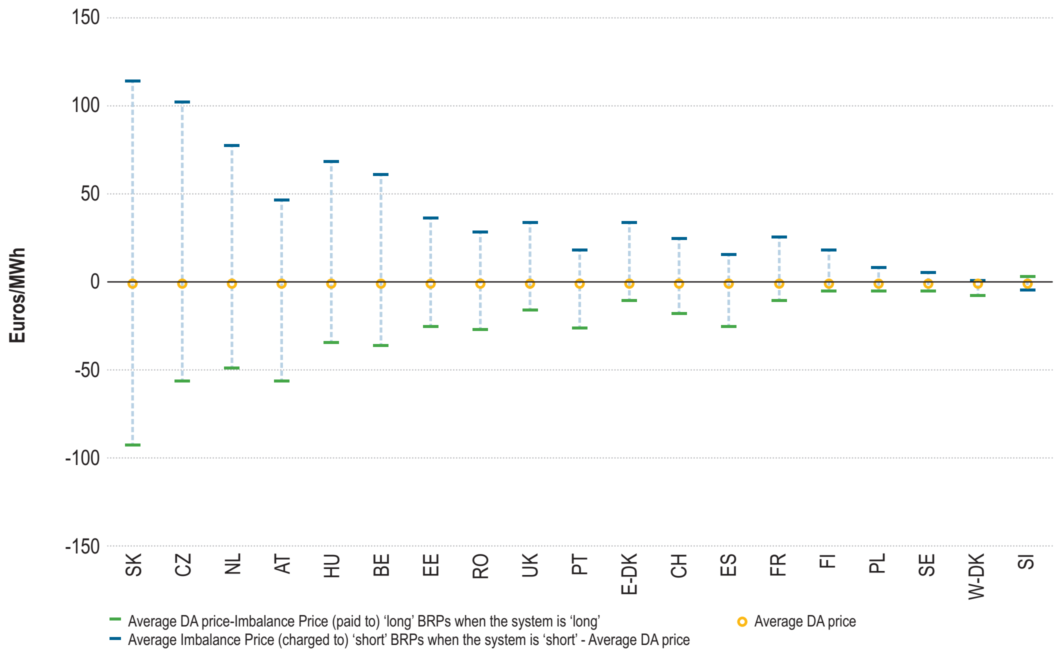
330 Imbalance prices show the effective prices that out-of-balance BRPs pay (or receive) for deviations from their schedules. Currently, existing imbalance settlement mechanisms are far from being harmonised and do not always provide the right incentives to support the system efficiently. For instance, systems with upward imbalance prices – charged to BRPs – that are systematically lower than day-ahead (or intraday) prices can result in inefficiencies, as BRPs may prefer not to balance their portfolio by using the preceding (day-ahead or intraday) markets (where the underlying marginal costs are typically lower than in the balancing timeframe).

331 Figure 57 shows the average imbalance prices paid or received by BRPs across MSs, depending on whether they are short or long of physical energy compared to their declared positions. In order to compare the results across MSs, the following approach was taken. First, the imbalance prices were presented as the absolute deviation from the respective day-ahead prices in order to smooth the effect of different levels of (day-ahead) wholesale prices across MSs. Second, the imbalance prices were calculated for 'short' and 'long' BRPs only for periods when they contribute to the system imbalance[191]. During these periods, the imbalance prices for 'short' and 'long' BRPs tend to reflect, respectively, the price of upward balancing energy and downward balancing energy, irrespective of whether the imbalance settlement system is a one-price or two-price system[192]. Figure 57 shows a significant level of price dispersion between MSs, suggesting important benefits could be achieved by further harmonising and integrating[193] national balancing markets.

Figure 57: Weighted average of imbalance prices when BRPs contribute to system imbalance – selection of MSs – 2013 (euros/MWh)



Source: Data provided by NRAs through the ERI (2014) and ACER calculations

Note: For Sweden, arithmetic averages of its four imbalance price areas are shown.

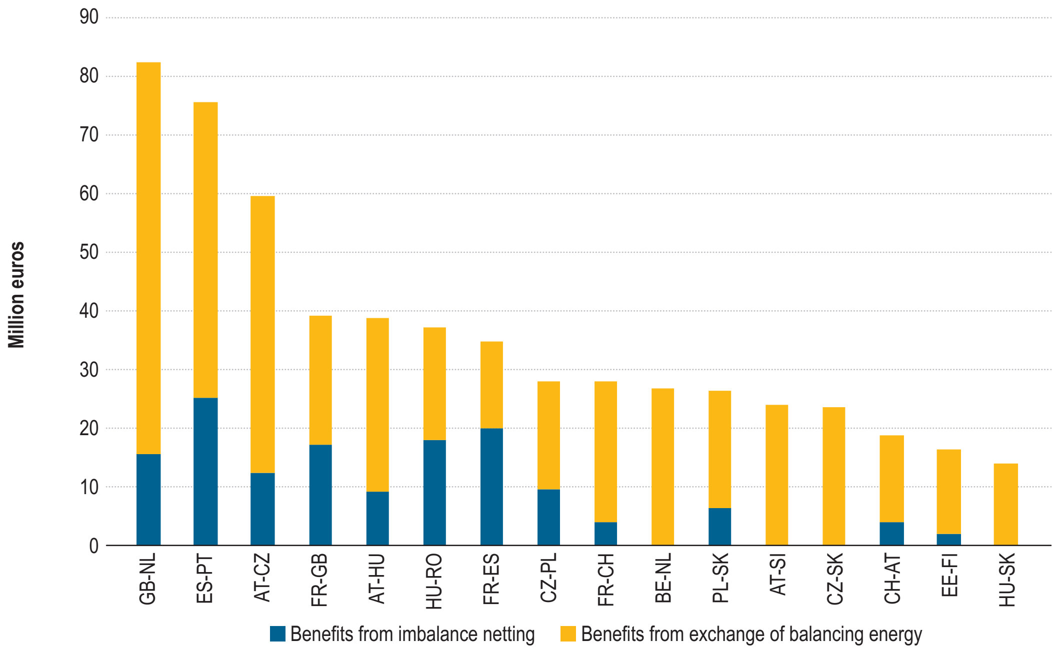
191 This means that the values presented are the imbalance prices for 'short' BRPs when the system is 'short' and similarly for 'long' BRPs when the system is 'long'.

192 Explanations of typical one-price or two-price systems are provided in Annex 11.

193 Subject to sufficient available cross-border capacity.

332 Any analysis of the benefits of integrating balancing markets which is based on imbalance price differentials should take into account the above-mentioned shortcomings (lack of harmonisation and possible inefficiencies). In particular, because lack of harmonisation may alter the results of the calculations of how much balancing energy can be efficiently exchanged. The analyses presented below are based on the divergent imbalance prices across MSs and therefore should be considered as an indication of potential efficiency gains from further harmonising and integrating balancing energy markets. Figure 58[194] shows these potential benefits for a selection of borders, which total more than 500 million euros per year.

Figure 58: Estimate of potential benefits from the integration of balancing energy markets per border – selection of borders – 2013 (million euros)



Source: Data provided by NRAs through the ERI (2014) and ACER calculations.

Note: Imbalance netting over different types of interconnectors may require different technical solutions. Imbalance netting is currently applied over various alternating current (AC) interconnectors in Europe where TSOs simply set the input parameters of load-frequency controllers. Imbalance netting over direct current (DC) interconnectors (e.g. on the borders between France and Great Britain or between the Netherlands and Great Britain) is not currently applied in Europe, and would, in addition, require an active regulation of the energy flow over the DC interconnector. Potential benefits from imbalance netting have been calculated irrespective of the required technical solution. See also the note under Figure 56.

333 In summary, the exchange of balancing services across EU borders is currently very limited. In 2013, only around 1.7% of the balancing reserves and 1.2% of the balancing energy[195] were, on average, shared or exchanged across the analysed EU borders. Imbalance prices charged to ('short' and 'long') BRPs present a significant dispersion across the different EU imbalance price areas, which suggests important potential for harmonising national designs and the further exchange of balancing energy[196]. In 2013, the application of imbalance netting could have avoided the activation of some 20% of the total activated balancing energy across the analysed EU borders. The value of further harmonisation of national designs, imbalance netting and the exchange of balancing energy in Europe is estimated at several hundred million euros per year. All in all, substantial benefits can

194 Details on the methodology used to make the estimates are shown in Annex 11.

195 See: footnote 183.

196 See: footnote 193.

be achieved from the exchange of balancing services, which reinforces the argument that Europe should pursue the further harmonisation and integration of balancing markets.

3.3.2 Long-term use of cross-border capacity

334 The forward electricity market offers market participants hedging opportunities against short-term (e.g. day-ahead) price uncertainties. The varied performance of competition and liquidity across forward markets in Europe determines whether market participants are able to hedge the short-term price risks sufficiently well and at a competitive price. A variety of forwards, futures, options, swaps, contracts for differences, etc. have been developed and are traded on various platforms.

335 In Europe, two forward market designs have emerged. The first design, implemented in the Nordic and Baltic countries and within Italy, relies mainly[197] on the market and a variety of products developed through the various market platforms (forwards, futures, options, swaps, contracts for differences, etc.).This design contains a set of hedging contracts for a group of bidding zones, and these contracts are linked to a hub price, which represents some sort of average day-ahead price within this group of zones (multi-zone hub). These hedging tools, developed and traded in the market, serve for both trade internal to a zone and cross-zonal trade.

336 The second design, implemented in nearly all MSs in continental Europe, also relies on the market, but gives an additional and specific role to TSOs with regard to cross-zonal trade. In this design, TSOs are responsible for calculating long-term capacities and auctioning transmission rights (TRs), enabling market participants to hedge against the specific risk of short-term zonal price differentials. In this design, there is a set of hedging contracts for each bidding zone which are linked to the day-ahead clearing price of this bidding zone (single-zone hub).

337 In a single-zone hub design, the liquidity of hedging products tends to depend, among other things, on the bidding zone's size. While large[198] bidding zones tend to have relatively good liquidity, the liquidity of hedging products in many small bidding zones is not satisfactory[199] and here, the TRs issued by TSOs play an important role. TRs may serve as a so-called bridge between a liquid financial electricity market (Market A) and an adjacent illiquid market (Market B). Market participants (e.g. suppliers holding contracts to deliver energy to customers in Market B) can simultaneously lock the price of electricity in Market A (e.g. by buying a forward energy product in Market A) and the difference between the energy price in Market A and Market B (by buying a TR from Market A to Market B). This effectively creates an alternative way to lock the price of electricity in Market B.

338 In a multi-zone hub design, the liquidity of hedging products linked to a hub price is usually high[200] and the day-ahead price of individual zones can be hedged with contracts that provide the hedge for the difference between the zonal price and the hub price (contracts for differences).

339 In 2011, the Agency defined a target model for the forward timeframe which requires TSOs to issue Financial Transmission Rights (FTR) or Physical Transmission Rights (PTR) with Use-It-Or-Sell-It

197 In the case of Italy, there is also a specific role for the TSO, which auctions FTRs.

198 In terms of production or consumption.

199 See: http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Report%20on%20Bidding%20Zones%202014.pdf.

200 See: footnote 199.

(UIOSI)[201] conditions, unless appropriate cross-border financial hedging is offered in liquid financial markets on both sides of an interconnector[202].

340 Hedging with TRs can have significant benefits for market participants. First, they can be used as an effective hedging tool by market participants, when alternative hedging instruments are not available, as explained above. This can help to increase competition in wholesale markets, which is particularly important in those markets with a dominant incumbent market player. Second, they could contribute to the liquidity of adjacent forward markets. This is the case if TRs are used to bid in neighbouring forward markets, i.e. when market participants act as arbitrage traders buying a forward contract in Market A and a TR from Market A to Market B in order to bid into the forward market of Market B, which would effectively increase the liquidity of the forward market of Market B. Nevertheless, market participants may prefer to use the TRs from Market A to Market B (combined with a forward energy contract in Market A) as an effective tool to hedge their position in Market B, which fragments the liquidity of forward markets. Finally, TRs, as opposed to financial products, are periodically auctioned and also lack well-developed secondary markets, which have not yet emerged. Market participants cannot easily buy them at any moment, like forward products in the financial market, while risk exposure is constantly changing.

341 The impact of TRs on the liquidity of adjacent forward markets may become more evident when the auction prices of TRs are not aligned with the energy price differentials on the relevant borders. What follows is intended to identify borders where energy price differentials are not reflected in the prices of TRs. Two approaches can be taken to assess this consistency. First, the price of TRs can be compared with the forward energy product prices differential that is observed when the cross-border auction was held, and second, they can be compared with the realised day-ahead price spreads.

342 The first approach is particularly useful when TRs are obligations, since the prices of TRs in the form of obligations should reflect (i.e. at least equal[203]) the forward energy price differentials (against which market participants wish to be hedged). However, this is less valid when TRs are options, since the option price represents the average of the expected day-ahead price differentials only when they are positive, i.e. in the economic direction (otherwise, the option is not exercised). Since most of the TRs in continental Europe are options, this approach has not been taken for the analysis.

343 The second benchmark is based on the assumption that the price of TRs in the form of options represent the expected positive day-ahead price differentials[204] and that in the long term they should be equal or higher (positive risk premium) than the realised positive day-ahead price differentials[205]. The analysis presented below assesses in this way a selection of borders for which complete data are available.

201 UIOSI means an automatic application whereby the underlying capacity of the non-nominated PTRs is made available for day-ahead cross-zonal capacity allocation and whereby PTR holders that do not nominate to use their rights receive a pay-out corresponding to any positive market spread.

202 For an full explanation of different types of long-term transmission rights i.e. FTRs, PTRs and Contract for Differences (CfDs). See: https://www.entsoe.eu/fileadmin/user_upload/_library/consultations/Network_Code_CACM/20120619_Educational_Paper_on_Risk_Hedging_Instruments_review5.pdf.

203 They can be higher due to the risk premium that PTR holders are willing to pay.

204 Assuming full firmness of PTRs, which means that if the nominated capacity is not finally made available, the capacity holder is compensated with an amount equal to the price differential across the border.

205 It is a common practice in forward and futures pricing literature to calculate the ex-ante premium in the forward price as the ex-post differential between futures prices and realised delivery date spot prices (See: Shawky, H. A., Marathe, A., and Barrett, C. L. (2003), A first look at the empirical relation between spot and futures electricity prices in the United States, Journal of Futures Markets, 23(10), pages 931–955).

344 Table 3 shows that on most borders, PTR auction prices are on average below the recorded day-ahead price spreads. If this were systematically the case, it would imply that the value of cross-border capacities are retained by the owners of PTRs, instead of being fully transferred to the market (by, for example, allocating all the capacity in the day-ahead timeframe provided day-ahead market coupling is applied). On borders where market coupling is applied, the assessed differences are equal to the profit of a PTR holder, since the latter can decide at any moment to exercise the "Sell-It" option and receive the positive day-ahead price spread. On borders without market coupling, the PTR owner is faced with the uncertainty of nomination[206] and one would also need to estimate the losses incurred due to wrong nominations in order to estimate the true profit from arbitrage. The results show that on borders where market coupling is applied, the spreads are lower, suggesting that market coupling has efficiency benefits in this regard.

345 On the border between Spain and Portugal, where FTRs (obligations) have been implemented, the observed ex-post risk premiums – corresponding to all the products (FTRs) auctioned in the period from June 2009 to December 2013 – was on average positive (0.12 euros/MWh)[207].

346 Financial products such as those used to hedge the price difference between the zonal and the system price in the Nordic markets (contract for differences, CfDs, which were more recently renamed Electricity Price Area Differentials, EPADs) can be analysed in a similar way. Due to the limited data available, this analysis was not done for this MMR. Nevertheless a recent study on the efficiency of contracts for differences in the Nordic electricity market[208] has made use of the same methodology as the one used in this section to calculate the risk premiums for PTRs. The results of the study show that the ex-post risk premiums of contract for differences traded in the Nordic market over the last few years do not present systematic negative values, as is the case with PTRs in Continental Europe.

206 On borders with explicit auctions, a capacity holder who nominates in the wrong direction would make a loss equal to the negative price spread.

207 Comisión Nacional de la Competencia (CNMC), 2014.

208 See: http://tiger-forum.com/Media/speakers/abstract/261405pm/petr_spodniak.pdf.

Table 3: Discrepancies between the auction price of PTRs (monthly auctions) and the day-ahead price spreads for a selection of EU borders and for the indicated periods (euros/MWh)

Border-direction	Day-ahead capacity allocation method	Average-auction price	Average price spread	Ex-post risk premium	Period analysed
GR > IT	Explicit	6.0	17.8	-11.8	2012-2013
CH > IT	Explicit	13.6	19.3	-5.7	2011-2013
AT > IT	Explicit	20.8	25.5	-4.7	2011-2013
AT > HU	Explicit	4.0	8.5	-4.5	2011-2013
FR > IT	Explicit	18.1	22.3	-4.2	2011-2013
IT > GR	Explicit	0.2	4.1	-3.9	2012-2013
AT > SI	Explicit	4.6	8.2	-3.6	2011-2013
DE > PL	Explicit	0.1	2.9	-2.8	2011-2013
SK > HU	Implicit	4.1	6.5	-2.4	2011-2013
PL > SK	Explicit	1.9	4.2	-2.3	2011-2013
DE > CH	Explicit	5.7	7.5	-1.8	2011-2013
PL > DE	Explicit	3.0	4.8	-1.8	2011-2013
AT > CZ	Explicit	0.0	1.8	-1.8	2011-2013
DE > CZ	Explicit	0.1	1.8	-1.7	2011-2013
CZ > DE	Explicit	0.9	2.6	-1.7	2011-2013
AT > CH	Explicit	5.8	7.5	-1.7	2011-2013
PL > CZ	Explicit	2.0	3.7	-1.7	2011-2013
CZ > AT	Explicit	0.9	2.5	-1.6	2011-2013
DE > NL	Implicit	4.0	5.5	-1.5	2009-2013
HU > AT	Explicit	0.4	1.7	-1.3	2011-2013
SI > AT	Explicit	0.1	1.2	-1.1	2011-2013
CH > DE	Explicit	0.0	1.1	-1.0	2011-2013
CH > AT	Explicit	0.0	1.1	-1.0	2011-2013
SI > IT	Implicit	15.2	16.0	-0.8	2011-2013
DK1 > DE	Implicit	3.0	3.8	-0.8	2011-2013
BE > NL	Implicit	2.1	2.9	-0.8	2009-2013
DE > FR	Implicit	3.9	4.5	-0.6	2009-2013
HU > SK	Implicit	0.1	0.6	-0.5	2011-2013
IT > FR	Explicit	0.4	0.8	-0.4	2011-2013
FR > DE	Implicit	1.1	1.5	-0.4	2009-2013
NL > DE	Implicit	0.2	0.4	-0.2	2009-2013
BE > FR	Implicit	1.2	1.4	-0.2	2009-2013
IT > CH	Explicit	0.1	0.2	-0.2	2013
NL > BE	Implicit	1.0	1.1	-0.1	2009-2013
FR > BE	Implicit	1.1	1.2	-0.1	2009-2013
DE > DK1	Implicit	1.1	1.2	-0.1	2011-2013
IT > AT	Explicit	0.1	0.1	0.0	2011-2013
IT > SI	Implicit	0.2	0.1	0.1	2011-2013

Source: CAO, CASC and Platts (2014) and ACER calculations

Note: The analysis has been made for the periods indicated for each border. The average auction price is the average value of all the monthly auctions in the period. The average price spread is the average differences of day-ahead prices for all the hours when the price differential is in the economic direction (otherwise, the value taken is zero, since the analysed PTRs are options, not obligations). For the average price differential, the hours during unavailability periods were excluded, because these periods are ex-ante known by market participants, i.e., before the monthly auction takes place. The ex-post risk premium is the difference between the two previous columns.

347 The observed differences between the marginal price of PTRs and the day-ahead price spreads may be due to several reasons. These reasons include the level of competition in the different auctions, the likelihood of curtailments and firmness regimes[209], the volume of capacity offered by TSOs and the design of secondary markets. The precise influence of all these factors on the discrepancies between the auction price of transmission rights and the actual day-ahead price spreads will be further tracked in the market monitoring process and needs further analysis. This analysis should also contribute to improving the functioning and design of forward markets (including forward capacity allocation) in Europe.

3.3.3 Unscheduled flows and loop flows, re-dispatching and counter-trading

3.3.3.1 Introduction

348 As in previous MMRs, this section presents the development of unscheduled flows. However, it will present loop flows and the related welfare losses based on an alternative methodology compared to the one used for last year's MMR. It is structured as follows. First, it briefly recaps some definitions and the methodology applied to distinguish unscheduled transit flows from loop flows (Section 3.3.3.2). Second, it shows the evolution of unscheduled flows (Section 3.3.3.3) and, respectively, loop and unscheduled transit flows, as well as their likely impact on the volume of cross-border capacities made available to the market (Section 3.3.3.4) between 2011 and 2013. Third, it estimates the foregone welfare losses associated with loop flows and unscheduled transit flows (Section 3.3.3.5) on the basis of a counter-factual social welfare loss analysis. The section ends with conclusions and recommendations (Section 3.3.3.6).

3.3.3.2 Definitions and data

349 This Section applies the same definitions of physical flows as in last year's MMR[210], which were agreed among NRAs. It includes schedules (SCHs), loop flows (LFs) and unscheduled transit flows (UTFs). The sum of LFs and UTFs equals unscheduled flows (UFs) and the sum of SCHs and UTFs equals transit flows (TFs).

350 As opposed to SCHs[211], UTFs are largely the result of insufficiently and inefficient calculations and allocation of cross-zonal capacity by TSOs. In continental Europe, UTFs can be mitigated by unifying capacity calculation with the application of a single flow-based method.

351 LFs originate from electricity exchanges inside bidding zones and are inherent to the EU zonal market design, with its highly meshed and synchronously connected grids. In fact, the effects of LFs on the efficiency of the IEM can be traced back to before market opening and have increased in recent years.

352 LFs are not captured by the cross-border congestion management mechanism, as they do not exactly follow the contractual paths. Instead, they flow to a certain extent through grids operated by neighbouring TSOs which are not directly notified to handle physical flows resulting from commercial transactions outside their control areas. This poses a challenge for TSOs to maintain network security and market efficiency. These flows and their effects can be mitigated by remedial security actions

209 E.g. the premium may not be positive if the capacity holder is not sure of being compensated with the price differential between the concerned zones in the relevant timeframe in the case of curtailment.

210 See: MMR 2012, page 94.

211 SCH is a declared flow resulting from a scheduling process and is subject to an electricity exchange between two different control areas and/or bidding zones.

in the short-term, by reconfiguring bidding zones in the medium term and by reinforcing infrastructure investments in the long term[212].

353 While facilitating cross-border wholesale trade is a key objective of the IEM, the negative impact of UFs is twofold: (i) since the TSOs cannot control UFs with capacity allocation, they may reduce the capacity available for cross-border trade in order to ensure that the total physical flow on the network elements remains within security limits; and (ii) the TSOs have to keep on applying more remedial security actions (bearing higher costs) in order to ensure secure grid operation in their own responsibility areas while transporting 'foreign' electricity flows. The first impact may lead to a loss of social welfare, which corresponds to the foregone added-value with respect to a situation in which these cross-border capacities were available for cross-border trade. This loss of social welfare needs to be assessed by comparing the benefits delivered by the available cross-border capacity with and without the presence of UFs. The second impact relates to network security and the efficiency of the market in general, and may induce re-dispatching, counter-trading and curtailment costs. The high volatility and limited predictability of UFs create a challenge for operational planning. If remedial security actions are not available (e.g. due to insufficient coordination among TSOs or lack of flexible generation), UFs may lead to insecure grid operation.

354 LFs and UTFs can be indirectly calculated on the basis of PTDFs (Power Transfer Distribution Factors)[213]. PTDFs provide information on how much power flows through a given network element (here, for interconnectors only) because of a cross-border exchange between two bidding zones, and are expressed as a percentage. Multiplying the actual cross-border exchange with the PTDF for a given interconnector yields the physical flow on that interconnector resulting from this cross-border exchange. Multiplying all cross-border exchanges with associated PTDFs and summing these products for a given interconnector provides the physical flows that result from all cross-border exchanges on this network element, i.e. flows resulting from capacity allocation, the TFs[214]. Flows not resulting from capacity allocation (the LFs) are then calculated as the difference between PFs and TFs, and the UTFs are the difference between TFs and SCHs.

355 The flows not resulting from capacity allocation were provided to the Agency by ENTSO-E for 2011, 2012 and 2013; they were calculated with hourly resolution and contain some simplifications. First, only four different sets of PTDF factors representing different seasons in a year were used. Second, the resulting flows on each interconnector were aggregated per border[215]. Third, PTDFs were calculated with the proportional Generation Shift Key, instead of following merit orders. The obtained data on flows not resulting from capacity allocation can thus be considered only as a proxy for calculating the total amount of LFs (and indirectly UTFs) on borders.

212 See: ENTSO-E's Technical report on bidding zones: https://www.entsoe.eu/Documents/MC%20documents/140123_Technical_Report_-_Bidding_Zones_Review__Process.pdf.

213 See: footnote 212.

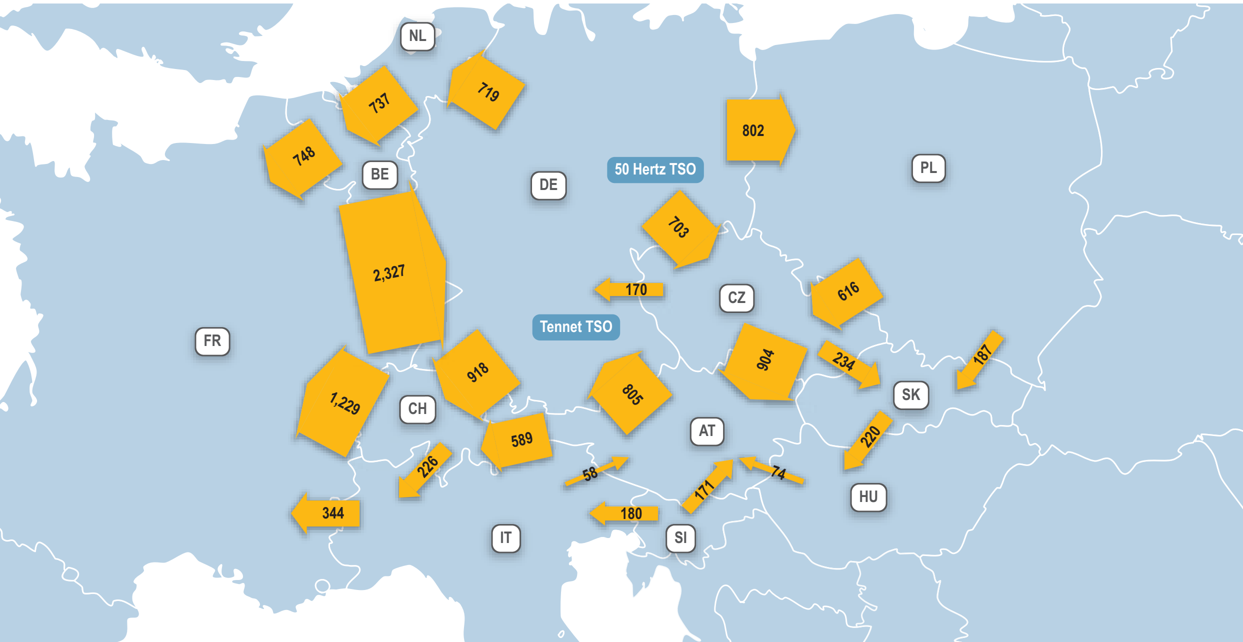
214 Denoted as CFb in ENTSO-E's Technical report on bidding zones review process.

215 If one border contains differently located interconnectors, the aggregated result might not reflect the nature of the flows, e.g. the Czech-German border. If the aggregations are made per bidding zone instead of per border, the situation grows even less clear, e.g. Czech-(DE+AT) bidding zone or Swiss-(DE+AT) bidding zone.

3.3.3.3 Unscheduled flows

356 Figure 59 shows the average UFs in CEE, CSE and CWE regions[216], except Greece[217], in 2013, representing a major part of continental Europe. The level of this indicator on each border is expressed by the width of the arrow[218]. The overall pattern mirrors last year's findings, showing significant UFs exiting north Germany east and west, flowing through Poland, the Czech Republic, the Netherlands, Belgium and France and then entering southern Germany and Austria. In addition, significant UFs can be observed while exiting France to the south of Germany and from the south of Germany to France through Switzerland and Italy.

Figure 59: Average unscheduled flow indicator for three regions – 2013 (MW)



Source: Vulcanus (2014) and ACER calculations

Note: Average UFs are averaged hourly values in 2013.

357 While average UF values provide information about prevailing directions of UFs, Figure 60 shows the evolution of the aggregated sum of UFs in CEE, CWE and CSE regions in 2012 and 2013[219]. The proportion of the UFs between the regions remained unchanged, and the total volume for all three regions decreased by 0.6% from 129.6 TWh in 2012 to 128.8 TWh in 2013. The amount of UFs in the CWE region is generally lower, because the Phase Shifting Transformers on the Dutch and Belgian borders block a significant quantity of physical flows and probably shift them to other borders.

216 In Regulation No. 714/2009 regions are defined in terms of countries; therefore the German-Austrian border could be attributed to the CEE region and CSE region. While on this border no capacity allocation takes place, unscheduled flows can be calculated. These flows have been, for the purpose of this report, assigned to the CEE region. Moreover, within a bidding zone, unscheduled flows cannot be divided into loop flow and unscheduled transit flow and therefore the German-Austrian border has not been included in the subsequent analysis in this chapter.

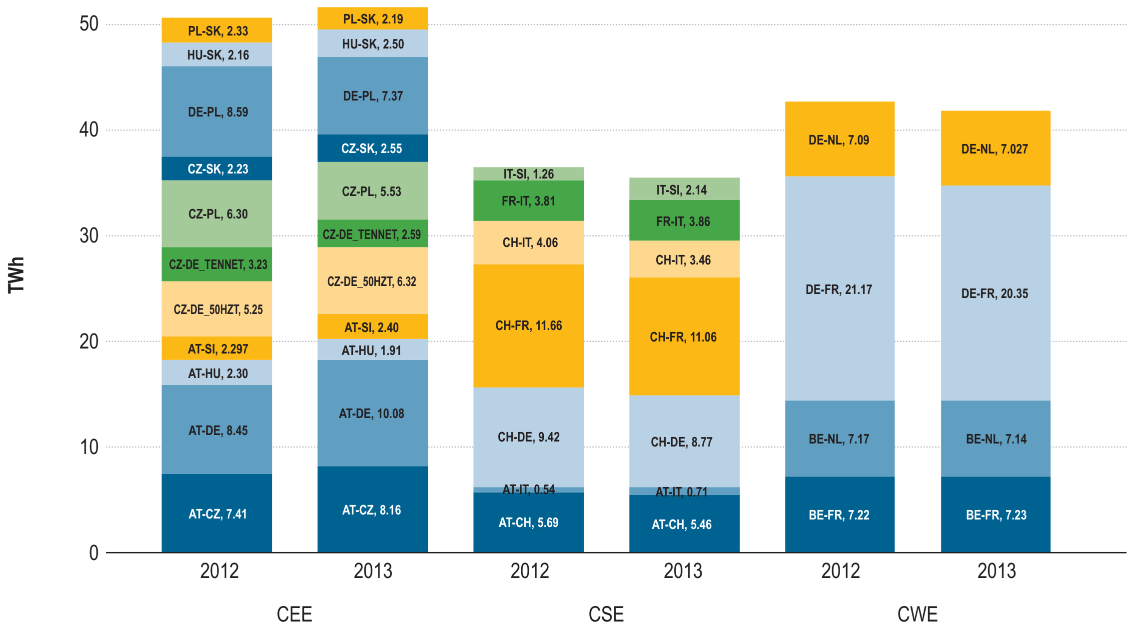
217 Greece is connected to the south of Italy only through a DC cable and therefore is not relevant for further UFs analysis.

218 For a comparison with the previous year, see MMR 2012, page 99.

219 For a comparison with previous years, see the MMR 2012, page 100.

358 Between 2012 and 2013, the level of UFs changed notably on some borders. UFs decreased most on the German-Polish and the German-French borders – in total by 1.2 TWh and 0.8 TWh each, representing 14% and 4% reductions, respectively. On the Austrian-German border, 50 Hertz German-Czech and Slovene-Italian borders, significant increases of 1.6 TWh (19%), 1.1 TWh (20%) and 0.9 TWh (71%), respectively, were recorded.

Figure 60: Absolute aggregate sum of unscheduled flows for three regions – 2012–2013 (TWh)



Source: Vulcanus (2014) and ACER calculations

Note: The calculation methodology used to derive UFs is not different from the one used for the previous MMR. 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.

3.3.3.4 Loop flows and unscheduled transit flows and their likely impact on the volume of cross-border capacities

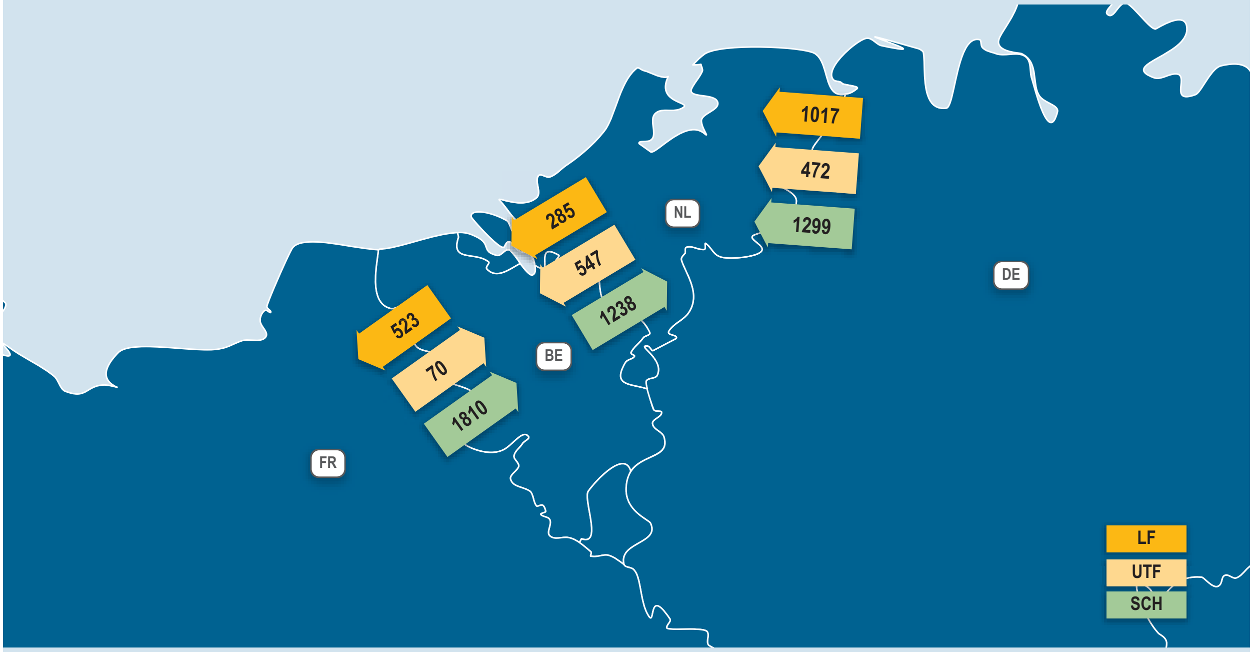
359 In previous editions of this report, due to the lack of data, the Agency and CEER presented UFs as a proxy for LFs. By applying the methodology described in Paragraph 3.3.3.2, it is now possible to assess the respective impact of UTFs and LFs. The box below explains the different possible combinations of cross-border flows, as well as their impact on cross-border capacities.

Box: Explaining the directions and combinations of different types of cross-border flows

The aim of this section is to present a counter-factual analysis of the different kinds of electricity flows that can be observed ex-post. Given that TSOs cannot predict these flows, it should be underlined that the relation presented below between flows and capacity allocations is theoretical and has no policy aims. In the examples below, the impact of UFs (i.e. the sum of LFs and UTFs) on cross-zonal capacities is explained in detail with a view to clarifying the relation between these flows and the cross-zonal capacities made available by TSOs. As explained in paragraph (361), cross-zonal capacities are impacted by the volume levels of UFs and by their uncertainties, which are, together with other factors, reflected in so-called reliability margins (the levels of these reliability margins are not known to the Agency). TSOs, which determine the cross-zonal capacities made available for trade, apply these reliability margins in order to maintain network security during real-time operation.

An ex-post analysis of the levels and directions of LFs, UTFs and SCHs was performed on a selection of borders[220], and their impact on cross-zonal capacities (expressed in NTCs) is explained in practice and in theory (i.e. ex-post). As the impact of reliability margins was not taken into account in the examples presented below, an ex-post observed positive impact of flows on cross-zonal capacity can actually be negative in reality, whereas the negative ex-post impact might in reality become even more negative. Figure i show examples of different combinations of flows.

Figure i. Different combinations of flows in one hour in 2012 for a selection of borders (MW)



Source: ENTSO-E, Vulcanus, EMOS (2014)

German-Dutch border, 3 January, hour 19:00

The LFs, UTFs and SCHs flowed in the same direction.
Theoretically, both the LFs (1,017 MW) and UTFs (472 MW) are expected to reduce cross-border capacity in the direction of the Netherlands and increase it in the direction of Germany. This is possible because of an assumption that physical capacity on this border is symmetrical (equal in both

220 The borders and hours were chosen randomly only for explanatory purposes.

directions) and that LFs and UTFs already consume 1,489 MW of capacity towards Netherlands, which should provide 1,489 MW more capacity towards Germany.

The actual NTC value in the direction of the Netherlands was 1,468 MW and 1,916 MW in the direction of Germany. Given that the maximum observed NTC on this border in 2012 was 2,449 MW in both directions, it can be concluded that UFs actually reduce capacities in both directions, but more significantly in the direction of the Netherlands.

Belgian-Dutch border, 23 January, hour 1:00

The LFs and UTFs both flowed against SCHs.
Theoretically, both the LFs (285 MW) and the UTFs (547 MW) should have a positive impact on the cross-border capacity in the direction of the Netherlands and a negative impact in the direction of Belgium. Hence, in the hypothetical situation of the complete absence of LFs and UTFs, the load on the interconnector would be 1,238 MW instead of 406 MW, and therefore less capacity in the direction of the Netherlands would be available.

However, the maximum capacity on this border was approximately 3,000 MW in 2012 in both directions, while for this same hour, the NTC values in both directions were 1,401 MW. In this case it can be concluded that cross-border capacity on this border and at this hour does not reflect the direction (or volume) of LFs and UTFs in specific hours, but rather the average uncertainties of these flows in the form of reliability margins.

French-Belgian border, 22 January, hour 19:00

The SCHs and UTFs flowed in the same direction, while LFs flowed in the opposite direction.
Theoretically, the UTFs (70 MW) are expected to reduce the capacity in the direction of Belgium, while the LFs (523 MW) are expected to positively impact the cross-border capacities while offsetting the TFs (1,810 MW + 70 MW) in the direction of Belgium. Hence, in the hypothetical situation of a complete absence of LFs and UTFs, the load on the interconnector would be 1,810 MW instead of 1,357MW and less cross-border capacity would be available in the direction of Belgium (depending on the magnitude of UTFs and LFs, e.g. 800 MW instead of 70 MW, the situation would change accordingly), and with the absence of only LFs, the load on the interconnector would be 1,880 MW instead of 1,357 MW and again less capacity would be available in the direction of Belgium.

However, the maximum capacity on this border was approximately 3,000 MW in 2012 in both directions, while for this hour, the NTC value in the direction of France was 1,800 MW and 3,000 MW in the direction to Belgium. In this case, it can be concluded that LFs on this border indeed reduce the cross-border capacity in the direction of France and do not increase cross-border capacity in the direction to Belgium.

These examples show that, in theory, UFs (LFs and UTFs) can be expected to decrease or increase (depending on their direction and volume) cross-border capacities, while in practice only reductions can be observed. Two reasons for this can be identified. The first is that cross-border capacities are not only influenced by the volumes of UFs, but also by their uncertainties and related reliability margins. The second reason is that capacity calculation currently applied by the TSOs is not yet precise enough in terms of coordination, accurate common grid modelling, forecasting and calculation of uncertainties.

360 The aggregate absolute value of LFs amounted to 69.7 TWh in 2011, 70.7 TWh in 2012 and 67.8 TWh in 2013, while UTFs kept increasing from 85 TWh to 87,6 TWh and 94.7 TWh for the respective years. In order to show the frequency and magnitude of LFs and UTFs per border, Figure 61 presents the average LFs and UTFs in MW for the hours in 2013 when these negatively impacted cross-zonal capacity in the ex-post assessment. The results show that all the Swiss borders, German-Dutch, Czech-Austrian, Polish-Czech, Slovenian-Italian and other borders recorded a significant number of negatively impacted hours caused by LFs or UTFs.

Figure 61: Loop flows and unscheduled transit flows negatively impacting cross-border trade – 2013 (average LFs, UTFs, % hours/year)

Source: ENTSO-E, Vulcanus, EMOS (2014) and ACER calculations

Note 1: The percentages of hours per year and averages were calculated as follows. First, every hour with a negative welfare impact on a border (LF or UTF flowing to the higher price area) was counted separately for LFs and UTFs, and then the total count of impacted hours in the whole year was divided by 8,784 to determine the percentage. Second, averages of LFs or UTFs in the impacted hours were calculated. Directions and borders fulfilling the conditions in less than 0.5% hours are omitted.

Note 2: Read the results as follows: on the Austrian-Hungarian border in the direction of Hungary, the condition that LFs (first row) flowed in the direction to the higher price area (having a negative impact on cross-border capacities) was fulfilled in 6% of hours in 2013 and the average LF amounted to 115 MW. The same applies for UTFs (second row), which amounted to 229 MW in 12% of hours in 2013.Similarly for the direction to Austria and other borders.

Note 3: For German-Czech border the Agency obtained only the aggregated values of LFs and UTFs. As shown in Figure 59 the UFs enter and exit this border, hence partially offsetting one another in the aggregated volumes, and thereby the figures presented for this border cannot show an adequate or comparable picture.

3.3.3.5 Welfare impact of loop flows and unscheduled transit flows

361 When assessing the effect of UFs on the amount of cross-border capacity, the assumption is that there is an optimum value for cross-zonal capacity on each border that represents the thermal limits of given network elements and the N-1[221] security criterion. However, the actual capacity available for cross-border trading deviates from the optimum capacity for two reasons. First, in the capacity calculation process, the TSOs try to forecast the amount of flows caused by internal exchanges in all bidding zones (i.e. LFs and internal flows), and second, they forecast the amount of flows caused by cross-zonal exchanges on other borders not included in coordinated capacity calculation (UTFs). Both calculations together result in the forecast UFs, and the optimum capacity is then reduced accordingly. However, as the forecasts of UFs are not deterministic, TSOs further reduce capacity, while including the reliability margin, which represents the uncertainty of these forecasts.

362 MMR 2012 analysed two selected borders in each of the CEE, CSE and CWE regions and estimated the potential welfare losses for these borders (including redistribution effects[222]) as follows. First, on a specific border, the maximum observed physical flows (without the top 1% of outliers) over the last three years served as a proxy of thermal interconnector capacity. This value was reduced with the maximum observed NTC value over the last year. This result was assumed to be the forgone cross-border transmission capacity due to UFs. Lastly, for each direction on a border, the volumes were multiplied by hourly day-ahead price differentials. The result was the value of lost welfare associated with UFs.

363 Due to more detailed data becoming available, this year's report applies a new methodology to estimate the welfare impact of LFs and UTFs. The new methodology builds on the basic assumption that UFs reduce cross-zonal capacity in the direction of its flow, but do not increase capacity in the opposite direction. Assuming the loss of capacity equals the amount of UF, the resulting welfare loss can be calculated as the volume of UFs multiplied by the day-ahead price differential whenever the UFs flow in the more expensive area. Conversely, if the UFs flow against the price differential, the associated welfare loss is zero. Once the welfare loss caused by UFs is known, it can be decomposed into the welfare loss caused by LF and the welfare loss caused by UTF, such that the sum of the two equals the welfare loss caused by UF[223].

364 The key differences between the two methodologies – i.e. this year's and last year's – are the volumes of lost capacities against which the price spreads are multiplied. Last year, the calculation of the lost capacity volumes was based on an estimate using PFs and NTC values. The new methodology assumes that the amount of lost capacity equals the amount of UFs and therefore disregards any further reduction in capacity due to the uncertainty of UFs (reliability margin). The new methodology also enables the separation of welfare losses due to LFs and UTFs. This provides additional transparency and provides a basis for developing potential measures to mitigate problems in the short term (i.e. prior to more robust solutions such as a reconfiguration of bidding zones)

221 A situation in which at least one Contingency from the Contingency List can lead to deviations from Operational Security Limits even after the effects of Remedial Actions (source: ENTSO-E ICS methodology from 13 November 2013).

222 Each time this section mentions welfare losses, it should be taken to include redistribution effects.

223 When LFs and UTFs flow in opposite directions, one of them can produce a welfare gain and the other a welfare loss, while both together amount to the welfare loss caused by UFs.

365 It is important to mention that the overall calculated social welfare impact is:

a) underestimated, as it does not take into consideration the loss of social welfare resulting from the uncertainty of UFs. This uncertainty obliges TSOs to calculate transmission reliability margins, which can reduce the cross-border capacity for trade (i.e. NTC) by more than the mere amount of UFs. The Agency and CEER consider that these unknown margins may substantially increase the loss of social welfare. In view of this, the Agency and CEER are preparing a modification to the currently applied methodology to accommodate this probably significant underestimation;

b) underestimated, since the analysis includes merely the existing aggregated borders, whereas including all interconnectors and 'internal' lines would provide a more accurate estimate;

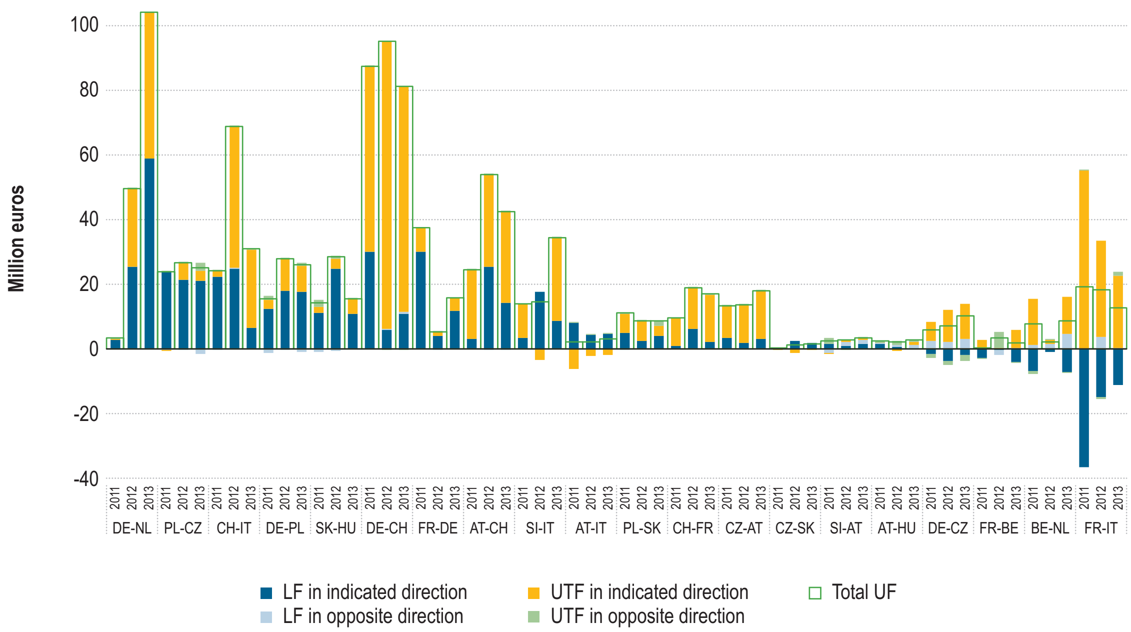
c) underestimated, since lowering the amount of LFs on negatively influenced borders would imply a different bidding zone configuration with lower prices in the source areas of LFs and higher prices in sink areas of LFs, and hence increased price spreads; and

d) overestimated, as the price spread – against which the result is calculated – decreases with each additionally traded unit of transmission capacity until a (possible) complete price convergence, i.e. only so-called dead-weight losses should be taken into account, not the current price spread multiplied by the volume.

366 The results from the application of the new methodology are shown in Figure 62 for all national borders in the CEE, CSE and CWE regions. In 2011, the total welfare loss based on UFs was 324 million euros, while in 2012 it was 461 million euros and 469 million euros in 2013, which indicates a 44.7% increase over the last three years. The differences between 2011, 2012 and 2013 are mostly caused by changes in the price differences on the borders and to a much lesser degree to changes in the volumes of UFs. The share due to LFs was 37% in 2011, (120 million euros), 39.7% in 2012 (183 million euros) and 35.9% in 2013 (168 million euros). This result is considered a conservative estimate based only on welfare losses at the borders; it does not represent the total welfare losses resulting from sub-optimal bidding zone configuration. Such an estimate could be made only by conducting a comprehensive review of bidding zones, which is currently being performed by ENTSO-E.

367 The results of the new methodology suggest that both LFs and UTFs can, in an ex-post assessment, reduce the total amount of UFs-based welfare losses (i.e. when they flow in opposite directions). This means that one of them can actually produce welfare gains, as in its absence the UFs would be higher. This implies that besides losers, there can also be latent winners due to LFs and UTFs. The welfare losses caused to losers by LFs amounted to 184 million euros in 2011, 234 million euros in 2012 and 231 million euros in 2013, and were partially offset by the winners' gains of 64 million euros, 52 million euros and 63 million euros for the respective years. Combined, they amounted to a total welfare loss of 120-183 million euros per year, as presented in paragraph (366). The detailed statistics on flows and welfare effects are presented in Annex 12.

Figure 62: Estimated loss of social welfare due to unscheduled flows in the CEE, CSE and CWE regions – 2011, 2012, 2013 (million euros)



Source: ENTSO-E, Vulcanus, EMOS (2014) and ACER calculations

Note: The German-Austrian border is omitted, as Austria and Germany form a single bidding zone and have one common price reference. The German-Czech border uses one aggregated value of flows not resulting from capacity allocation for both of its interconnectors. LFs and UTFs then partially offset one another in volumes and thereby the presented result cannot be meaningfully interpreted.

3.3.3.6 Conclusion

368 UFs remain a challenge for the further integration of the IEM. Their persistence reduces tradable cross-border capacities, impacting market efficiency and network security. Welfare losses due to UFs have shown an increasing trend since 2011, reaching nearly half a billion euros in 2013, without taking into account any of the under/overestimates listed in paragraph (365). A preliminary estimate of the underestimate in paragraph (365) a) suggests that this uncertainty can substantially reduce the cross-border capacity made available for trade (i.e. NTC), even by more than the mere amount of UFs. The Agency and CEER consider that these unknown margins may considerably increase the calculated loss of social welfare. Thanks to newly available data (i.e. flows not resulting from capacity allocation), a more precise and detailed analysis is possible to decompose UFs into LFs and UTFs and to asses these separately. Moreover, it exposes the magnitudes of welfare losses based on LFs and UTFs and their proportion, which is around 40% and 60%, respectively.

369 The calculation of welfare losses caused by UFs was built on the assumption that cross-border capacity loss due to UFs is equal to the volume of UFs. In some cases, LFs or UTFs flow in the opposite direction to UFs, which means that they reduce the amount of UFs and therefore induce a positive effect on cross-border capacities. Such positive effects have been observed on a few borders only, most notably on the French-Italian border. The extent to which this positive effect actually materialises in practice is yet to be analysed in detail.

370 In order to increase the accuracy and transparency of the level of LFs, the Agency and CEER are of the opinion that a process to calculate the flows resulting from capacity allocation for each hour and for each interconnector without the simplifications mentioned in paragraph (355) should be established in the near future. The Agency and CEER welcome and encourage this improved transparency, as it provides an important basis for assessing the reductions in cross-zonal capacities for trade and its welfare impacts more adequately. In this regard, the monitoring of LFs should be continued.

371 The impact of UTFs can be mitigated with further TSO coordination in capacity calculation and allocation (implementation of flow-based methods), while the impact of LFs can be mitigated by improving the bidding zone configuration in the medium term and by making investments in transmission infrastructure in the long term. Moreover, the presented results of welfare losses due to LFs provide a starting point for developing a short-term solution for addressing the distributional effects of LFs. A proper review of bidding zones, leaving open the possibility of abandoning the current design mainly based on political borders, is aimed at mitigating the inefficiencies due to LFs and hence the true welfare losses caused by the sub-optimal bidding zone configuration.

3.3.3.7 Re-dispatching, counter-trading and capacity curtailments

372 To ensure operational security, different remedial actions are applied by the TSOs to relieve congestion on either cross-border or internal network elements caused by physical flows resulting from both domestic and cross-border trade. Some remedial actions do not result in significant costs and are preventive (e.g. changing grid topology), while others come as a cost to the system or to TSOs and may be either preventive (e.g. offering less cross-border capacity) or curative (e.g. re-dispatching and counter-trading, and curtailment of capacity already allocated). The curative measures are presented in what follows.

373 Re-dispatching is a measure activated by one or several TSOs by altering the generation and/or load pattern in order to change physical flows in the transmission system and relieve physical congestion. More specifically, this refers to a TSO requesting (when congestion appears) some generators or certain consumers to start or increase production or reduce consumption, and some other generators to stop or reduce production or increase consumption in order to maintain network security. Moreover, TSOs may apply countertrading, which is a commercial cross-zonal exchange initiated by TSOs between two bidding zones to relieve physical congestion. In this case, the precise location of generation or load pattern alteration is not pre-defined.

374 Table 4 shows network congestion-related volumes and costs of remedial actions, reported separately for re-dispatching and counter-trading.

Table 4 Network congestion related volumes and costs of remedial actions – 2013 (GWh, thousand euros)

Country	Re-dispatching		Counter-trading		Other	Contributions from other TSOs	Total cost
	GWh	thousand euros	GWh	thousand euros	thousand euros	thousand euros	thousand euros
UK	8,381	256,535	42	-7	92,988	0	349,516
PL	4,474	86,200	525	11,358	0	10,057	87,501
EE	0	0	38	1,123	0	0	1,123
CZ	34	144	0	0	0	-799	943
FI	6	428	12	450	0	22	856
LV	0	0	20	838	0	23	814
RO	11	702	0	0	0	0	702
DK	n.a.	228*	n.a.	228*	0	0	456
PT	9	0	0	0	99	3	96
ES	0	0	44	-54	0	-149	95
AT	248	n.a.	0	n.a.	n.a.	n.a.	n.a.
CH	11	n.a.	44	n.a.	n.a.	n.a.	n.a.
SI	3	0**	0	0	0	0	0
BG	0	0	0	0	0	0	0
HU	0	0	0	0	0	0	0
LU	0	0	0	0	0	0	0
NL	0	0	0	0	0	0	0
SK	0	0	0	0	0	0	0

Source: Data provided by NRAs through the ERI (2014)

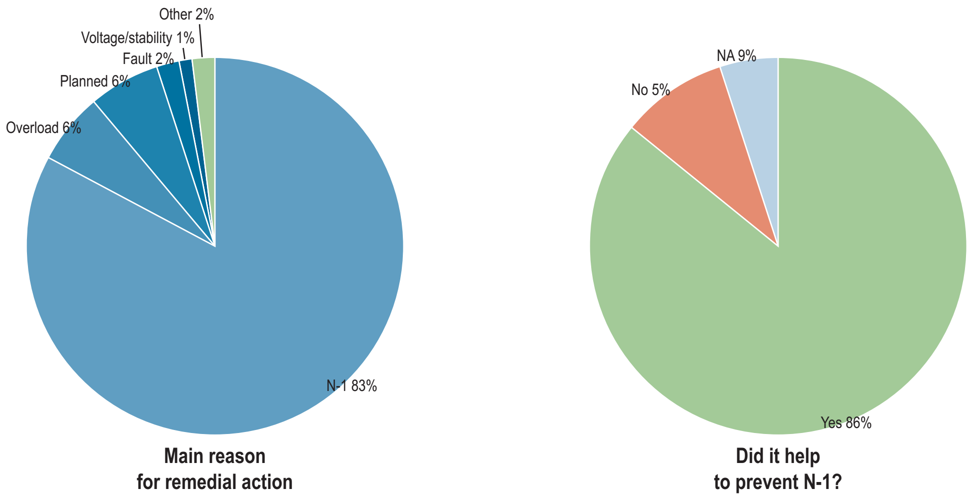
*Notes: Data for 2013 are not directly comparable to the 2012 data, as the question in the ERI template differs. In 2012, the Agency requested all remedial actions, while in 2013 only congestion-related ones. Positive euro values for remedial actions refer to costs incurred to TSOs, negative values to their revenues, whereas, positive values for contributions refer to money received from other TSOs and negative to money paid to other TSOs. Austria, Belgium, Croatia, France, Italy and Switzerland did not provide details on costs or did not have the data available. Countries which are not present in the table did not submit any remedial actions data. * Denmark reported on the sum of both cost components; in the table it has been divided into halves. ** Slovenian costs for re-dispatching are covered by Italy.*

375 Figure 63 extends the information summarised in Table 4 and shows the reasons for remedial action activations presented by the TSOs and whether they prevented or remedied N 1 violations.

376 Figure 64 shows that 5% (i.e. 296 cases) of the remedial action activations failed to prevent the N-1 violations from happening. According to the TSOs, 83%[224] of these cases were caused by the UFs and only 17% by other causes.

224 N-1 violations were reported in only 7 countries (Austria, Czech Republic, Hungary, Poland, Slovakia, Slovenia and Spain); 10 countries reported no occurrences of N-1 violations.

Figure 63: Reasons for and results of network congestion related remedial actions in Europe – 2013 (MWh)



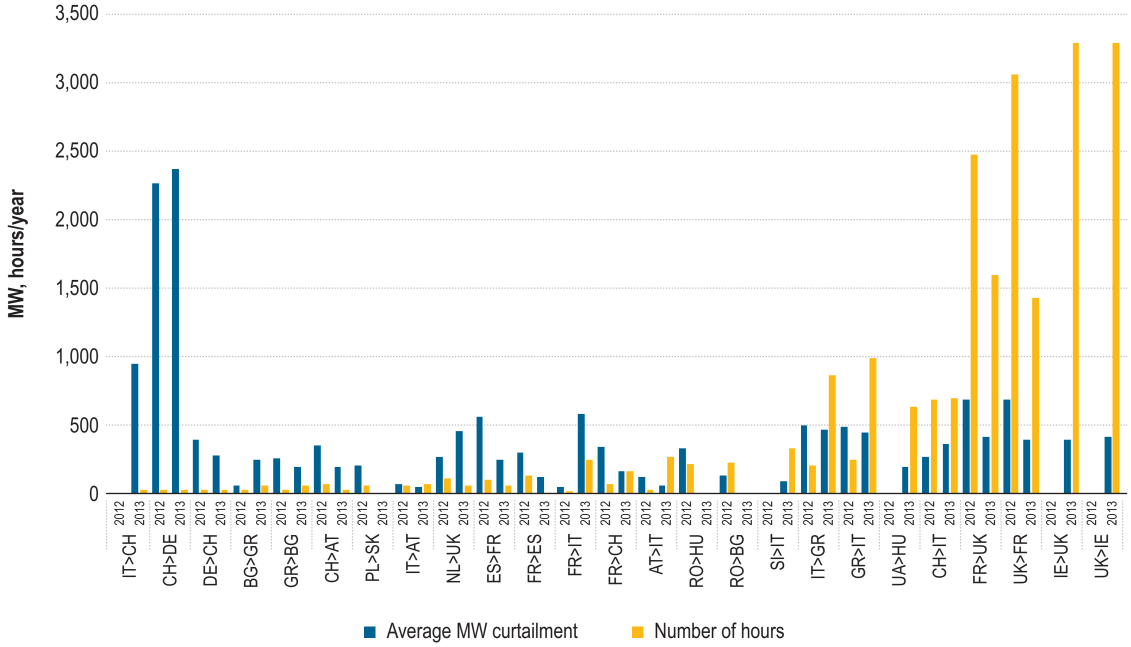
Source: Data provided by NRAs through the ERI (2014)

Notes: The percentages were calculated from the total amount of activations (12,746 activations in 17 countries), regardless of their volumes.

377 When dealing with emergency situations in which TSOs must act in an expeditious manner and when re-dispatching or countertrading is not possible, TSOs may curtail allocated capacity. Regulation EC No 717/2009 and the Framework Guidelines on CACM require that in the case of force majeure market participants owning the curtailed capacity should be reimbursed, whereas in all other cases market participants should be compensated for curtailed capacity. Such compensation should be equal to the price difference between the zones concerned in the relevant timeframe (market spread compensation).

378 Figure 64 shows the number of hours for a selection of borders for which cross-border capacity was curtailed, together with information on the average curtailed MW capacity in these hours.

Figure 64: Average curtailed capacities and number of curtailed hours per border – 2012 and 2013 (MW and hours/year)

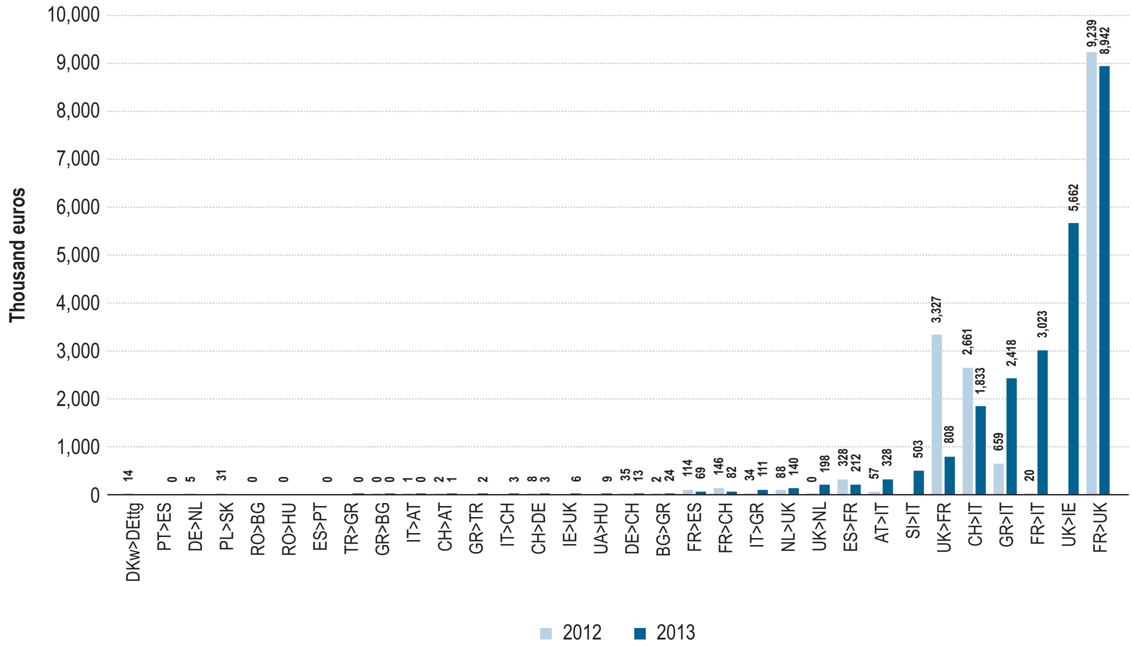


Source: Data provided by NRAs through the ERI (2014)

Notes: In this figure, 'curtailment' is defined as 'long-term capacity curtailment'; it refers to a situation in which the sum of monthly and yearly auctioned capacity is higher in a specific hour than the day-ahead NTC value in the same hour. For the borders of FR-ES, FR-IT, FR-CH, FR GB, AT-CH, CH-IT and AT-IT in 2012 and CH-AT, ES-FR, FR-ES, FR CH, FR-UK, GR-IT, IT-GR, SI-IT and UK-FR in 2013 the data provided on the two sides of the borders were not identical, and average MW capacity curtailed and the average number of hours curtailed are reported. Only borders with more than 24 hours of curtailments per year are included.

379 A capacity curtailment, if implemented by a TSO, is followed by compensation payments paid to the holders of cross-border transmission rights. Compensation schemes still differ across borders and the EU. For instance, while the CWE region offers compensation capped at the value of the day-ahead price differential, other regions usually reimburse the original price paid at the transmission rights auction. These costs are usually split between the TSOs proportionally to the auction revenues received by each TSO. Figure 65 shows the curtailment costs for a selection of borders.

Figure 65: Total curtailment costs per border – 2013 (thousand euros)



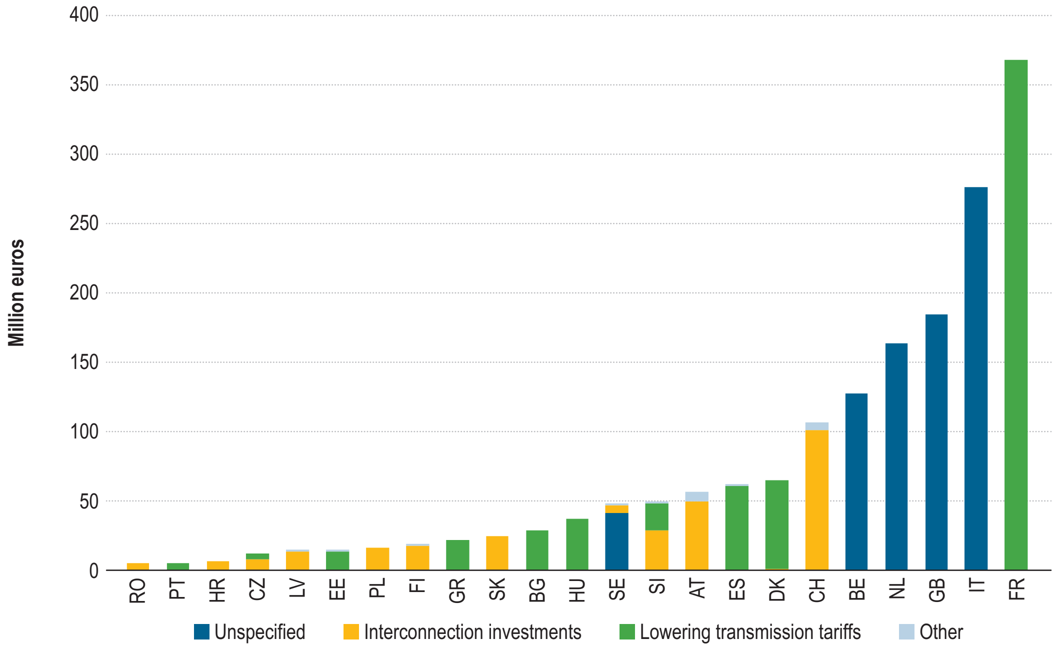
Source: Data provided by NRAs through the ERI (2013) and ACER calculations

Note: For the borders of FR-ES, FR-IT, FR-CH, FR-GB, AT-CH, CH-IT and AT-IT in 2012 and CH-AT, ES-FR, FR-ES, FR-CH, FR-UK, GR-IT, IT-GR, SI-IT and UK-FR in 2013 the data provided on the two sides of the borders were not identical and average total curtailment costs are reported.

380 On borders linked with DC interconnectors, and especially sub-sea cables, higher costs related to cross-border capacity curtailments can be observed, as the duration of curtailments on these borders is usually longer than on borders with AC interconnectors. Curtailment costs may also significantly increase on borders with capped market-spread compensation when the curtailment takes place in hours with a high price spread between bidding zones, compared to the originally paid cross-border capacity auction price.

381 Figure 66 shows the total congestion revenues and their decomposition, depending on how the TSOs spend them.

Figure 66: Congestion revenues – 2013 (million euros)



Source: Data provided by NRAs through the ERI (2014) and ACER calculations

Note: The results were cross-checked with ENTSO-E data, and when different from ERI, NRAs were asked separately to confirm either of the amounts. For Sweden, "Unspecified" refers to revenues placed on a separate internal account without further distinction of spending.

382 Not all the measures and data collection methods used to obtain the data mentioned earlier in the chapter have been unified among TSOs. This might cause slight discrepancies in comparisons between one country and another. Therefore, more and deeper cooperation is needed among all the involved parties (the Agency and CEER, NRAs, TSOs and ENTSO-E) in order to improve definitions and ways of collecting data, especially from TSOs, which have the core information. The Transparency Regulation[225] should help to increase transparency with regard to remedial actions applied by the TSOs to ensure efficient cross-border trade.

225 Commission Regulation (EU) No 543/2013 of 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.

3.4 Conclusions and recommendations

383 In 2013, the efficient use of interconnectors continued to increase due to market coupling reaching a level of efficiency of 77% in the day-ahead timeframe. The highest 'losses in social welfare' are still observed on the Swiss borders, on the border between Great Britain and Ireland and within the CEE region, due to the lack of market coupling, among other factors. The losses due to inefficient day-ahead allocation methods illustrate the urgent need to finalise the implementation of the ETM.

384 The combined analysis of available intraday cross-border capacity and intraday price differentials shows that the available capacity in the intraday timeframe was frequently underutilised in 2013 (more than 40% of the times, the capacity remained unused in the economic direction)

385 In 2013, the exchange of balancing services across EU borders was still incipient. The analysis shows that substantial benefits (in the order of several hundred million euros per year) could be achieved from the exchange of balancing services, which is why Europe should continue to harmonise and integrate balancing markets.

386 UFs remain a significant challenge for the further integration of the IEM. Their persistence reduces tradable cross-border capacities, impacting market efficiency and network security. Welfare losses due to UFs have shown an increasing trend since 2011 and reached nearly half a billion euros in 2013, without taking into account the losses associated with the reliability margins, which are expected to increase the amount substantially. In view of integrating RES into EU power systems, there is an increasing need for flexible resources in the system. Flexibility in wholesale electricity markets (including RES balancing) requires efficient and well-integrated gas markets.

387 Overall, the monitoring results for the electricity wholesale section show that significant scope remains to improve: i) the use of existing cross-border capacity in the different timeframes (i.e. LT, DA, ID and BM); ii) TSO coordination on capacity calculations and allocation; and iii) configuration of bidding zones.

4 Wholesale gas markets and network access

4.1 Introduction

388 In competitive markets, retail and wholesale markets are closely interrelated. Liquid and efficient wholesale gas markets, in combination with transparent and non-discriminatory gas network access mechanisms, help promote competition and efficient price formation across the EU gas value chain.

389 The GTM[226] and the provisions of the various gas network codes (NCs) and framework guidelines (FGs)[227] aim to enhance EU gas wholesale markets' functionality, by improving their transparency and accessibility. The model is intended to encourage wholesale market liquidity by making hub trading easier and more transparent, and will ultimately constitute a mature and attractive mechanism as an alternative to traditional long-term bilateral contracts.

390 The measures proposed include the setting of criteria on the appropriate size of market zones'[228], the offering of cross-border bundled capacity from/to virtual trading points[229] supported by trading platforms, the organisation of capacity auctions, harmonised transmission entry/exit tariff structures, market-based balancing mechanisms[230] and, possibly, following a cost-benefit analysis, the merging of market zones[231]. At the same time, the EU Infrastructure Package[232] is contributing to the establishment of integrated wholesale markets by encouraging the development of adequate cross-border transmission infrastructure. In addition, and in order to mitigate the lack of transparency in wholesale markets, Regulation (EC) No 1227/2011 on wholesale energy market integrity and transparency (REMIT[233]) is intended to prohibit insider trading and market abuse in gas wholesale markets across Europe through the establishment of a monitoring regime for wholesale energy trading.

391 This chapter provides a review of the main wholesale market developments in 2013 across the EU. It presents the key demand, price and gas supply developments (Section 4.2), then explores the level of market integration assessed through the evolution of price, competition and liquidity indicators (Section 4.3). This section also contains an assessment of the welfare losses that each individual

226 The GTM is an EU wholesale market model essentially promoting a hub-to-hub trading framework. The GTM is currently under review to assess whether enhancements are required to address some new challenges which have arisen in the gas sector.

227 The Commission Decision of 24 August 2012 amending Annex I to Regulation (EC) No 715/2009 on Congestion Management Procedures, the Commission Regulation (EU) No 984/2013 of 14 October 2013 establishing a Network Code on Capacity Allocation Mechanisms in Gas Transmission Systems and the Commission Regulation (EU) No 312/2014 of 26 March 2014 establishing a Network Code on Gas Balancing of Transmission Networks are already in place. The Network Code on Interoperability and Data Exchange Rules and the Network Code on Harmonised Transmission Tariffs Structures are currently under development.

228 The GTM1, published on December 2011, provided an initial vision of the European gas market and the necessary measures to foster IEM completion. See: http://www.ceer.eu/portal/page/portal/EER_HOME/EER_CONSULT/CLOSED%20PUBLIC%20CONSULTATIONS/GAS/Gas_Target_Model/CD/C11-GWG-82-03_GTM%20vision_Final.pdf. GTM1 market zones dimension criteria were: churn rate over 8; markets zone sizes over 20bcm; more than 3 supply source origins; HHI index, measuring concentration, over 2,000; and Residual Supply Index (RSI), measuring the share of consumption that can be met without the largest supplier based on supply capability higher than 110%. GTM2 will provide a revision of the initial model, with the aim of ensuring the GTM remains fit for purpose. GTM2 works are being conducted during 2014. GTM2 may set new criteria in relation to ask-bid spreads, the number of players or number of available offers in a given timeframe.

229 A virtual trading point consists of an entry/exit system where gas can be traded independently of its location. A virtual trading point offers users the possibility to bilaterally transfer the title of gas and/or swap imbalances between network users – processes facilitated by exchanges or balancing platforms.

230 Arguably, balancing market operations have more impact on short-term liquidity enlargement, but they help to constitute a price reference base, and this may also serve to spread liquidity to forward products.

231 See: GTM presentation on the current status of merging projects: http://www.acer.europa.eu/Media/Events/3rd-Gas-Target-Model-Stakeholders-Workshop/Documents/08.%20Hesseling%20Market%20integration%20projects.pdf.

232 See: Regulation (EU) No 347/2013 on guidelines for trans-European energy infrastructure. http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2013:115:0039:0075:EN:PDF.

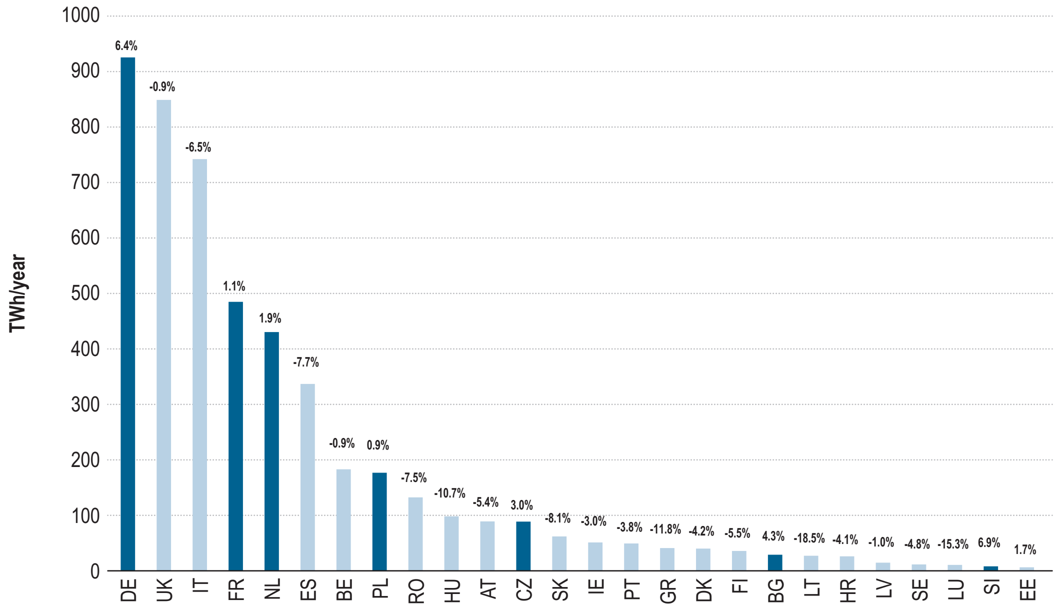
233 See: http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32011R1227.

MS is estimated to be facing pending the completion of a fully integrated EU internal gas market. Further, network access issues such as cross-border capacity utilisation, gas flows and transmission tariffs are tackled (Section 4.4) and, finally, the main barriers inhibiting further EU wholesale market integration are summarised, and mechanisms to remove them considered (Section 4.5).

4.2 Developments

392 EU-26 natural gas consumption totalled roughly 5,000 TWh in 2013, a slight decrease compared to 2012. The same factors that significantly reduced gas demand in previous years[234] – slow economic growth, the increased use of coal as the fuel of choice for power generation, the increasing penetration of RES and energy efficiency improvements – continue to be determining factors. This overall EU trend varied among MSs, as shown in Figure 67.

Figure 67: EU-26 gas consumption – 2013 (TWh/year and % variation with respect to 2012)



Source: Eurostat's gross annual inland consumption monthly data (Data series nrg_ind_103m in TJ (GCV), 8 May 2014) and ACER calculations

Note: Denmark, France, Germany, Lithuania and Luxembourg values were revised by NRAs. Those MSs, where demand increased in 2013 compared to 2012, are shown in dark blue. Cyprus and Malta have no gas market.

234 EU-26 gas demand decreased year-on year by 1.2% in 2013, 2.2% in 2012 and 10.5% in 2011.

393 One of the main reasons for the overall reduction in EU gas demand is the displacement of gas by other energy sources for power generation[235]. This has been driven by two factors: first, the availability of cheap international[236] coal imports in combination with the low price of CO_2 Emission Trading System (ETS) allowances[237], causing gas to remain less profitable than coal-fired generation during the year, leading to negative spark/dark[238] spreads. Second, as a result of lower generation costs and direct support schemes[239], electricity production from RES is increasing across the EU, in parallel with steps taken to meet the 20-20-20 targets. In addition, gas demand for industry was affected by a slight decrease in EU industrial production[240]. Colder weather conditions, on the other hand, particularly in the first quarter of the year, sustained household consumption. The impact of each of these factors on demand varies between MSs[241].

394 EU gas wholesale prices remain over twice as high than US prices, while Asian and Latin American LNG markets still sustain price levels which considerably exceed those of the EU. In the US, shale gas production and greater wholesale market competition continued to place downward pressure on domestic prices[242]. Higher EU energy prices relative to the US and other world regions affect industrial competitiveness and are reducing the EU's share of energy-intensive goods in global exports[243].

235 Gas consumption for electricity generation declined by 30% in Spain, 20% in France, 16% in Italy, and 8% in the United Kingdom compared to 2012. Sources: Enagas, GRTgaz, Snam and National Grid.

236 Cheap shale gas availability in the US has led to coal exports from this country. Additionally, the economic contraction in developing economies (highly dependent on coal) has led to an increase in global coal market liquidity resulting in lower coal prices. See Figure 39.

237 See underlying info on the ETS schemes and price evolution here: http://ec.europa.eu/clima/policies/ets/index_en.htm.

238 The spark spread is the gross margin of a gas-fired power plant from selling a unit of electricity, having bought the fuel required to produce this unit of electricity. The dark spread is the similar gross margin of a coal-fired power plant.

239 Support schemes differ across EU MSs. In certain markets, RES may be competitive without them. See: Annex 9.

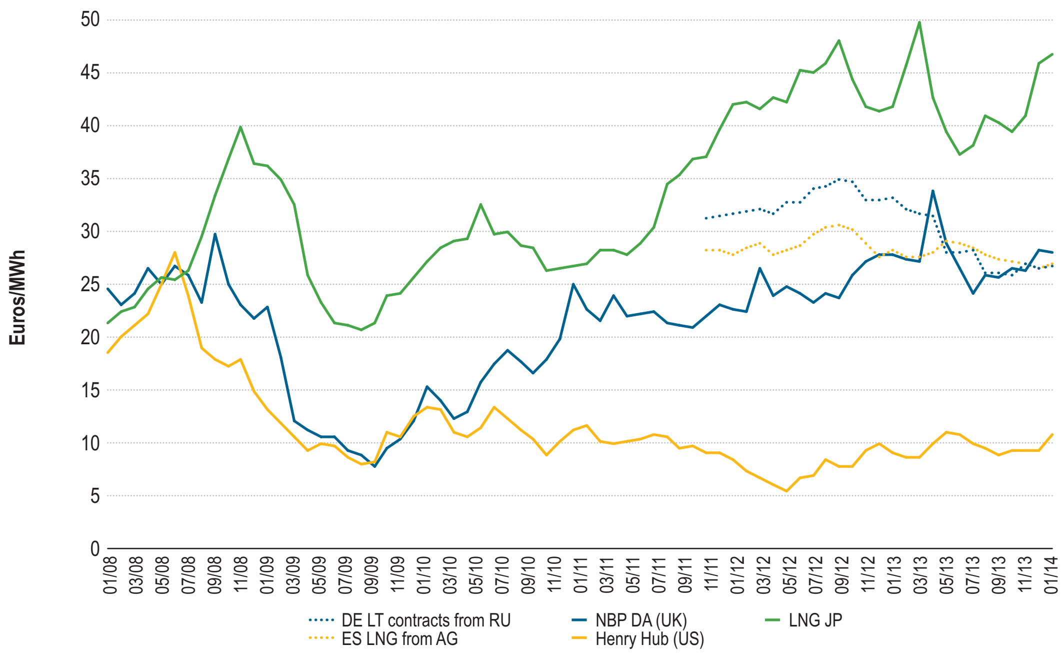
240 See: http://epp.eurostat.ec.europa.eu/cache/ITY_PUBLIC/4-12022014-AP/EN/4-12022014-AP-EN.PDF.

241 See, for example: Eurogas Statistical Report 2013: http://www.eurogas.org/uploads/media/Eurogas_Statistical_Report_2013.pdf.

242 See, for example: http://www.oxfordenergy.org/wpcms/wp-content/uploads/2011/12/NG_58.pdf.

243 According to the IEA, EU28 energy intensive goods exports could decline by one-third from the current share until 2035. See: http://www.worldenergyoutlook.org/publications/weo-2013/.

Figure 68: International wholesale price evolution – 2008–2014 (euros/MWh)



Source: Platts, Thomson Reuters, ICIS Heren (2014) and ACER calculations

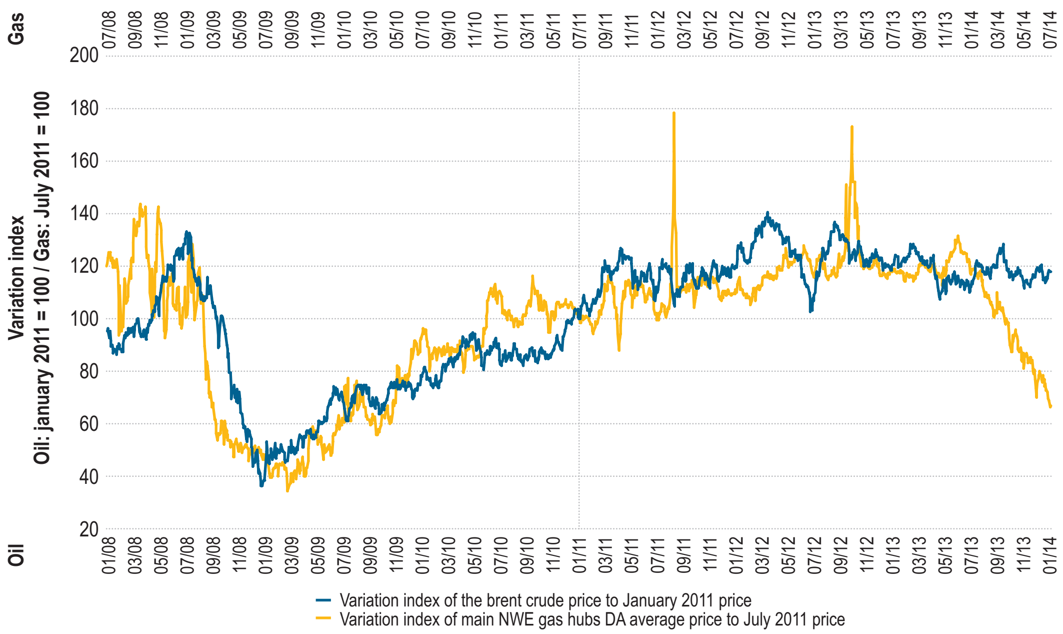
395 Compared to 2012, greater wholesale gas price convergence was observed across EU MSs in 2013, although considerable price differences still persist between certain markets. The convergence was assisted by the continued alignment of EU hubs' prices, and by the convergence of hub prices and the prices of long-term contracts (LTC) indexed to other commodities. On average, approximately half[244] of EU gas supplies are still linked to long-term oil-indexed contracts, although the tendency is increasingly for these contracts to be renegotiated or indexed to hub prices. This topic will be covered in more detail in Section 4.3.2.

396 Oil prices in 2013 generally remained the same as in 2012. Although the correlation[245] between the price variations of oil and gas is growing weaker as gas-on-gas competition rises, oil prices still seem to have been one of the main determinants of overall wholesale gas prices in Europe in 2013. This was a result of the continued direct oil-indexation of gas prices in a significant proportion of European supply contracts, and the impact those contracts would have as references for hub price formation. The data points to a divergence in correlation between gas and oil prices from the beginning of 2014, with gas prices showing a significant reduction in contrast to oil prices, which remained relatively stable. Downward price pressure specific to gas may have been a result of relatively mild weather conditions and high EU gas storage stocks, contributing to relatively benign supply conditions.

244 This overall value varies by region, with North-West Europe having the largest shares of indexation to hub prices and SEE and Mediterranean MSs the lowest. See International Gas Union Gas Wholesale prices Survey 2014 for regional values split: http://www.igu.org/sites/default/files/node-page-field_file/IGU%20Wholesale%20Gas%20Price%20Survey%20Report%20-%202014%20Edition.pdf.

245 It should be pointed out that correlation does not mean causation.

Figure 69: Oil and gas hubs price evolution in Europe – 2008–2014 (index)



Sources: Platts (2014) and ACER calculations

Note: A six-month forward lag is used for gas in the comparison with oil prices. The gas price index variation is calculated with reference to average hub gas prices on 1 July 2011 (on the upper X axis). The oil price variation is calculated with reference to the oil price on 1 January 2011 (on the lower X axis). This is because hub prices are predominantly influenced by oil-indexed contracts, the prices of which track oil with a lag of six to nine months.

397 As happened in 2012, in 2013 EU indigenous gas production continued to decline[246] while EU gas imports continued to increase. This trend continues to heighten the debate on shale gas extraction in Europe. At the moment, the views on the pros and cons of shale gas extraction differ among MSs. The European Commission published a Recommendation[247] aiming to clarify the conditions under which fracking can take place, while imposing no ban on them. In addition to shale gas, it is possible that biogas and power-to-gas technologies could also offer areas of growth for European gas supply in the future, although the scalability of these technologies is still unclear.

398 The share of Russian exports to the EU showed a significant increase compared to 2012[248]. This recovery is partly explained[249] by Gazprom renegotiating final offered contract prices with the aim of better utilising spare production capacity. This may have been in response to its loss of market share to more flexible competitors – i.e. Norway – in previous years, or in anticipation of the price reduction effects from increased competition due to the further development of organised markets and new interconnection infrastructure availability. The need to replenish EU gas storage stocks after the low stock levels reached at the end of March 2013 is also likely to have impacted demand for Russian gas. Another noticeable change compared to 2012 was the decline, by one third, in EU LNG imports, probably caused by higher Asian and Latin American prices. These analyses will be expanded in Section 4.4.1.

246 Indigenous production declined by 2.4%, source Cedigaz 2014. EU net gas imports in 2013 were worth approx. 130 billion euros.

247 See: http://ec.europa.eu/environment/integration/energy/unconventional_en.htm.

248 Aggregated Russian exports to Europe increased in 2013 by 15%, to roughly 155 bcm. Source: IEA. See Figure 80.

249 These and other market trends explained/referred to throughout the document confirm the Agency and CEER view on the basis of specialised media reports, different forum presentations and expert views. Additional reasoning on price downward pressure is presented in Section 4.3.2. Flow increase interpretations are continued in Section 4.4.1.

4.3 Markets' integration

4.3.1 Level of integration: liquidity evolution

399 Liquidity has a strong bearing on the level of competition and the efficiency of price formation in gas wholesale markets. The number and diversity of gas wholesale market participants, and the volume of wholesale gas trades at gas trading hubs are important liquidity indicators. Competitive hubs attract contending market participants and provide more options to source and hedge supplies. This places downward pressure on gas prices, which should translate into benefits for retail markets.

400 A series of factors are detrimental to liquidity and competition. These factors[250] include: the absence of hubs, high market concentration, insufficient interconnection capacity, capacity hoarding, the presence of vertically integrated incumbents and oligopolistic market structures which limit the trading of gas. Furthermore, the difficulty in obtaining trading licenses and high entry costs may particularly hinder the entry of small players, who are less able to achieve economies of scale.

401 Figure 70 shows the level of diversity of supply by country of origin across the EU. The figure shows that ten MSs rely on a single country of origin for more than 75% of their supply, meaning that a single source[251] is able to exert considerable influence on wholesale prices in these markets. These MSs often lack adequate interconnection capacity, do not have competitive hubs and have no access to LNG supply. Consequently, these MSs tend to face higher gas prices[252] than MSs with enhanced interconnections, LNG[253] terminals and liquid hubs, further demonstrating the need for more EU market integration.

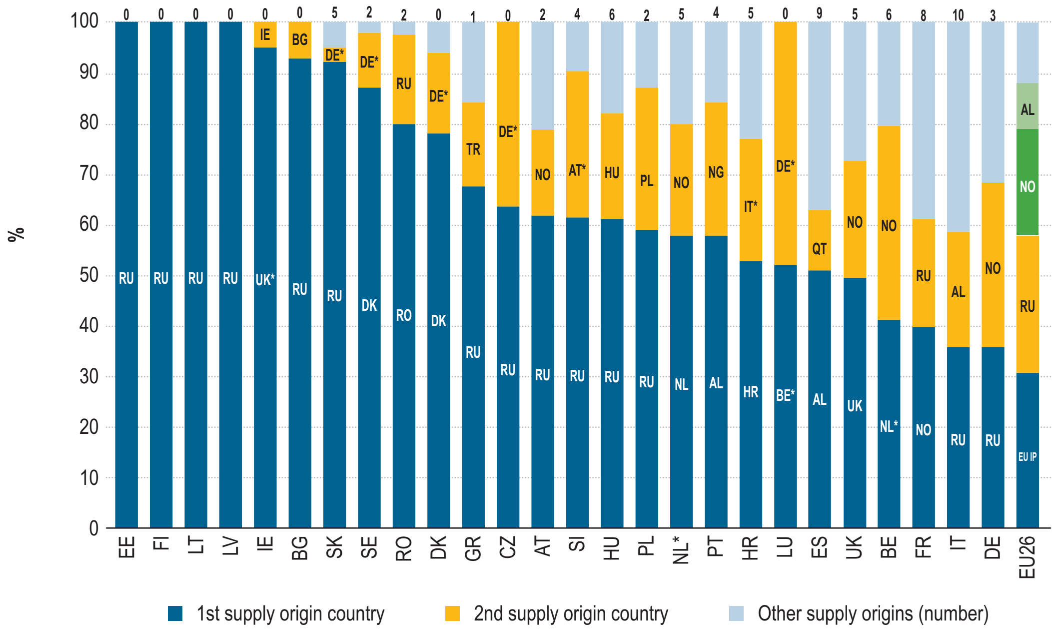
250 Factors are presented here as a theoretical list based on factual impacts observed in individual markets.

251 Arguably, several suppliers could be sourcing from the same country of origin and competing among themselves. Also, the situation may be quite different depending on whether the single source is the home country, an EU MS or Energy Community Contracting Party, or a third country.

252 See also Figure 73 showing EU-26 wholesale prices in correlation to MSs market concentration levels. For Denmark and Romania, the high single source dependency relies on the fact that a relevant share of total country consumption is met by indigenous production. Ireland, despite its high dependency on a single source, has similar prices to NWE MSs due to the competitiveness of the country's declared gas import contract prices.

253 Some LNG sources may only arrive in small quantities and/or at significant price premiums, but 'count' as a separate supply source.

Figure 70: Estimated diversity of gas supply in EU-26 per MSs and by origin of supply country – 2013 (%)



Source: Eurostat Comext, BP Statistical Report, Eurogas, MSs' National Reports (2014) and ACER calculations

Note: Supply origins indicate the upstream gas producer state or, in those origins marked with an asterisk, a MS featuring an organised market where gas has been purchased. The number at the top of the column relates to the total number of other different MSs declared as gas import origins in Eurostat Comext; again, either a gas-producing MS or MS with a gas market where gas has been purchased. The Netherlands split refers to the gas origins of overall traded volumes in the country, but the country constitutes itself as a net exporter even by solely considering its relevant indigenous production.

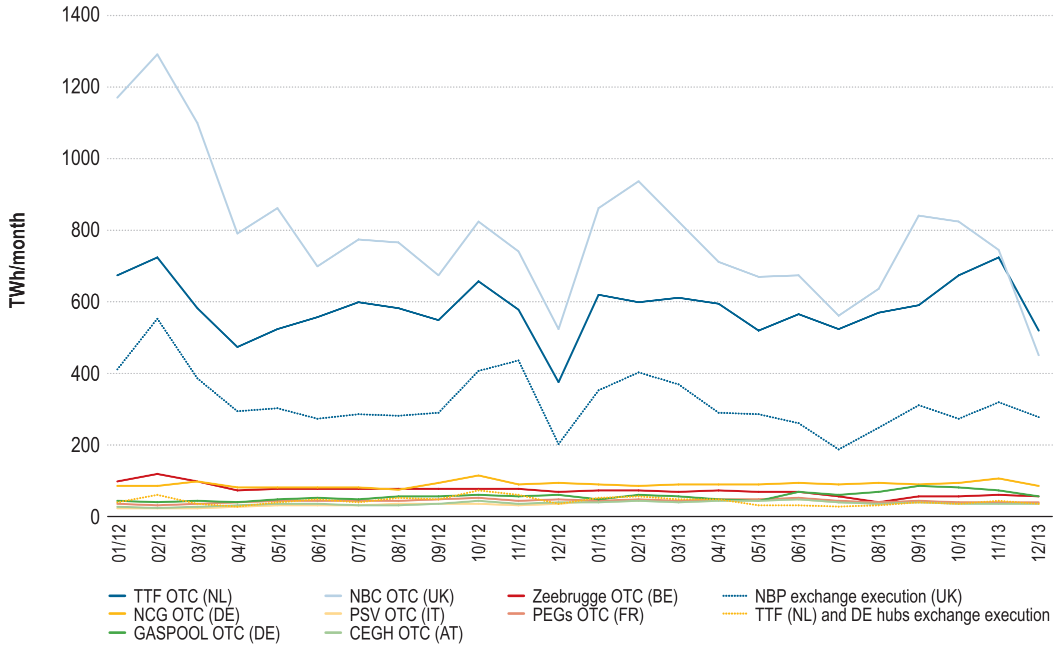
402 Figure 71 compares traded gas volumes at the main NWE EU hubs. It demonstrates that aggregated hub liquidity levels changed little in 2013: the continuing tendency to move away from oil-indexations in long-term contracts and to hedge short-term exposure on the hub has brought increased liquidity to some hubs, as did the establishment of hub-price components in certain MSs' regulated prices[254]. However, progressive reductions have been observed in the gap between hub prices and the price of long-term contracts, which may be reducing the profitability of pure hub sourcing activity in comparison to previous years[255]. In addition, the continued effect of slow economic growth, and particularly the lack of credit, has forced some financial entities and companies to reduce their financial exposure to gas markets. This could have reduced traded volumes at some hubs, particularly of longer-term products[256].

254 Belgium, France, Hungary and Italy (only for vulnerable customers) have introduced such regulatory provisions.

255 In addition, in certain long-term renegotiated contracts, clauses may have been imposed that reduce arbitrage flexibilities against the hub.

256 This is particularly valid for the NBP. Difficulties in obtaining products longer than the year-ahead product (longest curve) made the hubs less liquid. On EU-hubs, major volumes are typically negotiated on intra-month and month-ahead products. See Wagner, Elbling & Company forthcoming study on gas market functioning for an appraisal of the split of liquidity and products duration: http://www.acer.europa.eu/Media/Events/3rd-Gas-Target-Model-Stakeholders-Workshop/Documents/04.%20Wagner%20WEC%20-%20Functioning%20of%20Gas%20Markets%20-%20Albrecht%20WAGNER%20140515.pdf.

Figure 71: Traded volumes at main EU hubs – 2012–2013 (TWh/Month)



Source: ICIS Heren, Trayport (2014)

Note: Over-the-counter trade (OTC) refers to the volumes traded among parties without the supervision, credit risk management and clearing function of an exchange operator. Exchange execution refers to those volumes supervised and cleared by an organised market operator.

403 Total traded volumes at the main NWE EU hubs[257] ranged between four and five times the overall EU-26 physical gas consumption. OTC trade – bilateral plus broker cleared – remained the predominant[258] type of trading, especially on the Continent, where it accounted for more than 90%[259] of traded volumes. NBP and TTF continue to have the highest traded gas volumes, and generally remain the most liquid and competitive[260] European hubs. Although the traded volumes at both these hubs declined at the end of 2013 (in part a seasonal effect), the high liquidity of these two hubs[261] – particularly for longer-term products – means that their prices act as a reference for other hubs in the EU and other gas contracts.

257 Hubs considered: NBP (UK), TTF (NL), GASPOOL and NCG (DE), Zeebrugge (BE), PEG Nord (FR), CEGH (AT), PSV (IT).

258 Among other factors, OTC volumes' predominance over exchange cleared (organised markets) can be explained by the trust-based and relatively circumscribed trader community, by larger firms' presence (as arguably more capable of backing their credit positions) and by the option of customising products vs. exchange market standardisation. Arguably another factor in OTC predominance relies on the opportunity to price discriminate across buyers. Moreover, the clearing fees and guarantees imposed by organised markets with a central counter-party may constitute added costs. Howeber, data indicate that to some extent OTC trades are being progressively replaced by exchange clearing to better address counterparty risks, particularly for longer-term products. Organised markets prices in those liquid and low concentrated hubs, although representing smaller traded volumes than OTC, can be considered transparent and accessible price signals to be used as a market reference that usually matches OTC prices.

259 This percentage represents OTC aggregated traded volumes for all products. OTC and exchange executed traded volumes ratios may slightly differ per type of contract product, showing day-ahead exchange executed products have the relative higher shares. In UK NBP, exchange executed trades comprise more than 30% of overall traded volumes.

260 With the highest churn ratios (more than 10), the highest number of participants (more than 100) and the highest available number of offers at any given period. TTF is becoming an equally influential hub as NBP. Both hubs' liquidity levels are now comparable, given the increase in TTF liquidity registered in 2013 and the aggregate decline in NBP traded volumes. See also Section 4.4.1.

261 Liquidity values on the curve on these two hubs are promoted by the 'circle of virtuosity' factor; liquidity attracts liquidity as sourcing and hedging trades from adjacent areas. A relevant effect for liquidity is that these two hubs show the EU narrowest average bid-ask spreads in gas traded products. They are also favoured by the indigenous production factor in both MSs.

404 Across a number of markets, including Germany, Belgium, France, Austria and Italy, a trend has developed in favour of shorter-term gas contracting[262], additional to the balancing portfolio operations. This is likely to increase the number of gas trades and the liquidity of these markets' hubs, as participants seek to derive economic value from short-term price arbitrage. The higher reliance on hubs for gas contracting is progressively impacting capacity contract trends in those markets. Shorter-term capacity contracts are increasing[263], as they offer a more flexible way of matching commodity demand.

405 Facilitated by NRAs[264], the development of settled gas exchanges and newly implemented VTP configurations has also increased hub trading in several Central-East European countries, such as the Czech Republic, Hungary, Poland and Slovakia. Shippers in these countries are also relying more on adjacent organised markets, in Germany and Austria in particular, which is also improving competition[265]. Despite this, both in terms of number of supply sources and volume of trades, only a minority of MSs (mainly in North-West Europe) have wholesale gas markets with a high degree of liquidity. Furthermore, direct bilateral contracts with upstream producers remain the most common supply mechanism across most MSs in the EU.

4.3.2 Level of integration: price convergence[266]

406 Price convergence between EU gas wholesale markets is an important indicator of the level of market integration: in fully integrated markets, higher prices in one area should attract gas supplies from lower priced areas, thus reducing price differentials.

407 In aggregate, increased gas wholesale price convergence was observed across the EU in 2013 (see Figure 72). One of the main reasons for this was that the trend towards the renegotiation of long-term contract conditions, initiated in previous years, was amplified in 2013. During such renegotiations, hub prices have been increasingly used as a reference, and traditional price indexations to oil and other commodities have been reduced. Where modifications to the indexations were not made, in some cases, direct discounts were granted by upstream producers[267]. This arbitration tendency has contributed to greater wholesale price convergence among EU MSs, predominantly placing downward pressure on prices.

262 See, for example, NCG registry of traded volumes and products: http://datenservice.net-connect-germany.de/BoerslicherGashandel.aspx?MandantId=Mandant_Ncg&rdeLocaleAttr=en.

263 See data analysis in Section 4.4.1.

264 See, for example: http://www.reuters.com/article/2013/12/05/poland-gas-idUSL5N0JJ2BR20131205.

265 See, for example, data supporting this statement on the ICIS Heren European Gas Hubs Report 2013.

266 The trends in overall pricing and contractual conditions mentioned in this Section conform the view of the Agency and CEER on the basis of specialised media reports, different forum presentations and experts views.

267 See: KEMA study for the European Commission on LT-ST contracts in gas: http://ec.europa.eu/energy/gas_electricity/studies/doc/gas/lt-st_final_report_06092013final.pdf.

408 The increase of this arbitration tendency in 2013 derives in large part from the fact that Gazprom[268], and in Southern Europe Sonatrach[269], increasingly adopted this approach as a competitive response to earlier movements by Norwegian and Dutch producers, but also with a view to utilising their vacant production capacities in a context of lower demand. The downward pressure on Russian gas prices has also come from increases in competition in some Central-East markets, the further development of organised markets within the EU, and the delivery and planned expansion of new interconnection infrastructure[270].

409 However, despite increased contract renegotiations and greater NWE price convergence, significant price variations remain across the EU as a whole, reflecting the different degrees of bargaining power in different markets. The extent to which this is the case is mainly related to overall liquidity and competition levels along the whole gas value chain.

410 There is some evidence that Central-East and Southern European MSs tend to sustain a premium over more liquid, less concentrated and better interconnected Western countries. Oil-indexed and semi oil-indexed long-term contract prices also remain more common in Central-East and Southern Europe, and in 2013 the price of these contracts continued to be higher than hub spot prices, even though the gap has narrowed compared to previous years[271]. LNG import prices tend to be price competitive on average, providing benefits to those markets with access to LNG, although in some cases the price of LNG in Asian and Latin American markets led to that same gas subsequently being re-exported from the EU.

411 As hub spot prices are more exposed to EU gas supply and demand fundamentals, their volatility[272] is also higher. This can be observed in Figure 72, where the peak hub prices for March correspond to the spike in demand during the unexpectedly cold temperatures in northern Europe that month[273]. In such cases, hub prices may surpass the prices of gas contracts indexed to other commodities. For this reason, to spread their pricing risks, major shippers or large industrial consumers may retain, at reduced volumes, a portfolio of LT contracts indexed to other commodities.

268 Specialised reports (ICIS Heren, Platts) indicate that price reductions of more than 15% have been granted to Poland and Bulgaria. Gazprom seems to have a strategy of treating markets separately and thus establishing some price discrimination between MSs, arguably influenced by political considerations.

269 According to specialised reports, Sonatrach is still keen to maintain oil indexations in its existing LT contracts, but it is recently showing more flexibility on take-or-pay volumes obligations. Also, some hub indexation is being offered in LNG deliveries. See a detailed analysis on the subject in: http://www.oxfordenergy.org/wpcms/wp-content/uploads/2011/03/NG48.pdf.

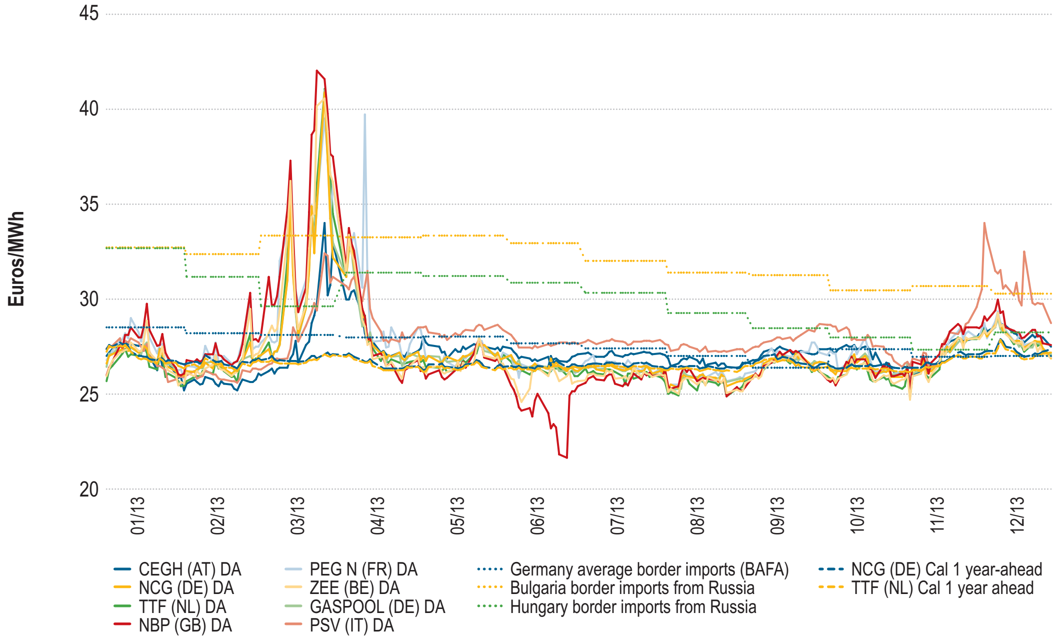
270 The efforts to promote diversification of supplies and the potential thread of competition from LNG and unconventional gas production are also playing a role. Lower aggregated EU gas demand is also a relevant factor. The international context also adds downward pressure on global prices, such as the possibility of forthcoming US or Australian LNG exports, the slow-down in China's economy or the indication that Japan may restart nuclear power stations.

271 See Figure 72 and Figure 73. In some MSs, the trend is now to correlate regulated prices to hub prices. By this procedure, the historical indexations of the regulated tariff to main LT contracts are progressively substituted by hubs' price references. In Italy, for example, AEEG ruled that Italian gas prices had to be linked to Dutch hub TTF from October 2013.

272 Arguably volatility is more reflected in total hub contracted volumes.

273 As another example of this volatility, in June, UK NBP prices were reduced due to a combination of factors: low demand, high imports from Norway – as Norwegian flows were diverted to the UK due to maintenance on the interconnector flowing Norwegian gas to Germany – and coincidence in time with the annual maintenance works of the Interconnector, a fact which impeded gas flows from the UK to Continental Europe.

Figure 72: Gas prices: comparison between main EU hubs and cross-border import prices – 2013 (euros/MWh)



Source: Platts, Eurostat Comext, BAFA (2014)

Note: BAFA provides an estimate of overall German cross-border gas imports prices. BAFA convergence to hubs' prices illustrates a reduction in lasting bilateral LT oil-indexed prices and the progressive indexation of German import contracts to hub price indexes.

412 As indicated above, the price correlation among major NWE hubs is quite significant; however, this may not necessarily mean that wholesale markets are wholly integrated. Price spreads may still arise as a result of differences in liquidity degrees, concentration levels, transmission tariff values, capacity constraints, congestion levels and individual MSs demand-supply fundamentals and existing contract portfolios. Under particular circumstances, the combination of these factors may have resulted in weaker correlations during some 2013 periods; for example, PSV still maintains a certain premium over NWE hubs, although it is lower than in previous years. Except for winter months with peak spot prices, one year forward product prices were mostly slightly above spot ones, perhaps reflecting the expectation[274] of price increases for the coming months.

274 This is also arguably due to financial and credit management parameters.

4.3.3 Benefits of market integration

413 As indicated above, despite increasing convergence in 2013, significant wholesale price[275] variation still exists across Europe, reflecting varying market fundamentals and varying degrees of competition along the gas value chain.

414 The data presented in Figure 73[276] below shows a positive relationship between market concentration[277] and prices: in general, less concentrated markets tend to have lower prices. The relationship is not so strong as to demonstrate that market concentration is the only price determinant, but the data do not take into account structural differences (which may make supplying gas more expensive in one country than another), and methodological issues may under-represent the trend in some cases (see notes for Figure 73).

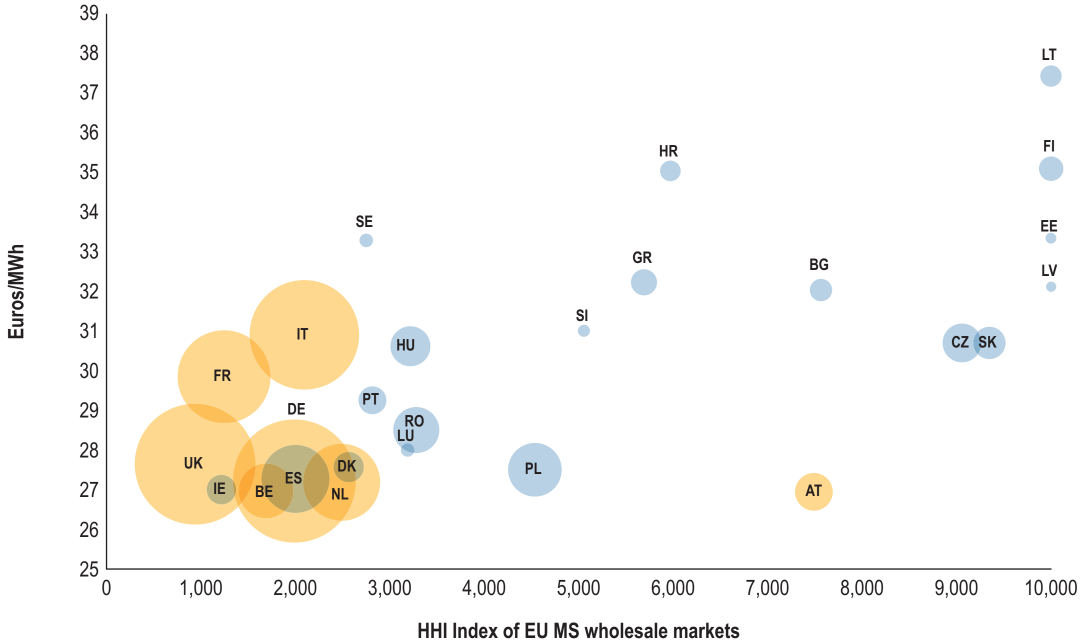
415 Nevertheless, considered together with the other data and analyses presented in this chapter, Figure 73 suggests that it is plausible that more benefits in terms of lower gas wholesale prices can be derived from the further integration of EU wholesale markets. As Figure 73 also demonstrates, larger markets may offer some specific suppliers the opportunity to benefit from greater economies of scale when exerting bargaining power on producers, thus leading to lower prices formation in certain larger MSs. Therefore, closer alignments of smaller markets with larger markets may also deliver benefits. The sub-sections which follow explore the materiality of some of these benefits in terms of welfare losses/gains.

275 The prices used in the overall subsection constitute an estimate of the average price level for each MS based on available data and the application of ACER/CEER methodology. See Figure 73 Notes.

276 Figure 73 provides an interesting comparison with the diversity of supply sources data represented in Figure 70. Certain MSs may not fully accomplish the general signalled correlation, given their specific market fundamentals (i.e. Austria, Italy, Poland or Sweden).

277 Herfindahl–Hirschman Index (HHI) values are calculated on the basis of the market shares of all different upstream companies sourcing gas into the MS, not by the shares of the wholesalers/importers i.e players buying this gas.

Figure 73: Gas wholesale prices in EU MSs compared with market concentration and gas demand – 2013 (euros/MWh)



Source: Eurostat, Comext, Platts, Frontier, and NRAs data (2014) and ACER calculations

Note: Circle sizes are proportionate to MSs gas demand. Those in orange denote MSs with more liquid organised markets. The prices used constitute an estimate of the average price level for each MS based on available data. Final prices may vary between suppliers and over time, depending on specific contracts and individual procurement strategies. The presented prices result from the application of the ACER/CEER MMR 2013 methodology[278]: in cases of an MS with no hub or a hub with very reduced liquidity, wholesale prices are solely referenced from the Eurostat Comext Database on declared gas import prices at the border weighted by import-origin volumes; in MSs with hubs but relatively illiquid forward products, a combination of long-term contracts prices (assessed from Eurostat Comext Database) plus short-term hub products prices was used; in MSs with sufficiently liquid hubs, the assessment is based exclusively on hub price references and hedging strategies around the hub. Monthly prices were weighted by monthly demand to arrive at a unique final yearly average price. It is to be noted that the methodology used has limitations that may result in inaccuracies for certain MSs. Nevertheless, it is consistently applied for comparability reasons. For example, the hub prices in France and Italy are reasonably correlated with the prices of other main European hubs like TTF and NCG (see Figure 72) but the methodology used may not fully reflect the realities or specificities of the French and Italian wholesale markets. The resulting higher final average prices in these two MSs can be explained by the higher prices of declared gas imports at the French and Italian borders derived from the Eurostat Comext Database. For instance, the wholesale market price for PEG Nord on the French gas exchange was on average 27.60 euros/MWh in 2013, and the wholesale market price for PSV on the Italian gas exchange was on average 27.98 euros/MWh. The Romanian price used is the Eurostat Comext one on border imports; the indigenous production price is estimated to be 30% lower. In the absence of Eurostat Comext data, the Polish wholesale price corresponds to the regulated industrial consumers' tariff – group E with the lowest tariff – net of transmission charges indicated by the NRA. The HHI values are calculated on the basis of market shares of different upstream companies sourcing gas into the MSs.

278 See the methodology details used for price estimates in the Annex 1.

a) Estimates of gross welfare losses

416 This section assesses prospective gross welfare losses across the EU – losses resulting from the limited integration of national gas markets –by contrasting the estimated price deviations of EU MSs gas wholesale markets with the baseline reference price of the Netherlands[279] (Dutch market price built on TTF). This provides an estimate of the potential savings that could be achieved if all wholesale markets in the EU had at least similar liquidity and competition levels, and hence comparable prices as the TTF[280]. This initial exercise does not take into account demand-supply constraints or other factors such as transportation costs, necessary investment costs or importing capacity availability[281], all factors that could affect the potential level of price convergence.

417 On an EU aggregated basis, the total potential annual gas wholesale gross welfare losses due to the current lack of market integration amounted to 7 billion euros in 2013. Losses have decreased significantly in comparison to 2012, when they totalled 11 billion euros. This decrease is mainly the result of the continued wholesale price convergence among MSs observed in 2013, the reasons for which were examined in Section 4.3.2: mainly due to LT contract price renegotiations, prompted by the enhanced competitive pressure facilitated by hub developments and increased interconnection capacity.

418 On a country-by-country basis, the highest aggregated potential losses were observed in Italy and France[282], an effect accentuated by the significant gas demands in these two MSs. The appraised wholesale market prices in these two MSs remain above the reference price of the Netherlands. This is likely to be driven by the fact that their supplies are, relative to the Netherlands, still more reliant on higher-priced existing long-term contracts[283], and because their hubs continue to show lower forward product liquidity[284]. Overall, the gross welfare loss in Italy's case amounts to approximately 2.8 billion euros and in France 1.2 billion euros.

419 Figure 74 shows the relative wholesale gross welfare losses in each MS per individual household consumer. For comparability purposes, calculations for all MSs were made using the EU average household consumption level. The results point towards potential significant welfare losses remaining in several MSs, although the precise values would be affected by individual consumers' consumption levels[285].

279 Yearly gross welfare losses are thus calculated as the aggregated sum of the assessed price differentials between EU MSs and the Netherlands monthly prices, multiplied by the monthly demand of each MS.

280 The formation of similar final prices to TTF in all EU MSs is not guaranteed in the presence of comparable competition and liquidity values as the Netherlands. Different MSs' market fundamentals would play a specific role in the setting of final gas prices.

281 Some of these factors are analysed in the next section.

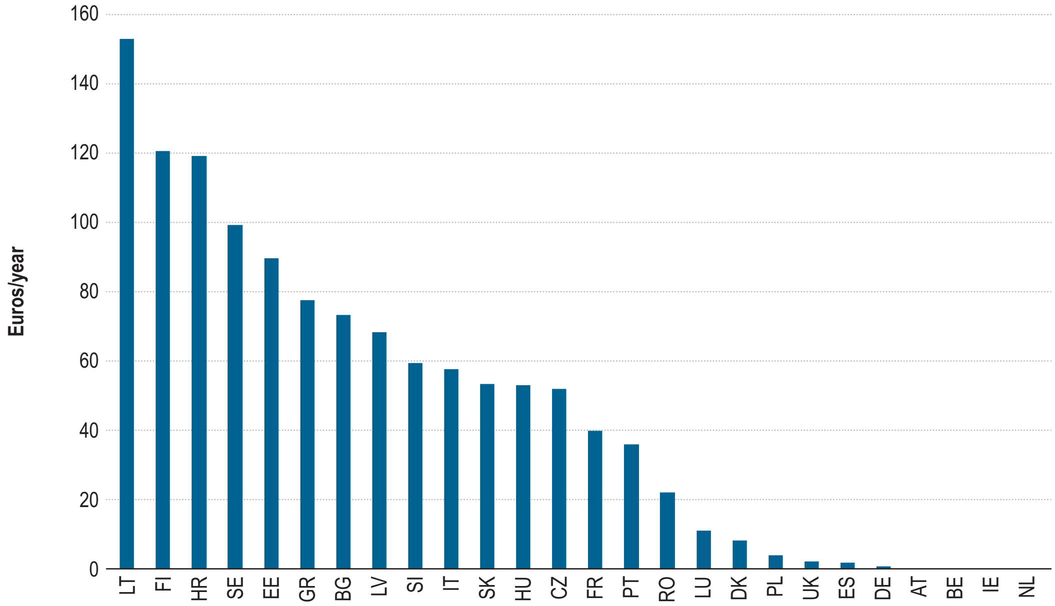
282 See the notes to Figure 73 explaining the limitations on estimates of wholesale prices in France and Italy.

283 Eurostat Comext data used in the price assessment refer to the gas import prices declared at the borders, based on information collected by customs agencies; they are deemed to be more representative of longer-term contracts.

284 Hub prices in both France and Italy (PEGs, PSV) are relatively convergent with TTF ones, but liquidity, particularly for longer curve products, is not so ample. According to specialised reports (ICIS Heren), during 2013 GDF and ENI obtained more hubs indexations and price discounts in their historical long-term contracts by increasing negotiations with upstream suppliers.

285 The EU average household consumption level considered is 15,000 kWh/year. This amount was calculated using EU MSs average from CEER National Indicators database. Significant consumption level differences may exist among MSs household consumers, a fact which would impact their precise welfare losses values.

Figure 74: Wholesale level of gross welfare losses per EU average household consumer in EU-26 – 2013 (euros/year)



Source: Eurostat Comext, Platts, NRAs, CEER Database Indicators data (2014) and ACER calculations

b) Net welfare gains estimations

420 Building on the gross welfare loss results, this section assesses potential net welfare gains across Europe by examining one of the several mechanisms that could serve to increase price convergence among EU MSs: the optimisation of existing capacities[286]. The scenario assumes that competitive firms would expand their sales to adjacent markets by using unused physical[287] capacities on existing cross-border interconnections (assessed as the IPs total technical capacity minus the physical registered flows during the year). These new entrants would undercut previous wholesale prices in entry markets, thus generating welfare gains.

421 This section also looks at the impact that new interconnection infrastructures could have on the reduction of supply constraints and the facilitation of new market entrants. However, given the complexity of the issue, no numerical analyses are presented on this particular aspect[288].

286 The Agency and CEER are aware that this scenario builds on a theoretical situation similar to the market coupling and implicit capacity allocation schemes referred to in the Electricity chapter. However, the physics of gas systems, the lack of liquid organised markets, contractual capacity issues, lack of trading counterparts, contractual obligations, gas resale restrictions, shippers' market strategies and other factors may in reality make optimisation of IPs capacities more difficult. The exercise aims to constitute a referential analysis which could be closer to reality in the future as IEM develops.

287 Unused physical capacity provides an indicator of the maximum new supplies which could be attracted to an adjacent market. Using unused physical capacity values assumes that all unwanted contractual capacity is made available on the secondary market and that no contractual congestion remains.

288 The scope of integration in EU gas wholesale markets can also be improved by several other instruments; (re)negotiation of upstream prices with suppliers, fairer allocation of existing capacities, the possibility of swapping flows between neighbouring countries, the deployment of an organised market fostering liquidity, the availability of alternative supply sources, and/or IPs tariffs aspects. Again, given the lack of data and the complexity of the issue, it has been not possible to include all these factors in assessments of other scenarios.

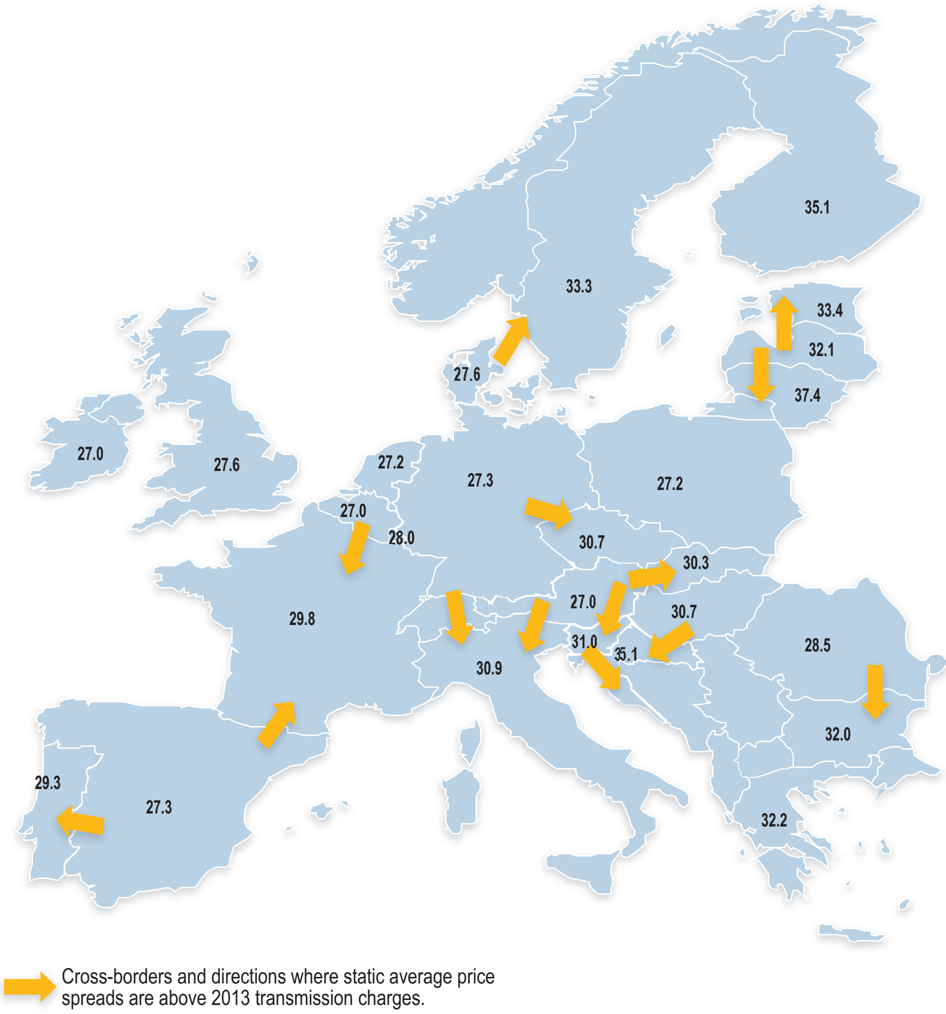
422 To our knowledge, the price convergence effect of new market entrants in EU gas markets has not yet been studied. This renders forecasts uncertain, and means that the benefits can only be correctly gauged on a case-by-case basis through experience. Hence, the results of the analysis presented below are static and based on assumptions about the new competitor's offered price level. It is also worth emphasising that the socially optimal level of investment (assessed in a cost-benefit analysis) is not necessarily the one that allows a 100% price convergence i.e. the costs of the new infrastructure could outweigh the benefits of lower wholesale prices.

423 The analysis is based on 2013 assessed wholesale price levels, recorded IPs capacity utilisation and registered gas flows. These inputs result from present market features and stakeholders' positions, but their interdependence could change in time, resulting in different values in the future. This analysis is not intended to forecast how the real physical flows should occur or which infrastructures should be constructed; it is intended to analyse only the range of welfare gains that seem to be theoretically feasible.

424 Figure 75 presents the 2013 EU MSs wholesale price levels used in the assessment. The blue arrows identify those border crossings and directions where zonal price spreads were – on a static yearly average basis – above the 2013 transmission charges at the respective IPs[289].

289 2013 cross-border IPs transmission tariffs across the EU were presented in the Agency/CEER MMR 2012, p. 194.

Figure 75: EU-26 Average annual cross-border gas wholesale price spreads – 2013[290] (euros/MWh)



Source: Eurostat Comext, Platts, NRAs data (2014) and ACER calculations

Note: As indicated in the note accompanying Figure 73, the indicated prices result from the application of the ACER/CEER MMR2013 methodology that, given its limitations, may result in inaccuracies for certain MSs.

425 Figure 76 shows physical capacity availability values for all EU-26 cross-border IPs in 2013. Those cross-border IPs connecting market zones where the price spreads were above the transmission tariffs are indicated by a grey circle.

290 See footnote 278.