All Baltic CCR TSOs' Common Capacity Calculation Methodology for Long-term Time Frames in Accordance with Article 10(1) of the Commission Regulation (EU) 2016/1719 of 26 September 2016 Establishing a Guideline on Forward Capacity Allocation

Among:

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Vilnius, Riga, Tallinn, Helsinki, Stockholm, Warsaw

TABLE OF CONTENTS

All Baltic CCR TSOs, taking into account the following,

Whereas

(1) This document is developed by Baltic Capacity Calculation region (hereafter referred to as “Baltic CCR”) Transmission System Operators (hereafter referred to as “TSOs”) as common Capacity Calculation Methodology for Long-Term time frames (hereafter referred to as “Long-term CCM”) in accordance with Article 10(1) of Commission Regulation (EU) 2016/1719 establishing a guideline on forward capacity allocation (hereafter referred to as the “FCA Regulation”).

(2) The Long-term CCM shall be compatible with the capacity calculation methodology established for the day-ahead and intraday time frames according to Article 10(3) of FCA Regulation.

(3) The goal of the FCA Regulation is the coordination and harmonisation of forecasted cross-zonal capacity calculation and capacity allocation in the forward markets. Moreover, the requirements are set for the TSOs to cooperate on the level of capacity calculation regions (hereinafter referred to as “CCRs”), on a pan-European level and across bidding zone borders. The Article 10(2) of FCA Regulation also sets rules for establishing capacity calculation methodologies based either on the coordinated net transmission capacity approach or on the flow-based approach. This Methodology foresees to apply coordinated net transmission capacity (CNTC) approach in Baltic CCR.

(4) The objective of providing Long-term CCM is two-fold. Firstly, market participants in the power market aim at forecasting future day-ahead pricing of the different bidding zones, acting as an input to the strategies for operation and investment decisions. The goal of Long-term CCM is to provide the market participants with the information of expected capacity between bidding zones, as this information has an impact on demand and supply of electricity and hence the day-ahead pricing. Secondly, the calculation of long-term capacity will act as input to the issuing of long-term transmission rights on bidding zone borders where long-term transmissions rights are implemented.

(5) Long-term CCM is ensuring and enhancing the transparency and reliability of information on forward capacity allocation, as the Long-term CCM determines the main principles and main processes for long-term capacity calculation timeframes. The Methodology enables TSOs in a transparent way to provide information on forecasted cross-zonal capacities for long-term transmission rights auctions where applicable on Baltic CCR borders.

(6) In this Long-term CCM, unless the context requires otherwise:

a) headings are inserted for convenience only and do not affect the interpretation of this Long-term CCM; and
b) any reference to legislation, regulations, directives, orders, instruments, codes or any other enactment shall include any modification, extension or re-enactment of it when in force.
c) references to an “Article” are, unless otherwise stated, references to an article of this Long-term CCM.

(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. The capacity of interconnection 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. TSOs will continue offering maximum capacity for cross-border trading, compliant with operational security limits and considering possible contingencies in the Polish and Lithuanian 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 and whereas (54) of Regulation (EU) 2024/1747 of the European Parliament and of the Council of 13 June 2024 amending Regulations (EU) 2019/942 and (EU) 2019/943 as regards improving the Union's electricity market design.

SUBMIT THE FOLLOWING LONG-TERM CCM TO ALL REGULATORY AUTHORITIES OF THE BALTIC CCR:

1 SUBJECT MATTER AND SCOPE

1.1. The common CCM for long-term timeframes as determined in this document shall be considered as the common Long-term Methodology of Baltic CCR TSOs in accordance with Article 10(1) and Article 21 of FCA Regulation.

1.2. Long-term CCM covers year ahead and month ahead long-term capacity calculation timeframes, which are foreseen by Article 9 of FCA Regulation, and any timeframe included in the regional design of long-term transmission rights pursuant to Article 31 of FCA Regulation.

1.3. No physical capacity allocation (both implicitly and explicitly) other than balancing capacity market allocations are made before day-ahead implicit allocation and no physical capacity is reserved (both implicitly and explicitly) for long-term capacity on the Baltic CCR borders.

2 DEFINITIONS

2.1. For the purposes of the Long-term CCM, terms used in this document shall have the meaning of the definitions included in Article 2 of the Commission Regulation (EU) 2015/1222 establishing a guideline on capacity allocation and congestion management (hereafter referred to as "CACM Regulation"), Article 2 of the FCA Regulation, Article 2 of Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity and Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU.

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

CCC – Coordinated capacity calculator established in accordance with Article 27 of CACM Regulation.

CEP – Clean Enegy Package.

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

CGMM – common grid model methodology in accordance with Articles 67(1) and 70(1) of Commission Regulation (EU) 2017/1485 of 02 August 2017 establishing a guideline on electricity transmission system operation.

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.

Elering – Elering AS, electricity 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.

GLSK – generation and load shif keys further elaborated in Article 24 of CACM Regulation.

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.

Baltic AC interconnectors – Interconnectors in Baltic area, covering Lithuania – Latvia, Lithuania – Poland, Latvia – Estonia cross-borders.

3 CAPACITY CALCULATION AND VALIDATION PROCESS

3.1. Capacity calculation and validation process involves TSOs and Coordinated Capacity Calculator (hereafter referred to as “CCC”) and consists of these main steps:

- Input data provision by TSOs for Capacity Calculator (further detailed in Paragraph 3.3).
- Capacity calculation (further detailed in Sections 8 - 15).
- Capacity validation and coordination procedure (further detailed in Section 20).
- Capacity publication to market operator (further detailed in Section 22).

Detailed data exchange processes rules describing input data provision, capacity calculation, coordination, validation and process step timings shall be described in agreements between TSOs and CCC.

3.2. TSOs of Baltic CCR shall set up CCC according to rules set out in Article 27.2 of the CACM Regulation and Article 37.1.a of CEP Regulation and establish rules governing their operations defined in agreements between TSOs and CCC.

3.3. TSOs of the Baltic CCR shall provide to the CCC and coordinate between the TSOs and the CCC the following inputs for TTC calculation according to Article 29.1 of the CACM Regulation:

- IGM - base case model, which includes power transmission equipment model of Control Area of TSO (according to CACM Article 17 and Section 8.4).
- Operational Security Limits (according to Section 5).
- Generation and Load Shift Keys (according to Section 6).
- Critical Network Elements (according to Section 5).
- Contingencies (according to Section 5).
- Remedial Actions (according to Section 7).
- TRM values or input data for TRM calculation (according to Section 4).
- Allocation constraints (according to Section 5.5).

3.4. If input data for capacity calculation process referred in 3.3 is used as static data and is constant in daily capacity calculation processes, such data shall be reviewed and shared between TSOs and CCC at least on a yearly basis or upon TSO or CCC request.

3.5. In accordance with Article 29 and 30 of the CACM Regulation, capacity calculation shall be performed by the CCC whereas the TSOs shall provide required input data and perform validation.

4 TRANSMISSION RELIABILITY MARGIN CALCULATION METHODOLOGY

4.1. The TRM is a capacity margin needed for secure operation of interconnected power systems considering the planning data inaccuracy (load and generation prognosis) , including the errors due to imperfect information during operational electrical system planning at the time the transfer capacities have been computed.

4.2. TRM calculation methodology is covering Baltic AC interconnectors of BSPS.

4.3. TRM value for DC interconnectors shall be equal to 0 MW.

4.4. 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 (1):

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

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;

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

n - number of elements in the data set.

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

4.6. For initial operation period after Baltic TSOs synchronisation with CESA, fixed TRM values shall be applied to AC interconnections of BSPS. These values shall be applied for 1 month period. After this period, TRM shall be calculated according to principles set out in 4.4 and 4.5. Fixed values provided in Table 1.

Table 1. 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

5 OPERATIONAL SECURITY LIMITS, CRITICAL NETWORK ELEMENTS, CONTINGENCIES AND ALLOCATION CONSTRAINTS

5.1. 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.

5.2. 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.

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

5.4. 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;

5.5. A TSO may use allocation constraints 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 - hereinafter referred to as balancing constraints), thus limiting the net position of the respective bidding zone with regards to all CCRs which are part of long term calculation process. The global net position constraint is used to ensure a minimum level of operational reserve for balancing in case of a central dispatch model. The balancing constraints introduced are bi-directional, with independent values for directions of import and export, depending on the foreseen balancing situation. This balancing constraints on long-term level, may be used only as long as they serve to accommodate the existing day-ahead balancing constraints. The details, justifications for use, and the methodology for the calculation of this kind of allocation constraints are set forth in Annex 1.

5.6. The allocation constraint specified in Article 5.5 may be used for an interim period of 2 years following the implementation of this Methodology. If all of the Baltic CCR TSOs still want to use allocation constraints after this period, they shall deliver a proposal for amendments to this Methodology, describing the technical details for calculating the allocation constraints and the justification for the need for them latest two years after the implementation of this Methodology. The justification shall include, in the explanatory document, the impact of the allocation constraint on economic surplus and the distributional effects during the MTUs when the allocation constraint has been binding during the last 12 months and alternative solutions. In case such a proposal has been submitted, the interim period shall be extended until the decision on the proposal is taken by all national regulatory authorites (hereafter referred to as “NRAs”) of the Baltic CCR.

5.7. The TSOs applying the long-term allocation constraints as specified in Article 5.5 shall:

a) update the calculation of allocation constraints at least on a quarterly basis; and

b) provide to all CCR Baltic TSOs and NRAs the detailed calculation and its results upon each update of the allocation constraints’ values.

5.8. Each Baltic CCR TSO and CCC shall perform regular review of CNEs, Contingencies, Allocation constraints and other input data and evaluate their relevance and application in capacity calculation process. Reviews shall be performed on a yearly basis, in line with the requirements set forth in Article 27(4) of the CACM and Article 3(f) of the FCA Regulation. Where the review identifies a need to update any long-term capacity calculation inputs, the following steps shall be undertaken:

- The updated information shall be published no later than one month prior to it's implementation.
- The updates shall be communicated to NRAs of the Baltic CCR and market participants. The Baltic CCR TSOs shall communicate the impact of any change of parameters listed in Article 27(4)(d) of the CACM Regulation to market participants and all Baltic CCR NRAs.
- If the update results in a change to the methodology, the Baltic TSO's shall submit a proposal for amendment of the methodology in accordance with Article 4(12) of the FCA Regulation.

6 GENERATION AND LOAD SHIFT KEYS (GLSK)

6.1. 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 according to Article 24 of the CACM Regulation. That forecast shall notably take into account the information from the generation and load data provision methodology according to Article 16 of CACM Regulation. GLSK strategy per TSO control 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 paragraphs 6.3 and 6.4.

6.2. Default GLSK strategy shall be based on merit order principle and set up according to paragraphs 6.3 and 6.4. To maintain Operational Security and data accuracy TSOs may determine different GLSK strategy based on best available forecast for generation and load according to Article

24 of the CACM Regulation. If TSOs determine different GLSK strategy, implementation in calculation algorithm shall be coordinated with Capacity Calculator.

6.3. TSOs shall define GLSK strategy to best represent latest specific changes of generation or load in TSO control area according to Article 24 of the CACM Regulation. Following generation and/or load groups merit order 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.

6.4. GLSK principle depending upon a merit order generation/load shift key method shall be performed according to following rules:

6.4.1. The chosen generation nodes scaled up or down according to the merit order list defined in the GLSK input, provided by TSOs. GLSK data shall contain the generation nodes which performs the total positive or negative shift are provided.

6.4.2. The merit order determines sequence how generation shift is applied to node. The order is defined by the TSOs to best represent latest specific changes of generation or load in TSO control area. If group of generators have the same merit order, then that group of generators will be shifted proportionally.

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

7 REMEDIAL ACTIONS (RAS)

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

7.2. List of possible remedial actions in Baltic CCR, which can be used during capacity calculation process shall cover changes of network topology.

7.3. 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. 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. Countertrading and redispatching possibilities along with other remedial actions shall be fully exploited before an internal Critical Network Element may affect cross zonal trade.

8 COMMON RULES CAPACITY CALCULATION METHODOLOGY FOR LONG-TERM TIME FRAMES

8.1. Long-term cross-zonal capacity shall be calculated for each timeframe which are foreseen by Article 9 of FCA Regulation and any timeframe included in the regional design of long-term transmission rights pursuant to Article 31 of FCA Regulation. Capacity calculation process shall be performed as separate calculation for each long-term timeframe.

8.2. TSOs cannot start long-term capacity calculation process for any of the upcoming year's timeframes before agreeing on preliminary transmission infrastructure outage plans, which taking into account provisions of Article 97 of Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation (SO GL) will be earliest on 1st of November of each year.

8.3. Long-term cross-zonal capacity shall be calculated for all Baltic CCR borders after TSOs and CCC have all information (needed for calculations – i.e. information mentioned in Articles 3 to 7 of this methodology, CGM, as well as planned transmission infrastructure outage plans. Latest agreed transmission infrastructure outage plan shall be used for each long-term capacity calculation period. The long-term cross-zonal capacity for respective border and respective timeframe is calculated according to Article 23(2) of FCA Regulation and applying requirements set out in Article 29 of CACM Regulation.

8.4. The uncertainties in long-term cross-zonal capacity calculation will be taken into account by applying a security analysis based on multiple scenarios in accordance with Article 3 of the CGMM developed in accordance with Article 18 and 19 of the FCA Regulation. Unless and until these scenarios have been developed, the default scenarios as defined in Article 3(1) of CGMM shall be used. On those scenarios outage sets can be applied as stipulated in 8.2 to take into account all available information for capacity calculation including transmission lines' outage plans, which can change on daily basis for long-term capacity calculation process.

8.5. Long-term cross-zonal CCM for each Baltic CCR border is given below in Sections 10-11. Long-term cross-zonal capacity calculation process shall be performed by CCC following requirements of Section 4 of FCA Regulation.

8.6. Limits of transmission capacity on the Polish-Lithuanian border shall be determined pursuant to Section 12, using the latest available CGM models in accordance with Article 3 of the CGMM developed in accordance with Article 18 and 19 of the FCA Regulation or special models prepared by TSOs for respective periods in which its closed 110 kV distribution grid is included as well as latest forecast of a load, generation and topology.

9 TTC CALCULATION METHODOLOGY

9.1. 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 5 of synchronous area and Control Area of Baltic TSOs.

9.2. TTC is maximum power flow value on Cross-Border Interconnection between two bidding zones resulted from modelling net position variation and performing 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 are reached for any CNE after modelling net position increase in exporting area and decrease in importing area and performing N-1 contingency analysis.

9.3. TSOs and Capacity Calculator shall not limit cross-zonal exchanges due to Critical Network Elements not significantly impacted by cross-zonal trade according to Article 29.3(b) of CACM Regulation and Section 5 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.

9.4. 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 time dependent stability limit (including frequency, oscillatory and rotor angle stability), based on TSOs internal stability assessment procedure.

9.5. TTC for each cross-border that consists solely of HVDC connections is limited by the sum of ratings of HVDC interconnectors that connect the 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 limits according to principles set out in paragraph 9.4.

10 COORDINATED NTC CALCULATION PRINCIPLES FOR INTERNAL BALTIC AC INTERCONNECTORS

10.1. For the long-term capacity calculation timeframes, CNTC (Coordinated Net transmission Capacity) approach is applied in the Baltic CCR.

10.2. Capacity Calculator shall calculate NTC value for Internal Baltic AC interconnections following equation:

$$NTC = TTC - TRM \qquad (2)$$

where:

TTC - Total Transfer Capacity according to actual power system network status, identified during TTC evaluation, defined in Section 9;

TRM - transmission reliability margin value calculated according to the methodology described in Section 4 of this Methodology.

10.3. 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.

10.4. Trading Capacity shall be defined for both interconnection directions according to formula (2). In case if during capacity validation process different NTC values are calculated for the same Cross-Border Interconnection direction the lowest value shall be used as a coordinated value.

$$NTC_{A\text{-}B;\,B\text{-}A} = \min(A\ NTC_{A\text{-}B};\ B\ NTC_{A\text{-}B});\ \min(A\ NTC_{B\text{-}A};\ B\ NTC_{B\text{-}A}) \qquad (3)$$

where:

$NTC_{A\text{-}B;\,B\text{-}A}$ – coordinated NTC values according to formula (2) for each interconnection direction between area A and B;

A $NTC_{A\text{-}B}$; A $NTC_{B\text{-}A}$ – as calculated by party A according to formula (2);

B $NTC_{A\text{-}B}$; B $NTC_{B\text{-}A}$ – as calculated by party B according to formula (2) .

11 COORDINATED NTC CALCULATION PRINCIPLES FOR DC INTERCONNECTORS

11.1. CCC shall calculate NTC value for Baltic DC interconnectors using formula (2) considering input data provided from TSOs.

11.2. (2)TTC calculation approach defined in Section 9 for DC interconnectors shall be applied by Capacity Calculator assigned by Baltic CCR.

11.3. Coordinated capacity value shall be obtained by evaluating minimum value according to principles defined in 10.4 and formula (3).

12 TOTAL TRANSFER CAPACITY (TTC) CALCULATION FOR LITHUANIAN - POLAND AC CROSS-BORDERS INTERCONNECTOR

12.1. While calculating TTC, list of considered CNE and contingencies should be determined according to Section 5.

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

12.2.1. 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.

12.2.2. 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.

12.2.3. Dynamic stability limits including:

i. transient stability.

ii. small signal stability (see further description in paragraph 12.3).

12.2.4. Frequency stability limit is assessed based on commonly agreed and coordinated availability of frequency support measures between Baltic TSOs. Measure 12.2.4.ii is agreed between relevant Baltic TSOs, Swedish TSO and Finnish TSO. The respective values in both directions are 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.

12.3. TTC values for relevant direction calculated considering small signal operational security stability limits (according 12.2.3.ii) shall be defined by applying following approach:

$$TTC_{SS(PL>LT)} = \min\left(TTC_{1(PL>LT)}; TTC_{2(PL>LT)}\right); \quad TTC_{SS(LT>PL)} = \min\left(TTC_{1(LT>PL)}; TTC_{2(LT>PL)}\right) \qquad (4)$$

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.

$$TTC_{2(PL>LT)} = TTC_{0(PL>LT)} – MaxInf; \quad TTC_{2(LT>PL)} = TTC_{0(LT>PL)} – MaxDem \qquad (5)$$

Where:

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

MaxInf - biggest N-1 infeed disconnection in BSPS.

MaxDem - biggest N-1 demand disconnection in BSPS.

12.4. The hourly values of matched TTC according to Operational security limits defined in 12.2.1 - 12.2.3 in direction to Lithuania are calculated according to the following formula:

$$TTC_{PL>LT} = \min (PL\ TTC_{SS(PL>LT)};\ LT\ TTC_{SS(PL>LT)};\ TTC_{(PL>LT)(F)}) \qquad (6)$$

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 12.2.1 - 12.2.3 and 12.3.

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 12.2.1 - 12.2.3 and 12.3.

$TTC_{(PL>LT)(F)}$ – TTC of Lithuania-Poland Cross-Border Interconnection in direction to Lithuania calculated by Lithuanian TSO considering frequency stability limits as in 12.2.4.

12.5. The hourly values of matched TTC according to Operational security limits defined in 12.2.1 - 12.2.3 in directions to Poland are calculated according to the following formula:

$$TTC_{LT>PL} = \min (PL\ TTC_{SS(LT>PL)};\ LT\ TTC_{SS(LT>PL)};\ TTC_{(LT>PL)(F)}) \qquad (7)$$

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 12.2.1 - 12.2.3 and 12.3.

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 12.2.1 - 12.2.3 and 12.3.

$TTC_{(LT>PL)(F)}$ – TTC of Lithuania-Poland Cross-Border Interconnection in direction to Poland calculated by Lithuanian TSO considering frequency stability limits as in 12.2.4.

NTC CALCULATION RULES BETWEEN LITHUANIAN AND POLISH POWER SYSTEMS

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

$$NTC_{(PL>LT)} = TTC_{(PL>LT)} - TRM_{(PL>LT)} \qquad (8)$$

where:

$TTC_{(PL>LT)}$ – TTC of Lithuania-Poland Cross-Border Interconnection in direction to Lithuania calculated by Polish and Lithuanian TSO’s according to formula (6) as in 12.4.

$TRM_{(PL>LT)}$ – 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 paragraph 4.6, but not higher, than 30% of $TTC_{(PL>LT)}$.

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

$$NTC_{(LT>PL)} = TTC_{(LT>PL)} - TRM_{(LT>PL)} \tag{9}$$

where:

$TTC_{(LT>PL)}$ – TTC of Lithuania-Poland Cross-Border Interconnection in direction to Poland calculated by Polish and Lithuanian TSO's according to formula (7) as in 12.5.

$TRM_{(LT>PL)}$ – 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 4.6, but not higher, than 30% of $TTC_{(LT>PL)}$.

13 LONG-TERM CAPACITY CALCULATION RULES FOR YEAR-AHEAD TIMEFRAME

13.1. For LV-LT, LT-PL, LT-SE4 Year-Ahead timeframe long-term capacity calculation process shall publish results to market participants and transparency platform by 15th of December as the latest.

13.2. For EE-LV and EE-FI Year-Ahead timeframe long-term capacity calculation process shall publish results to market participants and transparency platform by 8th of November as the latest.

13.3. Capacity calculation for Year-Ahead timeframe shall be performed on a yearly CGM. Scenarios and timestamps for yearly CGM shall be set according to CGMM methodology.

13.4. Capacity calculation for Year-Ahead timeframe shall be performed at least for each month of the year using latest available CGM scenario and yearly coordinated outages plan applied. Capacities shall also be calculated for each cross-zonal capacity impacting planned outages or outages combination period also including new infrastructure plans and generation/load patterns.

13.5. TTC and NTC values shall be calculated considering system security and net position variation in accordance with Section 9.

14 LONG-TERM CAPACITY CALCULATION RULES FOR MONTH-AHEAD TIMEFRAME

14.1. For Month-Ahead timeframe long-term capacity calculation process shall provide results 6 days before analysed month the latest.

14.2. Capacity calculation for Month-Ahead timeframe shall be performed on a latest available CGM or yearly CGM. Data for CGM shall be updated accordingly.

14.3. Capacity calculation for Month-Ahead timeframe shall be performed at least for each day of the month using latest available CGM scenario and yearly or latest available coordinated outages plan applied. Capacities shall also be calculated for each cross-zonal capacity impacting planned outages or outages combination period also including new infrastructure plans and generation/load patterns.

14.4. TTC and NTC values shall be calculated considering system security and net position variation in accordance with sections Section 9.

15 LONG-TERM CAPACITY CALCULATION FOR OTHER TIMEFRAMES

15.1. If any of Baltic CCR TSO needs to offer or publish capacities for any additional timeframes, the results from the previous capacity calculation (M-1, Y-1) that cover the additional timeframe will be used as default.

15.2. If, for the case mentioned in point15.1, there are any changes to outages defined respectively in yearly or monthly outage plan, NTC's used for processed timeframe shall be re-calculated for relevant cross-borders to ensure transparency of the capacities for the market.

15.3. The results of recalculation process shall be published as mentioned in point 22.1 and 22.2.

15.4. Capacity calculation for any other timeframe shall be performed using the latest available CGM as described in paragraph 8.4 and 8.6 and outage plan to calculate capacities.

15.5. TTC and NTC values shall be calculated considering system security and net position variation in accordance with sections in Section 8.

16 RULES FOR TAKING INTO ACCOUNT PREVIOUSLY ALLOCATED CROSS-ZONAL CAPACITY

When determining cross-zonal capacities for any long-term timeframe defined in this methodology, previously allocated capacities shall be considered. Cross-zonal capacities shall be reduced, where appropriate, by the amount of previously allocated capacities for long-term transmission rights (if present).

17 RULES FOR EFFICIENTLY SHARING POWER FLOW CAPABILITIES OF CRITICAL NETWORK ELEMENTS AMONG DIFFERENT BIDDING-ZONE BORDERS

17.1. 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. To ensure that potential congestions inside a control area do not affect the interconnection capacity the TSO shall exploit all available remedial actions such that cross-zonal capacities is at least as high as prescribed in Article 16(8) of the Electricity Market Regulation 2019/943.

17.2. Baltic TSOs network is radial which results in direct flows between areas without any loop flows and there is no such CNEs in Baltic CCR that would clearly and in majority cases influence power flow capabilities of several borders at once, therefore rules for efficiently sharing the power flow capabilities of CNEs among different bidding zone borders in Baltic CCR are not applied.

18 RULES FOR SHARING THE POWER FLOW CAPABILITIES OF CRITICAL NETWORK ELEMENTS AMONG DIFFERENT CCRS

In the Baltic CCR, no critical network elements (CNEs) that are important for more than one region were identified. Therefore, all CNEs are handled the same way (equaly) during the capacity calculation process. This ensures that the power-flow capacity is shared fairly and evenly among the different regions. It prevents any region from being favoured over others, promoting transparency and fairness. By using the network effectively, this method ensures that all regions can share resources without risking system reliability or safety.

19 RULES ON THE ADJUSTMENT OF POWER FLOWS OF CROSS-ZONAL CAPACITY DUE TO RAS

CCC shall take into account in the capacity calculation RAs as defined in Section 7 to increase the cross-zonal capacity for the long-term time frame. If RAs are agreed during capacity calculation for any long-term timeframe process, TSOs shall ensure availability of agreed RAs or provide alternative RAs to maintain operational security.

20 CROSS-ZONAL CAPACITY VALIDATION METHODOLOGY

20.1. Each TSO shall perform the validation of cross-zonal capacities on its bidding zone border(s) to ensure that the results of regional calculation of cross-zonal capacity will ensure operational security. When performing the validation, the TSOs shall consider operational security, taking into account new and relevant information obtained during or after the most recent capacity calculation.

20.2. According to Article 24 of FCA Regulation and Article 26 of CACM Regulation, each TSO shall validate and have the right to correct long-term cross-zonal capacity relevant to the TSO's bidding zone borders provided by the CCC. If during the initial or after capacity calculation/coordination process a TSO identifies an issue with the capacity calculation results or determines that it needs to make adjustments (e.g., due to updated data, operational constraints, or errors), it has the authority to correct or recalculate these capacities. Once the TSO recalculates or corrects the capacities, it must send the updated values back to the CCC. The CCC then coordinates with relevant parties to ensure these corrected capacities are used appropriately. The TSO must document the reasons for any correction or rejection of the original capacity values (e.g., technical issues, unexpected grid conditions, or operational security concerns). These reasons are shared with the CCC to maintain transparency and support the coordination process.

21 FALLBACK PROCEDURE

If long-term cross-zonal capacities cannot be calculated by CCC, the CCC informs relevant TSOs on inability to calculate capacities. Then relevant TSOs calculate, coordinate capacities and publish for respective Cross-Border Interconnection among themselves as set in accordance with Section 10 and provide coordinated capacities to CCC.

22 PUBLICATION OF DATA

22.1. Calculated long-term capacities shall be published in ENTSO-E Transparency platform as soon as available after calculations for all Baltic CCR borders by TSOs or CCC of Baltic CCR but not later than foreseen according to Article 11 of Regulation 543/2013.

22.2. Long-term capacities calculated according to this methodology and published at ENTSO-E Transparency Platform can be updated at any time before, during and/or after long term transmission rights auctions in case of changes of input data used in calculations (update of calculation input preliminary data e.g. transmission infrastructure outage plans).

23 REPORTING

23.1. According to CACM article 26(5) CCC shall, every three months, report all reductions made during the validation of cross-zonal capacity to all NRAs of the capacity calculation region. This report shall include the location and amount of any reduction in cross-zonal capacity and shall give reasons for the reductions.

23.2. Following article of 24(5) of the FCA regulation, each TSO shall, upon request, provide to their NRAs a report detailing how the value of long-term cross-zonal capacity for a specific time frame has been obtained. Following the objectives of forward capacity allocation, in particular Article 3(f) of the FCA regulation, to complete the objective of “ensuring and enhancing the transparency and reliability of information on forward capacity allocation”, CCC, together with the TSOs will ensure the publication of all relevant data items per calculated scenario used in the capacity calculation.

23.3. Relevant data items shall be counted as the data items outlined in the "list of relevant information to be communicated by ENTSO for Electricity to the Agency,” as stipulated in Article 63(3) of the FCA Regulation. This list, established within six months of the Regulation's entry into force, is created in cooperation with the Agency for the Cooperation of Energy Regulators (hereafter referred to as “Agency”) and may be subject to updates to ensure ongoing relevance and compliance. ENTSO for Electricity must maintain a comprehensive, standardized format and a digital archive for the data required by the Agency.

In alignment with Article 63(3), TSOs are obligated to provide ENTSO-E with the necessary data to support its tasks. These tasks include ensuring the consistency and accuracy of data for relevant timeframes such as month-ahead, year-ahead, or additional timelines. The data provided must align with the requirements of the capacity calculation approach applied in the Baltic region.

24 IMPLEMENTATION OF THE LONG-TERM CCM

24.1. The TSOs shall implement this Long-term CCM latest in 6 months after NRAs approval of the Long-term CCM within the Baltic CCR or a decision has been taken by the Agency in accordance with Article 4(4) and/or Article 4(10) and/or Article 4(11) of the FCA Regulation.
24.2. 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 in accordance with Article 4(13) of the FCA regulation.

24.3. The TSOs shall within 24 months after the implementation of this Methodology perform an evaluation of this Methodology and submit it to the NRAs in the Baltic CCR. If needed, the TSOs shall propose a revised version of the Methodology to the NRAs in the Baltic CCR.

25 LANGUAGE

The reference language for this Long-term CCM shall be English. For the avoidance of doubt, where TSOs need to translate this Long-term CCM into their national language(s), in the event of inconsistencies between the English version published by TSOs in accordance with Article 4(13) of the FCA Regulation and any version in another language, the relevant TSOs shall, in accordance with national legislation, provide the relevant NRAs with an updated translation of the Long-term CCM.

ANNEX 1: JUSTIFICATION OF THE METHODOLOGY FOR CALCULATION OF ALLOCATION CONSTRAINTS (ARTICLE 5.5) AND ITS APPLICATION

The following section depicts in detail the justification of usage and methodology currently used by PSE to design and implement allocation constraints, if applicable.

PSE may use an allocation constraint to limit the import and export of the Polish bidding zone.

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 dispatching model) 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. Central dispatching is one of the two dispatching models authorized by EB Regulation. 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 dispatching model, it is the TSO that dispatches generating units taking into account their: operational constraints, transmission constraints and reserve capacity requirements with the aim to balance national generation, demand and cross-border exchanges while ensuring secure operation of the transmission system.

In central dispatching model, the above process is realized in an integrated scheduling process run as a single optimization problem called security constrained unit commitment (SCUC – where generation units are being dispatch on and off) and security constrained economic dispatch (SCED – where generation output for all dispatched generation units is determined).

According to the national legislation, PSE is legally obliged to ensure availability of sufficient level of generating reserves for the whole Polish power system in order to safeguard its secure operation in case of contingency, as well as in case of insufficient and ineffective balancing activities performed by market participants in Poland. However, if balancing service providers (generating units) would already have sold too much energy in the day-ahead market in form of high exports, they may not be able to provide sufficient upward reserve capacity within the integrated scheduling process as required by national legislation. This conclusion equally applies for the case when market participants import significant amount of energy, as it could result in balancing service providers being unable to provide downward regulation capabilities due to not securing enough generation levels in the day-ahead market. The strength of the imbalance settlement pricing is also important in this process, together with the maturity and the ability of the market participants to maintain balanced portfolios under objectively high RES and demand uncertainties and underdeveloped intraday markets.

This leads to implementation of allocation constraints, being the necessary means to ensure operational security of Polish power system in terms of securing generating capacities for upward or downward regulation, as well as in order to cover the national imbalances in the direction of shortage (i.e. cover the residual demand) and surplus (i.e. manage and regulate down the surplus of power during periods of oversupply). Excluding such a solution and depriving TSOs under central dispatching model from the usage of allocation constraints to set appropriate limits to how much electricity can be imported or exported by the system as a whole may lead to insufficient balancing capacity reserves, making the provisions of EB Regulation void, and making it impossible or at least much more difficult to comply with SO Regulation.

It needs to be highlighted that despite implementation of explicit balancing capacity procurement in Poland as per 14 June 2024, and despite maintaining the use of allocation constraints, PSE still has to apply remedial measures at large scale in order to ensure equilibrium between demand and supply in the Polish power system. These measures are mostly the non-market-based curtailment of RES (in case of energy surplus) and emergency exchanges with neighbouring TSOs (in case of energy surplus or shortage). Both aforementioned measures have severe negative consequences, such as difficulties for TSO and DSO dispatching teams to manage hundreds of operational commands issued to dispersed RES facilities in very short time, difficulties of RES facility owners to respond to dispatching commands issued with short notice, as well as depletion of operational reserves of neighbouring TSOs when asked for emergency exchanges, reducing overall European power system resilience. In many instances of time, neighbouring TSOs are unable to provide the requested support.

Balancing market reform executed on 14 June 2024 has significantly improved market price signals, so that balancing responsible parties are better reacting to dynamically changing power system situation. Nonetheless, the observed levels of balancing energy that needs to be activated by PSE under integrated scheduling process is still very high, often exceeding the procured balancing capacity. This implies that the new improved balancing market prices are still unable to convey sufficient incentives for market participants to improve generation and demand planning as BRPs still do not balance their portfolios earlier on more attractive day-ahead and intraday markets. Moreover, new balancing capacity reserves procurement process is still immature and suffers from lack of liquidity, low supply and low competition. Both aforementioned items are a subject of intensive analysis on PSE side with the aim to prepare improvements and increase effectiveness of price signals.

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 SCUC 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 the minimum year ahead generation reserve margin[1] 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[2], if possible. This process includes also network maintenance planning, so any constraints coming from the network operation are duly taken into account.

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 frames.

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:

1 The generation reserve margin is regulated by the Polish grid code and currently set at 18% (point 10.2.11(3)). It is subject to change depending on the results of the development of operational planning processes.

2 The generation reserve margin for monthly and weekly coordination is also regulated by the Polish grid code (point 10.2.11(2) and (3)).

$$\mathrm{EXPORT}_{constraint} = \mathrm{P}_{CD} - (\mathrm{P}_{NA} + \mathrm{P}_{ER}) + \mathrm{P}_{NCD} - (\mathrm{P}_{L} + \mathrm{P}_{UPres}) \quad (1)$$

$$\mathrm{IMPORT}_{constraint} = \mathrm{P}_{L} - \mathrm{P}_{DOWNres} - \mathrm{P}_{CD_{min}} - \mathrm{P}_{NCD} \quad (2)$$

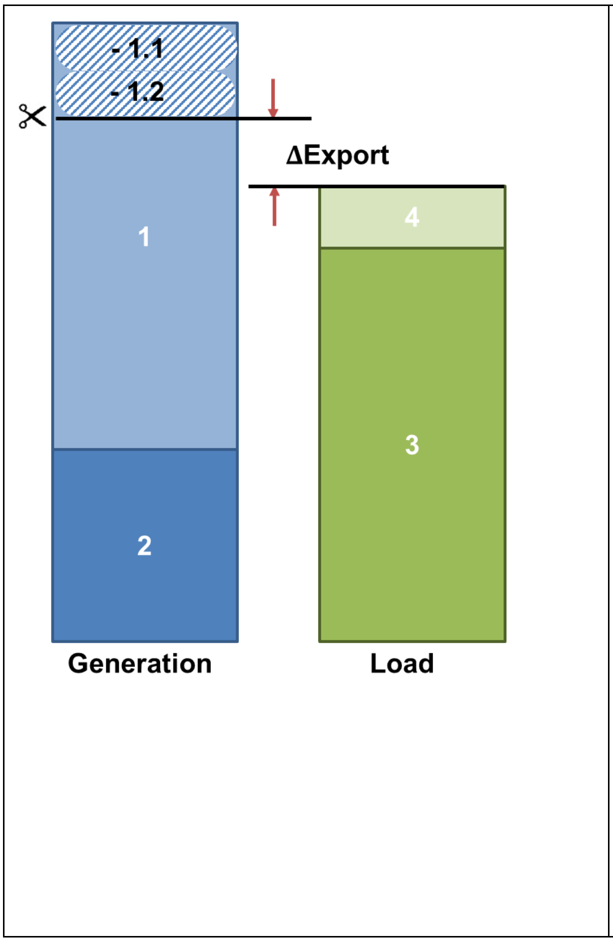
Where:

P_{CD}	Sum of available generating capacities of centrally dispatched units as declared by generators[3]
$\mathrm{P}_{CD_{min}}$	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 weather-dependent intermittent renewable generation: forecasted by PSE)
P_{NA}	Generation not available due to grid constraints (both planned outage and/or anticipated congestions).
P_{ER}	Generation unavailability's adjustment resulting from issues not declared by generators, forecasted by PSE due to exceptional circumstances (e.g. cooling conditions or prolonged overhauls)
P_{L}	Demand forecasted by PSE
P_{UPres}	Minimum reserve for up regulation
$\mathrm{P}_{DOWNres}$	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 the Polish 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.

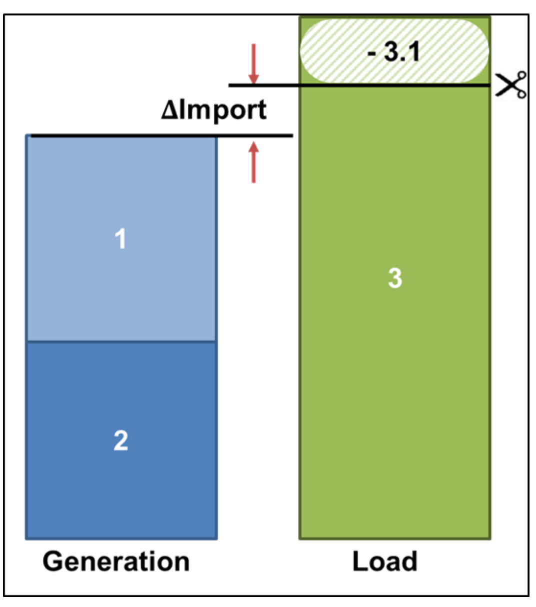
Allocation constraint in export direction is applicable if Export is lower than the sum of transfer capacities on all Polish interconnections in export direction. Allocation constraint in import direction is applicable if Import is lower than the sum of transfer capacities on all Polish interconnections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

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



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

Figure 1: Determination of 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 weather-dependent intermittent renewable generation: forecasted by PSE)

3 Demand forecasted by PSE, reduced by:

3.1 Minimum necessary reserve for down regulation

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

Frequency of review

Allocation constraints are determined in a continuous process based on the most recent information, for each capacity allocation time frame.