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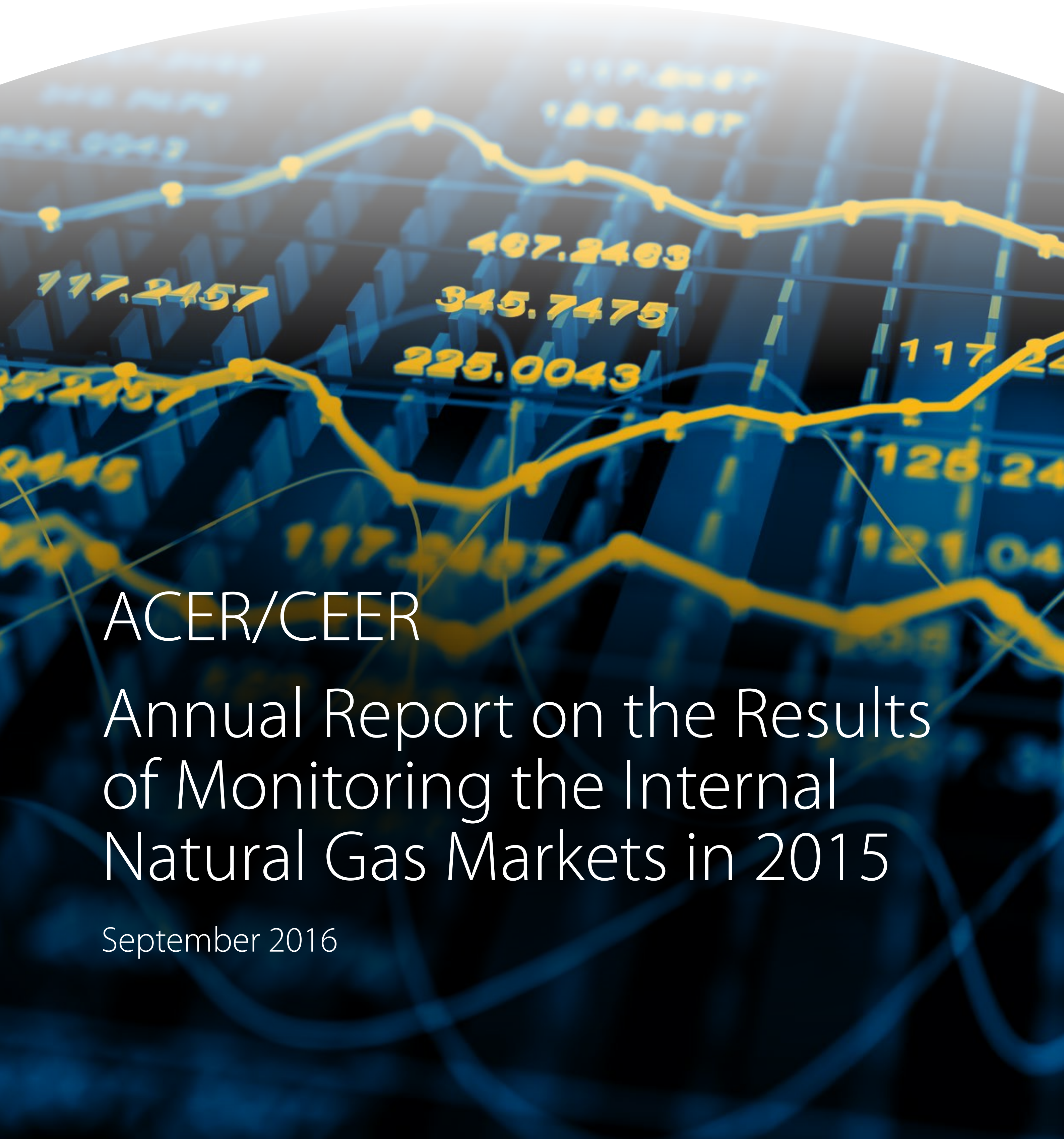

ACER/CEER

Annual Report on the Results of Monitoring the Internal Natural Gas Markets in 2015

September 2016

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Contents

1 Introduction

1 The Gas Wholesale volume is one of four volumes that make up the Market Monitoring Report (MMR). The other volumes are Electricity Wholesale, Electricity and Gas Retail, and Customer Protection and Empowerment. For this year, the Gas and Electricity Wholesale Chapters will be published earlier than the two other volumes. This will allow the reader to have access to these documents when they are ready, i.e. earlier than for the previous MMR.

2 This MMR is in its fifth edition and the Gas part sees some innovations. While this volume continues to monitor the state of the gas wholesale markets in the EU and its trajectory toward an internal gas market, the Agency for the Cooperation of Energy Regulators ("the Agency" or "ACER") has added two critical components.

3 Firstly, the calculation of the first set of Gas Target Model[1] (GTM) metrics of which a number are based on data reported under REMIT[2]. This allows for a more granular approach to assess key aspects of gas wholesale markets, such as the status of gas hubs in the EU as well as the concentration in wholesale markets. The reported REMIT data used in this MMR was not assessed for data quality and presents a limited set of data received by the Agency from October 2015 to April 2016. Pursuant to Article 7(3) of REMIT, 'the Agency shall at least on an annual basis submit a report to the Commission on its activities under this Regulation and make this report publicly available. In such reports the Agency shall assess the operation and transparency of different categories of market places and ways of trading […]. Reports may be combined with the MMR report referred to in Article 11(2) of Regulation (EC) No 713/2009.' Therefore, in line with Article 7(3) of REMIT, the Agency is using REMIT data for this MMR published in accordance with Article 11(2) of Regulation (EC) No 713/2009.

4 Secondly, a review of the implementation of the gas network codes (NCs) and their impact on gas wholesale market functioning. A first series of metrics defined for this purpose are assessed in this volume. The monitoring of the impact of network codes is the direct result of a legal requirement that the Agency has to fulfil[3]. Over the years more metrics will be added, which will allow for a more holistic review of this impact.

5 Chapter 2 of this volume includes a review of the main developments affecting gas markets in 2015. Chapter 3 focuses on what we could call the "hard core" building blocks on which a well-functioning gas market depends. This looks at diversity of supply sourcing and levels of concentration in the upstream market, gas flows and storage dynamics. This year's gas wholesale monitoring focuses along Chapter 4 on trading at gas hubs, with an emphasis on selected GTM metrics, as well as a review of price metrics. Additionally selected organised market places and virtual trading points are further analysed in detail. Chapter 5 ends with a deep dive into the monitoring of the impact of network codes.

6 Overall, the European Union (EU) Gas Wholesale Market continued to progress and market dynamics seem to work better and better. This is mainly evident from the market-driven development of gas hubs and the ongoing integration of these trading platforms. Growth can be observed not only in volumes, but also in product offering. These positive market trends can be clearly observed beyond North West Europe (NWE[4]), in Central and Eastern Europe (CEE[5]) and in selected markets in the Mediterranean rim[6]. South-South East (SSE[7]) and Baltic[8] MSs need further progress. This is also evident from high levels of price convergence and correlation of hub product prices. Selected infrastructure investments made this feasible or are having a reinforcing impact.

1 See ACER GTM 2014 here: http://www.acer.europa.eu/events/presentation-of-acer-gas-target-model-/documents/european%20gas%20target%20model%20review%20and%20update.pdf.

2 EU Regulation on wholesale energy market integrity and transparency. See: http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2011:326:0001:0016:en:PDF.

3 Article 9(1) of the Regulation (EC) No. 715/2009 establishes that the Agency shall monitor and analyse the implementation of the network codes and the Guidelines adopted by the Commission and their effect on the harmonisation of applicable rules aimed at facilitating market integration.

4 NWE is Benelux, Denmark, France, Germany and the UK. Austria is also included in this group.

5 The Czech Republic, Hungary, Poland and Slovakia.

6 The Mediterranean rim is Greece, Italy, Portugal and Spain.

7 Bulgaria, Croatia, Romania and Slovenia.

8 Finland, Latvia, Lithuania and Estonia.

2 Gas wholesale market developments[9]

Chapter summary

This Chapter reports on EU specific gas wholesale market developments in regulation, supply, demand, and prices.

Gas prices registered a constant decline across EU Member States which is the result of market fundamentals[10] and increased gas-to-gas competition. This goes at the expense of long-term bilateral contracts, also in the Central Eastern and Southern regions. Regulatory provisions like the implementation of network codes and of initiatives like the Gas Target Model facilitate hub development by breaking down cross-border competition barriers.

On the supply side, indigenous production continues to decrease, increasing further the EU's dependency on imports. The imports of Liquefied Natural Gas (LNG) increased thanks to its improved economics. This is linked to the growing global supply and lower than expected demand in Asia.

The EU's market integration policy is also affecting neighbouring countries, including importantly Ukraine which is benefiting from this. Reverse-flows capabilities on the EU borders have allowed Ukraine to tap into EU hubs and thus to secure a hub-based source of gas supply.

2.1 Recent EU policy environment

7 The EU Regulation on wholesale energy market integrity and transparency (REMIT) came into force on 28 December 2011. It provides an EU-wide regulatory framework specific to wholesale energy markets for detecting and deterring market abuse. In this context, market participants are required to report, directly or indirectly, detailed information regarding their wholesale market trading activities. Reporting of orders and trades to the Agency started on 7 October 2015 (for products admitted to trade in organised market places). For this MMR these data has been used, in an aggregated way, to calculate selected metrics, such as orders' bid-ask spread, order book volumes and number of trades.

8 In 2015, the Capacity Allocation Mechanism (CAM) and Balancing (BAL) Network Codes became applicable. The CAM[11] Network Code standardises cross-border capacity products and their allocation via transparent auctions held on joined booking platforms. The BAL Network Code[12] establishes a set of market-based measures for balancing, where both the Transmission System Operator (TSO) and market participants are incentivised to buy and sell gas for balancing purposes on the spot markets. This is subject to the publication by the TSO of reliable and updated data on the system's current and forecasted status and on the market participants' positions. The Congestion Management Procedure (CMP)[13] Guidelines, which entered into application in 2013, establish a set of measures in order to prevent and reduce contractual congestions at cross-border points in the EU. The Interoperability Network Code[14] has been finalised whereas the Tariffs Network Code[15] is still going through the legislative process. As network codes are entering into force and with them the legal requirement for the Agency to monitor their market effects, this MMR assesses this for the first time.

9 The market trends referred throughout the chapter confirm the Agency view on the basis of specialised media reports, different forum presentations and expert views.

10 I.e. depressed gas demand, oversupply market context and declining oil prices among others. See section 2.4.

11 Commission Regulation (EU) No 312/2014 of 26 March 2014 establishing the Network Code on Gas Balancing of Transmission Networks: http://eur-lex.europa.eu/legal-content/EN/ALL/?uri=CELEX:32013R0984.

12 See: http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A32014R0312.

13 Commission Decision of 24 August 2012 on amending Annex I to Regulation (EC) No 715/2009 of the European Parliament and of the Council on conditions for access to the natural gas transmission networks (2012/490/EU): http://eur-lex.europa.eu/legal-content/EN/ALL/?uri=CELEX%3A32012D0490.

14 Regulation EC 2015/7030. See: http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv%3AOJ.L_.2015.113.01.0013.01.ENG.

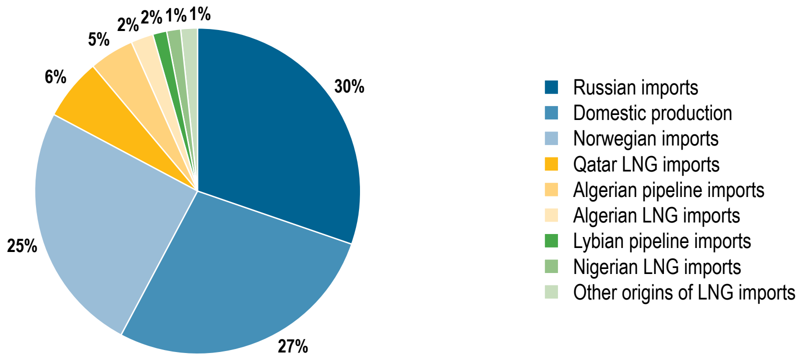
15 See: http://www.acer.europa.eu/en/gas/framework%20guidelines_and_network%20codes/pages/harmonised-transmission-tariff-structures.aspx.

9 A number of legislative and policy initiatives relevant for the gas market were put on the table in 2015, the changes in the ETS system and the Energy Union[16]. Selected Energy Community contracting parties, like Ukraine, are also implementing the Third Energy Package. This is expanding the EU energy market model beyond its borders.

2.2 Supply developments

10 As shown in Figure 1, the gas supply portfolio of the EU relies primarily on imports from third countries of piped gas and via LNG. These account for 70% of total consumption. Russia is the main supplier to the EU with a share of around 30% of supplies (42% share of imports from third countries[17]). Norway is the other key EU supplier, with Algeria following at some distance. LNG imports totalled more than 12% of EU supplies in 2015, a 18% increase compared to 2014. Qatar is the key LNG supplier, followed by Algeria. Domestic conventional EU production accounts for less than 30% of overall gas supplies and its share continues to decrease (-8% in 2015 vs 2014 and -10% in 2014 vs 2013, approximately 15bcm less in two years). It is expected that by 2030 the share of domestic production could drop to below 20%[18].

Figure 1: EU gas supply portfolio by origin in 2015 in % (100% = 437 bcm)



Source: BP Statistical Review 2016. BP EU domestic production figures deviate slightly from Eurostat figures.

Notes: The difference in consumption and supply figures are the result of re-exports of LNG, stock changes (i.e. underground storages, regasification terminals) and transportation losses.

11 Figure 2 presents recorded international gas traded volumes in 2015, with a focus on the EU. The graph underlines the EU's dependence on gas imports compared to other regions. In 2015, imports increased by 5% in comparison to 2014.The bedrock of contractual mechanisms for physical supply in most EU Member States (MSs) is bilateral long-term contracts[19]. The incorporation of hub price elements in the price indexation formulas of long-term contracts continued to increase in 2015. The International Gas Union (IGU)[20] estimates that hub-price linked long-term contracts, together with physical volumes purchased on hubs, account for 64% of supplies across the European continent. Nevertheless, substantial differences exist across MSs[21].

16 See: http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM%3A2015%3A80%3AFIN.

17 Gazprom exports to Europe increased 8% in 2015 with respect to the previous year. See: http://www.gazpromexport.ru/en/statistics/.

18 See: http://www.eurogas.org/uploads/media/Eurogas_Workshop_Long-Term_Outlook_for_gas_to_2035_221013.pdf.

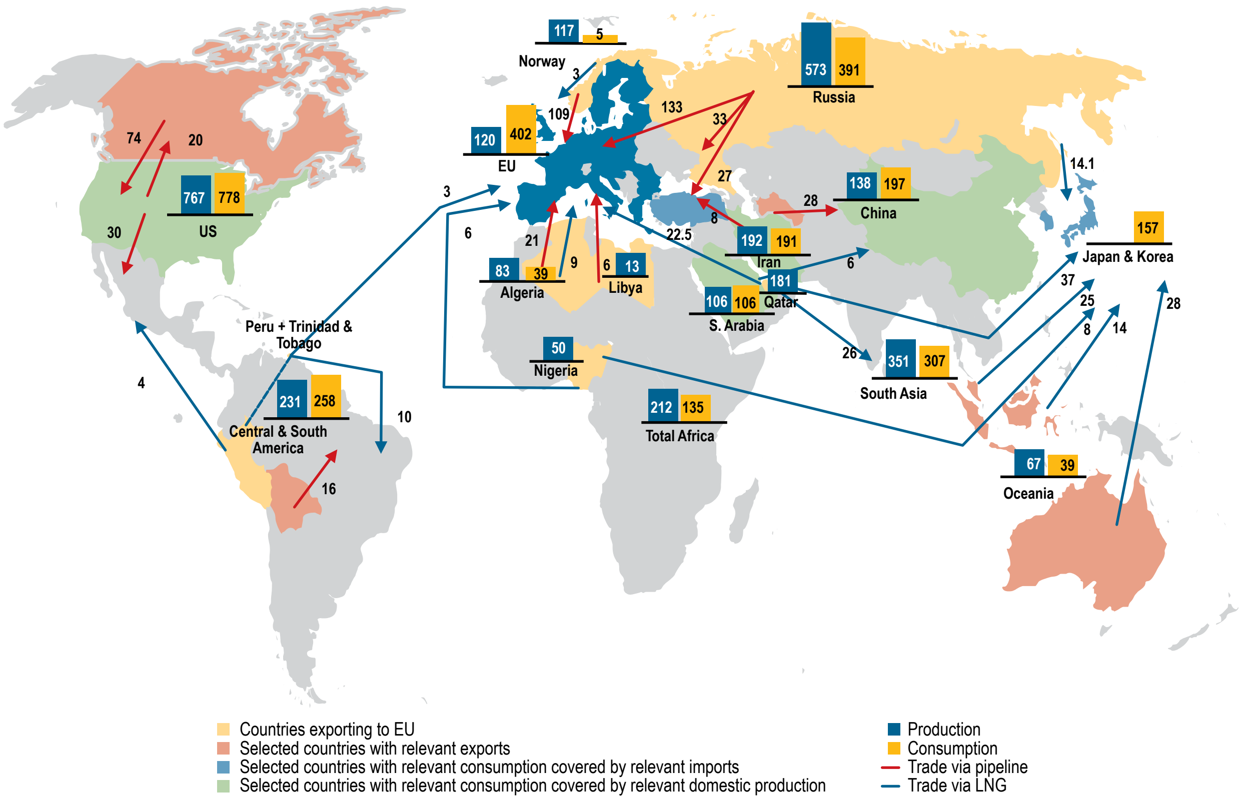
19 Significant volumes purchased initially under long-term contractual mechanisms may be resold latter by wholesale companies on hubs.

20 See IGU 2016 price survey result per EU region: http://www.igu.org/sites/default/files/node-news_item-field_file/IGU_WholeSaleGasPrice_Survey0509_2016.pdf.

21 E.g. according to IGU, gas-on-gas price formation is deemed to apply to 92% of supplies in the NWE region (Benelux, Denmark, France, Germany and the UK) and Austria; it drops to approx. 60% in the CEE region (the Czech Republic, Hungary, Poland and Slovakia), 35% in the Mediterranean area (Greece, Italy, Portugal and Spain) and is very limited in the SSE region (Bulgaria, Croatia Romania, and Slovenia).

12 Hub traded volumes increased year-on-year by 9% during 2015. As a result of the more prominent role of hubs as well as the increasing availability[22] of cross-border capacity, that contributes to enhance market integration, gas price formation in the EU is increasingly a matter of gas-on-gas competition factors.

Figure 2: International gas consumption, production and key trade movements during 2015 – (bcm/year)



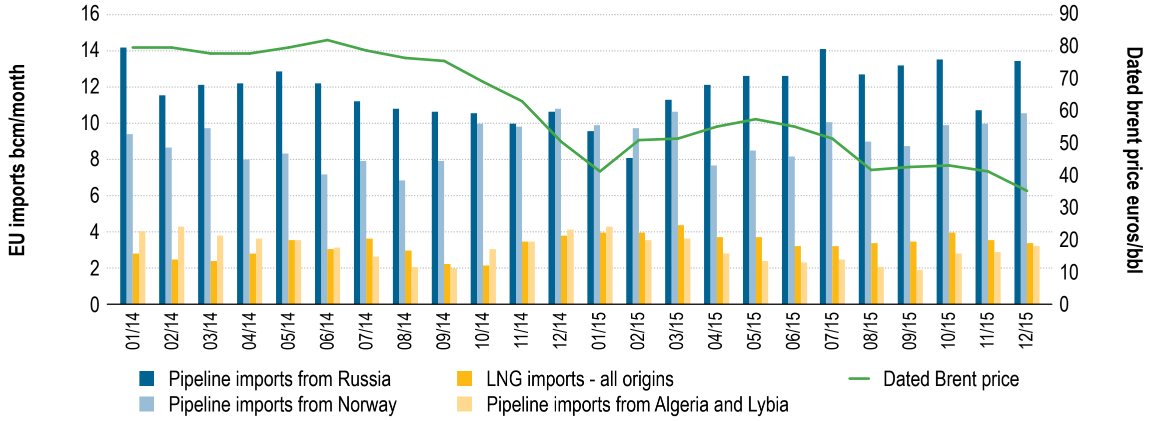
Source: BP Statistical review (2016) and ACER calculations.

13 The decreasing oil price impacted long-term contracts purchase strategies. Shippers tried to price hedge their supplies as far as their annual take-or-pay obligations and daily nomination would allow. This resulted in a reduction of Russian imports during the first quarter, as these tend to be more indexed to oil[23] as opposed to, for example, Norwegian gas contracts. Norwegian exports and LNG on the other hand increased. Also, storage withdrawals accelerated at the beginning of 2015 in order to compensate for the Russian gap and to provide space to inject cheaper gas later, following an expectation of lower summer prices. Russian, but also Algerian supplies recovered from the second quarter onwards when gas oil-indexed prices became more competitive. This is illustrated in Figure 3.

22 Capacity is increasingly made available thanks to new infrastructure investments but also to a gradual implementation of CAM and CMP harmonized provisions that serve to optimize their use.

23 In February 2015 – a winter month – aggregated Russian imports fell to the lowest monthly value in three years. The significant decline of the oil price since summer 2014 started to be more reflected in Russian import prices from the second quarter of 2015 onwards. The reason is that a six to nine months forward lag is usual practice in the pricing formulas of long-term oil indexed gas contracts.

Figure 3: Evolution of EU gas import volumes and oil price – 2014-2015 (bcm/month and euros/barrel)



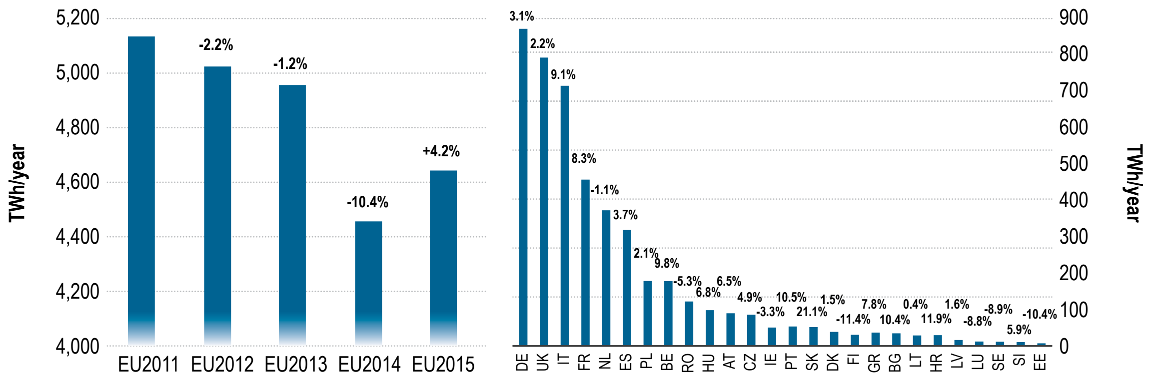
Source: IEA, Platts and ACER calculations.

2.3 Demand developments

14 EU gas consumption totalled 4,650TWh in 2015, a 4.2% recovery compared to 2014 and the first increase following four consecutive years of decline[24]. The recovery is mainly explained by somewhat colder weather conditions in the 2014/2015 winter compared to the very mild winter of the preceding year, which stimulated residential and commercial demand in the first quarter[25]. Moreover, declining gas prices led to a modest improvement in gas-to-power economics, allowing for a certain recovery – or at least stabilising gas-fuelled generation output. Examples of large markets using gas for electricity production include Spain, Italy, and the UK[26]. Nevertheless, EU gas demand is fragile and there is no structural demand recovery, given weak demand fundamentals, such as low economic growth, energy efficiency improvements and modest demand for electricity generation. The latter is influenced by more competitive coal prices[27] and increasing RES penetration.

15 While the EU, as a bloc, saw an increase in demand, the picture of demand recovery varies by MS. As Figure 4 shows, several markets underwent significant decreases reflecting local market dynamics.

Figure 4: EU gas gross inland consumption – 2015 (TWh/year and % variation with respect to 2014)



Source: Eurostat (Data series nrg_103m, April 2016).

24 EU gas consumption decreased year-on year by 10.4% in 2014, 1.2% in 2013, 2.2% in 2012 and 10.5% in 2011.

25 Summer temperatures have become an increasingly important factor in gas demand connected to weather patterns, as they have strong effects on the consumption of electricity for cooling; 2015 summer temperatures were also slightly warmer than 2014 ones.

26 See ENTSO-E statistics per EU MS: https://www.entsoe.eu/db-query/production/monthly-production-for-a-specific-country. In IT and ES a comparatively lower production of RES (mainly to declining hydro production) facilitated some increase in CGC generation which is being reinforced in 2016. In the UK, the government levies a price floor charge for CO2 emissions on all fossil fuels used for electricity generation. Even at a time of depressed EU ETS prices, this top-up tax incentivises the competitive use of gas instead of coal.

27 Overall the availability of cheap coal imports and the low price of CO2 allowances caused gas to remain less profitable than coal-fired generation during the year.

16 Although EU gas demand rose in 2015, future demand is expected to remain sluggish. Further evolution will undoubtedly depend on a number of (interrelated) market and regulatory factors, of which the competiveness of gas relative to other fuels will be a key driver[28]. Other determining factors are technical achievements in energy efficiency, CO2 pricing, fuel taxation levels and environmental targets. According to the IEA, gas consumption in Europe may not return to 2010 levels until the early 2030s[29].

17 On the other hand, there are prospects that certain innovative technological developments, in combination with, for example, environmental legal requirements, might somewhat boost gas consumption in the EU[30]. These pockets of growth, also called new uses of gas, point in particular to an increase in gas use in land and marine transportation, both in liquefied (LNG) and compressed (CNG) forms.

18 The number of natural gas vehicles (NGVs) in the EU reached 1.2 million units in 2014, equivalent to 3.2 bcm consumption. The penetration varies substantially among MSs, with the largest market penetration observed in Italy and Bulgaria, 2.2% and 2.0% of total vehicles respectively. Italy also has the largest number of filling stations (1,071) and NGVs (904,000) in the EU. Germany hosts the second largest number of filling stations (851). Overall, NGVs penetration in the EU accounts for 0.4% of Light Duty Vehicles (LDVs). LNG infrastructure is even more limited, with some 66 refilling stations and 1,500 LNG vehicles across Europe, mostly in the UK, Spain and the Netherlands.

19 Actual growth of this segment will be driven by market and regulatory issues including gasoline/diesel vs gas price dynamics, taxation levels, infrastructure availability[31] and market uptake. Certain barriers prevent the wider commercialisation of natural gas as a transportation fuel. These include limited incentives, the limited choice of factory produced vehicles, uncertain tax policy and insufficient infrastructure.

20 To encourage the use of alternative fuelled vehicles, the Directive on Alternative Fuels Infrastructure (DAFI) was adopted in October 2014. It obliges MSs to draft a deployment strategy by November 2016, in order to ensure a minimum amount of infrastructure for alternative fuels is built across the EU.

2.4 Price developments

21 Sluggish gas demand, a (globally) oversupplied market, LNG playing an increasing role as a flexible gas swing source, depressed oil prices and changing gas contractual terms, all contributed to declining gas wholesale prices during 2015 in Europe.

22 Figure 5 provides an overview of the evolution of international gas wholesale prices using the most representative price indicators. Most notable in 2015 was a relative alignment of North East Asian LNG prices with EU prices. NE Asia LNG spot prices declined dramatically due to lower than expected gas demand in Asia. The price reduction registered in Europe further reduced the gas price-spread with the US market. However, market-specific situations, such as domestic shale gas production, kept US wholesale prices as 40% on average than those in Europe. US Henry-Hub prices, adjusted for liquefaction, shipment and regasification costs, provide an extra signal for EU gas price formation[32], a signal more noticeable this year with regard to EU hubs forward prices negotiation, particularly at UK NBP.

28 E.g. according to some market analysts there is 50 bcm of switching potential if coal prices would remain relatively stable and EU hub prices continued to decline towards the Henry Hub reference. See for example Timera Energy: http://www.timera-energy.com/gas-vs-coal-switching-in-europe-key-markets/.

29 See IEA World Energy Outlook 2014 fact sheet: http://www.iea.org/media/news/2014/press/141112_WEO_FactSheet_FossilFuels.pdf.

30 For a review of the developments technical features and growth forecasts see the ACER study executed by Kantor: http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/Regulatory%20Implications%20of%20New%20Developments%20in%20the%20Gas%20Supply%20Chain.pdf.

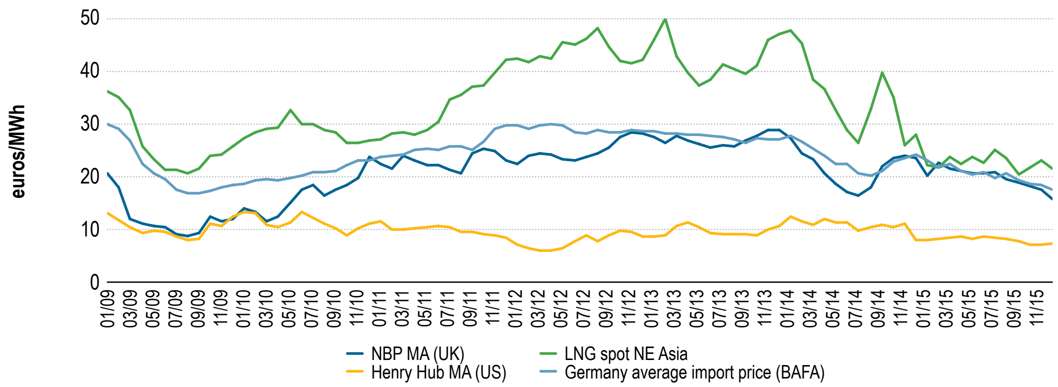
31 See EU current gas filling station availability here: http://www.ngvaeurope.eu/european-ngv-statistics. Italy and Germany have the highest uptake in absolute numbers.

32 According to the estimates of market analysts, the investment decision on new LNG liquefaction projects on exporting gas from the US into the EU would require a Henry Hub–EU price spread of about 7-8 euros/MWh. This spread is taken as a threshold to compensate for the LNG export costs, i.e. tolling fees plus liquefaction, shipment and regasification costs. Nonetheless, LNG costs are very project specific and depend on a number of technical, contractual and financial aspects. See for an example and analysis of the topic: http://www.igu.org/sites/default/files/node-page-field_file/IGU%20-%20World%20LNG%20Report%20-%202014%20Edition.pdf The narrowing EU-US spread is in fact putting pressure on certain new export projects, and market analysts believe that far from a clear direction, US exports will need to adapt to a dynamic changing market, as other target markets are also potential customers. This is also favoured by a more flexible contractual framework that allows buyers complete destination flexibility to respond to spot price signals.

23 Overall European gas markets continue to move towards a gas hub based model at the expense of the traditional role of long-term bilateral contracts. NWE markets are leading the pack, while other regions like the CEE or MSs such as Italy are also picking up. This redefines the business strategies of market players – from upstream producers, midstreamers to large final consumers active on hubs – to accommodate a gas-on-gas competition framework. Regulatory provisions like the network codes and initiatives like the GTM facilitate hub development by breaking down cross-border competition barriers.

24 Upstream producers are forced to increasingly incorporate gas hub (price) elements in their long-term contracts price indexation formulas. They have an incentive also to actively trade on hubs in the hope of influencing price formation as this affects their bilateral long-term contracts. Various producers exhibit different practices. Statoil is selling an increasing share of gas directly in the spot markets and to large end-customers. The company has revised most of its long-term contractual pricing terms, gradually moving away from oil indexation into hub indexation[33]. Also Gasterra[34] resells sizable volumes of Dutch gas into TTF via hub products[35]. Gazprom and other key producers, such as Sonatrach and several LNG exporting companies, prefer long-term bilateral contracting where oil-indexation is deemed still to play a more relevant role. However, Gazprom has, for example, increased its direct trading presence on EU hubs. Also in September 2015 it conducted a gas auction in order to test new mechanisms for selling gas. (See further analysis in Section 2.5).

Figure 5: Evolution of international wholesale gas prices during 2009 – 2015



Source: Platts, Thomson Reuters, BAFA and ACER calculations.

25 Decreasing international oil prices are still an important factor explaining lower EU gas prices. As 2015 progressed, retreating oil prices dragged down prices in oil-indexed gas supply contracts, exerting a further downward effect on hub prices. As gas prices track oil prices with a lag of several months, the impact was more clearly felt as 2015 advanced. This encouraged shippers to delay the purchase of gas acquired under contractual supply mechanisms, particularly from Russia.

26 The price of LNG also declined globally in 2015 impacting EU markets. Several factors explain this: lower than expected demand in Asia, which accounts for two thirds of global LNG deliveries; growing supply competition from newly commissioned liquefaction capacity in the Asian-Pacific basin where key players like Australia and the US[36] are exporting domestic unconventional gas; and lower oil prices reduced the charges of oil-indexed LNG long-term contracts[37]. For Europe, improved LNG competitiveness implied higher LNG imports during 2015, primarily into the UK and Spain.

33 See: http://www.statoil.com/en/OurOperations/Gas/Pages/Market.aspx

34 Gasterra is not a producer, but a sole entity entitled to sell and trade gas from the Groningen field as an outcome of the national law and contractual arrangements. NAM is the company responsible for producing the gas from the Groningen field. Gasterra purchases most of the gas produced by NAM (but also from other producers) under long-term contracts while its selling strategies involve hub trading and other contractual arrangements. See further details in Gasterra's annual report. See: http://www.gasterra.nl/en/news/publication-annual-report-2015.

35 A similar role is played by DONG Energy in the Danish market.

36 The first US LNG export cargo was shipped in February 2016, destination Brazil.

37 LNG global supplies, particularly Asian LNG markets, are chiefly sourced under oil-indexed long-term contracts. Asian LNG prices typically show a 3 to 5 month lag to oil prices. Anticipating lower LNG oil-indexed prices at the onset of 2015, purchases were reduced at the end of 2014 freeing up gas volumes that traded at spot markets with a discount.

27 LNG oversupply made LNG the supply mechanism that is helping to align intercontinental prices, including EU hub price formation. This situation corresponds with global LNG markets increasingly becoming more flexible and shorter-term price oriented, reinforced by the fact that regasification terminals in Europe have spare capacity[38]. In this regard, EU markets are among the key drivers for setting LNG spot pricing globally. The NBP hub is one of the key global references for market-based LNG contracts.

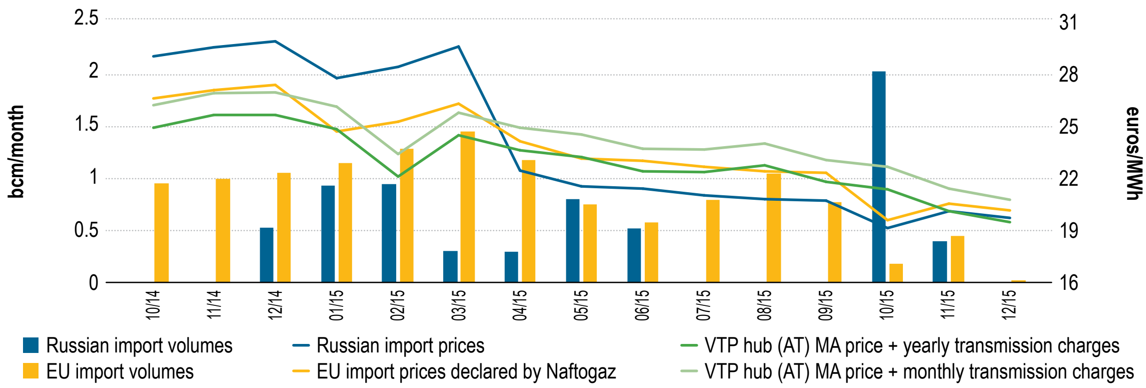
28 Developments in the global LNG market also exerted downward pressure on EU gas hub prices as spot-priced LNG vessels are important in determining marginal hub prices. Several factors explain this. Firstly, it lowered the prices of oil-indexed LNG supply contracts in the Mediterranean basin. Secondly, significant volumes of price competitive and destination flexible LNG – previously destined for Asian markets – were diverted to Europe. Thirdly, the presence of available regasification capacity levels at EU terminals. Fourthly, competition between LNG and pipes, where LNG acts as a ceiling price benchmark for other upstream producers.

2.5 Trends in Ukraine and Russia affecting EU markets

29 The EU's market integration policy is intended to create competitive and secure wholesale gas markets across Europe. This development is also affecting neighbouring countries, including importantly, on the gas side, Ukraine. The ongoing process of gas market development in Ukraine is still at an early stage and security of supply is one of Ukraine's main concerns. However, developments in the EU gas market enable Ukraine to benefit from this evolution. Two factors explain this: reverse flows[39] especially at the Slovakian border allowing Ukraine to import more sizeable volumes of gas from the EU, and improving liquidity at neighbouring EU hubs, i.e. the Austrian VTP and the German NCG, but also developments at the Polish, Czech and Slovakian hubs. This created favourable conditions to improve Ukraine's import diversification. Besides direct imports from Russia, it can now tap into a second, hub based source. The total volume of natural gas imported by Ukraine from the EU in 2015 was 9.5bcm, compared to 6 bcm of Russian imports. In comparison to the previous year, imports from the EU increased by 87%, while Russian imports decreased by 58%.

30 Figure 6 gives an impression of the pricing of gas sourced directly from Russia and via EU hubs. As declared by Naftogaz those prices have been converging in 2015. The hub price of VTP with respectively yearly and monthly transmission costs has been added for illustrative purposes as to show that Naftogaz' declared prices are to a certain degree aligned.

Figure 6: Estimated monthly Ukrainian gas import prices during 2015 (euros/MWh)



Source: volumes Naftogaz and IEA. Import prices: ACER calculations based on Naftogaz quarterly prices, Platts and ENTSOG TP

31 Greater reliance on EU supplies in the last months of 2014 was also due to Naftogaz' decision to postpone higher volume purchases from Gazprom until 2015. This was because of the expectation that decreasing international oil prices would allow purchases from Gazprom at a lower price, given prevailing oil-indexed price

38 See a dedicated analysis on the topic on this CEER LNG TF paper: http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Gas/2016/C15-LNG-25-03_LNG-SoS%20Analysis_3-Feb-2016.pdf.

39 Physical flows from the EU into Ukraine have been enabled since spring 2014 through smaller sized pipelines closer to the main trunk interconnection points with Ukraine: Beregdaroc-Testvériség in Hungary (trunk pipeline of Beregdaroc), Hermanowice in Poland (close to Drozdowicze) and Budince in Slovakia (close to Veľké Kapušany).

contract conditions. The first quarter of 2015 saw renewed imports from Russia, however the price that Ukraine was paying in the first quarter still exceeded the EU import price declared by Naftogaz[40].

32 The second quarter of 2015 brought significant changes, as Gazprom was aligning its oil-linked gas contract prices to EU market prices and also an agreement with Ukraine was reached. The price of Russian gas fell below the EU import price levels as reported by Naftogaz. Throughout 2015, it was observed that both prices were aligned, although the overall import volumes from Russia decreased mainly due to price and payment conditions negotiations between the countries. It would appear that besides the effect of reducing oil prices, the Austrian gas hub is increasingly putting a cap on what Gazprom can charge.

33 It is also worth mentioning that in April 2015 the EC sent Gazprom a statement of objections, which covered the EC's initial findings on the anti-trust proceedings against Gazprom initiated in 2012. The potential hindering of competition in CEE gas markets is being investigated. In particular, three aspects seem to be of concern for the EC as potential abuse of dominance behaviour: territorial restrictions on the resale of purchased gas, unfair pricing policy and unrelated commitments concerning gas transport infrastructure.

34 Gazprom disputes some of the allegations, particularly those regarding gas pricing. According to various market analysts, Gazprom seems to have reshaped somewhat its strategy and is taking a more market-oriented approach. In September 2015, for the first time, it conducted a gas auction in order to test new gas selling mechanisms and will repeat the exercise in 2016. This approach might be linked to its intention to obtain 100% access to the OPAL pipeline[41], currently limited to only a part by the third party access' exemption. Novatek, Rosneft and other producers are also challenging Gazprom's monopoly on gas exports. Approval by the Russian authorities of the export of Russian gas to the EU by more than one company may enhance the EU's gas sourcing options.

3 Upstream and infrastructure aspects of wholesale markets[42]

Chapter summary

This Chapter reviews market structure aspects that influence the way in which gas wholesale markets function. The focus is on diversity of supply and upstream market concentration aspects. More diversified and less concentrated markets allow market participants to strike a more cost-effective balance among their supply options.

To assess whether gas markets are structurally competitive, resilient and exhibit a high degree of diversity of supply, the GTM 2014 established the so-called 'Market health' metrics. A key factor for the analysis is market concentration, measured both in terms of the perspective of the number of distinct wholesale companies competing in the market, but also from the perspective of the geographical diversity of gas supply sources.

A significant disparity in terms of supply diversification is still observed across EU Member States: while some Member States have a balanced gas supply portfolio, other Member States still rely on less than three or even just one supply source. Commissioned new infrastructure positively impacted diversification in, for example, the Baltic and the CEE regions. This also allows market participants in this region to tap into adjacent hubs.

40 See EU import prices and volumes for 2015 declared by Naftogaz here: http://www.naftogaz.com/www/3/nakwebru.nsf/0/F681EC215D8E0C8CC2257F5300577E66?OpenDocument&year=2016&month=02&nt=%D0%9D%D0%BE%D0%B2%D0%BE%D1%81%D1%82%D0%B8&.

41 The OPAL pipeline is one of (two) pipelines connecting Nord Stream to the NWE gas network and has a flow capacity of 36 bcm/year. It crosses Germany and ends at the German-Czech border, connecting after with France via the Gazelle and the Megal lines. At present the pipeline capacity from Greifswald to Brandov is exempt from third-party access and tariff regulation on the condition that, unless a gas release programme is implemented, only up to 50% of capacity may be booked by undertakings dominant in the Czech Republic. This currently applies to Gazprom. The discussion concerns whether in the case of an exemption decision review competition would be hampered and also if allowing Gazprom full access to OPAL would affect security of supply as more gas would flow to Europe bypassing Ukraine.

42 Despite the fact that Belgium and Luxembourg integrated their H-gas markets from October 2015, data for both MSs are reported separately in all the sections of this volume.

Upstream supply concentration, as measured by the Herfindahl-Hirschman Index (HHI), shows an adequately diversified supply in more than a third of Member States, where the index value is in line or below the 2000 threshold. HHI improved in, for example, the Baltic and CEE regions.

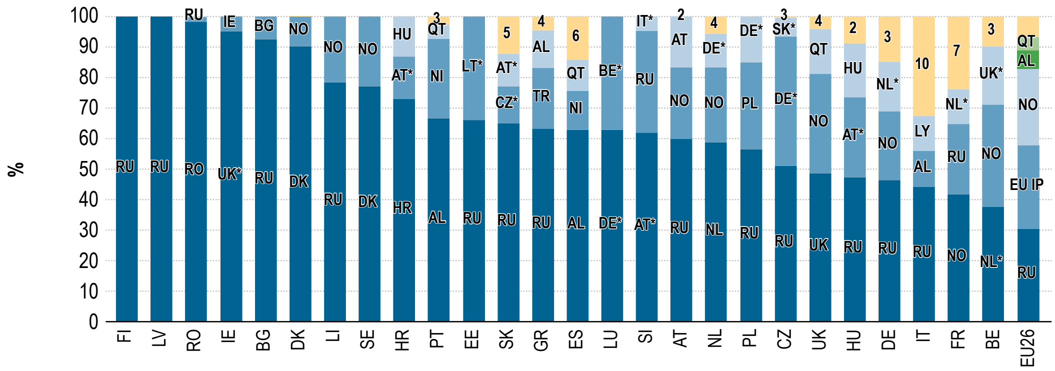
The utilisation of underground storage facilities decreased in the 2015/16 season. This is largely due to the steady decline of gas prices, which made imports and hub trading more competitive. However, the variations in daily withdrawals and injections dramatically increased showing the increased role of storage facilities in short-term optimisation and portfolio balancing.

3.1 Diversity in gas import sources

35 With regard to the number of import sources of supply per geographical origin, Figure 7 portrays the situation in 2015. Geographical origin is defined as 'the gas field origin where gas is produced or the firm origin from which gas is bought'. The GTM 2014 recommends all EU MSs to have at least three different geographical supply source origins, as this enables market competitiveness.

36 As illustrated, there is significant disparity in the number of geographical supply source origins across MSs. Diversification of gas sourcing has improved in recent years[43], for instance in the CEE and Baltic regions. They took advantage of hub development, cross-border capacity enhancements, via reverse flows and/or via new interconnectors, and the commissioning of new LNG terminals (e.g. Klaipeda). However, quite a few MSs are still de facto dependent on less than three distinct sources and even when MSs have access to more than three sources, one source often represents the bulk of total supplies. This is chiefly the case for Russian supplies to various MSs in Central and South-South Eastern Europe. It is anticipated that this situation will continue for some time, as selected infrastructure investments are still needed in certain cases, and these take time. An example of these are the bi-directional corridors that are planned to connect respectively Greece-Bulgaria-Romania-Hungary-Austria, or Poland-Baltics. These projects, once commissioned, will enhance the interconnectivity of these two regions with Central Europe.

Figure 7: Estimated number and diversity of supply sources in 2015 in terms of the geographical origin of the gas



Source: ACER calculations based on Eurostat Comext and BP Statistical report (2016).

Note: The asterisk refers to MSs featuring liquid organised markets where the gas has been purchased. See Annex 1 for additional clarifications.

3.2 Physical flows across borders

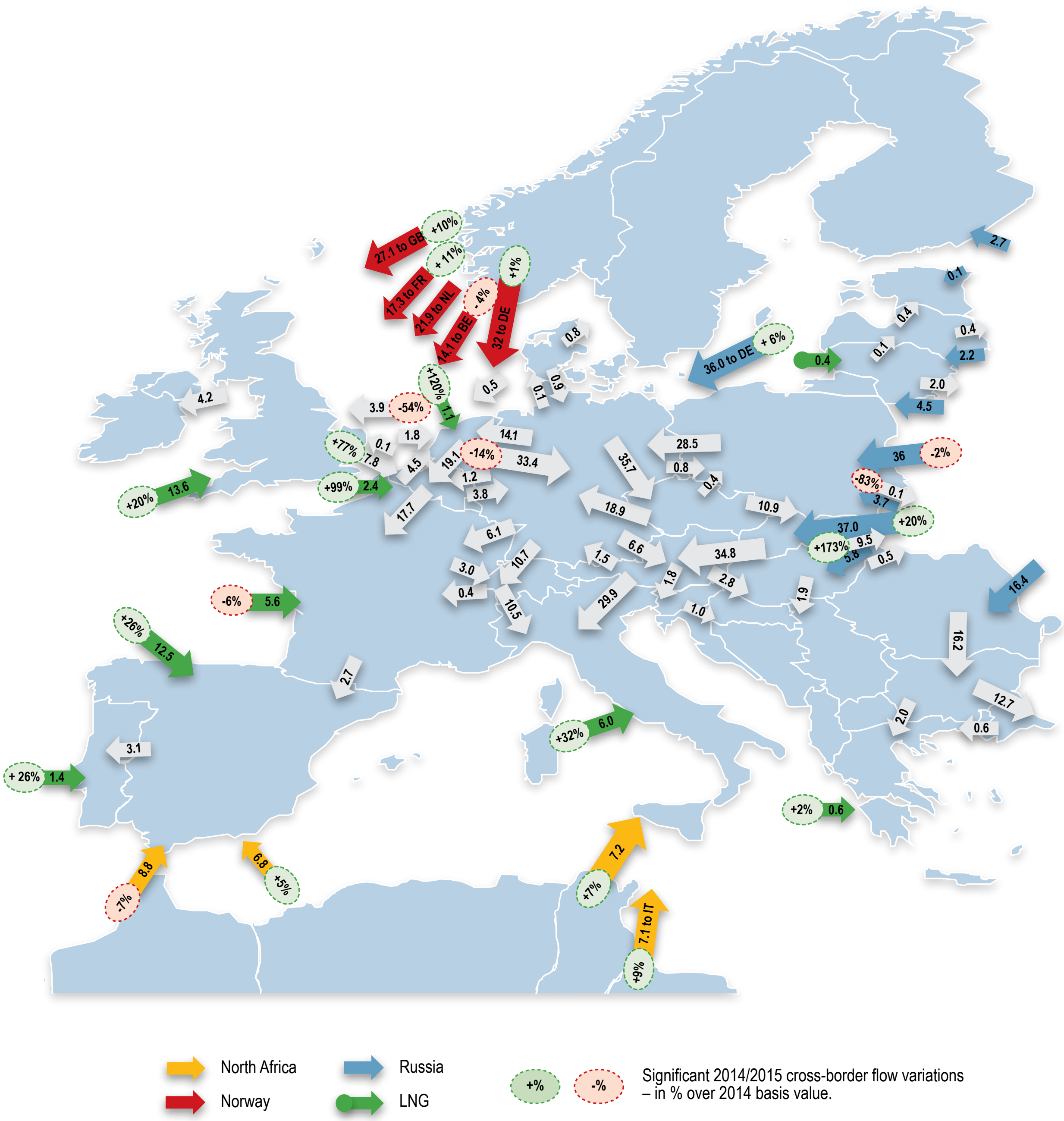
37 In addition to the geographical origin of supplies, Figure 8 shows registered physical flows across market-zone borders[44] in 2015 and the main variations with respect to 2014. The map shows not only how much gas enters the EU and where it enters, but also the intra-EU gas flows.

43 A comparison with 2013 values can be found in the MMR 2013.

44 The gas that physically flows across borders may have a distinct origin other than the exit zone (i.e. the geographical origin of the gas flowing from Austria into Italy is predominantly Russian).

38 Notable in 2015 in comparison to 2014 are the partial recovery of Russian gas transit volumes passing through the Ukrainian-Slovak pipeline[45] and the ongoing steady flow levels through Nord Stream. The consolidation of the Nord Stream route and the enhancement of reverse flows in the CEE region also explain the rise in the export of gas via German interconnection points[46]. Other noticeable aspects in 2015 are the surge in Norwegian gas exports to the EU, the recovery of gas imports from North Africa which are linked to retreating oil prices and the revitalisation of LNG imports[47].

Figure 8: EU cross-border gas flows in 2015 and main differences from 2014 (bcm/year)



Source: IEA (2015) and ACER calculations.

45 Reasons are primarily found in the stabilisation of the transits in comparison to the preceding year crisis. Maintenance works carried out on the Yamal and Nord Stream lines was also a contributing factor.

46 Export flows across Germany increased 35% year-on-year. See: http://www.ag-energiebilanzen.de/.

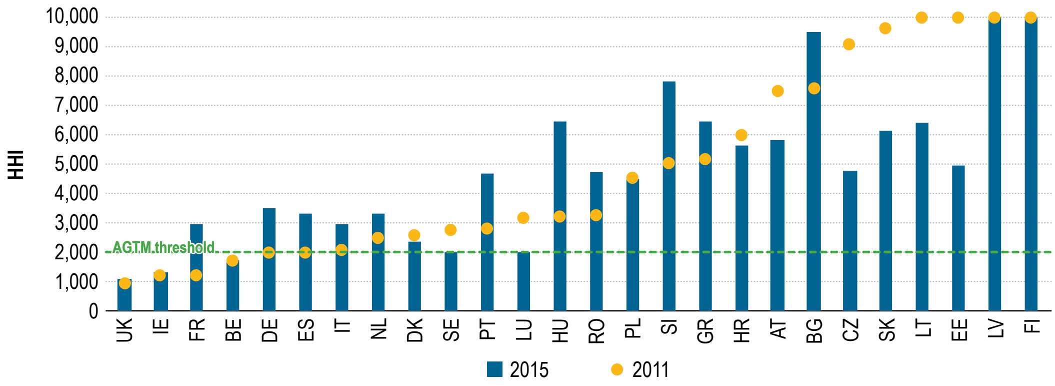
47 LNG flows were comparatively higher during the first half of the year, and lost ground in the second half in part due to the rise in Russian pipeline imports.

3.3 Market concentration of upstream gas companies

39 A high level of diversity of geographical origins of supply does not necessarily imply fierce competition at company level, even if evidence points to some degree of correlation between the two factors. The explanation is that two companies could be sourcing from the same upstream geographical origin and competing fiercely; on the other hand, a sole company could source its gas from distinct geographical origins and at the same time face no external competition from other companies. Therefore competition levels need to be assessed also via concentration indexes at company level.

40 To this end, the GTM 2014 includes an indicator, i.e. the HHI[48] concentration index of upstream gas sale companies, which examines more in depth competition at company level in the upstream market. In accordance with GTM methodology, the indicator does not take into account secondary sales from intermediaries[49]. The HHI threshold for a well-functioning market is a value of 2000. Figure 9 shows the estimated HHI values at MS level and their evolution with respect to 2011.

Figure 9: Estimated HHI index per EU MS at upstream sourcing companies' level 2011–2015



Source: ACER calculations based on Eurostat and Eurostat Comext, BP Statistical Report, Frontier Consultancy desktop research for GTM 2014 and NRAs data. (See annex 1 for methodology clarification)

41 As transparency of information on market shares of upstream producers is limited in many markets - the assumptions taken may have an impact on the calculations - hence the results have to be taken with some caution. Nevertheless, the analysis reveals interesting findings. Overall, more than a third of the MSs are below or close to the 2000 threshold, hence exhibiting concentration levels at the lower end. In contrast, mostly smaller gas markets score poorly on the HHI index. MSs that have well-functioning hubs and those that benefit from a flexible source, i.e. LNG, exhibit comparatively the lowest HHI values. MSs that fulfil their gas needs primarily from an adjacent market with a diversified hub also tend to exhibit low concentration values[50]. Ireland is one such example; it primarily sources gas from the UK, which has the NBP hub.

42 A comparison of 2015 with 2011 reveals some positive trends. Lithuania improved its HHI scoring dramatically, thanks to the commissioning of the Klaipeda LNG terminal. Unlike Latvia, Estonia seems to be willing to take advantage of the diversity of supply that Klaipeda offers. In the CEE region, MSs like the Czech Republic and Slovakia show improved HHI levels. They achieved this by progressively diversifying their supplies away from their historical Russian supplier.

43 Some MSs in the Mediterranean region show slightly higher HHI values in 2015 compared to 2011. The reason, among others, may be a comparative decline in LNG sourcing volumes[51], and also – and this is valid also for other MSs showing weaker HHI scores – the result of demand decline in recent years combined with the obliga-

48 HHI is calculated as the sum of squared market shares for each firm supplying gas at the import level.

49 E.g. domestic companies that may resell it within the MS wholesale market.

50 This situation is an outcome of the methodology. See Annex 1 for further clarification.

51 For example the enlarged pipeline interconnection capacity between France and Spain contributed to the decline of the share of LNG sourcing by displacing flows at periods when LNG prices were higher.

tion to honour legacy long-term gas supply contracts[52]. Methodological reasons also explain higher values in MSs as Slovenia and Hungary for 2015[53]. In the latter, the impact of the nationalisation policy is also a contributing factor in the deterioration of the HHI index.

3.4 Utilisation analysis of underground gas storage facilities

44 Storage facilities play an important role in covering EU gas demand especially during the winter season. They contribute to supplying gas in peak periods and ensure a certain level of security during sharp short-term changes in demand and/or supply. Moreover, storage facilities are essential for balancing the gas system, thanks to their flexible and quick response to changes in the system's balancing status.

45 The role of storage facilities varies among EU MSs: while in some MSs storage facilities are mainly considered as commercial tools, with market-driven, flexible and tailor-made products and with allocation procedures open to all interested parties, in other MSs storage facilities are critical to security of supply. Decisions on products, volumes and allocation procedures are set at a governmental level. In certain instances, these decisions may go beyond strict security of supply needs as such decreasng the flexibility in their access and utilisation from a purely market-based approach.

46 Some 17% of EU MSs gas demand was covered by storage withdrawals during the winter of 2015/16[54]. This is less than in the two preceding gas storage years, but in line with levels registered in earlier storage years. However, given the Russian-Ukrainian conflict, withdrawal levels related to the storage year 2014/15 might be considered as exceptional[55] .

47 An additional 14.5 bcm of storage capacity has become operational across EU MSs since 2009, a 17% increase (154 TWh out of a total 917 TWh of storage capacity)[56]. A situation of overcapacity in storage facilities might be observed across EU MSs, since 45% of EU storage capacity was left empty during the last storage year, compared to less than 30% in all previous storage years from 2010/11 to 2014/15. Figure 10 shows developments in storage capacity and in storage inventories from April 2010 to April 2016[57] .

52 In Germany for example the rise in HHI is linked to higher imports from Russia since the completion of Nord Stream but also to an upgrade of the Netherlands market share estimations.

53 See Annex 1, metric 5 calculation assumptions and methodology and footnote 151.

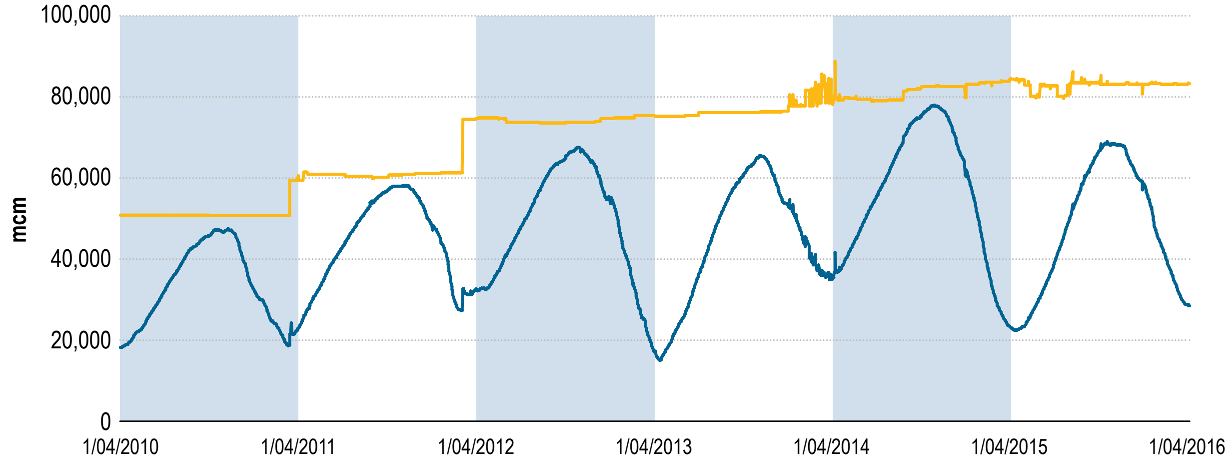
54 The indicator is calculated as follows: i) data for Alkmaar, Grijpskerk, Norg and Bergermeer storage fields in the Netherlands are not included, as the first three are to be considered as production facilities and operational data on the latter are not published in GIE's database; ii) gas demand for Ireland, Romania and Sweden is excluded from the calculation, as data related to their storage facilities is not available in GIE's database; (iii) for countries where storage data was published after the 1 April 2010, gas demand is included starting from the corresponding date of publication of storage data in GIE's database and (iv) gas demands of countries without storage facilities (Estonia, Greece, Finland, Lithuania, Luxembourg and Slovenia) has been included since 1 of April 2010.

55 See MMR 2014, pages 165–170.

56 GIE storage map 2015 http://www.gie.eu/index.php/maps-data/gse-storage-map. Capacity of the Bergermeer field is included, the capacity of the Alkmaar, Grijpskerk and Norg fields is not included (see footnote above).

57 Bergermeer is not included in the calculation as data are not available on GIE's database.

Figure 10: Daily inventories and capacity for gas storage from 2010 to 2016 (mcm)



Source: ACER based on Gas Infrastructure Europe's data.

Note: Increases in storage maximum technical capacity over the period January 2014 to May 2014 are due to data misreporting in GIE's database related to storage facilities in Germany, France, Poland, Hungary, the Czech Republic, Portugal and Slovakia. Therefore, they have not been considered as relevant for the analysis.

48 Eighty-three bcm of storage capacity was operational in EU MSs at the end of the storage season of 2015/16. Considering that only 14.5 bcm of new capacity became operational over the last six years, the capacity increase represented in the figure above over the observed period is mainly due to improved coverage of existing facilities in the GIE database.

49 The 2015/16 storage season started in April 2015 with a particularly low level of storage inventories (25%) compared to the previous storage year (46%), but similar to the average of the gas years before 2014/15[58]. This may mainly be due to suppliers maximising storage withdrawals in order to take advantage of lower oil-indexed prices later in the year.

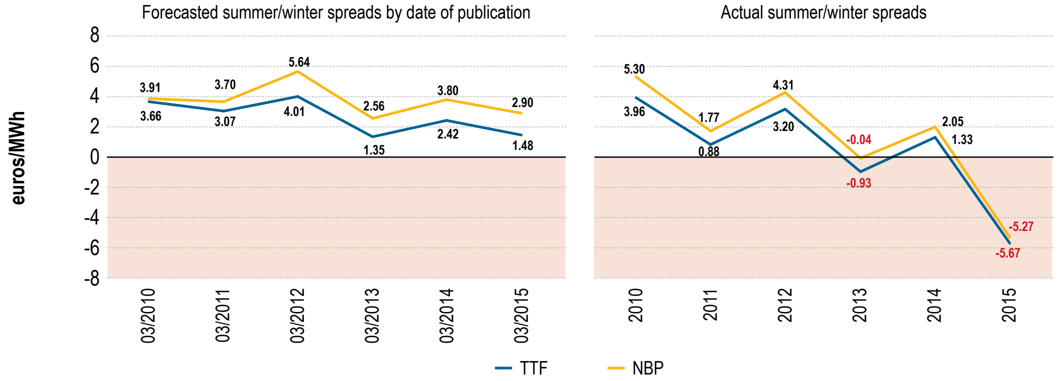
50 On the demand side, decisions on the extent to which storage is booked are based on a mix of economic, commercial and regulatory considerations. Factors which can affect gas storage injections include: availability of storage capacity (including any restrictions on cross border use); mandatory storage obligations at MS level; forward gas supply contracts held by gas storage users; storage capacity charges and the extent of storage capacity product flexibility and innovation, transmission network tariffs for putting gas into storage, as well as forecast winter-summer[59] gas price spreads. Factors which can affect gas storage withdrawal include: regulation of gas storage prices at MS level; long-term gas storage contracts and the terms and conditions for the use of such contracts; transmission network tariffs for withdrawing gas from storage; the level of gas demand generally and the price of storage gas relative to spot prices and prompt prices.

51 On the supply side, storage capacity products offered by the storage operators vary in terms of both product flexibility and length (products might cover from several years to just individual seasons or even shorter periods). As such, the decision to book storage capacity can be taken as from several years in advance to a date closer to the following storage year. In the second case, usually traders compare in the first quarter of the year the summer/winter forecasted spread to the storage total costs (i.e. capacity, injection, withdrawal charges). As shown in Figure 11, in spite of declining forecasted summer/winter spreads over the years, the forecasted summer/winter spread registered at TTF and NBP for 2015/16 was still positive and hovered between 1.5 and 3 euros/MWh. Also, a certain amount of storage capacity is still booked several seasons in advance.

58 As explained above, the withdrawal levels during storage year 2014/15 might be considered as exceptional given the Russian Ukrainian conflict.

59 The winter-summer gas price spread at a given hub can be calculated as the difference between the average price for a given gas supply contract at that hub from October to March and the average price of the same contract from April to September. Where the price spread is expected to be low, the attractiveness of holding gas in storage is reduced because, other things being equal, the margin between the price at which the gas can be sold at market (in winter) and the price paid for it (in summer) is reduced. Similarly, where an anticipated winter-summer spread does not materialise, demand for gas in storage is also reduced, because the price saving in buying storage gas instead of at the hub is reduced.

Figure 11: NBP and TTF forecasted and actual summer/winter spreads 2010–2016 (euros/MWh)



Source: ACER based on Platt's data.

Notes: 1) Ex-ante graph: for every storage year, the forward summer/winter spread is calculated as the difference between the Season +2 prices (covering the period from October "Y" to March "Y+1") and Season +1 prices (covering the period from April "Y" to September "Y"), as observed on average on March "Y".

2) Ex-post graph: for every storage year, the ex-post summer/winter spread is calculated as the difference between the average of the actual spot prices during the period from October "Y" to March "Y+1" and the average of actual spot prices during the period from April "Y" to September "Y".

52 Bearing in mind that both the access to storage facilities and the range and flexibility of products and conditions for storage vary across EU MSs due to technical and regulatory obligations and, as such, affect the response ability of storage facilities to short-term market signals, the following paragraphs describe the utilisation of storage facilities during the storage year of 2015/16.

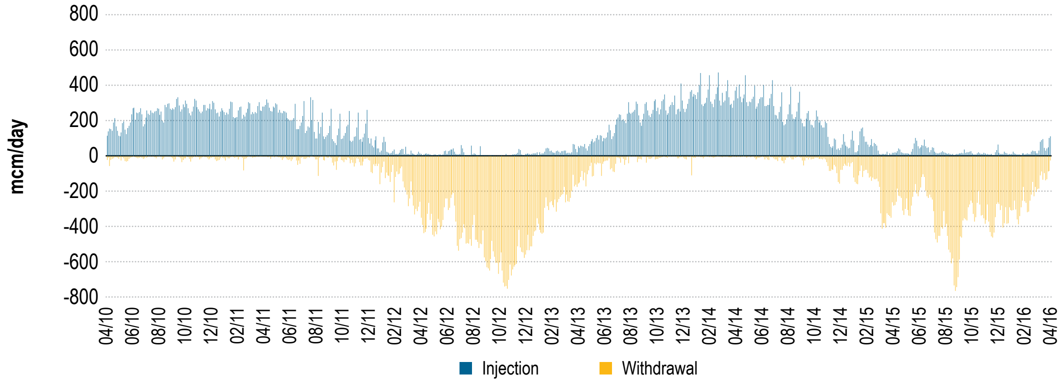
53 Given the low level of inventories at the start of the 2015/16 storage year and with the daily prices at hubs and of long term contracts falling more than expected in the course of the summer of 2015, users injected 15% more gas in UGS during the last storage year than in the previous one and 22% more than the average of the previous five storage years.

54 As winter ends, the price differential between the day-ahead and forward hub prices becomes an important driver of decisions on storage withdrawals. Gas is usually withdrawn as long as the spread between the day-ahead and summer contract prices remains positive[60]. However, day-ahead prices remained relatively low in winter 2015/16. As such, winter prices throughout Europe reached even lower levels than prices in summer 2015 (as shown in the right graph of Figure 11), leading to the exceptional circumstance of ex-post negative spreads, of less than 5 euros/MWh on average at TTF and NBP.

55 With storage less competitive than gas imports and/or gas purchases at hubs on a daily basis, withdrawals fell by 18% compared to the previous gas year. Consequently, the focus of storage users shifted to optimising against shorter-term fluctuations in prices, meaning that spot price volatility became more and more important.

60 The degree of implementation of this commercial approach differs by market participant due to a series of factors such as the regulatory obligations on storage utilisation, the technical limits to storage withdrawals/injections and the company's risk profile.

Figure 12: Daily storage injections and withdrawals for all EU storage during April 2014 – April 2016 (mcm/day)



Source: ACER based on GIE's data.

56 Figure 12 shows that storage facilities seem to have been more leveraged by traders for daily and within day portfolio optimisation. The monthly average of daily variations in both injections and withdrawals in the 2015/16 storage season were almost double those in the previous storage year, which registered a more concentrated pattern[61]. This confirms the increased key role of storage for short-term optimisation and portfolio balancing, by absorbing daily price fluctuations and ensuring flexible and rapid responses.

4 Status of EU gas hubs functioning

Chapter summary

According to the ACER Gas Target Model, well-functioning gas wholesale markets consist of a liquid spot market and, crucially, a liquid forward market, so that cost-effective supply hedging and risk-management is possible. This Chapter assesses the functioning of EU MSs gas wholesale markets against the ACER Gas Target Model criteria.

The NBP and TTF hubs are the leading hubs in the EU. They have the most developed spot, prompt and forward markets[62] and act as price reference for respectively the British Isles and the Continent. They approach the status of the Henry Hub in the US, which has a longer history as a price reference setting role for the US market.

However, across the EU, progress can be observed and gas wholesale markets are functioning better and better. Hub liquidity is on the rise. For example, notable progress can be observed in the CEE region.

Another measure indicating progress in the integration of gas wholesale markets is the increased price convergence and correlation. While price convergence and correlation has been very high for some years in the NWE region, the more recent dramatic improvement of other regions on these dimensions is striking.

At the other end of the spectrum though, there are still some Member States that lack or have an embryonic hub and or have a virtual trading point which is hampered by barriers to trade.

Compared to last year the assessed gas sourcing costs for a typical gas portfolio of a supplier further decreased and more importantly further aligned across the EU.

61 Lower average daily variations were also registered in previous storage years (2010/11–2013/14), although not shown in Figure 12.

62 For the purpose of the GTM metrics analysis, spot contracts are those for delivery day-ahead. Prompt contracts refer to one month forward. Forward-future contracts cover all quarterly, season and yearly products.

4.1 Gas volumes traded

57 EU hubs exhibited increasing liquidity levels in 2015 compared to the previous year. Figure 13 compares traded gas volumes – via OTC[63] and exchange trading platforms – for most EU hubs. Total traded volumes at EU hubs in 2015 were approximately nine times the total EU physical gas consumption. In 2015, the markets represented in Figure 13 saw an increase of total traded volumes of approximately 9% compared to 2014, reaching record highs. TTF's growth trajectory has been spectacular over the last four years with an annual compounded average growth rate (CAGR) of 30% between 2012 and 2015. Case study 1 describes the evolution of the TTF hub over time in more depth. Also, NCG and PSV (see case study 3) show significant growth. On the other hand, NBP seems to have stagnated somewhat, even though it is still the largest trading market in the EU. The main reason seems to have been the transfer of volumes into Continental hubs, particularly TTF. According to market analysts, the risk associated with the variability of the pound sterling/ euro exchange rate and the cost of hedging that risk are relevant factors in explaining this trend[64].

58 Growth was underpinned by the intensification of suppliers' preference for looking at hubs for physical short-term sourcing and for price risk management. The pivotal role of hubs in gas markets as witnessed in the NWE is gradually expanding into the CEE and Mediterranean areas. In these regions arbitrage operations with the adjacent NWE hubs are growing, facilitated by enhanced interconnection capacity and reverse flow possibilities[65]. Moreover, in selected markets, the obligations imposed by NRAs on incumbents to act as market makers for reselling specific supply volumes via the exchange are also promoting liquidity. Poland and Romania are good examples in this respect. Also the recent setting of balancing regimes around the hubs are helping liquidity.

59 Figure 13 also shows that OTC brokering remains by far the most common trading mechanism. Nevertheless, exchange-traded volumes are progressively increasing, and are percentage-wise substantial in Poland (98%), Denmark (61%), the UK (approx. 50%), and France (45%). Exchange trading better addresses financial counterparty risks for longer-dated products. Additionally, the use of spot exchange products by TSOs for the physical balancing of the network is increasingly relevant in supporting liquidity on newer exchanges – this setup goes together with the reduction of balancing position tolerances.

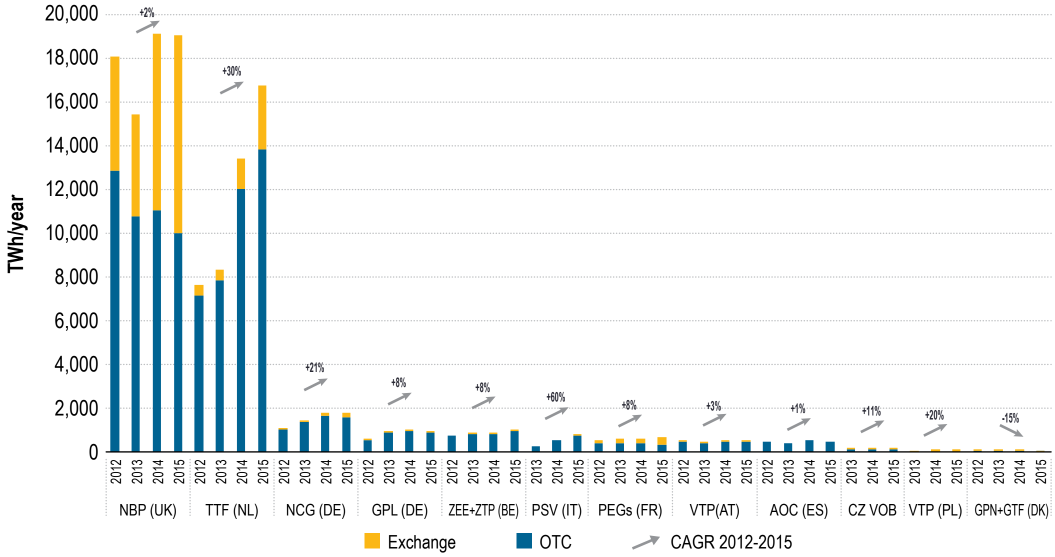
60 The upward trend in hub liquidity is also supported by the presence of an oversupplied market stimulating both producers and shippers that have long positions to market their excess gas volumes on hubs. Market participants' confidence to turn to hubs for flexible supply sourcing increases, because they expect volumes to be available.

63 According to the Commission Implementing Regulation (EU) No 1348/2014, 'over-the-counter' (OTC) means any transaction carried out outside an organised market. Please note that the data in Figure 13 refer to OTC transactions via brokers.

64 A factor in this regard is that when Continental companies hedge oil-indexed gas contracts they must cover their exposure to euro/dollar exchange (as oil is priced in dollars). Hedging oil-index contracts in NBP adds an extra layer of forex risk.

65 E.g. the rise in traded volumes in Czech, Polish, Slovak and Italian hubs displaced some of the volumes previously negotiated by those markets' suppliers from Gaspool (DE) or VTP (AT) hubs. For example in 2014 Austrian hub traded volumes increased to serve demand to Ukraine, but some of these volumes have migrated to Slovakian and Czech hubs in 2015, or also to the more liquid NCG hub.

Figure 13: Traded volumes at EU hubs and CAGR – 2012–2015 (TWh/year and %)



Source: Trayport, Hub operators and NRAs 2015.

Note: Over-the-counter trade (OTC) refers to volumes traded among parties via brokers, with either the parties managing credit risk or trading being cleared by the broker. Exchange execution refers to those volumes supervised and cleared by an organised central market operator. For Spain, data also include physical swaps and bilateral deals.

61 Other events that are also likely to have contributed to enhanced hub liquidity in 2015 were connected to an increase in gas price volatility. Volatility triggers certain types of trading activity and prompts forward price risk management. These events include: oil price movements impacting gas price formation, the Russian–Ukrainian supply dispute[66], the reduction of the production cap on the Dutch Groningen field, the partial closing of UK's Rough gas storage, movements in exchange rates and the price hedging of larger LNG volumes from new production sources[67]. Gas price volatility exposure is becoming increasingly more relevant for suppliers' as long-term contract indexations look further into hub price references – instead of oil ones. In this scenario, the need of market participants to engage in price risk management transactions via forward products on hubs is intensifying.

62 Like hub-traded volumes, net gas physical transfers that take place on virtual trading points (VTPs) have also been growing over the last years. For the NWE hubs this growth amounts to more than 25% over the last five years. This indicates that suppliers' rely on hubs for physical sourcing, and that a higher proportion of long-term contracts deliveries occur at VTPs. The requirement under the BAL Network Code to balance gas positions on VTPs may further foster this trend.

63 Most of the aggregated volumes traded are concentrated in prompt and short-term curve products (i.e. from month-ahead to season-ahead)[68] and serve medium-term portfolio optimisation. They also tend to attract more financial players as they are usually more price-volatile and offer a good number of trading counterparty opportunities. In terms of total number of trading operations, liquidity is concentrated in spot products used for final portfolio optimisation - ahead of physical delivery – and/or balancing purposes.

64 In less liquid hubs, longer curve liquidity (i.e. longer than the season) is lower. Financial traders tend to be more reluctant to trade in such markets as they are exposed to more risks, e.g. fewer trade matching parties. In general trading in longer-term curve and longer-term price risk management is concentrated in TTF and NBP, which take advantage of a higher number of counterparties and a larger availability of placed orders.

66 On top of the supply risk management by European suppliers, Ukrainian suppliers increased contracting on EU gas hubs. For example, UA relied mainly on EU imports to refill its storages.

67 The forthcoming US LNG exports are deemed to be having an effect on hub trading in Europe, particularly for the hedging of forward positions. See the following analysis: http://www.icis.com/resources/news/2016/05/12/9997655/us-lng-and-henry-hub-to-alter-european-trade-dynamics.

68 E.g. 44% of OTC trading volume is concentrated on gas delivered in the current month and the month immediately following. See AGTM 2014 analysis on the subject: 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.

Case study 1: Reasons for TTF liquidity development – historical account[69]

Over the last few years, wholesale gas trading volumes at the TTF have been rising. The underlying physical characteristics of the Dutch market and the historical background of the development of the Dutch (wholesale and retail) gas markets are important factors that lie behind this increase in liquidity. TTF benefited from a stable regulatory regime and a commitment to competitive markets. Retail competition was introduced in 2004 and in the following years efforts were made to relieve physical bottlenecks in the Dutch gas system. Another major contribution has been the fact that Dutch market players, notably the former incumbent Gasterra after an intervention by the Dutch competition authority, over time offered more and more differentiated products on TTF. In addition, TTF was able to gain first mover advantage on the continent and these early successes resulted in more confidence in TTF.

Gas is traded at a conceptual balancing point on the Dutch pipeline system, rather than at a specific physical delivery point, in line with the European GTM. TTF is a virtual market place where market parties transfer gas that is already present in the system to another party. Using the TTF, gas that is brought into the Dutch grid via an entry point can change ownership before it leaves the Dutch grid at an exit point.

The strong development of the TTF can be partly attributed to the underlying physical characteristics of the Dutch market, with its large domestic production volumes, particularly from the Groningen field[70], landing points for Norwegian gas, and high levels of interconnection to surrounding markets including an export-only interconnector to the UK and an LNG terminal.

The TTF was set up in November 2002 by Gasunie, back then an integrated network and supply business. This deterred potential new players from seeing TTF as a neutral hub and thus from using it. Also, Gasunie did not offer its main customers the choice of the TTF as a delivery point for its supplies. This kept volumes away from the market.

In July 2004, full retail competition was achieved. This, however, did not initially drive much change for trading at the TTF. The control by Gasunie of low calorific gas supply limited competition. However, retail supply companies had started to buy gas at the TTF for industrial and commercial customers and for power generation. Retail competition, especially for households, drove up demand for gas quality conversion between the Hi-Cal and Lo-Cal systems. Gasunie controlled the blending facilities, and offered a limited capacity for booking by third parties. However, demand for quality conversion far exceeded the capacity offered. This limited retail companies to supply users of low calorific gas including households.

Gasunie was broken up in 2005 in line with European ownership unbundling to create a network business, Gasunie Transport Services (GTS), and a supply business, Gasterra. Management of the TTF sat with the network business. For the first time, the market was operated by a neutral player who had an interest in seeing the market grow.

Active parties need a registration and a licence specific to the purpose for which they intend to use the TTF. This facilitates different type of parties to be active at the TTF, including pure financial players. Parties active on the TTF are well-informed (in Dutch and English) on developments of the TTF via the GTS website and regular so-called Shippers meetings held by GTS.

However, the development of the wholesale gas market in the Netherlands was still hampered by various factors, notably the limited access for market players to quality conversion and to (seasonal) flexibility and, given a lack of

69 Sources: The benefits of TTF liquidity, a report by Baringa partners for ACM – 25 September 2015, Gasunie and ACM Market monitoring reports.

70 The Groningen field was discovered in 1959 and has been the mainstay of the development of the Dutch and broader Northwest European gas markets. Its gas has a particular quality with a relatively high percentage of nitrogen. For this reason it has its own “Lo-Cal” midstream and downstream infrastructure. Most of the Dutch end users (especially households) use appliances that are adapted to this gas quality. The same goes for customers in certain export markets like Belgium, Germany and France. This infrastructure operates in parallel to a network system for Hi-Cal gas for production from the continental shelf, UK and Norway.

offer, the limitations to buy and exchange gas at the TTF. In 2008, based on an amendment of the Dutch Gas Act, the Dutch regulator annex competition authority NMa (now ACM) published its decision that quality conversion would have to be made available by GTS as a system service with socialised costs. This removed the physical constraint as a consideration for the traded market, and finally created one single gas market for Lo-Cal and Hi-Cal gas at the TTF, laying the path for real growth in trading volume.

In early 2011, the Dutch competition authority NMa ruled that GasTerra had used supply conditions in its contracts with energy companies, including a refusal to deliver gas at the TTF, which impeded the creation of competition in the Dutch wholesale gas market. The NMa considered this behaviour an abuse of a dominant position, covering the period from July 2004 until July 2009. It therefore fined GasTerra for a violation of the Dutch Competition Act and of the Treaty on the Functioning of the European Union. However, after having conducted an objection review process, the NMa came to the conclusion that there was insufficient certainty that GasTerra had abused its dominant position. This was based on several arguments put forward by GasTerra which, amongst others, made the NMa question whether GasTerra had prevented energy companies from utilising other wholesale suppliers. Since GasTerra had in the meantime put an end to the identified behaviour, the NMa had no reason to investigate further whether or not its behaviour constructed an antitrust violation. In the ruling of objection, the NMa established that GasTerra had taken measures in the first half of 2011, including the default delivery of gas products at the TTF, such that it had materially complied with the requirements of the earlier NMa decision. Together with an amendment of the Dutch Gas Act, these measures stimulated competition in the Dutch wholesale gas market.[71] As part of these measures, GasTerra increased its within-day and day- ahead product offerings at the TTF. These short-term products improved the access to flexibility and enabled market players to better adjust their gas purchases to the fluctuating gas demand in the short term. In addition GasTerra started to offer year products with a flexible component, allowing market parties to contract a seasonal profile on the hub. Furthermore, GasTerra introduced a new product for seasonal flexibility better known as *virtual gas storage*. It gave market players more seasonal flexibility to meet their seasonal demand profile.

Since then traded volumes and the number of market participants have risen strongly and, bid-offer spreads have fallen both in within-day, day-ahead as well as future trades, showing that traders started to use the TTF for balancing as well as for hedging purposes. The increase in liquidity for spot as well as future products has been self-reinforcing and increased the attractiveness and reliability of the TTF as a means to manage gas portfolio hedging and optimisation. It has reinforced the focus on TTF as the hub of choice for forward trading. The TTF has become the clear continental (euro) price benchmark, and the TTF is used extensively as a contractual price reference for long-term contracts indexation and for other EU hubs.

71 See news messages available on ACM's website (in English): https://www.acm.nl/en/publications/publication/6538/NMa-has-brought-about-increased-competition-on-natural-gas-market/ and https://www.acm.nl/en/publications/publication/6684/NMa-Abuse-of-GasTerras-dominant-position-not-established/. The underlying decisions are available on ACM's website (in Dutch): https://www.acm.nl/nl/publicaties/publicatie/4281/Besluit-op-bezwaar-boete-verboden-leveringsvoorwaarden-GasTerra/ and https://www.acm.nl/nl/publicaties/publicatie/4280/Besluit-boete-verboden-leveringsvoorwaarden-GasTerra/.

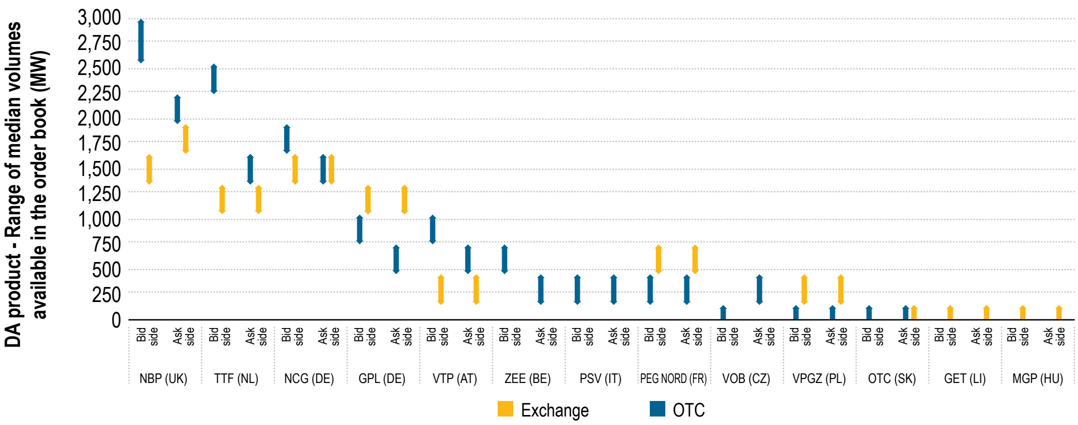
4.2 Gas target model market participants' needs metrics

65 For the 2015 monitoring year, the Agency started to calculate selected GTM 2014 metrics for those EU gas wholesale markets with a transparent trading venue[72]. Analyses were performed on the basis of data collected on orders and trades as reported in the REMIT database. GTM 2014 defined two sets of metrics to assess the degree of well-functioning of wholesale gas markets. This Section focuses on "Market participants' needs" metrics, which were established in order to evaluate if products and liquidity are available such that effective management of wholesale market risk is possible. The Section also looks into the concentration of trades metric[73]. All were assessed for spot, prompt, and forward products[74].

66 The trade data used covers November 2015 through April 2016. The six-month coverage is due to the fact that mandatory REMIT trades reporting started in October 2015. Only data for transactions executed in organised market places and within the framework of a standard contract have been processed[75]. Although only half a year is covered, the Agency believes that the results provide useful indications. While some figures might be somewhat biased due to the availability of only winter season months, winter is the most critical season for the gas market. However, because of the limited period coverage, in this MMR edition the Agency refrained from benchmarking the results against the targets set in the GTM.

67 The remainder of this Section shows the results for the metrics that were processed for available hubs using ranges[76]. Annex 1 gives a more exhaustive overview of the covered GTM metrics for all available hubs and also clarifies further the assumptions used. It is to be noticed that for selected metrics a distinction has been made between two different trading mechanisms: OTC and exchanges. OTC refers to transactions executed via broker platforms within the framework of a standard-contract. Figure 14 to Figure 16 below refer to GTM metric number 1, presenting the mean available order book volumes during the day for selected hub products[77] .

Figure 14: Available median bid and ask-side volumes in the order book during the day for DA in selected EU hubs in ranges of MW for November 2015 to April 2016



Source: ACER calculations based on REMIT data.

72 Wholesale gas markets are defined for this purpose as *"the sum of gas trading activities with delivery agreed at one specific point and concluded using a transparent trading venue. The main delivery points are the virtual points of the entry/exit systems."*

73 Concentration of trades metric fits into the Market health set that assesses if the markets are demonstrably competitive, resilient and have a high degree of security of supply (see preceding Chapter analyses).

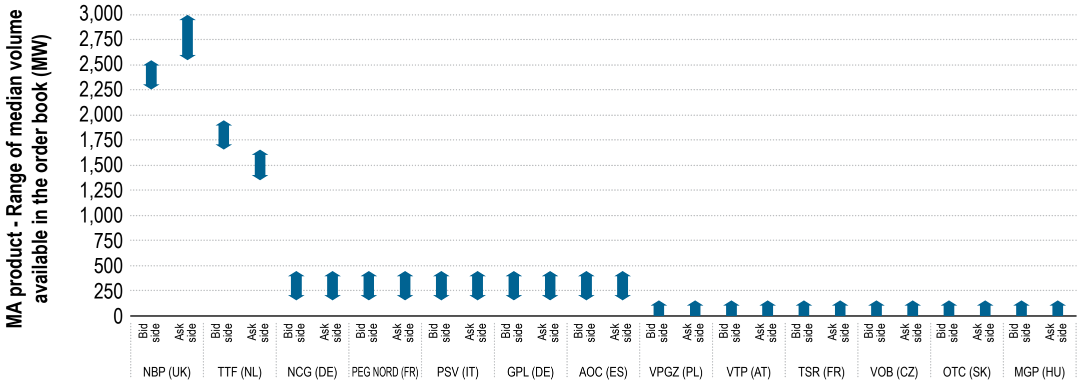
74 For the definition of spot, prompt and forward-future contracts in the context of the GTM metrics analysis, see footnote 63.

75 From October 2015, all orders and trades executed at organised gas wholesale market-places – i.e. exchanges or broker platforms – and within the framework of a standard contract are collected under REMIT. From April 2016, orders for transmission capacity and for non-standard contracts concluded outside organised markets are reported as well. See REMIT TRUM section 3.2. for a definition of the different concepts.

76 The results of the metrics are shown as ranges in order to avoid any potential confidentiality issues (see article 17 of REMIT regulation) as well as for reasons of data quality.

77 According to the GTM 2014 methodology across the day means a snapshot for every fifteen minutes.

Figure 15: Available median bid and ask-side volumes in the order book during the day for MA in selected EU hubs in ranges of MW – OTC and exchange aggregated – November 2015–April 2016

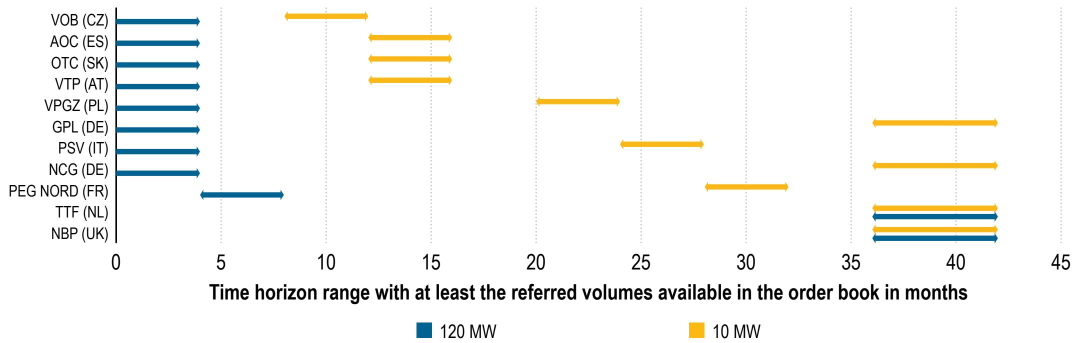


Source: ACER calculations based on REMIT data.

Notes: See Annex 1 for a clarification on the methodology used.

68 Figure 16 shows the maximum time horizon expressed in months until when market participants can find available forward products in the order book for respectively 10MW or more and 120MW or more.

Figure 16: Order book horizon in ranges of months for bids for forward products for different blocks of MWs - November 2015 – April 2016

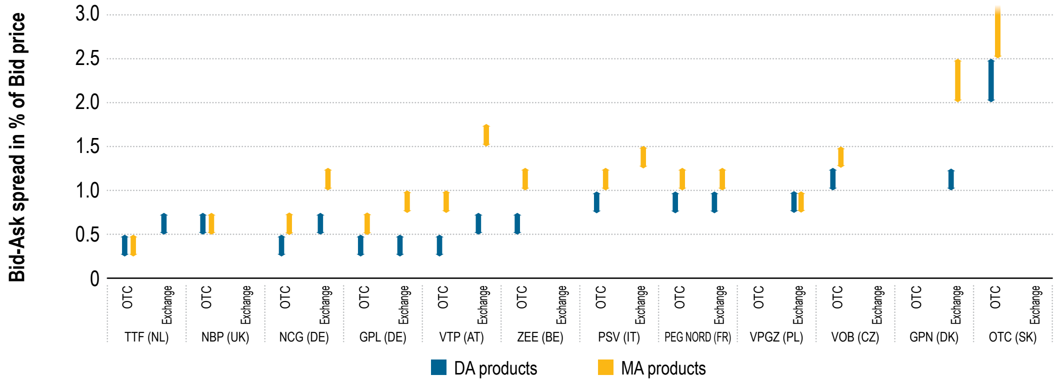


Source: ACER calculations based on REMIT data.

Notes: OTC and exchange aggregated.

69 Figure 17 shows the orders' bid-ask spreads in selected hubs and trading venues as a percentage of the bid-price for different duration products.

Figure 17: Bid-offer spread for November 2015–April 2016: measure of the average delta between the lowest ask price and the highest bid-price expressed as a percentage of the highest bid-price across the day



Source: ACER calculations based on REMIT data.

Notes: NBP and TTF metric values are based on a sample of trading days. For forward products sufficient liquidity, i.e. more than 60% of days showing orders is requested to show metric values. As explained in Annex 1 calculations may be affected by data quality aspects. Therefore the results need to be taken with caution.

70 The combined analysis of the two metrics outlined above indicate that NBP and TTF continue to be the EU's best functioning hubs in terms of higher order volumes and broader liquidity time horizons. This is already apparent from the larger scale of available month-ahead volumes, and even more clearly, from the longer-time horizon values for hedging more than 120MW.

71 Figure 16 indicates that NBP and TTF offer 120MW volumes for more than 3 years ahead. For smaller volumes others hubs, e.g. PEG Nord, PSV and NCG offer more than 1 year ahead. Also the gauged bid-ask spread for their longer-curve products is lower (see also Annex 1).

72 These metrics' values concur with the leading role for forward risk management and financial trades that NBP and TTF play in Europe[78]. NBP and TTF attract substantial market interest from participants from neighbouring countries, which seems to cement position of these hubs. Their liquidity also benefits from the relatively high indigenous production traded volumes which is sold into these hubs (see Section 4.3 a comparison of TTF and NBP with the US Henry hub).

73 The values of the metrics for the German, Belgian[79], French – in April 2015 PEG Sud and PEG TIGF market zones merged to create Trading Region South (TRS) –, Italian, and Austrian hubs confirm that these hubs improve their position year on year as market participants rely more and more on these hubs for hedging activities.

74 For all these hubs, metrics for spot products show results that are comparatively closer to those of NBP and TTF. However, the metric values of their prompt and short-term curve products are lower vis-à-vis the British and Dutch hubs. And their forward long-curve products metrics' are short, as liquidity seems to be limited for longer-dated products. Particularly in the case of German hubs, day-ahead available volumes are quite high. This can be explained by the vast size of the German market and higher liquidity of products with dates close to physical delivery which are negotiated directly on German trading venues. This is intended to optimise suppliers' portfolio and balancing positions[80]. However, German based forward products negotiation seems significantly pegged into TTF.

75 Also the Czech, Spanish, Polish and Danish hubs show improving performance, although their liquidity is lower. In Romania and Spain a granular analysis of the order book indicates that sizeable liquidity is not continuous for all days, but that relevant prompt and forward products volumes are negotiated on selected days – which results in sizeable GTM metric 1 values as an average for the whole period[81]. In other markets, like Hungary, Slovakia,

78 According to market analyst, the role of financial players is more prominent in NBP, meanwhile TTF is comparatively more used by the trading arms of the big European energy suppliers.

79 ZTP hub serves since October 2015 the VTP resulting from Belgian and Luxembourgish market zones integration. See also footnote 43.

80 Ahead of pure balancing operations that take place in the daily balancing system.

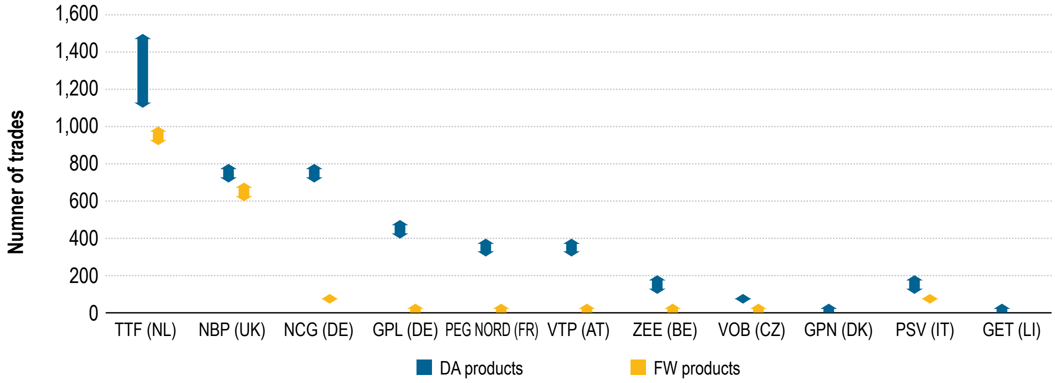
81 Explanations for Spain relate to OTC-traded LNG cargo volumes at selected moments and in Romania imposed selling obligations via the exchange for domestic producers. the exchange for domestic producers.

Finland or Lithuania, organised trading attracts very limited volumes. Discussions are ongoing to create a Baltic-wide exchange which, in order to be successful, would have to be accompanied by enhanced interconnections and supply competition. Finally, a number of markets, i.e. Bulgaria, Croatia, Estonia, Greece, Ireland, Latvia and Slovenia, despite having single virtual trading points, do not feature active transparent trading venues[82].

76 A comparison of trading mechanisms indicates that bid-ask spreads are usually higher in exchanges than in OTC, and that the volumes available in the order book are usually higher in OTC markets for most EU hubs. However in a number of NWE hubs (e.g. NCG, GPL or TTF), and particularly for day-ahead products, the order volumes available in the exchange are also sizeable[83] – despite the higher traded volumes being concluded over the counter.

77 Lower spreads are found in all EU hubs for spot products used for final portfolio optimisation and balancing purposes than on the forward curve. This situation can be explained primarily by spot products having higher levels of liquidity and more counterparties, as well as smaller quantities and closer delivery dates[84]. Also the (percentage) spreads increased slightly compared with previous assessments[85]. An explanation – beyond methodological and data quality aspects – may be that the commodity price has recently decreased and, as such, the absolute spread expressed as a percentage has increased[86].

Figure 18: Number of executed trades (daily average) for DA and FW products in selected hubs for November 2015–April 2016



Source: ACER calculations based on REMIT data.

Note: Metric values combine OTC and exchange trading mechanisms. Intragroup trades may also be included. For TTF and NBP a sample of days considered.

78 The results shown in Figure 18 demonstrate the more advanced role of NBP and TTF for forward trading, as significantly more trades are reported in those markets. The total number of trades concluded for day-ahead products are usually higher at all hubs, as the number of operations for physical portfolio optimisation and balancing purposes is operationally larger – though the absolute volumes comprised by DA products are comparatively lower than those covered by prompt and forward products.

79 GTM metric 9 looks at companies' concentration levels by analysing the market shares of those market participants active in gas trading on transparent organised markets. The figure below measures the market concentration of finalised transactions. Both HHI and CR3 (market share of the three largest players) are shown.

82 Market participants active in these markets may look into adjacent markets hub for hedging operations. Bulgaria and Greece are in the process of implementing some pending provisions related to VTPs constitution. See case study 2.

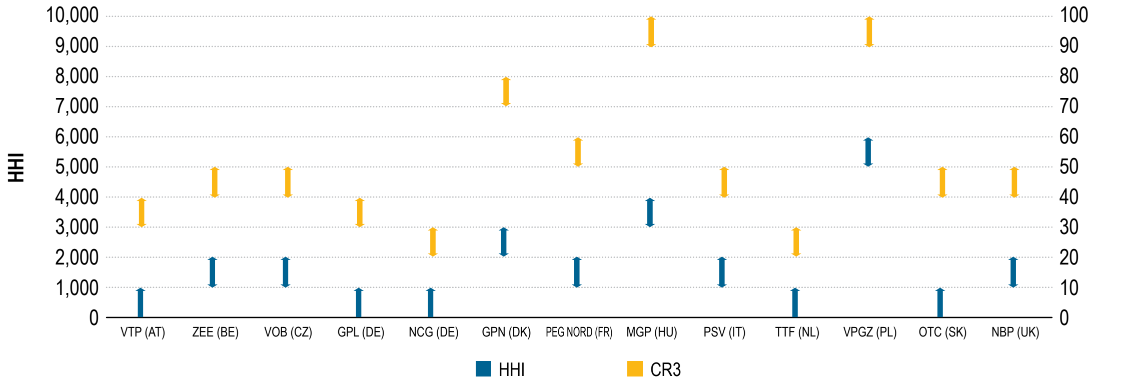
83 Explanations may be linked to the prioritisation of exchanges for balancing roles that the BAL NC introduces, but also a result of the data processing methodology as orders in the exchange seem to have a longer validity period than those in OTC and therefore the same orders may appear in more snapshots.

84 Financial cost, linked to collateral coverage, is deemed to have a diminishing impact over longer curve liquidity.

85 See the 2013 GTM metric values assessments here: http://www.acer.europa.eu/Events/Presentation-of-ACER-Gas-Target-Model-/default.aspx.

86 NWE hubs day-ahead average daily prices in 2013 were 27.4 euros/MWh meanwhile the average for the period November 2015 – April 2016 was 14.5 euros/MWh.

Figure 19 : Market concentration ranges of finalised transactions of MA products for selected EU hubs for the selling side - November 2015-April 2016



Source: ACER calculations based on REMIT data.

Note: Values for OTC and exchange trading mechanisms combined. Intragroup companies may be reported separately i.e. actual concentration levels could be higher.

80 The results indicate that concentration is relatively low in most markets, given the active presence of a large number of companies. As Annex 1 results further illustrate, concentration is higher for forward products, as these may attract fewer active players than prompt and spot operations. For forward markets, the concentration is typically higher on the selling than on the buying side, although this is not the case in all markets. Developing hubs, such as in the CEE region (e.g. Poland, Slovakia, and Hungary), show comparatively higher concentration levels than NWE hubs, especially when looking at the CR3 metric.

81 The results of the assessed metrics are relevant, as GTM 2014 proposes that if material gaps remain over time, enhancements, or even potential market integration projects[87], would be needed to achieve hub functioning objectives in all EU market areas. Cost-benefit analyses should validate the feasibility of deeper market integration measures. However, it may take time for emerging hubs to catch up to NBP/TTF performance levels. Two aspects illustrate this: first, there may be a different predominance of long-term bilateral legacy gas contracts in different MSs. In some cases (e.g. if there are hub reselling restrictions) this may reduce the availability of volumes that could be traded on hubs. Secondly, financial and risk management business has been drawn to NBP/TTF and thanks to the first-mover advantage they may retain volumes to the detriment of other hubs (see also Section 4.3). This situation suggests that merging zones could in certain cases be the preferred option.

82 It is agreed that the key requirement of a well-functioning hub is the full implementation of an entry-exit system per market area built on VTP configurations. VTPs are used as unique locations for gas title transfer and for the operation of the balancing accounts. Moreover the availability of transparent trading venues – either via brokers or exchanges – will facilitate market entry and competition. Furthermore hub performance is favoured by the standardisation of trading terms, and the harmonisation of balancing and capacity access provisions across hubs – i.e. full implementation of NCs. In addition, the possibility for non-physical traders to trade even when not contracting capacity services and the designation of the hub as an alternate offtake point for bilateral contracts can also be considered.

83 To improve the degree of functionality of hubs, the involvement of NRAs is essential. First, an analysis is needed of the regulatory provisions that are in place and of the major constraints that may be hampering hub trade. GTM 2014 suggests NRAs to perform a self-assessments on the status of their markets[88] and on the degree of alignment with GTM proposals. Second, the implementation of NCs and other market favouring provisions is deemed crucial for market integration.

87 See Section 4.5 of the GTM 2014 revision: http://www.acer.europa.eu/Events/Presentation-of-ACER-Gas-Target-Model-/Documents/European%20Gas%20Target%20Model%20Review%20and%20Update.pdf.

88 See for example BNetzA self-assessment and analysis of market integration potential here http://www.bundesnetzagentur.de/SharedDocs/Downloads/DE/Sachgebiete/Energie/Unternehmen_Institutionen/NetzzugangUndMesswesen/Gas/EN_summary_Expert_Opinion_Market_Integration_WECOM_for_BNetzA.pdf;jsessionid=C06E58926B25F8A055B31D80A7AB3611?__blob=publicationFile&v=4.

84 Within the context of the Gas Regional Initiative, the NRAs of the SSE region completed an assessment on the access conditions, operational aspects and transparency of their VTPs. This project led by E-Control, collected information via a questionnaire submitted to all VTP operators and NRAs in the region. Case study 2 below highlights the main outcomes of the survey as analysed and interpreted by the Agency.

Case study 2: Virtual trading points in South South-East Europe

In gas entry-exit systems, virtual trading points are places where the title transfer of gas takes place at wholesale market level.

A national VTP has been established in all South-South Eastern European MSs[89], except Greece and Bulgaria. In the latter, an entry-exit system is not in place yet, but Bulgaria plans to set up two VTPs[90] by the end of 2016, whereas in the former the deadline for implementation is still under discussion.

VTPs in AT, CZ, SI and SK are by regulation the only places where gas title transfer is allowed. This means that all transactions carried out both OTC and at the exchange[91], or on the balancing platform, are registered at the VTP. In all other countries, the gas title transfer is also possible at flanges and/or at storage/LNG points. Flange trading does not require VTP registration. However, all other types of OTC and centralised trades must still be registered at the VTP. Only in Romania the registration of transactions at the VTP is not mandatory because the VTP is used mainly as a balancing platform by the TSO.

The table below shows an assessment of the VTPs' characteristics in the SSE region. The establishment of a VTP per se is not a sufficient measure to ensure a liquid, effective and transparent wholesale gas market. Differences in access and operational conditions, coupled with independent market fundamentals, may be reflected in wholesale gas prices.

Table i: Assessment of VTPs in SSE based on data provided by the VTPs/NRAs

Application of following practices	AT	CZ	HR	HU	IT	PL	RO	SI	SK
Independent VTP operator*		✔	✔	✔	✔	✔	✔	✔	✔
Transport contract not required to access VTP	✔	✔		✔	✔			✔	✔
Trading license not required to access VTP	✔				✔		✔	✔	✔
Trade notifications 30 min	No, 2hrs	No (Oct 16)	No, 2hrs	No, 2hrs	No (Oct16)	No, 2hrs	No, 2hrs	No, 2hrs	No, 2hrs
Regular shioppers' meetings	✔			✔	✔			✔	✔
Consultation on VTP changes also in English	✔				Not always	✔	Not always		
Minimum notice period for changes		1 month		1 month		14 days			

**A VTP operator is considered independent if i) it is owned by a certified TSO or ii) the VTP operator is owned by neither the TSO nor the incumbent.*

89 MSs part of Agency's Gas Regional Initiative in SSE are (between brackets their VTPs): Austria (CEGH), Bulgaria (no VTP), Croatia (VTT or VTP-HR), the Czech Republic (CZ-VTP), Greece (no VTP but a Virtual Nomination Point is in place where title transfer is based on physical nominations instead of trade notifications at the VTP), Hungary (MGP), Italy (PSV), Poland (PL-VTP), Romania (RO-VTP), Slovenia (SI-VTP) and Slovakia (SK-VTP). Among those, Poland has 3 VTPs in place, respectively for the high-calorific, low-calorific and transit zones, this paragraph presents the information on the high-calorific zone VTP, being it mainly used for wholesale gas trading in Poland. Serbia is also a member of ACER's SSE-GRI and has a VTP in place, however its replies to the questionnaire are not included in the current analysis which is limited to EU MSs.

90 In Bulgaria two VTPs will be set up: one for the transit zone and one for the national transmission system.

91 Gas exchanges are in place in: Austria, the Czech Republic, Hungary, Italy and Poland.

The parameters listed below are deemed to contribute to the development of an effective VTP and hence to the establishment of an effective and well-functioning gas wholesale market:

1. *Independence of the VTP operator* from the national incumbent is an indication of the impartiality of the hub. This promotes confidentiality of information and provides a fairer level playing field for all market participants. In some MSs the VTP operator is owned by the national TSO and in other MSs by a third company (at AT-CEGH, CZ-VTP, RO-VTP, SK-VTP). Vertically integrated companies hold shares in the VTP operator in Austria (OMV), Hungary (MOL) and Slovenia.

2. *Ease of access to all market participants*. At some VTPs access is only granted to companies holding a transportation contract. This requirement limits participation and may distort price formation. Booking transmission capacity implies costs related to capacity booking, possible imbalances, taxes and financial and reporting obligations. In order not to book capacity with the TSO, wholesale gas traders must use the services of companies with a valid transportation contract willing to accept exposure risk with the VTP operator on behalf of a third party. This service usually comes at a cost that is not only related to the capacity booking and guarantees for the TSO, but also to hedging possible imbalances of the trader to whom the service is provided.

3. *Absence of a trading license*. Licenses are a pre-requisite to access some VTPs, which potentially limits the number of participants. In some MSs a locally-established company (e.g. VAT registration number) is required, and in general a trading license implies tax, financial, accounting, civil and criminal national obligations. This type of additional obligations should, as a rule, apply only to end-customer suppliers and not to gas wholesale traders. When not the case this may hamper liquidity and may increase prices.

4. *Operation 24/7, gate closures and trade notifications*. A well-functioning VTP should enable gas wholesale traders to register their transaction on a continuous basis with a 30-minute lead-time for trade notifications, extendable to a maximum of two hours under exceptional circumstances[92]. All the VTP operators except MGP and RO-VTP declared that their VTP is operating on a 24/7 basis and a majority registers trade notifications. As the majority of the VTPs has only been recently established, a reduction in the trade notification timings should be encouraged as soon as more experience is acquired. In Italy and the Czech Republic the trade notification timings will be implemented by October 2016[93]. The implementation of trade notifications is also related to the implementation of standard nominations and renominations on physical transmission capacity according to the Balancing Network Code[94] .

5. *Regular shippers meetings and consultations on changes in market rules, including in English*. This framework is a key contributor to the development of the VTP as it increases the participation of international market participants, which will further increase confidence in the market and liquidity. Regular shippers meetings are held at some VTPs, while at the PL-VTP shippers meetings are organised on a needs basis to discuss changes in market rules. Almost all VTP operators consult on changes to the market rules. At some VTPs a minimum notice period is established before changes apply, which is usually around one month. At others, a minimum notice time is not in place and changes can apply without notice or with a notice period decided on a case-by-case basis. At AT-CEGH, consultations on market changes are available in English, while at IT-PSV and at the RO-VTP consultations in English are held on a case-by-case basis. All the VTP operators in the region except for the RO-VTP declared that their website is fully available in English as well, which is an important signal for the effectiveness of a VTP as it reduces the language barriers for foreign market players. This begs the question as to whether English versions of contracts and user interfaces ought to be mandatorily made available as well.

92 As established by the Balancing Network Code, the standard time for trade notifications is 30 minutes; only in exceptional circumstances could the trade notification time be extended to up to 2 hours.

93 Given that in those countries the national regulator approved the postponement of the whole Balancing Network Code from October 2015 to October 2016.

94 The Balancing Network Code establishes that the lead time for nominations and re-nominations of physical transmission capacity is 2 hours.

4.3 Comparison of NBP/TTF with market features of US Henry Hub[95]

85 Well-developed hubs are a key element of well-functioning gas wholesale markets. The objective of this Section is first to understand the factors that explain the development of the US leading gas hub, i.e. Henry Hub, to learn from its experience and explore whether Europe's leading hubs – NBP and TTF – can evolve from their current levels of liquidity.

86 Henry Hub has a long-standing position as a price setter in North America and has gone through various phases.

87 There are several factors that explain the development of Henry Hub and its success as well as implications for Europe's gas hubs. The overall liberalisation of the US natural gas market, favourable characteristics of the hub and the launch of Henry Hub futures contracts propelled the hub to become the physical and financial gas hub in the US. The following four aspects are further elaborated below:

- Regulatory actions taken enabling favourable market conditions;
- Location and maturity of the gas hub giving it a competitive advantage;
- Installation of a futures markets giving Henry Hub the leading price reference role and;
- High levels of liquidity.

88 The US gas market started the process of liberalisation in the 1980s. The US Federal Energy Regulatory Commission (FERC), enforced third-party capacity access on the interstate transportation pipelines and limited the use of long-term contracts. Furthermore, it allowed distribution companies to exit long-term supply contracts with transmission companies and to purchase gas directly from producers. The beginning of the 1990s brought the complete liberalisation of the US natural gas market. FERC regulation was instrumental in that regard. In fact, FERC enforced the unbundling of gas sales from interstate transportation pipeline companies, as well as liberalised entry into the wholesale gas market, promoted competition and increased the flexibility in interstate pipeline transportation. Third party capacity access made it possible for other market participants to sell gas directly to their customers. This ultimately created a wholesale market and, as a consequence, the trading business could and did develop across the country.

89 Various hubs prospered over the years. Today there are around 130 in the US. However, the initially established Henry Hub had some critical advantages, which mainly related to its location. Henry Hub is located in a zone of conventional historical production and 50% of US gas production in the past was transferred via it. It also sits on a vast network of 13 interstate and intrastate pipelines which allowed for non-interruptible and constant gas transportation with very low risk of congestion.

90 These advantages and the liberalisation wave in the early 1990s led NYMEX (New York Mercantile Exchange) to launch its first future gas contract with delivery at Henry Hub. This further increased non-physical trade and, over time, Henry Hub became recognised as a price reference for the US gas market.

91 Today, Henry Hub is characterised by high liquidity which has gradually developed since its inception. Selected metrics attest this. For example the CAGR of the trading volumes over the period from 2004 to 2015 was ~ 8% for monthly products with physical delivery – both OTC and at the exchanges – and ~11% for future monthly products at NYMEX. The bid-ask spread for all the products traded has been extremely tight since 2012 hovering around 0 euros/MWh.

92 Moreover, the US natural gas market is not static; it experienced changes in market dynamics, lately the shale gas revolution. However, this did not affect the status of Henry Hub as the main US natural gas futures market. For example, Henry Hub saw declining physical trades, but it remained the financial reference market for natural gas trading. The rise of the Marcellus Hub is intimately linked to the shale gas revolution. Growth was dramatic but this pertains to an increase in physical trades. Financial trades did increase somewhat but not materially compared to the physical trade expansion.

95 This Section is the result of discussions and input from FERC.

93 There have been several attempts to create alternatives to Henry Hub's role as a financial hub, but competition never took off. It would appear that the Henry Hub financial contracts market had developed sufficiently over the years so that other initiatives were not needed[96].

94 Incidentally, it is worth noting in this context that the US natural gas market saw increased price convergence as trading spread across the country. In geographical areas where congestion occurred, investors saw an initiative to build new pipelines which further drove price convergence among hubs.

95 There seem to be important similarities between Henry Hub and some European gas hubs, in particular TTF and NBP. For example, a large number of transactions and a developed financial market acting as price reference for a whole region. However the analysis shows that, overall, Henry Hub is more developed than the TTF and NBP hubs. Thanks to its maturity and high levels of liquidity, it is used for physical and non-physical purposes. Henry Hub futures contracts are the most traded gas futures contracts in the world and are used for hedging and speculative purposes.

96 The trajectory of Henry Hub may give an indication as to where TTF and NBP may evolve in the (near) future, especially regarding the non-physical market. It should be remembered that trading of Henry Hub futures started in 1990, while trading of TTF futures only took off in 2010. The rising numbers of trades through exchanges and the increasing number of forward curve products offered might further attract additional market participants, making natural gas prices a truer reflection of supply and demand on the European gas market.

4.4 Assessment of supplier's sourcing cost

97 As mentioned in Section 2, EU gas prices gradually[97] decreased as 2015 progressed. Hub spot products prices were at their lowest values for five years, comparable to the level registered in the early-2010s. The prices of long-term contracts also fell, either because of the influence of hub elements or, in the case of oil-indexed contracts, due to falling oil prices. The prices of both hub spot products and also long-term contracts ended up lower than the prices that could have been hedged if having contracted hub forward products in the precedent year.

98 Hub product prices are strongly influenced by the pricing conditions of long-term contracts via the flexibility component of ToP volumes[98]. As such, the correlation between oil and gas hub prices has been historically high. Even if oil-indexation elements are gradually being substituted by hub ones in long-term contracts, the price correlation between oil and gas hubs prices was generally visible in 2015, as Figure 20 shows. On the whole, this was determined by the dynamic hedging strategies that, in a context of volatile oil prices, prompted a recurrent review of positions from gas market participants[99]. Nonetheless, at certain periods, solid gas fundamentals determined the level of gas spot prices.

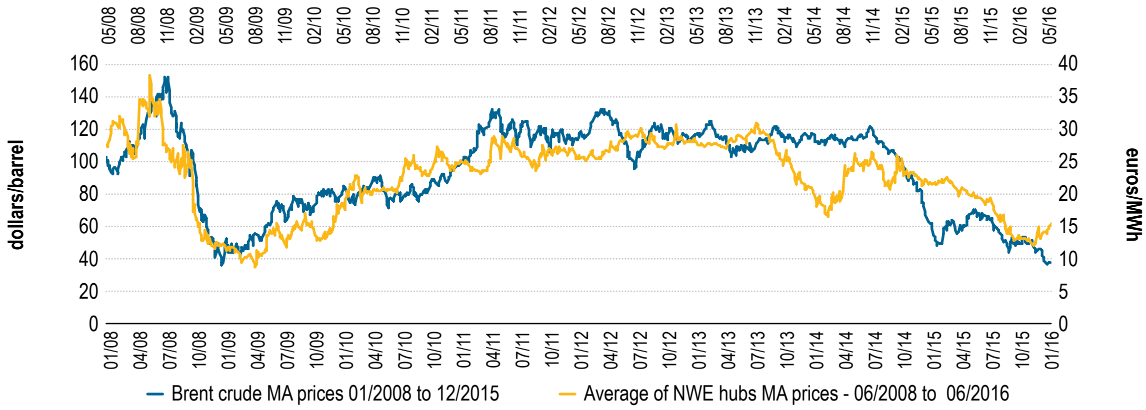
96 A similar trend can be observed in the US oil market. WTI (West Texas Intermediate) quantities traded declined in recent year(s), nevertheless WTI remains a price setter for the US oil market.

97 The fall in price was steadier through the year compared with the abrupt variations experienced in the preceding year, particularly in summer 2014 price falls.

98 Long-term contracts tend to establish a referential band for hub prices formation; recipients of long-term contracts can optimise the offtake of contractual volumes – within accepted delivery flexibilities – based on the difference of prices from hub products, and conversely can sell surplus volumes on hubs. According to various market analysts hub spot prices are generally lower than long-term contract ones because spot contracts do not include delivery flexibilities – and arguably the security – that long-term contracts do.

99 It is to be noticed that when EU companies hedge oil-indexed gas contracts they are also exposed to exchange risk since oil is priced in dollars.

Figure 20: Oil and gas hubs price evolution in Europe – 2008–2015



Source: Platts (2015) and ACER calculations.

Note: A six-month forward-lag is used for gas in the comparison with oil prices, which is the usual practice in the indexation formulas of gas long-term contracts.

99 A key recurring analysis for assessing the level of market integration in the EU is to compare the prices at which suppliers' source gas in different market zones. The exercise is based on a proprietary methodology, taking into account both long-term contract prices and hub product prices.

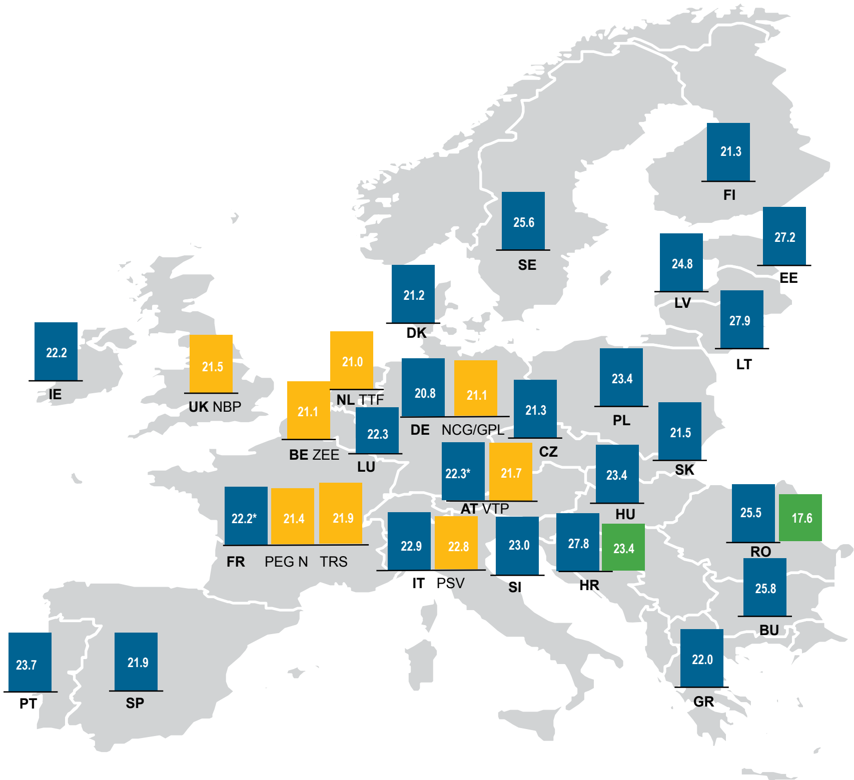
100 The extent of the gas supply cost differences is related to a combination of the predominant type of supply contract, the gas supply source and the level of liquidity and competition within the MS. All these factors interact with the role and degree of hub development and the degree of markets' integration.

101 As such, the results presented in Figure 21 indicate that markets where hubs have an important supply hedging role[100] lower sourcing costs occur. In this regard, markets in the NWE region exhibit the lowest gas sourcing prices. It is noticeable how the spread with most other geographies narrowed in 2015. In markets relying significantly more on long-term oil-indexed pipe or LNG contracts, such as the SSE and Mediterranean regions, the price drops are to a large degree connected with the drop in oil prices. The ongoing narrowing spreads of prices over recent years seem also to imply that most regions are progressively benefiting from stronger market interconnection, hence more competition. In turn, this is, for example, also facilitating price renegotiations with upstream suppliers[101].

100 The greater role that trading hubs play in price formation in these MSs is reflected via physical purchases but also by the fact that hub-indexations in long-term import contracts are most prevalent here. See IGU 2016 report.

101 For example, on the infrastructure side market analysts' quote, among others examples, the Klaipeda LNG terminal assisting Lithuania's renegotiation of pipeline imports with Gazprom, or the new interconnection between Slovakia and Hungary bolstering the latter's negotiation position, also with Gazprom.

Figure 21: EU MSs assessed gas suppliers' sourcing prices – 2015 yearly average (map) – 2014 yearly average for comparison (table) – both in euros/MWh



MS/sourcing mechanisms	2014 sourcing cost
AT imports	25.4
AT hub	24.6
BE hub	21.9
BG hub	30.9
BG imports	28.9
HR imports	24.3
CZ imports	24.1
DK imports	32.0
EE imports	28.2
FI imports	26.5
FR imports	24.7
FR hub	23.9
GR imports	28.2
HU imports	26.4
IE imports	22.1
IT imports	27.0
IT hub	25.7
LV imports	29.3
LT imports	27.8
LU imports	25.0
NL hub	23.7
PL imports	25.1
PT imports	31.8
RO imports	26.7
SK imports	25.4
SI imports	27.6
ES imports	26.2
SE imports	27.6
UK hub	24.1

- Import prices declared at the border
- Hub hedging prices
- Indigenous production

Source: Eurostat Comext, Platts, IGU, NRAs and ACER calculations.

Note: Prices are an estimate of the yearly average suppliers' sourcing price level in each MS, based on available public data and based on the ACER methodology. The Romanian and Croatian prices displayed are both the Eurostat Comext declared ones on border imports and the NRA indications on their indigenous production prices. Gazprom offers a retroactive price discount to the main Lithuanian supplier, which is not reflected in the figure calculations. The Estonian price is fully based on Eurostat Comext yearly declared Russian origin import prices; volumes purchased from Lithuania are deemed to be lower priced[102]. France and Austria import prices are estimated on the basis of the IGU 2016 wholesale price survey report.

102 The convergence of suppliers' sourcing costs to the TTF's reference has significantly improved in neighbouring areas like France, Italy and the CEE region. This is facilitated by the growing role of their hubs, and particularly, but not only[103], in the CEE region case, by the enhancement of cross-border capacity and the creation of physical or, in some cases, virtual reverse- flow capability. New interconnection capacity is beneficial to competition in two ways: first, the technical capability creates the possibility of supply from lower priced regions; secondly, the theoretical possibility exerts competitive pressure on prevailing contract prices. Both effects show the benefits of the creation of the IEM.

103 In countries like Romania and Croatia, which have significant domestic gas production, domestically-produced gas is priced lower than imports. The higher import prices are primarily linked to dependence on fewer supply sources, mainly Russia, but also to lower interconnection levels and the overall reduced competition along the gas value chain. Lower economies of scale are also likely to reduce the bargaining power of suppliers from smaller gas consuming MSs vis-à-vis external producers. As such the Baltic and SSE regions continue to have some of the highest import prices in the EU[104].

102 See: http://gaas.elering.ee/kasulikku/kuukokkuvotted/.

103 In 2015, Fluxys and Snam agreed on the final investment decisions to make the TENP and Transitgas systems bidirectional and thus to enable transports from Italy to Germany. As from the end of summer 2018 shippers will be able to move gas from Italy through Switzerland to Germany and France.

104 In the particular cases of Lithuania and Estonia, declared import prices have significantly decreased from the second semester and are now more closely aligned with NWE levels. Nonetheless as the exercise is done on a yearly basis the average values in Figure 21 show sizeable price differences. See also EC quarterly reports for a more granular price analysis: https://ec.europa.eu/energy/en/statistics/market-analysis.

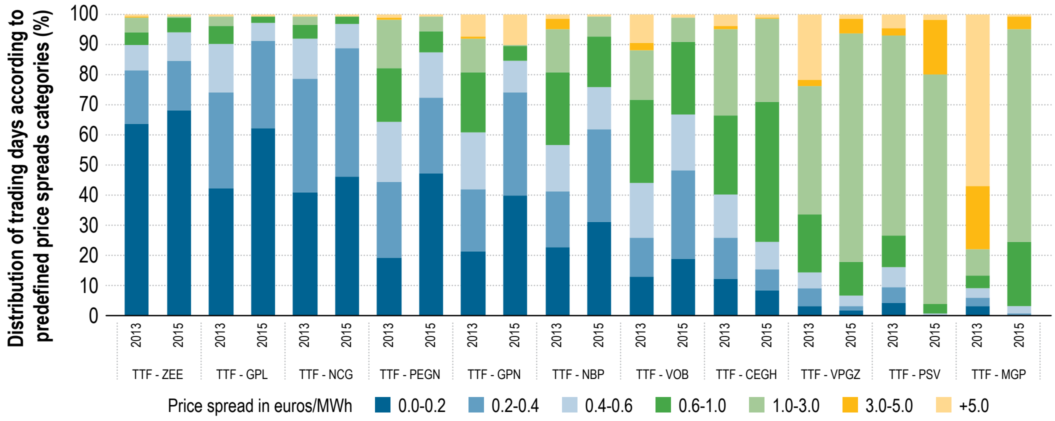
4.5 Gas hub price metrics

104 This Section measures the levels of price convergence, price correlation and price volatility among EU hubs and infers the reasons for their varying values. High levels of price alignment are a positive indication of market integration. However, full price convergence is not necessarily the target to achieve when pursuing the completion of the IEM, e.g. disproportionate infrastructure investment costs or market areas' very diverse market fundamentals may justify the persistence of certain price differences.

4.5.1 Price convergence

105 Price convergence implies narrowing price differences between hubs. In more integrated markets, these price differences are likely to be lower, and in theory would tend to be close to zero after discounting for gas transportation costs. Figure 22 displays the percentage frequency of days in the year when price spreads between TTF and selected hubs were within defined bands. The calculation of price convergence was based on daily average settlement prices of day-ahead products.

Figure 22: Levels of DA price convergence between TTF and selected hubs year on year



Source: ACER calculations based on Platts and hub operators data.

Notes: Spreads in euros/MWh are calculated as the absolute price differential between pair of hubs, with independence on which one is at discount or premium. Different categories were determined in order to calculate the distribution of price spreads among hub pairs. The distribution was made over a total number of trading days in a year.

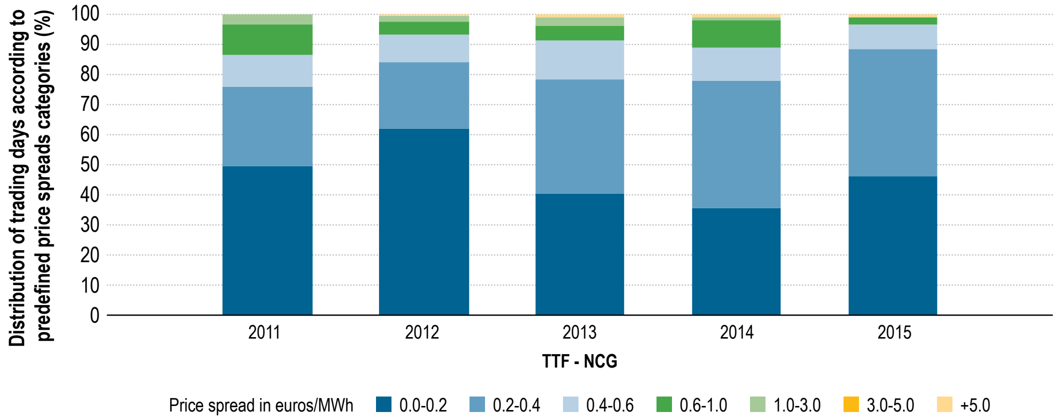
106 Price convergence across European hubs has improved in recent years. A combination of factors explains these results. On the one hand, there is the increasing market participants' involvement at hubs looking to take advantage of price arbitrage possibilities. On the other hand, a context of oversupply supports price convergence via arbitrage of surplus positions. In addition to that, broader coverage abilities for traders[105] facilitate the comparison of liquidity and prices fostering hub trade. Finally, the facilitation of cross-border trade via new infrastructure and harmonised regulation are also key contributors to higher convergence.

107 Price convergence is the highest among gas hubs in the NWE region. The reasons for this are the high levels of liquidity, sufficient available cross-border capacity and the presence of a more effective regulatory regime (e.g. more advanced implementation of network codes). However, in other regions, especially SSE and CEE, hub price differences persist. This is due to lower liquidity on individual hubs, higher contracting of gas through long-term oil-indexed contracts as well as infrastructure challenges which often result in physical and contractual congestions at the cross-border IPs.

105 For example, ICE Endex and PEGAS became active in Italy in 2015. PEGAS also became active in the UK in 2015.

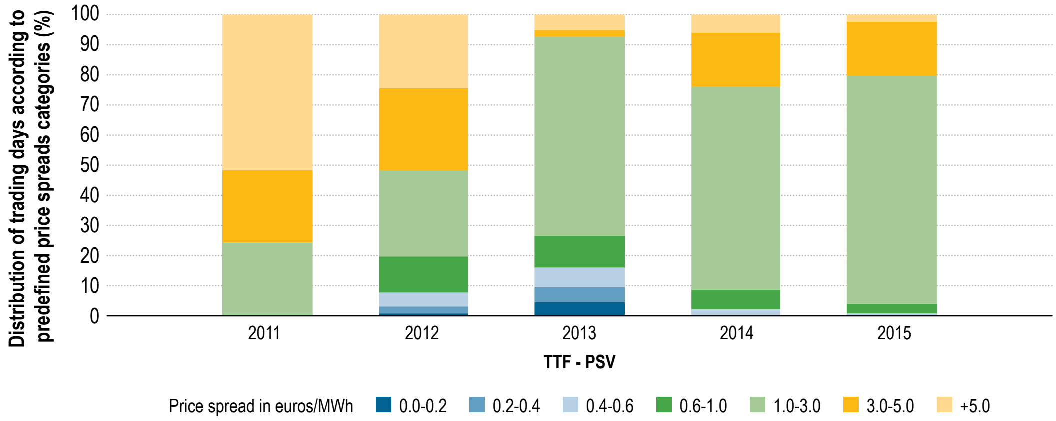
108 As Figure 22 illustrates, the range of price spreads among hubs has narrowed in recent years. A further breakdown, as shown in Figure 23 and Figure 24, details price convergence levels between selected hub pairs in the NWE and adjacent regions in the last 5 years. Convergence tends to be higher and steadier during this period in the NWE region, but has gradually improved also with adjacent MSs. In the case of Italy, one of the main factors contributing to enhanced convergence is deemed to be the higher levels of liquidity brought to the PSV hub by the Italian incumbent Eni and the overall facilitation of trade (see case study 3).

Figure 23: Levels of DA price convergence between TTF and NCG – 2011–2015



Source: ACER calculations based on Platts data.

Figure 24: Levels of DA price convergence between TTF and PSV by year – 2011–2015



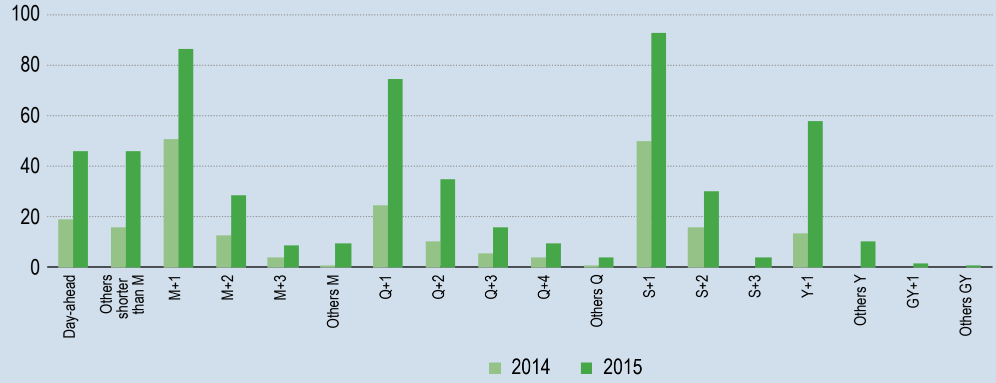
Source: ACER calculations based on Platts data.

Case study 3: Italian PSV developments

The Italian virtual trading point PSV, which was created in 2003, has seen stronger price convergence with NWE hubs in recent years. The trading volumes and the number of participants are also more aligned with NWE hubs. Since 2012, steady growth has been recorded in the Tradability Index – calculated by ICIS-Heren[106]. The index value for PSV rose from 3 at the end of 2012 to 13 by the end of 2015, also showing a bid-offer spread lower than 0.3 euros/MWh for an increased number of products. Since September 2015, both the ICE Endex and PEGAS exchange have offered physical natural gas futures contracts at the PSV, in particular M+3, Q+3, S+2 and Y+1 products. Some 7 TWh were traded in the first six months.

Figure i shows traded volumes for different hub products at PSV in the last 2 years. The increasing liquidity of products with delivery beyond one month confirms that market participants have better hedging possibilities at their disposal.

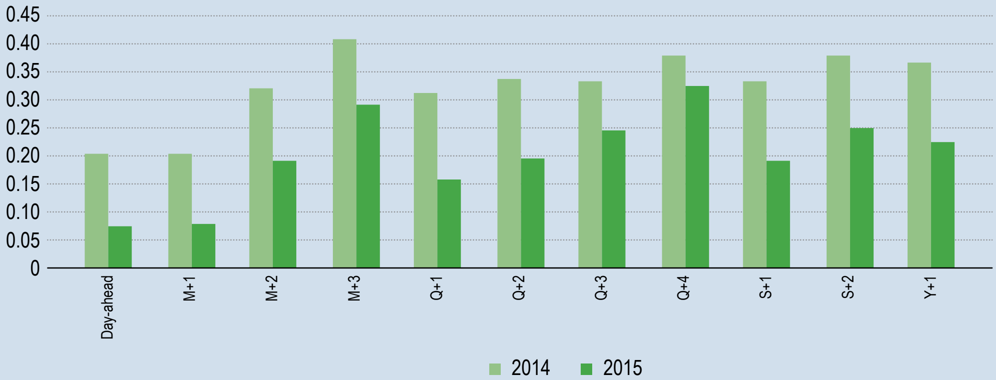
Figure i – PSV-traded volumes by contract type and delivery period (TWh) – 2014–2015



Source: AEEGSI based on ICIS Heren data.

Figure ii shows the significant improvements in the bid-offer spread metric in 2015. A threshold of 0.3 euros/ MWh is considered as a reference of good hub functioning for this indicator. In 2015 all bid-offer spreads for contracts with delivery beyond one month were below 0.3 euros/MWh, with the only exception being the Q+4 products.

Figure ii – Bid-offer spread at PSV by contract type and delivery period (euros/MWh) in 2014–2015



Source: AEEGSI based on ICIS Heren data.

106 The ICIS-Heren Tradability index illustrates developments of the bid-offer spreads of EU hubs contracts. The highest value is 20.

The following factors explain the developments of PSV over the last years:

1. *Introduction of a market-based balancing regime in 2011:* A balancing platform – called PB-GAS – was set up, allowing storage capacity holders to trade balancing volumes among themselves and with the TSO. Offers are selected on the basis of their merit order. This platform made the balancing system more transparent and competitive and introduced a daily transparent market price signal for all market participants, also fostering the development of liquidity of title products at the PSV. At present many contracts among wholesalers, with different duration and delivery time, foresee a physical delivery at PSV.

2. *Allocation of storage capacity via auctions.* Until 2013 storage capacity was allocated on a pro-rata basis to gas suppliers only. The auctioning mechanism allows new players to obtain storage capacities, facilitating trade in the wholesale market and access to the PB-GAS. Table i shows the concentration level of allocated storage capacity. Storage users active in the Italian wholesale gas market increased from 50 in 2014 to 75 in 2016. Since 2014 the number of pure traders among the first 5 storage users for allocated capacity has increased as well.

Table i: Concentration of capacity allocation for storages after auctions – 2014–2016 – CR % and Mcm

Storage capacity holders	2016		2015		2014	
	Capacity in Mcm	%	Capacity in Mcm	%	Capacity in Mcm	%
CR3	2598	37.9%	3974	44.4%	3323	62.5%
CR5	3492	51.0%	4879	54.4%	3777	71.0%
CR10	4771	69.6%	6690	74.6%	4584	86.4%
Others	2080	30.4%	2274	25.4%	724	13.6%
Total	6851		8964		5318	

Source: AEEGSI.

3. *Amendment to the formula that sets the reference gas price for small customers.* The Italian NRA (AEEGSI) has progressively amended the formula used to set this reference price (CMEM)[107]. It was initially linked to oil-indexed long-term contracts, but it is now based on TTF hub gas spot prices and on transport fees from TTF to PSV. This is deemed to have provided Italian traders with new hedging opportunities.

4. *Early implementation of the CAM Network Code:* Italy has implemented the provisions included in the CAM Network Code one year earlier than legally required. Capacity allocation is now more transparent facilitating cross-border trade.

5. *Most commodity fees have been moved from entry to exit points.* Since October 2015; AEEGSI has shifted most of the commodity component of transmission fees collected at the entry side to new fees collected at the exit side of the network. This is deemed to have increased liquidity and transparency in the wholesale market by reducing the operational risk for shippers. The transfer of entry charges into the PSV price impacts directly the spreads with other European hubs.

A further boost to PSV liquidity is expected to come from the implementation of the Balancing Network Code regime. PB-GAS will merge into the existing day-ahead and within-day platform, allowing network users to balance their position through the trading of short-term standardised products in a single wholesale market. The new allocation mechanism via auctions for LNG capacity introduced in February 2016 (where a bundled service of regasification and storage capacity is offered) shows encouraging results as 6 slots were allocated, for approx. 500 Mcm. Additional volumes of gas could further increase the offer at PSV.

107 CMEM (in Italian, average efficient cost of the gas commodity market) is used as the gas reference price for contracts offered by retailers to domestic customers.

109 Developments in hub liquidity in the CEE region are supporting a broad price converging trend. According to some market analysts, this trend may lead to the creation of regional hubs, and a movement towards a potential single future price signal for the whole region. Figure 25 and Figure 26 show the level of price convergence between selected CEE hubs and the NCG and CEGH hubs respectively. Convergence seems slightly higher with CEGH, except for the case of the Czech Republic, where convergence is stronger with NCG. The latest case can be explained by the availability of greater cross-border capacity between Germany and the Czech Republic. Since 2014, a decreasing trend in convergence between NCG and CEGH can be observed due to congestion at Austrian-German interconnection points and increasing flows towards Italy[108].

Figure 25: Levels of DA price convergence between NCG and selected hubs year on year (%)

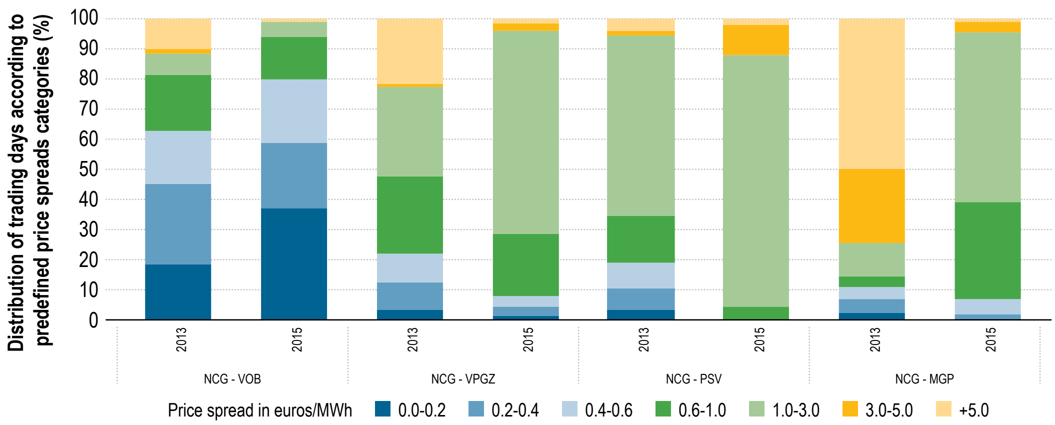
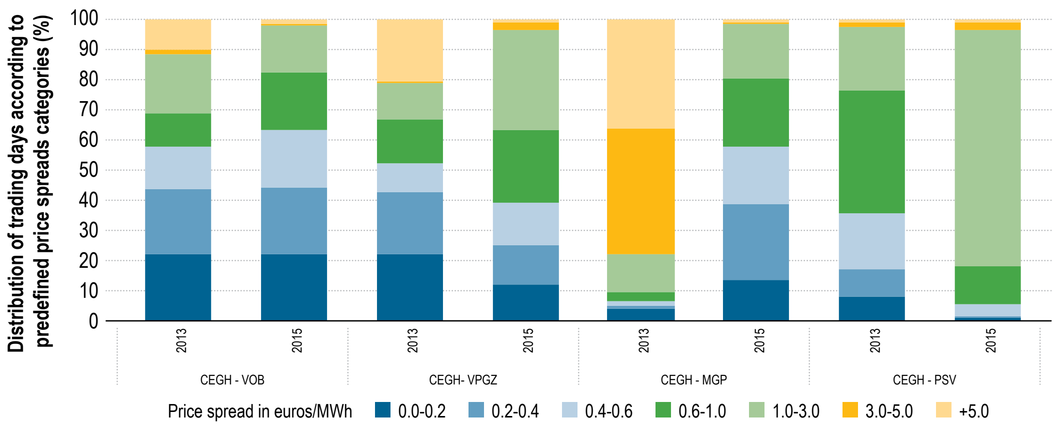


Figure 26: Levels of DA price convergence between CEGH and selected hubs year on year (%)



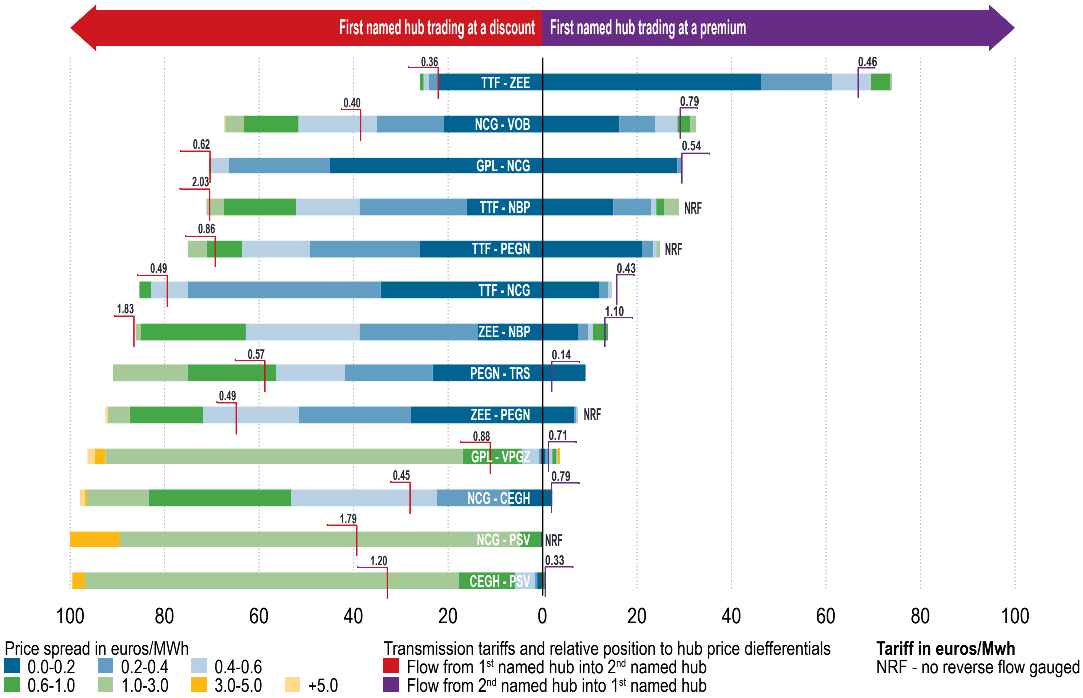
Source: ACER calculations based on Platts.

110 Figure 27 shows the absolute price differences between selected hub pairs during 2015, together with the capacity transportation charges among those market zones[109]. For example, when looking at the German NCG and Czech VOB hubs, during circa 70% of the days of the year (see left side of the X-axis) NCG traded at a lower price than its Czech counterpart. Furthermore, during 40% of the total days of the year (or approx. 60% of those days when NCG traded at discount – see the relative position of the tariff mark on the left side of the X-axis) the price spread between the two hubs was below the transmission costs for transporting gas from Germany into the Czech Republic that are assessed at 0.40 euros/MWh.

108 See for example OIES paper for an analysis on the topic: https://www.oxfordenergy.org/publications/aligned-reliable-gas-exchange-prices-europe/.

109 Simulation of cross-border capacity charges in euros per MWh on the basis of a yearly capacity contract signed in April 2015 for flowing 1 GWh/day/year by Entry/Exit IP. In certain IPs tariff units of measurement are not published on a yearly basis and/or may differ per period length. In those cases direct conversions were performed.

Figure 27: Day-ahead price convergence levels in EU hubs compared to transmission tariffs – 2015



Source: ACER calculations based on Platts and hub operators data for prices and ENTSOG for transmission tariffs.

Notes: For the hub pairs TTF-PEGN and ZEE-PEGN the charges in the flow direction exiting France have not been assessed (NRF). However since 1 November 2015 non-odorised gas can physically flow through the 'Artère des Flandres' pipeline between France and Belgium[110] .Also in the hub pair TTF-NBP transmission tariffs for exit direction UK have neither been assessed despite backhaul capacity is offered across BBL between the UK and the Netherlands.

111 Figure 27 indicates that, since EU hubs prices increasingly converge, situations in which hub price spreads are lower than transmission charges[111] are very frequent. This is particularly observable in the NWE region. In the other cases where hub price spreads are higher than transmission charges – and in the absence of capacity constraints – booking capacity and performing arbitrage trade should be advantageous.

112 Price convergence among hubs is favoured in recent years by various factors. Financial-arbitrage trading operations (e.g. spread trade, locational swaps) is one that has a considerable impact, as, in some markets, certain types of trade without physical capacity booking/use are allowed. Transport costs in this respect are less of a determining factor for taking the decision to trade. Another element that has an impact on this situation is that capacities may be booked on a long-term basis and, as such, they act as a sunk cost. In this situations arbitrage trade will take place, oriented purely to variable hub price differentials[112]. Finally, the enhanced hub-price indexation of long-term contracts observed across the EU is deemed to assist price convergence among hub products. This is also favoured by the use of common hub price references in various EU markets (e.g. TTF prices are used for long-term contract indexations in a number of Continental markets).

4.5.2 Price correlation

113 Price correlation assesses the relative evolution of price levels, and serves to measure whether adjacent markets are reacting in similar ways to the same supply/demand factors. Price correlation is not a metric that in itself necessarily implies price convergence, but it provides some insights into efficient pricing and market areas' integration. However, correlations can be affected by common trends and seasonality factors across all markets.

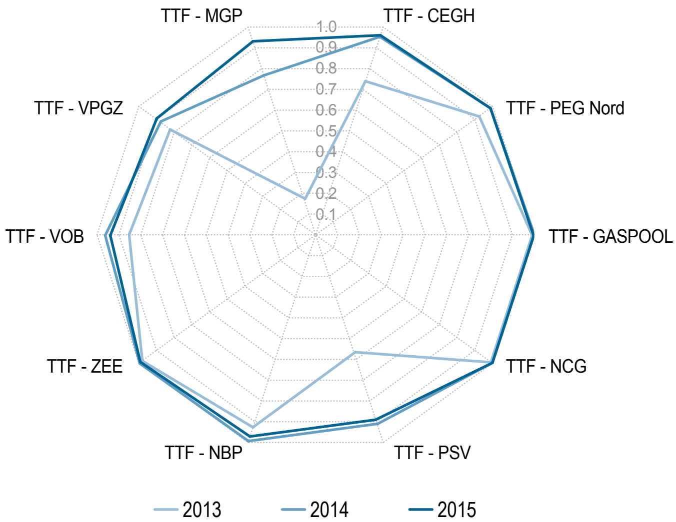
110 The project will in 2016 enable the connection of the Dunkirk liquefied natural gas terminal to the Belgian grid. Capacity is assessed at 8 bcm/year.

111 At least among hubs price references; perhaps not so applicable to overall MSs wholesale prices formation, also influenced by long-term contract prices.

112 For example, all IUK capacities have been allocated on long-term basis up to 2018, so capacity costs do not have much effect on shippers' short-term decisions to flow gas into the pipeline. The incentive is also driven by the commodity/capacity recovery split applied; it should be more clearly observable between those zones where transmission tariffs capacity components are higher.

114 Price correlation is stronger in the NWE region, suggesting that these markets are at a more advanced stage of integration. Nevertheless, higher correlation levels are also becoming more apparent in neighbouring hubs, as Figure 28 shows. Although correlation may be high, the underlying absolute price levels may reveal a price gap which is also linked to transmission charges.

Figure 28: Levels of DA price correlation between TTF and selected hubs



Source: ACER calculations based on Platts and hub operators data.

Notes: Hubs day-ahead average daily settlement prices for each individual year are correlated using the Pearson product-moment correlation coefficient[113]. The value of -1 represents perfect negative correlation between two data sets, while value 1 corresponds to a perfect positive correlation. A value of 0 resembles no correlation among data sets.

115 Improved price correlation was again subject to overall liquidity improvements in EU hubs in recent years. Higher correlation values within the CEE region (e.g. Polish and Czech hubs) are driven by infrastructure upgrades that improved cross-border trade as well as the increased number of market participants. In Hungary, although a good correlation of gas prices with TTF exists, there is still a limited number of gas wholesale trades executed on the exchange. The reason behind the observed good correlation with TTF may be linked to the applicable universal supply regulation, stipulating the indexation of Hungarian regulated prices to TTF[114] .

4.5.3 Price volatility

116 Price volatility is an indicator assessing the speed and amplitude of price changes. Higher correlation of price volatility levels are expected to occur between more integrated markets. This would signal, on the one hand, the influence of similar demand/supply fundamentals across markets. On the other hand, this also signals that market conditions having an impact only on a specific market prompt arbitrage trading from an adjacent one, leading to price adjustment. Higher volatility invites certain types of trading activity and stimulates forward-price risk management. Volatility levels also have an impact on the hedging strategies of suppliers[115].

117 In recent years, volatility levels in European markets have been subdued. This decrease in volatility - with low values shown until 2013 in Figure 29 – was mostly due to a market cycle of decreasing demand and excess of supply, which implied that fundamental market shocks were more easily absorbed. In addition, enhanced interconnection infrastructure and fairer capacity allocation rules are likely to have been contributing factors. The oversupply scenario, together with the narrowing of winter and summer price spread gaps, has reduced interest

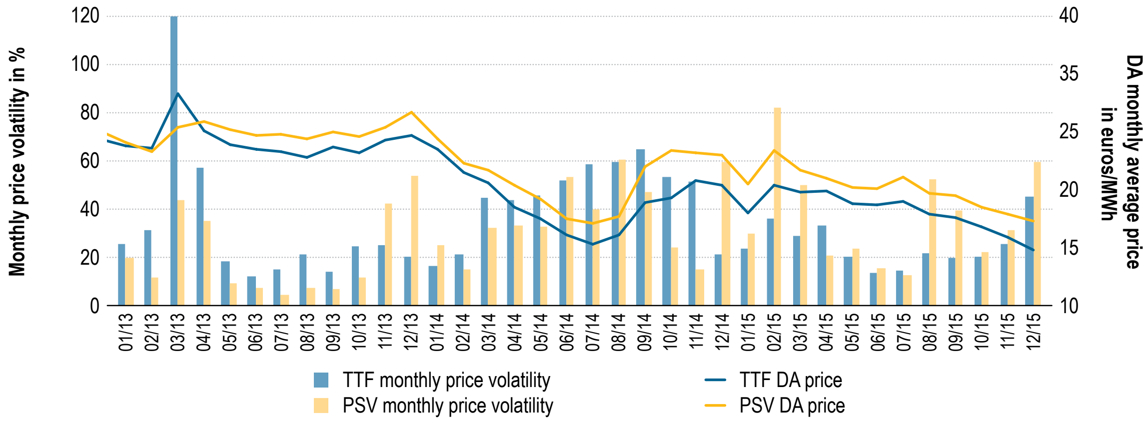
113 Pearson's correlation coefficient is the covariance of the two variables divided by the product of their standard deviations.

114 An average of the settlement price of the TTF Gas Base Load Futures is set as a one of the references used for Hungarian universal supply retail price formulation – the other relates to the prices of a basket of long term contracts. See further details here: http://njt.hu/cgi_bin/njt_doc.cgi?docid=124389.320126.

115 In fact, price stability is one of the factors that those advocating long-term contracts indexed to more liquid commodities (i.e. oil) cite in their favour. Forward-price risk management is also intended in part to reduce the exposure to volatility from spot markets.

in the use of certain supply flexibility mechanisms such as storage sites, but also promote short hedging on hubs in contraposition to long-term contracting. However, as Figure 29 shows, during 2015 some price volatility escalation was registered for the reasons discussed in Section 4.1.

Figure 29: Day-ahead gas prices and price volatility evolution in selected EU hubs – 2013–2015

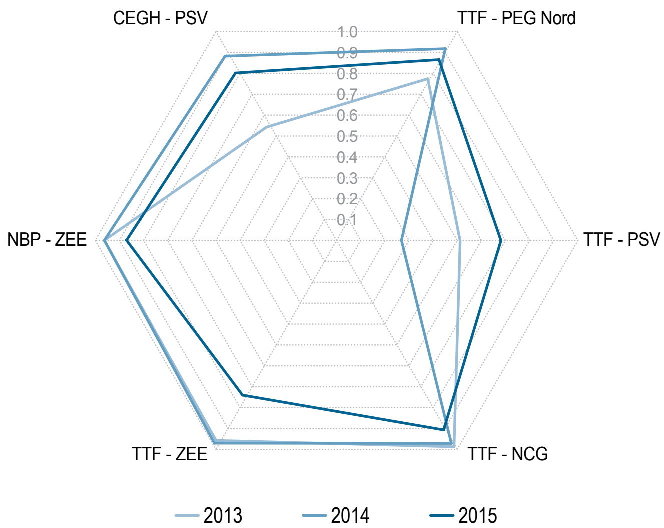


Source: ACER calculations based on Platts.

Notes: to conduct the volatility analysis first logarithmic returns of daily gas hub prices are gauged. Then, the standard deviation of returns is calculated and multiplied by the square root of total trading days in a year. The value is expressed as a percentage.

118 Figure 30 shows price volatility correlation between selected pairs of hubs. According to this metric, hubs in the NWE region have higher correlation levels. When taking this into account it together with the other price metrics analysed above it provides further proof of NWE being very integrated. In case of arbitrage opportunities prices seem to align quicker thanks to sufficient cross-border capacity. Among other regions larger differences persist. An example is the volatility correlation values between TTF and PSV. Weather effects and different gas for power generation portfolios can be among the main short-term drivers moving prices independently and resulting in different levels of volatility. Also noteworthy to mention is that in 2014 and 2015 volatility correlation values were quite high between CEGH and PSV; these two hubs seem to follow each other closer thanks to enhanced interconnection arrangements.

Figure 30: Price volatility correlation between selected pairs of hubs – 2013–2015



Source: ACER calculations based on Platts.

Notes: correlation was calculated using the Pearson product-moment correlation coefficient methodology looking at monthly values of standard deviation of logarithmic price returns, previously calculated for volatility values.

5 Impact of network codes on market functioning

Chapter summary

The progressive implementation of the gas network codes and guidelines is expected to promote cross-border trade and the well-functioning and integration of gas wholesale markets. This Chapter reviews for the first time a set of indicators to assess the market effects of the implementation of the Capacity Allocation Mechanisms Network Code and Congestion Management Procedure Guideline[116].

The Chapter provides a general picture about the market effects of the new regulatory provisions. However it does not draw at this stage isolated conclusions due to the difficulty to separate regulatory effects from market fundamentals, data quality challenges, as well as to the too recent implementation of these regulatory provisions. The analysis will be expanded in future editions of the MMR.

5.1 Degree of NCs implementation and market effects

119 Under the Third Package the Agency is legally required to monitor the implementation of the gas and electricity network codes[117]. This includes both compliance and effects monitoring. In this Section the Agency looks for the first time at the economic effects of gas Network Codes and Guidelines based on indicators specifically developed for this purpose[118]. The analysis looks at the indicators developed for the CAM NC and CMP GLs. Indicators for the other gas Network Codes, like Balancing and Tariffs, will be progressively added in future MMR editions. Therefore the coverage and evaluation of market effects will be expanded in the next few years.

120 The indicators rely on the transport data available on the ENTSOG Transparency Platform and on the monthly auction reports of the Booking Platforms. The Agency acknowledges that the data sets used for this analysis need to improve. Annex 2 describes the improvements needed and the methodology used for this analysis.

5.1.1 Impact of CAM NC

121 According to the CAM NC, TSOs will dynamically calculate the technical capacities of interconnection points over shorter timeframes than a year. This may result in an increase in the capacity availability for selected periods within the year. When recalculating capacity, TSOs will take into account expected flow patterns, gas quality, and unexpected weather conditions or outages. From 2014 to 2015, the aggregated average technical capacity at EU IP sides seem to have remained stable based on the list where data was available[119].

Booked capacity and its physical use

122 According to the CAM NC capacity is booked via auctions by those willing to pay the most for it. As such it is expected that bookings and physical utilisation will progressively converge over time. Despite convergence enhancement, the full matching of bookings and physical use will not occur for various reasons. First, shippers may need to contract extra capacity than their actual flow needs to adjust their portfolios in line with peak flow level expectations. Alternatively, some shippers may prefer yearly flat capacity to profiled bookings when the latter is not accessible or economic to buy. Finally, as gas demand is decreasing, it will become increasingly difficult for shippers owning unused booked long-term capacity to find a third party interested in taking over those bookings.

123 Figure 31 and Figure 32 assess the alignment between booked capacities and physical capacity utilisation at EU interconnection points. Their evolution over time helps to illustrate whether capacity optimisation, i.e. alignment between booked capacity and physical capacity utilisation took place in the European networks due to the

116 (1) market integration; (2) non-discrimination; (3) effective competition; and (4) efficient market functioning.

117 Article 9(1) of the Regulation (EC) No. 715/2009.

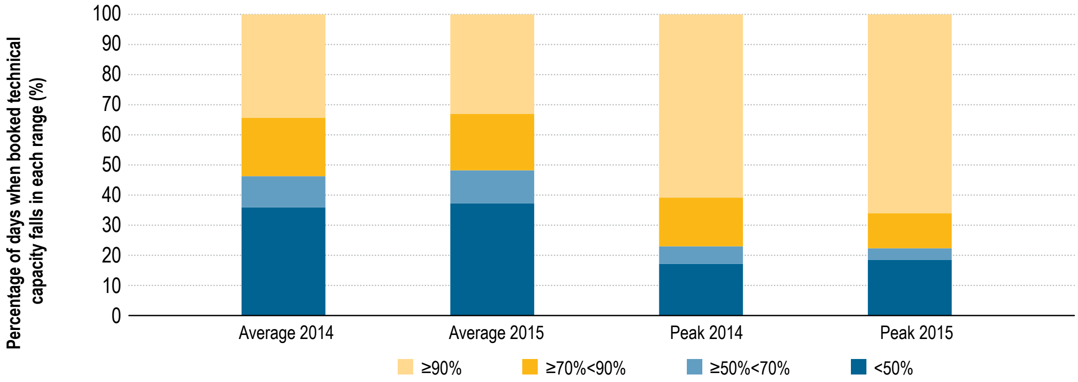
118 The Agency, supported by the consultancy CEPA, defined the relevant indicators to monitor the effects of the network codes. These metrics were discussed in a public consultation with stakeholders in 2015: http://www.acer.europa.eu/gas/market_monitoring/documents/cepa%20finalreport_monitoring%20%20evaluation%20of%20impacts%20of%20gas%20ncs_final_oct'15.pdf.

119 The number of IPs in scope represents three quarters of the total.

application of CAM NC and CMP GLs. However the displayed values cannot be considered as sufficient yet to reveal robust patterns given the recent implementation of the relevant provisions and therefore the short period for which data are available[120].

124 Figure 31[121] shows the ratio of booked capacity over technical capacity at EU market zone borders for 2014 and 2015 over four ranges. No distinction between entries and exits is applied.

Figure 31: Evolution of ratios of booked over technical capacity – 2014–2015



Source: ENTSOG TP and ACER calculations.

Notes: IP sides analysed represent circa 60% of the total CAM scope list (see Annex 2). Values represent the weighted average quantities of all IPs at each border. Calculations are made firstly for the average of all daily values during the year and secondly by considering the 10 peak days.

125 Between 2014 and 2015, the ratio between bookings and technical capacity remained stable for the daily average. However, the peak values analysis reveals that there has been an increase in booking rates, especially for the highest value range (above 90%).

126 A comparison with prior MMR results[122] shows however a decrease, on a yearly average, in aggregated technical capacity being contracted and a change in capacity utilisation trends. Shippers increasingly contract capacity for a shorter term to cover needs associated with high seasonal demand (profiling of bookings)[123]. In addition there could be a slight increase in confidence to acquire capacity as CMP measures[124] are gradually applied (i.e. triggering the release of unused capacity). In general, capacity seems progressively more accessible for shippers. In the broader market context, this is further explained by falling consumption levels and reverse nominations physical netting.

127 Figure 32[125] shows the aggregated ratios of physical flows over technical capacity on EU market zone borders for 2014 and 2015 over four ranges. The graph shows that for the vast majority of IP sides, both in 2014 and 2015, the physical utilisation is below 50 %. On average the physical utilisation values seem to have remained stable based on the list where data was available.

120 See ACER's Implementation Monitoring Report on CMPs the delays in implementation in selected MSs: http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20CMP%20Implementation%20Monitoring%20Report%202014.pdf.

121 This indicator corresponds to the CAM.5 indicator specified in the CEPA report.

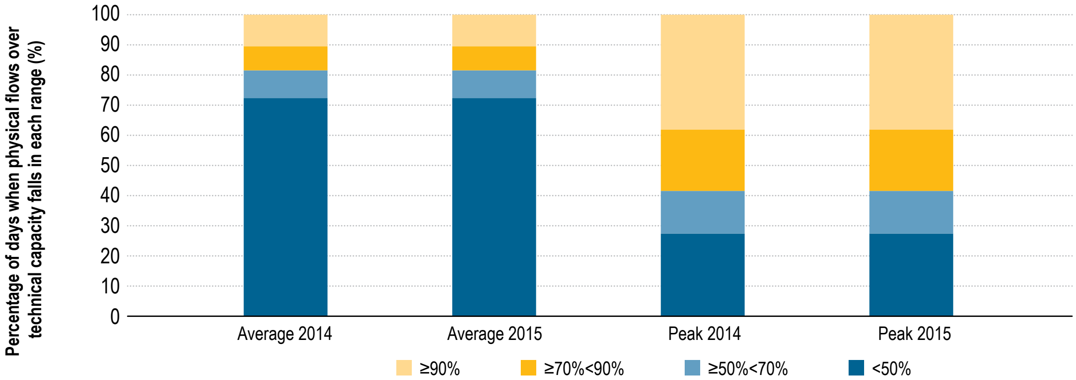
122 See MMR 2014 figure 116.

123 Once the tariff NC will be implemented, more capacity profiling can be expected if network users face variation in underlying unit costs of annual, quarterly, monthly and daily capacity.

124 Given the modest application of CMPs, profiling can still be improved further.

125 This indicator corresponds to the CAM.6 indicator specified in the CEPA report.

Figure 32: Evolution of ratios of physical flows over technical capacity – 2014–2015



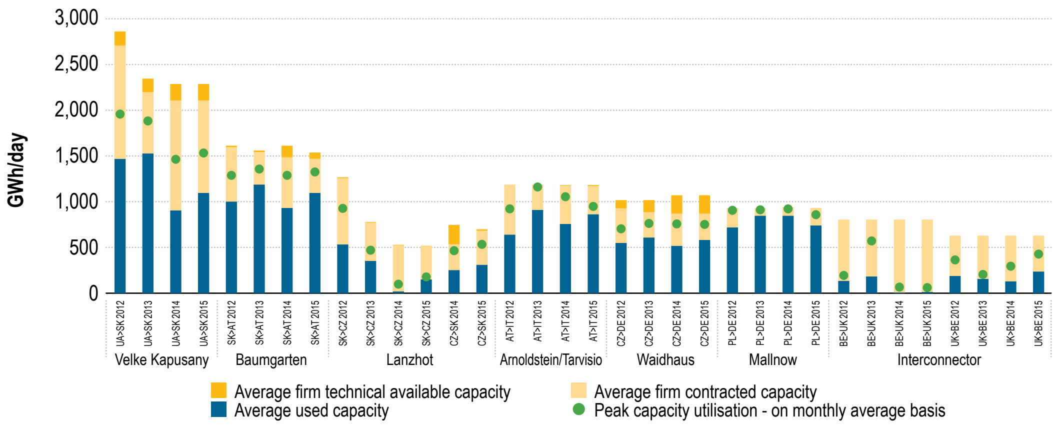
Source: ENTSOG TP and ACER calculations.

Notes: IP sides analysed represent circa 60% of the total CAM scope list (see Annex 2). Values represent the weighted average quantities of all the IPs at each border. Calculations are done first for the average of all daily values during the year and secondly by considering the 10 peak days.

128 However, the ratio between booking and physical capacity utilisation levels between the two years, (see Figure 35 below) reveals that the evolution of these two factors has improved[126]. Nonetheless, shippers are booking more capacity than they strictly use as for the reasons denoted in paragraph (137). Observations over a longer timeline for all these ratios will be important in better understanding capacity utilisation. Obviously the physical flow values would not give an accurate picture at bidirectional points where flows are netted by reverse nominations. For such an analysis different data sets are required, which at this stage are not available at good quality for the Agency.

129 It is acknowledged that the ratios of booked and physically utilised cross-border capacity may vary in different EU market zones. The underlying reasons for these variations are found in a combination of factors that go from the pre-eminence of legacy contracts, distinct market fundamentals, varying competition levels and the extent of NCs implementation. The sample in Figure 33 includes a collection of relevant gas flow directions throughout Europe to illustrate some of these differences.

Figure 33: Yearly average used versus booked capacity at selected IPs in the EU – 2012–2015 (GWh/day)



Source: ENTSOG transparency platform and individual TSO data (2014) and ACER calculations.

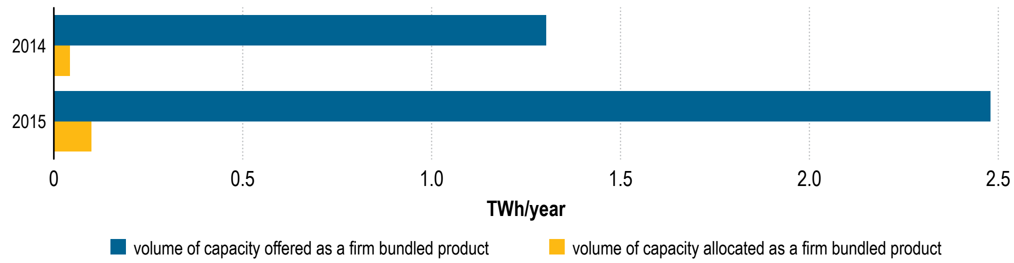
Note: In those IPs offering reverse flow possibilities, capacities can be nominated in both directions. Utilisation values are shown on the basis of physical flows after their commercial netting. This may result in lower rates than initially received nominations. In cases where technical capacities at both IP sides do not fully overlap, the lower value was considered.

126 Note however that the set of IPs analysed in Figure 35 is more prescriptive that those in Figure 31 and Figure 32 due to data consistency reasons.

Offer of bundled capacity

130 Figure 34 displays the second set of indicators related to the CAM Network Code implementation[127]. It shows both the volume of offered bundled capacity and the amount of bundled capacity sold at auctions[128] - bundled means that the allocation of capacity at both sides of the border occurs as a single capacity product.

Figure 34: Marketable and allocated bundled capacity for European cross-border IPs via dedicated auctioning platforms – 2014–2015 – TWh/year



Source: ENTSOG TP, PRISMA and ACER calculations.

131 The CAM NC establishes that at EU interconnection points, capacity must progressively be offered as a bundled product. Existing contracts of unbundled capacity shall be bundled over time at their expiry. Figure 34 shows that at present very limited volumes are offered[129] and sold as bundled capacity: 4.1% of the offered bundled capacity was sold by auctions in 2015, against 3.5% in 2014. The prevalence of legacy long-term contracts and the difficulty of revising those without regulatory or market pressure may keep the value of this indicator low in the coming years.

5.1.2 Impact of CMP GLs

132 The next set of indicators assesses the market impacts resulting from the implementation of the CMP GLs. The CMP provisions aim to achieve an optimal management of capacity by offering to the market the capacity booked but not used by shippers. They also aim to avoid or delay the need to invest in the creation of new capacities. CMP indicators are complementary to the CAM indicators shown above.

133 CMP GLs establish four mechanisms: (1) over-subscription and buyback (OSBB), (2) firm day-ahead use-it-or-lose-it (FDA UIOLI), (3) capacity surrender, and (4) long-term UIOLI (LT UIOLI)[130]. OSBB and FDA UIOLI[131] are considered alternative measures.

134 The analysis first evaluates the additional capacity volumes made available through each CMP for the years 2014 and 2015. The results show a 25% year-on-year increase in offered volumes for all CMP mechanisms applied. The number of countries using CMPs has also increased year on year, from four to six MSs. The UK and Poland are implementing these provisions, besides Austria, Germany, the Netherlands and France. No capacity has been released so far by the application of the long-term UIOLI mechanism. Remarkable levels of both oversubscription and capacity surrender were observed on the Dutch borders[132], where these measures removed previous congestions.

135 The 2016 edition of the ACER Congestion Report[133] identified 41 contractually congested IP sides in 8 Member States - out of 249 IP sides within the scope of the CMP GLs. At 13 of these congested IP sides, no

127 These indicators corresponds to the CAM.2 and CAM.3 indicators specified in the CEPA report.

128 The analysis is based on the monthly auction reports available on the capacity Booking Platforms.

129 Volumes of auctioned bundled capacity are less than 1% of total EU IPs technical capacity. The low figure is also because auction platforms only offer limited capacities – i.e. those not booked via prevailing contracts.

130 For further details on these mechanisms, see: http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2012:231:0016:0020:en:PDF.

131 FDA UIOLI is applied at present at the Germans and Austrian borders.

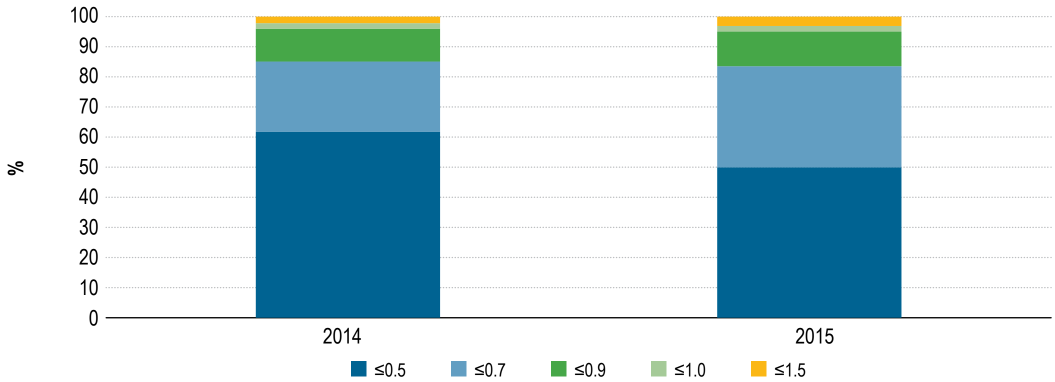
132 6,102 GWh/d for OS and 259 GWh/d for surrender in 2015. The Dutch IPs account for 93% of all capacity made available.

133 See http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%202016%20Report%20on%20Congestion%20at%20IPs%20in%202015.pdf.

capacity was made available via CMP mechanisms. These results point to additional improvement needed in the application of CMP provisions.

136 Figure 35 measures the aggregated ratio of physical flows over booked capacity at EU cross-border and in-country IPs[134] over five ranges. It reveals that the daily average of physical utilisation of booked capacity increased year on year. This was favoured by higher physical flows occurring in 2015, linked inter alia to the rise in demand. Nonetheless the figure shows that relatively low capacity utilization ratios (i.e. below 0.7) are still the most predominant for EU IPs. This situation seems to be explained by a combination of several factors including constraints to buy capacity close to real-time flows and by the prevalence of long-term capacity contracts in certain markets[135]. Moreover, and although the situation is gradually improving in several markets, highly priced short-term capacity products are also deemed to have an impact on the profiling of shorter-term capacity bookings. Finally, the further convergence of gas hub prices and the extension of swaps and flows netting mechanisms could be reducing some physical flow arbitrages.

Figure 35: Aggregated capacity utilisation of EU IPs - flows over bookings – 2014–2015



Source: ACER calculations based on ENTSOG TP and PRISMA.

Note: IP sides represent circa 80% of the CMP scope list (see Annex 2). Note that the analysed IPs list is not fully coincident with those in Figure 31 and Figure 32.

5.1.3 Benchmark of cross-border tariffs

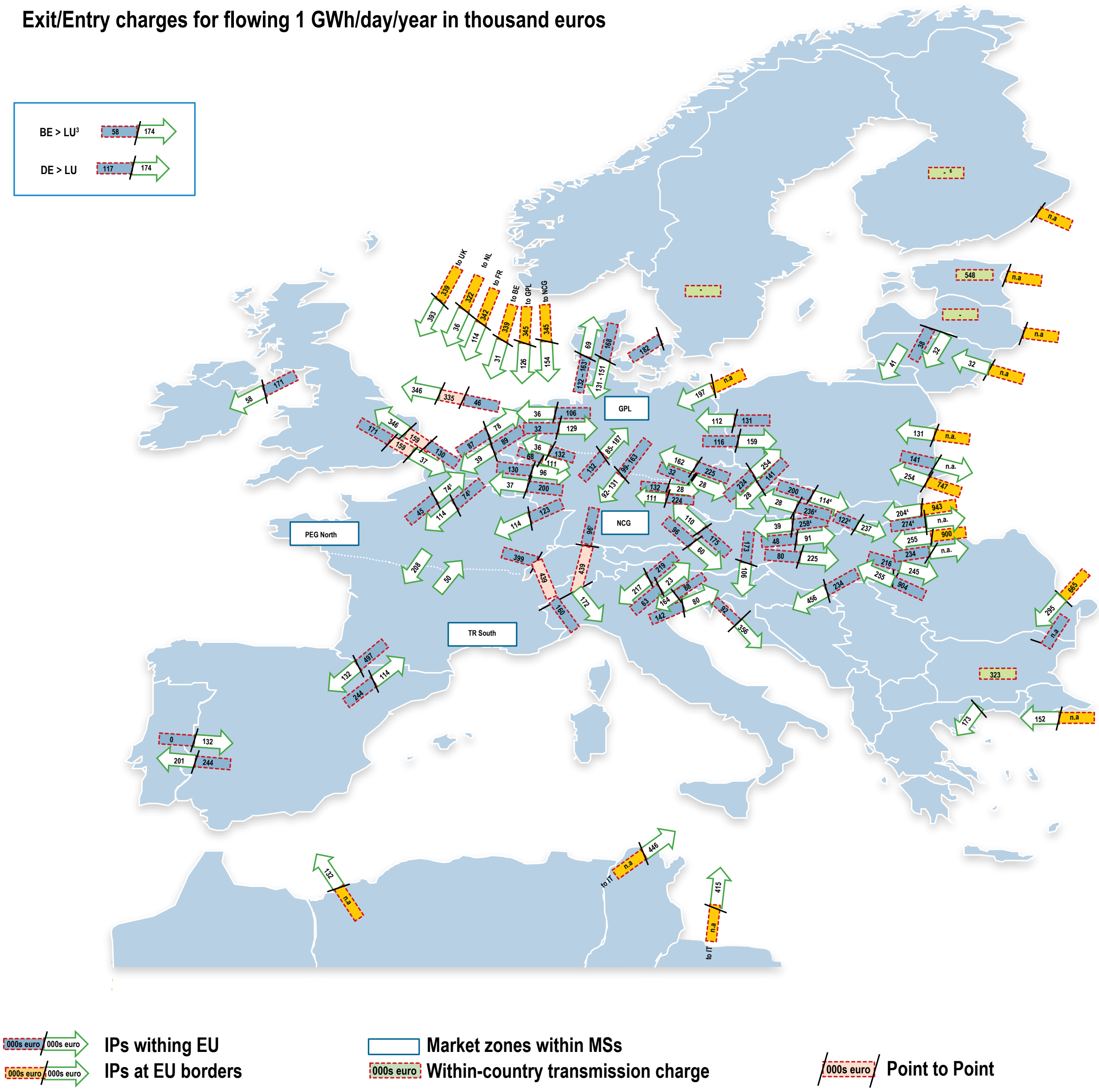
137 The NC on harmonised transmission tariff structures is under development[136]. In order to identify variations in the tariffs values and have the ability to properly observe the future impact of the Tariffs NC, the Agency calculates the evolution of cross-border IPs reference prices, the values of which for 2016 are shown in below – in an aggregated manner – per border side.

134 This indicator corresponds to the CMP.3 indicator specified in the CEPA report.

135 I.e. for operational reasons capacity products of a standard duration are offered by TSOs across delimited timeframes. However those may not always adjust to the dynamic needs of shippers' what may impel higher booking levels dimensioned to cover for their peak positions.

136 See: http://www.acer.europa.eu/en/Gas/Framework%20guidelines_and_network%20codes/Pages/Harmonised-transmission-tariff-structures.aspx.

Figure 36: Benchmark of average gas cross-border transportation tariffs – April 2016



Source: ENTSOG, individual TSOs (2016) and ACER calculations.

Note: See Annex 3 for methodological clarifications and important notes.

5.2 Assessment of potential welfare gains

138 As described in Section 4.4., convergence of gas supplier's sourcing costs continued in 2015. The realisation of a single continent-wide integrated market where gas flows freely across borders based on competition and on the best use of resources seems to be getting gradually closer. However, in selected geographical areas, wholesale price spreads persist, suggesting that further benefits in terms of lower gas wholesale prices can still be reaped from further integration, including by the correct implementation of the network codes. The extent of price convergence that can be attributed to these NCs is challenging as it is difficult to disentangle their effect from market developments.

139 On the basis of Figure 21, which shows an assessment of gas sourcing costs per MS, an analysis is performed to estimate the gross welfare losses across the EU caused by the incomplete integration of national gas markets. The losses are quantified by comparing the suppliers' sourcing price with the TTF sourcing price, which is taken as a reference. The results provide an estimate of potential savings that could be achieved if all suppliers'

in the EU had comparable gas sourcing prices as at the TTF hub[137]. This exercise does not take into account factors such as transportation costs and investment costs, nor elements such as contractual obligations, demand-supply constraints or capacity availability.

140 The total assessed gross welfare losses in 2015 ranged between 4.1 to 4.5 billion euros[138]. Estimated welfare losses have decreased significantly since the Agency began this type of analysis in 2012. Since then, welfare losses have decreased by 60%. This reduction is mainly driven by three factors: demand reduction, the drop in oil prices, and hub development, with the latter referring to a larger hub price orientation of long-term contracts in a number of sizeable markets – i.e. France, Italy and the CEE region – and improved convergence among EU hub products prices (see Section 4.5.). The values in the figure are indicative and intended to show a trend over time.

141 Figure 37 shows the wholesale gross welfare losses for each MS per household consumer. The values indicate that remaining welfare gains can be captured for consumers in several MSs, particularly the Baltic States, Bulgaria and Portugal. In the case of Lithuania and Estonia, it is also noticeable that prices have significantly further converged to CEE price levels from the second semester.

142 Building on these results, the net welfare gains that could be captured by optimising existing cross-border capacities – by exploiting wholesale price spreads between markets – are estimated. The hypothesis is that companies sourcing gas for their consumers in lower-priced market areas have an incentive to acquire capacity and expand their sales business into adjacent higher-priced gas zones. The facilitation in capacity acquisition that CAM and CMP NCs offer is beneficial to achieve this.

143 Suppliers would compete in these adjacent markets by using either unused physical or contractually available capacity at cross-border interconnections. They would undercut prevailing wholesale prices, even when taking into account transmission charges. Lower-priced gas delivered via unused cross-border capacity ought to put downward pressure on prices in the targeted markets, because players operating there will be compelled to adapt their selling strategies[139]. Over time, this would result in increased convergence among EU suppliers' gas sourcing prices, hence delivering welfare gains to final consumers.

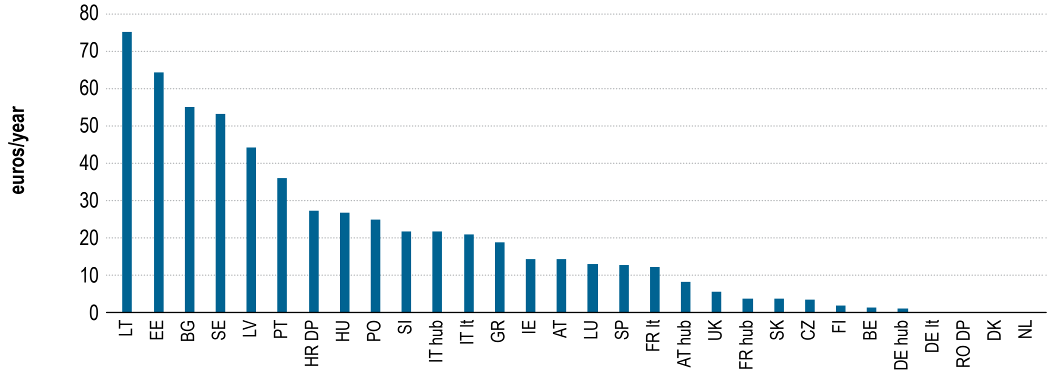
144 These calculations constitute a theoretical exercise and the Agency is aware that cross-border capacity contracting and utilisation values may not be determined solely by suppliers' aspirations to compete in adjacent market areas, but that this may also be driven by factors such as traders' price arbitrage opportunities between hubs. Moreover, a number of other factors may make optimisation of IPs capacity challenging. These include the physics of gas systems; the lack of sufficiently liquid organised markets and/or of trading counterparties; long-term contractual obligations; suitable granularity of tradable capacity contracts and variable transportation costs per capacity product duration, and the potential displacement effect on initial sourcing prices in one area if purchased volumes change.

137 See MMR 2014 Section 5.3.3 for further clarifications on the analysis.

138 The upper figure results from using declared import prices on the border, and the lower figure results from using hub product prices for those MSs where a range of prices was used to assess suppliers' average sourcing costs. The estimates constitute an educated proxy. Depending on multiple market factors, market prices in EU MSs could converge around a middle point or could be lower overall, thanks to enhanced competition and liquidity levels.

139 See MMR 2014, Section 5.3.3., for further details on the methodology.

Figure 37: Gross welfare losses per average household consumer in gas wholesale markets – 2015 (euros/year)



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

Notes: The EU average household consumption level of 11,000 kWh/year is taken from the CEER Indicators database 2014. Significant differences in average consumption levels exist among MSs household consumers; actual figures would have an impact on the values of real welfare losses. For example, in Lithuania, Estonia and Portugal, average consumption levels are below 4,000 kWh/year. 'l.t.' next to the name of a MS refers to border import prices, 'hub' to hub prices and 'DP' to domestic production prices used in suppliers' gas sourcing costs estimates. In 2014, Gazprom offered a retroactive price discount to the main Lithuanian supplier, which is not reflected in the figure. The Estonian price is fully based on Eurostat Comext declared Russian origin import prices; volumes purchased from Lithuania are however priced lower.

145 Cross-border IPs physical capacity utilisation figures were obtained from the ENTSOG TP[140]. The investigation reveals that if all physical unused capacities were used in an optimal way, i. e. following price spread signals – and after discounting transmission charges – aggregated EU net welfare gains could amount to 0.4 billion euros. This assumes that the pricing strategy[141] adopted by market entrants foregoes taking any profit (i.e. undercut the entire prevailing price spread, minus transmission charges). If the analysis were performed instead on the basis of available contractual capacity or on the basis of capacity available over peak monthly utilisation, the net welfare gains would be lower[142]. The year-on-year decrease of estimated net welfare gains[143] reveals that MSs sourcing prices are gradually further converging and that the remaining price gaps may not always be enough to cover for the (slightly increasing) transmission charges.

140 Values have also been contrasted with IEA gas flow statistics, see: https://www.iea.org/gtf/.

141 The pricing strategies of the new entrants' effect on the total level of assessed EU welfare gains: new entrants' profits constitute in this sense a transfer to suppliers from the theoretical EU maximum gains. See the detailed methodology in MMR 2014 Annex 12 explaining the considerations taken for modelling this aspect.

142 The net welfare assessment on the basis of these two last scenarios has not been done in MMR 2015. Relative results among scenarios can be contrasted in MMR 2014 Section 5.3.3. for the year 2014.

143 See the analysis for year 2014 in MMR 2014 Section 5.3.3.

Annex 1: Gas Target Model metrics

This Annex presents the full results and the assumptions adopted for the selected GTM metrics analysed in this MMR. Several of the explanations make reference to the REMIT transaction user reporting manual (TRUM). All methodologies are available in the Annex 3 of the GTM 2014[144].

a) Market participants' needs metrics

These metrics evaluate if "products and liquidity are available such that effective management of the wholesale risk is possible". Assumptions made:

- The trade data used covers November 2015 through April 2016. Only data for transactions executed in organised market places and within the framework of a standard contract have been processed.
- The 18 listed hubs constitute separate virtual[145] trading points for products' delivery, holding either one or several transparent organized trading venues. The identification of VTPs is based on ENTSOG EIC delivery point codes[146]. Both H and L calorific gas are taken into consideration in those markets where both types of gas are consumed.
- For some metrics, separate results for OTC and exchange trading are provided, while for other metrics combined results of the two trading mechanisms are given. OTC covers transactions executed via broker platforms. Exchange data covers transactions supervised and cleared by an organised central market operator.
- The results of the metrics are shown as ranges in order to avoid any potential confidentiality issues (see article 17 of REMIT regulation[147]) as well as for reasons of data quality
- A number of conditions were used to process data in a consistent manner: only limited[148] price orders and orders with a definite status[149] were included in the calculations. Orders referring either to locational physical swaps and/or spread trade with relative value between two hubs concluded under one sole agreement[150] were not considered.
- For the bid-ask spread metric, those orders whose prices are set via a spread to an index (e.g. of a price of an adjacent hub) are not taken into consideration. However these orders were used in the order volume assessments.
- "n.a.“ means metric not assessed, "n.r.“ means no relevant data obtained due to, for example, the absence of the product being traded. "tnm" means for metric 2 that GTM threshold of more than 60% of trading days showing results is not met.
- For NBP and TTF order-related metric values for prompt and forward products, a sample of days were taken. In concreto, data for 20 days along the 6 months period were taken due to data processing limitations.

144 See: http://www.acer.europa.eu/Events/Presentation-of-ACER-Gas-Target-Model-/Documents/A14-AGTM-13-03a_GTM_Annex%203%20-%20Calculation%20specification%20metrics_final.pdf.

145 Physical in the case of Zeebrugge.

146 See: http://www.entsog.eu/eic-codes/eic-connection-point-codes-z.

147 "(...) Confidential information (...) may not be divulged to any other person or authority, except in summary or aggregate form such that an individual market participant or market place cannot be identified."

148 See REMIT TRUM pages 44 and 45; limited price orders are orders executed either fully or in part at the limit or at a higher price. These constitute the bulk of reported orders.

149 See REMIT TRUM page 47; orders whose status is reported as 'OTH' are not taken into account.

150 See REMIT TRUM page 51; orders whose contract type is reported as 'SW' or 'SP' are not taken into account. In selected pairs of hubs swaps and spread trade orders are an extended practice: e.g. NBP-ZEE, GPL-NCG, TRS-AOC.

AGTM metric 1: Order book volumes for November 2015–April 2016 – measure of the median bid and ask-side volumes available in the order book across the day

	Metric 1: Order book volumes available											
	Spot products (DA). Median volume available in the order book (MW)				Prompt products (MA). Median volume available in the order book (MW)		Forward products (Qs, Ss, Ys). Time horizon (in months) with at least the below volumes available in the order book: 10 MW		60 MW		120 MW	
	Offer side		Bid side		Offer side	Bid side	Offer side	Bid side	Offer side	Bid side	Offer side	Bid side
Market	OTC	Exchange	OTC	Exchange	Order book volumes available in OTC and Exchange are aggregated							
AT-VTP	450-750	150-450	750-1050	150-450	0-150	0-150	8-12	12-16	0-4	0-4	0-4	0-4
BE-ZEE1	150-450	n.a.	450-750	n.a.	0-150	0-150	8-12	16-20	4-8	4-8	0-4	0-4
BE-ZTP2	0-150	n.a.	0-150	n.a.	n.a.	n.a.	n.r.	n.r.	n.r.	n.r.	n.r.	n.r.
CZ-VOB	150-450	n.a.	0-150	n.a.	0-150	0-150	8-12	8-12	0-4	0-4	0-4	0-4
DE-GPL	450-750	1050-1350	750-1050	1050-1350	150-450	150-450	36-42	36-42	4-8	4-8	0-4	0-4
DE-NCG	1350-1650	1350-1650	1650-1950	1350-1650	150-450	150-450	36-42	36-42	16-20	12-16	0-4	0-4
FR-PEG NORD	150-450	450-750	150-450	450-750	150-450	150-450	28-32	28-32	20-24	20-24	0-4	4-8
FR-TSR	n.a.	150-450	n.a.	150-450	0-150	0-150	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
IT-PSV	150-450	n.a.	150-450	n.a.	150-450	150-450	20-24	24-28	12-16	12-16	0-4	0-4
NL-TTF	1350-1650	1050-1350	2250-2550	1050-1350	1350-1650	1650-1950	36-42	36-42	36-42	36-42	36-42	36-42
UK-NBP 1	1950-2250	1650-1950	2550-3000	1350-1650	2550-3000	2250-2550	36-42	36-42	36-42	36-42	36-42	36-42
SK-OTC	0-150	n.r.	0-150	n.r.	0-150	0-150	8-12	12-16	0-4	0-4	0-4	0-4
PL-VPGZ	0-150	150-450	0-150	150-450	0-150	0-150	20-24	20-24	0-4	0-4	0-4	0-4
SP-AOC4	n.a.	n.a.	n.a.	n.a.	150-450	150-450	8-12	12-16	0-4	0-4	0-4	0-4
DK-GPN3	n.a.	450-750	n.a.	450-750	0-150	0-150	n.r.	n.r.	n.r.	n.r.	n.r.	n.r.
HU-MGP	n.r.	0-150	n.r.	0-150	0-150	0-150	0-4	0-4	0-4	0-4	0-4	0-4
LI-GET	n.r.	0-150	n.r.	0-150	n.r.	n.r.	n.r.	n.r.	n.r.	n.r.	n.r.	n.r.
RO-OPCO_BRM	n.r.	n.r.	n.r.	n.r.	n.a.	n.a.	0-4	0-4	0-4	0-4	0-4	0-4

Source: ACER calculations based on REMIT data.

Notes: 1 If spread trade orders[151] are also accounted, results for the Zeebrugge hub significantly increase for OTC. Also for NBP hub sizeable order volumes are reported if spread trade contracts are included.

2 In Belgium, orders reported with delivery point in Zeebrugge Trading Point (ZTP) are assigned to ZTP hub whereas those reported with delivery point in Zeebrugge Beach are assigned to the ZEE hub (both codes are ENTSOG EIC Z codes). The Belgian entry-exit zone includes both the port of Zeebrugge and the whole of the Belgian transmission and transit pipeline network. Additionally orders reported with delivery point in the Belgian balancing zone (ENTSOG Y virtual code) are sizeable.

3 For the Danish hub only exchange transactions are covered. 4 For Spain only OTC transactions are processed.

In Finland trading on the exchange occurs via hourly products. Metrics are not assessed for DA, MA and FWA products

151 See initial assumptions listed below, point 2.

AGTM metric 2: Bid-offer spread during November 2015–April 2016: measure of the average delta between the lowest ask price and the highest bid-price expressed as a percentage of the highest bid-price across the day

	Metric 2: Orders Bid-Ask spread (%)							
					Forward products (Qs, Ss, Ys)			
	Spot products (DA)		Prompt products (MA)		6th month	6th month	12th month	12th month
Market	OTC	Exchange	OTC	Exchange	OTC	Exchange	OTC	Exchange
AT-VTP	0.25%-0.5%	0.5%-0.75%	0.75%-1%	1.5%-1.75%	1.25%-1.5%	tnm	tnm	tnm
BE-ZEE	0.5%-0.75%	n.a.	1%-1.25%	n.a.	n.a.	n.a.	n.a.	n.a.
BE-ZTP	0.75%-1%	-	n.a.	n.a.	n.r.	n.r.	n.r.	n.r.
CZ-VOB	1%-1.25%	-	1.25%-1.5%	-	tnm	tnm	tnm	tnm
DE-GPL	0.25%-0.5%	0.25%-0.5%	0.5%-0.75%	0.75%-1%	0.75%-1%	1.75%-2%	tnm	tnm
DE-NCG	0.25%-0.5%	0.5%-0.75%	0.5%-0.75%	1%-1.25%	0.75%-1%	2%-2.5%	tnm	tnm
FR-PEG NORD	0.75%-1%	0.75%-1%	1%-1.25%	1%-1.25%	n.a.	1.75%-2%	n.a.	1.75%-2%
FR-TSR	n.a.	1.25%-1.5%	n.a.	2%-2.5%	n.a.	n.a.	n.a.	n.a.
IT-PSV	0.75%-1%	-	1%-1.25%	1.25%-1.5%	1%-1.25%	tnm	1.5%-1.75%	tnm
NL-TTF	0.25%-0.5%	0.5%-0.75%	0.25%-0.5%	n.a.	0.5%-0.75%	n.a.	0.75%-1%	n.a.
UK-NBP	0.5%-0.75%	n.a.	0.5%-0.75%	n.a.	0.5%-0.75%	n.a.	0.75%-1%	n.a.
SK-OTC	2%-2.5%	n.r.	2.5%-4%	n.r.	tnm	tnm	tnm	tnm
PL-VPGZ	n.a.	0.75%-1%	n.a.	0.75%-1%	tnm	1%-1.25%	tnm	tnm
SP-AOC	n.a.	n.a.	2%-2.5%	n.a.	tnm	tnm	tnm	tnm
DK-GPN	n.a.	1%-1.25%	n.a.	2%-2.5%	n.r.	n.r.	n.r.	n.r.
HU-MGP	n.r.	2.5%-4%	n.r.	2.5%-4%	n.r.	n.r.	n.r.	n.r.
LI-GET	n.r.	1.25%-1.5%	n.r.	n.r.	n.r.	n.r.	n.r.	n.r.
RO-OPCOM_BRM	n.r.	n.r.	n.a.	n.a.	tnm	tnm	tnm	tnm

Source: ACER calculations based on REMIT data.

Notes: For forward products sufficient liquidity – more than 60% of days showing results – is required as a condition to calculate and show metric values. If thus the condition is not fulfilled, this is indicated as “tnm”. The bid-ask spread metrics may be particularly affected by data quality and assumptions taken aspects. Therefore the results need to be treated with caution.

AGTM metric 4: Number of trades executed on a daily average in transparent trading venues in November 2015–April 2016

	Metric 4: Median daily number of executed trades		
Market	Spot products (DA)	Prompt products (MA)	Forward products (Qs, Ss, Ys)
AT-VTP	300-400	50-100	0-50
BE-ZEE	100-200	0-50	0-50
BE-ZTP	0-50	0-50	n.r.
CZ-VOB	50-100	0-50	0-50
DE-GPL	400-500	50-100	0-50
DE-NCG	700-800	100-200	50-100
FR-PEG NORD	300-400	0-50	0-50
FR-TSR	100-200	0-50	0-50
IT-PSV	100-200	0-50	50-100
NL-TTF	1100-1500	900-1000	900-1000
UK-NBP	700-800	1100-1500	600-700
SK-OTC	0-50	0-50	0-50
PL-VPGZ	200-300	0-50	0-50
SP-AOC	n.a.	0-50	0-50
DK-GPN	0-50	0-50	n.r.
HU-MGP	0-50	0-50	0-50
LI-GET	0-50	n.r.	n.r.
RO-OPCOM_BRM	0-50	0-50	0-50

Source: ACER calculations based on REMIT data.

Note: This metric combines both OTC and exchange trading. Intragroup trades are included. The calculation for the forward products part deviates from the GTM metric described methodology. GTM looks at the time horizon in which more than eight trades are taking place.

b) Market health metrics

This set of metrics evaluates whether "gas markets are demonstrably competitive, resilient and have a high degree of security of supply".

AGTM Metric 5: Herfindhal-Hirschman Index

Assumptions made:

- The HHI metric examines the concentration at company level for upstream companies selling gas destined for final consumption within individual MSs. The indicator does not take into account secondary sales from intermediaries.
- The market shares of the upstream companies selling gas from the respective supply source countries were assigned in accordance with desktop research methodology used for the GTM 2014. Upstream companies' market shares are derived from production statistics, shareholder structure of export facilities and desktop research.
- The shares of the upstream companies' selling gas from a specific MS origin are not tailored to the situation of the importing MS (e.g. the totalised export market shares of all Norwegian companies exporting gas from the country are equally applied to all MSs that declare imports of Norwegian gas).
- Declared imports from a market with a liquid organised market with minor domestic production (Germany, Austria, Italy, France and Belgium are considered as such) are used to calculate the concentration of the market hosting the hub (e.g. Slovenia and Hungary declare sizeable imports from Austria; for those volumes the share of the upstream companies selling gas are considered proportional to Austrian market concentration levels [152]).

152 In this case, both Hungarian and Slovenian suppliers declare imports of most volumes from Russia (fully assigned to Gazprom) and secondly most of the remaining imported gas comes from Austria – where Gazprom is also the dominant supplier. This results in high HHI levels for these two MSs (higher than those in 2011 when Austrian origin imports were assigned to Austrian domestic producers). Estonian suppliers also source mostly from Russia and the remainder from Lithuania. As Lithuanian imports from Gazprom are deemed not to be re-sellable at the hub (see reference to DG COMP case in Section 2.5), the Estonian imports from Lithuania have been fully assigned to a Norwegian (LNG) origin.

See metric results at the body text volume: Figure 9: Estimated HHI index per EU MS at upstream sourcing companies' level 2011 – 2015.

AGTM metric 6: Number of supply sources

Assumptions made:

- Supply source country origins refer to the upstream gas producer country (e.g. Russia) or to an EU MS with a liquid organised market where gas has been purchased (shown in the figure with an asterisk, e.g. Austria*). The supply origin of the gas should not be considered as the adjacent border from which gas is imported (e.g. Spain for Portugal) but the supply origin of the sourced/purchased gas (e.g. Algeria for Portugal).

- Calculations primarily look at imported and domestically produced gas devoted to final consumption within individual MSs.

AGTM metric 6: Estimated number and diversity of supply sources in terms of the geographical origin of gas in 2015

	1st supply origin country		2nd supply origin country		3rd supply origin country		Other supply origins
MS	%	Origin	%	Origin	%	Origin	Number
FI	100%	RU	0%		0%		
LV	100%	RU	0%		0%		
RO	98%	RO	2%	RU	0%		
IE	95%	UK*	5%	IE	0%		
BG	92%	RU	8%	BG	0%		
DK	90%	DK	10%	NO	0%		
LT	78%	RU	22%	NO	0%		
SE	77%	DK	23%	NO	0%		
HR	73%	HR	14%	AT*	13%	HU	
PT	67%	AL	26%	NI	5%	QT	3
EE	66%	RU	34%	LT*	0%		
SK	65%	RU	12%	CZ*	11%	AT*	5
GR	63%	RU	20%	TK	13%	AL	4
ES	63%	AG	13%	NI	10%	QT	6
LU	63%	DE*	37%	BE*	0%		
SI	62%	AT*	33%	RU	5%	IT*	
AT	60%	RU	24%	NO	17%	AT	2
NL*	59%	NL	25%	NO	11%	DE*	4
PL	57%	RU	28%	PL	15%	DE*	
CZ	51%	RU	42%	DE*	6%	SK*	3
UK	48%	UK*	33%	NO	15%	QT	4
HU	47%	RU	26%	AT*	18%	HU	2
DE	46%	RU	22%	AL	16%	NL*	3
IT	44%	RU	12%	RU	12%	LY	10
FR	42%	NO	23%	NO	11%	NL*	7
BE	38%	NL*	34%	NO	19%	UK*	3
EU26	30%	RU	27%	EU IP	25%	NO	*

Source: ACER calculations based on Eurostat and Eurostat Comext and BP Statistical report (2016).

Notes: NL and DK are both net exporters. The split refers to the origins of overall traded volumes. For CZ Eurostat volumes reported as imported from Germany are deemed to also include Norwegian supply contracts. Estonian imports from Lithuanian refer to gas purchased in the Lithuanian GET hub of which the physical origin is deemed to be Norwegian LNG. Those imports occur as swaps with Latvian underground gas storage. For the EU as a whole, Algeria is the fourth supplier (7%), Qatar is the fifth (6%) and others account for 4.5%.

AGTM Metric 9: Market concentration of finalised transactions

Assumptions made:

- See assumption considered in market participants' needs metrics assessment
- Metric 9 values combines both OTC and exchange trading.
- Intragroup companies are not treated separately (i.e. concentration of holding groups could be higher).

AGTM metric 9: Market concentration of finalised transactions in EU hubs

	Metric 9: HHI of traded volumes						Metric 9: CR3 of traded volumes					
	Buying side			Selling side			Buying side			Selling side		
Market	Spot product (DA)	Prompt products (MA)	Forward products (Qs, Ss, Ys)	Spot products (DA)	Prompt product (MA)	Forward products (Qs, Ss, Ys)	Spot products (DA)	Prompt products (MA)	Forward products (Qs, Ss, Ys)	Spot products (DA)	Prompt products (MA)	Forward products (Qs, Ss, Ys)
AT-VTP	0-1000	0-1000	0-1000	0-1000	0-1000	0-1000	30%-40%	30%-40%	20%-30%	40%-50%	30%-40%	20%-30%
BE-ZEE	1000-2000	1000-2000	0-1000	1000-2000	1000-2000	0-1000	50%-60%	30%-40%	40%-50%	60%-70%	40%-50%	40%-50%
BE-ZTP	1000-2000	2000-3000	n.r.	2000-3000	2000-3000	n.r.	50%-60%	60%-70%	n.r.	70%-80%	70%-80%	n.r.
CZ-VOB	0-1000	0-1000	0-1000	0-1000	1000-2000	1000-2000	30%-40%	30%-40%	60%-70%	30%-40%	40%-50%	70%-80%
DE-GPL	0-1000	0-1000	0-1000	0-1000	0-1000	0-1000	20%-30%	20%-30%	20%-30%	20%-30%	30%-40%	40%-50%
DE-NCG	0-1000	0-1000	0-1000	0-1000	0-1000	0-1000	30%-40%	20%-30%	20%-30%	30%-40%	20%-30%	30%-40%
FR-PEG NORD	0-1000	0-1000	0-1000	0-1000	1000-2000	1000-2000	40%-50%	40%-50%	40%-50%	40%-50%	50%-60%	40%-50%
FR-TSR	0-1000	0-1000	0-1000	0-1000	1000-2000	1000-2000	30%-40%	30%-40%	40%-50%	30%-40%	40%-50%	40%-50%
IT-PSV	0-1000	0-1000	0-1000	0-1000	1000-2000	1000-2000	30%-40%	30%-40%	40%-50%	30%-40%	40%-50%	70%-80%
NL-TTF	0-1000	0-1000	0-1000	0-1000	0-1000	0-1000	20%-30%	20%-30%	20%-30%	20%-30%	20%-30%	20%-30%
UK-NBP	0-1000	0-1000	1000-2000	0-1000	1000-2000	1000-2000	30%-40%	30%-40%	40%-50%	30%-40%	40%-50%	40%-50%
SK-OTC	1000-2000	1000-2000	1000-2000	1000-2000	0-1000	1000-2000	40%-50%	50%-60%	60%-70%	40%-50%	40%-50%	50%-60%
PL-VPGZ	2000-3000	2000-3000	2000-3000	5000-6000	5000-6000	4000-5000	80%-90%	70%-80%	70%-80%	70%-80%	90-100%	90-100%
SP-AOC	n.a.	0-1000	0-1000	n.a.	0-1000	1000-2000	n.a.	30%-40%	30%-40%	n.a.	30%-40%	40%-50%
DK-GPN	2000-3000	2000-3000	n.r.	1000-2000	2000-3000	n.r.	60%-70%	70%-80%	n.r.	60%-70%	70%-80%	n.r.
HU-MGP	2000-3000	1000-2000	n.a.	1000-2000	3000-4000	n.a.	70%-80%	50%-60%	90-100%	60%-70%	90-100%	n.a.
LI-GET	1000-2000	n.r.	n.r.	1000-2000	n.r.	n.r.	60%-70%	n.r.	n.r.	60%-70%	n.r.	n.r.
RO-OPCOM_BRM	n.r.	1000-2000	2000-3000	n.r.	1000-2000	3000-4000	n.r.	50%-60%	70%-80%	n.r.	60%-70%	90-100%

Source: ACER calculations based on REMIT data.

Annex 2: Data used in the network code indicators analysis

The analysis is based on data obtained from the EU-wide ENTSOG Transparency Platform (ENTSOG TP)[153] and PRISMA Booking Platform[154]. Indicators were calculated according to the methodology defined by the Agency with support of the consultancy company CEPA[155].

The data set from the ENTSOG TP was provided in two bulk exports files, one for 2014 and one for 2015. To extract data, the CAM IPs and CMP IPs scope filters were used respectively. The following indicators were calculated on the basis of ENTSOG TP data:

- CAM 5: Contractual capacity utilisation at IPs – See Figure 31;
- CAM 6: Physical capacity utilisation at IPs – See Figure 32;
- CMP 1: Additional volumes made available through each CMP; and
- CMP 3: Aggregated utilisation of contracted capacity at IPs (see Figure 35).

The Agency relied on PRISMA Booking Platform data for the calculation of CAM 2: *Bundled capacity release* and CAM 3: *Share of total capacity sold as bundled capacity on booking platforms* (See Figure 34).

While assessing ENTSOG TP data files, the Agency detected substantial data gaps, disordered data and an inconsistent range of points included in the list (e.g. reported non-CAM points). Thus, for all the indicators but CAM 2 and CAM 3, the Agency limited the scope of its calculations to the CMP IP range – obtained from the CAM range list[156]. By limiting the scope to the CMP IPs, the calculations benefitted from the following implications:

- Data showed fewer errors and inconsistencies;
- The CMP IPs scope list is an acceptable approximation of the CAM IPs scope list. It covers the relevant physical IP sides[157] and excludes those virtual IP sides without firm technical capacity values but with physical flow values; and
- IP sides connecting EU MSs with third countries where CAM NC is not applied are excluded from the CMP IPs scope list.

Nonetheless some CMP IPs list sides could not be unequivocally identified, mostly those with pipe-in-pipe competition, those with non-regulated products, those for which data are wrong and those not appropriately defined. As a result, the analysis covered only 208 CMP relevant IP sides for 2015 and 198 CMP relevant IP sides for 2014 (instead of 249 for the full CMP IPs list).

Further assumptions were made in order to mitigate issues relating to data quality:

- Those IPs showing errors in the annual averages were eliminated (e.g. #VALUE! or #DIV/0!);
- Extreme ratios – ratios taking values above 150% – were eliminated from the analysis for CAM5, CAM6 and CMP3. Values between 100–150% were considered; and

153 See: https://transparency.entsog.eu/.

154 See: https://platform.prisma-capacity.eu/.

155 See footnote 118.

156 At the time of writing the report, the CAM scope list was under review by the Agency as part of the implementation monitoring exercise for CAM NC. The list used for the analysis contained 341 sides.

157 An IP side is identified by the combination of geographical location, direction and reporting TSO.

- Physical flow data were used. In the context of capacity utilisation, it would have been more appropriate to use commercial flow data, nominations, or renominations instead as those better reflects commercial network utilisation[158]. However, commercial data were not available for many IP sides.

Based on this first experience the Agency recommends that ENTSOG and the TSOs:

- Apply the CAM IPs and CMP IPs scope lists' naming of IP sides both for the ENTSOG TP and the export file;
- Implement and keep updated the scope filter for the CAM IPs and CMP IPs relevant IP sides;
- Resolve the pipe-in-pipe and other special situations in terms of data reporting and data publication; and
- Apply automated data quality checks to the ENTSOG TP as soon as possible.

These improvements will allow the Agency to run its calculations on a more reliable, updated and comprehensive data set.

Annex 3: Methodology and notes for the tariffs benchmark exercise

This annex clarifies the methodology and the important notes of Figure 36: Benchmark of average gas cross-border transportation tariffs – April 2016.

- The exercise has been executed on the basis of ENTSOG and TSOs publicly available information. ACER appreciates the supportive collaboration of ENTSOG and individual TSOs that have validated most IPs charges.
- Charges for simulated flows were estimated on the basis of a yearly duration firm capacity contract signed in April 2016, using units of measurement published by TSOs. In those cases when tariffs units of measurement are not published in yearly basis and/or they differ per period length, direct conversions were performed. The assumption is made that the gas energy content is flown continuously though the yearly period[159].
- The tariffs reflect individual regulatory choices by Member States, for instance in terms of allowed total TSO revenues, regulatory rates of return, and valuation of the regulatory asset base. Any network tariff will always be a function of potentially differing network cost drivers, such as network size (length/distance), configuration, maximum capacity, flows, topology, density, and other structural or regional factors. They are also a function of possibly diverging national cost allocation policies, which are at the moment being coordinated through the network code on harmonised cross-border gas transportation tariffs. Cross-border tariff variability across Europe is not in itself a cause of concern, provided that tariffs result from a fair and transparent calculation mechanism.
- These tariffs do not reflect different purchasing powers and, for those countries not in the euro area, they are exposed to currency fluctuations.
- The exercise is principally done on the basis of the entry/exit (E/E) tariff model, currently in place in most EU MS. However this model is not yet fully applicable in some geographies. As such, in the map transmission is signposted for MSs where published tariffs comprise the service of cross-border entry into the MS plus the exit within the MS. Transit is signposted for IPs applying point to point charges for flows between borders (e.g. across Switzerland).
- At those market zones borders' featuring more than one cross-border IP - but with dissimilar tariffs - a single charge was appraised per border as the weighted average according to offered capacity per IP and/or distinct TSO. For example, cross-border flows in and out German market zones frequently attract different charges depending on the IP and/or TSOs. The following values present the range (min-max) of charges at German market zones – NCG and GPL – either at their entry or exit sides.
- BE to NCG: 107 – 130, NL to NCG: 67 – 130, NL to GPL: 68 – 150, GPL to NL: 98 – 163, CZ to NCG: 98–130, GPL to CZ: 36 – 142, AT to NCG: 91 – 130, NCG to AT: 113 – 172, NCG to FR: 113 – 132, NCG to CH: 57 – 172, GPL to PL: 98 – 176, NO to DE: 107-130 (to NCG). For those flows between GPL and NCG the map displays the maximum and minimum E/E values.

158 Physical flow data can be quite different from commercial flow data, in particular at bidirectional IPs. Physical flows represent the netted commercial utilisation at the IP, taking account the flows in both directions. It also includes the operational requirements of the TSOs for the relevant networks.

159 e.g. when the entire IP charge is expressed in volume units (e.g. Bulgaria BGN/1,000 m3), and also for the tariff commodity component that several TSOs apply, the assumption made is that the volume equivalent to the simulated energy content (i.e. 365 GWh/year) is flown constantly along the yearly period.

- In certain instances, more than one TSO may be offering capacity in a given IP where the total aggregated capacity is published but the capacity split among TSOs isn't. The assumption has been made in those cases that capacities are uniformly shared between TSOs.
- On April 2015 a common market area made up of the GRTgaz South and TIGF areas was set up under the name Trading Region South (TRS). Shippers have no longer to subscribe capacities between the two networks. The map displays the present PEG North to TR South and TR South to PEG North charges; just a unique payment – presented here as an entry – is necessary.
- The integration of the Luxembourger and Belgian hubs since October 2015 has resulted in the abolition of the BE/LU E/E tariffs. In Luxembourg, the reserve price applied for the conditional product at the Remich IP only covers the commercialisation and handling costs.
- In certain instances differences in tariffs may arise per gas quality (high vs low calorific value). The map does not differentiate this aspect and all calculations are done on the basis of the energy content.
- Entry tariffs from Byelorussia into Poland exhibit differences between the – higher capacity – Yamal pipeline (131) and the Gaz-system Poland network (254).

List of figures

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