

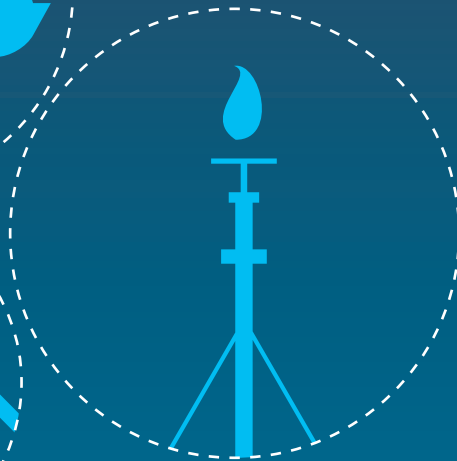
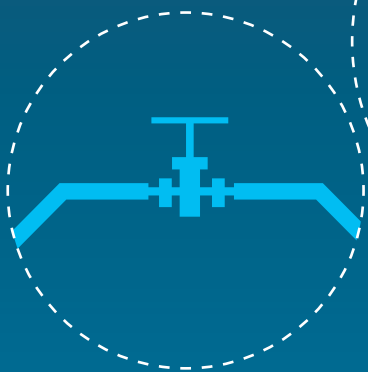


European
Commission

Quarterly report

On European gas markets

With focus on 2021, an extraordinary year
on the European and global gas markets



Market Observatory for Energy
DG Energy

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Energy

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HIGHLIGHTS OF THE REPORT

- **Wholesale gas prices in Europe were on a rollercoaster in the fourth quarter of 2021.** The TTF spot price started the quarter at 85 €/MWh, rising to 116 €/MWh in early October, falling back to 60 €/MWh by the end of that month, and as of November rebounding, and reaching levels never seen before (183 €/MWh on 21 December), to finish the year at 60 €/MWh. In 2022 so far, this volatility kept on and in early March once the daily average price was above 200 €/MWh. Forward contracts also rose significantly, which signalled that the market does not anticipate a quick return to the price levels seen in the previous years. Carbon prices also reached new highs in Q4 2021, rising to 88 €/tCO_{2e} in early December in February 2022 to 96 €/tCO_{2e}. High wholesale gas prices resulted in soaring wholesale electricity prices as well. Oil prices in Q4 2021 rose to highs last seen in 2014, and in early March 2022 they nearly reached records set in the summer of 2008. High wholesale gas prices have impacted the production in energy intensive industries, and resulted in rising consumer bills for citizens as well.
- **Policy developments and geopolitical tensions**, principally impacting energy relations between the EU and Russia had of key importance on shaping the wholesale gas markets. The suspension of the certification of the Nord Stream 2 gas pipeline and rising tensions over Ukraine as increasing number of Russian troops were deployed to its border, finally leading to an invasion, had much bigger importance than the gas market fundamentals of demand and supply, leading to extreme volatility of gas prices over the last few months.
- **Low gas storage levels in Q4 2021 continued to play an important role on the European gas market.** At the end of September 2021, the storage filling rate was 74.6% in the EU on average, which fell to 53% by the end of December, the lowest in a decade at this time of the year. Compared to the average of 2016-2020, at the beginning of Q4 2021 the EU average storage filling rate was lower by 15 percentage points, and this gap widened to 19 points by the end of 2021. However, owing to relatively mild weather in January and February 2022, this gap decreased to 12 percentage points by the end of February, and the EU average storage fullness was similar to years 2017 and 2018 at this time of the year. At the same time, storages managed by Gazprom in the EU remained at very low fullness rate (at 11-27% so far) over the whole heating season on 2021/2022.
- **EU net gas imports rose by 2% year-on-year** (by 1.8 bcm) in Q4 2021. Russian pipeline supplies fell by 24% year-on-year and covered only 37% of extra-EU net gas imports (the lowest share in the last eight years, but falling further to 25% in January 2022), followed by Norway (24%), and LNG imports, amounting to 22%. In spite of the competitive oil-indexed prices, pipeline imports from Algeria was down by 3% year-on-year, and covered less than 10% of the total extra-EU gas imports in Q4 2021, as the contract of the GME pipeline that supplied the Iberian peninsula with Algerian gas through Morocco expired on 31 October 2021, thus Spanish pipeline imports from Algeria fell by 27% in Q4 2021 year-on-year (in contrast, imports in Italy from Algerian pipeline source was up by 14%). The Trans Adriatic Pipeline (TAP) ensured 3.2% of the total extra-EU gas imports, whereas the share of Libya was less than 1% in Q4 2021. Net gas imports in the EU amounted to 86.5 bcm in Q4 2021, and in 2021 it reached 337.5 bcm, up from 326.7 bcm (+3%) in 2020. The EU spent an estimated €121 billion on gas imports in 2021, up from €37 billion in 2020, principally owing to higher import prices and volumes.
- **Russian gas imports through both the Belarus and Ukrainian transit routes fell significantly (respectively by 56% and 36% year-on-year** in Q4 2021, whereas through the Nord Stream 1 they remained unchanged and through Turk Stream were up by 43%. In spite of promises from the Russian side to start supplying more gas to EU storages as of 8 November 2021, the monthly average transit volumes via Ukraine fell to 3 bcm and those via Belarus to 1.5 bcm in Q4 2021, low levels not seen at this time of the year in the last eight years. In January-February 2022 monthly transited volumes via these two routes fell further. Out of the transited volume of 31 bcm through the following four routes, in Q4 2021 the share of Nord Stream was 49%, the share of Ukraine was 29%, that of Belarus was only 15% and Turk Stream had a share of 8%. In 2021, the EU imported 58 bcm of Russian gas via Nord Stream, 37 bcm via the Ukrainian route, 33 bcm via the Belarus transit and 9 bcm via the Turk Stream.
- **EU LNG imports were up by 33% in Q4 2021 year-on-year**, amounting to 22 bcm. In December 2021 LNG imports were up by 53% and in January-February 2022 they doubled year-on-year, principally owing to high wholesale gas prices in Europe, resulting in a rare price premium to Asia many occasions during this period, prompting increasing LNG shipments. In Q4 2021, Spain was the biggest LNG importer in the EU (7.2 bcm), followed by France (4.4 bcm), and the Netherlands (2.8 bcm). The United States was the largest LNG source for the EU, ensuring 6.4 bcm (29% of the total EU LNG imports), followed by Russia (4.6 bcm) and Qatar (4.4 bcm). In 2021, EU countries imported 80 bcm of LNG, which was lower than in 2020 (84 bcm), with principal import sources, such as the United States (22.3 bcm), followed by Qatar (16.3 bcm) and Russia (16 bcm).
- **EU gas consumption in Q4 2021 remained practically unchanged, up by 0.6%** (0.8 bcm) year-on-year, amounting to 121.4 bcm. Gas demand in electricity generation rose by 4% (5.7 TWh) year-on-year. On the other hand, increasing gas prices have led to decreasing demand for gas in energy intensive industries, even though EU GDP in Q4 2021 was up by 4.8% year-on-year, as economic growth would normally support gas consumption. EU gas consumption in 2021 amounted to 412 bcm, up by 4% (17 bcm) compared to 2020, and reached the highest since 2011, principally owing to higher residential gas consumption during colder periods of the year.
- **Indigenous gas production in the EU amounted to 12.1 bcm in Q3 2021, falling back by 13%** (1.8 bcm) compared to Q4 2020, after the short-lived production increase in the previous quarter. In Q4 2021, the biggest producer Netherlands produced 4.7 bcm of gas (-24% year-on-year), whereas Romania produced 2.2 bcm (-7%). In 2021, gas production in the EU amounted to

50.6 bcm, down by 7% (4 bcm) compared to 2020. The current security of gas supply situation might prompt some EU countries to rethink their attitude toward domestic gas production, which may lead to increasing production numbers in the future.

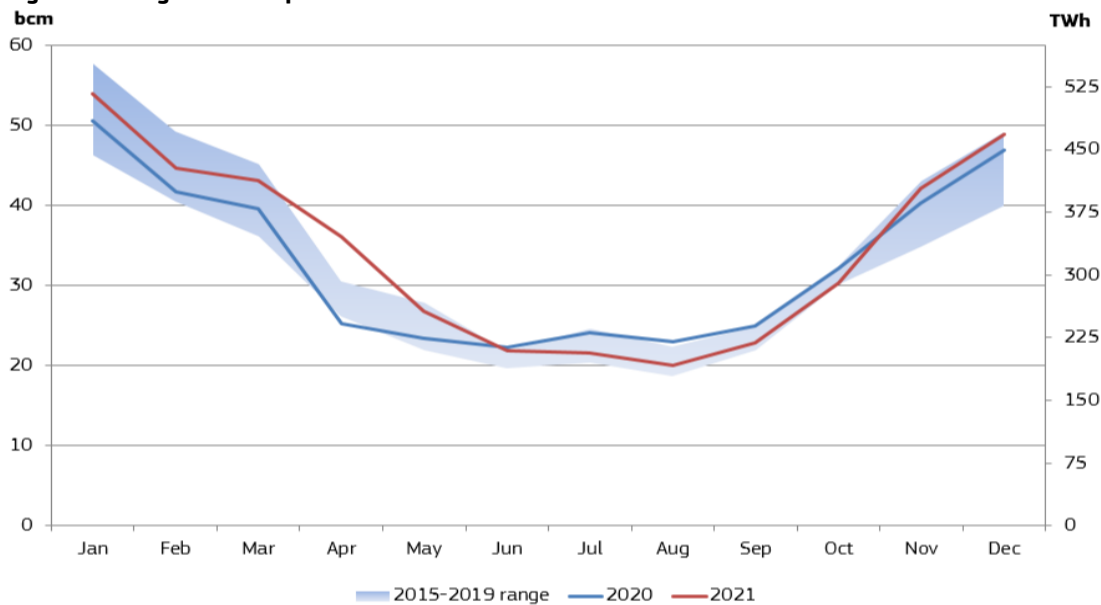
- **Gas traded volumes on the European hubs were down again, by 6% (975 TWh)** in Q4 2021 year-on-year, after the increase of 27% in the previous quarter. This was mainly due to the significant fall of the over-the-counter (OTC) trade (by 37% year-on-year), whereas exchange executed trade rose by 40%, as smaller traders, having lower financial coverage against default risk, were moving from OTC to exchange markets amid high and volatile wholesale gas prices. The share of exchange-executed contracts within the total trade rose to 60%, the highest in the last seven years.
- **Spot prices on the European gas hubs rose to the highest in Q4 2021** on quarterly average, and were in a range of 91-96 €/MWh, around six times higher than in Q4 2020. The discount of the forward contracts to the spot market remained at high levels (around 29 €/MWh on quarterly average, for year-ahead to spot), implying that the market anticipates a correction in high spot prices in the future. However, as the upward movement of the Dutch TTF hub forward curve suggests, price levels seen in the last few decade (15-25 €/MWh) will not return in the near future. Furthermore, the 2022 winter-summer TTF spread became negative in Q4 2021, and remained close to zero or in negative ranges in 2022 so far, which does not provide for strong incentives for refilling gas storages ahead of the next winter in 2022/2023.
- **Retail gas prices for household customers in EU capital cities were up by an estimated 65% in February 2022 year-on-year.** With the exception of two countries, gas prices for households in European capital cities were higher in February 2022 compared to the same month of 2021, and in six capital cities prices more than doubled, and in one even tripled. Recent price increases on wholesale gas markets have already been perceivable in retail contracts. Retail gas prices for industrial customers also increased, up by 36% year-on-year in Q4 2021 for consumers with median annual consumption.
- **Hydrogen costs-based assessments** showed that in the Netherlands **production costs of hydrogen** (capital expenditure costs included) with alkaline electrolyser technology amounted to 507 €/MWh in December 2021, whereas with polymer electrolyte fuel cells (PEM) the cost was assessed at 600 €/MWh, and with steam methane forming (SMR) at around 221 €/MWh, showing that recent steep increase in wholesale gas and electricity prices can also be tracked in rising hydrogen price assessments, as three months before, in September 2021 alkaline technology costs were only at 248 €/MWh, for PEM the cost was 300 €/MWh, whereas for SMR it was only 133 €/MWh.

1. Gas market fundamentals

1.1 Consumption

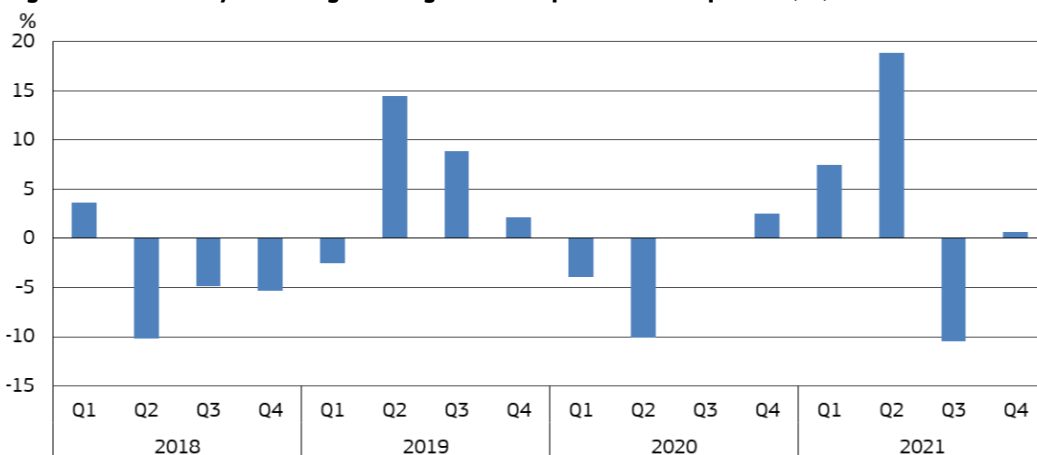
- EU gas consumption¹ in the fourth quarter of 2021 remained practically unchanged, up by 0.6% (+0.8 bcm) in year-on-year comparison, after the significant drop in Q3 2021 (-10%), and the measurable upturn in Q2 2021 (18.9%). In absolute numbers, the quarterly gas consumption in Q4 2021 amounted to an estimated 121.4 bcm, up from 120.6 bcm in Q4 2020, and up from 64.4 bcm in Q3 2021, as gas consumption increased with the onset of the heating season. Gas use in power generation was up by 4% (+5.7 TWh) year-on-year, which in itself explains a significant part of the gas demand decrease. High wholesale gas prices might also have had a negative impact on gas demand in energy intensive industries, leading to reduction in production. In November and December cold spells also have increased demand for gas in residential heating. As Figure 1 below shows, in the fourth quarter (specifically in November and December) of 2021 gas consumption in the EU was close to the upper end of the range of the last five years. In 2021 as whole, natural gas consumption in the EU amounted to 412 bcm, up by 4% (17 bcm) compared to 2020, and signalled the highest gas consumption since 2011, most probably owing to the high gas demand during the colder periods (e.g. April and May 2021) of the year in much of the EU.

Figure 1 - EU gas consumption



Source: Eurostat, data as of 10 March 2022 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 (%)

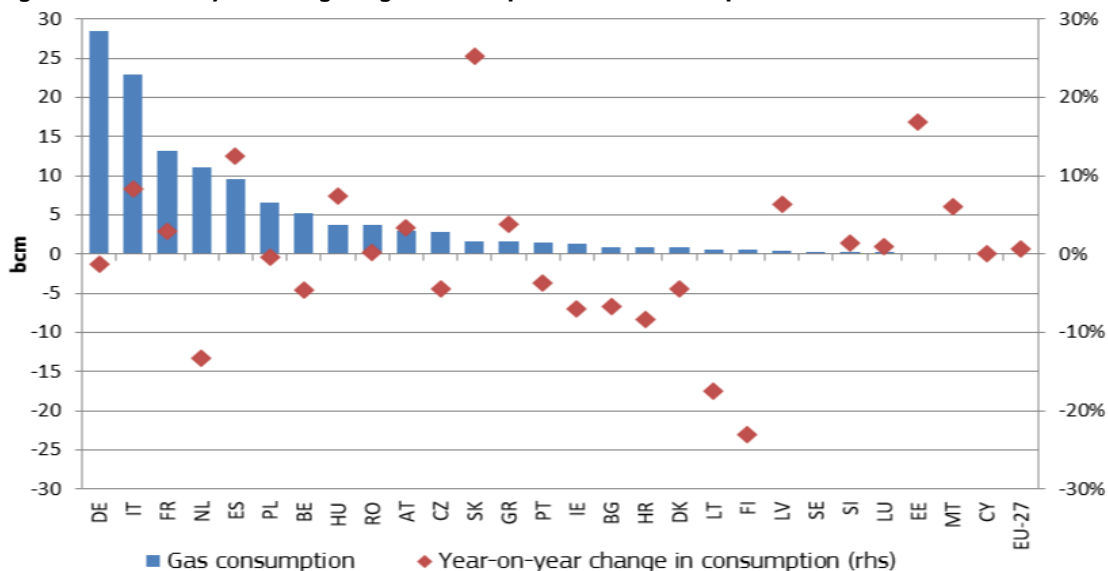


Source: Eurostat, data as of 10 March 2022 from data series nrg_103m. In the next edition of this report numbers might change retrospectively

¹ EU aggregates, unless otherwise indicated, refer to EU-27, and in order to ensure comparability over time, values of earlier periods and year-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 fourth quarter of 2021, gas consumption increased in the half of the EU Member States year-on-year, whereas in the other half (13, as there is no data for Cyprus) it decreased. Gas consumption, in the order of percentage changes, fell by the most in Sweden by 31%, (-0.15 bcm), in Finland by 23%, (-0.15 bcm), and in Lithuania by 18%, (-0.1 bcm), whereas it increased the most in Slovakia by 25%, (+0.3 bcm), in Estonia by 17%, (+0.02 bcm) and in Spain by 13%, (+1.1 bcm). Among the five biggest gas consumer countries, consumption fell by in the Netherlands by 13% (-1.7 bcm), in Germany by 1% (-0.4 bcm) whereas it rose in Spain by 13% (+1.1 bcm), in Italy by 8% (+1.8 bcm) and in France by 3% (+0.4 bcm). With the exception of six Member States, year-on-year changes were less than 10% (increase or decrease) in all countries.
- In 2021 as whole, gas consumption amounted to 94 bcm in Germany (up by 5%, +4 bcm in comparison to 2020), in Italy it reached 76 bcm (up by 7%, +5 bcm), in the Netherlands it was 42 bcm (down by 4%, -1.8 bcm) in France it reached 41 bcm (up by 6%, +2.3 bcm), and in Spain it amounted to 34 bcm (up by 6%, +1.8 bcm).

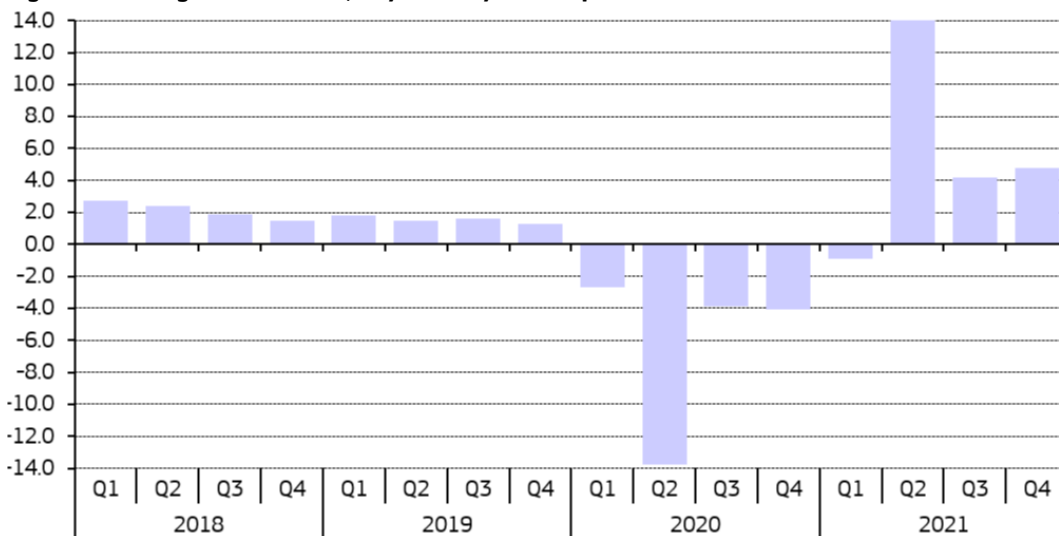
Figure 3 - Year-on-year change in gas consumption in the fourth quarter of 2021



Source: Eurostat, data as of 10 March 2022 from data series nrg_103m. In the next edition of this report numbers might change retrospectively

- In the fourth quarter of 2021, GDP in the EU-27 was up by 4.8% in year-on-year comparison. At the same time, GDP was up by 0.4% quarter-on-quarter, however, increase in the general economic activity did not really result in increasing gas consumption in the EU, as rapidly increasing wholesale gas prices prompted a decreasing use of gas in energy intensive sectors, which rather acted counterintuitively for the economic growth in the EU countries.

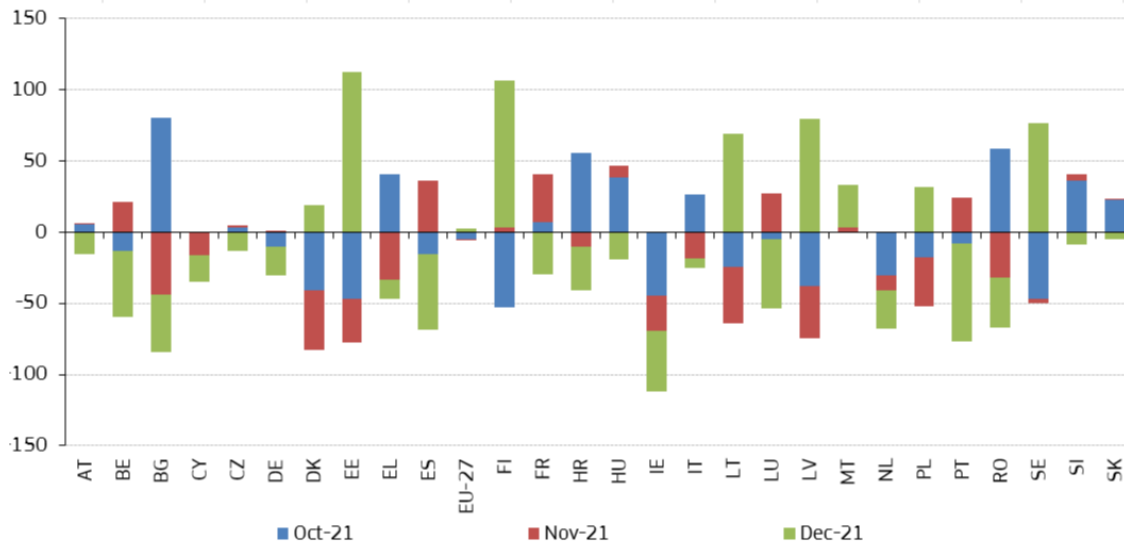
Figure 4 - Change in EU27 GDP, in year-on-year comparison (%)



Source: Eurostat, data as of 8 March 2022 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 average² in individual EU Member States in the fourth quarter of 2021. October 2021 was mixed relating to the deviation of temperatures from the long term average, but it was colder than usual in southern Europe. In contrast, November 2021 was milder than usual in most of the EU countries, whereas December 2021 was colder than the average in Nordic countries, but in many other parts it was milder than usual. However, short term weather forecasts had an impact on wholesale gas prices in a tight market, and the market watched the weather news from the aspect of depleting gas storage levels as well.

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



Source: Joint Research Centre (JRC), European Commission

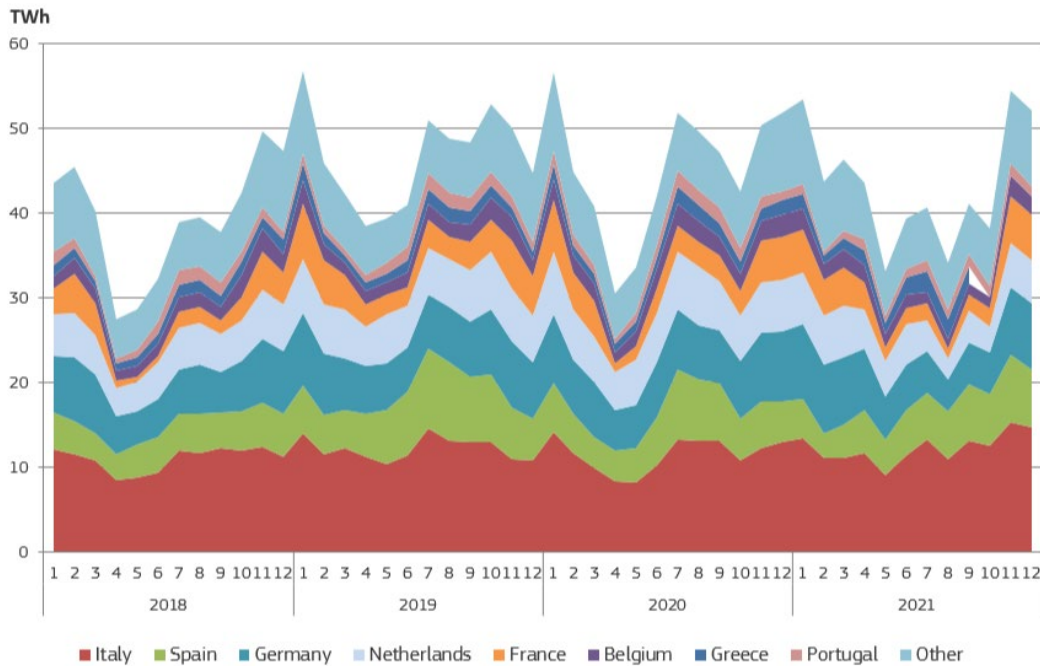
- Based on data from ENTSO-E, gas-fired power generation showed a slight rebound of 4% (+5.7 TWh) year-on-year in Q4 2021 in the EU, after the significant fall in the third quarter of 2021, as Figure 6 shows. In Q4 2021 gas wholesale prices were quite volatile and reached levels not seen before on most of the EU gas hubs, which was not favourable to generation costs and profitability of gas-fired generation. In fact, even with further increasing carbon prices, high gas prices prompted the comeback of coal to power mixes in many EU countries.
- In year-on-year comparison, the share of renewables in the EU power generation mix decreased slightly in Q4 2021, as wind, solar, biomass and hydro together represented around 35% of the EU power mix in Q4 2021, slightly down from 38% in Q4 2020. The share of gas remained practically unchanged year-on-year, and amounted to 21% in Q4 2021. The share of power generation from solid fuels rose slightly in Q4 2021, reaching 17% (up from 15% a year before)³, as coal and lignite-fired generation together rose significantly, by 19% in Q4 2021 year-on-year. Electricity generation from nuclear rose only by 2% year-on-year, and its share remained constant at 25% in Q4 2021 (same as in Q4 2020). Carbon prices kept on increasing over the course of Q4 2021, up from 62 €/MtCO_{2e} to 78 €/MtCO_{2e} (on 8 December reaching even 88 €/MtCO_{2e}) however, this had smaller impact on the power mix, as gas prices showed a sharp increase over the same period (from 85 €/MWh to 183 €/MWh on 21 December, then falling back to 61 €/MWh by the end of December). The profitability of gas-fired generation, even amid increasing carbon prices, comparatively decreased vis-à-vis coal and lignite, and hence solid fuel generation was up by 19% whereas gas-fired generation rose only by 4% in Q4 2021, year-on-year.
- In Q4 2021, the amount of electricity generated from gas fell by 23% in the Netherlands in year-on-year comparison, and in Germany it also decreased by 11%. At the same time, it rose by 35% in Spain, by 24% in Greece, by 19% in Italy and by 1% in France.
- Besides demand side factors, the share of gas was impacted by changes in the local power generation mixes in each country. In the Netherlands, the decrease in gas-fired generation was mainly compensated by increasing coal-fired generation and renewables (solar, wind, and biomass). In Germany, the decrease in gas-fired generation was accompanied by lower wind, biomass and hydro, which were mainly replaced by increasing coal and to a lesser extent, nuclear and solar power. In Spain, increasing gas-fired generation was needed to compensate falling hydro and nuclear generation, also helped by increasing coal and solar power. In Greece, increasing gas-fired generation and abundant wind compensated for falling lignite, and also contributed to the increase in the overall electricity generation. In Italy, increasing gas-fired generation, along with abundant wind, resulted in higher overall electricity generation, even amid falling hydro availability. In France, 1% increase in gas-fired generation could not really influence

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

³ See more information in Quarterly Report on the European Electricity Markets, Vol. 14, Issue 4

the electricity mix; coal, biomass and solar was up, whereas hydro power and nuclear energy was slightly down in the national electricity generation mix in Q4 2021.

Figure 6 - Gas-fired power generation in the EU



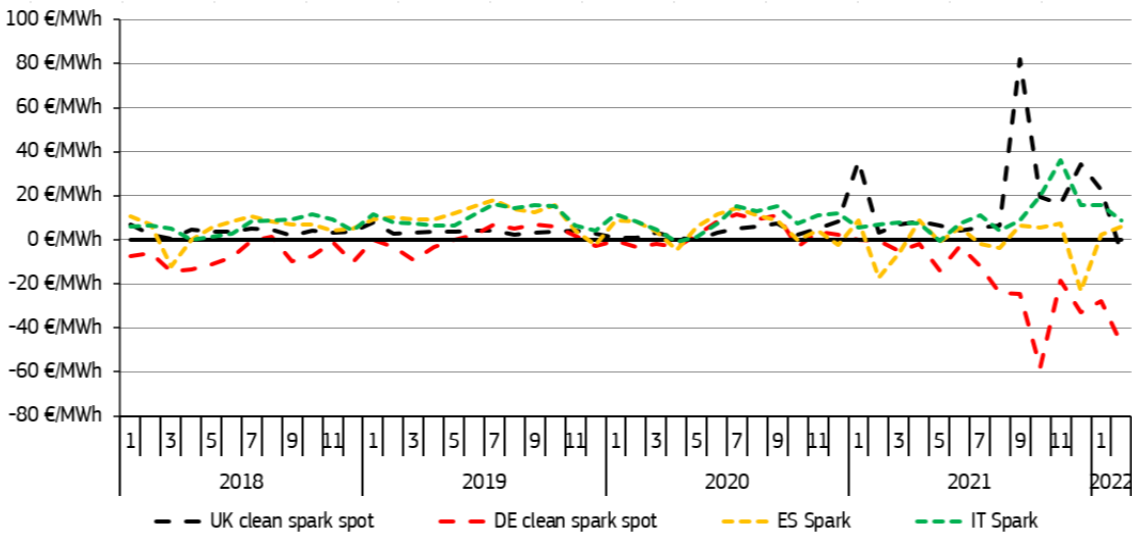
Source: Based on data from the ENTSO-E Transparency Platform and national data sources, data as of 2 March 2022.

- Clean spark spreads – measuring the profitability of gas-fired generation by taking into account variable costs – reached respectively -36.5 €/MWh, -3.5 €/MWh and 24 €/MWh in Germany, Spain and Italy in Q4 2021 on average, showing a mixed picture in comparison to the previous quarter, as in Germany and Spain spreads decreased (from -20.1 €/MWh and 0.4 €/MWh in Q3 2021, respectively), whereas in Italy they rose from 7.9 €/MWh measured in Q3 2021. The decrease in the clean spark spreads implied decreasing profitability of gas-fired generation⁴ in Germany and Spain and improving profitability in Italy (See Figure 7⁵). However, constantly increasing electricity prices in October in November 2021, largely driven by gas prices, improved the spreads in all of the three markets, but extremely high gas prices in December made the profitability of gas-firing deteriorating. Profitability improved again in January 2022, but fell back in February, owing to even higher gas prices.
- In the United Kingdom, having relevance for the European gas market, clean spark spreads averaged at 23.3 €/MWh in Q4 2021, down from 31.4 €/MWh, but increasing from 5.1 €/MWh in Q4 2020. In the UK, wholesale electricity prices were much higher than in continental Europe, resulting in higher profitability of gas fired generation. However, electricity generated from gas was down by 3% year-on-year in Q4 2021, and the share of gas-fired generation was 40% in the same period, practically the same as a year before, in Q4 2020.

⁴ Assuming an average gas power plant efficiency, see more in the Glossary

⁵ Charts of clean spark spreads can also be found in the Quarterly Report of European Electricity Markets (Vol. 14, Issue 4). 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

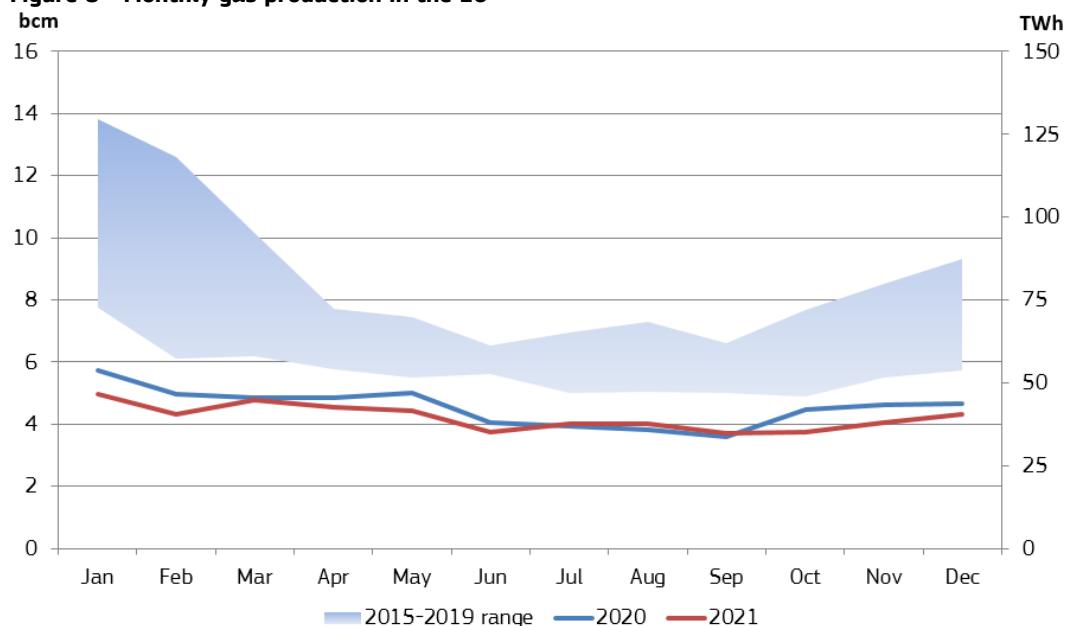
1.2 Production

- In the fourth quarter of 2021, EU natural gas production reached approximately 12.1 bcm⁶, falling year-on-year again by 13%, (1.8 bcm) after the short-lived upturn in Q3 2021 (See Figure 8). In Q4 2021 the actual quarterly production remained well below the 2015–2019 range, reflecting the long-term dwindling trend of domestic gas production in the EU. Compared to the previous quarter, production grew by 0.4 bcm in Q4 2021, following the increase in seasonal consumption during wintertime.
- In the biggest gas producer Netherlands, the production fell by 24% (by 1.5 bcm), amounting to 4.7 bcm. In Romania, the second biggest gas producer in the EU, production decreased by 7% (-0.2 bcm), in Poland it went down by a negligible 1% whereas in Germany it rose by 10% (0.1 bcm). Gas production in Italy fell by 10% (-0.1 bcm), and by 9% in Hungary and by 11% in Ireland (changing less than 0.1 bcm in both countries). In Denmark, the production was up 11% (0.03 bcm).
- However, the Dutch government expects to increase the amount of gas it allows to be produced from the Groningen gas field to up to 7.6 bcm from an earlier estimate of 3.9 bcm⁷. The Netherlands had been winding down production at Groningen, once Europe's largest gas field, for years due to damage and safety concerns over earthquakes it triggers. But the Economic Affairs Ministry said that the increase would be needed to guarantee security of supplies and it would make a final decision in April 2022.
- In 2021 as whole, Dutch gas production, amounting to 21 bcm, was down by 9% (-2.2 bcm), whereas in Romania production (8.9 bcm) remained practically stable (-1%). Gas production in Poland was also stable year-on-year, around 5.6 bcm, similarly to Germany, where it reached 4.8 bcm in 2021. In Italy however, gas production amounted to 3.3 bcm, and fell by 15%, (-0.6 bcm) year-on-year, Hungary produced 1.5 bcm (-11%, -0.2 bcm) and Ireland produced 1.4 bcm (-5%, -0.1 bcm) in 2021. The total natural gas production in the EU amounted to 50.6 bcm (-7% or -4 bcm compared to 2020).
- Gas production in Norway increased by 11% year-on year, from 28.9 bcm in Q4 2020 to 32 bcm in Q4 2021. In 2021, natural gas production in Norway amounted to 115 bcm, slightly up from 112 bcm in 2020. In the United Kingdom, gas production amounted to 9.6 bcm in Q4 2021, up from 8.9 bcm a year before, while in 2021 gas production fell to 39.3 bcm, from 32.5 bcm, measured in 2020.

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

⁷<https://www.reuters.com/markets/commodities/netherlands-nearly-doubles-estimated-groningen-gas-output-secure-supply-2022-01-06/>

Figure 8 - Monthly gas production in the EU



Source: Eurostat, data as of 10 March 2022 from data series nrg_103m. In the next edition of this report numbers might change retrospectively.

1.3 Imports

- According to Eurostat⁸, net gas imports in the EU increased by 2% (1.8 bcm) in the fourth quarter of 2021 (year-on-year), amid slightly increasing gas consumption and falling domestic production. Net imports in different EU countries showed a high variation in Q4 2021. In Romania it went up by 94% (+0.3 bcm) year-on-year, in Malta by 96% (+0.1 bcm). On the other hand, in the Netherlands it dropped by 42% (-1.6 bcm) and in Hungary by 41% (-0.6 bcm) year-on-year.
- Looking at the biggest importers, in Spain net gas imports rose by 24% (+1.9 bcm), in Italy by 15% (+2.4 bcm), in Poland by 8% (+0.3 bcm), in Germany by 3% (0.7 bcm). At the same time, net gas imports were down by 42% (-1.6 bcm) in the Netherlands and by 2% in France and Belgium (respectively -0.2 bcm and -0.1 bcm). The biggest net importers in the EU were Germany (24 bcm), Italy (18 bcm), France and Spain (both 10 bcm), Poland (4 bcm) and the Netherlands (2 bcm). These six countries altogether imported 68 bcm out of the total gas imports of 86.5 bcm in Q4 2021 (the total up from 80.7 bcm in Q4 2020).
- In 2021 as whole, net gas imports in the EU amounted to 337.5 bcm, up from 326.7 bcm in 2020 (representing an increase of 3%). Germany imported 83 bcm of gas, followed by Italy (71 bcm), France (40 bcm), Spain (34 bcm), Poland and Belgium (both 18 bcm).
- According to ENTSO-G data, net imports amounted to 931 TWh in the fourth quarter of 2021, of which 78% arrived through pipelines and around 22% through LNG terminals. Pipeline gas imports from Russia saw a steep fall by 24% in year-on-year comparison, especially in November and December via Yamal and Ukraine routes. In contrast, imports from Norway were up by 11% in Q4 2021. Pipeline gas imports from Algeria, showed a decrease of 3.2% year-on-year, the first decrease since few quarters. Pipeline gas imports from Libya fell again by 27% year-on-year. At the same time, LNG imports reached 205 TWh in Q4 2021.
- Similarly to the previous periods, Russia was the top gas supplier of the EU, however, however, the share of Russian pipeline gas in the extra-EU gas imports fell below 37% in the fourth quarter of 2021, to the lowest quarterly share in the last eight years⁹.
- The share of pipeline gas imports from Norway was 24% in the fourth quarter of 2021, slightly down from the previous quarter (27%) but up compared to Q4 2020 (22%), as the increase in imports from Norway outpaced the overall increase in gas imports in the EU. Competitive gas imports from Norway could partially replace dwindling Russian inflows, along with increasing LNG send-out. In the fourth quarter of 2021, Norwegian gas production¹⁰ amounted to 32 bcm, up by 11% year-on-year.
- In the third quarter of 2021, pipeline gas imports from Algeria were down by 3.2% year-on-year, which resulted in a decreasing share within the total extra-EU imports (falling below 10% in Q4 2021). Although oil-indexed contracts gas contracts with Algeria were quite competitively prices in Q4 2021, on 31 October 2021 the contract of the GME pipeline, supplying gas though Morocco to

⁸ Net imports equal imports minus exports and do not account for stock changes.

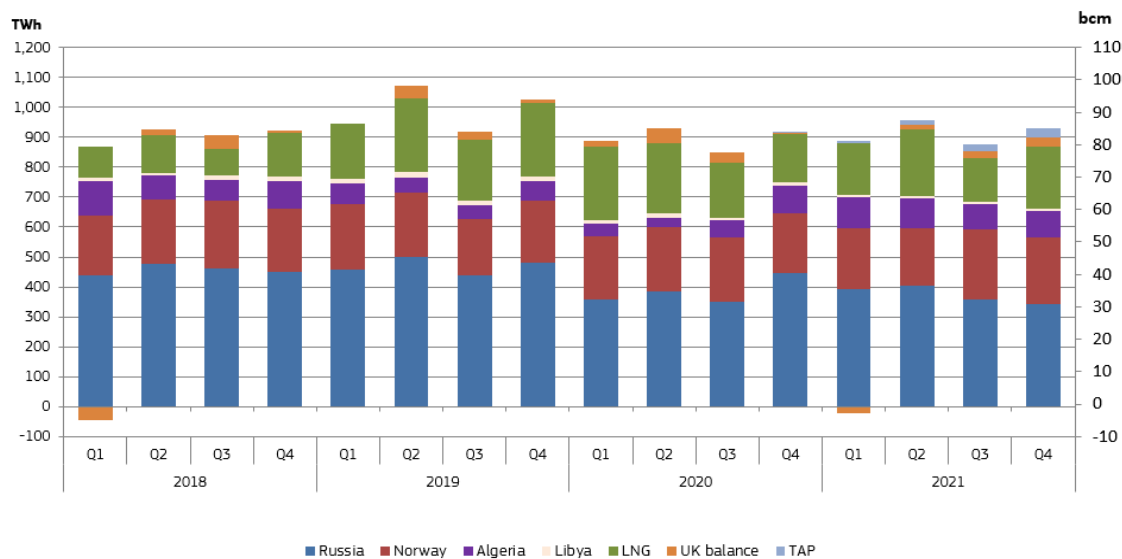
⁹ It is worth to note that Russia increased its importance in the EU LNG imports as well over the last few years, numbers presented in this section, with the exception of LNG or unless otherwise indicated, refer to pipeline imports

¹⁰ <https://www.npd.no/en/facts/news/Production-figures/2020/production-figures-march-2020/>

the Iberian-peninsula, has expired and thus only the subsea Medgaz pipeline remained to supply Spain with Algerian gas (see also Chapter 1.4). Thus Spanish (and Portuguese) pipeline gas imports from Algeria fell by 27 % in Q4 2021 year-on-year. However, pipeline gas supply from Algeria to Italy grew further, by 14% year-on-year, benefitting from the aforementioned competitive oil-indexed contract prices vis-à-vis gas hub prices in Europe. Imports from Libya continued to fall and its share was lower than 1% in the total EU gas imports, decreasing from 1.1% in Q4 2020.

- In Q4 2021, the share of LNG rose to 22% in the total EU gas imports, which was 4 percentage points higher than in Q4 2020. Increasing LNG imports were due to decreasing price premium of the Asian gas markets to Europe, which at the end of December (and in much of 2022 so far) fell into negative ranges, a quite rare phenomenon, which resulted in redirection of LNG cargoes towards Europe, and substantially increasing LNG send-out to the European gas grid. It seems that in Q4 2021 the year-on-year decrease in the share of Russian pipeline flows was compensated by increasing LNG, Norwegian imports, rising inflows from the UK and the appearance of the TAP pipeline, as new supply route.
- The Trans Adriatic Pipeline (TAP), operational since the end of 2020, ensured around 33 TWh gas imports in the EU in the fourth quarter of 2021, up from 23 TWh in the previous quarter, and representing around 3.2% of the EU total gas imports. TAP provides access to Azerbaijani gas resources via the Southern Gas Corridor, an important result of the EU security of gas supply policies.
- In 2021 as whole, gas imports in the EU amounted to 3 630 TWh, slightly up, 3 579 TWh in 2020. Russian pipeline gas was the biggest supply source (41%), followed from pipeline gas from Norway (23.5%), LNG regasification terminals (20.5%), Algerian pipeline gas (10.5%) and pipeline gas via the TAP (2%) and from Libya (1%).

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



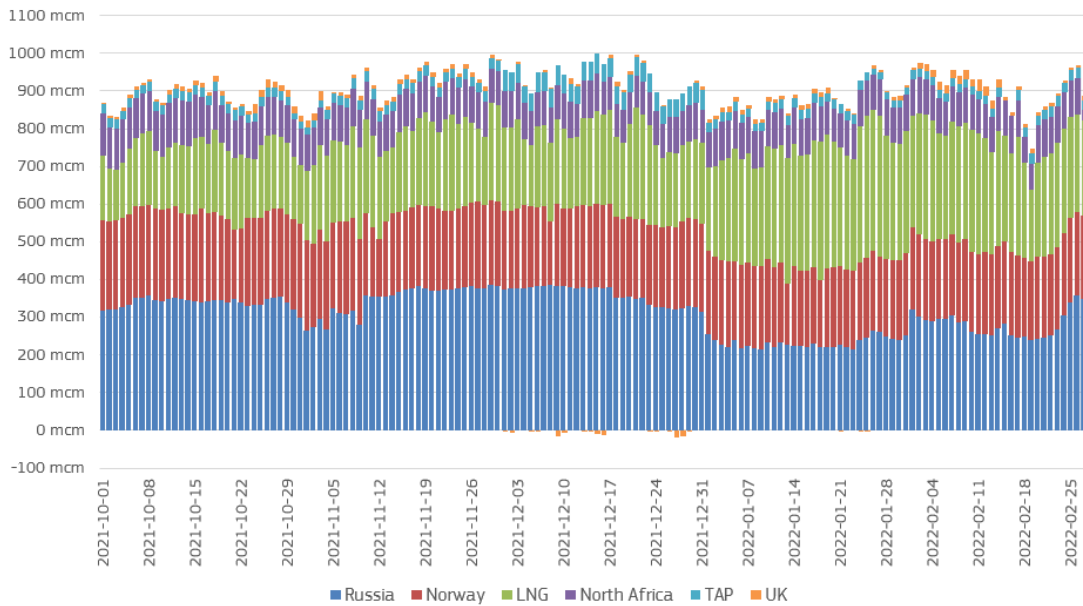
Source: Based on data from the ENTSO-G Transparency Platform, data as of 2 March 2022.

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

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

A trade balance with the UK is estimated, reflecting that the UK is no longer part of the EU, and it is not easy to determine the origin of gas molecules arriving to the EU after going through the UK market (it can be UK production, imports from Norway of LNG imports from the UK, etc.). As of 2021, imports via the Trans Adriatic Pipeline (TAP) is also included.

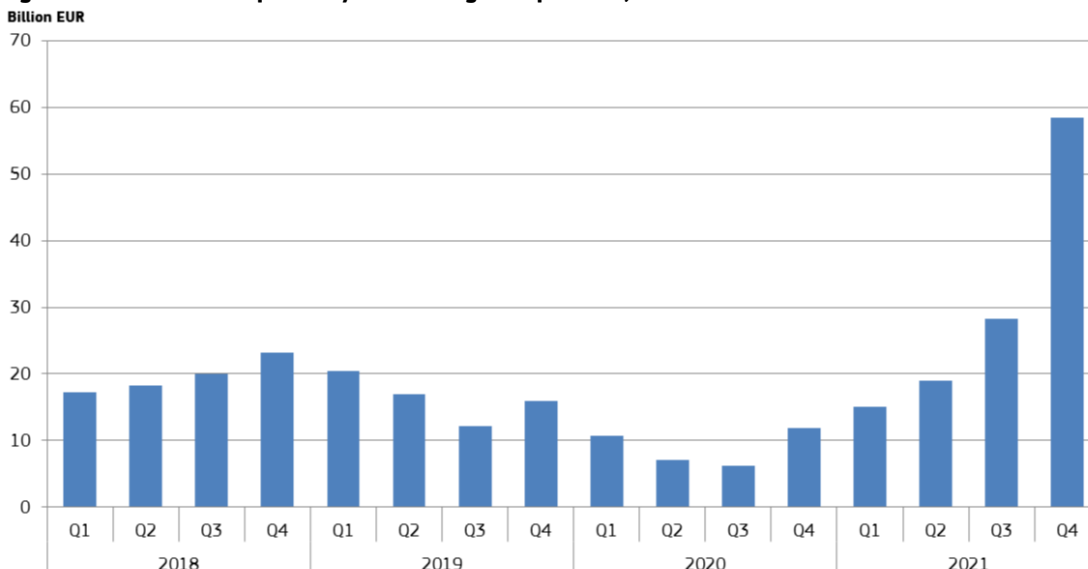
Figure 10 - EU daily imports of natural gas by source



Source: Based on data from the ENTSO-G Transparency Platform, data as of 2 March 2022.

- As average import prices significantly increased year-on-year (showing a nearly five-fold upturn compared to Q4 2020), in the fourth quarter of 2021, the estimated gas import bill amounted to €58 billion, which was the highest in the last eight years, and in comparison to €11.9 billion in Q4 2020, it rose by 391% year-on-year. However, it should be noted here that the estimation of the gas import bill is based on the mixture of sources on import prices (spot wholesale prices, foreign trade data, etc.), which might not give a fully accurate calculation on the actual gas import prices, rising by an estimated 382% in Q4 2021 year-on-year. Bearing this in mind, the quarterly gas import bill was up in Q4 2021 compared to the previous quarter (€28.2 billion in Q3 2021). In 2021 as whole, the EU gas import bill amounted to €120.8 billion, up from €35.9 billion compared to the same period of 2020. Out of these the estimated amount of gas imported from Russia on pipelines was around €41.5 billion, followed by Norway (€32.9 billion), Algeria (€6.6 billion), the TAP (€3.4 billion) and Libya (€0.6 billion). In the form of LNG, the EU imported gas in a value of €35.8 billion in 2021.

Figure 11 – Estimated quarterly extra-EU gas import bill, in billions of euros



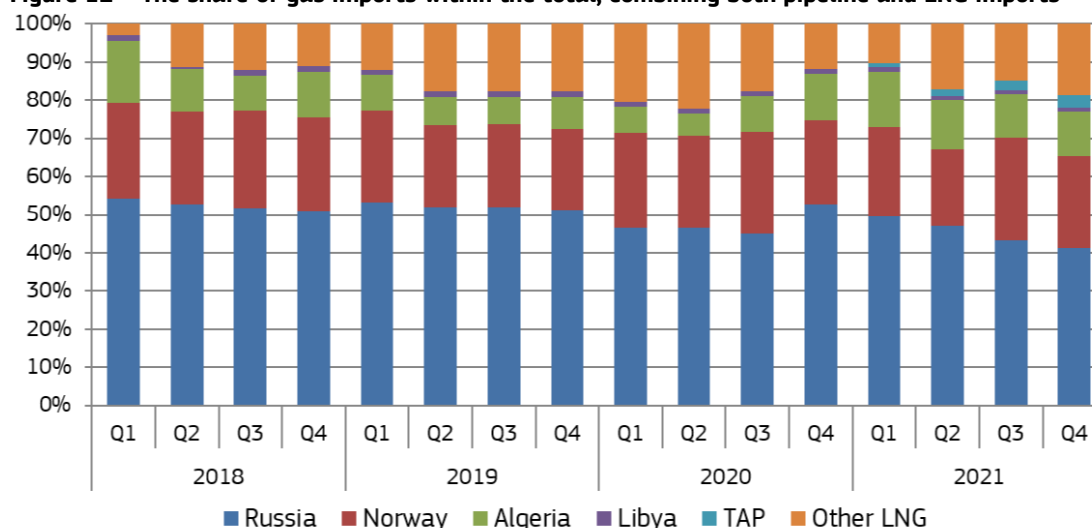
Source: ENTSO-G, Eurostat and own data calculations for the EU weighted average of import gas prices

- As important pipeline gas source countries, such as Russia, Norway and Algeria are also active on the LNG market, the quarterly gas report also takes a look at the combined imports of pipeline gas and LNG from these countries and attempts to calculate the share of imports including all gas sources. As Figure 12 shows, the share of Russia within total extra-EU gas imports (pipeline and LNG together) amounted to 41% in Q4 2021 (the lowest over the last eight years), split by 37% of pipeline imports and 4% of LNG. Russia is also an important participant in European LNG market, not only in the traditional pipeline gas supply, trying to maintain its

market share by switching to a more competitive export strategy. The share of pipeline import gas of Russian origin fell to 37% within the total extra-EU gas imports in Q4 2021, by taking into account LNG the share of Russia decreased from 53% to 41% in year-on-year.

- The share of Norway was 24% in Q4 2021 (practically the same share as the Norwegian pipeline imports, owing to ongoing repair and maintenance works on the country's sole LNG plant). The share of Algeria within the total extra-EU gas imports was 11.8% with LNG (as opposed to 9.7% only including pipeline gas). The share of LNG was 18.6% in Q4 2021, (on the top of LNG accounted in shipments from Russia, Norway and Algeria), up from 12% in Q4 2020 and from 14.8% in the previous quarter. The decreasing share of imports from Russia between the fourth quarters of 2020 and 2021 was mainly compensated by the increasing shares of LNG, the new TAP pipeline supply route and Norwegian (mostly pipeline) imports in Q4 2021.

Figure 12 – The share of gas imports within the total, combining both pipeline and LNG imports



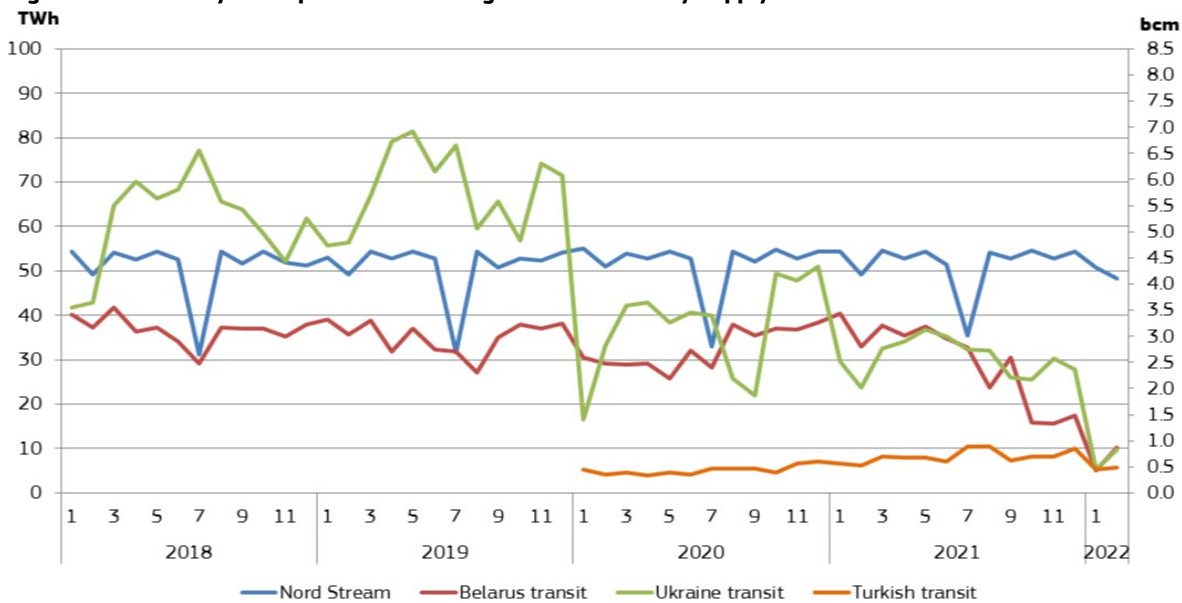
Source: Based on data from the ENTSO-G Transparency Platform, data as of 2 March 2022.

1.3.1. Pipeline imports from Russia and EU supply to Ukraine

- Figure 13 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 (practically the Yamal pipeline), Nord Stream 1 and Turk Stream.
- In the fourth quarter of 2021, the volume of Russian imports fell significantly, by 24%, if compared with the same quarter of 2020. As shown on Figure 13, gas flows transiting via Ukraine were down by 36% in comparison to Q4 2020, as during the second half of the year and specifically in Q4 2021 Gazprom was reluctant to book additional capacities and beyond the long term contracted volumes less and less gas flows arrived. During Q4 2021, a monthly average of 3 bcm of gas of Russian origin was transited through Ukraine, down from the monthly average of Q4 2020 (4.6 bcm). In January 2022 the monthly transit volume fell further, to barely 1 bcm, picking slightly up to 1.5 bcm in February.
- This was also true for the transit route of Belarus, where gas flows fell by a staggering 56% in Q4 2021 year-on-year. In spite of promises from the Russian side that Gazprom controlled storages in the EU would rapidly be filled up as of November, after finishing the injection of domestic storages in Russia, in November-December monthly volumes fell below 1.5 bcm, which was not seen in the last seven years. In January the transit volumes fell even further, picking up in February again. In contrast, transited volumes through the Nord Stream remained practically the same year-on-year in Q4 2021 (reaching 5 bcm on monthly average), and January-February 2022 flows were still strong (4.6 bcm). Transited volumes through the Turk Stream were up by 43% year-on-year in Q4 2021, and the monthly average transited volume was 0.8 bcm, falling back in January-February 2022 (to 0.5 bcm).
- As a result, in Q4 2021 the share of Nord Stream within Russian gas supply to Europe rose to 49% in Q4 2021, which was the highest ever quarterly share, up by 8 percentage points compared to Q3 2021 and by 12 points compared to Q4 2020. The Ukraine transit route came to the second place, ensuring 29% of the total Russian pipeline gas transit, up from 25% year earlier. The share of the Belarus transit route fell drastically, representing only 15% of the total Russian pipeline imports in Q4 2021, down from 25% in Q4 2020. The share of Turk Stream was 8% in Q4 2021, doubling from 4% in Q4 2020.

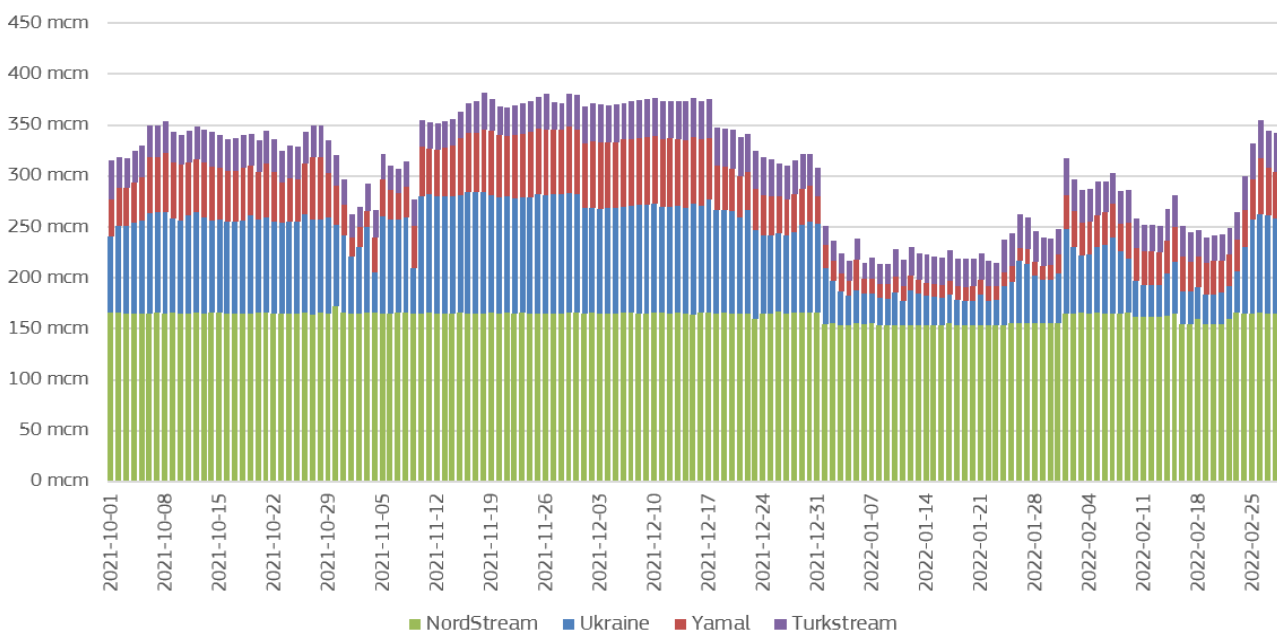
- In Q4 2021 Nord Stream represented 18% (15 bcm) in the total net extra-EU gas imports, the Ukrainian transit had a share of 5% (5 bcm), whereas the Belarus transit route ensured 11% (9 bcm). At the same time, the Turk Stream had a share of 3%, with around 3 bcm gas transit within the total net extra-EU gas imports in Q4 2021.
- In 2021 as whole, transited volumes through Nord Stream was almost 58 bcm (practically unchanged year-on-year), the Ukraine transit (only counting the destinations within the EU) was 37 bcm (down from 42 bcm in 2020), Belarus transit reached 33 bcm (down from 36 bcm in 2020), while transit on Turk Stream was more than 9 bcm (counting EU destinations only) up from 5.8 bcm in 2020. If the total transit through Ukraine (without Moldova) is counted, 38 bcm was transited and for the Turk Stream it was above 12 bcm.

Figure 13 – Monthly EU imports of natural gas from Russia by supply route



Source: Based on data from the ENTSO-G Transparency Platform, data as of 2 March 2022. Deliveries to Estonia, Finland and Latvia are not included; transit volumes from Russia to the Republic of North Macedonia and Serbia are excluded. Since the inauguration of Turk Stream flows to Turkey via the Balkans are not significant.

Figure 14 – Daily EU imports of natural gas from Russia by supply route



Source: Based on data from the ENTSO-G Transparency Platform, data as of 2 March 2022.

- Trade on Gazprom Electronic Sales Platform (ESP) has practically been halted since 13 October 2021, when contracts were last time concluded, and monthly volume in that month amounted to only 1.7 TWh (0.16 bcm), the lowest since the start of ESP's operation in September 2018. Under high spot prices, the demand decreased for ESP hub contracts, customers rather opted for relying on long-term contracts, amid increasing price environment. However, termination of sales on ESP could not be explained by solely market forces, according to some opinions the difficulties around the certification process of Nord Stream 2 might also play a role in stopping sales on ESP¹¹.
- According to early January 2022 estimations, Gazprom has missed its 2021 target¹² to export 183 bcm of gas to Europe (including Turkey), export numbers were rather estimated at 177 bcm. The company produced 515 bcm gas, which was the highest since 2008, and domestic gas consumption in Russia also picked up in 2021, reaching 258 bcm in 2021.
- Natural gas import to Ukraine amounted to 2.6 bcm, which is six times less than in 2020. The import was carried out mainly by virtual reverse (backhaul), which the Ukrainian transmission system operator introduced at the beginning of 2020.¹³ 89% of gas was imported by virtual reverse. Hungary became the main gas supply route, from which more than 2.2 bcm of gas was delivered (-47% year-on-year). Despite the stop of physical transit to Hungary from October 1 2021, the virtual imports remained at the Beregdaróc point: in October–December 2021, Ukraine imported 55.6 mcm from Hungary. And from January 1, 2022, the guaranteed capacity in the Hungarian direction became available (8 mcm per day), which made it possible to increase the import capabilities of Ukraine by a third and diversify the sources of imports. In 2021, import from Slovakia amounted to 285.3 mcm, down by 97%, and from Poland it was 78.6 mcm, down by 95% year-on-year.

1.3.2.LNG imports

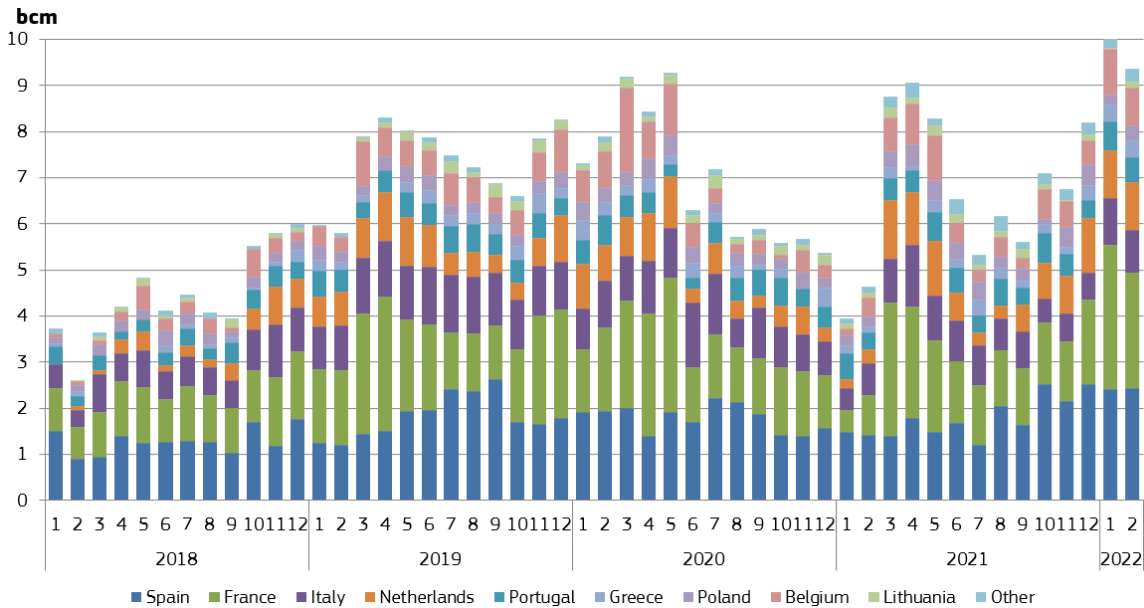
- LNG imports in the EU grew significantly, by 33% in Q4 2021 in year-on-year comparison, after decreasing by 9% in the previous quarter and stagnating in the second quarter of 2021. Looking at the three months of the quarter, EU LNG imports were up by 27% in October, by 19% in November and by 53% in December, compared to the same months of 2020. In January and February 2022 EU LNG imports more than doubled year-on-year, owing to European wholesale gas premiums to Asia. The quarterly LNG imports in Q4 2021 in the EU were 22.1 bcm, up from 17.1 bcm in the previous quarter and up from 16.6 bcm in Q4 2020, as Figure 15 shows. The total number of LNG cargoes arrived in the EU was 302 in Q4 2021, up from 245 in Q3 2021, and from 229 in Q4 2020.
- In Q4 2021, Spain was the biggest LNG importer in the EU, importing 7.2 bcm of LNG, ahead of France, where LNG imports amounted to 4.4 bcm. In year-on-year comparison imports were up by 65% in Spain, whereas in France they rose by 10%. LNG imports in the Netherlands more than doubled in Q4 2021 year-on-year, amounting to 2.8 bcm. Belgium and Italy were the fourth and fifth biggest importers, (both with 1.7 bcm, Belgium up by 97% and Italy down by 30% year-on-year). Portugal came to the sixth place, importing 1.5 bcm (+5% year-on-year), followed by Poland (1 bcm, +27% year-on-year). Croatia, starting to import LNG only in 2021, had a quarterly import of 0.4 bcm in Q4 2021. The total EU LNG imports amounted to an estimated €23.3 billion in Q4 2021, up from €2.7 billion a year before, principally owing to the impact of sharply increasing wholesale gas prices (rising to more than six-fold year-on-year, and also to the increase in imported volumes.
- LNG imports in the United Kingdom in Q4 2021, amounting to 4.3 bcm, were significantly up to the previous quarter (0.7 bcm in Q3 2021), but were still slightly lower compared to Q4 2020 (4.4 bcm). The number of cargoes berthed in the country picked up, and reached 43, as opposed to only 6 in Q3 2021.
- In 2021 as whole, EU countries imported 80 bcm of LNG, which was lower than in 2020 (84 bcm). In 2021, Spain imported 21.4 bcm, followed by France (18.1 bcm), Italy (9.3 bcm), the Netherlands (8.6 bcm) and Portugal (5.9 bcm). In 2021, the UK imported 15.1 bcm of LNG, down from 17.9 bcm in 2020.
- As in Q4 2021 wholesale gas prices rose significantly in the EU, price premium of Asian markets first started to decrease and in December 2021 it became negative, persisting in most part of January and February 2022 (see Figure 27 and Figure 28), which resulted in abundant LNG imports in the EU. 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.

¹¹ <https://www.spglobal.com/commodity-insights/es/products-services/energy-transition/global-integrated-energy-model>

¹² <https://www.worldoil.com/news/2022/1/3/gazprom-misses-2021-gas-export-targets-straining-european-markets>

¹³ <https://tsoua.com/en/news/key-indicators-for-gas-transportation-of-the-gas-tso-of-ukraine-qtsou-in-2021/>

Figure 15 - LNG imports to the EU by Member States

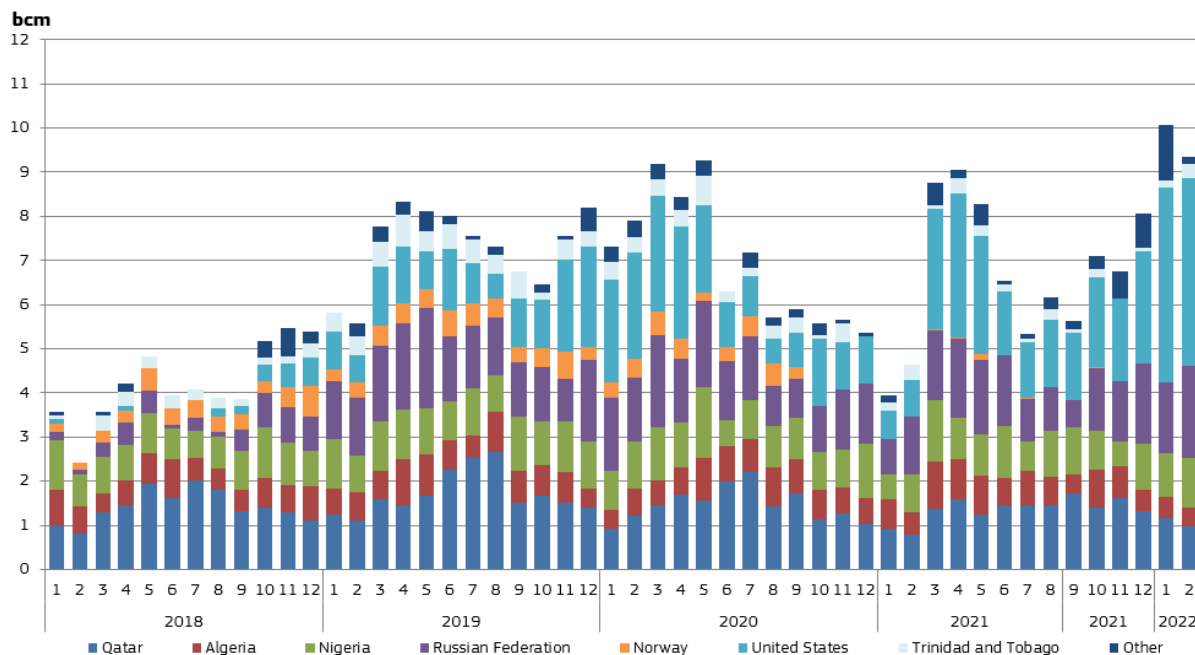


Source: Commission calculations based on tanker movements reported by Refinitiv "Other" includes Finland, Malta and Croatia

- In the fourth quarter of 2021, the United States became again the largest LNG supplier of the EU, shipping 6.4 bcm, which was around 29% of the total EU LNG imports. Russia came to the second place, representing 21% (4.6 bcm) in the EU LNG imports. Qatar was the third most important EU LNG source (with an import share of 20% - 4.4 bcm), followed by Nigeria on the fourth in the rank (with 2.5 bcm, 11%). In year-on-year comparison, the share of the United States was up by 7 percentage points, that of Russia went down by 2 percentage points, whereas the share of Qatar decreased by 1 percentage point and that of Nigeria by 7 points. LNG imports from Algeria amounted to 2 bcm, and represented 9% of the total imports. Trinidad and Tobago ensured only 1% (0.25 bcm) of the total EU LNG imports – See Figure 16.
- In Q4 2021, Norway still had a very low share (less than 0.1%) in total EU LNG imports, similarly to the previous quarter. This decrease can be explained by the ongoing outage of the Hammerfest LNG plant due to a fire incident¹⁴ in September 2020, which, requires repair and maintenance works. Due to the comprehensive scope of work, the revised estimated start-up date is now set to 17 May 2022.
- In 2021 as whole, the biggest LNG supplier to the EU were the United States (22.3 bcm), followed by Qatar (16.3 bcm), Russia (16 bcm), Nigeria (11.2 bcm), Algeria (8.5 bcm) and Trinidad and Tobago (2 bcm). Other countries shipped LNG to the EU in an amount of 3.7 bcm during this period. The trilateral competition between the United States, Qatar and Russia seemed to hold on in 2021, however, perspectives of the Russian LNG in the EU in the future might look less attractive in the wake of the latest geopolitical developments.

¹⁴ See more in the Quarterly Report on European Gas Markets, fourth quarter of 2020 (Vol 13, issue 4).

Figure 16 - LNG imports to the EU by supplier



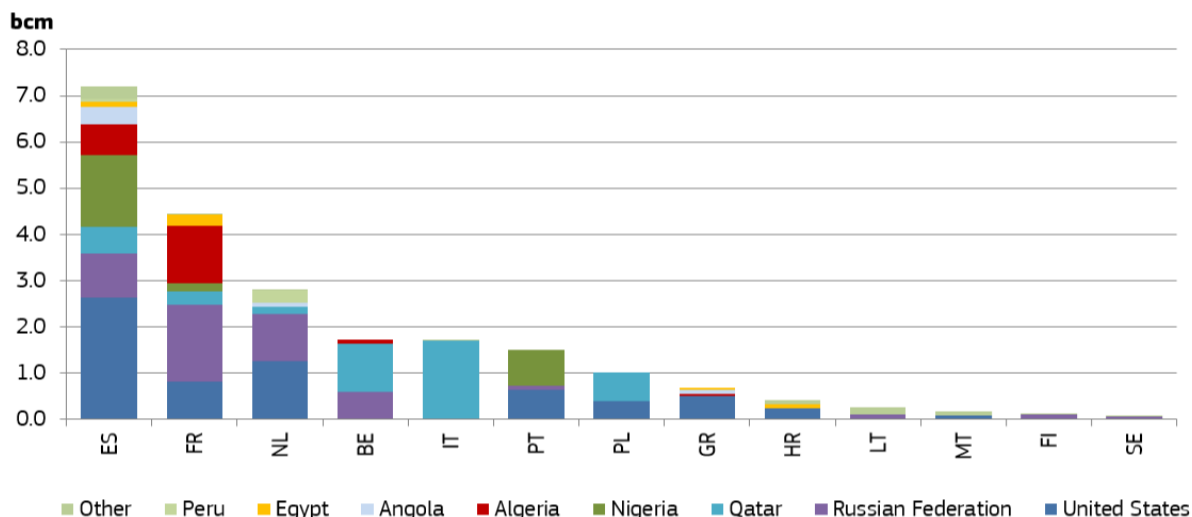
Source: Commission calculations based on tanker movements reported by Refinitiv

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

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

- In the fourth quarter of 2021, the United States were the biggest LNG supplier in Greece (73% of the total LNG imports), Croatia (53%), Malta (50%), Netherlands (45%), and Spain (36%), it came to the second place in Poland (40%). Russia ensured 95% of LNG imports in Finland and 82% of that in Sweden, while it was the second biggest supplier in France (38% of the total imports), the Netherlands (37%), in Belgium (35%) and in Lithuania (33%). Over the last few years Russian LNG has had increasing importance in the EU, especially in North-Western Europe, not independently from the dwindling domestic gas production in the Netherlands. Qatar was the biggest supplier in Italy (99% of the country's total LNG imports), Belgium (61%) and Poland (60%). Nigeria was the biggest supplier in Portugal (51%), and the second biggest in Spain (22%). Algeria ensured 28% of the French LNG imports in Q4 2021, whereas its share in Spain was around 9%. Angola had a share of 14% in the Greek LNG imports.
- In the fourth quarter of 2021, 78 LNG cargoes arrived in the EU from the US (up from 49 in Q3 2021, and from 38 in Q4 2020). LNG imports from the US amounted to 6.4 bcm in Q4 2021, up from 4.3 bcm in Q3 2021 and from 3.6 bcm in Q4 2020. The estimated market value of LNG imports from the US was around €6.9 billion in Q4 2021. In 2021 as a whole, LNG imports from the US amounted to 22.3 bcm, in a monetary value of €12.1 billion. In January-February 2020 LNG imports from the US turned up, 93 cargoes arrived, with 8.6 bcm of LNG, in a value of €7.9 billion. LNG imports from the United States became of particular importance in the EU, as geopolitical tensions mounted over the last few months, putting gas supply from the East under security risk.
- LNG exports to Europe represented 25% of the total US exports in Q4 2021, which was higher than the share of 18% in both Q3 2021 and Q4 2020. In 2021 as a whole, the share of Europe in the US LNG exports was 23%. Asia had an increasing share in US LNG destinations in 2021, pointing to a more profitable sale of LNG in that higher priced region. However, in the first two months of 2022, the share of EU in US LNG exports jumped to 41%.
- In the fourth quarter of 2021, the three most important EU destinations of the US LNG exports were Spain (2.6 bcm), the Netherlands (1.3 bcm) and France (0.8 bcm). The United Kingdom imported 1.2 bcm of US LNG in Q4 2021. In 2021 as a whole, Spain imported 5.8 bcm LNG from the US, followed by the Netherlands (4.6 bcm) and France (4.1 bcm).

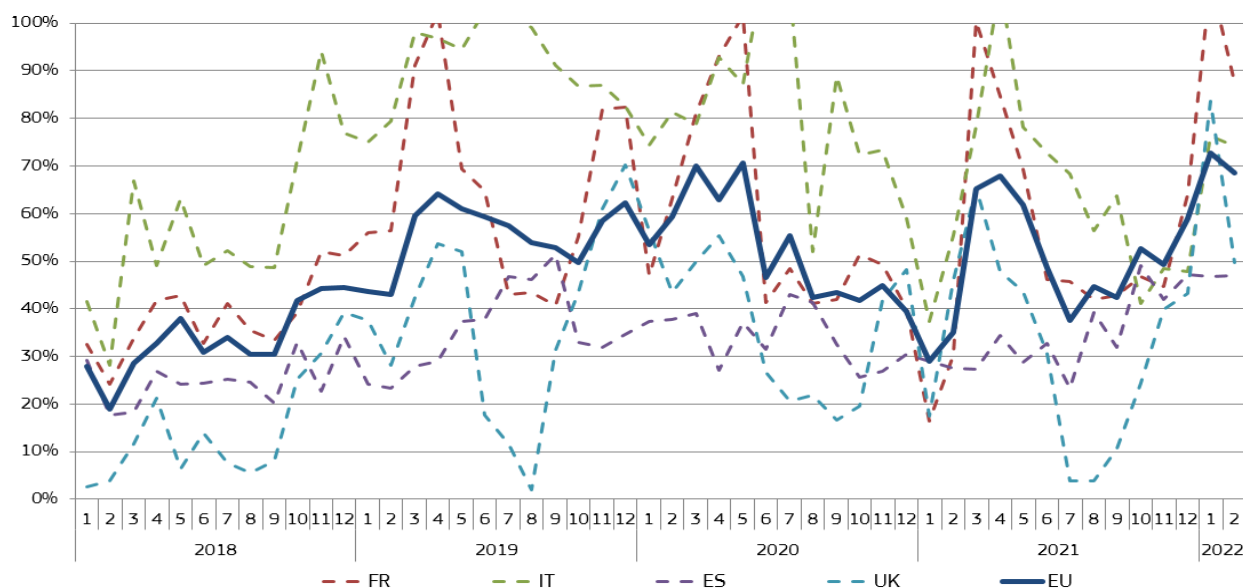
Figure 17 – LNG imports in the EU Member States from different sources in the fourth quarter of 2021



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, Oman, Singapore, the United Arab Emirates and Yemen

- The average monthly LNG terminal utilisation rates are presented on Figure 18, for some EU countries, the EU on average, and the UK. The average EU utilisation rate, which stood at 42% in September 2021, increased in Q4 2021, and in December it reached 59%. In January 2022, in parallel with soaring LNG imports, the average EU utilisation rate rose to 73%, which was the highest in the last nine years, since time series are available. In February 2022, it remained at high levels (68%). 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 France, the utilisation rate showed an increasing trend in Q4 2021, rising from 43% in September to 64% in December, whereas in Italy it decreased from 64% to 48% during the same period. Utilisation rates in Spain were up from 32% to 47% between September and December 2021, though they were below the EU average over the whole period. In the UK utilisation rates were extremely low last summer, and in September they were still only at 11%, gradually increasing to 43% in December. In January-February the average utilisation rate rose to 98% in France, to 75% in Italy, to 47% in Spain and to 67% in the UK, owing to the significant LNG arrivals to Europe.

Figure 18 – 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 and gas infrastructure

- On 25 October 2021, Moldova bought 1 million cubic metres (mcm) of natural gas from Poland's PGNiG Group in a trial purchase¹⁵ amid difficulties in striking a new deal with Russia's Gazprom, its traditional supplier. This was the first ever gas supply to Moldova from a non-Russian source, which might signal the start of gas flows between the EU single gas market and Moldova, having an annual gas consumption of 3 bcm. The trial purchase will test Moldova's ability to import gas from alternative sources and to balance the low pressure in the natural gas supply system. Earlier on 22 October, the country's parliament introduced a thirty-day state of emergency to a shortage of natural gas supplies and because it has not signed a new contract with Gazprom. During the state of emergency, the government was allowed to buy gas under a simplified procedure. Meanwhile, on 29 October Russia's Gazprom and the Moldovan government signed a new five-year contract for Russian gas supplies, starting entering into force on 1 November 2021¹⁶.
- On 27 October, Gazprom was ordered to start filling up gas storages it controls in the EU, after finishing the replenishment of underground gas storages in Russia¹⁷, which were also depleted during the preceding winter and were filled up slower than expected. Refilling of storages in the EU was scheduled as of 8 November. European wholesale gas prices fell on this news, however, after 8 November the pace of refilling storages did not meet expectations and Gazprom controlled storages remained at low levels during the whole 2021/22 winter heating season in the EU, resulting in fears of quick depletion and volatile wholesale gas prices.
- On 31 October 2021, the long-term transit agreement on the GME pipeline, transiting from Algeria through Morocco, has expired¹⁸ and with this around 7-8 bcm of gas imports into the Iberian-peninsula has become uncertain. Algeria has explicitly promised to fulfil its contractual agreements of gas deliveries to Spain, which could be done via the increased capacity of the Medgaz subsea pipeline and by increasing LNG deliveries. Owing to hub-based pricing formulae in the LNG contracts, under current market circumstances LNG shipments would probably be more expensive than oil-indexed pipelines deliveries. On the expansion of the Medgaz pipeline (annual capacity to be raised from 8 bcm to 10.5 bcm), the Algerian operator Sonatrach was aiming to bring online additional throughput in January 2022¹⁹, putting an additional compressor in operation on the Medgaz link.
- News around the certification process of the Nord Stream 2 pipeline have substantially added to the price volatility of the wholesale gas market in the fourth quarter of 2021. On 16 November, the ruling chamber of German Federal Network Agency, Bundesnetzagentur (BNetzA) suspended the certification procedure of Nord Stream 2. BNetzA concluded the certification of an operator of the Nord Stream 2 pipeline would only be possible if the operator is organised legally under German law, which was not the case with current operator Nord Stream 2 AG, based in Switzerland. Nord Stream 2 AG instead opted to set up a German subsidiary under German law, which has jurisdiction over the ownership and operation of the German section of the pipeline, caused by a change in legal form at Nord Stream 2 AG²⁰. The company has decided to found a subsidiary that is to become the owner and operator of the German part of the Nord Stream 2 pipeline. The new subsidiary has to fulfil the unbundling requirements of an independent transmission operator.
- Further on Nord Stream 2, on 12 December the German Foreign Minister made clear that the Nord Stream 2 gas pipeline from Russia will not be allowed to operate in the event of any new "escalation" in Ukraine, under an earlier agreement between Germany and the United States²¹. As increasing number of Russian troops were deployed to the Ukrainian border, geopolitical tension started to increase in late 2021. On 16 December, BNetzA said that Nord Stream 2 AG initiated a process to create a German subsidiary but not all documents had been submitted to restart the certification process, and probably there would be no decisions in the first half of 2022²². Even when the regulator receives all the necessary documents and gives approval, the European Commission has four months to review the project to ensure it complies with EU energy directives. After that, Bundesnetzagentur has another two months to give a final certification. However, as in February 2022 Russia started a military invasion in Ukraine, this is not likely to happen in the near future.
- On 22 November, on the proposal of the European Commission, the European Parliament and the Council of the European Union have reached an informal political agreement on the EU budget for 2022²³. Among other domains, the agreement aims at directing €2.8bn for the connecting Europe facility (CEF) to support cross-border infrastructure development at European level and finance projects of common interest (PCIs), which link the energy systems of EU countries. €1.2bn was agreed under the just transition fund to support the transition to climate neutrality.
- On 15 December, the European Commission proposed new EU framework²⁴ to decarbonise gas markets, promote hydrogen and reduce methane emissions. The set of legislative measures aims at promoting the shift from fossil natural gas to renewable and

¹⁵<https://seenews.com/news/moldova-buys-gas-from-polands-pgnig-amid-drop-in-russian-supplies-758677>

¹⁶<https://www.reuters.com/business/energy/russias-gazprom-moldova-sign-5-year-gas-deal-2021-10-29/>

¹⁷<https://www.cnn.com/2021/10/27/russia-seen-starting-to-fill-europes-gas-storage-after-nov-8.html>

¹⁸<https://www.spglobal.com/commodity-insights/en/market-insights/latest-news/natural-gas/102121-spanish-importers-nominate-zero-algerian-gas-imports-via-gme-link-for-nov-enagas>

¹⁹<https://www.energyvoice.com/oilandgas/africa/377322/sonatrach-capacity-medgaz-libya>

²⁰https://www.bundesnetzagentur.de/DE/Beschlusskammern/1_GZ/BK7-GZ/2021/BK7-21-0056/BK7-21-0056_Antrag.html?nn=361064

²¹<https://www.france24.com/en/live-news/20211212-no-green-light-for-nord-stream-pipeline-if-any-ukraine-escalation-germany>

²²<https://www.rferl.org/a/germany-nord-stream-2-russia-/31613365.html>

²³https://ec.europa.eu/commission/presscorner/detail/en/ip_21_5942

²⁴https://ec.europa.eu/commission/presscorner/detail/en/ip_21_6682

low-carbon gases, in particular bio-methane and hydrogen, and strengthen the resilience of the gas system. According to the framework, unabated fossil natural gas long-term contracts should not be extended after 2049. Making it easier for renewable and low-carbon gases to access the existing gas grid, by removing tariffs for cross-border interconnections and lowering tariffs at injection points are among the most important priorities of the proposal. Enabling voluntary joint gas procurement by Member States to have strategic stocks, in line with the EU competition rules and fostering more strategic approach to gas storage, integrating storage considerations into risk assessment at regional level are also key measures proposed by the framework.

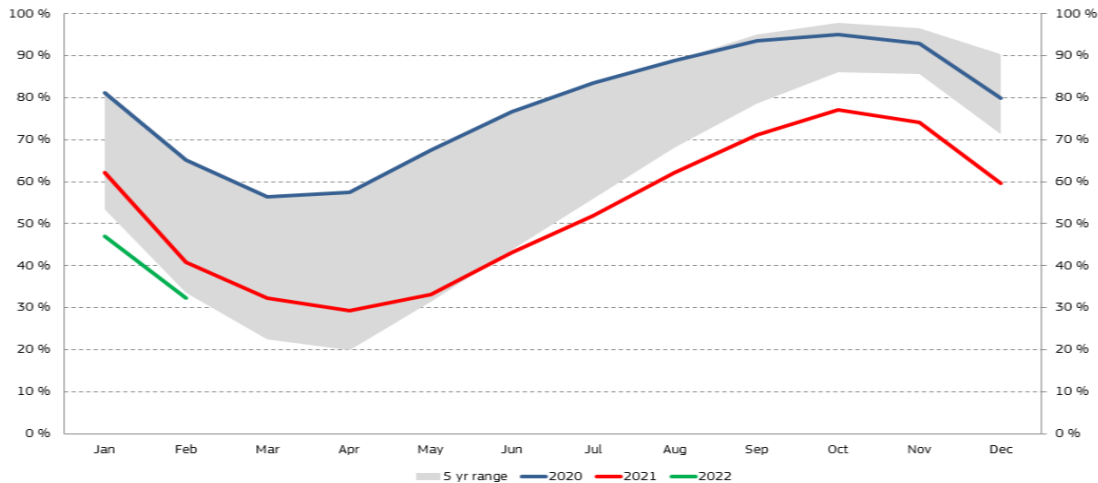
1.5 Storage

- Figure 19 shows EU gas stock levels as the percentage of storage capacity in gas years²⁵ 2020 and 2021, compared to the 5-year range of gas years 2015-2019. According to figures published by Gas Infrastructure Europe, operational EU storage capacity amounts to 1,148 TWh (roughly 102 bcm) as of July 2021²⁶.
- The fourth quarter of the year is traditionally the start of the heating season, with October as 'shoulder month' when storage in most of the EU countries switch from injection to withdrawal. During Q4 2021 the evolution of the storage withdrawals were particularly followed by the gas market, as lower than usual filling rates at the beginning of the heating season, lower than expected inflows from Russia and mounting geopolitical tensions, impacting the certification of the Nord Stream 2 pipeline, have all exerted influence on wholesale gas prices, reaching new highs and proved to be quite volatile over the quarter.
- On 30 September 2021, the average EU storage filling rate was 20 percentage points lower than on the same day of 2020 (74.6% vs. 94.7%), and was around 15 percentage points lower than the average of the last five years (2016-2020) on this day. Ahead of the heating season, EU storages reached the highest fullness rate on 21 October (77.5%), which was around 17% less than in 2020 on the same day of the year and was lower by 14 percentage points compared to the average of 2016-2020 filling rates on this day. The average EU filling rate at the end of December 2021 (53.5%) was the lowest at this time of the over the last decade (ranging historically between 70% and 88%), and was 19 percentage points lower than the average of the last five years, implying that the gap of the current filling rates compared to historical values increased over Q4 2021. Between 30 September and 31 December 2021, storage levels decreased by 21% on average, slightly up from 20% over the same period of 2020.
- Storages operated by Gazprom could be characterised by much lower filling rates compared to the EU average in Q4 2021, continuing the trend of the previous quarter. While the EU average filling rate was more than 74% on 30 September, storages controlled by Gazprom was barely 22% full, and on 31 December still significant differences could be observed (53% vs. 23%). Although at the end of October Russia promised to start to fill Gazprom controlled storages as of 8 November, in the last two months of 2021 gas inflows from Russia fell significantly, leaving EU storages at much lower filling rate than usual at wintertime.
- As Figure 19 and Figure 20 show, since the beginning of the summer, the average EU storage filling rate has been significantly lagging behind the usual values measured in the period of 2011-2020. Increasing wholesale spot gas prices and shrinking winter-summer spreads for the forthcoming year did not provide incentives for rapidly refilling storages. However, owing to relatively mild weather in January and February 2022, the aforementioned storage filling gap started to decrease, and by the end of February 2022 the average filling rate was 29%, albeit lower by 12 percentage points compared to the last five years, but similar to that in 2017 and 2018 on the same day.

²⁵ Gas year always starts on the 1 October of a given year, for example, gas year 2021 started on 1 October 2021 and will end on 30 September 2022

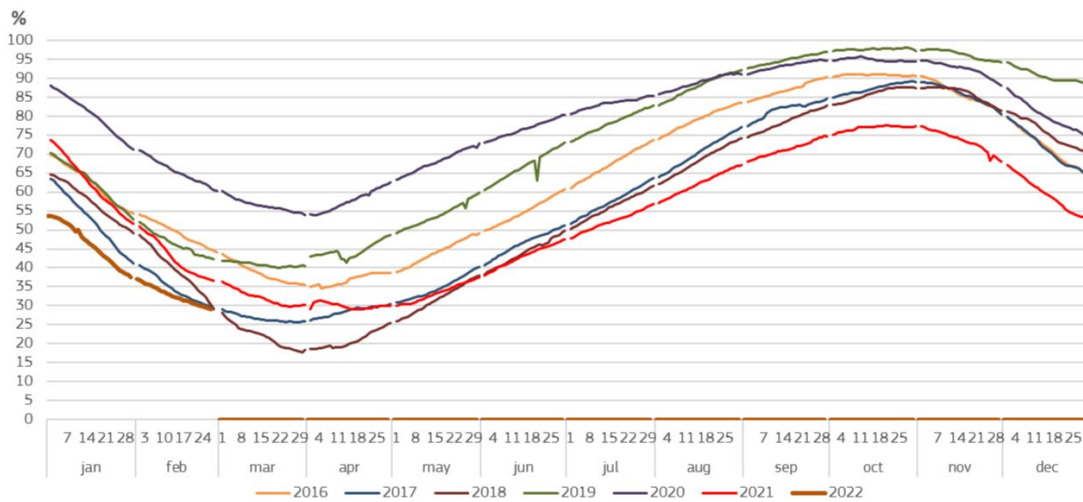
²⁶ https://www.gie.eu/wp-content/uploads/filr/1410/2021_Storage_DB_final.xlsx

Figure 19 - Gas storage levels as percentage of maximum gas storage capacity in the EU in the middle of the month



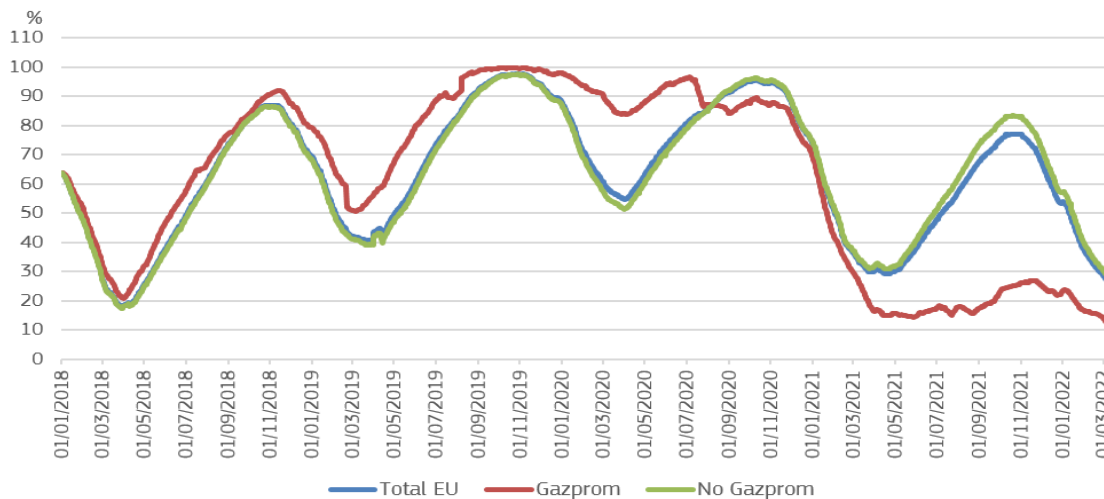
Source: Gas Storage Europe AGSI+ Aggregated Gas Storage Inventory, extracted on 2 March 2022. See explanations on data coverage at <https://aqsi.qie.eu/#/faq>. The 5-year range reflects stock levels in years 2015-2019. The graph shows stock levels on the 15th day of the given month.

Figure 20 – Daily gas storage levels in the EU on average in per cent of total available storage capacities



Source: Gas Storage Europe AGSI+ Aggregated Gas Storage Inventory, extracted on 2 March 2022. See explanations on data coverage at <https://aqsi.qie.eu/#/faq>.

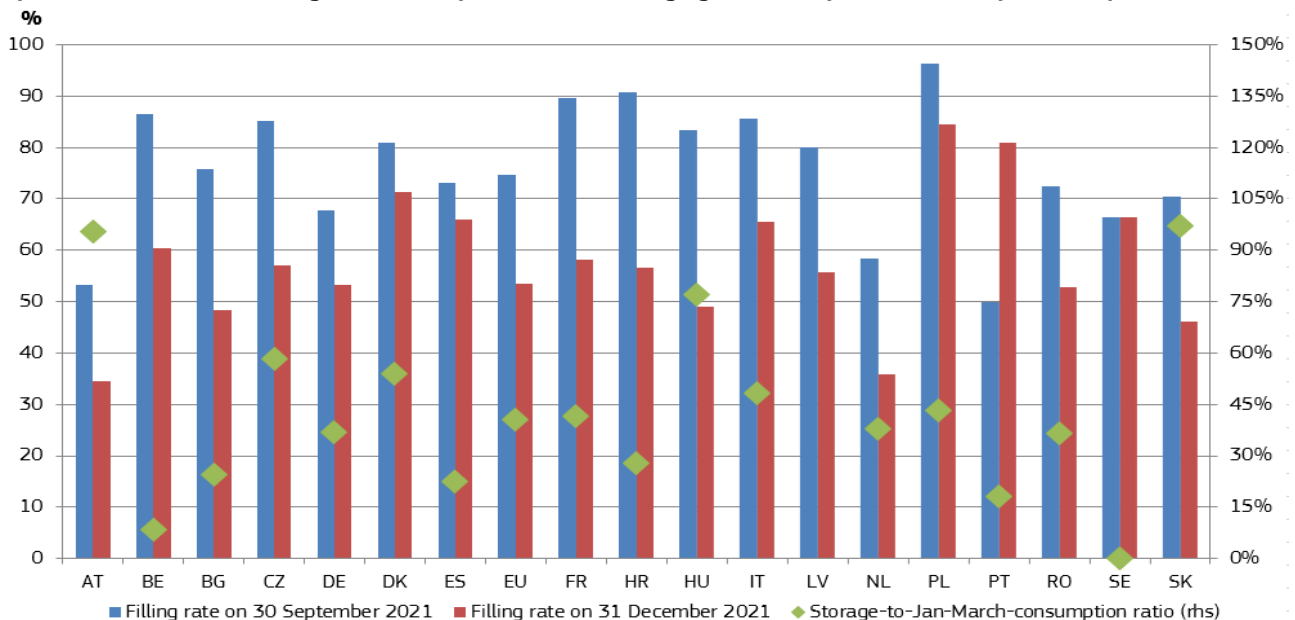
Figure 21 – Difference in the filling rates of Gazprom controlled storages and other storages



Source: JRC calculations, based on Gas Storage Europe AGSI+ data

- As Figure 22 shows, on 30 September 2021 the EU average filling rate was 75% with the lowest filling rates in Portugal (50%), Austria (53%) and the Netherlands, (58%), whereas the highest fullness rates could be observed in Poland (96%), Croatia (91%) and France (90%). On 31 December, the average rate was 53%, with the lowest filling rates measured in Austria (35%) and the Netherlands (36%), whereas the highest rates could be observed in Poland (84%) and Portugal (81%).
- The highest withdrawal rates between 30 September and 31 December 2021 could be observed in Hungary and Croatia (both 34 percentage points) and France (31 percentage points), whereas in Spain, Denmark and Poland filling rates only decreased respectively by 7, 9 and 11 percentage points, in Sweden (though having minimal storage capacities) filling rates did not change over Q4 2021, and interestingly, in Portugal they even increased by 30 percentage points.
- Beyond the evolution of filling rates over time, it is worth to take a look at the relation between the amount of gas in storages, and the average consumption of the remaining period of the winter, January–March, in different markets. At EU level, on 31 December the amount of stored gas covered around 40% of the average gas consumption of the 27 countries in the last five years for the January–March period. In Latvia the storage coverage rate of the ‘first quarter’ consumption was above 100%, while in Slovakia and Austria it was above 95%. On the other hand, in Belgium the coverage rate was less than 10%, in Portugal it was only 18% and in Sweden it was below 1%. However, it is important to recall that a measurable part of gas stored underground cannot be recovered, as under a certain level (cushion gas) the pressure is not sufficient to withdraw gas, so in reality the coverage rate is lower than these data would suggest. On the other hand, gas markets are of regional nature in Europe, and countries with high gas storages may supply neighbouring markets as well. The speed of withdrawal depends on weather conditions, gas import flows and market prices as well.

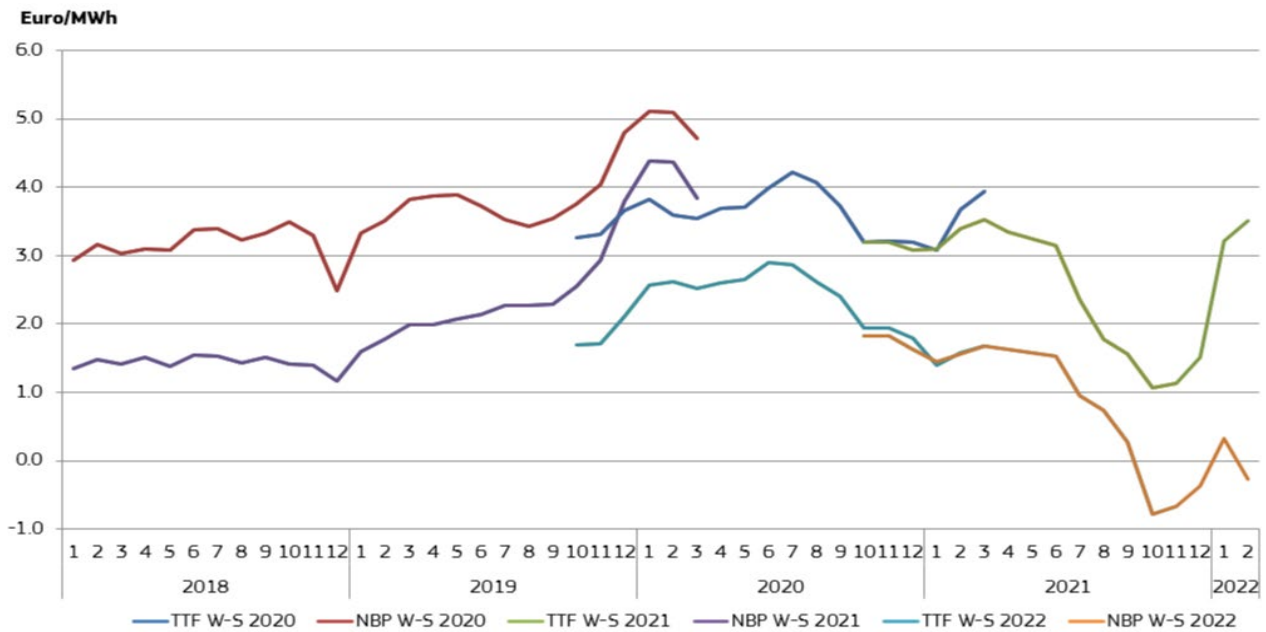
Figure 22 - Gas storage levels as percentage of maximum gas storage capacity at the end of the third and fourth quarters in 2021 and storage levels compared to the average gas consumption of January–March by Member State



Source: Gas Storage Europe AGSI+ Aggregated Gas Storage Inventory, extracted on 3 March 2022. 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.

- The next two charts (Figure 23 and Figure 24) show the winter-summer spreads, as depicted by the difference in the 2021 and 2022 summer and winter contracts. Although 2021 seasonal spreads ran out at the end of March 2021, they provided an indication for the incoming 2022 spreads.
- On the TTF, 2022 seasonal spreads were at 0.3 €/MWh in September 2021. In the fourth quarter of the year, in all of the three months, an unusual phenomenon could be observed, as seasonal spreads turned into negative range (-0.8 €/MWh, -0.7 €/MWh and -0.4 €/MWh respectively). The European gas market was in strong backwardation position, as winter 2022 contracts became cheaper than summer 2022. These negative spreads do not give much incentives for the future to refill storages. In January 2022 spreads became slightly positive again (0.3 €/MWh), while in February they turned negative again (-0.3 €/MWh).
- At the same time, the seasonal spread on the NBP remained in the positive range, reached 1.2 €/MWh in Q4 2021 on average, and in January and February it rose further above 3 €/MWh, probably owing to lower prices on the near end of the British wholesale gas curve. NBP winter-summer spreads had a premium of 1.8 €/MWh over the TTF spreads in Q4 2021.

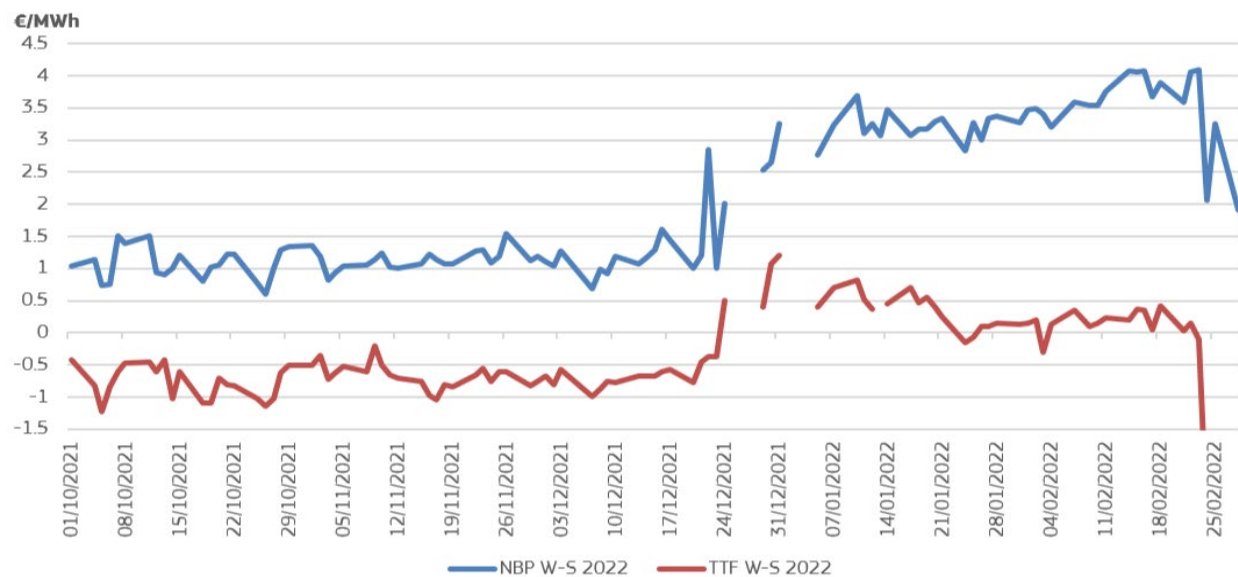
Figure 23 - Winter-summer spreads on the Dutch and British gas hubs



Source: S&P Global Platts

W-S 2020 refers to the premium of the winter 2020-21 contract over the summer 2020 price, W-S 2021 refers to the premium of winter 2021-22 contract over the summer 2021 price, and W-S 2022 refers to the premium of the winter period of 2022/23 over the summer 2022 price.

Figure 24 – Daily winter-summer spread on the Dutch TTF hub



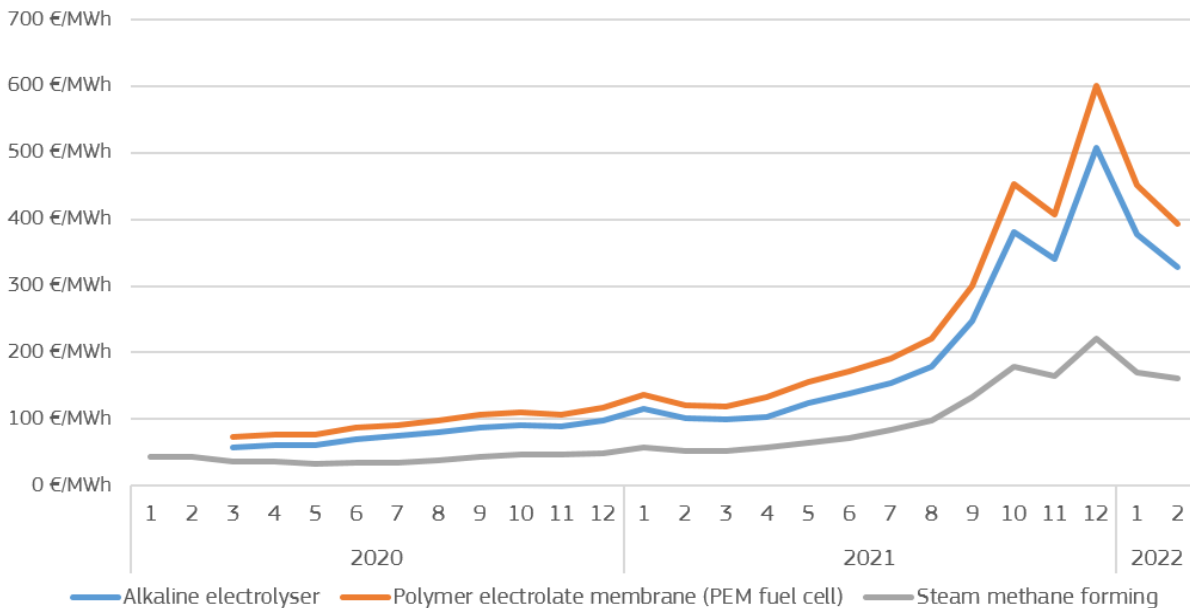
Source: S&P Global Platts

W-S 2022 refers to the premium of the winter period of 2022/23 over the summer 2022 price.

1.6 Hydrogen market developments and alternative fuels

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

Figure 25 - 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.

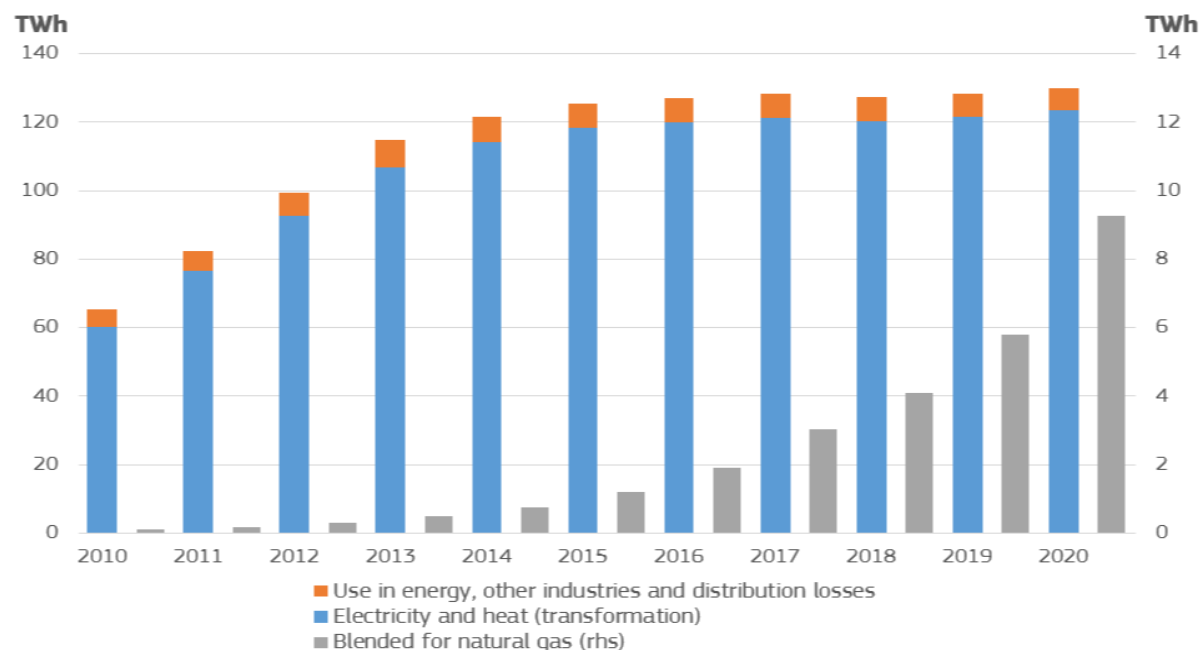
- Whereas alkaline electrolysis and PEM technology costs predominantly depend on the electricity price, the costs of SMR technology is driven by the cost of natural gas used for producing hydrogen. Alkaline and PEM are related to green power (hydrogen generation cost assessment is practically based on 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 October 2021 the TTF spot gas hub prices averaged at 88 €/MWh, falling to 81 €/MWh in November, rebounding to 113 €/MWh in December 2021. At the same time, the Pan-European Electricity wholesale price was around 139 €/MWh in October rising to 170 €/MWh in November and to 222 €/MWh in December 2021. In January and February 2022 both wholesale gas and electricity prices in the EU markets fell back compared to the December 2021 highs. The significant increase in wholesale gas and electricity prices over the last few months also resulted in increasing hydrogen price assessments.
- Cost-based assessment price for alkaline technologies rose from 248 €/MWh in September to 507 €/MWh in December 2021 (falling to 378 €/MWh in January and to 328 €/MWh in February 2022 with CAPEX costs), whereas prices of PEM fuel cell technology based generation rose from 300 €/MWh to 600 €/MWh over the same period (falling below 400 €/MWh in February 2022). These cost assessments were more than twice as high as wholesale electricity prices. At the same time, SMR technology based costs assessments rose from 133 €/MWh in September to 221 €/MWh in December 2021 (receding to 160-170 €/MWh in the first two months of 2022), being also almost twice the wholesale natural gas price in each month.
- It seems that alkaline electrolyser and PEM technologies, through higher wholesale electricity prices, were impacted by both increasing gas prices and rising carbon prices, as gas is the most common price setter on wholesale electricity markets. However, hydrogen produced by both alkaline and PEM technologies, using electricity from long term power purchasing agreements might have become competitive vis-à-vis gas based SRM technologies, facing increasing spot prices over the last few months of 2021.
- On recent project initiatives, the European Commission has granted over €1.1bn to seven largescale hydrogen and carbon projects under the Innovation Fund²⁷. Among the selected projects is the Hydrogen Breakthrough Ironmaking Technology demonstration

²⁷ https://ec.europa.eu/clima/system/files/2021-11/policy_funding_innovation-fund_large-scale_successful_projects_en.pdf

project which aims to help decarbonise iron and steel production in Sweden. The project will replace coal-based blast furnaces with direct hydrogen-based reduction technology, also including 500 MW of green hydrogen production. It is expected to come online in 2026. The final investment decision has not been made yet.

- As further project in the Nordic region, the Sustainable Hydrogen and Recovery of Carbon project at Finland's Porvoo refinery will include 50MW of hydrogen production with a higher capacity option being considered in the planning. The aim is to reduce the refinery's CO₂ emissions by introducing green hydrogen made from renewables and blue hydrogen with carbon capture and storage. The project is in the feasibility phase and an investment decision has not yet been taken, the promoters added. In order to receive funding from the Innovation Fund, the project must reach the financial close within four years. The Innovation Fund has given a positive grant decision of €88m, the promoters said. These projects were selected as part of the first call for projects under the Innovation Fund.
- In 2020, the total indigenous biogas production in the EU amounted to more than 616 thousand TJ (approximately 171 TWh). Out of this, the share of 'other gases from anaerobic fermentation was 80%, amounting to 137 TWh. The share of landfilled gas was around 11% (19 TWh), while that of sewage sludge gas was 8% (13 TWh). The remaining 1% was represented by biogases from thermal processes, with slightly less than 2 TWh volume. In 2020, according to data of Eurostat, the total biogas production increased further and reached 616 thousand TJ (171 TWh).
- Since 2010, total biogas production in the EU more than doubled, increasing by 89 TWh. In 2020, the biggest biogas producer in the EU was Germany (producing around 53% of the total EU production in 2020, around 90 TWh of biogas), followed by Italy (14%, around 23 TWh), France (8%, 13 TWh) and Czechia (4%, 7 TWh). Over the past decade Germany added 39 TWh to the EU production, followed by Italy (18 TWh), France (8 TWh) and Czechia (5 TWh).
- As the next chart shows, over the last decade there was a dynamic increase in biogas production in the EU, reaching 171 TWh in 2020, whereas in 2010 the total amount of produced biogas was barely 81 TWh. In 2020, around 78% of the biogas consumed were used for energy purposes, while 19% was used for other industrial purposes (and distribution losses accounted for 1%). Around 72% (123 TWh) was used in electricity and heat generation as fuel, while around 5% (9 TWh) was injected in the gas grids for blending natural gas.

Figure 26 - Biogas in electricity and heat generation and biogas blending for natural gas



Source: Eurostat

1.7 Focus on: 2021, an extraordinary year on the European and global gas markets

- In the decade between 2010 and 2019, wholesale gas prices, though reacting to the changes in market demand and supply and to the price movements of other energy benchmarks, such as prices of oil, coal and emission allowances, remained relatively stable, in a range of 15-25 €/MWh during most of the time. In the first half of 2020, owing to the Covid-19 related energy demand destruction, the spot wholesale gas price of the Dutch TTF benchmark fell to historic lows, by the end of May 2020 reaching 3-4 €/MWh. In the rest of 2020, a recovery followed, and prices reached around 20 €/MWh by the end of the year, rising to the typical level of the preceding decade.
- In 2021 however, price volatility has significantly increased compared to the previous years. In January 2021, East Asia, a principal destination of the global LNG cargo movements, underwent an unexpected cold spell, which resulted in the local wholesale price (JKM) doubling within two weeks. As Asia has relatively less storage facilities compared to Europe, sudden cold spells can result in gas price spikes. This spike was short-lived and could only temporarily impact EU wholesale gas prices. In February 2021, most of the United States underwent a significant price spike (showing a five-to-six fold increase in the middle of the month), as an extreme cold weather impacted energy grids and generation facilities as well.
- Over the first quarter of the year, European gas storage facilities showed a quick depletion, owing to the cold weather and increasing spot prices, making more profitable to recur to the gas stored at lower costs (as during 2020 purchase prices were lower). At the end of the heating season the average EU storage level was around 30%, which could not be deemed to be outstandingly low. However, in April and May 2021, the weather was colder than normal in most of Europe, which prompted further withdrawals from storages during the injection season, resulting in an increasing gap in filling levels compared to the seasonal average. By the end of June, this gap rose to 15% compared to the average of the preceding five years and storage levels reached the lowest over the last decade. In the following quarter, Q3 2021, this gap remained around 15%, starting to increasingly contribute to gas market tightness and increasing wholesale spot prices.
- Meanwhile, global LNG market prices started to increase as of the second quarter of 2021. Global economic recovery, lifting of Covid-19-related travel restrictions and increasing energy prices (investment funds started to invest in oil as commodity, hedging against increasing global inflationary expectations) supported gas prices as well. On the demand side, particularly strong demand in spring and summer months in Asia (China, Japan, Korea, Taiwan), owing to increasing cooling needs, switching away from coal-fired generation and drought, resulting in low hydro levels, supported gas demand. Unexpectedly, in Brazil, owing to low hydro availability, LNG imports also ramped up to satisfy increasing power needs. On the supply side, in several countries, such as Australia, US, Qatar, Russia, Nigeria and Trinidad, there were unexpected outages, or deferred maintenance works not implemented in the previous year 2020, also resulted in less than expected LNG output, not able to keep pace with increasing global demand. Increasing LNG prices in Asia and Latin America have outpaced the price increase in Europe, resulting in widening premiums and LNG cargo redirection to these more lucrative markets, leaving Europe with less LNG.
- This has also put an obstacle in the way of filling up European gas storages, along with lower than expected Norwegian inflows in the second quarter of 2021, owing to changes in the timing of maintenance works (brought forward from early autumn to spring). However, beside the global markets, from the summer more and more attention was directed towards the unusual transmission capacity booking practice of Russian gas supplier Gazprom and lower than expected Russian gas inflows, predominantly through the Yamal pipeline and Ukraine. The Russian company referred to the prioritisation of filling up storages in Russia during the summer and early autumn months, which could be tracked beside low inflows through the record low gas storage levels managed by Gazprom in Germany, the Netherlands and Austria. In many cases during Q3 2021 these storages switched to withdrawal during the height of the injection season.
- In the second and the third quarters of 2021, spot wholesale gas prices showed a rapid rise, reaching 36 €/MWh on 30 June, and 85€/MWh on 30 September. Beyond the aforementioned factors, gas demand in electricity generation was also impacted by low wind and solar availability over the summer of 2021. However, gas prices showed such a steep increase that coal fired generation, even amid increasing emission allowances prices, became more competitive vis-à-vis gas, resulting in a gas-to-coal switch, which increased the carbon emission of the EU power sector in 2021. High wholesale gas prices also resulted in increasing wholesale electricity prices, given that gas is the marginal cost setting technology of the electricity market in most of the time.
- In the fourth quarter of 2021, volatility on wholesale gas markets became even more important than in the previous two quarters. On 5 October 2021, the TTF average day ahead rose to record high, to 116 €/MWh, while on 21 December it went up to as high as 183 €/MWh, and in both cases a strong price correction followed. In early days of March 2022 the daily average TTF spot price rose above 200 €/MWh, amid gas supply concerns from the East. However, looking at the forward prices, year-ahead and further contracts on the far end of the curve showed price correction expectations (the market is in backwardation). However, in the next four-five years, the market does not anticipate to return to the price levels we saw over the last decade. Furthermore, market backwardation resulted in negative winter-summer spreads that has not given any incentives to fill up gas storages, which increases market tightness ahead of the next winter season.
- In the last quarter of 2021, gas markets were increasingly impacted by policy developments and geopolitical tensions instead of the fundamentals of supply and demand. In spite of being finished in September 2021, the certification process of Nord Stream 2 pipelines has not been finished, (currently being practically suspended), and in the current geopolitical situation any positive decision seems unlikely, at least on the short run (see also Chapter 1.4). Situation of Russian gas inflows and storage levels were also of particular importance over Q4 2021. In spite of Russian declarations on rapid filling up of storages as of November, in the last two months of 2021 Russian gas flows via Yamal and Ukraine dropped significantly compared to this period of previous years,

contributing to gas price spikes on European markets. In December 2021, (also stretching to January-February 2022) European wholesale gas prices reached a premium to the Asian markets, and this quite unusual phenomenon, helped by lower gas need in Asia amid milder winter, resulted in record high LNG inflows to Europe.

- Record high wholesale gas prices also resulted in high wholesale electricity prices, in some cases reaching ranges of 300-400 €/MWh on the EU markets. Depending on contracts with the consumers, wholesale gas prices in most of the EU countries appeared in retail consumer bills, increasing the burden of households and businesses. In order to address these concerns, the European Commission has adopted a toolbox²⁸, proposing immediate and mid-term measures. Member States has advocated the toolbox and in most cases adopted mitigating measures in line with the toolbox proposals.
- However, permanently high energy prices put a strain on the whole economy. A number firms active in energy intensive industry (steel, aluminium, fertilizers, ceramics, etc.) responded by reducing their production output, in line with the demand destruction impact of high energy prices. A few energy utilities, unable to pass through increasing energy purchase costs to retail customers, already went bankrupt in the EU. On macroeconomic side, Member States face high inflation rates not seen since decades and an increasing number of persons and undertakings asking for financial assistance, putting a strain on state budgets. The longer this high energy price period will last, the deeper and longer term impact it will probably have on EU citizens and economies.

2. Wholesale gas markets

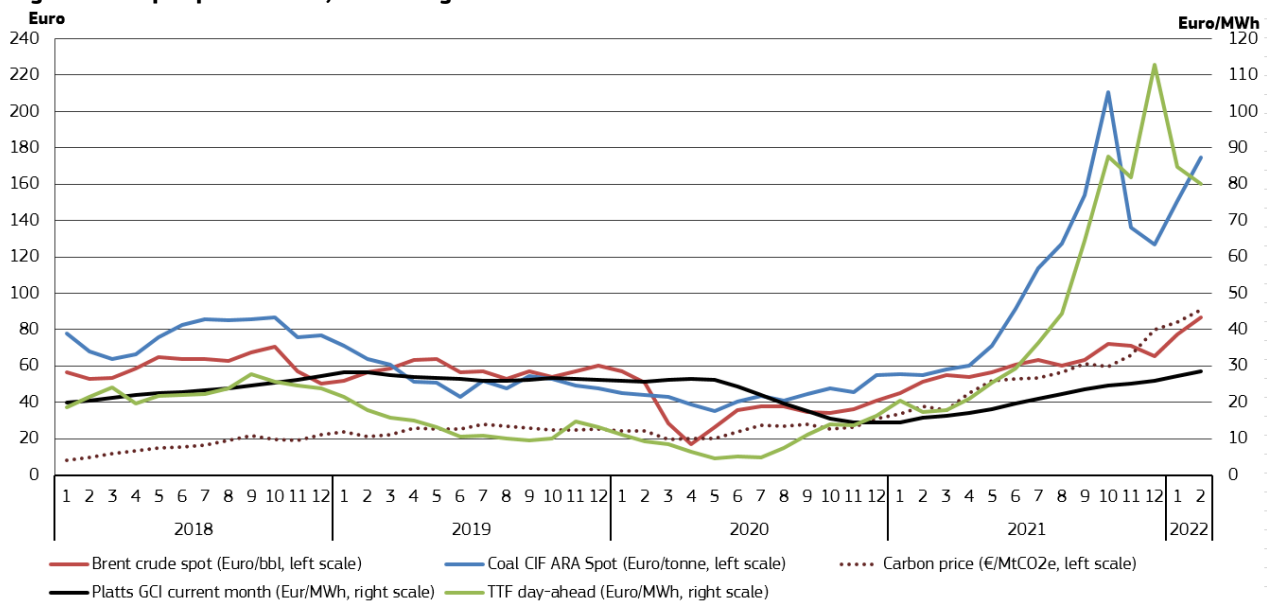
2.1 EU energy commodity markets

- The dated Brent crude oil price was in the range of 71-86 USD/bbl (61-74 €/bbl) in the fourth quarter of 2021, reaching the highest since 2014. From early October prices rose until late in that month. At the end of November a sudden price drop of 10 USD/bbl (9 €/bbl) occurred within one day, amid the fears from the new omicron variant of Covid-19 (potential lockdowns and travel restrictions). In December however, crude oil prices stabilised at lower levels than that of October and November. In 2022 so far, a significant upturn could be observed, and the Brent crude average rose to 130 USD/bbl (115 €/bbl) in the early days of March, owing to supply concerns after the Russian invasion in Ukraine. OPEC+ countries have not shown willingness so far to increase their production beyond the agreed 0.4 mbdp in each month, and the recovery of oil production in the US was slower than expected in 2021. Over the course of October-November 2021, the discount of the year-ahead contract was around 6-8 USD/bbl (5-7 €/bbl), in December it shrunk to 3-4 USD/bbl (2-3€/bbl), while by early March 2022 it rose to high levels, around 27 USD/bbl (25 €/bbl), signaling a market expectation for correction of the spot price increase, especially at spot price levels not seen since July 2008. For the European consumers, the usual cushioning impact of strengthening EUR vs. USD in high oil price periods did not appear, as the USD kept on appreciating against the euro.
- The Dutch TTF spot gas price reached new record highs in the fourth quarter of 2021, rising from 85 €/MWh at the end of September to 116 €/MWh on 5 October. This price spike was principally caused by decade low storage filling levels at the beginning of the heating season and by the generally increasing oil, coal and carbon prices. By the end of October, prices fell back on milder weather and declarations from Russia on ramping up flows towards Europe to help to replenish Gazprom controlled gas storages. However, this should have happened as of 8 November, but Russian inflows remained modest in the remaining part of the year. In December 2021, as market tightness increased amid colder weather, substantially depleting storages, low Russian inflows, outages of significant nuclear capacities in France, lower than usual wind availability and on some declarations on the future of the Nord Stream 2 project (See Chapter 1.4) prices rose again and on 21 December the daily TTF average spot reached the highest ever, 183 €/MWh, falling back to 60 €/MWh by the end of December, primarily owing to high LNG inflows and milder than usual weather around Christmas. Similarly to the oil market, 2022 so far brought continued volatility and on some days, extreme high price levels on the European wholesale gas markets. On 7 March amid security of supply concerns owing to the ongoing Russian invasion and negotiations with no tangible results between the parties in military conflict, the daily average TTF rose to 212 €/MWh, though intraday prices shot above 300 €/MWh. Forward price contracts on the TTF, though back in October had signaled that by spring 2022 spot prices would return to lower levels, now indicate permanently high prices until at least mid-2023.
- Platt's North West Europe Gas Contract Indicator (GCI), a theoretical index showing a gas price linked 100% to oil, continued to increase in Q4 2021, mirroring the increase of crude oil prices in the first half of 2021. Normally, crude oil price changes appear in the oil-indexed contracts with a time lag of 6 months. GCI contracts rose from 23.5 €/MWh in September 2021 to 25.8 €/MWh December 2021 (and rose slightly further to 27-28 €/MWh in January-February 2022. Owing to the significant crude oil price increase over the last few months, we can expect that the GCI increase will rise further during the spring and summer of 2022. In Q4 2021, and further in 2022 so far, rapidly increasing spot TTF contracts had an increasing premium over the oil-index contracts, which implied a competitive advantage of oil indexed contracts in Europe in these months. This was beneficial to some oil-indexed gas import sources (e.g. Algeria). The competitiveness of oil-indexed contracts strongly depend on the evolution of gas hub prices, but foreseeably the price advantage of oil-indexed contracts is likely to stay in the next couple of quarters.

²⁸ See more in the Quarterly Report on European Gas Markets, Vol. 14 Issue 3, third quarter of 2021.

- Spot coal prices (CIF ARA) in October 2021 rose above 250 €/Mt, around twice as high as the record high levels seen in 2008, before falling back later in the autumn. In November they reached 136 €/Mt, and in December they fell to 126 €/Mt. However, in January-February, following the wider energy complex, mainly oil and gas, they rebounded again, beating the record set in October (in early March 2022 rising above 300 €/Mt). European coal contracts were influenced principally by the energy complex, as high prices increased the demand for coal in electricity generation, however, this switch was limited in many markets. In October-November 2021 low levels of river Rhine hampered barges to deliver coal in north-western Europe, also putting upward pressure on coal prices.
- Carbon prices in the fourth third quarter of 2021, in parallel with energy commodities prices, extended their increase of the previous quarter, up from 62 €/MtCO₂e to 80 €/MtCO₂e. On 8 December the daily average carbon price reached record high, 88 €/MtCO₂e, also reflecting market expectations on quicker green transition (e.g. announcement from the German government on 'national carbon price floor'). In February 2022, the carbon price reached 96 €/Mt, however, by early March it fell back by a third on decreasing demand, as high energy prices are expected to result in energy demand destruction.

Figure 27 - Spot prices of oil, coal and gas in the EU



Source: S&P Global Platts

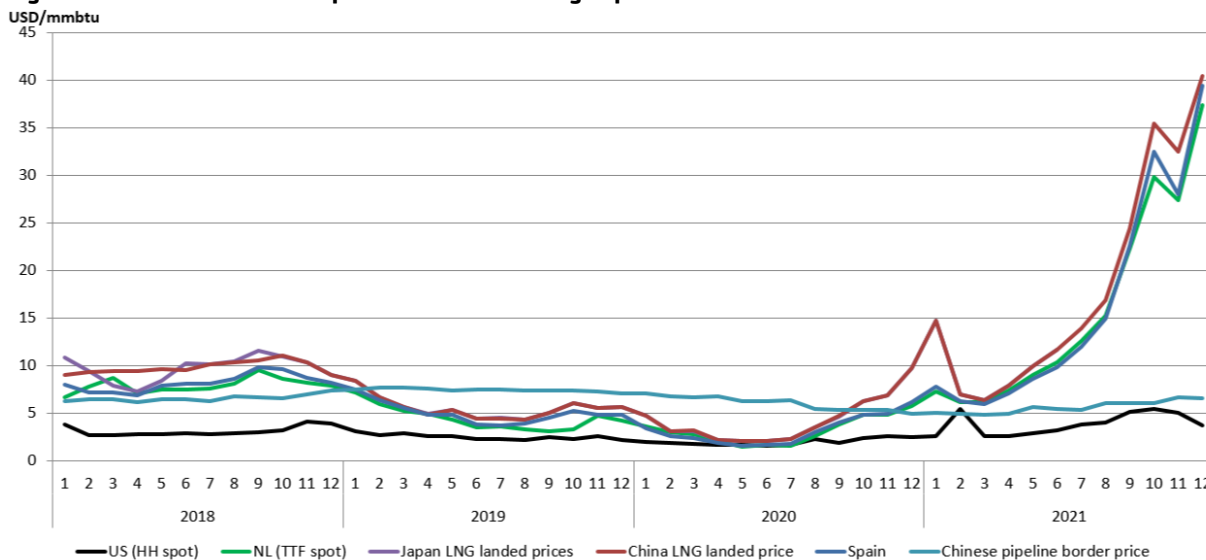
2.2 LNG and international gas markets

- Figure 27 displays the international comparison of wholesale gas prices, including hub, LNG landed and pipeline import gas prices. In October 2021, amid high global demand for LNG, Henry Hub reached the highest level since February 2014 on monthly average. In November and December, principally owing to milder weather in Asia, the Henry Hub average price fell back, but in 2022 it picked up again. Meanwhile, Asian contracts rose only slightly between October and December on monthly average, whereas the TTF went up significantly, reaching a premium to JKM, which is not a usual phenomenon.
- The quarterly average Japanese LNG price was 36.1 USD/mmbtu in Q4 2021, practically doubling from 18.4 USD/mmbtu in Q3 2021, and up from 7.6 USD/mmbtu in Q3 2021. The Japanese premium above the Dutch TTF hub was on average 4.2 USD/mmbtu in Q4 2021, up from 1.7 USD/mmbtu in Q3 2021, and from 2.4 USD/mmbtu in the fourth quarter of 2020. LNG import prices in China were comparable with their Japanese peers (36.1 USD/mmbtu in Q4 2021). However, quarterly price differentials might mask specific period, namely the second half of December, when Asian contracts were priced lower than the European ones.
- Chinese pipeline gas imports, presumably mostly based oil-indexed contracts, were at 6.5 USD/mmbtu in Q4 2021, having a significant price advantage vis-à-vis LNG imports (with the aforementioned quarterly average price of 36.1 USD/mmbtu in Q4 2021). However, similarly to European oil-indexed gas contracts, the time-lagged impact of increasing oil prices as of mid-2020 started to appear in import gas prices. High demand for LNG in East Asia is likely to ensure the competitiveness of oil-indexed contracts in the forthcoming months, even if recent price increases on the oil market are still to be priced in during the forthcoming couple of quarters.
- The Henry Hub price rose to 4.7 USD/mmbtu in Q4 2021 from 4.2 USD/mmbtu in Q3 2021 and from 2.5 USD/mmbtu in Q4 2020. As Figure 28 shows, both TTF and JKM continued to show measurable premiums vis-à-vis Henry Hub, however, in the second half of December 2021 (and in 2022 in several periods), TTF developed a premium to JKM, which resulted in LNG cargo redirection to

Europe in these periods. On quarterly average, TTF had a premium of 27 USD/mmbtu to Henry hub, whereas JKM had a higher premium of 31 USD/mmbtu. The euro slightly depreciated against the USD in Q4 2021 (in September 2021 the exchange rate was 1.18, while in December it fell to 1.13), but this did not really contribute to the increasing divergence between the TTF and the Henry Hub.

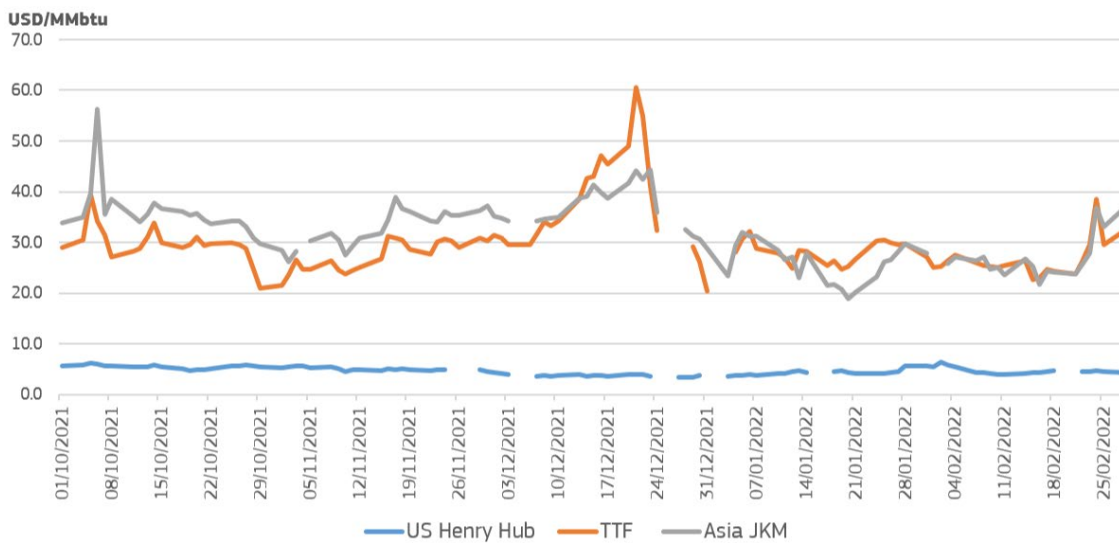
- In the fourth quarter of 2021, in parallel with increasing absolute differentials, price ratios of international contracts showed mostly further increases. The average TTF/Henry Hub ratio was 6.7 in Q4 2021, up from 3.9 in Q3 2021 and from 2.1 in Q4 2020. The ratio of the Japanese LNG price and US Henry Hub was 7.6 in Q4 2021, up from 4.3 in Q3 2021 and from 3.1 in Q4 2020, whereas the average price ratio of the Japanese LNG prices and the TTF was 1.2 in Q4 2021, slightly up from 1.1 in Q3 2021 but down from 1.5 in Q4 2020.
- In the fourth quarter of 2021, TTF averaged at 31.5 USD/mmbtu (94 €/MWh), up from 16.7 USD/mmbtu (48 €/MWh) and from 5.1 USD/mmbtu (14.6 €/MWh) in Q4 2020. The average German border price in Q4 2021 was lower than the TTF (15.6 USD/mmbtu or 47 €/MWh), showing that the impact of high spot prices in the long term contracts in the German gas import mix, either still oil-indexed or hub indexed, will appear only with a few months' time lag, resulting in less volatility compared to the European hub spot prices.
- In the fourth quarter of 2021, the Dutch TTF spot price averaged at 31.5 USD/mmbtu, the Spanish LNG landed price was 33 USD/mmbtu, and that in China and Japan reached 36.1 USD/mmbtu.
- The JCC (Japanese Crude Cocktail) contracts reached 13.5 USD/mmbtu in the fourth quarter of 2021 on average, up from 10.8 USD/mmbtu in Q3 2021 and from 6.7 USD/mmbtu in Q4 2020, but were significantly lower than Japanese LNG import prices (36.1 USD/mmbtu), and the TTF (31.5 USD/mmbtu) as well.

Figure 28 - International comparison of wholesale gas prices



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

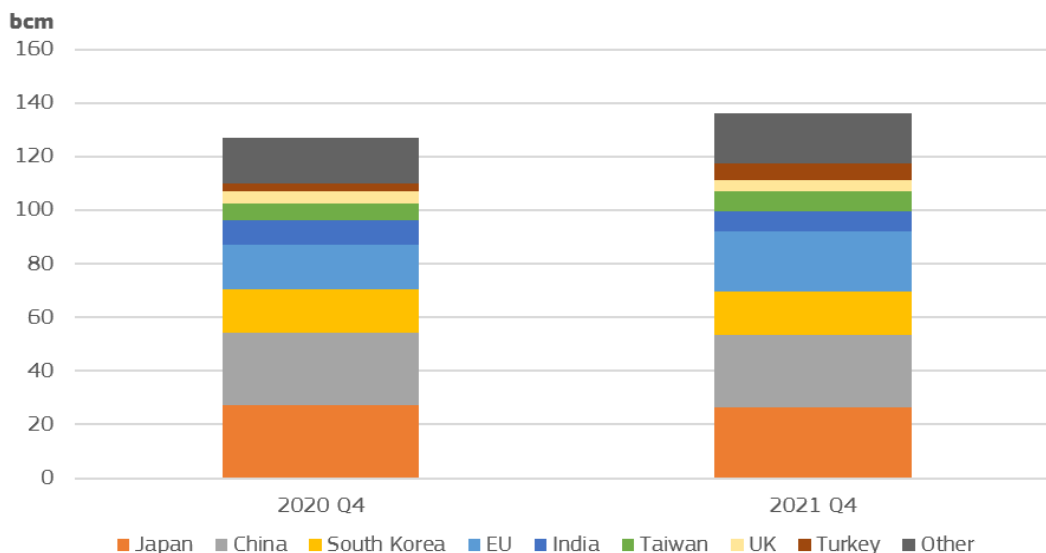
Figure 29 – Daily average prices on the TTF (Dutch), the US Henry hub and the JKM Asian reference index



Sources: S&P Global Platts

- The next two charts show the key actors of global LNG trade on importer (consumer) and exporter (producer) side. In Q4 2021 China retained the biggest global LNG importer position ahead of Japan, with quarterly imports amounting to 27.2 bcm, out of the total estimated 136 bcm market. Japan imported 26.3 bcm, whereas the EU (as 27 countries altogether) had a quarterly LNG import of 22.5 bcm, followed by South Korea (16.3 bcm), India (7.5 bcm), Taiwan (constituting a separate market, with an import volume of 7.3 bcm), Turkey (6 bcm) and the United Kingdom (4.3 bcm). Compared to the fourth quarter of 2020, a significant increase could be observed in Turkey (97%, by 3 bcm), in the EU as total (33%, +6 bcm), Taiwan (16%, +1bcm), whereas in India imports fell by 17% (-1.5 bcm), along with those in Japan (by 3%, -0.9 bcm). In 2021, the biggest LNG importers were: China (being the first for the first time, with 107 bcm), Japan (103 bcm), the EU (80 bcm), South Korea (63 bcm), India (32 bcm), Taiwan (26 bcm) and the United Kingdom (15 bcm). The biggest increase could be observed in China (+17%, +15 bcm), while UK imports fell by 18% (-3 bcm). The global LNG market could be estimated at 522 bcm in 2021, up from 493 bcm in 2020.

Figure 30 – LNG imports in the main consumer markets in the fourth quarters of 2020 and 2021

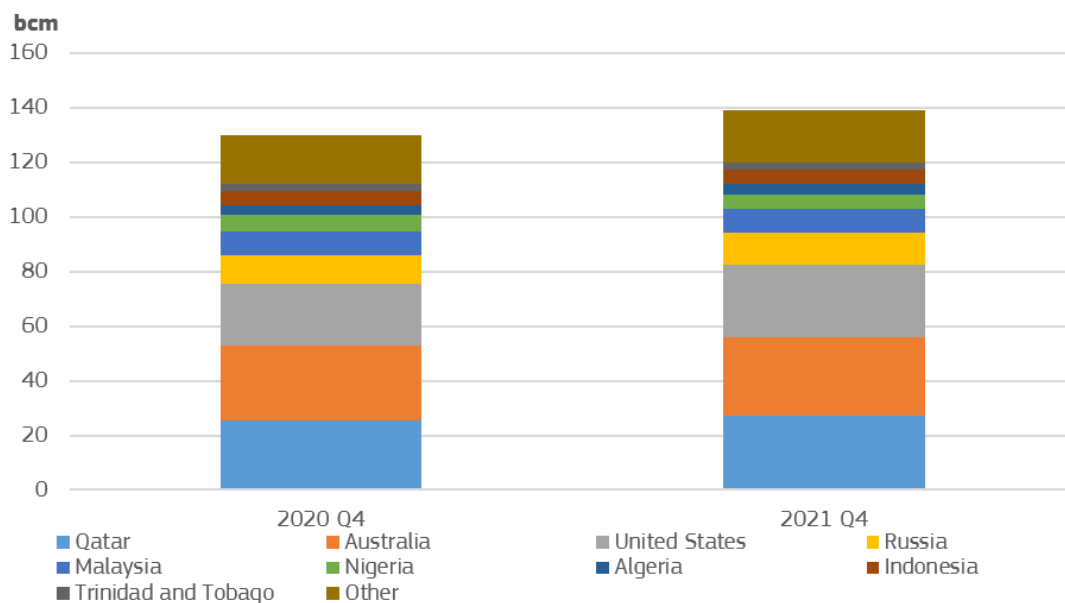


Source: Refinitiv tracking of LNG vessels. Import data are based on cargo arrival dates, therefore total amount of global imports might differ from global export numbers

- On the exporter side, in Q4 2021 Australia was the biggest LNG exporter in the world, ensuring 29 bcm (up by 5% year-on-year) of the estimated global LNG supply. Qatar came to the second place, exporting 27 bcm (+6%) LNG in Q4 2021. The United States were the third most important exporter, supplying 26.5 bcm of LNG (+19%), followed by Russia (12 bcm, +12%), Malaysia (8.5 bcm, -1%), Nigeria (5.3 bcm, -17%, facing infrastructure problems supplying its regasification terminals), Indonesia (5.3 bcm, +5%), Algeria (4 bcm, +7%) and Trinidad and Tobago (2.6 bcm, +4%). In 2021 Australia became the largest LNG exporter (with an annual exports of 110 bcm), ahead of Qatar (107 bcm), the United States (99 bcm), Russia (41 bcm), Malaysia (34 bcm), Nigeria (23 bcm),

Indonesia (20 bcm) and Algeria (15 bcm). LNG exports in 2021 were up by 50% in the United States year-on-year, while it fell in Nigeria by 17%.

Figure 31 – LNG exports in the main consumer markets in the fourth quarters of 2020 and 2021



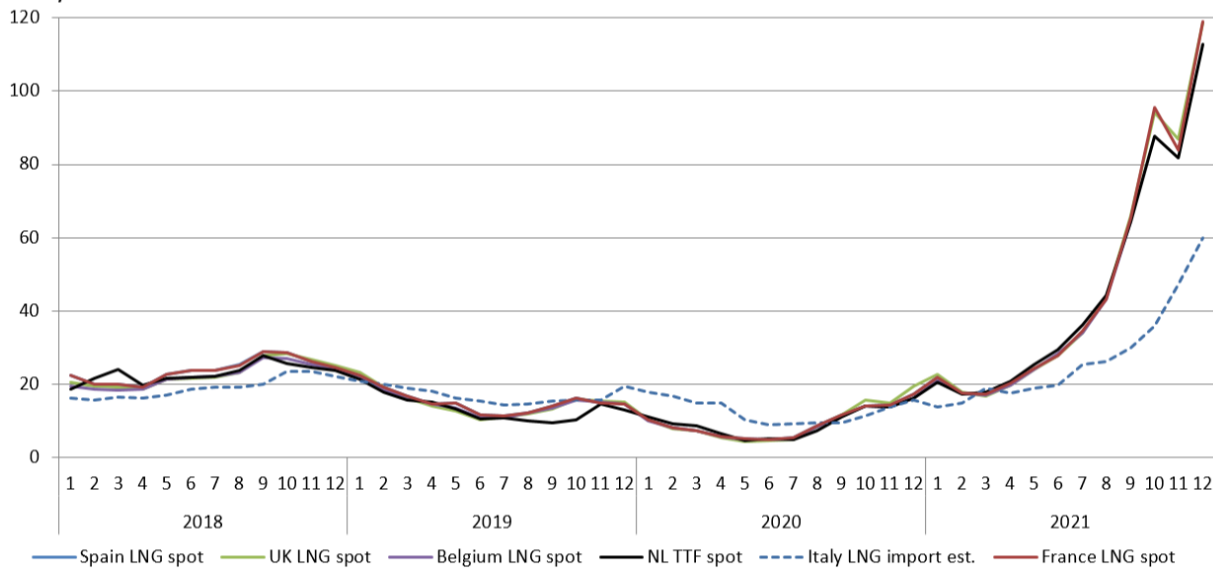
Source: Refinitiv tracking of LNG vessels. Export data are based on cargo departure dates, therefore total amount of global exports might differ from global import numbers

2.3 European gas markets

2.3.1 LNG contracts in Europe

- Figure 31 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 fourth quarter of 2021, hub prices and hub-based import price contracts in western-Europe showed a significant upturn amid general gas wholesale price increases. Looking merely the hub based contracts, they remained relatively well converged, and differentials in December 2021 amounted to 4.8 €/MWh (albeit being higher than 1.5€/MWh in Q3 2021, showing that differentials might also increase amid high price environment). However, if we take into account the Italian COMEXT derived average price, the difference was more than 52 €/MWh, implying that LNG import contracts in Italy are either not fully linked to spot prices or there is a time lag impact (oil indexation or link to forward gas price contract), which will be only observable in the following periods.
- The Q4 2021 quarterly average hub-based prices practically doubled compared to the previous quarter, reflecting the continued price upturn on wholesale gas markets and import contracts. In year-on-year comparison, most contracts showed more than fivefold increases. The estimated price increase for LNG import contracts in Italy showed an upturn of 76% quarter-on-quarter, while year-on-year it went up by 250%. If compared to the pre-Covid lockdown period, Q4 2019, hub-based prices showed a five-to-six-fold increases, implying that current prices are significantly higher even compared to 'normal' times.

Figure 32 - Price developments of LNG imports in the UK, Belgium, Spain and Italy, compared to the TTF benchmark
Euro/MWh

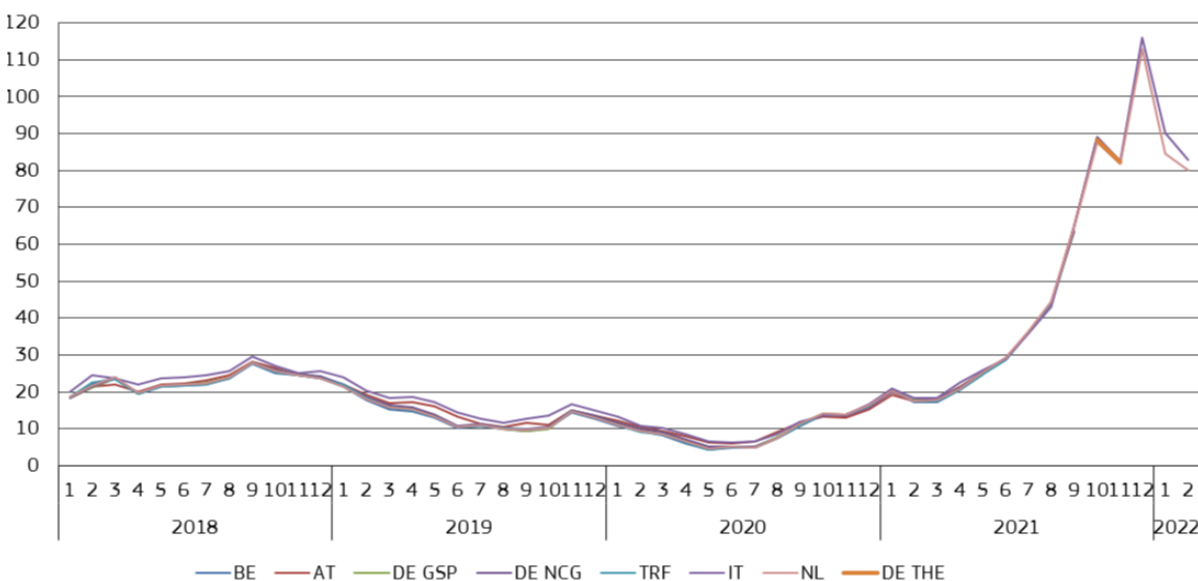


Note: Landed prices for LNG. Source: S&P Global Platts, Refinitiv, European Commission estimates based on Eurostat COMEXT data, retrieved on 10 March 2022.

2.3.2 Wholesale price developments in the EU

- European hub prices rose to record highs in the fourth quarter of 2021, and were in the range of 91-96 €/MWh, measurably higher than in the previous quarter, Q3 2021 (47-48 €/MWh), adding around 93-100% to the price level just within a quarter's time, which shows the continuation of the sharp upturn in gas prices. Hub prices in year-on-year comparison showed a six-fold increase, compared to the price range in Q4 2020 (13.9-15.3 €/MWh). The average TTF hub price was 94 €/MWh in Q4 2021, significantly up from 14.7 €/MWh measured in Q4 2020. Comparing to Q3 2019, the observed prices were up by 540-650%, signalling that current prices are also measurably higher than two years before.
- In the fourth quarter of 2021, tightness of the gas market has resulted in volatile prices. Underground storage filling rates showed a significant gap (around 15%) compared to the average of the preceding years, and in November-December with the onset of colder weather high spot prices resulted in intensive use of gas storages. During Q4 2021, albeit promises from the Russian side, inflow of Russian gas was much less than expected. News on the suspension of the permission process of the new Nord Stream 2 pipeline also added to market volatility.

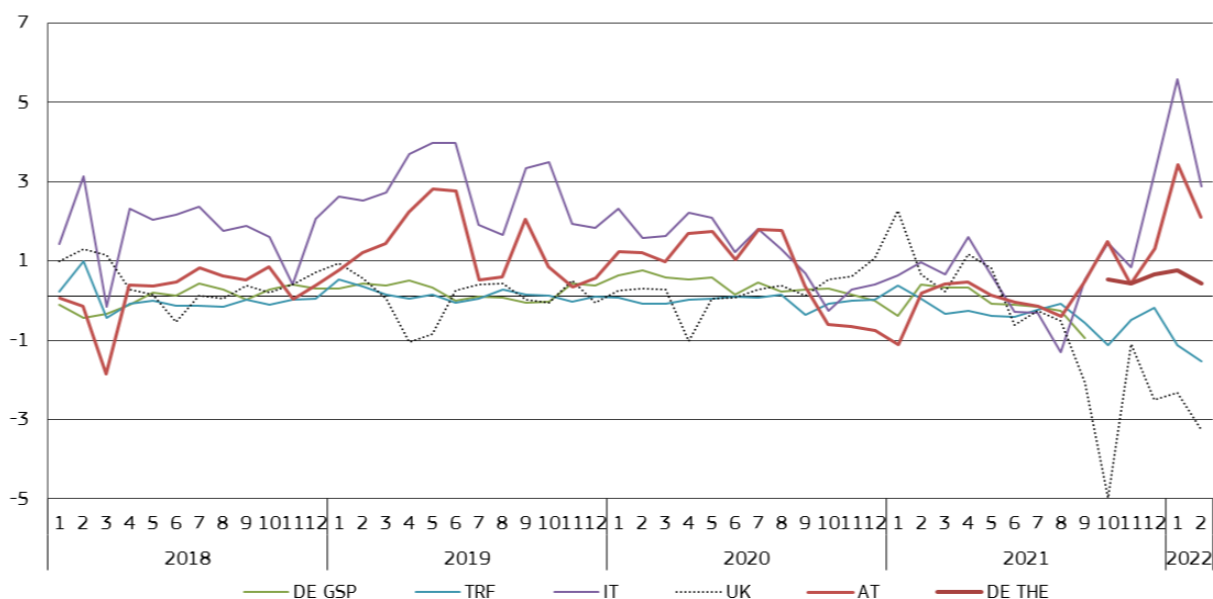
Figure 33 - Wholesale day-ahead gas prices on gas hubs in the EU
Euro/MWh



Source: S&P Global Platts

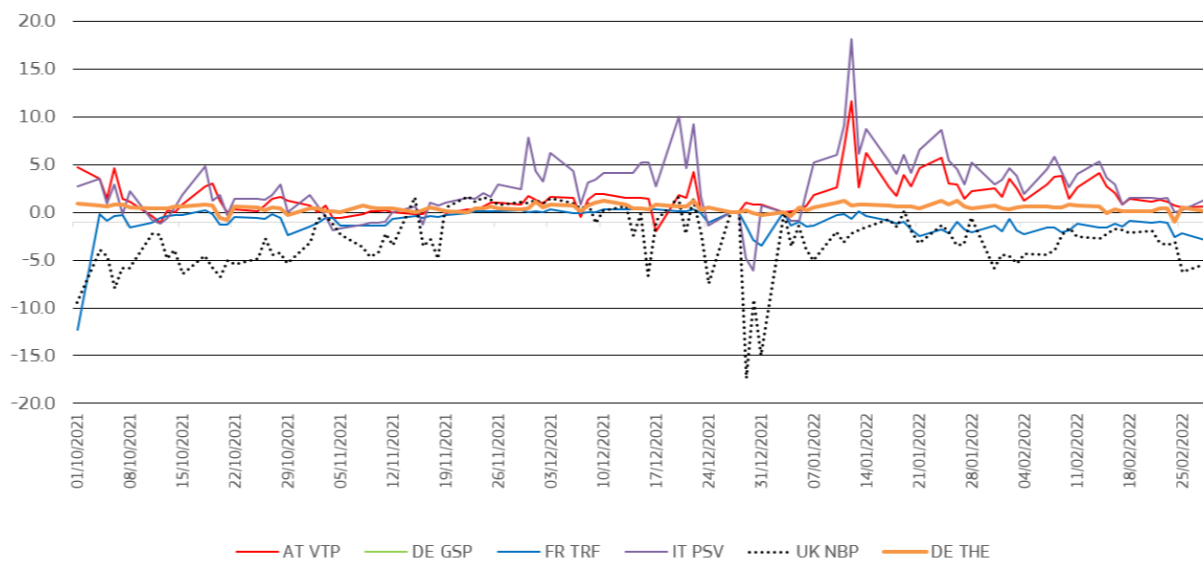
- As Figure 33 and Figure 34 show, the French TRF market was well aligned with the TTF during most of Q4 2021, even if the French market was also impacted by news on Russian flows, LNG availability and lower than usual renewable generation. In mid-December, two nuclear reactors were taken offline (unplanned), which resulted in increasing use of gas in power generation, however good levels of storages mitigated the upward pressure on spot gas prices. In January and February 2022, owing to abundant LNG send-out, French spot gas prices were in discount to TTF.
- The recently (1 October 2021) merged German market (THE) was in a slight premium to TTF over the fourth quarter of 2021 during most of the time, principally impacted by news on Russian inflows (in November and December lower than expected), and policy developments on Nord Stream 2, along with the lower-than-EU average gas storages, specifically those operated by Gazprom in the country. Lower than expected renewable generation also supported gas prices, mitigated by inflows from the competitively priced Dutch market.
- The Austrian hub showed a measurable premium to the TTF during most of Q4 2021. Low storage filling rates weighed on Austrian wholesale gas prices. The aforementioned story on low Russian inflows, especially in periods of colder weather, has pushed up Austrian contracts, in a land-locked country that cannot be directly benefit from LNG inflows. This premium has increased during January-February 2022.
- In Italy, the PSV hub price had a discount vis-à-vis TTF in early days of October 2021, owing to high storage filling rates and abundant inflows from North Africa and Azerbaijan. Then the discount turned into the usual premium, owing to outages on the TAG pipeline from Austria and maintenance works on 23-25 November, reducing inflows from Algeria and Libya. Price spikes in December 2021 resulted in significant premiums vis-à-vis the TTF several times.
- During the fourth quarter of 2021, the NBP hub price was below the TTF benchmark during most of the time, possibly because of less impacts from Russian inflows compared to the continental markets, abundant inflows from Norway and uptick in LNG availability. However, in December the discount disappeared, as gas flowed from the UK to France as nuclear capacities there decreased. In January and February 2022 the NBP discount reappeared, as less reliance on Russia and good LNG inflows were beneficial during increasing market tensions.

Figure 34 - 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

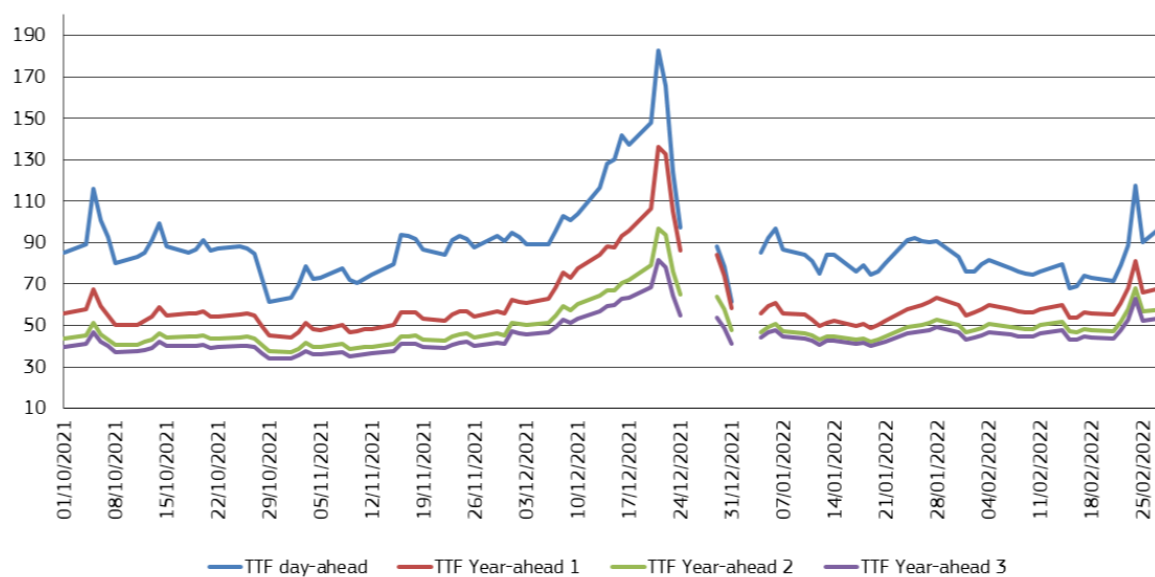
Figure 35 - Premium of daily average wholesale day-ahead gas prices at selected hubs compared to TTF
Euro/MWh



Source: S&P Global Platts, European Commission computations

- Figure 35 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, starting the quarter at 85 €/MWh, proved to be quite volatile over Q4 2021. On 5 October, spot prices rose to record high, 116 €/MWh on average, and after falling back by the end of October, it rebounded again, rising to as high as 183 €/MWh on 21 December, again followed by a correction in late 2021. Peaks in the spot contract was only partially mirrored by forward contracts. On 5 October the three forward contracts reached 67 €/MWh, 51 €/MWh and 46 €/MWh, while the spot was 116 €/MWh. On 21 December, these three contracts respectively were 136 €/MWh, 97 €/MWh and 82 €/MWh, as opposed to the spot contract of 183 €/MWh. The market remained in backwardation, and the discount of longer term contracts vis-à-vis spot prices decreased somewhat across Q4 2021, implying that a longer term high priced period was gradually priced in the forward curve.

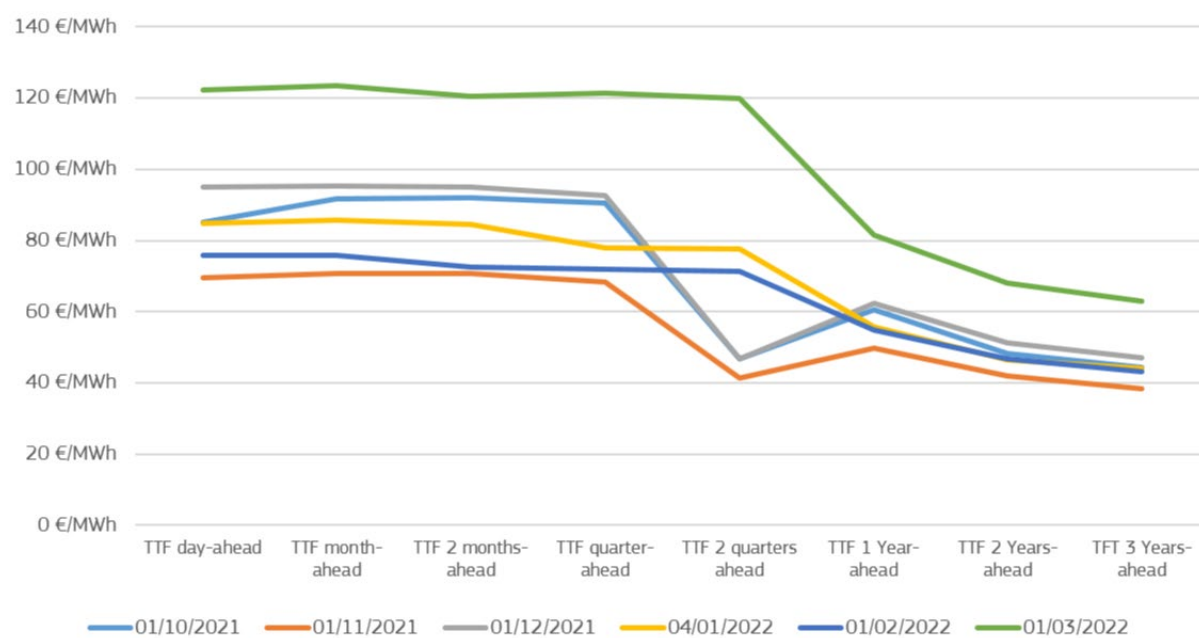
Figure 36 - Forward gas prices on the TTF hub
Euro/MWh



Source: S&P Global Platts

This expectation can also be followed on Figure 36, showing the forward price curves on the TTF market at the beginning of each month. Forward contracts also followed an upward trajectory, implying that return to lower price levels are also expected only in later periods by the market itself. Even the three-year forward prices were above 60 €/MWh on 1 March 2022, whereas at the beginning of October 2021 three year ahead contracts were only at 40 €/MWh.

Figure 37 - Forward price curves on the first trading day of each month on the TTF wholesale gas market



Source: TTF

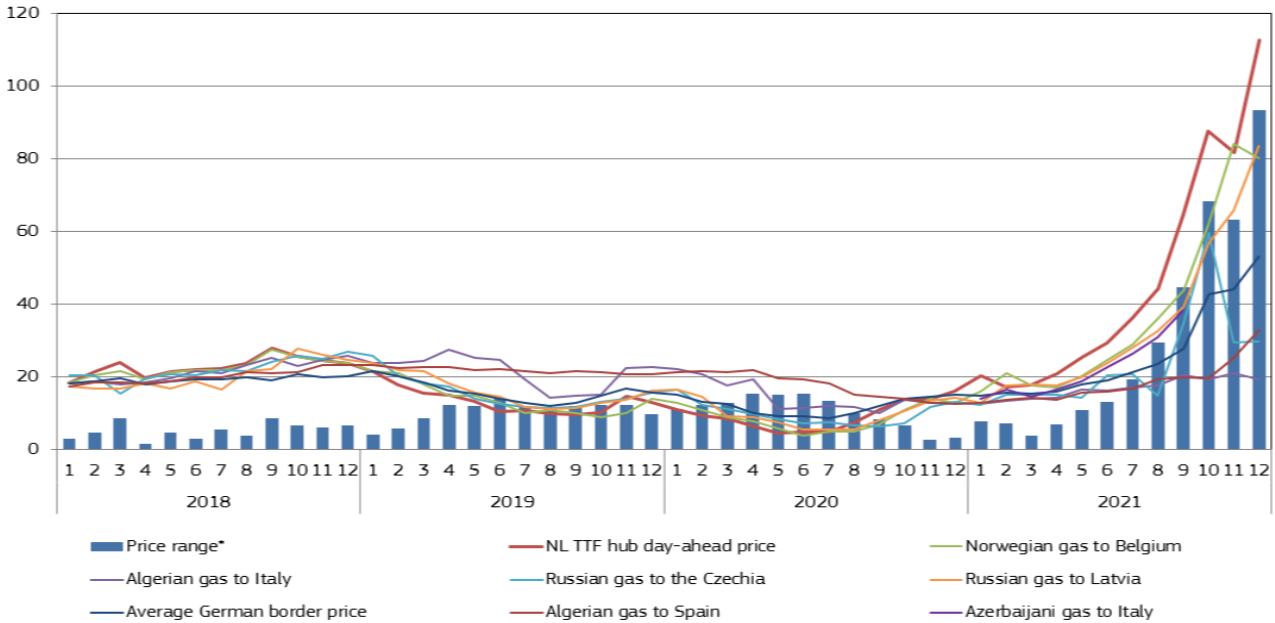
2.3.3. Prices of different pipeline contracts for gas in the EU

- Figure 37 compares a selection of estimated border prices of pipeline gas deliveries from the main exporters to the EU: Russia, Norway, Algeria and Azerbaijan. For comparison, the evolution of the day-ahead prices on the Dutch TTF hub is also presented on the chart.
- In the fourth quarter of 2021, the estimated Algerian pipeline import price in Spain was 26 €/MWh, up by 39% compared to the previous quarter (18.8 €/MWh), and by 96% compared to Q4 2020. The Algerian contract clearly reflects the time-lagged impact of recovering crude oil prices. In Q4 2021, the discount of the average estimated Algerian import price in Spain to the Spanish LNG import prices rose to historical highs of 73 €/MWh, providing a competitive advantage to Algerian imports. However, owing to the termination of the GME pipeline contract through Morocco (see Chapter 1.4), import volumes to Spain could not increase further, as Medgaz pipeline also operated at nearly full capacity.
- Algerian gas import price in Italy (20 €/MWh) was lower than that in Spain in the fourth quarter of 2021. In quarter-on-quarter comparison, Algerian import price in Italy was up by 8%, and year-on-year it rose by 51% in Q4 2021. Pipeline gas imports from Algeria was up by 15% in Q4 2021 year-on-year in Italy (See Chapter 1.3 Imports). For the future, the current advantage of oil-indexed contracts is likely to remain as long as spot gas prices are at current high levels, though recent high crude oil prices will filter in the oil-indexed contracts during the spring and summer of 2022.
- Russian gas imports prices in both Czechia and Latvia showed an accelerating increase in Q4 2021 and were respectively up by 69% and 106% compared to the previous quarter, whereas year-on-year they rose by 268% and 438%. 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 an increasing premium over the import prices in Czechia (40 €/MWh vs. 69 €/MWh) in Q4 2021.
- Prices of European gas contracts showed signs of divergence in Q4 2021, as the difference between the cheapest and most expensive contract rose from 45 €/MWh in September 2021 to 93 €/MWh in December 2021. In Q4 2021, the TTF spot prices proved to be the more expensive compared to the observed import contracts, as it takes some time till spot prices filter in the import contract pricing. However, even without TTF, price differential would have risen from 24 €/MWh to 64 €/MWh between

September and December 2021, implying that high price levels usually magnify differences between differently priced gas import contracts.

- Hub-based contracts and hub prices themselves continued their upturn in the fourth quarter of 2021. Reported German border prices also increased (to 47 €/MWh, up from 24.2 €/MWh in Q3 2021 and from 14.7 €/MWh in Q4 2020), 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 time-lagged impact of either hub or oil indexation in some import sources to Germany.

Figure 38 - Comparison of EU wholesale gas price estimations
Euro/MWh



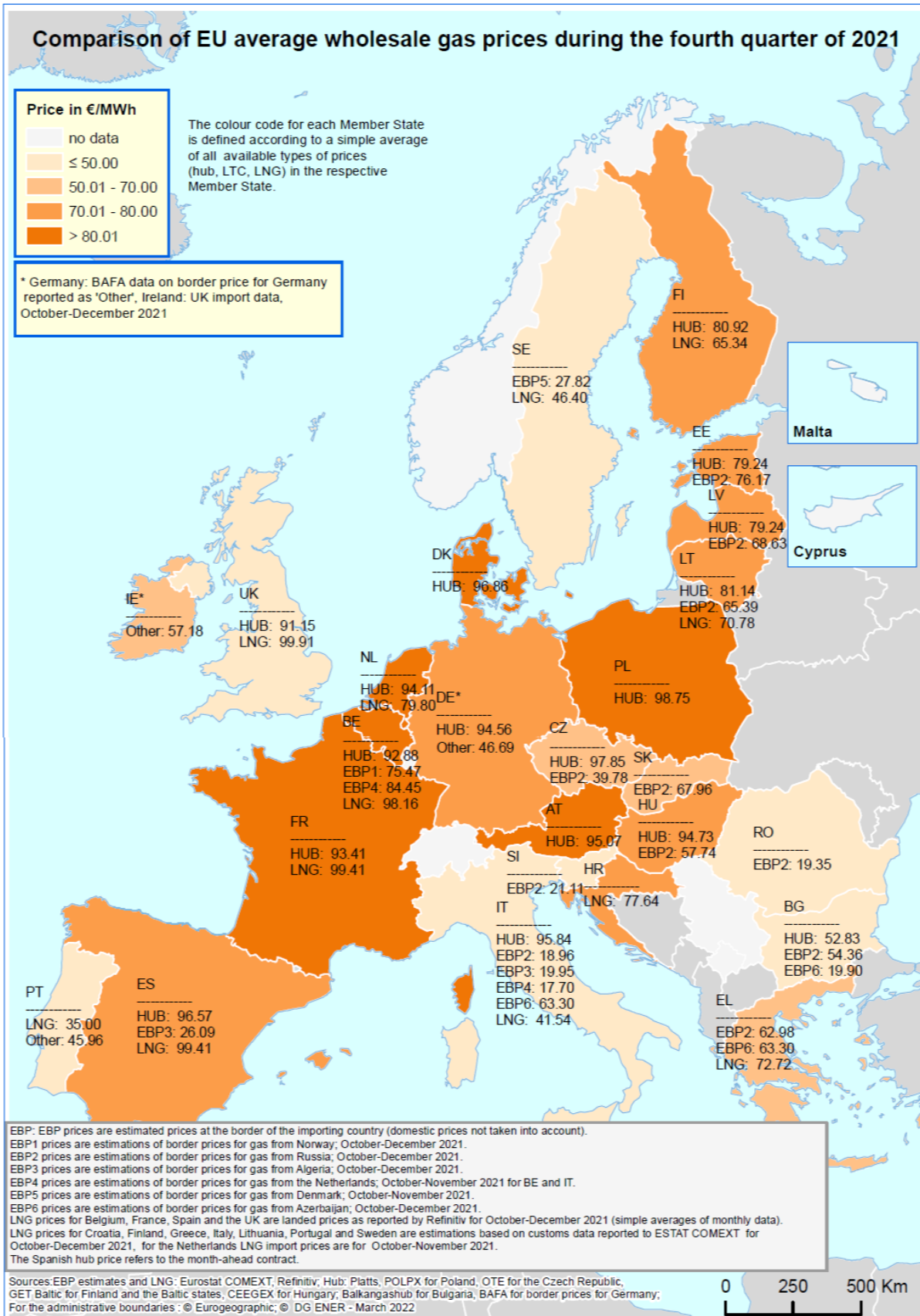
Source: Eurostat COMEXT and European Commission estimations, BAFA, S&P Global Platts

*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 in the fourth quarter of 2021.

Map 1 - Comparison of EU wholesale gas prices in the fourth 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.

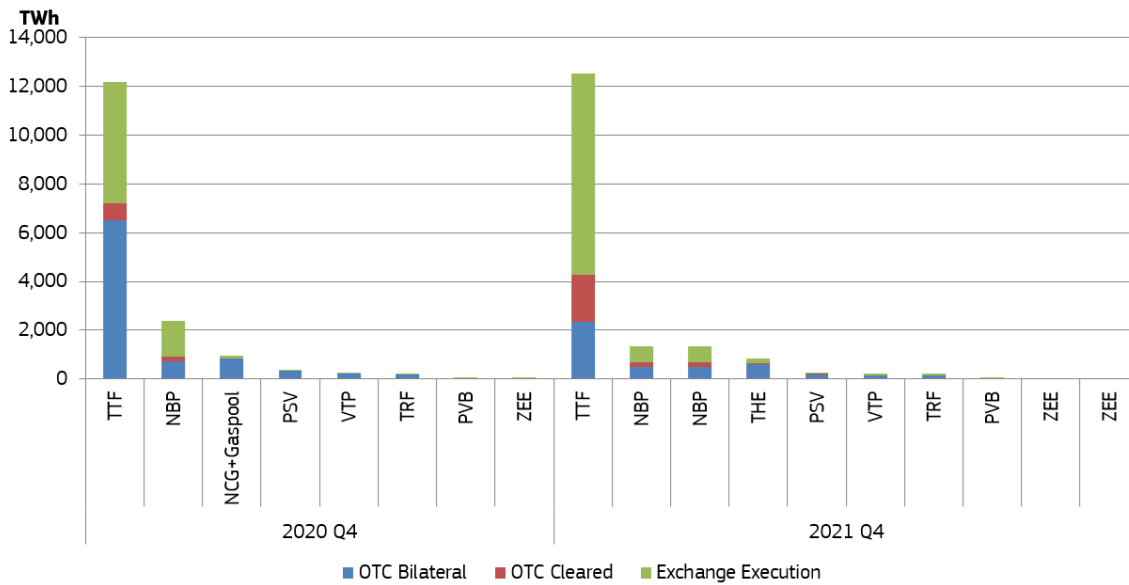
2.3.4. Gas trade on the EU hubs

- As Figure 38 shows, liquidity fell by 6% year-on-year on the main European gas hubs in the fourth quarter of 2021, after rising by 27% in Q3 2021 and falling by 4% year-on-year in Q2 2021. The total traded volume in Q4 2021 amounted to around 15 436 TWh (equivalent to around 1 432 bcm and in monetary terms representing €969 billion²⁹). The Q4 2021 traded volume was around 14 times more than the gas consumption in the seven Member States³⁰ covered by the analysis in October-December 2021. Comparing to the EU as a whole, traded volume in Q4 2021 represents 11 times the total EU-27 gas consumption in this period.
- The year-on-year change in traded volumes in Q4 2021 showed mixed picture among the observed trading hubs in Europe, but volumes mostly fall. Volumes on the largest and most liquid TTF hub rose slightly, by 3% year-on-year. Looking at the new German hub, THE (after the merger took place on 1 October 2021 between the two NGC and Gaspool hubs), traded volumes fell by 13% year-on-year. At the same time, traded volumes on the Italian PSV were steeply down, by 26%, whereas traded volumes on the VTP hub in Austria decreased by 14%. Traded volumes on the French TRF were down by 5%, whereas on the Belgian Zeebrugge the steep fall in volumes continued in Q4 2021, amounting to 63% year-one-year. As exception, volumes on the Spanish PVB turned up sharply, by 45% year-on-year in Q4 2021. Traded volumes on British NBP hub, which was still the second biggest hub on the broader European market, continued to fall, by 44% compared to Q4 2020.
- As the year-on-year change in traded volumes on the TTF hub rose by 3% in Q4 2021, while traded volumes on overall observed European markets fell by 6%, the share of TTF in the total European gas trade kept on increasing in Q4 2021 and amounted to 81%, whereas a year before it was only 74%. If looking at only the EU countries, its share was even bigger, 89%. 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 NBP traded volume in Q4 2021 fell by 44% compared to the same period of 2020, and the share of NBP in Q4 2021 fell below 9% in the total European observed trade, down from 15% in Q4 2020.
- Other markets had lower shares: the German THE had a share of 5.5%, while the Italian PSV had a lower share, 1.6%, followed by VTP and TRF (both 1.4%), while the Spanish PVB and the Belgian Zeebrugge had only minor shares of respectively 0.3% and 0.1% in the European gas trade in Q4 2021.
- Net gas import of gas was only slightly up by 2% in the EU in Q4 2021, however, LNG imports soared by 33% year-on-year, and consumption of gas was only up by less than 1% Amid slightly increasing imports and consumption, though significant LNG sendouts could have been supportive, traded volumes were down on the most liquid European hubs. Shifting trade from the OTC market to exchange-executed contracts was helped by rapidly increasing prices as the number of traders being able to effectively trade decreased, owing to elevated default risks for smaller traders on the OTC market. Exchange-executed trade is close by in term, helping smaller traders to engage in this market, in contrast to the OTC, where collaterals nowadays cover a decreasing number of contract and margin calls might be invoked for insurance reasons, also pushing out smaller participants from the OTC market.
- The share of exchange executed contracts on the Dutch TTF hub was 66% in Q4 2021, which was the highest among the observed countries, and was up by a staggering 25 percentage points compared to Q4 2020. For the first time, the share of exchange executed contracts on the TTF, 66%, surpassed than on the NBP hub in the UK (50%), where the share of exchange trade fell from 62% in Q4 2020, going against the general trend of increasing exchange execution share. On the Spanish PVB the share of exchange executed contracts amounted to 44% in Q4 2021, practically the same as a year before. On the French TRF the share of exchange executed contracts reached 32% in Q4 2021 (up by 9 percentage points). On the VTP hub in Austria this share more than doubled, up to 34% from 15% in the same period of 2020, while on the THE German hub it amounted to 24% (up from 12% a year before). On Zeebrugge, the share of exchange-executed contracts was lower, only 15% (though up from 5% in Q4 2020), whereas it was the lowest on the Italian PSV, amounting to 9% in Q4 2021 (up from barely 1% in Q4 2020).

²⁹ Assuming that all trade was carried out on the quarterly average spot price of the TTF hub. As spot prices significantly rose in Q4 2021 and developed a considerable premium over forward contracts, this amount might overestimate the monetised traded value

³⁰ Netherlands, Germany, France, Italy, Belgium, Austria and Spain. 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.

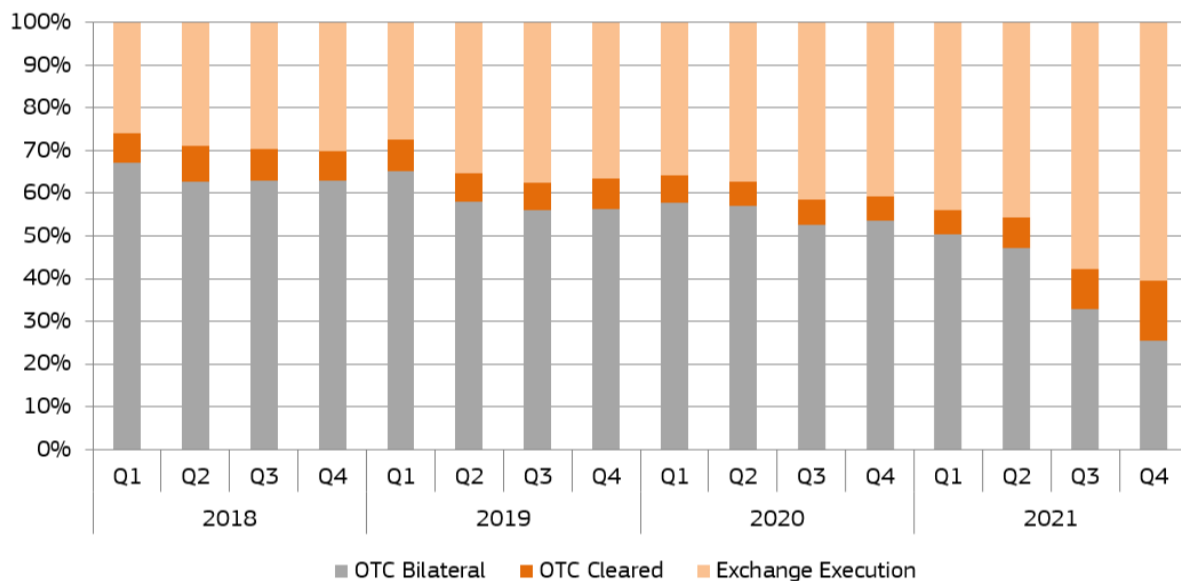
Figure 39 - Traded volumes on the main European gas hubs in the fourth quarters of 2020 and 2021



The chart covers the following trading hubs: Netherlands: TTF (Title Transfer Facility); Germany: THE (Trading Hub Europe); France: TRF (Trading Region France); Italy: PSV (Punto di Scambio Virtuale); Spain: PVB (Virtual Balancing Point); Austria: Virtual Trading Point (VTP); Belgium: Zeebrugge beach; UK: NBP (National Balancing Point)
 Source: Trayport Euro Commodities Market Dynamics Report

- On the European hubs as whole, in Q4 2021 26% of the total trade was OTC bilateral, 14% was OTC cleared, whereas the share of exchange-executed contracts reached 60%, the highest ever. The share of exchange-executed contracts increased by almost 20 percentage points year-on-year in Q4 2021, whereas the share of OTC bilateral fell by 27 percentage points, and that of OTC cleared went up by more than 8 percentage points.
- Amid the general decrease in traded volumes (6% in Q4 2021 year-on-year), exchange executed volumes managed increase measurably, by growing 40% year-on-year on the observed European markets. In the same period, the total OTC traded volume (bilateral and cleared together) fell by 37%. This underlines the increasing importance of exchange-executed contracts in the gas trade on the major European hubs.

Figure 40 - Share of traded volumes on the main European gas hubs



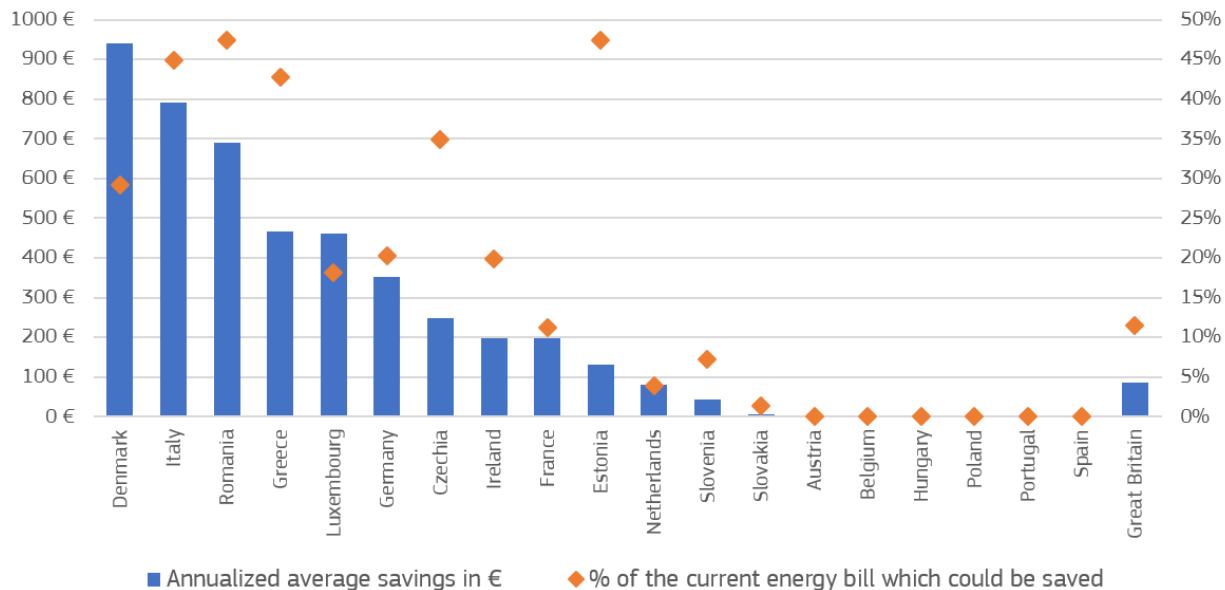
The chart covers the following trading hubs: Netherlands: TTF (Title Transfer Facility); Germany: THE (Trading Hub Europe); France: PEG (Point d'Echange Gaz); Italy: PSV (Punto di Scambio Virtuale); Spain: PVB (Virtual Balancing Point); Belgium: Zeebrugge beach, Austria: Virtual Trading Point (VTP); 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 estimated annualised average savings in euro and percent of the current energy bill available to typical households who switched away from their local by-default contract to the cheapest offer available in December 2021. Prices in capital cities were used as a proxy to assess prices at the national level.
- In December 2021 in absolute terms, Danish households could have the highest annualised savings (€939 or 29%), had they switched from their incumbent utility to the most competitive offer available. On the other hand, households in Slovakia could have the lowest annualised savings, amounting to 1.3% or €7 if they chose the most competitive offer.

Figure 41 – Annualised gas bill saving potential in December 2021 in the EU Member States and the United Kingdom



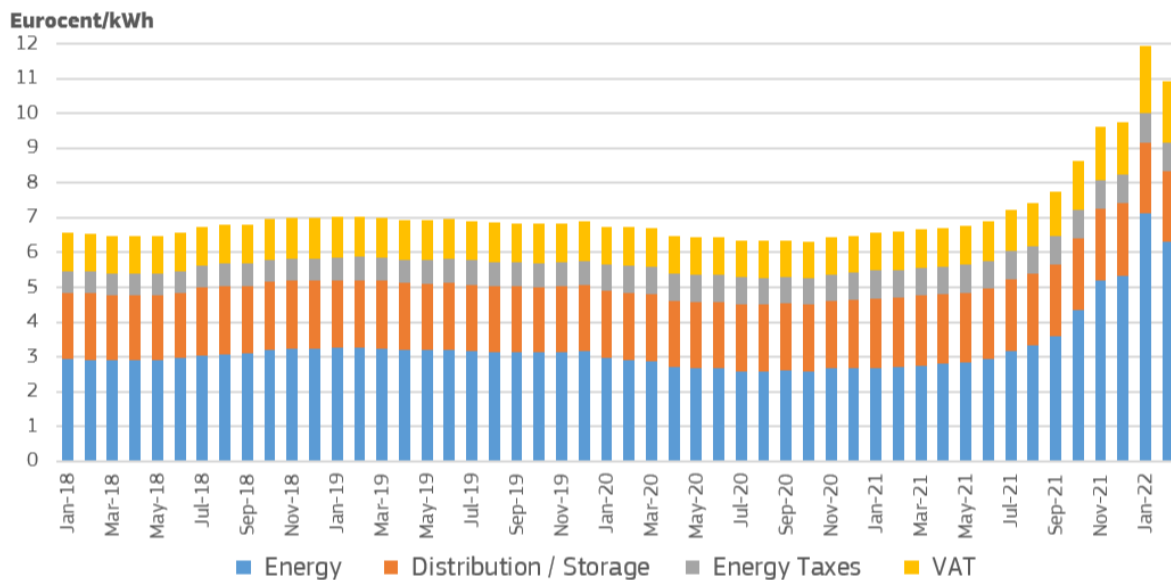
Source: VaasaETT data collection. Saving potential is reported to be zero for Spain and Hungary, for Bulgaria, Croatia, Finland, Latvia, Lithuania, Sweden, Cyprus and Malta no data are available

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 first half of 2021) and Harmonised Consumer Price Indices (HICP) for both the household prices and industrial consumers.
- For household consumers, the estimated average retail price in Q4 2021 in the EU (including all taxes) showed an increase of 9.1% in year-on-year comparison, and compared to the previous quarter, Q3 2021, the average price went up by 11.8%. In the most typical consumption Band, D2, in the fourth quarter of 2021 the estimated average price (including all taxes) was 7.1 Eurocents/kWh, up from 6.9 Eurocents/kWh in the previous quarter and from 7.0 Eurocents/kWh in Q4 2020. (See the estimated household prices on Map 2). It is important to recall that substantial retail gas price increases occurred in the fourth quarter of 2021, but all wholesale market price increases probably still not appeared in the final retail prices, or the latest available Eurostat data, corrected with the HICP index, could still not capture the retail price change in its entirety.
- In the fourth 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 Romania, Latvia and Lithuania (3.7 Eurocent/kWh, all of the three), whereas the highest prices could be measured in Denmark (15 Eurocent/kWh), Sweden (12.4 Eurocents/kWh) and the Netherlands (9.6 Eurocent/kWh). The price differential ratio between the cheapest and the most expensive Member State across the EU rose slightly, to 4.1 (in the previous quarter it was 3.9), and compared with Q4 2020 it also increased (when it was only 3.7).
- Figure 41 and Figure 42 show the monthly evolution of the EU average residential end-user retail gas prices over the last few years, the breakdown of prices paid by typical households in the European capitals in February 2022, and the change in percentages compared to February 2021. In February 2022, retail gas prices in EU capitals showed an estimated increase of 66%, year-on-year. Over the recent period, as higher wholesale gas prices measurably appeared in the retail contracts, the share of the energy component showed a significant increase. On average, 58% of the retail price could be assigned to the energy component in February 2022, while the rest covered distribution/storage costs (18%), energy taxes (8%) and VAT (16%). The share of the energy component was generally increasing, in November-December 2021 it reached 54% and in January 2022 it rose to close to 60%.

- There were significant differences in February 2022 in the share of energy costs, distribution costs and taxes within the total prices across Member States. The share of energy costs ranged from 33% (Stockholm) and 43% (Lisbon) to 82% (Warsaw) and 79% (Tallinn). The share of distribution/storage costs ranged from 7% (Amsterdam) and 8% (Brussels and Berlin) to 36% (Stockholm) and 34% (Bratislava). The share of energy taxes ranged from 1% (Brussels) and 2% (Athens and Madrid) to 22% (Amsterdam) and 18% (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.

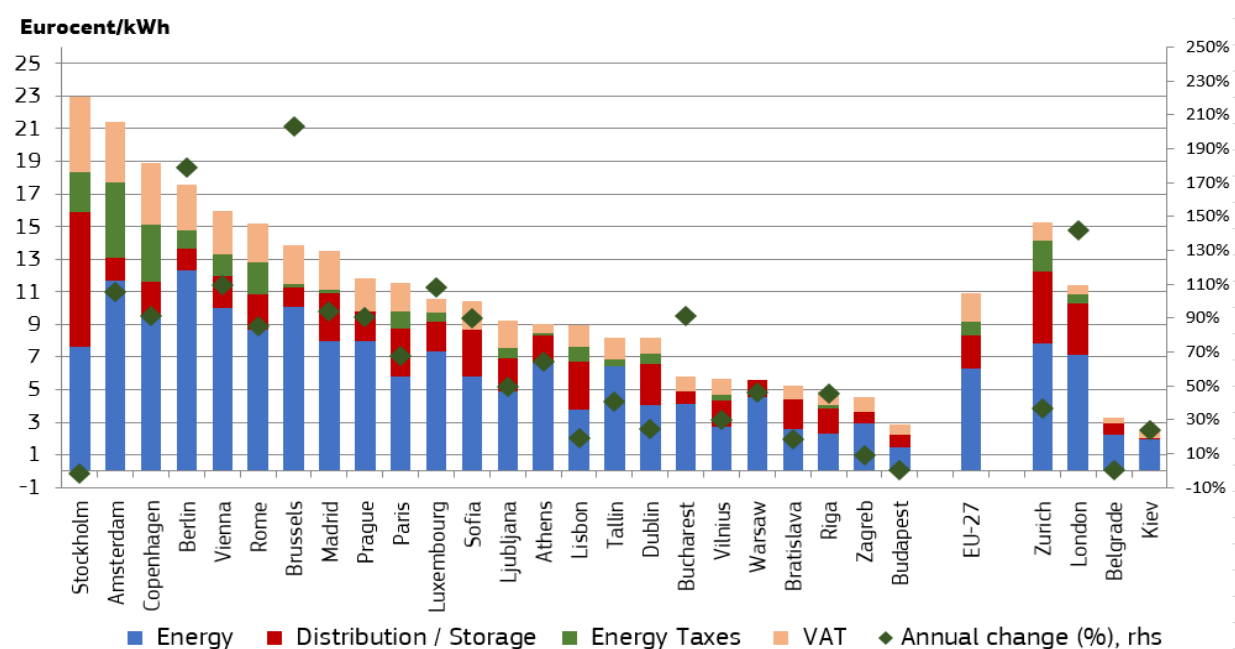
Figure 42 – Monthly average gas price in the EU, paid by typical household customers



Source: VaasaETT

- Figure 42 also shows that even the energy component is very variable in absolute terms: in February 2022, it was 8.4 times higher in Berlin than in Budapest. There were also considerable differences across the Member States in the relative share of network costs and taxes. The ratio of highest and lowest network components across the EU was 11.7 (between Zagreb and Stockholm, in Tallinn no data were available on this cost element). The highest-lowest tax component ratio (taking energy taxes and VAT together), not counting Warsaw, where energy taxes and VAT rates has been reported as 0, was 13.6 (Budapest and Amsterdam) in the same period.
- With the exception of two capital cities out of the observed 24, prices were higher in February 2022, compared to the same month of the previous year. Prices decreased only in Stockholm (2%), interestingly driven by the decrease in energy costs. Prices went up by the most in Brussels (203%), Berlin (178%), Vienna (109%), Luxembourg (108%) and Amsterdam (105%), practically driven by the increase of energy costs, whereas in some cases network costs or energy taxes slightly decreased. It seems that recent price increases on wholesale gas markets are already measurable in the final retail household prices in most of the EU capital cities. In February 2022, Budapest remained the cheapest capital in the EU in terms of gas prices for household consumers, followed by Zagreb and Riga, whereas Stockholm, Amsterdam and Copenhagen were the three most expensive capital cities.

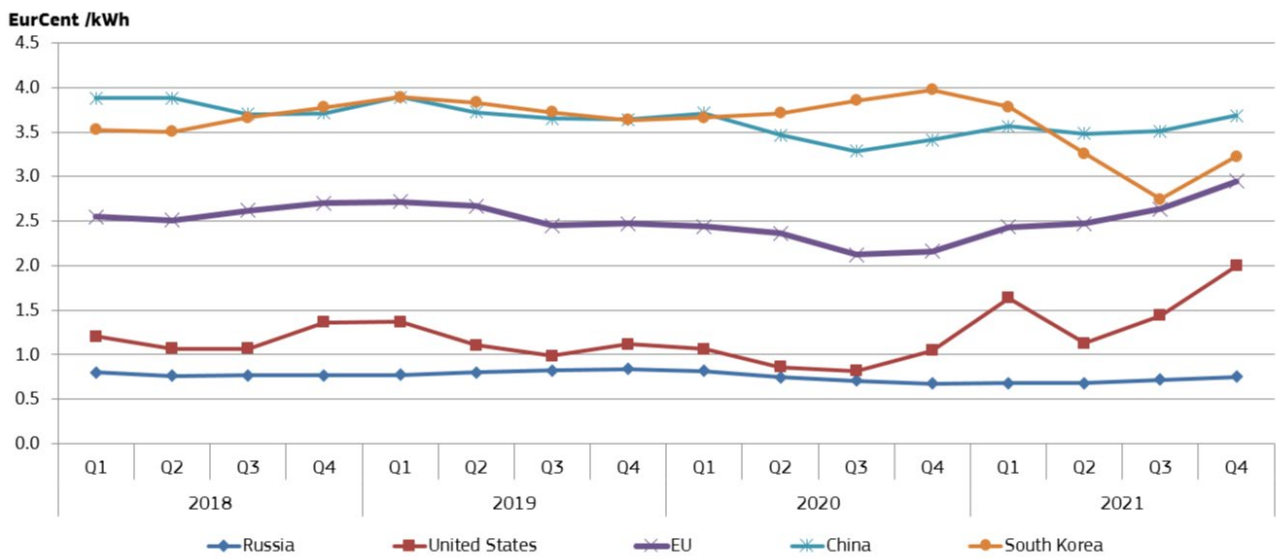
Figure 43 - Breakdown of gas price paid by typical household customers in European capitals and annual change in prices, February 2022



Source: VaasaETT

- Retail gas prices for industrial customers rose measurably, by 36% in Q4 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 2.95 Eurocent/kWh, up by 11.8% compared to Q3 2021 Eurocent/kWh. (See the estimated industrial prices on Map 3.) In all of the 24 observed countries (data were not available for Cyprus, Finland and Malta) price increases could be observed. It seems that price hikes on wholesale gas markets already appeared in the retail prices for industrial customers in Q4 2021, having an average consumption. Price increases could also be observed for industrial customers having larger annual gas consumption (in both Band I5 and Band I6 bands increases of 55-70% could be observed in Q4 2021 year-on-year). Significant price increases for energy intensive industries meant bigger production costs, leading to decrease in production and/or increases in the final product prices.
- It must be noted that these computed quarterly prices are based on Eurostat data (referring to the first half of 2021), corrected by HICP figures, implying that by the time the next half-yearly price data will be available, numbers might show different trends.
- In the fourth quarter of 2021, the lowest estimated industrial price in consumption Band I4 could be observed in Czechia (2.3 Eurocent/kWh), Romania and Latvia (both 2.4 Eurocent/kWh). The highest prices could be observed in Estonia (5.6 Eurocent/kWh), Denmark (4.9 Eurocent/kWh), Sweden (4.1 Eurocent/kWh). In Q4 2021, the price ratio of the cheapest and the most expensive country in the EU was 2.4.
- Figure 43 shows the evolution of industrial retail gas prices in the EU, compared with some important trade partners of the European economy. In the fourth quarter of 2021, retail gas prices for industrial customers in China and South Korea had a measurable premium to the EU average (as they respectively were higher by 45% and 27%). On the other hand, retail gas prices in the United States were 22% lower than in the EU, and gas prices in Russia had a discount of 70% to the EU average. Compared to Q4 2020, the biggest increase in industrial gas retail prices could be observed in the United States (91%). Prices were up in Russia (12%) and in China (8%) and whereas they fell in Korea (19%). In the EU retail industrial prices were up by more than 36%.

Figure 44 - 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 fourth quarter of 2021.

Map 2 - Retail gas price estimates for households in the EU – Fourth quarter of 2021



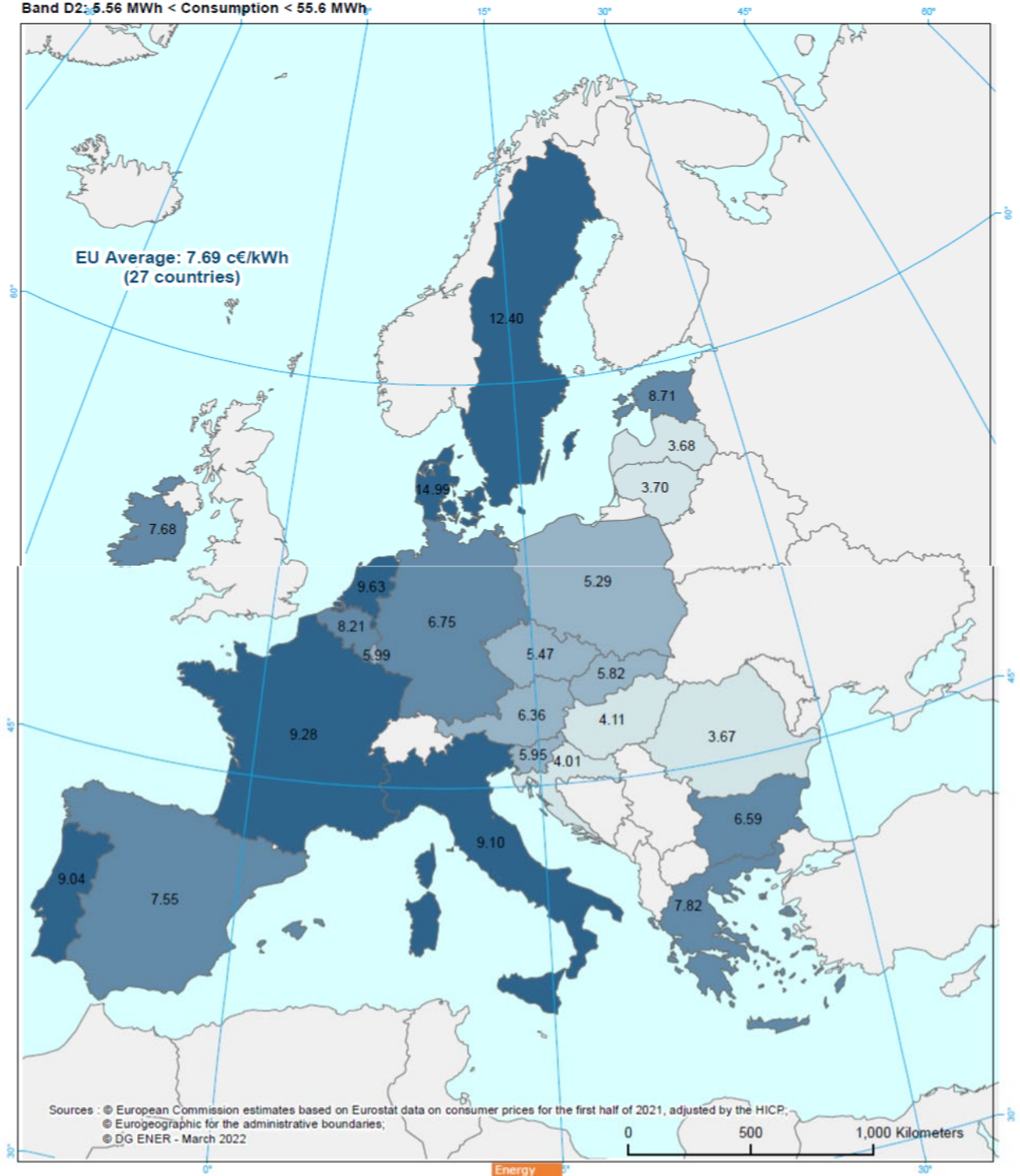
Prices in Eurocents/kWh

- no data
- ≤ 5.00
- 5.01 - 6.50
- 6.51 - 9.00
- > 9.01

GAS PRICES FOR DOMESTIC CONSUMERS Estimates for the fourth quarter of 2021

Including all taxes and levies

Band D2: 5.56 MWh < Consumption < 55.6 MWh



Source: Eurostat

Map 3 - Retail gas price estimates for industrial consumers in the EU – Fourth quarter of 2021



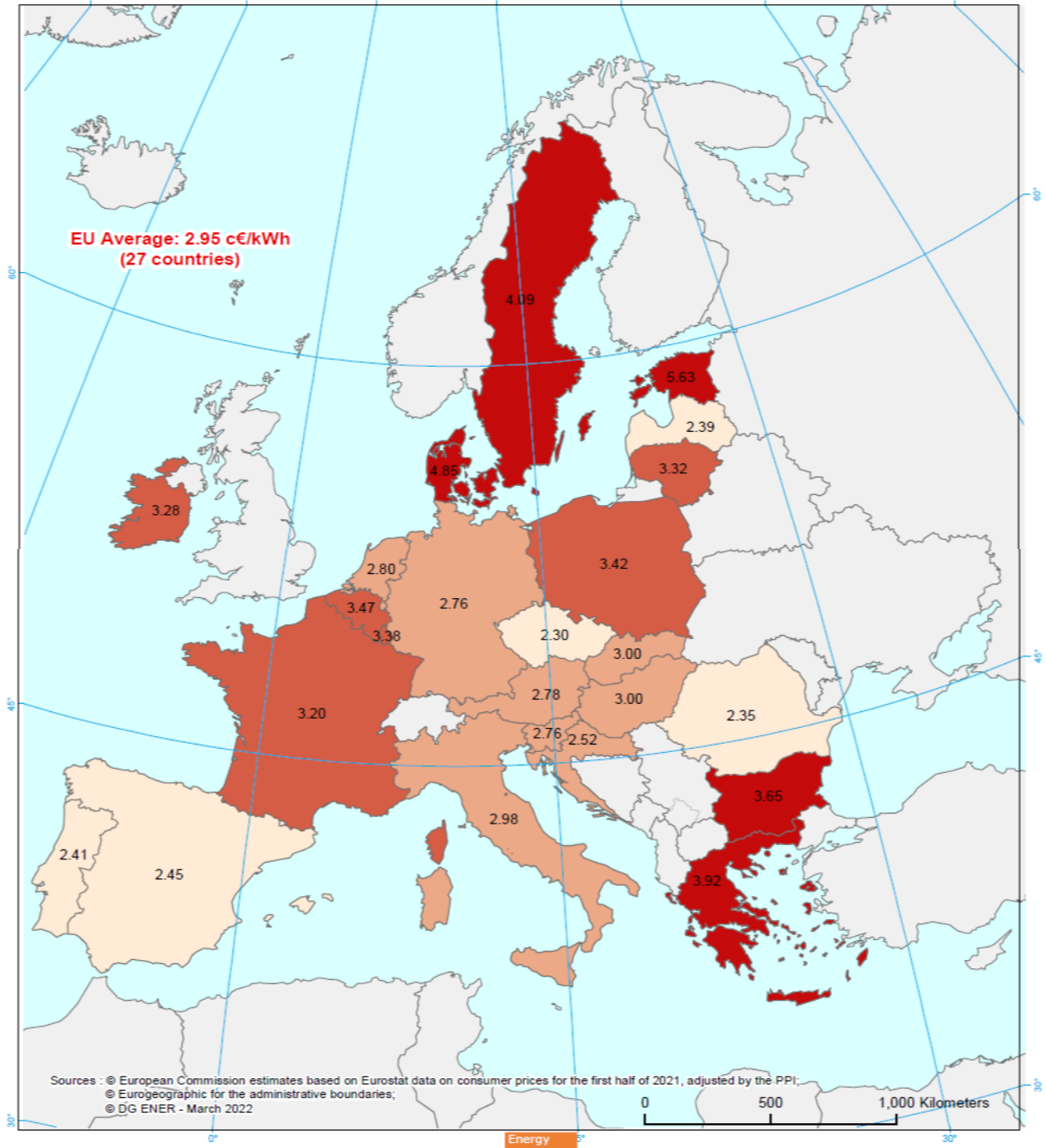
Prices in Eurocents/KWh

- no data
- ≤ 2.50
- 2.51 - 3.00
- 3.01 - 3.50
- > 3.51

GAS PRICES FOR INDUSTRIAL CONSUMERS Estimates for the fourth quarter of 2021

Excluding VAT (value added tax) and other recoverable taxes

Band I4: 27 780 MWh < Consumption < 277 800 MWh



Source: Eurostat

4. Appendix – charts providing further details on market developments³¹

Figure 45 – Annual gas production, imports from different sources, changes in storages and consumption in the EU

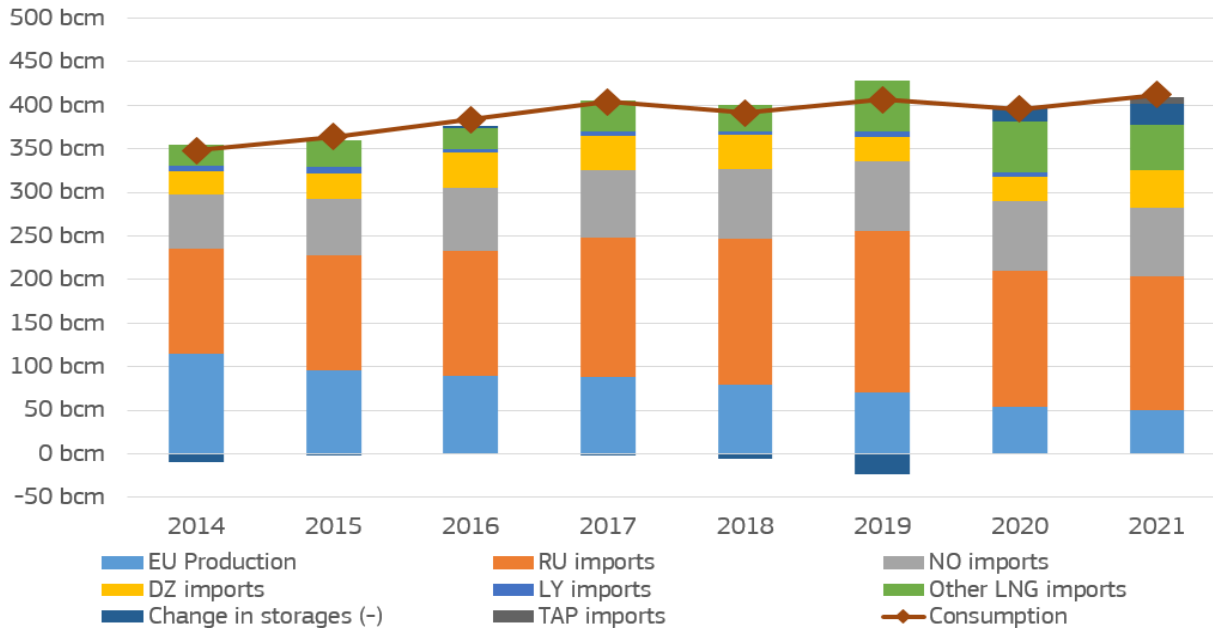
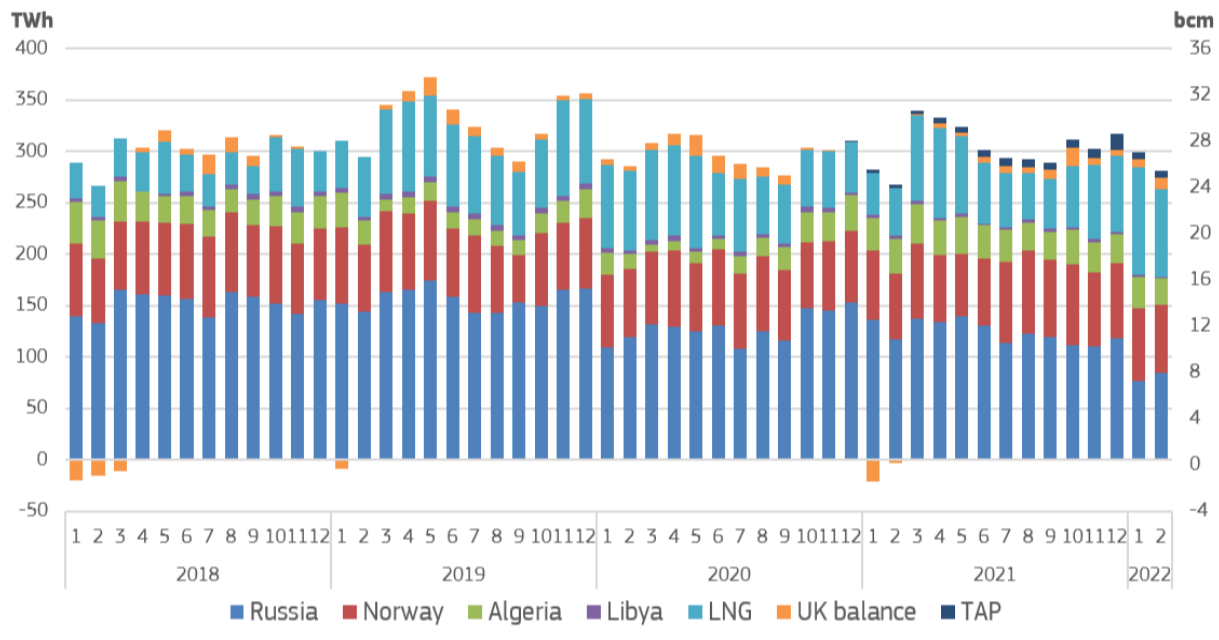
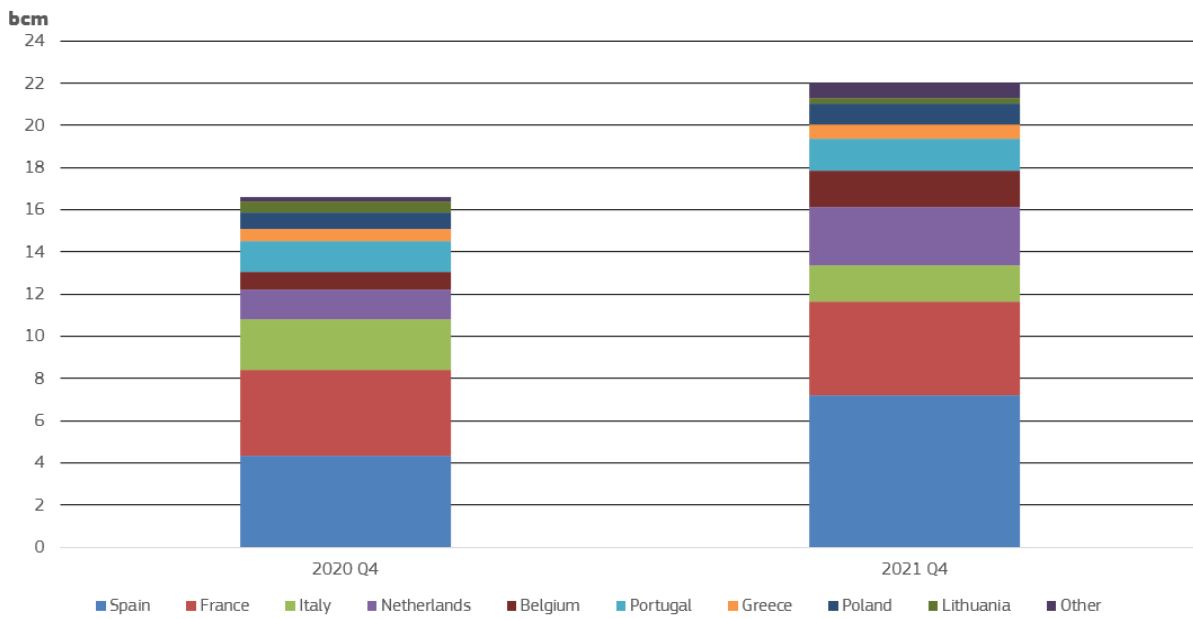


Figure 46 – Monthly evolution of gas imports from extra-EU sources



³¹ These charts provide additional information on the main market developments, without textual comments and/or further detailed analysis

Figure 47 – LNG imports in the EU Member States, fourth quarters of 2020 and 2021



Source: Refinitiv

Figure 48 – LNG imports in the EU Member States in 2021, from different sources

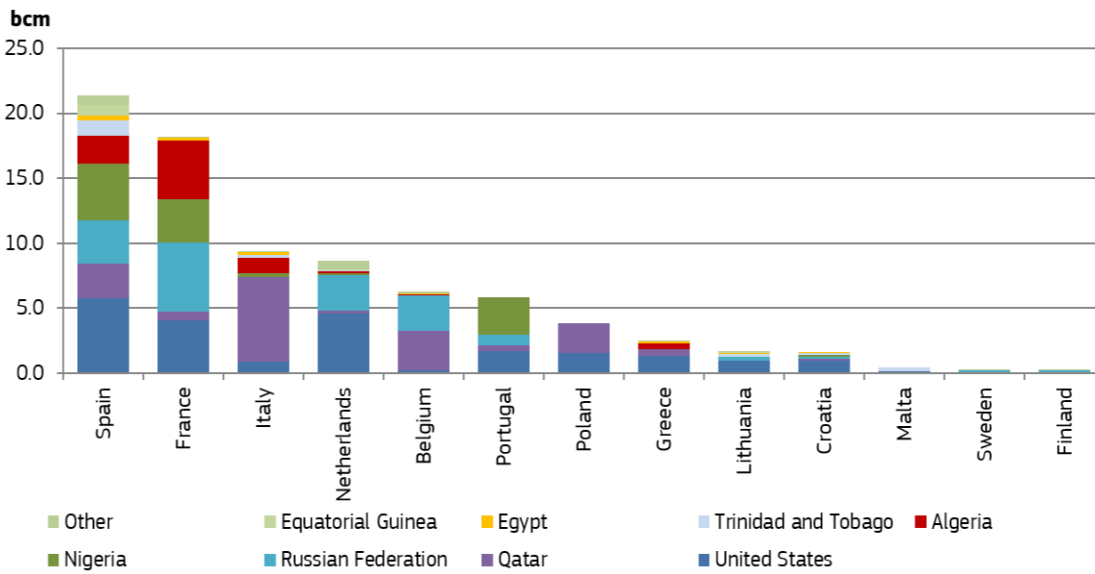


Figure 49 – LNG import from the main suppliers to the EU in the fourth quarters of 2020 and 2021

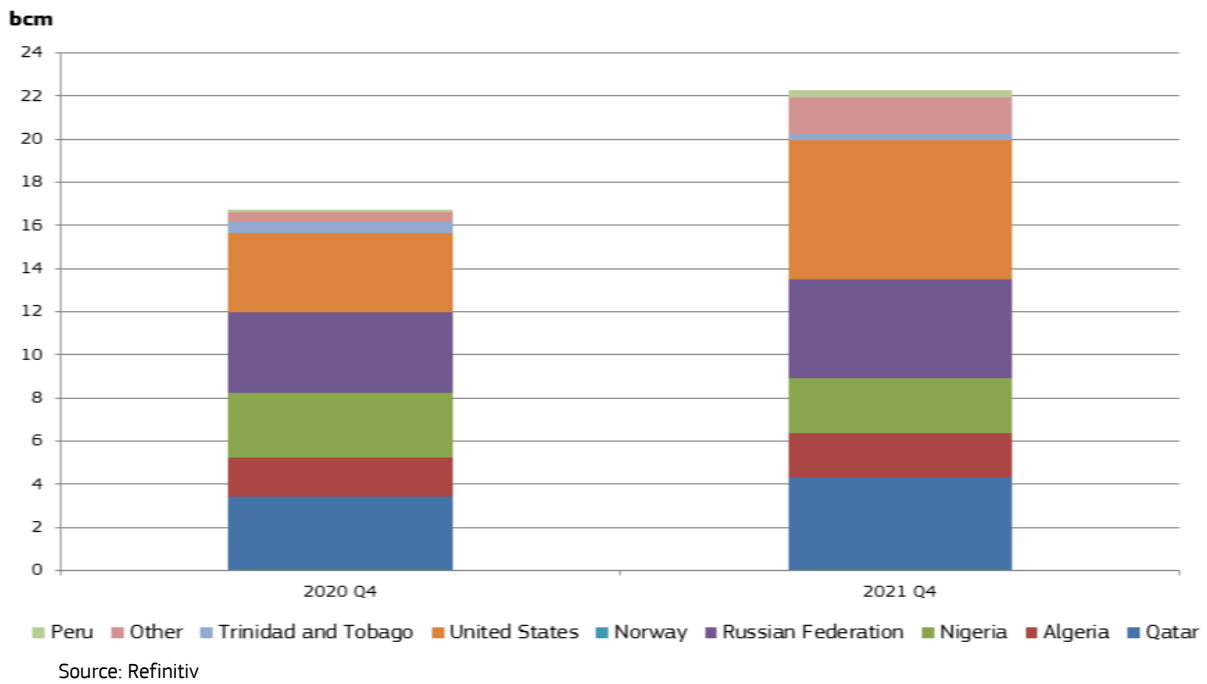


Figure 50 - LNG imports in the main consumer markets in January-December 2020 and 2021

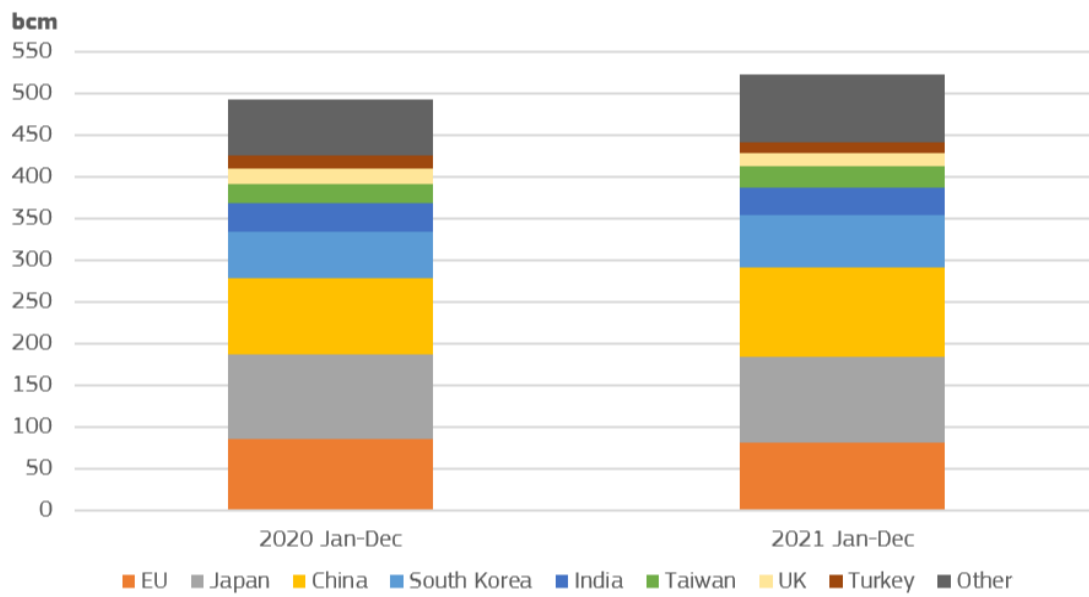
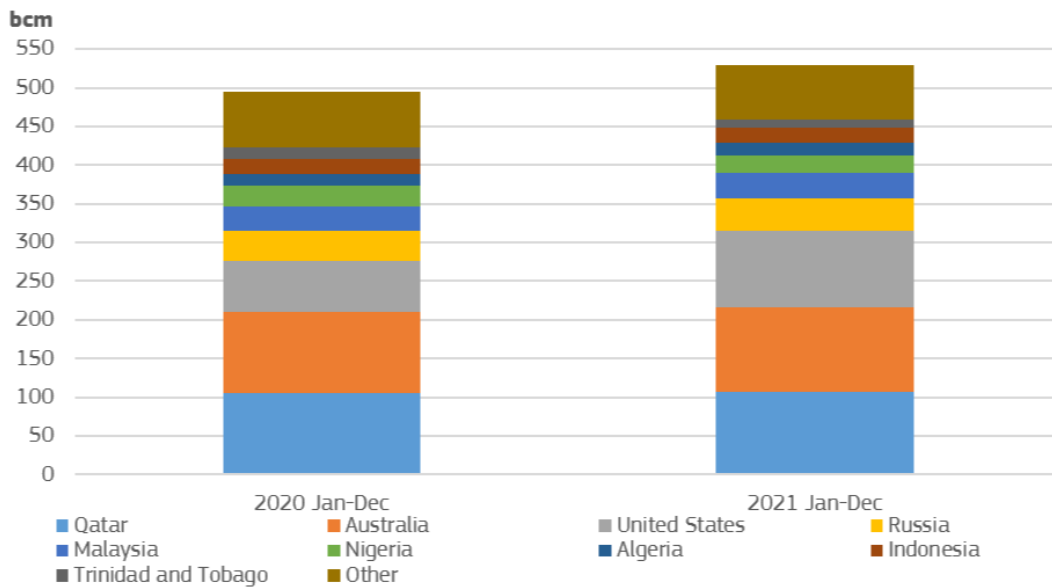
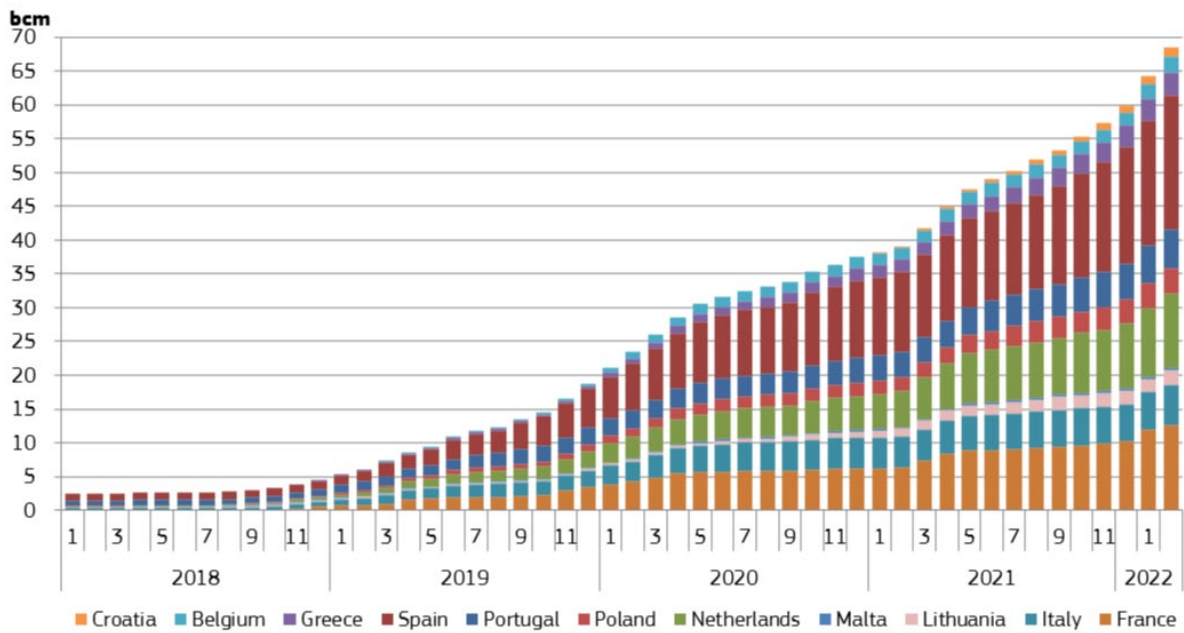


Figure 51 - LNG exports from the main producers in January-December 2020 and 2021



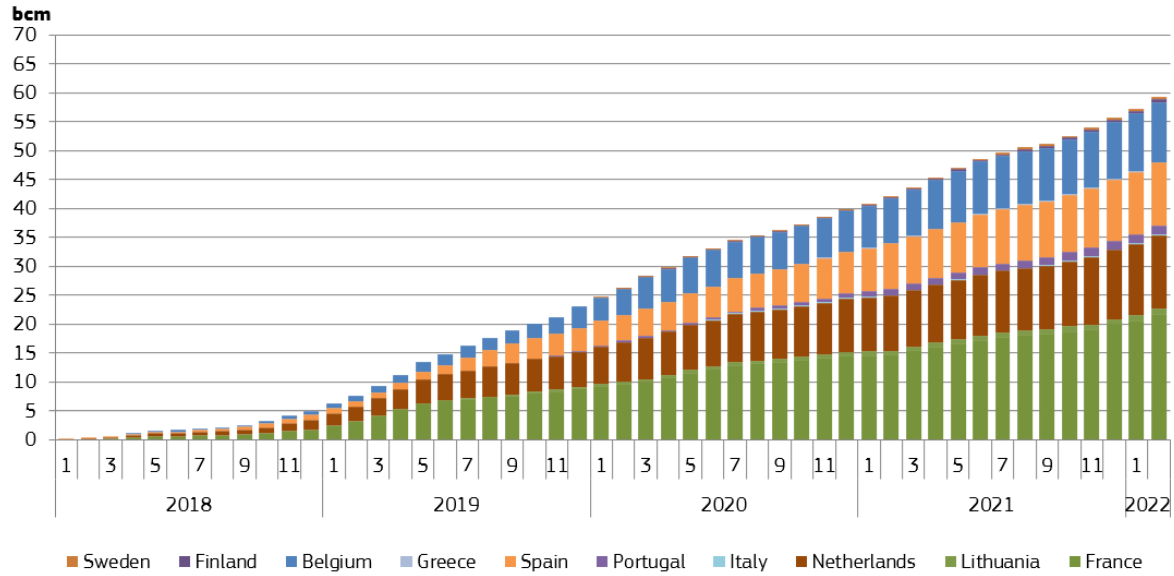
Source: Refinitiv

Figure 52 - Cumulative monthly LNG imports from the US in the EU



Source: Commission calculations based on tanker movements reported by Refinitiv

Figure 53 – Cumulative monthly LNG imports from Russia in the EU



Source: Commission calculations based on tanker movements reported by Refinitiv

5. Glossary

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

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

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

Contango: A situation of contango arises 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.

