ENTSO-E Market Report 2026

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ELECTRIFYING THE FUTURE

Mission Statement

ENTSO-E – the European Network of Transmission System Operators for Electricity – brings together 40 electricity Transmission System Operators (TSOs) from 36 countries. ENTSO-E members are responsible for the secure and coordinated operation of Europe's electricity system. Together, they operate a system of around 500,000 km of power lines **– the largest interconnected electrical grid in the world –** and serve about 520 million citizens.

Electricity is not merely a market commodity, it is an essential service, and TSOs are fully regulated public service entities whose work is essential to powering Europe. The grid is the backbone of the electricity system and has extended over the whole Continent, beyond the borders of the EU. TSOs working together guarantee a functioning infrastructure that makes the trade of electricity possible, contributes to decarbonisation goals, and ensures a reliable and efficient power supply for all members of society.

These shared public service responsibilities need close cooperation beyond national borders, which led to the creation of ENTSO-E. Today, the association serves two main complementary purposes:

1. Cooperation of European TSOs

The foundations of this cooperation date back to the 1950s with the creation of electrical synchronous areas and interconnections, which laid the groundwork for today's interconnected European power system. TSOs established associations to work together on their own mandates and missions, that came together into what today is ENTSO-E. The European electricity system is one of the most stable and reliable grids in the world and is supported by the cooperation and coordination of TSOs both within the European Union and closely interconnected European countries. ENTSO-E strives to build consensus for decision-making amongst its member TSOs as this forms the strongest foundation for cooperation.

2. Fulfilling EU legal mandates

With the adoption of the Third Energy Package in 2009, ENTSO-E's role was formally recognised by European institutions. ENTSO-E was granted legally mandated tasks to further develop the European interconnected grid and to facilitate the integration of European electricity markets. These mandates cover a large spectrum of tasks, including system operation, system development, market integration, information technologies, R&D and innovation.

ENTSO-E
Market Report 2026

Contents

Executive Summary

Over the 2025–2026 reporting period, Europe's electricity market achieved **major strategic advances** that significantly strengthened the foundations of an integrated, future-ready internal energy market. Regulatory reforms, forward-looking design choices, and coordinated cross-border developments collectively accelerated the transition towards a more flexible, resilient, and renewable-compatible system.

Forward capacity allocation continued to perform reliably, with the single allocation platform (SAP) ensuring consistent explicit allocation of cross-zonal transmission rights across Europe. The forthcoming amendment to the FCA Guideline is expected to shape the future design of forward markets and may introduce substantial changes to long-term (LT) hedging arrangements. In parallel, transmission system operators (TSOs) and the Joint Allocation Office (JAO) have advanced the implementation of long-term flow-based allocation (LTFBA) for the Core and Nordic capacity calculation regions (CCRs), with go-live planned for the end of 2026 to support yearly and monthly products for 2027. Ongoing updates to the Harmonised Allocation Rules (HAR) and SAP methodologies are being developed to incorporate an improved collateral framework. Additionally, JAO is progressing with a major renewal of its auction infrastructure through the development of the new Orion platform, designed to enhance scalability, resilience, and LT adaptability of European forward capacity allocation systems.

Short-term market integration advanced successfully through **the full rollout of the 15-minute market time unit (MTU)** in both the day-ahead (DA) and intraday (ID) markets. This milestone enhances the precision of supply and demand matching, which is increasingly vital as renewable generation introduces greater variability. By enabling more dynamic responses to short-term fluctuations, the new granularity supports the seamless integration of new technologies.

At the same time, progress in the implementation of **flow-based (FB) capacity calculation** – including the adoption of **advanced hybrid coupling (AHC)** – aims to make capacity allocation more efficient and reflective of actual grid constraints across the regions. These methodological enhancements are instrumental in maximising social welfare and using Europe's interconnected grid more efficiently.

The period also saw Europe strengthen its regional energy cooperation. With the entry of additional observers from neighbouring systems, the European market coupling framework is expanding its reach. This broader participation will enhance market depth and support LT energy security and regional alignment on market design principles.

Overall, the year was defined by **structural progress rather than incremental adjustments**. Regulatory preparation, methodological innovation, and cross-border collaboration have together laid the groundwork for the next phase of Europe's energy market evolution. The achievements of this period demonstrate the sector's collective ability to anticipate system needs, modernise market frameworks, and advance Europe towards a more integrated, flexible, and resilient electricity system.

The main achievements in 2025–2026

- To harmonise market granularity with the imbalance settlement period (ISP) and enhance market efficiency, the 15-minute MTU was successfully implemented in the DA market on 1 October 2025, following its gradual introduction in the ID market over the preceding months.
- To comply with relevant regulatory requirements, the intraday cross-zonal gate closure time (IDCZGCT) was reduced from 60 to 30 minutes on 14 January 2026 across multiple bidding zone borders (BZBs) in countries where the derogation provided for in the regulation was not deemed necessary.
- To improve efficiency in cross-zonal capacity (CZC) allocation, AHC was implemented in the Core CCR for the DA time frame in June 2026.
- To enhance collateral management for market participants in a LT FB auction setup, TSOs and the SAP are already working on improvements for the period after the go-live of LTFBA.
- To provide the market with a scalable and reliable system, JAO is currently developing a brand-new LT auction platform.
- To further develop cross-border hedging opportunities, the functional testing of LTFBA was successfully completed. The project remains on track for go-live in November 2026. To strengthen regional coordination and capacity calculation efficiency, TSOs delivered updated CCR methodologies, including new and expanded regions, approved by the Agency for the Cooperation of Energy Regulators (ACER) in December 2025.
- To increase liquidity and integration in balancing markets, multiple TSOs joined the PICASSO (aFRR) and MARI (mFRR) platforms throughout 2025, significantly expanding cross-border participation.
- To deliver measurable economic benefits, European balancing platforms generated over EUR 1.18 billion in surplus in 2025, driven by enhanced imbalance netting and optimised balancing activations.

1 Introduction

Each year, ENTSO-E monitors the development of the European electricity markets. This monitoring covers the various time frames in which electricity is traded, ranging from LT to DA, ID, and balancing markets. The 2026 edition of the ENTSO-E Annual Market Report covers the period from June 2025 to May 2026. The report is formally submitted to ACER and is published on the ENTSO-E website following the reporting period.

Electricity markets from long-term to real-time

Despite the increasing integration of storage units such as batteries, electricity remains, broadly speaking, a commodity that cannot be stored on a large scale. It must be generated at the moment it is consumed, in real time. However, trading of electricity occurs long before this point in time and across multiple market time frames. TSOs continue to play a central role in enabling the efficient functioning of the European electricity markets by providing the optimal level of cross-border transmission capacity across all market stages – from LT planning to real-time operations. The further integration of markets across all time frames, supported by harmonised processes and regulatory frameworks, enhances the efficiency and resilience of the European power system. This market integration ultimately delivers increased security of supply, more competitive prices, and greater value for all European consumers.

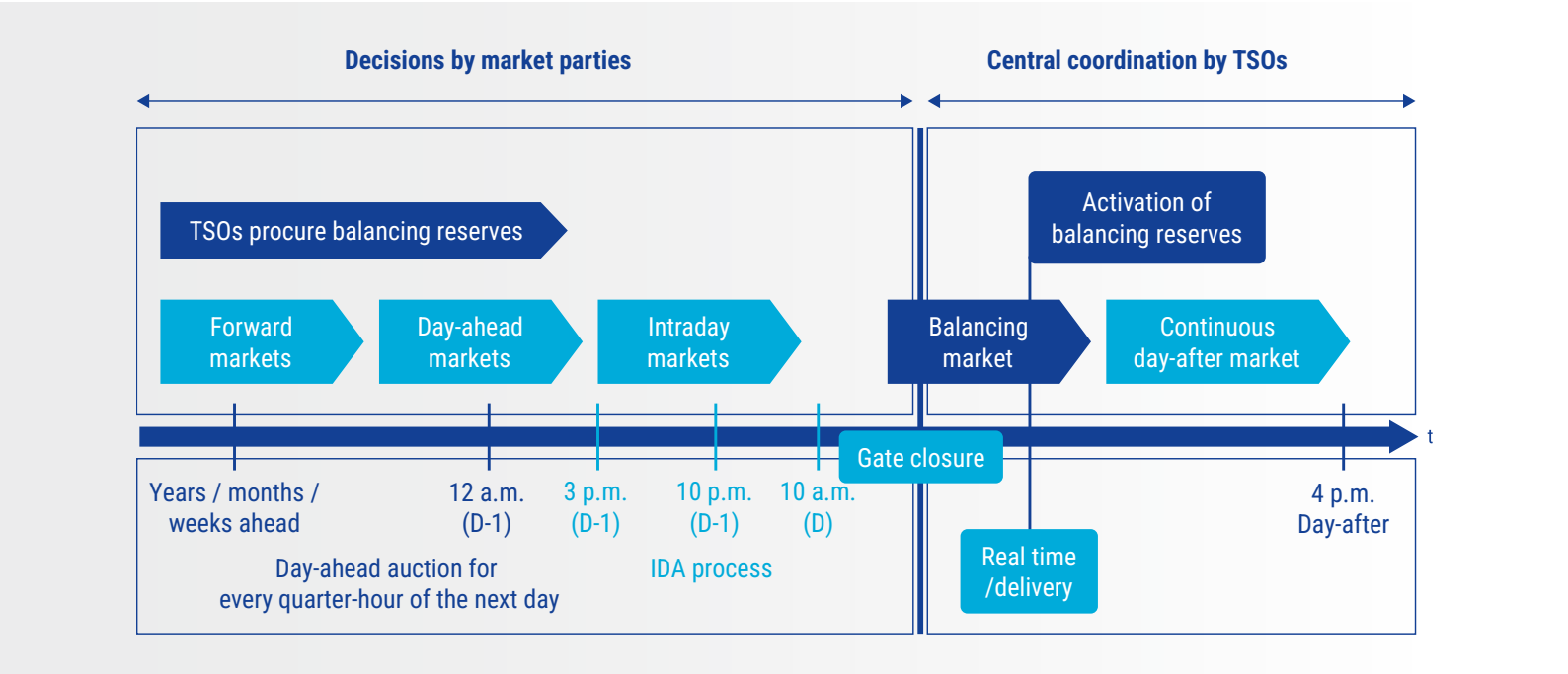


Figure 1.1: Overview of different time frames of the wholesale and balancing markets[1]

1 Where applicable

Long-term capacity calculation

As of 2026, TSOs continue to determine the appropriate level of LT cross-border transmission capacity up to one year ahead of the actual delivery date. In certain specific cases and jurisdictions, capacity calculations with a two-year-ahead horizon have also been implemented. This capacity is calculated for the borders they manage and forms the basis for the allocation of long-term transmission rights (LTTRs), which are offered through explicit auctions via the SAP, operated by the JAO. Determining LT capacity remains a complex task due to the high level of uncertainty associated with extended lead times. TSOs must make informed assumptions and ensure that the allocated transmission rights can be honoured throughout the product period. Factors such as unexpected outages, evolving network conditions, and variations in generation and consumption patterns must all be considered.

Unlike near-real-time capacity calculations, LT assessments must be made with significantly less reliable input data, making this process fundamentally different.

The Commission Regulation (EU) 2016/1719 establishing a guideline on forward capacity allocation ("FCA Regulation"), in force since 17 October 2016, continues to provide the regulatory framework for the calculation and allocation of LTTRs. It also outlines rules for the financial compensation of LTTR holders in the event of curtailment due to capacity recalculations before the DA time frame. The overarching aim is to support market participants in effectively hedging cross-border trading risks in scenarios where forward electricity markets do not offer sufficient hedging instruments.

Short-term day-ahead and intraday capacity calculation

As TSOs move closer to the actual delivery time, they can make more accurate forecasts of system conditions. This allows for a more precise determination of the available cross-zonal transmission capacity between bidding zones (BZs). Physical constraints in the transmission network are translated into commercial constraints, which are then factored into the market-clearing algorithms that determine prices and cross-zonal flows. In 2026, capacity calculations for short-term time frames – such as DA and ID – are conducted across several stages. These include the DA calculation at several stages, including the DA capacity calculation followed by a sequence of ID capacity calculations and continuous capacity assessments on the day of delivery.

Congestion issues that arise after the allocation phase are addressed through remedial actions, such as countertrading or redispatching, coordinated in real time by all affected TSOs to maintain system stability. The Commission Regulation (EU) 2015/1222 establishing a guideline on capacity allocation and congestion management ("CACM Regulation") continues to serve as the legal basis for the implementation of an integrated European electricity market in the DA and ID time frames. It defines the principles for calculating CZCs and the methodologies for capacity allocation in these time frames, supporting efficient price formation and cross-border electricity trade.

Report structure

This report is primarily structured according to the time frames described above:

- **Chapter 2** provides insights and ENTSO-E positions on current and future developments impacting the European electricity market.
- **Chapter 3** introduces the progress of the electricity market across all time frames previously described.
- **Chapter 4** provides a detailed overview of the common European processes of LT electricity trading and transmission capacity.
- **Chapter 5** outlines the current situation in the achievements of a single European DA and ID coupling process according to the CACM Regulation.
- **The annexes** include additional information, such as a market process overview of the FCA, CACM, and Electricity Balancing (EB) Regulations, as well as an explanation of how TSOs comply with the 70 % minimum capacity target requirement per country.

2 Current and future developments impacting the European electricity market

2.1 Development of long-term markets – FCA 2.0

In view of the European Commission's (EC's) ongoing impact assessment on the future design of the EU cross-border forward markets in electricity, ENTSO-E is preparing for an amendment of the FCA Regulation in 2026 ("FCA 2.0"). To that end, in 2025, ENTSO-E published a series of policy papers outlining the major challenges (see additional references below).

Electricity Market Design Regulation (EU) 2024/1747 (EMDR) obliges TSOs to provide hedging opportunities to market participants by issuing cross-zonal forward electricity contracts (i.e. LTTRs or equivalent measures) unless an assessment of the forward market on the BZBs performed by the competent regulatory authorities shows that there are sufficient hedging opportunities in the BZs concerned. Moreover, National Regulatory Authorities (NRAs) may require implementing additional measures if they determine that insufficient hedging opportunities are available for market participants. The current Regulation 2016/1719 ("FCA Regulation") sets out the regulatory framework to determine the volume and auctioning of LTTRs. TSOs settle transmission rights using congestion income (CI). This regulatory instrument enables market participants to hedge against volatile price differentials across short-term zonal electricity markets.

As a general principle, CI must be used for objectives set out in Article 19 of Regulation (EU) 2019/943. ENTSO-E would like to emphasise the trade-off when allocating CI to the various policy objectives. Since the adoption of the EMDR in July 2024, different beneficiaries compete for the use of CI: first, market participants who hold LTTRs are remunerated. The remaining net CI is then split between tariff payers – for all uses pertaining to maintaining or increasing grid capacity that would otherwise be funded through TSO tariffs – and offshore generators, through the transmission access guarantee that covers specific commercial risks associated with offshore BZs. Legislators will need to determine the appropriate balance and clear prioritisation of these beneficiaries.

As of today, it is challenging to fully assess the socioeconomic benefits of regulatory support to futures/forward markets in the form of LTTRs. Policy-makers and regulators must be aware and decide on the level of risk and associated costs they impose on TSOs and hence on tariff payers. ENTSO-E calls for a sound and continuous regulatory assessment of the assumed benefits and costs of providing hedging opportunities, including the impact on the system's affordability. For each BZ, the regulatory decision for supporting forward markets must be underscored by a thorough and recurring assessment of market participants' needs and existing (market-based) hedging opportunities. This assessment becomes even more relevant before introducing major changes to the current market design and relevant products in light of FCA 2.0. More details on the assessment can be found in the dedicated **ENTSO-E Advocacy Paper on Hedging Analysis**.

Where regulatory support is deemed necessary, the design of the regulatory instruments should strike a strong balance between the expected benefits, for example for the electricity traders, and the associated costs or risk for TSOs and, ultimately, the tariff payers. ENTSO-E is convinced that a straightforward maximisation of LTTR volumes will not lead to better hedging and a more affordable electricity system.

ENTSO-E considers the following measures to ensure a cost-efficient approach. The existing shortcomings of the electricity forward markets should not be addressed through disruptive regulatory interventions such as imposing regional virtual hubs. Should zone-to-hub LTTRs become a possibility, it should be ensured that the identified "hub" is the market where market activity is concentrated. Safeguards should be implemented to ensure that zone-to-hub LTTRs are not linked to illiquid hubs. ENTSO-E continues to explore more promising alternatives to the virtual hub model that could serve as target models for All TSOs, pending positive regional assessments. Further details on the models can be found in the dedicated **ENTSO-E Advocacy Note on Forward Markets**.

To ensure a cost-efficient approach, revenue adequacy is an important factor to consider. It is closely linked to volume determination as well as undervaluation of TSO-issued products. The volume of hedging products offered must be sufficient to meet market parties' hedging needs without endangering the financial security of TSOs and tariff payers. Coordination between TSOs and NRAs will increasingly focus on managing financial risk exposure. This risk can be reduced by adjusting the volume of LTTRs (revenue adequacy feedback loop) or additional safety nets, such as a supply function. A supply function or reserve prices would enable TSOs to adjust the volume offered based on price levels, in contrast to the current situation, where the volume offered is price inelastic. ENTSO-E's key principles for volume determination can be found in the dedicated **ENTSO-E Advocacy Note on Volume Determination**.

The volume of hedging instruments also influences the potential level of collateral requirements for TSOs. The burden of such requirements on TSOs' trading financial derivatives is a major concern and must be carefully considered in any proposals involving TSO participation in forward market design. Based on TSO internal stress tests using 2022 data, collateral requirements could reach several billion euros for some TSOs in extreme market conditions, resulting in high collateral costs. The stress test also showed potential liquidity risks due to daily volatility in margin calls, requiring TSOs to inject up to EUR 1 billion on short notice. The operational feasibility of this cannot be confirmed. Further information on the ENTSO-E position on collateral requirements can be found in the **ENTSO-E advocacy paper on collateral**.

In addition to the points mentioned above, the topic of full financial firmness must also be reconsidered. Firmness transfers additional risk from market participants to end consumers, which must be mitigated. Given the recent changes in the risk environment related to the energy infrastructure (such as the Estlink 2 incident), the ability to curtail financial transmission right options in the current setup on the TSO side is essential to avoid unlimited liabilities that could significantly increase financial risk for TSOs and, ultimately, end consumers. More on this topic can be found in the **ENTSO-E advocacy paper on FTR curtailment**. TSOs are open to evolving LTTRs into fully firm products, provided that regulators establish an agreed cost-recovery mechanism.

2.2 A view onto European electricity markets

Day-Ahead Price Development

In 2025, DA electricity prices in 24 European countries saw a slight overall decrease compared to the previous year, largely driven by lower natural gas prices. Although some price spikes occurred during the summer and in selected winter weeks, the average DA price across all European countries remained below 125 EUR/MWh. The DA market continued to function effectively within the nominated electricity market operator (NEMO)–TSO framework, providing clear and efficient price signals that support electricity generation where it is most cost-efficient, ultimately contributing to lower overall system costs.

Media attention often focuses on extreme price events, both high price peaks and periods of negative prices. While prices above 200 EUR/MWh and below 0 EUR/MWh do occur, the broader European price level typically centres around 100 EUR/MWh, with variations between countries as shown in Figure 2.1: DA price distribution in Europe. Prices around this level are most often set by conventional power plants. At the same time, the growing share of periods with prices at 0 EUR/MWh, driven by renewable generation setting the marginal price, is clearly noticeable, although it still represents a relatively small portion of the total hours.

The current price distribution aligns well with expectations for a market based on the marginal cost of generation. Electricity production is incentivised to occur where costs are lowest, independent of technology. This demonstrates the robustness of the market design and its continued effectiveness in delivering reliable, transparent, and efficient price signals across Europe. Country-specific price distribution can be found in Annex IV.

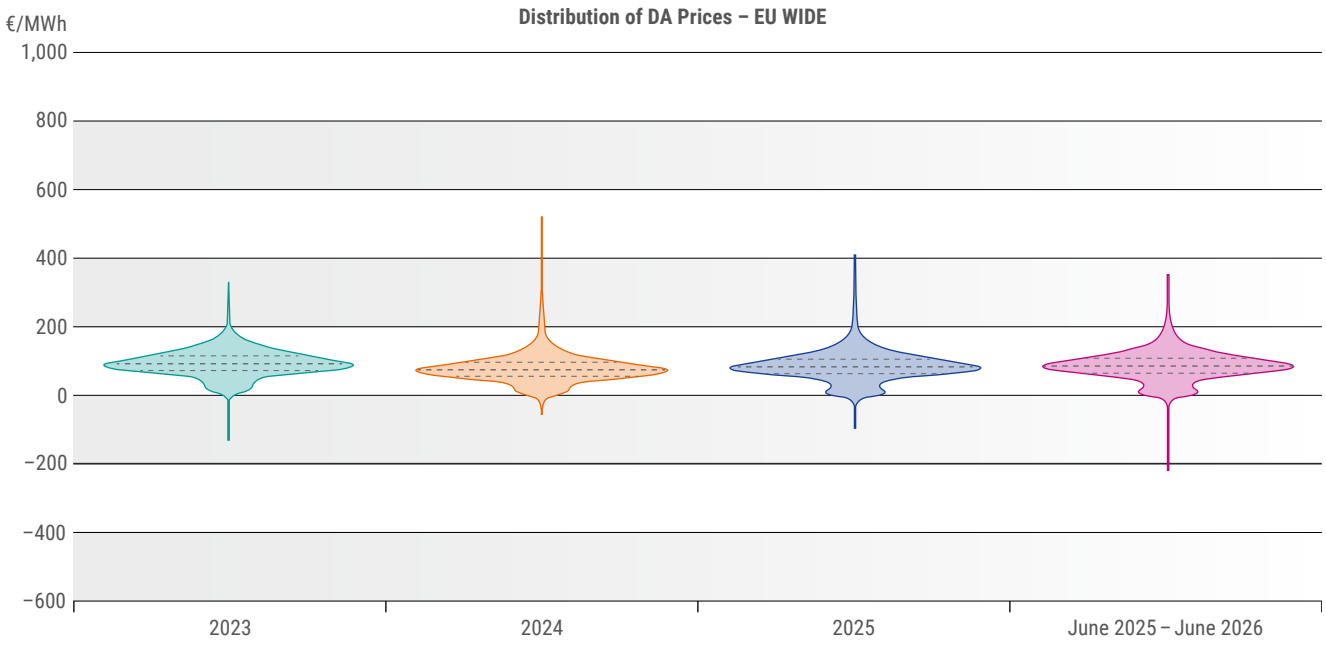


Figure 2.1: DA price distribution in Europe for 2023 – 2026, based on DA price data from the ENTSO-E Transparency Platform across 24 European countries. The dotted lines represent the mean and interquartile ranges.

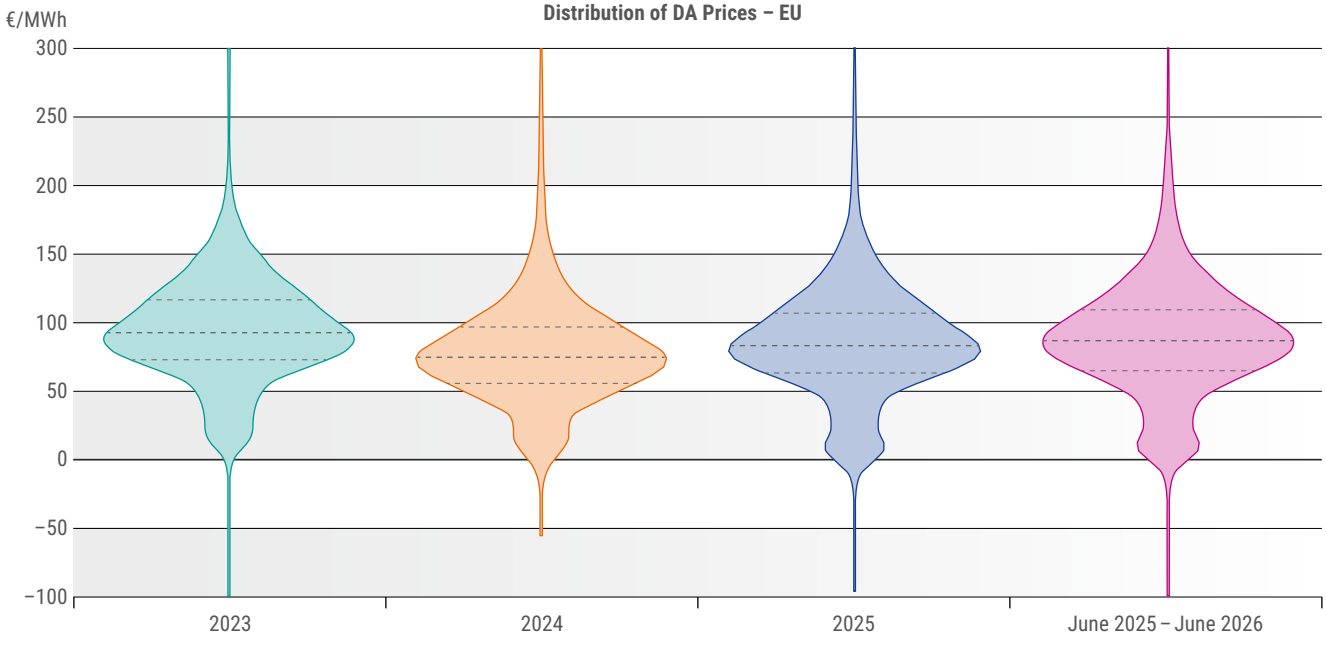


Figure 2.2: Zoomed-in DA price distribution in Europe for 2023 – 2026, based on DA prices from the ENTSO-E Transparency Platform across 24 European countries

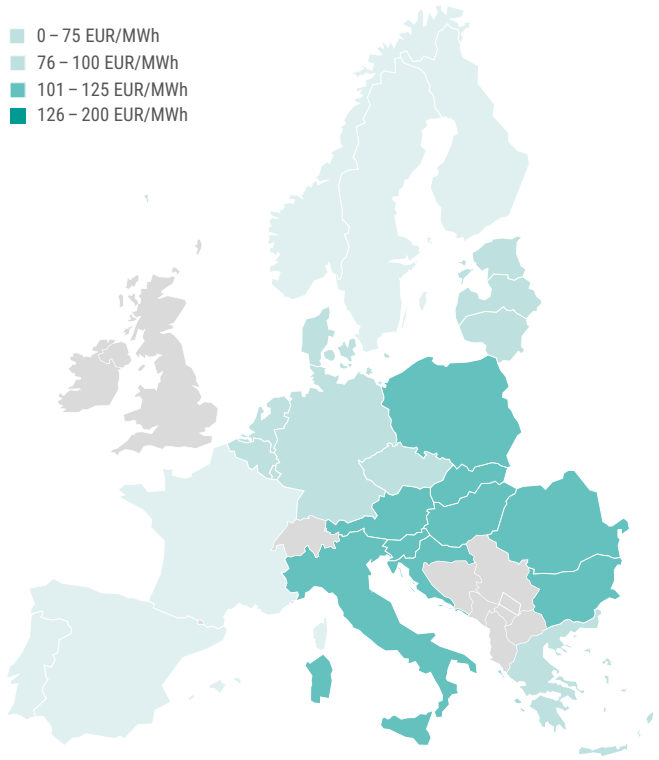


Figure 2.3: Average DA price for the period from 1 June 2025 through 1 June 2026, based on DA prices from the ENTSO-E Transparency Platform across 24 European countries

Value of New Technologies: Photovoltaics, Wind, and Storage

The DA electricity price continues to serve as the primary reference price for valuing electricity across Europe. As the power system increasingly integrates renewable energy sources and storage technologies, the DA price remains a crucial first indicator of investment opportunities.

Figure 2.1 illustrates the DA price distribution from 2023 to 2026, including the time frame from 1 June 2025 to 1 June 2026. During this period:

- **Southeastern Europe** exhibited slightly higher average DA prices compared to Central Europe.
- **Northern Europe** recorded the lowest DA price levels.

Among various influencing factors, local DA prices play a significant role in determining both cost competitiveness and investment attractiveness. To further clarify the investment implications, key performance indicators (KPIs) have been calculated for three emerging technologies: **photovoltaics (PV), wind, and storage.**

Value of Storage

The capability to store electricity and release it at a later time is becoming a fundamental element of the evolving power system. As batteries and other storage technologies gain prominence, assessing the revenue potential from daily charging and discharging becomes increasingly important.

For an initial indication of this value, a **storage value metric** solely on the DA price was computed for the period from **1 June 2025 to 1 June 2026**. This metric is based on the **daily average spread** between:

- the **8 lowest-priced hours** used for charging, and
- the **8 highest-priced hours** used for discharging.

Across Europe, the results show that:

- a **minimum of approximately 215 EUR/MW per day** can be earned on average,
- while many countries demonstrate revenue opportunities **exceeding 600 EUR/MW per day**.

These revenues are particularly pronounced in countries with higher DA prices. Figure 2.4 presents a complete and detailed illustration of the values across all countries. By integrating storage assets, electricity can be strategically shifted to periods with the highest market value, thereby enhancing overall system efficiency and economic returns. The current DA and ID markets operated jointly by NEMOs and TSOs effectively provide the necessary price signals to incentivise asset development and shift electricity supply to the hours where it is needed most.

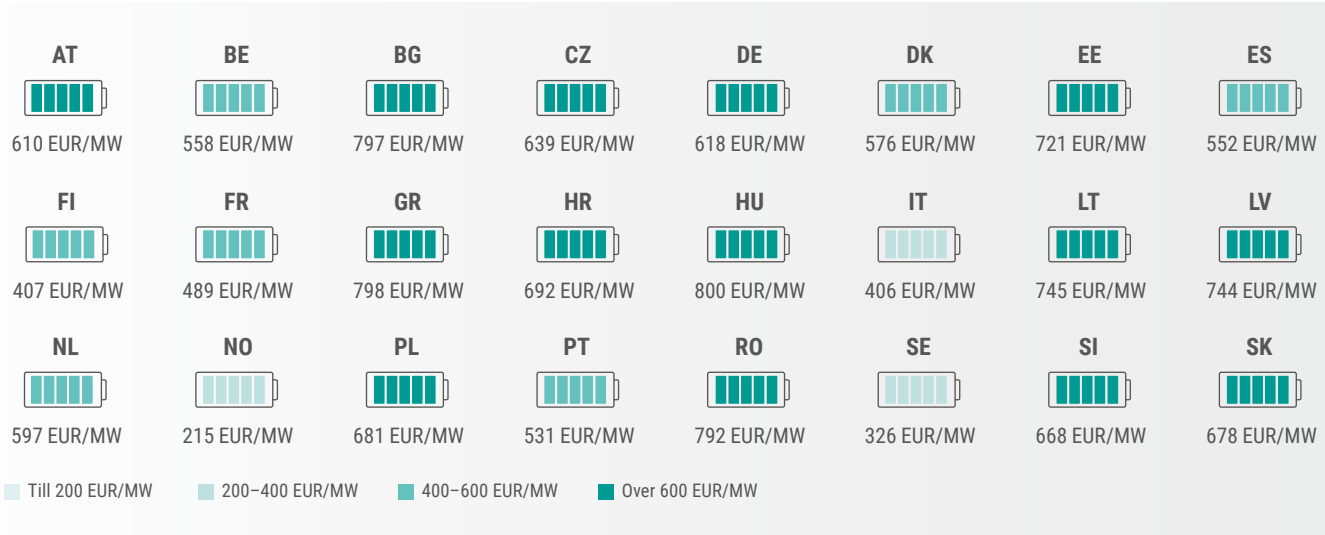


Figure 2.4: Values of storage across all countries

Value of PV

PV installations have grown substantially in recent years. While subsidy schemes have contributed to this expansion, the most significant driver has been the sharp decline in PV module and system costs, substantially improving the technology's economic competitiveness. PV generation follows a predictable daily pattern aligned with the day – night cycle, concentrating production into a limited number of daylight hours. As a result, **price cannibalisation** – the reduction in electricity prices during periods of high PV output – has become a key characteristic of PV economics.

To provide an initial indication of PV market value across Europe, a **PV value indicator – aka "capture price"** – was calculated for the period from **1 June 2025 to 1 June 2026.** This metric weights each country's hourly DA price with a representative PV generation profile based on generation data published on the ENTSO-E Transparency Platform.

It reflects the average market value of PV output based solely on:

- the **DA price level**, and
- the **characteristic PV generation shape**.

It does not reflect differences in total annual irradiation or energy yield. Therefore, locations with higher solar resources may still be more profitable in absolute terms, even if their calculated PV value appears lower.

Because PV output is concentrated in specific hours, the PV value consistently falls below the average DA price in all countries. On average, the PV value is approximately 30 % lower than the mean DA price. Typical PV values range between 50 and 70 EUR/MWh.

Key observations include:

- **Italy** achieves the highest PV value at **94 EUR/MWh**, driven by relatively high DA prices during daylight hours.
- **Portugal** exhibits the lowest PV value at **27 EUR/MWh**, reflecting lower overall DA prices and limited solar generation coincidence with higher-price periods.

In general, PV value is strongly influenced by the prevailing DA price level in each market. Nevertheless, the indicator also reflects the extent to which **cannibalisation effects** have already materialised, providing insights into how increasing PV penetration impacts the market value of solar generation.

Figure 2.5: Values of photovoltaics across all countries

Value of Wind

Both onshore and offshore wind assets have expanded significantly in recent years. Continuous improvements in turbine size and technology have strengthened the economic competitiveness of wind generation. While wind availability is generally higher during the winter months, its variability remains substantial, and overall production does not follow a fully predictable pattern. In markets where wind contributes a large share of total electricity generation, high wind, low demand hours increasingly lead to noticeable price effects and initial signs of cannibalisation.

To provide an initial indication of the market value of wind across Europe, a **wind value indicator** – also referred to as the capture price – was calculated for the period from **1 June 2025 to 1 June 2026**. This metric weights each country's hourly DA prices with a representative wind generation profile derived from publicly available generation data on the ENTSO-E Transparency Platform.

It reflects the average market value of wind output based on:

- the **DA price level,** and
- the **characteristic wind generation shape**.

The indicator does **not** account for differences in wind resource availability or total energy yield. As a result, locations with stronger wind resources may still achieve higher absolute revenues, even if their calculated wind value appears comparatively lower.

Across Europe, countries with a substantial share of wind generation tend to show wind values **5 – 15 EUR/MWh below** below their average DA prices, indicating the presence of early cannibalisation effects. Conversely, in markets with generally higher DA price levels, wind values also tend to be elevated.

Key Findings

- **Italy** records the highest wind value at **114 EUR/MWh**, with several other countries also exceeding 100 EUR/MWh.
- **Finland** shows the lowest wind value at **35 EUR/MWh**. Despite already low average DA prices, high wind output further depresses prices during windy periods.

Overall, wind value is strongly shaped by the underlying DA price environment in each market. Nonetheless, the indicator already highlights varying degrees of cannibalisation across Europe. During the period from **1 June 2025 to 1 June 2026**, electricity generated from wind experienced less cannibalisation than electricity from solar PV.

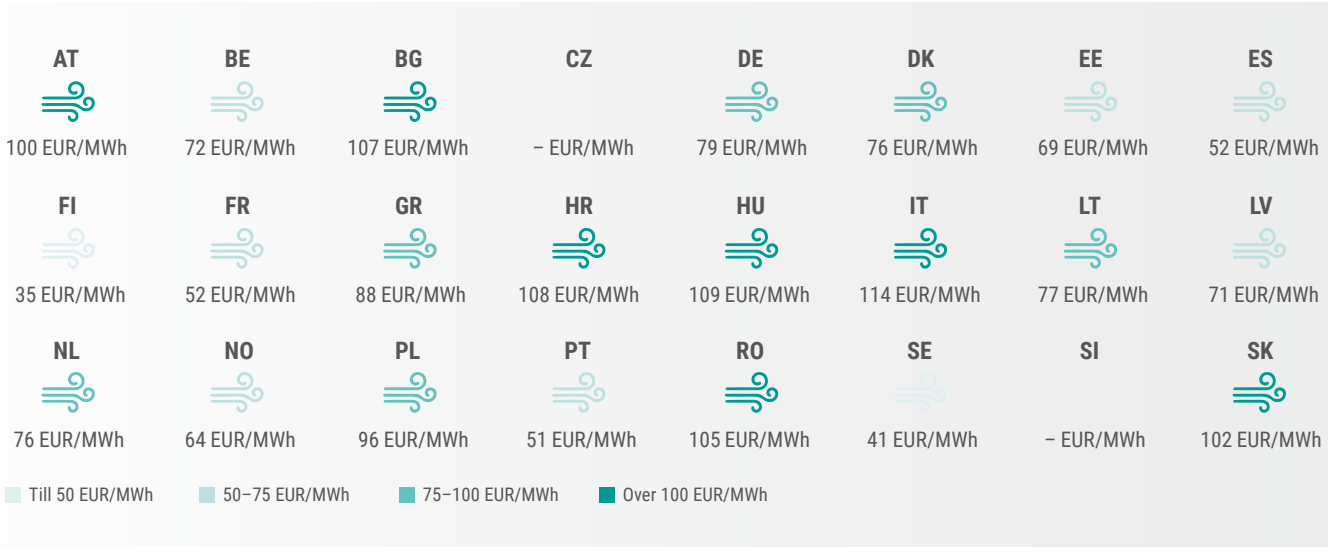


Figure 2.6: Values of wind across all countries

2.3 Implementation of CEP70 minimum capacity targets

To foster non-discriminatory and cross-zonal trade in the internal electricity market, Article 16(8) of the Electricity Regulation requires EU TSOs to make at least 70% of transmission capacity (respecting operational security limits) available for cross-zonal electricity trading (CEP70 requirement). Where TSOs have requested a "derogation" from the CEP70 requirement pursuant to Article 16(9) of the Electricity Regulation, or Member States have invoked an "action plan" pursuant to Article 15 of the same, a less ambitious target may apply for a given year or a transitional period defined in the action plan.

The CEP70 requirements on minimum levels of available capacity for cross-zonal trade pursuant to Article 16 of the Electricity Regulation were compiled for all CCRs in 2025. Any deviations from the 70% of transmission capacity were in line with the requirements of Articles 15 and 16 of the Electricity Regulation. They were justified either by Article 15(2), 15(4), and 16(3) or by derogations pursuant to Article 16(9).

2.3.1 Monitoring the fulfilment of the CEP70 requirement: Why do several reports exist?

The ENTSO-E Market Report 2026 incorporates in the following chapter the assessments by the relevant TSOs within the meaning of Article 14(4) of the Electricity Regulation on whether for the last 12 months (i.e. 2025), the available cross-border capacity has reached the linear trajectory or the CEP70 requirements, in accordance with Article 15(4) of the Electricity Regulation. In particular, these assessment reports by the relevant TSOs are based on individual contributions from each relevant TSO, subject to its NRA approval. Since the NRA's requirements for the approval of the individual TSO's contributions are not homogeneous, national reports for assessing the fulfilment of the CEP70 requirement exist. Providing inputs to the report of the relevant TSOs in accordance with Article 15(4) remains the responsibility of individual TSOs and NRAs remain responsible for assessing TSOs' alignment with the requirements in Article 16(8) of the Electricity Regulation. For the avoidance of doubt, the inclusion of the assessment reports by the relevant TSOs as per Article 15(4) of Electricity Regulation in this chapter of ENTSO-E Market Report 2026 does not confer to ENTSO-E any monitoring obligations or approval powers related to Article 15(4) of Electricity Regulation. The responsibility for ensuring alignment of these assessment reports with the requirements of Article 15(4) remains with the relevant TSOs.

ENTSO-E market report hosting the regional joint assessment reports

In ENTSO-E annual market reports, TSOs provide an easily accessible comparison of national contributions for external stakeholders. It should be noted that TSOs' contributions to the joint assessments of the CCRs are based on national methodologies, which may differ. For instance, some countries evaluate all contingencies for each critical network element (CNE) per MTU, resulting in multiple values per MTU, while others report only a single value per MTU.

To ensure transparency, TSOs provide country fact sheets (see Annex IV) with brief descriptions of each national compliance assessment and detailed information on the differences between the national methodologies. These sheets specify whether an NRA's compliance approach follows ACER's Recommendation 01/2019 and highlight the key differences.

ACER Market Monitoring Report

Additionally, ACER publishes an independent assessment as part of its annual market monitoring, applying a uniform methodology. ACER's approach differs from that of individual NRAs when approving TSO contributions. Therefore, to draw valid conclusions on whether cross-zonal trade capacity meets the minimum requirement or follows a linear trajectory, the legally required national compliance assessments must be checked. Another difference between the ENTSO-E Market Report and national assessments is that the ACER report provides both a comparison to the target minimum capacity (i.e. 70%) and, where action plans or derogation apply, to the transitional minimum capacity. As a summary of national compliance assessments, the ENTSO-E Market Report always compares the current fulfilment of the CEP70 provisions solely to the (transitional) minimum capacity, which can be lower than 70% if action plans or derogations are in place.

To support transparency, the graphs provided in Section 2.3.1 for 2025 aim to establish a basic level of comparability. Nonetheless, the comparability of these results remains limited due to variations in the underlying methodologies and data used to produce the visualised values. A comparison of the national CEP70 compliance assessments and ACER's monitoring results from 2021 to 2023 can be found in the ENTSO-E Technical Report. A comparison for 2025 could not be included in this market report, as ACER's monitoring results had not yet been published at the time of publication of this report.

2.3.2 Overview of joint assessments by region for 2025

The joint assessments of the regions are based on the national assessments for 2025. They are conducted by comparing the fulfilment of CEP70 provisions against the applicable 2025 target. Here, "target" refers either to the final minimum capacity target of 70% or a lower intermediate value set by action plans and/or derogations. To ensure the highest level of transparency in this joint assessment, the main differences in the underlying national methodologies are displayed by grouping national methods (e.g. percentage of constraints, percentage of MTUs) in the joint figure per region. Furthermore, a detailed description of national specificities is provided in the country fact sheets in the annex. At the end of each CCR section, the final conclusion of the joint assessment is provided.

Furthermore, it should be noted that the 70% minimum capacity is not an absolute (minimum) target, as deviations due to operational security are legally permitted. TSOs have the legal duty to reconcile it with physical reality. Article 16.3 of the EU Electricity Regulation allows deviations from the 70% rule to ensure grid operational security. If necessary, such deviations – i.e. capacity reductions – arise from the mandatory validation step in capacity calculation and are used only as a last resort when remedial actions are insufficient to respect operational security limits.

Joint assessment of the Core CCR

In the following, the joint assessment for 2025 is provided for the Core CCR. Figure 2.7 shows the relative margin available for cross-zonal electricity trade (MACZT) for each country in the Core region and across all relevant MTUs in 2025. It excludes MTUs where coordinated capacity calculation failed and fallbacks (e.g. spanning or default FB parameters) were used – 24 MTUs in 2025 (0.27% of 2025). Note that MTUs here always refer to hours. The data is based on the (national) monitoring results for 2025.

Countries are grouped based on the approach used by NRAs for the national compliance assessment. This differs significantly from ACER's market monitoring, which benchmarks countries using a uniform methodology. More methodological differences are explained in the country fact sheets in Annex IV.

The main difference concerns the scope of monitored instances. AT, PL, HR, and DE monitor the margin of each constraint per MTU (multiple values per MTU), while HU, NL, RO, SI, CZ, and SK monitor the constraints with the lowest margin of a given MTU (one value per MTU). FR also follows this approach, but also filters MTUs based on set criteria. Only MTUs without price convergence, where limiting critical network with a contingency (CNECs) were located in France, are assessed. BE monitors the margin of each constraint per MTU (multiple values per MTU), as well as the constraints with the lowest margin of a given MTU (one value per MTU). The cross-zonal high-voltage direct current (HVDC) interconnector ALEGrO between Belgium and Germany is considered in isolation due to its unique integration into the FB capacity calculation (one value per MTU and direction).

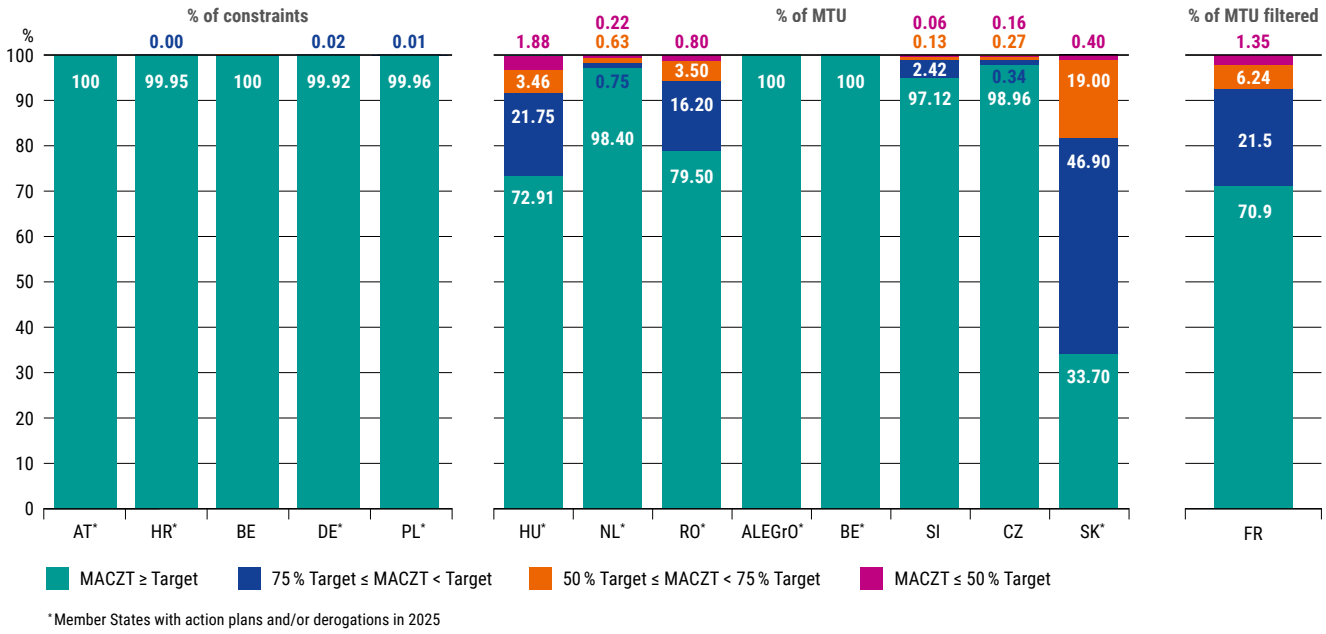


Figure 2.7: Results of the joint assessment (based on the national monitoring results) for 2025 in the Core CCR compared to the applicable values under derogations and action plans.

Note: Individual applicable targets can be found in the country fact sheets in Annex IV. The relative MACZT margin for BE is shown as % of constraints and % of MTU, aligning with NRA annual reporting. Small deviations from a total amount of 100 % are caused by rounding.

In line with the German action plan, the applicable intermediate target for German critical network elements (CNEs) in the Core region has been increased from 50.5% in 2024 to 60.3% in 2025. In 2025, the required margins have been provided in nearly every instance, specifically for 99.6% of all CNEs for each hour. TSOs consider all instances where the intermediate minimum margin was not met to be admissible under the Electricity Regulation. These results show that German TSOs reached the linear trajectory set out in the German action plan, consistently increasing market capacity each year while maintaining secure grid operation.

In line with the Austrian action plan and the granted derogation for the Core CCR, the 2025 minimum capacity target of 59.7% has been met. As in Germany, the few instances where minimum capacities had to be reduced at the CNEC level during the capacity validation step – via individual validation adjustment (IVA) based on available remedial action potential – are also deemed compliant, as these measures were necessary to maintain grid security.

For Romania, Transelectrica had an action plan in place until the end of 2025, based on a linear trajectory for gradually increasing the minimum available capacity for cross-zonal trade. In 2025, Transelectrica requested a derogation for the RO–HU border to ensure operational security, based on a minimum available capacity of 41% of the transmission capacity. Instances where this target was not met were due to security considerations and reductions applied during the capacity calculation process. These reductions may have resulted from multiple planned disconnections causing CNEC overloads or insufficient costly remedial actions.

Slovakia was granted a derogation for 2025 with the following conditions: it must provide 50% MACZT for two CNEs in at least 80% of MTUs, contingent on maintaining the security of the power system. For the remaining CNEs, a target of 70% MACZT was established. Based on the specific features of the Slovak BZ and transmission system, such as its size and geographic location within the Core region, SEPS considered granting a derogation essential to maintaining the operational security of the interconnected systems. Compared to SEPS's 2024 derogation request, the 2025 request reduced the scope from four to two CNEs.

France has no action plan nor derogation in place, so the target level remains 70%. In 2025, this target was reached for ~70% of MTU, similar to 2024. In 2025, the combination of record-high export levels and ongoing maintenance activities in France resulted in certain constraints on maintaining optimal grid security, as well as cross-border capacity limitations.

Slovenia has no action plan nor derogation in place, so the target level remains 70%. In 2025, this target was reached for 97.12% of MTU.

Result of the joint assessment of the Core CCR:

Overall, the joint assessment conducted by the Core TSOs indicates a strong level of achievement fulfilment with respect to the applicable targets, including intermediate targets set out in action plans and derogations. Any deviations from these targets were necessary to maintain operational security and are therefore in line with Article 16 of the Electricity Regulation.

Joint assessment of the Italy North CCR

In the following figure, the (national) monitoring results for 2025 are provided for the Italy North CCR. The percentages in the figure are based on the national assessments of Italy North TSOs. In the coordinated net transfer capacity (cNTC) calculation, each MTU is assigned with a potentially limiting CNEC, limiting the possible exchanges/allocations over the entire Italy North border. In 26 % of the MTUs in 2025, no limiting CNEC could be calculated due to process failure; therefore, the compliance assessment is based on the remaining 74 % MTUs. In the graphic below, "No limiting CNEC" refers to cases where the most limiting CNEC was outside the corresponding BZ.

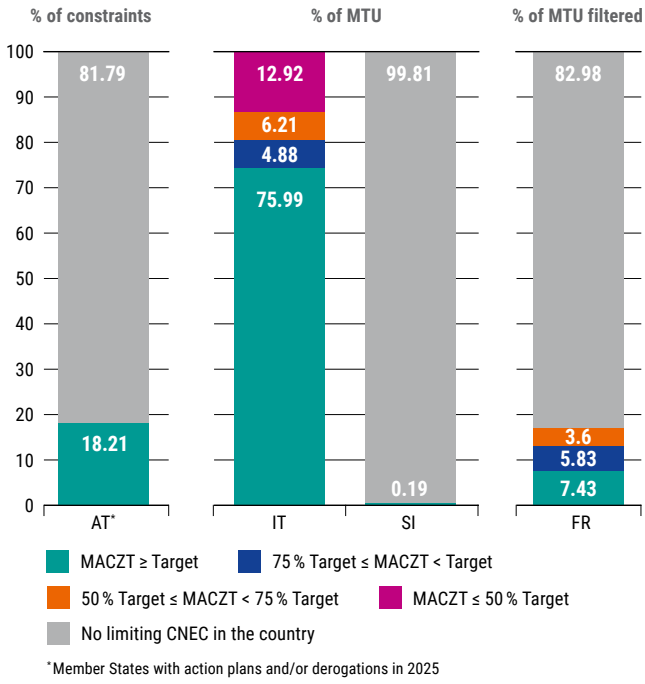


Figure 2.8: Results of the joint assessment (based on the national monitoring results) for 2025 for the Italy North CCR compared to the applicable values under derogations and action plans.

Note: Individual applicable targets can be found in the country fact sheets in Annex IV. Small deviations from a total amount of 100 % are caused by rounding.

For Italy's northern borders, the 70 % criterion is considered fulfilled once at least one limiting CNEC on the border meets this condition, regardless of the specific national frontier. According to the methodology approved by the NRAs of the CCR, the Italy North border is treated as a single entity. In some cases, the capacity made available to the market is further limited due to security constraints that cannot be represented as thermal transmission limits on the grid elements.

APG, assessing compliance at the CNEC level, limited exchanges in only ~18.2 % of the MTUs with potential limiting CNECs respectively MTUs without process failure. In line with the Austrian action plan for the Italy North CCR, the minimum target for 2025 has been met for these CNECs. The few cases where minimum capacities on limiting CNECs were reduced during the capacity validation step are also considered compliant, as these measures were necessary to maintain grid security. Compliance is also confirmed for all hours when the potentially limiting CNEC was outside the APG BZ or during hours with process failure.

RTE applies the 70 % target on the FR–IT border. MTU filtering is also considered, and MTUs with price convergence with Italy North BZs or when the limiting element is not in France are considered compliant. In 2025, compliance was high because for most of MTUs, the most limiting CNEC was outside France.

Overall, the Italy North TSOs demonstrate a high degree of fulfilment with the applicable targets, including intermediate targets from action plans and derogations. Deviations from the target were necessary to maintain operational security.

Joint assessment of the South-West Europe CCR

In the following, the (national) monitoring results for 2025 are provided for the South-West Europe (SWE) CCR.

SWE data is calculated and provided by its RCC, CORESO. Given that the cNTC approach is used, only limiting CNECs are monitored. When the limiting CNEC is not an interconnector but rather an internal element of one country, it is counted as "no limiting CNEC in the country" for the other bordering country. This implies fulfilment of the 70 % criterion, since that country is not limiting the net transfer capacity (NTC).

The amended regional capacity calculation methodology guarantees the monitoring of all MTUs by including a fallback mechanism that assigns a limiting CNEC and MACZT values even if the capacity calculation process fails. Another key feature of the SWE implementation is the use of available costly remedial actions to increase NTC values when the 70 % criterion is not met following the capacity calculation. This approach results in a high level of fulfilment.

While Portugal has a derogation of Article 16(8) for 2025, Spain and France do not. None of the three SWE countries has an action plan in place.

In France, ongoing maintenance activities and the need to maintain optimal grid security led to some cross-border capacity limitations in 2025.

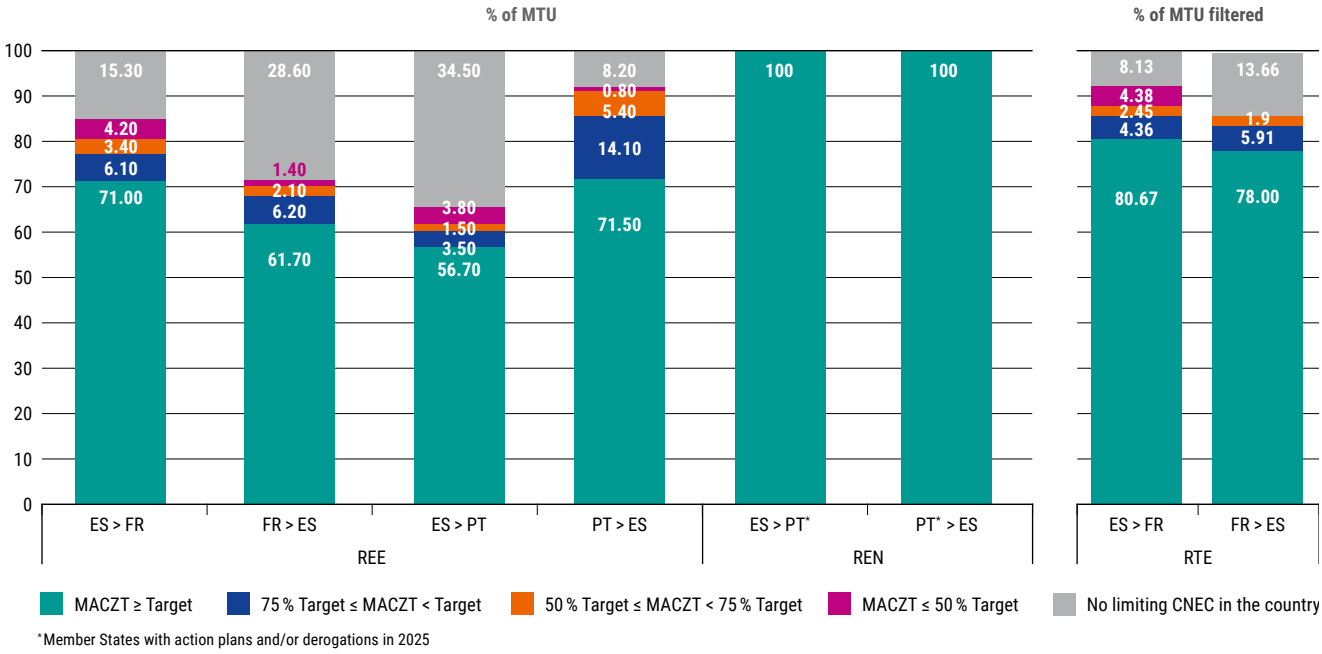


Figure 2.9: Results of the joint assessment (based on the national monitoring results) for 2025 for the SWE CCR compared to the applicable values under derogations and action plaaNote: Individual applicable targets can be found in the country fact sheets in Annex IV.

Note: Individual applicable targets can be found in the country fact sheets in Annex IV. Small deviations from a total amount of 100 % are caused by rounding.

Overall, the SWE TSOs demonstrate a high degree of fulfilment with the applicable targets. Deviations from the target were necessary to maintain operational security.

Joint assessment of the South-East Europe CCR

In the following, the joint assessment of the South-East Europe (SEE) CCR is provided for 2025. The graph below shows the MACZT margin for each SEE TSO, without distinguishing whether a derogation, action plan, or the final 70 % target applies. Timestamps for which the fallback procedure was triggered are considered failures in the capacity calculation process and are marked as "process failure". Additionally, if the limiting CNEC is neither an internal element nor an interconnector involving the reporting country, the MTU is counted as "no limiting CNEC in the country" for that country. The data is based on the (national) monitoring results.

The SEE CCR capacity calculation platform has been modified to allow the calculation of MACZT directly within the platform. However, the MACZT values currently calculated by the platform are based on preliminary calculated capacities, before the application of remedial actions and before the final validation step performed by the TSOs. At this stage, the platform does not yet have the capability to calculate MACZT after the full capacity calculation process, including the application of remedial actions and the final validated capacity values.

Nevertheless, the TSOs have also carried out internal calculations using the available input data, with the results to be further assessed against the data provided by ACER. For the first 23 days of the year, the multilateral non-coordinated capacity calculation (MNCC) term was not included, since the calculation process for this period was based on the Vulcanus file, and the corresponding MNCC values were not derived.

For the SEE CCR, the TSOs of Romania and Greece have applicable derogations and/or action plans for 2025, while the Bulgarian TSO applies the final target of 70 %.

For Romania, Transelectrica has an action plan in place to increase the minimum available capacity annually by 2026. In 2025, a derogation was in place to ensure operational security for the RO–BG border. According to this derogation, a minimum of 52 % of transmission capacity must be ensured for this border. Transelectrica also applies ACER Recommendation No. 01/2019 for MACZT calculation.

As of 1 October 2025, the MACZT verification process entered into operation. For the period prior to this date, the power transfer distribution factor (PTDF) values were calculated retrospectively; however, they were not operationally available and therefore were not taken into account during the capacity validation process.

Consequently, until 1 October 2025, there was no mechanism in place for verifying and adjusting the validated capacities from a MACZT perspective. During this period, Transelectrica performed the capacity validation with reference to the values established under the action plan, taking into account the derogation approved for the relevant period.

Starting from 1 October 2025, following the go-live of the MACZT process, the validation of capacities also began to take into account MACZT-related results.

For the export direction (RO → SEE), Transelectrica validated NTC values above the derogation value approved for the relevant period. However, despite these higher validated capacities, the resulting MACZT values remained relatively low in certain intervals, mainly due to high generation from wind power plants, combined with the limited availability of effective remedial actions and redispatching measures.

Despite these operational constraints, Transelectrica made efforts to maximise the capacities made available for cross-zonal trade. In this context, in certain operational situations, Transelectrica accepted an increased level of operational risk in order to provide higher capacities to the market, while continuing to ensure the secure operation of the transmission system. Nevertheless, grid security remains of paramount importance and cannot be neglected in the capacity validation process.

Ensuring higher and more stable MACZT values on a sustainable basis requires the implementation of the planned network development investments. In particular, the reinforcement of the transmission network through projects such as the 400 kV double-circuit OHL Cernavodă – Stâlpu, the uprating to 400 kV of the Brazi Vest–Teleajen – Stâlpu axis, and the 400 kV double-circuit OHL Smârdan – Gutinaș is necessary in order to increase the structural capacity of the grid and reduce the operational constraints affecting cross-zonal capacity.

Greece had a derogation in place for 2025, setting the target at 60 %, excluding periods of maintenance on Greek tie-lines or times of very low load conditions. For northern Greek imports, the target was met in 80 % of total MTUs (including periods of maintenance and low load conditions), while for exports it was 69 %. The reason Greece did not meet the target at all times is because three of its four borders are with non-EU TSOs, and despite IPTO's notifications, the non-EU TSOs have not yet participated in the SEE CCM as technical counterparties.

For Bulgaria (ESO EAD), neither a derogation nor an action plan applied. The MACZT results are based on the SEE CCR capacity calculation platform, which uses limiting CNECs from the DA capacity calculation data provided by the SEE TSOs.

The data shows that for nearly all MTUs (more than 98.5% of all TSs), there is no limiting CNEC within our own control area, when the BG–GR border is the calculated cross-section. On the other hand, for the BG–RO border, in around 80% of all TSs, the limiting CNEC is neither an internal transmission system element nor an interconnection tie-line of the Bulgarian EPS.

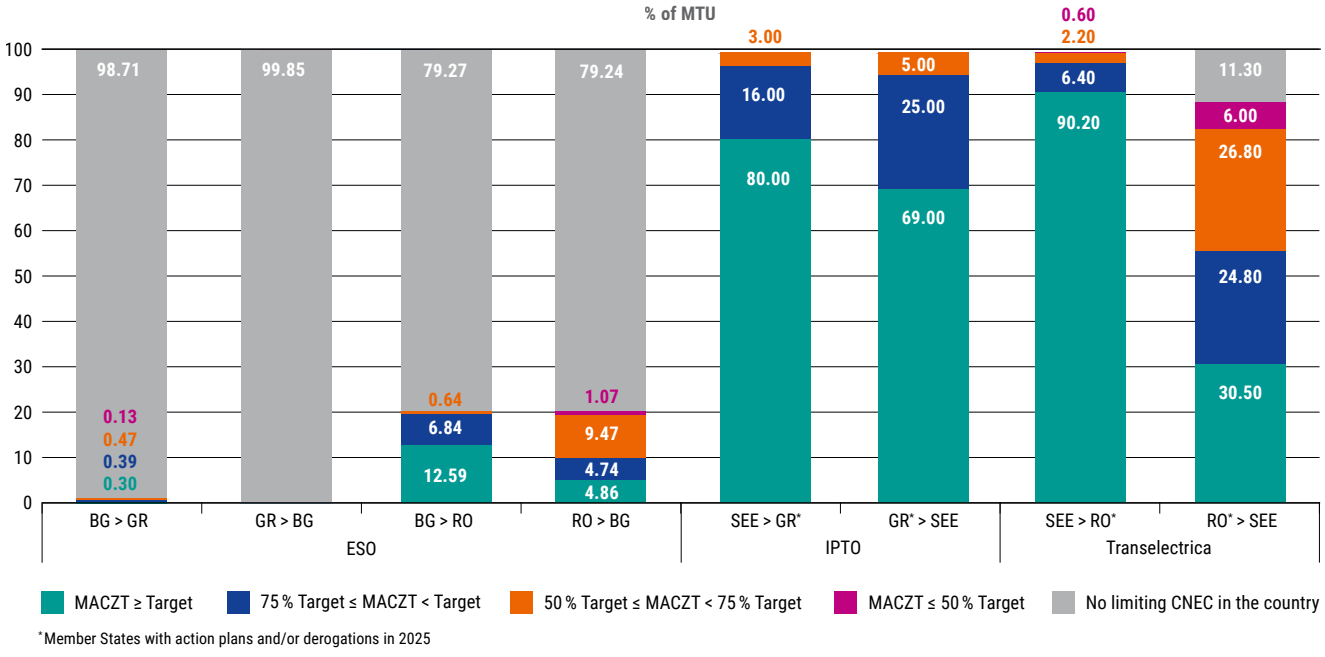


Figure 2.10: Results of the joint assessment (based on the national monitoring results) for 2025 for the SEE CCR compared to the applicable values under derogations and action plans (Romania and Greece) or the final applicable target (Bulgaria).

Note: Individual applicable targets can be found in the country fact sheets in Annex IV. Small deviations from a total amount of 100% are caused by rounding.

Result of the joint assessment of the SEE CCR:

In summary, the joint assessment conducted by the SEE TSOs demonstrates a high degree of fulfilment with the applicable targets, including intermediate targets from action plans and derogations. Deviations from the target were necessary to maintain operational security.

Joint assessment of the Greece–Italy CCR

In the following, the (national) monitoring results for 2025 are provided for the Greece–Italy CCR. Both TSOs within the GRIT CCR apply the 70 % minimum target. The percentage shown as "no limiting CNEC in the country" indicates that the interconnector was out of service.

Overall, the GRIT TSOs demonstrate a high degree of fulfilment with the applicable targets. No deviations from the target were necessary to maintain operational security.

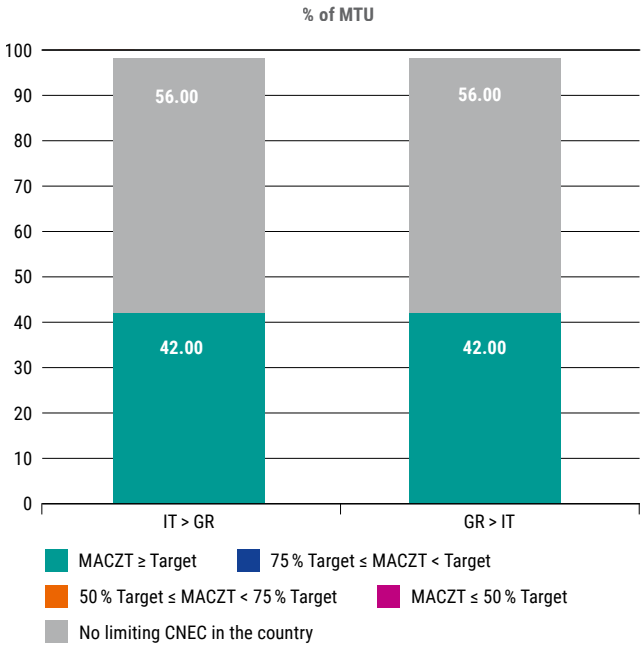


Figure 2.11: Results of the joint assessment (based on the national monitoring results) for 2025 for the Greece–Italy CCR compared to the applicable value.

Note: Percentages for GRIT do not sum to 100 % as 2 % of the total hours in 2025 were associated with process failures but are not reflected in the graph.

Joint assessment of the Nordic CCR

In the following, an analysis for 2025 is provided for the Nordic CCR.

The approach used by Nordic NRAs for individual national compliance assessment is specified in the country fact sheets in Annex IV.

2025 is the first whole year with flow-based market coupling (FBMC) in the Nordic CCR.

In 2025, Svenska kraftnät faced some challenges in delivering 70 % in BZs SE1 and SE3. In SE1, the main challenge in reaching MACZT >70 % was generation plants directly connected to cross-border elements in the transmission network. This results in high F0 flow, which leads to a lower allocation of capacity for cross-border trade. The predicted production volumes for these plants in the individual grid model have a significant impact on the outcome of the calculation.

In SE3, there is a temperature-sensitive CNEC that would not be included in the domain in normal operation, but due to a planned outage in 2025, it was included and at times resulted in allocation below 70 %.

Another challenge in SE3 is a CNEC affected by power production, where high production leads to lower 70 % fulfilment.

Of the total reported CNECs for Svenska kraftnät in 2025, only 0.4 % had a shadow price when capacity allocation was below 70 %, indicating a low market impact.

NO3 and NO5 had some CNECs in 2025 where the RAM was highly depleted due to internal flows and loop flows caused by intermittent power production (run-of-river hydropower and wind power) that do not participate in generation shift key (GSK) scaling. The choice of scaling units is made so that the capacities at the market point best represent the realised physical flows in operations, and in that way guarantees that the shadow price best represents the constraints in the grid.

For transparency, the results in this section for FI, DK, NO, and SWE are presented based on "% of constraints" to provide a broader perspective and a complementary view to ACER's monitoring report, which presents monitoring (one value per MTU). For the national compliance method, see the country fact sheet in Annex IV.

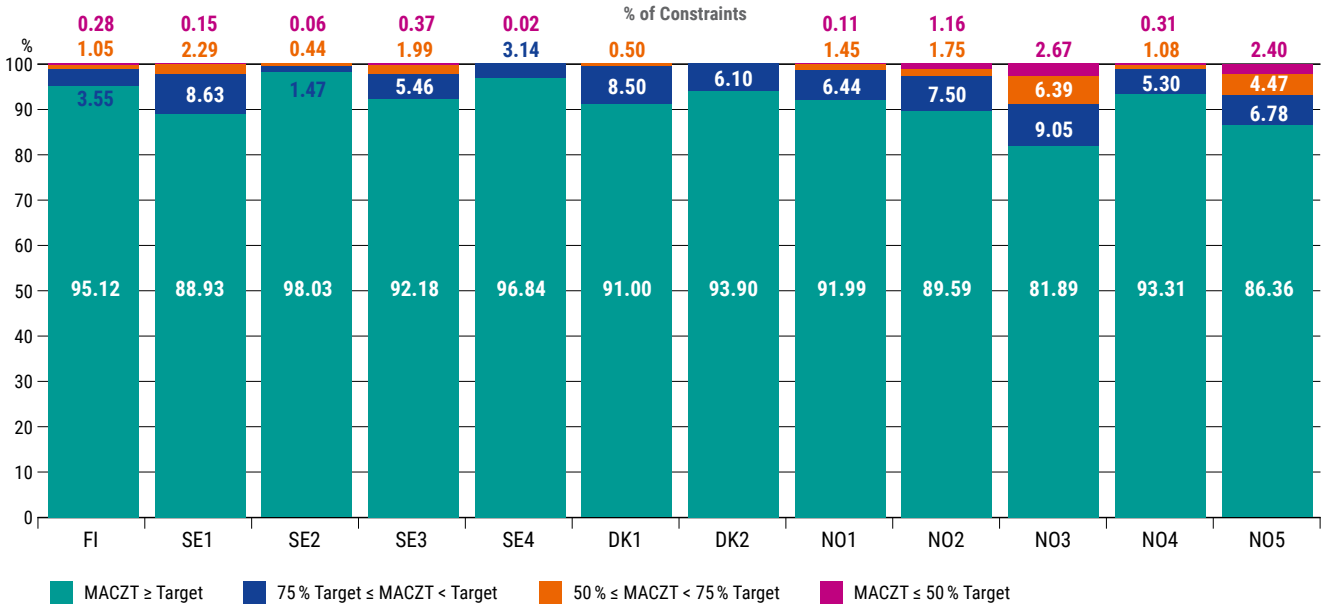


Figure 2.12: Results of the joint assessment (based on the national monitoring results) for the Nordic CCR compared to the applicable values under derogations and action plans.

Note: Individual applicable targets and national compliance methods can be found in the country fact sheets in Annex IV.
Small deviations from a total amount of 100 % are caused by rounding.

Deviations from the target were necessary to maintain operational security.

Joint assessment of the Baltic CCR

In the following, the (national) monitoring results for 2025 are provided for the Baltic CCR.

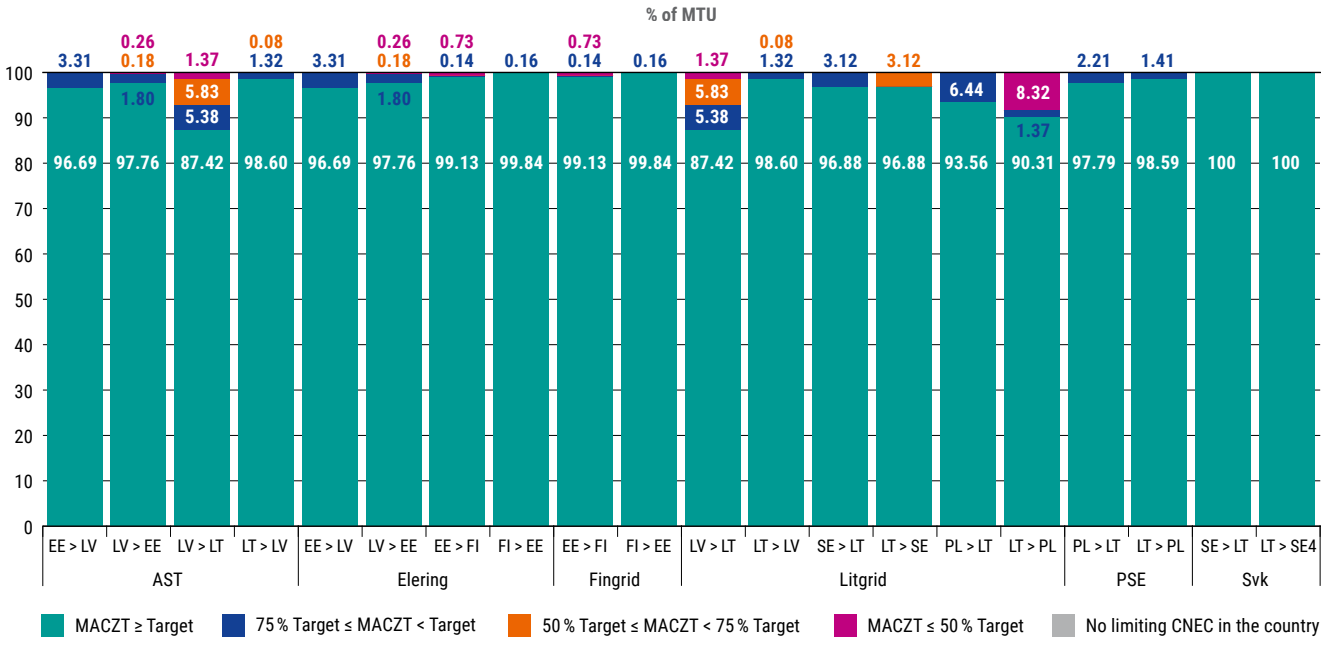


Figure 2.13: Results of the joint assessment (based on the national monitoring results) for 2025 for the Baltic CCR compared to the applicable values under derogations and action plans.

Note: Non-thermal constraints are treated as compliant and shown in the MACZT ≥ Target category. Small deviations from a total amount of 100 % are caused by rounding.

Deviations from the LV–LT target were caused by the need to maintain grid security. Overall, the applicable target on the LV–LT border was achieved to a high degree.

Deviations from the LT–PL target occurred only in January – February 2025 and were driven by temporary capacity limitations applied by Litgrid to ensure grid reliability.

January 2025: Restrictions were related to the implementation of measures for the Baltic synchronisation with the Continental European network, including network configuration changes and substation reconstruction works.

February 2025: After synchronisation, it was foreseen that a planned testing period would be carried out. It was agreed with PSE that, in the case of stable operation of the Baltic region, trading capacities on the LT – PL cross-border would be gradually released, starting from 19 February.

Overall, compliance with LT–PL targets was achieved to a very high degree, with deviations limited to these exceptional and temporary conditions.

Joint assessment of the Hansa CCR

In the following, the joint assessment of the Hansa CCR is provided for 2025. As Baltic Cable AB is not formally a member of ENTSO-E, it did not participate in the drafting of this market report. However, the reported capacities in the assessment of Chapter 2.3 do include those submitted by Baltic Cable AB, and the assessment for the relevant border DE/LU–SE4 in this chapter is based on the German national report, to which Baltic Cable AB contributed. The data of the joint assessment is based on the (national) monitoring results.[2]

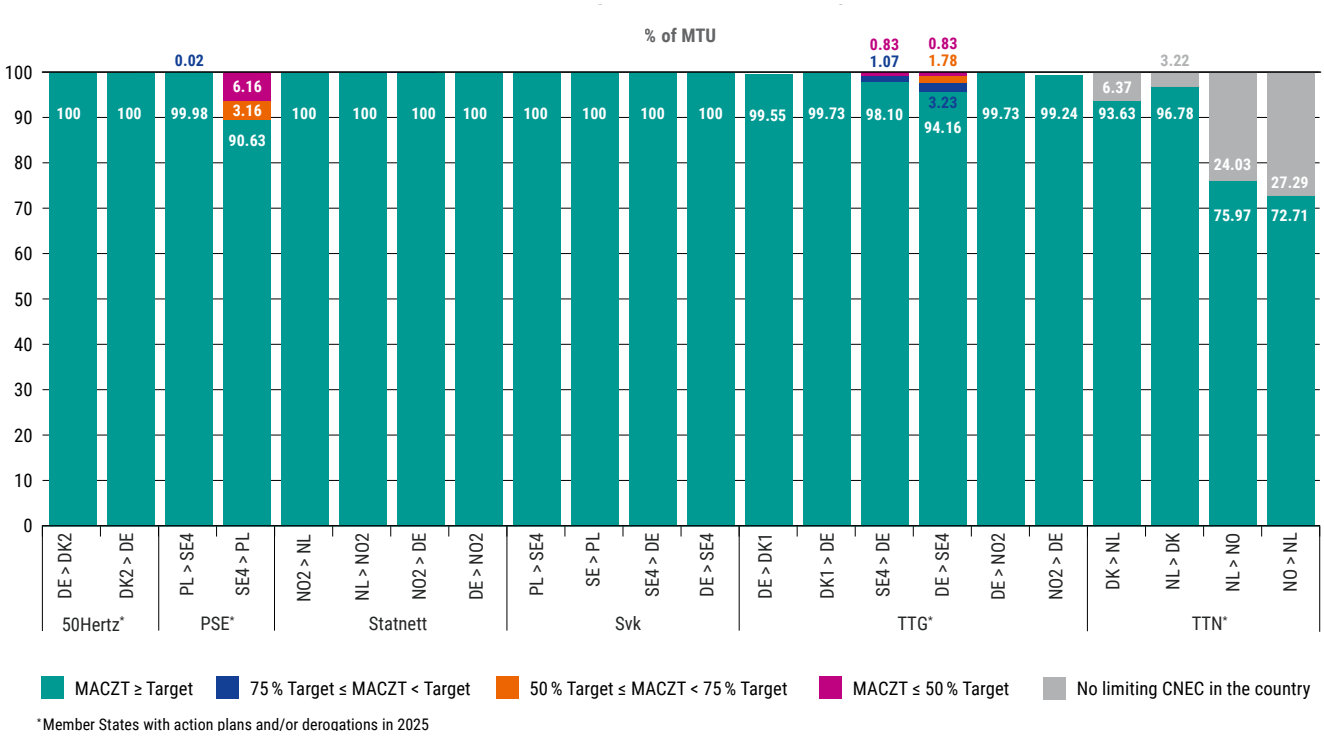


Figure 2.14: Results of the joint assessment (based on the national monitoring results) for 2025 for the Hansa CCR compared to the applicable values under derogations and action plans.

Note: Individual applicable targets can be found in the country fact sheets in Annex IV. Small deviations from a total amount of 100 % are caused by rounding.

On the DE–SE4 border, all deviations from the linear trajectory that occurred in 2025, were duly justified in line with Article 16 (3) of the Electricity Regulation. These were mainly driven by planned and unplanned outages of critical grid elements in the TenneT control area, including distribution grid assets. Many outages were necessary to implement grid reinforcements – most notably the construction of the Ostküstenleitung – which aims to resolve the specific connection constraints of the Baltic Cable by improving transmission availability in the region. The Ostküstenleitung, a 380 kV overhead line project between Göhl and Lübeck, is key to strengthening the integration of the Baltic Cable into the German extra-high voltage grid. This strategic grid reinforcement will enable full utilisation of the interconnector and help meet European targets for cross-border electricity trade.

On the TTN borders, the grey parts “No limiting CNECs” denotes outages on the cables.

Result of the joint assessment of the Hansa CCR:

Overall, the joint assessment conducted by the Hansa TSOs demonstrates a high degree of fulfilment with applicable targets, including intermediate targets from action plans and derogations. Any deviations from the target were necessary to maintain operational security.

2 Electricity Regulation 2019/943 is not applicable in Norway.

2.3.3 TSOs urge caution in applying the requirement within the ID time frame, as security is at stake

Providing sufficient CZC for the ID time frame is crucial to a well-functioning ID market and the integration of renewable energy resources into Europe's power system. TSOs provide sufficient cross-border capacities following their action plans and derogations (where applicable) for all time frames. TSOs firmly believe that repeating the (minimum) 70 % requirement from DA to ID will not help achieve that goal. An overarching approach across both time frames is essential: offering a 70 % minimum capacity in the DA time frame often means offering virtual capacities to the market. This involves TSOs offering capacities that may not physically exist to virtually increase cross-zonal trading. In doing so, TSOs assume that potential congestions in the transmission grid can be resolved after DA market clearing through remedial actions, such as redispatching power plants. Therefore, offering CZCs that fulfil the 70 % requirement implicitly depends on anticipating the availability of sufficient measures to alleviate the resulting congestion at a later stage. However, this does not apply in the ID time frame for the following reasons:

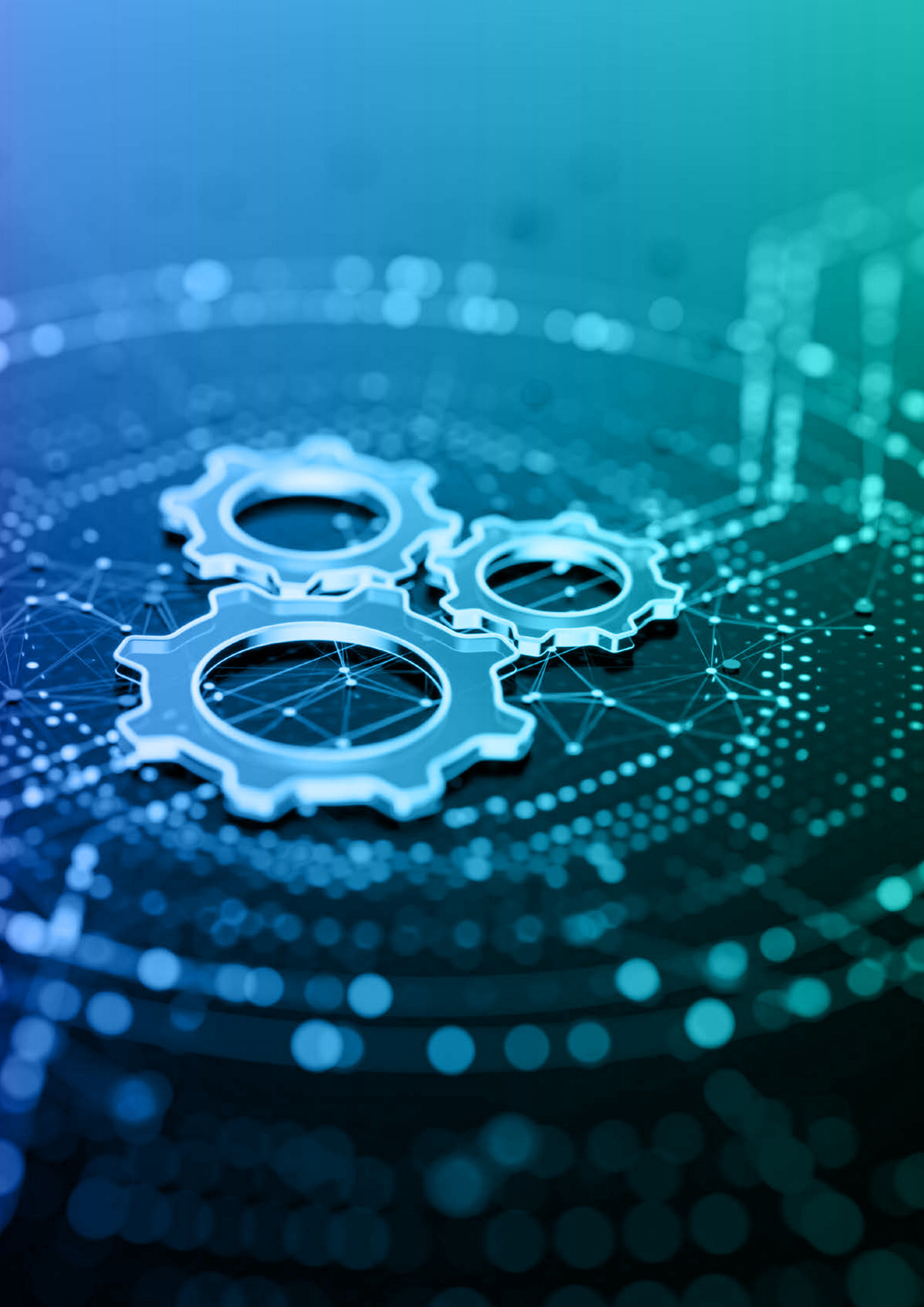
1 // Compared to the DA market, there is no equivalent coordination process for remedial actions after the closure of the ID market. Moreover, TSOs lack visibility into potential congestion resulting from ID market trades before real time and hence have no time to react to them.

2 // The remedial actions available to TSOs to maintain operational grid security diminish as security processes move closer to real time. For example, the lead times of generation units for redispatch are several hours, making them unavailable for deployment closer to real time. With the ID market closing 1 hour before delivery (or 30 minutes in the near future), current redispatch and coordination processes and generation units cannot accommodate such short lead times, leaving TSOs insufficient time to activate remedial actions before real time. Therefore, TSOs cannot provide virtual CZCs at the minimum 70 % level for allocation so close to real time without jeopardising secure system operation.

3 // The liquidity of the ID market is uneven, with significantly more trading activity occurring near real-time operation and limited interest many hours in advance. However, the ability to apply remedial actions close to real time to enable virtual capacities is severely limited, if feasible at all. This becomes even more relevant with the implementation of the new ID market closure time (i. e. 30 minutes before real time). Since many changes in the ID time frame already occur shortly before delivery, allowing trading up to 30 minutes before real time leaves even less time for TSOs to act.

4 // Finally, when approaching real-time grid operation, other technical aspects, such as reactive power control and voltage regulation, gain importance and must be considered when taking remedial actions.

To summarise, physical capacity cannot be increased beyond the security limits. TSOs are responsible for maintaining operational security. A strict 70 % minimum capacity requirement in the ID time frame will, in practice, be offset to maintain operational security – meaning it will not lead to additional capacity being made available for trade during this period. Alternative measures, such as grid investments and BZ reconfigurations, will not mitigate this issue, as they operate on longer time frames and are designed to address congestion with a more structural nature. Furthermore, as congestion patterns become more variable and temporary, TSOs will need to complement LT measures with daily capacity calculation and allocation to manage these congestions efficiently. As previously noted, TSOs provide sufficient cross-border capacities following their action plans and derogations (where applicable) and are making significant investments in grid expansion, including cross-border connections. To meet CEP70 requirements, TSOs are working diligently and demonstrating mutual support. One example of this collaboration is the DAVinCy validation process in the Core CCR, where the German, Austrian, and Dutch TSOs jointly assess validation adjustments in the DA capacity calculation. TSOs see a risk of being forced into an unrealistic obligation to provide virtual capacities in the ID time frame. This requirement disrupts the fragile balance between maximising CZC and ensuring the grid's operational security. Clarifying contradictions in the current regulation and focusing on an efficient transmission system alongside ID markets that accurately reflect physics will benefit all stakeholders during the challenging energy transition.



3 Implementation progress of the FCA, CACM, and EB Regulations

3.1 FCA Regulation

The FCA Regulation, which entered into force in September 2016, sets out rules on CZC calculation and allocation in the forward time frame, typically year-ahead and month-ahead.

On the calculation side, its core elements are the establishment of a common methodology for the calculation of LT CZC. As a result of this calculation, TSOs provide the optimal amount of LT CZCs for the allocation of LTTRs. On the allocation side, FCA establishes the method for explicit auctions of LTTRs.

Annex II outlines the implementation progress of this regulation, including links to all relevant documents, such as TSO proposals and ACER decisions.

Long-term flow-based allocation

The TSOs and JAO have been working on the implementation of the LTFBA project to prepare for the go-live in the Core and Nordic CCRs. Several workshops have been organised to share the progress of the project and the expected results of the implementation – one workshop with stakeholders was organised on 1 December 2025. In this workshop, updates were provided on the implementation progress of the LTFBA project, which included key milestones and highlights, involvement of market participants in the testing going forward, what has changed with the 2025 amendments of the HAR methodology, TSOs' work in assessing the implementation of an improved solution for collaterals to be implemented following the LTFBA project go-live, and updates on the Core and Nordic roadmaps regarding the implementation of the LTFBA project. The LTFBA go-live is planned for the end of 2026 for the LT yearly and monthly products for 2027. TSOs are fully committed to implementing LTFBA by November 2026 and are working intensively in cooperation with NRAs and ACER to achieve this goal.

In accordance with Article 9 of Regulation (EU) 2024/1747, in August 2024, the EC launched a targeted consultation and call for evidence to revise the FCA Regulation, to which ENTSO-E submitted a response. The EC conducted an impact assessment of measures to improve the ability of market participants to hedge price risks in the internal forward electricity market. This impact assessment was completed in Q1 2026 and will result in the amendment of the FCA Regulation. All TSOs and ENTSO-E will work on its implementation.

Improvements in collateral management

Under LTFBA, collateral requirements mechanically cumulate across borders, leading to a substantial increase in collateral requirements for market participants compared to per-border auctions. Ex-ante bid filtering based on maximum payment obligations (MPOs), including approaches complemented with bid-price caps, overestimates final payment obligations while still possibly exposing TSOs to some settlement risks. TSOs and the SAP commissioned a study to investigate possible improvements to enhance collateral management for market participants.

The study found that optimal bid filtering based on the auction final clearing prices (i.e. the final payment obligations) is technically feasible and can be embedded directly into the clearing algorithm.

Furthermore, it demonstrated that optimal bid filtering:

- avoids unnecessary bid rejections for registered participants,
- fully secures TSOs against settlement risk, and
- preserves auction outcomes (auction surplus, traded volumes) close to the no-filtering benchmark.

TSOs and SAP are making every effort to implement the enhanced collateral management as soon as possible in order to reduce the collateral requirements for market participants and create better conditions for participation in LTFBA auctions. For further explanation of the concept, please refer to the JAO website.

Harmonised Allocation Rules methodology (Articles 51 and 52 of the FCA Regulation)

ENTSO-E has reviewed the HAR methodology according to Article 68(5) of the HAR. The HAR should be periodically reviewed by the SAP and the relevant TSOs (at least every two years, involving the registered participants). All TSOs submitted proposed HAR amendments to ACER on 27 March 2025 according to the biennial update. The 2025 amendment included changes to the MTU, market participants' registration, and suspension and termination, and also clarified prices and price cap publication. ACER issued its decision on the HAR on 17 September 2025.

In June 2026, All TSOs submitted to ACER another round of proposed amendments to the HAR, resulting from the above-mentioned improvements of collateral management. In addition, the proposed amendments include clarifications regarding the contestation period, the curtailment cap on DC borders, changes related to the new auction tool, and changes related to REMIT II. ACER's decision on the proposal is expected in December 2026.

Single allocation platform requirements methodology (Article 49 of the FCA Regulation)

In June 2026, All TSOs submitted the proposal for the amendment of the establishment of the SAP methodology to ACER. The revision of this methodology and the associated requirements for the establishment and operation of the SAP were driven by the changes required for the introduction of an improved collateral solution, as mentioned above, as well as changes relevant to evolved flow-based (EFB). ACER is expected to publish its decision on the TSOs' submitted proposal in December 2026.

FCA data exchange (Article 63(3) of the FCA Regulation)

In 2026, ENTSO-E and ACER will amend the Agreement for Data Provision for Network Codes and Guidelines monitoring by adding Annex 4: FCA list of information and specific provisions.

This provides a list of information related to the implementation of the FCA regulation to be sent to ACER via ENTSO-E Transparency Platform (non-public domain) for monitoring purposes. TSOs will be responsible for providing the agreed-upon data.

3.2 CACM Regulation

3.2.1 Main developments in All TSOs' deliverables

Congestion Income Distribution Methodology (Art. 73 of the CACM Regulation)

The Cross-CCR Congestion Income Distribution (CID) project went live on 4 May 2026 (delivery day 5 May) for intraday auction (IDA) 1 and IDA2, 5 May 2026 (delivery day 5 May) for IDA3, and 5 May (delivery day 6 May) for DA. It implements the provisions of the CACM congestion income distribution methodology (CIDM) approved by ACER in December 2023. The aim of the project is to implement a tool to automatically distribute the CI arising from commercial flows within and between CCRs and deal with unintuitive flows. It was developed by TSOs from CCRs mutually affected by allocation mechanisms with cross-CCR impact (hereafter, the concerned TSOs) and JAO.

To comply with the regulatory deadline set in the CIDM, the concerned TSOs implemented a CI redistribution from October 2024 (the go-live of Nordic AHC) until the go-live of Cross-CCR CID.

Finally, the concerned TSOs began assessing the results of the application of the CACM CIDM with respect to the requirement to ensure fair and non-discriminatory treatment, pursuant to Article 10(6) of the CIDM. The assessment will be finalised after the first year of implementation of the cross-CCR mechanisms.

Determination of CCR methodology (Article 15(1) of the CACM Regulation):

The CACM Regulation defines CCRs as geographic areas in which coordinated capacity calculation is applied. Article 15(1) of the CACM Regulation requires All TSOs to jointly develop a common proposal regarding the determination of CCRs.

On 2 July 2025, All TSOs submitted a proposal to ACER to amend the determination of CCRs to take into account and amend the CCRs determined for the EnC, covering the BZBs between the Energy Community contracting parties (EnC CPs) as well as the EnC CPs and the adjacent EU Member States. The EU TSOs consulted the TSOs of the EnC CPs on this proposal. In addition, the All TSOs proposal included the further merger of the CCR Core and the CCR Italy North – a CCR known as Central Europe ("CCR CE") – into the ID market time frame and for ROSC and cost-sharing methodologies.

The All TSOs proposal was approved by ACER in **this decision** on 16 December 2025.

The approval of the All TSOs proposal reflects the culmination of intense negotiations and consensus-building among the EnC TSOs and their European Union neighbours, facilitated by ENTSO-E over several years.

The amended CCR configuration will enable stronger integration of the power systems of Ukraine and Moldova with their EU neighbours, as well as link ing the West Balkan TSOs with the already organised electricity market areas of Central and SEE.

The amended CCR configuration will also contribute to the optimisation of coordinated capacity calculation in the single largest CCR on the European continent by extending the scope of the CCR CE into the ID market time frame, as well as including the ROSC and cost-sharing methodologies.

IDCZGTs methodology (Article 59 of the CACM Regulation):

Article 59 of the CACM Regulation, concerning the operation of the single intraday coupling (SIDC), sets out the rules on ID cross-zonal gate opening times (IDCZGOTs) and gate closure times (IDCZGCTs).

On 2 July 2025, All TSOs submitted a proposal to ACER to amend the IDCZGT methodology. The proposed amendments introduce provisions concerning the implementation timeline for the 30-minute IDCZGCT, in accordance with Article 8(1) of Regulation (EU) 2019/943, and subject to possible derogations in accordance with Articles 8(1a) and 8(1b) of the same regulation, as amended by the 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 regarding improving the EU's electricity market design ("EMD Regulation").

The TSOs' proposal was approved by ACER in **this decision** on 19 December 2025.

Multiple interconnectors decreased the IDCZGCT from 60 to 30 minutes on 14 January 2026. The rest of the SIDC BZBs are expected to make the switch according to their revised action plans. The TSO- and border-based derogation overview for the 30-minute IDCZGCT is available **here**. The sectionfil is being updated regularly on the ENTSO-E website, following the go-live of each border.

3.2.2 Main developments in ENTSO-E deliverables

CACM amendment

In June 2025, the EC resumed its work on amending the CACM Regulation (hereinafter, CACM Amendment). The stated objective of this revision is to simplify and harmonise market rules, enhance transparency, and strengthen regulatory oversight.

ENTSO-E has engaged with the EC on several draft versions of the CACM Amendment. While ENTSO-E welcomed several provisions, several concerns encompassing governance (roles and responsibilities changes), legal (including scope of the implementing act and procedural steps), and technical aspects affecting market functioning and system operation have been identified. ENTSO-E has provided its technical expertise to ensure a balanced approach across the objectives of operational security and competitiveness. No official consultation on CACM 2.0 has been launched, including by ENTSO-E, with regard to the existing draft proposals.

Market coupling – mitigation measures to prevent decoupling events

ENTSO-E has participated in several ACER-led workshops with the EC, NRAs, TSOs, and NEMOs on mitigation measures to improve decoupling processes. TSOs and NEMOs are especially working on a more robust DA fallback capacity allocation that would ensure a single single day-ahead coupling (SDAC) reference price in every BZ under all conditions. ENTSO-E is an observer to the Market Coupling Steering Committee (MCSC).

3.2.3 Main developments in NEMOs' deliverables

CACM Annual Report

On 24 September 2025, the All NEMO Committee organised its third Annual Conference. Part of this conference was dedicated to the key findings from the **CACM Annual Report 2024**, which was delivered on 1 July 2025. The report focused on demonstrating the safe navigation of an energy crisis, showcasing the effectiveness of market coupling during difficult times.

CACM Cost Report

On 30 June 2025, NEMOs and TSOs published the **2024 CACM Cost Report**, providing a detailed account of expenditures related to the development and operation of SDAC and SIDC.

Algorithm methodology

At ACER's request, NEMOs also amended **Article 37** to consider the requirements submitted by the TSOs for the co-optimisation of DA energy and balancing capacity. The concept of co-optimisation, as outlined in Article 40 of the EB Regulation, aims to achieve the optimal allocation of CZC through the joint procurement of DA energy and balancing capacity within the SDAC market.

Based on Articles 4(15) and 4(16) of the updated methodology, NEMOs, in collaboration with TSOs, are carrying out research and development (R&D) activities to assess the technical feasibility, impacts, and implications of integrating co-optimisation into the price coupling algorithm. This work is structured around several milestones, including the delivery of R1, R2, and R3 R&D Reports to ACER.

In May–June 2025, NEMOs, in cooperation with TSOs, conducted a public consultation on the first of the required reports, referred to as "R0-Report", covering concepts of bidding products, bid design, and pricing, receiving 23 responses.

Among other things, the public consultation revealed serious concerns from market participants about bid construction and portfolio representation, challenges related to coupling to heat and hydrogen markets, hydro river system cascades, and cost burdens. They also pointed to a remaining need for price forecasts for certain types of assets. Several expressed clear preferences for a sequential solution. NEMOs and TSOs share some of these concerns but recognise that several will be addressed and evaluated in upcoming co-optimisation R&D phases.

NEMOs and TSOs updated the original R0 report with the provided feedback by adding separate sections with a summary of public consultation feedback. The final delivery of the updated **R1 report** to ACER was on 28 November 2025. Although the R&D work is conducted in several steps, R&D areas cannot be viewed in isolation. Therefore, choices may be reconsidered upon the provision of new insights in the next phases of the R&D work. After all R&D phases are concluded, the outcomes will inform further discussions among NEMOs and TSOs together with ACER on the next steps for co-optimisation.

Harmonised maximum and minimum clearing price methodology

According to CACM Article 41, all NEMOs shall, in cooperation with the relevant TSOs, develop a proposal on harmonised maximum and minimum clearing prices (HMMCP) to be applied in all BZs that participate in SDAC. CACM Article 54 stipulates that a similar proposal shall be developed for SIDC. The proposals shall take into account an estimation of the value of lost load.

On 4 August 2025, the All NEMO Committee submitted, on behalf of all NEMOs, a proposal for amendments to the HMMCP methodology for SDAC in accordance with Article 41 (1) of the CACM Regulation, and a proposal for amendments to the HMMCP methodology for SIDC in accordance with Article 54 (1) of the CACM Regulation.

On 4 February 2026, ACER issued **Decision 02/2026** on **HMMCP methodology for SDAC** and **Decision 03/2026** on **HMMCP methodology for SIDC**.

The methodology stipulates that the harmonised minimum clearing price for SDAC shall be decreased by 100 EUR/MWh if the clearing price falls below a value of 70 % of the harmonised minimum clearing price for SDAC in at least two MTUs in an individual BZ or multiple BZs and in at least two different days within 30 rolling days from the first low price detection. This condition was initially met by the clearing price level reached on 25 April 2026, for delivery date 26 April 2026, and subsequently again on 30 April 2026, for delivery date 1 May 2026, in several European countries and MTUs. As a consequence, the current harmonised minimum clearing price for SDAC, equal to −500 EUR/MWh, has been lowered to −600 EUR/MWh. The new minimum clearing price applies in all BZs that participate in SDAC, since 28 May 2026, the first trading session, for the delivery date 29 May 2026.

HMMCP methodologies showcase the need for strong cooperation between NEMOs and TSOs to ensure the effective functioning and operation of market coupling in Europe.

3.2.4 Single day-ahead and intraday coupling observership and non-disclosure agreement

The CACM GL requires that TSOs, ENTSO-E, power exchanges (PXs), and market operators or PXs acting as NEMOs cooperate and exchange information to fulfil the obligations set out in the CACM GL for completing single DA and ID coupling. To protect the exchange of confidential information, the Single Day-Ahead and Intraday Coupling Observership and Non-Disclosure Agreement (known as "CACM Global NDA") went into effect on 23 February 2016, replacing individual NDAs from early implementation projects. The CACM Global NDA expired on 23 February 2026 and was replaced by a new NDA (known as "CACM NDA") which is broadly based on the same wording and rules than the "CACM Global NDA", with necessary and adequate updates.

Following up on the information presented in the previous edition of this report (ENTSO-E Market Report 2025), this section provides an update about the new parties that joined the "CACM Global NDA" between March 2025 and February 2026 (before the expiration of the "CACM Global NDA"). Importantly, in accordance with Article 8 of the expired "CACM Global NDA", all "CACM Global NDA parties" were required to consent to the adherence of new parties

Based on the above-mentioned Article 8, the following parties adhered to the "CACM Global NDA" during the period from March 2025 to February 2026:

- 24 October 2025: Ukrenergo, a certified TSO for the power system of Ukraine

Name of party	Member since
Affärsverket Svenska Kraftnät	23 February 2016
Amprion GmbH	23 February 2016
Austrian Power Grid AG	23 February 2016
Britned Development Limited	23 February 2016
Creos Luxembourg S.A	23 February 2016
Elia System Operator NV/SA	23 February 2016
Energinet Elsystemansvar A/S	23 February 2016
Fingrid Oyj	23 February 2016
National Grid Interconnectors Limited	23 February 2016
Red Eléctrica de España, S.A.U.	23 February 2016
REN – Rede Eléctrica Nacional, S.A.	23 February 2016
RTE Réseau de transport d'électricité	23 February 2016
Statnett SF	23 February 2016
TenneT TSO B.V	23 February 2016
TenneT TSO GmbH	23 February 2016
TransnetBW GmbH	23 February 2016
50Hertz Transmission GmbH	23 February 2016
Vorarlberger Übertragungsnetz GmbH	23 February 2016
Elektroenergien Sistemen Operator EAD	23 February 2016
Swissgrid AG	23 February 2016
Cyprus TSO	23 February 2016
ČEPS a.s	23 February 2016
Elering AS	23 February 2016
National Grid Electricity Transmission plc	23 February 2016
SONI Limited	23 February 2016
Moye Interconnector Limited	23 February 2016
Independent Power Transmission Operator S.A	23 February 2016
Croatian Transmission System Operator PLC.	23 February 2016
MAVIR – Hungarian Independent Transmission Operator Company Ltd	23 February 2016
EirGrid plc	23 February 2016
Landsnet hf	23 February 2016
Terna – Rete Elettrica Nazionale S.p.A	23 February 2016
Litgrid AB	23 February 2016
AS "Augstsprieguma tīkls"	23 February 2016
CGES AD	23 February 2016
MEPSO – Operator na elektroprenosniot sistem na Makedonija AD	23 February 2016
Polskie Sieci Elektroenergetyczne S.A	23 February 2016
Compania Naţională de Transport al Energiei Electrice Transelectrica SA	23 February 2016
EMS – JOINT STOCK COMPANY Elektromreža Srbije BeLGRADE	23 February 2016
Slovenská elektrizačná prenosová sústava, a.s	23 February 2016
ELES, d.o.o, sistemski operater prenosnega elektroenergetskega omrežja	23 February 2016
SP Transmission Limited	23 February 2016
Scottish Hydro Electric Transmission plc	23 February 2016
APX Power B.V. and APX Commodities Ltd.	23 February 2016
Belpex NV	23 February 2016
Croatian Power Exchange Ltd.	23 February 2016
EPEX SPOT SE	23 February 2016
Gestore dei Mercati Energetici S.p.A	23 February 2016
Nord Pool AS	23 February 2016
OMI – Polo Español S.A.	23 February 2016
OTE A.S.	23 February 2016
HEnEX S.A (LAGIE legal successor)	23 February 2016
HUPX Hungarian Power Exchange Company Limited by Shares	23 February 2016
EirGrid plc	23 February 2016
Towarowa Giełda Energii S.A.	23 February 2016
Operatorul Pieţei de Energie Electrică şi de Gaze Naturale SA	23 February 2016
OKTE a.s	23 February 2016
BSP Regional Energy Exchange LLC	23 February 2016
SONI Limited	23 February 2016
Independent Bulgarian Energy Exchange EAD	23 February 2016
EXAA Abwicklungsstelle für Energieprodukte AG	23 February 2016
SEEPEX	13 June 2016
Nemo Link Limited	26 July 2017
Operatori i Sistemit të Transmetimit Albania sh.a	29 January 2018
ElecLink Limited	9 March 2018
Kraftnät Åland	27 March 2019
Nasdaq Oslo ASA	1 April 2019
National Grid NSL Ltd.	28 June 2019
National Grid IFA2 Ltd.	28 June 2019
Berza elektricne energije d.o.o. (BELEN)	21 January 2020
MEMO	17 July 2021
Baltic Cable	13 August 2021
ETPA	02 August 2022
JSC MO	17 November 2022
BRM	11 October 2023
OPEM	16 October 2024
ALPEX	14 January 2025
Moldelectrica	22 January 2025
KOSTT	07 April 2025
Ukrenergo	24 October 2025

Table 3.1: List of all parties under the CACM Global NDA and the date when each party became part of the agreement in chronological order

3.3 EB Regulation

In compliance with the EB Regulation, ENTSO-E publishes a biennial balancing report. ENTSO-E would like to highlight that the Balancing Report 2026 complements the Market Report 2026 and invites readers to consult it to observe updates on recent developments in European balancing markets since the publication of the **ENTSO-E Market Report 2025**.

4 Forward capacity allocation

In accordance with Article 49 of the FCA Regulation,[3] as of 1 November 2018, all TSOs have appointed JAO to act as the SAP for FCA. JAO is a joint service company currently owned by 26 TSOs[4] that hosts SAP services for TSOs.

SAP enables LT auctions of transmission capacity and currently services 25 TSOs from 22 EU countries. The IT system is scalable on a border-by-border basis, allowing for annual, non-calendar annual, half-yearly, quarterly, monthly, weekly, weekend, daily, and ID auctions.

4.1 Governance

In accordance with Article 1 of the approved SAP methodology, all TSOs and regulatory authorities[5] bound by the FCA Regulation agreed to appoint JAO as the SAP operator. Consequently, the SAP Cooperation Agreement (SAP CA), according to Article 2(2)(t) of the SAP methodology, was developed and signed by all TSOs that issue LTTRs.

The SAP operator is governed by the SAP Council, consisting of TSOs and JAO representatives, which is the sole competent body for deciding on operational and budget related topics to the fulfilment of SAP tasks, in accordance with the FCA Regulation.[6]

Figure 4.1: Countries whose TSOs are obliged to be part of the SAP Council and are part of the SAP CA (as of May 2024)[7]

3 All TSOs' proposal of 7 April 2017 for the establishment of SAP in accordance with Article 49 of the FCA regulation and for the cost-sharing methodology in accordance with Article 59 of the FCA regulation.

4 Also includes TSOs/companies operating undersea cable interconnectors. These are: 50Hertz, Amprion, APG, ČEPS, Creos, EirGrid, ELES, ELIA, EMS, Energinet, ESO, HOPS, IPTO, MAVIR, Moyle, PSE, RTE, SEPS, Statnett, SvK, Swissgrid, TenneT DE, TenneT NL, Terna, Transelectrica, and TransnetBW.

5 Some Regulatory Authorities (those of Lithuania and Sweden) have exempted their TSOs pursuant to Article 30(1) of FCA Regulation from issuing LTTRs and therefore, according to Article 30(7) of the FCA Regulation and these TSOs, are not yet part of the SAP CA.

6 Further details on the governance structure of JAO can be found in the **ENTSO-E Market Report of 2020**

7 Creos does not issue LTTRs, nor commercialise any interconnector. Brexit did not have any impact on EirGrid participation as a full member of SAP CA and the SAP Council.

4.2 Operations

JAO performs all tasks in compliance with the SAP CA, the SAP methodology and the HAR.[8] As of 2026, the SAP operator organises forward capacity rights auctions at 67 BZ directional borders and provides services via a common IT system for more than 545 registered market participants.[9] Only yearly, quarterly, and monthly products were allocated at EU borders in 2025. A gradual shift is being observed from physical transmission rights (PTR) to financial transmission rights (FTR) options at EU borders. This tendency is supported by the fact that PTR holders on average nominate only around 5.25% of allocated rights. A broad transition to FTRs occurred in the context of the launch of FB DA market coupling in the Core CCR, when a vast majority of remaining BZBs in the region switched to FTRs.

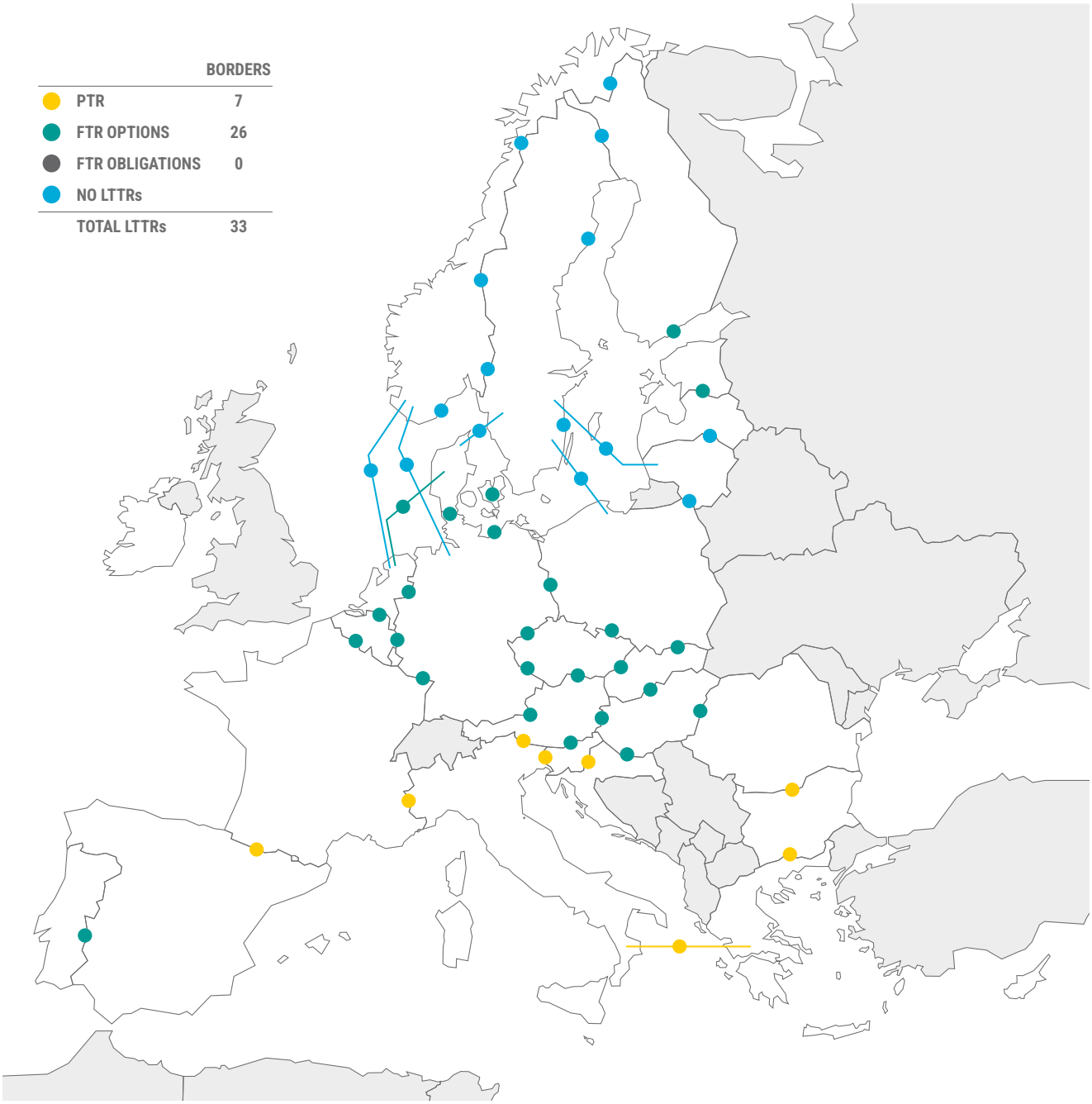


Figure 4.2: Overview of products offered at SAP (as of 2025)[10]

8 More details on SAP tasks are described in the ENTSO-E Market Report of 2020.

9 A detailed description of the common IT System eCAT can be found in the ENTSO-E Market Report 2019.

10 At the DE–CZ border, FTR options are offered for CZ–DE (TenneT) and CZ–DE (50Hertz). After Go-Live of LTFBA, this will be changed to one CZ-DE auction. At the EE–LV and FI–EE borders, FTR options are only offered for the directions EE to LV and FI to EE.

Regarding the mentioned borders, in 2025, the SAP operator organised more than 789 auctions with LTTRs. A similar number is expected for 2026.

Figure 4.3: Average number of participants in every auction versus number of participants that won capacity during 2025

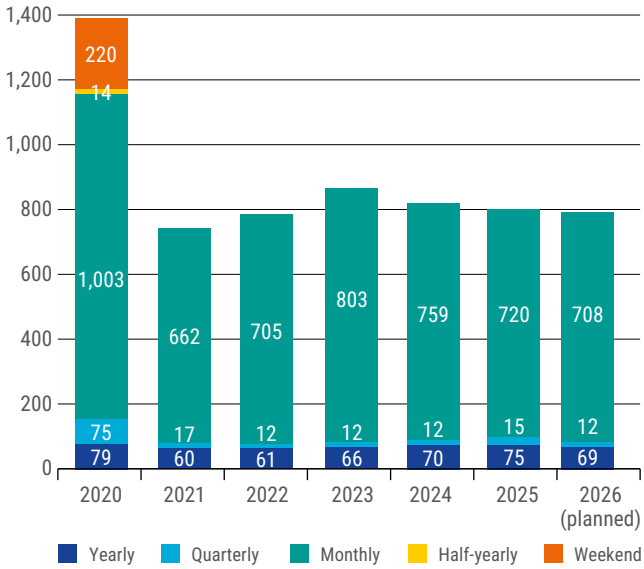


Figure 4.4: Overview of auctions

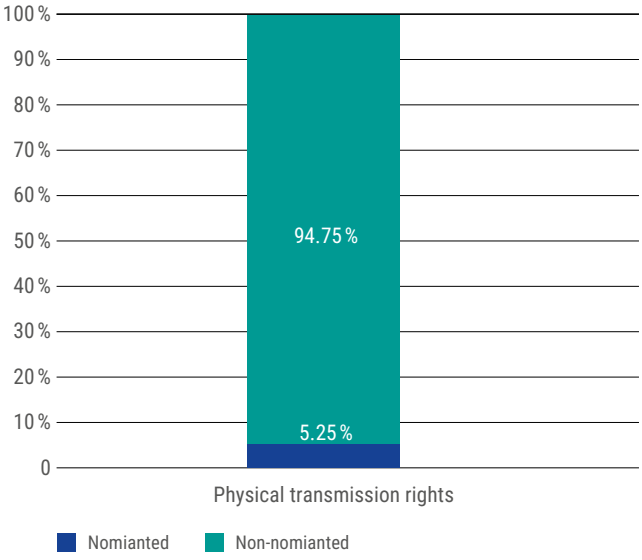


Figure 4.5: Usage (nomination) rate of long-term transmission rights

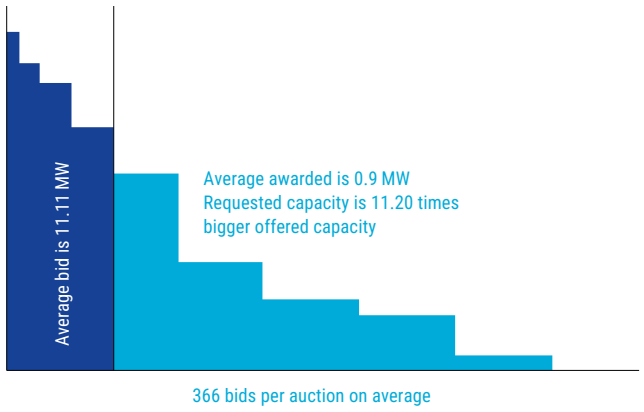


Figure 4.6: Average long-term capacity rights auction structure

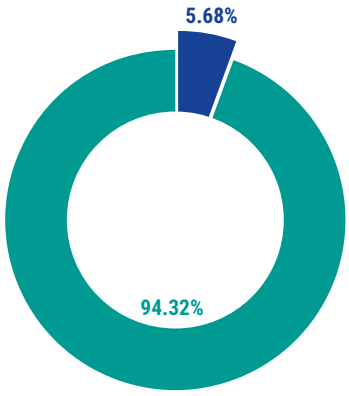


Figure 4.7: Rate of return of long-term capacity rights for reallocation at subsequent long-term auction

4.2.1 Quality of operations

The SAP Council regularly monitors the quality of operations performed by the SAP operator. More than 7,200 auctions have taken place since SAP operations began.

To monitor the SAP operator's operational quality, the TSOs of the SAP Council calculated 23 detailed KPIs, which were merged into three meta-KPIs[11] (see Table 4.1).

CATEGORIES	DETAILS
› Fulfilling reporting Obligations	› Whether data to be reported was provided to EMFIP and ACER platform in line with Transparency and REMIT Regulations and whether the data were correct
› Operational Effectiveness	› SAP system availability – Invoicing correctness – Operational incidents occurrence
› Customer Satisfaction	› User's satisfaction with JAO – SAP's effectivity in solving user's problems and requests – Website usabilty

Figure 4.8: SAP key performance indicators

Month	Fulfilling Reporting Obligations	Operational Effectiveness	Customer Satisfaction	TOTAL	Quarterly Score
Jan-25	9.80	9.00	6.00	8.27	
Feb-25	9.90	9.00	7.50	8.80	8.68
Mar-25	9.90	9.50	7.50	8.97	
Apr-25	9.90	10.00	7.50	9.13	
May-25	9.90	10.00	6.00	8.63	8.80
Jun-25	9.90	9.00	7.00	8.63	
Jul-25	9.90	9.00	7.50	8.80	
Aug-25	9.90	10.00	7.50	9.13	8.97
Sep-25	9.90	10.00	9.00	9.63	
Oct-25	9.90	9.00	6.00	8.30	
Nov-25	9.30	9.00	7.50	8.60	8.73
Dec-25	9.90	9.00	9.00	9.30	
Jan-26	9.80	8.00	6.00	7.93	
Feb-26	9.10	8.00	6.00	7.70	8.19
Mar-26	9.80	8.00	9.00	8.93	

Table 4.1: Overview operation Meta-KPIs of SAP (as of March 2024)

11 A more detailed description is available in the last ENTSO-E Market Report 2020

Customer interaction and satisfaction

JAO has created a platform to gather feedback and requests from users of the JAO eCAT system related to IT interfaces and other services performed. The users' expertise and views are essential for the continuous improvement of the services provided by JAO.

Therefore, JAO has established the User's Group, which serves as a platform for relevant stakeholders. The User's Group comprises representatives from key European stakeholder organisations interested in participating therein while ensuring broad geographical coverage by the group.

In an annual survey conducted in early 2025 and repeated in 2026, market participants consistently rated JAO's performance as very good. Overall satisfaction remained high at 4.0 out of 5, broadly in line with the 4.1 recorded the previous year. Scores improved in invoicing and bids, remained stable for fund transfers, and showed only minor variations across other categories.

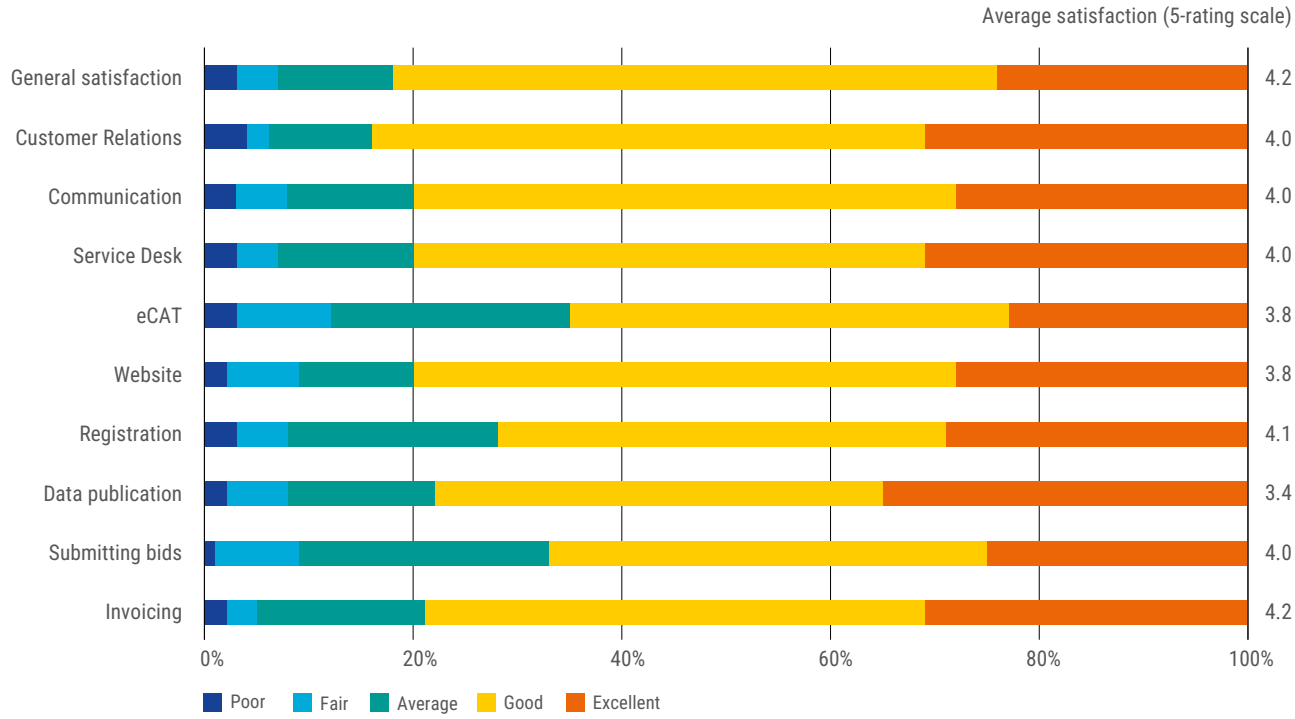


Figure 4.9: SAP customer interaction and satisfaction

4.3 Expenditures

This report provides a summary of TSOs' common costs of establishing, amending, and operating the SAP. Figure 4.10 depicts the planned and actual costs since 2019.[12]

The reported establishment and development costs consist of annual depreciation and amortisation of investments to establish and develop SAP in addition to the existing tools in JAO. SAP operational costs consist of annual depreciation and amortisation of the tools and other assets used for LT auctions. They also include the financial clearing and settlement of auction revenues (including bank fees) and operational support covering the entire LT allocation process, contact with market participants, service desk, risk management, and other related services. From 2026, clearing and settlement costs are included under operational costs in Figure 4.11.

Compared to SDAC/SIDC projects, SAP costs cover the entire business chain for capacity allocation to market participants. The organisation and meeting of the SAP Council generated no direct costs.

SAP fee principles are defined based on the SAP methodology, which is derived from All TSOs' proposal for the establishment of the SAP in accordance with Article 49 and the cost-sharing methodology in accordance with Article 59 of the FCA Regulation.

The SAP methodology is applicable to the costs of running LT auctions on the SAP borders only, and to the relevant SAP tasks, as defined in Article 9 of the rules establishing the SAP as of October 2018 (i. e. the date of establishing the SAP).

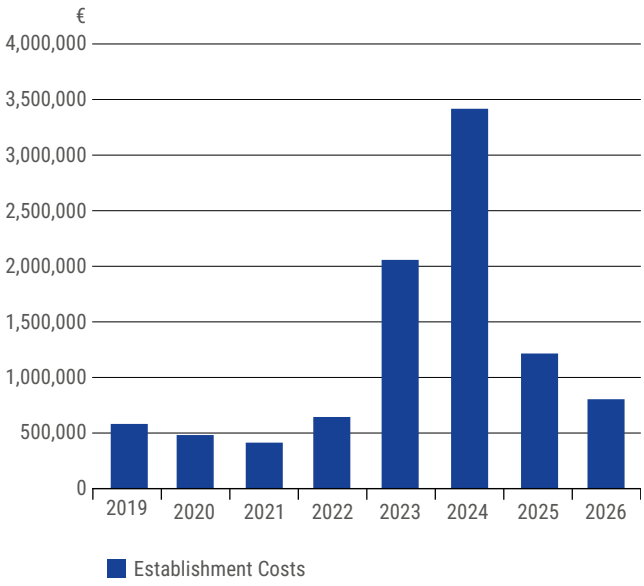


Figure 4.10: Overview of the single allocation platform for establishing and amending costs

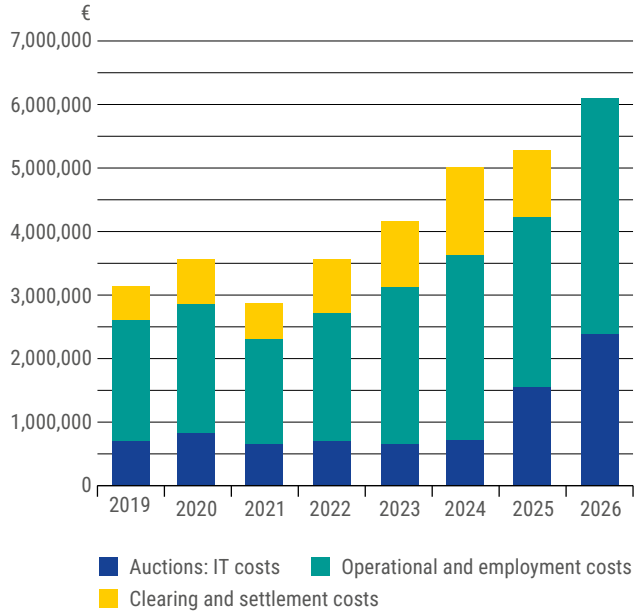


Figure 4.11: Overview of operating costs for the single allocation platform

12 In line with the regulatory guidance costs for the coupling, projects are planned and shared between TSOs and/or NEMOs as of 14 February 2017.

4.4 Evolution of services

The SAP operator has implemented and operates all obligations stemming from the FCA Regulation. All TSOs focus on the continuous improvement of SAP operator services provided to both TSOs and market participants.

4.4.1 Operations

JAO is undertaking a major transformation through the implementation of a new capacity-auction platform, Orion, designed to replace the current legacy systems and support the future evolution of the European electricity market. The initiative is driven by the need to improve scalability, robustness, and operational resilience, while ensuring LT compliance with evolving regulatory requirements and market design changes. Orion aims to enhance performance, transparency, and flexibility across all auction time frames, streamline operational processes, and provide a more modern, secure, and user-friendly experience for TSOs and market participants. The go-live of Orion is currently planned for September 2027.

4.4.2 Long-term capacity calculation and allocation

The go-live of the LTFBA is planned for the end of 2026 for the LT yearly and monthly products for 2027. Involved TSOs are fully committed to implementing LTFBA by November 2026 and are working intensively in cooperation with NRAs and ACER to achieve this goal.

Since the last ENTSO-E Market Report, further milestones have been achieved. In August and September 2025, market participants were involved in testing the LTFBA simulation platform, which enables simulations of LT auctions to be run under the new LTFBA setup. The platform was made available to market participants in February 2026. Additionally, in November 2025, the external parallel run of long-term capacity calculation (LTCC) commenced.

Results of coordinated capacity calculation runs and allocation were published via the Publication Tool and the JAO website. In the parallel run, the LTFBA simulation platform was used, taking LT FB domains calculated for the yearly and monthly time frames, according to the new methodology and using historical bids as inputs. Further information can be found on the dedicated JAO website. As of the writing of this report, the LTCC parallel run is still ongoing, as well as the FIT and SIT testing of JAO internal systems. As the SIT tests are progressing, it is also expected that market participants will be included in the testing.

5 Market Coupling

This chapter was prepared in cooperation with the All-NEMO Committee, which reviewed the content and accompanying illustrations for compliance, considering confidentiality requirements. The information on costs provided in this chapter is a summary of the full content from the CACM Cost Report 2025 to be released by All TSOs and NEMOs in Q3 2026.

All NEMOs and TSOs have been working in close cooperation in recent years, striving to create more integrated European electricity markets. The SDAC creates a single pan-European cross-zonal DA electricity market. SDAC uses the DA Market Coupling Operator (MCO) function to calculate electricity prices and match volumes across Europe and to implicitly allocate CZC in a single auction. The algorithm used is the Pan-European Hybrid Electricity Market Integration Algorithm (EUPHEMIA).

The SIDC creates a single pan-European cross-zonal ID electricity market. Since 13 June 2024, SIDC has enabled IDAs alongside the already existing cross-border Continuous Trading (CT) across Europe.

SIDC CT is based on a common IT system, the Cross-Border Intraday Project (XBID), with a Shared Order Book (SOB), a single Capacity Management Module (CMM) and a Shipping Module (SM). This common IT system facilitates the continuous matching of orders from market participants from several BZs, provided CZC is available.

SIDC IDAs make use of both EUPHEMIA and XBID via the intermediate system, namely the IDA Central Interface Point (CIP). IDAs are organised as implicit auctions where collected orders are matched, and CZC is allocated simultaneously for different BZBs. IDAs provide the ability to accumulate offers and efficiently allocate limited transmission capacity. In contrast, in CT, capacity is allocated on a first-come, first-served basis.

CZCs cannot be allocated simultaneously for IDAs and CT along the same borders. Therefore, CZC allocation within CT is suspended for a limited period, during which CZCs are allocated via IDAs. However, continuous intrazonal trading may be allowed during IDAs, at least in BZs with more than one active NEMO.

The figure below shows the interaction between the timings of the SDAC, SIDC/CT, and SIDC/IDAs.

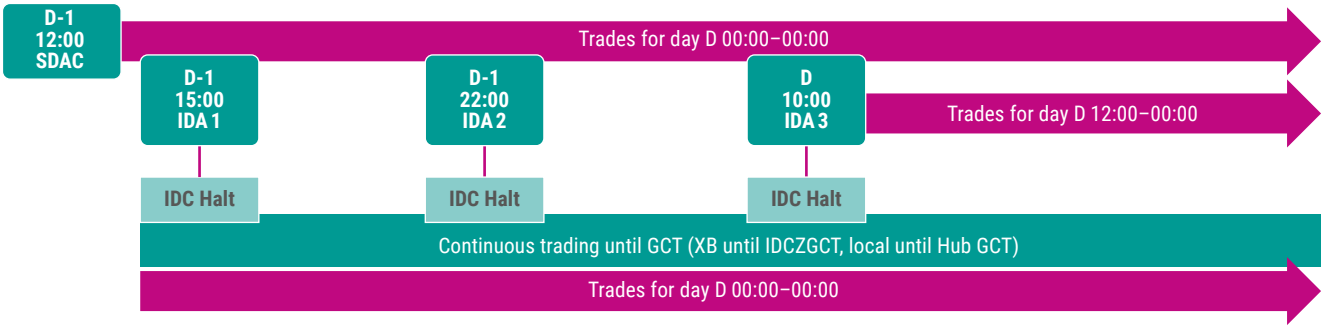


Figure 5.1: Operational timings for SDAC, SIDC/CT, and SIDC/IDAs

In SDAC, the GCT occurs at noon on D-1 for delivery day D. In SIDC, which consists of CT and IDAs, the GOT is at D-1 15:00 for delivery day D. During the IDAs, for each auction, cross-border CT is halted for 40 minutes (20 minutes before GCT and 20 minutes after GCT). For IDA1 (GCT D-1, 15:00) and IDA2 (GCT D-1, 22:00), market participants submit orders for delivery on day D; whereas for IDA3 (GCT D, 10:00), both the auction and allocation take place on the delivery day D itself.

The allocation period for IDA1 and IDA2 spans 24 hours (00:00–24:00), while for IDA3 it covers only 12 hours (12:00–24:00).

The structure of SDAC and SIDC facilitates competition among multiple NEMOs offering trading solutions within the relevant BZs and in accordance with CACM provisions. This is made possible through Multi-NEMO Arrangements (MNAs), which, although not applicable in all BZs, are implemented in certain BZs and BZBs.

5.1 Governance

The MCSC is the contractually established body of the NEMOs and TSOs, set up to facilitate the cooperation of all NEMOs and all TSOs in relation to the operation and further development of the DA and ID markets.

Looking at governance, in Q2 2026, the CACM NDA entered into force, replacing the previous agreement at the end of its 10-year term and incorporating updates reflecting developments in the projects and relevant new legislation since 2016. The revised NDA clarifies provisions on information sharing with observers, establishes a rotating TSO–NEMO administrator model, and streamlines the adherence process to address any possible issues. Additional adjustments were included to ensure more consistent and transparent governance arrangements moving forward.

Regarding market design developments, during the period covered by this report, MCSC approved the creation of the temporary Fallback Expert Group (FEG) to streamline the various discussions taking place in various fora with regard to alternatives to the current SDAC fallback mechanism for cross-border capacity allocation. Here, MCSC is working closely with ACER.

In terms of membership, MCSC granted observership in both SDAC and SIDC to ALPEX (Albanian NEMO), OPEM (Moldavian NEMO), KOSTT (Kosovan TSO), Moldelectrica (Moldavian TSO), and NPC Ukrenergo (Ukrainian TSO).

5.1.1 Single Day-Ahead Coupling

In total, 32 TSOs[13] and 18 NEMOs[14] from 26[15] countries cooperate under the Day-Ahead Operational Agreement (DAOA), which is the agreement governing SDAC.

5.1.2 Single Intraday Coupling

In total, 29 TSOs[16] and 17 NEMOs[17] from 25[18] countries cooperate under the Intraday Operational Agreement (IDOA), which is the agreement governing SIDC.

Figure 5.2: Countries of SDAC as of June 2026

Figure 5.3: Countries of SIDC as of June 2026

13 50Hertz, Amprion, APG, AST, Baltic Cable, ČEPS, Creos, EirGrid, Elering, ELES, Elia, Energinet, ESO, Fingrid, HOPS, IPTO, Kraftnät Åland, Litgrid, MAVIR, PSE, Red Eléctrica, REN, RTE, SEPS, SONI, Statnett, Svenska Kraftnät, TenneT DE, TenneT NL, Terna, Transelectrica and TransnetBW.

14 BRM, BSP SouthPool, CROPEX, EirGrid and SONI acting jointly as SEMOpx, EPEX SPOT, ETPA (non-operational until accession), EXAA, GME, HEnEx, HUPX, IBEX, Nord Pool EMCO, OKTE, OMIE, OPCOM, OTE, and TGE.

15 Austria, Belgium, Bulgaria, Croatia, the Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, the Netherlands, Norway, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, and Sweden.

16 50Hertz, Amprion, APG, AST, ČEPS, Creos, Elering, ELES, Energinet, Elia, ESO, Fingrid, HOPS, IPTO, Kraftnät Åland, Litgrid, MAVIR, PSE, Red Eléctrica, REN, RTE, SEPS, Statnett, Svenska Kraftnät, TenneT DE, TenneT NL, Terna, Transelectrica and TransnetBW.

17 BRM, BSP SouthPool, CROPEX, EirGrid and SONI acting jointly as SEMOpx, EPEX SPOT, ETPA, GME, HEnEx, HUPX, IBEX, Nord Pool EMCO, OKTE, OMIE, OPCOM, OTE, and TGE.

18 Austria, Belgium, Bulgaria, Croatia, the Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Italy, Latvia, Lithuania, Luxembourg, the Netherlands, Norway, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, and Sweden.

5.2 Key Achievements and Operational Performance

This section provides an overview of the recent key milestones reached in both SDAC and SIDC.

5.2.1 Single Day-Ahead Coupling

The reporting period was marked by stable SDAC operations, with key implementation milestones and no partial decouplings recorded.

SDAC 15-Minute MTU Implementation

A significant milestone in 2025 was the SDAC 15-minute MTU go-live. On 1 October 2025, the SDAC successfully completed the transition from a 60-minute MTU to a 15-minute MTU. This milestone, mandated by EU regulations, enhances market efficiency, supports renewable integration, and optimises price formation. With shorter market intervals, market participants can react swiftly to fluctuations in wind and solar generation, reducing imbalances and ensuring accurate real-time pricing.

The EUPHEMIA algorithm was upgraded to handle the complexity of shorter MTUs. All BZs and BZBs within SDAC now apply this uniform MTU approach, ensuring consistent cross-border trading. Extensive testing, stakeholder engagement, and frequent communication ensured a smooth go-live, activities that included all TSOs, NEMOs, Capacity Calculation Regions (CCRs), Regional Coordination Centres (RCCs), and hundreds of market participants across Europe.

Hansa CCR Phase II

Hansa CCR Phase II went live in March 2026. This implementation assigns the capacity submission role of the BZs present in the Hansa CCR to two RCCs: TSCNET, and the Nordic RCC.

This implementation contributed to more efficient handling of the pre-coupling phase in the Hansa region.

Flow-Based Capacity Allocation and Advanced Hybrid Coupling (AHC)

Flow-based capacity allocation has become the cornerstone of CZC calculation in several CCRs, evolving through multiple implementations over recent years.

In the Core CCR, this development began on 8 June 2022 with the introduction of Flow-Based Market Coupling (FBMC) in the DA timeframe. The FB methodology also expanded beyond Core, entering the Nordic CCR for the DA timeframe on 29 October 2024, which was the first trading day. In between, FB capacity calculation expanded to the ID timeframe as well.[19]

AHC forms an integral part of this broader FB approach when dealing with cross-border interactions between CCRs. AHC was first introduced in the Nordic CCR alongside the FB DA launch in October 2024, and was later implemented in the Core CCR in June 2026. Its role is to ensure that any impact, if any, on critical network element constraints (CNECs) within a FB CCR – caused by allocated flows at the borders between neighbouring CCRs – is considered. By treating cross-regional flows consistently within the FB framework, AHC enhances both the efficiency of capacity allocation and the resulting socioeconomic welfare.

Together, FB capacity allocation and AHC form a coherent methodological framework that supports more efficient and transparent use of scarce grid capacities across Europe.

19 Since May and June 2024, IDCC(a) and IDCC(b) are running daily, with results submitted at 14:45 and 21:45, respectively, 15 minutes before the GCT of IDA1 and IDA2, ensuring that implicit auctions rely on the most up-to-date network information. In June 2025, the third iteration, IDCC(c), was introduced to provide updated capacities for the hours preceding IDA3. In April 2026, IDCC(d) was launched, with results being submitted at 09:45, 15 minutes before the GCT of IDA3.

Cross-CCR Congestion Income Distribution (CID)

The Cross-CCR Congestion CID project went live in Q2 2026. Under this new framework, TSOs from CCRs that are mutually affected by cross-border allocation mechanisms will share CI across regions rather than only within individual CCRs. This marks a shift towards a more integrated and equitable approach to CI management.

Co-Optimisation Phase 1

Article 40 of the Electricity Balancing Guideline (EB GL) requires all TSOs to develop a proposal for a methodology for a co-optimised allocation process ("co-optimisation") of CZC for exchanging balancing capacity or sharing reserves. Work on this feature has been ongoing for several years across various cooperations (ENTSO-E, MCSC), proving over the years more complex than originally anticipated.

NEMOs and TSOs worked together on the report for R&D Phase 1, which was initiated towards the end of 2024 and continued until Q4 2025, when it was finally published.

During this phase, NEMOs and TSOs analysed initial design assumptions regarding bid design, bidding products, and pricing. The first report version, R0, discussed several considerations and outlined the need for deeper assessment of various aspects in the next phase. It was publicly consulted in Q2 2025, aiming to receive valuable insights from market parties. Based on this feedback, NEMOs and TSOs updated the initial report and prepared the version R1, which was submitted to ACER on 28 November 2025. This achievement paved the way for scoping the subsequent R&D phases and the forthcoming co-optimisation simulations.

Multi-NEMO Arrangements

After conducting several functional and system integration tests to access the French, Belgian, and Dutch markets, EXAA successfully went live in these markets in January 2026.

The ability to manage multiple NEMOs within and between BZs was first implemented in the Central Western European (CWE) CCR in July 2019 and it is possible via MNAs. Since then, this capability has been gradually introduced in other regions: in the Nordic CCR in June 2020; in the Hansa CCR (starting with NorNed in November 2020, followed by the Cobra Cable and the Danish borders in June 2021); in Poland (for the SwePol Cable and the LitPol Link in February 2021, with the remaining borders added in June 2021); and in parts of the Italian Borders Working Table (IBWT) CCR in June 2022. The MNA on the French side of the French–Spanish border was achieved in February 2024, followed by another MNA implementation in Romania in November 2024.

Additionally, NEMOs in the Core CCR are implementing volume allocation as an alternative to local auctions in case of partial decoupling of one NEMO in an MNA area (BZ). With volume allocation, the SDAC price for a NEMO that is decoupled in a BZ is the same as the SDAC price for the NEMO(s) that remained coupled in that BZ.

EUPHEMIA Upgrades

Following the go-live of the 15-minute MTU, EUPHEMIA experienced some challenges in finding solutions. These were caused by issues in rounding numbers in the intermediate steps of EUPHEMIA. In other words, the numerical boundaries (tolerances) of EUPHEMIA were breached more frequently. Together with the increased computational load from the 15-minute MTU implementation, this made it more difficult for EUPHEMIA to find a solution. To solve the numerical issues, parties tested an enlargement of the numerical boundaries EUPHEMIA uses. It was concluded that all parties can successfully process results under the new numerical boundaries, allowing EUPHEMIA to find more easily a solution.

Since its launch, the development of EUPHEMIA is an ongoing process. With the arrival of Core AHC in Q2 2026, the performance of EUPHEMIA version E11.4 was deemed to be insufficient. Therefore, to accommodate the implementation of Core AHC, E12.0 and PMB14.0 were developed. After extensive functional and user tests conducted by the so-called "Price Coupling of Regions (PCR) NEMOs", these went live in Q2 2026.

SDAC Operations

SDAC continues to operate successfully, with no instances of full decoupling since operations began in February 2014. Additionally, as reported in the last iteration of this report, no instances of partial decoupling have occurred since 2024. The figure below illustrates all incidents since 2014 by severity type. More details on the incidents can be found in the CACM Annual Reports.[20]

In general, all incidents are assessed and monitored on a regular basis by the SDAC Operations Committee (OPSCOM), and depending on the issue, an adequate follow-up is provided to prevent reoccurrence. Any change in the operational procedures is also adequately reviewed by both TSOs and NEMOs and transparently communicated to external stakeholders whenever needed. Operational procedures are publicly available on the ENTSO-E website.

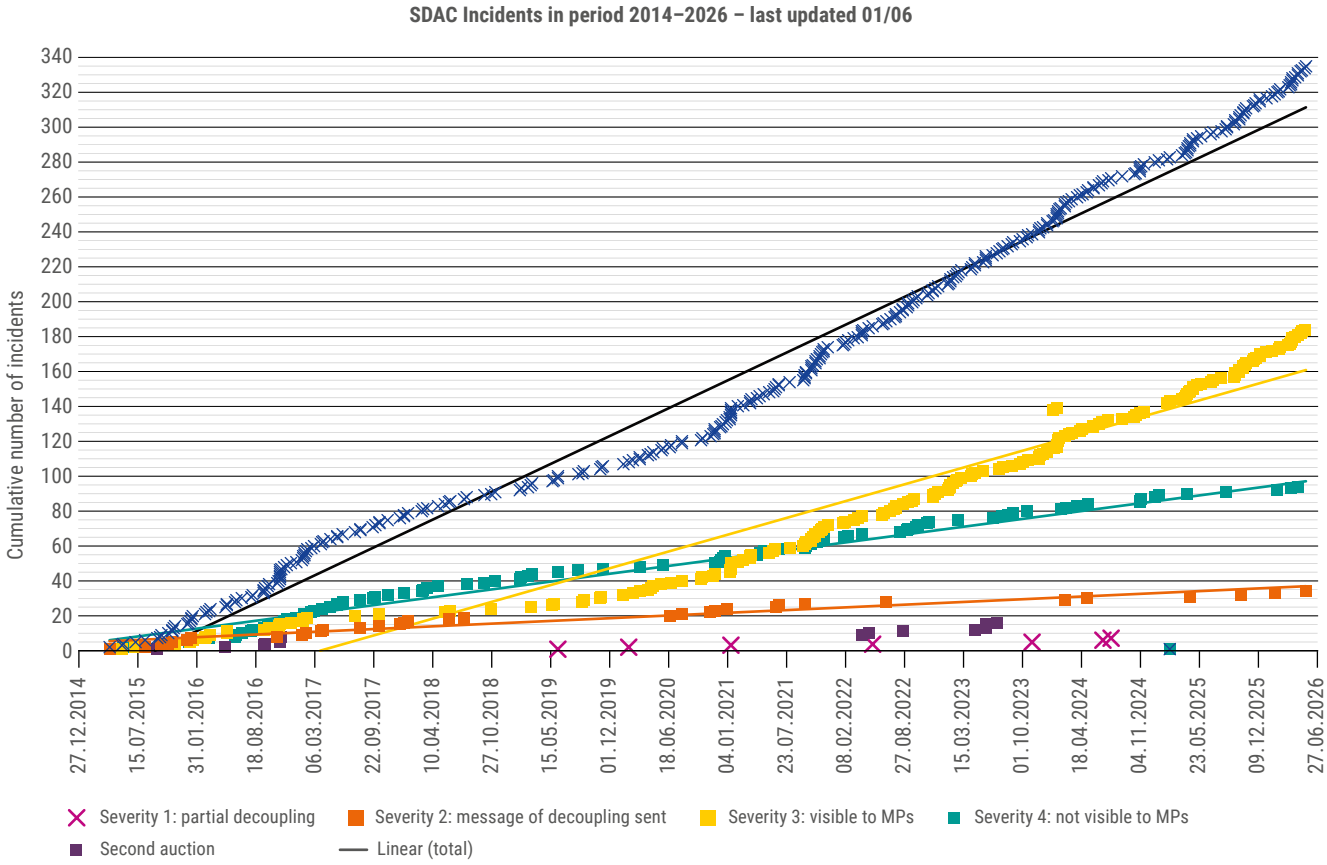


Figure 5.3: SDAC incidents since 2014

Requests for Change (RfCs)

Algorithm improvements are implemented through two complementary frameworks: the Change Control Procedure (CCP) and the Algorithm Methodology (AM).[21] Together, they ensure that changes are introduced efficiently, with controlled risk and minimal operational disruption.

The CCP defines the process for implementing changes within SDAC operations, while the NEMO AM sets the rules and principles governing the submission, evaluation, decision, and implementation of requests for change (RfCs) to the SDAC algorithm (EUPHEMIA). During the reporting period, the MCSC also finalised improvements to the CCP, further strengthening the effective handling of change requests.

20 See CACM reports for 2018, 2019, 2020, 2021, 2022, 2023, and 2024.

21 Available here

5.2.2 Single Intraday Coupling

The reporting period was marked by stable SIDC operations, with key implementation milestones and only a few disruptions recorded.

Continuous Trading

SIDC 15-Minute MTU Implementation

Another significant milestone in 2025 was the completion of the 15-minute MTU rollout in the ID timeframe, which was implemented through several waves in 2025 and previous years. All BZs and BZBs within SIDC now apply this uniform approach, ensuring consistent cross-border trading.

The benefits include greater flexibility for market participants and optimised price formation. Extensive testing, stakeholder engagement, and frequent communication ensured smooth go-live waves. The implementation delivered similar benefits and was exposed to similar complexities as the one in SDAC.

30-Minute Intraday Cross-Zonal Gate Closure Time

Article 8(1) of the regulatory amendment (EU) 2024/1747 to the Electricity Regulation (EU) 2019/943 provides that, from 1 January 2026, the IDCZGCT must not exceed 30 minutes unless a temporary derogation is granted following a request from a TSO.

Fourteen BZBs implemented this change by reducing the IDCZGCT from 60 to 30 minutes on 14 January 2026.

Rising Number of Trades in Continuous Trading

In SIDC CT, the IT systems have been executing an increasing number of transactions and of trades.

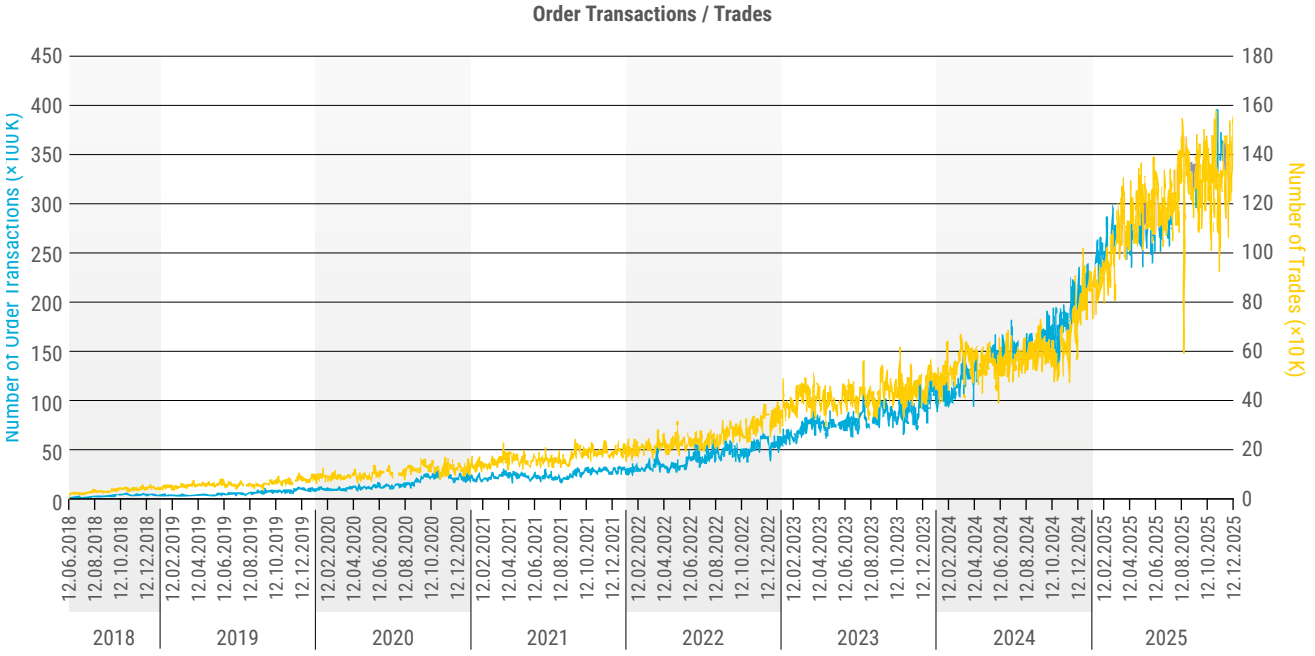


Figure 5.4: SIDC order evolution of transactions/trades since 2018

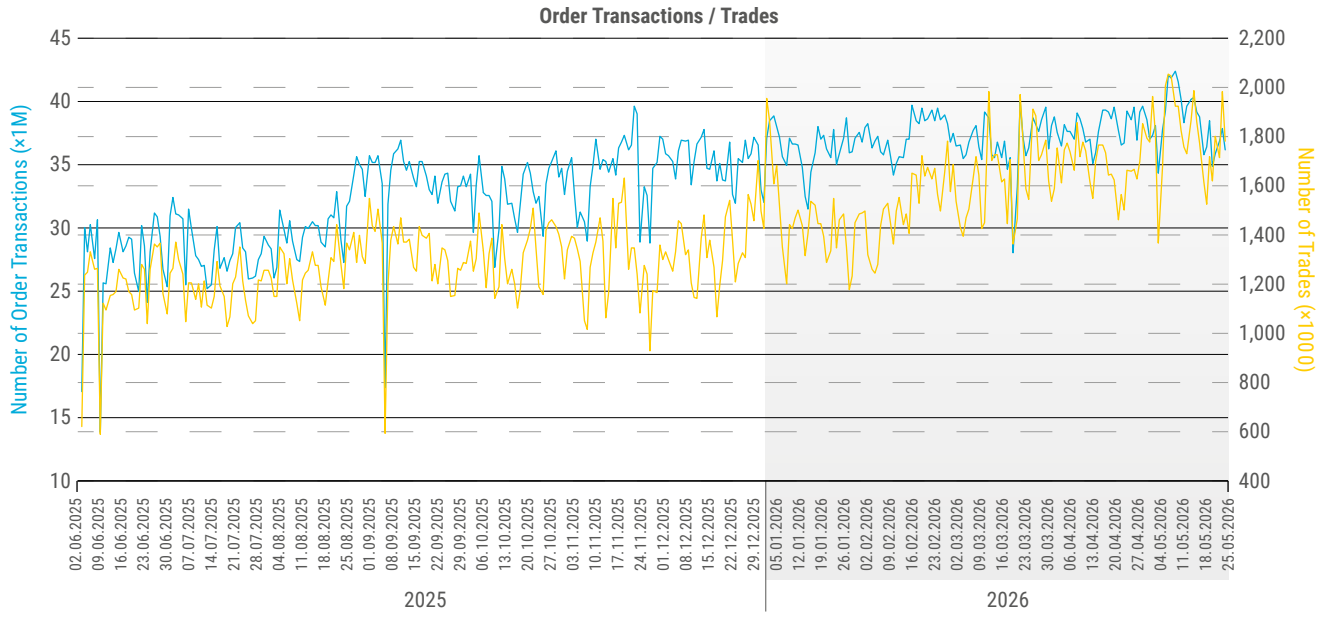


Figure 5.5: SIDC order evolution of transactions/trades since 2025

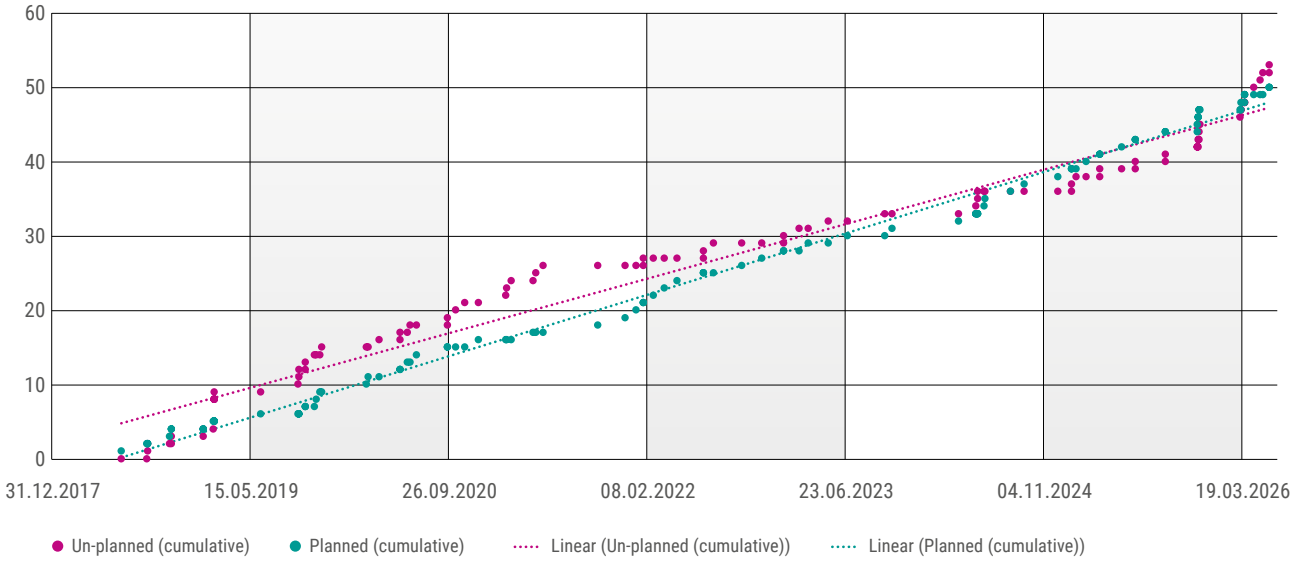


Figure 5.6: Number of unplanned and planned SIDC non-availabilities (as of 2018)

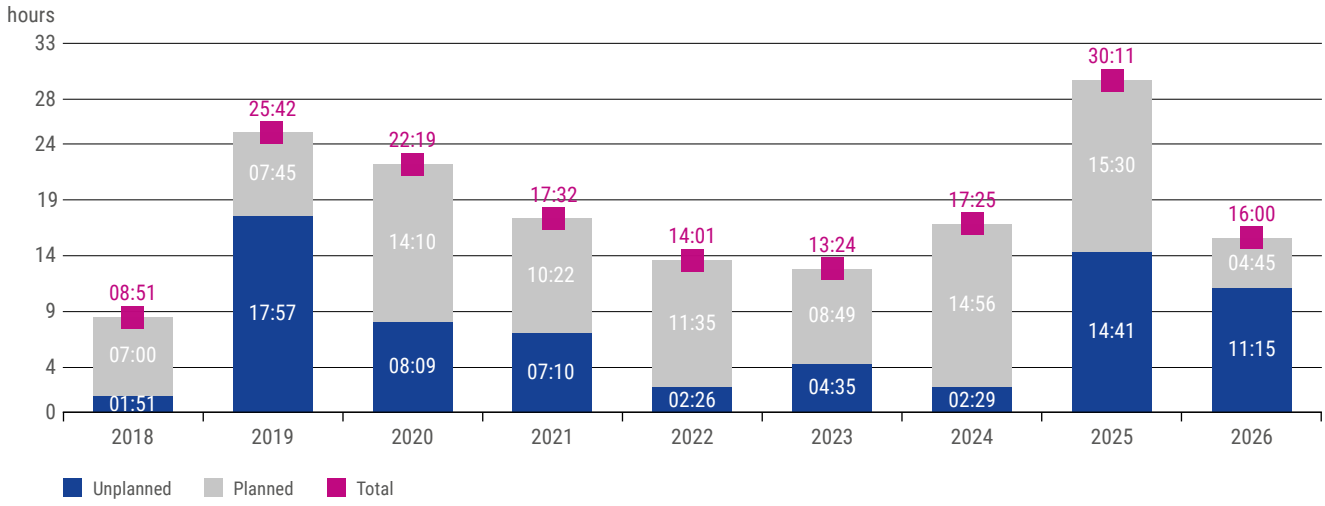


Figure 5.7: Hours of unplanned and planned XBID non-availabilities

In light of the rising complexity, and to ensure future operational resilience, TSOs active in the SDAC and the SIDC welcomed the publication of a Future Market Coupling IT Architecture Study conducted by Capgemini Invent, an AI-powered global business and technology transformation partner, with contributions from Fraunhofer FIT and PONTON (Hamburg), exploring options for a future IT architecture to better support European electricity market coupling. The work focused exclusively on infrastructure design and was published in December 2025.[22]

22 Study-on-Next-Generation-Day-Ahead-and-Intraday-Market-Coupling-Architecture.pdf.

Multi-NEMO Arrangements

On 25 November 2025, EPEX expanded into the Baltics in the SIDC CT market, becoming active in Estonia, Latvia, and Lithuania. This also meant that the European Commodity Clearing (ECC) became active as the shipping agent on both the internal and external Baltic borders (EE–FI, EE–LV, LT–SE4, LV–LT, LT–PL).

SIDC Operations

In 2025, four incidents occurred that resulted in the halt of CT. The first occurred on 24 January, the second on 6 September, the third between 25 and 29 November, and the fourth on 2 December. Further IDCT incidents also occurred in 2026, specifically on 14, 15, 24 and 25 March, as well as on 18 April, 2 May, and 9 May.

All operational incidents are regularly monitored and analysed.[23] Process updates are introduced through the SIDC Operations Committee (OPSCOM) group to mitigate relevant risks. Any change in the operational procedures is also appropriately reviewed by both TSOs and NEMOs and transparently communicated to external stakeholders whenever needed. Operational procedures are publicly available on the ENTSO-E website.

XBID Releases

The current version that is live in production, XBID R5, was deployed in June 2026. Immediately after the go-live of R4.1, testing activities for R5.0 were initiated. This release introduced technical enhancements and ensured that market operation remained more stable, guaranteeing that the SIDC market could handle more trades per second without performance degradation issues. The testing campaign for release R5.1 has begun, with go-live planned for Q1 2027.

Intraday Auctions

IDA Operations

Since the go-live of IDAs, 2208 auctions have been approximately conducted. This resulted in an IDA availability rate of 98.77% as of 7 June 2026. In the last year of operations, the IDA market cleared approximately 172,536 GWh. The trading volumes are particularly high during IDA1.

Months	Year	Total Cleared Energy (GWh)
June	2025	15,153
July	2025	14,478
August	2025	15,174
September	2025	14,793
October	2025	13,770
November	2025	13,362
December	2025	13,528
January	2026	14,559
February	2026	14,190
March	2026	15,413
April	2026	13,700
May	2026	14,416
TOTAL		**172,536**

Table 5.1: Cleared volumes in IDAs per months since go-live

23 After each incident, a report explaining the causes was drafted. These reports can be consulted here.

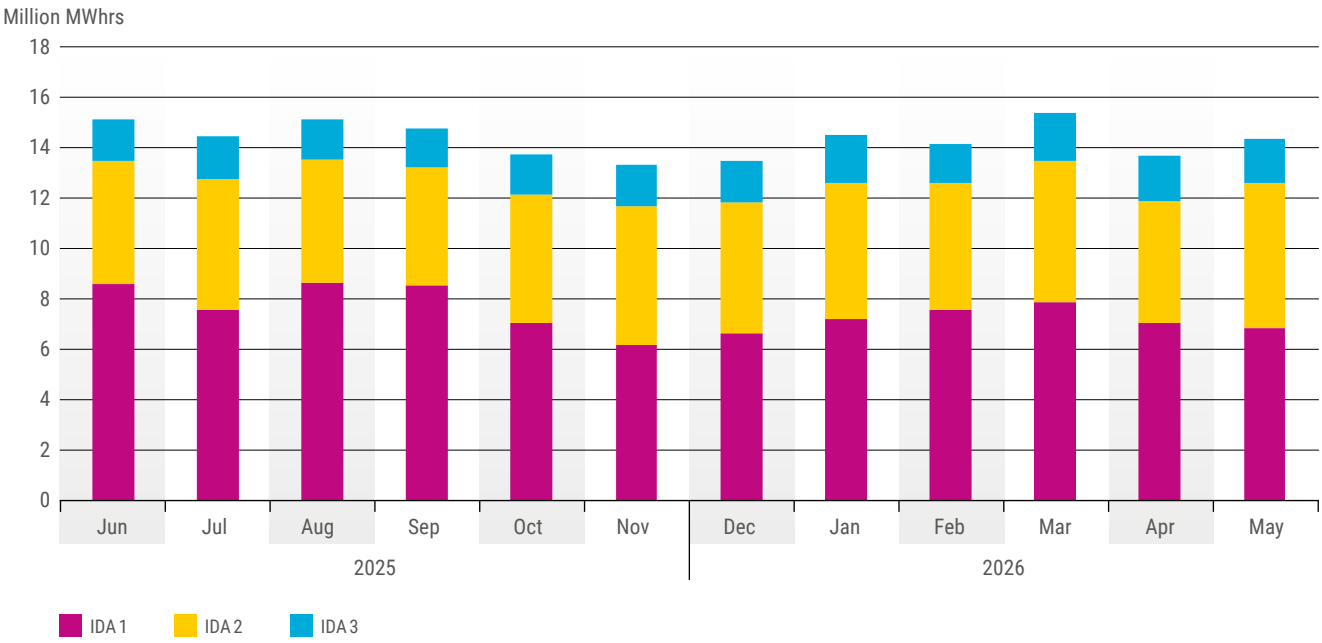


Figure 5.8: Traded volume per IDA and per month since June 2025 › millions of cleared MWhrs

More information on IDAs can be found on the ENTSO-E[24] and NEMO Committee[25] websites, where information on operational performance is reported on a weekly basis.

SIDC IDA Deployments

To effectively run the IDAs, the CIP is required as an intermediate system between EUPHEMIA and XBID. Development and testing of CIP 2.0 began in 2025 and went live in Q2 2026. With this new version, fixes were provided for several latent faults from previous versions.

Multiple functional changes, such as support for partial cross-zonal continuous allocation opening during IDA, was also introduced. Non-functional changes like updates to libraries used in CIP were also implemented.

5.3 Expenditures

TSOs and NEMOs provide an annual detailed cost report to ACER and the NRAs in accordance with Article 80 of the CACM Regulation.[26]

24 ENSTO-E IDA reporting.

25 NEMO Committee IDA reporting.

26 See CACM Cost Reports for 2018, 2019, 2020, 2021, 2022, 2023, and 2024.

5.3.1 Expenditures in Single Day-Ahead Coupling

This section provides a summary of the costs of establishing, amending, and operating the SDAC, categorised by TSO-only costs, NEMO-only costs, and joint costs (from all TSOs and all NEMOs combined). Figures 5.9 and 5.10 show the budgeted and actual costs since 2017. The second Y-axis displays the total SDAC traded volume per year in billion MWh.

All TSOs' costs (e.g. for external support), all NEMOs' costs (e.g. for third-party services), and joint TSO–NEMO costs are governed by the respective cooperation agreements: the TSO Cooperation Agreement for Market Coupling (TCMC), the All-NEMO Cooperation Agreement (ANCA), and the DAOA for joint matters.

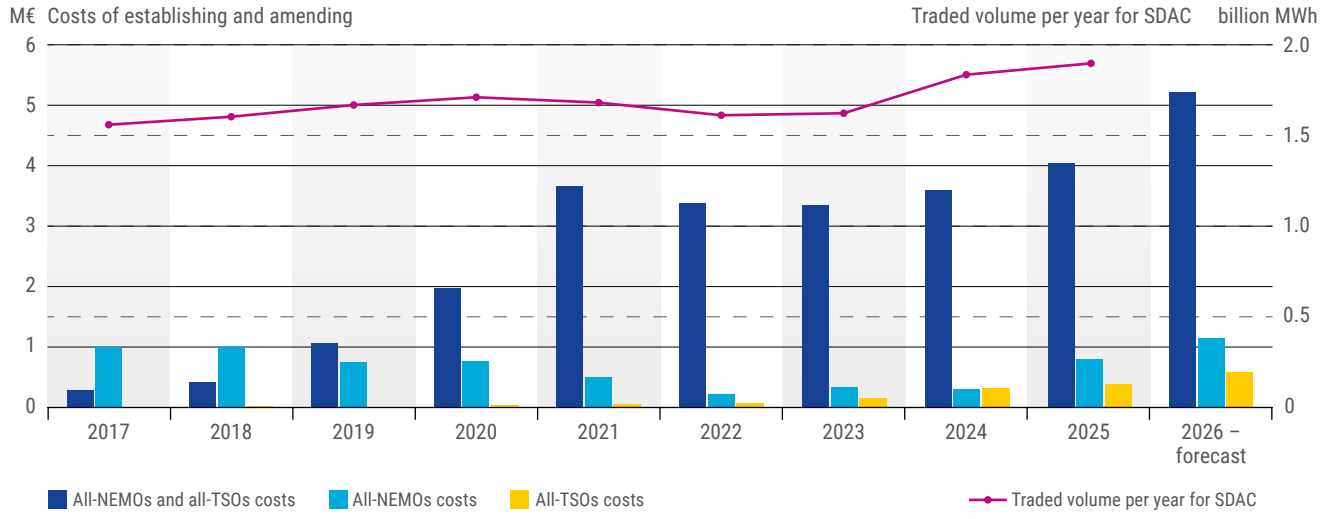


Figure 5.9: Overview of SDAC for "all TSOs' costs", "all NEMOs' costs" and "all NEMOs' and all TSOs' costs" of establishing and amending

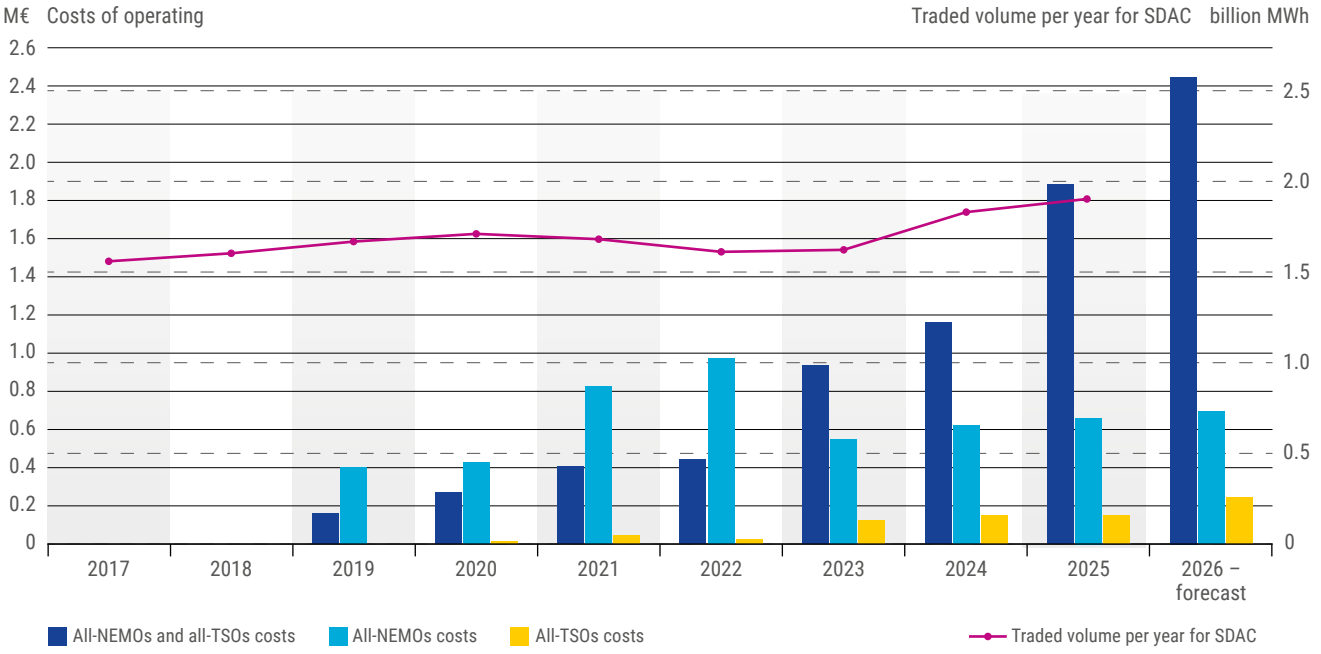


Figure 5.10: Overview of SDAC for "all TSOs' costs", "all NEMOs' costs" and "all NEMOs' and all TSOs' costs" of operating

5.3.2 Expenditures in Single Intraday Coupling

This section provides a summary of the costs of establishing, amending, and operating the SIDC, categorised by TSO-only costs, NEMO-only costs, and joint costs (from all TSOs and all NEMOs combined). Figures 5.11 and 5.12 show the budgeted and actual costs since 2017.[27]

The second Y-axis displays the total SIDC traded volume per year in billion MWh. All TSOs' costs (e.g. for external support), all NEMOs' costs (e.g. for third-party services), and joint TSO–NEMO costs are governed by the respective co-operation agreements: the TCMC, the ANCA, and the IDOA for joint matters.

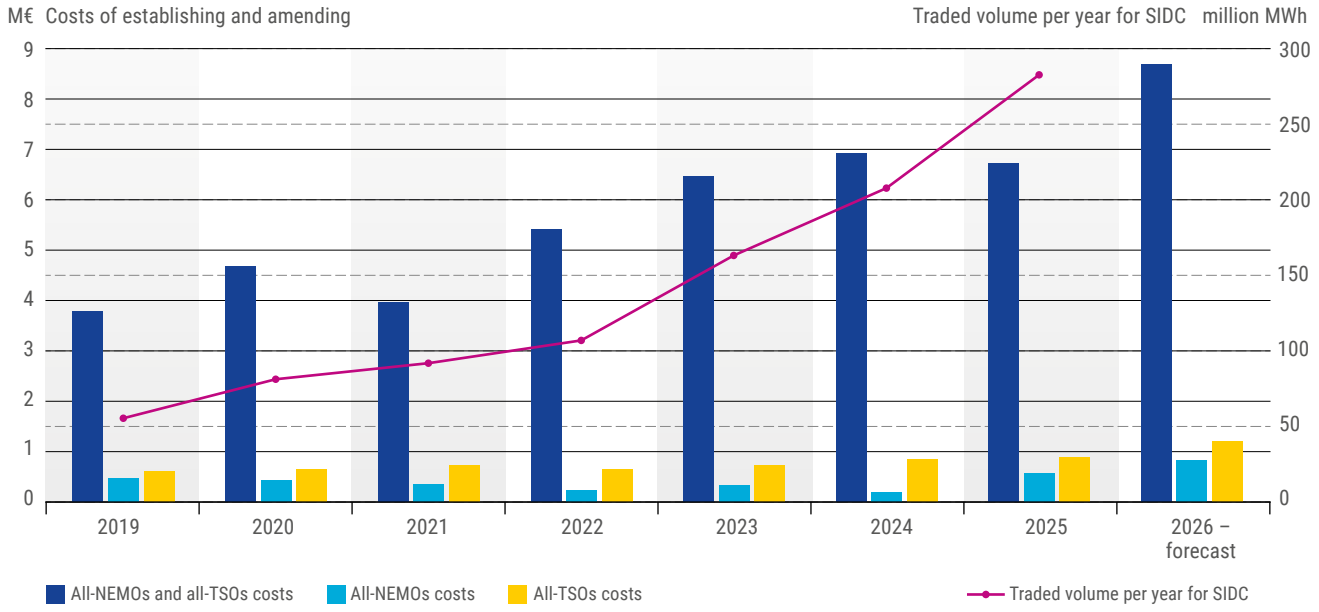


Figure 5.11: Overview of SIDC for "all TSOs' costs", "all NEMOs' costs", and "all NEMOs' and all TSOs' costs" of establishing and amending

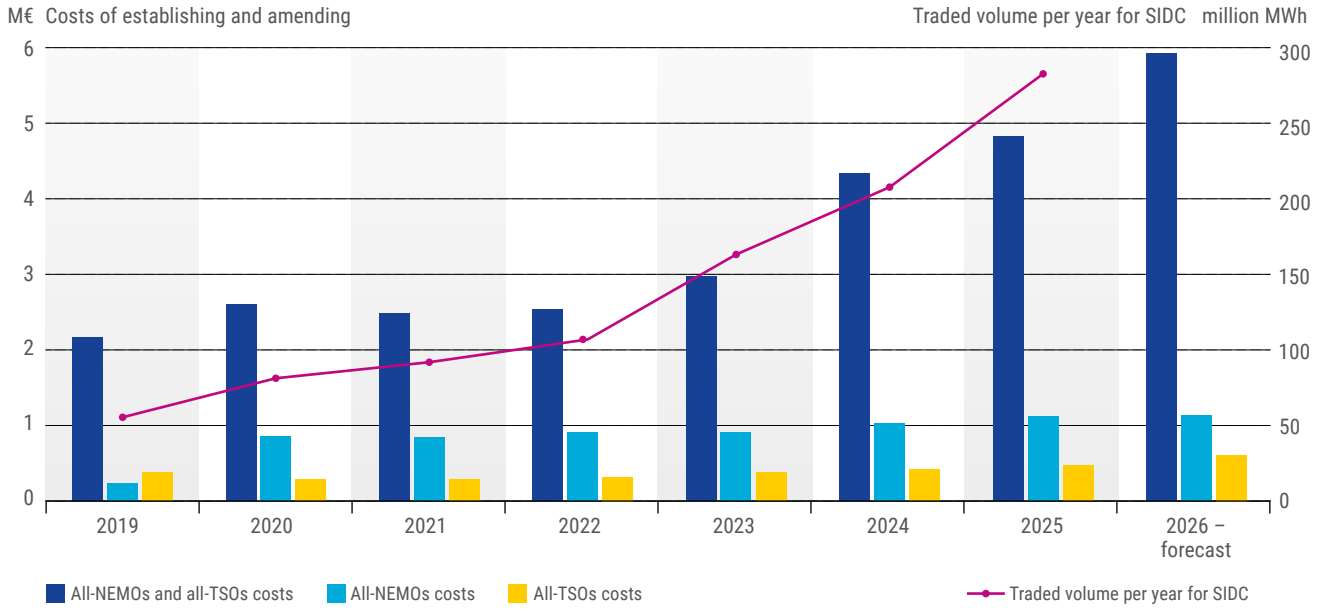


Figure 5.12: Overview of SIDC for "all TSOs' costs", "all NEMOs' costs" and "all NEMOs' and all TSOs' costs" of operating

27 In line with regulatory guidance, costs for the coupling projects are planned and shared between TSOs and/or NEMOs as of 14 February 2017.

5.4 Outlook: Market Evolution

This section highlights the future milestones expected to influence the development of SDAC and SIDC.

5.4.1 Single Day-Ahead Coupling

Multi-NEMO Arrangements

In the coming months, the DA market is expected to see several monopolistic regions transition to MNAs, while several competitive areas (MNAs) boost competition by increasing the number of NEMOs active in them:

- EPEX aims to extend its operations in the Baltics in Q3 2026.
- In Q3 2026 Nordpool plans to extend its services to Slovenia.
- In Q3 and Q4 2026, CROPEX and BSP plan to further extend their services to Slovenia and Croatia, respectively.
- Also in Q4 2026, ETPA aims to enter the DA market by starting operations in the Netherlands.
- Nord Pool also plans to become operational in SEM in Q1 2027.

Central Europe CCR

Following the ACER decision (10-2025), work has advanced on the CCR CE – created by merging the Core and Italy North CCRs – for the DA timeframe. Operationalisation of this, within SDAC, is planned for January 2028.

A merged Central Europe capacity calculation – under a FB domain – is expected to better reflect the capacity in the respective countries.

Energy Community (EnC) Countries

Following the current transposition of the Electricity Integration Package (EIP) into national legislation, the gradual integration of EnC countries into SDAC is expected over the coming years. To support this process, the task force responsible for the implementation is making the necessary preparations.

Regional Projects

As seen in many previous projects, like FB implementation, AHC, and Hansa Phase II, several regional projects require changes in central SDAC systems. Conversely, SDAC developments are also driven by adjustments in systems at the regional level.

Looking ahead, further adaptations will be needed for the commissioning of the Celtic Interconnector, currently planned for Q4 2028, as well as for the implementation of upcoming MNAs and many other future developments.

EUPHEMIA Releases

Following the release of E12.0 in Q2 2026, development began on its successor, E12.1, which is scheduled to go live in late 2026, in combination with PMB14.1. At the time of writing, the scope for E12.1 is under discussion.

Research and Development Program

A significant portion of the SDAC budget is spent investigating ways to improve the performance of the algorithm so that it can accommodate all required foreseeable future changes. This work is conducted under the umbrella of the EUPHEMIA Lab program, which has shown overall positive results and is leading to the industrialisation of promising improvements in the algorithm. The R&D for the algorithm is categorised into the following areas:

- **Functional:** Focusing on enhancing the core functionalities of the algorithm, improving performance, and ensuring efficient and reliable operations.
- **Algorithm:** Involving modifications and optimisations to the underlying algorithm, aiming to refine computational processes, improving scalability, and addressing potential limitations. Examples include new branching strategies, new heuristics, removal of variables in FB, welfare maximisation, and many others.
- **Features:** Introducing new capabilities and enhancements to the algorithm, expanding its scope by integrating additional functionalities that address evolving market or operational requirements. Examples include new mechanisms to limit polarity reversals on HVDC links, new order types such as storage orders, the usage of negative RAM (remaining available margin) values, optimising the usage of Phase-Shifting Transformers (PSTs), and many others.

Co-optimisation R&D Phase 2

Co-optimisation R&D Phase 2, as the continuation of co-optimisation R&D Phase 1, will require substantial effort throughout 2026, with active involvement from ACER and market parties. A key element of this phase will be the presentation and assessment of simulation results. Following the completion of this initial simulation stage by NEMOs and TSOs, the scope will be expanded to cover a broader geographical area. The findings from these simulations, together with the assessment of co-optimisation requirements, will be consolidated in the R2 Report.

Following replanning by NEMOs and TSOs and subsequent confirmation by ACER, the second report (R2) is expected to be submitted to ACER in Q1 2027, covering areas listed in points (d) to (g) of Article 4(15) of Annex I,[28] including initial simulation results. The R2 must conclude on the technical feasibility of the options selected in the **R1 Report**. TSOs and NEMOs note that no final decision on a potential co-optimisation design can be made at this time, and that interim results may be revisited during future R&D phases.

28 ACER Decision on amendments to the price coupling algorithm and the CT matching algorithm, including the common sets of requirements: **Annex I from 23 September 2024**

5.4.2 Single Intraday Coupling

30-Minute Intraday Cross-Zonal Gate Closure Time

The SIDC BZBs that are still operating under the 60-minute IDCZGCT are expected to make the switch according to their approved plans by their respective NRAs.

Multi-NEMO Arrangements

In the coming months, the ID timeframe is expected to see several monopolistic regions transition to MNAs, while several competitive areas (MNAs) boost competition by increasing the number of NEMOs active in them. This will concern both CT and IDAs:

- In Q3 2026, following the go-live in the CT market, EPEX plans to extend its activities to the Baltics in the SIDC IDA.
- Also targeting a Q3 2026 go-live, Nord Pool intends to expand its operations to Slovenia in both the CT and IDA markets.
- In Q3 2026, BSP and CROPEX plan to further extend their services: BSP to Croatia and CROPEX to Slovenia, covering both the IDA and CT markets.
- Lastly, Nord Pool will become the operational NEMO in the Single Electricity Market (SEM) via an MNA for both IDA and CT; however, its timeline remains unconfirmed.

Energy Community Countries

Following the current transposition of the EIP into national legislation, the gradual integration of EnC countries into SIDC is expected over the coming years. To support this process, the task force responsible for the implementation is making the necessary preparations.

Flow-based allocation in continuous trading

After the implementation of IDAs, a key priority in SIDC is the integration of FB capacity allocation in both CT and IDAs. For regions already applying FB allocation in the DA time frame, FB allocation in the ID time frame is regarded as having the potential to enhance social welfare compared to an NTC-based approach, as it can make more capacity available and enable more efficient trades.

However, due to the complexity of the FB design and its foreseen impact on SIDC (especially for CT), additional R&D resources, including third-party expertise, have been devoted to investigating different approaches. Given the significant time and effort required for the assessment, a stepwise approach was agreed upon – FB implementation in IDAs to be followed by its introduction in CT.

SIDC IDA deployments

Following the release of CIP 2.0 in Q2 2026, several updates are being developed via subsequent CIP2.X releases. In parallel, the development of CIP 3.0 has begun, and functional improvements of this release are under discussion in SIDC quality assurance and release management (QARM). At the time of writing, no timelines have been finalised.

XBID releases

The expansion and development of the CT market through geographical extensions increases system performance needs. Performance is therefore constantly monitored and improved. Over the years, multiple sets of performance optimisation measures were finalised and implemented with updated versions of XBID.

In parallel with the testing of R5.0, preparations for R5.1 testing were finalised in Q2 2026. With deployment to production targeted for Q1 2027, the objective is to begin the R5.1 testing campaign immediately following the R5.0 go-live. At the same time, development activities for R6.0 have also been initiated. The main driver of the R6.0 scope is support for FB calculations in IDA, which, according to the current roadmap, is planned for launch in late H2 2027.

Annexes

Annex I – Legal references and requirements

The ENTSO-E Market Report was originally based on ENTSO-E monitoring obligations on the implementation of network codes (NCs) and guidelines (GLs), pursuant to Article 8(8) of Regulation (EC) No. 714/2009 on conditions for access to the network for cross-border exchanges in electricity and repealing Regulation (EC) No 1228/2003.

Under the EU Clean Energy Package, adopted in the course of 2019, ACER is responsible for monitoring and analysing the implementation of NCs and GLs and their effect on the harmonisation of applicable rules aimed at facilitating market integration as well as on non-discrimination, effective competition and the efficient functioning of the market18. Indeed, Regulation (EU) 2019/943 on the internal market for electricity (recast) ("Electricity Regulation"), which repealed Regulation (EC) No. 714/2009, does not include an equivalent of Article 8(8) of Regulation (EC) No. 714/2009 and does not foresee ENTSO-E monitoring obligations on the NCs and GLs implementation. Therefore, ENTSO-E general monitoring obligations referred to in the NCs and GLs and linked to Article 8(8) of Regulation (EC) No. 714/2009 cannot be considered binding after Regulation (EU) 2019/943 entered into force.

However, ENTSO-E has decided to continue monitoring activities as a good project management practice to ensure high-quality deliverables of network codes and guidelines. In this regard, although the provisions in NCs and GLs linked to Article 8(8) of Regulation (EC) No. 714/2009 are not binding anymore for ENTSO-E, the ENTSO-E Market Report 2026 focuses on the information included in Article 82(2)(a) of the Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management (CACM Regulation); Articles 63(1)(a) and 63(1)(d) of the Commission Regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation (FCA Regulation); and Article 63(1) of the Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing (EB Regulation).

Also, the ENTSO-E Market Report 2026 incorporates in Chapter 2.3 the assessments by the relevant TSOs within the meaning of Article 14(4) of the Electricity Regulation on whether for the last 12 months (i.e. 2025), the available cross-border capacity has reached the linear trajectory or the CEP70 requirements, in accordance with Article 15(4) of the Electricity Regulation. In particular, these assessment reports by the relevant TSOs are based on individual contributions from each relevant TSO, subject to its NRA approval. Since the NRA's requirements for the approval of the individual TSO's contributions are not homogeneous, national reports for assessing the fulfilment of the CEP70 requirement exist. Providing inputs to the report of the relevant TSOs in accordance with Article 15(4) remains the responsibility of individual TSOs and NRAs remain responsible for assessing TSOs' alignment with the requirements in Article 16(8) of the Electricity Regulation. For the avoidance of doubt, the inclusion of the assessment reports by the relevant TSOs as per Article 15(4) of Electricity Regulation in Chapter 2.3 of ENTSO-E Market Report 2026 does not confer to ENTSO-E any monitoring obligations or approval powers related to Article 15(4) of Electricity Regulation. The responsibility for ensuring alignment of these assessment reports with the requirements of Article 15(4) remains with the relevant TSOs.

Annex II – Overview of All TSOs' FCA, CACM and EB deliverables

The following table provides an overview of All TSOs' deliverable based on FCA

Proposal	FCA regulation article(s)	First submission	NRAs' request for amendments	TSO Submission after Request for Amendment	NRAs approval or ACER decision
Common Grid Model (CGM)	17[29] 18[30]	May 2017 June 2017	– February 2018	– May 2018	October 2017 June 2018
Harmonised Allocation Rules (HAR)[31]	51	April 2017			October 2017[32] October 2017[33] October 2017[34]
Single Allocation Platform (SAP)	49 59	April 2017			September 2017
Congestion Income Distribution (CID)	57	May 2018	November 2018	March 2019	May 2019
Cost of ensuring firmness and remuneration of LTTRs (FRC)	61	April 2020			October 2020 October 2020

Table A.1: Overview of All TSOs' FCA regulation deliverables (as of May 2025)

The following table provides an overview of All TSOs' deliverable based on CACM

Type	Proposal	CACM regulation Art.	First submission	NRAs' approval(s) or ACER decision	TSOs' request for amendment	NRAs' approval(s) or ACER decision	TSOs' request for amendment
All-TSO (I)	Capacity calculation Regions	15(1)	October 2015	November 2016[37]	June 2017[38]	September 2017	March 2018[39]

Table A.2: Regulatory process of the proposal for the determination of capacity calculation regions

29 Generation and load data provision methodology for LT time frames.
30 CGM methodology for LT time frames.
31 As part of the biennial review of the HAR, All TSOs submitted a third TSO proposal in June 2021, and ACER issued decision (No 15/2021) in November 2021, approving a new HAR methodology.
32 On 17 August 2017, all NRAs referred to ACER to adopt a decision.
33 On 2 October 2017, ACER issued decision (No 03/2017)
34 HAR 2017 approved methodology.
35 On 29 October 2019, ACER adopted a decision (No 14/2019).
36 HAR 2019 approved methodology.
37 Referral to ACER from all NRAs.
38 All TSOs drafted an amendment to Annex I of the CCRs established by ACER decision 06/2016 ("the draft CCR Amendment Proposal") to include the BZB between Belgium and Great Britain (BE–GB) and to assign this new BZB to the Channel CCR by 17 January 2018. The CCR amendment proposal was adopted upon the decision of the last Regulatory Authority concerned (14 February 2018).
39 All TSOs drafted an amendment to include the new DK1–NL BZB and its corresponding TSOs in the Hansa CCR, add the TSOs National Grid IFA2 Limited and Eleclink Limited to the FR–GB BZB in the Channel CCR, and add the TSO Amprion to the BE–DE/LU BZB in the Core CCR.
40 Referral to ACER from all NRAs.
41 As a result of the General Court decisions in cases T-332/17 and T-333/17 concerning ACER appeal (A-001-2017), ACER issued a decision on 22 May 2020 inviting the competent party or parties to amend the concerned proposal. ACER subsequently requested that All TSOs amend or confirm it.

	TSOs' request for amendment	ACER decision	TSOs' request for amendment	ACER decision	TSOs' request for amendment	ACER decision	TSOs' request for amendment	ACER decision	TSOs' request for amendment
	July 2019	October 2019[35] October 2019[36]	June 2021	November 2021 November 2021	March 2023 resubmitted in August		August 2023	December 2023 December 2023	March 2025
	September 2022	March 2023 March 2023							
	September 2022	March 2023 March 2023							
		October 2021 October 2021	September 2022	March 2023 March 2023					

	NRAs' approval(s) or ACER decision	TSOs' request for amendment	ACER decision	TSOs' request for amendment	ACER decision	TSOs' request for amendment	ACER decision	ACER request for amendment
	April 2019[40]	November 2020[41]	May 2021	October 2022	April 2023 April 2023	November 2023	March 2024 March 2024	

Type	Proposal	CACM regulation Art.	First submission	NRAs' request for amendment	First Submission after the request for amendment
All-TSO (II)	Common grid Model	16 17	May 2016	December 2016	April 2017
	ID cross zonal GOT ID cross zonal GCT	59	December 2016	June 2017	August 2017
	Scheduled exchange	43 56	February 2018[43] February 2018	September 2018	December 2018[44] December 2018[45]
	ID cross zonal capacity pricing	55(3)	August 2017	Referred to ACER	
	Congestion income distribution	73	June 2016	January 2017	April 2017

Table A.3: Overview of All TSOs' CACM regulation deliverables (as of May 2025)

Type	Proposal	CACM regulation Art.	First submission	NRAs' request for amendment	First Submission after the request for amendment
All-TSOs & All-NEMOs	Day-ahead and intraday algorithm	37	February 2017[49]	July 2017	November 2017
	Max/min price	41 54	February 2017 February 2017	Referred to ACER	

Table A.4: Overview of All TSO and All NEMO CACM regulation deliverables (as of May 2025)

Type	Proposal	CACM regulation Art.	First submission	NRAs' request for amendment	First Submission after the request for amendment
All-NEMOs	Plan of the market coupling operator	7(3)	April 2016	September 2016	December 2016
	Back-up methodology	36	February 2017	July 2017	November 2017
	Products accommodated	40 53(4)	February 2017 February 2017	July 2017 July 2017	November 2017 November 2017

Table A.5: Overview of All NEMOs' CACM regulation deliverables (as of May 2025)

42 Referral to ACER from all NRAs.
43 For DA and ID proposals, only the TSOs which intended to calculate scheduled exchanges.
44 DA proposal.
45 ID proposal.
46 DA cost coefficients – 2021 update.
47 ID cost coefficients – 2021 update.
48 All-NRAs' referral to ACER.
49 DA and ID requirements as annexes.
50 Referral to ACER from all NRAs.
51 All NEMOs' request for amendment.
52 On 22 December 2020, ACER adopted decision (No 37/2020).
53 SDAC products.
54 On 30 January 2020, ACER adopted decision (No 05/2020).
55 SIDC products.

	NRAs' approval(s) or ACER decision	Request for amendment	ACER decision	Request for amendment	ACER decision
	May 2017				
	April 2018[42] April 2018				
	February 2019[46] February 2019[47]	December 2022	May 2023 May 2023	March 2024	September 2024
	January 2019				
	December 2017[48]	July 2021	December 2021 December 2021	June 2023	December 2023 December 2023

	NRAs' approval(s) or ACER decision	Request for amendment	ACER decision	Request for amendment	ACER decision
	July 2018[50]	August 2019	January 2020	November 2023	September 2024 September 2024
	November 2017 November 2017 November 2017 November 2017	Day Ahead: September 2022 Intraday: September 2022	Day Ahead: January 2023 January 2023 Intraday: January 2023 January 2023		

	NRAs' approval(s) or ACER decision	Request for amendment	ACER decision	ACER decision
	June 2017			
	January 2018			
	January 2018 January 2018	June 2020[51] August 2019	December 2020[52] December 2020[53] January 2020[54] January 2020[55]	September 2024 March 2025

Balancing implementation status

Type	Proposal	EB Art.	First TSOs' submission	NRAs' approval/1st request for amendment/ Referral to ACER
All-TSOs	Implementation framework for the European RR platform	19	18 June 2018	15 January 2019 (approval)
All-TSOs	1st Amendment of the Implementation framework for the European RR platform	19	16 March 2021	18 October 2021[56]
All-TSOs	2nd Amendment of the Implementation framework for the European RR platform	19	31 March 2022	
All-TSOs	Implementation framework for the European mFRR platform	20	11 February 2019	24 July 2019 (referred to ACER)
All-TSOs	1st Amendment of the Implementation framework for the European mFRR platform	20	31 March 2022	
All-TSOs	2nd Amendment of the Implementation framework for the European mFRR platform	20	31 March 2022	
All-TSOs	Implementation framework for the European aFRR platform	21	11 February 2019	24 July 2019 (referred to ACER)
All-TSOs	1st Amendment for the Implementation framework for the European aFRR platform	21	31 March 2022	
All-TSOs	2nd Amendment for the Implementation framework for the European aFRR platform	21	31 January 2024	5 July 2024
All-TSOs	Implementation framework for the European IN platform	22	18 June 2018	9 November 2018 (RfAs by individual NRAs)
All-TSOs	1st Amendment for the Implementation framework for the European IN platform	22	31 March 2022	
All-TSOs	Classification of the activation purposes of balancing energy bids	29	11 February 2019	23 July 2019 (RfAs by individual NRAs)
All-TSOs	Pricing method for all products	30	11 February 2019	24 July 2019 (referred to ACER)
All-TSOs	1st Amendment – Pricing method for all products	30	28 August 2021	
All-TSOs	2nd Amendment – Pricing method for all products	30	31 January 2024	5 July 2024

Table A.6: Status of the balancing energy procurement and activation deliverables

Type	Proposal	EB Art.	First TSOs' submission	NRAs' approval / 1st request for amendment / Referral to ACER
All-TSOs	List of standard balancing capacity products for FRR and RR	25	18 December 2019	
All-TSOs	Methodology for the allocation of cross-zonal capacity based on the co-optimisation allocation process	40	18 December 2019	
All-TSOs	Cross-Zonal Capacity Allocation Harmonised Methodology (HCZCA)	38	17 December 2022	
All-TSOs	1st Amendment – Cross-Zonal Capacity Allocation Harmonised Methodology (HCZCA)	38	31 July 2024	
All-TSOs	ENTSO-E Proposals for the Regional Coordination Centres' (RCCs) Procurement and Sizing		17 March 2023	
Regional	Methodology for the allocation of the cross-zonal capacity market-based allocation process	41	Baltic: 18 December 2019	18 June 2020
Regional			Core: 18 December 2019	12 August 2020
Regional			GR / IT: 18 December 2019	1 July 2020
Regional			Hansa: 18 December 2019	24 July 2020
Regional			IT North: 18 December 2019	29 June 2020
Regional			Nordic: 7 April 2019	17 October 2019
Regional	Methodology for the allocation of cross-zonal capacity based on an economic analysis	42	Core: 18 December 2019	12 August 2020
Regional			GR / IT: 18 December 2019	1 July 2020
Regional			Hansa	Did not submit.
Regional			IT North: 18 December 2019	29 June 2020

Table A.7: Status of the balancing capacity procurement and CZC allocation deliverables

56 Approval from RR NRAs was received via email. No official letter/document had been issued at the time of publication of this report.
57 2nd RfAs are not available (same as 1st RfAs) as those requests made by each NRA to their respective TSO.
58 2nd RfAs are not available (same as 1st RfAs) as those requests made by each NRA to their respective TSO.

	1st TSOs' submission after the request for amendment	NRAs' approval / 2nd request for amendment / Referral to ACER	2nd TSOs' submission after the request for amendment	ACER / NRAs decision
				24 January 2020
				30 September 2022
				24 January 2020
				30 September 2022
	23 January 2019	19 July 2019 (2nd RfA[57]) 16 January 2020 (referred to ACER)	10 September 2019	24 June 2020 Corrigendum: 8 December 2020
				30 September 2022
	11 November 2019	19 July 2019 (2nd RfA[58]) 16 January 2020 (referred to ACER)		15 July 2020
				24 January 2020
				25 February 2022

	1st TSOs' submission after the request for amendment	NRAs' approval / 2nd request for amendment / Referral to ACER	2nd TSOs' submission after the request for amendment	ACER / NRAs decision
				17 June 2020
				17 June 2020
				Decision No 11/2023 of 19 July 2023
				29 January 2025
				Decision No 12/2023 of 19 July 2023
	28 August 2020	30 October 2020 (2nd RfA)	30 December 2020 (NRAs forwarded for decision to ACER on 19 February 2021)	ACER approved on 13 August 2021
	6 December 2020	NRAs forwarded for decision to ACER on 22 February 2021		ACER approved on 13 August 2021
	24 September 2020	1 December 2020 (2nd RfA)	1 April 2021	NRAs approved on 22 June 2021
	13 October 2020	Withdrawn by respective TSOs on 12 May 2021		
	4 September 2020	15 December 2020 (2nd RfA)	26 March 2021	NRAs approved on 1 June 2021
	17 December 2019	28 February 2020 (referred to ACER)		5 August 2020
	4 December 2020	Withdrawn by respective TSOs on 24 May 2021		
	24 September 2020	1 December 2020 (2nd RfA)	9 April 2021	NRAs approved on 22 June 2021
	4 September 2020	15 December 2020 (2nd RfA)	26 March 2021	Withdrawn by corresponding TSOs on 27 May 2021

Type	Proposal	EB Art.	First TSOs' submission	NRAs' approval / 1st request for amendment / Referral to ACER
All-TSOs	TSO–TSO settlement of intended exchanges of energy as a result of the RRP, FRP and INP	50.1	18 December 2018	23 July 2019
All-TSOs	TSO–TSO settlement of intended exchanges of energy due to ramping restrictions and FCR between synchronous areas (SAs)	50.4	18 June 2019	4 December 2019
All-TSOs	TSO–TSO settlement of unintended exchanges between SAs	51.2	18 June 2020	
Regional	TSO-TSO settlement of intended exchanges of energy due to ramps and FCR within the Continental Europe SA and of unintended exchanges of energy within the Continental Europe SA	50.3	18 June 2019	4 December 2019
Regional		51.1	18 June 2019	4 December 2019
Regional	TSO–TSO settlement of unintended exchanges among TSOs within the Nordic SA, and TSO–TSO settlement of intended exchanges of energy due to ramps and FCR within the Nordic SA	50.3a	18 June 2019	18 December 2019
Regional		51.1b		
All-TSOs	Imbalance settlement harmonisation	52	11 February 2019	11 July 2019

Table A.8: Status of the imbalance settlement and other settlements deliverables (FSkar)

	1st TSOs' submission after the request for amendment	NRAs' approval / 2nd request for amendment / Referral to ACER	2nd TSOs' submission after the request for amendment	ACER / NRAs decision
	11 November 2019	16 January 2020 (referred to ACER)		16 July 2020
	27 March 2020	22 May 2020 (NRAs' approval)		
		4 December 2019 (NRAs' approval)		
	15 March 2020	27 May 2020 (NRAs' approval)		
	15 March 2020	27 May 2020 (NRAs' approval)		
	18 February 2020	31 March 2020 (NRAs' approval)		
		16 January 2020 (referred to ACER)		15 July 2020

Annex III – Market process overview of FCA, CACM, and EB Regulations

Abbreviations and legend used in the following process overview:

AC	Allocation Constraint
AOF	Activation Optimisation Function
aFRP	Automatic Frequency Restoration Process
aFRR	Automatic Frequency Restoration Reserves
BC	Balancing Capacity
BE	Balancing Energy
BRP	Balancing Responsible Party
BSP	Balancing Service Provider
CCC	Central Capacity Calculator
CCP	Central Counter Party
CET	Central European Time
CGM	Common Grid Model
CI	Congestion Income
CID	Congestion Income Distributor
CNEC	Critical Network Element and Contingency
CPOF	Capacity Procurement Optimisation Function
CZC	Cross-Zonal Capacity
D2CF	D-2 Congestion Forecast
DA	Day-Ahead
DACF	Day-Ahead Congestion Forecast
DAFD	Day-Ahead Firmness Deadline
EBP	European balancing platforms: European platforms for operating the imbalance netting process and exchanging the balancing energy from aFRR, mFRR, and RR
FRP	Frequency Restoration Process (aFRP + mFRP)
GCT	Gate Closure Time
GOT	Gate Opening Time
GSK	Generation Shift Key
ID	Intraday
IDA	Intraday Auction
IDCF	Intraday Congestion Forecast
IDCZGCT	Intraday Cross-Zonal Gate Closure Time
IDCZGOT	Intraday Cross-Zonal Gate Opening Time
IGM	Individual Grid Model
IN	Imbalance Netting
ISP	Imbalance Settlement Period
LT	Long Term
LT Nom.	Long Term Nomination
MCO	Market Coupling Operator
mFRP	Manual Frequency Restoration Process
mFRR	Manual Frequency Restoration Reserves
mFRR-DA	Direct Activation of mFRR
mFRR-SA	Scheduled Activation of mFRR

MP	Market Participant
MR	Market Result
MTU	Market Time Unit
NEMO	Nominated Electricity Market Operator
PTR	Physical Transmission Rights
RA	Remedial Action
RRP	Reserve Restoration Process
RR	Restoration Reserves
RCC	Regional Coordination Centre
SA	Shipping Agent
SAO	Shadow Auction Organiser(s)
SAP	Single Allocation Platform
SEC	Scheduled Exchange Calculator
T&C	Terms and Conditions for BSPs/BRPs
TSO	Transmission System Operator
UIOSI	Use It or Sell it

Legend

Forward capacity allocation process

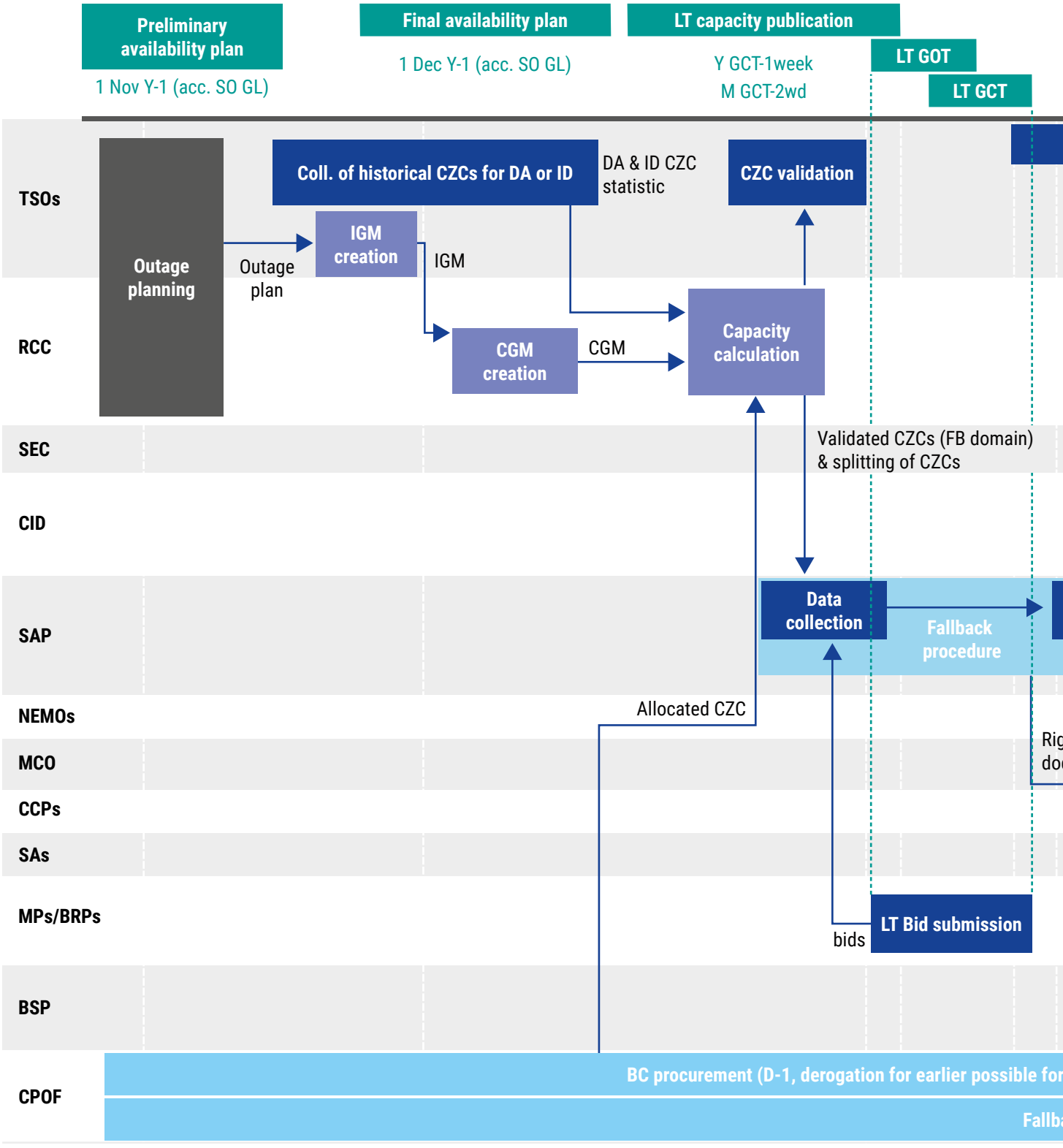
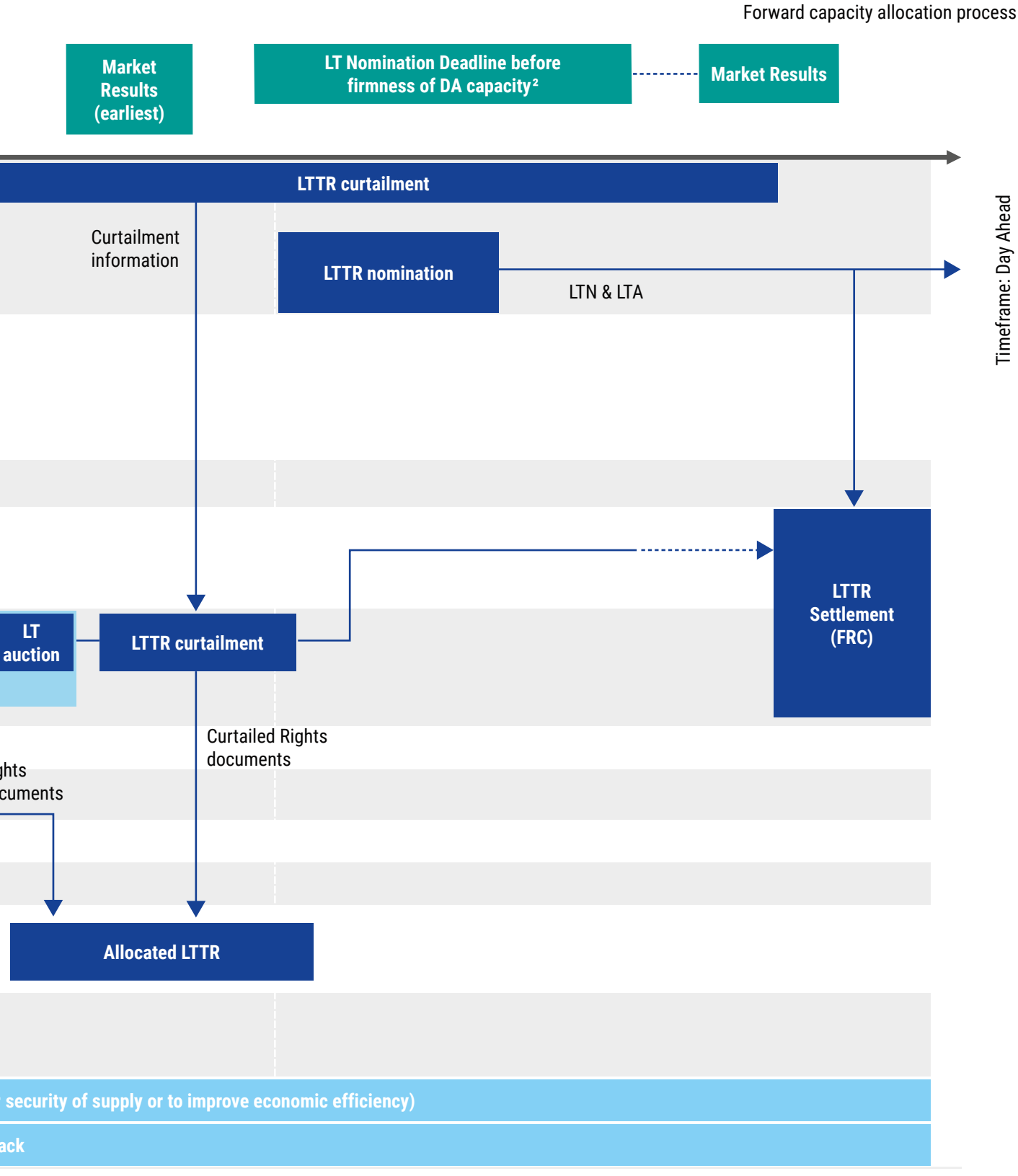
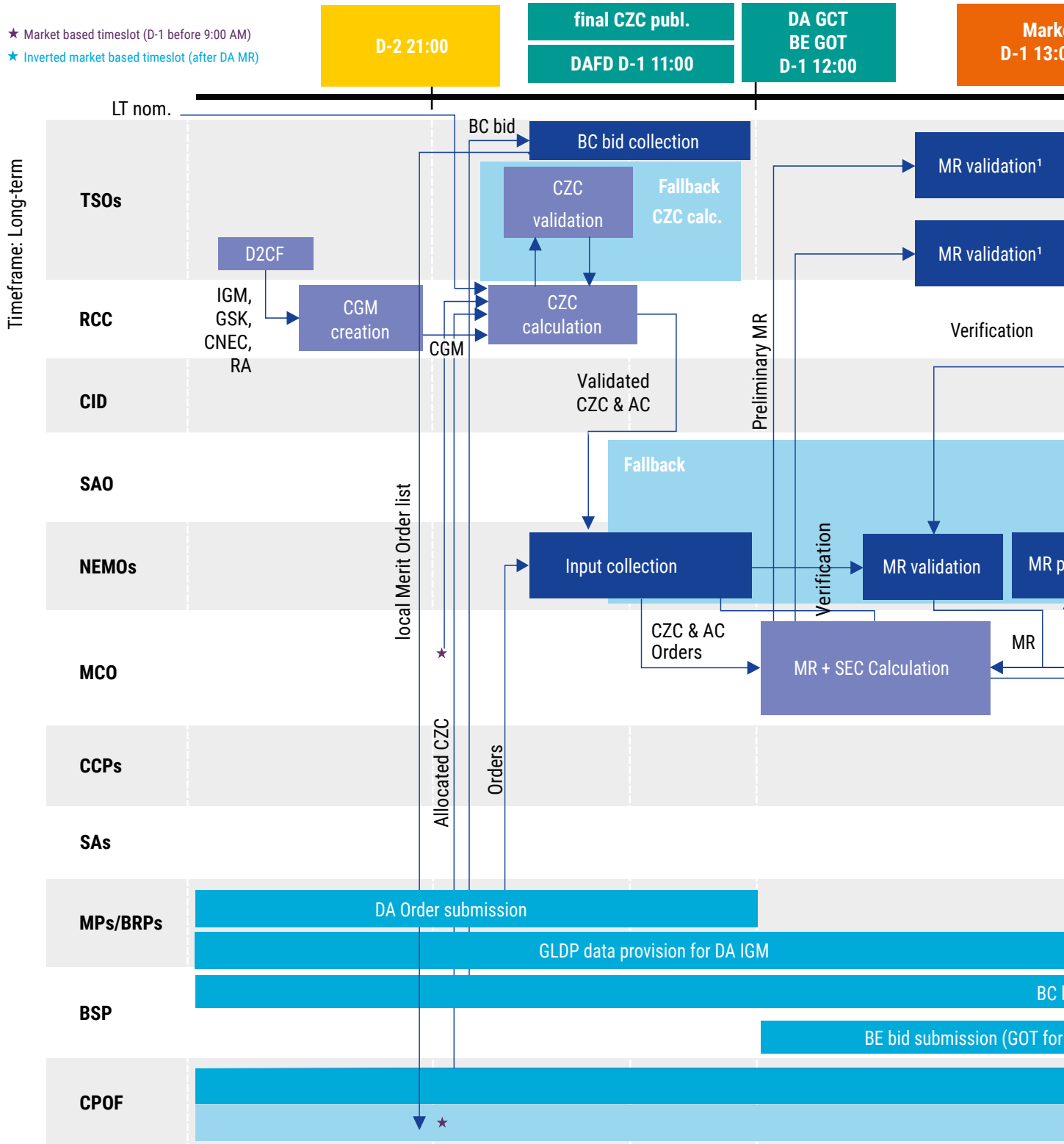


Figure AIII.1: Forward capacity allocation process

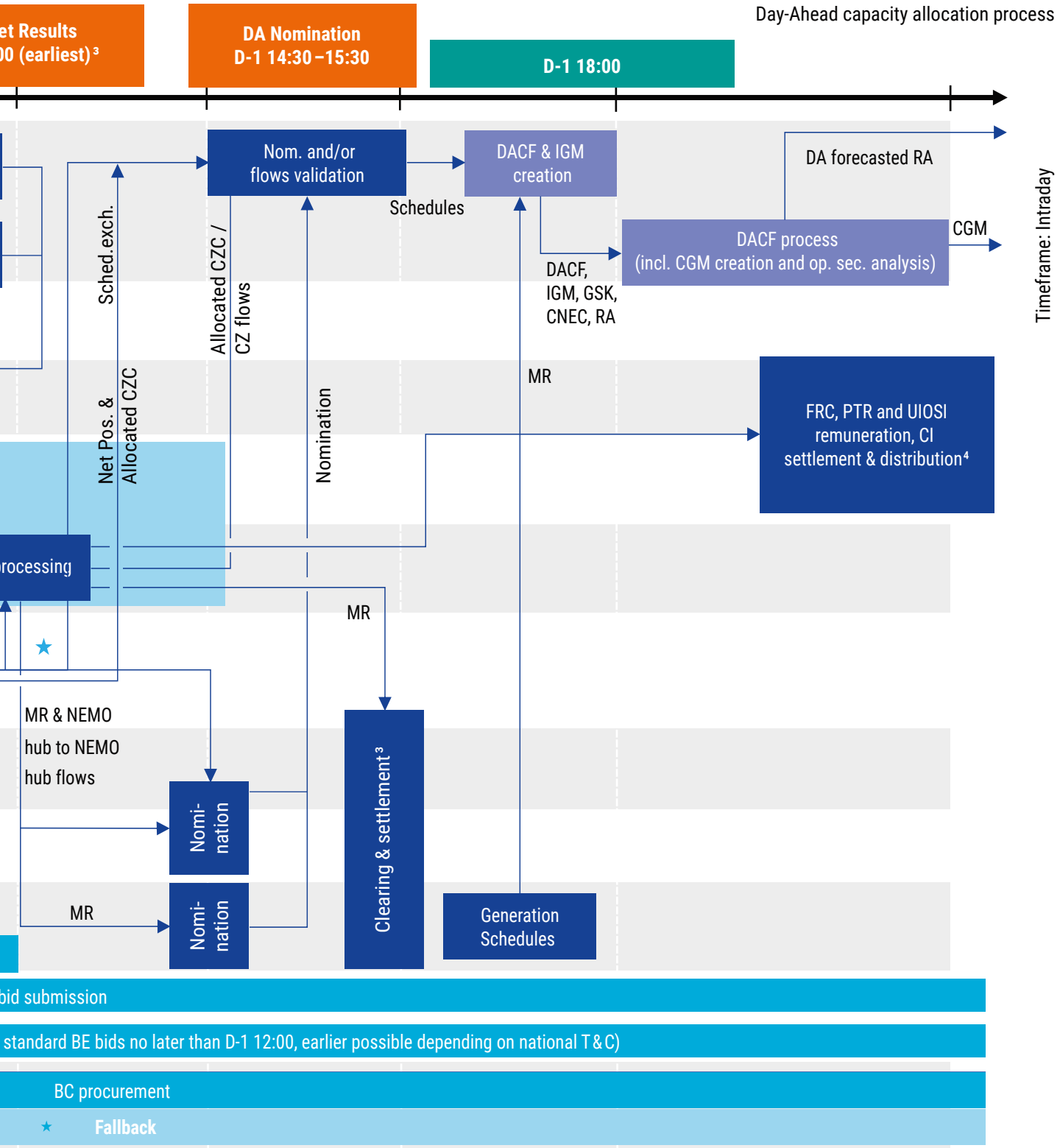

Forward capacity allocation process
Market Results (earliest)
LT Nomination Deadline before firmness of DA capacity²
Market Results
LTTR curtailment
Curtailment information
LTTR nomination
LTN & LTA
Timeframe: Day Ahead
LTTR Settlement (FRC)
LT auction
LTTR curtailment
Curtailed Rights documents
ghts
cuments
Allocated LTTR
security of supply or to improve economic efficiency)
ack

Day-Ahead Capacity Allocation Process



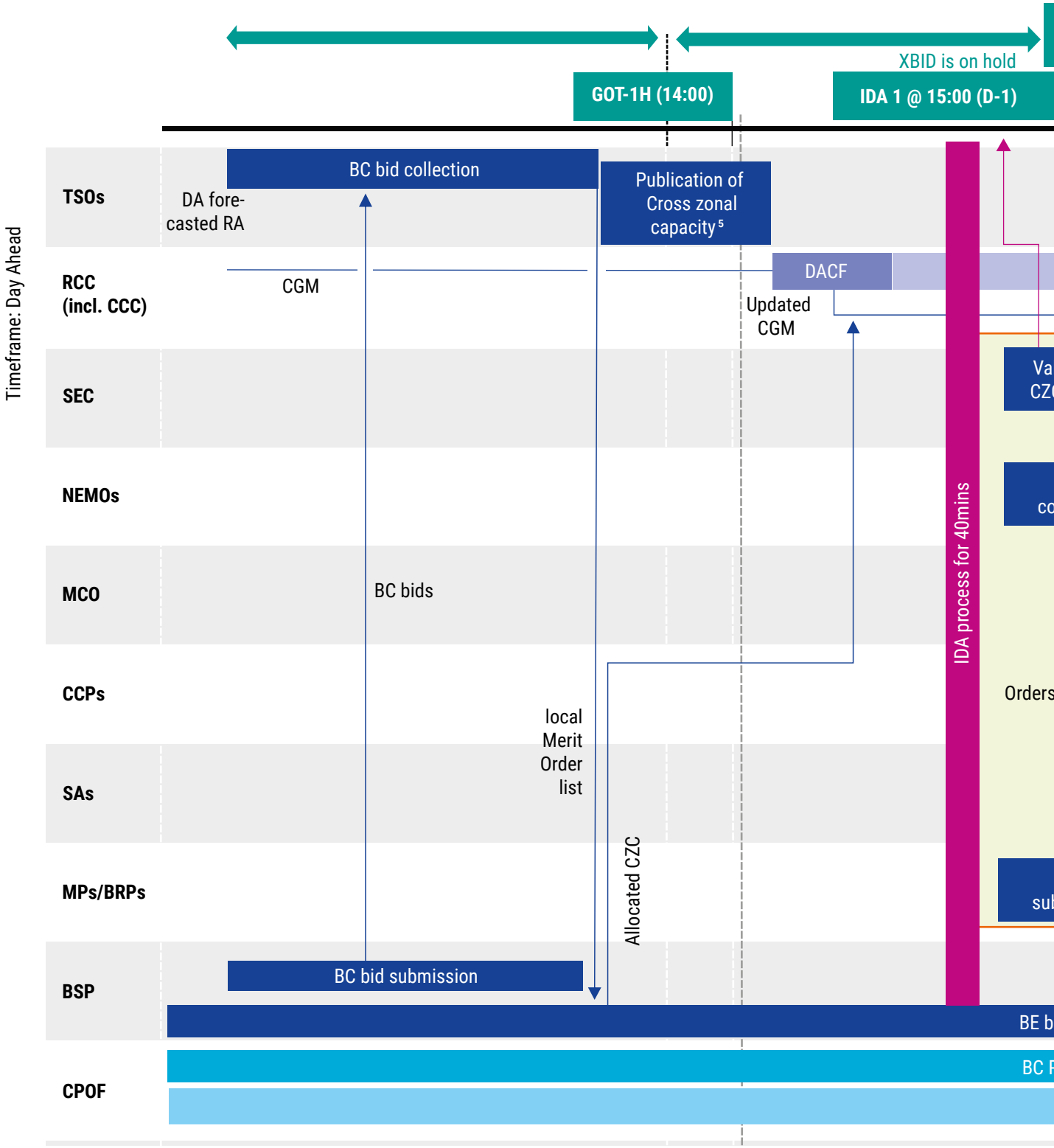
1) No parallel processes, solution depends on the regional design. **2)** Only in case of market-based allocation and economic efficiency analysis based allocation.
4) This processes are performed close to the delivery date or even after delivery.

Figure AIII.2: Day-Ahead Capacity Allocation Process



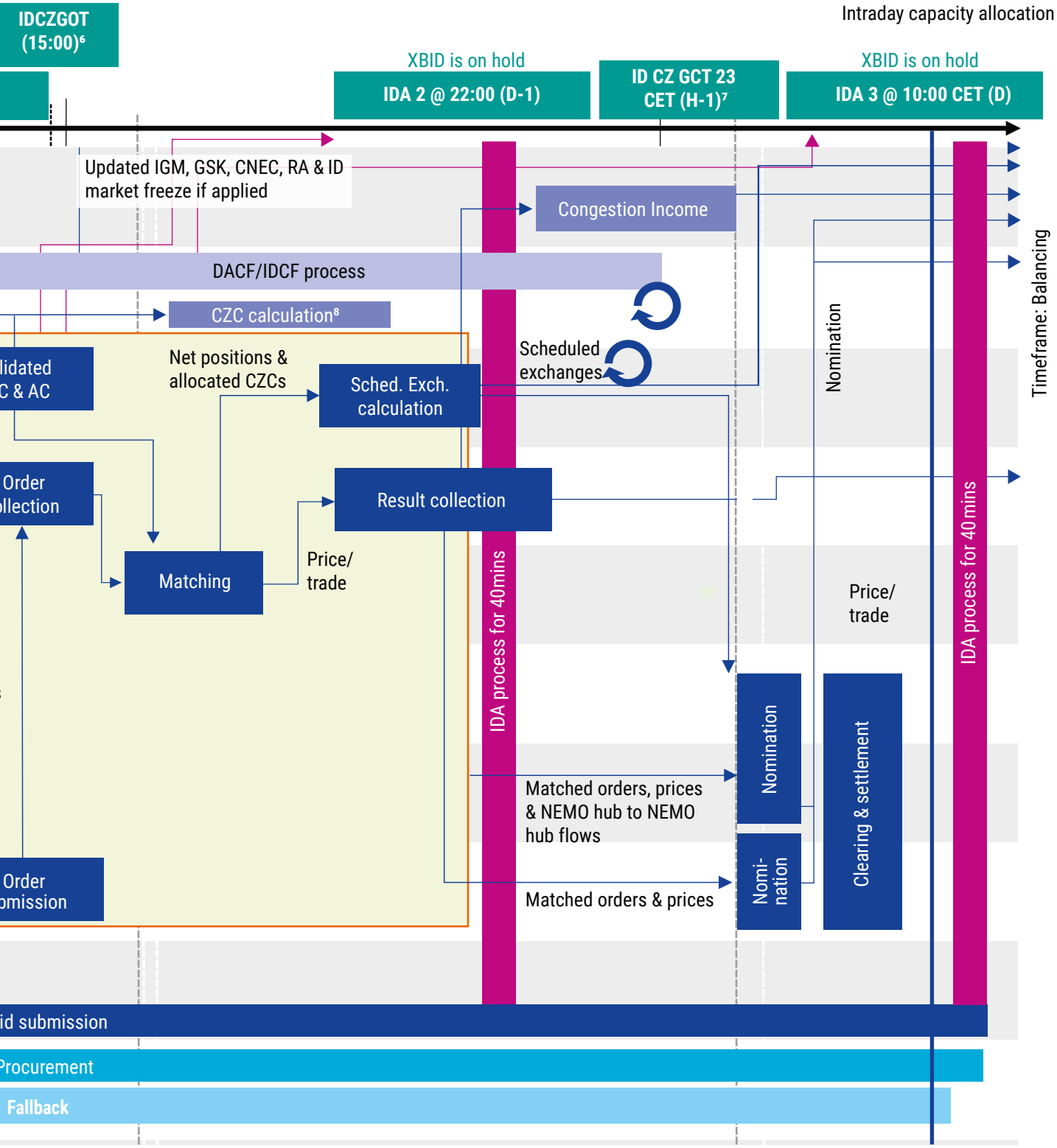
. Please note that co-optimisation is not shown on the slide. **3)** The latest possible time of market result publication is D-1 15:00 (in fallback situations)

Intraday capacity allocation



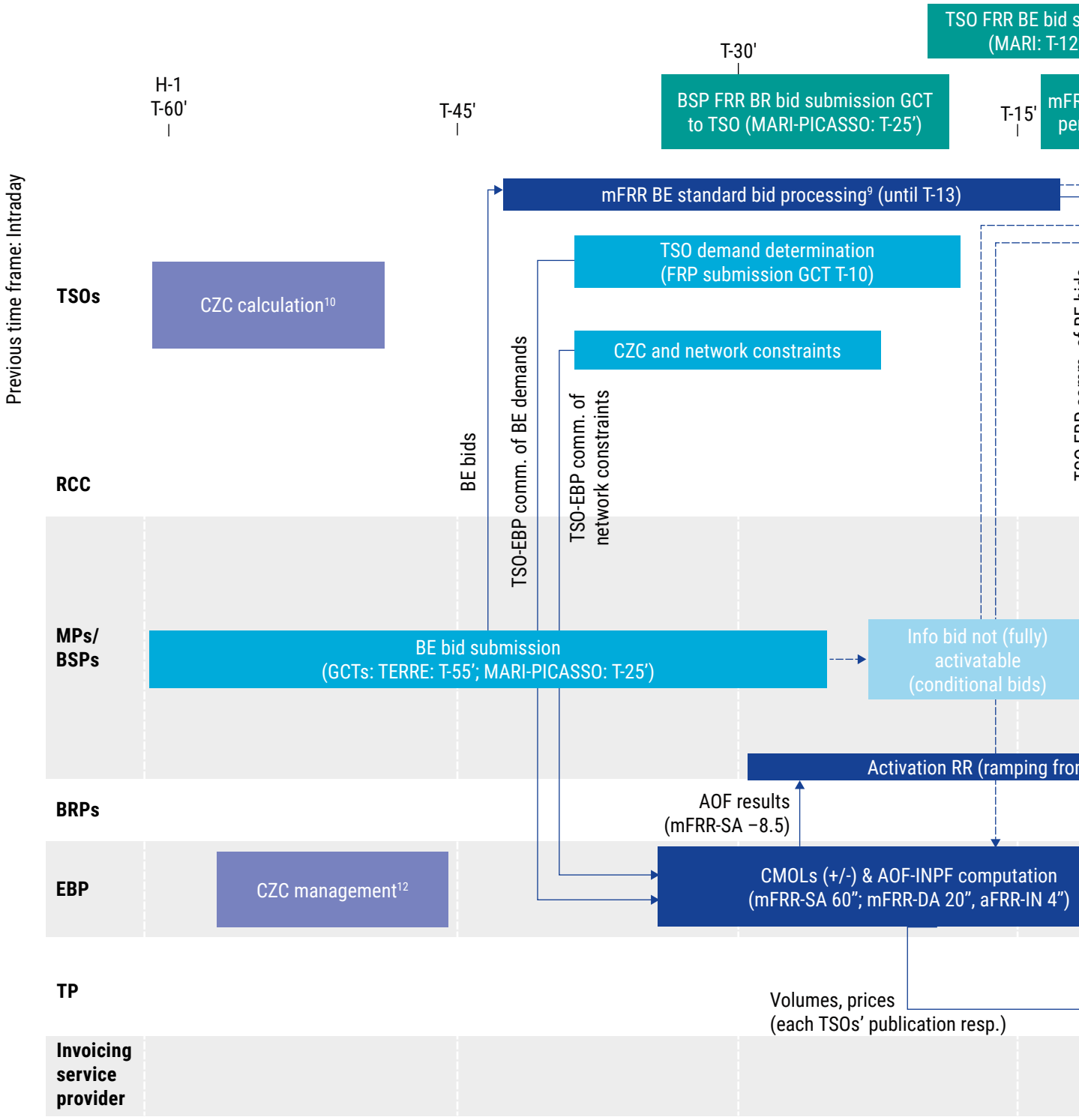
5) Preparation of CGM might be completed close or even after publication deadline. **6)** IDCZGOT-15:00 D-1, IDCZ capacity might not be available at IDCZGOT or Time suspension of XB continuous trading for 20 minutes before and after IDAs GCT. **7)** The first GCT for the first MTU of the next day is at 23:30 D-1 for count

Figure AIII.3: Intraday capacity allocation



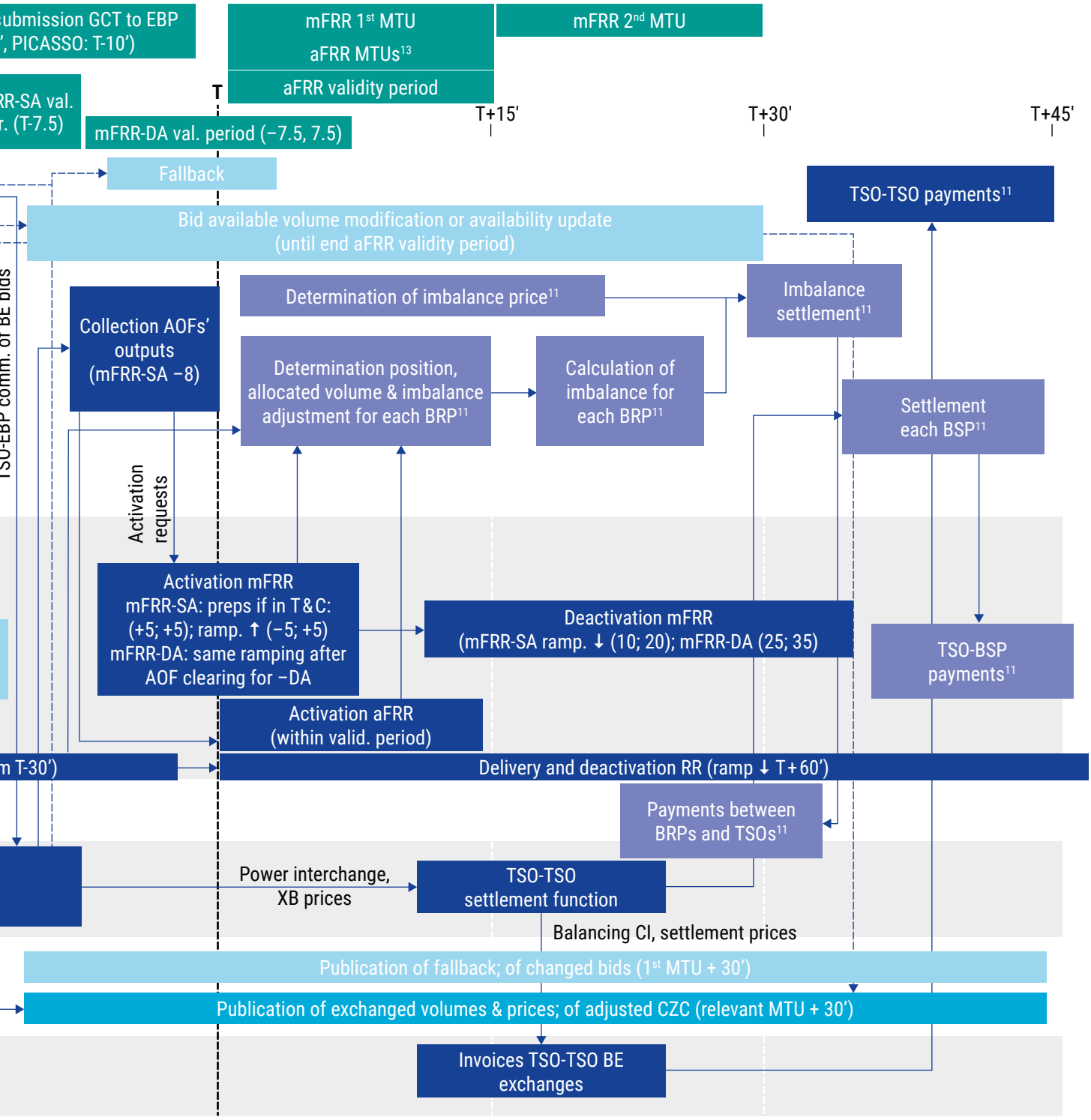
n some interconnections and might be provided only at 22:00 D-1 depending on CCR.
ries without derogations **8)** First IDCC is carried out ahead of IDA at 10

Cross-Zonal Balancing Energy Processes



9) Including collecting, conversion integrated scheduling process bids and specific BE bids to standard BE bids, modification bids EB 29 (9), update availability
10) CCRs' CZC calculation methodologies are currently under approval process. The entity or entities performing CCRs' EB CC are yet to be decided (e. g. EBPs, R
11) The imbalance settlement and payments detailed process and timing is defined nationally. For the points under reference 8), the time scale on the top does n
12) A new capacity management function manages the updates of CZC usage of all balancing platforms.
13) Each aFRR MTU corresponds to an optimisation cycle of the AOF of the aFRR-Platform (four seconds).

Figure AIII.4: Cross-Zonal Balancing Energy Processes



of bids EB 29 (14), validation, preparation for submission and submission of standard BE bids to EBP.
CCs, TSOs …)
ot represent actual timings.

Annex IV – CEP70 country fact sheets

In Chapter 2 of this report, TSOs provide an overview of their performance related to the CEP70 provision in 2025. Recognising that NRAs are responsible for assessing TSOs' compliance with the CEP70 provisions, this report aims to provide external stakeholders with an easily accessible overview of the national compliance assessments. In addition to the joint assessments per CCR, which are based on 2025 national monitoring results (see Section 2), this will be supported by country fact sheets offering a brief description of the national assessment methodology, an indication of whether ACER recommendations have been applied, national monitoring results (if available), and information on whether an action plan and/or deroga-tion was applied in 2025.

Austria

TSO(s)

Austrian Power Grid AG (APG)

Borders/Region

Core region and Italy North

Competent regulatory authority

Energie-Control Austria (E-Control)

Is any transitional regulation in place?

- ☐ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable
- ☑ **Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943**
- ☑ **Yes, TSO requested derogation pursuant to Art. 16 (9) of Regulation (EU) 2019/943**

Applicable target in 2025

59.7% (not including Core CCR derogation on CNEC level, respecting MTU situation)

Summary of national compliance assessment for 2025

In the report submitted to the NRA, APG finds that the minimum capacity requirement (considering the national action plan, the approved derogation, and the compliance methodology of E-Control) was fulfilled in all hours, including:

- Compliance for Core CCR
- Compliance for Italy North CCR

The assessment of APGs report by E-Control is not closed yet (June 2026)

Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

- ☐ Yes
- ☑ Partially (see explanation)
- ☐ No (see explanation)

Explanation

- Where the Agency only assesses the CNEC with the lowest trade margin per MTU, E-Control assesses each CNEC of each relevant MTU in 2025.
- Each of those CNEC entries is assessed with a compliance value (regarding the approved derogation and action plan target). A CCR's compliance is based on the average of all related CNEC entries.
- Whereas in the Core CCR, all CNECs from the final domain are considered rele-vant, in Italy North, only those CNECs that were potentially limiting the coordi-nated NTC are assessed.

Belgium

TSO(s)

Elia

Borders/Region

Core region

Competent regulatory authority

Commission de Régulation de l'Electricité et du Gaz (CREG)

Is any transitional regulation in place?

- ☐ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable
- ☐ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943
- ☑ Yes, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/943

Applicable target in 2025

[70 % MACZT in at least 56.2 % of the hours]

70 % > MACZT > 50 % in 34.8 % of the hours

50 % > MACZT > 20 % in 9 % of the hours

Summary of national compliance assessment for 2025

The minimum target is reached on all CNECs ~100 % of the time. The minMACZT target is defined according to the rules set out in the derogation on excessive loop flows granted to Elia. In this approach, 70 % is used as the baseline and is reduced only by the amount of excessive loop flows observed on the specific CNEC during the capacity calculation for that particular MTU. Elia uses remedial actions to reduce excessive loop flows by optimising the settings of its PSTs, thereby further reducing the extent of the derogation.

Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

- ☑ Yes
- ☐ Partially (see explanation)
- ☐ No (see explanation)

Explanation

CREG evaluated Elia's compliance with the target from its derogation.

Bulgaria

TSO(s)

ESO EAD

Borders/Region

B-RO, BG-GR/SEE Region

Competent regulatory authority

Energy and Water Regulatory Commission (EWRC)

Is any transitional regulation in place?

- ☑ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable
- ☐ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943
- ☐ Yes, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/943

Applicable target in 2025

70 %

Summary of national compliance assessment for 2025

The MACZT findings for Bulgaria are based on the results received from SELeNe's (SEE RCC) calculations, which rely on limiting CNECs from the DA capacity calculation provisions and the respective PTDF estimated.

For the North Greek border, several TSs show MAZCT values below 70 %. However, because the focus is only on a few specific TSs for all of 2025, we consider this result to be extremely indicative, and it unequivocally proves the successful implementation of the 70 % rule for the ESO side.

For the South Romanian border, the available results show strong interdependencies between ESO, Transelectrica, and other non-EU neighbouring TSOs. Despite this, the MACZT calculation outcome indicates that in almost 80 % of all TSs in 2025, the limiting CNE was neither an interconnection tie-line nor an internal transmission element. The remaining approximately 20 % of all cases are distributed differently depending on the calculation direction (import or export), with the main percentage again being in the "MACZT ≥ Target" group (between approximately 5 % and 10 %). For the remaining MACZT subgroups respecting ESO's grid (approximately 10–15 % depending on the direction of the capacity calculation process), the impact of maintenance activities and forecast inaccuracies provides important context and should be factored into the overall assessment. The most important conclusion from the aggregated results is that there is no internal bottleneck in our own transmission network when the 70 % capacity calculation is performed.

Considering the explanations above and the fact that Bulgaria is heavily influenced by flows from third countries, the 2025 results are satisfactory.

Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

- ☑ Yes
- ☐ Partially (see explanation)
- ☐ No (see explanation)

Croatia

TSO(s)

Croatian Transmission System Operator (HOPS)

Borders/Region

Core region

Competent regulatory authority

Croatian Energy Regulatory Agency (HERA)

Is any transitional regulation in place?

- ☐ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable
- ☑ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943
- ☐ Yes, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/943

Applicable target in 2025

Core region: 57.6% on all CNECs for each MTU

Summary of national compliance assessment for 2025

- In the report submitted to HERA, HOPS found that the minimum capacity requirement (considering the national action plan) was fulfilled in all hours.
- In the report submitted to HERA on average cross-zonal trading capacities, HOPS met the 2025 linear trajectory based on the FB approach, maintaining minimum MACZT on all CNECs throughout all time units and averaging over 70% MACZT on most CNECs. Deviations from the linear trajectory occurred on four CNECs 22.3% of the time in 2025, which is permitted due to operational security considerations.
- Given that HOPS meets the linear trajectory requirements 100% of the time for average MACZT values and 77.7% of the time for observed minimum MACZT values, it can be concluded that HOPS conforms to action plan requirements.
- The report was submitted on 17 March 2026 and approved by HERA on 15 April 2026.

Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

- ☐ Yes
- ☑ Partially (see explanation)
- ☐ No (see explanation)

Explanation

- Where the Agency only assesses the CNE with the lowest trade margin per MTU, HERA assesses each CNE (including contingencies, CNEC) of each relevant MTU in 2025.
- Each of those CNEC entries is assessed with a compliance value (regarding the approved action plan target). A CCR's compliance is based on the average of all related CNEC entries.

Czech Republic

TSO(s)

ČEPS

Borders/Region

Core region

Competent regulatory authority

ERÚ

Is any transitional regulation in place?

- ☑ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable
- ☐ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943
- ☐ Yes, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/943

Applicable target in 2025

70 %

Summary of national compliance assessment for 2025

The Czech Republic is fully compliant with Article 16 of Regulation (EU) 2019/943. Only minor deviations occur in the CZ Core direction, where the individual value adjustment (IVA) was applied to reduce capacities in order to maintain operational security.

Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

- ☐ Yes
- ☐ Partially (see explanation)
- ☑ No (see explanation)

Denmark

TSO(s)

Energinet

Borders/Region

DK1

DK2

Competent regulatory authority

Danish Utility Regulator

Is any transitional regulation in place?

- ☑ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable
- ☐ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943
- ☐ Yes, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/943

Applicable target in 2025

70 %

Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

- ☑ Yes
- ☐ Partially (see explanation)
- ☐ No (see explanation)

Explanation

The Danish Utility Regulator is expected to assess and report Energinet's methodology related to compliance with the 70 % requirement in 2026. The percentage of constraints is reported as an indicator, as it offers a transparent representation of the extent to which the overall Danish grid complies with the 70 % requirement.

Estonia

TSO(s)

Elering

Borders/Region

EE › FI

FI › EE

LV › EE

EE › LV

Competent regulatory authority

Estonian Competition Authority

Is any transitional regulation in place?

- ☑ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable
- ☐ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943
- ☐ Yes, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/943

Applicable target in 2025

70 %

Summary of national compliance assessment for 2025

Estonia uses the coordinated NTC approach for cross-border capacity calculation for the Estonia–Finland and Estonia–Latvia borders. For both, the minimum target was reached most of the time.

Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

- ☑ Yes
- ☐ Partially (see explanation)
- ☐ No (see explanation)

Finland

TSO(s)

Fingrid

Borders/Region

FI <-> SE1

FI <-> SE3

FI <-> NO4

FI <-> EE/Nordic CCR

Competent regulatory authority

EV (Energiavirasto)

Is any transitional regulation in place?

- ☑ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable
- ☐ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943
- ☐ Yes, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/943

Applicable target in 2025

70 %

Summary of national compliance assessment for 2025

Compliance assessment for 2025 is not completed by the Finnish NRA.

Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

- ☐ Yes
- ☑ Partially (see explanation)
- ☐ No (see explanation)

Explanation

The approach for national compliance assessment has not yet been verified by the Finnish NRA. The assessment is expected to be ready at the end of Q2 2026. However, Fingrid has presented compliance in the market report using the percentage-of-constraints method.

France

TSO(s)

RTE

Borders/Region

Core region, Italy North region, SWE region

Competent regulatory authority

CRE

Is any transitional regulation in place?

- ☑ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable
- ☐ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943
- ☐ Yes, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/94

Applicable target in 2025

70 %

Summary of national compliance assessment for 2025

The 2025 results are satisfactory regarding the criterion of compliance agreed with the French regulator CRE.

CRE publishes an annual report on the application of the 70 % target on French borders to assess national compliance.

Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

- ☐ Yes
- ☑ Partially (see explanation)
- ☐ No (see explanation)

Explanation

According to the smart compliance agreed with CRE, an MTU is considered compliant with the 70 % criterion if at least one of the following conditions is met:

- Price convergence is reached with BZs inside the corresponding CCR
- All limiting CNECs are in a neighbouring country
- The minimum MACZT is over 70 %

Germany

TSO(s)

50Hertz Transmission GmbH, Amprion GmbH, Baltic Cable AB, TenneT TSO GmbH, TransnetBW GmbH

Borders/Region

Core CCR, Hansa CCR

Competent regulatory authority

Bundesnetzagentur (BNetzA)

Is any transitional regulation in place?

☐ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable

☑ **Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943**

☐ Yes, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/943

Applicable target in 2025

Core CCR borders: 60.3% on all CNEs for each MTU

DE – DK1: 62.3% on all CNEs for each MTU

DE – DK2: 70% for Kontek cable/58.3% for KF CGS

DE – SE4: 65.2% on all CNEs for each MTU

DE – NO2: 58.3% on all CNEs for each MTU

Summary of national compliance assessment for 2025

› In the report submitted to the regulatory authority, the German TSOs confirm full compliance with Article 16 of Regulation (EU) 2019/943 at all times. Any capacity adjustments below the minimum threshold were duly justified.

Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

☐ Yes

☑ Partially (see explanation)

☐ No (see explanation)

Explanation

› Where the Agency only assesses the CNE with the lowest trade margin per MTU, BNetzA assesses each CNE per MTU (taking into account the most lim-iting contingency; only FB borders).

› Diverging MNCC calculation: Where ACER recommends using forecasted trans-fer capacities, the BNetzA uses offered transfer capacities (both FB and cNTC borders).

› BNetzA also considers the additional capacity provided through extended long-term allocation (LTA) inclusion (only FB borders).

Greece

TSO(s)

IPTO

Borders/Region

SEE/GRIT

Competent regulatory authority

RAAEY

Is any transitional regulation in place?

- ☑ No for GRIT, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable
- ☐ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943
- ☑ Yes for SEE, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/943

Applicable target in 2025

SEE: 60% MACZT excluding periods of maintenance on Greek tie-lines or very low load conditions

GRIT: 70%

Summary of national compliance assessment for 2025

IPTO has a derogation in place for the northern Greek borders for 2025. The assessment is based on the limiting CNEC per direction and MTU, compared to both the applicable target and the 70% requirement. Given that Greece is significantly affected by flows from third countries, since three of its four borders are with non-EU countries, only results that consider flows from third countries are used.

Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

- ☑ Yes
- ☐ Partially (see explanation)
- ☐ No (see explanation)

Hungary

TSO(s)

MAVIR

Borders/Region

Core region

Competent regulatory authority

Magyar Energetikai és Közmű-szabályozási Hivatal (MEKH)

Is any transitional regulation in place?

- ☐ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable
- ☑ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943
- ☐ Yes, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/943

Applicable target in 2025

70%

Exceptions: applicable for five CNEs

Different minimum capacity per CNEC in line with linear trajectory of the action plan

58.75% for four CNEs

60.75% for one CNE

Summary of national compliance assessment for 2025

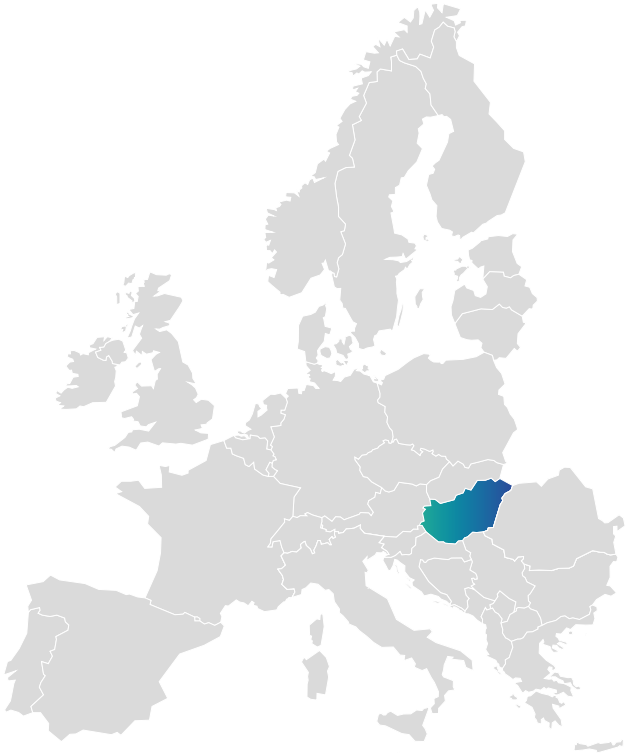
In line with our expectations, most transmission lines fulfil the 70% requirement. For the five network elements pre-recorded in the adopted action plan, the threshold values stated in the linear trajectory were met in all but 8 hours in 2025.

The national compliance report was sent to our national regulator (MEKH) on 30 March in the Hungarian language.

Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

- ☐ Yes
- ☑ Partially (see explanation)
- ☐ No (see explanation)



Explanation

In line with our expectations, most of the transmission lines fulfil the 70% requirement. For the five network elements pre-recorded in the adopted action plan, the threshold values stated in the linear route were met in all but 8 hours in 2025. However, in a smaller part of the transmission lines that met the 70% requirements, non-fulfilment occurred in a different way than in previous years, and in a higher number of hours. There were many investments, developments, and projects not only in our country but also in out neighbouring TSOs in 2025; therefore, a significant number of planned outages occurred on the network. The majority of non-fulfilment can be attributed to such outages caused by investments on the Slovak and Austrian sides.

In our action plan, the limit value of certain network elements was not reached at least 95% of the time due to significant transit flows, which caused congestions at our Romanian, Austrian, and Slovak tie-lines and in the internal network. The situation could only be managed through remedial actions to maintain operational security. As a result, we complied with the 70% rule and our individual minimum capacity according to our action plan 73.02% of the time. We expect that our higher non-fulfilment will be positively affected and resolved by the grid restructuration planned by SEPS on the Slovak network. Despite the higher non-fulfilment in 2025, we have achieved the goals of the action plan by reaching the end point of the linear trajectory; therefore, from January 1, 2026, we will apply the 70% capacity target on all transmission lines.

Ireland

TSO(s)

EirGrid

Borders/Region

No EU borders in 2025

Competent regulatory authority

Is any transitional regulation in place?

- ☐ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable
- ☐ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943
- ☐ Yes, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/943

Applicable target in 2025

Not applicable

The SEM market is currently not physically interconnected to other Member States or third countries that apply EU VO 2019/943. Hence, the SEM runs as an isolated market. The assessment of cross-zonal trade capacity will become relevant when the SEM reconnects to the European IEM with the commissioning of the Celtic interconnector.

Italy

TSO(s)

TERNA

Borders/Region

Italy North, GRIT

Competent regulatory authority

ARERA

Is any transitional regulation in place?

- ☑ No for GRIT, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable
- ☐ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943
- ☑ **Yes for Italy North; TSO requested derogation pursuant to Art. 16 (9) of Regulation (EU) 2019/943**

Applicable target in 2025

70 % for Italy North, except derogation period (allocation constraints, export when export corner is not triggered)

70 % for GRIT

Summary of national compliance assessment for 2025

For Italy North, a derogation was in place for 2025 for all MTUs where allocation constraints are applied. No minimum capacity target was defined.

The 70 % criterion is considered fulfilled if at least one limiting CNEC on Italy's northern border satisfies this condition, regardless of the specific national frontier involved. According to the methodology approved by the NRAs of the CCR, the Italy North border is assessed as a single entity.

The percentages are calculated based on MTUs without process failures, which account for 74 % of the total. In the remaining 26 %, the calculation process failed.

Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

- ☑ Yes
- ☐ Partially (see explanation)
- ☐ No (see explanation)

Explanation

According to the methodology in force, all Italy North borders are considered as a whole.

Latvia

TSO(s)

AST

Borders/Region

EE–LV/LV–LT/Baltics

Competent regulatory authority

The Public Utilities Commission Regulation, English (PUC) and Latvian (SPRK)

Is any transitional regulation in place?

- ☑ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable
- ☐ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943
- ☐ Yes, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/943

Applicable target in 2025

70 %

Summary of national compliance assessment for 2025

AST uses the coordinated NTC approach for cross-border capacity calculation on the Latvia – Lithuania and Estonia – Latvia borders. For both, the minimum target was reached most of the time.

Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

- ☑ Yes
- ☐ Partially (see explanation)
- ☐ No (see explanation)

Lithuania

TSO(s)

LITGRID

Borders/Region

LT–LV/LT–SE/LT–PL/Baltics

Competent regulatory authority

National Energy Regulatory Council (NERC)

Is any transitional regulation in place?

- ☑ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable
- ☐ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943
- ☐ Yes, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/943

Applicable target in 2025

70 %

Summary of national compliance assessment

Lithuania uses the coordinated NTC approach for cross-border capacity calculation for the Lithuania – Sweden, Lithuania – Poland, and Lithuania – Latvia borders. For all borders, the minimum target was reached most of the time.

Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

- ☑ Yes
- ☐ Partially (see explanation)
- ☐ No (see explanation)

Luxembourg

TSO(s)

Creos Luxembourg

Borders/Region

Core region

Competent regulatory authority

Institut Luxembourgeois de Régulation (ILR)

Is any transitional regulation in place?

- ☐ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable
- ☐ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943
- ☐ Yes, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/943

Applicable target in 2025

§16.8 CEP does not apply to the specific Luxembourg situation, as the Creos transmission system does not limit flows for cross-zonal exchanges. Luxembourg is part of the German/Luxembourg BZ, and cross-border capacities are currently not available due to operational constraints.

Netherlands

TSO(s)

TenneT TSO BV

Borders/Region

Core region, HVDC

Competent regulatory authority

Autoriteit Consument & Markt

Is any transitional regulation in place?

- ☐ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable
- ☑ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943
- ☑ Yes, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/943

Applicable target in 2025

Changes by CNE, statistics:

Minimum: 62%

Maximum: 70%

Average: 62.8%

Median: 62%

Summary of national compliance assessment for 2025

Link to national compliance report.

Explanation

N/A

Norway

TSO(s)

Statnett SF

Borders/Region

Nordic CCR: NO1, NO2, NO3, NO4, NO5

Hansa CCR: NO2 – NL, NO2 – DE

Competent regulatory authority

Reguleringsmyndigheten for Energi (RME)

Is any transitional regulation in place?

- ☑ No, the minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is not applicable in Norway because Regulation (EU) 2019/943 is not implemented in the EEA agreement.
- ☐ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable.
- ☐ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943
- ☐ Yes, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/943

Applicable target in 2025

None

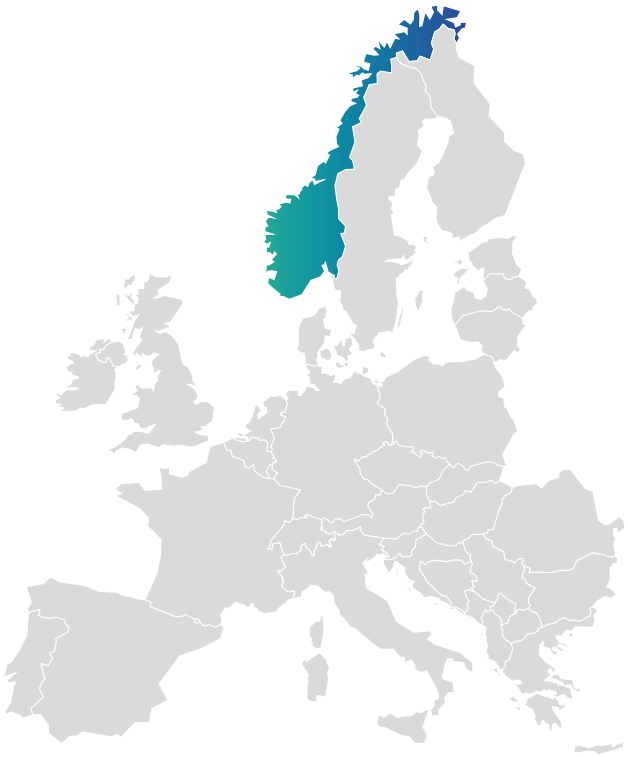
Summary of national compliance assessment for 2025

The Norwegian regulator RME has not completed a national compliance assessment for 2025.

Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

- ☐ Yes
- ☐ Partially (see explanation)
- ☑ No (see explanation)



Explanation

Statnett is reporting on the minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 on a voluntary basis. The minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is not applicable in Norway because Regulation (EU) 2019/943 is not implemented in the EEA agreement.

Statnett has not been able to calculate the margin from non-coordinated capacity calculation (MNCC) because we do not have the PTDFs for NO2 – NSL from 2025. This means that flows from NSL have not been considered as a part of MACZT.

Poland

TSO(s)
Polskie Sieci Elektroenergetyczne S.A. (PSE)

Borders/Region
Core region, PL – LT, PL – SE4

Competent regulatory authority
Urząd Regulacji Energetyki (URE)

Is any transitional regulation in place?
- ☐ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable
- ☑ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943
- ☑ Yes, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/943

Applicable target in 2025
Different minimum capacity per CNEC in line with action plan:
CORE: average 55.21 %
PL › LT: 70 %
LT › PL: 70 %
PL › SE4: 65 %
SE4 › PL: 70 %

Summary of national compliance assessment for 2025
In the national report submitted to the NRA (URE), PSE considers the minimum capacity requirement fulfilled in all hours. Hours meeting the minimum required MACZT levels are marked as fulfilled. Similarly, hours in which the minimum MACZT was considered conditionally fulfilled due to legitimate reasons (outages, derogations, lack of redispatching potential) are also marked as fulfilled.

A link to the national compliance report is not yet available as the approval is pending (2026).

Methodology
Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

- ☐ Yes
- ☑ Partially (see explanation)
- ☐ No (see explanation)

Explanation
ACER only evaluates the CNE with the lowest trade margin per MTU, whereas URE evaluates each CNE (including CNECs) for each relevant MTU.

An important difference from the Agency's approach is the treatment of allocation constraints, defined as "constraints to be respected during capacity allocation to maintain the transmission system within operational security limits and have not been translated into CZC or that are needed to increase the efficiency of capacity allocation".

Minimal capacity obligations consider the percentage of capacity that respects operational security limits, so the application of allocation constraints cannot reduce capacities below the trajectory thresholds. However, in its monitoring report, ACER recalculated the CZC figures for Poland by reducing the capacities made available on the Polish DC borders, even though the full capacity of the link was usually offered (or at least the minimal threshold or derogation was respected). The basis for this interpretation is unclear, as the applicable legal framework clearly allows for the application of allocation constraints. Besides aiming to maintain the system within operational security limits, allocation constraints are not listed in Regulation 2019/943 as factors included within the 30 % margin designated for, among others, loop flows. It should be emphasised that for hours marked by ACER as not fulfilled, the respective DC borders were used for transits through Poland (often to the full capacity of the links), thus contributing to European social welfare.

On 9 February 2025, the Baltic Synchronous Power System (LT, LV, EE) desynchronised from the IPS/UPS (BRELL) ring and synchronised with the Continental Europe SA; permanent synchronous operation was confirmed on 25 November 2025 in coordination with ENTSO E RGCE. Following synchronisation, cross zonal capacity on the PL – LT border is calculated under the coordinated NTC approach pursuant to the Baltic DA and ID CCM (within CCR Baltic), replacing the previous HVDC/NTC basis applied until 8 February 2025.

Portugal

TSO(s)

[REN – Rede Eléctrica Nacional, S.A.]

Borders/Region

[SWE Region]

Competent regulatory authority

ERSE – Entidade Reguladora dos Serviços Energéticos]

Is any transitional regulation in place?

- ☐ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable
- ☐ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943
- ☑ **Yes, TSO requested derogation pursuant to Art. 16 (9) of Regulation (EU) 2019/943**

Applicable target in 2025

[70 % MACZT in at least 87.5 % of the hours]

- Summary of national compliance assessment for 2025 The SWE RCC has conducted the CZC regional monitoring process since April 2021.
- CZC recalculations using countertrading began in February 2022.
- A fallback CNEC has been used to compute the MACZT when the CNEC is unavaila-ble (since 2022).
- In 2025, there was a derogation for REN. During this period, REN applied the amended capacity calculation methodology proposal in the SWE CCR for the operational DA coordinated capacity calculation process (approved by SWE NRA in Jan-uary 2022), ensuring continued operational security in the SWE CCR. REN provided at least the minimum required capacity in accordance with Article 16 (8)(a) of Reg-ulation 2019/943 during 87.5 % of the hours in which this 1-year derogation was applied, where the minimum levels were offered in line with Article 16 (8) (a) of Regulation 2019/943 and paragraphs 4.2 and 5.1 of ACER Recommendation No. 01/2019 regarding limiting CNECs.
- The SWE capacity calculation methodology includes a fallback CNEC mechanism, allowing compliance with the CEP70 requirement to be assessed when the CNEC is not available within the allotted time frame.

For the 70 % compliance assessment in the previous chapter, the following criteria were applied:

1. MTUs with a limiting CNEC outside Portugal are deemed compliant.
2. For MTUs where the SWE capacity calculation process did not provide a limiting CNE, the methodology includes a fallback CNEC, allowing for the assessment of compliance with the CEP70 requirement.

Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

- ☑ Yes
- ☐ Partially (see explanation
- ☐ No (see explanation)

Explanation

- ERSE's compliance assessment for 2025 is not closed.

Romania

TSO(s)

Transelectrica

Borders/Region

Romania – Hungary/Core

Romania – Bulgaria/SEE

Competent regulatory authority

National Energy Regulatory Authority (ANRE)

Is any transitional regulation in place?

- ☐ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable
- ☑ **Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943**
- ☑ **Yes, TSO requested derogation pursuant to Art. 16 (9) of Regulation (EU) 2019/943 (Derogation for 2025)**

Applicable target in 2025

Romania – Hungary:

Derogation: 41 % on all CNEs for each MTU

Romania–Bulgaria:

Derogation: 52 % on all CNEs for each MTU

CNTEE Transelectrica SA applied for a derogation from the obligations set out in Article 16 (8) of Regulation (EU) 2019/943 for the Romania – Hungary and Romania – Bulgaria borders, in accordance with Article 16 (9) of Regulation (EU) 2019/943. In Decision No. 314 of 18 Feburary 2025, ANRE granted the derogation, requiring Transelectrica SA to maintain a minimum available capacity for cross-zonal trade of 980 MW (41 % of transmission capacity) for the Romania – Hungary border and 1,890 MW (52 % of transmission capacity) for the Romania – Bulgaria border in 2025.

Summary of national compliance assessment for 2025

- Transelectrica applies ACER Recommendation No. 01/2019 to assess the compli-ance of its borders with the interim targets set by the action plan and derogation.
- The national compliance report is split between the SEE and Core regions as follows:
- **Core (RO – HU)**
  - The assessment is carried out relative to both the 70 % target and the 41 % interim target according to the derogation granted by ANRE. The CNECs with the lowest RAM per MTU are used for this evaluation.
  - The results include values both with and without third countries. Given that Romania is heavily influenced by the flows of third countries, it is essential to consider the values that include them.

The report presents average MACZT values overall, as well as MACZT when targets were met and when they were not.

Figures are also provided for all presolved CNECs per MTU and month, along with their average values.

Another major factor is the MNCC values, as Romania has four other bor-ders with third countries that are subject to daily allocation.

› SEE (RO – BG)

- The assessment is carried out relative to both the 70 % target and the 52 % interim target according to the dero-gation granted by ANRE. Limiting CNECs per MTU and direction are used for this evaluation.
- The results include values both with and without third countries, as well as a breakdown by direction. Given that Romania is heavily influenced by the flows of third countries, it is essential to consider the values that include them. The report presents average MACZT values overall, as well as MACZT where targets are met and when they are not.

Additionally, as the action plan sets an annual NTC [MW] target, the report includes both the calculated capacity values and the validated NTC values

Methodology

Did the competent regulatory authority adopt the non-bind-ing ACER Recommendation No. 01/2019 for its compliance assessment?

☑ Yes

☐ Partially (see explanation)

☐ No (see explanation)

Explanation

› The 2025 assessment has not yet begun.

Slovak Republic

TSO(s)

Slovenská elektrizačná prenosová sústava, a.s. (SEPS)

Borders/Region

Core region

Competent regulatory authority

Úrad pre reguláciu sieťových odvetví (ÚRSO)/Regulatory Office for Network Industries (RONI)

Is any transitional regulation in place?

- ☐ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable
- ☐ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943
- ☑ Yes, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/943

Applicable target in 2025

50% MACZT (applicable to two CNEs, in at least 80% of MTUs if the security of the power system is secured)

70% MACZT (applicable to the remaining CNEs)

Summary of national compliance assessment for 2025

In accordance with the granted derogation for 2025, allowing the provision of 50% of MACZT (applicable to two CNEs in at least 80% of MTUs, provided that system security is maintained), the target value for the affected CNECs was achieved in 40.9% of MTUs.

The value of 40.9% is calculated over 100% of MTUs, while the derogation requires meeting the minRAM target in at least 80% of MTUs. The lowest values were observed during the winter period. Although the above-mentioned CNECs have higher limits in winter compared to summer due to seasonal ratings, the reduced performance is more likely related to increased system constraints during winter rather than to thermal limit.

Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

- ☑ Yes
- ☐ Partially (see explanation)
- ☐ No (see explanation)

Slovenia

TSO(s)

ELES

Borders/Region

CORE and Italy North

Competent regulatory authority

Agencija za energijo

Is any transitional regulation in place?

- ☑ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable
- ☐ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943
- ☐ Yes, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/943

Applicable target in 2025

70%

Summary of national compliance assessment for 2025

- In the Core region, the 70% target was reached for 97.12% of MTUs.
- When the 70% target was not reached (2.88% of MTUs), the MACZT fell within 100 – 75% of the target range 2.42% of time, within the 57 – 50% 0.13% of the time and below 50% of the target 0.06% of the time.
- In the Italy North region, the 70% target was reached in all of MTUs when SI CNECs limited the NTC calculation (0.14% of the time).

Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

- ☐ Yes
- ☑ Partially (see explanation)
- ☐ No (see explanation)

Spain

TSO(s)

Red Eléctrica de España S.A.U. (Red Eléctrica)

Borders/Region

SWE CC region/Spain – France, Spain – Portugal

Competent regulatory authority

Comisión Nacional de los Mercados y la Competencia (CNMC)

Is any transitional regulation in place?

☑ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable

☐ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943

☐ Yes, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/943

Applicable target in 2025

70 %

The CC methodology currently implemented in the SWE CCR has the following relevant features related to 70 %:

1. The SWE RCC has conducted the regional monitoring process since April 2021.
2. CZC recalculations using countertrading began in February 2022.
3. Since 2022, a fallback CNEC has been used to compute the MACZT when the capacity calculation algorithm does not identify a limiting CNEC. This fallback procedure ensures MACZT monitoring for 100 % of the MTUs.

   Since February 2022, the SWE region has applied an amended SWE capacity calculation methodology for the operational DA coordinated capacity calculation process, approved by SWE NRAs in January 2022. This amendment introduced the principles and goals set out in the EU Regulation to meet minimum capacity requirements according to Article 16 of the Electricity Regulation, taking into account the availability of costly remedial actions. When a limiting CNEC does not meet the CEP70 requirement, Red Eléctrica, together with the relevant TSO, implements costly remedial actions (such as countertrading) to increase the MACZT and thus raise capacity to meet the 70 % target.

   In addition, the methodology includes the use of a fallback CNEC, which enables the assessment of CEP70 compliance when the CNEC is not available within the allotted time due to a failure in the regional capacity calculation tool.

   This approach ensures that a limiting CNEC and its corresponding MACZT are identified for 100 % of the hours in both directions of each border.

   These improvements in the SWE CC methodology have resulted in a very high level of compliance. As a result, no derogation or action plan has been requested since January 2023.

Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

☑ Yes

☐ Partially (see explanation)

☐ No (see explanation)

Explanation

The methodology proposed by ACER Recommendation No. 01/2019 is implemented in the SWE CC methodology to calculate the MACZT for each limiting CNEC, per border, direction, and MTU.

Sweden

TSO(s)

Svenska kraftnät

Borders/Region

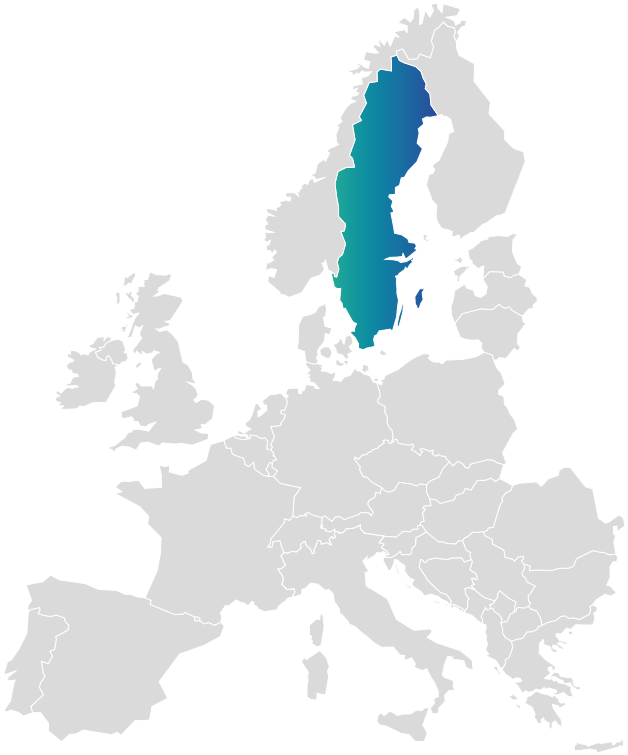
Nordic CCR, DE – SE4, PL – SE4, LT – SE4

Competent regulatory authority

Energimarknadsinspektionen (Ei)

Is any transitional regulation in place?

- ☑ No, minimum trade requirement pursuant to Art. 16 of Regulation (EU) 2019/943 is fully applicable
- ☐ Yes, Member State invoked action plan pursuant to Art. 15 of Regulation (EU) 2019/943 (if applicable, insert URL to governmental action plan)
- ☐ Yes, TSO requested derogation pursuant to Art. 16(9) of Regulation (EU) 2019/943 (if applicable, insert URL to derogation request)



Applicable target in 2025

70 %

Summary of national compliance assessment for 2025 (max. 300 words)

› National regulatory authority Energimarknadsinspektionen (Ei) has not performed a compliance assessment for 2025 and will rely on the ACER methodology.

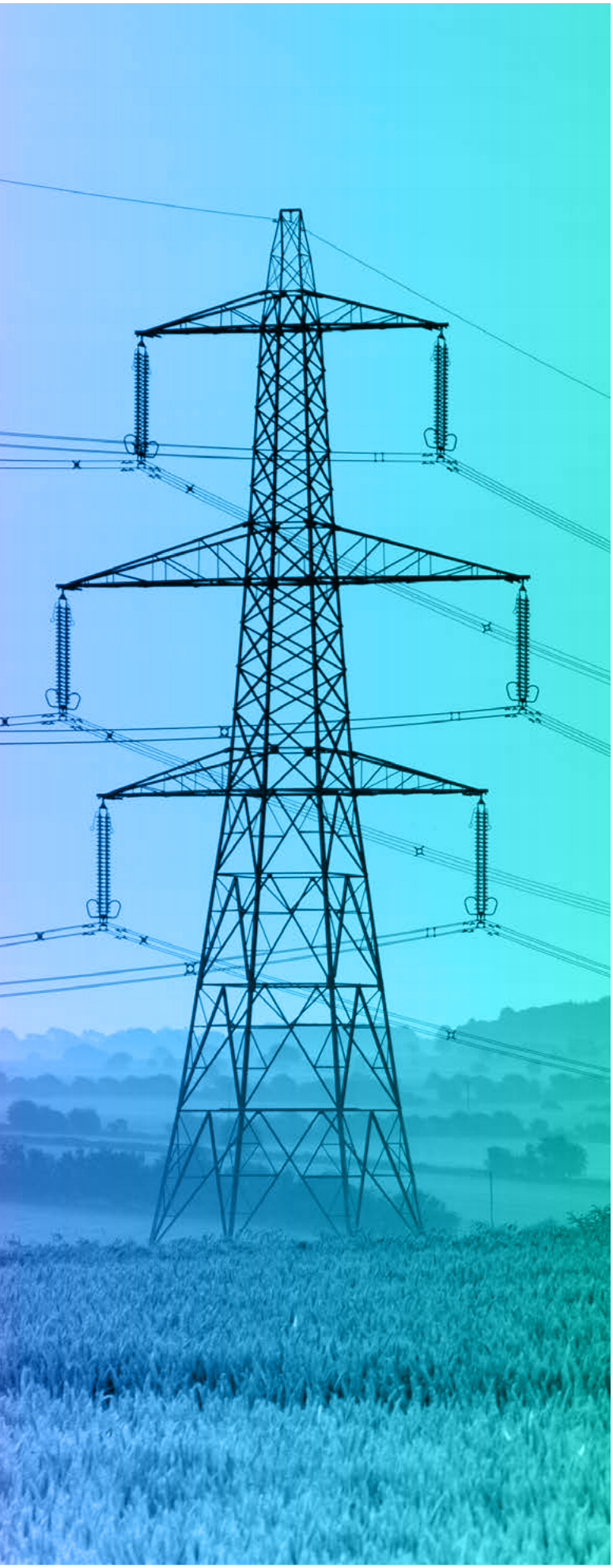
Methodology

Did the competent regulatory authority adopt the non-binding ACER Recommendation No. 01/2019 for its compliance assessment?

- ☑ Yes
- ☐ Partially (see explanation)
- ☐ No (see explanation)

Explanation

Compliance assessment for 2025 is not completed. The Swedish NRA will rely on the ACER methodology.



Annex V – Day Ahead Prices

DA average prices (not volume weighted) in EUR/MWh for the period 1 June 2025 till 1 June 2026.

AT	100.84
BE	82.11
BG	105.14
CZ	98.23
DE	89.53
DK	86.43
EE	81.29
ES	59.61
FI	54.27
FR	56.54
GR	95.19
HR	105.29
HU	109.68
IT	116.7
LT	89.97
LV	89.38
NL	87.54
NO	60.49
PL	106.26
PT	59.3
RO	107.35
SE	48.51
SI	104.69
SK	101.97

DA price distribution per country in EUR/MWh for the period 1 June 2025 till 1 June 2026

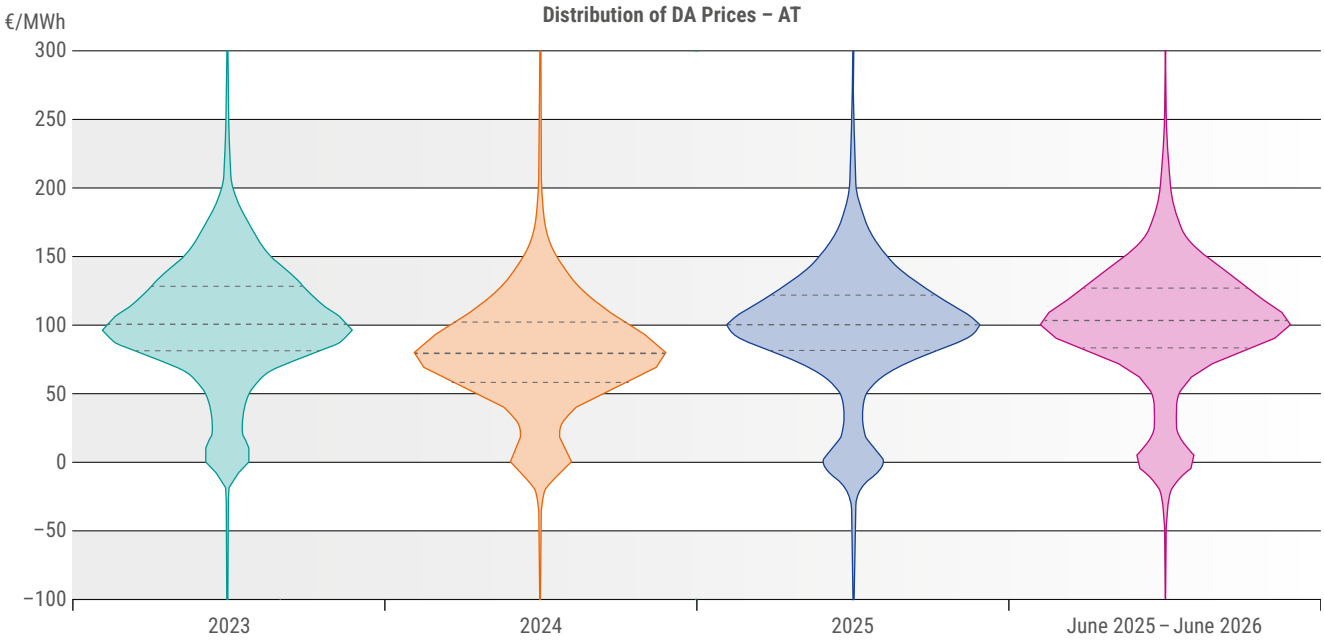


Figure AV.1: Price Distribution for 2023 – 2026 (AT)

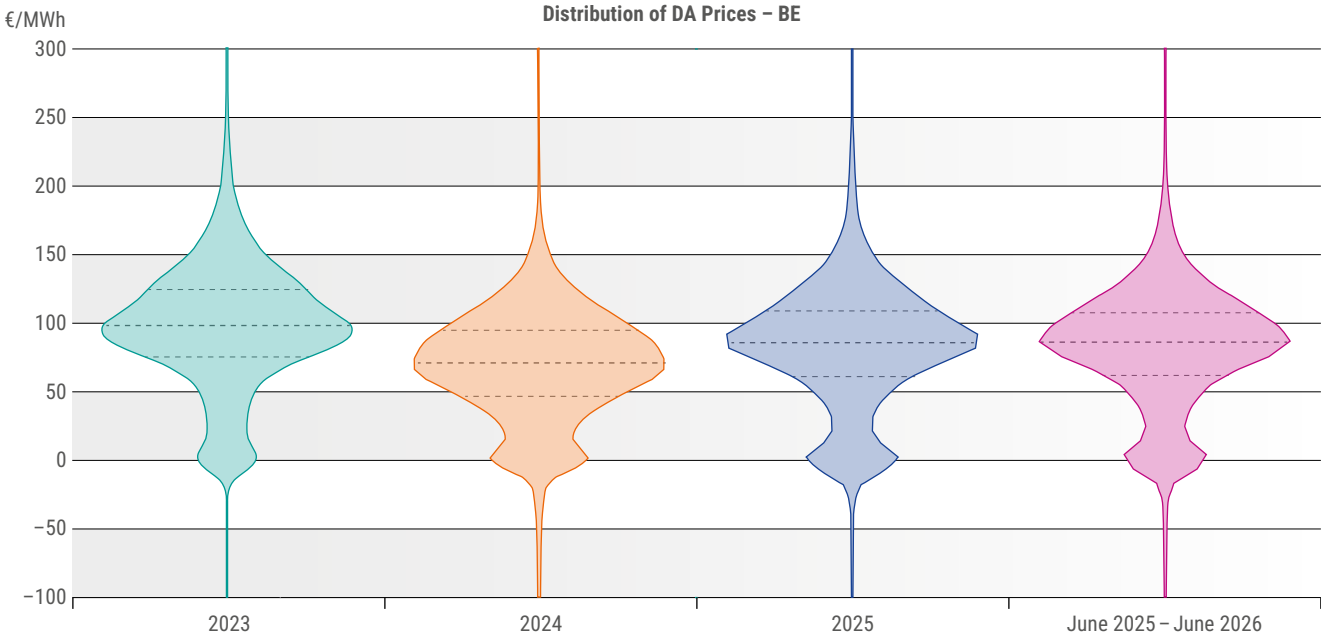


Figure AV.2: Price Distribution for 2023 – 2026 (BE)

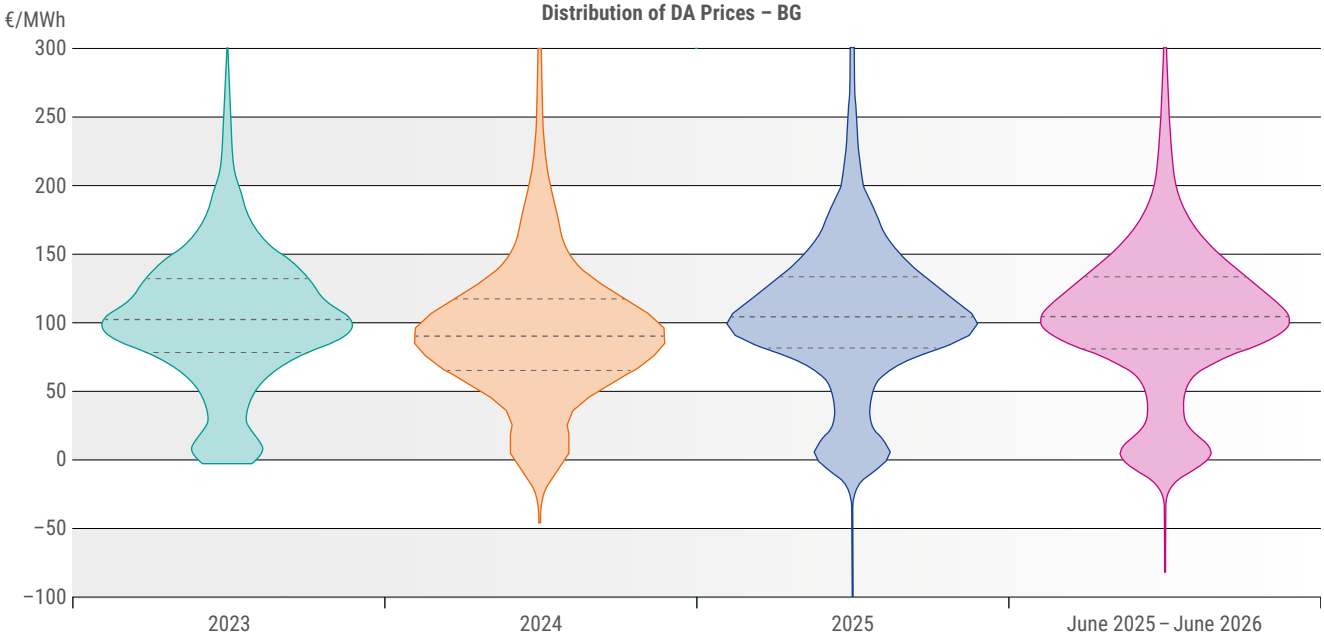


Figure AV.3: Price Distribution for 2023 – 2026 (BG)

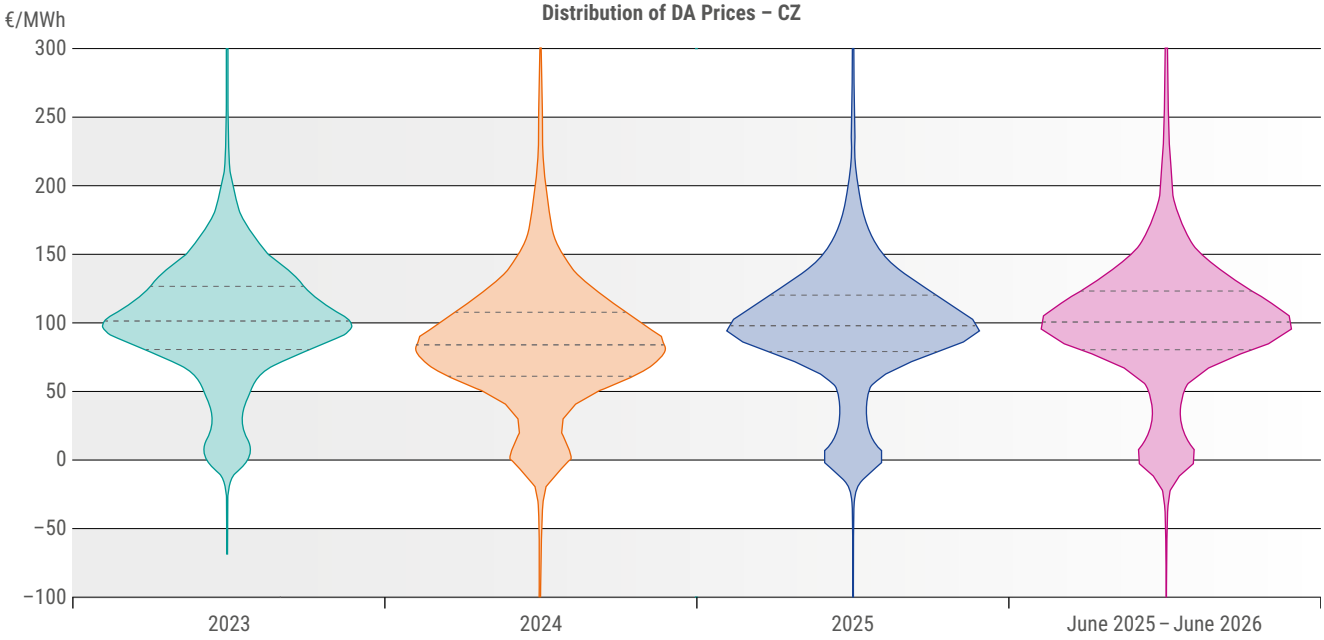


Figure AV.4: Price Distribution for 2023 – 2026 (CZ)

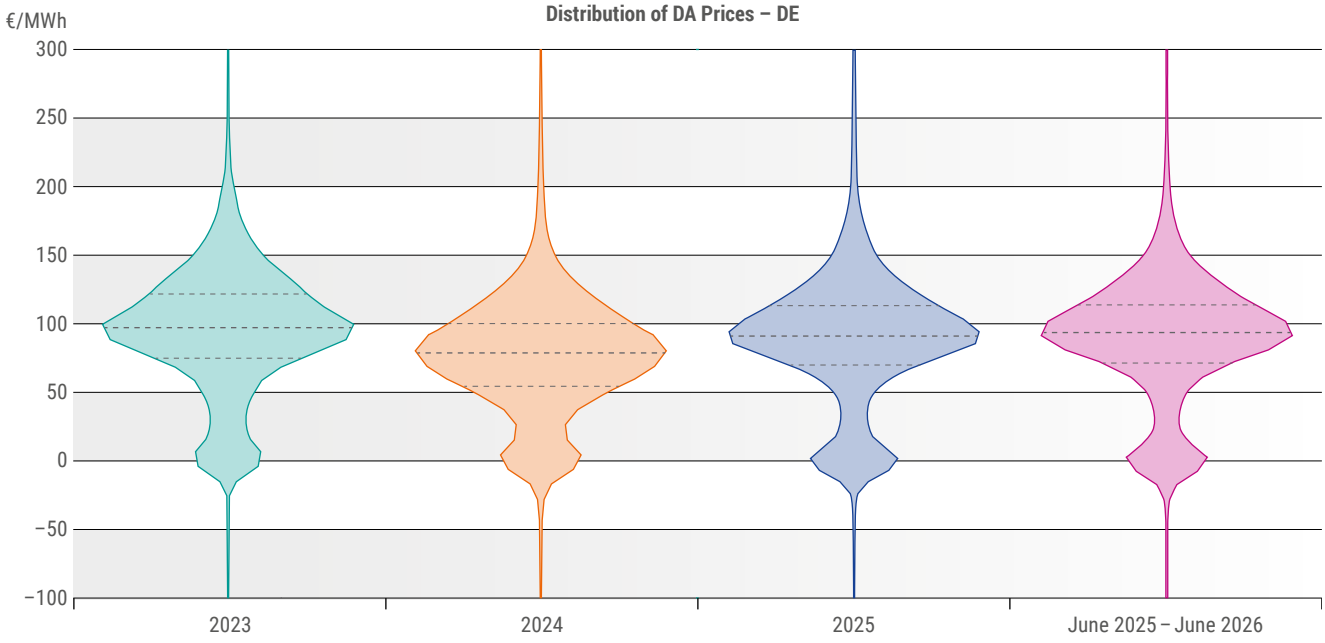


Figure AV.5: Price Distribution for 2023 – 2026 (DE)

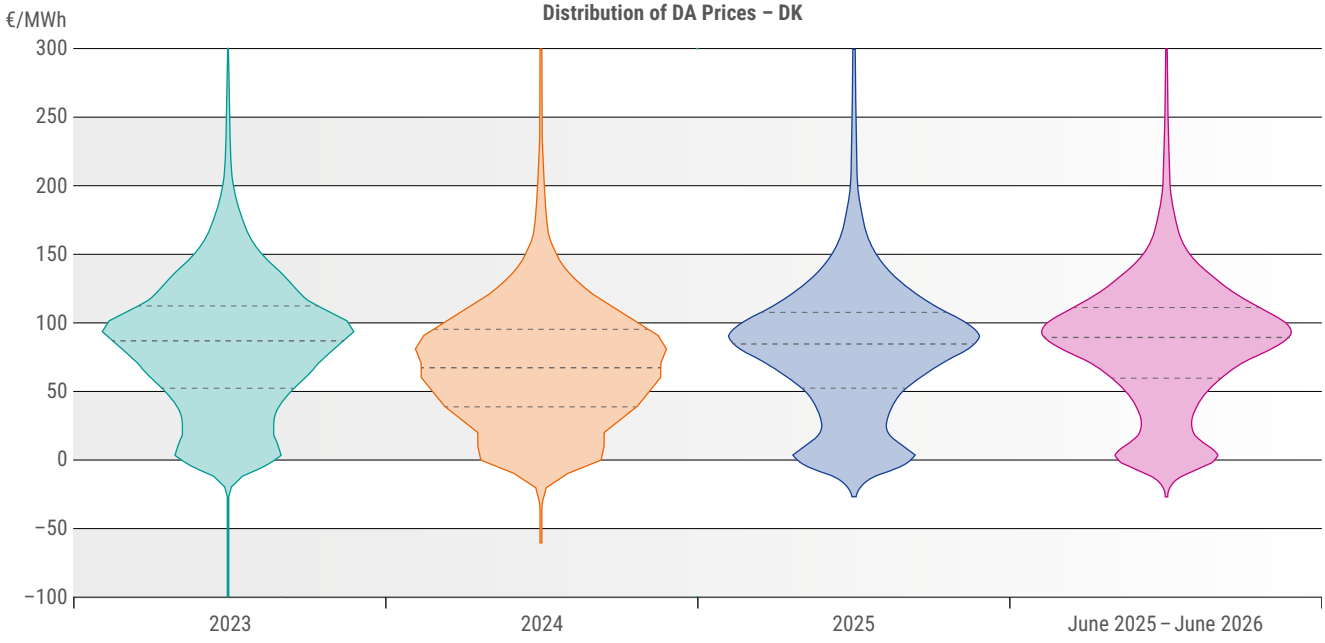


Figure AV.6: Price Distribution for 2023 – 2026 (DK)

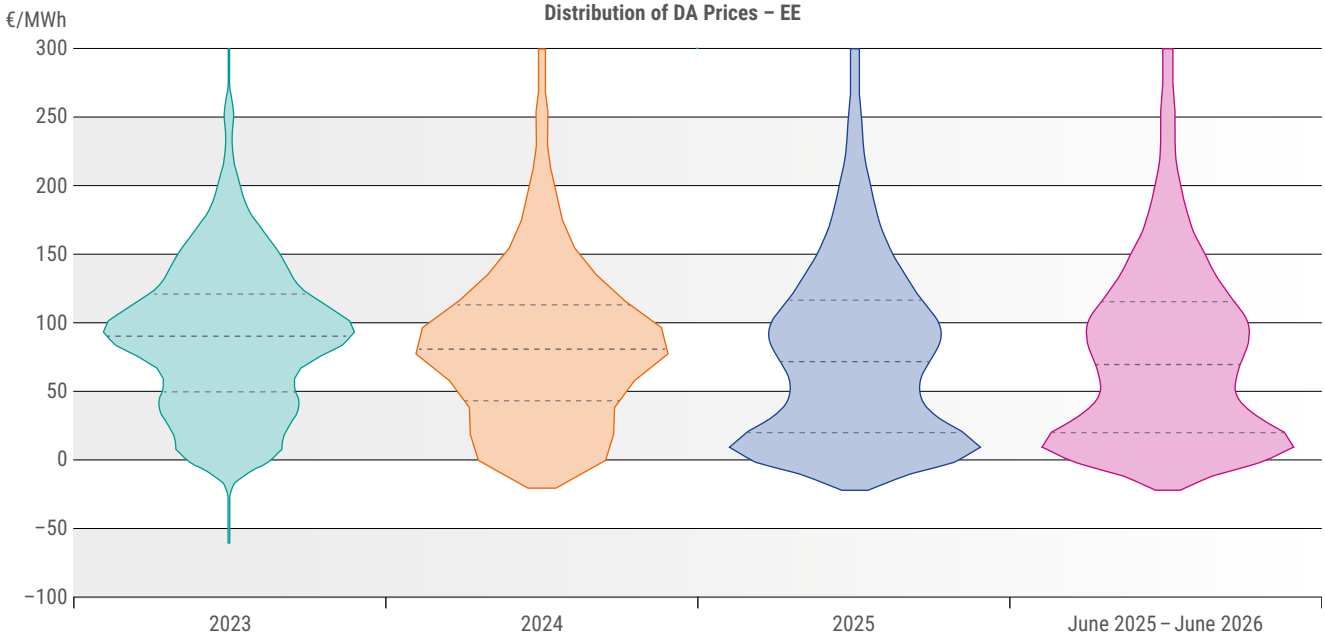


Figure AV.7: Price Distribution for 2023 – 2026 (EE)

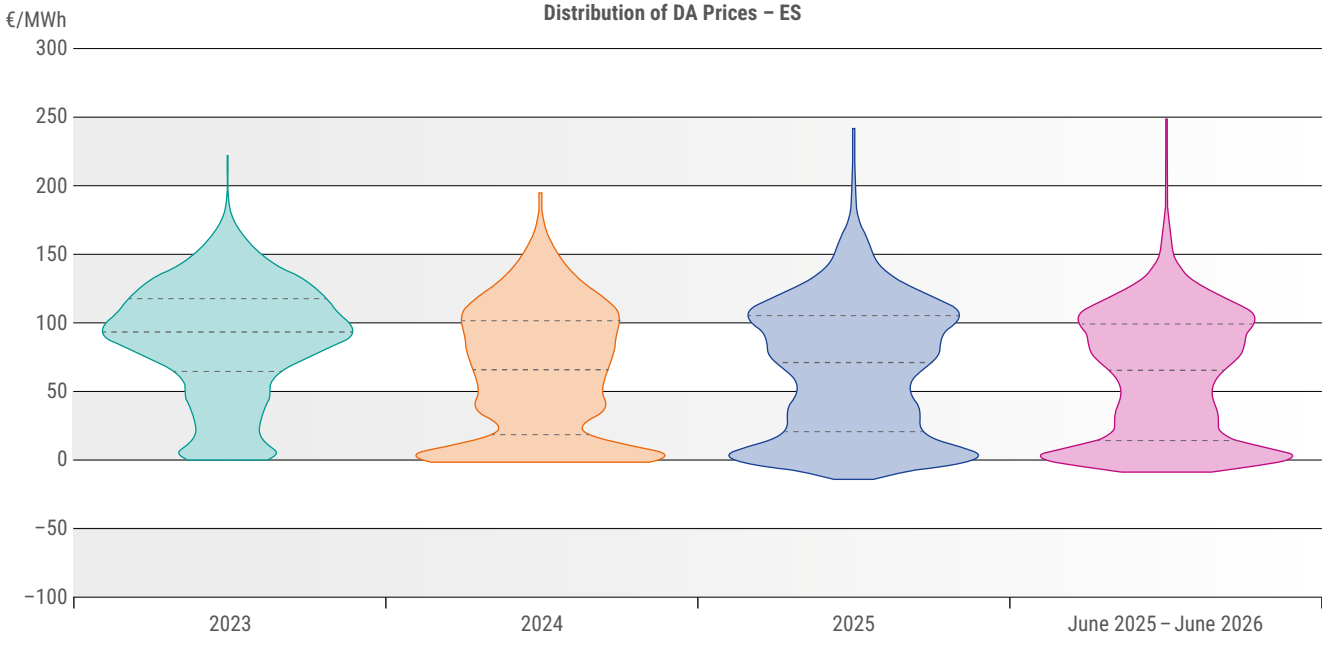


Figure AV.8: Price Distribution for 2023 – 2026 (ES)

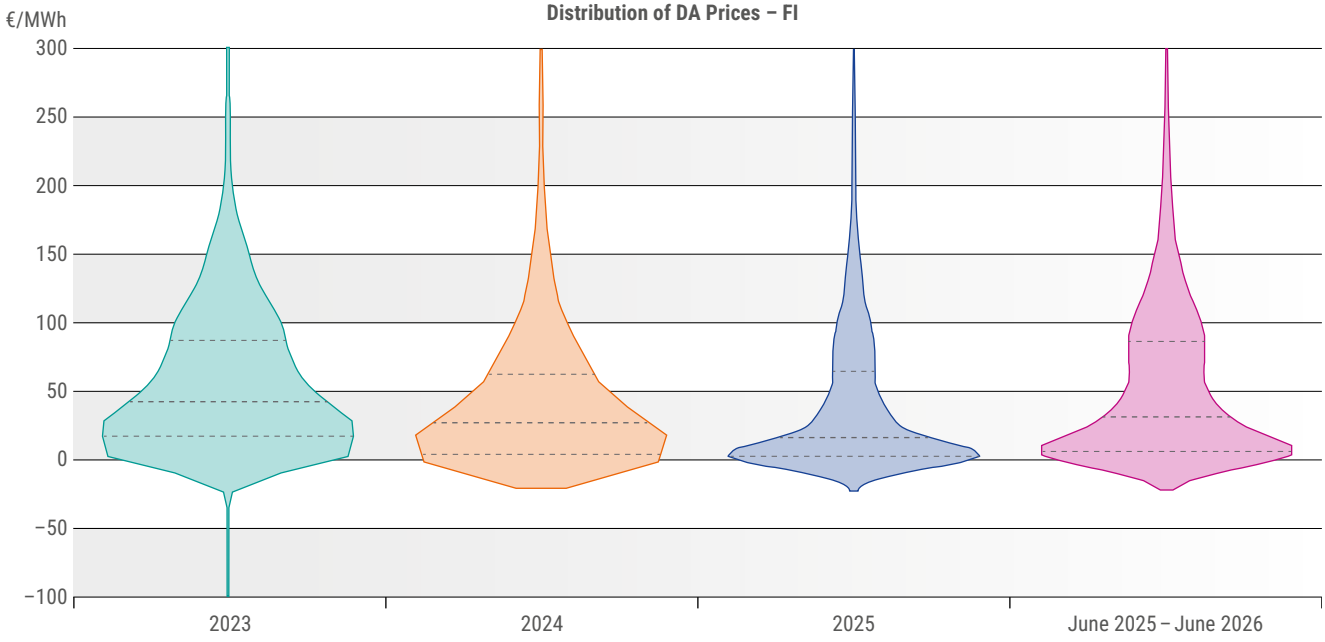


Figure AV.9: Price Distribution for 2023 – 2026 (FI)

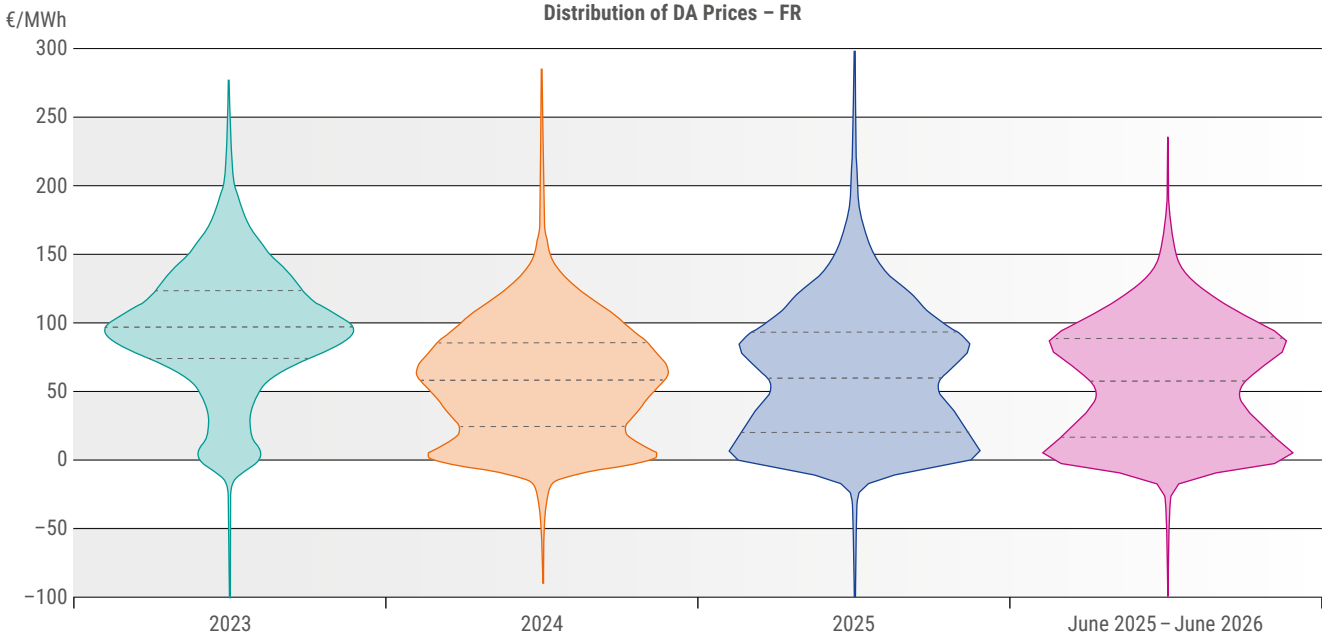


Figure AV.10: Price Distribution for 2023 – 2026 (FR)

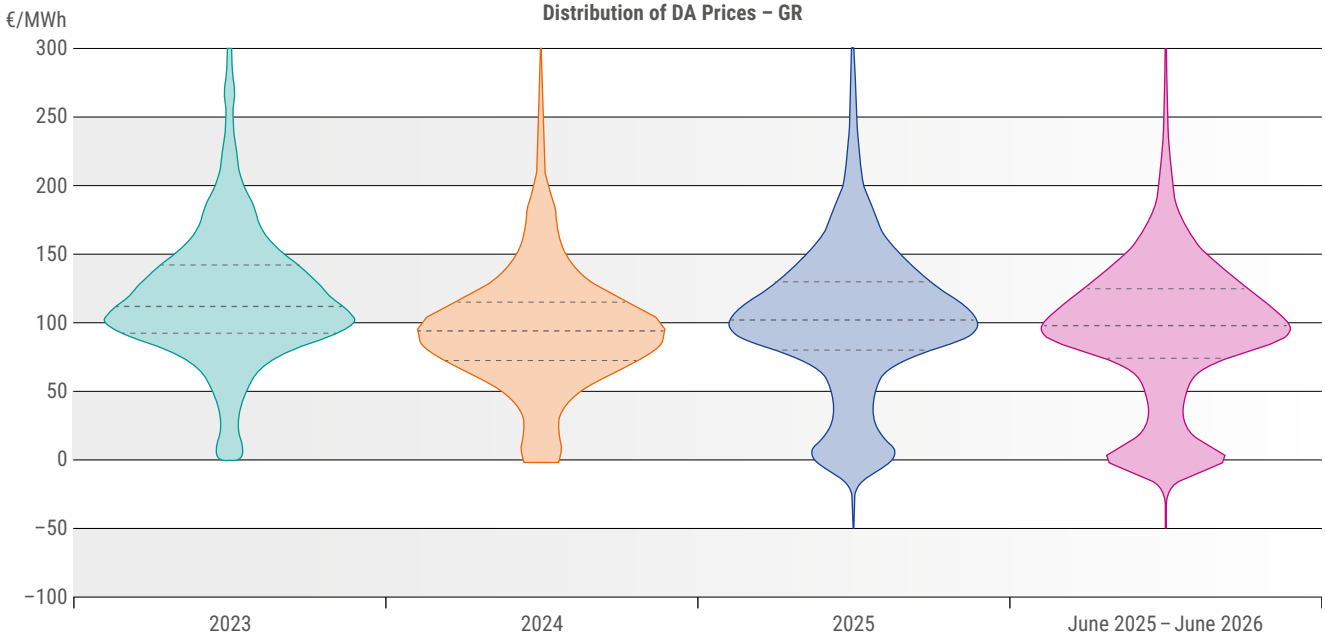


Figure AV.11: Price Distribution for 2023 – 2026 (GR)

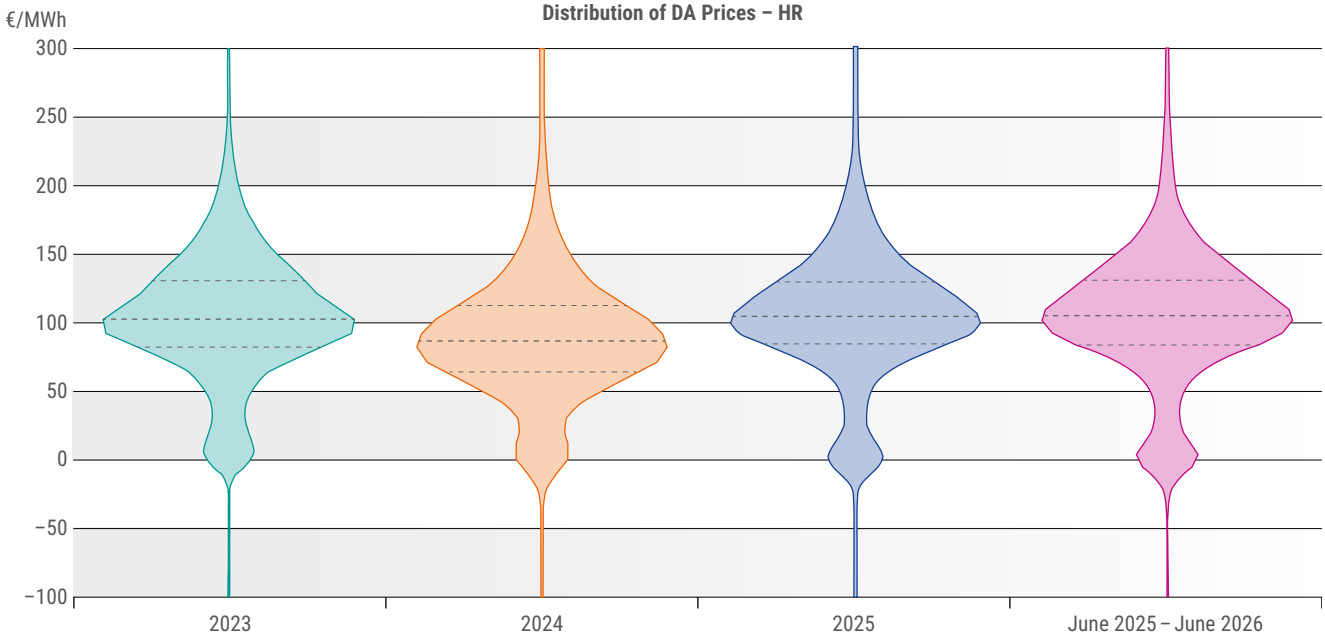


Figure AV.12: Price Distribution for 2023 – 2026 (HR)

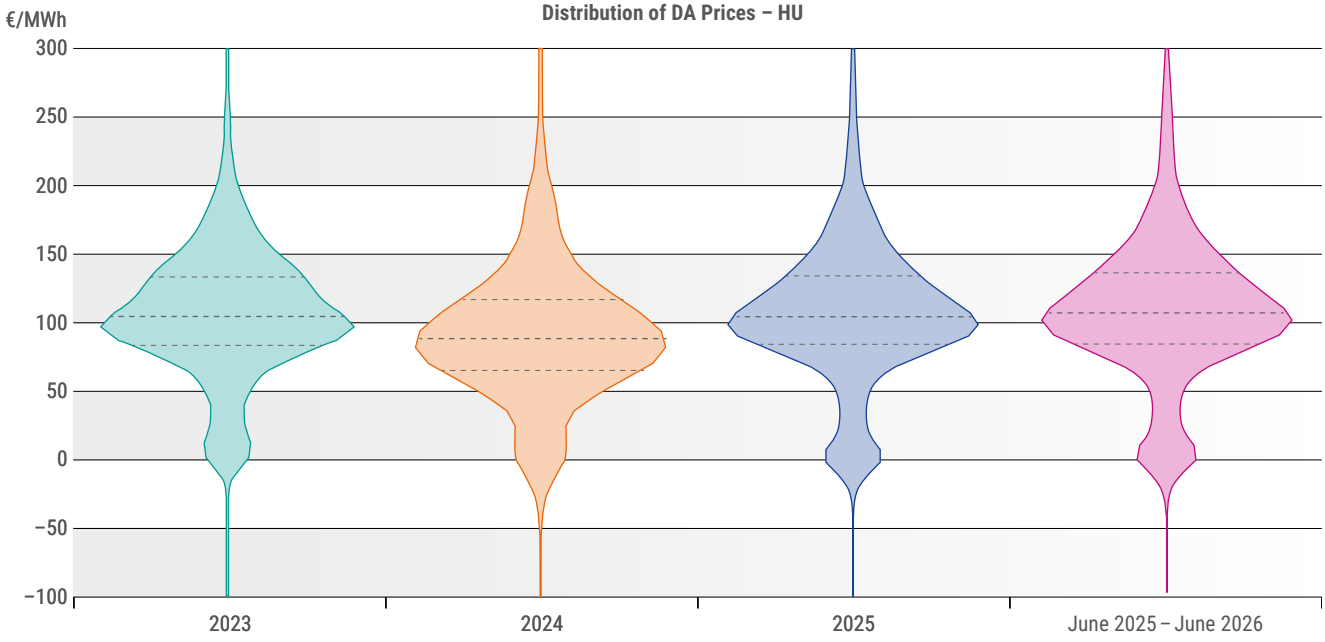


Figure AV.13: Price Distribution for 2023 – 2026 (HU)

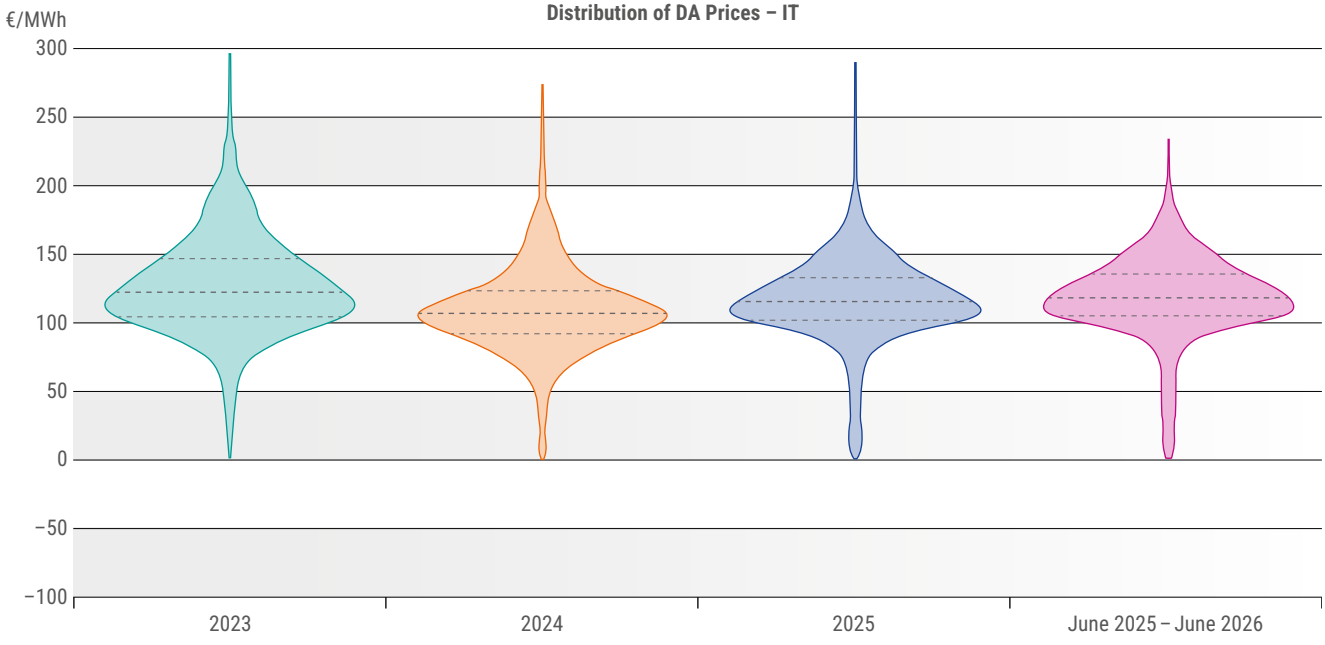


Figure AV.14: Price Distribution for 2023 – 2026 (IT)

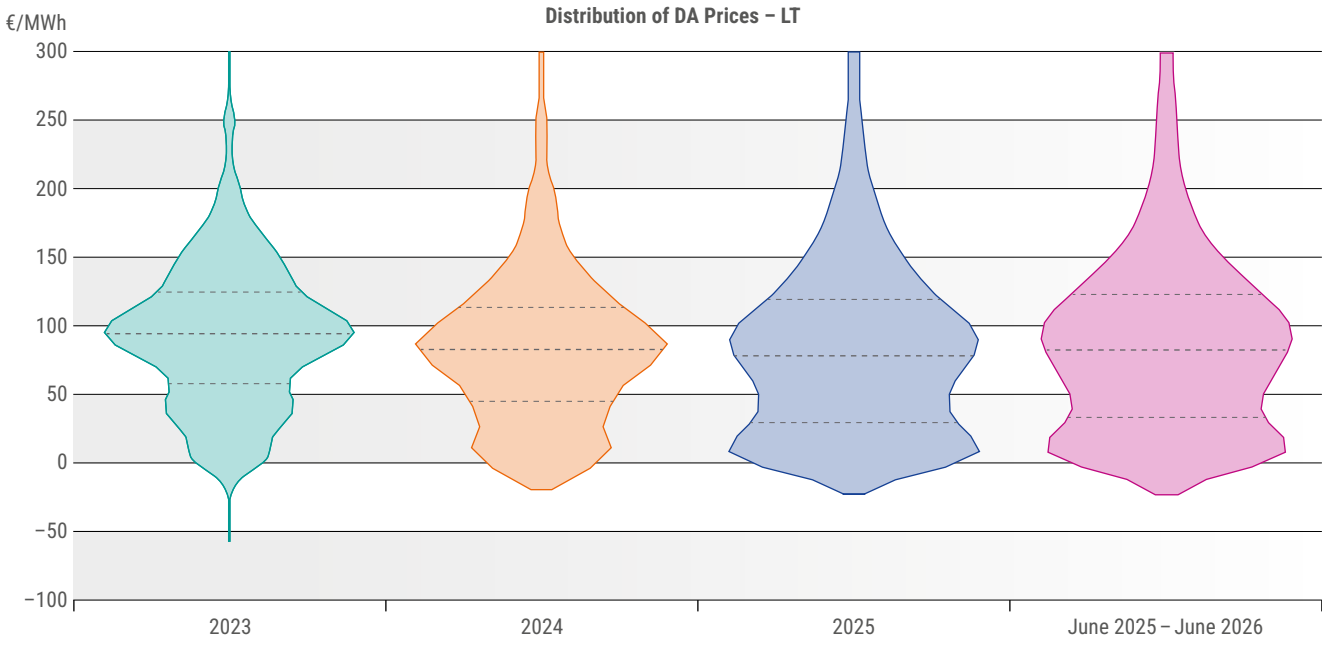


Figure AV.15: Price Distribution for 2023 – 2026 (LT)

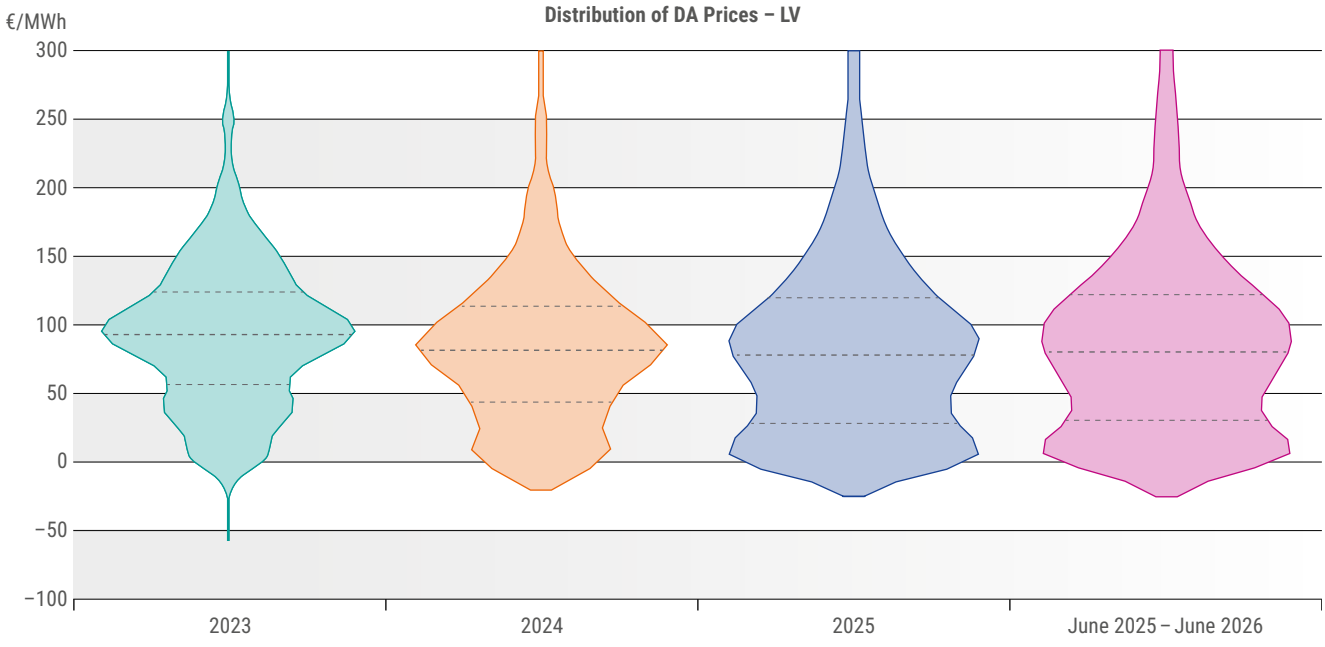


Figure AV.16: Price Distribution for 2023 – 2026 (LV)

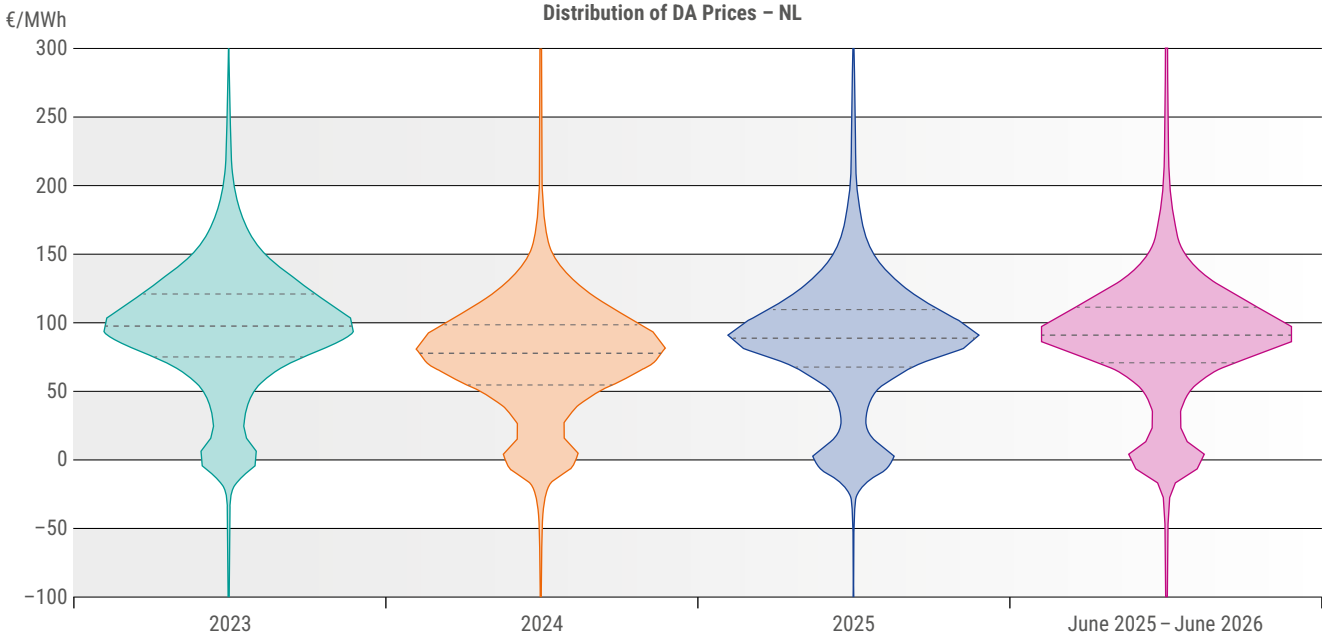


Figure AV.17: Price Distribution for 2023 – 2026 (NL)

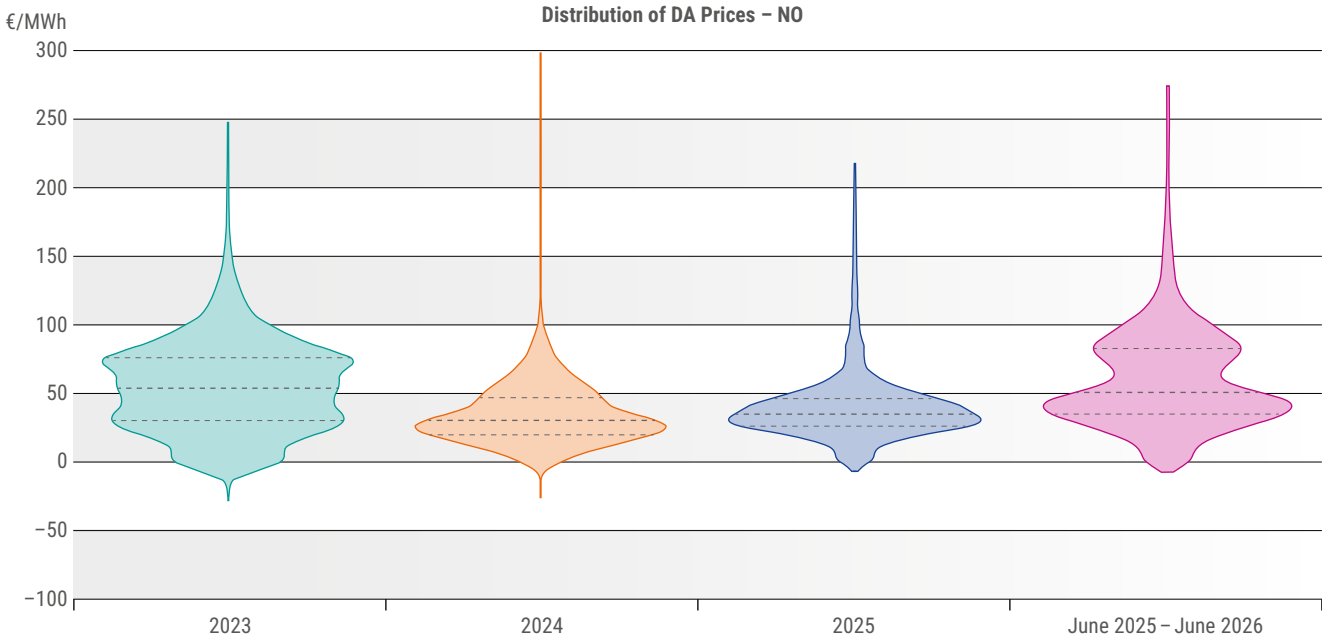


Figure AV.18: Price Distribution for 2023 – 2026 (NO)

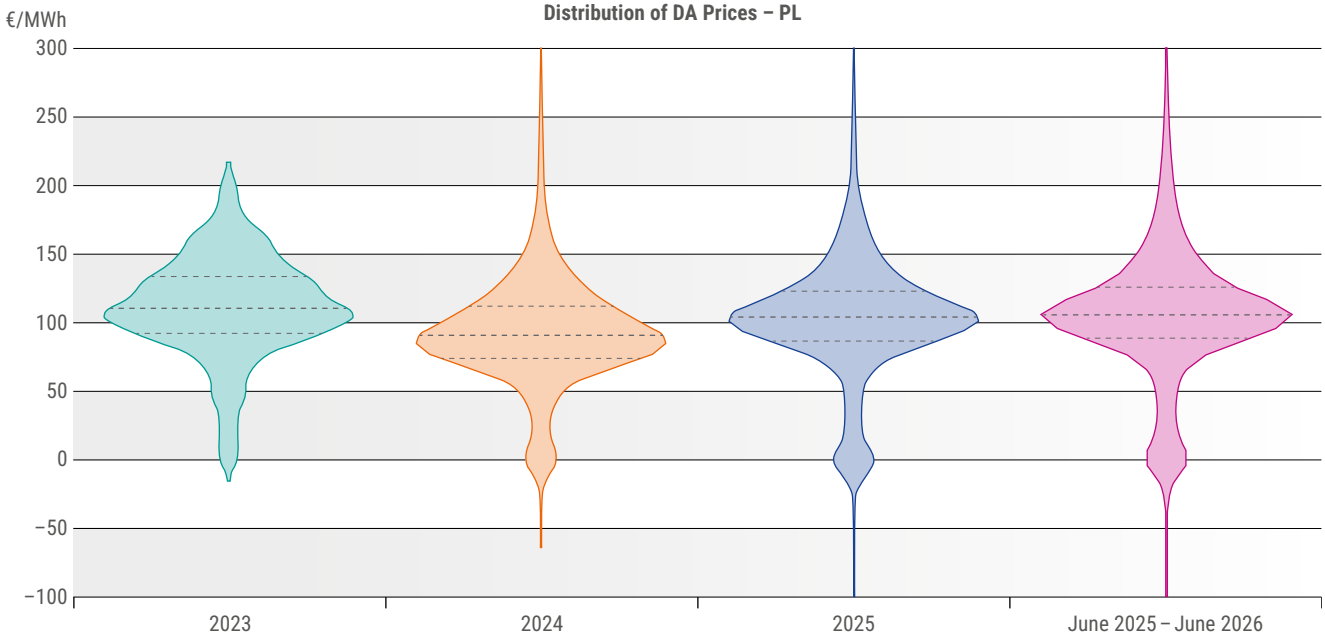


Figure AV.19: Price Distribution for 2023 – 2026 (PL)

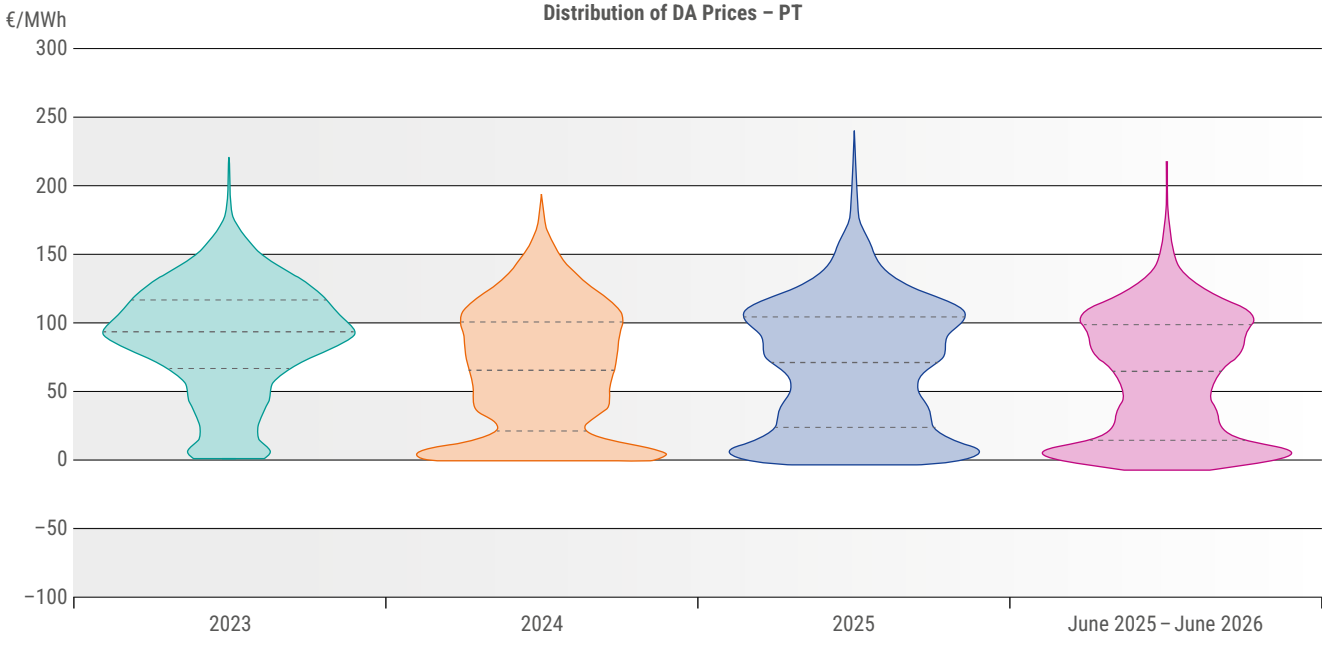


Figure AV.20: Price Distribution for 2023 – 2026 (PT)

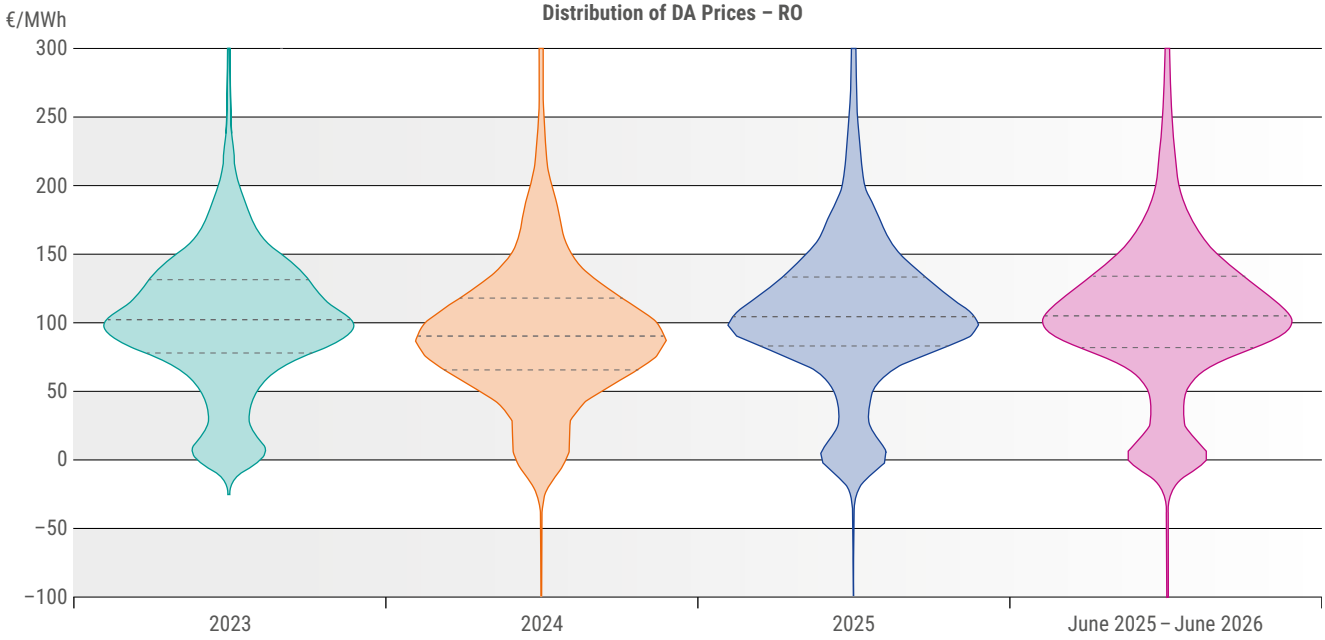


Figure AV.21: Price Distribution for 2023 – 2026 (RO)

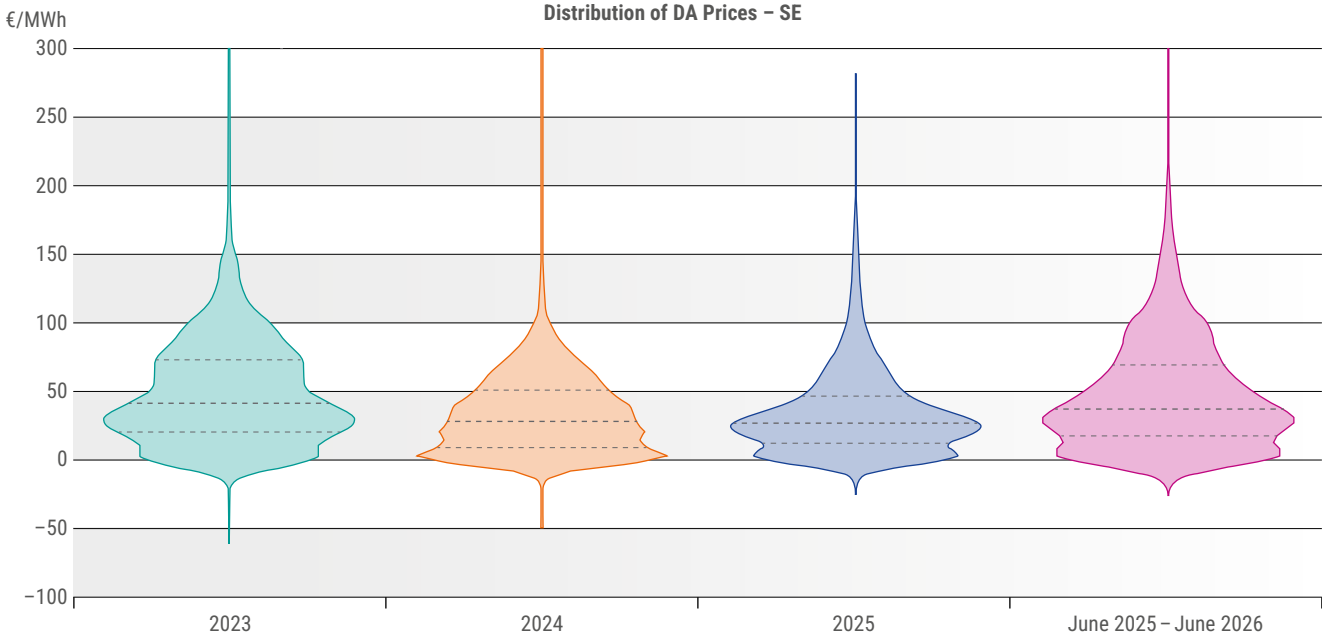


Figure AV.22: Price Distribution for 2023 – 2026 (SE)

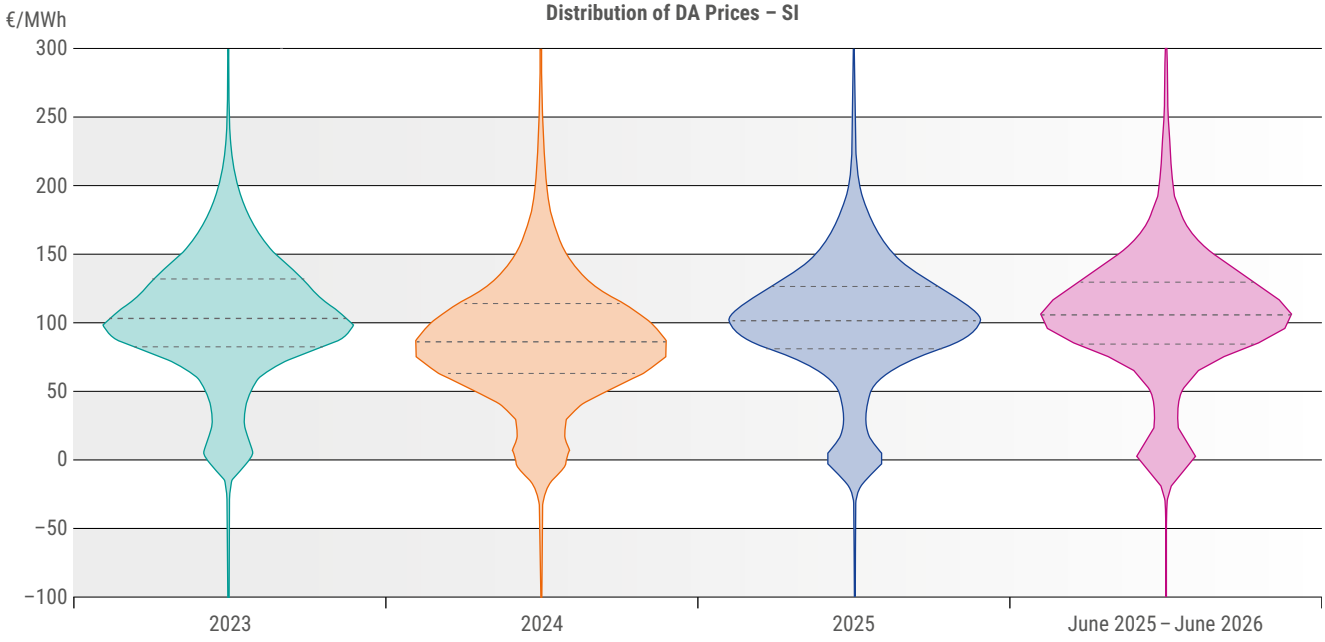


Figure AV.23: Price Distribution for 2023 – 2026 (SI)

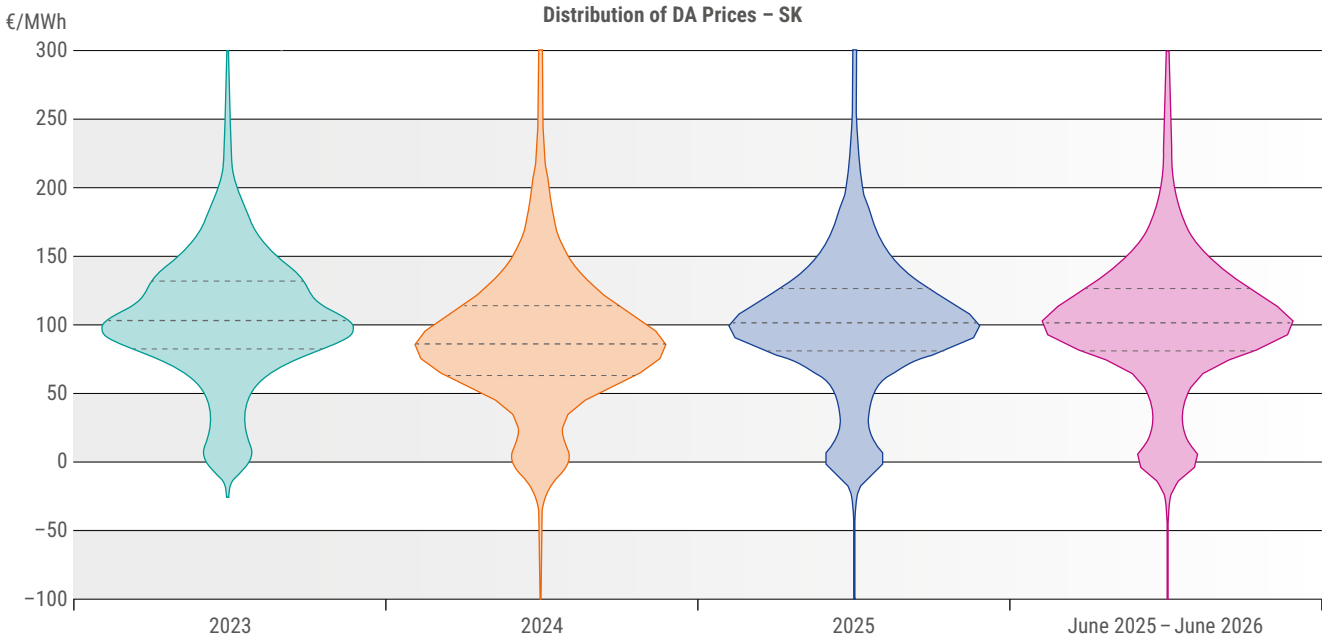


Figure AV.24: Price Distribution for 2023 – 2026 (SK)

Annex VI – Glossary

4M MC	4M Market Coupling between the Czech Republic, Slovakia, Hungary, Romania
50Hertz	50Hertz Transmission GmbH (1 out of 4 German TSOs)
ACER	Agency for the Cooperation of Energy Regulators
aFRR	Frequency Restoration Reserves with Automatic Activation
AHC	Advanced Hybrid Coupling
AL	Albania
Amprion	Amprion GmbH (1 out of 4 German TSOs)
ANDOA	All NEMOs Day-Ahead Operational Agreement
ANIDOA	All NEMOs Intraday Operational Agreement
AOF	Activation Optimisation Function
APG	Austrian Power Grid AG (Austrian TSO)
AST	AS Augstsprieguma tikls (Latvian TSO)
AT	Austria
ATC	Available Transfer Capacity
BA	Bosnia and Herzegovina
BC	Balancing Capacity
BCC	Balancing Capacity Cooperation
BE	Belgium
BEPP	Balancing Energy Pricing Periods
BG	Bulgaria
BRP	Balance Responsible Party
BSP	Balancing Service Provider
BZB	Bidding Zone Border
BZR	Bidding Zone Review
BZRR	Bidding Zone Review Region
CA	Cooperation Agreement
CACM	Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management
CBMP	Cross Border Marginal Price
CCM	Capacity Calculation Methodology
CCR	Capacity Calculation Region
CEE	Central Eastern Europe
CGES	Crnogorski Elektroprenosni Sistem AD (Montenegrin TSO)
CGM	Common Grid Model
CGMM	Common Grid Model Methodology
CH	Switzerland
CID	Congestion Income Distribution
CMM	Capacity Management Module
CMOL	Common Merit Order List
CNE	Critical Network Element
CNEC	Critical Network Element and Contingency
cNTC	Coordinated Net Transfer Capacity
CWE	Central Western Europe
CZ	Czech Republic
CZC	Cross-Zonal Capacity

DAOA	Day-Ahead Operational Agreement
DC	Direct Current
DE	Germany
DK	Denmark
EB	Commission Regulation (EU) 2017/2195 of 23 November establishing a guideline on electricity balancing
EE	Estonia
ELIA	Elia System Operator SA (Belgian TSO)
EMIR	Regulation (EU) No 648/2012 of the European Parliament and of the Council of 4 July 2012 on OTC derivatives, central counterparties and trade repositories (European Market Infrastructure Regulation)
EMD	Electricity Market Design
EMS	Joint Stock Company Elektromreža Srbije (Serbian TSO)
ENTSO-E	European Network of Transmission System Operators for Electricity
ES	Spain
ESO	Electroenergien Sistemen Operator EAD (Bulgarian TSO)
EU	European Union
EUPHEMIA	Pan-European Hybrid Electricity Market Integration Algorithm
FAT	Full Activation Time
FB	Flow-Based
FBMC	Flow-Based Market Coupling
FCA	Forward Capacity Allocation
FCR	Frequency Containment Reserve
FI	Finland
FR	France
FRR	Frequency Restoration Reserves
FTR	Financial Transmission Right
GB	Great Britain
GCT	Gate Closure Time
GL	Guideline
GOT	Gate Opening Time
GR	Greece
HAR	Harmonised Allocation Rules
HOPS	Croatian Transmission System Operator Plc. (Croation TSO)
HR	Croatia
HU	Hungary
HVDC	High-Voltage Direct Current
IBWT	Italian Working Table
IDA	Intraday Auction
IDCC	Intraday capacity calculation
IDOA	Intraday Operational Agreement
IDSC	Intraday Steering Committee
IE	Ireland
IFA	Interconnexion France-Angleterre
IGCC	International Grid Control Cooperation
IGM	Individual Grid Model
IN	Imbalance Netting

IPTO	Independent Power Transmission Operator S.A. (Hellenic TSO)
ISP	Imbalance Settlement Period
IT	Italy
JAO	Joint Allocation Office
KPI	Key Performance Indicator
LFC area	Load-Frequency Control area
LIP	Local Implementation Project
LMP	Locational Marginal Pricing
LTA	Long Term Allocation
LTTR	Long-Term Transmission Rights
LU	Luxembourg
MACZT	Margin Available for Cross-Zonal Electricity Trade
MARI	Manually Activated Reserves Initiative
MAVIR	Magyar Villamosenergia-ipari Átviteli Rendszerirányító Zártkörűen Működő Részvénytársaság (Hungarian TSO)
MC	Market Coupling
MCCC	Multilateral Coordinated Capacity Calculation
MNCC	Multilateral Non-Coordinated Capacity Calculation
MCO	Market Coupling Operator
ME	Montenegro
MEMO	Electricity Market Operator of North Macedonia
MEPSO	Macedonian Transmission System Operator AD (Macedonian TSO)
mFRR	Frequency Restoration Reserves with Manual Activation
MifiD II	Directive 2014/65/EU of the European Parliament and of the Council of 15 May 2014 on markets in financial instruments and amending Directive 2002/92/EC and Directive 2011/61/EU (recast) (Markets in Financial Instruments Directive II)
MiFIR	Regulation (EU) No 600/2014 of the European Parliament and of the Council of 15 May 2014 on markets in financial instruments and amending Regulation (EU) No 648/2012 (Markets in Financial Instruments Regulation)
MNA	Multiple NEMOs Arrangement
MRC	Multi Regional Coupling
MTU	Market Time Unit
NTC	Net Transfer Capacity
NDA	Non-Disclosure Agreement
NEMO	Nominated Electricity Market Operator
NL	Netherlands
NO	Norway
NOS BiH	Nezavisni Operator Sustava u Bosni i Hercegovini (Bosnian and Herzegovinian TSO)
NRA	National Regulatory Authority
OPSCOM	Operations Committee
OST	OST sh.a – Albanian Transmission System Operator (Albanian TSO)
PCR	Price Coupling of Regions
PICASSO	Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation
PL	Poland
PMB	PCR Matcher and Broker IT system
PSE	Polskie Sieci Elektroenergetyczne (Polish TSO)
PST	Phase Shifting Transformer

PT	Portugal
PTDF	Power Transfer Distribution Factor
PTR	Physical Transmission Right
QARM	Quality Assurance and Release Management
R&D	Research and Development
RA	Regulatory Authorities
RCC	Regional Coordination Centre
REE	Red Eléctrica de España S.A.U. (Spanish TSO)
REN	Rede Eléctrica Nacional, S.A. (Portuguese TSO)
RGCE	Regional Group Continental Europe
RO	Romania
RR	Replacement Reserves
RS	Serbia
RTE	Réseau de Transport d'Electricité (French TSO)
SA	Synchronous Area
SAFA	Synchronous Area Framework Agreement
SAP	Single Allocation Platform
SAP CA	Single Allocation Platform Cooperation Agreement
SDAC	Single Day-Ahead Coupling
SE	Sweden
SEE	South-East Europe
SEPS	Slovenská elektrizačná prenosová sústava, a.s. (Slovakian TSO)
SI	Slovenia
SIDC	Single Intraday Coupling
SK	Slovakia
SM	Shipping Module
SOB	Shared Order Book
SONI	System Operator for Northern Ireland Ltd. (Northern Irish TSO)
Statnett	Statnett SF (Norwegian TSO)
Svenska	Svenska kraftnät (Swedish TSO)
SWE	South-Western Europe
Swissgrid	Swissgrid ag (Swiss TSO)
TCDA	TSO Cooperation Operational Agreement
TCID	TSO Cooperation Agreement for Single Intraday Coupling
TCM	Terms, Conditions and/or Methodologies
TCOA	TSO Cooperation Agreement for Day-Ahead Coupling
TenneT DE	TenneT TSO GmbH (1 out of 4 German TSOs)
TenneT NL	TenneT TSO BV (Dutch TSO)
Terna	Rete Elettrica Nazionale SpA (Italian TSO)
TERRE	Trans-European Restoration Reserves Exchange
Transelectrica	National Power Grid Company Transelectrica S.A. (Romanian TSO)
TransnetBW	TransnetBW GmbH (1 out of 4 German TSOs)
TSO	Transmission System Operator
VWAP	Volume Weighted Average Price
XBID	Cross-Border Intraday Project

The terms used in this document have the meaning of the definitions included in Article 2 of the CACM, FCA and EB Regulations.

Annex VII – List of Figures

Annex VIII – List of Tables

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