ACER

European Union Agency for the Cooperation of Energy Regulators

Transmission capacities for cross-zonal trade of electricity and congestion management in the EU

2025 Monitoring Report

5 September 2025

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Executive summary

€580 m

Estimated welfare gains, had TSOs in the Core region made available 70% of capacity for cross-zonal trade in 2024

147

Severe price spikes potentially avoided in South-East Europe in summer 2024, if 70 % of capacity had been offered

54 %

Average margin of physical capacity made available on the most congested lines in the Core region in 2024

€4.3 bn

Cost of managing grid congestion in the EU in 2024 (amounting to 60 TWh, comparable to Austria's power demand)

1 Europe's electricity system is at a turning point. To speed up decarbonisation and further reduce its dependence on imported fossil fuels, it will need to accommodate vast amounts of renewable energy generation in the coming years. In doing so, it must ensure that prices remain affordable and electricity supply remains secure. This calls for a European electricity market that is more integrated, flexible and coordinated across borders.

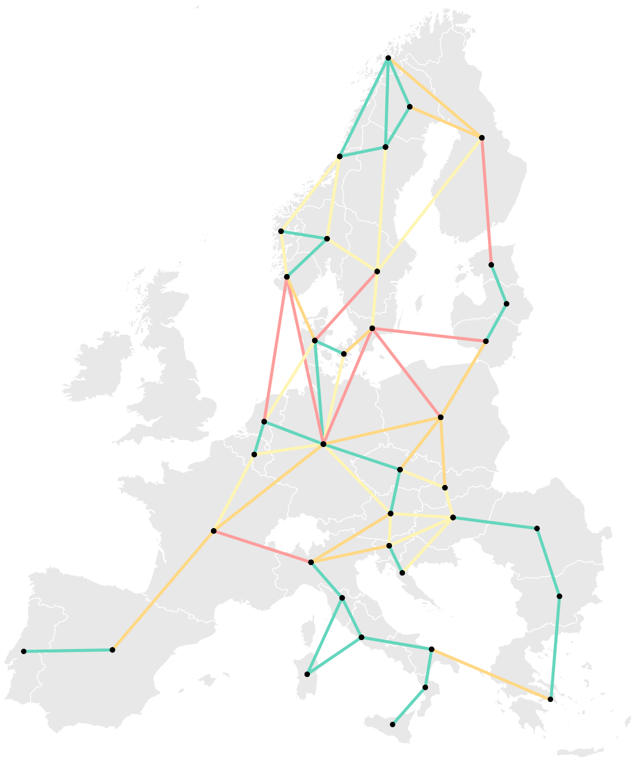
2 A highly integrated electricity market guarantees the efficient use of available resources in the EU. It facilitates the growth of renewable generation and cushions both households and industry from price volatility. In recent years, the EU has made significant strides towards deeper market integration. The finalisation of market coupling and the expansion of flow-based to the Core and Nordic regions are two notable examples. Still, persistent price differences across the EU signal that there is value in further integrating markets.

The 70% requirement is the main regulatory tool to boost cross-zonal trade

3 EU law requires transmission system operators (TSOs) to offer at least 70% of their physical capacity on all lines of relevance for cross-zonal trade. This requirement is intended to maximise cross-zonal trade and mitigate its discrimination over internal trade. This ACER report examines the role of cross-zonal electricity trade in shaping a more integrated and efficient EU electricity market, and tracks progress, challenges and benefits in the implementation of the 70% requirement.

Significant market bottlenecks remain across the EU.

Average price difference per bidding zone border in single day-ahead coupling – 2024 (EUR/MWh)

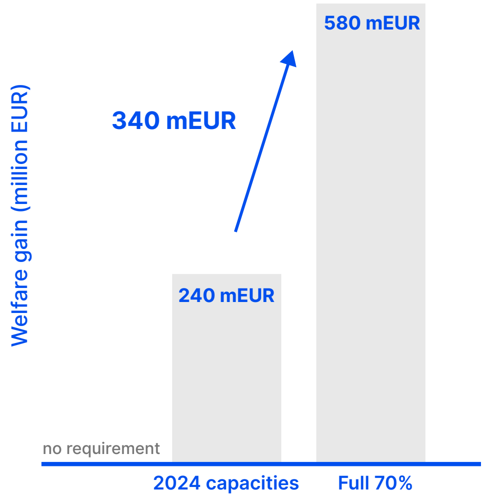


Source: ACER calculation based on ENTSO-E TP data.

Maximising cross-zonal capacity dampens electricity prices and delivers efficiency gains

Greater levels of cross-zonal capacity unlock more efficient market functioning.

Comparison of economic surplus of single day-ahead coupling under different capacity scenarios in the Core region – 2024 (million EUR)



Note: Further details on the scenarios simulated by ACER are presented in the main body of this report.

4 The value of cross-zonal trade becomes more evident when the system is under pressure. During the summer of 2024, South-East Europe experienced a sustained period of price spikes in the evening hours. Higher availability of cross-zonal capacities in central Europe would have mitigated both the frequency and the severity of these high-price events, revealing the effectiveness of cross-zonal trade as a provider of flexibility to the system. Indeed, meeting the 70% requirement would have prevented approximately half of the most severe price spikes.

5 More broadly, ACER estimated the impact on market functioning of the implementation of the 70 % requirement. In 2024 alone, meeting 70 % in the Core region would have provided at least EUR 580 million in additional economic welfare. Instead, the partial implementation of the 70 % requirement realised only 40 % of this gain. Notably, EU consumers would benefit the most, through lower electricity prices and reduced volatility. This underlines the need for a swift implementation of the requirement.

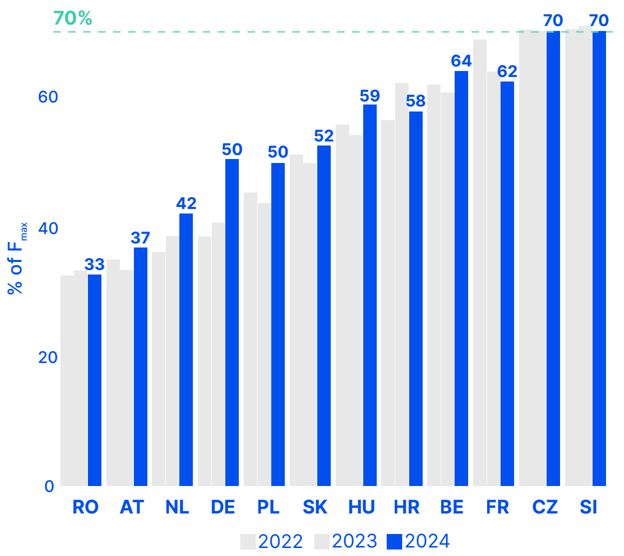
Challenges remain in implementing the 70% requirement

6 To fulfil the 70% requirement without endangering system security, EU Member States could opt for a transitional period to address structural congestion in the power grid while gradually implementing the requirement until the end of 2025. In the years since the introduction of the requirement, notable improvements have been recorded across the EU. For example, in 2022 the implementation of Core flow-based market coupling led to the minimum capacity requirements being enforced in the capacity calculation process for most of continental Europe, with two of its Member States being generally able to uphold the 70% requirement since then.

7 However, delays in introducing key operational processes have hindered progress in some Member States, risking the end-2025 deadline. In the Core region, the lack of a regional congestion management and cost-sharing framework prevents the long-standing issue of loop flows from being adequately resolved[1]. This results in multiple TSOs requiring derogations from the capacity requirements every year and in average margins of capacity of 54% on the most congested lines.

Applicable derogations limit progress in implementing the minimum 70% requirement in the Core region.

Average minimum hourly margin available for cross-zonal trade in the Core capacity calculation region per Member State, considering flows induced by third-country exchanges – 2022-2024 (% of F_{max})



Source: ACER calculation based on TSO data.

1 Loop flows correspond to the impact of internal exchanges within one bidding zone on the grid of neighbouring bidding zones.

8 While the day-ahead electricity market remains the most relevant in the EU, intraday trading is becoming increasingly important. The effective integration of the growing renewable energy share and non-fossil flexibility requires significant close-to-real-time adjustments. Therefore, the maximisation of cross-zonal capacities for intraday trade will warrant further attention going forward.

9 However, respecting the 70% requirement in the intraday time frame, wherever remedial actions would be needed, is technically challenging. After intraday trading, TSOs have less time to identify and trigger remedial actions[2] to address congestion. Despite this, it is important to underscore that the 70% requirement aims to safeguard the principle of non-discrimination between cross-zonal and internal trade, which as a general principle must be upheld both in the day-ahead and intraday time frame.

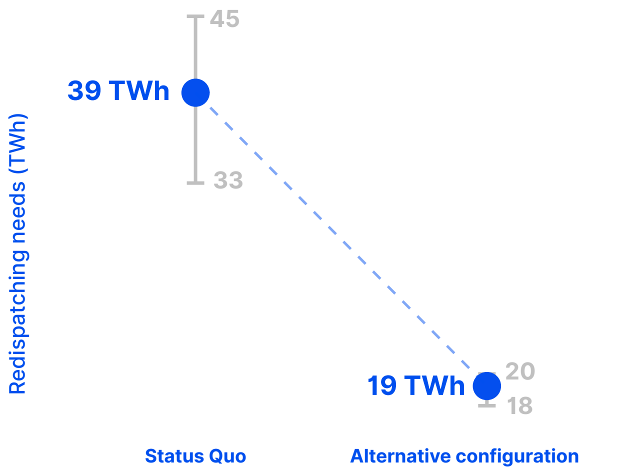
Build, pay, split? Trade-offs in maximising cross-zonal trade in the EU

10 The options for maximising availability of cross-zonal capacity, measured by the ability to offer at least 70 % of the physical capacity to the market, are implicitly defined in the Electricity Regulation. TSOs were mandated to relieve structural congestion within bidding zones by 2025 through grid reinforcement and to ensure that interim capacity requirements would be met in the meantime using remedial actions. If insufficient to consistently fulfil 70%, Member States could opt for a reconfiguration of the bidding zones to better reflect structural congestion.

11 Remedial actions serve to mitigate forecasted or realised grid congestion, potentially allowing TSOs to safely increase the amount of cross-zonal capacity made available to the market. However, they may carry significant associated costs, their use is mostly uncoordinated and they may face technical limitations closer to real time. The need for remedial actions has increased in recent years, alongside the expansion of renewables, and it is expected to grow further in the future. In 2024 alone over 60 TWh[3] of remedial actions were activated in the EU — a 5% increase compared to the previous year — at a total cost of EUR 4.3 billion.

Redispatching needs could be halved under a more granular bidding zone configuration.

Redispatching volume triggered in central Europe under different bidding zone configurations and climate years – 2025 scenario (TWh)



Source: ACER calculation based on ENTSO-E bidding zone review data.

Note: The alternative configuration selected for the purpose of this figure is the split of the Germany-Luxembourg bidding zone into five bidding zones.

12 Grid reinforcement has been identified as the main long-term solution to address structural congestion in central Europe. This may include both the construction of new power lines and the deployment of non-wire alternatives. However, delays in project delivery continue to widen the gap between grid development and system needs, ensuring continued reliance on costly remedial actions. ACER's 2024 infrastructure monitoring report noted that over 60% of analysed projects were delayed compared to their initial commission date.

2 Remedial actions, such as redispatching, are TSO interventions to relieve network congestion after the market clearing. They serve to ensure that all operational security constraints, beyond those linked to cross-zonal trade, are respected.

3 This is approximately equivalent to the entire annual demand of electricity of a Member State like Austria or Czechia.

13 Building on ENTSO-E's bidding zone review study, ACER notes that a more efficient configuration of bidding zones in the EU could help to significantly relieve grid congestion. Indeed, the need for redispatching could be reduced by up to 60% under a different configuration. In addition, a better bidding zone configuration would facilitate the implementation of the 70% requirement.

14 Meeting the EU's objectives of decarbonising the power system and ensuring its independence from imported fossil fuels will require greater interdependence within the EU. This process will demand the acceleration of the roll-out of new grid infrastructure, both within and across borders, but also the efficient use of the existing network. Indeed, boosting the availability of current assets for cross-zonal trade will be essential to ensure a secure, efficient and climate-neutral electricity system.

List of abbreviations

Abbreviation	Term in full
AC	Alternating Current
ACER	European Union Agency for the Cooperation of Energy Regulators
AMR	Adjustment for Minimum RAM
ATC	Available Transfer Capacity
CACM	Capacity Allocation and Congestion Management
CCA	Capacity Coordination Area
CCR	Capacity Calculation Region
CEST	Central European Summer Time
CGM	Common Grid Model
CNE	Critical Network Element
CNEC	Critical Network Element with Contingency
CNTC	Coordinated Net Transfer Capacity
DC	Direct Current
ENTSO-E	European Network of Transmission System Operators for Electricity
F_{0all}	Flow on critical network elements with contingencies not stemming from any cross-zonal exchange
F_{max}	Maximum flow on critical network elements, respecting operational security limits
$F_{ref,Core}$	Flow originated from the Core net positions already included in the CGM
F_{uaf}	Flow on critical network elements with contingencies resulting from commercial exchanges outside a CCR
GRIT	Greece-Italy
HVDC	High Voltage Direct Current
IDA	Pan-European intraday auctions
IDCC	Intraday capacity calculation
IVA	Individual Validation Adjustment
JAO	Joint Allocation Office
LTA	Long-Term Allocation
LTTR	Long-Term Transmission Right
MACZT	Margin Available for Cross-Zonal Trade
NRA	National Regulatory Authority
NTC	Net Transfer Capacity
PTDF	Power Transfer Distribution Factor
RAM	Remaining Available Margin
RCC	Regional Coordination Centre
RES	Renewable Energy Sources
ROSC	Regional Operational Security Coordination
SDAC	Single Day-Ahead Coupling
SEE	South-East Europe
SIDC	Single Intraday Coupling
SWE	South-West Europe
TSO	Transmission System Operator
TYNDP	Ten-Year Network Development Plan

Introduction

15 The EU's electricity system is undergoing a massive transformation. Renewable electricity generation must double by 2030 to address the decarbonisation challenge[4] and reduce the EU's dependency on imported fossil fuels. At the same time, ensuring affordability and security of supply calls for optimising this transition by leveraging the EU's key advantages to achieve cost-effective solutions.

16 In this regard, increasing the level of electricity trade between EU Member States enhances the resilience of the power system, optimises available resources and facilitates the efficient integration of renewable energy. Indeed, cross-zonal trade constitutes a key source of flexibility for the power system, enabling renewable energy to reach demand centres across the EU while curbing price volatility.

17 A highly integrated internal electricity market, facilitating the efficient exchange of electricity across borders, is crucial for the EU's decarbonisation efforts and for guaranteeing the security of electricity supply. In a context of rapidly developing renewable technologies, the timely expansion of electricity transmission infrastructure, through both new build-out and non-wire alternatives, and the maximisation of cross-zonal trading possibilities across the EU are key to the completion of the internal market for electricity.

18 The development and implementation of processes for the efficient calculation and allocation of cross-zonal capacities for cross zonal trade are an integral step in this effort. Over the last decade, progress in capacity calculation and allocation has been considerable, with all EU bidding zone borders being included in single day-ahead coupling (SDAC) and single intraday coupling (SIDC), and the introduction of flow-based market coupling. However, progress in maximising the availability of capacities offered for cross-zonal trade across the EU has been slower.

19 To address the need for maximising cross-zonal capacities, the recast Electricity Regulation introduced a minimum level of cross-zonal capacity to be offered to the market by transmission system operators (TSOs), while respecting operational security limits. This minimum 70% requirement entered into force in 2020. To implement the requirement, without endangering system security, Member States and TSOs could opt for a transitional period, which enabled TSOs to address structural congestion within bidding zones, until the end of 2025 at the latest. In parallel, a process was agreed upon whereby TSOs were to cooperate to identify structural congestions within and between bidding zones and assess potential bidding zone reconfigurations in a pan-European bidding zone review.

20 In order to ensure the implementation of the minimum 70 % requirement across the EU, the European Union Agency for the Cooperation of Energy Regulators (ACER) was asked to develop a harmonised monitoring approach for all Member States, described in ACER Recommendation No 01/2019, which would enable to track progress in the implementation of the requirement and to compare all Member States on an equal footing. ACER has since produced yearly reports monitoring the progress of the implementation of the minimum 70 % requirement in the EU.

4 European Union Agency for the Cooperation of Energy Regulators (ACER) and European Environment Agency (EEA), Flexibility solutions to support a decarbonised and secure EU electricity system, Publications Office of the European Union, Luxembourg, 2023.

21 This report is produced in accordance with Article 15 of Regulation (EU) 2019/942 establishing a European Union Agency for the Cooperation of Energy Regulators (ACER Regulation), as part of the monitoring activities performed by ACER. These activities are intended to assess, and report on, barriers to the completion of the internal market for electricity. This report assesses potential barriers related to the availability of cross-zonal capacity and thus focuses on indicators relevant to it. A dedicated dashboard is published in parallel to the report, allowing for greater granularity on some of the data items presented in the report.

22 The report is structured as follows. Chapter 1 presents a series of analyses exemplifying the importance of maximising cross-zonal trade for the well-functioning of the EU internal market for electricity. Chapter 2 monitors the margin of cross-zonal capacity made available for cross-zonal trade (MACZT[5]) in 2024, assessing the progress made and challenges encountered in implementing the minimum 70 % requirement. Where applicable, it also measures the fulfilment of the national interim requirements stemming from derogations and/or action plans. Finally, Chapter 3 reflects on the on-going processes that may facilitate the implementation of the minimum 70% requirement, namely the use of remedial actions, the reinforcement of the power grid and the reconfiguration of the bidding zones in the EU.

23 ACER expresses its gratitude for the valuable contributions received from all EU national regulatory authorities (NRAs) and TSOs in the drafting of this market monitoring report.

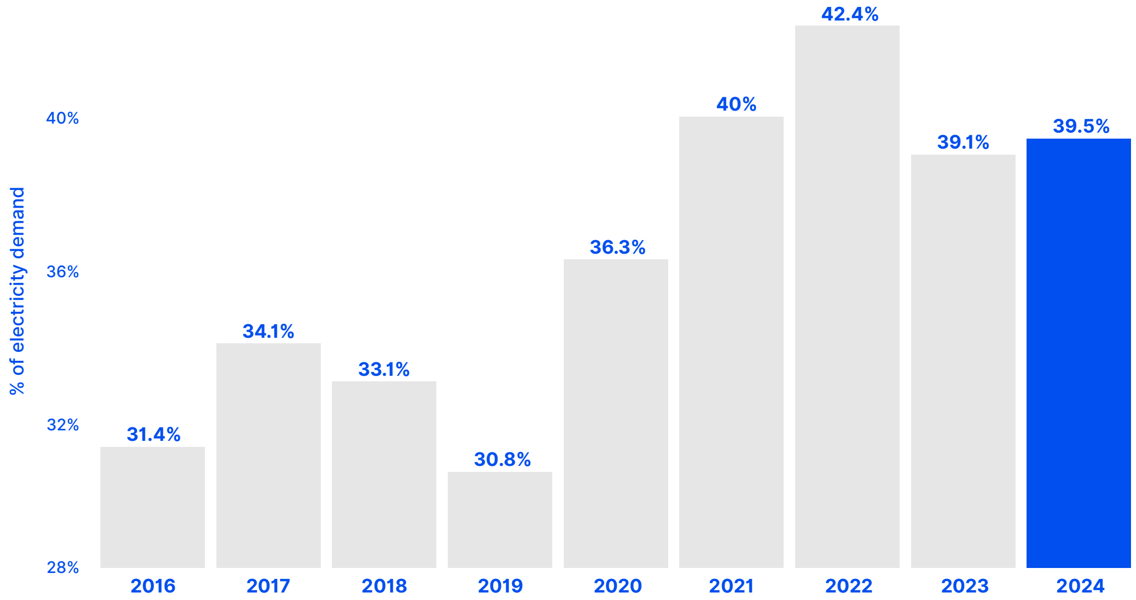
5 The margin available for cross-zonal trade corresponds to the portion of the physical capacity of a given CNEC that is made available for cross-zonal trade by the TSOs. According to the Electricity Regulation, TSOs will need to ensure that the MACZT on all CNECs is at least 70%. This is further developed in Chapter 2 of this market monitoring report.

1. The availability of cross-zonal capacity is key to reaping the benefits of the internal electricity market

24 Over the past decade, the integration of European electricity markets has advanced significantly, driven by key projects such as the completion of market coupling and the progressive implementation of flow-based capacity calculation and allocation. These developments have strengthened cross-border electricity trading over time, as highlighted in Figure 1, playing a central role in optimising the use of generation resources across the EU.

25 Cross-zonal electricity trading allows for the dispatch of the most cost-efficient generation assets available across the EU. It supports the integration of renewable energy sources into the system and dampens price volatility, which is particularly relevant during periods of sustained high prices such as the 2022 energy crisis. A highly integrated EU electricity market is thus instrumental in ensuring a cost-efficient energy transition and enhancing the resilience of the power system.

Figure 1: Evolution of the average share of cross-zonal exchanges in the day-ahead timeframe over electricity demand in EU and Norwegian bidding zones - 2016-2024 (% of electricity demand)



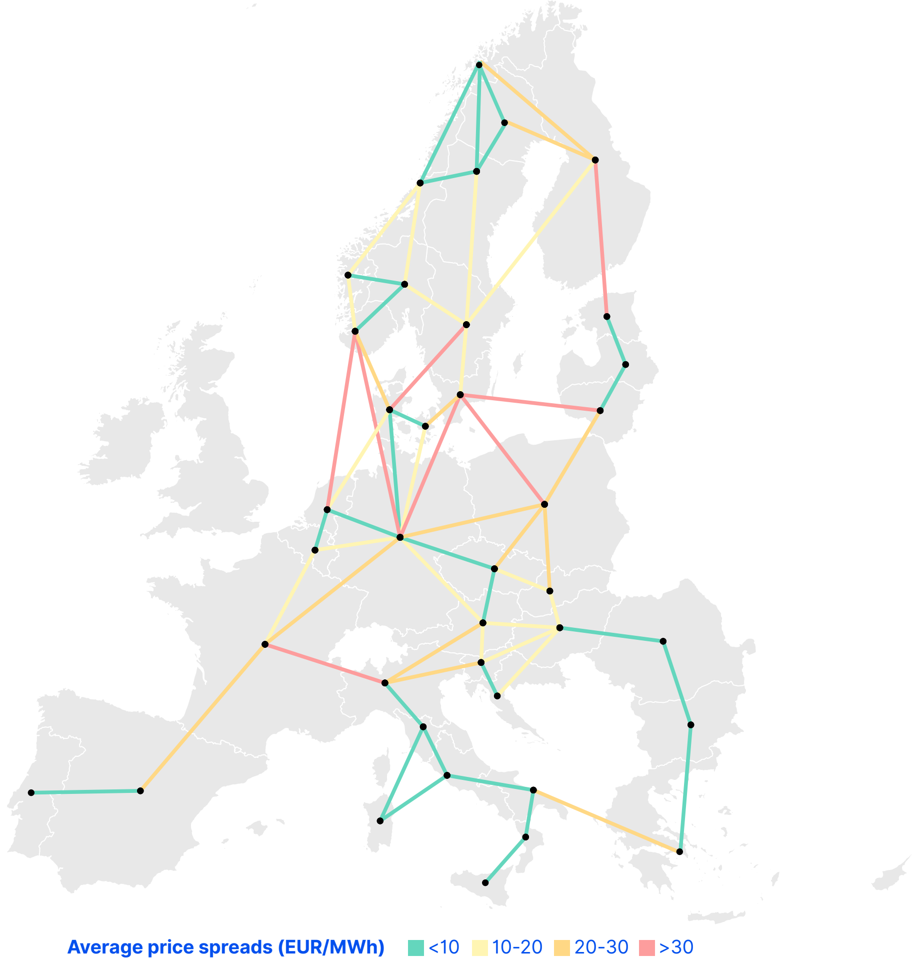
Source: ACER calculation based on ENTSO-E Transparency Platform data.

Note: Average yearly share is first calculated per bidding zone, as SDAC net position over electricity demand, and then averaged over all bidding zones in the EU and Norway. Data gaps have been identified on the relevant table of the ENTSO-E Transparency Platform over specific periods, which may affect the accuracy of the results.

26 The exchanges of electricity across bidding zones are enabled by the levels of cross-zonal capacity made available by TSOs. When available capacity is sufficient to meet all of the market's needs, prices across bidding zones will tend to converge. By contrast, insufficient capacity prevents additional cross-zonal exchanges, leading to price differences between bidding zones. Such price differences are the indication of market congestion, signalling that all of the capacity that was made available was used.

27 In recent years, capacity calculation and allocation processes have been gradually improved across the EU's different capacity calculation regions (CCRs), increasing the availability of capacity and ensuring its efficient allocation. Despite this progress, physical bottlenecks in the power grid continue to prevent additional cross-zonal trade. In 2024, limitations to additional cross-zonal trade were particularly visible at the borders between the continental Europe and Nordic synchronous areas, as well as at the Italy North and France-Spain borders. An overview of the average price spreads at EU bidding zone borders is presented in Figure 2.

Figure 2: Average price difference per bidding zone border in SDAC – 2024 (EUR/MWh)



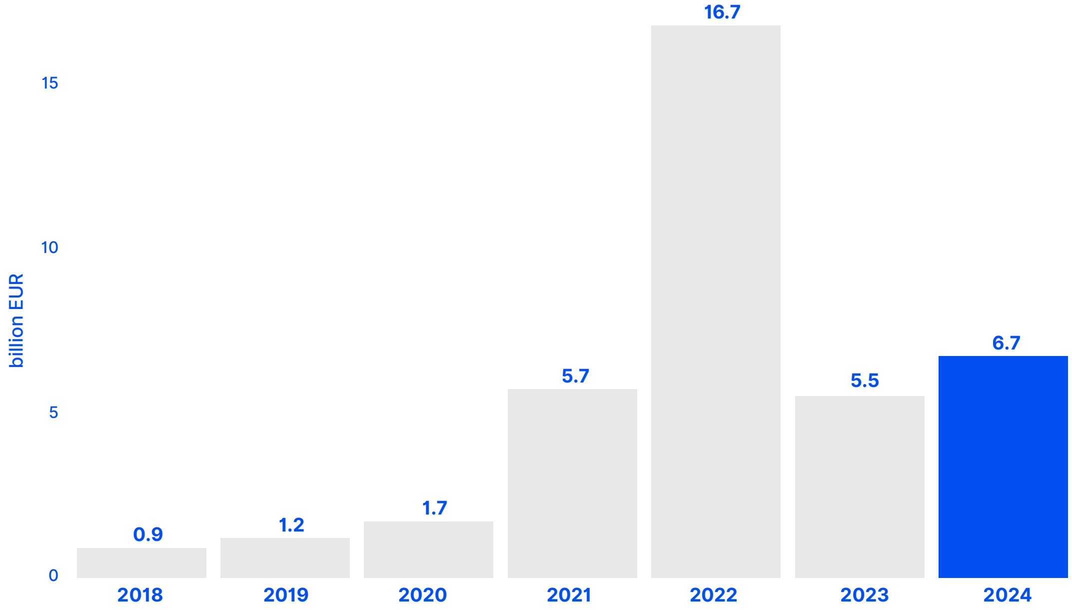
Source: ACER calculation based on ENTSO-E Transparency Platform data.

28 Price differences between bidding zones reflect the value of additional cross-zonal trade. Consistently high price differentials may signal the need for additional cross-zonal capacity but need to be weighed against the costs associated with increasing it. Price differences between bidding zones generate congestion income, which is collected by TSOs. The use of this income is regulated: TSOs receiving the congestion income must primarily reinvest it to strengthen the power grid and alleviate congestion in the long term.

29 In 2024, total congestion income from the SDAC exceeded EUR 6.5 billion, continuing an upward trend over recent years, as highlighted in Figure 3[6]. The Core and Nordic CCRs accounted for the largest volume of congestion income generated – 30% and 28% respectively – partly due to their larger number of bidding zone borders.

6 In 2022, generally high price levels across the EU and significant volatility resulted in exceptionally large price spreads.

Figure 3: Yearly evolution of congestion income generated in SDAC – 2018-2024 (billion EUR)



Source: ACER calculation based on ENTSO-E Transparency Platform data.

Note: Congestion income is calculated as the scheduled commercial exchange multiplied by the price spread on each bidding zone border.

30 In Chapter 1, this market monitoring report delves deeper into the concept of market congestion. It aims to underscore the value of relieving market congestion through greater availability of cross-zonal capacity. In doing so, it presents concrete examples from relevant market outcomes during 2024.

1.1. Market congestion prevents additional cross-zonal trade in the EU: a look into Core flow-based market coupling

31 Within the Core CCR, which encompasses most of the central European bidding zone borders, flow-based market coupling has been implemented since June 2022. In this region, exchanges of electricity between bidding zones are bound by a set of pairs of network elements (critical network element with contingency, or 'CNEC'[7]). These are modelled through the combination of the remaining available margin (RAM), which quantifies the available capacity of the relevant network element, and the power transfer distribution factors (PTDFs), which describe the influence of cross-zonal exchanges on that element.

32 The market coupling algorithm aims to maximise regional economic surplus, while respecting the bounds defined by the cross-zonal capacity constraints. This may lead to non-intuitive outcomes, such as electricity flowing from high- to low-price zones, when these exchanges help relieve congestion elsewhere and increase overall system welfare.

33 There are generally two drivers of cross-zonal exchanges of electricity and hence of market congestion. First, market fundamentals, reflected by the supply and demand curves in all bidding zones, define what the optimal level of cross-zonal trade is. Second, the availability of cross-zonal capacity will determine the feasible set of cross-zonal exchanges, resulting in congested CNECs where cross-zonal capacity is fully used.

7 A critical network element is a network element (a line or a transformer) that is significantly impacted by cross-zonal trade and that needs to be considered during the capacity calculation process under certain operational conditions. A CNEC is a critical network element that limits the amount of power that can be exchanged, potentially associated with a contingency. A contingency is defined as the trip of a single or several network elements.

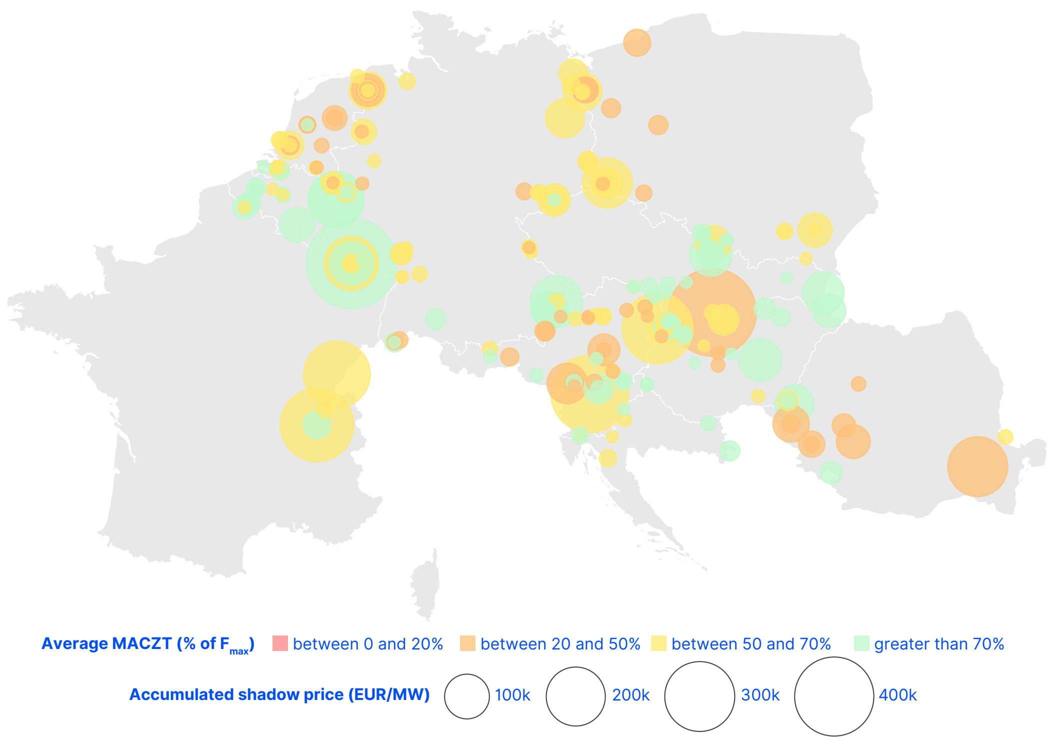
34 It is important to underscore the distinction between market congestion, which refers to the situation in which all available commercial capacity on a CNEC is used by the market, and physical congestion, whereby TSOs forecast or observe a violation of an operational security limit on a single or pair of network elements.

35 In 2024, two main dynamics shaped the most severe market bottlenecks in the region. During spring, capacity reductions imposed by the French TSO to address physical congestion within the grid limited exports from France to the rest of the region. During summer, a tight supply–demand balance during the evening hours in central and eastern European bidding zones resulted in a significant import need from neighbouring bidding zones, revealing major bottlenecks in Austria and Slovakia. The latter case is further analysed in Section 1.2.

Shadow prices highlight the impact of scarce capacity on economic surplus

36 The European market clearing algorithm quantifies the value of market congestion on every pair of network elements, by computing the potential increase in economic surplus incurred by relaxing the capacity constraint by a single megawatt (MW). This metric is referred to as the shadow price. A non-zero shadow price on a given CNEC indicates that there is value in increasing its capacity, as that would allow for further cross-zonal trade. On the other hand, increasing capacity in network elements with a zero shadow price would not alter the market dispatch.

Figure 4: Market congestion in the Core CCR weighted by the accumulated shadow price and categorised by margin available for cross-zonal trade – 2024 (EUR/MW and % of F_{max})



Source: ACER calculation based on JAO Publication Tool data.

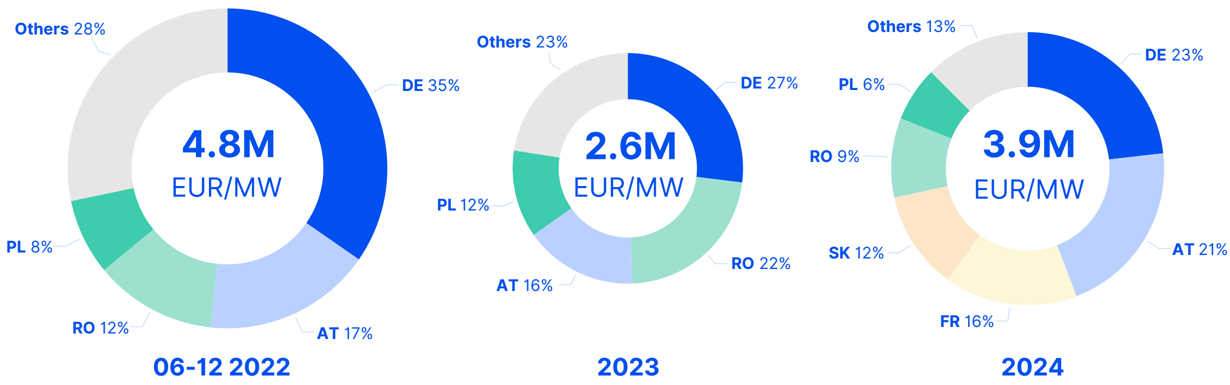
Note: For the creation of the figure, CNECs with non-zero shadow prices are groupped by CNE, displaying the sum of shadow price over the year. While long-term allocations and allocation constraints may also bound cross-zonal exchanges within the Core CCR, only flow-based constraints are considered for the purpose of this figure.

37 Figure 4 represents the most relevant market congestions in Core flow-based market coupling during 2024, weighted by how constraining they were to SDAC (i.e., weighted by their shadow price), and categorised by the average margin available for cross-zonal trade ('MACZT') offered in each congested CNEC over the year. As anticipated, the most significant bottlenecks to the market dispatch within Core flow-based market coupling during 2024 were located within France, Austria and Slovakia, as well as on the border between Germany and France.

38 On the other hand, comparing the patterns of market congestion over time reveals valuable information on the underlying market dynamics and availability of grid capacity. Figure 5 shows the yearly volume of market congestion in the Core CCR since the implementation of flow-based market coupling in June 2022, together with the share of market congestion per Core Member State.

39 In comparison with 2023, market congestion saw an increase in 2024 in the Core CCR following a year of greater market volatility, although remained well below 2022 values. This can be observed in the accumulated shadow price on all flow-based constraints over the years, which saw a 50% year-on-year increase in 2024.

Figure 5: Evolution of the distribution of market congestion in the Core CCR per Member State – June 2022 to December 2024 (EUR/MW)



Source: ACER calculation based on JAO Publication Tool data.

Note: While long-term allocations and allocation constraints may also bound cross-zonal exchanges within the Core CCR, only flow-based constraints are considered for the purpose of this figure. Market congestion on the Alegro HVDC cable is not considered in the relative shares per Member State.

40 Notably, the share of market congestion corresponding to German CNECs has seen a diminishing trend since 2022, following the increase in cross-zonal capacity levels in accordance with the German action plan, leading to a more even distribution in the share of market congestion in the region. Instead, 2024 saw growing shares of market congestion on network elements in France, Austria and Slovakia, compared with previous years.

41 Moreover, other limitations to cross-zonal trade may be binding in the Core CCR, beyond the thermal limits of specific pairs of network elements. This is the case of allocation constraints. In particular, the Polish TSO introduces a limitation to the total import or export position of the Polish bidding zone within Single Day-Ahead Coupling, which has limited exchanges to or from Poland for 31% of hours in 2024. While this still constitutes a major impact to cross-zonal trade in the region, it has also seen a decreasing trend over the last three years (down from 68% of hours in the second half of 2022).

Quantifying the benefits of relieving market congestion in Core flow-based market coupling

42 Relieving congested network elements in flow-based market coupling, by increasing the availability of cross-zonal capacity on such elements, enables further electricity trade between bidding zones. Consequently, it results in a more optimal outcome of the EU electricity market, enabling the dispatch of lower-cost generation assets to meet power demand.

43 In the EU, the main regulatory tool to ensure the maximisation of cross-zonal capacities is the 70% requirement, introduced in the Electricity Regulation. This requirement was introduced to address the discrimination of cross-zonal exchanges in favour of intra-zonal exchanges, inherent to a zonal market design. As will be further elaborated in the second section of this market monitoring report, the 70% requirement is currently being implemented by EU TSOs, with uneven progress across the EU.

44 To quantify the expected benefits from relieving market congestion in Core flow-based market coupling, through the on-going implementation of the minimum 70% requirement, ACER simulated the outcome of the internal market for electricity under different levels of cross-zonal capacity. For this purpose, ACER made use of the Simulation Facility tool developed jointly by EU nominated electricity market operators (NEMOs) and TSOs[8]. The following scenarios were assessed:

- **Historical run.** Re-run of market coupling, with no modification to the capacity levels made available by TSOs. This scenario represents the realised market outcomes of 2024.

- **70 %.** Available capacity is increased so that all CNECs in the pre-solved flow-based domains[9] offer at least 70% of capacity for cross-zonal trade. This scenario corresponds to the levels of capacity in 2024, should the 70% requirement have been fully met across the Core region.

- **Natural RAM.** Available capacity is decreased for all CNECs in the pre-solved flow-based domains to remove the impact of the adjustment for minimum RAM (or 'virtual capacities')[10]. This scenario estimates the available capacity levels, should TSOs not need to comply with any minimum cross-zonal capacity requirement at all.

- **Long-term allocations (LTA) only.** Capacities are set to zero in all CNECs in the pre-solved flow-based domain. Cross-zonal exchanges within the Core region are thus defined exclusively by the LTA domain. This scenario represents the capacity levels should no day-ahead capacity calculation be performed by TSOs at all.

45 The results of the simulations performed by ACER are assessed through different market indicators, highlighting the benefits of increased cross-zonal capacities over different market dimensions. The main indicators assessed are SDAC economic surplus, average peak day-ahead prices, the levels of price convergence and price volatility.

8 The Simulation Facility tool replicates the European market coupling algorithm. Due to inherent limitations in its reproducibility, simulation outcomes may vary across different runs, potentially leading to divergent results.

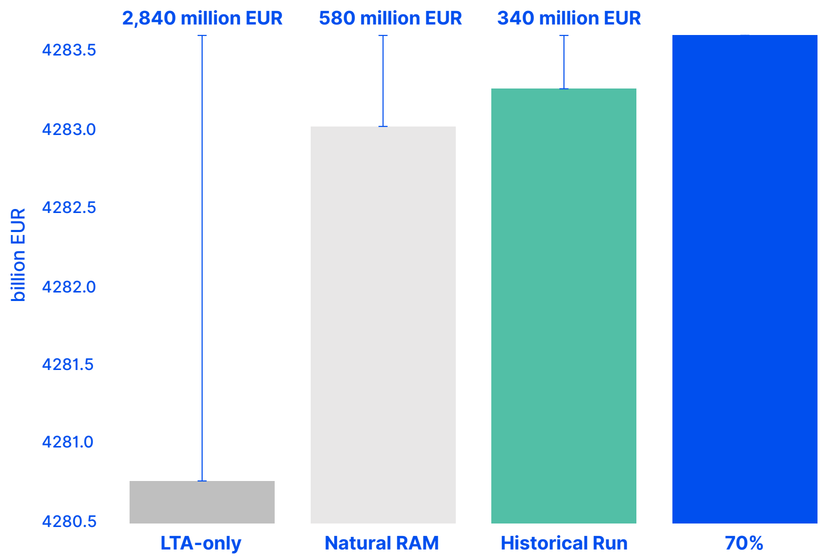
9 Simulations are performed by modifying the capacity levels on the pre-solved flow-based domain directly. This is as simplification as it assumes that different minimum capacity levels do not result in different CNECs being pre-solved, thus altering the shape of the flow-based domain.

10 The adjustment for minimum RAM is the mechanism implemented in the Core day-ahead capacity calculation to ensure that the applicable interim cross-zonal capacity requirements are met. This concept is further discussed in Chapter 2 of this report.

46 The objective function of the market coupling algorithm is to maximise economic surplus, defined as the sum of consumer surplus, producer surplus and congestion income. Consumer surplus represents the difference between what consumers are willing to pay for electricity and the price they pay, producer surplus reflects the difference between the market price and the minimum price at which producers are willing to supply electricity, and congestion income reflects the value of cross-zonal capacity.

47 Figure 6 shows the total economic surplus of SDAC over 2024 of the four scenarios simulated, together with the comparison of every scenario with that of a full 70% implementation. The analysis revealed that the finalisation of the implementation of the 70 % requirement in the Core CCR would have yielded an economic surplus gain of EUR 340 million in 2024, compared with the actual 2024 levels of capacity. As a comparison, the use of virtual capacities to guarantee the applicable requirements yielded EUR 240 million of economic surplus in 2024. In total, the implementation of the minimum 70% requirement would have produced a minimum of EUR 580 million in economic surplus in 2024.

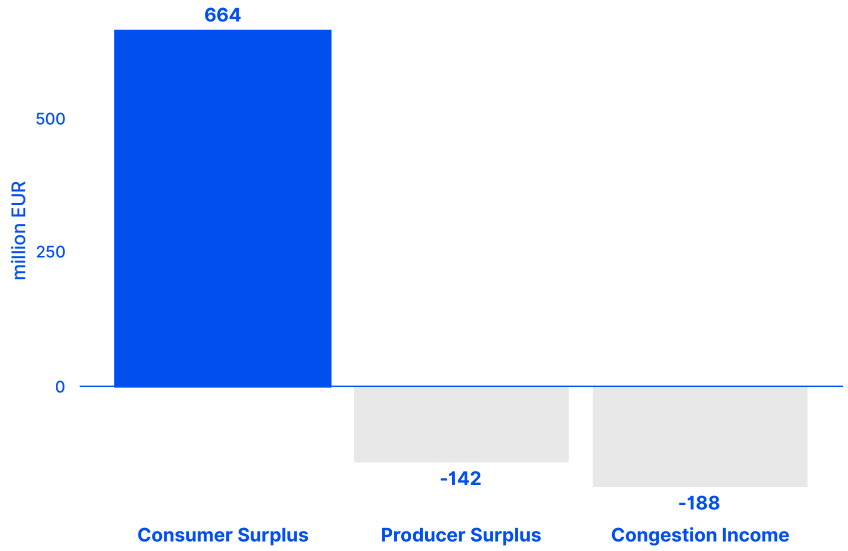
Figure 6: SDAC economic surplus in 2024 under different cross-zonal capacities scenarios in the Core CCR – 2024 (billion EUR)



Source: ACER simulation based on Simulation Facility.

48 Moreover, Figure 7 shows the breakdown from the expected economic surplus gains on the SDAC from finalising the implementation of the minimum 70 % requirement in the Core CCR. It confirms that the consumer benefits most from increased levels of cross-zonal capacities. Indeed, consumers would have reaped EUR 664 million in additional consumer surplus in 2024 in the form of lower average day-ahead prices.

Figure 7: Breakdown of the variation in SDAC economic surplus stemming from finalising the implementation of the minimum 70 % requirement in the Core CCR – 2024 (million EUR)



Source: ACER simulation based on Simulation Facility.

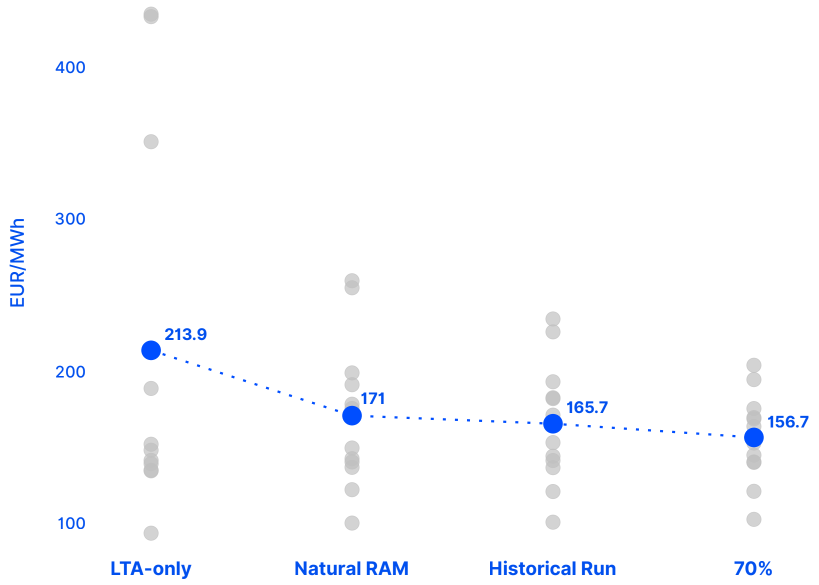
49 It is important to note that the implementation of the minimum 70% requirement may come with associated investment or operating costs, which would partly offset the economic surplus gains stemming from it[11]. However, the loss of economic surplus stemming from not having yet implemented the minimum 70% requirement highlights the on-going distribution of welfare from the EU internal market – and specially its consumers – to some of the Member States where the minimum 70% requirement is yet to be fully implemented. This distribution is a direct consequence of the prioritisation of internal exchanges over cross-zonal exchanges, inherent to a zonal market design, which the minimum 70% requirement aims to mitigate.

50 The benefits of maximal availability of cross-zonal capacities can be observed directly in the electricity prices resulting from SDAC. The simulations performed in this analysis show that the day-ahead prices would have been an average of 2 EUR/MWh lower in 2024 in the Core CCR should the minimum 70% requirement have been fully implemented already.

51 When assessing the peak hours, defined as those with the highest price per day, this average drop reaches 9 EUR/MWh, confirming the key role of cross-zonal capacity in providing flexibility to the power system. Moreover, it can be noted that the average spread between the highest and lowest-priced bidding zone in the Core CCR continuously decreases when higher levels of cross-zonal capacity are available.

11 This aspect is further developed in Chapter 3 of this market monitoring report.

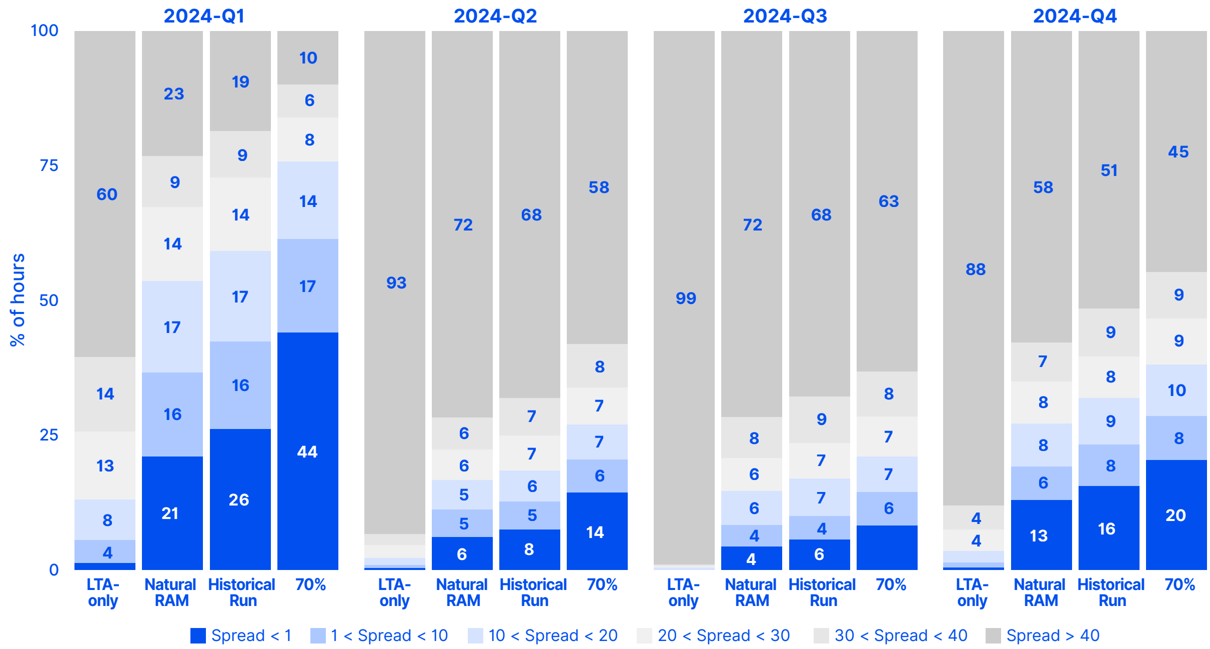
Figure 8: Average day-ahead prices in peak hours for the bidding zones in the Core CCR under the different simulated scenarios – 2024 (EUR/MWh)



Source: ACER simulation based on Simulation Facility.

52 Figure 9 shows the levels of price convergence in the Core CCR, under the different simulated scenarios. Hours of full price convergence indicate market periods when there is no market congestion in the region, as all of the market's need for cross-zonal exchanges can be fully accommodated by the available cross-zonal capacity. As confirmed by Figure 9, the availability of cross-zonal capacity plays a key role in determining the levels of price convergence. When cross-zonal capacity is maximized, the instances of significant price spreads in the region drop.

Figure 9: Levels of price convergence in the Core CCR (excluding Poland) under different cross-zonal capacity scenarios per quarter – 2024 (% of hours)



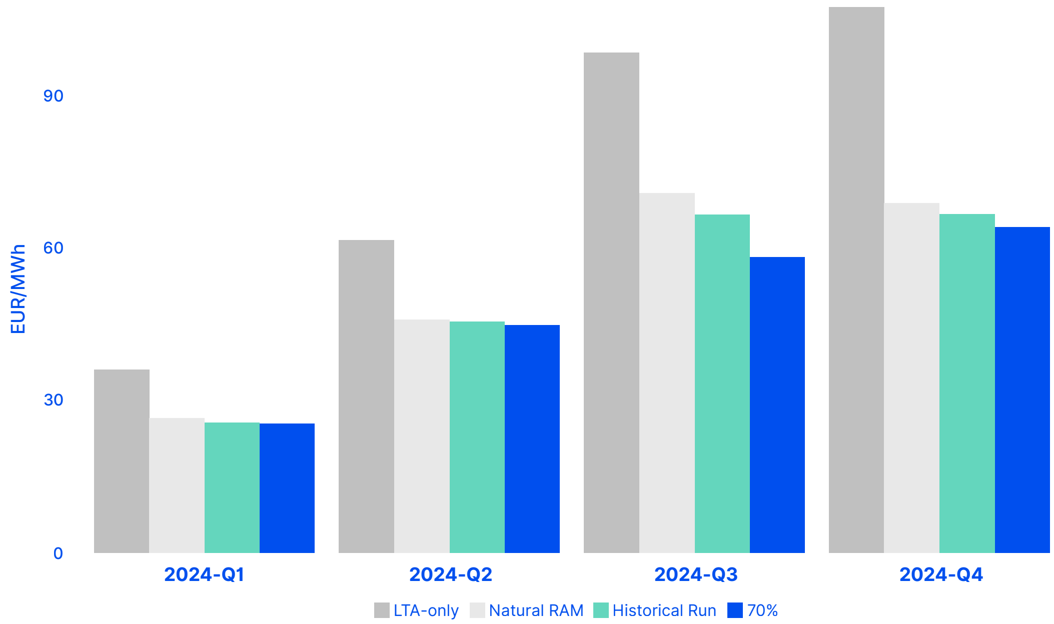
Source: ACER simulation based on Simulation Facility.

Note: The figure displays the average spread between the highest-priced and lowest-priced bidding zone in the Core CCR. The Polish bidding zone is excluded from the calculation, due to the relevance of allocation constraints in defining cross-zonal trade to and from Poland.

53 Finally, it is important to emphasise that cross-zonal trade is the main source of cost-efficient flexibility in the power system. The availability of cross-zonal capacity helps mitigate price volatility and reduces occurrences of high prices. To quantify this impact, ACER calculated the average price volatility in the bidding zones of the Core CCR, under the four simulated scenarios. The results are shown in Figure 10.

54 The current levels of cross-zonal exchanges within the Core CCR already provide much-needed flexibility to the system, while further progress towards the implementation of the minimum 70% requirement will yield additional benefits in terms of market stability, contributing to more predictable and resilient electricity prices.

Figure 10: Average standard deviation of day-ahead prices in the bidding zones of the Core CCR under different capacity scenarios per quarter – 2024 (EUR/MWh)



Source: ACER simulation based on Simulation Facility.

1.2. Cross-zonal trade can mitigate the impact of scarcity situations: high-price events in South-east Europe

55 During the summer of 2024, the EU saw a significant increase in electricity prices, affecting mostly bidding zones in central- and south-eastern Europe, as highlighted in Figure 11. Prices particularly spiked during the evening hours of the day, reaching values of up to 1000 EUR/MWh. During these high-price events, price spreads at several bidding zone borders in central Europe rose to unprecedented levels, signalling insufficient availability of cross-zonal capacity to accommodate the market's need for cross-zonal exchanges.

56 The analysis presented in this section serves to exemplify the role of cross-zonal capacity as a key source of flexibility in the power system, dampening electricity prices during periods of scarcity, but it does not aim to provide a comprehensive assessment of the root causes of these high-price events.

57 Several fundamental drivers explain the market conditions observed in South-east Europe during the evening hours of the summer of 2024, which resulted in significant pressure on both the demand and the supply sides of the electricity system, leading to extreme-price incidents during the evening hours.

Figure 11: Average day-ahead prices in South-east Europe at 19:00 CEST – July to September 2024 (EUR/MWh)

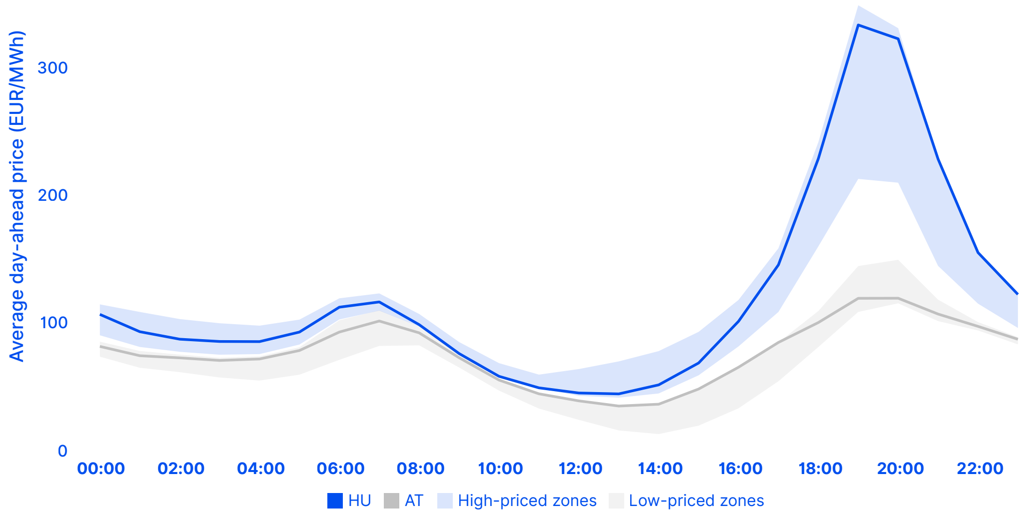
Source: ACER calculation based on ENTSO-E transparency platform.

58 On the supply side, solar energy showed significant infeed levels during the central hours of the day, followed by a steep decline in output towards the evening. On the demand side, above-average electricity consumption was recorded, particularly high during the evening hours, driven by extreme temperatures affecting the region. At the same time, the region saw limited availability of flexible assets that could quickly ramp up production to replace the drop in solar infeed—partly due to outages of gas-fired power plants and low water levels in hydro reservoirs, but also due to insufficient storage and demand response capabilities.

59 The lack of system flexibility to match the growing evening power demand with the steep decline in solar infeed resulted in a high need for exchanges from central Europe towards the most affected bidding zones, which were constrained by insufficient cross-zonal capacity. Additionally, increased electricity exports from Hungary and Romania to Ukraine further intensified the tight regional supply-demand balance during the evening hours.

60 Figure 12 shows the average daily profile of day-ahead prices in a selection of bidding zones across continental Europe. While electricity prices remain convergent during most periods of the day, there is a sharp decorrelation of prices between central-western and central-eastern bidding zones in the evening hours, coinciding with the demand peak of most Member States in the region.

Figure 12: Average hourly SDAC price in a selection of EU bidding zones – July to September 2024 (EUR/MWh)



Source: ACER calculation based on ENTSO-E TP data.

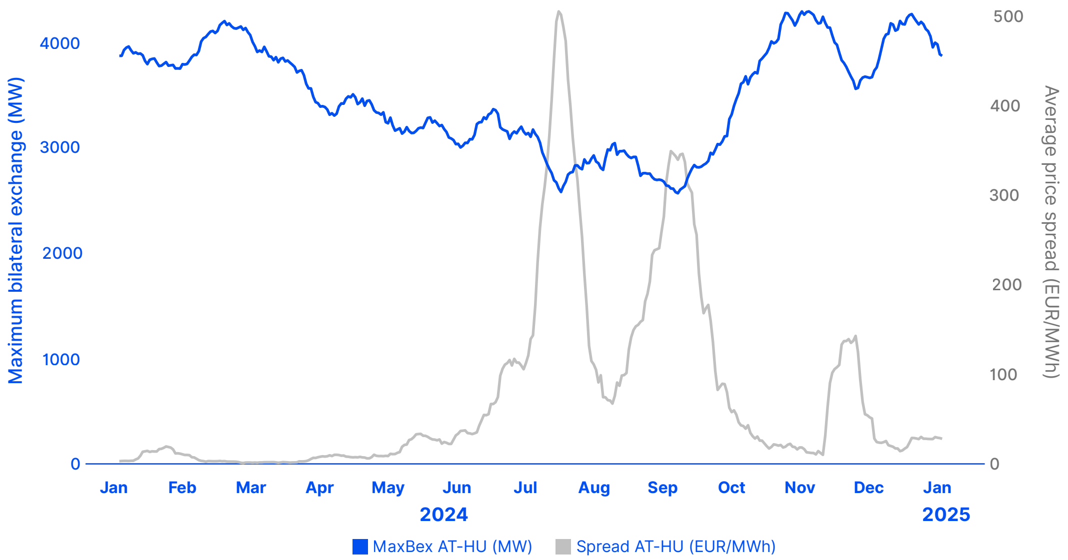
Note: Prices reflected in low-priced zones correspond to the following bidding zones: BE, FR, AT, CZ, DE-LU and NL; while prices reflected in high-priced zones correspond to the following bidding zones: GR, BG, RO, HU, SK, HR, SI and PL.

61 The above-mentioned market dynamics resulted in severe price spreads at the relevant bidding zone borders, far exceeding those of recent years. The most pronounced impact was observed at the bidding zone border between Austria and Hungary, where the average price spread during the summer months at 19:00 CEST reached 214 EUR/MWh.

62 The observed price spreads are a consequence of available cross-zonal capacities not being able to accommodate all of the market's need for cross-zonal trade. During the summer period, available capacity is usually at lower levels compared to other periods of the year, limiting the total possibilities for cross-zonal exchange. This so as a large share of maintenance of transmission assets is scheduled during the summer months, as this is a period when the system is traditionally under less stress.

63 Figure 13 displays a two-week rolling average of the maximum bilateral exchange at the Austria-Hungary bidding zone border at 19:00 CET/CEST. This metric represents the maximum possible bilateral exchange between Austria and Hungary during the evening peaks, provided that there is no other exchange within the Core region. In parallel, it also shows the price spread recorded at that same bidding zone border.

Figure 13: Two-week rolling average of the maximum possible bilateral exchange and price spread on the Austria-Hungary bidding zone border at 19:00 CET/CEST – 2024 (MW and EUR/MWh)



Source: ACER calculation based on JAO Publication Tool and ENTSO-E Transparency Platform data.

Note: Maximum possible bilateral exchange is based on the MaxBex indicator, which is calculated under the assumption that no other cross-zonal exchanges are present in the Core CCR.

64 The figure confirms that the sharpest periods of price divergence between Austria and Hungary occurred when available cross-zonal capacity is lowest, coinciding with when relevant transmission assets in central Europe were undergoing maintenance.

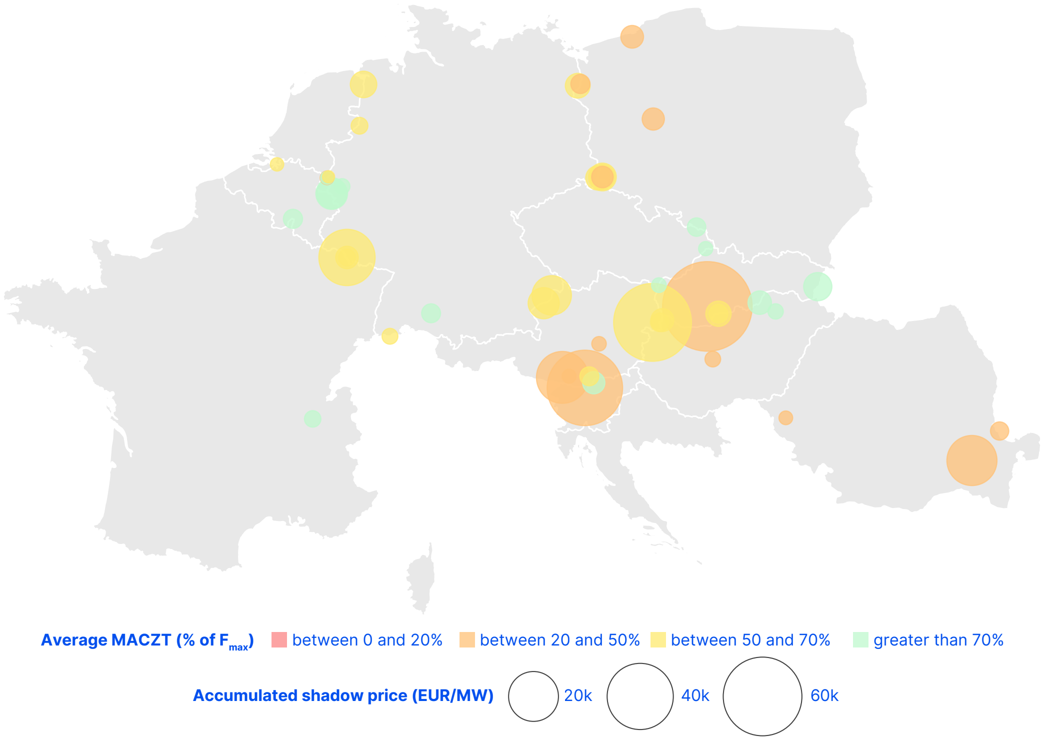
65 When system tightness is expected, shifting or cancelling scheduled works on transmission assets can contribute to expanding cross-zonal trading possibilities and thus mitigating the price impact of such market conditions. These measures would require coordination at a broad geographical scale, as the resulting price effects may extend well beyond the location of the outage.

Relieving congested network elements mitigates both the frequency and the severity of the observed price spikes

66 Assessing the active flow-based constraints during the high-price incidents reveals which network elements specifically prevented additional cross-zonal exchanges into the affected bidding zones. As introduced Chapter 1.1, releasing additional capacity for cross-zonal trade in these congested network elements would have enabled further cross-zonal trade to take place, thus contributing to mitigating the severity of these events.

67 Figure 14 presents an overview of the network elements with a non-zero shadow price during the high-price events in summer 2024. Notably, it can be observed that the most limiting network elements were, for the most part, not yet fulfilling the minimum 70% requirement. In accordance with applicable derogations and action plans, CNECs in Austria and Slovakia were bound by interim requirements and thus were offering between 40% and 60% of their physical capacity to the market for cross-zonal trade, on average.

Figure 14: Active constraints in Core flow-based market coupling at 19:00 CEST, weighted by accumulated shadow price and categorised by average MACZT - July to September 2024 (EUR/MW and % of F_{max})

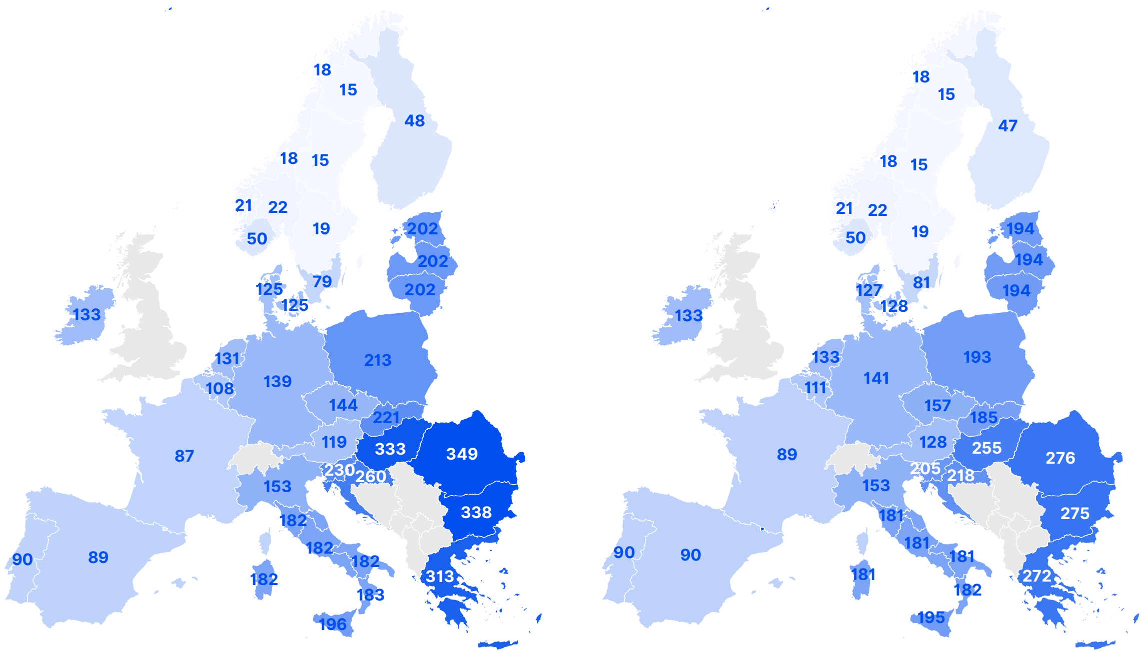


Source: ACER calculation based on JAO Publication Tool data.

68 In order to exemplify the role of cross-zonal trade in providing flexibility during periods of tight supply–demand balance and the benefits from the on-going implementation of the minimum 70% requirement, ACER replicated the market conditions observed during the price spikes, under higher levels of cross-zonal capacity in the Core region.

69 Comparing the average realised day-ahead prices during the evening peaks with the counterfactual scenario shows a considerable mitigation of prices. Specifically, it reveals that the implementation of the 70% requirement would have led to an average reduction of peak prices of up to 78 EUR/MWh in central and south-east bidding zones, underlining the dampening effect of cross-zonal trade.

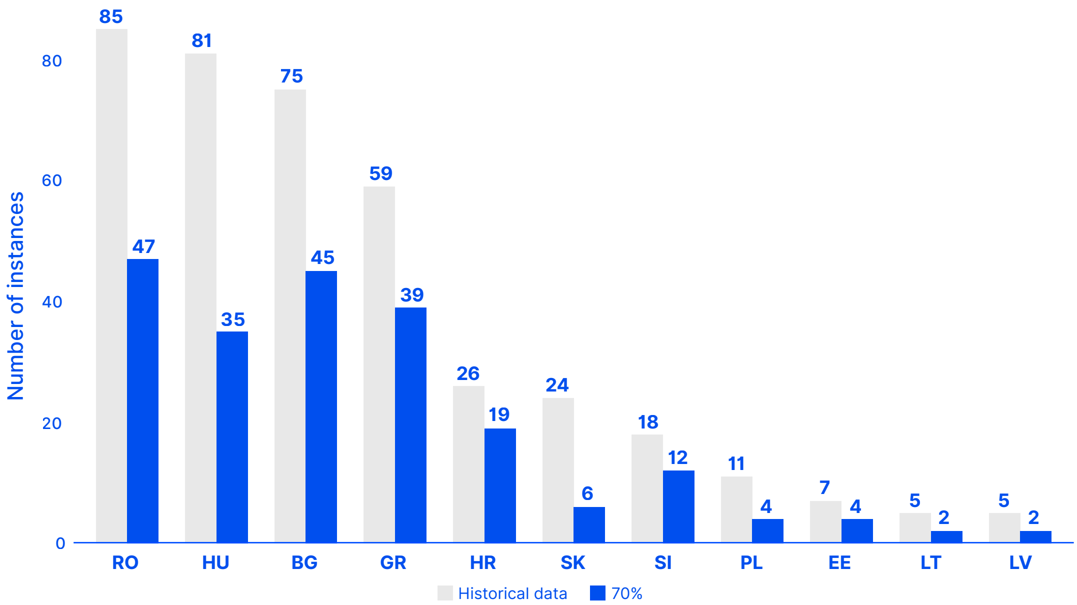
Figure 15: Average SDAC prices at 19:00 CEST in operational data (left) and 70% simulation (right) – July to September 2024 (EUR/MWh)



Source: ACER simulation based on Simulation Facility and ENTSO-E Transparency Platform.

70 ACER also assessed the impact of increased cross-zonal capacities on the number of instances of price spikes. Figure 16 shows the number of instances when day-ahead prices exceeded 400 EUR/MWh during the summer in the most affected EU bidding zones, comparing the historical data with the case of full 70% implementation. As observed in the figure, the results indicate a reduction of more than half in the number of occurrences of extreme price events in some bidding zones, with Hungary seeing the most impact.

Figure 16: Count of instances of day-ahead prices above 400 EUR/MWh in select EU bidding zones, compared with the counterfactual analysis – July to September 2024 (number of instances)

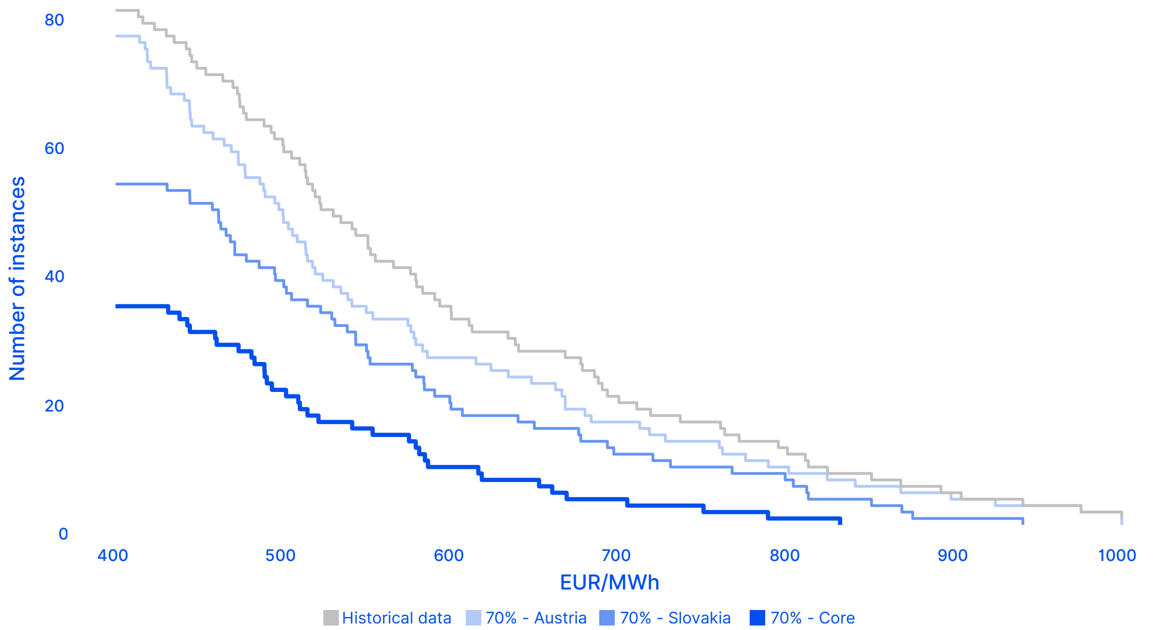


Source: ACER simulation based on Simulation Facility.

71 To better understand the underlying dynamics resulting from relieved market congestion, the number of extreme prices in Hungary was also assessed when additional capacity is released in the identified bottlenecks in Austria and Slovakia separately. Figure 17 shows the number of instances when day-ahead prices in Hungary surpassed a varying threshold, under different capacity scenarios.

72 While the implementation of the minimum 70% requirement in specific Member States would provide measurable benefits in terms of dampening extreme prices, the figure demonstrates that the full extent of such benefits can only be realized when all bottlenecks are relieved simultaneously. Indeed, alleviating a particular congested element individually most likely results in a different capacity constraint becoming binding to cross-zonal exchanges.

Figure 17: Number of instances of day-ahead prices in Hungary above a varying threshold under different cross-zonal capacity scenarios – July to September 2024



Source: ACER calculation based on Simulation Facility.

1.3. Impact of severe restrictions of capacity: default flow-based parameters on 25 June

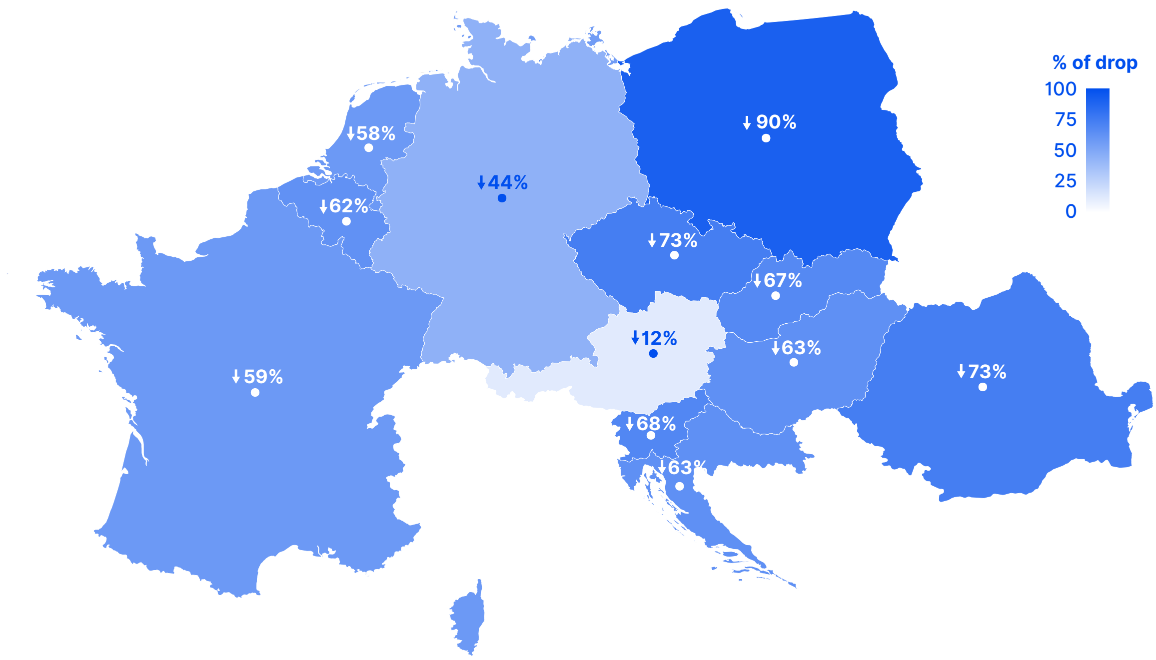
73 Parallel to the flow-based domains calculated daily, Core TSOs provide the market coupling operator with a set of simultaneously feasible capacities to be guaranteed across all Core bidding zone borders. This is the LTA domain, and it corresponds to the long-term transmission rights (LTTRs) – in particular financial transmission rights or non-nominated physical transmission rights – issued by TSOs and allocated through yearly and monthly auctions.

74 To ensure that TSOs generate sufficient congestion income in the day-ahead market to consistently meet their financial obligations to LTTR holders, the market coupling algorithm incorporates both the flow-based and the LTA domains in the clearing process. As capacities made available for long-term auctions are currently not based on a coordinated capacity calculation process, the LTA domain is particularly large on certain bidding zone borders and, in certain cases, may even exceed the size of the daily flow-based domain. On other bidding zone borders, the LTA domain offers zero capacity, as no LTTRs are allocated. LTA constraints may thus have an associated shadow price, reflecting the additional welfare gains from expanding the LTA domain, in cases where the LTA domain is not fully covered within the flow-based domain.

75 During the Core day-ahead capacity calculation process of 24 June 2024, an IT error in the creation of the common grid model (CGM) used as basis for the calculation led to flow-based domains not being available for the market coupling session of 25 June 2024. In such cases, according to the day-ahead capacity calculation methodology, only the LTA domain is provided to the market coupling operator as fallback, potentially enlarged at the bidding zone border level when both responsible TSOs agree to it.

76 The application of this fallback resulted in very constrained capacities being offered across the Core region. Figure 18 presents the decrease in non-simultaneous cross-zonal trading possibilities of each Core bidding zone on 25 June 2024, compared with the rest of June. It shows decreases of up to 90% in the possibilities for exchange of some bidding zones, coinciding with the borders where LTA values are lowest.

Figure 18: Relative decrease of non-simultaneous minimum and maximum Core net position on the 25 June 2024, compared to the rest of June 2024, per Core bidding zone – June 2024 (% of decrease)



Source: ACER calculation based on JAO Publication Tool data.

Note: The relative decrease of cross-zonal trading possibilities is calculated using the average of the minimum and maximum non-simultaneous Core net position per bidding zone on 25 June 2024, compared with the average of the remaining days of June.

77 This in turn resulted in very noticeable price spreads at most Core internal bidding zone borders and higher prices all throughout eastern Europe. In this analysis, ACER aims to simulate a counterfactual of this trading day, replicating flow-based domains for each hour based on historical data as input, and to quantify the potential benefits from improving the current fallback approach.

78 It is important to underscore that this assessment does not aim to obtain the optimal compromise between minimising operational security risks and maximising cross-zonal capacities in the case of a fallback. Instead, it aims to invite Core TSOs to investigate a different fallback approach to the one currently in use.

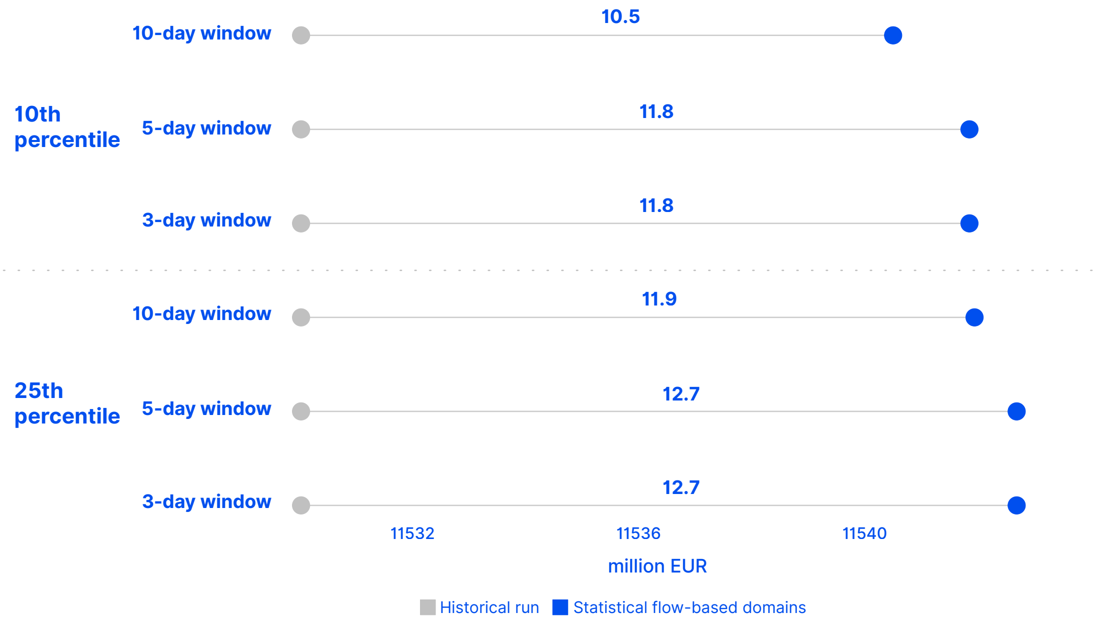
Using a statistical flow-based domain would limit the severity of the fallback in the Core capacity calculation process

79 In this analysis, ACER tested different parameters to recreate the flow-based domains for each hour of 25 June 2024 based on capacity calculation results from prior days and performed market simulations with each of the constructed flow-based domains. The main assumptions taken when constructing the statistical flow-based domains are as follows:

- number of days considered ahead of the fallback – 3, 5 and 10 days ahead of the 25 June 2024, excluding weekends;
- relevance threshold – a CNEC is included in the statistical flow-based domain for a given hour, if it appears in a minimum number of days for this hour:
    - in 3 days, at least two appearances;
    - in 5 days, at least four appearances;
    - in 10 days, at least six appearances;
- The RAM and PTDFs for every selected CNEC are defined using the nearest lower available observation to the 10th or 25th percentile of RAM.

80 Figure 19 compares the potential outcomes, in terms of the economic surplus of the day ahead market, of the different market simulations performed with statistical flow-based domains, compared with the current fallback. This analysis shows that issuing fallback capacities based on statistical flow-based domains would have yielded up to EUR 13 million of economic surplus gains for the single trading day of 25 June 2024.

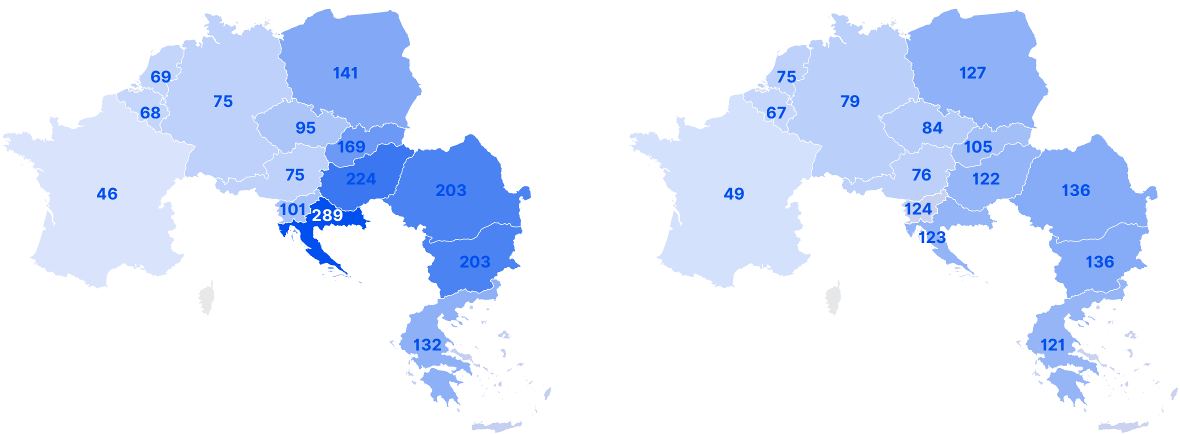
Figure 19: Economic surplus of SDAC under different statistical flow-based domains as an alternative to the current fallback process – 25 June 2024 (million EUR)



Source: ACER simulation based on Simulation Facility data.

81 Figure 20 presents the potential price impact of a more sophisticated fallback approach. It shows, as an example, the average day-ahead prices across selected bidding zones in continental Europe, under the realised market coupling session of 25 June 2024, and a counterfactual simulation using the most conservative of the tested statistical flow-based domain. The most notable impact is observed across central and south-eastern European bidding zones, where average day-ahead price reductions of over 150 EUR/MWh were recorded.

Figure 20: Average day-ahead price in selected bidding zones when default flow-based parameters are applied (left), compared with simulated prices under a statistical flow-based domain (right) – 25 June 2024 (EUR/MW)



Source: ACER simulation based on Simulation Facility and ENTSO-E Transparency Platform data.

2. The minimum 70% requirement is the main regulatory tool in the EU to increase cross-zonal trade

82 Chapter 1 of this market monitoring report introduced the interplay between the availability of cross-zonal capacity and market needs, while quantifying the benefits of relieving market congestion by ensuring available cross-zonal capacity is maximised. The main regulatory tool in the EU to ensure that cross-zonal capacity is maximised is the minimum 70% requirement. Chapter 2 assesses the status and progress of the implementation of this requirement in 2024 across the EU.

83 The minimum 70% requirement translates in practice into the margin made available for cross-zonal trade (MACZT), which corresponds to the portion of the physical capacity of a given CNEC that is made available for cross-zonal trade by the TSOs. Monitoring the MACZT not only assesses the degree of implementation of the requirement but also serves as a proxy for the level of integration of EU national electricity markets.

84 ACER's analysis of the MACZT does not assess the legal compliance of TSOs on the obligations derived from Article 16(8) of the Electricity Regulation. This is the competence of the relevant NRA. Instead, ACER's monitoring provides an overview of the status of implementation of the requirement in all Member States, measured against a single methodology, based on the principles defined in ACER Recommendation No 01/2019.

85 This chapter presents the results of ACER's monitoring of the implementation of the minimum 70% requirement for each Member State. The results are presented for those CCRs where a coordinated capacity calculation methodology has been implemented (i.e. the Core, Nordic, SWE, Italy North, SEE and GRIT regions). The monitoring of regions where a coordinated process has yet to be introduced (i.e. the Hansa and Baltic regions) is presented, based on the available data, in Annex I. The monitoring results are complemented by a dedicated dashboard, providing the reader with access to additional granularity on the data.

86 All figures presented in this chapter consider, whenever it has been possible to calculate it, the impact of flows induced by exchanges with non-EU countries. The results of the monitoring excluding the impact of such exchanges can be consulted through the dedicated dashboard.

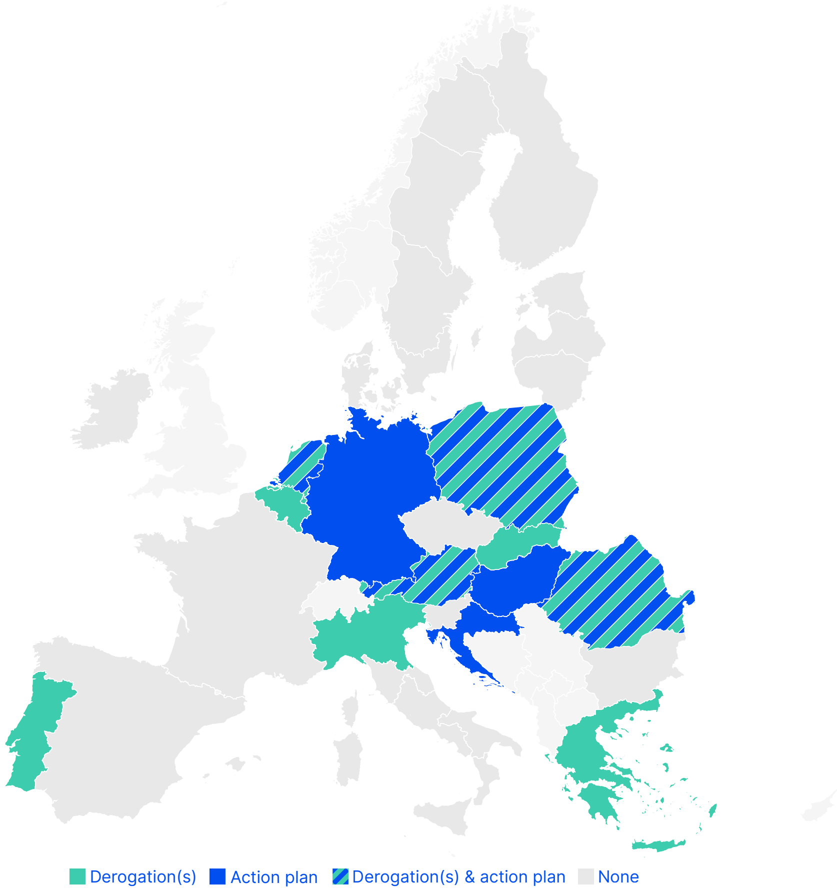
2.1. Status of implementation of the minimum 70 % requirement in the EU

87 While the minimum 70% requirement entered into force in 2020, the Electricity Regulation allowed the gradual implementation of the requirement by introducing two transitional measures. Firstly, TSOs were to cooperate to identify structural congestions within and between bidding zones and assess potential bidding zone reconfigurations. Second, to support this process, Article 15 allowed Member States to establish multi-year action plans to ensure the gradual fulfilment of the minimum 70% requirement, up to the end of 2025, in parallel with the implementation of structural measures to cope with the identified structural congestion.

88 In the meantime, where necessary for maintaining operational security, the relevant regulatory authority may, at the request of the TSO, grant a derogation from the minimum 70% requirement, pursuant to the first subparagraph of Article 16(9) of the Electricity Regulation, to the extent necessary to ensure operational security, relaxing the requirements under Article 16(8) for a limited period. Other regulatory authorities in the CCR may object to the granting of such derogation.

89 Since its introduction, a significant number of Member States have required action plans and/or derogations to implement the minimum 70% requirement. Figure 21 presents an overview of the Member States that had a derogation and/or an action plan in place in 2024. In such Member States, interim cross-zonal capacity requirements are usually defined. That is the case for all Member States where an action plan is in place, as these require a linear trajectory toward the 70% requirement. Derogations may or may not define a specific numeric commitment.

Figure 21: Overview of the status of implementation of the minimum 70% requirement in the EU for each Member State - 2024



Source: ACER elaboration based on NRA data.

2.2. Progress in implementing the minimum 70% requirement in the Core region

90 The Core CCR includes most bidding zone borders in central Europe. In the Core CCR, a fully coordinated capacity calculation process, based on flow-based, is used for the day-ahead time frame since June 2022. The first coordinated intraday calculation process — also flow-based but still under an NTC allocation — went live in June 2024. This section assesses the progress made and challenges encountered in the implementation of the minimum 70% requirement in the region, assessing both the day-ahead and intraday time frames.

2.2.1. Day-ahead time frame

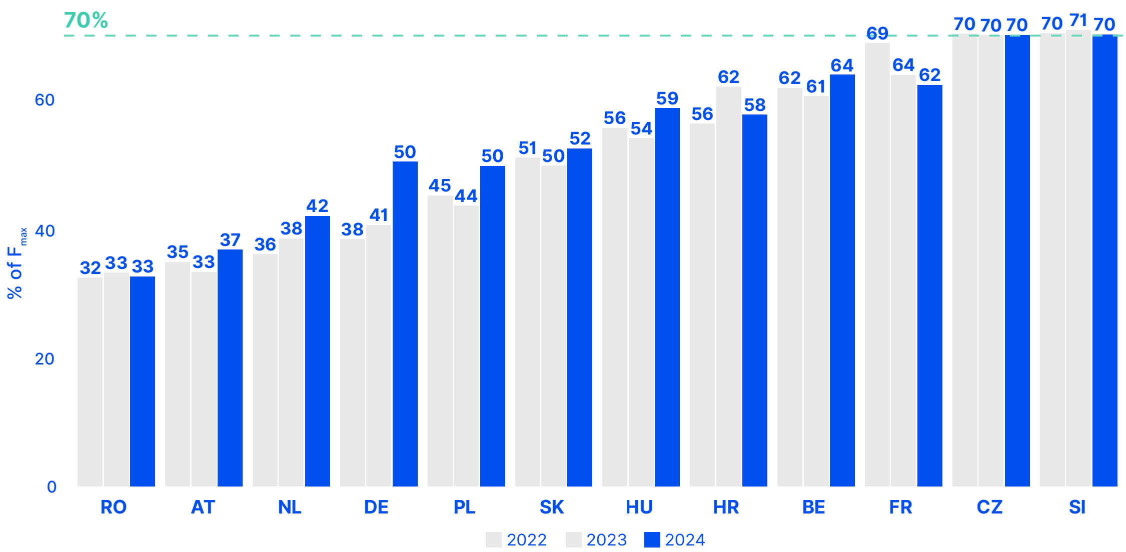
91 Following the implementation of the Core day-ahead capacity calculation methodology in June 2022, all the bidding zone borders in the region were integrated into flow-based market coupling. Within that process, the MACZT is calculated and reported on all network elements relevant to the capacity calculation (i.e., CNECs), thus ensuring a high degree of transparency.

92 As the minimum 70% requirement is to be fulfilled on all CNECs for a given market time unit, ACER generally monitors the requirement by assessing the CNEC that offers the lowest MACZT for every market time unit. When the lowest-MACZT CNEC fulfils the minimum 70% requirement, all other CNECs will do so as well. This is a crucial element of MACZT monitoring, as one single CNEC may prove detrimental to the well-functioning of the EU internal electricity market.

Visible progress in implementing the minimum 70% requirement in the Core region, with some exceptions

93 Figure 22 presents an overview of the progress made by Core TSOs in implementing the minimum 70% requirement. To do so, it highlights the yearly average of the lowest MACZT for every market time unit, since the implementation of the Core flow-based market coupling. As shown in the figure, some progress is observed in several Member States compared with 2023. This is the case for Germany, Poland and Hungary. On the other hand, Member States such as Romania, Croatia and France have seen either no increase or a decrease in the average minimum MACZT levels.

Figure 22: Average minimum hourly MACZT in the Core CCR per Member State, considering flows induced by third-country exchanges – 2022-2024 (% of F_{max})

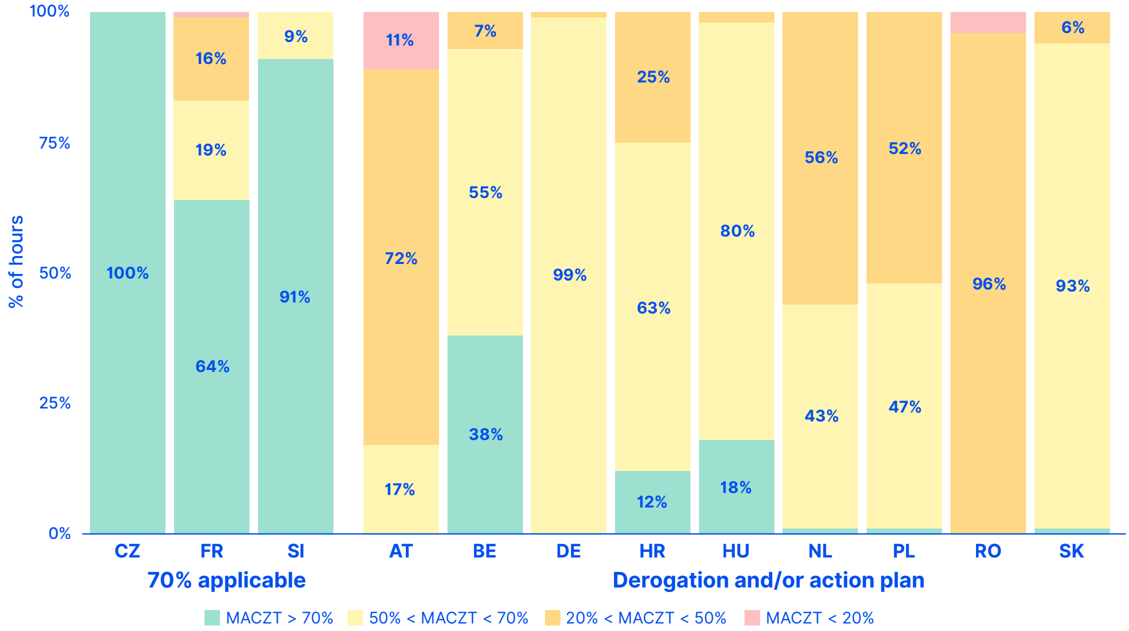


Source: ACER calculation based on TSO data.

94 Beyond the average levels of MACZT, Figure 23 illustrates how often all relevant grid elements in a bidding zone offered at least 70% of their capacity for cross-zonal trading in 2024, providing insight into the distribution of the MACZT levels over the year. More specifically, the figure shows the percentage of hours when the CNECs with the lowest hourly MACZT of a given Member State offered were above 70% or within different ranges of MACZT.

95 It is important to underscore once again that, in 2024, only three TSOs in the Core CCR were legally bound by the minimum 70% requirement, because they did not have approved derogations or action plans, namely the TSOs from Czechia, France and Slovenia. As can be seen in the figure, these TSOs offer, relatively, the highest levels of MACZT in the region yet cannot always uphold the minimum 70% requirement.

Figure 23: Percentage of hours when the minimum hourly MACZT was above 70% or within predefined ranges in the Core CCR for each Member State, considering flows induced by third-country exchanges – 2024 (% of hours)

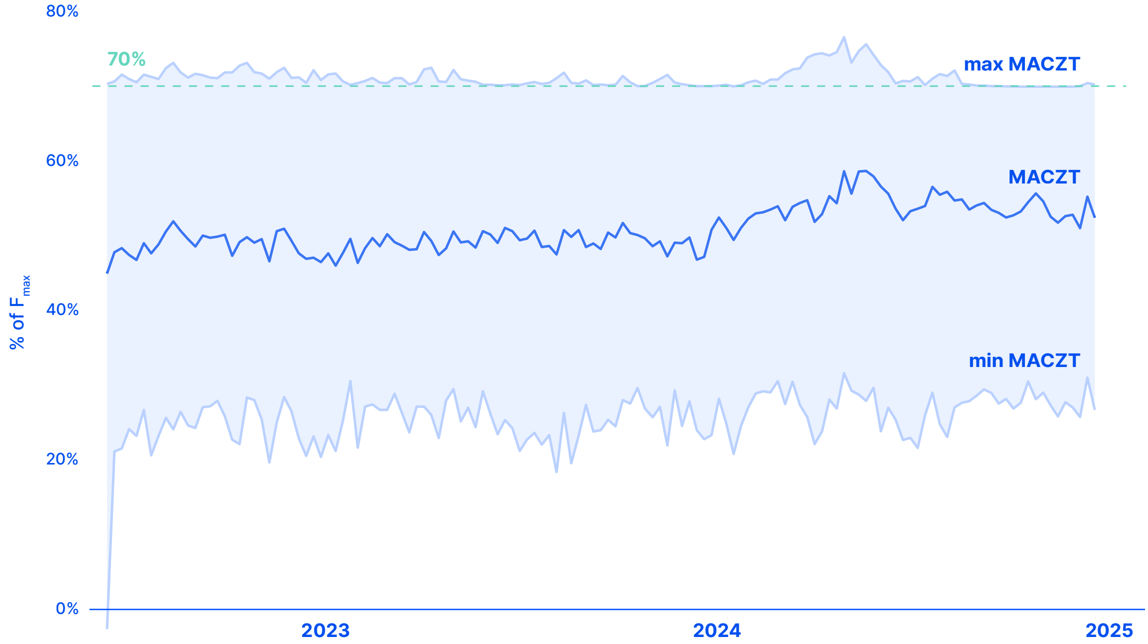


Source: ACER calculation based on TSO data.

96 As highlighted in Chapter 1 of this market monitoring report, cross-zonal exchanges within the Core region are determined by a subset of CNECs, most often those offering lower levels of capacity. As such, it is crucial that all TSOs jointly implement the minimum 70% requirement. Indeed, increases in capacity in the CNECs of a given TSO might prove ineffective if other TSOs in the region lag behind.

97 Figure 24 shows the evolution of the minimum, average and maximum MACZT in the most limiting CNECs in the Core CCR, independent of the TSO responsible for it. As highlighted previously, applicable derogations and action plans have resulted in a wide range of MACZT values offered by Core TSOs, with average minima around 30% of F_{max} and slow progress in the region.

Figure 24: Weekly averages of minimum, average and maximum MACZT on the CNECs with minimum hourly MACZT per TSO in the Core CCR, considering flows induced by third-country exchanges – June 2022 to December 2024 (% of F_{max})



Source: ACER calculation based on JAO Publication Tool data.

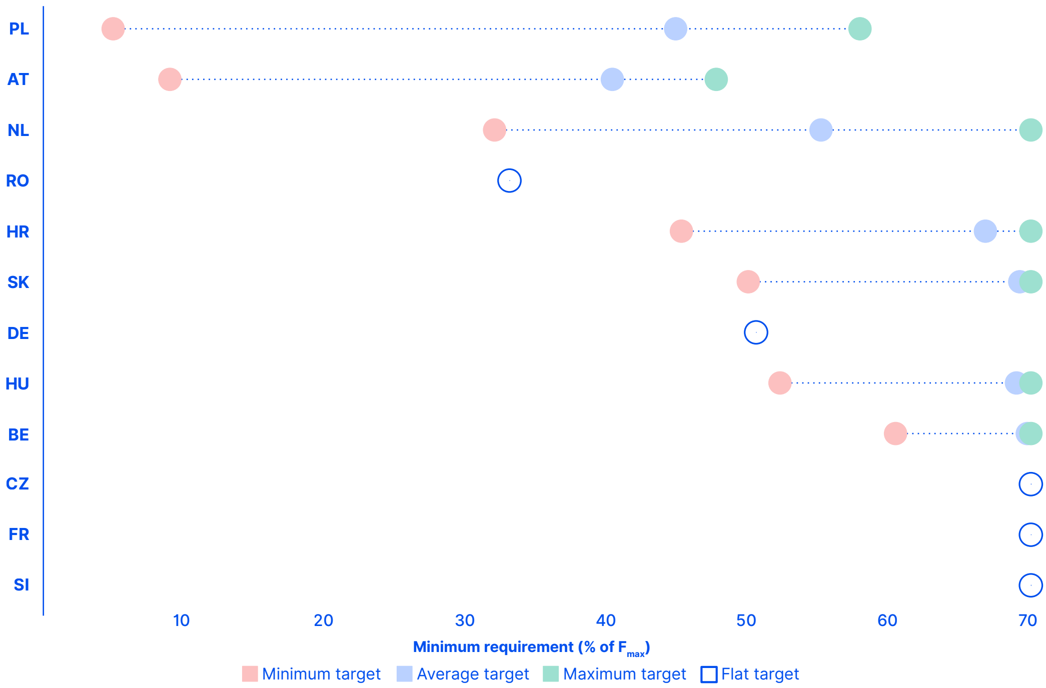
98 The figure also shows that, after two years of stable values, an increase in average MACZT levels was indeed recorded throughout 2024. The minimum values have also been steadily increasing since 2022, although they remain far from 70%.

Applicable capacity requirements were generally upheld in 2024, yet these can be significantly reduced under situations of high loop flows

99 In the Core CCR, most TSOs are not yet bound by the minimum 70% requirement, following the approval of an action plan and/or a derogation. These TSOs are instead subject to interim minimum capacity requirements, which are defined in line with the applicable derogation and/or action plan. The interim requirements may be static, constant for all CNECs and hours of the year, or they may be dynamic, setting different values per CNEC and/or hour.

100 Figure 25 presents an overview of the cross-zonal capacity requirements that were applicable in the Core CCR in 2024. Notably, the TSOs of Austria, Belgium, the Netherlands and Poland have requested derogations on the grounds of excessive loop flows from neighbouring Member States. These derogations, for every CNEC, deduct the forecasted loop flows above a certain acceptable threshold from 70% or the action plan linear trajectory value. NRAs have granted such derogations under the assumption that, as the origin of the loop flows is outside the control area of a given TSO, the local remedial action potential is insufficient to alleviate the impact of such flows.

Figure 25: Overview of the interim capacity requirements as defined by applicable action plans and/or derogations in the Core CCR for each Member State – 2024 (% of F_{max})



Source: ACER calculation based on TSO data.

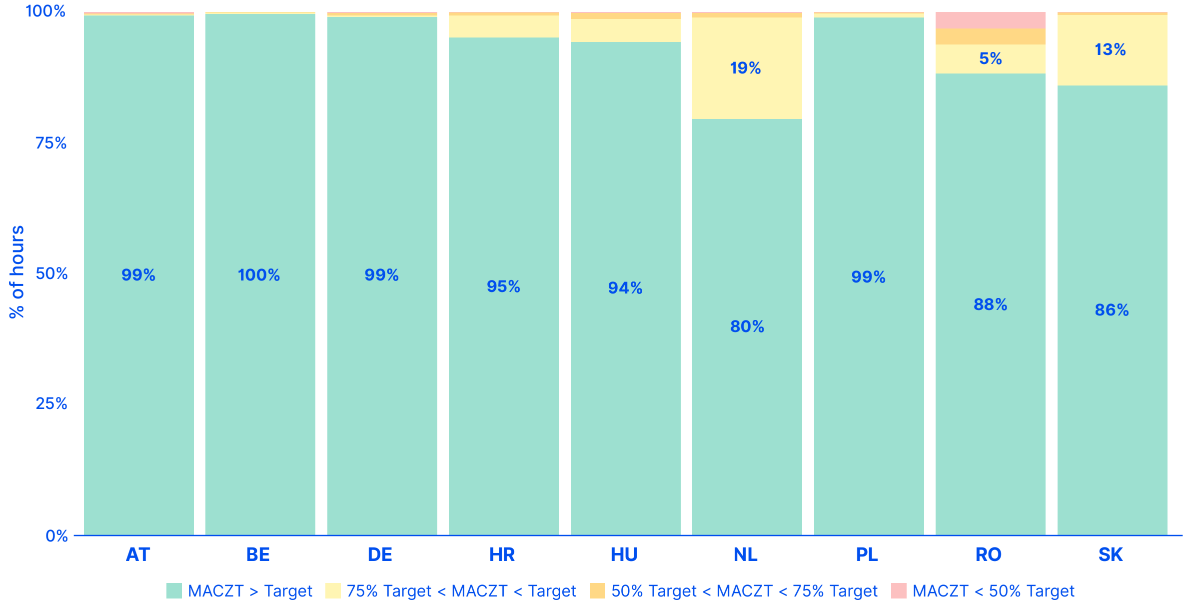
Note: 'Flat target' corresponds to derogations and/or actions plans that define a single requirement for all CNECs and hours of the year. When no derogation nor action plan is applicable, the minimum requirement shall be 70% for all CNECs and hours.

101 As highlighted in the figure, situations of high loop flows (i.e. flows stemming from transactions internal to a given bidding zone) in the Core region effectively leads to very low cross-zonal capacity requirements in some CNECs of the TSOs of Austria, the Netherlands and Poland. This underscores the importance of tackling jointly the presence of such flows, to enable the implementation of the minimum 70% requirement across the region.

102 These interim targets, defined in line with the approved derogations and/or action plans, were generally upheld in 2024, as shown in Figure 26. The capacity calculation methodology implemented in the Core CCR ensures that this is so, with an adjustment mechanism that increases the calculated margin of capacity to comply with the applicable requirement (either 70% or the interim target).

103 These are often referred to as 'virtual capacities', as they result in more than the physical capacity of a given CNEC to be accounted for, relying on remedial actions to secure the capacity offered should the market allocate all of it. Only when an operational security violation is identified, and insufficient remedial actions are forecasted to be available to address such violations, do TSOs reduce capacities below the applicable interim capacity requirement.

Figure 26: Percentage of hours when the minimum hourly MACZT was above the interim targets in the Core CCR for each Member State with an action plan and/or derogation, considering flows induced by third-country exchanges – 2024 (% of hours)



Source: ACER calculation based on TSO data.

Note: In the case of Slovakia, an interim requirement (50%) applies to a subset of the CNECs, yet the derogation specifies that such a target needs to be met only in 80% of the hours of the year.

104 While the interim requirements have generally been met, this is not always the case. In the case of Romania, for example, the interim requirement of 33% could not be upheld in 12% of the hours of the year. In the case of the Netherlands, on the other hand, an error in the local tool performing the dynamic calculation of the interim requirement, based on the forecasted loop flows, led to the legal requirement not being met for 20% of hours.

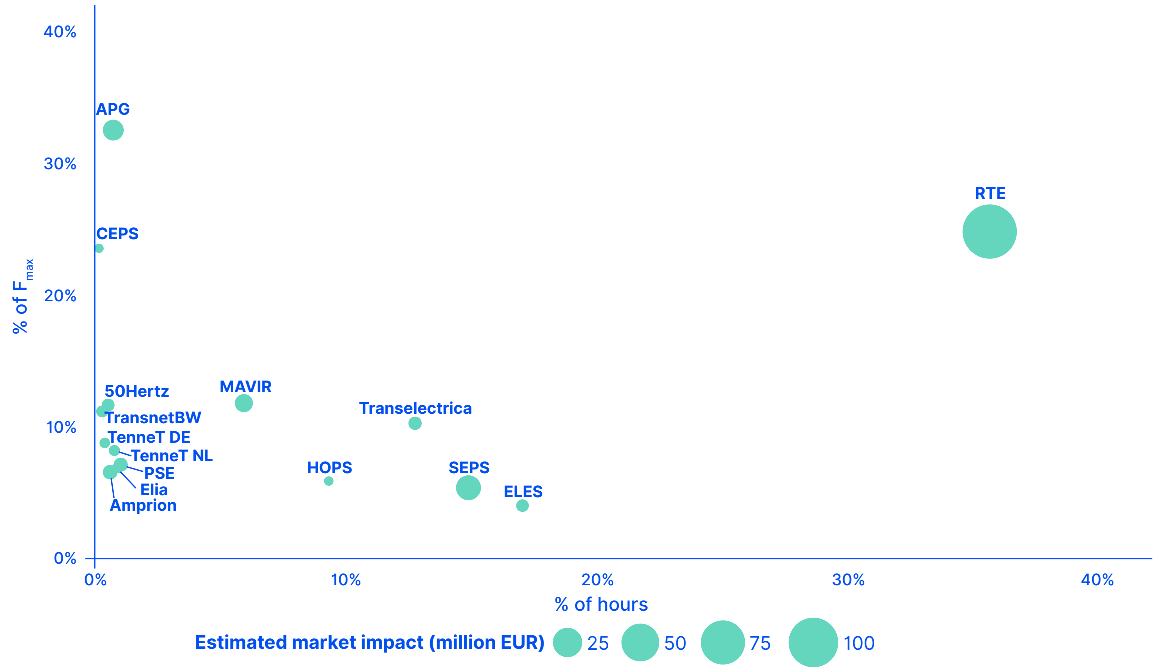
105 TSOs may, in accordance with Article 16(3) of the Electricity Regulation, deviate from the legally binding minimum cross-zonal capacity requirements, as a measure of last resort when such capacity levels would result in a violation of the operational security limits defined by each TSO. These deviations are accounted for by allowing a reduction in the cross-zonal capacities calculated by the regional coordination centre (RCC) either unilaterally or in a coordinated manner, whenever a risk to operational security that cannot be resolved through remedial actions is detected.

106 Currently, operational security in the validation of capacities is not assessed at the regional level, as a coordinated validation process has not yet been implemented, but is instead assessed within processes individual to each TSO or subset of TSOs. These are known as individual validation adjustments (IVAs). Figure 27 shows how often IVAs were applied (as a percentage of all hours, on the x-axis) and how much they effectively reduced the RAM on average (as a percentage of F_{max}, on the y-axis) in 2024, together with the estimated market impact.

107 In 2024, France stood out as the Member State with the highest need for validation reductions, following a period of physical congestion on non-Core network elements during spring[12]. These capacity reductions were imposed by the French TSO on Core CNECs to alleviate congestion on the non-Core network elements, leading to a significant impact in limiting the exchanges between France and the other Core bidding zones.

12 See RTE's communication to market participants in April 2024.

Figure 27: Application of IVA of each Core TSO weighted by the estimated market impact – 2024 (% of F_{max} and % of hours)



Source: ACER calculation based on JAO Publication Tool data.

Note: The market impact is estimated as the validation reduction (in MW) multiplied by the shadow price of each CNEC (in EUR/MW).

108 After the period of significant IVA application by the French TSO, the congested network elements were integrated into the Core capacity calculation process as CNECs. This has reduced the need for validation reductions by the French TSO, as the thermal limits of these network elements are now accounted for within the flow-based domain. However, these same elements continue to significantly restrict cross-zonal exchanges in the region, as they are heavily loaded by flows resulting from exchanges with Switzerland and Italy North. These exchanges are assumed as a baseline in the CGM used for capacity calculation, thereby in practice reserving a share of capacity of Core CNECs for them[13].

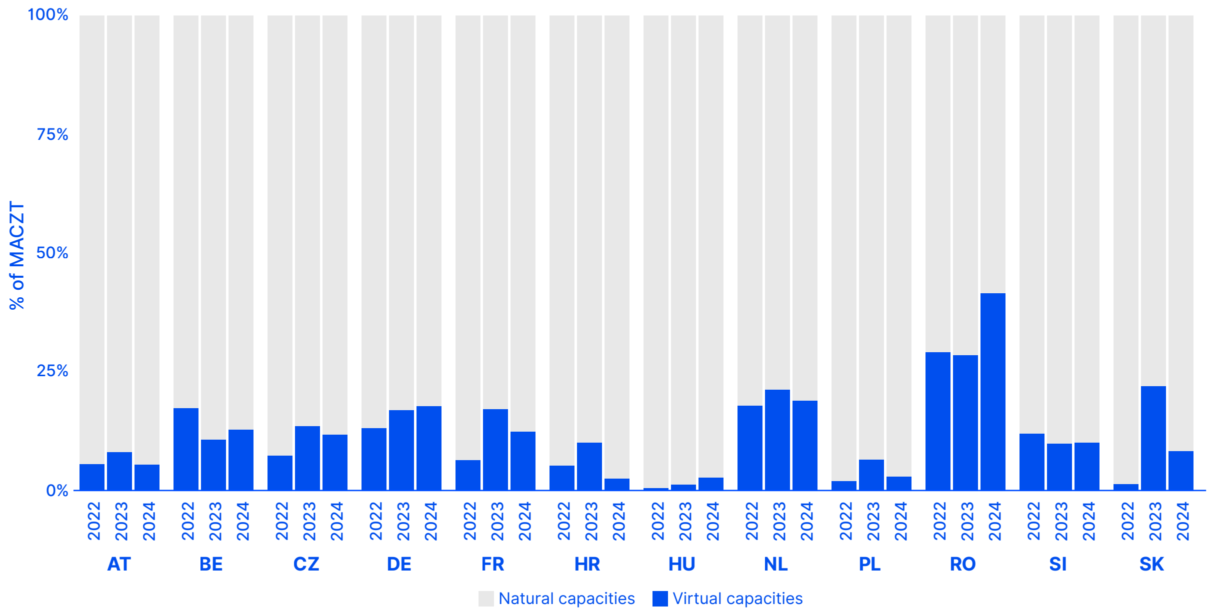
Applicable requirements are partly fulfilled by relying on virtual capacities, to a different extent per Member State

109 As previously mentioned, Core TSOs rely on virtual capacities to ensure that the applicable cross-zonal capacity requirements are fulfilled. The reliance on virtual capacities for such purpose depend mostly on two factors: on the one hand, the applicable cross-zonal capacity requirements defined in line with the applicable derogations and/or action plans and, on the other hand, the calculated capacities (or 'natural capacities') based on the forecasted loop and internal flows, and the forecasted exchanges outside the Core CCR.

13 For further information on the consideration of non-EU exchanges in EU capacity calculation, please consult section 2.4 of the ACER 2024 Market Monitoring Report on cross-zonal capacities and congestion management.

110 Figure 28 shows the share of the average MACZT offered in the worst-performing CNEC that corresponds to the adjustment for minimum RAM, compared with the share that initially calculated by TSOs, since the implementation of Core flow-based market coupling. As will be further discussed in Chapter 3, an increase in the use of virtual capacities may be associated with an increase in congestion management needs and costs.

Figure 28: Share of MACZT that corresponds to the adjustment for minimum RAM (AMR) and natural RAM in the CNECs with minimum hourly MACZT per Core TSO, considering flows induced by third-country exchanges – 2022-2024 (% of MACZT)



Source: ACER calculation based on JAO Publication Tool data.

111 In 2024, the TSOs needing to rely more on the use of AMR to fulfil the applicable requirements were those of Romania, the Netherlands and Germany. Over the last three years, the average reliance on AMR to fulfil the applicable requirements has not seen a generalised increase, in part due to applicable requirements not always increasing linearly.

2.2.2. Intraday time frame

112 A well-developed intraday market is a key-enabler for a more sustainable, affordable, and secure power system in the EU. The intraday time frame offers the possibility for market participants to adjust their positions close to real time, which is essential for optimal management of renewable, and intermittent, energy assets. This enables the rapid penetration of renewable energy generation into the system, while reducing the associated balancing needs and costs, which in turn results in a power system that is less reliant on fossil fuels, and therefore more independent and secure.

113 More efficient cross-zonal trade in the intraday time frame, through the improvement of capacity calculation and allocation processes, can meaningfully contribute to the success of intraday markets in enabling renewable penetration. In May 2024, Core TSOs implemented the first intraday flow-based capacity calculation (the IDCC(b)), which constitutes a major achievement in congestion management. This capacity calculation process is performed after the day-ahead operational security assessment, under a more accurate forecast of the state of the power system and feeds cross-zonal capacities to the second pan-European intraday

auction (IDA2). To unlock the full potential of intraday markets in the EU, continuing with other integration milestones, such as further flow-based calculations, the introduction of flow-based allocation, and the fulfilment of the minimum 70% requirement, will prove increasingly important.

114 During the amendment process of the Core intraday capacity calculation methodology, TSOs highlighted the difficulty of relying on remedial actions to secure a specific level of cross-zonal capacity in the intraday time frame. Indeed, in the intraday time frame TSOs have less time to identify and trigger remedial actions, should the capacities offered result in physical congestion. Therefore, the technical feasibility of the use of virtual capacity in the intraday time frame is not always guaranteed.

115 As mentioned in Chapter 2.2.1, virtual capacity plays a role in enlarging day-ahead domains to ensure the interim capacity requirements are met. Moreover, the inclusion of the LTA domain in the day-ahead capacity calculation process also results in capacities being offered to the day-ahead market beyond the calculated flow-based domains. Both these mechanism are not currently considered in the IDCC(b).

116 In light of the above, it is expected that the intraday capacity calculation process results in generally smaller domains, compared with those of the day-ahead time frame. In particular, the TSOs making extensive use of virtual capacity and releasing, or being affected by, large amounts of LTA will likely see the biggest decreases.

117 To quantify the differences between Core day-ahead and intraday capacity calculations, ACER computed the following metrics to compare the capacity calculation outputs:

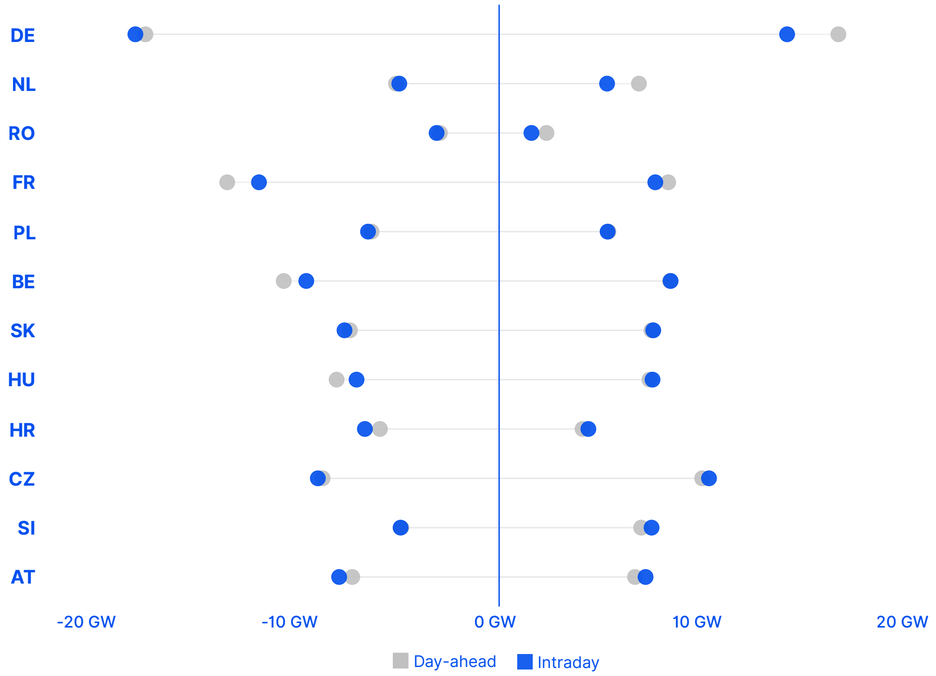
- minimum and maximum net positions in day ahead and IDCC(b);
- number of instances and magnitude of negative RAMs in IDCC(b);
- margin available for cross-zonal trade in day-ahead capacity calculation and IDCC(b).

118 This section aims to further investigate the challenges associated with the implementation of the minimum 70% requirement in the intraday time frame and quantify what the starting point of each TSO is in terms of margins of capacity offered in the intraday time frame, in order to facilitate an eventual implementation of the requirement.

Minimum and maximum net positions define the bounds of the flow-based domains

119 Maximum and minimum net positions represent the potential import and export values for each bidding zone with regard to the rest of the Core CCR, defining the bounds of the flow-based domains and thus providing an estimation on the size of the domains.

Figure 29: Average minimum and maximum net positions of Core bidding zones within Core IDCC(b) and day-ahead capacity calculation – June to December 2024 (GW)



Source: ACER elaboration based on JAO Publication Tool data

Note: The minimum and maximum net position corresponds to the maximum amount of electricity that a given bidding zone can export or import to or from the other bidding zones in the Core CCR, within the bounds of the flow-based domain.

120 The average minimum and maximum net positions per bidding zone, as presented in Figure 29, show significant reductions in several bidding zones (such as Germany–Luxembourg, the Netherlands, Belgium and Romania), highlighting lower bounds of the intraday flow-based domains. Notably, in most of these cases, it is the export bound that is relatively lower in IDCC(b), with the import bound being less affected.

121 On the other hand, bidding zones such as Slovakia, Croatia or Poland do not see such a drop in min-max average net positions, presenting greater or equal bounds to the IDCC(b) flow-based domains, compared to day-ahead, both in import and export directions.

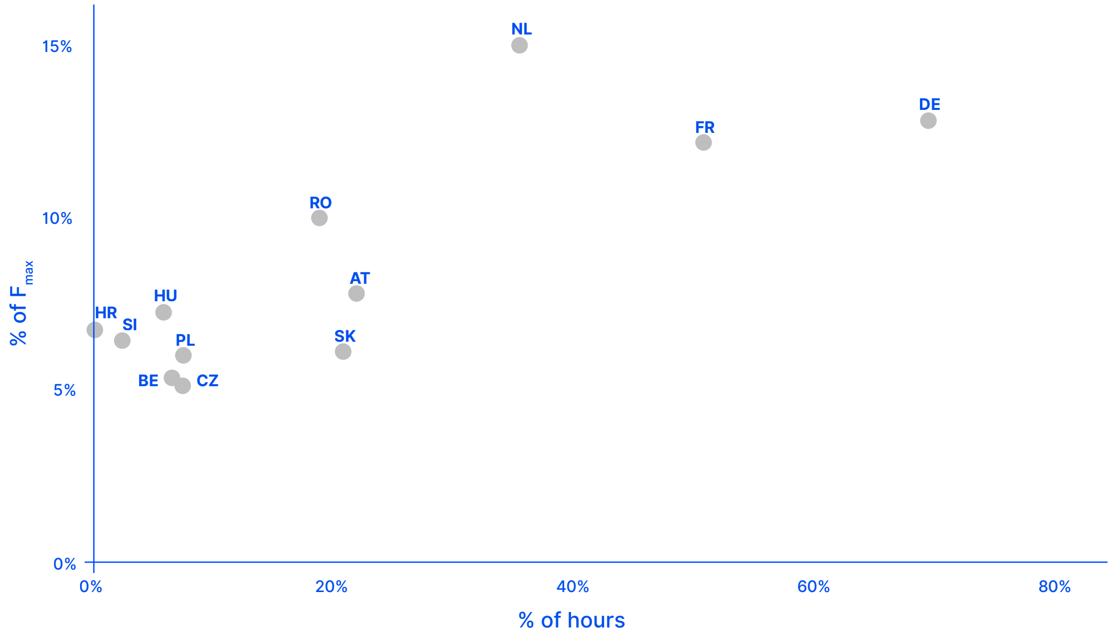
Negative RAMs highlight instances where the day-ahead clearing is no longer technically feasible under the intraday flow-based domains

122 Whenever the capacity offered on a given CNEC is smaller in intraday IDCC(b) compared with day-ahead capacity calculation, and when all available capacity on such a CNEC is used by the day-ahead market, the day-ahead market clearing point will be located outside the intraday flow-based domain. In such cases, the distances between the market clearing point and the nearest CNEC (i.e. the RAM) will be negative, as illustrated in Annex II: Flow-based explanatory figures.

123 Figure 30 presents the number of instances where at least one CNEC had a RAM below zero in the IDCC(b) domains, together with the average absolute value of such negative RAM. It shows a significant number of instances in which the intraday domains are smaller than the day-ahead domain in specific CNECs and quantifies the average distance between the day-ahead clearing and the intraday domain.

124 It is worth noting that this metric accounts for all instances in which the day-ahead clearing is no longer feasible under the intraday domains, thus revealing a share of the instances in which the calculated intraday domains are smaller than the day-ahead domains. Nonetheless, this metric does not include all instances where this is the case, as the day-ahead market will not always make use of all trade permitted under the day-ahead flow-based domain.

Figure 30: Percentage of hours in which at least one CNEC has a RAM below zero in the IDCC(b) domains for the Core Member States and average absolute negative RAM as a share of F_{max} – June to December 2024 (% of hours and % of F_{max})



Source: ACER calculation based on JAO Publication Tool data.

Use of virtual capacities in the day-ahead time frame will result in lower intraday MACZT levels, if these are not reoffered

125 A key metric of the levels of capacity released in the intraday time frame is the MACZT offered on each CNEC of the intraday flow-based domain. Similarly to the day-ahead time frame, this metric represents the share of the physical capacity of a given CNEC that is made available to accommodate for cross-zonal trade. This metric needs to account for physical capacity that was offered and used in previous market time frames – for IDCC(b), day-ahead and previous intraday trading – as these result in loading of the CNEC[14].

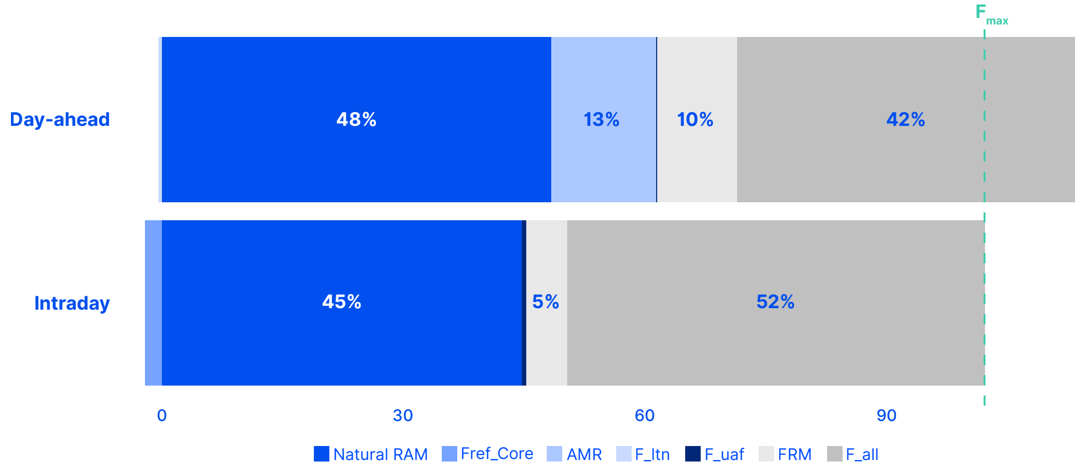
126 As highlighted across this section, TSOs are currently not adjusting calculated capacities in IDCC(b) to account for any minimum cross-zonal capacity requirement. Therefore, the MACZT in IDCC(b) will tend to be smaller than in day-ahead, expect for the CNECs where all offered capacity is effectively used by previous market time frames.

127 Figure 31 displays the average breakdown of the flow components on the most constrained CNECs in the IDCC(b) domains, and its comparison with the same CNECs in the day-ahead domain. As expected, this metric reveals a significant drop in the average minimum MACZT, resulting from the absence of the adjustment for minimum RAM in the intraday time frame. On the other hand, the reduced uncertainty closer to real time, enables 5% more physical capacity to be offered to the market through a lower reliability margin.

14 Cross-border remedial actions triggered after the day-ahead market clearing may affect the flows induced by previous cross-zonal trading reported by Core TSOs, as they may be implemented already in the CGM that is used as basis for the intraday capacity calculation.

128 As the metric is created by assessing the CNEC with the lowest MACZT value in IDCC(b) per TSO, and comparing those same CNEC with day-ahead capacity calculation, it is reasonable to assume that these CNECs are generally not in the direction that was useful to the market in previous time frames. This is because the CNECs that were useful in the previous market time frame will have a high share of flows induced by capacities already allocated (or $F_{ref,Core}$), and thus also a relatively high level of MACZT.

Figure 31: Average breakdown of F_{max} in the Core day-ahead and IDCC(b) domains, on the CNECs with the lowest MACZT per TSO and hour in IDCC(b) – June to December 2024 (% of F_{max})



Source: ACER elaboration based on JAO Publication Tool data.

Note: MACZT in intraday includes RAM, $F_{ref,Core}$ and F_{uaf}. The legend presented in the figure is defined as follows:

- $F_{ref,Core}$: flow originated from the Core net positions which are already included in the CGM;

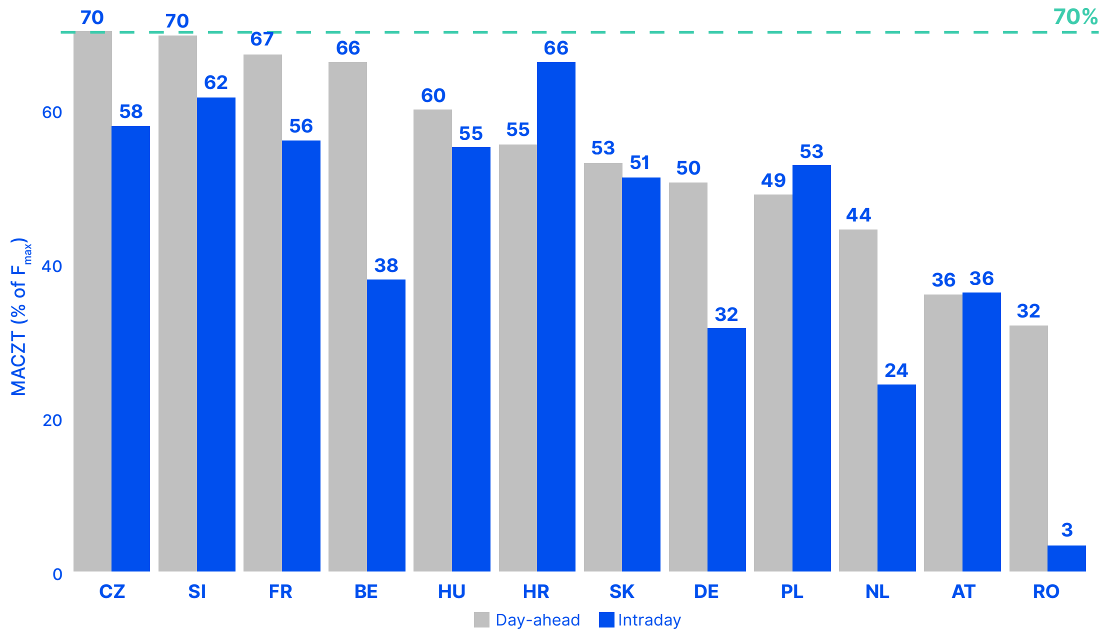
- F_{ltn}: flow induced by long-term nominations;

- F_{uaf}: unscheduled allocated flow (i.e. the flow per CNEC resulting from commercial exchanges outside Core CCR);

- F_{all}: flow per CNEC in a situation without any commercial exchange between bidding zones.

129 As specified in section 2.2.1, Core TSOs rely to a varying extent on virtual capacities to secure their minimum cross-zonal capacity requirements in the day-ahead time frame. Therefore, they will be unevenly affected by not relying on the same mechanism in IDCC(b). Figure 32 assesses the breakdown of the average minimum MACZT offered in IDCC(b) and day-ahead capacity calculation per Member State. While the Member States most reliant on virtual capacities in the day-ahead time frame show the largest relative decreases in intraday MACZT levels, others exhibit only minor reductions—or even increases.

Figure 32: Average minimum hourly MACZT in the Core CCR per Member State in IDCC(b) and day-ahead capacity calculation, considering flows induced by third-country exchanges – June to December 2024 (% of F_{max})



Source: ACER elaboration based on JAO Publication Tool data.

Note: MACZT in intraday capacity calculation includes RAM, $F_{ref,Core}$ and F_{uaf}.

130 These results highlight the different starting points for Core TSOs in the implementation of the minimum 70% requirement in the intraday time frame, as a consequence of the need to rely on virtual capacities to fulfil the applicable cross-zonal capacity requirements in the day-ahead time frame.

Despite the Core IDCC(b) go-live being a major achievement, it resulted in an average reduction of the offered cross-zonal capacities

131 In May 2024, Core TSOs implemented the first flow-based capacity calculation for the intraday time frame, defining the capacities released at 22:00 of the day before delivery of electricity. However, the implementation process is only partially complete, as flow-based allocation is not yet enabled within SIDC, with the potential of flow-based market coupling being constrained by the need to perform an ATC-extraction after the flow-based capacity calculation.

132 Prior to the implementation of pan-European intraday auctions, in June 2024, Core TSOs did not release any capacity for (continuous) cross-zonal trade until 22:00 of day-ahead. Currently, Core TSOs release a share of the leftovers from day-ahead already at 15:00. These leftovers are based on an ATC-extraction from the day-ahead flow-based domains, which are adjusted to partially remove the effect from virtual capacities and LTAs.

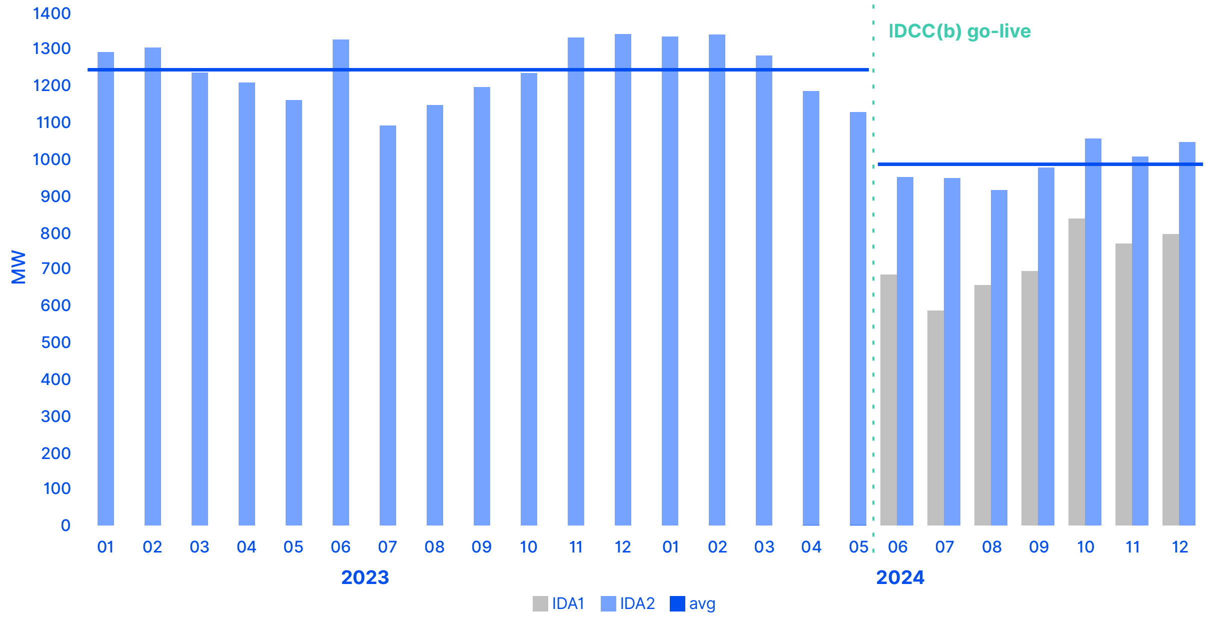
133 Since the go-live of Core IDCC(b), capacities released at 22:00 are no longer based on day-ahead leftovers and a bilateral increase process but are the outcome of the dedicated flow-based capacity calculation process. Figure 33 displays the average monthly ATCs released in the Core CCR, at both 15:00 and 22:00 of the day before delivery of electricity, a noticeable reduction of average capacities offered to the intraday market at 22:00, since the go-live of Core IDCC(b). The reason is two-fold:

- ATC-extraction is performed on the IDCC(b) flow-based domains, as opposed to the day-ahead flow-based domains, thus not relying at all on virtual capacities and LTA to expand the flow-based domains.

- Prior to IDCC(b) go-live, TSOs were performing a bilateral capacity increase (or decrease) process from the day-ahead leftovers, which occasionally resulted in additional cross-zonal capacities released to continuous intraday trading.

134 The relatively low levels of offered intraday ATCs exemplify the inefficiencies of an ATC allocation after a flow-based capacity calculation process, stressing the importance of a prompt implementation of flow-based allocation in pan-European intraday auctions[15].

Figure 33: Average intraday cross-zonal capacities released at 15:00 and 22:00 in Core CCR before and after IDCC(b) go-live – 2023-2024 (MW)



Source: ACER elaboration based on ENTSO-E Transparency Platform data.

Note: The metric shows the sum of capacity released in both directions of a given bidding zone border, averaged for the whole region. The capacity levels displayed for the period before the implementation of pan-European intraday auctions correspond to the cross-zonal capacity released for continuous trading at 15:00 and 22:00.

2.3. Assessment of the first months of flow-based market coupling in the Nordic region

135 In October 2024, Nordic TSOs implemented flow-based market coupling in the day-ahead time frame, constituting a major step forward in the integration of electricity markets in the Nordic region. Up until then, Nordic TSOs relied on uncoordinated or bilateral NTC calculation processes to define the exchanges between Nordic bidding zones. This section assesses the performance of the first months of Nordic flow-based market coupling, including the level of fulfilment of the minimum 70% requirement by Nordic TSOs, and the impact of flow-based implementation on cross-zonal capacities for the intraday time frame.

15 ACER intends to estimate the potential benefits on economic surplus of implementing flow-based allocation in pan-European intraday auctions in the next volume of the 2025 market monitoring report, with publication planned for November.

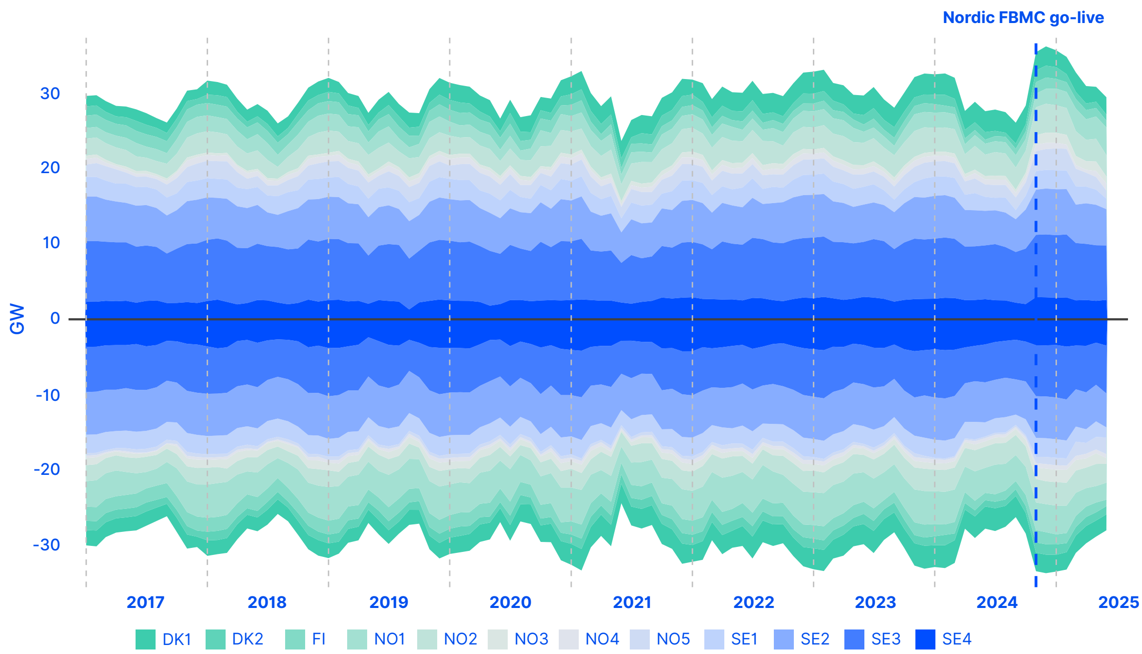
2.3.1. Day-ahead time frame

136 Within the flow-based process, Nordic TSOs model a subset of network constraints and provide information on such network constraints to the price coupling mechanism. The algorithm can then allocate the capacity made available on each CNEC to the electricity exchanges that generate the most economic surplus, allowing for a more efficient use of the available network in the Nordic CCR. Unlike NTC values, which are simultaneously feasible on all bidding zone borders of a given bidding zone, the maximum import and export capacities in flow-based regions on a given bidding zone border are dependent on other exchanges within the region.

137 One potential metric to quantify the impact of the implementation of flow-based market coupling on available capacity is the average non-simultaneous minimum and maximum net positions from Nordic bidding zones within the capacity calculation process. This represents the limits of how much a given bidding zone can theoretically import or export to the other bidding zones in the region, provided that this is the optimal level of cross-zonal exchanges.

138 When comparing the bounds of cross-zonal exchanges under flow-based market coupling with the previous NTC processes, as shown in Figure 34, it can be observed that the implementation of flow-based market coupling has indeed led to an increase in the monthly averages of the capacities offered, which is particularly noticeable in the export direction.

Figure 34: Evolution of the monthly average non-simultaneous minimum and maximum net positions per bidding zone in the Nordic CCR – 2017-2024 (GW)



Source: ACER elaboration based on JAO Publication Tool and ENTSO-E Transparency Platform data.

Note: The figure aggregates the monthly average of the maximum import and export capacity offered per bidding zone within the Nordic CCR. Since the introduction of flow-based market coupling, the non-simultaneous minimum and maximum net position value is used, as published in the JAO Publication Tool. Prior to flow-based market coupling, the sum of NTCs in the export and import directions was calculated for every bidding zone.

The minimum 70% requirement in the Nordic capacity calculation region

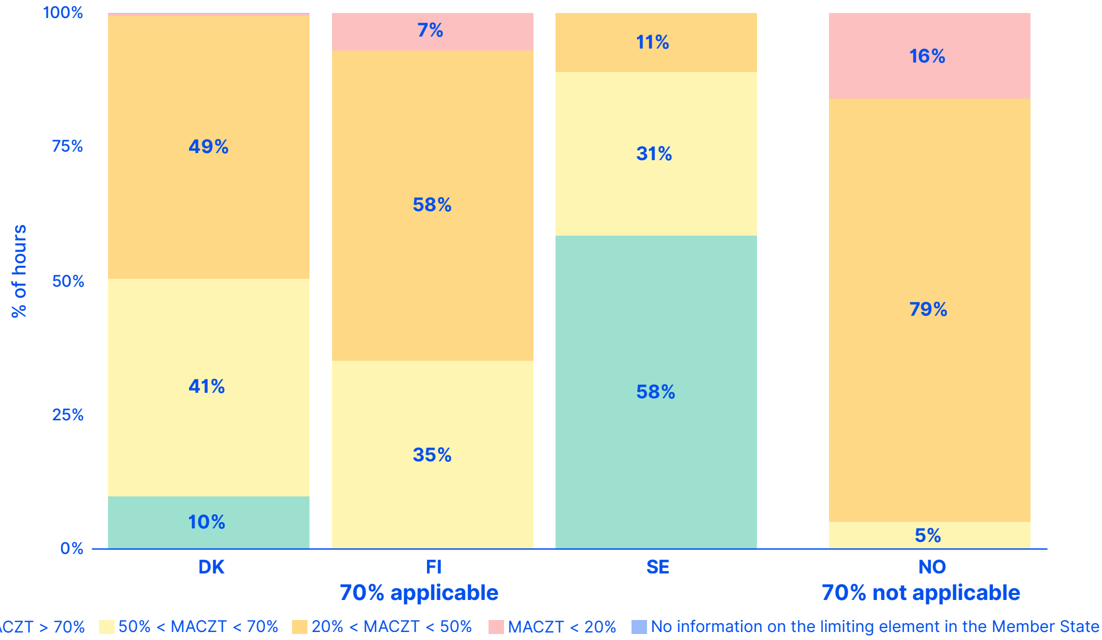
139 The implementation of Nordic flow-based capacity calculation allows for the MACZT to be computed and monitored on all CNECs defined by Nordic TSOs. The go-live of the Nordic flow-based market coupling increased the degree of coordination among Nordic TSOs when calculating capacities, compared with the previous NTC national calculations.

140 In the Nordic CCR, two major considerations are to be considered in terms of the status of the minimum 70% requirement. First, no derogation or action plan is in place in the Nordic CCR – the minimum 70% requirement is applicable today[16]. Second, the more granular bidding zone configuration in the Nordic CCR is expected to enable the fulfilment of the minimum 70% requirement without widespread reliance on remedial actions. For this reason, the Nordic capacity calculation methodology does not currently consider the use of virtual capacities to fulfil 70%.

141 Moreover, Nordic flow-based applies advanced hybrid coupling on the bidding zone borders external to the Nordic CCR that are part of SDAC. By doing so, such borders are modelled as virtual bidding zones within SDAC, and the capacity released in Nordic CNECs can then be allocated to the border that results in higher economic surplus. For the purpose of MACZT monitoring, advanced hybrid coupling entails that there is no impact from external bidding zone borders on the RAM offered on each CNEC.

142 Figure 35 presents the level of fulfilment of the minimum 70% requirement since the implementation of Nordic flow-based market coupling. Also in this case, as the minimum 70% requirement is to be respected in all CNECs for every hour, ACER's monitoring assesses the CNECs with the lowest value of MACZT for every hour. It is important to note, that these CNECs are not necessarily the ones limiting cross-zonal trade in the Nordic CCR.

Figure 35: Percentage of hours when the minimum hourly MACZT was above 70%, or within predefined ranges, in the Nordic CCR for each Member State – 29 October to 31 December 2024 (% of hours)



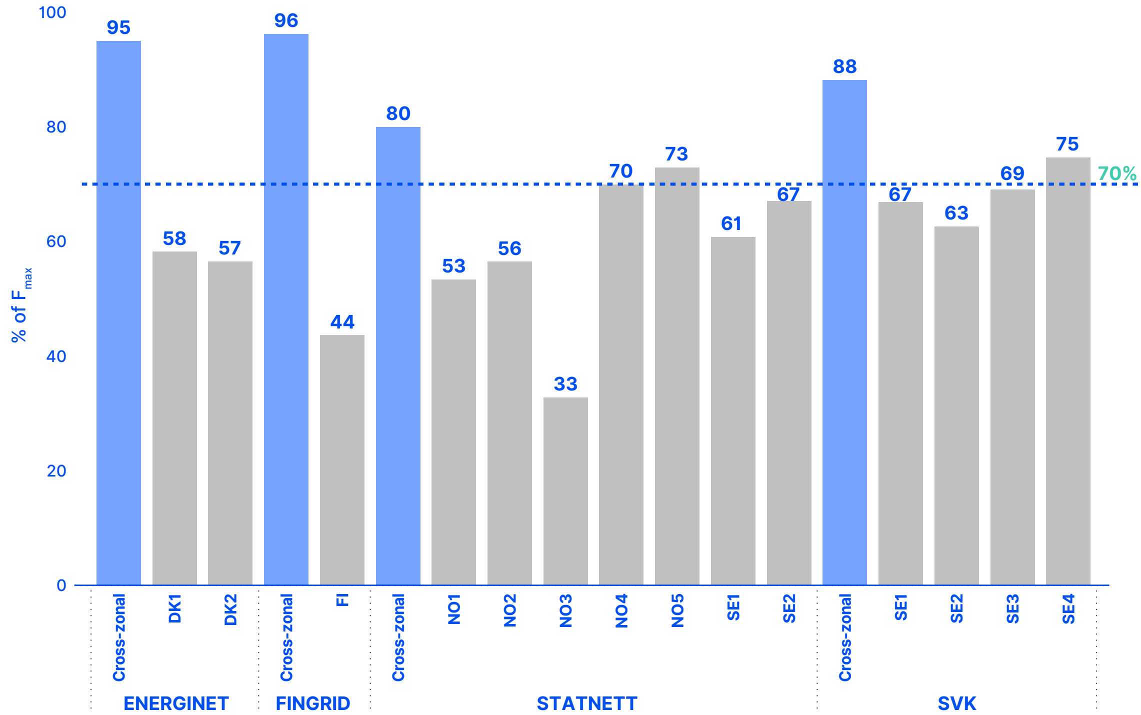
Source: ACER elaboration based on TSO data for Denmark, Finland and Sweden, and JAO Publication Tool data for Norway.

Note: The figures presented do not include the impact of flows induced by forecasted exchanges with the UK, as the information necessary to calculate it was not made available to ACER.

16 In the case of Norway, the Clean Energy Package is pending incorporation into the EEA Agreement. Therefore, the Norwegian TSO is not legally bound by the obligations defined in the Electricity Regulation.

143 Data reported from Nordic TSOs enables the CNECs introduced by Nordic TSOs in the flow-based capacity calculation to be grouped by whether they are internal to a given bidding zone or cross-zonal. Such analysis indicates that loop flows in the cross-zonal network elements appear to be negligible, leading to cross-zonal CNECs offering high levels of MACZT (above 80% on average). However, some bidding zones appear to have significant flows not stemming from cross-zonal exchanges (e.g. NO3 and FI), limiting the values of the capacity offered to the day-ahead market on specific network elements. This is shown in Figure 36.

Figure 36: Average minimum hourly margin available for cross-zonal trade in the Nordic capacity calculation region per TSO and constraint location – 29/10/2024 to 31/12/2024 (% of F_{max})



Source: ACER calculation based on JAO Publication Tool data.

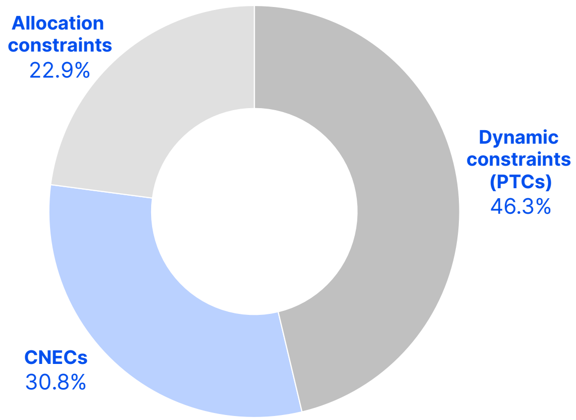
Note: The figures presented do not include the impact of flows induced by forecasted exchanges with the UK, as the information necessary to calculate it was not made available to ACER.

Non-thermal constraints and HVDC limits are mostly defining cross-zonal trade in the Nordic CCR.

144 In Nordic flow-based market coupling, different types of constraints are introduced by Nordic TSOs to define the cross-zonal exchanges within the Nordic CCR. Combined dynamic constraints (PTCs) are introduced for the purpose of respecting dynamic stability limits, as a limit on the sum of power flows on a set of network elements, usually on the bidding zone borders. Moreover, allocation constraints are introduced to define capacities on HVDC lines, mostly corresponding to bidding zone borders external to the Nordic CCR (i.e., those connecting the Nordic and continental Europe synchronous areas).

145 These non-thermal constraints, together with the CNECs defined by Nordic TSOs, bound the cross-zonal exchanges within the Nordic CCR and in the external bidding zone borders. Assessing the active constraints in Nordic flow-based market coupling reveals that only 30% of the total market congestion in the region corresponded to thermal constraints on specific pairs of network elements (i.e. CNECs), with the remaining 70% corresponding to both PTCs and allocation constraints.

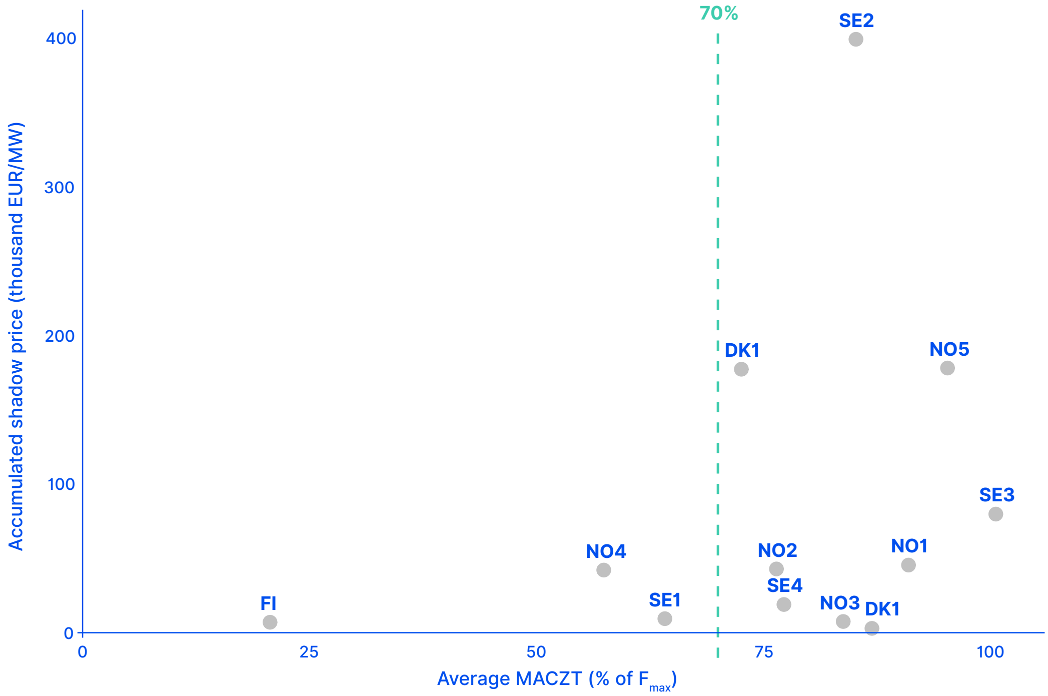
Figure 37: Relative share of market congestion in the Nordic CCR per type of capacity constraint - 29 October 2024 to 31 March 2025 (% of accumulated shadow price)



Source: ACER calculation based on JAO Publication Tool.

146 In particular, it is worth noting that all active constraints at the bidding zone borders in Nordic flow-based market coupling correspond to either PTCs or allocation constraints, while CNECs that limit additional cross-zonal trade are mostly internal. Figure 38 shows the location, and average MACZT, of all active CNECs in Nordic flow-based market coupling. As observed in the figure, internal CNECs that are most limiting to additional cross-zonal trade in the Nordic region usually offer a high degree of MACZT.

Figure 38: Accumulated market congestion and average MACZT per location of CNECs in the Nordic CCR - 29 October 2024 to 31 March 2025 (thousand EUR/MW and % of F_{max})



Source: ACER calculation based on JAO Publication Tool.

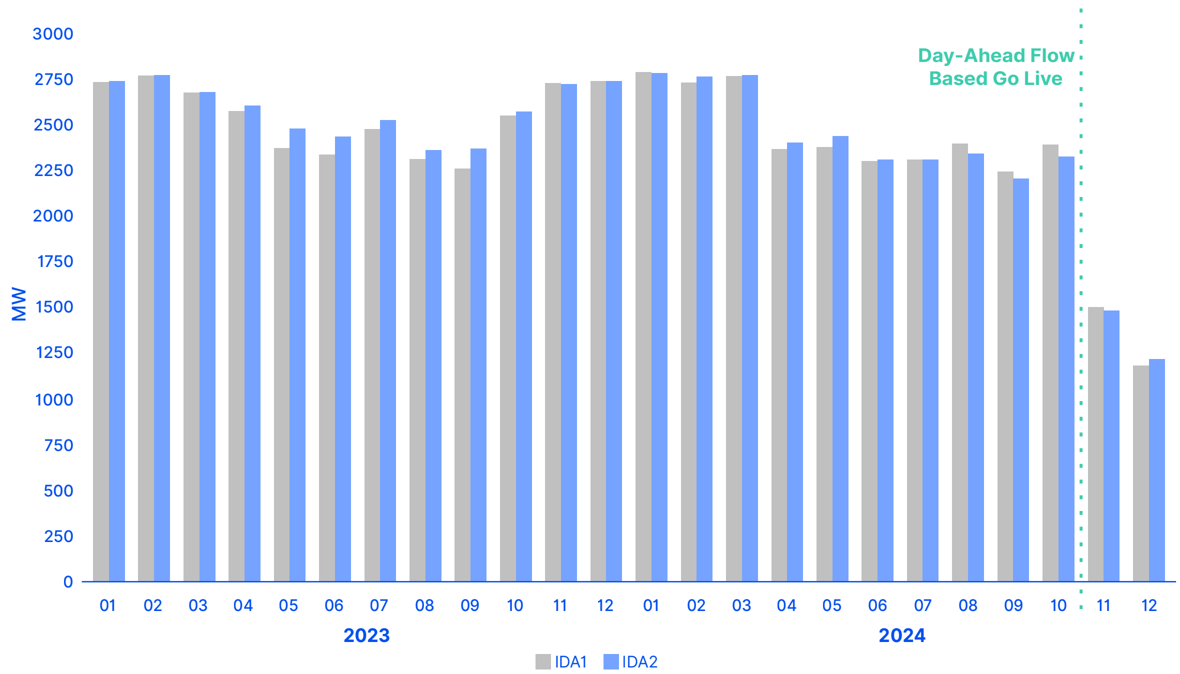
Note: The figures presented do not include the impact of flows induced by forecasted exchanges with the UK, as the information necessary to calculate it was not made available to ACER.

2.3.2. Intraday time frame

147 Cross-zonal capacities offered to intraday markets in the Nordic CCR, both auctions and continuous, are based on day-ahead leftovers, as there is no specific intraday flow-based calculation implemented yet. Up until the implementation of Nordic flow-based market coupling in the day-ahead time frame, intraday capacities were based on the leftovers from the NTCs calculated in day-ahead. Since October 2024, leftover capacities are extracted from the day-ahead flow-based domain using an ATC-extraction algorithm, similar to the process used in the Core region.

148 Figure 39 shows the average cross-zonal capacities offered in the Nordic CCR at 15:00 and 22:00 day-ahead (corresponding to the timings of IDA1 and IDA2). Following the go-live of Nordic flow-based in day-ahead, intraday capacities have seen a significant drop, revealing the inefficiencies associated with an ATC allocation after a flow-based capacity calculation process.

Figure 39: Average intraday cross-zonal capacities at 15:00 and 22:00 day-ahead in the Nordic CCR before and after Nordic flow-based market coupling go-live – 2023-2024 (MW)



Source: ACER elaboration based on ENTSO-E Transparency Platform data.

Note: The metric shows the sum of capacity released in both directions of a given bidding zone border, averaged for the whole region. The capacity levels displayed for the period before the implementation of pan-European intraday auctions correspond to the cross-zonal capacity released for continuous trading at 15:00 and 22:00.

2.4. Other regional developments

149 In other CCRs, an NTC capacity calculation process applies, with varying degrees of coordination between TSOs. In the Italy North, Greece-Italy, SEE and SWE CCRs, a coordinated NTC (CNTC) process is applied. In these regions, TSOs monitor and report to ACER the CNEC, or the allocation constraint, that has limited each capacity calculation process. This means that, for a given market time unit, information on only one single CNEC is provided for every calculation.

2.4.1. Italy North

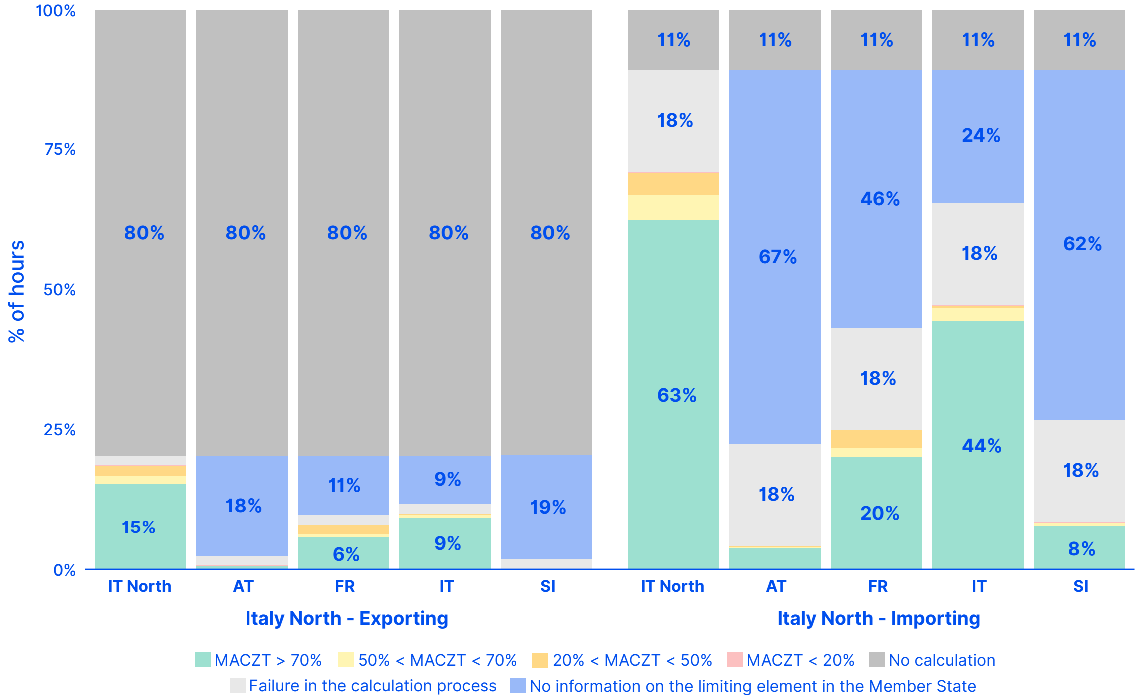
150 The Italy North CCR encompasses the northern borders of Italy, covering the following bidding zone borders: France–Italy North, Austria–Italy North and Slovenia–Italy North. It applies the coordinated NTC calculation approach, based on the approved capacity calculation methodology. In this region, a single calculation is performed to maximise the total import capacity into Italy, including in the bidding zone border Switzerland–Italy North. The calculated value for total capacity is then split among all borders.

151 Since 18 June 2024, for trading day 19 June 2024, a coordinated capacity calculation process in the export direction has also been implemented for the day-ahead time frame. Within this process, the likely market direction is forecasted and an export calculation is triggered on the borders with expected export from Italy North, replacing the calculation where the total import capacity into Italy is maximised. Therefore, since 19 June 2024, Italy North TSOs have reported on the limiting CNEC of the capacity calculation process, flagging the market time units where an export calculation is performed on at least one bidding zone border. Up until that point, the Italian TSO requested a derogation from the minimum 70% requirement in this direction.

152 Figure 40 shows the percentage of hours when the limiting element was above the minimum 70% requirement, or within a set of predefined ranges, in each Member State in the region and in the CCR as a whole. It also presents the percentage of hours when the limiting CNEC was, from the perspective of each Member State, located elsewhere in the region. The figure shows that, for most hours, Italy North TSOs were able to offer 70% on the CNECs that limit the capacity calculation.

153 It is relevant to note that, during 19% of the reported hours in the import direction and 8% of those in the export direction, Italy North TSOs reported a failure of the capacity calculation process, which implies that information on the limiting CNEC could not be provided. In such cases, long-term capacities are offered to the day-ahead market.

Figure 40: Percentage of hours when the hourly MACZT was above 70% or within predefined ranges in the Italy North CCR for each Member State, considering flows induced by third-country exchanges – 2024 (% of hours)



Source: ACER calculation based on TSO data.

Note: The Italy North export corner was implemented on 19 June 2024. Therefore, the figure on the left includes only 19 June to 31 December 2024. 'Italy North – Exporting' corresponds to the calculation in which at least one bidding zone border is maximised in the export direction.

154 While the figure shows the extent to which Member States in the Italy North region offered a minimum of 70% MACZT on the limiting CNECs in 2024, it does not assess the reasons for the deviation below 70%. The relatively high margins of capacity offered in Italy North can be explained by the fact that the capacity calculation includes an adjustment process that increases the calculated capacities through remedial actions made available by the TSOs, ensuring that the margin made available on the limiting CNEC is always above 70%.

155 Additionally, the Italian TSO applies an allocation constraint on the total capacity in the import and export directions for the northern borders of the Italy North bidding zone. This is done to take into account the voltage and stability restrictions of the Italian system, and a derogation has been granted to the Italian TSO for this purpose.

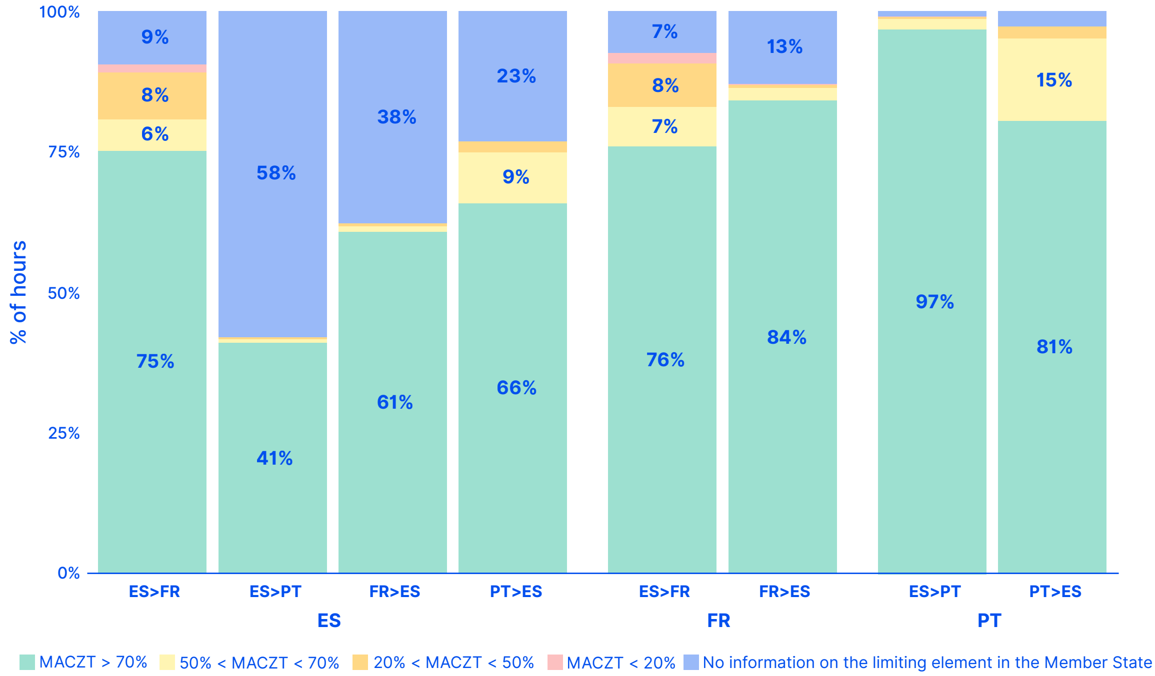
2.4.2. South-West Europe

156 The SWE CCR encompasses the following bidding zone borders: Spain–Portugal and Spain–France. It applies a coordinated NTC calculation approach, based on the approved capacity calculation methodology. In contrast to the Italy North region, in SWE one calculation is performed for each border separately and in both directions; thus, one limiting CNEC is reported for each border and direction.

157 Figure 41 shows the percentage of hours when the limiting element was above the minimum 70% requirement, or within a set of predefined ranges, in the SWE region. It also presents the percentage of hours when the limiting CNEC was, from the perspective of every Member State, located in the neighbouring Member State and, therefore, the TSO had no limiting CNEC to report.

158 In the SWE region, the impact of flows induced by cross-zonal exchanges outside the region (i.e., the margin for non-coordinated capacity calculation) is considered low; thus, SWE TSOs neither calculate such impact nor provide the necessary information for ACER to estimate it.

Figure 41: Percentage of hours when the hourly MACZT was above 70% or within predefined ranges in the SWE CCR for each Member State and oriented bidding zone border – 2024 (% of hours)



Source: ACER calculation based on TSO data.

159 In this region, mostly due to its geographical set-up, the impact from both loop flows and uncoordinated allocated flows from other CCRs is limited. Moreover, an adjustment process within the capacity calculation leads to a relatively high degree of fulfilment of the 70% requirement.

2.4.3. South-East Europe

160 The SEE CCR encompasses the following bidding zone borders: Bulgaria-Romania and Bulgaria–Greece. It applies a coordinated NTC calculation approach, based on the approved capacity calculation methodology. In this region, critical network elements are heavily influenced by exchanges in nearby bidding zone borders, mainly those with and between the Western Balkans countries.

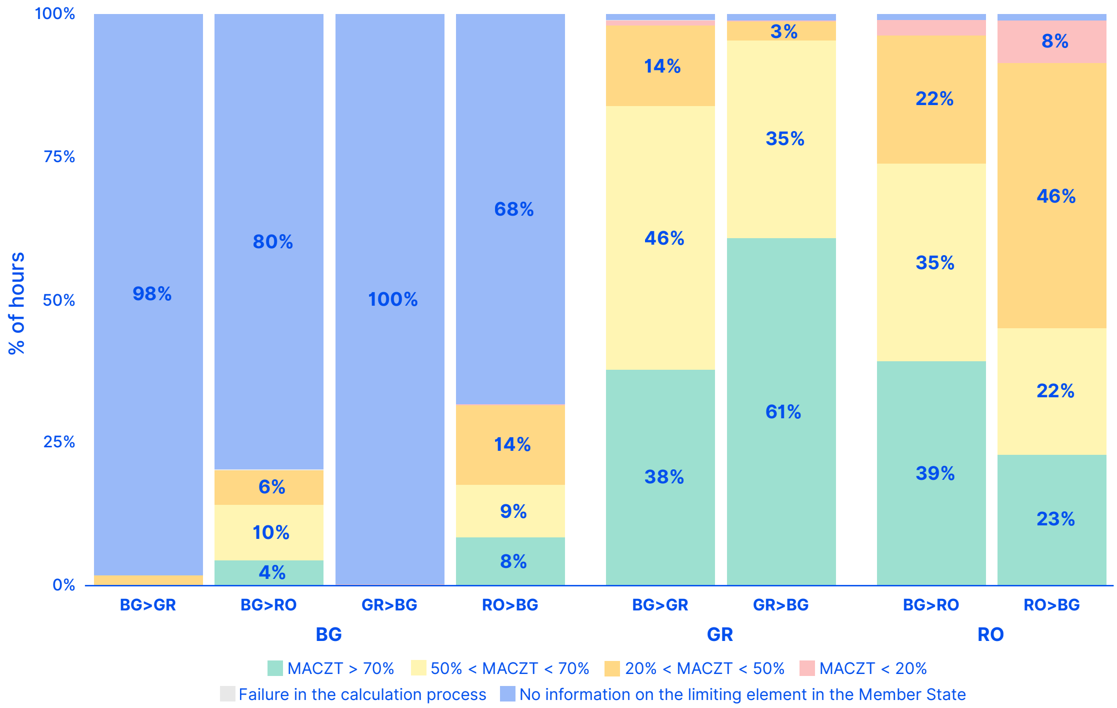
161 In SEE, calculations are performed for the northern Greek (Albania–Greece, North Macedonia–Greece, Bulgaria–Greece and Türkiye–Greece) and southern Romanian (Romania–Serbia and Romania–Bulgaria) bidding zone borders, in both directions, and the calculated capacity is then split among all borders. One limiting CNEC is thus reported for each calculation and direction.

162 Figure 42 shows the percentage of hours when the relative MACZT was above the minimum 70% requirement or within a set of predefined ranges in the SEE region. It also presents the percentage of hours when the limiting CNEC was, from the perspective of every Member State, located in the neighbouring Member State, and therefore the TSO had no limiting CNEC

to report. This is particularly evident in the case of Bulgaria, for which the limiting CNEC on the Bulgaria–Greece and Bulgaria–Romania borders is often located in Greece and Romania, respectively.

163 While the figure shows the extent to which Member States in the SEE region offered a minimum of 70% MACZT on its limiting CNECs in 2024, it does not assess the reasons for deviating below 70%. Reductions of capacity may be sent by either TSO on each bidding zone border during the capacity validation phase.

Figure 42: Percentage of hours when the hourly MACZT was above 70% or within predefined ranges in the SEE CCR for each Member State and oriented bidding zone border, considering flows induced by third-country exchanges – 2024 (% of hours)

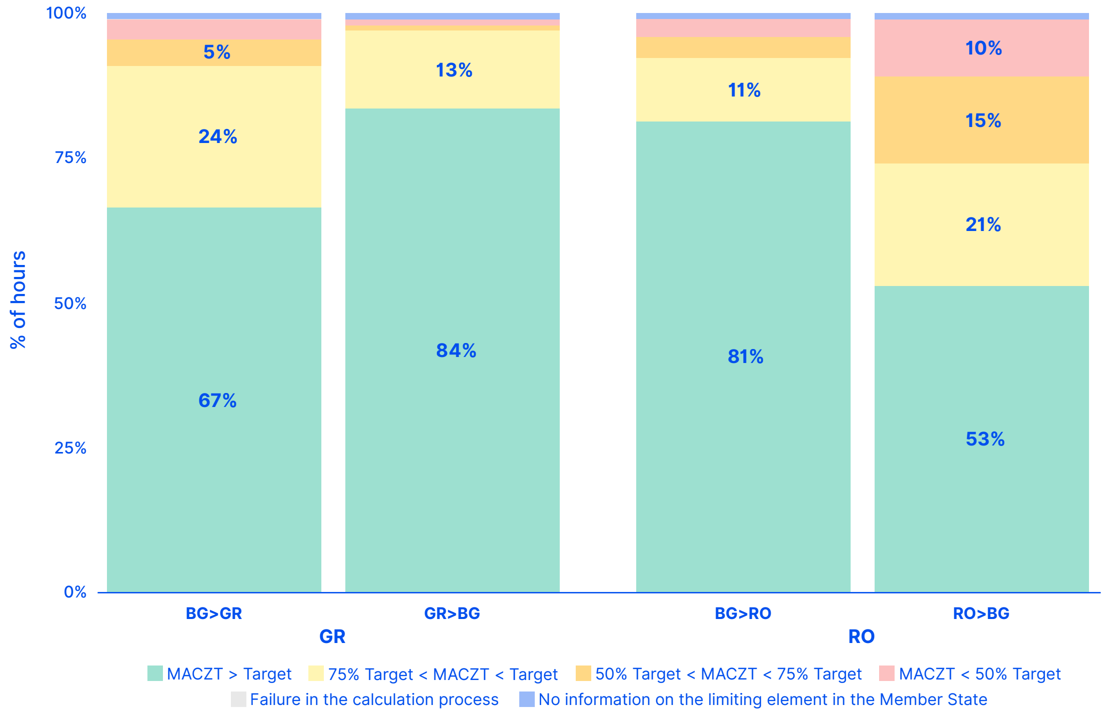


Source: ACER calculation based on TSO data.

164 Unlike in the previous regions analysed, the capacity calculation methodology currently implemented in the SEE region does not yet include a specific provision to adjust the calculated capacities to comply with the minimum cross-zonal capacity requirements, considering the remedial action potential in the region. This provision is expected to be implemented in the course of 2025.

165 In Romania, both an action plan and a derogation were applicable during 2024, with an interim requirement of 43% of MACZT, while a derogation was applicable in Greece in 2024, with an interim requirement of 60% of MACZT. In Bulgaria, no action plan or derogation was in place in 2024. Figure 43 represents the level of fulfilment of the applicable requirements in Greece and Romania.

Figure 43: Percentage of hours when the minimum hourly MACZT was above the interim targets in the SEE CCR for each Member State, considering flows induced by third-country exchanges – 2024 (% of hours)



Source: ACER calculation based on TSO data.

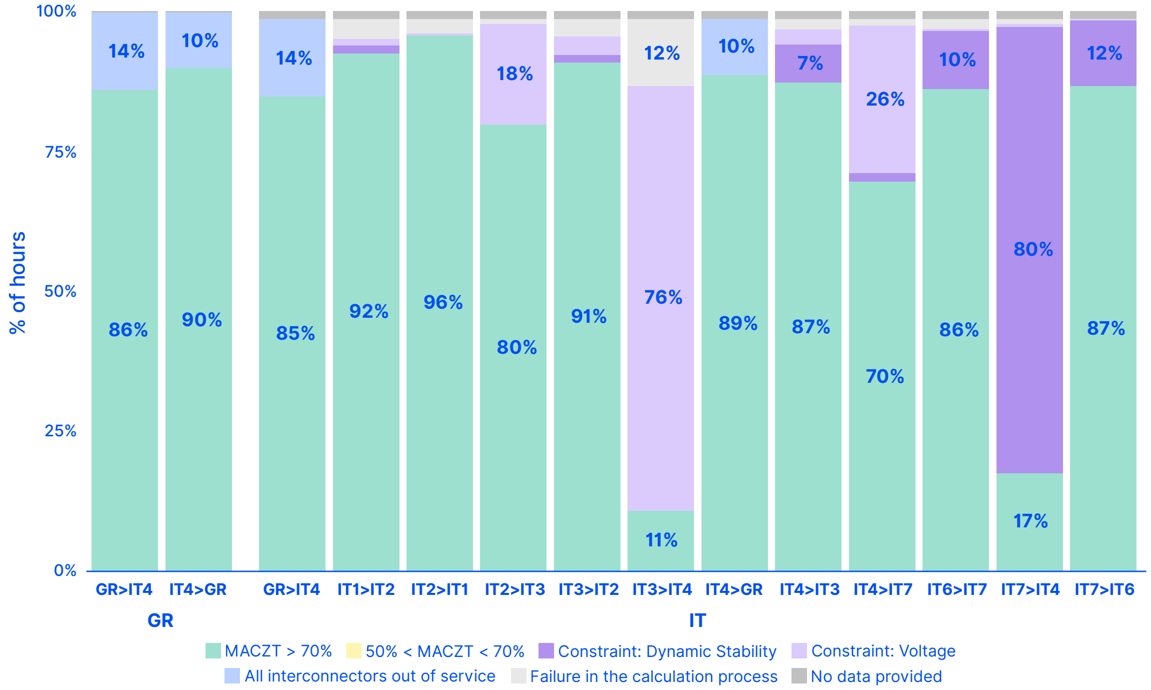
2.4.4. Greece-Italy

166 The Greece-Italy (GRIT) CCR contains the internal Italian bidding zone borders and the DC bidding zone border with Greece. The impact of exchanges with third countries is considered to be limited and therefore no corresponding data was delivered by the TSO. Moreover, due to the particular grid topology, the impact of exchanges across other borders within the region is deemed negligible and therefore is not reported.

167 Figure 44 shows the percentage of hours when the MACZT was above the minimum 70% requirement, or within a set of predefined ranges, for the GRIT CCR. The figure also shows the percentage of hours when the capacity calculation was limited by other constraints.

168 As shown in Figure 44, the share of hours when the MACZT could not be assessed at the CNEC level due to other constraints is significant. The share of hours when the MACZT could not be assessed or was limited by non-thermal constraints remained similar to 2023. One exception being the IT3–IT4 border, where the share of hours when the MACZT was greater than 70% declined from 32% in 2023 to 11% in 2024.

Figure 44: Percentage of hours when the hourly MACZT was above 70% or within predefined ranges in the Greece-Italy CCR for each Member State and oriented bidding zone border – 2024 (% of hours)



Source: ACER calculation based on TSO data.

Note: The internal Italian bidding zones are labelled as follows: IT1 – Italy North, IT2 – Italy Centre-North, IT3 – Italy Centre-South, IT4 – Italy-South, IT5 – Italy Sardinia, IT6 – Italy Sicily, IT7 – Italy Calabria.

3. Build, pay or split? Progress and challenges

169 The regulatory options to achieve the maximum availability of cross-zonal capacity, measured by the ability to offer at least 70% of the physical capacity to the market in all CNECs and bidding zone borders, are implicitly defined in the Electricity Regulation.

170 Notably, these are the following:

- Relieving increased physical congestion through remedial actions. In the short-term, TSOs may ensure that the minimum cross-zonal capacity requirements are met by triggering remedial actions that address physical congestion resulting from the levels of cross-zonal capacity offered, with the associated difficulties in time frames closer to real time presented in Chapter 2.

- Targeted grid investments. Reinforcing the power grid where internal physical congestion occurs in a structural manner may reduce the relative share of internal and loops flows on critical network elements, thus enabling such capacity to be offered to the market for cross-zonal exchanges.

- Improving the bidding zone configuration. Where it is not possible to fulfil the minimum 70% requirement in a timely manner under the previous options, Member States may review the bidding zone configuration to better align the bidding zones with network congestion. EU TSOs have recently completed a pan-European study assessing alternative bidding zone configurations.

171 This chapter aims to present an overview of the on-going efforts and trade-offs in the three processes mentioned above, all of which may facilitate the implementation of the minimum 70% requirement.

3.1. Costs and volumes of the use of remedial actions to relieve physical congestion

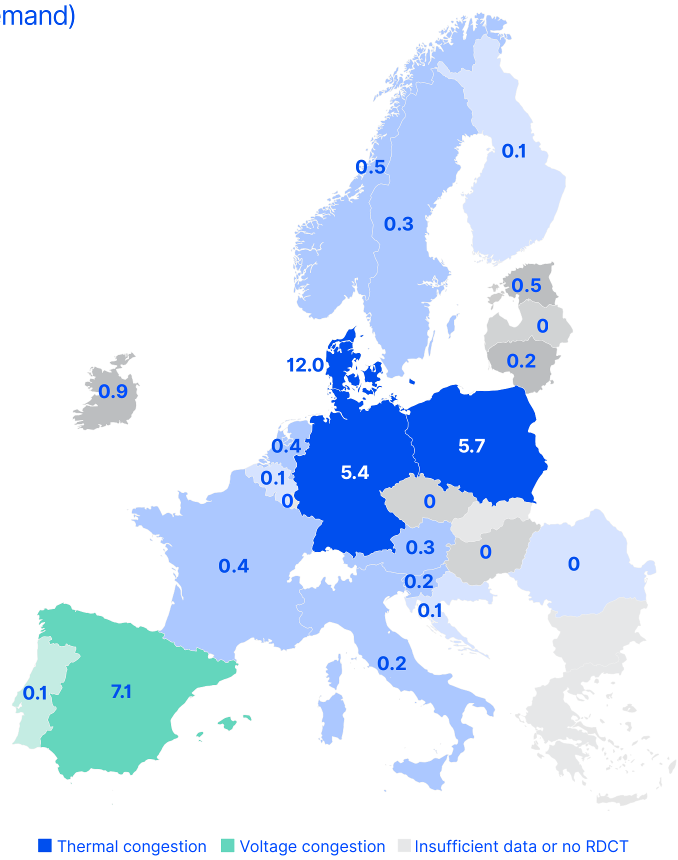
172 Physical congestion is defined in Regulation (EU) 2015/1222 (CACM Regulation) as a network situation in which forecasted or realised power flows violate the thermal limits of grid elements, or the voltage or angle stability limits of the power system. As these technical limits are only partially considered in the market coupling algorithm – specifically insofar as they may limit cross-zonal trade – the resulting market outcome may not always be physically feasible. In such cases, TSOs must rely on remedial actions, such as redispatching or countertrading, to address the physical congestion identified.

173 EU NRAs report to ACER the costs and volumes of all costly remedial actions activated in each Member State on a yearly basis. The volumes of all costly remedial actions activated in the EU in 2024 amounted to 60 TWh, including both redispatching and countertrading, with the costs totaling EUR 4.3 billion.

174 It is important to underscore that not all remedial actions serve to ensure that the thermal limits of transmission assets are respected. Remedial actions may also need to be triggered by TSOs to safeguard other technical limits of the system, such as voltage or stability. In 2024, the share of redispatching triggered for active power management at the transmission level in the EU amounted to 73%. A notable exception is the case of Spain, where almost half of the volume of remedial actions reported by the NRA aim to address violations of voltage security limits.

175 Figure 45 represents the volume of remedial actions activated in each EU Member State in 2024, as a percentage of the national electricity demand, and categorized by the most common operational security constraint experienced in each Member State.

Figure 45: Volume of remedial actions activated in each Member State as a percentage of electricity demand, and categorised by the most common operational security violation – 2024 (% of electricity demand)



Source: ACER calculation based on NRA and ENTSO-E Transparency Platform data.

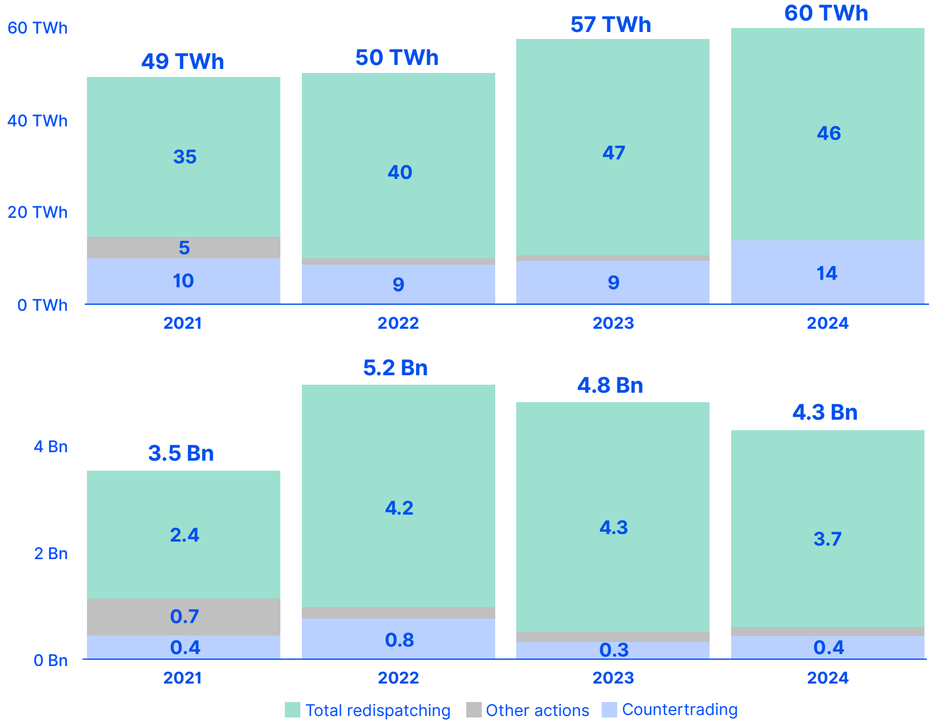
Note: The share of remedial actions over electricity demand considers all remedial actions, including both redispatching and countertrading, reported by NRAs as necessary to address network congestion within Member States. Data reported for Ireland included the volumes related to countertrading only, as the volumes of redispatching were not provided.

176 The levels of remedial actions that are triggered in the EU are in part a consequence of the zonal model of electricity markets in the EU, where electricity trading within bidding zones is unrestricted and technical constraints are, to a large extent, not considered in the market coupling algorithm. Furthermore, the need for triggering remedial actions is dependent on market dynamics, especially renewable generation, and thus volumes of remedial actions may vary year-on-year.

177 Compared with the previous year, 2024 saw a 5% increase in the volumes of remedial actions triggered across the EU, associated with a 10% decrease in the costs incurred for that purpose. Notably, more than half of the congestion management cost in 2024 corresponded to Member States in central Europe (53 %). In 2024, the data reported confirm the upward trend detected in previous years, with increasing congestion management needs due to the fast penetration of renewable energy in the power system.

178 Figure 46 shows the evolution of the volume and costs of remedial actions triggered in the EU, highlighting this growing trend over recent years. A study published by the European Commission's Joint Research Centre in 2024 signalled that, under a business-as-usual grid expansion scenario, the volume of yearly redispatching needs in the EU in 2040 would increase by a factor of 16, with a significant rise in costs.

Figure 46: Evolution of the volume (top) and costs (bottom) of remedial actions activated in the EU and Norway – 2021-2024 (TWh and billion EUR)



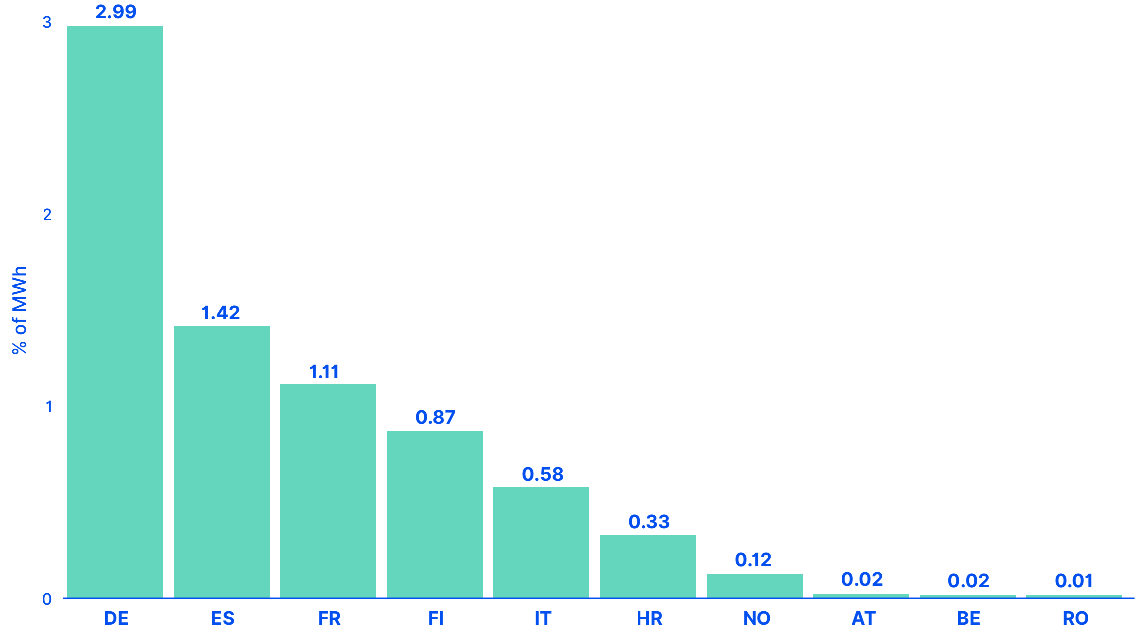
Source: ACER calculation based on NRA data.

Note: Figures shown for redispatching include curtailment of electricity from RES sources. 2021 value for Spain was not available, and thus is not included in the figure. Ireland reported only the volumes of countertrading, not redispatching.

179 The data reported to ACER by NRAs also show a growing trend in the need for congestion management involving renewable energy technologies, mainly in the form of downward regulation or curtailment. In 2024, over 10 TWh of electricity from renewable energy sources was curtailed in the EU due to grid congestion.

180 Figure 47 shows the volume of redispatching involving renewable energy technologies as a percentage of the total renewable energy generated in 2024 for several Member States. It is worth noting, that the curtailment of renewable energy production generally results in greater use of more polluting generation sources, such as coal- or gas-fired power plants, which may be detrimental to the on-going transition towards a net-zero power system.

Figure 47: Curtailment of energy generated by renewable technologies as a percentage of total renewable energy generation for each Member State – 2024 (% of renewable electricity generation)



Source: ACER calculation based on NRA and ENTSO-E Transparency Platform data.

Note: This figure shows downward redispatching of electricity produced from RES sources in Member States, excluding production from hydroelectric power plants. RES curtailment is dependent on, among other factors, the level of penetration of renewable energy in the power system, which varies greatly between Member States. No data on curtailment of RES were available for Ireland, Poland and Greece.

Use of remedial actions to guarantee minimum cross-zonal capacity requirements

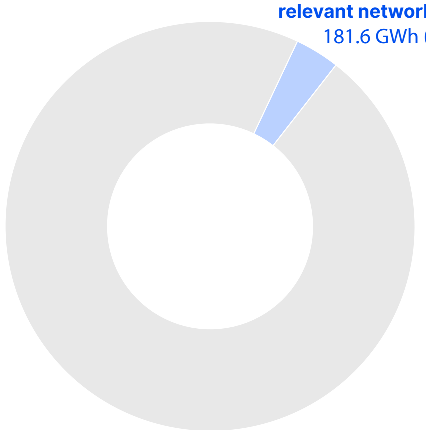
181 In the case of high non-allocated flows at critical network elements, the most immediate way for TSOs to guarantee that the applicable minimum level of cross-zonal capacity can be respected, is to account for more than the thermal limits of the CNECs when calculating the capacity to be offered to the market for cross-zonal exchanges, and then relying on the use of remedial actions after the market clears to address physical congestion on such CNECs, should the market allocate all of the capacity offered.

182 Gradually increasing the minimum cross-zonal capacity requirements towards 70%, in line with applicable derogations and action plans, and without parallel structural mitigation measures such as targeted grid reinforcements or a bidding zone reconfiguration, may thus result in an increase in congestion management needs. Such an increase would be primarily linked to the use of virtual capacities in capacity calculation to fulfil the applicable requirements.

183 As highlighted in Chapter 2 of this monitoring report, the degree to which each Member State relies on remedial actions to fulfil the applicable requirements varies greatly. The Nordic CCR relies on a more granular bidding zone configuration to ensure sufficient levels of cross-zonal capacity. In the Core, SWE or Italy North CCRs, on the other hand, the applicable capacity requirements are indeed guaranteed through the use of virtual capacities, with varying reliance on this mechanism across TSOs, depending on applicable derogations and action plans.

184 Quantifying the share of congestion management needs stemming from the applicable cross-zonal capacity requirements is not straightforward. ACER requests from NRAs a breakdown of the redispatching volumes by whether the underlying congested element is cross-border relevant (i.e. XNE) or not. While not all NRAs are able to report on this level of granularity, as the same remedial action may serve to address physical congestion on both types of network elements, a large majority of the volumes reported correspond to addressing congestion on network elements that are not cross-border relevant, as presented in Figure 48. This would imply that the observed volumes of remedial actions are primarily triggered to address internal congestion, and not as a consequence of cross-zonal capacity requirements.

Figure 48: Distribution of redispatching volumes according to the type of network element that is congested in the Member States from the Core CCR – 2024 (GWh and % of redispatching volume)



Source: ACER calculation based on NRA data.

Note: Breakdown by type of congested network element was not available for Germany or France. Since Germany accounts for the largest share of redispatching volume in the Core region (67%), the result should only be interpreted as an estimation of the order of magnitude.

Implementation delays on coordinated processes limit progress in implementing the minimum 70% requirement in the Core region

185 Although the finalization of the national action plans by the end of 2025 was expected to reduce the level of loop flows across the Core CCR, the general applicability of the 70% requirement after that is no guarantee that the negative effect of loop flows in neighbouring control areas is fully tackled. The implementation of processes to forecast, activate and share the cost of remedial actions across the TSOs of the region are necessary to address this issue, by reducing the detrimental effect of loop flows on the capacity levels made available to the market.

186 The most relevant processes in that regard are the coordinated validation assessment within the capacity calculation, the regional operational security coordination (ROSC) and the redispatching and countertrading (RDCT) cost-sharing methodologies. The coordinated validation step will enable Core TSOs to assess the operational security of the calculated capacities with the forecast of all of the remedial actions that would be available in the region. The ROSC and RDCT cost-sharing methodology will then ensure that regionally optimal remedial actions are triggered, and that their costs are borne by the TSOs at the source of the excessive loop flows.

187 Despite the legal deadlines for the implementation of these methodologies being set before the end of 2025, the projected development timeline of the Core TSOs clearly indicates that these processes will not be established by then. For instance, the Core ROSC and RDCT cost sharing processes are not expected before 2029. These delays raise the concern that derogations to address the impact of loop flows from neighbouring bidding zones will continue to be requested beyond 2025, thereby hampering the progress towards meeting the minimum 70% requirement in the Member States most affected by loop flows.

188 Moreover, the need to rely significantly on the use remedial actions to secure minimum cross-zonal capacity requirements in the day-ahead time frame has knock on effects on the margins of capacity being offered in time frames closer to real time, as described in Chapter 2 of this market monitoring report.

3.2. Progress and challenges on network development to address structural congestion

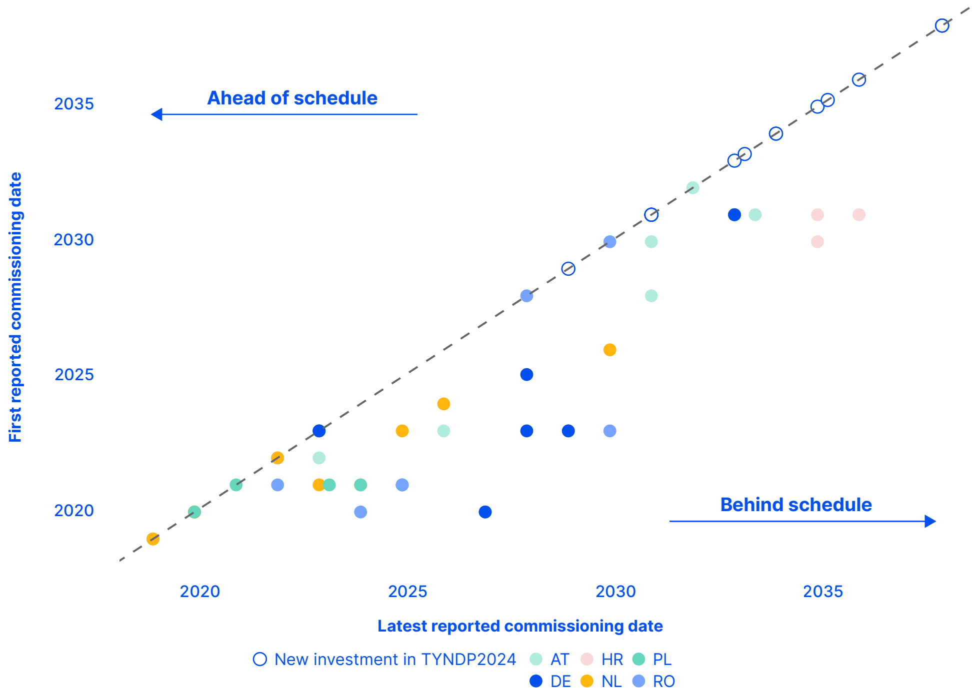
189 As outlined in the introduction of this report, the Electricity Regulation allowed Member States with identified structural congestion within their bidding zones to develop multi-year action plans to gradually meet the minimum 70% requirement by the end of 2025. These plans were to be implemented alongside structural measures designed to address such congestion.

190 The reinforcement of congested areas of the power grid was the primary solution envisioned to address this challenge. By reinforcing the power grid, electricity flows stemming from internal exchanges would have less impact on cross-border relevant network elements, enabling additional cross-zonal capacity to be released on critical network elements without needing to rely on remedial actions to secure such capacities.

191 However, large-scale grid reinforcement projects in the EU have faced significant obstacles in their commissioning, which may prevent them from resolving structural congestion within bidding zones in a timely manner. ENTSO-E reports every two years on the major infrastructure projects planned for the upcoming years in its ten-year network development plan (TYNDP), together with their expected commissioning dates.

192 An analysis of the major projects reported in the TYNDP by Member States that introduced an action plan to address structural congestion shows that commissioning delays are common, and in some cases are sizeable. This is presented in Figure 49. Moreover, a number of the projects initially expected to go live before the end of 2025 will not be introduced by then.

Figure 49: Comparison of the first and last planned commissioning date for internal infrastructure projects in the ten-year network development plan – 2016-2024

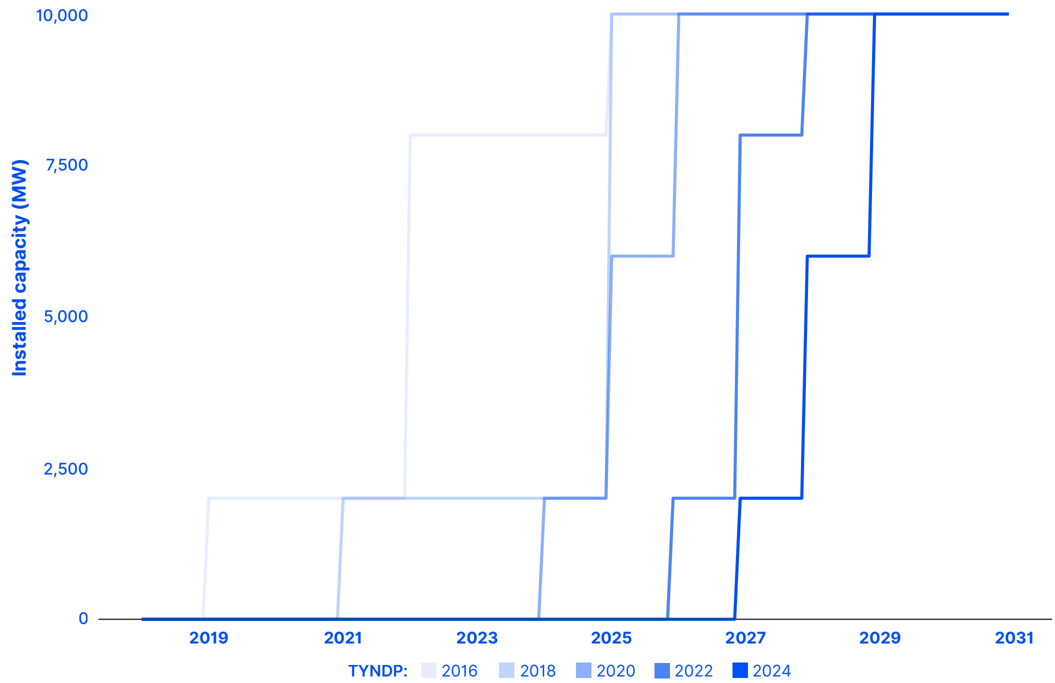


Source: ACER calculation based on TYNDP data.

193 One of the Member States with identified structural congestion, leading to the establishment of a multi-year action plan is Germany. To address such congestion the German TSOs, in coordination with the German NRA, planned the development of major HVDC assets within the Germany-Luxembourg bidding zone, to connect renewable generation in the north of Germany with the main consumption centres.

194 An analysis of the commissioning dates of these HVDC cables in recent TYNDPs, however, indicates that no major assets are expected to become operational before the end of 2025, after accumulating significant delays. The first HVDC project is scheduled for commissioning in December 2026, as shown in Figure 50. Consequently, it is likely that significant redispatching will remain necessary to address physical grid congestion in the German grid well after 2025, including that related to guaranteeing the applicable cross-zonal capacity requirements, with the associated challenges and costs discussed in this report.

Figure 50: Evolution of planned HVDC infrastructure investments within the Germany-Luxembourg bidding zone over different ten-year network development plans - 2016-2024 (MW)



Source: ACER calculation based on TYNDP data.

3.3. Insights from the ENTSO-E bidding zone review study

195 In 2025, EU TSOs delivered a study assessing the current bidding zone configuration in the EU, on the basis of their ability to create a reliable market environment and analysing different configurations of bidding zones in a coordinated manner. ACER was given the possibility to access and analyse preliminary data from the ENTSO-E bidding zone review for continental Europe, ahead of its publication.

196 In this subsection, ACER seeks to present key insights from the ENTSO-E bidding zone review, on how alternative bidding zone configurations could support a more efficient implementation of the minimum 70% requirement and contribute to reducing congestion management needs across the EU. The analyses developed in this subsection are without prejudice to any potential detrimental market impact or transition costs that may arise as a consequence of a bidding zone reconfiguration, as examined in the ENTSO-E bidding zone review study, and which will need to be weighed against the observed benefits in the subsequent decision-making process.

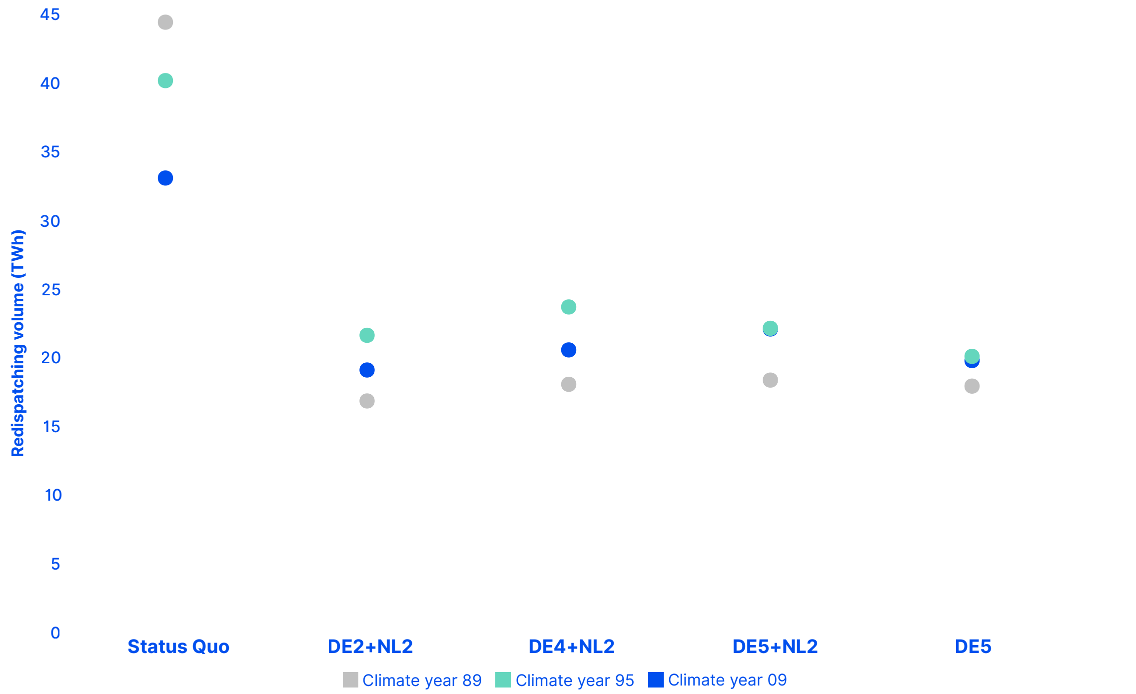
197 Indeed, a more granular configuration of the bidding zones in the EU is expected to significantly reduce the intensity of flows stemming from intra-zonal exchanges in the network and thus facilitate the fulfilment of the minimum 70% requirement. Moreover, it would also reduce the overall need for costly remedial actions by integrating some of the physical congestion in the market coupling algorithm and thus contributing to mitigating growing system costs.

198 It is important to note that the results of the bidding zone review are based on simulations performed by ENTSO-E, reflecting a model of the EU power system in 2025 under different climate scenarios, and a set of modelling assumptions described in the bidding zone review methodology. Considering this, the numbers assessed in this section are not directly comparable to the operational data presented throughout the report and should be interpreted only as an indication of the potential effects of a bidding zone reconfiguration.

199 One of the modelling assumptions that prevent direct comparison with operational data is that of full coordination and cost-sharing of remedial actions at the level of central Europe. As highlighted in Chapter 3.1, these methodologies will not be implemented in the short-term, and thus the volumes and costs calculated in the bidding zone review are likely to be underestimated[17].

200 Figure 51 presents the modelled volume of redispatching triggered in central Europe, both in upward and downward direction, under different bidding zone configurations and climate scenarios. As highlighted in the figure, all three combinations of bidding zone splits studied in the ENTSO-E bidding zone review (i.e. the combination of the Netherlands split into two zones, with the split of the Germany-Luxembourg bidding zones into two, four and five zones) and the individual split of the Germany-Luxembourg bidding zone into five zones, under all three climate scenarios, would result in a significant drop in congestion management needs compared with the status quo.

Figure 51: Redispatching volume triggered in central Europe under different bidding zone configurations and climate years – 2025 scenario (TWh)



Source: ACER calculation based on ENTSO-E bidding zone review data.

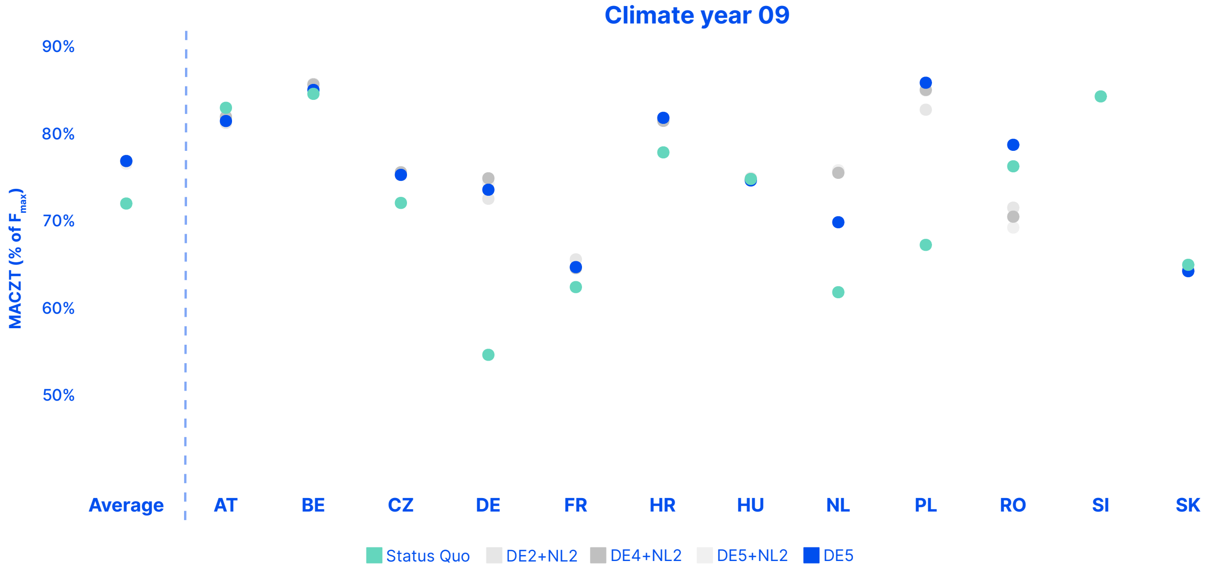
201 According to the results of the ENTSO-E study, a different configuration of the bidding zones in Continental Europe would reduce redispatching volumes by between 40% and 60%, depending on the climate year modelled, with a similar decrease of its costs. Based on the data reported by NRAs for 2024, the cost of redispatching in central Europe due to network congestion at transmission level alone amounted to EUR 2.3 billion. A reduction of 40% to 60% in redispatching volumes could save upwards of EUR 1 billion per year in associated costs.

202 Moreover, the introduction of more granular bidding zones would lead to a general reduction in the flows induced by exchanges within bidding zones in critical network elements, especially loop flows. Indeed, a large share of the flows currently stemming from non-allocated exchanges would become allocated under SDAC. This, in turn, would facilitate fulfilment of the minimum 70% requirement on the CNECs that are currently significantly loaded by loop flows.

17 ACER will assess the level of fulfilment of the requirements listed in the bidding zone review methodology in an upcoming Opinion to the Council of the European Union, which is expected to be published during the second half of September 2025.

203 Figure 52 presents the average MACZT levels on all CNECs in the pre-solved flow-based domains calculated within the bidding zone review, excluding the adjustment for minimum RAM (i.e. virtual capacities). For the purpose of simplicity and given that the observed dynamics are analogous across climate years, only one climate year is presented in the figure. As highlighted in the figure, Member States such as Germany, the Netherlands and Poland would indeed see a significant increase in the average MACZT levels under a more granular bidding zone configuration, due to a reduction in the flows stemming from intra-zonal exchanges.

Figure 52: Average natural MACZT levels on the CNECs pre-solved flow-based domain for all Core Member States under different bidding zone configurations – 2025 scenario for climate year 09 (% of F_{max})



Source: ACER calculation based on ENTSO-E bidding zone review data.

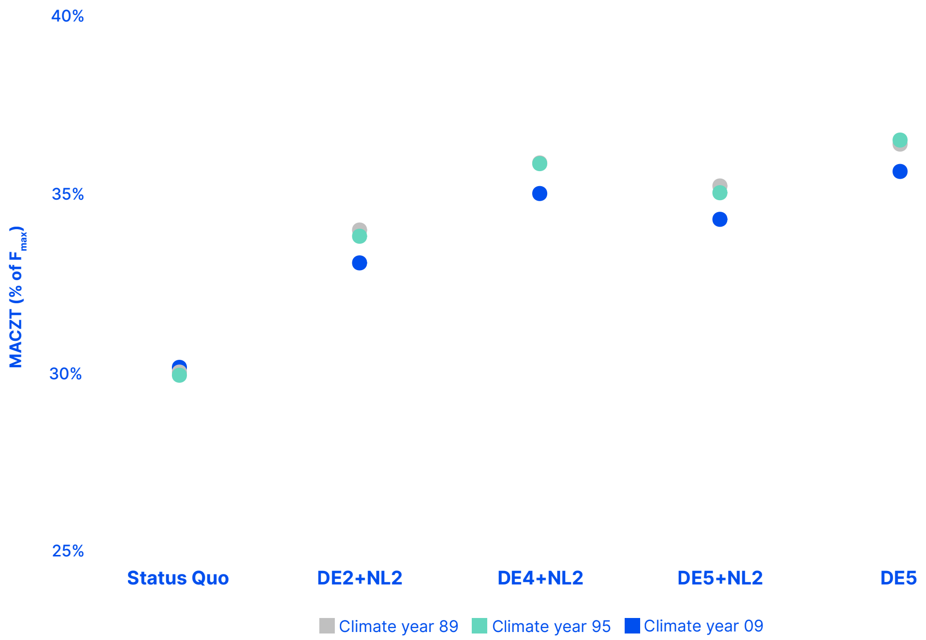
Note: Natural MACZT is calculated as the sum of RAM in a zero-balanced model (RAM0) and the flows induced by exchanges outside the Core CCR (Fuaf), as a share of F_{max}. For the purpose of this figure, the values are averaged per Member State.

204 Such an increase in the natural MACZT levels for some CNECs would reduce the reliance on virtual capacity to respect the minimum 70% requirement. This, in turn, will minimize the need for remedial actions to secure the capacities offered, and mitigate the observed knock-on effects on the capacities made available in the intraday time frame.

205 Nonetheless, it is worth noting that a more granular bidding zone configuration will not result in an immediate fulfilment of the 70% requirement across the Core CCR. Indeed, specific CNECs congested by internal flows and not subject to high loop flows, will still require local solutions, such as targeted grid reinforcements, to be able to consistently respect the requirement.

206 Figure 53 assesses the average MACZT level observed in all Core TSOs on the CNEC with the lowest natural MACZT for every TSO and hour. While the introduction of a more granular bidding zone configuration does result in average increases of MACZT also on the most constrained CNECs, some of these remain congested under all of the configurations studied.

Figure 53: Average natural MACZT levels on the worst CNEC of the pre-solved flow-based domain under different bidding zone configurations and climate years per Core Member State – 2025 scenario (% of F_{max})



Source: ACER calculation based on ENTSO-E bidding zone review data.

Note: Natural MACZT is calculated as the sum of RAM in a zero-balanced model (RAM0) and the flows induced by exchanges outside the Core CCR (Fuaf), as a share of F_{max}. For the purpose of this figure, the minimum values for every market time unit are first averaged per Member State, and then for the Core CCR.

Conclusions and recommendations

The maximization of cross-zonal capacities contributes to cheaper and less volatile power prices across Europe, which is a key enabler for European competitiveness.

207 Exchanges of electricity across bidding zones in the EU are determined by the European market clearing algorithm, which aims to maximise the total economic surplus, while respecting a set of pre-defined cross-zonal capacity constraints. Increasing the availability of cross-zonal capacity offered to the market results in cheaper and less volatile prices across Europe. The minimum 70% requirement was introduced in the Electricity Regulation to ensure that available cross-zonal capacity is maximised, and its implementation is currently on-going.

208 To quantify the value of additional cross-zonal trade, ACER performed several simulations assessing the market impact of different levels of cross-zonal capacities in the Core region. The analysis revealed that the full implementation of the minimum 70% requirement would have unlocked an additional EUR 340 million economic surplus in 2024, leading to lower and less volatile day-ahead prices.

Additional cross-zonal capacities would have helped mitigate high-price events in South-East Europe during the summer of 2024.

209 A situation of sustained high-price events took place in the evening hours across central and South-east Europe bidding zones during summer 2024, with day-ahead prices reaching 1000 EUR/MWh. Severe price spreads were observed at several bidding zone borders, being particularly noticeable at the Austria-Hungary bidding zone border, revealing insufficient cross-zonal capacity to address the market's needs for exchanges.

210 ACER replicated this market scenario in a counterfactual analysis in which additional cross-zonal trade was allowed, such as by fully implementing the minimum 70% requirement. The results of the analysis show that the number of high-price instances could have been reduced by more than half, confirming the crucial role of cross-zonal capacities as a key source of flexibility in the power system.

Improvements to the fallback process used in Core day-ahead capacity calculation could unlock significant benefits.

211 On 25 June 2024, a failure in the calculation of cross-zonal capacities in the Core CCR due to an IT error led to long-term capacities being used as fallback. This resulted in very constrained capacities across the region, up to 90% lower than a normal day for some bidding zones, allowing only limited cross-zonal exchanges. This, in turn, led to considerable price spreads at most bidding zone borders and higher prices throughout eastern Europe.

212 To assess the potential benefit of a different fallback approach, ACER tested the possibility of using statistical flow-based domains to compute capacities in the case of a fallback. The results of the simulations show that such an approach may have resulted in an increase of economic surplus up to EUR 13 million for a single trading day. The outcome of this analysis suggests that there is scope for assessing better fallback solutions.

Applicable interim requirements, which in the case of derogations may be significantly lower than 70% or linear trajectory values, are mostly met in the Core CCR.

213 The implementation of the 70% requirement across the EU is currently on-going, with uneven progress. In the Core region, TSOs are at different stages in their 70% implementation, ranging from full applicability of the requirement to action plans and/or derogations introducing interim requirements, which may result in very constrained capacities on specific network elements and market circumstances.

214 While some improvement was recorded in 2024, the need for derogations across the Core region, mostly due to the existence of excessive loop flows from neighbouring Member States and the lack of coordinated processes to adequately address them, has effectively slowed down the progress made toward the full implementation of the 70% requirement and may put at risk the target implementation deadline of the end of 2025.

However, the use of virtual capacities to reach the applicable requirements has knock-on effects in the intraday market.

215 In May 2024, Core TSOs implemented the first flow-based capacity calculation for the intraday time frame, an important milestone towards a more efficient and coordinated capacity calculation process closer to real time. However, the lack of flow-based allocation in intraday auctions significantly reduces the potential of flow-based capacity calculation in the intraday time frame, by requiring an ATC-extraction from the calculated flow-based domains.

216 ACER's assessment shows that the Member States relying mostly on the use of virtual capacities in the day-ahead time frame to fulfil the applicable minimum capacity requirement see significant drops in the capacities made available for cross-zonal trade in the intraday time frame. This underscores the challenging path ahead for the implementation of the minimum 70% requirement in the intraday time frame.

In the Nordic CCR, the implementation of flow-based market coupling is an important milestone, yet additional efforts are needed in the implementation of the 70% requirement.

217 In October 2024, Nordic TSOs implemented flow-based market coupling in the day-ahead time frame, marking a significant step toward more efficient use of the available infrastructure in the Nordic CCR. While the current bidding zone configuration ensures that the impact from loop flows in the Nordic CCR is limited, and thus that availability of capacity remain high, preliminary results indicate that Nordic TSOs don't consistently uphold the minimum 70% requirement in all relevant network elements. TSOs are encouraged to evaluate structural solutions to fulfil the requirement.

Congestion management in the EU is costly, and remains uncoordinated at the regional level.

218 The cost of congestion management in 2024 was approximately EUR 4.3 billion in the EU and Norway. With additional renewable energy capacity being installed, congestion management needs are likely to continue growing, amounting to higher system costs. A recent study published by the European Commission's Joint Research Centre highlighted that, under a business-as-usual grid expansion scenario, the volume of yearly redispatching needs in the EU would increase by a factor of 16 by 2040, with a significant rise in costs.

219 Moreover, congestion management processes remain mostly uncoordinated at the regional level, and without a proper cost-sharing mechanism. Delays in key implementation projects ensure that such processes will continue to be uncoordinated in the short term. This, in turn, has led to derogations from the minimum 70% requirement being required in several Member States.

Delays in grid reinforcements hamper addressing structural congestion in a timely manner, with an impact on the neighbours.

220 Grid reinforcement within bidding zones can relieve physical congestion where it happens structurally, enabling additional cross-zonal capacities to be released to the market, in both the day-ahead and intraday time frames and reducing the congestion management needs. However, major infrastructure projects often face significant delays in commissioning. ACER assessed the progress made by German HVDC projects and noted that no major assets are expected to be put online before the end of 2025, hampering a timely mitigation of structural congestion.

In 2025, TSOs delivered a pan-European study on the configuration of the bidding zones, highlighting potential improvements in congestion management.

221 TSOs delivered in 2025 a pan-European study assessing the current bidding zone configuration on the basis of their ability to create a reliable market environment and analysing different configurations of bidding zones in a coordinated manner. The delivery of the study will be followed by a policy decision on maintaining or amending the current bidding zone configuration in the EU.

222 Preliminary results from the bidding zone review process show that an alternative, more granular, bidding zone configuration would significantly reduce congestion management needs and associated costs in the EU. It would also facilitate the implementation of the minimum 70% requirement, in both the day-ahead and intraday time frames, by reducing the severity of flows induced by exchanges within bidding zones.

Annex I: Results of monitoring the margin available for cross-zonal trade in uncoordinated regions

223 Annex I presents the results of the monitoring for capacity calculation regions (CCR), where a fully coordinated process has yet to be introduced (Hansa and Baltic). In capacity calculation regions where a capacity calculation methodology has not yet been implemented, TSOs typically rely on interim national capacity calculation processes, based on the NTC principle, which may vary in the degree of coordination among neighbouring TSOs and between bidding zone borders. In these regions, data availability is only partial.

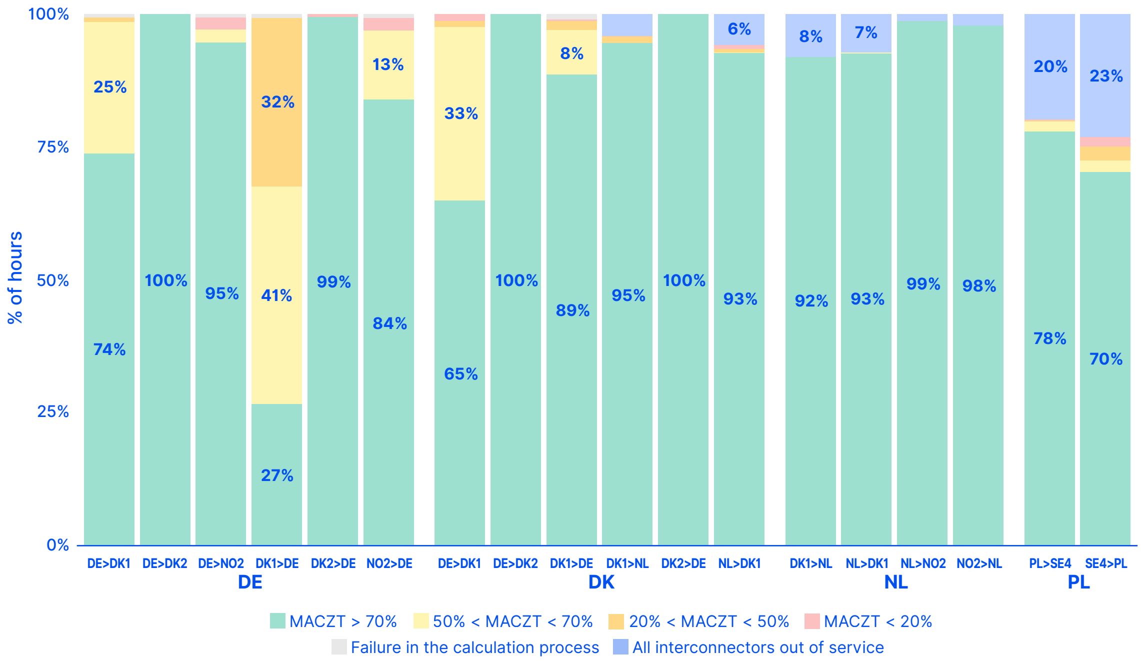
Hansa

224 The Hansa CCR contains mostly DC bidding zone borders connecting the Nordic and the Continental Europe synchronous areas. The only AC bidding zone border in the region is that between Denmark 1 and Germany-Luxembourg. A coordinated capacity calculation methodology has not yet been implemented at the regional level; thus, TSOs rely on interim capacity calculation approaches.

225 Since the implementation of Nordic flow-based market coupling, the AC network elements that may limit exchanges on the Hansa bidding zone borders are now considered within the Nordic capacity calculation process. Therefore, the fulfilment of the minimum 70% requirement in these network elements is considered in section 2.3.

226 On the continental Europe side, however, dedicated capacity calculation processes considering potential limitations on the AC network, will continue to be used to determine available capacities on the Hansa bidding zone borders until the implementation of advanced hybrid coupling in the Core CCR.

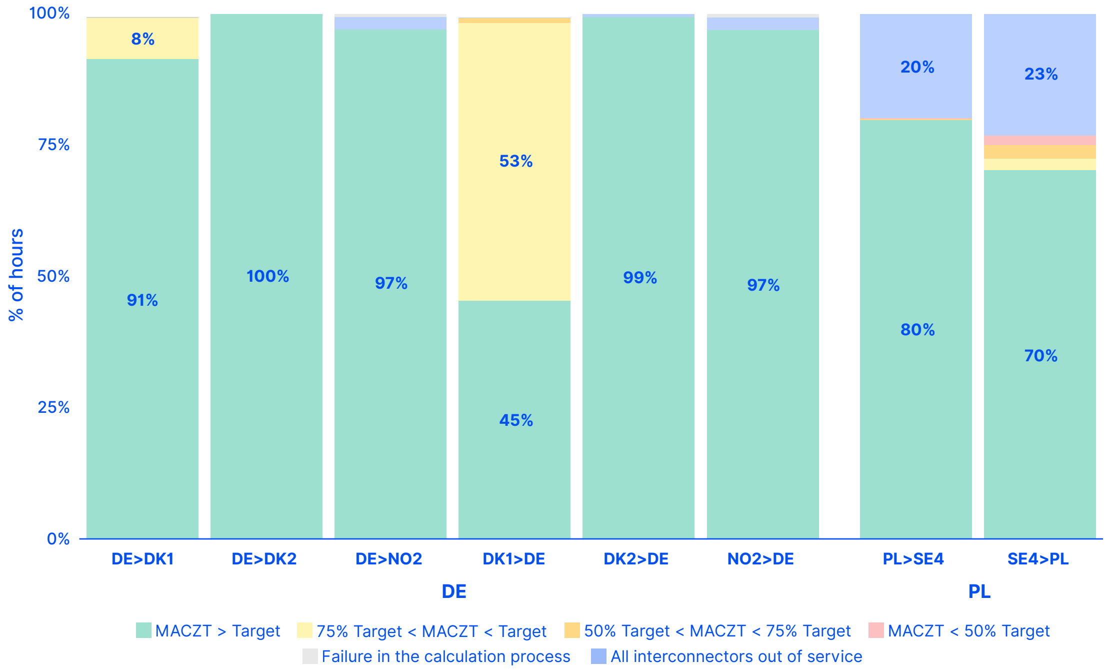
Figure 54: Percentage of hours when 70% of MACZT, or predefined ranges of values, was offered in the Hansa CCR for each Member State and oriented bidding zone border – 2024 (% of hours)



Source: ACER calculation based on TSO data.
Note: Nordic flow-based market coupling was implemented on 29 October 2024. The data for Denmark thefore includes only the period of the year since 1 January 2024 until 28 October 2024.

227 Figure 55 shows the extent to which Member States in the Hansa CCR that have an action plan have fulfilled the applicable interim requirements and, where the requirements have not been met, how far away the relevant Member State is from fulfilling them. The analysed data shows that deviations below the applicable requirement occur mostly on the DK1-DE oriented bidding zone border, from the German side.

Figure 55: Percentage of hours when the minimum hourly MACZT was above the interim targets in the Hansa CCR for each Member State, considering flows induced by third-country exchanges – 2024 (% of hours)



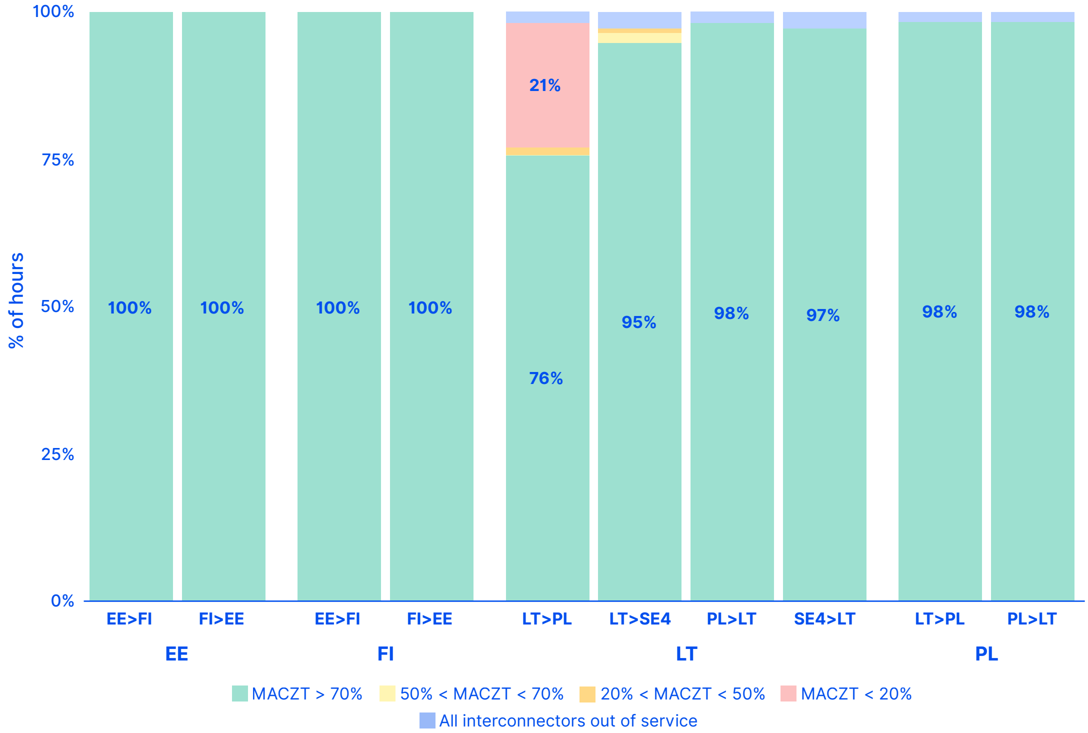
Source: ACER calculation based on TSO data.

Baltic

228 The Baltic CCR encompasses the bidding zone borders between the Baltic states Estonia, Latvia and Lithuania, and those with neighbouring Member States Finland, Poland and Sweden. Currently, no data on the AC bidding zone borders is provided by the TSOs of the region and no common grid models are made available to ACER. Therefore, only the DC bidding zone borders of the Baltic CCR can be analysed.

229 The Baltic regulatory authorities informed ACER that a process for MACZT monitoring would be set up as of the synchronisation of the electricity systems of the Baltic states with those in continental Europe, which successfully took place on 9 February 2025.

Figure 56: Percentage of hours when 70% of MACZT, or predefined ranges of values, was offered in the Baltic CCR for each Member State and oriented bidding zone border – 2024 (% of hours)



Source: ACER calculation based on TSO data.

Annex II: Flow-based explanatory figures

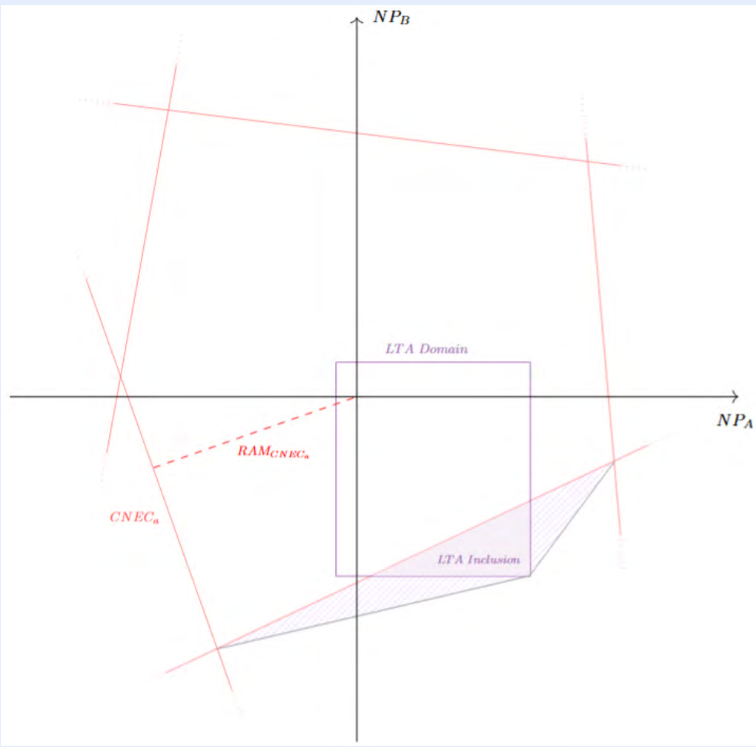
230 This annex includes explanatory material and visuals on day-ahead and intraday flow-based domains, as well as on the relevant metrics used in this Market Monitoring Report. The figures are intended for educational purposes and are not based on real operational data stemming from a flow-based capacity calculation process.

Explanatory figure 1: Key components of a flow-based domain (NPs, RAM, CNECs and PTDFs)

1 The net position ('NP') of a bidding zone is the amount of electricity that a given bidding zone is importing (i.e. negative NP) or exporting (i.e. positive NP) to a subset of other bidding zones for a market time unit. In particular, the Core or Nordic NPs usually refers to the net position a given bidding zone has with respect to the rest of the Core or Nordic region.

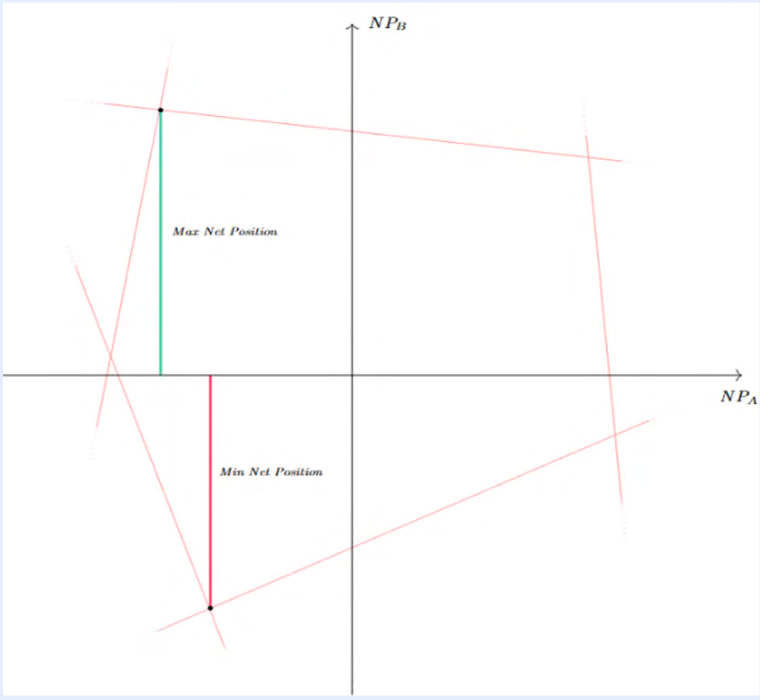
2 A flow-based domain represents the area in which the market clearing point ('MCP') can move, or the set of feasible net positions for each bidding zone. The flow-based domain is delimited by the Critical Network Elements with Contingency ('CNECs'), represented in the figure by the pink segments. The distance from the origin to the CNECs is the Remaining Available Margin ('RAM'), represented by the dashed red line. The slopes of the CNECs are determined by the Power Transmission Distribution Factors ('PTDFs').

3 In Core flow-based, the day-ahead MCP can move within the combination of the flow-based domain (represented in pink) and the LTA domain (represented in purple), which corresponds to the capacities allocated as Financial Transmission Rights in yearly and monthly auctions.



Explanatory figure 2: Minimum and maximum non-simultaneous net positions within a flow-based domain

4 The maximum and minimum non-simultaneous net position of a bidding zone represents the limits of what it can theoretically export or import to/from the other bidding zones in the region. This metric is non-simultaneous, as there is a dependency between net positions in the region. In a simplified two-dimensional domain, the maximum and minimum net positions would be represented by the green and red lines. Simply put, the min-max NPs corresponds to the far-most corners of the flow-based domain.

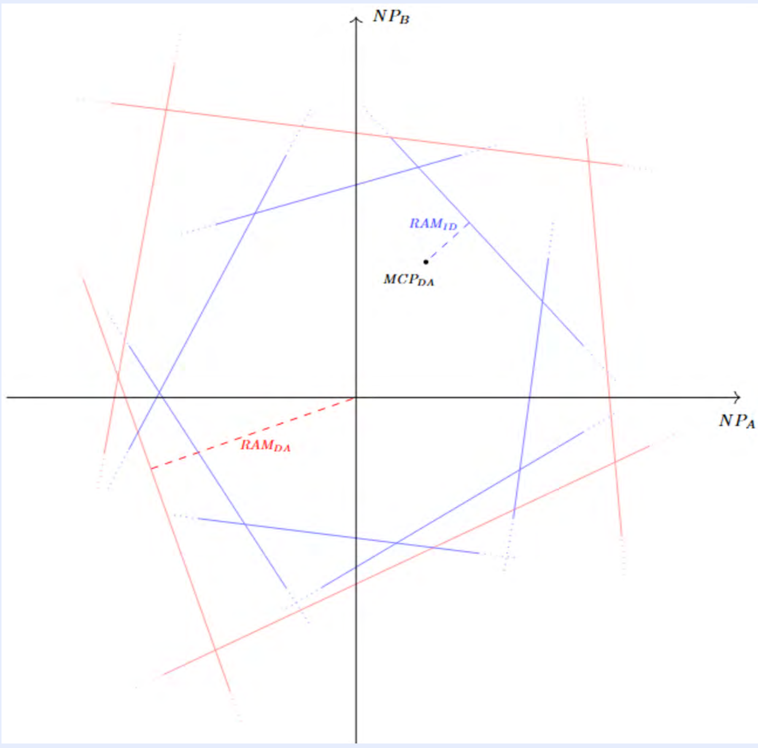


Explanatory figure 3: Day-ahead and intraday flow-based capacity calculations

5 Core and Nordic TSOs perform a daily calculation of flow-based domains to bound cross-zonal trade in the Single Day-Ahead Coupling within the Core and Nordic CCRs. This calculation is based on two-day-ahead congestion forecasts, created by TSOs and merged into a Common Grid Model ('CGM') by the RCCs. As already mentioned, the RAM of each CNEC in day-ahead is determined as its distance from the origin (i.e. the case where there is no cross-zonal trade in the region).

6 After day-ahead market clearing, TSOs perform an intraday capacity calculation, based on day-ahead congestion forecasts, which feeds into the Single Intraday Coupling. At the moment of drafting this market monitoring report, a flow-based capacity calculation is only performed in the Core CCR to compute cross-zonal capacities for the second pan-European intraday auction ('IDA2'). The intraday flow-based domain is represented in blue, and the RAM of each CNEC in the intraday flow-based domain is determined by its distance from the day-ahead MCP (dashed blue line).

7 As the Single Intraday Coupling is not yet adapted to perform a flow-based allocation of cross-zonal capacities, an ATC domain needs to be extracted from the flow-based domain. This is further explained in Explanatory box 5.

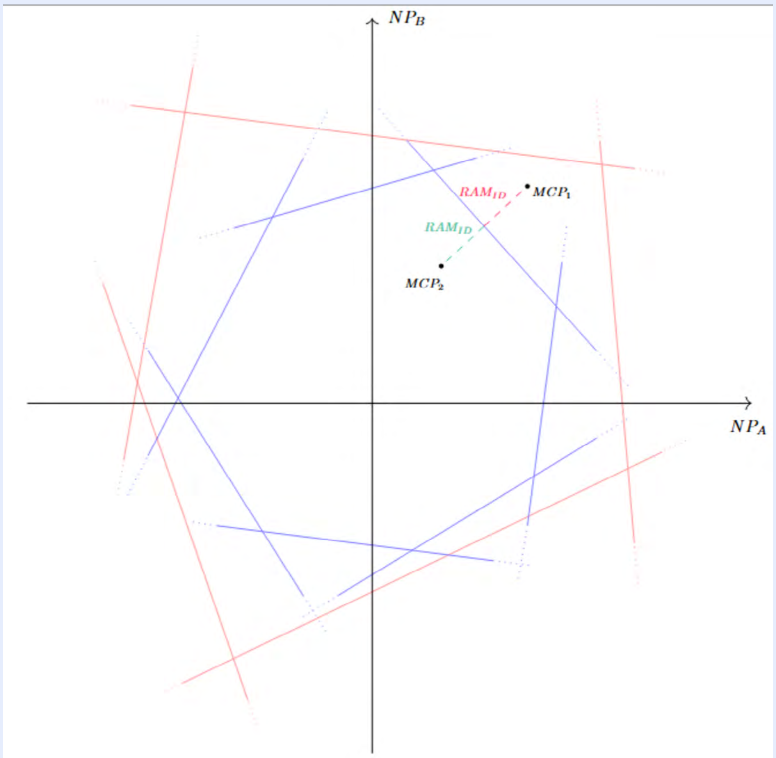


Explanatory figure 4: Negative RAMs in intraday flow-based domains

8 The RAM of CNEC in intraday is determined as its distance from the day-ahead market clearing point. This RAM may be positive, if the MCP is contained within the intraday flow-based domain, or negative, if the MCP is not contained within the day-ahead flow-based domain. The former case is highlighted in green in the figure, while the latter is highlighted in red.

9 For the RAM of a given CNEC of the intraday flow-based domain to be negative, the intraday flow-based domain needs to be smaller in size, on this particular corner, than the day-ahead flow-based domain. This is so as the day-ahead market clearing point was originally bounded by the day-ahead flow-based domain.

10 As discussed in section 2.2.2 of the report, this is often the case, as the day-ahead flow-based domain is currently enlarged by long-term allocations and adjustment for minimum RAM to comply with the applicable cross-zonal capacity requirements.



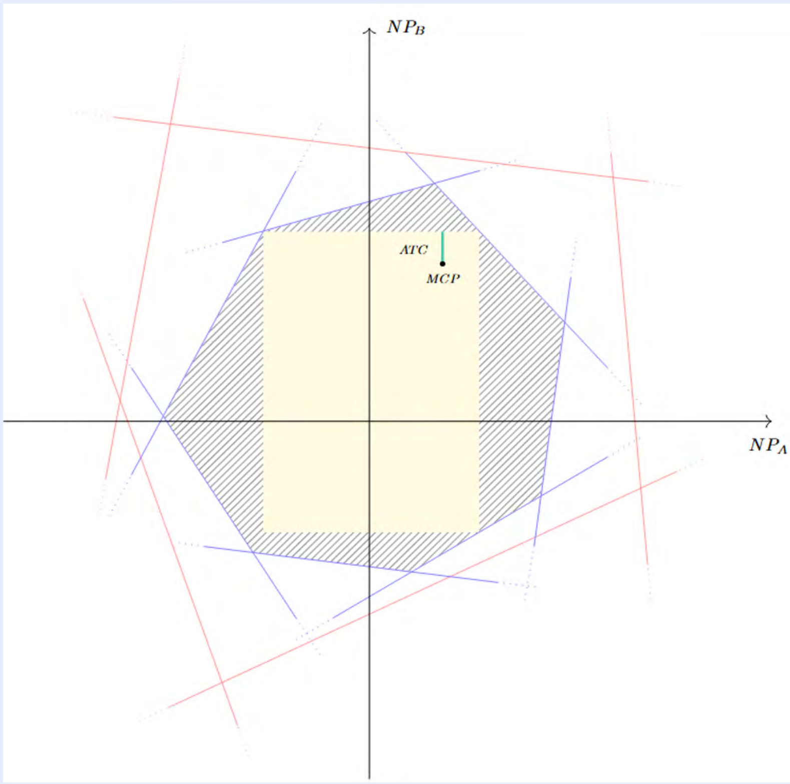
Explanatory figure 5: ATC-extraction from a flow-based domain

11 Wherever flow-based allocation is not possible, an ATC extraction from the flow-based domain needs to be performed. This process consists of producing a set of simultaneously feasible capacities at the bidding zone border level from the flow-based domain.

12 At the moment of drafting this market monitoring report, the following ATC-extractions are performed in the EU:

- Nordic TSOs perform an ATC-extraction from the day-ahead flow-based domain to feed the whole Single Intraday Coupling.
- Core TSOs perform an ATC-extraction from an adjusted day-ahead domain (after partially removing the impact form LTA and virtual capacities) for IDA1.
- Core TSOs perform an ATC-extraction from the IDCC(b) flow-based domain for IDA2.

13 The ATC-extraction from an intraday flow-based domain (in blue) is represented by the yellow rectangle. The intraday market clearing point can then move only within the capacity extracted, losing access to a significant area within the flow-based domain.



Annex III: Quality assessment of the data collected by ACER for MACZT monitoring

Table 1: Overview of the completeness and quality of the data provided by TSOs for the monitoring of the MACZT for each coordination area – 2024

CCR/ Border	Member State	TSO	Overall ACER assessment of data collected	Observations
Core	AT	APG		
	BE	Elia		
	CZ	CEPS		
	DE	50Hertz		
		Amprion		
		TenneT		
		Transnet		
	FR	RTE		
	HR	HOPS		
	HU	MAVIR		
	NL	TenneT		
	PL	PSE		
	RO	Transelectrica		
	SI	ELES		
	SK	SEPS		
Nordic	DK	Energinet		No data was made available to calculate the impact of forecasted cross-zonal exchanges with the UK on MACZT.
	FI	Fingrid		No data was made available to calculate the impact of forecasted cross-zonal exchanges with the UK on MACZT.
	NO	Statnett		No grid model and no CNECs were provided; partial monitoring was possible using JAO Publication Tool data.
	SE	SvK		The list of critical network elements (CNECs) has been anonymised by the TSO. No data was made available to calculate the impact of forecasted cross-zonal exchanges with the UK on MACZT.

CCR/ Border	Member State	TSO	Overall ACER assessment of data collected	Observations
Italy North	AT	APG		
	FR	RTE		
	IT	TERNA		
	SI	ELES		
SWE	ES	REE		The TSO did not calculate MNCC. The impact on results is likely limited.
	FR	RTE		
	PT	REN		
GRIT	IT	TERNA		The TSO did not calculate MNCC. The impact on results is likely limited.
	GR	IPTO		
SEE	BG	ESO		The TSO did not provide PTDFs and did not calculate MCCC nor MNCC. ACER calculated them.
	GR	IPTO		The TSO did not provide PTDFs and did not calculate MCCC nor MNCC. ACER calculated them
	RO	Transelectrica		
DE–DK1 DE–NO2 DE–SE4	DE	TenneT		The MNCC values provided were not calculated in line with the Recommendation. ACER recalculated them.
DE–DK2		50 Hertz		
DE–DK1 DK1–NL DE–DK2	DK	Energinet		The TSO did not provide PTDFs and did not calculate MCCC nor MNCC. ACER calculated them, where possible.
DK1–NL NL–NO2	NL	TenneT		
FI-EE	FI	Fingrid		
EE–LV	EE	Elering		No grid model and no CNECs were provided; no monitoring was possible.
LT–LV	LT	Litgrid		No grid model and no CNECs were provided; no monitoring was possible.
EE–LV LT–LV	LV	AST		No grid model and no CNECs were provided; no monitoring was possible.

All the data was provided as requested.

Most or all the data was provided. Some non-critical elements were missing or the provision of data was not fully in line with the Recommendation. The impact on the MACZT results was limited and/or fallback data could be used.

Most or all the data was provided. Some essential elements were missing or the provision of data deviated significantly from the Recommendation. The impact on the MACZT results was relevant and/or using fallback data was not always possible.

No or insufficient data provided. Monitoring the MACZT was not possible at all, or was very limited.

List of figures