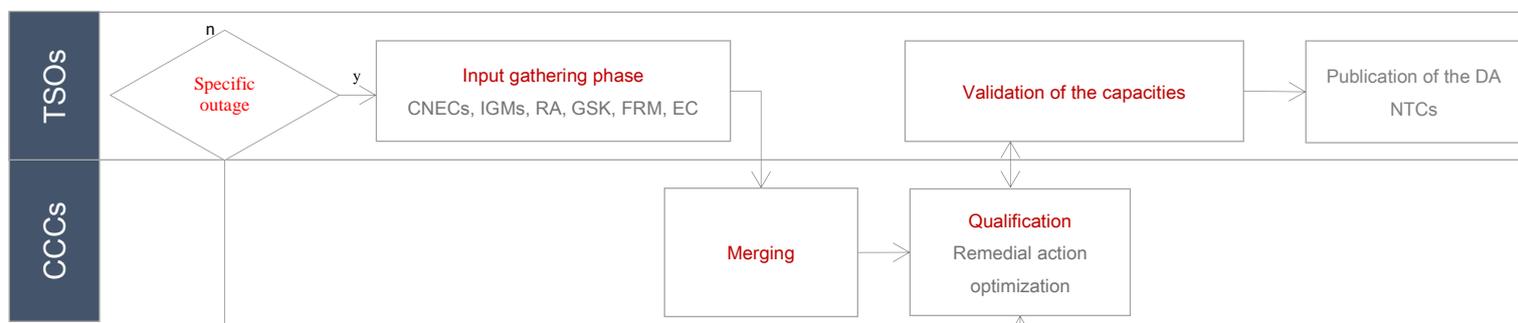


Figure 3. Day-ahead cross-zonal Capacity Calculation process

The CCC shall calculate the cross-zonal capacity for each interconnector on a bidding zone border and for each day ahead market time unit using the coordinated net transmission capacity approach as follow :

- a. The cross-zonal capacity shall be equal to the MPTC value unless a specific planned or unplanned outage exists with significant impact on the interconnector in one of the bidding zones to which that interconnector is connected.
- b. In case of occurrence of a specific planned or unplanned outage with significant impact on the interconnector in one of the bidding zones to which that interconnector is connected, the cross-zonal capacity for each day-ahead market time unit may be calculated using the latest CGMs developed according to the common grid model methodology in accordance with Article 17 of the CACM Regulation. The day-ahead capacity calculation shall be composed of the following 3 phases; Input gathering phase, Qualification phase and the Validation phase

The TSOs will have first to provide all the required input data: Individual Grid Models (IGMs) aiming at representing the best forecast of his control area for the computed timestamps, the list of Critical Network Elements and Contingencies (CNECs), Flow Reliability Margins (FRMs), available Remedial Actions (RAs), the Generation Shift Key (GSK) and the External Constraints (ECs). These inputs will be provided for each hour of the day.

Then the CCC shall merge the IGMs to generate the CGMs and shall perform the qualification of the NTCs using a remedial action optimization based on a binary approach.

After validation of the resulting capacities by TSOs and comparison with the already allocated capacities, the final NTCs are submitted to the TSOs for the Day-Ahead allocation

2.1.2 Intraday cross-zonal capacity calculation

On an abstract level, the intraday cross-zonal Capacity Calculation process can be described by the following flow chart in Figure 4.

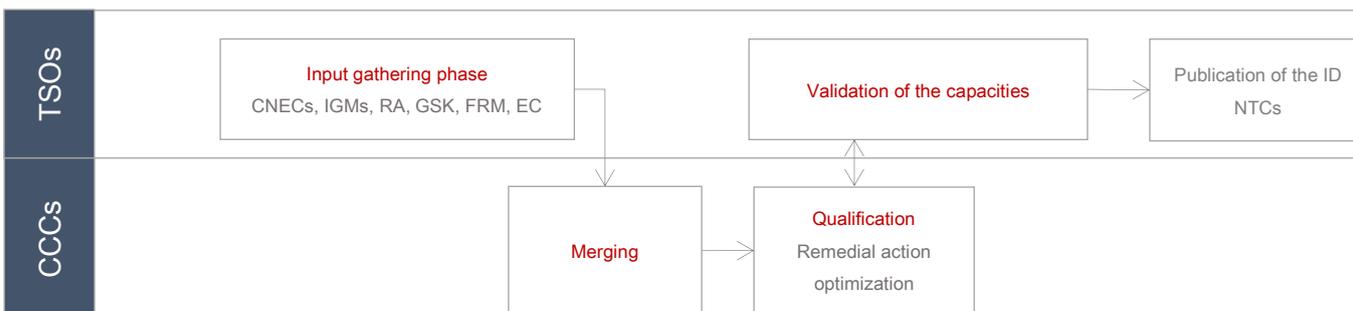


Figure 4. Intraday cross-zonal Capacity Calculation process

For the intraday market time-frame, the cross-zonal capacity for each interconnector and for remaining intraday market time units shall be calculated using the coordinated net transmission capacity approach using the latest CGMs developed according to the common grid model methodology in accordance with Article 17 of the CACM Regulation.

The TSOs will have first to provide all the required input data: Individual Grid Models (IGMs) aiming at representing the best forecast of his control area for the computed timestamps, the list of Critical Network Elements and Contingencies (CNECs), Flow Reliability Margins (FRMs), available Remedial Actions (RAs), the Generation Shift Key (GSK) and the External Constraints (ECs). These inputs will be provided for each remaining hour of the day.

Then the CCC shall merge the IGMs to generate the CGMs and shall perform the qualification of the NTCs using a remedial action optimization based on a binary approach.

After validation of the resulting capacities by TSOs and comparison with the already allocated capacities, the NTCs are submitted for the intraday allocation.

2.2 Inputs gathering phase

In order to compute the NTCs, the following inputs will be needed

- Critical Network Elements (CNEs) and Contingency (Cs)
- Flow Reliability Margin (FRM)
- Maximum current on a Critical Network Elements (I_{max}) / Maximum allowable power flow (F_{max})
- DA / ID CGM and reference Programs
- Remedial Actions (RAs)
- Generation Shift Key (GSK)
- External constraints: specific limitations not associated with flow limitation on Critical Network Elements
- Long Term Allocations (LTA) and Already Allocated Capacities (AAC)
- Maximum Permanent Technical Capacity (MPTC)

As a general rule, if there is agreement between some NRAs and TSOs of the Channel Region to update the method for the input generation for the day-ahead and/or intraday capacity calculation process in other Capacity Calculation Region, the consequences of the implementation of these changes for the Channel Region will be analysed and, if possible, the proposed methodology will be adapted in order to, as much as possible, align and ensure consistency.

2.2.1 Definition of a Critical Network Element and a Contingency (CNEC)

A Critical Network Element (CNE) is a network element, significantly impacted by Channel cross-zonal flows, which can be monitored under certain operational conditions, the so-called Contingencies. The CNECs (Critical Network Element and Contingencies) are determined by each Channel TSO for its own network according to agreed rules, described below.

The CNECs are defined by:

- A CNE: a line or a transformer that is significantly impacted by cross-zonal flows;
- An “operational situation”: normal (N) or contingency cases (N-1, N-2, busbar faults; depending on the TSO risk policies).

A contingency can be:

- Trip of a line, interconnector or transformer;
- Trip of a busbar;
- Trip of a generating unit;
- Trip of a (significant) load;
- Trip of several elements.

The combination of a CNE and a C is referred to as a CNEC.

Given that all interconnectors in Channel region are HVDC links, considering their ability to control the flow to a fixed value, these interconnectors shall not be monitored as Critical Network Elements, but are considered as Contingencies.

Each TSO should consider putting in internal critical network elements considering the following criteria:

- CNEC selection criteria will be based at least on cross-zonal flow sensitivity thresholds; and
- The cross-zonal flow sensitivity thresholds determine the maximum CNEC list, but TSOs have the possibility to discard elements from the list, based on operational studies or operational experience.

Explanation of the cross-zonal sensitivity thresholds:

The cross-zonal flow sensitivity is a crucial criterion for selecting relevant CNECs. The significantly influenced CNECs shall be defined at least on the basis of a minimum sensitivity from any cross zonal flow in the Channel Region above a certain threshold.

This sensitivity criterion is based on the maximum of the following bidding zone to bidding zone power transfer distribution factor (PTDF) absolute value:

- i. Great Britain to France
- ii. Great Britain to Belgium
- iii. Great Britain to The Netherlands

TSOs want to point out the fact that the identification of this threshold is driven by three objectives:

- Need for an objective and quantifiable notion of “significant impact”;
- Guaranteeing security of supply by allowing as much exchange as possible, in compliance with TSOs’ risks policies, which are binding and have to be respected. In other words, this value is a direct consequence of Channel TSOs’ risk policies standards; and
- Striving for consistency with the other CCR’s methodologies, including Core CCR. This consistency might also lead to the need to introduce additional criteria on top of the cross-zonal flow sensitivity threshold one.

The TSOs of the Channel Region that are also within the Core Region will implement the CNEC selection principles as defined in the Core Region (cross-zonal trade sensitivity threshold, minimum margin,...) also in the Channel Region. In the absence of approved CNEC sensitivity thresholds in the Core Region, these TSOs will apply a cross-zonal trade sensitivity threshold of 5%, which corresponds to the approach followed in the CWE flow-based mechanism. The reason for this approach is that, for the continental TSOs in Channel, it would not make sense to apply different CNEC selection criteria (on the same CNECs) within the Core and Channel CCR.

For GB a minimum sensitivity threshold for cross-zonal trade of 5% will be applied for the Channel Region. This corresponds to the value defined for GB in the IU Region.

For the Channel region the cross-zonal flow sensitivity of a CNE to an exchange over one of the bidding zone borders of the Channel Region expresses the MW flow impact of such exchange over the CNE;

- E.g. a sensitivity of X% on a CNE for exchanges over the IFA interconnector implies that an exchange of 100 MW over IFA will result in an additional flow of X MW on the CNE.

This is equivalent to saying that the maximum “zone to zone” PTDF of a given grid element should be at least equal to X% for it to be considered objectively “critical”.

For each CNEC the following sensitivity value is calculated:

$$\text{Sensitivity} = \max(\text{Zone to slack PTDFs}) - \min(\text{Zone to slack PTDFs})$$

If the sensitivity is above the threshold value of X%, then the CNEC is said to be significantly impacted by Channel trades.

For the Channel Region, the cross-zonal sensitivity relates to exchanges over the Channel CCR bidding zone borders.

Thus, to find the influence on any grid constraint from any cross border exchange, we may trace the route between the two bidding zones by PTDFs. For example if we would like to find the influence on network element "n" by a cross-zonal trade from zone "A" to zone "B", we can calculate:

The influence of cross border trade from zone "A=Great Britain" to zone "B=Continental Europe" (the Netherlands, Belgium or France) on constraint "n".

$$\text{PTDF A-B (n)} = \text{PTDF A(n)} - \text{PTDF B(n)}.$$

The PTDF of zone "A" on constraint "n"

The PTDF of zone "B" on constraint "n"

Generally, we would like to find the largest between any bidding zones (A,B) on each grid constraint "n" and evaluate if this is above chosen threshold. This might be found directly by calculating:

$$\text{Max PTDF A-B (n)} = \text{Max PTDF A,B (n)} - \text{Min PTDF A,B (n)}.$$

If this value is below the threshold X%, the CNEC is considered as not significantly influenced by the changes in bidding zone net positions.

Specificities of the TSOs :

The CNEC selection criteria for the different TSOs will be:

	Day-ahead	Intraday
France, Belgium and the Netherlands	Core CNEC selection criteria	Core CNEC selection criteria
France, Belgium and the Netherlands (intermediate criteria in absence of approved CNEC selection principles in the Core Region)	5% cross-zonal flow sensitivity threshold	5% cross-zonal flow sensitivity threshold
GB	5% cross-zonal flow sensitivity threshold	5% cross-zonal flow sensitivity threshold

The TSOs of the Channel Region shall regularly challenge and if feasible change the threshold in order to maintain consistency within Channel CCR and the other CCRs.

2.2.2 Flow Reliability Margin

The methodology for the capacity calculation is based on forecast models of the transmission system. The inputs are created two days before the delivery date of electricity with available knowledge. Therefore the outcomes are subject to inaccuracies and uncertainties. The aim of the reliability margin is to cover a level of risk induced by these forecast errors.

This section describes the methodology of determining the level of reliability margin per Critical Network Element and Contingency (CNEC) – also called the flow reliability margin (FRM) – which is based on the assessment of the uncertainties involved in the Capacity Calculation

process. In other words, the FRM has to be calculated such that it prevents, with a predefined level of residual risk, that the execution of the market coupling result leads to electrical currents exceeding the thermal rating of network elements in real-time operation in the CCR due to inaccuracies of the process.

The FRM determination is performed by comparing the power flows on each CNEC of the Channel CCR with the real time flows observed on the same CNEC. All differences for a defined time period are statistically assessed and a probability distribution is obtained. Finally a risk level is applied yielding the FRM values for each CNEC. The risk level will be harmonized between the same TSOs of the same synchronous area and shall be harmonized between the different CCRs where the TSOs are active.

The FRM values are constant for a given time period, which is defined by the frequency of FRM determination process. The concept is depicted on the figure below.

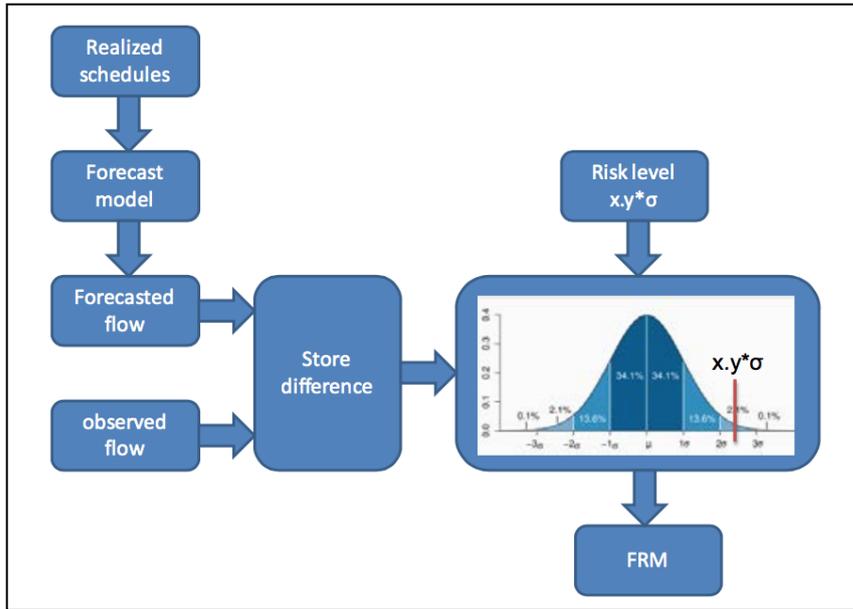


Figure 5. Flow reliability margins determination process.

For all the hours within the observatory period of the FRM determination, the D-2, DA or ID Common Grid Models (CGMs) can be modified to take into account the real time situation of some remedial actions that are controlled by the TSOs (e.g. PSTs) and thus not foreseen as an uncertainty. The power flows of the latter CGM are computed (F_{ref}) and then adjusted to realised commercial exchanges inside the CCR with the D-2, DA or ID PTDFs. Consequently the same commercial exchanges in Channel Region are taken into account when comparing the flows based on the model created in D-2, DA or ID with flows in the real time situation. These flows are called expected flows (F_{exp}).

$$F_{exp} = F_{ref} + \sum_{k=1}^n PTDF_k \times (NP_{k,real} - NP_{k,ref})$$

For the same observatory period, the realised power flows are calculated using the real time European grid models by means of contingency analysis. Then for each CNEC the difference between the real flow (F_{real}) and the forecasted flow (F_{exp}) is calculated. Results are stored for further statistical evaluation.

Based on the archived flow differences the statistical evaluation is conducted. Each TSO applies a risk level specified individually. The calculated value represents the amount of flow deviation on the respective Critical Network Elements (CNEs) and CNECs being covered by the FRM.

The statistical evaluation is repeated on a regular basis.

As a summary, the FRM covers the following forecast uncertainties with a certain risk level:

- Channel external transactions;
- Generation pattern including specific wind and solar generation forecast;
- Generation Shift Key;
- Load forecast;
- Topology forecast; and
- Unintentional flow deviation due to the operation of load frequency controls.

After computing the FRM following the above-mentioned approach, TSOs may potentially apply an “operational adjustment” before practical implementation into their CNE and CNEC definition. The rationale behind this is that TSOs remain critical towards the outcome of the pure theoretical approach in order to ensure the implementation of parameters which make sense operationally. The possibility to adjust FRM based on operational adjustment is relevant e.g. in case of no statistical representativeness of the data set which has been used for the FRM computation for a specific CNE (e.g. absence of sufficient historical data of flows in a certain direction,...). For any reason (e.g. data quality issue, perceived TSO risk level), it can occur that the “theoretical FRM” is not consistent with the TSO’s experience on a specific CNE. Should this case arise, the TSO will proceed to an adjustment. It is important to note here that this adjustment is supposed to be relatively “small”. It is not an arbitrary re-setting of the FRM but an adaptation of the initial theoretical value. The differences between operationally adjusted and theoretical values shall be systematically monitored and justified, which will be formalized in a dedicated report towards NRAs.

Eventually, the operational FRM value is determined once and then becomes a fixed parameter in the CNE and CNEC definition until the next FRM determination.

Specificities of the TSOs

National electricity transmission system of Great Britain Flow Reliability Margins

National Grid shall be entitled to apply an FRM input value of zero for any CNE without undertaking specific analysis to assess FRM since an FRM = 0 has no adverse impact on NTC. National Grid shall be responsible for managing the operational risks associated with this approach, although the TSO considers this risk to be low for the GB transmission network.

RTE, TTN and ELIA as TSOs of the CE synchronous area

The methodology shall be reviewed and if necessary updated in order to keep full consistency with the methodology and its evolution in the Core region.

It has to be noticed that, as the proposed methodology is consistent with to the one used in the Core region, the FRM value for any CNEC which would be monitored in both Channel and Core region shall be identical.

For the Channel TSOs that are both active in Channel and Core region the risk level is currently fixed at 90%.

2.2.3 Maximum current on a Critical Network Element (I_{max}) / Maximum allowable power flow (F_{max})

Maximum current on a Critical Branch (I_{max}):

The maximum admissible current (I_{max}) is the physical limit of a CNE determined by each TSO in line with its operational security policy. I_{max} is defined as a permanent or temporary physical (thermal) current limit of the CNE. A temporary current limit means that an overload is only allowed for a certain finite duration (e.g. 115% of permanent physical limit can be accepted during 15 minutes). Each individual TSO is responsible for deciding which value (permanent or temporary limit) should be used.

As the thermal limit and protection setting can vary in function of weather conditions, I_{max} is usually fixed (at least) per season. Its value can be adapted by the concerned TSO if a specific weather condition is forecasted to deviate from the seasonal values (e.g. where dynamic line rating is applied).

I_{\max} is not reduced by any security margin, as all uncertainties in capacity calculations on each CNEC are covered by the Flow Reliability Margin.

Maximum allowable power flow (Fmax)

The value Fmax describes the maximum allowable power flow on a CNEC in MW. Fmax will be calculated using reference voltages.

Fmax is calculated from Imax by the given formula:

$$F_{\max} = \sqrt{3} \cdot I_{\max} \cdot U \cdot \cos(\varphi)$$

where Imax is the maximum permanent allowable current in kA of a critical network element (CNE). The values for $\cos(\varphi)$ and the reference voltage U (in kV) are fixed values for all CNE of one synchronous area. For continental Europe TSOs, in line with current practises, the $\cos(\varphi)$ will be 1 and reference voltage U will be 225 kV and 400 kV.

Specificities of TSOs

National electricity transmission system of Great Britain operational security limits

The operational security limits for the national electricity transmission system of Great Britain are outlined within the NETS Security and Quality of Supply Standard (SQSS). This document outlines the acceptable operating boundaries for secure grid operation such as thermal limits, voltage limits, short-circuit current limits, frequency and dynamic stability limits.

These operational security limits are the same as those used in operational security analysis.

Since NGET is applying a zero FRM any monitored CNEC in GB can be monitored using operational security limits in Imax, therefore NGET shall not be required to provide corresponding Fmax limits. Hence NGET shall not define a conversion formula to convert Imax to Fmax

RTE, TTN and ELIA as TSOs of the CE synchronous area

It has to be noticed that, as the proposed methodology is consistent with to the one used in the Core region, the Imax/Fmax value for any CNEC which would be monitored in both Channel and Core region shall be identical.

2.2.4 IGMS and CGMs

For the day-ahead and intraday capacity calculation, each TSOs of the Channel region shall submit for each hour of the day IGMS and the CCC shall merge these IGMS into CGMs following the CGMES methodology which has been developed in accordance to the Section 2 of CACM Regulation.

For intraday capacity calculation the latest available version of the day ahead or intraday Congestion Forecast process (DACF or IDCF) will be used at the moment the capacity calculation process is initiated.

For the creation of the D2, DA and ID IGMS, according to the methodology developed in line with Article 16 and 17 of the CACM Regulation, the model shall include:

- Best estimation of net exchange program;
- Best estimation exchange program on DC interconnectors;
- Best estimation for the planned grid outages, including tie-lines and the topology of the grid;
- Best estimation for the forecasted load and its pattern;
- If applicable best estimation for the forecasted renewable energy generation, e.g. wind and solar generation;
- Best estimation for the outages of generating units;
- Best estimation of the production of generating units; and
- All agreed remedial actions during regional security analysis.

2.2.5 External Constraints

The following sections will depict in detail the method used by each TSO² to design and implement external constraints.

Besides active power flow limits on Critical Network Elements, other specific limitations may be necessary to maintain the transmission system within operational security limits. Since such specific limitations cannot be efficiently transformed into maximum flows on individual CNEs, they are expressed as import/export limits, i.e. maximum import and/or export of bidding zones. These so-called External Constraints are determined by the TSOs and taken into account during the day-ahead market coupling in addition to the power flow limits on CNEs. As the physics behind the external constraints remain the same irrespective of the market time period under investigation, the same constraints in the intraday stage as in the day-ahead allocation shall be applied in the intraday allocation. The usage of External Constraints is justified by several reasons, among which avoiding market results which lead to stability problems in the network, detected by system dynamics studies.

In other words, the capacity calculation includes contingency analysis based on a load flow approach, and the constraints are determined as active power flow constraints only. Since grid security goes beyond the active power flow constraints, issues like:

- voltage stability; and/or
- dynamic stability,

need to be taken into account as well. This requires the determination of other constraints: the so-called External Constraints (ECs).

The External Constraints are regularly reviewed and potentially updated on a regular basis.

Specificities of TSOs

Dutch External Constraint:

TenneT NL determines the maximum import and export constraints for the Netherlands based on off-line studies, which include voltage collapse analysis, stability analysis and an analysis on the increased uncertainty introduced by the GSK, during different import and export situations. The study can be repeated when necessary and may result in an update of the applied values for the external constraints of the Dutch network.

Belgian External Constraint:

No specific external constraints is foreseen related to the BE – GB interconnector.

Great Britain External constraint:

National Grid uses a maximum individual loss per synchronous area constraint which is related to the frequency and dynamic stability limit of the network. This limitation is estimated with offline studies which are performed on a daily basis.

RTE Constraint:

No external constraints shall be used.

²Any time a TSO plans to change its method for EC implementation, it will have to be done with NRAs' agreement, as it is the case for any methodological change.

2.2.6 Generation shift keys

The Generation Shift Key (GSK) defines how a change in net position is mapped to the generating units in a bidding zone. Therefore, it contains the relation between the change in net position of the bidding zone and the change in output of every generating unit inside the same bidding zone.

In case generating units are injecting electricity in lower voltage layer which are not contained in the CGM, TSOs can attribute factors on consumption.

Due to the convexity pre-requisite of the flow-based domain and in order to ensure consistency with other CC region where some Channel TSOs are involved (e.g. Core Region which applies a flow-based approach), the GSK must be constant per calculation unit.

Every TSO assesses a GSK for its control area taking into account the characteristics of its system. Individual GSKs can be merged if a bidding zone contains several control areas.

A GSK aims to deliver the best forecast of the impact on Critical Network Elements of a net position change, taking into account the operational feasibility of the reference production program, projected market impact on generation units and market/system risk assessment.

In general, the GSK includes power plants that are market driven and that are flexible in changing the electrical power output. TSOs can also use less flexible units, e.g. nuclear units, if they don't have sufficient flexible generation for matching maximum import or export program or if they want to moderate impact of flexible units. Since the generation pattern (locations) is unique for each TSO and the range of the NP shifting is also different, there is no unique formula for all Channel TSOs for creation of the GSK. Finally, the resulted change of bidding zone balance should reflect the appropriate power flow change on CNECs and should be relevant to the real situation.

The GSK values can vary for every hour and are given in dimensionless units. For instance, a value of 0.05 for one unit means that 5 % of the change of the net position of the bidding zone will be realized by this unit. Technically, the GSK values are allocated to units in the Common Grid Model. In cases where a generation unit contained in the GSK is not directly connected to a node of the CGM (e.g. because it is connected to a voltage level not contained in the CGM), its share of the GSK can be allocated to one or more aggregated generation units of the CGM in order to model its technical impact on the transmission system.

Justification on why GSKs can be different for different TSOs

Each bidding zone has its specificities in terms of market and systems: the pattern and type of market players are not the same in each market area and the design of the network is also not the same. As GSKs intend to represent at best the market behavior in a specific area, it is of importance to take into consideration these specificities of each area. As a consequence, it is hard to impose the same principles and rules everywhere.

Additionally, technical limitation on the tools need to be taken into account too when designing the GSKs in an area. And as, for a question of transparency, the TSOs of Channel intend to use the same GSK definition for an area which may be involved in different regions, these technical limitations have to consider the tools used not only in Channel, but also in other regions like CORE. In the CORE region, a flow-based approach and Flow based tools are used, which introduce today an important technical limitation: the real Pmin/Pmax of the units cannot be taken into account when adjusting the net position of an area using the GSKs. Moreover, in order to ensure convexity, GSKs need to be linear and the same for an increase or a decrease of the net position. Both technical limitations have a strong influence on the way the design/definition of the GSKs may impact the loading of the system, especially in bidding zone where the number of market driven units is low.

Then, for each area, considering these technical limitations, there is a need to find the best compromise between representing at best the expected market behavior while respecting the limits and specificities of the network. We can notice that the Belgian and Dutch TSOs, which have similar size of grid and number of market driven units, have similar approach in their definition of the GSKs, aiming at avoiding unrealistic loading of grid equipment that would be the case with a pure pro-rata approach while for the French TSO, considering the higher size of system and number of market driven units, a pure pro-rata approach is sufficient.

Specificities of the TSOs

Great Britain GSK:

In day ahead and intraday, the Britain GSK shall represent the best forecast of the relation of a change in net position of the bidding zone to a specific change of generation or load in the common grid model.

French GSK:

The French GSK is composed of all the units connected to RTE's network. The variation of the generation pattern inside the GSK is the following: all the units which are in operations in the base case will follow the change of the French net position on a pro-rata basis. That means, if for instance one unit is representing n% of the total generation on the French grid, n% of the shift of the French net position will be attributed to this unit. This choice of the proportional GSK is mainly related to the fact that generation in France is composed at 75% by nuclear power that does not vary following a merit order. Indeed the French electricity market being a portfolio market, the merit order is not geographically relevant. Thus a proportional representation of the generation variation, based on RTE's best estimate of the initial generation profile, ensure the best modelling of the French market.

Belgian GSK:

The Belgian TSO will use in its GSK a fixed list of nodes based on the locations where most relevant flexible and controllable production units (market oriented generating units) are connected. This list will be determined in order to limit as much as possible the impact of model limitations on the loading of the CNEs. The variation of the generation pattern inside the GSK is the following: in day-ahead, the variation of the generation pattern inside the GSK shall be such that the sum of the generation which are in operations on each of these nodes in the CGM will follow the change of the Belgian net position in such a way that the generation at the node will reach its maximum when the maximum generation capability of the Belgian bidding zone is reached and will reach its minimum when the minimum generation capability of the Belgian bidding zone is reached. In Intraday, the sum of the generation which are in operations in the base case of each of these nodes will follow the change of the Belgian net position on a pro-rata basis. That means, if for instance one node is representing n% of the sum of the generation on all these nodes, n% of the shift of the Belgian net position will be attributed to this node.

Dutch GSK:

The Dutch GSK will dispatch the main generators in a manner which avoids extensive and unrealistic under- and overloading of the units for extreme import or export scenarios. The GSK is directly adjusted in case of new power plants. Also unavailability of generators due to outages are considered in the GSK.

All GSK units are re-dispatched pro rata on the basis of predefined maximum and minimum production levels for each active unit. The total production level remains the same.

The maximum production level is the contribution of the unit in a predefined extreme maximum production scenario. The minimum production level is the contribution of the unit in a predefined extreme minimum production scenario. Base-load units will have a smaller difference between their maximum and minimum production levels than start-stop units.

It has to be noticed that, for the TSOs of the CE synchronous area (RTE, TTN, ELIA), as the proposed methodology is consistent with to the one used in the Core region, the GSK values in both Channel and Core region shall be identical.

2.2.7 Remedial actions

During Coordinated Capacity Calculation, TSOs take Remedial Actions (RA) into account available in DA and ID to maximize as much as possible the allowed exchanges over the bidding zone borders of the CCR while ensuring a secure power system operation, i.e. N-1/N-k criterion fulfilment.

Remedial Actions used in capacity calculation embrace the following measures:

- changing the tap position of a phase shifter transformer (PST)
- topology measure: opening or closing of a line, interconnector, transformer, bus bar coupler, or switching of a network element from one bus bar to another
- curative (post-fault) redispatching: changing the output of some generators or a load.

The effect of these RAs on the CNEs is directly determined in the calculation process to monitor the shift of load flow in the synchronous area.

There are several types of RAs, differentiated by the way they are used in the capacity calculation.

- Preventive (pre-fault) and curative (post-fault) RAs: While preventive RAs are applied before any fault occurs, and thus to all CNECs of the domain, curative RAs are only used after a fault occurred. As such the latter RAs are only applied to those CNECs associated with this contingency. Curative RAs allow for a temporary overload of grid elements and reduce the load below the permanent threshold.
- Shared and non-shared RAs: Each TSO can define whether he wants to share the RA provided for capacity calculation or not. In case a RA is shared, it can be applied to increase the remaining available margin on all relevant CNECs. If it is non-shared a TSO can determine the CNECs for which the RA can be applied in the capacity optimization.

Each TSO defines the available RAs in its responsibility area according to his operational principles and ensures the availability of the measure until real-time.

Each TSO shall ensure all relevant available non costly remedial actions are made available to the coordinated capacity calculator.

At least all RAs used for the DA capacity calculation and still available at the time of the ID capacity calculation have to be considered.

Each TSO can also choose to make costly (preventative and curative) remedial actions available to the coordinated capacity calculator. The proposed concepts of DA and ID CNTC calculation do not foresee, although also not exclude, any economic optimisation in the use of the available RAs.

At the end of the calculation of cross zonal capacity, where a remedial action is assumed to be used to increase the cross zonal capacity, the coordinated capacity calculator shall inform the respective TSO. The decision to instruct any remedial action remains with each TSO.

In case a RA made available for the capacity calculation is also a RA which may be used during capacity calculation in another region, the TSO owning the RA shall take care when defining the RA to ensure consistent, non-contradicting, use in his potential application in both regions to ensure a secure power system operation.

Specificities of the TSOs

Belgian RA:

For ELIA, the application of BE PSTs shall be considered as RA in both Core and Channel regions. In order to ensure consistent use in both regions, ELIA may restrict the range of application of each PST depending on the loading of the Belgian CNEs in the base cases.

2.3 Qualification phase : Coordinated NTC approach

2.3.1 NTC calculation : Mathematical description

In theory, the coordinated NTC approach should aim at assessing the maximum transfer of power on each direction of each of the bidding zone borders of the region that will be possible to reach simultaneously without endangering the security of the system.

This maximum power transfer is called Total Transfer Capacity. When each of the bidding zone border is composed of HVDC links, no Transfer Reliability Margin needs to be considered for these links and the Net Transfer Capacity is equal to the Total Transfer Capacity.

In minimum and certainly as a starting point, for the Channel region, the assessment will consider the maximum secure value of simultaneous import/export over all the interconnectors of the Channel CCR bidding zone borders. This maximum import/export is further called 'market direction'.

Practically, in Channel region, the assessment of this maximum import and export will be done through a binary approach, using the common grid model as reference and considering the MPTC of each interconnector as a starting position (unless it excludes EC applicable to the interconnector).

The binary approach will evaluate at each step of the assessment the ability to cope with the operational security limits expressed by the I_{max}/F_{max} on each CNEC taking into account an optimal use of the available Remedial Actions in the defined market direction. A Remedial Action Optimizer (RAO) will be used which has as objective function to increase margins until a positive value is reached on all CNECs.

If no CNEC has to be monitored in a bidding zone, the maximum capacity transfer will be available on the interconnectors of this bidding zone for the concerned market directions.

If no CNECs have to be monitored for all bidding zones of one CCR, the maximum capacity transfer will be available on all interconnectors and no calculation will be needed.

If no available remedial actions can be found to fulfil the operational security limit of a CNEC in one market direction in one bidding zone, the assessment will be repeated with a reduced value of the import/export from the interconnectors linked to this bidding zone.

The assessment will be stopped when operational security limits are respected on all CNECs.

At the end of the assessment, the resulting NTC for each hour of the day shall be compared, in day-ahead, with the LTA and, in intraday, with the AAC and the maximum of these values will be considered.

2.3.2 Remedial Action optimization

As referred in CACM, TSOs should use a common set of remedial actions to deal with both internal and cross-zonal congestion. In order to facilitate more efficient capacity allocation and to avoid unnecessary curtailments of cross-zonal capacities, TSOs should coordinate the use of remedial actions in capacity calculation. Moreover the selected remedial actions used in capacity calculation process, must ensure operational security.

The coordinated capacity calculator shall optimise cross-zonal capacity using the list of available remedial actions given by the TSOs within the capacity calculation process.

To achieve this optimization in the calculation process, the coordinated capacity calculator will use a Remedial Action Optimizer (RAO).

RAO tool:

The Remedial Action Optimizer (RAO) tool determines the optimal Remedial Actions (RAs) from a defined objective function.

More precisely, the goals of the optimizer are twofold:

- Secure the reference network situations; and
- Determine the optimal remedial actions from a defined objective function.

In particular, the objective function of RAO tool for Channel region is to increase margins of all CNEC until a positive value is reached for all CNECs.

High level process flow of optimisation process is as followed:

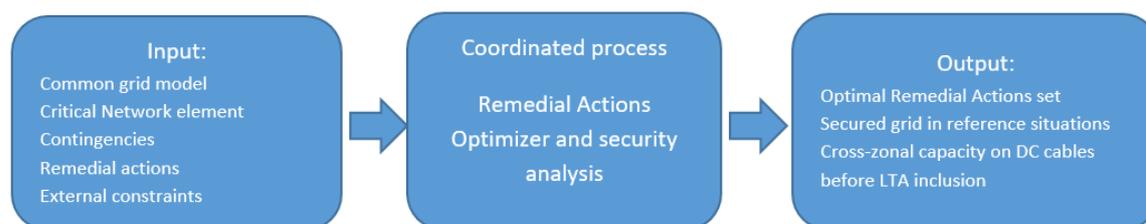


Figure 6. High level process flow of optimisation process.

Depending on the base case (Common Grid Model) and contingencies, different kind of remedial actions can be used during the capacity calculation:

- preventive Remedial Actions: it could be a change of taps of a PST on a given range, or a change of state (open / close) of a circuit breaker;
- Curative Remedial Actions: among others it could be a change of taps of a PST on a given range, or a change of state (open / close) of a circuit breaker.

In addition, the remedial actions optimizer (RAO) will take into account 'remedial action usage rules' in the process, i.e. in which case a remedial action can be used.

The 'remedial action usage rules' will be defined upfront by TSOs. Concretely, for each Remedial Action (RA) within its grid, each TSO indicates in its input data for which kind of cases this RA can be used. For instance:

- to solve congestion only on a specific Critical Network Element;
- to solve congestion on any Critical Network Elements being part of its Control Area;
- to solve congestion on a specific state of the grid (preventive or curative).

Determining the preventive and curative RAs

The inputs of the RA optimisation process are the following data:

- Common grid model : resulting from the merging of individual grid model on the concerned capacity calculation region;
- List of Critical Network elements and Contingencies;
- List of Remedial actions available per TSO;
- External constraints.

The outputs of the optimisation process are the optimal remedial actions set for the considered capacity timeframe (DA or ID) and the computed cross-zonal capacity:

- Preventive Remedial Actions;
- If relevant, Curative Remedial Actions after each Contingency ("C");
- Cross-zonal capacity on the HVDC interconnectors before LTA or AAC inclusion.

The RAO algorithm explores solutions through a sequential approach made of two sub-problems:

1. Preventive problem for all CNECs;
2. Curative problem for every Contingency.

On both preventive and curative steps, the available remedial actions are tested. The objective function selects the most efficient ones, which are then implemented. RAs are tested and implemented through iterations within a search tree by simulating all the implemented contingencies for preventive RAs. Once the preventive optimization is finished, the set of preventive actions is fixed and implemented as starting point for all curative optimizations. For curative RAs, approach is different, and is made contingency per contingency.

Algorithm keeps applying RA until one of the following conditions is fulfilled:

In preventive :

- All preventive remedial actions have been tested;
- At a certain step of optimization, no preventive remedial actions improve the objective function.

In curative:

- The maximum number of curative actions have been reached;
- At a certain step of optimization, no curative actions improve the objective function.

The output of the RAO is a coordinated set of preventive RAs and curative RAs linked to each Contingency.

2.3.3 How to implement a reduction of the import/export

In case of a limitation on CNECs which cannot be solved with available Remedial actions, the import/export from DC interconnectors will have to be reduced.

The reduction of import/export will only concern the bidding zone where the limiting CNECs are located.

In case several interconnectors are located in the concerned bidding zone, the concerned TSOs of the bidding zone have to define in a coordinated way the splitting rule, if needed, in order to manage the reduction. CNE are linked to DC interconnectors through CNEC selection criteria. In case one CNE is linked to multiple DC interconnectors, the reduction rule shall be done proportionally to the influence of the power shift of the interconnectors on the CNE.

This is illustrated by the below example, where the capacity over the interconnectors must be reduced in order to resolve an overload on CNEC X. In this particular case the capacity reduction over HVDC1 will be twice the reduction of capacity on HVDC2 since the impact of an exchange of HVDC1 on CNEC X is twice the impact of an exchange of HVDC2 over CNEC X.

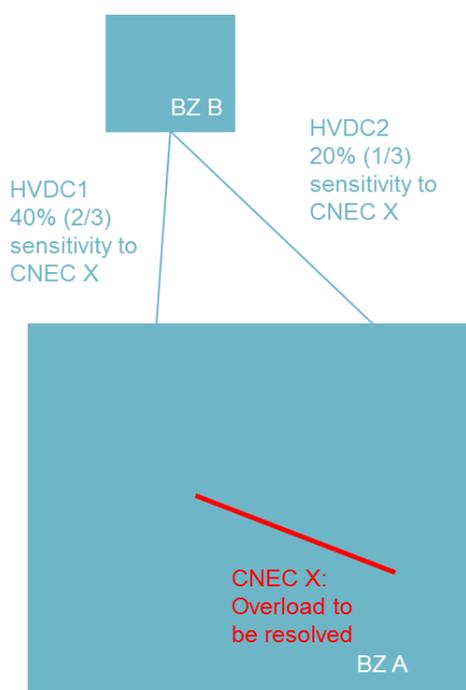


Figure 7 reduction of interconnector capacity in case of multiple interconnectors connected to a bidding zone

During implementation phase and internal parallel run, TSOs will assess the feasibility of a daily quantification of the reduction rule or if it should be done offline by the TSO based on statistical or reference cases studies.

Specificities of DA or ID time Horizon

The day ahead capacity can differ from the maximum permanent technical capacity only in case of a specific planned or unplanned outage with significant impact on the interconnector exists in one of the bidding zones to which that interconnector is connected. The TSO is responsible to transfer the specific planned or unplanned outage in the CRAC file for the

coordinated capacity calculator. Each HVDC link will be associated with a set of CNECs that will be monitored in order to implement reductions of the import/export on this interconnector.

The NTC values will be computed per interconnector in each bidding zone border. In case of limiting CNECs which cannot be solved with available Remedial Actions, the congestion is solved by reducing only the NTC on the interconnectors in the bidding zone border where the constraint is located. As each interconnector is associated with a set of potential CNECs, the NTC will be reduced on the interconnectors associated with the limiting CNECs.

At least one capacity calculation shall be performed every day for the ID timeframe.

2.3.4 How to implement a shift of import/export

Any shift of the power transfer between 2 bidding zones shall be realized by adjusting the generation in each of the bidding zone in line with the GSK of the bidding zone.

2.3.5 How to perform the N-1 security assessment of the maximum import/export for the 24h of the business day

Updated NTCs will be provided for the 24h of the business day.

The solution aims at computing those updated NTCs based on a N-1 security assessment of both import and export market directions for the Channel Region for the 24h. However, due to time and tooling constraints, this ideal solution might not be technically feasible for the first implementation.

A more realist target is to divide the day in periods, perform the N-1 security assessment for a representative timestamp of the period and apply the result for each hour of the period.

At minimum, the N-1 security assessment will be done on one hour for peak and off-peak periods and the result will be applied to each hour of the respective period.

The representative timestamps will have to be agreed between the TSOs of the Channel Region. The definition of the periods and timestamps will be done by season and for each season per weekdays, Saturdays and Sundays.

Taking into account the abilities of the tools and their foreseen development, the CCC shall maximize the number of assessed representative timestamps.

During the implementation phase and especially during internal parallel run, TSOs and CCR will consider the maximum number of assessed representative timestamps. Considering the time available to perform the process in DA and ID time horizon, the number of assessed timestamps may be different in each case.

2.3.6 CNTC Process

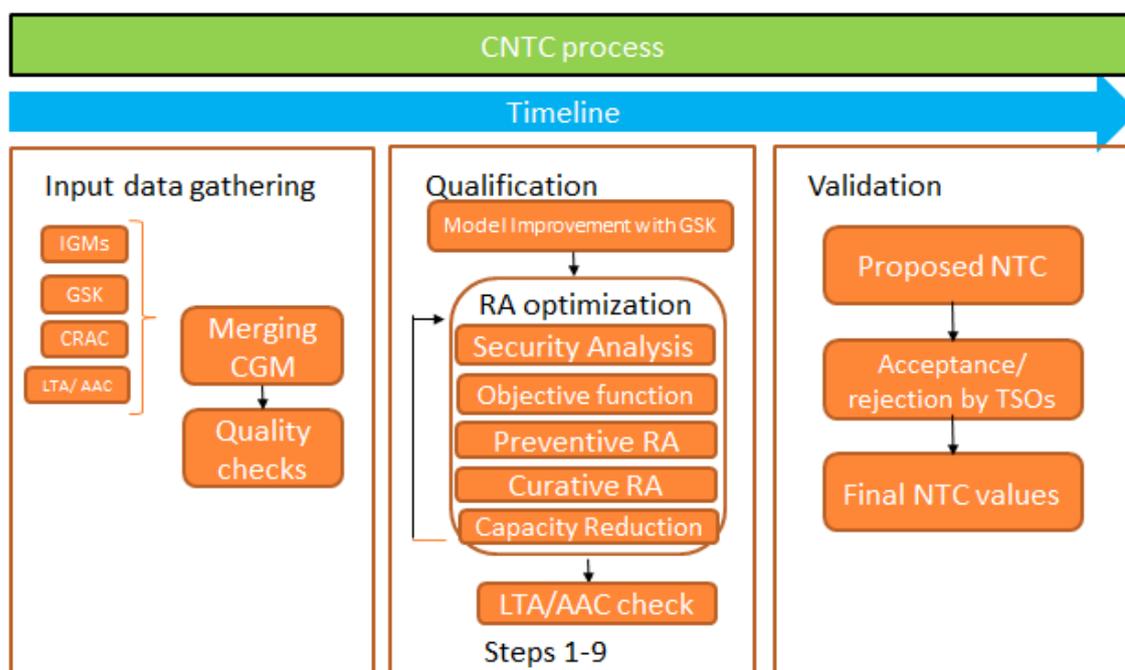


Figure 8. High level description of CNTC steps

Step 1. Select and load the representative CGM base case for each period

Step 2. Apply Generation Shift Keys to each base case in order to reflect each Interconnector operating at:

- a. Maximum import;
- b. Maximum export;
- c. Or alternative lower figures utilised in place of a or b above if an established longer term restriction is identified based on technical limitations or as the result of a contract or agreement).

Step 3. Run contingency analysis on the base case using the CNEC list provided by the TSOs

Step 4. Evaluate results to identify base cases

- a. that permit Interconnector capacity at maximum import/export without further consideration
- b. indicating a potential Interconnector import or export limitation as a result of a Critical Network Element violation or Operational Security Standard.

Step 5. For each relevant base case identified in Step 4 (b), deploy the list of remedial actions to alleviate the Critical Network Element.

Step 6. Evaluate the impact of remedial actions. If remedial actions can mitigate the CNE or Operational Security Standard violation, the Interconnector maximum import/export capacity can be made available for that base case.

Step 7. If the remedial actions provided cannot alleviate the CNE violation, the Interconnector import/export of the bidding zone where is/are located the limiting CNECs should be progressively reduced in steps from the maximum values or other starting points. In case several interconnectors are located in the concerned bidding zone, the reduction shall be applied only to the interconnectors which have an influence on the limiting CNE above the CNE selection thresholds and proportionally to their influence.

Following each import/export reduction, the contingency analysis should be repeated with the remedial actions already deployed until a level of Interconnector import/export has been identified for which no CNE violations occur. This establishes the Interconnector import/export limits for these base cases.

Step 8. Apply the result obtained for each base case to each hour of the period whose base case was representative.

Step 9. For each hour, take the maximum between the result of step 8 and the LTA for DA or AAC for ID.

Specificities of DA or ID time Horizon

In DA, in case step 7 leads to the need to reduce the capacity on interconnectors within a bidding zone, the TSO operating the bidding zone shall be contacted by the CCC to confirm the reduction.

Breakdown example

For each CNE / CNEC, the available margin for exchanges in the Channel CCR is resulting from the delta between:

- the maximum allowable flow (Fmax);
- the Flow Reliability Margin (FRM); and
- the forecasted initial flows computed in the best forecast CGM.

These forecasted initial flows reflect also the influence of other commercial exchanges of other CCRs outside the Channel CCR. These flows remains fixed during the Channel capacity calculation stage.

The available margin resulting is fully given to the Channel capacity calculation.

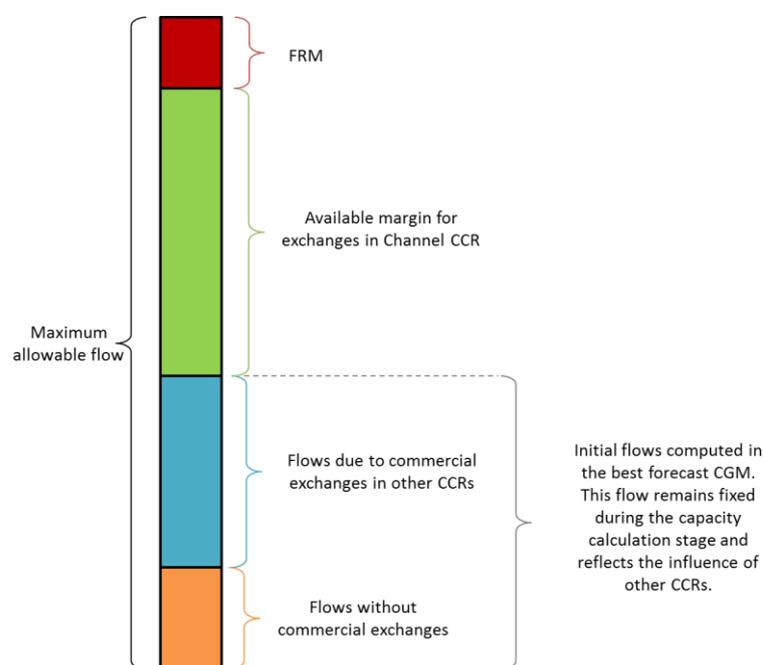


Figure 9. Breakdown example

2.4 Validation Phase

After the calculation, all TSOs have the responsibility to validate the capacities proposed by the CCC and may locally re-assess the computed NTCs and ATCs per bidding zone or interconnector. This re-assessment may be necessary to prevent a large risk on the Security of Supply, due to possible unforeseen changes in grid situations which has occurred during the qualification phase.

In the case of such unforeseen changes and if a TSO is detecting a constraint, he may reduce the proposed NTCs up to zero.

The reduction of the proposed capacities has to be monitored, based at minimum with an identification of the limiting CNEC and the explanation of the unforeseen event. The output of this process is the amended NTCs.

2.4.1 Day Ahead cross-zonal capacity validation

1. The coordinated capacity calculator shall provide the calculated cross zonal capacities (NTCs), including when applicable, the limiting CNECs and the RAs which have been applied, for the day ahead market to each TSO in the capacity calculation region for validation.
2. The coordinated capacity calculator shall provide cross-zonal capacities, following the mathematical description of the applied capacity calculation approach, for;
 - a) each individual interconnector, i.e. values for IFA, BritNed, Nemolink, etc.
 - b) each direction, i.e. import and export values,
 - c) each market time unitat an agreed reference point(s) for each Interconnector
3. The coordinated capacity calculator shall send the proposed cross-zonal capacities for the day ahead market by a deadline which TSOs and the coordinated capacity calculator have agreed upon.
4. Each TSO in the capacity calculation region shall send a reject or an accept response concerning the proposed cross-zonal capacities to the coordinated capacity calculator.
 - a. In case of rejection, the concerned TSO shall have to provide
 - i. for monitoring purpose, the explanation of the unforeseen event and and the limiting CNEC which justifies the reduction of the capacities
 - ii. the value of the NTCs which can be provided
5. If the coordinated capacity calculator receives accept responses from all TSOs in the capacity calculation region then the coordinated capacity calculator shall immediately issue a global acceptance message to each TSO in the capacity calculation region.
6. If the coordinated capacity calculator does not receive all accept responses by a deadline which TSOs and the coordinated capacity calculator have agreed upon, then the coordinated capacity calculator shall take this to indicate an deemed acceptance of the proposed cross-zonal capacities.
7. In the case of a rejection of the proposal the coordinated capacity calculator shall immediately issue for information a rejection message to each TSO in the capacity calculation region.

2.4.2 Intraday cross-zonal capacity validation – initial calculation and within day recalculation

1. The coordinated capacity calculator shall provide the calculated cross zonal capacities (NTCs and ATCs), including when applicable, the limiting CNECs and the RAs which have been applied for the intraday market to each TSO in the capacity calculation region for validation.
2. The coordinated capacity calculator shall provide cross-zonal capacities for;
 - a) each individual interconnector, i.e. values for IFA, BritNed, NemoLink, etc.
 - b) each direction, i.e. import and export values,
 - c) each market time unitat an agreed reference point(s) for each Interconnector
3. The coordinated capacity calculator shall send the proposed initial cross-zonal capacities for the intraday market by a deadline which TSOs and the coordinated capacity calculator have agreed upon.
4. Each TSO in the capacity calculation region shall send a reject or an accept response concerning the proposed cross-zonal capacities to the coordinated capacity calculator. In case of rejection, the concerned TSO shall have to provide
 - i. for the monitoring the explanation of the unforeseen and and the limiting CNEC which justifies the reduction of the capacities
 - ii. the value of the NTCs which can be provided
5. If the coordinated capacity calculator receives accept responses from all TSOs in the capacity calculation region then the coordinated capacity calculator shall immediately issue a global acceptance message to each TSO in the capacity calculation region.
6. If the coordinated capacity calculator does not receive all accept responses by a deadline which TSOs and the coordinated capacity calculator have agreed upon, then the coordinated capacity calculator shall take this to indicate a deemed acceptance of the proposed cross-zonal capacities.

7. In the case of a rejection of the proposal the coordinated capacity calculator shall immediately issue for information a rejection message to each TSO in the capacity calculation region.

2.5 Intraday reassessment frequency

The ideal solution shall consider:

1. At any point a TSO in the region should be able to make changes to:
 - a) Their individual grid model submission
 - b) Their list of contingencies, remedial actions, and additional constraints
2. Following a telephone call with the coordinated capacity calculator to determine the feasibility of a new calculation, a recalculation should be made following the methodology in section 2.3.6.
3. The validation for these updated cross zonal capacities should follow the same process in Section 2.4.

As a minimum target, we may consider to perform ID reassessment based on IDCs in line with the principles defined for pricing of intraday capacity in accordance with Article 55 of the CACM Regulation.

Due to time and tooling constraints, we propose as starting point that no recalculation on top of the one done based on the DA CGMs will be performed. No later than two years after the implementation of the Channel CC Methodology the Channel TSOs shall study the number of intraday capacity computations.

It has to be clarified that, only as an exceptional and in order to protect system security, TSOs will have the right to set the NTC in one or both directions equal to the value of the AAC at any time of the day, such that the ATC will equal zero. For avoidance of doubt, this may be the case where an interconnector asset becomes unavailable.

In the same spirit, if at any point the TSOs assets become unavailable, then the TSO should be able to immediately limit the NTCs/ATCs to respect this new limitation.

2.6 Allocation constraints

Besides the limitations on Critical Network Elements, other specific limitations may be necessary to guarantee a secure grid operation. In CACM GL the term "allocation constraints" is introduced, meaning constraints that need "to be respected during capacity allocation to maintain the transmission system within operational security limits and have not been translated into operational security limits of individual CNEs or into capacity limitation on an interconnector as described in chapter 2.2.5, or that are needed to increase the efficiency of capacity allocation".

In the case of HVDC interconnectors, on top of the external constraints described before, other constraints exist that are totally independent from the capacity calculation but need to be considered in the allocation phase.

According to their definitions, these constraints shall not directly impact the way the transfer capacities are computed, but, depending on the way they will be modelled in the allocation platform, they may limit or lead to an adjustment of the final values that will be made available to the market parties

These additional constraints may cover HVDC loss factor and ramping limitation, shall be communicated by TSOs to the NEMO(s) in charge of the allocation and shall be taken into account during the day-ahead and intraday market coupling.

2.7 Fallback procedure

If the coordinated capacity calculator is not available to perform the calculation, then capacities calculated from a previous calculation for the same business day and period will be used. If no such values exist, the MPTC of each interconnector shall be used.

The values still remain subject of the validation phase according to chapter 3.4.

If the TSO fails to receive NTC values from the coordinated capacity calculator, due a communication system failure or other unforeseen circumstance, the TSO will agree on an alternative way of communication.

3 Channel DA&ID Experimentation Results

3.1 Approach of the experimentation

TSOs in collaboration with CCCs performed a qualitative experimentation in order to assess the feasibility of the proposed capacity calculation process for the Channel Region. The experimentation process was simplified from the target process as all tools were not available for this phase. Therefore, TSOs provided input data on a few relevant scenarios and Coreso executed the capacity calculation process using existing tools in addition with manual actions.

The objectives of this experimentation were, among other things,

- To validate the capacity calculation methodology and the choice of the binary approach;
- To identify the gap before implementation phase and the IT requirements needed to support the capacity calculation process for this Capacity Calculation Region.

Three scenarios were tested

- Exceptional situations were chosen and specific grid adaptations to test the feasibility of the methodology;
- Scenarios are not representative for quantitative assessment of the process

3.2 Assessment results and learnings

The first experimentation has highlighted some lessons learned which should be taken into account for the next phases of the capacity calculation project:

- Importance of quality of input data: necessity of input data which are in line with the objective of the methodology;
- Minimum level of consistency for remedial actions used in different CCRs ensures Security of Supply;
- Outcome of the simulations is mainly driven by known operational challenges in the CWE FB CC process, rather than constraints coming from the Channel Region.

As conclusion, the experimentation has demonstrated the feasibility of the proposed capacity calculation methodology and has identified the main challenges for the implementation process, certainly concerning the application of this process to GB area due to lack of current experience in using CGMs for this area.

4 Criteria for an operational process

TSOs will assess the process against several criteria. The following list is not exhaustive and will evolve during the parallel run, in order to provide the best measure of the reliability and outputs of the process.

4.1 Criteria for the process operation

The first criterion is to have a reliable process that can produce results every day. The number of process fails will be monitored.

4.2 Criteria for the computed capacity

The second criteria will monitor the output of the process:

- The capacity computed with the new process will be compared to the results of the current coordinated bilateral process.

Annex 1

List of elements for which a planned or unplanned outage may trigger a detailed day-ahead capacity calculation

France:

- Mandarins-Warande n°1 400 kV
- Attaques-Warande n°1 400 kV
- Fruges-Mandarins n°1 400 kV
- Argoeuves-Fruges n°1 400 kV
- Argoeuves-Mandarins n°1 400 kV
- Chevalet-Warande n°1 400 kV
- Chevalet-Warande n°2 400 kV

Belgium:

- | | |
|-------------------------------|---------|
| • Avelgem - Mastaing | 380.79 |
| • Avelgem - Avelin | 380.80 |
| • Avelgem - Horta 1 | 380.101 |
| • Avelgem - Horta 2 | 380.102 |
| • Mercator - Horta 1 | 380.73 |
| • Mercator - Horta 2 | 380.74 |
| • Doel -Mercator 1 | 380.51 |
| • Doel -Mercator 2 | 380.52 |
| • Doel -Mercator 3 | 380.53 |
| • Doel -Mercator 4 | 380.54 |
| • Doel - Zandvliet 1 | 380.25 |
| • Doel - Zandvliet 2 | 380.26 |
| • Zandvliet - Borsele | 380.29 |
| • Zandvliet - Geertruidenberg | 380.30 |
| • Horta - Maerlandt 1 | 380.103 |
| • Horta - Maerlandt 2 | 380.104 |
| • Maerlandt - Gezelle 1 | 380.107 |
| • Maerlandt - Gezelle 2 | 380.108 |
| • Maerlandt - Gezelle 3 | 380.109 |
| • Maerlandt - Gezelle 4 | 380.110 |

Netherlands:

- Borssele - Geertruidenberg BSL-GT380Z
- Crayestein - Krimpen CST-KIJ380W
- Crayestein - Krimpen CST-KIJ380Z
- Diemen - Lelystad DIM-LLS380W
- Diemen - Lelystad DIM-LLS380Z
- Ens - Lelystad LLS-ENS380W
- Ens - Lelystad LLS-ENS380Z
- Krimpen - Geertruidenberg KIJ-GT380W
- Krimpen - Geertruidenberg KIJ-GT380Z
- Zandvliet - Borsele BSL-ZVL380 G

- Zandvliet - Geertruidenberg ZVL-GT380 W
- Van Eyck - Maasbracht MBT-VYK380 Z
- Van Eyck - Maasbracht MBT-VYK380 W

Great Britain:

- No critical outages