Explanatory document to the Day-Ahead Capacity Calculation Methodology of the Central Europe Capacity Calculation Region

in accordance with article 20ff. of the Commission Regulation (EU) 2015/1222 of 24th July 2015 establishing a guideline on capacity allocation and congestion management

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1. Introduction

The Commission Regulation (EU) 2015/1222 establishing a guideline on Capacity Calculation and Congestion Management ('CACM') requires the development and implementation of a common Day-Ahead Capacity Calculation Methodology ('DA CCM') per Capacity Calculation Region ('CCR').

The CACM Regulation aims at harmonizing capacity calculation of CCR, this includes the possibility to merge CCRs in case this is deemed most efficient. Therefore, on 19 March 2024 ACER approved the amendment on the determination of capacity calculation regions (Decision No 04/2024). This decision includes the merger of Core CCR and Italy North CCR, forming Central Europe CCR. For the time being only this day-ahead capacity calculation methodology will be implemented in Central Europe CCR.

In this explanatory document Central Europe TSOs aim at explaining the background to the articles and technical proposals resulting from the merger of Core & Italy North CCRs included in the proposal for the Central Europe DA CCM.

1. Methodology for operational security limits

Non-modelled tie-lines

This article includes a part aiming at explaining the technical solution adopted for the CE DA CC process regarding the existing tie - lines on borders between Italy and Austria and Italy and Switzerland, which are currently not modelled on both sides of the bidding-zone border and considered separately during capacity calculation.

During the merging phase, some differences in the modelling of some interconnections below the 220 kV level in Core and Italy North CCRs were identified. The CE TSOs decided to investigate if a feasible solution could be found for handling such interconnections in the CE DA CCM, because modelling of these tie-lines in IGM is not feasible for all TSOs till the implementation of CGMES.

In particular, the existing tie-lines currently not modelled in the common grid model are the following:

- Interconnection AT – IT 'Tarvisio – Greuth' 132 kV with a capacity up to 85 MW[1]
  [AT-IT] Tarvisio – Greuth, U = 132 kV
- Interconnection CH – IT 'Villa di Tirano – Campocologno' 132 kV with a capacity up to 40 MW
- Interconnection CH – IT 'Villa di Tirano – Campocologno' 150 kV with a capacity up to 150 MW.

Additional interconnections, expected to be in operation before the go-live of CGMES, might be considered, e.g. the future interconnection AT-IT 'Stainach – Prati di Vizze'

[1] The values provided for impacted capacities are determined in an annual process in the IN CCR and these are the values provided for 2025.

110 kV with a capacity up to 100 MW.

Seasonal limits

Article 6(3) in the Core DA CCM describes that Core TSOs shall aim at gradually phasing out the use of seasonal limits and replace them with dynamic limits when the benefits are greater than the costs.

The CE DA CCM does not include this point for the following reasons:

1. In the European perimeter, different methods, standards and developments are currently existing on the ways in which TSOs run the Dynamic rating (DTR). Therefore, as it is stated, the Art. 6.3 does not define a common approach (incl. common algorithm, common criteria, common methods) to be adopt by CE TSOs. As a consequence, the obligations and the analysis mentioned in the Art. 6.3 are not comparable and affordable in absence of a common approach among, at least, the CE TSOs to the DTR.
2. In this light, such kind of differences must be properly managed and harmonized before being comparable for a wider evaluation and analysis.
3 Many challenges will be faced for to the implementations of CE DA CC. Developments are expected in every part of the process (in particular for the inclusion of Swissgrid and Terna). The inclusion of this obligation adds further pressure to the developments.

2. Inclusion of Celtic Interconnector and SEM-FR Bidding Zone Border

The inclusion of the Celtic interconnector and the bidding zone border between SEM and France (SEM-FR) attributed to EirGrid and Réseau de Transport d'Electricité (RTE) is not covered in this iteration of the CE DA CCM as it will be first covered in Core CCR. The amendment to the Core CCR DA CCM for integrating the Celtic cable and the SEM-FR border will need to be incorporated into the CE DA CCM before CE Go Live.

3. Integration of HVDC interconnectors on CE bidding zone borders

This section aims to broaden the scope for the treatment of HVDC interconnectors in the CE CCR, taking into account all the peculiarities of existing HVDC interconnectors in the Region. Should the evolved flow-based (EFB) methodology continue to be the reference approach for treatment of HVDC interconnectors within the Region, the CE CCR decided to investigate if a feasible solution could fit with all operational use cases for HVDC interconnectors. This is due to the identification of some differences in the treatment of HVDC interconnectors in Core and Italy North CCRs during the merging phase.. In particular, the HVDC interconnectors in the IN CCR have been designed to be used as a remedial action in the Region to relieve congestion on cross border elements. Their setpoint range are considered as non-costly remedial actions applied in the NRAO process.

The solution found in the CE CCR proposes the following treatment of HVDC interconnectors during the Day-ahead capacity calculation process:

The DA CC process may permit to consider the HVDC Setpoint Range as a new non-costly remedial action, as reported in article 10.7 of the CE DA CCM.

In the allocation phase, EFB methodology will be the reference for treatment of HVDC interconnectors in the CE CCR.

- Among the expected benefits of the proposed solution are that it allows:To optimise and enlarge the FB domain around NPF in coordination with other remedial, like topological RA (opening/close busbar coupler) or PSTs in the NRAO process.
- To leave NRAO objective function unchanged.
- Each TSO to individually decide whether to include the HVDC setpoint range as an RA in the CC process.
- Possibility to use HVDC as a RA, when it is reflecting its real time operation.
- To keep EFB in the allocation phase

Circular flows around HVDC interconnectors

Disclaimer: *In general, CE TSOs do not see the usage of PTDF-threshold as an adequate way forward as it implies neglecting some physical effects in the grid. Therefore, the PTDF-threshold for the evolved flow-based internal Virtual Hubs shall only be applied if there is no adequate alternative solution ready to solve given issues of circular flows in the proximity of the evolved flow-based Virtual Hubs. The PTDF-threshold can be considered as an interim solution until an adequate alternative solution is in place. A PTDF threshold is not considered for any other use case.*

The evolved flow-based method described in Article 12 has been introduced with the commissioning of the ALEGrO HVDC link between Belgium and Germany and is applicable for any additional *evolved flow-based internal Virtual Hub* in CE CCR. The DA-schedules of HVDC interconnectors modelled with EFB are determined during DA market coupling with the aim of maximizing the overall social welfare. This can lead to very frequent undesired behaviour during real-time grid operation as the set point of HVDC interconnectors can be chosen to relieve very distant network elements with a very low sensitivity to exchanges over the HVDC interconnectors in order to maximize the social welfare during DA Market Coupling. This has been observed for the ALEGrO HVDC interconnector in the past. The slight relief of a very distant market limiting CNEC is achieved by an HVDC interconnector setpoint which leads to circular flows and full loading in the surrounding area of the HVDC interconnector. In real-time grid operation the high loading of the surrounding area might lead to n-1 violations, application of (costly) remedial actions and can impact intraday capacity in a negative way.

In order to prevent such a behaviour of existing and future HVDC interconnectors on CE CCR borders, CE TSOs aim to keep the possibility of applying a zone-to-zone PTDF threshold for Internal Virtual Hubs (IVH) in the context of the *evolved flow-based* method. In this regard, a past analysis performed for the ALEGrO HVDC interconnector showed that introducing a PTDF-threshold of 0.5% prevents this undesired impact.

Upon introducing a new Internal Virtual Hub, the PTDF threshold gets a start value of 0 which equates to no threshold being implemented. CE TSOs may alter the threshold when they deem it necessary or after running a parameter study with the objective of finding the best trade-off between maximizing operational security and maximizing economical social welfare. However, this threshold shall not exceed 1%. CE TSOs shall report on a quarterly basis on any change of the threshold.

At the moment, there is no coordinated process in place, which would allow a frequent deviation from the DA schedule of HVDC interconnectors. A PTDF threshold may be applied per HVDC interconnector during the transition period preceding the go-live of a coordinated process to determine the operational HVDC setpoint of the respective HVDC interconnector pursuant to Article 76(1) of the SO Regulation.

4. CH Integration

The introduction of new CE CCR shall lead to a change of the methodology for determining day-ahead capacities on all CH borders. In the absence of an electricity agreement between EU and CH, CH has no access to the single day-ahead electricity market in Europe. Consequently, CH borders shall not be part of the SDAC, and a specific step after the validation processes in the capacity calculation chain is required.

CE TSOs and Swissgrid have identified two fundamentally distinct approaches on how capacities for CH borders can be ultimately determined for an explicit day-ahead allocation. These two new options are being evaluated to balance operational security and cross-border capacity optimization. To reach this balance, the best forecast and relieving effect principles might no longer be considered.

Since the options have different consequences on the CH market design and operation, it is the TSOs aim to pre-emptively capture the market participants preferences.

Further details on the two options are given below.

Option 1: Extraction of NTCs for CH bidding zone borders

Section 1. Context

1. This approach consists in taking the validated full CE domain as basis and extracting an NTC domain for the CH borders out of it.
2. Parametrisation of the extraction process shall be tested and defined during implementation phase.

Section 2. How are the NTCs extracted from the FB domain?

1. As a result of FB CC, flow-based domains are determined for each MTU as an input for the FB MC process. The flow-based domains will serve as the basis for the determination of the Swiss border NTC values that are input to explicit day-ahead NTC allocation for CH borders.
2. As the selection of a set of NTCs from the flow-based domain leads to an infinite set of choices, the algorithm adopted for determining Shadow-Auction ATCs for the Core Day-Ahead process is selected as basis for the extraction. This algorithm shall determine NTC values in a systematic way. It is based on an iterative procedure starting from a pre-determined point.

Starting point: First, the remaining available margins (RAM) of the constraints (CNEs, CNECs and ECs) have to be adjusted to take into account the starting point of the iteration. From the zone-to-slack PTDFs (PTDFz2s), one computes zone-to-zone PTDFs (pPTDFz2z), where only the positive numbers are stored:

$$pPTDF_{z2z}(A > B) = max\big(0, PTDF_{z2s}(A) - PTDF_{z2s}(B)\big)$$

where A, B are two different bidding zones. Only zone-to-zone PTDFs of neighbouring market area pairs are needed (e.g. pPTDFz2z (CH > DE). The iterative procedure to determine the NTC starts from a pre-determined point. As such, the RAMs need to be adjusted in the following way:

$$\overrightarrow{RAM}_{NTC}(k = 0) = \overrightarrow{RAM}_{bn} - \mathbf{pPTDF}_{\boldsymbol{zone-to-zone}} * \text{Starting Point}$$

Iteration: the iterative method applied to compute the NTCs in short, comes down to the following actions for each iteration step i:

- For each CNE, CNEC and EC, share the remaining margin between the oriented bidding-zone borders that are positively influenced with a specific share.
- From those shares of margin, maximum bilateral exchanges are computed by dividing each share by the positive zone-to-zone PTDF.
- The bilateral exchanges are updated by adding the minimum values obtained over all CNEs, CNECs and ECs.
- Update the margins on the CNEs, CNECs and ECs using new bilateral exchanges from step 3 and go back to step 1.

These iterations continue until the maximum value over all constraints of the absolute difference between the margin of iterations i+1 and i is smaller than a stop criterion (1 kW).

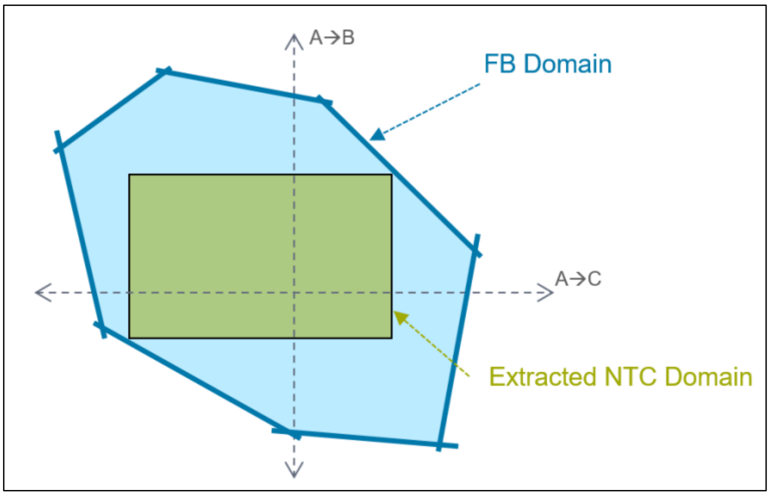
The resulting NTCs are the maximum bilateral exchanges between CH and CE bidding zone borders computed in iteration i+1 after rounding down to integer values. After algorithm execution, there are some CNEs, CNECs and ECs with no remaining available margin left. These are the limiting constraints of the NTC computation.

Note: CE TSOs are investigating alternative options to the algorithm described above , with the intent of improving the efficiency of the extraction procedure.

Option 2: Explicit day-ahead flow-based allocation on CH bidding zone borders

Section 1. Context

1. Another option for determining capacities on the CH border in an explicit manner, consists in submitting to the market allocation a zone-to-zone oriented FB domain (see graphical example of the comparison of domain resulting from both options below)



2. This approach was intended to be implemented in former CEE day-ahead CC, and constitutes the foundations for future allocation of long-term capacities in Core.
3. The flow-based domain for the explicit allocation on CH borders needs to be deducted from the CE domain, while in an NTC extraction approach only the NTCs needs to be deducted.

Section 2. Introduction to explicit Flow-Based allocation

1. Explicit flow-based allocation on the CH borders requires a change in the market design of the affected bidding zone borders.
2. In an explicit flow-based allocation regime, cross-border capacities compete for the flows on the most critical branches. The flow-based domain is constituted by a single set of PTDFs (zone-to-zone) and RAM per CNEC for each MTU.
3. In contrast to existing bilateral auctions, bids can be placed for each pair of zones for which the capacity is required. As a result, there will no longer be the need for separate market allocations per CH border, but instead, a single auction will take place

allocating all the capacity rights at once. Bids such as DE>IT could theoretically also be accommodated. This will result in some changes for Market Participants compared to today where single border auctions are run. Bidding and results will be treated per BZ border direction like today.

4. It continues to be an explicit mechanism for allocating physical transmission rights. Only after the auctioning of transmission capacity, the energy market opens, and the required quantities of energy can be bought and transmitted according to the awarded transmission rights.
5. During the auctioning process of a flow-based coordinated explicit auction, three steps can be defined:
    (1) TSOs inform JAO about physical network parameters (for PTDF calculation and border capacities). JAO then merges data and opens an auction.
    (2) Market participants place their bids for capacity between any of the participating countries.
    (3) JAO conducts the clearing and notifies Bidders and TSOs about the outcome.

Summary of differences between the two capacity/allocation methods

	NTC-based Allocation	**Explicit FB Allocation**
Capacity Calculation	NTCs for CH borders are extracted from the CE FB domain and published for the existing market allocation mechanisms. No visible changes to the market participants other than an expected increased volatility on the magnitude of capacities due to a daily computation.	There are no NTCs anymore. A sub-space from the calculated CE FB domain is reserved for allocation on CH borders, allowing to bypass the inefficiencies associated to an NTC extraction process. TSOs will provide FB domain (PTDFs and RAMs), which represents the available capacities to be allocated and offers a better representation of physical flows when compared with its NTC counterpart.¨ Market participants will need to interpret these new set of values ahead of placing their bids.
Market Allocation	Status-Quo: Independent allocations per CH border continue to exist as current practice.	CH market re-design: One single allocation mechanism comprised of different borders/directions, ensuring competition for cross-zonal capacities on all CH borders. Market participants can individually bid for any of the available borders/directions.

Questions to Market participants:

1. What allocation option would be preferrable?
2. If explicit Flow-Based allocation is preferred, what time for implementation do Market Participants need?
3. Is there an openness for a shift of current auction timings to enable a sequential market allocation between CH borders and CE FBMC? Leftovers from CH allocation could then be re-used for CE FBMC.
4. If it cannot yet be assessed which allocation option would be preferred, what additional information would MPs need to make this assessment?

5. Best forecast

The source of the “best forecast” is currently a model called NPF (Net Position Forecast). It is a machine learning based forecasting model that performs a forecast of commercial exchanges (currently Core net positions for Core hubs and bilateral exchanges on selected borders).

Its inputs are historic realised commercial schedules and meteorologically influenced data relevant for cross-border exchanges (forecast of wind power, solar power, load…)

The model is fitted using those inputs over a longer time period (typically the last 2 to 12 months of data), i.e. it “learns” from past situations.

The model then forecasts the commercial exchanges of the business day, using the latest available inputs (scheduled commercial exchanges of BD-1 ad meteorologically influenced data forecasts for the BD). It is furthermore constantly further developed.

6. Allocation constraints

The scope of this section refers to methodological aspects concerning the use of allocation constraints (AC) in the Day – Ahead calculation.

Considering TSOs part of the Central Europe CCR, PSE and Terna intend to use allocation constraints. The general provision for applying allocation constraints are listed in Article 11, while Annex I contains the list of Central Europe TSOs that will use allocation constraints together with detailed technical and legal reasoning for the need to use allocation constraints. Additionally, provisions were proposed indicating to CE TSOs the conditions that must be met for a given CE TSO to apply for the possibility of using allocation constraints in the future. It is proposed that a request to use allocation constraints by any CE TSO (other than those listed in Annex 1) should be preceded by the submission of a proposal for amendment of the methodology to all CE national regulatory authorities, along with the submission of an appropriate explanation of the need to use the AC.

Reasons why PSE intends to use allocation constraints

Disclaimer: *PSE confirms that allocation constraints is a critical means to ensure secure operation of the Polish power system. CE TSOs other than PSE are not able to validate the legitimacy of PSE's need for the allocation constraints.*

Operational experience gathered over the previous two years has proven that allocation constraints are an effective measure to maintain the transmission system within operational security limits and cannot be transferred efficiently into maximum flows on critical network elements, as prescribed by provisions of the CACM Art. 23(3). Allocation constraints allow to ensure availability of sufficient balancing capacity reserves in Poland, so that no case of insecure operation that could not have been resolved by operational means has been experienced in Poland.

The impact of allocation constraints was analysed and described in "Core DA CC 2022 report". The report shows that the largest social welfare impact concerns Poland (order of magnitude higher than for other Core countries), resulting in a loss of social welfare in Poland due to application of allocation constraints. However, as demonstrated in the report, this apparent loss of social welfare in Poland avoids much higher welfare losses when secure operation of the Polish power system is threatened and extraordinary measures must be applied to mitigate this threat (i.e. demand curtailment or RES curtailment). Due to the fact that no alternatives to using allocation constraints have been identified as plausible to be implemented until two years following implementation of flow-based in Core, which could both have lower overall cost while maintaining the similar level of operational security and which would not require a major overhaul of the market design, PSE aims at still using allocation constraints in the region Central CCR.

For PSE & Terna, the legal justification for use of Allocation Constraints are described in annex 1 of the CE DA CCM.

7. Implementation timeline

The implementation timeline provided in Article 30 is still under assessment by CE TSOs and under the precondition that the CE DA CCM is approved 6 months after the submission to CE NRAs.