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Annual Report on the Results of Monitoring the Internal Electricity and Gas Markets in 2016

Electricity Wholesale Markets Volume

October 2017

Legal notice

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Executive Summary

Key developments in 2016

1 The downward trend in wholesale electricity prices observed in previous years continued in 2016. In parallel, price spikes occurred significantly more frequently than in previous years, with 1,195 occurrences in Europe in 2016, which is around five times the average over the preceding four years. These spikes were observed more often in the Member States (MSs) with the tightest adequacy margins, such as Belgium, Finland, France and Great Britain. Although these spikes may reflect efficient price formation at times of scarcity, they also highlight the importance of addressing security of supply efficiently and in a coordinated manner.

2 In 2016, different degrees of price convergence were observed across Europe. The average absolute day-ahead (DA) price spreads ranged from less than 0.5 euros/MWh on the borders between Portugal and Spain, the Czech Republic and Slovakia, and between Latvia and Lithuania, to 10 euros/MWh or more on all British borders, the borders between Austria and Italy, and between Germany and Poland (see Table i). This confirms the relevance of maximising the amount of tradable cross-zonal capacity, particularly on borders with the highest price spreads.

Table i: Borders with the biggest DA price differentials– 2012–2016 (euros/MWh)

	Average hourly price differentials						Average of absolute hourly price differentials					
Border	2012	2013	2014	2015	2016	Average 2012-2016	2012	2013	2014	2015	2016	Average 2012-2016
NL-GB	-7.1	-7.1	-11.0	-15.6	-16.9	-11.5	9.1	8.8	11.2	15.8	17.0	12.4
FR-GB	-8.2	-15.8	-17.6	-17.2	-12.4	-14.2	13.4	17.4	17.7	17.5	15.4	16.3
IE-GB	11.6	10.0	8.1	-1.5	-4.0	4.9	16.9	18.6	17.7	15.2	13.8	16.4
AT-IT	-31.5	-23.8	-17.6	-21.1	-13.7	-21.5	31.5	24.1	17.7	21.1	13.7	21.6
DE-PL	1.1	1.1	-10.2	-5.9	-7.5	-4.3	7.4	8.2	11.7	8.6	10.0	9.2
CH-DE	6.9	7.0	4.0	8.6	8.9	7.1	9.1	9.3	5.6	9.8	9.5	8.7
AT-CH	-6.9	-7.0	-4.0	-8.6	-8.9	-7.1	9.1	9.3	5.6	9.8	9.5	8.7
PL-SE-4	7.3	-3.3	11.1	14.6	6.9	7.3	10.6	5.2	11.9	15.3	9.2	10.4
CZ-PL	0.9	0.1	-10.0	-5.2	-5.3	-3.9	6.5	7.8	11.2	7.9	9.1	8.5
PL-SK	-1.4	-0.6	9.3	4.0	5.0	3.3	6.9	8.1	11.1	8.1	9.1	8.7

Source: ACER calculations based on data provided by National Regulatory Authorities (NRAs) through the EW template (2017), ENTSO-E and Nordpool Spot.

Note: A negative average DA price differential indicates that the average price was lower in the first member of the pair of bidding zones identifying a border, e.g. prices were lower in the Netherlands than in Great Britain in all years. The borders are ranked based on the 2016 average absolute price differentials. The average absolute price differentials (right side of the table) are higher than the 'simple' spreads (left side) where negative and positive price spreads are netted.

3 The Baltic, the Core (Central-West Europe (CWE))[1] and the South-West Europe (SWE) regions recorded the highest annual increases in the frequency of intraregional full price convergence in 2016. In these three regions, the DA price differential was, respectively, below 1 euro/MWh in 71%, 39% and 30% of the hours in 2016. The factors explaining these developments include investments in new interconnector lines in the Baltic and SWE regions and the go-live of Flow-Based Market Coupling (FBMC) in the Core (CWE) region.

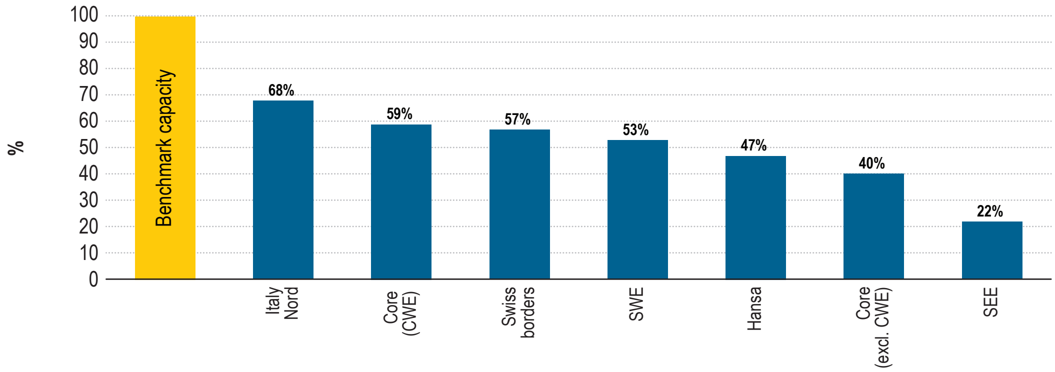
1 Bidding zones are grouped into regions, as follows: the Baltic region (Estonia, Latvia and Lithuania), the Central-East Europe (CEE) region (the Czech Republic, Hungary, Poland and Slovakia), the CWE region (Belgium, France, Germany/Austria/Luxembourg and the Netherlands), the Ireland and United Kingdom region (IU) (the Republic of Ireland and the United Kingdom), the Nordic region (Denmark, Finland, Norway and Sweden) and the SWE region (France, Portugal and Spain). These regions are in line with Agency Decision No 06/2016 of 17 November 2016 on the TSOs' proposal for the determination of CCRs, except for the CWE and CEE regions, which are identified throughout this document as the Core (CWE) region and the Core (CEE) region, for consistency with previous years' MMRs. The Decision is available at: http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions/ACER%20Decision%2006-2016%20on%20CCR.pdf.

4 While FBMC does indeed contribute to increasing price convergence, recent experience in the Core (CWE) region illustrates that FBMC alone is not sufficient to deliver an integrated electricity market. Full price convergence dropped in this region from 48% in the first three quarters of 2016 to 11% in the last quarter, due to high DA prices in France and Belgium. These high DA prices were mainly the result of a significant number of nuclear reactors being offline in these countries, combined with a significant reduction in the level of tradable cross-zonal capacity during the second semester of 2016.

Available cross-border capacity

5 In 2016, despite recent investments in transmission networks and some improvements in capacity calculation (CC) methods, the increase in tradable cross-zonal capacities in Europe has remained limited. In an attempt to shed light on this feature, the Agency has developed a new methodology to assess the so-called 'benchmark capacity', i.e. the maximum capacity that could be made available to the market on a given border if the recent Agency's Recommendation on CC Methodologies[2] ('the Recommendation') were to be followed. The results of this assessment show that, on High-Voltage Alternating Current (HVAC) interconnectors, an average of 47% of the benchmark capacity was made available for trading, showing considerable room for improvement. As expected, the share of the benchmark capacity made available for trading was much higher (over 85% on average) for High-Voltage Direct Current (HVDC) interconnectors. Important variations among regions are shown in Figure i.

Figure i: Ratio between available cross-border capacity and the benchmark capacity of HVAC interconnectors per region – 2016 (%)



Source: ACER calculations based on data provided by NRAs through the Electricity Wholesale (EW) template (2017), ENTSO-E and Nordpool Spot.

Note: Available cross-border capacity refers to average Net Transfer Capacity (NTC) values, except for the Core (CWE) region, where available capacity relates to the size of the actual Flow-Based (FB) domain and the benchmark capacity relates to the size of a benchmark domain.

6 Table ii shows that on 31 border directions, less than 50% of the benchmark capacity was offered to the market and that, on a large range of EU borders, only a residual part of the benchmark capacity was actually offered to the market in 2016.

2 Recommendation of the Agency No 02/2016 of 11 November 2016 on the common capacity calculation and redispatching and countertrading cost-sharing methodologies, available at: http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Recommendations/ACER%20Recommendation%2002-2016.pdf.

Table ii: Borders with the lowest ratio between tradable capacity (NTC) and benchmark capacity – 2016 (%, MW)

Border-Direction	NTC 2016 (MW)	TC [MW]	Benchmark capacity (MW)	Ratio NTC/ benchmark
PL > DE/LU	1	3,095	2,424	0%
DE/LU > PL	9	3,095	2,424	0%
CZ > PL	22	3,527	1,881	1%
SK > PL	21	2,075	1,386	2%
DE/LU > CZ	278	5,564	2,745	10%
RO > BG	250	4,156	2,443	10%
BG > RO	281	4,156	2,443	12%
DK1 > DE/LU	194	3,748	1,582	12%
PL > SE4	99	600	600	16%
PL > SK	231	2,075	1,386	17%
PL > CZ	406	3,527	1,881	22%
AT > CZ	527	3,576	1,908	28%
AT > CH	802	4,120	2,794	29%
DE > CH	1,467	11,991	5,059	29%
CZ > AT	561	3,576	1,908	29%
PL > LT	149	500	500	30%

Border-Direction	NTC 2016 (MW)	TC [MW]	Benchmark capacity (MW)	Ratio NTC/ benchmark
AT > HU	472	3,115	1,474	32%
NORD > AT	100	421	306	33%
AT > SI	642	2,505	1,743	37%
ES > PT	1,932	9,614	5,179	37%
HR > HU	1,000	5,159	2,503	40%
HU > AT	605	3,115	1,474	41%
CH > AT	1,152	4,120	2,794	41%
IT > CH	1,722	8,332	3,987	43%
NORD > FR	1,020	5,336	2,324	44%
CH > FR	1,125	10,545	2,461	46%
PT > ES	2,382	9,614	5,179	46%
HU > HR	1,164	5,159	2,503	46%
HU > SK	811	2,736	1,689	48%
SK > CZ	1,192	4,480	2,477	48%
SI > NORD	551	2,150	1,126	49%

Source: ACER calculations based on data provided by NRAs through the EW template (2017), ENTSO-E and Nordpool Spot.

Note: To improve comparability with NTC values, the technical profiles setting simultaneous limits on commercial capacity on some borders of the former CEE region (see footnote 1) were translated into maximum bilateral exchanges (i.e. DE > PL, PL > DE, DE > CZ, CZ > DE, PL > CZ, CZ > PL, PL > SK, SK > PL) based on actual price differentials by ensuring that all constraints were taken into account simultaneously.

7 The relatively low cross-zonal capacities are a reflection of underlying (probably structural) network congestion, which is not efficiently addressed by the existing bidding zone configuration. The CC process can mitigate this problem. However, there are two key reasons why this mitigation is currently not observed. First, the process applied by Transmission System Operators (TSOs) to calculate the capacity made available for cross-zonal trade is insufficiently coordinated. In 2016, insufficient coordination accounted for approximately one third of the gap between the capacities made available for trading and the benchmark capacities. Second, TSOs tend to prioritise internal over cross-zonal exchanges, i.e. they regularly limit cross-border capacity to relieve internal congestion or to accommodate unscheduled flows. This explains the other two thirds of the gap observed in 2016.

8 Lack of coordination in capacity calculation usually leads to insufficient cross-border capacity, but in exceptional cases it can also lead to an excess of capacity on a specific border, potentially at the expense of limiting cross-border trade on adjacent borders. This may be the case on the German-Austrian border, where a recent bilateral agreement between the Austrian (E-Control) and German (Bundesnetzagentur) NRAs[3] sets this capacity to at least 4,900 MW (reserved for long-term capacity allocation), whereas the Agency estimates the maximum capacity that could be made available to the market on this border is 2,519 MW. Although the difference may be partly due to the commitment to apply redispatching actions that were not considered in the Agency's calculations[4], the bilateral agreement has raised concerns among market participants, TSOs and NRAs from neighbouring countries as to whether a significant part of the exchanges between Germany and Austria will keep on transiting through the neighbouring countries and whether the related negative impacts on neighbouring markets will remain.

3 For more information on the bilateral agreement, see: https://www.bundesnetzagentur.de/SharedDocs/Pressemitteilungen/EN/2017/15052017_DE_AU.html.

4 According to the Austrian and German NRAs, the agreement envisages the application of redispatching actions, in cases where neither the cross-border capacity between Germany and Austria nor the physical flows across the Polish-German border are sufficient to ensure trade up to 4.9 GW.

9 Analysing the extent to which internal exchanges are prioritised requires access to detailed information. The Flow-based (FB) method increases the transparency of the CC process and allows such an analysis to be performed. For example, in the Core (CWE) region where FB applies, the data made available to the Agency leads to the conclusion that in case of congestion in the CWE region (more than 60% of the hours in 2016), the available cross-zonal capacity is more often constrained by internal lines (72% of the occurrences in 2016) than cross-zonal lines (28%). Moreover, 77% of the congestions relate to lines located in Germany (including cross-border lines), of which 62% are related to internal lines in the Amprion's area.

10 Moreover, in 2016 the average proportion of capacity made available for cross-zonal trade in internal-to-bidding zone lines in the Core (CWE) region was only 12% of their maximum capacity, whereas the remaining 88% was 'consumed' by flows resulting from internal exchanges.

11 More generally, TSOs tend to use cross-zonal capacity as an adjustment variable to address various internal-to-bidding-zone issues, which could be resolved without a reduction of cross-zonal capacity. For example, on the Lithuanian and Swedish borders with Poland, cross-zonal capacities were often reduced in 2016 by the Polish TSO to guarantee sufficient balancing reserves in the Polish system. Although balancing capacity is indeed needed to ensure operational security, the reduction of cross-zonal capacity is not necessarily needed to achieve this objective.

12 In 2016, the volume of remedial actions (countertrading or redispatching) that TSOs applied to guarantee adequate levels of cross-border capacity in Europe was lower than in 2015, and remained insufficient to address the discrimination of cross-zonal exchanges in Europe. This confirms the lack of correct and adequate incentives for TSOs to take remedial actions, the latter preferring to limit ex-ante cross-zonal capacities in order to limit the costs of such actions.

13 The gross welfare benefits of applying the Agency's Recommendation to the Core (CWE) region were estimated at more than 150 million euros per year in 2016, an amount that is comparable to the benefits from the implementation of the FBMC itself. The gross welfare benefits from applying the Recommendation to the whole of Europe are estimated to total several billion euros per year. Although these estimates do not account for the costs incurred by TSOs in making this cross-border capacity available to the market, additional benefits can be expected from enlarging the amount of available cross-zonal capacity in the long term. This includes stronger incentives for reinforcing the internal networks[5], stronger incentives to coordinate both TSOs' action and national energy policies and, finally, stronger incentives to consider the bidding zone reconfiguration as a crucial and possibly more efficient tool to foster market integration in the medium term.

14 An important final remark regarding CC is that transparency in 2016 remained an issue both for market participants and for the Agency. Market participants are affected because they have difficulties predicting how much capacity will be available for trade. The Agency is impacted because it has to devote disproportionate effort to obtain the necessary information, rather than focusing on fulfilling its monitoring mission. It often has to rely on voluntary data collection involving TSOs, NRAs and ENTSO-E[6].

Efficient use of available cross-zonal capacity

15 In general, the liquidity of forward markets in Europe remained low in 2016, with the main exceptions being Germany/Austria/Luxembourg, followed by the United Kingdom, France and the Nordic region. The highest growth in the same period was recorded in the French forward market.

16 In the context of a limited number of liquid forward markets in Europe, cross-zonal access to these markets becomes particularly important. Without prejudice to the NRAs' competence to decide on this matter, the Agency will monitor the extent to which the implementation of the Forward Capacity Allocation (FCA) Regulation helps provide market participants with sufficient hedging opportunities.

5 When this produces positive net benefits.

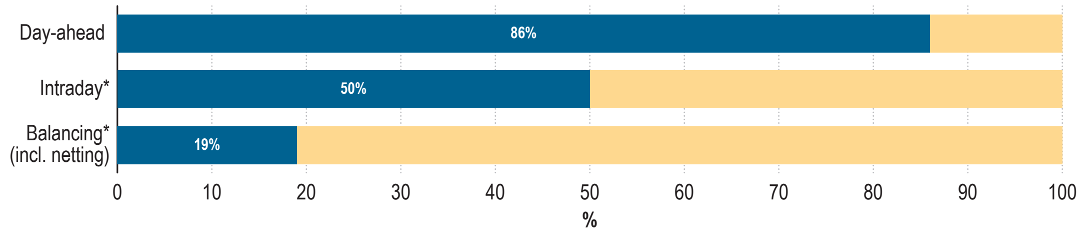
6 For instance, the Agency needed a disproportionate effort and more than six months in order to obtain the final consent of Core (CWE) TSOs and NRAs to access the FB data, while the latter are already accessible to all Core (CWE) NRAs.

17 Thanks to the DA market coupling of two thirds of the European borders, covering 22 European countries[7] by the end of 2016, the level of efficiency in the use of the interconnectors in this timeframe increased from approximately 60% in 2010 to 86% in 2016. The analysis shows that the overall level of efficiency in the use of the interconnectors slightly increased between 2015 and 2016 due to the extension of market coupling to the Austrian-Slovenian border as of 22 July 2016.

18 Over the past seven years, thanks to market coupling, the EU has reaped significant efficiency gains – and therefore welfare gains – to the benefit of consumers. Furthermore, the finalisation of market coupling implementation, as required by the Capacity Allocation and Congestion Management (CACM) Regulation, on all remaining European borders that still applied explicit DA auctions by the end of 2016 would render a social welfare benefit of more than 200 million euros per year. Among the non-coupled regions, the largest social welfare gains could be obtained on the British borders with Ireland and Northern Ireland and on the Swiss borders with Italy and France.

19 As illustrated in Figure ii, compared to the DA timeframe (86%), the level of utilisation of cross-zonal capacity in the intraday (ID) timeframe remains low (50%), which leaves a large part of the potential benefits from the use of existing infrastructure untapped across Europe. Moreover, the same analysis concludes that, in 2016, cross-zonal capacity was used more efficiently in the ID timeframe on borders which applied implicit auctions (100%) compared to borders with implicit continuous trading (49%) or explicit capacity allocation methods (40%).

Figure ii: Level of efficiency in the use of interconnectors in Europe (% use of available commercial capacity in the 'right economic direction') – 2016



Source: ACER calculations based on ENTSO-E, NRAs, EMOS and Vulcanus.
*Note: *Intraday and Balancing values are based on a selection of EU borders.*

20 In absolute terms, the aggregated cross-zonal volumes traded in the ID timeframe across Europe between 2010 and 2016 increased. Similarly, the upward trend in ID liquidity levels observed in most of the countries over the past years continued in 2016. Compared to 2015, the most notable relative increases in ID liquidity were observed in the Netherlands (40%), Belgium (35%) and Switzerland (20%), followed by Italy (14%), Portugal (12%) and Germany/Austria/Luxembourg (10%). This is mainly due to the integration of the ID markets in Belgium, France, Germany/Austria/Luxembourg, the Netherlands and Switzerland through implicit continuous capacity allocation and a higher share of renewable-based generation (including hydropower) sold in the Portuguese market.

21 In fact, this trend is consistent with the growing need for short-term adjustments due to the greater penetration of intermittent generation from renewables into the electricity system, in which ID liquidity will play an important role in the future. Furthermore, ID liquidity is expected to be positively affected by, among other factors, the introduction of new products, the extension of balancing responsibility to all renewable generators and the implementation of the Single ID Coupling (SIDC). In the medium term, requirements laid down in the CACM Regulation, such as setting the ID gate closure time no more than one hour before physical delivery or the possibility to complement the ID continuous trading with regional auctions, could also have an impact on ID liquidity and the efficient use of the cross-zonal capacity in the ID timeframe.

7 By the end of 2016, DA market coupling was implemented on 30 out of 42 EU borders (excluding the four borders with Switzerland), covering Austria, Belgium, the Czech Republic, Denmark, Estonia, Finland, France, Germany, Great Britain, Hungary, Italy, Latvia, Lithuania, the Netherlands, Norway, Poland, Portugal, Romania, Slovakia, Slovenia, Spain and Sweden.

22 In 2016, despite some improvements, large disparities in balancing energy and balancing capacity prices persisted in Europe. These disparities, together with a significant amount of unused cross-border capacity (see Figure ii), suggest considerable potential for further cross-border exchanges of balancing services in Europe. In 2016, the overall cross-border exchange of balancing services increased significantly (almost doubled) compared to 2015, although it continued to be limited when compared to its maximum potential.

23 In some countries, such as Austria, the overall costs of balancing show a decreasing trend following the introduction of improvements in recent years. These improvements include regulatory measures aimed at enabling the participation of a wider range of technologies in balancing, the increasing cross-border exchange of balancing services and the wider geographical scope of projects aimed at exchanging these services. This confirms the importance of rapidly and effectively implementing the recently adopted Regulation establishing an electricity Balancing Guideline.

Capacity mechanisms and adequacy assessments

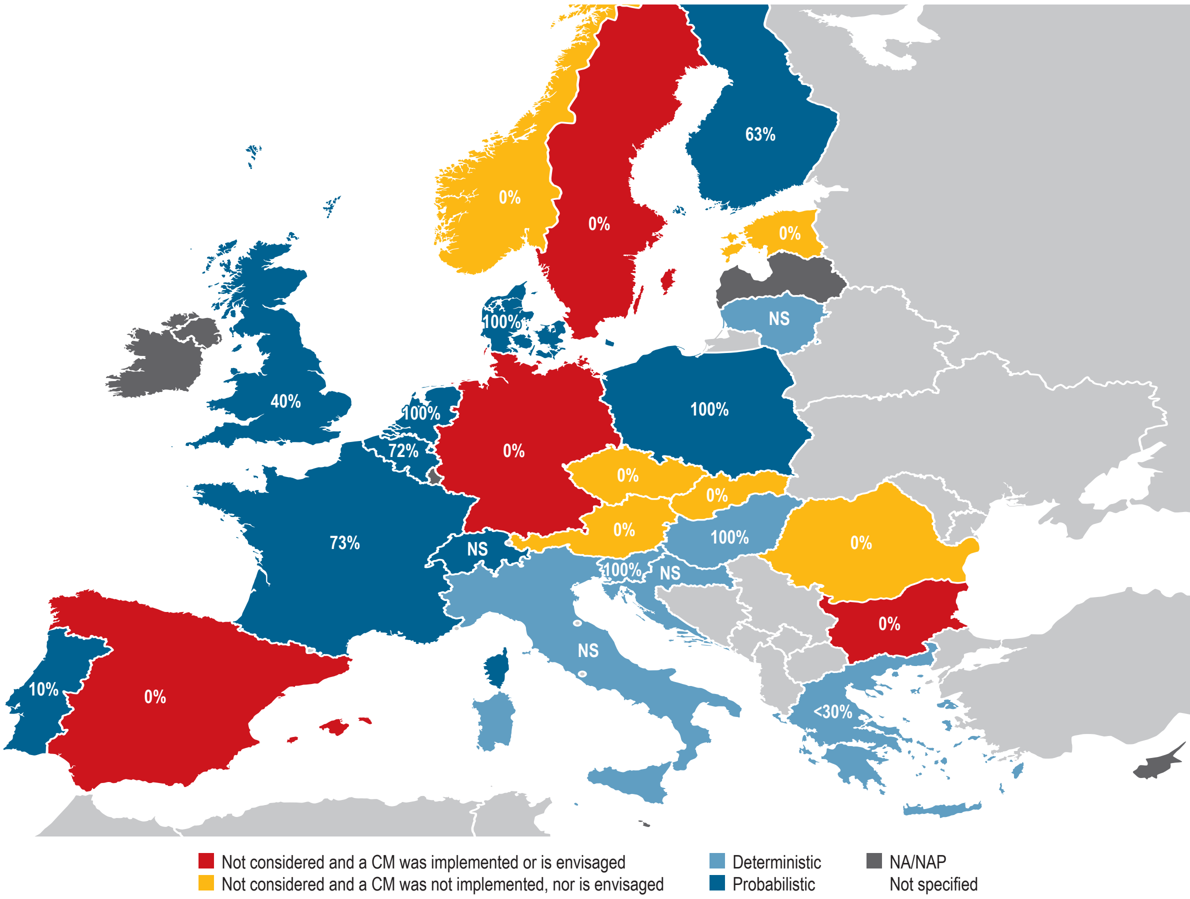
24 In 2016, a patchwork of different Capacity Mechanisms (CMs) remained throughout Europe in 2016. There are several key changes compared to what was presented in last year's Market Monitoring Report. First, Latvia is now shown as having an operational mechanism which resembles the German planned network reserves mechanism[8], and could be considered as a CM. Second, the transitional capacity payments designed in Greece for the period from May 2016 to April 2017 were approved by the European Commission. Additionally, Poland decided to extend the operation of strategic reserves until the end of 2019, while in Spain, one of the existing types of capacity payments no longer applies to new capacity as of 1 January 2016. Furthermore, in Germany, the plan to implement a capacity reserves mechanism has been postponed until the end of 2018 (envisaged start of the first contracting period), while the formal approval of this mechanism is still pending.

25 The starting point in the process of determining whether to implement a CM should be an assessment of the resource adequacy situation. Given the increasing interdependence of national electricity systems, a robust adequacy assessment needs to carefully consider the contribution of interconnectors to adequacy, because such a contribution may be a determining factor when deciding to implement a CM.

26 However, more than one third of the national adequacy assessments used as a basis to decide on the implementation of a CM consider the contribution of interconnectors to be equal to zero MW of capacity (see Figure iii).

8 Although the mechanism is in place since 2005, the update on the existence of a CM in Latvia is based on the most recent information received from the Latvian NRA, which was previously not made available to the Agency.

Figure iii: Treatment of interconnectors in national generation adequacy assessments, in Europe – 2016



Source: NRAs (2017).

Notes: The information shown in the table is based on the national adequacy assessments used to take a decision on whether to implement a CM or, in countries where such a decision was not considered, on the latest national adequacy assessment. The percentages shown on the map are calculated, for a given country, as the ratio between the average expected net contribution of all interconnectors during scarcity situations and the sum of the average commercial import cross-border capacity. These percentages do not represent the actual contribution (in MW) which can be negligible on some borders due to the low availability of cross-zonal capacity (e.g. on some of the Polish borders).

27 Moreover, evidence (e.g. ex-post analysis) shows that most of the other two thirds of the national generation adequacy assessments tend to significantly underestimate the contribution of interconnectors. This purely national approach is all the more surprising in the context of the significant progress made towards a more integrated electricity market, and may lead to (or contribute to) a situation of overcapacity at the expense of end consumers.

Recommendations

28 Electricity markets are facing emerging unprecedented challenges as they adapt to meet global decarbonisation targets while safeguarding security of supply and ensuring affordability. In this context, the timely and effective implementation of all the Regulations establishing Network Codes and Guidelines shall remain an utmost priority. The Agency is strongly convinced that implementing the following list of policy recommendations 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 market integration project is meaningless; 2) recommendations on how to make use of existing cross-zonal capacity made available for trading more efficiently in the different 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 limited amount of cross-zonal capacity made available for trading, which is currently one of the most significant limiting factors for integrating electricity markets in Europe. This requires, among other things, ensuring the equal treatment of internal-to-bidding-zones and cross-zonal exchanges, increasing the level of TSOs' coordination, and improving the level of transparency in capacity calculation.

31 In order to ensure the equal treatment of internal and cross-zonal exchanges, the Agency recommends a profound paradigm shift in the way cross-border capacities are currently considered: instead of using these capacities as the main adjustment variables in the overall network security equation, the level of cross-border capacity made available to the market should become a clear priority. In this respect, the following is recommended:

a) As a first step, the Agency recommends that the three high-level principles proposed in the Agency's Recommendation No 02/2016 be followed by TSOs and NRAs when developing, approving, implementing and monitoring capacity calculation methodologies. In the context of this Recommendation, the argument that available cross-border capacity needs to be reduced due to operational security reasons should be used by TSOs only in exceptional situations, i.e. when no other remedies are available (instead of a recurrent and vague justification) and, in any case, such reductions need to be thoroughly and transparently substantiated.

b) Where the use of remedial actions is not sufficient to ensure an appropriate level of cross-border capacities, the Agency recommends that a reconfiguration of bidding zones be applied as a matter of urgency.

c) As the required paradigm shift will require strong political support from Member States, these could consider setting a binding target for the availability of existing and future cross-border capacity, e.g. by defining a minimum share of physical cross-zonal capacity which should be made available for cross-zonal trade at, for example, the regional level.

32 In order to improve the level of TSO coordination, the following is recommended:

a) NRAs and TSOs should ensure the effective and rapid implementation of all legal provisions related to TSO coordination (for instance, as introduced by the Regulation establishing a System Operation Guideline[9] for the Regional Security Centres or potentially for Regional Operation Centres in the future[10]).

b) NRAs and TSOs should ensure the effective and rapid implementation of FB capacity calculation, as required by the CACM Regulation.

9 See the provisional final version of the System Operation Guideline at https://ec.europa.eu/energy/sites/ener/files/documents/SystemOperationGuideline%20final%28provisional%2904052016.pdf.

10 See more in the EC's 'Clean Energy for All Europeans' legislative proposal, which is available at: https://ec.europa.eu/energy/en/news/commission-proposes-new-rules-consumer-centred-clean-energy-transition.

33 In order to increase the transparency of capacity calculation, the following is recommended:

a) NRAs and/or the EC should request from TSOs the publication of all data generated for cross-zonal capacity calculation in a timely and user-friendly manner. This could be done on a voluntary basis or by amending the existing Regulation (e.g. the so-called 'Transparency Regulation'[11]).

b) The EC and the European Legislators should consider providing the Agency with stronger data collection powers in order to fulfil its monitoring tasks.

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

a) NRAs and TSOs should implement DA market coupling on the 16 European borders (including the Swiss borders) that were still uncoupled at the end of 2016.

b) When developing and approving a cross-zonal ID capacity pricing methodology[12], TSOs and NRAs should take into account that ID auctions are not only a possible tool to price capacity, but also a way to increase the level of efficient interconnector use in the ID timeframe.

c) In order to support and foster ID liquidity, NRAs and TSOs should ensure full balancing responsibility for all technologies[13] and should enforce cost-reflective balancing charges.

d) TSOs should optimise the procurement of balancing capacity.

e) TSOs should increase the exchange of balancing resources.

f) In general, effective and rapid implementation of the Regulation establishing an EB Guideline is needed.

35 The third group of recommendations is intended to address adequacy concerns in an efficient manner. In this field, the Agency recommends the following:

a) Before implementing a CM, MSs should exhaust all possible no-regret measures, including the removal of price caps, ensuring the equal treatment of generation technologies regarding balance responsibilities, increasing demand-side participation, removing undue limitations on cross-zonal trade and removing any other barrier to efficient price formation in the wholesale electricity markets.

b) MSs, the EC and NRAs should seek ways to strengthen the role of European adequacy assessments. In particular, the estimated contribution of interconnectors when considering the implementation of a CM should be based on regional or pan-European assessments, as they have a clear potential to provide better results than fragmented national assessments.

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11 Commission Regulation (EU) No 543/2013 of 14 June 2013 on the submission and publication of data in electricity markets and amending Annex I to Regulation (EC) No 714/2009 of the European Parliament and of the Council.

12 On 14 August 2017, an all TSOs' common proposal for a single methodology for pricing intraday cross-zonal capacity was submitted to all NRAs.

13 Except pilot projects for the purpose of research and development.

1 Introduction

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

37 The goal of the Electricity Wholesale Markets Volume is to present the results of the monitoring of the performance of the internal electricity market in the European Union[14] (EU), which depends on the efficient use of the European electricity network and the good performance of electricity wholesale markets in all timeframes. When electricity wholesale markets are integrated via sufficient interconnector capacity, then competition will work to the benefit of all consumers and improve energy system adequacy and supply security in the long run.

38 The Regulation establishing a Capacity Allocation and Congestion Management (CACM) Guideline[15] that is currently being implemented provides for clear objectives to deliver an integrated internal electricity market in the following areas: (i) full coordination and optimisation of Capacity Calculations (CCs) performed by Transmission System Operators (TSO) within regions; (ii) definition of appropriate bidding zones, including regular monitoring and reviewing of the efficiency of bidding zone configuration; and iii) the use of Flow-Based (FB) CC methods in highly meshed networks. These processes are intended to optimise the utilisation of the existing infrastructure and to provide the market with more possibilities to exchange energy, enabling the cheapest supply to meet demand with the greatest willingness to pay in Europe, subject to the capacity of the existing network.

39 The recently adopted Regulations establishing Guidelines on Forward Capacity Allocation (FCA)[16] and on Balancing[17] will also play a crucial role in the further integration of the Internal Energy Market (IEM). The former establishes a framework for calculating and allocating interconnection capacity, and for cross-zonal trading, in forward markets, while the latter sets rules on the operation of balancing markets, i.e. those markets that TSOs use to procure energy and capacity to keep the system in balance in real time. Moreover, it aims to increase the opportunities for cross-zonal trading and the efficiency of balancing markets.

40 Although implementing the provisions included in the above-mentioned Guidelines remains a key priority for the Agency for the Cooperation of Energy Regulators (‘the Agency’ or ‘ACER’), the document should also be read in the context of the ongoing discussions regarding the European Commission’s (EC) legislative proposal ‘Clean Energy for All Europeans’[18] on new rules for a consumer centred clean energy transition.

41 The volume is organised as follows. Chapter 2 presents the key developments in electricity wholesale markets in the EU in 2016. Chapter 3 assesses the level of cross-zonal capacities made available for trade and the performance of the CC processes, with a focus on the comparative treatment of internal-to-bidding zones as opposed to cross-zonal exchanges. The performance of forward, Day-ahead (DA), Intraday (ID) and balancing markets, and particularly the use of cross-zonal capacity across these timeframes, is presented in Chapter 4. The document ends with a presentation of the situation of Capacity Mechanisms (CMs) and on the treatment of interconnectors in the national adequacy assessments (Chapter 5).

14 The Norwegian and Swiss markets are also analysed throughout in several Chapters of this report, but for simplicity, the scope of the analysis is referred to as the ‘EU’ or ‘Europe’.

15 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.

16 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.

17 See the provisional final version of the Electricity Balancing Guideline at https://ec.europa.eu/energy/sites/ener/files/documents/informal_service_level_ebgl_16-03-2017_final.pdf.

18 The Commission’s ‘Clean Energy for All Europeans’ legislative proposal covers energy efficiency, renewable energy, the design of the electricity market, security of electricity supply and governance rules for the Energy Union, and is available at: https://ec.europa.eu/energy/en/news/commission-proposes-new-rules-consumer-centred-clean-energy-transition.

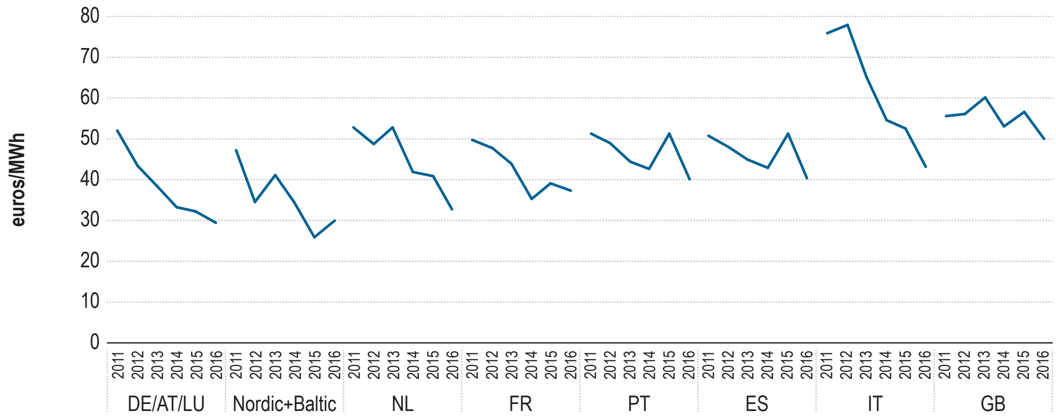
2 Key developments in 2016

42 This Chapter reports on prices in European electricity wholesale markets in 2016 (Section 2.1), including an analysis of the evolution of the level of price convergence (Section 2.2).

2.1 Evolution of electricity wholesale prices

43 In 2016, electricity wholesale prices continued the downward trend observed since 2011. This is shown for a selection of markets in Figure 1. In 2016, the average wholesale DA prices in Belgium, Germany (including Austria and Luxembourg), Great Britain, Italy and the Netherlands reached their lowest level in the last decade.

Figure 1: Evolution of DA electricity wholesale prices in different European power exchanges – 2011–2016 (euros/MWh)



Source: European Network of Transmission System Operators for Electricity (ENTSO-E) and Platts (2017).

44 In all the markets except the Nordic-Baltic ones, prices fell compared to 2015. The Nordic-Baltic markets saw a 16% increase in prices, although prices in these markets are among the lowest in Europe. The most significant decreases were observed in Spain and Portugal, where prices decreased by 21 and 22% respectively.

45 Overall, this trend is consistent with lower gas prices observed in 2016, when prices fell on average by almost 30% compared to the previous year, and with the reduction in the price of other fossil fuels observed during the first half of 2016[19]. At the same time, between 2015 and 2016, the volume of electricity produced from wind and solar generation plants increased by 5 %, in spite of the slight increase of 0.7% in electricity demand[20] in the EU.

46 The increase in prices by 16% observed in the Nordic-Baltic markets in 2016 is linked to a circumstantial, yet noticeable decrease of 5% in the contribution of wind and solar generation in this region, in addition to lower hydro generation compared to 2015. In contrast, between 2015 and 2016, the minor rise in demand by 0.6% in Portugal was more than offset by the increase in hydropower, wind and solar production, by 73%, 8% and 3%, respectively, resulting in a fall in prices by 22%.

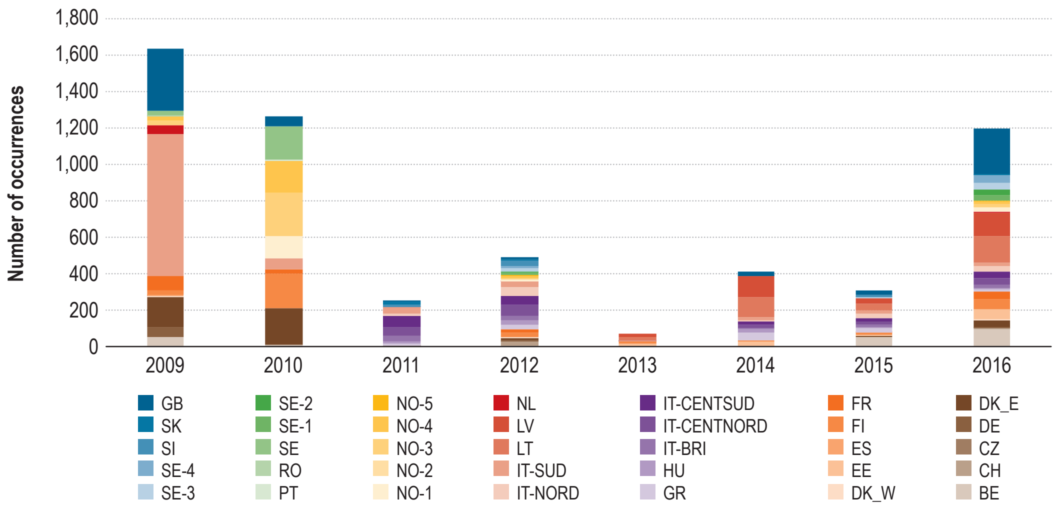
47 In 2016, German prices, which were among the lowest in the EU (28.98 euros/MWh on average), saw a further decline by 8% compared to the previous year. This was due to a combination of relatively stable demand (which decreased by 1%), falling production costs and a modest – yet relevant – increase of 2% in the volume of electricity produced from intermittent renewable sources.

19 During the first half of 2016, both gas (Title Transfer Facility (TTF)) and coal prices (CIF ARA 6000 kcal/kg)) remained significantly lower on average than over the same period compared to the previous year (respectively 39% and 22%, respectively). During the second half of 2016, coal prices were higher than in previous year (36% increase), while gas prices remained low (19% decrease) compared to 2015.

20 In this Chapter, Eurostat data is used to report on demand and ENTSO-E data is used to report on electricity production per technology. The electricity demand values up to 2015 are based on the yearly electricity demand values as provided by Eurostat. As the 2016 yearly values will not be published until 2018, the electricity demand in 2016 used in this MMR is based on the 2015 yearly value and the relative change in 2016 compared to 2015, the latter based on the monthly values recorded by Eurostat.

48 In 2016, price spikes[21] were significantly more frequent than in previous years (see Figure 2). In 2016, their frequency (1195 occurrences for the analysed 35 bidding zones) was comparable to what was observed in 2009 and 2010. As shown in Figure 3, the order of magnitude of some price spikes in Belgium, France and Great Britain and to a lesser extent in Finland was remarkable. In Finland, spikes occurred sporadically in January 2016. In Belgium, France and Great Britain, price spikes were recorded on several occasions during the last quarter of 2016. The occurrence of price spikes in these markets is consistent with the fact that these four MSs appear to be exposed to relatively tighter adequacy margins[22] than others.

Figure 2: Frequency of price spikes in main wholesale DA markets in Europe – 2009–2016 (number of occurrences per year)



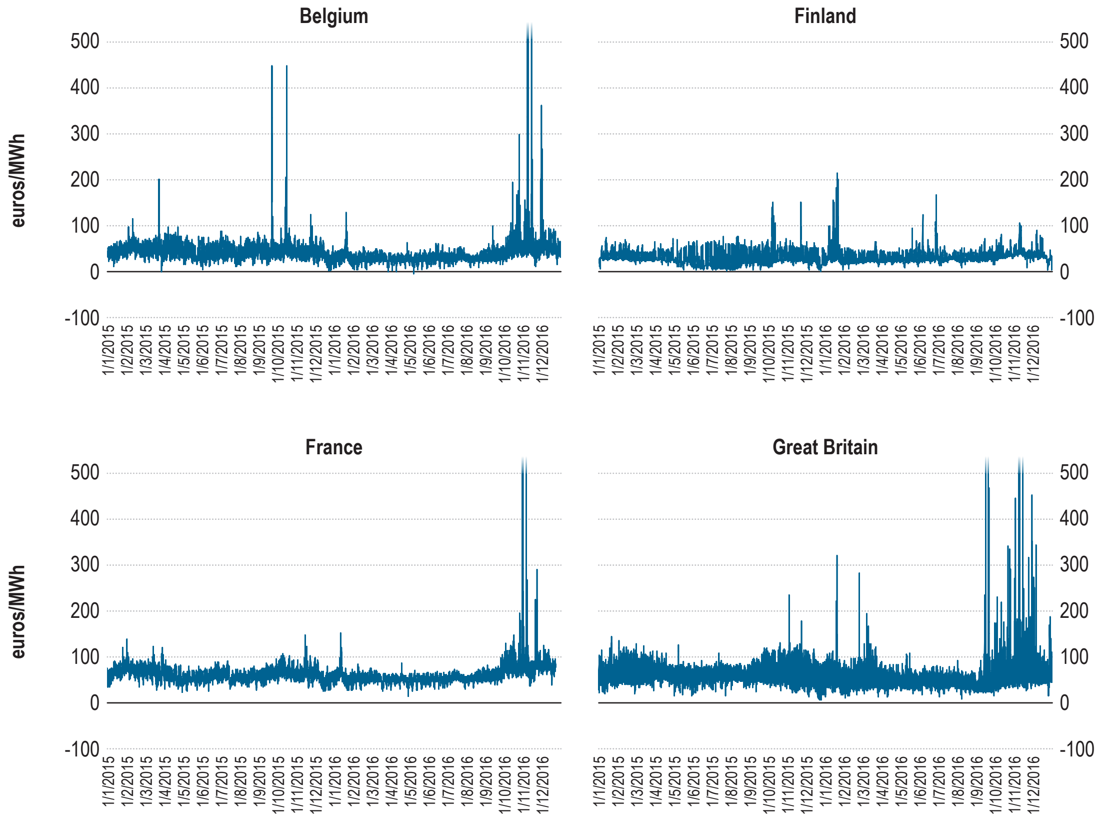
Source: ENTSO-E, Platts (2017) and ACER calculations.

Note: For Great Britain, N2EX and Elexon prices were used for the period 2012–2016 and respectively for 2009–2011.

21 For this analysis, a price spike occurrence is considered as an hourly DA price three times above the theoretical variable cost of generating electricity with gas-fired generation plants, based on the TTF gas DA prices in the Netherlands. See more details in footnote 12 of the Electricity Wholesale Markets volume of the MMR 2015, available at: http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Monitoring%20Report%202015%20-%20ELECTRICITY.pdf.

22 See Figure 7 and Table 3 of ENTSOE's 'Winter outlook report 2016/2017 and summer review 2016', available at: https://www.entsoe.eu/Documents/Publications/SDC/2016-wor_report.pdf, as well as the specific analysis of the situation in Belgium, France and Great Britain in Section 4.3.

Figure 3: Hourly DA electricity prices in Belgium, France, Great Britain and Finland – 2015–2016 (euros/MWh)



Source: ENTSO-E, Platts (2017) and ACER calculations.

Note: The y-axis is truncated at 500 euro/MWh in order to improve the readability of the figure.

49 On the one hand, the occurrence of prices spikes at times of scarcity may reflect efficient price formation[23], provided that this is not the result of an abuse of market power or of price manipulation. These price spikes allow generators to cover, at least, a share of their fixed costs. This contribution to cost recovery may become more relevant, as the production mix is changing. The importance of renewable sources is growing to the detriment of the utilisation rate of conventional ones[24]. This should result in more frequent price spikes, e.g. when peak load periods are coupled with situations of low injections from wind, solar or both.

50 On the other hand, the increasing frequency of scarcity situations stresses the importance of efficiently addressing the security of supply issue. Member States have a legitimate interest to ensure security of supply in their countries at all times. However, unilateral or uncoordinated actions cannot only harm the internal market, but also security of supply in the region. Therefore, the need for further market integration and more tradable cross-zonal capacity remains. Reliable generation adequacy assessments are essential for ensuring adequate levels of security of supply at the lowest possible cost. Given the increasing interdependence of national electricity systems, the scope of these assessments should be at least regional, i.e. wider than national. Such assessments should realistically consider the contribution of interconnectors. This is further analysed in Section 5.2.

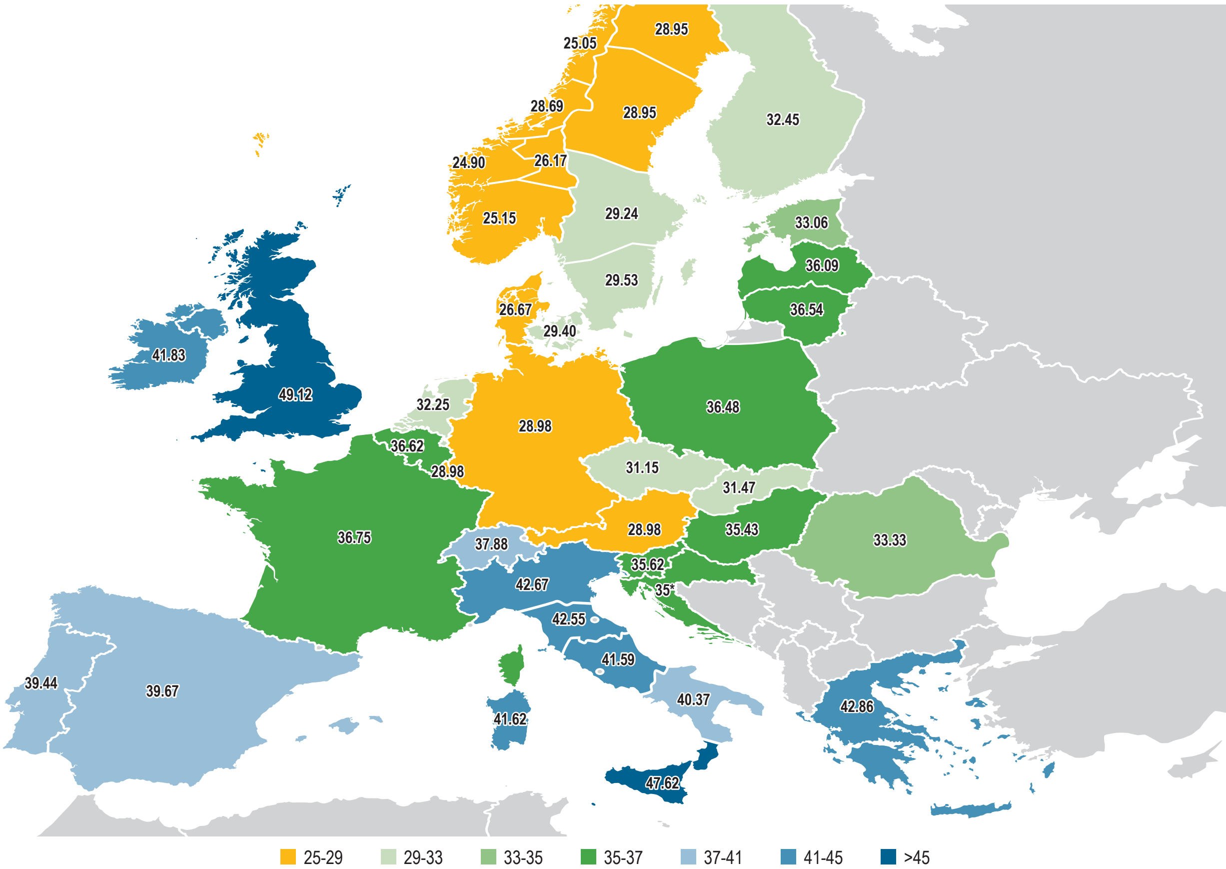
23 See also the European Energy Regulators' White Paper #4 on 'Efficient Wholesale Price Formation', available at: http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/White%20Papers/Positions/ACER-CEER%20White%20Paper%204-%20Efficient%20Wholesale%20Price%20Formation.pdf.

24 See ENTSO-E's 2016 'Mid-term adequacy forecast' (MAF), available at: https://www.entsoe.eu/Documents/SDC%20documents/MAF/ENSTOE_MAF_2016.pdf.

2.2 Price convergence

51 The price convergence of DA markets provides an indication of the level of market integration, which depends both on the efficient use of interconnectors and on the existent infrastructure. Different levels of price convergence across European borders can be observed (Figure 4). On some borders (Portugal-Spain, Czech Republic-Slovakia and Latvia-Lithuania), the absolute price spreads in 2016 were on average below 0.5 euros/MWh. Other borders, including British borders, Austria-Italy and Germany-Poland, showed average absolute price spreads equal or higher than 10 euros/MWh during the same period[25]. Table 5 in Annex 1 shows the evolution of average price spreads across European borders in the period from 2012 to 2016.

Figure 4: Average electricity wholesale DA prices – 2016 (euros/MWh)



Source: ENTSO-E and Platts (2017).

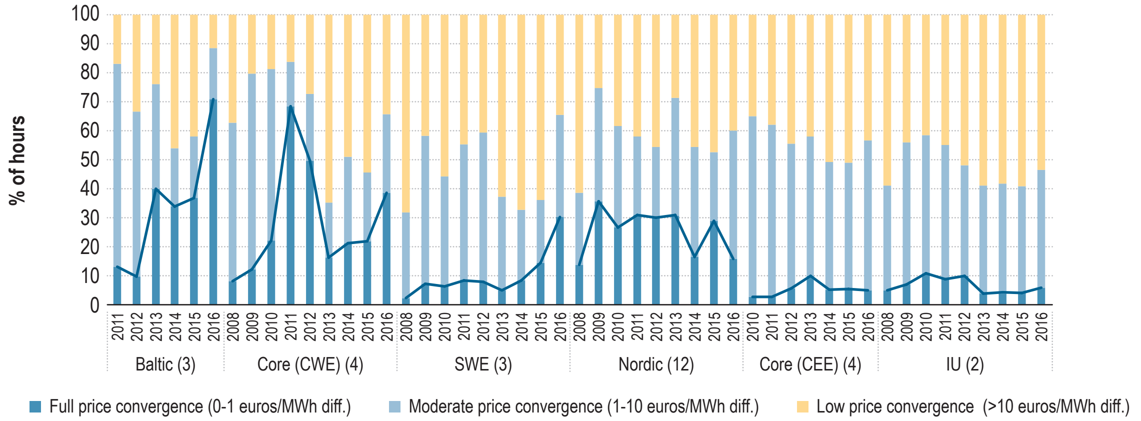
*Note: *For Croatia, an average value with decimals is not provided, as hourly DA prices are not yet available at the ENTSO-E's Transparency Platform (TP).*

52 Overall, Figure 4 and Table 5 in Annex 1 illustrate the existing scope for further price convergence. This confirms the relevance of maximising the amount of tradable cross-zonal capacity, particularly on borders with the highest price spreads. However, reaching full price convergence is not an objective per se, because it would require overinvestment in interconnectors, which is inefficient from an economic point of view.

25 The price differentials reported in this paragraph are average absolute DA spreads. These are higher than the 'simple' spreads where negative and positive price spreads are netted.

53 Figure 5 provides an overview of the degree of price convergence within European market coupling regions[26] between 2008 and 2016. It shows that the Baltic, Central-West Europe (CWE) and South-West Europe (SWE) are the three regions that recorded the highest frequency of full convergence[27] in hourly DA prices in 2016 (71%, 39% and respectively 30%). Moreover, between 2015 and 2016, these three regions recorded the highest increases in the frequency of full DA price convergence.

Figure 5: DA price convergence in Europe by region (ranked) – 2008–2016 (% of hours)



Source: ENTSO-E, Platts (2017) and ACER calculations.

Note: The numbers in brackets refer to the number of bidding zones included in the calculations per region.

54 In the Baltic region, the frequency of DA price convergence increased from 37% in 2015 to 71% in 2016, mainly due to the two new electricity interconnectors commissioned in 2015 between Lithuania, Poland and Sweden.

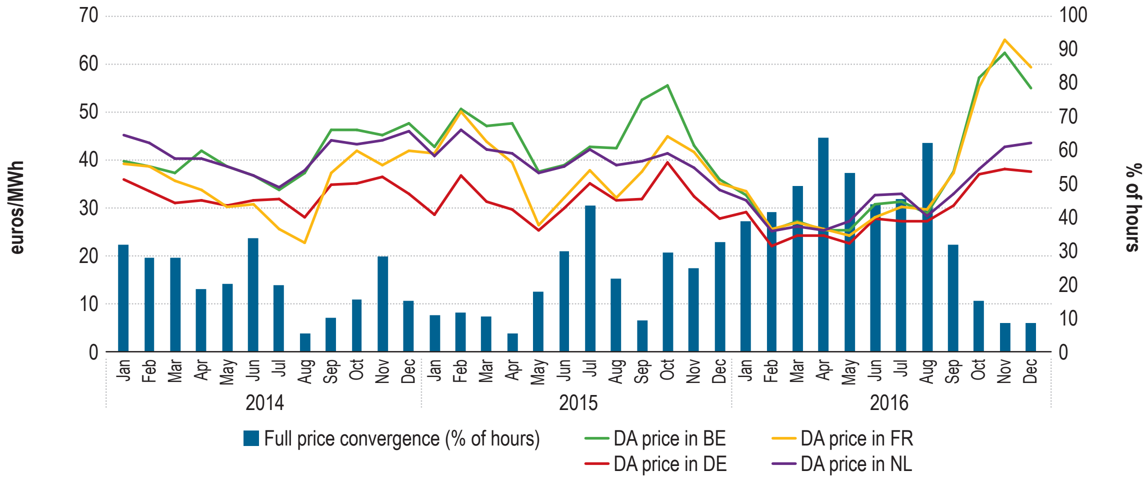
55 In the SWE region, the upward trend in the frequency of hourly price convergence observed in 2015 following the extension of market coupling to the French-Spanish border (13 May 2014), continued in 2016. The frequency of full price convergence in the SWE region increased from 14% in 2015 to 30% in 2016. This was mainly due to the new interconnector between Spain and France, which also led to higher volumes of cross-zonal tradable capacities (see Section 3.2.1 for more information on recent investments in network infrastructure with cross-zonal relevance in the Baltic and SWE regions).

56 In the Core (CWE) region, the frequency of full price convergence increased from 22% in 2015 to 39% in 2016, mainly due to the go-live of Flow-Based Market Coupling (FBMC) in May 2015. Figure 6 shows the monthly evolution of DA prices and the degree of full price convergence in the Core (CWE) region between 2014 and 2016. It indicates that the frequency of full price convergence increased to 48% during the first three quarters of 2016. This trend was reversed in the last quarter of 2016, when the frequency of full price convergence dropped to 11%. The different trends between the first three quarters and the last quarter are explained by high DA prices in France and Belgium in the last quarter of 2016. These were mostly caused by the significant number of reactors that were offline in France (and to a lesser extent in Belgium), in combination with a significant reduction (see Sub-section 3.2.1) in the amount of tradable cross-zonal capacity within the Core (CWE) region during the second half of 2016.

26 For the purpose of this analysis, bidding zones are grouped into regions, as follows: the Baltic region (Estonia, Latvia and Lithuania), the Central-East Europe (CEE) region (the Czech Republic, Hungary, Poland and Slovakia), the CWE region (Belgium, France, Germany/Austria/Luxembourg and the Netherlands), the Ireland and United Kingdom region (IU) (the Republic of Ireland and the United Kingdom), the Nordic region (Denmark, Finland, Norway and Sweden) and the SWE region (France, Portugal and Spain). These regions are in line with Agency's Decision No 06/2016 of 17 November 2016 on the TSOs' proposal for the determination of CCRs, except for the CWE and CEE regions, which are identified throughout this document as the Core (CWE) region and the Core (CEE) region, for consistency with previous years' MMRs. The Decision is available at: http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions/ACER%20Decision%2006-2016%20on%20CCR.pdf.

27 Price convergence is defined as 'full', 'moderate' or 'low' if the hourly difference between the maximum and minimum price within the region is below 1 euro, between 1 and 10 euros or above 10 euros, respectively.

Figure 6: Monthly DA prices in Core (CWE) and the frequency of full price convergence – 2014–2016 (euros/MWh and % of hours)



Source: ENTSO-E, Platts (2017) and ACER calculations.

57 Overall, despite the discrepancies observed between the first three quarters and the last quarter of 2016, the analysis confirms that, in general, FBMC contributes to increasing price convergence by providing larger cross-zonal trading possibilities. Moreover, the reduced level of price convergence observed in the second semester confirms that higher levels of market integration can be achieved by avoiding reductions in tradable cross-zonal capacity.

58 As further analysed in Chapter 3, increasing the amount of tradable cross-zonal capacity does not necessarily require investment in new interconnectors. In the shorter term, priority should be given to increasing the share of physical cross-zonal capacity that is made available to the market.

3 Available cross-zonal capacity

59 The optimisation of cross-zonal capacity is an essential prerequisite for an efficient IEM. First, this Chapter introduces a number of improvements in the methodologies used to monitor available cross-zonal capacity (Section 3.1). Second, it provides an overview of the volumes of tradable[28] (i.e. available for trade) cross-zonal capacity in the EU, including the relation between these volumes and the physical capacity of interconnectors (Section 3.2). Third, it assesses the reasons for the large gap between physical and tradable capacity on most EU borders and provides recommendations on how to reduce this gap (Section 3.3).

3.1 Methodological improvements

60 The Agency already examined the relationship between physical and tradable capacity on EU borders in the last year MMR[29]. However, this edition of the MMR makes use of a number of data items which have been made available to the Agency for the first time. It introduces a number of new methodologies which have been developed to assess the issue of CC.

61 The first novelty relates to a Recommendation[30] recently issued by the Agency (hereinafter 'the Recommendation'). This Recommendation builds, *inter alia*, on the following two provisions:

a) Article 16(3) of the Regulation (EC) No 714/2009[31]: "The maximum capacity of the interconnections and/or the transmission networks affecting cross-zonal flows shall be made available to market participants, complying with safety standards of secure network operation" and Point 1.7 of Annex I to the same regulation: "TSOs shall not limit interconnection capacity in order to solve congestion inside their own control area […].");

b) Article 21(I)(b)(ii) of the CACM Regulation[32], which specifies that CC and allocation methodologies must be based on "rules for avoiding undue discrimination between internal and cross-zonal exchanges".

62 The Recommendation establishes two high-level CC principles[33]. First, limitations on internal network elements should not be considered in cross-zonal CC methods. Second, the capacity of the cross-zonal network elements considered in the common CC methodologies should not be reduced in order to accommodate Loop Flows (LFs). TSOs and National Regulatory Authorities (NRAs) are expected to follow these high-level principles when developing, approving, implementing and monitoring their CC methodologies. However, the Recommendation allows for deviations from these principles if they are properly justified (from an operational security and socio-economical point of view at the EU level) and do not unduly discriminate against cross-zonal exchanges.

63 Based on this Recommendation, this edition of the MMR introduces the concept of 'benchmark' capacity, which is defined as the capacity that could be made available to the market if the two high-level principles underlying the Recommendation were strictly followed. The calculated benchmark capacities are presented in Sub-section 3.2.2. As deviations from the high-level principles are acceptable subject to adequate justifications, as outlined above, the monitoring of CC should not only focus on the deviations from the benchmark capacities but also on the proportion of capacity of Critical Network Elements (CNEs) that is made available for cross-border exchanges and the proportion reserved for internal exchanges. The combined analysis of these elements allow an assessment of the extent to which internal exchanges are prioritised (Sub-section 3.3.2).

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

29 The MMR 2015 is available at http://www.acer.europa.eu/en/electricity/Market%20monitoring/Pages/Current-edition.aspx.

30 Recommendation of the Agency No 02/2016 of 11 November 2016 on the common capacity calculation and redispatching and countertrading cost-sharing methodologies, available at: http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Recommendations/ACER%20Recommendation%2002-2016.pdf.

31 Regulation (EC) No 714/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the network for cross-zonal exchanges in electricity and repealing Regulation (EC) No 1228/2003, available at: http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32009R0714&from=EN.

32 See footnote 15.

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

64 The second novelty refers to the availability of new data, enabling the Agency to enhance its analysis on CC. In 2017, two sets of data were provided to the Agency for the first time. First, TSOs provided information on the Common Grid Model (CGM)[34] for continental Europe. The Agency used this information to estimate the benchmark capacities. Second, the Core (CWE) region TSOs provided via ENTSO-E detailed information on the most relevant data items used in the Flow-Based Capacity Calculation (FB CC) process in the Core (CWE) region. This data included, *inter alia*, hourly information on the forecasted physical flows on internal and cross-zonal transmission lines in the Core (CWE) region resulting from internal exchanges. These forecasted physical flows are used to define the constraints determining the tradable cross-zonal capacity in a FB context.

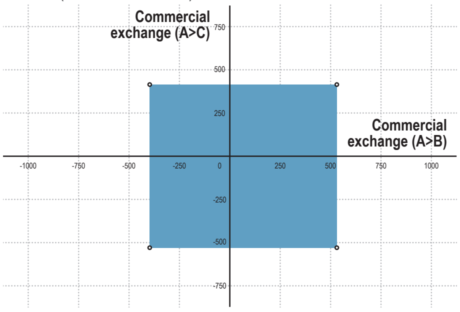
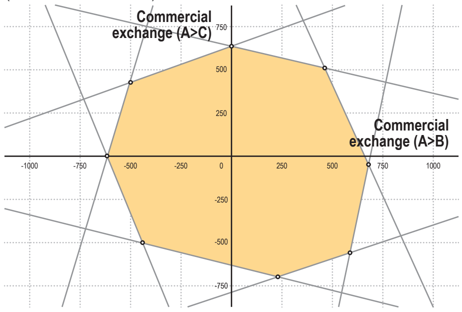
65 With this new information, the Agency devised a set of new indicators to improve the monitoring of the FB CC process. The indicators are based on the same principles as for the NTC-based CC. They are adapted for use in a FB context, as further detailed in the different Sections of this Chapter. For a better understanding of the principles and the concepts underlying these indicators, an explanatory overview highlighting the main differences between the Coordinated Net Transfer Capacity ('CNTC')[35] and the FB CC methods is presented below in Table 1.

Table 1: Principles, similarities, main differences and parameters of the CNTC and FB CC processes

<table>
<tr><th></th><th>CNTC</th><th>FB CC</th></tr>
<tr><td>Principle</td><td>CC method based on the principle of assessing and defining ex ante a maximum energy exchange between adjacent bidding zones.</td><td>CC method in which energy exchanges between bidding zones are limited by a set of constraints intended to represent the physical limits of the network. These constraints are determined by Power Transfer Distribution Factors (PTDFs) and available margins on critical network elements (CNEs). These margins determine the capacity that can be offered to the market in order to be allocated to where its value is the highest.</td></tr>
<tr><td>Similarities</td><td colspan="2">• Both are intended to maximising tradable cross-zonal capacity while safeguarding the operational security standards of the transmission system.
• Both result in the determination of a capacity domain. This is the domain of possible commercial capacity that can be allocated for each direction on each bidding zone border.</td></tr>
<tr><td>Differences</td><td>• The actual exchange between two given bidding zones is not dependent on the exchanges across adjacent borders.
• The maximum bilateral exchanges are fixed ex ante. The combination of possible exchanges (on a set of adjacent borders) cannot be optimised via the capacity allocation algorithm.
• Lower visibility of the location of physical congestions.
• It is an acceptable CC method for non-meshed networks (provided that a sufficient level of coordination is applied).</td><td>• The actual exchange between two bidding zones is dependent on the exchanges across adjacent borders within a Capacity Calculation Region (CCR). Energy exchanges between bidding zones are limited by PTDFs and available margins on CNEs.
• The combination of possible exchanges is optimised via the FBMC algorithm.
• Higher visibility of the location of physical congestions.
• It is the most efficient CC method for meshed networks.</td></tr>
<tr><td rowspan="2">Relevant input parameters</td><td colspan="2">CNEs: a network element either within a bidding zone or between bidding zones taken into account in the CC process, limiting the amount of power that can be exchanged.
Reliability Margin (RM): capacity reserved by TSOs to be able to cope with uncertainties on the relevant network elements.
Generation Shift Keys (GSKs): factors describing a linear estimate of the most probable change in the generation pattern within a bidding zone in relation to the change of the net position of this bidding zone.
Maximum flow (Fmax): maximum power flow that a CNE can accommodate.</td></tr>
<tr><td>Total Transfer Capacity (TTC): maximum exchange programme between two areas compatible with operational security standards applicable to each system if future network conditions, generation and load patterns were perfectly known in advance.</td><td></td></tr>
</table>

34 A 'common grid model' means an EU-wide data set agreed between various TSOs that describes the main characteristics of the power system (generation, loads and grid topology) and the rules for changing these characteristics during the CC process. Pursuant to the CACM Regulation, a CGM should be established for each hour. So far, the Agency has been provided with four GCMs corresponding to an identical number of hours that were representative of the generation, load conditions and the network topology in the period from the summer of 2015 to the winter of 2016/2017. These hours are: 15 July 2015 at 10:30, 20 January 2016 at 10:30, 20 July 2016 at 10:30, 18 January 2017 at 10:30, and are the winter and summer reference cases as often used by TSOs to calculate long-term capacity.

35 Throughout this Chapter, CNTC refers to one of the two possible CC methodologies envisaged in the CACM Regulation (in addition to FB), while NTC is used to refer to existing CC methodologies, which are not necessarily as coordinated as required by the CACM Regulation. CNTC also refers to CNTC values pursuant to the CACM Regulation, rather than actual NTC values.

	CNTC	FB CC
Relevant output parameters	**Capacity domain:** set of all feasible combinations of cross-zonal exchanges, i.e. those that are compatible with the network constraints.	
	The perimeter of the domain is defined by one single value per border (the CNTC value) 	The perimeter of the domain is defined by a set of constraints (the FB constraints). 
	Net Transfer Capacity (NTC): Maximum total exchange programme (MW) between two interconnected power systems available for commercial purposes, for a certain period and direction. CNTC=TTC-RM.	**(Zone-to-line) PTDFs:** factors quantifying the impact that a change in the commercial flow between two bidding zones (or the change in the net position of a given bidding zone) causes on the physical load on a CNE. **Remaining Available Margin (RAM):** commercial capacity available for cross-zonal trade in a CNE. **Allocation constraints:** constraints (others than those on CNEs) set to maintain the transmission system within operational security limits.
Other relevant concepts (used in capacity allocation)	**Net position:** netted sum of electricity exports and imports for each market time unit for a bidding zone.	
		Active constraint: commercially congested CNE, i.e. a CNE for which all RAM has been allocated; **Shadow price:** welfare gain resulting from relaxing the capacity constraint related to a CNE (i.e. from increasing its available capacity) by 1 MW.

Source: ACER (2017).

66 The third novelty refers to the gross social welfare indicator used in previous editions of the MMR that was adapted (Sub-section 4.2.2) in order to reflect the gross benefits resulting – to varying degrees – from the application of the principles underlying the Recommendation of the Agency.

67 The fourth novelty is that the borders have been regrouped and renamed in accordance with the new CCRs[36].

68 The fifth novelty relates to the methodology for evaluating the level of regional coordination in the calculation of tradable capacity, which has been enhanced and further detailed with additional data collected from NRAs (Sub-section 3.3.1 and Annex 3).

69 An important final remark is that access to available data remains an issue for the Agency. As the Agency has no general powers to request the information needed to fulfil its monitoring mission, it often has to rely on voluntary data collection involving TSOs, NRAs and ENTSO-E[37].

36 Except for the Swiss and Norwegian borders, CCRs are based on Annex I of the Decision of the Agency No 06/2016 of 17 November 2016 on the Electricity TSOs' Proposal for the Determination of Capacity Calculation Regions, available at: http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/ANNEXES_CCR_DECISION/Annex%20I.pdf.

37 For instance, it took a disproportionate effort and more than six months for the Agency to get the final consent of Core (CWE) TSOs and NRAs to access the FB data, while the latter is already accessible to all Core (CWE) NRAs.

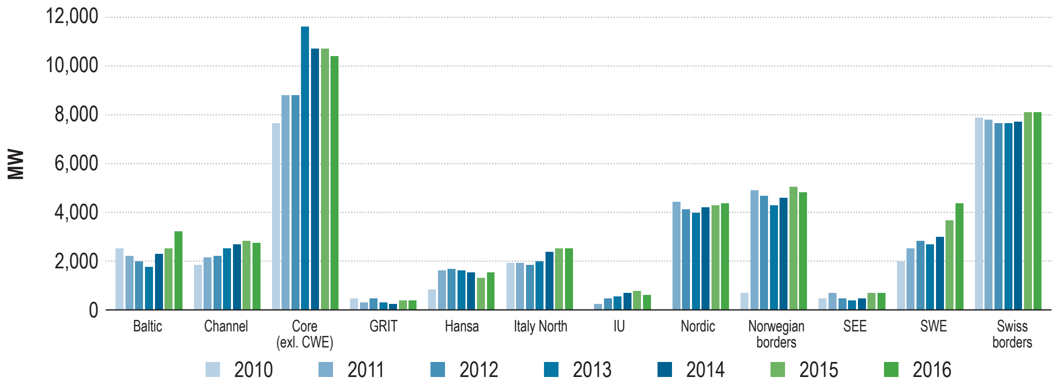
3.2 Amount of cross-zonal capacity made available to the market

70 First, this Section assesses the amount of cross-zonal capacity made available to the market in 2016 compared to 2015 (Sub-section 3.2.1). Second, it compares actual cross-zonal capacity with a benchmark (i.e. maximum feasible) cross-zonal capacity (Sub-section 3.2.2).

3.2.1 Evolution of commercial cross-zonal capacity

71 Figure 7 presents average available cross-zonal NTC values aggregated per CCR[38] from 2010 to 2016. The overall level of tradable capacity increased slightly in 2016 compared to 2015 (2.2%). The highest increases were observed in the Baltic and SWE regions, followed by the Hansa, Nordic and Italy North regions. The highest decrease occurred in the Ireland-United Kingdom (IU) region, followed by GRIT (comprising only the connection between Greece and Italy for the purpose of this analysis), the Norwegian borders, the Channel (United Kingdom's connections with France and the Netherlands), and the Core (excluding CWE) regions.

Figure 7: NTC averages of both directions on cross-zonal borders, aggregated per CCR – 2010–2016 (MW)



Source: ENTSO-E, NRAs and Nord Pool Spot (2017).

72 Figure 8 shows the major changes in tradable NTC capacity on selected European borders between 2015 and 2016. The full list is available in Table 7 in Annex 1.

73 The largest increases in absolute values relate to investments in new interconnectors. This includes the following:

- On the French-Spanish border, an additional 1,112 MW (+85% compared to 2015) in the direction from France to Spain and 810 MW (+72%) in the opposite direction. This additional tradable capacity was made available following the commissioning of a new interconnector (2,000 MW) between France and Spain, which started commercial operation on 5 October 2015[39];
- The first interconnection between Alytus in Lithuania and Elk in Poland, following the commissioning of the LitPol link in December 2015. The project is a double-circuit High-Voltage Direct Current (HVDC) interconnector operating at 400 kV, and provides 500 MW of tradable capacity;
- The new 300 kV HVDC interconnector (NordBalt), partly subsea and partly underground, between Klaipeda in Lithuania and Nybro in Sweden, which was commissioned in December 2015. The project provides 700 MW of tradable capacity.

74 Another increase in NTC could be observed from Germany (Tennet) to West Denmark (+51%), which is partly explained by the introduction of an improved capacity calculation software which allowed to reduce the uncertainty in capacity calculation and consequently the associated reliability margins.

38 The Core (CWE) region is not included, as the FB CC has been applied there since 2015 (see separate Figure 3).

39 The new interconnector is a HVDC link of 320 kV consisting of converter stations in Baixas (France) and Santa Llogaia (Spain).

75 The largest NTC reductions in percentage terms occurred at the borders from Germany to the Czech Republic (-68%), at the British-Irish East-West interconnector (-28% in both directions), and from Norway to Sweden (-22%).

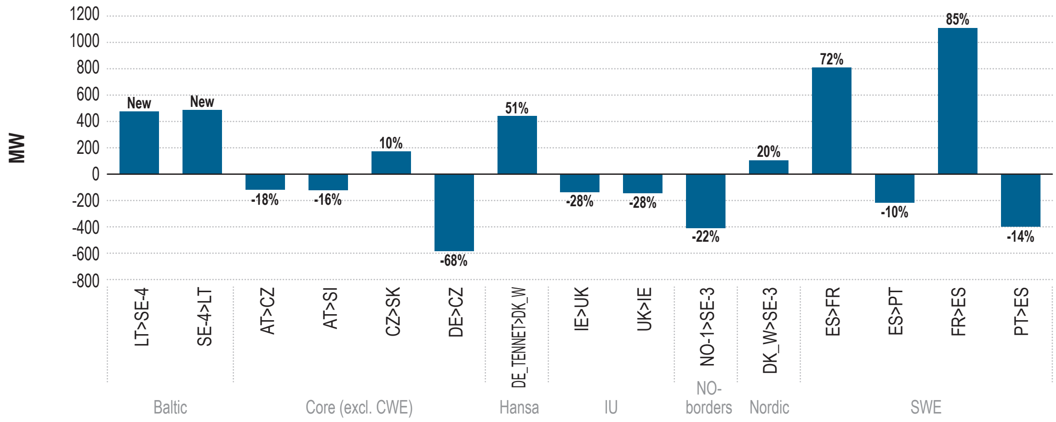
76 The reduction at the German-Czech border was mainly related to the temporary disconnection of one interconnector on the German-Polish border[40] in combination with the current TSOs' approach to consider LFs, resulting from internal exchanges within the German-Austrian bidding zone, in the capacity calculation process.

77 The reduced physical capacity on the German-Polish border impacts the maximum exchange between Germany and the Czech Republic as these two variables are linked through several 'technical profiles'[41]. In 2016 the exchange from Germany to Czech Republic was most frequently limited by the technical profile that 50 Hertz (in Germany) estimates as the maximum simultaneous possible exchange from its own area to Poland and the Czech Republic. This technical profile was often set at zero MW during the first half of 2016.

78 The current approach to consider LFs in the capacity calculation processes explains why the above mentioned reduction in physical capacity affected cross-border exchanges and internal exchanges unequally. Requests for internal exchanges (e.g. resulting in LFs) get unlimited and prioritised access to the scarce network capacity, whereas the requests for cross-zonal exchanges can access only that part of the scarce network capacity which is not already used by internal exchanges. Overall, this example confirms the urgent need to address the unequal treatment of internal and cross-border exchanges.

79 The British-Irish East-West link was unavailable most of the time between September and December 2016 due to a technical fault on the interconnector which occurred upon re-energisation following a planned outage. The NTC decrease from Norway-1 to Sweden-3 was the result of a failure on an internal cable in Norway crossing the Oslo fjord, which restricted the available exchange capacity between some areas in Norway and the exchange capacity to Sweden.

Figure 8: Changes in tradable capacity (NTC) in Europe from 2015 to 2016 (MW, %), excluding differences lower than 100 MW



Source: ENTSO-E, NRAs and Nord Pool Spot (2017).

Note: A->B means in the direction from bidding zone A to bidding zone B. The analysis involved 45 borders in Europe and is presented in Table 7 in Annex 1. The figure excludes border directions with NTC changes lower than 100 MW (absolute values). The bars represent the change (in MW) by comparing 2015 and 2016 NTC values; the indicated percentages show the relative change from 2015 to 2016. To improve comparability with NTC values, the technical profiles setting simultaneous limits on commercial capacity on some borders of the former CEE region were translated into maximum bilateral exchanges (of which only DE->CZ is shown in this figure) based on actual price differentials and ensuring that all constraints are taken into account simultaneously.

40 The Hagenwerder (Germany)-Mikulowa (Poland) line, which was often disconnected during the first half of 2016. This was related to the commissioning of the first stage of Phase Shifting Transformers (PSTs) on the German-Polish border aiming to, *inter alia*, mitigate the impact of LFs on the amount of tradable cross-border capacity. During a fewer number of hours, the capacity offered on the German-Czech border was also affected by disconnections of the Hradec (Czech Republic)-Rohrsdorf (Germany) line as part of the preparatory works for the installation of PSTs in Hradec.

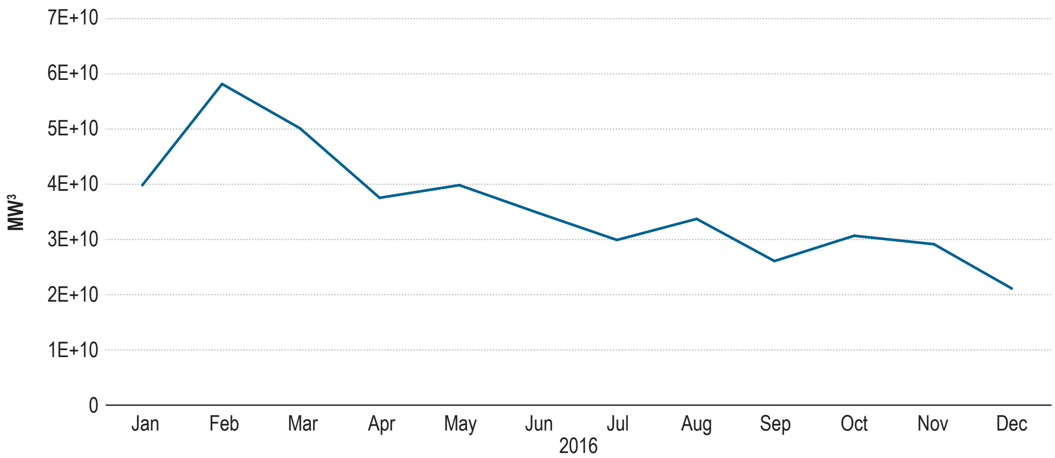
41 On several borders of the Core (CEE) region, several 'technical profiles' are used for cross-zonal capacity calculation. These profiles set simultaneous limits on commercial capacity on a set of borders.

80 In the Core (CWE) region, NTC values have no longer been provided since the launch of FBMC[42] on 20 May 2015. Instead, a new indicator for the development of tradable capacity in the Core (CWE) region in 2016 is presented in Figure 9. It shows the size (i.e. the volume[43]) of the FB domain, computed for every hour, for the economic direction, i.e. the "directional volume". The latter is defined – for the purpose of this indicator – as the FB domain volume in the octant that contains the solution of the market coupling algorithm, i.e. in the direction corresponding to the net positions of the bidding zones.

81 Contrary to NTC, in FBCC, the maximum capacity that can be allocated on a specific border is not dependent on one NTC value, but on a set of constraints determining the FB domain. The larger the size of the domain, the more trading possibilities exist. Hence, the size of the domain in the economic direction (i.e. the 'directional volume') can be used as an appropriate indicator to assess the evolution of tradable cross-zonal capacity in a FB context.

82 Figure 9 shows a clear downward trend in the size of the domain in 2016. The precise reasons for this decrease are further discussed in Sub-section 3.3.2.

Figure 9: Monthly average size of the FB domain (volume) intersecting the economic directions in the Core (CWE) region in 2016 (MW^3)



Source: Data provided by the Core (CWE) region TSOs to ENTSO-E (2017) and ACER calculations.

Note: The economic direction is defined as the directional FB domain volume in the octant that contains the solution of the market coupling algorithm that maximises social welfare.

83 Despite the decrease in the size of the FB volume in the course of 2016, price convergence and gross welfare gains increased compared to the period before the FB method was adopted[44]. The evolution of price convergence in this region is further analysed in Section 2.2.

84 Overall, the application of FBCC in combination with market coupling (i.e. FBMC) usually increases efficiency by optimising the use of cross-zonal capacity. However, this gain can be severely diminished, or even completely offset, if the amount of cross-zonal capacity is drastically reduced to accommodate flows from internal exchanges, as suggested by the observed developments of the FB volume during 2016. More details on the extent to which, the reduction in cross-zonal trading possibilities are explained by the discrimination of cross-zonal as opposed to internal exchanges are provided in Sub-section 3.3.2. The relationship between the amount of cross-zonal capacity and gross welfare benefits in the Core (CWE) region is analysed in Sub-section 4.2.2.

42 More information on FBMC is available at: http://www.jao.eu/support/resourcecenter/overview?parameters=%7B%22IsCWEFBMC%22%3A%22True%22%7D or in the published decision on each of the CWE NRAs' websites.

43 The volume is measured in MW^3, as the FBCC problem to be solved is a three-dimensional one in the Core (CWE) region. It involves determining the net position of four bidding zones that maximises social welfare with one dependent variable, which is that the net positions of all four bidding zones should be zero.

44 The NTC calculation method was applied until 19 May 2015 in the Core (CWE) region. Based on 2014 data, the welfare gain under FB was simulated to amount to 132 million euros, see page 157 of the MMR 2014, available at: http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER_Market_Monitoring_Report_2015.pdf.

3.2.2 Ratio between commercial and benchmark cross-zonal capacity

85 This Sub-section analyses the potential scope for increasing the available cross-zonal capacity. The underlying assumption in analysing this potential is that in an efficient zonal market design (i.e. if the bidding zones are properly defined according to physical constraints) the only factor limiting trade between two bidding zones is the capacity of the network elements on the bidding zone borders (i.e. the interconnection lines)[45]. This assumption is equivalent to the principles underlying the Agency's Recommendation on Capacity Calculation Methodologies.

86 Therefore the ratio between actual commercial cross-zonal capacity and the maximum capacity that could be made available to the market (hereinafter referred to as benchmark capacity) indicates the potential scope for increasing the available cross-zonal capacity.

87 In order to assign a benchmark capacity value to a specific border, a distinction between HVDC interconnectors and High-Voltage Alternating Current (HVAC) interconnectors needs to be made. In the case of HVDC interconnectors, the benchmark capacity is assumed to be equal to the thermal capacity of the interconnector[46]. In the case of HVAC interconnectors, several elements limiting the capacity that can be offered to the market need to be considered.

88 The first of these elements is the security criteria (i.e. N-1)[47]. The second is the uncertainty of CC (i.e. a RM). Finally, the electricity exchange on a specific border will create an uneven distribution of physical flows on the various interconnectors of that specific border. Therefore, the capacity on a specific border could be further limited to the maximum exchange at which one interconnector is being congested first, while others might be not. In order to account for these elements, the Agency has developed a calculation methodology which is described in Annex 2. The results of the calculations can be considered as realistic targets for HVAC interconnectors, although due to the assumptions, the following caveats need to be made.

89 First, the benchmark capacities could be higher if data not currently available to the Agency on all non-costly remedial actions (e.g. the setting of PSTs and various topological measures) and on all available redispatching and countertrading possibilities were considered in the calculations. Second, the results could be affected by the use of more specific GSKs[48]. Third, the commercial capacity is based on average actual observed values (NTC or FB volumes) irrespective of whether some reductions were caused by some justified reasons (e.g. planned maintenance).

90 Figure 10 shows the different elements that are considered in the methodology used to calculate benchmark capacities.

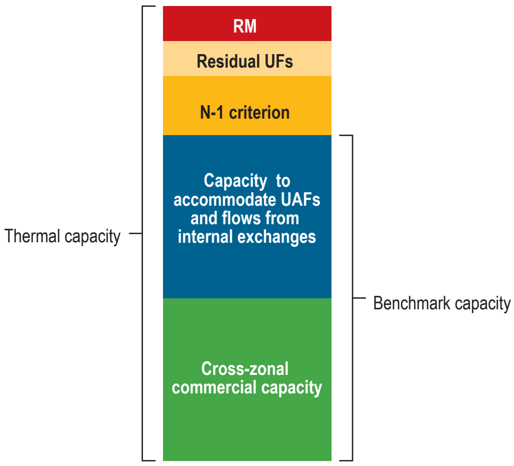
45 This implies that remedial actions should be applied to avoid that cross-border trade is limited by the (residual) LFs or internal congestions that will always exist in a close-to-optimal bidding zone configuration.

46 As HVDC interconnectors are virtually unaffected by the factors that impact available cross-zonal capacity on HVAC interconnectors.

47 N-1 security criterion is used to provide protection from cascading failures in the interconnected grids.

48 For the calculations, GSKs proportional to the generation output modelled within a CGM were used. Two exceptions were France and Switzerland where the use of proportional GSKs would lead to a specific congestion on some interconnectors due to the proximity of few large nuclear power plants to the border. In order to avoid this, GSKs with equal participation of generation nodes with the largest generation were used.

Figure 10: Breakdown of capacity components used to calculate benchmark capacity



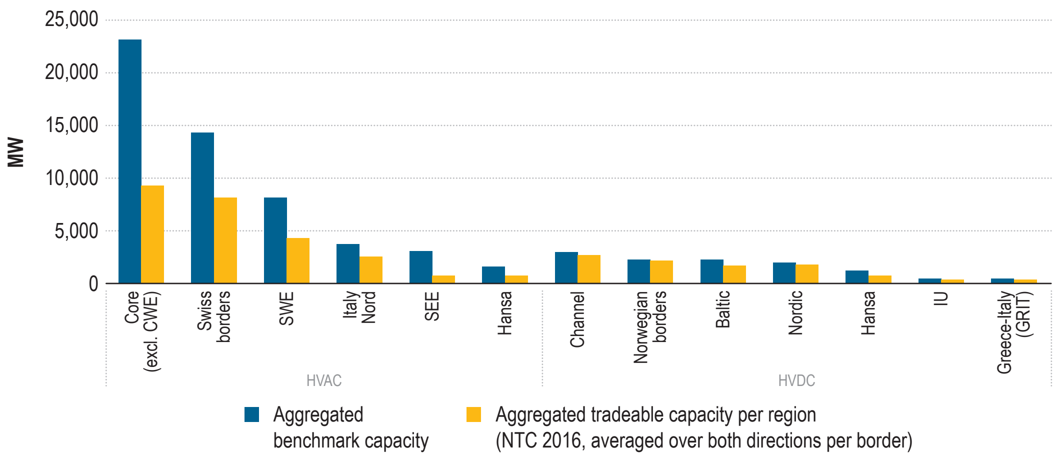
Source: ACER.

Note: The illustration corresponds to the breakdown of capacity on individual interconnectors. On borders where CC is NTC-based, the benchmark capacity additionally accounts for the uneven distribution of flows on individual interconnectors, which defines the maximum exchange (i.e. the benchmark capacity) at which one interconnector is being congested first while others are not. In a FB context, the individual capacities are translated into constraints determining the benchmark FB domain. Residual UFs refer to the UFs, which will remain in any close-to-optimal bidding zone configuration. The actual UFs (including unscheduled allocated flows (UAFs) and LFs) are part of the component "capacity to accommodate UAFs and flows from internal exchanges".

91 Following the aforementioned methodology, the Agency calculated benchmark capacity for the HVAC interconnectors in continental Europe for which data was available. On borders applying NTC-based CC, the benchmark capacity was based on the data included in the latest CGM[49] provided by the TSOs to the Agency. On borders applying FB CC, the benchmark capacity (i.e. the size of the FB "benchmark domain") was calculated based on detailed information provided by the Core (CWE) region TSOs.

92 The ratios between commercial capacity and benchmark capacity are analysed below. Figure 11 and Table 6 in Annex 1 present the ratio of NTC over benchmark capacity, aggregated by CCRs, in descending order of absolute amounts of tradable capacity in 2016. Furthermore, Table 7 in Annex 1 displays the information per border. Both Figure 11 and the tables in Annex 1 show that, on average, significantly less than half of the benchmark capacity is offered to the market in the Core (excl. CWE) and SEE regions.

Figure 11: Aggregated available tradable capacity (NTC) compared to aggregated benchmark capacity of interconnectors per Region – 2016 (MW)



Source: ENTSO-E YS&AR (2014, last corrected Nov 2016), Data provided by NRAs through the EW template (2017), Nord Pool Spot, 2016/2017 ENTSO-E's CGM and ACER calculations.

49 Corresponding to 18 January 2017 at 10:30. See footnote 34.

Note: Out of 51 borders, 35 borders are included in the analysis (see Table 7 in Annex 1). The following borders are excluded from the analysis for the following various reasons: the DE_TENNET-SE-4 border because this is a merchant line not included in the CCR, the Nordic, Norwegian and Baltic borders because they were not part of the CGM provided to the Agency and the four Core (CWE) region borders because FBCC is applied in Core (CWE). The values for the thermal capacity of interconnectors were taken from ENTSO-E YS&AR, and – where updated information was available via the 'EW template' or via the available CGMs – from NRAs or from TSOs, respectively. Tradable capacities are calculated as average NTC values per border in both directions, whereas benchmark capacity is calculated according to the methodology described in Annex 2.

93 Figure 11 shows that HVDC interconnectors have higher ratios, with an average of 85%, whereas on HVAC interconnectors an average of only 47% of benchmark capacity is available for trading.

94 Two of the main reasons for this higher percentage for HVDC interconnectors are that i) these interconnectors are not impacted by UFs[50] and that ii) these interconnectors are usually not considered in the N-1 assessment. The lowest ratios for HVDC interconnectors were observed on the border from Poland to Sweden-4 (Hansa region) and from Poland to Lithuania.

95 According to the Polish NRA, these reduced values are partly related to operational security issues, including the need to guarantee sufficient upward or downward reserves for balancing the Polish system in real time. The Polish system is centrally dispatched and the reserves are procured after the closure of the day-ahead market and as close-to-real-time as possible. In the view of the Polish NRA this is an essential feature of the Polish market design and there is a need to restrict the cross-border capacity through capacity allocation constraints, to avoid a situation where there are not enough balancing reserves in the Polish system close-to-real time.

96 However, in the Agency's view, the argument that TSOs are forced to reduce cross-zonal capacity (and thereby discriminate between internal and cross-zonal trade) in order to ensure secure operation of the network is a false dichotomy. This is because TSOs have at their disposal several remedies by which both the non-discrimination as well as secure network operation could be efficiently maintained. For instance, the balancing capacity can be procured ahead of real time, before the day-ahead capacity calculation without systematically reducing cross-zonal capacity. Moreover, although balancing capacity is indeed needed to ensure operational security, the reduction of cross-zonal capacity is not inherently needed to achieve this objective.

97 By contrast, the very low ratio of NTC over benchmark capacity on several HVAC cables continued to be correlated with the presence of UFs. For example, on the border from Germany to Poland, 76% of the benchmark capacity is used to accommodate UFs[51]. This is of particular concern in light of the observed average price differential between Germany and Poland (7.5 euros/MWh) which is among the largest average price differentials recorded on European borders in 2016 (as seen in Table 5 in Annex 1).

98 On HVAC interconnectors, relatively low ratios are observed in both meshed (average 46%) and non-meshed networks (i.e. on the Spanish borders with France and Portugal and on the border between Germany and Denmark 1 with an average 52%). However, individual results per border vary, as can be seen in Table 7 in Annex 1. The lowest values are observed on the borders of Germany to Poland (0%), the Czech Republic to Poland (1%) Slovakia to Poland (2%), Germany to the Czech Republic (10%), on the Bulgarian-Romanian border (average 11% considering both directions) and on the border of West Denmark to Germany (12%). An improvement on the West Denmark to Germany border is expected after the joint declaration between the ministries and the regulators of the respective MSs issued on 14 June 2017 that aims gradually to increase the minimum available cross-zonal capacity on this border for both directions up to 1100 MW in 2020.

99 At the other end, relatively high ratios (on average around 80%) can be observed on the Northern Italian borders (directions to Italy).

50 See Figure 36 on capacity losses due to UFs. More information on the different types of UFs, on the underlying definitions and on their magnitude can be found in Annex 4.

51 Calculated by combining information on benchmark capacity from Table 7 and on UFs from Figure 36.

100 Finally, on the German-Austrian border, no ratio was calculated, as there was no CC on this border in 2016. However, the recent agreement[52] between the Austrian (E-Control) and German (Bundesnetzagentur) NRAs set this capacity to at least 4,900 MW (reserved for long-term capacity allocation). This appears to be inconsistent with the calculations of the Agency, which estimate the maximum capacity that could be made available to the market on this border at 2,519 MW[53]. An explanation for this significant difference is that the 4,900 MW stems from a bilateral agreement rather than from a coordinated process with neighbouring TSOs. The difference can also be partly explained by the fact that the agreement envisages the application of redispatching actions[54] which have not been considered in the Agency's calculations. The Agency believes that the parties involved in the bilateral agreement should clarify the extent to which the envisaged redispatching actions will relieve capacity for trade on adjacent borders. In fact, the bilateral agreement has raised concerns among market participants, TSOs and NRAs from the neighbouring countries as to whether a significant part of the exchanges between Germany and Austria will keep on transiting through the neighbouring countries[55] and whether the related negative impacts on neighbouring markets will remain.

101 The examples listed in this Sub-section illustrate the wide disparities in the performance of CC methods from one border to another. Moreover, the good performance on some borders suggests that the benchmark capacities are achievable targets and emphasises that the commercial cross-zonal capacity in Europe could be significantly improved through enhanced CC methods.

102 For FB CC, an equivalent method was applied (see Annex 2). It allows the calculation of a ratio between the volume of the actual FB domain and the volume of a FB 'benchmark domain'[56]. The result of this calculation for the Core (CWE) region indicated a ratio of 59%[57], which suggests significant scope for increasing available cross-zonal capacity in the region.

103 To sum up, on most EU borders, actual NTC values (or the size of the FB domain) are significantly lower than what would be expected from the benchmark capacities (or respectively, the benchmark FB domain), which are considered by the Agency as realistic targets[58]. There is a large scope for improvement, because commercial capacity can potentially be doubled through improved CC methodologies.

104 The reasons for the relatively low values of commercial capacity are explained in the next Section.

3.3 Factors impacting commercial cross-zonal capacity

105 The relatively low cross-zonal capacities are a reflection of underlying (probably structural) network congestion, which is not efficiently addressed by the existing bidding zone configuration, neither by the application of remedial actions (e.g. redispatching or countertrading). The CC process can mitigate this problem. However, there are two key reasons why this mitigation is currently not observed. First, the process applied by TSOs to calculate the capacity made available for cross-zonal trade is insufficiently coordinated, an aspect which is analysed in Sub-section 3.3.1. Second, TSOs treat internal and cross-zonal exchanges unequally, which is explained in Sub-section 3.3.2.

106 As concluded in the previous Section, the gap between the commercial and the maximum possible (benchmark)

52 See more information at https://www.bundesnetzagentur.de/SharedDocs/Pressemitteilungen/EN/2017/15052017_DE_AU.html.

53 This value is consistent with available publications on this matter, e.g. see the paper "Splitting price zones: The impact of the German-Austrian: breakup on European energy objectives" at https://www.ihs.ac.at/fileadmin/public/2016_Files/Documents/2017-02_Blume-Werry_Splitting_price_zones%40EuropeanEnergy_Journal.pdf.

54 According to the Austrian and German NRAs, the agreement envisages the application of redispatching actions, in cases where neither the cross-border capacity between Germany and Austria nor the physical flows across the Polish-German border are sufficient to ensure trade up to 4.9 GW.

55 Based on previous Agency's estimations on average, about 59% of the physical flows resulting from the DE-AT cross-zonal exchanges are not realised through the DE-AT border, but are flowing as LFs through other borders. See paragraph 56 of the Agency's Decision on the TSOs' Proposal for determining Capacity Calculation Regions (see also footnote 36).

56 See more information on benchmark capacity and 'benchmark domain' in paragraph (91) and in Annex 2.

57 In order to improve comparability with the NTC ratios (based on values in MW), the cubic root of the FB volume was used for the FB ratio. For consistency with previous Sections, the directional volume (see paragraph (80) was used).

58 As mentioned above, this is partly confirmed by the fact that the actual available commercial capacity on some borders is indeed close to 100% of the benchmark value.

capacity is on average 15% and 53% of the benchmark capacity for HVDC and HVAC interconnectors, respectively. Although it is not currently possible to disentangle accurately the relative proportion of this gap that can be attributed to the two above-mentioned reasons, Sub-sections 3.3.1 and 3.3.2, provide some insight into the extent to which these two aspects (lack of coordination and discrimination of exchanges) are indeed affecting actual commercial capacity.

3.3.1 Level of coordination

107 Coordination between TSOs is essential for the well-functioning of the IEM, as their actions and the electricity exchanges within and between control areas can significantly influence physical flows and operational security in other areas. In this respect, the CACM Regulation requires better coordination in the CC process among the TSOs within and between CCRs. One of the consequences of insufficient coordination is the presence of flows resulting from non-coordinated capacity allocation on other borders (UAFs)[59]. They reduce the amount of tradable capacity.

108 This Sub-section presents the results of the following analyses. First, it provides an update on the implementation status of the CACM Regulation provisions related to the TSO coordination in CC processes. To this end, the evaluation and scoring methodology applied last year has been enhanced with additional data that the Agency collected from NRAs. A detailed description of the methodology is presented in Annex 3. Second, based on the assessed capacity losses due to UAFs, it provides an estimate of the scope for improving cross-zonal capacity by means of better coordination.

109 To assess the level of TSO cooperation in CC, NRAs had to report via a new questionnaire – among other things – the following key information for each border and CC timeframe[60]:

- which of the predefined coordination methodologies[61] is applied;
- whether a common grid model is used for the CC; and
- which of the relevant input parameters[62] are (re)assessed in the CC process.

110 The NRA's response for each border and timeframe was matched by the Agency with the response from the other side of the same border. Congruent answers were evaluated and scored as provided. When the information reported by two NRAs for the same border was different, only the lower level of coordination reported and the consistently reported parameters were further considered in the assessment and respective scoring[63]. This approach was chosen because it is assumed that the coordination on a given border is only as strong as its weakest part.

111 The results of the enriched CC coordination assessment for 2016 is presented per border in Table 2 and aggregated at the regional level in Figure 12. The notes below the table define the different coordination levels, and list the (re)assessed CC parameters and the key explanations on the applied scoring methodology.

59 More information on UAFs and LFs and on their magnitude can be found in Annex 4.

60 Ranging from year-ahead (Y), month-ahead (M), DA to ID.

61 See notes below Table 2.

62 Relevant parameters are: a) RM, b) operational security limits (mostly CNEs) and contingencies (i.e. outages) relevant to CC, c) allocation constraints (e.g. import/export limits, losses, etc.), d) generation shift keys, (e) remedial actions.

63 In three cases, exceptions from the general rule applied. These are explained in the description of the methodology in Annex 3.

Table 2: Application of CC methods on 50 borders in different timeframes – 2016

Cap.calc.	Coordination level				Parameters (re) assessed on both border sides	CGM used ("y"=yes, if both sides confirmed it)		
Border	Year-ahead (Y)	Month-ahead (M)	Day-ahead (D)	Intra-day (ID)	Y/M/D/ID	Y M D ID	D/ID res.	Score
AT-CH	BIL	BIL	BIL		b/b/ab/	nnnn	24	8.2%
AT-CZ	BIL	BIL	BIL		ab/ab/a/	yynn	<24	12.9%
AT-HU	BIL	BIL	BIL		b/b/b/	yynn	<24	11.4%
AT-SI	BIL	BIL	BIL		abd/abd/ab/	yynn	<24	14.3%
BE-NL	BIL	BIL	FB	PC	//abcde/	nnyn	24	37.5%
BG-RO	BIL	BIL			a/abd//	nnnn	<24	6.4%
BRNN-GR	BIL	BIL	BIL		///	nnnn	24	6.3%
CH-DE					///	nnnn	24	0.0%
CH-FR					///	nnnn	<24	0.0%
CH-IT	FC		FC		d//d/	ynyn	24	30.0%
CZ-PL	BIL	BIL	BIL	BIL	abd/abd/abd/	yynn	<24	14.3%
CZ-SK			BIL		//ab/	nnnn	<24	0.0%
DE/LU-CZ					abd/abd/abd/	nnnn	<24	0.0%
DE/LU-PL	BIL	BIL	BIL		abd/abd/abde/	nnnn	24	10.4%
DK_W-NO-2	BIL	BIL	BIL	BIL	b//bce/b	nnnn	24	11.3%
DK1-DE/LU	BIL	BIL	BIL		b//bde/	nnnn	24	8.8%
DK1-SE3	BIL	BIL	BIL	BIL	//be/b	nnnn	24	9.6%
DK2-DE/LU	BIL	BIL	BIL	BIL	///	nnnn	24	8.3%
DK2-SE4	BIL	BIL	BIL	BIL	//be/b	nnnn	24	9.6%
EE-FI	BIL	BIL			b/b//	nnnn	24	6.7%
EE-LV	BIL	BIL	BIL	BIL	ab/ab/ab/ab	nnnn	24	13.3%
ES-PT	PC	PC			abd/abd//	yynn	24	33.3%
FR-BE	BIL	BIL	FB		//abcde/	nnyn	24	32.1%
FR-DE/LU	BIL	BIL	FB		abd/abd/abcde/	nnyn	24	35.7%
FR-ES	BIL	BIL			a/a//	yynn	24	13.3%
FR-GB					///	nnnn	24	0.0%
GR-BG					b/b//	nnnn	<24	0.0%
HR-HU	BIL	BIL			b/b//	yynn	<24	11.4%
HR-SI	BIL	BIL			abd/abd//	yynn	<24	14.3%
HU-SK	BIL	BIL	BIL		b/b/b/	yynn	<24	11.4%
LT-PL			BIL		//abe/	nnnn	24	3.3%
LT-SE4	BIL	BIL	BIL		//be/be	nnnn	24	7.1%
LV-LT	BIL	BIL	BIL		abe/abe/abe/abe	nnny	<24	7.5%
NL-DE/LU	BIL	BIL	FB	PC	ab/ab/abcde/b	nnyn	24	41.4%
NL-GB	BIL	BIL	BIL	BIL	//c/	nnyn	24	11.3%
NL-NO-2			BIL	BIL	//c/c	nnnn	24	5.0%
NO-1-SE-3	PC	PC	PC	PC	//be/b	nnnn	24	28.8%
NO-3-SE-2	PC	PC	PC	PC	//be/b	nnnn	<24	20.4%
NO-4-FI	PC	PC	PC	PC	b/b/be/b	nnnn	<24	27.9%
NO-4-SE-1	PC	PC	PC	PC	//be/b	nnnn	<24	20.4%
NO-4-SE-2	PC	PC	PC	PC	//be/b	nnnn	<24	20.4%
NORD-AT	FC	BIL	FC		d//d/	ynyn	24	31.8%
NORD-FR	PC		FC		cd//cd/	ynyn	24	26.4%
NORD-SI	FC	BIL	FC		d//cd/	ynyn	24	33.9%
PL-SK	BIL	BIL	BIL		abc/abc/abc/	yynn	<24	12.9%
RO-HU	BIL	BIL			/b/b/	nynn	<24	7.5%
SE1-FI	PC	PC	PC	PC	abd/abd/abd/abd	yyyy	<24	51.7%
SE3-FI	PC	PC	PC	PC	abd/abd/abd/abd	yyyy	24	60.0%
SE4-PL			BIL		//be/	nnnn	24	2.9%
UK-IE	BIL	BIL	BIL	BIL	bc/bc/bc/bc	nnnn	24	12.5%

Source: Data provided by NRAs through the EW template (2017), ENTSO-E, Nordpool Spot (2016) and ACER calculations.

Note 1: Abbreviations & definitions of coordination levels of CC:

*CC timeframes: **Y** – year-ahead, **M** – month-ahead, **D** – DA, **ID** – ID*

***Pure bilateral NTC calculation (BIL)** – CC on a given border is completely independent of CC on any other border. Both TSOs on a border calculate the NTC value for this border based only on its own CCs inputs and, subsequently, the lower of the two values is offered for capacity allocation;*

***Partially coordinated NTC calculation (PC)** – CC on this border is coordinated with at least one, but not all, the borders that are significantly affected by exchanges on this border. All TSOs on these borders perform CC in a coordinated way, using their CC inputs. When capacity on two borders is coordinated individually by one TSO, but other TSOs are not involved, this should be considered as pure bilateral coordination.*

***Fully coordinated NTC calculation (FC)** – The calculation of NTCs values is performed together on all borders significantly affected by exchanges on this border by the relevant TSOs, by including the conditions of all significantly affected networks in the calculation process.*

***FB CC (FB)** – This process leads to the definition of FB parameters, i.e. PTDFs, describing how cross-zonal exchanges influence flows on CNEs, and the available margins on these network elements, describing how much the flows on these elements can further increase due to cross-zonal exchanges. FB CC in combination with market coupling results in welfare-maximising exchanges between bidding zones, given the capability of the network, which is assessed in a coordinated way.*

***CC parameters** (re)assessed: a) RM, b) operational security limits (mostly critical network elements) and contingencies (i.e. outages) relevant to CC, c) allocation constraints (e.g. import/export limits, losses, etc.), d) GSKs, e) remedial actions*

***CGM** - common grid model used: y – yes, n – no*

Note 2: Scoring method and benchmark:

***Coordination level** (basic scores): no CC [empty]: 0 points, BIL: 1 point, PC: 2 points, FC: 3 points, FB: 4 points*

Parameters reassessed: For each timeframe, multipliers to the basic scores have been introduced depending on how many and which parameters a) to d) are indicated for both sides of a border. The multipliers range from 0.5-1.0 and are listed in the methodological description in Annex 3.

***CGM:** If the use of a CGM was not indicated for both sides of a border for a given timeframe, 0.5 points have been deducted from the respective basic score.*

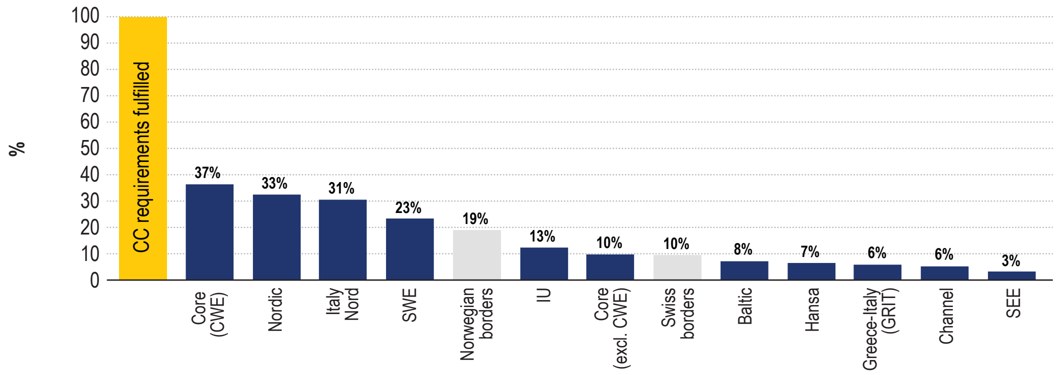
***D/ID resolution:** If capacity (re)calculation at DA or ID level was not done with an hourly resolution (i.e. the same NTC value valid for 24 hours), the basic scores for the D and ID timeframes were reduced by 0.5 (each). In the case of HVDC interconnections and borders where the FB method is already applied, a calculation resolution of 24 hours was assumed a priori.*

***Score:** The sum of the basic scores per timeframe (adjusted by multipliers or reductions) was calculated for each border and then divided by the maximum possible sum of points (benchmark). The benchmark is 14 for 25 borders, where FB CC should be applied in the D&ID timeframes, and 12 on borders where fully coordinated NTC capacity allocation should be applied.*

Note 3: Scope:

50 borders in Europe were analysed. The border 'DE_TENNET - SE-4' (exempted merchant line) was excluded from the analysis. The scores for the Swiss and Norwegian borders are informative and were calculated for comparison only (as they are not part of the legally defined CCRs).

Figure 12: Regional performance based on the fulfilment of CC requirements – 2016 (%)



Source: Data provided by NRAs through the EW template (2017), ENTSO-E, Nordpool Spot and ACER calculations.

Note: The ratings in the chart were calculated by adding together the scores of 50 borders according to the CCR of which they are part, and dividing them by the maximum possible score (benchmark according to the CACM Regulation). The results of the assessment of Norwegian and Swiss borders are informative and for comparison only (as they do not fall under the legal obligations of the CACM Regulation).

112 The assessment of the individual and regional results of the current implementation analysis suggests generally low fulfilment of the CC coordination requirements of the CACM Regulation and shows a wide difference in performance between regions. The regions with the best performance are the Core (CWE), Nordic and Italy North regions. For the Core (CWE) region, this is mainly explained by the application of the FB method and the common grid model for the DA timeframe, while for the Nordic region it can be explained by the relatively good performance of the Finnish-Swedish border in all timeframes. For the Italy North region, this is mainly due to the relatively high level of coordination reported for the DA and year-ahead timeframes. The SEE region shows the lowest level of fulfilment.

113 Because of the significant methodological changes, including the new definition of CCR, a direct comparison of the individual scores per border or per region with the scores of previous years would not be meaningful. The additional information requested for the analysis[64] and the fact that the lower level of coordination was used in the case of incongruent answers on specific borders partly explains the generally lower scores for individual borders.

114 An important caveat underlying the assessment of the level of coordination is that the related obligations stemming from the CACM Regulation and the FCA Guideline[65] do not yet apply[66]. Therefore, the assessment should be understood as an indication of the room for improvement at this early stage of implementation. In addition, the following main issues that are currently leading to the low fulfilment on many borders still stand out. First, on many borders, TSOs reported that no CC was performed: out of the 50 borders assessed, this applied to 28 EU borders (+4 non-EU) for the ID timeframe, 10 EU borders (+2 non-EU) for DA, 7 EU borders (+4 non-EU) for month-ahead and 6 EU borders (+3 non-EU) for year-ahead. Second, either a bilateral or partly coordinated CC method is still applied on many borders[67]. There are still only very few exceptions where a fully coordinated NTC CC (Italy North region) or FB (Core (CWE) region) are implemented. These two exceptions apply to at least the DA timeframe.

115 As a result, the degree of coordination in CC has not yet reached the level required by the CACM Regulation[68]. Therefore, significant efforts are still to be made by TSOs and NRAs to improve the coordination of CC.

116 Improved coordination will contribute to increasing the amount of tradable capacity. In particular, as concluded in preceding MMRs, more coordination, e.g. through the introduction of FB CC, should result in a reduction in the amount of UAFs. UAFs, together with LFs, tend to decrease the amount of tradable capacity.

117 Given the impact of UAFs and LFs on market efficiency and integration, the Agency has been monitoring such flows since 2012. An updated analysis of the amount of these two types of UFs and the associated capacity losses is presented in Annex 4.

118 The analysis shows that UAFs decreased from 104.6 TWh in 2015 to 96.2 TWh in 2016. Following the implementation of the improvements required by the CACM Regulation, this decrease is expected to consolidate in the coming years. In theory, where FB applies, UAFs should disappear. However, this is not yet seen in the Core (CWE) region for two reasons. First, some exchanges scheduled on the Core (CWE) borders physically flow through borders outside the Core (CWE) region. The opposite is also true, i.e. some exchanges scheduled on borders outside the Core (CWE) region physically flow through Core (CWE) borders. Second, the methodology applied to estimate AFs (which are necessary to calculate UAFs) is still subject to improvements[69].

119 Finally, the potential increase in tradable cross-zonal capacity expected from improved coordination can be estimated to an average 16% of benchmark capacity or to an average of 35% when compared to the currently offered commercial capacity (average NTC) in 2016. This is derived from the actual capacity losses due to UAFs on the borders analysed for 2016 (see Annex 4) when compared with the respective benchmark capacities.

64 E.g. on the application of a CGM and the kind of parameters (re)assessed in the different calculation processes.

65 See footnotes 15 and 16.

66 Although similar obligations, with a less detailed legal and governance framework, were already required by Regulation (EC) No 714/2009.

67 For example, 22 EU borders (+8 non-EU) for the DA timeframe.

68 Requirements in CACM Regulation and similar requirements applicable since 2006, following Regulation (EC) No 1228/2003, Annex I. Once these requirements are fulfilled, all borders should score 100% according to the scoring methodology described in this Sub-section.

69 This includes the use of more CGMs, which should ideally be one per market time unit and an improved methodology for calculating GSKs that are input parameters for estimating UAFs.

3.3.2 Discrimination between internal and cross-zonal exchanges

3.3.2.1 The issue of discrimination

120 Electricity wholesale markets in Europe are structured in bidding zones within which any consumer may contract electricity with any generator without limitations. Therefore, to ensure operational security, TSOs limit exchanges between bidding zones through the CC and allocation process. Regulation (EC) No 714/2009 and, in particular, the CACM Regulation require that CC and allocation should not result in undue discrimination between different types of flows. This is also the purpose of the Agency's Recommendation on Capacity Calculation Methodologies (see Section 3.1). In practice, this means that the capacity of the network elements should not be disproportionally allocated to support internal exchanges to the detriment of cross-zonal exchanges. Offering less cross-zonal capacity for cross-zonal trade due to unequal treatment of electricity exchanges reduces market efficiency and hence reduces social welfare.

121 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 UFs was analysed in previous editions of the MMR. An update on the volumes of LFs and the associated capacity losses on interconnectors is presented in Annex 4.

122 As explained at the beginning of Section 3.3, the gap between the commercial and the maximum (benchmark) capacity is largely the consequence of a suboptimal bidding zone configuration. Whereas in the mid-term the reconfiguration of bidding zones is possibly the most efficient tool to address this issue, in the short-term CC may contribute to alleviate the gap. However, this relevant gap persists on most European borders, which can be mainly explained by either flows resulting from non-coordinated capacity allocation on other borders (i.e. UAFs) or by the prioritisation of internal exchanges.

123 As concluded in Sub-section 3.3.1, a proportion of this gap (approximately one third[70]) can be addressed by improved coordination in CC. Based on this, there are grounds to conclude that the largest proportion of this gap (approximately two thirds), which is on average 53% of the benchmark capacity on HVAC interconnectors, is explained by the prioritisation of internal exchanges. The individual ratios between commercial and benchmark capacity included in the last column of Table 7 in Annex 1 and the ratios between available commercial capacity and maximum flow (Fmax) in the Core (CWE) region provide an indication of the borders where this prioritisation is the highest.

124 In addition, the Agency could access detailed data on FB CC in the Core (CWE) region. This allowed further analysis of the issue of discrimination in this region. This analysis is included in Sub-section 3.3.2.2 below and concludes for instance, that the constraints associated with internal lines in Amprion's area in Germany strongly limit cross-zonal exchanges within the Core (CWE) region.

125 In other regions, where CC is NTC-based, discussions are ongoing between ENTSO-E and the Agency on how to provide data with a level of detail similar to the FB case.

3.3.2.2 Analysis of the level of discrimination of cross-zonal exchanges on individual network constraints in the Core (CWE) region

126 This Sub-section analyses the frequency and extent to which discrimination of cross-zonal exchanges on individual CNEs affect the availability of cross-zonal capacity in the Core (CWE) region[71].

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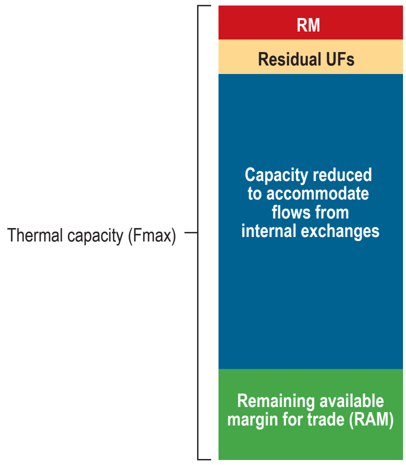
70 See paragraph (119) concluding that approximately 16% of the benchmark capacity could be added to the commercial capacity by improved coordination in CC. This is roughly one third of the gap between the commercial and benchmark capacity.

71 The analysis in this Sub-section is limited to the DA timeframe. However, given the fact that most of the cross-border capacity allocated in the long-term timeframe is not nominated on the borders of the region (i.e. the share of long-term nominated capacity represents only between 0% and 6% of all nominations depending on the border) and that the cross-border capacity available for the closer-to-real-time timeframes is a small share of the overall offered cross-border capacity, the conclusions of this Sub-section can be considered as valid for all timeframes taken together.

127 Figure 13 shows the breakdown of the capacity components used in this analysis. The analysis compares restrictions on individual CNEs, when they are active (i.e. during the hours when they are commercially congested). For each of these situations, the ratio between RAM and Fmax is calculated. Then, in order to account for the relative impact of individual constraints on social welfare, an average of these ratios, weighted with the corresponding shadow prices[72], is calculated.

Figure 13: Breakdown of capacity components on individual CNEs in FB CC



Source: ACER.

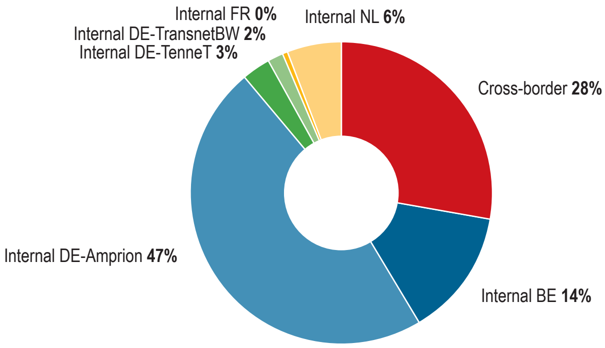
Note: Residual UFs refer to UFs which will remain in any close-to-optimal bidding zone configuration. The component "capacity reduced to accommodate flows from internal exchanges" may include a certain amount of UAFs resulting from exchanges outside the FB region, which are assumed to be residual; otherwise, UAFs are assumed to be null within the Core (CWE) region. The N-1 criterion that also limits the share of thermal capacity that can be made available to the market is not included in the illustration, as this is directly taken into account in the process of calculating PTDFs.

128 Table 8 in Annex 1 presents the main results of the analysis. Additionally, Figure 14 focuses on the location of the active CNEs, whereas Figure 15 focuses on portion of capacity made available to the market on internal-to-bidding zones CNEs. From these figures, following conclusions can be derived. When congestion occurs in the CWE region (more than 60% of the hours in 2016[73]) internal lines constrain the available cross-zonal capacity more often (72% of the occurrences) than cross-zonal lines (28%). Second, 77% of the congestions relate to CNEs located in Germany, of which 62% are related to internal lines in Amprion's area.

129 Overall, the constraints associated with internal lines in Amprion's area strongly limit cross-zonal exchanges within the Core (CWE) region. This is due to both the frequency of this congestion (about 47% of the occurrences in the region), but also due to the low proportion of capacity available for cross-zonal trade in these lines, i.e. only 10% of the total theoretical capacity in these CNEs (see Figure 15) is available to accommodate flows resulting from cross-zonal exchanges. Conversely, an average 90% of the capacity on these CNEs is 'consumed' by flows that are not required to participate in a competitive capacity allocation procedure.

72 See the definition of shadow prices in Section 3.1.
73 See Section 2.2

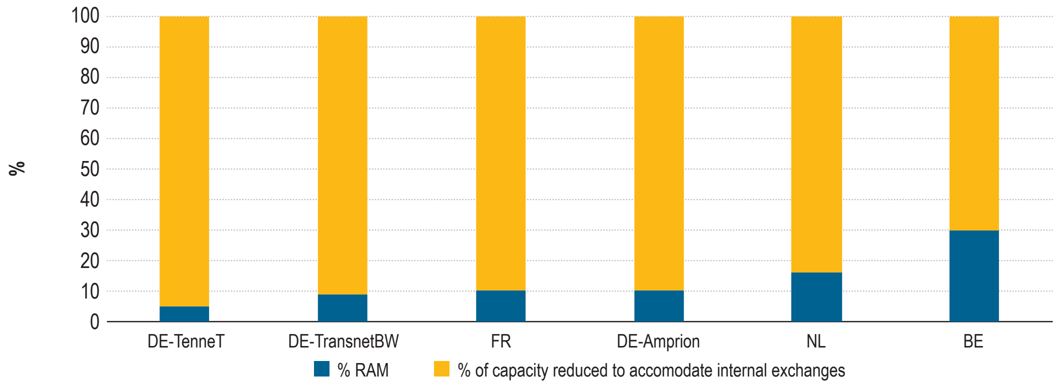
Figure 14: The share of constraints associated to internal vs. cross-border CNEs and the share of internal CNEs per TSO in CWE (%)



Source: Data provided by Core (CWE) TSOs to ENTSO-E (2017) and ACER calculations.

Note: The assessment focuses on CNEs. Additional allocation constraints (i.e. bidding zone export-import limits[74] as currently defined within the Core (CWE) region) were not considered, although they were the factor limiting cross-zonal exchanges in 590 hours in 2016.

Figure 15: The average percentage of RAM for cross-zonal exchange over Fmax in internal-to-bidding-zone CNEs, per TSO's control area in 2016 (%)



Source: Data provided by Core (CWE) TSOs to ENTSO-E (2017) and ACER calculations.

Note: The percentages of capacity made available for cross-zonal exchanges for each transmission system in 2016 are an average of the percentages associated with each CNE in the system, weighted against the shadow price associated with the CNE. The RAMs used to calculate the percentages shown in this figure correspond to the capacity available for cross-zonal trade in the DA timeframe, after discounting the effect of long-term nominations.

130 Some of the constraints associated to Amprion's internal lines were added[75] to the CC and allocation process few months after the launch of FB[76]. This addition exacerbated the decrease in the amount of available cross-zonal capacity within the Core (CWE) region and reduced the social welfare gains that were expected from the application of FB based on simulations which did not consider the inclusion of those constraints.

131 The gross welfare gains from the (partial or complete) removal of these and other internal constraints is analysed in Sub-section 4.2.2. It shows that removing the constraints associated to all internal lines within the Core (CWE) region and increasing the RAM on interconnectors would result in gross welfare gains[77] (156 million euros per year) that are comparable to the incremental welfare benefits from the implementation of FB CC it-

74 Overall limits on exports and imports per bidding zone that are used as additional constraints of the FB domain on an equal footing with CNEs.

75 This was decided by Amprion in view of the potential congestion on certain CNEs. Currently, individual TSOs can decide on which constraints are considered in CC, hence added to the capacity allocation procedure. The criteria to select which CNEs are to be considered in the CC and allocation is currently under discussion in the Core (CWE) region.

76 According to the information provided by CWE TSOs.

77 As further explained in Section 3.4, it is important to note that gross welfare benefits, as opposed to net welfare benefits, exclude all costs incurred by TSOs for making this cross-zonal capacity available to the market.

self, when compared to the former NTC-based CC in the Core (CWE) region[78]. As of December 2016, Amprion applied measures to increase Fmax up to 20%, on the relevant CNEs, during the winter period. This measure was expected to have a positive effect on the cross-zonal trading possibilities, although additional and more permanent measures are needed.

132 As further explained in Section 3.4, TSOs can relieve congestions, and consequently avoid reductions in the amount of the available cross-zonal capacity, by applying remedial actions. The costs of remedial actions incurred by Amprion increased in 2016 (slightly more than 13 million euros[79]) compared to 2015 (slightly more than 1 million euros). However, this increase was insufficient to mitigate the level of discrimination of cross-zonal flows within the Core (CWE) region. Indeed, Section 3.4 concludes that these costs are residual for most of Europe, which indicates that in most cases, TSOs prioritise avoiding the costs of remedial actions at the expense of reductions in cross-zonal capacity.

133 As a summary, the findings presented above emphasise the urgent need to address the currently observed level of discrimination of cross-zonal exchanges. In the medium term, this can mainly be addressed by bidding zone reconfiguration. In the short term, an upgrade of the CC methodologies is needed. In particular, the Agency recommends that the CC methodologies be implemented according to the requirements in the CACM Regulation as further detailed in the Agency's Recommendation. These requirements ensure that undue discrimination is avoided.

134 According to the Agency's Recommendation, deviations from the general principles included in the Recommendation are acceptable under the following conditions: any reduction should be (1) temporary, (2) justified as necessary to ensure the security of the system, and (3) justified against other remedial solutions (see the following Section) as economically more efficient. The Agency expects that these aspects are addressed as part of the ongoing process to define the CC methodologies pursuant to the CACM Regulation.

3.4 Remedial actions

135 To ensure operational security, TSOs apply different remedial measures to relieve physical congestion on their networks. Some remedial measures do not result in significant costs (e.g. changing grid topology). Others (e.g. re-dispatching, counter-trading and curtailment of allocated capacity) come at a cost to the system or to TSOs.

136 The use of remedial measures in Europe has become frequent, and will become even more frequent in the near future for the following key reasons. First, bidding zones in Europe are usually defined according to political borders, and they cannot efficiently address structural (physical) congestion in the network. In the absence of properly defined bidding zones, structural congestion can only be relieved with remedial actions.

137 Second, as the share of intermittent renewable energy production is increasing, the location of network congestion is more dynamic and less predictable, which requires more intervention by TSOs' close to real-time operation.

138 Third, the CACM Regulation requires that CC and allocation do not result in undue discrimination. However, as concluded in Sub-section 3.3.2, internal exchanges, as opposed to cross-zonal exchanges, are at present prioritised in most of Europe.

139 The adequate implementation of the CACM Regulation together with the Agency's Recommendation should reverse this situation, which can be addressed in the short term mainly by the application of remedial actions.

140 Based on the analysis included in previous editions of the MMR, there were grounds to suspect that, due to the lack of correct and adequate incentives for TSOs, the latter often prefer to limit ex-ante cross-zonal capacities in order to limit the costs of remedial actions. This is indeed suggested[80] by Table 3, where the annual costs of remedial actions in 2015 and 2016 are displayed. Table 3 shows that these costs are residual for most of Europe (e.g. reported as zero or almost zero in 4 countries).

78 See footnote 44.

79 According to information published in the ENTSO-E's TP, available at: https://transparency.entsoe.eu/.

80 A relatively low application of remedial actions could also be the result of a very low level of congestion. However, this does not seem to be the case in a majority of countries.

141 The need to apply remedial actions is partly subject to uncontrollable factors (e.g. in Germany remedial actions were applied more intensively in 2015 than in 2016 due to stronger wind in 2015). However, Table 3 in combination with the findings of Sub-section 3.3.2 suggest that the level of application of remedial actions is currently insufficient to address the discrimination of cross-zonal exchanges in Europe.

Table 3: Evolution of the costs of remedial actions – 2015–2016 (thousand euros, %)

Country	Re-dispatching*	Counter-trading*	Costs of other actions*	Contribution from other TSOs*	Total cost 2016*	Total cost 2015*	Relative change 2015 to 2016
DE	590,775	11,850	26	0	602,651	911,985	-34%
ES	515,509	541	0	0	516,050	690,932	-25%
UK	300,272	60	0	0	300,332	465,553	-35%
PL	6,616	36	0	28,751 (1)	6,652	31,685	-79%
AT	16,573	0	13,434	-1,629	31,636	27,712	14%
NO	15,699	213	1,183	11	17,084	20,830	-18%
NL	65,366	0	0	38	65,328	5,539	1079%
FI	1,242	2,619	0	3,861	0	3,784	-100%
BE	NA	NA	NA	NA	3,295	NA	NAP
CZ	1,808	0	0	-201	2,009	3,055	-34%
EE	0	404	0	0	404	1,746	-77%
FR	24	594	0	0	618	854	-28%
LV	0	959	0	577	383	709	-46%
SI	147	-5	0	142	0	0	NAP
IT	NA	40	0	0	NA	NA	NAP
CH	0	0	0	0	0	NA	n.a.
PT	0	0	10	0	10	-133	NAP
Total	1,514,030	17,311	14,653	2,798	1,546,451	2,164,251	-29%

*Thousand euros

Source: Data provided by NRAs through the EW template (2017)

Note: The Agency requested data for congestion-related remedial actions. "Contribution from other TSOs" refers to the costs of actions taken by one TSO but borne by adjacent TSOs. "Cost of other actions" refers to the costs of remedial actions others than redispatching and countertrading, e.g. changing the grid topology. In general, positive euro values refer to costs incurred by TSOs, and negative values to their revenues, whereas for "contributions from other TSOs", positive values refer to money received from other TSOs and negative values to money paid to other TSOs. Bulgaria, Croatia, Hungary, Luxembourg and Slovakia did not report any remedial action cost. Denmark, Greece, Romania, Sweden and Switzerland did not provide details on costs or did not have the data available. (1) For Poland, contribution from other TSOs is included in the preceding columns.

142 Furthermore, in order to provide the correct and adequate incentives for TSOs to apply actions with cross-zonal relevance, the costs of these should be distributed between TSOs through a fair cost-sharing methodology[81]. This illustrates the importance of the third high-level principle of the Recommendation, which envisages that "the costs of remedial actions should be shared based on the 'polluter-pays principle', where the UFs over the overloaded network elements should be identified as 'polluters' and they should contribute to the costs in proportion to their contribution to the overload."

143 In addition, these costs should support the cost-benefit analysis of the short-term remedies against longer-term solutions. Indeed a disproportionate increase in re-dispatching costs may reveal the need for longer-term structural measures, such as investments, or a reconfiguration of bidding zones.

144 Finally, there is still insufficient transparency concerning the costs associated with remedial actions (in particular, on internal redispatching costs), let alone concerning the technical and economic analyses justifying their use.

81 Pursuant to the CACM Regulation, TSOs are requested to submit methodologies for cost sharing of countertrading and redispatching.

4 Efficient use of available cross-zonal capacity

145 This Chapter presents first an update on the liquidity of European forward markets and on the most recent developments regarding cross-zonal hedging tools (Section 4.1). Second, it reports on the progress in the efficient use of cross-zonal capacities in the DA timeframe (Sub-section 4.2.1) and on the gross welfare benefit from market integration and from a better use of the existing network (Sub-section 4.2.2). Third, it reports on the liquidity level of ID markets for several MSs (Sub-section 4.3.1) and on the use of cross-zonal transmission capacity during the ID timeframe (Sub-section 4.3.2). Last, it provides an update on the prices of balancing services (energy and capacity) and imbalance charges in Europe (Sub-section 4.4.1) and on the scope for a further exchange of balancing services across EU borders (Sub-section 4.4.2).

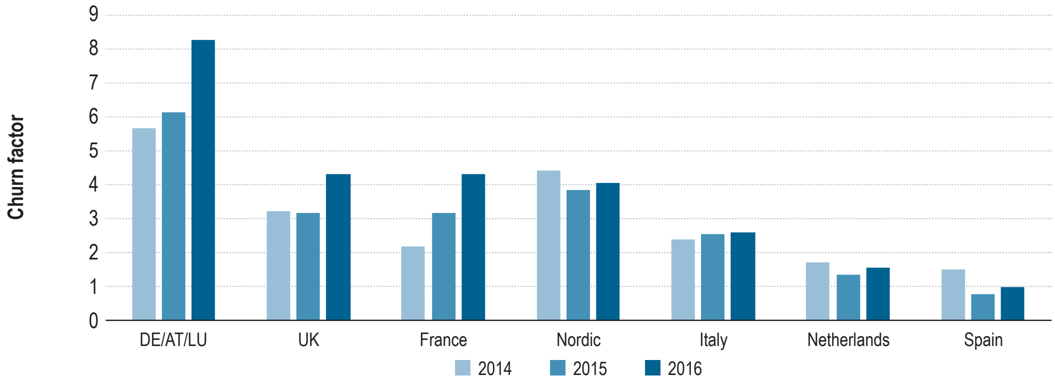
4.1 Forward markets

146 Market liquidity can be measured in several ways. A frequently used metric of liquidity is the 'churn factor', i.e. volumes traded through exchanges and brokers expressed as a multiple of physical consumption. There is no consensus on the level of the churn factor that indicates sufficient market liquidity. Based on the view of different stakeholders, this level[82] ranges from 3 to 10.

147 Figure 16 presents the churn factors of the largest European forward markets in the period from 2014 to 2016. Based on the ample range of thresholds mentioned above, the figure suggests that liquidity is limited in most of Europe, except the German[83], British, French and Nordic markets.

148 Furthermore, Figure 16 shows that liquidity, measured by the churn factor, increased in all major European forward markets and that Germany/Austria/Luxembourg consolidated its position as the most liquid electricity forward market in Europe, with an increase in liquidity of approximately 35% between 2015 and 2016. The highest growth in the same period was recorded in the French forward market, with an increase in liquidity of almost 40%. The most modest increase was recorded in Italy (+3%).

Figure 16: Churn factors in major European forward markets – 2014–2016



Source: European Power Trading 2017 report, © Prospex Research Ltd, March 2017.

Note: The figure shows estimates of total volumes traded from 2014 to 2016 as a multiple of consumption from Eurostat (see footnote 20).

149 Several factors contributed to increasing liquidity in the French forward market. In recent years, and until the third quarter of 2016, the main driver has been the relatively low wholesale market prices compared to the price under the Regulated Access to Incumbent Nuclear Electricity (ARENH). As these prices were frequently below the level of ARENH, buyers (e.g. independent suppliers) started to source energy and hedge risks directly in the

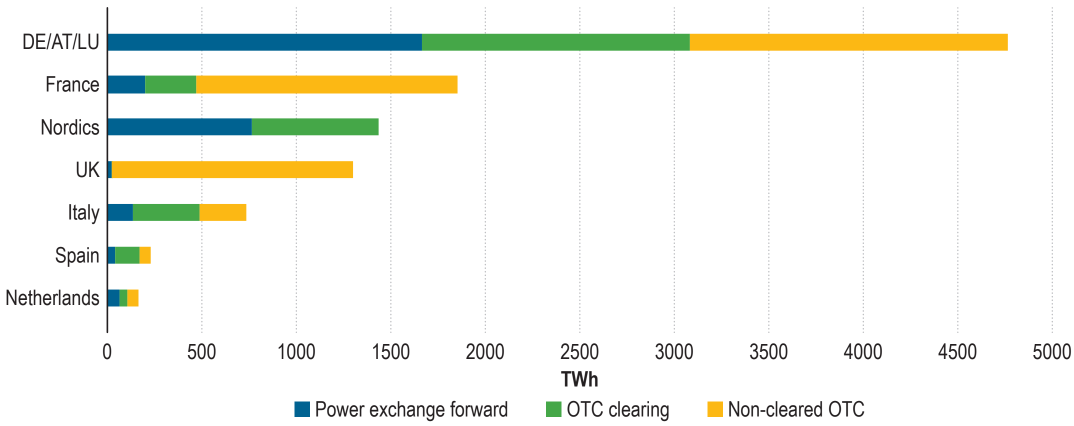
82 For example, a churn ratio of 10 can be seen as the minimum for a mature market, according to the British energy regulator, Ofgem (Liquidity in the GB wholesale energy markets, a discussion paper published by the British regulator, Ofgem, 8 June 2009). However, in other stakeholders' opinion, this minimum value is 3 ('Report on the influence of existing bidding zones on electricity markets', p. 13 at http://www.acer.europa.eu/official_documents/acts_of_the_agency/publication/acer%20market%20report%20on%20bidding%20zones%202014.pdf). At the other end, a churn rate of 1.77 in the context of a study on European gas markets is quoted as 'very poor' (The evolution of European traded gas hubs, Oxford Institute for Energy Studies, 2015, p. 45).

83 Considered together with Austria and Luxembourg.

market rather than buying energy from the incumbent (Électricité de France) at ARENH levels. Furthermore, the uncertainty triggered by the nuclear outages in France (see Section 2.2) created additional (or at least different) needs for hedging during the last quarter of 2016.

150 Figure 17 shows the trading volumes per type across the major European forward markets. It shows the divergent structure of these markets. While in a majority of markets most forward market volumes are traded over the counter (OTC)[84], in the Nordic markets the largest share is traded at the power exchange (53% in 2016). In Germany/Austria/Luxembourg, the share of volumes traded at the power exchange was 35% in 2016. The latter is a significant development, as the volumes traded at the power exchange in Germany/Austria/Luxembourg soared by 259% over a five-year period. Two of the main reasons that explain this increase are, first, the uncertainty triggered by the nuclear outages in France (see the previous paragraph), and second, the business opportunity that some market participants are seeing in offering risk management services in view of increasing short-term trading associated with the rise of renewables.

Figure 17: Forward market trading volumes per type in the largest European forward markets – 2016 (TWh)



Source: European Power Trading 2017 report, © Prospex Research Ltd, March 2017.

151 In the context of a limited number of liquid forward markets in Europe, the cross-zonal access to these markets becomes particularly important. The FCA Regulation[85] which entered into force on 17 October 2016 will play a crucial role in this regard, as its provisions establish a framework for calculating and allocating interconnection capacity, and for cross-zonal trading in forward markets. In particular, this Regulation foresees the issuance of Long-Term Transmission Rights (LTTRs) on all borders. However, the relevant NRAs may decide to derogate from the requirement to issue LTTRs on a specific border, after consultation with market participants and an assessment concluding that the existing electricity forward market provides sufficient hedging opportunities.

152 In most of Europe, LTTRs already exist or a decision to issue LTTRs has been taken[86]. The main exceptions are the Nordic and Baltic markets, where cross-zonal access to forward markets is based on system price contracts and contracts for differences, i.e. electricity price area differentials (EPADs), which cover the difference between the system price (which is used as the forward price reference for a group of bidding zones) and each specific bidding zone price.

153 In previous editions of the MMR[87], some crucial aspects of the performance of both LTTRs and EPADs, such as the correlation between the prices of relevant products, ex-post risk premia and bid-ask spreads were analysed. The analysis allowed the ranking of borders and bidding zones according to the performance of their respective products. Cases of undervaluation of LTTRs and potential liquidity issues in the market for EPADs in some bidding zones were identified.

84 Including cleared and non-cleared OTC.

85 See footnote 16.

86 E.g. see the coordinated decision of the Czech and Slovak NRAs to introduce LTTRs on the Czech-Slovak borders, available at: https://www.eru.cz/documents/10540/3221065/Spole%C4%8Dn%C3%A9_prohl%C3%A1%C5%A1en%C3%AD_AJ.pdf/cd5db5f2-aac2-4db2-9db3-837812271c39.

87 For example, see Chapter 6 of the Electricity Wholesale Markets volume of the MMR 2015.

154 In this regard, and pursuant to the FCA Regulation, the Nordic NRAs (except Norway) have recently assessed whether the electricity forward markets in the Nordic region provide sufficient hedging opportunities in the bidding zones concerned[88]. Based on different indicators, the Finnish and Swedish NRAs have concluded that the existing hedging opportunities are indeed sufficient in their respective areas of jurisdiction[89].

155 However, the Danish NRA has concluded[90] that there are insufficient hedging opportunities in the two Danish bidding zones (DK1 and DK2). In general, the conclusions on the existence of hedging opportunities in the Danish, Finnish and Swedish jurisdictions are consistent with the findings of the MMR 2015[91].

156 As a conclusion, the relevant NRAs have issued decisions[92] in accordance with the FCA Regulation provisions. Pursuant to these decisions, TSOs are not requested to implement any specific measure on borders connecting bidding zones with sufficient hedging opportunities. On the borders between DK1 and SE3 and between DK2 and SE4[93], TSOs are not requested to introduce LTTRs, but to ensure that other long-term cross-zonal hedging products are made available to support the functioning of the electricity wholesale markets. TSOs are expected to develop and submit for approval the necessary arrangements within the subsequent six months[94].

157 Without prejudice to the NRAs' competence to decide on this matter, the Agency will monitor the extent to which the implementation of the FCA Regulation contributes to providing market participants with sufficient hedging opportunities and more generally, the effects of this Regulation on market integration, non-discrimination and effective competition and on the efficient functioning of the market[95].

4.2 Day-ahead markets

4.2.1 Progress in day-ahead market coupling

158 The Electricity Target Model (ETM) for the DA timeframe foresees a single DA coupling at European level, which enables the efficient utilisation of cross-zonal capacity, i.e. the utilisation of cross-zonal capacity in the 'right direction' (from low to high price areas) in the presence of a price differential across a given border.

159 Figure 18 illustrates that, due to market coupling, the efficiency[96] of the use of European interconnectors increased from approximately 60% in 2010 to 86% in 2016. Between 2015 and 2016, the level of such efficiency increased slightly, from 84% to 86%, due to the extension of market coupling to the Austrian-Slovenian border as of 22 July 2016. This increase was moderate, because the improvement on this border was partly offset by the less efficient use of capacity on non-coupled borders, such as the Italian-Swiss border, probably due to less accurate price forecasts by traders in the context of several consecutive months with unexpectedly low[97] hourly DA prices.

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88 Norway has not yet performed the analysis as the FCA Guideline is not applicable in Norway before its incorporation in the EEA Agreement.

89 See the evaluation of the Finnish NRA, available at: http://www.energiavirasto.fi/documents/10191/0/FCA_Calculations+on+the+Finnish+BZ+Borders.pdf/783233ec-7a77-451c-b738-f3a7c1cd63c8 and of the Swedish NRA at: http://ei.se/Documents/Projekt/Natkoder/FCA/FCA_evaluation_Annex_1.pdf.

90 See the evaluation of the Danish NRA, available at: http://energitilsynet.dk/fileadmin/Filer/Hoeringer/EL/2017/Bilag_3._Investigation_of_Danish_power_hedging_ver_02_April_2017.pdf.

91 The MMR 2015 pointed to potential liquidity and competition issues together with relatively high levels of risk premia in the market of EPADs in some bidding zones (e.g. in East Denmark). In other areas (e.g. in SE-4) where relatively high levels of risk premia were observed, the liquidity and competition levels were relatively higher.

92 See the decision of the Swedish NRA on the DK1-SE3 border, available at: http://ei.se/Documents/Projekt/Natkoder/FCA/2017_100719.pdf and on the DK2-SE4 border, available at http://ei.se/Documents/Projekt/Natkoder/FCA/2017_100720.pdf. See also the decision of the Danish NRA, available at: http://energitilsynet.dk/fileadmin/Filer/0_-_Nyt_site/EL/Sekretariatsafgoerelser/2017/16-12197_-_ET_transmissionsrettigheder/Summary_in_English.pdf.

93 LTTRs between DK1 and DK2 already exist.

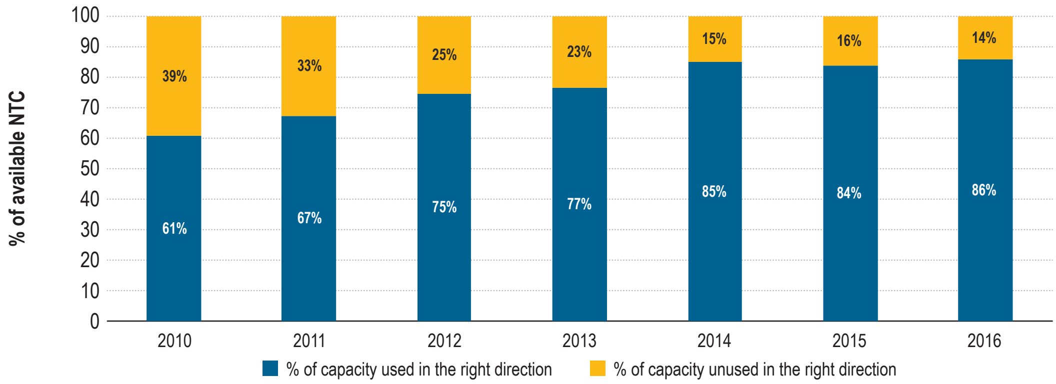
94 I.e. by 17 November 2017.

95 As required by Article 6 of the Commission Regulation (EU) 713/2009.

96 For the purpose of this analysis, efficiency refers to the efficient use of electricity interconnectors, which is defined as the percentage of available capacity (NTC) used in the 'right direction' in the presence of a significant (>1 euro) price differential.

97 For example, in the Italy-Nord bidding zone, hourly DA prices dropped to 36 euros/MWh on average in the first semester of 2016, compared to 60, 49 and 50 euros/MWh during the same period of 2013, 2014 and 2015, respectively.

Figure 18: Percentage of available capacity (NTC) used in the 'right direction' in the presence of a significant (>1 euro) price differential on 37 European electricity interconnectors – 2010 (Q4) – 2016 (%)



Source: ENTSO-E, Vulcanus (2017) and ACER calculations.

160 In the past seven years, consumers benefitted from most of the potential social welfare gains thanks to the extension of the pan-European market coupling to two thirds of the European borders, covering 22 countries[98] by the end of 2016. Furthermore, Figure 19 shows that the social welfare gains that can still be obtained by implementing more efficient DA capacity allocation methods on the remaining European borders is estimated at 203 million euros per year, based on 2016 data.

161 Figure 19 illustrates that in the absence of market coupling, the loss in social welfare in 2016 was highest on the borders between Ireland[99] and Great Britain, and on the French and Italian borders with Switzerland. Between 2015 and 2016, the highest increase in social welfare losses was observed on the border between Northern Ireland and Great Britain, and between Switzerland and Italy.

162 More specifically, between 2015 and 2016, although the level of efficiency in the use of the interconnectors between Great Britain and Ireland remained essentially unchanged (e.g. see Figure 30 in Annex 1 on the evolution of 'wrong-way flows'), the price differential between the two bidding zones increased from 1.4 to 4.0 euros/MWh, which led to higher social welfare losses. On the Swiss-Italian border, the increase in social welfare losses in 2016 could be explained by less efficient use of cross-border capacity due to less accurate traders' forecasts, as mentioned above.

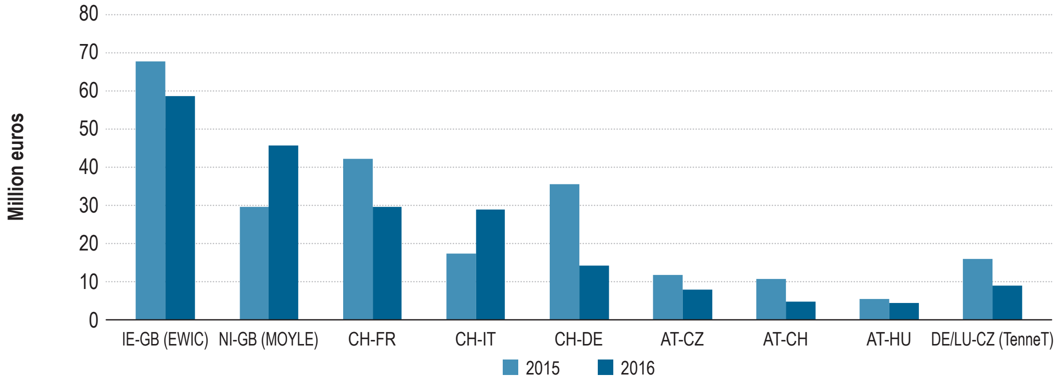
163 Overall, the efficient use of interconnectors increased significantly over the past seven years due to market coupling. However, the persistently high amount of possible social welfare gains due to more efficient DA capacity allocation methods illustrates the need to finalise the implementation of market coupling, as required by the CACM Regulation on all remaining European[100] borders that still applied explicit auctions at the end of 2016.

98 By the end of 2016, DA market coupling was implemented on 30 out of 42 EU borders (excluding the four borders with Switzerland), covering Austria, Belgium, the Czech Republic, Germany, Denmark, Estonia, Spain, Finland, France, Hungary, Italy, Lithuania, Latvia, the Netherlands, Norway, Poland, Portugal, Romania, Sweden, Slovenia, Slovakia and Great Britain.

99 Throughout this document, IE-GB (EWIC) refers to the East-West Interconnector, which links the electricity transmission grids of Ireland and Great Britain and NI-GB (MOYLE) refers to the Moyle Interconnector, which links the electricity grids of Northern Ireland and Great Britain.

100 According to the CACM Regulation, the single DA and ID coupling may be opened to market operators and TSOs operating in Switzerland on the condition that the Swiss national law implements the main provisions of EU electricity market legislation and that there is an intergovernmental agreement on electricity cooperation between the EU and Switzerland.

Figure 19: Estimated 'social welfare losses' in the absence of market coupling, per border – 2015–2016 (million euros)



Source: ENTSO-E, NRAs, Vulcanus (2017) and ACER calculations.

Note: Only non-coupled borders are shown. The borders within the Core (CEE) 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 Core (CEE) borders for this calculation. Figure 30 in the Annex shows that cross-zonal capacity was underutilised in 2016 on those borders (DE/LU-CZ, DE/LU-PL, PL-SK), as they were affected by 'wrong-way flows'.

4.2.2 Gross welfare benefit of better use of the existing network

164 Market integration is expected to deliver several benefits. One of these is enhanced economic efficiency, allowing the lowest cost producer to serve demand in neighbouring areas. This Sub-section shows the extent to which this benefit has been achieved, using the same indicator introduced in preceding editions of the MMR, the 'gross welfare benefits'[101] indicator.

165 For the purpose of this Chapter, several European Power Exchanges[102] were asked to perform a simulation in order to estimate these gross welfare benefits for 2016. The algorithm used for the simulations originates from the Price Coupling of Regions (PCR) Project (Euphemia), which is used for clearing the single European DA price coupling of power regions.

166 On the basis of a set of assumptions[103], two different analyses were carried out. The first was intended to estimate the order of magnitude of the overall benefits of market integration in Europe in 2016, while the second analysis aimed to estimate the gross welfare benefits from increasing cross-border capacity by a certain amount, in accordance with the Recommendation of the Agency on CC and redispatching and countertrading cost-sharing methodologies (see Section 3.1).

167 The geographical scope of the first analysis was the Multi-Regional Coupling (MRC) region, comprising 35 borders. This analysis included the computation of gross welfare benefits in 2016 for two scenarios:

- Historical scenario: the gross welfare benefit in 2016 calculated on the basis of detailed historical information such as network constraints, the exchange participants' order books (that is, supply offers and demand bids) and available cross-border capacity. For the latter, the relevant Available Transfer Capacity (ATC) and FB constraints[104] were used as a proxy for capacity effectively made available.

101 Gross welfare benefit includes, first, the 'consumers' and 'producers' surplus gained by consumers and producers who participate in power exchanges (welfare is measured as the difference between the prices bid into the market and the matched prices obtained multiplied by the quantity), and second, congestion rents. The first component measures the monetary gain (saving) that could be obtained by consumers (producers) because they are able to purchase (sell) electricity at a price that is less than the higher (lower) price they would be willing to pay (offer) as a result of changes in cross-border transmission capacity. The second component corresponds to price differences between interconnected markets multiplied by hourly aggregated nominations between these markets. It is important to note that gross welfare benefits, as opposed to net welfare benefits, exclude all costs incurred by TSOs for making this cross-border capacity available to the market.

102 EPEX SPOT, Nord Pool, GME, OMIE, OTE, OPCOM and TGE.

103 Due to the assumptions, several caveats need to be made, which are the same as mentioned in the MMR 2014, paragraph 503.

104 ATC was used for borders where CC is CNTC-based, and FB constraints for the borders within the Core (CWE) region where CC is FB.

- Zero scenario: the same as in the historical scenario, with all the ATC and RAM (in the case of FB) values simultaneously reduced to zero (that is, isolated national markets). The assumption is that all other elements (market bids, market rules, etc.) remain unaltered.

168 The difference in gross welfare benefit between the historical and the zero scenarios can be considered as a proxy for the overall gross welfare benefits currently obtained from DA market integration. These are estimated at slightly more than 18 billion euros per year in 2016. They represent the gain in welfare from i) having access to cross-border capacity compared to not having access to the capacity at all, and from ii) using this capacity efficiently. A relevant share of the estimated gains is the result of market coupling implementation in recent years, as opposed to the application of less efficient capacity allocation methods.

169 The gains reported above are particularly relevant given the scope for improvement in CC (see Sub-section 3.2.2), which has the potential to approximately double the tradable cross-border capacity. As the increase in welfare gain is not proportional to the increase in commercial cross-border capacity, an additional analysis is needed to shed more light on what the welfare gains from such an improvement in CC would be.

170 In this context, the second analysis estimates the gross welfare benefits from the application – to varying degrees – of the Recommendation of the Agency on CC and redispatching and countertrading cost-sharing methodologies. For this MMR edition, the geographical scope of this second analysis is limited to the Core (CWE) region, although the scope will be wider, data and resources permitting, in future editions of the MMR. The gross welfare benefits for this second analysis were computed for three different scenarios:

- Historical scenario: as described above.

- “Benchmark” incremental scenario: the same as the historical scenario, except that the set of constraints defining the historical FB domain in the Core (CWE) region are replaced by a new set of constraints consistent with the Agency’s benchmark FB domain (see Sub-section 3.2.2). This benchmark domain assumes the removal of constraints associated with internal CNEs within the Core (CWE) region, and a RAM on interconnectors equal to 85% of thermal capacity (Fmax). The so-called ‘external’ constraints defining import and export limits are also removed. As in the first analysis, the assumption is that all other elements remain unaltered.

- Intermediate incremental scenario: the same as the historical scenario, except that the constraints defining the FB domain are modified by setting the RAM on internal and cross-zonal CNEs to 50% and 70% of Fmax, respectively. As in the benchmark scenario, ‘external’ constraints are removed.

171 The calculated difference in gross welfare benefit between the historical and the benchmark scenario amounts to around 156 million euros per year in 2016[105]. This amount is comparable to the incremental welfare benefits from the implementation of FB itself, when compared to the former NTC-based CC in the Core (CWE) region[106].

172 The calculated difference in gross welfare benefit between the historical and the intermediate scenario amounts to approximately 102 million euros per year in 2016. This suggests that a significant amount of the gross welfare gains could be achieved even with a partial application of the Agency’s Recommendation on calculation and redispatching and countertrading cost-sharing methodologies.

173 Although a proportional extrapolation to all European borders is not possible, the potential gross benefits of the implementation of the Agency’s Recommendation on CC and redispatching and countertrading cost-sharing methodologies to the whole of Europe can be estimated at several billion euros per year. As mentioned above, an important caveat underlying these results is that the costs associated with the change in capacity were not considered in the analysis. Although these costs may have a relevant impact on net welfare gains, additional benefits can be expected from enlarging the amount of available cross-zonal capacity in the long-term. This

105 A sample of 31 representative days was used. The selection was based on average hourly price differentials, First, all days in 2016 were ranked according to the average hourly DA price differentials (difference between the highest and the lowest DA prices in the region). Second, 31 days evenly distributed across this rank were selected. Finally, the results were extrapolated to the whole year.

106 See footnote 44.

includes stronger incentives for reinforcing the internal networks, stronger incentives to coordinate national energy policies, and finally, stronger incentives to consider the bidding zone reconfiguration as a crucial and possibly more efficient tool to foster market integration in the mid-term.

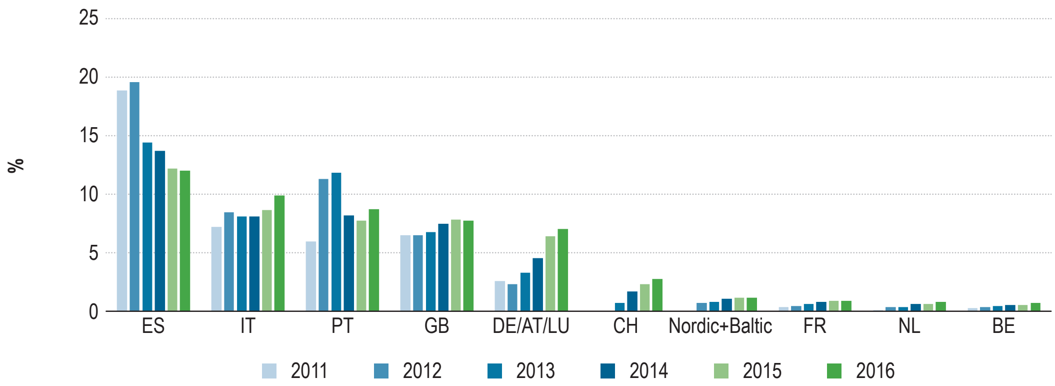
4.3 Intraday markets

4.3.1 Evolution of intraday market liquidity

174 An efficient ID market requires sufficient ID liquidity, because it plays an important role in providing price signals to market participants, in attracting new market players and eventually in leading to more competition. As a percentage of electricity demand, ID traded volumes can be regarded as an indicator of ID liquidity.

175 Figure 20 shows the ratio between ID traded volumes in national organised markets and physical consumption[107] across a selection of EU MSs with functioning ID markets. It indicates that in 2016 Spain, Italy, Portugal and Great Britain, followed by Germany/Austria/Luxembourg continued to have the highest ID traded volumes expressed as a percentage of physical consumption.

Figure 20: Ratio between ID traded volumes and electricity demand in a selection of EU markets – 2011–2016 (%)



Source: Power exchanges, Eurostat, CEER National Indicators Database and ACER calculation (2017).

176 The upward trend in liquidity levels observed over the past years in most of the countries continued in 2016. The trend is consistent with the growing need for short-term adjustments due to the greater penetration of intermittent generation from renewables into the electricity system. Compared to 2015, the most notable relative increase in ID liquidity in 2016 was observed in the Netherlands (40%), Belgium (35%) and Switzerland (20%), followed by Italy (14%), Portugal (12%) and Germany/Austria/Luxembourg (10%).

177 In 2016, the increase in the Dutch and Belgian markets is partially explained by the introduction of a new implicit ID cross-zonal capacity allocation platform connecting the Dutch and Belgian market with the French, German, Swiss and Austrian ID markets which went live on 5 October 2016. The increase in the Swiss ID market is probably related to the integration of the French and Swiss markets[108] with the Germany/Austria/Luxembourg market through the implicit continuous allocation of ID cross-zonal capacity. In Portugal, the increase observed in 2016 was probably driven by a higher share of renewable-based generation under the feed-in-system, which is mandatorily bought by the Supplier of Last Resort (SoLR) and sold directly on the market, and by the increase in the production from hydro resources.

178 Over the past five years, liquidity in Germany/Luxembourg/Austria almost tripled (298%). In 2016, ID liquidity in this market continued to benefit from the same factors as in previous years, such as: the increasing market penetration of renewable electricity; the introduction of regulatory measures aimed at reducing the share of

107 See footnote 20.

108 In general, the relatively high level of ID cross-border trades observed between France and Switzerland are partly explained by the existence of long-term contracts which are not always in the 'right' economic direction, based on DA price differentials. Therefore, the ID timeframe, where continuous allocation is operational since 2013, provides an opportunity to arbitrage between the long-term and short-term timeframes.

renewable electricity generators exempt from balancing responsibility (around 43% of installed German renewable capacity by the end of 2015), and measures aimed at avoiding imbalance prices being set below incurred cost; the launch of 15-minute products ID auctions; and the extension of the trading of 15-minute contracts to the continuous ID market in Austria.

179 In the near future, several factors are expected to have a positive effect on ID liquidity across the EU.

180 First, new ID products were recently introduced or are planned to be introduced in a number of markets and borders. This includes the launch of 30-minute products continuous ID trading in France, Germany and Switzerland on 30 March 2017 and the plan to introduce 15-minute products auctions in the Netherlands and 30-minute products auctions in France. The effect of these developments on liquidity is not yet reflected in Figure 20, as the latter captures annual increases only up to 2016.

181 Second, the extension of balancing responsibility to renewable electricity generators is expected to further increase ID liquidity. As of 31 December 2016, renewable generation was not treated in the same way as conventional generation regarding balancing responsibility in at least 10 MSs[109]. The Agency advocates[110] the integration of electricity from renewables in the wholesale market, which implies the removal of derogations to balancing responsibility and market-based principles applied to curtailments or redispatching.

182 Third, the implementation of a single ID coupling (SIDC) with implicit continuous cross-zonal capacity allocation, as laid down in the CACM Regulation, is expected to increase liquidity, because participants will have access to a larger portfolio of bids and offers to meet their balancing needs. The implementation of the SIDC through the cross-border ID (XBID) project[111] is planned for 2018.

183 Fourth, the requirement laid down in the CACM Regulation to set the ID cross-zonal Gate Closure Time (GCT) to at most one hour[112] before real time is also expected to have a positive effect on liquidity. In general, setting CGTs closer to real time, when more accurate information on the supply-demand balance is available, should lead to higher liquidity levels and reduce the need for more costly balancing services.

184 National ID GCTs are also expected to be set at most one hour before real time. Currently, various GCTs are being applied throughout national markets, ranging from 30 minutes before the beginning of physical delivery in Germany, Austria and France to 60 minutes in Great Britain and Switzerland or more, which is the case in Spain (135 minutes), Portugal (135 minutes) and Italy (195-540 minutes). An important caveat regarding the setting of GCTs closer to physical delivery time is that this measure should not jeopardise operational security or hamper the integration of balancing markets, which might occur if they are set too close to real time. Irrespective of this caveat, the scope for harmonising ID GCTs across Europe is evident.

185 Finally, some other aspects of the CACM Regulation potentially affecting ID liquidity are left to agreement at the regional level. This includes the possibility that continuous trading between and within bidding zones of the SIDC is complemented by regional[113] ID auctions. This is subject to several conditions, including, *inter alia*, the absence of an adverse impact on the liquidity of the SIDC and the absence of undue discrimination between market participants from adjacent regions.

186 Without prejudice to the NRAs' competence to decide on these matters, the Agency will monitor the extent to which the implementation of the different provisions of the CACM Regulation affect ID liquidity and, in particular, whether they limit the access of market players to ID trading opportunities beyond the physical constraints of the network.

109 Austria, Croatia, Cyprus, France, Germany, Greece, Italy, Lithuania, Malta and Portugal.

110 For further information, see the ACER/CEER White Paper #1 on 'Renewables in the Wholesale Market Relevant to European Commission's Clean Energy Proposals' of 11 May 2017, available at: http://www.acer.europa.eu/Official_documents/Position_Papers/Position%20papers/WP%20ACER%2001%2017.pdf. See also the European Energy Regulators' White Paper #4 on 'Efficient Wholesale Price formation'.

111 Nominated electricity market operators (NEMOs) proposed to NRAs in the 'All NEMO proposal for the Market Coupling Operator (MCO) Plan' that the delivery of the ID market coupling should be based on the XBID commercial solution.

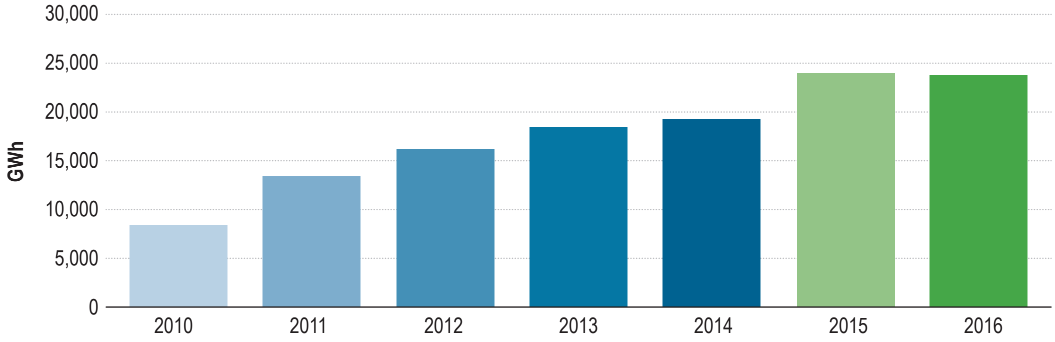
112 Article 59(3) of the CACM Regulation.

113 In the first semester of 2017, two initiatives have undergone public consultations for the introduction of regional auctions (one in the Iberian market and the other in Italy).

4.3.2 Intraday use of cross-zonal capacity

187 Figure 21 shows the absolute sum of net ID nominations for a selection of EU borders over the past seven years. In spite of a slight decrease of approximately 1% between 2015 and 2016, Figure 21 shows an upward trend in traded cross-zonal volumes in the ID timeframe between 2010 and 2016. As shown in Figure 31 in Annex 1, in 2016 the most significant progress compared to the previous year was recorded on the border between Spain and France, where volumes more than doubled (increased by 118%), probably thanks to the new interconnector between these two MSs (see Sub-section 3.2.1).

Figure 21: Level of ID cross-zonal trade per year (absolute sum of net ID nominations for a selection of EU borders) – 2010–2016 (GWh)



Source: ENTSO-E, NRAs, Vulcanus (2017) and ACER calculations.

Note: This figure contains data for those borders for which data was consistently available for the period analysed, i.e. AT-DE, AT-SI, BE-FR, BE-NL, CH-DE, CH-FR, CH-IT, CZ-SK, CZ-DE, DE-FR, DE-NL, DE-PL, ES-FR, ES-PT and FR-IT.

188 Figure 22 shows the level of utilisation of cross-zonal capacity in the ID timeframe when it has a value (>1euro/MWh), for a selection of borders. First, this Figure illustrates that the level of efficiency[114] in the utilisation of cross-zonal capacity in the ID timeframe (on average 50% for the borders analysed) was relatively low in 2016, compared to the level of efficiency in the DA timeframe (86%, as shown in Figure 18). Second, Figure 22 confirms that cross-zonal capacity was used more efficiently in 2016 in the ID timeframe on borders where the capacity was allocated by using implicit allocation methods (61% of efficiency) as opposed to explicit or other allocation methods (40%).

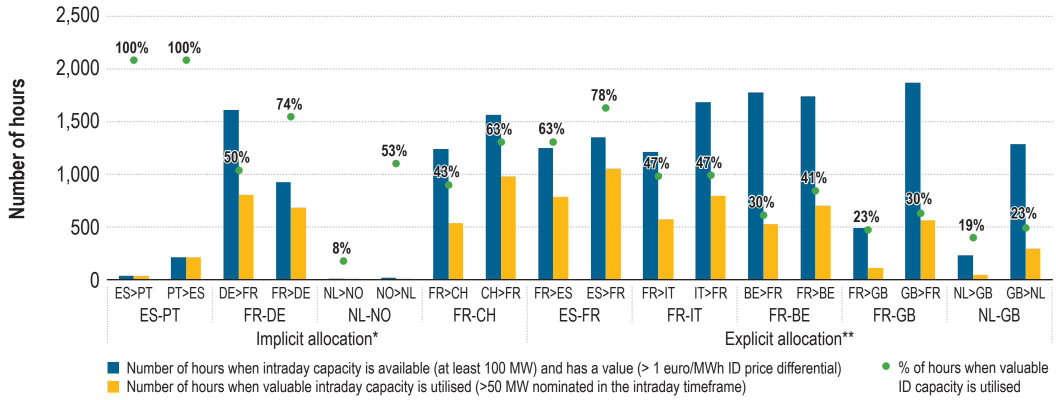
189 Furthermore, Figure 22 suggests that implicit auctions (100% efficiency for the Spanish-Portuguese border) perform better than implicit continuous trade (on average 49% efficiency for the French-German, Dutch-Norwegian and French-Swiss borders) in terms of efficient utilisation of ID cross-zonal capacity[115].

190 In conclusion, the level of utilisation of cross-zonal capacity in the ID timeframe remains low, which leaves a large part of the potential benefits from infrastructure investments untapped. However, despite significant delays experienced in the implementation of the SIDC, mainly caused by technical and decision-making issues among the project parties involved in the XBID project, the forthcoming go-live of the SIDC in first quarter of 2018 is expected further to increase the efficient use of the cross-zonal capacity in the ID timeframe.

114 For the purpose of this analysis, the most representative prices are provided by the closest-to-real-time trades, since they are considered better to reveal the value of cross-zonal capacity at the time when final cross-zonal nominations are determined. Where ID markets are auction-based, the closest-to-real-time trades can be valued at the price of the last auction for every delivery hour. Where ID markets are based on continuous trading, the weighted average ID prices can be used as a proxy for the value of the closest-to-real-time trades. See more details in Sub-section 3.3.1 on ‘Utilisation of cross-zonal capacity in the ID and balancing timeframes’ of the MMR 2013.

115 This means that the final net ID nominations on borders featuring implicit continuous allocation of capacity are not always aligned with the close-to-real-time value of cross-zonal capacity, which can be derived from the close-to-real time ID price differentials.

Figure 22: Level of utilisation of cross-zonal capacity in the ID timeframe when it has a value (>1euro/MWh), for a selection of borders – 2016



Source: ENTSO-E, data provided by NRAs through the EW template, Vulcanus (2016) and ACER calculations.

Note: In some markets, ID liquidity (volumes traded) is relatively low. Therefore, an arbitrary threshold of 50 MW was used for this analysis. The percentages indicate the share of the hours when capacity is used in the right direction (>50 MW used) with ID price differentials of at least 1 euro/MWh and a sufficient availability of cross-zonal capacity (at least 100 MW). Only those hours with at least 50 MW of ID liquidity at both sides of the border were considered. The threshold for the ID price differential was raised to 2 euro/MWh for the borders applying loss factors, i.e. the Netherlands-Norway, France-Great Britain and the Netherlands-Great Britain. (*) The French-German border features both implicit continuous and explicit OTC capacity allocation. (**) On 5 October 2016, a new implicit ID cross-zonal capacity allocation platform went live, connecting the Dutch and Belgian market with the French, German, Swiss and Austrian ID markets.

4.4 Balancing markets

4.4.1 Balancing (capacity and energy) and imbalance prices

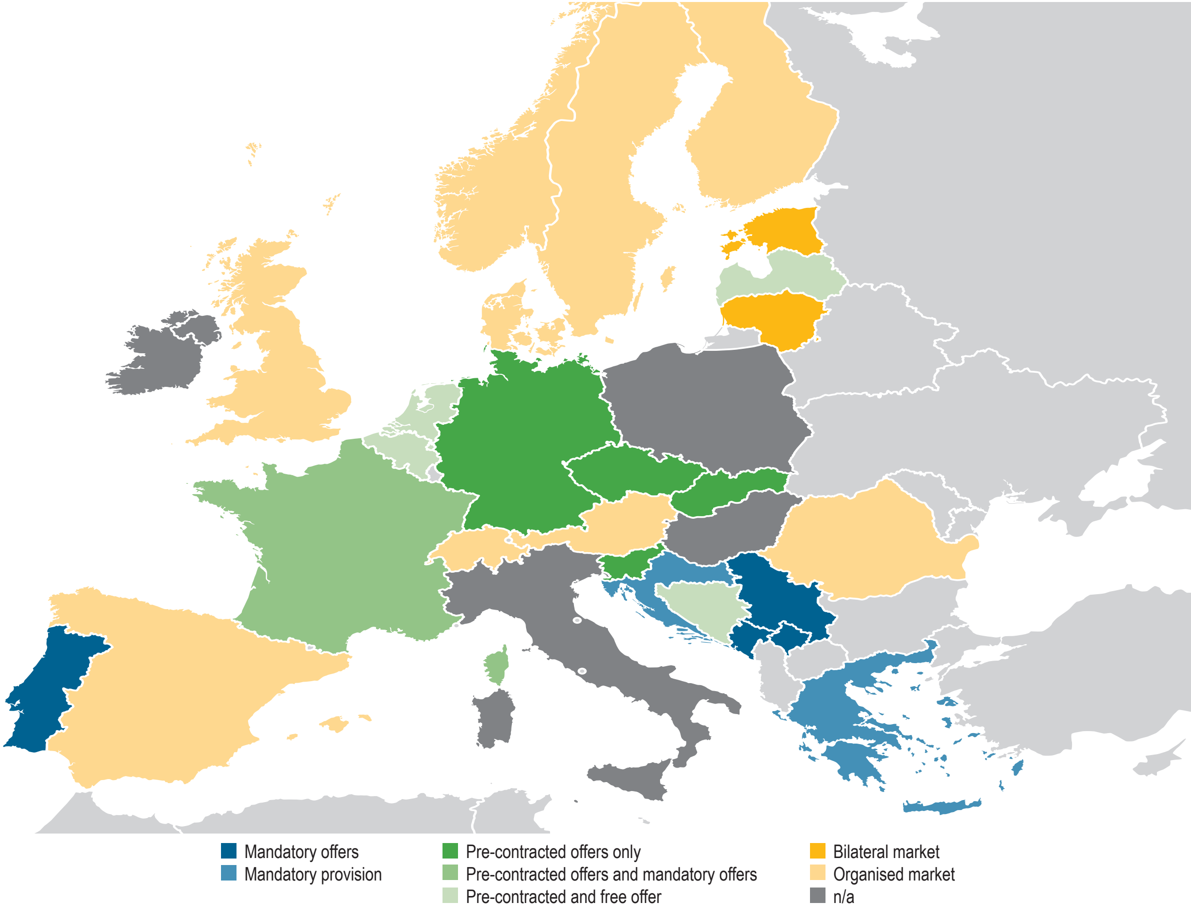
191 Figure 32 and Figure 33 in the Annex confirm the persistence of large disparities in balancing energy and balancing capacity prices in Europe in 2016. These disparities are slightly lower than those observed in preceding years, probably due to the increasing trend in the exchange of balancing services. However, the price differentials in the balancing timeframe are still significantly larger than the price differentials observed in the preceding DA and ID timeframes. This suggests that important efficiency gains are still to be obtained from the exchange of balancing energy and capacity and from cross-zonal sharing of balancing reserves, subject to available cross-zonal capacity and security limits. The efficient exchange of balancing services is the core element of the recently adopted Electricity Balancing (EB) Guideline[116], which will provide the legal framework for integrating national balancing markets.

192 The large disparities in the prices of the various balancing services can be explained first by the lack of progress observed in the integration of balancing markets, and second by national market characteristics. The latter includes, *inter alia*, the underlying costs of the available resources to provide flexibility, the level of penetration of renewables, and the level of development of national markets.

193 The procurement scheme of the different services is one of the aspects of balancing markets design that differs significantly across EU MSs. While in some countries these schemes are essentially market-based, in others the procurement of balancing services are still carried out, to varying degrees, in a regulated manner. Figure 23 provides an illustrative example of the current divergence in the procurement schemes of balancing energy (manually-activated from frequency restoration reserves, mFRRs) across Europe.

116 See footnote 17.

Figure 23: Schemes for procuring balancing energy (activated from mFRRs) in Europe – 2016



Source: ENTSO-E (2017).

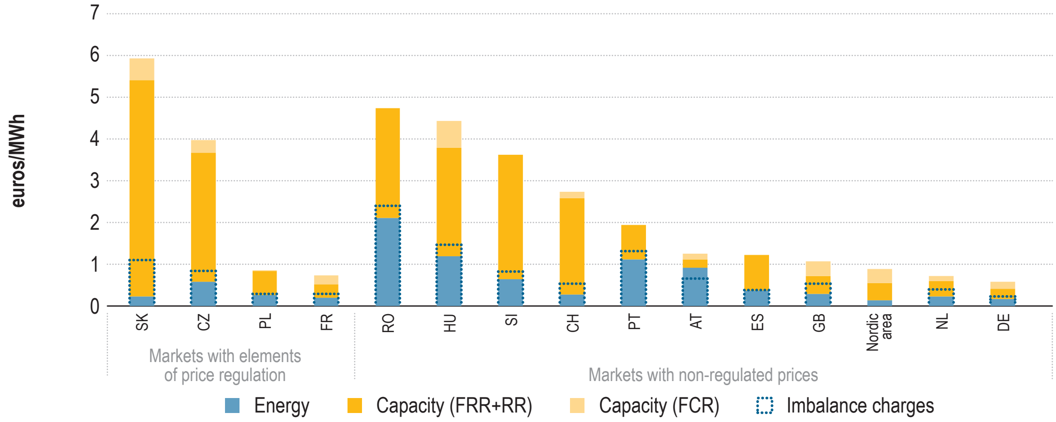
Note: The definitions for the different categories presented in this figure can be found in page 64 of the ENTSO-E's survey on ancillary services procurement, balancing market design (2016) available at https://www.entsoe.eu/Documents/Publications/Market%20Committee%20publications/WGAS_Survey_final_10.03.2017.pdf.

194 Figure 24 displays the overall costs of balancing per unit of electricity demand in a selection of EU markets. Several conclusions can be drawn from this Figure. First, it shows that in most MSs the largest share of balancing costs continued to be the costs of procuring balancing capacity, which illustrates the importance of optimising the balancing capacity procurement costs.

195 Second, it confirms the influence of the level of development of national markets on the observed balancing procurement costs. For example, the MSs applying price regulation appear to be among those with the lowest unit costs of activating balancing energy in Europe. This includes Slovakia, where price regulation applies to the energy activated from all types of reserves, the Czech Republic, where price regulation applies to the energy activated from automatically activated Frequency Restoration Reserves (aFRRs), and France, where price regulation applies to the energy activated from FCRs and from aFRRs, accounting for approximately 30% of activations in the French system.

196 However, lowering artificially the balancing energy procurement costs through price regulation is counter-productive. The target should not be to guarantee the lowest possible balancing energy prices, but to ensure efficient price formation, i.e. prices reflecting the 'true' value of flexibility. In general, price regulation is a barrier to balancing energy prices to reflect this value, and therefore fails to attract the adequate investments in flexible resources from either generation or demand assets. Moreover, relatively low (average) balancing energy procurement costs can be observed in countries without price regulation as shown in Figure 24 for Germany, the Netherlands, the whole Nordic area and Switzerland.

Figure 24: Overall costs of balancing (capacity and energy) and imbalance prices over national electricity demand in a selection of European markets – 2016 (euros/MWh)



Source: Data provided by NRAs through the EW template (2017) and ACER calculations.

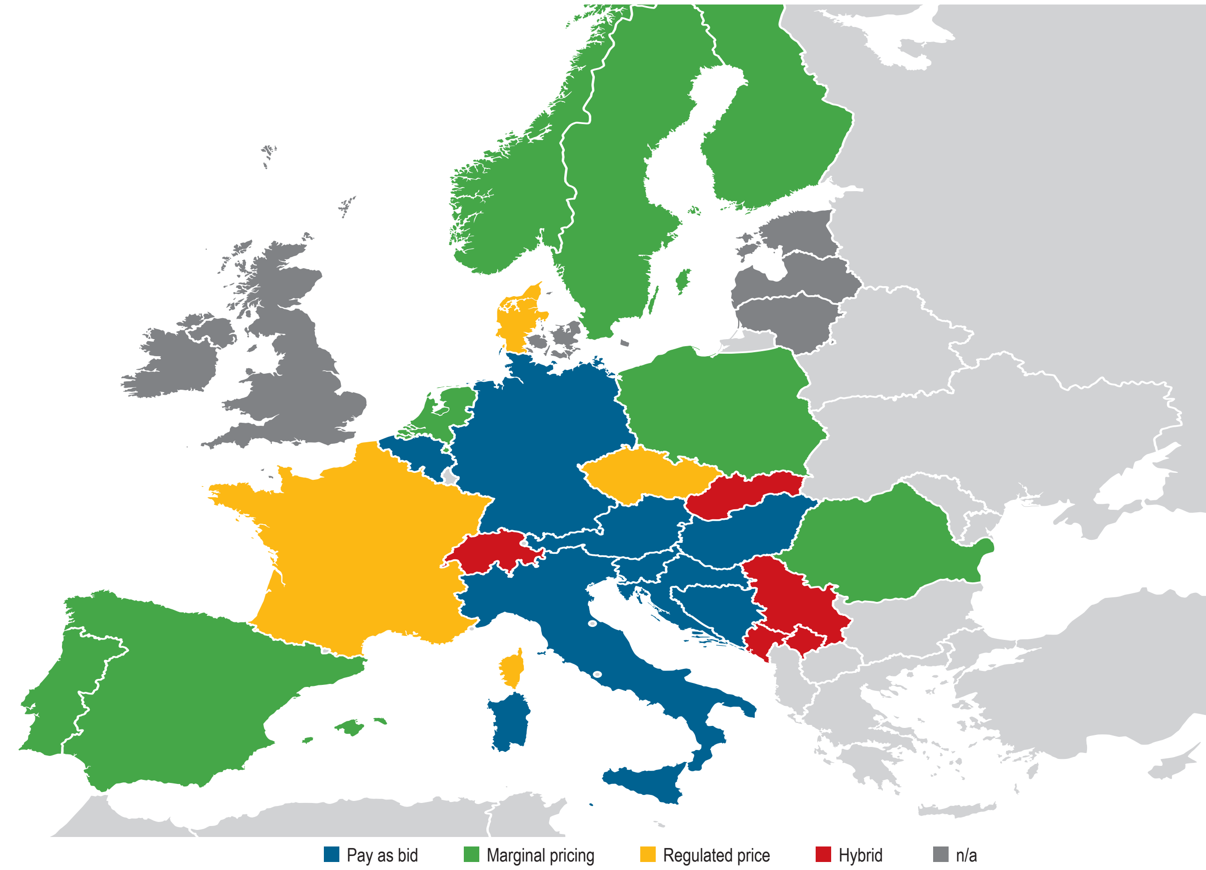
Note 1: The overall costs of balancing are calculated as the procurement costs of balancing capacity and the costs of activating balancing energy (based on activated energy volumes and the unit cost of activating balancing energy from the applicable type of reserve). For the purposes of this calculation, the unit cost of activating balancing energy is defined as the difference between the balancing energy price of the relevant product and the DA market price. Imbalance charges applied in the Nordic market are not included in the figure, as data were not available for all Nordic countries.

Note 2: The procurement costs of reserves reported by the Polish TSO comprise only a share of the overall costs of reserves in the Polish electricity system. This is due to the application of central dispatch in Poland, which makes it difficult to disentangle the balancing and redispatching costs.

197 Third, although not explicitly reflected in Figure 24, some other elements of market design hinder the efficient formation of balancing energy prices[117]. This includes the application of pricing methods (e.g. pay-as-bid pricing) other than marginal pricing, or schemes whereby balancing energy bids of pre-contracted reserves are predetermined as part of the tender to procure balancing capacity. Figure 25 shows that several MSs, including Austria, Belgium, Croatia, Germany, Hungary, Italy, Slovakia and Slovenia still apply ‘pay-as-bid’ rules in their energy balancing regimes.

117 See more details on those elements in Section 9.1 of the MMR 2015.

Figure 25: Pricing methods for procuring balancing energy activated from aFRRs in Europe – 2016



Source: ENTSO-E (2017).

198 Finally, compared to 2015, the following key changes were observed in 2016. First, capacity procurement costs decreased in several markets, e.g. in Austria, Germany and the Netherlands by 45%, 34% and 16% respectively. This was partly due to the consolidation of the coordinated procurement of FCRs, a project that was launched in 2015 and extended to Belgium in 2016. As a result, average prices of contracted FCRs in these markets decreased for the second consecutive year (e.g. in the Netherlands between 2014 and 2016 the average decreased by around 50%).

199 Second, in Austria, a pronounced decrease (of around 45%) in the overall costs of balancing was recorded in 2016 compared to 2015. This was due to the introduction of some regulatory measures in the balancing market in Austria, including measures that enabled the participation of a wider range of technologies already introduced in 2014[118], the exchange of balancing energy activated from aFRRs between Germany and Austria, which started in July 2016 (see more details on the latter in Sub-section 4.4.2) and the wider geographical scope of the projects for the coordinated procurement of FCR and for imbalance netting. These developments confirm the benefits of the further integration of balancing markets and the scope for improvement in national balancing markets.

200 In conclusion, the lack of harmonisation of the main aspects of balancing markets across the EU remains one of the main challenges for the implementation of the EB Guideline. In this respect, priority should be given to removing those elements of balancing market design that impede the free fluctuation of balancing energy prices. This includes, *inter alia*, the inefficient procurement of balancing capacity, the application of regulated prices or of pricing methods that are not based on marginal pricing[119]. These elements reduce the incentives for generators and demand to respond to immediate balancing needs.

118 This has led to an increase in the number and variety of BSPs which resulted in a more liquid balancing market.

119 An effective implementation of marginal pricing needs to be supported by other measures, such as the timely publication of all relevant information to engage market participants close to real time.

4.4.2 Cross-zonal exchange of balancing services

201 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.

202 Figure 26 and Figure 27 show, respectively, the share of activated balancing energy and of balancing capacity (for FCRs) procured abroad compared to system needs in 2016. Although some relevant improvements were observed in the exchange of balancing services in 2016 compared to 2015, the Figures illustrate that the exchange of balancing services (excluding imbalance netting) across EU borders in 2016 continued to be limited. Some of the exceptions in the exchange of these two services are the Baltic countries, Austria and France, where 47%, 23% and 19%, respectively, of the system requirements for upward balancing energy were fulfilled abroad (see Figure 26), and Finland, the Netherlands and Belgium where 48%, 34%, and 32%, respectively, of the balancing capacity (upward FCRs) was contracted abroad (see Figure 27) in 2016.

203 The increase in the exchange of balancing services in 2016 was largely the result of several pilot initiatives intended to support the implementation of the EB Guideline. This includes, among other projects, the aFRR-cooperation project and the project for the common procurement of FCRs.

204 The aFRR-cooperation project, which involves the German and Austrian TSOs, went live on 14 July 2016. The cooperation allows the activation of the most efficient aFRRs based on a common merit order list and a TSO-TSO model[120]. As a result, the overall costs of activating aFRRs can be reduced. The project for the common procurement of FCRs, which already involved the German, Austrian, Dutch and Swiss TSOs, was extended to Belgium on 26 July 2016 with an auction for delivery in August 2016. Compared to 2015, in 2016 these five countries recorded a reduction of approximately 30% in the overall balancing capacity (FCRs) procurement costs. In mid-January 2017, the French TSO joined the cooperation project.

Figure 26: EU balancing energy activated abroad as a percentage of the amount of total balancing energy activated in national balancing markets – 2016 (%)

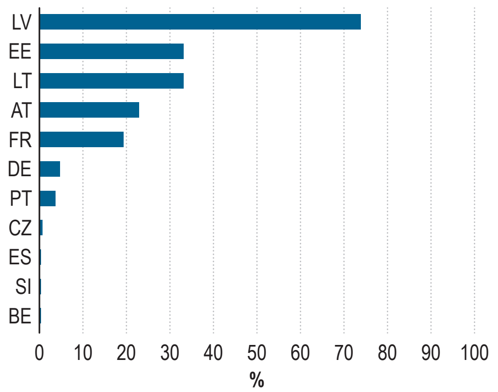
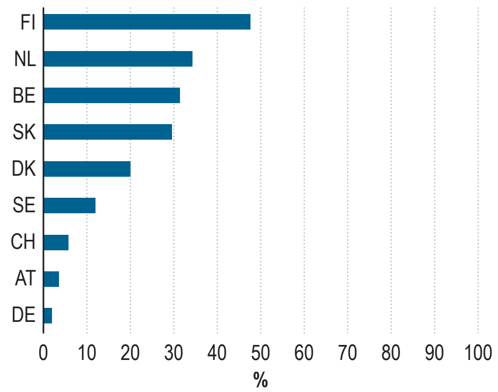


Figure 27: EU balancing capacity contracted abroad as a percentage of the system requirements of reserve capacity (upward FCRs) – 2016 (%)



Source: Data provided by NRAs through the EW template (2017) and ACER calculations.

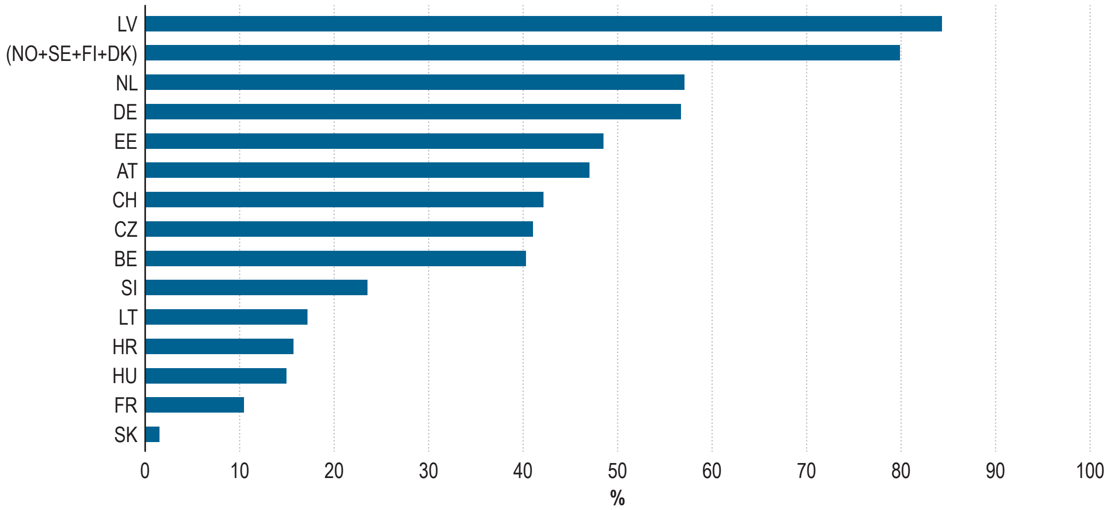
Note: These figures include only those countries that reported some level of cross-zonal exchange. The actual exchange of balancing energy across borders within the Nordic region is not included in Figure 26, because the Nordic electricity systems are integrated and balanced as one single Load Frequency Control (LFC) area. Therefore, the cross-zonal exchange of balancing energy cannot be disentangled from imbalance netting across borders. Instead, they are reported together in Figure 28.

120 TSO-TSO model means a model for the exchange of balancing services where the balancing service provider provides balancing services to its connecting TSO, which then provides these balancing services to the requesting TSO.

205 In 2016, the most successfully applied tool to exchange balancing services continued to be the utilisation of imbalance netting across borders.

206 Figure 28 shows that imbalance netting covers an important share of the needs of balancing energy in several European markets. In Latvia, the Netherlands and Germany, imbalance netting avoided 84%, 57% and 57%, respectively, of the electricity system's balancing energy needs in 2016. In the Nordic region, the combined application of imbalance netting[121] and cross-zonal exchange of balancing energy covered around 80% of the electricity system's balancing energy needs in 2016[122].

Figure 28: Imbalance netting as a percentage of the total need for balancing energy (activated plus avoided activation due to netting) from all types of reserves in national balancing markets – 2016 (%)



Source: Data provided by NRAs through the EW template (2017) and ACER calculations.

Note: This figure includes only the countries that reported some level of cross-zonal exchange. The Nordic electricity systems are integrated and balanced as a single LFC area; the percentage for the Nordics is the sum of the percentages of imbalance netting and exchanged balancing energy, which cannot be disentangled.

207 Finally, 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 an improved version of the methodology described in the MMR 2013[123], the actual application of imbalance netting and exchange of balancing energy is estimated at approximately 19% of their potential in 2016 for a selection of 15 borders where sufficient information was available. Although this value indicates a significant improvement (almost doubled) compared to the previous year, it is still relatively low when compared to the level of efficiency recorded in the preceding DA (86%) and ID (50%) timeframes in 2016.

121 Imbalance netting is not explicitly applied, but is inherent to the existence of a single LFC area.

122 The application of imbalance netting and cross-zonal exchange of balancing energy cannot be disentangled in the Nordic region for the reasons set out in the note under Figure 26.

123 For more details on this methodology, see Annex 11 of the MMR 2013, available at http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER_Market_Monitoring_Report_2014.pdf. Compared to the original methodology, two relevant improvements were introduced for its application in the 2016 MMR. First, the decision on whether exchanging balancing energy is economical for a given market time unit is based on the actual prices of balancing energy activated from aFRR rather than on imbalance prices. Second, the maximum exchange of balancing energy for a given market time unit is subject not only to sufficient available cross-zonal capacity, but also to an upper limit for activating balancing energy from aFRR in a given market time unit. This limit was defined as the maximum balancing energy activated in the relevant electricity system in a market time unit in the year analysed.

5 Capacity mechanisms and generation adequacy

208 This Chapter first presents an update on the situation of CMs in Europe (Section 5.1) and, second, a report on how the contribution of interconnectors is taken into account in national generation adequacy assessments (Section 5.2).

5.1 Situation in capacity mechanisms

209 Figure 29 presents the updated situation of the different types of CMs[124] and their stage of implementation in Europe by the end of 2016[125]. The update includes some key changes compared to last year. First, the figure shows that Latvia has had a scheme since 2005 which resembles the German planned network reserves mechanism[126] and could be considered as a CM. Second, in Greece, capacity payments considered as a transitional measure for the period from May 2016 to April 2017 were approved by the European Commission. Third, in Germany, the plan to implement a capacity reserves mechanism has been postponed until the end of 2018 (envisaged start of the first contracting period). However, the formal approval of this mechanism is still pending. Fourth, in Poland it was decided that the operation of strategic reserves would be extended until the end of 2019. Poland currently considers to implement a market-wide capacity mechanism similar to the British capacity market. Fifth, in Spain, one of the existing types of capacity payments no longer applies to new capacity (as of 1 January 2016). Finally, in France, the first auction of capacity guarantees, for delivery in 2017, took place on 15 December 2016, while in Great Britain the first delivery of capacity acquired in the CM is expected on 1 October 2017[127].

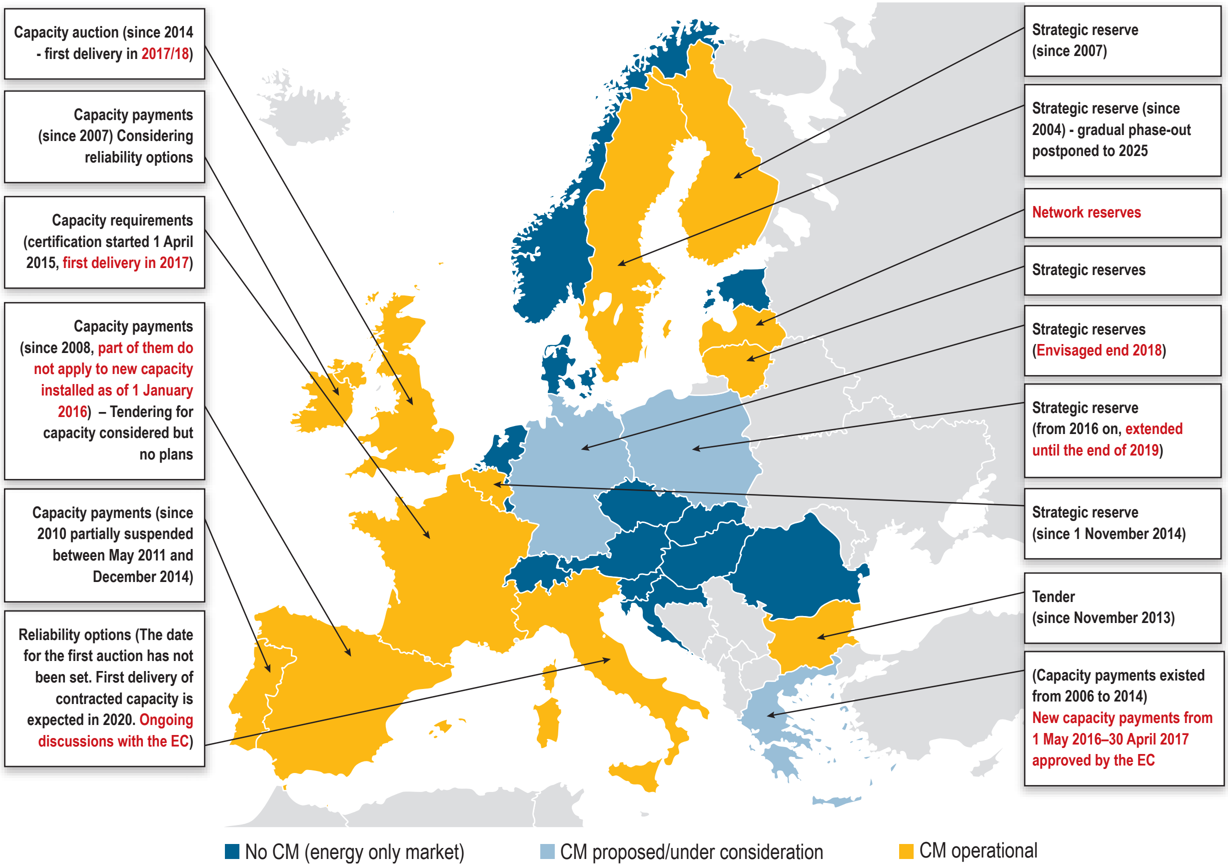
124 A variety of CMs have been proposed. They can be classified according to whether they are volume-based or price-based. Volume-based CMs can be further grouped in targeted and market-wide categories. For the taxonomy of the main CMs, see http://europa.eu/rapid/press-release_MEMO-15-4892_en.htm.

125 The update is based on information provided by NRAs and the European Commission's report (DG Competition) of the sector inquiry into capacity mechanisms published in November 2016. The report draws conclusions as to when capacity mechanisms are justified interventions in the market and sets out which types of capacity mechanisms are appropriate in which situation. The final report is available at http://ec.europa.eu/competition/sectors/energy/capacity_mechanisms_final_report_en.pdf.

126 Based on the most recent information received from the Latvian NRA.

127 The production of the Electricity Wholesale Markets Volume was completed before this date.

Figure 29: CMs in Europe – 2016



Source: NRAs (2017) and European Commission's report on the sector inquiry into CMs (2016).

Notes: In Germany, one scheme is in place (the network reserve) and another scheme is planned (the capacity reserve). The Commission temporarily approved the network reserve. The assessment of the capacity reserve is ongoing. The main changes compared to 2015 are highlighted in red.

5.2 Treatment of interconnectors in adequacy assessments

210 The starting point in the process of determining whether to implement a CM should be an assessment of the resource adequacy situation. Given the increasing interdependence of national electricity systems, a robust adequacy assessment needs properly to consider the contribution of interconnectors to adequacy, as such a contribution may be a determining factor when deciding to implement a CM. The importance of properly considering the contribution of interconnectors can be derived from the results provided by ENTSO-E's 2016 MAF[128], a Pan-European assessment of the risks to security of supply over the next decade. Some illustrative examples of these results are shown below.

211 The MAF assesses adequacy for different scenarios based on key metrics such as Energy Not Served (ENS) and Loss of Load Expectation (LOLE)[129]. An indication of the relevance of interconnectors to security of supply is provided by the different results (i.e. the calculated values of ENS and LOLE) under different scenarios. In particular, two of these scenarios (S0 and S2) differ mainly in how the contribution of interconnectors is considered. The first considers this contribution as zero, whereas the second estimates the contribution of interconnectors by using a probabilistic modelling of market outcomes[130].

128 See footnote 24.

129 Information on the metrics used in EU MSs to assess generation adequacy at national level can be found in the Table 8 of the Electricity Wholesale Markets volume of the MMR 2015.

130 This allows to derive, inter alia, the expected direction of commercial flows on interconnectors.

212 By comparing the security of supply levels in these two scenarios, it can be derived that the outcome of the adequacy assessments (i.e. the values obtained for ENS and LOLE) are highly sensitive to the approach followed in considering the contribution of interconnectors to adequacy. This is the case even in countries where the ratio of cross-zonal capacity to national demand is relatively low. For example, in Italy, Germany, Bulgaria, and Greece, the LOLE assessed without interconnector capacity (scenario S0) would be 588, 3, 15, and 11 hours/year, respectively, for the year 2020. All these values (except in Germany) are above the most frequently used reliability standards (LOLE between 3 and 8)[131], which would lead to the conclusion that these countries might[132] face a security of supply issue in 2020.

213 By contrast, when the contribution of interconnectors is considered (scenario S2), the LOLE is assessed to be 0.2, 0, 0.1 and 0 hours/year, respectively, for the same year. These results, together with the fact that most national adequacy assessments ignore or at best underestimate the contribution of interconnectors[133], confirm the key importance of correctly estimating the contribution of interconnectors to adequacy.

214 In this regard, several countries have started or intend to use probabilistic techniques similar to the ones used in the MAF in their national adequacy assessments. However, the underlying assumptions used in these assessments are often more conservative. The current situation of national adequacy assessments with respect to the treatment of interconnectors is provided below.

215 Table 4 shows that in ten countries the contribution of interconnectors is not considered, or is assessed to be non-existent[134] in the scenario used to take a decision on whether to implement a CM. In these countries, the concept of security of supply is treated as national 'self-sufficiency'. Such an approach might be due to MSs distrusting that interconnectors will be available at times of scarcity. For example, curtailments in cross-border electricity flows or explicit export bans were imposed in a few EU Member States (e.g. in Greece and in Bulgaria) during the January cold spell with the aim of 'protecting domestic consumers'. This lack of cross-border cooperation is in conflict with the legal provisions aiming to avoid discrimination between internal and cross-border flows.

216 It is worth highlighting that out of these ten countries, three (Bulgaria, Spain and Sweden) have already implemented a CM, one (Germany) has already taken the decision to introduce a CM, while in the other six (Austria, the Czech Republic, Estonia, Norway, Romania and Slovakia) the national generation capacity is considered to provide 'adequate' security of supply levels. The latter can be considered as a de-facto situation of overcapacity.

217 In 15 other countries the contribution of interconnectors to adequacy is quantified. However, considering the contribution of interconnectors is not sufficient to remove the risk of overcapacity. A robust methodology should include probabilistic modelling techniques and avoid insufficiently grounded conservative assumptions[135]. Based on this, Table 4 suggests that, even in countries that consider the contribution of interconnectors to adequacy, there is a significant room for improvement in the methodologies used to quantify this contribution, as further detailed below.

131 See footnote 129.

132 With a probability above the desired levels of security of supply.

133 As further elaborated below.

134 I.e. the contribution of interconnectors is considered, but is assessed to be equal to zero MW of capacity. This is the case in Spain, for instance.

135 Examples of such assumptions are provided below.

Table 4: Treatment of interconnectors in national generation adequacy assessments in Europe – 2016

Methodology to estimate the contribution of interconnectors	Country	Estimated % of commercial capacity contributing to adequacy
Not considered and a CM is implemented/envisaged	BG	0%
	ES	
	SE	
	DE	
Not considered and a CM is not implemented/envisaged	AT	
	CZ	
	EE	
	NO	
	RO	
	SK	
Deterministic	GR	<30%
	SI	100%
	HU	100% aprox (1)
	HR	NS
	LT	NS
	IT	NS
Probabilistic	PT	10%
	UK (GB)	40% (2)
	FI	63%
	BE	72%
	FR	73%
	NL	100% (3)
	PL	100% (4)
	DK	100%
	CH	NS

Source: NRAs (2017).

Note: The information shown in the table is based on the national adequacy assessments used to take a decision on whether to implement a CM or, in countries where such a decision was not considered, on the latest national adequacy assessment. The percentages shown in the table are calculated, for a given country, as the ratio between the average expected net contribution of all interconnectors during scarcity situations and the sum of the average commercial import cross-border capacity. These percentages do not represent the actual contribution (in MW) which can be negligible on some borders due to the low availability of cross-zonal capacity (e.g. on some of the Polish borders). (1) Values differ depending on the source used for the NTC values. (2) The value is the result of considering the estimated imports less the estimated exports at times of scarcity as assessed in the adequacy assessment used to take a decision on whether to implement a CM. The estimated average contribution increased in the most recent assessments used to take decisions on the capacity auction parameters. (3) Without considering a de-rating factor representing the probability of an outage. (4) The value represents the input values used for the adequacy assessments. The actual estimated contribution of interconnectors at times of scarcity was not provided. IE did not answer to the questionnaire and LV did not specify how the contribution of interconnectors to adequacy is treated. CY, MT (isolated systems) and LU (with no direct responsibility on interconnectors) are not shown in the figure. (NS) means not specified.

218 In this respect, Table 4 shows that in 6 out of the 15 countries, the contribution of interconnectors is taken into account by means of a deterministic method. This is equivalent to assuming certainty about a specific level of contribution during tight supply and demand conditions. As a consequence, the assumptions underlying the contribution of interconnectors tend to be overly conservative[136]. An example is Greece, where less than 30% of the tradable import capacity (average of NTC values) is assumed to be available during scarcity events.

219 In the other nine countries that evaluate the contribution of interconnectors, the assessment is performed stochastically. A robust, stochastically designed adequacy assessment requires the use of advanced modelling techniques, e.g. Monte Carlo simulations, such as the ones used in the MAF. However, it often remains unclear whether the statistical analysis is limited to computing historical values of cross-zonal commercial import capacity and whether the interaction with other variables determining the presence of tight situations is assessed. Disregarding this interaction implies that the relatively low probability that an event of scarcity and a situation of limitedly available cross-zonal capacity occur simultaneously is ignored. Indeed, the most conservative assessments assume that any scarcity situation would necessarily be coupled with a situation of low availability of interconnectors. This seems to be the case in Portugal, where, based on the lowest historical values, the contribution of interconnectors to adequacy during scarcity events is assumed to be only 10% of the average NTC.

136 This is because, with this approach, a low (unrealistic) level of contribution is often selected in order to mitigate the possibility of false assumptions.

220 Even in countries that perform relatively advanced adequacy assessments, some assumptions on the contribution of interconnectors appear to be excessively prudent. For example, in Great Britain, one of the assumptions included in the adequacy assessment used to determine whether to implement a CM considered that full exports over the interconnectors to Ireland could be expected at times of stress in Great Britain[137]. Although an available analysis had preliminarily suggested that imports from Ireland to Great Britain at times of stress would be possible[138], the revised (more conservative than the initial) assumption was considered as 'reasonable'.

221 By contrast, during six of the eight highest price spike events[139] observed in Great Britain in 2016 (in fact, among the highest price spikes recorded in Europe in recent years), the interconnector capacity was used (on average more than 0.2 GW) in the direction from Ireland to Great Britain[140]. In the other two occasions, the interconnector was unavailable and, consequently, no exports to Ireland during these events were observed. This suggests that assuming with certainty full exports to Ireland at times of stress in Great Britain is – to say the least – an overly conservative assumption. In quantitative terms, the revised hypothesis was equivalent to increasing the needs for adequacy in Great Britain by around 1 GW[141].

222 It should be emphasised that, since the introduction of the CM in Great Britain, there has been a focus on improving the methodologies and modelling on the expected interconnector flows which has led to a significant increase in the expected contribution of imports to security of supply at times of stress. While the "net contribution" assumed in the adequacy assessment used to determine whether to implement a CM considered an average 40% contribution from all interconnectors (see Table 4), the estimated contribution increased to an average higher than 60% in the most recent evaluations of capacity auction parameters[142]. The experience in Great Britain underlines the importance of having a robust methodology and strong base on which to take decisions, as evidence shows that these assumptions can have a significant effect on the adequacy metrics (such LOLE and ENS)[143] in European markets.

223 Another conclusion that can be derived from Table 4 is that the estimates of the contribution of interconnectors to adequacy are at best based on average historical values of available cross-zonal capacity (i.e. average NTC values). Given that these values are the outcome of conservative CC processes (see Sub-section 3.2.2 on the ratio between commercial and physical cross-zonal capacity), the estimates used for adequacy assessments may end up being disproportionately conservative.

224 Based on Table 4 and the additional details provided above, there are grounds to conclude that most national adequacy assessments ignore, or at best tend to underestimate, the 'true' contribution of interconnectors to security of supply. This purely national approach is all the more surprising in the context of a move towards a more integrated IEM. This may lead to (or contribute to) a situation of overcapacity at the expense of end consumers.

225 Instead, a number of improvements in the process of estimating the contribution of interconnectors should be introduced. First, the methodology and assumptions used to assess the contribution of interconnectors should be more transparent. Second, estimates should be based on the expected availability of interconnectors during stress situations, not on annual or seasonal averages, as these may not be adequate proxies.

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137 This assumption was based on "historical exports to Ireland", and the fact that "market coupling with Ireland is yet to be implemented". For more information, see para 1.11, available at https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/354677/CM_-_revised_IA_and_front_page__September_2014__pdf_-_Adobe_Acrobat.pdf.

138 For instance, this study shows that for the 'baseline scenario', the Irish-British interconnector would be used on average in the direction from Ireland to Great Britain in times of stress, with a utilisation rate ranging between 0% and 53%, depending on the level of tightness assumed in Ireland.

139 15 September 2016-hour 21 (1174.92 euros/MWh), 19 September 2016-hour 21 (1127.04 euros/MWh), 15 September 2016-hour 22 (939.7 euros/MWh), 7 November 2016-hour 19 (894.7 euros/MWh), 19 September 2016-hour 20 (880.5 euros/MWh), 19 September 2016-hour 22 (876.98 euros/MWh), 8 November 2016-hour 19 (870.2 euros/MWh) and 14 November 2016-hour 19 (810.6 euros/MWh).

140 Analysis based on DA prices and DA nominations.

141 The assumptions imply that the British generation capacity should serve not only domestic consumption, but also provide an additional 0.75 GW for exports to Ireland in times of stress. This is in addition to a certain amount of possible imports from Ireland that are 'ignored' (see footnote 138).

142 For example, see the decision on the capacity auction parameters for the auctions planned in January and February 2018 available at https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/625657/170705_SoS_to_National_Grid.pdf.

143 E.g. see paragraphs 171 to 174.

226 Third, estimates of the contribution of interconnectors for the purpose of assessing adequacy should benefit from the most advanced CC methods, i.e. they should be FB, rather than NTC-based (at least in meshed networks) and they should consider the Agency's principles of non-discrimination to the maximum extent possible.

227 An illustration of the potential of adequately applied FB methods is provided by the fact that, in 2016, the amount of energy imported during a given hour to France and Belgium (i.e. their joint net position) from Germany and the Netherlands reached a maximum of 8,328 MW, which is about twice the equivalent value (i.e. the sum of the highest recorded import NTC values) observed before FBMC was implemented (4,501 MW in 2014). At the same time, both countries faced several moderate stress events in 2016, resulting in the highest price spreads observed within the Core (CWE) region in recent years.

228 However, during those events, net imports to Belgium and France were still less than half the above-mentioned 2016 maximum. As shown in Sub-section 3.2.1, the relatively low level of imports was largely the result of the limited amount of tradable cross-zonal capacity in the Core (CWE) region in the second half of 2016. The application of the high-level principles of the Agency's Recommendation which are intended to avoid undue discrimination in CC would probably have allowed the maximisation of the Core (CWE) region flows to these two countries during those events, hence maximising welfare within the Core (CWE) region, while ensuring security of supply in Belgium and France at a lower cost.

229 Fourth, more operational coordination as envisaged in the CACM Regulation and the System Operation Guideline should be put in place as soon as possible. These Guidelines will enable the application of the most efficient CC techniques and the most efficient remedial actions in the case of a supply shortage, based on regional rather than country-level calculations.

230 Finally, the geographical scope of adequacy assessments should also be at least regional, i.e. wider than national. Overall, the suggested improvements will definitely contribute to achieving the desired levels of security of supply at a lower cost for end consumers.

Annex 1: Additional figures and tables

Table 5: Average DA price differentials across European borders (ranked) – 2012–2016 (euros/MWh)

	Average hourly price differentials						Average of absolute hourly price differentials					
Border	2012	2013	2014	2015	2016	2012-2016	2012	2013	2014	2015	2016	2012-2016
NL-GB	-7.1	-7.1	-11.0	-15.6	-16.9	-11.5	9.1	8.8	11.2	15.8	17.0	12.4
FR-GB	-8.2	-15.8	-17.6	-17.2	-12.4	-14.2	13.4	17.4	17.7	17.5	15.4	16.3
IE-GB	11.6	10.0	8.1	-1.5	-4.0	4.9	16.9	18.6	17.7	15.2	13.8	16.4
AT-IT	-31.5	-23.8	-17.6	-21.1	-13.7	-21.5	31.5	24.1	17.7	21.1	13.7	21.6
DE-PL	1.1	1.1	-10.2	-5.9	-7.5	-4.3	7.4	8.2	11.7	8.6	10.0	9.2
CH-DE	6.9	7.0	4.0	8.6	8.9	7.1	9.1	9.3	5.6	9.8	9.5	8.7
AT-CH	-6.9	-7.0	-4.0	-8.6	-8.9	-7.1	9.1	9.3	5.6	9.8	9.5	8.7
PL-SE-4	7.3	-3.3	11.1	14.6	6.9	7.3	10.6	5.2	11.9	15.3	9.2	10.4
CZ-PL	0.9	0.1	-10.0	-5.2	-5.3	-3.9	6.5	7.8	11.2	7.9	9.1	8.5
PL-SK	-1.4	-0.6	9.3	4.0	5.0	3.3	6.9	8.1	11.1	8.1	9.1	8.7
GR-IT-BRI	-11.8	-15.4	11.2	2.5	2.5	-2.2	21.0	20.8	14.6	9.7	8.2	14.8
DE-FR	-4.3	-5.5	-1.9	-6.8	-7.8	-5.3	5.1	7.8	4.7	7.5	8.0	6.6
ES-FR	0.3	1.0	7.5	11.8	2.9	4.7	11.4	17.6	16.7	14.7	8.0	13.7
FI-NO-4	5.5	2.6	4.6	9.3	7.4	5.8	5.6	2.9	5.0	9.8	7.6	6.2
NL-NO-2	18.8	14.6	14.0	20.3	7.1	14.9	19.1	15.1	14.1	20.3	7.5	15.2
AT-HU	-8.9	-4.6	-7.7	-9.0	-6.4	-7.3	11.7	8.9	9.2	10.1	7.4	9.5
AT-SI	-10.4	-5.4	-7.7	-9.8	-6.6	-8.0	12.6	8.5	8.7	11.7	7.4	9.8
FR-IT	-27.1	-18.3	-15.7	-14.2	-5.9	-16.3	29.0	19.4	16.0	14.4	7.3	17.2
IT-SI	21.0	18.4	9.9	11.3	7.0	13.5	21.1	18.5	10.0	11.4	7.2	13.6
LT-SE-4	10.4	9.0	18.2	19.0	7.0	12.7	14.0	11.2	18.2	19.2	7.1	14.0
CH-IT	-24.5	-16.9	-13.6	-12.5	-4.8	-14.5	24.9	17.3	13.7	13.3	6.2	15.1
LT-PL	3.1	12.3	7.1	4.4	0.1	5.4	8.5	13.6	13.5	10.9	6.1	10.5
BE-NL	-1.0	-4.5	-0.4	4.6	4.4	0.6	2.7	6.1	2.2	5.9	6.1	4.6
DE-SE-4	8.4	-2.1	0.8	8.8	-0.5	3.1	11.7	7.7	6.5	11.1	4.9	8.4
CH-FR	2.6	1.5	2.2	1.7	1.1	1.8	7.1	5.3	4.6	5.1	4.9	5.4
DE-DK_E	5.0	-1.8	0.6	7.2	-0.4	2.1	7.1	5.8	5.0	9.2	4.3	6.3
NO-4-SE-1	-0.6	-0.6	0.0	-0.7	-3.9	-1.2	0.7	1.0	0.8	1.3	4.1	1.6
NO-4-SE-2	-0.6	-0.6	0.0	-0.7	-3.9	-1.2	0.7	1.0	0.8	1.4	4.1	1.6
HU-SK	8.7	5.1	6.9	7.0	4.0	6.3	10.2	5.2	6.9	7.0	4.0	6.7
DE-DK_W	6.3	-1.2	2.1	8.8	2.3	3.6	7.5	6.8	4.8	9.7	3.9	6.5
CZ-DE	-0.2	-1.0	0.2	0.7	2.2	0.4	4.0	4.3	2.8	3.2	3.9	3.6
AT-CZ	0.2	1.0	-0.2	-0.7	-2.2	-0.4	4.0	4.3	2.8	3.2	3.9	3.6
DE-NL	-5.4	-14.2	-8.4	-8.4	-3.3	-7.9	5.5	14.2	8.4	8.7	3.8	8.1
FI-SE-1	4.9	2.0	4.6	8.5	3.5	4.7	4.9	2.0	4.6	8.5	3.5	4.7
NO-1-SE-3	-2.8	-1.9	-4.3	-2.2	-3.1	-2.8	2.9	3.2	4.4	2.2	3.3	3.2
FI-SE-3	4.3	1.7	4.4	7.7	3.2	4.3	4.4	1.8	4.4	7.7	3.2	4.3
DK_W-NO-2	7.2	1.6	3.4	3.1	1.5	3.4	8.8	6.4	6.1	4.5	3.1	5.8
EE-LV		-8.0	-12.5	-10.8	-3.0	-8.6		8.0	12.5	10.8	3.1	8.7
DK_W-SE-3	4.0	-0.5	-0.9	0.9	-2.6	0.2	6.3	4.2	3.0	3.1	2.7	3.9
BE-FR	0.0	4.2	6.2	6.2	-0.1	3.3	2.8	4.6	6.2	6.3	2.6	4.5
HU-RO	2.5	7.0	5.8	4.2	2.1	4.3	13.9	12.5	10.1	4.4	2.5	8.7
NO-3-SE-2	-0.3	-0.2	0.1	0.1	-0.3	-0.1	0.4	0.8	0.6	0.6	0.9	0.7
EE-FI	2.6	2.0	1.6	1.4	0.6	1.6	4.8	3.0	1.6	1.4	0.7	2.3
DK_E-SE-4	3.4	-0.3	0.2	1.6	-0.1	0.9	4.6	1.8	1.5	2.1	0.7	2.1
CZ-SK	-0.5	-0.5	-0.7	-1.2	-0.3	-0.6	0.5	0.5	0.7	1.3	0.6	0.7
LT-LV		0.0	0.0	-0.1	-0.4	-0.1		0.0	0.0	0.1	0.5	0.2
ES-PT	-0.8	0.6	0.3	-0.1	0.2	0.0	0.8	1.1	0.5	0.1	0.3	0.6

Source: ENTSO-E, Platts (2017) and ACER calculations.

Note: For the analysis of price differentials, Irish prices include capacity payments (euro/MWh) applied to imports/exports to/from Ireland.

Table 6: Ratio between tradable capacity (NTC) and benchmark capacity (regional performance) – 2016 (%, MW)

HVAC/HVDC	Capacity calculation region	Aggregated tradable capacities (NTC) 2016 (avg. of both directions per border) [MW]	Aggregated benchmark capacity [MW]	Ratio NTC/benchmark capacity
HVAC	Core (excl. CWE)	9,231	23,098	40%
	Swiss borders	8,114	14,356	57%
	SWE	4,340	8,176	53%
	Italy Nord	2,554	3,757	68%
	SEE	700	3,115	22%
	Hansa	750	1,582	47%
HVDC	Channel	2,718	3,000	91%
	Norwegian borders	2,102	2,250	93%
	Baltic	1,683	2,200	76%
	Nordic	1,786	1,910	94%
	Hansa	760	1,200	63%
	IU	362	500	72%
	Greece-Italy (GRIT)	362	500	72%

Source: ENTSO-E YS&AR (2014, corrected in 2016), NRAs, Nord Pool Spot (2017), and ACER calculations.

Note: Tradable capacities are calculated as average NTC values per border in both directions, whereas benchmark capacity is calculated according to the methodology described in Annex 2. These values are added together for each region. The ratio between them is presented in the last column.

Table 7: Changes in tradable capacity (NTC) in Europe from 2015 to 2016 and ratios between NTC and benchmark capacity – 2016 (%, MW)

New CC region	AC_DC	New CC border label	Direction	NTC 2015 (MW)	NTC 2016 (MW)	Change of NTC 2016 vs. 2015	TC [MW]	Benchmark capacity (MW)	Ratio benchmark/ TC	Ratio NTC/ benchmark
Baltic	HVDC	EE-FI	EE > FI	892	965	8.2%	1,000	1,000	100%	97%
Baltic	HVDC	EE-FI	FI > EE	934	975	4.4%	1,000	1,000	100%	98%
Baltic	HVAC	EE-LV	EE > LV	729	779	6.9%	836	CGM NA	CGM NA	CGM NA
Baltic	HVAC	EE-LV	LV > EE	620	670	8.0%	836	CGM NA	CGM NA	CGM NA
Baltic	HVAC	LV-LT	LT > LV	536	554	3.4%	2,751	CGM NA	CGM NA	CGM NA
Baltic	HVAC	LV-LT	LV > LT	978	1,021	4.4%	2,751	CGM NA	CGM NA	CGM NA
Baltic	HVDC	LT-SE4	SE-4 > LT		490	new	700	700	100%	70%
Baltic	HVDC	LT-SE4	LT > SE-4		476	new	700	700	100%	68%
Baltic	HVDC	LT-PL	PL > LT	174	149	-14.5%	500	500	100%	30%
Baltic	HVDC	LT-PL	LT > PL	257	311	21.0%	500	500	100%	62%
Core (excl. CWE)	HVAC	AT-CZ	AT > CZ	646	527	-18.4%	3,576	1,908	53%	28%
Core (excl. CWE)	HVAC	AT-CZ	CZ > AT	562	561	-0.1%	3,576	1,908	53%	29%
Core (excl. CWE)	HVAC	AT-HU	AT > HU	510	472	-7.4%	3,115	1,474	47%	32%
Core (excl. CWE)	HVAC	AT-HU	HU > AT	620	605	-2.5%	3,115	1,474	47%	41%
Core (excl. CWE)	HVAC	AT-SI	AT > SI	763	642	-15.7%	2,505	1,743	70%	37%
Core (excl. CWE)	HVAC	AT-SI	SI > AT	940	924	-1.7%	2,505	1,743	70%	53%
Core (excl. CWE)	HVAC	DE/LU-PL	DE/LU > PL	0	9	from 0	3,095	2,424	78%	0%
Core (excl. CWE)	HVAC	DE/LU-PL	PL > DE/LU	3	1	-55.3%	3,095	2,424	78%	0%
Core (excl. CWE)	HVAC	DE/LU-CZ	CZ > DE/LU	2,455	2,551	3.9%	5,564	2,745	49%	93%
Core (excl. CWE)	HVAC	DE/LU-CZ	DE/LU > CZ	856	278	-67.5%	5,564	2,745	49%	10%
Core (excl. CWE)	HVAC	CZ-PL	CZ > PL	0	22	from 0	3,527	1,881	53%	1%
Core (excl. CWE)	HVAC	CZ-PL	PL > CZ	409	406	-0.6%	3,527	1,881	53%	22%
Core (excl. CWE)	HVAC	CZ-SK	CZ > SK	1,692	1,865	10.2%	4,480	2,477	55%	75%
Core (excl. CWE)	HVAC	CZ-SK	SK > CZ	1,180	1,192	1.0%	4,480	2,477	55%	48%
Core (excl. CWE)	HVAC	HU-SK	HU > SK	788	811	2.9%	2,736	1,689	62%	48%
Core (excl. CWE)	HVAC	HU-SK	SK > HU	1,013	1,049	3.6%	2,736	1,689	62%	62%
Core (excl. CWE)	HVAC	PL-SK	PL > SK	256	231	-9.8%	2,075	1,386	67%	17%
Core (excl. CWE)	HVAC	PL-SK	SK > PL	0	21	from 0	2,075	1,386	67%	2%
Swiss borders	HVAC	AT-CH	AT > CH	778	802	3.0%	4,120	2,794	68%	29%
Swiss borders	HVAC	AT-CH	CH > AT	1,182	1,152	-2.5%	4,120	2,794	68%	41%
Italy Nord	HVAC	NORD-AT	AT > NORD	250	243	-2.9%	421	306	73%	79%
Italy Nord	HVAC	NORD-AT	NORD > AT	105	100	-4.3%	421	306	73%	33%

New CC region	AC_DC	New CC border label	Direction	NTC 2015 (MW)	NTC 2016 (MW)	Change of NTC 2016 vs. 2015	TC [MW]	Benchmark capacity (MW)	Ratio benchmark/ TC	Ratio NTC/ benchmark
Swiss borders	HVAC	CH-DE	CH > DE	3,934	4,000	1.7%	11,991	5,059	42%	79%
Swiss borders	HVAC	CH-DE	DE > CH	1,398	1,467	4.9%	11,991	5,059	42%	29%
Swiss borders	HVAC	CH-FR	CH > FR	1,184	1,125	-5.0%	10,545	2,461	23%	46%
Swiss borders	HVAC	CH-FR	FR > CH	3,064	2,974	-2.9%	10,545	2,461	23%	121%
Swiss borders	HVAC	CH-IT	CH > IT	2,914	2,986	2.4%	8,332	3,987	48%	75%
Swiss borders	HVAC	CH-IT	IT > CH	1,696	1,722	1.5%	8,332	3,987	48%	43%
Italy Nord	HVAC	NORD-FR	FR > NORD	2,457	2,547	3.6%	5,336	2,324	44%	110%
Italy Nord	HVAC	NORD-FR	NORD > FR	1,019	1,020	0.1%	5,336	2,324	44%	44%
Greece-Italy (GRIT)	HVDC	BRNN-GR	GR > BRNN	383	362	-5.3%	500	500	100%	72%
Greece-Italy (GRIT)	HVDC	BRNN-GR	BRNN>GR	382	362	-5.3%	500	500	100%	72%
Core (excl. CWE)	HVAC	HR-SI	HR > SI	1,454	1,445	-0.6%	3,906	1,766	45%	82%
Core (excl. CWE)	HVAC	HR-SI	SI > HR	1,454	1,491	2.6%	3,906	1,766	45%	84%
Italy Nord	HVAC	NORD-SI	NORD > SI	636	648	1.9%	2,150	1,126	52%	58%
Italy Nord	HVAC	NORD-SI	SI > NORD	526	551	4.8%	2,150	1,126	52%	49%
Channel	HVDC	FR-GB	FR > GB	1,805	1,715	-5.0%	2,000	2,000	100%	86%
Channel	HVDC	FR-GB	GB > FR	1,805	1,715	-5.0%	2,000	2,000	100%	86%
IU	HVDC	UK-IE	IE > UK	488	351	-28.1%	500	500	100%	70%
IU	HVDC	UK-IE	UK > IE	517	372	-28.1%	500	500	100%	74%
Channel	HVDC	NL-GB	NL > UK	990	1,002	1.3%	1,000	1,000	100%	100%
Channel	HVDC	NL-GB	UK > NL	993	1,004	1.2%	1,000	1,000	100%	100%
Hansa	HVDC	DK2-DE/LU	DE/LU > DK2	568	534	-6.0%	600	600	100%	89%
Hansa	HVDC	DK2-DE/LU	DK2 > DE/LU	543	519	-4.4%	600	600	100%	87%
Hansa	HVAC	DK1-DE/LU	DE/LU > DK1	864	1,306	51.0%	3,748	1,582	42%	83%
Hansa	HVAC	DK1-DE/LU	DK1 > DE/LU	236	194	-17.6%	3,748	1,582	42%	12%
Nordic	HVAC	DK2-SE4	DK2 > SE4	1,537	1,525	-0.8%	2,614	CGM NA	CGM NA	CGM NA
Nordic	HVAC	DK2-SE4	SE4-DK2	1,174	1,208	2.9%	2,614	CGM NA	CGM NA	CGM NA
Norwegian borders	HVDC	DK_W-NO-2	DK_W > NO-2	1,407	1,475	4.8%	1,550	1,550	100%	95%
Norwegian borders	HVDC	DK_W-NO-2	NO-2 > DK_W	1,333	1,397	4.8%	1,550	1,550	100%	90%
Nordic	HVDC	DK1-SE3	DK1 > SE3	536	641	19.7%	710	710	100%	90%
Nordic	HVDC	DK1-SE3	SE3 > DK1	528	564	6.8%	710	710	100%	79%
Nordic	HVAC	SE1-FI	FI > SE-1	1,070	1,058	-1.1%	2,375	CGM NA	CGM NA	CGM NA
Nordic	HVAC	SE1-FI	SE-1 > FI	1,411	1,424	0.9%	2,375	CGM NA	CGM NA	CGM NA
Nordic	HVDC	SE3-FI	FI > SE-3	1,166	1,183	1.4%	1,200	1,200	100%	99%
Nordic	HVDC	SE3-FI	SE-3 > FI	1,143	1,184	3.6%	1,200	1,200	100%	99%
Norwegian borders	HVDC	NL-NO-2	NL > NO-2	691	702	1.6%	700	700	100%	100%
Norwegian borders	HVDC	NL-NO-2	NO-2 > NL	667	630	-5.5%	700	700	100%	90%
Norwegian borders	HVAC	NO-1-SE-3	NO-1 > SE-3	1,856	1,446	-22.1%	2,628	CGM NA	CGM NA	CGM NA
Norwegian borders	HVAC	NO-1-SE-3	SE-3 > NO-1	1,844	1,809	-1.9%	2,628	CGM NA	CGM NA	CGM NA
Norwegian borders	HVAC	NO-3-SE-2	NO-3 > SE-2	591	587	-0.6%	798	CGM NA	CGM NA	CGM NA
Norwegian borders	HVAC	NO-3-SE-2	SE-2 > NO-3	722	735	1.9%	798	CGM NA	CGM NA	CGM NA
Norwegian borders	HVAC	NO-4-SE-1	NO-4 > SE-1	387	396	2.3%	1,023	CGM NA	CGM NA	CGM NA
Norwegian borders	HVAC	NO-4-SE-1	SE-1 > NO-4	373	306	-18.2%	1,023	CGM NA	CGM NA	CGM NA
Norwegian borders	HVAC	NO-4-SE-2	NO-4 > SE-2	118	87	-26.5%	238	CGM NA	CGM NA	CGM NA
Norwegian borders	HVAC	NO-4-SE-2	SE-2 > NO-4	145	133	-8.8%	238	CGM NA	CGM NA	CGM NA
Hansa	HVDC	SE4-PL	PL > SE-4	78	99	26.0%	600	600	100%	16%
Hansa	HVDC	SE4-PL	SE-4 > PL	387	367	-5.0%	600	600	100%	61%
SEE	HVAC	GR-BG	BG > GR	531	496	-6.7%	1,082	672	62%	74%
SEE	HVAC	GR-BG	GR > BG	380	374	-1.5%	1,082	672	62%	56%
SEE	HVAC	BG-RO	BG > RO	265	281	6.2%	4,156	2,443	59%	12%

New CC region	AC_DC	New CC border label	Direction	NTC 2015 (MW)	NTC 2016 (MW)	Change of NTC 2016 vs. 2015	TC [MW]	Benchmark capacity (MW)	Ratio benchmark/ TC	Ratio NTC/ benchmark
SEE	HVAC	BG-RO	RO > BG	178	250	40.1%	4,156	2,443	59%	10%
Core (excl. CWE)	HVAC	HR-HU	HR > HU	1,000	1,000	0.0%	5,159	2,503	49%	40%
Core (excl. CWE)	HVAC	HR-HU	HU > HR	1,200	1,164	-3.0%	5,159	2,503	49%	46%
Core (excl. CWE)	HVAC	RO-HU	HU > RO	610	612	0.4%	2,160	1,102	51%	55%
Core (excl. CWE)	HVAC	RO-HU	RO > HU	639	581	-9.1%	2,160	1,102	51%	53%
SWE	HVAC	FR-ES	ES > FR	1,132	1,941	71.5%	6,435	2,997	47%	65%
SWE	HVAC	FR-ES	FR > ES	1,314	2,426	84.7%	6,435	2,997	47%	81%
SWE	HVAC	ES-PT	ES > PT	2,147	1,932	-10.0%	9,614	5,179	54%	37%
SWE	HVAC	ES-PT	PT > ES	2,781	2,382	-14.3%	9,614	5,179	54%	46%
Core (excl. CWE)	HVAC	DE-AT	DE > AT		NAP		10,938	2,519	23%	NAP
Core (excl. CWE)	HVAC	DE-AT	AT > DE		NAP		10,938	2,519	23%	NAP

Source: Data provided by NRAs through the EW template (2017), ENTSO-E, Nordpool Spot and ACER calculations.

Note: The following borders are excluded from the analysis for the following reasons: the DE_TENNET-SE-4 border because this is a merchant line not included in the CCRs and the four Core (CWE) borders because FB CC is applied in the Core (CWE) region. Moreover, no benchmark capacity was calculated for the Nordic, Norwegian and Baltic borders (marked in the table as “CGM NA”) because they were not part of the CGM provided to the Agency. The values for the thermal capacity of interconnectors were taken from ENTSO-E YS&AR, and – where updated information was available via the ‘EW template’ or via the available CGMs – from NRAs or from TSOs, respectively. To improve comparability with NTC values, the technical profiles setting simultaneous limits to commercial capacity on some borders of the former CEE region were translated into maximum bilateral exchanges (i.e. DE->PL, PL->DE, DE->CZ, CZ->DE, PL->CZ, CZ->PL, PL->SK, SK->PL) based on the actual price differentials and ensuring that all constraints are taken into account simultaneously. On the German-Austrian border, no capacity allocation procedure was in place in 2016. However, following the Agency’s Decision No 06/2016 (November 2016), the Austrian and German NRAs reached to set this capacity to at least 4,900 MW (reserved for long-term capacity allocation) starting from October 2018. This value is about twice the benchmark value calculated by the Agency.

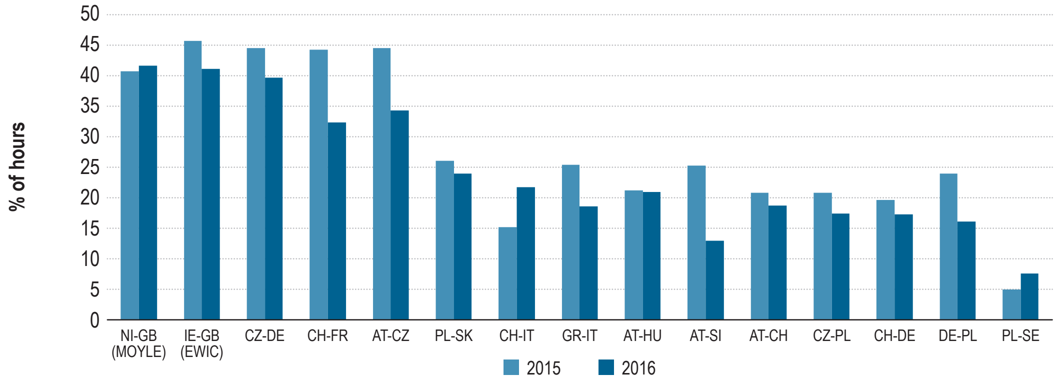
Table 8: Assessment of the impact of CNEs on cross-zonal exchanges in the Core (CWE) region, per TSO and CNE – 2016 (number of hours, %)

Type of line	TSO	Number of occurences (hours)	Average RAM/Fmax (%)
Internal	DE-Amprion	3,232	10%
	DE-TenneT	212	5%
	DE-TransnetBW	114	9%
	FR	38	10%
	BE	928	30%
	NL	386	16%
Cross-border	DE-Amprion	862	45%
	DE-TenneT	810	30%
	FR	9	12%
	BE	139	47%
	NL	79	52%

Source: Data provided by the Core (CWE) region TSOs to ENTSO-E (2017) and ACER calculations.

Note: i) The percentages of capacity made available for cross-zonal exchanges for each transmission system in 2016 are an average of the percentages associated with each CNE in the system, weighted against the shadow price associated with the CNE. ii) The RAMs used to calculate the percentages shown in this table correspond to the capacity available for cross-zonal trade in the DA timeframe, after discounting the effect of long-term nominations. iii) The sum of all congestions shown in this table and the congestions associated to allocation constraints (not shown in this figure) exceeds the number of hours with congestion in the region in 2016, as the congestion during a given hour can occasionally be related to two or more CNEs.

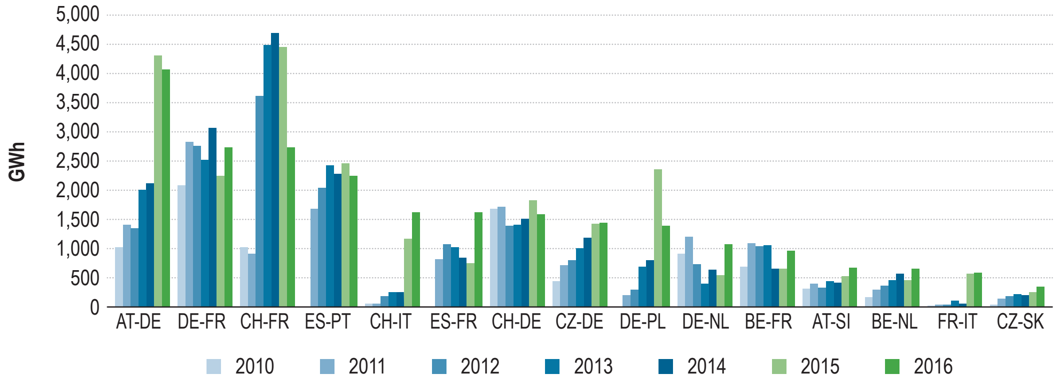
Figure 30: Percentage of hours with net DA nominations against price differentials per border (ranked) – 2015–2016 (%)



Source: ENTSO-E, NRAs, Vulcanus (2017) and ACER calculations.

Note: Only borders with 'wrong-way flows' during more than 2% of the hours of 2016 are shown in this figure. 'Wrong-way flows' are not present on borders which are already coupled (those coupled before 2016 are not shown in the figure), with the exception of the Polish-Swedish border. The borders between Poland and Sweden record a small percentage of 'wrong-way flows' when they are calculated on the basis of the most liquid DA price reference in the Polish market.

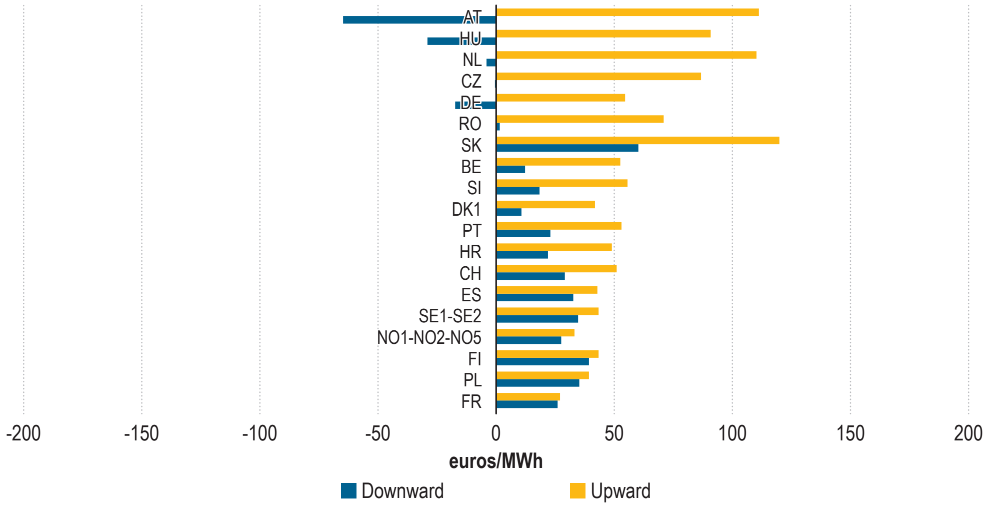
Figure 31: Level of ID cross-zonal trade (absolute sum of net ID nominations for a selection of EU borders) – 2010–2016 (GWh)



Source: ENTSO-E, NRAs, Vulcanus (2017) and ACER calculations.

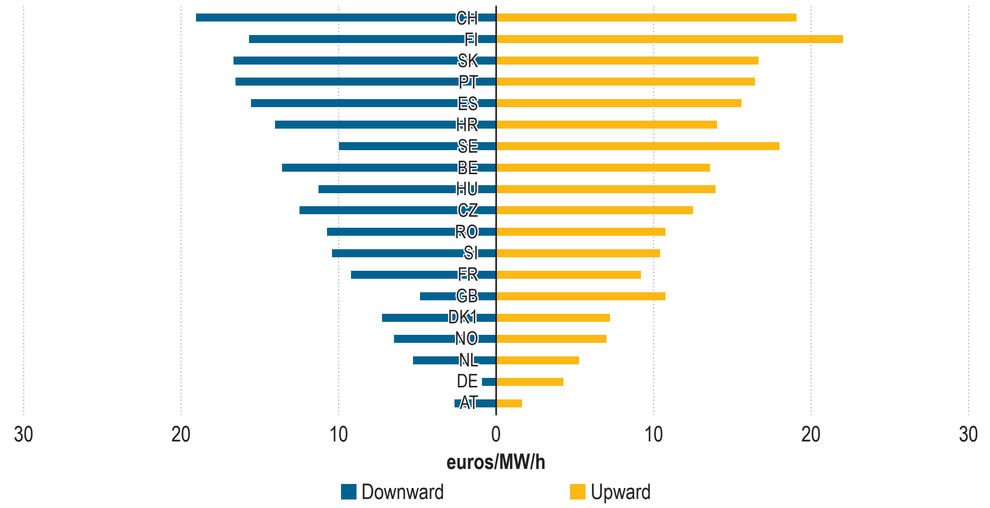
Note: The reported values are the absolute sum of the net hourly ID cross-zonal schedules. As there could be trades in both directions for a specific market time unit, the reported values may be a slight underestimate of the total cross-zonal traded volumes in the ID timeframe. Furthermore, the figure shows only borders with aggregated net ID nominations above 200 GWh in 2016. The volumes of ID cross-zonal trade that are shown in the figure also include cross-zonal schedules resulting from the application of remedial actions such as cross-zonal redispatching (e.g. this explains the level on the German-Polish border in 2015 and 2016).

Figure 32: Weighted average prices of balancing energy activated from aFRRs (upward and downward activation) in a selection of EU markets – 2016 (euros/MWh)



Source: Data provided by NRAs through the EW template (2017).

Figure 33: Average prices of balancing capacity (upward and downward capacity from aFRRs) in a selection of EU markets – 2016 (euros/MW/h)



Source: Data provided by NRAs through the EW template (2017).

Annex 2: Methodology for calculating the benchmark capacity for CNTC and FB CC methods

The Agency intends to monitor the gap between the level of cross-zonal capacity that is currently made available to the market and the capacity (hereinafter benchmark capacity) that could be made available if the recent Agency's Recommendation on Capacity Calculation Methodologies[144] is followed with no (or very limited) deviations. This annex describes the assumptions and process applied to calculate the benchmark capacity both for CNTC and FB CC methods. It is therefore assumed that the CC methodologies envisaged in the CACM Regulation are applied.

The Agency's Recommendation assumes that the delimitation of bidding zones addresses all structural physical congestion and that the remaining congestion within bidding zones is addressed via remedial actions. Hence, the benchmark capacity can be calculated assuming that i) cross-zonal capacity is only limited by cross-zonal network elements and that ii) the full capacity of these network elements is fully available for cross-zonal exchanges. This is without prejudice to the possibility of applying the deviations to the Agency's Recommendation by which internal congestion and LFs could be taken into account in cross-zonal CC, if this can be proved to be needed to ensure operational security and socio-economic efficiency at the EU level and can be done in non-discriminatory manner.

In order for the benchmark capacity to be a realistic target, the following basic assumptions are adopted:

a) It is assumed that the thermal capacity of all individual cross-zonal network elements is reduced by 15% to cope with uncertainty (RM) and with a residual amount of UFs that would remain in any "close-to-ideal" configuration of bidding zones

b) The methodology for calculating benchmark capacity respects the N-1 security criterion.

These two assumptions take into consideration only the thermal limits of network elements; however, other operational security limits (e.g. voltage stability, dynamic stability), which under some circumstances[145] may additionally decrease the level of cross-zonal capacity, are not considered.

1. Benchmark capacity in the context of calculating the CNTC

The methodology for calculating benchmark capacity in a CNTC context must allow a comparison between the currently available capacity (actual NTC value) and the benchmark CNTC values on a border-per-border basis. The benchmark should correspond to a maximum CNTC capacity. Furthermore, it entails that the values of benchmark capacity on different borders must be simultaneously feasible[146].

This requirement is difficult to achieve in highly meshed networks as in the CNTC method the physical flows on network elements are fundamentally defined by a set of net positions of bidding zones, whereas CNTC values are only an indirect attempt to limit the net positions via limitations of exchanges on individual borders. In the case of small bidding zones in highly meshed networks, calculating a set of CNTCs that are simultaneously feasible is particularly difficult. The proposed methodology provides a certain degree of simultaneity but it does not guarantee full efficiency (which would not be not be efficient) as further explained below.

1.1 The problem of the interdependency of CNTC values in meshed networks

In meshed networks, CNTC values are interdependent. The capacity allocated on one border will create physical flows on the other borders. CC on one border must take account of the part of the physical capacity on that border that will be 'consumed' by cross-zonal capacity on other borders, i.e. the share of the physical capacity on that border necessary to provide commercial cross-zonal capacity on other borders.

144 See footnote 30.

145 The frequency of these occurrences may differ largely per border and should be justified by the respective TSOs on an ad-hoc basis.

146 By contrast, in FBCC methods, the equivalent values (maximum bilateral exchanges) are not simultaneously feasible.

To that end, TSOs split the physical capacities of network elements into quantities reserved for each border. This split is based on a number of assumptions, more or less arbitrary, that this methodology does not intend to reproduce.

Instead, in order to ensure the simultaneity of CNTC values, the Agency proposes the following assumption: the CNTC value on a specific border is equal to the maximum physical flow that this border can accommodate[147]. This assumption provides certain degree of simultaneity of CNTC values, but it does not guarantee full simultaneity. Achieving full simultaneity would mean that if a certain critical network element is, for example, significantly impacted by five bidding zone borders, it would not become overloaded in case of maximum exchanges on these borders (i.e. equal to CNTC values) in the direction with a positive impact (i.e. PTDF) on this critical network element. Because the likelihood of such an event (i.e. maximum exchanges on five borders/directions the same time) is very small, striving for full simultaneity in CNTC capacity calculation would not be efficient as it would lead to very low cross-border capacities.

1.2 Proposed steps for calculating CNTC values

The calculation of benchmark capacity takes account of cross-zonal network elements only, as internal elements should not be allowed to reduce possibilities for cross-zonal trade. Hence, the calculation of CNTC values on a specific border essentially translates into calculating the physical flows on the cross-zonal network elements on that border which do not exceed the 85% of the maximum capacity of these interconnectors in contingency[148] (i.e. respecting the N-1 criterion). Furthermore, the benchmark capacity methodology accounts for the uneven distribution of flows on individual interconnectors, which defines the maximum exchange (i.e. the benchmark capacity) at which one interconnector is being congested first while others are not. Then the maximum CNTC corresponds to the sum of the calculated physical flows on all cross-zonal network elements when the first of these cross-zonal network elements reaches congestion.

Based on these principles, the benchmark CNTC capacity is calculated using the following process:

a) **Define the contingency list for cross-zonal network elements on a border.** The starting point is to identify those network elements that – in the case of contingency – have the most significant impact on the increase of physical flows on the cross-zonal network elements. This results in a list of CNECO (CNE, critical outage) pairs. In these pairs, CNEs consist of cross-zonal network elements on the border in question. Associated critical outages consist of any other network element which in the event of contingency is found to significantly impact flows on CNEs. Additionally, CNEs without contingency should be added to the list. Finally, when completing the list, the following should be considered:
   - in non-meshed networks (e.g. on the Spain to France or Germany to West Denmark borders), the list may include cross-zonal network elements on the border in question. This is because the increase of physical flow in case of an interconnector outage cannot be accommodated within the remaining 15% of the physical capacity of the interconnectors on other borders. Therefore it has to be accommodated by the interconnectors on the given border; and
   - in meshed networks, the contingency of cross-zonal network elements is not considered. It is assumed that the flow increase due to such contingency can be accommodated within the 15%[149] of physical capacity of other interconnectors in the region.

147 Explanation/justification: TSOs calculate a set of CNTC values for each border in a specific CCR (original CNTC values) and apply rules – determined to some extent on an arbitrary basis – in order to split the capacities among borders to address the interdependency problem. These CNTC values are then allocated via the market coupling algorithm that provides a market outcome, i.e. a set of net positions (per bidding zone) and a set of flows on the borders of the regions. The actual physical flows are not necessarily equal to the commercial flows on the borders.
If – instead of the original CNTC values – alternative CNTC values equal to the set of flows created by the original CNTC values were provided to the market coupling algorithm, the market outcome and the resulting flows on the border would not change. This is explained by the fact that the trading possibilities (sum of CNTC values) of a given bidding zone would remain unaffected, although the distribution of capacities across the borders of that bidding zone within the region would be different. This means that instead of arbitrary CNTC values, the assumption described above creates alternative CNTC values with a more justified criterion (i.e. to align the commercial and the physical reality).

148 Contingency means the identified and possible or already occurred fault of an element, including not only the transmission system elements, but also significant grid users and distribution network elements if relevant for the transmission system operational security.

149 I.e. within the 15% margin foreseen to cope with uncertainty and residual UFs. This assumption might slightly underestimate the impact of the N-1 criterion on certain borders where the outage of one interconnector line could not be accommodated within the 15% margin defined above.

b) **Define PTDFs:** This requires a calculation of the PTDF values for the elements in the CNECO list corresponding to an exchange on the border.

c) **Define maximum exchange:** This is the exchange (Mex) on the border which creates a physical flow equal to 85% of the thermal capacity (Fmax) for one (the first to reach this limit) CNECO. This is calculated as :

$$Mex = min(85\%*Fmax/PTDF_{CNECO}).$$

d) **Calculate CNTC values:** this is the sum of physical flows that the maximum exchange (Mex) causes on the cross-zonal network elements without contingency.

This is calculated as the sum CNTCi = Sum(MeX*$PTDF_{CNE}$)j, where j refers to the individual lines on a border i.

As a final result, the calculated CNTC value ensures that:

a) None of the flows on cross-zonal network elements exceeds 85% Fmax in the event of contingency; and
b) NTC values on different borders in a given CCR are simultaneous.

2. Benchmark capacity in the context of flow-based capacity calculation

The initial assumption for calculating benchmark capacity in a FB context is that the actual FB parameters provide the best framework for calculating the theoretical maximum capacity. These include the PTDFs and the technical characteristics of CNEs. In particular, these characteristics include information on the maximum possible flow in CNEs (Fmax).

In FB, there is no single value limiting bilateral cross-zonal exchanges. There is a set of constraints defining a domain of possible net positions compatible with the physical limits of the network. Therefore, the calculation of benchmark capacity is equivalent to building a new theoretical domain whereby:

a) Only cross-zonal network elements are considered as CNEs, whereas internal CNEs and allocation constraints are not considered; and
b) All the physical capacity in CNEs is offered to the market.

This process is consistent with the calculation of benchmark capacity under CNTC. Both the issues of contingency and uncertainty are treated as follows:

a) Contingency (N-1 criterion) is accounted for, as PTDFs in CNECOs do already account for this aspect; and
b) Reliability and residual UFs can be treated in the same way as in CNTC, i.e. by considering a RM (e.g. 15% of Fmax) which is deducted from the Fmax when setting the remaining available capacity (RAM).

For FB CC, the size of the FB domain (i.e. its 'volume') based on the assumptions listed above, can be considered as the benchmark capacity, since this volume represents all the simultaneous possibilities of cross-zonal exchanges within a region. Then, the volume of this benchmark FB domain can be compared to the volume of the actual FB domain.

Annex 3: Adapted scoring methodology for the level of fulfilment of capacity calculation requirements

Based on the data collected by the Agency from NRAs, three dimensions have been assessed for scoring the fulfilment level of CC requirements: CC timeframes, CC resolution for DA/ID and CC coordination level[150].

For each of the 4 timeframes (year, month, DA, ID), an initial score was attributed to a border, depending on the actual CC method applied (Questions # 1 and # 4) on this border as follows:

Table 9: Scoring used for the applied CC method

Method of applied capacity calculation	Basic Score
None	0
Pure bilateral NTC (BIL)	1
Partially coordinated NTC (PC)	2
Fully coordinated NTC (FC)	3
Flow-based (FB)	4

Three additional questions had to be answered by NRAs for each timeframe and border. These were:

- Question # 2 on the use of a common grid model,
- Question # 3 on which specific CC parameters are (re)assessed in the different timeframes; and
- Question # 5 on the specific (further) TSOs/borders with which the CC is coordinated.

The analysis of the answers to questions 2 and 3 were used to cross-check and adapt the (basic) scoring for the CC method. The answers to question 5 could only partially be used to cross-check the consistency of the answers to the question on the “level of coordination”, as they were not provided for all borders. Therefore, an initially planned potential (downward) adjustment of the scoring (where inconsistent answers were provided) was not applied (i.e. answers to question 5 were not scored).

The full basic score for the CC coordination level could now be attained only if the use of a common grid model for CC was indicated for both sides of a border in the responses to question #2 (otherwise, the basic scores were ‘downgraded’ by 0.5), as outlined in Table 10.

Table 10: Adapted scoring for the applied CC method

Method[151] of applied CC	Basic Score	Adjusted basic score depending on the use of a common grid model
None	0	None
(Pure bilateral NTC)	0.5	no ‘bilateral’ common grid model used
Pure bilateral NTC	1	‘bilateral’ common grid model is used
(Partially coordinated NTC)	1.5	no common grid model used among those ≥3
Partially coordinated NTC	2	a common grid model used among the ≥3
(Fully coordinated NTC)	2.5	no common grid model is used
Fully coordinated NTC	3	a common grid model is used
FB	4	FB applied and a common grid model is used

150 Descriptions of CC methods applied (coordination level):
Pure bilateral NTC calculation (BIL) – CC on a given border is completely independent of CC on any other border. Each TSO on a border calculates the NTC value for this border based only on its own CC inputs, and subsequently the lower of the two values is offered for capacity allocation;
Partially coordinated NTC calculation (PC) – CC on this border is coordinated with at least one, but not all the borders that are significantly affected by exchanges on this border. All TSOs on these borders perform CC in a coordinated way using their CC inputs. When capacity on two borders is coordinated individually by one TSO, but other TSOs are not involved, this should be considered as pure bilateral coordination.
Fully coordinated NTC calculation (FC) – The calculation of NTCs values is performed together on all borders significantly affected by exchanges on this border by the relevant TSOs, by including the conditions of all significantly affected networks in the calculation process.
FBCC – See definition in Section 3.1.

151 The definitions of coordination level of CC (asked in question 4 of the EW template) are somewhat more detailed for the 2016 EW template compared to 2015.

In order to reflect whether the relevant CC parameters (a) – (e) addressed in question 3[152] "are explicitly (re)assessed and used as an input for CC for the specific timeframe", an adjustment multiplier for each timeframe was introduced, as shown in Table 11.

Table 11: Multiplier for parameters (re)assessed/used in the CC method applied per timeframe

Timeframe	Multi-plier	Conditions
Year-ahead, month-ahead, DA, intra-day	0.5	No parameter is assessed/used
Year-ahead, month-ahead	1	At least parameters (a), (b), (d) are assessed/used
Year-ahead, month-ahead	0.9	At least two of param. (a), (b), (d) are assessed/used
Year-ahead, month-ahead	0.8	At least one of param. (a), (b), (d) are assessed/used
DA, intra-day	1	All parameters (a) – (e) are assessed/used
DA, intra-day	0.9	Only 4 out of 5 parameters are assessed/used
DA, intra-day	0.8	Only 3 out of 5 parameters are assessed/used
DA, intra-day	0.7	Only 2 out of 5 parameters are assessed/used
DA, intra-day	0.6	Only 1 out of 5 parameters are assessed/used

For each timeframe, the basic score attained for the applied CC method (cf. Table 9) was multiplied with the respective multiplier derived from Table 11.

Under specific circumstances, the following additional rules and adjustments were applied:

- In the event of divergent NRA replies to the questions on the same border, the lower (i.e. less favourable/CACM Regulation compliant) scoring (or multiplier) was used for this border[153].

- If capacity (re)calculation at the DA or ID level was not made with an hourly resolution (i.e. the same NTC value[154] valid for 24 hours), the scores for the DA and intra-day timeframes were reduced by 0.5 (each). In the case of HVDC interconnections and borders where FB CC is already applied, a calculation resolution of 24 hours was assumed a priori.

All (adjusted) scores for the timeframes were then aggregated for each border and the ratio of the total score over the maximum possible score (12 for NTC or 14[155] for the FB method[156]) was calculated per border (see results in Table 2).

The scores of all borders within a region were aggregated and then divided by the maximum possible score per region. The regional 'performances' of CC requirements are illustrated in Figure 12.

152 Question 3: "Which of the following parameters are explicitly (re)assessed and used as an input for capacity calculation for the specific timeframe? Possible answers: a) RM, b) operational security limits (mostly CNEs) and contingencies (i.e. outages) relevant to capacity calculation, c) allocation constraints (e.g. import/export limits, losses, etc.), d) GSKs; (e) remedial actions.

153 Exceptions applied to 3 borders (AT-CH, UK-IE, NO-FI), where no data was provided for one of the two sides of a border. In these cases, the information provided (only) on the other side of the border was used for the assessment.

154 The (non-)application of an hourly resolution is assessed per border direction by analysing the average daily variation of hourly D-1 NTC values in 2016. An hourly resolution was assumed if the number of changes of hourly NTC values exceeded 2.5 on average per day. As the – possibly slightly updated – ID NTC values are not available to the Agency, the result for the D-1 NTC analysis is also taken for the ID evaluation of the (non-)existence of an hourly resolution.

155 The maximum (benchmark) score per border was calculated from Table 1 as follows: for fully coordinated NTC: 4 timeframes x 3 = 12 points (if capacity was (re)calculated DA or ID with an hourly resolution), and for FB CC: 2 timeframes (Y&M) x 3 + 2 timeframes (D&ID) x 4 = 14 points (The implementation of FB is not obligatory for the year-ahead and month-ahead timeframes, therefore, the maximum score was reduced to 14 (instead of 16, as applied in the MMR 2015). FB CC is envisaged for meshed networks. Therefore, the 'benchmark' score of 14 was attributed to 25 borders in Europe (the same as in the MMR 2015).

156 The CACM Regulation requires the implementation of FB CC on all bidding zone borders, whereas CNTC may be applied in the F-UK-I, Nordic and Baltic regions, within Italy, the SWE region, as well as on all direct current (DC) interconnectors. Although the CACM Regulation was adopted only recently and not all its provisions have entered into application, similar requirements are already applicable based on Regulation (EC) No 714/2009 and Commission Regulation (EU) 543/2013. They require fully coordinated CC (either FB or CNTC) in all timeframes (yearly, monthly, daily and ID).

Annex 4: Unscheduled flows

As shown in previous editions of the MMRs[157], UFs present a challenge to the further integration of the IEM. Their persistence reduces tradable cross-zonal capacity, market efficiency and network security.

The definitions of the flows used in this Annex are provided in the MMR 2014. Briefly, UFs are comprised of UAFs, most of which stem from an insufficient coordination in CC and allocation process and LFs, which originate from electricity exchanges inside other bidding zones.

The data on the 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[158], although several improvements compared to previous years were introduced[159]. Because of the simplifications used, the obtained AFs data can be considered only as a proxy for the total amount of AFs (and indirectly LFs and UAFs) observed on each border.

The Agency has been monitoring the evolution of UFs in Europe (i.e. on the borders in the former CEE, CSE and CWE regions[160]) since 2012. They have increased from 129.6 TWh in 2012 to 155.5 TWh in 2015, a 20% increase. In 2016, they decreased to 134.2 TWh, a 13.7% decrease compared to 2015, but still 3.6% higher than in 2012.

The main factor contributing to this decrease in 2016 appears to have been the reduction in commercial exchanges between Germany and Austria by 11.2% from 2015 to 2016, which were identified by the Agency as one important cause of UFs on borders of the Core (CEE) region[161]. In addition the specific decrease on the German-Polish border may be the consequence of the reduction in physical capacity (and consequently physical flows) between Germany and Poland due to a temporary disconnection of the Vierraden-Krajnik interconnector.

Figure 34[162] shows the evolution of the aggregated sum of UFs volumes in the former three regions in 2014 and 2016[163]. The highest decrease can be observed in the Core (CWE) region, where volumes decreased by 25.9% or 11.5 TWh in 2016. These volumes are the lowest since 2012, with an overall decrease of 22.5% or 9.6 TWh over the period. A similar conclusion can be drawn for the former CEE, with a decrease of 13.6% or 10.2 TWh in 2016. However, the level of UFs remained 28%% or 14 TWh higher in this region than in 2012. The level of UFs in the CSE region remained stable, with a slight increase of 1.2% or 0.42 TWh in 2016.

157 See Chapter 5, in particular Section 5.1, of the Electricity Wholesale Markets volume of MMR 2015.

158 For more details on the assumptions used, see footnote 44 of the Electricity Wholesale Markets volume of the MMR 2015.

159 For example, six different sets of PTDFs based on the GCMs of six representative days in 2016 were used in this MMR edition, as opposed to three in previous ones. This could be further improved, e.g. by using one GCM per market time unit.

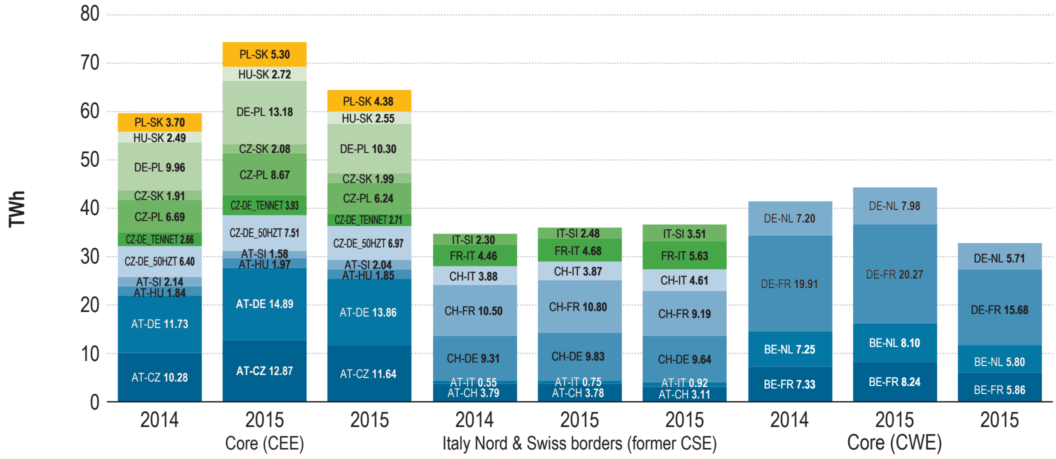
160 Following the Agency's Decision on the TSOs' Proposal for determining Capacity Calculation Regions (see footnote 36), the German-Austrian border should be allocated to the new Core region. As the former CWE and CEE regions are identified throughout this document as the Core (CWE) region and respectively the Core (CEE) region, for consistency with previous MMR editions, this border was included in the Core (CEE) region. The former CSE region comprises the new 'Italy North' and the Swiss borders as identified in this Annex.

161 See page 12 of the Agency's Decision on the TSOs' Proposal for determining Capacity Calculation Regions (see also footnote 36).

162 The German-Austrian border, included in Figure 34, has not been included in the subsequent analysis in this Chapter, as UFs within the same bidding zone cannot be divided into LFs and UAFs. The border between Italy and Greece is a part of the former CSE region. However, since they are connected through a DC cable, this border is not relevant to the UFs analysis.

163 For a comparison with previous years, see the MMR 2012 (p. 100), MMR 2013 (p. 150), MMR 2014 (p. 165), available at http://nra.acer.europa.eu/en/Electricity/Market%20monitoring/Pages/Reports.aspx and MMR 2015, Electricity Wholesale Markets volume (p. 29).

Figure 34: Absolute aggregate sum of UFs for three regions – 2014–2016 (TWh)



Source: Vulcanus (2017) and ACER calculations.

Note: The calculation methodology used to derive UFs is the same as that used for previous MMRs. 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.

Figure 35 shows the prevailing directions of UFs volumes and their average values. It reveals that the overall pattern still consists of two major loops, from Germany to the Netherland to the west, and to Poland to the east. Moreover, it shows that UF volumes decreased on the German-Polish and the Austrian-German border, by 22.1% and 10.3% in 2016, respectively, compared to 2015.

Figure 35: Average UFs for three regions – 2016 (MW)

Source: Vulcanus (2017) and ACER calculations.

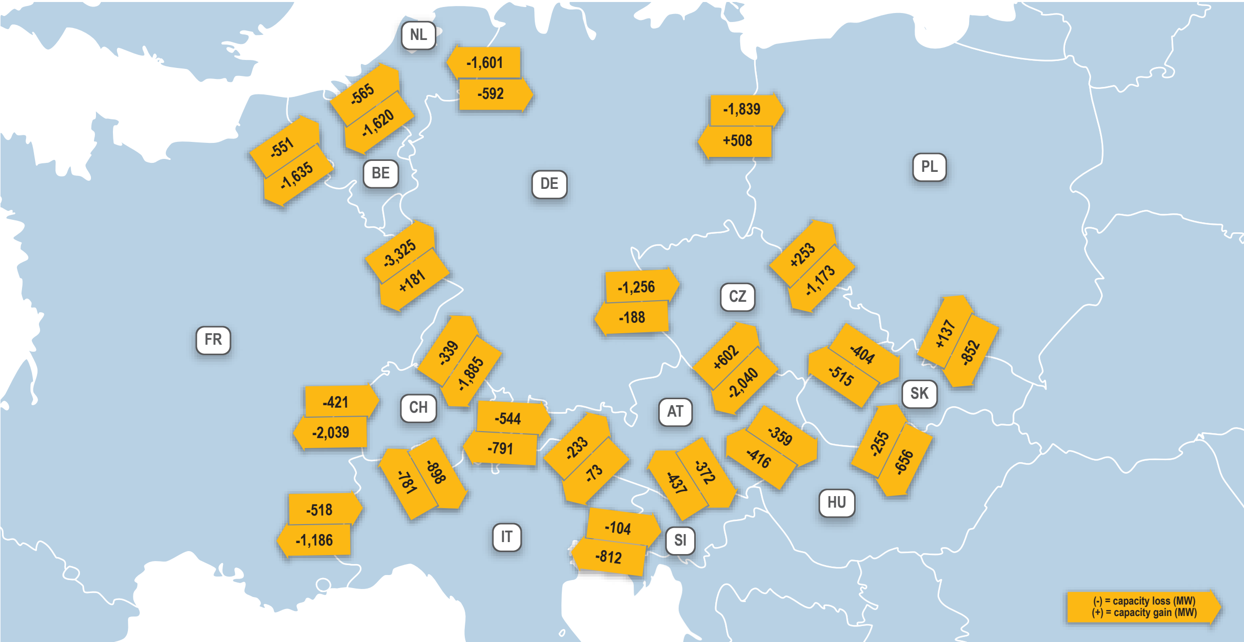
Note: Average UFs are average hourly values in 2016. The direction of the UF is the same as of the physical flow if the physical flow exceeds the cross-border schedule, or if both run in the opposite directions. The direction of the UF is the opposite of the physical flow if the cross-border schedule exceeds the physical flow.

231 The capacity loss associated with UFs has been evaluated following the same methodology as described in the MMR 2015[164]. The results are presented in Figure 36. It shows that in some cases, the capacity losses are significantly higher than the actual UFs presented in Figure 35. This is due to the effect of the capacity loss associated with the uncertainty of UFs forecast.

164 See Figure 48 in the Electricity Wholesale Markets volume of the MMR 2015.

In order to show the magnitude of the impact of UFs in terms of cross-zonal capacity losses or, in some cases, theoretical capacity gains, Figure 36 presents both values separately for all directions. The figure shows that the highest capacity loss is noted on borders with a high level of UFs, in the east on the CZ->AT, DE->PL, DE->CZ and PL->CZ borders, and in the west on the FR->DE, BE->FR, NL->BE, DE->NL and IT->FR borders. High losses were also observed on the CH->FR and DE->CH borders. Theoretical capacity gains were noted on some borders with the highest UFs in the opposite direction, i.e. on the AT->CZ, PL->DE, CZ->PL, DE->FR, and SK->PL borders.

Figure 36: UFs mostly negatively impacting cross-zonal trade – 2016 (average capacity loss/gain in MW)



Source: Vulcanus, ENTSO-E (2017), and ACER calculations.

Note: The results can be interpreted as follows: on the German-Polish border, UFs are having a negative impact on cross-zonal capacity in the direction from Germany to Poland (-1839 MW) and a positive impact in the direction from Poland to Germany (508 MW). The capacity losses/gains can be observed in both directions, because the uncertainty of forecast UFs requires RMs to be taken into account in both directions of the interconnection.

Finally, separating UFs into its LFs and UAFs components shows that the aggregated absolute value of LFs last year increased to 106.5 TWh (87 TWh in 2015), while UAFs decreased to 96.2 TWh (104.6 TWh in 2015). In theory, where FB applies, UAFs should disappear. However, this is not yet seen in the Core (CWE) region for two reasons. First, some exchanges scheduled on the Core (CWE) region borders physically flow through borders outside this region. The opposite is also true, i.e. some exchanges scheduled on borders outside the Core (CWE) region physically flow through the Core (CWE) region borders. Second, the methodology applied to estimate AFs (which are necessary to calculate UAFs) is still being improved[165].

165 This includes the use of a higher number of CGMs, which should ideally be one per market time unit, and an improved methodology for calculating GSKs that are input parameters for estimating UAFs. See also footnote 159.

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