



# Quarterly Report

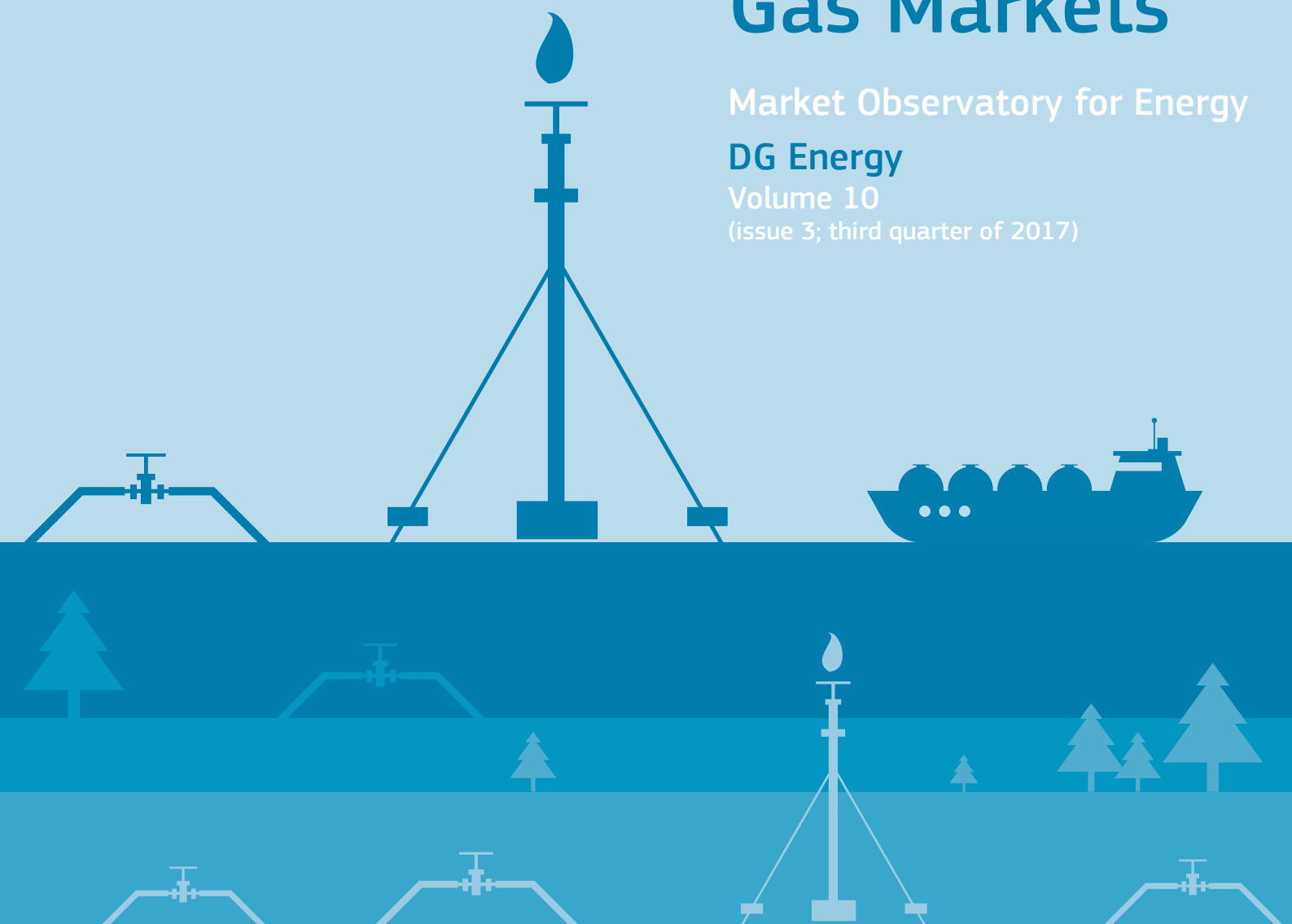
## on European Gas Markets

Market Observatory for Energy

**DG Energy**

Volume 10

(issue 3; third quarter of 2017)



DISCLAIMER: This report prepared by the Market Observatory for Energy of the European Commission aims at enhancing public access to information about prices of electricity in the Members States of the European Union. Our goal is to keep this information timely and accurate. If errors are brought to our attention, we will try to correct them. However the Commission accepts no responsibility or liability whatsoever with regard to the information contained in this publication.

Copyright notice: Reproduction is authorised provided the source is acknowledged.

© European Commission,  
Directorate-General for Energy, Market Observatory for Energy, 2017

Commission européenne, B-1049 Bruxelles / Europese Commissie, B-1049 Brussel –  
Belgium

E-mail: [ENER-MARKET-OBSERVATORY-QUARTERLY-REPORTS@ec.europa.eu](mailto:ENER-MARKET-OBSERVATORY-QUARTERLY-REPORTS@ec.europa.eu)

## CONTENT

Highlights of the report.....	2
Executive summary.....	3
1. Gas market fundamentals.....	4
1.1. Consumption .....	4
1.2. Production .....	8
1.3. Imports .....	9
1.4. Storage .....	13
2. Wholesale gas markets.....	16
2.1. The broader energy commodity picture: comparisons between oil, gas and coal prices in the EU.....	16
2.2. International gas markets.....	17
2.3. European gas markets .....	20
3. Retail markets in the EU .....	27
4. Glossary.....	32

## **HIGHLIGHTS OF THE REPORT**

- **EU gas demand has shown a year-on-year increase for the seventh quarter in a row, helped by the economic recovery and a continuous expansion of gas use in the power sector.**
- **Pipeline import from North Africa significantly decreased as high oil-indexed prices provided an incentive to importers to switch to cheaper LNG.**
- **The share of LNG from total imports reached 16% in both the second and third quarters, the highest level in the last four years. This was facilitated by a convergence of Asian and European LNG prices.**
- **The US was the fifth largest LNG supplier of the EU in the third quarter, covering 6% of total LNG imports. Lithuania became the eighth Member State to import LNG from the US.**

## EXECUTIVE SUMMARY

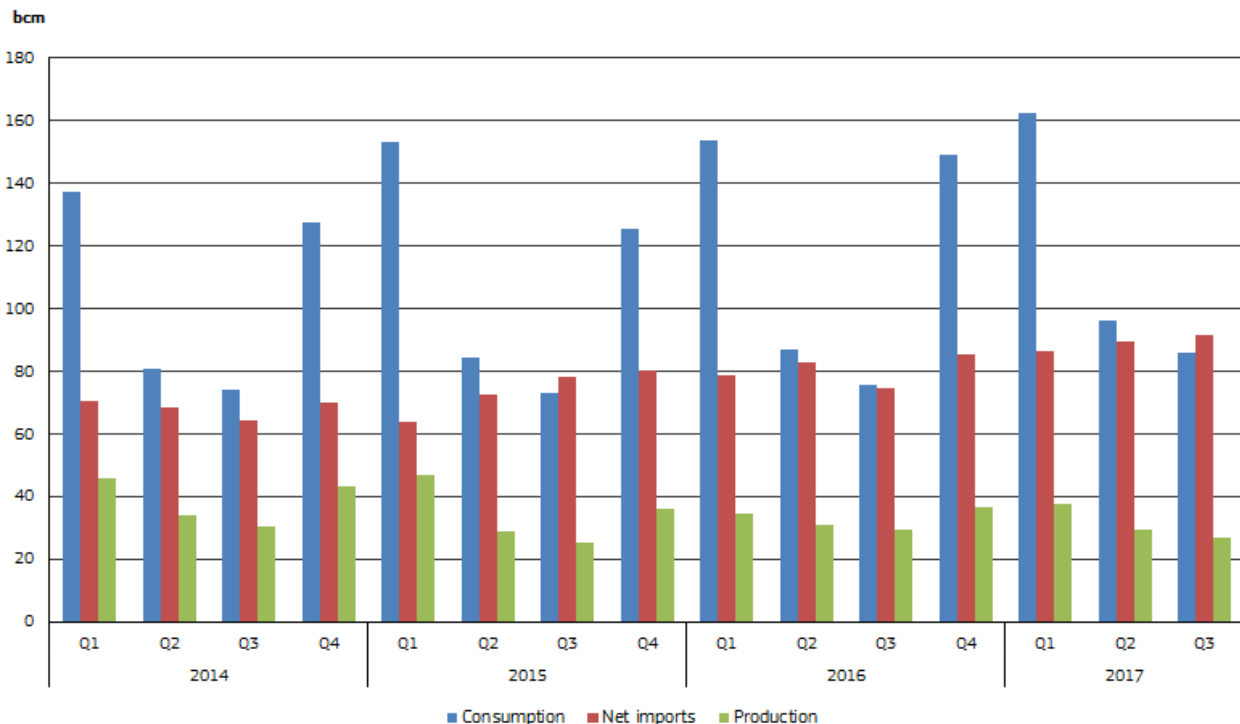
- Preliminary Eurostat data shows that **EU gas consumption increased by 14% year-on-year in the third quarter of 2017**. This means consumption has increased for the seventh consecutive quarter, driven by the growing gas use in the power sector, and also supported by the gradual economic recovery.
- EU gas **production decreased by an estimated 9% year-on-year in the third quarter of 2017** according to Eurostat data; in the first nine months of the year, EU output was 2% lower than in the same period of 2016.
- **In the third quarter of 2017, EU gas imports were 14% higher than a year earlier** according to ENTSO-G data. Pipeline imports from North Africa decreased compared to the same period in 2016 but this was more than offset by increasing flows from Russia and Norway, as well as rising LNG imports.
- In the third quarter of 2017, **Russia remained the EU's top supplier**, covering 44% of extra-EU imports, followed by Norway (33%); LNG imports made up 16%, the highest share in the last four years. The market share of North African pipeline supplies decreased year-on-year from 12% to 7% as high oil-indexed prices provided an incentive to Italy and Spain to reduce imports and replace it with cheaper LNG.
- **Ukraine remained the main supply route of Russian gas** coming to the EU, covering 50% of total imports from Russia. Nord Stream deliveries increased in August, following a court ruling that lifted a suspension on Gazprom's right to book additional capacity on the OPAL pipeline but flows decreased in September when Nord Stream was closed for 11 days due to maintenance.
- **EU LNG imports increased by 22% year-on-year** in the third quarter of 2017. Deliveries decreased in Northern Europe which had other competitive sources to rely on but this was more than offset by rising flows to the Mediterranean countries, partly replacing expensive Algerian pipeline gas. **Imports from the US reached record level** (0.84 bcm) in the third quarter, covering 6% of total EU LNG imports. Lithuania became the eighth Member State to import LNG from the US.
- The EU's **estimated gas import bill was around 17 billion euros** in the third quarter of 2017, around 32% more than a year earlier. Both the import volumes and the average import price were higher than in the third quarter of 2016.
- After a colder-than-average winter, filling rates of European gas storage facilities decreased to unusually low levels. Although net injections started earlier than usual, **throughout the injection period, the average filling rate was 5-10 percentage points lower than a year earlier**. Low seasonal spreads and a premium of day-ahead prices over forward prices reduced the incentive to inject gas. On 30 September 2017, the average filling rate was 85%, compared to 90% a year earlier.
- There has been a **strong correlation between** the development of **European hub prices and global oil and coal benchmarks** in 2017, reflecting the close relationship between the gas market and the wider energy complex.
- **Spot prices at European gas hubs started to increase from August**, driven by a number of factors, including the relatively low storage levels, continuing coal-to gas switching, rising oil and coal prices, cooling temperatures, Norwegian outages and persistent concerns about French nuclear availability. In the third quarter, hub prices were roughly 20% higher than a year earlier. **Oil-indexed prices**, on the other hand, **increased** by 58% compared to the same period of 2016 and clearly exceeded hub prices in Northwest Europe. The difference peaked in July but decreased afterwards.
- Since 2016, **prices at the UK gas hub are increasingly disconnected from mainland hubs**, showing a distinct seasonality. Because of the woes of the Rough storage facility, the UK has low injection demand and oversupply in summer and a tighter market in winter, thereby increasing the seasonal spread.
- After strong convergence in mid-2017, **international gas prices diverged** again from August as Asian and European prices started to rise while the US Henry Hub price remained remarkably stable. Asian and European LNG prices, in turn, remained well-aligned, contributing to the rising EU LNG imports.
- After a decrease in the first half of 2017, **trading activity on European gas hubs increased** in the third quarter of 2017 by 3% year-on-year. The Dutch and UK hubs continued to dominate trading, but the lead of the Dutch TTF hub decreased.
- After decreasing in the last 2-3 years, **retail prices seem to have stabilised** or in certain cases even increased. At the same time, the trend of diverging prices across the EU has come to an end in case of both household and industry prices.

# 1. Gas market fundamentals

## 1.1 Consumption

- After the 7% growth seen in 2016, EU gas consumption continued to be on the rise in 2017. Consumption showed a year-on-year increase of 6% in the first quarter when it was supported by low temperatures (especially in January).
- Gas demand continued to increase after the end of the heating season: in the second quarter, consumption was 11% higher than in the same period of 2016. The main factor was the increasing use of gas in power generation. The biggest year-on-year growth rates were observed in the Netherlands (50%), Portugal (37%) and Slovakia (27%) while consumption decreased in Luxembourg (-9%), the UK (-8%) and France (-5%). In Germany, Europe's largest gas market, demand increased by a robust 23%.
- According to preliminary Eurostat data, the increasing trend continued in the third quarter: consumption was around 14% higher than in the same period of 2016, with particularly strong growth in the Netherlands, Croatia and Lithuania. If confirmed, this would mean a year-on-year increase of 9% in the first nine months of 2017.
- As Figure 2 indicates, EU gas consumption has consistently grown since the first quarter of 2016, showcasing a year-on-year increase for seven quarters in a row. In absolute level, the consumption in the first three quarters of 2017 amounted to 345 bcm.
- In its medium-term gas outlook published in July 2017, the International Energy Agency (IEA) said it expects European gas demand to stay flat in the next 5 years, as "a very large share of the potential increase of gas for power generation in OECD Europe already took place in 2016 and will decline slightly again towards 2022" while there is some potential for slight increases in the residential and industry sectors.<sup>1</sup> It is too early to judge the validity of this forecast but the continuing growth of EU gas consumption in 2017 seems to cast some doubt on it.

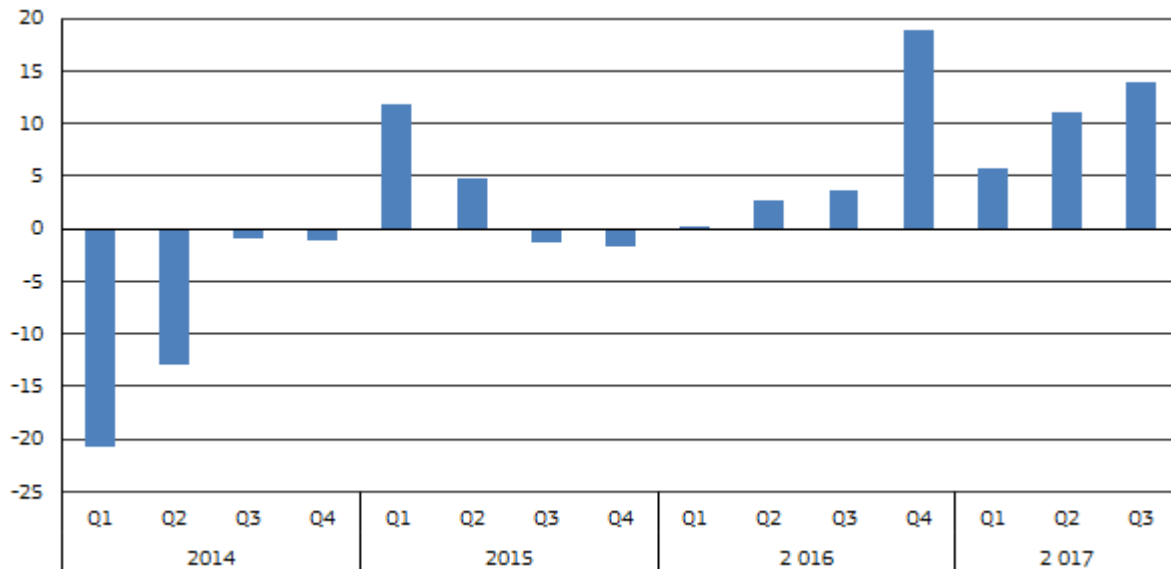
**Figure 1. EU gas consumption, imports and production**



Source: Eurostat, data as of 18 December 2017 from data series nrg\_103m. Net imports refer to imports minus exports. In case of 2017Q3, short-term monthly data (data series nrg\_ind\_343m) was used to fill in the gaps.

<sup>1</sup> Market Report Series: Gas 2017 – Analysis and Forecasts to 2022

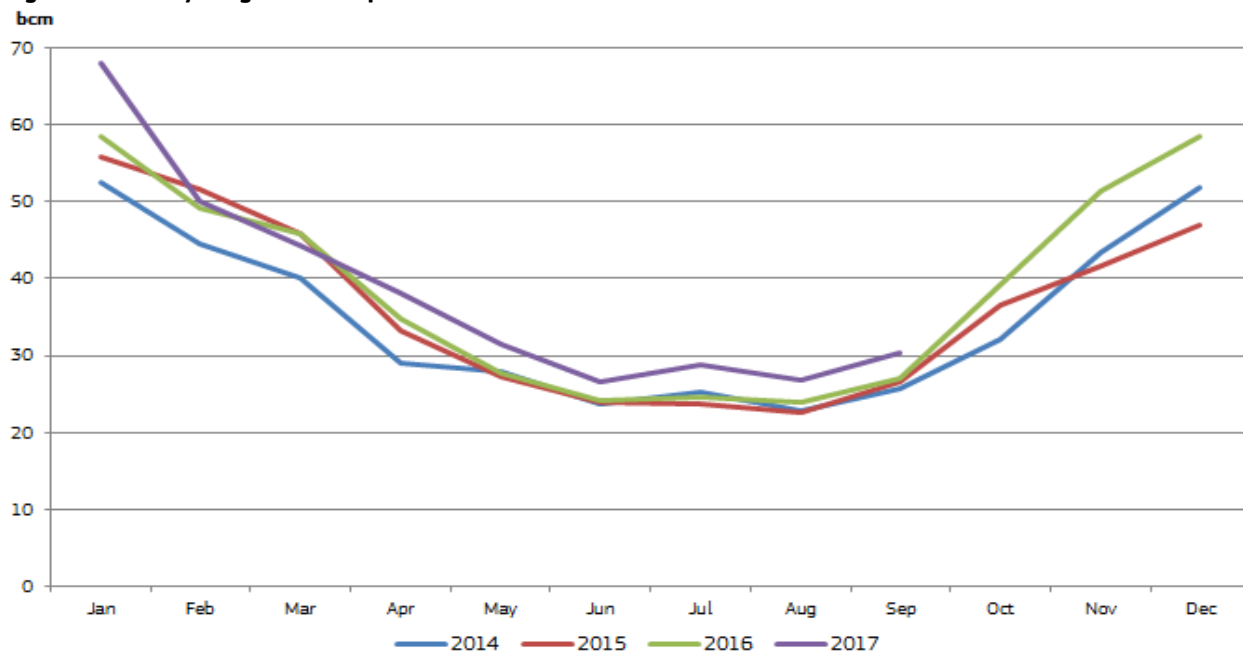
**Figure 2. EU gas consumption Q/Q-4 change (%)**



Source: Eurostat, data as of 18 December 2017 from data series nrg\_103m; calculations of DG Energy (based on consumption measured in bcm). In case of 2017Q3, short-term monthly data (data series nrg\_ind\_343m) was used to fill in the gaps.

- EU gas demand shows a strong seasonality, reflecting the fact that a large proportion of gas is used for space heating. According to 2015 data, the residential sector covered 27% of the gross inland consumption of gas in the EU; in comparison, the share of transformation input (gas use mainly in power stations and district heating plants) was 28%.<sup>2</sup>
- During the winter months the level of gas consumption can be rather volatile, largely depending on temperatures. For example, an unusually cold January in 2017 has helped demand to reach record levels.
- On the other hand, looking at the May to September period, consumption has been rather stable in 2014-2016, with hardly any difference between the three years. 2017 marks a step change in gas demand in this period: monthly consumption has been on average 3-4 bcm higher than in the previous years, mostly driven by an increase of gas use in the power sector.

**Figure 3. Monthly EU gas consumption in 2014-2017**

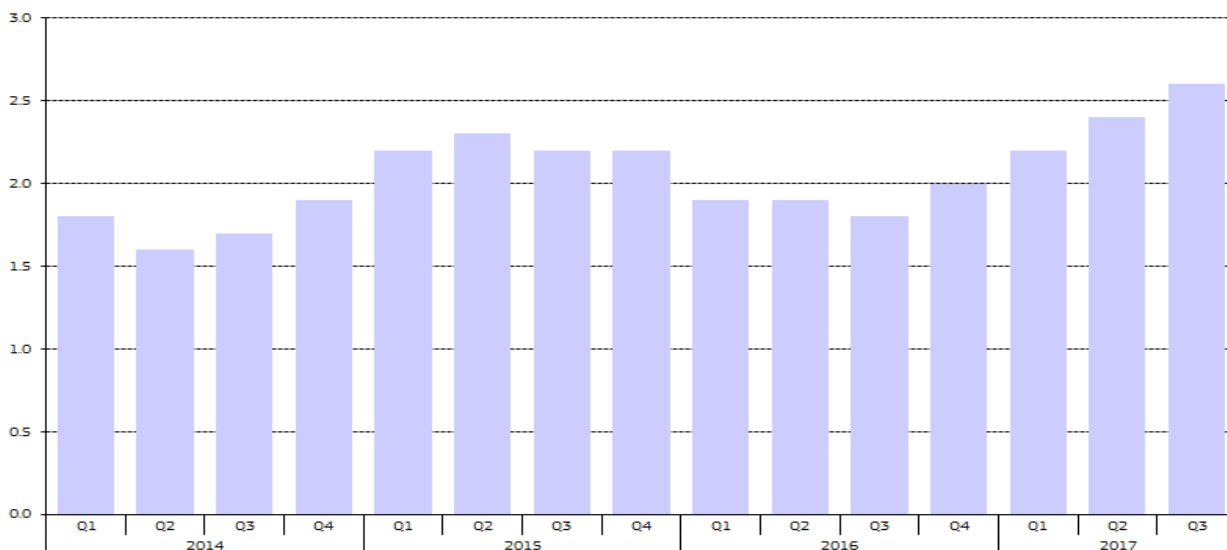


Source: Eurostat, data as of 18 December 2017 from data series nrg\_103m; in case of 2017Q3, short-term monthly data (data series nrg\_ind\_343m) was used to fill in the gaps.

<sup>2</sup> <http://ec.europa.eu/eurostat/web/energy/data/energy-balances>

- GDP growth is picking up in the EU: compared with the same quarter of the previous year, seasonally adjusted gross domestic product (GDP) rose by 2.6% in the third quarter of 2017. This is the biggest growth rate seen since the first quarter of 2011. Since the first quarter of 2017, GDP has been consistently growing in each Member State.
- The growth rate of GDP is gradually increasing since mid-2016 which probably contributed to the increase of gas consumption over the same period. Industrial activity is also on the rise: the gross value added in the manufacturing sector was 3.9% higher in the third quarter of 2017 than a year earlier which is the fastest growth since 2015.<sup>3</sup>

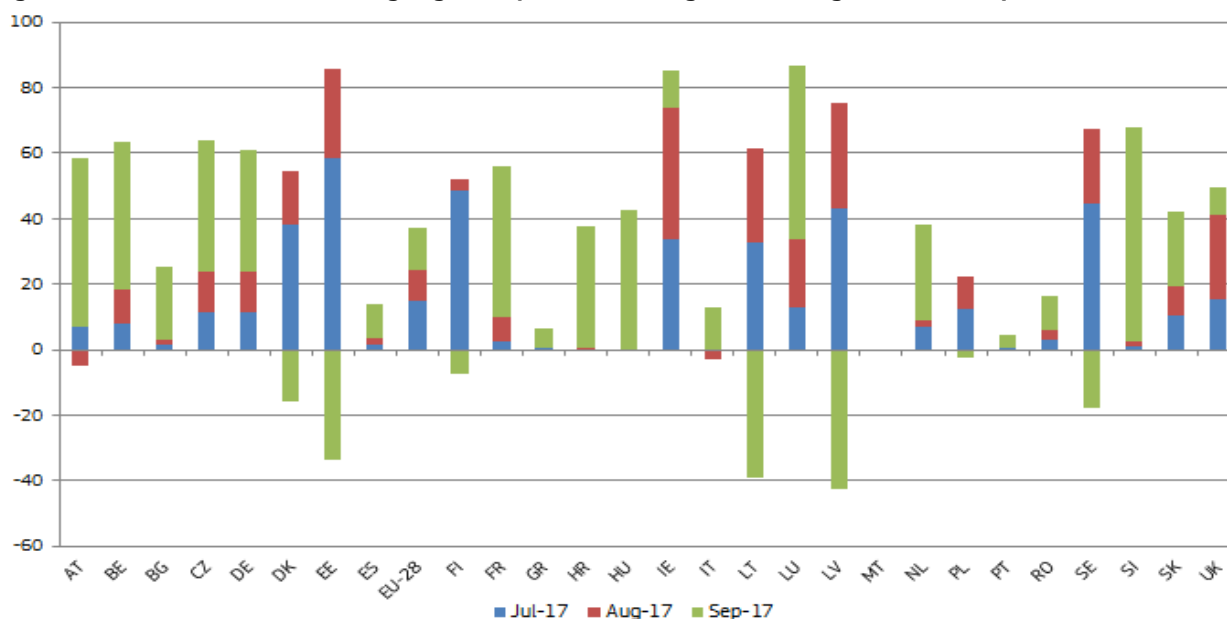
**Figure 4. EU GDP Q/Q-4 change (%)**



Source: Eurostat, data as of 11 December 2017 from data series namq\_10\_gdp Seasonally and calendar adjusted data

- Figure 5 shows the deviation of actual heating degree days (HDDs) from the long-term average in individual EU Member States in the third quarter of 2017. Overall, the number of heating degree days in this period was above the long-term average, although September was relatively mild in Scandinavia and the Baltic states. As the third quarter is the period with the lowest number of heating degree days in the northern hemisphere, the impact of any deviation from the long-term average on gas demand is probably muted.

**Figure 5. Deviation of actual heating degree days from the long-term average in the third quarter of 2017**



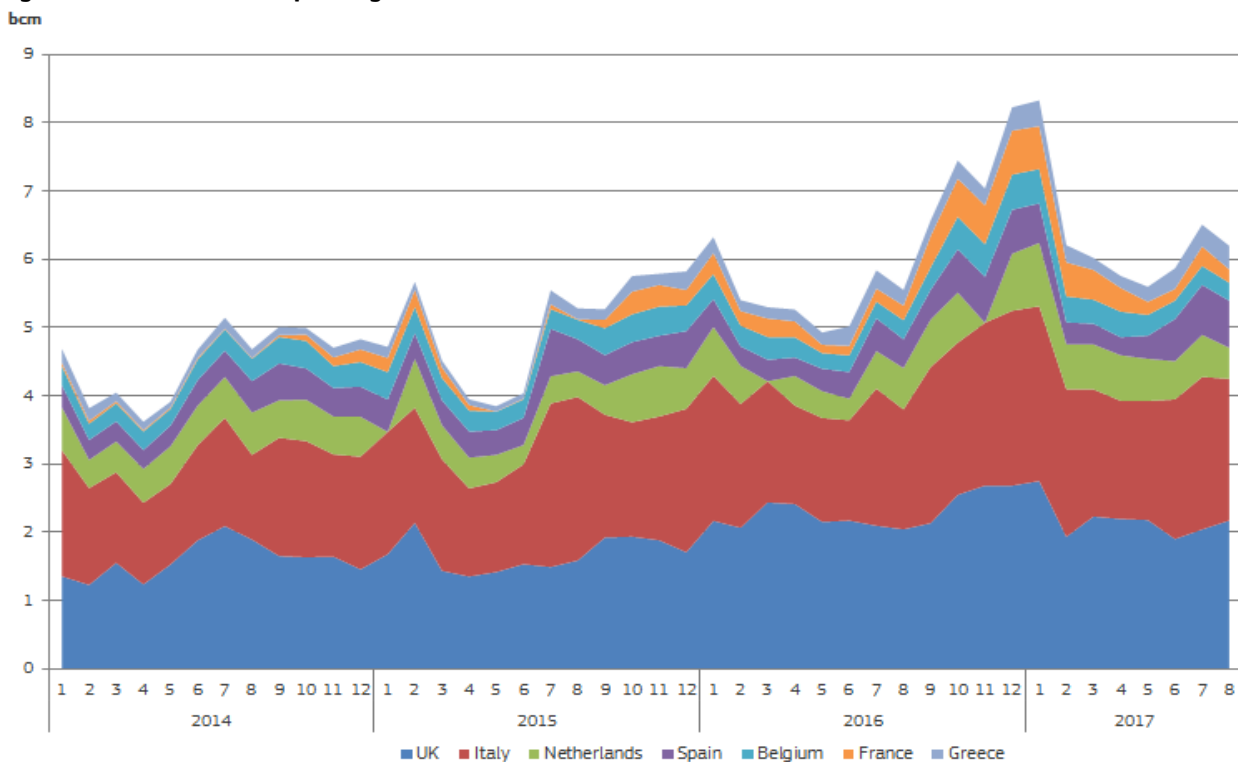
Source: Joint Research Centre (JRC), European Commission

<sup>3</sup> Source: Eurostat, data as of 19 September 2017 from data series namq\_10\_a10; seasonally and calendar adjusted data



- Since mid-2015, gas deliveries to power generation in the EU as a whole have consistently shown a year-on-year increase. In the seven markets<sup>4</sup> reported in Figure 6, gas deliveries to power generation increased by 13% in the second quarter of 2017. The growth rate was 62% in the Netherlands, 43% in France, 24% in Italy and Belgium, 23% in Spain, 10% in Greece while consumption dropped by 7% in the UK. In France, reduced nuclear capacity helped gas-fired generation to increase.
- Gas continued to gain ground in the third quarter: in these seven markets, gas deliveries to power generation increased by 12% in July and August 2017, compared to the same period of 2016 (September data was not available for all countries at the time of writing the report). In this period, the growth rate was 58% in Spain, 34% in Greece, 18% in France, 14% Italy, 3% in Belgium and 2% in the UK while gas use fell by 7% in the Netherlands. High temperatures and low hydro levels provided support to prices in Spain during summer.
- Gas use in the power sector continued to increase despite the fact that, from August, gas prices started to increase. Coal prices also increased in this period, suggesting that the favourable economics of gas-fired generation persisted. (See more details about the price development of different fuels in chapter 2.1.)
- UK clean spark spreads – measuring the profitability of gas-fired generation – averaged 8 Euro/MWh in both the second and third quarters of 2017, helped by the carbon price support mechanism. They were lower than during the preceding winter but gas-fired generation remained competitive compared to coal. Nevertheless, the share of gas in power generation slightly decreased in the second quarter of 2017: it was 41.3%, compared to 44.2% a year earlier. The share of gas decreased at the expense of renewables and nuclear while coal continued its declining trend. Generation from low carbon sources (renewables plus nuclear) provided a record 53.4% whereas the share of coal dropped to a record low of 2.1%, indicating that the potential for further coal-to-gas switching is minimal.<sup>5</sup> As a result of the changing electricity mix, Britain's emissions from electricity (measured in g/kWh) almost halved (-47%) between 2012 and 2016.<sup>6</sup>
- Clean spark spreads in Germany averaged just above 0 Euro/MWh in the second and third quarters of 2017; this is well below the level observed in late 2016 and January 2017.<sup>7</sup> Yet, the share of gas-fired power generation slightly increased in the third quarter of 2017: it was 10.0%, compared to 9.4% in the same period of 2016.<sup>8</sup>

**Figure 6. Gas deliveries to power generation in selected Member States**



Source: Eurostat, data as of 18 December 2017 from data series nrg\_103m. Germany is not included because of gaps in reporting.

<sup>4</sup> Germany is not included because of gaps in reporting.

<sup>5</sup> [https://www.gov.uk/government/uploads/system/uploads/attachment\\_data/file/647752/Energy\\_Trends\\_Sep\\_17.pdf](https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/647752/Energy_Trends_Sep_17.pdf)

<sup>6</sup> [http://electricinsights.co.uk/#/reports/report-2017-q3/detail/the-low-carbon-electricity-league-table?\\_k=zilly7](http://electricinsights.co.uk/#/reports/report-2017-q3/detail/the-low-carbon-electricity-league-table?_k=zilly7)

<sup>7</sup> Charts of clean spark spreads in Germany and the UK can be found in the Quarterly Report of European Electricity Markets

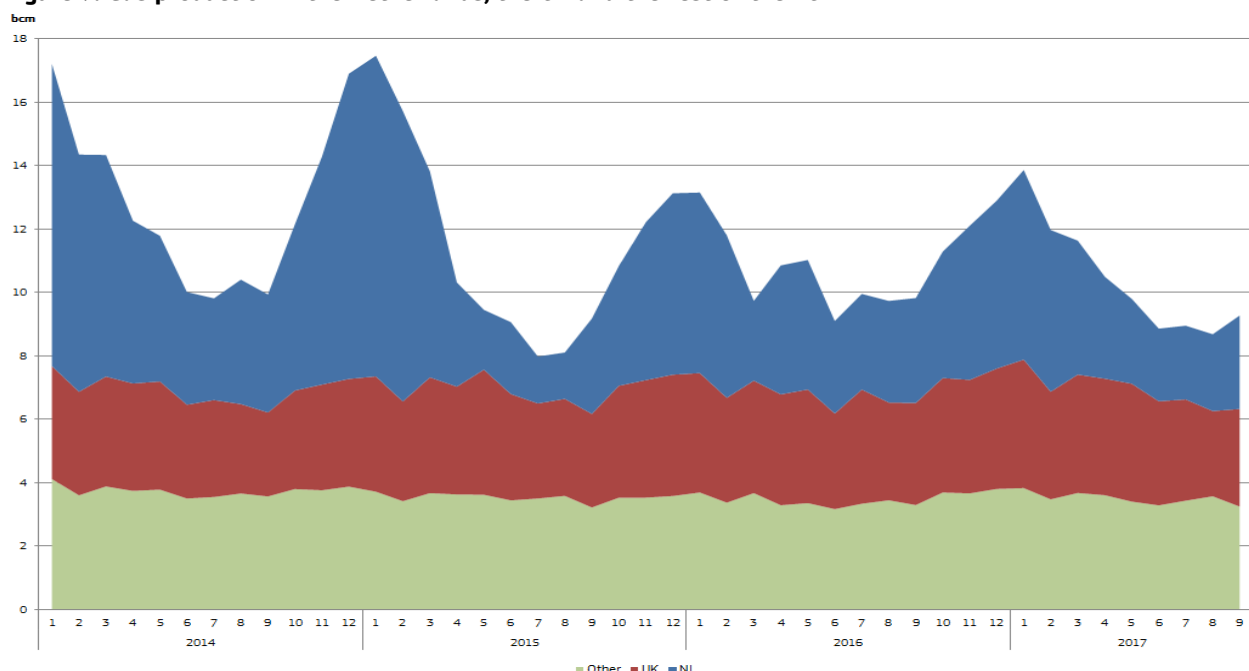
<sup>8</sup> <https://www.destatis.de/EN/FactsFigures/EconomicSectors/Energy/Production/Tables/ElectricityProductionSupply.html>

- In addition to economics, regulation also points towards a reduction of coal use in Europe over the coming years. On 31 July 2017, the European Commission adopted an implementing act which brings into effect "Best Available Technique" (BAT) conclusions for large combustion plants. For all affected installations, the Commission proposes that a review of their permits must happen within four years, so that by mid-2021 stricter EU-wide standards for all large combustion plants will be met.<sup>9</sup> This means that many existing coal power stations will have to carry out costly upgrades, reduce operations or shut down by the 2021 deadline. Furthermore, a couple of Member States have recently announced their intention to phase out coal. These include Finland (by 2030), France (by 2022), Italy (by 2025), the Netherlands (by 2030), Portugal (by 2030) and the UK (by 2025), while in Sweden and Austria utilities have announced closures of all coal capacity by 2022 and 2025, respectively. In addition to renewables, gas is likely to gain from these measures.

## 1.2 Production

- After an unusual 8% increase in the first quarter, in the second quarter of 2017 EU gas production was 6% lower than in the same period of 2016. Looking at the largest producers, gas output decreased in the Netherlands (-26%), Germany (-5%) and Italy (-2%), partly offset by increases in the UK (6%), Romania (16%) and Denmark (4%). Ireland continued its robust growth (39%) thanks to the ramp-up of production at the Corrib field.
- According to preliminary Eurostat data, in the third quarter of 2017 EU gas production decreased by 9% year-on-year as Dutch output continued its downward trend and the growth of UK output turned to negative. If confirmed, this would mean that in the first nine months of 2017 EU output was 2% lower than in the same period of 2016. In Ireland, output from the Corrib field was temporarily constrained from 22 September due to technical issues.<sup>10</sup>
- In the Netherlands, cold weather provided support to production during the first quarter of 2017 with output showing a 15% year-on-year increase. In view of the declining production cap of the Groningen field (24 bcm for the 2016 gas year), it is not surprising that output had to be constrained during the second and third quarters of the year.
- As Figure 7 shows, the Netherlands, the UK and the rest of the EU each cover roughly one third of EU gas production. The monthly output of the UK and the rest of the EU is quite stable, showing very low seasonality. In turn, Dutch production still shows a distinct peak in winter, followed by a trough during summer, despite the fact that – in order to avoid earthquakes in the area – the government aims to minimise fluctuations in the output of the Groningen field. Fluctuations indeed decreased in 2016 but in 2017 the strong seasonal pattern returned. In practice, the Netherlands uses production as "dynamic" storage which is a cheaper alternative to physical storage.

**Figure 7. Gas production in the Netherlands, the UK and the rest of the EU**



Source: Eurostat, data as of 18 December 2017 from data series nrg\_103m; in case of 2017Q3, short-term monthly data (data series nrg\_ind\_343m) was used to fill in the gaps.

<sup>9</sup> [http://europa.eu/rapid/press-release\\_MEX-17-2223\\_en.htm](http://europa.eu/rapid/press-release_MEX-17-2223_en.htm)

<sup>10</sup> <https://uk.reuters.com/article/uk-norway-gas-statoil/irelands-corrib-gas-field-output-to-resume-wednesday-statoil-idUKKBN1CF15Q>

### 1.3 Imports

- Strong consumption and falling indigenous production provided support to a year-on-year increase in imports in the second and third quarters of 2017. According to Eurostat data, net imports in the second quarter were 8% higher than a year earlier. Among the biggest EU gas markets, the net imports of Germany and Italy increased by 13% and 10%, respectively, while those of the UK and France fell by 38% and 8%, respectively (in the latter two countries gas consumption decreased in the second quarter year-on-year). As a result of its falling output, the Netherlands was a net importer in the second quarter, with net imports (6.5 bcm) 15 times higher than in the same period of 2016. After the rapid ramp-up of production at the Corrib field, indigenous production in Ireland covered 78% of the country's consumption in the second quarter of 2017, up from 58% in the same period of 2016 and 4% in the same period of 2015.
- ENTSO-G data show that the trend of rising imports continued in the third quarter of 2017: in this period, total extra-EU imports increased by 14% year-on-year (see Figure 8). In absolute terms, this was the highest third-quarter volume observed in the last four years. The increase was driven by growing consumption and injection demand. Pipeline supplies from North Africa decreased year-on-year but this was more than offset by increasing deliveries from Russia and Norway, as well as a rapid rise of LNG imports.
- In the third quarter of 2017, imports from Russia increased by 12% year-on-year and were only 2% less than the record-high level reached in the last quarter of 2016. Purely oil-indexed prices clearly exceeded hub prices in Northwest Europe in this period, but moving towards more competitive pricing allowed Russia to increase its sales. Russia remained the top supplier of the EU in the third quarter of 2017, covering 44% of total extra-EU imports, down from 45% in the same period of 2016. In the first nine months of 2017, Russian imports were 14% higher than in the same period of 2016, suggesting that 2017 could become a record year for Russian gas supplies to Europe.
- According to a supplementary agreement signed in July 2017, Russia will start gas supplies to China via the Power of Siberia pipeline in December 2019. The original Sales and Purchase Agreement was signed by Gazprom and CNPC in 2014, providing for gas deliveries in the amount of 38 bcm/year for 30 years.<sup>11</sup> According to previous reports, the contract contains a price formula linked to oil prices and a take-or-pay clause.<sup>12</sup> The first train of Novatek's Yamal LNG project started up in December, providing another new supply route for Russian gas.
- Gas imports from Norway were constrained in the third quarter of 2017 by outages, e.g. at the Kollsnes processing plant. Nevertheless, total gas flows from Norway increased by 29% year-on-year in the third quarter from an unusually low base (a busy maintenance schedule restricted exports in the third quarter of 2016). The country's share from total extra-EU imports increased from 29% to 33%.<sup>13</sup>
- In the third quarter of 2017, Norwegian gas production amounted to 30.2 bcm, 29% more than in the third quarter of the previous year. For 2017 as a whole, the Norwegian Petroleum Directorate expects a gas production of 122.7 bcm (January-September fact, October preliminary and November-December forecast), which is 5% more than the 2016 output.<sup>14</sup>
- Between June and October 2017, the Polish and Danish natural gas transmission system operators held two rounds of open season for the Baltic Pipe Project. The planned pipeline would transport 10 bcm/year of Norwegian gas from Denmark to Poland. The capacity allocation procedure proved a market interest in the capacity proposed in the project. In case of a positive investment decision taken in 2018, the first gas is to be delivered in 2022.<sup>15</sup> The realization of the project would allow Poland to reduce or even eliminate its dependence on Russian gas. (Poland's long-term contract with Gazprom expires in 2022.)
- After 2 years of consistent year-on-year growth, pipeline imports from Algeria started to decrease in the second quarter of 2017. In the third quarter, imports were 35% lower than in the same periods of the previous year. Supplies to both Italy and Spain decreased, by 34% and 36%, respectively. High oil-indexed prices coupled with low spot LNG prices provided an incentive for importers to reduce pipeline gas purchases (taking advantage of the flexibility provided in long-term contracts) from the North African country and partly replace them by spot LNG cargoes. Imports from Libya also decreased although to a smaller extent: in the third quarter of 2017, volumes were 6% lower than a year earlier. The combined share of Algeria and Libya from total extra-EU imports was only 7% in the third quarter of 2017, down from 12% in the same period of 2016.
- Imports of LNG significantly increased in the third quarter of 2017 and covered 16% of total extra-EU gas imports, up from 14% a year ago (see further details below).

<sup>11</sup> <http://www.gazprom.com/press/news/2017/july/article340477/>

<sup>12</sup> <http://www.gazprom.com/press/news/2014/may/article191451/>

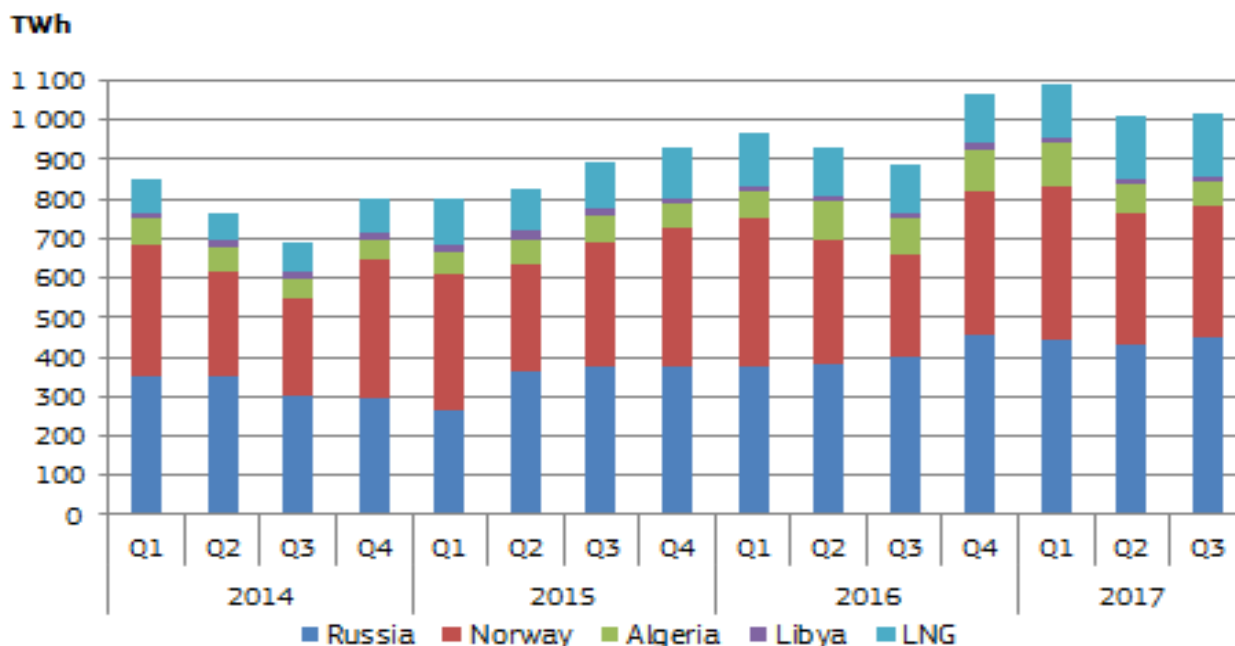
<sup>13</sup> Note that Norway to UK flows reported by ENTSO-G include some gas from UK offshore fields, resulting in an overestimation of Norwegian imports.

<sup>14</sup> <http://www.npd.no/Global/Norsk/1-Aktuelt/Produksjonstall/P2017/Okt-2017/Data-oktober-2017.xlsx>

<sup>15</sup> <http://en.gaz-system.pl/press-centre/news/information-for-the-media/artykul/202594/>

- The EU's estimated gas import bill was around 17 billion euros in the third quarter of 2017, around 32% more than a year earlier. Both the import volumes (1017 TWh) and the estimated average import price (around 16.3 Euro/MWh) were higher than in the third quarter of 2016.

**Figure 8. EU imports of natural gas by source, 2014-2017**



Source: Based on data from the ENTSO-G Transparency Platform, data as of 8 November 2017

Russian deliveries to Finland are reported from 1 June 2014; deliveries to Estonia and Latvia are reported for a limited period (Narva from 15 June 2015 to 10 December 2015, Värskä and Misso Izborsk from 26 May 2015)

Norway and Algeria include pipeline imports only; LNG imports coming from these countries are reported in the LNG category.

Norway to UK flows reported by ENTSO-G include some gas from UK offshore fields, resulting in an overestimation of Norwegian imports.

- Figure 9 depicts EU gas imports from Russia on the three main supply routes: Ukraine (which includes the Brotherhood Pipeline and the Balkan route), Belarus (mainly the Yamal pipeline) and Nord Stream.
- In the third quarter of 2017, the volume of Russian imports transiting Ukraine was 29% higher than in the same period of 2016. Ukraine remained the main supply route of Russian gas to the EU, covering 50% of the total. In August, deliveries reached nearly 80 TWh (around 7.5 bcm), the highest monthly level in the last four years.
- Gas flows on the Nord Stream pipeline represented 26% of total EU imports from Russia in the third quarter of 2017. In absolute terms, volumes were 11% higher than in the same period of 2016. Deliveries increased in August, following a ruling of the EU's General Court that lifted a suspension on Gazprom's right to book additional capacity on the OPAL pipeline.<sup>16</sup> (The final decision on access to the OPAL pipeline is expected in 2019.) However, flows decreased in September when Nord Stream went through an 11-day planned maintenance.<sup>17</sup>
- Gas supplies transiting Belarus decreased by 3% in the third quarter of 2017 compared to the same period of 2016 and covered 22% of total EU imports from Russia. In August, flows shortly changed direction at the Mallnow interconnection point between Poland and Germany because maintenance along the Yamal pipeline.<sup>18</sup>
- Ukraine has not purchased gas from Russia since November 2015 and, in the third quarter of 2017, continued to rely on imports from Europe. Gas flows coming from Hungary, Poland and Slovakia reached around 3.8 bcm in this period, 12% more than in the same period of 2016.<sup>19</sup> In July, Polish gas transmission system operator GAZ-SYSTEM announced that from 1 September 2017 the transmission capacities in the direction of Ukraine will be increased to 6 mcm/day.<sup>20</sup>

<sup>16</sup> <https://curia.europa.eu/jcms/upload/docs/application/pdf/2017-07/cp170083en.pdf>

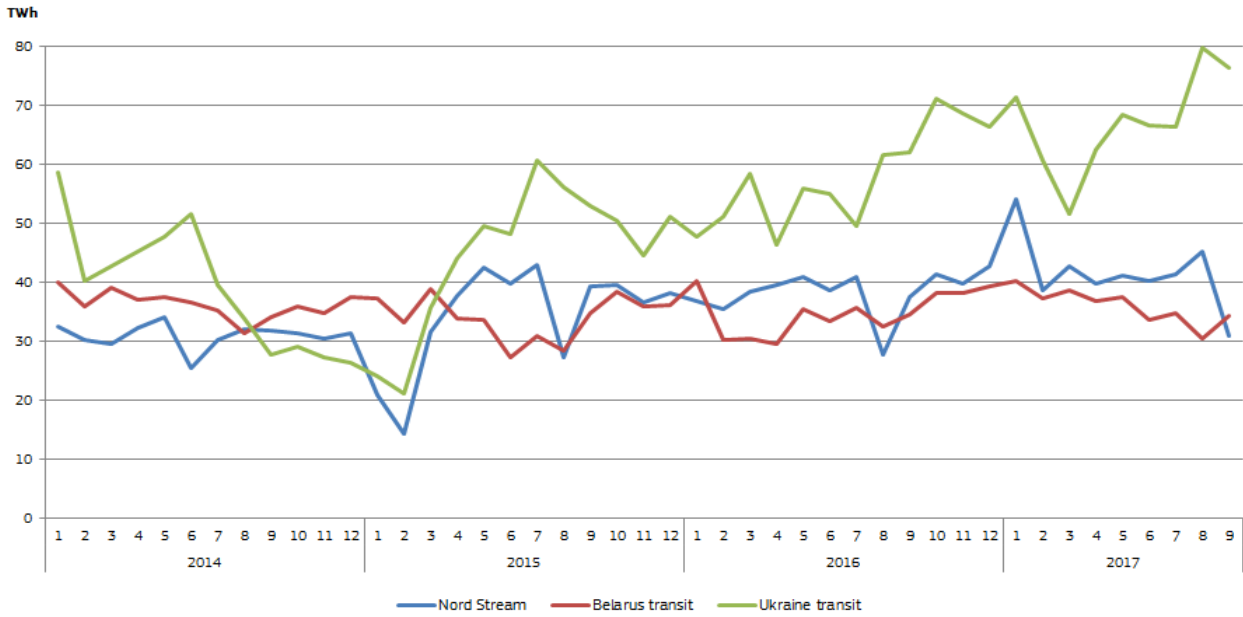
<sup>17</sup> <https://www.nord-stream.com/press-info/press-releases/annual-maintenance-works-successfully-completed-496/>

<sup>18</sup> ICIS European Gas Markets, 31 August 2017

<sup>19</sup> Based on data from the ENTSO-G Transparency Platform, data as of 11 December 2017

<sup>20</sup> <http://en.gaz-system.pl/press-centre/news/information-for-the-media/artykul/202533/>

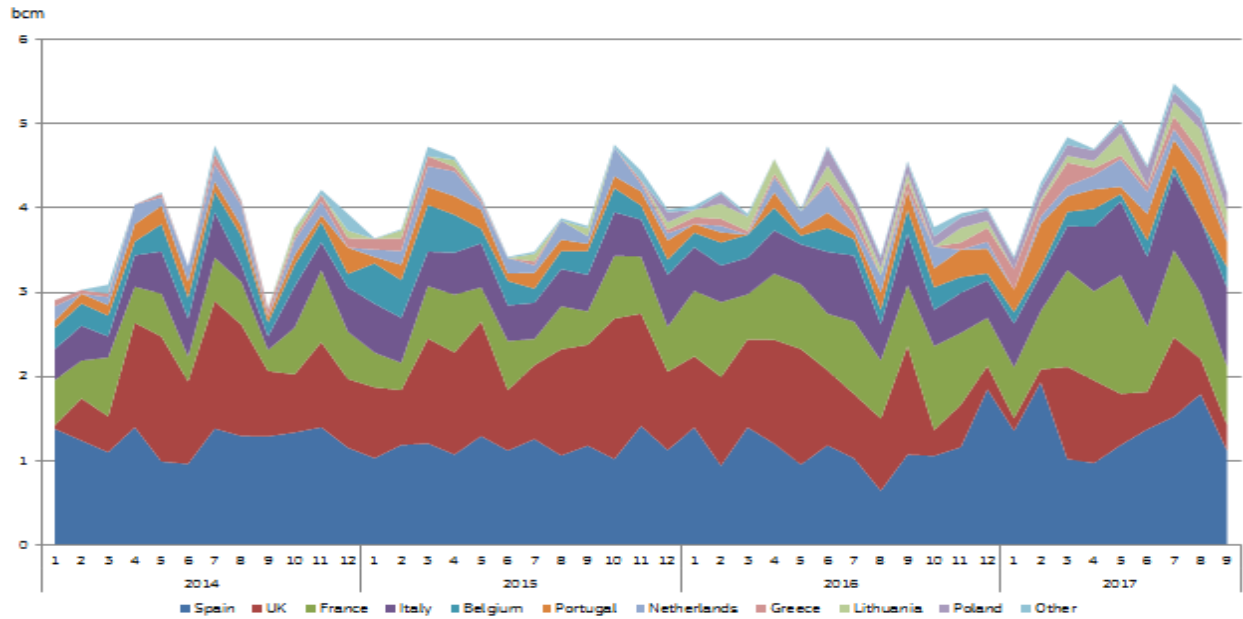
**Figure 9. EU imports of natural gas from Russia by supply route, 2014-2017**



Source: Based on data from the ENTSO-G Transparency Platform, data as of 8 November 2017  
 Deliveries to Estonia, Finland and Latvia are not included; transit volumes to the Former Yugoslav Republic of Macedonia, Serbia and Turkey are excluded

- After a modest 5% increase in the first half of 2017, in the third quarter EU LNG imports increased by 22% year-on-year, facilitated by converging international LNG prices. In July, LNG imports reached nearly 5.5 bcm (of gas equivalent), the highest monthly level observed in the last four years.
- Similarly to the first six months of the year, the trend was markedly different in Northwest Europe and the Mediterranean: compared to the third quarter of 2016, imports decreased in Belgium (-47%) and the UK (-42%) which was more than offset by increases in Portugal (118%), Spain (61%), Greece (58%), Italy (49%) and France (10%). In the liquid and well-connected Northwest European market, LNG was struggling to compete with the Russian and Norwegian pipeline supplies, leading to a decrease of LNG imports. During the summer months the UK also had to cope with the lack of injection demand at the Rough facility, thereby reducing the demand for LNG imports. In Southern Europe, in turn, high temperatures and low hydro levels provided support to gas demand for power generation and, in addition, the favourable price of spot LNG compared to oil-indexed contracts provided an incentive to import more LNG (mainly at the expense of lower pipeline imports from Algeria). In case of Italy, the planned maintenance of several import pipelines during the summer also contributed to higher LNG imports.

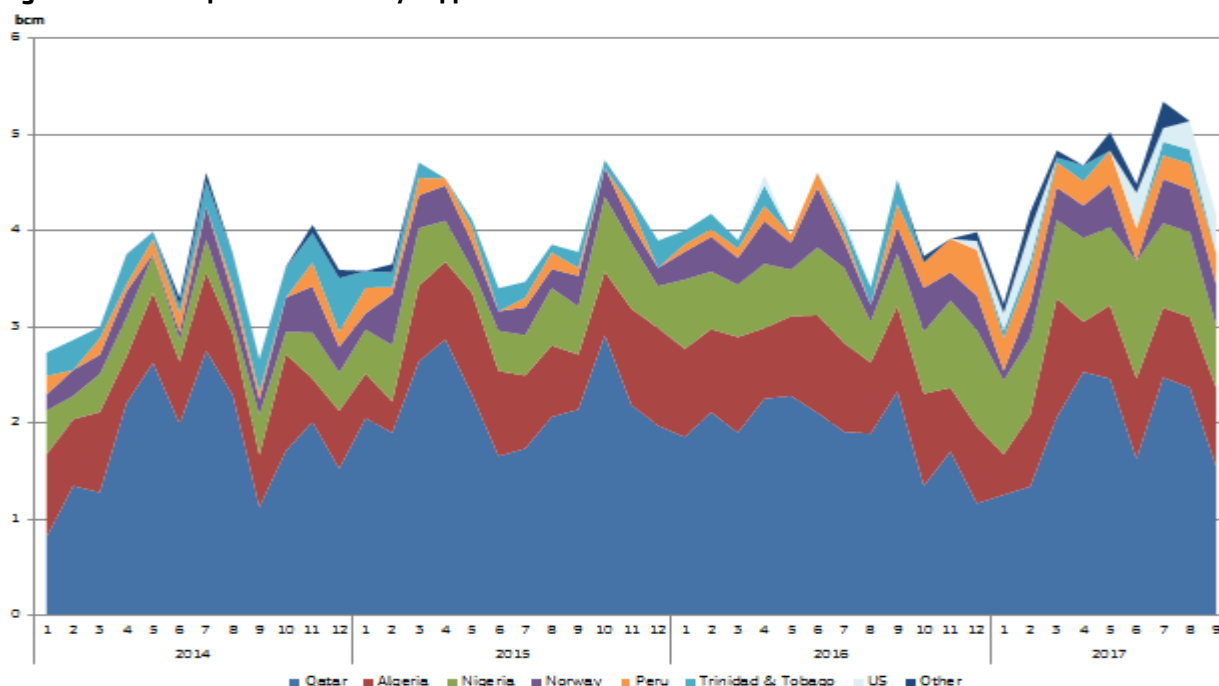
**Figure 10. LNG Imports to the EU by Member State**



Source: Commission calculations based on tanker movements reported by Thomson Reuters  
 "Other" includes Finland, Malta and Sweden

- Qatar has been consistently the main LNG supplier of the EU in the last couple of years. After relatively low volumes in the last quarter of 2016 and the first quarter of 2017, imports returned to the usual level seen in previous years, with the country's market share rebounding to 44% in the third quarter of 2017. The ongoing Qatari diplomatic crises had no discernible impact on the country's exports.
- Qatar was followed by Nigeria (16%), Algeria (16%) and Norway (9%). The US became the fifth LNG supplier of the EU (6%), narrowly overtaking Peru (6%). After a 4-year hiatus, imports resumed from Egypt in May 2017; in the third quarter the share of Egypt from total EU LNG imports exceeded 1%. (Egypt started importing LNG in 2014 but rising domestic production will enable the country to become a net exporter again.) In July 2017, for the first time, an LNG cargo arrived to Europe from Brazil; the destination was Portugal.
- In the third quarter of 2017, Qatar had a dominant role in the Belgian (97%), Dutch (73%), Italian (67%), Polish (82%) and UK (82%) markets. Algeria was the main supplier of France (47%) and Greece (77%) while Portugal's largest supplier was Nigeria (53%). Norway was the dominant supplier of Lithuania (55%). Spain had the most diversified portfolio; from its eight suppliers (including reexport from the Netherlands), Qatar had the biggest market share (34%).

**Figure 11. LNG Imports to the EU by supplier**



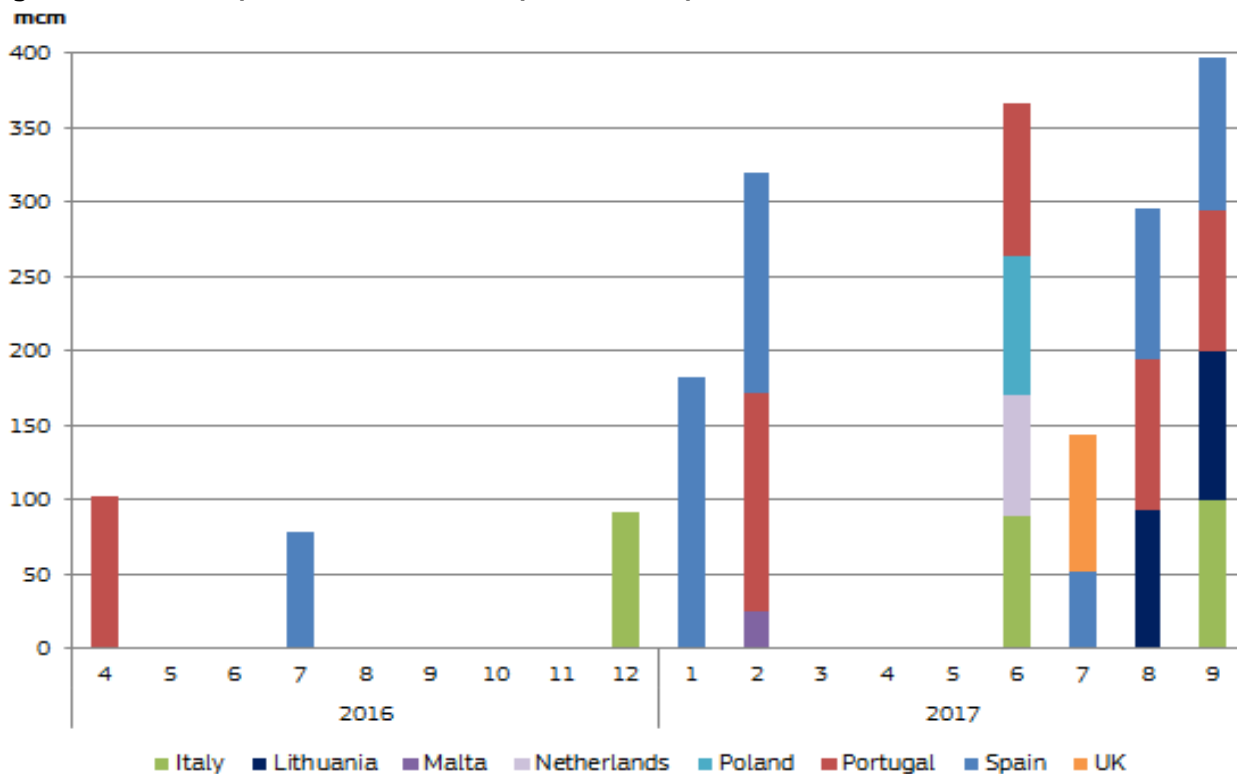
Source: Commission calculations based on tanker movements reported by Thomson Reuters  
 Imports coming from other EU Member States (reexports) are excluded  
 "Other" includes Angola, Brazil, Egypt, Equatorial Guinea, Oman, Singapore and the United Arab Emirates

- In the third quarter of 2017, five Member States imported LNG from the US: three cargoes arrived to Spain<sup>21</sup>, two to Portugal and Lithuania and one to Italy and the UK. The UK and Lithuania became the seventh and eighth Member State receiving LNG deliveries from the US.<sup>22</sup> US supplies reached the highest market share in Lithuania where they represented 31% of total LNG imports in this period.
- In the third quarter of 2017, EU LNG imports from the US totalled a record 0.84 bcm (of gas equivalent), representing 23% of total US LNG exports in this period, up from less than 10% in the previous quarter. Increasing European hub prices were instrumental in the gradual growth of US imports over the third quarter.

<sup>21</sup> One of the vessels arriving to Spain continued its voyage to Egypt, discharging half of its cargo there.

<sup>22</sup> The cargo destined to the UK was loaded in June but arrived in early July.

**Figure 12. EU LNG imports from the US from April 2016 to September 2017**

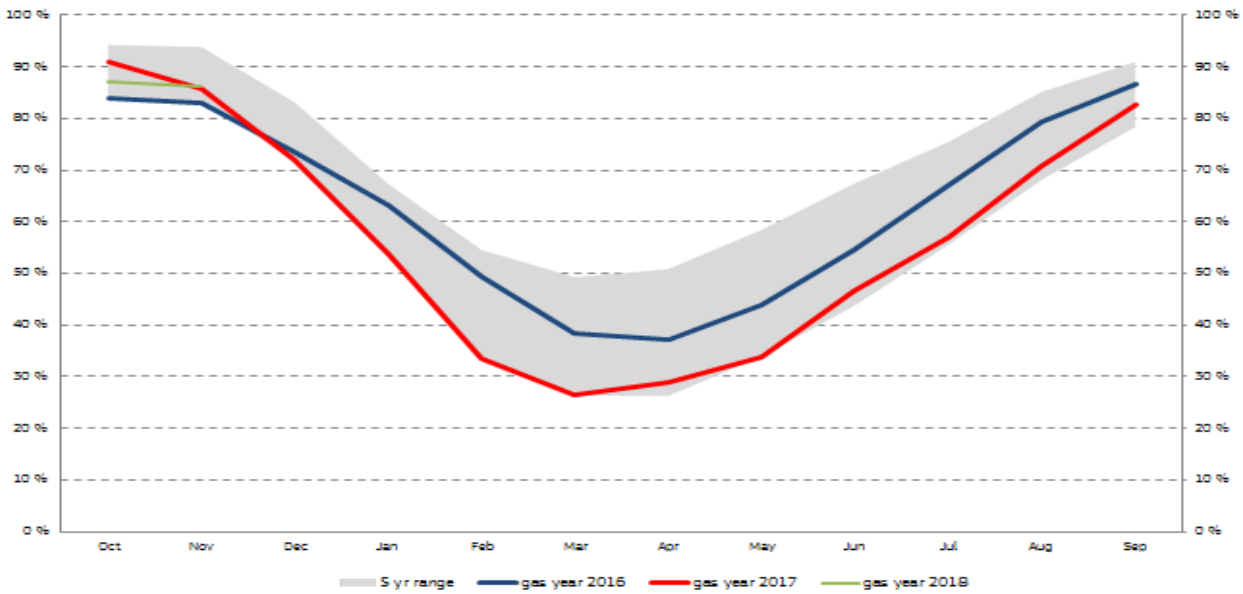


Source: Commission calculations based on tanker movements reported by Thomson Reuters

### 1.4 Storage

- Figure 13 shows EU stock levels as percentage of storage capacity in gas years 2016, 2017 and 2018, compared to the 5-year range of 2013-2017. According to figures published by Gas Infrastructure Europe, EU storage capacity amounted to 1,064 TWh (roughly 100 bcm) on 30 September 2017.
- During the 2016-2017 winter, withdrawals were much stronger than a year earlier, driven by cold temperatures, an increased gas use in the power sector and relatively low LNG imports. By 31 March 2017, the stock level fell below 280 TWh. This was equivalent to an average filling rate of 26%, 10 percentage points lower than a year earlier and below the 5-year range (of 2012-2016).
- The injection season started earlier than usual: EU stock levels bottomed out already on 28 March. After the strong injection observed in April, the pace of injections was similar to 2016 but it started from a lower base which means that, throughout most of the injection period, the average filling rate was 5-10 percentage points lower than a year earlier. During summer, a premium of day-ahead prices over forward prices provided an incentive to defer injections, especially in the Netherlands. Outages in Norway and planned maintenance of the Nord Stream pipeline restricted imports to Northwest Europe and, thereby, also curbed replenishments.
- At the end of the gas summer, on 30 September 2017, the average filling rate was 85%, compared to 90% a year earlier. Injections continued in October, with total EU stock levels peaking on 29 October, at 89% of storage capacity.
- Ukraine had relatively comfortable stock levels at the beginning of the gas winter: on 30 September, the filling rate was 53%, 7 percentage points higher than a year earlier, suggesting that the country will be able to ensure stable gas transit to Europe over the 2017-2018 winter.

**Figure 13. Gas storage levels as percentage of maximum gas storage capacity in the EU**

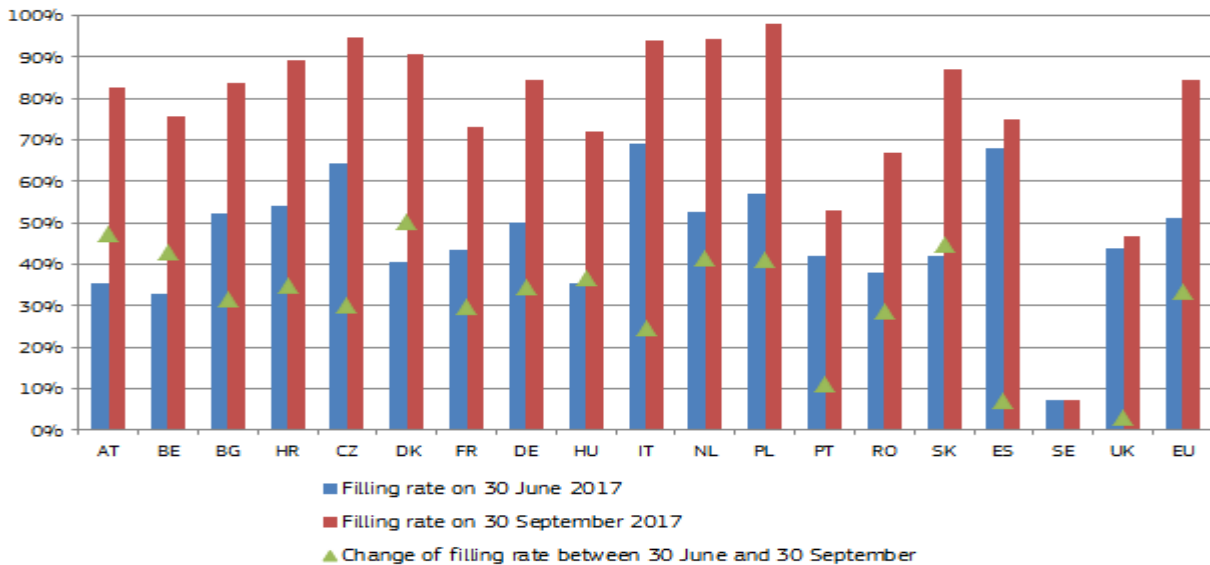


Source: Gas Storage Europe AGSI+ Aggregated Gas Storage Inventory, extracted on 19 November 2017. See explanations on data coverage at <https://agsi.gie.eu/#/faq>.

The 5-year range reflects stock levels in gas years 2013-2017. The graph shows stock levels on the 15<sup>th</sup> day of the given month.

- On average, injections made during the third quarter of 2017 were equivalent to 33.5% of storage capacity (compared to 25.4% in the second quarter and 29.6% in the third quarter of 2016): the average filling rate increased from 51% on 30 June to 85% on 30 September. However, as Figure 14 shows, there was significant variation among Member States in terms of both the starting position (the filling rate at the end of the second quarter) and the pace of injections.
- Denmark saw the highest rate of injections in this period, with filling rates rising from 40% to 91%, followed by Austria, Slovakia and Belgium. Italy started with the highest stock levels at the end of the second quarter and hence injections were relatively low in the third quarter.
- On 30 September, five Member States had a filling rate of more than 90%: the Czech Republic, Denmark, Italy, the Netherlands and Poland. From the biggest markets, France had unusually low stock levels at 73% of capacity, compared to 88% a year earlier. German stocks also significantly fell short of year-ago levels (85% in 2017 compared to 94% in 2016) but filling rates increased to 92% by the end of October, eliminating most of deficit compared to the previous year. In around 70% of Member States, the level of stocks on 30 September 2017 was lower than on the same day of 2016.

**Figure 14. Gas storage levels as percentage of maximum gas storage capacity by Member State**

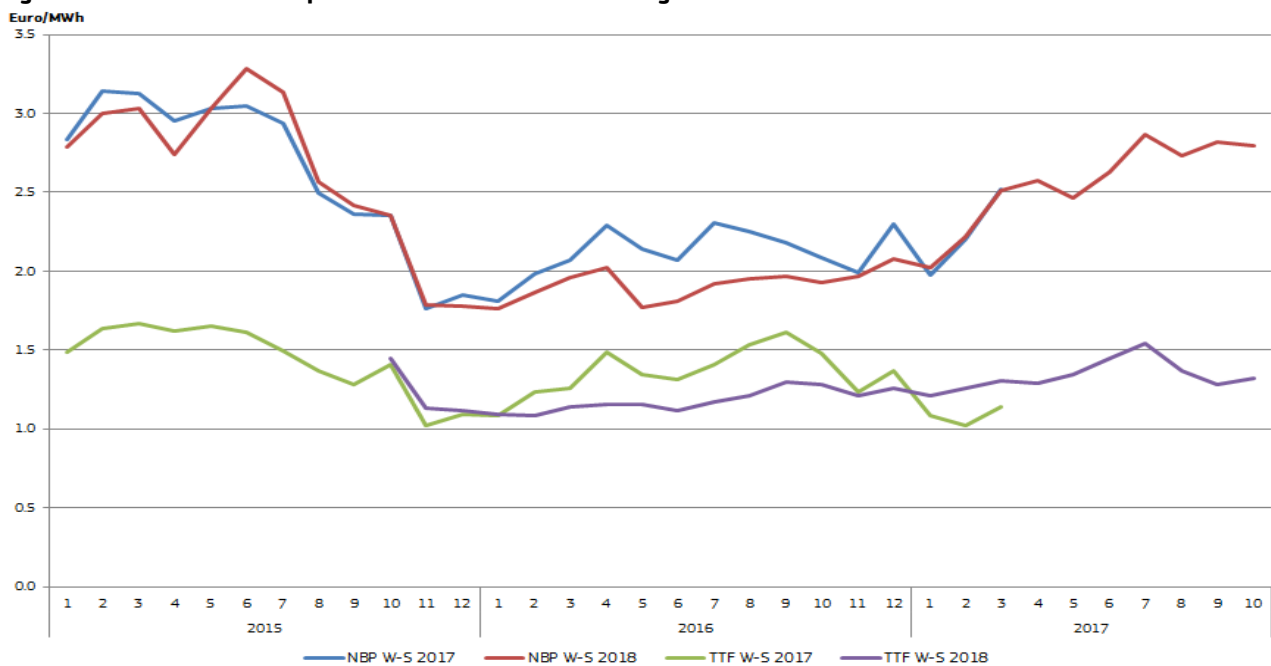


Source: Gas Storage Europe AGSI+ Aggregated Gas Storage Inventory, extracted on 17 December 2017; calculations of DG Energy. See explanations on data coverage at <https://agsi.gie.eu/#/faq>.



- Figure 15 shows that seasonal spreads have been relatively high in late 2014 and the first half of 2015 but started to fall in July 2015, dropping to 1.5-2.0 Euro/MWh on the NBP and as low as 1.0 Euro/MWh on the TTF. From early 2016, spreads slightly recovered but remained below the 2014 levels. On the NBP, seasonal spreads averaged 2.8 Euro/MWh in the third quarter of 2017, around 0.8 Euro/MWh more than in the same period of 2016. On the TTF, the average seasonal spread was 1.4 Euro/MWh in the third quarter, barely more than a year earlier.
- Low seasonal spreads are seen as result of an oversupply of storage capacity in Europe and increasing competition from alternative sources of supply flexibility (e.g. Dutch production, Norwegian pipeline imports, LNG imports, the increasingly interconnected European gas network and reliable price signals and growing liquidity at EU hubs).<sup>23</sup>
- In the UK, seasonal spreads have been clearly on the rise in 2017, reaching levels not seen since 2015. This is probably related to the woes of the Rough storage facility which mean low injection demand and oversupply in summer and a tighter market in winter, thereby increasing the seasonal spread. In contrast to the mainland Europe, where there is ample storage capacity, the UK market sends a price signal to storage operators incentivising seasonal storage.

**Figure 15. Winter-summer spreads in the Dutch and British gas hubs**



Source: Platts

W-S 2017 refers to the difference between the winter 2017-18 price and the summer 2017 price; W-S 2018 refers to the difference between the winter 2018-19 price and the summer 2018 price

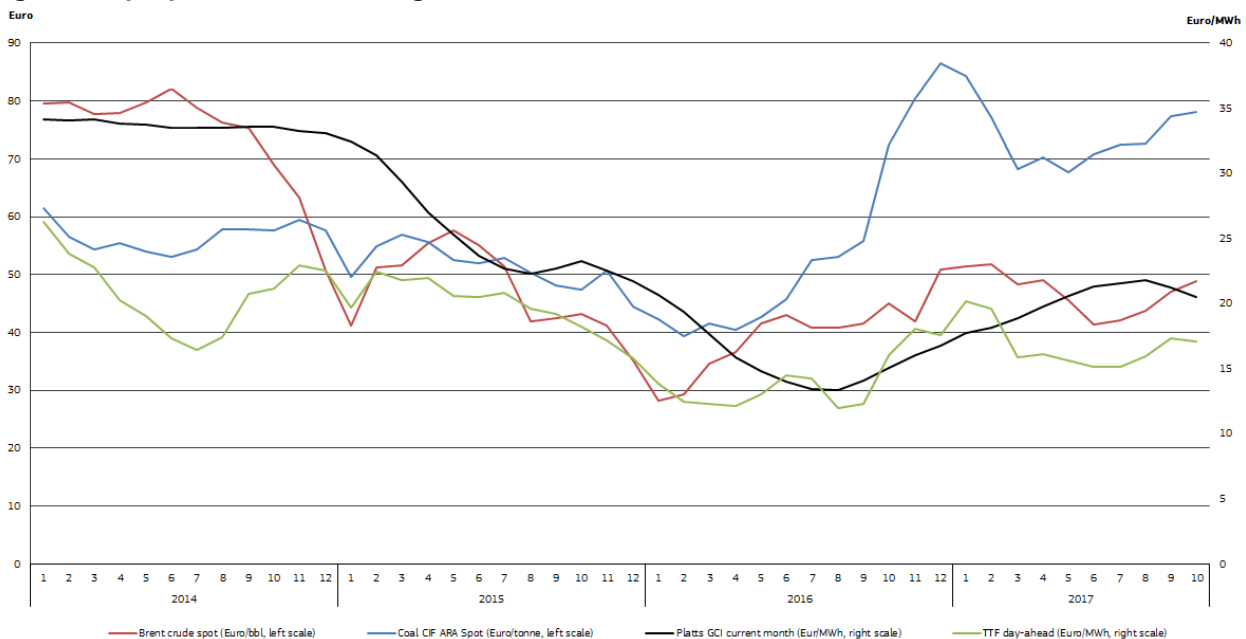
<sup>23</sup> ICIS European Gas Markets, 31 July 2017

## 2. Wholesale gas markets

### 2.1 The broader energy commodity picture: comparisons between oil, gas and coal prices in the EU

- Despite the November 2016 agreement of OPEC and non-OPEC producers to reduce output, oil prices decreased in the first half of 2017 as increasing drilling and production in the US, as well as growing output in Libya and Nigeria (which are exempted from the OPEC cut) raised doubts about the rebalancing of the global oil market. The extension of the cut in May 2017 failed to reverse the trend: in the second half of June, the price of Brent dropped below 45 USD/bbl, the lowest level since November 2016. The trend turned in the third quarter: prices increased driven by a combination of factors, including the robust growth of global demand, growing tensions in the Middle East and a number of supply disruptions (Northern Iraq, hurricanes in North America). By November, Brent gradually increased to 64 USD/bbl, the highest level in two and a half years. In spite of the recent price rise, there has been no fundamental change in the global supply-demand balance and – unless there is a major disruption – most analysts expect the market to remain well supplied in 2018, with the average Brent price remaining below 60 USD/bbl.
- After a gradual decrease seen in 2015 and most of 2016, the TTF spot price started to grow in the last quarter of 2016. After a peak in January, as the winter receded, hub prices returned to the declining trajectory. An uptick in LNG imports also put pressure on prices. Prices started to increase in the third quarter of 2017, with the TTF price averaging 16.1 Euro/MWh, 26% more than in the same period of 2016. Relatively low storage levels, continuing coal-to gas switching, rising oil and coal prices, cooling temperatures, Norwegian outages and persistent concerns about French nuclear availability all provided support to European hub prices in this period. Like in the previous quarter, gas hub prices were strongly correlated to oil prices in the third quarter 2017.
- Due to the typical 6-9 month time lag structure used in the pricing formulas, oil-indexed prices bottomed out in August 2016 and started to grow gradually afterwards. From the second quarter of 2017, oil-indexed prices clearly exceeded hub prices. Platt's North West Europe Gas Contract Indicator (GCI), a theoretical index showing what a gas price linked 100% to oil would be, reached 21.6 Euro/MWh in July, 6.5 Euro/MWh more than the TTF. This is the biggest difference since early 2016. Afterwards, due to rising hub prices, this differential decreased. In the third quarter of 2017, the average GCI price was 21.5 Euro/MWh, 58% more than in the same period of 2016.
- Driven by market tightness in Asia after China introduced measures restricting domestic coal output, coal prices increased significantly in the second half of 2016. In December 2016, the CIF ARA spot price averaged 86.5 Euro/ton, the highest level since 2011. After easing in the first quarter of 2017, coal prices started to rise again from mid-2017, helped by steady demand, some supply interruptions (including industrial action in Australian mines and a dispute between Russia and Latvia on coal transit) and rising freight rates. The CIF ARA spot price averaged 74.1 Euro/ton in the third quarter of 2017, 38% more than a year earlier. As a result, the relative competitiveness of gas remained favourable compared to coal.

**Figure 16. Spot prices of oil, coal and gas in the EU**

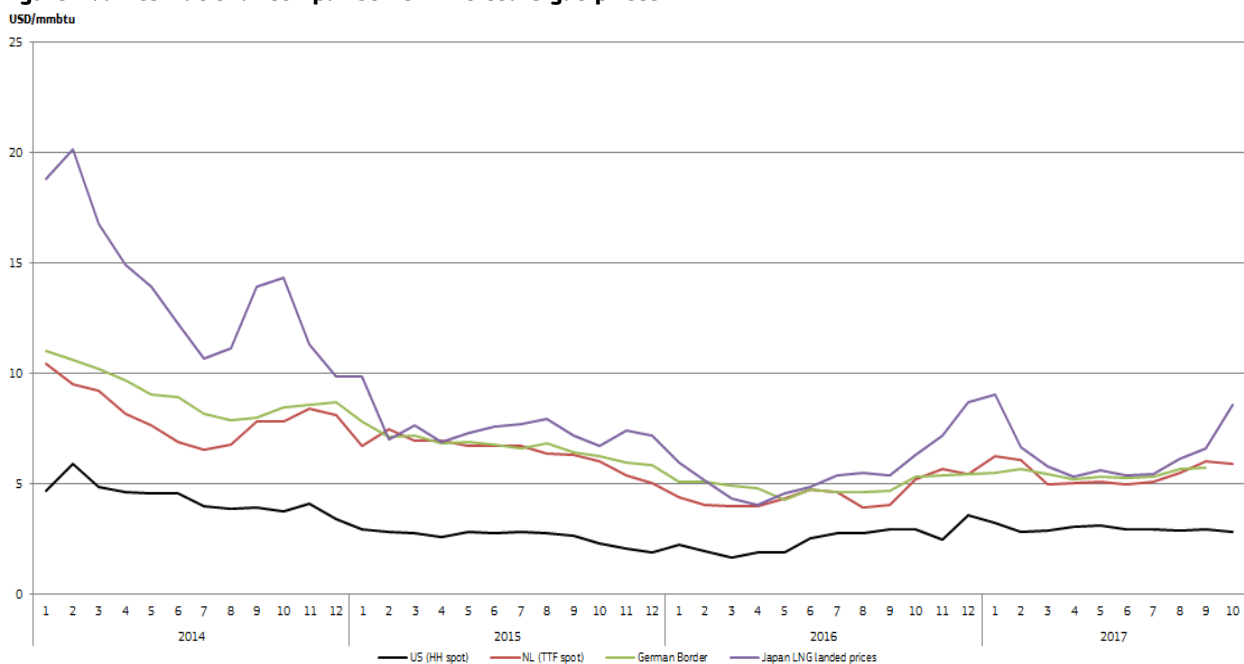


Source: Platts

## 2.2 International gas markets

- Figure 17 displays an international comparison of wholesale gas prices. In the last few years, prices have been on a declining trajectory in all regions but this trend was interrupted by an increase in practically all regions during the 2016-2017 winter. In the second quarter of 2017, international gas prices have been remarkably stable but in the third quarter both Asian and European prices rose.
- In 2015-2016, Japanese LNG prices traded on average 1.1 USD/mmbtu higher than TTF, the Dutch gas hub but in certain periods the premium has practically disappeared. During the 2016-2017 winter, strong demand in Asia and a number of production outages supported Japanese prices and, as a result, the difference significantly increased and in December 2016 reached 3.3 USD/mmbtu, a level not seen since 2014. Prices eased from February 2017 as demand weakened while Australian and US output continued to grow.
- In the third quarter of 2017, Japanese prices picked up as above-average summer temperatures increased seasonal demand, firm Chinese demand also provided support while in September Hurricane Harvey caused some delays to US LNG exports. In the third quarter of 2017, Japanese landed prices averaged 6.1 USD/mmbtu which means that the average premium over TTF was 0.5 USD/mmbtu. With the approach of winter, Japanese prices increased further, developing in October a sizeable 2.7 Euro/MWh premium compared to TTF, suggesting that during the coming winter Asia will again absorb a large part of LNG supply.
- After years of gradual decrease, European gas prices started to grow from October 2016 and the TTF averaged 6.3 USD/mmbtu (20.1 Euro/MWh) in January 2017. Prices decreased afterwards and were rather stable between March and July but started to rise again from August, helped by a combination of factors: relatively low storage levels, continuing coal-to gas switching, rising oil and coal prices, cooling temperatures, Norwegian outages and persistent concerns about French nuclear availability. In the third quarter, TTF averaged 5.6 USD/mmbtu (16.1 Euro/MWh). The average German border price was practically the same (5.6 USD/mmbtu or 16.2 Euro/MWh).
- Since a small peak reached in the end of December 2016, the Henry Hub price has been rather stable. In the third quarter of 2017, the average price was 2.9 USD/mmbtu, 0.1 USD/mmbtu more than in the same period of 2016. US gas prices were hardly affected by the hurricanes: Hurricane Harvey caused some supply disruptions but this was offset by its negative impact on gas demand.
- In the second quarter of 2017, the convergence among key international gas prices reached the greatest level since the Fukushima accident in 2011. From August, however, international prices diverged again: as Asian and European ones started to rise, their premium to the rather stable Henry Hub benchmark increased, thereby contributing to the rising EU LNG imports from the US.
- The ratio of the Japanese LNG price and US Henry Hub increased to 2.1 in the third quarter of 2017 while in April 2017 it was as low as 1.7. The average TTF/Henry Hub ratio increased to 1.9 in the third quarter of 2017 from 1.6 in May 2017. In absolute terms, the TTF/Henry Hub differential increased to 2.6 USD/mmbtu in the third quarter, up from an average 2.0 USD/mmbtu in the previous quarter.

**Figure 17. International comparison of wholesale gas prices**

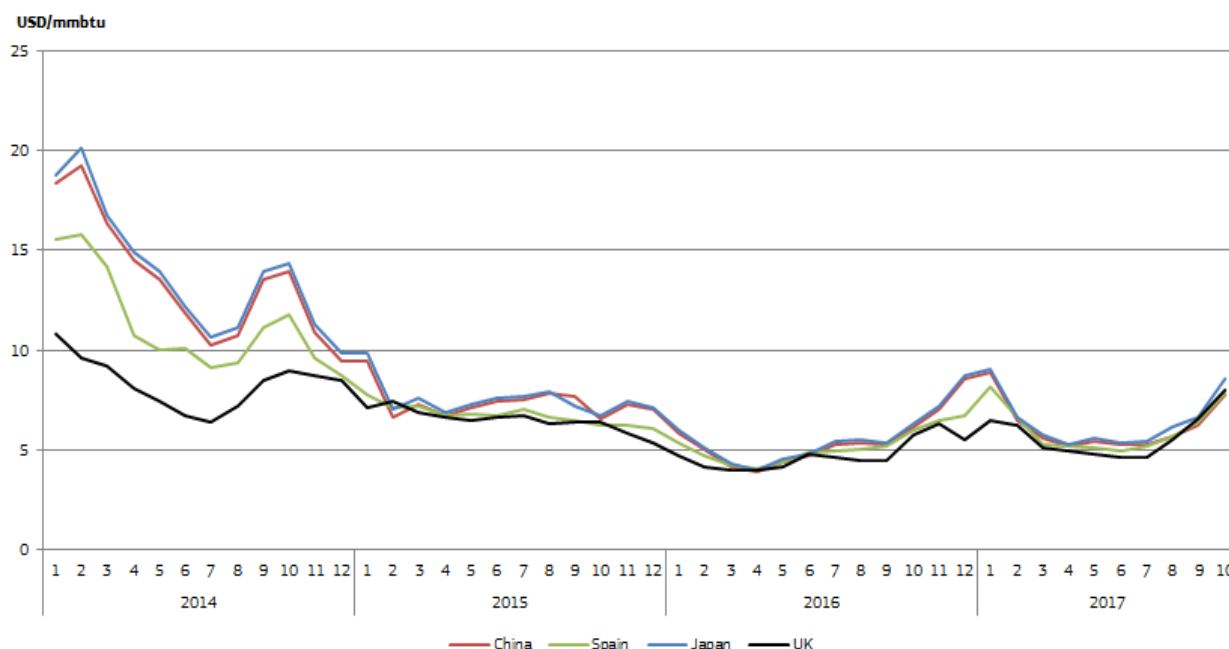


Sources: Platts, Thomson-Reuters, BAFA

## 2.2.1 LNG markets

- Spot LNG prices decreased significantly in 2014 and early 2015 in both Asia and Europe, driven by weak demand in Asia and increasing global supplies, and compounded by the fall of oil prices. The decrease was steeper in Asia and, as a result, the premium of Asian LNG prices over European ones, which regularly exceeded 5 USD/mmbtu in previous years, practically disappeared.
- For most of 2015 and early 2016, spot prices in Asia were higher than those in Europe and this difference increased significantly in December 2016 and January 2017, driven by high winter demand and supply outages in Asia. From February, however, prices in both Asia and Europe decreased, returning to the levels observed in July-September 2016. In the second and third quarters of 2017, there has been a clear convergence of international LNG prices, with minimal differences between Asian and European prices. In the third quarter, spot prices averaged 5.6 USD/mmbtu in the UK, 5.8 USD/mmbtu in Spain, 6.1 USD/mmbtu in Japan and 5.7 USD/mmbtu in China. JCC, the Japanese benchmark of oil-indexed LNG prices was significantly higher, averaging around 8.5 USD/mmbtu in the third quarter of 2017.
- Asian LNG demand continued to pick up: in the third quarter of 2017, imports increased by 58% in China, by 22% in Korea, by 3% in India, while deliveries to Japan decreased by 5%, all compared to the same period in 2016. Latin American imports increased by 19% year-on-year.<sup>24</sup>
- The planned phase-out of both coal and nuclear (which together cover 70% of electricity generation) from the Korean power sector, announced by the country's new president, will be a gradual process, taking place over decades and is expected to benefit LNG, the consumption of which could rise by up to 50% by 2030.<sup>25</sup> Today, Korea is the world's second-largest LNG importer.
- The ongoing diplomatic crisis between Qatar on the one hand and Saudi Arabia, the United Arab Emirates (UAE), Bahrain and Egypt on the other had no significant impact on Qatari LNG supplies and on LNG prices. Some analysts actually believe that the dispute may benefit the global LNG market by forcing Qatar to increase production and offer more flexible and cheaper contracts.<sup>26</sup>
- While US exports to the EU reached record levels in the third quarter, total US LNG exports decreased to 3.7 bcm (of gas equivalent), around 1 bcm less than in the previous quarter. The decrease is partly explained by delays caused by the hurricanes. Latin America remained the main destination of US LNG (34%), followed by Asia (26%), the EU (23%) and the Middle East (14%). The share of the EU has significantly increased compared to the second quarter, mainly at the expense of Latin America. Looking at individual countries, the three largest buyers of US LNG were Mexico, Korea and Spain.<sup>27</sup>

**Figure 18. Spot LNG prices in the EU and Asia**



Note: Landed prices for LNG

Source: Thomson-Reuters Waterborne

<sup>24</sup> Source: Commission calculations based on tanker movements reported by Thomson Reuters

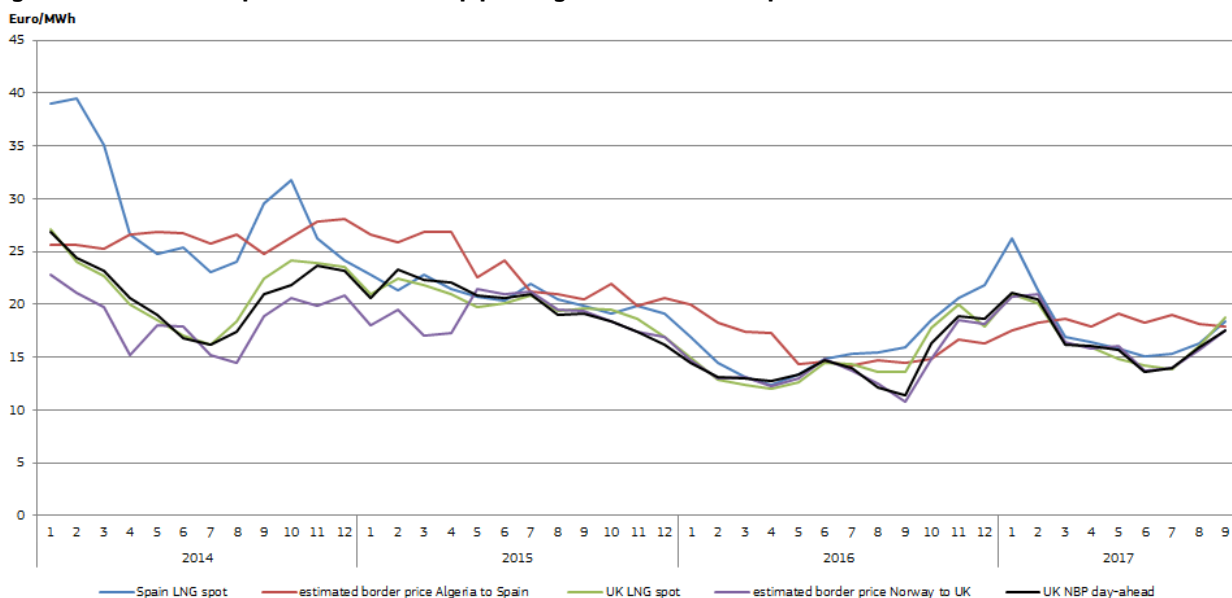
<sup>25</sup> Platts Energy Economist, September 2017

<sup>26</sup> ICIS European Gas Markets, 17 July 2017

<sup>27</sup> Source: Commission calculations based on tanker movements reported by Thomson Reuters

- In Australia, to address concerns that the eastern part of the country could face gas shortages in the coming years, possibly triggering LNG export restrictions, the federal government agreed with the three largest LNG exporters of the region that the companies will offer to the domestic market the gas that was identified as the expected demand shortfall. The exporters stated that they will offer domestic customers any uncontracted gas in the future as a priority.<sup>28</sup>
- Considering the large amount of LNG capacity – including the addition of new capacity in Qatar around 2022-2024 (see details in the previous report) – to come online in the coming years, LNG prices are generally expected to remain low. As a result, developers cancel or delay the construction of new liquefaction capacity. For example, Canada's proposed Pacific NorthWest LNG project was cancelled in July.<sup>29</sup> Hardly any new projects have been sanctioned in 2017, one of them is Mozambique's Coral South Floating LNG project led by Eni which is due to begin production in 2022, three years later and with a smaller production capacity than originally planned.<sup>30</sup> On the other hand, the prospect of abundant and cheap LNG supply is conducive to the development of new regasification terminals, and demand is gradually expected to absorb the increasing supply. Europe's underutilised gas-fired power generation capacity could also help to absorb surplus LNG volumes from the global market in the coming years.<sup>31</sup>
- Figure 19 displays the evolution of spot LNG prices paid in the UK and Spain and estimated border prices for pipeline imports from Norway and Algeria, which account for the major part of pipeline imports in the UK and Spain, respectively. The evolution of the day-ahead prices on the UK NBP hub is also presented.
- In the UK, spot LNG prices closely follow the NBP price although, unusually, in September 2016 the average LNG price was 2.3 Euro/MWh above the average NBP price. For a long time, the estimated price of Norwegian imports was below the NBP price but the difference largely vanished from May 2015, indicating that Norwegian export prices are now clearly linked to European hub prices. In the third quarter of 2017, the estimated price of Norwegian imports was on average 0.1 Euro/MWh below the NBP price while the spot LNG price was on average 0.4 Euro/MWh above the NBP price.
- In previous years, there have been seasonal differences in the price development of Algerian pipeline imports and spot LNG in Spain: LNG had a high premium during the winter months but was cheaper than Algerian pipeline gas in the summer. In the 2014-2015 winter, however, LNG prices plummeted and, until mid-2016, remained below the price of Algerian pipeline imports. From the second half of 2016, however, LNG was more expensive than the pipeline gas coming from Algeria as the price of the latter was pushed down by the lagged effect of falling oil prices while LNG prices were supported by strong Asian demand during the 2016-2017 winter. By the second quarter of 2017, however, LNG prices decreased while the price of Algerian pipeline gas recovered. In the third quarter, the estimated price of Algerian pipeline imports was on average 1.7 Euro/MWh more expensive than spot LNG prices. Gas flows reflected this price development: Spanish LNG imports gradually increased over the second and third quarters, while pipeline supplies from Algeria significantly decreased.

**Figure 19. Price developments of LNG and pipeline gas in the UK and Spain**



Note: Landed prices for LNG. Source: Platts, Thomson Reuters, European Commission estimates based on Eurostat COMEXT data

<sup>28</sup> <https://www.pm.gov.au/media/press-conference-deputy-prime-minister-and-minister-energy-and-environment>

<sup>29</sup> <http://www.petronas.com.my/media-relations/media-releases/Pages/article/PETRONAS-AND-PARTNERS-WILL-NOT-PROCEED-WITH-PACIFIC-NORTHWEST-LNG-PROJECT.aspx>

<sup>30</sup> Platts Energy Economist, July 2017

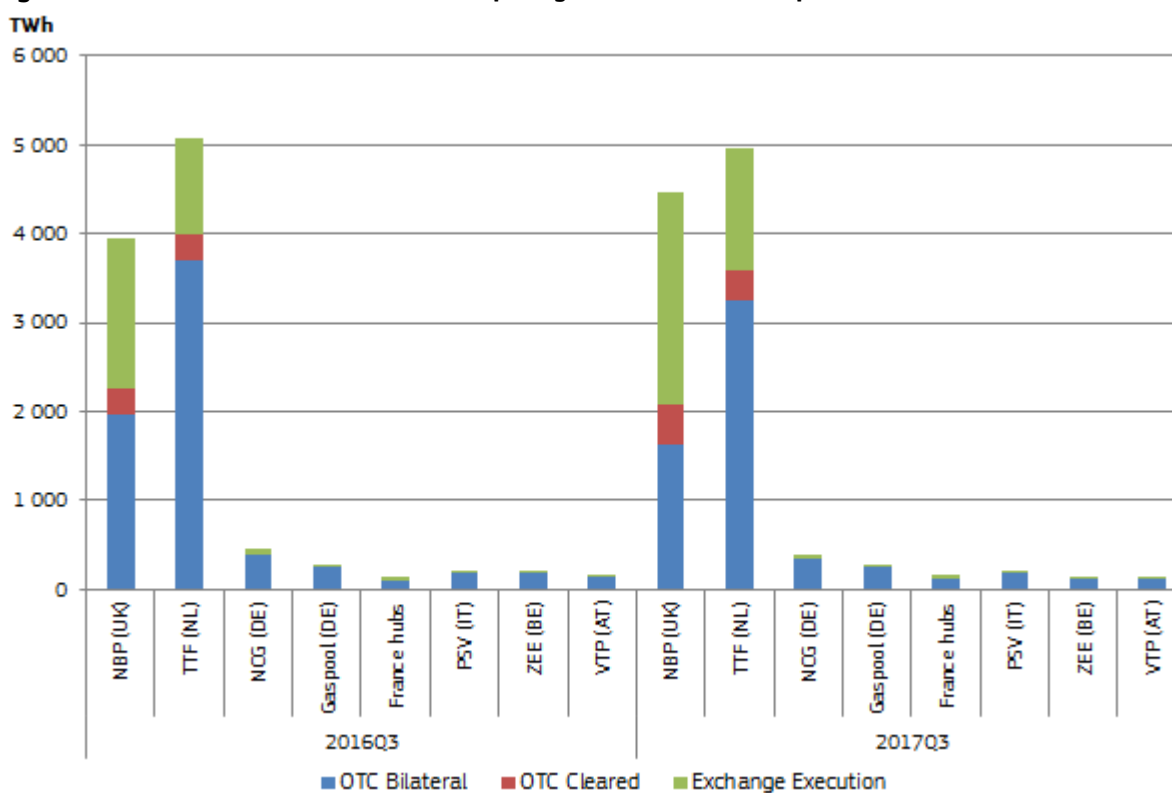
<sup>31</sup> ICIS European Gas Markets, 17 July 2017

## 2.3 European gas markets

### 2.3.1. Wholesale markets in the EU

- After decreasing in the first and second quarters of the year, liquidity on the main European gas hubs improved in the third quarter of 2017: total traded volumes amounted to around 10,700 TWh (equivalent to around 1,020 bcm or 340 bcm/month), 3% more than in the same period of 2016. Traded volumes increased year-on-year in the UK (13%), French (11%) and Italian (6%) hubs but decreased in the Netherlands (-2%), Germany (-7%), Belgium (-41%) and Austria (-1%). Increasing seasonal spreads (see chapter 1.4) contributed to the rising liquidity in the UK hub.
- Looking at the first nine months of the year, traded volumes amounted to 33,500 TWh (equivalent to around 3,200 bcm or 355 bcm/month), 7% less than in the same period of 2016. This is around 12 times more than the gas consumption of the seven Member States covered by the analysis in this period. Lower volatility and weak trade in seasonal products are some of the main reasons for smaller liquidity in 2017.
- The Dutch and UK hubs have a dominant position in the European market. In the third quarter of 2017, TTF and NBP covered 46% and 42% of hub traded volumes, respectively. Compared to the same period of the previous year, the share of TTF decreased (by 2.5 percentage points) while that of NBP increased (by 3.8 percentage points). With their decreasing trading volumes, German and Belgian hubs lost some ground compared to the third quarter of 2016: from 6.9% to 6.3% and from 1.8% to 1.0%, respectively.
- On the UK NBP hub, 53% of total traded volumes were executed directly on an exchange in the third quarter of 2017. This share was 28% on the Dutch TTF hub, 25% at the French hubs, 18% at the Austrian hub, 11% at the German hubs, 5% at the Italian hub and less than 1% at the Belgian hub. Compared to the same period of the previous year, the share of exchange trade increased by 12 percentage points at the Austrian hub and by 10 percentage points at the UK hub. On the other hand, this share decreased by 3 percentage points at both the Belgian and French hubs.
- At EU level, OTC markets remained the main trading venue but their share decreased from 72% in the third quarter of 2016 to 64% in the same period of 2017. 12% of OTC volumes were cleared at a clearing house in the third quarter of 2017, up from 8% in the same period of the previous year.

**Figure 20. Traded volumes on the main European gas hubs in the third quarter of 2016 and 2017**

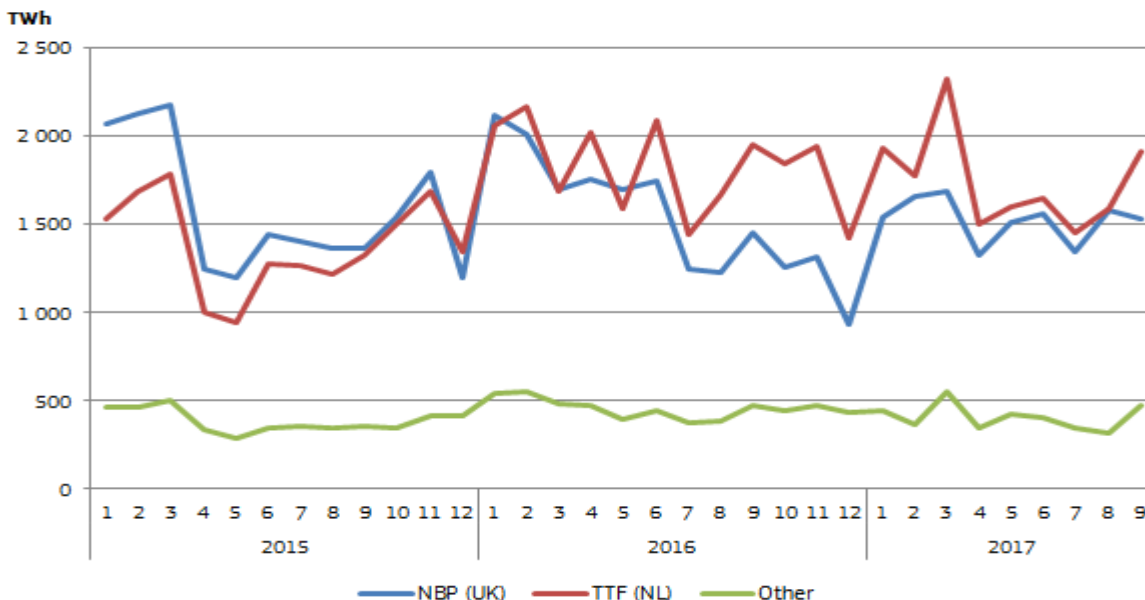


The chart covers the following trading hubs: UK: NBP (National Balancing Point); Netherlands: TTF (Title Transfer Facility); Germany: NCG (NetConnect Germany) and Gaspool; France: PEG (Point d'Echange Gaz); Italy: PSV (Punto di Scambio Virtuale); Belgium: Zeebrugge beach, Austria: Virtual Trading Point (VTP).

Source: Trayport Euro Commodities Market Dynamics Report

- As Figure 21 shows, TTF firmly overtook NBP from the second half of 2016. After the Brexit referendum of 23 June 2016, the volatility of the GBP/EUR exchange rate increased, adding risk to the trade at the UK hub. In addition to the advantage of euro-denomination, the Dutch hub also benefits from its good connection to various supply sources (including domestic production and storage). Liquidity at NBP recovered to some degree in 2017 but, since June 2016, trading volumes at the TTF have been consistently exceeding those at the NBP.
- NBP and TTF continue to overshadow the other European hubs which failed to increase their combined market share over the last three years.

**Figure 21. Traded volumes on the main European gas hubs in 2015-2017**



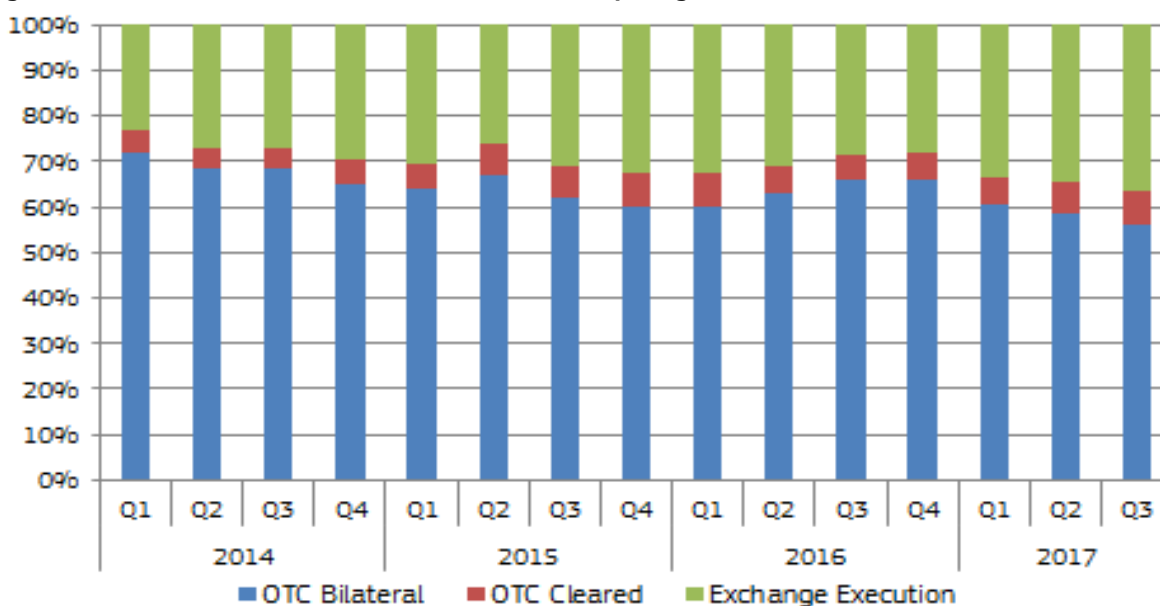
"Other" includes the following trading hubs: Germany: NCG (NetConnect Germany) and Gaspool; France: PEG (Point d'Echange Gaz); Italy: PSV (Punto di Scambio Virtuale); Belgium: Zeebrugge beach.

1 bcm is equivalent to 10.647 TWh.

Source: Trayport Euro Commodities Market Dynamics Report

- Since 2014, exchanges gradually gained ground: their share from total trading volumes was 37% in the third quarter of 2017, compared to 28% in the same period of 2016. The share of cleared OTC volumes was 8% of total traded volumes in the third quarter of 2017, up from 6% a year earlier.

**Figure 22. The share of traded volumes on the main European gas hubs**



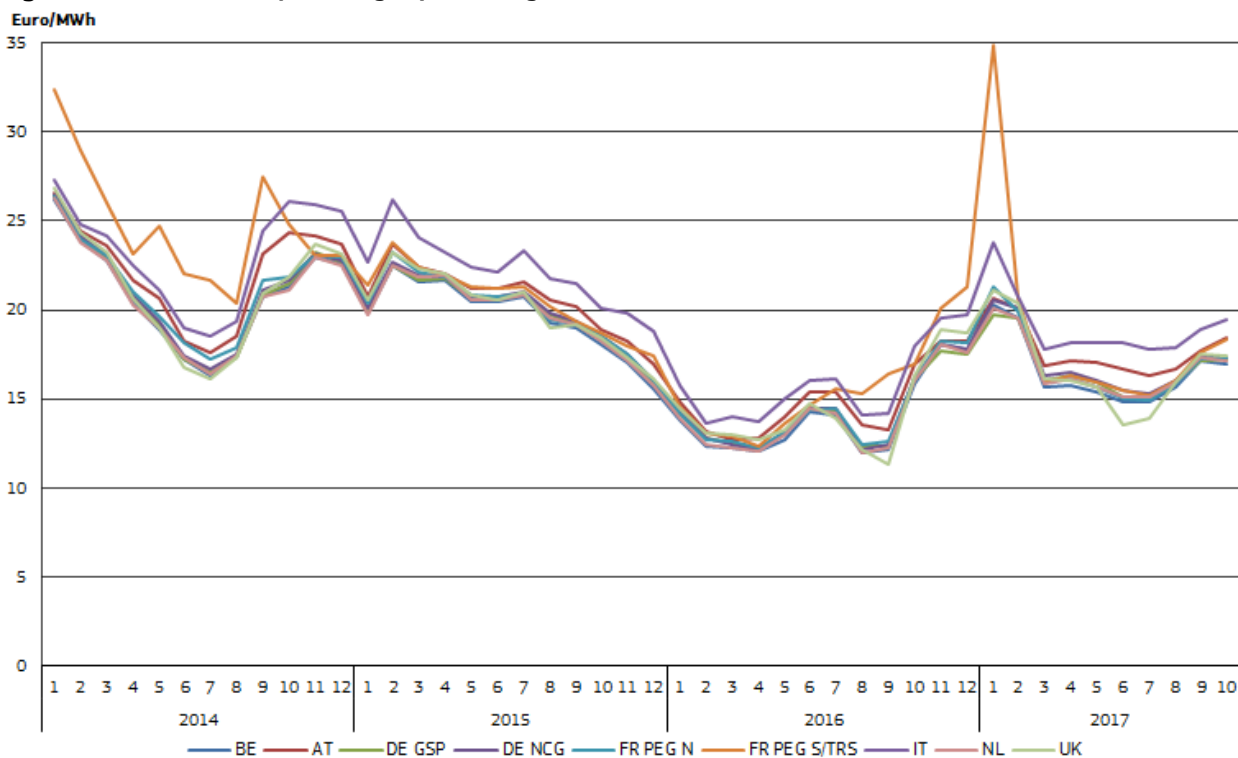
The chart covers the following trading hubs: UK: NBP (National Balancing Point); Netherlands: TTF (Title Transfer Facility); Germany: NCG (NetConnect Germany) and Gaspool; France: PEG (Point d'Echange Gaz); Italy: PSV (Punto di Scambio Virtuale); Belgium: Zeebrugge beach.

Source: Trayport Euro Commodities Market Dynamics Report

### 2.3.2. Wholesale price developments in the EU

- European hub prices significantly increased between September 2016 and January 2017, supported by cold weather (especially when compared to the previous year), strong demand in the power sector, depleting stocks, the outages of several French nuclear reactors, low LNG imports in Northwest Europe and uncertainty about the Rough storage site in the UK. In February 2017 and especially March 2017, relatively mild weather and growing LNG imports helped prices to reverse. In the second quarter, prices were relatively stable, with a slow decrease in May and June, helped by higher temperatures and rising LNG imports.
- Prices started to rise again from August, driven by a variety of factors, including relatively low storage levels, continuing coal-to-gas switching, rising oil and coal prices, cooling temperatures, Norwegian outages and persistent concerns about French nuclear availability. In the third quarter, European hub prices averaged around 16-17 Euro/MWh, roughly 20% more than in the same period of 2016.

**Figure 23. Wholesale day-ahead gas prices on gas hubs in the EU**



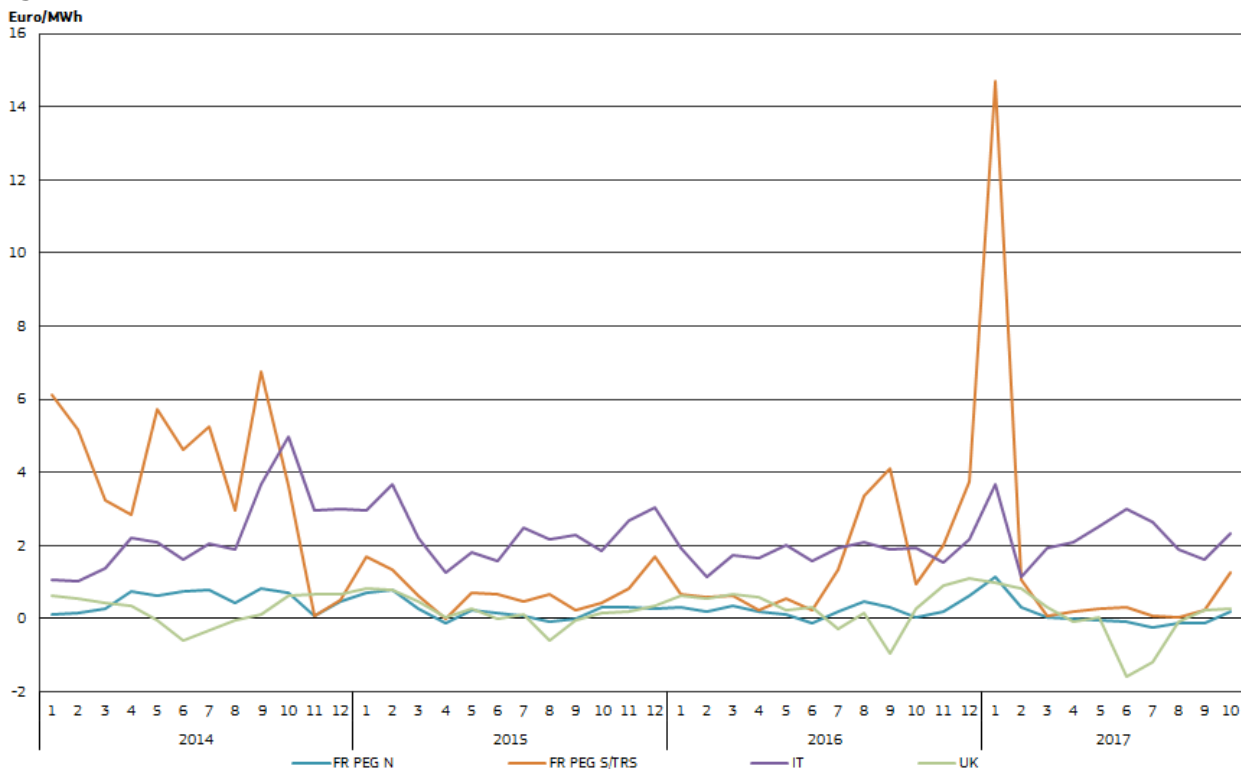
Source: Platts

- Since 2016, prices at the UK gas hub are increasingly disconnected from mainland hubs, showing a distinct seasonality. During the past winter, gas at the UK hub traded at an usually high price compared to mainland Europe: in the November 2016-February 2017 period, the average difference compared to the Dutch TTF hub was nearly 1.0 Euro/MWh (see Figure 24). Low stock levels after the outage of the Rough site, the UK's largest storage facility and low LNG imports caused supply tightness in the UK and the country had to rely more on pipeline imports from Norway and mainland Europe. Increased import flows were fostered by the relatively high prices in the UK.
- The trend turned with the arrival of summer: in June and July 2017, gas at the UK hub traded on average 1.4 Euro/MWh cheaper than at the Dutch hub. With no injection demand at Rough and ample imports, the UK market was oversupplied, putting pressure on day-ahead prices. The Belgium-UK Interconnector was closed for annual maintenance between 14 and 28 June; as the surplus gas could not leave the country, the discount of NBP to TTF reached up to 5.0 Euro/MWh in this period. NBP continued to trade at a discount to TTF in July and, to a lesser extent, in August (when outages in UK and Norwegian offshore infrastructure drove the NBP higher), driving record volumes of exports to mainland Europe on the Interconnector pipeline. From September, the NBP price again exceeded the TTF price. As imports from Norway decreased because of outages, exports to Belgium also declined.
- Prices at the Italian PSV hub remained relatively high in the third quarter of 2017, with an average premium of 2.0 Euro/MWh above TTF, the Dutch hub. High summer temperatures, low hydro levels, reduced imports from North Africa and the planned maintenance of the pipelines coming from Austria and Switzerland provided support to Italian prices in this period.



- In France, the premium of TRS over PEG Nord reached exceptional levels in January 2017 when high seasonal demand coupled with low LNG imports (and the persistent capacity restrictions on the north-south pipelines within France) caused supply tightness in the southern part of the country.<sup>32</sup> Since then, the premium of TRS over PEG Nord has practically disappeared. In the third quarter of 2017, TRS traded only 0.3 Euro/MWh above PEG Nord on average. In this period, the average price at the PEG Nord hub was slightly lower than at TTF, helped by low summer demand and a high level of LNG imports to the terminals in northern France.
- French market players are preparing for the creation of a single gas market area from 1 November 2018. The future single marketplace, named Trading Region France (TRF), will be a single Entry/Exit zone made up of two balancing zones (one for TIGF and one for GRTgaz) and a virtual Gas Exchange Point (GEP). To facilitate the merger of the two French hubs, two infrastructure upgrade projects have been started which should help to reinforce the gas network and debottleneck France's north-south link.<sup>33</sup>

**Figure 24. The premium of wholesale day-ahead gas prices at selected hubs compared to TTF**



Source: Platts

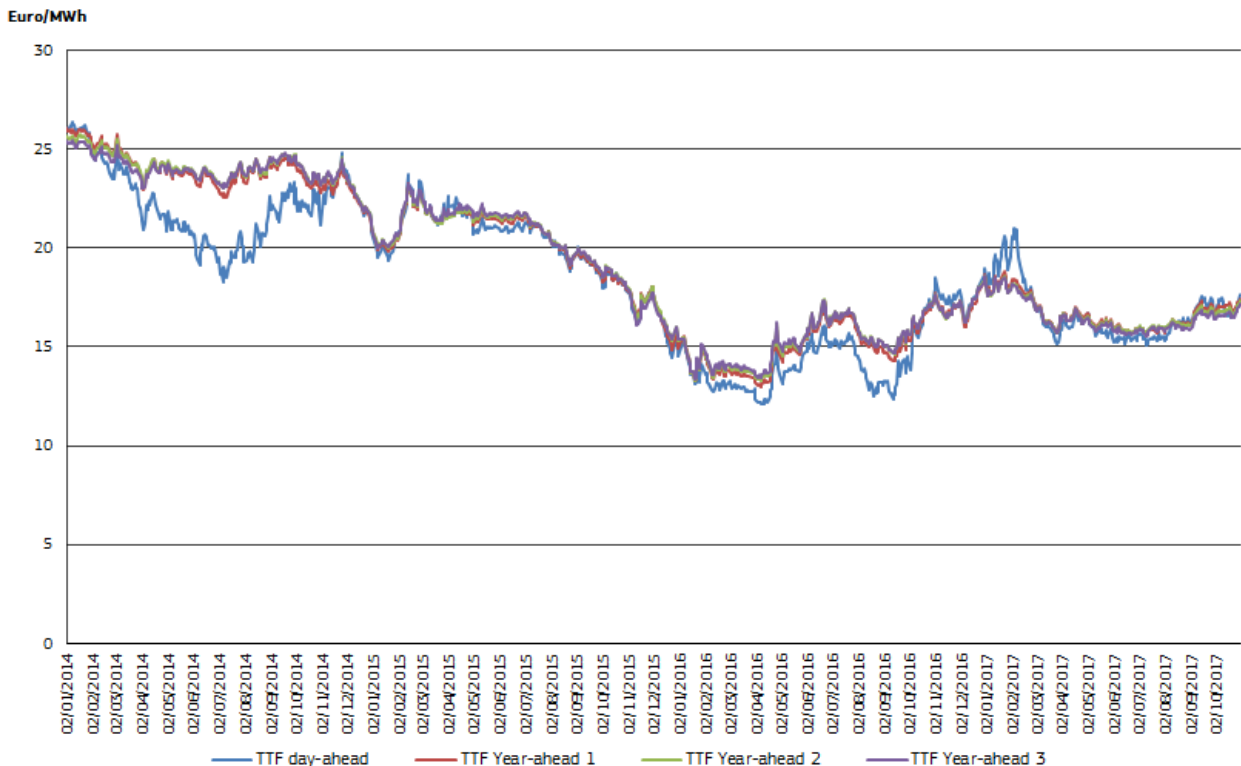
- Figure 25 looks at the development of forward prices one, two and three years ahead in comparison to the development of the day-ahead price on the Dutch TTF. For most of 2014, there has been a situation of contango<sup>34</sup>, whereby closer to the present date prices are lower than prices for future deliveries. With seasonally high stock levels and ample physical supply, spot prices significantly decreased in the first half of the year, while higher forward prices reflected the general uncertainty about future developments, in particular the Russia-Ukraine conflict.
- Day-ahead and forward prices have been more or less at parity in 2015 but in 2016 the forward curve moved higher. In 2016, the year-ahead price was on average 0.7 Euro/MWh higher than the day-ahead price but in certain days of August the difference exceeded 2 Euro/MWh. In this period, the oil price rise which started in late January 2016 provided support to forward prices.
- In the last quarter of 2016, this premium of forward prices over day-ahead prices have practically disappeared. In fact, from mid-October 2016 to mid-February 2017, day-ahead prices have been consistently higher than year-ahead prices. In January-February 2017, the difference averaged 1.0 Euro/MWh as day-ahead prices were supported by below-average temperatures while a looming LNG oversupply put pressure on forward prices. From March, the difference between day-ahead and year-ahead prices has decreased, and by the third quarter has practically disappeared: in this period, year-ahead prices were on average 0.1 Euro/MWh higher.

<sup>32</sup> See more details in a recent study on the early 2017 cold spell at [https://ec.europa.eu/energy/sites/ener/files/documents/platts\\_report\\_final\\_version\\_rrr.pdf](https://ec.europa.eu/energy/sites/ener/files/documents/platts_report_final_version_rrr.pdf)

<sup>33</sup> <https://www.tigf.fr/en/press-resources/news/2017/summer-2017-a-crucial-step-halfway-to-the-single-marketplace.html>

<sup>34</sup> See the glossary for a definition of contango

**Figure 25. Forward gas prices on the Dutch gas hub**

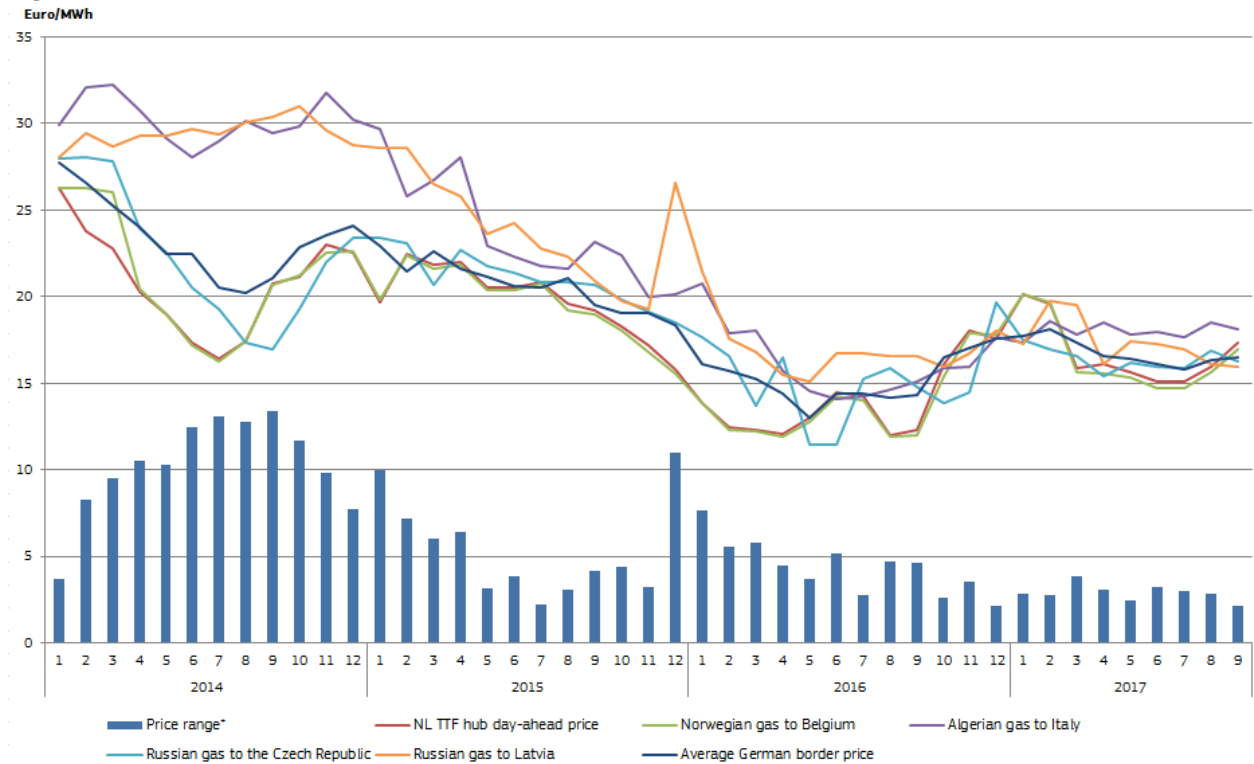


Source: Platts

### 2.3.3. Comparing the prices of different contracts for gas in the EU

- Figure 26 compares a selection of estimated border prices of gas deliveries from the main exporters to the EU: Russia, Norway, and Algeria. For comparison, the evolution of the day-ahead prices on the Dutch TTF hub is also presented.
- In 2014, the development of hub-based prices has clearly diverged from that of oil-indexed prices, with the difference between the two reaching up to 13 Euro/MWh during the year. Since then, there has been a gradual price convergence, helped by significantly falling oil prices in the second half of 2014 and in 2015. Moving towards more competitive pricing by certain producers (e.g. introducing a hub element into the pricing formulas) also contributed to converging prices.
- For most of the time, the typically oil-indexed prices of Russian gas to Latvia and Algerian gas to Italy remained higher than hub-based prices but in 2017 the difference decreased to 2-3 Euro/MWh. In exceptional cases, e.g. in January 2017, oil-index prices were lower than hub-based prices.
- During the 2016-2017 winter, the different prices had been rather volatile, often moving in the opposite direction. After relatively stable prices in the May-July period, hub-based prices started to increase while oil-indexed prices stabilised or even decreased. As a result, prices showed further convergence. In September, the difference between the highest and lowest price depicted in Figure 26 decreased to 2.2 Euro/MWh, the lowest level since December 2016.

**Figure 26. Comparison of EU wholesale gas price estimations**

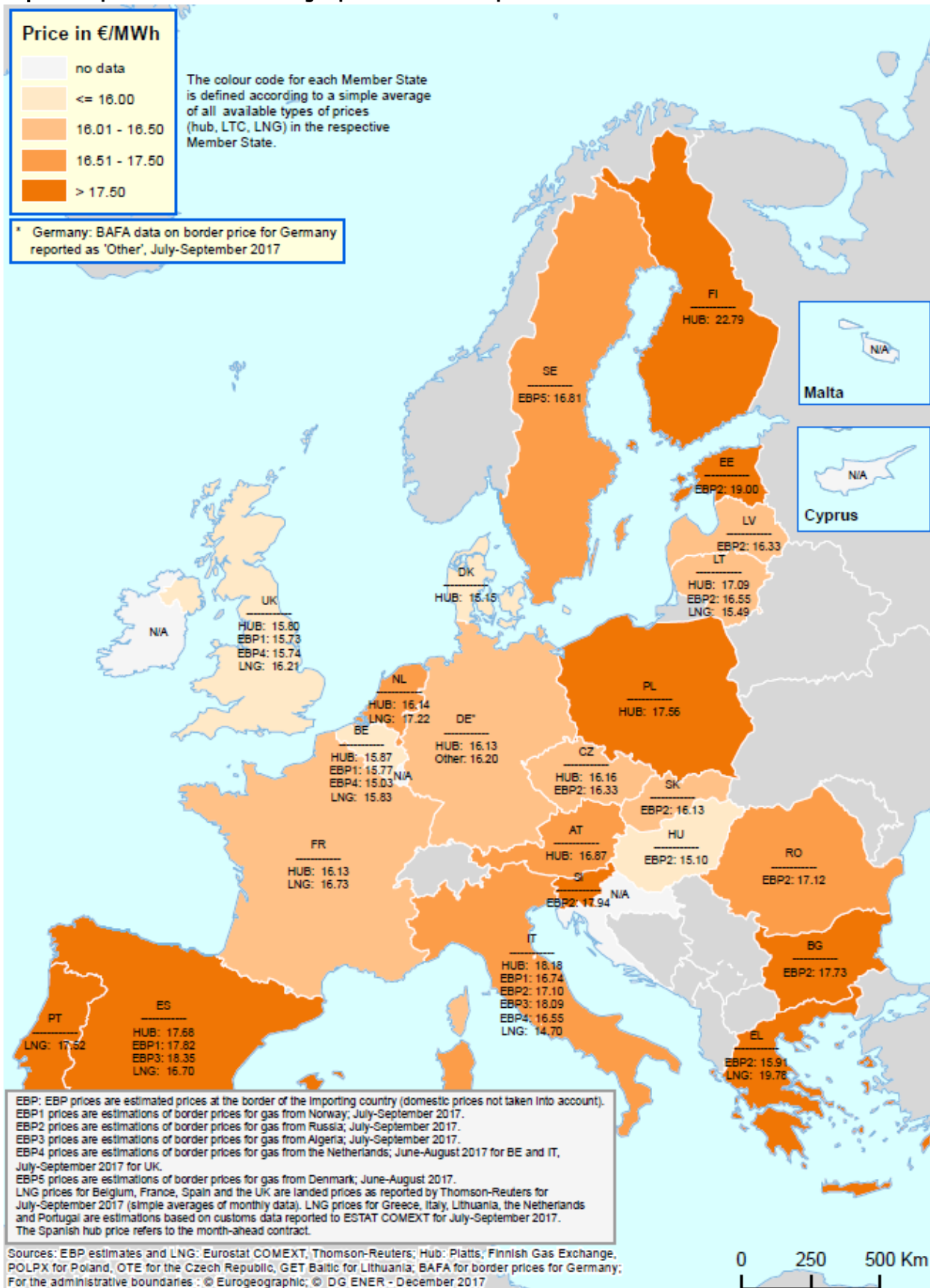


Source: Eurostat COMEXT and European Commission estimations, BAFA, Platts

\*The difference between the highest and lowest price depicted on the graph

Note: Border prices are estimations of prices of piped gas imports paid at the border of the importing country, based on information collected by customs agencies, and are deemed to be representative of long-term contracts.

**Map 1. Comparison of EU wholesale gas prices in the third quarter of 2017**

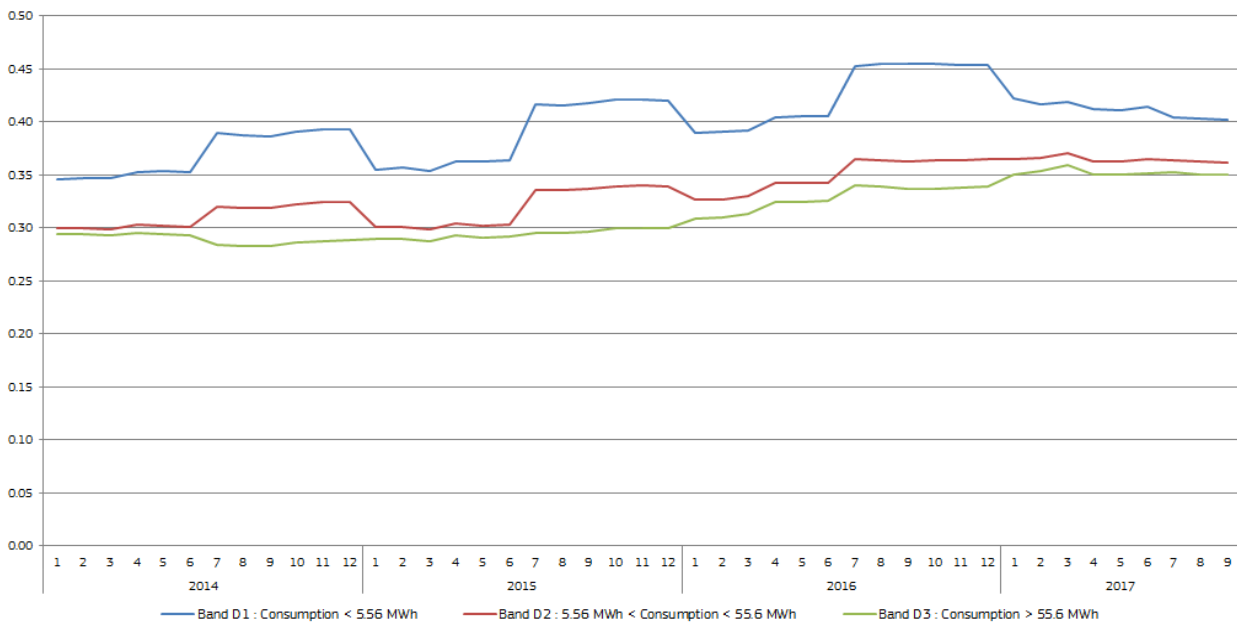


Note: Border prices are estimations of prices of piped gas imports paid at the border of the importing country, based on information collected by customs agencies, and are deemed to be representative of long-term gas contracts.

### 3. Retail markets in the EU

- Figures 27 and 29 show the degree of convergence of retail gas prices for household and industrial consumers, using as a metric the relative standard deviation of the prices in individual Member States. Monthly retail prices are estimated by using half-yearly prices from Eurostat (with the latest available figures relating to the first half of 2017) and Harmonised Consumer Price Indices (HICP) for the household prices and Producer Price Indices (PPI) for industrial consumers.
- For household consumers, the estimated average retail price (including all taxes) showed an increasing trend between 2010 and 2014 and has been decreasing since then. In the most typical consumption band, D2, the estimated average price (including all taxes) in the third quarter 2017 was 6.44 Eurocents/kWh, 1% more than a year earlier. In most Member States the estimated price actually decreased in this period but Bulgaria, Denmark and Estonia experienced a double-digit growth of the estimated price. (See the estimated household prices on Map 2.)
- In contrast to converging wholesale prices, retail prices for households show a slightly diverging trend, as shown by the increase of the relative standard deviation in 2014-2016 in Figure 27. In 2017, the standard deviations stabilised or – in case of band D1 – even decreased, indicating that the diverging trend has come to an end. Observed price differences are higher for the consumers with lower annual consumption.
- There are still significant differences in retail gas prices across the EU: in the third quarter of 2017, the estimated household price in consumption band D2 varied between 3.23 Eurocent/kWh in Romania and 12.12 Eurocent/kWh in Sweden, resulting in a price differential ratio of 3.8 between the cheapest and the most expensive Member State. This ratio decreased from 4.8 in March 2012 to 3.4 in February 2016 but has slightly increased since then.

**Figure 27. Relative standard deviation of gas prices paid by household consumers in EU Member States**



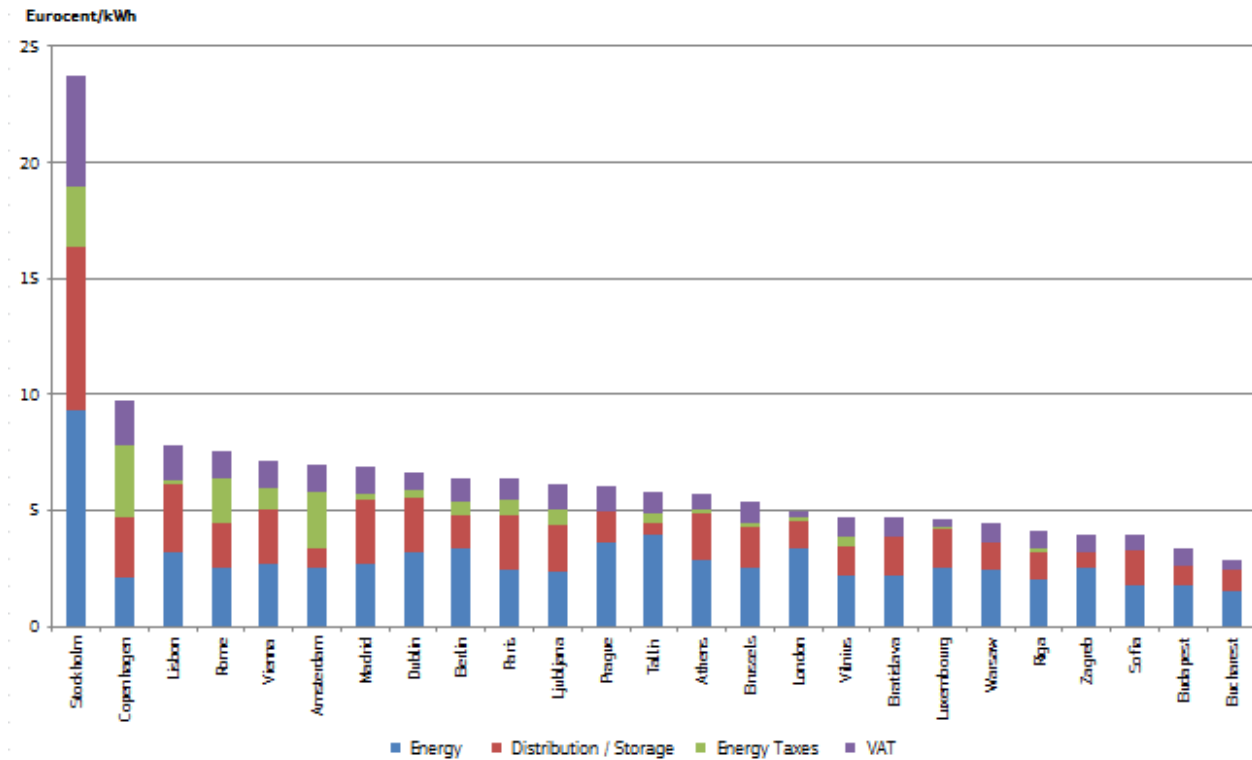
Note: all taxes included.

Source: European Commission estimates based on Eurostat data on consumer prices adjusted by the HICP

- Figure 28 shows the level and the breakdown of residential end-user gas prices paid by typical households in 25 European capitals in September 2017. On average, 45% of the price covered the energy component, while the rest covered distribution/storage costs (29%), energy taxes (10%) and VAT (17%).<sup>35</sup>
- There are significant differences across Member States, with the share of energy cost ranging from 21 to 68%, the share of distribution/storage costs ranging from 8 to 40% and the share of taxes ranging from 8 to 52%. In Amsterdam and Copenhagen, taxes make up more than half of the price while in London and Luxembourg their share is less than 10%. For 7 of the 25 capitals covered, the price does not include an energy tax component.
- In 18 of the 25 capitals, prices were higher in September 2017 than a year earlier, with the biggest increases in Tallinn (48%) and Riga (12%). At the other end of the spectrum, prices decreased by 6% in Lisbon and by 4% in Berlin.

<sup>35</sup> Note that these are arithmetic averages.

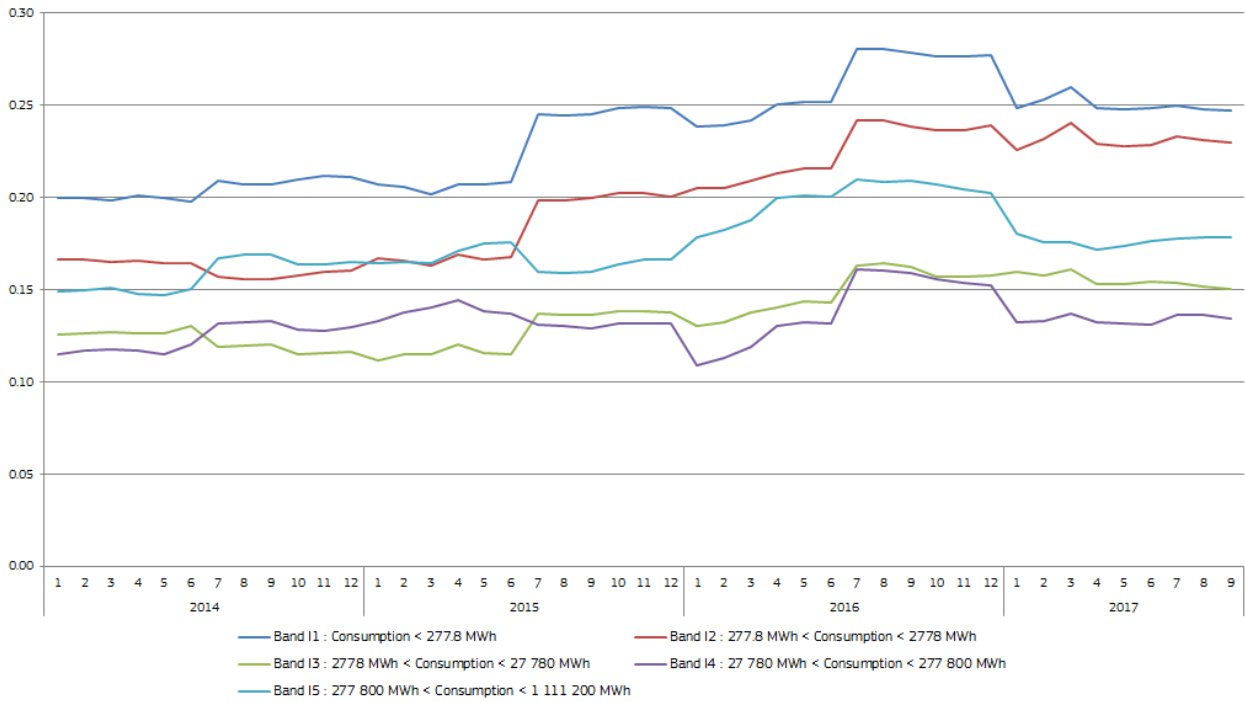
**Figure 28. The breakdown of gas price paid by typical household customers in European capitals, September 2017**



Source: VaasaETT

- Estimated industrial prices started to decrease already in 2014, and the trend continued in 2015-2016. In 2017, industrial prices seem to have stabilised. The average estimated price (VAT and other recoverable taxes excluded) in consumption band I4 was 2.43 Eurocent/kWh in the third quarter of 2017, 1% more than a year earlier. Prices increased in this period in around half of the Member States. Estonian (31%), Bulgarian (29%) and Lithuanian (27%) industrial consumers had to cope with the most significant year-on-year increases while the Slovakia (-9%) and Ireland (-8%) saw the biggest decreases. (See the estimated industrial prices on Map 3.)
- Figure 29 indicates that, for industrial customers, the relative standard deviation has been significantly lower than in the case of households, indicating smaller price differences across Member States. However, in most consumption bands the standard deviation grew in 2015-2016, implying that price differences increased in this period. Relative standard deviations plateaued in the second half of 2016 and decreased in 2017.
- In the third quarter of 2017, the UK had the lowest estimated industrial price in consumption band I4 (1.90 Eurocent/kWh), while the highest price was observed in Sweden (3.34 Eurocent/kWh). The price differential ratio between the cheapest and the most expensive Member State of the EU increased from 1.7 at the beginning of 2016 to 2.4 in mid-2016 but decreased afterwards, reaching 1.8 in September 2017.

**Figure 29. Relative standard deviation of gas prices paid by industrial consumers in EU Member States**

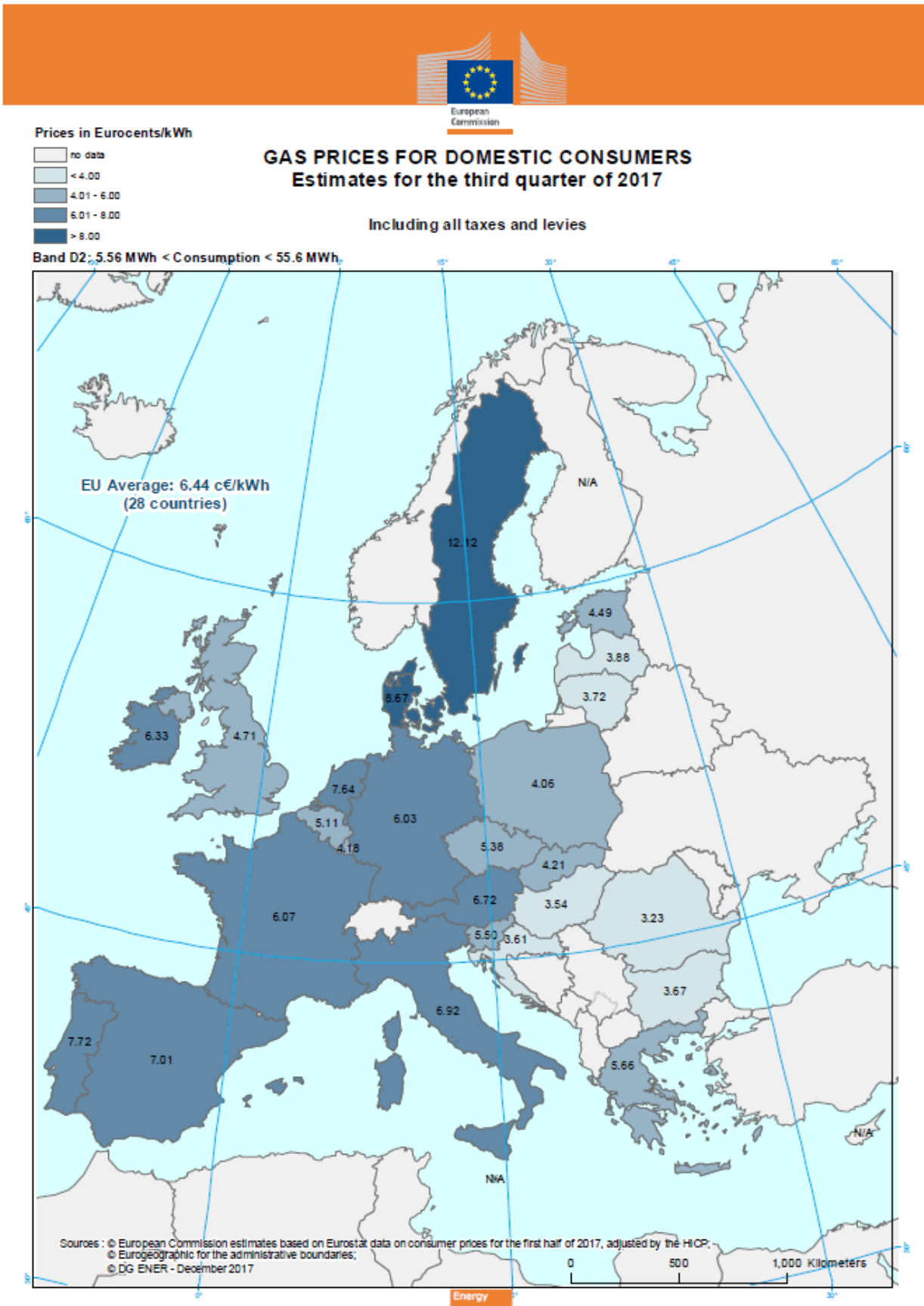


Note: Excluding VAT and other recoverable taxes.

Source of data: European Commission estimates based on Eurostat data on industrial prices adjusted by the PPI

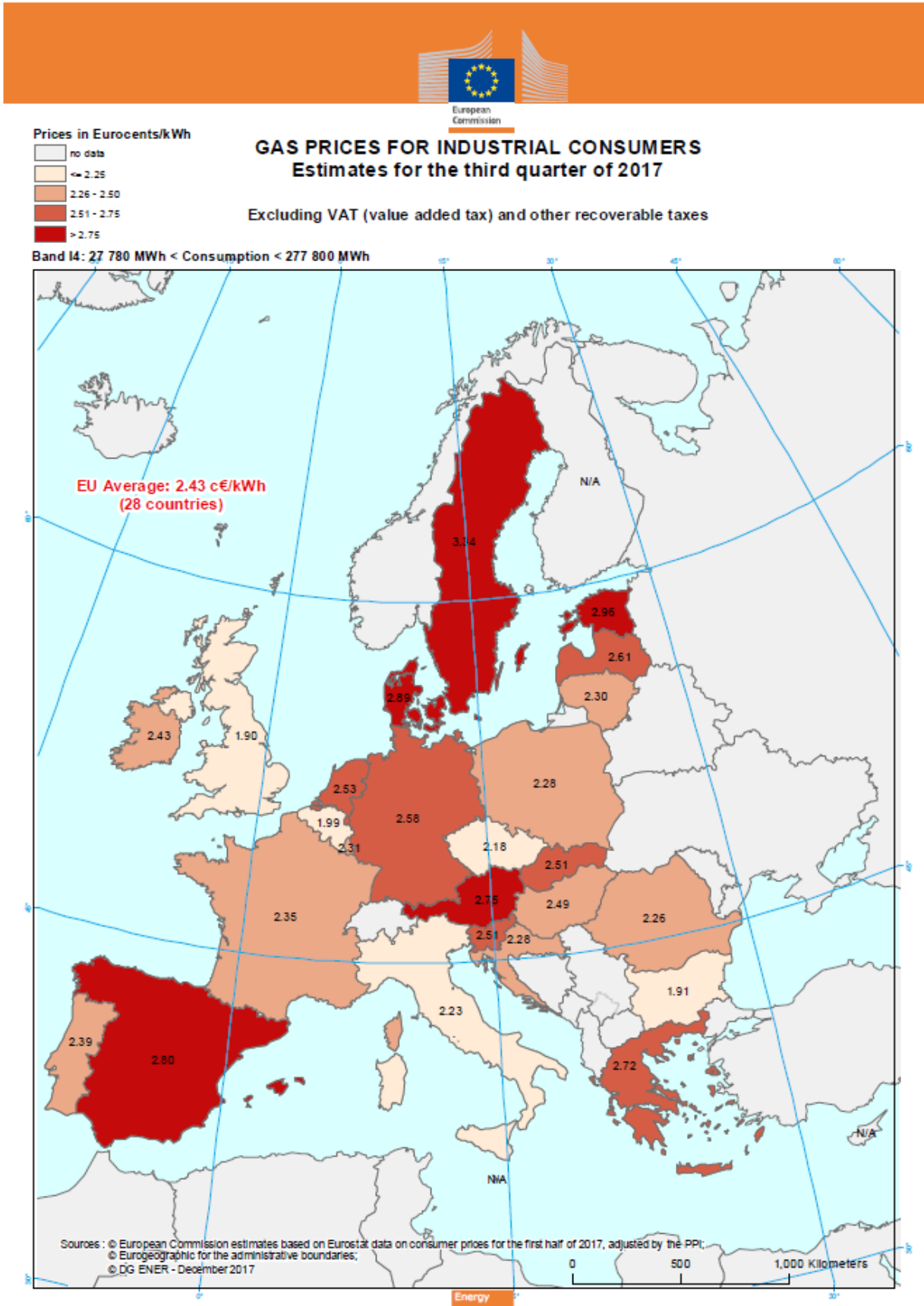
- Maps 2 and 3 show the estimated retail gas prices paid by households and industrial consumers in the third quarter of 2017.

Map 2. Retail gas price estimates for households in the EU – Third quarter of 2017





Map 3. Retail gas price estimates for industrial consumers in the EU – Third quarter of 2017



## 4. Glossary

**Backwardation** occurs when the closer-to-maturity contract is priced higher than the contract which matures at a later stage.

**Clean dark spreads** are defined as the average difference between the price of coal and carbon emission, and the equivalent price of electricity. Dark spreads are reported as indicative prices giving the average difference between the cost of coal delivered ex-ship and the power price. As such, they do not include operation, maintenance or transport costs. Spreads are defined for a coal-fired plant with 35 % efficiency. Dark spreads are given for UK and Germany, with the coal and power reference price as reported by Platts.

**Clean spark spreads** are defined as the average difference between the cost of gas and emissions, and the equivalent price of electricity. Spark spreads are indicative prices showing the average difference between the cost of gas delivered on the gas transmission system and the power price. As such, they do not include operation, maintenance or transport costs. The spark spreads are calculated for gas-fired plants with standard efficiencies of 50% and 60%. This report uses the 50% efficiency. Spreads are quoted for the UK, German and Benelux markets.

**Contango:** A situation of contango arises in the when the closer to maturity contract has a lower price than the contract which is longer to maturity on the forward curve.

**Flow against price differentials (FAPDs):** By combining daily price and flow data, Flow Against Price Differentials (FAPDs) are designed to give a measure of the consistency of economic decisions of market participants in the context of close to real time operation of natural gas systems. With the closure of the day-ahead markets (D-1), the price for delivering gas in a given hub on day D is known by market participants. Based on price information for adjacent areas, market participants can establish price differentials. Later in D-1, market participants also nominate commercial schedules for day D. An event labelled as an FAPD occurs when commercial nominations for cross border capacities are such that gas is set to flow from a higher price area to a lower price area. The FAPD event is defined by the minimum threshold of price difference under which no FAPD is recorded. The minimum threshold for gas is set at 0.5 Euro/MWh. After the day ahead market closes, market participants still have the opportunity to level off their positions on the balancing market. That is why a high level of FAPD does not necessarily equate to irrational behaviour. In addition, it should be noted that close-to real time transactions represent only a fractional amount of the total trade on gas contracts. The FAPD chart provides detailed information on adverse flows. It has two panels: The first panel estimates the ratio of the number of days with adverse flows to the total number of trading days in a given period. It also estimates the monetary value of energy exchanged under adverse flow conditions (mark-up) compared to the total value of energy exchanged across the border. The mark-up is also referred to as "welfare loss". A colour code informs about the relative size of FAPD events in the observed sample, going from green if less than 10% of traded days in a given period are FAPDs to red if more than 50% of the days are FAPDs. The second panel gives the split of FAPDs by sub-category of pre-established intervals of price differentials. It represents the average exchanged energy and relative importance of each sub-category on two vertical axes.

**Heating degree days (HDDs)** express the severity of a meteorological condition for a given area and in a specific time period. HDDs are defined relative to the outdoor temperature and to what is considered as comfortable room temperature. The colder is the weather, the higher is the number of HDDs. These quantitative indices are designed to reflect the demand for energy needed to heat a building.

**Relative standard deviation** is the ratio of standard deviation (measuring the dispersion within a statistical set of values from the mean) and the mean (statistical average) of the given set of values. It measures in percentage how the data points of the dataset are close to the mean (the higher is the standard deviation, the higher is the dispersion). Relative standard deviation enables to compare the dispersion of values of different magnitudes, as by dividing the standard deviation by the average the impact of absolute values is eliminated, making possible the comparison of different time series on a single chart.

**LNG sendout** expresses the amount of gas flowing out of LNG terminals into pipelines.

