

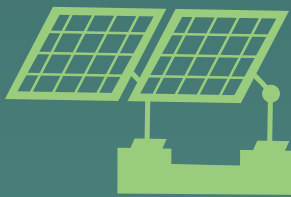


European  
Commission

# Quarterly report

## On European electricity markets

With focus on developments in annual  
wholesale prices



Market Observatory for Energy  
DG Energy

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## HIGHLIGHTS OF THE REPORT

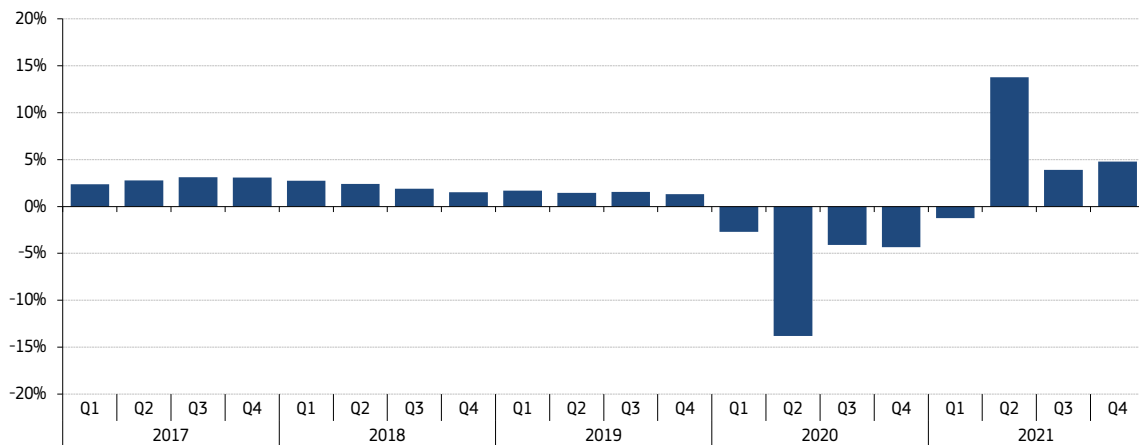
- **The fourth quarter of 2021 brought electricity consumption in Europe back to pre-pandemic levels**, despite the mild weather. **In 2021, consumption across the EU was equivalent to 2019 levels (pre-COVID) and increased by 5% compared to 2020 consumption**, as a result of the recovery of industrial and labour activity.
- **Wholesale electricity prices in European markets broke several records high during 2021, from the second half of the year.** The post-pandemic economic recovery significantly increased global demand for commodities, having a direct impact on the price of gas in Europe. Ireland has the highest baseload electricity prices (136 €/MWh on average) in 2021, followed by the UK, Malta, Italy, and Greece.
- **Prices registered a sharp increase in Q4 2021, due to the tightness in European gas markets fuelled by increasing global LNG demand, low levels of storage and geopolitical tensions with Europe's main gas supplier.** The sustained rise in this commodity drove record highs of electricity prices in European markets. In Q4 2021, the largest year-on-year price increases in the European Union were registered in France, Spain and Portugal (+425%). The European Power Benchmark averaged 194 €/MWh in Q4 2021, 400% higher on yearly basis. Compared to Q3 2021, the quarterly average price rose by 85%. Following the peak in December, the rising trend in prices softened in the following months thanks to improved gas supplies to the region. However, the Russian invasion of Ukraine, the associated sanctions, and the market fears of supply disruption, triggered unprecedented record highs in European markets in early March.
- Increased levels of gas-to coal and gas-to lignite switching were registered in markets with spare installed capacity. The rise of gas prices reversed the coal-to gas switching observed in 2020, boosting coal generation gains despite increasing carbon prices in 2021. When compared to the atypical year of 2020, coal and lignite generation rose by 21% (+68 TWh), whereas less CO<sub>2</sub>-intensive gas generation fell slightly at 3% (-16 TWh). Yet, the **share of renewables still managed to reach 38%, outplaying fossil fuels (35%) in 2021.** This was the result of an increase of 12% in solar generation (+17 TWh), 6% of biomass (+8 TWh) and 2% of offshore wind (+1 TWh) on a yearly basis, despite onshore wind generation decreasing by 3% (-11 TWh). Ultimately, renewable generation improved its output by 1% (+10 TWh) year-on-year while nuclear generation increased by 7% (+47 TWh). **Compared to pre-pandemic levels (2019), renewable generation increased its output by 10% (+90 TWh)**, at the expense of a decrease of 6% (-58 TWh) of fossil fuel and 4% (-32 TWh) of nuclear generation. When compared with 2019, annual gas generation fell by 6% (-34 TWh), while coal and lignite drop by 4% (-19 TWh). In absolute terms, renewables have been delivering in the past years, which shows the evolution of the power system in Europe.
- **A new record of installed renewable capacity was reached in the EU in 2021, as 37 GW of solar and wind capacity were added to the system - resulting in an increase of 20% on a yearly basis.** This highlights that the economic recovery has supported renewable expansion, although rising price of raw materials could increase the costs of renewable energy products in the near term.
- **Carbon prices registered significant price gains throughout Q4 2021, further persisting into 2022.** Several new records were established in quick succession, rising to 88 €/tCO<sub>2</sub> in early December and culminating at 96 €/tCO<sub>2</sub> at the beginning of February, due to rising gas prices, high power sector emissions and expectations of an accelerated green transition.
- Based on preliminary estimates, **the 2021 carbon footprint of the EU power sector fell by 6% compared to pre-pandemic levels (2019). However, emissions rose by 9% compared to the atypical year of 2020.** Despite high carbon prices, high commodity prices, especially gas, triggered a wider use of coal-fired generation at the detriment of gas-fired generation during 2021.
- **High wholesale electricity prices have resulted in rising consumer bills for households, impacting the industry sector as well.** Retail electricity prices for household costumers in EU capital cities were up by 30% in February 2022, compared with the same month in 2021. Most impacted countries were Belgium (+101%), the Netherlands (+95%), Italy (+70%), and Spain (+55%). On average, wholesale electricity costs already represent 57% of final household retail prices in Europe. Retail electricity prices for industrial customers also increased, up by 18% year-on-year in the fourth quarter of 2021 for mid-sized industrial consumers.
- Demand for electrically chargeable vehicles (ECVs) reached new highs in Q4 2021. **More than 532,000 new ECVs were registered in the EU in Q4 2021 (+12% year-on-year).** This is the highest quarterly figure on record, translating into a of 25% market share, slightly higher than China and almost four times more than the United States. Policy support, additional stimulus measures, and steady recovery in activity following the peak of the pandemic contributed to the impressive increase in ECV numbers. In the end, 1.7 million new ECVs were sold in the EU in 2021, an increase of 70% year-on-year.

# 1 Electricity market fundamentals

## 1.1 Demand side factors

- **Figure 1** shows the steady economic recovery from the pandemic shock since 2020. The gradual return to normal levels of economic and social activity, altogether with the massive roll-out of vaccination, had a palpable impact on the daily lives of millions of citizens and operations of most businesses. According to an estimate published by Eurostat in February 2022, seasonally adjusted GDP in the EU increased by 4.8% year-on-year between October and December 2021. Although not as impressive as the GDP growth registered during Q2 2021 (13.8%), the growth of the reference quarter is an example of the scale of the economic recovery. This quarter is the third registering positive growth since the five consecutive negative growth quarters that followed the start of the pandemic. A rise in output was observed in every Member State. Double digit increases were reported in Ireland (+10.7%), Slovenia (+10.5%), Malta (+10.2%), and Croatia (+10.0%). The lowest year-on-year growths were observed in Slovakia (+1.1%), Germany (+1.8%) and Latvia (+3.1%).

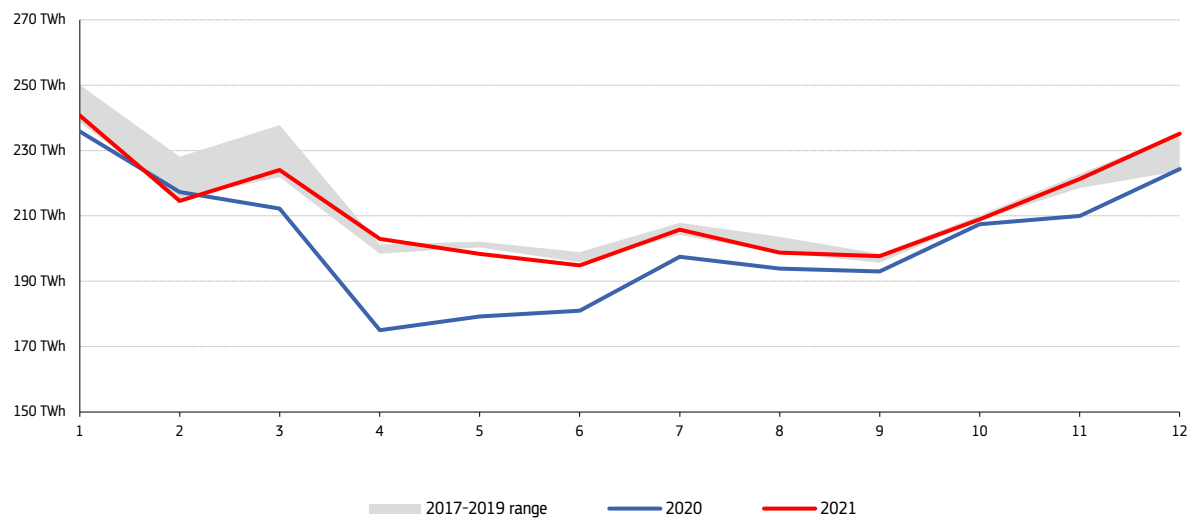
**Figure 1 – EU GDP annual change (%)**



Source: Eurostat

- According to Eurostat, the electricity consumption in the EU rose 4% above last year's levels in Q4 2021, following the steady economic recovery and the ease of COVID measures. Demand has already returned to pre-pandemic levels, positioning on the high range of the historical levels throughout the quarter. However, the EU average hides wide differences in developments in individual Member States. While twenty-three Member States saw an increase in consumption year-on-year, those range from considerable grows in Denmark (+18%), Poland (+11%), Finland (+9%) to the small increases reported in Portugal (+1%) and Czechia (+2%). Moreover, Romania and Cyprus remained practically unchanged, and the Netherlands and Spain presented a minor decrease in electricity consumption during the reference quarter (-1%).

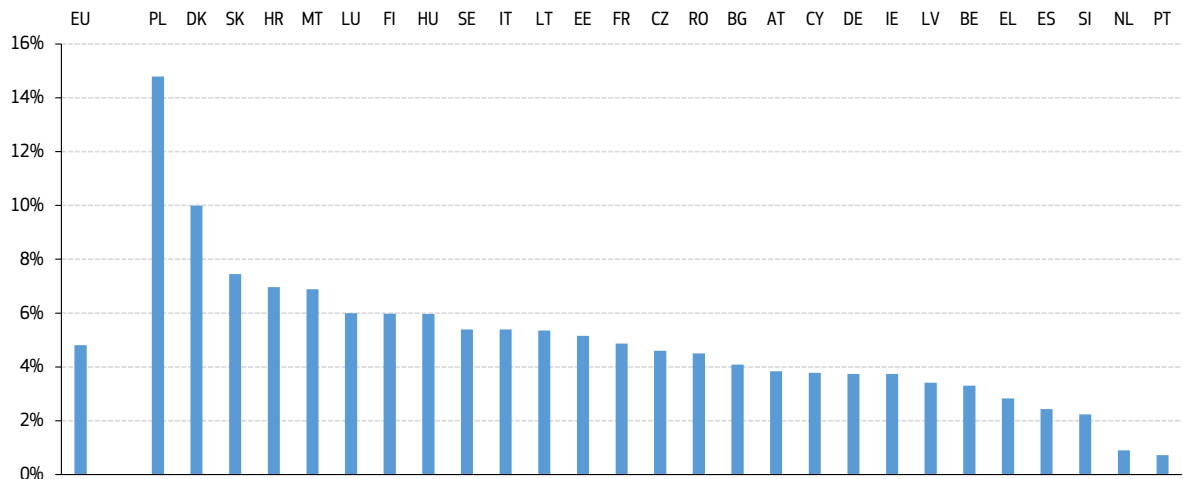
**Figure 2 – Monthly EU electricity consumption**



Source: Eurostat

**Figure 3** sums up changes in electricity consumption over the year of 2021, compared to the exceptional year of 2020. EU electricity consumption returned to pre-pandemic levels (consumption in levels in 2021 were equivalent to those registered in 2019). All Member States registered increases in consumption, the biggest of which occurred in Poland (+15%), Denmark (+10%) and Slovakia (7%). By contrast, the recovery in consumption remained weaker in Portugal (+1) and the Netherlands (+1%), in 2021. Compared with 2020, EU-wide consumption increased by 5%, on the back of the steady recovery on industrial and labour activity, despite a mild winter (see **Figure 4**).

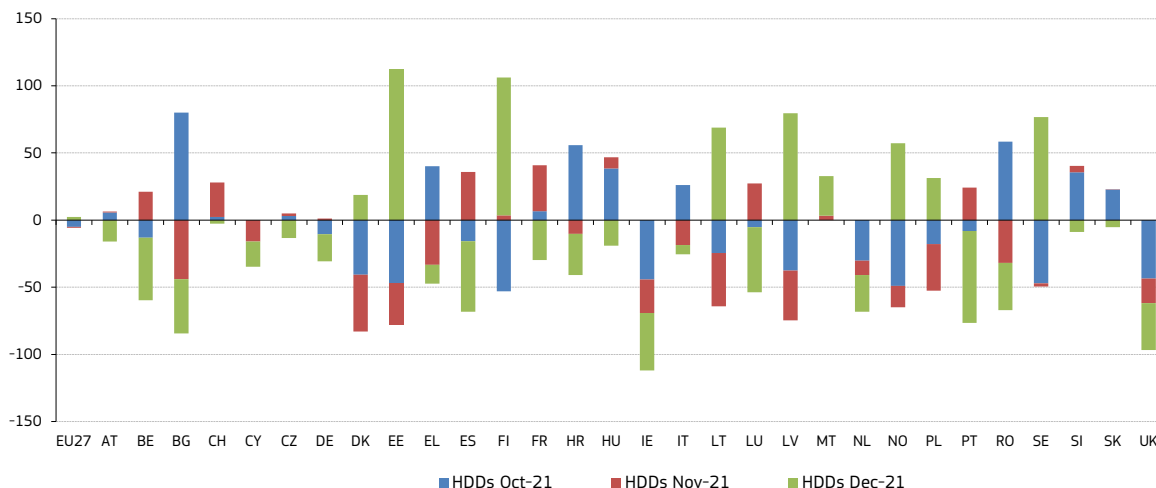
**Figure 3 – Annual changes in electricity consumption in 2021 by Member State**



Source: Eurostat

- Figure 4** illustrates the monthly deviation of actual Heating Degree Days (HDDs) from the long-term average (a period between 1978 and 2018) in Q4 2021. EU-wide, the reference quarter was slightly warmer than usual, registering only 3 HDDs below the long-term average. This means that temperatures during Q4 2021 were practically at the same level than the historical average. Some countries in southern Europe experienced a colder October. In general, November was milder than usual and Nordic countries registered relatively colder-than-usual temperatures in December. Overall, the mild weather helped keeping the energy price situation from worsening during the fourth quarter of 2021.

**Figure 4 - Deviation of actual heating days from the long-term average in October-December 2021**

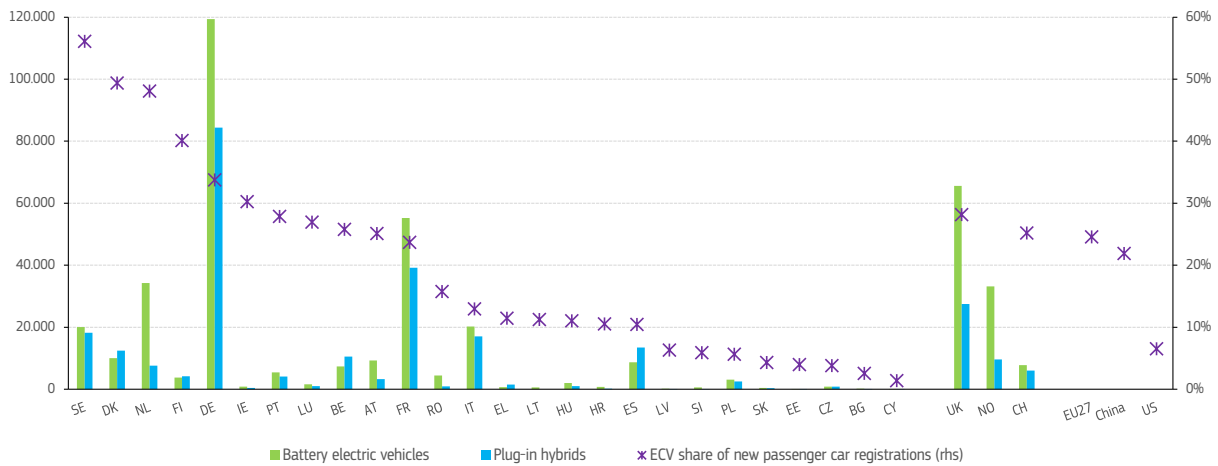


Source: JRC. The colder the weather, the higher the number of HDDs. The hotter the weather, the higher the number of CDDs

- Figure 5** shows that demand for electrically chargeable passenger vehicles (ECVs) reached new highs in Q4 2021 thanks to the support policies of some Member States aiming at incentivising ECV purchases, and their efforts on setting targets to phase out new internal combustion vehicle sales. As part of the delivery package of the Green Deal, the European Commission has proposed a 100% CO<sub>2</sub> emission reduction from new cars and vans by 2035. Germany, Sweden, Denmark, Ireland and the Netherlands plan to end the sale of new internal combustion cars by 2030. In addition, Austria, Croatia, Cyprus, Denmark, Finland, Ireland, Lithuania, Luxembourg, Netherlands, Poland, Slovenia and Sweden (among other non-EU MS) signed a declaration at the COP 26 in Glasgow, to work on the sales of zero-emissions new cars by 2040 and 2035 in leading markets.
- More than 532,000 new ECVs were registered in the EU in Q4 2021 (+12% year-on-year). This is the highest quarterly figure on record and translates into a 25% market share; slightly higher than China and almost four times more than the United States. ECV sales figures represent the third highest quarterly figure on record. The battery electric vehicles segment continued to grow (+25% year-on-year to almost 310,000) while demand for plug-in hybrid vehicles decreased slightly (-2% year-on-year to 223,000). The ECV category beat the hybrid electric vehicles (not chargeable) for the first time since Q4 2020.
- The highest ECV penetration was once again observed in Sweden, where more than half of the passenger cars sold could be plugged, thanks to significant policy changes introduced in 2021. From 1 April, battery-powered electric vehicles (BEV) owners in Sweden are being supported by a climate bonus of €6800, for new zero-emission cars and light trucks. In addition, almost half of the Q4 2021 car sales in Denmark and the Netherlands were ECVs. The 49% share in Denmark is all the more impressive since it is taking place against the backdrop of zero direct purchase incentives (only tax benefits). Germany retained the position of the largest individual market (more than 200,000 ECV sales in Q4 2021) thanks to its generous incentive programme, which since 2020, offers up to €9,000 in direct purchase bonuses. In addition, almost 120,000 new battery electric vehicles were sold in Germany during the fourth quarter of 2021, the highest figure on record for this segment in a single MS. The German government announced the extension of the support programme by the end of 2022. However, from 2023 the incentives will be realigned to reflect the increased ambition for climate action. After Germany, growth numbers in BEVs were also supported by France, where sales grew almost up to 95,000 new ECVs in the reference quarter (+26% year-on-year). In 2021, 10 Member States did not provide any substantial incentives for ECV purchases (four more than in 2020), although most of them granted tax reductions or exemptions for EVs. Besides, 17 EU Member States offered incentives in the form of fiscal support (tax benefits related to vehicle acquisition and ownership, as well as company cars) or purchase incentives (bonuses or premiums) for buyers of electric vehicles in 2021 ([European Automobile Manufacturers' Association \(ACEA\)](#)).



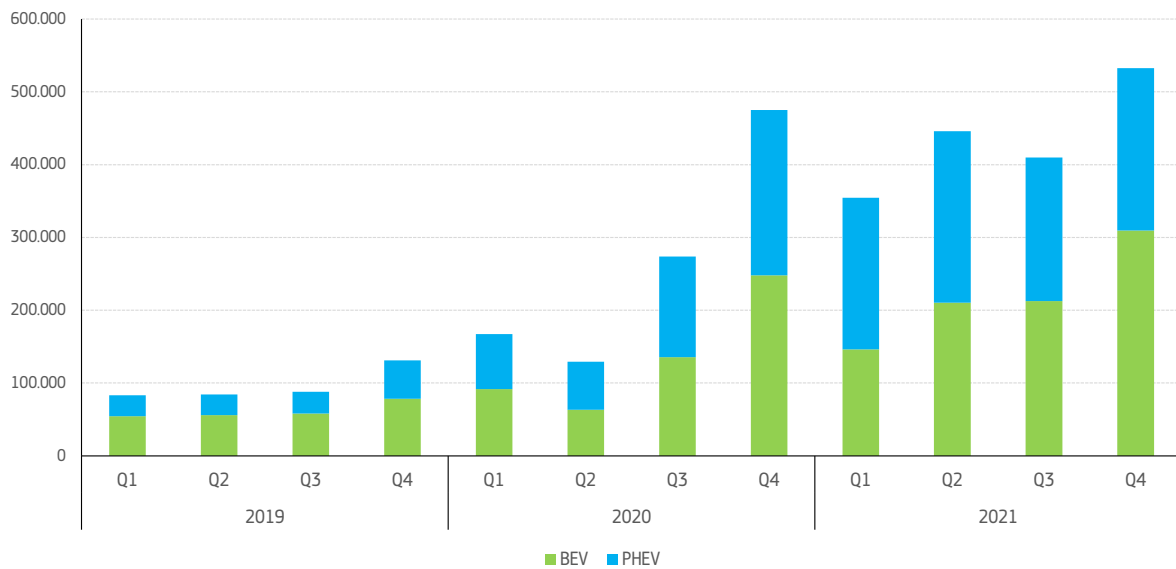
**Figure 5 – Electrically chargeable passenger vehicle (ECV) sales in selected countries in Q4 2021**



Source: ACEA, CPCA, BloombergNEF

- **Figure 6** shows how the rapid expansion of electric vehicles in Europe unfolded in 2021. Policy support, additional stimulus measures, as well as steady recovery in activity following the pandemic peak, have contributed to the impressive increase in ECV numbers. Ultimately, 1.7 million new ECVs were sold in the EU in 2021 (compared to 3.2 million cars with a plug sold in China and almost 700 thousand ECVs sold in the US), increasing by almost 70% the number of ECVs sold during 2020. As the number of ECVs on European roads is expected to continue growing fast in the years ahead, so will its impact on electricity demand and network load.

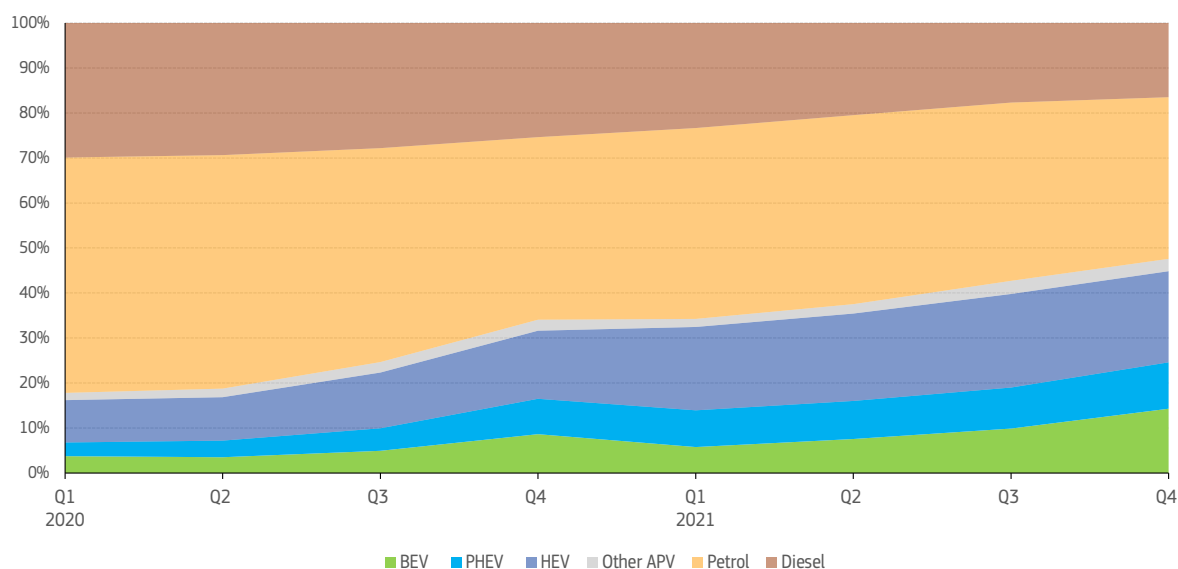
**Figure 6 – Quarterly ECV sales in the EU**



Source: ACEA

- **Figure 7** shows the decline of sales of diesel cars, which saw their market share fall to 17% in Q4 2021, from 25% in Q4 2020. Petrol car sales experienced a fall in their share to 36% in Q4 2021, from 41% in the fourth quarter of the previous year. On the other hand, the share of new Hybrid electric vehicles (HEV) in the market increased from 15% in Q4 2020, to 20% in Q4 2021. The share of new ECVs has almost doubled year-on-year (from 16% in Q4 2020 to 25% in Q4 2021). In July of 2021, the European Commission introduced the main package of proposals to deliver the Green Deal (Fit for 55 package), presenting strong CO2 emissions reduction for cars and the support to market growth for zero- and low-emissions vehicles, among other initiatives.

**Figure 7 – Evolution of quarterly drivetrain shares in the EU**



Source: ACEA

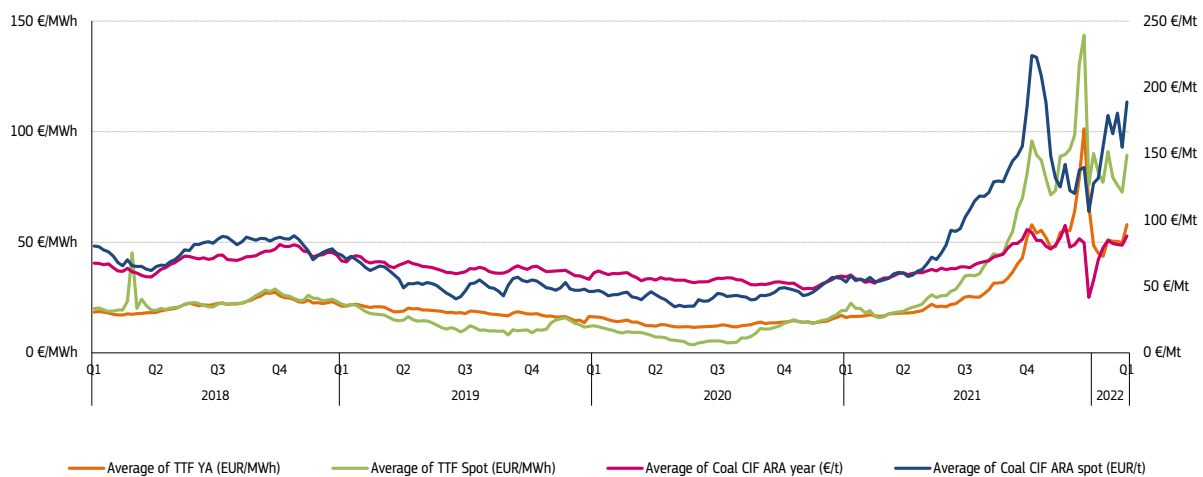
## 1.2 Supply side factors

- Figure 8** reports on developments in European coal and gas prices. In Q4 2021, prices of coal and gas rose to record levels in the spot market, way above their year-ahead peers. The situation follows the trend of increasing global demand for commodities registered during the previous quarter, linked to tighter global supply, as economic recovery is peaking up. The strong post pandemic recovery has put global supply chains under stress and led to significant disruptions. In this context, many commodities have become scarce, triggering high and volatile prices. Rising demand for gas was not matched by increasing supply, with effects felt not only in the EU, but also in other regions of the world. Global demand is expected to continue to grow, as a significant share of the increase in gas demand up to 2025 is expected to come from Asian markets. The action of key gas suppliers to the EU as well as the key suppliers and consumers in the global Liquefied Natural Gas (LNG) market, had a relevant influence on the price evolution in the EU during Q4 2021.
- The record highs of spot gas prices (represented by the TTF day-ahead contract) during 2021 was strengthened as a result of increasing demand, tight Liquefied Natural Gas (LNG) and pipeline supplies, and uncertainty over geopolitical events during Q4 2021. The EU gas prices are more linked to global market dynamics than before. This is shown by the increasing convergence of TTF with the Asian LNG benchmark (JKM) since mid-2021. Fears of scarcity in the main global consumption markets have continued to push prices up. Moreover, low gas storage levels continued to play an important role in the European gas market, as storage levels fell to 53% by the end of December, below historical averages. In addition, geopolitical tensions impacting relations with Europe's main gas supplier were also relevant on the developments of gas prices. All in all, the suspension of the certification of Nord Stream 2 gas pipeline and the rising tensions and later military invasion over Ukraine led to extreme gas price volatility.
- Record-high gas prices significantly undermined the competitive edge of gas-fired power plants in Europe and allowed their coal and lignite competitors to regain some of the lost ground of previous years. The trend has intensified to unprecedented levels following the invasion of Ukraine by Russia, increasing market uncertainty, driving up volatility and prices even further. On 8 March 2022, the TTF price skyrocketed reaching a new all-time high of 209 €/MWh.
- Following the invasion of Ukraine by Russia, the European Commission adopted a new Communication: [REPowerEU: Joint European Action for more affordable, secure and sustainable energy](#). REPowerEU outlines a plan to make Europe independent from Russian fossil fuels well before 2030, starting with gas. The communication also presents a series of measures to respond to rising energy prices and to replenish gas stocks for next winter.
- Spot gas prices averaged 94 €/MWh in Q4 2021, establishing a new record high. Prices were 94% higher than the previous quarter (Q3 2021) and represented a 540% increase compared to Q4 2020, which reflects the unprecedented level of tightness of the gas market. A new peak price was reached on 21 December 2021 (182 €/MWh) on the back of reduced Russian flows from Malinow and Velke Kapusany, combined with historical low levels of gas storage in Europe. All in all, the average spot gas price of 2021 averaged 49 €/MWh, registering a 400% increase compared to 2020 average prices (9 €/MWh). While in 2020, cheaper gas and the resilience of the carbon market

contributed to intensified coal-to-gas and lignite-to-gas switching, current high prices are likely to be detrimental to the reduction of emissions, as they support gas-to-coal and gas-to-lignite switching, driving up the carbon footprint of EU electricity sector. Gas prices have a significant influence on electricity wholesale prices, as gas-fired generation commonly sets the wholesale electricity marginal prices in many markets of the region.

- Thermal coal spot prices, represented by the CIF ARA contract, reached an early peak in Q4 2021, where prices surged up to 254 €/t on 5 October 2021. This impressive surge can be explained by supply tightness (especially in Asian markets), increasing global demand and higher freight rates. As Chinese economy started to rebound from COVID-19, demand for electricity was also enhanced leading, to an increase of coal-fired power generation. However, prices eased as China announced a cap on coal prices. Prices were also partially helped by the pledge of more than 40 nations to phase out coal and a commitment to cut methane emissions, a movement led by the EU during the recent COP26 in Glasgow (first week of November 2021). The average CIF ARA spot price averaged 157 €/t in the fourth quarter of 2021, up 220% compared to Q4 2020 and 20% to the third quarter of 2021. Nonetheless, prices skyrocketed to new all-time highs at 366 €/t on 7 March 2022, amid the Russian invasion to Ukraine. The high global demand for energy commodities, amplified by geopolitical factors, may sustain high prices in the short term. However, the medium-term outlook points to lower prices as supply factors normalise after the post-covid demand shock and economies continue to phase-out coal from their power grids.

**Figure 8 – Weekly evolution of spot and year-ahead coal and gas prices**



Source: S&P Global Platts

- The European market for emission allowances, shown in **Figure 9**, registered significant price gains throughout Q4 2021, which continued well into 2022. Several new records were established in quick succession, culminating in a peak at the beginning of February when the closing price climbed above 96 €/tCO<sub>2</sub> for the first time, thanks to rising gas prices, high power sector emissions and the expectation of an accelerated green transition. High gas prices contribute to rising carbon price since they lead to an increased use of coal for power generation and consequently higher demand for emission allowances. However, since the start of the Russian invasion to Ukraine, gas prices stopped supporting the price of EU allowances, resulting in disassociation of EU ETS from TTF price. EU ETS prices started to fall at beginning of March possibly driven by anticipated lower industrial demand for carbon allowances due to high energy prices.
- In October, high power emissions continued to support the carbon price, but the risk of curbed industrial demand maintained prices around 60 €/tCO<sub>2</sub>. Prices surged again in November, reaching levels around 75 €/tCO<sub>2</sub> at the end of the month, thanks to the tightness of the market and the release of a preliminary analysis by the [European Securities and Markets Authority \(ESMA\)](#) of the EU ETS, which confirmed that so far no specific cases of market manipulation have been detected so far. Prices in December reached a new historical peak of 89 €/tCO<sub>2</sub>, on the back of cold weather and enhanced coal-fired generation, increasing demand for allowances. The average CO<sub>2</sub> spot price in Q4 2021, at 69 €/tCO<sub>2</sub>, represented an increase of 20% with respect to Q3 2021 and a change of 150% year-on-year. At the end of March, [ESMA published its final report on the European Union Carbon Market](#). ESMA did not find any major abnormality in the functioning of the EU ETS market based on the data available. ESMA reported that price movements and volatility appear to be driven by market dynamics, the structural decline in allowances and rising energy prices. However, some policy recommendations were made, including position limits, to restrict the amount of allowances market participants can hold at one time and the creation of a central authority to monitor the market.
- The average spot price of CO<sub>2</sub> in 2021 (54 €/tCO<sub>2</sub>), more than doubled the prices registered during 2020, registering an increase of 117%. Carbon prices stabilised around 80 €/tCO<sub>2</sub> in January, only to resume its steady upwards trend

in early February to reach a new historical high during the second week of the month. However, in early March, EU ETS prices fell to a low of 58 €/tCO<sub>2</sub> (7 March) on market fears of reduced industrial demand in Europe. Since then, prices have been increasing towards 80 €/tCO<sub>2</sub> at the end of the month. Price volatility is expected to continue as market fundamentals (tight supply and high emissions from the power sector) continue to support high prices, while fears of low demand for emissions allowances in the industrial sector could contribute to curb EU ETS prices.

- Higher carbon prices put coal and lignite power plants at a greater disadvantage against their less polluting gas-fired competitors. However, under the current situation of exceptionally high gas prices, the European Union Allowances (EUA) price is not enough to support coal-to-gas fuel switching in power generation (see **Figure 21**). They also tend to drive wholesale electricity prices higher. Nevertheless, as noted in the European Commission Communication "[Tackling rising energy prices: a toolbox for action and support](#)", the effect of the gas price increase on the electricity price was found to be nine times bigger than the effect of the carbon price increase.

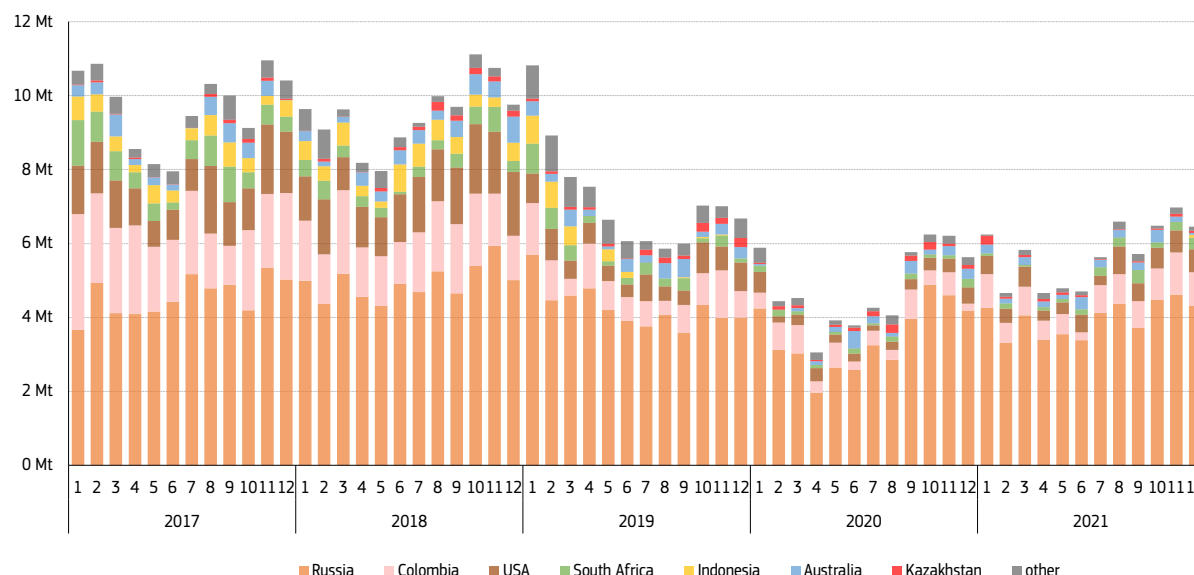
**Figure 9 – Evolution of emission allowance spot prices from 2018**



Source: S&P Global Platts

- As visible from **Figure 10**, monthly thermal coal imports into the EU held at roughly 6.6 Mt in Q4 2021, as high gas prices made more space for coal-fired generation in the mix. The total volume of imports increased by 10% year-on-year to 20 Mt in the fourth quarter of 2021. For the whole year 2021, EU thermal coal imports increased by a fifth to 69 Mt compared to 2020, due to the effects of the post-pandemic economic recovery and the increase in demand for global commodities. Nevertheless, the 2021 total thermal coal imports value was still 20% lower than the registered imports in 2019. The estimated EU import bill for thermal coal amounted to €3 billion in the reference quarter, 173% higher compared to Q4 2020, enhancing the year-on-year increase in imported volumes due to higher contracted prices of this commodity. The total 2021 import bill for thermal coal increased by 91% to €7.1 billion, a level similar to that of 2019.
- The largest part of extra-EU thermal coal imports in Q4 2021 came from Russia which accounted for 67% of the total. Russian traders managed to achieve the highest share of the market, despite a decrease in the share (-8%) with respect to Q4 2020, as most of their rivals find it difficult to compete in the tough low-price/low-demand environment. The invasion of Russia in Ukraine in late February is expected to change the future distribution of coal imports, as traders are already seeking alternative suppliers to Russian commodities. Colombia saw its market share going up to 14% compared to 7% in the fourth quarter of 2020. The position of Australia and Kazakhstan shrunk from 4% and 2% in Q3 2020, to 3% and less than 1%, respectively. The share of deliveries from US ports increased from 6% to 9%. Shares of other trading partners were not relevant enough.

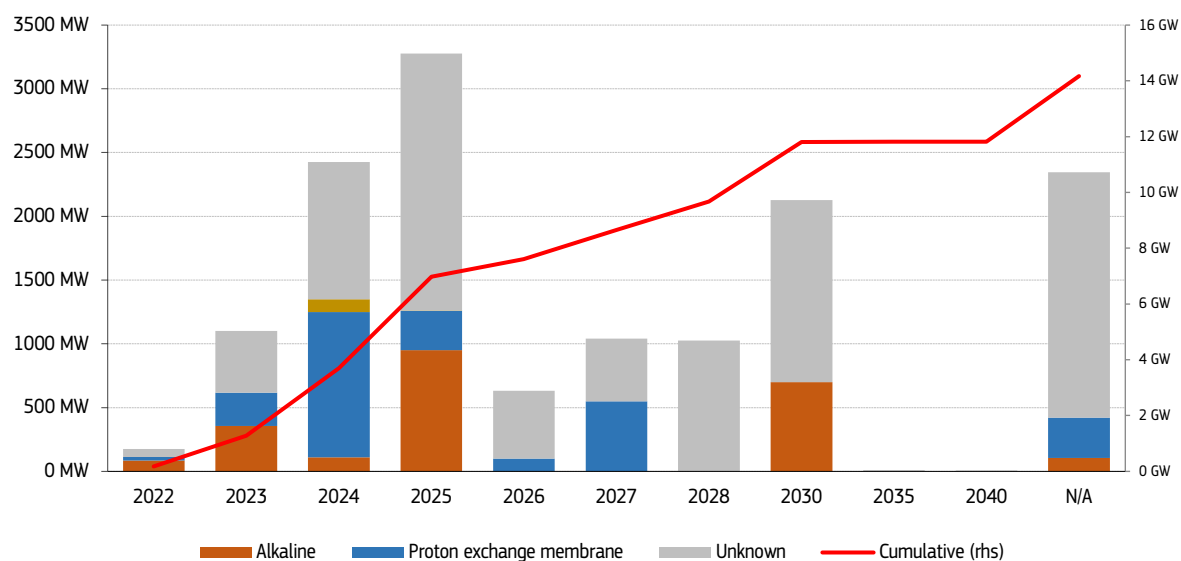
**Figure 10 – Extra-EU thermal coal import sources and monthly imported quantities in the EU**



Source: Eurostat

- Figure 11** presents announced electrolysis projects by technology in the European Union. So far, 14 GW of electrolyser projects to produce hydrogen have been proposed by Member States. Net zero emissions targets, associated strategies for the uptake of hydrogen capacity and high carbon prices are driving hydrogen deployment in Europe. Carbon prices also support the uptake of hydrogen, turning the clean production of H<sub>2</sub> competitive in comparison to fossil fuels in hard-to-decarbonise industries.
- Alkaline and proton exchange membrane (PEM) are the two most mature electrolyser technologies. Both share the same principles of electrolysis. Alkaline water electrolysis is characterised by having two electrodes operating in a liquid alkaline electrolyte solution of potassium hydroxide (KOH) or sodium hydroxide (NaOH). PEM (or polymer-electrolyte membrane) 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.

**Figure 11 – Announced hydrogen electrolyser capacity additions by planned commissioning year in the EU**



Source: BloombergNEF, Hydrogen Production Database

Note: Graphic includes only officially announced projects that have disclosed electrolyser capacity and are expected to come online by 2040. N/A and unknown mean that the developer has not disclosed the project's commissioning year and the technology to produce the hydrogen has not been announced yet.

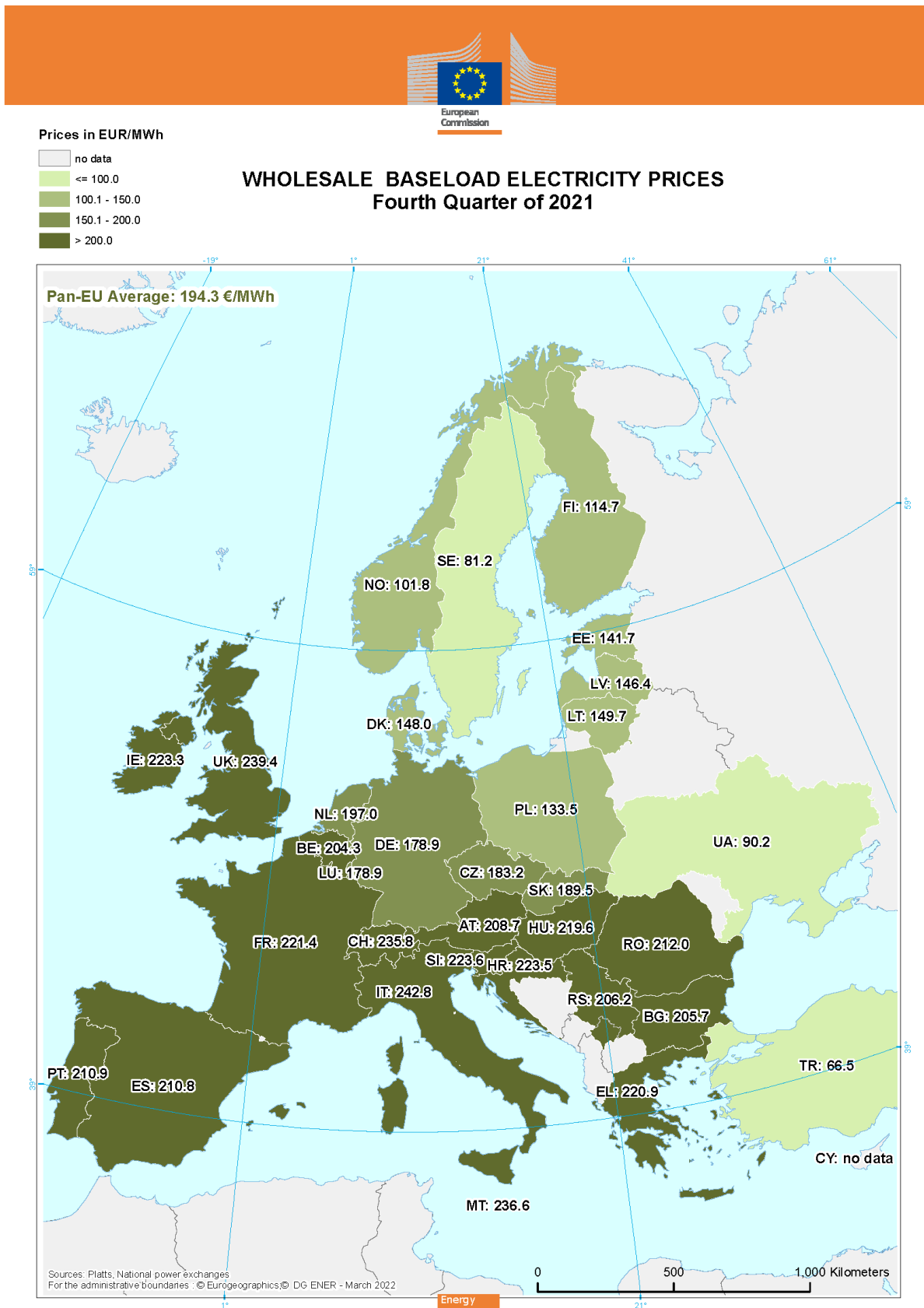
**2.1 European wholesale electricity markets and their international comparison**

- The map on the next page (**Figure 12**) shows average day-ahead wholesale electricity prices across Europe in Q4 2021. The reference quarter saw a sharp increase compared to the previous quarter, as prices reached all-time highs across Europe, due to high commodity prices (mainly gas, but also coal and CO<sub>2</sub>), increasing demand caused by the steady but strong recovery of activity, and lower availability of some conventional power plants. Practically every market in Europe experienced a considerable surge in prices (changes over 200%, 300% and even above 400%<sup>1</sup>). Italy reported the highest quarterly average price (243 €/MWh), which was 394% higher than in Q4 2020 (405% above Q4 2019 levels). The United Kingdom became the second most expensive market with an average baseload price of 239 €/MWh, which was 355% higher compared to the same period last year (413% above Q3 2019 levels). Switzerland reported prices of 236 €/MWh, while Slovenia registered quarterly prices of 224 €/MWh during the same period.
- The European Power Benchmark averaged 194 €/MWh in Q4 2021, 400% higher on yearly basis. Compared to Q3 2021, the quarterly average price rose by 85%.
- The largest year-on-year price increases were registered in Norway (+760%), Switzerland (+440%), France, Spain and Portugal (+425%). Conversely, Poland experienced the lowest increase in prices during Q4 2021 (+146%), due to lower dependence on gas in their power mix. Nevertheless, prices increased (yet less) due to its high reliance on coal and lignite in the mix, and the need to pay more for their higher emissions. It should be noted that the prices during the pandemic last year were unusually low (especially in the case of Norway, with an average price of 12 €/MWh during the fourth quarter of 2020).
- Given the situation of high energy prices, the European Commission adopted the [Energy Prices Toolbox](#) in October 2021. The Toolbox communication included a structured set of short and medium-term tools to be used by Member States to alleviate the impact on final consumers. The document also provided suggestions to further expand the legislative package on Delivering the European Green Deal. Member States have already been taking steps to mitigate the effects of rising energy prices, especially to reduce the impact on households' electricity bills.
- In light of the continued high energy prices and the aggravated situation following the Russian invasion of Ukraine, the Commission adopted [REPowerEU](#) on the 8 of March. Building from the last October communication, REPowerEU presented additional guidance to provide support to households and businesses affected by high energy prices and a plan to make Europe independent from Russian fossil fuels well before 2030 (starting with gas).
- Following up on the REPowerEU Communication and the [Versailles declaration](#), the Commission outlined a set of ideas for collective European action in a new [Communication on security of supply and affordable energy prices](#), adopted on 23 March. The Communication presented concrete exceptional [short-term and limited options](#) to tackle the impact of high gas prices on the wholesale electricity market. In addition, the Commission tabled a [new legislative proposal for securing gas storage](#) filled up to at least 80% of capacity by 1 November 2022 (rising to 90% in the following year).

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<sup>1</sup> Twenty-five MS experienced increases over 200%, twenty MS above 300% and three MS beyond 400%, compared to Q4 2020

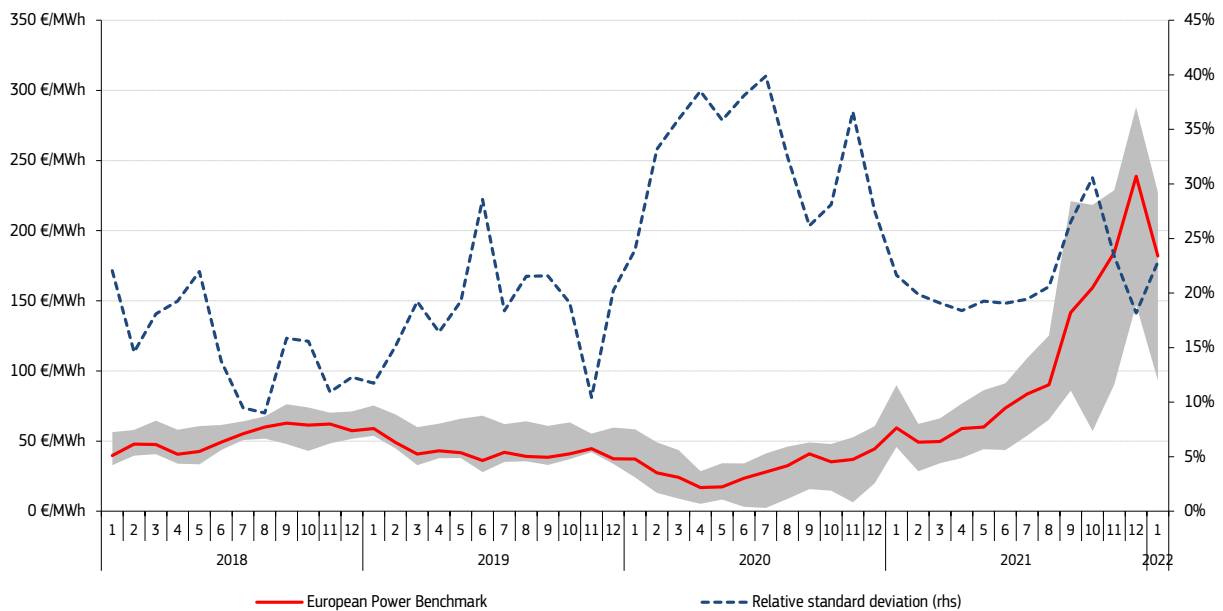
Figure 12 – Comparison of average wholesale baseload electricity prices, fourth quarter of 2021



Source: European wholesale power exchanges, government agencies and intermediaries

- Figure 13** shows the European Power Benchmark of nine markets, including the lowest and highest regional prices in Europe represented by the two boundary lines of the shaded area, as well as the relative standard deviation of regional prices. The relative standard deviation metric shows that divergence levels started to decrease in Q4 2021, as nearly every European market reached all-time record prices during the quarter. Central Western Europe, Great Britain and the Iberian Peninsula, among others, experienced a surge in prices linked to the variations in gas prices. The phase-out of coal and nuclear capacity is increasing the sensitivity of power prices to the developments of the gas market. The Nordic region experienced dry weather condition reducing hydropower output, which combined with the tightness of the continental European markets, resulted in a steep increase in prices. Soaring gas prices in Italy, combined with tight supply margins, made Italy the most expensive market in Europe during the fourth quarter of 2021. The European Power Benchmark averaged 194 €/MWh in Q4 2021. This was 400% higher than in the same quarter last year. Prices were still 374% higher than Q4 2019 (pre-pandemic levels). Following the peak in December, the rising trend in prices softened in the following months thanks to improved gas supplies to the region. However, the Russian invasion of Ukraine, the associated sanctions and the market fears of supply disruption, caused prices to rise again to new record highs in European markets in early March.

**Figure 13 – The evolution of the lowest and the highest regional wholesale electricity prices in the European day-ahead markets and the relative standard deviation of the regional prices**

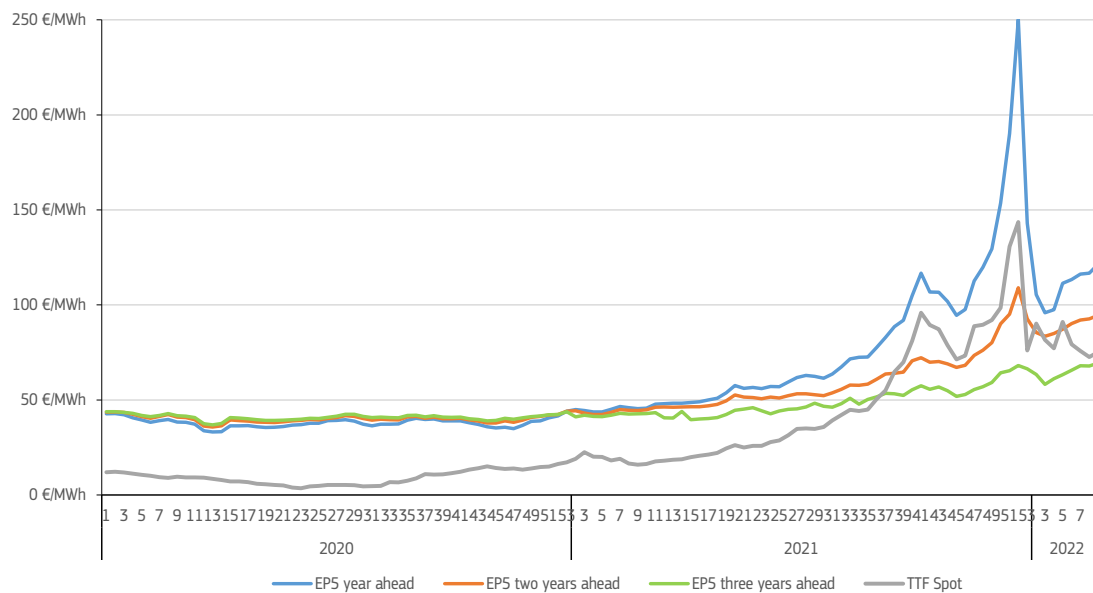


Source: Platts, European power exchanges. The shaded area delineates the spectrum of prices across European regions.

- Figure 14**, reveals that gas prices have been the main driver behind changing expectations of future electricity prices since the first quarter of the year. The rally in gas prices that took place for most of 2021, lifted the benchmark above pre-crisis levels and into all-time record highs. The TTF spot price surged 94% during the fourth quarter of the year, whereas the year ahead benchmark increased by 76% in the same period. Carbon prices have also been rising since the last months of 2020, registering a 20% increase during Q4 2021. This increase has also influenced electricity prices, yet to a far lower extent than gas prices.
- During the first week of Q4 2021, the electricity year-ahead, two-year ahead and three-year ahead contracts were respectively 117 €/MWh, 72 €/MWh and 57 €/MWh, whereas close to the end of December, these three values reached a weekly maximum of 250 €/MWh, 109 €/MWh and 68 €/MWh. Moreover, the discount of the year-ahead contract to the spot market indicates a backwardation which has been developing in parallel to the latest price increase in spot markets. The discount of the year-ahead contract to the spot market oscillated between 26 €/MWh and 87 €/MWh during Q4 2021.



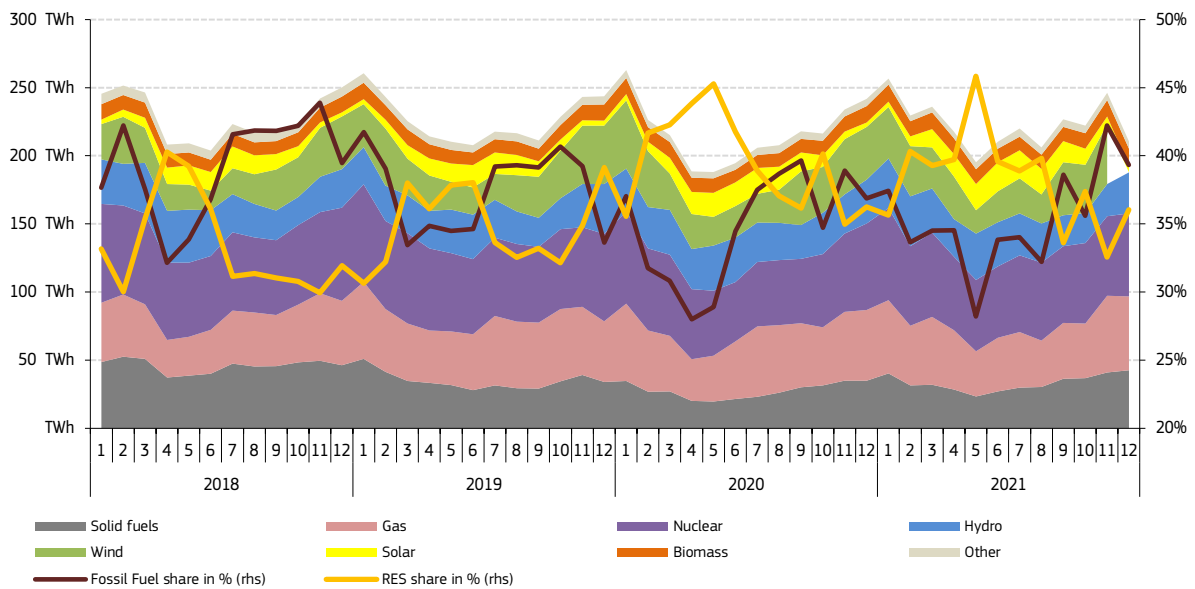
**Figure 14 – Weekly futures baseload prices – weighted average of selected European markets**



Source: Platts.

- **Figure 15** shows the monthly evolution of the electricity mix in the EU. Recovering electricity demand left more space for fossil fuels in the mix. The share of electricity generated by burning coal, gas and oil (fossil fuel generation) reached 39% in Q4 2021, while renewables scored 35%. Fossil fuel generation increased its share in the mix compared to the 37% observed in Q4 2020. Nuclear generation remained under pressure due to unplanned outages towards the end of the year in France. However, its share of generation stood practically unchanged compared to the reference quarter in 2020 (25%).
- Within the fossil fuels complex, coal gained ground both in absolute and relative terms compared to Q4 2020 due to rising demand (higher than a year earlier), but mostly as a reaction to the rally of gas prices which has reversed the coal-to-gas switch registered in previous quarters, despite rising carbon prices. Coal's share in the mix rose to 17%, whereas less CO<sub>2</sub>-intensive gas generation saw its share practically unchanged at 21% in the reference quarter. In absolute terms, coal-based generation rose by 19 TWh year-on-year, while gas-fired power plants' output increased by 6 TWh. Renewables, in contrast, generated 3 TWh less of electricity year-on-year on the back of subdued hydro output, despite improved solar and wind generation.
- Between hard coal and lignite (the distinction between them is not visible in **Figure 15**), the latter tends to be more resilient in the face of changing market environment. Lignite generation traditionally displays more competitive marginal costs per unit of energy produced even facing the current level of CO<sub>2</sub> prices. This stems mainly from low production costs of the input fuel, which is usually mined in close proximity to power plants that use it. Conversely, lignite generators have a larger carbon footprint per generated MWh (by about 20% compared to coal), which penalises them more when emission allowances become costlier. Emission allowances were 150% more expensive in Q4 2021 compared to Q4 2020, but this was compensated by rising gas and hard coal prices, which meant that lignite power plants weathered the reference quarter in a significant better shape. In the end, lignite-based generation in Q4 2021 rose by 10% year-on-year (more than 5 TWh), while hard coal-fired generation increased by 29% year-on-year (or 14 TWh).

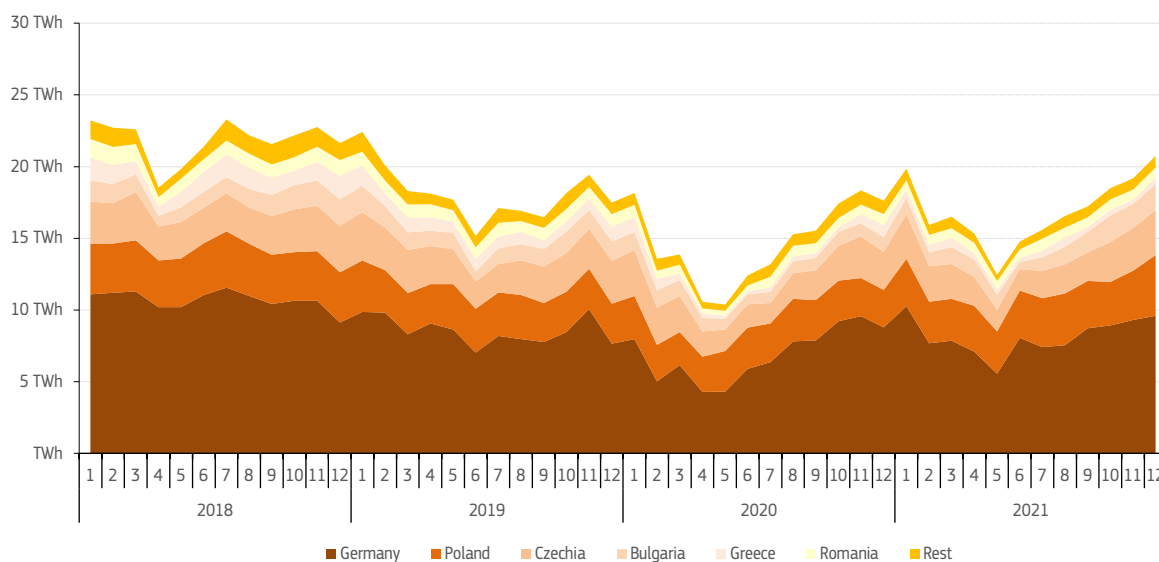
**Figure 15 – Monthly electricity generation mix in the EU**



Source: ENTSO-E, Eurostat, DG ENER. Data represent net generation. Fossil fuel share calculation covers power generation from coal, lignite, gas and oil.

- Figure 16** shows that after a large covid-related drop during 2020, lignite generation has staged a powerful comeback in 2021, helped by soaring gas prices (which decreased the competitive edge of gas-fired power plants). Most Member States with lignite-fired capacity increased its output during Q4 2021. Monthly output rose through Q4 2021 and peaked in December at roughly 21 TWh. In Germany, home to the largest lignite fleet, generation from the dirtiest fuel rose by 1% year-on-year in Q4 2021, due to falling gas, hydro and wind output, and supported by increasing demand. Lignite-fired generation in Poland increased by 32% year-on-year in Q4 2021, triggered by a significant increase in electricity demand and decreased gas, hydro and biomass generation. The output of the Czech lignite fleet rose by 11% year-on-year. The three Member States accounted for 81% of the total lignite-based generation in the EU in Q4 2021. In Greece, lignite generation decreased by 36% year-on-year on the back of increased gas, hydro and wind output, and a small rise in demand. In Bulgaria, decreased gas and nuclear output, combined with growing demand facilitated the generation of additional volumes of lignite (84%) compared to Q4 2020. Lignite power plants reached an 8% share in the EU generation mix in Q4 2021 (slightly up from Q4 2020) and were responsible for approximately 31% of the electricity sector’s total carbon emissions in the reference quarter.

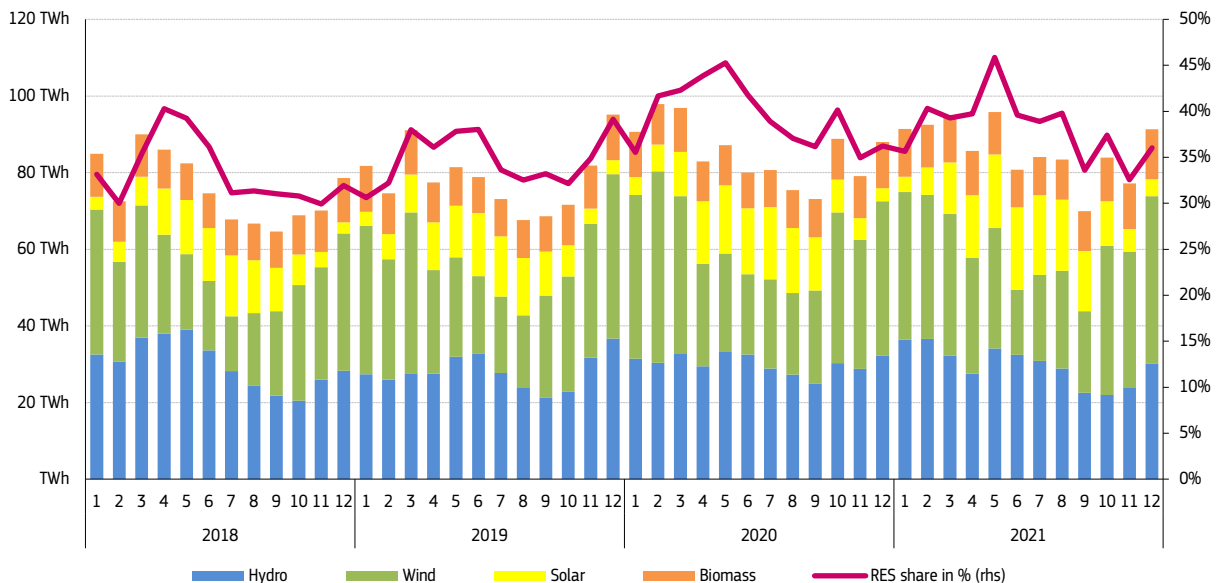
**Figure 16 – Monthly generation of lignite power plants in the EU**



Source: ENTSO-E, Eurostat, DG ENER. Data represent net generation.

- **Figure 17** depicts the evolution of monthly renewable generation in the EU, alongside its share in the electricity generation mix. Renewable penetration reached 35% in Q4 2021, lower than the 37% share of Q4 2020, and lower than the third quarter of 2021 (37%). Higher demand and a 1% drop (-3 TWh) in renewable generation contributed to the decrease in renewable penetration during Q4 2021.
- The main losses in renewable output came from hydro (-15 TWh), falling by 17% during Q4 2021. Main hydro generation volume losses were registered in Spain (-34%), Italy (-21%) and France (-20%), as a result of low stock levels and limited precipitations. Austria, Sweden, Romania, Germany, Slovenia and Finland also registered declines in hydro generation compared to Q4 2020. Conversely, the largest increase in hydro generation came from Greece, where hydro generation rose by 108% compared to Q4 2020.
- However, most of the gains in renewable generation came from solar (+4 TWh), wind onshore (+4 TWh) and biomass (+3 TWh) in comparison to the reference quarter in 2020. Thanks to newly added panels, solar PV generation rose by 24% in Q4 2021 to 4 TWh, more than six times than oil-fired generation. The increase was mostly driven by Spain, where solar generation rose 38% year-on-year. Additionally, the share of solar generation in Spain reached 7% in Q4 2021, surpassing the share of hard coal (3%).
- Overall, wind output remained with a surplus (+5 TWh) in Q4 2021, increasing its generation by 4%. Wind gains during the reference quarter were reported mainly in Italy (+34%) and Sweden (+23%), thanks to their onshore fleet output, among other Member States. Conversely, France and Germany registered calm weather, which resulted in a decline of wind generation by 11% and 3% respectively. In addition, biomass increased its generation by 8% during the reference quarter. Main gains were reported in Denmark (+47%), Finland (+37%) and the Sweden (+27%).

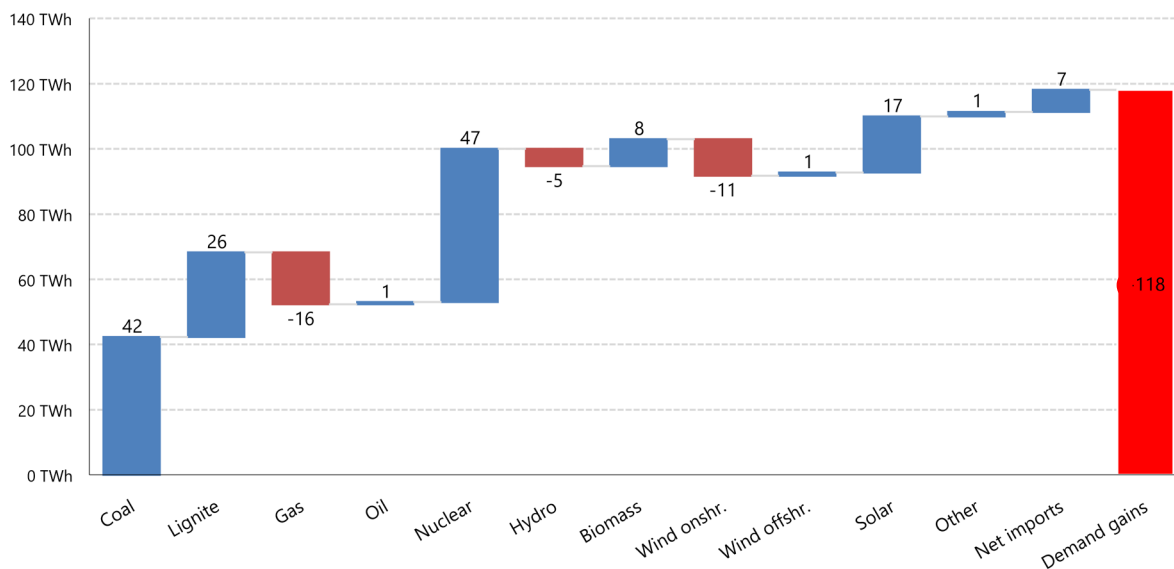
**Figure 17 – Monthly renewable generation in the EU and the share of renewables in the power mix**



Source: ENTSO-E, Eurostat, DG ENER. Data represent net generation.

- **Figure 18** visualises changes in the EU27 electricity generation, imports and consumption in 2021 compared to 2020. The space for conventional power plants' running hours was augmented by increases on the demand side. The steady but strong economic recovery from the coronavirus pandemic, increased power demand by 118 TWh. Fossil fuels and Nuclear boosted their generation by +53 TWh and +47 TWh, respectively. Renewable sources generation also rose (+10 TWh), whereas net imports increased (+7 TWh) compared to 2020. An increase in power demand during the year strengthened more polluting technologies of fossil fuel generation. All in all, hard coal increased its output by 42 TWh, lignite by 26 TWh, whereas gas fell significantly by 16 TWh as a result of high prices. Oil generation remained practically at almost the same levels than 2020 (+1 TWh). Based on preliminary estimates, the carbon footprint of the power sector in the EU rose by 9% year-on-year in 2021, due to a larger use of fossil fuels. However, emissions were still 6% lower than in 2019.
- The high prices of commodities (mainly gas), combined with pre-pandemic levels of demand in line with the gradual return to normal industrial and labour activity in Europe, can be considered as the main drivers behind the 2021 increase in carbon emissions.

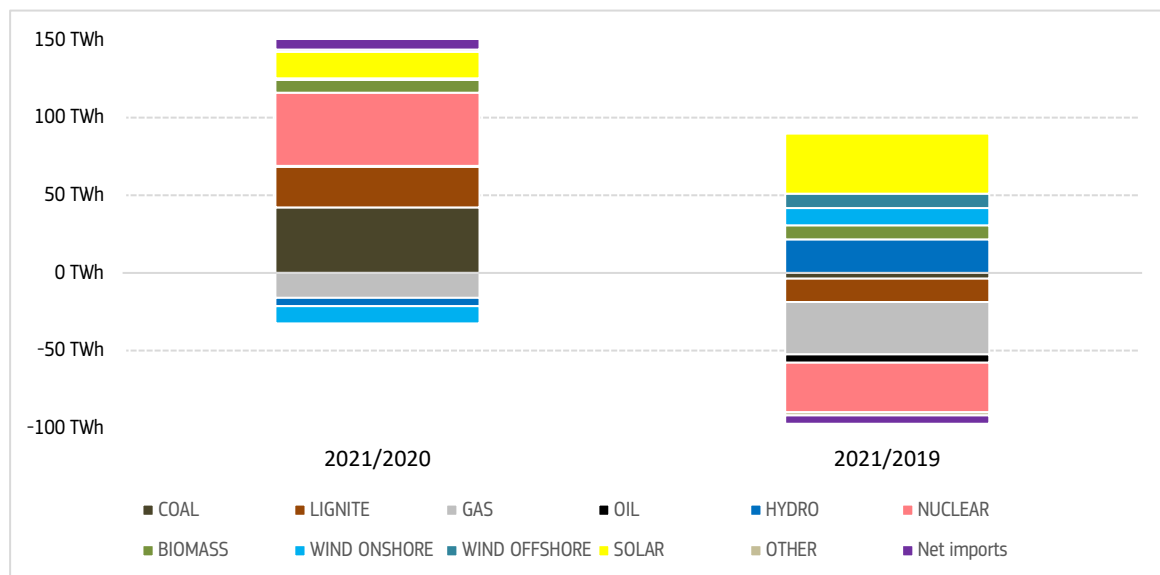
**Figure 18 – Changes in power generation in the EU between 2020 and 2021**



Source: ENTSO-E, Eurostat, DG ENER. Data represent net generation

- Figure 19** provides a different comparison angle. As 2020 was a peculiar year due to the combination of low demand and high generation from renewables, the comparison with a pre-pandemic year, such as 2019, could provide a better assessment of the short-term evolution of the power system in Europe. As can be observed from the right-hand side column, when comparing with 2019 net generation levels, there has been an increase on renewables generation at the expense of gas, nuclear and coal (hard coal and lignite) output. 90 TWh of additional renewable energy were produced in 2021 when compared to 2019. Solar increased its production by almost 39 TWh, followed by hydro (+22 TWh), onshore wind (+11 TWh), biomass (+9 TWh) and offshore wind (+9 TWh). Conversely, fossil fuel reported losses of 58 TWh in total. Compared to 2019, the main falls are in gas generation down to 34 TWh. Moreover, lignite (-15 TWh), oil (-5 TWh) and coal (-4 TWh) decreased in 2021. The former is an indication of the level of expansion of electricity generated by renewable sources in Europe. 1,030 TWh of electricity were generated by renewable sources in 2021, a 1% increase (+10 TWh) from 2020 and 10% above (+90 TWh) 2019 volumes.

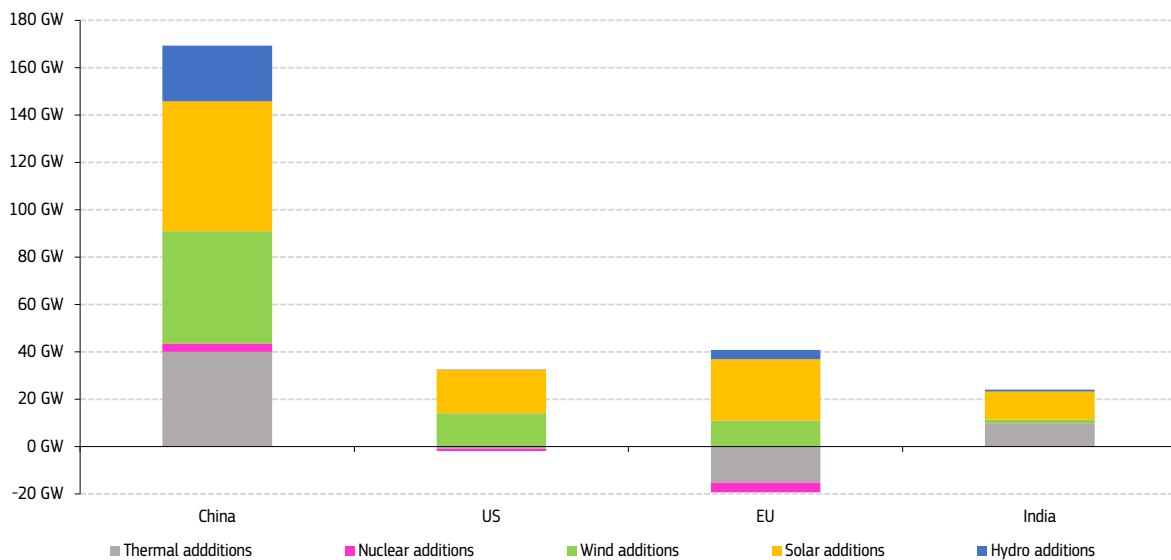
**Figure 19 – Changes in power generation in the EU per technology between 2021-2020 and 2021-2019**



Source: ENTSO-E, Eurostat, DG ENER. Data represent net generation

- **Figure 20** maps newly installed power capacities on a net basis in the EU in 2021 and, for the sake of comparison, in other major economies. Rising carbon-free generation in the EU was greatly helped by 37 GW of renewable additions (11 GW of wind and 26 GW of solar PV), which is 20% higher than in 2020. This shows that the economic recovery supported renewable expansion, although rising price of raw materials could increase the costs of renewable energy products in the near term. Nevertheless, meeting more ambitious 2030 climate targets will require a significantly increased tempo of renewable additions.
- The largest increases in the renewable capacity were registered in Germany (+7.2 GW), where solar PV was the main driver, and the Netherlands (+4.6 GW), where both solar and wind sectors contributed to the result. Spain (+4.5 GW) and Poland (+3.9 GW) also saw significant renewable capacity additions, followed by France (+3.7 GW) and Sweden (+2.8 GW). Greece (+1.9 GW) was also among Member States making notable progress. Three nuclear reactors in Germany (Grohnde, Brokdorf and Gundremmingen-C) were shut down at the end of the year, removing 4.2 GW of carbon-free capacity from the grid. Roughly 15 GW of thermal (mostly coal- and lignite-fired) capacity was retired on a net basis. This includes a 12 GW of hard coal and 2 GW lignite decommissioned in the EU during 2021.
- Outside Europe, the largest renewable additions were registered in China (48 GW of wind, 55 GW of solar and 24 GW of hydro) which also put 40 GW of additional thermal capacities online in 2021. The US experienced a similar development in net additions as the EU, witnessing 2 GW of thermal and nuclear retirements put together and 33 GW of additions in the renewable segment.

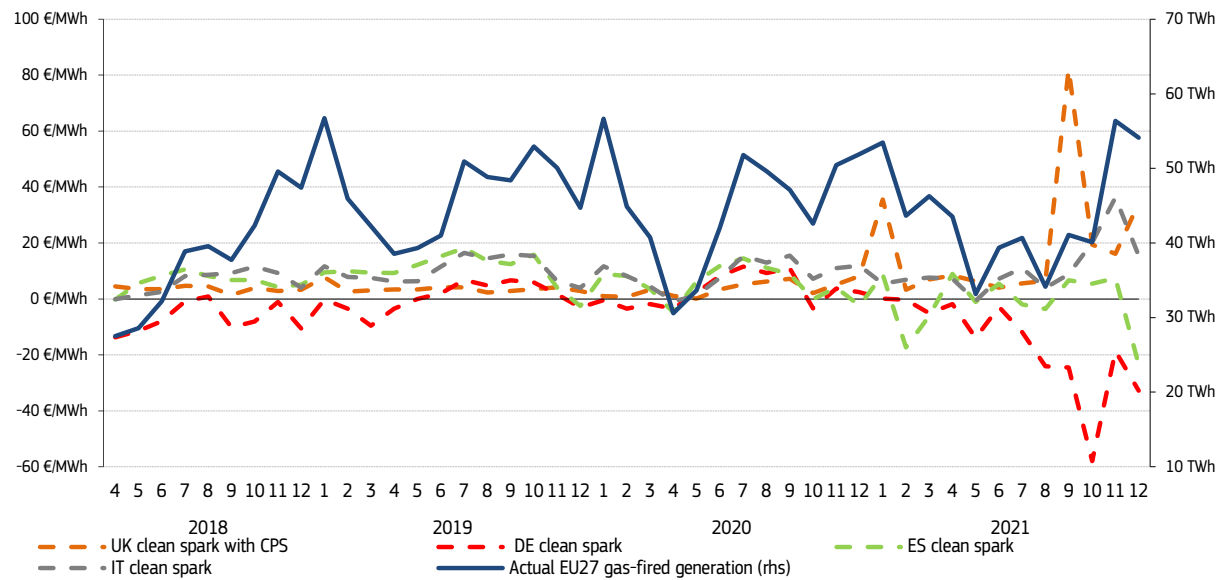
**Figure 20 – Net capacity additions across major economies in 2021**



Source: China Electricity Council, Central Electricity Authority of India, FERC. For the EU, ENTSO-E figures were used for thermal, nuclear and hydro additions; latest estimates from WindEurope and SolarPower Europe for wind and solar additions.

- The following two figures report on the profitability of gas-fired and coal-fired electricity generation in Germany, the UK, Spain and Italy by looking at their clean spark indicators. Gas reduced its traditional competitiveness advantage to coal for a third quarter in a row in Q4 2021. During the whole quarter of reference, rapidly rising gas prices resulted in coal gaining the upper hand, despite high carbon prices. Overall, mix clean spark spread in the UK, Spain and Italy driven by rising electricity and gas prices. High prices created health margins not only for gas, but also for coal generators, as the spark spreads remained into the positive area during the reference quarter (with the notorious exception of Germany and Spain). The increasing rally in gas prices during 2021 ought to a combination of rising global demand, low storage levels and geopolitical events. As such, coal usage has been increasing throughout the year to reach electricity demand.
- As shown in **Figure 21**, in the UK and Italy, the profitability of gas firing for electricity generation remained in positive territory for a plant with an average efficiency during Q4 2021 (as opposed to the German clean spark spread who has not been in positive territory since January 2021). In November, the Italian clean spark climbed to 36 €/MWh. The Spanish market started with positive number in October, only to fall into negative territory in December. The highest [clean spark spreads](#) in Q4 2021 were assessed in Italy (24 €/MWh), followed closely by the UK (23 €/MWh). The lowest was presented in Germany (-36 €/MWh), registering a minimum of -58 €/MWh in October. Gas-fired generation volumes largely corresponded to the movement of spreads in respective markets. The total EU gas generation reached 151 TWh in the reference quarter, up by 4% compared to Q4 2020.

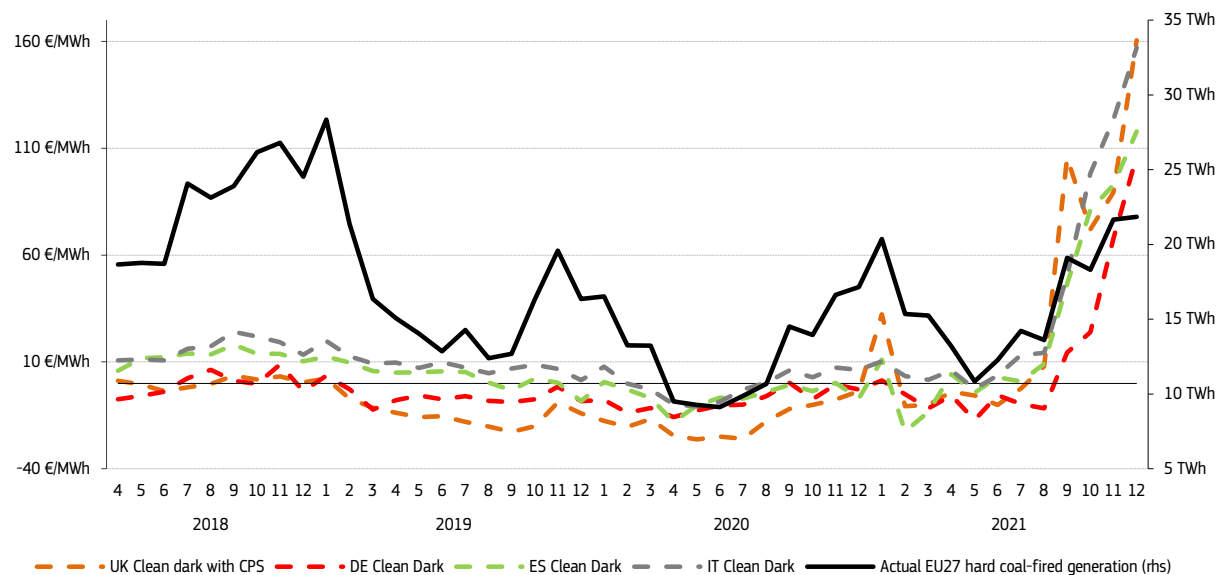
**Figure 21 – Evolution of clean spark spreads in the UK, Spain, Italy and Germany, and electricity generation from natural gas in the EU**



Source: ENTSO-E, Eurostat, Bloomberg

- For the whole year 2021, gas generation fell by 16 TWh EU-wide. The fall was led by Germany where coal and lignite replaced part of the gas output. In 2021, hard coal generation rose by 42 TWh and lignite by 26 TWh. The increase was driven by markets where coal (hard coal or lignite) still has a sizeable presence, such as Germany, Poland, the Netherlands or Bulgaria. Gas-to-coal or gas-to-lignite switching intensified during the second half of 2021, despite rising carbon prices, meaning that hard coal and lignite power plants were able to increase their running hours at the expense of gas competitors.
- **Figure 22** shows that Italy, followed by the UK, experienced the most profitable coal-fired power generation in Q4 2021. In December, all selected markets presented spikes in the profitability indicator for an average plant, despite rising coal and carbon prices. [Clean dark spreads](#) in Italy averaged 126 €/MWh in Q4 2021, five times higher than in the case of gas-fired power plants. Coal generation in Spain increased by 90% year-on-year in the fourth quarter of 2021, with only few units remaining in the market. German coal generators increased their output by 32% year-on-year in Q4 2021, as nuclear generation has been gradually fading in accordance with the German nuclear phase-out plan and no other conventional capacities were available as replacement to meet increasing electricity demand.

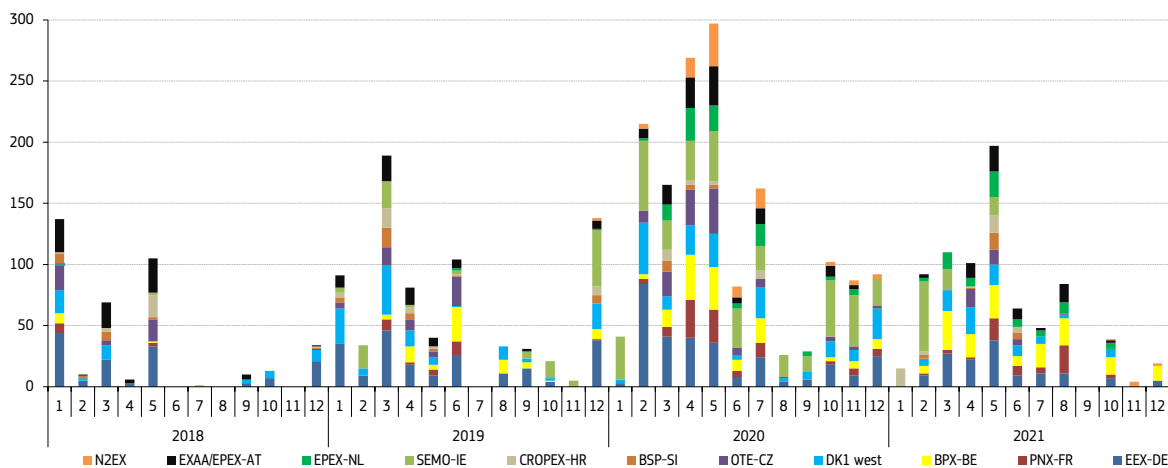
**Figure 22 – Evolution of clean dark spreads in the UK, Spain, Italy and Germany, and electricity generation from hard coal in the EU**



Source: ENTSO-E, Eurostat, Bloomberg

- **Figure 23** shows the monthly frequency of the occurrence of negative hourly wholesale electricity prices in selected European markets. Negative hourly prices usually appear when demand for electricity is lower than expected and when variable renewable generation is abundant, combined with ongoing relatively non-flexible large baseload power generation (e.g.: nuclear or lignite). In such cases, conventional power plants offer their output for a negative price in an effort to avoid switching the unit off and having to go through the costly and high-maintenance operation of restarting the facility when they want to enter the market again.
- The number of hours with negative wholesale prices in Q4 2021 (62) was 78% lower in the observed bidding zones than in the previous Q4. Most of the falls into negative territory occurred in October of the reference quarter and took place mostly during weekends when low consumption coincided with high renewable generation. The highest number of negative prices was recorded on Sunday 3 October, when strong wind speed combined with strong solar generation and weak demand, pushed most of Central Western Europe markets (German, French, Dutch, Belgium, and Austrian) and Nordic markets (Swedish, Danish, Norwegian) prices below zero during several hours of the day. Wind generation covered a large part of the German consumption during that day.
- 2021 negative prices decreased to pre-pandemic levels (2019), which numbered at 773 in the bidding zones under observation, a decrease of 51% compared with the exceptional year of 2020.
- The Belgium zone recorded the highest number of negative hourly prices (159) in 2021, followed by Germany (139), the integrated Irish zone (89) and Danish mainland (DK2) zone (8). The Belgium zone recorded an increase of 53% of negative hourly prices in Q4 2021 and 17% in 2021. The aftermath of the pandemic has made balancing the grid a harder task and accentuated the need for more flexibility in the European power system in both directions. It has also intensified the search for market instruments that would find a proper value of flexibility. Flexibility will gain importance as we transition to a renewable-based energy system.

**Figure 23 – Number of negative hourly wholesale prices on selected day-ahead trading platforms**

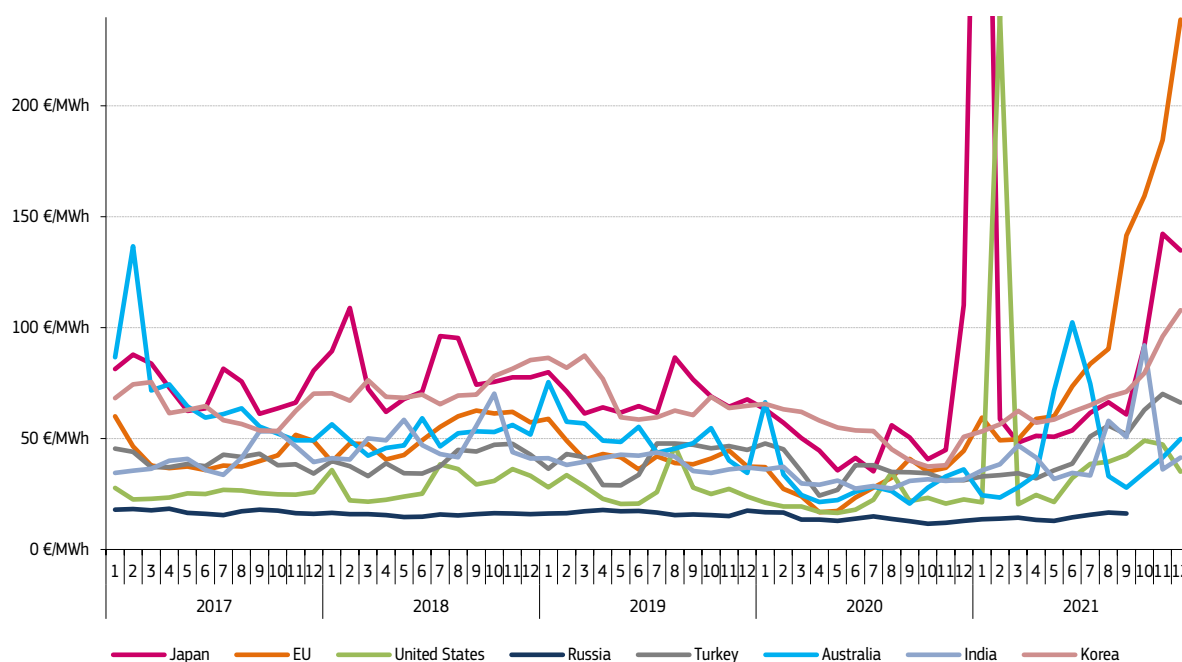


Source: Platts, ENTSO-E. For Austria, the EXAA market is used prior to October 2018, and the EPEX market is used afterwards.

- **Figure 24** compares price developments in wholesale electricity markets of selected major economies. Most markets saw prices rising as a result of the tight global markets, increase in demand and steady recovery from the pandemic in Q4 2021. In the U.S., wholesale electricity prices rose through the reference quarter by 98% in comparison to Q4 2020. The increase was influenced by rising natural gas prices at the U.S. benchmark (Henry Hub), leading to high prices and augmented utilisation rate of coal-fired plants from the second half of 2021. As a result of the current situation, the [EIA \(Energy Information Agency\)](#) estimated an increase in CO2 emissions by 6% in 2021. Furthermore, the IEA expects that increased economic activity, among other factors, will result in a further increase in emissions by 2022.
- Japan experienced an increase of 95% in prices during Q4 2021. Limited gas supply due to steep LNG prices, led to low gas-fired electricity generation. China and South Korea have been equally exposed to tightening LNG market fundamentals, turning the gas scarcity into a regional issue. Prices in South Korea increased by 38% in the reference quarter.
- European wholesale prices were the highest of the observed economies in Q4 2021, reaching 194 €/MWh. In Australia, despite a less volatile quarter, November and December saw prices return to high levels. Australian prices fell by 7% year-on-year across regional markets throughout Q4 2021. Renewables output during daytime and cool weather influenced prices and demand. Prices in India rose by 19% in Q4 2021.
- For the whole year of 2021, wholesale prices in the EU averaged 104 €/MWh, slightly below Japan (110 €/MWh), but well above other economies such as Korea (70 €/MWh), Turkey (47 €/MWh), Australia or India (45 €/MWh). European prices were 103% higher than in the US.



**Figure 24 – Monthly average wholesale electricity prices in international markets (D-A markets)**

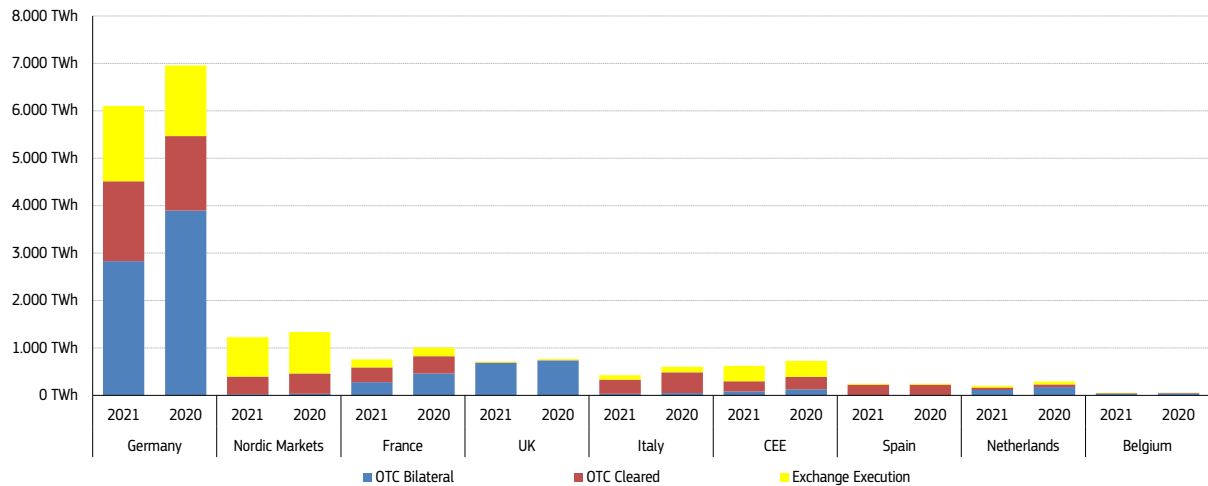


Source: European Power Benchmark, JPEX (Japan), AEMO (Australia), JCS ATS (Russia), Energy Exchange Istanbul (Turkey) and the average of selected PJM West, ERCOT, MISO Illinois and CAISO regional wholesale hubs in the United States. BloombergNEF (India and Korea).

## 2.2 Traded volumes and cross border flows

- Figure 25** shows annual changes of traded volumes of electricity in the main European markets, including exchange-executed trade and over-the-counter (OTC) trade. Most markets and regions witnessed a year-on-year decline in trading activity in 2021. The largest annual falls in total traded volumes were registered in the Netherlands (-31%), Italy (-30%) and France (-25%), split approximately equal by the OTC and Exchange sectors (except in France where losses were driven mainly by the OTC sector). The total traded volume in all markets under observation fell by 14% to 10363 TWh in 2021.
- Despite falls in traded volume, Germany was by far the largest and most liquid European market, as total volumes reached 6103 TWh (equivalent to 59% of the total traded volumes under observation in 2021). Activity fell in OTC contracts (-17%) and increased at exchanges (+7%) in 2021. Overall, total activity fell (-12%) in Germany during 2021. The market share of exchanges experienced a slight increase (+5 p.p.) and the OTC contracts share decreased (-5 p.p.) compared to 2020. Relative decreases in activity were visible in the UK where total volumes fell (-7%) to 714 TWh. Similar relative decreases were also visible in the CEE region where total volumes fell by 14% to 623 TWh. Nordic markets registered a decrease of 8% in total activity to 1228 TWh. Increases in activities were reported in the OTC segment in Spain where volumes rose by 22% to 228 TWh, although total volumes remained practically unchanged at 247 TWh.
- Overall, the market share of power exchanges expanded from 26% to 30%. The largest falls in exchange-based volumes were reported in the Netherlands (-36%) and Italy (-23%). Overall, exchange-based trading volumes decreased by 19 TWh in 2021 and increased their share of the market to 30%. The OTC segment traded 1625 TWh less of electricity in 2021 compared to 2020, as a result of lower volumes changing hands in Italy, France and the Netherlands. OTC volumes reduced their share off the market to 70%. Spain, France and CEE markets registered the largest decrease in bilateral OTC deals (-60%, -39%, and -36% respectively).

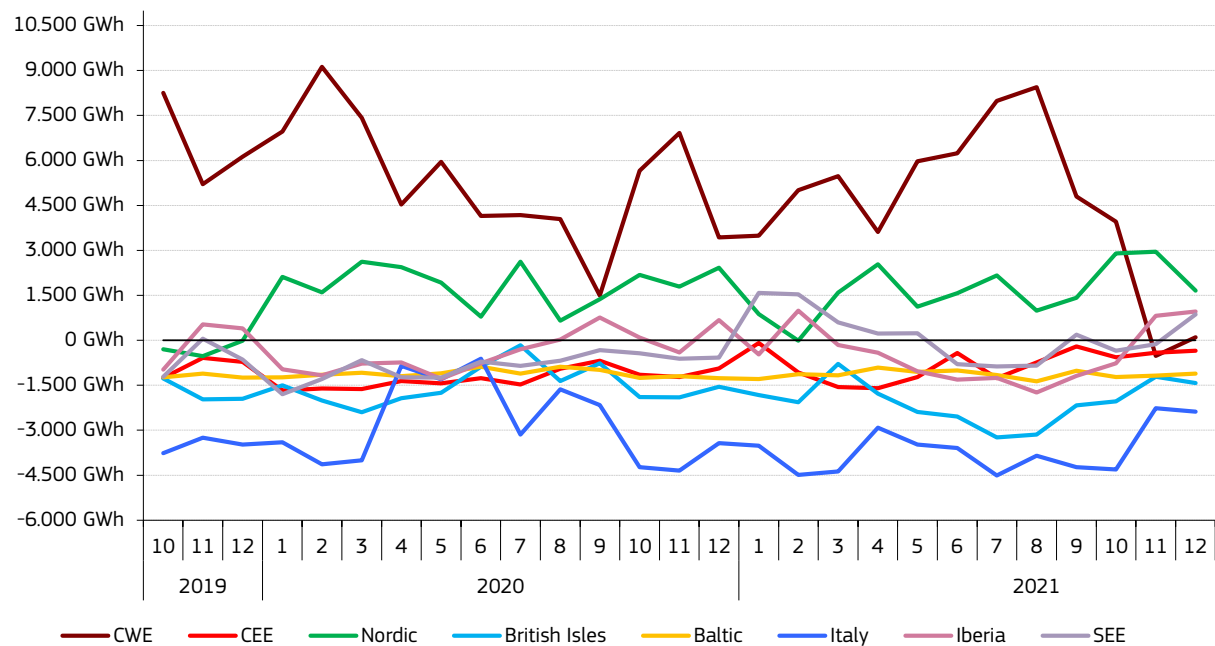
**Figure 25 – Annual change in traded volume of electricity on the most liquid European markets**



Source: Platts, wholesale power markets, Trayport, London Energy Brokers Association (LEBA) and DG ENER computations

- Figure 26** reports on the regional cross-border flows of electricity. Central Western Europe registered a considerable drop in its position as the main exporting region during November when the net balance flowed towards the region. CWE, which has abundant and diverse generation capacities and a suitable central position to supply other regions, has traditionally been in a privileged position to act as a net exporter. During the fourth quarter of 2021, CWE registered only 3.5 TWh of net exports, decreasing its outflows by 78% during the quarter in comparison to Q4 2020. The decrease can be traced mainly to slightly lower generation within CWE market, which decreased the availability of exports. The Nordic region recorded a surplus of 7.5 TWh in the reference quarter, 17% above from the net exports in Q4 2020. South Eastern Europe turned into net exporter (+0.4 TWh), a significant improvement compared to Q4 2020 (-1.6 TWh). The Iberian Peninsula also emerged as net exporter, registering a surplus of +1 TWh during the reference quarter.
- The rest of the regions ended up in deficit. Net flows to the British Isles decreased compared to Q4 2020 at -4.7 TWh, improving by 12% on yearly basis. This was mainly due to less available generation for exports in France, supported by high gas prices, nuclear availability and increasing demand following the post-pandemic recovery. Italian net imports decreased by 25% year-on-year to -8.9 TWh in Q4 2021. The CEE region's net position (-1.3 TWh) improved by 60% in Q4 2021 compared to Q4 2020.

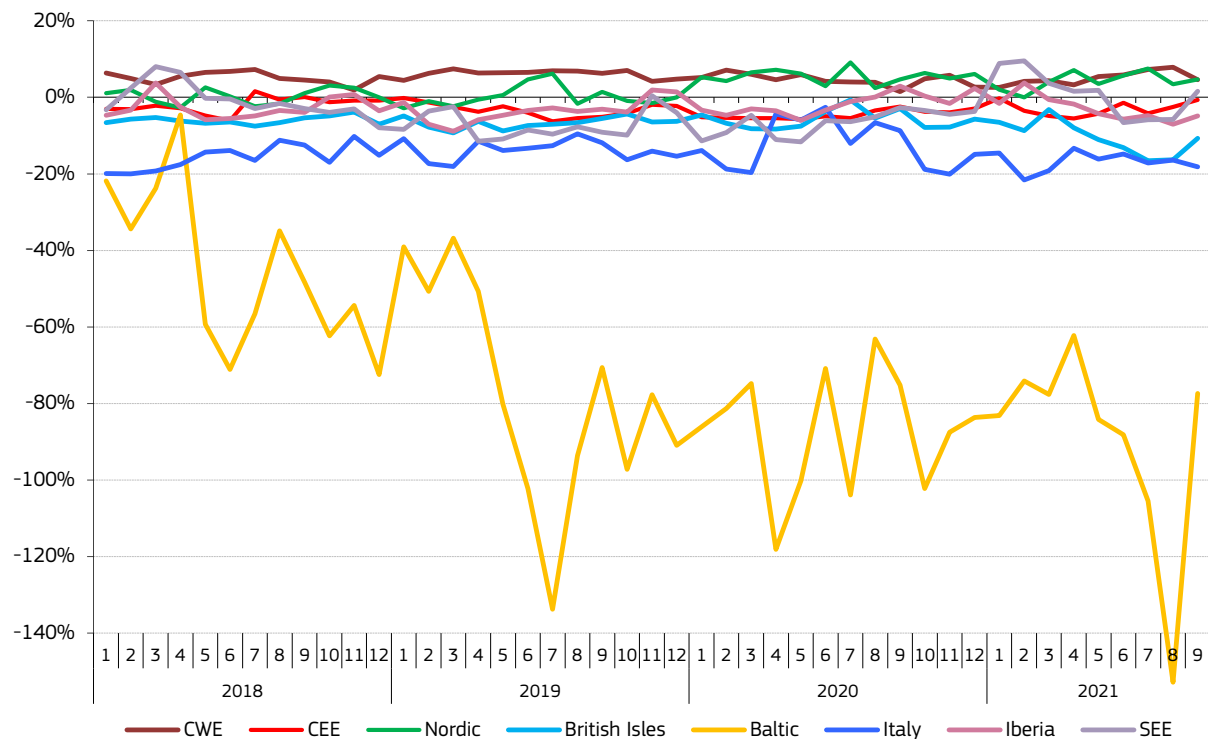
**Figure 26 – European cross-border monthly physical flows by region**



Source: ENTSO-E. Key to country distribution in regions: CWE (AT, DE, BE, NL, FR, CH), CEE (CZ, HU, PL, SK, SI, RO), Nordic (DK, SE, FI, NO), Baltic (LT, LV, EE), Iberia (ES, PT), SEE (BG, GR, HR, RS, BA, ME, MK, AL), British Isles (UK, IE), Apennine Peninsula (IT, MT). Source: ENTSO-E, TSOs

- **Figure 27** compares net cross border flows to regional power generation to give a better comparative perspective on the flows and their size. Positive values indicate a net exporter. The position of the Baltic region, which has the biggest deficit compared to the size of its power sector, remained largely unchanged in Q4 2021 compared to the same quarter a year ago. Net imports (3.5 TWh) reached about 77% of domestic generation. Italy became the second largest importer relative to its domestic generation (13%), followed by the British Isles (6%). For the rest of the regions, net imports (or exports) did not exceed 7% of domestic generation.

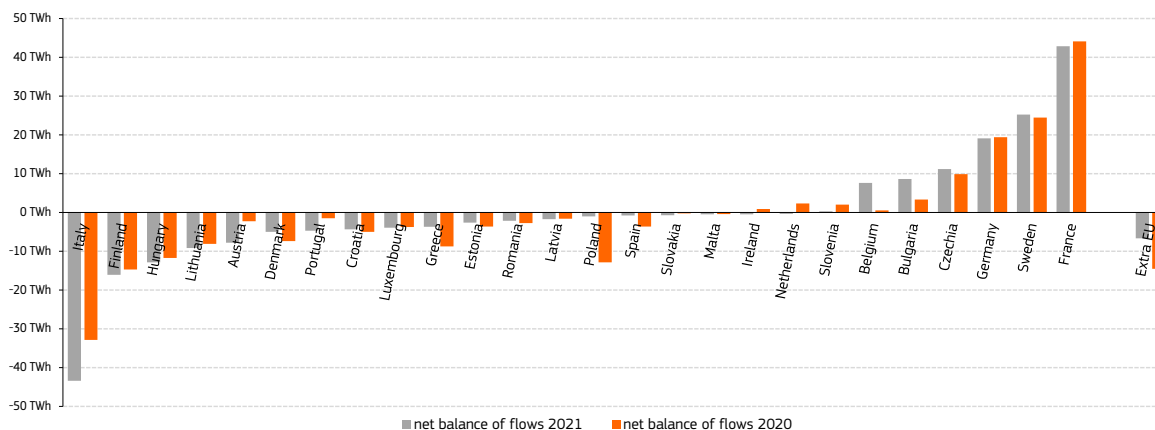
**Figure 27 – The ratio of the net electricity exporter position and the domestic generation in European regions**



Source: ENTSO-E. Country distribution in regions is the same as in the previous figure. The -100% level means the same amount of electricity is imported as produced domestically. Source: ENTSO-E, TSOs, Eurostat, DG ENER calculation

- **Figure 28** compares net balances of physical electricity flows among EU Member States in 2020 and 2021. The pandemic, coal-to-gas switching and rising renewable generation in certain regions combined to make net trading positions more balanced than in previous years.
- France topped the list of net exporters with 43 TWh of net surplus, which was 3% below the 2020 level. This was driven mainly by higher consumption. German net exports fell by 2% to 19 TWh (the lowest net surplus in a decade) on the back of closing of nuclear, coal- and lignite-fired generation, which was replaced by gas plants or renewables elsewhere. Germany closed 4.2 GW of nuclear capacity at the end of 2021. Moreover, Germany will retire its three remaining nuclear reactors (1.3 GW Emsland, 1.4 GW Isar 2 and 1.3 Neckarwestheim 2) by the end of 2022. As Germany is retiring roughly 20 GW of dispatchable nuclear, lignite and coal capacities between 2020-2023, the country is expected to shift to being a net importer of electricity in 2023. Conversely, Bulgaria and Czechia saw their surpluses improve due to increasing domestic lignite output.
- After a year of becoming a net exporter in 2020, the Netherlands returned to a mild deficit condition in 2021 (-0.3 TWh), as consumption rose slightly while domestic generation fell on the back of subdued gas output. Italy increased its net deficit by 32% to 43 TWh, above the net import values of 2019, as domestic generation grew to a smaller extent than consumption. Finland, Hungary, Lithuania and Austria increased their net imports for the same reason. Spain decreased its net imports as consumption increased to a lesser extent than generation, thanks to expanding renewable capacities.

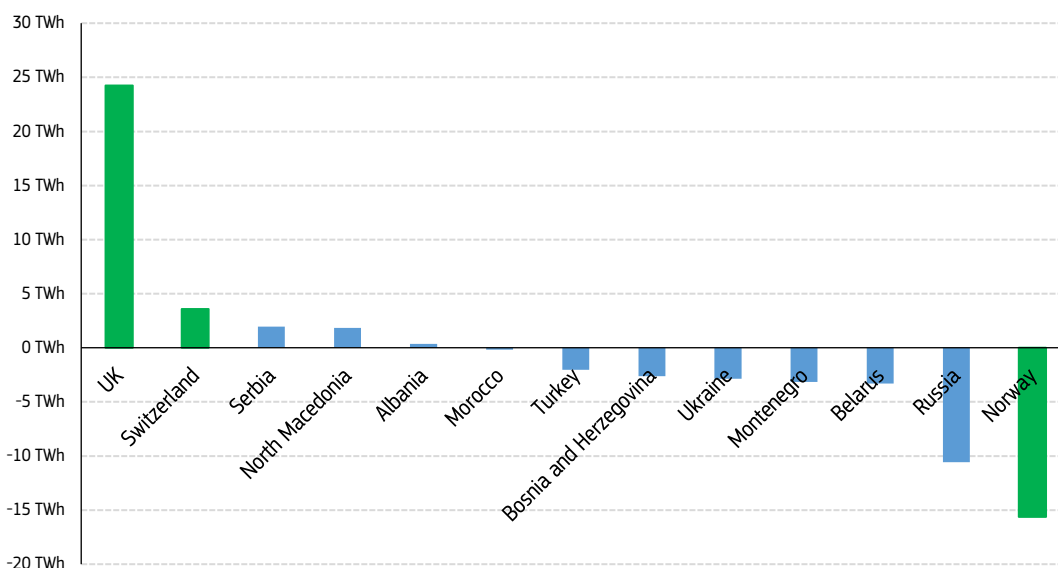
**Figure 28 – Member States’ net export/import positions within the EU in 2021 and 2020**



Source: ENTSO-E, TSOs, Eurostat

- Figure 29** shows netted electricity exchanges with EU neighbours in 2021. Great Britain became EU's biggest export market with 24 TWh of net outflows from the continent, which was 28% higher than in 2020 due to the impact of the post-pandemic recovery on British consumption. Norway stood at the opposite side with 16 TWh of net exports, registering 22% decrease of volumes into the EU. Subdued hydro generation, despite rising wind output, was responsible for the decline in exports. Russian exports to the EU increased to 11 TWh, as a result of reduced Norwegian flows and rising consumption in Finland (see **Figure 3**). Nevertheless, Russian net imports were still 15% lower than in 2019. Net imports from Ukraine also increased (20% compared to 2020) in 2021, as high electricity prices in Hungary and Romania encouraged cross-border trade. However, net imports from Ukraine were still 33% lower than in 2019. Exchanges with countries not applying similar level of carbon pricing resulted in net import of 21 TWh (similar levels than in 2019 and up 9 TWh than in 2020). Coal generation in Serbia and Bosnia and Herzegovina decreased by 12% and 6% respectively in 2021, crowded out by improved hydro generation. Serbia imported more from the EU than exported in 2021, while Bosnia and Herzegovina was a net exporter to the EU in 2021.

**Figure 29 – Extra-EU electricity exchanges in 2021 – netted**



Source: ENTSO-E, TSOs, Eurostat. Negative values indicate net imports to the EU. Green colour denotes neighbours with similar or identical levels of carbon pricing.

## 3 Focus on developments in annual wholesale prices

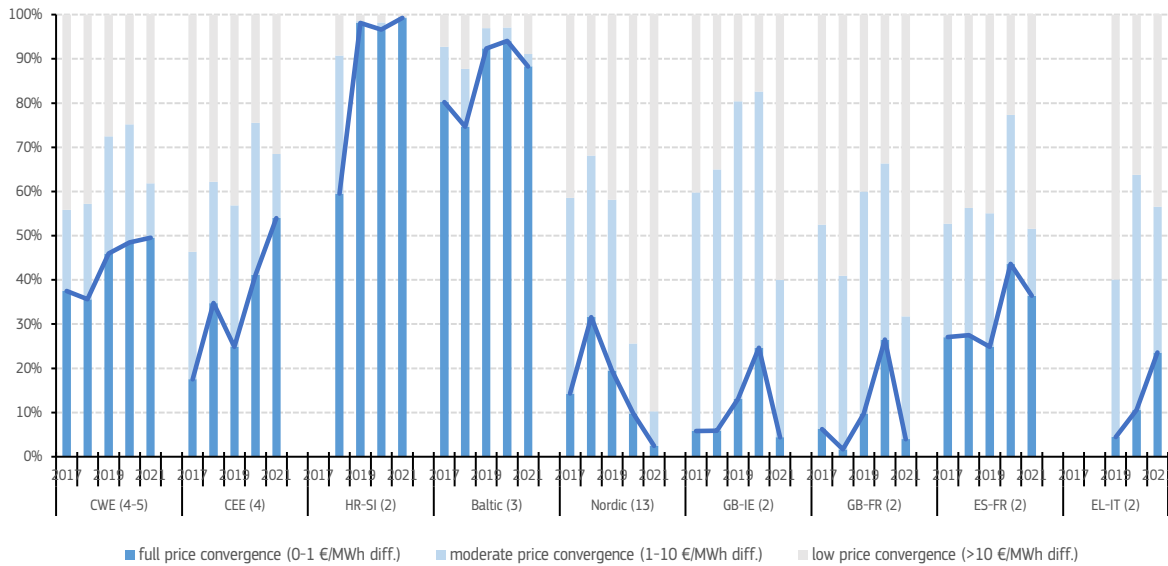
### 3.1 Day-ahead price convergence

- **Figure 30** illustrates the degree of price convergence in day-ahead markets within selected European regions, expressed in percentages of hours in a given year. Price convergence provides an indication of the level of market integration. Its longer-term drivers are market coupling initiatives or the expansion of interconnection capacities. In the short term, fluctuations in convergence may also be caused by factors not necessarily related to the level of market integration, such as changes in the amount of cross-zonal capacity designated by TSOs for commercial purposes, long-lasting outages of transmission lines, significant shifts in the power mix or in consumption patterns. Several of these one-off factors influenced developments in convergence in 2021, the post pandemic economic recovery and the return to historical levels of demand being one of them.
- Overall, price convergence results in European electricity markets saw mixed developments during 2021. In the CWE region, which is the only one where flow-based market coupling has been applied since 2015, the number of occurrences of full price convergence (when the difference between hourly prices in all bidding zones is lower than 1 €/MWh) increased slightly (from 49% to 50% of hours). The exact causes are dissected in the following figures, but the impact of the post pandemic recovery was double-sided. A considerable increase in full price convergence occurred within the four coupled markets (4M MC) in Central Eastern Europe (CEE), reaching more than 54% of hours. In June 2021, these markets were coupled to the Multi Regional Coupling (MRC) through the borders of PL-DE, PL-CZ, PL-SK, CZ-DE, CZ-AT, and HU-AT. Higher convergence levels in both regions (CWE and CEE) were observed especially in the first part of the year, as the second half of 2021 was marked by the impressive escalation and volatility of prices which impacted differently across regions. Consequently, prices diverged more often during the second half of the year. The three Member States in the Baltic region remained highly convergent in 2021, although the full convergence of prices fell from 94% in 2020, to 88% in 2021. This could be explained due to price divergences between the different Baltic bidding zones, accentuated by the high wholesale prices. Price convergence fell across the British Isles as the two islands, linked by two interconnectors, were decoupled in 2021 as a result of Brexit. This translated into an explicit system of trading where the British day-ahead order books were no longer coupled with other European markets. This represented a setback from the continued rise in convergence after the implementation of market coupling between Great Britain and the Irish Integrated Single Electricity Market in 2018. This situation has also contributed to halt the positive trend of rising convergence between Great Britain and France observed in the last three years, as the full price convergence between UK and FR fell from 27% in 2020 to 4% in 2021. On the other hand, the 1 GW interconnector linking Great Britain and France (IFA2), operational since January 2021, partially mitigated the effects of the decoupling. As part of the post-Brexit trade and cooperation agreement, EU and UK TSOs were tasked to set up a market coupling for allocating implicit day-ahead capacity (MRLVC) by April 2022, which could improve levels of price convergence in the near future.
- The decrease in convergence between Spain and France in 2021 can be attributed mainly to rising consumption levels in both countries combined with high gas prices. This resulted in Spanish prices often rising more than their French counterparts and moving further away from French price levels. Conversely, French prices skyrocketed at the end of the year, while Spanish prices eased, pushing the price divergence levels. Italy and Greece were coupled only since the middle of December 2020. Since then, convergence levels have been doubling year-on-year, with hourly prices nearly identical 24% of the time in 2021. The Nordic registered another year of significant drop in convergence levels in 2021. This marked a continuation of a trend visible since 2018, driven by growing trade imbalances of the four Scandinavian countries not matched by an expansion of interconnection capacity. In 2021, the low convergence levels could have been caused by a combination of new interconnections entering to force (NO-DE and NO-UK) and possible structural congestions within the Swedish network<sup>2</sup>.

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<sup>2</sup> [ACER \(2022\)](#). Wholesale Electricity Markets Monitoring 2021. Key developments.

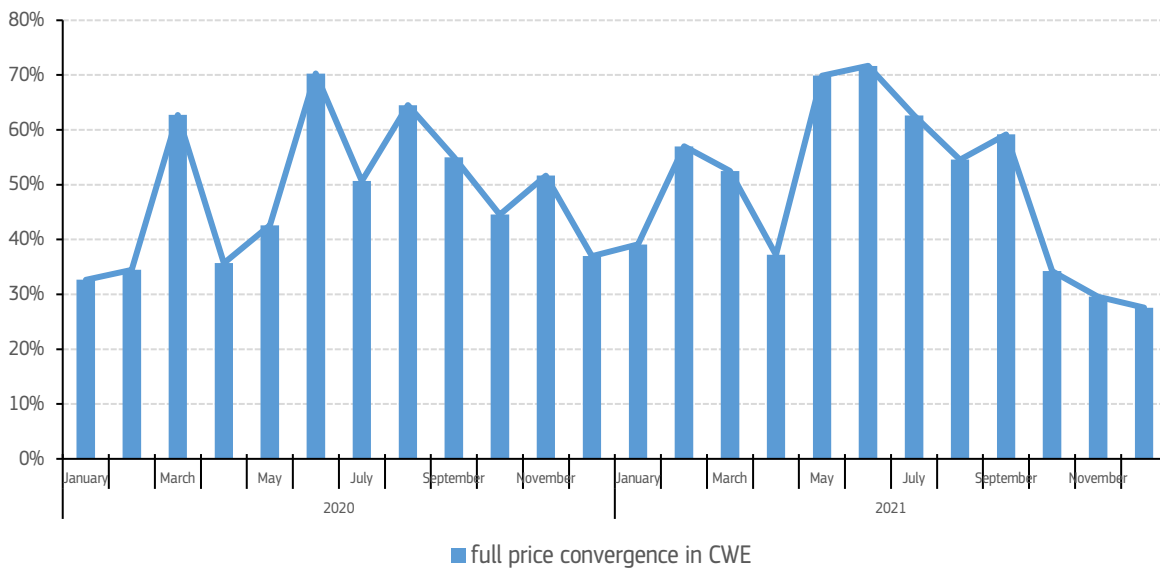
**Figure 30 – Price convergence on day-ahead markets in selected regions as percentage of hours in a given year**



Source: ENTSO-E, OTE, Nord Pool, Platts. The numbers in brackets refer to the number of bidding zones included. The CWE region comprises of BE, FR, NL and DE-LU-AT zones until October 2018, and separate DE-LU and AT zones since then. The CEE region includes CZ, SK, HU, RO bidding zones which are coupled. The Baltic region includes EE, LV, LT bidding zones. The Nordic region includes 13 bidding zones of Norway, Sweden, Finland and Denmark.

- **Figure 31** demonstrates that price convergence is subject to seasonal fluctuations and that it changes from month to month. In the case of the CWE region, lower price convergence is observed during winter months when electricity consumption increases, and the grid is under greater stress due to higher loads. The last months of 2021 are a case in point. Convergence levels were lower in November and December 2021 when French nuclear generation was subdued compared to the same months in 2020. In turn, Germany saw seasonally stronger wind generation during the same period, influencing prices to a greater extent than during the rest of the year.

**Figure 31 – Monthly full price convergence in the CWE region in 2021 and 2020**

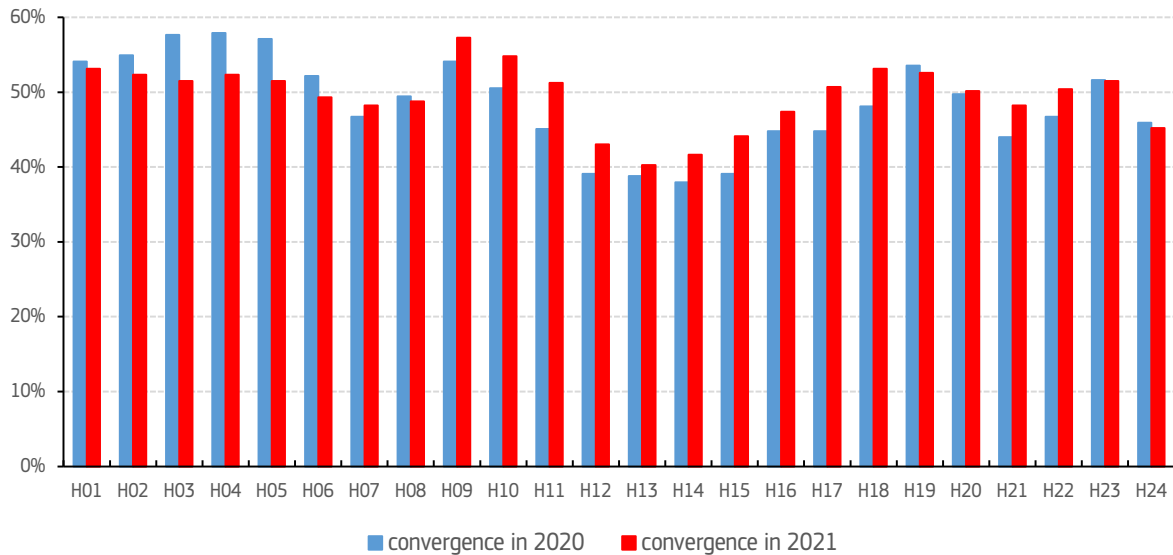


Source: ENTSO-E

- **Figure 32** investigates how price convergence developed throughout 24 hours of the average day in 2020 and 2021 offering additional clues about possible sources of changes. It is visible that hourly prices were more convergent during most part of the peak hours of the day, which could be the result of the return to normal activities along with the post pandemic recovery. Conversely, prices converged in the early morning hours in 2020, which could be the result of slower starts of workdays as more people worked from home and did not have to commute. As demand

curves returned to their peaks of load during the morning and evening, higher ramping demand led to greater price convergence. In 2020, as a result of the pandemic, the biggest annual drops in network load in most CWE countries occurred between 5 a.m. and 9 a.m. when the load usually increases quickly. In addition, growing disparities between generation bases in the CWE region have thus driven local electricity prices further apart. That is one of the factors behind low convergence levels in the last months of 2021 when wind generation increased to considerable high levels.

**Figure 32 – Average hourly full price convergence in the CWE region in 2021 and 2020**



Source: ENTSO-E

- Expected adjustments in the capacity calculation methodologies and the application of the cross-zonal capacity targets set by [Regulation \(EU\) 2019/943](#) on the internal market for electricity, together with the completion of market coupling, are expected to increase price convergence across Europe. Another strong impetus towards greater convergence should be provided by a number of interconnectors scheduled to come online in the next years. The Nordic border transmission capacity should expand from 8.4 GW at the end of 2021 to 14 GW by 2030. A considerable part of that capacity should be linked to Germany.

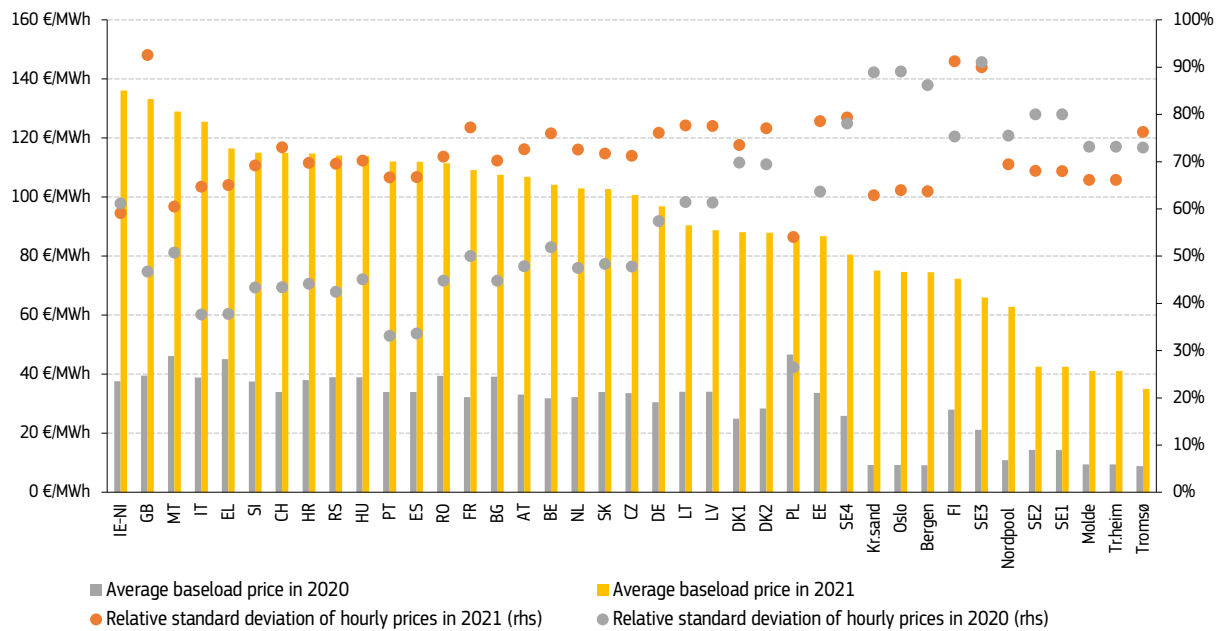
### 3.2 Average annual price levels and volatility

- **Figure 33** maps annual changes in average day-ahead baseload prices and in hourly price dispersion across European day-ahead markets. 2021 was a special year, as the global economic recovery from the pandemic pushed up the prices of energy commodities. The universal increase in the price of baseload electricity observed in 2021 can be attributed to higher fuel costs and the strength of the post covid-related economic recovery (see **Figure 3** and **Figure 8**). In 2021, gas prices at TTF were on average traded 400% higher than in 2020, while emission allowances increased their price by 117% compared to the previous year. However, wholesale prices did not rise to the same extent. The highest prices in Europe were registered in markets dependent on gas for a large share of their electricity generation. Ireland, with almost half of their electricity generation coming from gas, became the most expensive European market (136 €/MWh) in 2021. Besides the three south eastern Norwegian bidding zones, the island market of Ireland experienced the largest yearly increase in prices (+261%), despite the fact that its power demand increased less (4%) than the EU average (5%). Likewise, the UK, Italy, Greece, Croatia, Hungary and Spain; markets which largely rely on gas generation were also situated on the high end of the spectrum. Conversely, markets with large shares of hydro reservoir generation, registered the lowest prices in Europe. The Norwegian northern bidding zones Trondheim (NO3) and Tromsø (NO4) experienced the lowest prices in Europe (41 €/MWh and 35 €/MWh, respectively). However, both bidding zones experienced one of the largest increases in prices during 2021 (334% and 295%), compared to the previous year. This difference could be attributed to the amplifying effect of low prices registered in 2020 in the NordPool market thanks to extended hydro generation and low demand due to the pandemic effect.
- Markets at the higher end of the spectrum are typically markets that have a significant presence of gas-fired power plants in their generation mix (IE, IT, HR, HU, EL, ES), or in the so-called energy islands which are relatively isolated areas dependent on imports (MT, GB, IT) (sometimes a combination of both). Markets with spare coal and lignite generation capacity in their energy mix (PL, DE, CZ, SK, BG) were able to weather the impact of the price increase, up to some extent. Gas prices undermined the competitive advantage of gas-fired power plants in Europe, improving comparative levels of coal generation (despite high carbon prices) intensifying the switch from gas to coal. The

lowest prices were observed in the Nordic region, displaying also high levels of difference in prices. Norwegian bidding zones were on average at 60 €/MWh thanks to record high wind output which was able to partially compensate subdued hydro generation in the second part of the year (see **Figure 41**). Northern Norwegian bidding zones with high levels of hydro generation registered lower prices than their southern counterparts. Bidding zones in Denmark, Finland and Sweden with a different mix consisting also of fossil fuels and nuclear could not match such low levels of the northern Norwegian zones.

- Most markets experienced higher levels of price volatility in 2021 (measured as relative standard deviation of hourly prices and plotted on the right-hand scale of the chart). This could be the result of the post pandemic recovery which brought prolonged periods of very high and volatile prices into the market. Also, generally higher price levels can be conducive to greater relative jumps in both directions. High volatility was observed in Nordic markets with below-average prices. Ireland, Italy, Greece on the other hand, registered lower price volatility (although still higher than in 2020). Volatility can greatly influence asset profitability in the electricity sector. For storage technologies, for instance, the greater the absolute spread between minimum and maximum prices in a day, the more they can earn by buying low and selling high.

**Figure 33 – Changes in average baseload prices and hourly price volatility in European day-ahead markets between 2021 and 2020**



Source: ENTSO-E, OTE, Nord Pool, Platts. Italy is represented by the national average (PUN), the rest of the markets under observation correspond to bidding zones. Ireland has a common bidding zone with Northern Ireland (ISEM). Prices in Great Britain are represented by the N2EX power market.

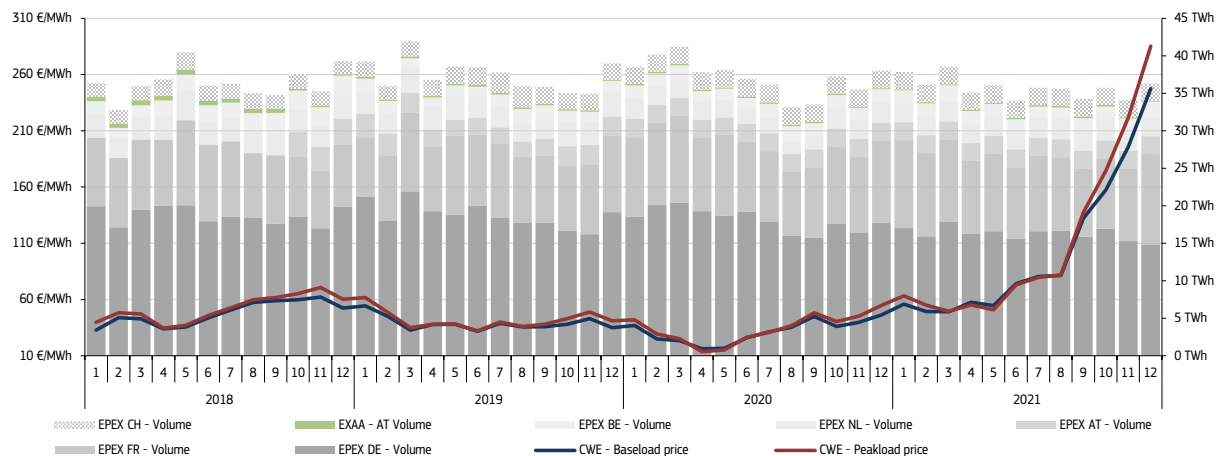


## 4 Regional wholesale markets

### 4.1 Central Western Europe (Austria, Belgium, France, Germany, Luxembourg, the Netherlands, Switzerland)

- Following a continuous rise in prices in the previous quarter, monthly average wholesale baseload electricity prices in Central Western Europe (CWE) continued to climb to unprecedented levels during the fourth quarter of 2021. The increase in spot prices has intensified, amid expensive gas, in the context of historically low levels of storage stocks leading to unprecedented global LNG market tightness. Wholesale electricity prices reached a peak in December (248 €/MWh), on the back of the previously mentioned factors. Compared to Q4 2020, the average baseload price in the region increased by 392% to 200 €/MWh in the reference quarter. Meanwhile, average peakload prices increased by 385% to 227 €/MWh. The rally of prices in Europe experienced a drop in January 2022, reaching however new historical highs in early March 2022, in the context of the Russian invasion to Ukraine.
- In France, nuclear availability reached a new record low in December 2021 on the back of maintenance outage towards the end of the year. In December, France registered high electricity demand amid cold weather, in the context of low wind and hydro output. EDF's fleet of 54 reactors reached the 300 TWh mark on November 3, despite the major reshuffle of annual maintenance of the nuclear fleet targeting 345-365 TWh in 2021. French nuclear output fell below 39 GW during week 38, following lower net exports caused by an outage on both the IFA 1 interconnector and the IFA 2 cable on 15 September in Kent. Eleven nuclear reactors ended 2021 in maintenance, compared with five in the last quarter of 2020. As a result, the nuclear share generation was at 68% in 2021.
- In Germany, three of the remaining six reactors (Brokdorf, Grohnde and Gundremminge) permanently ceased power operation on 31 December 2021, as a result of a national nuclear power and coal phase-out policy. The three reactors combined a capacity of 4.2 GW (respectively 1.4 GW, 1.5 GW and 1.3 GW). Three reactors were already decommissioned at end-2015, end-2017 and end-2019. German nuclear generated over 65 TWh of electricity in 2021, covering a share of 12% of German total generation. These closures coincided with coal and lignite plant termination. The country's biggest power generator RWE has shut 2.2 GW of lignite and nuclear capacity on 31 December 2021, including three 300 MW units in the Rhenish lignite mining region were taken off the grid (Neurath B, Niederaussem C and Weisweiler E), and the 1.3 GW Gundremmingen-C reactor. An additional 3GW is planned to be shut in December 2022. These closures added extra tightness and combined with expensive gas prices, triggered record highs of German power prices in the last quarter of 2021. Gas-fired generation fell by 11% (-2.5 TWh) during Q4 2021; with a considerable decrease in December generated by concerns around Nord Stream 2 pipeline and the consequent high prices in natural gas.

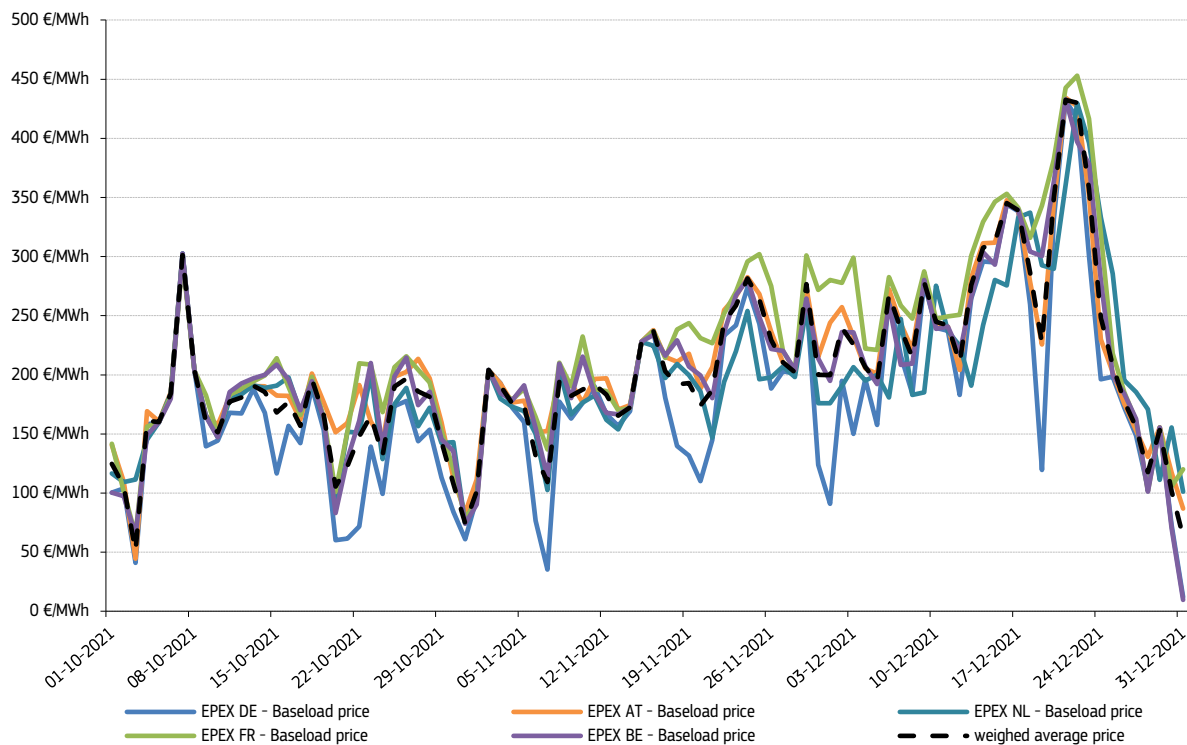
**Figure 34 – Monthly exchange traded volumes of day-ahead contracts and monthly average prices in Central Western Europe**



- **Figure 35** shows the daily average day-ahead prices in the region in the reference quarter. The last quarter of 2021 was marked by an important volatility in prices from October onwards. The first week of October 2021 showed strong volatility driven by high commodity prices, increased demand, and variations in wind generation. The prices decreased from 106 €/MWh on 2 October to 51 €/MWh on 3 October and climbed back up to 301 €/MWh on October 7. Yet, daily prices in October stood around an average of 160 €/MWh. Daily average prices in November increased further to 198 €/MWh (+24% from October).

- All-time highs were registered over 430 €/MWh on 21 and 22 December, showing an increase of 745% from the lowest price on 3 October. This energy crisis was triggered by spiralling gas prices pushing European electricity contracts to unprecedented highs. Power prices greatly decreased on December 31, down to 63 €/MWh (-85% from Dec. 21), due to mild weather and lower gas prices. Despite steady prices on the first days of January 2022, power prices raised back to new highs in Q1 2022.
- At the lowest peaks, Germany experienced the lowest power prices in comparison to its neighbours. As an example, on 31 October, Germany's power prices reached 61 €/MWh, while Belgium and the Netherlands stood at 74 €/MWh, and France at 79 €/MWh (for a CWE average of 75€/MWh). Most noteworthy, on 19 December, Germany's power prices reached 120 €/MWh, whereas the Netherlands experienced power prices at 293 €/MWh, Belgium at 300€/MWh, and France at 343€/MWh (for an average of 227 €/MWh in CWE). Germany's baseload averaged prices in Q4 2021 stood at 179 €/MWh, compared to an average of 221 €/MWh in France, showing how renewable energy generation can contribute to lower prices.

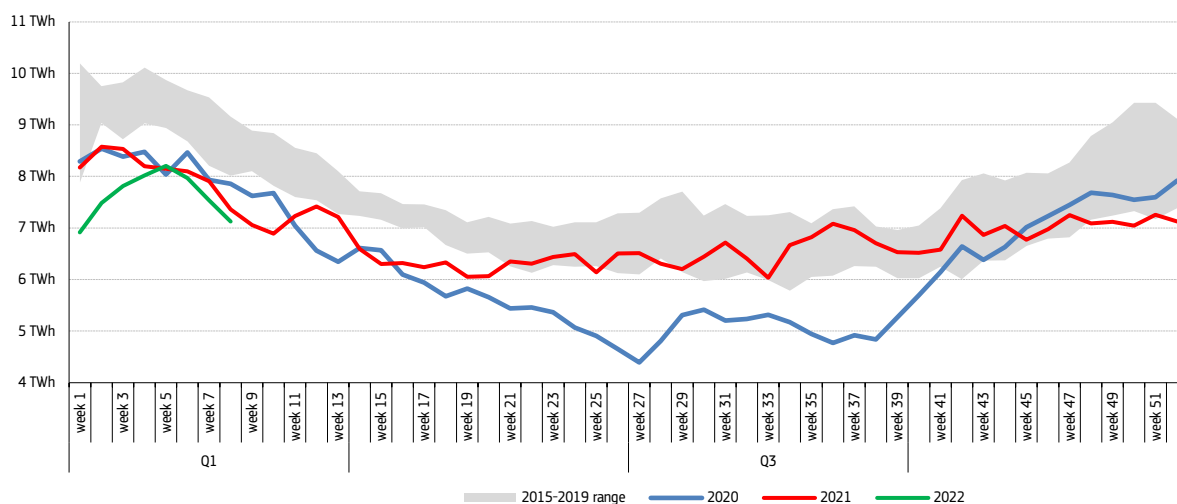
**Figure 35 – Daily average power prices on the day-ahead market in the CWE region**



Source: Platts.

- As shown in **Figure 36**, French nuclear output was down by 2% (-1.7 TWh) year-on-year in Q4 2021. EDF's fleet of 54 reactors reached the 300 TWh mark on November 3, below the target set during the major reshuffle of annual maintenance of the nuclear (345-365 TWh in 2021).
- The available capacity fell below 39 GW during week 38, as the 2 GW IFA 1 cable remained unavailable until 23 October. December nuclear output tumbled to 31 TWh, 2.9 TWh less than in December 2020. Eleven reactors ended 2021 in maintenance, compared with five in the last quarter of 2020. The new French reactor Flammanville 3 (1.6 GW) has been delayed starting commercial operations around mid-2023. The French government announced to relaunch the construction of nuclear reactors while continuing to develop renewables in the country. France's 2030 growth plan has a focus on the support of small modular reactors (SMRs), with an indicative decision on whether to build more EPR reactors, which should be taken in the near term. EDF noted that the first of six EPRs could start operating in 2035.
- In Belgium, the 1-GW nuclear reactor Doel-4 was taken offline on 22 October for annual refuelling and reconnected to full capacity in December. Belgium has plans to decommission the existing nuclear capacity (6 GW) by 2025. The plan involves the closure of Doel 3 from October 2022 and Tihange 2 from February 2023. The remaining (five) reactors are scheduled to close between February and December 2025.

**Figure 36 – Weekly nuclear electricity generation in France**

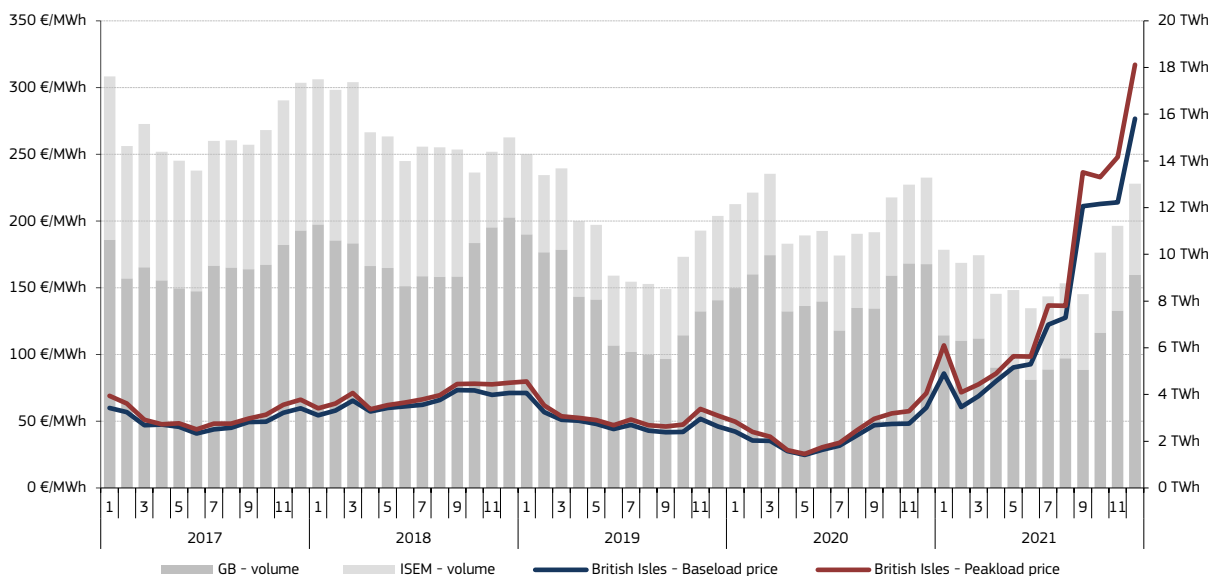


Source: ENTSO-E

#### 4.2 British Isles (GB, Ireland)

- Figure 37** illustrates monthly volumes and prices on the day-ahead markets in Great Britain and in the all-island integrated market in Ireland. Monthly averages for both baseload and peakload power rose again reaching new all-time highs during the last month of Q4 2021. The surge was driven mainly by soaring gas prices, combined with tight supply margins, low wind availability, robust demand, unplanned interconnector outages and reduced nuclear output. From September 2021 to November 2021, baseload prices remained relatively steady, rising from 211 €/MWh to 214 €/MWh (+1%). Following this relative stabilisation, baseload prices increased to 277 €/MWh (+29% from November 2021, +362% year-on-year) in December. Compared to Q4 2020, the average baseload price on the British Isles rose by 350% to 235 €/MWh during Q4 2021, and stood 53% above the level from Q3 2021.
- Great Britain had insufficient spare capacity to meet demand, resulting in gas, coal and even oil plants ramping up to meet the demand during the quarter. The outage of the IFA1 2GW interconnector with France has increased the tightness of the system, resulting in soaring prices, as the lack of imported flows has made the UK more reliant on expensive gas-fired generation. [National Grid](#) announced the interconnector is expected to be fully operational by mid-December 2022. In December, transmission capacity on the 1.4 GW NSL power interconnector from Norway to the UK was restricted to 700 MW until February 2022, caused by a fault in one of the UK converters. Since the start of the operation of the NSL, the link has been importing electricity from Norway at the maximum available capacity.

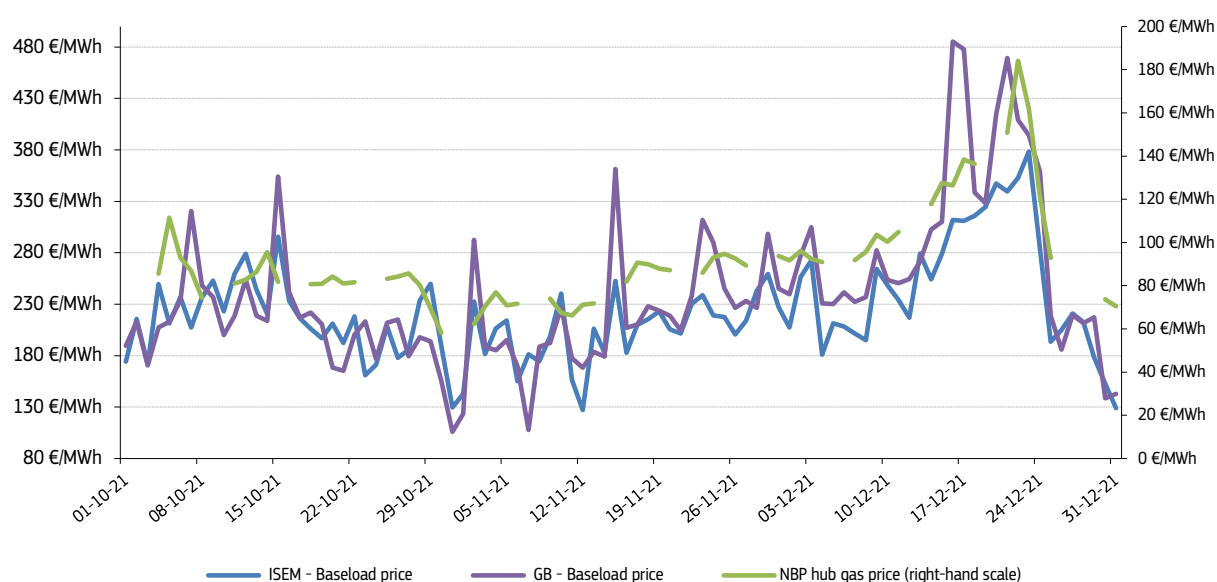
**Figure 37 – Monthly exchange traded volumes of day-ahead contracts and monthly average prices in Great Britain and Ireland**



Source: Nord Pool N2EX, SEMO, Utility Regulator

- Figure 38** follows the developments of daily average baseload electricity prices in Great Britain (N2EX) and Ireland (ISEM). British baseload prices experienced soaring prices, important volatility and spikes along Q4 2021. Market imbalances including gas prices in Europe and supply uncertainties triggered unprecedented high prices and volatility. In Great Britain, daily average prices held mostly between 180 and 240 €/MWh during October and November. Prices in December saw volatility increased to exceptional levels with prices moving between 230 and 340 €/MWh. The highest peak was registered in Great Britain on 18 December (485 €/MWh), on the back of a spike in the NBP prices. The Irish market registered its highest spike on December 23 (378 €/MWh). Baseload wholesale prices were higher than in any previous quarter. Prices finally fell at the end of the year, thanks to lower gas prices and improved wind output.
- Prices in the all-island Irish market generally followed the UK contract, albeit slightly less volatility during Q4 2021. The all-island Irish market registered an increase of 44% from Q3 to Q4 2021, whereas the British market registered an increase of 59% from Q3 to Q4 2021.

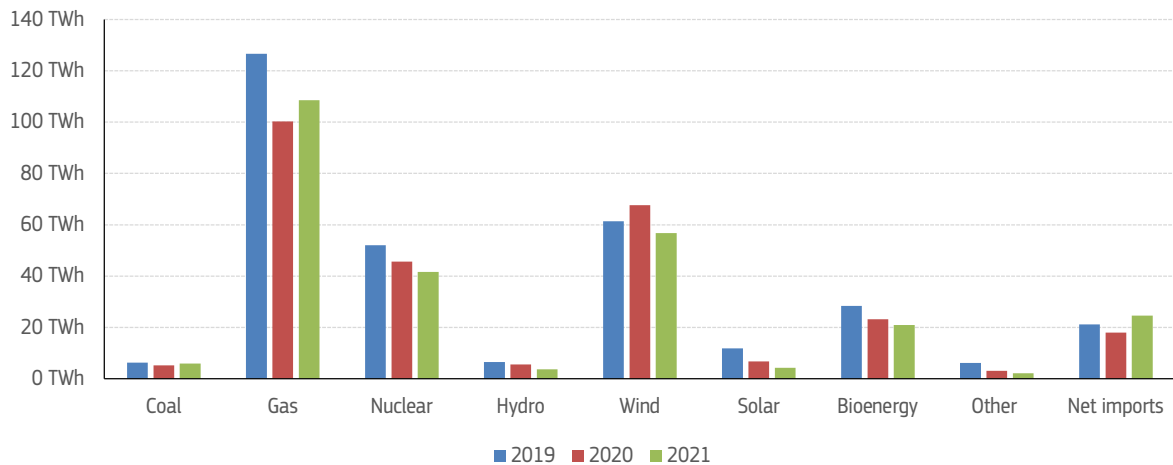
**Figure 38 – Daily average electricity prices on the day-ahead market in Great Britain and Ireland**



Source: Nord Pool N2EX, SEMO

- Figure 39** shows the decrease of gas and nuclear generation between 2019 and 2021, despite the increased output of the former in 2021, compared to 2020. The renewable output was reduced compared to previous years. Net imports from the continent increased to the highest of the studied years in 2021. The position of coal has not changed significantly, as the remaining capacity is now used mainly to cover demand peaks at times of low renewable availability. The renewable share fell to 35% in 2021, as a result of a decrease in wind output during the year.
- The early closure of nuclear reactors Hunterston B and Hinkley Point B by mid-2022, combined with the closure of Dungeness B nuclear power plant (1 GW) will remove nuclear installed capacity by two thirds by the end of 2022 (6 GW will remain). All existing UK reactors are scheduled to shut down by the end of 2031, with the exception of Sizewell B, which should be in operation until 2055. The exit date for coal generation was moved forward to October 2024. Ratcliffe power plant will be the last remaining unit from September 2022. The recent resurgence of coal generation in the UK has been fuelled by the surge in gas prices. Considering the nuclear and coal phase-out, the UK would become more reliant on electricity imports and flexible use of capacity to meet demand.
- The UK is a net importer of electricity. Great Britain has 5 GW of interconnection capacity to other Member States (France, Belgium and the Netherlands). Commercial operations of the 1 GW Eleclink interconnector via the channel tunnel to France are expected from mid-2022. The North Sea Link to Norway (1.4 GW) came online Q4 2021. In addition, the Viking link to Denmark (1.4 GW) should further increase interconnectivity between the UK and the continent in 2023. Another 1.4 GW power cable is due to be built in 2023-2024, connecting the Isle of Grain in the UK with Wilhelmshaven in Germany. The UK government plans to become a net exporter of electricity by 2040, thanks to a surplus of electricity coming from 20 GW of wind capacity (mainly offshore).

**Figure 39 – Evolution of the UK electricity mix in 2019, 2020 and 2021**

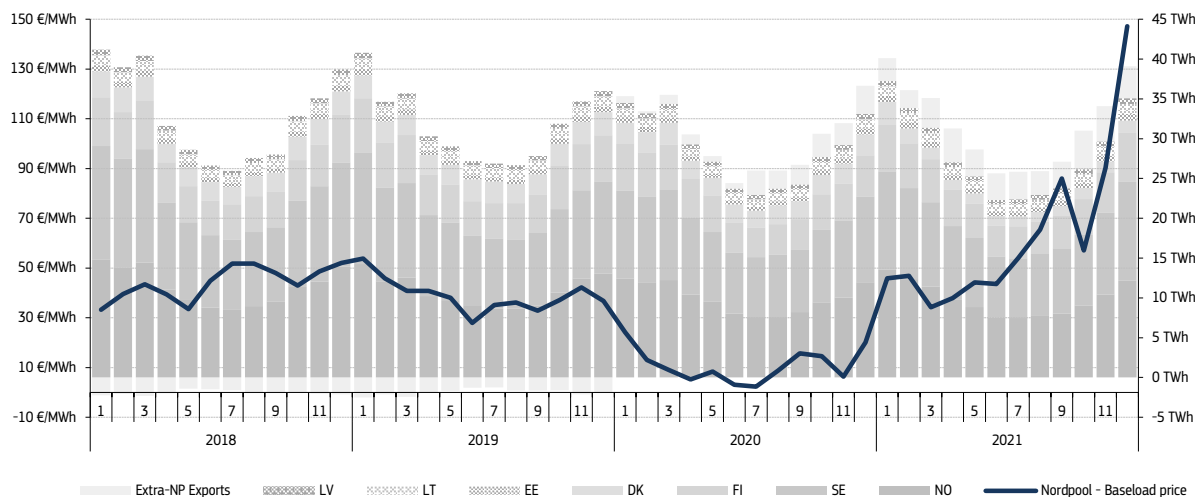


Source: BEIS

### 4.3 Northern Europe (Denmark, Estonia, Finland, Latvia, Lithuania, Sweden, Norway)

- As shown in **Figure 40**, Nord Pool prices strongly decreased in October, after a peak reached at the end of Q3 2021, showing important volatility. After a peak of 86 €/MWh in September, baseload prices dropped to 57 €/MWh in October (-34%). Baseload prices raised back to unprecedented highs in December, reaching 147 €/MWh (+158% from October 2021). Compared to Q4 2020, the average system baseload price surged by 618% to 98 €/MWh in the reference quarter. Low prices in the last quarter of 2020 helped to amplify the increasing effect of prices during the reference quarter. In December, Nordic hydropower reservoir levels fell amid cold and dry weather in Norway, Sweden and Finland. Increased demand as a result of colder-than-average December also contributed to the increase in prices at the end of Q4 2021.
- Finland is expected to improve its condition of net importer of electricity when Olkiluoto-3 nuclear power plant is commissioned during 2022, expecting to ease the pressure on Nordic power markets. Test productions on the nuclear power plant started in March 2022, with a ramp-up to full capacity planned by the end of July 2022.
- In December, Denmark awarded the 1 GW Thor wind farm project by the German company RWE. The wind farm is scheduled to reach full operation by 2027. Thor is the first of three offshore wind farms planned to meet net zero climate targets, in line with Denmark’s plans. Denmark also plans two energy islands, including a 5 GW offshore wind in the North and Baltic Sea acting as hubs and power-to-x conversion centres starting in the early years of the 2030 decade.

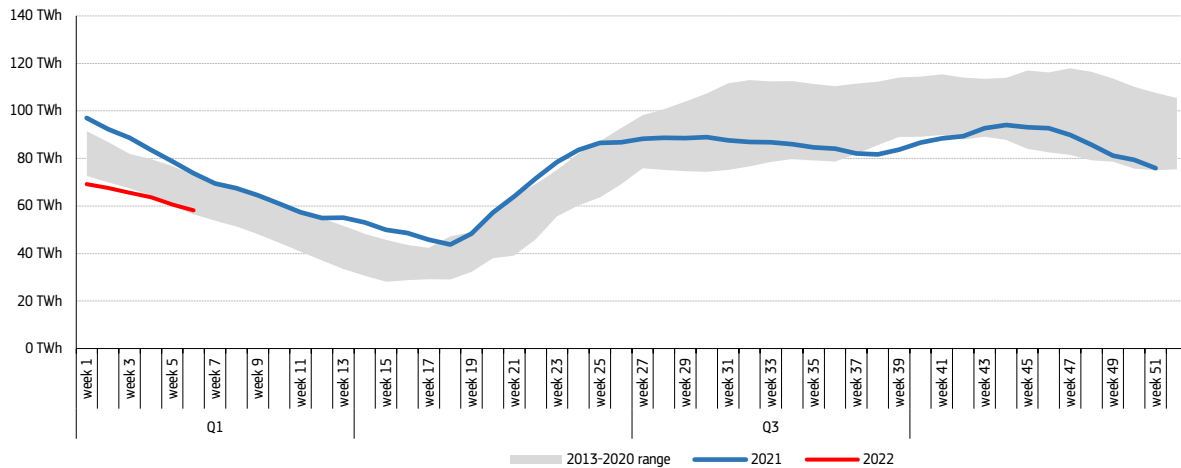
**Figure 40 – Monthly electricity exchange traded volumes and the average day-ahead wholesale prices in Northern Europe**



Source: Nord Pool spot market

- Figure 41** shows the weekly evolution of the combined hydro reservoir levels in the Nordic area (Norway, Sweden and Finland) in 2021 compared to previous eight years. Hydroelectric stocks slightly increased by 7% from October (average of 89 TWh) to the third week of November 2021 (average of 93 TWh), before falling steadily throughout the end of the quarter (average of 81 TWh in December). Dry and cold weather condition in the area triggered this reduced reservoir in the end Q4. Overall, hydro generation in the region registered a decline during Q4 2021, driven by Norway's 4% decrease (-1.4 TWh), Finland's 5% losses (-0.2 TWh), and the year-on-year drop of 6% in Sweden (-1.2 TWh).

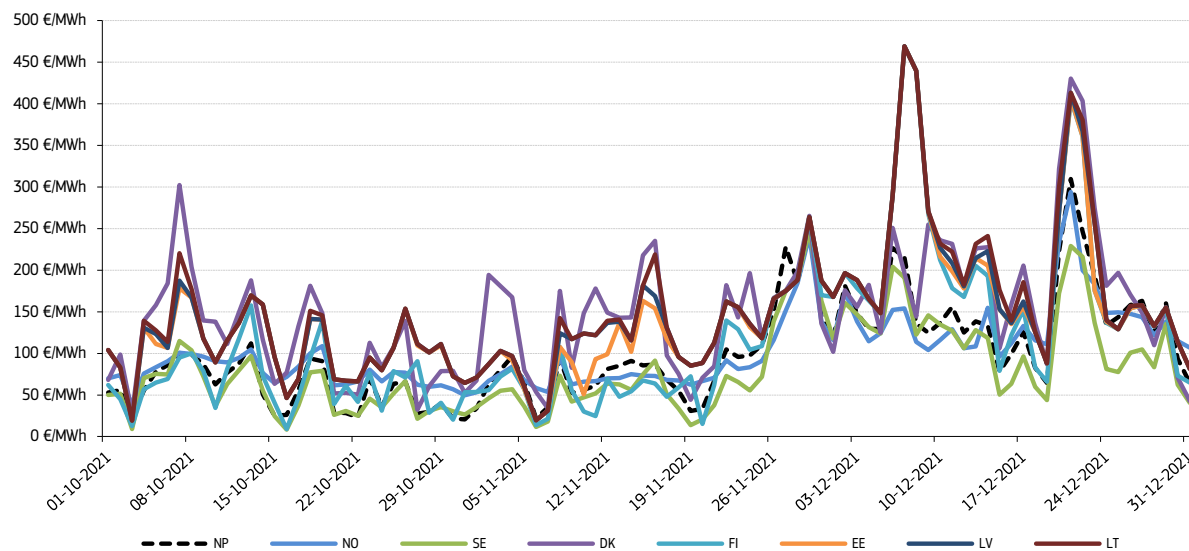
**Figure 41 – Nordic hydro reservoir levels in 2021, compared to the range of 2013-2020**



Source: Nord Pool spot market

- Figure 42** shows that average daily prices across Northern Europe continued to display a high degree of divergence throughout Q4 2021. The lowest daily regional price registered in the reference quarter dropped to 21 €/MWh on October 31, whereas the highest daily regional price registered reached 310 €/MWh on December 21 (+1376%). The highest spike was reached in the three Baltic countries on December 7 (469 €/MWh), amid colder-than-average temperatures and reduced Polish flows due to balancing difficulties registered in Poland on 6 December. Poland and Lithuania carried an emergency support test on the 488 MW LitPol link in early December to assess the blackstart capacities of the Lithuania grid. The synchronization of the Baltic network with the continental European grid is expected to be completed by 2025 at the latest.

**Figure 42 – Daily average regional prices and the system price on the day-ahead market in the Nordic region**

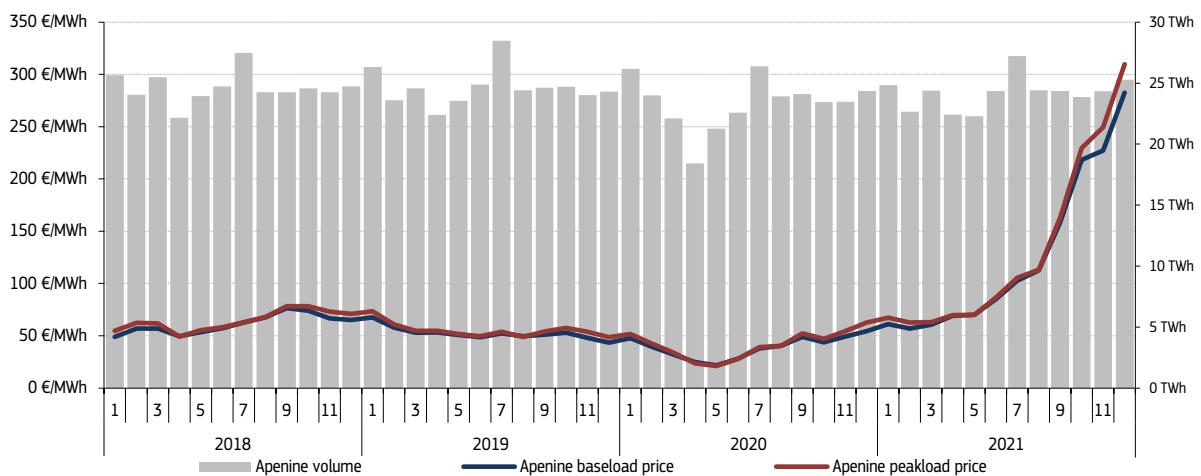


Source: Nord Pool spot market

#### 4.4 Apennine Peninsula (Italy, Malta)

- Rising Italian monthly average baseload electricity prices (**Figure 44**) reached a new all-time peak in December (310 €/MWh), driven by rising commodity prices (mainly gas). At 243 €/MWh, the Italian market recorded largest average baseload price in Europe during Q4 2021. The average baseload price rose 394% compared with Q4 2020 and was 95% above Q3 2021 levels. Trading volumes increased by 3% compared to the previous Q4. The rally of prices eased during January 2022 in the Apennine Peninsula, when baseload average prices returned to November 2021 levels on the back of lower gas prices.
- Like many other countries, Italy has been taking measures to alleviate the effect of high energy prices to end-consumers. The Italian government announced in December an increase amount of €3.8 billion fund to alleviate the effect of the crisis. New measures were announced in January, on top of what was scheduled for 2022. The total amount of funds was increased to €5.5 billion for the Q1 2022 spending.
- The results of the seventh auction for renewable capacity in the context of Italy's new renewable support scheme awarded 1.5 GW of renewable capacity out of 4.8 GW available. 72 GW of solar PV and wind are expected by 2030 in the country. The Italian Transition Ministry pushed through authorization of 347 MW of wind power capacity in the southern regions of Apulia and Basilicata. In December, Enel received authorization from the Transition Ministry of Italy to permanently close the 534 MW coal-fired power plant at La Spezia.
- The 1.2 GW link between Italy and France is expected to start its operations during the first half of 2022. Italy has eleven projects of interconnection planned by 2030, including increased capacities with Austria, Slovenia, Greece, Switzerland and Montenegro, and a new cable to Tunisia. A new link to Austria (300 MW) via Nauders is scheduled to start operating in 2023, while a new expansion at the Brenner Pass (100 MW) is set to go online during the same year.

**Figure 43 – Monthly electricity exchange traded volumes and average day-ahead wholesale prices in Italy**



Source: GME (IPEX)

- **Figure 44** shows the daily evolution of the national average price and the range of the regional price areas in the Italian market. The national average stayed mostly between 200 and 250 €/MWh during October and November. In December, prices moved above increasing volatility in the range of 220-330 €/MWh. Prices reach a peak value of 438 €/MWh on 22 December, due to skyrocketing gas prices and fell to 167 €/MWh at the end of the year.
- Italy is one of the largest producers of electricity from gas in the EU (gas represented 59% of the total generation in Italy during Q4 2021). Rising commodity prices, especially gas, played an important role in the surge in prices, in the context of continent-wide supply tightness (see **Figure 35**). Italian spot prices surged significantly in December, as record gas kept wholesale prices high. As a result, net power imports (mainly from Switzerland) increased to close the demand gap, despite the increase in wind and solar output during December.
- The Italian Power Exchange provides data on foreign price zones such as Malta, in addition to individual regional markets in Italy. The island is a net electricity importer from Italy (through Sicily) and thereby daily prices from the Italian power exchange (especially the Sicilian price zone) influence the Maltese wholesale electricity market. Traditionally, the Maltese zone forms the upper boundary of the band of regional prices. However, as visible in **Figure 44**, prices in the Maltese area did not follow the traditional pattern during the fourth quarter of 2021, often forming the lower bound of regional prices, as a direct result of the gap between prices in the north and south of Italy.

**Figure 44 – Daily average electricity prices in the Italian day-ahead market, within the range of different area prices**

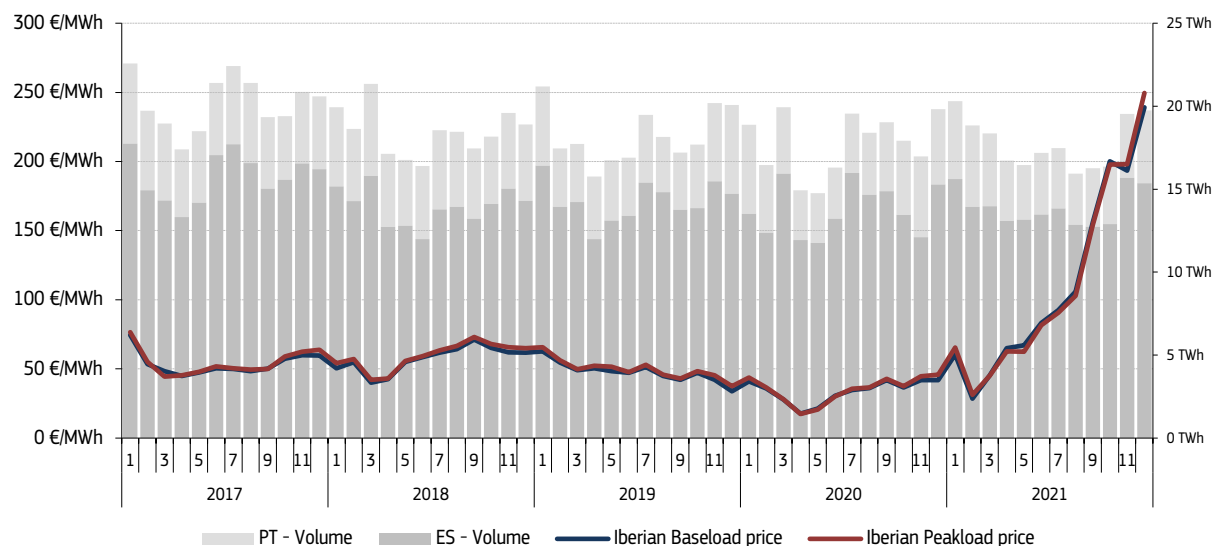


Source: GME (IPEX)

#### 4.5 Iberian Peninsula (Spain and Portugal)

- Figure 45** reports on monthly average baseload and peakload contracts in Spain and Portugal. During the fourth quarter of 2021, prices recorded all-time highs, mainly driven by gas prices. The average baseload electricity prices surged to 200 €/MWh in October, decreased slightly to 193 €/MWh in November on the back of improved wind output and they spiked to 250 €/MWh in December, due to booming gas prices and increased gas generation. Compared to Q4 2020, the average baseload price rose by 425% to 211 €/MWh in the reference quarter. Peak prices increased by 405% to 215 €/MWh. Trading activity was 8% higher compared to the previous Q4.
- Nearly 10 million customers (40% of consumers in Spain) are on tariffs directly linked with the wholesale electricity market. In light of the surges in wholesale prices that took place during the second half of 2021, the Government has been announcing different measures to tackle the social and economic effects of rising energy prices.

**Figure 45 – Monthly electricity exchange traded volumes and average day-ahead prices in the Iberian Peninsula**

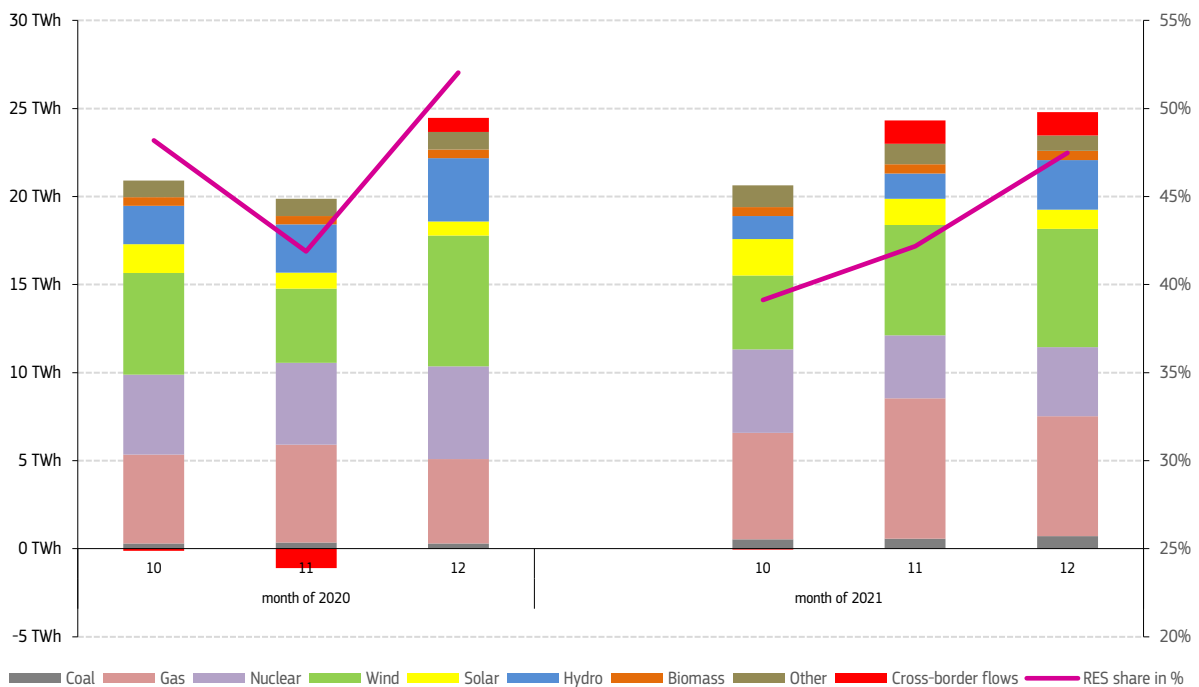


Source: Platts, OMEL, DGEG



- **Figure 46** displays the evolution of the monthly electricity generation mix in Spain during the fourth quarter of 2021, as well as during the same period of the previous year. Net generation increased by 4% year-on-year. Rising solar generation caused the share of renewable electricity sources to reach 43% during the reference quarter, although down from 47% a year before. Wind generation decreased by 1%, whereas solar output rose by 38%. Gas generation fell by 15% and the reduced remaining coal capacity increased its production by 90% (+0.6 TWh) year-on-year in Q4 2021. Nuclear generation decreased by 15% during Q4 2021 and covered a share of 18% of the total generation, lower than in the previous year. Spain switched from net exporter in Q4 2020, to net importer during Q4 2021, with 0.9 TWh of net imports accounting for 4% of the total generation during the quarter.
- In Spain, the coal fleet was closed at the end of 2021 with the exception of the two units in the Balearic Islands and the Abono power plant, which is integrated with steel manufacturing facilities. However, As Pontes coal-fired plant started generating electricity at the end of November to contribute with the functioning of the Spanish electricity system in the context of the energy crisis. Between 2025 and 2030 the nuclear plants of Almaraz, Asco I and Cofrentes are scheduled to shut down, leaving Asco II, Vandellos and Trillo which will close between 2030 and 2035.

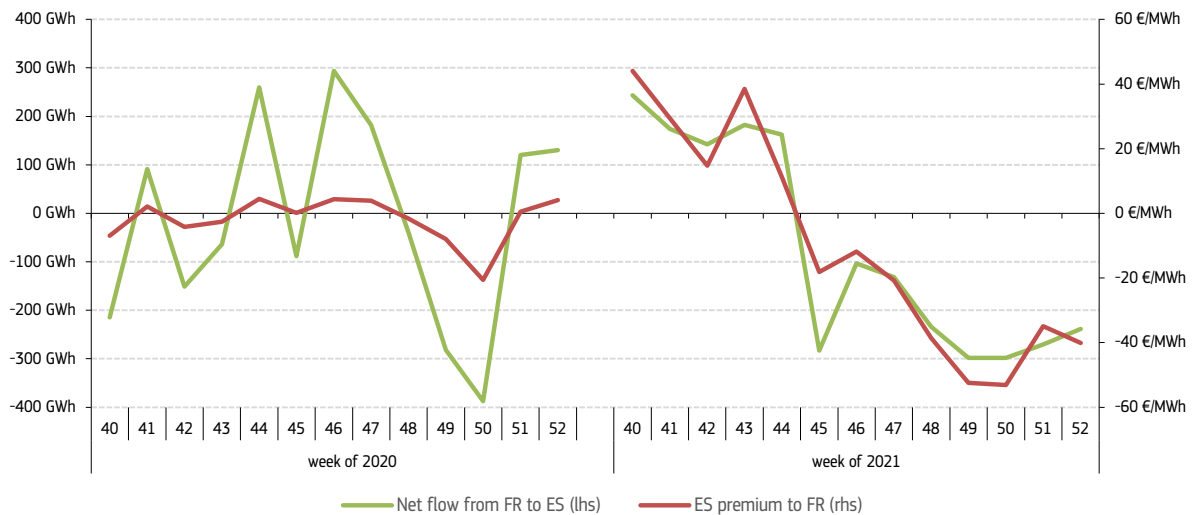
**Figure 46 – Monthly evolution of the electricity generation mix in Spain in Q4 of 2020 and 2021**



Source: ENTSO-E, Eurostat. Positive values of cross-border flows indicate net imports. Data represent net generation.

- **Figure 47** shows weekly electricity flows between France and Spain and price differentials between the two bidding zones. Spain kept its usual premium over the French day-ahead price until the fifth week of Q4 2021. As from the sixth week of quarter, Spain turned into a net power exporter on the back of strong wind output and reduced availability of the French nuclear fleet. The differential reached its maximum (36 €/MWh) during the second week of December amid the Spanish wind record output and delays of a couple of days in French nuclear reactors returning from maintenance. Additionally, reduced French hydroelectric reserves provided more room for France to rely on imports during that period.
- Currently, limited interconnection capacity with France is a bottleneck in the European power market as both sides could further benefit from complementary seasonal generation. The 2 GW Biscay interconnector project with France, delayed to 2027, will double the interconnection capacity between Spain and France. Spain needs 10 GW of cross border links to meet the EU target of interconnection capacity equal to the 10% of installed generation capacity.
- Bilateral trade with Morocco in Q4 2021 resulted in net imports of 105 GWh from Morocco. A third interconnection link with Morocco (700 MW) is expected to be online by 2026.

**Figure 47 – Weekly flows between France and Spain and price differentials between them**

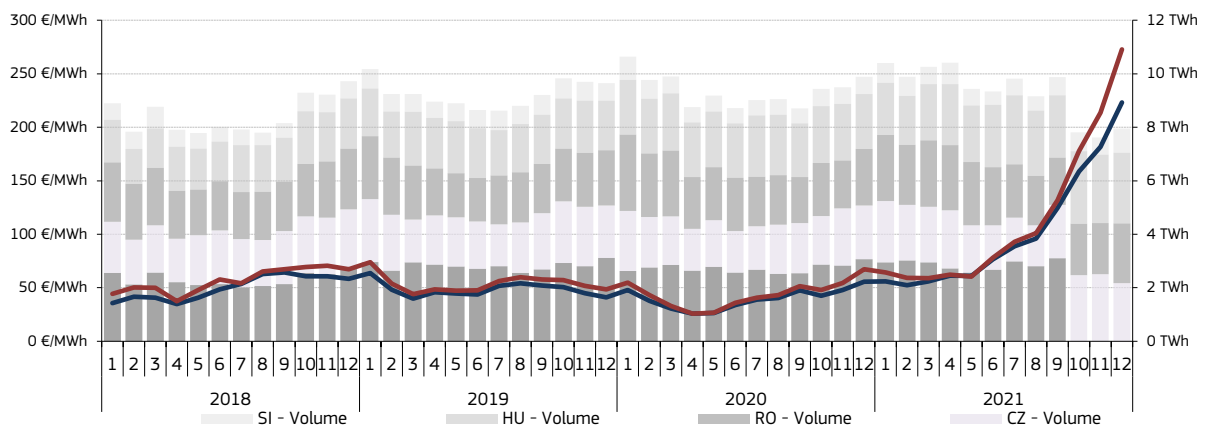


Source: ENTSO-E, OMEL, Platts

#### 4.6 Central Eastern Europe (Czechia, Hungary, Poland, Romania, Slovakia, Slovenia)

- **Figure 48** shows that average monthly prices for baseload power in Central Eastern Europe reached new historical levels, climbing to 223 €/MWh in December. Baseload prices escalated throughout the fourth quarter of the year, mainly triggered by tightness of the gas markets driving the price of this commodity up. The gap between baseload and peakload monthly averages increased from 12% in July to 22% at the end of the Q4 2021. When compared to Q4 2020, the average baseload price in the reference quarter rose by 286% to 188 €/MWh. Traded volumes in the reference quarter increased by 11% compared to the previous Q4.
- Polish electricity demand rose considerably during 2021 in comparison to the previous year (see **Figure 3**) and Q4 2021 was not an exception to this development. The economic recovery supported the increase in demand and the gap was filled by increased coal generation and net imports. A HDVC 700 MW interconnector of 290 kilometres is expected to connect Poland and Lithuania by 2025. Despite the 180 €/MWh average prices of December in Poland, baseload prices are still at discount to most of neighbouring countries thanks to current lower generation costs of the Polish coal fleet.

**Figure 48 – Monthly electricity exchange traded volumes and average day-ahead prices in Central Eastern Europe (CEE)**



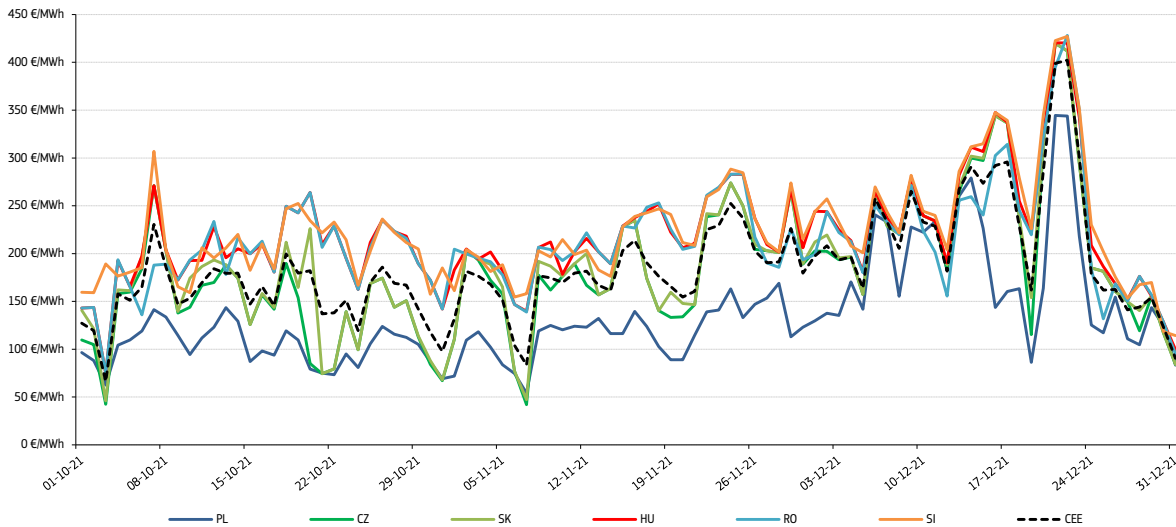
Source: Regional power exchanges, Central and Eastern Europe (CEE), CEE: PL, CZ, SK, HU, RO, SI

- **Figure 49** shows that daily average baseload prices in the markets (CZ, SK, HU, RO, PL) saw an unprecedented increase in price and volatility during Q4 2021, on the back of rising commodity prices (mainly gas, but also coal). Moreover, Q4 2021 price developments in CEE show how markets with higher dependence on gas (e.g. Hungary) were impacted more than markets relying on different sources (e.g. Poland). CEE prices moved between 140 and 180 €/MWh in October, rose among 160 and 200 €/MWh in November, increasing prices and volatility in December between 160 and 270 €/MWh. The Polish market, having started a day-ahead market in February 2021, reversed

its former premium towards CEE prices from an average of almost +6 €/MWh in Q4 2020, to a discount of -53 €/MWh in Q4 2021. The large coal-fired fleet in Poland has also been taking the impact of high commodity prices (coal and also CO<sub>2</sub>), as high electricity prices have also affected Member States with reduced exposure to gas, such as Poland (although to a lesser extent than markets relying on gas). This is an interesting signal towards renewables, as high penetration levels of solar and wind would reduce exposure of electricity prices to commodities (gas and carbon).

- The Pan-European day-ahead power market coupling was extended across six new borders during June 2021. The project started in December 2018 and connects borders of the group integrated by Czechia, Slovakia, Hungary and Romania with the Multi Regional Coupling on the borders of Poland, Germany and Austria. Price coupling maximises the social welfare of market participants by allowing simultaneous calculation of prices and cross-border flows.

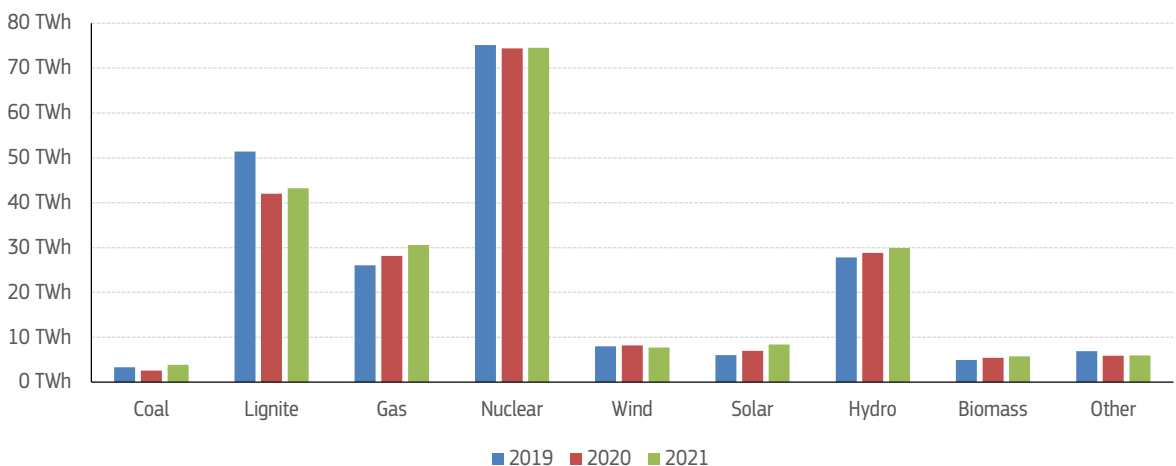
**Figure 49 – Daily average power prices on the day-ahead market in the CEE region**



Source: Regional power exchanges

- **Figure 50** compares the combined electricity generation mix of the CEE region (excluding Poland) among 2019, 2020 and 2021. The most substantial change took place in the lignite segment which bore the brunt of the covid-related demand shock in 2020 and increased slightly in 2021. All in all, lignite and experienced an 8 TWh drop in output (2019-2021). This was mainly driven by falling generation in Czechia (-4 TWh) and Romania (-3 TWh). The missing lignite volumes were partly replaced by higher gas generation (+4 TWh) in Czechia, Slovakia and Hungary. The share of renewables increased from 22% in 2019 to 25% thanks to a solar generation boom in Hungary (and Poland) and improved hydro generation in Czechia, Romania and Slovenia. Nuclear remained the dominant generation technology with a 35% share in the mix and a considerable presence in all five markets. Total generation fell remained at similar levels of 2019 and increased by 5% compared to 2020.

**Figure 50 – Evolution of the electricity mix in the CEE region (excluding Poland) in 2019, 2020 and 2021**



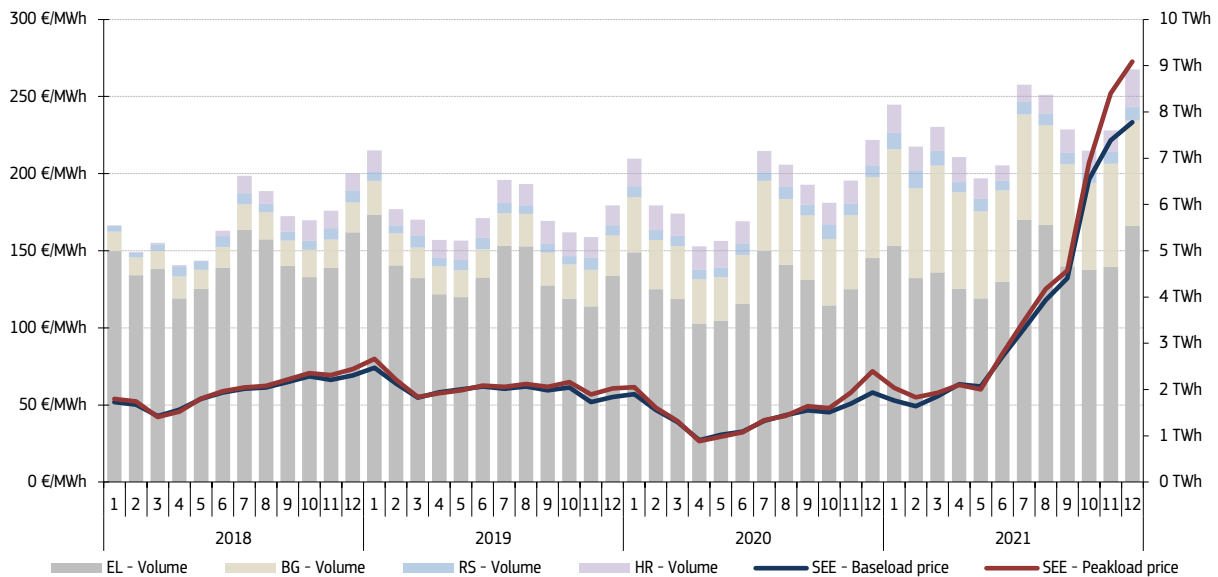
Source: ENTSO-E.

- In Poland, which is analysed separately due to significant differences in the size and structure of its generation base, the combined share of coal and lignite in its mix decreased to 72% in 2021 (compared to 73% in 2019), while renewables increased their share from 16% in 2019 to 18% in 2021, thanks to booming generation of solar and the increase in wind, hydro and biomass generation. Gas decreased its share in the mix from 10% in 2019 to 9% in 2021, underlining the limited short-term potential for coal-to-gas switching (or vice versa). Poland's solar PV capacities have been growing rapidly thanks to the introduction of an auction support system and grants for rooftop installations. Around 3.2 GW of additional solar PV capacity were registered in 2021 (up from 1.3 GW in 2019).
- The share of coal in Poland's mix should decrease to 56% by 2030 thanks mainly to significant wind capacity additions (especially in the offshore segment). Additionally, Europe's largest coal-fired plant, Bełchatów (5 GW), is planned to cease operations by 2036.

#### 4.7 South Eastern Europe (Bulgaria, Croatia, Greece and Serbia)

- **Figure 51** shows that trade-weighted monthly average baseload prices in the SEE region climbed steadily throughout the reference quarter. Peakload contracts climbed up even faster and their premium over baseload rose to 17% in December. Baseload average prices reached 233 €/MWh in December, exceeding all previous monthly record prices from the past years. Strong gas prices in the context of economic recovery drove electricity prices up. Marginal costs of gas generation in countries like Greece, with high levels of generation from this energy commodity supported high energy prices, especially in December. The average quarterly baseload price rose by 322% year-on-year to 217 €/MWh in Q4 2021, 86% above Q3 2021 and 287% higher than Q4 2019. The average quarterly peakload price rose 311% above Q4 2020 levels to 244 €/MWh.

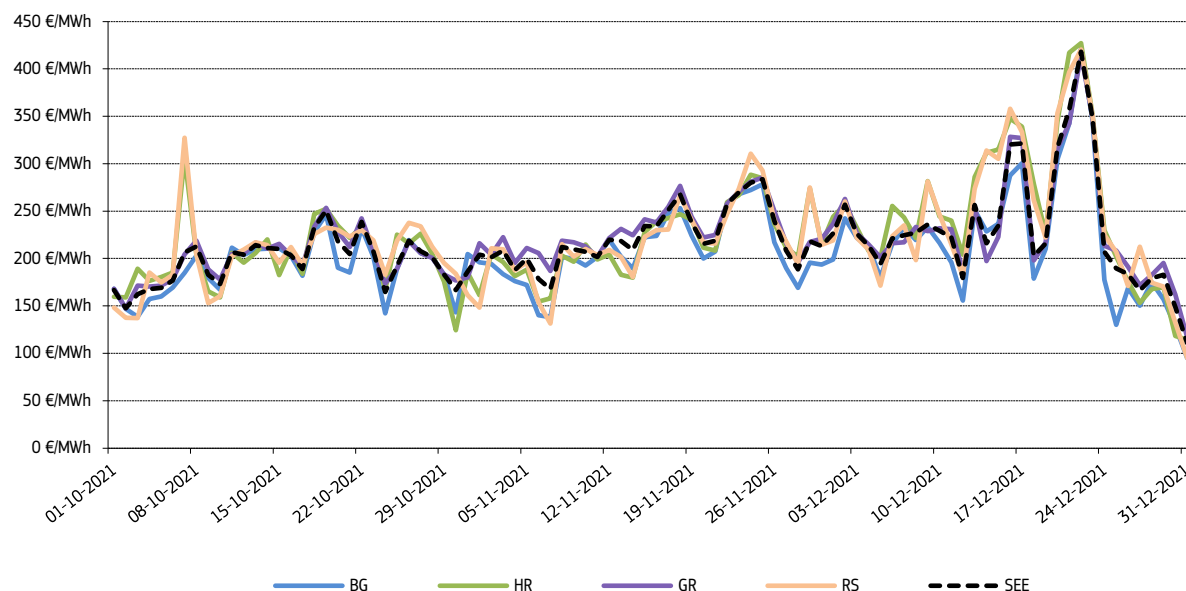
**Figure 51 – Monthly traded volumes and baseload prices in South-Eastern Europe (SEE)**



Source: IBEX, LAGIE, CROPEX, SEEPEX

- As shown in **Figure 52**, daily baseload price movements in individual markets were relatively aligned during Q4 2021, with the exception of elevated Serbian and Croatian day-ahead prices in early October and parts of December. Prices moved between 170 and 210 €/MWh in October and between 200 and 240 €/MWh in November. Volatility started to increase to high levels in December, on the back of general tightness of supply in Europe due to high gas prices. Prices moved between 190 and 260 €/MWh in December. In line with the rest of Europe, wholesale electricity prices reached an all-time peak on 22 December at 418 €/MWh, on the back of skyrocketing gas prices and low wind output. However, prices fell towards the end of the year reaching a low 111 €/MWh on the last day of the year thanks to eased gas prices and improved renewable output.

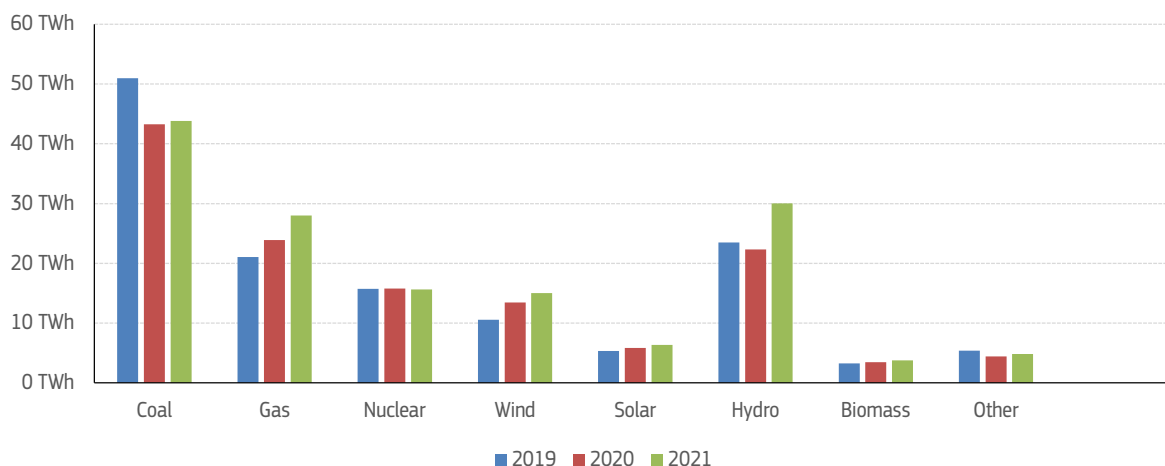
**Figure 52 – Daily average power prices on the day-ahead market in Bulgaria, Croatia, Greece and Serbia**



Source: IBEX, LAGIE, SEEPEX, CROPEX

- Figure 53** compares the combined electricity generation mix of the SEE region between 2019, 2020 and 2021. In 2021, coal and lignite generation increased slightly its output (+1 TWh) year-on-year and decreased by 7 TWh compared to 2019 levels. Gas output increased by 4 TWh year-on-year and 7 TWh when compared with 2019. Nuclear generation remained practically unchanged through the three years. Hydro experienced an improved year with additional 8 TWh year-on-year. The share of lignite in the regional mix fell from 38% in 2019, 33% in 2020 to 30% in 2021. Increased gas generation in Greece (+4 TWh) drove up the share of gas from 16% in 2019 to 19% in 2021. Renewable penetration rose from 31% in 2019, to 37% in 2021 thanks to rising hydro generation in the region and wind output in Greece. During COP26, Croatia announced the closure of Plomin 2 coal thermal power plant by 2033 or sooner. Greece continues with its plan to phase out lignite by 2025 with the conversion of Ptolemaida 5 to natural gas.

**Figure 53 – Evolution of the electricity mix in the SEE region in 2019, 2020 and 2021**



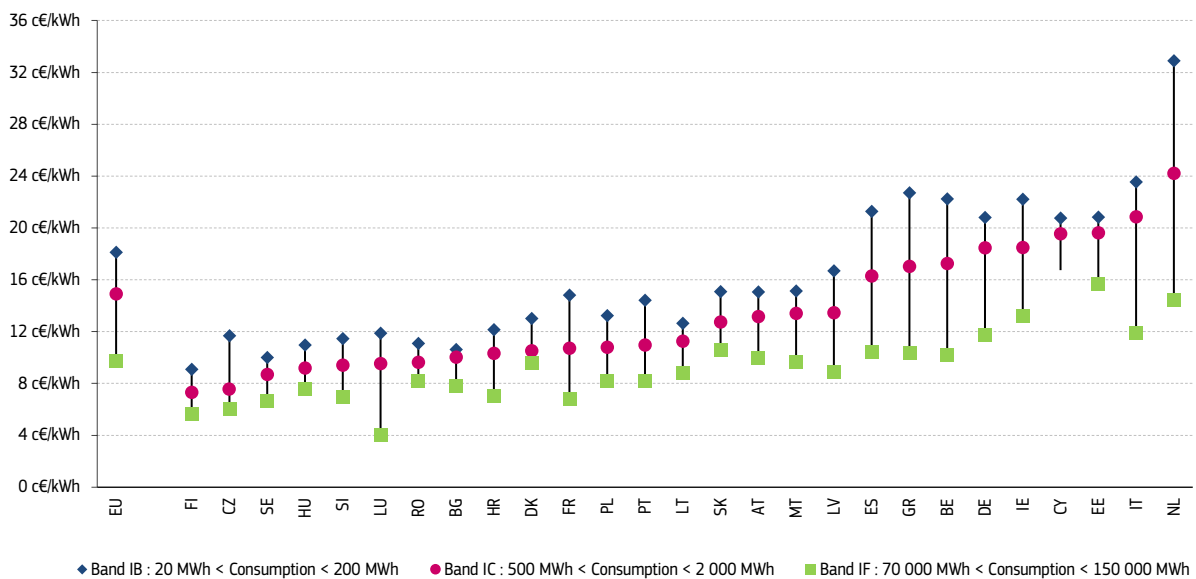
Source: ENTSO-E

## 5 Retail markets

### 5.1 Retail electricity markets in the EU

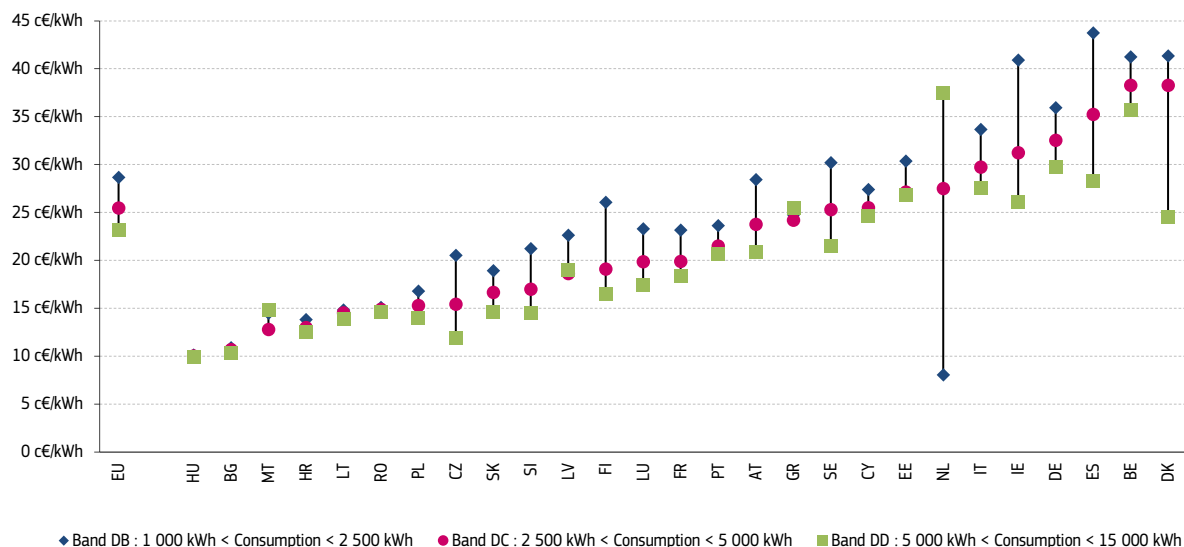
- Figures 54 and 55** display the estimated retail prices in December 2021 in the 27 EU Member States for industrial customers and households. Monthly and quarterly retail prices are estimated by using half-yearly prices from Eurostat (with the latest available figures relating to the first half of 2021) and Harmonised Consumer Price Indices (HICP) for both the household prices and industrial consumers. Prices are displayed for three different levels of annual electricity consumption for both consumer types (Eurostat bands IB, IC and IF for industrial customers and bands DB, DC and DD for households). In most cases, it holds for both consumer types that the lower the consumption, the higher the price of one unit of electricity (per MWh consumed). Dutch, Maltese, Greek and Latvian household prices are an exception.
- Smaller industrial consumers (band IB) were assessed to pay the highest prices in the Netherlands (32.9 c€/kWh) and Italy (23.6 c€/kWh), followed by the Greece and Belgium (22.7 and 22.2 c€/kWh respectively). The lowest prices in the same category were assessed to be in Finland (9.1 c€/kWh) and Sweden (10.0 c€/kWh). The ratio of the largest to smallest reported price was above 3:1. Compared to December 2020, the average assessed EU retail price for the IB band rose by 20% to 18.1 c€/kWh. On the other side of the consumer spectrum, industrial companies with large annual consumption (band IF), including most energy-intensive users, paid the highest prices in Cyprus (16.7 c€/kWh), followed by Estonia (15.7 c€/kWh), the Netherlands (14.4 c€/kWh) and Ireland (13.2 c€/kWh). Luxembourg (4.0 c€/kWh) was assumed to have by the lowest prices, with Finland and Czechia (5.7 and 6.0 c€/kWh) coming close behind. The ratio of the highest to lowest price for large industrial consumers was 4:1 for this consumer type. Compared to December 2020, the average assessed EU retail electricity price for the IF band rose by 24% to 9.8 c€/kWh.
- In the household segment, the Netherlands (37.5 c€/kWh) was assessed to have the highest electricity price for large consumers (band DD), followed by Belgium (35.7 c€/kWh), and Germany (32.5 c€/kWh) in the third place. The lowest prices for big households were calculated for Hungary (9.9 c€/kWh) and Bulgaria (10.3 c€/kWh). Compared to December 2020, the average assessed EU retail electricity price for the DD band rose by 17% to 23.1 c€/kWh. In the case of small households, Spain saw the highest prices (43.8 c€/kWh), followed by Denmark (41.3 c€/kWh) and Belgium (41.2 c€/kWh), while Netherlands (8.1 c€/kWh), Hungary (10.1 c€/kWh) and Bulgaria (10.9 c€/kWh), found themselves on the other side of the price spectrum. Compared to December 2020, the average assessed EU retail electricity price for the DB band rose by 17% to 28.7 c€/kWh.

**Figure 54 – Industrial electricity prices, December 2021 – without VAT and recoverable taxes**



Source: Eurostat, DG ENER.

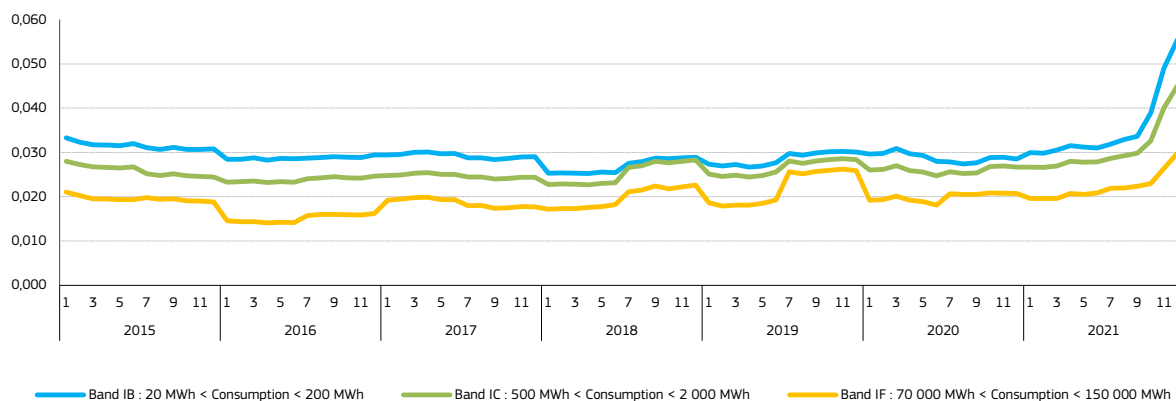
**Figure 55 – Household electricity prices, December 2021 – all taxes included**



Source: Eurostat, DG ENER

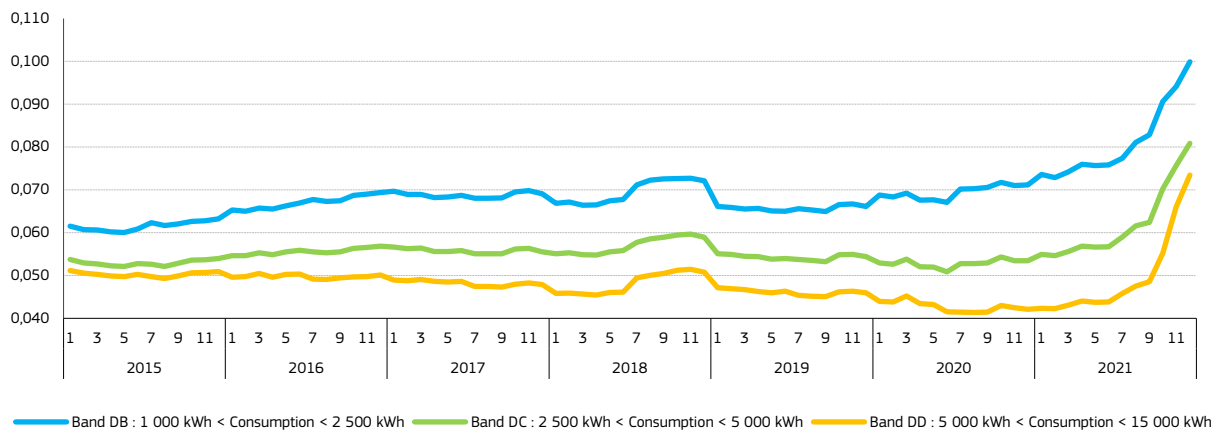
- **Figure 56 and Figure 57** display the convergence of retail prices across the EU over time, by depicting their standard deviation. Industrial prices for small and medium-sized businesses showed increasing divergence in Q4 2021, at an accelerated higher pace than in the previous quarter. In all industrial retail prices bands (small, medium and large businesses), the divergence levels reached the highest register of the series.
- In the household sector, price divergence increased during Q4 2021. In fact, household prices reached the highest level of divergence on record in all the three analysed categories. Household prices tend to be more impacted by regulated elements (network charges, taxes and levies) so their variation across Member States is greater than in the case of industrial consumers.

**Figure 56 – Standard deviation of retail electricity prices in the EU for industrial consumers**



Source: Eurostat, DG ENER

**Figure 57 – Standard deviation of retail electricity prices in the EU for household consumers**

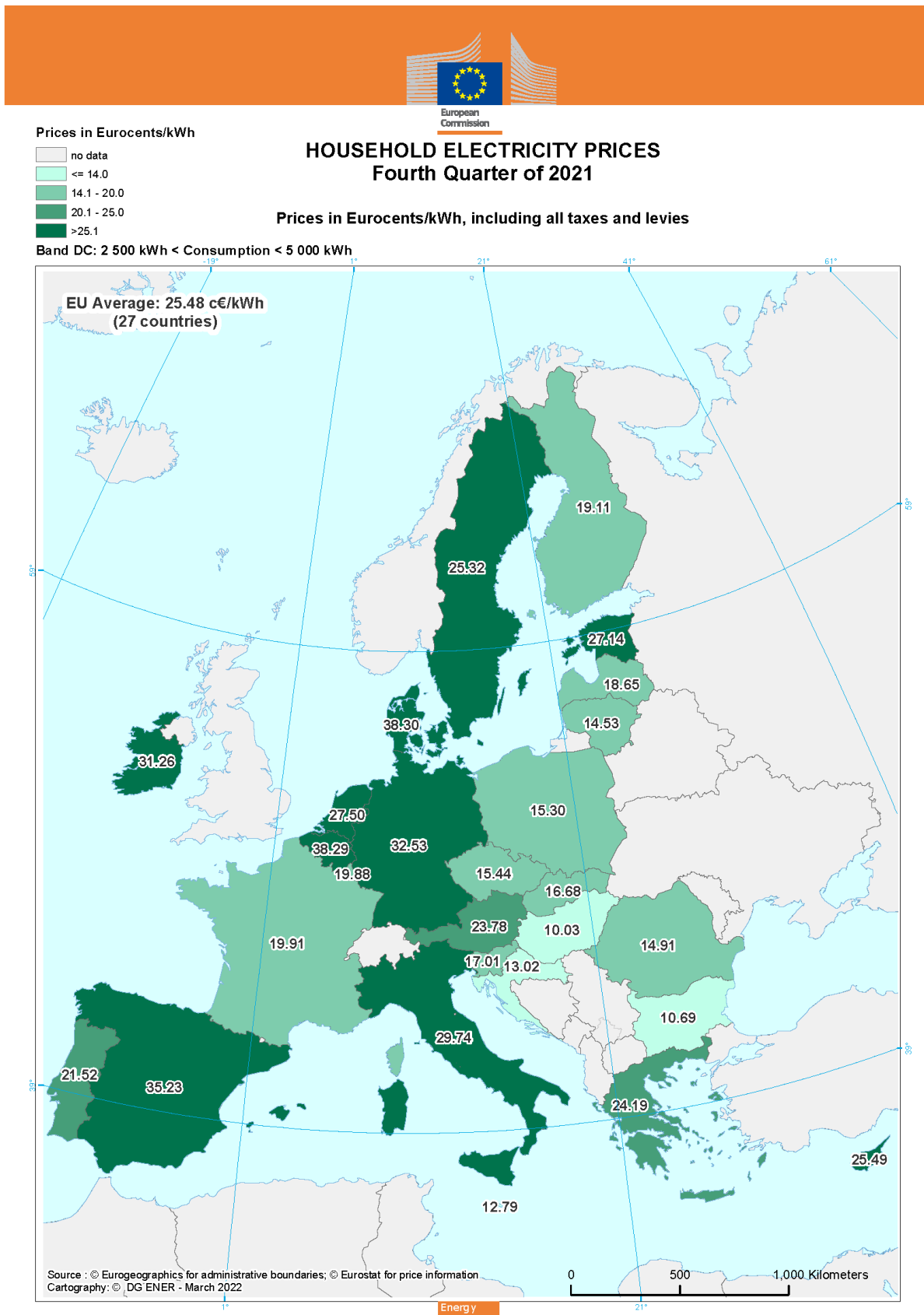


Source: Eurostat, DG ENER

- Figures 58 and 59** display the estimated electricity prices paid by EU households and industrial customers with a medium level of annual electricity consumption in the last month of Q4 2021. In the case of household prices, Denmark and Belgium topped the list (38.3 c€/kWh), followed by Spain (35.2 c€/kWh) and Germany (32.5 c€/kWh). As was the case in previous quarters, Hungary (10.0 c€/kWh) and Bulgaria (10.7 c€/kWh) retained their position as Member States with the cheapest household electricity prices. The EU average increased by 18% to 25.5 c€/kWh in the reference quarter compared to December 2020. The largest year-on-year increases in the household category were assessed in the Netherlands (+100%), Estonia (+98%), followed by far from Greece and Spain (+47%). The biggest year-on-year falls were estimated for Czechia (-13%) and Slovakia (-3%). See **Figure 60** for more details.
- In the case of mid-sized industrial consumers, Finland was assessed to have the most competitive price in Q4 2021 (7.3 c€/kWh), followed by Czechia (7.6 c€/kWh), and with Sweden (8.7 c€/kWh) taking the third place. Meanwhile, the Netherlands (24.2 c€/kWh) and Italy (20.9 c€/kWh) stood at the other end of the spectrum. At 14.9 c€/kWh, the average retail price for industrial customers in the EU in the reference period rose by 18% compared to Q4 2020.

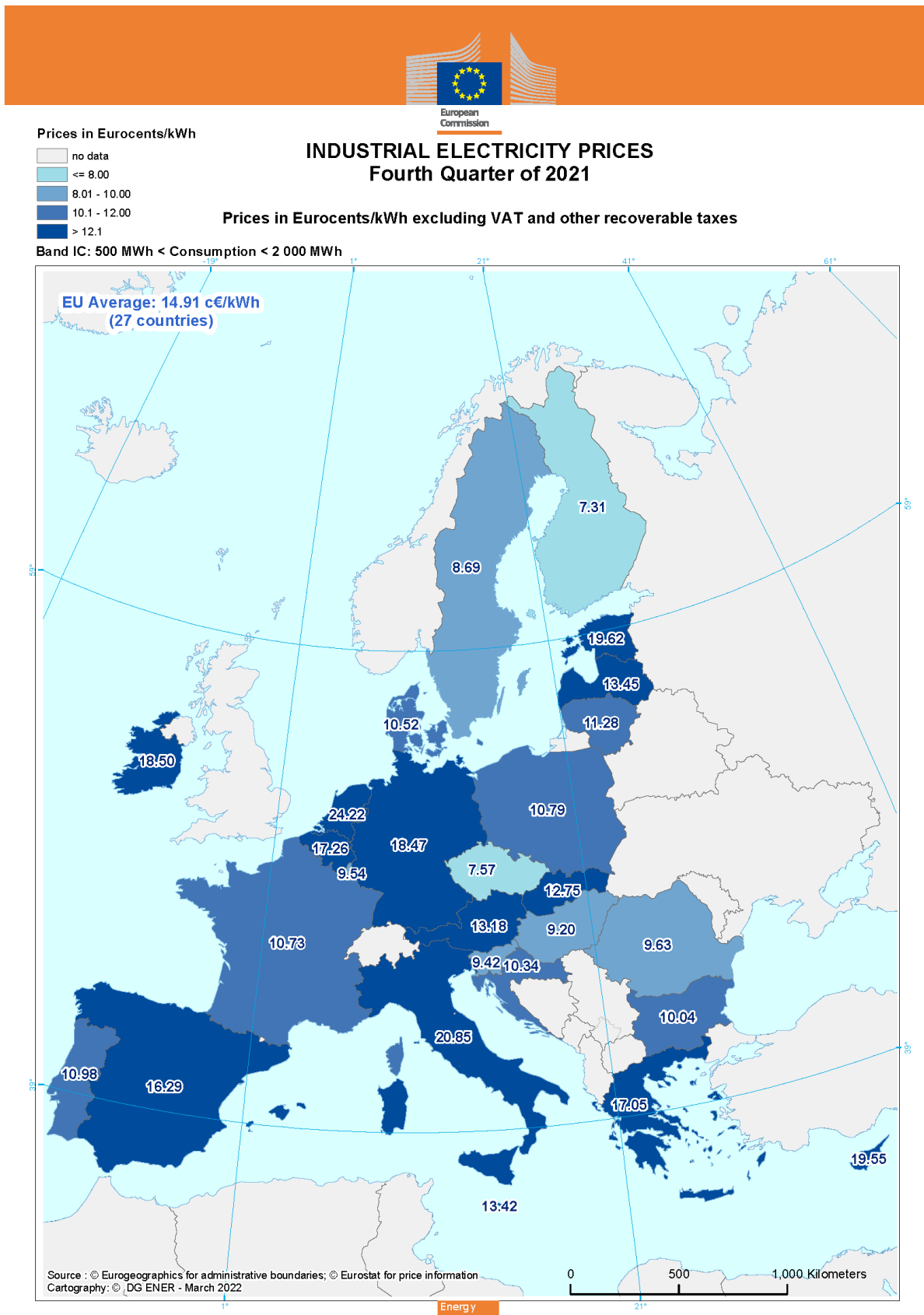


Figure 58 – Household Electricity Prices, fourth quarter of 2021



Source : Data computed from Eurostat half-yearly retail electricity prices and consumer price indices

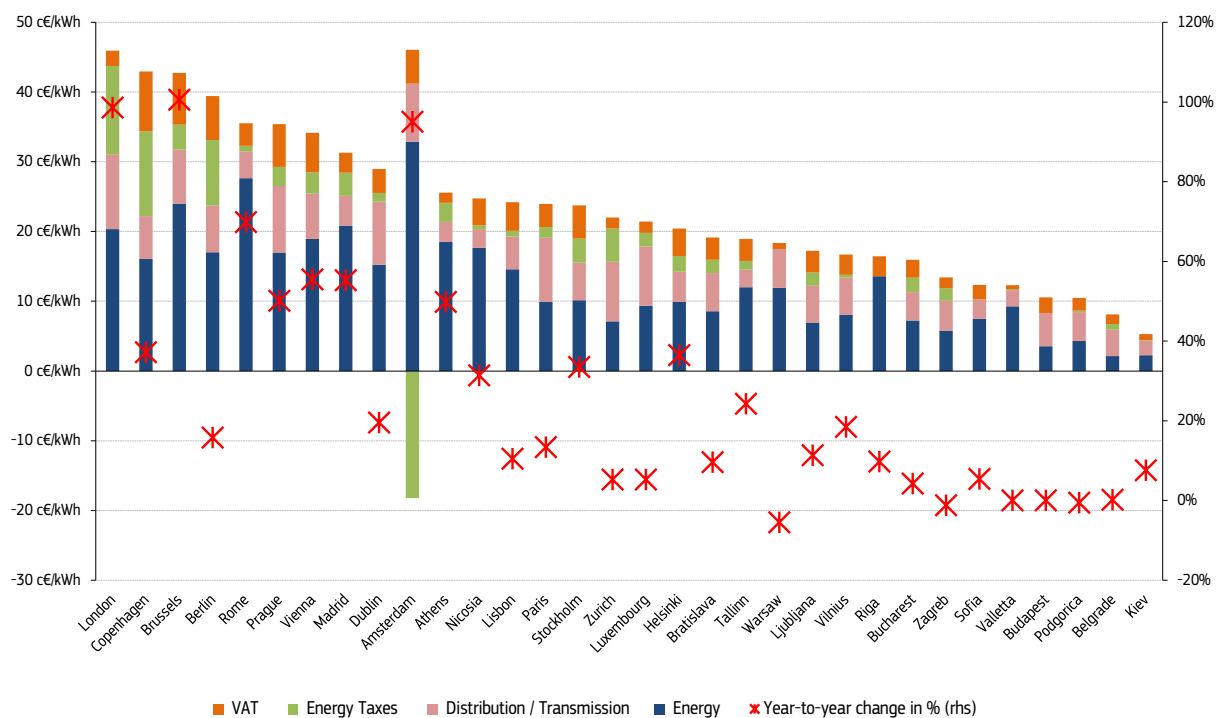
Figure 59 – Industrial Electricity Prices, fourth quarter of 2021



Source : Data computed from Eurostat half-yearly retail electricity prices and consumer price indices

- Figure 60** shows retail electricity prices for representative household consumers in European capital cities, and their composition divided into four categories (energy, network charges, energy taxes and the value added tax). In February 2022, the highest prices were observed in London, Copenhagen and Brussels (45.9, 43.0 and 42.7 c€/kWh, respectively). In the case of London and Brussels, the energy component share was 44% and 56% of the final bill, while in the case of Copenhagen, energy taxes accounted for almost a third of the final bill. The lowest prices among EU capitals were recorded in Budapest (10.5 c€/kWh), Valletta and Sofia (12.3 c€/kWh). This corresponds to the Eurostat data analysed in **Figure 55**. EU-wide, retail prices have been rising since the end of 2020 and have started a steep climb since September 2021. Inflation pressures have intensified throughout the year, due to rising wholesale prices, which have been driven largely due to high gas prices and to a lesser extent, more expensive emission allowances.
- The highest levels of the energy component in Europe were reported from Amsterdam, Rome, and Brussels (32.9, 27.7 and 24.0 c€/kWh). The lowest levels of the energy component (2-4 c€/kWh) were recorded in the capitals of countries with stronger forms of price regulation (Belgrade, Kiev and Budapest). The EU average for the energy component was 13.9 c€/kWh (up from 7.5 c€/kWh in February 2021). Out of the 27 capitals, twelve had a more expensive energy component than the EU average.
- The highest network charges were recorded in London (10.7 c€/kWh), Prague and Paris (9.6 c€/kWh and 9.2 c€/kWh, respectively) where they accounted between 23%-48% of the total price. The lowest network fees were collected in Riga (0 c€/kWh), Kiev (2.1 c€/kWh) and Valletta (2.8 c€/kWh). The EU average in the reference quarter was 5.3 c€/kWh (down from 5.6 c€/kWh in February 2021).
- Apart from London (12.7 c€/kWh), the highest energy taxes were paid by households in Copenhagen (12.1 c€/kWh) and Berlin (9.4 c€/kWh). Riga, Sofia, Budapest and Warsaw stood at the other end of the range, with zero energy taxes collected by local authorities. The average energy tax component reached 1.5 c€/kWh (down from 2.7 c€/kWh in February 2021). Varied VAT rates applied to electricity, ranging from 5% in Malta and London to 21% in Hungary, also contribute to differences in household prices across Europe. Member States have already been using the measures included in the [Energy Prices Toolbox](#) to alleviate the effects of rising energy prices, in the form of lower energy taxes, levies and VAT applicable to household customers of energy.
- The tax reduction subcomponent (tax credit) that applies to electricity customers in the Netherlands is currently higher than the annual energy tax amount that corresponds to a typical residential customer in Amsterdam. Even in cases when the tax credit is higher than the tax amount, the customers still receive the full credit as a discount from their overall annual bill. In practice, this has resulted in a negative value of the Dutch tax component in the price breakdown. This development has also significantly reduced household electricity prices countrywide, which is visible in **Figure 55**, and contributed to the unusual effect in which the lower the consumption, the lower the price per kWh.

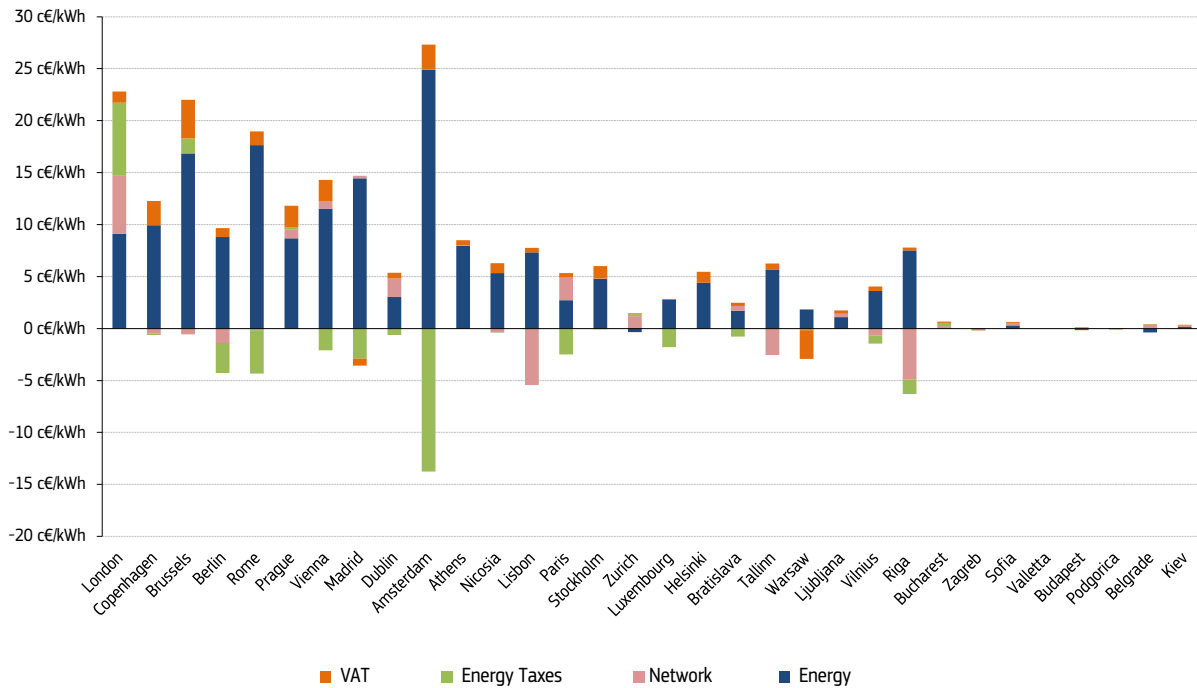
**Figure 60 – The Household Energy Price Index (HEPI) in European capital cities in Eurocents per kWh, February 2022**



Source: Vaasaett

- Compared to the same month of the previous year, the largest price increase in relative terms in Europe in February 2022 were observed in Brussels (+101%), London (+99%) and Amsterdam (95%). As shown in **Figure 61**, rising prices were driven by increasing wholesale prices in Netherlands, Latvia and Italy. In fact, the rise of wholesale prices was the most important factor for the increase of end user prices in 26 of the 27 EU capitals (Budapest being the only exception). 4 of the 27 EU capitals reported prices lower or unchanged, compared to the same month of the previous year, with Warsaw (-5%) and Zagreb (-1%) posting the largest relative drops. Households in the Polish and the Croatian capitals benefited mainly from lower energy and VAT components.

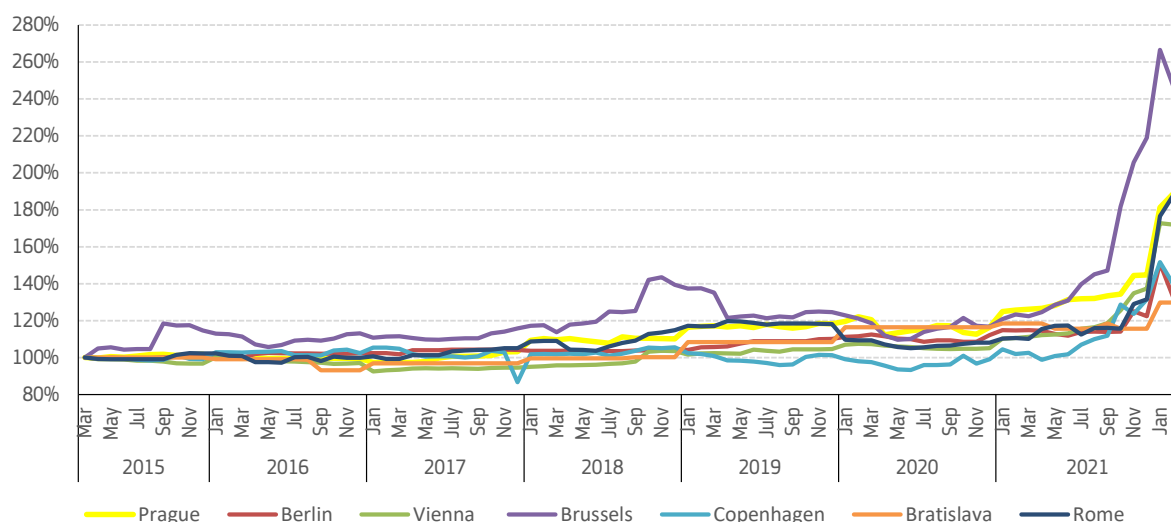
**Figure 61 – Year-on-year change in electricity prices by cost components in the European capital cities comparing February 2022 with February 2021**



Source: Vaasaett

- Figure 62** compares how household retail prices in selected EU capitals changed in relative terms over the last six years. The biggest increase (+147%) was registered in Brussels and was driven mainly by a rising energy component (39% of the change). Prague came in second with an 89% increase since February 2015, followed closely by Rome (+88%) and Vienna (+72%). Retail prices for households in Copenhagen, which have been roughly the same as six years ago, have recently seen an increase (+40% compared to February 2015) due to a rise in the energy component.

**Figure 62 – Relative changes in retail electricity prices in selected EU capitals since 2015**

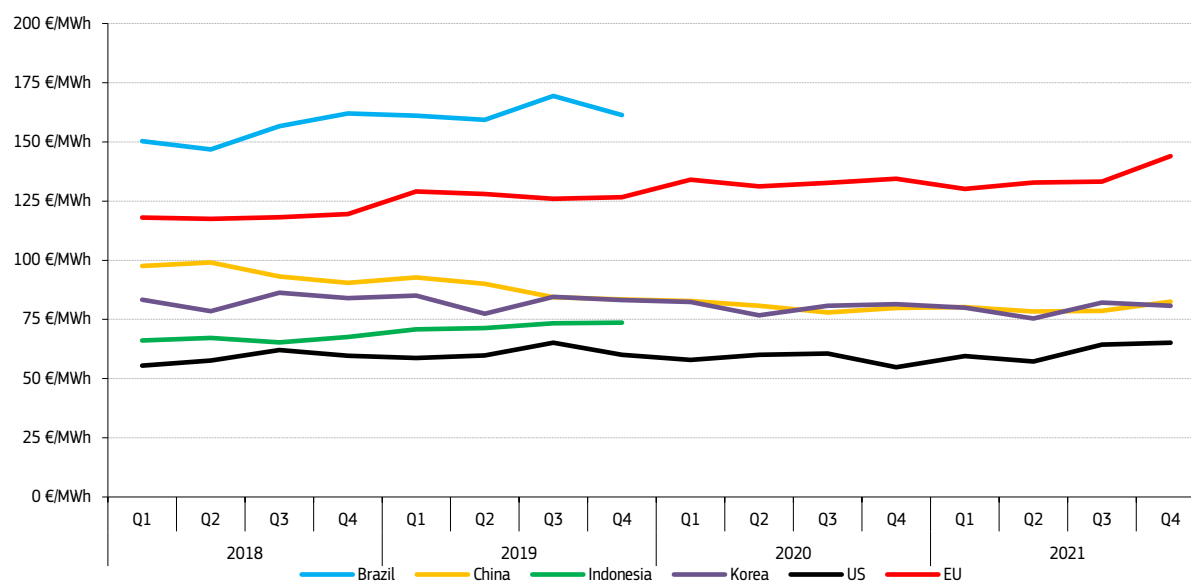


Source: Vaasaett

## 5.2 International comparison of retail electricity prices

- **Figure 63** displays industrial retail prices paid by consumers in the EU and in its major trading partners. Prices include VAT (with the exception of US prices) and other recoverable taxes for the purpose of comparability.
- Electricity prices for industrial users in the EU increased by 7% in Q4 2021 compared to the equivalent quarter in 2020. Meanwhile, Chinese industrial prices increased by 3%, halting the steady downward trend observed over the past two years. Industrial electricity prices in the United States increased by 19% quarter-to-quarter in Q4 2021.

**Figure 63 – Retail electricity prices paid by industrial customers in the EU and its main trading partners**



Source: Eurostat, IEA, CEIC, DG ENER computations. The latest data for Brazil and Indonesia is not available.

## 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. If the level of dark spreads is above 0, coal power plant operators are competitive in the observed period. *See dark spreads.*

**Clean spark spreads** are defined as the average difference between the cost of gas and emissions, and the equivalent price of electricity. If the level of spark spreads is above 0, gas power plant operators are competitive in the observed period. *See spark spreads.*

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

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

**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 36% efficiency. Dark spreads are given in this publication, with the coal and power reference price as reported by *Bloomberg*.

**Emission allowances' spot prices** are defined as prices for an allowance traded on the secondary market and with a date of delivery in the nearest December.

**European Power Benchmark (EPB9)** is a replacement of the former Platt's PEP index discontinued at the end of 2016, computed as weighted average of nine representative European markets' (Belgium, Czechia, France, Italy, Germany, Netherlands, Spain, the United Kingdom and the Nord Pool system price) day-ahead contracts.

**EPS** is a consumption-weighted baseload benchmark of five most advanced markets offering a 3-year visibility into the future. Markets included in the benchmark are France, Germany, the Netherlands, Spain and Nord Pool. Prices are weighted according to the consumption levels in individual markets. Forward prices are rolled over towards the end of each year, meaning that the year-ahead benchmark in 2021 shows the price for 2022; and the year-ahead curve in 2022, in turn, shows baseload prices for delivery in 2023.

**Flow against price differentials (FAPDs):** By combining hourly price and flow data, 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 electrical systems.

With the closure of the day-ahead markets (D-1), the prices for each hourly slot of day D are known by market participants. Based on the information from the power exchanges of two neighbouring areas, market participants can establish hourly price differentials. Later in D-1, market participants also nominate commercial schedules for day D. An event named 'flow against price differentials' (FAPD) occurs when commercial nominations for cross border capacities are such that power is set to flow from a higher price area to a lower price area. The FAPD chart in this quarterly report provides detailed information on adverse flows, presenting the ratio of the number of hours with adverse flows to the number of total trading hours in a quarter.

**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.

**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 electricity prices:** Twice-yearly Eurostat retail electricity price data and the electricity component of the monthly Harmonised Index for Consumer Prices (HICP) for each EU Member States to estimate monthly electricity retail prices for each consumption band. The estimated quarterly average retail electricity 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.

**Spark spreads** are reported as indicative prices giving the average difference between the cost of natural gas delivered ex-ship and the power price. As such, they do not include operation, maintenance or transport costs. Spreads are defined for a gas-fired plant with 49% efficiency. Spark spreads are given with the gas and power reference price as reported by *Bloomberg*.

**Tariff deficit** expresses the difference between the price (called a tariff) that a *regulated utility*, such as an electricity producer is allowed to charge and its generation cost per unit.

