



Quarterly Report

on European Electricity Markets

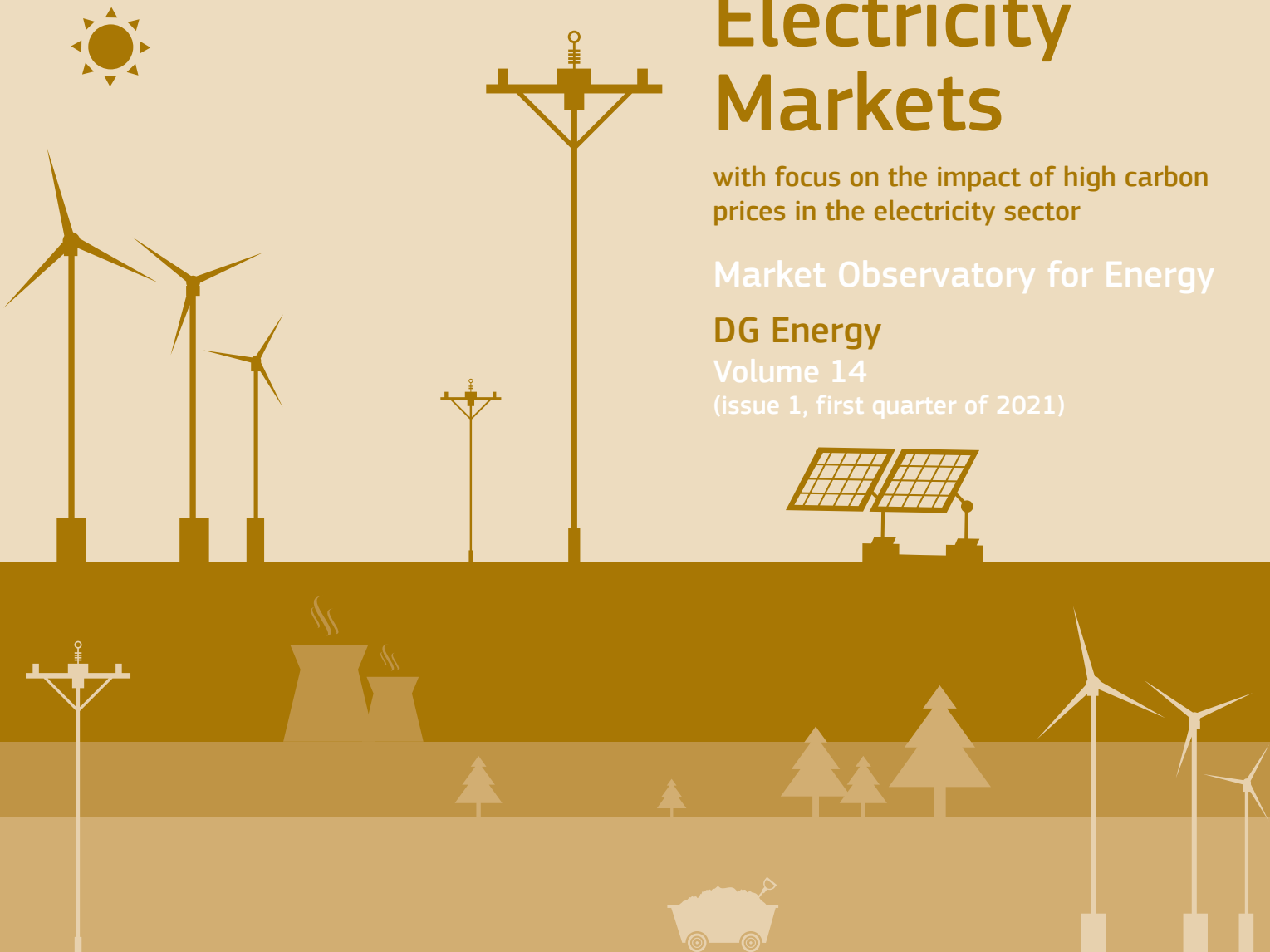
with focus on the impact of high carbon
prices in the electricity sector

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HIGHLIGHTS OF THE REPORT

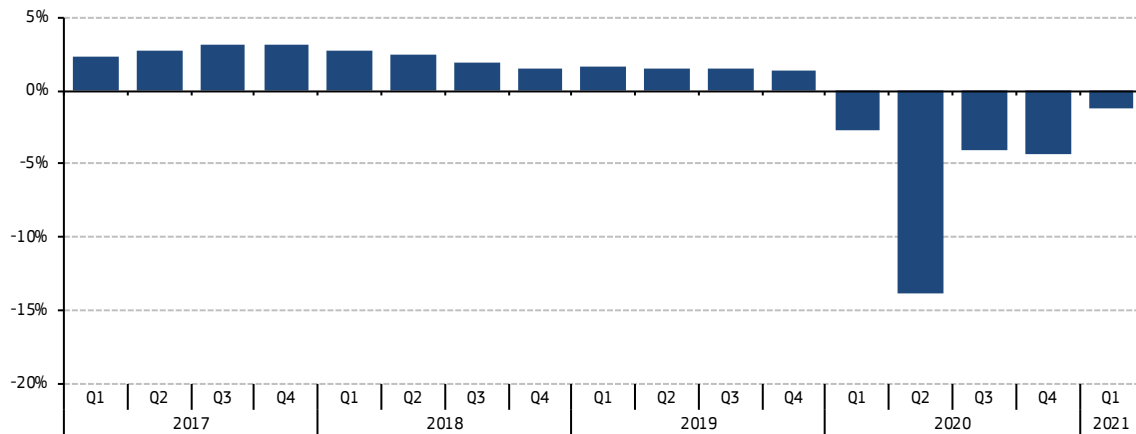
- **The first quarter of 2021 brought electricity consumption in Europe close to pre-pandemic levels**, despite remaining restrictions on economic and social activity. However, part of the recovery stemmed from colder temperatures compared to 2020. **EU-wide consumption increased by 2% year-on-year in Q1 2021**, as increasing heating load and recovering manufacturing industry were able to reverse low levels of consumption in other sectors of the economy.
- The first quarter of 2021 was exceptional in several aspects. The long and cold winter of 2020/2021, fostered a recovery in electricity demand and made more space for fossil fuels in the electricity mix, in spite of increasing carbon prices. Despite lower average wind speeds across Europe, **the share of renewables still managed to reach 38%, beating fossil fuels (35%) as in the last quarter of 2020**. The presence of renewables in the mix was supported by an increase of 11% in hydro generation (+11 TWh), 7% of biomass (+2 TWh) and solar (+1 TWh) on yearly basis. Low levels of electricity demand during the start of the COVID crisis (Q1 2020) amplified the comparative increase in fossil fuel generation during this quarter. Coal and lignite generation rose by 14% (+15 TWh), while nuclear output remained practically unchanged. Gas profited from the increased demand only marginally, seeing its output grow by 3% (+5 TWh), as higher gas prices, partially reversed coal-to-gas switching in some markets during the reference quarter. The carbon footprint in the EU power sector increased by 9% in Q1 2021 compared to Q1 2020, but it was still 12% lower than in Q1 2019. Despite high carbon prices, emissions could still rise this year not only compared to 2020 (which had exceptionally lower emissions), but also to 2019. This is due to more extreme temperatures, both colder winter spells and warmer summer temperatures, the unexpected strength of the post-pandemic recovery, and lower than average wind speeds, that all together, offset the higher carbon price.
- **Prices of emission allowances have moved decidedly above 50 €/tCO₂ since May**, putting coal and lignite power plants at a greater disadvantage against their less polluting gas-fired competitors. CO₂ prices have already reached the level at which most older and less efficient hard coal and lignite power plants in Europe are no longer profitable to operate. As a result, early closures have been announced and carried out. High carbon prices also raise wholesale electricity prices as costs are passed into retail prices with some delay. The impact will ultimately depend on the composition of electricity prices in each market. In the medium-term, high carbon prices send a powerful signal boosting investments in renewable capacities. At current CO₂ prices, it is cheaper to build a renewable generation source rather than keep state-of-the-art coal/gas power plants in most Member States.
- **Carbon prices are an important player in the decarbonisation of the electricity sector** in the medium-term, but in the short-term perspective, high carbon prices alone are not a guarantee of falling CO₂ emissions. **Other factors such as low renewable generation, high gas prices or high demand due to cold winters/warm summers can overcome their effect**. Rising gas prices can lead to a worsening of gas-fired power plant margins, in spite of record-high carbon prices as can be observed in 2021. In the long-term, as the system decarbonises over time, the effect of high carbon prices on investment in renewables will gradually weaken. Renewables will have to present themselves as cheaper alternatives to carbon-intensive processes in hard-to-decarbonise sectors of the economy.
- **Most electricity markets in the region saw wholesale prices returning to pre-pandemic levels during Q1 2021**. Practically every European country experienced a surge in prices and multi-year records in January (with the exception of South Eastern Europe). The European Power Benchmark averaged 53 €/MWh in Q1 2021, 79% higher on yearly basis. The rising trend continued in the following months on the back of extremely high fuel prices. In June, electricity prices in many markets, including France and Germany, reached 13-year highs.
- **The number of hours with negative wholesale prices in Q1 2021 (217) was relatively low compared to previous quarters**. Most of negative hourly prices instances occurred in February and March, during periods of mild weather, high renewable generation and low consumption (weekends). **In contrast, prices hit multi-year highs in early January (59 €/MWh) amid low wind speeds, lack of dispatchable capacities, increasing CO₂ and gas prices, and strong demand due to cold weather**. A similar event took place in the second week of February. Under the current transformation of the electricity system, such episodes are likely to be more frequent as renewable sources are variable by nature and conventional power plants are retired from the system.
- Demand for electrically chargeable vehicles (ECVs) rose over Q1 2021 on yearly basis as Member States kept support policies aimed at incentivising purchases, higher number of models are being advertised at more affordable prices, and uncertainty around the use of the combustion engine increases. **More than 350,000 new ECVs were registered in the EU in the first quarter of 2021**. This was the second-highest quarterly figure on record and translated into an impressive 14% market share, more than one and a half times higher compared to China and four times higher than in the United States.

1 Electricity market fundamentals

1.1 Demand side factors

- Figure 1** shows that the second wave of the pandemic which swept across Europe during Q4 2020, has partially faded in Q1, fostering a recovery from the previous months. The start of lift on restrictions on economic and social activity, had a palpable impact on the daily lives of millions of citizens and operations of the majority of business. According to an estimate published by Eurostat in June 2021, seasonally adjusted GDP in the EU decreased by 1% year-on-year between January and March 2021. This was a relevant improvement compared to the depths of the last spring contraction, but nevertheless meant a fifth consecutive quarter of negative growth since the start of the pandemic. Member States with a growing economy in Q1 2021 were Ireland (+12.8%), Estonia (+5.0%), Luxembourg (+4.9%), France and Lithuania (both +1.2%). The highest year-on-year declines in Q1 2021 were reported in Portugal, Austria and Spain.

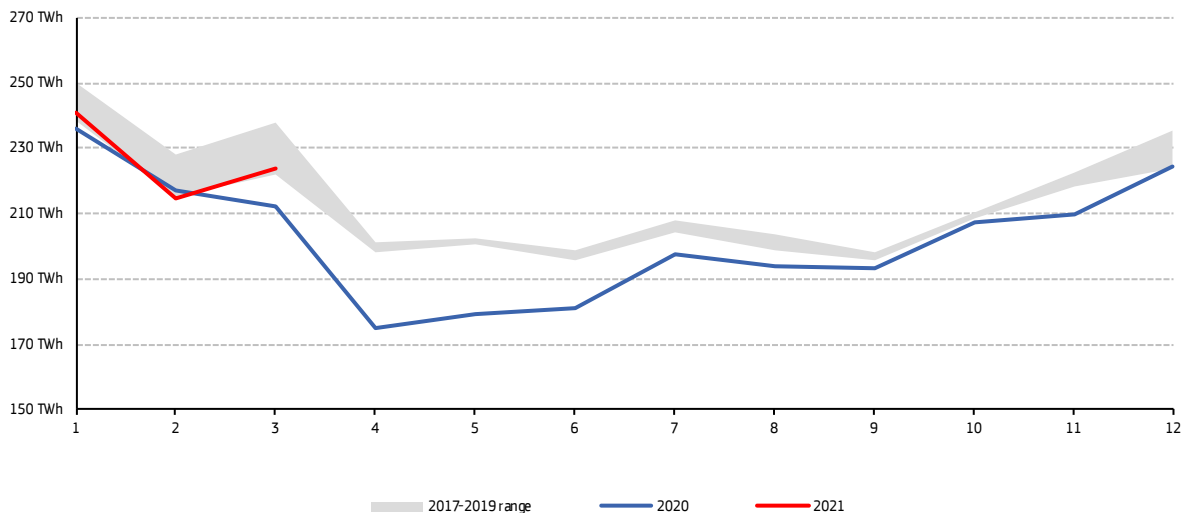
Figure 1 – EU GDP annual change (%)



Source: Eurostat

- Electricity consumption in the EU stayed 2% above last year's levels in Q1 2021, helped by recovering industrial activity and strong household demand. Despite a small setback in February, influenced by less cold average temperatures, demand returned to pre-pandemic levels in March, helped by a colder beginning of the quarter than in 2020. The EU average hid wide differences in developments in individual Member States. While most of Member States saw consumption going up year-on-year, sometimes considerably (Estonia +10%, Finland +8%, Sweden +8%), six remained in negative territory. Cyprus and Greece experienced notable falls in consumption on the back warmer than usual weather (Cyprus -7%, Greece -6%, see **Figure 4**). Major economies presented similar levels of consumption as Q1 2020.

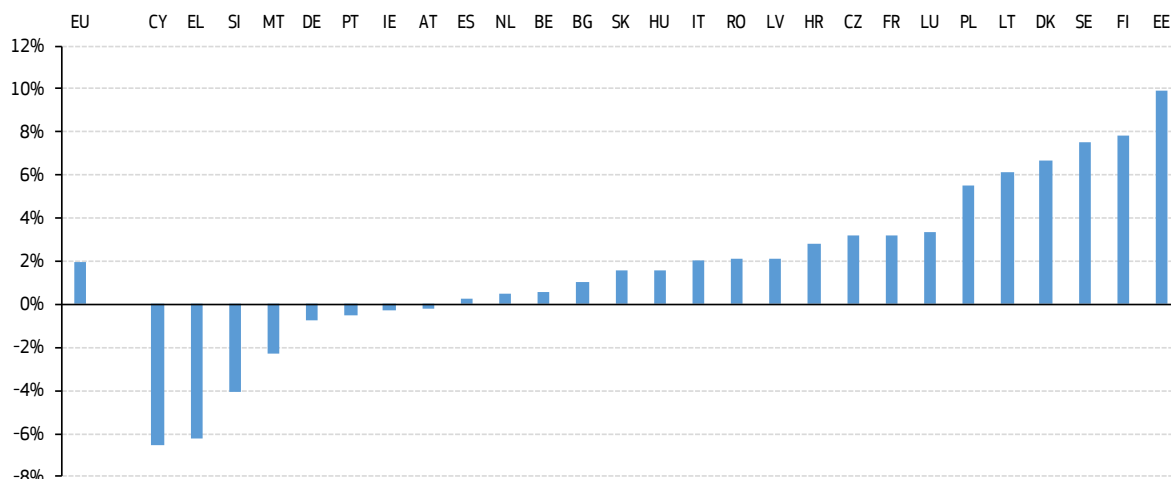
Figure 2 – Monthly EU electricity consumption



Source: Eurostat

- **Figure 3** sums up changes in electricity consumption between the first quarter of 2020 and Q1 2021. Greatest declines in electricity consumption occurred in southern regions due to warmer weather than average (Cyprus and Greece). Nordic and Baltic countries increase was influenced by cold weather and the slight economic recovery from the pandemic. EU-wide consumption increased by 2% on the back of lower temperatures, especially during January. Total figures conceal structural changes in energy use across the economy which could be long-lasting. Large industrial consumers, responsible for the biggest portion of total demand, are still struggling to return to normal levels of demand, while the rising demand in residential consumption from winter working from home pushed overall electricity demand in Europe.

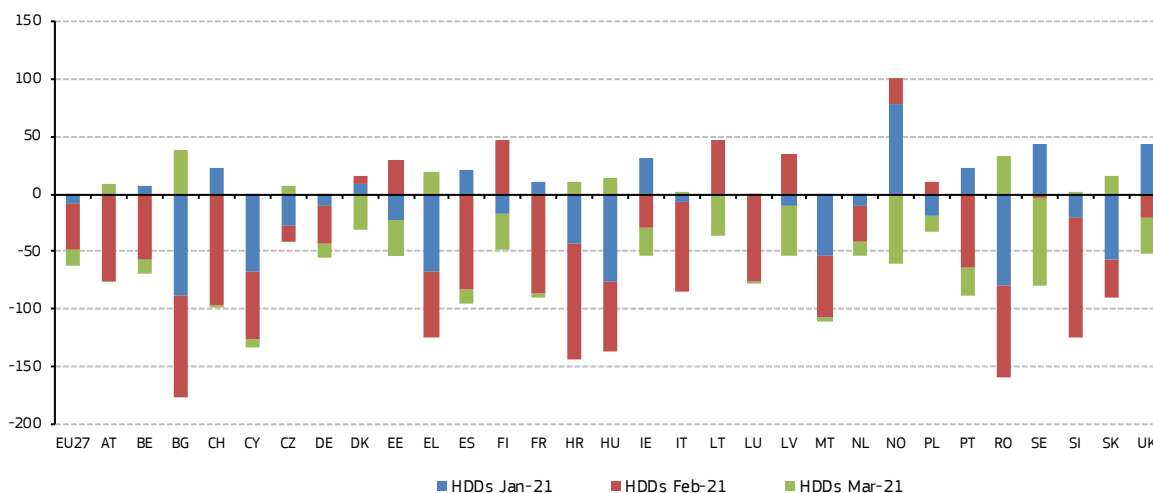
Figure 3 – Annual changes in electricity consumption in Q1 2020 and Q1 2021 by Member State



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 Q1 2021. EU-wide, the reference quarter was slightly warmer than usual, registering 62 HDDs below the long-term average. This means that temperatures were about 0.7 degree Celsius higher than usual. Most of the deviations took place in February. However, lower-than-usual temperatures were measured notably in the northern, and sometimes in the southern part of the continent, mostly during January. Norway, Sweden and the United Kingdom, plus France, Spain and Portugal, experienced cold spells above the normal, which increased electricity demand and prices.

Figure 4 - Deviation of actual heating days from the long-term average in January-March 2021



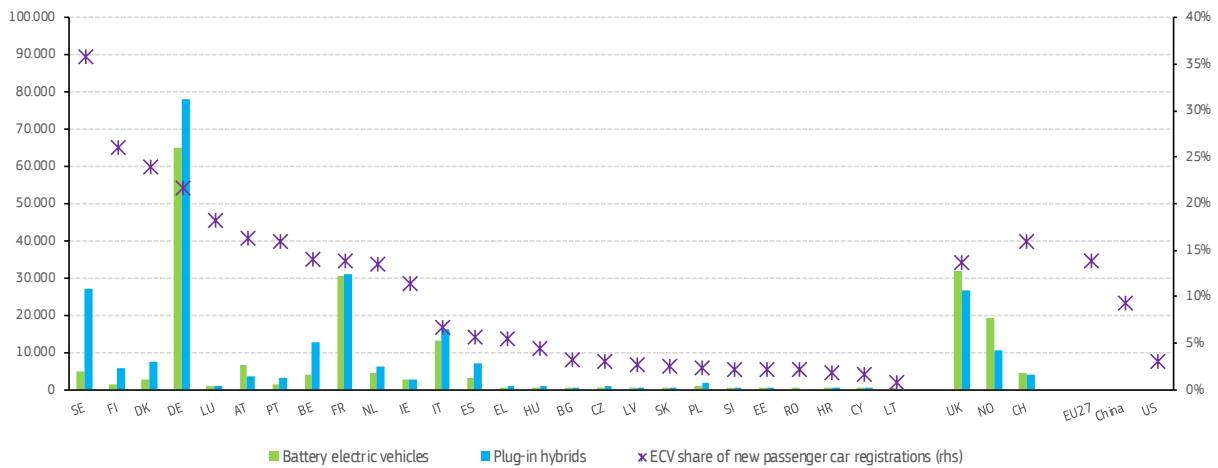
Source: JRC. The colder the weather, the higher the number of HDDs. The hotter the weather, the higher the number of CDDs

- **Figure 5** shows that demand for electrically chargeable passenger vehicles (ECVs) kept growing in thanks to efforts by major automobile manufacturers to meet stricter emission targets and also thanks to support policies of some Member States aimed at incentivising ECV purchases. Additionally, higher number of models are being advertised at more affordable prices, and uncertainty around the use of the combustion engine increases. More than 350,000 new ECVs were registered in the EU in Q1 2021 (+112% year-on-year). This was the second highest quarterly figure

on record (after the impressive numbers of Q4 2020) and translated into a 14% market share, one and half times higher compared to China and four times higher than in the United States. The plug-in hybrid segment continued to grow (+176% year-on-year to 208,000), while demand for battery electric vehicles grew at a slower but still remarkable pace (+59% year-on-year to 146,000).

- The highest ECV penetration was observed in Sweden where more than a third of the passenger cars sold could be plugged. From 1 April, BEV owners in Sweden are being supported by a total BEV rebate of EUR 6800, up to a maximum of 25% of the vehicle original price. Relatively high ECV market shares were observed in Finland, Denmark, Germany and Luxembourg. The 24% share in Denmark is all the more impressive since it took place against the backdrop of zero direct purchase incentives (only tax deduction benefits). Germany retained the position of the largest individual market. Its generous incentive programme, which offers up to 9,000 EUR in direct purchase bonuses, drove up ECV sales to 143,000 in Q1 2021, an increase of more than 172% over the first quarter of 2020. Growth numbers in BEVs were supported most notably by Germany and France, where sales grew 268% and 17% respectively year-on-year.

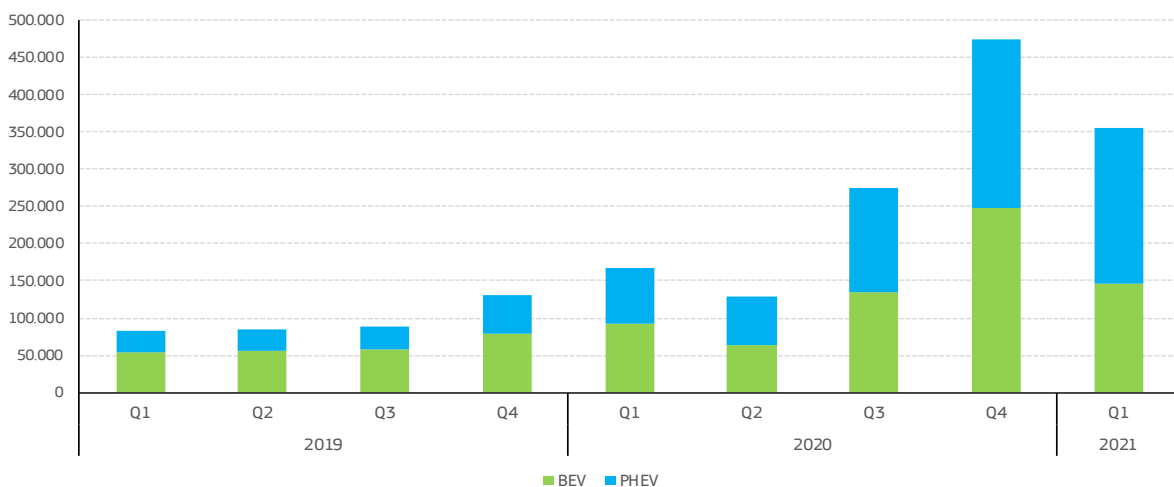
Figure 5 – Electrically chargeable passenger vehicle (ECV) sales in selected countries in Q1 2021



Source: ACEA, CPCA, BloombergNEF

- **Figure 6** shows how the rapid expansion of electric vehicles in Europe unfolded in 2020 and keeps track in 2021. Lockdown measures during the first quarters of 2020 curtailed manufacturing capacities, strained supply chains and dampened consumer demand. However, the effect was only temporary and the sector recovered in the second half of the year, underpinned by existing policy support and additional stimulus measures. Overall, 1.2 million new ECVs were sold in the EU in the year between Q1 2021 and the same quarter in 2020 (compared to 1.5 million cars with a plug sold in China), doubling the existing electric fleet. 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 on network load.

Figure 6 – Quarterly ECV sales in the EU

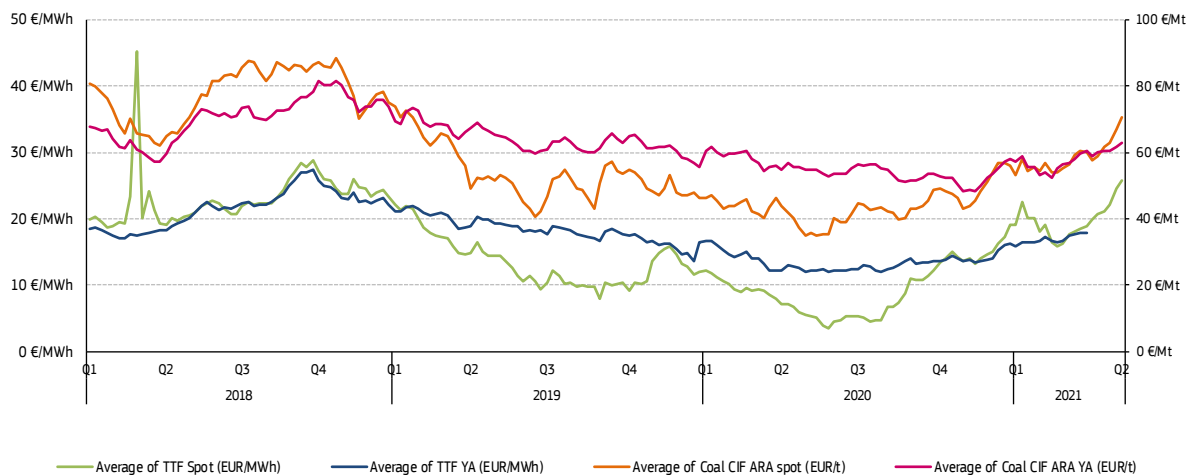


Source: ACEA

1.2 Supply side factors

- Figure 7** reports on developments in European coal and gas prices. Thanks to recovering economic activity and increasing demand tied to winter weather, prices of coal and gas in the spot market caught up with their year-ahead peers in Q1 2021. Spot gas prices (represented by the TTF day-ahead contract) rose in the end of last year on the back of forecasts of colder weather and rising storage withdrawals. The trend intensified in January 2021 as cold spells affecting the whole Northern Hemisphere increased demand and sent spot prices sharply up, especially in the LNG segment. The price rally largely dissipated by the end of January as conditions returned to normal, until the last section of the quarter, where falling temperatures provided support for further increases in the gas prices. This trend has been strengthened during the months of the second quarter of 2021, on the back of increasing demand and high CO₂ prices. This situation has 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.
- Spot gas prices averaged 19 €/MWh in Q1 2021, a level last seen in 2018. Prices are 26% higher than the previous quarter (Q4 2020) and represent a 91% increase compared to Q1 2020, which reflects the strong drop in temperatures and the tightness of the gas market. While in 2020, cheaper gas and the resilience of the carbon market contributed to intensified coal-to-gas and lignite-to-gas switching in 2020, driving down the carbon footprint of EU electricity sector to record lows, current high prices could be detrimental to the reduction of emissions during the current year.
- Thermal coal spot prices, represented by the CIF ARA contract, began to climb during the last part of 2020 amid supply disruptions in Australian ports and colder weather conditions which stimulated more coal burn. However, rising carbon prices at the beginning of 2021 and warmer temperatures in February limited coal's potential. March saw the comeback of coal prices with values slightly over 60 €/t, as a result of supply tightness and higher freight rates. Nonetheless, spot prices are expected to remain around current levels, limited by carbon prices on the upside and low ARA port stocks on the coal price downside. The average CIF ARA spot price averaged 56.2 €/t in the first quarter of 2021, up 28% compared to Q1 2020 and 14% to the last quarter of 2020. The smaller increase in coal spot prices compared to its gas peers reflects the fact that coal is already under pressure.

Figure 7 – 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 8**, saw impressive price gains throughout Q1 2021 which continued well into the second quarter of 2021. Several new records were established in quick succession, culminating in the middle of May when the closing price climbed above 56 €/tCO₂ for the first time.
- The rally started in November when a delay to the start of 2021 auctions was announced, meaning a longer-than-expected break in fresh supply from auctions in January. Prices continued to head higher in December and clearly broke through the 30 €/tCO₂ barrier in the aftermath of the European Council endorsing the Commission proposal for a new EU target to reduce GHG emissions by at least 55% by 2030. The barrier of 40 €/tCO₂ was broken in late February-March attributed to unusual cold temperatures in the continent and increasing activity of financial players. Several new price records were established in the following weeks as cold and calm weather necessitated the start-up of more emission-intensive power plants, increasing CO₂ emissions and demand for allowances. Allowances held their gains even after temperatures rose, indicating a shift in market expectations and more bullish long-term outlook. This can be traced down to reforms of several key aspects of the EU ETS which are planned to be introduced in 2021 and which are expected to lead to a tighter supply-demand balance.

- The average CO2 spot price in Q1 2021, at 38 €/tCO2, represented an increase of 36% with respect to Q4 2020 and a change of 65% year-on-year. Higher carbon prices put coal and lignite power plants at a greater disadvantage against their less polluting gas-fired competitors (see **Figure 17**). They also tend to drive wholesale electricity prices higher (see **Figure 12**). The special **Focus on the impact of high carbon prices in the electricity sector** will dig deeper into this relevant topic.

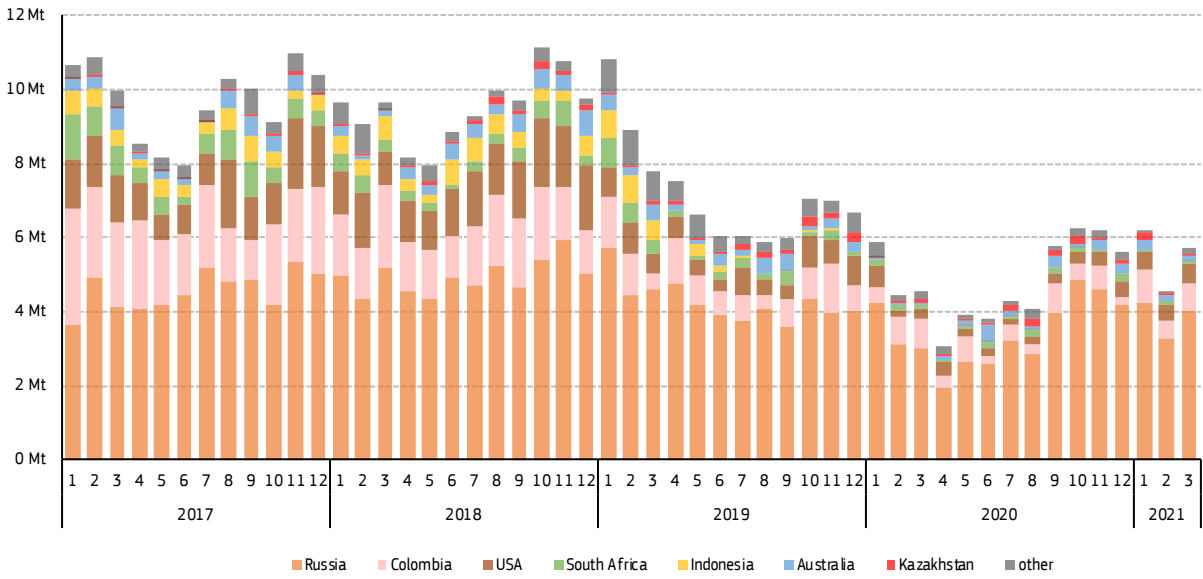
Figure 8 – Evolution of emission allowance spot prices from 2018



Source: S&P Global Platts

- As visible from **Figure 9**, monthly thermal coal imports into the EU held at roughly 5.5 Mt in Q1 2021 as electricity demand increased and made more space for fossil fuels in the mix. The total volume of imports increase by 11% year-on-year to 16 Mt in the first quarter of 2021. The estimated EU import bill for thermal coal amounted to €1.1 billion in the reference quarter, 5% higher compared to Q1 2020 stopping the year-on-year decline in imported volumes of this commodity.
- The largest part of extra-EU thermal coal imports in Q1 2021 came from Russia which accounted for 70% of the total. Russian traders continued to cement their dominant position as most of their rivals find it difficult to compete in the though low-price, low-demand environment. Colombia saw its market share growing to 13% compared with 7% in the previous quarter. The position of Australia and Kazakhstan remained almost unchanged (3% and 2% shares respectively). The share of deliveries from US ports increased from 6% to 9%. Shares of other trading partners were not relevant.

Figure 9 – Extra-EU thermal coal import sources and monthly imported quantities in the EU



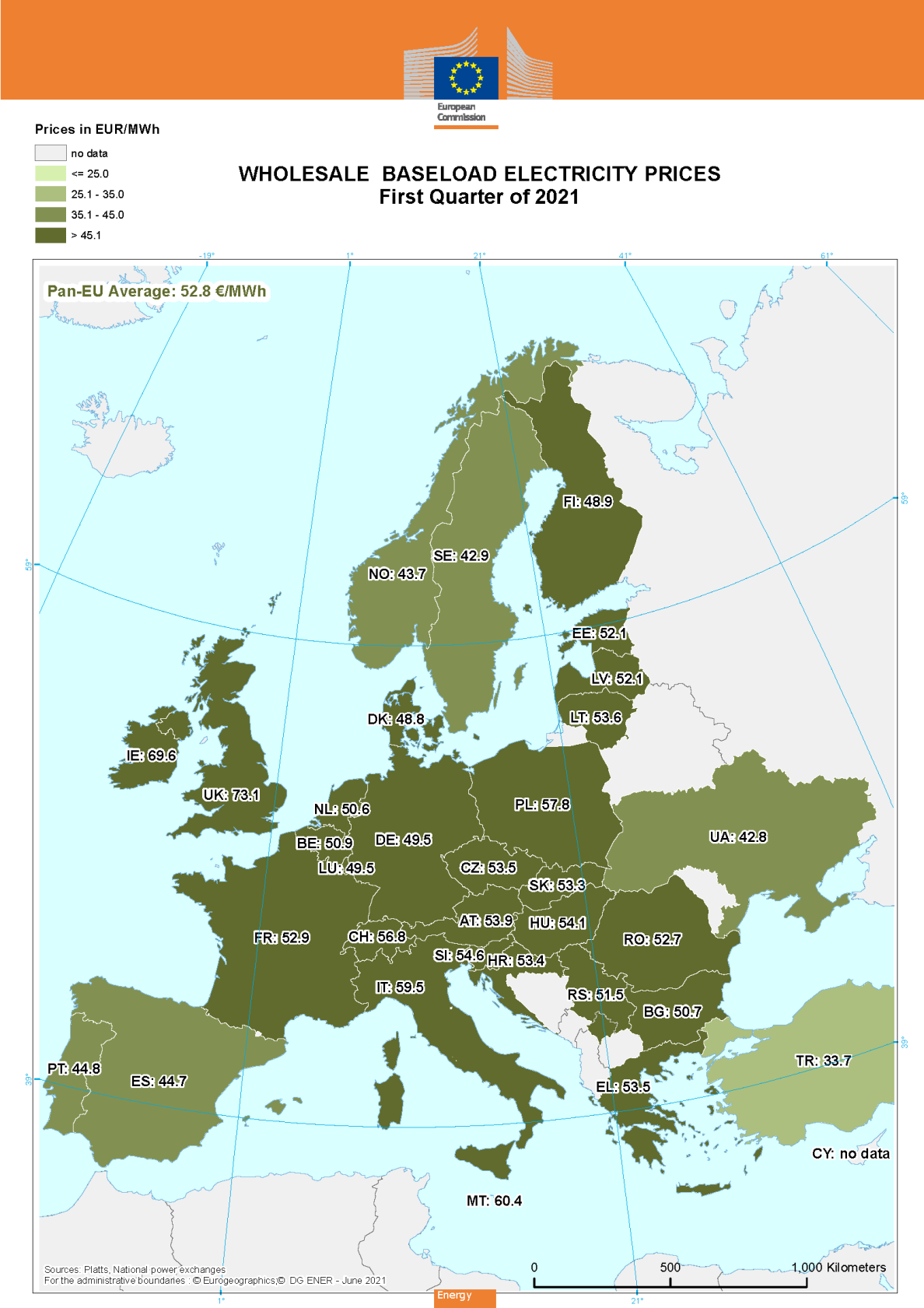
Source: Eurostat

2 European wholesale markets

2.1 European wholesale electricity markets and their international comparison

- The map on the next page shows average day-ahead wholesale electricity prices across Europe in Q1 2021. The reference quarter saw a sharp increase compared to Q4 2020, as prices rose on the back of increasing demand due to low temperatures and high commodity prices (fuels and CO₂). Practically every European country experienced a surge in prices. Although spot prices in the Nordic region experienced one of the largest year-on-year increases, the cheapest baseload power in Europe on the day-ahead market was still available in this market. Countries such as Sweden, presented values of 43 €/MWh on average. Likewise, Norway reported prices around 44 €/MWh on average. Most markets moved between 50 and 60 €/MWh. The United Kingdom reported the highest quarterly average price (73 €/MWh), which was 92% higher than in Q1 2020. Ireland became the second most expensive market with an average baseload price of 70 €/MWh, which was 91% higher compared to the same period last year.
- The pan-EU average of day-ahead baseload prices reached 53 €/MWh in the reference quarter, up 57% in a year-on-year comparison. Compared to Q4 2020, the quarterly average rose by 22%.
- The largest year-on-year price increases were registered in Norway (+189%), Sweden (+156%), Denmark (+131%), and Finland (+104%), on the back of lower than average temperatures pushing records on power demand in the region, plus diminished hydro reservoir levels in line with seasonal behaviour. Conversely, Greece experienced the least increase in prices during Q1 2021 (+6%).

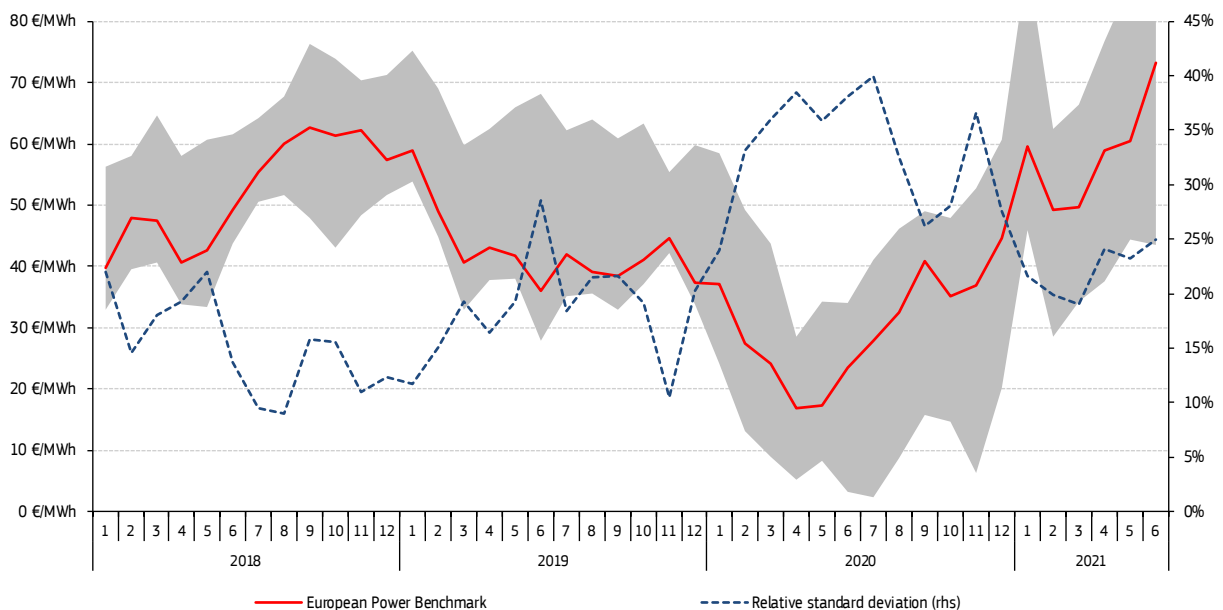
Figure 10 – Comparison of average wholesale baseload electricity prices, first quarter of 2021



Source: European wholesale power exchanges, government agencies and intermediaries

- Figure 11** shows the European Power Benchmark of nine markets and, as the two lines of boundary of the shaded area, the lowest and the highest regional prices in Europe, as well as the relative standard deviation of regional prices. Both the shaded band and the relative standard deviation metric show that despite wholesale prices increasing across different regional markets in Q1 2021, divergence levels registered a decrease, as the supply-demand balance was similarly affected in most of the individual regions. Central Western and Eastern Europe experienced rising prices on the back of recovering demand fostered by cold weather, together with rising fuel and carbon costs. The Iberian Peninsula witnessed a surge in prices during January, due to rising demand as result of low temperatures. The Nordic region, experienced a seasonal fall in hydro reservoir levels amid record demand, which resulted in a steep increase in prices. Great Britain went through a tight winter with average prices spiking in January. This made Britain the most expensive market in Europe during the first quarter of 2021. The European Power Benchmark averaged 53 €/MWh in Q1 2021. This was 79% higher than in the same quarter last year. The rising trend continued in the following months on the back of extremely high fuel prices. In June, electricity prices in many markets, including France and Germany, reached 13-year highs.

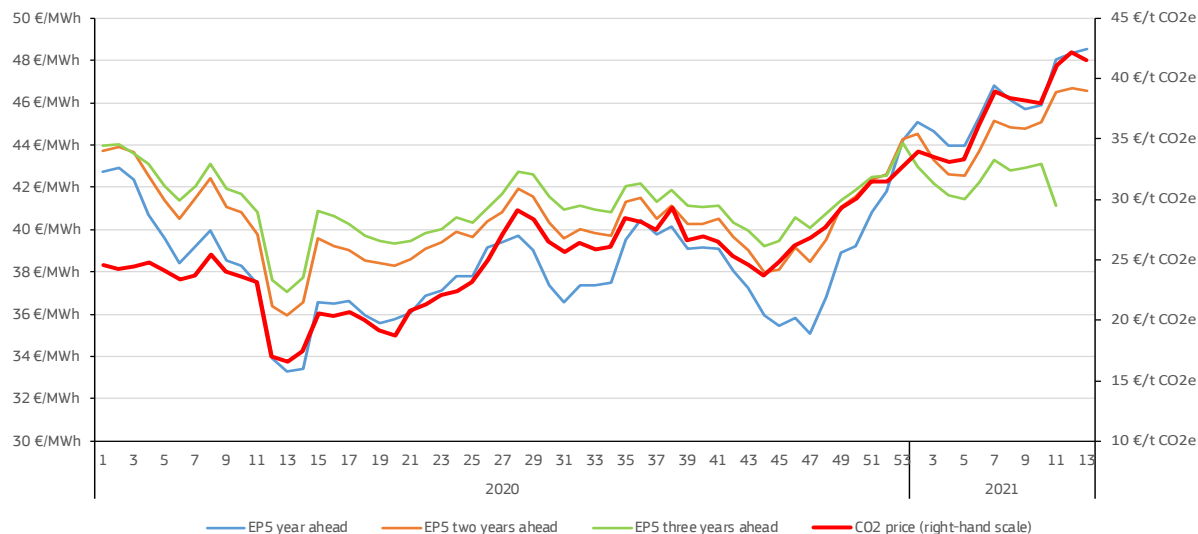
Figure 11 – The evolution of the lowest and the highest regional wholesale electricity prices in the European day-ahead markets and the relative standard deviation of the regional prices



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

- A consumption-weighted futures benchmark ([EPS](#)) of five markets, shown in **Figure 12**, reveals that carbon prices have been one of the main drivers behind changing expectations of future electricity prices since the beginning of the spring lockdown during last year. The rallies in CO₂ prices that have been taken place since November 2020 and May 2021, lifted the benchmark above pre-crisis levels. On average, 1 €/tCO₂ adds roughly 0.6 €/MWh to electricity prices, which reflects the average carbon content of fossil-based electricity generation in the EU (approximately 0.6 tCO₂/MWh). Thus, higher carbon costs factored in future generation costs have outweighed the effect of lower demand expected in the years ahead as a result of lasting covid-related shifts in the structure of the economy.

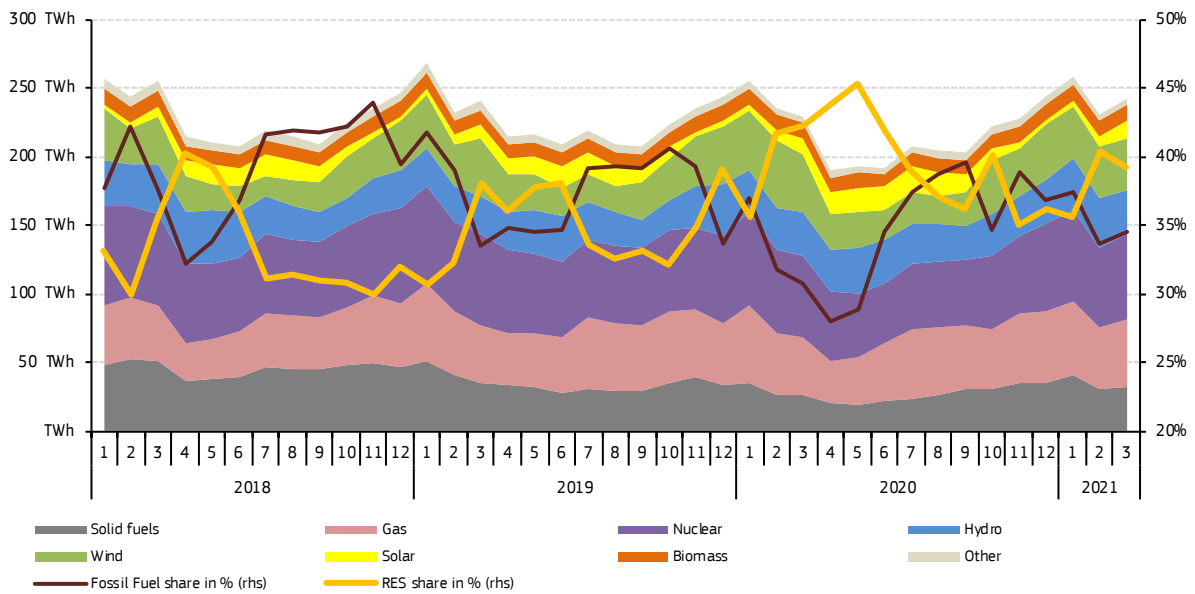
Figure 12 – Weekly futures baseload prices – weighted average of 5 European markets



Source: Platts.

- **Figure 13** shows the monthly evolution of the electricity mix in the EU. Recovering electricity demand supported by winter temperatures made more space for fossil fuels in the mix. As a result, fossil fuel generation was slightly higher than renewables during the month of January. However, the share of energy produced by renewables still managed to reach 38% in Q1 2021, while fossil fuel generation (coal, gas and oil) stayed below registering 35% of the share during the quarter. Nuclear generation remained at the same level of generation compared with the reference quarter in 2020 (26%).
- Within the fossil fuels complex, coal gained terrain both in absolute and relative terms compared to Q1 2020 due to rising demand (higher than a year earlier) despite rising carbon prices. Coal's share in the mix rose to 14%. Meanwhile, less CO₂-intensive gas generation practically saw its share unchanged at 20% in the reference quarter. In absolute terms, coal-based generation rose by 15 TWh year-on-year, while gas-fired power plants' output decreased by almost 5 TWh. Renewables, in contrast, generated 6 TWh of electricity less year-on-year on the back of lower wind generation.
- Between hard coal and lignite (the distinction between them is not visible in **Figure 13**), the latter tends to be more resilient in the face of changing market environment, as lignite generation traditionally displays more competitive marginal costs per unit of energy produced even facing the current level of CO₂ 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 65% more expensive in Q1 2021 compared to Q1 2020, but this was compensated by rising hard coal prices, which meant that lignite power plants weathered the reference quarter in a better shape. In the end, lignite-based generation in Q1 2021 rose by 15% year-on-year (or almost 7 TWh), while coal-fired generation increased by 19% year-on-year (or 8 TWh).

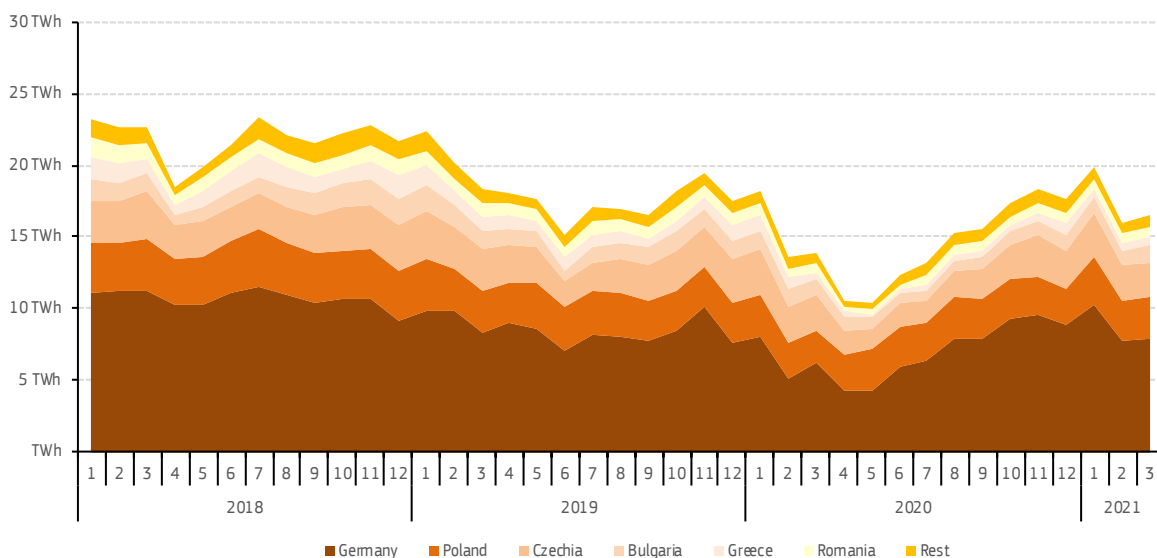
Figure 13 – Monthly electricity generation mix in the EU



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

- Figure 14** shows that after a large covid-related drop during spring and summer months, lignite generation staged a powerful comeback at the beginning of Q1 2021, helped by rising gas prices (which decreased the competitive edge of gas-fired power plants) and recovering demand. Monthly output peaked in January at 20 TWh, the highest figure since the winter of 2020. In Germany, home to the largest lignite fleet, generation from the dirtiest fuel rose by 35% year-on-year in Q1 2021, due to falling nuclear output and increasing demand. Lignite-fired generation in Poland increased 16% year-on-year in Q1 2021. The output of the Czech lignite fleet fell by 3% year-on-year, and was partly replaced by increased biomass, hydro and gas generation. The three Member States accounted for 82% of the total lignite-based generation in the EU in Q1 2021. The largest fall in lignite generation (-23% year-on-year) was observed in Greece where rising hydro and wind output were able to compensate the shortfall. Significant drops in lignite generation were also observed in Bulgaria (-11%). In Bulgaria, rising gas and biomass stepped in to make up for the missing lignite volumes. Lignite power plants reached a 7% share in the EU generation mix in Q1 2021 (up from 6% on Q1 2020) and were responsible for approximately 31% of the electricity sector's total carbon emissions.

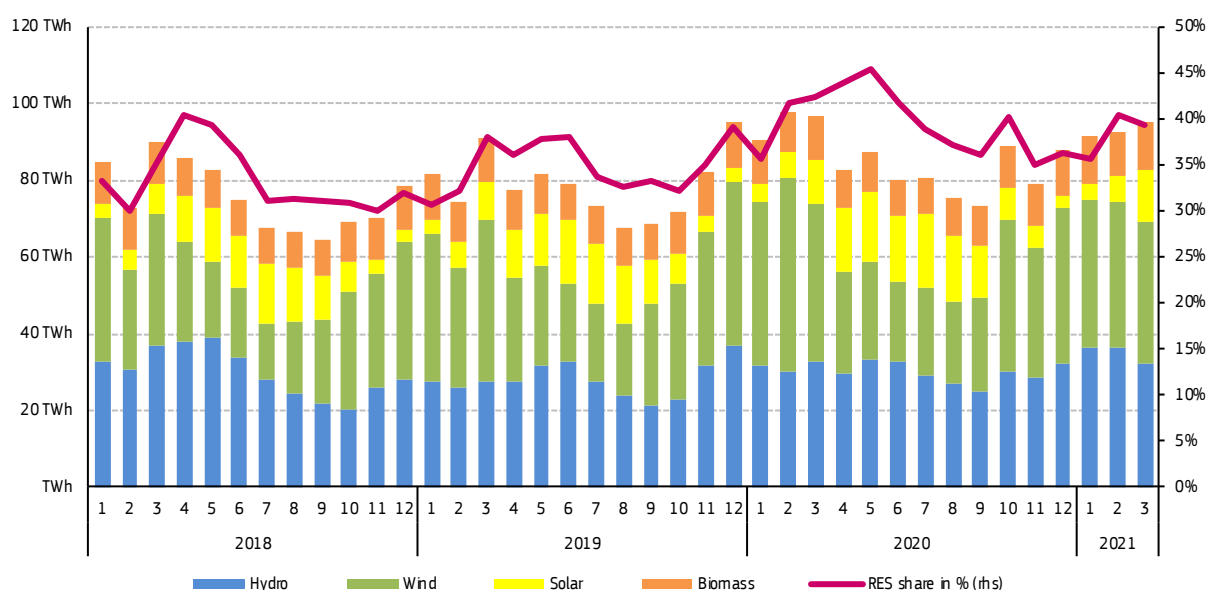
Figure 14 – Monthly generation of lignite power plants in the EU



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

- **Figure 15** depicts the evolution of monthly renewable generation in the EU, alongside its share in the electricity generation mix. Renewable penetration reached 38% in Q1 2021, slightly higher compared to Q4 2020, but still somewhat lower than during the same quarter last year (39%). Stronger demand and a 2% year-on-year decline in renewable generation contributed to the slight year-on-year decrease in renewable penetration.
- Most of the decrease in renewable generation came from wind (-20 TWh) while solar experienced gains (+1 TWh) compared with the reference quarter in 2020. Largest decrease in wind generation came from Germany, where onshore and offshore generation fell by 35% and 27% respectively compared with Q1 2020. The UK experienced cold but calm weather, which resulted in a decline of wind generation by 38% and 19% respectively. On the other side of the coin, Spain and Portugal increased their wind onshore output by 31% and 17% on a year-on-year basis. Spanish wind and solar set records of power generation during Q1 2021, as wind generated +4 TWh than in the same quarter of 2020.
- Thanks to newly added panels, solar PV generation rose by 6% in Q1 2021 to 24 TWh, more than three times than oil-fired generation. The increase was almost singlehandedly driven by Spain. Solar generation rose 25% year-on-year. Also the share of solar generation in Spain reached 6% in Q1 2021, putting it within striking distance of hard coal (2%).

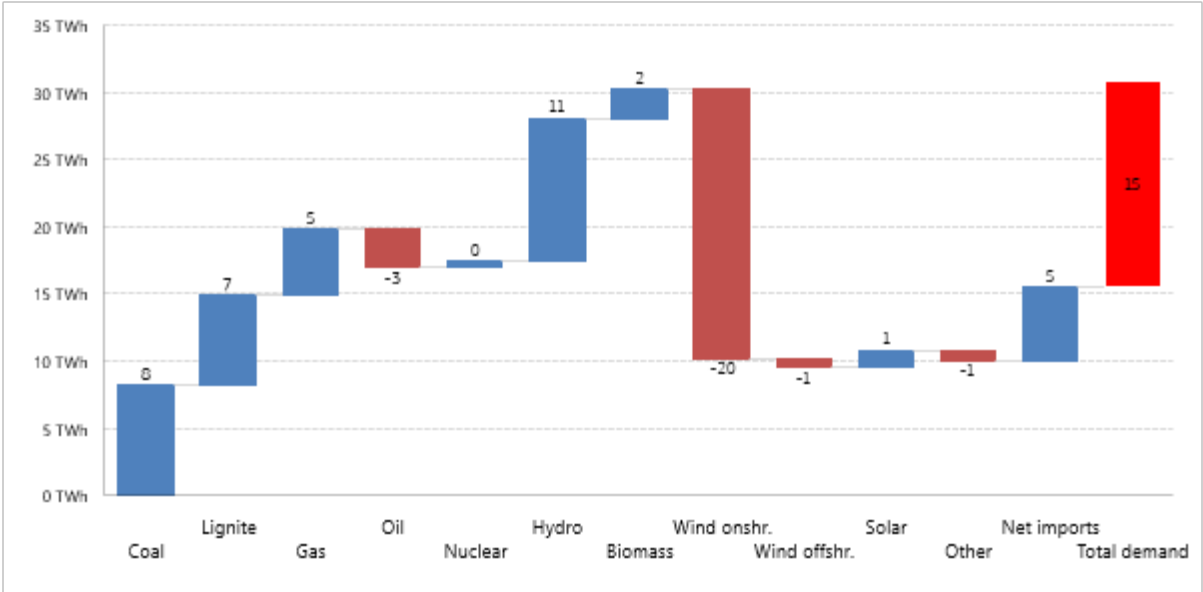
Figure 15 – Monthly renewable generation in the EU and the share of renewables in the power mix



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

- **Figure 16** visualises changes in the EU27 electricity generation balance in the reference quarter compared to the same quarter a year before. The space for conventional power plants' running hours was increased by major shifts both on the supply and demand side. The cold winter of 2020/2021 and the incipient recovery from the coronavirus pandemic increased power demand by 15 TWh. As a result, fossil fuels increased their generation (+19 TWh), nuclear remained practically unchanged. Renewable sources generation decreased (-7 TWh) and net imports increased (+5 TWh), mainly due to lower wind generation and the need to meet increasing electricity demand in most parts of Europe. The EU27 net balance finished with an 8 TWh surplus in Q1 2021. During January, weak renewable production strengthen fossil fuel generation. All in all, coal increased its output by 8 TWh, lignite by 7 TWh, gas rose by 5 TWh, while oil decreased by 3 TWh in Q1 2021. Based on preliminary estimates, the carbon footprint of the power sector in the EU rose by 9% year-on-year in Q1 2021 due to the larger use of fossil fuels. However, emissions were still 12% lower than in Q1 2019.
- Most of the main drivers behind the Q1 2021 increase in carbon emissions were exceptional or seasonal (the covid-related demand recovery, cold weather, very low wind generation). As demand continues to increase in line with the gradual opening of the post-pandemic economy in Europe and high temperatures arrive with summer, it is likely that both the power sector's carbon footprint and carbon intensity will rise in 2021.

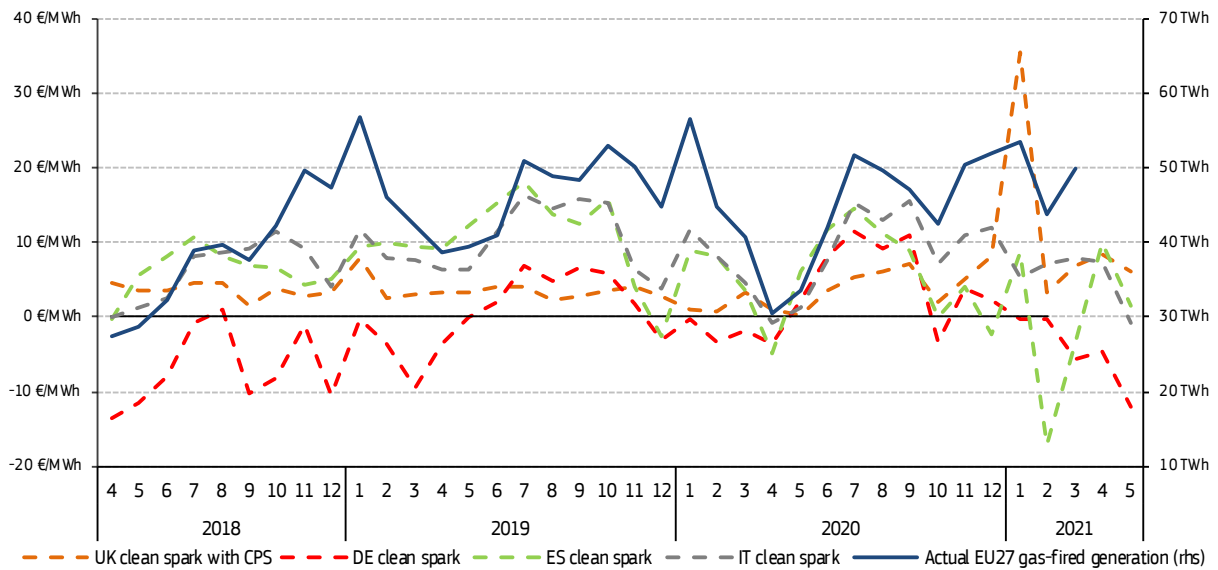
Figure 16 – Changes in power generation in the EU between Q1 2020 and Q1 2021



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

- 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 on average in Q1 2021. In January 2021 rapidly rising gas prices resulted in coal gaining the upper hand, despite rising carbon prices. The spike in the January clean spark spread in the UK was driven by extremely high prices during scarcity events in the first two weeks of the month. High prices created health margins not only for gas, but also for coal generators in the UK, as the spark spread climbed to the highest levels since November 2016. The increasing steady rally in gas prices since March has been a combination of low storage and rising demand. As such, coal usage to reach electricity demand could keep increasing.
- As shown in **Figure 17**, in the UK and Italy, the profitability of gas firing for electricity generation remained mostly in positive territory for a plant with an average efficiency during Q1 2021 (as opposed to Spain and Germany who sunk in February). However, the slight recovery in March, was out weighted by the downward trend of the following months for the four markets. The highest [clean spark spreads](#) in Q1 2021 were assessed in the UK (15 €/MWh), followed by Italy (7 €/MWh). The lowest was presented in Spain (-4 €/MWh). Gas-fired generation volumes largely corresponded to the movement of spreads in respective markets. The total EU gas generation reached 147 TWh in the reference quarter, up by 3% compared to Q1 2020.

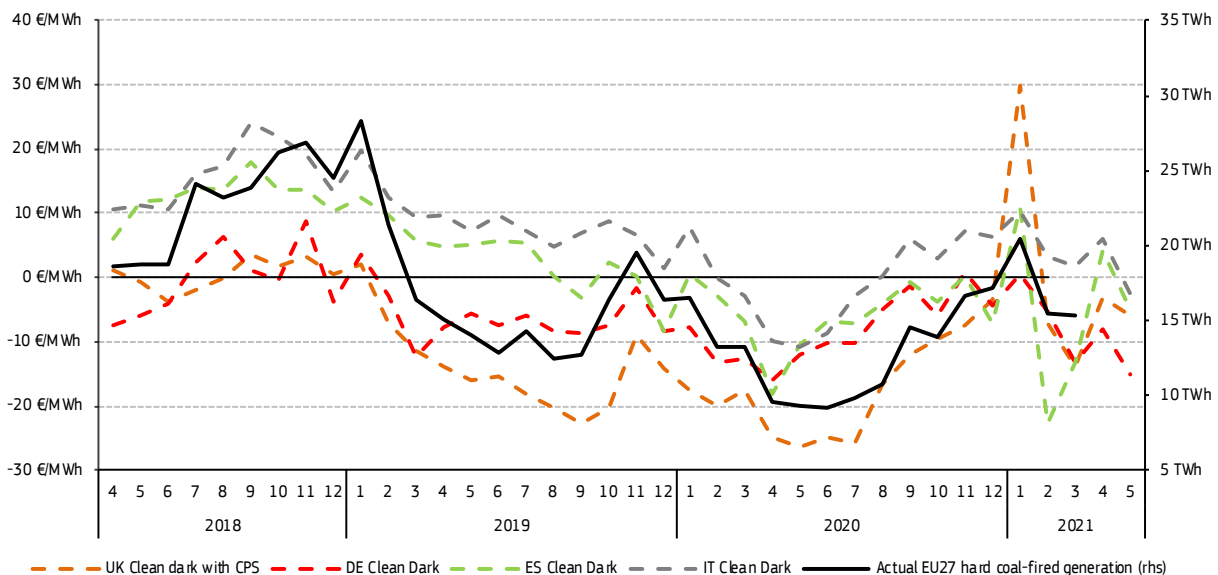
Figure 17 – Evolution of clean spark spreads in the UK, Spain, Italy and Germany, and electricity generation from natural gas in the EU



Source: ENTSO-E, Eurostat, Bloomberg

- Figure 18** shows that Italy and the UK experienced profitable coal-fired power generation in Q1 2021. In January, both presented spikes in the profitability indicator for an average plant, despite rising coal and carbon prices. [Clean dark spreads](#) in Italy, where power prices were relatively higher, averaged 5 €/MWh in Q1 2021, lower than in the case of gas-fired power plants. Coal generation in Spain declined by 52% year-on-year in Q1 2021 to the point of irrelevance, with only few units remaining in the market. German coal generators, in contrast, increased their output by 32% year-on-year in Q1 2021, as nuclear generation gradually faded in accordance with the German nuclear phase-out plan and no other capacities were available as replacement to meet increasing electricity demand.

Figure 18 – Evolution of clean dark spreads in the UK, Spain, Italy and Germany, and electricity generation from hard coal in the EU



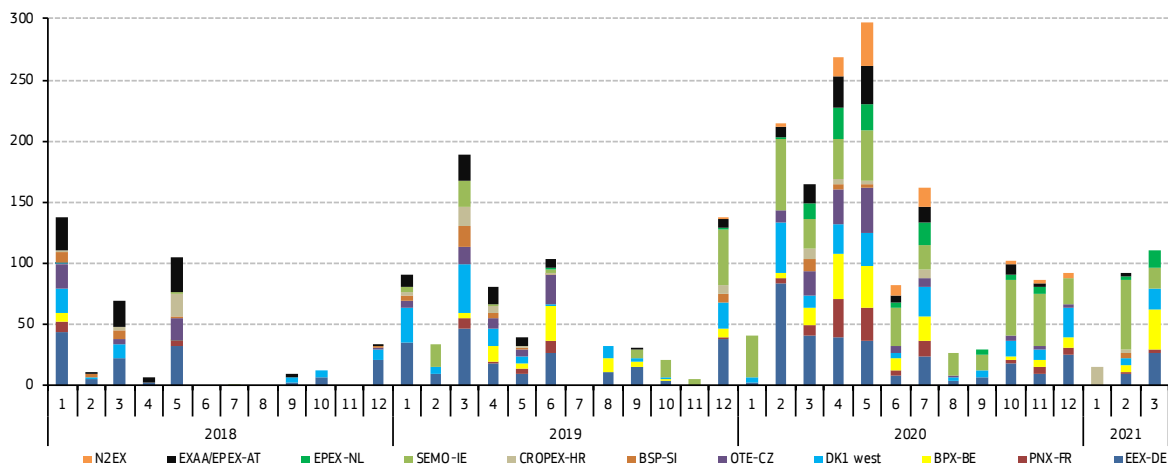
Source: ENTSO-E, Eurostat, Bloomberg

- Figure 19** 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 intermittent 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 Q1 2021 (217) was 48% lower in the observed bidding zones than in the previous Q1. Most of the falls into negative territory occurred in February and March 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 7 February (Sunday) when strong wind speed pushed German, Belgium and Danish (DK1 zone) prices below zero during several hours of the day. Wind generation covered a large part of the German consumption during that day.
- The integrated Irish zone recorded the highest number of negative hourly prices (74) in Q1 2021 and was trailed by Belgium (38), Germany (36) and the Danish mainland (DK1) zone (23). Croatia experienced 18 negative hourly prices during Q1 2021 and Greece increased the number of negative prices since the previous quarter, after it started day-ahead trading for the first time in mid-December. 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.

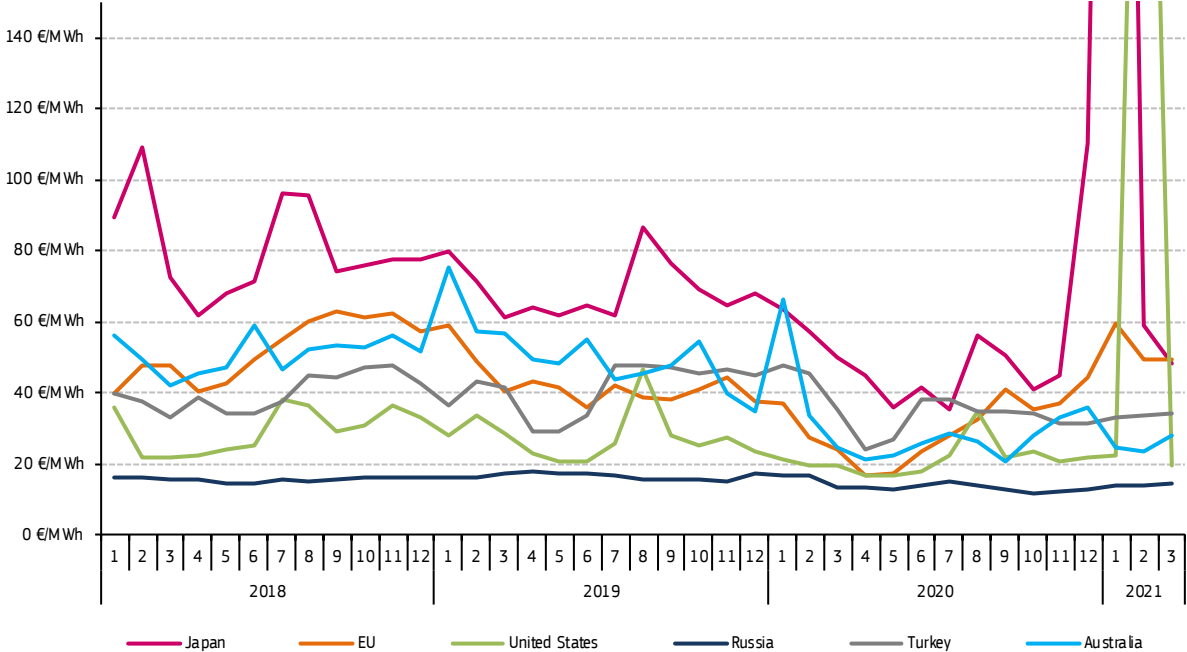
Figure 19 – Number of negative hourly wholesale prices on selected day-ahead trading platforms



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

- **Figure 20** compares price developments in wholesale electricity markets of selected major economies. While most markets saw prices returning to pre-pandemic levels in Q1 2021, wholesale electricity prices in the US experienced a dramatic spike during February, when prices in Texas (ERCOT) surged to 7500 €/MWh on 17 February, influenced by an extreme cold weather event. Electric power generator struggled to meet the demand, leading to outages and skyrocketing price which lasted several days. 12-month record prices were also recorded in California (CAISO), Midwest (MISO), Mid-Atlantic (PJM) and other areas of the country.
- Japan experienced a sharp increase in January when prices surged to 2000 €/MWh on some occasions, above levels reached in the aftermath of the Fukushima disaster. The primary driver behind the price spike was a combination of high demand due to very cold weather and steep LNG prices which boosted electricity demand to ten-year highs. A similar story was developed in China and South Korea, turning the gas scarcity into a regional issue. Many Japanese generators were unprepared for such high demand and had insufficient LNG stocks ahead of winter. The event demonstrated the risk of high dependence on a particular fuel, considering that of the 33 nuclear units currently operable in Japan, sixteen have received preliminary or final approval to restart and only nine have been restarted since 2015.
- With the exception of the US and Japan, European wholesale prices were the highest of the observed group in Q1 2021, reaching 53 €/MWh. Russia remained at the other end of the spectrum with 14 €/MWh, which was 11% lower than in the same quarter last year. The decrease was mainly driven by the weakening rouble. Australian prices decreased 39% year-on-year across all regional markets throughout Q1 2021, on the back of mild weather and supported by a record installation of solar capacity during the quarter, resulting in a reduction of the average cooling load of summer in the Southern Hemisphere.

Figure 20 – Monthly average wholesale electricity prices in Europe, US, Japan and Australia (D-A markets)

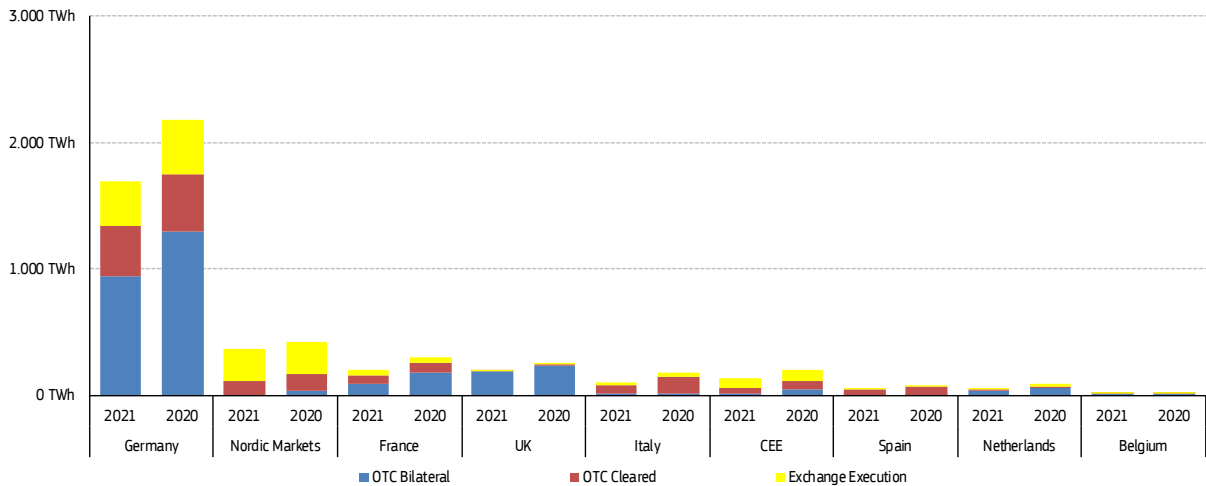


Source: European Power Benchmark, JPEX (Japan), AEMO (Australia), JCS ATS (Russia), Energy Exchange Istanbul (Turkey) and the average of selected PJM West, ERCOT, MISO Illinois and CAISO regional wholesale hubs in the United States.

2.2 Traded volumes and cross border flows

- Figure 21** 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 Q1 2021. The largest annual falls in total traded volumes were registered in Italy (-43%), the Netherlands (-41%) and CEE (-36%), split approximately equal by the OTC and Exchange sectors (except in CEE where losses were driven mainly by the OTC sector). The total traded volume in all markets under observation fell by 24% year-on-year to 2807 TWh in Q1 2021.
- Despite falls in traded volume, Germany was by far the largest and most liquid European market, total volumes reached 1695 TWh (equivalent to 60% of the total traded volumes under observation in Q1 2021). Activity fell year-on-year basis both at exchanges (-18%) and in OTC contracts (-23%) in 2020. The market share of exchanges experienced a slight increase compared to 2020 (+3%). Similar relative decreases in activity were visible in the UK where total volumes fell by 20% to 197 TWh. French and Nordic markets registered a decrease in bilateral OTC deals (-38% and -30% respectively). The market share of power exchanges expanded from 24% to 27% year-on-year. The largest falls in exchange-based volumes were reported in the Netherlands (-46%) and Italy (-42%). Overall, exchange-based trading volumes decreased by 133 TWh in Q1 2021. The OTC segment traded 785 TWh of electricity less in 2021 compared to the same reference quarter in 2020, as a result of lower volumes changing hands in Germany, France and Italy.

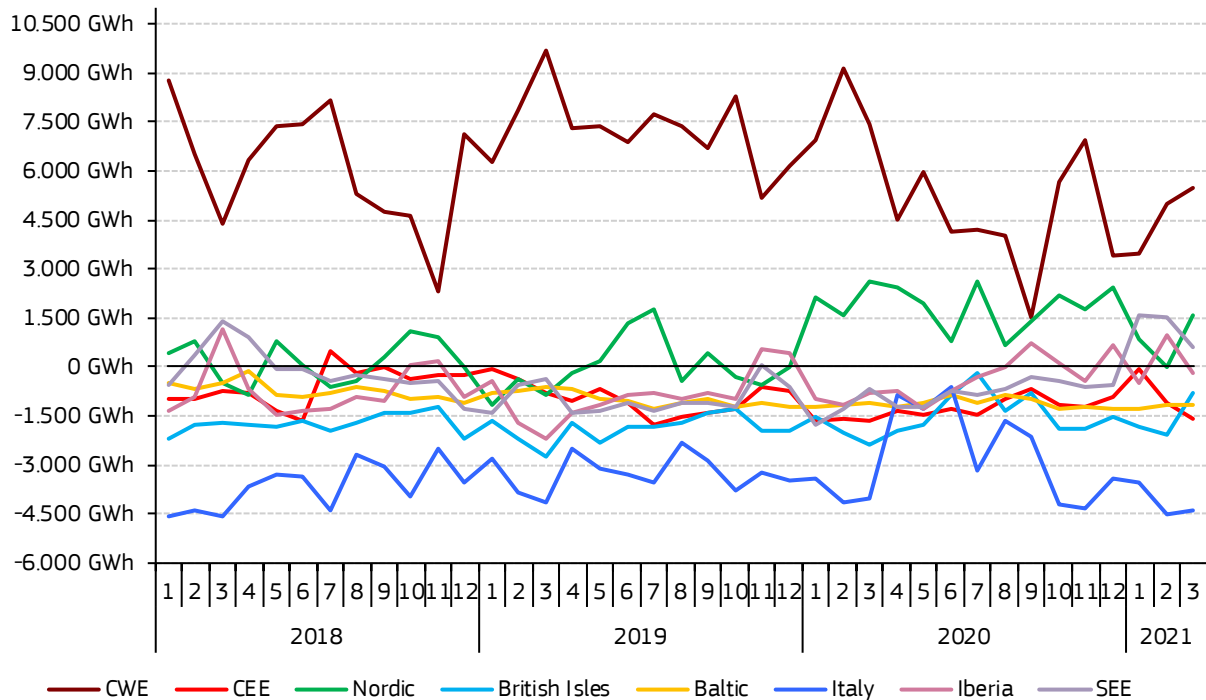
Figure 21 – Annual change in traded volume of electricity on the most liquid European markets



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

- Figure 22** reports on the regional cross-border flows of electricity. Central Western Europe exploited its strong potential and with 14 TWh of net exports was again the largest source of outflows in the first quarter of 2021, still 41% lower than in Q1 2020. The decrease can be traced mainly to higher demand within CWE market, which reduced the availability of exports. Despite the seasonal low levels of hydro reservoirs levels, the Nordic region recorded a surplus of 2 TWh in the reference quarter, still lower from the 6 TWh of net exports in Q1 2020. South Eastern Europe presented an unusual behaviour, when on the back of lower demand, strong hydro and renewables in January and February, turned into a net exporter in Q1 2021 (+4 TWh). The Iberian Peninsula also emerged as a net exporter, even though only by a slight margin. Favourable wind weather conditions and the increase of wind capacity resulted in 33% higher wind output year-on-year.
- The rest of the regions ended up in deficit. Italian net imports rose by 7% year-on-year to 12 TWh in Q1 2021, in line with pre-pandemic levels. Net flows to the British Isles decreased compared to Q1 2020 at 5 TWh. The CEE region's net position (-3 TWh) improved in Q1 2021 compared to Q1 2020.

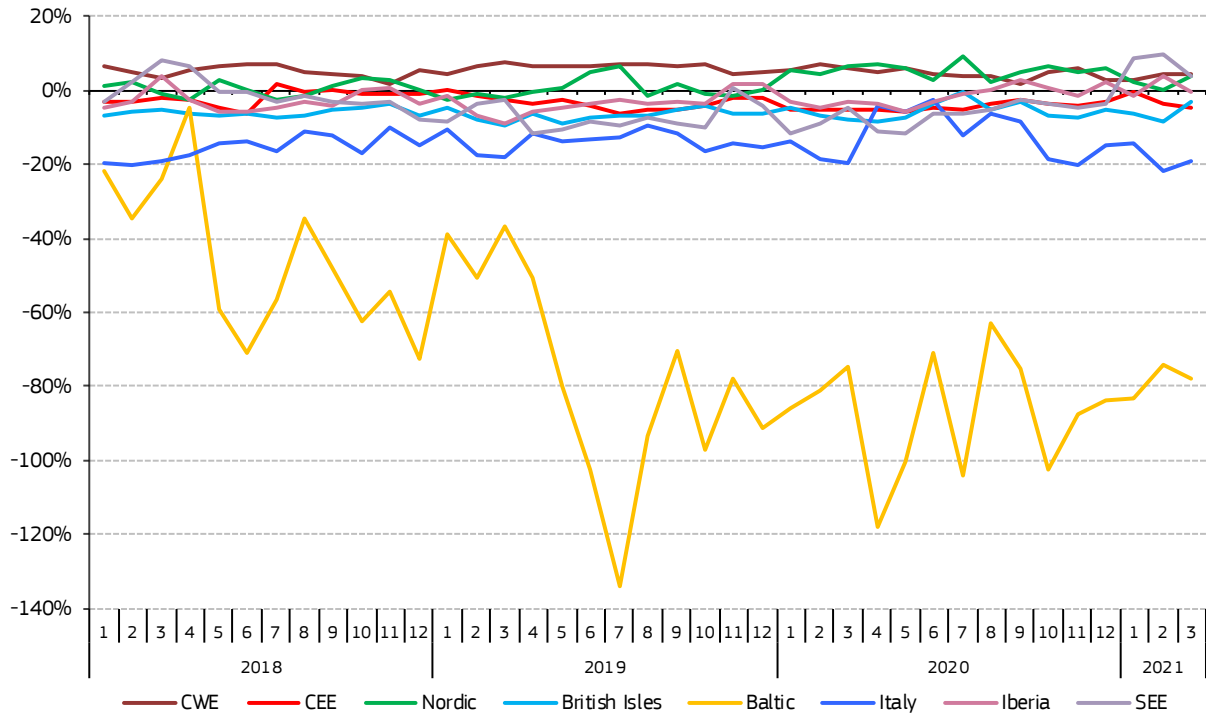
Figure 22 – European cross-border monthly physical flows by region



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 23** 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 Q1 2021 compared to the same quarter a year ago. Net imports (4 TWh) reached about 78% of domestic generation. Italy became the second largest importer relative to its domestic generation (18%). For the rest of the regions, net imports (or exports) did not exceed 8% of domestic generation.

Figure 23 – 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

3 Focus on the impact of high carbon prices in the electricity sector

3.1 Price developments and factors

- **Figure 24** illustrates the overview of price developments of the EU ETS since 2008. Carbon prices crashed during the first phase of the lockdown in March 2020. Contrary to many expectations, the EU ETS price quickly rebounded on the back of the Green Deal agenda, recovery measures, an expected tightening of the EU ETS parameters and the outlook for more ambitious climate policies. The rising trend intensified after the European Council endorsed the 55% GHG emission reduction target in December 2020. Shortly after, emission allowances definitely broke through the important 30 €/tCO₂ barrier, hit 40 €/tCO₂ only several weeks later, and on 8 May 2021, prices breached the 50 €/tCO₂ barrier (an overall increase of 50% from January levels). Scarcity of allowances fed the rally, together with higher gas prices and increased interest from non-compliance parties such as investment funds. The rally was interrupted by the first UK ETS auction in late May (UK ETS was initially on premium over EU ETS, until mid-June were the trend was reversed), but prices continued rising after the first week of June. Prices are expected to keep growing ahead of the upcoming “Fit for 55” package by the European Commission in mid-July.

Figure 24 – EU ETS price development since 2008



Source: Platts

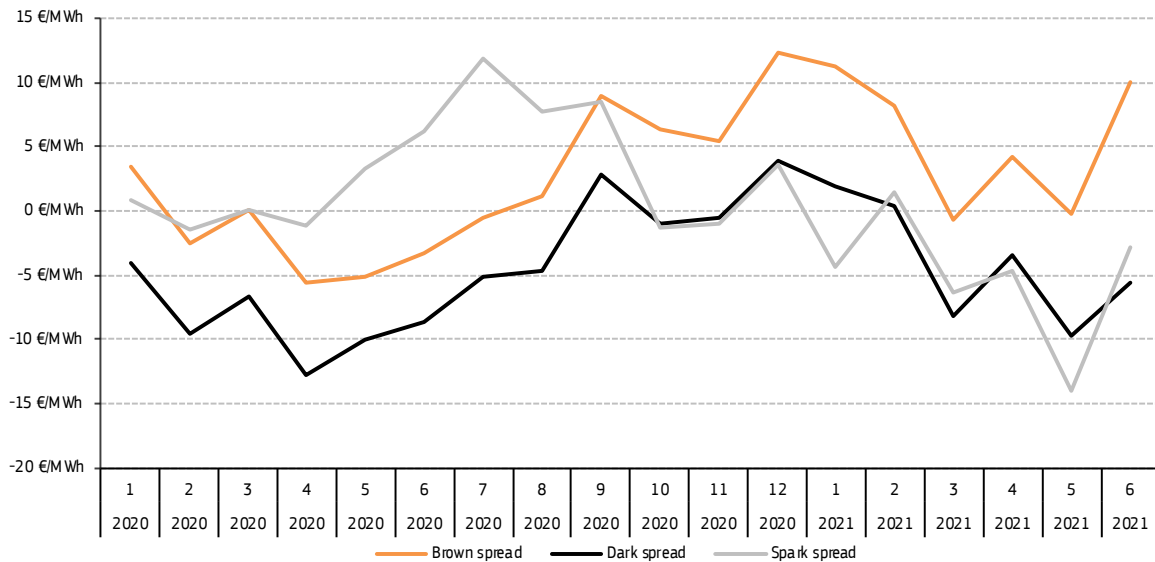
- Several factors have combined to drive up prices. Expected scarcity is one of them, as the market is undersupplied in 2021. With the start of Phase IV of the EU ETS, the Market Stability Reserve is reducing the surplus of allowances while upcoming reforms to the EU ETS as part of the “Fit for 55” package are supporting a tighter market. Another bullish factor is added by the prospect of phasing out free allocation for industry with the introduction of a Carbon Border Adjustment Mechanism proposal. Cold winter spells in the first months of 2021 and a strong recovery in electricity demand, have also provided support to prices in the latest months. Also, a rally in commodity prices (notably gas) is putting pressure on the market, as carbon is chasing the gas price to keep coal-to-gas fuel switching in check in order to save the fuel in gas storages.
- The average price of allowances in 2019 and 2020 was 25 €/tCO₂. In the first six months of 2021, the average rose to 44 €/tCO₂. The jump in prices is an important milestone, considering that only a few years ago, allowances were sold for 6 €/tCO₂. Carbon prices affect the electricity sector for two main reasons. First, by impacting the profitability and investment prospect of several generation technologies and by extension, the pace of electricity decarbonisation. Second, the carbon market influences wholesale and retail prices, impacting the electricity bill of household and business.

3.2 Short and medium-term impacts

- The rise in the carbon prices impacts most prominently the electricity sector which has to buy its allowances, unlike other industries in the EU ETS. Rising carbon prices put coal and lignite power plants at a competitive disadvantage to less emission-intensive generation technologies such as gas-fired plants. CO₂ prices have already reached the level at which older hard coal power plants in Europe are no longer profitable. As a result, several early closures have been announced and carried out in Europe. After 2025, substantial hard coal capacities in the EU are expected to survive only in Germany and Poland.
- Carbon prices are, however, not the only determinants of the profitability of coal and gas power plants. Coal and gas prices are just as important an ingredient. Rising gas prices, for instance, can lead to a worsening of gas-fired power plants margins, in spite of record-high carbon prices. This can be observed in 2021, when high gas prices kept the utilization of gas-fired generation capacities in Germany, Netherlands or the UK under pressure.

- **Figure 25** shows how low gas prices, in conjunction with resilient carbon prices lead to record levels of fuel-switching in 2020. However, the trend partially reversed in 2021, with coal and especially lignite generation retaking some of the lost ground. This dynamic, coupled with so far lacklustre wind speeds, will probably result in greater utilization of coal- and lignite-fired power plants during this year and in an increase in the power sector's carbon footprint compared to 2020, and maybe even to 2021.

Figure 25 - Profitability of different generation technologies in Germany

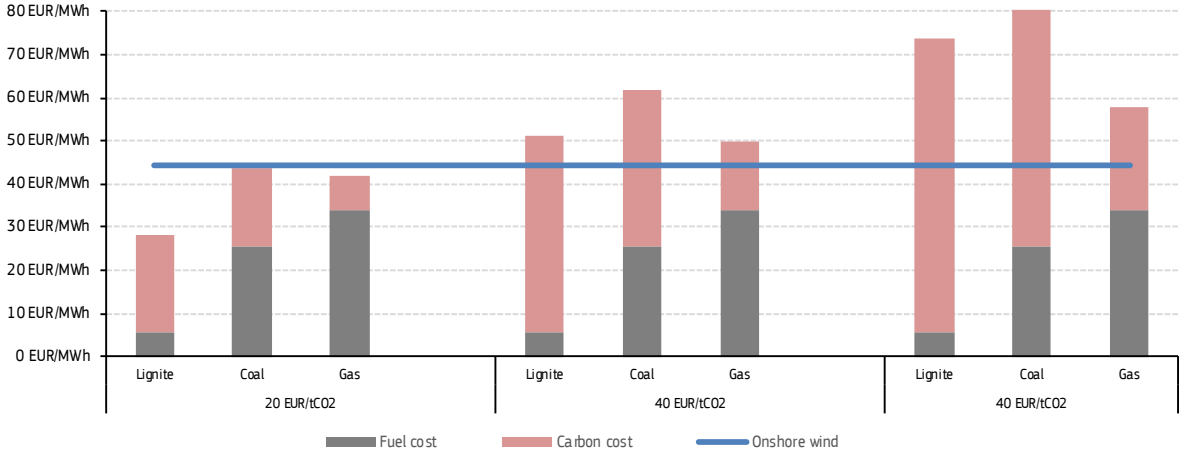


Source: ICE, BloombergNEF

Note: spark spread refers to gas power plants, dark spread to coal power plants and brown spread to lignite power plants. Assumption of fixed cost of 5.5 EUR/MWh with 36.5% lignite plant efficiency

- Additionally, rising carbon prices are the best support for renewables since they translate into higher electricity prices (i.e. higher revenues), while keeping operating costs unchanged. **Figure 26** shows that at a carbon price of 40 €/tCO₂, it is already cheaper to build an onshore wind farm rather than keep running an existing gas/coal power plant in Germany. This situation encourages investment in new unsubsidised renewable projects, as the gap between prices sought by private investors and market prices narrows. This is an example of how carbon prices can drive a reduction in emissions in the mid-term (since it takes some time for the price signal to be converted into a finished project).
- However, in the short-term perspective high carbon prices alone are not a guarantee of falling CO₂ emissions, since other factors such as low renewable generation, high gas prices or high demand due to cold winters/warm summers can overpower their effect (some factors were already present during the first quarter of 2021). Thus, despite high carbon prices, carbon emissions could still increase in 2021, driven by factors such as higher-than-average summer temperatures and the post-pandemic recovery in electricity demand.

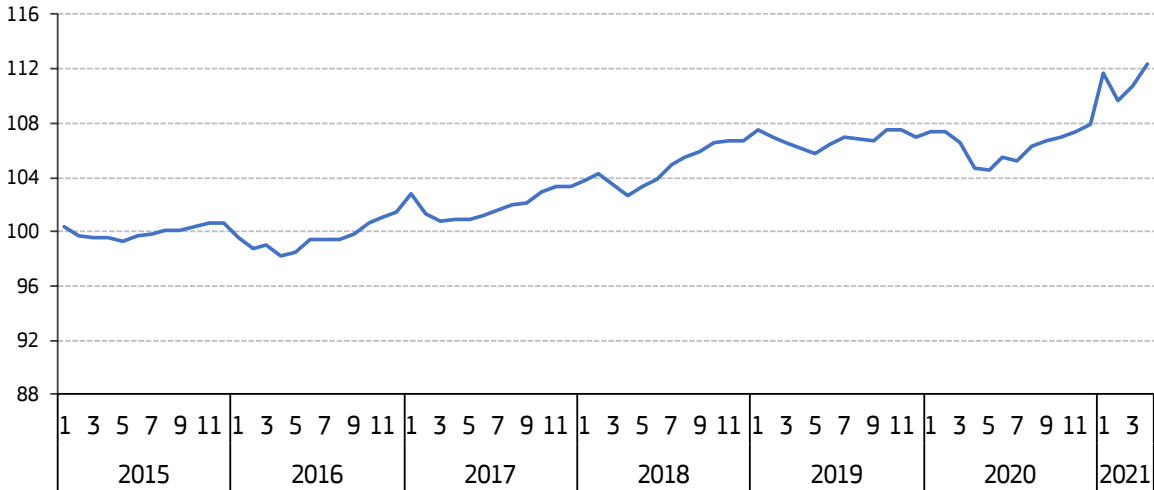
Figure 26 – Generation cost of German lignite, coal, and gas plants at different carbon prices, and onshore wind



Source: BloombergNEF

- While they bring more revenue for renewables, higher carbon prices drive up electricity bills. Wholesale electricity prices lifted by carbon prices, usually translate into retail electricity prices with a 6-12-month delay. A 1 €/tCO₂ rise in the carbon prices pushes up wholesale electricity prices by 0.6 €/MWh on average (See **Figure 12**). This means that if CO₂ prices averaged 44 €/tCO₂ in 2021 (up from 25 €/tCO₂ in 2020), wholesale electricity prices would rise roughly by 11 €/MWh compared to 2019, pushing retail prices up by 5% on average for a typical household. The effect will depend on the structure of retail prices and on the composition of the electricity mix. In countries where taxes make the bulk of the electricity bill, the impact will be less visible. In countries where wholesale prices play an important role in the tariff, retail prices could see a bigger relative increase. The situation in 2021 is further complicated by the fact that apart from emission allowances, fuel costs have gone up significantly too. The compound effects means that, wholesale prices in many European markets reached record levels last seen in 2008. As a result, retail electricity prices in most markets are expected to rise by more than 10% by the end of the year.
- **Figure 27** presents the latest available data on the electricity price inflation index, confirms that retail prices are likely to be under heavy inflationary pressures due to rising fuel and carbon costs. The effect could be more marked in the case of businesses since wholesale electricity prices constitute a relatively large portion of their final bill.

Figure 27 – Electricity prices inflation index



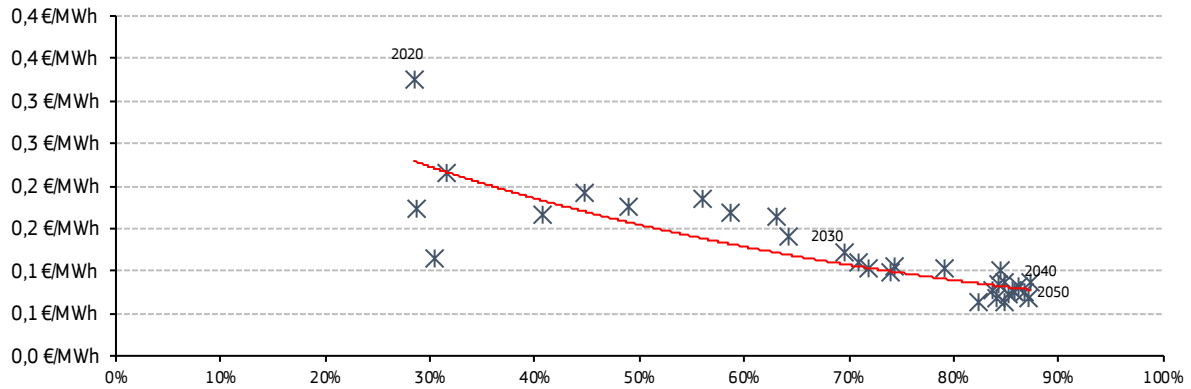
Source: EUROSTAT, HICP indicator

3.1 Long-term impacts

- In the long term, the effect of high carbon prices on investment in renewables will gradually weaken. As the share of renewable capacity expands in the electricity generation mix, the effect of carbon over power prices will decrease. Carbon and electricity will increasingly de-couple, until the carbon price stops playing a meaningful role in decarbonising the electricity sector. **Figure 28** shows that around 2020, when wind and solar meet 30% of generation in

Germany, for every 1 €/tCO₂ of carbon price increase, electricity prices rise by around 0.4 €/MWh. As renewables reach an 80% share by the late 2030s, the impact of carbon on power prices is projected to cut to a quarter.

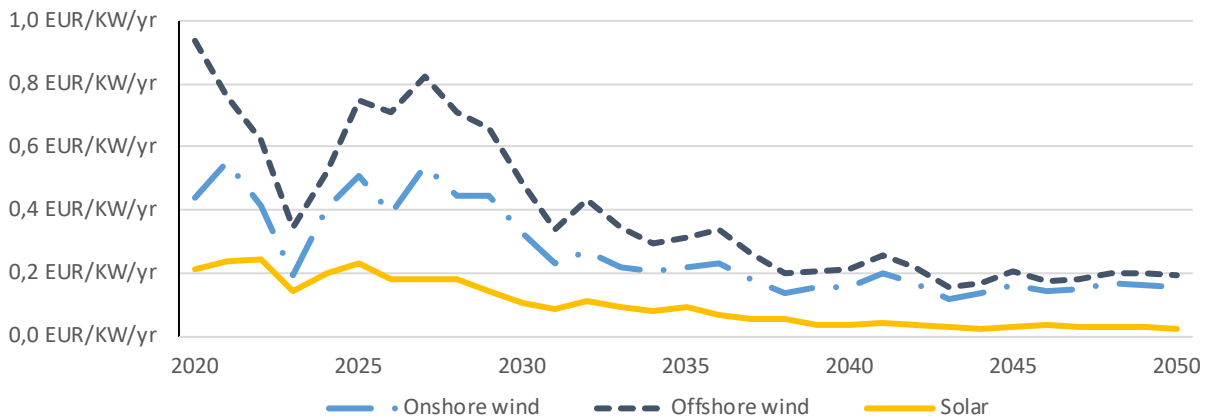
Figure 28 – Outlook for relationship between the impact of a 1 €/tCO₂ change in carbon prices on German power prices, and the share of wind and solar generation



Source: BloombergNEF

- A direct impact of this dynamic is that carbon prices will stop feeding through renewable generator's revenue. For example, this year, one of the largest German solar power plant with 166 MW of capacity can expect to see its revenue increase by 33,000 euros for every additional 1 €/tCO₂. In 2030, the same rise would boost revenue just by 16,000 euros (See **Figure 29**). This means that over the long-term, carbon prices are going to become much less relevant as a driver of investment in renewables, even though today they play an crucial role in decarbonisation of the electricity sector. For renewables to make the most of rising carbon prices in the future, they will have to present themselves as cheaper alternatives to carbon-intensive processes in hard-to-decarbonise sectors of the economy. This entails convincing industry, transport and households to increase electrification to avoid costs related to carbon.

Figure 29 - Evolution of the impact of a 1 euro/tCO₂ increase in carbon prices on the revenue of German on-shore and offshore wind, and solar



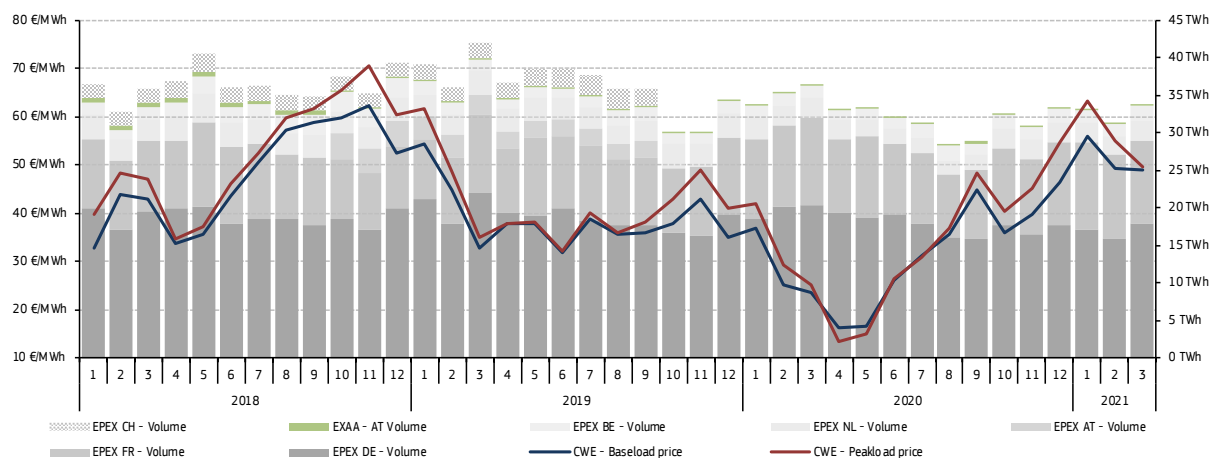
Source: BloombergNEF

4 Regional wholesale markets

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

- In the first quarter of 2021, monthly average wholesale baseload electricity prices in Central Western Europe (CWE) reached a peak in January (51 €/MWh), following the rally in prices that started in Q4 2020, amid increasing power demand due to cold spells, expensive gas and high CO2 prices. Baseload electricity prices experienced a drop during February due to mild temperatures and increased renewable generation. Overall, prices remained relatively stable as the cold spells of the beginning of March were compensated with mild weather and increased renewable generation at the end of the quarter. The monthly average price for baseload power in January, represented the highest price experienced, since the winter of 2019/2020 reflecting levels of demand of pre-pandemic times. Compared to Q4 2020, the average baseload price in the region increased by 26% to 51 €/MWh in the reference quarter. Meanwhile, average peakload prices increased by 20% to 56 €/MWh.
- Low levels of availability impacted the French nuclear fleet, experiencing record-low levels during Q1 2021 (nuclear generation fell 2% year-on-year). Relatively low wind and hydro availability together with high demand, increased the space of fossil-based capacity in the system. French exports to Spain, Germany and Belgium reversed in February (on the back of low levels of wind, hydro and nuclear), but returned to normal in March. Cold temperatures and periods of weak renewable production strengthen the thermal generation in Germany. Typical of the winter period, Germany returned to a surplus status as exports were driven by rising levels of lignite and hard coal generation which also had to replace part of the falling nuclear output and lower renewable output. The Netherlands, experienced a 5% year-on-year increase in generation (+2 TWh) due to increased coal, biomass, offshore wind and solar output. Hydro generation rose in Austria (+2 TWh year-on-year), pushing out gas and coal generation from the merit order.
- Germany installed 1.3 GW of new solar capacity during Q1 2021. German government announced plans to extend solar power tender volume to 6 GW in 2022. Cross-border transmission capacity received a considerable boost thanks to several projects that became operational in Q1 2021. The world's 1400 MW longest subsea cable between Germany and Norway was fully commissioned in connecting Nordic hydropower with German wind energy. However, the capacity of the link will be restricted in the first years of operation due to limitations of the German grid which is beset by internal bottlenecks and saturation zones. Additionally, the second compensation auction in Germany to close coal-fired plants was oversubscribed with bids for a total of 1.5 GW of capacity to be shut down (Wilhelmshaven, Merhum and Deuben were set to cease operations).
- *Interconnexion France-Anglaterre 2* (IFA2), French's 1 GW new interconnector with Great Britain, started operations on 22 January. It is the second interconnector between Great Britain and France and links Hampshire and the Normandy coastlines.

Figure 30 – Monthly exchange traded volumes of day-ahead contracts and monthly average prices in Central Western Europe



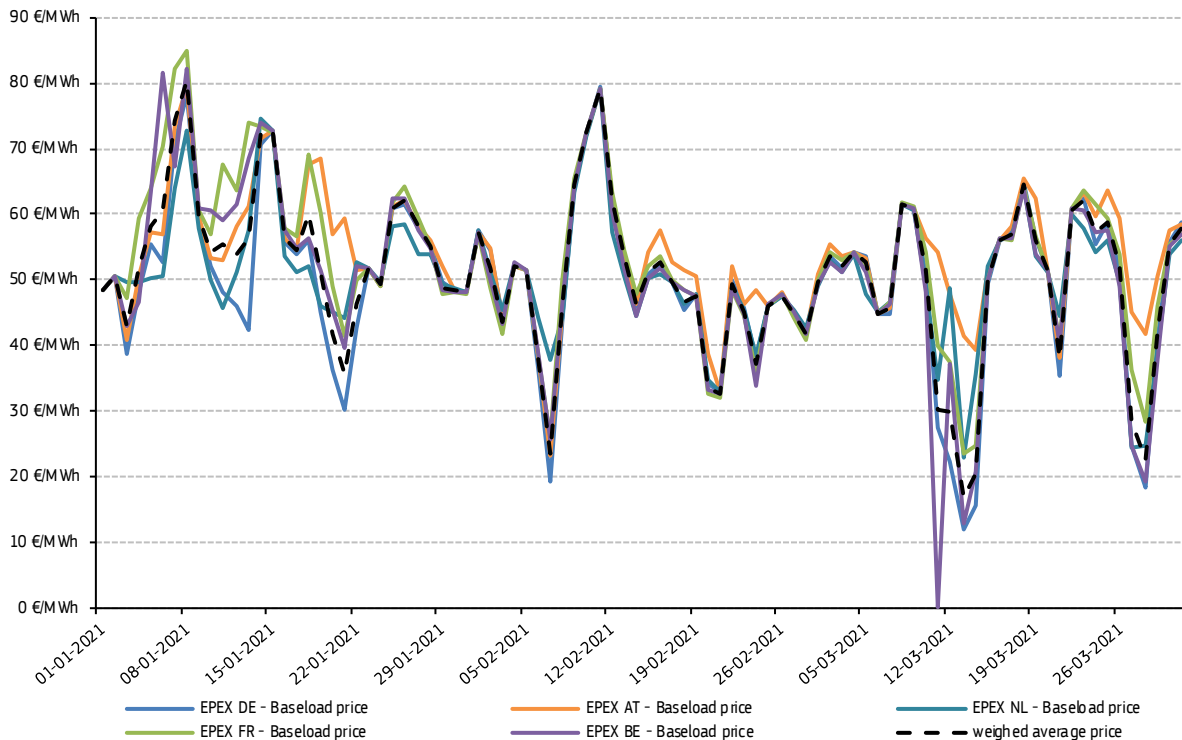
Source: Platts, EPEX. Volumes for EPEX-CH and EPEX-AT are missing.

- **Figure 31** shows the daily average day-ahead prices in the region in the reference quarter. Q1 2021, was marked by high volatility of prices. In January, daily average prices held mostly between 40 and 70 €/MWh. Volatility increased from February to March, driven by sharp variations of temperatures and wind generation, experiencing prices in the range of 30-60 €/MWh, with some markets moving close to zero on certain days. Peaks were registered close

to 80 €/MWh during the quarter. In particular, on 8 January, prices spiked to 80.3 €/MWh, before they started decreasing towards early February. Another similar peak in prices was registered on 7 February, when extremely low wind generation in Germany and high CO2 and gas prices contributed to the sudden increase in power prices.

- In contrast, after extended lull in winds, prices plummeted on 13 March when wind generation registered output record of 116 GW in Europe. German daily wind generation peaked at 47 GW. Negative hourly prices were restricted only to Germany and Belgium. Again, a combination of strong wind speeds, with strong solar generation and low weekend consumption in Germany drove hourly prices below zero for most of the last weekend of March. Combined wind and solar generation peaked above 57 GW on March 27.

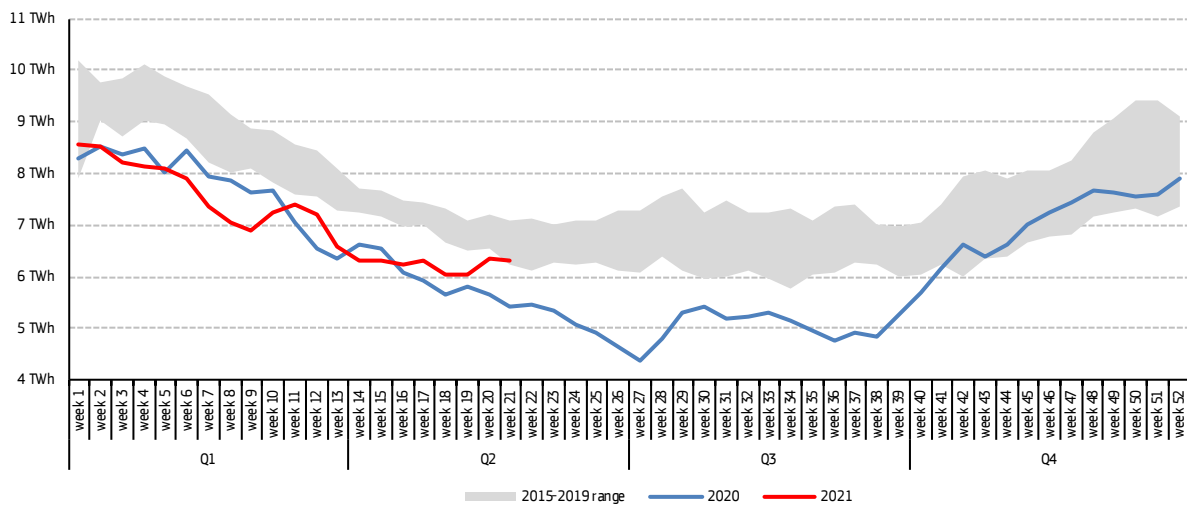
Figure 31 – Daily average power prices on the day-ahead market in the CWE region



Source: Platts.

- After briefly returning to the historical average output range in Q4 2020, French nuclear generation came to new monthly lows in Q1 2021. Despite having reached low records during Q1, nuclear output climbed towards historical average record in March, as shown in **Figure 32**. The available capacity plunged below 46 GW in the first quarter of. French nuclear output was down 2% (2 TWh) year-on-year in Q1 2021.
- Nuclear availability in April 2021 held close to weak 2020 levels. Capacity remained constrained due to a prolonged outage at Chooz 2 and a delayed return of Flamanville 1 (only in May) negatively impacted generation volumes. In February, output fell to record low levels (below 37 GW) as 11 reactors started maintenance before March. Dampierre 1 and Paluel 3 reactors went offline as planned during early April, where Paluel 1 and Paluel 4 units were forced offline as a result of unplanned maintenance. Output was also reduced due to strike action. French nuclear output fell in 2020 to a record-low of 335 TWh, mainly due to the economic recession, planned maintenance, closure of assets and extended outages. The 2021 output is estimated in the range of 330-360 TWh, which is still measurably lower than in the years before the pandemic.
- Nuclear availability in Belgium was marked by the return of Tihange-2 on 22 January, after it was shut in December for maintenance works. Additionally, Doel 2 unit went into maintenance at the end of March. Nonetheless, Belgian nuclear output rose almost 37% (3 TWh) year-on-year in Q1 2021. The nuclear phase-out plan foresees the first retirement in 2022. The last units are scheduled to be shut down in 2025.

Figure 32 – Weekly nuclear electricity generation in France

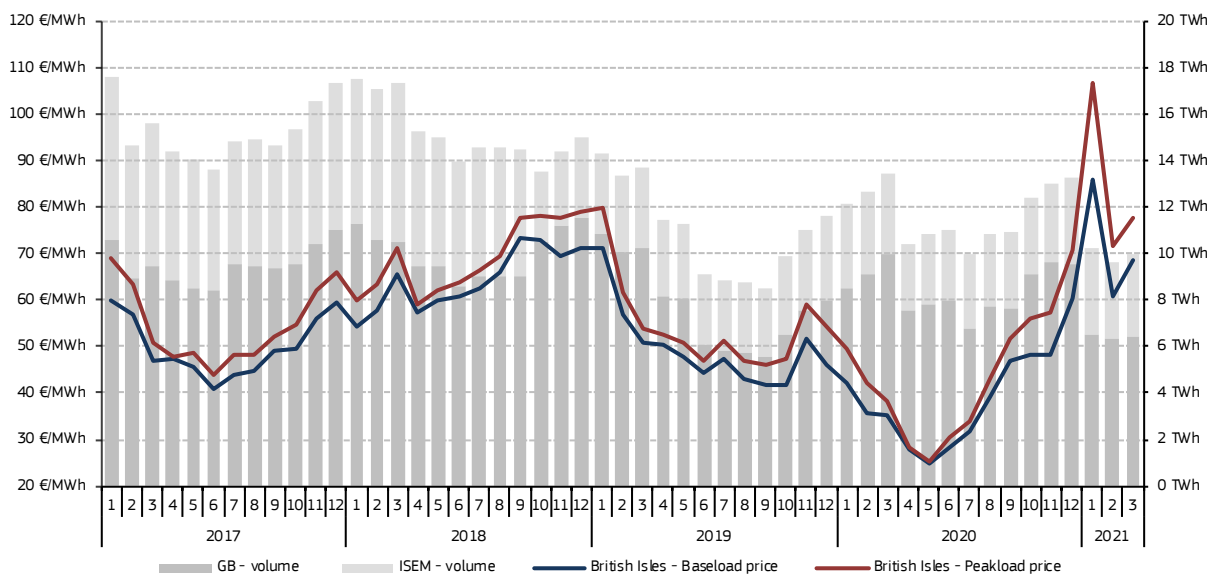


Source: ENTSO-E

4.2 British Isles (GB, Ireland)

- Figure 33** 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 dramatically in January, the highest level in fifteen years. The surge was driven by low wind availability, rising gas prices, robust demand, plant outages and a tightening balance on the continent. Great Britain had insufficient spare capacity to meet the high power demand, resulting in gas and coal plants ramping up in January to meet the increasing demand. Compared to Q4 2020, the average baseload price on the British Isles rose by 37% to 72 €/MWh in the reference quarter and was 91% above the level from Q1 2020. Trading activity on the British day-ahead market decreased by 30% in Q1 2021 compared to the same quarter last year and was unchanged in Ireland. Main tight factors on the supply side were the nuclear outages prolonged through the winter, the unplanned outage on 9 March of the BritNed 1 GW interconnector with the Netherlands and the outage of the subsea 2.3 GW Western HDVC during parts of February and March, constraining wind output from Scotland. The electricity grid operator issued three electricity margin notices in January.

Figure 33 – Monthly exchange traded volumes of day-ahead contracts and monthly average prices in Great Britain and Ireland

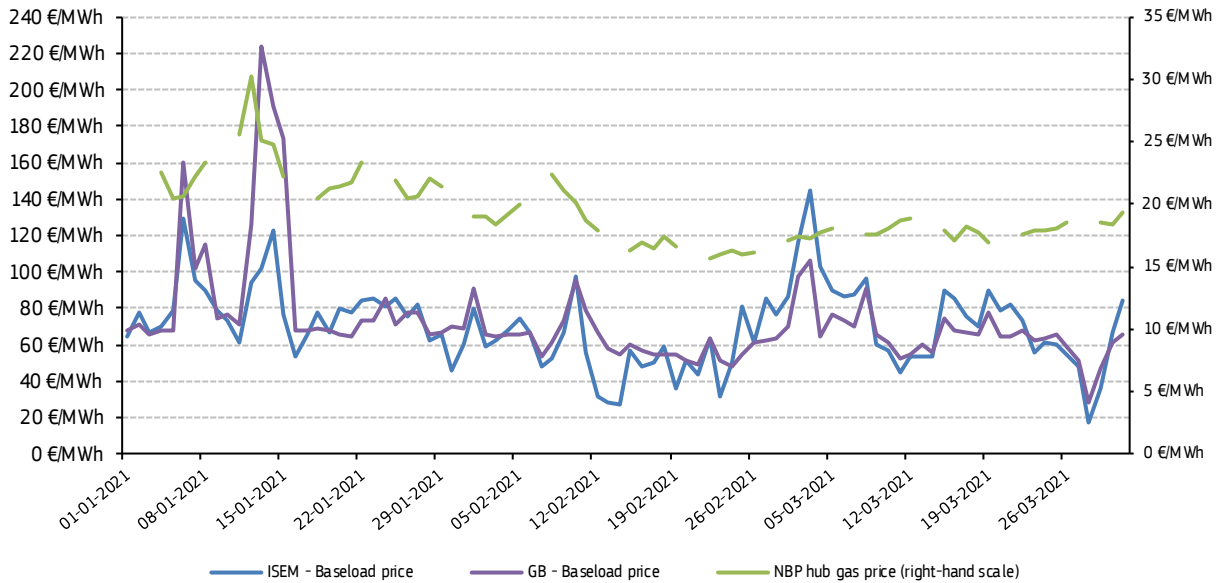


Source: Nord Pool N2EX, SEMO, Utility Regulator

- Figure 34** follows the developments of daily average baseload electricity prices in Great Britain (N2EX) and Ireland (ISEM). British baseload prices hit 15-year high record day-ahead prices (223 €/MWh), on the back of high demand

due to cold weather and tight margins of spare electricity capacity. Prices fluctuated among 55-100 €/MWh during the rest of the quarter, falling during the last week of March due to high wind output. Day-ahead prices hourly prices spiked between 5 pm and 6 pm exceeding 1100 €/MWh on three separate occasions during the first two weeks of the year. During this situation, Great Britain draw power from Northern Ireland and the Republic of Ireland along the Moyle and East-West interconnectors. Sustainable flexibility in the form of storage or demand response has plenty of room to increase flexibility during these events. The Irish market generally followed the British contract albeit less volatility during the quarter.

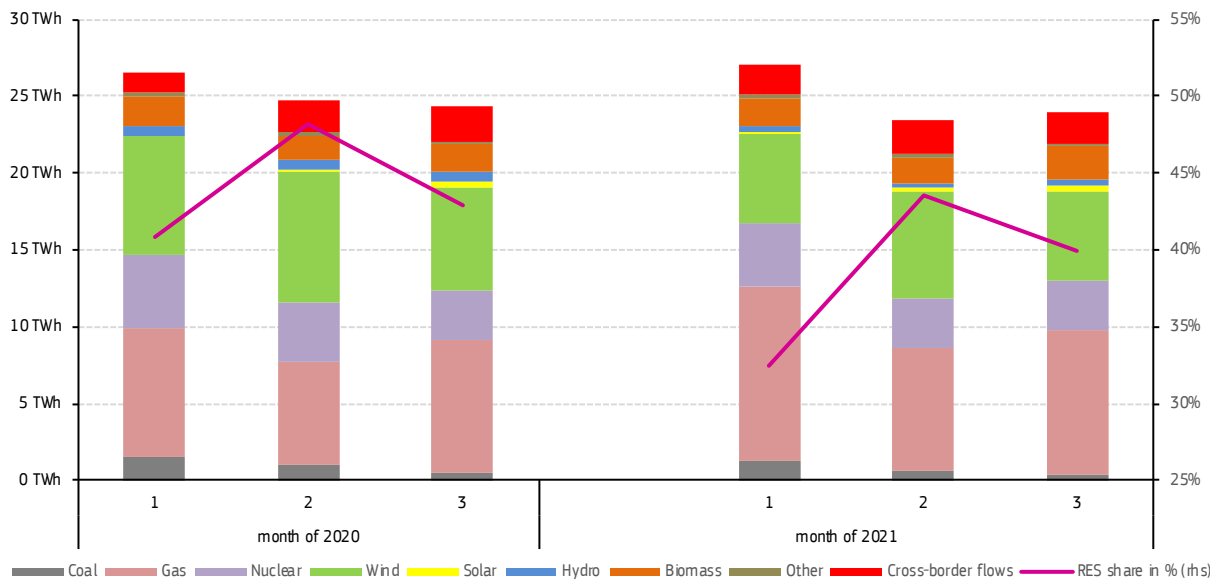
Figure 34 – Daily average electricity prices on the day-ahead market in Great Britain and Ireland



Source: Nord Pool N2EX, SEMO

- **Figure 35** shows that gas was the main winner of generation mix during Q1 2021, as it required to fill the gap due to low wind generation (especially during March). Imports from the continent increased by 9% on a net basis. The position of coal did not change significantly, as the fuel is now used mainly to cover demand peaks at times of low renewable availability and should leave the mix soon. Biomass output hit a record high, peaking at almost 4 GW on 27 March. The renewable share decreased to 39%, up from 44% in the reference quarter during 2020, as March saw one of the longest wind lulls in over a decade. The main driver behind rising renewable output was wind energy, especially in the offshore segment.

Figure 35 – Changes in the UK electricity mix between Q1 2020 and Q1 2021

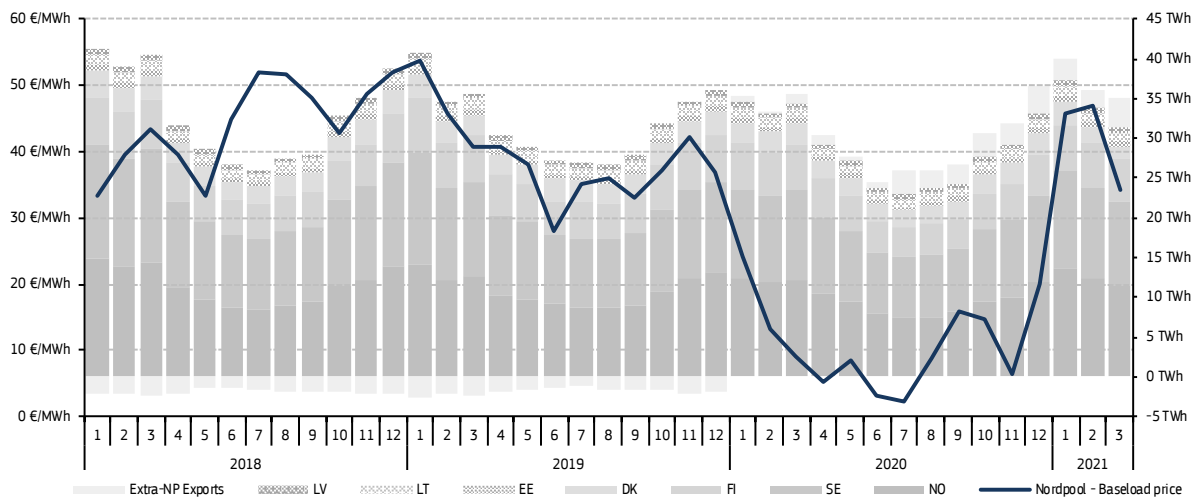


Source: BEIS

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

- As shown in **Figure 36**, Nord Pool prices began to rise since the end of Q4 2020, lifted by the start of operations of the 1.4 GW interconnector (NordLink) between Norway and Germany, increasing Norwegian export potential. Base-load prices continued rising until February, reaching 47 €/MWh on the back of record power demand due to sustained cold weather. Prices started to fall again thanks to the mild weather in March. Compared to Q1 2020, the average system baseload price surged by 175% to 42 €/MWh in the reference quarter. Trading activity was 7% higher compared to the previous Q1.
- End of March saw the start of fuel loading at Finish nuclear power plant Olkiluoto-3, which is due to begin commercial operation in February 2022 and it is scheduled to meet 14% of Finnish demand when operating at full capacity.

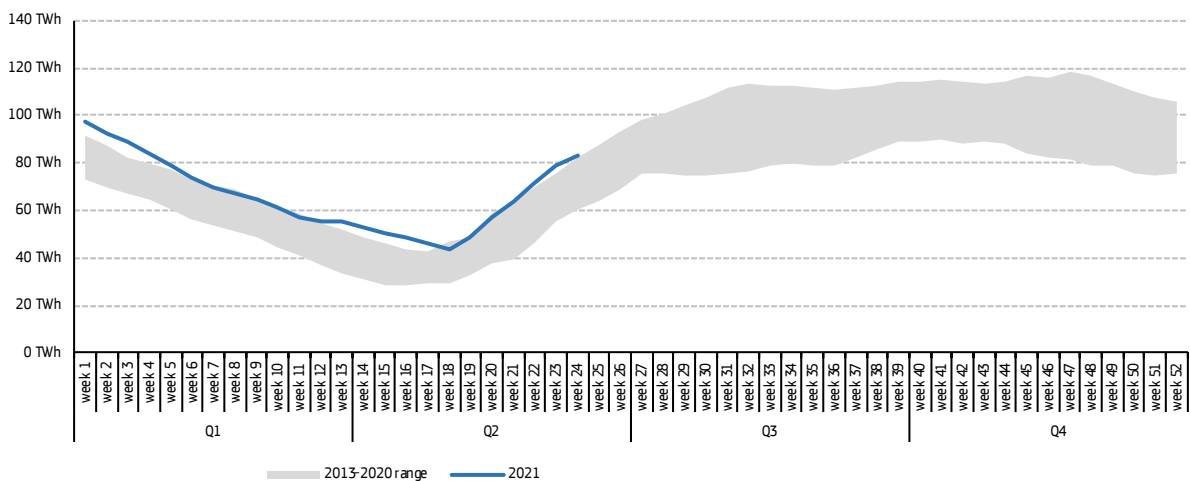
Figure 36 – Monthly electricity exchange traded volumes and the average day-ahead wholesale prices in Northern Europe



Source: Nord Pool spot market

- Figure 37** 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 have fallen steadily in line with seasonal behaviour, since the initial overflow in early 2021, but still holding on the top tier. Record power demand due to cold weather, accelerated the rundown of vast hydro reservoir stocks in the region, which increased prices on the continent and prompted a rise in Nordic exports. However, imports decreased towards the spring as hydro generation fell by 14%. The total hydro generation in the region increased by 23% (or 5 TWh) year-on-year to 42 TWh in Q1 2021.

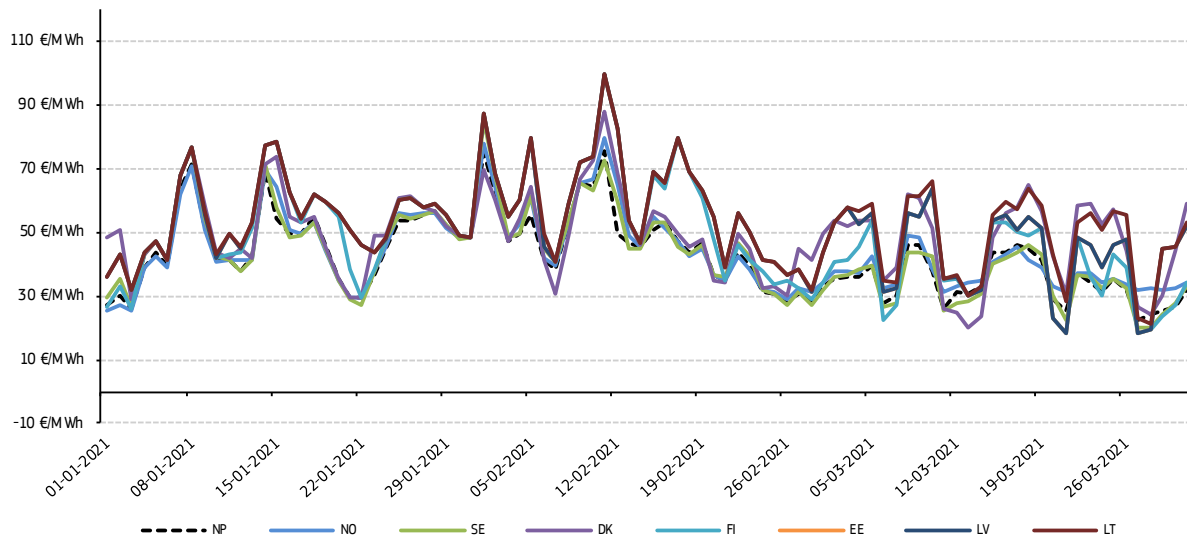
Figure 37 – Nordic hydro reservoir levels in 2021, compared to the range of 2013-2020



Source: Nord Pool spot market

- **Figure 38** shows that average daily prices across Northern Europe continued to display a high degree of divergence in Q1 2021, as in previous quarters. Continued cold weather caused electricity demand to hit record highs on 12 February (75 €/MWh). Increased electrification of industry, transportation, and home energy use has boosted energy demand in the region, especially during cold periods. The Baltic region and Finland, which both suffer from considerable structural deficits (see **Figure 23**), registered nearly permanent premiums over the system contract. The Nordic region was severely affected by cooler temperatures and lulls in wind availability, which together with rising export opportunities, increased system prices during the first half of Q1 2021.

Figure 38 – Daily average regional prices and the system price on the day-ahead market in the Nordic region

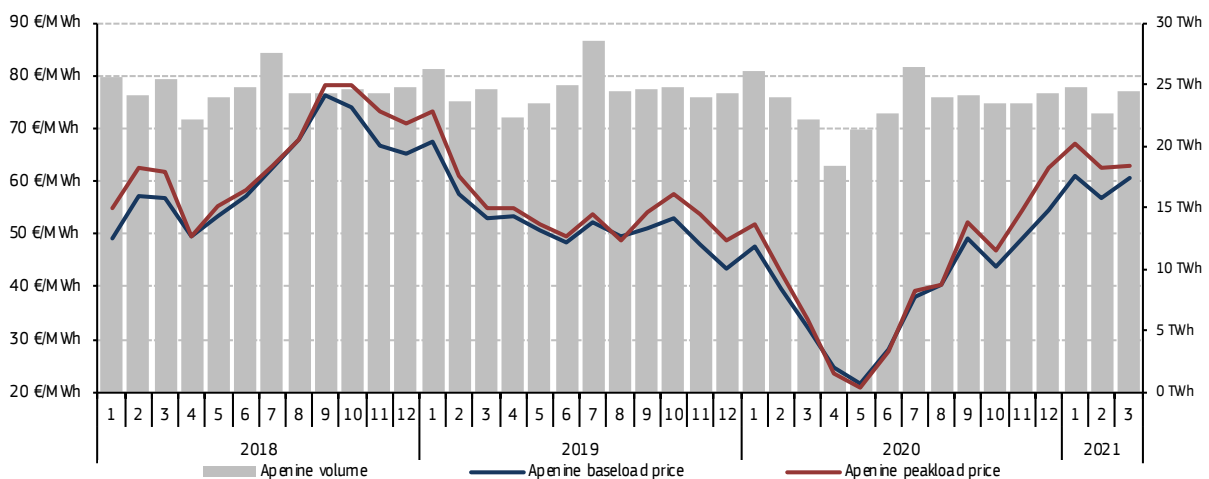


Source: Nord Pool spot market

4.4 Apennine Peninsula (Italy, Malta)

- Rising Italian monthly average baseload electricity prices (**Figure 39**) reached a peak in January (61 €/MWh), the highest level since January 2019, driven by cold temperatures combined with relatively low renewable generation and rising gas prices. The average baseload price in Q1 2021 rose by 21% compared to Q4 2020 to 60 €/MWh, and was 49% above Q1 2020 levels. Trading volumes decreased by 1% compared to the previous Q1.

Figure 39 – Monthly electricity exchange traded volumes and average day-ahead wholesale prices in Italy

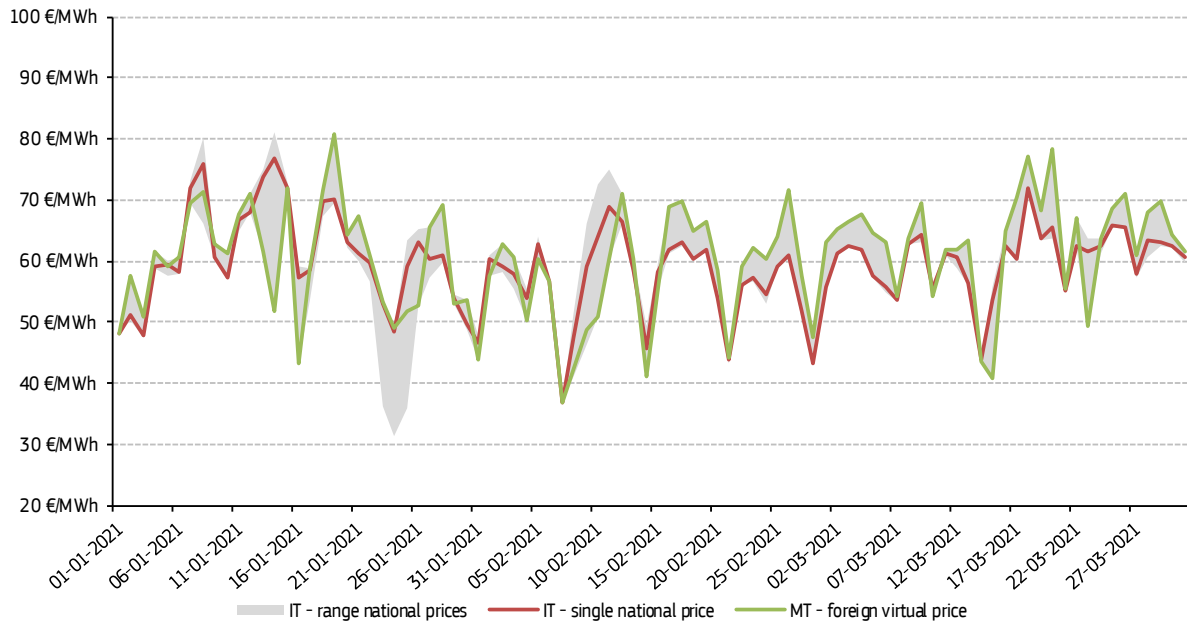


Source: GME (IPEX)

- **Figure 40** 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 50 and 75 €/MWh during the first weeks of the reference quarter and moved below in the range of 45-65 €/MWh until the last weeks of March, rising again on the back of cold weather, low renewables and higher gas prices. Peaks in prices came early in January amid a continent-wide supply tightness (see **Figure 31**).

- 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. As visible in **Figure 40**, prices in the Maltese zone mostly formed the upper boundary of the band of regional prices in the reference period with a few exceptions at the beginning of January.

Figure 40 – Daily average electricity prices in the Italian day-ahead market, within the range of different area prices

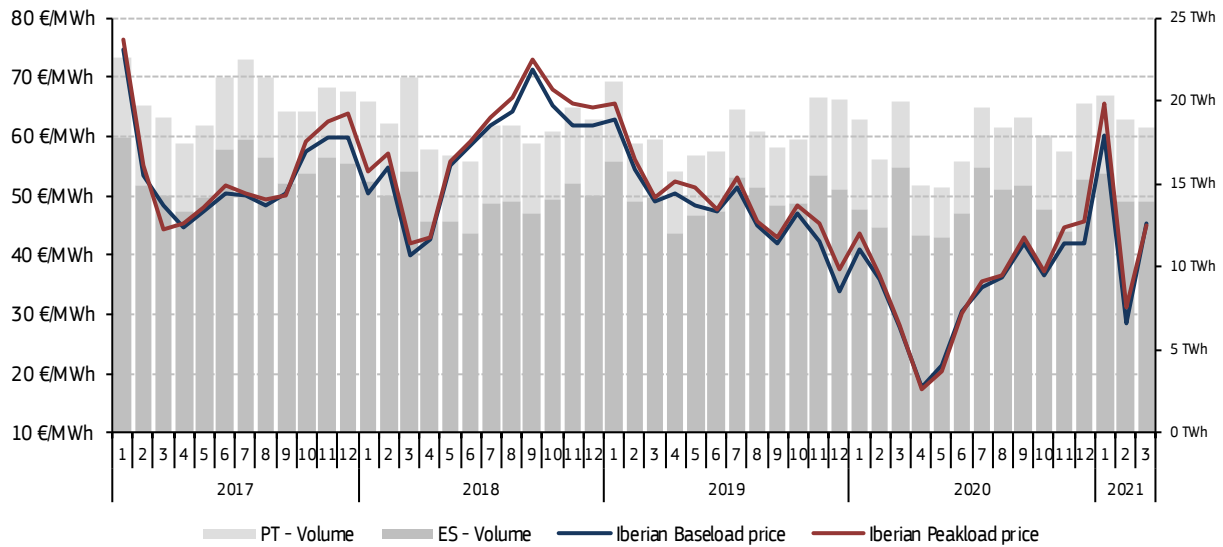


Source: GME (IPEX)

4.5 Iberian Peninsula (Spain and Portugal)

- **Figure 41** reports on monthly average baseload and peakload contracts in Spain and Portugal. Average baseload electricity prices surged to 60 €/MWh in January on the back of high gas prices due to tight LNG market and cold spells. Prices fell in February by 52% on the back of strong hydro and wind generation, which prompted net exports lowering thermal generation. In March, prices rose again, as lower hydro and reduced nuclear generation almost coupled prices with France in April. Compared to Q1 2020, the average baseload price rose by 28% to 45 €/MWh in the reference quarter. Peak prices increased by 31% to 47 €/MWh. Trading activity was 7% higher compared to the previous Q1.

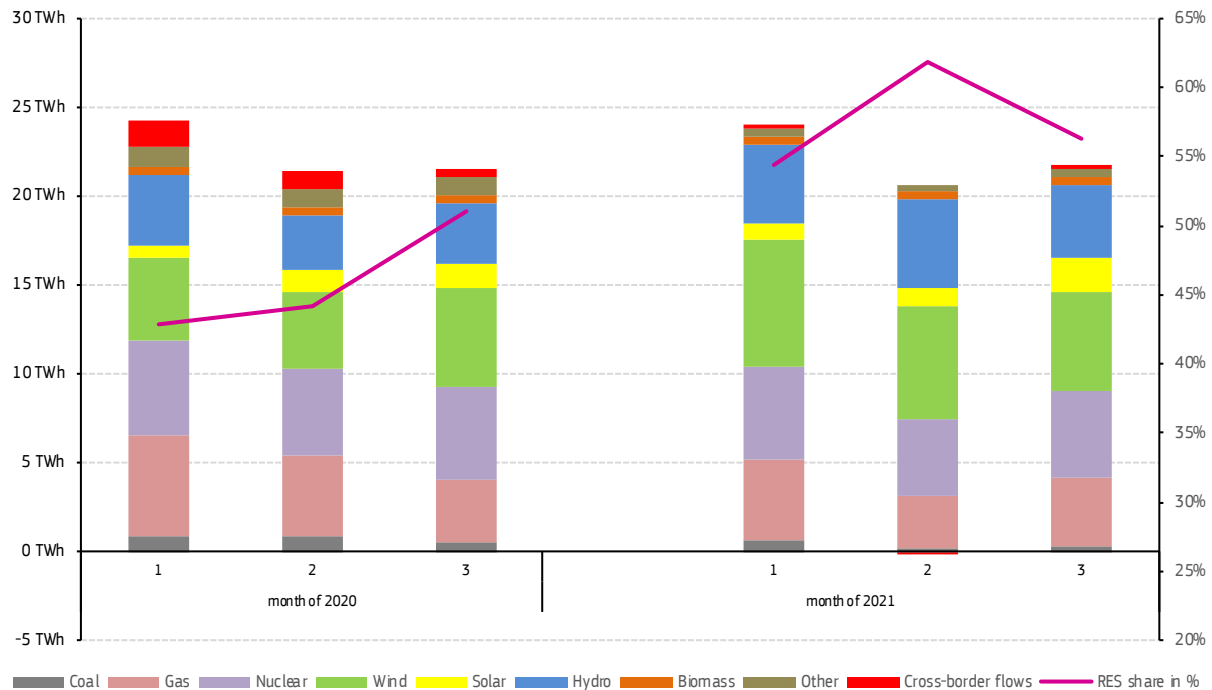
Figure 41 – Monthly electricity exchange traded volumes and average day-ahead prices in the Iberian Peninsula



Source: Platts, OMEL, DGEG

- Figure 42** displays the evolution of the monthly electricity generation mix in Spain during the first quarter of 2021, as well as during the same period of the previous year. Net generation increased by 3% year-on-year, in line with a surge in consumption. Wind output was 56% up year-on-year during January. Generation in February was dominated by renewables output (62% of the electricity mix) on the back of strong hydro/wind generation and weak demand which fostered net exports to France. Spain remained a net importer during the months of January and March due to low hydro levels and reduced nuclear availability. Squeezed out by low demand, surging renewables and high gas prices, gas generation fell by 18% year-on-year in Q1 2021. Thus, the share of gas in the mix shrank from 22% in Q1 2020 to 17% in Q1 2021. Coal has virtually disappeared from the mix. The share of nuclear energy decreased from 24% in Q4 2019 to 22% in the first quarter of 2021. Wind output was higher 31% year-on-year and became the principal source of energy during Q1 2021 covering 29% of the supply (19 TWh).

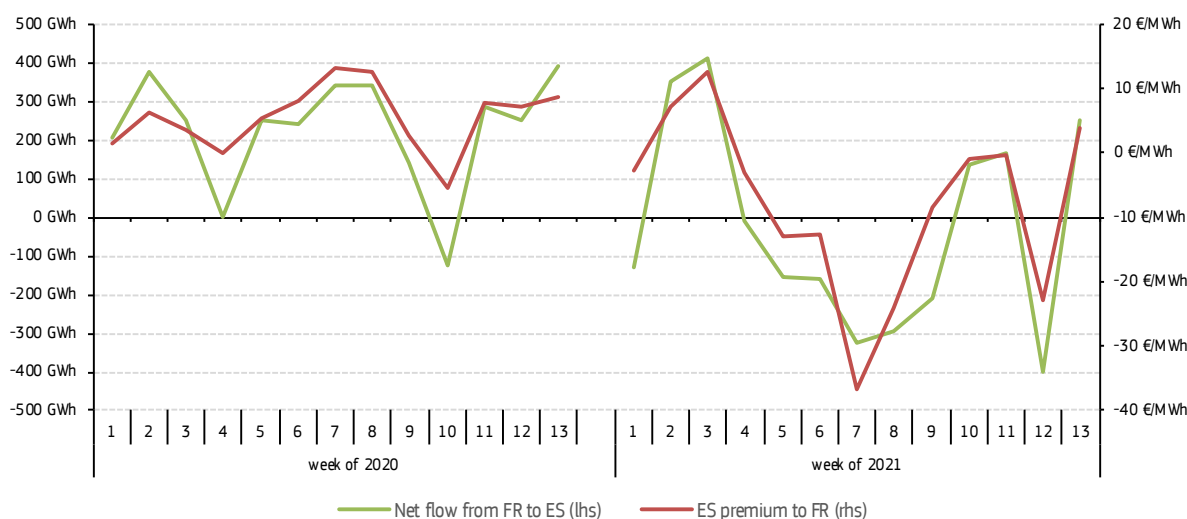
Figure 42 – Monthly evolution of the electricity generation mix in Spain in Q1 of 2020 and 2021



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

- **Figure 43** shows weekly electricity flows between France and Spain and price differentials between the two bidding zones. The balance of prices between the two markets shifted during February, where strong Spanish renewable generation and weak demand driven by new coronavirus measures turned local prices consistently below the French level. During the rest of the Q1 2021, the usual Spanish premium was maintained, due to lower rainfall and reduced winds depending mainly on French nuclear availability. The differential reached its maximum (13 €/MWh) during the third week of January when the French nuclear fleet experienced outages and Spanish wind generation reached record levels. The trend reversed in February, on the back of low French nuclear output and surge in power demand, combined with strong hydro and wind output in Spain, reaching a negative differential of -36 €/MWh. Cross-border flows followed price differentials, adding up to 0.3 TWh of net exports to France. Spain and France are connected through five high-voltage power lines of combined 2.8 GW capacity. Spain turned into a net exporter to France in February, on the back of Iberian oversupply of wind and hydro in February.
- Bilateral trade with Morocco in Q1 2021 resulted in net imports of 83 GWh from Morocco. In February, the exchanges developed in Spain's favour and developed into 9 GWh of net exports due to the oversupply of wind and hydro.

Figure 43 – Weekly flows between France and Spain and price differentials between them

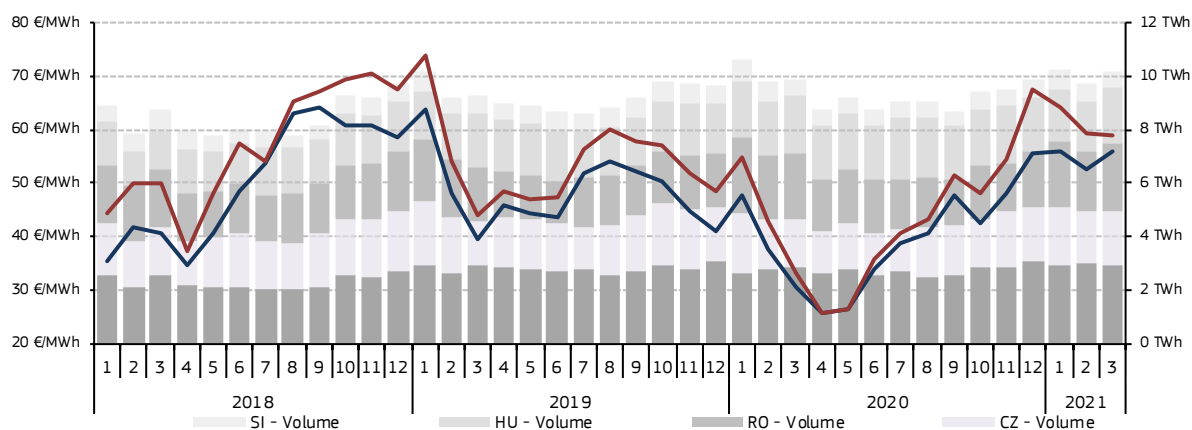


Source: ENTSO-E, OMEL, Platts

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

- **Figure 44** shows that average monthly prices for baseload power in Central Eastern Europe maintained in January the two-year high peak from December 2020 reaching 56 €/MWh. This was driven by a tighter supply-demand balance, rising carbon prices and a strong winter demand. Baseload prices fell slightly in February, as renewable generation increased. Prices rebounded in March, on the back of cold spells and wind lulls. The gap between baseload and peakload monthly averages fell from 21% in December 2020, to 6% at the end of the Q1 2021, as peakload demand declined due to mild temperatures. When compared to Q1 2020, the average baseload price in the reference quarter rose by 41% to 55 €/MWh. Traded volumes in the reference quarter fell slightly compared to the previous Q1.
- High carbon prices had supported calls for early coal phase-out in Czechia, as the government is assessing to phase-out coal earlier than 2038 (initial date recommended by the Coal commission, in line with Germany). This would most likely translate into an increment of gas and nuclear capacity.
- In Hungary, the second tender of the METAR subsidy scheme awarded 210 MW of new solar capacity. Winners bid prices 23% below the previous tender. The country expects to increase solar PV capacity to 6.5 GW by 2030.
- Solar turned into the fastest growing technology in Poland, after exceeding 4 GW of installed capacity during the reference quarter. The introduction of an auctioning subsidy system has been mentioned as one of the main drivers of this growth.
- Poland started day-ahead market on 9 February, following the launch of intraday markets and clearing in the country in August 2020. On the first day, 1347 MWh were traded on the Polish Day-ahead market, as reported by [EPEX spot](#).

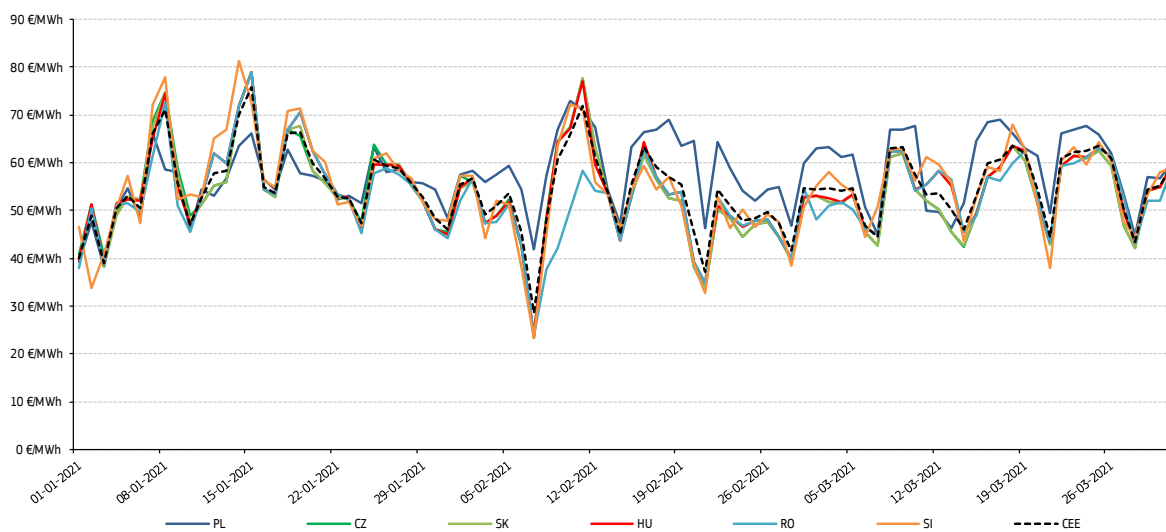
Figure 44 – Monthly electricity exchange traded volumes and average day-ahead prices in Central Eastern Europe (CEE)



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

- Figure 45** shows that daily average baseload prices in the coupled markets (CZ, SK, HU, RO, Poland since 9 February) saw an increase in volatility during Q1 2021, on the back of tightening supply-demand balance caused by cold spells, interconnector and plant outages and ebbs and flows of wind availability. Prices moved between 40 and 70 €/MWh, while the Polish market retained its typical premium. Polish peakload demand hit an all-time high of nearly 28 GW on 12 February amid a cold snap. During peakload demand in Poland, generation shortfall was supplied through imports from Germany, Sweden, Lithuania, and Czechia. Hard coal and lignite-fired generation share of the total was up 10 percentage points to 81% during the event. Hungary also set a price peakload record at on 11 February, on the back of freezing conditions across the region.

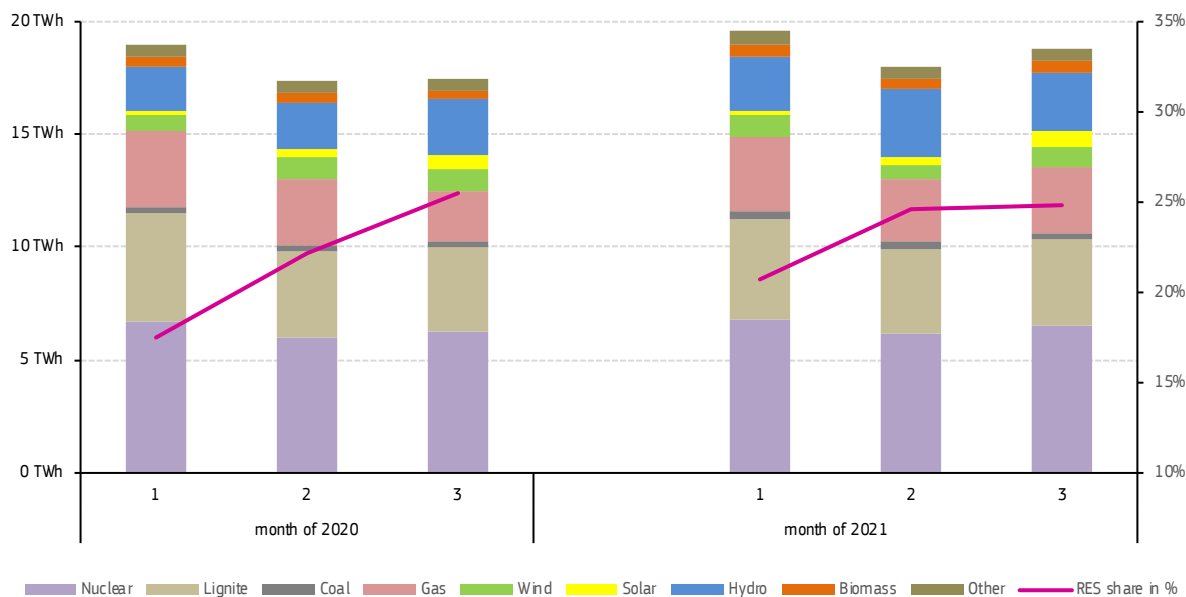
Figure 45 – Daily average power prices on the day-ahead market in the CEE region



Source: Regional power exchanges

- Figure 46** compares the combined electricity generation mix of the reference quarter of the CEE region (excluding Poland) and the quarter a year before. The most substantial change took place in hydro generation with added output of 2 TWh, due to increased Romanian generation (+1 TWh) and good conditions in Slovenia. Increasing demand due to low temperatures saw higher gas generation in the mix (+1 TWh) in Czechia, Slovakia and Slovenia. The lignite segment experienced less than 1 TWh drop in output. The share of renewables increased from 22% to 23% thanks to higher biomass generation in Czechia and Hungary, hydro generation in Romania and the solar boom in Hungary and Poland. Nuclear remained the dominant generation technology with a 35% share in the mix and a considerable presence in all five markets. Total generation increased by 3%, in line with the rise in demand. Hungary was a net power exporter to the Balkans for the first time during 2021, as solar generation remained high supported by strong wind output.

Figure 46 – Changes in the electricity mix in the CEE region (excluding Poland) between Q1 2020 and Q1 2021



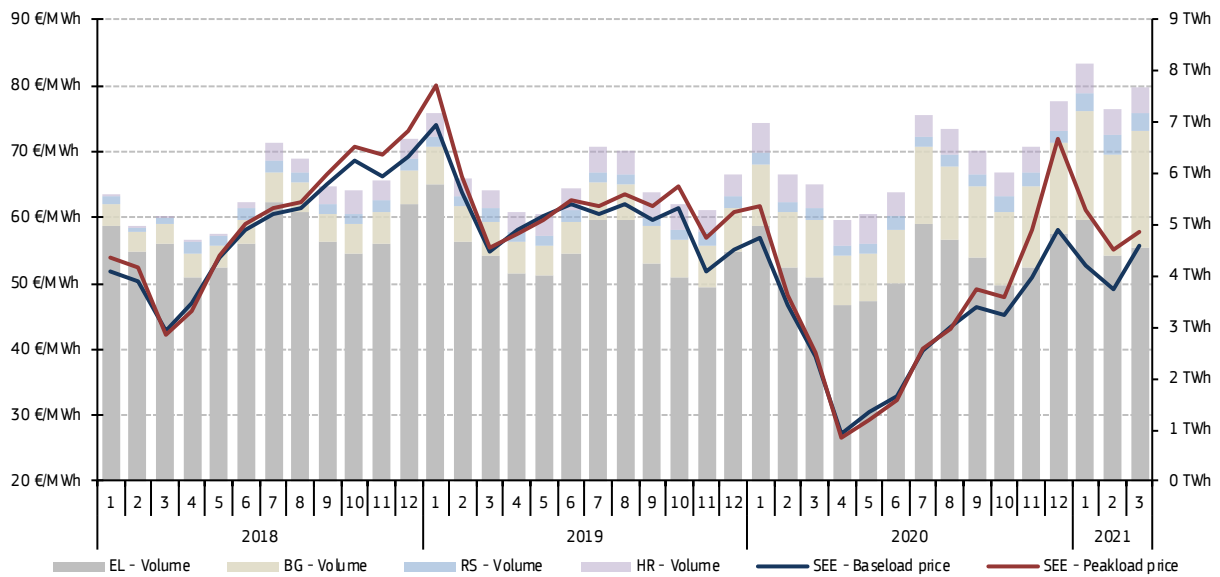
Source: ENTSO-E.

- 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 increased to 72% in Q1 2021 (compared to 67% in Q1 2020), thanks to a strong demand. Renewables decreased their share from 22% to 17% year-on-year due to increased thermal generation, and low wind output. Gas maintained its share in the mix by 10% year-on-year, underlining the limited short-term potential for coal-to-gas switching. 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), according to a strategy document approved in February 2021 by the Polish government. Poland is also planning to increase gas capacity to replace coal-fired power plants to be shut down. 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 47** shows that after a peak in December, trade-weighted monthly average baseload prices in the SEE region fell in January and February, only to rebound in March. Baseload prices in the region were driven by Greek prices (by far the most liquid market in the region). Low demand, strong hydro and renewables kept growth of prices in line, compared with other regional markets. Nonetheless, the average quarterly baseload price rose by 11% year-on-year to 53 €/MWh in Q1 2021 and 2% above Q4 2020. The average quarterly peakload price, rose 16% above Q1 2020 levels to 58 €/MWh.

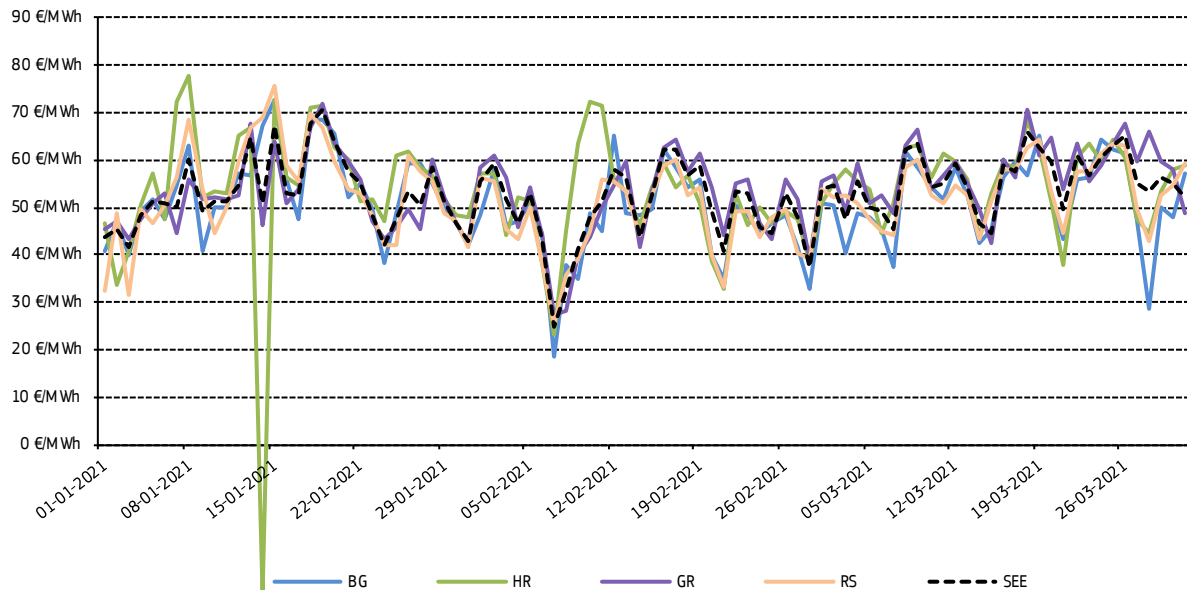
Figure 47 – Monthly traded volumes and baseload prices in South-Eastern Europe (SEE)



Source: IBEX, LAGIE, CROPEX, SEEPEX

- Greece became a net exporter in January on the back of strong hydro, renewable generation and a continued lag in demand. In March, Greek renewables led the generation mix as demand continued dipping. During Q1 2021, imports from Greece to Italy averaged 0.2 GW, a notorious contrast to the traditional imports flows seen in the past from Italy.
- Croatian grid outages triggered frequency deviation in Europe on 8 January, occasioning a 6.3 GW imbalance between the Northwest and Southeast regions, as [ENTSO-E reported](#). This imbalance of 0.25 hertz northeast area caused the split of the southeast region from the European interconnected grid. Countermeasures were taken in the European grid by the TSOs ensuring that the situation was restored to normal operation.
- As shown in **Figure 48**, Croatian day-ahead prices were relatively elevated on some occasions in January and February on the back of grid outages and maintenance of interconnectors. Prices in Greece were relatively convergent with the rest of the region during the quarter. During January, the usual Greek premium over Bulgaria reversed to a discount of 1%, due to low prices in the Greece.

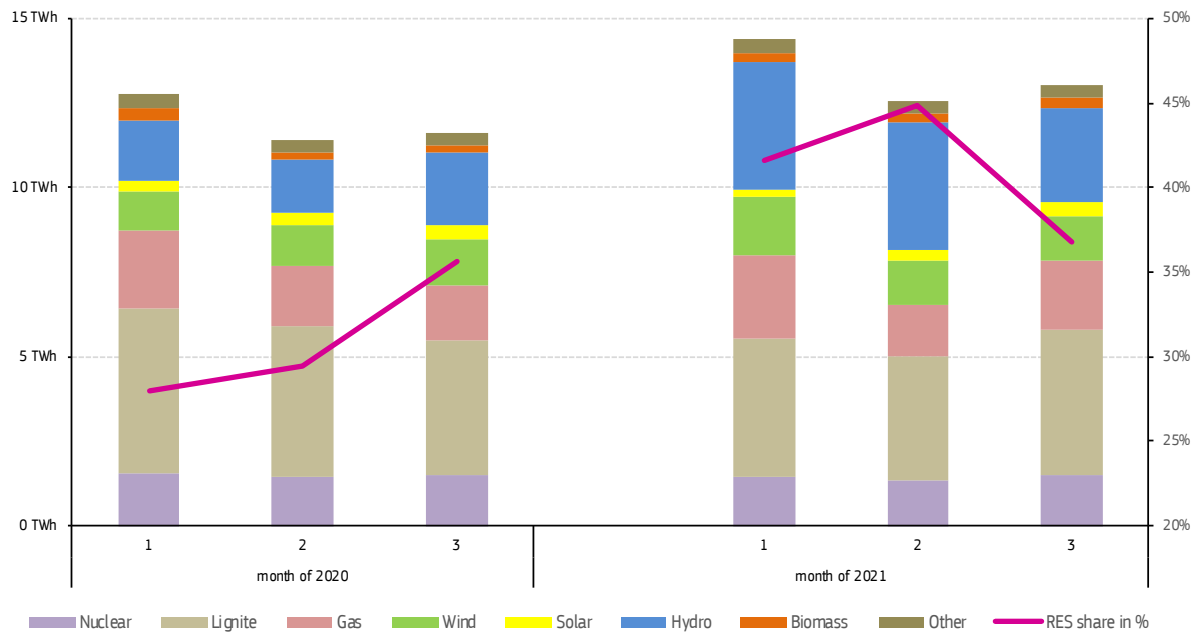
Figure 48 – Daily average power prices on the day-ahead market in Bulgaria, Croatia, Greece and Serbia



Source: IBEX, LAGIE, SEEPEX, CROPEX

- Figure 49** compares the combined electricity generation mix of the SEE region between Q1 2020 and Q1 2021. Lignite generation suffered losses mainly in Greece by 24%, being replaced mainly by gas and wind. Lignite output decreased its output also in Bulgaria (-11%). The share of lignite in the regional mix fell from 37% to 30% year-on-year. The share of gas generation remained practically unchanged during the quarter. Renewable penetration rose from 31% to 41% thanks to rising wind and hydro output in Greece and lower consumption in the region. Two new gas power plants in Greece are close to completion (Mytilineos' 826 MW and Agios Nikolaos' 780 MW). The Regulatory Authority for Energy (RAE) in Greece, announced in April the permanent retirement of 27% of Greece's lignite-fired capacity (four thermal power plants of 1.2 GW in total). The government pledges to close the remaining 2.2 GW coal-fired plant in northern Greece by 2023. The remaining coal power plant Ptolemaida 5 may be converted to gas by 2025, instead of 2028, as originally planned.

Figure 49 – Changes in the electricity generation mix in the SEE region between Q1 2020 and Q1 2021



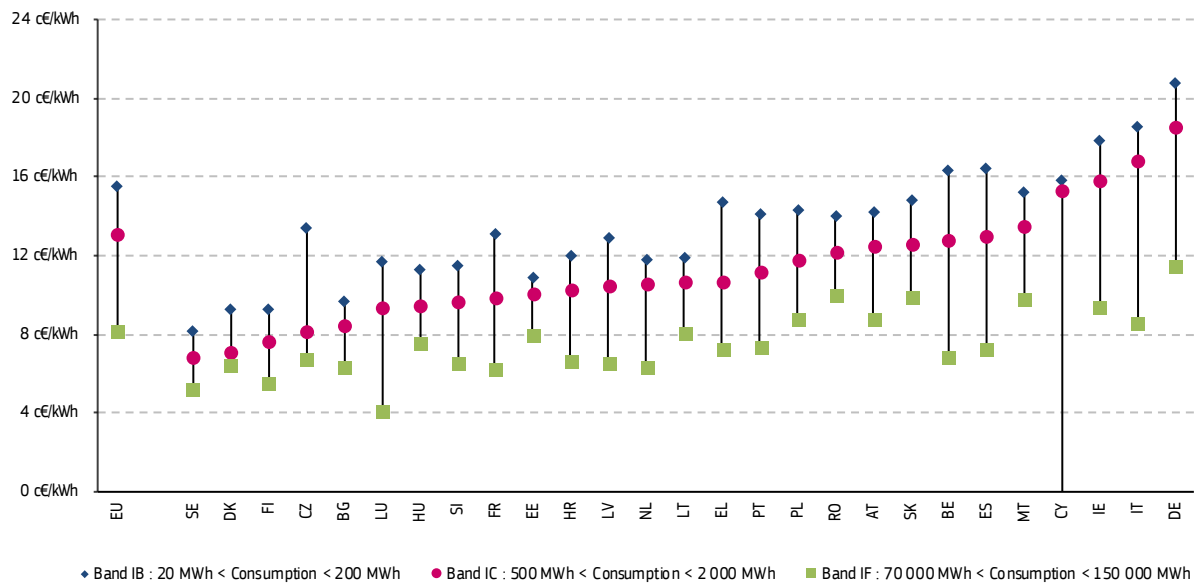
Source: ENTSO-E

5 Retail markets

5.1 Retail electricity markets in the EU

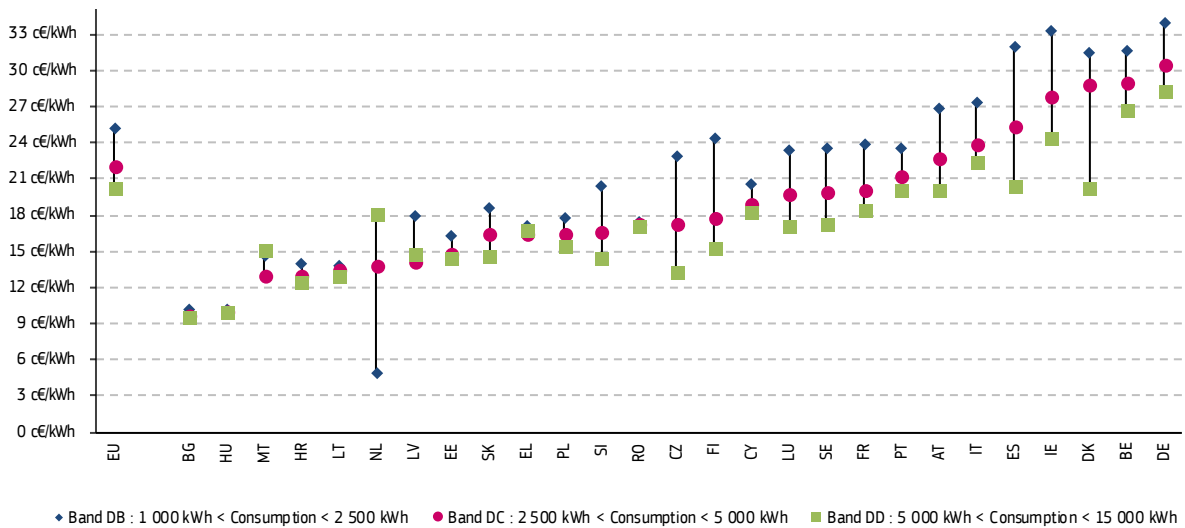
- Figures 50 and 51** display the estimated retail prices in March 2021 in the 27 EU Member States for industrial customers and households. Prices are displayed for three different levels of annual electricity consumption for both consumer types (Eurostat bands IB, IC and IF for industrial customers 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 and Greek household prices are a notable exception.
- Smaller industrial consumers (band IB) were assessed to pay the highest prices in Germany (20.7 c€/kWh) and Italy (18.5 c€/kWh), followed by Ireland and Cyprus (17.8 and 15.8 c€/kWh respectively). The lowest prices in the same category were assessed to be in Sweden (8.1 c€/kWh) and Denmark (9.3 c€/kWh). The ratio of the largest to smallest reported price was above 2:1. 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 Germany (11.4 c€/kWh both), followed by Romania (9.9 c€/kWh) and Slovakia (9.8 c€/kWh). Luxembourg (4.0 c€/kWh) was assumed to have by the lowest prices, with Sweden and Finland (5.2-5.4 c€/kWh) coming close behind. The ratio of the highest to lowest price for large industrial consumers was slightly below 2:1 for this consumer type. Compared to March 2020, the average assessed EU retail electricity price for the IF band rose by 14% to 8.1 c€/kWh.
- In the household segment, Germany (28.5 c€/kWh) was assessed to have the highest electricity price for large consumers (band DD), followed by Belgium (26.8 c€/kWh), and with Denmark (20.3 c€/kWh) in the third place. The lowest prices for big households were calculated for Bulgaria (9.5 c€/kWh) and Hungary (10.0 c€/kWh). In the case of small households, Germany saw the highest prices (34.0 c€/kWh), followed by Belgium (31.6 c€/kWh), while Bulgaria and Hungary (both at 10.2 c€/kWh), found themselves again on the other side of the price spectrum. Compared to March 2020, the average assessed EU retail electricity price for the DD band rose by 3% to 20.2 c€/kWh.

Figure 50 – Industrial electricity prices, March 2021 – without VAT and recoverable taxes



Source: Eurostat, DG ENER. Data for the IF band for CY is either confidential or unavailable.

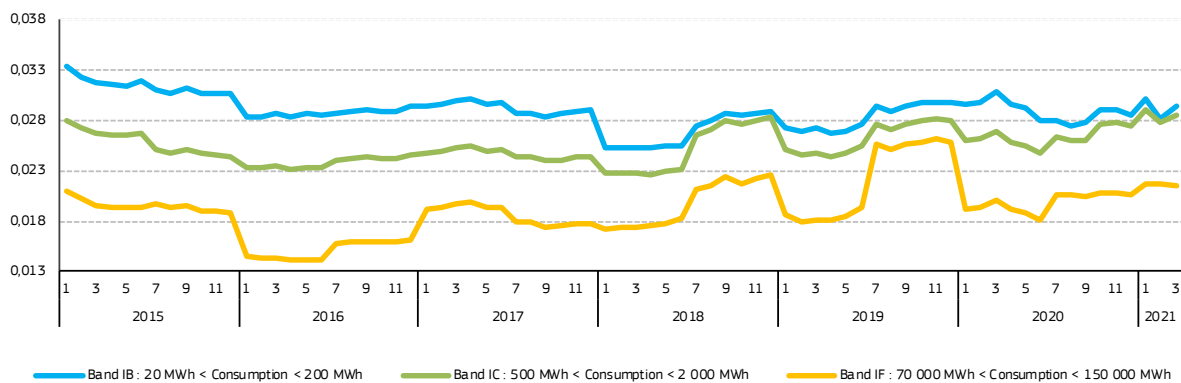
Figure 51 – Household electricity prices, March 2021 – all taxes included



Source: Eurostat, DG ENER

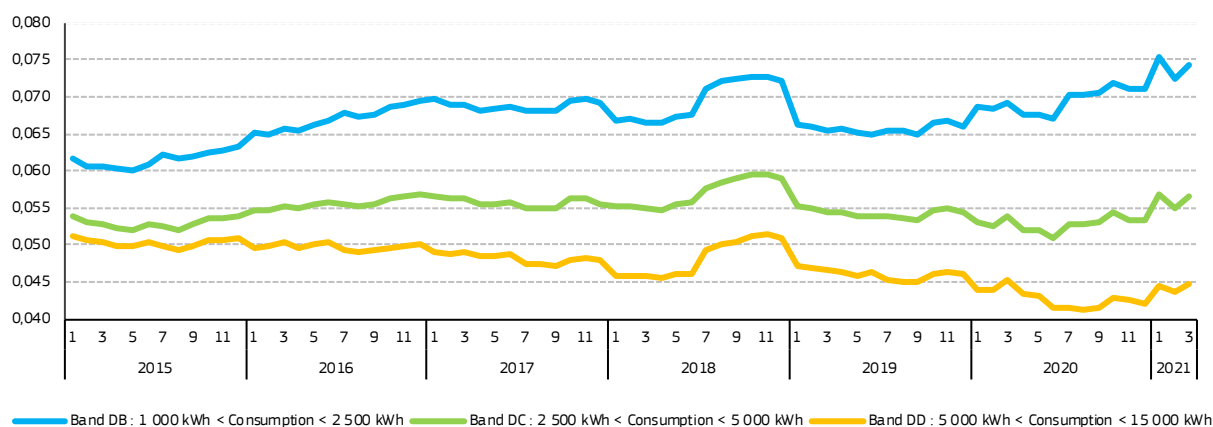
- **Figure 52 and Figure 53** display the convergence of retail prices across the EU over time, by depicting their standard deviation. Industrial prices for large and medium-sized businesses continued to converge in Q1 2021, at a higher pace than in the previous quarter. In the case of retail prices for small businesses, there was an increase of the standard deviation compared with March 2020.
- In the household sector, price convergence continues to be stable in Q1 2021. 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 52 – Standard deviation of retail electricity prices in the EU for industrial consumers



Source: Eurostat, DG ENER

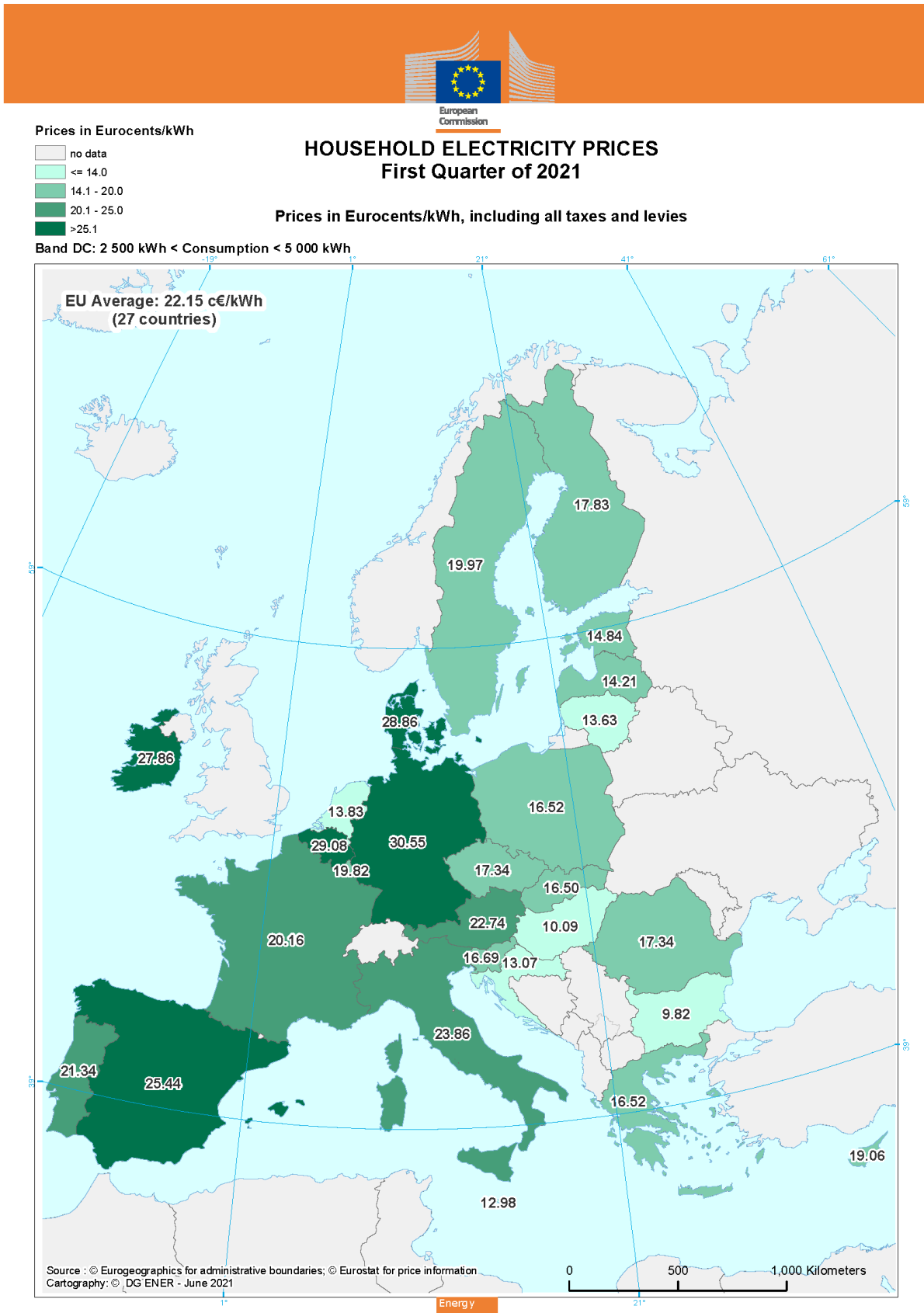
Figure 53 – Standard deviation of retail electricity prices in the EU for household consumers



Source: Eurostat, DG ENER

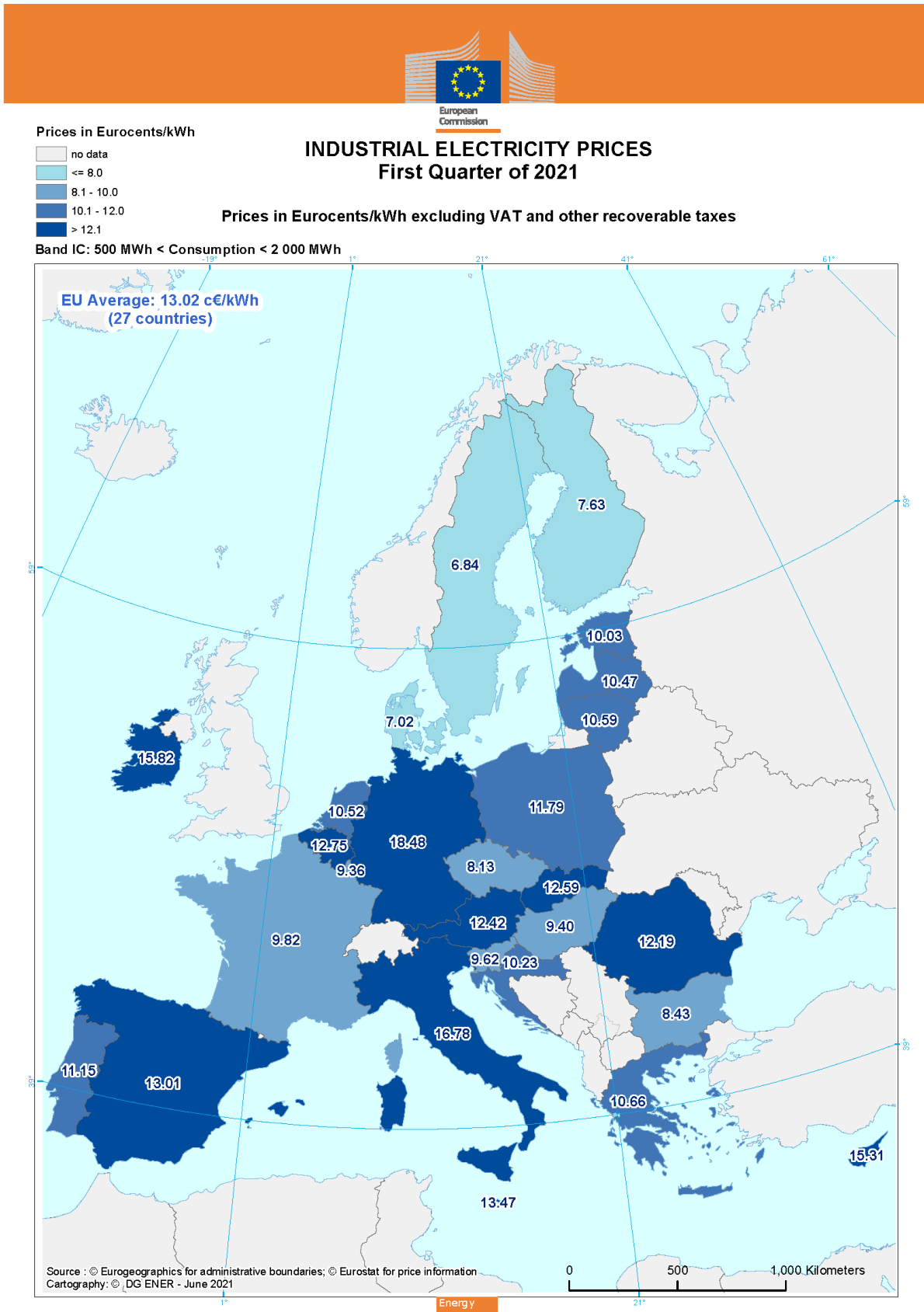
- **Figures 54 and 55** display the estimated electricity prices paid by EU households and industrial customers with a medium level of annual electricity consumption in the last month of Q1 2021. In the case of household prices, Germany topped the list (30.6 c€/kWh), followed by Belgium and Denmark. As was the case in previous quarters, Bulgaria and Hungary retained their position as Member States with the cheapest household electricity prices. The EU average increased by 3% in the reference quarter compared to March 2020. The largest year-on-year increases in the household category were assessed in Slovenia (+38%), Estonia (+29%) and Spain (+23%). The biggest year-on-year falls were estimated for Cyprus (-14%, see **Figure 56** for more details) and Latvia (-11%).
- In the case of mid-sized industrial consumers, Sweden was assessed to have the most competitive price in Q1 2021, followed by Denmark and with Finland taking the third place. Meanwhile, Germany and Italy stood at the other end of the spectrum. At 13.0 c€/kWh, the average retail price for industrial customers in the EU in the reference period fell by 39% compared to Q1 2020.

Figure 54 – Household Electricity Prices, first quarter of 2021



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

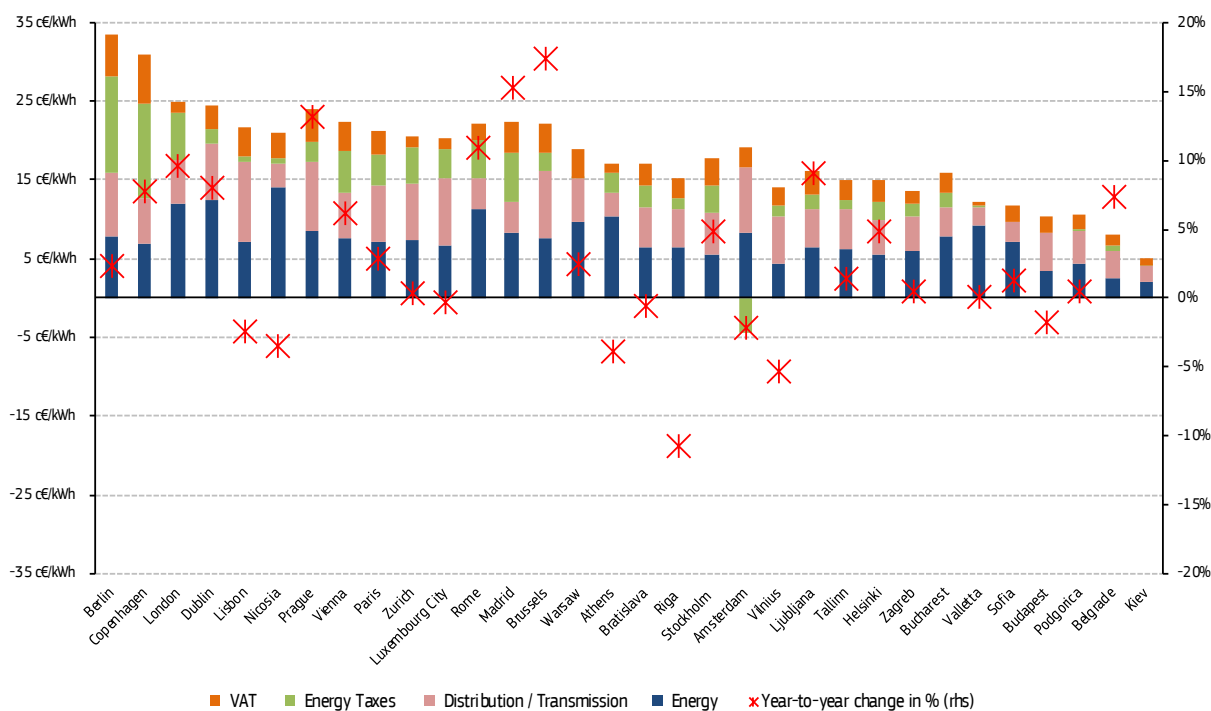
Figure 55 – Industrial Electricity Prices, first quarter of 2021



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

- **Figure 56** 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 May 2021, the highest prices were observed in Berlin and Copenhagen (35.5 and 30.9 c€/kWh, respectively) where energy taxes accounted for more than a third of the final bill. The lowest prices among EU capitals were recorded in Budapest and Sofia (10.4 c€/kWh and 11.7 c€/kWh, respectively). This corresponds to the Eurostat data analysed in **Figure 51**. EU-wide, retail prices have been climbing since the end of 2020. Inflation pressures have intensified throughout the year, due to rising wholesale prices, which were driven by increased demand, high gas prices, and more expensive emission allowances.
- The highest levels of the energy component in Europe were reported from Nicosia, Dublin, and London (12-14 c€/kWh), cities in relatively isolated island markets. The lowest levels of the energy component (3-6 c€/kWh) were recorded in the capitals of countries with stronger forms of price regulation (Belgrade, Budapest, Vilnius) or with a high degree of renewable generation (Copenhagen, Stockholm). The EU average for the energy component was 7.7 c€/kWh (unchanged from February 2020). Out of the 27 capitals, 20 had a cheaper energy component than the EU average.
- The highest network charges were recorded in Lisbon (10.2 c€/kWh), Prague and Luxembourg City (8.8 c€/kWh and 8.5 c€/kWh, respectively) where they accounted for roughly 40% of the total price and were higher than the energy component. The lowest network fees were collected in Valletta (2.4 c€/kWh) and Sofia (2.6 c€/kWh). The EU average in the reference quarter was 5.6 c€/kWh (up from 5.5 c€/kWh in May 2021).
- Apart from Berlin and Copenhagen (12 c€/kWh), the highest energy taxes were paid by households in Madrid and London (6 c€/kWh). Sofia and Budapest stood at the other end of the range, with zero energy taxes collected by local authorities. The average energy tax component reached 2.7 c€/kWh (up from 2.6 c€/kWh in May 2020). 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.
- 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 51**, and contributed to the unusual effect in which the lower the consumption, the lower the price per kWh.

Figure 56 – The Household Energy Price Index (HEPI) in European capital cities in Eurocents per kWh, May 2021

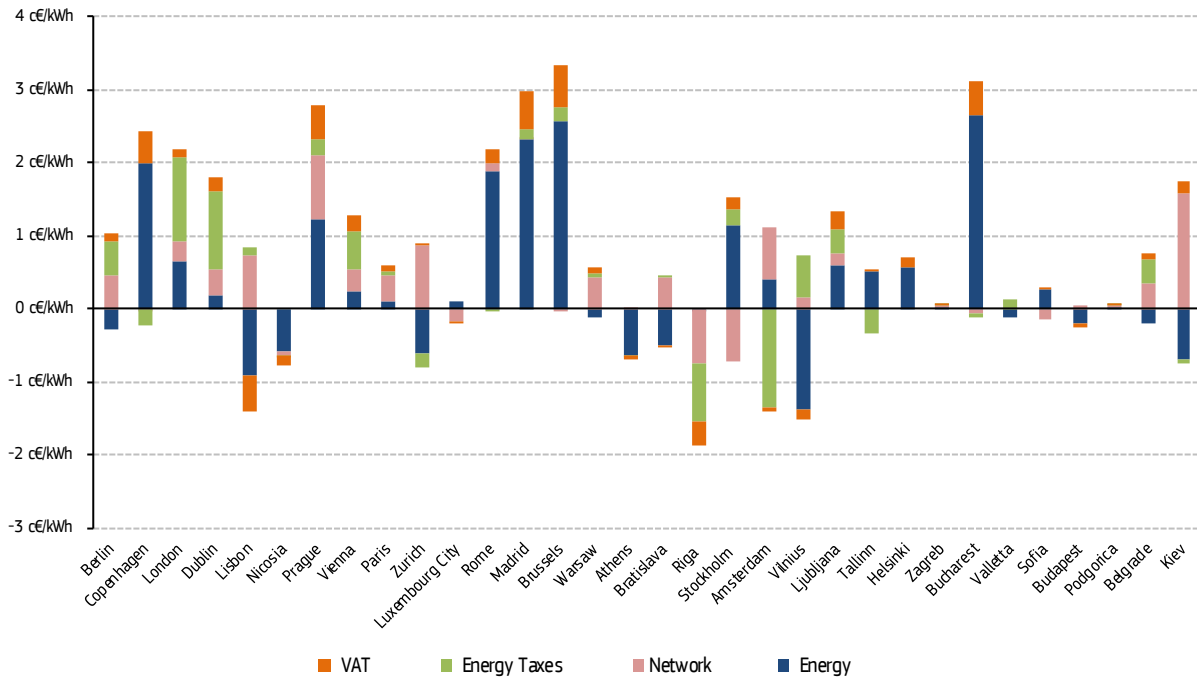


Source: Vaasaett

- Compared to the same month of the previous year, the largest price increases in relative terms in May 2021 were observed in Kiev (+24%) and Bucharest (+23%). As shown in **Figure 57**, the distribution component was the biggest

contributor to rising prices in the Ukrainian capital. In Romania, rising prices were driven by increasing wholesale prices. 11 of the 27 EU capitals reported prices lower or unchanged compared to the same month of the previous year, with, Riga (-11%), Vilnius (-7%), Nicosia and Athens (-4%) posting the largest relative drops. The price fall in the Latvian capital was driven mainly by a lower energy taxes and network charges, whereas households in the Lithuanian capital benefited mainly from lower energy component.

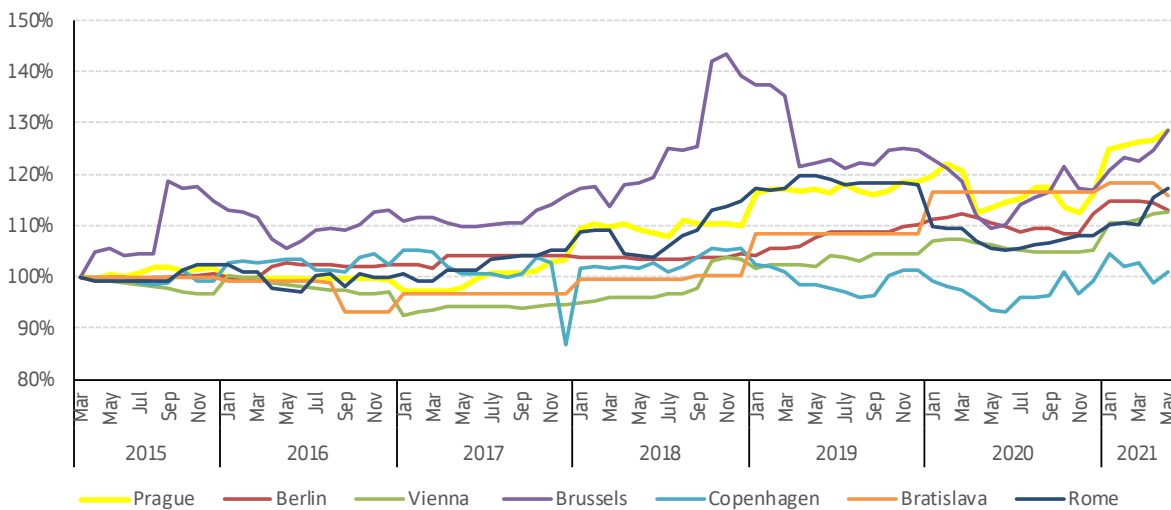
Figure 57 – Year-on-year change in electricity prices by cost components in the European capital cities comparing May 2021 with May 2020



Source: Vaasaett

- **Figure 58** compares how household retail prices in selected EU capitals changed in relative terms over the last six years. The biggest increase (+29%) was registered in Brussels and was driven mainly by a rising VAT component (13% of the change). Prague came in second with a 28% increase since February 2015, followed by Rome (+17%) and Bratislava (+16%). On the other end, retail prices for households in Copenhagen are now more or less the same they were six years ago, as a rise in the local energy component was compensated by falling energy taxes in Denmark.

Figure 58 – Relative changes in retail electricity prices in selected EU capitals since 2015

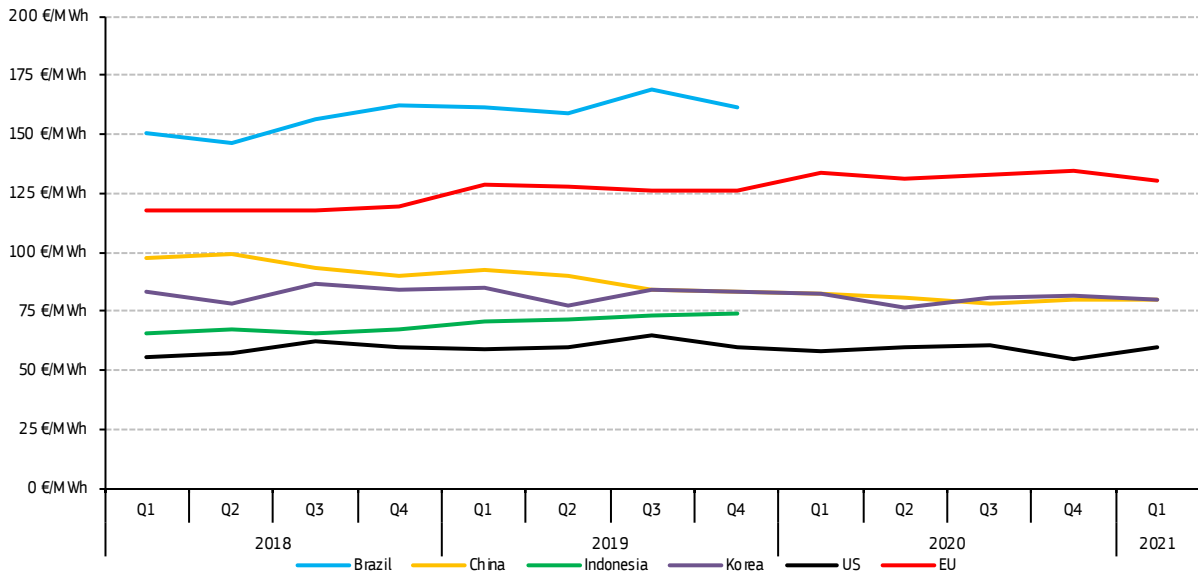


Source: Vaasaett

5.2 International comparison of retail electricity prices

- **Figure 59** 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 fell by 3% in Q1 2021 compared to the previous quarter, similar to the developments in South Korea. Meanwhile, Chinese industrial prices increased less than 1%, reversing a steady downward trend observed over the past two years. Industrial electricity prices in the United States rose by 3% quarter-to-quarter in Q1 2021.

Figure 59 – 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 are 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 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 2018 shows the price for 2019; and the year-ahead curve in 2019, in turn, shows baseload prices for delivery in 2020.

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.