

Quarterly Report

on European Gas Markets

with focus on the European barriers in retail gas markets

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HIGHLIGHTS OF THE REPORT

- In spite of new lockdown measures in many EU countries and other parts of the world, in Q4 2020 energy markets, including natural gas and oil markets, were generally in positive mood and followed an upward price trajectory over the quarter. As of early November, this was reinforced by news on the availability of anti-Covid-19 vaccines, which raised expectations of the end of the pandemic crisis and recovery, implying rising demand for energy products. GDP in the EU was still down by 4.6% in Q4 2020 in year-on-year comparison in the EU.
- In the fourth quarter of 2020 **EU gas consumption went up slightly, by 1.3%** (1.5 bcm) compared to Q4 2019, after the 10% fall in the second quarter and stagnation in the Q3 2020. Consumption of gas was limited by relatively mild weather in Q4 2020, however, the widespread practice of teleworking might have contributed to the overall increase, in the residential sector. Gas consumption in Q4 2020 was 119.2 bcm, up from 117.7 bcm in Q4 2019. In 2020, consumption of natural gas amounted to 394 bcm, down from 406 bcm (by 3%, and 12 bcm) in 2019.
- Indigenous gas production in the EU, amounting to 14 bcm in Q4 2020, was down by 15% (2.4 bcm) compared to Q4 2019. In Q4 2020 the Netherlands produced 6.2 bcm of gas, down by 17% year-on-year. The Dutch government announced that the production cap for the Groningen field is going to be halved compared to the current gas year as of October 2021. Romania produced 2.4 bcm of gas, followed by Poland (1.5 bcm) and Germany (1.1 bcm). In 2020, gas production in the EU amounted to 54 bcm, down from 70 bcm in 2019. The United Kingdom produced slightly less than 40 bcm natural gas, whereas production in Norway amounted to 112 bcm.
- EU net gas imports fell by 9% year-on-year (8.8 bcm) in Q4 2020. Russian pipeline supplies covered 49% of extra-EU net gas imports. Norwegian pipeline gas was the second most important source (22%), LNG imports together covered 18% of the total EU imports followed by pipeline imports from Algeria (10%) and Libya (1%). Net gas imports amounted to 84 bcm in Q4 2020, while in 2020 it reached 326 bcm, down from 358 bcm in 2019. If pipeline and LNG supplies are also taken into account, in 2020 Russian gas ensured 48% of the total extra-EU imports, followed by Norway (24%), LNG from non-Russian, Norwegian and Algerian sources (18%), Algeria (9%) and Libya (1%). In 2020, the total gas import bill was €36.5 billion, down from €59.4 billion in 2019.
- Nord Stream remained the most important supply route of Russian pipeline gas to the EU in Q4 2020, having a share of 37% in the Russian pipeline imports (15 bcm transit), the Ukrainian transit route re-emerged to the second place (34%, 14 bcm), and the Belarus transit came to the third place, with 25% (10 bcm), ahead of Turk Stream (4%, around 2 bcm). In 2020 52 bcm gas was transited through Nord Stream, around 38 bcm gas was transited through Ukraine with EU destination, 33 bcm though the Yamal pipeline (Belarus) and only 5 bcm through the Turk Stream. Decrease in EU Russian gas imports mainly impacted the Ukrainian transit route.
- The new **Trans Adriatic Pipeline**, being part of the Southern Gas Corridor and providing access to Azeri gas sources, began operations in November 2020 and the first gas shipments were delivered to Italy on 30 December 2020. The pipeline is to deliver 10 bcm gas per year, principally to Italy, Greece and Bulgaria. The importance of Turk Stream is to increase in Russian gas supply to the Balkans, as the new Bulgaria-Serbia gas interconnector became operational since January 2021.
- EU LNG imports fell by 27% year-on-year in Q4 2020, owing to increasing Asian wholesale gas market price premiums to Europe, which resulted in cargo redirections towards the Asian markets. Russia, the US and Qatar had almost equal shares in the extra-EU LNG supply (17 bcm). In 2020, the total EU LNG imports amounted to 84 bcm, down from 88 bcm in 2019. The biggest EU LNG consumers were: Spain (21 bcm), France (20 bcm), Italy (12 bcm), Netherlands (8 bcm) and Belgium (7 bcm). The United States supplied 19 bcm of LNG to the EU, followed by Qatar (18 bcm) and Russia (17 bcm). In global comparison the EU was the third biggest LNG market after Japan (102 bcm) and China (91 bcm) in 2020.
- Gas traded volumes on the European hubs was up by 21% (plus 3 439 TWh) in Q4 2020 year-on-year, after the temporary
 decrease in the previous quarter. In spite of falling LNG imports, storage withdrawals intensified and trading volumes were mainly
 driven by near-curve contracts on the European hub optimising seasonal storages and hedging for international players. The Dutch
 TTF remained the most liquid hub in Europe, pooling around three quarters of all European gas trade.
- **Gas storage levels in the EU fell to 74% by the end of December 2020,** which was 21% lower than at the beginning of Q4 2020, as higher spot market prices increased the competitiveness of consuming gas from storages, injected at lower costs.
- Spot prices on the European gas hubs in Q4 2020 kept on increasing and were 6-21% higher in year-on-year comparison. By the end of December 2020 the TTF spot price rose to 19 €/MWh, the highest since the beginning of 2019. As during the course of Q4 2020 the price premium of the Asian wholesale gas markets widened to Europe, reaching the highest since the end of 2018, LNG cargoes were redirected towards the more lucrative Asian markets, reducing gas supply in Europe and propelling the EU wholesale market prices.
- Retail gas prices for household customers showed a decrease of 8% year-on-year in Q4 2020, while industrial customers faced a decrease of 2% in the same period. With the exception of seven countries, gas prices for households in European capital cities were lower in February 2021 compared to a year earlier.
- Hydrogen costs base assessments show that in the Netherlands production costs of hydrogen with alkaline electrolyser technology amounted to 118 €/MWh in December 2020, whereas with polymer electrolate fuel cells the cost was assessed to 99 €/MWh, and with steam methane forming at around 48 €/MWh, if capital costs are included as well.

1. Gas market fundamentals

1.1 Consumption

EU gas consumption¹ in the fourth quarter of 2020 rose slightly, by 1.3% (1.5 bcm) in year-on-year comparison, after falling by more than 10% in Q2 2020 and practically stagnating in the third quarter of the year. In absolute numbers, the quarterly gas consumption in Q4 2020 amounted to an estimated 119.2 bcm, increasing slightly from 117.7 bcm in Q4 2019, and rising from 71.9 bcm in Q3 2020, with the onset of the heating season in October. It seems that Covid-19 related confinement measures in Q4 2020 could not impact gas consumption in such an extent as during the first wave of the pandemic in spring 2020. In electricity generation, demand for gas was slightly down, by 1.9% year-on-year (decreasing by 2.8 TWh). Weather across Europe in Q4 2020 was generally warmer than usual, impacting residential heating needs. However, widespread practice of teleworking might have contributed to the increase of natural gas consumption in the residential sector in year-on-year comparison. As Figure 1 below shows, in the fourth quarter of 2020 gas consumption in the EU was similar to that in Q4 2019, with the exception of December, when it was slightly higher, close to the upper range of the last five years. In 2020 gas consumption in the EU amounted to 394 bcm, down by 12 bcm (3%) compared to 2019.

Figure 1. EU gas consumption



Source: Eurostat, data as of 10 March 2020 from data series nrg_103m. In the next edition of this report numbers might change retrospectively



Figure 2. Year-on-year change in EU gas consumption in each quarter (%)

Source: Eurostat, data as of10 March 2020 from data series nrg_103m. In the next edition of this report numbers might change retrospectively

¹ EU aggregates, unless otherwise indicated, refer to EU-27, and in order to ensure comparability over time, values of earlier periods and year-onyear comparison indices also refer to EU aggregates without the United Kingdom. Therefore, in comparison to earlier editions, total EU aggregate numbers might differ in the current report.

- In the fourth quarter of 2020, the biggest year-on-year percentage decrease in gas consumption could be observed in Hungary (34%, by 1.1 bcm) and in Malta and Estonia (respectively representing increases of 12% and 11%, though representing marginal values, 0.01 bcm and 0.02 bcm, compared to Q4 2019). Gas consumption, measured in percentages, rose by the most in Greece (by 26%, 0.3 bcm) and in Bulgaria (by 23%, 0.2 bcm). Among the five biggest gas consumer countries, consumption went down by 7% in Spain (by 0.7 bcm), by 4% in the Netherlands (by 0.5 bcm), and by 2% in France (0.2 bcm), whereas in Italy it rose by 6% (by 1.2 bcm) and in Germany by 4% (by 1 bcm). In the remaining EU Member States, the change in gas consumption remained in the range of -10% to +10%, compared to Q4 2019. In the United Kingdom², consumption of natural gas fell by 21% (5.1 bcm) in Q4 2020 compared to the fourth quarter of 2019.
- In 2020 gas consumption in the EU was down by 3% (12 bcm). The biggest decreases could be observed in Spain (3.7 bcm, -10%), Italy (3.4 bcm, or -5%), France (3.1 bcm, -7%) Germany (2.5 bcm, -3%), compared with the same period of 2019. In the United Kingdom consumption of gas decreased by 9.4 bcm (-12%) during the same period.





Source: Eurostat, data as of 10 March 2020 from data series nrg_103m. In the next edition of this report numbers might change retrospectively.

In the fourth quarter of 2020, GDP in the EU-27 was still down by 4.6% in year-on-year comparison³, albeit the rebound in the
previous quarter in quarter and quarter comparison, the EU economy still could not get back to its pre-pandemic level. However,
natural gas consumption managed to increase in Q4 2020 year-on-year, even if GDP decreased, amid the introduction of new
confinement measures in many EU countries.

² The United Kingdom has in many respect still much relevance for the European gas market, therefore developments in this country are often mentioned in the text

³ Source: Eurostat, data as of 11 March 2020 from data series namq_10_a10; seasonally and calendar adjusted data





Source: Eurostat, data as of 11 March 2020 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 average⁴ in individual EU Member States in the fourth quarter of 2020. In most of the EU countries, the fourth quarter of 2020 was warmer than usual, implying lower heating needs in the residential sector, which translates into less demand for gas, and in countries where heating is largely based on electricity, less electricity generated from natural gas. October 2020 was milder than usual in most of the EU, with the exception of some southern countries (Spain, Italy, Portugal) where the heating season arrives a bit later in the year anyway. November 2020 was also milder than usual, with the exception of Slovakia and Slovenia, whereas Ireland was the only country where HDDs in December 2020 were higher than usual. It is worth to recall that in spite of the generally milder weather, there were some cold spells in many parts of Europe during Q4 2020, impacting demand for gas in residential heating and wholesale gas market prices.



Figure 5 Deviation of actual heating degree days (HDDs) from the long-term average in the fourth quarter of 2020 $_{\rm 150~\gamma}$

Source: Joint Research Centre (JRC), European Commission

Based on data from ENTSO-E, gas-fired power generation decreased by 1.9% in the fourth quarter of 2020 in the EU, compared to
the same period of 2019. In absolute terms, electricity generated from gas dropped by 2.8 TWh year-on-year, as Figure 6 shows. In
Q4 2020 gas wholesale prices kept on increasing and by the end of December 2020 they rose to the highest since early 2019.
Increasing gas prices were not favourable to generation costs and profitability of gas fired generation.

⁴ Long term average temperatures, heating and cooling degree days refer to the period between 1978 and 2018

- In year-on-year comparison the share of renewables in the EU power generation mix rose further in Q4 2020. Wind, solar, biomass and hydro together represented around 37% of the EU power mix (up from 35.2% in Q4 2019), leaving only a smaller share for gas (around 21%, practically unchanged year-on-year). Power generation from solid fuels extended its falling trend, decreasing by 5.8% compared the same period of 2019⁵. The share of solid fuels fell to 12.9% in Q4 2020 in the EU power mix, down from 15.2% a year earlier. Nuclear generation was slightly down by 3.3% in Q4 2020 year-on-year, and its share reached 25.2%, slightly down from 25.7% in Q4 2019. Carbon prices showed a measurable increase over the course of Q4 2020, rising from 27 €/MtCO2e to 32 €/MtCO2e, which, through increasing fossil generation costs, did not contribute either to the competitiveness of coal and lignite in EU power generation.
- In 2020, gas-fired electricity generation in the EU decreased by 3.2% (18 TWh) compared to 2019, which was a bit less than the overall decrease in power generation (4.1%), resulting in a relatively stable share of gas in the EU power mix (20.8% in 2020 vs 20.5% in 2019). The share of solid fuels fell from 15.3% to 12.6%, nuclear also went down from 26.7% to 24.8%, whereas the share of renewables rose from 34.5% to 39.1% between 2019 and 2020. Increasing carbon prices from the second half of 2020 indeed penalised coal and lignite fired generation, but owing to the uptick of gas prices in the same period, it was not natural gas, rather renewables that could increase their share in the EU electricity generation mix.
- In Q4 2020 the amount of electricity generated from gas fell in Spain by 19% in year-on-year comparison, in France and in the Netherlands it was down by 7%, and in Belgium by 6%. At the same time, gas-fired generation rose 3% in Italy and by 5% in Germany. Besides demand side factors, the share of gas was impacted by changes in the local power generation mixes. In Spain rise in electricity generation from solar, hydro and wind contributed to the replacement of gas in the local mix, whereas coal-fired generation practically halved year-on-year in Q4 2020. In France the increase in nuclear and wind power generation compensated the decrease in gas and hydro. In the Netherlands the decrease in gas and steep fall in coal-fired generation was compensated by increasing wind, biomass and solar generation. In Belgium decreasing gas and nuclear generation was partially replaced by increasing wind. In Italy the increase in gas-fired generation partially replaced dwindling coal and wind power, whereas in Germany increasing qas, and exceptionally, coal and lignite fired generation, replaced decreasing nuclear in renewable sources in Q4 2020.



Figure 6 Gas-fuelled power generation in the EU

Source: Based on data from the ENTSO-E Transparency Platform and national data sources, data as of 22 March 2021

Clean spark spreads – measuring the profitability of gas-fired generation by taking into account variable costs – reached respectively 0.9€/MWh, 0.5€/MWh and 10€/MWh in Germany, Spain and Italy in Q4 2020, which were definitely lower compared to the previous quarter values (10.7 €/MWh, 11.6 €/MWh and 14.4 €/MWh). This decrease in the clean spark spreads implied a decreasing profitability of gas-fired generation⁶ in the biggest markets of continental Europe (See Figure 7⁷). The impact of

 $^{^{5}}$ See more information in Quarterly Report on the European Electricity Markets, Vol. 13, Issue 4

⁶ Assuming an average gas power plant efficiency, see more in the Glossary

⁷ Charts of clean spark spreads can also be found in the Quarterly Report of European Electricity Markets (Vol. 13, Issue 4). Data on the share of gas in electricity generation come from the database of ENTSO-E

increase in gas prices and carbon prices in Q4 2020 was bigger than increase in wholesale electricity prices, which resulted in decreasing spreads. In Italy gas-fired generation remained more profitable compared to Germany and Spain, owing to higher local electricity wholesale prices.

In the United Kingdom, having relevance for the European gas market, clean spark spreads averaged at 5.1 €/MWh in Q4 2020, slightly lower compared to 6.4 €/MWh in the previous quarter. Increasing gas prices in the UK had bigger upward impact on wholesale electricity prices, preserving the profitability of gas-fired generation. In January 2021, albeit further increasing gas prices, clean spark spreads climbed even higher, owing to frequent price spikes on the UK wholesale electricity market. Decreasing profitability of gas-fired generation was also reflected in the UK power mix in Q4 2020, as electricity generated from gas decreased by 7% compared to Q3 2020. However, in spite of increasing clean spark spreads compared to the fourth quarter of 2019, in Q4 2020 gas-fired generation in the UK was down by 7.6% year-on-year, and the share of gas went down slightly, from 41.9% to 40.6%.



Figure 7 Clean spark spreads in Germany, Spain, Italy and the United Kingdom

Source: Bloomberg

1.2 Production

- In the fourth quarter of 2020 EU gas production reached approximately 13.7 bcm⁸, 15% (2.4 bcm) less than in the same quarter of 2019 (See Figure 8). During the whole Q4 2020, similarly to the previous three quarters, gas output was below the 2015-2019 range, reflecting the dwindling trend of gas production in the EU. Over the last seven years, total EU gas production in Q4 2020 was the second lowest quarterly figure.
- In the biggest EU producer Netherlands natural gas production in Q4 2020 decreased significantly, by 17% (by 1.3 bcm), amounting to 6.2 bcm. Production cap for the Groningen gas field is set to 8.1 bcm for the 2020 gas year (1 October 2020 to 30 September 2021), and the Dutch government recently announced that as of October 2021 the production of the current gas year could be halved.⁹
- In Romania, being the second biggest gas producer in the EU, production went down by 4% (0.1 bcm), falling to 2.4 bcm in Q4 2020, which was slightly higher than the production level of the previous quarter. Gas production decreased slightly (3%, 0.04 bcm) in Poland in Q4 2020 and amounted to 1.5 bcm. In Germany, Italy and Ireland, where production respectively amounted to 1.1 bcm, 0.9 bcm and 0.5 bcm in Q4 2020, year on year decreases varied between 17% and 25% and production went down by 0.2-0.3 bcm. Gas output in Denmark showed a very strong decrease (by 27%, 0.1 bcm year-on-year, principally owing to the redevelopment of the Tyra field in the Danish North Sea, which will come online later than expected, only in 2023). The country produced 0.3 bcm of gas in Q4 2020.

⁸ Given that in some countries data for some periods are based on estimation, this number might retrospectively change

⁹ <u>https://www.reuters.com/article/uk-netherlands-gas-groningen-idUKKBN2ABOSX</u>

- In 2020, gas production in the EU amounted to 54.4 bcm, down from 70 bcm in 2019. The Netherlands produced 24 bcm gas (vs. 33.7 bcm a year before), followed by 9 bcm in Romania (10 bcm in 2019) and by Germany (4.9 bcm vs 5.7 bcm a year before).
- Gas production in the United Kingdom amounted to 10 bcm in Q4 2020, down by 7% (0.8 bcm) than in Q4 2019, whereas in 2020 it produced 39.5 bcm, slightly less than a year before (39.9 bcm). Gas production in Norway decreased by 4%, from 30.2 bcm in Q4 2019 to 28.9 bcm in Q4 2020. In 2020, gas production in Norway reached 112 bcm, slightly down from 115 bcm in 2019.



Figure 8 Monthly gas production in the EU

Source: Eurostat, data as of 10 March 2020 from data series nrg_103m. In the next edition of this report numbers might change retrospectively.

1.3 Imports

- According to Eurostat¹⁰, net gas imports in the EU decreased by 9% in the fourth quarter of 2020 (year-on-year), even if gas consumption rose slightly and domestic production in the EU fell again. Net imports in different EU countries showed a high variation in Q4 2020, ranging from a decrease of 55% (0.5 bcm) in Romania to an increase of 77% (0.2 bcm) in Sweden in year-on-year comparison. Among big gas consumer countries net imports decreased in France (18%, by 2.1 bcm), Germany and Spain (13% both, and respectively by 3.4 bcm and 1.1 bcm), Belgium (5%, by 0.3 bcm), Poland (1%, by 0.03 bcm). Net imports in Italy remained practically unchanged, whereas in the Netherlands it rose significantly (by 48%, by 1.2 bcm). In Q4 2020, the United Kingdom imported 11.3 bcm of natural gas, 18% less (2.4 bcm) than in Q4 2019.
- In the fourth quarter of 2020, the total net extra-EU gas imports reached 84.1 bcm, down by 9% (8.8 bcm) from 92.9 bcm in the same period of 2019. The five biggest importers in the EU were Germany (23 bcm), Italy (16 bcm), France (10 bcm), Spain (8 bcm), and Belgium (5 bcm), representing together almost three quarters of the total EU net gas imports in Q4 2020. In 2020 as whole, total net gas imports in the EU amounted to 326 bcm, down from 358 bcm in 2019. The five biggest net importer countries were: Germany (79 bcm), Italy (66 bcm), France (37 bcm), Spain (31 bcm), and the Netherlands (20 bcm). The United Kingdom imported 32 bcm of natural gas in 2020.
- According to ENTSO-G data, net imports amounted to 914 TWh in the fourth quarter of 2020, of which 82% through pipelines and 18% through LNG terminals. Pipeline gas imports from Russia, though to a lesser extent than in the previous quarters, fell significantly, by 8% in year-on-year comparison, as gas transit through the Ukrainian route still showed a significant drop year-onyear. Imports from Norway were slightly down, by 2% in Q4 2020 in year-on-year comparison. Pipeline gas imports from Algeria, continuing the trend of the previous quarter, rose by 37% in Q4 2020. Pipeline gas imports from Libya fell further, by 26% yearon-year. At the same time, LNG imports, decreased by 27% year-on-year (after going down by 13% on the previous quarter), and reached 161 TWh in Q4 2020.

¹⁰ Net imports equal imports minus exports and do not account for stock changes.

- Similarly to the previous periods, Russia was the top gas supplier of the EU and the share of Russian pipeline gas in the extra-EU gas imports rose to 49% in the fourth quarter of 2020, up from 47 % in Q4 2019¹¹.
- The share of pipeline gas imports from Norway was 22% in the fourth quarter of 2020, up from 20% in Q4 2019, as pipeline gas imports from Norway decreased less than the overall gas imports (2% vs. 9%)¹². In the fourth quarter of 2020, Norwegian gas production¹³ amounted to 28.9 bcm, decreasing by 4% year-on-year.
- In the fourth quarter of 2020 pipeline gas imports from Algeria increased significantly, by 37% year-on-year, which resulted in an increasing share within the total extra-EU imports (10.2% in Q3 2020, the highest share since Q1 2018, whereas up from 6.7% in Q4 2019). Increasing pipeline gas imports from Algeria must have been related to favourable market prices in the oil-indexed contracts, benefiting from the time-lagged impact of the oil price fall in earlier 2020 periods, and to contractual obligations to ship determined gas volumes to the EU customers before the end of the year. Imports from Libya continued to fall (-26% in Q4 2020 compared to the same period of the previous year), and its share was only 1.2% in the total EU gas imports.
- In Q4 2020, the share of LNG fell to 17.6% in the total EU gas imports, which was the lowest since Q4 2018 and 6 percentage
 points lower than in Q4 2019. Decreasing LNG imports in the EU was principally owing to increasing price premium of the Asian gas
 markets to Europe that resulted in redirection of LNG cargoes towards Asia. It seems that the decreasing share of LNG between the
 fourth quarters of 2019 and 2020 was mainly compensated by the increasing share of Russian, Norwegian and Algerian pipeline
 sources in EU gas imports.
- In 2020 as whole, gas imports in the EU fell by 9%, in year-on-year comparison, as result of 18% less import from Russia, an increase of 1% in Norwegian imports, whereas gas imports from Algeria decreased by 3% and that from Libya fell steeply by 21%). LNG imports fell by 5% in the EU in 2020 year-on-year. Looking at the share of different supply sources in 2020, Russian pipeline gas came to the first place, with a share of 43%, followed by Norwegian pipeline gas and gas in the form of LNG (23%, both), pipeline gas from Algeria (6%) and Libya (1%), whereas the share of 'UK trade balance' was around 3%. (see the explanation below the chart)



Figure 10 EU imports of natural gas by source, 2017-2020

Source: Based on data from the ENTSO-G Transparency Platform, data as of 10 March 2020. Exports to the Baltic-states and Finland are not included in the chart owing to unavailability of reliable data Russia, Norway, Algeria and Libya include pipeline imports only; LNG imports coming from these countries are reported in the LNG category. A trade balance with the UK is estimated, reflecting that the UK is no longer part of the EU, and it is not easy to determine the origin of gas molecules arriving to the EU after going through the UK market (it can be UK production, imports from Norway of LNG imports from the UK, etc.).

• Due to the combined impact of year-on-year decreasing import volumes and increasing average import prices, in the fourth quarter of 2020 the estimated gas import bill amounted to €13.5 billion, (in comparison to €14.4 billion in Q4 2019, falling by 6% year-on-year). Wholesale gas prices in Europe, following the recovery started in the previous quarter, were up by 5% in Q4 2020 year-on-

¹¹ It is worth to note that Russia increased its importance in the EU LNG imports as well over the last two-three years, numbers presented in this section, with the exception of LNG or unless otherwise indicated, refer to pipeline imports

¹² Note that Norway to UK flows reported by ENTSO-G includes some gas from UK offshore fields, resulting in an overestimation of Norwegian imports.

¹³ https://www.npd.no/en/facts/news/Production-figures/2020/production-figures-march-2020/

year. The quarterly gas import bill however rose significantly in Q4 2020 compared to the previous quarter (\in 7.1 billion). In 2020, the total gas import bill was \in 36.5 billion, down from \in 59.4 billion in 2019.



Figure 9 - Estimated quarterly extra-EU gas import bill, in billions of euros

Source: ENTSO-G, Eurostat and own data calculations for the EU weighted average of import gas prices

- As important pipeline gas source countries, such as Russia, Norway and Algeria are also active on the LNG market, it is worth to look at the combined imports of pipeline gas and LNG from these countries and to calculate the share of import sources in this way, too. As Figure 10 shows, the share of Russia within total extra-EU gas imports (pipeline and LNG together) amounted to 53% in Q4 2020, split by 49% of pipeline imports and 4% of LNG, indicating that Russia is also an important actor in European LNG imports, not only in the traditional pipeline gas supply. Russia is trying to maintain its market share by switching to a more competitive export strategy, integrating EU benchmarks in the contract price formation formula, for both pipeline gas and LNG contracts. The share of pipeline import gas of Russian origin went up from 47% to 49% within the total extra-EU gas imports, by taking into account LNG the share of Russia rose from 51% to 53% in Q4 2020 year-on-year.
- The share of Norway was 22% in Q4 2020 (which was practically identical with the share of the Norwegian pipeline imports, owing to repair and maintenance works on the country's sole LNG plant), and the share of Algeria is 12.1% with LNG (as opposed to 10.2% only including pipeline gas) within the total extra-EU gas imports. The share of LNG fell below 12%, (on the top of LNG accounted in shipments from Russia, Norway and Algeria), being the lowest since Q4 2018. Decreasing share of LNG between the fourth quarters of 2019 and 2020 was mainly compensated by the increasing shares of Russia, Algeria and Norway. In 2020 the share Russia in the total gas imports (pipeline and LNG combined) amounted to 48%, followed by Norway (24%), LNG from countries other than Russia, Norway and Algeria (18%), Algeria (9%), and Libya (1%).



Figure 10 - The share of gas imports within the total, combining both pipeline and LNG imports

Source: Based on data from the ENTSO-G Transparency Platform, data as of 10 March 2020.

1.3.1. Pipeline imports from Russia and EU supply to Ukraine

- Figure 11 shows the breakdown of EU gas imports from Russia on the four main pipeline supply routes: Ukraine (which includes the Brotherhood Pipeline and the recently less important Balkan route), Belarus (mainly the Yamal pipeline), Nord Stream and Turk Stream.
- In the fourth quarter of 2020, the volume of Russian imports fell by 18%, if compared with the same quarter of 2019. As shown on Figure 11, gas flows transiting Ukraine were 27% lower than in Q4 2019, which is still significant, even if less steep that that in the previous quarter (57%). During Q4 2020 a monthly average of 4.2 bcm of gas of Russian origin was transited through Ukraine, which was albeit higher than in Q3 2020 (2.5 bcm), though still lower than in Q4 2019 (5.7 bcm). Based on the calculations from the database of ENTSO-G, in 2020 around 38 bcm gas was transited through Ukraine with EU destination, down from 69 bcm in 2019, a decrease of 45% year-on-year. This was measurably lower than the contractual obligation of 65 bcm for Russian gas transit through Ukraine for 2020, set by the transit agreement signed at the end of 2019 (this latter covers destinations in non-EU countries as well).
- Flows through Belarus were slightly down, by 0.8% in Q4 2020 compared to the same quarter of 2019. In 2020 as whole, transited volumes through Belarus decreased by more than 7% and reached 33 bcm. Transited volumes through the Nord Stream were up by 1.5% in Q4 2020 year-on-year. In 2020, the Nord Stream route managed to increase its transited volume, by 1.4%, amounting to 52 bcm, signalling a high utilisation rate as the total capacity of Nord Stream is 55 bcm per year.
- As a result, in Q4 2020 Nord Stream remained the main supply route of Russian gas to Europe, as its share reached 37% of the total Russian pipeline gas imports the EU, up from 34% a year earlier. The share of the transit through Ukraine was down in year-on-year comparison, reaching 34%, compared to 43% in Q4 2019, though up from the trough of 25% in Q3 2020, when maintenance works were implemented on the Ukrainian transit route. The Belarus transit route represented 25% in Q4 2020, up from 24% in Q4 2019. The share of Turk Stream was still lower, around 4% in Q4 2020. In 2020 a little bit more than 5 bcm of natural gas was transited through Turk Stream. This route is expected to have bigger importance as of 2021, as after the inauguration of the interconnector between Bulgaria and Serbia, the Balkan countries will increasingly be supplied through Turk Stream (in February 2021 its share reached 8% within the total Russian pipeline gas imports in the EU).
- In Q4 2020 Nord Stream represented 18% (15 bcm) in the total net extra-EU imports, the Ukrainian transit had a share of 16% (14 bcm), and the Belarus transit route ensured 12% (10 bcm). At the same time, the Turk Stream had a share of 2%, with around 1.7 bcm gas transit within the total net extra-EU gas imports in Q4 2020. It seems that the European demand decrease for Russian gas principally impacts the Ukrainian transit route in Q4 2020 and in 2020 as whole.



Figure 11 EU imports of natural gas from Russia by supply route, 2017-2020

Source: Based on data from the ENTSO-G Transparency Platform, data as of 10 March 2020. Deliveries to Estonia, Finland and Latvia are not included; transit volumes from Russia to the Former Yugoslav Republic of Macedonia and Serbia are excluded. Since the inauguration of Turk Stream flows to Turkey via the Balkans are not significant.

- In the fourth quarter of 2020, Ukrainian natural gas imports from EU countries fell to low levels, only 0.5 bcm, almost exclusively using the Slovakian route. Compared to both Q3 2020, when Ukraine imported 2.4 bcm gas from the EU and to Q4 2019, when imports amounted to 2.2 bcm, the decrease is significant. Lower imports might have been explained by high storage filling rates at the beginning of October 2020, as this time storages were filled to 76%, compared to the typical filling rate of 50% or the situation in 2019 (67%). In 2020, the total Ukrainian gas imports from the EU amounted to 7.6 bcm, down from 12 bcm in 2019. Over the past few years gas market in Ukraine has evolved in a storage balancing facility, namely if storages are full in the EU, gas traders tend to use Ukrainian storage capacities to store additional gas volumes.
- Traded volumes on Gazprom Electronic Sales Platform (ESP) continued to decrease in Q4 2020, amounting to 2.7 bcm in the quarter, whereas in Q3 2020 the total trade volume was still 4.7 bcm, and in Q4 2019 it amounted to 3 bcm, implying a 10% decrease year-on-year in Q4 2020. Decreasing volumes over the last two quarters might be related to increasing spot gas prices on the EU hub, making the long-term contract prices more competitive, as spot price levels became higher compared to contract prices. Nevertheless, in 2020 the total ESP sales amounted to 24 bcm, up from 13.1 bcm observed in 2019.
- In Q4 2020 the principal delivery points from ESP sales were the German Gaspool market (0.68 bcm delivered), and the Slovakian, Austrian and Hungarian virtual trading points (VTP Slovakia – 0.68 bcm and VTP Austria – 0.56 bcm both, VTP Beregdaroc – 0.31 bcm), and Olbernhau on the German-Czech border (0.5 bcm). In 2020, the three most important delivery points were: Gaspool (6.8 bcm), VTP Slovakia (4.7 bcm), and VTP Austria (3.9 bcm).



Figure 12 - Ukrainian pipeline gas imports from Poland, Slovakia and Hungary

Source: Based on data from the ENTSO-G Transparency Platform, data as of 10 March 2020



Figure 13 - Monthly sales on the Gazprom Electronic Sales Platform (ESP) with delivery points

1.3.2.LNG imports

- LNG imports in the EU fell by 27% in Q4 2020 year-on-year, signalling the third consecutive quarter when a contraction could be observed in a row (after the decrease of 1% in Q2 2020 and the fall of 13% in Q3 2020). Looking at the three months of the quarter, EU LNG imports were respectively down by 16% in October, by 28% in November and by 35% in December 2020, in year-on-year comparison, sharply contrasting the rising trend of the end of 2019. The quarterly LNG import in Q4 2020 in the EU was 16.6 bcm, decreasing from 18.8 bcm in Q3 2020 and from 22.7 bcm in Q4 2019, as Figure 14 shows. The total number of LNG cargoes arrived in the EU was 227 in Q4 2020, down from 238 in Q3 2020 and from 293 a year ago in Q4 2019. With the exception of Sweden and Finland, importing marginal amount of LNG (respectively 75 mcm and 57 mcm in Q4 2020) imports decreased in all major EU importer countries in Q4 2020 year-on-year.
- In Q4 2020 Spain remained the biggest importer (with a quarterly import of 4.3 bcm, down by 15% year-on-year), followed by France, importing 4 bcm, showing a year-on-year fall of 36%. Italy was the third biggest importer, (2.4 bcm, falling by 24% year-on-year). Portugal imported 1.4 bcm of LNG in Q4 2020 (down by only 1% year-on-year), similarly to the Netherlands, where the imports of 1.4 bcm meant a decrease of 31% year-on-year. In both Belgium and Poland LNG imports amounted to 0.8 bcm, respectively translating to a fall of 58% and 5% in Q4 2020. The total EU LNG imports amounted to an estimated €2.7 billion in Q4 2020, down from €3.2 billion a year before, as the result of sharply decreasing LNG imports year-on-year, whereas in Q4 2020, for the first time since several quarters, the average import price was higher than a year before in the same period (up by 16%).
- In 2020 LNG import volumes in the EU amounted to 84 bcm (representing an estimated value of €8.3 billion), down from 88 bcm (€13.1billion) in 2019. In 2020 the biggest LNG importer countries in the EU were Spain (21.4 bcm), France (20 bcm), Italy (12 bcm), Netherlands (7.8 bcm) and Belgium (7.4 bcm).
- Similarly to continental Europe, LNG imports in the United Kingdom fell measurably, by 37% in Q4 2020, reaching almost 4.4 bcm. The UK has always been playing an important role as berthing site of LNG vessels for continental Europe and shipments are transported to Europe via gas interconnectors with Belgium and the Netherlands. However, during the winter period LNG shipments rather serve for domestic consumption in the UK, especially regarding the limited storage capacities. In 2020 as whole, UK LNG imports reached 17.9 bcm, slightly down from 18 bcm in 2019.
- In Q4 2020, the price premium of the Asian markets widened measurably to Europe, providing better profitability for LNG exporters
 to ship cargoes to Asia than to Europe (see Figure 24 and Figure 25). Such price premium of Asia to Europe could last time
 observed in 2018, luring away significant LNG cargoes from Europe. Even though Europe has a good geographical position, offering
 proximity to cargos from the Atlantic Basin, the Middle East and LNG of Russian origin (production at the Yamal Peninsula),
 resulting in favourable shipment costs, if price premiums are high enough in Asia, LNG exporters will direct shipments there to
 benefit from higher profitability.



Figure 14 LNG imports to the EU by Member States

Source: Commission calculations based on tanker movements reported by Refinitiv "Other" includes Finland, Malta and Croatia

- In the fourth quarter of 2020 the competition between Russia, the United States and Qatar and in supply the EU with LNG was quite close, as the three countries respectively exported 3.8 bcm (23% of the total EU supply), 3.6 bcm (22%) and 3.5 bcm (21%) 2020). Compared to the previous quarter, Q3 2020, the share of Qatar in the EU LNG imports fell by 8%, whereas the share of Russia and the United States rose by respectively 5% and 10%. The share of the US increased significantly, as the impact of LNG cancellations in Q3 2020 was over and cargoes were back. Nigeria was the fourth biggest import source in Q4 2020, (with a market share of 18%, up by 3 percent to Q3 2020), followed by Algeria (11%). Trinidad and Tobago ensured 3% of imports See Figure 15.
- In 2020 as whole, the biggest LNG supplier of the EU were the United States, exporting 18.8 bcm of LNG to the block of 27, which represented 22% of the total EU LNG imports. Qatar exported 18 bcm to the EU, having a share of 21%, followed by Russia (17 bcm -20%). Nigeria exported 12 bcm of LNG to the EU (14%), whereas Algeria had a share in the EU LNG imports slightly less than 10%, with imports of 8 bcm. The share of other LNG suppliers remained below 5% in 2020.
- In Q4 2020, Norway had a share of only 0.1% in total EU LNG imports, down from 7% in Q3 2020. This decrease can be explained by the outage of the Hammerfest LNG plant due to a fire incident¹⁴ on 28 September 2020, which, as the operator Equinor announced on 26 October, will require ongoing repair and maintenance works and the plant will only back on 1 October 2021. It can be anticipated that Norway's LNG exports will be minimal to the EU in the forthcoming months.

¹⁴ <u>https://www.ogi.com/pipelines-transportation/lng/article/14186120/longterm-outage-for-hammerfest-lng</u>



Figure 15 LNG imports to the EU by supplier

Source: Commission calculations based on tanker movements reported by Refinitiv Imports coming from other EU Member States (re-exports) are excluded "Other" includes Angola, Brazil, the Dominican Republic, Egypt, Equatorial Guinea, Oman, Peru, Singapore, the United Arab Emirates and Yemen

- In the fourth quarter of 2020, Russia was the biggest supplier in Finland (94% of the country's total LNG imports), Sweden (83%), Belgium (67%), the Netherlands (45%), France (29%), implying that Russian LNG has increasing importance in North-Western Europe, not independently from the dwindling domestic gas production in the Netherlands. The United States were the biggest LNG supplier in Lithuania (84%), Greece (48%) and it came to the second place in the Netherlands (37%) and Portugal (35%). Qatar was the biggest supplier in Italy (78%) and Poland (76%), whereas in Greece it ensured around 20% of the total LNG supply.
- Nigeria was the biggest supplier in Portugal (51%), whereas in Spain and France it respectively ensured 28% and 25% of all LNG imports. Algeria had a share of 27% in France and it ensured around one seventh of LNG imports in Italy and Greece in Q4 2020. Norway ensured 16% of the Swedish LNG imports. At the same time, Trinidad and Tobago was the sole LNG supplier of Malta and ensured around 6-7% of LNG imports in Spain and the Netherlands. In Q4 2020 Spain and France had the most diversified LNG import source structure, receiving cargoes respectively from seven different countries each. On the other hand, Malta had a single supplier of LNG sources.



Figure 16 - LNG imports in the EU Member States from different sources in the fourth quarter of 2020

Imports coming from other EU Member States (re-exports) are excluded

"Other" includes Angola, Brazil, the Dominican Republic, Egypt, Equatorial Guinea, Oman, Singapore, the United Arab Emirates and Yemen

- In the fourth quarter of 2020, 38 LNG cargoes arrived from the US, unloading 3.6 bcm of LNG (in re-gasified form). In the fourth quarter of 2019 58 US LNG cargoes arrived in the EU (with a total re-gasified volume of 5.4 bcm). In 2020 as whole the total number of US cargoes was 201, while the total imported volume of LNG from the US amounted to 18.8 bcm in the EU.
- LNG exports to Europe represented 18% in Q4 2020 of the total US exports, which was lower than in the previous quarter (25%¹⁵), implying that US LNG exports could find more profitable markets, principally in Asia than in Europe. In the fourth quarter of 2020 the four most important EU destinations of the US LNG exports were Spain (1160 mcm), Netherlands (503 mcm), Portugal (493 mcm), and Lithuania (434 mcm). After very low imports in the previous quarter, the United Kingdom imported more than 2.2 bcm LNG from the US LNG in Q4 2020. In 2020, out of the total US LNG imports of 18.8 bcm, 5.7 bcm arrived in Spain, 2.6 bcm in France, 2.5 bcm in the Netherlands and 2.2 bcm in Italy. The UK imported 4.9 bcm LNG from the US. In 2020 29% of the total US LNG exports were shipped to the EU Member States and the UK.
- The average monthly utilisation rates of terminals in the LNG importing EU Member States are presented on Figure 17 for some countries in the EU, the EU on average, and the UK. In Q4 2020 the average EU utilisation rate continued to decline compared to the previous quarters; in parallel with decreasing LNG import numbers. By December 2020 the average EU utilisation rate fell to 30%, which was the lowest since September 2018. At individual terminal or country level, monthly utilisation rates can be quite volatile, depending on the arrival of cargoes and the hourly regasification capacities. In Italy, utilisation rates remained higher than the EU average in in Q4 2020, similarly to France. On the other hand, in Spain utilisation rates were lower than EU average in October and November, while they were practically equal with the EU average in December 2020. In the UK utilisation rates ramped up in Q4 2020 and in December the average rate was 48%, compared to 30% in the EU.

100% 90% 80% ۱ 70% 60% 50% 40% 2 30% 20% 10% 0% 6 7 8 9 10 11 12 1 1 2 3 Δ 5 6 7 8 9 10 11 12 1 2 ζ 4 5 6 7 8 9 10 11 12 1 23 4 5 2 ٦ 4 5 6 7 8 9 10 11 12 1 2 2017 2020 2021 2018 2019 – FR - UK – IT – FS FU

Figure 17 – Average monthly regasification terminal utilisation rates in the EU and in some significant LNG importer countries

Source: Commission calculations for LNG imports based on tanker movements reported by Refinitiv. Regasification capacities are based on data from International Group of Liquefied Natural Gas Importers (GIINGL) and Gas Infrastructures Europe (GIE)

 $^{^{\}rm 15}$ Europe here includes the EU and the UK

1.4 Policy developments, new gas infrastructure and contracts

- On 12 October 2020 TAP AG, the company in charge of the construction of the Trans-Adriatic Pipeline, announced that the after almost four and a half years since the start of the works, the Trans Adriatic Pipeline is substantially complete, finalising preparations for launching the commercial operations and offering capacity to the market in alignment with the adjacent TSOs. TAP is the European leg of the Southern Gas Corridor, a gateway project that will transport 10 billion cubic metres (bcm) a year of new gas supplies from Azerbaijan through Greece and Albania, crossing the Adriatic Sea to Italy. According to current supply contracts, capacity is booked for 25 years, with 8 bcm to Italy and 1 bcm respectively to Greece and Bulgaria. On 15 November, TAP began operations. First commercial deliveries to Italy were reported on 30 December 2020¹⁶.
- As data of ENTSO-G show, in January and February 2021 daily average delivery to Italy amounted to around 9-10 million cubic meter. Gas flows from Azerbaijan to Italy might result in decreasing price premium of the Italian price hub PSV to the TTF, whereas they might enable Italy to export gas to north-western Europe, a flow in reverse direction compared to usual market situation. For south-east Europe the importance of the TAP will increase once the interconnector between Bulgaria and Greece is finalised (expected in 2021), enabling alternative gas sources for the region, still largely dependent on imports from Russia.
- On 13 October 2020 Qatar Petroleum (QP) has secured storage and redelivery capacity at the UK's Grain LNG terminal for 25 years from mid-2025¹⁷. The deal was signed after the conclusion of an open season process. Qatar Petroleum said it would subscribe to the equivalent of up to 7.2 mpta (10 bcm) terminal's future throughput capacity. QP is also a 67.5% shareholder in another UK LNG terminal, South Hook. This contract is of EU relevance as well, as the UK is regularly used as berthing point for LNG shipments of (at least partly) EU destination. Qatar will expand its gas production capacity from the current 78 mpta (106 bcm) to 126 mpta (171 bcm) until 2027. Over the last few years Qatar was among the first three LNG suppliers to the EU beyond the US and Russia.
- On 21 October 2020, the Polish state-owned Oil and Gas company (PGNiG) has signed a multi-year contract¹⁸ for purchase of natural gas with the Danish utility Orsted. The agreement covers a total volume of approx. 70 TWh (6.4 bcm) to be supplied between 1 January 2023 and 1 October 2028. This coincides with the planned inauguration of the Baltic pipe (planned for October 2022), linking Norwegian and Danish sources with customers in Poland. However, on 6 November Total, the operator of the Danish Tyra gas field, potential source for the Baltic Pipe, announced¹⁹ that the restart of production at Tyra will take place later than expected, possibly only on 1 June 2023.
- Nevertheless, in November PGNiG's subsidiary operating in Norway (PUN) has started gas production at the Ærfugl field²⁰ on the Norwegian Continental Shelf, and in 2021 the total production is expected to reach 1 bcm. This new development may also increase the company's bargaining power vis-à-vis Gazprom, as on 2 November 2020 the company filed a request to the Russians for re-negotiating the gas purchase price²¹, for which the current Yamal long-term supply contract provides framework in each three years, pending the terms of supplies fail to reflect actual market conditions.
- On 11 December 2020, the European Council endorsed²² a binding EU target of a net domestic reduction of at least 55% in greenhouse gas emissions by 2030 compared to 1990. To meet the objective of a climate-neutral EU by 2050 in line with the objectives of the Paris Agreement, the EU needs to increase its ambition for the coming decade and update its climate and energy policy framework. As the earlier adopted Climate Target Plan²³ demonstrated, the share of natural gas will substantially decrease in all scenarios until 2050 among elevated reduction emission ambition while renewable and alternative fuels are set to dominate the EU's future energy system, such as hydrogen. In 2021, the Commission will table 'Fit for 55 package', covering a wide-ranging policy revisions aimed at achieving the goal of emission reductions by 55% until 2030.
- According to the new TEN-E proposal adopted on 15 December 2020 by the European Commission²⁴, natural gas projects will no
 longer be eligible for EU funding via the key funding program for strategic energy infrastructure. Key EU projects enhancing
 security and diversity of supply and improving interconnections between countries may be eligible for funding. While the objectives
 of the current Regulation (security of supply, internal market) remain largely valid, the current TEN-E framework does not fully
 reflect the expected changes to the energy system that will result from the new political context and in particular the upgraded
 2030 targets as well as the 2050 climate neutrality objective. The new proposal reflects the objective of decarbonisation of energy
 grids, smart system integration, offshore renewables and new sources, such as hydrogen.

²⁰ <u>https://en.pqniq.pl/news/-/news-list/id/pqniq-group-boosts-its-output-on-the-norwegian-continental-</u>

¹⁶ <u>https://www.tap-ag.com/news/news-stories/tap-starts-transporting-first-gas</u>

¹⁷ https://www.reuters.com/article/gatar-petroleum-national-grid-grain-lng-idUSKBN26Y29Y

¹⁸ https://pst-energie.com/pgnig-group-to-buy-danish-natural-gas-from-orsted/

¹⁹ https://www.oedigital.com/news/483012-denmark-total-delays-tyra-field-start-up-due-to-pandemic-partner-noreco-says

shelf/newsGroupId/1910852?changeYear=2020¤tPage=1

²¹ <u>https://en.pgnig.pl/news/-/news-list/id/pgnig-files-request-for-price-reduction-under-yamal-</u>

contract/newsGroupId/1910852?changeYear=2020¤tPage=2

²² https://www.consilium.europa.eu/media/47296/1011-12-20-euco-conclusions-en.pdf

²³ See Quarterly Report on European Gas Market, Vol 13, issue 3

²⁴ <u>https://ec.europa.eu/energy/sites/ener/files/revised_ten-e_regulation_.pdf</u>

- On the same day, 15 December, for the first time in Germany, green hydrogen, produced with an electrolyser using renewable electricity from wind turbines, was fed into the gas transmission pipeline system DEUDAN (linking Germany with Denmark)²⁵. The green hydrogen was blended with the gas in the pipeline, up to a concentration of two percent. The underlying hydrogen production plant has a capacity of 1 MW and can produce 210 standard cubic metres of green hydrogen per hour. Using surplus wind energy to produce hydrogen fed into the transmission pipeline system is a forward-looking contribution to sector coupling, i.e. the interconnection of gas, electricity and heat consumption.
- At the end of December The US Congress has authorised the US President to impose sanctions²⁶ against companies constructing the Nord Stream 2 pipeline. The measure allows the administration to impose sanctions against any entity that is involved in construction, provides underwriting and insurance to pipe-laying vessels or facilitates ship retrofitting and upgrading. The sanctions also can apply to any entity that "provided services for the testing, inspection or certification" of the pipeline.
- On 1 January 2021, Gazprom began to supply Serbia and Bosnia Hercegovina using the new Bulgaria-Serbia interconnector²⁷, through the supply route of Turk Stream. The new interconnector is an important element of the Balkan stream, allowing gas supply sources to flow to Central Europe from southern direction. In the first two months of 2021 gas flows from Hungary to Serbia decreased measurably, replaced by the route through Bulgaria, contributing to the increasing role of the Turk Stream in Russian gas flows to Europe.
- On the same day, 1 January 2021 the first LNG cargo arrived at the Krk terminal²⁸ in Croatia, signalling a long-awaited operation
 of a project contributing to the regional security of gas supply and import source diversification. Earlier in June 2020, all the free
 terminal capacity was booked for the next three gas years by gas traders, who will deliver LNG cargoes mainly of Qatar and the US
 origin.

1.5 Storage

- Figure 18 shows EU stock levels as the percentage of storage capacity in gas years²⁹ 2019 and 2020, compared to the 5-year range of gas years 2015-2019. According to figures published by Gas Infrastructure Europe, operational EU storage capacity amounted to 1,131 TWh (roughly 100 bcm) by the end of 2018³⁰.
- The fourth quarter of the year is traditionally the start of the new gas year (the 2020 gas year began on 1 October), and the period when gas storage injection switches to withdrawal, normally in October. On 30 September 2020 the average EU storage filling rate was slightly lower than on the same day of 2019 (94.7% vs. 96.9%), and on 31 December the average filling rate was much lower than at the end of 2019 (74% vs. 88.2%). This huge difference was due to on one hand the uncertain outcome of negotiations of gas transit agreements of Russian gas in the final months of 2019³¹, resulting in security of supply related gas storing, whereas in 2020 no such factor played a role, allowing for lower filling rates and storage costs. On the other hand, spot gas prices followed an increasing trend in Q4 2020, and as in earlier injections periods spot prices was lower, the average costs of stored gas was probably lower in Q4 2020 compared to spot and forward contracts, prompting an intensive recourse to storage withdrawals. On EU average, net storage withdrawals made during the fourth quarter of 2020 were equivalent to 20.7% of storage capacity, which was much higher than that of 8.7% in the same period of 2019.
- Although storage levels were generally lower in Q4 2020 comparing with the same days in Q4 2019, by comparing Q4 2020 levels
 of the five year average of 2014-2018 it is obvious that actual storage levels were close to the upper end of the range at the
 beginning of the 2020 gas year. Increasing withdrawals helped in putting a lid on wholesale spot gas prices, as LNG imports
 decreased significantly in Q4 2020 year-on-year, similarly to most of the pipeline imports, creating a need on the supply side to
 use storages.

²⁵ <u>https://www.gasunie.de/en/news/first-green-hydrogen-to-be-fed-into-gas-transmission-system-in-northern-germany</u>

²⁶ https://www.argusmedia.com/en/news/2173670-us-congress-authorizes-new-nord-stream-2-sanctions

²⁷ https://www.gazprom.com/press/news/2021/january/article521930/

²⁸ <u>https://ceenergynews.com/oil-gas/first-lng-carrier-arrives-at-krk/</u>

²⁹ Gas year always starts on the 1 October of a given year, for example, gas year 2020 started on 1 October 2020 and will end on 30 September 2021

³⁰ <u>https://www.gie.eu/maps_data/downloads/2018/Storage_DB_Dec2018.xlsx</u>

³¹ See more in the Quarterly Report on European Gas Markets, Vol 12, issue 4 (4th quarter of 2019)



Figure 18 Gas storage levels as percentage of maximum gas storage capacity in the EU in the middle of the month

Source: Gas Storage Europe AGSI+ Aggregated Gas Storage Inventory, extracted on 9 March 2021. See explanations on data coverage at https://agsi.gie.eu/#/faq.

The 5-year range reflects stock levels in gas years 2014-2018. The graph shows stock levels on the 15th day of the given month.

- As Figure 19 shows, on 30 September 2020 filling rates across the EU Member States were generally high, ranging from 90.1% in Austria to 98.7% in Portugal, reaching 94.7% on EU average. On 31 December however, differentials in filling rate were higher; the lowest filling rate could be observed in Croatia (57.8%) and the highest in Sweden (94.7%), though in this latter country storage capacities are not significant and no change in filling rates were reported during the quarter. The EU average filling rate was 74% on 31 December 2020, whereas in Portugal, Romania, France, Netherlands and Czechia filling rates fell in the range of 60-70%.
- The biggest decreases in storage filling rates (highest withdrawals) could be observed in Portugal and Croatia (both 37%), France (29%), Romania (28%), Poland and Italy (both 24%), whereas in Denmark, Bulgaria and Slovakia filling rates decreased by less than 10% over Q4 2020 In the EU the average filling rate went down by 21%.
- Figure 19 also shows the relation between actual storage filling rates on 31 December 2020 and the typical January-March gas consumption of the last five winters, estimating the coverage of the storage levels for the remaining part of the winter heating season. As it turned out, around 49% of the average January-March gas consumption in the EU could be covered from the storages for the remaining winter season, with great variation across the EU Member States. In Latvia, Austria, Slovakia and Hungary the actual storage level could cover the whole local gas consumption (though it is worth to recall here that on a single EU gas market local storages may also cover partly the consumption of neighbouring countries, which is important from security of gas supply perspective). At the same time, in countries like Sweden, Belgium, Portugal storages on 31 December could cover less than 15% of the typical gas consumption of the remaining part of the heating season.



Figure 19 Gas storage levels as percentage of maximum gas storage capacity and actual storage levels compared to average January-March consumption at the end of the fourth quarter of 2020 by Member State

Source: Gas Storage Europe AGSI+ Aggregated Gas Storage Inventory, extracted on 9 March 2020. See explanations on data coverage at https://agsi.gie.eu/#/fag. Injection level data in Sweden changed significantly for the first time since the first data reporting period in March 2017. Nevertheless, the Swedish storage facility has a limited capacity (10 mcm), mainly used for LNG storage.

- The next chart (Figure 20) shows the winter-summer spreads, as depicted by the difference in the 2021 summer and winter contracts. The 2021 seasonal spread on the TTF continued its downward trend began in the third quarter of 2020 and in December 2020 it fell to 1.8 €/MWh (in June it was reached 2.9 €/MWh and in September it was still 2.4€/MWh). On the NBP, 2021 seasonal spreads reached 4.2 €/MWh in June 2020, in September it was still 3.7 €/MWh, but falling back to 3.2 €/MWh in December 2020.
- In Q4 2020 the prices at the near-end of the gas curve continued to increase and this drove up spot and near forward prices (including the 2021 summer contracts), thus reducing the premium of 2021 summer to 2021-22 winter contracts.
- UK exhibits a structural gas oversupply during the summer and tighter market during the winter, owing to less storage capacities in comparison to continental Europe. The UK seasonal (winter-summer) spreads developed a perceivable premium to the continental spreads (in this case TTF) over the last few years (amounting to 1.3 €/MWh for the 2021 spreads in Q4 2020).



Figure 20 Winter-summer spreads in the Dutch and British gas hubs

W-S 2019 refers to the difference between the winter 2019-20 price and the summer 2019 price, W-S 2020 refers to the difference between the winter 2020-21 price and the summer 2020 price, W-S 2021 refers to the difference between the winter 2021-22 price and the summer 2021 price.

Source: S&P Global Platts

1.6 Hydrogen and other alternative fuels

The next chart shows the production cost-based estimated prices for hydrogen, generated by three different technologies. Alkaline water electrolysis is a type of electrolyser that is characterised by having two electrodes operating in a liquid alkaline electrolyte solution of potassium hydroxide (KOH) or sodium hydroxide (NaOH). A fuel cell is an electrochemical device that directly converts the chemical energy of reactants (a fuel and an oxidant) into electricity. Polymer electrolyte membrane (PEM) electrolysis is the electrolysis of water in a cell equipped with a solid polymer electrolyte that is responsible for the conduction of protons, separation of product gases, and electrical insulation of the electrodes. Steam methane forming (SMR) refers to a technology for producing hydrogen from natural gas; in the case on the chart below it includes the costs of Carbon Capture and Storage (CCS) as well.



Figure 21 – Production cost based hydrogen price assessments for different technologies (including CAPEX)

Source: S&P Platts. The calculated prices reflect both the commodity production cost and the capital expenditure associated with building a hydrogen facility.

- Whereas alkaline electrolysis and PEM technology costs predominantly depend on the electricity price, the costs of SMR technology is driven by the cost of natural gas used for producing hydrogen. Alkaline and PEM are related to green power (hydrogen generation cost assessment is practically based on green power costs, adding EU wind guarantee of origin prices to wholesale electricity prices), whereas costs of SMR hydrogen generation is based on costs of natural gas (by adding CCS costs).
- In December 2020 the TTF spot gas hub prices averaged at 16 €/MWH, whereas the Pan-European Electricity wholesale price was around 45 €/MWh, which compares to 90-100 €/MWh costs of the alkaline and PEM technologies (without CAPEX costs), and to 48 €/MWh for SMR, being respectively twice and three times as much compared to wholesale electricity and gas prices.
- According to the estimations of Morgan Stanley, the hydrogen market in 2020 was around USD 150 billion³² (€131 billion), of which more than 60% was linked to ammonia production, around 20% to the oil refining sector, 10% to methanol manufacturing, and the remainder was used in other sectors. In 2050 the global hydrogen market is expected to grow as big as USD 600 billion (€525 billion), of which around 30% will be consumed in power generation, another 25% in mobility and as chemical feedstock, while nearly 20% will be used in the construction sector.
- According to the calculation of Hydrogen Council, in 2020 15 EU Member States rolled out plans on hydrogen (for example Germany with 5 GW installed electrolyser capacity, with annual production volume of 14 TWh by 2030, or France, aiming at installing 6.5 GW capacity by the end of the current decade). In most cases the plans include financial support mechanisms to bring down hydrogen production costs, which are quite elevated compared to other fuels, as it was mentioned above.
- Over the next decade, at least USD 300 billion (€263 billion) investments are expected globally from private and public sources, in the calculation of Hydrogen Council, however, the actual commitments stand only at USD 80 billion (€70 billion). According to some estimations, \$150bn (€131 billion) is being made available by governments globally to back hydrogen projects, in the form of subsidies and support. Similarly to the experiences with wind and solar, the costs of producing hydrogen is expected to decrease over time, with broader deployment of the technologies, which are to be helped by subsidies at the beginning of the technology cycle.

³² <u>https://www.ft.com/content/7eac54ee-f1d1-4ebc-9573-b52f87d00240?shareType=nongift</u> - in the following two paragraphs the data source is also this article

- In 2019, the total indigenous biogas production in the EU amounted to more than 589 thousand TJ (approximately 164 TWh). Out
 of this, the share of 'other gases from anaerobic fermentation was 80%, amounting to 130 TWh. The share of landfilled gas was
 around 11% (18 TWh), while that of sewage sludge gas was 8% (13 TWh). The remaining 1% was represented by biogases from
 thermal processes, with slightly less than 2 TWh volume. In 2019, according to data of Eurostat, the total biogas production
 increased further and reached 590 thousand TJ (164 TWh).
- Since 2010, total biogas production in the EU more than doubled, increasing by 82 TWh. In 2019 the biggest biogas producer in the EU was Germany (producing around 54% of the total EU production in 2019, around 88 TWh of biogas), followed by Italy (14%, around 23 TWh), France (7%, 11 TWh) and Czechia (4%, 7TWh). Over the past decade Germany added 37 TWh to the EU production, followed by Italy (18 TWh), France (6 TWh) and Czechia (5 TWh).
- As the next chart shows, over the last decade there was a dynamic increase in biogas production in the EU, reaching 164 TWh in 2019, whereas in 2010 the total amount of produced biogas was barely 81 TWh. In 2019, around 71% of the biogas consumed were used for energy purposes, while 18% was used for other industrial purposes (and distribution losses accounted for 1%). Around 74% (122 TWh) was used in electricity and heat generation as fuel, while around 5% (6 TWh) was injected in the gas grids for blending natural gas.



Figure 22 - Biogas in electricity and heat generation and biogas blending for natural gas

Source: Eurostat

2. Wholesale gas markets

2.1 EU energy commodity markets

- The dated Brent crude price remained relatively stable in October 2020, similarly to Q3 2020, and was in a range of 36-41 USD/bbl (31-35 €/bbl) during most of the time. The price premium of the year-ahead contract to the dated Brent remained in the range 3-5 USD/bbl (2.5-4 €/bbl). As of early November, in spite of new Covid-19 pandemic induced lockdowns in many regions of the world, oil prices started to increase, in parallel with the announcement of the first Covid-19 vaccines, which prompted bullish mood on global commodity and energy markets, as investors anticipated economic recovery after the pandemic. In parallel with economic rebounds, inflationary expectations were also increasing, helping a further rise in the crude oil price, as this commodity traditionally serves as hedging instrument in times of rising inflation expectations. On the demand side, oil imports in China also helped global demand for oil. By the end of 2020 the Brent crude oil price rose to 51 USD/bbl (41 €/bbl) and in early March 2021 the oil price spiked above 70 USD/bbl (58 €/bbl), for the first time since the beginning of 2020. However, since early December 2020 the spot price was higher than the year-ahead (backwardation), implying that we might have seen an overshoot in the crude price at the turn of 2020/21.
- The Dutch TTF spot gas price started October 2020 at 12.5 €/MWh and at the beginning of the month impacted by a strike in the Norwegian gas industry (ending on 9 October 2020), which led to lower flows from Norway. By the end of the month with the onset of colder weather prices increased further and in the last week of the month they rose above 15 €/MWh. In the first half of November 2020, owing to milder weather and relatively high LNG send-out, gas prices fell back again. However, in the remaining part of 2020 Asian gas price benchmarks, owing to cold weather expectations and economic recovery in the biggest LNG markets in the world, increased further their premium to Europe, resulting in decreasing LNG cargo expectations in the EU markets. This, coupled with cold spells in December, and individual factors, such as a strike in the French nuclear sector (implying higher gas demand for electricity generation), resulted in an increasing price trend in EU wholesale gas prices. By the end of December 2020 the TTF spot rose as high as 19 €/MWh. As the market situation in Asia became even tighter in early days of January 2021 and cold spells impacted the European demand for gas, the TTF spot rose above 30 €/MWh on 12 January 2021, the highest since the 'Beast from the East' cold spell induced price spikes in early March 2018. In spite of confinement measures in many EU countries, demand for gas did not decrease in contrast to the first wave of the pandemic during spring 2020.
- Platt's North West Europe Gas Contract Indicator (GCI), a theoretical index showing what a gas price, linked 100% to oil, would be, continued its decline and in November-December 2020 it fell to 14.4 €/MWh, whereas in September it was still 17.5€/MWh. Normally crude oil price changes appear in the oil-indexed contracts with a time lag of 6-9 months; by the end of the year the big price fall in crude oil in the first half of 2020 might have been all priced in. In January 2021 the GCI contract started to rise again and in February it was around 16 €/MWh. As GCI troughed and the TTF spot price kept increasing at the end of 2020, GCI contracts, for the first time since September 2018 were below the TTF. At the end of 2020, lower price of oil-indexed contracts (e.g. Algerian gas imports in Spain) showed improving competitiveness of oil-indexed contracts vis-à-vis hub prices, and thus gas imports in the EU from these sources rose. However, GCI is expected to rise again in the forthcoming months, mirroring the price increase of the oil market over the last few months, which will probably have adverse impact on the current competitive advantage of the oil-indexed contracts.



Figure 23 Spot prices of oil, coal and gas in the EU

- Spot coal prices remained stable in October-November 2020, moving in a narrow range of 43-50 €/Mt. However, in December, in parallel with generally increasing energy prices, coal price also rose and by the end of the month it reached 56 €/Mt. Demand in Asia for coal also increased, in parallel with colder temperatures, resulting in higher coal-fired generation needs, principally in China at the end of December 2020.
- Over the fourth quarter of 2020, carbon prices showed a measurable increase, rising from 27 €/MtC02e to 32 €/MtC02e. The price rise was on one hand driven by increasing energy prices in Q4 2020. On the other hand, January 2021 marked the beginning of phase 4 of the Emission Trading System and the combination of anticipating a tighter cap and updated levels of free allocation quantities supported the carbon price. Investors seem strongly believe in increased EU climate ambitions on continuing the energy transition, and carbon is gradually becoming and investment product as well, increasing liquidity on the market and providing further support to the prices. In early March 2021 the carbon price rose above 40 €/MtC02e for the first time since the start in trade in 2005.

2.2 LNG and international gas markets

- Figure 24 displays the international comparison of wholesale gas prices, including hub, LNG landed and pipeline import gas prices. In Q4 2020 prices of European, Japanese and Chinese landed LNG, after moving together in the preceding two quarters, showed signs of divergence, as US Henry Hub prices remained relatively stable whereas European and Asian LNG contracts rose significantly. By December 2020 both European and Asian hub and LNG prices rose to levels last seen at the turn of 2018/19, which of course increased the profitability and exported volume of LNG from the US. Asian prices developed a premium to the European peers as well, prompting redirection of LNG cargoes towards Asia.
- The average Japanese LNG price was 7.6 USD/mmbtu in Q4 2020, more than doubling compared to 3.5 USD/mmbtu in Q3 2020, and up from 5.8 USD/mmbtu in the fourth quarter of 2019, implying a price increase of 32% year-on-year. The Japanese premium above the Dutch TTF hub was on average 2.5 USD/mmbtu in the fourth quarter of 2020, definitely up from 0.8 USD/mmbtu in Q3 2020, and up from 1.6 USD/mmbtu in Q4 2019. On quarterly average, LNG import prices in China were comparable with their Japanese peers (7.6 USD/mmbtu in Q4 2020). These numbers show that price differentials between European and Asian LNG contracts grew further in Q4 2020 amid the general price recovery.
- In contrast to the LNG contracts, the average price of Chinese pipeline gas imports continued its descend and reached 5.2 USD/mmbtu in Q4 2020, down from 5.7 USD/mmbtu in Q3 2020 and from 7.3 USD/mmbtu in Q4 2019. It was the first time since the beginning of 2019 that pipeline import prices in China were below the Asian LNG reference prices, by more than 2.4 USD/mmbtu. Pipeline import contracts might have reflected decreasing oil prices in earlier periods, with oil-indexation time lag, however, the Chinese pipeline import price did not show such volatility as the oil price in 2020. In the previous quarter (Q3 2020) the pipeline premium over the Asian LNG reference was around 2.2 USD/mmbtu, which in Q4 2020 turned to a similar discount.
- The Henry Hub price rose to 2.5 USD/mmbtu in Q4 2020 (from 2 USD/mmbtu in the previous quarter), and as Figure 25 shows, both TTF and JKM continued to develop their premiums vis-à-vis Henry Hub. By December 2020 both the TTF and the Asian JKM benchmark developed a measurable premium over Henry Hub (3.3 USD/mmbtu and 7.3 USD/mmbtu, respectively), which provided perfect opportunities for US LNG exporters. However, the scarcity of available LNG vessels put a lid on tanker movements, which, during the January 2021 price spike in East Asia, also contributed to the market tightness. In the US, during mid-February an intense cold spell, especially in mid-Western and some Southern parts of the country (e.g. Texas) Henry hub rose to several years' high, reaching 24 USD/mmbtu on 17 February. Given that the EUR appreciated against the USD in Q4 2020 (in September 2020 the exchange rate was 1.18 while in December it was 1.22), divergence between the TTF and the Henry Hub was slightly less measured in euros.
- In the fourth quarter of 2020, TTF averaged at 5.1 USD/mmbtu (14.7 €/MWh), after 2.7 USD/mmbtu (7.8 €/MWh) in Q3 2020. The average German border price was at similar levels with the TTF (5.1 USD/mmbtu or 14.7 €/MWh), showing that this time the impact of still existing oil-indexed contracts in the German gas import mix resulted in less volatility compared to the European hub prices.
- Over the course of the fourth quarter of 2020, differentials in international price contracts showed measurable increases. The average TTF/Henry Hub ratio rose to 2.1 in Q4 2020 from 1.4 in Q3 2020, and from 1.8 in Q4 2019. The ratio of the Japanese LNG price and US Henry Hub was 3.1 in the fourth quarter of 2020, up from 1.8 in Q3 2020, and from 2.4 in Q4 2019. The average price ratio of the Japanese LNG prices and the TTF was 1.5 in Q4 2020, only slightly higher compared to Q3 2020 (1.3) and to Q4 2019 (1.4).
- In absolute terms, in Q4 2020 the TTF showed an increasing premium to the Henry hub (2.6 USD/mmbtu, after 0.7 USD/mmbtu in Q3 2020), whereas the premium of Japanese LNG prices to TTF rose from 0.8 USD/mmbtu to 2.5 USD/mmbtu between the third and fourth quarter of 2020. During the same period premium of Japanese LNG prices to Henry Hub rose from 1.5 USD/mmbtu to 5.1 USD/mmbtu, implying better profitability (even if higher shipment costs are counted) of US LNG exports to Asia compared to Europe.

- In the fourth quarter of 2020, spot prices averaged 5.1 USD/mmbtu in the Netherlands, 5.3 USD/mmbtu in Spain, and 7.6 USD/mmbtu in China and Japan.
- The JCC (Japanese Crude Cocktail) contracts reached 6.7 USD/mmbtu in Q4 2020 on average, slightly decreasing from 7.2 USD/mmbtu in Q3 2020, though being still higher than Japanese LNG import prices (7.6 USD/mmbtu) or the TTF (5.1 USD/mmbtu), reflecting the impact of decreasing oil prices (with the time-lag in the oil indexation).



Figure 24 International comparison of wholesale gas prices

Sources: S&P Global Platts, Refinitiv, BAFA, CEIC



Figure 25 - Daily average prices on the TTF (Dutch), the US Henry hub and the JKM Asian reference index

Sources: S&P Global Platts

- The next two charts show the main actors of global LNG trade on importer (consumer) and exporter (producer) side. Since 2013 Japan has been the biggest LNG importer in the world, though its share decreased a bit over, however, in 2020 it ensured around 102 bcm of imports out of the total estimated 492 bcm market. China came to the second place, with an estimated annual import of 91 bcm, followed by the EU (84 bcm), South Korea (55 bcm), India (34 bcm), Taiwan (constituting a separate market, with an import volume of 24 bcm), the United Kingdom (18 bcm), Turkey (15 bcm) and South America (Brazil and Argentina, 5 bcm).
- These numbers clearly show that the demand side has been dominated over the last few years by Asian markets, though the EU as whole came to the third place (in wider European interpretation, the EU with the UK and Turkey would come to the first place with 118 bcm, though the dynamics of the Asian markets is incontestable over time). Europe has been playing the role of global

balancing market between producers and the principal Asian customers, providing place for eliminating global supply and demand side imbalances.



Figure 26 - Annual LNG imports in the main consumer markets

Source: Refinitiv tracking of LNG vessels. Import data are based on cargo arrival dates, therefore total amount of global imports might differ from global export numbers

On the exporter side, Qatar has played a leading role in global LNG production, exporting 109 bcm LNG in 2020. However, Australia came to the second place in the same year, trailing Qatar by just few hundred million mcm of production. The United States started to export LNG in 2016, and by 2020 it became the third most important exporter, supplying 69 bcm in 2020. Russia, mainly focussing on pipeline gas business in earlier periods, came to the fourth place with exports of 39 bcm, ahead of Malaysia (33 bcm), Nigeria (28 bcm), Indonesia (19bcm), Trinidad and Tobago, and Algeria (both with 15 bcm).



Figure 27 - Annual LNG exports of the key global suppliers

Source: Refinitiv tracking of LNG vessels. Export data are based on cargo departure dates, therefore total amount of global exports might differ from global import numbers

2.3 European gas markets

2.3.1 LNG contracts in Europe

- Figure 28 displays the evolution of spot LNG prices paid in the UK, Spain, France, Belgium and Italy, compared with the TTF spot benchmark. With the exception of Italy, where LNG prices are estimated from commercial statistics (Eurostat COMEXT), from the imported values and volumes of LNG, other markets represent landed prices based on vessel movements (from Refinitiv data).
- In the fourth quarter of 2020 hub prices and hub-based import price contracts in western Europe showed higher divergence than in the previous quarter, as the differentials between these prices were around 3.5 €/MWh (between 13.3 €/MWh and 16.6 €/MWh), implying that differentials increased amid the general price increase as well. Taking out the Italian COMEXT derived average price, the difference was only 2 €/MWh. The quarterly average prices showed a significant increase of 42-101% compared to the previous quarter, Q3 2020, reflecting the continued price upturn on wholesale gas markets and import contracts. In year-on-year comparison, the picture is mixed; some contracts showed increased in prices whereas other wend down.

Figure 28. Price developments of LNG imports in the UK, Belgium, Spain and Italy, compared to the TTF benchmark



Note: Landed prices for LNG. Source: S&P Global Platts, Refinitiv, European Commission estimates based on Eurostat COMEXT data, retrieved on 9 March 2020.

2.3.2 Wholesale price developments in the EU

- European hub prices were in a narrow range, averaging around 13.9–15.3 €/MWh in the fourth quarter of 2020, measurably higher than in the previous quarter, Q3 2020 (7.7-9.0 €/MWh), adding around 80-90% to the price level just within a quarter's time, which shows the generally increasing trend. Hub prices reached the highest since Q1 2019, however, in year-on-year comparison they went up by less than 20%, as in Q4 2019 they averaged around 12.4-15.0 €/MWh. The average TTF hub price was 14.7 €/MWh in Q4 2020, going up by 16% in year-on-year comparison.
- In October 2020 only short-lived supply-side events (e.g. strike in the Norwegian gas industry) could impact hub prices in the EU, and until mid-November the generally mild weather put a lid on price increase. However, over the last few weeks of the year as gas prices in Asia increased sharply, LNG shipments to the EU started to decrease, falling to three-year low in January 2021. This prompted decrease in LNG supply and increasing wholesale gas prices. Wholesale gas prices in Q4 2020 were also impacted by the general positive mood on energy commodity markets, as favourable opinions on the first Covid-19 vaccines made the market actors believe that demand for energy will increase in parallel with economic rebound. One off stories, for example a strike in the French nuclear power industry and cold spells in December also increased demand for natural gas, supporting the increasing price trend.

Figure 29 Wholesale day-ahead gas prices on gas hubs in the EU Euro/MWh



Source: S&P Global Platts

- As Figure 30 and Figure 31 show, the French TRF market was closely aligned with the TTF market during the most of the time in the fourth quarter of 2020 (and in January-February 2021 as well), only amid the price spikes in mid-January were there small premiums. Although temperatures turned colder in December 2020 in France, as well and a strike occurred in the nuclear power sector, increasing the demand for natural gas in electricity generation, this could not result in developing a measurable premium over the TTF benchmark.
- The German Gaspool remained well-aligned with the TTF in Q4 2020, however in the first three weeks of January 2021 the German contracts developed a small discounts to TTF, apparently less impacted by dwindling LNG send-out as they could rely more on alternative supply sources and storage withdrawals.
- The Austrian hub showed many times a measurable price discount to the TTF in Q4 2020, which is rather a unique situation. In
 October 2020, the weather was several times milder in Austria, which reduced heating related demand compared to usual. Later in
 the quarter the country could rely on its storage withdrawals, as the costs of using gas in storages was lower than buying on the
 spot market. Furthermore, Austria could rely on imports from Russia and less import demand from Italy also reduced the upward
 pressure on VTP spot contracts.
- In Italy the PSV hub price was well aligned with the TTF during October and November 2020, helped on the demand side by the
 impact of Covid-19 induced lockdown measures, and increasing inflow of cheaper gas from Algeria on the supply side, along with
 intensifying storage withdrawals. At the end of December, as anticipation of the inflows from the new supply route, the TAP, spot
 and quarter-ahead gas prices dropped again below the TTF. However, during the mid-January spikes, coupled with local cold spells,
 the PSV developed a premium of 4-5 €/MWh on some trading days vis-à-vis TTF.
- During Q4 2020 the NBP hub price was during most of the time above the TTF benchmark, as usual during the beginning of the winter period and the heating season; the country has low gas storage facilities compared to its consumption and strongly depends on gas imports. In early October dwindling gas inflows from Norway, owing to the aforementioned industrial action, contributed to higher prices on the NBP. As LNG cargo arrivals started to decrease in December and fell significantly in January, the price premium of spot NBP contracts widened to the TTF. In mid-January on some days NBP premium over the TTF reached 3-4 €/MWh.



Figure 30 Premium of monthly average wholesale day-ahead gas prices at selected hubs compared to TTF Euro/MWh

Source: S&P Global Platts, European Commission computations



Figure 31 Premium of daily average wholesale day-ahead gas prices at selected hubs compared to TTF Euro/MWh

- Figure 32 looks at the development of forward prices of one-year, two-year and three-year ahead contracts in comparison to the development of the day-ahead price on the Dutch TTF.
- Daily spot prices on the TTF underwent a measurable increase in Q4 2020, starting October 2020 just at 12 €/MWh, whereas by the end of December they rose above 19 €/MWh, reaching the highest since early 2019. On 12 January 2011 the daily spot price peaked around 26€/MWh, the highest since March 2018. At the same time, one-year, two-year and three-year ahead contracts showed less intensive increases over Q4 2020, around by 2-4€/MWh (the year-ahead went up from 13.5€/MWh to 17.1€/MWh, the two-year ahead contract from 14 €/MWh to 16.5 €/MWh and the three year-ahead contract from 14.2 €/MWh to 16.1€/MWh), implying that the generally upward trend on the spot market might face a correction in the forthcoming period as this happened by the end of Febraury 2021. Interestingly, year-ahead prices were below the spot contracts most of the time during the whole Q4 2020, two-year and three-year ahead contracts had a premium to year-ahead prices and were closer to the higher spot contracts.

Figure 32 Forward gas prices on the TTF hub

Euro/MWh



Source: S&P Global Platts

2.3.3. Prices of different pipeline contracts for gas in the EU

- Figure 33 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 on the chart.
- In the fourth quarter of 2020, the estimated Algerian pipeline import price in Spain fell to 13.3 €/MWh, decreasing measurably (by 18%), compared to the previous quarter, and was down by 37% compared to Q4 2019. By December 2020 it fell to the lowest (12.8 €/MWh) in more than a decade time, clearly reflecting the time-lagged impact of decreasing crude oil prices. However, in Q4 2020 for the first time since the beginning of 2019, the average estimated Algerian import price in Spain fell below the Spanish LNG import price, showing a discount of 2.5 €/MWh.
- In the fourth quarter of 2020 Algerian gas import price in Italy (13.3 €/MWh) it was similar to that in Spain, however, compared to the previous quarter, Q3 2020 the Italian import price rose by 16%, implying significantly different pricing formula in the two markets, with probably higher importance of hub pricing elements in the Italian contract. However, in year-on-year comparison, Algerian import price in Italy was down by 34% in Q4 2020. Probably owing to more competitive pricing and annual contractual obligations on volumes to be shipped to EU customers, pipeline gas imports in the EU from Algeria was up by 37% in Q4 2020 year-on-year (See Chapter 1.3 Imports).
- Russian gas imports prices in both Czechia and Latvia increased measurably in Q4 2020 compared to the previous quarter (respectively by 58% and 99%), whereas they were still down year-on-year, by 25% and 11%. This implies a much closer mirroring of European hub prices compared to oil priced contracts, implying that the latter must have had a minimal share in the pricing formulae. Latvian import price of Russian gas still had a premium to import prices in Czechia (12.8 €/MWh vs. 10.8 €/MWh) in Q4 2020.
- Prices of European gas contracts showed signs of slight convergence in Q4 2020, as the difference between the cheapest and most expensive contract decreased from 8.4 €/MWh in September to 3.5 €/MWh in December 2020, principally owing to lower gas import prices from Algeria. In June 2020 the highest-lowest price difference among the observed contracts still amounted to 15 €/MWh, however, taking the highly oil price driven Algerian contracts out of the picture the price differential hovered around 2.5-7€/MWh during the whole 2020.
- Hub based contracts and hub prices themselves continued their upturn in the fourth quarter of 2020. Reported German border
 prices also increased, similarly to most of the hub-based contracts, however the increase was less intense than in the case of hub
 prices, probably owing to the existence of oil-indexation in some import sources to Germany.

Figure 33 Comparison of EU wholesale gas price estimations



Source: Eurostat COMEXT and European Commission estimations, BAFA, S&P Global 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 fourth quarter of 2020

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.

2.3.4. Gas trade on the EU hubs

- As Figure 34 shows, in contrast to the previous quarter, when liquidity on the main European gas hubs decreased year-on-year, in the fourth quarter of 2020 the total traded volume amounted to around 16 375 TWh (equivalent to around 1 367 bcm and in monetary terms representing €240 billion³³), being 21% more in volume than in Q4 2019. In Q3 2020 the year-on year decrease in traded volumes was 8%, following a rate of increase of 7% in Q2 2020 and that of 32% in Q1 2020. The Q4 2020 traded volume however was around 16 times more than the gas consumption in the seven Member States³⁴ covered by the analysis in October-December 2020. In 2020 as whole, the total traded volumes on the observed European markets amounted to 66 218 TWh (5 527 bcm, 14 times the total EU gas consumption in 2020), up by 14% compared to 2019.
- Traded volumes in Q4 2020 grew by 33% year-on-year on the most-liquid European hub Dutch TTF, which signalled the return of dynamics after stagnation in the previous quarter. On two German hubs (Gaspool and NGC) together traded volumes rose by 27% over the same period. In Italy (PSV) the volume went up by 9%, and in Austria on the VTP hub traded volumes went up by 20%. Traded volume on the French TRF fell by 4%, in Q4 2020. The steepest fall in traded volumes could be observed on the Belgian Zeebrugge hub (by 66%) in Q4 2020 year-on-year, and total volumes amounted only to 26 TWh (whereas on the TTF volumes reached 12 168 TWh). At the same time, traded volumes on British NBP hub, which was still the second biggest hub on the broader European market, continued to fall, by 15% compared to Q4 2019.
- As the year-on-year increase in trade on the TTF hub in Q4 2020 managed to outnumber the growth rates of other hubs, the share of TTF increased further among the observed hubs in Europe and reached 74% in Q4 2020 (a year earlier its share in Q4 2020 was 67%). If looking at only the EU countries, its share is even bigger, 87%). TTF has emerged to a liquid continental benchmark, having the advantage of euro-denomination, and benefiting from its good connection to various supply sources and access to seasonal storage as well. On the other hand, decrease on the NBP hub signalled a further shift from once Europe's most liquid market. The traded volume in Q4 2020 fell by 15% compared to the same period of 2019, and the share of NBP in Q4 2020 fell to less than 15% in the total European observed trade, down from 21% in Q4 2019.
- Other markets had lower shares: Germany (NGC and Gaspool together) had a share of 5.9%, while the Italian PSV only had 2%, whereas VTP, TRF and Zeebrugge respectively had shares of 1.6%, 1.4% and 0.2% in Q4 2020.
- Although net gas imports in the EU was down by 9% and LNG imports fell by 27% year-on-year in the fourth quarter of 2020 in the EU, consumption of gas in the EU went up by 1.3% and volumes on most liquid European hubs grew by 21%. Withdrawals from gas storages intensified in Q4 2020 at the beginning of the heating season, also helped by lower costs of withdrawals (gas injected in earlier periods with lower average prices) compared to spot prices. Trading volumes were mainly driven by near-curve contracts on the European hubs, (principally Q1 2021 and summer 2021 contracts), optimising seasonal storages and hedging for international players. The share of far curve trade was more important in the case of smaller hubs, whereas the bulk of spot and near-curve trade was realised on larger hubs, such as TTF.
- The share of exchange executed contracts on the Dutch TTF hub was 41% in Q4 2020, which was the highest among the observed EU countries, and was up by 6 percentage points compared to Q4 2019. On the French TRF it amounted to 23%, up by 5 percentage points since Q4 2019. On the VTP hub in Austria this share was 15%, down from 19% in the same period of 2019, and was 14% on the two German hubs together, down by 2 percentage points year-on-year. On Zeebrugge, the share of exchange-executed contracts was much lower, only 5%, whereas it was the lowest on the Italian PSV, amounting to barely 1%. On the NBP hub in the UK, the share of exchange trade was still the highest among all observed markets, amounting to 62% in Q4 2020, even up by 6 percentage points compared to Q4 2019.

³³ Assuming that all trade was carried out on the quarterly average spot price

³⁴ Netherlands, UK, Germany, France, Italy, Belgium, Austria The ratio of the quarterly traded volume and gas consumption can show a big volatility across different quarters, as gas consumption has a high seasonality, whereas gas trade depends on market factors, which are albeit linked to consumption but have less seasonality. Comparing to the EU as a whole, traded volume in Q4 2020 represents 11 times the total EU-27 gas consumption in this period.



Figure 34 Traded volumes on the main European gas hubs in the fourth quarters of 2019 and 2020

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

Source: Trayport Euro Commodities Market Dynamics Report

- On the European hubs as whole, in Q4 2020 54% of the total trade was OTC bilateral, 5% was OTC cleared, whereas the share of exchange-executed contracts increased by 4 percentage points year-on-year in Q4 2020, whereas the share of OTC bilateral went down by than 3 percentage points, and that of OTC cleared by 1 percentage point.
- Amid the general increase in traded volumes (21% in Q4 2020 year-on-year), exchange executed volumes grew even faster, by 35% in this quarter year-on-year on the observed European markets. In the same period, the total OTC traded volume (bilateral and cleared together) went up by 13%. This underlines the increasing importance of exchange-executed contracts in the gas trade on the major European hubs.



Figure 35 Share of traded volumes on the main European gas hubs

The chart covers the following trading hubs: 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); UK: NBP (National Balancing Point).

Source: Trayport Euro Commodities Market Dynamics Report

3. Retail gas markets in the EU and outside Europe

3.1 Focus on: European Barriers in Retail Energy Markets (results for gas markets)

- After more than two decades of the liberalisation of electricity and gas retail markets in the EU Member States, new actors should be able to enter these retail markets and compete with incumbent utilities, and customers are free to choose service providers, and manage to switch between them without significant difficulties and costs. The European Barriers in Retail Energy Markets project was established to research the extent to which the theory is the case in practice; the extent to which energy suppliers across Europe face a variety of barriers to enter and compete in the market; to identify which barriers exist and to provide some suggested solutions to those barriers³⁵. In the 'Focus on' part of the current gas market report, a summary is provided on the main conclusions for retail gas markets for residential (household) customers.
- The concept of the Barriers in retail markets index was related to the enhancement of retail competition, consumer empowerment and protection, supporting these objectives by giving an easily understandable but comprehensive overview of the avoidable, sector-specific barriers that constrain the ability of actual or potential competitors to enter and compete effectively in the residential segment of the energy retail markets. In the context of the report, barriers are defined as conditions that constrain the ability of actual or potential competitors to enter and compete effectively. This means that the index covers not only barriers related to the entry process, but also hurdles that hinder an established supplier in operating and growing in the market.
- Generally speaking, countries already abolished retail price regulation for residential natural gas customers and having longer experience in market liberalisation (e.g. Netherland, Belgium, Germany, Austria, Czechia or the UK) have lower overall barriers index than those who maintain price regulation (at least for some consumer segments) and went not so far in liberalisation (e.g. Poland, Romania, Bulgaria, Croatia, Latvia, Greece, Hungary and Slovakia).
- The next chart provides an overall summary of how these different factors add up to the overall barriers index that quantify the competitive situation in each country. The higher numbers on the chart mean higher barriers in each category, so on the left end of the chart we find countries with high barriers, whereas the opposite is the case on the right end of the chart (the United Kingdom is depicted separately from the EU Member States).



Figure 36 - Barriers index for retail gas markets in the EU Member States and the UK

Source: Chart recreated from EUROPEAN BARRIERS IN RETAIL ENERGY MARKETS PROJECT: Index Report. The lower are the partial and the total values, the lower are the barriers to enter the retail gas market in a given country

- Barriers were structured around four different categories. The first group is called regulatory disincentivisation, including barriers arising as consequence of the general regulatory framework, impact of price regulation, regulatory burdens and unpredictability and access to innovation. In the second group, market inequality, the report looked at barriers arising from uneven playing field of different suppliers. For example, vertically integrated utilities can have competitive advantage over new entrants.
- In the third group (operational and procedural hindrances) the study focussed on the complexity and national/regional differences in standards and procedures in different process areas, affecting how easily new entrants can enter and operate in the energy

³⁵ See here the report: https://op.europa.eu/en/publication-detail/-/publication/b5a17f00-71ae-11eb-9ac9-01aa75ed71a1/language-en?WT.mc_id=Searchresult&WT.ria_c=37085&WT.ria_f=3608&WT.ria_ev=search

retail market. This comprised of features, such as licensing, signing up and operations compliance, as well as data access. Finally, the fourth group of barriers focussed on consumer inertia, namely on barriers arising due to market conditions which deter consumers' willingness and ability to switch supplier, and therefore make it harder for an entrant to attract consumers. These include customer awareness and attitude, availability of information and comparability of offer, and difficulties of the switching process. Detailed results are summed up in the following points.

- Regulated offers are present in 12 out of 24 analysed markets in the case of natural gas. Price regulation is likely to foreclose the
 markets in Latvia, Hungary, Romania, Croatia, Bulgaria, Slovakia and Poland. For regulatory burdens and unpredictability, Denmark
 received the highest barrier scores in this category owing to the topmost tax levels in Europe, in combination with the maximum
 scores received from the suppliers in relation to unpredictability of the regulatory framework. On the other hand, Ireland's top
 performance was mainly a result of maximum satisfaction with the regulatory predictability.
- Market inequality, as measured by the market share of vertically integrated suppliers, got the highest score in Slovenia, as the
 distribution system operators (DSOs) are small, integrated companies (exempt from the legal unbundling rules), and they supply
 the vast majority of the market. On the other hand, DSOs are fully independent companies in the Netherlands, Belgium, Denmark,
 with no vertically integrated players on the market. On market liquidity, six markets are liquid enough to receive the lowest (zero)
 score for that indicator, while the others have high scores, suggesting that low gas hub liquidity (or non-existence of a centralised
 trading platform) is still a widespread issue in the EU.
- The complexity of the licencing procedure is quantified by the time that it requires to get a supplier licence. For seven gas markets there is no licencing procedure, whereas licencing procedure is the longest in Greece and Ireland. Regarding the quality of data access, eight countries have the highest score (low quality of access), whereas Nordic countries perform better in EU comparison.
- Regarding the comparability of utility offers for natural gas, the top performer is Portugal, as many reliable comparison websites are available, and this is reflected in customers' opinions as well. Austria, Ireland, France, Estonia and Germany are also amongst the best performers. The perceived difficulties of switching indicator incorporates the experience and opinions both of customers who have switched, and also of those who have not because they faced obstacles or thought it might be too difficult. Belgium, Netherlands and Portugal reached the best (lowest) scores regarding switching difficulties.

3.2 Savings from switching for residential gas customers

- The next chart shows the annualised average savings in euro and percent of the current energy bill available to typical households who switched away from their local by-default contract to the cheapest offer available in December 2020. Prices in capital cities were used as a proxy to assess prices at the national level.
- In December 2020 in absolute terms, German households could have the highest annualised savings (€694, or 45%), had they switched from their incumbent utility to the most competitive offer available. In percentage terms, the highest savings could be achieved also by Austrian households, which could have saved 43.9% on their annual electricity bill, amounting to €590.



Figure 37 – Annualised gas bill saving potential in December 2020 in the EU Member States and the United Kingdom

Annualised average savings in EUR Source: VaasaETT data collection. Saving potential is reported to be zero for Spain and Hungary, for Bulgaria, Croatia, Finland, Latvia, Lithuania, Sweden, Cyprus and Malta no data are available

3.3 Recent developments on EU retail gas markets

- Monthly and quarterly retail prices are estimated by using half-yearly prices from Eurostat (with the latest available figures relating to the first half of 2020) and Harmonised Consumer Price Indices (HICP) for both the household prices and industrial consumers.
- For household consumers, the estimated average retail price in Q4 2020 in the EU (including all taxes) extended the decreases of the previous two quarters in year-on-year comparison. In the most typical consumption Band, D2, in the fourth quarter of 2020 the estimated average price (including all taxes) was 6.6 Eurocents/kWh, down up by 8.4% compared to 7.2 Eurocents/kWh in Q4 2019, but slightly up from 6.5 Eurocents/kWh in Q3 2020. (See the estimated household prices on Map 2).
- In the fourth quarter of 2020, significant differences could be observed in retail gas prices across the EU. The lowest estimated household prices in consumption Band D2 could be observed in Hungary (3.0 Eurocent/kWh), Romania (3.2 Eurocent/kWh), and Latvia (3.3 Eurocent/kWh), whereas the highest prices could be measured in Sweden (10.2 Eurocent/kWh), Netherlands (10.0 Eurocent/kWh), France (8.1 Eurocent/kWh). The price differential ratio between the cheapest and the most expensive Member State remained unchanged at 3.4. Since the first quarter of 2017, when this ratio was 4.0, price differentials decreased, and in Q1 2020 the ratio fell to 3.0, however, since then it rose slightly.
- Figure 38 shows the level and the breakdown of residential end-user gas prices paid by typical households in European capitals in February 2021. On average, 42% of the price covered the energy component, while the rest covered distribution/storage costs (31%), energy taxes (12%) and VAT (16%).³⁶
- There were significant differences in February 2021 in the share of energy costs, distribution costs and taxes within the total prices across Member States. The share of energy costs ranged from 26% (Amsterdam) and 27% (Copenhagen) to Tallinn (65%) and Zagreb (62%). The share of distribution/storage costs ranged from 11% (Tallinn) and Amsterdam (14%) to 52% (Sofia) and 41% (Athens, Bratislava and Riga). The share of energy taxes ranged from 3% (Athens) and 4% (Brussels) to 43% (Amsterdam) and 32% (Copenhagen). For 7 of the 24 capitals covered, the price does not include an energy tax component. VAT content in the total gas price also varied a lot across the EU from 6% in Athens and 7% in Luxembourg to 21% in Budapest.
- Figure 38 also shows that even the energy component is very variable in absolute terms: it was 6.5 times higher in Stockholm than in Riga in February 2021. There were also considerable differences across Member States in the relative share of network costs and taxes. The ratio of highest and lowest network components across the EU was 12 (between Tallinn and Stockholm), and highest-lowest tax component ratio (taking energy taxes and VAT together) was 17 (Athens and Stockholm) in February 2021.
- With the exception of seven capital cities out of the observed 24, prices were lower in February 2021, compared to the same month of the previous year. Prices decreased by the most in Sofia (14%), whereas prices fell by more than 10% in Warsaw and Poland, mainly driven by the decrease in energy costs and to a lesser extent, network costs. In Copenhagen and Stockholm prices rose respectively by 11% and 6%, also mostly impacted by energy costs and network charges. It seems that recent price increases on wholesale gas markets started to filter in the final retail household prices in some of the EU capital cities at the beginning of 2021. In February 2021, Budapest remained the cheapest capital in the EU in terms of gas prices for household consumers, followed by Bucharest and Riga, whereas Stockholm, Amsterdam and Copenhagen were the three most expensive capital cities.

³⁶ Note that these are rounded arithmetic averages. No data are available for Helsinki (Finland), Nicosia (Cyprus), and Valetta (Malta).



Figure 38 Breakdown of gas price paid by typical household customers in European capitals, February 2021 Eurocent/kWh

- Retail gas prices for industrial customers decreased by 1.9% in Q4 2020 year-on-year in the EU on average, and the average estimated price (VAT and other recoverable taxes excluded) in consumption Band I4 was 2.4 Eurocent/kWh, slightly up from 2.37 in Q3 2020 but down from 2.47 in Q4 2019. (See the estimated industrial prices on Map 3.) There were only three countries in the EU (Netherlands, Sweden and Croatia) where industrial gas prices increased in year-on-year comparison in Q4 2020, while in the other 21 observed countries (data were not available for Cyprus, Finland and Malta) decreases could be observed. It seems that price decreases of the first half of 2020 on the wholesale gas markets already filtered in retail prices for industrial customers in Q3 2020, having average consumption, however, recent price rebound on the wholesale markets only partially appeared in the retail prices. Decreases could also be observed for industrial customers having larger annual gas consumption (5% decrease in both Band I5 and Band I6 in Q4 2020 year-on-year).
- In the fourth quarter of 2020, the lowest estimated industrial price in consumption Band I4 could be observed in Bulgaria (1.8 Eurocent/kWh) and in Belgium, Luxembourg and Lithuania (1.9 Eurocent/kWh). The highest prices could be observed in the Netherlands (3.7 Eurocent/kWh), Sweden (3.6 Eurocent/kWh) and Croatia (2.6 Eurocent/kWh). In Q4 2020, the price ratio of the cheapest and the most expensive country in the EU was 2.1. This price differential was lower compared to the first quarter of 2017, when it was 2.8, but higher compared to the fourth quarter of 2019, when it was only 1.7.
- Figure 39 shows the evolution of industrial retail gas prices in the EU, compared with some important trade partners of the European economy. In the fourth quarter of 2020, retail gas prices for industrial customers in China and Korea had a price premium to the EU average (respectively 41% and 64%). On the other hand, retail gas prices in the United States were 57% less than in the EU and in Russia gas prices had a discount of more than 70% to the EU average. Compared to Q4 2019, the biggest decrease in industrial gas retail prices could be observed in Russia (19%), United States (7%) and China (6%), while prices in Korea rose by 9%.



Figure 39 The EU average industrial retail gas price in comparison with the prices of some important trade partners of the EU

• Maps 2 and 3 on the next two pages show the estimated retail gas prices paid by households and industrial customers in the fourth quarter of 2020.

account. EU prices are without VAT and other recoverable taxes

Map 2. Retail gas price estimates for households in the EU - Fourth quarter of 2020





Source: Eurostat

Map 3. Retail gas price estimates for industrial consumers in the EU - Fourth quarter of 2020





Source: Eurostat

4. Appendix - charts providing further details on market developments³⁷

Figure 40 Change in weekly consumption of natural gas for industrial and non-household customers in Q4 2020 in some EU countries, as compared to the same week of the previous year



Source: S&P Global Platts Eclipse, own computations. The chart shows in different countries change in gas consumption in the industry or customers supplied by non-local distribution companies, an approximation of non-household consumers, therefore the numbers are not fully comparable across countries.



Figure 41 - Natural gas domestic production in the EU, with imports from different sources and changes in storage levels

Source: Commission calculations based on tanker movements reported by Refinitiv and data from Eurostat

³⁷ These charts provide additional information on the main market development, without textual comments or further detailed analysis



Figure 42 - Annual LNG imports in the EU Member States

Source: Refinitiv



Figure 43 - Annual LNG import from the main suppliers to the EU



Figure 44 Cumulative monthly LNG imports from the US in the EU

Source: Commission calculations based on tanker movements reported by Refinitiv



Figure 45 - Cumulative monthly LNG imports from Russia in the EU

Source: Commission calculations based on tanker movements reported by Refinitiv

5. 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 S&P Global 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.

Cooling degree days (CDDs) are defined in a similar manner as Heating Degree Days (HDDs); the higher the outdoor temperature is, the higher is the number of CDDs. On those days, when the daily average outdoor temperature is higher than 21°C, CDD values are in the range of positive numbers, otherwise CDD equals zero.

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 \in /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.

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.

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

Long-term average for HDD and CDD comparisons: In the case of both cooling and heating degree days, actual temperature conditions are expressed as the deviation from the long-term temperature values (average of 1975-2016) in a given period.

Monthly estimated retail gas prices: Twice-yearly Eurostat retail gas price data and the gas component of the monthly Harmonised Index for Consumer Prices (HICP) for each EU Member States to estimate monthly retail gas prices for each consumption band. The estimated quarterly average retail gas prices on the maps for households and industrial customers are computed as the simple arithmetic mean of the three months in each quarter.

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.

Retail prices paid by households include all taxes, levies, fees and charges. Prices paid by industrial customers exclude VAT and recoverable taxes. Monthly retail electricity prices are estimated by using Harmonised Consumer Price Indices (HICP) based on biannual retail energy price data from Eurostat.

