Annex 1
Justification of Usage and Methodology for Calculation of Allocation Constraints in PSE as Described in Article 8(3)

Allocation constraints in Poland are applied as stipulated in Article 8(3) of the CCM. These constraints reflect the ability of Polish generators to increase generation (potential constraints in export direction) or decrease generation (potential constraints in import direction) subject to technical characteristics of individual generating units as well as the necessity to maintain minimum generation reserves required in the whole Polish power system to ensure secure operation. This is explained further in subsequent parts of this Annex.

Rationale behind implementation of allocation constraints on PSE side

Implementation of allocation constraints as applied by PSE side is related to the fact that under the conditions of the integrated scheduling based market model applied in Poland (also called central dispatch system) the responsibility of the Polish TSO on system balance is significantly extended comparing to such standard responsibility of TSOs in so-called self-dispatch market models. The latter is usually defined up to hour-ahead time frame (including real time operations), while for PSE as Polish TSO this is extended to short (intraday and day-ahead). Thus, PSE bears the responsibility, which in self-dispatch markets is allocated to balance responsible parties (BRPs). That is why PSE needs to take care of back up generating reserves for the whole Polish power system, which leads to implementation of allocation constraints if this is necessary to ensure operational security of Polish power system in terms of available generating capacities for upward or downward regulation capacity and residual demand[1]. In self-dispatch markets BRPs are themselves supposed to take care about their generating reserves and load following, while TSO ensures them just for dealing with contingencies in the time frame of up to one hour ahead. In a central dispatch market, in order to provide generation and demand balance, the TSO dispatches generating units taking into account their operational constraints, transmission constraints and reserve requirements. This is realized in an integrated scheduling process as an optimization problem called security constrained unit commitment (SCUC) and security constrained economic dispatch (SCED). Thus these two approaches (i.e. self and central dispatch market) ensure similar level of feasibility of transfer capacities offered to the market from the generating capacities point of view.

It was noted above that systemic interpretation of all network codes is necessary to ensure their coherent application. In SO Regulation, the definitions of specific system states involve a role of significant grid users (generating modules and demand facilities). To be in the 'normal' state, a transmission system requires sufficient active and reactive power reserves to make up for occurring contingencies (Article 18) – the possible influence of such issues on cross-zonal trade has been mentioned above. Operational security limits as understood by SO Regulation are also not defined as a closed set, as Article 25 requires each TSO to specify the operational security limits for each element of its transmission system, taking into account at least the following physical characteristics (…). The CACM Regulation definition of contingency (identified and possible or already occurred fault of an element, including not only the transmission system elements, but also significant grid users and distribution network elements if relevant for the transmission system operational security) is therefore consistent with the abovementioned SO Regulation framework, and shows that CACM Regulation application should involve circumstances related to generation and load.

As regards the way PSE procures balancing reserves, it should be noted that the EB Regulation allows TSOs to apply integrated scheduling process in which energy and reserves are procured simultaneously (inherent feature of central dispatch systems). In such a case, ensuring sufficient reserves requires setting a limit to how much electricity can be imported or exported by the system as a whole (explained in more detail below). If CACM Regulation is interpreted as excluding such a solution and mandating that a TSO offers capacity even if it may lead to insufficient reserves, this would make the provisions of EB Regulation void, and make it impossible or at least much more difficult to comply with SO Regulation.

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1 Residual demand is the part of end users' demand not covered by commercial contracts (generation self-schedules).

Specification of security limits violated if the allocation constraint is not applied

With regard to constraints used to ensure sufficient operational reserves, if one of interconnected systems suffers from insufficient reserves in case of unexpected outages or unplanned load change (applies to central dispatch systems), there may be a sustained deviation from scheduled exchanges of the TSOs in question. These deviations may lead to an imbalance in the whole synchronous area, causing the system frequency to depart from its nominal level. Even if frequency limits are not violated, as a result, deviation activates frequency containment reserves, which will thus not be available for other contingencies, if required as designed. If another contingency materializes, the frequency may in consequence easily go beyond its secure limits with all related negative consequences. This is why such a situation can lead to a breach of operational security limits and must be prevented by keeping necessary reserves within all bidding zones, so that no TSO deviates from its schedule in a sustained way (i.e. more than 15 minutes, within which frequency restoration reserve shall be fully deployed by any given TSO). Finally, the inability to maintain scheduled area balances resulting from insufficient operational reserves will lead to uncontrolled changes in power flows, which may trigger lines overload (i.e. exceeding the thermal limits) and as a consequence can lead to system splitting with different frequencies in each of the subsystems. The above issue affects PSE in a different way from other TSOs due to reasons explained in the subsequent paragraph.

PSE role in system balancing

PSE directly dispatches all major generating units in Poland taking into account their operational characteristics and transmission constraints in order to cover the load forecasted by PSE, having in mind adequate reserve requirements. To fulfil this task PSE runs the process of operational planning, which begins three years ahead with relevant overhaul (maintenance) coordination and is continued via yearly, monthly and weekly updates to day-ahead SCUD and SCED. The results of this day-ahead market are then updated continuously in intraday time frame up to real time operation.

In a yearly time frame PSE tries to distribute the maintenance overhauls requested by generators along the year in such a way that on average the minimum year ahead generation reserve margin[2] over forecasted demand including already allocated capacities on interconnections is kept on average in each month. The monthly and weekly updates aim to keep a certain reserve margin on each day[3], if possible. This process includes also network maintenance planning, so any constraints coming from the network operation are duly taken into account.

The day-ahead SCUC process aims to achieve a set value of spinning reserve[4] (or quickly activated, in current Polish reality only units in pumped storage plants) margin for each hour of the next day, enabling up and down regulation. This includes primary and secondary control power pre-contracted as an ancillary service. The rest of this reserve comes from usage of balancing bids, which are mandatory to be submitted by all centrally dispatched generating units (in practice all units connected to the transmission network and major ones connected to 110 kV, except Combined Heat and Power (CHP) plants as they operate mainly according to heat demand). The remaining generation is taken into account as scheduled by owners, which having in mind its stable character (CHPs, small thermal and hydro) is a workable solution. The only exception from this rule is wind generation, which due to its volatile character is forecasted by PSE. Thus, PSE has the right to use any available centrally dispatched generation in normal operation to balance the system. The negative reserve requirements during low load periods (night hours) are also respected and the potential pumping operation of pumped storage plants is taken into account, if feasible.

The further updates of SCUC/SCED during the operational day take into account any changes happening in the system (forced outages and any limitations of generating units and network elements, load and wind forecast updates, etc.). It allows to keep one hour ahead spinning reserve at the minimum level of 1000 MW, i.e. potential loss of the largest generating unit, currently 850 MW (subject to change as new units are commissioned) and ca. 150 MW of primary control reserve (frequency containment reserve) being PSE's share in RGCE.

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2 The generation reserve margin is regulated by the Polish grid code and currently set at 18% (point II.4.3.4.18). It is subject to change depending on the results of the development of operational planning processes.

3 The generation reserve margin for monthly and weekly coordination is also regulated by the Polish grid code (point II.4.3.4.18) and currently set at 17% and 14% respectively.

4 The set values are respectively: 9% over forecasted demand for up regulation and 500 MW for down regulation. These values are regulated by the Polish grid code (point 4.3.4.19) and subject to change.

Determination of allocation constraints in Poland

When determining the allocation constraints, the Polish TSO takes into account the most recent information on the aforementioned 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 horizons.

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

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

$$\text{EXPORT}_{constraint} = P_{CD} - (P_{NA} + P_{ER}) + P_{NCD} - (P_L + P_{UPres}) \tag{1}$$

$$\text{IMPORT}_{constraint} = P_L - P_{DOWNres} - P_{CD_{min}} - P_{NCD} \tag{2}$$

Where:

P_{CD}	Sum of available generating capacities of centrally dispatched units as declared by generators[5]
$P_{CD_{min}}$	Sum of technical minima of centrally dispatched generating units in operation
P_{NCD}	Sum of schedules of generating units that are not centrally dispatched, as provided by generators (for wind farms: 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 up regulation
$P_{DOWNres}$	Minimum reserve for down regulation

For illustrative purposes, the process of practical determination of allocation constraints in the framework of day-ahead transfer capacity calculation is illustrated below: figures 1 and 2. The figures illustrate how a forecast of the Polish power balance for each hour of the next day is developed by TSO day ahead in the morning in order to determine reserves in generating capacities available for potential exports and imports, respectively, for day ahead market. For the intraday market, the same method applies mutatis mutandis.

Allocation constraint in export direction is applicable if ∆Export is lower than the sum of transfer capacities on all Polish interconnections in export direction. Allocation constraint in import direction is applicable if ∆Import is lower than the sum of transfer capacities on all Polish interconnections in import direction.

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[5] 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.

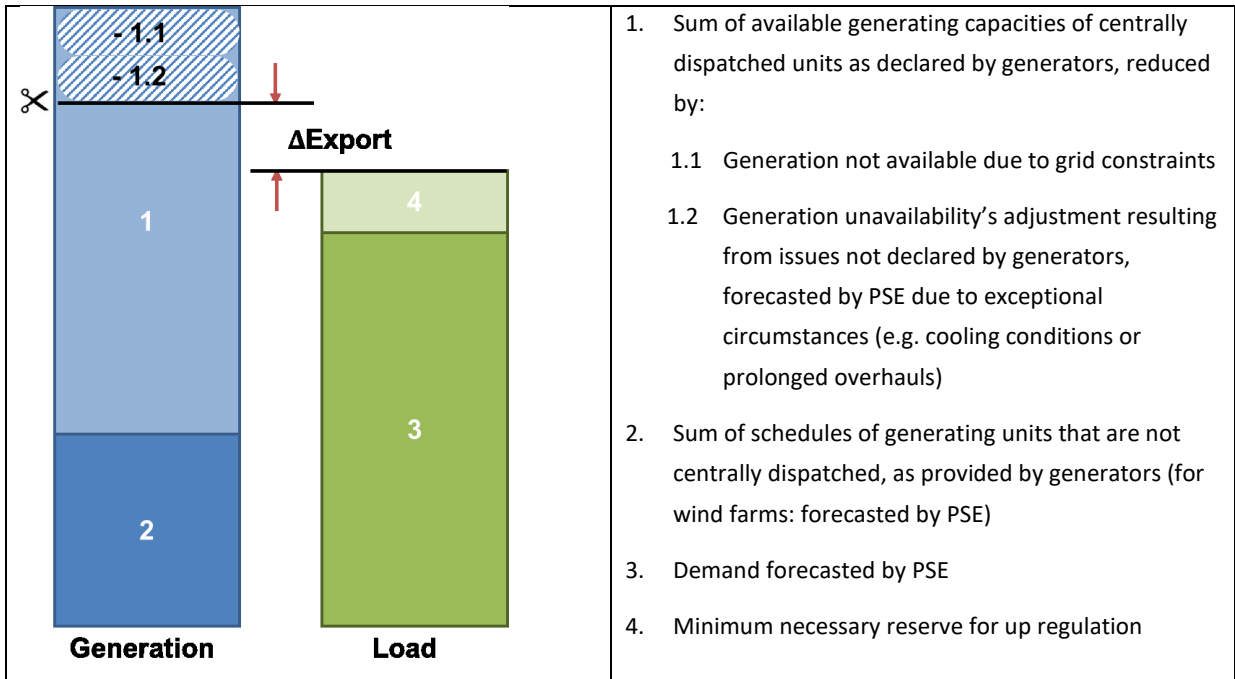|	1.	Sum of available generating capacities of centrally dispatched units as declared by generators, reduced by:
	1.1	Generation not available due to grid constraints
	1.2	Generation unavailability's adjustment resulting from issues not declared by generators, forecasted by PSE due to exceptional circumstances (e.g. cooling conditions or prolonged overhauls)
	2.	Sum of schedules of generating units that are not centrally dispatched, as provided by generators (for wind farms: forecasted by PSE)
	3.	Demand forecasted by PSE
	4.	Minimum necessary reserve for up regulation

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

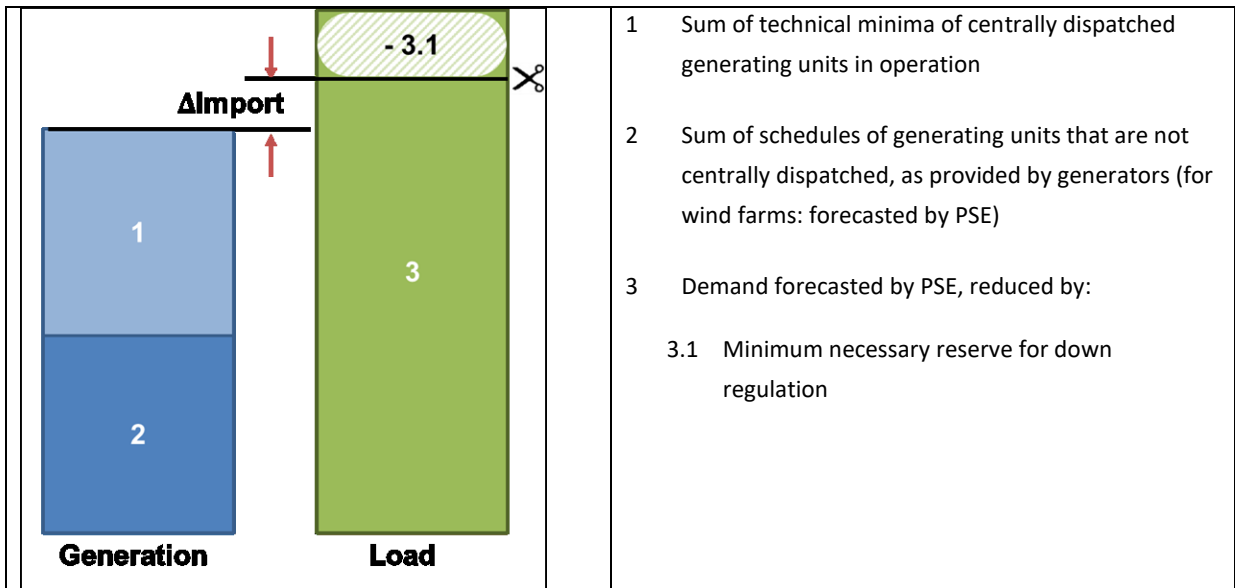|	1	Sum of technical minima of centrally dispatched generating units in operation
	2	Sum of schedules of generating units that are not centrally dispatched, as provided by generators (for wind farms: forecasted by PSE)
	3	Demand forecasted by PSE, reduced by:
	3.1	Minimum necessary reserve for down regulation

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

Frequency of re-assessment

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

Impact of allocation constraints on single day-ahead coupling and single intraday coupling

Allocation constraints in form of allocation constraints as applied by PSE do not diminish the efficiency of day-

ahead and intraday market coupling process. Given the need to ensure adequate availability of generation and generation reserves within Polish power system by PSE as TSO acting under central-dispatch market model, and the fact that PSE does not purchase operational reserves ahead of market coupling process, imposing constraints on maximum import and export in market coupling process – if necessary – is the most efficient manner of reconciling system security with trading opportunities. This approach results in at least the same level of generating capacities participating in cross border trade as it is the case in self-dispatch systems, where reserves are bought in advance by BRPs or TSO, so they do not participate in cross-border trade, either. Moreover, this allows to avoid competition between the TSO and market participants for generation resources.

It is to be underlined that allocation constraints applied in Poland will not affect the ability of any Hansa country to exchange energy, since these constraints only affect Polish export and/or import. Hence, transit via Poland will be possible in case of allocation constraints applied.

Impact of allocation constraints on adjacent CCRs

Allocation constraints are determined for the whole Polish power system, meaning that they are applicable simultaneously for all CCRs in which PSE has at least one border (i.e. Core, Baltic and Hansa).

It is to be underlined that this solution has been proven as the most efficient application of allocation constraints. Considering allocation constraints separately in each CCR would require PSE to split global allocation 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 generation requirements, or when Poland is unable to export any more power due to insufficient generation reserves in upward direction, Polish transmission infrastructure still can be – and indeed is - offered for transit, increasing thereby trading opportunities and social welfare in all concerned CCRs.

Time periods for which allocation constraints are applied

As described above, allocation constraints are determined in a continuous process for each capacity allocation time frame, so they are applicable for all MTUs (hours) of the respective allocation day.

Why the allocation constraints cannot be efficiently translated into capacities of individual borders offered to the market

Use of capacity allocation constraints aims to ensure economic efficiency of the market coupling mechanism on these interconnectors while meeting the security requirements of electricity supply to customers. If the generation conditions described above were to be reflected in cross-border capacities offered by PSE in form of an appropriate adjustments of border transmission 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 CNTC approach, this would need to be done in a form of ATC reduction per border. 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 – overstated on one interconnection and underestimated on the other, or vice versa. Consequently, application of allocation constraints to tackle the overall Polish balancing constrains at the allocation phase allows for the most efficient use of transmission infrastructure, i.e. fully in line with price differences in individual markets.