Explanatory document to the third amendment of the Day-Ahead Capacity Calculation Methodology of the Core 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

08th December 2023

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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').

Based on Article 5 (5), Article 7 (4), Article 8 (7), Article 9 (6) and Article 20 (4) of the currently effective DA CCM for the CCR Core ('Core DA CCM'), the Core TSOs must no later than eighteen months after the implementation of this methodology and in accordance with Article 28 (3), develop a proposal detailing the methodology for coordinated validation, a list of internal network elements (combined with the relevant contingencies) to be defined as CNECs, further harmonisation of the generation shift key methodology, an approach and justification for selecting FRM, and an approach for using allocation constraints, and submit them by the same deadline to all Core regulatory authorities as a proposal for amendment of said methodology in accordance with Article 9 (13) of the CACM Regulation.

In this explanatory document Core TSOs explain the background to the changes included in the proposal for amendment of the Core DA CCM. A track-change version of the Core DA CCM reflecting the proposed changes is shared for informative purpose.

2. Flow Reliability Margin

The implementation of the detailed FRM determination shall be postponed. Core TSOs will prioritize the improvement of data input quality mainly the quality of the common grid model used for DA capacity calculation.

To harmonize the FRM approach, 10% of Fmax shall be used for all CNECs considered during the Core DA capacity calculation. 10% FRM approach shall also reflect hourly changing Fmax values due to e.g., dynamic line rating.

3. Coordinated validation

3.1. Introduction

Coordinated Validation (CV) and Individual Validation (IV) are two complementary steps that coexist in the DACC process. While the IV has been in place since go-live of Core DA CC, the CV shall be gradually introduced. With this proposal for amendment, the "full analysis" as described in Article 20(4) is specified.

The Coordinated Validation takes place with the aim to assess the security of the grid in a coordinated manner. If available remedial actions (RAs) are not sufficient to solve any detected operational security violations, a Coordinated Validation Adjustment (CVA) will be applied. Thanks to its coordinated nature, the cross-zonal benefit of RAs for ensuring cross-zonal capacity (CZC) can be considered in the CV step of the DA CC, in alignment with closer to real-time operational planning processes.

The IV is performed by each TSO based on the outcome of the CV. The IV allows considering local specifics such as additional input data or the assessment of potential market outcomes (so-called circumstances) that have not yet been analysed in the CV but are relevant from a local perspective. The IV also serves as a back-up that enables Core TSOs to validate cross-zonal capacities in case the CV yields no or insufficient results.

In the DA CCM, the IV is specified on a high level. This has given Core TSOs the necessary degrees of freedom to develop and implement IV methods suited to their local or regional needs, while being based on the harmonised principles set out in the DA CCM. For the to-be-implemented CV, the proposal for amendment takes a different approach by specifying CV in a greater level of detail than the IV. This is necessary because in CV, which implements a single method executed centrally by the CCC, the inputs from each TSO have an increased impact on the CZC and operational security through the Core CCR. A more detailed specification is also possible because when drafting the proposal for amendment, Core TSOs could build upon their acquired experience from the application and evolution of their IV methods.

Owing to the complexity of a process such as CV, it is neither recommended nor possible to specify in the proposal every input parameter and threshold level that will be used in the CV. Core TSOs will determine the concrete values of such parameters and thresholds by means of experimentation during the implementation phase such that unnecessary capacity reductions are avoided. Based on experience from the application of IV it is also foreseeable that inputs and parameters may have to undergo further adjustment after the initial implementation of the CV. This can become necessary due to the evolution of external factors such as penetration of renewable energy sources, evolution of EU and national rules impacting operational processes, or learnings from practical application of the CV. Core TSOs are deeply convinced that the objectives of Article 3 CACM can be met best by allowing for adaptability, accompanied by transparency. Core TSOs are committed to a transparent process of justifying and reporting on the choice of input and parameter settings, as set out in Article 20(4b).

3.2. Inputs

The scope of this section on inputs is limited to the **additional** process inputs required for the Coordinated Validation step. It is important to note that the section refrains from duplicating existing inputs already incorporated within the DA CC process, such as CGMs, intermediate flow-based domain or GLSKs and therefore also incorporates all initiatives started to improve the quality of those input files. First, each Core TSO can additionally provide a list of XNEs and scanned Elements (as defined in the ROSC methodology) that should be considered during the coordinated validation step. The consideration of XNEs and scanned elements implies that non-CNECs can be added in the coordinated validation process. It should be noted that the overall objective of coordinated validation can differ in function of the network elements that are considered: for CNECs and XNEs the aim is to solve any overloads to ensure operational security limits are not violated, while for scanned elements the aim is not to create or worsen an already existing overload throughout the process. For all network elements, Core TSOs can increase the maximum permissible power flow compared to the value in the CGM. This, as well as the scanned elements concept, does not mean that higher flow and overloading are deemed physically feasible. Rather, a nominal increase of flow limits for the simulations undertaken during Coordinated Validation can increase the overall consistency of the Coordinated Validation with closer to real-time processes and operational security standards, see also section 3.5.

Finally, each Core TSO shall prepare a list of remedial actions (RAs) which can be considered during the coordinated validation. In accordance with Article 20(3) of the DA CCM the provided list shall at least include all expected available RAs. This means the considered RAs are deemed available in subsequent operational planning processes, such as the ROSC process or real time grid operation. The provided RAs shall at least include the categories defined in accordance with Article 22 of the SO Regulation.

In general, cross border relevant RAs like cross border redispatch shall only be considered if operational processes (e.g., reliable cross-border redispatch contracts) are in place that allow for a reliable usage of such RAs before real time grid operation. Also, RAs from non-Core bidding zones can be considered, to the extent these are aligned with the connecting TSO(s).

The real availability of the RAs is partly of stochastic nature, while the RAO is a deterministic model. To not overestimate the available RAs, the probability of RAs being available under the modelling assumptions should be taken into consideration. For example, there is no knowledge about reservoir content of small-scale pumped-hydro storage power plants ahead of real time. Therefore, using such a power plant to the full extent in the remedial action optimisation could endanger operational security. Hence, only a share of their capacity may be considered for coordinated validation. This is one possible example, but other examples might exist as well. Furthermore, time-coupled restrictions are not modelled. To not overstate the real RD potential, the modelled RD potential needs to properly reflect the limitations that exist in system operation.

3.3. Selection of circumstances

During coordinated validation, only the intermediate FB-domain with D-2 reference program and bilateral exchange restrictions domain, but no market results, are available yet. TSOs and the CCC must make sure that market coupling does not lead to infeasible flows in the transmission grid. To deal with the uncertainty imposed by the possible range of market outcomes, the CCC chooses an appropriate set of circumstances according to Article 2 CCM. The choice of circumstances will enable the CCC to conclude that TSOs are able to securely operate the grid in all plausible market outcomes, or otherwise limit the domain by applying CVAs. Therefore, a choice of circumstances must cover a sufficiently large part of the domain within which market results can be realized. On the other hand, the analysed circumstances also must be as close to likely market results as possible in order to infer that market results can be secured. At the same time, the choice of circumstances must make sure that CVAs can be applied effectively in case operational constraints are not met in a particular circumstance (see section 2.3).

Given these trade-offs, the selection of circumstances is expected to be based at least on the following criteria:

1. Each circumstance shall be a plausible market outcome having regard to forecasted Core net positions
2. Each circumstance shall be technically plausible having regard to the power generation potential and load consumption potential per Core bidding zone
3. Each circumstance shall be extreme but feasible in terms of being on or close to the edge of the CZC domain

Regarding 1., the likelihood will be assessed on the basis of the forecasted Core net positions (Net Position Forecast; NPF) using distance measures developed in the course of method implementation. For example, the Euclidian distance to the NPF, the angle difference to NPF, or statistical assessment of historical market outcomes may be used to identify circumstances that cover the range of likely market results sufficiently.

For a number of reasons, it is useful to analyse several circumstances.[1] These include, but are not limited to:

- NPF error;
- Setpoints of controllable network elements such as the ALEGrO DC link.

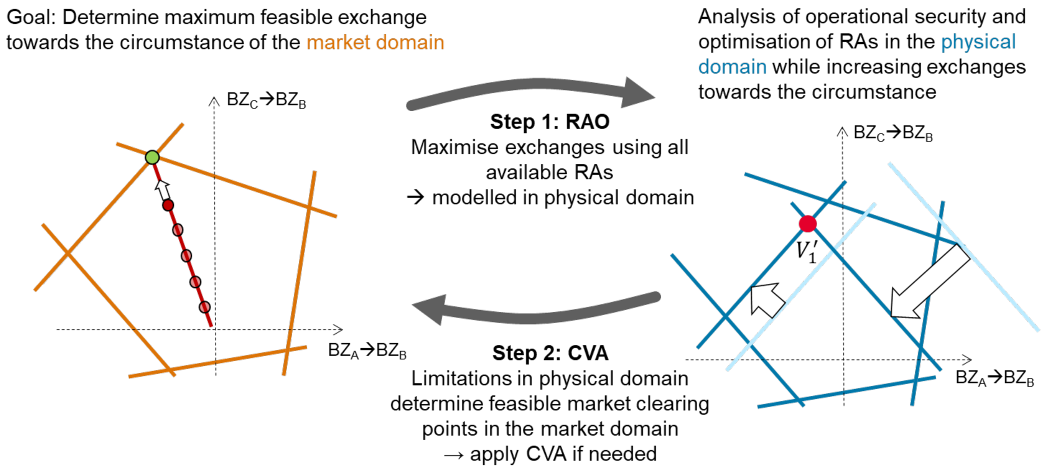
Regarding 2., the technical plausibility of circumstances is ensured by limiting generation shift in such a way that generator limits are respected. In order to prevent generator overload when moving from zero balance towards the circumstance, redispatching of power plants may be used.

Regarding 3., the extremeness of circumstances may be ensured by orienting the choice of circumstances towards the vertices of the CZC domain. However, in order to meet the other two criteria, vertices may be insufficient, and circumstances lying on the linear trajectory between vertex and zero balance might be chosen. Additionally, during the implementation phase, other methods may be evaluated.

3.4. Analysis of circumstances

When shifting the Core NPs towards the circumstance, generator limits need to be respected. Thereto, redispatching of generation units within the same bidding zone may be necessary to reach the desired circumstance. In essence, this means that the GLSK used to shift the net position towards the circumstance needs to reflect the physical realities and therefore may differ from the GLSK used to compute the flow-based domain (‘the market domain’) during capacity calculation. As a consequence of any change in the GLSK, the PTDFs in a quasi-nodal representation (‘the physical domain’) may differ from those from the CZC domain (‘the market domain’).

[1] Note that if the market outcome was predictable enough to make it sufficient to analyse a single circumstance, no flow-based domain (offering different “market directions”) would be needed in the first place.



A power flow and contingency analysis of the grid is necessary to check the loading of the elements in the base case and all relevant contingencies. However, the lists of XNEs, as described in chapter 3.2, may be adapted to exclude specific elements from further analysis.

The TSOs may define the list of scanned elements. The scanned elements shall be network elements (any possible element that is excluded from the CNEC list and is included in CGM), which shall be monitored during the CV process and limit the additional (over)loading stemming from application of the remedial actions. The level of the additional loading shall be defined by threshold based on experimentation.

3.5. Remedial action optimisation

This section refers to Art. 20(4e)f of the amended DA CCM.

The remedial action optimisation (RAO) is executed subsequently for each considered circumstance. It serves to check if in the event the market outcome is equal to the considered circumstance, Core TSOs and optionally technical counterparties can facilitate cross-zonal exchange leading to these net positions by applying RAs in a coordinated manner to maintain operational security. In case this is not possible for a given circumstance, the CZC domain must be restricted to limit the set of realisable net positions. The objective of the RAO is to compute the least required reduction of the domain. This is achieved by determining a set of net positions as close as possible to the circumstance, using all available RAs, such that operational security is maintained. If the circumstance can be facilitated without operational security violations, the domain is not reduced.

The RAO simulates the impact of shifts in net positions in accordance with section 3.4. In addition, it models the impact of RAs on the flows on all considered network elements with contingencies. This allows to optimise the net positions (to make them as similar as possible, if not equal, to the circumstance) while selecting the most suitable set of RAs among the available RAs.

The choice of RAs for the RAO shall be consistent with what TSOs have at hand in close-to-real-time congestion management planning processes. This comprises in particular

ROSC, but also other processes that are in place on a local or subregional level. In other words, the RAO of the coordinated validation mimics the processes used to identify the RAs that will be actually activated, to anticipate the beneficial effect that these processes (and thus the activated RAs) would have in the simulated situations.

One the one hand, the coordinated validation would overestimate the need for capacity reduction via CVA if it failed to consider the aforementioned benefits. On the other hand, it would underestimate the need for CVA if it assumed a higher degree of coordination than the one applied in practice. This has two implications. Firstly, the inputs and parameters will, therefore, evolve over time along with the evolution of the congestion management planning processes, in particular ROSC. Secondly, while for complexity and performance reasons it will not be possible to explicitly model every local process, it is important to at least implicitly consider their benefits. To achieve this, the TSOs shall have the possibility to adjust their inputs. For example, by ignoring branches or allowing a certain degree of overload on some branches, TSOs can implicitly reflect the benefit of their local procedures even if these are not explicitly modelled in the RAO.

The so-called sharing rules constitute another aspect by which TSOs can reflect their operational planning principles and/or the degree of cross-zonal coordination closer to real-time. When an RA of a given TSO is shared with other TSOs, this means that the benefit of the RA on the loading of the other TSOs' network elements is taken into account. While the physical effect of an RA always "happens" and by principle can never be ignored, sharing denotes if other TSOs are aware and rely on the activation of the RA from another TSO. An example of a lack of awareness is a local process, where a TSO applies an RA for the sake of its own grid while neighbouring TSOs are not involved (and thus not aware). An example of non-reliance on foreign RAs is when a TSO applies curative RAs, which are activated only after occurrence of a contingency, while its neighbouring TSO follows an operating principle by which RAs must be activated pre-fault (i.e., preventive RAs only). The RAO shall be able to model preventive and curative RAs including full or partial sharing of the latter, to cover the range of actual operating regimes.

The RAO implements a model of the real power system, which is by principle an abstraction from reality and, as every model, subject to imperfections. To reach the objective of maintaining operational security while avoiding CZC domain reduction as much as possible, the RAO will allow the setting of parameters that on the one hand help avoiding unnecessary reductions due to model restrictions and on the other hand help avoiding "too perfect" results that cannot be implemented in practice.

For example, an increase of net positions might have a very low but positive impact on the loading of a network element, which might lead to unreasonably large reduction of CZC for a small reduction of the loading. Such effect might be overcome by ignoring very low impacts (so-called sensitivities), especially when these are deemed to be insignificant with regards to the model and computation accuracy. Also, the selection of network elements, their possible designation as scanned elements and the possible adaptation of their maximum loading for the RAO (see sections 3.2 and 3.4) are means to bridge the gap between the imperfect RAO model and operational reality.

The RA potential is not only defined by the individual RAs, but might also be subject to practical limitations of the local operational processes, e.g., the number of RAs that can be activated in a constrained period of time close to real-time. For example, there may be 100 topological RAs and 100 redispatch resources available. However, "available" then only means that *any* of these can be activated, but not *all* of them at once. If the RAO was allowed to treat all RAs independently, the availability of RAs as a whole would be overstated. To avoid this, the optimisation can be constrained by imposing limits on the number of simultaneously activated RAs or on the total amount of redispatch. Such limitations could be differentiated per RA type, per bidding zone, per TSO, etc., in order to reflect the practical limitations that the TSOs are facing.

The objective of the RAO has been set out at the beginning of this section. This must be distinguished from the so-called objective function, which is the mathematical formula whose value shall be formally maximised or minimised by the RAO. In order to be able to determine if the circumstance can be realised while maintaining operational security and, if it cannot be entirely realised, determine a realisable set of net positions as close as possible to the circumstance, it is not sufficient to strictly model the cross-zonal exchanges of the circumstance and at the same time strictly require the fulfilment of operational security requirements. Namely, this could lead to infeasibility, i.e., yield a too simple yes/no result. A common way to overcome this is the introduction of so-called soft constraints, which are mathematically formulated as components of the objective function. Therefore, the objective function may be specified to minimize the extent of operational security violations and/or to maximize the extent to which the cross-zonal exchanges match the circumstance. With this approach one avoids a need for iterative "probing" of net positions at or close to the circumstance, since the optimisation yields the realisable net positions closest to the circumstance in a single run.

If a circumstance cannot be realised, CVA is needed. CVA is determined in a separate step after the RAO. This is because the RAO is performed in the realm of the physical domain. Overloads on network elements (in particular, on CNECs) in the physical domain are not equal to the required reduction of RAM in the market domain. The link between the two domains is achieved via the net positions: Those net positions that are feasible (as close as possible to the analysed circumstance) can be mapped as a potential market clearing point in the market domain (i.e., the CZC domain). The area "beyond" this point cannot be safely provided to the SDAC and must thus be eliminated from the domain. This can be achieved by imposing CVA on a suitable subset of CNECs. When doing so, a minimum capacity floor is always maintained, i.e., if CVA would push RAM below this floor, CVA is capped.

It might happen that a TSO, when checking the Coordinated Validation results, finds out that all or part of the results are of bad quality. For instance, bad input quality might have led to overestimation of CVA. Therefore, a TSO may reject parts or all of the Coordinated

Validation results, however with clear rules and limitations. The TSO must present a justification for the rejection. It must align with the other TSOs and the CCC, and an attempt must be made to resolve the reason for the rejection. In any case, only the entire results of a circumstance (or of several circumstances) can be rejected. It is not allowed to reject a subset of CVA for a given circumstance, because all CVAs together protect the grid from operational security violations in that circumstance.

3.6. Dissemination of results

In the context of the validation processes (individual and coordinated), it is essential to execute individual validation subsequent to the coordinated validation process. This sequence ensures that the results of individual validation and coordinated validation remain distinct and coherent, without overlapping and/or contradicting each other. When coordinated validation identifies any remaining overload, for example when a coordinated validation adjustment is capped, it is crucial that this is known when individual validation starts. This ensures that individual validation can assess whether local measures should be taken into account, or if additional adjustments through the individual validation step are required.

Also, for efficiency purposes, coherence and well aligned processes are essential, to avoid any duplicate or obsolete checks.

Furthermore, it is important to continuously improve the efficiency of the validation process and its tools. Therefore, a feedback loop will be put in place to monitor and analyse the outcomes of coordinated validation by Core TSOs and/or the CCC. This includes a thorough examination of whether non-CNECs cause a coordinated validation adjustment.

Finally, when it comes to reporting, Core TSOs and the CCC shall provide transparent reporting to stakeholders, according Article 27. In this reporting, each CVA application will be published together with its relevant CNEC, the value of the CVA, the circumstance that led to the CVA application and the justification for the CVA application.

4. Allocation constraints

4.1. General changes in CCM

The scope of this section refers to a change in methodology for allocation constraints. Based on the information that ELIA and TTN will not utilize external constraints, they will be excluded from the CCM regarding both Article 7 and Annex 1.

On the other hand, PSE intends to continue using allocation constraints. Due to this fact and in order to make the provisions of Article 7 more general, the list of Core TSOs that can use allocation constraints has been removed and this list has been moved to Annex 1 which contains detailed technical and legal justification for the need to continue using allocation constraints. It is hence proposed to extend the transitional period for another two years. Moreover, minor changes in the detailed methodology for calculating the values for allocation constrains in a given MTU have been also introduced in Annex 1.

Additionally, provisions were proposed indicating to Core TSOs the conditions that must be met in order for a given Core TSO to apply for the possibility of using allocation constraints. It is proposed that a request to use allocation constraints by any Core TSO (other than those listed in Annex 1) should be preceded by the submission of a proposal for amendment of the methodology to all Core national regulatory authorities, along with the submission of an appropriate explanation of the need to use the AC and the frequency of its calculation.

4.2. Reasons why PSE intends to continue using allocation constraints

Disclaimer: *PSE maintains that allocation constraints is a critical means to ensure secure operation of the Polish power system. Core 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.

Considering the fact, that Poland operates under Central Dispatch regime, the approach to ensure availability of generation reserves applied in Poland differs from the approach applied in other Core countries. Given current legal framework in Poland, PSE as a TSO is responsible for dispatching generation units connected to the transmission grid. When doing so, PSE is obliged to respect power system operation conditions, as well as the technical characteristics of generation units both on the level of individual generation units and on the level of power plants. Moreover, there is no explicit balancing capacity reserves procurement process in Poland, and hence the only means of ensuring sufficient reserves capacity is to use allocation constraints.

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 extending the period of using AC by additional two years.

Currently, balancing market in Poland is undergoing a significant redesign, aiming at strengthening balancing energy price signals and creating stronger incentives for balanced positions of balancing responsible parties. In combination with the planned market-based process for procuring balancing capacity reserves, this should improve the ability of Polish transmission system operator to manage the secure operation of the Polish power system and limit the need for allocation constraints of cross-border market coupling process.

PSE expects that these new Terms and Conditions for Balancing will be implemented mid 2024. NRA approval for the proposed Terms and Conditions for Balancing is expected to take place in Q3/Q4 2023, giving market participants and PSE the required time to introduce and test all needed changes in the IT systems. However, this is a very significant change for the whole Polish market and such reform must be well prepared and tested against security requirements. The steps undergone on legal side to pave the way for this are as follows (among other):

- Decree of the Ministry for Climate and Environment on the detailed conditions for power system operation has been adopted on 28 April 2023, after having been notified with the European Commission. This is the most significant reform of this comprehensive legal act since 2007 (https://www.gov.pl/web/klimat/rozporzadzenie-ministra-klimatu-i-srodowiska-ws-szczegolowych-warunkow-funkcjonowania-systemu-elektroenergetycznego-opublikowane).

- Based on the abovementioned updated legal act, PSE has launched public consultation of the new updated Terms and Conditions for Balancing ("Warunki Dotyczące Bilansowania" – WDB), stemming from EBGL. Consultation run from 22 February till 5 May 2023. On 30 June 2023, PSE provided a finalized proposal for updated Terms and Conditions for Balancing after public consultation. The process for approval of this document by Polish NRA is currently undergoing and its result is expected soon.

- Update of the Polish Grid Code, adjusting its text to the adopted Decree of the Ministry for Climate and Environment on the detailed conditions for power system operation as well as to the proposed Terms and Conditions for Balancing, has been already sent to Polish NRA for approval and it is planned to be introduced in force together with the new updated Terms and Conditions for Balancing.

Finally, it is very important to highlight, that after successful completion of the changes in the Polish balancing market, real-live operational experience from this market redesign must be collected. It is therefore impossible for PSE to make any firm commitment with respect to the future application of allocation constraints. PSE is unable to give up the only tool that is able to ensure secure operation of the Polish power system without having a proven and reliable alternative. Hence the period of 2 years is indeed necessary.

Technical and legal justification

Implementation of external constraints as applied by PSE is related to Integrated Scheduling Process ISP applied in Poland (also called central dispatching model) and the way how reserve capacity is being ensured by PSE. Within the current legal framework in Poland, there is no explicit balancing capacity reserves procurement process – which makes for a significant difference between Poland and other Core CCR countries with respect to the approach to ensure availability of generation reserves. Therefore, for Poland, the only means of ensuring sufficient generation reserves is to use allocation constraints and thus set a limit to how much electricity can be imported or exported in the SDAC. Capacity allocation constraints are a legally prescribed means, defined by CACM Regulation (Art. 23(3) and art. 21(1)(a)(ii) CACM).

In a central dispatching model, in order to balance generation and demand and ensure secure energy delivery, the TSO dispatches generating units taking into account their operational constraints, transmission constraints and reserve capacity requirements. This is realised in an integrated scheduling process as a single optimisation problem called security constrained unit commitment (SCUC) and economic dispatch (SCED).

Integrated Scheduling Process starts after the day-ahead capacity calculation and SDAC and continues until real-time. This means that reserve capacity is not blocked by TSO in advance of SDAC and in effect not removed from the wholesale market and SDAC. However, if balancing service providers (generating units) would already sell too much energy in the day-ahead market because of high exports, they may not be able to provide sufficient upward or downward reserve capacity within the integrated scheduling process.[2]

Within aforementioned integrated scheduling process, generation units connected to the transmission grid are dispatched by PSE with the aim to respect power purchase agreement concluded between the market participants on the wholesale market, while minimizing overall costs of energy supply. When doing so, PSE is obliged to respect power system operation conditions, as well as the technical characteristics of generation units both on the level of individual generation units and on the level of power plants.

Allocation constraints serve thus as a means to limit balancing service providers to sell too much energy in the day-ahead market, so that to ensure and enforce that they will be able to provide sufficient reserve capacity in the integrated scheduling process that is run after the day-ahead market. This limitation cannot be efficiently expressed by translating it into transfer capacities of critical network elements offered to the market. If this limit was to be reflected in cross-zonal capacities offered by PSE in the form of an appropriate adjustment of cross-zonal capacities, this would imply that PSE would need to guess the most likely market direction (imports and/or exports on particular interconnectors) and accordingly reduce the cross-zonal capacities in these directions. In the flow-based approach, this would need to be done on each CNEC in a form of reductions of the RAM. However, from the point of view of market participants, due to the inherent uncertainties of market results, such an approach is burdened with the risk of suboptimal splitting of allocation constraints onto individual interconnections – overestimated on one interconnection and underestimated on the other, or vice versa. Also, such reductions of

[2] This conclusion equally applies for the case of lack of downward balancing capacity, which would be endangered if balancing service providers (generating units) sell too little energy in the day-ahead market, because of too high imports.

the RAM would limit cross-zonal exchanges for all bidding zone borders having impact on Polish CNECs (i.e. transit flows), whereas the allocation constraint has an impact only on the import or export of the Polish bidding zone, whereas the trading of other bidding zones is unaffected.

Allocation constrains are applied in DA allocation process, with values determined in D-1, per each hour individually based on generation adequacy analysis for this hour. They are determined for the whole Polish power system, meaning that they are applicable simultaneously for all CCRs in which PSE has at least one bidding zone border (i.e., Core, Baltic and Hansa). This solution is the most efficient application of external constraints. Considering allocation constraints separately in each CCR would require PSE to split global external constraints into CCR-related sub-values, which would be less efficient than maintaining the global value. Moreover, in the hours when Poland is unable to absorb any more power from outside due to violated minimal downward reserve capacity requirements, or when Poland is unable to export any more power due to insufficient upward reserve capacity requirements, Polish transmission infrastructure is still available for cross-border trading between other bidding zones and between different CCRs.

Methodology to calculate the value of external constraints

When determining the external constraints, PSE takes into account the most recent information on the technical characteristics of generation units, forecasted power system load as well as minimum reserve margins required in the whole Polish power system to ensure secure operation and forward import/export contracts that need to be respected from previous capacity allocation time frames.

External constraints are bidirectional, with independent values for each DA CC MTU, and separately for directions of import to Poland and export from Poland.

For each hour, the constraints are calculated according to the below equations:

$$EXPORT_{constraint} = P_{CD} - (P_{NA} + P_{ER}) + P_{NCD} - (P_L + P_{UPres}) \quad (1)$$

$$IMPORT_{constraint} = P_L - P_{DOWNres} - P_{CD_{min}} - P_{NCD} \quad (2)$$

Where:

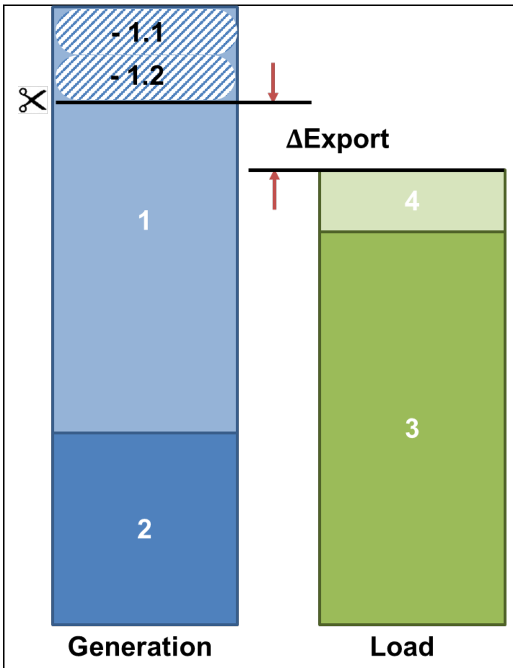
P_{CD}	Sum of available generating capacities of centrally dispatched units as declared by generators[3]
$P_{CD_{min}}$	Sum of technical minima of available centrally dispatched generating units

[3] Note that generating units which are kept out of the market on the basis of strategic reserve contracts with the TSO are not taken into account in this calculation.

P_{NCD}	Sum of schedules of generating units that are not centrally dispatched, as provided by generators (for weather-dependent intermittent renewable generation: forecasted by PSE)
P_{NA}	Generation not available due to grid constraints (both planned outage and/or anticipated congestions)
P_{ER}	Generation unavailability's adjustment resulting from issues not declared by generators, forecasted by PSE due to exceptional circumstances (e.g., cooling conditions or prolonged overhauls)
P_L	Demand forecasted by PSE
P_{UPres}	Minimum reserve for upward regulation
$P_{DOWNres}$	Minimum reserve for downward regulation

For illustrative purposes, the process of practical determination of external constraints in the framework of the day-ahead capacity calculation is illustrated below in Figures 1 and 2. The figures illustrate how a forecast of the Polish power balance for each hour of the delivery day is developed by PSE in the morning of D-1 in order to determine reserves in generating capacities available for potential exports and imports, respectively, for the day-ahead market.

External constraint in export direction is applicable if ΔExport is lower than the sum of cross-zonal capacities on all Polish interconnections in export direction. External constraint in import direction is applicable if ΔImport is lower than the sum of cross-zonal capacities on all Polish interconnections in import direction.



1. Sum of available generating capacities of centrally dispatched units as declared by generators, reduced by:
   1.1 Generation not available due to grid constraints
   1.2 Generation unavailability's adjustment resulting from issues not declared by generators, forecasted by PSE due to exceptional circumstances (e.g., cooling conditions or prolonged overhauls)
2. Sum of schedules of generating units that are not centrally dispatched, as provided by generators (for weather-dependent intermittent renewable generation: forecasted by PSE)

	3. Demand forecasted by PSE 4. Minimum necessary reserve for up regulation

Figure 1: Determination of external constraints in export direction (generating capacities available for potential exports) in the framework of the day-ahead capacity calculation.

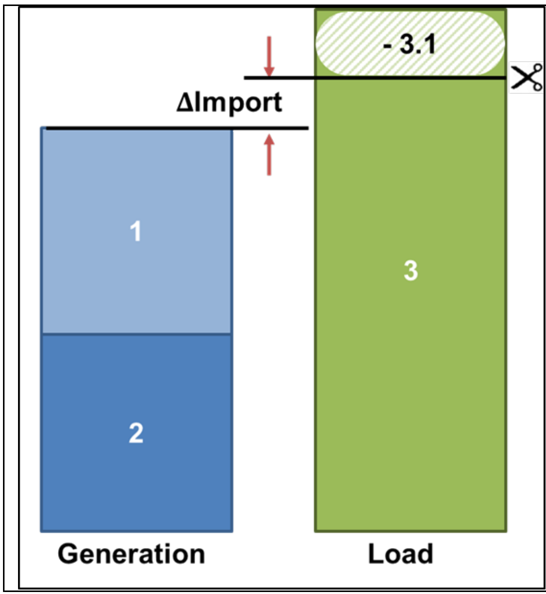
	1 Sum of technical minima of centrally dispatched generating units in operation 2 Sum of schedules of generating units that are not centrally dispatched, as provided by generators (for weather-dependent intermittent renewable generation: forecasted by PSE) 3 Demand forecasted by PSE, reduced by: 3.1 Minimum necessary reserve for down regulation

Figure 2: Determination of external constraints in import direction (reserves in generating capacities available for potential imports) in the framework of the day-ahead capacity calculation.

Frequency of re-assessment

External constraints are determined in a continuous process based on the most recent information, for each capacity allocation time frame, from forward till day-ahead and intra-day. In case of day-ahead process, these are calculated in the morning of D-1, resulting in independent values for each DA CC MTU, and separately for directions of import to Poland and export from Poland.

Time periods for which external constraints are applied

As described above, external constraints are determined in a continuous process for each capacity allocation timeframe, so they are applicable for all DA CC MTUs of the respective allocation day.

5. Circular flows around HVDC interconnectors

Disclaimer: *This is a preliminary status until further assessment has been completed. It is being investigated whether the problem can be solved by appropriate parameterization within the market coupling algorithm. If this is the case, the PTDF threshold for virtual hubs will be removed from Article 12 before submitting the RfA.*

The evolved flow-based method described in Article 12 has been introduced with the commissioning of the ALEGrO HVDC link between Belgium and Germany. The DA-schedule of the ALEGrO HVDC is determined during DA market coupling with the aim of maximizing the overall social welfare. This leads to very frequent undesired behaviour during real-time grid operation as the ALEGrO setpoint is chosen to relieve very distant network elements with a very low sensitivity to ALEGrO exchanges in order to maximize the social welfare during DA Market Coupling. The slight relief of a very distant market limiting CNEC is achieved by ALEGrO setpoint which lead to circular flows and full loading in the surrounding area of ALEGrO 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 Core bidding zone borders, Core TSOs aim to introduce a zone-to-zone PTDF threshold for virtual hubs in the context of the Evolved flow-based method. Analysis showed that introducing an ALEGrO PTDF-threshold of 0.5% prevent this undesired impact.

After approval of the RfA the PTDF threshold will get a start value of 0 which equates no threshold being implemented. Core TSOs may alter the threshold if 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, the threshold shall not exceed 1%. Core TSOs shall report on a quarterly basis on any change of the threshold.

The quarterly report shall also include the economic social welfare deviation which was provoked by the above-described threshold.

A change of the ALEGrO setpoint after DA Market Coupling requires coordination between all affected TSOs namely TenneT NL, RTE, Elia and Amprion as the change of the setpoint impacts the loading in the surrounding AC grid. At the moment there is no coordinated process in place which would allow a frequent deviation from ALEGrO DA schedule. When Core CCR ROSC process will be in operation, a coordinated process between all affected TSOs will exist, and consequently the ALEGrO PTDF-threshold for virtual hubs is no longer required and will be removed.