Capacity calculation methodology for the day-ahead and intraday market timeframes within the Baltic Capacity Calculation Region

Among:

AS “Augstsprieguma tikls”
Elering AS
LITGRID AB
PSE S.A.
Svenska kraftnat
Fingrid Oyj

26th October 2023

Vilnius, Riga, Tallinn, Helsinki, Stockholm, Warsaw

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1 GENERAL TERMS

1.1. The Capacity calculation methodology within the Baltic Capacity Calculation Region is required by Article 20(2) of the Commission Regulation (EU) 2015/1222 establishing a guideline on capacity allocation and congestion management (CACM Regulation).

1.2. Capacity calculation methodology within the Baltic Capacity Calculation Region (hereinafter referred to as “the Methodology”) are set to define:

1.2.1. Cross-Zonal Capacity calculation, provision and allocation rules between Estonian and Latvian power systems;

1.2.2. Cross-Zonal Capacity calculation, provision and allocation rules between Lithuanian and Latvian power systems;

1.2.3. Cross-Zonal Capacity calculation, provision and allocation rules between Estonian and Finnish power systems;

1.2.4. Cross-Zonal Capacity calculation, provision and allocation rules between Lithuanian and Swedish power systems;

1.2.5. Cross-Zonal Capacity calculation, provision and allocation rules between Lithuanian and Polish power systems.

1.3. Article 9(9) of the CACM Regulation requires that the expected impact of the Proposal on the objectives of the CACM Regulation is described. The impact is presented below in section 1.4.7

1.4. The Methodology Proposal contributes to and does not in any way hamper the achievement of the objectives of Article 3 of the CACM Regulation. Cross-Zonal Capacities within the Baltic Capacity Calculation Region (hereinafter referred to as “Baltic CCR”) shall be calculated using the coordinated Net Transmission Capacity approach in a way that facilitates and serves the achievement of the following objectives:

1.4.1. promoting effective competition in the generation, trading and supply of electricity (Article 3(a) of the CACM Regulation) by ensuring that maximum Cross-Zonal Capacity (with regards of operational security) is made available to the market in the Baltic CCR;

1.4.2. ensuring optimal use of the transmission infrastructure (Article 3(b) of the CACM Regulation) by applying the net transmission capacity approach, compared to which flow-based approach is not yet more efficient assuming the comparable level of operational security in the Baltic CCR.

The Methodology for the Baltic CCR treats all bidding zone borders within the Baltic CCR equally and provides non-discriminatory access to cross-zonal capacity. Proposed approach aims at providing the maximum available capacity to market participants within the operational security limits. The Methodology for the Baltic CCR ensures non-discrimination in calculation of Cross-Zonal Capacities.

1.4.3. ensuring operational security (Article 3(c) of the CACM Regulation) as grid constraints are taken into account while providing the maximum available capacity to market participants within the operational security limits.

1.4.4. optimising the calculation and allocation of cross-zonal capacity (Article 3(d) of the CACM Regulation) and ensuring that Cross-Zonal Capacities in day-ahead and intraday markets are provided and allocated in a most optimal and reasonable manner by taking into account structure of the Baltic CCR power system, as well as from one side, operational security limits and N-1 situations which are limiting capacities, and from another side - remedial actions which can increase capacities.

1.4.5. ensuring and enhancing the transparency and reliability of information (Article 3(f) of the CACM

Regulation), as the CCM determines the main principles and main processes for the day-ahead and intraday timeframes. The Methodology enables Transmission System Operators (hereinafter referred to as "TSOs") to in a transparent way provide Market Coupling Operator (hereinafter referred to as "MCO") with the same reliable information on cross-zonal capacities and allocation constraints for day-ahead and intraday allocations.

1.4.6. contributing to the efficient long-term operation and development of the electricity transmission system and electricity sector in the Union (Article 3(g) of the CACM Regulation). The Methodology, by taking most important grid constraints into consideration, will support efficient pricing in the market, providing the right signals from a long-term perspective.

1.4.7. respecting the need for a fair and orderly market and fair and orderly price formation (Article 3(h) of the CACM Regulation) as well as providing non-discriminatory access to cross-zonal capacity (Article 3(j) of the CACM Regulation) by providing all cross-zonal capacities for allocations to MCO.

1.5. All the data exchange process and timing among TSOs and Coordinated Capacity Calculators (hereinafter referred to as just "Capacity Calculator" or "Capacity Calculators") is described in respective Coordinated Capacity Calculators Rules.

Until Coordinated Capacity Calculators are established and perform capacity calculation/coordination function, capacity calculation and coordination is performed by TSOs related to respective borders.

1.6. Processes and principles described in this Methodology cover Cross-Zonal Capacity calculation, provision and allocation for day-ahead and intraday time horizons.

1.7. This Methodology also takes into account and acts upon the fact that the Baltic States are foreseen to be synchronized with the Continental Europe Synchronous Area by double circuit line connecting Poland and Lithuania. Upon synchronisation, the capacity of this line will have to be, in large part, kept for reliability margins in a case of unexpected tripping of aforementioned double circuit line (with simultaneous transfer of Baltic System into island operation) or outage (of load or generation/infeed) in the Baltic System. Transmission system operators will continue offering maximum capacity for cross-border trading, compliant with operational security limits and considering possible contingencies in the Polish and Lithuanian power systems, including those resulting from aforementioned unexpected events. The specific situation of this interconnection is hereby taken into consideration for the calculation of the total capacity and contingencies pursuant to Article 16(8) of Regulation (EU) 2019/943.

2 DEFINITIONS

For the purposes of this Methodology, the definitions in Articles 2 of Regulations (EC) No 2015/1222, No 2019/943, No 543/2013, Article 3 of Regulation (EC) No 2017/1485 and Article 2 of Directive 2009/72/EC shall apply. In addition, the following definitions shall apply and shall have the following meaning:

AAC - the Already Allocated Capacity is the total amount of allocated physical transmission rights.

AST - AS “Augstsprieguma tikls”, electricity transmission system operator of the Republic of Latvia.

ATC - the Available Transmission Capacity of the designated Cross-Border Interconnections, which is available to the market after each phase of the transmission capacity allocation procedure.

Baltic TSOs - the transmission system operators for electricity of the Republic of Estonia, the Republic of Latvia and the Republic of Lithuania.

Baltic CCR TSOs - the transmission system operators for electricity of the Republic of Finland, Republic of Estonia, the Republic of Latvia and the Republic of Lithuania, the Republic of Poland, Kingdom of Sweden.

Baltic CCR - Capacity calculation region Baltic. According to ACER decision No 04/2021 on the electricity TSOs' proposal for Capacity Calculation Regions Baltic CCR shall include the Bidding Zone borders listed below:

a) Estonia - Latvia (EE-LV), Elering AS and AST;

b) Latvia - Lithuania (LV-LT), Augstsprieguma tikls and LITGRID AB;

c) Estonia - Finland (EE-Fl), Elering AS and Fingrid Oyj;

d) Lithuania — Sweden 4 (LT-SE4), LITGRID AB and Svenska kraftnat; and

e) Lithuania - Poland (LT-PL), LITGRID AB and PSE S.A.

BSPS- Baltic State Power Systems (Republic of Estonia, the Republic of Latvia and the Republic of Lithuania)

Cross-Border Interconnection - is a physical transmission link (e.g. tie-lines) which connects two power systems.

CACM Regulation - European Commission Regulation (EU) No 2015/1222 establishing a Guideline on Capacity Allocation and Congestion Management.

CGM (Common Grid Model) - electrical system grid model agreed between TSOs describing the main characteristic of the power system (generation, loads and grid topology) and rules for changing these characteristics during the capacity calculation process in accordance with Article 17 of the CACM Regulation.

CGMES – Common grid model exchange standard.

D-1 – one day ahead planning timeframe.

D-2 - two days ahead planning timeframe.

ID - intraday planning timeframe.

Elering - Elering AS, Transmission System Operator of the Republic of Estonia.

Fingrid - Fingrid Oyj, electricity transmission system operator of the Republic of Finland.

Litgrid - LITGRID AB, electricity transmission system operator of the Republic of Lithuania.

Market Coupling Operator (MCO)/Nominated Electricity Market Operator (NEMO) - the operator/-s of day-ahead and intraday markets in Baltic CCR.

NTC - coordinated Net Transmission Capacity of the designated Cross-Border Interconnections is the maximum Trading Capacity, which is permitted in transmission Cross-Border Interconnections compatible with Operational Security standards and taking into account the technical uncertainties on planned network conditions for each TSO.

PSE - PSE S.A., electricity transmission system operator of the Republic of Poland.

Shift Key - means a method of translating a net position change of a given power system into estimated specific injection increases or decreases in the Common Grid Model. Shift Key is settled as generation, renewable generation and load.

SvK - Svenska kraftnat, electricity transmission system operator in Sweden.

SO GL - European Commission Regulation (EU) No 2017/1485 establishing a Guideline on electricity transmission system operation.

TRM - Transmission Reliability Margin which shall have meaning of "reliability margin" definition of CACM Regulation.

TTC - Total Transfer Capacity of the designated Cross-Border Interconnections is the maximum transmission of active power, which is permitted in transmission Cross-Border Interconnections compatible with Operational Security standards applicable for each TSO.

Trading Capacity - the maximum available Cross-Zonal Capacity for trade in Day-Ahead Market and Intraday Market.

CESA – Continental Europe synchronous area.

MTU – Market time unit.

Internal Baltic AC interconnectors – Interconnectors between Baltic TSOs in Baltic area, covering Lithuania – Latvia and Latvia – Estonia cross-borders.

IDA – Capacity auctions in ID timeframe according to CACM Regulation Article 35 where price coupling algorithm and of the continuous trading matching algorithm are applied.

3 CRITICAL NETWORK ELEMENTS AND CONTIGENCIES

3.1. Each Baltic CCR TSO shall define list of critical network elements (CNEs) of its control area for capacity calculation process. Elements could be all cross-border interconnectors, lines, transformers, HVDC elements.

3.2. CNEs for capacity calculation shall be defined considering impact computation principles defined in methodology according to art. 75 of SO GL annex 1 and factor determining impact for CNE shall be cross zonal power flow exchange. Internal CNEs which power flow filtering influence factor according to art. 75 of SO GL annex 1 is less than percentage, defined by TSOs based on operational and planning expertise, shall be excluded from capacity calculation process. TSO shall update CNE list in case of significant change in grid topology when influence value for CNE element significantly changed from average value and CNE became relevant/irrelevant for capacity calculation process.

3.3. Contingency Analysis is performed at least for those contingencies which are agreed among Baltic CCR TSOs in the Contingency Lists. Contingency Lists shall be agreed and provided among Baltic TSOs and provided to Capacity Calculator for Capacity Calculation.

3.4. Each Baltic CCR TSO shall provide Contingency List to be used in capacity calculation process in accordance with art. 33 of SO GL. Contingency list shall include contingencies of TSO observability area. Contingency can be:

- Line, cable;
- Transformer;
- Generator;
- Load;
- Busbar;
- Multiple elements combined;
- HVDC;

3.5. Each Baltic CCR TSO and Capacity Calculator shall perform regular review of CNEs, Contingencies and other input data and evaluate their relevance in capacity calculation process. Such evaluation shall be performed at least on a yearly basis.

4 OPERATIONAL SECURITY LIMITS

4.1. Operational security analyses shall be performed with respect of operational security limits applied in Control Areas of Baltic CCR TSOs. Operational Security Limits are agreed among TSOs of respective synchronous areas. Power flow limits shall be determined according to Article 32 SO GL.

4.2. Operational security limits shall be considered as thermal limits and expressed as maximum admissible load of CNE. Operational security limits shall be defined and specified according to Article 25 of SO GL. Maximum admissible operational limits of CNE could be defined as follows:

- Fixed limit - constant value over all market time units despite seasons and ambient conditions.
- Seasonal limit – Fixed limit per market time unit for specific season.
- Dynamic limit – unique limit value for each market time unit, considering different ambient conditions.

4.3. Operational security limits used in capacity calculation shall be the same as those used in operational security analysis performed according to Articles 74 and 75 of SO GL. Each TSO shall provide thermal operational security limits for electrical system elements within its IGM.

4.4. Baltic CCR TSOs and Capacity Calculator shall perform regular review of operational security limits and evaluate their relevance in Capacity Calculation. Such evaluation shall be performed at least on a yearly basis.

4.5. Stability limits shall be taken into account in Capacity Calculation process. These limits shall cover static, dynamic stability limit according to Article 38 of SO GL and any other time dependent stability limit (including oscillatory). Application of these limits shall be according to national grid codes, EU regulations and TSOs internal stability assessment procedures.

5 ALLOCATION CONSTRAINTS

5.1. In accordance with the definitions in Article 2 points (6) and (7), Article 23(3)(a) of the CACM Regulation, and respecting the objectives described in Article 3 of the CACM Regulation, besides active power flow limits on Cross-Border Interconnections, other specific limitations may be necessary to maintain the secure grid operation. Under the CACM Regulation, allocation constraints constitute measures defined as to the purpose of keeping the transmission system within operational security limits. As the transmission system parameters used for expressing operational security limits (inter alia frequency, voltage, and dynamic stability) depend on production and consumption in a given system, these specific limitations can be related to generation and load. Since such specific limitations cannot be efficiently transformed into operational security limits of individual Cross-Border Interconnections, they are expressed as maximum import and export constraints of bidding zones and/or cross-border(s).

If applicable, allocation constraints are determined by Baltic CCR TSOs and taken into account during the single day-ahead and intraday coupling in addition to the power flow limits on Cross-Border Interconnections.

5.2. These allocation constraints shall be applied as a constraint on the cross-border and/or on the global net position (the sum of all Cross-Border exchanges for a certain bidding zone in the single day-ahead and intraday coupling), thus limiting the net position of the respective bidding zone with regards to all CCRs which are part of the single day-ahead and intraday coupling. Allocation constraints translated into ramping restrictions are described in paragraph 5.5.

5.3. A TSO can also use allocation constraints in case of a central dispatch model for ensuring a required level of operational reserve for balancing (hereinafter referred to as balancing constraints). The balancing constraints depend on the foreseen balancing situation and are bidirectional, with independent values for each market time unit and separately in the directions of import and export. This is applicable for PSE, for all market time units. The details for the use and the methodology of calculation of allocation constraints as described in this article are set forth in Appendix 1.

5.4. A TSO may discontinue the usage of an allocation constraint as described in paragraph 5.3. The concerned TSO shall communicate this change to the Baltic regulatory authorities and to the market participants at least one month before its implementation.

5.5. On HVDC Interconnections, maximum Ramping Rate restrictions are applied during D-1 and ID capacity calculation processes. Maximum Ramping Rate restriction indicates the maximum possible rate of active power change for sequential trading periods. The restrictions imply that trade plans on all HVDC connections cannot be changed with no more than the predetermined maximum Ramping Rate restriction from one trading period to the next. Ramping restrictions are taken into account in the D-1 Market in order to maintain operational security. Capacities available for trading during ID Market depend not only on maximum trading capacities provided by TSOs/ Capacity calculators, but also on AACs for consecutive previous and following trading periods.

5.6. TSOs may apply implicit loss factors in day-ahead and intraday timeframes in accordance with Article 23(3) of the CACM Regulation. The relevant TSOs shall provide these allocation constraints to the Capacity Calculators. The implicit loss factors are calculated as:

*Export quantity = (1 – "Loss Factor") * Import quantity*

The implicit loss factor is a correction mechanism for a negative external effect incentivising the market to respect the cost of electricity losses on HVDC interconnections in the market coupling. The implicit loss factor may be applied on an HVDC interconnection if an EU-wide welfare economic benefit can be demonstrated to the NRAs.

6 GENERATION AND LOAD SHIFT KEYS

6.1. The TSOs of Baltic region shall define the generation shift keys in accordance with Article 24 of the CACM Regulation.

6.2. The generation and load shift keys (hereinafter referred to as "GLSK") shall represent the best forecast of the relation of a change in the net position of a bidding zone to a specific change of generation or load in the CGM. That forecast shall notably take into account the information from the generation and load data provision methodology according to Article 16 of CACM Regulation. Shift key strategy per power system area shall be the responsibility of each involved TSO, which has to be communicated with other TSOs and Capacity Calculator before commencing TTC calculation process in case of deviation from default GLSK strategy set out in paragraph 6.3.

6.3. GLSK strategy consists of GLSK definition principle/-s and ranking sequence/-s. GLSK strategy consists of default GLSK ranking sequence and default GLSK definition and it shall be used as default unless specified otherwise by respective TSO. Each TSO may choose GLSK definition principle/-s and ranking sequence/-s and shall notify other TSOs and Capacity Calculator about chosen GLSK definition principle/-s and ranking sequence/-s.

6.4. Following generation and/or load ranking sequence (generation or load shift shall be proportional to the base case generation/load) shall be used as default:

a. Internal specific area generation shift.
b. HVDCs setpoint change.
c. Neighbouring system generation shift (including HVDCs setpoint change, if HVDC's flow goes into synchronous area).
d. Load shifting in specific area.

6.5. If TSO does not specify GLSK definition principle/-s, as a default proportional to the base case GLSK definition principle shall be applied for TSO. GLSK definition principle representing proportional to the base case generation/load shift key strategy shall be performed according to following rules:

6.5.1. The participation of node n in the shift, among generation nodes (GSK) is given by:

$$K_g\,(n,a) = G(a)\frac{P_g(n,a)}{\sum_i P_i(i,a)} \quad (1)$$

Where:

K_g(n, a) – calculated GSK value of evaluated specific generation in node n, belonging to area a.

P_g(n, a) – generation in node n, belonging to area a.

$\sum P_i$(i, a) – total sum of evaluated generators belonging to area a.

G(a) – Participation factor for generation nodes in area "a"

6.5.2. The participation of node n in the shift, among load nodes (LSK) is given by:

$$K_l\,(n,a) = L(a)\frac{P_l(n,a)}{\sum_i P_i(i,a)} \quad (2)$$

Where:

K_l(n, a) – calculated LSK value of evaluated specific load in node n, belonging to area a.

P_l(n, a) – active load in node n, belonging to area a.

$\sum P_i$(i, a) – total sum of active loads belonging to area a.

L(a) – Participation factor for load nodes in area "a"

6.5.3. The sum of G(a) and L(a) for each area is to be equal to 1 (i.e. 100%).

6.6. GLSK strategy applied in Nordics is described in detail in Nordic CCR Capacity Calculation Methodology.

7 REMEDIAL ACTIONS

7.1. Relevant TSOs shall provide relevant Capacity Calculators with information on available and applicable non-costly remedial actions that shall be used in capacity calculation process.

7.2. Non-costly remedial actions are such actions which don't result in additional costs to TSO in case of planned operational regime for which capacity calculation is performed.

7.3. Costly remedial actions are such actions which result in additional costs to TSO even in case of planned operational regime for which capacity calculation is performed.

7.4. Non-costly remedial actions shall be fully exploited before an internal Critical Network Element may affect Cross-Border trade.

8 PROVISION OF THE INPUT DATA

8.1. TSOs of the Baltic CCR shall provide to the Capacity Calculator before a certain deadline commonly agreed and coordinated between the TSOs and the Capacity Calculator the following inputs for TTC calculation:

- Individual Grid Model (IGM) - base case model, which includes power transmission equipment model of Control Area of TSO;
- Generation and Load Shift Keys;
- Critical Network Elements;
- Contingency List;
- Remedial Actions;
- TRM values or input data for TRM calculation;
- Allocation constraints;
- Available power reserves.

8.2. If input data for capacity calculation process is used as static data set and is constant in daily capacity calculation processes, then such data shall be reviewed and shared between relevant parties at least on a yearly basis or upon TSO or Capacity Calculator request.

8.3. IGM, provided by TSO, shall consist of valid Operational Security Limits, outage cases, forecast data. IGM shall consist of relevant input scenario data describing net positions, grid topology and system element data for each market time unit and valid for given calculation purposes.

8.4. As a basis for D-2 IGM creation input balance data shall be selected according to Table 1 also applying latest available grid outage schedules and forecasts of renewable generation.

Table 1. Schedule data definition for D-2 planning phase.

Monday (working day)	Tuesday-Friday (working days)	Saturday	Sunday	Public holidays
Last Friday's balance plan	Yesterday's balance plan	Last Saturday's balance plan	Yesterday's balance plan	Last Sunday's or the closest last public holiday's balance plan

8.5. Capacity Calculator shall use CGM for capacity calculation process according to CACM Regulation art. 17. CGM shall consist of IGMs of synchronous area, including Baltic TSOs and other relevant power systems. CGM shall represent base case model, which includes power transmission equipment model of synchronous area and scenario describing net positions for each of Control Area of Baltic TSOs and other relevant power systems, valid for given TTC calculation purposes.

9 TOTAL TRANSFER CAPACITY (TTC) CALCULATION METHODOLOGY

9.1. Capacity Calculator shall coordinate capacity values with the neighbouring Coordinated Capacity Calculators during capacity calculation and validation.

9.2. TSOs and Capacity Calculator shall not limit cross-zonal exchanges due to Critical Network Elements which are not significantly impacted by cross zonal trade according to Article 29.3(b) of CACM Regulation and Section 3 unless performed Contingency Analyses determines threat to Operational Security or when operational security analyses show that boundaries of stability limits are exceeded during operation of the transmission system.

9.3. While calculating TTC and performing Contingency Analyses after applying of N-1 criteria following Operational Security limits shall be not exceeded:

- Permanently allowed thermal limits, that correspond to the relevant ambient temperature, of network elements, i.e. the maximum amount of electric current that a given network element can conduct without sustaining damage or being in violation of safety requirements;
- Voltage and load stability limits in network nodes, i.e. maximum and minimum voltage levels permitted at given network node in order to prevent equipment damage or voltage collapse respectively;
- Dynamic and/or any other stability limits based on TSOs internal stability assessment procedure.

9.4. To determine the TTC values for DC interconnectors, TSOs and Capacity calculator shall take into account balancing reserves within Control Area of Baltic TSOs to ensure Operational Security.

10 TOTAL TRANSFER CAPACITY (TTC) CALCULATION FOR INTERNAL AC CROSS-BORDERS INTERCONNECTORS IN BALTIC TSOS CONTROL AREA

10.1. The Cross-Border Interconnection TTC determination for AC interconnectors shall be done by performing Contingency Analyses based on N-1 criterion on a CGM, while taking into account the intra and intersystem Operational Security limits according to Section 4 of synchronous area and Control Area of Baltic TSOs.

10.2. TTC is maximum power flow value on Cross-Border between two bidding zone areas resulted from modelling net position variation and contingency analysis. TTC value is obtained by summing up power flow values of cross-border lines above 110 kV after Operational Security or stability limits reached for any CNE while modelling net position increase in exporting area and decrease in importing area and performing N-1 contingency analysis.

10.3. Contingency Analysis is performed for those contingencies which are agreed among Baltic TSOs in the Contingency List. Contingency List shall be agreed and provided among Baltic TSOs and to Capacity Calculator.

10.4. The shifting strategies used in TTC calculations are described in Section 6 of this Methodology.

10.5. If during capacity validation process neighbouring TSOs and Capacity Calculator determine different TTC values for the same Cross-Border Interconnection, the lowest value shall be used as a coordinated value.

11 TOTAL TRANSFER CAPACITY (TTC) CALCULATION FOR CROSS-BORDERS WITH HVDC INTERCONNECTORS

11.1. TTC for each cross-border that consists solely of HVDC connections is limited by the sum of ratings of HVDC interconnectors that connect the relevant Bidding Zones. In order to define TTC limitation related to adjacent AC networks, Contingency Analyses based on N-1 criterion (i.e. a loss of any single element of power system) shall be performed using CGM, while taking into account the intra and intersystem Operational Security according to Section 4.

11.2. Maximum permissible capacity on HVDC interconnector shall be limited when there is lack of available balancing reserves to replace the failure of the HVDC interconnector. While relevant party is performing Contingency Analysis according to paragraph 11.1 it is checked if maximum capacity for each link for each direction could be provided to the market. If Contingency Analysis reveals that network security is not assured when the HVDC interconnectors are fully loaded in any direction, then capacity on the relevant cross-border on relevant direction is reduced until network parameters are within permissible limits during the analysis.

11.3. The TTC on relevant HVDC interconnector is the minimum capacity value that is the outcome of the Contingency Analyses that are performed by the relevant parties on each side of the relevant interconnector.

11.4. The shifting strategy applied during TTC determination of HVDC interconnector shall be performed in accordance with Section 6.

11.5. TTC of cross-border Estonia-Finland is the sum of permissible capacities on HVDC links Estlink 1 and Estlink 2. When there is a need to limit the capacities on the links according to paragraph 11.2 the links are limited in minimal possible combination - meaning the maximum possible capacity is given to the market.

12 TRANSMISSION RELIABILITY MARGIN (TRM) CALCULATION METHODOLOGY OF AC CROSS-BORDERS INTERCONNECTORS IN BALTIC TSO’S CONTROL AREA

12.1. The Transmission Reliability Margin (hereinafter referred to as "TRM") is a capacity margin needed for secure operation of interconnected power systems considering the planning errors, including the errors due to imperfect information at the time the transfer capacities have been computed.

12.2. TRM calculation methodology is covering Cross-Border Interconnections between Lithuanian and Latvian, Lithuanian and Polish power systems as well as between Latvian and Estonian power systems.

12.3. For HVDC interconnectors TRM value shall be 0 MW.

12.4. For determining of the TRM values for each Cross-Border Interconnection, the statistical data of historically planned and actual power flows (historical physical flows) shall be used for each MTU. TRM shall be determined as the arithmetic average of the deviations between the expected power flows at the time of the capacity calculation and realised power flows in real time value plus standard deviation based on historical data. TRM shall be rounded to the nearest integer. TRM shall be calculated for each cross-border direction according to formula (3):

$$TRM = \frac{\sum_{i=1}^{n} X_i}{n} + \sqrt{\frac{\sum_{i=1}^{n} (X_i - \overline{X})^2}{n-1}} \quad (3)$$

where:

X_i - data sets of the i-th element, defined as deviation of planned power flow from actual power flow (actual flow subtracted from planned flow) over Cross-Border Interconnection.

$\overline{X}$ arithmetic average value of X_i equal to $\frac{\sum_{i=1}^{n} X_i}{n}$;.

n - number of elements in the data set.

12.5. TRM shall be recalculated every month or more frequently upon TSOs agreement using last 1 year or latest available historical period data. Historical data for TRM evaluation shall be acquired since Baltic TSOs synchronisation with CESA.

12.6. For initial operation period after Baltic TSOs synchronisation with CESA, fixed TRM values shall be applied to LT-LV, LV-EE, and LT-PL Cross-Borders. These values shall be applied for 1 month period. After this period, TRM shall be calculated according to principles set out in 12.4 and 12.5. Fixed values provided in Table *2*.

Table 2. Fixed TRM values for initial operation period

Border	EE-LV	LV-EE	LT-LV	LV-LT	LT-PL	PL-LT
TRM value	50 MW	50 MW	50 MW	50 MW	50 MW	50 MW

13 TRADING CAPACITY CALCULATION MATHEMATICAL DESCRIPTION OF NTC CALCULATION FOR DAY AHEAD TIMEFRAME OF INTERNAL BALTIC AC INTERCONNECTORS IN BALTIC TSO'S CONTROL AREA

13.1. TSOs and Capacity Calculator calculate NTC value for Internal Baltic AC interconnectors and Available Transmission Capacity (ATC) for both interconnection directions. ATC would represent capacity allocations for day ahead timeframe. Calculation shall be performed using following equations:

$$NTC_{A>B} = TTC_{A>B} - TRM_{A>B}; \quad NTC_{B>A} = TTC_{B>A} - TRM_{B>A} \quad (4)$$

$$ATC_{DA,\,A>B} = NTC_{A>B} - AABC_{A>B}; \quad ATC_{DA,\,B>A} = NTC_{B>A} - AABC_{B>A} \quad (5)$$

where:

$TTC_{A>B}$; $TTC_{B>A}$ - Total Transfer Capacity according to actual power system network status, identified during TTC evaluation, defined in Section 10 in direction from areas A>B and B>A.

$TRM_{A>B}$; $TRM_{B>A}$ - transmission reliability margin value calculated according to the methodology described in Section 12 in direction from areas A>B and B>A.

$ATC_{DA,\,B>A}$; $ATC_{DA,\,B>A}$ – available transmission capacity given to the Day-Ahead electricity market from areas A>B and B>A.

$AABC_{A>B}$; $AABC_{B>A}$ – Already allocated capacity for balancing market in accordance with Baltic CCR methodology for Electricity Balancing Guideline Article 38 in direction from areas A>B and B>A.

13.2. In case if during capacity validation process neighbouring TSOs determine different NTC values for the same Cross-Border Interconnection the lowest value shall be used as a coordinated value.

13.3. Final AC Cross-Border ATC value given to Day-ahead market shall be calculated according to formula (5).

14 INTRADAY AVAILABLE TRANSMISSION CAPACITY CALCULATION OF INTERNAL BALTIC AC INTERCONNECTORS IN BALTIC TSO'S CONTROL AREA

14.1. In ID capacity calculation timeframe D-1 Common Grid Model with day-ahead trading results shall be used to calculate ID ATC values.

14.2. ATC value is directional and is calculated considering that the TSOs and Capacity calculator shall, as far as technically possible, net the capacity values of any power flows in opposite directions over congested interconnection line in order to use that line to its maximum capacity.

14.3. ATC for ID market shall be calculated for both interconnection directions according to formulas:

$$ATC_{ID\ A>B} = NTC_{ID\ A>B} - AABC_{A>B} - AAC_{A>B} + AAC_{B>A} \quad (6)$$

$$ATC_{ID\ B>A} = NTC_{ID\ B>A} - AABC_{B>A} - AAC_{B>A} + AAC_{A>B} \quad (7)$$

where:

$ATC_{ID\ A>B}$; $ATC_{ID\ B>A}$ – available transmission capacity given to the ID electricity market in direction from areas A>B and B>A.

$NTC_{ID\ A>B}$; $NTC_{ID\ B>A}$ – coordinated Net Transmission Capacity relevant for intraday timeframe for the Cross-Border interconnections in direction from areas A>B and B>A.

$AAC_{A>B}$; $AAC_{B>A}$ – Already Allocated Capacity for the Cross-Border Interconnections in direction from areas A>B and B>A after previous capacity allocation phases.

$AABC_{A>B}$; $AABC_{B>A}$ – Already allocated capacity for balancing market in accordance with Baltic CCR methodology for Electricity Balancing Guideline Article 38 in direction from areas A>B and B>A.

14.3.1. NTC_{ID} value defined in formulas (6) and (7) shall correspond to the latest grid situation in ID timeframe with respect to grid topology, generation and load distribution and operational security limits. In general case NTC_{ID} shall be equal to NTC coordinated in DA timeframe. In case of changes in the network which affect NTC value it shall be recalculated in according to Section 13 and re-coordinated according to paragraph 14.4 between relevant parties for ID timeframe.

14.3.2. AABC value defined in formulas (6) and (7) used for ATC calculation shall correspond to chosen ATC calculation direction meaning AABC variable shall always have positive value.

14.4. In case if during capacity validation process neighbouring TSOs determine different ATC values for the same Cross-Border Interconnection the lowest value shall be used as a coordinated value.

14.5. TSOs can re-coordinate ID ATC values for each IDA auction in due time and provide updated values to NEMO.

14.6. As a fallback ID ATC values equal to "0 MW" (zero MW) shall be provided to the Intraday Market if following conditions occur:

a) In case if DA Market results have not been provided by NEMOs.

b) There are significant changes in the grid that impact cross-zonal capacity value and CGM including DA trading results is not available.

c) There are significant changes in the grid that impact cross-zonal capacity value and there is insufficient time to reassess and re-coordinate cross-zonal capacity values.

14.7. ID ATC values shall be reassessed and re-coordinated by TSOs and Capacity Calculator as soon as technically possible and provided to Intraday Market.

14.8. To ensure operational security of power systems reassessment of Intraday capacity value (ATC) shall be performed every time if any of the following situations occur:

14.8.1. Changes in topology of transmission network - unplanned outages or unplanned (earlier) returning to operation of network elements that affect transmission capacities.

14.8.2. Day-Ahead Market results update e.g., in case of fallback procedure applied by NEMO.

14.8.3. Major changes in generation and load plans, renewable generation forecasts changes.

15 TRADING CAPACITY CALCULATION RULES BETWEEN ESTONIAN AND FINNISH POWER SYSTEMS

15.1. TTCs on cross-border Estonia-Finland are validated and calculated by respective TSOs and Capacity calculators on both sides of the interconnector using CGMs that represent the AC-networks of observable areas of synchronous areas that each belong to.

15.2. Trading Capacity shall be defined for both interconnection directions according to formula (4) on each side of HVDC link. In case if during capacity validation process different NTC values are proposed for the same Cross-Border Interconnection direction the lowest value shall be used as a coordinated value.

$$NTC_{FI>EE;\ EE>FI} = \min(FI\ NTC_{FI>EE};\ EE\ NTC_{FI>EE});\ \min(FI\ NTC_{EE>FI};\ EE\ NTC_{EE>FI}) \quad (8)$$

where:

FI $NTC_{FI>EE}$; FI $NTC_{EE>FI}$ – NTC between FI>EE and EE>FI Bidding Zones directions, determined by operational security limits in Nordic CCR TSOs' synchronous area or technical limitation on HVDC interconnection (from Finland side),

EE $NTC_{FI>EE}$; EE $NTC_{EE>FI}$ – NTC between FI>EE and EE>FI Bidding Zones directions, determined by operational security limits in Baltic CCR TSOs' synchronous area or technical limitation on HVDC interconnection (from Estonia side).

Intraday capacity allocation procedure

15.3. The available capacity after the Day-Ahead Market results is offered to the Intraday Market in line with actual operational conditions. The intraday capacity can be influenced by changed TTC caused by changes in prognosis, topology, and in maintenance plans.

15.4. Intraday trading Capacity on cross-border Estonia-Finland is allocated according to formulas (6) and (7).

15.5. AABC allocation for HVDC shall be defined in the balancing capacity exchange agreements between relevant parties. In case no capacity exchange agreement is in place, AABC value for HVDC interconnectors shall be 0.

16 TRADING CAPACITY CALCULATION RULES BETWEEN LITHUANIAN AND SWEDISH POWER SYSTEMS

16.1. TTCs on cross-border Lithuania-Sweden are checked by respective TSOs and input data is provided to Capacity Calculators on both sides of the interconnector. Checks are performed by TSOs using CGMs that represent the AC and DC networks including observability areas of each TSO.

16.2. Trading capacity shall be defined by Capacity Calculators for both interconnection directions according to formula (4) on each side of HVDC link. In case if during capacity validation process different NTC values are proposed for the same cross-border interconnection direction the lowest value shall be used as a coordinated value.

16.3. Capacities for Lithuania – Sweden interconnection shall be defined according to formula:

$$ATC_{SE>LT,\,LT>SE} = \mathrm{MIN}\,(SE\ ATC_{SE>LT};\ LT\ ATC_{SE>LT});\ \mathrm{MIN}\,(SE\ ATC_{LT>SE};\ LT\ ATC_{LT>SE}) \qquad (9)$$

where:

SE ATC$_{SE>LT}$; SE ATC$_{LT>SE}$ — ATC between SE–LT and LT–SE Bidding Zones directions, determined by operational security limits in Nordic CCR TSOs' synchronous area or technical limitation on HVDC interconnection (from Sweden side);

LT ATC$_{SE>LT}$; LT ATC$_{LT>SE}$ — ATC between SE–LT and LT–SE Bidding Zones directions, determined by operational security limits in Baltic CCR TSOs' synchronous area or technical limitation on HVDC interconnection (from Lithuania side).

16.3.1. Capacities on Nordic side for Lithuania – Sweden interconnection shall be defined according to formulas:

$$TTC_{I,\,A>B} = \alpha_I \cdot P_{I,\,MAX\,THERMAL} \qquad (10)$$

$$SE\ ATC_{SE>LT} = TTC_{SE>LT} - AAC_{SE>LT} + AAC_{LT>SE} \qquad (11)$$

$$SE\ ATC_{LT>SE} = TTC_{LT>SE} - AAC_{LT>SE} + AAC_{SE>LT} \qquad (12)$$

If the HVDC link is not in service (TTC = 0) due to a planned or an unplanned outage:

$$ATC_{SE>LT} = ATC_{LT>SE} = 0$$

Where:

ATC - Available Transfer Capacity on a DC line i in direction SE>LT or LT>SE provided to the day-ahead market.

TTC - Total Transfer Capacity (TTC) of a DC line i in direction SE>LT or LT>SE. The TTC corresponds only to the full capacity of the DC line, in case of no failure on the interconnector, including converter stations.

AAC$_{SE>LT}$; AAC$_{LT>SE}$ - Already Allocated and nominated Capacity for a DC line i in directions SE>LT LT>SE.

α- Availability factor of equipment defined through scheduled and unscheduled outages, α_i being a real number in between and including 0 and 1.

P$_{maxthermal}$ - Thermal capacity for the HVDC link.

Intraday capacity allocation procedure

16.4. The available capacity is reassessed after the Day-Ahead Market and offered to the Intraday

Market in line with actual operational conditions. The intraday capacity can be influenced by changed TTC caused by changes in prognosis, topology, and in maintenance plans.

16.5. Intraday trading capacity on cross-border Lithuania-Sweden is allocated according to formulas (6) and (7).

16.6. AABC allocation for HVDC shall be defined in the balancing capacity exchange agreements between relevant parties according to Electricity Balancing Guideline Article 38. In case no capacity exchange agreement is in place, AABC value for HVDC interconnectors shall be 0.

17 TOTAL TRANSFER CAPACITY (TTC) CALCULATION FOR LITHUANIAN - POLAND AC CROSS-BORDER INTERCONNECTOR

17.1. While calculating TTC, list of considered CNE and contingencies should be determined according to Section 3**.**

17.2. While calculating TTC and performing contingency analyses after applying of N-1 criteria following operational security limits shall be not exceeded:

17.2.1. Permanently allowed thermal limits, that correspond to the relevant ambient temperature, of network elements, i.e. the maximum amount of electric current that a given network element can conduct without sustaining damage or being in violation of safety requirements;

17.2.2. Voltage and load stability limits in network nodes, i.e. maximum and minimum voltage levels permitted at given network node in order to prevent equipment damage or voltage collapse respectively.

17.2.3. Dynamic stability limits including:

i. transient stability.

ii. small signal stability (see further description in paragraph 17.3).

17.2.4. Frequency stability limit is assessed based on commonly agreed and coordinated availability of frequency support measures between Baltic TSOs. Measure 17.2.4.ii is agreed between relevant Baltic TSOs, Swedish TSO and Finnish TSO. The respective values in both directions is calculated by Lithuanian TSO taking into account the following commonly agreed and coordinated measures/parameters:

i. Forecasted inertia level in BSPS.

ii. Available fast frequency response settings on HVDC links in BSPS.

iii. Forecasted available fast frequency reserves amount provided by Battery Energy Storage Systems (BESS) in BSPS.

iv. Disconnection of AC interconnection with CESA shall not cause rate of change of frequency (ROCOF) greater than 1 Hz/s and activation of load shedding in BSPS.

17.3. TTC values for relevant direction calculated considering small signal operational security stability limits (according 17.2.3.ii) shall be defined by applying following approach:

$$TTC_{SS(PL>LT)} = \min(TTC_{1(PL>LT)}; TTC_{2(PL>LT)}); \quad TTC_{SS(LT>PL)} = \min(TTC_{1(LT>PL)}; TTC_{2(LT>PL)}) \qquad (13)$$

Where:

$TTC_{SS(PL>LT)}$; $TTC_{SS(LT>PL)}$ – Total Transfer Capacity considering dynamic small signal stability limits.

$TTC_{1(PL>LT)}$; $TTC_{1(LT>PL)}$ – small signal stability limit with N-1 line outages evaluation in directions to PL>LT and LT>PL.

$TTC_{2(PL>LT)}$; $TTC_{2(LT>PL)}$ – security limit based on small signal stability criteria without N-1 line outages evaluation shall be calculated considering security limits based on small signal stability criteria and possible loss of **biggest infeed in Baltic PS** in directions to PL>LT and LT>PL.

$$TTC_{2(PL>LT)} = TTC_{0(PL>LT)} - MaxInf; \quad TTC_{2(LT>PL)} = TTC_{0(LT>PL)} - MaxDem \tag{14}$$

Where:

$TTC_{0(PL>LT)}$; **$TTC_{0(LT>PL)}$** – small signal stability limit without N-1 line outages in directions PL>LT and LT>PL.

MaxInf - biggest N-1 infeed disconnection in BSPS.

MaxDem - biggest N-1 demand disconnection in BSPS.

17.4. The hourly values of matched TTC according to Operational security limits defined in 17.2.1 - 17.2.34 in direction to Lithuania are calculated according to the following formula:

$$TTC_{PL>LT} = \min (PL\ TTC_{SS(PL>LT)}; LT\ TTC_{SS(PL>LT)}; TTC_{(PL>LT)(F)}) \tag{15}$$

where:

PL $TTC_{SS(PL>LT)}$ – TTC between LT and PL bidding areas in direction to Lithuania, determined by PL TSO, considering Operational security limits defined in 17.2.1 - 17.2.3 and 17.3.

LT $TTC_{SS(PL>LT)}$ – TTC between LT and PL bidding areas in direction to Lithuania, determined by LT TSO, considering Operational security limits defined in 17.2.1 - 17.2.3 and 17.3.

$TTC_{(PL>LT)(F)}$ – TTC of Lithuania-Poland Cross-Border interconnection in direction to Lithuania calculated by Lithuanian TSO considering frequency stability limits as in 17.2.4.

17.5. The hourly values of matched TTC according to Operational security limits defined in 17.2.1 - 17.2.34 in directions to Poland are calculated according to the following formula:

$$TTC_{LT>PL} = \min (PL\ TTC_{SS(LT>PL)}; LT\ TTC_{SS(LT>PL)}; TTC_{(LT>PL)(F)}) \tag{16}$$

where:

PL $TTC_{SS(LT>PL)}$ – TTC between LT and PL bidding areas in direction to Poland, determined by PL TSO, considering Operational security limits defined in 17.2.1 - 17.2.3 and 17.3.

LT $TTC_{SS(LT>PL)}$ – TTC between LT and PL bidding areas in direction to Poland, determined by LT TSO, considering Operational security limits defined in 17.2.1 - 17.2.3 and 17.3.

$TTC_{(LT>PL)(F)}$ – TTC of Lithuania-Poland Cross-Border interconnection in direction to Poland calculated by Lithuanian TSO considering frequency stability limits as in 17.2.4.

18 TRADING CAPACITY CALCULATION RULES BETWEEN LITHUANIAN AND POLISH POWER SYSTEMS FOR DAY AHEAD TIMEFRAME

18.1. NTC values for Lithuania-Poland Cross-Border Interconnection in direction to Lithuania shall be calculated by using following formula:

$$NTC_{(PL>LT)} = TTC_{(PL>LT)} - TRM_{(PL>LT)} \tag{17}$$

where:

$TTC_{(PL>LT)}$ – TTC of Lithuania-Poland cross border interconnection in direction to Lithuania calculated by Polish and Lithuanian TSOs according to formula (15) as in 17.4.

$TRM_{(PL>LT)}$ – transmission reliability margin due to unintentional deviations in the Lithuania-Poland cross border interconnection. For initial operation period after Baltic TSOs synchronisation with CESA, TRM shall be calculated and applied according to 12.6, but not higher, than 30% of $TTC_{(PL>LT)}$.

18.2. NTC values for Lithuania-Poland Cross-Border Interconnection in direction to Poland shall be calculated by using following formula:

$$NTC_{(LT>PL)} = TTC_{(LT>PL)} – TRM_{(LT>PL)} \quad (18)$$

where:

$TTC_{(LT>PL)}$ – TTC of Lithuania-Poland cross border interconnection in direction to Poland calculated by Polish and Lithuanian TSOs according to formula (16) as in 17.5.

$TRM_{(LT>PL)}$ – transmission reliability margin due to unintentional deviations in the Lithuania-Poland cross border interconnection. For initial operation period after Baltic TSOs synchronisation with CESA, TRM shall be calculated and applied according to 12.6, but not higher, than 30% of $TTC_{(LT>PL)}$.

19 INTRADAY AVAILABLE TRANSMISSION CAPACITY CALCULATION BETWEEN LITHUANIAN AND POLISH POWER SYSTEMS

19.1 The available capacity after the Day-Ahead Market results is offered to the Intraday Market in line with actual operational conditions. The intraday capacity can be influenced by changed TTC caused by changes in prognosis, topology, and in maintenance plans.

19.2 Intraday Trading Capacity on cross-border Lithuania-Poland in direction to Lithuania allocated according to formula:

$$ATC_{PL>LT} = NTC_{(PL>LT)} - AAC_{(PL>LT)} + AAC_{(LT>PL)} \quad (19)$$

where:

$NTC_{(PL>LT)}$ - NTC between Lithuanian and Polish power systems calculated in accordance to formula (17) by taking into account actual value of $TTC_{(PL>LT)}$ and $TTC_{(PL>LT)(F)}$ ($TTC_{(PL>LT)}$ and $TTC_{(PL>LT)(F)}$ used in day ahead time frame for NTC calculation can be changed in case of changes in prognosis, topology, and in maintenance plans).

$AAC_{(PL>LT)}$ - Already Allocated Capacity to the Lithuania-Poland interconnection in the direction from Poland to Lithuania for relevant time period after previous capacity allocation phases.

$AAC_{(LT>PL)}$ - Already Allocated Capacity to the Lithuania-Poland interconnection in the direction from Lithuania to Poland for relevant time period after previous capacity allocation phases.

19.3 Intraday Trading Capacity on cross-border Lithuania-Poland in direction to Poland allocated according to formula:

$$ATC_{LT>PL} = NTC_{(LT>PL)} - AAC_{(LT>PL)} + AAC_{(PL>LT)} \quad (20)$$

where:

$NTC_{(LT>PL)}$ - NTC between Lithuanian and Polish power systems calculated according to formula (18) by taking into account actual value of $TTC_{(LT>PL)}$ and $TTC_{(LT>PL)(F)}$ ($TTC_{(LT>PL)}$ and $TTC_{(LT>PL)(F)}$ used in day ahead time frame for NTC calculation can be changed in case of changes in prognosis, topology, and in maintenance plans).

$AAC_{(PL>LT)}$ - Already Allocated Capacity to the Lithuania-Poland interconnection in the direction from Poland to Lithuania for relevant time period after previous capacity allocation phases.

$AAC_{(LT>PL)}$ - Already Allocated Capacity to the Lithuania-Poland interconnection in the direction from Lithuania to Poland for relevant time period after previous capacity allocation phases.

20 CROSS-ZONAL CAPACITY VALIDATION METHODOLOGY

20.1. Each TSO shall validate and have the right to correct Cross-Zonal Capacity relevant to the TSO's Bidding Zone borders or Critical Network Elements provided by the Capacity calculators in accordance with Articles 27 to 31 of CACM Regulation.

20.2. Each TSO may reduce Cross-Zonal Capacity during the validation of Cross-Zonal Capacity referred to in this Section for reasons of Operational Security according to Article 26.3 of CACM Regulation.

20.3. Article 26.2 of CACM Regulation (rule for splitting the correction of Cross-Zonal Capacity) is not included in this methodology due to the fact that splitting of capacities among borders of Baltic CCR is not performed.

20.4. Capacity Calculator shall report cross-zonal capacity reduction in accordance with Article 26.5 of CACM Regulation.

21 CAPACITY CALCULATION FALLBACK PROCEDURES

21.1. According to Article 21(3) of the CACM Regulation, when the day-ahead capacity calculation for specific DA capacity calculation MTUs cannot be calculated due to a technical failure in the tools, an error in the communication infrastructure, or corrupted or missing input data, the Baltic TSOs and the CCC shall calculate the missing results by applying one of the following capacity calculation fallback procedures:

21.1.1. Capacity Calculator shall use latest data available considering available input data set out in Section 8, CGM replacement procedures according to CGMES if CGM is not available and updated grid topology for calculating cross-zonal capacity.

21.1.2. If CGM does not correctly represent network situation and/or there is insufficient data for capacity calculation, Capacity Calculator shall use regional model (regional model with relevant IGMs, correctly representing regional situation) with sufficient synchronous area data including relevant TSOs IGMs, which is suitable for calculation.

21.2. If Cross-Zonal Capacities cannot be calculated by Capacity Calculator, Capacity Calculator shall inform respective TSOs on inability to calculate capacities. Then respective TSOs calculate and coordinate capacities for respective Cross-Border Interconnections among themselves and provide coordinated capacities to Capacity Calculator and/or NEMO.

21.3. For ID ATC capacities DA NTCs and the results of the day ahead market coupling shall be used as a basis, with respect to operational security by TSO. In case if neighbouring TSOs come up with different capacity values, the lowest value shall be used as a coordinated value. As soon as technically possible updated capacity values shall be provided to DA or ID markets after calculation and validation has been successfully finalised between Capacity Calculator and relevant TSOs.

22 PROVISION AND ALLOCATION OF TRADING CAPACITY

22.1. Coordinated Capacity Calculator shall provide calculated and validated Trading Capacities and allocation constraints for relevant trading time frames to MCO for subsequent capacity allocation through implicit auctioning carried out by MCO.

22.2. Trading Capacities within the Baltic CCR are provided and allocated, subject to allocation constraints, in day-ahead and intraday timeframes - Day Ahead Market and Intraday Market. No physical capacity is reserved for long-term capacity on the Baltic CCR borders.

22.3. Trading Capacities provided for trade between the Baltic CCR Bidding Zones are equal to the offered capacities calculated according to the Sections 9-21 of this Methodology, and which is subsequently allocated through the implicit auctioning following the trading rules established by the MCO, subject to allocation constraints.

23 FIRMNESS

23.1. After the Day-ahead Firmness Deadline, all Cross-Zonal Capacity and allocation constraints are firm for day-ahead capacity allocation unless in case of Force Majeure or Emergency Situation.

23.2. The Day-ahead Firmness Deadline is 60 minutes before Day-Ahead Gate Closure Time unless there is other deadline included in “All TSOs’ Proposal for the day-ahead firmness deadline (DAFD) in accordance with Article 69 of the Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a Guideline on Capacity Allocation and Congestion Management”.

23.3. After the Day-ahead Firmness Deadline, Cross-Zonal Capacity which has not been allocated may be adjusted for subsequent allocations, subject to allocation constraints.

23.4. Intraday Cross-Zonal Capacity is firm as soon as it is allocated, subject to allocation constraints, unless in case of Force Majeure or Emergency Situation.

24 RULES FOR AVOIDING UNDUE DISCRIMINATION BETWEEN INTERNAL AND CROSS-ZONAL EXCHANGES. CCR RULES FOR EFFICIENTLY SHARING THE POWER FLOW CAPABILITIES OF CRITICAL NETWORK ELEMENTS AMONG DIFFERENT BIDDING ZONE BORDERS

24.1. When defining appropriate network areas in and between which congestion management is to apply, TSOs shall be guided by the principles of cost-effectiveness and minimisation of negative impacts on the internal market in electricity. Specifically, TSOs shall not limit interconnection capacity in order to solve congestion inside their own control area, save for the abovementioned reasons and reasons of operational security. If such situation occurs, this shall be described and transparently presented by the TSOs to all the system users. Such situation shall be tolerated only until a long-term solution is found.

24.2. The methodology and projects for achieving the long-term solution shall be described and transparently presented by the TSOs to all the system users.

The methodology and projects for achieving the long-term solution can be implicitly described in existing TSOs' documents:

- TSOs' individual power transmission system development documents.
- TSOs' common power transmission system development documents, e.g. ENTSO- E "Ten year network development plan".

In case if the methodology and projects for achieving the long-term solution is implicitly described in existing TSOs' documents, creation of additional explanatory document(-s) is not required.

24.3. In Baltic CCR rules for efficiently sharing the power flow capabilities of Critical Network Elements among different Bidding Zone borders are not needed, as there is no such Critical Network Element/-s in Baltic CCR that would clearly and in majority cases influence power flow capabilities of several borders at once. Therefore, there is no sharing of the power flow capabilities of Critical Network Elements between Bidding Zone borders and this Methodology doesn’t contain the rules for efficiently sharing the power flow capabilities of Critical Network Elements among different Bidding Zone borders.

25 IMPLEMENTATION OF THE METHODOLOGY

25.1. The TSOs shall implement the Methodology when all the following provisions are fulfilled:

a) NRA approval of the Methodology within the Baltic CCR or a decision has been taken by the Agency for the Cooperation of Energy Regulators in accordance with Article 9(11) and 9(12) of the CACM Regulation.

b) The implementation of the Coordinated Redispatching and Countertrading Methodology according to Article 35 of the CACM Regulation.

c) The implementation of the Redispatching and Countertrading Cost Sharing Methodology within the Baltic CCR required by Article 74 of the CACM Regulation.

d) Baltic TSOs are synchronised with CESA.

25.2. The Methodology shall be published on web pages of Baltic CCR TSO within 7 days after NRA approval of the Methodology within the Baltic CCR or a decision has been taken by the Agency for the Cooperation of Energy Regulators in accordance with Article 9(11) and 9(12) of the CACM Regulation.

26 APPENDIX 1: USE OF ALLOCATION CONSTRAINTS

1. Justification for using allocation constraints in the form of import and export limits as described in Section 5.3

<u>The link between net position and operational security limits</u>

Under CACM Regulation, allocation constraints are understood as *constraints needed to keep the transmission system within operational security limits,* which are in turn defined as *acceptable operating boundaries for secure grid operation.* The definition of the latter (Art. 2.7 CACM Regulation) lists *inter alia* frequency limits as one of the boundaries to be taken into account.

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 another 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 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.

<u>Legal interpretation: eligible grounds for applying allocation constraints</u>

Regarding the process of defining what allocation constraints should be applied, it should first be noted that allocation constraints (‘ACs’) are tools defined as to their purpose. CACM Regulation does not enumerate ACs in a form of a list which would allow for checking whether specific constraint is allowed by the Regulation. Thus, the application of provision on allocation constraints requires further interpretation.

CACM Regulation was issued based on Regulation 714/2009 and complements that Regulation. The general principle in Regulation 714/2009 (Art. 16.3) is that TSOs make available the maximum capacity allowed under secure network operation standards. Operational security is explained in a footnote to annex I *as keeping the transmission system within agreed security limits.* CACM Regulation rules on AC and operational security limits (‘OSLs’) seem to regulate the same matter as Article 16.3 in greater detail. The definition of ACs relates to OSLs, so to define what is an allocation constraint, we first need a clear idea of OSLs.

Similarly to the ‘open’ notion of allocation constraints in the CACM Regulation, the definition of OSLs *(the acceptable operating boundaries for secure grid operation such as thermal limits, voltage limits, short-circuit current limits, frequency and dynamic stability limits*) does not include an enumerative catalogue (a closed set), but an open set of system operation characteristics defined as to their purpose - ensuring secure grid operation. The list is indicative (using the words ‘such as’). The open-set character of the definition is also indicated by systemic interpretation, i.e. by the usage of the term in other network codes and guidelines.

In SO GL, 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 (Art. 18) - the possible influence of such issues on cross-zonal trade has been mentioned above. Operational security limits as understood by SO GL 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 GL framework, and shows that CACM Regulation application should involve circumstances related to generation and load. Moreover, as regards the way the TSOs procure balancing reserves, it should be noted that the Guideline on Electricity Balancing (EB GL) 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 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 GL void, and make it impossible or at least much more difficult to comply with SO GL.

In PSE's point of view, systemic interpretation allows for consistent implementation of all network codes. In this specific case, understanding operational security limits under CACM Regulation can be complemented by applying SO GL provisions. These, in turn, require the TSOs to apply specific market mechanisms to ensure that generation and load schedules resulting from cross-zonal trade do not endanger secure system operation. In sum, operational security limits cover a broad set of system characteristics to be respected when defining the domain for cross-zonal trade. With regard to generation and load, this is done by applying allocation constraints, in this case balancing constraints, in the form of import/export limits.

The CACM Regulation provisions on ACs should also be interpreted systemically. They ensure offering maximum possible trading opportunities while preserving system security. CACM Regulation and Regulation 714/2009 should also be interpreted in the light of Union policy on energy as prescribed in Article 194 of the TFEU. The four objectives (to *ensure the functioning of the energy market; ensure security of energy supply in the Union; promote energy efficiency and energy saving and the development of new and renewable forms of energy; and promote the interconnection of energy networks)* are of equal importance and are balanced against each other, as well as applied in the spirit of solidarity between the Member States.

In the context of allocation constraints, these principles can be seen as requiring TSOs in each Member State to use market processes to ensure security of supply as far as possible, only limited by legitimate (non-arbitrary) constraints where not applying them could threaten security of supply in one or more control areas.

CACM Regulation provisions on allocation constraints reflect these trade-offs. See e.g. recital (18), which mandates that the Union-wide price coupling process respects transmission capacity and allocation constraints. Therefore, it can be concluded that CACM Regulation does not mandate trading opportunities to the point of endangering security of supply. If there is no arbitrary discrimination, CACM Regulation, along with other codes, allow a TSO to *ex ante* prevent loss of network stability or occurrence of insufficient reserves.

2. How import and export limits contribute to meeting the CACM Regulation objectives?

Contribution to meeting the CACM Regulation objectives

Recital 2 of CACM Regulation preamble draws a reciprocal relationship between security of supply and functioning markets. Thanks to grid interconnections and cross-zonal exchange, member states do not have to fully rely on their own assets in order to ensure security of supply. At the same time, however, the internal market cannot function properly if grid security is compromised, as market trade would constantly be interrupted by system failures, and as a result potential social welfare gains would be lost. Recital 18 can be seen as a follow-up, drawing boundaries to ensure a Union-wide price coupling process, namely to respect transmission capacity and allocation constraints.

For the above reasons, one of the aims of the CACM Regulation, as expressed in Article 3, is to ensure operational security. This aim should be fulfilled insofar it does not prejudice other aims. As explained in this methodology, allocation constraints applied by Baltic CCR TSOs are proportional and do not undermine other aims of CACM Regulation.

Compliance of the three reasons for allocation constraints with Article 23

Article 23 requires that allocation constraints are:

1) a) required to maintain the system within operational security limits and b) cannot be transformed efficiently into maximum flows on critical network elements; or
2) intended to increase the economic surplus for single day-ahead or intraday coupling.

As demonstrated under point 1 above, maintaining the transmission system within operational security limits also requires maintaining the necessary reserves to respond to possible contingencies. The inability to efficiently transform these constraints into maximum flows on individual borders is explained below. Therefore, allocation constraints as proposed should be seen as compliant with the CACM Regulation.

3. Detailed reasons and method for calculating allocation constraints by PSE

Allocation constraints in Poland are applied as stipulated in the Article 5 of the Methodology. 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 document.

Rationale behind the 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 integrated scheduling based market model applied in Poland (also called central dispatch system) responsibility of Polish TSO on system balance is significantly extended comparing to such standard responsibility of TSO 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 intraday and day-ahead time frames. 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 sometimes 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] (this is why such allocation constraints are called balancing constraints). 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 optimisation problem called security constrained unit commitment and economic dispatch (SCUC/ED). Thus these two approaches ensure similar level of feasibility of transfer capacities offered to the market from the generating capacities point of view.

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 expected load, which is also

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

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 SCUC and ED. The results of this day-ahead market are then updated continuously in intraday time frame up to real time operation.

In a yearly timeframe PSE tries to distribute the maintenance overhauls requested by generators along the year in such a way that the minimum year ahead 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 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/ED 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, which corresponds to the size of the largest unit in the system.

Determination of balancing constraints in Poland

When determining the balancing 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.

Balancing constraints are bidirectional, with independent values for each market time unit, and separately for directions of import to Poland and export from Poland.

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

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

[2] The 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 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 - see footnote 2.

$$IMPORT_{constraint} = P_L - P_{DOWNres} + P_{CDmin} - P_{NCD} \quad \textbf{(2)}$$

where:

P_{CD} - sum of available generating capacities of centrally dispatched units as declared by generators[5]

P_{CDmin} - sum of technical minima of centrally dispatched generating units in operation

P_{NCD} - sum of schedules of not centrally dispatched generating units, as provided by generators (for wind farms: forecasted by PSE)

P_{NA} - generation not available due to grid constraints

P_{ER} - generation unavailabilities 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

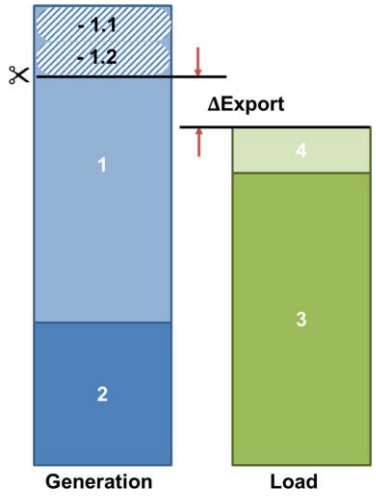
P_{Ures} - minimum reserve for up regulation

$P_{DOWNres}$ - minimum reserve for down regulation

For illustrative purposes, the process of practical determination of balancing 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.*

Balancing constraint in export direction is applicable if AExport is lower than the sum of transfer capacities on all Polish interconnections in export direction. Balancing constraint in import direction is applicable if AImport is lower than the sum of transfer capacities on all Polish interconnections in import direction.

[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

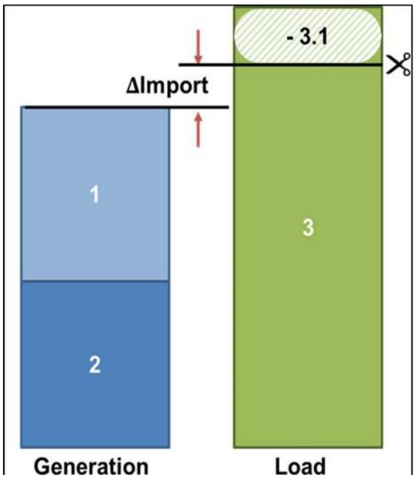
1.2 generation unavailabilities adjustment resulting from issues not declared by generators, forecasted by PSE due to exceptional circumstances (e.g. cooling conditions or prolonged overhauls)

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 balancing 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 balancing 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

Balancing 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 od D-1, resulting in independent values for each market time unit, and separately for directions of import to Poland and export from Poland.

Impact of balancing constraints on single day-ahead coupling and single intraday coupling Allocation constraints in form of balancing 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 TSO and market participants for generation resources.

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

Impact of balancing constraints on neighbouring CCRs

Balancing 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 balancing constraints are applied

As mentioned above, balancing constraints are determined in a continuous process for each allocation timeframe, so they are applicable for all market time units of the respective allocation day.

Why these 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 most likely market direction (imports and/or exports on particular interconnectors) and accordingly reduce the cross-zonal capacities in these directions. In the NTC approach, this would need to be done in the form of ATC reduction per border. However, from the point of view of market participants, due to the inherent uncertainties of market results such approach is burdened with the risk of suboptimal splitting of allocation constraints into 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 constraints at the allocation phase allows for the most efficient use of transmission infrastructure, i.e. fully in line with price differences in individual markets.