**Publishing date:** 11/11/2019

**Document title:** ACER Market Monitoring Report 2018 – Electricity Wholesale Markets Volume

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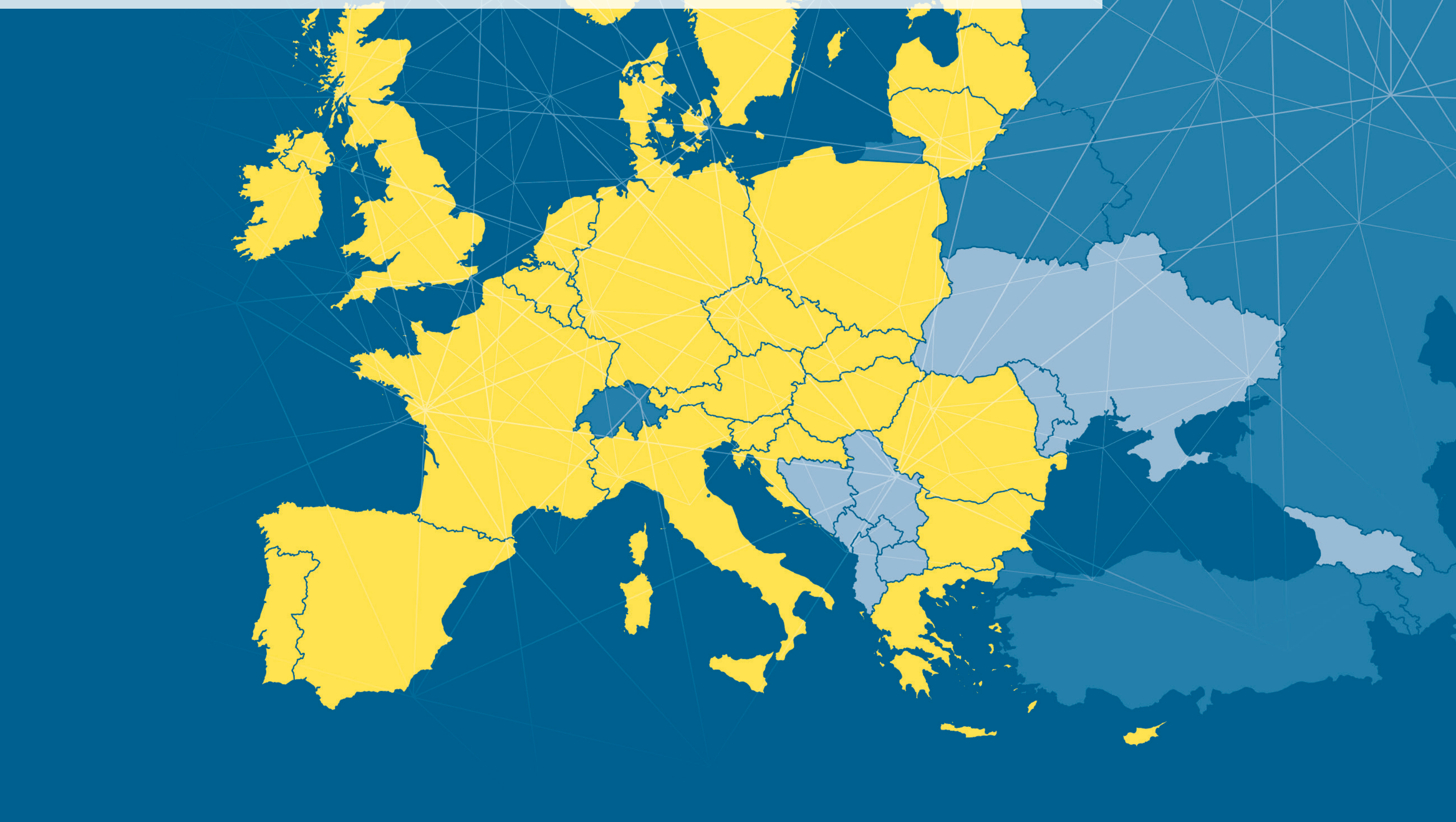
# Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2018

## Electricity Wholesale Markets Volume

November 2019



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# ACER/CEER

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## Electricity Wholesale Markets Volume

November 2019

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# Executive Summary

## Key developments in 2018

1 **In 2018, annual average day-ahead (DA) electricity prices increased in all bidding zones, except in Romania.** The highest annual average DA prices were observed in the British, Italian, Irish (Single Energy Market, SEM), Greek and Iberian markets, whereas the lowest annual average DA prices were recorded in the Bulgarian, Nordic and German markets. The number of price spikes (200) significantly decreased in 2018 compared to the previous two years (more than 1,000 each year). The significant drop in the number of DA price spikes across the EU is partly the result of mild weather conditions, which smoothened the load and therefore diminished the frequency of scarcity in most Member States (MSs) in 2018. Future situations of scarcity are likely to result in the reappearance of more frequent price spikes. In the absence of market power or price manipulation, price spikes may be a sign of well-functioning markets and tend to reduce the need for implementing capacity mechanisms (CM), possibly categorised as state aid, to the benefit of end consumers.

2 Although price convergence is not an objective as such, it provides an indication of the level of electricity market integration. **In 2018, different levels of price convergence persisted across Europe. Average absolute DA price spreads ranged from less than 0.5 euro/MWh on the borders between Estonia and Finland, Portugal and Spain, and Latvia and Lithuania, to 10 euros/MWh or more on several borders, e.g. on all Bulgarian and British borders, or on the border between Austria and Italy** (see Table i). The persistent price differentials confirm how relevant it is to complete market coupling on all borders and to maximise the amount of cross-zonal capacity made available for trade, particularly on borders with the highest price spreads.

Table i: Borders with the greatest absolute average DA price differentials – 2016–2018 (euros/MWh)

| | Average DA price differentials (euros/MWh) | | | | Average of absolute DA price differentials (euros/MWh) | | | |
|---|---|---|---|---|---|---|---|---|
| Border | 2016 | 2017 | 2018 | 2016-2018 | 2016 | 2017 | 2018 | 2016-2018 |
| BG - GR | -6.0 | 14.6 | -20.5 | -4.0 | 14.6 | 19.8 | 24.2 | 19.5 |
| FR - GB | -12.4 | -6.8 | -14.7 | -11.3 | 15.4 | 12.5 | 15.6 | 14.5 |
| AT - IT | -13.7 | -20.2 | -14.4 | -16.1 | 13.7 | 20.2 | 14.4 | 16.1 |
| BG - RO | -0.3 | -8.3 | -6.528 | -5.0 | 11.4 | 14.8 | 13.1 | 13.1 |
| GB - NL | 16.9 | 12.4 | 12.4 | 13.9 | 17 | 13.1 | 12.7 | 14.3 |
| FR - IT | -5.9 | -9.4 | -10.5 | -8.6 | 7.3 | 9.8 | 11.0 | 9.4 |
| ES - FR | 2.9 | 7.3 | 7.1 | 5.8 | 8.0 | 10.2 | 10.8 | 9.7 |
| NL - NO2 | 7.1 | 10.4 | 9.3 | 8.9 | 7.5 | 10.6 | 10.6 | 9.6 |
| GB - IE | 4.0 | 5.9 | 2.9 | 4.3 | 13.8 | 10.5 | 10.4 | 11.6 |
| DE - PL | -7.5 | -2.8 | -7.7 | -6.0 | 10.0 | 8.7 | 9.9 | 9.5 |

*Source: ACER calculations based on ENTSO-E data.*

*Note: A negative average DA price differential indicates that the average price was lower in the first of the two bidding zones identifying a border, e.g. prices were lower in Austria than in Italy in all years. The borders are ranked based on the 2018 average absolute price differentials. Average absolute price differentials (right side of the table) are higher than the 'simple' spreads (left side of the table), where negative and positive price spreads are netted.*

3 The largest increase in the frequency of full price convergence between 2017 and 2018 was observed in the Nordic region, recovering from two consequent years of low convergence. The factors explaining this rise include increased cross-zonal capacity on Norwegian bidding-zone borders by more than 10% compared to 2017 and relatively low hydro reservoirs in Norway in 2018, which simultaneously increased prices and lowered price spreads in Nordic markets.

4 Year-on-year changes in price convergence are often caused by market fundamentals, not necessarily related to market integration, so price convergence should also be analysed over a period of a few years. **The evolution of regional price convergence in Europe in recent years confirms that market coupling contributes to price convergence.**

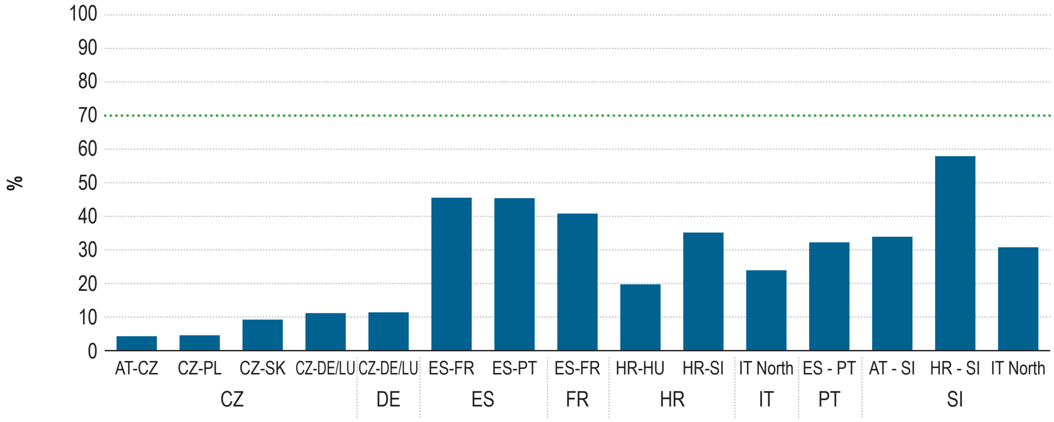
## Available cross-zonal capacity and remedial actions

5 As reported by the Agency in previous MMRs, the amount of cross-zonal capacity made available for trading, particularly in high-voltage alternating current (HVAC) interconnectors, has remained low in recent years.

6 The adoption of the Clean Energy for All Europeans[1] Package (Clean Energy Package, CEP) legislation in June 2019 has initiated a period of significant changes, aiming to foster the creation of more efficient electricity markets[2]. For example, in view of the persistently low levels of electricity cross-zonal capacity, the CEP requires a minimum level of capacity to be made available for cross-zonal trade. In particular, at least 70% of the maximum admissible active power flow (Fmax) of critical network elements considering contingencies (CNECs) shall be made available for cross-zonal trade.

7 Consequently, the Agency adapted its methodology to track the amount of cross-zonal capacity available for trade and to compare it to the minimum target set in the CEP. This analysis is based on the Agency's Recommendation 01/2019[3] and it does not assess legal compliance of Transmission System Operators' (TSOs) actions, but rather estimates the margin for improvement with respect to the minimum 70% target. Figure i, ii and iii provide a visual representation of the average capacity made available for cross-zonal trade between 2016 and 2018 in selected countries. **On most of the analysed alternate current (AC) and on some Direct current (DC) bidding-zone borders, the margin available for cross-zonal trade was much lower than 70%, suggesting significant room for improvement.** An important caveat is that exchanges with non-EU countries were not considered, while these exchanges impact the MACZT. For example, exchanges between the EU and Switzerland significantly impact the MACZT on the IT-North borders.

Figure i: Average relative margin available for cross zonal trade (MACZT) on selected AC bidding-zone borders in Europe – 2016–2018




*Source: ACER calculations based on ENTSO-E/TSOs and Nordpool data.*

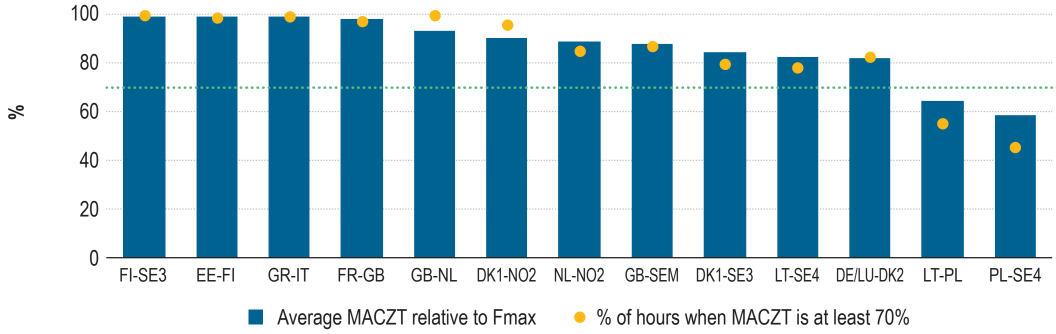
*Note: The average relative MACZT is computed over all declared CNECs, taking EU bidding-zone borders into account. The coordination areas delineation required for the underlying calculations is based on the level of coordination in day-ahead capacity calculation declared by NRAs for the MMR 2017. The margin available for trade on a given border is displayed from the perspective of the two MSs at both sides of the border, subject to data confidence. MSs and borders are selected based on the confidence in data, i.e. only borders for which the confidence was sufficient are displayed.*

1 The Commission's Clean Energy for All Europeans legislative proposal covered energy efficiency, RES generation, the design of the electricity market, security of electricity supply and governance rules for the Energy Union. Relevant material along with the adopted directives and legislation is available at: https://ec.europa.eu/energy/en/topics/energy-strategy-and-energy-union/clean-energy-all-europeans.

2 See for example the main legislative documents on the electricity markets here: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=OJ:L:2019:158:TOC.

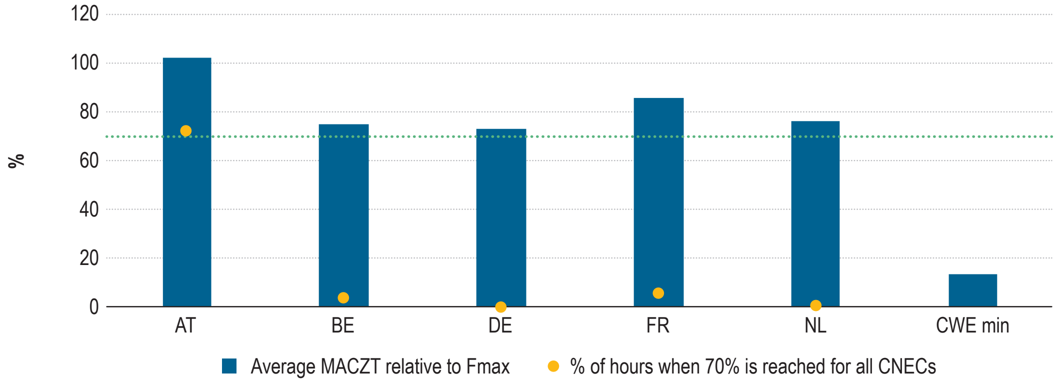
3 See https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Recommendations/ACER%20Recommendation%2001-2019.pdf.

Figure ii: Average relative MACZT and percentage of time when the minimum 70% target is achieved on DC bidding-zone borders in Europe – 2016–2018




*Source: ACER calculations based on ENTSO-E/TSOs and Nordpool data.*

Figure iii: Average relative MACZT and percentage of time when 70% is reached for all CNECs in the Core (CWE) region – 2016–2018




*Source: ACER calculations based on ENTSO-E/TSOs and Nordpool data.*

*Note: The bar to the extreme right describes the average over all hours of the minimum relative MACZT over all Core (CWE) CNECs of the considered hour.*

8 **Overall, urgent action is thus needed, either significantly to increase the capacity made available for cross-zonal trade by 1 January 2020 or to design a transition period** (e.g. through action plans or derogations pursuant to the CEP). Such actions should ideally rely on more detailed data increasing the robustness of the analyses. Besides, agreements with non-EU countries may allow to include exchanges with these countries in the MACZT, possibly increasing it.

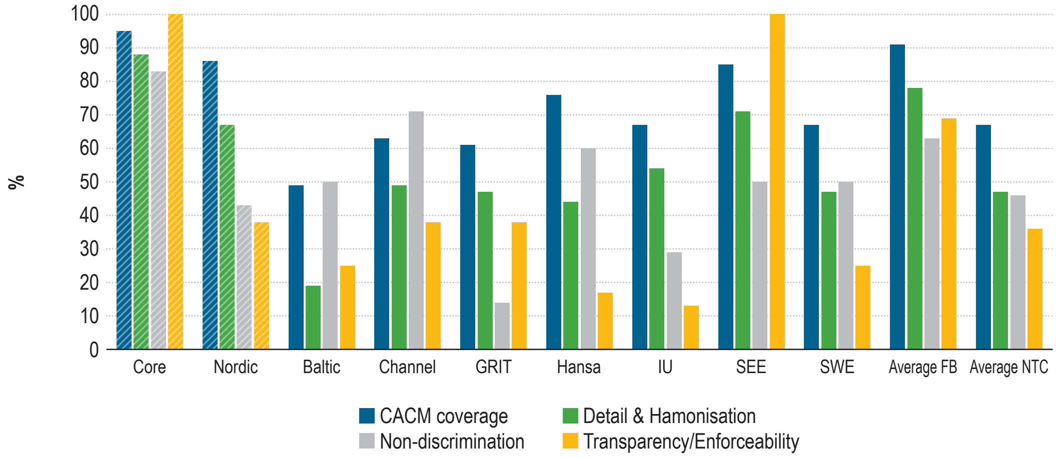
9 As concluded in the latest 'market report'[4] on the efficiency of the current bidding zone configuration, compiled as a chapter of last year's MMR, the low cross-zonal capacities made available for trade are probably the result of congestions not being properly addressed by the current bidding zone configuration in Europe. The validity of this finding is supported by the fact that, **in 2018, congestion continued frequently to relate to intra-zonal critical network elements (CNEs) rather than to interconnectors**.

10 **For example, in the CWE region**, an increase in the tradable cross-zonal capacity was observed following the introduction of changes (including a conditional requirement for minimum margin) to the capacity calculation methodology (CCM) in 2018. Despite the improvement, when congestion occurred in this region, **internal lines still constrained available capacity more than half of the times (57% of occurrences) in 2018, mainly in Germany, the Netherlands and Belgium.** This is partly due to the fact that the relevant CCM had no rules to avoid internal exchanges being unduly prioritised over cross-zonal ones. This distortion was removed in February 2019 when a new CCM was approved by the Agency for the Core capacity calculation region (CCR).

4 Pursuant to Article 34(1) of the Capacity Allocation and Congestion Management (CACM) Regulation, the Agency has to produce such a report every three years.

11 In fact, **a thorough evaluation of the recently adopted CCMs according to a set of quality criteria defined by the Agency has led to the conclusion that there is significant room for improvement for most of them.** Figure iv illustrates this finding and that the approved methodologies offer a diverse panorama with respect to the criteria used in the analysis, namely the level of "Capacity Allocation and Congestion Management (CACM) Regulation[5] coverage", the "level of detail and harmonisation", "non-discrimination", and "transparency and enforceability". Outstandingly, three of the nine analysed CCMs did not include any explicit provision guaranteeing the prevention of undue discrimination of cross-zonal exchanges. Even though discrimination of cross-zonal exchanges is not currently a reason for concern in some regions, there is no guarantee that discrimination issues will not arise in those regions in the future.

Figure iv: Share of assessment criteria met by approved CCMs per category (%)




*Source: ACER.*

*Note: The assessment is not an analysis of legal compliance. The assessment includes all CCRs except Italy North. For this region, a common coordinated CCM was not yet approved by the relevant regulatory authorities as of June 2019.*

12 Although improving the CCMs will mitigate the discrimination issue, **the persistence of structural congestions in Europe[6] confirms the need for conducting a bidding zones review in combination with other longer-term measures such as cost-effective network investments.** The CEP provides a new framework for the bidding zones review process, including the definition of a methodology which should aim to identify a bidding zone configuration that delivers the highest benefits to EU electricity consumers.

## Efficient use of available cross-zonal capacity

13 **Due to DA market coupling over more than two thirds of European borders, involving 25 European countries by the end of 2018, the level of efficiency in the use of interconnectors in this timeframe increased from approximately 60% in 2010 to 87% in 2018.** In 2018, market coupling was extended to the borders between Croatia and Slovenia (June) and between Great Britain and the SEM of Ireland and Northern Ireland (October).

14 At the end of 2018, the following MSs still applied explicit DA auctions on at least one of their borders: Austria, Bulgaria, Croatia, the Czech Republic, Germany, Greece Hungary, Italy, Poland, Romania, and Slovakia.

15 As indicated in previous MMRs, market coupling has rendered a benefit of approximately 1 billion euros per year to European consumers. **The extension of market coupling implementation to the above-listed borders would render an additional social welfare benefit of more than 200 million euros per year. This highlights the urgency of such an extension, which has been delayed for several years.**

5 Commission Regulation (EU) 2015/1222 of 24 July 2015, available at: http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32015R1222&from=EN.

6 See the 2018 ENTSO-E bidding zone configuration technical report at https://docstore.entsoe.eu/Documents/Events/2018/BZ_report/20181015_BZ_TR_FINAL.pdf.

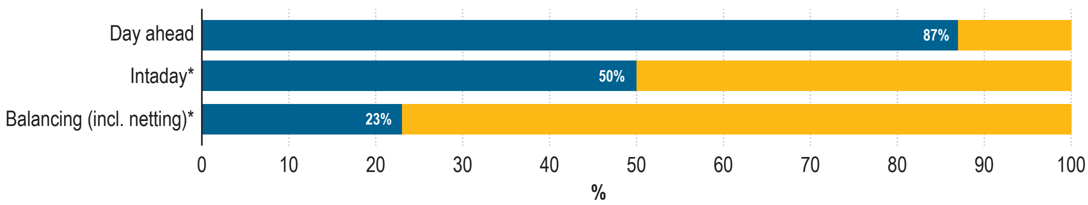
16 A relevant part of these benefits will be delivered when the borders between Switzerland and the EU are coupled. However, this does not appear to be possible until the conditions envisaged in the CACM Regulation are met: the implementation of the main provisions of Union electricity market legislation in the Swiss national law and the conclusion of an intergovernmental agreement on electricity cooperation between the Union and Switzerland.

17 As illustrated in Figure v, compared to the DA timeframe, the level of efficiency in the utilisation of cross-zonal capacity in the intraday (ID) timeframe remains low (around 50%), which leaves a large part of the potential benefits from the use of existing infrastructure untapped across Europe.

18 **A crucial step towards the more efficient and sustainable use of available capacities across Europe was taken on 12 June 2018 with the go-live of the single intraday coupling (SIDC), one of the key elements of market design envisaged in the CACM Regulation. The SIDC still needs to cover the whole of Europe[7] and to be complemented with a system to price ID capacity, in line with the Agency's decision on the matter[8].**

19 The additional welfare benefits from the more efficient use of ID cross-zonal capacity across Europe are estimated at more than 50 million euros per year.

Figure v: Level of efficiency in the use of interconnectors in Europe in the different timeframes (% use of available commercial capacity in the 'right economic direction') – 2018




*Source: ACER calculations based on NRAs, ENTSO-E and Vulcanus data.*

*Note: For the purpose of this figure, efficient use is defined as the percentage of available Net Transfer Capacity (NTC) used in the 'right economic direction' in the presence of a significant (>1 euro/MWh) price differential. Intraday and balancing values (*) are based on a selection of EU borders.*

20 With regard to the balancing timeframe, **the effective application of imbalance netting and exchange of balancing energy is estimated at approximately 23% of their potential in 2018** for a selection of 13 borders where sufficient information was available. Although this value indicates a slight improvement (one percentage point) compared to 2017, it is **still relatively low when compared to the level of efficiency recorded in the DA and ID timeframes in 2018.**

21 **The consolidation of the existing initiatives, together with the upcoming go-live of various platforms aiming to exchange balancing services across Europe, is expected to improve the efficient use of cross-zonal capacity in the balancing timeframe.** The expected benefits from efficient imbalance netting and the exchange of balancing energy for the whole of Europe is as high as 1.3 billion euros annually, which confirms the importance of rapidly and effectively implementing the Regulation establishing an Electricity Balancing Guideline.

## Capacity mechanisms and adequacy assessments

22 **A variety of uncoordinated CMs remained in operation throughout Europe in 2018.** A relevant change compared to 2017 relates to the European Commission's approval in February 2018 of six electricity CMs, adopting different structures, to ensure security of supply in Belgium, France, Germany, Greece, Italy and Poland. Moreover, in 2018, Lithuania initiated the process of introducing a new market-based CM with a view to replace strategic reserves and aiming for the legal acts introducing the new mechanism to be operational by the end of 2020.

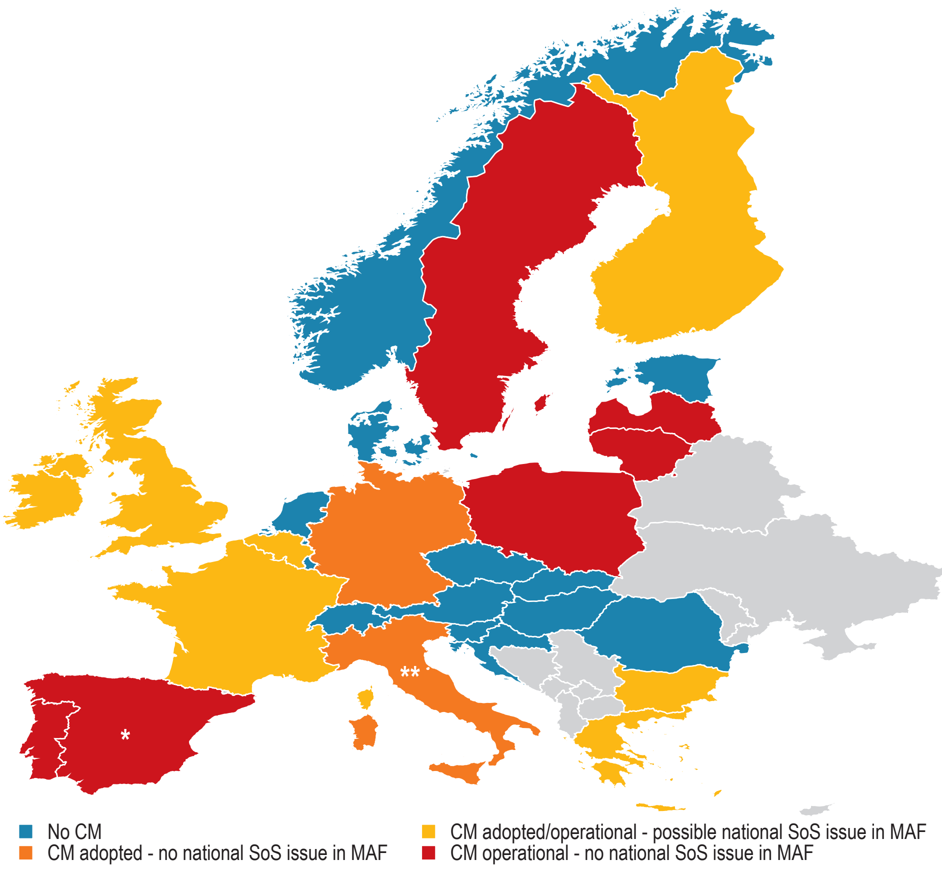
7 The second phase of SIDC, currently covering 14 countries, is expected to include 7 more countries (Bulgaria, Croatia, Czech Republic, Hungary, Poland, Romania and Slovenia) in the so-called "second wave" which is envisaged to go live within 2019.

8 See the Agency's decision of 24 January 2019 establishing a single methodology for pricing ID cross-zonal capacity, available at https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions/ACER%20Decision%2001-2019%20on%20intraday%20cross-zonal%20capacity%20pricing%20methodology.pdf.

23 **In 2018, the overall cost of CMs across the EU reached 2.5 billion euros**, which constitutes a 7% decrease compared to 2017. **Nevertheless, costs are expected to be higher in 2019 and beyond**, based on the available forecasts and the fact that CMs will become operational in various MSs in 2019 and 2020. The substitution of administratively-set capacity payments with competitive schemes, e.g. following the provisions of the Guidelines on state aid for environmental protection and energy 2014–2020, led to significant overall cost reductions in 2018 in Ireland and Northern Ireland. However, capacity payments still account for a large share of total energy costs in this jurisdiction. Costs also remain significant in other MSs, such as Lithuania, Greece, Great Britain, France, Spain and Bulgaria.

24 The increasing impact of CMs on consumers' bills is particularly concerning in the light of the conclusions that can be derived from the ENTSO-E's 2018 Mid-term Adequacy Forecast (MAF 2018). **In fact, according to the MAF 2018 results for the base-case scenario, seven MSs that have introduced or are planning to introduce a CM, i.e. Germany, Latvia, Lithuania, Poland, Portugal, Spain and Sweden, do not seem to face an adequacy problem in either 2020 or 2025. In Italy, the MAF results indicate that adequacy issues may arise at the BZ level rather than at the country level.** This is presented in Figure vi, which illustrates both the national situation with regard to CMs and whether possible adequacy concerns may arise in each MS based on the MAF.

Figure vi: Perceived need for CMs based on the MAF 2018 results




*Source: ACER.*

*Note: In Spain (*), the CM used to comprise "investment incentives" and "availability payments". The availability payments were removed in June 2018 and the investment incentives apply only to generation capacity installed before 2016. In Italy (**) the analysis suggests potential adequacy issues at the bidding zone level, in Italy-Centre-North and Italy-Sicily, rather than at the national level.*

25 While MSs have a legitimate interest to safeguard security of supply in their countries at all times, the need for a more efficient and pan-European approach to the adequacy issue remains; ensuring adequacy at pan-European level would yield annual benefits of approximately 3 billion euros[9].

9 See e.g. https://ec.europa.eu/energy/sites/ener/files/documents/20130902_energy_integration_benefits.pdf p.89, where the benefits are estimated in the range of 1.5 to 3 billion euros in 2015, and in the range of 3 to 7.5 billion euros by 2030.

26 The CEP introduces several improvements in this area, as it requires, inter alia, that CMs are introduced only where adequacy issues are expected to arise and that justifications are provided in case of discrepancies between the national and the pan-European adequacy studies.

# Recommendations

27 **Electricity markets continue to face unprecedented challenges as they adapt to meet global decarbonisation targets, while safeguarding security of supply and ensuring affordability.** Moreover, the market integration process is at a critical point due to the adoption of new EU Regulations (as part of the CEP), while the implementation of all the Regulations establishing Network Codes and Guidelines has not been finalised yet. **Whereas the implementation of the Network Codes and Guidelines remains a key priority,** the Agency is well aware that **the CEP will become the reference framework for the functioning of the European electricity markets in the upcoming years.**

28 The Agency is strongly convinced that implementing the policy recommendations proposed in this Volume would also help to address both existing and emerging challenges, with the ultimate goal of ensuring a well-functioning internal electricity market.

29 These **recommendations are grouped into three distinct categories:**

**(1) recommendations on how to increase the limited amount of cross-zonal capacity made available for trading throughout Europe, without which any electricity market integration project is severely hampered;**

**(2) recommendations on how to use the cross-zonal capacity made available for trading more efficiently in the different trading timeframes; and**

**(3) recommendations on how to address adequacy concerns in an efficient manner.**

30 The first group of recommendations is aimed at increasing the amount of cross-zonal capacity made available for trading, which is currently one of the most significant factors limiting the integration of electricity markets throughout Europe. This requires ensuring that congestions are efficiently addressed by the existing bidding zone configuration and the equal treatment of intra-zonal and cross-zonal exchanges.

31 In particular, **the Agency recommends that the CCMs be amended as soon as possible in order to take into account the requirements of the CEP, which introduced minimum levels of capacity to be made available for cross-zonal trade by 1 January 2020,** and with a view to a possible harmonised approach by 31 December 2020 (pursuant to Article 21(4) of the CACM Regulation). **When amending the CCMs, the Agency recommends that TSOs and national regulatory authorities (NRAs) take utmost account of the following aspects:**

a) **The best practices identified in other CCMs.**

b) **The need further to elaborate the CCMs in order to avoid undue discrimination of cross-zonal exchanges** (which should not be limited to the minimum cross-zonal capacity target). In particular, internal network elements should not be allowed to constrain cross-zonal capacity unless it can be proven that this is more cost-efficient than addressing congestions on the concerned internal network element through other means (such as remedial actions or a reconfiguration of bidding zones).

c) **The need to guarantee effective transparency of the CCMs**, including on their inputs and outputs; More specifically, **the Agency expects TSOs to enhance their processes to collect the data required for the effective monitoring by NRAs and the Agency of the achievement of the 70% target from 2020 onwards.** Significant improvements are expected from all TSOs applying NTC-based capacity calculation methods, and in particular from those TSOs which could not be covered in this year's MMR due to insufficient data quality.

d) **The need to clearly assign responsibilities to the concerned parties ahead of the implementation of the methodologies.**

e) **The need to specify that TSOs should, as much as possible, avoid delaying the offering of 'large'[10] cross-zonal capacity after the DA timeframe.**

32 Moreover, **the Agency recommends the rapid adoption and implementation of regional methodologies for coordination of remedial actions (and related cost-sharing)** according to the CACM and System Operation (SO) Regulations[11], and taking into account the Regulation (EU) 2019/943[12] on the internal market for electricity, to facilitate that cross-border capacities are maximised, as required by the latter Regulations.

33 Finally, in order **to ensure that congestions are efficiently addressed, the Agency recommends that a bidding zone review be performed in line with the CEP.** This includes:

a) **TSOs defining a robust methodology that allows bidding zone configuration(s) to be ranked rigorously and unambiguously** according to welfare benefits (or losses) that each of them would deliver compared to the status-quo configuration.

b) **The TSOs proposing a sufficient number of alternative bidding zone configurations** covering most of Europe as recommended in the latest 'market report' on the efficiency of the current bidding zone configuration[13]. The alternative bidding zone configurations should be defined **with a view to address structural congestions and maximise economic efficiency**.

c) The alignment of the alternative bidding zone configurations to be considered with the objectives set by the CEP for the bidding zone review process. In particular, **given the persistence of structural congestions and the limited level of cross-zonal capacity in most of Europe, the focus should be mostly on splitting rather than on merging existing bidding zones**.

d) The **compliance with all other rules stipulated in the CEP, in particular those referring to the time horizon for the inclusion of future network investments, which should be three years**.

e) **The involvement of stakeholders, in particular during the bidding zone review study**.

34 The second group of recommendations is aimed at ensuring that the cross-zonal capacity made available for trading is used efficiently in the different market timeframes. For this, the Agency reiterates the need for:

a) **NRAs and TSOs urgently to finalise the implementation of single day-ahead coupling (SDAC) and single intraday coupling (SIDC)**.

b) **TSOs to urgently finalise the implementation of the common grid model (CGM) methodologies** as required by the CACM, Forward Capacity Allocation (FCA) and SO Regulations, which are necessary to increase the level of TSOs' coordination in capacity calculation and system operation.

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10 'Large' capacity in the day-ahead timeframe refers to the relevance of fulfilling the capacity target set by the CEP as much as possible in the day-ahead timeframe rather than in the intraday timeframe. If the minimum target for cross-zonal capacity set by the CEP (or the general requirement to maximise cross-zonal capacity) is fulfilled in different timeframes by TSOs (e.g. in the intraday timeframe by some TSOs while others maximise day-ahead capacity), there is a risk that cross-zonal capacity is not simultaneously available in any of these timeframes and therefore is never effectively used. For more details see Section 4.3 and Annex III of the Agency's Recommendation No 01/2019 on the implementation of the minimum margin available for cross-zonal trade pursuant to Article 16(8) of Regulation (EU) 2019/943, available at https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Recommendations/ACER%20Recommendation%2001-2019.pdf.

11 Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation, available at https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32017R1485&from=EN.

12 Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 available at: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019R0943&from=EN.

13 See footnote 4.

c) **A full, effective and rapid implementation of the Regulation establishing an Electricity Balancing Guideline**.

d) **The implementation of pan-European ID auctions for pricing capacity** in line with the Agency's decision on the matter[14].

35 The third group of recommendations is aimed at addressing adequacy concerns in an efficient manner. In this respect, the Agency recommends the following measures, in line with the CEP:

a) **The definition of a robust methodology for assessing resource adequacy at the European level, which shall properly take the contribution of, *inter alia*, interconnectors and demand response into account**.

b) **CMs shall only be adopted (or maintained) where resource adequacy issues are forecasted pursuant to national or European adequacy assessments. Discrepancies between national and European assessment** shall be justified and (if these discrepancies are frequent) they **should trigger improvements in the European or national resource adequacy assessment methodologies or both**.

c) **Before implementing a CM, MSs should exhaust all possible measures to eliminate distortions contributing to the identified resource adequacy concern.** These measures include: removing price caps (or setting them at levels that reflect the value of lost load); ensuring the equal treatment of all generation technologies regarding balance responsibility; enabling, supporting and increasing demand-side participation; removing undue limitations on cross-zonal trade; and removing any other barrier to efficient price formation in wholesale electricity markets.

d) **CMs should as much as possible avoid distorting energy markets** (for example with respect to the ability of energy prices to reflect actual scarcity), and should allow wide cross-border participation.

36 As final recommendation, **the Agency emphasises the need for additional efforts to improve the quality of the data provided to the Agency, in particular of the data that is publicly available through e.g. the ENTSO-E Transparency Platform**.

14 See Footnote 8.

# 1. Introduction

37 The Market Monitoring Report (MMR), in its eighth edition, consists of four volumes, respectively on: Electricity Wholesale Markets, Gas Wholesale Markets, Electricity and Gas Retail Markets, and Consumer Protection and Empowerment.

38 The goal of the Electricity Wholesale Markets volume is to present the results of the monitoring of the performance of the internal market for electricity (IEM) in the European Union[15] (EU), which largely depends on how efficiently the European electricity network is used and on how the wholesale markets perform in all timeframes. When electricity wholesale markets are integrated via an optimal amount of interconnector capacity and such capacity is efficiently used, competition will benefit all consumers and will contribute to ensure long-term security of supply (SoS) at a lower cost.

39 The Regulation establishing a Guideline on Capacity Allocation and Congestion Management (CACM)[16] provides clear objectives to deliver an integrated IEM in the following areas: (i) full coordination and optimisation of cross-zonal capacity calculations performed by Transmission System Operators (TSOs) within regions; (ii) definition of appropriate bidding zones, including regular monitoring and reviewing of the efficiency of the bidding zone configuration; (iii) use of Flow-Based (FB) capacity calculation methods in highly meshed networks and (iv) efficient allocation of cross-zonal capacity in the Day-ahead (DA) and Intraday (ID) timeframes. These processes are intended to optimise the utilisation of the existing infrastructure and to provide more possibilities to exchange energy, enabling the cheapest supply to meet demand with the greatest willingness to pay in Europe, given the capacity of the network.

40 The Regulations establishing Guidelines on Forward Capacity Allocation (FCA)[17] and on Electricity Balancing (EB)[18] also play a crucial role in the further integration of the IEM. The former establishes a framework for calculating and efficiently allocating interconnection capacity and for cross-zonal trading in forward markets, while the latter sets rules on the operation of balancing markets with the aim to increase the opportunities for cross-zonal trading and efficiency close to real time.

41 The implementation of the provisions included in the above mentioned Regulations is currently ongoing. First, long-term harmonised allocation rules have been in place since January 2018, while the EU single allocation platform was launched in October 2018[19]. Second, there has been significant progress towards the full implementation of the Single Day- Ahead Market Coupling, however some issues are still pending, in particular the implementation of Flow-Based Market Coupling (FBMC) for the whole Core region, the incorporation of MSs with markets that are not yet coupled and the integration of the various market coupling projects that still coexist in Europe[20]. Third, the second phase of Single Intraday Coupling (SIDC), currently covering 14 countries, is expected to include 7 more countries (Bulgaria, Croatia, the Czech Republic, Hungary, Poland, Romania and

15 The Norwegian and Swiss markets are also analysed in several chapters of this report, but for simplicity, the scope of the analysis is referred to as 'the EU' or 'Europe'. Norway enforces most of the EU energy legislation, including legislation on the internal energy market, and is included in the data reported in several sections of this report. Switzerland has been included in some parts of the wholesale sections on the basis of a voluntary commitment of the NRA. Consequently, the terms 'countries' and 'EU Member States (MSs)' are used interchangeably throughout this report, depending on whether the particular section/graph also covers Norway and/or Switzerland or not. Several maps included in this report show Kosovo. In this context the following statement applies: "This designation is without prejudice to positions on status, and is in line with UNSCR 1244 and the ICJ Advisory Opinion on the Kosovo declaration of independence".

16 Commission Regulation (EU) 2015/1222 of 24 July 2015, available at: http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32015R1222&from=EN.

17 Commission Regulation (EU) 2016/1719 of 26 September 2016, available at: http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32016R1719&from=EN.

18 Commission Regulation (EU) 2017/2195 of 23 November 2017, available at: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32017R2195&from=EN.

19 For more information, see https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/FCA_CACM_Implementation_Monitoring_Report_2019.pdf.

20 Two market coupling regions still coexist, the 4M Market Coupling (4MMC) region covering the Czech Republic, Slovakia, Hungary and Romania, and the Multi-Regional Coupling (MRC) region covering, for the time being, the following 21 countries: Austria, Belgium, Croatia, Germany, Denmark, Estonia, Finland, France, United Kingdom, Ireland, Italy, Lithuania, Latvia, Luxembourg, the Netherlands, Norway, Poland, Portugal, Spain, Slovenia and Sweden.

Slovenia) in the so-called "second wave" which is envisaged to go live within 2019[21]. Developments regarding the exchange of balancing energy and reserves, the definition of the relevant terms and conditions or methodologies and the implementation of relevant initiatives are also underway.

42 The adoption of the Clean Energy for All Europeans[22] Package (Clean Energy Package, CEP) legislation in June 2019 initiated a period of significant changes fostering the creation of smarter and more efficient electricity markets[23]. The CEP defines an enhanced framework for a well-functioning, integrated market with non-discriminatory participation of all available sources, providing appropriate and affordable SoS while enabling innovation and decarbonisation in line with the EU energy and climate objectives.

43 Moreover, under the new framework, the European Union Agency for the Cooperation of Energy Regulators ('the Agency' or 'ACER') has an enhanced role in the development, monitoring and surveillance of energy markets, as well as in the area of SoS. ACER's competences are adapted to the new challenges faced by the electricity sector, for example in the context of increased regional cooperation. While the implementation of the provisions included in the above mentioned regulations remains a key priority for the Agency, the Agency is well aware that the CEP will become the reference framework for the functioning of the European electricity markets in the upcoming years, as explained above.

44 In fact, this volume includes a number of novelties, partly to reflect some of the provisions introduced by the CEP. First, following the requirement of a minimum available capacity for cross zonal trade, the Agency has adapted its methodology to monitor the amount of cross-zonal capacity, which will be, from now on, compared to the minimum target set in legislation (see Sub-section 3.1.2). Second, a thorough assessment of the currently approved Capacity Calculation Methodologies (CCM) is presented in Section 3.2. It aims to identify improvements, which could help to meet the minimum target set for cross-zonal capacity. Third, a preliminary assessment of the consistency between the implementation of Capacity Mechanisms (CMs) to address SoS concerns and the existence of adequacy issues in MSs is included in Chapter 5.

45 However, some assessments included in the previous MMRs[24] (such as on intraday or forward markets liquidity) have been temporarily discontinued for this year's MMR. This is due to the priority given to the above mentioned topics related to CEP, together with the limited resources of the Agency which are largely devoted to the approval (and often amendment) of an increasing number of methodologies required by the CACM, FCA and Balancing Guidelines, which falls onto the Agency when the National Regulatory Authorities (NRAs) fail unanimously to agree[25].

46 As a result, this year's Electricity Wholesale Markets volume is organised as follows[26]. Chapter 2 presents the key developments in electricity wholesale markets across Europe in 2018. Chapter 3 assesses the level of cross-zonal capacities made available for trade, the performance of the capacity calculation processes and evaluates the quality of the CCMs approved pursuant to the CACM Regulation. Chapter 4 presents an analysis of the efficient use of cross-zonal capacity across the DA, ID and balancing timeframes. Finally, a presentation of the CMs operating or planned in the EU, along with the above mentioned preliminary analysis of the necessity of CMs, is included in Chapter 5.

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21 In June 2019, the preparation and testing for a 2nd wave go-live was underway and expected to be launched towards the end of 2019. See, https://www.entsoe.eu/news/2019/06/12/press-release-xbid-1st-anniversary-and-announcement-of-2nd-wave-go-live/.

22 The Commission's Clean Energy for All Europeans legislative proposal covered energy efficiency, RES generation, the design of the electricity market, security of electricity supply and governance rules for the Energy Union. Relevant material along with the adopted directives and legislation are available at: https://ec.europa.eu/energy/en/topics/energy-strategy-and-energy-union/clean-energy-all-europeans.

23 See for example the main legislative documents on the electricity markets here: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=OJ:L:2019:158:TOC.

24 See previous editions of the MMR at https://www.acer.europa.eu/en/Electricity/Market%20monitoring/Pages/Current-Edition.aspx. This reference applies to all mentions of the MMR in this annex.

25 In addition to the preparatory work for the approval of relevant pan-European methodologies, as envisaged in the CEP.

26 To facilitate the reading of the document, the most relevant monitoring methodologies used across this Volume have been compiled into a set of 'methodological papers', which are cross-referenced in the relevant chapters where those methodologies are applied. These are available at: https://www.acer.europa.eu/en/Electricity/Market%20monitoring/Pages/Methodologies.aspx.

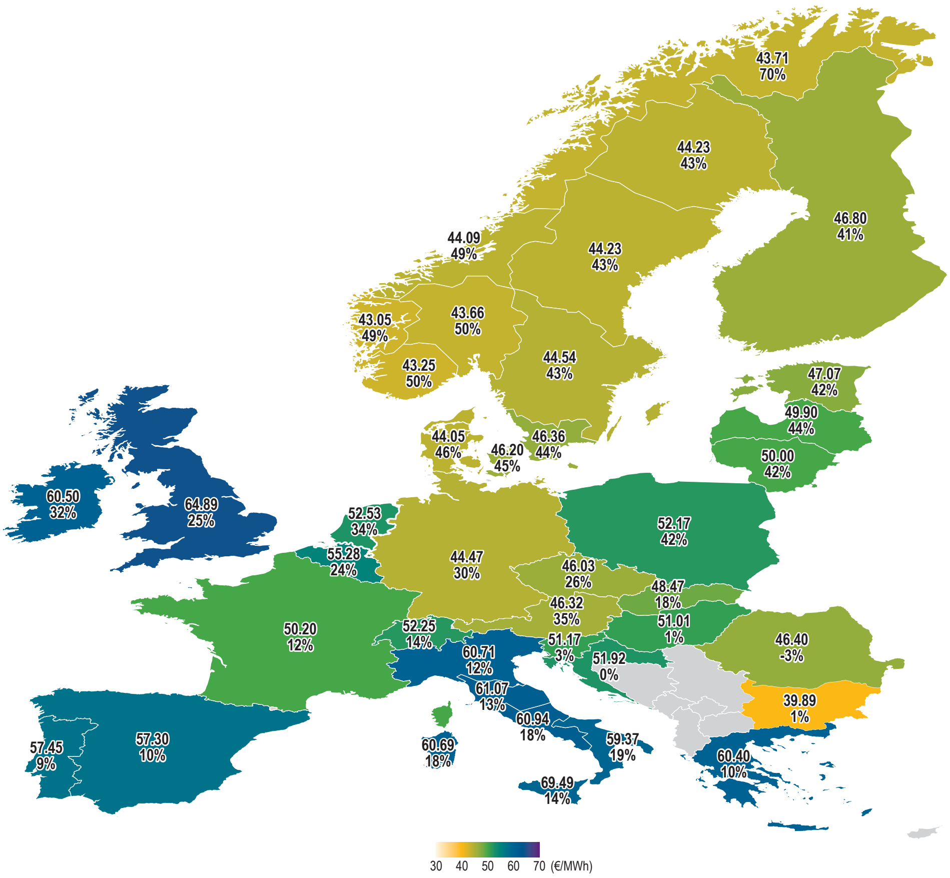
# 2. Key developments in 2018

47 This Chapter reports on the evolution of prices in European electricity wholesale markets in 2018 (Section 2.1) and the level of price convergence within European market coupling regions (Section 2.2).

## 2.1 Evolution of prices

48 Figure 1 shows the average DA electricity prices in 2018 in all European bidding zones, as well as the relative price change compared to 2017. In 2018, the highest annual average DA prices were observed in the British, Italian, Irish (Single Energy Market, SEM[27]), Greek and Iberian markets, whereas the lowest annual average DA prices were recorded in the Bulgarian, Nordic and German markets. Compared to 2017, average DA prices increased in all bidding zones, except Romania.

Figure 1: Average annual DA electricity prices and relative change compared to the previous year in European bidding zones – 2018 (euros/MWh and %)




*Source: ACER calculations based on the ENTSO-E's TP data.*

*Note: Due to the split of the German-Austrian-Luxembourg bidding-zone which took place on 1 October 2018, the joint DA price was used prior to this date in order to calculate the annual DA prices of the two new bidding zones (i.e. Germany/Luxembourg and Austria).*

49 On the demand side of the market, the main explanatory factor for the overall increase in DA prices in 2018 seems to be economic growth. In 2018, the Gross Domestic Product[28] (GDP) in the EU grew by 1.9% compared to the previous year.

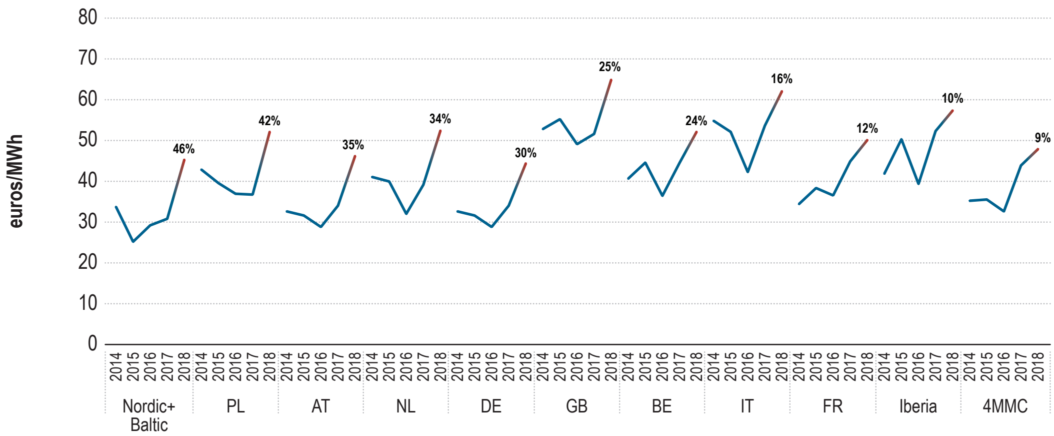
27 SEM refers to the common Irish electricity market (Northern Ireland and Ireland).

28 In the absence of electricity demand data for 2018, the EU's GDP development provides an indication of electricity demand trends. For more information on GDP growth rates, see: https://ec.europa.eu/eurostat/documents/2995521/9573370/2-14022019-AP-EN.pdf/74195ad7-ce17-4c2f-b86c-c990c938bf30. (data source: Eurostat: nama_10_gdp).

50 On the supply side of the market, the share of Renewable Energy Sources (RES) in the electricity generation mix increased by two percentage points on an annual basis[29]. However, their downward impact on DA prices was more than offset by the significant increase of the costs associated with fossil fuel electricity generation. In particular, coal, gas and CO2 European Emission Allowance (EEA) prices climbed by 4%, 32% and 170%, respectively[30].

51 Figure 2 shows the annual average DA price evolution between 2014 and 2018 for a selection of European markets. The increasing prices in 2017 and 2018 seem to break the five-year downwards price trend, observed between 2011 and 2016[31]. On a year-to-year basis, the 2018 prices in the Nordic and Baltic regions and Poland increased by over 40%, showing the highest rate recorded in the EU since 2011.

Figure 2: Evolution of annual DA electricity prices in a selection of European markets – 2014–2018 (euros/MWh)




*Source: ACER calculations based on the ENTSO-E's TP data.*

*Note: The DA price for the "Nordic+Baltic", "Iberia" and "4MMC" regions, which is the market coupling in the Czech Republic, Slovakia, Hungary and Romania, is the average of the DA prices of the involved bidding zones. Due to the split of the German-Austrian-Luxembourg bidding-zone which took place in 2018 (1 October), the joint DA price was used prior to this date in order to calculate the annual DA prices of the two new bidding zones (i.e. Germany/Luxembourg and Austria).*

52 In addition to the general price drivers described in paragraphs (49) and (50), regional or national drivers also affected the formation of the 2018 DA price.

53 For example, in Belgium, the extended nuclear outages[32] during the second half of 2018 pushed the DA prices upwards. The outages resulted in a 50% decrease of infeed from nuclear power plants and implied an increase of electricity production from gas-fired generation, combined with a large increase of imports (mainly from France).

54 Romania was the only market that displayed a lower average annual DA price compared to 2017. However, if the particularly high prices of January 2017 are not taken into account, DA prices show a similar increase in 2018 as in the rest of Europe[33].

29 2017 and 2018 ENTSO-E's statistical factsheets, see https://www.entsoe.eu/publications/statistics-and-data/.

30 Source: PLATTS. The Dutch Title Transfer Facility (TTF) DA prices for natural gas, the Thermal Coal CIF ARA 6000 kcal/kg index for coal and the EEA DA prices for CO2 emissions allowances were used.

31 See Chapter 2 of the Electricity Wholesale Markets volume of the 2017 MMR.

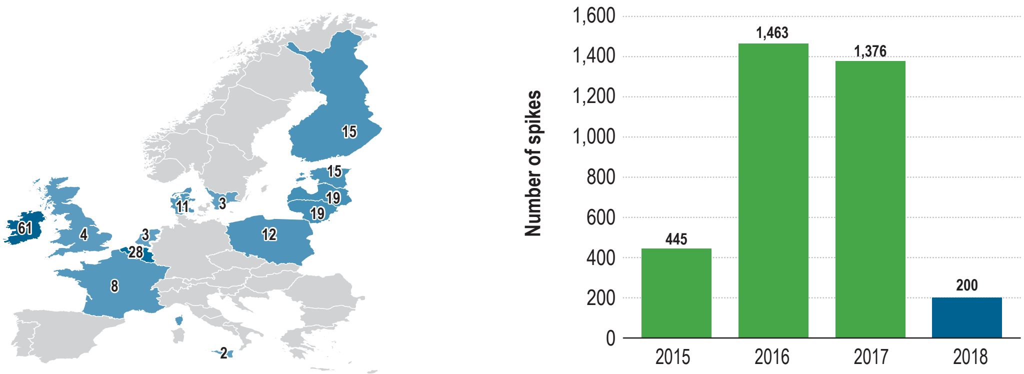
32 Source: ENTSO-E Transparency Platform. These outages also affected the prices in neighbouring bidding-zones.

33 This is actually valid for most bidding zones, however the magnitude of this early month effect differs among bidding-zones.

55 Figure 3 (right) shows that the number of price spikes significantly decreased in 2018 compared to the previous two years[34]. The largest share of these spikes (31%) occurred in Ireland (SEM, 61 occurrences[35]) and Belgium (28 occurrences). Moreover, in contrast to the previous two years, the 2018 price spikes did not show a strong concentration during summer and winter months.

56 The significant drop of the number of DA price spikes across the EU may be the result of mild weather conditions in most MSs in 2018. This factor likely played a key role in smoothing the load and therefore diminishing the frequency of scarcity. Future situations of scarcity are likely to result in the reappearance of more frequent price spikes, as seen in recent years in Europe. As highlighted in previous MMRs, the occurrence of such price spikes is necessary to allow generators to cover their fixed costs.

Figure 3: Evolution of the number of occurrences of DA price spikes (right side) – 2015–2018 (number of occurrences) and the distribution of these occurrences per bidding zone (left side) – 2018 (total number of price spikes)




*Source: ACER calculations based on the ENTSO-E's TP and PLATTS data.*

*Note: For the calculation of the DA price spikes, the virtual bidding zones of Italy have been excluded from the calculation. Furthermore, due to data availability in all bidding zones this year, the total numbers of price spikes which refer to previous years (2015–2017) are also updated.*

57 Another development observed in Europe in recent years is the increasing occurrence of negative prices in DA markets, which is shown in Figure 4. These occurrences normally take place at times of i) high RES feed-in in combination with low demand and ii) the presence of inflexible non-RES generators that are willing to pay for continue to produce[36] rather than to interrupt their production for a short time, as the latter ends up being more costly.

58 In fact, the increasing number of negative prices is related to the increasing penetration of intermittent RES, in particular in the German market (including Austria before its split), as long as part of these generators are still subsidised with payments that do not depend on the instantaneous needs of the system[37]. Furthermore, the presence of negative prices emphasises the need for more flexible resources in the system, including demand response.

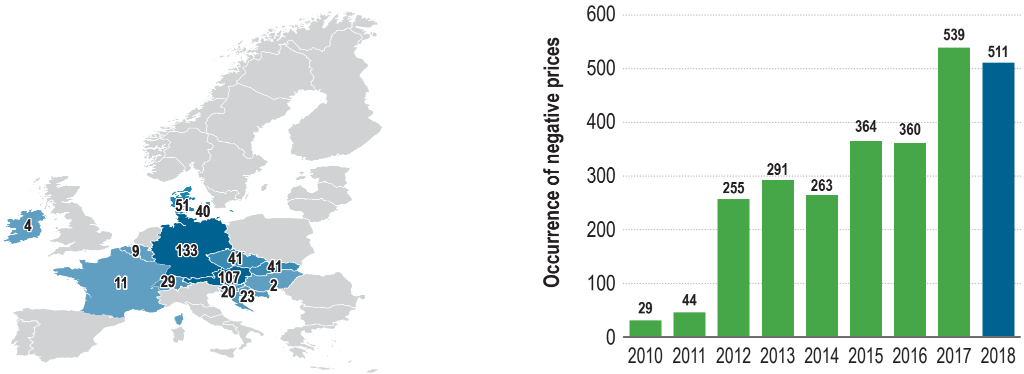
34 Consistently with the previous edition of the MMR, a price spike is defined as an hourly DA price that is three times above the theoretical variable cost of generating electricity with gas-fired power plants, based on the TTF DA gas prices. See more details in footnote 12 of the Electricity Wholesale Markets volume of the 2015 MMR.

35 For most of 2018, the SEM design included an uplift algorithm in pricing, whereby the start-up and no-load costs of generator are recovered in a small subset of hours, was in place. This explains price spikes to some extent. This market feature changed from 1 October 2018 when revised SEM arrangements came into effect, along with market coupling.

36 Depending on the specific national rules to integrate RES in wholesale markets, some subsidised RES generators could also be interested in paying a certain amount of money for producing, as long as this amount is lower than the subsidy.

37 According to the Guidelines on State aid for environmental protection and energy 2014–2020, from January 2016 onwards aid granted to energy produced from renewable sources should be market based, RES beneficiaries shall be subject to standard balancing responsibilities unless no liquid intra-day markets exist, and measures shall be taken to ensure that RES generators have no incentive to generate electricity under negative prices.

Figure 4: Evolution of the number of occurrences of negative DA prices (right side) – 2010–2018 (number of occurrences) and the distribution of these occurrences per bidding zone (left side) – 2018 (number of occurrences)

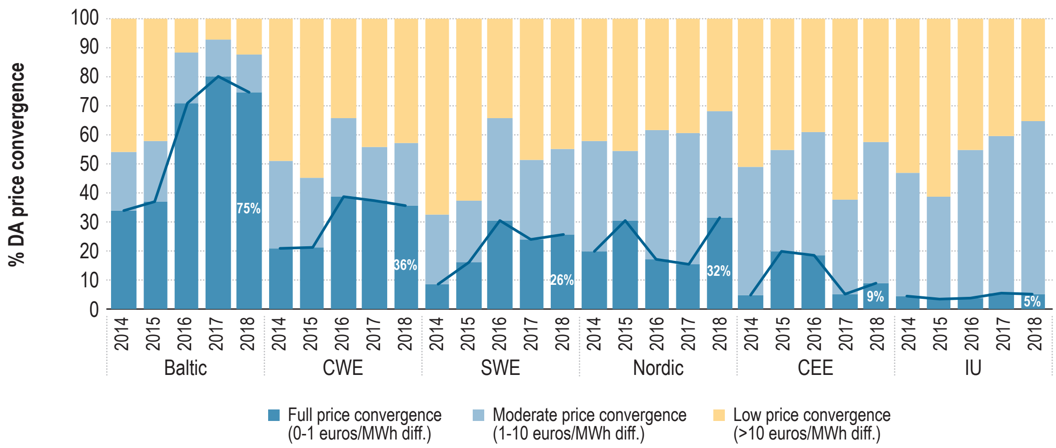



*Source: ACER calculations based on the ENTSO-E's TP data.*

## 2.2 Price convergence

59 The price convergence in DA markets provides an indication of the level of electricity market integration. For instance, price convergence is expected to increase following the introduction of market coupling, the expansion of the existing infrastructure, or an increase in commercial cross-zonal capacity. As year-on-year changes may also be caused by market fundamentals, which are not necessarily related to market integration, price convergence should be analysed over a period of a few years. Figure 5 provides an overview of price convergence[38] within the European regions[39] between 2014 and 2018.

Figure 5: DA price convergence in Europe – 2014–2018 (% of hours)




*Source: ACER calculations based on the ENTSO-E's TP data.*

60 The highest level of price convergence took place in the Baltic region, where full price convergence was recorded 75% of the hours, despite a drop of 6 percentage points compared to 2017, partly explained by the reduction of the cross-zonal capacities during September-October.

38 Information on price convergence on per border basis is included in Table 1 in Annex 1.

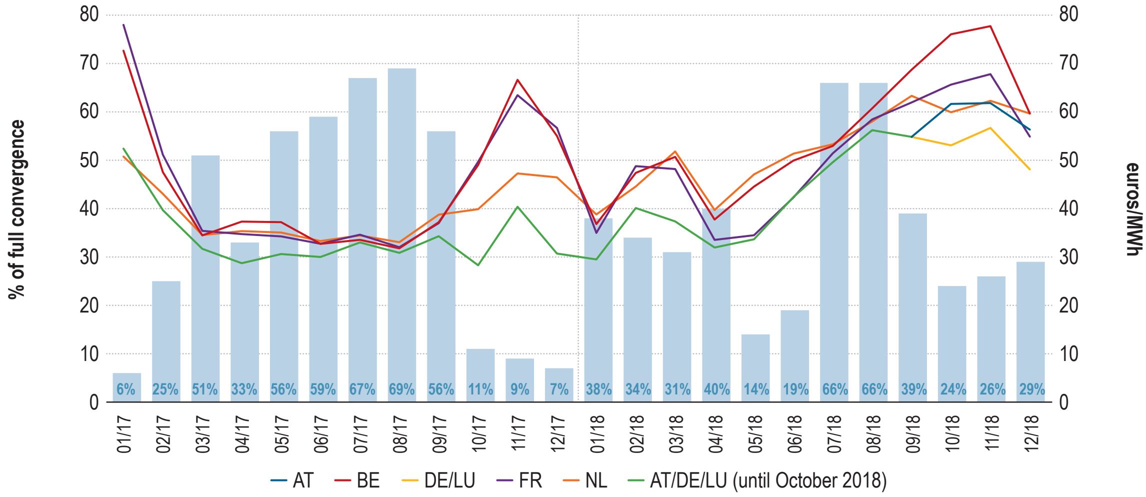
39 For the purpose of this analysis, bidding zones are grouped into regions, in consistency with the results presented in previous MMRs:
- Baltics region: Estonia, Latvia and Lithuania;
- Central-East Europe (CEE): the Czech Republic, Hungary, Poland and Slovakia;
- Central West Europe (CWE): Austria, Belgium, France, Germany/Luxembourg and the Netherlands;
- IU region: Republic of Ireland and United Kingdom;
- Nordic region: Denmark, Finland, Norway and Sweden;
- South-West Europe (SWE): France, Portugal and Spain.

61 Figure 5 also shows a substantial increase in full price convergence in the Nordic region, reaching 32%, compared to 16% in 2017[40] and returning to its pre-2016 levels. This change could partly be attributed to the increase of cross-zonal capacity on Norwegian bidding-zone borders[41] by more than 10% compared to 2017 as well as to lower hydro-reserves that tends to increase price convergence in the region.

62 Finally, in the CWE region, which is the only one where FBMC has been applied since 2015, the number of occurrences of full price convergence slightly decreased in 2018 (36% vs. 37% in 2017). This reduction can be partly explained by the prolonged nuclear outage in Belgium[42] as well as by the split between German/Luxemburg and the Austrian bidding zones (October 2018), which resulted in additional price spreads in the region, as seen in Figure 6.

63 Overall, price convergence remains low in most of the regions, as it is limited by the amount of offered cross-zonal capacity, by the lack of market coupling, or both. The expected improvements in the capacity calculation methodologies (CCMs) and the application of the cross-zonal capacity targets set by Regulation (EU) 2019/943 on the internal market for electricity[43] (hereafter referred to as 'the recast Electricity Regulation'), together with the completion of market coupling, are expected to increase price convergence within all EU regions. For example, price convergence is expected to increase in the IU region following the implementation of market coupling between Great Britain and the SEM in October 2018.

Figure 6: Monthly DA prices and frequency of full price convergence in the Core (CWE) region – 2017–2018 (euros/MWh and % of hours)




*Source: ACER calculations based on the ENTSO-E's TP data.*

40 Increased price convergence coincided with higher average DA prices in all Nordic markets (see Figure 2).

41 Mainly on the NO1 > SE3 bidding-zone border, see Figure 8 on change of Net Transfer Capacities (NTCs).

42 Due to nuclear unavailability, see paragraph (53).

43 Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 available at: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019R0943&from=EN.

# 3. Available cross-zonal capacity

64 The optimal provision of cross-zonal capacity is an essential prerequisite for a well-integrated and efficient IEM. This Chapter first provides an overview of the levels of cross-zonal capacity available for trade (tradable capacity)[44] in Europe, including an estimate of the percentage of physical capacity available for cross-zonal trade (Section 3.1). Second, it assesses the reasons for the large gap between physical and tradable capacity on most European borders (Section 3.2). This Section also studies the CCMs approved pursuant to the CACM Regulation, which provides an indication on whether those methodologies will ensure an optimal provision of cross-zonal capacity and will avoid the discrimination of cross-zonal exchanges in the near future.

## 3.1 Amount of cross-zonal capacities made available to the market

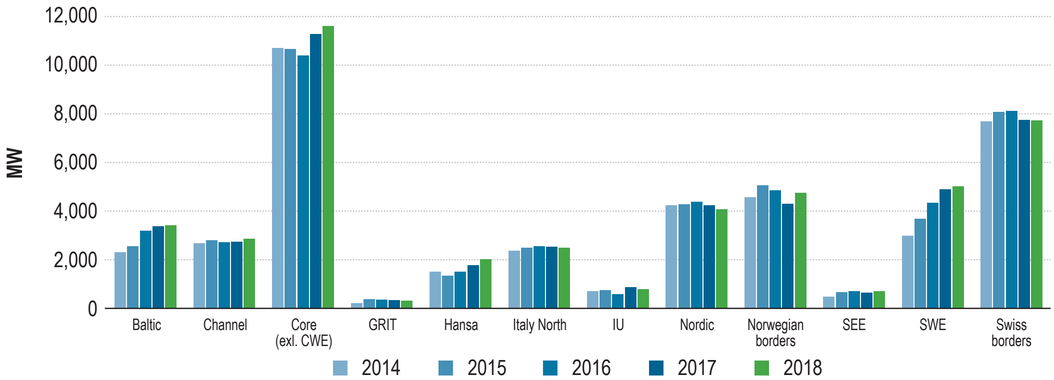
65 First, this Section assesses the amount of cross-zonal capacity made available to the market in 2018 compared to 2017 (Sub-section 3.1.1). Furthermore, it estimates the margin made available for cross-zonal trade on critical network elements, and compares it to the physical capacity of these elements, in line with Article 16(8) of the recast Electricity Regulation (Sub-section 3.1.2).

### 3.1.1 Evolution of commercial cross-zonal capacity

66 Figure 7 presents the average cross-zonal DA NTC values per Capacity Calculation Region (CCR)[45] from 2014 to 2018. The aim of the figure is to identify trends within regions rather than comparing absolute values across regions as those depend, among other factors, on the number of interconnectors and their thermal capacity.

67 The general increasing trend of the last years continued in 2018, yet with some differences across CCRs. The highest increase occurred in the Hansa region (+14%) followed by the Norwegian borders (+10%), the SEE (+7%) and the Channel (+5%) regions. NTC also increased, but at a smaller pace, in the Core (excl. CWE) (+3%), the SWE (+2%) and the Baltic (+1%) regions while it remained practically unchanged at the Swiss borders. At the same time, a significant reduction was observed in the IU region (-10%) while smaller reductions were also observed in the GRIT (-4%), Nordic (-4%) and Italy North (-2%) CCRs.

Figure 7: NTC averages of both directions on cross-zonal borders, aggregated per CCR – 2014–2018 (MW)




*Source: ACER calculations based on ENTSO-E, NRAs and NordPool data.*

*Note: Only cross-zonal NTC and technical profiles' values are considered in this figure.*

44 Throughout this Volume, tradable cross-zonal capacity is also referred to as commercial cross-zonal capacity, available cross-zonal capacity or, simply, commercial or available capacity.

45 The Core (CWE) region is not included in this graph, as FBMC is applied. Average NTCs are also displayed for the Norwegian and the Swiss borders.

68 Figure 8 shows the major changes in NTCs on selected European borders between 2017 and 2018[46]. The largest increase in absolute terms occurred at the border of Germany/Luxembourg with the Czech Republic[47] (reaching 1,839 MW, up by almost 1,600 MW from 2016). The NTC between Denmark West and Germany/Luxembourg also increased significantly (+96%, more than double the 2016 NTC)[48,49], as did the technical profile[50] between Germany (50 Hertz), the Czech Republic and Poland (+398 MW or +66% from 2017 levels). Significant increases were also observed for the Polish technical profile in the direction from Germany, the Czech Republic and Slovakia to Poland[51] (+68%), and between Norway and Sweden (NO1 and SE3 bidding zones) in both directions (44% and 22%), recovering from last year's reduction due to planned outages[52].

69 To a lesser extent, increases were recorded at the Lithuanian-Polish interconnector (+27%), which was in its third year of operation since its being commissioned in 2015. At the border between Spain and Portugal, the NTC increased by 12%, reaching a 5-year high in both directions. The NTC at the HVDC interconnector between France and Great Britain was 7% higher due to reduced outages (planned or unplanned) compared to 2017[53]. Finally, the overall upward trend at border between Hungary and Slovakia, which started in 2015[54], continued in 2018.

70 At the other end, a significant reduction was observed at the borders between Denmark and Sweden (-17%), partly due to maintenance works during the second quarter of 2018[55]. A similar decrease was observed on the border between the Netherlands and Norway, and was partly attributed to planned and unplanned outages during the second quarter of the year. Significant reductions in average NTC values due to extensive maintenance programmes were also observed on the border between France and Italy, while NTCs on Swiss borders (apart from the border with Austria) generally decreased in 2018 compared to 2017. The reduced capacity on the Swiss borders was due to a combination of factors, including the forced outage of two 380 kV lines on the border with Italy following a storm at the end of October 2018[56] and more frequent than usual (planned and unplanned) maintenance works on the border with France.

46 See Table 2 in Annex 1 for detailed NTC values.

47 Probably due to the commissioning of two new PSTs on the German side by 50Hz in late 2017. See https://www.50hertz.com/en/Grid/Griddevelopement/Interconnectorsandphaseshifters.

48 At the same time, the average NTC in the opposite direction (from DE/LU to DK1 and DK 2) remained stable at an average of 1,863 MW (for the 2016-2018 period). According to the quarterly reports on "Availability of transmission capacity in the Nordics" (see footnote 55) the observed increase, mainly an outcome of a bilateral agreement between Germany and Denmark in 2017, was partially offset by countertrading due to limitation on the German side of the grid. As a matter of fact, the large increase in the DK1->DE/LU border was followed by a smaller, yet significant (-14%), decrease at the border of DE/LU and DK2 in both directions.

49 In March 2018, the European Commission (EC) initiated an investigation into TenneT for limiting cross border capacity in the borders with Denmark that resulted in legally binding commitments on TenneT, including the guarantee of a minimum hourly NTC of 1,300 MW for both directions of the DE/LU-DK1 border from May 2019 onwards. See http://ec.europa.eu/competition/antitrust/cases/dec_docs/40461/40461_462_3.pdf.

50 In general, technical profiles describe simultaneous limits to commercial capacity across a set of bidding-zone borders.

51 The Polish profiles refer to the maximum simultaneous export (or import) commercial capacity to (from) Poland across its borders with the Czech Republic, Germany and Slovakia.

52 See 2017 MMR.

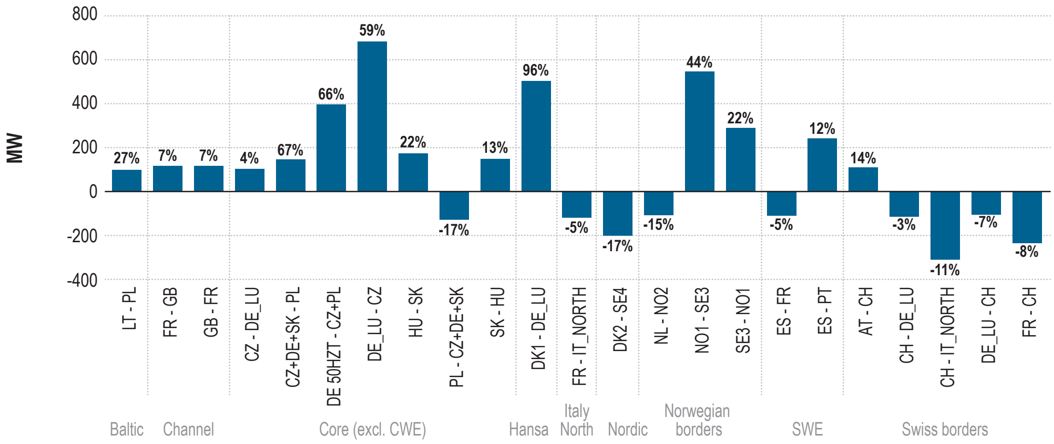
53 According to the annual outage programme http://ifa1interconnector.com/media/1027/outage-programme-2018-v1.pdf and data from ENTSO-E's transparency platform.

54 In 2017 a small decrease (-9 MW or -2%) was observed for HU→SK.

55 See quarterly reports on "Availability of transmission capacity in the Nordics" available at https://www.svk.se/sok/?search-field=transmission+capacity+available+to+the+market.

56 For more information, see https://www.swissgrid.ch/en/home/about-us/newsroom/newsfeed/20181116-01.html.

Figure 8: Changes in tradable capacity (NTC) in Europe (excluding differences lower than 100 MW) – 2017–2018 (MW, %)




*Source: ACER calculations based on ENTSO-E, NRAs and Nord Pool data.*

71 In the Core (CWE) region, NTC values have not been relevant since the launch of the FBMC[57] on 20 May 2015. According to the implementation of capacity calculation methodologies in line with the CACM Regulation, FBMC will be implemented in the whole Core[58] and Nordic[59] CCRs by 2021.

72 The indicator for the development of tradable capacity in the Core (CWE) region between 2016 and 2018 is presented in Figure 9. It shows the monthly average size (i.e. nth root of the volume[60]) of the FB domain, computed for every hour, but only for the economic direction, i.e. the "directional size". The latter is defined for the purpose of this indicator as the FB domain in the orthant[61] which includes the solution of the DA market coupling algorithm, i.e. in the direction corresponding to the bidding zones' net positions[62].

57 Detailed information on FBMC may be found at http://jao.eu/support/resourcecenter/overview?parameters=%7B%22IsCWEFBMCRelevantDocumentation%22%3A%22True%22%7D or in the published decision on each of the Core (CWE) NRAs' websites.

58 See https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions/ACER%20Decision%2002-2019%20on%20CORE%20CCM.pdf.

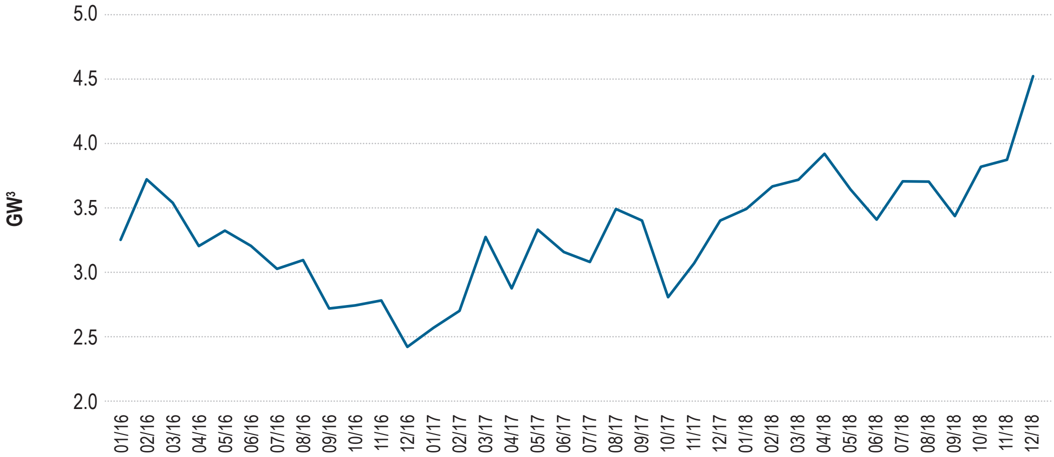
59 See https://nordic-rsc.net/wp-content/uploads/2018/08/supp.pdf.

60 Since the launch of CWE FBMC, the FB domain has been three-dimensional. The introduction of an additional bidding-zone border between Austria and Germany/Luxembourg added one more dimension, thus leading to a four-dimensional domain. As a result, to ensure comparability, the cubic root of the volume is used up to September 2018, and for subsequent periods the fourth root of the volume is used.

61 An orthant corresponds to a subdivision of an n-dimensional space by coordinate planes (and is equivalent to an octant for a three-dimensional space).

62 For more information, see Sub-section 3.2.1 on 'Evolution of commercial cross-zonal capacity' (p. 80) of the Electricity Wholesale Markets Volume of the 2016 MMR.

Figure 9: Average size of the FB domain in the economic direction in the Core (CWE) region – 2016–2018 (GW)




*Source: ACER calculations based on Core (CWE) TSOs data.*

*Note: The directional FB domain lies in the orthant, which contains the solution of the DA market-coupling algorithm maximising market welfare. A 30% increase in FB domain size is equivalent to doubling a three dimensional domain volume.*

73 Figure 9 shows that, after a clear downward trend in 2016 and a gradual recovery in 2017, FB sizes increased again in 2018. Part of the increase may be due to the introduction of a minimum Remaining Available Margin (RAM) requirement by CWE TSOs from 26 April 2018 onwards[63]. The FB size further increased following the introduction of the bidding-zone border between Austria and Germany/Luxembourg; this increase may result from the fact that large capacities were offered on this border compared to other Core (CWE) borders[64]. The increase may also be partly due to a reduction in flows coming from internal-to-bidding zone exchanges (as flows originating from exchanges between Germany and Austria became cross-border flows instead of flows due to internal exchanges) as well as from the removal of the external constraint after the introduction of the new bidding zone border . Finally, part of the increase may also stem from the use of winter thermal limits of Critical Network Elements with Contingencies (CNECs)[65] during this quarter[66].

74 The analysis presented in Sub-section 3.1.2 shows that there is still room to increase available cross-zonal capacity in the Core (CWE) region, in line with the recast Electricity Regulation[67]. Overall, the application of FBMC increases efficiency and cross-zonal capacity available for trading, while relying on the same underlying physical network capacities. However, this gain may severely decrease if the amount of cross-zonal capacity is reduced to accommodate flows originating from internal exchanges, as still observed in 2018 (see Section 3.2).

### 3.1.2 Share of physical capacity of network elements offered for cross-zonal trade

75 Provisions in the recast Electricity Regulation aim to ensure non-discrimination of cross-zonal exchanges. In particular, Article 16(8) prescribes that *"Transmission system operators shall not limit the volume of interconnection capacity to be made available to market participants as a means of solving congestion inside their own bidding zone or as a means of managing flows resulting from transactions internal to bidding zones"*. According to the same Article, the above requirement is deemed to be fulfilled, if *"...the following minimum levels of available capacity for cross-zonal trade are reached:*

63 See https://www.creg.be/sites/default/files/assets/Publications/Decisions/B1814Annex4.pdf.

64 The Shadow Auction Available Transfer Capacities (ATCs) provide an indication of the bilateral exchange that is allowed on the CWE borders. On the Austrian-German border, these ATCs are over four times higher than the average shadow auction ATCs on the other CWE borders and may lead to negative impacts on neighbouring bidding-zone borders (e.g. with respect to the bidding-zone border between Germany and Poland, see MMR 2016 p.7). Such negative impact may be alleviated through the implementation of FB capacity allocation in the Core CCR.

65 A critical network element means a network element either within a bidding-zone or between bidding-zones taken into account in the capacity calculation process, limiting the amount of power that can be exchanged.

66 Some CWE TSOs (including Amprion) used to rely on summer line limits during winter, see section 3.1.2 of the Electricity Wholesale Markets Volume of MMR 2017.

67 The same is implied by the moderate DA price convergence presented in section 2.2.

- *for borders using a coordinated net transmission capacity approach, the minimum capacity shall be 70% of the transmission capacity respecting operational security limits after deduction of contingencies […]*

- *for borders using a flow-based approach, the minimum capacity shall be a margin set in the capacity calculation process as available for flows induced by cross-zonal exchange. The margin shall be 70% of the capacity respecting operational security limits of internal and cross-zonal critical network elements, taking into account contingencies […]"*

76 This Article finally mentions that *"The total amount of 30% can be used for the reliability margins, loop flows and internal flows on each critical network element".* Therefore, from 1 January 2020 onwards, at least 70% of the maximum admissible active power flow (Fmax) shall be made available for cross-zonal trade on all CNECs. This requirement will apply unless MSs implement action plans where structural congestion has been identified pursuant to Article 15 of the recast Electricity Regulation, or NRAs introduce coordinated derogations pursuant to Article 16(9) of the same Regulation.

77 While the main underlying principles remain similar, the Agency, in monitoring the amount of capacity made available to the market, no longer focuses on benchmarking cross-zonal capacities (as in previous years), but instead estimates the share of Fmax available for cross-zonal trade in line with the adopted CCMs, and compares it with the target set by the recast Electricity Regulation[68]. The Agency, following numerous interactions with the European Commission, ENTSO-E, NRAs and TSOs, issued a Recommendation[69] to ensure that the implementation and monitoring of the achievement of this minimum target are consistent and to support legal compliance enforcement[70].

78 A methodological paper[71] complemented the Recommendation, describing how to estimate the margin available for cross-zonal trade (MACZT) on CNECs for the time period between 2016 and 2018. The main calculation principles included in the methodological paper are:

a) The calculations focus on the DA timeframe until coordinated ID capacity calculation is implemented;

b) The MACZT mostly stems from trade on EU bidding-zone borders. The impact of borders between EU and non-EU countries is separately monitored; and

c) The MACZT is only monitored for CNECs[72], and is split between the margin made available within coordinated capacity calculation (MCCC), and the flow induced by cross-zonal exchanges beyond coordinated capacity calculation (MNCC). As a consequence, the concept of coordination areas is introduced. It describes sets of bidding-zone borders within which capacity calculation is fully coordinated[73].

79 In line with the Recommendation, and as the legal requirement stemming from Article 16(8) of the recast Electricity Regulation does not yet apply, this analysis does not assess legal compliance of TSOs' actions, but rather estimates the margin for improvement with respect to the minimum 70% target.

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68 Preceding MMRs estimated capacity levels on bidding-zone borders, whereas this volume focuses on the margin induced by trade on individual CNECs. However, the results are presented in a similar manner, i.e. they are aggregated per bidding-zone border or region. The main differences relate to the geographic scope of the margin (regional in preceding MMRs compared to EU-wide in this volume, pursuant to the recast Electricity Regulation) and to the target margin level (85% of Fmax for benchmark cross-zonal capacity in previous MMRs compared to 70% in this volume, pursuant to the recast Electricity Regulation).

69 See https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Recommendations/ACER%20Recommendation%2001-2019.pdf.

70 This Recommendation may later be complemented by further guidance on how the results of the monitoring should be used to assess and, where necessary, address the overall compliance.

71 Methodological paper on "Estimating margin available for cross-zonal trade pursuant to Article 16(8) of Regulation (EU) 2019/943 and ACER Recommendation 01/2019" available at https://www.acer.europa.eu/en/Electricity/Market%20monitoring/Documents/Estimating%20the%20margin%20available%20for%20cross-zonal%20trade.pdf.

72 i.e. allocation constraints and technical profiles were not monitored. According to CACM regulation Art. 2(6) 'allocation constraints' means 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.

73 Eventually, when CCMs pursuant to the CACM Regulation are implemented, coordination areas will become equal to CCRs.

80 In order to assess the MACZT in Europe, the Agency requested historical information from European TSOs on CNECs introduced in capacity calculations, and the merged grid models necessary to estimate power transfer distribution factors (PTDFs[74]). Except for the Core (CWE) region, where the quality and granularity of the data was the highest, the data was often provided to the Agency in a simplified manner. For example, most TSOs with NTC borders provided a set of CNECs which were typically used in capacity calculation during the analysed period, without further specifying the hours or periods for which those CNECs were relevant.

81 The aforementioned assumptions lead to the following main caveats

a) The coordination areas delineation required for the underlying calculations is based on the level of co-ordination in day-ahead capacity calculation declared by NRAs for the MMR 2017. In particular, bilateral capacity calculation was assumed, unless full coordination among all concerned TSOs was declared[75]. The delineation of coordination areas impacts the MACZT.

b) Some of the provided NTC CNECs may not be limiting during some market time units (MTUs). This may lead to underestimating the MACZT[76] for the non-limiting CNECs during those MTUs

c) The PTDFs are approximated based on only one representative merged grid model (this caveat applies to all regions when calculating MNCC and only to NTC-based regions when calculating MCCC). This may lead to either under- or over-estimating the MACZT.

82 Additionally, the Agency restricted the geographic scope of the analysis to the bidding-zone borders for which the availability and robustness of the provided data were sufficiently high[77]. Results are therefore available only for some of the EU borders where NTC applies and for the Core (CWE) region where FB applies, involving a total of 20 MSs[78]. Due to higher data granularity provided for the Core (CWE) region, the results are presented in a more detailed manner for this region, while elsewhere the results refer mainly to average MACZT levels. Hence, in the absence of more detailed data, the presented results are not fully in line with ACER's Recommendation, which suggests to monitor individually and separately the MACZT for each CNEC and MTU (provided sufficient data is available)[79]. This individual monitoring is needed because capacity offered to the market is sensitive to the network element with the lowest margin, rather than to the average offered margin on all network elements.

83 Figure 10 and Figure 11 describe the average MACZT level (relative to Fmax) on NTC borders. Figure 10 refers to borders with AC interconnectors, while Figure 11 refers to borders with only DC interconnectors. As the analysis for DC interconnectors focuses on cross-zonal lines[80], it allows accurate estimates of the percentage of the time when the minimum 70% target is met.

74 PTDFs represent the sensitivity of flows to cross-zonal trade.

75 For example, although bilateral capacity calculation is conducted on the Czech bidding-zone borders, the Czech TSO ensures simultaneity of NTC values on all its border together. Therefore, the Czech coordination areas assumed for the analysis may lead to underestimating MACZT values for the Czech Republic.

76 See section 3.2 of the methodological paper "Estimating margin available for cross-zonal trade pursuant to Article 16(8) of Regulation (EU) 2019/943 and ACER Recommendation 01/2019".

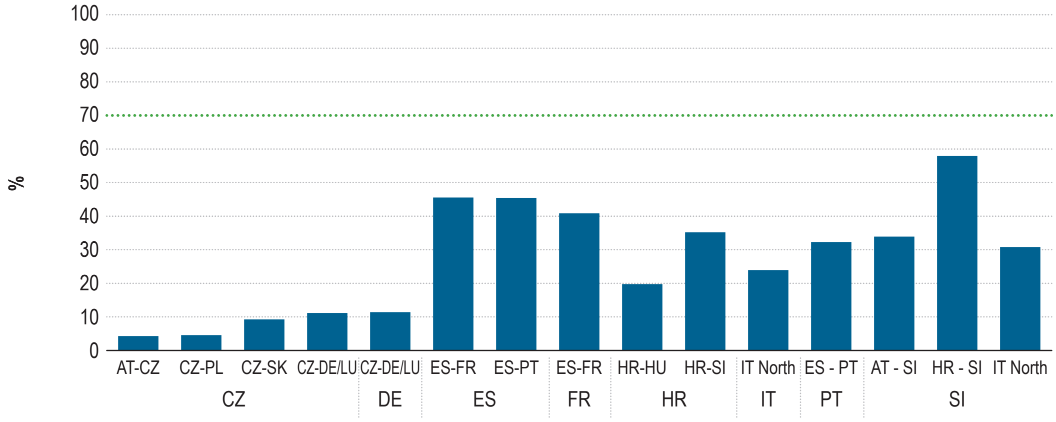
77 See Table 6 in Annex 4 on the quality of the underlying data. In particular, the lack of robustness in the data provided did not allow to assess the performance with respect to the 70% target on certain borders, such as the DK1 - DE/LU border, where cross-zonal capacity significantly increased in 2018 following an agreement to guarantee 1,300 MW NTC on this border (see footnote 49). According to the German NRA, the thermal interconnection capacity respecting N-1 security limits is 1,780MW on this border. The Agency expects that improvements in the provided data allows to add these borders to the assessment in future MMRs.

78 The MACZT on at least one bidding-zone border could be estimated for Austria, Belgium, Croatia, the Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Ireland (SEM), Italy, Lithuania, Poland, Portugal, the Netherlands, Slovenia, Spain, Sweden and the United Kingdom. As of 2018, Cyprus is not interconnected and Luxembourg has no bidding-zone border; these MSs are therefore not included in the analysis. Given the lack of data on the interconnector between Italy (Sicily) and Malta, this interconnector is also beyond the scope of the analysis.

79 In fact, the historical analysis of margins on NTC borders focuses on CNECs limiting cross-zonal capacity, as margin information related to all CNECs considered in capacity calculation was not available, except in the Core (CWE) region.

80 In case of multiple DC interconnectors on one border, the analysis would still focus on the border as a whole.

Figure 10: Average relative MACZT on selected AC bidding-zone borders in Europe – 2016–2018

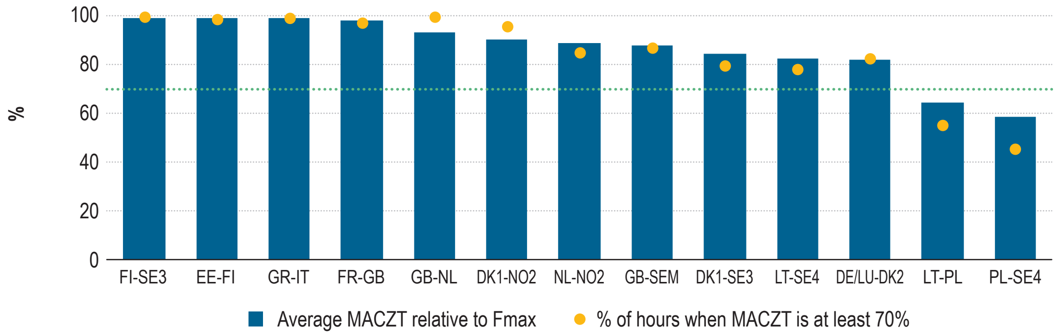



*Source: ACER calculations based on ENTSO-E/TSOs and Nordpool data.*

*Note 1: The average relative MACZT is computed over all declared CNECs, taking EU bidding-zone borders into account. The coordination areas delineation required for the underlying calculations is based on the level of coordination in day-ahead capacity calculation declared by NRAs for the MMR 2017.*

*Note 2: The margin available for trade on a given border is displayed from the perspective of the two MSs at both sides of the border, subject to data confidence. MSs and borders are selected based on the confidence in data (see Annex 4), i.e. only borders for which the confidence was sufficient are displayed. For example, the ES-FR border is presented from the perspective of both MSs, while the HR-HU border is only presented from the perspective of Croatian CNECs. The impact of internal Italian bidding-zone borders has not been considered.*

Figure 11: Average relative MACZT and percentage of time when the minimum 70% target is achieved on DC bidding-zone borders in Europe – 2016–2018




*Source: ACER calculations based on ENTSO-E/TSOs and Nordpool data.*

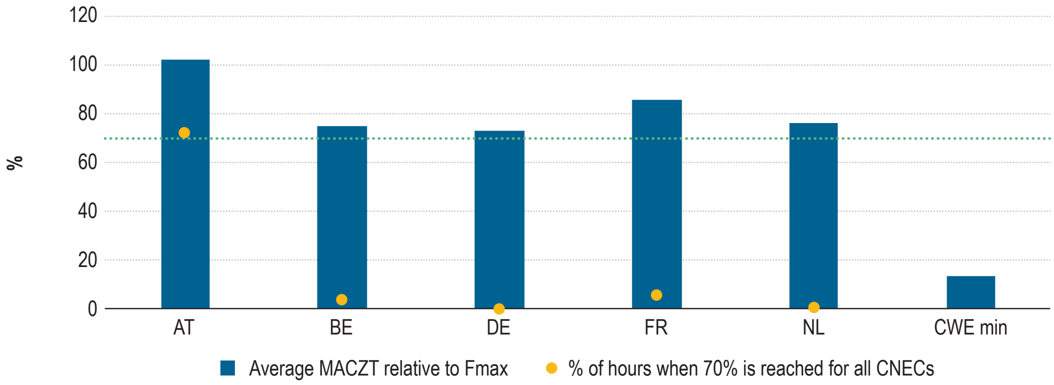
*Note: the MACZT is assumed to be equal to the NTC on the considered border. Outages are declared by TSOs. For each bidding-zone border, the percentage of hours during which the MACZT reaches at least 70% is averaged over both directions. Borders are ranked by decreasing average relative MACZT.*

84 The current average MACZT level shows a very different status for AC and DC borders. On the one hand, the MACZT remains significantly below 70% on many AC borders, especially in the Core (excl. CWE) region. On the other hand, on most DC borders, a MACZT of at least 70% is available during over 80% of hours, although there is significant room for improvement on the PL – SE4 and LT – PL borders. Overall, on NTC bidding-zone borders, most additional benefits brought by the minimum 70% target will likely be achieved on AC borders. This finding is consistent with those presented in previous MMRs, where available capacities were compared with the Agency's benchmark capacities.

85 Within the Core (CWE) region, the Agency accessed more detailed data, which allowed for a refined analysis. Figure 12 shows that average MACZT tend to be higher in this region than on other AC bidding-zone borders, and is usually above 70%. However, the percentage of hours during which the minimum 70% level is reached on all CNECs is very low, except for Austria. The relatively high value of the MACZT on Austrian CNECs is partly explained by the request of CWE NRAs that, before the introduction of the Austria – Germany/Luxembourg bidding-zone border, the margin on those CNECs should usually increase by applying final adjustment values (FAVs)[81].

81 See Section 4.1.4 of the Documentation of the CWE FB MC solution (available at http://www.jao.eu/support/resourcecenter/overview?parameters=%7B%22IsCWEFBMCRelevantDocumentation%22%3A%22True%22%7D).

Figure 12: Average relative MACZT and percentage of time when 70% is reached for all CNECs in the Core (CWE) region – 2016–2018




*Source: ACER calculations based on ENTSO-E/TSOs and Nordpool data.*

*Note: For each MS, the bar depicts the average relative MACZT within Core (CWE) over all Core (CWE) CNECs. The bar to the extreme right describes the average over all hours of the minimum relative MACZT over all Core (CWE) CNECs of the considered hour. Due to the fact that some CNECs may be monitored in both directions, and that internal and loop flows sometimes run opposite to the (oriented) CNEC, relative MACZT may be higher than 100%. When no CNEC is limiting the offered capacity for a considered MS and hour, the MACZT is assumed to reach at least 70% on all CNECs for this hour.*

86 Furthermore, at least one CNEC usually has a MACZT below 15% during each hour[82]. This finding is particularly relevant, as ACER's Recommendation suggests to monitor all CNECs individually, rather than the average performance of all CNECs.

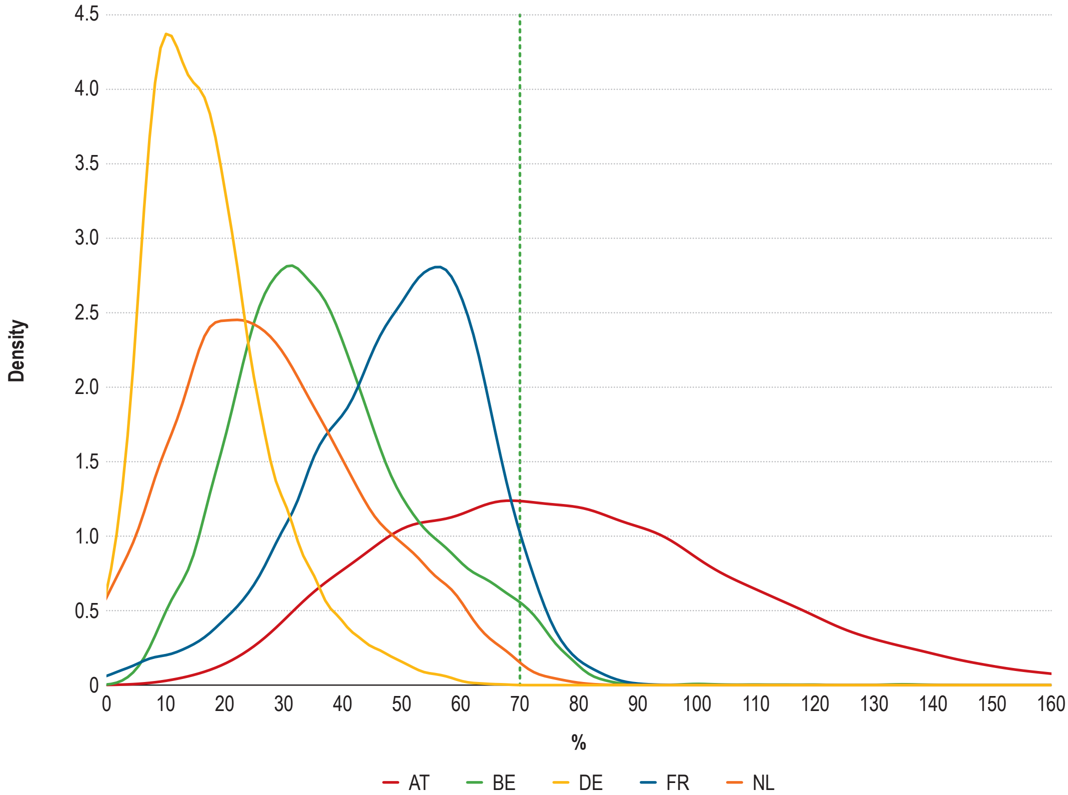
87 In order to illustrate the impact of individually monitoring each CNEC compared to monitoring the average MACZT over all CNECs, Figure 13 focuses on the performance of the CNEC with the lowest hourly MACZT (relative to Fmax) per MS in the Core (CWE) region. This figure describes the density of the hourly minimum relative MACZT on CNECs[83], and thus indicates the effort required to ensure that at least 70% is offered on all CNECs at all times. The Figure shows that this will require the greatest effort in Germany. Significant effort is also needed in the Netherlands and in Belgium. Some effort would also be necessary in France and Austria. This finding is broadly consistent with Figure 15, although the latter focuses on commercially-congested CNECs.

88 An important caveat is that low MACZTs may originate from inside (e.g. from structural internal congestion or lack of redispatching potential) or outside a given country (e.g. from LFs of neighbouring countries). Increasing the MACZT of one country may depend on the efforts made in the neighbouring countries.

82 As mentioned in Section 3.2.1, a 20% minimum RAM requirement was introduced in April 2018, subject to operational security constraints.

83 For each hour and MS, the CNEC with the minimum relative MACZT is retained. The density of these hourly values is then plotted for each MS. For each MS, hours when during no CNEC are excluded from the figure.

Figure 13: Density function of the lowest hourly relative MACZT of CNECs in the Core (CWE) region, per MS – 2016–2018



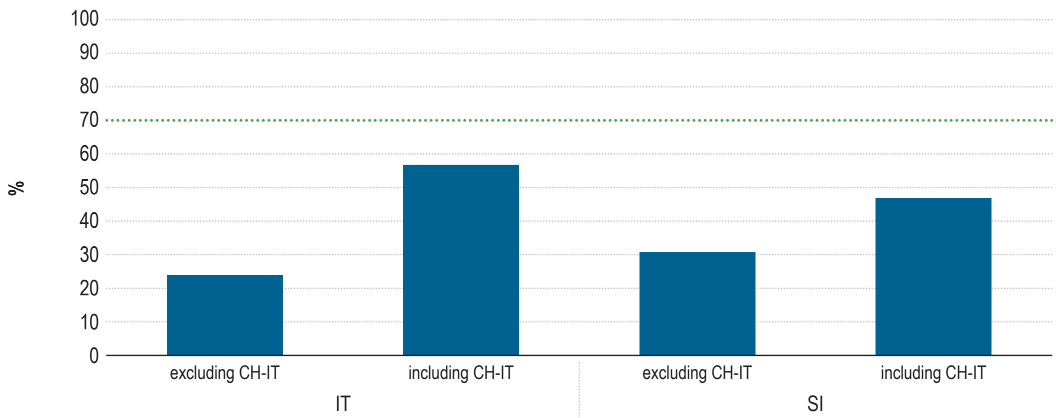

*Source: ACER calculations based on ENTSO-E/TSOs and Nordpool data.*

*Note: For each MS, the density describes the relative frequency of the value among all considered values. Part of the density function lies beyond 160% for Austria.*

89 Overall, the margin for improvement with respect to the 70% target is therefore significant in the Core (CWE) region.

90 Trade with third (non EU) countries may also impact the MACZT on EU CNECs. This impact may be significant. Figure 14 describes how exchanges on the bidding-zone border between Switzerland and Italy impact the relative average MACZT in the Italy North coordination area.

Figure 14: Average relative MACZT in the Italy North region, when including or excluding consideration of the Swiss-Italian border – 2016–2018




*Source: ACER calculations based on ENTSO-E/TSOs and Nordpool data.*

*Note: For each MS, the value on the left describes the MACZT for IT North excluding all exchanges with Switzerland; the value on the right describes the MACZT for IT North taking full account of the NTC on the Italy – Switzerland border. Both values are computed based on the same set of CNECs, NTCs and schedules. The impact of the Italy – Switzerland border on the MACZT in Austria and France is not presented due to a lack of robust data for these MSs within this coordination area.*

91 When assessing the MACZT within the Italy North coordination area, including the NTCs between Italy and Switzerland more than doubles the average Italian MACZT, and increases the average Slovenian MACZT by more than 50%, compared to when exchanges on this border are fully excluded. Following guidance from the EC[84], the Recommendation suggests that exchanges between EU and third countries be taken into account, under the conditions that

a) internal network constraints within the third country are considered for intra-EU capacity calculation;

b) internal network constraints within the EU are considered in the capacity calculation with the third country; and

c) an agreement on the sharing of the costs of remedial actions applies between EU countries and the third country.

92 All in all, between 2016 and 2018, on most of the analysed AC and on some DC bidding-zone borders, the MACZT was much below 70%, suggesting significant room for improvement with respect to the minimum target set by Article 16(8) of the recast Electricity Regulation. Part of this improvement may come from increased coordination in capacity calculation, e.g. by reducing unscheduled allocated flows (UAFs) and the uncertainty associated with them.

93 As mentioned at the beginning of this Section, the minimum 70% capacity requirement will apply from 1 January 2020 onwards, unless MSs decide to implement transitional measures, i.e. action plans or derogations (as described in the recast Electricity Regulation). MSs thus need quickly to decide whether to implement transitional measures, or how significantly to increase the MACZT by this date.

94 The Agency expects TSOs to enhance their processes to collect the data required for the effective monitoring by NRAs and the Agency of the achievement of the 70% target from 2020 onwards. Significant improvements are expected from all TSOs applying NTC-based capacity calculation methods, and in particular from those TSOs – APG (Austria), ESO (Bulgaria), Energinet (Denmark), Elering (Estonia), Fingrid (Finland), RTE (France), TenneT DE and 50Hertz (Germany), IPTO (Greece), MAVIR (Hungary), AST (Latvia), Litgrid (Lithuania), Statnett (Norway), PSE (Poland), Transelectrica (Romania), SEPS (Slovakia), Svenska Kraftnät (Sweden) – which could not be covered in this year's MMR due to insufficient data quality.

## 3.2 Factors impacting commercial cross-zonal capacity

95 As concluded in the Section 3.1.2, on most of the analysed AC and on some DC bidding-zone borders, the available cross-zonal capacity is far from the target set by Article 16(8) of the recast Electricity Regulation. The relatively low values of the available cross-zonal capacities reflect underlying (structural)[85] network congestion, which is not effectively addressed by the existing bidding-zone configuration.

96 The capacity calculation process may mitigate the problem: some short-term actions were taken by TSOs to alleviate the issue (Sub-section 3.2.1), and the capacity calculation methodologies elaborated and approved pursuant to the CACM Regulation (combined with the recast Electricity Regulation) should aim at improving the situation in the long term, but sometimes such capacity calculation methodologies lack ambition on some topics (Sub-section 3.2.2).

### 3.2.1 Discrimination between internal and cross-zonal exchanges

97 Wholesale electricity markets in Europe are structured in bidding-zones. Within each bidding-zone, any consumer may contract electricity with any generator without limitations. However exchanges between bidding-zones are limited by TSOs through the capacity calculation and allocation process.

84 See Section 4.1 of the Recommendation.

85 See Section 3.4 of the 2017 MMR.

98 Regulation (EC) No 714/2009 and, in particular, the CACM Regulation, already required that capacity calculation and allocation should not result in undue discrimination. This is also stressed by the Agency's Recommendation on capacity calculation[86]. The Recommendation establishes two high-level capacity calculation principles[87]. First, limitations on internal network elements should not be considered in CCMs. Second, the capacity of the cross-zonal network elements should not be reduced in order to accommodate loop flows (LFs). The Recommendation envisages temporary deviations from these principles when they are properly justified (from an operational security and socio-economic perspective at the EU level) and do not unduly penalise cross-zonal exchanges.

99 In practice, this means that the capacity of the network elements should not be disproportionally allocated to accommodate flows resulting from internal exchanges to the detriment of cross-zonal exchanges. Offering less cross-zonal capacity for trade due to the unequal treatment of different types of electricity exchanges reduces market efficiency and hence may reduce social welfare[88].

100 The prioritisation of internal exchanges may take the form of i) LFs impacting interconnections, as well as ii) reductions of capacity available for cross-zonal exchanges in order to relieve congestion on internal lines. The issue of LFs and more generally of unscheduled flows (UFs) was further analysed in previous editions of the MMR. An update on the volumes of UFs is included in Annex 2.

101 As indicated previously, whereas the target of the recast Electricity Regulation is to offer 70% of Fmax on critical network elements, the capacity offered for cross-zonal trade is often below this target. Whereas in the mid-term the reconfiguration of bidding zones (in combination with other longer-term measures such as cost-effective network investments) is possibly the most efficient way to address this issue, in the short-term, capacity calculation may contribute to alleviate the gap, as described in Sub-section 3.2.2. However, this is yet to be seen on most European borders, either due to the presence of UAFs resulting from non-coordinated capacity allocation on other borders, or due to the prioritisation of internal exchanges.

102 In addition, the Agency could access detailed data on FB capacity calculation in the Core (CWE) region. This data allowed further analysis of the issue of discrimination in this region, which is presented below. Pursuant to the CACM Regulation, ENTSO-E is expected to provide the Agency with data on other regions where capacity calculation is NTC-based, with the same level of detail as for the FB case.

103 The remainder of this Section analyses the frequency and extent to which discrimination of cross-zonal exchanges on individual CNEs affects the availability of cross-zonal capacity in the Core (CWE) region[89].

104 Figure 15 describes the location and extent to which various constraints limit cross-zonal trade, i.e. the share of limiting constraints, with and without taking into account shadow prices, per element type and TSO in the Core (CWE) area[90]. While the total number of constraints increased in 2018 (+9%), the situation improved overall with respect to non-discrimination of cross-zonal exchanges. The number of constraints linked to internal lines was significantly reduced compared to 2017 (-17%); consequently, the number of cross-zonal active constraints nearly doubled year-on-year (+95%)[91]. Despite the decrease in the share of internal line constraints (57% compared to 76% in 2017) such constraints still account for more than half of the total. Dutch internal constraints accounted for over a third of internal constraints in the Core (CWE) area, whereas Elia and Amprion accounted for approximately a quarter of them[92]. Notably, internal French lines never restricted capacity allocation in the Core (CWE) area in 2018.

86 Available at https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Recommendations/ACER%20Recommendation%2002-2016.pdf.

87 Additionally, the recommendation includes a third principle related to redispatching and countertrading cost-sharing methodologies.

88 A full social welfare analysis should also focus on redispatching (and other) costs, and potential long term benefits.

89 The analysis in this Sub-section is limited to the DA timeframe. In the Core (CWE) area, most of the cross-border capacity allocated in the long-term timeframe is not nominated (i.e. the share of long-term nominated capacity accounts for only between 0% and 2% of all nominations, depending on the border). Moreover, the cross-zonal capacity available for closer-to-real-time timeframes is a small share of the overall cross-zonal capacity offered. As a result, the conclusions of this sub-section can be considered as valid for all timeframes taken together.

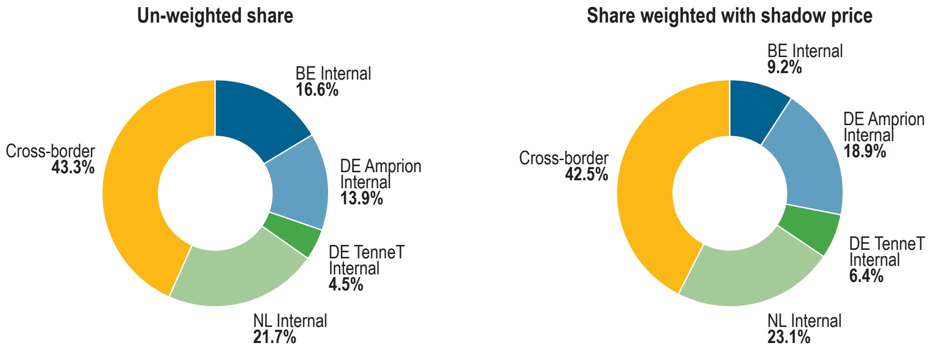
90 For a description of the methodology and for 2017 figures, see Sub-section 3.2.2 of the Electricity Wholesale Markets Volume of the MMR 2017.

91 Notably, the largest part of this increase occurred after the implementation of the 20% minimum RAM requirement (+130% compared to the same period in 2017, see also paragraph (107)).

92 When the shadow prices are taken into account however, the constraints of Amprion's control region seem more important than those of Elia's.

105 The share of allocation (or external) constraints remained small and was even slightly reduced from 2017 (8.6% in 2018 from 9.3% in 2017)[93]. The number of external constraints on the German side, which are no longer used since 1 October 2018[94], was slightly reduced (-6%).

Figure 15: Share of active constraints in the Core (CWE) domain per TSO control area and category – 2018 (%)




*Source: ACER calculations based on ENTSO-E.*

*Note: Elements with shares of active constraints weighted with shadow prices below 5% were removed from the pie chart. See Table 3 in Annex 1 for detailed data.*

106 On 26 April 2018, a 20% minimum RAM requirement on all CNECs was introduced in the Core (CWE) region. The requirement prescribes that at least 20% of the maximum admissible active power flow of each CNEC shall be available for cross-zonal trade within the Core (CWE) region[95], subject to operational security constraints[96]. The introduction of the requirement was the outcome of a request from all Core (CWE) NRAs for the completion of a CNEC-selection study in order to tackle the issue of limitations imposed to cross-zonal exchanges. However, the introduction of the minimum RAM requirement has so far been proposed only as a partial and temporary solution[97].

107 Figure 16 depicts the share of constraints by element type before and after the introduction of the 20% minimum RAM. The share of constraints due to internal lines significantly decreased following the introduction of the minimum RAM, but such constraints still account for more than half of the total[98]. The outcome is a clear indication of the scope for improvement of the capacity calculation methodologies and TSO practices, and suggests that the introduction of minimum RAM rules, subject to operational safety standards, may well improve market efficiency and reduce undue discrimination of cross-zonal exchanges. At the same time, the remaining high share of internal lines limitations implies that 20% is likely not enough to ensure that internal lines do not strongly limit cross-zonal trade. The introduction of higher minimum RAM requirements (as envisaged in the recast Electricity Regulation and the approved CCM for the Core Region)[99] or possibly the reconfiguration of bidding zones, may eliminate the remaining market distortions.

93 Although the number of such occurrences remained practically the same as in 2017.

94 See Table 3 for more details. According to the updated FBMC methodology that was approved in September 2018, external constraints in DE/LU were removed after the introduction of the bidding-zone border between Austria and Germany/Luxembourg on 1 October 2018.

95 Flows originated in countries beyond the CWE are not considered within the 20%. The actual share of capacity of CNECs used by cross-zonal flows can be above 20%.

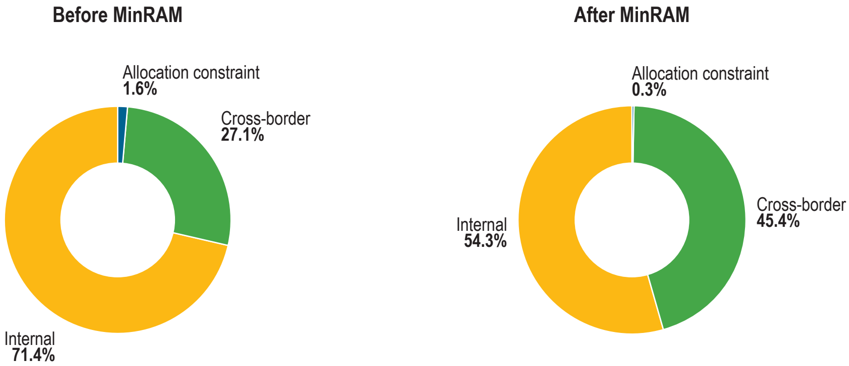
96 Including the availability of remedial actions.

97 See the common position paper of CWE NRAs on the update of the FBMCM available at https://www.cre.fr/content/download/19766/245830.

98 Allocation constraints almost disappeared in the same period, as expected based on the updated FBMCM provisions.

99 See footnote 58.

Figure 16: Share of occurrence of active constraint by element type in the Core (CWE) region, before and after the introduction of the 20% minRAM rule – 2018 (%)




*Source: ACER calculations based on ENTSO-E data.*

108 As a comparison, and based on publicly available[100] data on CNEs in the Nordic region, the average RAM in this region is probably higher than 65% of Fmax. Indeed, for over 90% of CNEs, internal flows and LFs consumed at most a maximum of 20% of Fmax. Assuming a 10–15% reliability margin (in line with the benchmark capacity calculation methodology[101]), a 65–70% RAM level may be estimated for over 90% of Nordic CNEs.

### 3.2.2 Capacity calculation methodologies

109 This Sub-section aims to provide an overview of the status of DA and ID CCMs and to identify improvements that could be implemented, either through the 2020 review prescribed by Article 21(4) of the CACM Regulation, or when aligning CCMs to the recast Electricity Regulation.

110 The analysis included in this Sub-section takes into account the capacity calculation requirements described in the CACM Regulation, the Agency's Recommendation on capacity calculation[102], as well as best practices observed across Europe.

111 Following important caveats underlying the assessment of the CCMs apply. First, the assessment is based solely on the documents themselves. Non-binding documents such as explanatory notes or the context in which they were developed are not considered.

112 Second, the assessment is not an analysis of legal compliance. When legal provisions are referred to, the assessment identifies the extent to which the related requirements are explicitly included in the CCMs. The inclusion or absence of a provision reflects a regulatory choice, and cannot be used as a basis to identify any potential infringement. In the Agency's view the explicit reference to provisions is crucial because it tends to better ensure that certain requirements are applied in practice and identifies responsibilities. For example, the extent to which methodologies explicitly tackle non-discrimination of cross-zonal exchanges is particularly important. Despite the legal requirements to prevent discrimination that have applied for many years, CCMs have not often included provisions to address this issue. The absence of such provisions in combination with other factors explains why the discrimination of cross-zonal exchanges has remained a major issue in European electricity wholesale markets in recent years, as reported in preceding MMRs.

113 Finally, obligations stemming from a number of the provisions (e.g. those included in the recast Electricity Regulation), did not apply at the time when the CCMs were approved. Therefore, the assessment should be understood exclusively as an indication of the room for improvement at this stage of implementation.

100 See a presentation by Nordic TSOs on "The Nordic Capacity Calculation Methodology (CCM) project": https://www.entsoe.eu/Documents/Network%20codes%20documents/Implementation/stakeholder_committees/MESC/2018-06-08/2.1%20Nordic%20CCM.pdf?Web=1, slide 26.

101 See the methodological paper on 'Benchmark cross-zonal capacity calculation', available at: https://www.acer.europa.eu/en/Electricity/Market%20monitoring/Documents/ACER%20Methodological%20paper%20-%20Benchmark%20cross-zonal%20capacity%20calculation.pdf.

102 See footnote 86.

#### 3.2.2.1 Context and methodology

114 Pursuant to Article 20 of the CACM Regulation, all TSOs in each CCR shall jointly develop a proposal for a common coordinated CCM within the respective CCR and submit it to all regulatory authorities of the respective CCR for approval and to the Agency for information. As of June 2019, the relevant regulatory authorities approved common coordinated CCMs in all CCRs except for Italy North[103,104].

115 In the comparative analysis, the following four aspects of the approved CCMs were assessed[105]:

a) The 'CACM Regulation coverage'. This aspect assesses the explicit inclusion (or absence) of the provisions addressing the relevant requirements set by Articles 9, 20 to 27, 29 and 30 of the CACM Regulation;

b) The level of 'detail and harmonisation'. This aspect assesses the content of the provisions, i.e. if they are sufficiently detailed to allow transparency and reproducibility of the calculation (e.g. possibility for third parties to replicate it), and the extent to which they result in harmonised principles, methodologies or values for a series of parameters of the CCM within a CCR;

c) 'Non-discrimination'. This aspect assesses the extent to which CCMs include explicit provisions to ensure non-discrimination between internal and cross-zonal exchanges[106];

d) 'Transparency and enforceability'. This aspect assesses: (i) the extent to which CCMs ensure that relevant information will be published timely, transparently, ensuring user-friendliness and the quality of the data, and (ii) the extent to which CCMs are drafted so as to clarify tasks, responsibilities and implementation deadlines.

116 Each of those four aspects was assessed following the same process. First, a benchmark reference was selected (e.g. in the form of a provision from the CACM Regulation or of a good practice, depending on the aspect[107]). Second, essential features were identified for each aspect. Third, a list of closed-ended questions was developed, each question relating to the essential identified features. Finally, each CCM was assessed against the list of questions.

117 Possible answers to the closed-ended questions were affirmative, negative or questions were deemed non-applicable to the aspect for a given CCM. Affirmative answers were awarded one point, while the negative ones did not get any points. The resulting score is the ratio of the sum of points earned over the number of questions applicable to the aspect. Then, all aspects were given equal weight, hence the overall scoring for a region was calculated as the arithmetic average of the individual score of the four aspects.

118 The overall score combines the evaluation of the four aspects into a single metric, thereby simplifying the assessment of the CCMs and making it easier to compare them across regions. As a simplification, however, it does not necessarily provide for a deeper understanding of CCMs and details can be lost. This can also give rise to misinterpretation, particularly if the results are not presented appropriately. In order to mitigate this risk, a more detailed analysis (and scoring) per aspect and region is included in Annex 3 and all the specific questions used for each aspect are available online[108].

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103 The methodologies were approved by the relevant NRAs, except for the CCM of the Core CCR. For the latter, the NRAs of the Core CCR requested that the Agency adopt a decision on the proposed CCM as they failed to agree on its approval. For the Agency's' decision, see footnote 58.

104 Italy North began the work on capacity calculation methodology with a delay, due to unclear legal provisions. For further details see footnote 66 of the First implementation monitoring report on Capacity Allocation and Congestion Management and Forward Capacity Allocation https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/FCA_CACM_Implementation_Monitoring_Report_2019.pdf.

105 The study is based solely on the approved methodologies and does not take into account supporting documents such as explanatory notes, which are non-binding.

106 Non-discrimination of cross-zonal exchanges may be ensured through various means, including e.g. the design of bidding zones and CCMs.

107 The precise reference used for each aspect is further detailed in the dedicated Sub-sections below.

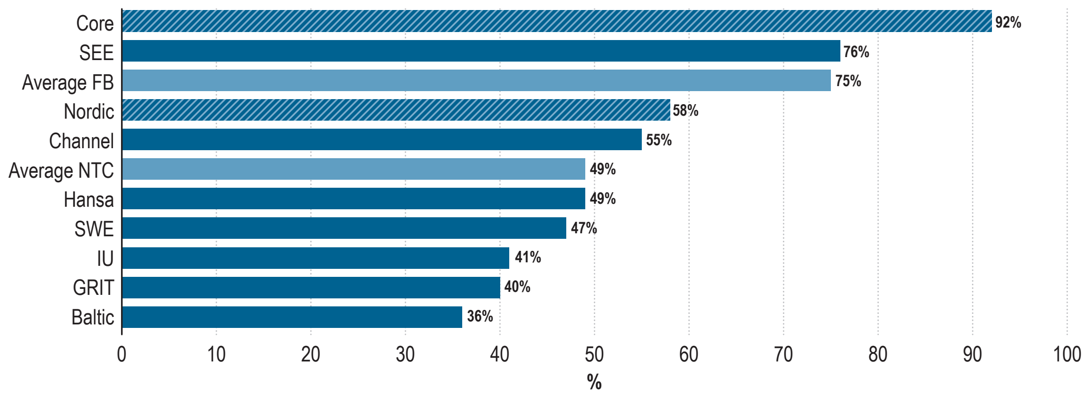
108 See the methodological paper "Capacity Calculation Methodologies – Overview" available at https://www.acer.europa.eu/en/Electricity/Market%20monitoring/Documents/ACER%20Methodological%20paper%20-%20Capacity%20Calculation%20Methodologies%20Overview.pdf.

### 3.2.2.2 Analysis, results and conclusions

#### 3.2.2.2.1 Overview

119 Figure 17 displays the overall results of the assessment, i.e. the level of fulfilment of the analysed four criteria, per region. It shows that the regions applying FB methodologies (i.e. in the Core and Nordic CCRs)[109] met the assessment criteria to a larger extent than Coordinated NTC (CNTC) methodologies, to the exception of the SEE CCR.

Figure 17: Overall share of assessment criteria met by approved CCMs (%)

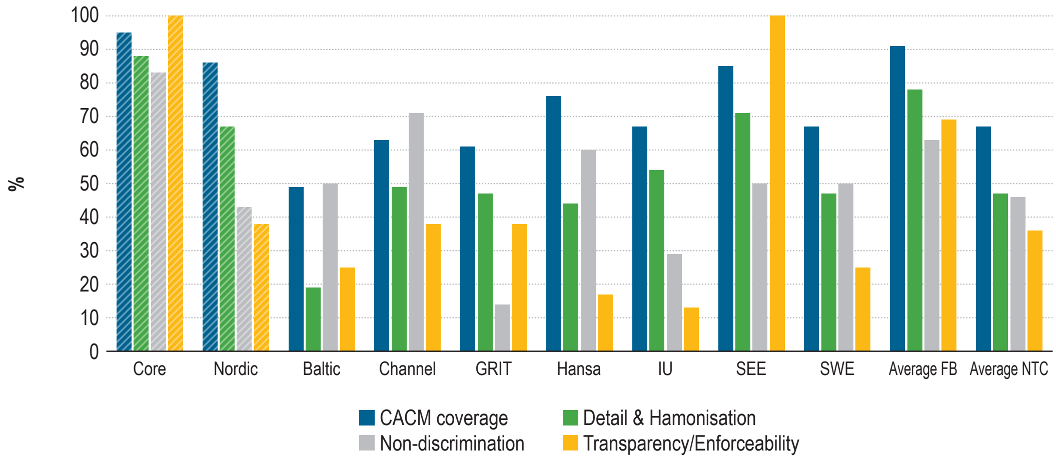



*Source: ACER.*

*Note: The assessment includes all CCRs except Italy North. For this region, a common coordinated CCMs was not yet approved by the relevant regulatory authorities as of June 2019.*

120 Figure 18 reveals that the main differences between the scoring of FB and CNTC CCMs relate to the level of 'Detail and Harmonisation' (on average 78% vs. 47%) and the level of transparency (on average 69% vs. 36%).

Figure 18: Share of assessment criteria met by approved CCMs per category (%)




*Source: ACER.*

121 More detailed analysis is provided in specific Sub-sections, for each analysed aspect, below.

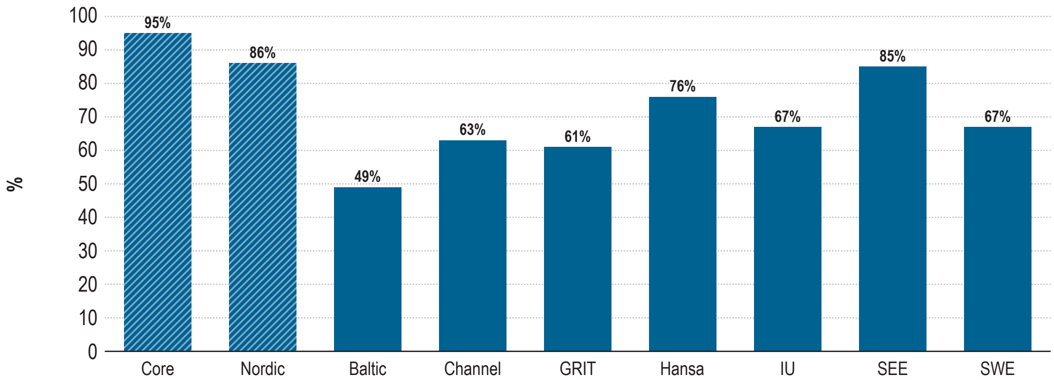
109 While the sample for FB is not large (2 regions), actual practice suggests that FB tends to demand a higher level of explicitness and detailed descriptions in CCMs from TSOs.

### 3.2.2.2.2 CACM Regulation coverage

122 The reference for this assessment is the relevant provisions of the CACM Regulation. The assessment is conducted through a series of 76 closed-ended questions, directly related to legal requirements set in Articles 9, 20 to 27, 29 and 30 of the CACM Regulation. Questions are answered affirmatively if the CCM explicitly suggests an answer to a requirement[110]. The assessment does not evaluate the content of the policy, but rather the extent to which the legal requirements are explicitly included in the various CCMs.

123 Figure 19 displays the results of the assessment of the CACM Regulation coverage. It reveals that FB CCMs (Core and Nordic), with an overall average of 91%, are significantly more explicit than CNTC CCMs, with an overall average of 67%.

Figure 19: Share of the requirements in the CACM Regulation explicitly addressed in the approved CCMs, CACM Regulation coverage (%)




*Source: ACER.*

124 Outstandingly, provisions that were found in no more than one CCM[111] are:

125 Provisions regarding the cooperation with neighbouring coordinated capacity calculators, pursuant to article 29(9) of the CACM Regulation;

126 Provisions regarding the necessary agreement of all TSOs in each CCR on the use of remedial actions that require the action of more than one TSO, pursuant to Article 25(3) of the CACM Regulation.

127 Although the legal requirements that are not addressed in the CCMs may be tackled during the implementation phase, the likely outcomes of this situation are (i) a lower level of harmonisation within CCRs and (ii) diverging implementations across CCRs. As a consequence, reaching the target of a harmonised EU-wide capacity calculation approach by 31 December 2020 pursuant to Article 21(4) of the CACM Regulation will prove challenging.

### 3.2.2.2.3 Detail and harmonisation

128 This aspect assesses two sub-aspects, first the level of detail, i.e. if the provisions on the CCMs are sufficiently detailed to allow reproducibility of the calculation, and, second, the level of harmonisation, i.e. the extent to which they result in harmonised principles, methodologies or values for a series of parameters of the CCM[112] within a CCR. The references used for this assessment are ideal harmonised practices which can often be best practices observed among the approved CCMs.

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110 For example, Article 21(3) of the CACM Regulation requests that the capacity calculation methodology include a fall-back procedure. The associated question is whether the CCM includes a fall-back procedure.

111 “no more than one” means either “no methodology” or “only one methodology”. When a single CCM covers the provisions mentioned in paragraph (124), this single CCM is the Core CCM. For more details, see Annex 3.

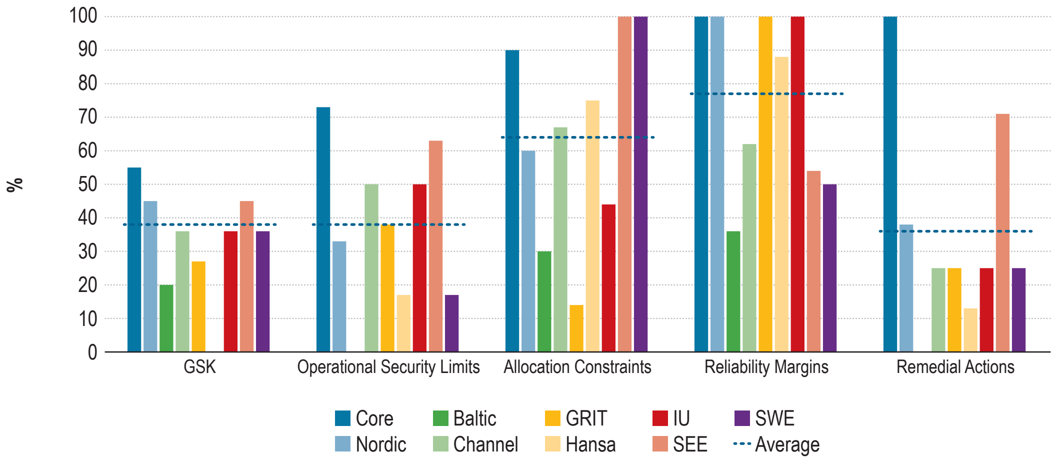
112 The harmonisation level does not necessarily reflect the ambition of CCMs, but may also reflect regional specificities.

129 Both sub-aspects are evaluated based on a series of closed-ended questions (respectively five questions on the level of detail and eleven questions for the level of harmonisation). Questions are applied to the description of the capacity calculation process itself (for the DA and the ID timeframes), but also to the inputs to this calculation i.e. generation shift keys (GSK), operational security limits, allocation constraints, reliability margins, and remedial actions.

130 Questions related to the level of detail cover the extent of the mathematical description of the calculation steps, the availability of inputs to the methodology, and the communication of information at each calculation steps.

131 Questions related to the level of harmonisation focus on whether applying the CCM will imply that TSOs follow harmonised principles, harmonised calculation steps, or harmonised outputs. The questions further assess the geographical perimeter of the harmonisation resulting from the CCM (e.g. the CCR, bidding zones etc.). Finally, a set of questions help to assess the possibilities to deviate from the general rules.

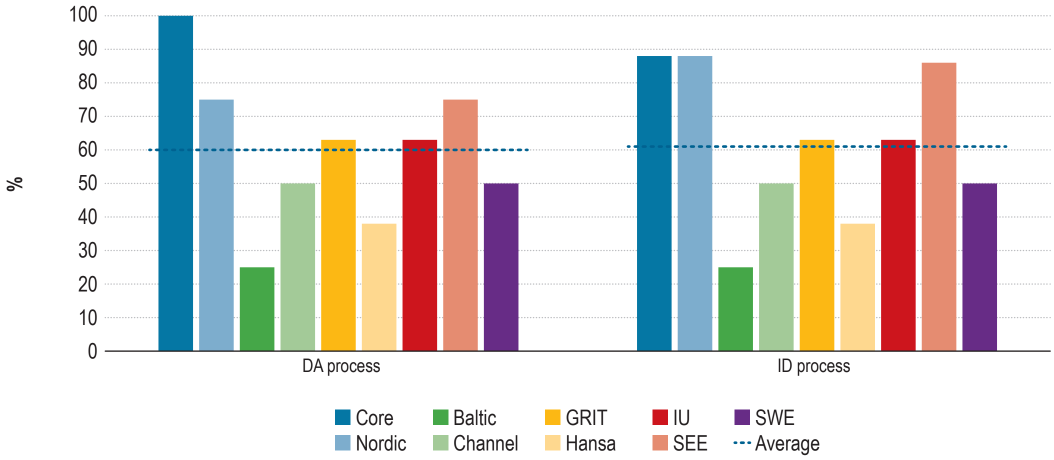
Figure 20: Level of detail and harmonisation of the main features of the approved CCMs (%)




*Source: ACER.*

*Note: Within the approved CCMs, PTDFs were assessed but are not displayed as the only apply for FB CCMs, which both scored 100% regarding this feature. The 100% score applies to full level of detail and harmonisation of process and parameters for the considered aspect.*

Figure 21: Level of detail and harmonisation of the processes for the calculation of DA capacity and ID capacity in the CCMs (%)




*Source: ACER.*

*Note: The 100% score applies to full level of detail and harmonisation of process and parameters for the considered aspect.*

132 Figure 20 and Figure 21 show that the level of detail and harmonisation varies greatly depending on the parameters, ranging from reliability margins (average 77%) to Remedial Actions (average 36%), possibly reflecting different priorities[113] among the tackled topics for each CCR. A closer look at the descriptions on how the parameters of the various CCMs are to be calculated confirms that the Core CCM is generally significantly more detailed than the CCMs of other CCRs.

133 With regards to harmonisation, the Agency notes divergent approaches across and within regions, (the latter depending on the parameter). The following approaches were identified:

a) Some approaches do not aim at harmonising, but rather list current calculation practices;

b) Some approaches describe the current status as a starting point, with a process to reach a higher level of harmonisation in the future;

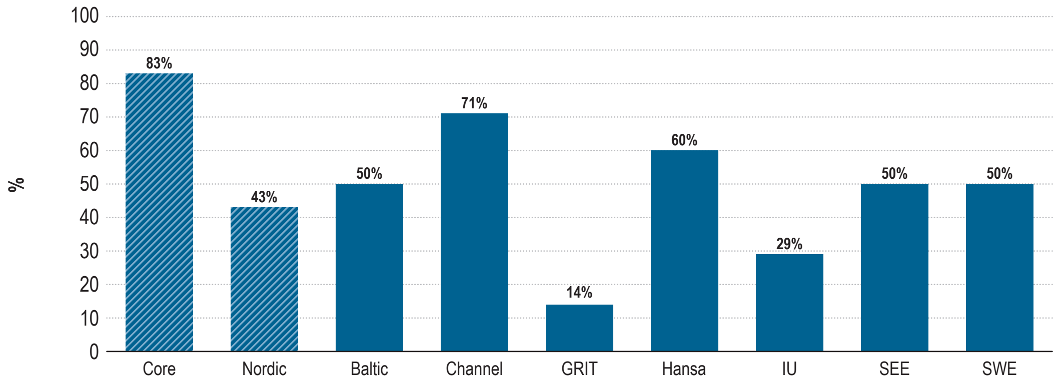
c) Some approaches set a harmonised calculation from the start.

#### 3.2.2.2.4 Non-discrimination

134 This aspect assesses whether provisions of the CCM ensure the prevention of undue discrimination of cross-zonal trade, namely, whether during the capacity calculation process, actions are taken to avoid that cross-zonal capacity is limited due to internal constraints (corresponding to the first principle of the Agency's Recommendation[114]) or LFs (second principle). Both principles, in combination with the relevant provisions of the recast Electricity Regulation[115], are taken as a reference for the assessment, which is based on a series of closed-ended questions (four questions for each principle).

135 Questions related to the first principle aim to assess the extent of limitations of cross-zonal capacity due to internal constraints, by questioning if these are taken into account, and in such case, how this is justified. Questions related to the second principle aim to assess if the CCM includes measures to guarantee a minimum level of cross-border capacity.

Figure 22: Share of measures to prevent undue discrimination of cross-border exchanges explicitly included in the approved CCMs (%)




*Source: ACER.*

136 Figure 22 displays the results of the analysis on how the CCMs aim to prevent discrimination in capacity calculation. It shows that the performance of this aspect varies significantly across regions. More detailed findings of the analysis are summarised below.

113 For example, using one single GSK over the whole CCR may even contradict the objective according to which GSKs should represent a best forecast. Therefore, harmonised detailed principles may be more efficient than harmonised GSKs.

114 See footnote 86.

115 Mainly, Article 16(8). It is important to note that the recast Electricity Regulation was not adopted at the time when the CCMs were developed. Therefore, the aim of the assessment is not to point at shortcomings, but rather possible improvements in the new legal context.

137 First, most methodologies do not include sufficient provisions to guarantee non-discrimination of cross-zonal trade. The observed lack of provisions is irrespective of whether discrimination is actually observed in the relevant region[116]. At the same time, including those provisions is important because discrimination could appear in the future, in regions where this is currently not an issue.

138 Second, all methodologies but one (for the Hansa region) allow the inclusion of internal constraints in the CCM. Three methodologies (for the Channel, GRIT and IU CCRs) do not explicitly refer to the prevention of non-discrimination as an objective of the methodology. Furthermore, the CCMs for the IU, GRIT and SEE CCRs do not condition the inclusion of limitations on internal network elements to a detailed technical or economic assessment. Only the Core and Nordic CCMs base such an assessment on considerations of maximisation of welfare, in accordance with the Agency's Recommendation.

139 Third, only the Core CCM includes explicit measures to guarantee the prevention of undue discrimination, in line with the Agency's Recommendation and taking into account the recast Electricity Regulation[117]. Such guarantee implies a minimum threshold for cross-border capacity, some conditions to the inclusion of internal CNEs in capacity calculation, and the limitation of LFs.

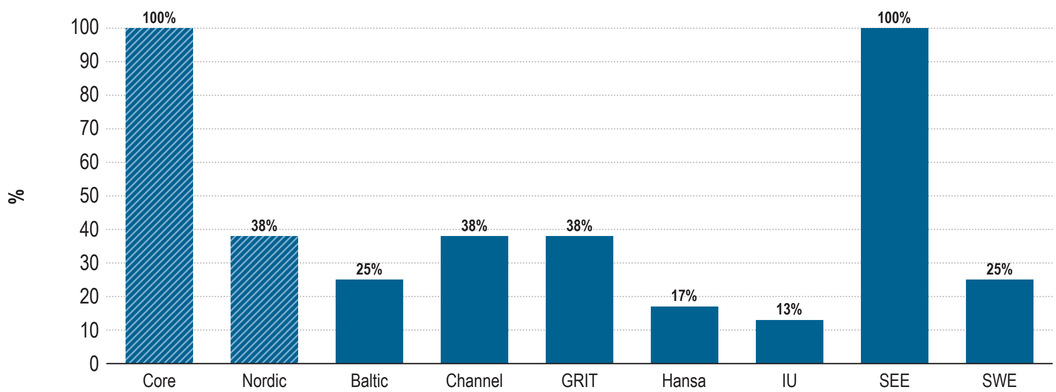
140 Fourth, the lack of provisions addressing the discrimination issue could be the result of discrimination being addressed through other means, such as the design of bidding zones. This may partly explain the fact that the Nordic CCM scores significantly worse than the Core CCM. As bidding zones seem to be comparatively better defined within the Nordic CCR than in other CCRs, ensuring non-discrimination through the CCM may be less crucial in this CCR than, for example, in the Core CCR[118].

#### 3.2.2.2.5 Transparency and enforceability

141 This aspect assesses whether provisions of the CCM ensure transparency over the information used (i.e. availability and quality of information), and whether they ensure enforceability of the policies (i.e. whether provisions of the CCM set clear responsibilities and deadlines for implementation). Both sub-aspects are evaluated based on a series of closed-ended questions (five questions for each sub-aspect). The reference for this assessment is the best practice observed among the approved CCMs, namely the relevant provisions of the Core CCM.

142 Figure 23 displays the results of the analysis on how transparency and enforceability are ensured in the approved CCMs. It shows a significant room for improvement except for the Core region.

Figure 23: Extent of the transparency and the enforceability guaranteed by the approved CCMs (%)




*Source: ACER.*

116 For example, the lack of provisions addressing discrimination is highlighted for the Channel region and GRIT, while preceding MMRs (based on the % of physical cross-zonal capacity offered to the market) did not find evidences of internal exchanges being prioritised over cross-zonal exchanges in these regions. See also the last two editions of the MMR, where discrimination was observed in most CCRs where HVAC interconnectors are predominant, while it was not observed, or observed to a lower extent, in most CCRs where HVDC interconnectors are predominantly used.

117 Many CCMs were however approved before a compromise was reached on the recast Electricity Regulation.

118 See Section 3.4 of the MMR 2017.

143 Concerning transparency and data publication, five out of the nine CCMs include provisions ensuring transparency over the causes and remedies to address deviations from the general framework of the CCM. Remarkably, only the Core and SEE CCM include provisions to ensure that all relevant data is published in a unique format, in a centralised platform, and subject to quality checks. Such provisions should be seen as best practices to be applied in all CCRs. This is particularly important as stakeholders have pointed at shortcomings in the past[119].

144 Concerning enforceability, only four out of the nine CCMs set an unconditional implementation deadline by 2020. Deadlines in other methodologies may be subject to delays. The Agency is particularly concerned about this issue, as significant delays were already observed regarding essential inputs to the methodology[120].

145 Further, the Agency faced difficulties identifying parties responsible for the various processes or deliverables. This is revealed by the percentages of passive forms used when drafting the documents (ranging from 21% for GRIT CCM to 39% for the Baltic CCM) and has resulted in uncertainty about the entity responsible for each process step.

#### 3.2.2.3 Conclusions and observations

146 Nine CCMs pursuant to the CACM Regulation were approved by the relevant regulatory authorities[121]. The approved methodologies are diverse in terms of the level of "CACM Regulation coverage", the level of detail and harmonisation, non-discrimination, transparency and enforceability. Overall, the assessment revealed the following issues:

a) CACM Regulation coverage: the CCMs are not explicit on the implementation of a significant number of provisions in the CACM Regulation, as the share of those requirements explicitly covered is on average 72%. This may lead to diverging implementations across CCRs, in contradiction with the goal of a possible harmonised approach by 31 December 2020 pursuant to Article 21(4) of the CACM Regulation.

b) Detail and Harmonisation: a close look at the provisions on key aspects of the CCMs[122] confirms a great variety in the level of detail and harmonisation. For each of these aspects, the Agency identified good practices to be used as examples when amending or implementing the CCMs.

c) Non-discrimination: apart from the Core CCM, the methodologies for the other CCRs do not include measures explicitly targeted sufficiently to guarantee the prevention of undue discrimination, such as a guaranteed minimum level of cross-border capacity, conditions to the inclusion of internal critical network elements, and the limitation of LFs.

d) Transparency and enforceability: only the Core CCM includes provisions to ensure that all relevant data is published in a unique format, in a centralised platform, and subject to quality checks.

147 When interpreting the results of the analysis, the following important caveats apply. First, the differences in the level of detail are sometimes explained by the various tools available to NRAs and TSOs to address the challenges they face. For example, non-discrimination of cross-zonal exchanges may be tackled through bidding zone reviews and reconfigurations.

148 Second, low levels of harmonisation may have also been, in some instances, the consequence of the approach taken by NRAs during the approval process[123].

119 See for example question 11 of Annex III to the ACER Decision 02-2019 on the Core CCR TSOs' proposals for the regional design of the day-ahead and intraday common capacity calculation methodologies.

120 For example the Common Grid Model, as documented in paragraph 119 of the First Implementation Monitoring Report on Capacity Allocation and Congestion Management and Forward Capacity Allocation. See footnote 103 above for a complete reference.

121 See footnotes 103 and 104.

122 GSKs, Operational Security Limits, Allocation Constraints, Reliability Margins, Remedial Actions, and specific provisions on DA and ID capacity calculation.

123 In some instances, NRAs may have preferred to approve an agreeable text, even if they shared the view that there was room for further harmonisation in the proposal submitted by TSOs, rather than request amendments to TSOs (if the legal requirements were not met) or refer it to the Agency, which may be perceived by NRAs as a last resort measure.

149 Third, there is some room for interpretation of the level of harmonisation required by the CACM Regulation. Moreover, for some parameters, full harmonisation may not be necessary to achieve the most efficient outcome; in view of this, it might be even advisable that some parameters remain specific to ensure an efficient implementation (e.g. GSKs).

150 In addition, the implementation of these CCMs will likely be challenging because the approved CCMs introduced many changes and additional requirements compared to many current operational capacity calculation processes. The Agency is particularly concerned as TSOs are facing significant delays in the early implementation stages of inputs to these CCMs (e.g. CGMs)[124].

151 Therefore, the Agency recommends that the CCMs be amended as soon as possible in order to take into account the requirements of Article 16 of the recast Electricity Regulation, in particular regarding the guarantee of a minimum level of capacity available for cross-zonal trade, with a view to a possible harmonised approach by 31 December 2020 pursuant to Article 21(4) of the CACM Regulation. When amending the CCMs, the Agency recommends that TSOs and NRAs take utmost account of the following aspects:

a) The best practices identified in other CCMs (see Table 5 in annex 3 for the region with the highest score for each specific sub-aspect);

b) The need further to elaborate the CCMs in order to avoid undue discrimination of cross-zonal exchanges;

c) The need to guarantee effective transparency of the CCMs, including on their inputs and outputs;

d) The need clearly to assign responsibilities to the concerned parties ahead of the implementation of the methodologies;

e) The opportunity to harmonise approaches across CCRs.

124 See footnote 120.

# 4. Efficient use of available cross-zonal capacity

152 This Chapter reports on the progress made regarding the efficient use of existing cross-zonal transmission capacities in the DA (Section 4.1), ID (Section 4.2) and balancing (Section 4.3) timeframes across Europe.

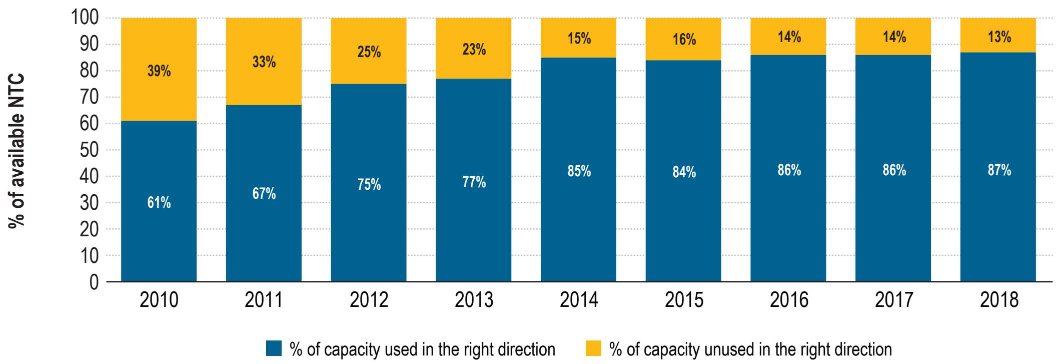
## 4.1 Day-ahead markets

153 In recent years, significant progress has been made towards implementing the Electricity Target Model (ETM) for the DA market timeframe, which foresees a single DA coupling at European level that enables cross-zonal capacity to be used in the 'right economic direction' (from low- to high- price areas) in the presence of a price differential across a given bidding-zone border[125]. The progress already made towards market integration, as well as the potential for further progress, is illustrated by two indicators.

154 First, Figure 24 shows the progress made over the past eight years in the efficient use of electricity interconnectors in the DA market timeframe. For the purpose of this analysis, efficient use is defined as the percentage of available capacity (NTC) used in the 'right economic direction' in the presence of a significant (>1 euro/MWh) price differential. This figure shows that, thanks to the use of DA market coupling on two thirds of European borders (covering 25 European countries[126]) by the end of 2018, the level of economic efficiency in the use of interconnectors in this timeframe increased from approximately 60% in 2010 to 87% in 2018.

155 Since 2016, the level of efficiency in the use of interconnectors has remained essentially unchanged despite the extension of market coupling to a few borders, e.g. between Austria and Slovenia (July 2016), between Croatia and Slovenia (June 2018) and between Great Britain and the SEM of Ireland and Northern Ireland (October 2018)[127].

Figure 24: Level of efficient use of interconnectors in the DA market timeframe in Europe – 2010 (Q4)–2018 (%)




*Source: ACER calculations based on ENTSO-E, Vulcanus and Nord Pool data.*

*Note: This figure contains data on 37 borders for which data was consistently available for the analysed period.*

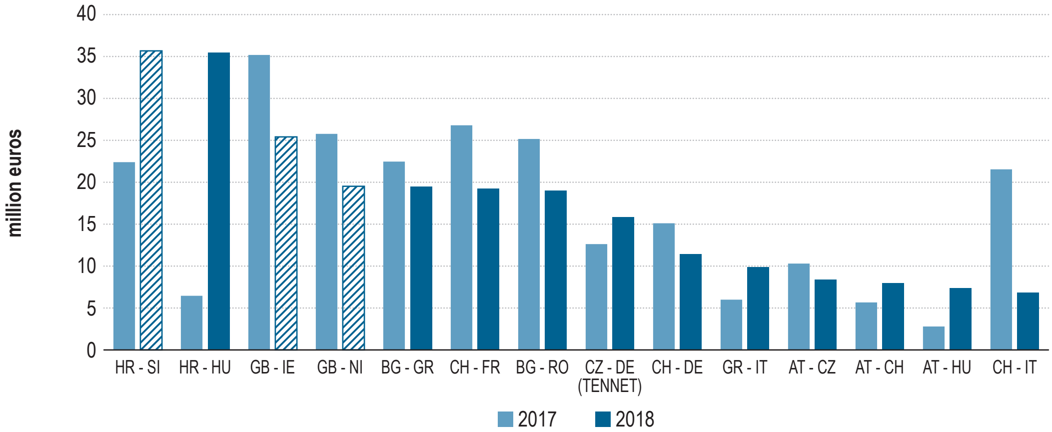
125 See the methodological paper on 'Benefits from day-ahead and intraday market coupling', available at: https://www.acer.europa.eu/en/Electricity/Market%20monitoring/Documents/ACER%20Methodological%20paper%20-%20Benefits%20from%20day-ahead%20and%20intraday%20market%20coupling.pdf.

126 By the end of 2018, DA market coupling had been implemented on 32 out of 42 EU borders (excluding the four borders with Switzerland). See footnote 20 for the countries included in the two differentiated market coupling initiatives that still coexist in Europe.

127 Even though the borders between Croatia and Slovenia and between Great Britain and the SEM of Ireland are not included in Figure 24 – see the reason in the note below the figure-, the effects of their inclusion in the level of overall efficient use of capacity in Europe would be minimal because market coupling has only applied for respectively half and a quarter of a year.

156 Second, Figure 25 shows that the overall estimated welfare gains still to be obtained from extending DA market coupling to all EU borders amounts to over 200 million euros per year[128]. Among the non-coupled borders the largest social welfare gains could still be obtained on all Swiss borders with the EU and on several borders of the Core Region[129]. The borders between Croatia and Slovenia and between Ireland and Great Britain are still included in Figure 25 although market coupling on these two borders was implemented in June and October 2018 respectively.

Figure 25: Estimated social welfare gains still to be obtained from further extending DA market coupling per border – 2017–2018 (million euros)




*Source: ACER calculations based on ENTSO-E, NRAs and Vulcanus data.*

*Note 1: Only non-coupled borders are shown. The borders within the Core (excluding CWE) region with 'multilateral' technical profiles are not included in this figure, because the methodology applied to the other borders, based on NTC values, is not applicable to these borders for this calculation.*

*Note 2: The borders between Croatia and Slovenia and between Ireland and Great Britain are depicted in a different pattern as market coupling on these two borders was implemented in June and October 2018 respectively. GB-IE refers to the East-West Interconnector, which links the electricity transmission grids of Ireland and Great Britain, and GB-NI refers to the Moyle Interconnector, which links the electricity grids of Northern Ireland and Great Britain.*

157 In conclusion, DA market coupling remains a crucial outstanding element in the integration of European electricity markets. The efficient use of interconnectors did not significantly increase in the last five years and the relevant welfare gains which could be obtained from extending implicit DA capacity allocation methods to all remaining European bidding zone borders that still applied explicit DA auctions at the end of 2018 highlight the urgency of such an extension.

## 4.2 Intraday markets

158 An efficient ID market requires sufficient ID liquidity because liquidity plays an important role in providing the right price signals to market participants, in attracting new market players and eventually in leading to more competition.

159 As shown in the preceding MMRs, ID liquidity has increased in recent years due to a combination of reasons, including the growing penetration of RES, which increases the need for short-term adjustments and the introduction of new ID products that better meet market participants' needs (e.g. the 15 minute-ID auctions in Germany).

128 Compared to the previous MMRs, the method used to calculate the welfare gains was slightly improved for this year's volume. In particular, the fact that the price spread does not remain constant but usually decreases when additional exchanges take place, is now taken into account. The link to the methodological paper describing the methodology is mentioned in footnote 125.

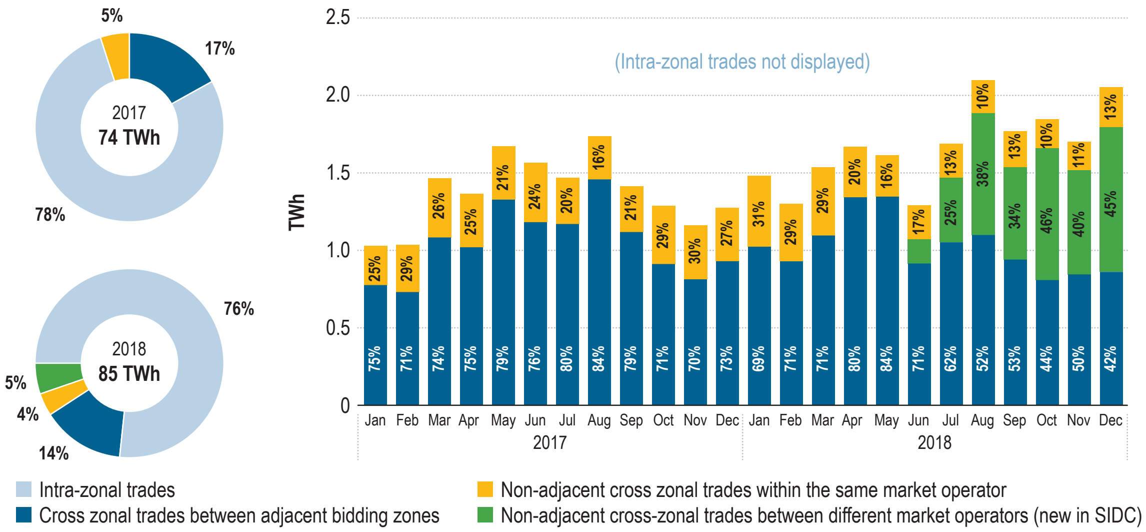
129 The remaining 10 non-coupled EU borders are: AT-CZ, AT-HU, BG-GR, BG-RO, CZ-DE, CZ-PL, DE-PL, GR-IT, PL-SK and HR-HU. The borders between the 4MMC and the MRC regions, i.e. AT-CZ, AT-HU, CZ-DE, CZ-PL, PL-SK and DE-PL are expected to be coupled initially through a NTC method (probably in 2020) before moving to FBMC. The HR-HU border is not included in this group and so far there is no roadmap for market coupling other than the Core FBMC. The coupling of the Greek and Italian markets is also expected in 2020 due to technical reasons and the ongoing process of the Greek market reform towards the target model. The coupling of the Bulgarian-Greek-Romanian market depends on the developments of the integration of the whole Core region, and it could be expected to take place after the coupling of the 4MMC and MRC regions. A new project for the coupling of Bulgarian-Croatian-Serbian markets has been initiated in February 2019 with a goal to implement trilateral market coupling within the MRC framework.

Moreover, precedent MMRs concluded that liquidity is higher in market areas where explicit ID auctions apply (i.e. the Iberian Peninsula and Italy-Slovenia), although the presence of ID auctions is not the only determinant factor of a higher liquidity in these areas[130].

160 The launch of SIDC in June 2018 was a major development and a significant step towards the completion of the IEM[131]. Together with other developments, such as the go-live of the Bulgarian (April 18) and the Irish and Northern Irish[132] ID market, it contributed to fostering ID liquidity in Europe even further.

161 In fact, Figure 26 (left side) shows that 85 TWh were traded in ID continuous markets in Europe in 2018, which is 15% more than the year before. Figure 26 (right side) shows a significant increase of cross-zonal continuous ID trading after the launch of the SIDC. In particular, the Figure shows that this growth can be attributed to the significant increase of long-distance cross-zonal trades, i.e. between non-adjacent bidding zones, which are facilitated by SIDC.

Figure 26: Share of total ID-traded volumes according to intra-zonal vs cross-zonal nature of trades in Europe (left side, %) and monthly evolution of the cross-zonal intraday traded volumes for all continuous trading markets 2017–2018 (right side, TWh)




*Source: ACER calculations based on Nominated Electricity Market Operators (NEMOs) data.*

162 The above-mentioned increase in cross-zonal ID trading suggests an improvement in the level of efficient use of ID cross-zonal capacity in Europe Although the required data to analyse the level of efficient use of ID cross-zonal capacity on a per border basis was not available to the Agency for 2018, it can be inferred that in 2018, this level was, on average, higher than in 2017[133] (i.e. probably higher than 50% for the whole Europe).

163 A more significant increase in the level of efficient use of ID capacity is expected from the implementation of pan-European ID auctions as envisaged in ACER's decision 01/2019[134].

130 For more information on the factors explaining ID liquidity, see Section 4.2 of the 2017 MMR.

131 The first go-live of the SIDC includes the following countries: Austria, Belgium, Denmark, Estonia, Finland, France, Germany, Latvia, Lithuania, Norway, the Netherlands, Portugal, Spain and Sweden. A second wave, scheduled for the last quarter of 2019 will expand the SIDC to seven additional markets (Poland, the Czech Republic, Hungary, Slovenia, Croatia, Bulgaria and Romania).

132 The SEM has introduced two continuous and three auctioned ID trading products in October 2018.

133 See Paragraph 224 of the 2017 MMR edition of the Electricity Wholesale Markets volume.

134 See the Agency's Decision 01/2019 establishing a single methodology for pricing intraday cross-zonal capacity at https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions/ACER%20Decision%2001-2019%20on%20intraday%20cross-zonal%20capacity%20pricing%20methodology.pdf.

## 4.3 Balancing markets

164 An integrated cross-zonal balancing market is intended to maximise the efficiency of balancing by using the most efficient balancing resources while safeguarding operational security. In fact, the efficient exchange of balancing services (i.e. balancing capacity and balancing energy including imbalance netting) is the core element of the recently adopted EB Guideline[135], which provides the legal framework for integrating national balancing markets.

165 The actual volumes of imbalance netting and exchanged balancing energy can be compared to the potential of these two services, i.e. the maximum amount of imbalance netting and balancing energy volumes that could be exchanged subject to sufficient available cross-zonal capacity. Based on the methodology used in last year's MMR[136], the actual application of imbalance netting and exchange of balancing energy for a selection of 13 borders for which sufficient information was available is estimated at approximately 23% of their potential in 2018.

166 Although this value (23%) indicates a slight improvement (1 percentage point) compared to the previous year, it is still relatively low when compared to the level of efficiency recorded in the preceding DA (87%) and ID (slightly above 50%) timeframes in 2018. This is mainly due to the fact that the exchange of balancing energy (except imbalance netting) is still inexistent or residual on most European borders. The potential benefits from imbalance netting and exchange of balancing energy calculated for the whole of Europe, would be as high as 1.3 billion euros annually[137].

135 See footnote 18.

136 See methodological paper on 'Benefits from balancing markets integration', available at: https://www.acer.europa.eu/en/Electricity/Market%20monitoring/Documents/ACER%20Methodological%20paper%20-%20Benefits%20from%20balancing%20markets%20integration.pdf.

137 See footnote 136 and paragraph 582 of the Electricity Wholesale Markets Volume of the MMR 2014.

# 5. Capacity mechanisms and generation adequacy

167 As pointed out in the recast Electricity Regulation, and in line with the principles of the IEM and the Energy Union, CMs[138] should only be introduced as a last resort to address adequacy problems that cannot be solved through the removal of market distortions. MSs applying or considering a CM shall review its necessity and design in light of the recast Electricity Regulation[139]. The necessity of temporary CMs should be based on a European resource adequacy assessment carried out by ENTSO-E. The European assessment may be complemented by studies at national level. The methodologies to carry out both European and national adequacy studies shall duly consider the impact of market rules and the contribution of interconnections.

168 This Chapter presents the status of CMs in Europe and provides an overview of the costs incurred or expected for financing them (Section 5.1). It then briefly presents updates concerning the way MSs take into account interconnections in their national adequacy assessments (Section 5.2). Finally, the Chapter includes a preliminary analysis of the necessity of CMs, already in operation or under consideration, on the basis of perceived adequacy concerns resulting from ENTSO-E's 2018 Mid-term Adequacy Forecast (MAF 2018)[140] (Section 5.3).

## 5.1 State of play of capacity mechanisms

169 Figure 27 presents the status of different types of CMs in Europe by the end of 2018. Following the relevant approvals by the European Commission with respect to the State Aid Guidelines[141] in February 2018[142], Belgium, France, Germany, Greece, Ireland, Italy and Poland have new CMs in place. However, the establishment of strategic reserves in Germany has been delayed[143], while Italy has not conducted any capacity auction yet. In Greece[144] and Poland, the first auctions took place in October and December 2018, respectively, while the first long-term auction in Ireland and Northern Ireland[145] occurred in April 2019. In 2018, Lithuania initiated the process of introducing a new market-based CM with a view to replacing strategic reserves and aiming for the legal acts introducing the new mechanism to be operational by the end of 2020[146].

170 The most prominent development last year, however, was the decision of the General Court of the European Union issued on November 2018 to annul the EC's 2015 approval of the CM of Great Britain. The decision states that the EC should have conducted a more thorough investigation of the necessity and appropriateness of the proposed mechanism. As a result, other CM proposals may have to be updated[147].

138 Pursuant to Article 2(22) of the recast Electricity Regulation, a CM is *'a temporary measure to ensure the achievement of the necessary level of resource adequacy by remunerating resources for their availability, excluding measures relating to ancillary services or congestion management'*. Interruptibility schemes are beyond the scope of this chapter.

139 See e.g. Article 21(6) and 22(5) of the recast Electricity Regulation.

140 See https://www.entsoe.eu/outlooks/midterm/. See also https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Opinions/Opinions/ACER%20Opinion%2011-2019%20on%20the%20ENTSO-E%20draft%20Ten-Year%20Network%20Development%20Plan%202018.pdf (p. 32) for the Agency opinion about the MAF 2018.

141 Communication from the Commission, Guidelines on State aid for environmental protection and energy 2014-2020, (2014/C 200/01) available at: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52014XC0628(01)&from=EN.

142 See http://europa.eu/rapid/press-release_IP-18-682_en.htm.

143 The first auctions are scheduled for December 2019 with a contract period set from October 2020 to September 2022 (see https://www.bgbl.de/xaver/bgbl/start.xav#__bgbl__%2F%2F*%5B%40attr_id%3D%27bgbl119s0058.pdf%27%5D__1555054522343 in German language).

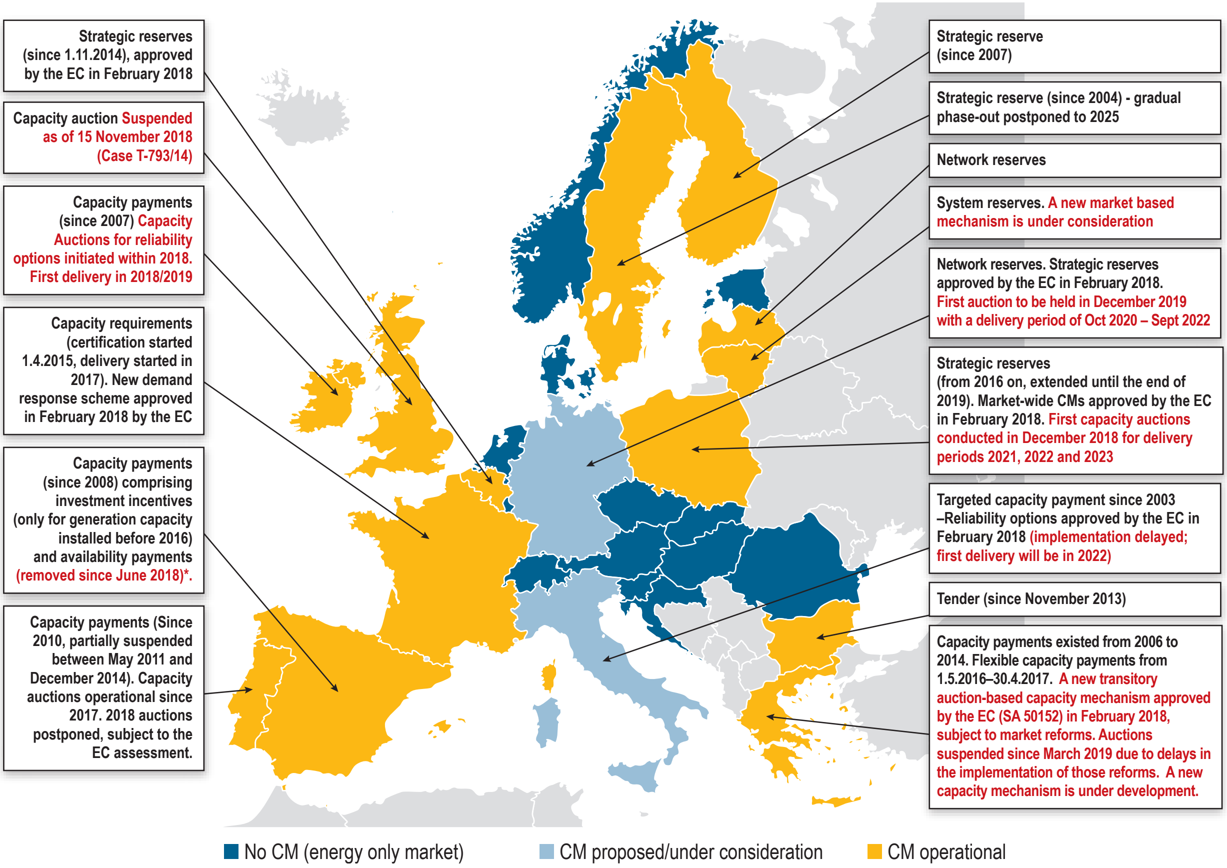
144 An auction-based transitory flexible capacity remuneration scheme was initially approved subject to additional market design measures in line with the ETM to be implemented by March 2019. As the implementation of those measures were postponed beyond this deadline, no additional auctions have been undertaken after that date.

145 The capacity payment scheme was replaced with auctions for reliability options. Transitional capacity auctions for year ahead delivery (T-1) replaced capacity payments from December 2017 on. In April 2019, the first capacity auction for reliability options with four-year ahead delivery (T-4) took place.

146 More details at https://enmin.lrv.lt/en/news/energy-ministry-invites-you-to-submit-proposals-on-the-long-term-capacity-mechanism-concept.

147 See https://curia.europa.eu/jcms/upload/docs/application/pdf/2018-11/cp180178en.pdf. The Commission has appealed the General Court's judgement to the European Court of Justice. However, the appeal does not suspend the effects of the General Court's judgment.

Figure 27: CMs in Europe – 2018



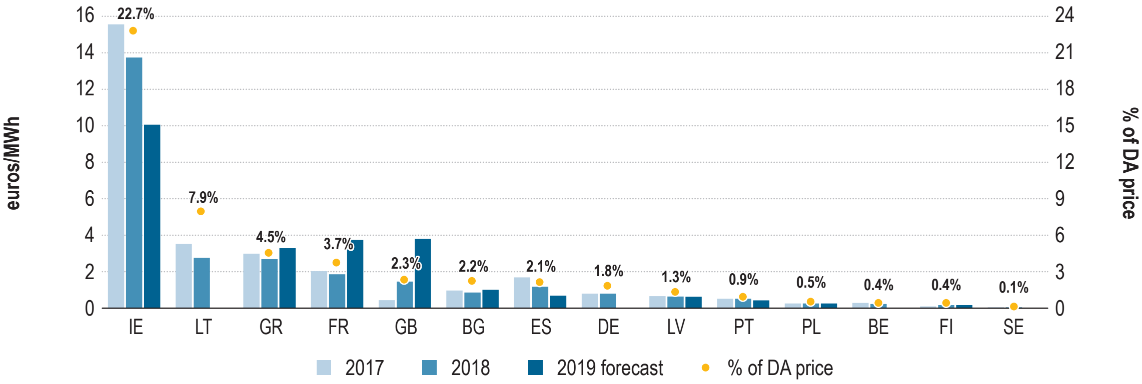

*Source: Based on information from NRAs and the EC.*

*Note: Changes with respect to 2017 are outlined in red. Information regarding the consideration of a new CM in Lithuania was derived from the website of the Lithuanian Ministry of Energy. The network reserves might not be considered as a CM in the context of the CEP (see footnote 138) but they are included for consistency with previous MMRs and because they were considered as such in the EC's Sector Inquiry on Capacity Mechanisms, see https://ec.europa.eu/energy/sites/ener/files/documents/com2016752.en_.pdf. In Spain, the CM used to comprise "investment incentives" and "availability payments". The availability payments were removed in June 2018 and the investment incentives apply only to generation capacity installed before 2016.*

171 Figure 28 provides an update on the national costs incurred or expected to be incurred in order to finance CMs. In 2018, the overall cost of CMs across the EU reached 2.5 billion euros, which constitutes a 7% decrease compared to 2017. Nevertheless costs are expected to be higher in 2019 and beyond, based on the available forecasts and the fact that some of the CMs displayed in Figure 27 will become operational in 2019 or 2020.

172 The substitution of administratively-set capacity payments with competitive schemes, following the provisions of the Guidelines on state aid for environmental protection and energy 2014-2020, significantly reduced overall cost in Ireland and Northern Ireland (61 million euros or 12% less compared to 2017) in 2018, which is expected to continue at a higher pace in 2019. However, capacity payments still account for a large share of total energy costs in the SEM. Costs remain significant in some other MSs, including Lithuania, Greece, Great Britain, France, Spain and Bulgaria.

Figure 28: Costs incurred or forecast to finance CMs per unit demand and expressed as a percentage of the yearly average DA price in Europe – 2017–2019 (euros per MWh demand and %)




*Source: ACER calculations based on NRAs data.*

*Note 1: Percentages refer to 2018 data unless otherwise stated herein. Costs per unit demand are based on total annual realised payments to capacity providers for delivery of capacity in the relevant year; when and where the payments have not been realised yet, the values are the best estimates of the expected payments due to CMs provided by NRAs. Demand data refers to the latest available annual demand figures (2016 values) from Eurostat. Average DA prices follow the same convention as for Figure 1. For Sweden, the average DA price over all bidding-zones is used.*

*Note 2: The overall costs for France are an approximation considering that all capacity certificates are valued at the market reference price, while a significant share (which varies year on year) of those capacity certificates are implicitly valued through the ARENH mechanism which is a right that entitles suppliers to purchase electricity from nuclear generators at a regulated price. As a consequence, the actual costs for France are dependent on the reference used to value the capacity certificates related to the ARENH mechanism. For Greece, the provided costs referred only to the reference period i.e. January–April for 2017 and October–December for 2018, and were scaled up to approximate yearly costs. Great Britain's cost figures for 2018 refer to the period until 15 November 2018, i.e. the time of the CM's suspension, while for 2019 they refer to the period from December 2018 until the end of November 2019 and are estimates based on the provisions of the suspended CM. For 2018 these costs were scaled up accordingly to approximate yearly costs. For Germany, only the costs for the current Network Reserves scheme are provided (preliminary costs for 2018), since a forecast of the costs related to the new CM was not available. As costs data for Belgium for 2019 are confidential, last year's forecast for 2019 is presented in the graph for this MS; however, the Belgian NRA reported that the actual 2019 costs are lower. In Spain, the CM was cancelled in June 2018. The depicted costs refer to the remaining long term investment incentives provided to installations before 2016 and availability payments for the first half of the year.*

## 5.2 Contribution of interconnectors to adequacy

173 Concerning the contribution of interconnectors to SoS, six MSs, i.e. Austria, Bulgaria, the Czech Republic[148], Latvia, Romania and Spain[149], as well as Norway still do not take interconnectors into account in their national adequacy studies. Of these, Bulgaria, Latvia and Spain have operational CMs. Since the last MMR, Sweden and Slovakia have introduced ways to account for interconnectors in their adequacy methodologies, while Greece has improved the modelling of interconnections. Therefore, the relevance of the adequacy studies results has improved for these countries.

174 In view of the provisions of the recast Electricity Regulation, national resource adequacy studies will have to take all resources (including interconnections) into account, hence improvements are expected in the future. Furthermore, the evaluation of cross-zonal contribution at times of scarcity should rely on an appropriate statistical or probabilistic approach, leading to a better representation of capacity needs at national and regional level.

175 Moreover, Article 16(8) of the recast Electricity Regulation sets a 70% minimum level of available capacity for cross-zonal trade from 1 January 2020 onwards[150]. This requirement should be taken into account in the European and national mid-term adequacy studies and is expected to increase the level of contribution of interconnections to SoS significantly, reducing the total regional needs for available capacity for resource adequacy purposes[151].

148 Based on data received for 2017 since no updates on this matter were available for this year's report.

149 Spain does consider interconnections in the adequacy assessment methodology, however it does not account for them in the decisive scenario to justify interventions regarding adequacy issues.

150 Derogations and action plans may allow MSs gradually to implement this measure.

151 The impact is difficult to quantify, as the 70% minimum capacity requirement is subject to operational security constraints. In addition, decreasing resource margins may be perceived for some exporting MSs, although the total resource adequacy need is very likely to decrease.

## 5.3 Capacity Mechanisms and resource adequacy concerns

176 According to Article 21(4) of the recast Electricity Regulation, *"Member States shall not introduce capacity mechanisms where both the European resource adequacy assessment and the national resource adequacy assessment, or in the absence of a national resource adequacy assessment, the European resource adequacy assessment have not identified a resource adequacy concern"*. Similarly, article 21(6) states that *"Where a Member State applies a capacity mechanism, it shall review that capacity mechanism and shall ensure that no new contracts are concluded under that mechanism where both the European resource adequacy assessment and the national resource adequacy assessment, or in the absence of a national resource adequacy assessment, the European resource adequacy assessment have not identified a resource adequacy concern […]"*.

177 Comparing the SoS levels measured in national or regional adequacy assessments to national adequacy standards would likely allow to draw conclusions about the possible presence and location of adequacy concerns. However, not all MSs have defined an adequacy standard, and the current national adequacy standards are very heterogeneous and do not rely on a uniform methodology[152]. Article 25(3) of the recast Electricity Regulation states that *"The reliability standard shall be calculated using at least the value of lost load and the cost of new entry over a given timeframe and shall be expressed as 'expected energy not served' and 'loss of load expectation'"*. As a result, many MSs will likely update their national adequacy standards in the near future.

178 In order to foresee whether future regional adequacy studies may highlight adequacy concerns, the Agency relied on the results of the MAF 2018[153], and applied a conservative reliability standard as follows. The preliminary condition for hinting at the need for further studies to assess potential adequacy concerns for the purposes of this initial appraisal[154] is based on two relevant reliability indicators, i.e. the Loss of Load Expectation (LOLE)[155] and the Expected Energy Not Served (EENS)[156], i.e. further studies would be needed if both indicators exceed the following limits[157].

- LOLE > 1 hour
- EENS > 0.001% of annual demand

In this respect, for a given MS, if either of the reliability indicators is below the respective threshold for both of the examined years, i.e. 2020 and 2025[158], there is some indication that no SoS issues may be perceived at the regional level for this MS. The necessity of a CM in this MS may thus be challenged.

179 Figure 29 and Figure 30 depict the levels of LOLE and EENS/total annual demand respectively, compared to the aforementioned thresholds, for 2020 and 2025, for the MSs which have CMs in place (either approved or operational). Based on the aforementioned methodology, Figure 31 then describes whether possible adequacy concerns may arise in each MS, based on the regional study. The analysis indicates that seven MSs, i.e. Germany, Latvia, Lithuania, Poland, Portugal, Spain and Sweden, do not seem to face an adequacy problem in either 2020 or 2025, according to the MAF 2018 results. On the other hand, further investigations would be needed on potential adequacy concerns for Belgium, Bulgaria, Greece, Finland, France, Ireland and the United Kingdom.

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152 See Section 10.2 (p.61) of the MMR 2015 for a detailed description of national adequacy standards.

153 As a consequence, adequacy concerns derived from national adequacy assessments have not been considered in this chapter. The results of national adequacy assessments and the results of ENTSO-E's MAF 2018 may not be directly comparable as they may be based on different assumptions and scenarios.

154 This initial appraisal does portend neither the methodology nor the results of the European adequacy assessment to be implemented pursuant to Article 23 of the recast Electricity Regulation.

155 Loss Of Load Expectation or LOLE is the average number of hours per year, during which loss of load, i.e. load shedding, occurs in a given area (based on modelling results).

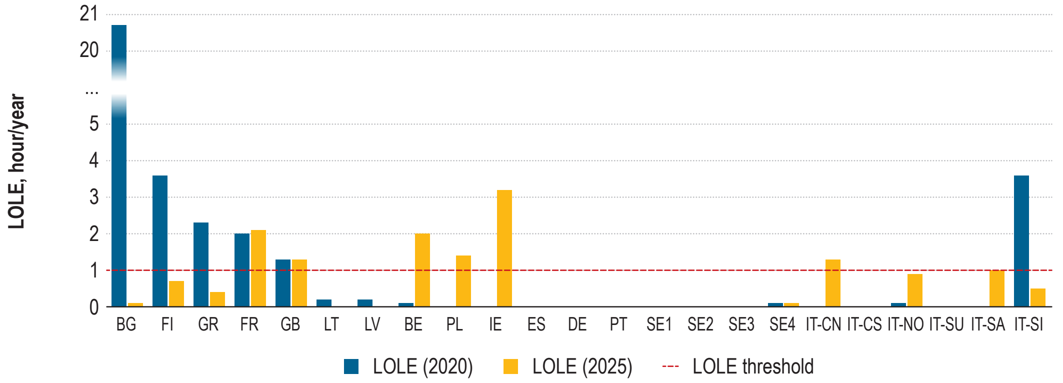
156 Expected Energy Not Served (EENS) is the average energy not supplied (i.e. shed) per year.

157 The approach followed is a conservative one, e.g. the limit of LOLE (1hr) is significantly below all LOLE thresholds declared by NRAs for the 2015 MMR.

158 This study focuses on base case MAF 2018 scenarios for these years, assuming that these scenarios best reflect the "appropriate central reference scenario" pursuant to Article 23(5)(b) of the recast Electricity Regulation.

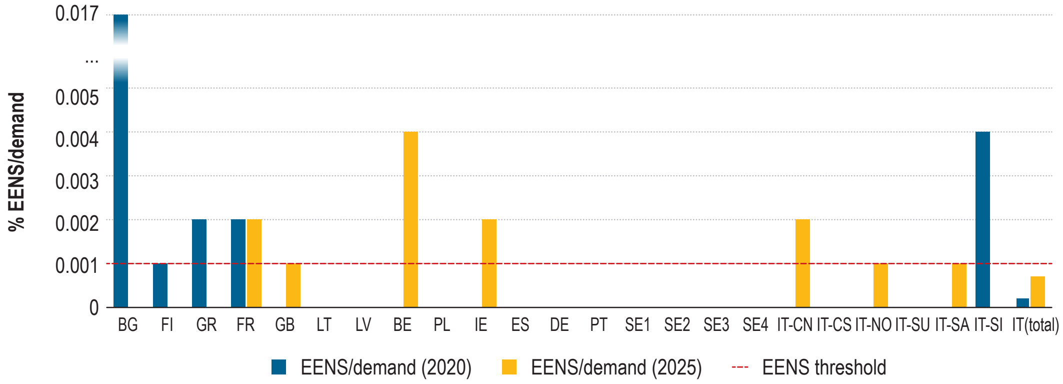
180 For Italy, the analysis is made at the bidding zone level, consistently with MAF 2018. It shows that Italy-Centre-North and Italy-Sicily (representing respectively approximately 11% and 6% of total load[159]) exceed the thresholds for both LOLE and EENS/demand for 2025 and 2020 respectively. However, when considering Italy as a whole, the (aggregated) EENS is lower than the threshold of annual demand for both 2020 and 2025, indicating that possible resource adequacy issues may occur at the bidding zone level rather than at the national level. As a consequence, and given the national scope of the Italian CM, Figure 31 displays Italy among the countries with an "adopted CM and no SoS issues detected in MAF".

Figure 29: LOLE for MSs with approved or operational CMs according to ENTSO-E's MAF 2018 (hours/year)




*Source: ACER calculations based on ENTSO-E's MAF 2018 results.*

Figure 30: EENS relative to total annual demand, for MSs with approved or operational CMs according to ENTSO-E's MAF 2018 (%)

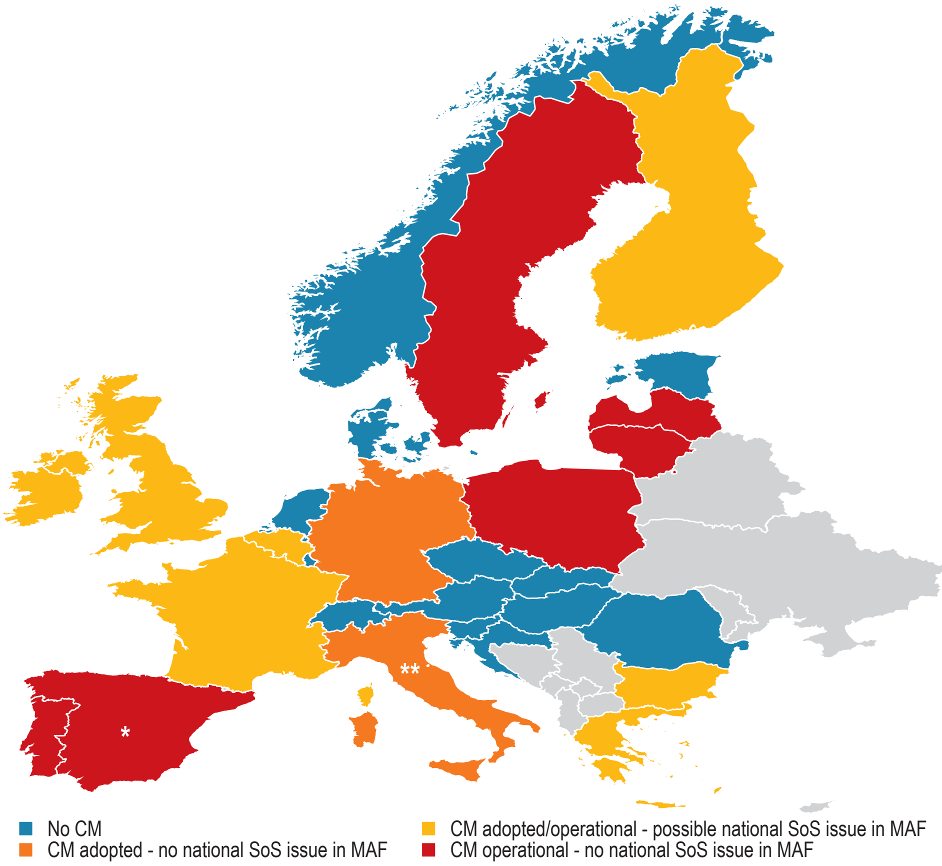



*Source: ACER calculations based on ENTSO-E's MAF 2018 results and dataset.*

*Note: For Italy the total EENS at national level is calculated as the sum of all EENS values for each bidding zone divided by the total national demand of the relevant year.*

159 According to ENTSO-E TP data for 2018.

Figure 31: Perceived need for CMs based on MAF 2018 results




*Source: ACER.*

*Note: In Spain (*), the CM used to comprise "investment incentives" and "availability payments". The availability payments were removed in June 2018 and the investment incentives apply only to generation capacity installed before 2016. In Italy (**) the analysis suggests potential adequacy issues at the bidding zone level, in Italy-Centre-North and Italy-Sicily, rather than at the national level.*

181 Despite the preliminary character of the analysis, the outcomes clearly indicate that an appropriate methodology for assessing resource adequacy both at European and at national level, properly taking interconnections' contribution into account, and reliability standards derived from a harmonised calculation methodology, may better enable MSs to grasp the benefits of market integration with respect to SoS. Such integration would eliminate distortions stemming from uncoordinated assessment of resource adequacy and would reduce the need for costly actions possibly categorised as state aid, to the benefit of end consumers.

# Annex 1: Additional figures and tables

Table 1: Average DA price differentials across European borders (ranked) – 2016–2018 (euros/MWh)

| | Average price differentials (euros/MWh) | | | | Average of absolute price differentials (euros/MWh) | | | |
|---|---|---|---|---|---|---|---|---|
| Border | 2016 | 2017 | 2018 | 2016-2018 | 2016 | 2017 | 2018 | 2016-2018 |
| BG - GR | -6.0 | 14.6 | -20.5 | -4.0 | 14.6 | 19.8 | 24.2 | 19.5 |
| FR - GB | -12.4 | -6.8 | -14.7 | -11.3 | 15.4 | 12.5 | 15.6 | 14.5 |
| AT - IT | -13.7 | -20.2 | -14.4 | -16.1 | 13.7 | 20.2 | 14.4 | 16.1 |
| BG - RO | -0.3 | -8.3 | -6.5 | -5.0 | 11.4 | 14.8 | 13.1 | 13.1 |
| GB - NL | 16.9 | 12.4 | 12.4 | 13.9 | 17.0 | 13.1 | 12.7 | 14.3 |
| FR - IT | -5.9 | -9.4 | -10.5 | -8.6 | 7.3 | 9.8 | 11.0 | 9.4 |
| ES - FR | 2.9 | 7.3 | 7.1 | 5.8 | 8.0 | 10.2 | 10.8 | 9.7 |
| NL - NO2 | 7.1 | 10.4 | 9.3 | 8.9 | 7.5 | 10.6 | 10.6 | 9.6 |
| GB - IE | 4.0 | 5.9 | 2.9 | 4.3 | 13.8 | 10.5 | 10.4 | 11.6 |
| DE - PL | -7.5 | -2.8 | -7.7 | -6.0 | 10.0 | 8.7 | 9.9 | 9.5 |
| IT - SI | 7.0 | 4.9 | 9.5 | 7.1 | 7.2 | 7.0 | 9.8 | 8.0 |
| CH - IT | -4.8 | -8.8 | -8.5 | -7.4 | 6.2 | 10.2 | 9.5 | 8.6 |
| CH - DE | 8.9 | 11.8 | 7.7 | 9.5 | 9.5 | 13.0 | 9.0 | 10.5 |
| CZ - PL | -5.3 | -0.5 | -6.1 | -4.0 | 9.1 | 8.4 | 8.9 | 8.8 |
| PL - SK | 5.0 | -4.1 | 3.7 | 1.5 | 9.1 | 11.1 | 8.7 | 9.6 |
| GR - IT | 2.5 | 5.5 | 1.0 | 3.0 | 8.2 | 9.0 | 8.4 | 8.5 |
| DE - NL | -3.3 | -5.1 | -8.1 | -5.5 | 3.8 | 6.6 | 8.3 | 6.2 |
| AT - CH | -8.9 | -11.8 | -5.9 | -8.9 | 9.5 | 13.0 | 7.4 | 10.0 |
| PL - SE4 | 6.9 | 4.6 | 5.8 | 5.8 | 9.2 | 5.5 | 7.1 | 7.3 |
| AT - HU | -6.4 | -16.2 | -4.7 | -9.1 | 7.4 | 16.9 | 6.9 | 10.4 |
| DE - FR | -7.8 | -10.8 | -5.7 | -8.1 | 8.0 | 10.9 | 6.8 | 8.6 |
| DE - SE4 | -0.5 | 1.9 | -1.9 | -0.2 | 4.9 | 7.9 | 6.7 | 6.5 |
| BE - NL | 4.4 | 5.3 | 2.7 | 4.1 | 6.1 | 7.0 | 6.3 | 6.5 |
| BE - FR | -0.1 | -0.4 | 5.1 | 1.5 | 2.6 | 3.8 | 5.6 | 4.0 |
| CH - FR | 1.1 | 1.0 | 2.0 | 1.4 | 4.9 | 4.5 | 5.2 | 4.9 |
| DE - DK2 | -0.4 | 2.1 | -1.7 | 0.0 | 4.3 | 6.2 | 5.1 | 5.2 |
| AT - SI | -6.6 | -15.3 | -4.8 | -8.9 | 7.4 | 15.3 | 5.0 | 9.2 |
| HU - RO | 2.1 | 2.4 | 4.6 | 3.0 | 2.5 | 3.0 | 5.0 | 3.5 |
| DK1 - NO2 | 1.5 | 1.3 | 0.8 | 1.2 | 3.1 | 4.8 | 4.9 | 4.3 |
| HR - HU | | 1.5 | 1.0 | 1.3 | | 5.0 | 4.7 | 4.9 |
| FI - NO4 | 7.4 | 7.5 | 3.1 | 6.0 | 7.6 | 7.6 | 4.5 | 6.6 |
| LT - PL | 0.1 | -1.7 | -2.2 | -1.3 | 6.1 | 4.2 | 4.5 | 4.9 |
| AT - CZ | -2.2 | -2.3 | 0.3 | -1.4 | 3.9 | 4.5 | 4.2 | 4.2 |
| CZ - DE | 2.2 | 2.3 | 1.6 | 2.0 | 3.9 | 4.5 | 4.1 | 4.2 |
| DE - DK1 | 2.3 | 4.0 | 0.4 | 2.2 | 3.9 | 6.6 | 4.1 | 4.9 |
| DK1 - SE3 | -2.6 | -1.2 | -0.5 | -1.4 | 2.7 | 2.9 | 4.1 | 3.2 |
| LT - SE4 | 7.0 | 2.9 | 3.6 | 4.5 | 7.1 | 3.0 | 3.8 | 4.6 |
| HR - SI | | -0.1 | 0.8 | 0.3 | | 10.3 | 3.1 | 6.7 |
| EE - LV | -3.0 | -1.5 | -2.8 | -2.4 | 3.1 | 1.5 | 2.9 | 2.5 |
| FI - SE1 | 3.5 | 2.3 | 2.6 | 2.8 | 3.5 | 2.3 | 2.6 | 2.8 |
| HU - SK | 4.0 | 9.4 | 2.5 | 5.3 | 4.0 | 9.4 | 2.6 | 5.3 |
| CZ - SK | -0.3 | -4.5 | -2.4 | -2.4 | 0.6 | 4.5 | 2.5 | 2.5 |
| FI - SE3 | 3.2 | 1.9 | 2.3 | 2.5 | 3.2 | 1.9 | 2.3 | 2.5 |
| DK2 - SE4 | -0.1 | -0.2 | -0.2 | -0.2 | 0.7 | 1.7 | 2.1 | 1.5 |
| NO4 - SE1 | -3.9 | -5.1 | -0.5 | -3.2 | 4.1 | 5.4 | 1.9 | 3.8 |
| NO4 - SE2 | -3.9 | -5.1 | -0.5 | -3.2 | 4.1 | 5.4 | 1.9 | 3.8 |
| AT - DE | 0.0 | 0.0 | 1.8 | 0.6 | 0.0 | 0.0 | 1.8 | 0.6 |
| NO1 - SE3 | -3.1 | -2.2 | -0.9 | -2.1 | 3.3 | 2.9 | 1.5 | 2.6 |
| NO3 - SE2 | -0.3 | -1.3 | -0.1 | -0.6 | 0.9 | 1.7 | 0.9 | 1.2 |
| EE - FI | 0.6 | 0.0 | 0.3 | 0.3 | 0.7 | 0.1 | 0.4 | 0.4 |
| ES - PT | 0.2 | -0.2 | -0.2 | -0.1 | 0.3 | 0.4 | 0.3 | 0.3 |
| LT - LV | -0.4 | 0.4 | 0.1 | 0.0 | 0.5 | 0.5 | 0.2 | 0.4 |

*Source: ACER calculations based on the ENTSO-E's TP data.*

*Note: No data were available for the Croatian borders in 2016.*

Table 2: Average oriented NTCs on European borders – 2017–2018 (MW and % change)

| CCR | Directional border | NTC 2017 (MW) | NTC 2018 (MW) | Change 2017/2018 |
|---|---|---|---|---|
| Baltic | EE → FI | 1,006 | 977 | -3% |
| | FI → EE | 1,008 | 981 | -3% |
| | EE → LV | 795 | 764 | -4% |
| | LV → EE | 649 | 711 | 9% |
| | LT → LV | 587 | 589 | 0% |
| | LV → LT | 1,044 | 1,025 | -2% |
| | LT → PL | 377 | 477 | 27% |
| | PL → LT | 268 | 295 | 10% |
| | LT → SE4 | 450 | 441 | -2% |
| | SE4 → LT | 579 | 562 | -3% |
| Channel | FR → GB | 1,736 | 1,853 | 7% |
| | GB → FR | 1,736 | 1,853 | 7% |
| | GB → NL | 997 | 1,016 | 2% |
| | NL → GB | 997 | 1,016 | 2% |
| Core (excl. CWE) | AT → CZ | 621 | 550 | -11% |
| | CZ → AT | 659 | 576 | -13% |
| | AT → HU | 526 | 495 | -6% |
| | HU → AT | 597 | 585 | -2% |
| | AT → SI | 727 | 693 | -5% |
| | SI → AT | 933 | 839 | -10% |
| | CZ → DE/LU | 2,568 | 2,671 | 4% |
| | DE/LU → CZ | 1,156 | 1,839 | 59% |
| | CZ → PL | 599 | 591 | -1% |
| | PL → CZ | 837 | 829 | -1% |
| | CZ → SK | 1,824 | 1,859 | 2% |
| | SK → CZ | 1,200 | 1,200 | 0% |
| | CZ+DE+SK → PL | 217 | 365 | 68% |
| | PL → CZ+DE+SK | 783 | 647 | -17% |
| | HR → HU | 1,000 | 967 | -3% |
| | HU → HR | 1,200 | 1,200 | 0% |
| | HR → SI | 1,464 | 1,450 | -1% |
| | SI → HR | 1,467 | 1,457 | -1% |
| | HU → RO | 678 | 661 | -3% |
| | RO → HU | 582 | 500 | -14% |
| | HU → SK | 792 | 966 | 22% |
| | SK → HU | 1,117 | 1,266 | 13% |
| | PL → SK | 540 | 542 | 0% |
| | SK → PL | 491 | 493 | 1% |
| Core (tech. prof.) | CZ+PL → DE (50 Hertz) | 1,302 | 1,358 | 4% |
| | DE (50 Hertz) → CZ+PL | 604 | 1,002 | 66% |
| Greece-Italy (GRIT) | GR → IT | 337 | 325 | -4% |
| | IT → GR | 340 | 325 | -5% |
| Hansa | DE/LU → DK1 | 1,384 | 1,400 | 1% |
| | DK1 – DE/LU | 525 | 1,028 | 96% |
| | DE/LU → DK2 | 513 | 442 | -14% |
| | DK2 – DE/LU | 501 | 431 | -14% |
| | PL → SE4 | 180 | 196 | 9% |
| | SE4 → PL | 466 | 557 | 20% |
| Italy North | AT → IT North | 244 | 252 | 3% |
| | IT North → AT | 100 | 105 | 5% |
| | FR → IT North | 2,528 | 2,410 | -5% |
| | IT North → FR | 1,019 | 1,020 | 0% |
| | IT North → SI | 649 | 644 | -1% |
| | SI → IT North | 548 | 539 | -2% |
| IU | GB → SEM | 974 | 895 | -8% |
| | SEM → GB | 759 | 672 | -12% |

| CCR | Directional border | NTC 2017 (MW) | NTC 2018 (MW) | Change 2017/2018 |
|---|---|---|---|---|
| Nordic | DK1 → SE3 | 529 | 527 | 0% |
| | SE3 → DK1 | 634 | 637 | 0% |
| | DK2 → SE4 | 1,210 | 1,008 | -17% |
| | SE4 → DK2 | 1,177 | 1,081 | -8% |
| | FI → SE1 | 1,056 | 1,073 | 2% |
| | SE1 → FI | 1,514 | 1,503 | -1% |
| | FI → SE3 | 1,183 | 1,133 | -4% |
| | SE3 → FI | 1,183 | 1,181 | 0% |
| Norwegian borders | DK1 → NO2 | 1,223 | 1,250 | 2% |
| | NO2 → DK1 | 1,223 | 1,238 | 1% |
| | NL → NO2 | 691 | 584 | -15% |
| | NO2 → NL | 648 | 572 | -12% |
| | NO1 → SE3 | 1,247 | 1,793 | 44% |
| | SE3 → NO1 | 1,308 | 1,597 | 22% |
| | NO3 → SE2 | 548 | 571 | 4% |
| | SE2 → NO3 | 730 | 784 | 7% |
| | NO4 → SE1 | 442 | 468 | 6% |
| | SE1 → NO4 | 301 | 348 | 15% |
| | NO4 → SE2 | 101 | 122 | 21% |
| | SE2 → NO4 | 140 | 174 | 25% |
| SEE | BG → GR | 408 | 450 | 10% |
| | GR → BG | 364 | 362 | -1% |
| | BG → RO | 300 | 319 | 6% |
| | RO → BG | 263 | 277 | 6% |
| SWE | ES → FR | 2,294 | 2,184 | -5% |
| | FR → ES | 2,559 | 2,568 | 0% |
| | ES → PT | 1,979 | 2,221 | 12% |
| | PT → ES | 2,978 | 3,066 | 3% |
| Swiss borders | AT → CH | 756 | 866 | 14% |
| | CH → AT | 1,027 | 1,043 | 2% |
| | CH → DE/LU | 4,000 | 3,885 | -3% |
| | DE/LU → CH | 1,500 | 1,394 | -7% |
| | CH → FR | 1,180 | 1,183 | 0% |
| | FR → CH | 3,006 | 2,770 | -8% |
| | CH → IT North | 2,919 | 2,609 | -11% |
| | IT North → CH | 1,719 | 1,722 | 0% |

*Source: ACER calculations based on ENTSO-E and NordPool data.*

Table 3: Number of active capacity constraints and shadow prices by element type in the Core (CWE) region –2018

| TSO | Element type | Number (2017) | Number (2018) | Difference | Total of shadow prices 2018 (euro/MW) | Average shadow price 2018 (euro/MW) |
|---|---|---|---|---|---|---|
| AT | Internal line | 0 | 117 | NEW | 14,115 | 121 |
| BE | Internal line | 1,318 | 1,109 | -16% | 65,934 | 59 |
| DE | Allocation constraint | 485 | 457 | -6% | 3,292 | 7 |
| DE-Amprion | Internal line | 1,411 | 927 | -34% | 134,985 | 146 |
| DE-TenneT | Internal line | 642 | 301 | -53% | 45,658 | 152 |
| DE-TransnetBW | Internal line | 179 | 80 | -55% | 22,361 | 280 |
| FR | Allocation constraint | 9 | 1 | -89% | 247 | 247 |
| FR | Internal line | 79 | 0 | -100% | - | - |
| NL | Allocation constraint | 77 | 190 | 147% | 1,725 | 9 |
| NL | Internal line | 1,229 | 1,452 | 18% | 164,921 | 114 |
| | Cross-border line | 1,486 | 2,897 | 95% | 303,819 | 105 |
| | Total | 6,915 | 7531 | 9% | 757,058 | 101 |

Source: ACER calculations based on ENTSO-E data.

# Annex 2: Unscheduled flows

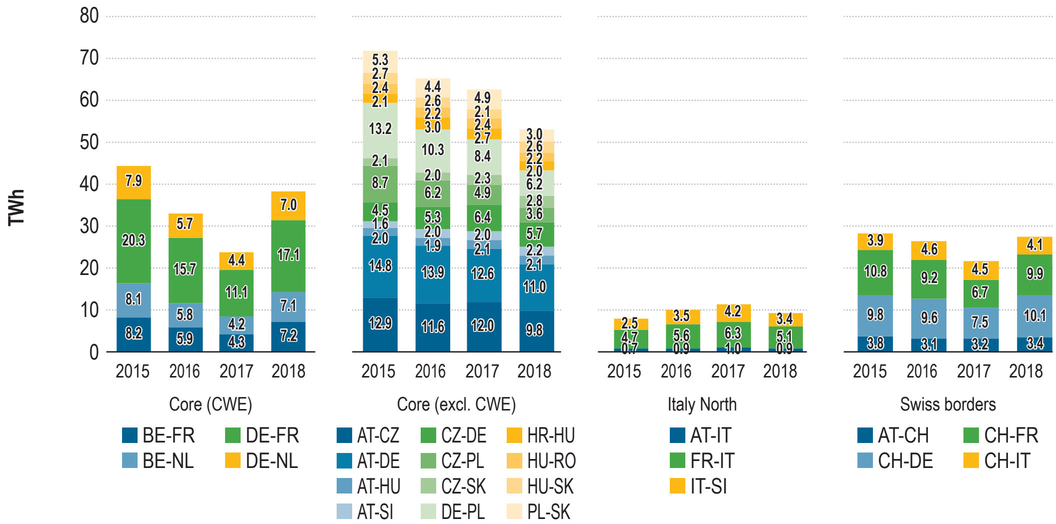
182 As shown in previous editions of the MMR[160], UFs present a challenge to the further integration of the IEM. Their persistence reduces tradable cross-zonal capacity, market efficiency and network security.

183 The definitions of the flows used in this Annex and the detailed process description are provided in the methodological paper on UFs[161]. Briefly, UFs are comprised of unscheduled allocated flows (UAFs), most of which stem from insufficient coordination in capacity calculation and allocation processes, and LFs, which originate from electricity exchanges inside other bidding zones.

184 The data on the allocated flows[162] (AFs) used in the analysis of this Annex were provided to the Agency by ENTSO-E. AFs were calculated on an hourly basis, using some simplifications. Because of the simplifications used, the AFs data obtained can be considered only as a proxy for the total amount of AFs (and indirectly LFs and UAFs) observed on each border. For the Core (CWE) region, ENTSO-E provided improved information on schedules, thus refining the analysis and reducing the amount of UAFs for this region.

185 The Agency has been monitoring the evolution of UFs in Europe (on the borders in the Core and Italy North regions and on Swiss borders) since 2012. In 2018, total UFs increased for the first time since 2015 and amounted to 128 TWh (+7% compared to 2017).

Figure 32: Absolute aggregate sum of UFs for the Core (CWE and non-CWE borders) and Italy North regions and for Swiss borders – 2015–2018 (TWh)




*Source: ACER calculations based on ENTSO-E and Vulcanus data.*

*Note: The calculation methodology used to derive UFs is described in the methodological paper on UFs[163]. The UFs are calculated with an hourly frequency; the absolute values are then summed across the hours and aggregated for borders belonging to the relevant regions.*

186 In the Core (CWE) region, UFs increased 61% year-on-year, following a similar trend in all four borders. In the Swiss borders region, UFs increased by 26%, slightly below their 2015 peak level (3%). In the Core (excl. CWE) region, the region with the highest volumes of UFs, UFs decreased by 15% (following a 8% decrease between 2016 and 2017), while their share over all UFs shown in Figure 32 dropped to 41% compared to 52% in 2017. In the IT North region, UFs dropped by 18%, due to decreases on the French-Italian and Italian-Slovenian borders.

160 See Section 5.1 "Unscheduled flows" (p. 28), of the Electricity Wholesale Markets Volume of MMR 2015.

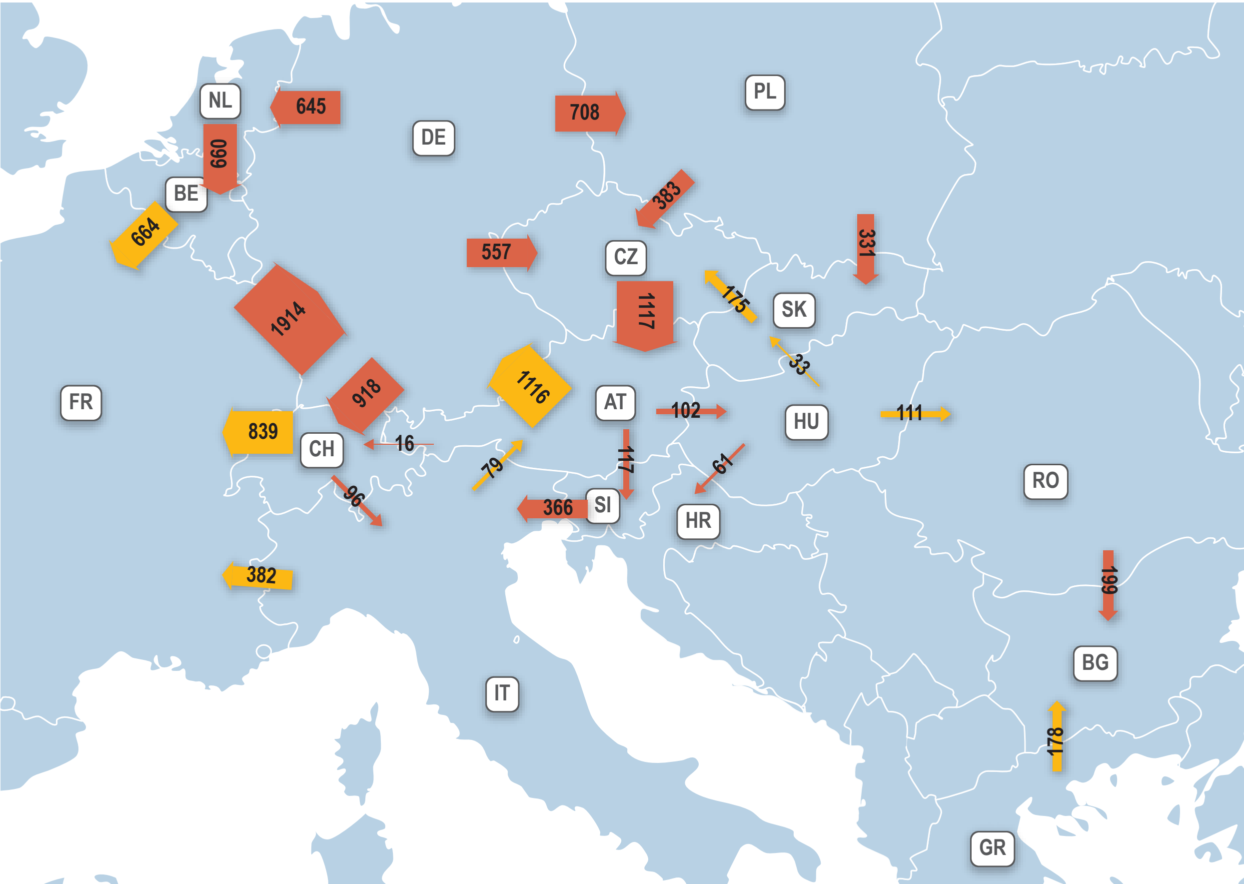
161 See the methodological paper on 'Unscheduled flows', available at: https://www.acer.europa.eu/en/Electricity/Market%20monitoring/Documents_Public/ACER%20Methodological%20paper%20-%20Unscheduled%20flows.pdf.

162 Allocated flows describe the actual flows coming from cross-zonal capacity allocation.

163 See footnote 161.

187 Figure 33 shows the prevailing direction of UFs volumes. It reveals that the overall pattern still consists of two major loops, from Germany to the Netherlands to the west, and to Poland to the east. UFs on the German-Polish border further decreased by almost 26% year-on-year and are 53% lower than in 2015. Unscheduled flows between Austria and Germany decreased by 13%, year-on-year. Figure 34 and Figure 35 depict the UFs decomposition into UAFs and LFs.

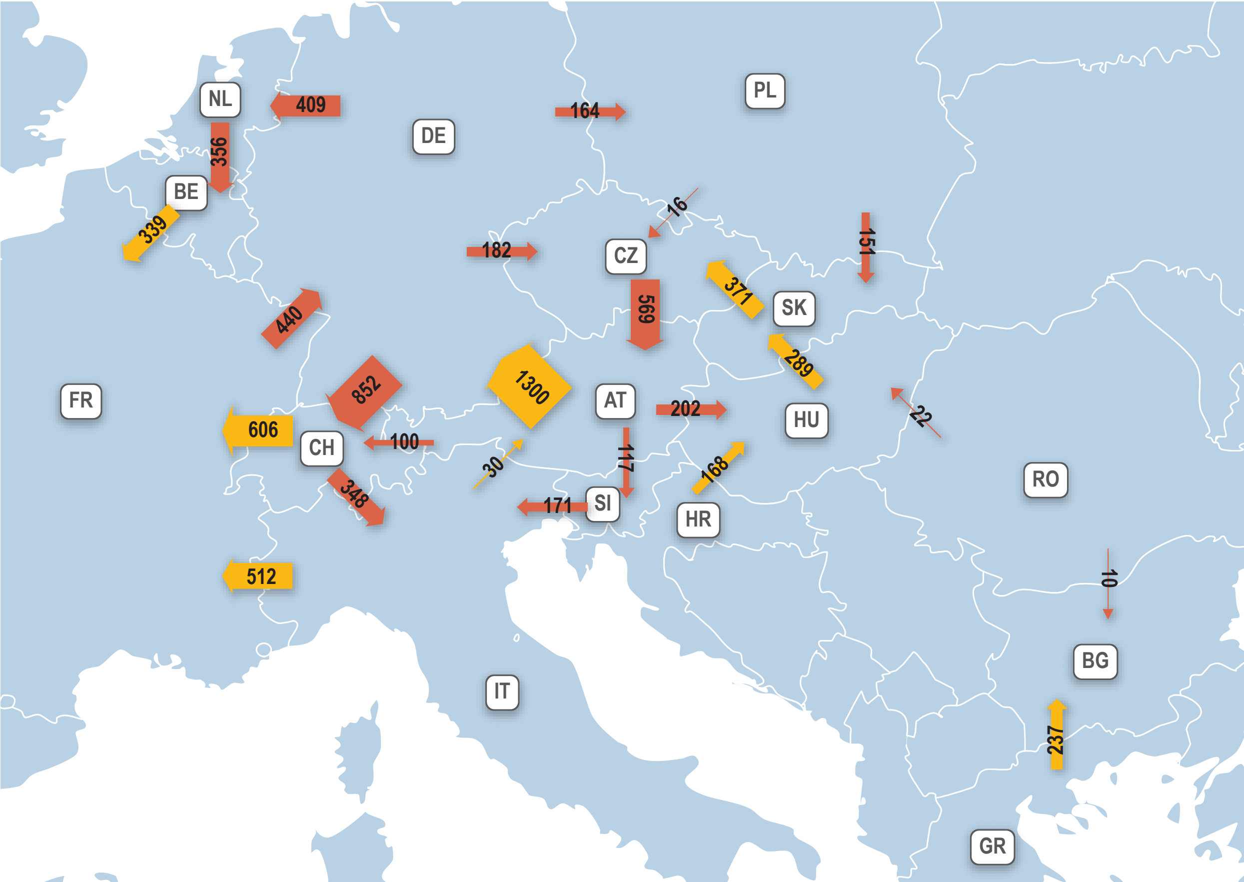
Figure 33: Average oriented UFs in Continental Europe – 2018 (MW)




*Source: ACER calculations based on ENTSO-E and Vulcanus data.*

*Note: Average UFs are average hourly oriented values in 2018. The arrow width and label describe the average UF. The arrow is red when UFs flow in the same direction as the physical flow, and yellow when UFs flow opposite to physical flows. The direction of the UF is the same as that of the physical flow if the physical flow exceeds the cross-zonal schedule, or if both run in opposite directions. The direction of the UF is the opposite of the physical flow if the cross-zonal schedule exceeds the physical flow.*

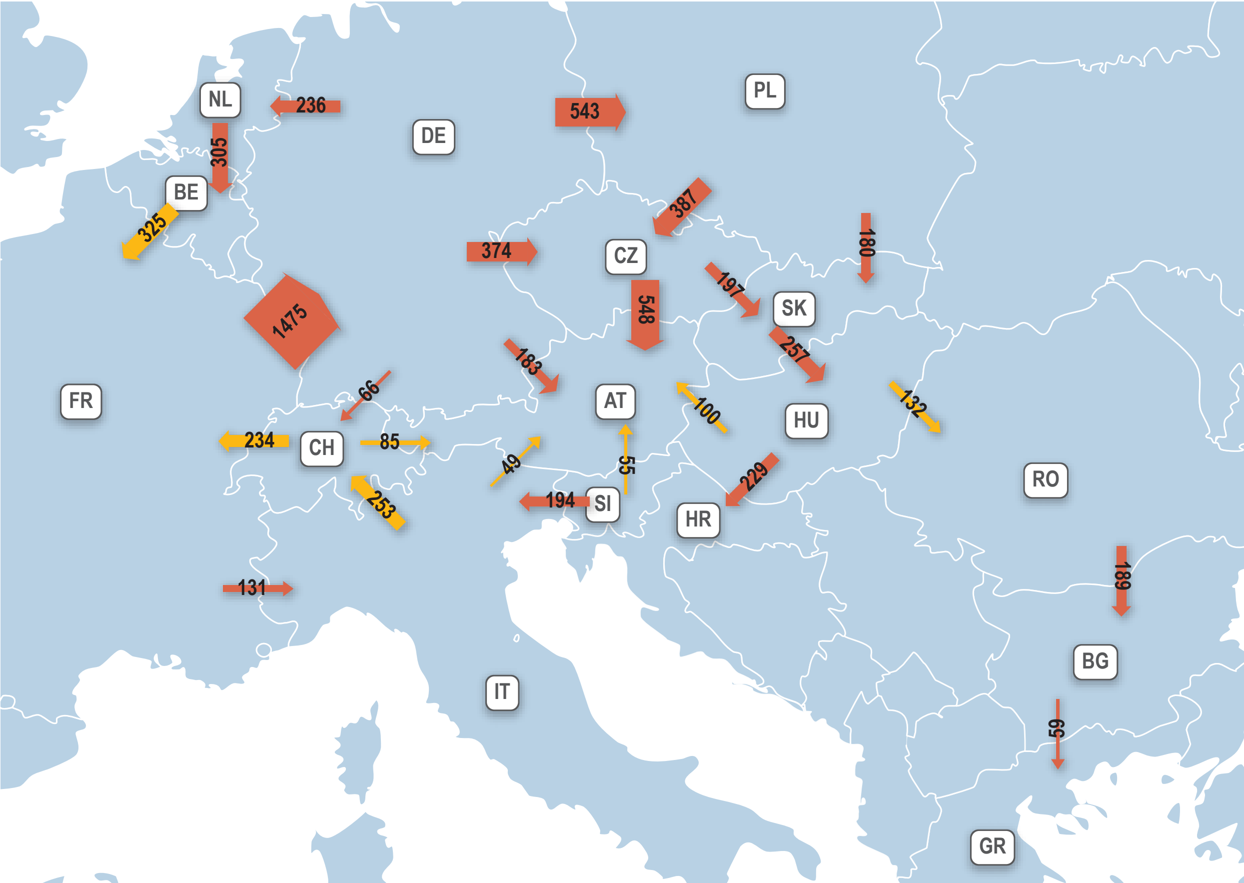
Figure 34: Average oriented UAFs in Continental Europe – 2018 (MW)




*Source: ACER calculations based on ENTSO-E and Vulcanus data.*

*Note: Average UAFs are average hourly oriented values in 2018. The arrow width and label describe the average UAF. The arrow is red when UAFs flow in the same direction as the physical flow, and yellow when UAFs flow opposite to physical flows. For the border between Germany and Austria the average UAF only refer to Q4, as the necessary calculation parameters were only available for that period. As a consequence the sum of average LFs and average UAFs does not equal the average UFs shown for this border in Figure 33. For the following borders AT - IT, BE - NL, BG - GR, DE - NL, DE - PL, IT - SI, and PL - SK the necessary parameters to calculate UAFs were missing for a limited number of hours. For these hours and borders, hourly UAFs were estimated as a share of hourly UFs by using the average ratio between UFs and UAF for the rest of the year.*

Figure 35: Average oriented LFs in Continental Europe – 2018 (MW)




*Source: ACER calculations based on ENTSO-E and Vulcanus data.*

*Note: Average LFs are average hourly oriented values in 2018. The arrow width and label describe the average LF. The arrow is red when LFs flow in the same direction as the physical flow, and yellow when LFs flow opposite to physical flows. For the border between Germany and Austria the average only refer to Q4, as the necessary calculation parameters were only available for that period. As a consequence the sum of average LFs and average UAFs does not equal the average UFs shown for this border in Figure 33. For the following borders AT - IT, BE - NL, BG - GR, DE - NL, DE - PL, IT - SI, and PL - SK the necessary parameters to calculate LFs were missing for a limited number of hours. For these hours and borders, hourly LFs were estimated as a share of hourly UFs by using the average ratio between UFs and LF for the rest of the year.*

188 Table 4 describes the average absolute UAFs and LFs in Continental Europe. The largest UAFs and LFs were both observed in the Core (excl. CWE) region.

Table 4: Average absolute UAFs and LFs in Continental Europe – 2018 (MW)

| CCR | Average absolute UAFs (MW) | Average absolute LFs(MW) |
|---|---|---|
| Core (CWE) | 2,491 | 2,937 |
| Core (excl. CWE) | 4,772 | 4,047 |
| Italy North | 1,143 | 798 |
| SEE | 400 | 256 |
| Swiss borders | 3,329 | 2,032 |

*Source: ACER calculations based on ENTSO-E and Vulcanus data.*

*Note: For a given CCR, the UAFs (resp. LFs) are the sum of absolute UAFs (resp. LFs) on all individual borders. Neither UAFs nor LFs were observed in the GRIT region, because this region only has one DC border. Compared to the previous figures, the absolute UAFs and LFs are non-oriented.*

189 Despite significant improvements in many regions, UFs still significantly impede the efficient functioning of the Internal Electricity Market, mainly by 'consuming' flow on interconnectors. As a result, the capacity available for cross-zonal trade is limited. FB market coupling should lead to decrease UAFs (in particular those resulting from exchanges within the region) but does not affect LFs. LFs may be tackled through bidding zone reconfiguration or other measures to ensure non-discrimination in capacity calculation.

# Annex 3: Detailed analysis of regional capacity calculation methodologies

190 The aim of this annex is to provide additional details on the regional context in which each CCR developed their CCM, together with specific suggestions for improving the CCMs in each region[164].

191 In order to track the evolution of the CCMs, the analysis per region includes a reference to the assessed level of fulfilment of the capacity calculation coordination requirements of the CACM Regulation that was performed in the two last editions (2016 and 2017) of the MMR. Compared to this year's analysis, the assessment in the two preceding MMRs was more limited in scope. However, the findings included in these MMRs together with the findings of the first edition of the Implementation Monitoring Report[165] (the 'IMR') are very useful to explain the status of the CCMs and, in particular, to understand where the main difficulties come from.

192 The following table presents the detailed scoring of each region for every sub-aspect taken into consideration in this analysis as well as the total scoring per region and the average scoring per sub-aspect.

Table 5: Detailed scoring of the regions per sub-aspect examined as of June 2019

| | | Region | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Sub-aspect | Baltic | Channel | Core | GRIT | Hansa | IU | Nordic | SEE | SWE | Average |
| CACM coverage | General Proceedings | 50% | 25% | 100% | 50% | 38% | 50% | 50% | 63% | 50% | 53% |
| | Input to capacity calculation | 52% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 6% |
| | Capacity calculation | 46% | 62% | 96% | 60% | 84% | 85% | 96% | 88% | 73% | 77% |
| | Average CACM coverage | 49% | 63% | 95% | 61% | 76% | 67% | 86% | 85% | 67% | 72% |
| Detail and Harmonisation | GSK | 20% | 36% | 55% | 27% | N.A. | 36% | 45% | 45% | 36% | 38% |
| | Operational security limits | 0% | 50% | 73% | 38% | 17% | 50% | 33% | 63% | 17% | 38% |
| | Allocation constraints | 30% | 67% | 90% | 14% | 75% | 44% | 60% | 100% | 100% | 64% |
| | Reliability margin | 36% | 62% | 100% | 100% | 88% | 100% | 100% | 54% | 50% | 77% |
| | Remedial actions | 0% | 25% | 100% | 25% | 13% | 25% | 38% | 71% | 25% | 36% |
| | PTDF(1) | N.A. | N.A. | 100% | N.A. | N.A. | N.A. | 100% | N.A. | N.A. | 100% |
| | DA process(2) | 25% | 50% | 100% | 63% | 38% | 63% | 75% | 75% | 50% | 60% |
| | ID process(3) | 25% | 50% | 88% | 63% | 38% | 63% | 88% | 86% | 50% | 61% |
| | Average Detail and Harmonisation | 19% | 49% | 88% | 47% | 44% | 54% | 67% | 71% | 47% | 54% |
| Non-Discrimination | Principle 1(4) | 67% | 67% | 50% | 0% | 100% | 33% | 50% | 67% | 67% | 56% |
| | Principle 2(5) | 25% | 100% | 100% | 25% | 33% | 33% | 25% | 25% | 25% | 44% |
| | Flows from other CCRs | 100% | 0% | 100% | 0% | 100% | 0% | 100% | 100% | 100% | 67% |
| | Average Non-Discrimination | 50% | 71% | 83% | 14% | 60% | 29% | 43% | 50% | 50% | 50% |
| Transparency and Enforceability | Publication of data | 40% | 20% | 100% | 0% | 0% | 0% | 20% | 100% | 20% | 33% |
| | Enforceability | 0% | 67% | 100% | 100% | 100% | 33% | 67% | 100% | 33% | 67% |
| | Average Transparency and Enforceability | 25% | 38% | 100% | 38% | 17% | 13% | 38% | 100% | 25% | 44% |
| Total | | 36% | 55% | 92% | 40% | 49% | 41% | 58% | 76% | 47% | 55% |

*Source: ACER.*

193 The detailed analysis per region is included below.

164 The assessment includes all CCRs except Italy North. For this region, a common coordinated CCMs was not yet approved by the relevant regulatory authorities as of June 2019.

165 ACER Monitoring Report on the implementation of the CACM Regulation and the FCA Regulation, 31 January 2019, available at https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/FCA_CACM_Implementation_Monitoring_Report_2019.pdf. This reference applies to all mentions of the IMR in this annex.

### a) Baltic – overall assessment score: 36%

194 The 2016 and 2017 MMRs revealed a low level of fulfilment of the capacity calculation coordination requirements of the CACM Regulation in the Baltic Region, for 2016 and 2017, although significant improvement was observed over the two years on Lithuanian borders.

195 The first edition of the IMR revealed that TSOs and regulatory authorities of the Baltic CCR faced difficulties in coordinating their actions for implementing network codes, in particular due to the difficulties in agreeing with the treatment of third countries (the Russian Federation and Belarus) within the capacity calculation methodology .

196 The above findings in combination with the analysis of the approved CCMs indicate that the implementation of the CCM will be challenging; more specifically, the following aspects require specific attention:

- Detail and harmonisation of the CCM (assessment score 19%), in particular regarding the provisions related to operational security limits and remedial actions:
    - Regarding the operational security limits, the proposal (Article 3 of the approved CCM) is not sufficiently detailed. The selection process is not explained, only partly justifies the use of constraints, and only partly describes the methodology to select them.
    - Regarding remedial actions (Article 5), the proposal does not detail the requirements foreseen in Article 25 of the CACM Regulation. Moreover, the following elements are missing: i) a methodology, and differentiation between the treatment of costly and non-costly remedial action, ii) the consideration of cost efficiency and iii) a detailed list of remedial actions.
- Transparency and enforceability (assessment score 25%): the provisions regarding data publication do not guarantee a sufficient level of transparency and the implementation timeline (Article 15) is conditioned to the fulfilment of several provisions.

### b) Channel – overall assessment score: 55%

197 The 2016 and 2017 MMRs revealed a low level of fulfilment of the capacity calculation coordination requirements of the CACM Regulation, for 2016 and 2017. In 2017, the Channel CCR showed the lowest level of fulfilment (mainly due to the poor coordination reported on the British-French border). At the same time, the 2017 MMR revealed that internal congestions in the Channel CCR do not seem to lead to discrimination of cross-zonal exchanges.

198 Furthermore, as mentioned in the IMR, electricity exchanges on DC interconnectors in the CCRs Hansa and Channel are interdependent with borders within the CCRs Core and Nordic. The flow-based CCMs will be sub-optimal until the exchanges on these DC interconnectors are properly taken into account in these CCMs. This can be achieved either by merging these bidding zone borders with the CCR Core or CCR Nordic, or by applying the advanced hybrid coupling solution[166].

199 The implementation of the CCM will therefore be challenging; based on the approved CCM, the following aspects require specific attention:

- Transparency and enforceability (assessment score 38%): the provisions regarding data publication (Art. 26) do not guarantee a sufficient level of transparency.
- Non-discrimination (assessment score 71%): although discrimination of cross-zonal exchanges was not identified as an issue so far in the Channel CCR, the methodology does not include sufficient provisions to guarantee that discrimination will not arise in the future.

166 See information on the advanced hybrid coupling solution in page 47 of the IMR.

### c) Core – overall assessment score: 92%

200 The 2016 and 2017 MMRs revealed a fulfilment of the capacity calculation coordination requirements of the CACM Regulation which was above average for the Core CCR for 2016 and 2017; however:

- The Core CCR with the exclusion of the former CWE region showed poor scores;
- The CCR faces a problem regarding the guarantee of non-discrimination – in 2017, regarding RAMs on congested internal CNEs, the average margin (relative to Fmax) remained low at 12% of Fmax. The average relative margin remained above 15% for Belgium, France and the Netherlands, whereas it remained below 10% for all German TSOs. An analysis of LFs revealed large LF volumes; internal congestions were reported in Germany and, to a lesser extent, in Austria and the Netherlands.

201 In this difficult context, the Core national regulators requested the Agency to make a decision, as they could not come to an agreement. The approved CCM includes the necessary provisions to address the above-mentioned issues; nevertheless, the implementation of the CCM will prove challenging, as the Core CCR includes the largest number of countries (13), showing various levels of capacity calculation coordination and non-discrimination.

202 As highlighted in the IMR, another urgent issue that regulatory authorities of the Core region must address is the lack of coordination between the CCRs of Italy North and Core. Currently, decisions related to flows in one of these CCRs affect the other. The Agency thinks that these CCRs should merge as soon as practicably feasible.

### d) GRIT – overall assessment score: 40%

203 The 2016 and 2017 MMRs revealed a low level of fulfilment of the capacity calculation coordination requirements of the CACM Regulation for 2016 and 2017. The IMR did not highlight any problems regarding the network code implementation. The GRIT CCR is highly unmeshed and isolated, which may result in a lesser need for cooperation in comparison with other regions.

204 Nevertheless, based on the approved CCM, the following aspects require specific attention:

- Non-discrimination (assessment score 14%): although discrimination of cross-zonal exchanges was not identified as a significant issue so far in the GRIT CCR, the methodology regarding non-discrimination related to DA and ID capacity calculation (Art. 11 and 12) does not include sufficient provisions to guarantee that discrimination will not arise in the future.
- Transparency and enforceability (assessment score 38%): the provisions regarding data publication do not guarantee a sufficient level of transparency.

### e) Hansa – overall assessment score: 49%

205 The 2016 and 2017 MMRs revealed a low level of fulfilment of the capacity calculation coordination requirements of the CACM Regulation for 2016 and 2017. Moreover, the analysis of non-discrimination in the CCR in the 2017 MMR revealed that internal congestions in Germany required to improve the CCM and the need for investigating bidding zone improvements.

206 As mentioned in the IMR[167], electricity exchanges on DC interconnectors in the CCRs Hansa and Channel are also interdependent with the borders within the CCRs Core and Nordic. The FB capacity calculation methodologies will be suboptimal until the exchanges on these DC interconnectors are properly taken into account in the methodologies. This can be achieved either by merging these bidding zone borders with the CCR Core or CCR Nordic, or by applying the Advanced Hybrid Coupling solution.

167 See paragraph 117 of the IMR. Following the advanced hybrid coupling approach, these interconnectors can remain within a separate CCR and apply the CNTC approach, but the electricity exchanges on them can additionally be limited by the flow-based capacity calculation on one or both ends of the DC interconnector.

207 In the context of the implementation of the CCM and based on the approved CCM the following aspects require specific attention:

- Transparency and enforceability (assessment score 17%) – the provisions regarding data publication do not guarantee a sufficient level of transparency; at the moment, the implementation timeline (Art. 19) is conditioned to the adoption of the methodology in the CORE region (see introductory comment above).

- Detail and harmonisation (assessment score 44%) – regarding the operational security limits (Art. 7) the proposal is open, due the possibility to re-evaluate operational security limits, without sufficient detail about the context of this re-evaluation. The CCM does not detail how it takes into account these operational security limits.

### f) IU – overall assessment score: 41%

208 The 2017 MMR revealed that internal congestions in the IU CCR do not seem to lead to discrimination of cross-zonal exchanges. The IMR did not report any specific implementation issue.

209 Based on the evaluation of the approved CCM, the following aspects require specific attention:

- Transparency and enforceability (assessment score 13%): the provisions regarding data publication (Art. 27) do not guarantee a sufficient level of transparency; regarding the implementation timeline (Art. 27), Art. 27(5) offers the possibility of indefinite postponing.

- Non-discrimination (assessment score 29%): although discrimination of cross-zonal exchanges was not identified as a significant issue so far in the IU CCR, the methodology does not include sufficient provisions to guarantee that discrimination will not arise in the future.

### g) Nordic – overall assessment score: 58%

210 The 2016 and 2017 MMRs revealed a fulfilment of the capacity calculation coordination requirements of the CACM Regulation which was above average for the Nordic CCR for 2016 and 2017. In addition, significant improvements were recorded in 2017 in the Nordic CCR and at Norwegian borders.

211 The Nordic CCR performs significantly better than others regarding the issue of non-discrimination; as observed in the 2017 MMR, a 65–70% RAM level was estimated for over 90% of Nordic CNEs.

212 Based on the evaluation of the approved CCM the following aspects require specific attention:

- Transparency and enforceability (assessment score 38%): the provisions regarding data publication do not guarantee a sufficient level of transparency; the implementation timeline (Art. 32) depends on the fulfilment of several technical milestones.

- Non-discrimination (assessment score 43%): bearing in mind the introductory remark on the current status of non-discrimination in the Nordic CCR, the methodology does not include sufficient provisions to guarantee that discrimination will not arise in the future.

### h) SEE – overall assessment score: 76%

213 The 2016 and 2017 MMRs revealed a low level of fulfilment of the capacity calculation coordination requirements of the CACM Regulation for 2016 and 2017; in 2017, the SEE CCR showed the lowest level of fulfilment[168]. The analysis of UFs in 2017 revealed that UFs are comparatively smaller in the SEE (4.6 TWh) than the Core region.

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168 See table ii of the 2016 MMR, revealing that the RO>BG and BG<RO borders present some of the lowest ratios between tradable capacity (NTC) and benchmark capacity in the EU. See also paragraph (272) of the 2017 MMR, explaining that regarding bidding zones efficiency, as far as cross-zonal capacity is concerned, Bulgaria and Romania are two of the three countries which performed the worst, approximately 75% below the benchmark capacity.

214 The IMR has revealed difficulties in implementing the Codes so far. The TSOs of the SEE CCR initiated the work on their capacity calculation methodology with delay; implementation of the Harmonised Allocation Rules (EU HAR) was delayed because the Bulgarian TSO did not anticipate the necessary adaptations of its IT system. Therefore, specific regulatory attention is needed in this CCR.

215 An end goal for the SEE CCR should be to gradually merge with the Core CCR and thereby properly coordinate on interdependencies already affecting both regions[169].

216 In light of the issues highlighted above, the implementation of the CCM will be challenging; however, the approved SEE CCM offers good guarantees that it will address such issues. Nevertheless, the following aspects require specific attention:

- Non-discrimination (assessment score 50%): the methodology does not include rules for avoiding undue discrimination between internal and cross-zonal exchanges to ensure compliance with point 1.7 of Annex I to Regulation (EC) No 714/2009 – the methodology does not include sufficient provisions to guarantee that discrimination will not arise in the future.

- Details and harmonisation (assessment score 71%): the methodology for establishing GSKs must be further detailed, and deviations to the general calculation of reliability margins must be better framed.

### i) SWE – overall assessment score: 47%

217 The SWE CCR is highly unmeshed and isolated, which may result in a lesser need for cooperation in comparison with other regions. The 2017 MMR revealed that the prevention of non-discrimination is a relatively relevant issue in the SWE CCR, which, together with internal congestions in Spain suggests the need for investigating bidding zone improvements. The analysis of UFs in 2017 revealed that UFs are comparatively smaller in the SWE (0.4 TWh) than in other regions of continental Europe. The IMR did not highlight any problems regarding the network code implementation.

218 Based on the evaluation of the approved CCM, the following aspects require specific attention:

- Transparency and enforceability (assessment score 25%): the provisions regarding data publication do not guarantee a sufficient level of transparency.

- Detail and harmonisation (assessment score 47%): regarding operational security limits, Article 7 of the CCM does not say how they are established.

169 See paragraph 116 of the IMR.

# Annex 4: Quality of the data available to estimate the MACZT

219 The following table describes the level of confidence in the data underlying Section 3.1.2. The low level of confidence for many MSs or bidding-zone borders limited the geographic scope of the analysis to 20 MSs. This table also describes ways to improve the provided data for future monitoring work.

Table 6: Confidence of the data provided to estimate historical MACZT levels

| Member State | Grid model | Network elements | Comment – network elements |
|---|---|---|---|
| Austria | 🟡 | 🟡 | Core (CWE) data robust<br>CNECs provided for other borders unlikely to lead to robust calculations based on the Recommendation. Lack of information about which (oriented) NTC CNEC(s) are limiting for which hours, and in which CNEC direction(s) (forward, backward, both?) the margin should be estimated. |
| Belgium | 🟡 | 🟢 | Only Core (CWE) CNECs |
| Bulgaria | 🟡 | 🔴 | CNECs provided unlikely to lead to robust calculations based on the Recommendation. Lack of information about which (oriented) NTC CNEC(s) are limiting for which hours. |
| Croatia | 🟡 | 🟡 | CNECs provided decrease the robustness of calculations based on the Recommendation. Lack of information about which (oriented) CNEC(s) are limiting for which hours, and in which CNEC direction(s) (forward, backward, both?) the margin should be estimated. |
| Czech Republic | 🟡 | 🟡 | CNECs provided decrease the robustness of calculations based on the Recommendation. Lack of information about which (oriented) CNEC(s) are limiting for which hours, and in which CNEC direction(s) (forward, backward, both?) the margin should be estimated. |
| Germany | 🟡 | 🟡 | CNECs provided decrease the robustness of calculations based on the Recommendation. Lack of information about which (oriented) NTC CNEC(s) are limiting for which hours, and in which CNEC direction(s) (forward, backward, both?) the margin should be estimated. |
| Estonia | 🟡 | 🔴 | CNECs provided unlikely to lead to robust calculations based on the Recommendation. Inconsistencies detected on PTDF and initial flow values. |
| France | 🟡 | 🟡 | Core (CWE) data robust<br>CNECs provided for the ES-FR border decrease the robustness of calculations based on the Recommendation. CNECs provided for other borders unlikely to lead to robust calculations based on the Recommendation.<br>Lack of information about which (oriented) NTC CNEC(s) are limiting for which hours, and in which CNEC direction(s) (forward, backward, both?) the margin should be estimated. |
| Greece | 🟡 | 🔴 | CNECs provided unlikely to lead to robust calculations based on the Recommendation. Lack of information about which (oriented) CNEC(s) are limiting for which hours. |
| Hungary | 🟡 | 🔴 | CNECs provided unlikely to lead to robust calculations based on the Recommendation. Lack of information about which (oriented) CNEC(s) are limiting for which hours, and in which CNEC direction(s) (forward, backward, both?) the margin should be estimated. |
| Ireland | NAP | NAP | |
| Italy | 🟡 | 🟡 | The MACZT estimated only for IT North due to limitations in the UCTE file format. CNECs provided decrease the robustness of calculations based on the Recommendation. Lack of information about which (oriented) CNEC(s) are limiting for which hours, and in which CNEC direction(s) (forward, backward, both?) the margin should be estimated. |
| Latvia | 🟡 | 🔴 | CNECs provided unlikely to lead to robust calculations based on the Recommendation. Inconsistencies detected on PTDF and initial flow values. |
| Lithuania | 🟡 | 🔴 | CNECs provided unlikely to lead to robust calculations based on the Recommendation. Inconsistencies detected on PTDF and initial flow values. |
| Netherlands | 🟡 | 🟢 | Only Core (CWE) CNECs |

| Member State | Grid model | Network elements | Comment – network elements |
|---|---|---|---|
| Nordic | 🔴 | 🔴 | CNECs provided for the Nordic region as a whole, without information about their affectation to countries.<br>CNECs provided unlikely to lead to robust calculations based on the Recommendation. Margin information provided (for twelve weeks) does not seem to match historical NTC values. |
| Poland | 🟠 | 🟠 | CNECs provided unlikely to lead to robust calculations based on the Recommendation. Lack of information about which (oriented) CNEC(s) are limiting for which hours, and in which CNEC direction(s) (forward, backward, both?) the margin should be estimated. |
| Portugal | 🟠 | 🟠 | CNECs provided decrease the robustness of calculations based on the Recommendation. Lack of information about which (oriented) CNEC(s) are limiting for which hours, and in which CNEC direction(s) (forward, backward, both?) the margin should be estimated. |
| Romania | 🟠 | 🔴 | CNECs provided unlikely to lead to robust calculations based on the Recommendation. Lack of information about which (oriented) CNEC(s) are limiting for which hours. |
| Slovenia | 🟠 | 🟠 | CNECs provided decrease the robustness of calculations based on the Recommendation. Lack of information about which (oriented) CNEC(s) are limiting for which hours, and in which CNEC direction(s) (forward, backward, both?) the margin should be estimated. |
| Slovakia | 🟠 | 🔴 | CNECs provided unlikely to lead to robust calculations based on the Recommendation. Lack of information about which (oriented) CNEC(s) are limiting for which hours, and in which CNEC direction(s) (forward, backward, both?) the margin should be estimated. |
| Spain | 🟠 | 🟠 | CNECs provided decrease the robustness of calculations based on the Recommendation. Lack of information about which (oriented) CNEC(s) are limiting for which hours, and in which CNEC direction(s) (forward, backward, both?) the margin should be estimated. |
| United Kingdom | NAP | NAP | |

*Note: Grid model refers to the number and quality/usability of the provided merged grid models. Network elements refers to the representativeness of the declared critical network elements, in particular whether they can reasonably be expected to frequently limit capacity calculation/allocation (for NTC regions). A green box means a rather high level of confidence in the data, whereas an orange box means that the provided data is subject to significant uncertainty, or may not fully match the data request. A red box means that the level of confidence is too low to enable robust results to be obtained.*

*In the Baltic region, no merged grid model was provided; PTDFs were computed by Baltic TSOs based on an operational merged grid model. Six merged network models were provided for the synchronous area of Continental Europe. Due to limitations in the provided CNEC data, only one model was used.*

*In the Nordic region, PTDFs were computed for the first twelve weeks of 2017 by Nordic TSOs, based on a research project.*

# Annex 5: Data Sources

220 Table 7 displays the data sources used throughout the present Electricity Wholesale Volume of the MMR, together with the associated data items. The last column lists the main issues identified by the Agency indicating that additional efforts are needed to improve the quality of the data.

Table 7: Data sources - Electricity Wholesale Volume of the 2018 MMR

| Source | Data Items | Applicable Regulation | Public source | Issues identified |
|---|---|---|---|---|
| ENTSO-E Transparency Platform | • DA Prices,<br>• NTC,<br>• Generation per production type<br>• Scheduled DA and ID commercial exchanges<br>• Nominated capacities | (EU) 543/2013 | YES | • Data completeness (e.g. DA and ID schedules and nominations<br>• Potential data quality issues (discrepancies with other sources, e.g. DA and ID schedules)<br>• Non-standardised use of the EIC codes for particular borders (e.g. IT-GR). |
| ENTSO-E/TSOs | • CWE FB parameters<br>• PTDF indicators for continental Europe | (EU) 1222/2015 | NO | |
| Joint Allocation Office (JAO) | Long Term Auctions | (EU) 2016/1719 | YES | |
| Vulcanus (centralised database including data on cross-border flows) | • Scheduled DA and ID commercial exchanges<br>• Physical flows<br>• Realised scheduled exchanges | N/A | NO | Potential data quality issues (discrepancies with other sources, e.g. regarding DA and ID schedules). |
| Nordpool Historical data | NTC for Nordic+Baltic borders | N/A | YES | |
| Eurostat | Electricity demand –annual values. | (EU) 222/2009 | YES | As of September 2019, the latest data on annual electricity demand referred to 2016. |
| NEMOs | ID traded volumes and prices | (EU) 1222/2015 | NO | |
| NRAs | • Various data items on balancing (cross-zonal exchange of balancing services, activated balancing energy, balancing capacity and balancing energy prices)<br>• Nominated capacities (long-term) | (EU) 2019/942 | NO | UTC not consistently used. |

# Annex 6: List of Abbreviations

| Abbreviation | Definition |
|---|---|
| 4MMC | 4M Market Coupling |
| AC | Alternate Current |
| ACER | Agency for the Cooperation of Energy Regulators |
| AF | Allocated Flow |
| ATC | Available Transmission Capacity |
| CACM | Capacity Allocation and Congestion Management (electricity) |
| CCM | Capacity Calculation Methodology |
| CCR | Capacity Calculation Region |
| CEE | Central-East Europe (electricity region) |
| CEER | Council of European Energy Regulators |
| CEP | Clean Energy Package |
| CGM | Common Grid Model |
| CM | Capacity Mechanism |
| CNE | Critical Network Element |
| CNEC | Critical Network Element with Contingencies |
| CNTC | Coordinated NTC |
| CWE | Central-West Europe (electricity region) |
| DA | Day-ahead |
| DC | Direct Current |
| EB | Electricity Balancing |
| EC | European Commission |
| EEA | European Emission Allowance |
| EENS | Expected Energy Not Served |
| ETM | Electricity Target Model |
| EU | European Union |
| FAV | Final Adjustment Value |
| FB | Flow Based |
| FBMC | Flow Based Market Coupling |
| FCA | Forward Capacity Allocation |
| GDP | Gross Domestic Product |
| GRIT | Capacity calculation region, consisting of the border Greece-Italy and the bidding zone borders within Italy. |
| GSK | Generation Shift Keys |
| HVAC | High-Voltage Alternating Current |
| ID | Intraday |
| IEM | Internal Energy Market |
| IMR | Implementation Monitoring Report |
| JAO | Joint Allocation Office |
| LF | Loop Flow |
| LOLE | Loss of Load Expectation |
| MACZT | Margin Available for Cross-Zonal Trade |
| MAF | Mid-term Adequacy Forecast |
| MCCC | Margin from Coordinated Capacity Calculation |
| MMR | Market Monitoring Report |
| MNCC | Margin from Non-coordinated Capacity Calculation |
| MRC | Multi-Regional Coupling |
| MS | Member State |
| MTU | Market Time Unit |
| NEMO | Nominated Electricity Market Operator |
| NRA | National Regulatory Authority |
| NTC | Net Transfer Capacity |
| PTDF | Power Transfer Distribution Factor |
| RAM | Remaining Available Margin |
| RES | Renewable Energy Sources |
| SDAC | Single Day-Ahead Coupling |
| SEM | Single Energy Market (comprising Northern Ireland and the Republic of Ireland) |
| SIDC | Single Intraday Coupling |
| SO | System Operation |
| SoS | Security of Supply |
| SWE | South-West Europe (capacity calculation region) consisting of the border Spain-Portugal and France-Spain. |
| TSO | Transmission System Operator |
| TTF | Title Transfer Facility (the Dutch gas hub) |
| UAF | Unscheduled Allocated Flow |
| UF | Unscheduled Flow |

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