



# Quarterly Report

## on European Gas Markets

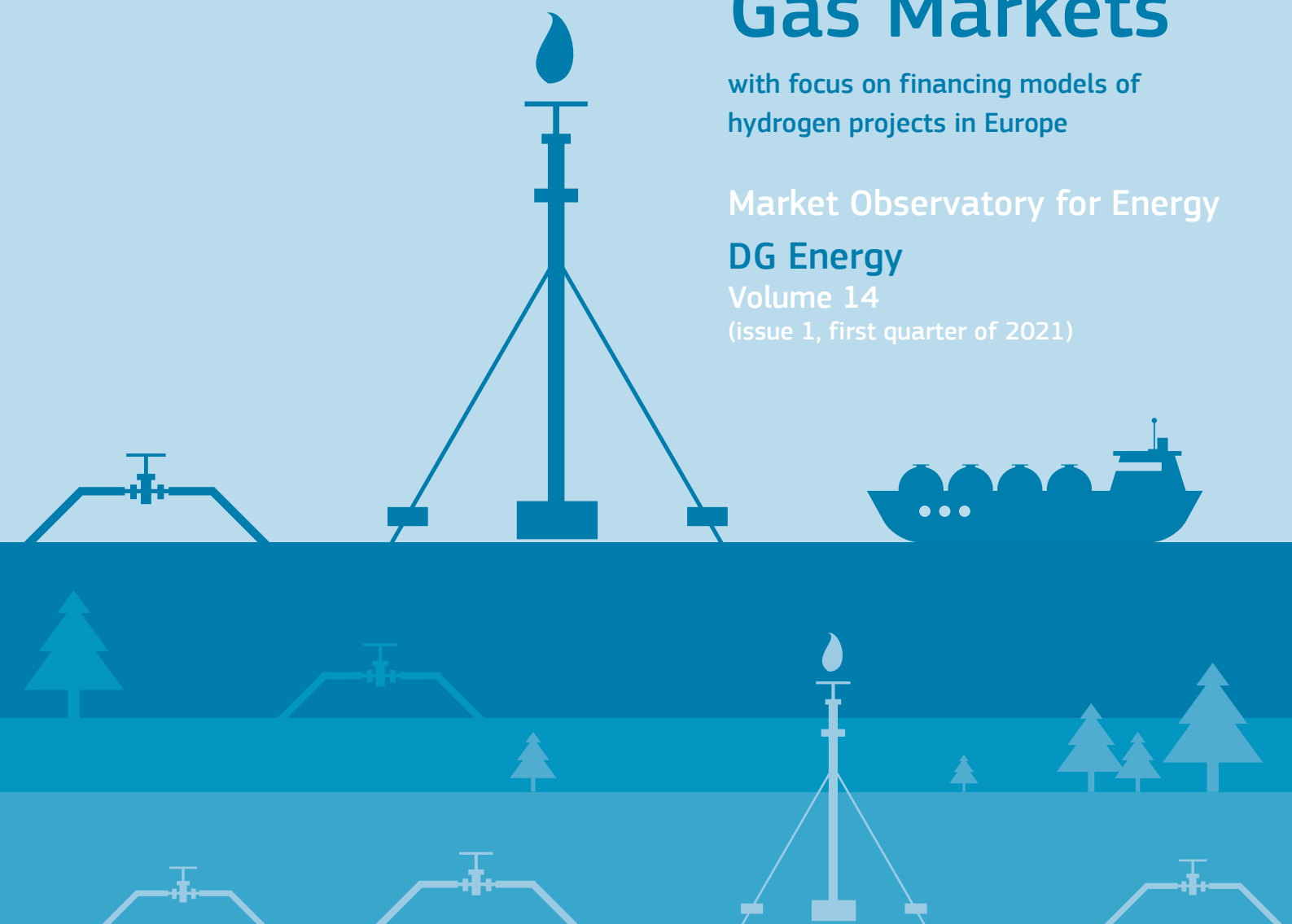
with focus on financing models of  
hydrogen projects in Europe

Market Observatory for Energy

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## CONTENT

CONTENT .....	2
HIGHLIGHTS OF THE REPORT .....	3
1. Gas market fundamentals .....	4
1.1 Consumption .....	4
1.2 Production .....	8
1.3 Imports.....	9
1.3.1 Pipeline imports from Russia and EU supply to Ukraine.....	12
1.3.2 LNG imports .....	13
1.4 Policy developments, new gas infrastructure and contracts .....	17
1.5 Storage.....	18
1.6 Hydrogen market developments.....	21
1.7 Focus on: Financing models of hydrogen projects in Europe.....	21
2. Wholesale gas markets .....	23
2.1 EU energy commodity markets.....	23
2.2 LNG and international gas markets.....	24
2.3 European gas markets.....	27
2.3.1 LNG contracts in Europe .....	27
2.3.2 Wholesale price developments in the EU.....	28
2.3.3. Prices of different pipeline contracts for gas in the EU .....	30
2.3.4. Gas trade on the EU hubs .....	33
3. Retail gas markets in the EU and outside Europe .....	35
3.1 Savings from switching for residential gas customers.....	35
3.2 Recent developments on EU retail gas markets.....	35
4. Appendix – charts providing further details on market developments.....	41
5. Glossary.....	44

## HIGHLIGHTS OF THE REPORT

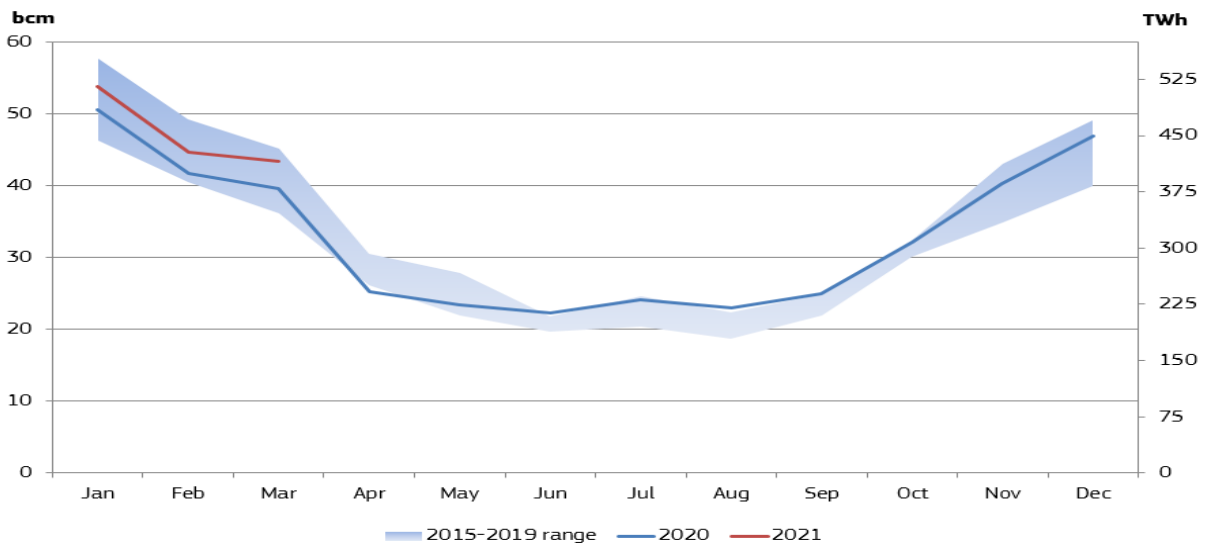
- **Energy markets (including oil, gas and coal) and emission allowance trade in the first quarter of 2021 continued to be in a positive mood, and the direction of price movements was generally upwards. Wholesale gas prices in Europe were largely impacted by the high price premium of East Asian gas markets in January 2021, resulting in redirection of LNG cargoes towards Asia and reducing gas supply in Europe, which prompted a price spike on the TTF and other hubs. This reflected the globalised nature of natural gas markets and reminded Europe that Asian markets can swiftly and significantly influence European hub prices, a phenomenon last seen in 2018.**
- Although GDP in the EU was still down by 1.2% in Q1 2021 in year-on-year comparison, signalling that the EU economy could still not recover and reach the pre-pandemic level, **EU gas consumption was up by 7.6%** (10 bcm) compared to Q1 2020, after the slight increase (2.4%) in the fourth quarter of 2020 and the stagnation in Q3 2020. Consumption of gas in electricity generation was up by 3.4% in Q1 2021, and the widespread practice of teleworking might also have contributed to the overall increase in gas consumption in the residential sector. However, weather in Q1 2021 was milder than usual, but occasional cold spells also impacted gas consumption for residential heating needs. Gas consumption in Q1 2021 was 141.8 bcm, up from 131.7 bcm in Q1 2020.
- Indigenous **gas production in the EU, amounting to 13.8 bcm in Q1 2021, was down by 11%** (1.7 bcm) compared to Q1 2020, and reached the second lowest quarterly production over the last decade. In Q1 2021 the Netherlands produced 6.1 bcm of gas, down by 13% year-on-year. Romania produced 2.4 bcm of gas, followed by Poland (1.4 bcm) and Germany (1.2 bcm). As gas production at the Groningen field will be cut to half in its final year of regular extraction in 2021/2022, the Zebrugge LNG terminal operator announced a gradual extension of the re-gasification capacity by 2026 to enable more LNG imports in Belgium, replacing natural gas imports from the Netherlands.
- **EU net gas imports fell by 3% year-on-year** (by 2.5 bcm) in Q1 2021. Russian pipeline supplies covered 45% of extra-EU net gas imports. Norwegian pipeline gas was the second most important source (23%), LNG imports together covered 20% of the total EU imports. Pipeline imports from Algeria more than doubled year-on-year, and covered 12% of the total extra-EU gas imports in Q1 2021, as oil-indexed price contracts became competitive vis-à-vis increasing gas hub prices. The share of Libya was slightly more than 1% and the recently inaugurated Trans Adriatic Pipeline (TAP) ensured 1.2% of the total extra-EU gas imports. Net gas imports amounted to 78.5 bcm in Q1 2021, down from 81 bcm in Q1 2020.
- **Nord Stream remained the most important supply route of Russian pipeline gas to the EU in Q1 2021**, having a share of 41% in the Russian pipeline imports (15 bcm of gas transit), the Belarus transit came to the second place, with a share of 29% with 10 bcm gas transit. The Ukrainian transit was only the third most important supply route for Russian pipeline gas, with a share dropping to 22% (8 bcm), ahead of Turk Stream (8%, with slightly less than 3 bcm).
- **EU LNG imports fell by 29% year-on-year** in Q1 2021, amounting to 17 bcm. Imports were down especially in January and February, when Asian wholesale gas markets had the aforementioned significant price premium to Europe, which resulted in LNG cargo redirections towards the Asian markets. Spain remained the biggest LNG importer in the EU (with imports amounting to 4.3 bcm), closely followed by France (4.2 bcm) and Italy (2.1 bcm). The United States were the largest LNG source for the EU, ensuring 4.2 bcm imports, followed by Russia (3.7 bcm) and Qatar (3.1 bcm). The EU remained the third biggest LNG market after Japan (36 bcm) and China (32 bcm) in Q1 2021.
- **Gas storage levels in the EU fell to 30% by the end of March 2021**, which was 24% lower than at the end of March 2020, implying higher refilling needs in the following two quarters, which additional demand had an upward impact on wholesale gas prices during the spring months of 2021. In Q1 2021 higher spot market prices increased the competitiveness of consuming gas from storages, injected at lower costs earlier in 2020.
- **Gas traded volumes on the European hubs fell by 13% (by 2 705 TWh)** in Q1 2021 year-on-year, after the temporary increase in the previous quarter. Amid decreasing gas, and especially falling LNG imports, storage withdrawals intensified to satisfy gas consumption but this did not manage to boost gas trade. Trading volumes were mainly driven by near-curve contracts on the European hubs. The Dutch TTF remained the most liquid hub in Europe, pooling around three quarters of all European gas trade.
- **Spot prices on the European gas hubs in Q1 2021**, after reaching two-year high in January 2021, fell in February, but in March they started to rise again. Compared to the previous quarter, prices were up by around 25-30%, however, in year-on-year comparison wholesale gas spot prices rose significantly, by 70-100%, in comparison to the trough in spring 2020. Spot gas prices in Q1 2021 were in the range of 18-20 €/MWh. Forward contracts were lower than spot prices (backwardation) in January 2021, which disappeared by mid-February but started to reappear in March, as spot prices were on an upward trajectory again.
- **Retail gas prices for household customers showed an increase of 9% year-on-year in Q1 2021, while industrial customers faced a decrease of 9% in the same period.** With the exception of seven countries, gas prices for households in European capital cities were higher in May 2021 compared to the same month of 2020, implying that recent price increases on wholesale gas markets started to filter in some retail contracts.
- **Hydrogen costs-based assessments** showed that in the Netherlands **production costs of hydrogen** (without capital expenditure costs) with alkaline electrolyser technology amounted to 76 €/MWh in March 2021, whereas with polymer electrolyte fuel cells the cost was assessed to 85 €/MWh, and with steam methane forming at around 30 €/MWh.

# 1. Gas market fundamentals

## 1.1 Consumption

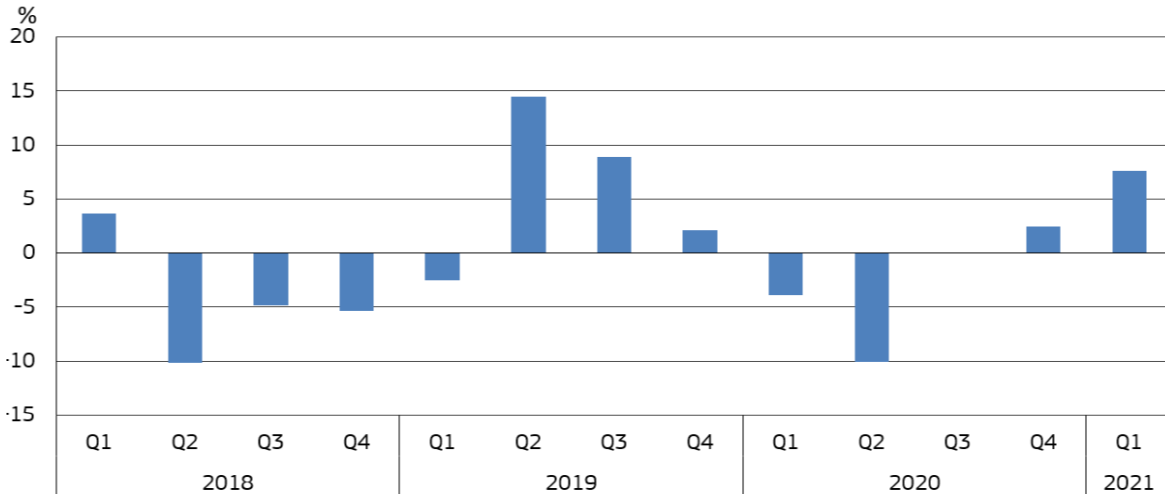
- EU gas consumption<sup>1</sup> in the first quarter of 2021 rose by 7.6% (10 bcm) in year-on-year comparison, after practically stagnating in the third quarter of 2020 and a slight increase (2.4%) in Q4 2020. In absolute numbers, the quarterly gas consumption in Q1 2021 amounted to an estimated 141.8 bcm, up from 131.7 bcm in Q1 2020, and rising from 120.6 bcm in Q4 2020, with the peak of the heating season in the first three months of the year. In electricity generation, demand for gas rose by 3.4% year-on-year (increasing by 4.9 TWh). Weather across Europe was generally warmer than usual in Q1 2021, but in January and February occasional cold spells also impacted residential heating needs. However, widespread practice of teleworking might also 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 first quarter of 2021 gas consumption in the EU was higher than in the same months of 2020, closer to the upper range of the last five years.

**Figure 1. EU gas consumption**



Source: Eurostat, data as of 2 June 2021 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 (%)**

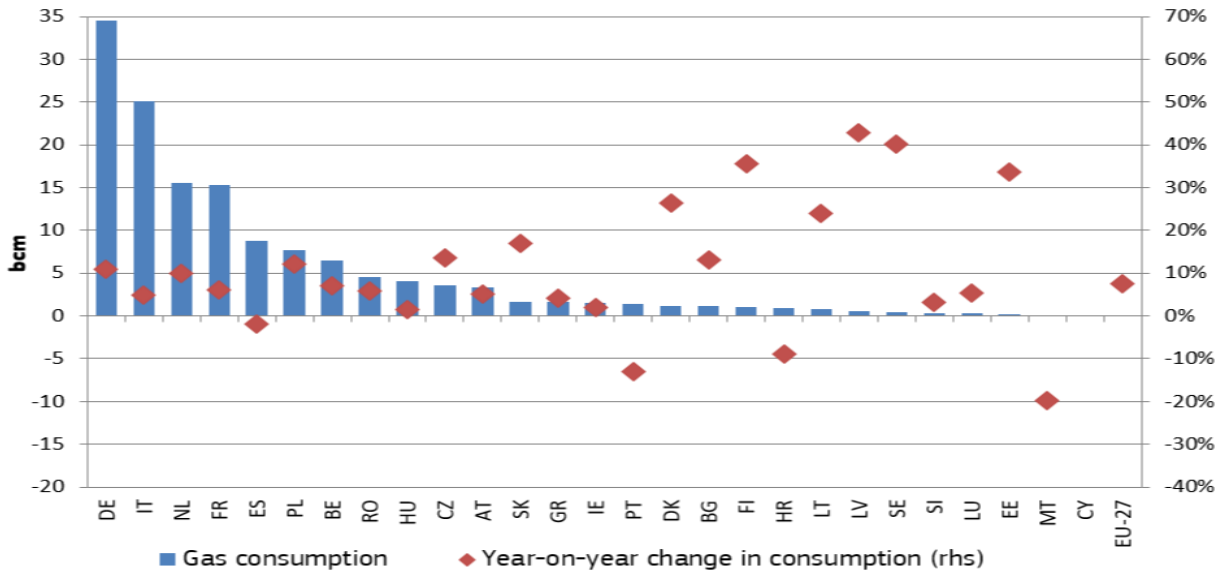


Source: Eurostat, data as of 2 June 2021 from data series nrg\_103m. In the next edition of this report numbers might change retrospectively

<sup>1</sup> EU aggregates, unless otherwise indicated, refer to EU-27, and in order to ensure comparability over time, values of earlier periods and year-on-year 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 first quarter of 2021, the biggest year-on-year percentage decrease in gas consumption could be observed in Malta (by -20%, though with marginal quantity), Portugal (by -13%, -0.2 bcm), and Croatia (by -9%, -0.1 bcm). Out of the bigger gas consumer countries, only Spain faced a decrease in consumption in Q1 2021 (by -2%, -0.2 bcm). In all other 22 Member States (no data available for Cyprus) gas consumption in Q1 2021 was up year-on-year. Gas consumption, in order of percentage changes, rose by the most in Latvia (43%, by 0.2 bcm), Sweden (by 40%, 0.1 bcm) and in Finland (by 36%, 0.3 bcm). Among the five biggest gas consumer countries, consumption went down in Spain (see above), whereas it rose in Germany (by 11%, 3.4 bcm), in the Netherlands (by 10%, 1.4 bcm), in France (by 6%, 0.9 bcm) and in Italy (by 5%, 1.2 bcm). In Q1 2021 there were twelve EU Member States where the year-on-year change in gas consumption was greater than 10%.

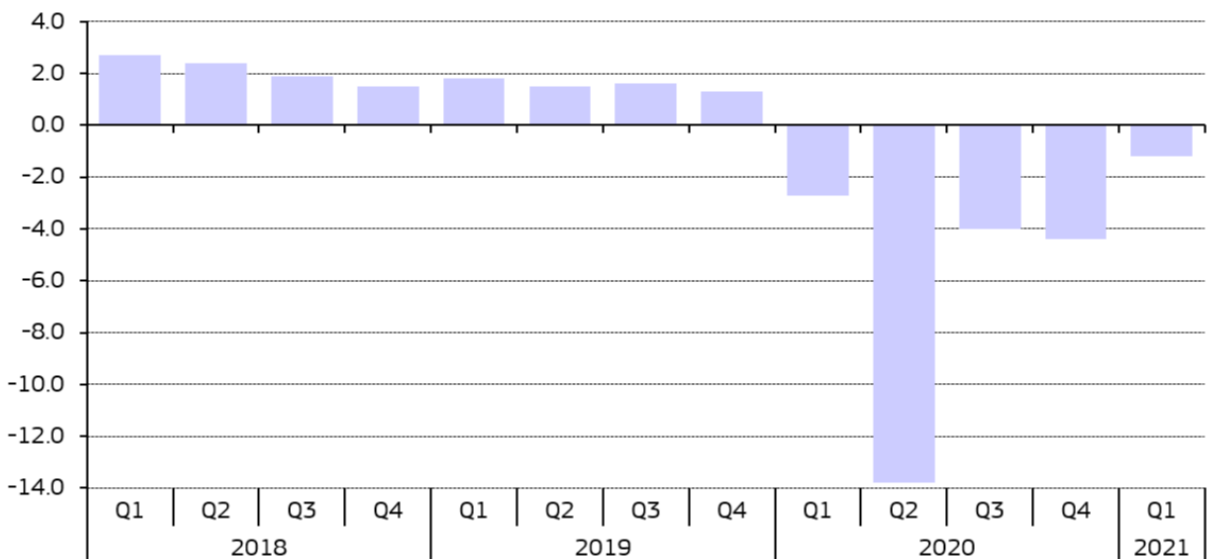
**Figure 3 Year-on-year change in gas consumption in the first quarter of 2021**



Source: Eurostat, data as of 2 June 2021 from data series nrg\_103m. In the next edition of this report numbers might change retrospectively

- In the first quarter of 2021, GDP in the EU-27 was still down by 1.2% in year-on-year comparison, after registering a decrease of 4.6% year-on-year in Q4 2020. The EU economy still could not get back to its pre-pandemic level. However, natural gas consumption managed to increase in Q1 2021 year-on-year, even if GDP decreased, which points to an increase in those sectors that consume significant amount of gas.

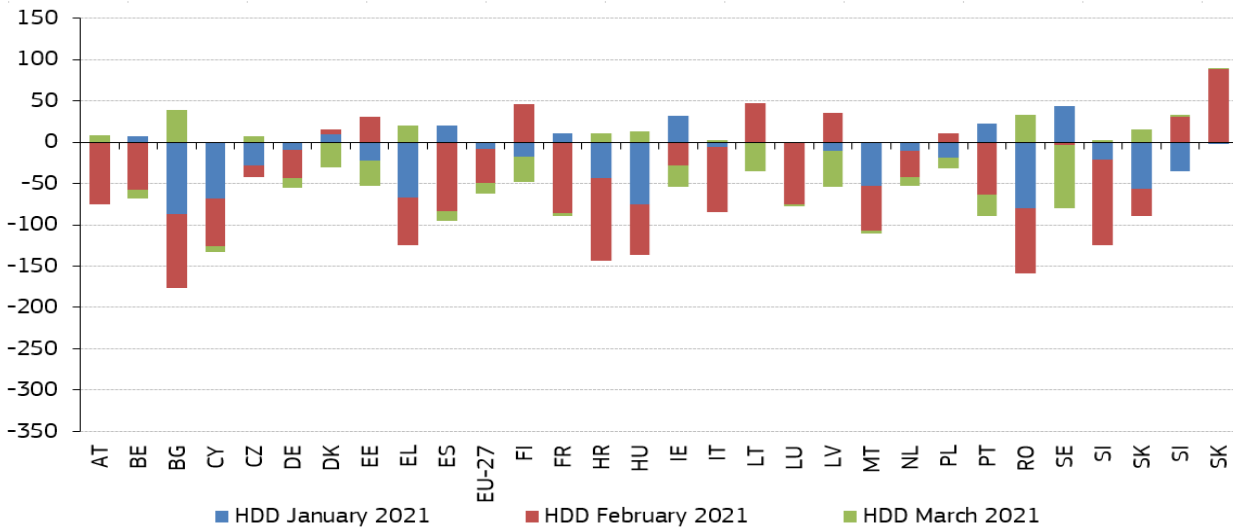
**Figure 4 Change in EU27 GDP, in year-on-year comparison (%)**



Source: Eurostat, data as of 8 June 2021 from data series namq\_10\_gdp - Seasonally and calendar adjusted data

- Figure 5 shows the deviation of actual heating degree days (HDDs) from the long-term average<sup>2</sup> in individual EU Member States in the first quarter of 2021. In most of the EU countries, the first quarter of 2021 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. January 2021 was colder than usual in Sweden, Ireland and Spain than usual, whereas the impact of the cold wave in mid-February can be clearly see on the figures of Slovakia, Finland, Lithuania, Latvia, Estonia and Slovenia. March 2021 was colder than usual in Bulgaria, Romania, Slovakia and Greece. Occasional cold spells in many parts of Europe resulted in temporary wholesale gas price increases.

**Figure 5 Deviation of actual heating degree days (HDDs) from the long-term average in the first quarter of 2021**



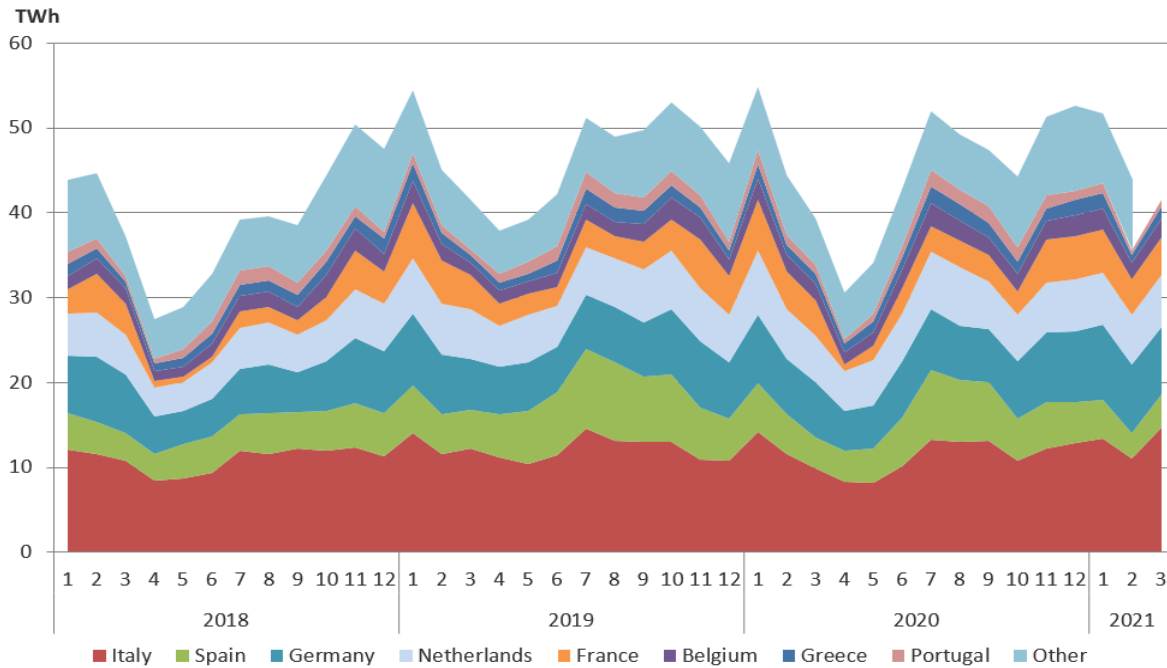
Source: Joint Research Centre (JRC), European Commission

- Based on data from ENTSO-E, gas-fired power generation increased by 3.4% in the first quarter of 2021 in the EU, compared to the same period of 2020. In absolute terms, electricity generated from gas went up by 4.9 TWh year-on-year, as Figure 6 shows. In Q1 2021 gas wholesale prices remained relatively stable. Increasing gas prices were not favourable to generation costs and profitability of gas-fired generation.
- In year-on-year comparison the share of renewables in the EU power generation mix decreased slightly in Q1 2021. Wind, solar, biomass and hydro together represented around 38% of the EU power mix (down from 39.5% in Q1 2020), leaving only a smaller share for gas (around 20%, practically unchanged year-on-year). The share of power generation from solid fuels rose slightly, from 12% to 14%<sup>3</sup>, as coal and lignite-fired generation together rose by 17% in Q1 2021 year-on-year. Nuclear generation remained practically unchanged in Q1 2021 year-on-year, and its share was 26%. Carbon prices showed a measurable increase over the course of Q1 2021, rising from 33 €/MtCO<sub>2e</sub> to 42 €/MtCO<sub>2e</sub>, which, through increasing generation costs, did not contribute either to the competitiveness of fossil fuels in EU power generation.
- In Q1 2021 the amount of electricity generated from gas fell in Spain by 18% in year-on-year comparison, and in France and in the Netherlands it was respectively down by 6% and 4%. At the same time, gas-fired generation rose by 18% in Germany and by 10% in Italy. 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 Q1 2021. In France the decrease in gas, nuclear and wind fired generation was compensated by rebounding coal and biomass. In the Netherlands the decrease in gas-fired generation was compensated by rebounding wind, biomass and solar, and coal-fired generation also went up. In Germany increasing gas, and more importantly, rebounding coal and lignite-fired generation replaced dwindling renewable sources in Q1 2021. In Italy the increase in gas-fired generation covered the total incremental power production, reducing import needs, while other generation sources showed mixed picture.

<sup>2</sup> Long term average temperatures, heating and cooling degree days refer to the period between 1978 and 2018

<sup>3</sup> See more information in Quarterly Report on the European Electricity Markets, Vol. 14, Issue 1

**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 25 June 2021

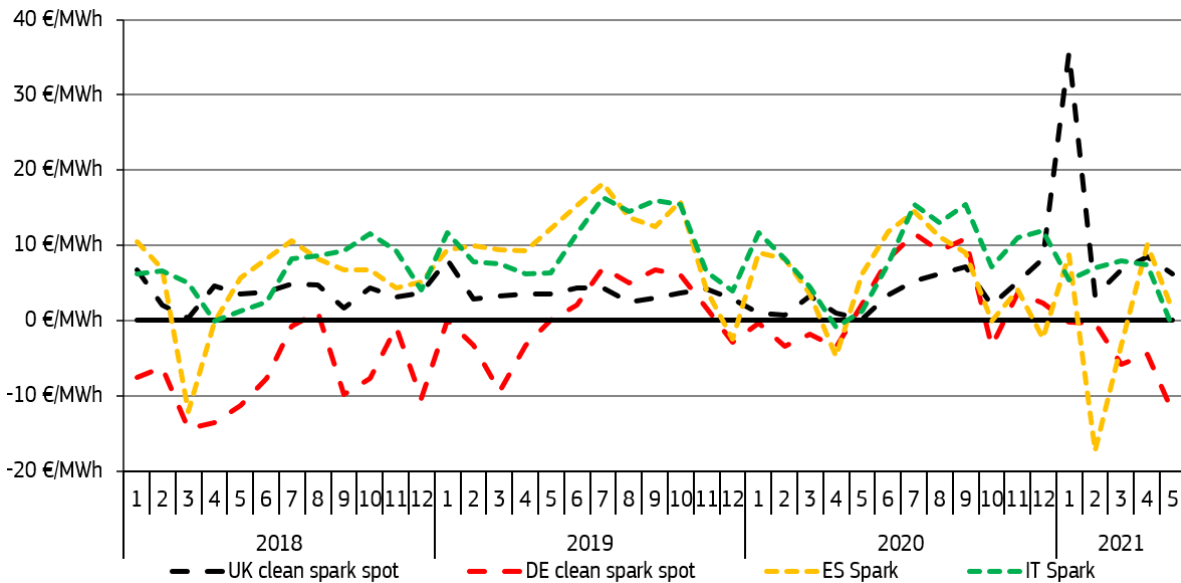
- Clean spark spreads – measuring the profitability of gas-fired generation by taking into account variable costs – reached respectively -2.1€/MWh, -3.9€/MWh and 6.8€/MWh in Germany, Spain and Italy in Q1 2021, which were definitely lower compared to the previous quarter values (respectively 0.9 €/MWh, 0.5 €/MWh and 10.4 €/MWh). This decrease in the clean spark spreads implied a decreasing profitability of gas-fired generation<sup>4</sup> in the biggest markets of continental Europe (See Figure 7<sup>5</sup>). The impact of increase in gas prices and carbon prices in Q1 2021, compared to the previous quarter, 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 15.2 €/MWh in Q1 2021, up from 5.1 €/MWh in the previous quarter. However, this increase was principally owing to the outstandingly high January spread – 36 €/MWh, when price spikes on the gas market resulted in extremely high wholesale electricity prices and high profitability of gas-fired generation. In the UK increasing gas prices have normally bigger upward impact on wholesale electricity prices, preserving the profitability of gas-fired generation. In February and March clean spark spreads returned to the levels close to Q4 2020. However, as wholesale electricity prices were higher in the UK than in continental Europe, profitability of gas-fired generation remained higher. Electricity generated from gas was up by 7% in Q1 2021 year-on-year, and the share of gas-fired generation was 42% in the same period, as opposed to 32% in Q1 2020.

<sup>4</sup> Assuming an average gas power plant efficiency, see more in the Glossary

<sup>5</sup> Charts of clean spark spreads can also be found in the Quarterly Report of European Electricity Markets (Vol. 14, Issue 1). Data on the share of gas in electricity generation come from the database of ENTSO-E



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



Source: Bloomberg

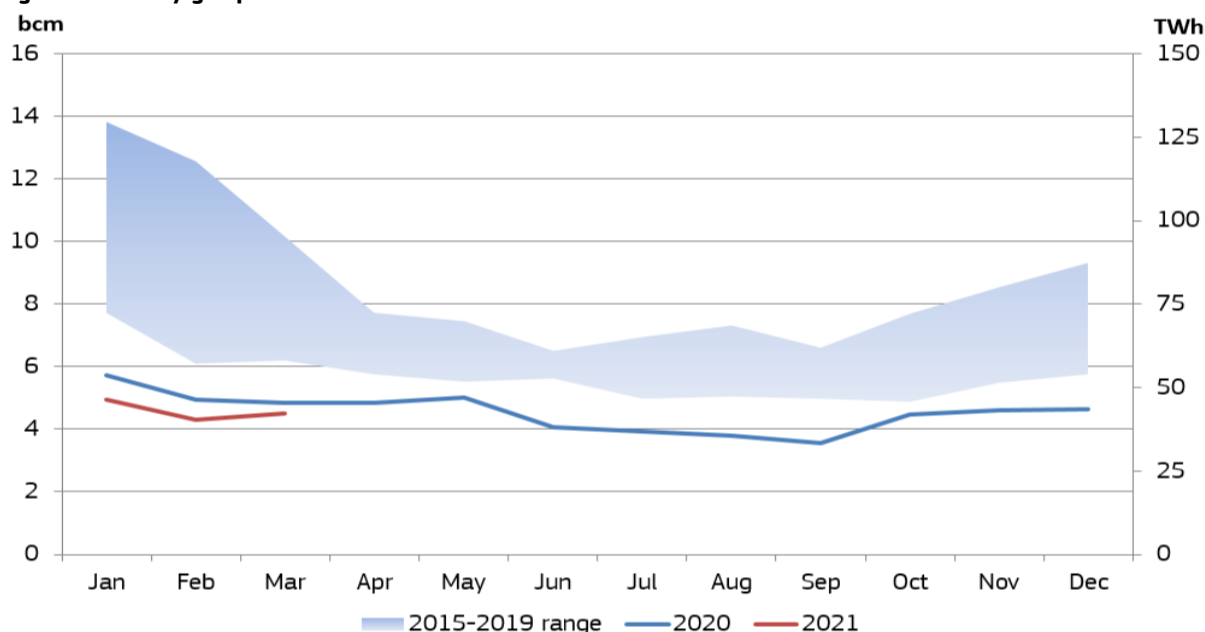
## 1.2 Production

- In the first quarter of 2021, EU gas production reached approximately 13.8 bcm<sup>6</sup>, 11% (1.7 bcm) less than in the same quarter of 2020 (See Figure 8). During the whole Q1 2021, similarly to the previous 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 Q1 2021 was the second lowest quarterly figure (a bit higher than the trough of Q3 2020 – 11.3 bcm).
- In the biggest EU producer Netherlands, natural gas production in Q1 2021 decreased significantly, by 13% (by 0.9 bcm), amounting to 6.1 bcm. In Romania, being the second biggest gas producer in the EU, production went down by 7% (0.2 bcm), falling to 2.4 bcm in Q1 2021, which was equal to the production level of the previous quarter. Gas production decreased slightly (2%, 0.04 bcm) in Poland in Q1 2021 and amounted to 1.4 bcm.
- In Germany, Italy and Ireland, where production respectively amounted to 1.2 bcm, 0.9 bcm and 0.4 bcm in Q1 2021, year-on-year decreases varied between 7% and 25% and production went down by around 0.1 bcm in each country. Gas output in Denmark still showed a very strong decrease (by 21%, 0.1 bcm year-on-year, principally owing to the redevelopment of the Tyra field in the Danish North Sea, which will come online only in 2023). The country produced 0.3 bcm of gas in Q1 2021.
- Gas production in Norway decreased by 6%, from 31.1 bcm in Q1 2020 to 29.1 bcm in Q1 2021. According to the forecast<sup>7</sup> of the Norwegian Petroleum Directorate gas production in the country will reach around 115 bcm per year in the period of 2021-2025.

<sup>6</sup> Given that in some countries data for some periods are based on estimation, this number might retrospectively change

<sup>7</sup> <https://www.norskpeteroleum.no/en/production-and-exports/production-forecasts/>

**Figure 8 Monthly gas production in the EU**



Source: Eurostat, data as of 10 March 2021 from data series nrg\_103m. In the next edition of this report numbers might change retrospectively.

### 1.3 Imports

- According to Eurostat<sup>8</sup>, net gas imports in the EU decreased by 3% (2.5 bcm) in the first quarter of 2021 (year-on-year), even if gas consumption rose and domestic production in the EU continued to fall. Net imports in different EU countries showed a high variation in Q1 2021. In the Netherlands net imports fell from 2.2 bcm to 0.1 bcm year-on-year, whereas in Slovakia it fell from 0.9 bcm to practically zero over the same period, implying a 97% drop in both countries. On the other hand, in Czechia net imports rose by 45% (0.6 bcm), in Sweden by 39% (by 0.1 bcm) and in Estonia, Finland and Lithuania respectively by 34%, 33% and 32%, implying an increase of 0.1 bcm to 0.2 bcm in each of these countries in Q1 2021, year-on-year. Among big gas consumer countries, net imports decreased in Germany (10%, by 2.3 bcm), whereas in net imports were up in Poland (by 30%, 1.1 bcm), France (by 21%, 1.7 bcm), Italy (by 7%, 1.1 bcm), and Spain (by 3%, 0.2 bcm). In Belgium net imports remained practically unchanged, in Q1 2021 year-on-year.
- In the first quarter of 2021, the total net extra-EU gas imports reached 78.5 bcm, down by 3% (2.5 bcm) from 81 bcm in the same period of 2020. The five biggest importers in the EU were Germany (22 bcm), Italy (17 bcm), France (10 bcm), Spain (8 bcm), and Belgium (6 bcm), representing together more than 85% of the total EU net gas imports in Q1 2021.
- According to ENTSO-G data, net imports amounted to 865 TWh in the first quarter of 2021, of which 80% arrived through pipelines and almost 20% through LNG terminals. Pipeline gas imports from Russia, in contrast to the previous quarter, rose by 9% in year-on-year comparison. Imports from Norway were slightly down, by 2% in Q1 2021 in year-on-year comparison. Pipeline gas imports from Algeria, continuing the trend of the previous quarter, showed a triple-digit increase (141%) in Q1 2021. Pipeline gas imports from Libya fell further, by 18% year-on-year. At the same time, LNG imports reached 170 TWh in Q1 2021.
- 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 was 45% in the first quarter of 2021, up from 41 % in Q1 2020<sup>9</sup>.
- The share of pipeline gas imports from Norway was 23% in the first quarter of 2021, practically identical to Q1 2020, as pipeline gas imports from Norway (2%) decreased by a similar extent as the overall gas imports<sup>10</sup>. In the first quarter of 2021, Norwegian gas production<sup>11</sup> amounted to 29.1 bcm, decreasing by 6% year-on-year.

<sup>8</sup> Net imports equal imports minus exports and do not account for stock changes.

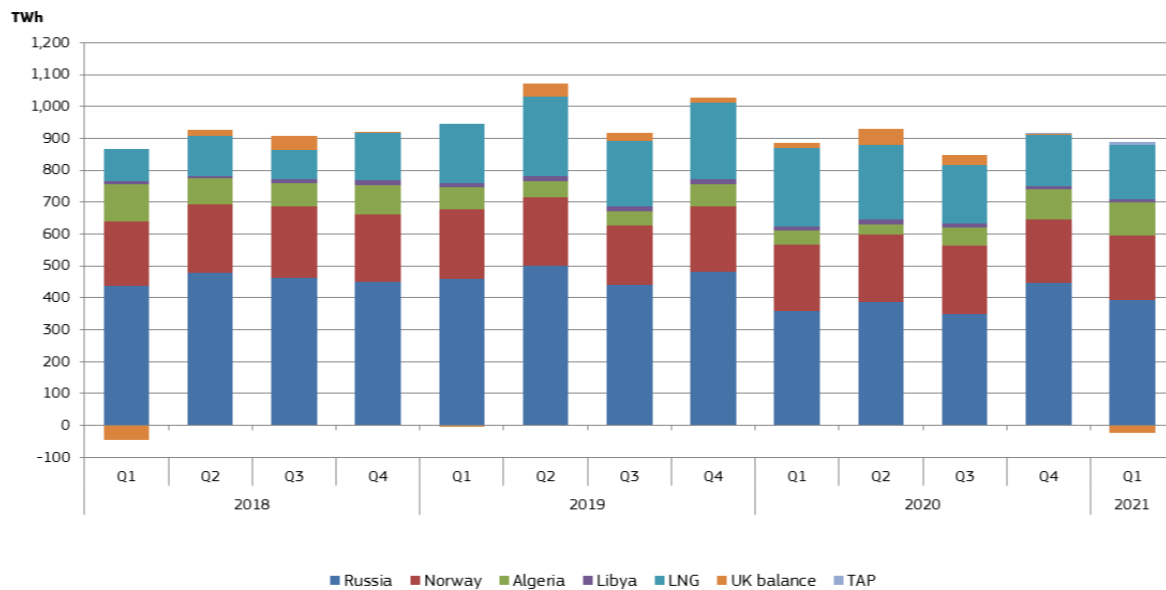
<sup>9</sup> It is worth to note that Russia increased its importance in the EU LNG imports as well over the last two-three years, numbers presented in this section, with the exception of LNG or unless otherwise indicated, refer to pipeline imports

<sup>10</sup> Note that Norway to UK flows reported by ENTSO-G includes some gas from UK offshore fields, resulting in an overestimation of Norwegian imports.

<sup>11</sup> <https://www.npd.no/en/facts/news/Production-figures/2020/production-figures-march-2020/>

- In the first quarter of 2021, pipeline gas imports from Algeria increased significantly, by 141% year-on-year, which resulted in an increasing share within the total extra-EU imports (12% in Q1 2021, being the highest share since Q4 2017, and up from 5% in Q1 2020). Increasing pipeline gas imports from Algeria must have been related to the oil-indexed contracts, becoming competitive to hub based pricing, in consequence of the time-lagged impact of the oil price fall in 2020 and the recent increase in wholesale gas prices on the European hubs. Imports from Libya continued to fall and its share was only 1.1% in the total EU gas imports.
- In Q1 2021, the share of LNG was 19.6% in the total EU gas imports, which was although higher than in Q4 2020 (17.6%), but 8 percentage points lower than in the first quarter of 2020. Decreasing LNG imports in the EU was principally owing to high price premium of the Asian gas markets to Europe, especially in January 2021, resulting in redirection of LNG cargoes towards Asia. It seems that the decreasing share of LNG between the first quarters of 2020 and 2021 (and less inflows from the UK) was mainly compensated by the increasing share of Algerian and Russian pipeline sources in EU gas imports.
- At the end of 2020 the new Trans Adriatic Pipeline became operational, and in the first quarter of 2021 it ensured around 10 TWh gas imports in the EU, around 1.2% of the total imports. The TAP is a key project of the Southern Gas Corridor, providing access to gas sources from Azerbaijan, with key EU destinations of Italy, Greece and Bulgaria.

**Figure 9 - EU imports of natural gas by source, 2018-2021**



Source: Based on data from the ENTSO-G Transparency Platform, data as of 2 June 2021.

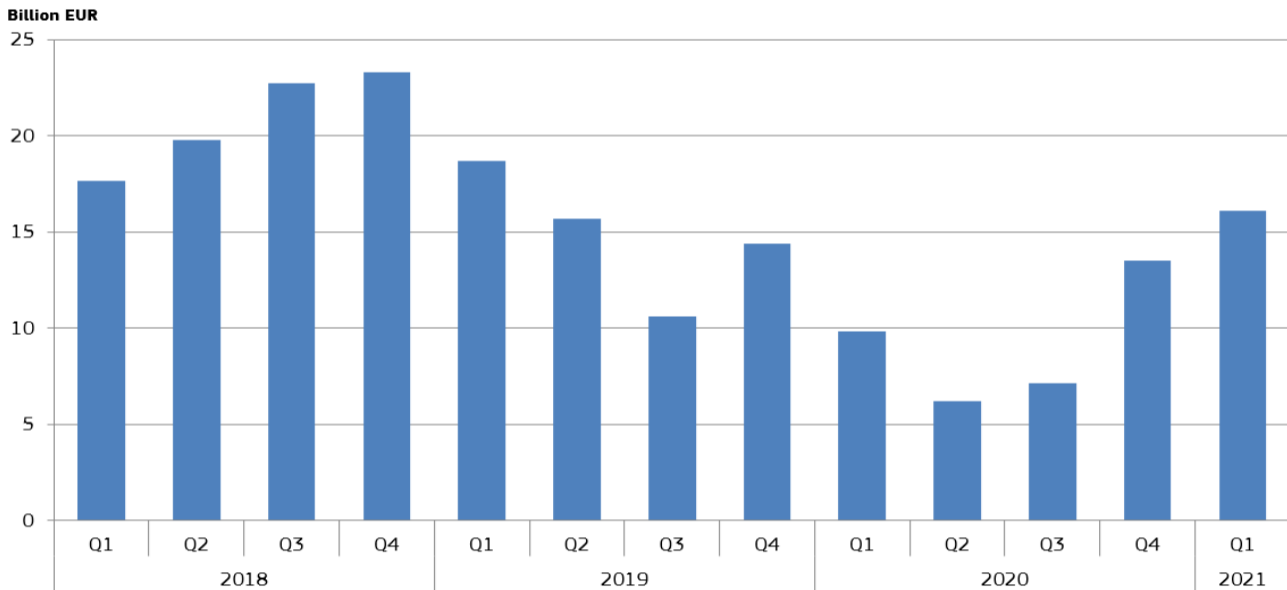
Exports to the Baltic-states and Finland are not included in the chart owing to unavailability of reliable data

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 or LNG imports from the UK, etc.). As of 2021, imports via the Trans Adriatic Pipeline (TAP) is also included.

- Due to the combined impact of slightly decreasing import volumes and significantly increasing average import prices year-on-year, in the first quarter of 2021 the estimated gas import bill amounted to €16.3 billion, in comparison to €9.9 billion in Q1 2020, rising by 65% year-on-year. Wholesale gas prices in Europe, following an increasing trajectory, were up by 69% in Q1 2021 year-on-year. The quarterly gas import bill was also up in Q1 2021 compared to the previous quarter (€13.5 billion in Q4 2020).

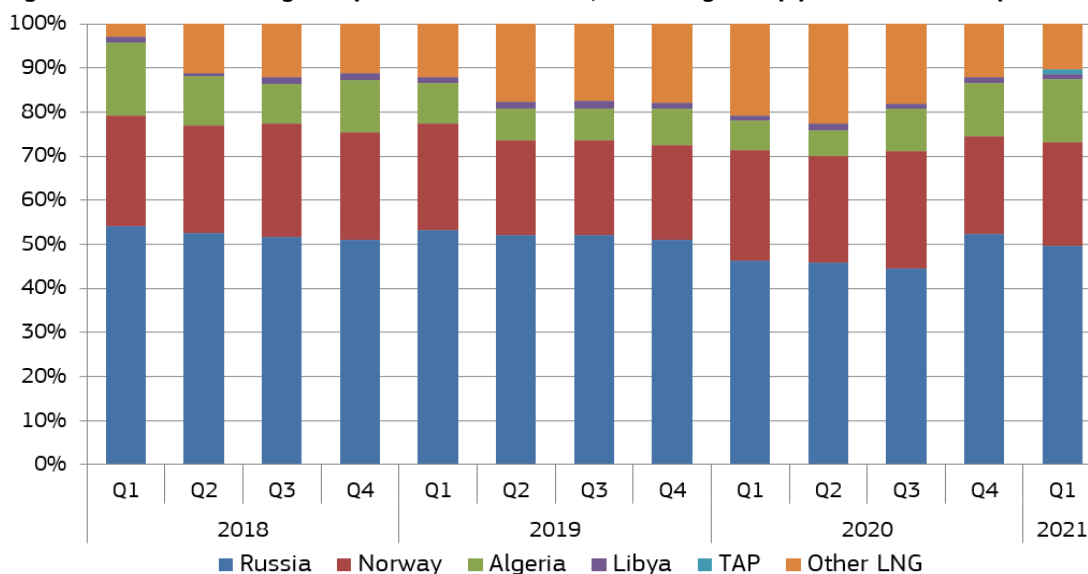
**Figure 10 – Estimated quarterly extra-EU gas import bill, in billions of euros**



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 11 shows, the share of Russia within total extra-EU gas imports (pipeline and LNG together) amounted to 50% in Q1 2021, split by 45% of pipeline imports and 5% 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 41% to 45% within the total extra-EU gas imports, by taking into account LNG the share of Russia rose from 46% to 50% in Q1 2021 year-on-year.
- The share of Norway was 24% in Q1 2021 (similar to 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 was more than 14% with LNG (as opposed to 12% only including pipeline gas) within the total extra-EU gas imports. The share of LNG fell to barely 10%, (on the top of LNG accounted in shipments from Russia, Norway and Algeria), practically halving (10 percentage points drop) since Q1 2020, which was the lowest since Q1 2018. Decreasing share of LNG between the first quarters of 2020 and 2021 was mainly compensated by the increasing shares of Algeria and Russia. The share of the new TAP pipeline was 1.2% in the total extra-EU gas imports in Q1 2021.

**Figure 11 – The share of gas imports within the total, combining both pipeline and LNG imports**

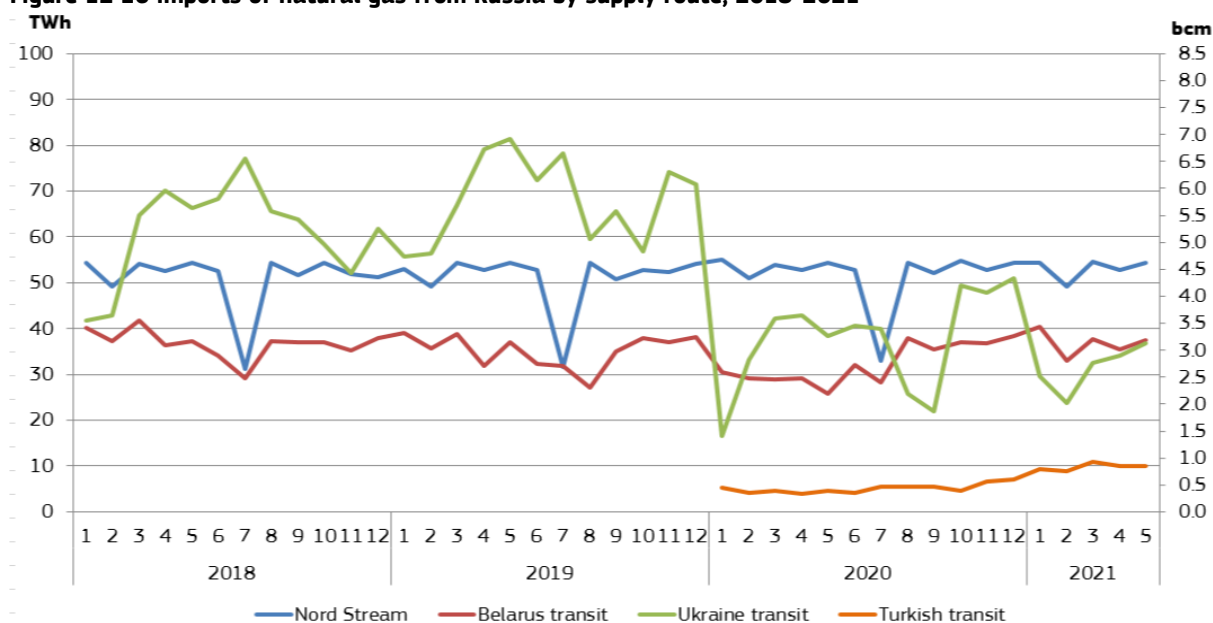


Source: Based on data from the ENTSO-G Transparency Platform, data as of 2 June 2021.

### 1.3.1. Pipeline imports from Russia and EU supply to Ukraine

- Figure 12 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 first quarter of 2021, the volume of Russian imports rose by 9%, if compared with the same quarter of 2020. As shown on Figure 12, gas flows transiting Ukraine were almost 7% lower than in Q1 2020, which is still significant, even if less steep fall than that in the previous quarter (27%). During Q1 2021 a monthly average of 2.7 bcm of gas of Russian origin was transited through Ukraine, implying a decrease compared to Q1 2020 (2.9 bcm), and a drop compared to the last quarter of 2020 (4.6 bcm), when imports ramped up at the beginning of the winter season and ahead of year-end fulfilling the annual shipment contractual obligation of 2020.
- Flows through Belarus were up by more than 25% in Q1 2021 year-on-year. Transited volumes through the Nord Stream were slightly down by 1% in Q1 2021 compared to the first quarter of 2020.
- As a result, in Q1 2020 Nord Stream remained the main supply route of Russian gas to Europe, as its share reached 41% of the total Russian pipeline gas imports in the EU, though down from 45% a year earlier. The Belarus transit route became the second most important supply route, representing 29% in Q1 2021, up from 25% in Q1 2020. The share of the transit through Ukraine fell to the third place again, ensuring only 22% of the total Russian pipeline gas transit, down from 26% a year earlier. The share of Turk Stream practically doubled within a year, reaching 8% in Q1 2021, compared to only 4% in Q1 2020, as Gazprom started to supply some of its Balkan clients (e.g. Serbia, Bosnia) using the pipeline through Bulgaria, instead of the route through Ukraine and Hungary.
- In Q1 2021 Nord Stream represented 19% (15 bcm) in the total net extra-EU gas imports, the Belarus transit route ensured 13% (10 bcm) and the Ukrainian transit had a share of 10% (8 bcm). At the same time, the Turk Stream had a share of more than 3%, with around 2.7 bcm gas transit within the total net extra-EU gas imports in Q1 2021. It seems that in Q1 2021 the European demand increase for Russian gas was principally satisfied via the Belarus route and the Turk Stream, whereas the Ukrainian transit decreased further, amid stagnating volumes on Nord Stream.

**Figure 12 EU imports of natural gas from Russia by supply route, 2018-2021**



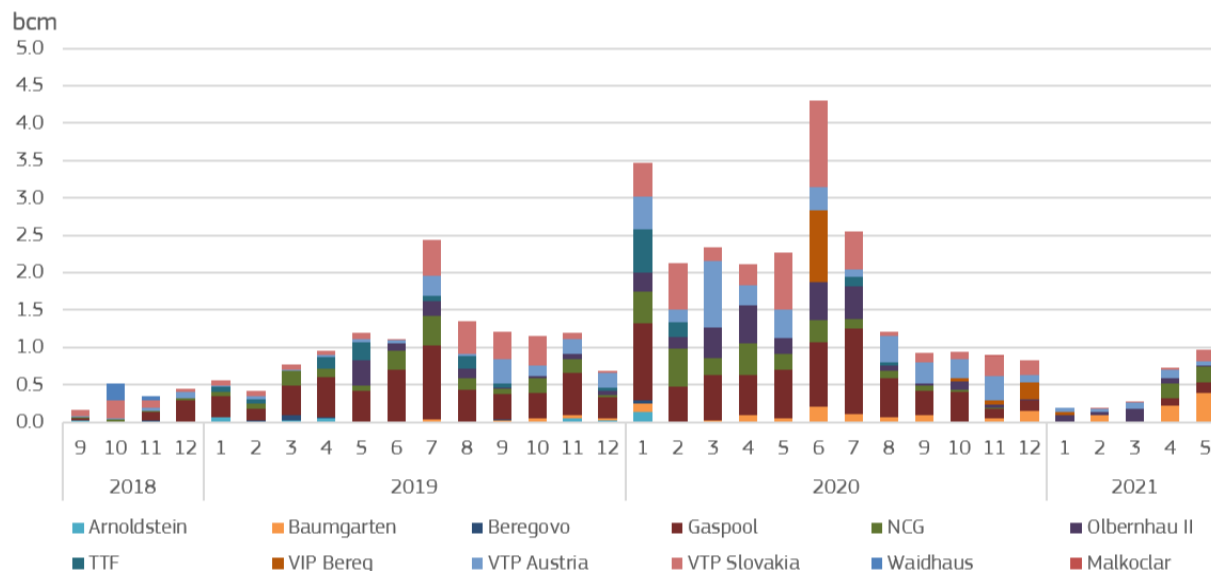
Source: Based on data from the ENTSO-G Transparency Platform, data as of 2 June 2021.

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.

- Traded volumes on Gazprom Electronic Sales Platform (ESP) reached the lowest in Q1 2021 since the start of trading in September 2018, amounting only to 0.64 bcm in the quarter, whereas in Q4 2020 the total trade volume was still 2.7 bcm, and in Q1 2020 it amounted to almost 8 bcm, implying a 92% decrease year-on-year in Q1 2021.
- Decreasing volumes mainly impacted the short term trade contracts, which 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.

Gazprom preferred to rely on withdrawals from own storages on the EU territory to supply its clients, given that the average costs of injected gas was much lower compared to hub prices in Q1 2021. In Q1 2021 the principal delivery points from ESP sales were Olbernhau on the German-Czech border (0.3 bcm) the Austrian virtual trading point (VTP Austria – 0.18 bcm) and Baumgarten (0.1 bcm).

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



Source: Gazprom Electronic Sales Platform

- According to data from the Ukrainian gas TSO, natural gas transportation from EU countries to Ukraine in the first quarter of 2021 amounted to 476 million cubic meters, which was 83% less than in the same period of 2020<sup>12</sup>. Ukraine imported 410.4 million cubic meters from Hungary, 65 million cubic meters from Slovakia and 0.2 million cubic meters of gas from Poland, and virtual reverse flows made up 86% of gas volumes. Ukrainian underground gas storage facilities stored record volumes of gas in Q1 2021 (at the beginning of January 2021 the Ukrainian storage filling rate stood at 62%), and Ukrainian suppliers used their own reserves from underground storage facilities. Over the past few years gas market in Ukraine has evolved in a storage balancing facility for European customers.

### 1.3.2.LNG imports

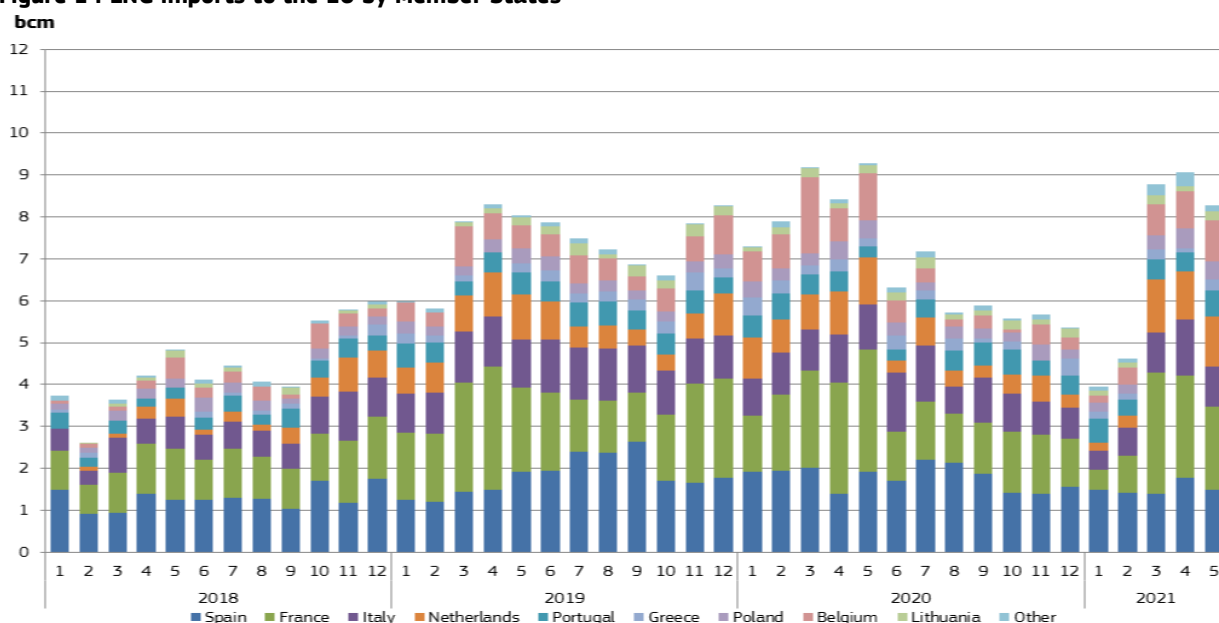
- LNG imports in the EU fell by 29% in Q1 2021 year-on-year, signalling the fourth consecutive quarter when a contraction could be observed in a row (after the decrease of 1% in Q2 2020 and the falls of 13% in Q3 2020 and 27% in Q4 2020). Looking at the three months of the quarter, EU LNG imports were respectively down by 46% in January, by 41% in February and only by 5% in March 2021, in year-on-year comparison. The quarterly LNG import in Q1 2021 in the EU was 17.3 bcm, a bit higher than in Q4 2020 (16.6 bcm), but down from Q1 2020 (24.4 bcm), as Figure 14 shows. The total number of LNG cargoes arrived in the EU was 239 in Q1 2021, up from 229 in Q4 2020 but significantly down from 308 in Q1 2020. With the exception of Finland, importing marginal amount of LNG (41 mcm) LNG import decreased in all major EU importer countries in Q1 2021 year-on-year.
- Croatia became the 13<sup>th</sup> EU Member State being capable to directly import LNG, at its regasification terminal in Krk. In January one cargo arrived to Krk, followed by two others in March, and the country imported 283 million cubic metre LNG in Q1 2021. The new regasification facility has important security of gas supply aspect for the Central Eastern European region, still largely dominated by pipeline imports from Russia.
- In Q1 2021 Spain remained the biggest LNG importer (with a quarterly import of 4.3 bcm, down by 27% year-on-year), closely followed by France, importing 4.2 bcm, showing a year-on-year fall of 23%. Italy was the third biggest importer, (2.1 bcm, falling by 26% year-on-year). The Netherlands came to the fourth place, with the quarterly imports amounting to 1.7 bcm, meaning a decrease of 33% year-on-year. Portugal imported 1.4 bcm of LNG in Q1 2021 (down by 12% year-on-year), In Belgium LNG imports amounted to 1.3 bcm (falling by 60% year-on-year), and Poland imported 0.7 bcm of liquefied natural gas, down by 21%

<sup>12</sup> <https://www.ukrinform.net/rubric-economy/3223182-ukraine-cuts-natural-gas-imports-in-q1-2021-by-83.html>

compared to Q1 2020. The total EU LNG imports amounted to an estimated €3.5 billion in Q1 2021, up from €2.6 billion a year before, as the combined result of decreasing LNG imports and sharply increasing wholesale gas prices (up by 69%) year-on-year.

- LNG imports in the United Kingdom fell measurably, though by a lesser extent than in the continental Europe, by 14% in Q1 2021, reaching almost 5.1 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.
- As in January 2021 Asian wholesale gas market prices showed a significant premium to the European markets (see Figure 24 and Figure 25), LNG cargos were directed to Asia to sell gas at higher profits, resulting in low cargo berthing in 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**

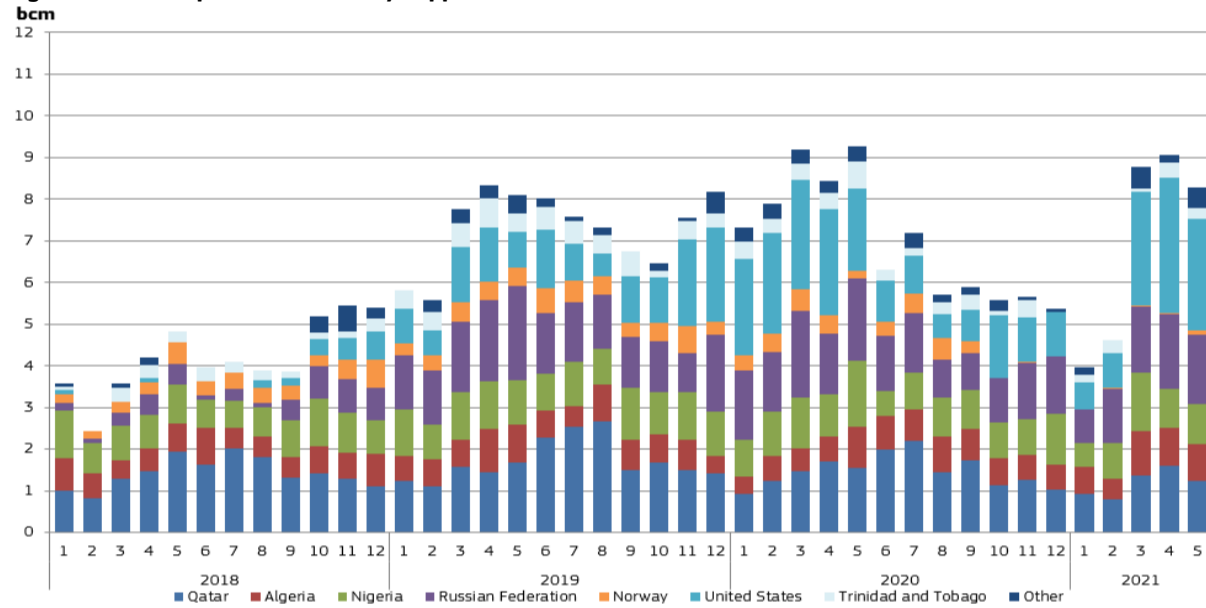


Source: Commission calculations based on tanker movements reported by Refinitiv "Other" includes Finland, Malta and Croatia

- In the first quarter of 2021 the United States was the largest LNG supplier of the EU, ensuring 24% (4.2 bcm) of the total EU LNG imports, closely followed by Russia (with an import share of 21% - 3.7 bcm) and Qatar (18% - 3.1 bcm). Compared to the previous quarter, Q4 2020, the share of the US rose by 2 percentage points whereas the share of Russia decreased by 2 percentage points and that of Qatar went down by 3 percentage points. Nigeria was the fourth biggest import source in Q1 2021, (with a market share of 16%, down by 2 percentage points to Q4 2020), followed by Algeria (13%). Trinidad and Tobago ensured 3% of imports – See Figure 15.
- In Q1 2021, Norway had a share of only 0.2% in total EU LNG imports, similarly to the share measured in the previous quarter (0.1%) and down from 7% in Q3 2020. This decrease can be explained by the ongoing outage of the Hammerfest LNG plant due to a fire incident<sup>13</sup> in September 2020, which, requires 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 still minimal to the EU in the forthcoming months.

<sup>13</sup> See more in the Quarterly Report on European Gas Markets, fourth quarter of 2020 (Vol 13, issue 4).

**Figure 15 LNG imports to the EU by supplier**



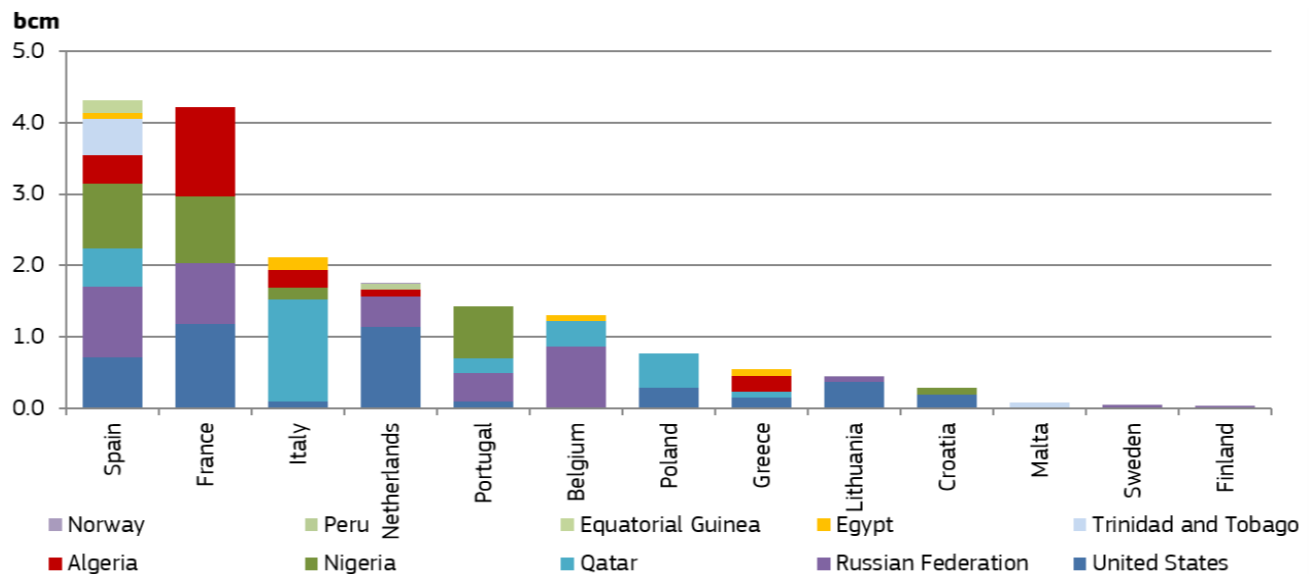
Source: Commission calculations based on tanker movements reported by Refinitiv

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 first quarter of 2021, the United States were the biggest LNG supplier in Lithuania (83% of the total LNG imports), Croatia (67%), the Netherlands (65%), Lithuania (84%), Greece (48%) and it came to the second place in Poland (37%), France (28%), and Spain (17%). Russia was the biggest supplier in Finland (78% of the country's total LNG imports), Sweden (76%), Belgium (66%), the Netherlands (45%), and was the second biggest in Portugal (28%), the Netherlands (25%) and Lithuania (16%), implying that Russian LNG has increasing importance in North-Western Europe, not independently from the dwindling domestic gas production in the Netherlands. Qatar was the biggest supplier in Italy (68%) and Poland (63%), and the second biggest in Belgium (28%).
- Nigeria was the biggest supplier in Portugal (51%), and the second biggest in Croatia (33%), whereas in France and Spain it respectively ensured 22% and 21% of all LNG imports. Algeria had the biggest share in the Greek and French LNG imports (respectively 40% and 30%) in Q1 2021. Trinidad and Tobago was the sole LNG supplier of Malta and ensured around 12% of LNG imports in Spain. Egypt had a share of 18% in the Greek LNG imports. Albeit having minimal exports, Norway ensured 24% of the Swedish LNG imports and had a share of 22% in the Finnish LNG imports. In Q1 2021 Spain had the most diversified LNG import source structure, receiving cargoes from eight different countries. 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 first quarter of 2021**



Source: Commission calculations based on tanker movements reported by Refinitiv

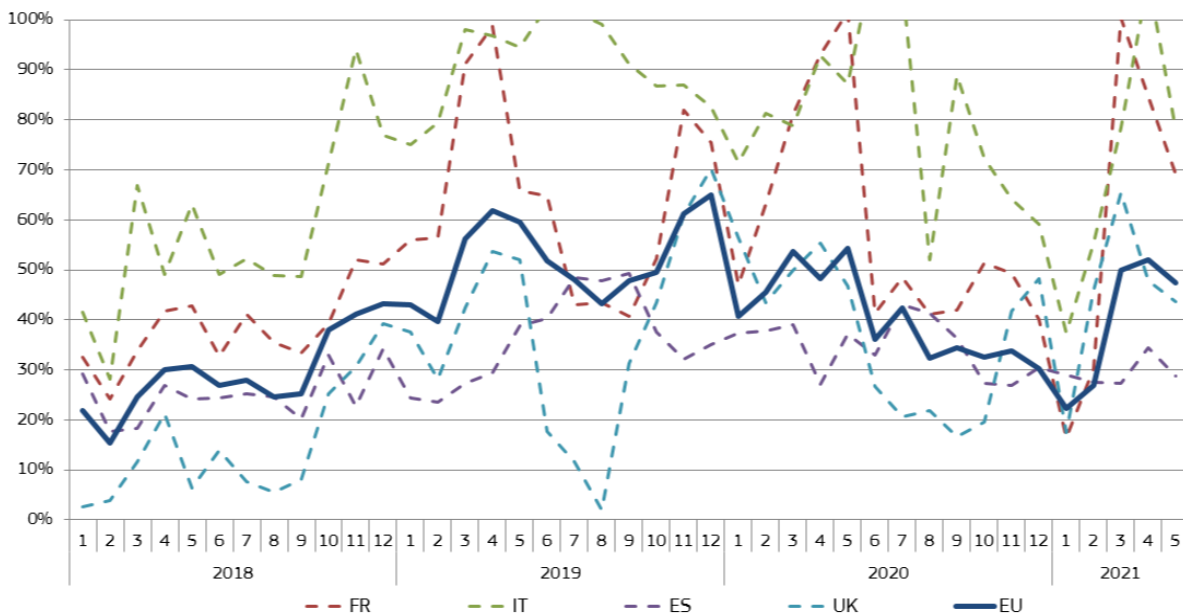
Imports coming from other EU Member States (re-exports) are excluded

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



- In the first quarter of 2021, 44 LNG cargoes arrived from the US (down from 80 in Q1 2020). LNG imports from the US amounted to 4.2 bcm in Q1 2021, down from 7.3 bcm in Q1 2020.
- LNG exports to Europe represented 18% in Q1 2021 of the total US exports, which was similar to the previous quarter but was significantly lower than in Q1 2020 (38%), implying that US LNG exports could find more profitable markets, principally in Asia than in Europe. In the first quarter of 2021 the four most important EU destinations of the US LNG exports were France (1183 mcm), the Netherlands (1138 mcm), Spain (711 mcm) and Lithuania (366 mcm). The United Kingdom imported more than 2 bcm of US LNG in Q1 2021, after importing 2.2 bcm in Q4 2020.
- 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 January 2021 the average EU utilisation rate fell to 22%, which was the lowest since February 2018, in parallel with decreasing LNG import volumes. However, as of February, with increasing LNG shipments, it started to pick up again and by March-April 2021 it rose to 50%. 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 Q1 2021, similarly to France. On the other hand, in Spain utilisation rates were lower than EU average in February and March, while they were bit higher than with the EU average in January 2021. In the UK utilisation rates were very even lower (17%) than the EU average in January, but by March they rose above the EU, reaching 65% on monthly average.

**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)

## 1.4 Policy developments, new gas infrastructure and contracts

- On 11 February 2021, the Dutch government announced that gas production at the Netherlands' Groningen natural gas field can be cut to 3.9 bcm in the gas year from October 2021, which is set to be its final year of regular extraction<sup>14</sup>. The Netherlands announced in 2019 that output at Groningen would end by mid-2022 to limit seismic risks in the region, with gas only to be extracted thereafter in the event of extreme weather conditions, for which a few sites will remain on stand-by. Production is expected to fall to 8.1 bcm in the gas year 2020/21, and final decision on the 2021/22 production cap is to be taken in September 2021. Over the last decade dwindling Dutch gas production has led to increasing imports, mainly in the form of LNG, substantially changing the gas source patterns in North-West Europe.
- On 15 February 2021 the Zeebrugge LNG terminal operator, Fluxys Belgium announced that after successfully closing the open season procedure, it has reached the final investment decision and will expand the regasification capacity of the terminal in two steps<sup>15</sup>. As of 2024, the regasification capacity will rise by 4.7 mpta (6.5 bcm per year) and by 2026 the total incremental capacity will reach 6 mpta (8.3 bcm per year). This capacity expansion is closely related the accelerated closure the Groningen gas field in the Netherlands. By 2026 the total regasification capacity at Zeebrugge will reach 17 bcm per year.
- Over the first six months of 2021, a number of events impacted the construction of the Nord Stream 2 pipeline, which originally should have been operational since 2020. In January the outgoing US administration has imposed sanctions<sup>16</sup> on a Russian pipe-laying vessel (Fortuna) and its owner. A Norwegian firm dealing with certification of gas pipeline systems also withdrew from the project on fears facing sanctions, targeting not only pipe-laying and financing companies but other ones necessary to complete the project. In February, the idea of creating a state-owned environmental foundation in Germany, aiming at purchasing necessary equipment to finalise the project, also emerged, putting the US sanctions into the aspect of official German-US state relations.
- On 25 May the new US administration has decided to waive sanctions against the company behind the Nord Stream 2 gas pipeline because the project was nearly complete<sup>17</sup>. On the preceding week, US State Department said Nord Stream 2 AG - the German company behind the Russian gas pipeline to Germany, engaged in sanctionable activity, but waived those sanctions for what it called national security reasons. This important achievement increases the probability that Nord Stream 2 will be finalised and operational, though over the last few months a number of political actors in Europe called for its cancellation. By early June 2021 around 95% of the project was said to be completed.
- On 26 May 2021 an announcement<sup>18</sup> was made on the delay of construction of the Interconnector Bulgaria-Greece. The coronavirus pandemic and need for additional environmental assessment for a crossing under a dam in the Bulgarian stretch had delayed the construction of the pipeline, said the ICGB company, which runs the project. The interconnector will not become operational until June 2022, originally planned to be ready by the end of 2020, when Bulgaria's 25-year deal with Azeri gas company SOCAR to import 1 billion cubic metres of natural gas a year kicked off. The pipeline, with an initial annual capacity of 3 billion cubic metres, is important to Europe's plans and will be linked to the Trans Adriatic Pipeline (TAP).
- On the EU energy policy side, on 5 February 2021 the environmental committee of the European Parliament (EP) adopted a resolution<sup>19</sup>, promoting the introduction of carbon levy on imports from countries outside the EU, underlining that the EU's increased ambition on climate change must not lead to 'carbon leakage' as global climate efforts will not benefit if EU based industrial production is just moved to non-EU countries with less ambitious emissions reduction targets. On 10 March, the Parliament adopted a resolution on a WTO-compatible EU carbon border adjustment mechanism (CBAM)<sup>20</sup>. The CBAM would equalise the price of carbon between domestic products and imports and will serve as an essential element of the EU toolbox to meet the objective of a climate-neutral EU by 2050 in line with the Paris Agreement by addressing risks of carbon leakage resulting from the increased EU climate ambition.
- On 21 April the College of Commissioners reached a political agreement on the EU Climate Taxonomy Delegated Act<sup>21</sup> (formally adopted when it was available later in all official languages of the European Union), introducing the first set of technical screening criteria to define which activities contribute substantially to two of the environmental objectives under the Taxonomy Regulation: climate change adaptation and climate change mitigation. Natural gas, strictly speaking not included in the EU taxonomy, will be covered by a complementary Delegated Act, to be adopted later this year, along with gas related technologies, as transitional activity as far as they fall within the limits of the EU Taxonomy Regulation.

<sup>14</sup> <https://www.reuters.com/article/uk-netherlands-gas-groningen-idUKKBN2AB05X>

<sup>15</sup> <https://www.offshore-energy.biz/fid-reached-for-zeebrugge-lng-regas-capacity-expansion/>

<sup>16</sup> <https://www.reuters.com/world/europe/us-imposes-sanctions-russian-vessel-involved-with-nord-stream-2-pipeline-2021-01-19/>

<sup>17</sup> <https://www.reuters.com/business/energy/nord-stream-2-sanctions-would-be-counter-productive-european-ties-biden-2021-05-26/>

<sup>18</sup> <https://www.reuters.com/business/energy/gas-pipeline-link-between-bulgaria-greece-delayed-until-june-2022-2021-05-26/>

<sup>19</sup> <https://www.europarl.europa.eu/news/en/press-room/20210201IPR96812/carbon-levy-on-eu-imports-needed-to-raise-global-climate-ambition>

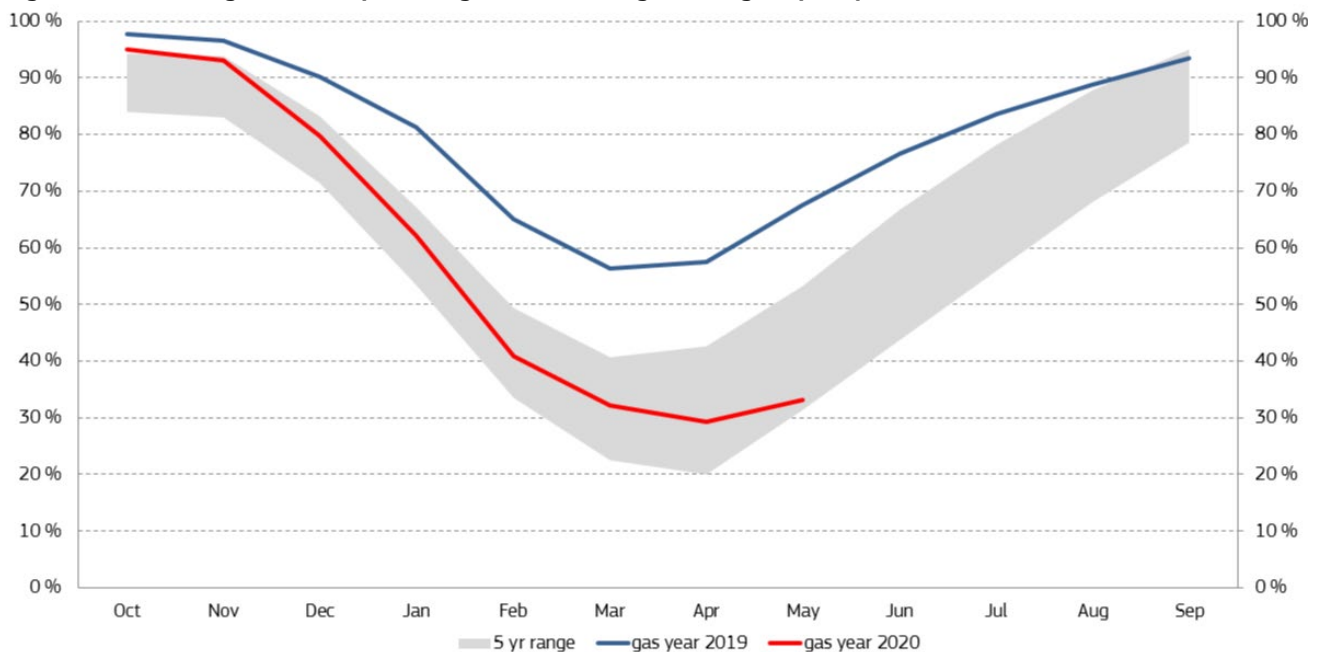
<sup>20</sup> <https://www.europarl.europa.eu/news/en/press-room/20210304IPR99208/meps-put-a-carbon-price-on-certain-eu-imports-to-raise-global-climate-ambition>

<sup>21</sup> [https://ec.europa.eu/info/law/sustainable-finance-taxonomy-regulation-eu-2020-852/amending-and-supplementary-acts/implementing-and-delegated-acts\\_en](https://ec.europa.eu/info/law/sustainable-finance-taxonomy-regulation-eu-2020-852/amending-and-supplementary-acts/implementing-and-delegated-acts_en)

## 1.5 Storage

- Figure 18 shows EU stock levels as the percentage of storage capacity in gas years<sup>22</sup> 2019 and 2020, compared to the 5-year range of gas years 2014-2018. According to figures published by Gas Infrastructure Europe, operational EU storage capacity amounts to 1,131 TWh (roughly 100 bcm) since the end of 2018<sup>23</sup>.
- The first quarter of the year is traditionally the peak of the heating season and results in rapid depletion of gas storages before the refilling period starts next spring. On 31 December 2020 the average EU storage filling rate was already lower than on the last day of 2019 (74% vs. 88.2%), owing to more intensive recourse to storage withdrawals at the beginning of the winter period. On 31 March however, the average filling rate was much lower than on the same day of 2020 (30.2% vs. 53.9%). The average EU filling rate at the end of March 2021 was the lowest at this time of the year since 2018. Consuming gas stored in earlier periods when purchase prices for storage operators were much lower than actual market prices was a competitive alternative in Q1 2021, compared to buying gas on the wholesale market. In Q1 2021 the increase in spot wholesale market prices continued on the EU gas hubs, which resulted in higher depletion rates than in Q1 2020 (44.4% vs. 34.3% between 31 December and 31 March). On the other hand, lower levels of storages will increase demand for gas during the spring and summer months, implying higher wholesale gas market prices.
- Although storage levels were generally lower in Q1 2021 comparing with the same days in Q1 2020, storage levels in Q1 2021 were in the five year average of 2014-2018, however, moving ahead in the spring months they moved closer to the lower end of the range, reaching it by the end of May 2021. Beside storage levels, volatile price spreads between the main Asian and European gas hubs, impacting EU LNG imports, became an important factor influencing wholesale gas prices in the EU in 2021 so far.

**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 8 June 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 15<sup>th</sup> day of the given month.

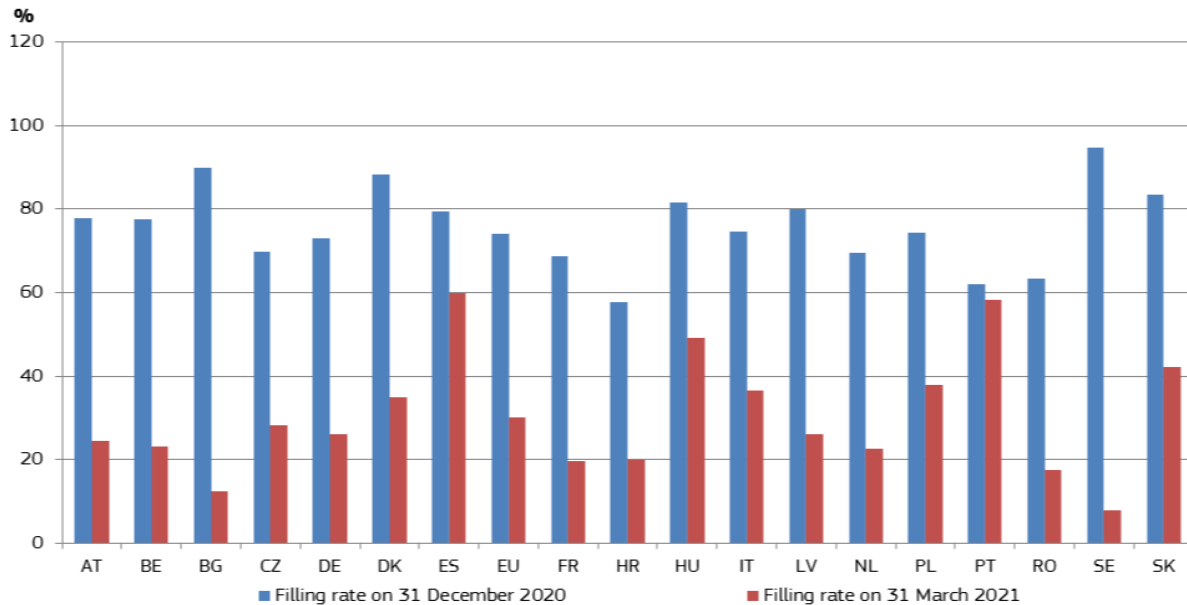
- As Figure 19 and Figure 20 show, on 31 December 2020 filling rates across the EU Member States ranged from 57.8% in Croatia to 94.7% in Sweden (even though with very low overall storage capacities), reaching 74% on EU average. On 31 March 2021 however, differentials in filling rate were higher; the lowest filling rate could be observed in Sweden (8%) and the highest in Spain (59.9%). The EU average filling rate was 30.2% on 31 March 2021, with filling rates lower than 20% in Bulgaria, Romania, France and Croatia. Storage fullness remained relatively high in Portugal (58.4%) and Hungary (49.1%).

<sup>22</sup> 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

<sup>23</sup> [https://www.gie.eu/maps\\_data/downloads/2018/Storage\\_DB\\_Dec2018.xlsx](https://www.gie.eu/maps_data/downloads/2018/Storage_DB_Dec2018.xlsx)

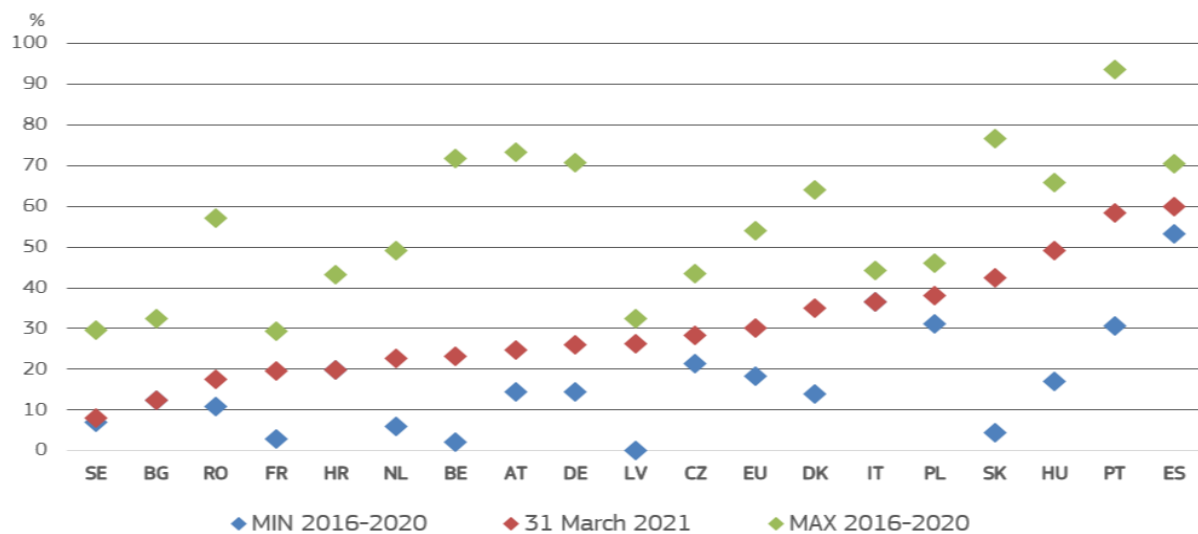
- The biggest decreases in storage filling rates (highest withdrawals) could be observed in Sweden (87%) and Bulgaria (78%), Belgium and Latvia (both 54%) and Denmark and Austria (both 53%), whereas in Portugal and Spain filling rates respectively decreased by 4% and 20%, less than the EU the average (44%) in Q1 2021.
- Figure 20 also shows the filling rates on 31 March 2021 comparing to the minimum and maximum values in the time period of 2016-2020. In countries such as Sweden, Bulgaria, Romania, Czechia, Poland and Spain the 2021 filling rates were quite close to the minimum of the preceding five years at this time of the year (mostly to the 2018 values, when at the end of the heating season an unexpected cold spell resulted in rapid storage depletions), whereas on other countries, such as Latvia, Slovakia, Hungary and Portugal filling rates were at least 20 percentage points higher than the aforementioned five-year minimum, implying less gas demand for storage refilling purposes in the forthcoming two quarters.

**Figure 19 Gas storage levels as percentage of maximum gas storage capacity at the end of the first quarter of 2021 by Member State**



Source: Gas Storage Europe AGSI+ Aggregated Gas Storage Inventory, extracted on 8 June 2021. See explanations on data coverage at <https://agsi.gie.eu/#faq>. 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.

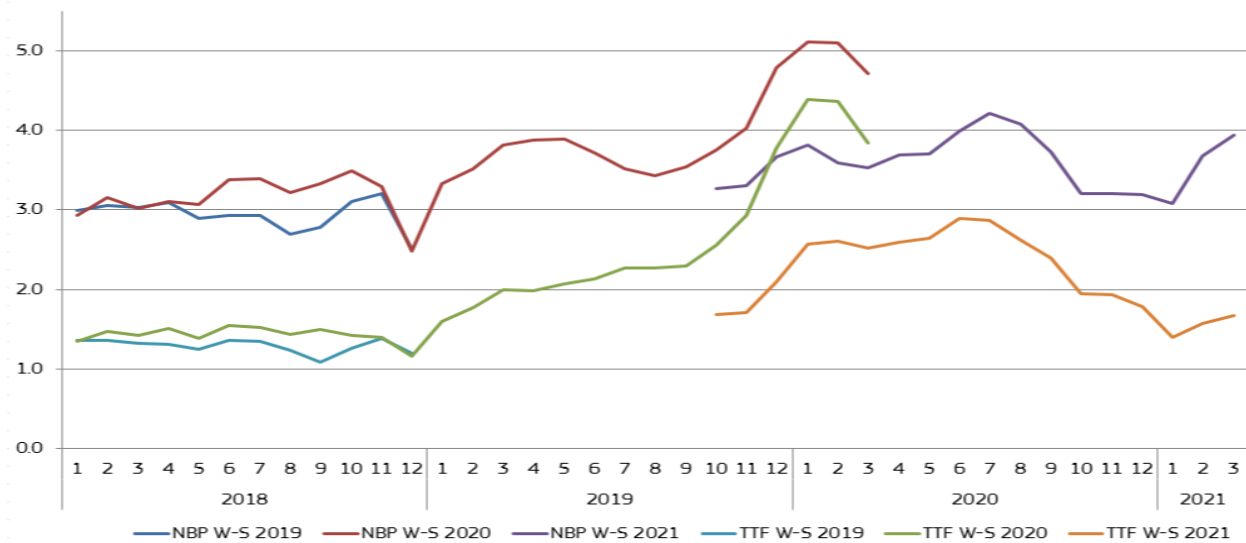
**Figure 20 – Gas storage levels on 31 March 2021, compared to minimal and maximal levels of 2016-2020**



Source: Gas Storage Europe AGSI+ Aggregated Gas Storage Inventory, extracted on 8 June 2021.

- The next chart (Figure 21) shows the winter-summer spreads, as depicted by the difference in the 2021 summer and winter contracts. The 2021 seasonal spread on the TTF rose again in Q1 2021, and in March it reached 1.7 €/MWh, up from 1.4 €/MWh in January 2021. At the same time, the seasonal spread on the NBP hub was up from 3.1 €/MWh to 3.9 €/MWh between January and March 2021.
- It seems that in Q1 2021 the overall increase in wholesale gas prices across the curve (stemming from refilling needs and volatile LNG availability) also impacted the premium of the 2021-22 winter contracts to the 2021 summer contracts, and this impact was more intensive in the UK, having less storage capacities.
- 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 increased their premium to the continental spreads (in this case TTF), reaching 2 €/MWh in Q1 2021.

**Figure 21 Winter-summer spreads in the Dutch and British gas hubs**  
Euro/MWh



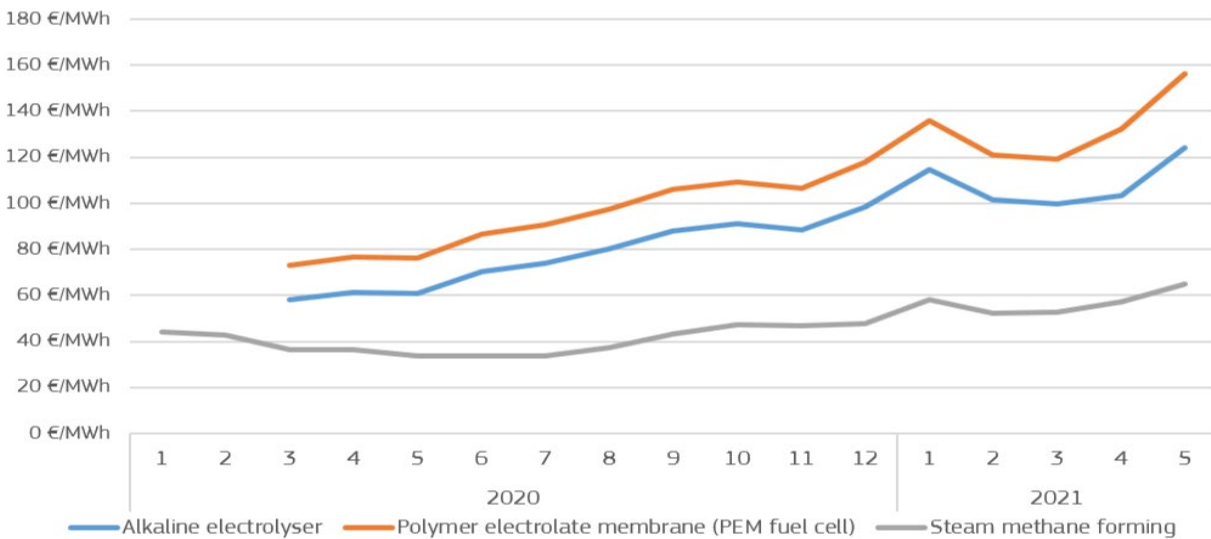
Source: S&P Global Platts

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.

## 1.6 Hydrogen market developments

- 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 22 – 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 March 2021 the TTF spot gas hub prices averaged at 17.8 €/MWh, whereas the Pan-European Electricity wholesale price was around 49.7 €/MWh, which compares to 75-85 €/MWh costs of the alkaline and PEM technologies (without CAPEX costs), and to 30€/MWh for SMR, being respectively almost twice as much compared to wholesale electricity and gas prices.

## 1.7 Focus on: Financing models of hydrogen projects in Europe

- Over the last few years policy makers in the EU and its Member States have been focussing their attention on hydrogen, and new strategies have been drawn up, paving the way for the new hydrogen economy. The coming decade will be key to launch, structure, and develop the hydrogen market that will contribute to the EU decarbonisation target. Currently hydrogen is a nascent market, though in all hydrogen related strategies in Europe (and in other countries in the world) a significant increase is foreseen even for 2030, and in 2050 hydrogen is expected to make up a measurable part of the EU energy mix.
- Current hydrogen consumption is estimated to 110 Mt worldwide, mostly used in refining, petrochemicals and fertiliser industries, and only a negligible portion of the total consumption is traded. Therefore, given the lack of significant volumes, market prices do not exist, either for spot or forward contracts. Price reporting agencies have developed 'costs plus' assessments, depending principally on the hydrogen production technologies (see above in the previous subchapter). Thus, these assessments are mainly impacted by the evolution of natural gas and electricity prices.
- Most of the hydrogen strategies, including the one presented by the European Union in July 2020, foresee a clear link between decarbonisation of the economy and promotion of hydrogen, building largely on developing the market of clean hydrogen technologies, implying production based on electrolysis technologies, using renewable and/or low carbon electricity sources. Beyond the lack of market signals, risks around investments in the hydrogen sector need to be overcome to realise the necessary

investments. The current global electrolyser production capacity (3.5 GW) compared to the expected needs (around 90 GW in 2030, of which 40 GW in the EU) perfectly shows the gap that needs to be overcome in the forthcoming decade. In addition, continued investment in renewable electricity generation is required to provide sufficient renewable electricity to power these planned hydrogen electrolysers and avoid the push for green hydrogen indirectly stimulating demand for electricity from fossil fuels.

- However, from financing perspective, the hydrogen sector shows a diverse economic value chain at the crossroads of different sectors, such as energy, industry and mobility, and it consists of different segments associated with different risk challenges<sup>24</sup>. The upstream segment of hydrogen refers to manufacture of equipment needed for hydrogen production (e.g. electrolysers). The mid-stream segment consists of the production of hydrogen itself, whereas the downstream is related to equipment for hydrogen use (e.g. boilers, fuel cells, etc.), and the fourth segment (logistics) is focussed on infrastructure, such as preparation, storage, transport, distribution and, refueling stations. This raises challenges for the financial sector, as it needs both developing specific instruments for each segment to address arising risks and to take advantage of the existing financing mechanisms that have proven efficient in other areas.
- Arising risks can vary across different segments. In the upstream sector the main risks relating to quality, specifications, competitiveness and overcapacity, which is also the case in the downstream sector. In the mid-stream, beyond technical, competitiveness and regulatory barriers, we can see a double risk related to demand for electricity and hydrogen (for both volumes and prices), whereas the logistics segment faces the risks of competitiveness, size and geographical coverage and regulation.
- Several factors can contribute to the mitigation of these investment risks. A clear political support in the most significant economies of the world, including the EU is needed to give confidence to investors, as investments in infrastructure and hydrogen production have long payback time. Moreover, competitiveness will depend on scale and learning curves of the industry, which will need time. Clear and effective regulation, aiming at minimizing/eliminating regulatory burdens (e.g. insufficient carbon pricing, the absence of or technical limitations of guarantees of origin schemes, unclear and incomplete industrial emission and safety regulations, unclear status of power-to-hydrogen plants, outdated electricity and gas market rules, discrimination of specific energy technologies and insufficient support to retrofit natural gas networks) are needed to foster new entrants to the hydrogen market.
- Further on risk mitigation, the availability of sufficient renewable generation, as the main driver of clean hydrogen production costs, is also of key importance. Instruments, such as power purchase agreements can mitigate the production cost related risks for electrolyser operators. Other instruments, such as integrated hydrogen production to utilities profiting from curtailments or dedicated oversized renewable generation linked to electrolysers and combined (solar and wind) electricity generation solutions can also play an important role. On the demand side, addressing the risks of the lack of off-takers, insufficient demand for hydrogen might be addressed by obligatory quotas (a proposal from some stakeholders), to encourage existing hydrogen users to switch to more environmentally friendly hydrogen sources, vertically integrated projects (producers and off-takers), development of publicly driven clusters and increasing carbon prices.
- Currently there is already a wide range of available financing instruments for hydrogen projects, involving both equity and debt type of sources. On the equity side shares of ownership in the cooperation (common stock), preferred stock (no voting rights) and dividends (reward to investors) can be considered, whereas on the debt side senior secured and unsecured debt, hybrid debt (combined financial instruments) and subordinated debt. At current stage project financing plays a less important role, but the future development of the hydrogen market will probably enable more opportunities for these instruments.
- At the nascent stage of the market, public financing might also play a crucial role for investments to gain momentum. Currently several European programs and instruments are also in place that will allow the financing of hydrogen related projects, such as Connecting Europe Facility, Horizon Europe, European Growth Finance Facility and Next Generation EU. Apart from direct public financing, other public support mechanisms are being set up in some EU countries, such as direct tax benefits in the form of exemption of contributions, tax credits on investments, or carbon contracts for differences.
- In the upstream sector, in order to build up sufficient electrolyser manufacturing capacities, a scale-up of the value chains must happen quickly and effectively to allow the learning-curve and the volume effect to lower enough the capex costs. Corporate financing, together with public support, will probably remain the main mechanism to ensure the necessary investments at this initial stage. Most electrolyser producers have now links to large partners either in the renewable generation sector, on the industrial gas market or on the transport/distribution sector. Thus investment risks might be minimised by means of vertical integration.
- Investments in the mid-stream sector will face a series of specific risks, as production of hydrogen will face not only technical and operations risks, but also a double counterparty risk. The profitability of a hydrogen production facility will depend on the availability and competitiveness of the electricity (main cost driver) as well as on the existence of sufficient off-take demand at a competitive price. Most of the projects today related to the mid-stream sector are being developed either by large utilities and commodities with the capacity to plan and provide enough and competitive renewable electricity, or by leading players in the

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<sup>24</sup> The 'Focus on' subchapter of the current report largely builds on the report on 'Towards a hydrogen market – Elements on financing models', available here: [https://ec.europa.eu/energy/topics/markets-and-consumers/euro-field-energy\\_en](https://ec.europa.eu/energy/topics/markets-and-consumers/euro-field-energy_en)

industrial gases business. It is likely that the mid-stream sector will develop on the basis of clusters (ensuring demand and therefore mitigating the downstream risk), of dedicated production units. Mid-stream projects could be candidates to qualify for project financing (as it is widely done for utilities), and therefore the main foreseeable model could become an asset based financing, allowing to take off the investment from the investors balance sheet and ring-fencing the risks.

- Demand for hydrogen products (downstream sector) is still at a very nascent stage, increasing the risk for upstream hydrogen production projects, as the need for stable cash-flows and off-takes are primary indicators of the future profitability and pay-back for the investments. There are some already existing projects in the steel sector and for retrofitting existing natural gas turbines. Sales of heavy duty vehicles (fuel cell trucks) are still very limited and technology for hydrogen in aviation is still under development. Bearing in mind all of the risks, the financing model for the downstream sector will heavily rely at the beginning on corporate finance, backed by public support. Public support will help decreasing the associated risks to nascent applications by helping in the R&D and development stages and by providing more certainty on the future cash-flows.
- Finally, on the logistics side, the development of transport, distribution, and storage infrastructure for hydrogen is a key in the emergence of the hydrogen markets, not only physically, but also financially. The existence of hubs and demand centres will reassure investors and lenders, helping to diversify risks and increasing confidence on the stability of future cash-flows. Similarly to public infrastructure projects, costs for engineering, development and equipment could be passed to the end customer via tariffs of the services provided. In some cases, private companies could be involved via concession type of contracts. The regulation provides the necessary certainty on future cash flows to mitigate the risks for investors.
- Putting all of these aspects in one point, each segment of the hydrogen value chain follows its own financing logic. It is likely that the involvement of more structured financial actors and instruments will increase as market develops. It can already be noted that the stakeholders themselves are finding ways to de-risk and makes investment happen, mainly by associating actors belonging to different segments of the value chain in project-specific basis.

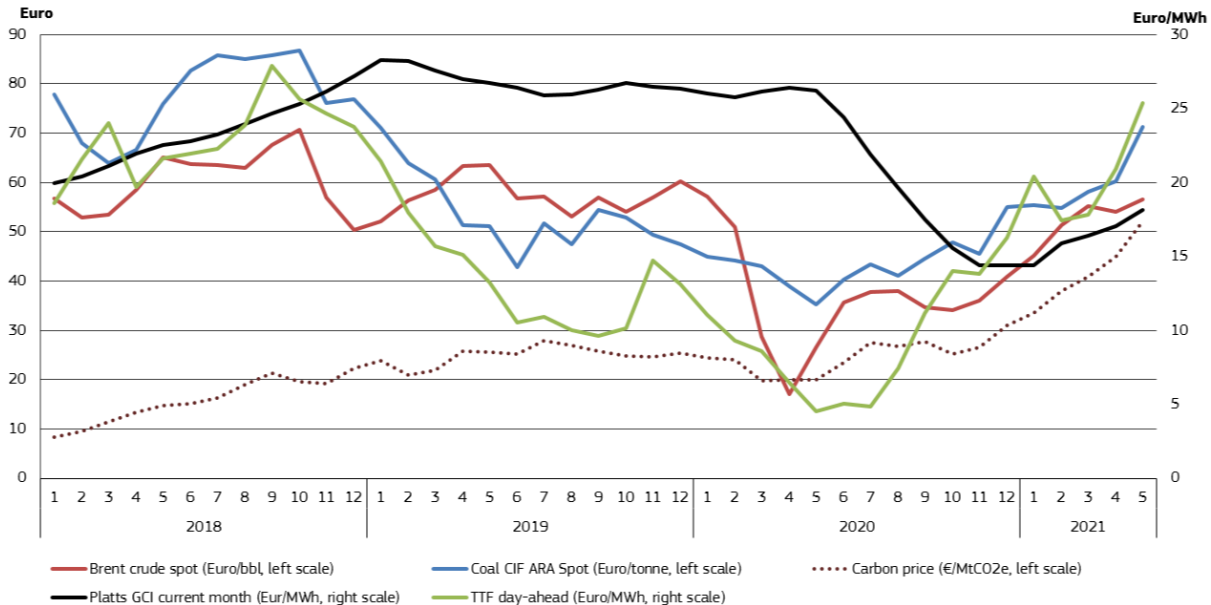
## 2. Wholesale gas markets

### 2.1 EU energy commodity markets

- The dated Brent crude oil price continued to increase in the first quarter of 2021, rising from 51 USD/bbl (41.2 €/bbl) at the end of December 2020 to 64 USD/bbl (54 €/bbl) by the end of March 2021. In the following quarter oil prices kept on rising, by mid-June reaching the highest since October 2018. In parallel with economic rebound and opening up for more travel opportunities, 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 supply side, OPEC+ countries increased their production only to the pre-agreed level (and having high compliance rate to the production limits), and other producers, such as in the US, ramped up their production slower than expected, resulting in market tightness and rising spot prices. However, the price discount of the year-ahead contract to the dated Brent (backwardation) reappeared during the quarter, and by the end of March it rose to 5 USD/bbl (4 €/bbl), increasing further in the second quarter of 2021, implying that the market prices in a correction in spot contracts, as soon as oil supply will be able to keep pace with the increasing demand.
- The Dutch TTF spot gas price started the year at 19 €/MWh, finishing Q1 2021 at similar level. However, in January, as high gas prices in Asia lured LNG shipments away from Europe and occasional cold spells resulted in gas demand increases in many European countries, the TTF spot rose above 26 €/MWh on 12 January 2021. After the decrease in the Asian gas price premium, in February, as LNG imports increased, prices went down again, reaching 17€/MWh on average. In March however, some unplanned outage in Norwegian gas supplies, a week-long blocking of the Suez canal (by the Ever Given ship incident), hampering LNG cargoes from Qatar, and intensive recourse to gas storage withdrawals (helped by past injections costs being lower than increasing spot wholesale gas prices) all put tightness on the supply side of the market, contributing to wholesale gas price recovery. In April and May 2021, the level of gas storages ramped up slower than expected (owing to the cold weather, resulting in unusual withdrawals this time of the year), increasing storage related demand expectations and prices.
- Platt's North West Europe Gas Contract Indicator (GCI), a theoretical index showing what a gas price, linked 100% to oil, started to reflect in Q1 2021 the recovery of crude oil prices occurring in the second half of 2020, and it rose from 14.4 €/MWh in December 2020 to 16.4 €/MWh in March 2021. Normally crude oil price changes appear in the oil-indexed contracts with a time lag of 6-9 months. In April-May the GCI contract continued to rise and was around 18 €/MWh in May 2021. TTF spot prices rose in parallel with the GCI over the first months of 2021, keeping a premium to the oil-index contracts, which implied a competitive position of oil indexed contracts in Europe in this period. This was beneficial to some oil-indexed import sources (e.g. Algeria). However, GCI is expected to rise further in the forthcoming months, mirroring the price increase of the oil market, which will probably have adverse impact on the current competitive advantage of the oil-indexed contracts, unless natural gas prices continue to increase.



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



Source: S&P Global Platts

- Spot coal prices (CIF ARA) remained relatively stable during Q1 2021, moving most of the time in a range of 50-60 €/Mt. In the second half of March, as increasing seaborne freight rates also impacted coal trade, the average spot coal price was around 60 €/Mt. Further in April and May, still impacted by the tightness of the freight rates, increasing demand in China and the generally bullish mood of energy commodities, spot coal prices rose further, reaching 78€/Mt by the end of May 2021.
- Carbon prices in the first quarter of 2021 kept on increasing, up from 34 €/MtCO2e to 43 €/MtCO2e. The carbon price rise was basically following the general increase in energy commodity prices, especially going hand in hand with increasing gas price at the end of Q1 2021 and further in the following quarter. By the mid-May 2021, the carbon price rose above 56 €/MtCO2e for the first time since the start in trade in 2005, and finished the month around 51 €/MtCO2e.

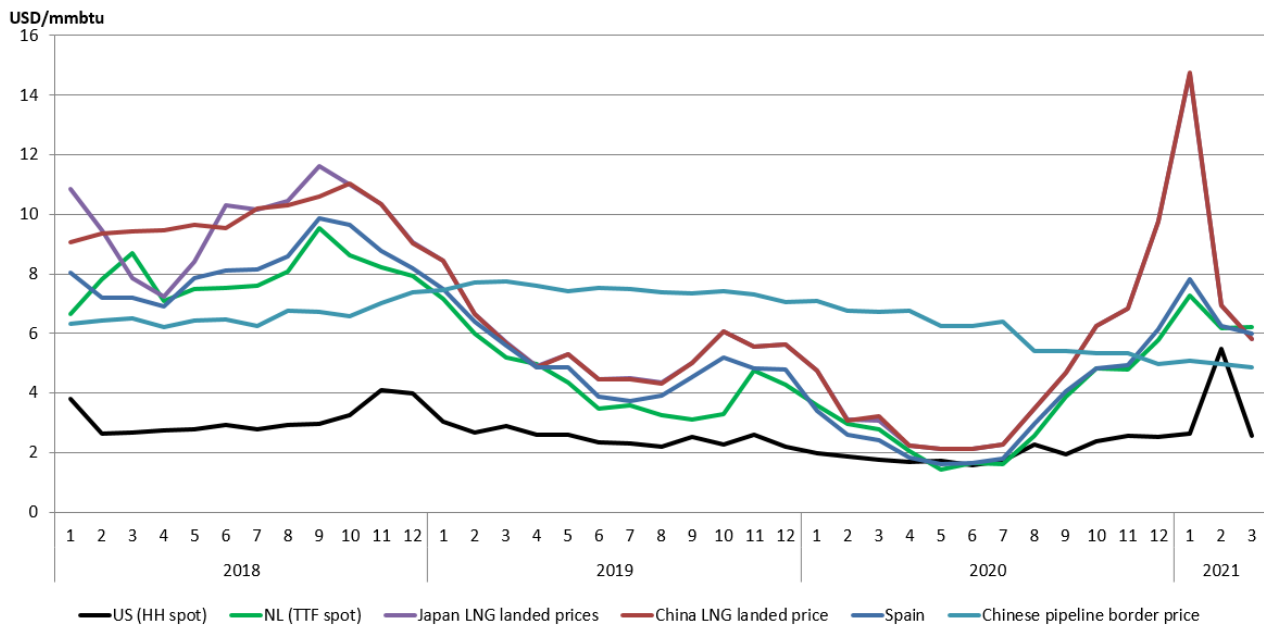
## 2.2 LNG and international gas markets

- Figure 24 displays the international comparison of wholesale gas prices, including hub, LNG landed and pipeline import gas prices. In January 2021 European, Japanese and Chinese landed LNG prices showed huge differentials in consequence of the gas price spike in Asia and its aftermath on global LNG trade. US Henry Hub prices remained relatively stable whereas European LNG contracts also rose. In February, as a rare cold spell impacted large part (including the oil and gas producer Texas) of the United States, Henry hub prices spiked, reaching seven year high. In March 2021 however, after the end of cold weather in most of the regions, prices converged again among the three benchmark areas, though differences remained measurable.
- The average Japanese LNG price was 9.2 USD/mmbtu in Q1 2021, up from 7.6 USD/mmbtu in Q4 2020, and from 5.8 USD/mmbtu in Q1 2020, implying a price increase of 59% year-on-year. The Japanese premium above the Dutch TTF hub was on average 3 USD/mmbtu in Q1 2021, slightly up from 2.6 USD/mmbtu in the fourth quarter of 2020, and from 2.2 USD/mmbtu in Q1 2020. On quarterly average, LNG import prices in China were comparable with their Japanese peers (9.2 USD/mmbtu in Q1 2021). However, in January 2021 LNG import prices in East Asia rose to the highest since April 2014, principally owing to cold wintry weather and increasing role of gas in electricity generation. High wholesale gas prices in the Asian markets resulted in LNG cargo redirection from Europe to Asia, impacting storage levels and wholesale prices in Europe.
- In contrast to the LNG contracts, the average price of Chinese pipeline gas imports continued its descend and reached 5.0 USD/mmbtu in Q1 2021, down from 5.2 USD/mmbtu in Q4 2020, and from 7.3 USD/mmbtu in Q1 2020. Pipeline import prices in China became competitive vis-à-vis LNG imports, as they were below the Asian LNG reference prices, by more than 4 USD/mmbtu. Pipeline import contracts might have reflected decreasing oil prices in earlier periods, with the oil-indexation time lag, however, the Chinese pipeline import price did not show such volatility as the oil price in 2020.
- The Henry Hub price rose to 3.6 USD/mmbtu in Q1 2021, up from 2.5 USD/mmbtu in Q4 2020 (and from 1.9 USD/mmbtu in Q1 2020), and as Figure 25 shows, both TTF and JKM showed a measurable premium vis-à-vis Henry Hub. On quarterly average, TTF and JKM respectively had a premium over Henry Hub (3.0 USD/mmbtu and 5.6 USD/mmbtu) which provided perfect opportunities for US LNG exporters. However, the aforementioned February 2021 cold spell in the US put an obstacles to shipments and the utilisation of the LNG terminals. After the end of the cold spike, and further in the spring months, increasing global gas prices gave boost to LNG exports from the US. Given that the EUR depreciated against the USD in Q1 2021 (in December 2020 the

exchange rate was 1.22 while in March 2021 it was 1.19), divergence between the TTF and the Henry Hub was even higher measured in euros.

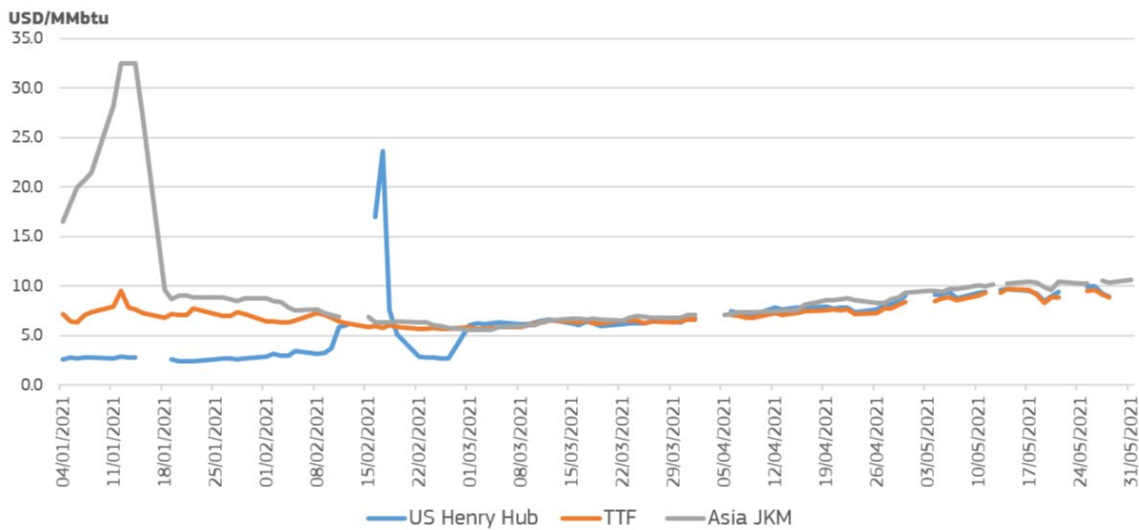
- Over the course of the first quarter of 2021, in spite of increasing absolute differentials, price ratios of international contracts showed slight decreases. The average TTF/Henry Hub ratio was 1.8, down from 2.1 in Q4 2020 and from 2.2 in Q1 2020. The ratio of the Japanese LNG price and US Henry Hub was 2.6 in Q1 2021, down from 3.1 both in the fourth quarter of 2020 and the first quarter of 2020. The average price ratio of the Japanese LNG prices and the TTF was 1.4 in Q1 2021, slightly down from 1.5 in Q4 2020, and equaling that in Q1 2020.
- In absolute terms, in Q1 2021 the TTF showed an increasing premium to the Henry hub (3.0 USD/mmbtu, after 2.6 USD/mmbtu in Q4 2020), whereas the premium of Japanese LNG prices to TTF slightly rose in Q1 2021 to 2.6 USD/mmbtu from 2.5 USD/mmbtu in the fourth quarter of 2020. During the same period premium of Japanese LNG prices to Henry Hub rose from 5.1 USD/mmbtu to 5.6 USD/mmbtu, implying better profitability (even if higher shipment costs are counted) of US LNG exports to Asia compared to Europe.
- In the first quarter of 2021, TTF averaged at 6.6 USD/mmbtu (18.6€/MWh), up from 5.1 USD/mmbtu (14.7 €/MWh) in Q4 2020 and, after 4.1 USD/mmbtu (9.7 €/MWh) in Q1 2020. The average German border price in Q1 2021 was at lower than the TTF (5.4 USD/mmbtu or 15.3 €/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.
- In the first quarter of 2021, spot prices averaged 6.6 USD/mmbtu in the Netherlands, 6.7 USD/mmbtu in Spain, and 9.2 USD/mmbtu in China and Japan.
- The JCC (Japanese Crude Cocktail) contracts reached 8.6 USD/mmbtu in the first quarter of 2021 on average, up from 6.7 USD/mmbtu in Q4 2020, and down from 10 USD/mmbtu in Q1 2020, being still lower than Japanese LNG import prices (9.2 USD/mmbtu), but measurably higher than the TTF (6.6 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

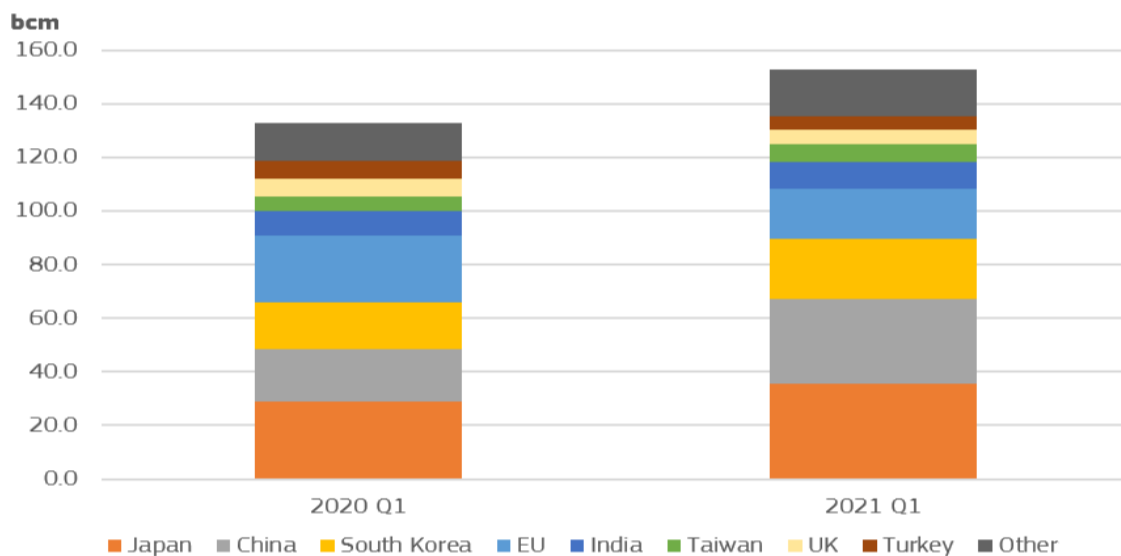
**Figure 25 – Daily average prices on the TTF (Dutch), the US Henry hub and the JKM Asian reference index**



Sources: S&P Global Platts

- The next two charts show the main actors of global LNG trade on importer (consumer) and exporter (producer) side. Similarly to the previous years, Japan remained the biggest LNG importer in the world in Q1 2021, ensuring around 36 bcm of imports out of the total estimated 152 bcm market. China came to the second place, with an estimated quarterly import of 32 bcm, followed by South Korea (22 bcm), the EU (17 bcm), India (10 bcm), Taiwan (constituting a separate market, with an import volume of 7 bcm), the United Kingdom and Turkey (both 5 bcm). Compared to the first quarter of 2020, a huge increase could be observed in China (61%), South Korea (28%), Japan (22%) and Taiwan (20%), whereas EU LNG imports fell by 29%, showing how demand in Asia soaked up LNG from EU markets. Europe only plays the role of global balancing market between producers and the principal Asian customers, providing place for eliminating global supply and demand side imbalances.

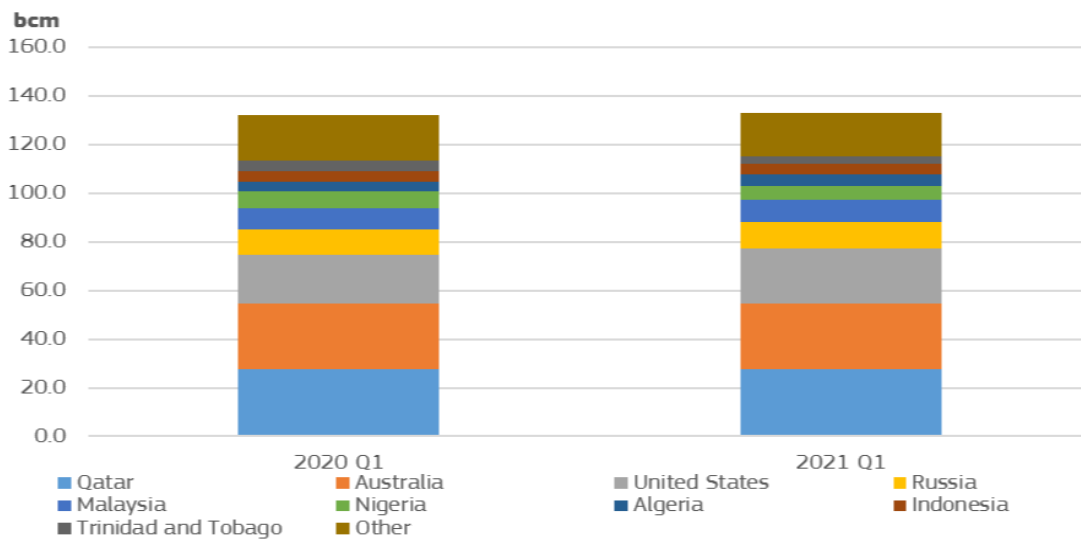
**Figure 26 – LNG imports in the main consumer markets in the first quarters of 2020 and 2021**



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 28 bcm LNG in Q1 2021. However, Australia came close to the second place in the same period, trailing Qatar only by 0.5 bcm of production. The United States were the third most important exporter, supplying 23 bcm in Q1 2021. Russia, mainly focussing on pipeline gas business in earlier periods, came to the fourth place with exports of 11 bcm, ahead of Malaysia (9 bcm), Nigeria (6 bcm), Indonesia and Algeria (both 4 bcm) and Trinidad and Tobago (3 bcm).

**Figure 27 – LNG exports in the main consumer markets in the first quarters of 2020 and 2021**



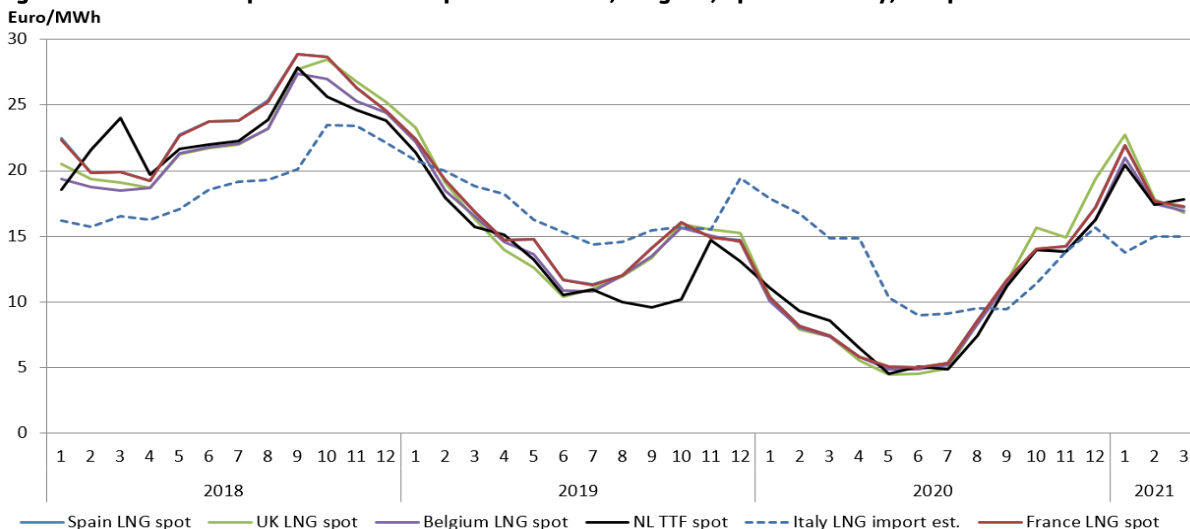
Source: Refinitiv tracking of LNG vessels. Export data are based on cargo departure dates, therefore total amount of global exports might differ from global import numbers

## 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), using the imported values and volumes of LNG, other markets represent landed prices based on vessel movements (from Refinitiv data).
- In the first quarter of 2021 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 4.5 €/MWh (between 14.6 €/MWh and 19.1 €/MWh), implying that differentials increased amid the general price increase as well. Taking out the Italian COMEXT derived average price, the difference was only 0.7 €/MWh, which was however, slightly lower than in the previous quarter (2 €/MWh). The quarterly average prices showed a significant increase of 7-26% compared to the previous quarter, Q4 2020, reflecting the continued price upturn on wholesale gas markets and import contracts. In year-on-year comparison, the picture is mixed; most contracts showed increases, whereas other went down.

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

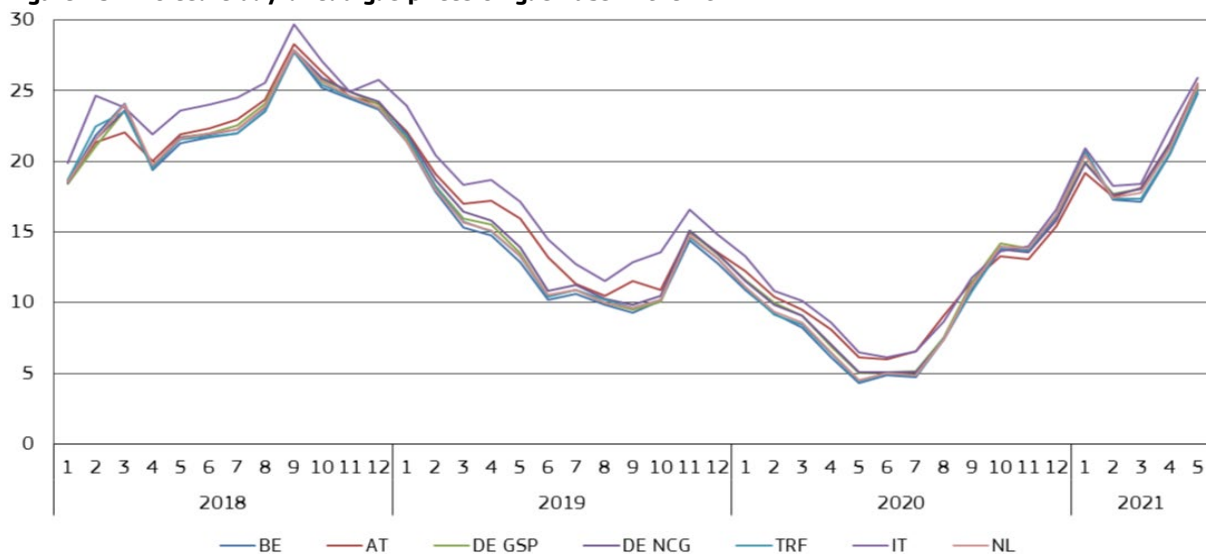


Note: Landed prices for LNG. Source: S&P Global Platts, Refinitiv, European Commission estimates based on Eurostat COMEXT data, retrieved on 9 June 2021.

### 2.3.2 Wholesale price developments in the EU

- European hub prices were in a narrow range, averaging around 17.9–19.8 €/MWh in the first quarter of 2021, measurably higher than in the previous quarter, Q4 2020 (13.9–15.3 €/MWh), adding around 26–32% to the price level just within a quarter's time, which shows the generally increasing trend. Hub prices reached the highest since Q1 2019, and in year-on-year comparison they went up by 70–100, as in Q1 2020 they averaged around 9.4–11.4 €/MWh. The average TTF hub price was 18.6 €/MWh in Q1 2021, going up by 92% in year-on-year comparison. A year before the market was largely impacted by LNG glut and high level of gas storages in the EU.
- In January 2021 cold spells and rapidly depleting gas storages put a strain on the European wholesale gas market. However, more importantly, huge gas demand in Asia resulted in an increasing wholesale market gas price premium to Europe, resulting in dwindling LNG sendout on the European markets, and in increasing wholesale gas prices. In February, as the weather turned milder and LNG shipments picked up, wholesale prices decreased, however, in March the generally positive mood on energy markets and some outages in the Norwegian gas supply, coupled with LNG shipment delays in the consequence of the blocking of the Suez Canal, contributed to an increase in wholesale gas prices. In April and May low storage levels, also owing to the extended heating season in consequence of the cold weather, added to the upward price pressure on European wholesale gas markets.

**Figure 29 Wholesale day-ahead gas prices on gas hubs in the EU**

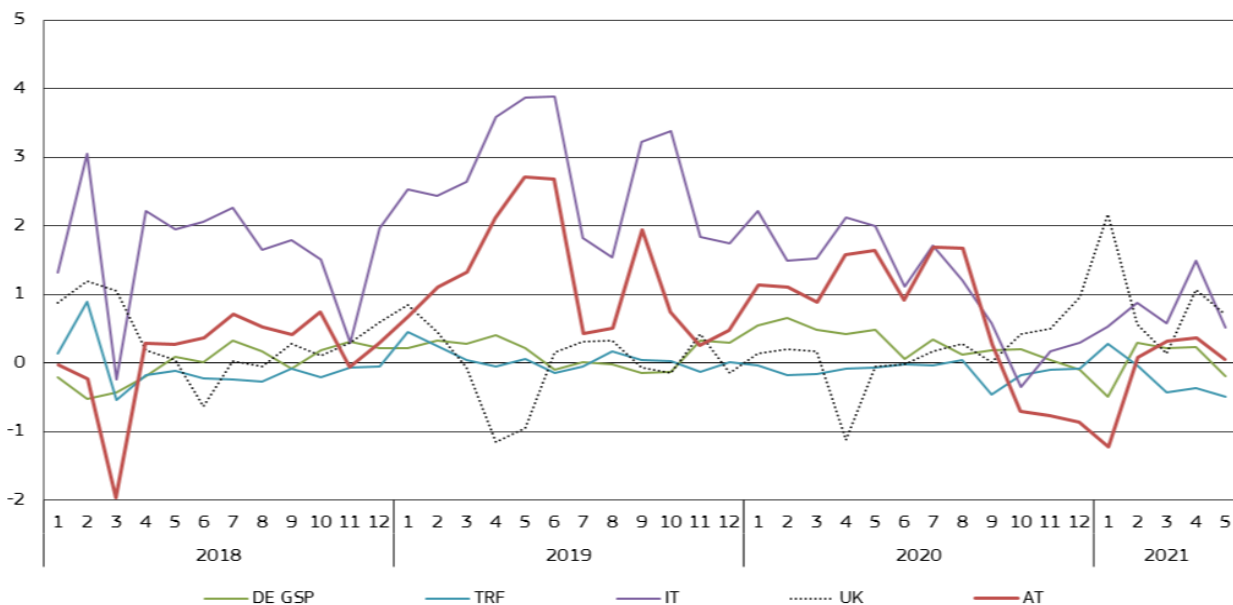


Source: S&P Global Platts

- As Figure 30 and Figure 31 show, the French TRF market was closely aligned with the TTF market during most of the time in the first quarter of 2021, however in January, TRF was in a slight premium, while in February and March it was in a slight discount to the TTF, depending on the Norwegian gas availability on the TTF hub, LNG shipments in France, and flow directions from Spain (in periods of high renewable availability in the Spanish power generation cheaper local market prices resulted in gas flows to France).
- The German Gaspool also remained well-aligned with the TTF in Q1 2021, however in the first three weeks of January 2021 the German contracts developed a small discount to TTF, apparently less impacted by dwindling LNG send-out as they could rely more on alternative supply sources (for example from Norway) and storage withdrawals.
- The Austrian hub showed many times a measurable price discount to the TTF January 2021, which is rather a unique situation. This might be explained to less exposure of LNG imports, which became more expensive following the demand spike in Asia, and better access to pipeline sources from Russia and withdrawal of abundant storage capacities. In early February flows to Italy through the TAG pipeline also dropped, resulting in oversupply in Austria.
- In Italy the PSV hub price, developed a premium of 4–5 €/MWh on some trading days vis-à-vis TTF during the mid-January spikes, coupled with local cold spells. As TTF prices were also up, inflows from North-Western Europe dropped in Italy. With the TAP link coming online however, in some periods, e.g. 23–24 January 2021, Italy managed to export gas to North-Western Europe, a quite unique situation during wintertime. Later in Q1 2021, in early February cold spells and low LNG availability resulted in a measurable price premium, whereas in early April the cold weather played again a role in higher PSV hub prices.
- During Q1 2021 the NBP hub price was during most of the time above the TTF benchmark, as usual during the winter period and the heating season; the country has low gas storage facilities compared to its consumption and strongly depends on gas imports. As LNG cargo arrivals fell significantly in January, the price premium of spot NBP contracts widened to the TTF. In mid-January on

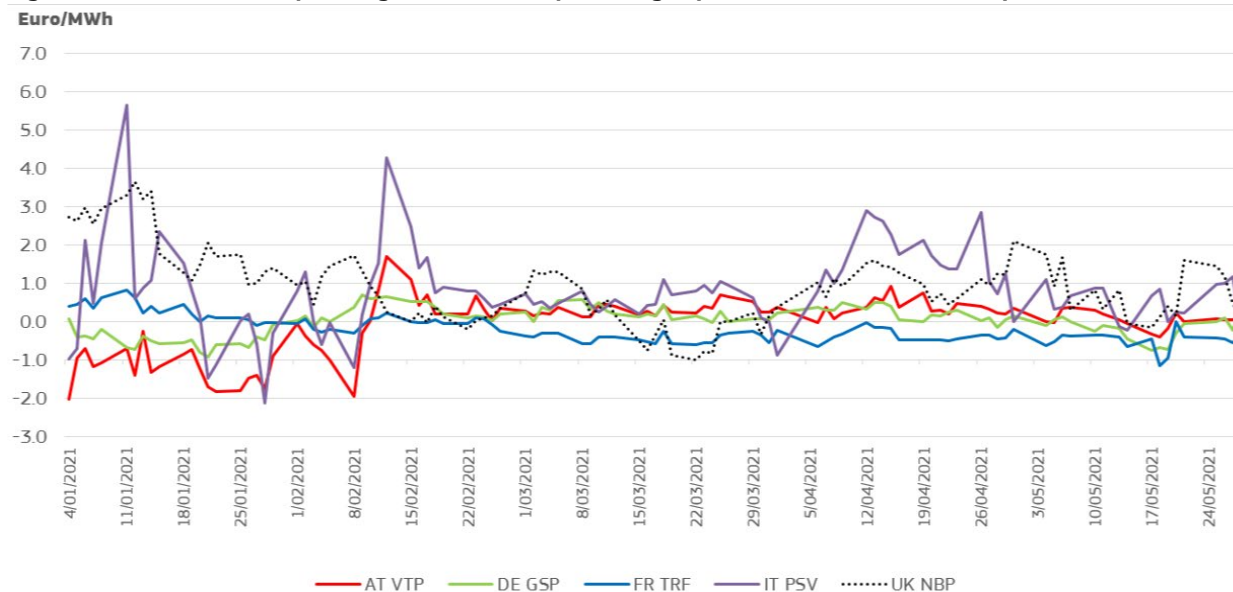
some days NBP premium over the TTF reached 3-4 €/MWh. In later months the price relation between NBP and TTF strongly correlated with LNG arrivals in the UK.

**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**

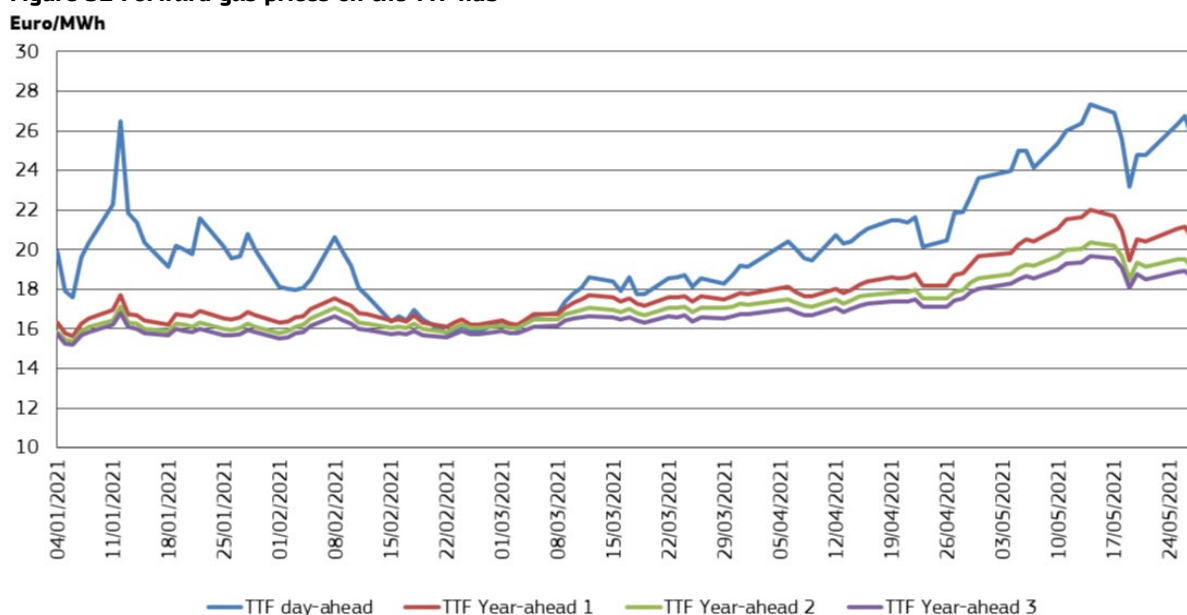


Source: S&P Global Platts, European Commission computations

- 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 hub spiked on 12 January 2021, around 26€/MWh, in consequence of rapidly increasing demand for LNG on the Asian gas markets. However, by mid-February spot prices returned to the levels of the beginning of 2021, reconverging with one-year, two-year and three-year ahead contracts that remained practically stable in January and February 2021, in a range of 15-18 €/MWh. However, as of mid-March spot contracts started to decouple again from the forward contracts. By the end of March 2021 the spot price reached 19.2€/MWh, whereas the year-ahead, two-year ahead and three year-ahead contracts were respectively 17.8€/MWh, 17.3€/MWh and 16.8€/MWh. In April and May, lower than seasonal filling rates and renewed demand

increase for gas in Asia gave a boost to the spot contracts again, by the end of May reaching 27€/MWh, similar levels to mid-January, whereas forward contracts, albeit also rising, but remained in a strong backwardation, in a range of 18-21€/MWh, which implied that the generally upward trend on the spot market might face a correction in the forthcoming period.

**Figure 32 Forward gas prices on the TTF hub**



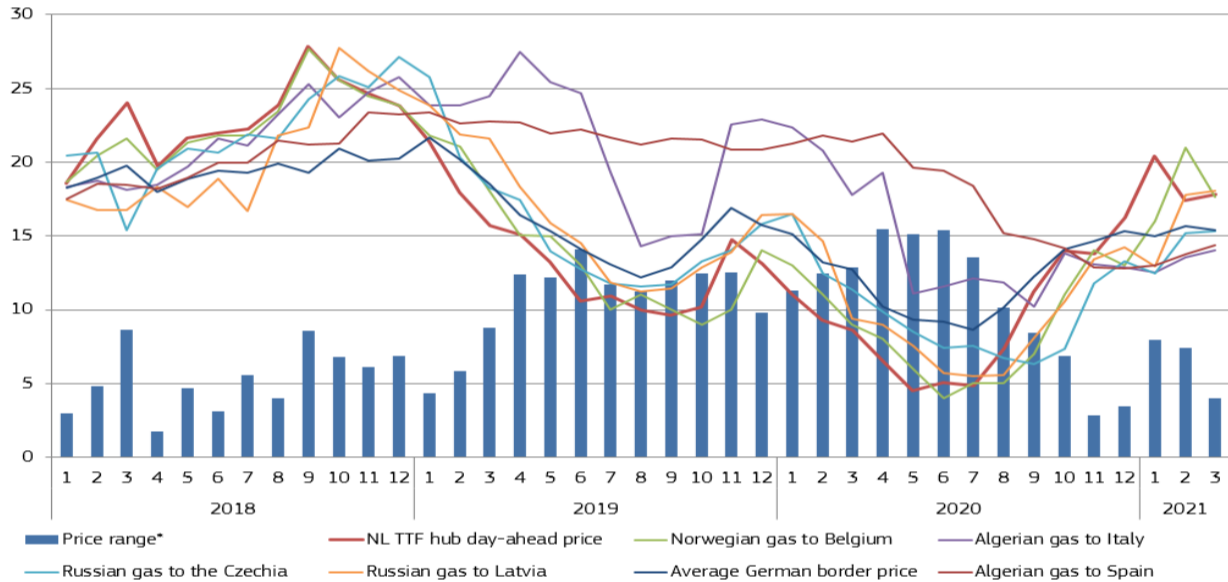
Source: S&P Global Platts

### 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 first quarter of 2021, the estimated Algerian pipeline import price in Spain was 13.7 €/MWh, slightly up compared to the previous quarter (by 3%, from 13.3€/MWh), but was down by 36% compared to Q1 2020. Between December 2020 and March 2021 the Algerian import price rose by around 1.5€/MWh, clearly reflecting the time-lagged impact of recovering crude oil prices as of mid-2020. However, in Q1 2021, the average estimated Algerian import price in Spain had a discount of more than 5€/MWh to the Spanish LNG import price, providing a competitive advantage to Algerian imports, more than doubling in Q1 2021 in year-on-year comparison in Spain.
- In the first quarter of 2021 Algerian gas import price in Italy (13.4 €/MWh) was similar to that in Spain. In year-on-year comparison, Algerian import price in Italy was down by 34% in Q1 2021. Probably owing to more competitive pricing, pipeline gas imports in Italy from Algeria was up by 160% in Q1 2021 year-on-year (See Chapter 1.3 Imports). For the future, the current advantage of oil-indexed contracts is likely to decrease as spot gas prices might reverse their increasing trend and the time lag impact of increasing oil prices will filter in the oil-indexed price contracts.
- Russian gas imports prices in both Czechia and Latvia continued to increase in Q1 2021 and were respectively up by 33% and 28% compared to the previous quarter, whereas year-on-year they rose by 7% and 21%. This implies a much closer mirroring of European hub prices compared to the 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 (16.3 €/MWh vs. 14.3 €/MWh) in Q1 2021.
- Prices of European gas contracts showed signs of slight divergence compared to the end of 2020 in January-February 2021, as the difference between the cheapest and most expensive contract rose from 3.5 €/MWh in December to 8 €/MWh in January and to 7.5€/MWh in February 2021, whereas in March they started to converge again, as price differential dropped to 4 €/MWh. Without Algerian price contracts, lagging behind in increase compared to the other observed contracts, price differential would have fallen to 2.7 €/MWh by March 2021.

- Hub-based contracts and hub prices themselves continued their upturn in the first quarter of 2021. 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**  
Euro/MWh



Source: Eurostat COMEXT and European Commission estimations, BAFA, S&P Global Platts

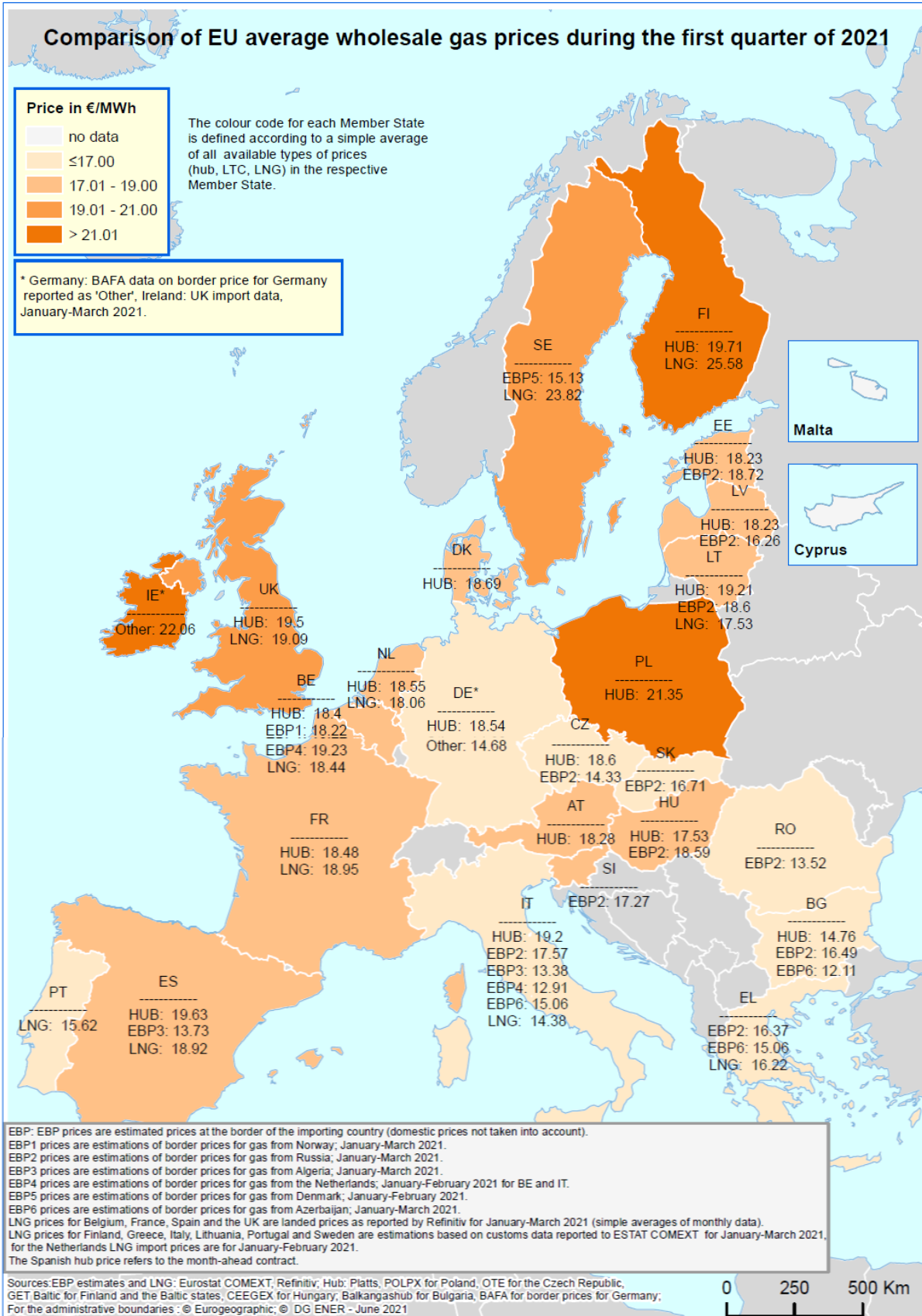
\*The difference between the highest and lowest price depicted on the graph

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 on the next page shows the different hub prices, estimated pipeline and LNG import prices in most of the European countries, giving an indication to wholesale gas prices in the given country.



**Map 1. Comparison of EU wholesale gas prices in the first quarter of 2021**



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

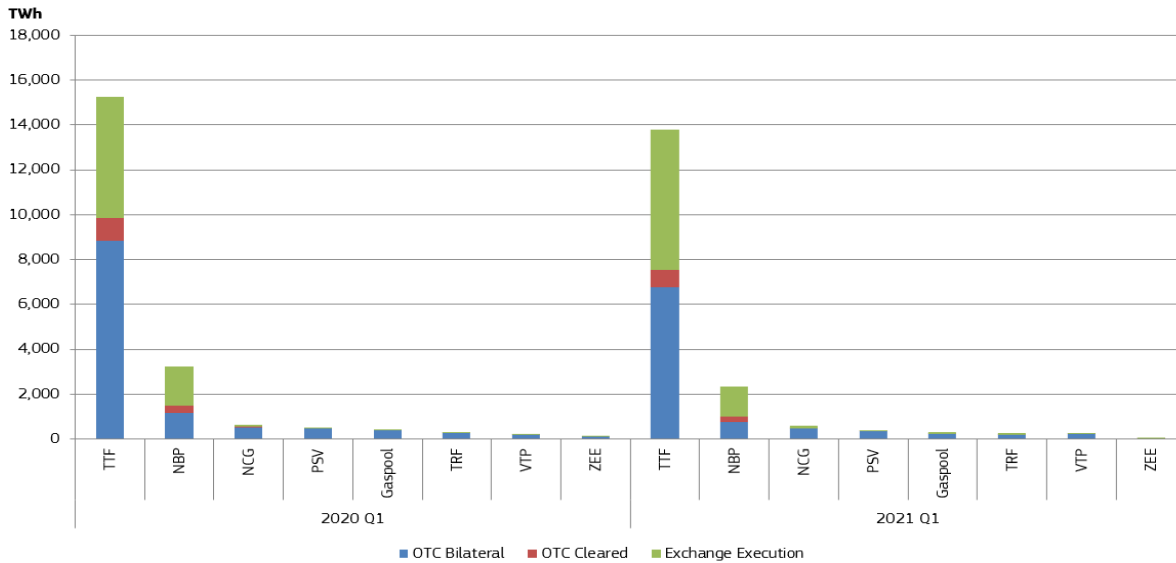
- As Figure 34 shows, liquidity on the main European gas hubs decreased year-on-year in the first quarter of 2021 by 13%, principally owing to the outstandingly high traded volumes in Q1 2020. As compared to the previous quarter, Q4 2020, volumes were up by 10%. In Q1 2021, the total traded volume amounted to around 17 974 TWh (equivalent to around 1 668 bcm and in monetary terms representing €333 billion<sup>25</sup>). In Q4 2020 traded volumes increased by 21% year-on-year, following a decrease of 8% in Q3 2020. The Q1 2021 traded volume however was around 16 times more than the gas consumption in the six Member States<sup>26</sup> covered by the analysis in January-March 2021.
- Traded volumes in Q1 2021 fell on almost of all of the observed trading hubs in Europe in year-on-year comparison. On the most liquid hub, the TTF, the year-on-year decrease amounted to 10%. On two German hubs (Gaspool and NGC) together traded volumes fell by 15% over the same period. In Italy (PSV) the volume went down by 25%, and on the French TRF it fell by 14%, in Q1 2021. As an exception, on the VTP hub in Austria traded volumes rose by 24%. The steepest fall in traded volumes could be observed on the Belgian Zeebrugge hub (by 65%) in Q1 2021 year-on-year, and total volumes amounted only to 37 TWh (whereas on the TTF volumes reached 13 781 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 27% compared to Q1 2020.
- As the year-on-year change in traded volumes on the TTF hub went down by 10% in Q1 2020, which was less than the decrease on the overall observed European markets (13%), the share of TTF in the total European gas trade increased further (in Q1 2021 amounting to 77%, whereas a year before it was only 74%). If looking at only the EU countries, its share is even bigger, 88%. 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 Q1 2020 fell by 27% compared to the same period of 2020, and the share of NBP in Q1 2021 fell to 13% in the total European observed trade, down from 16% in Q1 2020.
- Other markets had lower shares: Germany (NGC and Gaspool together) had a share of 5.1%, while the Italian PSV only had 2%, whereas VTP, TRF had shares of 1.5% each, and Zeebrugge had only a minor share in the European gas trade (0.2%) in Q1 2021.
- Although net gas imports was down by 3% and LNG imports fell by 29% year-on-year in the EU in the first quarter of 2021, consumption of gas went up by almost 8%. Amid decreasing imports and production, increasing consumption was satisfied by withdrawals from gas storages, however, this was not enough to boost trade on hubs. Trading volumes were mainly driven by near-curve contracts on the European hubs, (spot and month-ahead), whereas trade on the far end of the curve decreased further. Gas spikes in January 2021 contributed to the increase in traded volumes in that month, however, the calmer period in February and March resulted in an overall decrease in trade in Q1 2021.
- The share of exchange executed contracts on the Dutch TTF hub was 45% in Q1 2021, which was the highest among the observed EU countries, and was up by 9 percentage points compared to Q1 2020. On the French TRF, and on the two German hubs together it amounted to 21%, respectively up by 5 percentage points and by 8 percentage points compared to Q1 2020. On the VTP hub in Austria this share was 15%, down from 16% in the same period of 2020. On Zeebrugge, the share of exchange-executed contracts was much lower, only 2%, 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 57% in Q1 2021, even up by 3 percentage points compared to Q1 2020.

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<sup>25</sup> Assuming that all trade was carried out on the quarterly average spot price

<sup>26</sup> Netherlands, 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 Q1 2021 represents 10 times the total EU-27 gas consumption in this period.

**Figure 34 Traded volumes on the main European gas hubs in the first quarters of 2020 and 2021**

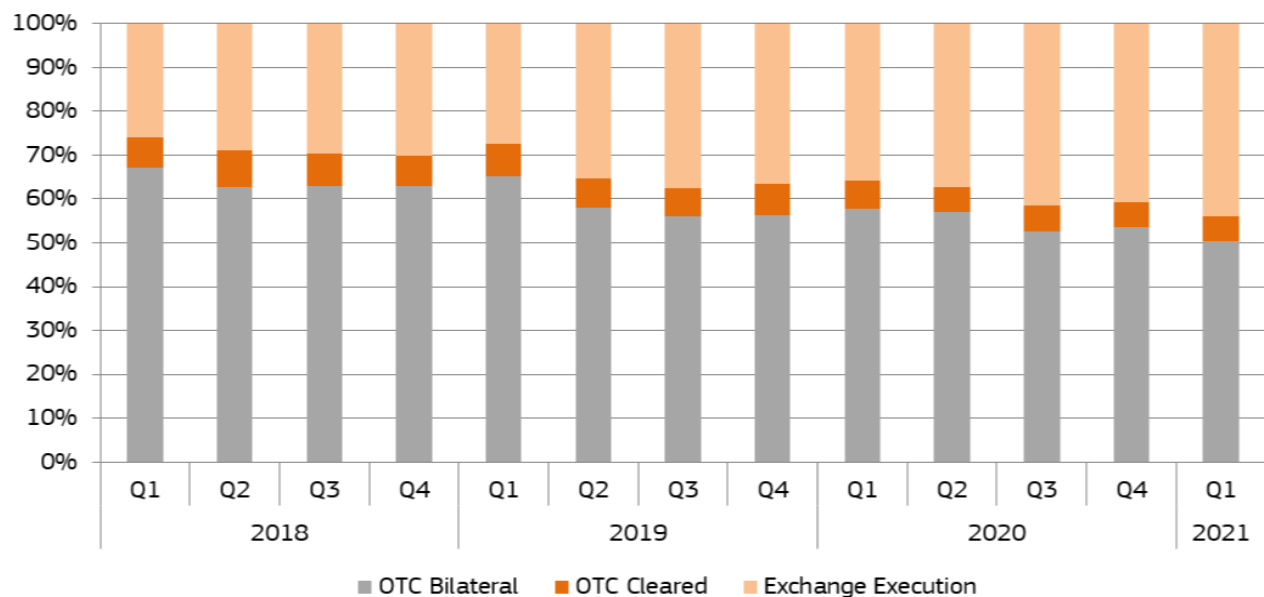


The chart covers the following trading hubs: Netherlands: TTF (Title Transfer Facility); Germany: NCG (NetConnect Germany) and Gaspool; France: TRF (Trading Region France); Italy: PSV (Punto di Scambio Virtuale); Austria: Virtual Trading Point (VTP); Belgium: Zeebrugge beach; UK: NBP (National Balancing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

Source: Trayport Euro Commodities Market Dynamics Report

- On the European hubs as whole, in Q1 2021 50% of the total trade was OTC bilateral, 6% was OTC cleared, whereas the share of exchange-executed contracts was a 44%. The share of exchange-executed contracts increased by 8 percentage points year-on-year in Q1 2021, whereas the share of OTC bilateral went down by than 7 percentage points, and that of OTC cleared by 1 percentage point. The share of exchange executed volumes (44%) was the highest in the last six years, reinforcing the trend of shift towards exchanges from the OTC market.
- Amid the general decrease in traded volumes (13% in Q1 2021 year-on-year), exchange executed volumes managed to go against the trend, by growing 7% year-on-year on the observed European markets. In the same period, the total OTC traded volume (bilateral and cleared together) fell by 24%. 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).

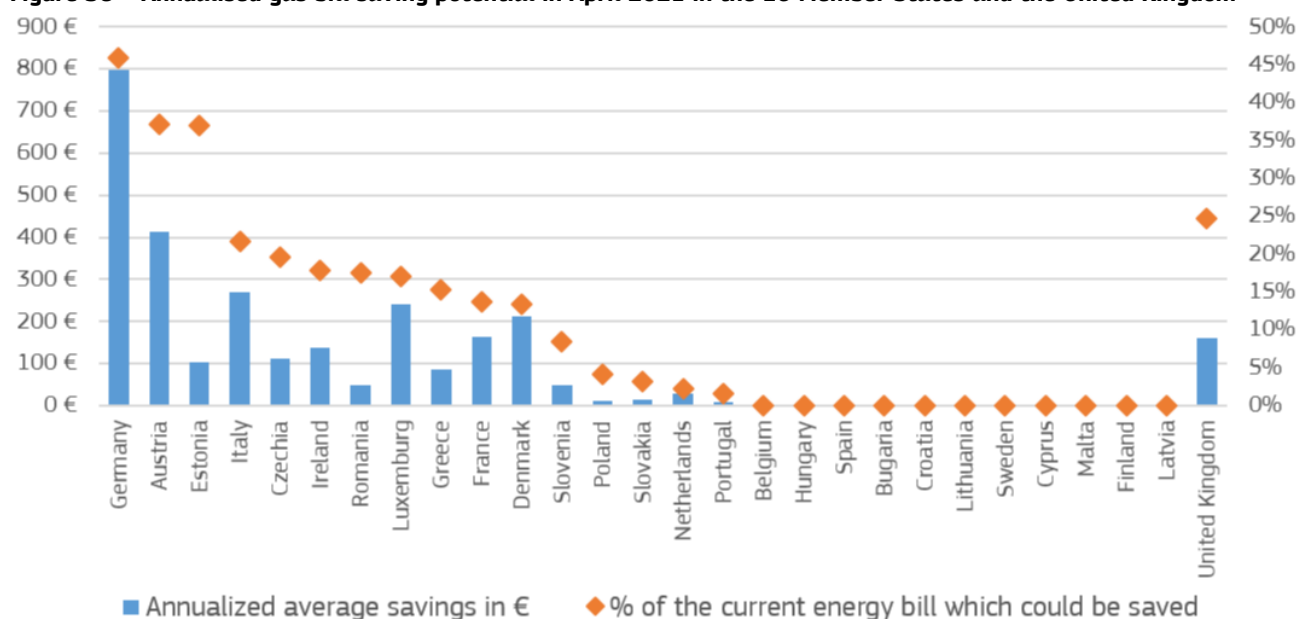
Source: Trayport Euro Commodities Market Dynamics Report

### 3. Retail gas markets in the EU and outside Europe

#### 3.1 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 April 2021. Prices in capital cities were used as a proxy to assess prices at the national level.
- In April 2021 in absolute terms, German households could have the highest annualised savings (€798, or 46%), had they switched from their incumbent utility to the most competitive offer available. On the other hand, households in Portugal could have the lowest annualised savings, amounting to 1.6% or €8 if they chose the most competitive offer.

**Figure 36 – Annualised gas bill saving potential in April 2021 in the EU Member States and the United Kingdom**

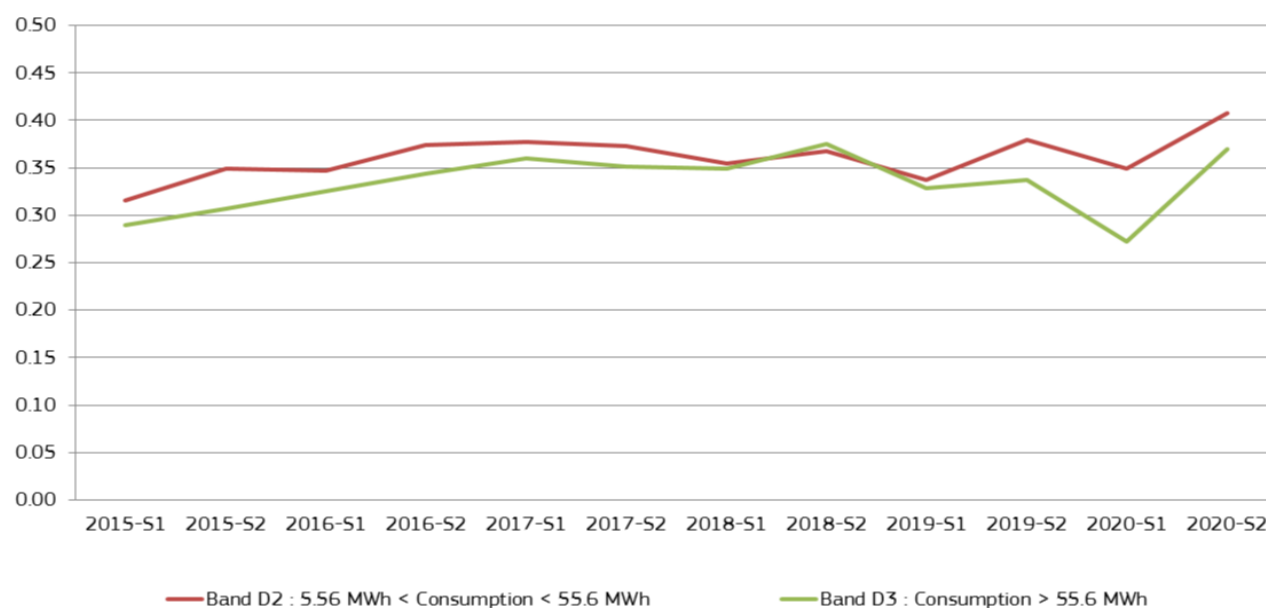


Source: VaasaETT data collection. Saving potential is reported to be zero for Spain and Hungary, for Bulgaria, Croatia, Finland, Latvia, Lithuania, Sweden, Cyprus and Malta no data are available

#### 3.2 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 second 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 Q1 2021 in the EU (including all taxes) reversed the decreasing trend of the previous two quarters and was up by 9.1% in year-on-year comparison. In the most typical consumption Band, D2, in the first quarter of 2021 the estimated average price (including all taxes) was 7.3 Eurocents/kWh, down up from 7.0 Eurocents/kWh in Q4 2020, and from 6.7 Eurocents/kWh in Q1 2020. (See the estimated household prices on Map 2).
- In the first quarter of 2021, 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 Lithuania (3.1 Eurocent/kWh), Romania and Latvia (both 3.2 Eurocent/kWh), whereas the highest prices could be measured in Sweden (11.1 Eurocent/kWh), Netherlands (10.1 Eurocent/kWh), Italy (9.8 Eurocent/kWh). The price differential ratio between the cheapest and the most expensive Member State rose slightly, to 3.6 (in the previous quarter it was 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. As Figure 37 shows, in the second half of 2020 household retail gas prices showed a higher degree of divergence across the EU Member States than in 2019 and in the first half of 2020.

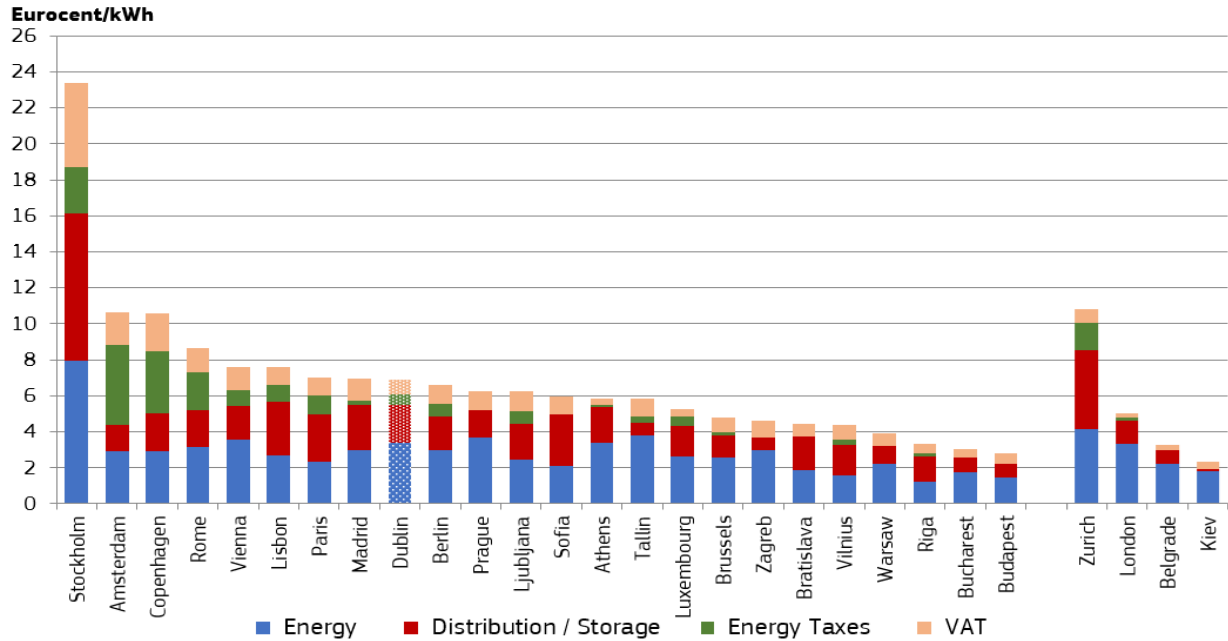
**Figure 37 – Bi-annual retail gas price dispersion for household customers across the EU Member States, as measured by relative standard deviation**



Source: Computation based on Eurostat data

- Figure 38 shows the level and the breakdown of residential end-user gas prices paid by typical households in European capitals in May 2021. On average, 42% of the price covered the energy component, while the rest covered distribution/storage costs (30%), energy taxes (12%) and VAT (16%).
- There were significant differences in May 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 27% (Amsterdam) and 28% (Copenhagen) to Tallinn (65%) and Zagreb (64%). The share of distribution/storage costs ranged from 11% (Tallinn) and Amsterdam (14%) to 48% (Sofia) and 41% (Bratislava and Riga). The share of energy taxes ranged from 2% (Athens) and 3% (Madrid) to 42% (Amsterdam) and 33% (Copenhagen). For 7 of the 24 capitals covered, the price does not include any 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 May 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 12.3 (between Tallinn and Stockholm) highest-lowest tax component ratio (taking energy taxes and VAT together) was 15.5 (Athens and Stockholm) in May 2021.
- With the exception of seven capital cities out of the observed 24, prices were higher in May 2021, compared to the same month of the previous year. Prices decreased by the most in Warsaw, Madrid and Riga (5% each), mainly driven by the decrease in energy costs and to a lesser extent, network costs (e.g. in Madrid). Prices went up by the most in Athens (40%), Copenhagen (24%) and Sofia (18%), also principally impacted by energy costs. It seems that recent price increases on wholesale gas markets are already measurable in the final retail household prices in many of the EU capital cities. In May 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.

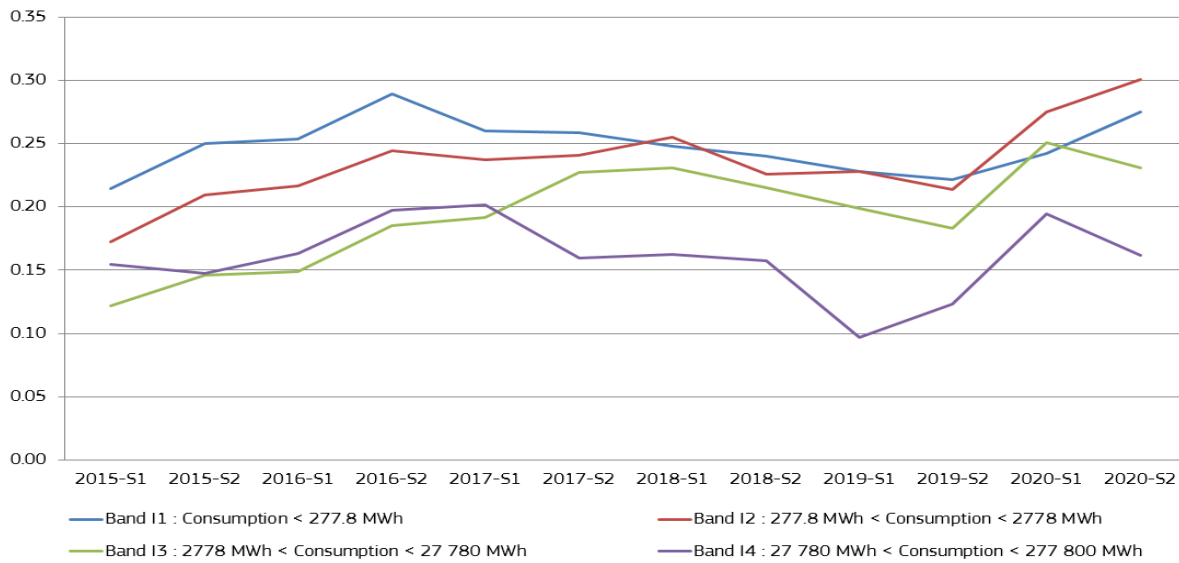
**Figure 38 - Breakdown of gas price paid by typical household customers in European capitals, May 2021**



Source: VaasaETT

- Retail gas prices for industrial customers decreased by 8.6% in Q1 2021 year-on-year in the EU on average, and the average estimated price (VAT and other recoverable taxes excluded) in consumption Band I4 was 2.23 Eurocent/kWh, slightly up from 2.16 in Q4 2020 but down from 2.44 in Q1 2020. (See the estimated industrial prices on Map 3.) There were six countries in the EU where industrial gas prices increased in year-on-year comparison in Q1 2021, while in the other 18 observed countries (data were not available for Cyprus, Finland and Malta) decreases could be observed. It seems that price recovery on wholesale gas market, started in the second half of 2020 only partially appeared in retail prices for industrial customers in Q1 2021, having average consumption. Decreases could also be observed for industrial customers having larger annual gas consumption (5% decrease in both Band I5 and 8% decrease in Band I6 in Q1 2021 year-on-year).
- In the first quarter of 2021, the lowest estimated industrial price in consumption Band I4 could be observed in Bulgaria (1.6 Eurocent/kWh) and in Belgium, Luxembourg and Romania (1.9 Eurocent/kWh). The highest prices could be observed in Sweden (2.9 Eurocent/kWh) and Slovakia (2.6 Eurocent/kWh). In Q1 2021, the price ratio of the cheapest and the most expensive country in the EU was 1.8. This price differential was lower compared to the first quarter of 2017, when it was 2.8, but slightly higher compared to the fourth quarter of 2019, when it was only 1.7. As Figure 39 shows, retail gas prices for industrial customers showed a higher degree of divergence in the case of lower annual consumption bands (Band I1 and I2), whereas for prices with larger customers (Band I3 and Band I4) the convergence slightly improved across the EU Member States.

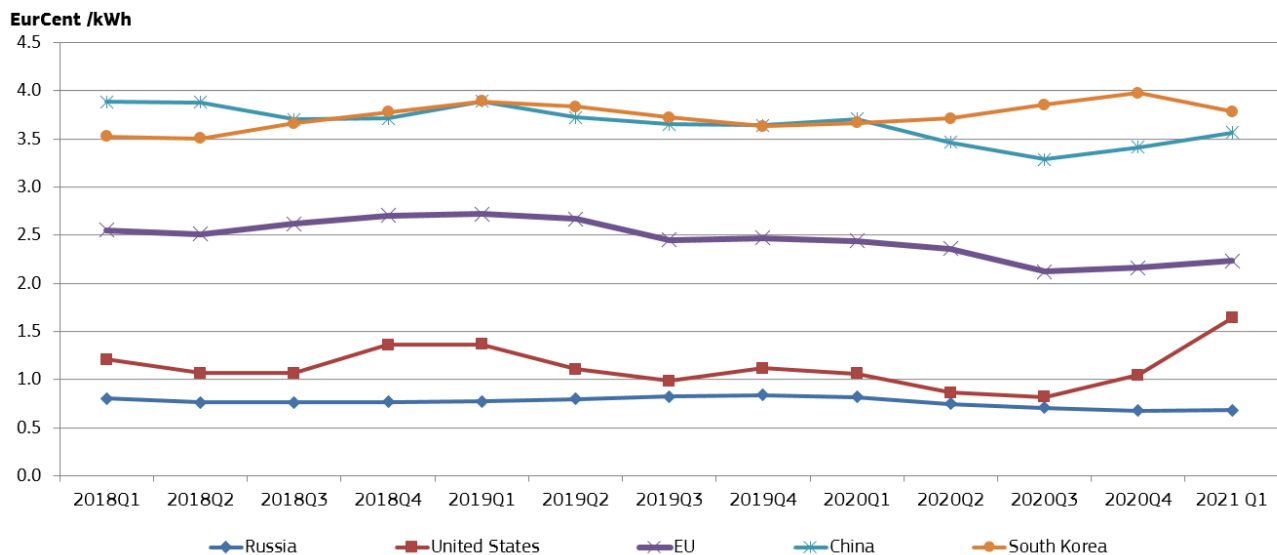
**Figure 39 - Bi-annual retail gas price dispersion for industrial customers across the EU Member States, as measured by relative standard deviation**



Source: Computation based on Eurostat data

- Figure 40 shows the evolution of industrial retail gas prices in the EU, compared with some important trade partners of the European economy. In the first quarter of 2021, retail gas prices for industrial customers in China and Korea had a price premium to the EU average (respectively 60% and 70%). On the other hand, retail gas prices in the United States were 27% less than in the EU and in Russia gas prices had a discount of almost 70% to the EU average. Compared to Q1 2020, the biggest increase in industrial gas retail prices could be observed in United States (55%), probably owing to the wholesale price spike in January 2021. Prices slightly rose in Korea (3%), whereas they fell in Russia (16%), and in China (3%). In the EU retail industrial prices were down by almost 9%.

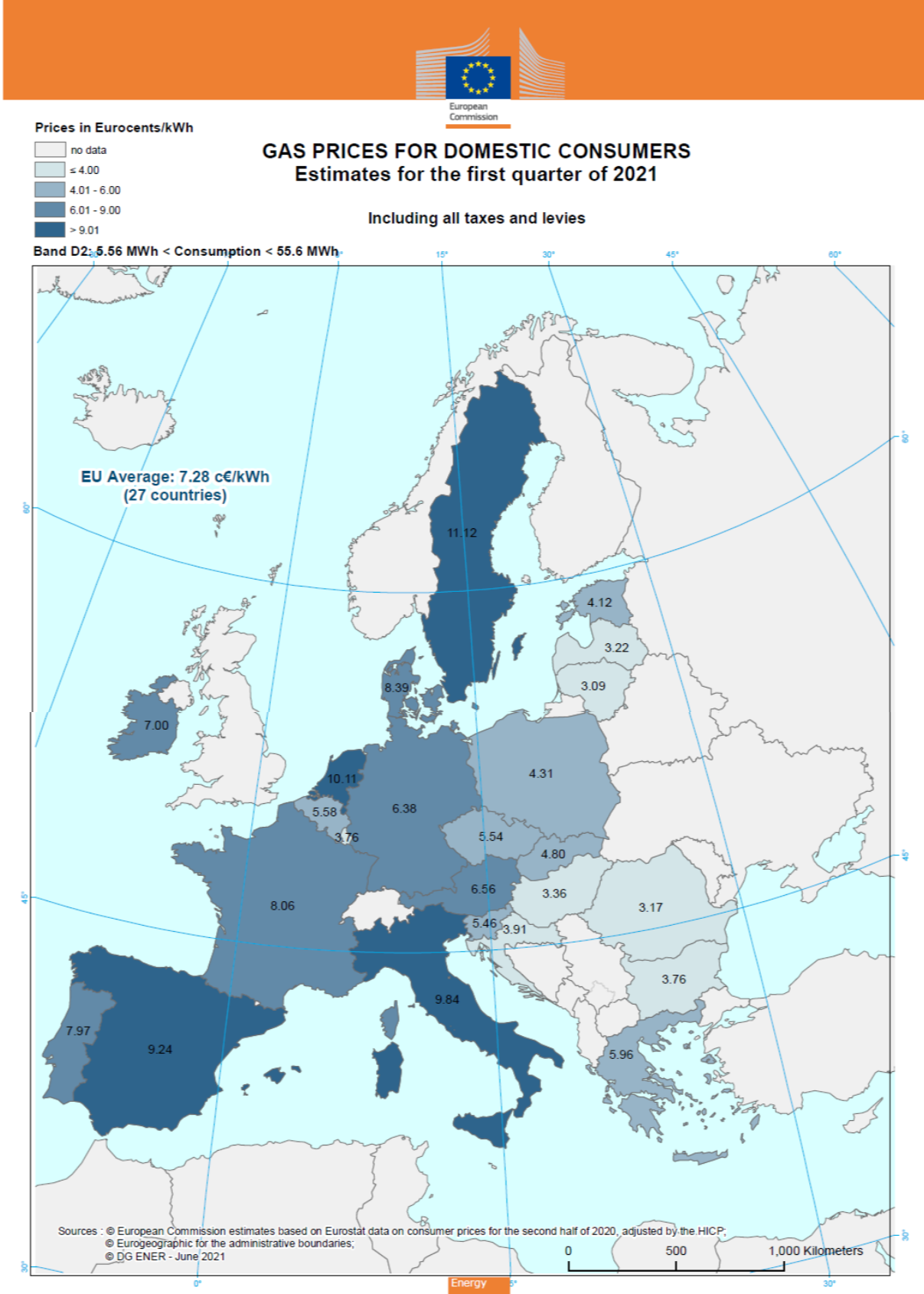
**Figure 40 The EU average industrial retail gas price in comparison with the prices of some important trade partners of the EU**



Source: Eurostat (EU average, for industrial consumption band I4) and CEIC. Data of the United States, China, Russia and Korea were taken into account. EU prices are without VAT and other recoverable taxes

- Maps 2 and 3 on the next two pages show the estimated retail gas prices paid by households and industrial customers in the first quarter of 2021.

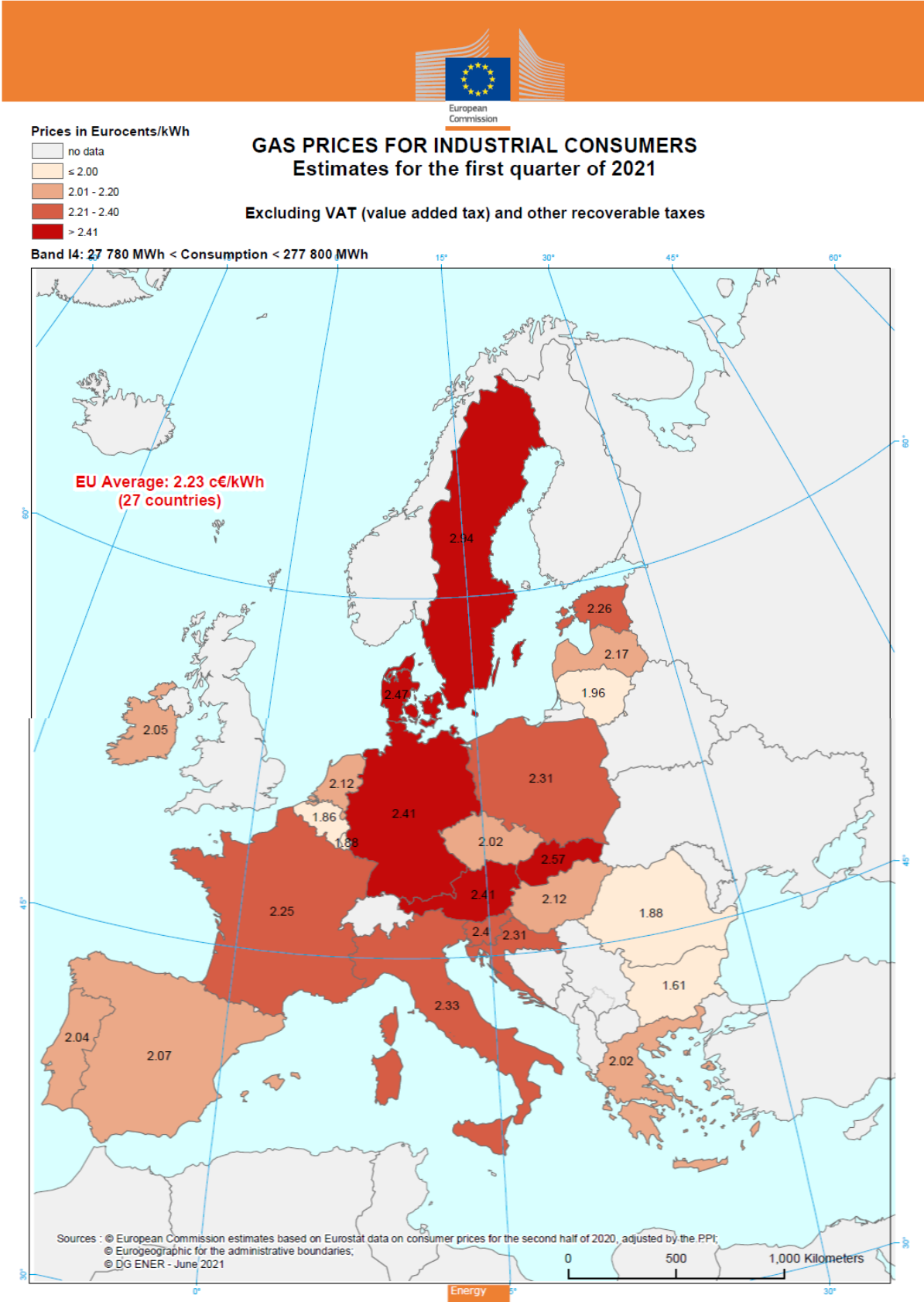
**Map 2. Retail gas price estimates for households in the EU – First quarter of 2021**



Source: Eurostat



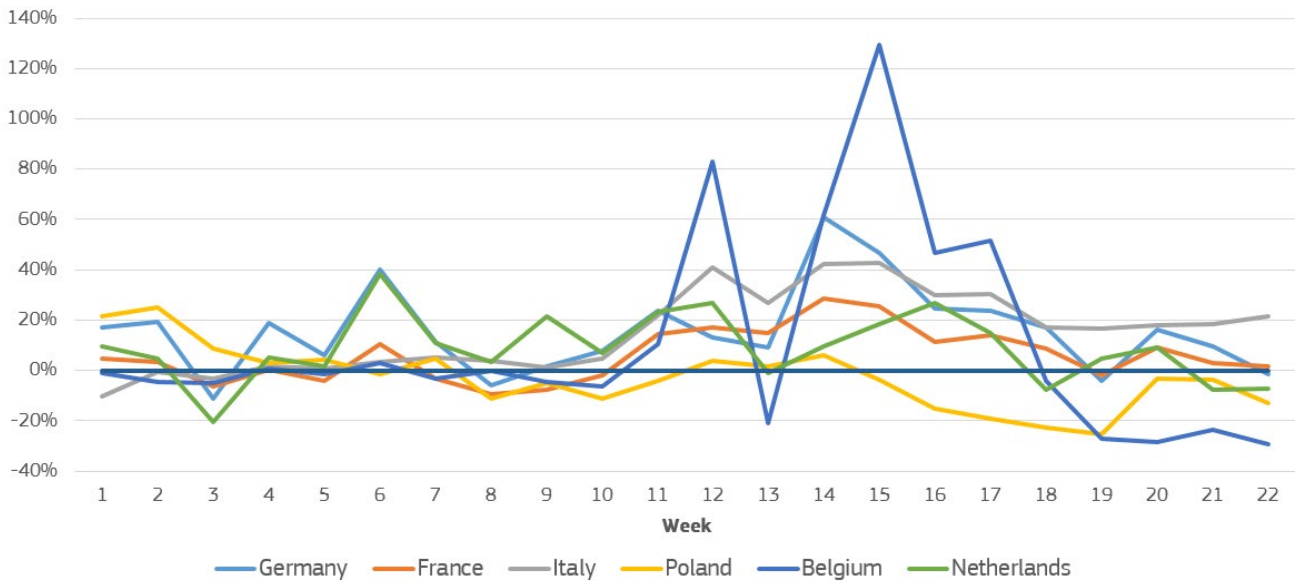
**Map 3. Retail gas price estimates for industrial consumers in the EU – First quarter of 2021**



Source: Eurostat

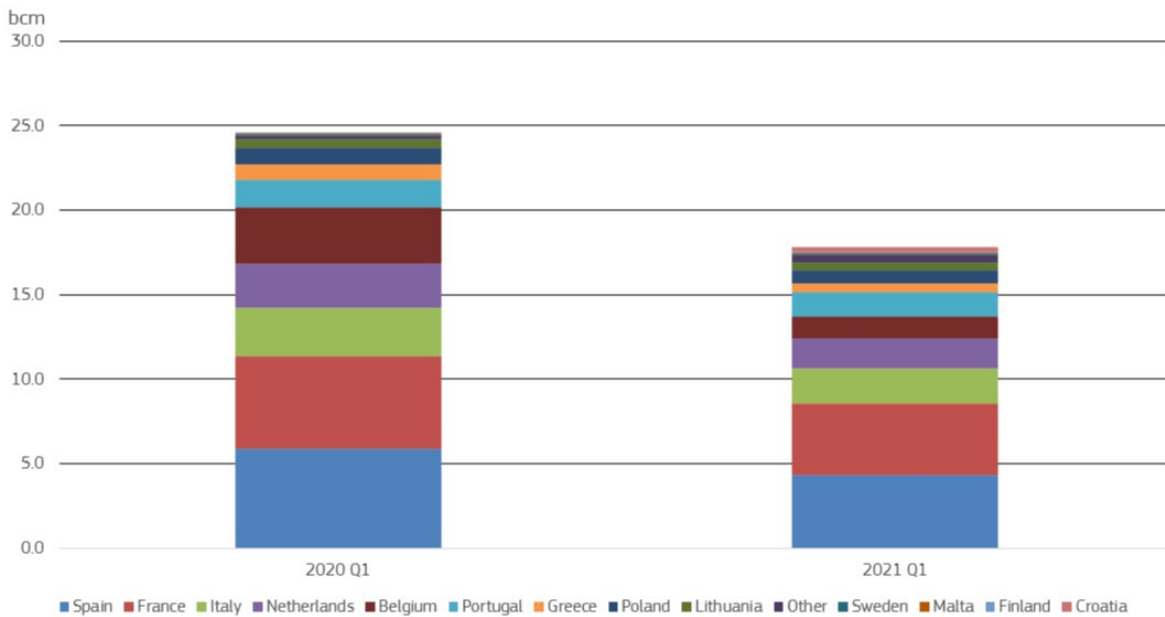
#### 4. Appendix – charts providing further details on market developments<sup>27</sup>

**Figure 41 Change in weekly consumption of natural gas for industrial and non-household customers in Q1 2021 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.

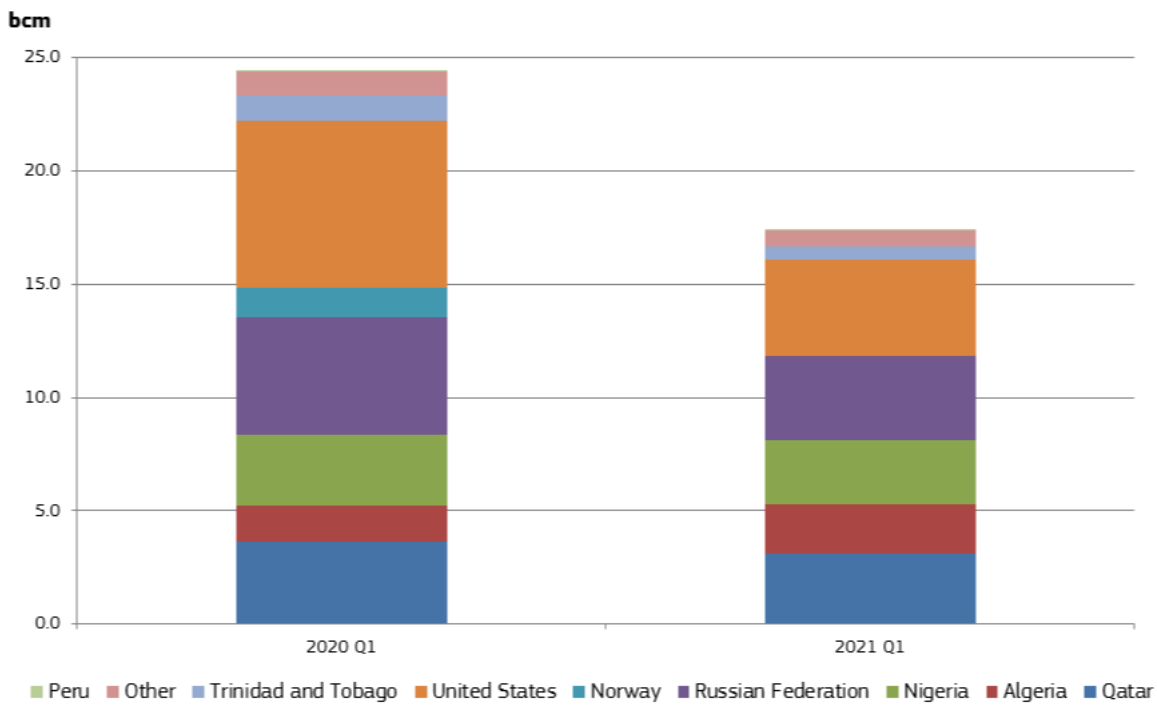
**Figure 42 – LNG imports in the EU Member States, first quarters of 2020 and 2021**



Source: Refinitiv

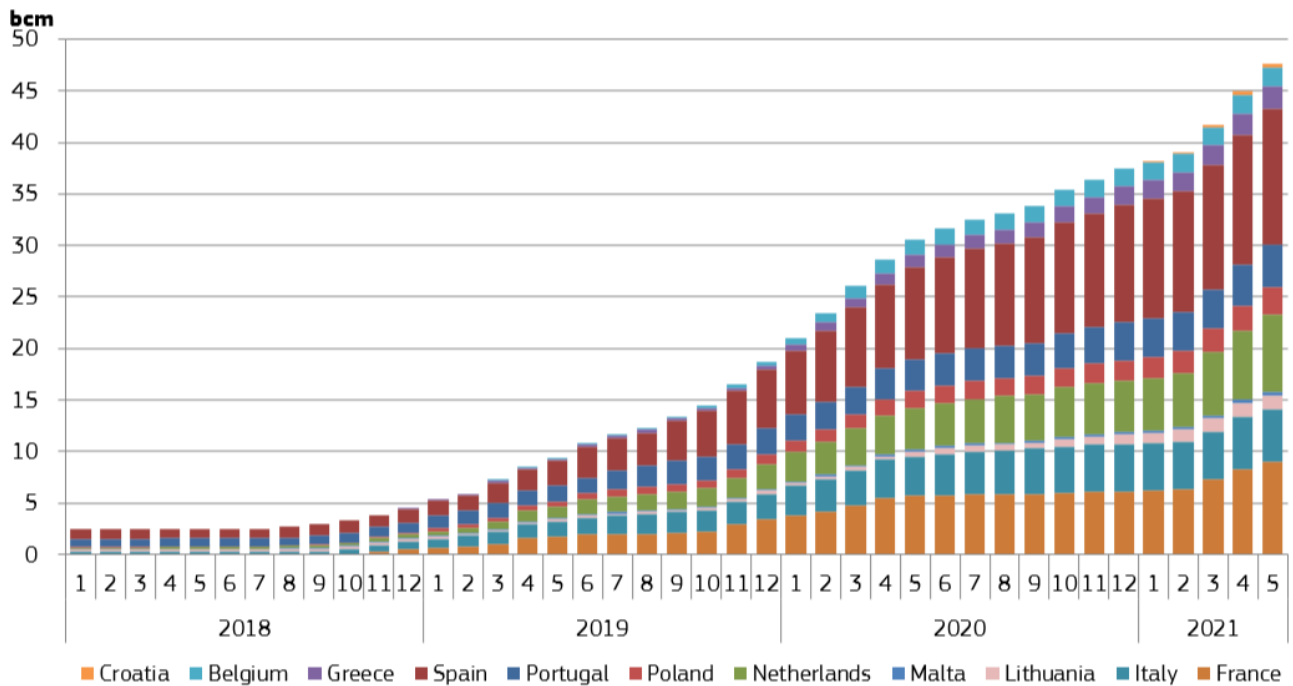
<sup>27</sup> These charts provide additional information on the main market developments, without textual comments or further detailed analysis

**Figure 43 – LNG import from the main suppliers to the EU in the first quarters of 2020 and 2021**



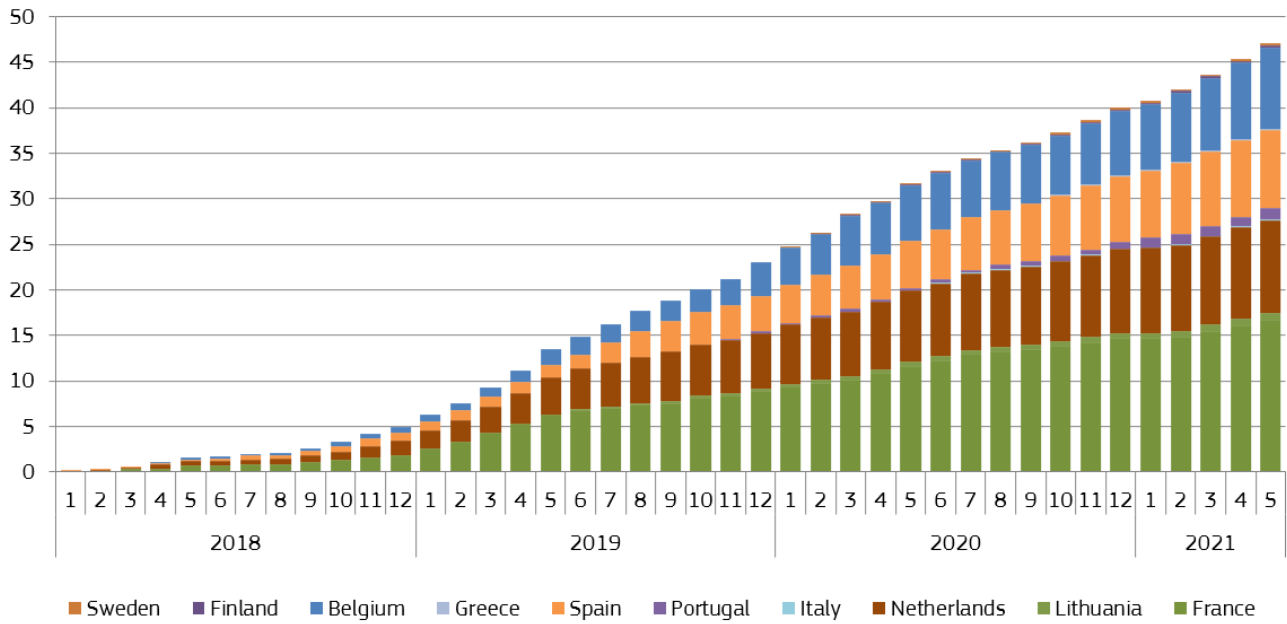
Source: Refinitiv

**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**  
bcm



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 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 €/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 1978-2018) 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 bi-annual retail energy price data from Eurostat.