ACER

European Union Agency for the Cooperation of Energy Regulators

ACER
European Union Agency for the Cooperation of Energy Regulators

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

2024 Market Monitoring Report

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EUR 4.2 bn

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<100 MW

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30-70%

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10 TWh

Renewables curtailed in Germany due to congestion, 4% of its total renewable generation

1 Integrated EU energy markets can turn the diversity of European energy systems into an asset. By fostering further market integration in the electricity sector, the EU can harness more of the benefits of deploying cost-effective renewable energy generation. Increasing interconnectivity and enhancing system flexibility allows to further mitigate electricity price volatility, enhance resilience to market disturbances and facilitate the integration of renewables, paving the way for cost-effective decarbonisation in the EU[1]. However, the full potential of the EU internal electricity market has yet to be realized.

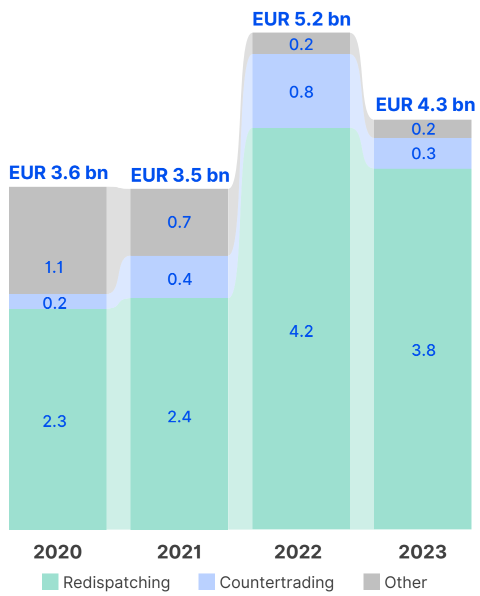
Increasing congestion management needs reveal insufficient available grid capacity

2 The EU power system faces growing congestion, with a 14.5% increase in congestion management needs in 2023, leading to hefty system costs. In 2023, the costs of managing congestion in the EU power grid exceeded EUR 4 billion, with 60% of these costs borne by the German system.

3 Increasingly, congestion management in the EU results in renewable energy production being curtailed, with mainly fossil-based energy generation filling the gap. Limited grid expansion, coupled with the rapid uptake of renewable energy technologies, is likely to exacerbate grid congestion going forward[2]. This may jeopardize efforts in further electricity market integration across the EU and thereby also delay the transition to a power system that is both carbon-neutral and cost-efficient.

Post energy crisis, congestion costs dropped with energy prices, yet volumes rose.

Evolution of the cost of congestion management in the EU – 2020–2023 (billion EUR)



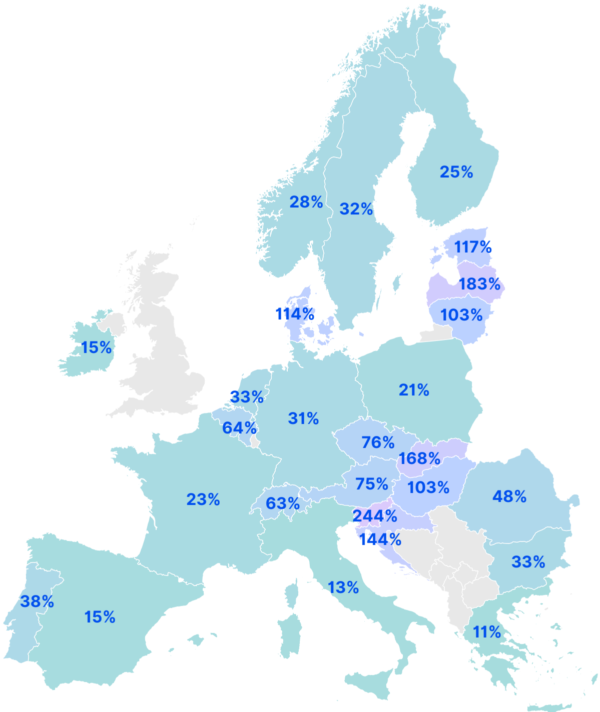
1 For further details, see Zachmann, G., C. Batlle, F. Beaude, C. Maurer, M. Morawiecka and F. Roques (2024) 'Unity in power, power in unity: why the EU needs more integrated electricity markets', Policy Brief 2024/03, Bruegel.

2 As highlighted in Thomassen, G., Fuhrmanek, A., Cadenovic, R., Pozo Camara, D. and Vitiello, S., Redispatch and Congestion Management, Publications Office of the European Union, Luxembourg, 2024, doi:10.2760/853898, JRC137685.

Improving access to neighbouring markets eases the cost-effective integration of renewables

Levels of interconnectivity vary greatly among EU Member States

Level of interconnectivity of Member States in the day-ahead market measured as the average yearly offered import capacity as a percentage of peak demand – 2023 (% of peak demand)



4 Further integration of EU markets is pivotal in fostering flexibility, enabling renewable energy to reach demand across the EU, while curbing price volatility. Using current networks to their full extent, alongside developing new infrastructure, will be a key factor for market integration.

5 The current level of interconnectivity of EU Member States is best defined by the capacities made available by transmission system operators for trade with neighbours. In particular, the report evaluates day-ahead market average import and export capacities in the external borders of each Member State, compared with their peak demand and generation. This analysis shows large disparities among Member States influenced mainly, but not exclusively, by geographical conditions, load profiles, cross-border infrastructure investment and network optimisation levels.

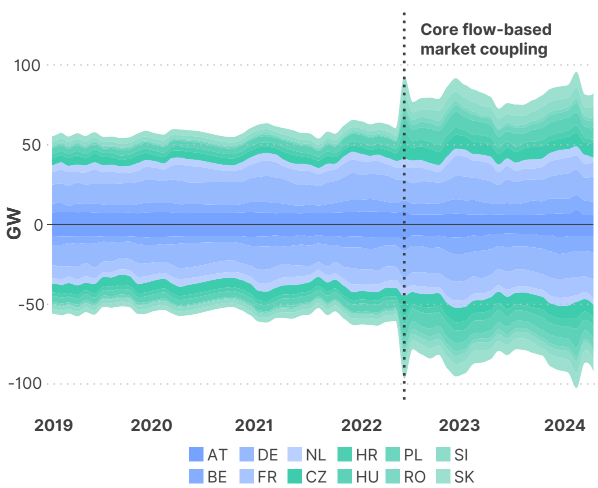
Optimization of capacity calculation for cross-zonal trade brings about significant benefits

6 Improving capacity calculation and allocation enhances cross-zonal trade within the EU. The implementation of a flow-based capacity calculation and allocation in the Core capacity calculation region in June 2022, encompassing most continental Member States, led to a significant increase in cross-border trade opportunities across the region, demonstrating how coordinated network optimisation can expand the possibilities for cross-zonal exchange in the EU.

7 While the implementation of Core flow-based market coupling marks a major milestone in EU market integration, in this respect the EU still has room for improvement. Notably, coordinated processes for capacity calculation have yet to be (fully) implemented for the different market time frames in several EU capacity calculation regions.

Flow-based calculation optimizes cross-border trading opportunities across the Core region.

Evolution of monthly average import and export possibilities within the Core capacity calculation region – 2019-2023

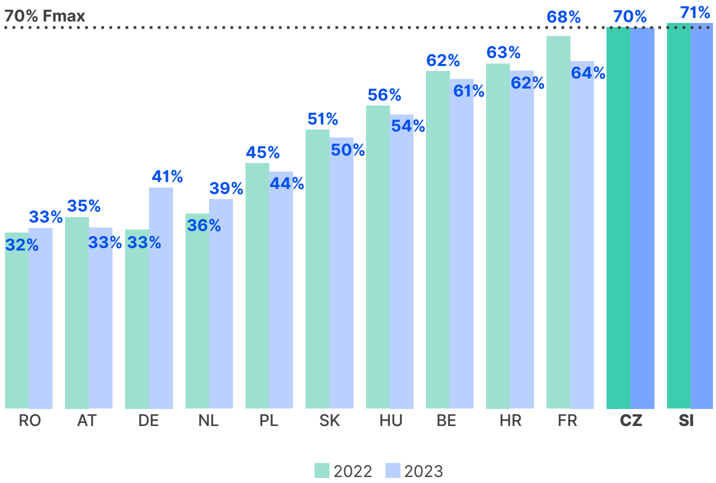


Implementation delays limit progress in maximising cross-zonal capacity

8 Efficient market integration requires all Member States to maximise availability of transmission capacity to trade with their neighbours. The Electricity Regulation introduced a minimum requirement for capacity available for cross-zonal trade. This requirement refers to the obligation to make available for cross-zonal trade at least 70% of the physical capacity of the critical network elements, setting a clear standard for cross-zonal capacity in the EU and ensuring certainty in network access. The minimum 70% requirement applies to each EU transmission system operator (TSO) and is to be met by the end of 2025 at the latest.

In 2023, two Member States in the Core region consistently met the 70% requirement

Average minimum hourly margin available for cross-zonal trade in the Core capacity calculation region per Member State – June to December 2022 and 2023 (% of F_{max})



9 ACER shows that significant effort is still needed to fulfil the requirement by the end of 2025, and that delays in implementing key processes have limited progress in most EU regions. Notably, coordinated capacity calculation processes have yet to be implemented in the Nordic, Hansa and Baltic capacity calculation regions, hindering comprehensive assessments on the progress to 70%, while the lack of a coordinated congestion management and cost-sharing framework, prevents the long-standing issue of loop flows in the Core region being addressed. This, in turn, results in national derogations from the requirements in several Member States.

10 However, delays in the implementation of methodologies are not the only barriers to maximising cross-zonal capacity. Longer-term solutions, such as large-scale grid reinforcements and potential bidding zone reconfigurations, have yet to materialise. About 30% of all projects of common interest (PCIs), representing major infrastructure works, are delayed, while the on-going pan-European bidding zone review process has also undergone several delays.

Each TSO has an individual obligation to meet the minimum 70 % requirement. However, national efforts need to be duly coordinated at the regional level, such as to address loop flows.

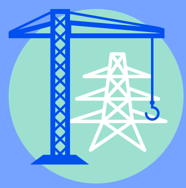
11 Notwithstanding these difficulties, implementation delays beyond the legal deadlines must not jeopardise the timeline provided in the Electricity Regulation for the fulfilment of the minimum 70% requirement. Meeting the set timeline remains a joint responsibility of all TSOs in a capacity calculation region.

Implement coordinated processes

Without delay, TSOs should implement the necessary processes to coordinate the calculation of cross-zonal capacities at the regional level and the processes to identify, trigger and share the cost of remedial actions across borders.

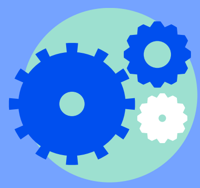
Targeted grid investments

Reinforce the grid in congested areas to reduce the share of internal and loop flows, increasing network availability for cross-zonal trade.



Improve bidding zone configuration

If unable to consistently meet the minimum 70% requirement, reconfigure the bidding zones to better align them with structural network congestions.



12 Meeting ambitious decarbonisation targets requires rapid roll-out of new infrastructure, both cross-border and internal, to accommodate renewable energy penetration. Optimising existing infrastructure and maximising its availability for trading between neighbours is just as crucial for a successful and cost-effective transition to net-zero.

List of acronyms

Abbreviation	Term in full
AC	Alternating Current
ACER	European Union Agency for the Cooperation of Energy Regulators
ATC	Available Transfer Capacity
AMR	Adjustment for Minimum RAM
CACM	Capacity Allocation and Congestion Management
CCA	Capacity Coordination Area
CCR	Capacity Calculation Region
CEE	Central East Europe
CNE	Critical Network Element
CNEC	Critical Network Element with Contingency
CNTC	Coordinated Net Transfer Capacity
CWE	Central West Europe
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
FCA	Forward Capacity Allocation
GRIT	Greece-Italy
HVDC	High Voltage Direct Current
IVA	Individual Validation Adjustment
JAO	Joint Allocation Office
LTTR	Long-Term Transmission Rights
MACZT	Margin Available for Cross-Zonal Trade
MCCC	Margin from Coordinated Capacity Calculation
MNCC	Margin from Non-Coordinated Capacity Calculation
MS	Member State
NRA	National Regulatory Authority
NTC	Net Transfer Capacity
PCI	Project of Common Interest
PTDF	Power Transfer Distribution Factor
RAM	Remaining Available Margin
RES	Renewable Energy Sources
ROSC	Regional Operational Security Coordination
SEE	South-East Europe
SWE	South-West Europe
TSO	Transmission System Operator
TTC	Total Transfer Capacity

Introduction

13 The EU's power system is undergoing a massive transformation. Renewable electricity generation must double by 2030 to address the decarbonisation challenge[3] and reduce the EU's dependency on imported fossil fuels. At the same time, sustaining the competitiveness of the EU industry calls for optimising decarbonisation, identifying the EU's key advantages for cost-effective solutions. In this regard, the fast penetration of renewable energy into the power system comes with significant underlying challenges.

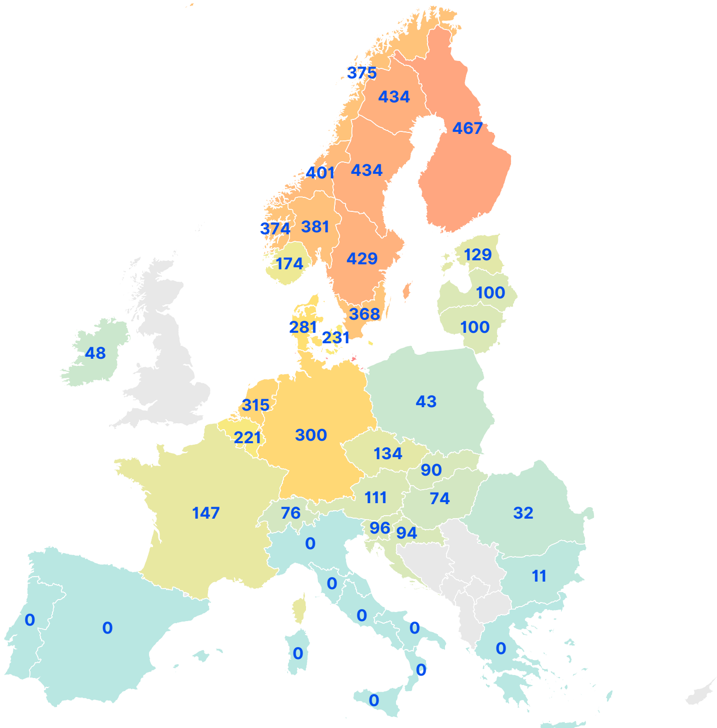
14 Boosting energy exchange between Member States enhances the resilience of the power system, optimises generation asset utilisation and promotes renewable energy integration. A well-operating internal electricity market, facilitating cross-zonal electricity exchange, is crucial for the EU's efficient decarbonisation efforts. A well-operating market also increases the security of electricity supply.

15 In 2023, electricity production from renewable energy sources (RES) rose to a record 45% of overall electricity generation in the EU.[4] Wind and solar energy powered this growth, with an 18% surge in solar generation. The latest 10-year national energy and climate plans of some Member States suggest a remarkable, often triple-digit, planned growth in use of these two renewable energy sources.

16 In this context, both the roll-out of cross-border electricity infrastructure and the maximal use of interconnections across the EU are key to the completion of the EU internal market for electricity, expanding cross-zonal trading opportunities. These cross-zonal trading opportunities are pivotal in fostering flexible solutions, enabling renewable energy to reach demand centres across the EU and curbing price fluctuations.

17 As displayed in Figure 1, 2023 saw an explosion in negative day-ahead prices in the EU. This occurred when significant renewable supply was met with low electricity demand in a given bidding zone.[5] Situations like this emphasize the need for local flexibility, and the importance of availability of cross-zonal transmission capacity across all time frames, including near real time, to ensure system-wide flexibility and the ability to efficiently distribute vast amounts of renewable energy, largely dependent on regional weather conditions, and its benefits, in the form of lower electricity prices.

Figure 1: Occurrences of day-ahead negative prices in EU bidding zones - 2023 (number of occurrences)



Source: ACER calculation based on European Network of Transmission System Operators for Electricity (ENTSO-E) Transparency Platform data.

3 ACER-EEA, Flexibility solutions to support a decarbonised and secure EU electricity system, October 2023.

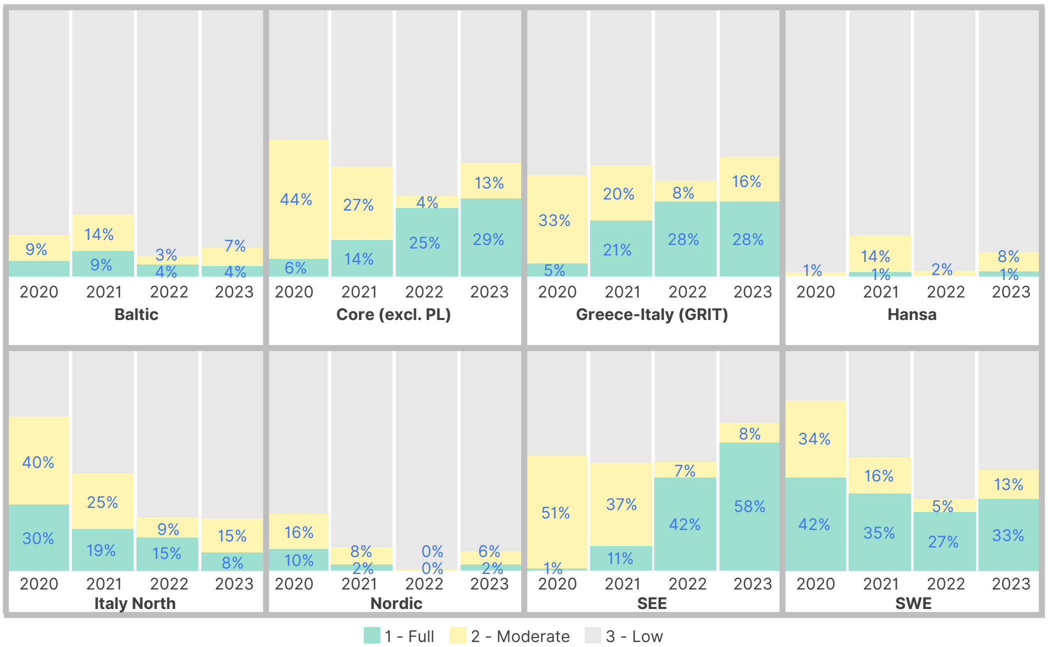
4 ACER, Key Developments in EU Electricity Wholesale Markets: 2024 Market monitoring report, March 2024.

5 A bidding zone refers to the largest geographical area within which market participants can exchange energy without capacity allocation.

18 Price convergence of bidding zones within capacity calculation regions in the day-ahead market, while not being an end goal, may serve as a proxy for the integration of the EU power system of EU Member States and the maximization of socio-economic welfare. The evolution of day-ahead price convergence in the different EU capacity calculation regions since 2020[6] is shown in Figure 2.

19 Price convergence is explained by several factors: first, by the difference of generation mixes between bidding zones; second, by how transmission capacity for trade between zones is allocated to the market (e.g. by implicit market coupling in intraday and day-ahead markets); and, lastly, by the level of transmission capacity that is available for cross-zonal trade. In turn, the available capacity for cross-zonal trade is affected by the transmission infrastructure built between and within bidding zones, and how such physical capacity translates into cross-zonal trading possibilities in the form of commercial cross-zonal capacities.

Figure 2: Day-ahead price convergence in the EU per capacity calculation region – 2020-2023 (% of hours)



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

Note: Price convergence indications calculated as the difference between the highest and lowest day-ahead price of a given capacity calculation region: Full, <1 EUR/MWh. Moderate: 1-10 EUR/MWh. Low: >10 EUR/MWh. Allocation constraints in Poland have significantly affected the opportunities for trade in the Core capacity calculation region; thus, their impact has been removed from this figure.

20 The development and implementation of rules for the calculation and allocation of cross-zonal capacities on electricity interconnectors is therefore an integral step towards the completion of the EU's internal electricity market. Over the last decade, progress in capacity allocation has been considerable, with all EU bidding zone borders being included in the Single Day-Ahead Coupling (SDAC) and Single Intraday Coupling (SIDC), ensuring that the cross-zonal capacity offered to the market is always allocated efficiently in the related time frames. On the other hand, progress in maximising the capacities offered to the different markets for cross-zonal trade in the EU has been slower. Limited levels of cross-zonal capacity offered to electricity markets can constitute an obstacle to the development of a functioning internal market for electricity.

21 To address the need for 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. In order to implement the requirement, without endangering system security, Member States and TSOs could opt for a transitional period – via action plans to address structural congestion in the power grid and/or temporary derogations – to enable them to gradually fulfil the obligation by the end of 2025 at the latest. Until then, structural congestion in the grid was to be addressed using remedial actions[7],

6 Capacity calculation regions are defined in ACER Decision 04/2024 on the determination of capacity calculation regions.

7 Remedial actions are measures that TSOs take to tackle grid congestion. They can be costly, such as redispatching or countertrading or non-costly, such as the use of phase shifting transformers.

for which the relevant TSOs would bear the costs. In parallel, a process was agreed upon whereby the relevant stakeholders 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.

22 In monitoring the implementation of the minimum 70% requirement across the EU, ACER was asked to develop a harmonised monitoring approach for all Member States, described in ACER Recommendation 01/2019, which would allow to track progress in the implementation of the requirement and compare Member States on an equal footing. ACER has since produced yearly reports monitoring the progress of implementation of the minimum 70% requirement in the EU.

23 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, the barriers to the completion of the internal market for electricity. This report assesses the barriers related to the availability of cross-zonal capacity and thus focuses on the indicators relevant to such availability. Moreover, the report fulfils ACER's obligation set under Article 34 of Regulation (EU) 2015/1222 establishing a guideline on capacity allocation and congestion management (CACM Regulation) to produce a market report evaluating the impact of the current bidding zone configuration on market efficiency.

24 The report is structured as follows. Chapter 1 presents a high-level overview of the evolution of the level of cross-zonal capacity for all regions and across different market time frames. It offers the reader a comprehensive overview of the principles guiding the calculation of cross-zonal capacities in the EU and explains the key concepts used throughout the report. Chapter 2 monitors the margin of cross-zonal capacity made available for day-ahead cross-zonal trade in 2023, assessing the progress in implementing the minimum 70% requirement and, where applicable, the fulfilment of the national interim requirements. Lastly, Chapter 3 assesses the costs and volumes of remedial actions activated by TSOs to address grid congestion, which are in part triggered to enable the current levels of cross-zonal capacity.

25 ACER expresses its gratitude for the valuable contributions received from all national regulatory authorities (NRAs) in the drafting of this report.

1. Evolution of cross-zonal capacities in the EU

26 EU power markets are structured in different time frames: market participants exchange electricity with varying lead times, from years-ahead in the long-term markets to close to real time in the intraday and balancing markets. Under the current market design in the EU, transmission capacity for trade between bidding zones is released by TSOs at the earliest 1 year ahead of delivery.

27 EU rules allow two possible approaches for TSOs to calculate the capacity made available for trade between EU bidding zones in a coordinated manner: the coordinated net transfer capacity (CNTC) approach and the flow-based approach. The flow-based approach is defined as the default in areas of the transmission grid where the exchanges across bidding zone borders are highly interdependent. The CNTC approach, on the other hand, can be applied in regions where cross-zonal exchanges are less interdependent and thus no significant added value is expected to be gained from implementing the flow-based approach.

28 Flow-based capacity calculation models a subset of network constraints, the so-called critical network elements with contingency (CNECs)[8], and provides detailed information on such network constraints to the price coupling mechanism. The price coupling mechanism can then allocate the capacity made available on each CNEC to the electricity exchanges that generate the most socio-economic welfare. This allows for an optimised allocation of cross-zonal capacities at the level of the capacity calculation region.

29 The effectiveness of flow-based market coupling to enable the most efficient, physically feasible, market outcome across interconnected bidding zones hinges on the precise calculation of the flow-based parameters, which specify both how cross-zonal power exchanges affect power flows on network elements and how much capacity on each element is available to accommodate flows induced by cross-zonal exchanges:

- The zonal power transfer distribution factors (PTDF) matrix maps the impact of the variation of a bidding zone's net exchange (i.e. the variation of its 'net position') to the flow on selected CNECs.
- For each CNEC, the remaining available margin (RAM) defines the margin of the physical capacity that is available for cross-zonal trading in the region for the relevant market time frame.

30 The net transfer capacity (NTC) model, on the other hand, assesses and defines ex-ante a maximum value of electricity exchange between adjacent bidding zones that is considered to be always physically feasible. In CNTC processes, a centralized computation based on an alternating current (AC) power flow calculation delivers the total energy that can be exchanged across one or several bidding zone borders. This value of total transfer capacity (TTC) is then usually reduced to introduce a reliability margin and split among the different borders involved in the calculation, thus obtaining a NTC value.

31 The coordinated processes for capacity calculation across the different regions and time frames are based on regional capacity calculation methodologies. Such processes define inputs, the approach to be implemented and the requirements for reductions of capacity in the event of potential operational security violations. Their implementation is a key milestone in the progress of EU market integration.

32 The status of such implementation differs between capacity calculation region and time frame. Table 1 provides an overview of the implementation status of the regional capacity calculation methodologies stemming from the forward capacity allocation (FCA Regulation) and CACM Regulation, as of June 2024. 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. Where intraday and balancing capacity calculation methodologies have not yet been implemented, these markets usually receive the portion of the capacity that has not been used in previous time frames (the so-called leftovers).

8 A critical network element is a network element (a line or a transformer) either within a bidding zone or between bidding zones, that is significantly impacted by cross-zonal trades, and which is monitored 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.

Table 1: Status of the implementation of the regional capacity calculation methodologies stemming from the FCA and CACM Regulations in the EU capacity calculation regions - June 2024

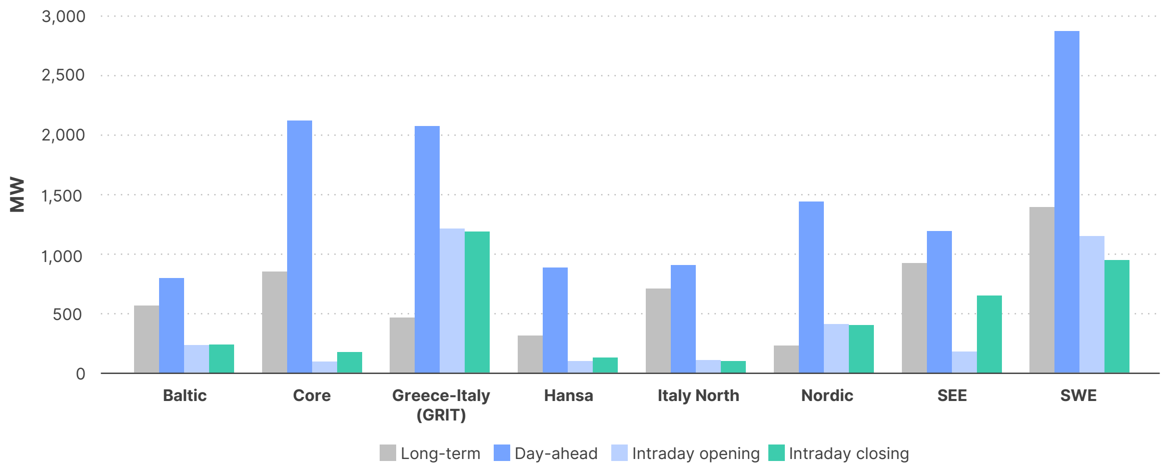
CCR	Calculation approach	Long-term		Day-ahead		Intraday	
		Reg.	Implementation status	Reg.	Implementation status	Reg.	Implementation status
Baltic	CNTC	FCA	Not implemented	CACM	Not implemented	CACM	Not implemented
Core	FB		Not implemented		Mostly		Partially
Central Europe	FB		—		Not implemented		—
GRIT	CNTC		Mostly		Mostly		Mostly
Hansa	CNTC		Not implemented		Not implemented		Not implemented
Italy North	CNTC		Mostly		Partially		Partially
Nordic	FB		Not implemented		Not implemented		Not implemented
SEE	CNTC		Mostly		Mostly		Mostly
SWE	CNTC		Mostly		Mostly		Mostly

Source: ACER elaboration based on NRA data.

Note: Capacity calculation methodologies are subject to amendments and thus are always undergoing continuous improvement. CCR, capacity calculation region; FB, flow-based; GRIT, Greece-Italy; Reg., regulation; SEE, South-East Europe; SWE, South-West Europe.

33 Under the current market design, calculation of transmission capacity for cross-zonal trade for the different market time frames is to be done at the level of capacity calculation regions. Cross-zonal capacity is released by TSOs from 1 year ahead of delivery of electricity to close to real time. Effectively, most cross-zonal transmission capacity is currently offered, and allocated, in the day-ahead time frame. In the intraday time frame, cross-zonal trade is possible from 15:00 on the day before delivery of electricity (even if capacity may be released by TSOs after that) and up to 60 minutes before the relevant market time unit. Figure 3 provides an overview of the average levels of capacity released in 2023 in the bidding zone borders of every capacity calculation region and in the different market time frames.

Figure 3: Level of cross-zonal capacity offered on average in the bidding zone borders of the EU capacity calculation regions and in different market time frames – 2023 (MW)



Source: ACER calculation based on ENTSO-E Transparency Platform, Joint Allocation Office (JAO) Auction Tool and JAO Publication Tool data.

Note: The assumptions used to create this figure are detailed in the subsections that follow. In particular:

- cross-zonal capacities offered in the long-term time frame correspond only to capacity released for the purpose of auctions of long-term transmission rights, and thus excludes borders where these instruments are not issued;

- the average value of capacity released in the Core region in the day-ahead time frame is calculated as the sum of the average non-simultaneous minimum and maximum net position of each bidding zone, and normalised by the number of bidding zone borders in the region;

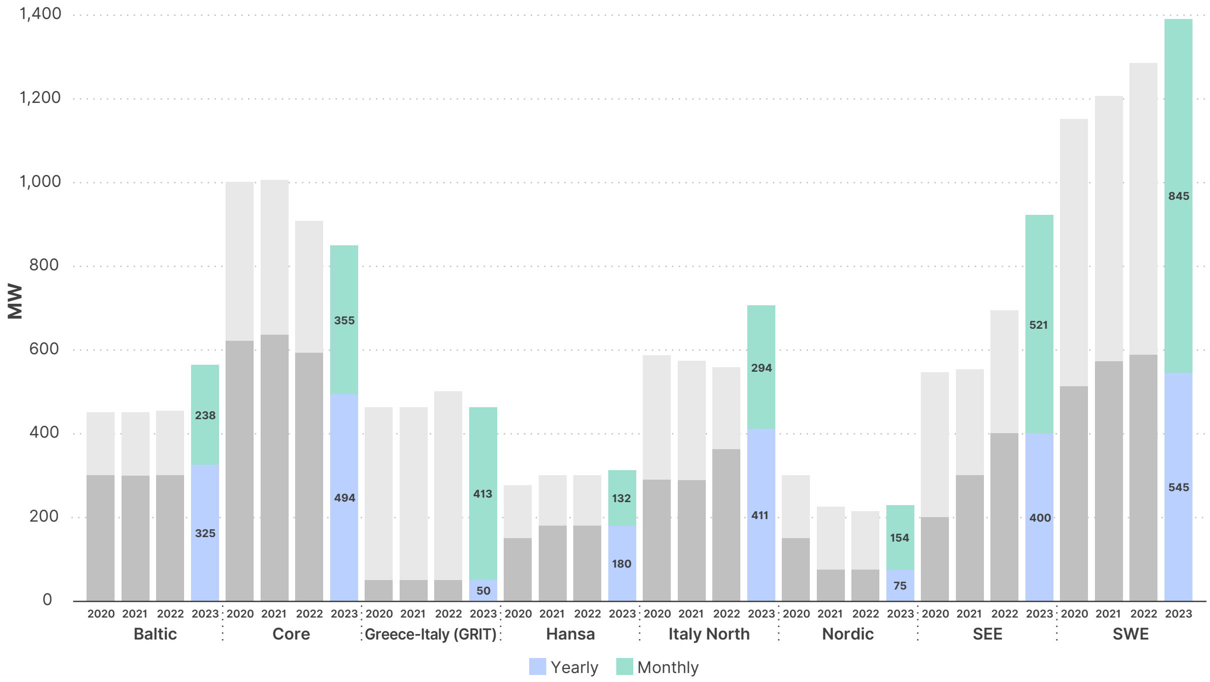
- intraday available transfer capacities (ATCs) are evaluated at the point they are first released by TSOs (i.e., the effective start of cross-zonal intraday trade) and at gate closure time, for the congested direction of every bidding zone border.

34 The following subsections analyse the yearly evolution of transmission capacities available for cross-zonal trade in the different market time frames, in decreasing order of lead time to the delivery of electricity.

1.1. Long-term market

35 Cross-zonal capacities are released in the EU up to 1 year ahead of electricity delivery. On most EU borders, capacities in the long-term time frame, both month-ahead and year-ahead, are released in the form of long-term transmission rights (LTTRs). These instruments allow the hedging of price differentials between bidding zones and are a key element of the current forward market design. LTTRs are auctioned to market participants via a single allocation platform. Most countries apply financial transmission rights, with a few countries in the former Central-East Europe region still using physical transmission rights.[9] Figure 4 shows the evolution of the average levels of capacity offered by EU TSOs through yearly and monthly auctions of LTTRs.

Figure 4: Annual evolution of average monthly and yearly cross-zonal capacity offered for the purpose of long-term transmission rights in the capacity calculation regions – 2020-2023 (MW)



Source: ACER calculation based on JAO Auction Tool data.

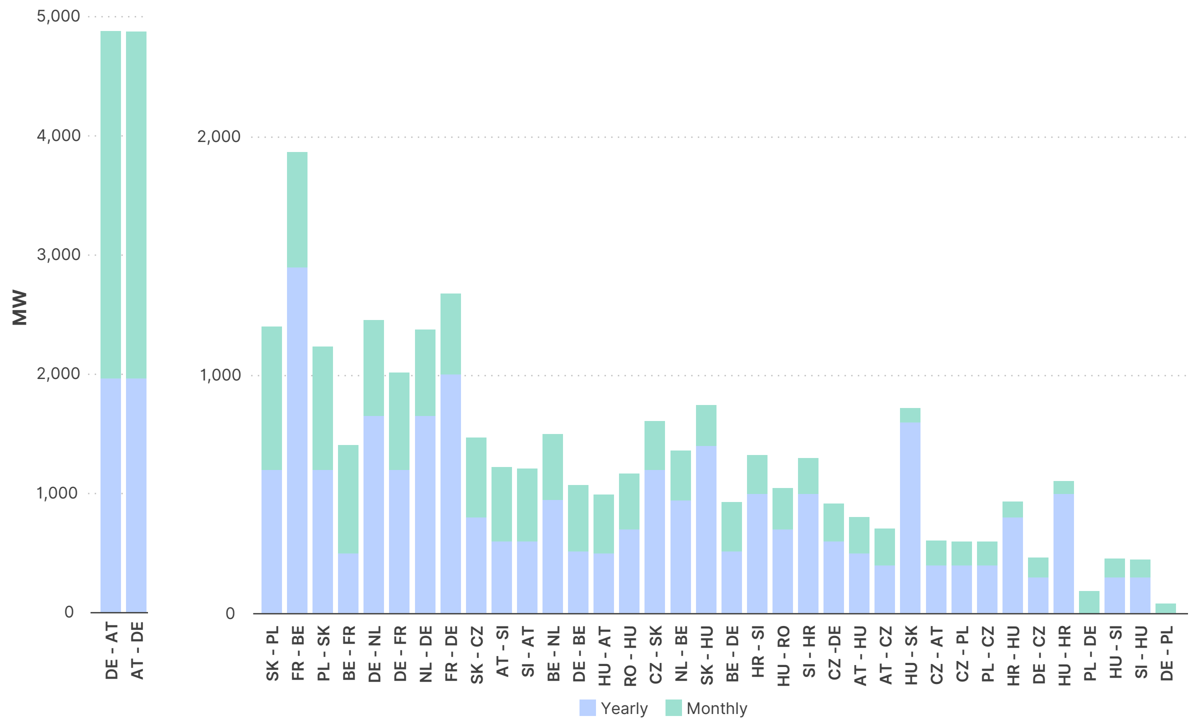
Note: The figure considers the average long-term capacity released for the purpose of LTTR auctions in every bidding zone border included in an EU capacity calculation region. It thus excludes bidding zone borders where these products are not issued.

36 The differences between regions can be explained by differences in market structure and by the level of implementation of coordinated capacity calculation processes for the long-term time frame. Physical grid topology and market structure is significantly different across regions, which is evident from the varying average levels of offered capacities for LTTRs. The level of implementation of coordinated capacity calculation processes for the long-term time frame also differs greatly across the EU. Generally, less interdependent areas of the EU power grid are subject to less uncertainty and can offer relatively more capacity to the market in longer time frames (such as South-West Europe (SWE)).

37 In the case of the Core capacity calculation region, covering the bidding zone borders between most western and central European Member States, values of capacity released in the long-term time frame are especially uneven across borders, as shown in Figure 5. Capacities released are relatively high on the border between the Austria and Germany/Luxembourg bidding zones where, after the split of the Austria/Germany/Luxembourg bidding zone, LTTRs to an agreed value of approximately 5 GW are released. Conversely, capacities released are notably low on the bidding zone border between Poland and Germany/Luxembourg.

9 A physical transmission right (PTR) allows the holder the option to either nominate energy on the concerned border or not nominate and thus receiving financial compensation. A financial transmission right allows the holder to receive financial compensation.

Figure 5: Annual average monthly and yearly cross-zonal capacity offered for the purpose of long-term transmission rights in the bidding zone borders of the Core capacity calculation region – 2023 (MW)



Source: ACER calculation based on JAO Auction Tool data.

Note: The figure considers the average of long-term capacity released for the purpose of LTTR auctions in every bidding zone border included in an EU capacity calculation region. It thus excludes bidding zone borders where these products are not issued.

38 Generally, whenever cross-zonal capacities calculated in the day-ahead time frame result in values lower than capacities already allocated in yearly and/or monthly auctions, such capacities are increased to be able to guarantee the pay-out to LTTR holders. In the Core region, this is done through a process named extended LTA inclusion[10], where capacities allocated in the long-term time frame at a bidding zone border level are delivered, in parallel with the flow-based domain, to the day-ahead market coupling algorithm. The algorithm can then choose the combination of domains that maximises socio-economic welfare. This process is particularly relevant for the Austria – Germany/Luxembourg border, where large amounts of capacities in the form of LTTRs are released.

39 According to the Harmonised Allocation Rules, TSOs may curtail cross-zonal capacities allocated in the long-term time frame for the purpose of LTTRs in the case of force majeure or to ensure operation remains within security limits. In the case of curtailment, holders of LTTRs are entitled to receive reimbursement or compensation. The valuation of LTTRs by market participants is influenced by the expected day ahead price difference between the concerned bidding zones and the probability of curtailment on a given border. ACER intends to assess the market valuation of LTTRs in its 2024 market monitoring report on EU wholesale market integration, expected in October 2024.

1.2. Day-ahead market

40 In the current market design, most cross-zonal capacities are offered and allocated in the day-ahead market. The single day-ahead coupling mechanism allocates scarce cross-zonal transmission capacity by coupling wholesale electricity markets from different regions using a common algorithm. Considering all cross-zonal transmission constraints simultaneously ensures the maximisation of socio-economic welfare.

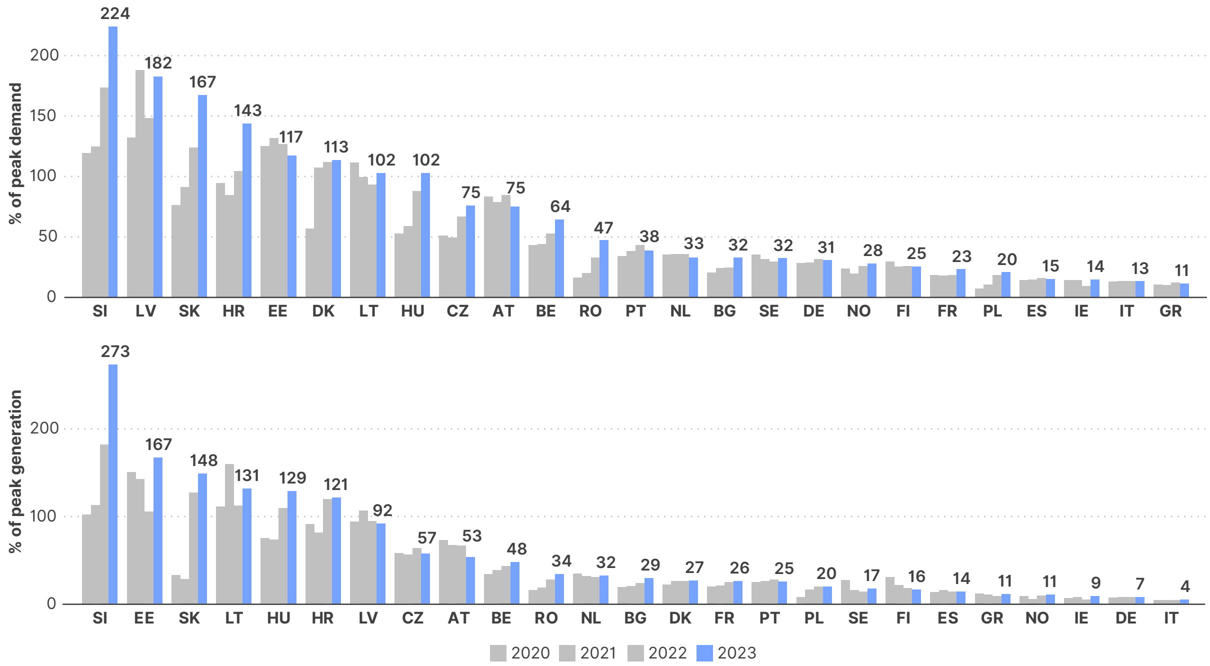
41 Figure 6 compares the level of interconnectivity of Member States, calculated as the yearly average offered import capacity of every Member State as a percentage of peak electricity demand, and the

10 This process is detailed in Article 18 of the Core day-ahead capacity calculation methodology.

yearly average offered export capacity of every Member State as a percentage of peak generation. It shows that large disparities in interconnectivity exist between Member States, driven mainly by differences in geography, investment in cross-border infrastructure and optimisation of the network.

42 In particular, Member States included in flow-based market coupling in June 2022 (i.e., those in the former CEE region) see a considerable increase in their levels of interconnectivity, as measured by this metric. As previously mentioned, flow-based market coupling generally offers more exchange possibilities than NTC calculation, as it incorporates the modelling of the underlying electricity network in the allocation of cross-zonal capacities. Unlike NTC values, which are simultaneously feasible on all bidding zone borders, the maximum import and export capacities in flow-based regions on a given bidding zone border are dependent on other exchanges in the region. This leads to available capacities on specific network elements being allocated where they generate most socio-economic welfare.

Figure 6: Level of interconnectivity of Member States in the day-ahead market measured as the average yearly import capacity as a percentage of peak demand (top) and average yearly export capacity as a percentage of peak generation (bottom) – 2020-2023 (% of peak demand and % of peak generation)



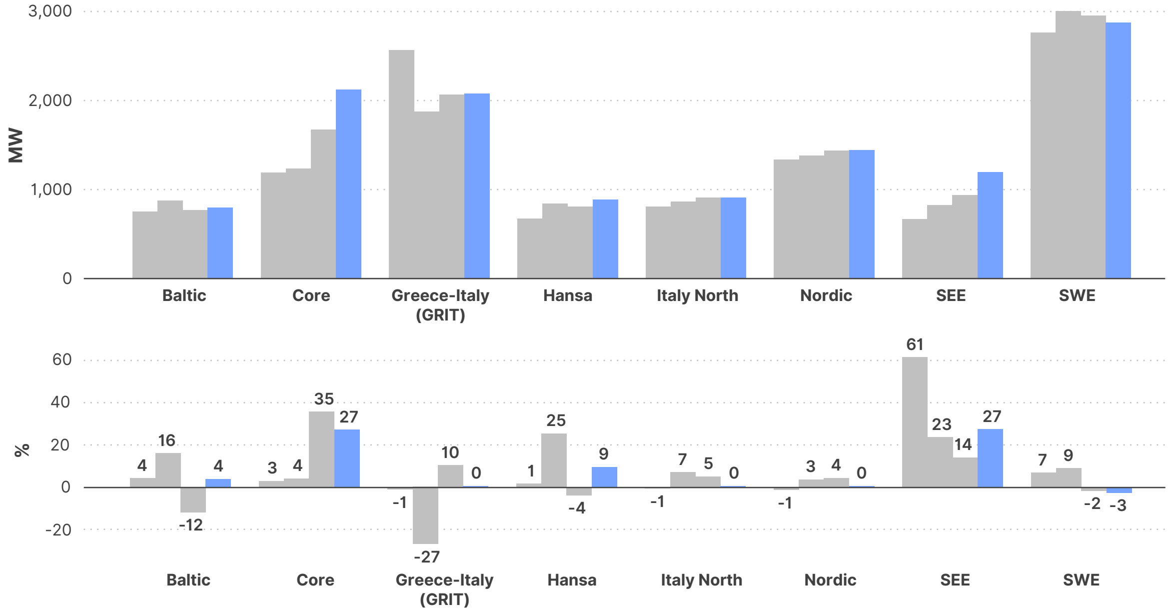
Source: ACER calculation based on JAO Publication Tool and ENTSO-E Transparency Platform data.

Note: In flow-based regions, the average value of the minimum and maximum non-simultaneous net position is used, as reported by the Core TSO in the JAO Publication Tool. This figure considers the total import and export possibilities in the day-ahead market, and thus includes exchanges with non-EU countries.

43 With regards to the figure shown above, two caveats should be noted. First, it represents only one of the many possible metrics for assessing the interconnectivity levels of Member States, based on average cross-zonal capacities available for trade in the day-ahead market, as well as the peak demand and generation values of each Member State. And second, the figure does not account for capacities released for trade between bidding zones within a single Member State, which is particularly relevant for Italy or Sweden. Consequently, it only assesses interconnectivity between Member States, and not within them.

44 Figure 7 shows the average annual evolution of import and export cross-zonal transmission capacities in each CCR since 2020. Consistent increases in available capacities over the last few years are observed mainly in the Core and SEE regions. As was the case with the previous figure, the benefits brought forward by flow-based market coupling in the Core region can also be observed in Figure 7, which suggests that the change from NTC to flow-based calculation for some of the Core bidding zone borders in mid-2022 resulted in a significant overall increase in cross-zonal capacity available for trade within the region.

Figure 7: Yearly evolution of the average day-ahead import and export cross-zonal capacity of every bidding zone border in the capacity calculation regions, in terms of absolute value (top) and year-on-year change (bottom) – 2020–2023 (MW and %, respectively)



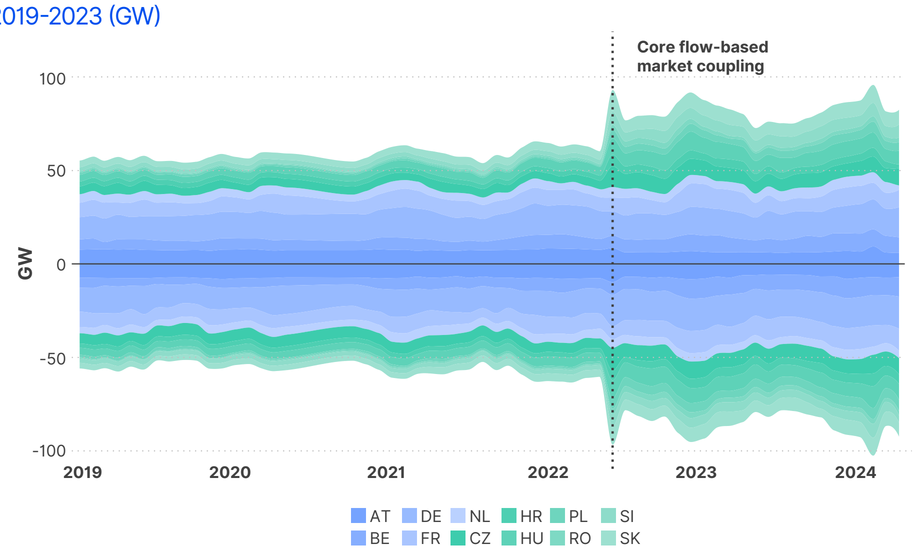
Source: ACER calculation based on JAO Publication Tool and ENTSO-E Transparency Platform data.

Note: In order to enable the comparison between flow-based and NTC regions, the average export and import capacities of every bidding zone to and from the other bidding zones of the region are summed, and then normalised by the number of bidding zone borders in the region. In flow-based regions (CWE, and then Core), the minimum–maximum non-simultaneous net position per bidding zone is used to define the export and import capacities of every bidding zone. In NTC regions, the annual averages of the NTC values in the import and export direction are used.

45 Lastly, Figure 8 provides a more granular view on the evolution of cross-zonal capacities in the Core region over time. It shows the monthly averages of the minimum and maximum possible net position for every bidding zone in the Core region, both before and after the implementation of the Core flow-based market coupling framework. As previously mentioned, the values displayed for flow-based bidding zones are not simultaneously feasible on all bidding zone borders.

46 While the figure shows a slight upward trend in the former Central-West Europe (CWE) bidding zones (highlighted in the figure with different shades of blue), driven by the progress in implementing the minimum 70% requirement since 2020, most of the observed increases in capacity are a result of former Central-East Europe (CEE) bidding zones (highlighted in shades of green) moving from NTC-based to flow-based capacity calculation processes, after the implementation of Core flow-based market coupling.

Figure 8: Evolution of monthly average import and export potential net positions of Core region bidding zones – 2019-2023 (GW)



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

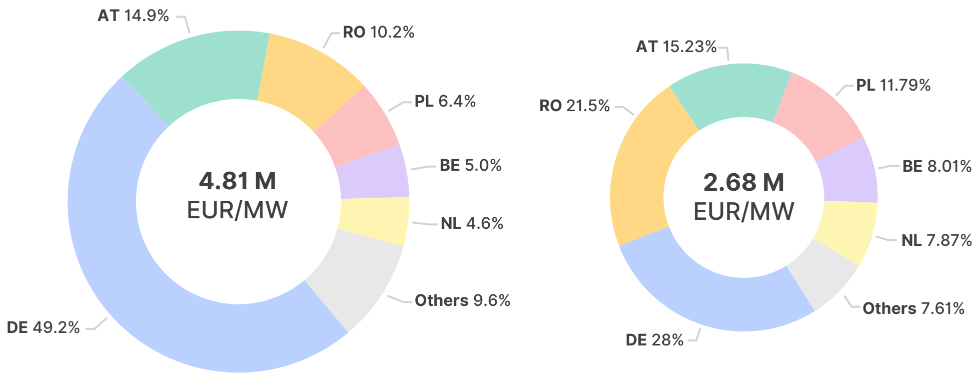
Note: The figure aggregates the monthly average of the maximum import and export offered capacity per bidding zone. In flow-based bidding zones, the non-simultaneous minimum–maximum net position value is used, as published in the JAO Publication Tool. In fully NTC bidding zones, the sum of NTCs in the export and import directions is calculated for every bidding zone.

Congestion limits additional socio-economic welfare, quantified in flow-based day-ahead market coupling by the active constraints

47 In flow-based day-ahead market coupling, the allocation algorithm defines the CNECs that effectively limit the allocation of cross-zonal capacities. These limiting CNECs are the so-called active constraints, and they are associated with a positive shadow price (also referred to as 'dual value'). This value estimates the potential socio-economic welfare gain that would be realised by allowing for one additional MW of cross-zonal trade on the relevant CNEC (i.e., increasing its RAM by one MW).

48 The monitoring of these elements provides valuable information on where additional cross-zonal capacity was most needed during a given period, and thus where grid congestion was a limiting factor to additional socio-economic welfare. Figure 9 shows an overview of the total volume of shadow prices on active constraints, and its distribution across the Core region Member States, comparing 2023 with the period of 2022 that followed the introduction of Core flow-based market coupling (9 June 2022). Allocation constraints[11], often limiting market allocation in the Polish bidding zone, are not considered for the purpose of this figure.

Figure 9: Distribution of the total shadow price of active constraints in Core flow-based market coupling from 9 June to 31 December 2022 (left) and in 2023 (right) in Core Member States - 9 June 2022 to 31 December 2022 and 2023 (EUR/MW)



Source: ACER calculation based on JAO Publication Tool data.

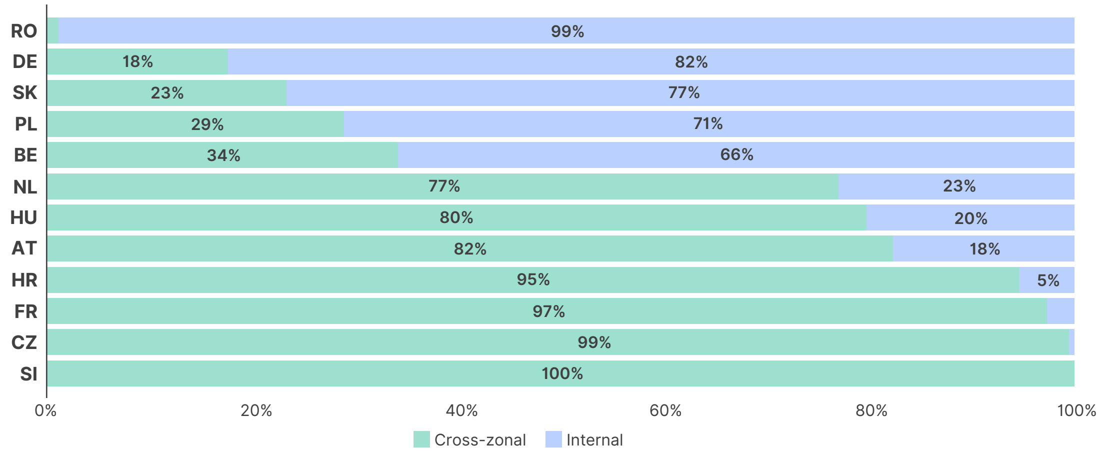
Note: Distribution by Member State for the purpose of this figure is performed on the sum of shadow prices of all CNECs with a non-zero shadow price. The sum of shadow prices on all CNECs for each period is presented at the centre of the charts, highlighting the welfare gain that would be obtained from one additional MW of cross-zonal capacity in the CNECs limiting allocation for the analysed period.

49 Further analysis of the active constraints provides several insights into the power system in the Core region. Firstly, the sum of all shadow prices the region is significantly lower in 2023 than in the second half of 2022, highlighting the fact that transmission capacities were less limiting to socio-economic welfare in the day-ahead market in 2023 than in 2022. This is mostly driven by the higher prices and related effects on cross-zonal trade, experienced in the context of the energy crisis of 2022. Moreover, as will be further assessed in Chapter 2, the increasing minimum margins of capacity offered for cross-zonal trade by some Core TSOs, in line with obligations under Article 16(8) of the Electricity Regulation, have surely also played a role.

50 Information on the location of the active constraints is also very relevant. In the second half of 2022, almost half of the welfare gains extracted from additional cross-zonal capacities was found in German critical network elements. This share has become much lower in 2023, with the potential welfare gains being more evenly spread across the Core region. The annual increase in interim requirements, in line with the linear trajectory on the margin of cross-zonal capacity of the German action plan, together with smaller increases in other TSOs in the region, has surely contributed to this change.

11 See section 2.3.1.

Figure 10: Distribution of the sum of shadow prices in all active constraints in Core flow-based market coupling, attributed to internal or cross-zonal network elements, in each Member State in the Core region - 9 June 2022 to 31 December 2022 and 2023 (% of total shadow price)



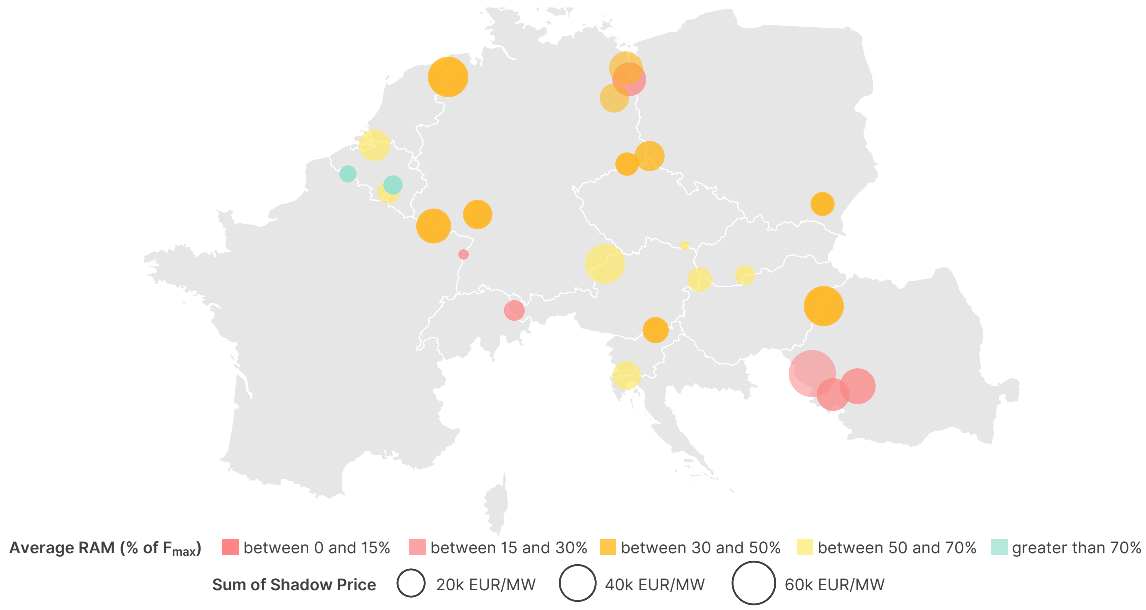
Source: ACER calculation based on JAO Publication Tool data.

Note: Distribution by element type for the purpose of this figure is performed on the sum of shadow prices of all CNECs with a non-zero shadow price.

51 Figure 10 shows that in some Member States, critical network elements internal to the bidding zones are most severely limiting market allocation. Namely, this is the case for Romania in particular (but also Belgium, Germany and Slovakia). On the other hand, Member States such as Croatia, Czechia, France and Slovenia present most of their active constraints on cross-zonal elements.

52 Moreover, there is a link between the critical network elements that limit cross-zonal capacity allocation and the margins made available for cross-zonal trade, which are monitored in Chapter 2. CNECs with a lower offered margin of capacity tend to restrict the allocation of capacities more. This is highlighted in Figure 11, which shows the 25 most limiting critical network elements, measured by the sum of shadow price over the course of the year, and their average RAM as a share of the maximum flow on critical network elements, respecting operational security limits (F_{max}). These are the critical network elements for which one additional MW of cross-zonal capacity would have led to the highest socio-economic welfare increase in 2023.

Figure 11: Location and relative margin of coordinated capacity of the 25 most limiting critical network elements in Core flow-based market coupling per sum of shadow price - 2023



Source: ACER calculation based on JAO Publication Tool data.

Note: Ranking of the most constraining critical network elements is performed by summing the shadow price associated with each critical network element over the course of 2023 and is represented by the size of the bubbles in the figure. The colour of the bubble represents the average RAM as a share of F_{max} for the selected CNECs.

1.3. Intraday market

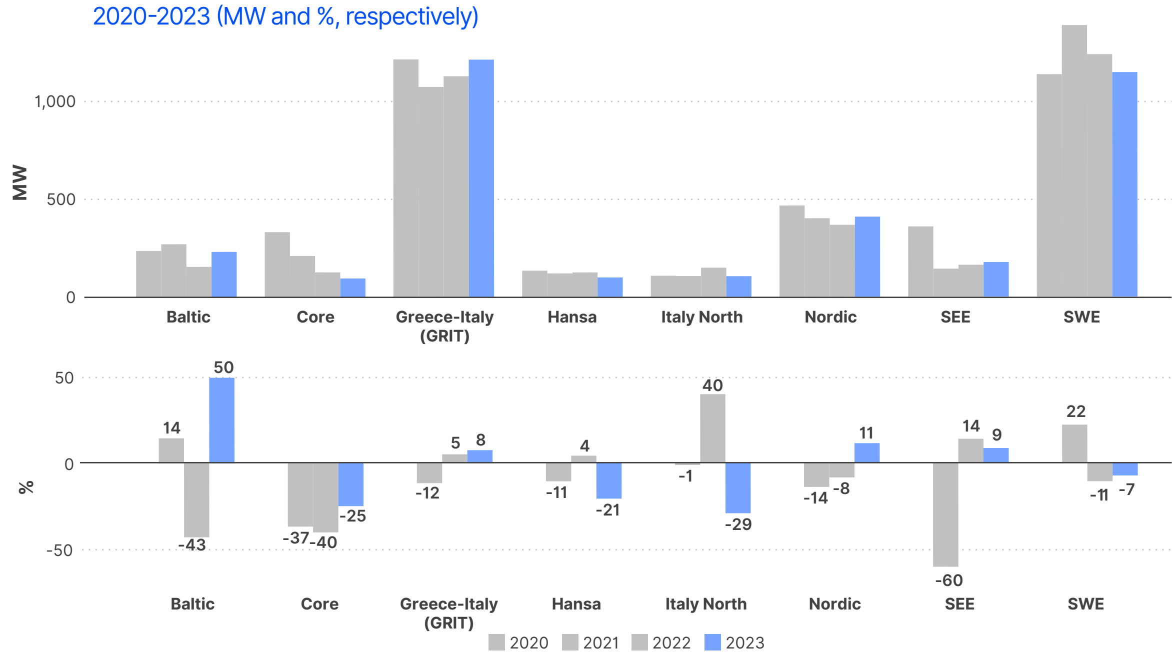
53 In the intraday market, market participants can continue trading electricity after the day-ahead market clearing, with transactions taking place closer to the delivery of electricity. In particular, cross-zonal intraday trading is currently possible up to one hour ahead of electricity delivery.[12] As intraday trading allows for a high degree of flexibility, market participants use the intraday market to adjust their positions close to real time and thus reduce potential imbalance costs. In the EU, most cross-zonal transactions in the intraday time frame are currently done through continuous trading, where as soon as a buy and sell order match, and there is sufficient cross-zonal capacity, the trade is executed. Pan-European intraday auctions, on the other hand, are expected to be implemented in the course of 2024.

54 Over the last decade, closer-to-real-time trading has become increasingly relevant as more volatile power generation technologies get integrated into the system.[13] This is the case mainly for weather-dependent renewables, as quickly changing forecasts may result in an unplanned shortfall or surplus of power produced by renewable source plants. Fully functioning and integrated intraday markets and sufficient cross-zonal intraday capacity are thus key components of efforts invested in the transition of the power system to net zero.

55 Cross-zonal trading is an essential element of intraday trading, and European intraday markets are connected via the Single Intraday Coupling (SIDC). As highlighted in Table 1, capacity calculation methodologies for the intraday time frame are still being implemented in most EU capacity calculation regions. Where not yet implemented, the capacities released by TSOs on the intraday time frame are based on leftovers from day-ahead trading, at times combined with interim calculation processes.

56 Figure 12 shows the average values of available transfer capacities (ATCs) when cross-zonal capacities are first released by TSOs in every EU capacity calculation region, on the most congested direction for every bidding zone border. For most EU bidding zone borders, cross-zonal capacity is released for intraday trading at 22:00 of the day before delivery of electricity. The values presented are driven mainly by two factors. Firstly, the figure shows the share of cross-zonal capacities that are not fully used in the day-ahead market. Whenever a given direction of a bidding zone border is not congested in the day-ahead time frame, leftover capacities will generally be available for the intraday time frame. Secondly, such leftover capacities can be increased through recalculations of capacity in the intraday time frame.

Figure 12: Yearly evolution of the average intraday cross-zonal capacities in the congested direction of every bidding zone border in the capacity calculation regions, in absolute value (top) and year-on-year change (bottom) – 2020-2023 (MW and %, respectively)



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

Note: Intraday ATCs are evaluated at the moment they are first released by TSOs (i.e., assessing the first non-zero ATC value recorded in the ENTSO-E Transparency Platform in either direction for a given bidding zone border), and displayed in the congested direction for every bidding zone border.

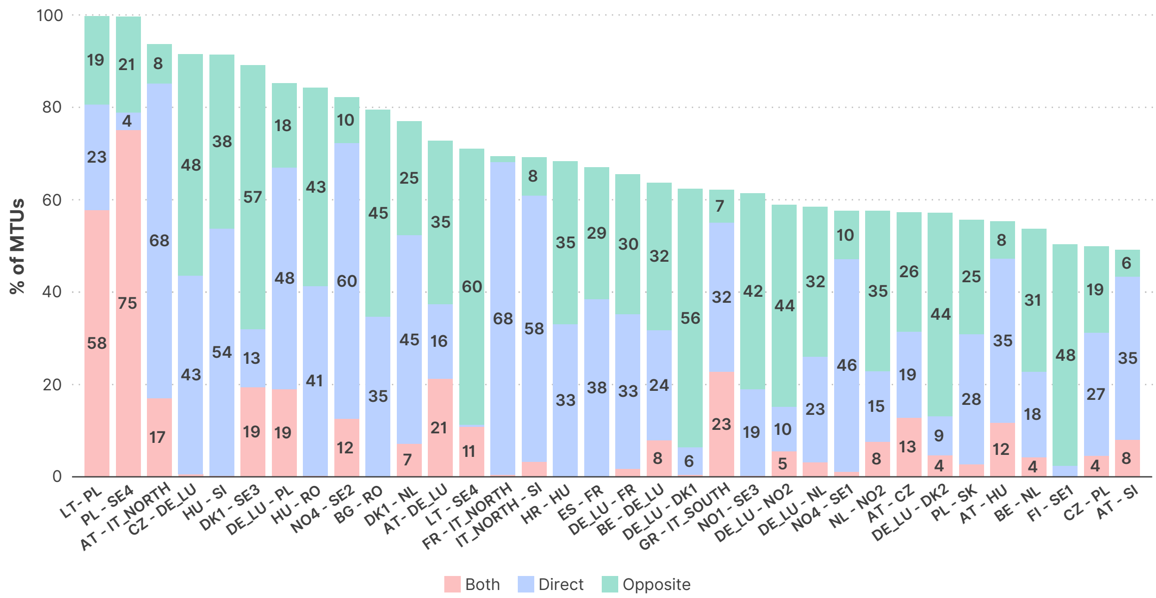
12 The Electricity Market Design reform agreed by EU legislators introduces an intraday cross-zonal gate closure time of 30 minutes, to be applicable from 1 January 2026.

13 See section 2.3 of the ACER's 2023 market monitoring report, Progress of EU Electricity Wholesale Market Integration, for more details on the increasing importance of intraday trading in EU electricity markets.

57 The figure provides insights into the average levels of capacity released for cross-zonal intraday trading in the different capacity calculation regions, as well as the trends observed in recent years. The share of allocation of cross-zonal capacities in the day-ahead time frame, combined with the lack of fully coordinated processes for intraday capacity calculation, leads to notably low average capacity values in the congested direction for some CCRs. Moreover, a downward trend over the last 4 years is observed in the Core region, with other regions, such as Greece-Italy (GRIT) and SWE, appearing to be less congested after the day-ahead time frame.

58 Beyond the average intraday capacities shown in Figure 12, capacities released to the intraday market are often zero. This implies that no cross-zonal exchange is possible in the intraday time frames in a given direction of a bidding zone border. Moreover, in certain situations, no capacity is released in either direction of a given bidding zone border, preventing any cross-zonal trade from taking place in such a border. Figure 13 highlights the number of market time units where selected bidding zone borders presented no available capacity in the intraday time frame on one or both directions, in 2023.

Figure 13: Percentage of market time units with zero available capacity in the intraday time frame per bidding zone border in one or both directions at the start of cross-zonal intraday trading – 2023 (% of market time units)

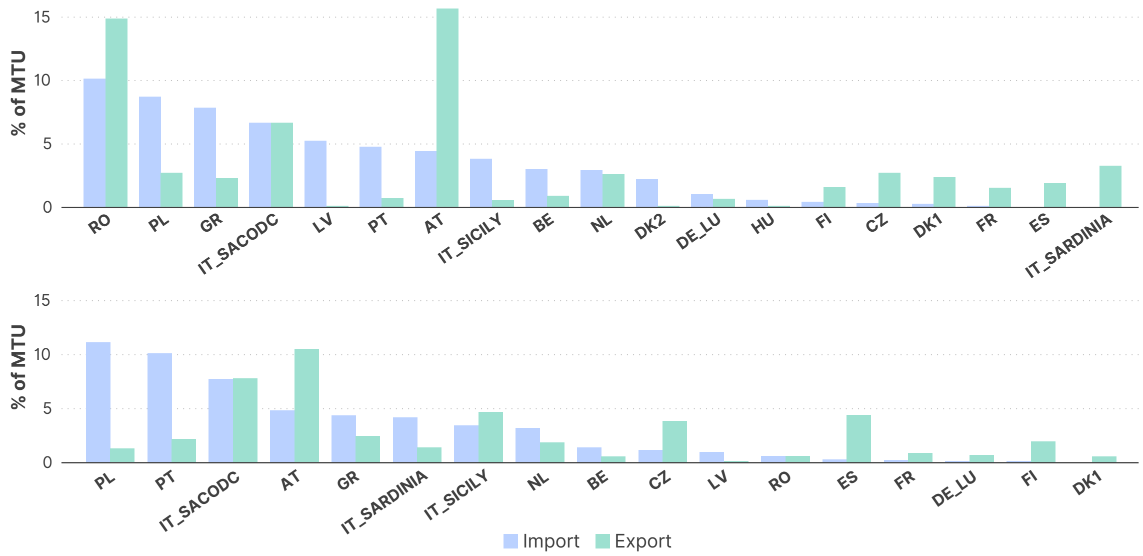


Source: ACER calculation based on ENTSO-E Transparency Platform data.

Note: Intraday ATCs are evaluated when they are first released by TSOs (i.e., assessing the first non-zero ATC value recorded in the ENTSO-E Transparency Platform in either direction for a given bidding zone border). Only the bidding zone borders with most occurrences (above 50% of MTUs) are displayed. 'Both' denotes instances where both directions of a given bidding zone border present zero ATC; 'Direct' denotes instances where the direction of the bidding zone border given in the column label presents zero ATC; and 'Opposite' denotes instances where the direction of the bidding zone opposite to that given in the column label presents zero ATC.

59 The large number of market time units with no available capacity for intraday cross-zonal trading in one or both directions of some bidding zone borders, may lead to situations where a bidding zone is fully isolated in the intraday time frame, that is, it may not be possible for a given bidding zone to further import or export electricity in the intraday time frame. Figure 14 shows the share of market time units with no available capacity for cross-zonal trade in the intraday market on any of the EU borders of a given bidding zone for 2023, in either the import or export direction. It shows multiple instances of isolated bidding zones, both at the start and end of cross-border trading in the EU intraday market.

Figure 14: Percentage of market time units with zero available capacity in the intraday time frame on all EU bidding zone borders in the import or export direction for EU bidding zones at the start (top) and end (bottom) of cross-border intraday trading – 2023 (% of market time units)



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

Note: Intraday ATCs are evaluated at the moment they are first released by TSOs (i.e., assessing the first non-zero ATC value recorded in the ENTSO-E Transparency Platform in either direction for a given bidding zone border). Only EU bidding zone borders are considered for the purpose of this figure, and thus the results are sensitive to the number of EU bidding zone borders of every Member State. Bidding zones with occurrences below 1% of MTUs for both import and export are not displayed.

60 Closer to real time, the level of uncertainty that TSOs face when calculating cross-zonal capacities is generally reduced, which may allow additional capacities to be safely released to the intraday markets. The full implementation of dedicated processes for capacity calculation for the intraday time frame, coordinated at the regional level, will presumably allow additional cross-zonal capacity to be released around the market clearing point, increasing the capacities made available for intraday trading.

61 In the Core CCR, an interim process for capacity calculation in the intraday time frame has been in place until the implementation of a flow-based intraday capacity calculation. In this interim process, TSOs assess whether the left-over capacity from the day-ahead clearing can be securely increased by a pre-defined amount, or whether such capacity needs to be reduced. Table 2 shows the frequency and average value of such capacity increases and decreases in the former CWE region, covering a subset of the bidding zone borders that are currently part of the Core CCR, for the year 2023.

62 Most increases in capacity for the intraday time frame are recorded in both directions of the France - Belgium bidding zone border, while reductions in capacity have been requested mainly in the Austria - Germany/Luxembourg bidding zone border. This could be partly explained by the large amount of LTTRs that are released in this border, which cannot be secured in the intraday time frame.

Table 2: Results of the interim capacity increase and decrease process in the CWE region per bidding zone border – 2023 (% of hours and MW)

Border	Increase		Decrease	
	Frequency (% of hours)	Average increase (MW)	Frequency (% of hours)	Average decrease (MW)
AT – DE	5.7	188	31.3	855
BE – DE	22.2	212	0.1	229
BE – FR	65.8	292	0.0	0
BE – NL	8.4	232	0.0	0
DE – AT	19.7	212	6.2	611
DE – BE	21.9	211	1.5	618
DE – NL	6.21	183	0.0	0
FR – BE	53.4	274	0.0	0
NL – BE	14.9	270	0.0	0
NL – DE	3.3	170	0.0	0

Source: ACER calculation based on JAO Publication Tool data.

2. Margin available for cross-zonal electricity trade in the EU in 2023

63 As highlighted in the introduction and in the previous chapter, the availability of cross-zonal capacity is crucial for EU electricity market integration. Chapter 1 assessed cross-zonal capacity evolution in the EU, highlighting progress and bottlenecks. The minimum 70% requirement, introduced in the Electricity Regulation, sets a clear standard for the margin available for cross-zonal trade in the EU, providing certainty to all market participants on their future access to the network. This second chapter clarifies the main principles behind the minimum 70% requirement and presents the status of implementation across the EU.

2.1. Methodological principles

64 The minimum 70% requirement translates in practice into the margin made available for cross-zonal trade (MACZT). This corresponds to the portion of capacity of a given CNEC that is made available for cross-zonal trade by the TSOs. Monitoring the MACZT assesses not only the degree of implementation of the requirement, but provides insight into the current level of optimisation of the cross-zonal electricity transmission infrastructure in the EU. The MACZT is thus a proxy for the level of integration of EU national day-ahead electricity markets.

65 The present chapter monitors the MACZT across the EU following the principles described in ACER Recommendation 01/2019 and the agency's methodological paper on estimating the MACZT and practical note on monitoring the MACZT. It is important to note that ACER's analysis of the MACZT does not assess the legal compliance of TSOs with regard to the obligations under Article 16(8) of the Electricity Regulation, as this is the competence of the relevant NRA. Rather, it aims to monitor the progress of the EU in addressing the underlying issues, and highlight potential limitations to the implementation of the requirement.

66 The main principles of monitoring the MACZT, as described in the three documents mentioned above, are as follows:

- The MACZT is monitored for each Critical Network Element with Contingency (CNEC).[14] The minimum 70% requirement, or interim requirement in the case of action plans and/or derogations, is considered fulfilled for a given hour when the MACZT in all CNECs of a TSO is equal to or above the requirement.

- The MACZT is calculated as the combination of the margin of capacity made available for trade within the coordinated capacity calculation region (MCCC), and the estimated flows induced by cross-zonal exchanges outside the coordinated capacity calculation region (i.e., the margin from non-coordinated capacity calculation or MNCC).

- The MACZT is estimated as the portion of the physical capacity of a given CNEC that is offered for trade up to the day-ahead time frame, including long term nominations. Future editions of the report will also monitor the margin made available for intraday cross-zonal trading.

- The impact of flows induced by exchanges with and between non-EU (i.e., third country) bidding zones in the MACZT is monitored separately. In contrast to previous reports, the analysis presented in section 2.3 considers the flows induced by exchanges with non-EU countries, while the impact of such flows is assessed in a dedicated section (section 2.4).

67 It is worth noting that the methodology used by NRAs to assess compliance of the relevant TSOs with regard to the obligations under Article 16(8) of the Electricity Regulation may differ from that presented in ACER Recommendation 01/2019. In such cases, the ACER pan-European assessment may report slightly different values from those reported in national compliance assessments. The most notable methodological differences are highlighted in ACER's practical note on monitoring the MACZT.

14 Currently, for CNTC regions, only the CNEC that limits the calculation of capacity is monitored.

68 Generally, the MACZT is assessed for each capacity calculation region. In cases where a coordinated capacity calculation process has not been implemented, the information is instead presented for each coordination area, which describes the set of bidding zone borders within which capacity calculation is fully coordinated.[15] In each coordination area, the obligation to meet the minimum 70% or interim requirement lies with the Member State's TSO(s). Consequently, the report also presents the results for each Member State, in addition to each coordination area.

69 In the regions in which a CNTC methodology has been implemented, namely SWE, Italy North, SEE and GRIT, TSOs monitor and report to ACER the MACZT on the CNEC, or the allocation constraint, that has limited the capacity calculation process. This means that, for a given market time unit, information on only one single CNEC is provided for every calculation of capacity.

70 In addition, in the areas where the applicable capacity calculation methodology has not yet been implemented, an uncoordinated NTC approach is in place, with varying degrees of coordination for each process. ACER does not have full visibility on the interim process used by each TSO, and the degree of coordination of such processes is defined in cooperation with the relevant NRA and TSO. A full list of the coordination areas used for the purpose of this report is available in Annex III.

2.2. Status of implementation of the minimum 70% requirement

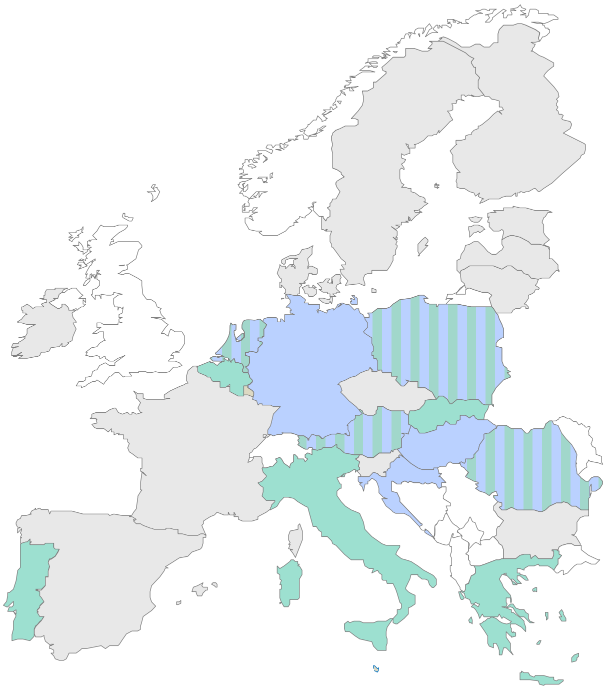
71 While the minimum 70% requirement entered into force in 2020, the Electricity Regulation allowed for the gradual implementation of the requirement by introducing two transitional measures. Firstly, relevant stakeholders were to cooperate to identify structural congestions within and between bidding zones and assess potential bidding zone reconfigurations. Secondly, and to support this process, Article 15 of the Electricity Regulation 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.

72 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) of the Electricity Regulation for a limited period. Other regulatory authorities in the capacity calculation region may object to the granting of such derogation.

73 Since its introduction, a significant number of Member States have required action plans and/or derogations to implement the minimum 70% requirement. Figure 15 presents an overview of the Member States that have had a derogation and/or an action plan in place in 2023. In such Member States, interim cross-zonal capacity requirements may be defined. That is the case for all Member States where an action plan is in place, as these require a linear trajectory toward the requirement, while derogations may or may not define a specific numeric commitment.

15 Coordination areas are relevant mostly in capacity calculation regions where a fully coordinated process has not yet been implemented.

Figure 15: Overview of the status of implementation of the minimum 70% requirement in the EU for each Member State - 2023



Source: Produced by ACER based on information provided by NRAs.

Note: A Member State is considered to have a derogation and/or an action plan in place if they apply to at least one of its capacity calculation regions or for one of its bidding zone borders.

74 For more details about the derogation and action plans in place for all Member States, as well as a complete overview of the derogations and action plans granted for the 2020–2024 period, please refer to a detailed overview published on ACER's website.

2.3. Results of monitoring the margin available for cross-zonal trade in each capacity calculation region

75 This section presents the results of ACER's monitoring of the implementation of the minimum 70% requirement in the day-ahead time frame for each EU Member State. The results are presented for each capacity calculation region (CCR), including both the regions where a coordinated capacity calculation methodology has been implemented (Core, SWE, Italy North, SEE and GRIT) and those where a coordinated process has yet to be introduced (Hansa, Nordic and Baltic). All figures presented in this section consider the impact of flows induced by exchanges with non-EU countries. This impact is assessed separately in section 2.4.

2.3.1. Core CCR

76 Following the implementation of the Core day-ahead capacity calculation methodology in June 2022, the Member States with bidding zone borders in the former CEE region started applying the flow-based approach to compute cross-zonal capacities. Within that process, the MACZT is calculated and reported on all network elements relevant to the capacity calculation (i.e., CNECs), thus guaranteeing a high degree of transparency. Moreover, in the 2024 MACZT data reporting exercise, all Core TSOs used a common reporting tool, which ensures that the data provided are fully aligned with the specifications of ACER Recommendation 01/2019, constituting a significant step forward towards the harmonization of MACZT monitoring.

77 The introduction of the Core flow-based approach has also led to the integration of the requirements under Article 16(8) of the Electricity Regulation, that is either the minimum 70% requirement or the interim requirements (in the case of an action plan and/or derogation), into the capacity calculation process.

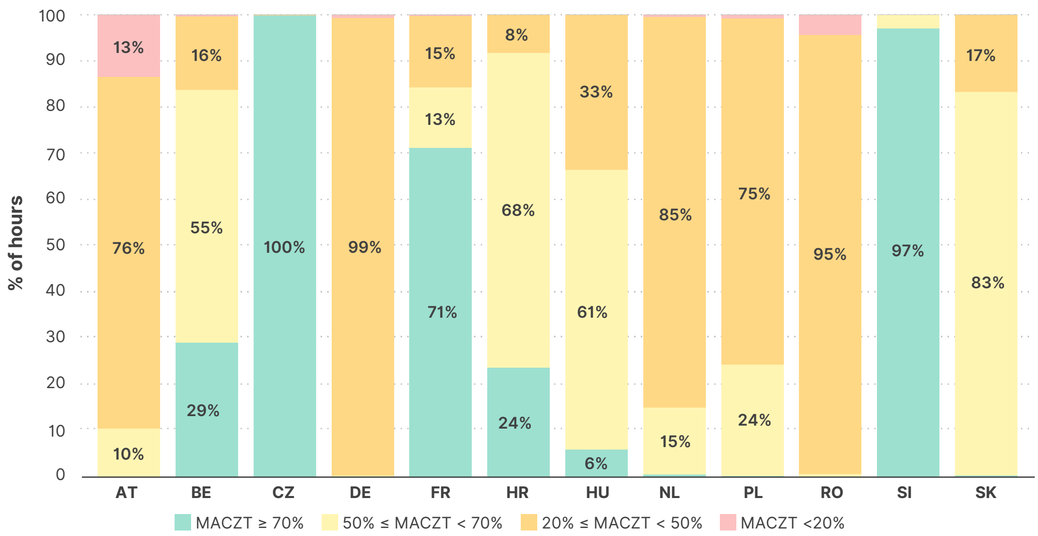
An adjustment mechanism[16] in the calculation process increases the calculated margin of capacity to comply with the applicable requirements. Whenever sufficient remedial actions are available to secure such an increase, the capacities are validated and then offered to the day-ahead market. Alternatively, whenever an operational security violation is detected that cannot be avoided through remedial actions, capacities can be reduced to below the applicable thresholds.

The minimum 70% requirement has not yet been implemented in most Core Member States.

78 To provide an overview of the status of implementation of the minimum 70% requirement in the Core CCR, Figure 16 illustrates how often all relevant grid elements in a bidding zone offer at least 70% of their capacity for cross-zonal trading. More specifically, the figure shows the percentage of hours when all CNECs of a given Member State have a MACZT above 70%, or within several predefined ranges of MACZT. For this purpose, it assesses the CNEC for which the lowest margin of capacity for cross-zonal trade was offered for every hour.

79 The values shown depend on the implementation approach of every Member State, and thus are greatly influenced by the presence of derogations and actions plans, as clarified in section 2.2. In the Core region, only Czechia, France and Slovenia did not have a derogation and/or action plan in place in 2023, thereby being bound by the minimum 70% requirement. While Czechia and Slovenia did largely offer 70% on all their CNECs in 2023, France was able to do so only in 71% of the hours of the year.

Figure 16: 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 – 2023 (% of hours)



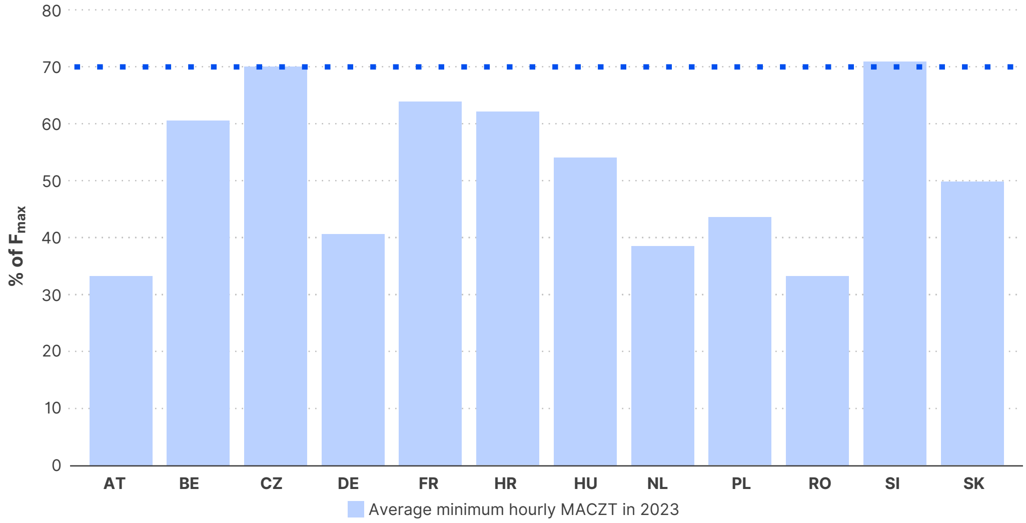
Source: ACER calculation based on TSO data.

Note: Belgium, the Netherlands and Poland have declared allocation constraints limiting total exchanges from and/or to these Member States. Allocation constraints are monitored separately and thus not considered in this figure.

80 In addition, to indicate how much additional capacity still needs to be made available on average in the most constrained CNEC to fulfil the minimum 70% requirement, Figure 17 displays the average value of the lowest margin of capacity offered in every hour in each Member State in the Core CCR.

16 See also section 3.2.

Figure 17: Average minimum hourly margin available for cross-zonal trade in the Core CCR for each Member State, considering flows induced by third-country exchanges – 2023 (% of F_{max})



Source: ACER calculation based on TSO data.

Note: Belgium, the Netherlands and Poland have declared allocation constraints limiting total exchanges from and/or to these Member States. Allocation constraints are monitored separately and thus not considered in this figure.

81 In 2023, the TSOs furthest away from offering a minimum of 70% MACZT on all CNECs were the Austrian and Romanian TSOs, followed by the Dutch and German TSOs. A high degree of fulfilment of the minimum 70% requirement in the Core CCR in 2023 is observed in Czechia and Slovenia.

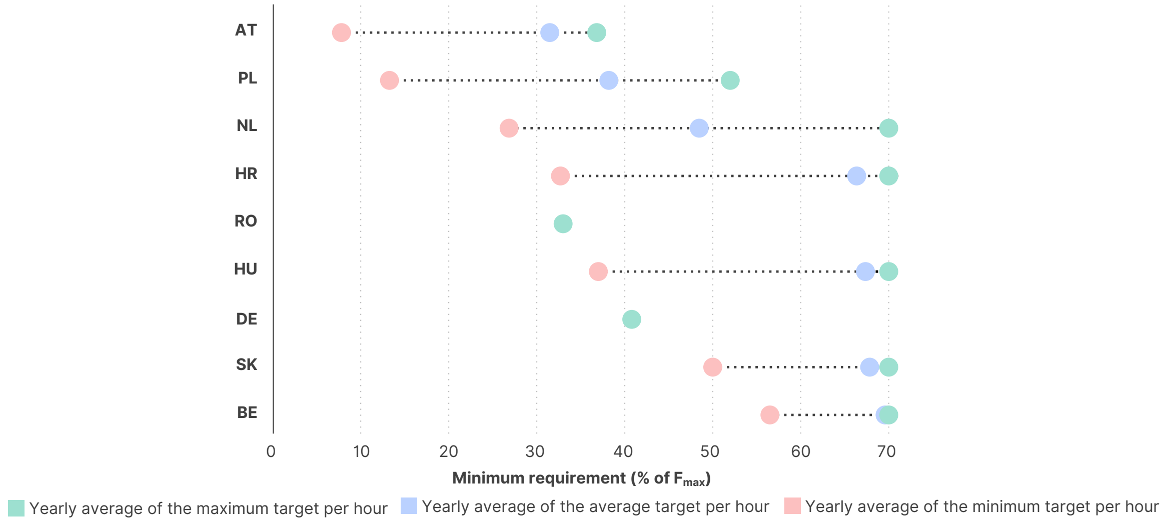
82 While the figures show the extent to which Member States could offer a minimum of 70% MACZT on all CNECs in 2023, they do not indicate the reasons for not being able to do so. Such reasons can be found within the Member State or its neighbours and are explored in the following subsections.

Most Core Member States are bound by interim cross-zonal capacity requirements stemming from action plans and/or derogations.

83 As Figure 15 shows, most Core Member States are not yet bound by the minimum 70% requirement, given that an action plan and/or derogation has been granted in all but three Core Member States (Czechia, France and Slovenia). In such Member States, TSOs are instead subject to interim minimum capacity requirements that are defined in the derogation and/or action plan. These values may be static for all CNECs and hours of the year, for example in the case of a linear action plan trajectory value, or they may be dynamic, setting different values per CNEC and/or hour of the year.

84 Figure 18 presents an overview of the applicable cross-zonal capacity requirements in the Core CCR in 2023, as reported by Core TSOs. 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 18: Overview of the interim capacity requirements as defined by applicable action plans and/or derogations in the Core capacity calculation region for each Member State– 2023 (% of F_{max})



Source: ACER calculation based on TSO data.

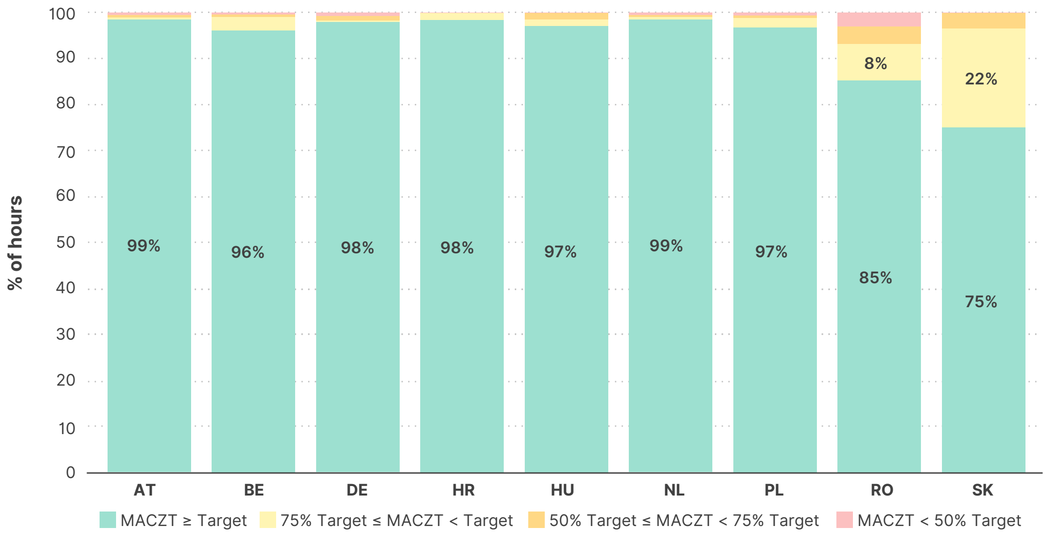
Note: For every hour, the minimum, average and maximum cross-zonal capacity requirement is calculated, and then averaged over the year 2023. In the case of Germany and Romania, the minimum, average and maximum value are the same, as the relevant TSOs define a single cross-zonal capacity requirement value for all CNECs and hours of the year.

85 As highlighted in the figure, high loop flows in the Core region in 2023 effectively led to very low cross-zonal capacity requirements in some CNECs of the Austrian, Dutch and Polish TSOs. Additionally, the case of the Romanian TSO stands out: it maintained the action plan trajectory value applicable in 2021 (of 33%) until 2024 for all CNECs, requesting yearly derogations.

86 As clarified by recital 20 of the Electricity Regulation, where the coordinated capacity calculation performed at a regional level does not result in cross-zonal capacity equal to or above the minimum capacity set out in the Electricity Regulation, regional coordination centres ('RCCs') are tasked with considering all available costly and non-costly remedial actions to further increase capacity up to the minimum requirement, including redispatching potential within and between the CCRs, while respecting the operational security limits of the CCR TSOs.

87 As per the Core day-ahead capacity calculation methodology, the cross-zonal capacity requirements (either the 70% or the interim requirement) introduced as an input to the calculation will always be enforced by means of an adjustment mechanism, provided that no capacity reductions are requested by the relevant TSOs in the validation phase. Figure 19 shows the extent to which Core Member States that have a derogation and/or action plan have fulfilled the applicable interim requirements on every CNEC and, where the requirements have not been met, how far the Member State is from fulfilling them.

Figure 19: Percentage of hours where the applicable minimum capacity requirements, stemming from derogation and/or action plans, were met in all CNECs in the Core CCR for each Member State, considering flows induced by third-country exchanges – 2023 (% of hours)



Source: ACER calculation based on TSO data.

Note: Only Member States with an applicable derogation and/or action plan in 2023 are displayed in the figure. Belgium, the Netherlands and Poland have declared allocation constraints limiting total exchanges from and/or to these Member States. Allocation constraints are monitored separately and thus not considered in this figure.

88 The analysed data shows that the applicable cross-zonal capacity requirements, defined in line with the derogations and action plans, have generally been met in the Core region in 2023. The exception being the Romanian and Slovak TSOs. As will be presented in the following subsection, the share of hours where the requirements cannot be met corresponds to reductions of capacity in the validation phase.

89 In the case of Slovakia and Hungary, the applicable action plan and derogation, respectively, introduces interim targets to be met only on certain CNECs. The remaining network elements are thus bound by 70%. While Figure 19 assesses the fulfilment of the applicable requirements on all CNECs (70% or interim requirement, depending on the CNEC), Table 3 assesses the fulfilment of the targets specifically set in the action plan and derogation for these two Member States.

Table 3: Comparison between MACZT and interim requirements for Core TSOs that define interim cross-zonal capacity requirements to specific network elements – 2023

MS	CCA(s)	Applicable network elements	Interim requirement for 2023	Comparison between the offered margins of capacity and the interim requirements
HU	Core	Győr – Neusiedl (AT), Győr – Wien (AT), Győr – Oroszlány, Dunamenti - Oroszlány	36.25% MACZT	Interim requirements met 100% of the hours of the year.
		Paks – Sándorfalva	42.25% MACZT	
SK	Core	Križovany – Veľký Ďur, Veľké Kapušany – Mukacheve (UA), Lemešany – Krosno-Iskrzynia (PL) 1, Lemešany – Krosno-Iskrzynia (PL) 2, Veľký Ďur – Levice 1, Veľký Ďur – Levice 2	The derogation sets that 50% MACZT must be offered at least 80% of hours	Interim requirements met 83% of the hours of the year.

Source: ACER calculation based on JAO Publication Tool data.

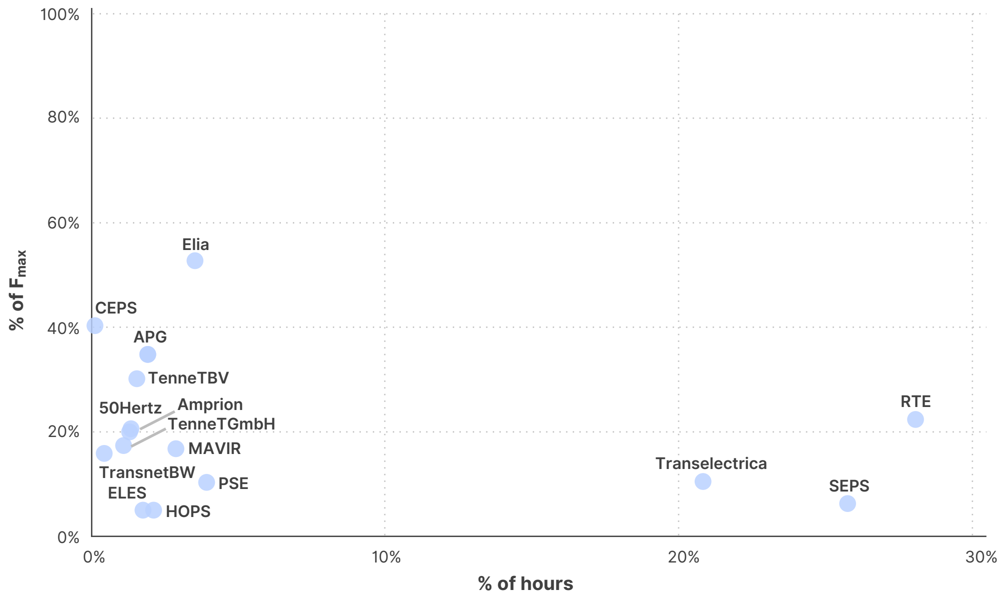
The 70% or applicable interim requirements are not met whenever a risk to operational security that cannot be resolved with remedial actions, is detected by the relevant TSO.

90 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 in cases where such capacity levels would result in a violation of the operational security limits defined by each TSO. These deviations are accounted for in the regional coordinated capacity calculation processes by allowing a reduction in the cross-zonal capacities calculated by the RCC. Reductions can be implemented either unilaterally or in a coordinated manner, whenever a risk to operational security is detected that cannot be resolved through remedial actions.

91 Article 20 of the Core day-ahead capacity calculation methodology describes the validation adjustments that enable Core TSOs to reduce the margins for cross-zonal exchanges whenever a potential risk to operational security is detected. Currently, operational security in the validation of capacities is assessed not at the regional level, as a coordinated validation process has not yet been implemented, but within processes individual to each TSO or subset of TSOs. These are known as individual validation adjustments (IVAs).

92 Figure 20 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 2023. Most TSOs applied IVAs in the range of 0-5% of hours, while three TSOs (RTE – FR, SEPS – SK and Transelectrica – RO) needed to use these adjustments more frequently in 2023. In 2024, the need for IVAs in France, following several outages in the power grid, has severely limited the capacity of France to export electricity to other bidding zones.[17]

Figure 20: Application of IVA for each Core TSO – 2023 (% of F_{max} and % of hours)



Source: ACER calculation based on JAO Publication Tool data.

Note: The average size of IVA is calculated on all CNECs that have a positive value of IVA. The figure therefore does not make a distinction between the IVAs applied as the result of a process fallback, and those applied during normal operating conditions.

93 The application of validation adjustments, effectively reducing the levels of capacity offered in the region, can have a significant impact on day-ahead electricity prices across the whole CCR. In flow-based market coupling, this impact is not necessarily limited to the bidding zone where the capacity reduction has been applied. This increases the importance of a transparent and limited usage of this mechanism to the minimum degree that is needed to ensure operational security, after having exhausted all forecasted available costly and non-costly remedial actions.

94 Moreover, it is important to note that the methodologies for assessing the need for validation adjustments at the individual level are not harmonized across Core TSOs. In these assessments, it remains critical that all costly and non-costly remedial actions are considered, and that the security limits of internal network elements that are not defined as CNECs, and which are not sufficiently sensitive to cross-zonal exchanges (i.e. maximum zone-to-zone PTDF below 5%), do not lead to validation adjustments.

17 See 'RTE – Cross-border capacity limitations on French eastern borders for grid operational security' on the JAO message board.

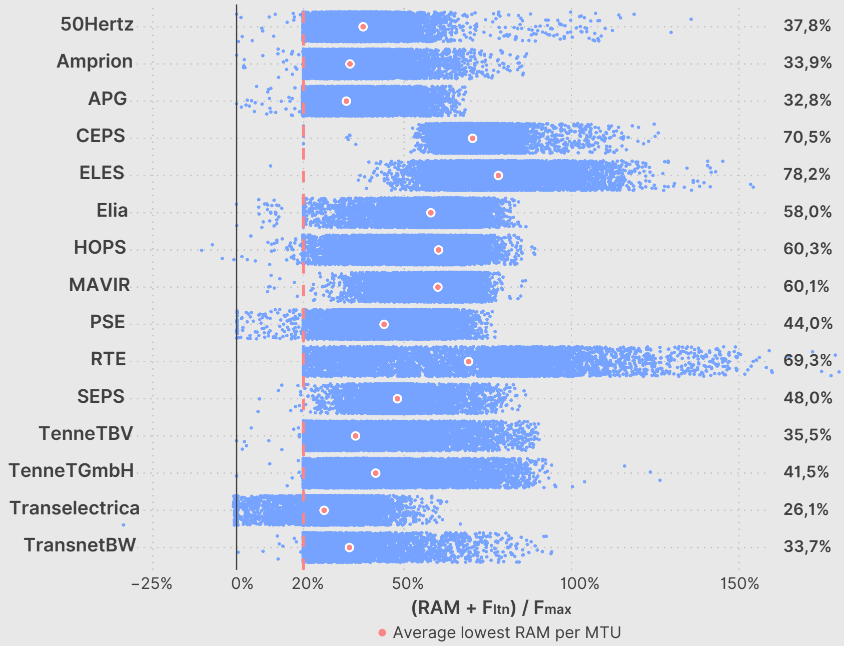
95 The growing share of renewable generation in the power system could, under the current system conditions, exacerbate the existence of grid congestion that cannot be resolved through remedial actions, leading to a more frequent need for deviations. ACER considers it crucial that deviations from the applicable minimum cross-zonal capacity requirements do not become systematic, and that there is sufficient oversight to ensure deviations are only implemented as a measure of last resort.

The remaining available margin may also go below the agreed minimum 20% threshold in case of validation adjustments

Besides the minimum cross-zonal capacity requirement defined in the Electricity Regulation, a minimum threshold applies specifically in the Core CCR for the margin of capacity that is offered for trade between the bidding zones of the region (i.e., MCCC). MCCC should be at least 20% of the thermal capacity of the relevant network element (F_{max}). In flow-based regions, this corresponds to the RAM, adjusted for the flows induced by long-term nominations[18].

Figure 21 describes, for each Core TSO, the distribution of the lowest MCCC per hour, expressed as a percentage of the F_{max} of that network element. Observations to the left of the red line show violations of this principle. These violations are only possible through the application of IVAs, whenever a risk to operational security is invoked. The figure illustrates the number of violations of the minimum RAM 20% threshold in 2023, together with the average value of MCCC offered for the most constrained CNEC.

Figure 21: Distribution of the lowest RAM as a percentage of F_{max} among all CNECs and average relative RAM in the Core CCR for each TSO – 2023 (% of F_{max})



Source: ACER calculation based on JAO Publication Tool data.

Note: In accordance with Article 17 of the Core day-ahead capacity calculation methodology, the 20% minimum RAM is assessed, per CNEC, on the value (RAM + F_{LTN}) / F_{max}.

In the second half of 2023, some Core TSOs agreed to implement a limit on their individual validation to ensure that the 20% threshold of MCCC is always upheld. ACER welcomes this development and recommends that all other TSOs pursue a similar approach.

18 F_{LTN} is the expected flow after considering long-term nominations over a certain CNEC; F_{max} is the maximum admissible power flow over a certain CNEC, also referred to as the thermal capacity of the CNEC; (RAM + F_{LTN}) defines MCCC, i.e., the portion of capacity of a CNEC available for cross-zonal trade on bidding zone borders within the considered coordination area.

Derogations from 70% or action plan linear trajectory values are required by TSOs affected by significant loop flows

96 As discussed previously, excessive loop flows are one of the main factors currently preventing some Core TSOs from being able to fulfil the minimum 70% requirement. Loop flows are physical flows that are induced not by a cross-zonal exchange of electricity, but by exchanges of electricity within bidding zones. They are a natural consequence of the physical reality of an interconnected power grid and the current EU market design, where trade within bidding zones is unrestricted.

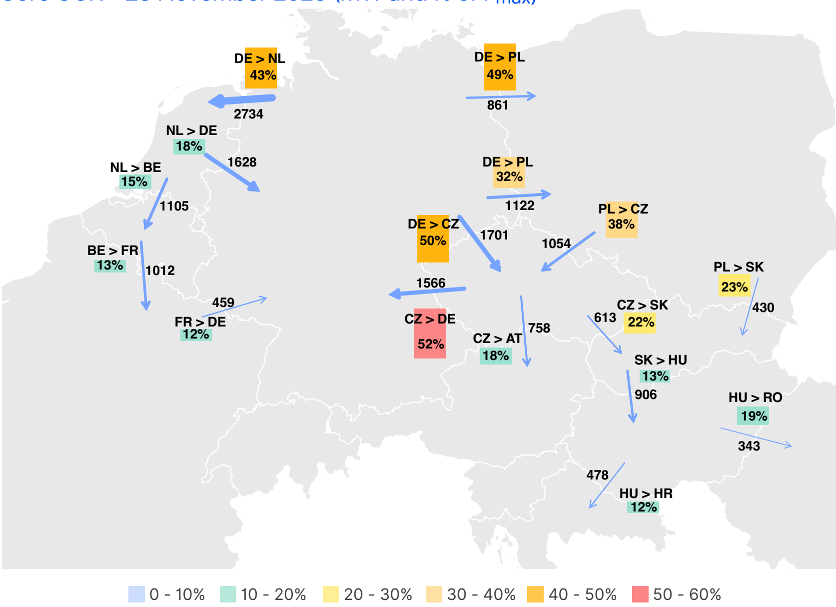
97 Loop flows are 'free-riding flows' that can use up a high share of the physical capacity of certain network elements, reducing the capacity available for cross-zonal trade, and thus hindering the ability of the affected TSOs (those where the network elements concerned are located) to fulfil the minimum 70% requirement. Such flows may lie outside the control span of a given individual TSO and thus need to be tackled at their source.

98 The Core day-ahead capacity calculation methodology introduces a way to accurately forecast the intensity of such flows in the cross-zonal network elements in the bidding zone borders of the Core CCR. To calculate cross-zonal capacities, the grid model is brought to a zero-balance position, where no exchanges between the European bidding zones are active. In this scenario, the electricity flows detected on cross-zonal network elements correspond to forecasted loop flows.

99 The value and direction of the loop flows for a given hour depend significantly on the generation and demand pattern of every bidding zone. In the Core region, situations of high renewable infeed in the northern Germany, combined with imports from Scandinavia, typically lead to significant electricity flows going through the power grids of neighbouring Member States.

100 Figure 22 assesses the average value of forecasted loop flows on the critical network elements, without contingencies, at the bidding zone borders in the Core capacity calculation on a specific day, 23 November 2023. This day has been selected as, for several hours, the volumes of forecasted loop flows recorded across the Core region were the highest for the year, following a high share of renewable infeed. While the selected day is not necessarily representative of the power system as a whole, the figure shows that the significant presence of loop flows in some bidding zone borders of the region can effectively consume a large portion of the physical interconnection capacity of the cross-zonal lines.

Figure 22: Average forecasted loop flows on a selection of cross-zonal critical network elements (without contingencies) in the Core CCR – 23 November 2023 (MW and % of F_{max})



Source: ACER calculation based on JAO Publication Tool data.

Notes: This figure shows the average level of forecasted loop flows, in both absolute and relative terms, at the level of CNE or a combination of parallel CNEs. Forecasted loop flows are calculated based on the parameters F_{0all} and F_{max} of the CNEs defined as tie-lines and with a voltage level of 400kV in the final flow-based computation of the Core capacity calculation process. CNEs with a share of loop flow below 10% of F_{max} are not displayed in the figure. TSOs operating the DE-NL, PL-SK and HU-RO borders defined different values of F_{max} on the same cross-zonal elements: the average value has been used for the purpose of this figure.

101 The presence of significant physical flows not deriving from any cross-zonal exchange requires TSOs to rely on activating remedial actions to cope with such flows. The absence of the necessary processes to forecast, activate and share the cost of remedial actions across the TSOs of the region, hampers the ability of the TSOs that face significant loop flows to offer 70%.

102 What is depicted in Figure 22, on the other hand, is not an isolated case. Instead, most Core TSOs face significant loop flows on some of their CNECs during most hours of the year, as shown in Figure 23. This figure shows the percentage of hours when each TSO forecasted loop flows above a certain threshold on at least one of its cross-zonal CNECs. It shows that the cross-zonal elements of some TSOs face loop flows above 100% of their physical capacity for some hours of the year.

Figure 23: Percentage of hours when the forecasted loop flows are above the indicated share of its physical capacity on at least one cross-zonal CNEC for each TSO in the Core CCR – 2023 (% of hours)

	RTE	Transelectrica	Elia	HOPS	ELES	TransnetBW	TenneT BV	50Hertz	Amprion	SEPS	MAVIR	CEPS	PSE	TenneT GmbH	APG
≥ 100 %	0	0	0	0	0.3	0.2	13.8	0	0	0	0	0	0.7	4.4	1.1
≥ 90 %	0	0	0	0	0.5	1.2	18.2	0.1	0.3	0	0	0.4	1.7	7.1	3
≥ 80 %	0	0	0	0	1	3.3	23.2	0.6	1	0	0	1.4	3.4	11.9	6.4
≥ 70 %	0	0	0	0.1	2	7.1	28.8	2.8	2.8	0	0	4.6	6.6	18.2	13.6
≥ 60 %	0.2	0	0.3	0.6	4.9	13	35.2	7.6	8.8	0.3	0	11.8	13	27.1	24.9
≥ 50 %	1.1	0	1.4	1.8	10.6	22	42.8	16.4	19.6	2.7	1.3	24.1	28.1	41.1	43.2
≥ 40 %	4.2	0.7	6	8.2	24.1	38.9	55.2	33.7	40	21.6	13.9	45.5	58.9	61.8	71.1
≥ 30 %	17	10.6	21.9	30.9	50.9	61.8	73.2	61.9	68.4	68.8	59.8	76.4	85.9	85.6	94.7
≥ 20 %	52.7	53.4	58.7	76.3	84.6	88.6	91.1	91.3	92.5	96.9	97.1	97.9	98.4	98.5	100

Source: ACER calculation based on JAO Publication Tool data.

Notes: Forecasted loop flows are calculated based on the parameters F_{0all} and F_{max} of the CNECs, both of 220kV and 400kV voltage levels, defined as tie-lines in the final flow-based computation of the Core capacity calculation process.

103 Several processes are foreseen to mitigate the impact of loop flows on grid congestion in the Core CCR and thus in the cross-zonal capacities offered across the region. The main processes are the coordinated validation and the coordinated congestion management framework, namely the regional operational security coordination (or ROSC), and cost-sharing methodologies.

104 The coordinated validation process will enable TSOs in the Core region to assess the operational security of the calculated capacities considering the forecast of all remedial actions that would be available in the region. The ROSC and cost-sharing methodologies will then ensure that TSOs at the source of the loop flows will trigger and bear the cost of the necessary remedial actions to mitigate their impact.

105 These methodologies are not expected to be fully implemented by the end of 2025, however, when all TSOs should be able to guarantee 70% of MACZT. Moreover, relying heavily on remedial actions to cope with the impact of loop flows has limitations, which are particularly evident in time frames closer to real time, when the availability of remedial actions decreases as the delivery of electricity nears. Reducing the level of loop flows in a structural manner is thus necessary for efficient cross-zonal trading in the Core region.

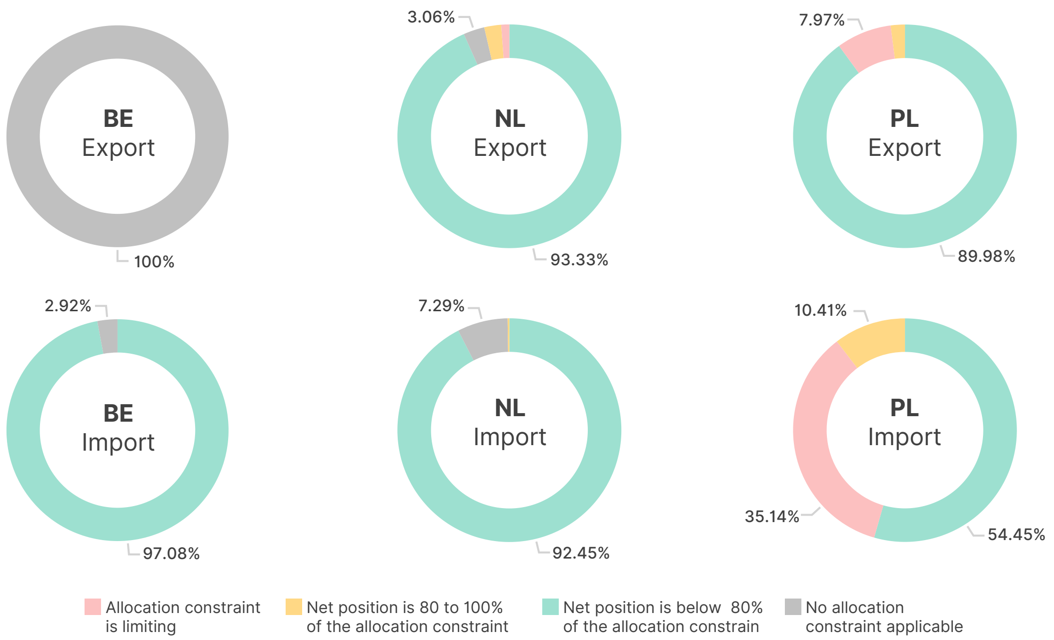
Allocation constraints effectively limit export and import possibilities below the calculated capacities in some Core bidding zones.

106 Beyond the need for deviations from the requirements on the grounds of operational security and the applicable derogations from the cross-zonal capacity requirements, allocation constraints may also limit the possibilities for cross-zonal trade in the region. Allocation constraints reflect operational security limits that cannot be transformed into flow-based parameters on a given CNEC.[19] In the Core region, they take the form of import or export limitations for a given bidding zone.

107 Allocation constraints hence add additional constraints to the cross-zonal capacity given to the market and affect the outcome of flow-based market coupling. Article 7 of the Core day-ahead capacity calculation methodology considers the application of allocation constraints a temporary measure for the Belgian, Dutch and Polish TSO. As allocation constraints are defined separately to the coordinated capacity calculation process, they may effectively reduce the offered capacities below the requirements stemming from Article 16(8) of the Electricity Regulation.

108 Figure 24 assesses the impact of allocation constraints (per bidding zone and direction) on cross-zonal trade in 2023. Red values indicate that the allocation constraint effectively limited the allocation of capacities for that hour, as the net position was equal to the allocation constraint limit. Orange values indicate the hours when the net position corresponded to 80–100% of the allocation constraint value, thus not effectively limiting the allocation of capacities, but almost doing so. Green values indicate that the allocation constraint was far from limiting, while grey values indicate that no allocation constraints were applied for a given hour and direction.

Figure 24: Limitations of realised import and export net positions due to allocation constraints in selected bidding zones of the Core CCR - 2023 (% of hours)



Source: ACER calculation based on TSO data.

Note: While this figure considers only the effective limitations of net positions due to allocation constraints, offered cross-zonal capacities are in most cases limited by the allocation constraints implemented by the Polish TSO.

109 Figure 24 shows that allocation constraints limited cross-zonal exchanges involving the Polish bidding zone for a significant share of hours in 2023. In some cases, this limitation completely precludes any import or export of electricity to/from the Polish bidding zone, as the allocation constraint in either export or import direction is set to zero. This has played a significant role in the European day-ahead electricity market, by effectively decoupling the Polish bidding zone from the rest of the Core hubs for a significant share of hours. Moreover, as the allocation constraint restricts the global net position of the Polish bidding zone, it has an impact on exchanges beyond the Core CCR.

19 The CACM Regulation defines allocation constraints as 'the constraints to be respected during capacity allocation to maintain the transmission system within operational security limits and have not been translated into cross-zonal capacity or that are needed to increase the efficiency of capacity allocation'.

110 In the case of Belgium and the Netherlands, the allocation constraints imposed by the relevant TSOs had a minor impact on capacity allocation. For this reason, both the Belgian and Dutch TSOs have discontinued the use of allocation constraints.[20]

2.3.2. Italy North CCR

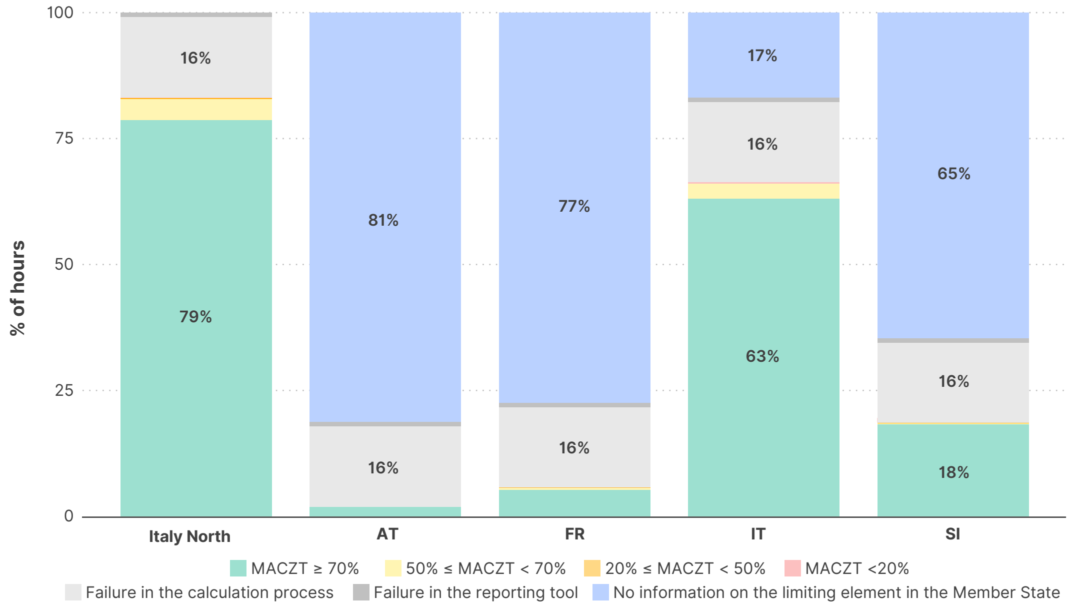
111 The Italy North CCR encompasses the northern borders of Italy, covering bidding zone borders France–Italy North, Austria–Italy North and Slovenia–Italy North. It applies the CNTC calculation approach, based on the approved capacity calculation methodology. In this region, a single calculation is 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.

112 A coordinated capacity calculation process in the export direction from Italy North has not yet been implemented for the day-ahead time frame. For this reason, the Italian TSO requested a derogation from the minimum 70% requirement in this direction for the whole of 2023. Italy North TSOs therefore reported a limiting CNEC for the calculation of Italian import only.

113 Figure 25 shows the percentage of hours for 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 import into Italy North.

114 It is relevant to note that, during 16% of the hours, Italy North TSOs reported a failure of the capacity calculation process, which implies that information on the limiting CNEC could not be provided. This highlights a need to improve the robustness of the process robustness.

Figure 25: Percentage of hours when the minimum 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 – 2023 (% of hours)



Source: ACER calculation based on TSO data.

Notes: This figure considers the impact of flows induced by exchanges with Switzerland. 'No limiting element in the Member State' means that the limiting element for capacity calculation was identified in the network of another TSO. When the limiting element is an interconnector, it is counted for the Member State on both sides of the border.

115 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 2023, 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

20 See 'Phase-out external contraint for NL in Core day-ahead capacity calculation', the market message on the discontinuation of the allocation constraints in the Netherlands.

remedial actions made available by the TSOs, ensuring that the margin made available on the limiting CNEC is always above 70%.

116 Deviations may occur whenever insufficient remedial actions are detected in the adjustment process and when a reduction in the NTCs is requested by any TSO in the region during the validation step, including the Swiss TSO.

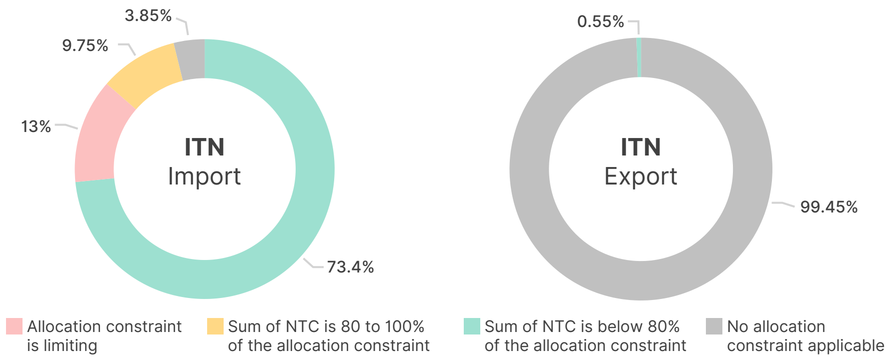
The use of allocation constraints effectively limits import possibilities into Italy North from neighbouring countries

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

118 In contrast to previous years, when a constraint limited ex ante the Italian northbound import in the Italy North capacity calculation process, the constraint is currently modelled within the market coupling algorithm. Italy North TSOs thus report the CNEC that limits capacity calculation, without considering the potential impact of the allocation constraint. The Italian TSO has requested a derogation for these hours, as the effective values of cross-zonal capacities when limited by the allocation constraint may lead to MACZT values below 70%.

119 A separate analysis is performed, to assess how often the allocation constraint effectively limits the values of cross-zonal capacity provided. Figure 26 shows the share of hours when the introduction of allocation constraint effectively limited the total NTC in the northern borders of the Italy North bidding zone. In the import direction, during 13% of the hours of 2023 the allocation constraint effectively led to lower import possibilities in the Italy North region, as the sum of all NTCs was higher (sometimes considerably) than the allocation constraint. For these hours, the effectively offered capacities may result in the 70% requirement not being met.

Figure 26: Limitations of import and export capacities due to allocation constraints in the northern borders of Italy North – 2023 (% of hours)



Source: ACER.

2.3.3. South-West Europe CCR

120 The SWE CCR encompasses the bidding zone borders Spain–Portugal and Spain–France. It applies a CNTC 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.

121 Following an update to the capacity calculation methodology approved by SWE NRAs on 18 January 2022, a fallback CNEC is provided in case the capacity calculation process in the SWE region is not successful in identifying the limiting CNEC. The fallback CNEC is defined as the most frequently limiting CNEC of the capacity calculation process for the specific timestamp.[21]

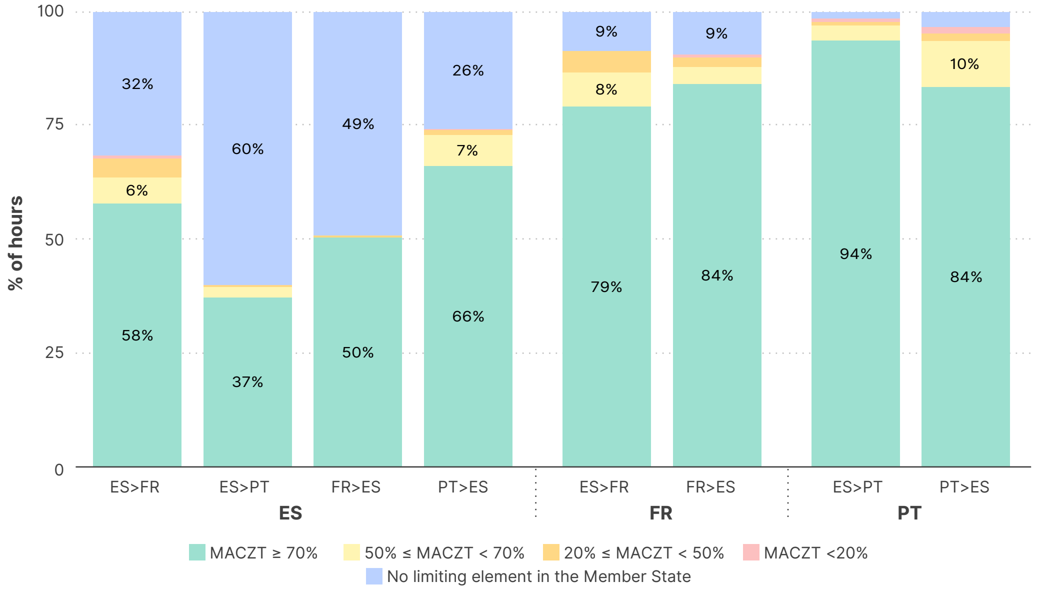
21 See Article 15(2)(b) of the SWE TSOs common capacity calculation methodology for the day-ahead and intraday market time frame.

122 Figure 27 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.

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

124 Compared with 2022, all borders in the SWE region show a slight improvement in the fulfilment of the minimum 70% requirement. In this region, due to its geographical set-up, the impact from both loop flows and uncoordinated allocated flows from other CCR is limited, leading to a relatively high degree of fulfilment of the 70% requirement.

Figure 27: Percentage of hours when 70% of MACZT, or predefined ranges of values, was offered in the SWE CCR for each Member State and oriented bidding zone border – 2023 (% of hours)



Source: ACER calculation based on TSO data.

Notes: 'No limiting element in the Member State' means that the limiting element for capacity calculation was identified in the network of another TSO. When the limiting element is an interconnector, it is counted for the Member States on both sides of the border.

A derogation from the minimum 70% requirement applies only to the Portuguese TSO

125 Similarly to the Italy North process, calculated capacities are increased to comply with the minimum cross-zonal capacity requirements, provided that sufficient remedial actions are made available by the SWE TSOs. Deviations may happen whenever insufficient remedial actions are detected in the adjustment process, and when a reduction in the NTCs is requested by either of the two TSOs operating the relevant bidding zone border during the validation step.

126 In 2023, only the Portuguese TSO requested a derogation from the minimum 70% requirement in the SWE region. As shown in Table 4, the derogation requested by the Portuguese TSO required a fulfilment of 70% in 82.5% of hours. This threshold was achieved in both directions of the Spain–Portugal border.

Table 4: Comparison between MACZT and interim requirements in SWE per Member State – 2023

MS	CCA(s)	Direction	Interim requirement for 2023	Comparison between the offered margins of capacity and the interim requirements
PT	SWE (ES–PT)	ES > PT	The derogation states that 70% MACZT must be offered for at least 82.5% of hours.	70% MACZT met for 94% of the hours of the year, and for 95% of the hours when a limiting CNEC was declared in PT.
		PT > ES		70% MACZT met for 84% of the hours of the year, and for 86% of the hours when a limiting CNEC was declared in PT.

Source: ACER calculation based on TSO data.

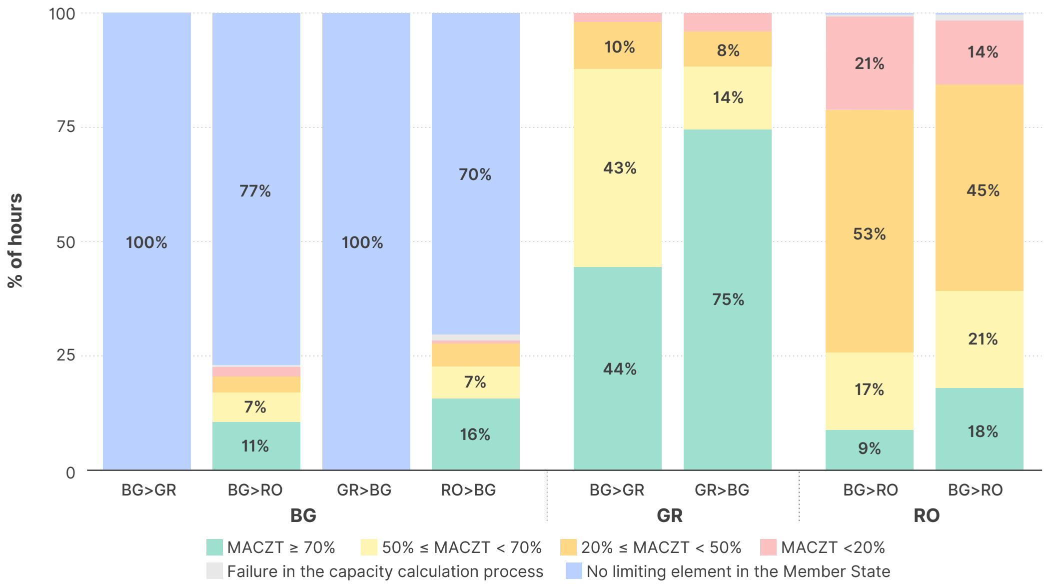
2.3.4. South-East Europe CCR

127 The SEE CCR encompasses the bidding zone borders Romania–Bulgaria and Bulgaria–Greece. It applies a CNTC 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 Balkan countries.

128 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.

129 Figure 28 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.

Figure 28: Percentage of hours when the minimum 70% requirement was reached in the SEE CCR for each Member State and oriented bidding zone border, considering flows induced by third-country exchanges – 2023 (% of hours)



Source: ACER calculation based on TSO data.

Notes: 'No limiting element in the Member State' means that the limiting element for capacity calculation was identified in the network of another TSO. When the limiting element is an interconnector, it is counted for the Member States on both sides of the border.

130 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 2023, 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. In particular, most limitations in the SEE CCR during 2023 have been requested by the Bulgarian TSO, which had an effect on the MACZT results of the neighbouring TSOs.

No adjustment of capacities to guarantee the minimum cross-zonal capacity requirements applies in the SEE region

131 Unlike in the previous CCRs analysed, the capacity calculation methodology 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, taking into account the remedial action potential in the region. While this provision will be implemented in the future, this explains the relatively poorer performance observed in the SEE region in 2023.

132 An action plan is applicable in Romania, with a linear trajectory value of 43% of the MACZT in 2023, and a derogation applies in Greece. The derogation requested by the Greek TSO does not include a commitment on the levels of MACZT offered but sets a minimum value of 15% of the MCCC. As shown in Table 5, while the MCCC commitment applicable in Greece has been largely met in 2023, the same cannot be said about the action plan linear trajectory value in Romania.

Table 5: Comparison between the MACZT and interim requirements in SEE for each Member State – 2023

MS	CCA(s)	Direction	Interim requirement for 2023	Comparison between the offered capacities and the interim requirements
RO	SEE (RO – BG)	RO > BG	43% of MACZT	43% MACZT met for 51% of the hours of the year, and for 52% of the hours when a limiting CNEC was declared in RO.
		BG > RO		43% MACZT met for 37% of the hours of the year, and for 38% of the hours when a limiting CNEC was declared in RO.
GR	SEE (BG – GR)	GR > BG	15% of MCCC	15% of MCCC met for 100% of the hours of the year, and for 100% of the hours when a limiting CNEC was declared in GR.
		BG > GR		15% of MCCC met for 100% of the hours of the year, and for 100% of the hours when a limiting CNEC was declared in GR.

Source: ACER calculation based on TSO data.

2.3.5. Greece-Italy CCR

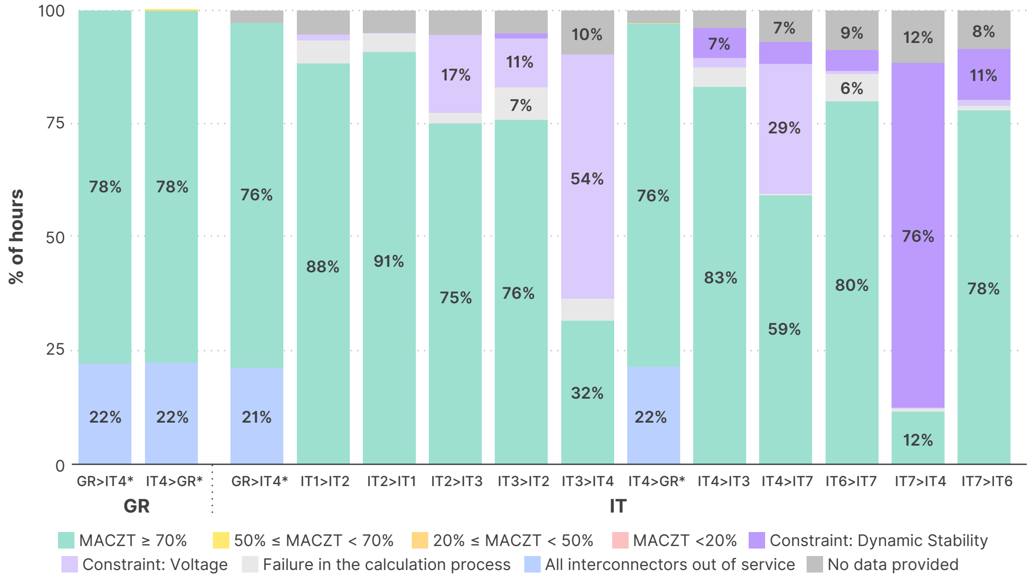
133 The GRIT CCR contains the internal Italian bidding zone borders and the DC bidding zone border with Greece. The impact of exchanges with third countries is considered limited and therefore no corresponding data was delivered by the TSO. Moreover, due to the particular grid structure, the impact of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

134 Figure 29 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.

135 As shown in Figure 29, the share of hours when the MACZT could not be assessed at 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 2022. One exception being the border IT3 > IT4, where the share of hours when the MACZT was greater than 70% declined from 59% in 2022 to 32% in 2023.

136 The analysed results show that dynamic stability, referring to the system's ability to return to a normal system state after a disturbance, is often the limiting factor in the exchanges on the border IT7 > IT4, while voltage constraints often apply in borders IT3 > IT4 and IT4 > IT7. Both limitations to cross-zonal trade are linked with a lack of the regulating capacities necessary to avoid violations of stability limits, such as voltage or frequency.

Figure 29: Percentage of hours when the minimum hourly MACZT was above 70% or within predefined ranges in the GRIT CCR for each Member State and oriented bidding zone border – 2023 (% of hours)



Source: ACER calculation based on TSO data.

Notes: Bidding zone borders marked with an asterisk (*) correspond to DC borders and were represented in a separate figure in previous reports. The internal Italian bidding zones are labelled as follows.

IT1	***Italy North***	***IT4***	***Italy South***	***IT7***	***Italy Calabria***
IT2	*Italy Centre North*	***IT5***	*Italy Sardinia*		
IT3	*Italy Centre South*	***IT6***	*Italy Sicily*		

2.3.6. Nordic CCR

137 The Nordic CCR encompasses all borders between bidding zones corresponding to the Nordic countries.[22] Within the Nordic CCR, the capacity calculation processes of each TSO remain uncoordinated, that is, each TSO defines unilaterally a value of NTC for the bidding zone borders it operates, and the minimum value of NTC defined at both sides of the border is offered to the market.

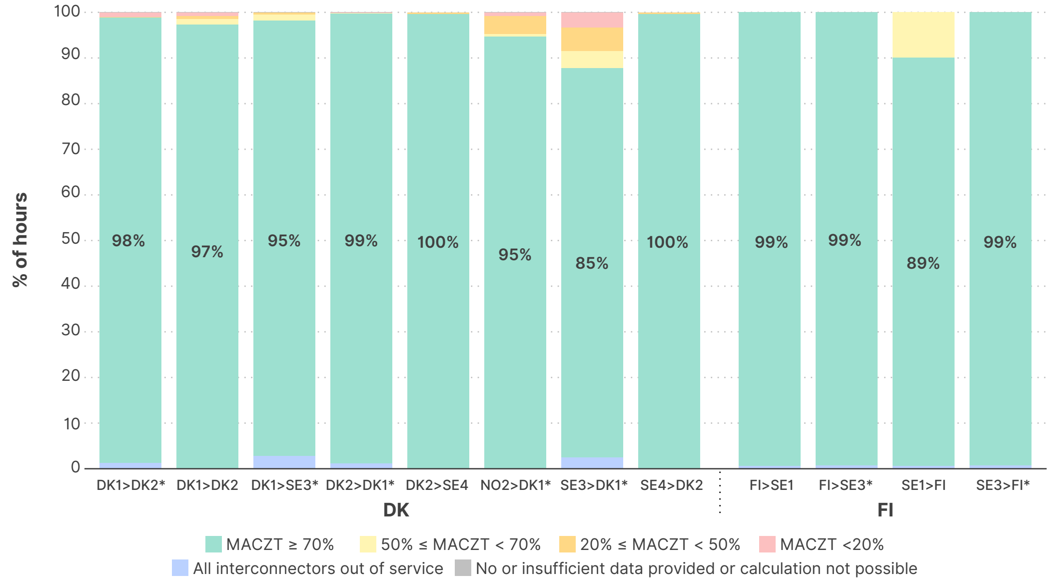
138 Due to the high degree of interdependence between the bidding zone borders in this region, a flow-based approach for capacity calculation is to be implemented. This is currently expected during the course of 2024. In the meantime, the MACZT analysis aggregates the results from the interim processes of capacity calculation from the Danish and Finnish TSOs. The case of Sweden is analysed separately in Section 2.3.9, as an interim capacity calculation process is used that covers bidding zone borders in the Nordic, Hansa and Baltic CCRs.

139 Figure 30 shows the percentage of hours when the MACZT was above the minimum 70% requirement or within a set of predefined ranges in the Nordic region, excluding data from the Swedish TSO. There are no relevant action plans or derogations for the Nordic region to be considered.

140 The share of hours when 70% can be offered by the Danish and Finnish TSOs in the bidding zone borders of the Nordic CCR is, and has been in previous years, generally high. In the case of the Danish TSO, deviations below 70% are mainly observed in the import direction of the bidding zone borders with Norway 2 and Sweden 3.

22 For Norway, the application of the minimum 70% requirement is pending EEA Joint Committee Decision on the incorporation of the Electricity Regulation into the EEA Agreement.

Figure 30: Percentage of hours when the minimum hourly MACZT was above 70% or within predefined ranges in the Nordic CCR for each Member State and oriented bidding zone border – 2023 (% of hours)



Source: ACER calculation based on TSO data.

Notes: On the border SE1 > FI, for the share of hours when MACZT was below 70%, the Finish TSO reported an outage of the parallel line, such that both F_{max} and the MCCC were limited due to an islanding criterion. Bidding zone borders marked with an asterisk (*) correspond to DC borders and were represented in a separate figure in previous reports.

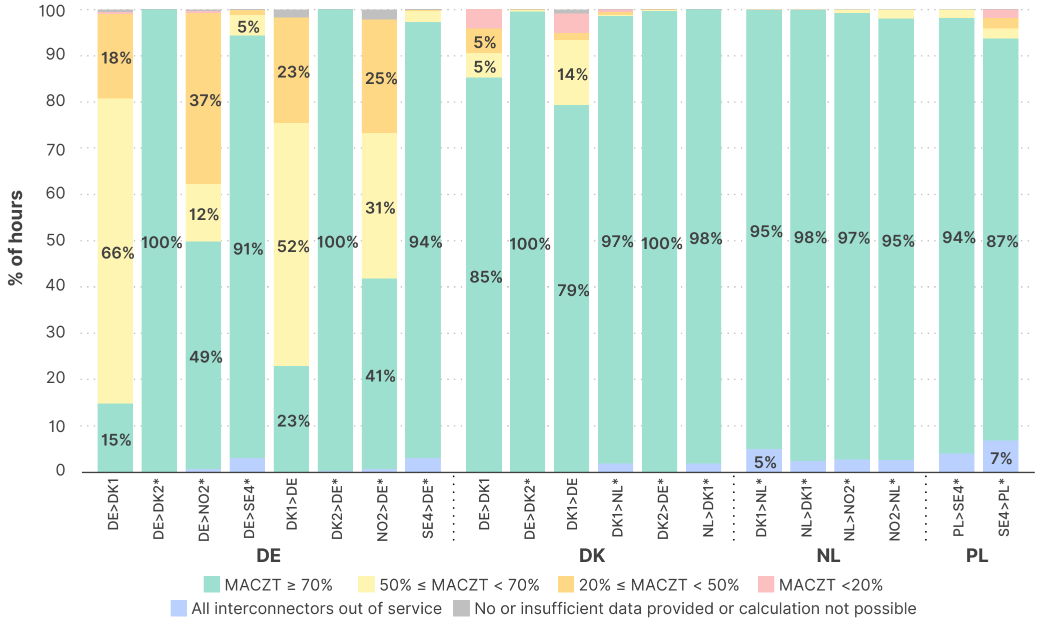
2.3.7. Hansa CCR

141 The Hansa CCR contains mostly DC bidding zone borders connecting Scandinavia with continental Europe. The only AC bidding zone border in the region is between the Denmark 1 and Germany/Luxembourg bidding zones. A coordinated capacity calculation methodology has not yet been implemented at the regional level; thus, TSOs rely on interim capacity calculation approaches.

142 Figure 31 shows the percentage of hours when the MACZT was above the minimum 70% requirement or within a set of predefined ranges, in the Hansa region, excluding data from the Swedish TSO. As stated in the previous section, the bidding zone borders of the Hansa CCR operated by the Swedish TSO are covered in a separate analysis in Section 2.3.9.

143 Several bidding zone borders in this region show a high degree of fulfilment of the minimum 70% requirement in 2023. The notable exceptions are the AC border DK1–DE and the DC border NO2–DE from the German side, where AC CNECs on the German grid limit the permissible exchange on the DC link.

Figure 31: Percentage of hours when the minimum hourly MACZT was above 70% or within predefined ranges in the Hansa capacity calculation region per Member State and oriented border – 2023 (% of hours)



Source: ACER calculation based on TSO data.

Notes: Poland has declared allocation constraints limiting total exchanges to and from the Polish bidding zone. The impact of this allocation constraint is monitored separately, and thus is not considered in this figure. Bidding zone borders marked with an asterisk (*) correspond to DC borders and were represented in a separate figure in previous reports. For the border DK1-NL, data inconsistencies regarding the reported F_{max} were found for 12.4% of MTUs in the direction DK1>NL and 2.2% of MTUs in the direction NL>DK1. These could not be solved at time of publication and the shown data for this share of hours is to be considered approximate.*

Action plans apply in Poland and Germany in the Hansa CCR

144 Both Poland and Germany have an action plan in place for the bidding zone borders pertaining to the Hansa CCR. The linear trajectory values relevant for 2023 are listed in Table 6.

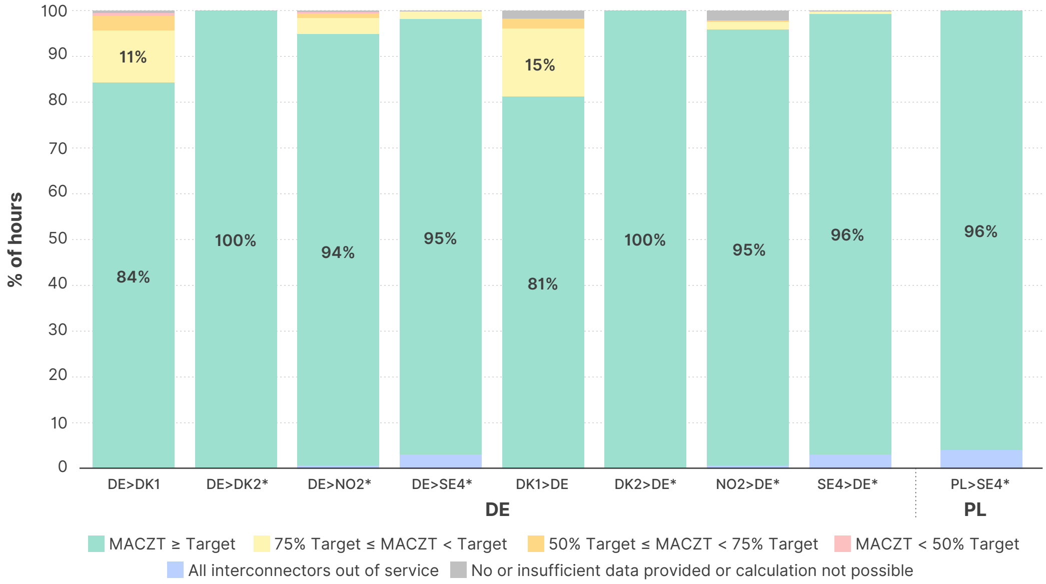
Table 6: Comparison between the MACZT and transitional targets of Member States in the Hansa CCR - 2023

Member State	Border	Direction	Interim MACZT requirement for 2023
DE	DE–DK1	DE > DK1	47%
		DK1 > DE	47%
	DE–DK2	DE > DK2	70% and 35% (Kontek and Kriegers Flak)
		DK2 > DE	70% and 35% (Kontek and Kriegers Flak)
	DE–NO2	DE > NO2	35%
		NO2 > DE	35%
	DE–SE4	DE > SE4	55.7%
		SE4 > DE	55.7%
PL	PL–SE4	PL > SE4	55%

Source: ACER elaboration.

145 Figure 32 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 in circa 15-20% of the hours in the DE–DK1 border in both directions, from the German side. In comparison with 2022, when the linear trajectory value was set at 39.4%, the share of hours when the interim requirements were met increased from 61% to 84% for export from DE to DK1 and decreased from 97% to 81% for import to DE from DK1.

Figure 32: Percentage of hours when the minimum hourly MACZT was above the interim capacity requirement or predefined ranges in the Hansa CCR for each Member State and oriented bidding zone border – 2023 (% of hours)



Source: ACER calculation based on TSO data.

Notes: Poland has declared allocation constraints limiting total exchanges to and from the Polish bidding zone. The impact of this allocation constraint is monitored separately, and thus is not considered in this figure. Bidding zone borders marked with an asterisk (*) correspond to DC borders and were represented in a separate figure in previous reports.

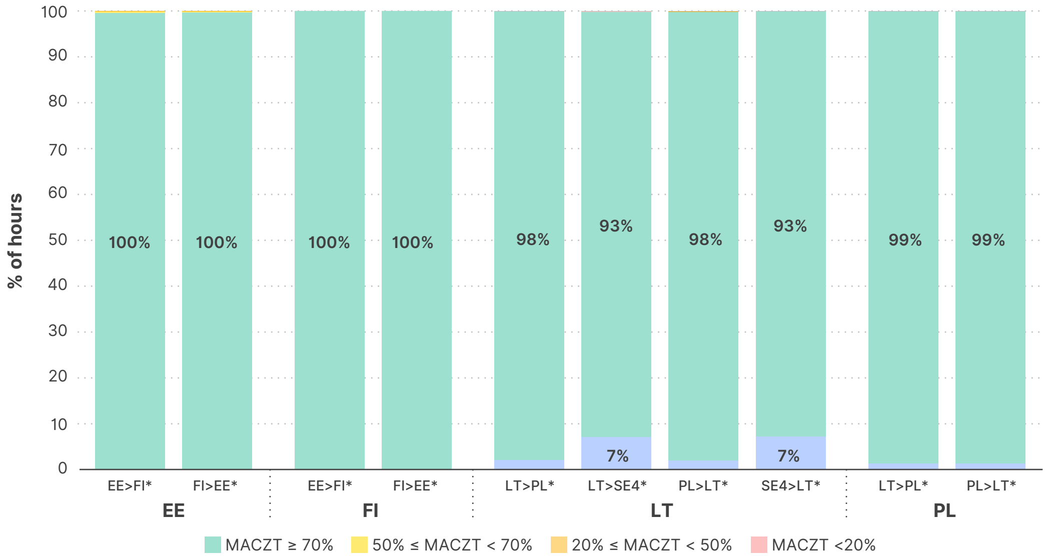
2.3.8. Baltic CCR

146 The Baltic CCR encompasses the bidding zone borders between the Baltic states Estonia, Latvia and Lithuania, and those with neighbouring countries Finland, Poland and Sweden. No data on the AC bidding zone borders are currently provided by the TSOs of the region and no common grid models are made available to ACER. Only the DC bidding zone borders of the Baltic CCR are thus analysed. The Baltic regulatory authorities informed ACER that common grid models would not be available before the synchronisation of the electricity systems of the Baltic states with those in continental Europe, expected in 2025.

147 Figure 33 shows the percentage of hours when the MACZT was above the minimum 70% requirement or within a set of predefined ranges in the Baltic region, excluding the data from the Swedish TSO. There are no relevant action plans or derogations for the Baltic region to be considered. The figure shows that DC bidding zone borders in the Baltic region generally fulfil the minimum 70% requirement and that capacities are reduced only in the case of maintenance on one of the DC links.

148 As mentioned previously, the bidding zone borders of the Baltic CCR operated by the Swedish TSO are covered in a separate analysis in section 2.3.9.

Figure 33: Percentage of hours when the minimum hourly MACZT was above 70% or within predefined ranges in the Baltic CCR for each Member State and oriented bidding zone border – 2023 (% of hours)



Source: ACER calculation based on TSO data.

Notes: Poland has declared allocation constraints limiting total exchanges to and from the Polish bidding zone. The impact of such allocation constraint is monitored separately, and thus is not considered in this figure. Bidding zone borders marked with an asterisk (*) correspond to DC borders and were represented in a separate figure in previous reports.

2.3.9. Sweden

149 As stated in the previous sections on the Nordic, Hansa and Baltic CCRs, the analysis of the MACZT offered by the Swedish TSO is performed separately. The reason for this split is the interim process for capacity calculation used by the Swedish TSO, which varies in the degree of coordination between Swedish borders and may include bidding zone borders from all three CCRs. This interim process will be in place until the implementation of a coordinated capacity calculation process, based on the flow-based approach, in the Nordic CCR.

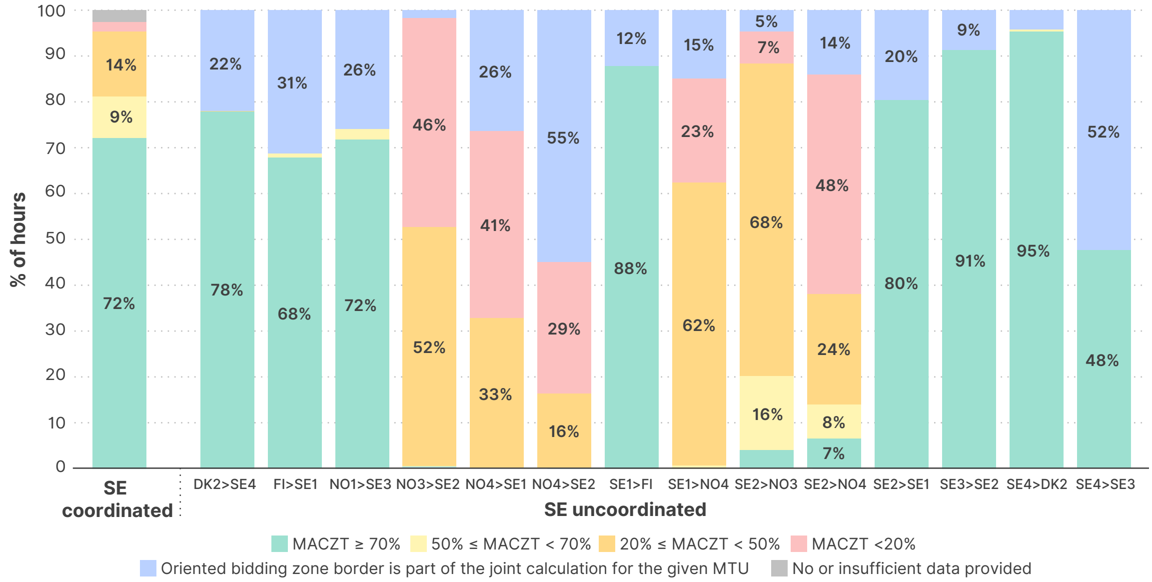
150 In the current interim capacity calculation process, NTC values offered for day-ahead trade are optimised by the Swedish TSO based on a forecasted market direction. The capacity calculation performed covers a subset of the oriented bidding zone borders operated by the Swedish TSO. This subset of oriented bidding zone borders spans different CCRs (Nordic, Hansa and Baltic) and may change over time, meaning that the coordinated analysis contains different oriented bidding zone borders for different market time units. The NTCs for the oriented bidding zone borders not included in the analysis are set based on pre-defined NTC limits.

151 To be able to represent the MACZT offered by the Swedish TSO within the described process, the analysis has been split into two. The left section of Figure 34, labelled 'SE coordinated', includes all limiting CNECs reported under the joint calculation of capacities, while the right section of the figure, labelled 'SE uncoordinated', covers the oriented bidding zone borders that are not part of the joint assessment. For these oriented bidding zone borders, the Swedish TSO has defined CNECs they consider to be fully loaded with the NTCs delivered to the market.

152 In addition, an allocation constraint applies to the joint export of bidding zone Sweden 3 to bidding zones Norway 1 and Denmark 1. As of 30 March 2022, a so-called line set optimisation function was introduced in the day-ahead market coupling algorithm.[23] This function allows the capacity on the two oriented bidding zone borders to be optimised by the market algorithm. For example, a commercial exchange from Denmark 1 to Sweden 3 can increase the exchange from Sweden 3 to Norway 1, as long as it remains below the NTC of that border.

23 For further details about the line set, please refer to https://www.nordpoolgroup.com/49594f/globalassets/download-center/day-ahead/explanation-document-for-nordic-line-sets-march-2022-.pdf.

Figure 34: Percentage of hours when the minimum hourly MACZT was above 70% or within predefined ranges for each bidding zone borders and coordination area – 2023 (% of hours)



Source: ACER calculation based on TSO data.

Notes: Zone-to-zone PTDFs for the internal Norwegian bidding zone borders have not been provided by the Swedish TSO. However, the impact of exchanges on these borders is likely to be not negligible for the borders between Swedish and Norwegian bidding zones. Line-set optimisation in the export of SE3 to NO1 and DK1 has been considered by correcting the NTCs in oriented bidding zone borders SE3 – NO1 and SE3 – DK1 to the combination of feasible NTCs that lead to the highest loading for each CNEC.

153 The meshed grid in the Nordic CCR, which encompasses multiple highly interdependent bidding zone borders, shows the need to implement a robust coordinated capacity calculation process in the region, based on the flow-based approach. The current interim capacity calculation approach, as described by the Swedish TSO, does not allow for a comprehensive assessment of the margins currently made available for cross-zonal trade.

2.3.10. Impact of non-coordinated flows on available capacity

154 As highlighted throughout the chapter, TSOs calculate cross-zonal capacities in the EU with varying degrees of coordination. CCRs define the subset of bidding zone borders within which a coordinated calculation of capacity shall take place in the EU, based on their degree of interdependence. Some CCRs, however, do not yet have an implemented capacity calculation methodology, relying on the less coordinated interim processes that are in place in each TSO.

155 The introduction of larger areas for the calculation of cross-zonal capacities results in, among other aspects, increased availability of information on the grid status and expected power flows in the region, and therefore reduces the uncertainty in the calculation. When calculating cross-zonal capacities, exchanges outside the coordinated area are based on forecasts, which have inherent uncertainties. The impact of these exchanges on the flows of the CNECs of a dedicated CCR is represented by the MNCC.

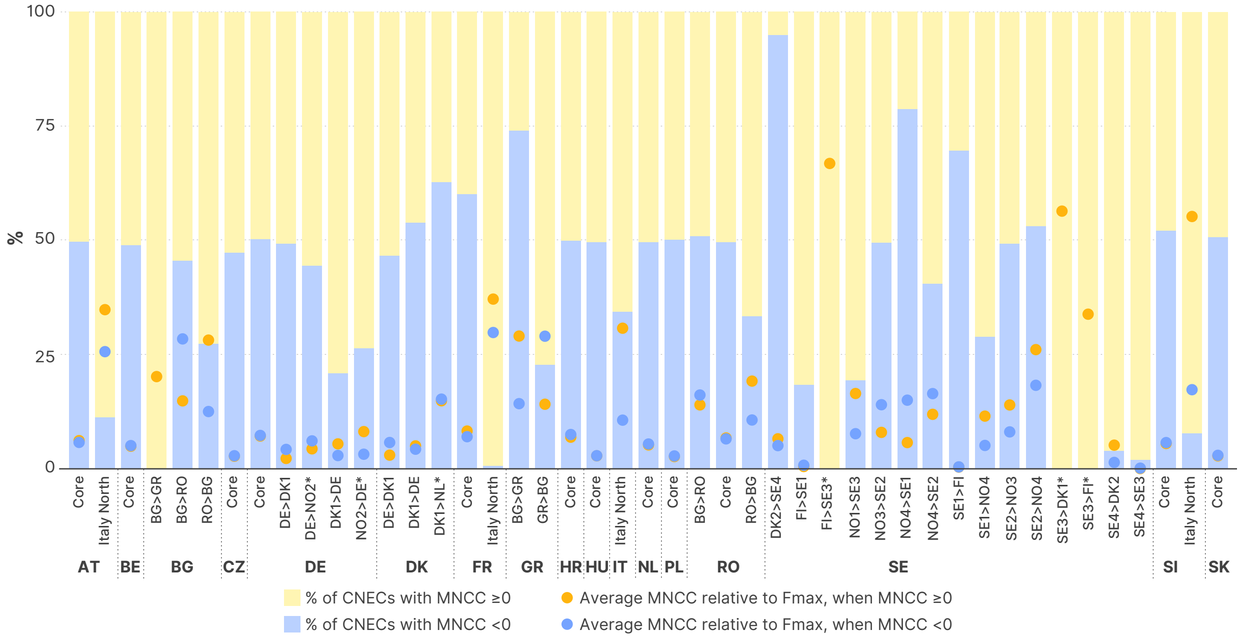
156 As MNCC represents the flows induced by cross-zonal exchanges beyond coordinated capacity calculation, this contribution may be positive (i.e. 'using' capacity on a given CNEC) or negative (i.e., it may free capacity on the CNEC). In the case of a negative contribution of flows induced by exchanges outside the coordinated region, the calculation process must ensure that the capacity freed up is made available for trade at the bidding zone borders within the coordination area.[24]

157 Figure 35 presents, for each Member State and coordination area, the share of limiting CNECs with positive and negative MNCC. It also shows the average levels, in percentage of F_{max}, of the MNCC values when MNCC was positive, and when it was negative (indicated by the orange and blue dots, respectively). Overall, the figure provides insight into how and to what extent the flows from other coordination areas influence the capacity TSOs can offer on their CNECs.

24 The netting of flows opposite to congestion is legally required. Therefore, TSOs are required to increase MCCC to account for negative MNCC.

158 Notably, the MNCC values shown in Figure 35 appear relatively high in the Italy North and SEE regions, while they are generally low in the Core CCR. High MNCC values are an indicator of the benefit of introducing more bidding zone borders into the coordination region. Enlarging the capacity coordination regions, and thus internalising flows induced by exchanges outside the region, would be beneficial in fulfilling the minimum 70% requirement.

Figure 35: Share of CNECs with positive and negative MNCC as a percentage of all CNECs and respective average levels of MNCC as a percentage of F_{max}, considering flows induced by third-country exchanges – 2023



Source: ACER calculation based on TSO data.

Note: The SWE region, Finland, Italy's internal borders and the border DK2–SE4 for Denmark are not part of this figure because the TSOs did not calculate the MNCC. In general, the MNCC is considered low on these borders.

159 MNCC values are expected to continue decreasing in the future, for example following the implementation of the common grid model methodology and the capacity calculation methodologies pursuant to the CACM Regulation. The introduction of the Central Europe CCR, combining the current Core and Italy North CCRs for the calculation of cross-zonal capacities for the day-ahead time frame, constitutes a significant step forward in this direction.

2.4. Impact of exchanges with non-EU countries on MACZT

160 In the current coordinated capacity calculation processes implemented in the EU for the day-ahead and intraday time frames, common grid models representing the European interconnected power system are established to calculate the possibilities for cross-zonal exchange in a coordinated way. When defining such models, TSOs provide a best estimate of the location of generation units and loads, as well as the expected cross-zonal exchanges.

161 As discussed in section 2.3.10, when calculating cross-zonal capacities based on the common grid model for a given region, flows induced by exchanges outside the region (including non-EU exchanges) have an impact on the critical network elements of the region, by either loading or decongesting them. Cross-zonal capacities for exchanges within the region are then based on the remaining physical capacity of the critical network elements of the region. In the case of non-EU countries, the upfront consideration of flows induced by exchanges with and between non-EU countries in capacity calculation may mean that such exchanges get priority access to the EU grid, as a portion of capacity in EU network elements are 'reserved' for them.

162 To address this, the Directorate-General for Energy of the European Commission, in a letter of 16 July 2019, provided guidance to ACER, NRAs and TSOs. The letter stated that consideration of non-EU member country flows in capacity calculation and the MACZT should be possible on the condition that an agreement has been concluded between all TSOs of a CCR and the TSO of the non-EU country and

has been approved by the relevant regulatory authorities. The agreement should be fully in line with EU capacity calculation principles and rules, and should cover at least:

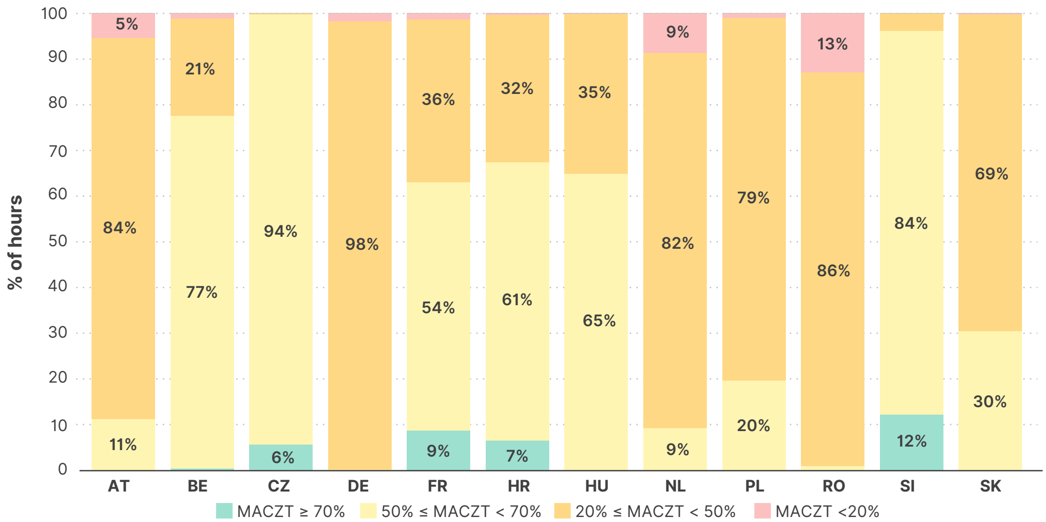
- consideration of internal non-EU country constraints for intra-EU capacity calculation;
- consideration of EU internal constraints for capacity calculation on the border with the non-EU country;
- cost-sharing of remedial actions.

163 The monitoring performed by ACER to date shows that flows induced by non-EU country exchanges are considered by default in all implemented coordinated capacity calculation processes, and that their impact on the MACZT is not negligible. In doing this, TSOs consider the best estimate of the state of the power grid when calculating intra-EU cross-zonal capacities but may implicitly give preferential access to the EU network to non-EU exchanges. In order to quantify the impact of exchanges with non-EU countries in intra-EU day-ahead capacity calculation, some of the figures produced in the preceding sections are replicated, excluding the contribution of flows induced by exchanges with non-EU countries.

164 In the Core region, a standard hybrid coupling solution is currently in place to capture the influence of exchanges with non-Core bidding zones on Core CNECs within the calculation of capacities. This standard hybrid coupling solution is used for both EU and non-EU borders (i.e., the border with Spain and the border with the United Kingdom). It assumes a forecast of the exchanges on these borders, effectively reserving a portion of capacity of every CNEC to accommodate these exchanges.

165 Figure 36 shows the extent to which the 70% requirement was fulfilled, when excluding the impact of non-EU country flows. Generally, the impact of non-EU country exchanges in some Core bidding zones is high, as can be estimated by comparing the values shown in the figure with those in Figure 16. HVDC links with Norway and the United Kingdom, and AC bidding zone borders with Switzerland, the western Balkans and Ukraine, have a significant effect on the margins of capacity made available for cross-zonal trade in the Core region.

Figure 36: Percentage of hours when the minimum hourly MACZT was above 70% or within predefined ranges in the Core CCR for each Member State, excluding flows induced by non-EU country exchanges – 2023 (% of hours)

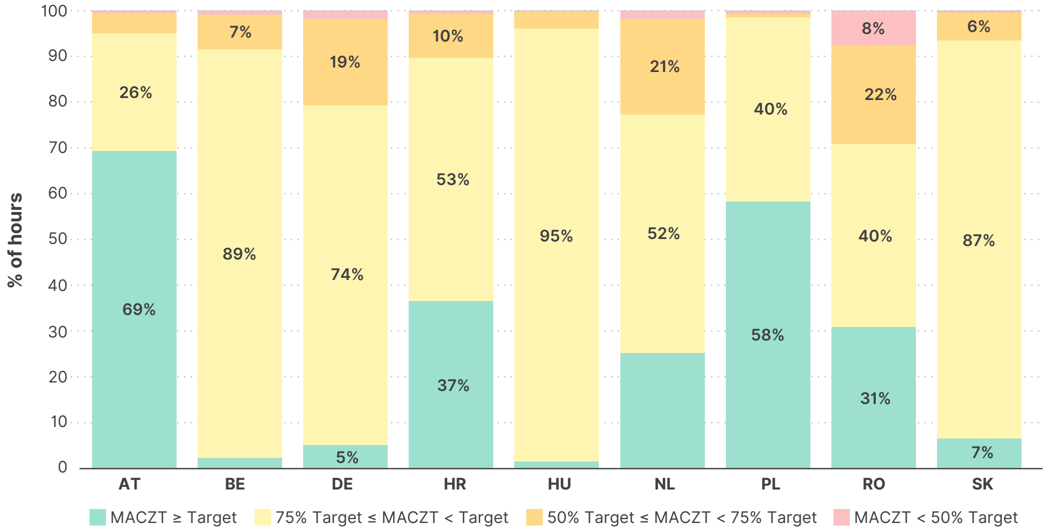


Source: ACER calculation based on TSO data.

Note: Belgium, the Netherlands and Poland have declared allocation constraints limiting total exchanges to and/or from these Member States. Allocation constraints are monitored separately and are thus not considered in this figure.

166 When assessing the fulfilment of interim requirements in the Core region, excluding the impact of flows induced by non-EU country exchanges in the offered capacities makes the impact even more visible. While such requirements can be deemed to have been mostly met in 2023 when considering the impact of third countries, that would generally not the case when the flows induced by non-EU country exchanges are excluded. This is highlighted in Figure 37.

Figure 37: Percentage of hours when the interim capacity requirements were met in all CNECs in the Core CCR for each Member State, excluding flows induced by non-EU country exchanges – 2023 (% of hours)

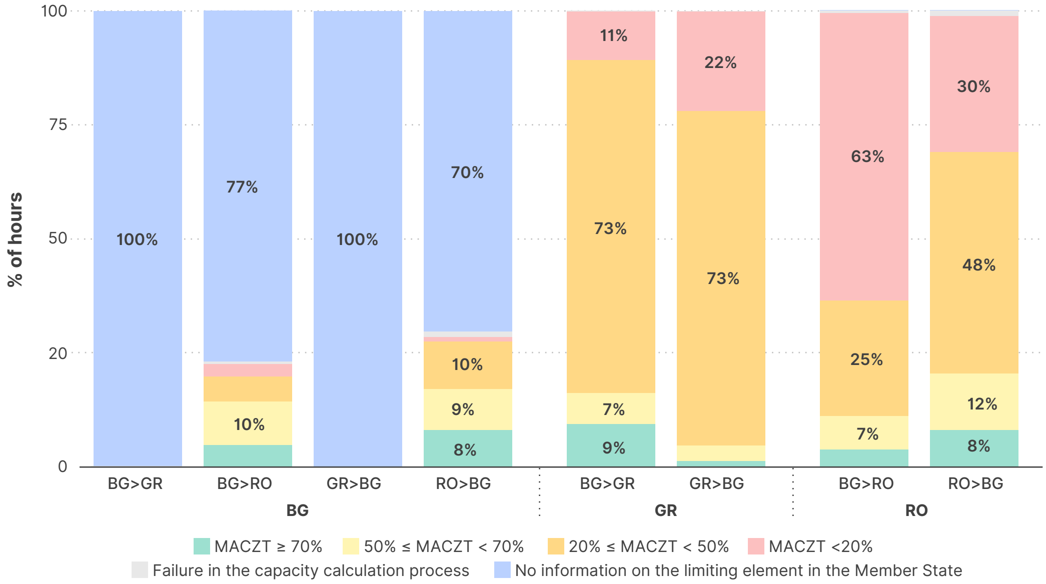


Source: ACER calculation based on TSO data.

Note: Only Member States with an applicable derogation and/or action plan in 2023 are displayed in the figure. Belgium, the Netherlands and Poland have declared allocation constraints limiting total exchanges to and/or from these Member States. Allocation constraints are monitored separately and are thus not considered in this figure.

167 The SEE region is also heavily impacted by exchanges with non-EU countries. In this region capacity is calculated jointly for intra-EU bidding zone borders and borders with non-EU countries. Figure 38 shows that EU network elements are being used significantly to accommodate exchanges with non-EU countries in the SEE region.

Figure 38: Percentage of hours when the minimum hourly MACZT was above 70% or within predefined ranges in the SEE CCR for each Member State, excluding flows induced by third-country exchanges – 2023 (% of hours)



Source: ACER calculation based on TSO data.

168 Given the significant impact of non-EU country exchanges in intra-EU capacity calculation, it appears relevant to ensure that sufficient coordination takes place with the relevant non-EU countries in cross-zonal capacity calculation and allocation, in order to be able to consider such exchanges in intra-EU capacity calculation.

3. Congestion management in the EU

169 The process of EU electricity market integration requires sufficient available cross-zonal capacity made available for cross-zonal trade. Chapter 1 presents the progress that has been made in enabling more cross-zonal trading opportunities in the different market time frames and EU regions; however, Chapter 2 highlights margin for improvement in optimising the use of current cross-border electricity infrastructure, assessed by the degree of implementation of the minimum 70% requirement.

170 This third chapter analyses congestion management and the increasing need for costly remedial actions by transmission system operators to manage system security. It analyses and compares the costs and volumes of remedial actions activated by EU TSOs in 2023. It also shows the evolution of costs and volumes over time, specifically since the introduction of the minimum 70% requirement. Furthermore, the chapter investigates the reasons for congestion management needs and the technologies used to tackle grid congestion.

171 Remedial actions are measures taken by TSOs to address violations of security limits after the market gate closure time. Specifically, they are triggered to ensure that voltage and power flows in the system are within the predefined operating ranges. Some corrective measures used by TSOs, such as changes in grid topology or the use of phase-shifting transformers, incur no operating costs and thus are generally given priority over others, such as redispatching, countertrading or curtailment of capacities allocated prior to day-ahead, which can come at a significant cost to the system.

172 Costly remedial actions to alleviate physical grid congestions entail that system operators need to adjust the market outcome to ensure the system operates securely. They have been used extensively across the EU in recent years, and their use is expected to increase further in the future, for several reasons.

- Firstly, given the growing share of variable renewable electricity generation in the system, and general delays in grid infrastructure development[25], the location of network congestion will continue to change more often with flow patterns. This requires TSOs to activate more remedial actions and to intervene in time frames closer to real time.

- Secondly, the minimum cross-zonal capacity requirements set out in Article 16(8) of the Electricity Regulation anticipates an increased application of both costly and non-costly remedial actions to ensure their fulfilment. Prior to the introduction of the minimum 70% requirement, a share of capacity of cross-zonal network elements was effectively used to accomodate flows induced by internal trade, preventing or minimising grid congestion within bidding zones. With a larger share of capacity being available for cross-zonal trading, and without swift reinforcement of the power grid, more remedial actions will be needed to deal with internal congestions.

- Thirdly, bidding zones in the EU are currently still mainly defined according to political borders, and potential changes to their configuration are usually met with some degree of resistance. Thus, they often cannot efficiently address structural, physical congestion in the network. As a result, locational price signals are partly distorted via wholesale prices and do not always reflect the cost of congestions.

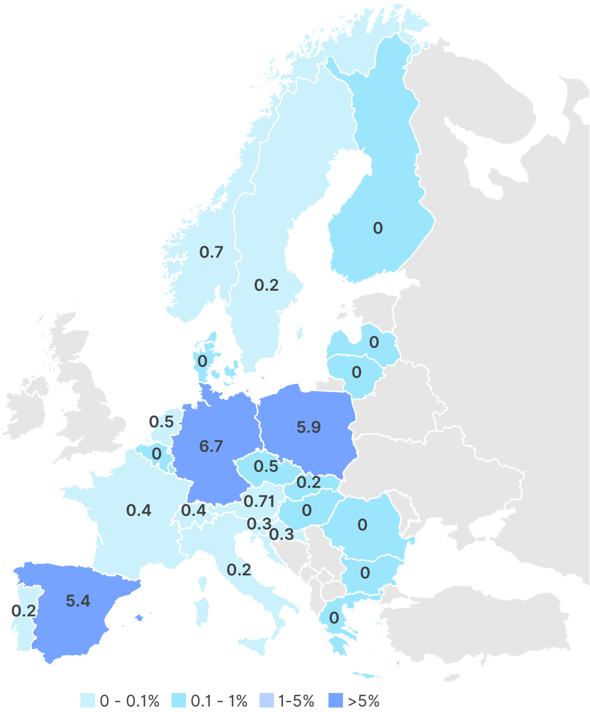
3.1. Costs and volumes of remedial actions in 2023

173 EU NRAs report to ACER the costs and volumes of costly remedial actions activated in each Member State on a yearly basis. In 2023, the data reported confirmed the trend detected in previous years. The volumes of costly remedial actions activated in the EU in 2023 amounted to 57.28 TWh, including both redispatching and countertrading. This constitutes a 14.45% increase when compared with 2022. On the other hand, the cost incurred by EU TSOs for costly remedial actions totalled EUR 4.26 billion, corresponding to a 21.12% decrease from the 2022 total. This cost drop is mainly due to electricity prices returning to pre-energy-crisis levels.

25 About 30% of all Projects of Common Interest (PCIs), representing major infrastructure works, are delayed. See: ACER's Consolidated report on the progress of electricity and gas Projects of Common Interest of June 2023.

174 Figure 39 shows a comparative overview of Member States' use of remedial actions in 2023, measured as the total volume of remedial actions activated in each Member State as a percentage of the national electricity demand. It is worth noting that this figure considers all costly remedial actions reported to ACER, including redispatching and countertrading, independently of the underlying operational security limit that they aim to address. The need for congestion management appears to be relatively highest in Germany, Spain and Poland. A complete overview of the data used to produce the figure is provided in Annex IV.

Figure 39: Volume of remedial actions activated in Member States as a percentage of electricity demand – 2023 (% of electricity demand)



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

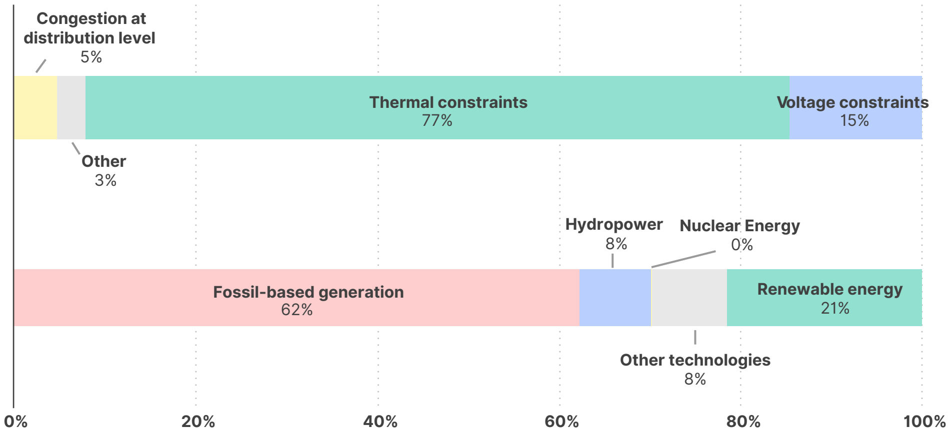
Note: The use of remedial actions serves to address various operational security constraints and is not exclusively tied to active power congestion management, nor does it always have an impact on cross-zonal trade. The figure considers all remedial actions, including both redispatching and countertrading, reported by NRAs as necessary to address network congestion within the Member States.

175 The data on the use of remedial actions reported by NRAs to ACER enables a detailed breakdown of the underlying cause of the redispatching activated by each TSO, based on the type of operational security violation that it intends to address, and of the technology involved in the upwards and downward regulation.

176 Figure 40 shows the distribution of redispatching by underlying security constraint and by the technology involved in the upward and downward regulation in the EU. Currently, most redispatching activated in the EU relates to managing thermal grid congestions at transmission level, corresponding to around 77% of the total volume. A notable exception is the case of Spain, where almost 50% of the remedial actions reported by the NRA aim to address violations of voltage security limits, while 20% address congestion at the distribution level.[26] Furthermore, most redispatching triggered in the EU in 2023 involves fossil-based generation units, covering 62% of the total volume.

26 As highlighted in Chapter 6 of the ACER 2023 market monitoring report Demand response and other distributed energy resources: what barriers are holding them back?, most distribution system operators (DSO) do not use congestion management services to solve congestion at distribution level. Like Spain, DSOs in at least nine Member States request the TSO to solve the congestion.

Figure 40: Distribution of total upward and downward redispatching volume in the EU, by underlying cause (top) and technology involved (bottom) – 2023 (% of MWh)



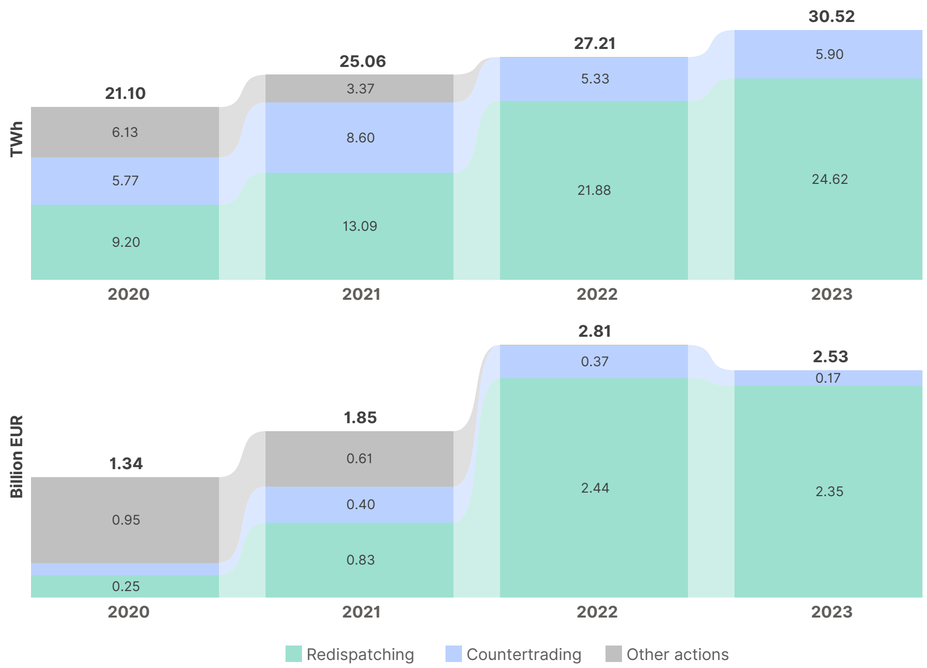
Source: ACER calculation based on NRA data.

Note: No data were available on the breakdown of redispatching volume by underlying cause for Greece and Ireland. No data were available on the breakdown of redispatching volume by technology for Ireland, Finland and France.

177 When analysing congestion management needs of the EU in 2023, Germany stands out again as the Member State needing to rely the most on the use of costly remedial actions. This is the case in terms of both volume, totalling 30.5 TWh of costly remedial actions activated, and share of its electricity demand. Such a high volume of remedial actions comes at a significant cost to the German system, amounting to EUR 2.53 billion in 2023.

178 The data for 2023, shown in Figure 41, continue a multi-year upwards trend that started in 2020, with increasing reliance on redispatching to cope with physical congestion within the Germany/Luxembourg bidding zone. There are two main drivers of this trend, which is expected to continue in coming years: the fast penetration of renewable energy in the German power system and the increasing minimum cross-zonal capacity requirement stemming from the German action plan, both combined with a limited pace of grid reinforcement.

Figure 41: Evolution of volume (top) and cost (bottom) of remedial actions activated in Germany – 2020-2023 (TWh and billion EUR)



Source: ACER calculation based on NRA data.

Note: Figures shown for redispatching include curtailment of electricity from RES sources.

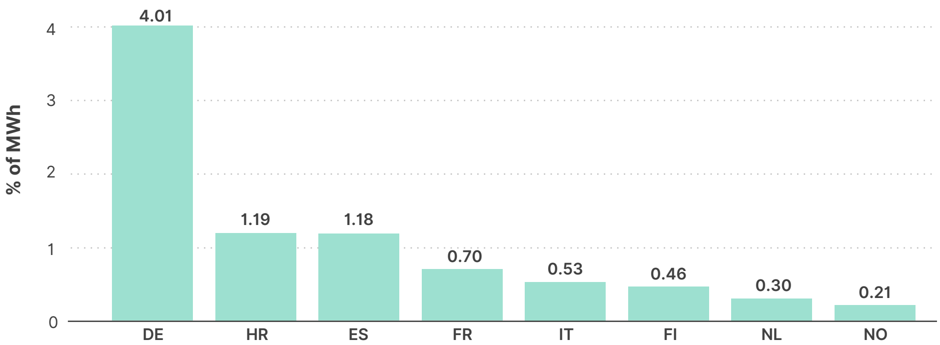
179 The data also show that the need for congestion management involving renewable energy technologies, mainly in the form of downward regulation or grid curtailment, is growing rapidly in some Member States. Over 12 TWh of electricity from renewable energy sources was curtailed in the EU during 2023 due to grid congestion. The share of energy generated by renewable technologies redispatched in the EU, out of the total volume of redispatching, has increased to an all-time high of 21.4% in 2023.

180 The Electricity Regulation introduced provisions to facilitate the integration of renewable energy sources into the system, by ensuring the networks in the EU are capable of transmitting electricity from renewable energy sources with the minimum redispatching possible. This, however, should not prevent network planning from taking into account limited renewable redispatching, provided that it is proven to be the most economically efficient option, and does not exceed 5% of the annual renewable generated electricity.[27]

181 Figure 42 shows the volume of redispatching involving renewable energy technologies as a percentage of the total renewable energy generated in 2023 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 could potentially be detrimental to the goals of the energy transition.[28]

182 In the case of Germany, the increase in the curtailment of renewable energy production observed over the last few years (from 2.56% in 2020 to 4.01% in 2023) and the limited pace of grid reinforcement, suggests that the need for curtailment will continue to grow in the coming years, driven mainly by the ambitious targets set for offshore wind installations and the linear trajectory of cross-zonal capacity requirements.

Figure 42: Curtailment of energy generated by renewable technologies as a percentage of total renewable energy generation for each Member State – 2023 (% 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 were available on curtailment of RES for Ireland.

3.2. Guaranteeing the minimum cross-zonal capacity requirements through remedial actions

183 As described in previous sections, the current market design, where trading within a bidding zone cannot be limited, relies on the use of remedial actions to ensure that minimum levels of cross-zonal capacities are offered. Different provisions have been implemented in the regional capacity calculation methodologies to ensure that is the case.

184 In the case of the Core CCR, which uses a flow-based approach in its capacity calculation and allocation processes, an additional margin (adjustment for minimum RAM, or AMR[29]) is added to the calculated cross-zonal capacity values on each CNEC to ensure that the minimum cross-zonal capacity

27 See article 13(5) of the recast Electricity Regulation.

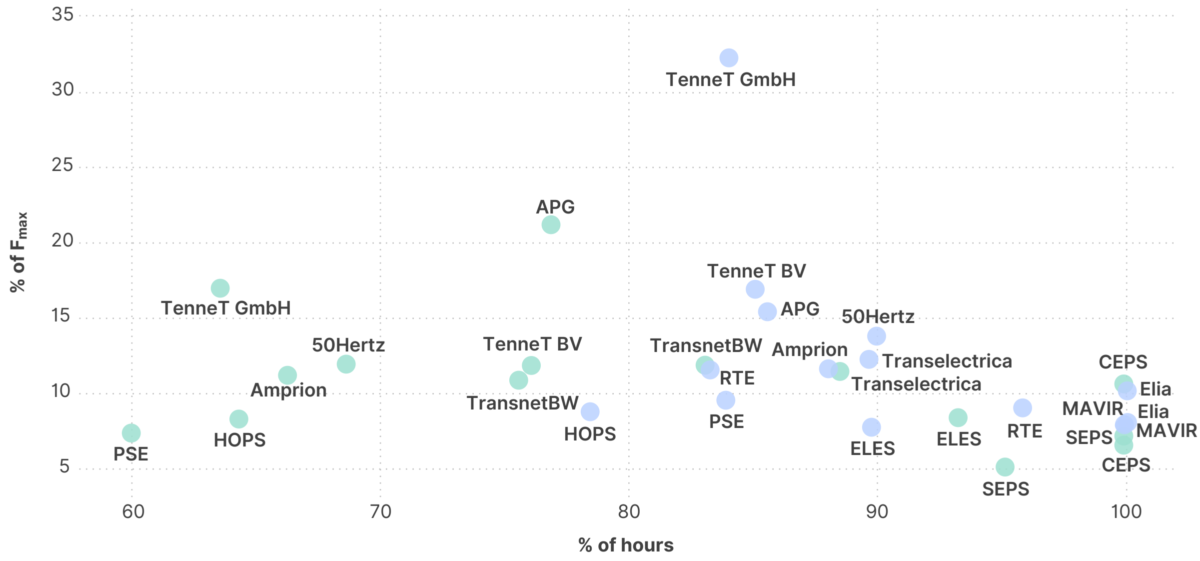
28 Assuming the 12TWh of RES curtailment need to be generated by gas-fired power plants instead, this corresponds to approximately 4.2 million tons of greenhouse gas emissions, which broadly corresponds to the total power-related greenhouse gas emissions of Slovenia.

29 This mechanism is described in article 17 of the Core day-ahead capacity calculation methodology.

requirements are met. This additional capacity, if allocated, requires the activation of remedial actions to reduce the electricity flow in the relevant CNEC. When a TSO considers that not enough remedial actions will be available to cope with the forecasted overload, the cross-zonal capacity to be offered can be reduced through the validation process.

185 Figure 43 shows the average need for additional capacity in order to comply with the minimum cross-zonal capacity requirements, presented as the percentage of hours when the adjustment is needed in least one CNEC and the average value of the adjustment in the CNECs where it is needed (percentage of F_{max}). In other words, the values shown in the figure represent the effort needed by each TSO to align with the applicable minimum cross-zonal capacity requirements, monitored in Chapter 2 of the current report.

Figure 43: Average need for application of AMR in the Core CCR for each TSO – from 9 June to 31 December 2022 and in 2023 (% of F_{max} and % of hours)



Source: ACER calculation based on JAO Publication Tool data.

Note: The figure shows TSO's average need for AMR in the Core CCR, by assessing the share of hours when parameter AMR of the CNECs in the final flow-based computation (as defined in the JAO Publication Tool) is positive and its average value when it is positive.

186 This assessment shows that some TSOs rely significantly on the activation of remedial actions across the Core region to cope with the applicable cross-zonal capacity requirements, and that this reliance was more frequent in 2023 than in 2022. A notable example is that of TenneT Germany, which in 2023 needed to rely on an increase in capacity in over 80% of hours and, on average, above 30% of F_{max}.

187 CCRs that apply a CNTC calculation approach, such as SWE and Italy North, have opted for an increase process within the capacity calculation that includes a set of remedial actions defined ex ante by the TSOs. This adjustment process ends either when the minimum cross-zonal capacity requirement has been met or when all the available remedial actions defined by the TSOs have been exhausted. The SEE region has yet to implement such an adjustment process.

188 At the current pace of grid development and without any changes to the bidding zone configuration, the need for remedial actions to guarantee the cross-zonal capacity requirements will continue to increase in the future in some areas of the EU. A recent study published by the European Commission's Joint Research Centre highlights 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.[30] This is because the integration of renewable energy technologies into the system will continue steadily, while the cross-zonal capacity requirements will need to be set at 70% by the end of 2025.

30 See Thomassen, G., Fuhrmanek, A., Cadenovic, R., Pozo Camara, D. and Vitiello, S., Redispatch and Congestion Management, Publications Office of the European Union, Luxembourg, 2024, doi:10.2760/853898, JRC137685.

4. Conclusions and recommendations

- **Maximum availability of cross-zonal capacities for the trade of electricity is a key element for the energy transition and achieving the EU's energy objectives, enabling further market integration.**

189 The full potential of the EU internal electricity market has yet to be realized. Further integrated electricity markets will allow for the penetration of renewable energy sources into the EU power system, in turn leading to more cost-effective decarbonisation pathways. Ensuring non-discriminatory access to the EU electricity network is a fundamental step towards this.

190 Renewable energy targets, such as 300 GW of offshore wind by 2050, will need to be accompanied by a means of moving the vast electricity supply to consumers across the EU. In a scenario of increasing price volatility, driven by greater electrification of most, if not all, sectors of the economy and the predominance of renewable generation, all sources of flexibility need to be tapped into. This includes the flexibility offered by cross-zonal trading.

191 To meet these challenges, the development of new grid infrastructure will have a key role to play. The pace of investment in cross-border infrastructure will also be dependent on how efficiently such infrastructure is used, however. Investing in cross-border infrastructure and optimising the calculation and allocation of cross-zonal capacities in all time frames will therefore play a keyrole in the process of EU market integration in the future.

- **All Member States will need to reach the minimum 70% requirement, by the end of 2025 at the latest.**

192 The minimum 70% requirement, introduced in the Electricity Regulation, sets a clear standard for the availability of cross-zonal capacity in the EU, providing certainty to all market participants on their future access to the network.

193 To comply with this provision without endangering the security of the power system, the Electricity Regulation established a transitory period until the end of 2025 for all transmission system operators to deal with any potential structural grid congestion internal to the bidding zones. The minimum 70% requirement should become fully applicable in all Member States by the end of 2025.

194 National efforts to implement the requirement need to be duly coordinated at the pan-European level. The externalities of one bidding zone on network elements of neighbouring bidding zones, for example via loop flows, need to be addressed at their root. A fair cost-sharing that ensures the 'polluter pays' principle is an essential element of the implementation of the requirement. The minimum 70% requirement can be deemed to have been successfully met only when all bidding zones can meet it.

- **The report concludes that significant effort is still needed to implement the minimum 70% requirement in some areas.**

195 ACER's monitoring of the implementation of the minimum 70% requirement over the last few years has shown that significant progress is still needed. The delay in implementing key processes, such as the capacity calculation methodologies and redispatching framework (notably the ROSC and cost-sharing methodologies), has led to repeated derogations from the legal requirements.

196 Furthermore, the effects of more structural solutions such as necessary investments in grid reinforcement and potential bidding zone reconfigurations have yet to materialize. Moreover, the lack of coordinated capacity calculation processes in some regions is impeding a comprehensive assessment of the progress towards 70%.

197 Given the rapidly increasing volumes of renewable generation and the difficulties of developing grid infrastructures, the challenge of reaching 70% may get harder and more costly by the year. As stated in ACER Opinion 02/2024, ACER considers that implementation delays beyond legal deadlines must not jeopardise the timeline provided in the Electricity Regulation for the fulfilment of the minimum 70% requirement. Meeting the set timeline remains a joint responsibility of all TSOs in a CCR.

- **The options to achieve the minimum 70% requirement by the end of 2025 are limited and will entail trade-offs.**

198 To achieve efficient use of cross-zonal infrastructure, measured by the ability to meet the minimum 70% requirement in all bidding zone borders, 'all tools in the toolbox' need to be considered. These are the following.

  - **Swift process implementation.** Without delay, implement and improve the necessary processes to coordinate the calculation of cross-zonal capacities at the regional level, with advanced hybrid coupling linking the external borders, and the processes to forecast, identify and trigger remedial actions within and between CCRs, ensuring adequate cost-sharing;
  - **Targeted grid investments.** Expedite the reinforcement of the grid where internal congestions occur, thus reducing the share of capacity used by internal and loops flows on critical network elements;
  - **Improve the bidding zone configuration.** Where not sufficient to fulfil the minimum 70% requirement in all bidding zone borders, review the bidding zone configuration to better align the bidding zones with network congestion. Such a bidding zone configuration would allow for a more cost-efficient fulfilment of the minimum 70% requirement.

- **In line with Article 34 of the CACM Regulation, ACER assesses the impact of the current bidding zone configuration on market efficiency.**

199 The high share of loop flows under certain market scenarios and growing congestion management needs are indicators of potential inefficiencies in EU market functioning. The relatively low margin of capacity currently made available for cross-zonal trade in some EU regions limits progress in EU market integration. Until 70% of the physical capacity is consistently made available for cross-zonal trade on all bidding zone borders, the current bidding zone configuration may be hampering EU market efficiency.

- **The need for cross-zonal capacities in time frames closer to real time will continue to increase in the coming years.**

200 In recent years, the introduction of more volatile power generation technologies to the system has led to closer-to-real-time trading becoming increasingly relevant. This trend increases the importance of ensuring sufficient cross-zonal capacity can be made available for trade also in the intraday time frame.[31]

201 In the intraday time frame, however, guaranteeing the minimum cross-zonal capacity requirements by relying solely on remedial actions may pose a major challenge to TSOs. Closer to real time, the availability of remedial actions tends to decrease, as some of the assets currently used in congestion management are not flexible enough to be activated close to real time.

202 With the increasing penetration of generation from variable renewable energy sources into the system, the importance of intraday markets means that the maximisation of cross-zonal capacities offered in that time frame should become a priority. At the same time, this report shows that current cross-zonal capacities available in the intraday time frame are relatively low, and very often zero.

- **Going forward, congestion management warrants further attention.**

203 ACER's monitoring in recent years has shown increases in the costs and volumes of congestion management needs across the EU, mainly in the form of redispatching and countertrading. While a certain level of redispatching is unavoidable in a zonal market and may be needed to address various system restrictions, the surge of certain renewable energy sources in the power system driven by the ambitious emission reduction targets set by the EU as well as individual Member States, may exacerbate the need to activate remedial actions and its costs, as highlighted by a recent study published by the European Commission's Joint Research Centre.[32] This is unless more structural measures are implemented at the same time.

31 This importance, together with the expected steps for the implementation of the minimum 70% requirement in the intraday time frame, is highlighted in ACER Decision 03/2024.

32 See Thomassen, G., Fuhrmanek, A., Cadenovic, R., Pozo Camara, D. and Vitiello, S., Redispatch and Congestion Management, Publications Office of the European Union, Luxembourg, 2024, doi:10.2760/853898, JRC137685.

204 Reinforcing the transmission network would alleviate current levels of congestion in the power grid, enabling more electricity to be transported from areas of high renewable penetration, while reconfiguring bidding zones would ensure more granular locational price signals, thereby reflecting the actual cost of congestions and incentivising the installation of future generation and demand assets where most needed. Either of these solutions come with respective challenges, including politically, which must be fully acknowledged.

205 Nevertheless, in the absence of either of these measures, or a combination of them, the EU may face an increased need for curtailment of renewable energies, at the expense of the use of more expensive and likely also more carbon-intensive, and thus more polluting, generation technologies. This, in turn, could risk squandering some of the efforts invested in meeting the EU's emission reduction targets and thereby also increase the energy bill for end-consumers.

- **Further integrated energy markets have knock-on effects on future competitiveness.**

206 Meeting the ambitious decarbonisation targets will require not only optimising the available infrastructure but also rolling out new infrastructure, both cross-border and internal, at a significant pace to cope with the penetration of renewable energy sources. Closer coordination of investments across borders, ensuring adequate cost-benefit analyses, and the optimisation of such a significantly more interconnected system will help bring about a more cost-effective energy transition with positive knock-on effects on future competitiveness, in terms of overall energy prices.

207 To enable this, it seems pertinent to prioritise the implementation and rigorous enforcement of existing legal obligations that help to ensure trust in the free flow of energy across Member State borders. This includes the implementation of the minimum 70% requirement, assessed in this monitoring report. Indeed, going further, the risk of network unavailability may jeopardise the fundamental trust that Member States need to have in cross-border energy flows for them to embark upon greater levels of energy interdependence across the EU.

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

Table 7: Overview of the completeness and quality of the data provided by TSOs for the monitoring of the MACZT for each coordination area – 2023

CCA/ Border	Member State	TSO	Overall ACER assessment of data completeness and quality	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		
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		The TSO did not provide PTDFs and did not calculate MCCC nor MNCC. ACER calculated them.

CCA/ Border	Member State	TSO	Overall ACER assessment of data completeness and quality	Observations
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.
DK2–SE4, DK1–DK2, DK1–SE3, DK1–NO2				The TSO did not provide PTDFs and did not calculate MCCC nor MNCC. ACER calculated them, where possible.
DK1–NL, NL–NO2	**NL**	TenneT		Inconsistencies were detected on the F_{max} reported for border DK1–NL.
FI–SE1, FI–SE3	**FI**	Fingrid		The TSO did not calculate MNCC. The impact on results is likely limited.
FI–EE				
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 borders	**SE**	SVK		The list of critical network elements (CNECs) has been anonymised by the TSO and no grid models were shared with ACER. This prevents ACER from performing a number of consistency checks.

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 only very limited.

Annex II: Overview of the data used by ACER for MACZT monitoring

Table 8: Overview of the data used by ACER in the report and for the calculation when performed by ACER – 2023

CCA / Border	MS	TSO	Results			Data used by ACER for calculation					Comments
			MCCC	MNCC without non-EU countries	MNCC with non-EU countries	CNECs	PTDFs	NTC	Forecast sched.	Alloc. const.	
Core	AT	APG	TSO	TSO	TSO						
	BE	Elia	TSO	TSO	TSO					TSO	
	CZ	CEPS	TSO	TSO	TSO						
	DE	50Hertz	TSO	TSO	TSO						
		Amprion	TSO	TSO	TSO						
		TenneT	TSO	TSO	TSO						
		Transnet	TSO	TSO	TSO						
	FR	RTE	TSO	TSO	TSO						
	HR	HOPS	TSO	TSO	TSO						
	HU	MAVIR	TSO	TSO	TSO						
	NL	TenneT	TSO	TSO	TSO					TSO	
	PL	PSE	TSO	TSO	TSO					TSO	
	RO	Trans-electrica	TSO	TSO	TSO						
	SI	ELES	TSO	TSO	TSO						
	SK	SEPS	TSO	TSO	TSO						
Italy North	AT	APG	TSO	TSO	TSO						
	FR	RTE	TSO	TSO	TSO						
	IT	Terna	TSO	TSO	TSO						
	SI	ELES	TSO	TSO	TSO						
SWE	ES	REE	TSO								
	FR	RTE	TSO								
	PT	REN	TSO								
GRIT	IT	Terna	TSO								
	GR	IPTO	TSO								
SEE	BG	ESO	ACER	ACER	ACER	TSO	ACER	EE-TP	EE-TP		
	GR	IPTO	ACER	ACER	ACER	TSO	ACER	EE-TP	EE-TP		
	RO	Trans-electrica	ACER	ACER	ACER	TSO	ACER	EE-TP	EE-TP		
DE–DK1, DE–NO2	DE	TenneT	TSO	ACER	ACER	TSO	TSO	TSO	TSO		See Note
DE–SE4			TSO								
DE–DK2		50Hertz	TSO								

CCA / Border	MS	TSO	Results			Data used by ACER for calculation					Comments
			MCCC	MNCC without non-EU countries	MNCC with non-EU countries	CNECs	PTDFs	NTC	Forecast sched.	Alloc. const.	
DE-DK1, DK1-NL	DK	Energinet	ACER	ACER	ACER	TSO	ACER	TSO	EE-TP		
DK2-SE4			ACER			TSO	TSO	TSO			
DK1–NL, NL–NO2	NL	TenneT	TSO								
FI–SE1, FI–SE3	FI	Fingrid	TSO								
EE-LV	EE	Elering									
LT-LV	LT	Litgrid									
EE-LV, LT-LV	LV	AST									
All borders	SE	SVK	ACER	ACER	ACER	TSO	TSO	TSO	TSO	TSO	

ACER — ACER calculation
TSO — Data provided by the TSO
EE-TP — Data from the ENTSO-E Transparency Platform
TSO/EE-TP — Data provided by the TSO or retrieved from ENTSO-E Transparency Platform
Data not provided and/or calculations not possible
Data not applicable or not used for the calculations

Source: ACER elaboration.

Note: ACER estimated the MNCC values as the MNCC estimates provided by the TSO were calculated using the NTC in the most loading direction, as opposed to using forecast schedules.

Annex III: Capacity coordination areas in the EU in 2023

Table 9: List of coordination areas used for the purpose of this report – 2023

Bidding zone border	Side(s)	Coordination area	Calculation type
AT–CZ	Both	Core	FB
AT–DE	Both	Core	FB
AT–HU	Both	Core	FB
AT–IT1	Both	Italy North	CNTC
AT–SI	Both	Core	FB
BE–DE	Both	Core	FB
BE–FR	Both	Core	FB
BE–NL	Both	Core	FB
BG–GR	Both	North GR borders	CNTC
BG–RO	Both	South RO borders	CNTC
CZ–DE	Both	Core	FB
CZ–PL	Both	Core	FB
CZ–SK	Both	Core	FB
DE–DK1	DE	DE–DK1_NO2 (DE side)	UNILATc
DE–DK1	DK	Hansa (DK side)	UNILATc
DE–DK2	DE	DE–DK2 (DE side)	UNILAT
DE–DK2	DK	Hansa (DK side)	UNILATc
DE–FR	Both	Core	FB
DE–NL	Both	Core	FB
DE–NO2	DE	DE–DK1_NO2 (DE side)	UNILATc
DE–PL	Both	Core	FB
DE–SE4	DE	DE–SE4 (DE side)	UNILAT
DE–SE4	SE	DE–SE4 (SE side)	UNILATc
DK1–DK2	Both	Nordic	UNILATc
DK1–NL	DK	Hansa (DK side)	UNILATc
DK1–NL	NL	DK1–NL (NL side)	UNILAT
DK1–NO2	DK	Nordic (DK side)	UNILATc
DK1–SE3	SE	DK1–SE3 (SE side)	UNILATc
DK1–SE3	DK	Nordic (DK side)	UNILATc
DK2–SE4	SE	DK2–SE4 (SE side)	UNILAT
DK2–SE4	DK	Nordic (DK side)	UNILATc
EE–FI	EE	EE–FI (EE side)	UNILAT
EE–FI	FI	EE–FI (FI side)	UNILAT
ES–FR	Both	SWE	CNTC
ES–PT	Both	SWE	CNTC
FI–SE1	FI	FI–SE1 (FI side)	UNILAT
FI–SE1	SE	FI–SE1 (SE side)	UNILAT
FI–SE3	FI	FI–SE3 (FI side)	UNILAT

Bidding zone border	Side(s)	Coordination area	Calculation type
FI–SE3	SE	FI–SE3 (SE side)	UNILAT
FR–IT1	Both	Italy North	CNTC
GR–IT4	Both	GRIT	CNTC
HR–HU	Both	Core	FB
HR–SI	Both	Core	FB
HU–RO	Both	Core	FB
HU–SK	Both	Core	FB
IT1–IT2	Both	GRIT	CNTC
IT1–SI	Both	Italy North	CNTC
IT2–IT3	Both	GRIT	CNTC
IT3–IT4	Both	GRIT	CNTC
IT2–IT5	Both	GRIT	CNTC
IT3–IT5	Both	GRIT	CNTC
IT4–IT7	Both	GRIT	CNTC
IT6–IT7	Both	GRIT	CNTC
LT–PL	LT	LT–PL (LT side)	UNILAT
LT–PL	PL	LT–PL (PL side)	UNILAT
LT–SE4	LT	LT–SE4 (LT side)	UNILAT
LT–SE4	SE	LT–SE4 (SE side)	UNILATc
NO1–SE3	SE	NO1–SE3 (SE side)	UNILATc
NO3–SE2	SE	NO3–SE2 (SE side)	UNILATc
NO4–SE1	SE	NO4–SE1 (SE side)	UNILATc
NO4–SE2	SE	NO4–SE2 (SE side)	UNILATc
PL–SE4	PL	PL–SE4 (PL side)	UNILAT
PL–SE4	SE	PL–SE4 (SE side)	UNILATc
PL–SK	Both	Core	FB
SE1–SE2	Both	SE1–SE2	CNTC
SE2–SE3	Both	SE2–SE3	CNTC
SE3–SE4	Both	SE3–SE4	CNTC
SE2-SE3	Both	SE2-SE3	CNTC
SE3-SE4	Both	SE3-SE4	CNTC

Source: ACER elaboration.

Notes: A coordination area describes a set of bidding zone borders within which capacity calculation is fully coordinated. Until capacity calculation methodologies pursuant to the CACM Regulation are implemented, such coordination areas will normally remain smaller than capacity calculation regions defined across the EU. The coordination level of day-ahead capacity calculation is defined as follows: FB, flow-based capacity calculation; CNTC, fully coordinated NTC calculation; UNILATc, coordinated unilateral NTC capacity calculation on several half bidding zone borders; UNILAT, unilateral NTC capacity calculation, i.e., not coordinated on either side of a border (half bidding zone border coordination).

Annex IV: Costs and volumes of remedial actions in the EU in 2023

Table 10: Costs and volumes of remedial actions triggered in the EU for congestion management – 2023

MS	Cost 2023 (MEUR)	Volume 2023 (GWh)	Redispatching 2023 (GWh)	Counter-trading 2023 (GWh)	Other actions 2023 (GWh)	Volume 2022 (GWh)	Volume 2021 (GWh)	Volume 2023 as a percentage of demand (%)
AT	43.96	413.84	413.84	0	0	102.82	377.6	0.71
BE	1.43	18.38	15.85	2.53	0	40.7	97.08	0.02
BG	0	0	-	-	-	0	0	0
CH	0	244.31	78.87	165.44	0	140.44	85.24	0.4
CZ	0.28	4.48	4.48	-	-	0	0.17	0.01
DE	2525.81	30520.56	24618.32	5902.24	0	27209.15	25059.96	6.66
DK	0	0	0	0	0	5.58	0	0
EE	0.85	6.36	-	-	6.36	7.99	1.88	0.08
ES	949.72	12394.6	11014.2	1380.4	0	7219	0	5.4
FI	0.86	11.6	5	6.6	-	0	12.10	0.01
FR	65	1500	53	1447	-	1482.30	1154	0.35
GR	0	1.7	-	-	1.7	4.07	16.26	0
HR	0	51.13	51.129	0	0	5.53	2.69	0.29
HU	0	0	0	0	0	0	0	0
IT	60.10	451	330	-	121	306	4982.32	0.16
LT	2.91	4.45	0	4.45	0	4.56	10.81	0.04
LU	0	0	-	-	-	0	0	0
LV	0.22	1.26	0	0	1.264	1.15	0	0.02
NL	274.81	574	574	-	-	876.65	1284	0.53
NO	24.92	894	894	-	-	1167	1017.62	0.66
PL	288.87	9812.62	8662.91	9.15	1140.56	11058	15099.18	5.91
PT	6.20	78.69	5.394	73.295	0	0.08	0.40	0.16
RO	0.02	0.42	0.42	-	0	1.62	0	0
SE	15.66	263.21	0	103.65	159.56	355.56	26.61	0.2
SI	0.09	40.06	0	40.06	0	0	1.70	0.33
SK	0	0	0	0	0	0	0	0

Source: ACER elaboration based on NRA data.

Note: The Polish NRA reports the volume of non-costly remedial actions (DC setpoint changes and phase-shifting transformer settings) in the category 'Other actions'.

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