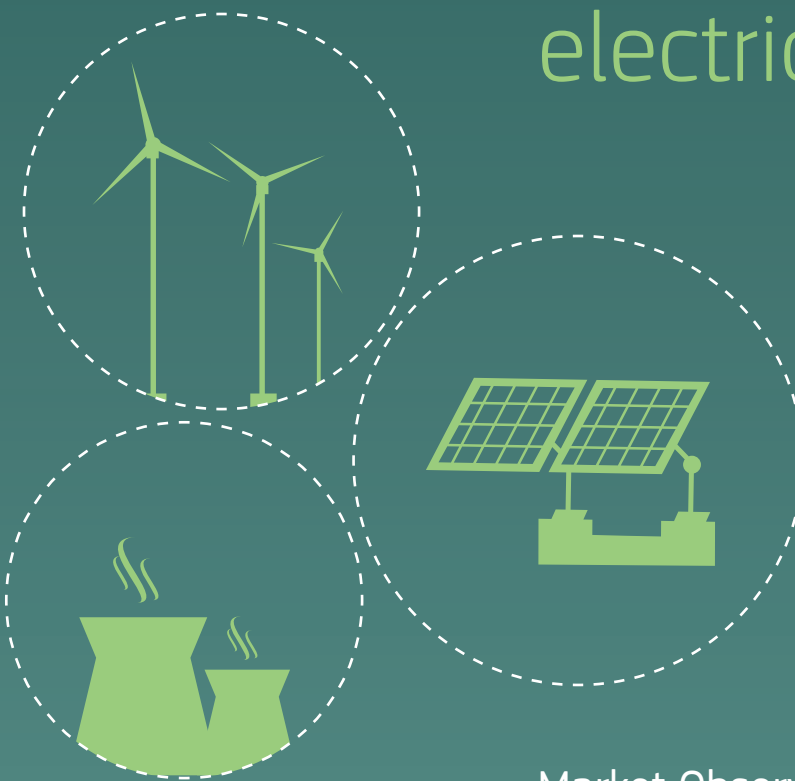




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Commission

Quarterly report

On European electricity markets



Market Observatory for Energy
DG Energy

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HIGHLIGHTS OF THE REPORT

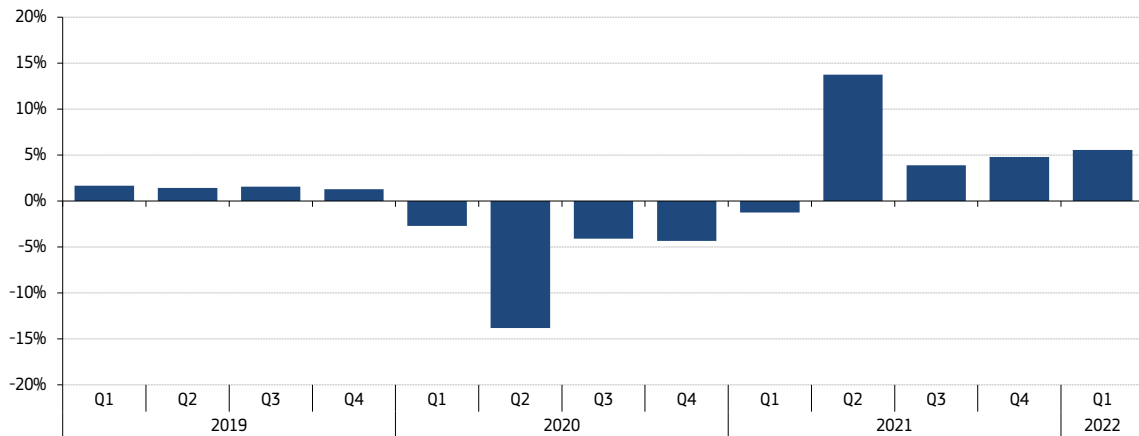
- **The first quarter of 2022 was marked by the impact of the unprovoked Russian invasion of Ukraine**, the associated international energy sanctions, and the fears of supply disruption on a market already tight. Following the peak in March, the wholesale electricity market has been reacting to announcements impacting the price of gas in Europe. In particular, it reacted to the risk of partial or total cuts of gas supplies from Russia and to the policy response from the EU and its Member States.
- **The rise in energy commodities prices, especially gas** (marginal fuel used in the price setting of wholesale electricity prices), **triggered record prices and high volatility during Q1 2022**. In Q1 2022, the largest year-on-year wholesale price increases in Member States were registered in Spain and Portugal (+411%), Greece (343%), and France (+336%). The European Power Benchmark averaged 201 €/MWh in Q1 2022, 281% higher on yearly basis. Practically every national or regional market in Europe experienced a considerable surge in prices (changes ranged from 50% to more than 400%). Italy reported the highest quarterly average price (249 €/MWh), which was 318% higher than in Q1 2021.
- **The first quarter of 2022 saw a slight decrease (-1%) in electricity consumption in Europe**, supported by a mild winter and the impact of high electricity prices. The electricity consumption has returned to pre-pandemic levels, however, demand levels of Q1 2022 were still in the low range of the historical record.
- In Q1 2022, coal and lignite generation rose by 11% (+11 TWh), whereas less CO₂-intensive gas generation still managed to grow 4% (+5 TWh). **The share of renewables reached 39%, outplaying fossil fuels' share (37%) in Q1 2022**. This was possible thanks to an increase of 20% in onshore wind generation (+20 TWh), 31% in solar (+8 TWh) and 8% in offshore wind (+1 TWh) on a yearly basis, despite hydro generation decreasing by 27% (-28 TWh). Ultimately, renewable generation improved its output by 1% (+1 TWh) year-on-year. Nuclear generation remained under pressure due to unplanned outages in France and the scheduled closure of capacity in Germany, decreasing its output by 9% (-16 TWh) in Q1 2022.
- Despite high commodity prices (gas, but also coal and carbon prices), **fossil fuel generation increased by 6% (+17 TWh) year-on-year in Q1 2022**. Based on preliminary estimates, the **Q1 2022 carbon footprint** of the EU power sector **rose by 8% compared to Q1 2021**.
- **Carbon prices registered high levels of volatility throughout Q1 2022**. Carbon allowances registered a new peak in early February, climbing above 96 €/tCO₂. **However, contrary to fossil fuels, the price of carbon allowances fell in early March and then bounced back to prices around 80-85 €/tCO₂ which continued well into Q2 2022**. For the first time since the rally in gas prices started, TTF prices stopped supporting the price of EU allowances. Prices remained volatile supported by a tight carbon market, limited by fears of curbed industrial demand and responding to political events. Under the current situation of high gas prices, the carbon price is not sufficient to support coal-to-gas fuel switching. However, elevated coal prices during Q2 2021 are starting to close the cost gap between coal and gas generation. The recent announcements by some Member States to increase the use of coal-fired plants, to replace Russian gas used for power generation, have risen expectations for coal prices in the coming months.
- **High wholesale electricity prices have resulted in rising consumer bills for households, impacting the industry sector as well**. Increasing wholesale prices is putting upward pressure on retail prices, while governments interventions in some Member States are helping to alleviate the bill for consumers. Retail electricity prices for household customers in EU capital cities were up by 44% in May 2022, compared to the same month in 2021. Most impacted countries were the Netherlands (+167%), Austria (+122%) and Italy (+118%). On average, wholesale electricity costs already represent 60% of final household retail prices in Europe, up from 52% in December 2021. Retail electricity prices for industrial customers also increased, up by 40% year-on-year in the first quarter of 2022 for mid-sized industrial consumers. Elevated industrial retail prices in the EU imply a cost disadvantage for energy intensive industries.
- Demand for electrically charged vehicles (ECV) increased during the first quarter of 2022 on yearly basis, as EU and Member State policies continue to incentivise ECV purchases, in lieu of combustion engine vehicles. **More than 423,000 new ECVs were registered in the EU in Q1 2022 (+19% year-on-year)**. This is the third highest quarterly figure on record, translating into a 19% market share, still lower than China and more than three times higher than the United States. The rapid global increase in ECV sales and high prices for raw materials needed for battery production could constrain the supply chain for batteries required for ECV deployment.

1 Electricity market fundamentals

1.1 Demand side factors

- **Figure 1** shows the steady economic recovery from the pandemic shock since 2020. According to an estimate published by Eurostat in May 2022, seasonally adjusted GDP in the EU increased by 5.6% year-on-year between January and March 2022. Although not as impressive as the GDP growth registered during Q2 2021 (13.8%), the growth of the reference quarter is an example of the scale of the economic recovery. This quarter is the fourth registering positive growth since the five consecutive negative growth quarters that followed the start of the pandemic. A rise in output was observed in every Member State. Double digit increases were reported in Portugal (+11.9%) and Ireland (+11.3%), The lowest year-on-year growths were observed in Slovakia (+3.0%), Sweden (3.1%) and Finland (+3.7%).

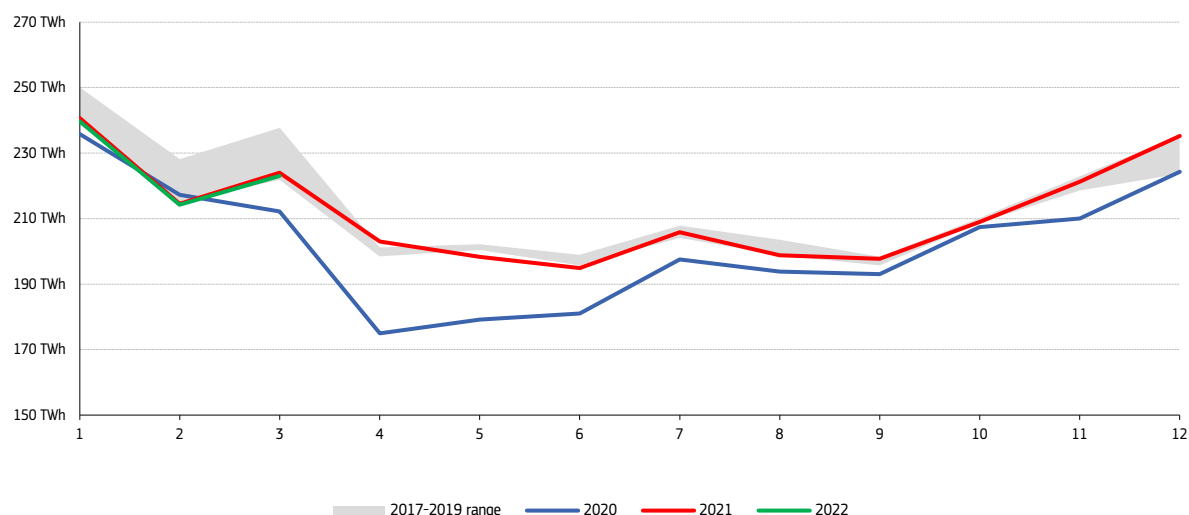
Figure 1 – EU GDP annual change (%)



Source: Eurostat

- According to Eurostat, the electricity consumption in the EU decreased 1% above last year's levels in Q1 2022, following a mild winter in Europe and the impact of high electricity prices. Demand has already returned to pre-pandemic levels; however, demand levels for the first quarter of 2021 were still in the low range of the historical record. It is important to note that the EU average hides wide differences of developments in individual Member States. While fifteen Member States saw an increase in consumption year-on-year, this ranges from considerable grows in Cyprus (+20%) and Malta (+12%) to the small increases reported in Germany, Croatia and Poland (+1%). Moreover, Lithuania remained practically unchanged, while twelve Member States registered a drop in consumption, led by Finland and Estonia (-7%), the Netherlands (-6%) and Sweden (-5%).

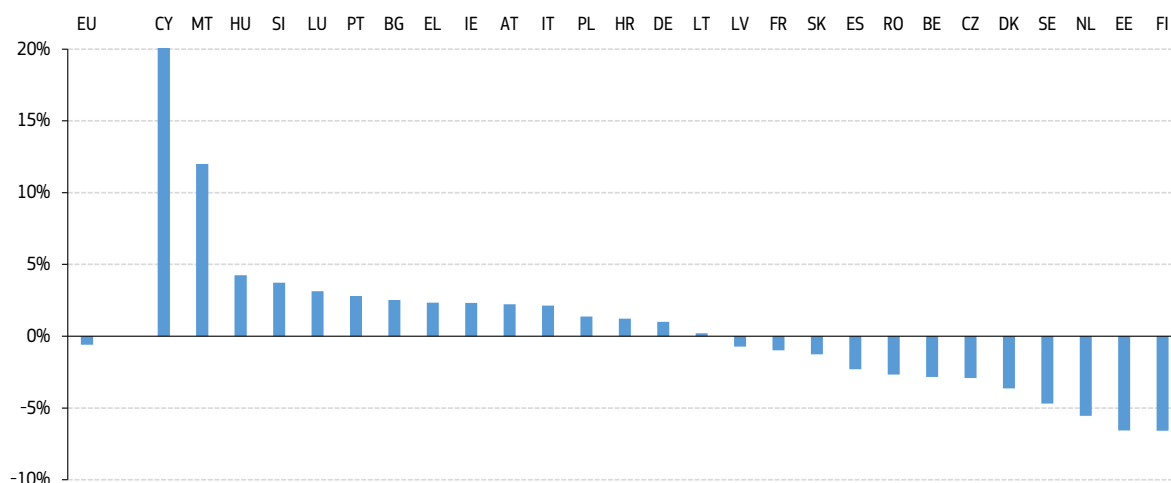
Figure 2 – Monthly EU electricity consumption



Source: Eurostat

- Figure 3** sums up changes in electricity consumption over the first quarter of 2022, compared to Q1 2021. Greatest declines in electricity consumption occurred in northern regions due to warmer-than-usual weather (Finland, Estonia, Sweden and Denmark). Mediterranean islands (Cyprus and Malta) electricity consumption increase was influenced by colder-than-average weather. Overall, large industrial consumers, responsible for the biggest portion of the demand, are starting to struggle with high energy prices, resulting in a decrease of the consumption. Compared to Q1 2021, EU-wide consumption decreased by 1%, on the back of a mild winter (see **Figure 4**) and the impact of high energy prices in the industrial activity.

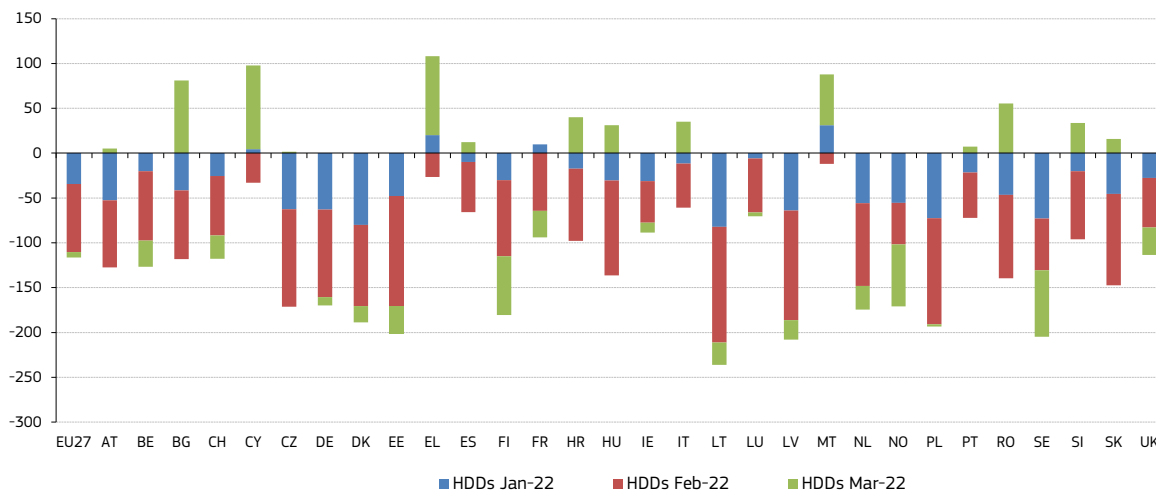
Figure 3 – Annual changes in electricity consumption in Q1 2021 and Q1 2022 by Member State



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 2022. EU-wide, the reference quarter was warmer than usual, registering 116 HDDs below the long-term average. This means that temperatures during Q1 2022 were 1.3 degrees Celsius higher than usual, although some Mediterranean countries experienced a colder March (Cyprus, Greece, Malta). In general, January and especially February were milder than usual. Nordic and Baltic countries registered relatively warmer-than-usual temperatures during the quarter. However, in some southern and south-eastern Europe countries, the weather was colder than usual during March. Overall, the mild weather helped keeping the energy price situation from worsening during the first quarter of 2022.

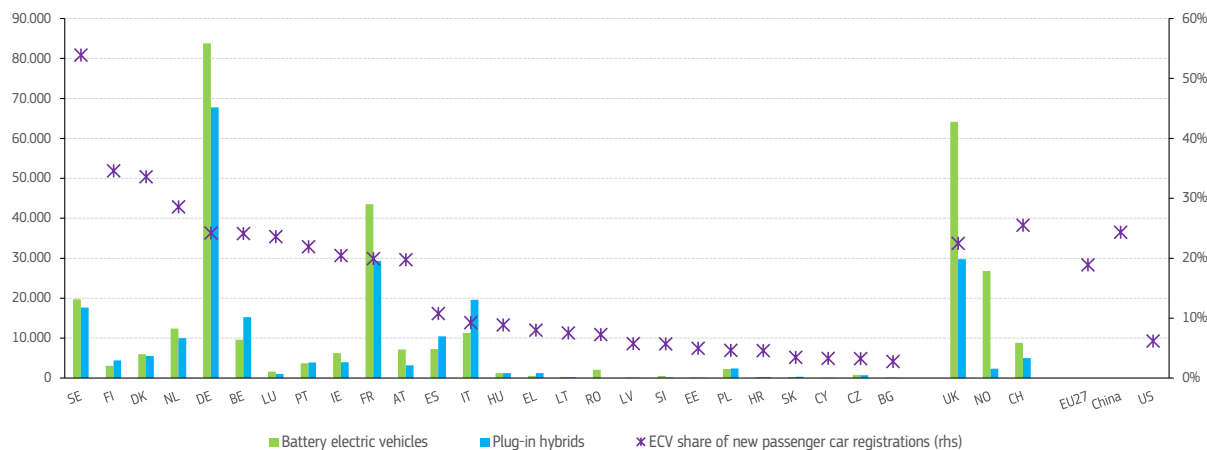
Figure 4 - Deviation of actual heating days from the long-term average in January-March 2022



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 more than 423,000 new ECVs were registered in the EU in Q1 2022 (+19% year-on-year). This is the third highest quarterly figure on record (after sales in Q4 2021 and Q2 2021) and translates into a 19% market share; still lower than China (24%), but higher than in the United States (6%). The battery electric vehicles segment continued to grow (+53% year-on-year to more than 224,000) while demand for plug-in hybrid vehicles decreased slightly (-4% year-on-year to almost 200,000). Hybrid electric vehicles (not chargeable) sales amounted to 563,000, higher than the ECV category.
- Green Deal initiatives, such as the proposal for a 100% reduction in CO2 emissions from new cars and vans by 2035, and the Alternative Fuels Infrastructure Regulation, which will require Member States to develop infrastructure to recharge electric vehicles (among other clean technologies), are supporting the adoption of ECVs in Europe, along with the help of national policies.
- The highest ECV penetration was once again observed in Sweden, where more than half of the passenger cars sold could be plugged, thanks to the support of a climate bonus for battery-powered electric vehicles (BEV) owners in Sweden and new zero-emission cars and light trucks. In addition, a third of the Q1 2022 car sales in Finland and Denmark were ECVs. In Finland, sales were supported by new subsidy schemes for purchasing low-emission passenger cars, vans or trucks, which entered into force on 1 January 2022. Moreover, the 34% share in Denmark is all the more impressive since it is taking place against the backdrop of zero direct purchase incentives (only tax benefits). Germany retained the position of the largest individual market (more than 150,000 ECV sales in Q1 2022) thanks to its generous incentive programme, which since 2020 and until the end of 2022, offers up to €9,000 in direct purchase bonuses. After Germany, numbers in ECVs were also supported by France, where sales amounted to more than 72,000 new ECVs in the reference quarter.
- The latest [IEA's Global Electricity Outlook 2022](#), notes that the rapid increase in ECV sales during the pandemic, the lack of structural investments in new supply capacity and the recent impact of Russia's war in Ukraine (Russia supplies 20% of global high purity nickel) are exerting pressure on the battery supply chains. Prices of raw materials have surged (cobalt, lithium and nickel). The mentioned factors and the rising demand for batteries represent key factors to consider in the near future for the deployment of ECVs.

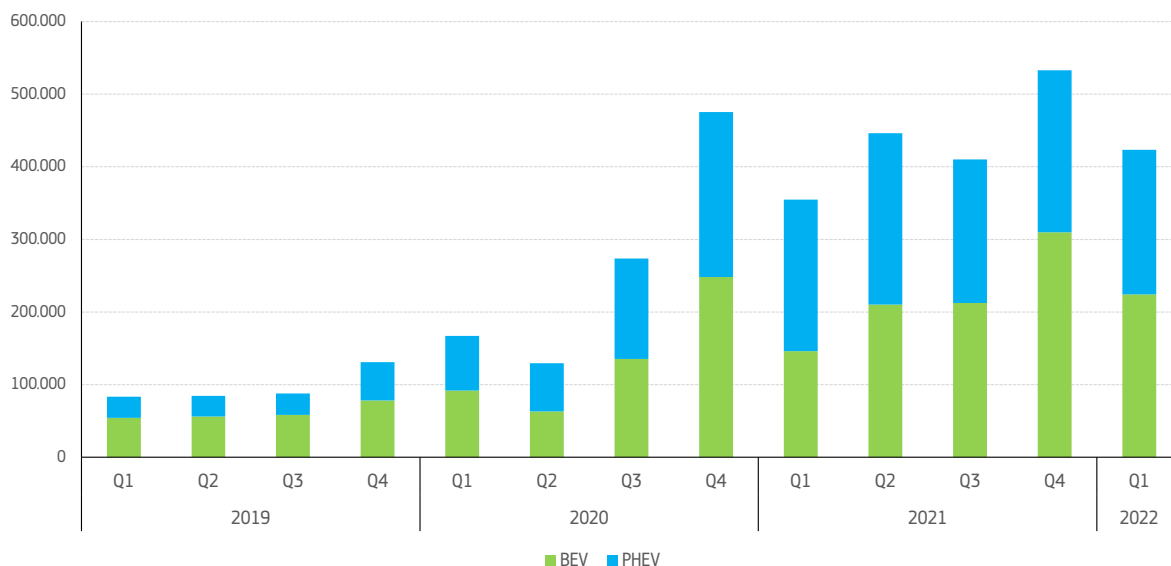
Figure 5 – Electrically chargeable passenger vehicle (ECV) sales in selected countries in Q1 2022



Source: ACEA, CPCA, BloombergNEF

- Figure 6** shows how the rapid expansion of electric vehicles in Europe unfolded in 2021 and keeps track in 2022. Policy support, additional stimulus measures, as well as steady recovery in activity following the pandemic peak, have contributed to the impressive increase in ECV numbers. However, the demand and constraints in the supply chain of batteries might slow down the development in the near future. As the number of ECVs on European roads is expected to continue growing fast in the years ahead, so will its impact on electricity demand and network load.

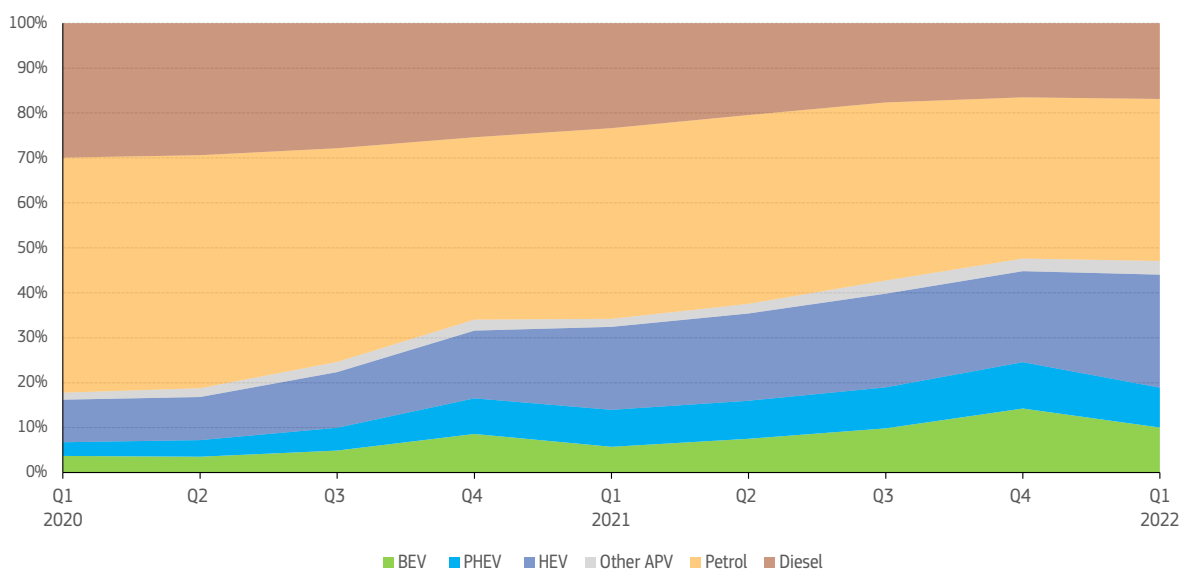
Figure 6 – Quarterly ECV sales in the EU



Source: ACEA

- Figure 7** shows the decline of sales of diesel cars, which saw their market share fall to 17% in Q1 2022, from 23% in Q1 2021. Petrol car sales experienced a fall in their share to 36% in Q1 2022, from 42% in the first quarter of the previous year. On the other hand, the share of new Hybrid electric vehicles (HEV) in the market increased from 18% in Q1 2021, to 25% in Q1 2022. The share of new ECVs has also risen year-on-year (from 14% in Q1 2021 to 19% in Q1 2022).

Figure 7 – Evolution of quarterly drivetrain shares in the EU



Source: ACEA

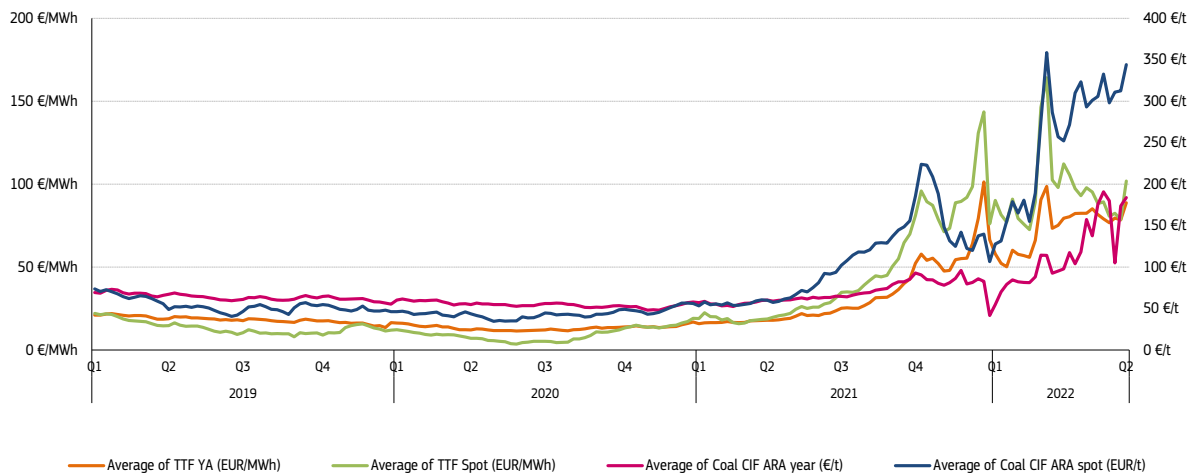
1.2 Supply side factors

- Figure 8** reports on developments in European coal and gas prices. In Q1 2022, prices of coal and gas rose to new record levels in the spot market, way above their year-ahead peers. The situation follows the existing trend of increasing global demand for commodities, linked to tighter global supply, as economic recovery is peaking up. Furthermore, the Russian invasion to Ukraine and related international sanctions are deeply affecting energy markets resulting in substantial increases in prices, volatility and uncertainty on energy supply. In particular, main commodity prices soared to new all-time highs on 8 March with the announcement of the first international sanctions on energy imports from Russia. Fears of gas scarcity in the main global consumption markets have continued to push prices up. In Europe, fears of interruption of gas supplies are also linked to Russia's imposition to seek payments in roubles for gas sold to Europe. The worsening of the geopolitical picture has had a direct impact on the gas market. Gas prices have recently spiked on the news of a fire at an important LNG facility in the US, the outage's extension until late 2022 coupled with the impact from Gazprom announcement that Nord Stream flows will be limited to 40% of its capacity for the foreseeable future. Moreover, Gazprom announcement of partial or total cuts to Member States (PL, BG, FI, NL, DK, SK, IT, AT, FR) might also slow down or jeopardise the refilling pace of gas storages before the heating season.
- The record highs of spot gas prices (represented by the TTF day-ahead contract) during Q1 2022 was strengthened as a result of the Russian invasion to Ukraine, related sanctions, increasing demand, tight Liquefied Natural Gas (LNG) and pipeline supplies, and uncertainty over the development of geopolitical events. Moreover, low gas storage levels during Q1 2022 continued to play an important role in the European gas market, as storage levels fell to 26% by the end of March, below historical averages.
- Record-high gas prices significantly undermined the competitive edge of gas-fired power plants in Europe and allowed their coal and lignite competitors to regain some of the lost ground of previous years. The trend was intensified to unprecedented levels following the invasion of Ukraine by Russia, increasing market uncertainty, driving up volatility and prices even further. On 8 March 2022, the TTF price skyrocketed reaching a new all-time high of 209 €/MWh.
- Following the invasion of Ukraine by Russia, the European Commission adopted a new Communication: [REPowerEU: Joint European Action for more affordable, secure and sustainable energy](#). Moreover, in May, the European Commission adopted a follow up Communication on the [REPowerEU plan](#) to make Europe independent from Russian fossil fuels well before 2030, starting with gas.
- Spot gas prices averaged 98 €/MWh in Q1 2022, establishing a new all-time high. Prices were 5% higher than the previous quarter (Q4 2021) and represented a 432% increase compared to Q1 2021, which reflects the unprecedented level of tightness of the gas market. A new all-time high price was reached on 8 March 2022 (209 €/MWh)

where prices shown unprecedented intraday volatility on the back of the uncertainty of the Russian war in Ukraine and the announcement of the first international energy sanctions. The rise of gas prices in Q1 2022 continued to support the gas-to-coal switching observed in the second half of 2021, boosting coal generation gains despite high carbon prices. Gas prices have a significant influence on electricity wholesale prices, as gas-fired generation commonly sets the wholesale electricity marginal prices in many markets of the region.

- Thermal coal spot prices, represented by the CIF ARA contract, reached a new peak in Q1 2022, where prices surged up to 366 €/t on 7 March 2022, on the back of international sanctions to Russian energy exports (Russia is the third largest exporter of thermal coal to the global market and the most relevant exporter of coal to Europe). The average CIF ARA spot price in March ended up in 290 €/t. Consequently, the prices averaged 209 €/t in the first quarter of 2022, up by 273% compared to Q1 2021 and 33% to Q4 2021. The high global demand for energy commodities, amplified by spiralling LNG price have increased the demand for thermal coal in power generation in Europe and Asia. Moreover, on 8 April 2022, the EU adopted a new round of sanctions against Russia, prohibiting imports of coal, solid fossil fuels and a range of industrial goods from Russia. Coal prices reached new record highs in May (average at 309 €/t) due to the strong demand in European and Asian markets, and supply constraints in the global market. The announcements in June by Member States (DE, NL, AT) to use more coal for producing electricity to replace Russian gas used for power generation have risen expectations for coal prices in the coming months. The plan of the German government to return 10 GW of coal-fired reserve plants online as a way to cut dependence on Russian natural gas is also impacting on rising future coal prices. Similarly, Austria is preparing to bring one coal-fired power plant online. Likewise, the Netherlands government lifted on 20 June the production restrictions for coal-fired generation, as part of the country's gas crisis plan.

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



Source: S&P Global Platts

- The European market for emission allowances, shown in **Figure 9**, registered high levels of volatility in Q1 2022. However, contrary to fossil fuels, the price of carbon allowances fell in early March and then bounced back to prices around 80-85 €/tCO₂ which continued well into Q2 2022. During Q1 2022, several new records were established in quick succession, culminating in a peak on 8 February when the closing price climbed above 96 €/tCO₂ for the first time, thanks to rising gas prices, high power sector emissions and expectations of an accelerated green transition. High gas prices contribute to rising carbon price since they lead to an increased use of coal for power generation and consequently higher demand for emission allowances. However, the fears of disruption of energy commodities due to the Russian war in Ukraine had an impact on carbon prices. The allowances dropped to 58 €/tCO₂ on 7 March, at the same time prices in the TTF hub were reaching record highs. For the first time since the rally in gas price started, gas prices stopped supporting the price of EU allowances, resulting in disassociation of EU ETS from TTF price. Prices remained volatile but hovering around 80-85 €/tCO₂ in the following months, supported by a tight carbon market, limited by fears of curbed industrial demand and responding to political events.
- At the end of March, [ESMA published its final report on the European Union Carbon Market](#). ESMA did not find any major abnormality in the functioning of the EU ETS market based on the data available. ESMA reported that price movements and volatility appear to be driven by market dynamics, the structural decline in allowances and rising energy prices. However, some policy recommendations were made, including position limits, to restrict the amount of allowances market participants can hold at one time and the creation of a central authority to monitor the market

- The average spot price of CO₂ in Q1 2022 (83 €/tCO₂), more than doubled the prices registered during Q1 2021, registering an increase of 121% and representing an increase of 20% with respect to the fourth quarter of 2021. Higher carbon prices put coal and lignite power plants at a greater disadvantage against their less polluting gas-fired competitors. However, under a situation of exceptionally high gas prices, the European Union Allowances (EUA) price is not enough to support coal-to-gas fuel switching in power generation (see **Figure 20**). Nevertheless, elevated coal prices during Q2 2021 are starting to close the cost gap between coal and gas generation.

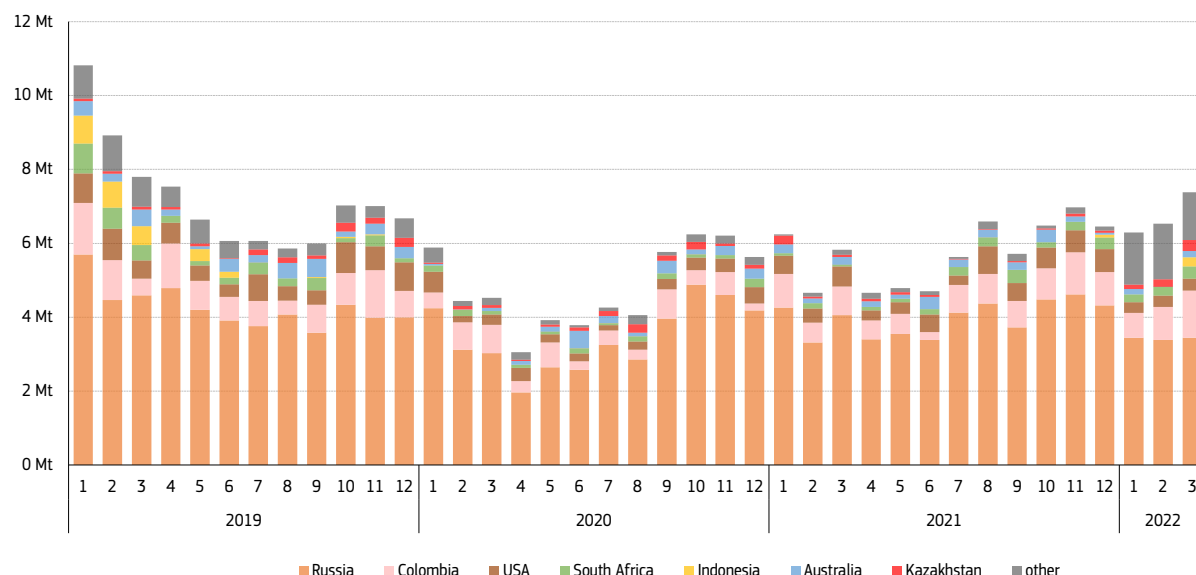
Figure 9 – Evolution of emission allowance spot prices from 2019



Source: S&P Global Platts

- As visible from **Figure 10**, monthly average thermal coal imports into the EU held at roughly 6.7 Mt in Q1 2022, as high gas prices made more space for coal-fired generation in the mix. The total volume of imports increased by 21% year-on-year to 20 Mt in the first quarter of 2021. The estimated EU import bill for thermal coal amounted to €3.4 billion in the reference quarter, 214% higher compared to Q1 2021, enhancing the year-on-year increase in imported volumes due to higher contracted prices of this commodity.
- The largest part of extra-EU thermal coal imports in Q1 2022 came from Russia which accounted for 51% of the total. Russian traders managed to achieve the highest share of the market, despite a significant decrease in the share (-19%) with respect to Q1 2021. The invasion of Russia in Ukraine in late February is already changing the distribution of coal imports, as traders were already seeking alternative suppliers to Russian commodities. Moreover, the 5th package of sanctions adopted by the EU banned the purchase, import, or transfer of coal and other solid fossil fuels into the EU from Russia as from August 2022. This is estimated to have an impact over one fourth of all Russian coal imports, amounting to around €8 billion loss of revenue per year for Russia. The current events would act as a game-changer in the distribution of EU coal imports, as for many Russian competitors it was difficult to compete in a low-price/low-demand environment. Colombia saw its market share growing by 1% compared to 13% in the first quarter of 2021. The share of deliveries from US ports decreased from 9% to 5%. The position of Kazakhstan rose from 2% to 3% in Q1 2022.

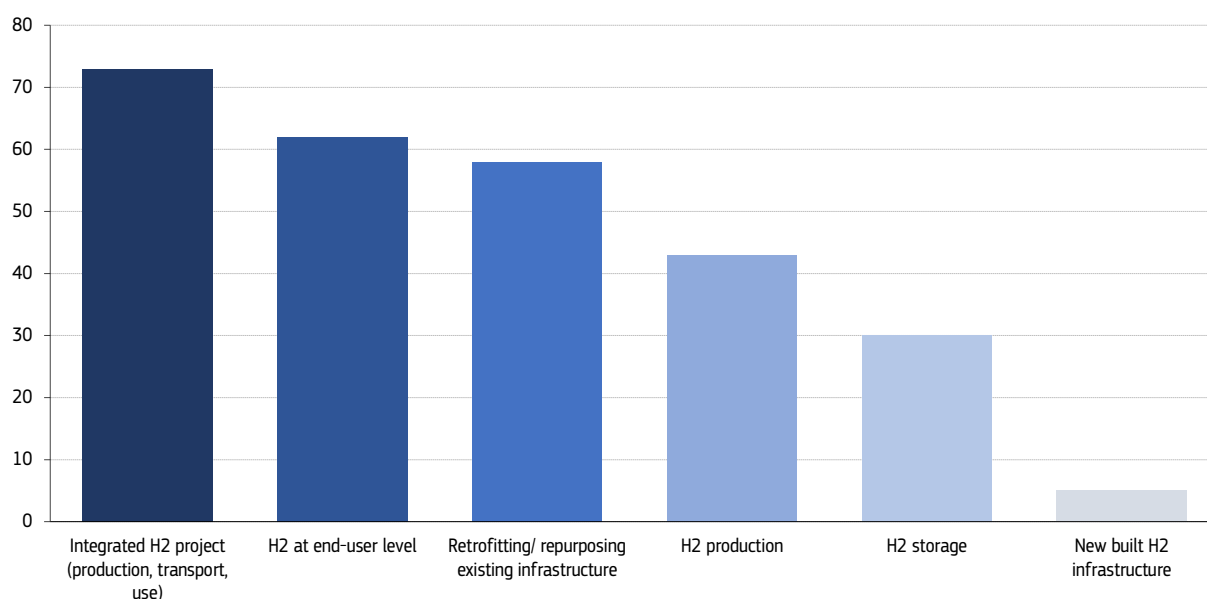
Figure 10 – Extra-EU thermal coal import sources and monthly imported quantities in the EU



Source: Eurostat

- **Figure 11** presents different types of renewable and low-carbon hydrogen projects in the European Union. This overview of current hydrogen projects across the value chain (production, transmission and distribution) includes projects with different levels of scope, maturity level and estimated timeline. So far, more than 270 hydrogen projects in Member States of the EU are included in this ENTSOG database.
- The EU [Hydrogen Strategy](#) adopted in 2020, put forward the main guidelines to establish a European hydrogen ecosystem to scale up production. With the publication of the [REPowerEU Plan](#) in May 2022, the European Commission outlined a ‘Hydrogen accelerator’ concept to scale up the deployment of renewable hydrogen. The aim of the plan is to produce ten million tonnes and import ten million tonnes of renewable hydrogen in the EU by 2030.

Figure 11 – Renewable and low-carbon hydrogen projects in the EU



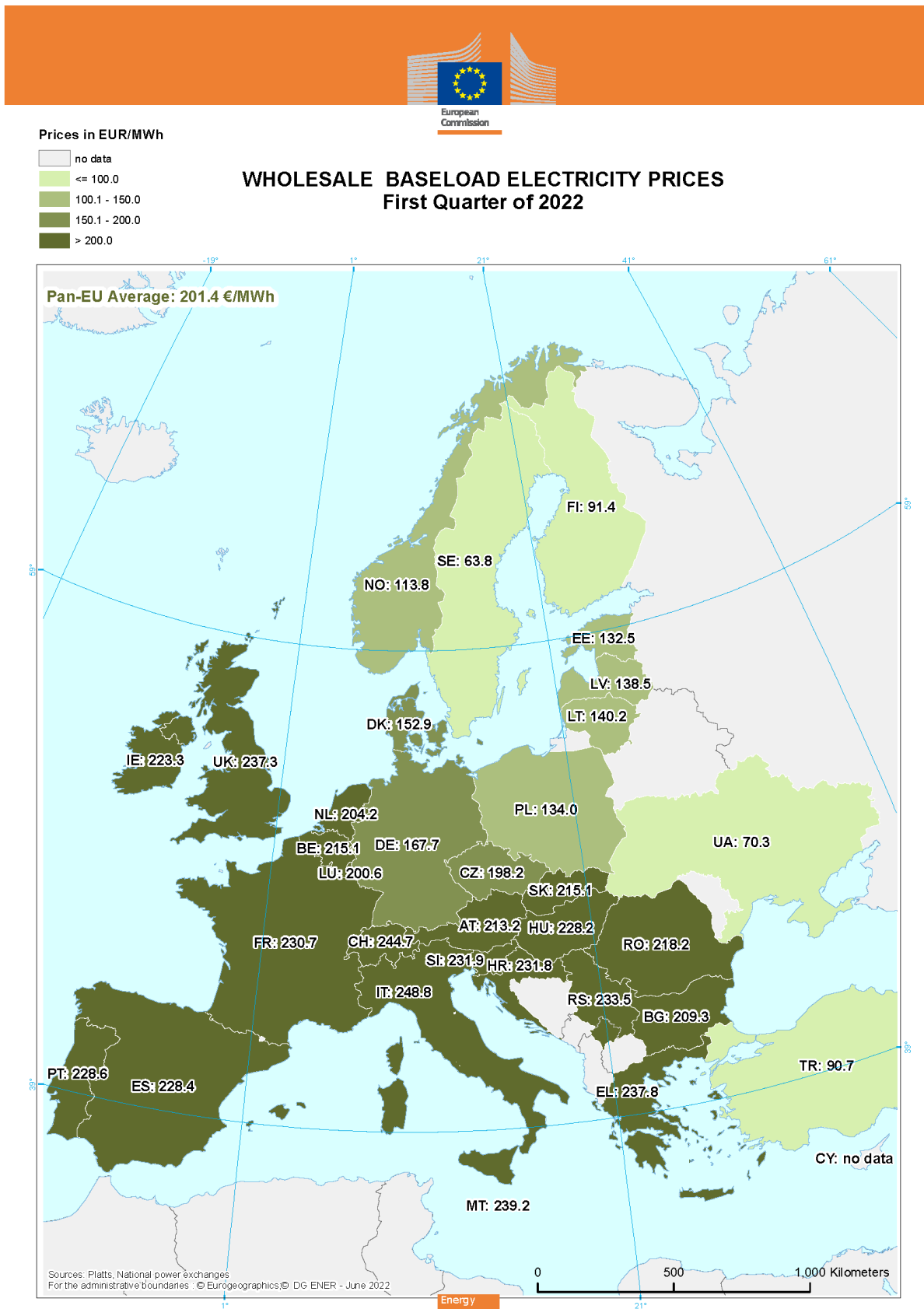
Source: ENTSOG – Database for hydrogen projects

2.1 European wholesale electricity markets and their international comparison

- The map on the next page (**Figure 12**) shows average day-ahead wholesale electricity prices across Europe in Q1 2022. Overall, the reference quarter saw an increase in prices compared to the previous quarter. In Q1 2022, prices reached new all-time highs across Europe, due to the impact of Russia's unprovoked invasion against Ukraine, geopolitical tensions already present during the previous months, and the uncertainty of the markets around European security of gas supply. The mentioned factors reinforced the price volatility from previous months, while high commodity prices (mainly gas, but also coal) and lower availability of some conventional power plants put extra pressure to wholesale electricity markets. In the following months, the wholesale electricity market has been reacting to announcements impacting the price of gas in Europe, due in particular to the uncertainty of gas supplies from Russia, and policy responses from the EU and its Member States.
- On a yearly basis, practically every market in Europe experienced a considerable surge in prices (changes ranged from 50% to more than 400%¹). Italy reported the highest quarterly average price (249 €/MWh), which was 318% higher than in Q1 2021. Switzerland became the second most expensive market with an average baseload price of 245 €/MWh, which was 330% higher compared to the same period last year. Malta reported prices of 239 €/MWh, while the United Kingdom registered quarterly prices of 237 €/MWh during the same period.
- The European Power Benchmark averaged 201 €/MWh in Q1 2022, 281% higher on yearly basis. Compared to Q4 2021, the quarterly average price rose by 4%.
- The largest year-on-year price increases in Member States were registered in Spain and Portugal (+411%), Greece (343%), and France (+336%). Conversely, Sweden experienced the lowest increase in prices during Q1 2022 (+49%) followed by Finland (+87%), due to lower dependence on gas in their power mix (less than 1% and 2%, respectively). Nevertheless, prices increased (yet less) due to subdued levels of hydropower output and high prices in mainland European markets.
- Following a request by the Ukrainian grid operator (Ukrenergo) and Moldova, the TSOs of Continental Europe started on 16 March the emergency trial synchronisation with the power systems of Ukraine and Moldova. On 27 June, ENTSOE [Continental Europe TSOs](#) confirmed that Ukrenergo, together with the grid operators of Hungary, Romania and Slovakia had fulfilled the technical pre-conditions to reopen Ukrainian electricity exports to the EU, as of 30 June. In the first phase, the total trade capacity will be set to 100 MW. A gradual increase in the trade capacity will be assessed based on power systems stability and security considerations.
- In light of the continued high energy prices and the aggravated situation following the Russian invasion of Ukraine, the Commission adopted [REPowerEU](#) on 8 March 2022. Building from the last October communication, REPowerEU presented additional guidance to provide support to households and businesses affected by high energy prices and a plan to make Europe independent from Russian fossil fuels well before 2030 (starting with gas). In addition, the Commission adopted the communication on [Security of supply and affordable prices](#) on 23 March, presenting concrete short-term and limited options to tackle the impact of high gas prices on the wholesale electricity market.
- On 18 May 2022, the Commission adopted the [REPowerEU plan](#) to rapidly reduce dependence on Russian fossil fuels and fast-forward the green transition. To quickly diversify from Russian fossil fuels, REPowerEU plan proposes actions for three parallel priorities tackling both short-term and long-term dependency challenges: saving energy, accelerating clean energy production and diversifying EU energy supplies. The Commission also adopted the communication on [Short-Term Energy Market Interventions and Long-Term Improvements to the Electricity Market Design](#), with additional short-term measures to tackle high energy prices and address supply disruptions from Russia. It also presented a number of areas where the electricity market can be optimised, built on the ACER's [Final Assessment of the EU Wholesale Electricity Market Design](#).

¹ Twenty EU MS experienced increases over 200%, thirteen above 300% and two beyond 400%, compared to Q1 2021.

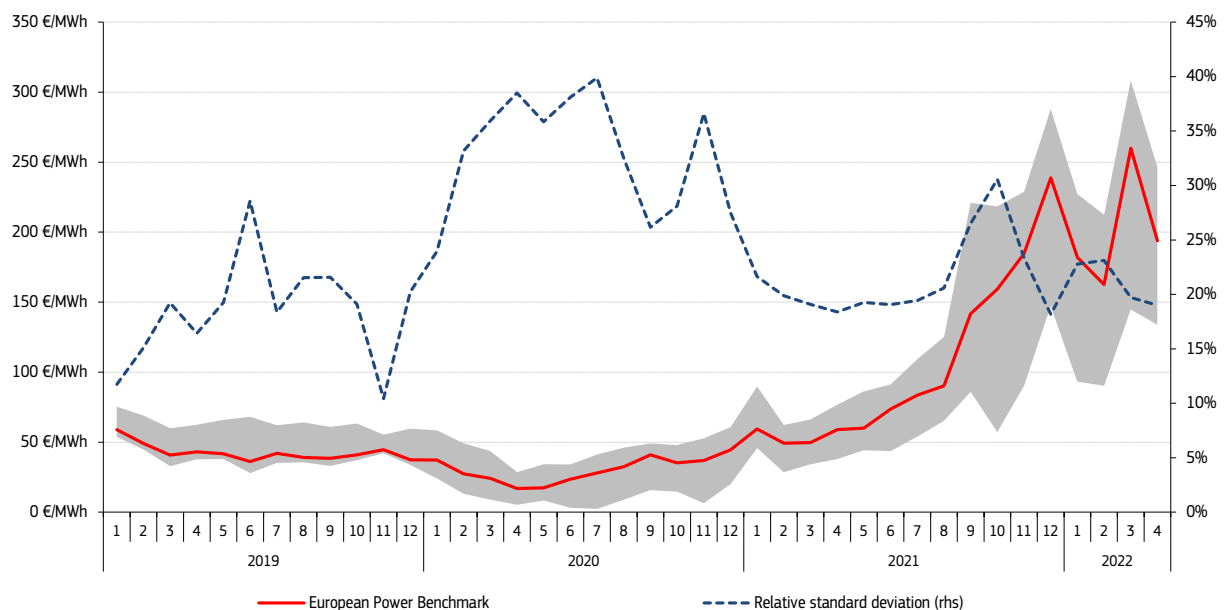
Figure 12 – Comparison of average wholesale baseload electricity prices, first quarter of 2022



Source: European wholesale power exchanges, government agencies and intermediaries

- Figure 13** shows the European Power Benchmark of nine markets, including the lowest and highest regional prices in Europe represented by the two boundary lines of the shaded area, as well as the relative standard deviation of regional prices. The relative standard deviation metric shows that divergence levels have rather stabilised since Q4 2021, as nearly every European market reached new record prices during the quarter. Central Western Europe, Great Britain and the Iberian Peninsula, among others, experienced a surge in prices linked to the variations in gas prices. The phase-out of coal and nuclear capacity is increasing the sensitivity of power prices to the developments of the gas market. In July 2022, some member states (Austria, Germany, Italy and the Netherlands) have announced plans to temporarily increase coal-fired power generation, with the aim of saving gas and boosting gas storage filling in the summer. The Nordic region experienced dry weather conditions reducing hydropower output, which combined with the tightness of the continental European markets, resulted in a steep increase in prices. Soaring gas prices in Italy, combined with tight supply margins, made Italy the most expensive market in Europe for a consecutive quarter (Q4 2021 and Q1 2022). Following the peak in December, the rising trend in prices softened in the following months thanks to improved gas supplies to the region. However, the Russian invasion of Ukraine, the associated sanctions and the market fears of supply disruption, caused prices to rise again to new record highs in European markets in early March. Since then, the wholesale electricity market has been reacting to announcements impacting the price of gas in Europe, due to the availability of gas supplies from Russia and by policy responses from the EU and its Member States.

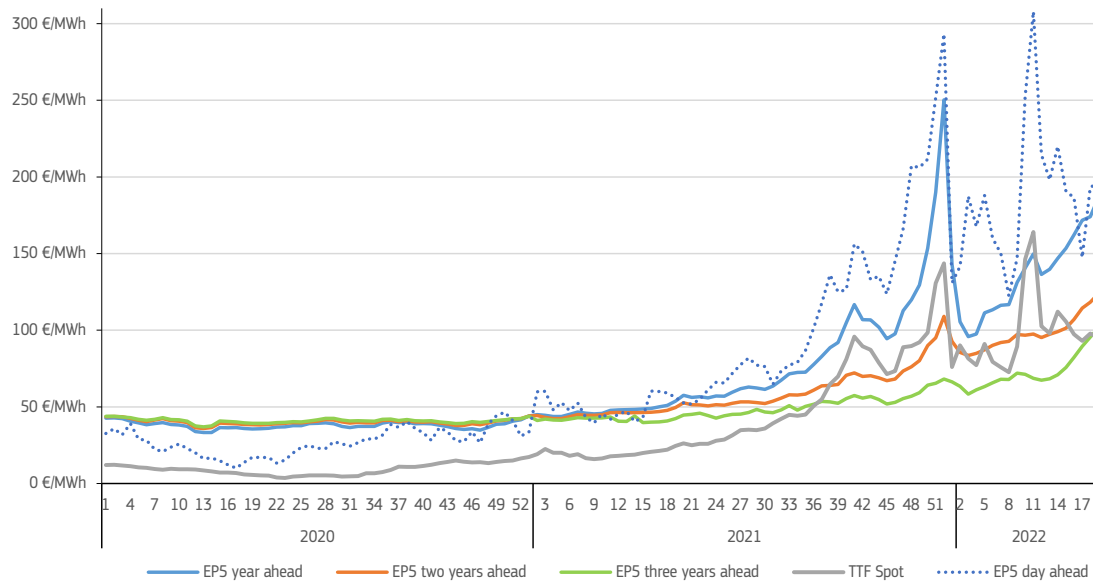
Figure 13 – The evolution of the lowest and the highest regional wholesale electricity prices in the European day-ahead markets and the relative standard deviation of the regional prices



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

- Figure 14**, reveals that gas prices have been the main driver behind changing expectations of future electricity prices since the first quarter of 2021. The rally in gas prices that took place for most of 2021, lifted the benchmark above pre-crisis levels and into all-time record highs. The TTF spot price, after having surged 94% during the fourth quarter 2021, decreased to values below 100 €/MWh in the first weeks of 2022. At the end of Q1 2022, the TTF spot price increased sharply again, reaching the record high value of 164 €/MWh in the middle of March. Consequently, the year ahead power benchmark rose to very high values at the end of 2021, and then decreased at the beginning of 2022 reaching a minimum of 96 €/MWh. From that point, as increasing uncertainty over the supply of gas from Russia was building up, the year ahead benchmark started climbing again, and at the end of Q1 2022 was attested around 150 €/MWh.
- During the first week of Q1 2022, the electricity year-ahead, two-year ahead and three-year ahead contracts were respectively 105 €/MWh, 86 €/MWh and 63 €/MWh, whereas in the third week of March, these three values reached a weekly maximum of 150 €/MWh, 97 €/MWh and 69 €/MWh. During this week, the discount of the year-ahead benchmark amounted to 158 €/MWh (as compared to 36 €/MWh at the beginning of January 2022). Moreover, the significant increase of forward curves in Q1 2022 and beyond, implies that the market does not anticipate a quick return to lower price levels. The discount of the year-ahead contract to the spot market oscillated between 6 €/MWh and 158 €/MWh during Q1 2022.

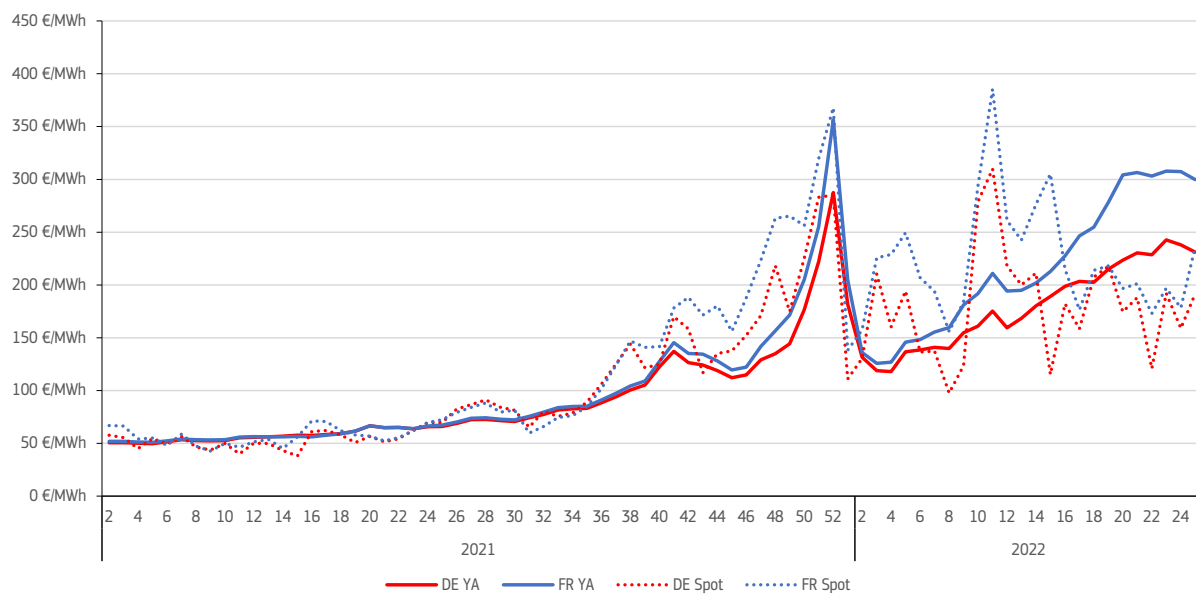
Figure 14 – Weekly futures baseload prices – weighted average of selected European markets



Source: S&P Global Platts.

- **Figure 15** shows the evolution of year-ahead contracts of Germany and France, together with their equivalent spot (day-ahead) prices. The divergence between the two forward contracts has been increasing since the beginning of the year, reflecting structural differences between the two markets. The French premium over the German forward contract reflects worries over the availability of the French nuclear fleet. The premium of the French contract reached 35 €/MWh during the third week of March and more recently, registered a difference of 69 €/MWh in the third week of June, over their equivalent German year ahead contract.

Figure 15 – Weekly German and French year ahead contracts



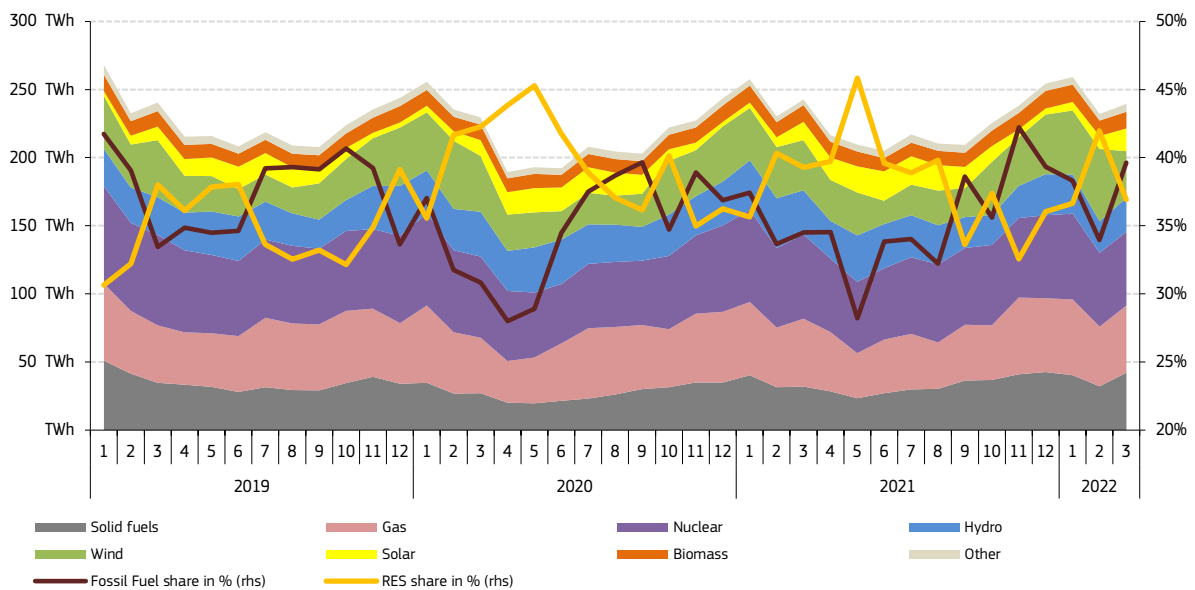
Source: S&P Global Platts.

- **Figure 16** shows the monthly evolution of the electricity mix in the EU. Despite decreased electricity demand in Q1 2022, fossil fuels were able to increase their level of generation in the mix. The share of electricity generated by

burning coal, gas and oil (fossil fuel generation) reached 37% in Q1 2022, while renewables slightly increased their share at 39%. Nuclear generation remained under pressure due to unplanned outages in France and scheduled closure of capacity in Germany, decreasing its share of generation in Q1 2022 to 23%.

- Within the fossil fuels realm, coal gained ground both in absolute and relative terms compared to Q1 2021 as a reaction to the rally of gas prices which reversed the coal-to-gas switch registered in 2020, despite high carbon prices. Overall, fossil fuel generation registered an increase of 18 TWh y-o-y (+7%). Coal's share in the mix rose to 16%, whereas less CO₂-intensive gas generation saw its share practically unchanged at 20% in the reference quarter. In absolute terms, coal-based generation rose by 11 TWh year-on-year (+11%), while gas-fired power plants' output rose by 5 TWh (+4%). Renewables generated 1 TWh more of electricity year-on-year on the back of improved wind and solar generation, despite subdued hydro output.
- Between hard coal and lignite (the distinction between them is not visible in **Figure 16**), the latter tends to be more resilient in the face of changing market environment. Lignite generation traditionally displays more competitive marginal costs per unit of energy produced even facing the current level of 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 121% more expensive in Q1 2022 compared to Q1 2021, but this was compensated by rising gas and hard coal prices. In the end, lignite-based generation in Q1 2022 rose by 6% year-on-year (more than 3 TWh) and hard coal-fired generation increased by 16% year-on-year (8 TWh).

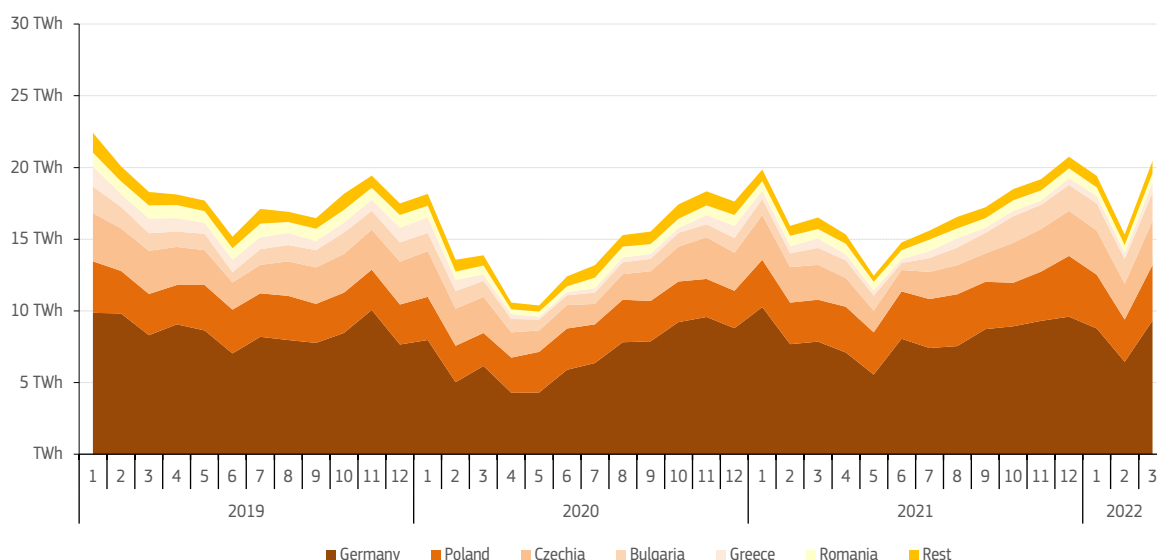
Figure 16 – Monthly electricity generation mix in the EU



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

- **Figure 17** shows that after a large covid-related drop during 2020, lignite generation staged a powerful comeback in 2021, helped by soaring gas prices (which decreased the competitive edge of gas-fired power plants). Most Member States with lignite-fired capacity increased its output during Q1 2022 (despite a drop in February due to a surplus in renewable generation). Monthly output peaked in March at roughly 20 TWh. In Germany, home to the largest lignite fleet, generation from the dirtiest fuel fell by 5% year-on-year in Q1 2022, due to increasing wind and hard-coal output. Lignite-fired generation in Poland increased by 16% year-on-year in Q1 2022, supported by decreased gas and hard-coal generation. The output of the Czech lignite fleet rose by 7% year-on-year. The three Member States accounted for 79% of the total lignite-based generation in the EU in Q1 2022. In Greece, lignite generation decreased by 7% year-on-year on the back of increased gas and solar output, and a rise in demand. In Bulgaria, decreased gas combined with growing demand facilitated the generation of additional volumes of lignite (85% compared to Q1 2021). Lignite power plants reached an 8% share in the EU generation mix in Q1 2022 (slightly up from Q1 2021) and were responsible for approximately 30% of the electricity sector's total carbon emissions in the reference quarter.

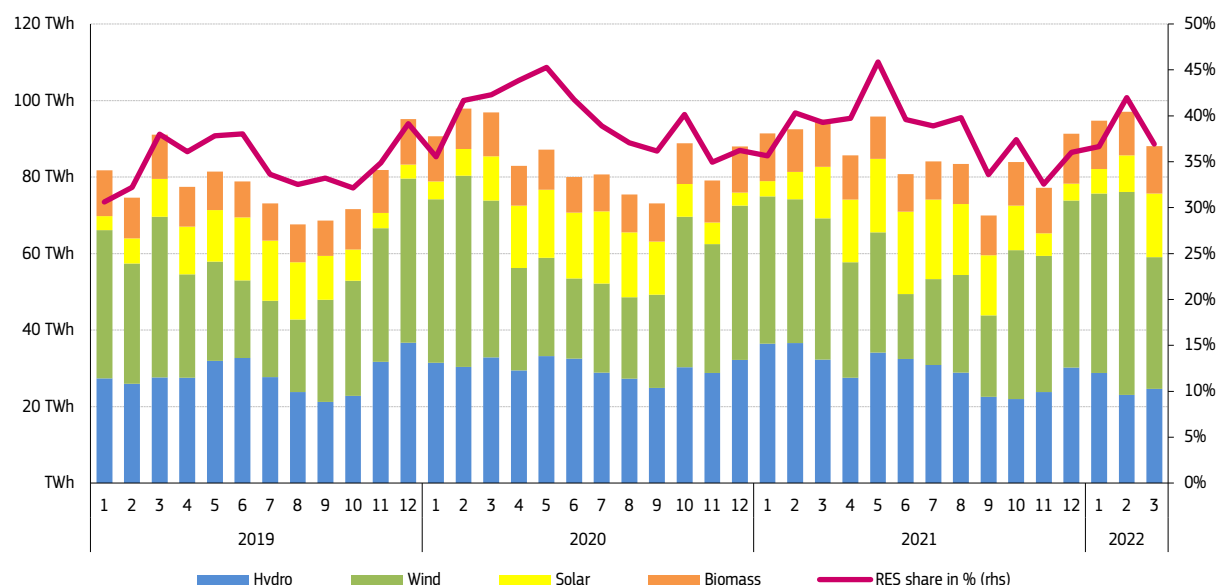
Figure 17 – Monthly generation of lignite power plants in the EU



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

- Figure 18** depicts the evolution of monthly renewable generation in the EU, alongside its share in the electricity generation mix. Renewable penetration reached 39% in Q1 2022, slightly higher than the 38% share of Q1 2021, and greater than the fourth quarter of 2021 (35%). An increase of 1 TWh in renewable generation contributed to the growth in renewable penetration during Q1 2022.
- The main gains in renewable output came from wind onshore (+20 TWh), solar (+8 TWh), and wind offshore (+1 TWh) in comparison to the reference quarter in 2021. Thanks to the rapid development of new capacity, onshore wind gains during the reference quarter (+20%) were reported mainly in Sweden (+59%), the Netherlands (+56%) and Germany (+40%). Conversely, Spain and France registered calm weather, which resulted in a decline of wind generation by 16% and 1% respectively. Offshore wind gains (+8%) during Q1 2022 were reported mainly in Denmark (+61%) and Sweden (59%). Overall, wind output remained with a surplus (+21 TWh) in Q1 2024, increasing its generation by 19%.
- Thanks to newly added panels, solar PV generation rose by 31% in Q1 2022 to a total of 33 TWh, more than three times than oil-fired generation. In absolute terms, the increase was mostly driven by +2 TWh in Germany (+30%), +1 TWh in Spain (+25%), +0.7 TWh in the Netherlands (+56%) and the impressive figures registered in Poland, with an additional +0.7 TWh and a 178% increase in solar output. Moreover, the share of solar generation in Spain reached 7% in Q1 2022, surpassing the share of hard coal (3%). In addition, biomass also increased its generation by 1% during the reference quarter. Main gains were reported in Bulgaria (+23%), Estonia (+16%) and the Portugal (+10%).
- However, the brunt of the losses in renewable generation came from hydro (-28 TWh), falling by 27% during Q1 2022. Main hydro generation volume losses were registered in Portugal (-67%), Spain (-56%) and Italy (-44%), as a result of low stock levels and limited precipitations. Bulgaria, Croatia, Finland, France, Greece, Ireland, Romania, Sweden and Slovenia also registered declines in hydro generation compared to Q1 2021. Conversely, the largest increase in hydro generation came from Estonia, where hydro generation rose by 155% compared to Q1 2021.

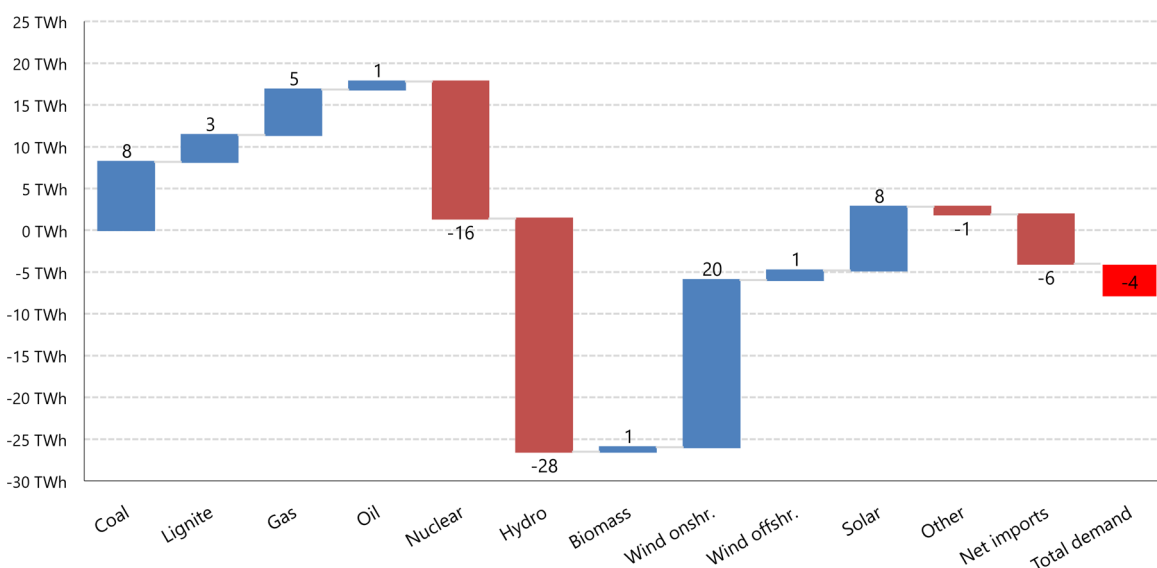
Figure 18 – Monthly renewable generation in the EU and the share of renewables in the power mix



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

- Figure 19** visualises changes in the EU27 electricity generation, imports and consumption in the reference quarter (Q1 2022) compared to Q1 2021. The space for conventional power plants' running hours was augmented, following the trend of previous quarters, despite a slight decrease in power demand by 4 TWh. Fossil fuels boosted their generation by +17 TWh. Renewable sources generation rose (+1 TWh), despite relevant falls in hydro generation (-28 TWh), whereas net imports fell (-6 TWh) compared to Q1 2021. Nuclear generation registered a significant drop (-16 TWh) due to reduced fleet availability and phase out policies in key Member States. All in all, hard coal increased its output by 8 TWh, lignite by 3 TWh, and gas by 5 TWh, despite high commodity prices. Oil generation rose slightly (+1 TWh) compared to Q1 2021. Based on preliminary estimates, the carbon footprint of the power sector in the EU rose by 8% year-on-year in Q1 2022, due to a larger use of fossil fuels. However, emissions were still 3% lower than in Q4 2021.
- In spite of the high prices of energy commodities (mainly gas, but also coal) fossil fuel generation increased in Q1 2022 due to low nuclear and hydro output. If the current trend continues, it is likely that both the power sector's carbon footprint and carbon intensity will rise in 2022.

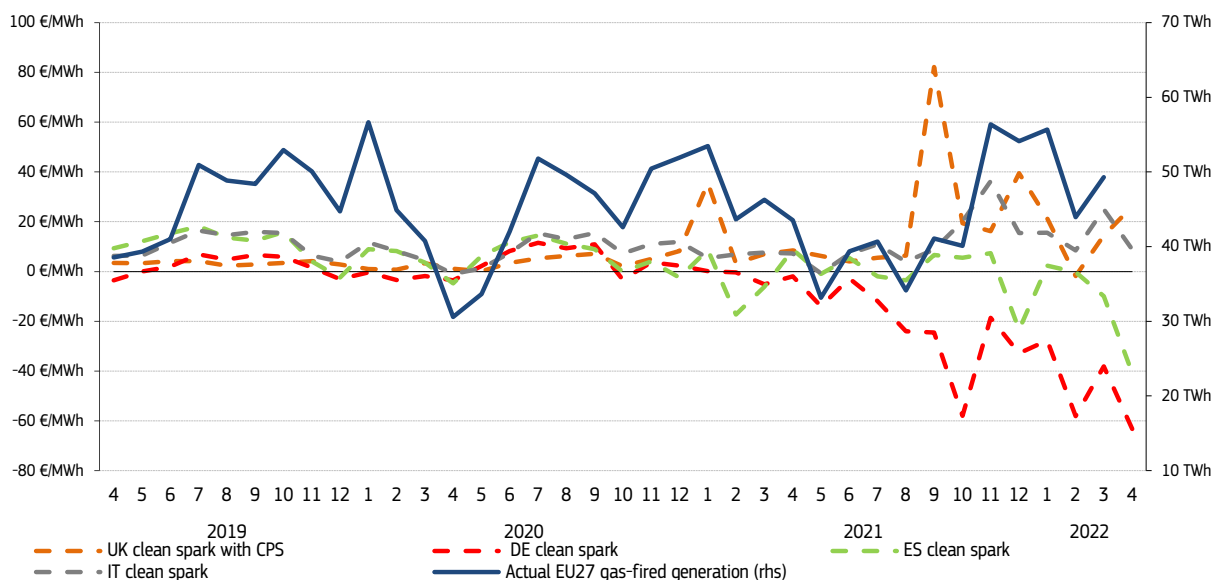
Figure 19 – Changes in power generation in the EU between Q1 2021 and Q1 2022



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 spread indicators. Gas reduced its traditional competitiveness advantage to coal in Q1 2022, following the trend registered in most part of 2021. During the whole quarter of reference, steep rising gas prices resulted in coal gaining the upper hand, despite high carbon prices. However, high prices created health margins not only for gas, but also for coal generators, as the UK and Italy clean spark spreads remained into the positive area during most of the reference quarter. Conversely, [clean spark spreads](#) remained at significant low levels in the case of Germany and Spain. The 2021 gas price rally continued well into 2022 and was exacerbated by the disruption of global commodity markets due to the Russian invasion of Ukraine. As such, coal usage has been increasing to reach electricity demand. However, despite low levels of profitability for gas-fired generation compared to coal-fired generation, the fuel switching capacity is limited by the scarcity of coal-fired plants still in operation, resulting from the decommissioning of the fleet over the last years.
- As shown in **Figure 20**, 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 2022 (as opposed to the German clean spark spread who has not been in positive territory since January 2021). In November, the Italian clean spark climbed to 36 €/MWh. The Spanish market started with positive number in January, only to fall into negative territory from February onwards. The highest clean spark spreads in Q1 2022 were assessed in Italy (16 €/MWh), followed by the UK (11 €/MWh). The lowest was presented in Germany (-41 €/MWh), registering a minimum of -58 €/MWh in February. Gas-fired generation volumes largely corresponded to the movement of spreads in respective markets. The total EU gas generation reached 143 TWh in the reference quarter, up by 4% compared to Q1 2021.

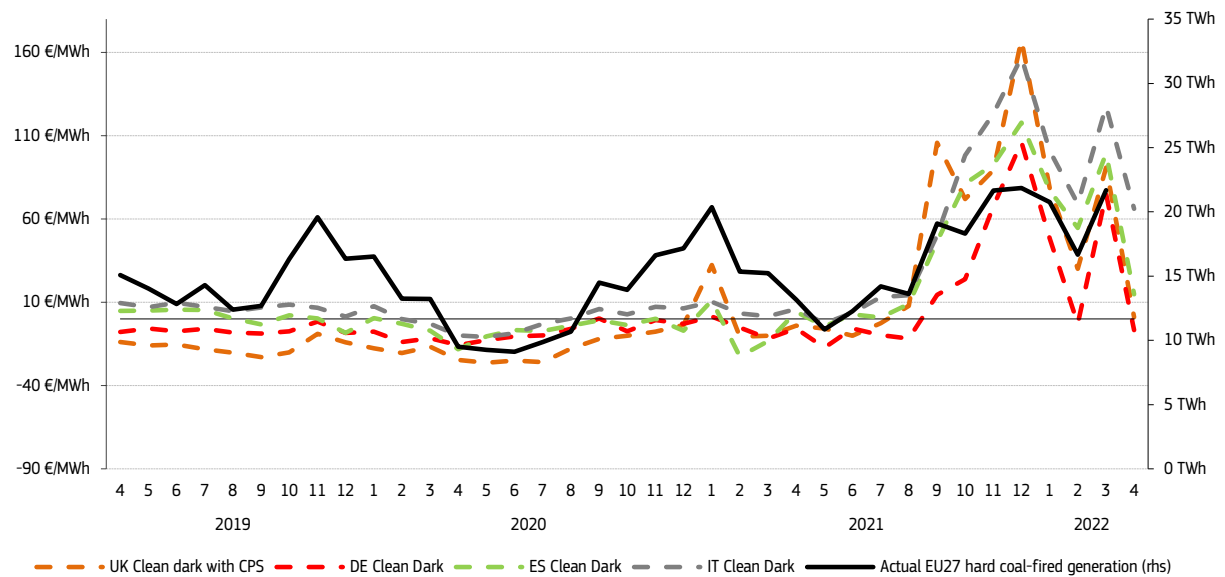
Figure 20 – Evolution of clean spark spreads in the UK, Spain, Italy and Germany, and electricity generation from natural gas in the EU



Source: ENTSO-E, Eurostat, Bloomberg

- For the whole year 2021, gas generation fell by 16 TWh EU-wide. The fall was led by Germany where coal and lignite replaced part of the gas output. In 2021, hard coal generation rose by 42 TWh and lignite by 26 TWh. The increase was driven by markets where coal (hard coal or lignite) still has a sizeable presence, such as Germany, Poland, the Netherlands or Bulgaria. Gas-to-coal or gas-to-lignite switching intensified during the second half of 2021, despite rising carbon prices, meaning that hard coal and lignite power plants were able to increase their running hours at the expense of gas competitors.
- **Figure 21** shows that Italy, followed by the ES, experienced the most profitable coal-fired power generation in Q1 2022. In March, all selected markets presented spikes in the profitability indicator for an average plant, despite rising coal prices. [Clean dark spreads](#) in Italy averaged 99 €/MWh in Q1 2022, six times higher than in the case of gas-fired power plants. Coal generation in Spain increased by 91% year-on-year in the first quarter of 2022, with only few units remaining in the market. German coal generators increased their output by 41% year-on-year in Q1 2022, as nuclear generation has been gradually fading in accordance with the German nuclear phase-out plan and other conventional capacities were limited as a replacement to meet electricity demand. However, as coal prices continue on the current rising trend, coal-fired generators will experience further pressure to remain in the profitability zone.

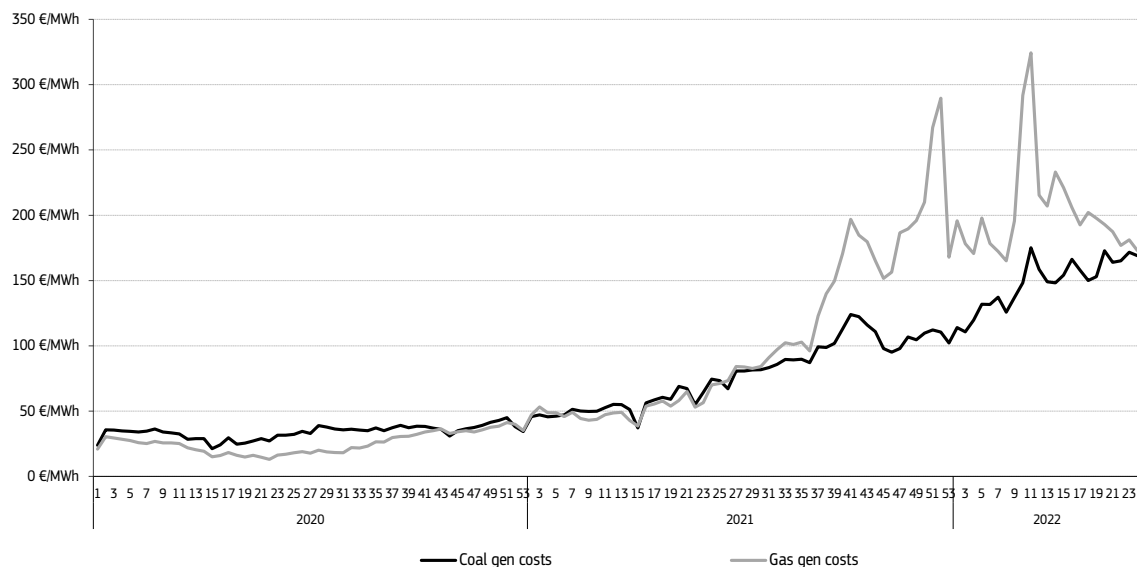
Figure 21 – Evolution of clean dark spreads in the UK, Spain, Italy and Germany, and electricity generation from hard coal in the EU



Source: ENTSO-E, Eurostat, Bloomberg

- Figure 22** shows the significant impact of gas prices on gas-fired generation variable costs (fuel and emission allowances) from the second half of 2021. Under normal conditions, the elevated carbon price would have promoted fuel switching (from coal to gas) as it was the case in 2020, as a result of a combination of low gas prices and increasing prices of emissions allowances. However, unprecedented gas prices have had a more significant impact on gas-fired generation costs, than the increase in coal and carbon prices on coal-fired generation costs. Nonetheless, elevated coal prices during June are closing the gap in variable costs and could support coal-to-gas switching for the first time since July 2021.

Figure 22 – Variable generation costs of coal- and gas-fired power plants



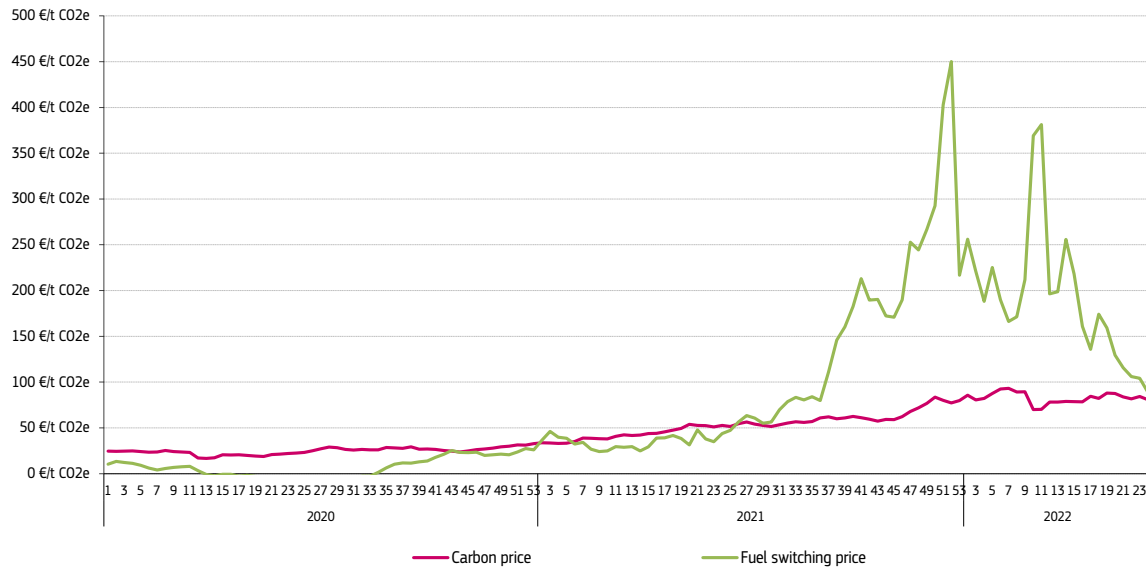
Source: S&P Platts, ENER.

Note: Thermal efficiency values used for coal- and gas-fired plants were 41% and 55% respectively. Emissions intensity values used were 0.85 and 0.37 tCO₂e/MWh respectively for coal- and gas-fired generation.

- Figure 23** shows how the supply tightening of the coal market during May and June, combined with a relative decline in gas prices is improving the economics of gas-fired plants for the first time in eight months. The average

fuel switching price required to make gas-fired plants economically viable vis-à-vis coal-fired plants fell to 88 €/tCO₂ during the third week of June, approaching to the average carbon price of 85 €/tCO₂ during May. However, fears of gas supply disruption keep incentivising coal-fired generation, although the potential of increasing coal generation is limited by the reduced fleet capacity as part of efforts of Member States to phase-out coal-fired plants.

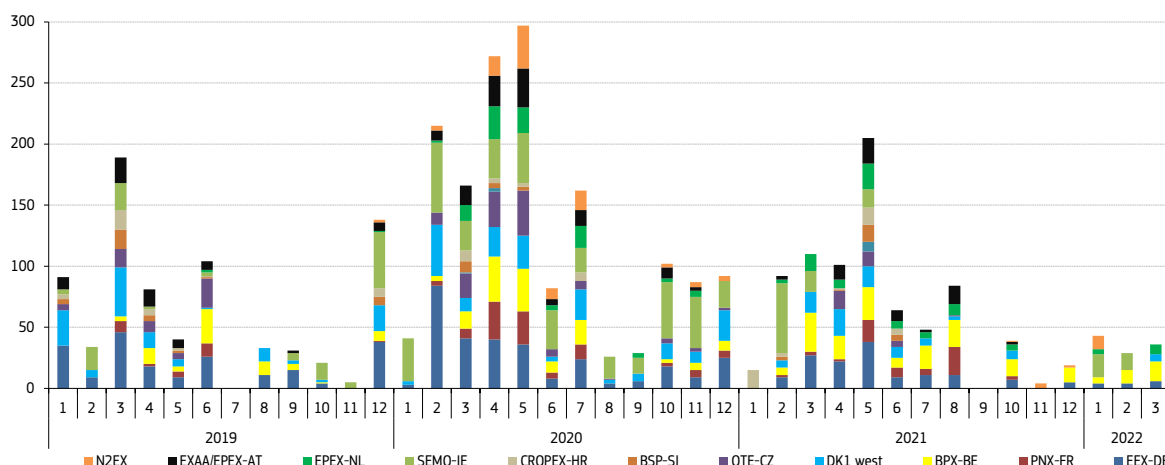
Figure 23 – Coal-to-gas fuel switching



Source: S&P Platts, ENER.

- **Figure 24** shows the monthly frequency of the occurrence of negative hourly wholesale electricity prices in selected European markets. Negative hourly prices usually appear when demand for electricity is lower than expected and when variable renewable generation is abundant, combined with ongoing relatively non-flexible large baseload power generation (e.g.: nuclear or lignite). In such cases, conventional power plants offer their output for a negative price in an effort to avoid switching the unit off and having to go through the costly and high-maintenance operation of restarting the facility when they want to enter the market again.
- The number of hours with negative wholesale prices in Q1 2022 (108) was 50% lower in the observed bidding zones than in the previous first quarter. Most of the falls into negative territory occurred in January of the reference quarter and took place in days when low consumption coincided with high renewable generation. The highest number of negative prices was recorded on 3 January, when strong wind speed combined weak demand, pushed the British Isles and some Central Western Europe markets (German, Dutch and Belgian) prices below zero during several hours of the day. Wind generation covered a large part of the Irish consumption during that day.
- The integrated Irish zone recorded the highest number of negative hourly prices (33) in Q1 2022, followed closely by Belgium (32), and Germany (14). Nevertheless, the integrated Irish zone recorded a decrease of 55% of negative hourly prices in Q1 2022. The higher level of penetration of variable renewables has introduced new challenges to the grid balance and has accentuated the need for more flexibility in the European power system. It has also intensified the search for market instruments that would find a proper value of flexibility. Flexibility will gain more and more importance as we transition to a renewable-based energy system.

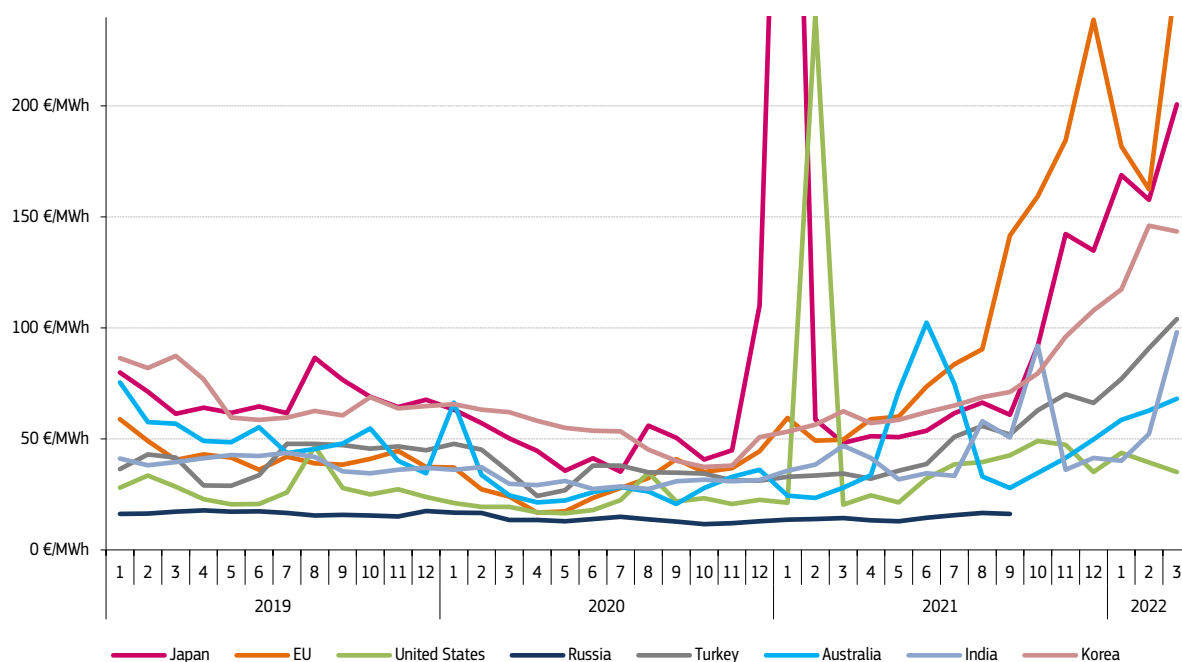
Figure 24 – Number of negative hourly wholesale prices on selected day-ahead trading platforms



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

- Figure 25** compares price developments in wholesale electricity markets of selected major economies. Most markets saw prices rising as a result of the already tight global markets, exacerbated by the global impact on commodities by the Russian war in Ukraine. In the U.S., wholesale electricity prices rose in most of the analysed regional benchmarks, as a result of rising natural gas prices at the U.S. Henry Hub, leading to high prices. Nevertheless, influenced by the extreme prices in ERCOT market during the first quarter of 2021, the average U.S. prices for Q1 2022 amounted only to 39 €/MWh. The EIA expects significant increases in wholesale electricity prices during the summer of 2022 as informed in its [Short Term Energy Outlook \(STEO\)](#). The rising prices of gas at Henry Hub will continue to put pressure on gas-fired generators as they often perform as the marginal technology to supply power.
- In Japan, the sharp increase in prices in January 2021 limited the effect of average year-on-year variation registered in Q1 2022 (-13%). However, the Russian invasion to Ukraine has increased the pressure on the already high LNG prices in Japan (which relies heavily on fossil-fuel power generation, and it is one of the most important LNG buyers in the global market) exposing energy security challenges towards the summer of 2022. South Korea have been equally exposed to tightening LNG market fundamentals, driving prices 136% higher in the reference quarter.
- European wholesale prices were once again, the highest of the observed economies in Q1 2022, reaching 201 €/MWh. In Australia, episodes of high demand and price volatility in some regions of the National Electricity Market (NEM) were present in Q1 2022. Prices were consistently higher in all the NEM regions, as Australian prices rose almost 150% year-on-year throughout Q1 2022. In June, outages of coal-fired power plants, subdued renewable generation and a cold snap put the Australian electricity network under a major strain. After the trigger of safety nets (price cap), the Australian market operator had to suspend the market, in order to secure sufficient supply to the grid. Despite the critical situation, the Australian operator was able to avoid any significant load shedding or blackouts in the grid. Prices in India rose by 57% in Q1 2022.

Figure 25 – Monthly average wholesale electricity prices in international markets (D-A markets)

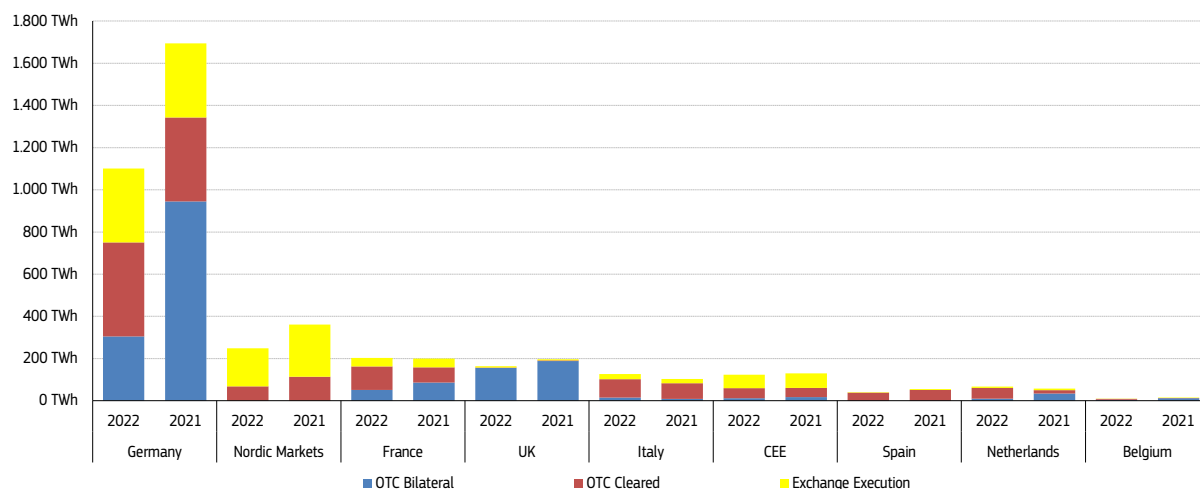


Source: European Power Benchmark, JPEX (Japan), AEMO (Australia), JCS ATS (the latest data for Russia is not available), Energy Exchange Istanbul (Turkey) and the average of selected PJM West, ERCOT, MISO Illinois and CAISO regional wholesale hubs in the United States. BloombergNEF (India and Korea).

2.2 Traded volumes and cross border flows

- **Figure 26** 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 2022, following the trend registered during 2021. The largest annual falls in total traded volumes were registered in Germany (-35%), Belgium (-32%) and the Nordic markets (-31%). Losses were driven mainly by the OTC sector, especially in the case of Germany. The total traded volume in all markets under observation fell by 26% to 2084 TWh in Q1 2022.
- Despite falls in traded volume, Germany was by far the largest and most liquid European market, as total volumes reached 1100 TWh (equivalent to 53% of the total traded volumes under observation in Q1 2022). Activity dropped significantly in OTC contracts (-44%) and decreased slightly at exchanges (-1%) in Q1 2022. Overall, total activity fell (-35%) in Germany in Q1 2022. The market share of exchanges experienced an increase (+11 p.p.) and the OTC contracts share decreased (-11 p.p.) compared to Q1 2021. Belgium and the Nordic markets registered a drop in activity of 34% and 31%, to 11 TWh and 248 TWh, respectively. Relative decreases in activity were also visible in the UK where total volumes fell (-17%) to 164 TWh. Also, relative decreases were also visible in the CEE region where total volumes fell by 5% to 124 TWh.
- Overall, the market share of power exchanges expanded from 27% to 32%. The largest increase in exchange-based volumes were registered in Italy (+23%), while falls were reported in Spain (-46%) and the Netherlands (-29%). Overall, exchange-based trading volumes decreased by 75 TWh in Q1 2022 (-10%). The OTC segment traded 654 TWh less of electricity in Q1 2022 compared to Q1 2021, as a result of lower volumes changing hands in Germany, Nordic markets and the UK. OTC volumes reduced their share off the market to 68%. The Netherlands, Germany, Belgium and Spain registered the largest decrease in bilateral OTC deals (-71%, -68%, -63% and -56% respectively).

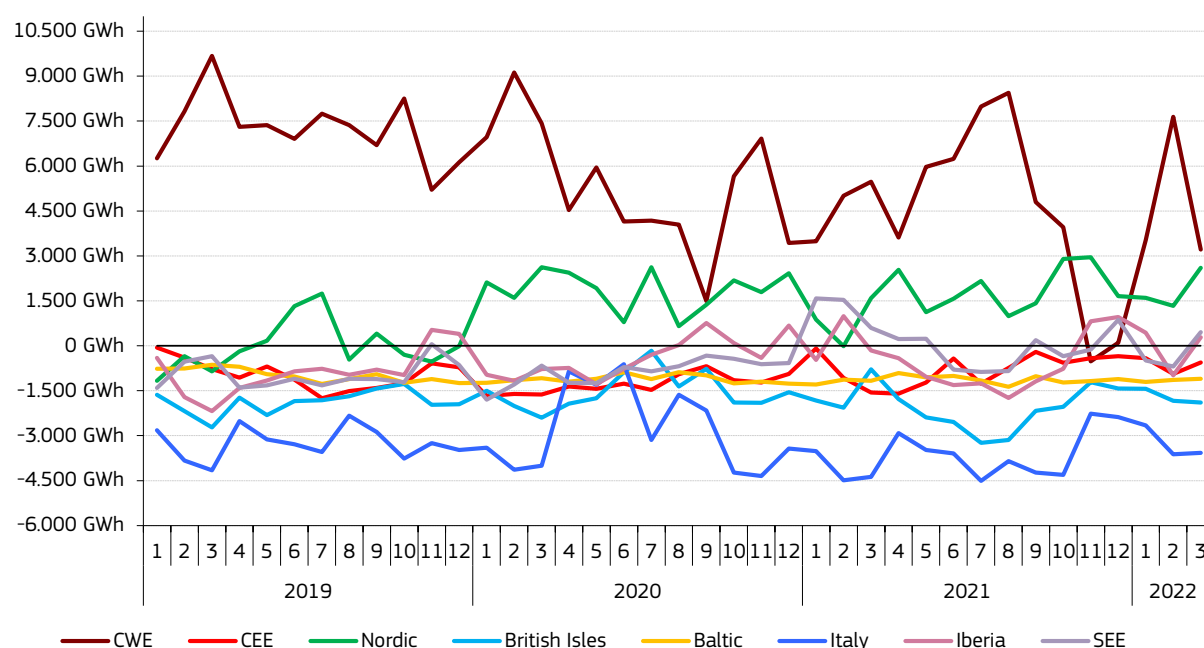
Figure 26 – Annual change in traded volume of electricity on the most liquid European markets



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

- Figure 27** reports on the regional cross-border flows of electricity. Central Western Europe registered a rise in its position as the main exporting region during February when the net balance flowed outwards the region. CWE, which has abundant and diverse generation capacities and a suitable central position to supply other regions, has traditionally been in a privileged position to act as a net exporter. During the first quarter of 2022, CWE registered 14.4 TWh of net exports, increasing its outflows by 3% during the quarter in comparison to Q1 2021. The increase can be traced mainly to lower demand within CWE market, which increased the availability of exports. The Nordic region recorded a surplus of 5.5 TWh in the reference quarter, 126% above from the net exports in Q1 2021. Net flows to the British Isles decreased compared to Q1 2021 at -4.7 TWh, improving by 12% on yearly basis
- The rest of the regions ended up in deficit. This was mainly due to less available generation across the EU in general, supported by high gas prices, reduced nuclear availability and hydro output. South Eastern Europe returned to being net importer (-0.7 TWh), a significant drop compared to the positive numbers of Q1 2021 (+3.7 TWh). The Iberian Peninsula also returned to the traditional condition of net importer, registering a shortfall of -0.3 TWh during the reference quarter. Italian net imports increased by 20% year-on-year to -12.3 TWh in Q1 2022. The CEE region's net position (-2.7 TWh) worsened by 30% in Q1 2022 compared to Q1 2021.

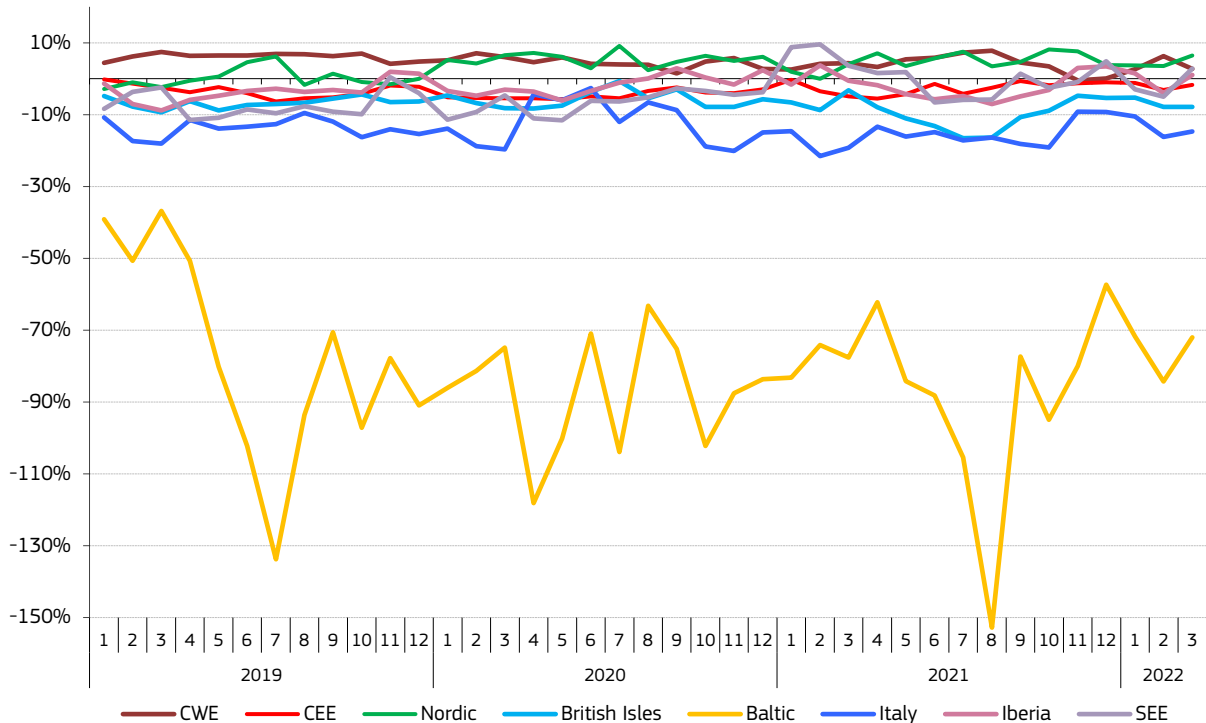
Figure 27 – European cross-border monthly physical flows by region



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 28** 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 2022 compared to the same quarter a year ago. Net imports (3.5 TWh) reached about 76% of domestic generation. Italy became the second largest importer relative to its domestic generation (14%), followed by the British Isles (7%). For the rest of the regions, net imports (or exports) did not exceed 5% of domestic generation.

Figure 28 – The ratio of the net electricity exporter position and the domestic generation in European regions



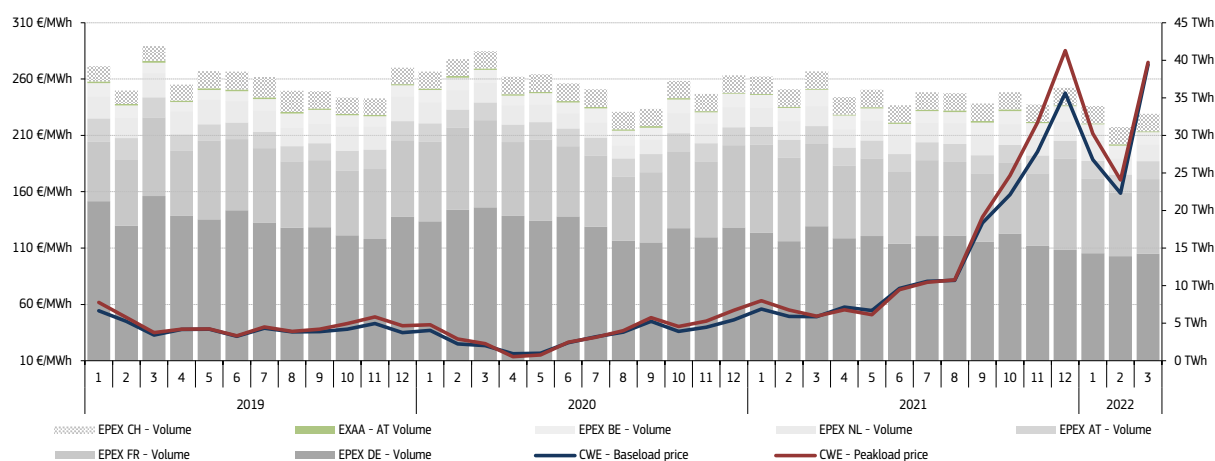
Source: ENTSO-E. Country distribution in regions is the same as in the previous figure. The -100% level means the same amount of electricity is imported as produced domestically. Source: ENTSO-E, TSOs, Eurostat, DG ENER calculation

3 Regional wholesale markets

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

- Following a continuous rise in prices in the last quarter of 2021, monthly average wholesale baseload electricity prices in Central Western Europe (CWE) started to decrease in January and February 2022, before it reached historical levels in March 2022. Indeed, wholesale electricity prices reached an unprecedented peak in March (273 €/MWh), following the Russian invasion of Ukraine on 24 February 2022. On top of expensive gas, historically low levels of storage stocks and global LNG tightness in the last quarter of 2021, the invasion of Ukraine in February has further exacerbated the high-energy prices crisis throughout 2022. Compared to Q1 2021, the average baseload price in the region increased by 302% to 207 €/MWh in the reference quarter. Meanwhile, average peakload prices increased by 291% to 219 €/MWh.
- In France, nuclear generation has drastically decreased, reaching a new record low in March 2022. EDF has lowered expectations of nuclear availability for 2022, on account of unprecedented high number of outages and some delay in the return dates of multiple reactors. Nuclear generation decreased from 7 TWh in the first week of January 2022 to slightly more than 5 TWh in the last week of March 2022. Subdued nuclear generation continued well into Q2 2022, and it reached a new low in the last week of May (4.5 TWh). Among other factors, the reduced nuclear fleet availability is keeping the French forward contracts in premium over Germany (see **Figure 15**). The French president set out a new policy on nuclear in February 2022, aiming at the construction of six new EPR reactors (10 GW) and the revision of the planned reactor closures.
- The Eurotunnel interconnector (1 GW ElecLink) started commercial operations on 25 May, with UK power flowing into France. The link has boosted interconnection between France and the UK to 4 GW. However, the total interconnection capacity between the markets is limited to 2.8 GW due to the repairs on the 2-GW IFA-1 link.
- In Germany, three of the remaining six reactors (Brokdorf, Grohnde and Gundremminge) permanently ceased power operation on 31 December 2021, as a result of a national nuclear power and coal phase-out policy. The three reactors combined a capacity of 4.2 GW (respectively 1.4 GW, 1.5 GW and 1.3 GW). These closures added extra tightness and combined with expensive gas prices, triggered record highs of German power prices in the last quarter of 2021. The Russian invasion of Ukraine has reignited the debate in Germany on the closing of nuclear reactors, regarding the important share of gas import from Russia in the country. However, the extension of the nuclear running time has not been considered by the German government. In June, the government triggered the second level of its emergency gas plan and announced its plan to reactivate 10 GW of coal capacity in reserve to mitigate the impact of Russian gas cuts.

Figure 29 – Monthly exchange traded volumes of day-ahead contracts and monthly average prices in Central Western Europe

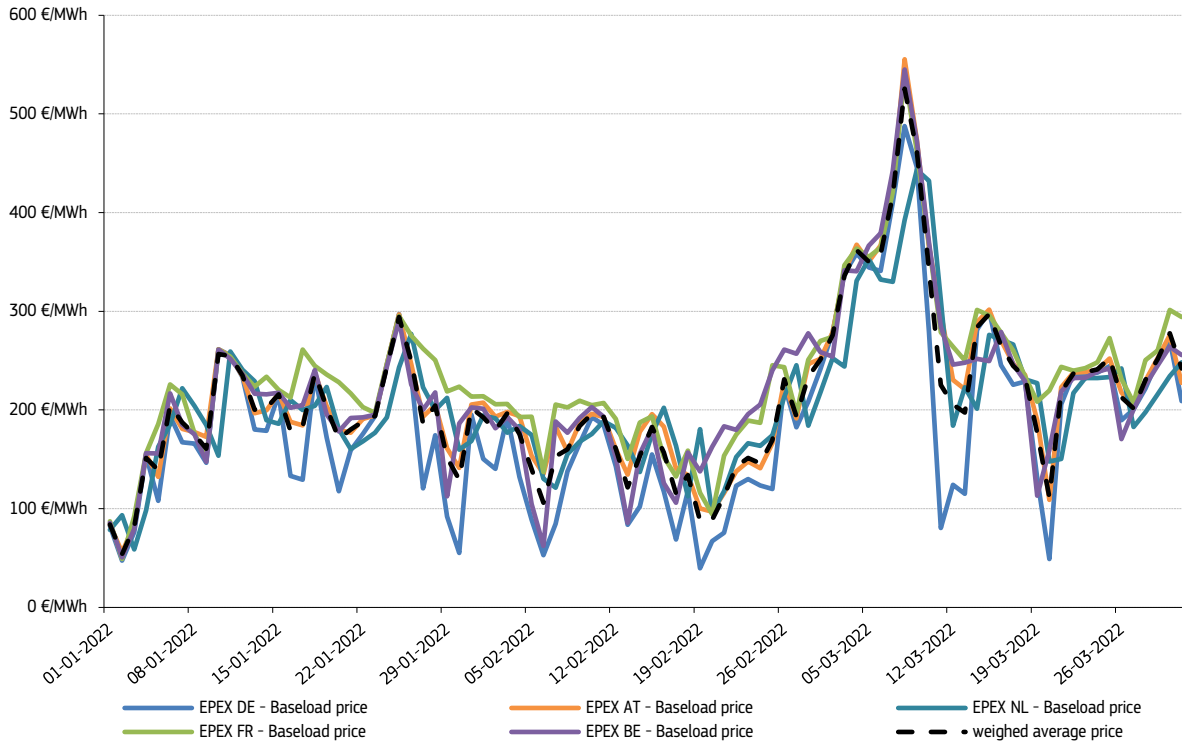


Source: Platts, EPEX. Volumes for EPEX-CH and EPEX-AT are missing.

- **Figure 30** shows the daily average day-ahead prices in the region in the reference quarter. Price volatility reached historical levels in the first quarter of 2022, on the back of Russia's invasion of Ukraine and the consequent high commodity prices. Indeed, daily prices stood around an average of 187 €/MWh in January 2022 and 159 €/MWh in February 2022. Following the invasion of Ukraine on 24 February 2022, the average daily prices climbed up to an unprecedented 275 €/MWh and an all-time high was registered over 526 €/MWh on 8 March, in reaction to the announcement of international energy sanctions on Russia and fears of supply disruptions in an already tight market

- At the lowest regional peaks, Germany experienced the lowermost power prices in comparison to its neighbours. As an example, on 20 March, Germany's prices reached 49 €/MWh on the back of high renewable output, while Belgium stood at 160 €/MWh, the Netherlands at 148 €/MWh, and France at 220 €/MWh (for a CWE average of 112€/MWh). CWE power prices dropped end of March amid higher than seasonal average temperatures.

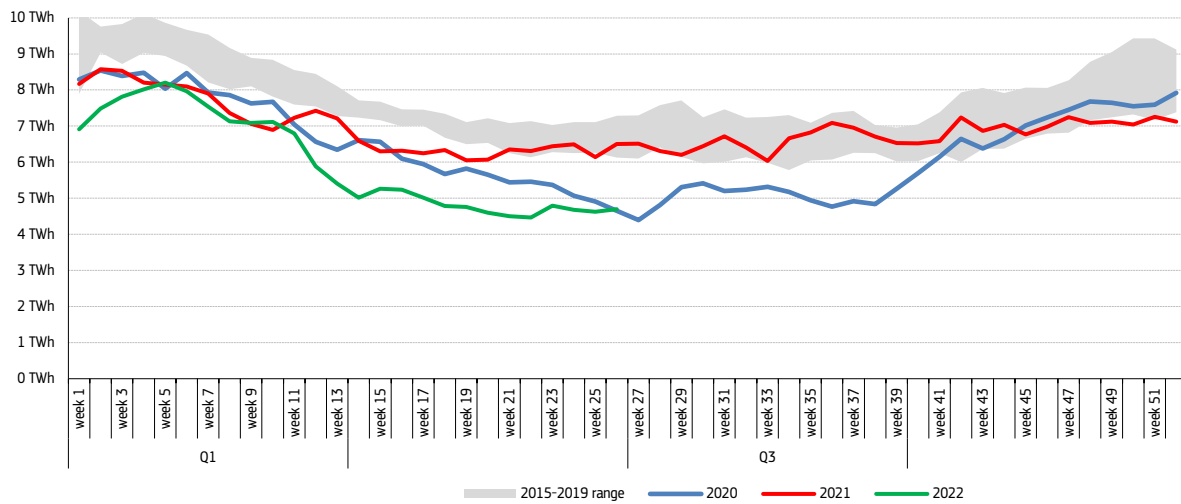
Figure 30 – Daily average power prices on the day-ahead market in the CWE region



Source: Platts.

- As shown in **Figure 31**, French nuclear output was down by 8% (-8 TWh) year-on-year in Q1 2022. Nuclear generation has drastically decreased, reaching a new record low in March 2022 (average of 6 TWh). EDF has lowered nuclear availability for 2022, as the fleet experienced an unprecedented high number of outages in the first quarter of 2022. Indeed, eleven reactors ended 2021 in maintenance, compared with five in the last quarter of 2020. The new French reactor Flamanville 3 (1.6 GW) has been delayed starting commercial operations around mid-2023. Furthermore, in the light of the crisis, the French president has set out policy on nuclear in February 2022, aiming at the construction of six new EPR reactors (10 GW) and the revision of the planned reactor closures. In June, seasonal output restrictions due to rising temperatures on rivers are increasing the pressure on the fleet.
- In Belgium, the federal government has initially planned to decommission the existing nuclear capacity (6 GW) by 2025. However, in the light of the Russian invasion of Ukraine and the consequent disruption of the European energy markets, Belgium has agreed to extend the operation of Doel 4 and Tihange 3 reactors until 2035 (2GW).

Figure 31 – Weekly nuclear electricity generation in France

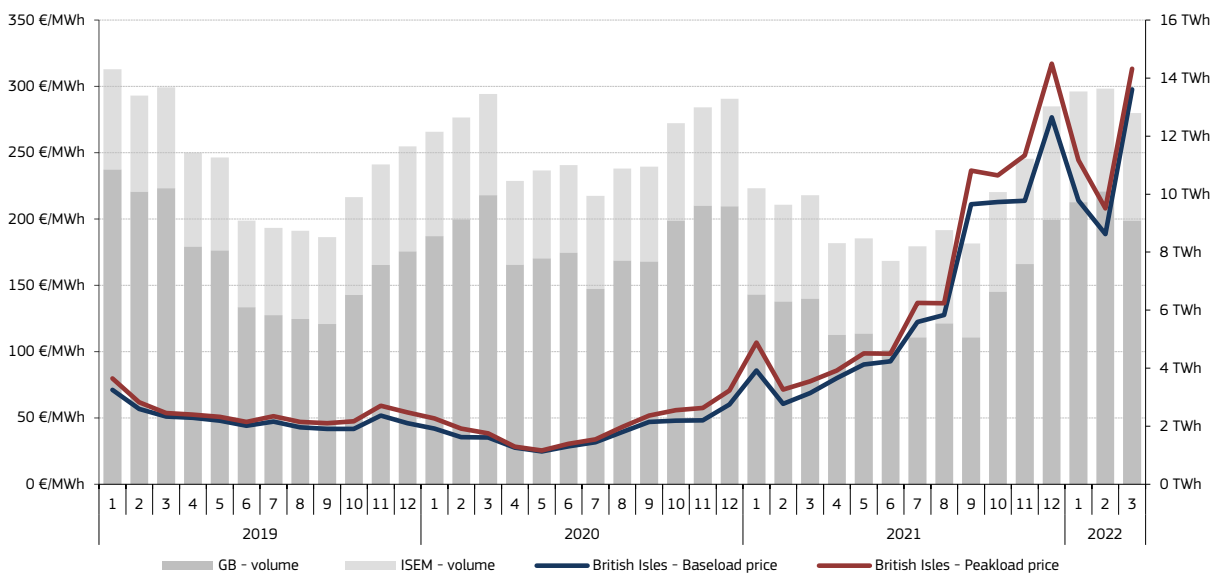


Source: ENTSO-E

3.2 British Isles (GB, Ireland)

- Figure 32** illustrates monthly volumes and prices on the day-ahead markets in Great Britain and in the all-island integrated market in Ireland. Monthly averages for both baseload and peakload power rose again reaching new all-time highs during the last month of Q1 2022. As in the case of the continent, the surge was driven mainly by the Russian invasion of Ukraine and the consequent reactions in the energy market based on the international sanctions and the fear of disruptions. Although the British Isles are less dependent than mainland Europe from Russian energy commodities, the interconnection between the markets has contributed to increase prices in the British Isles. From January 2022 to February 2022, baseload prices experienced a drop, decreasing from 214 €/MWh to 189 €/MWh (-12%). Following this relative fall, baseload prices increased to 298 €/MWh in March (+58% from February 2022, +333% year-on-year). Compared to Q1 2021, the average baseload price on the British Isles rose by 226% to 233 €/MWh during Q1 2022 and stood only less than 1% above the level from Q4 2021.
- National Grid is in conversations with a number of generators to keep coal-fired plants available for this winter. The bilateral agreement with EDF involves keeping 2 GW coal-fired plant West Burton A available to provide additional power if required.

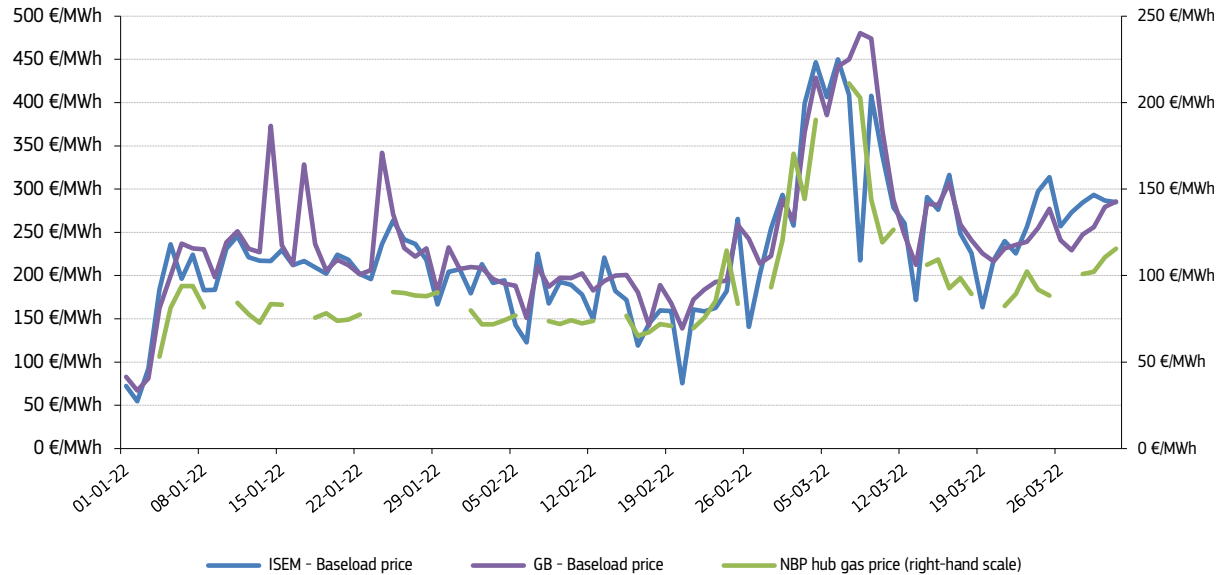
Figure 32 – Monthly exchange traded volumes of day-ahead contracts and monthly average prices in Great Britain and Ireland



Source: Nord Pool N2EX, SEMO, Utility Regulator

- **Figure 33** follows the developments of daily average baseload electricity prices in Great Britain (N2EX) and Ireland (ISEM). British baseload prices have experienced soaring prices, strong volatility and spikes along Q1 2022. The highest peak was registered in Great Britain on 8 March (480 €/MWh), on the back of a spike in the NBP prices following the international energy sanctions against Russia. The Irish market registered its highest spike on 6 March (450€/MWh). Baseload wholesale prices were almost equivalent than the previous quarter, as prices fell slightly in January 2022, but strongly increased in the last month of Q1 2022 in the wake of Russia's invasion of Ukraine.

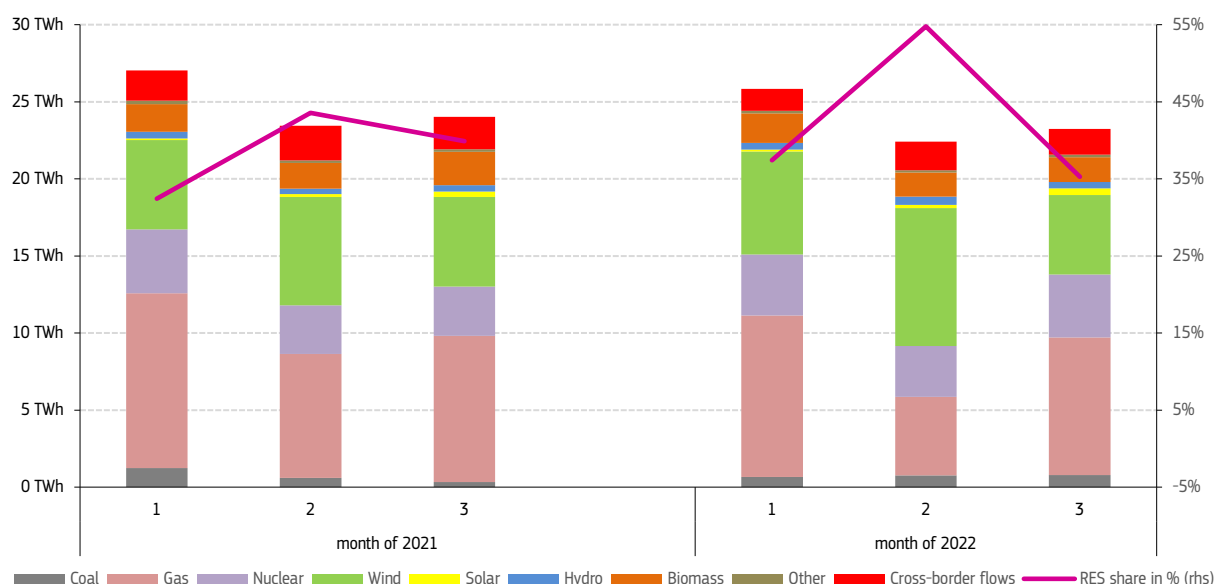
Figure 33 – Daily average electricity prices on the day-ahead market in Great Britain and Ireland



Source: Nord Pool N2EX, SEMO

- **Figure 34** shows the decrease of gas generation and the increase of nuclear generation between Q1 2021 and Q2 2022. The renewable share increased from 39% in Q1 2021 to 42% in Q1 2022, as a result of a climb in wind (+22%) output. Nuclear generation was 8% higher despite the closure of Humberston B nuclear plant. Net imports from the continent decreased from 9% in 2021 to 7% in 2022. The position of coal has slightly increased (2%) amid fears of supply interruption following the Russian invasion of Ukraine. Gas generation registered a fall of 15% compared to Q1 2021, although the share of gas-fired generation remained the largest of the generation mix.
- The early closure of Hinkley Point B nuclear reactor by August, combined with the closure of Dungeness B nuclear power plant (1 GW) will remove nuclear installed capacity by two thirds by the end of 2022 (6 GW will remain). All existing UK reactors are schedule to shut down by the end of 2031, with the exception of Sizewell B, which should be in operation until 2055. The recent resurgence of coal generation in the UK has been fuelled by the surge in gas prices and the fear of supply interruption following the crisis in Ukraine.

Figure 34 – Evolution of the UK electricity mix between Q1 2021 and Q1 2022

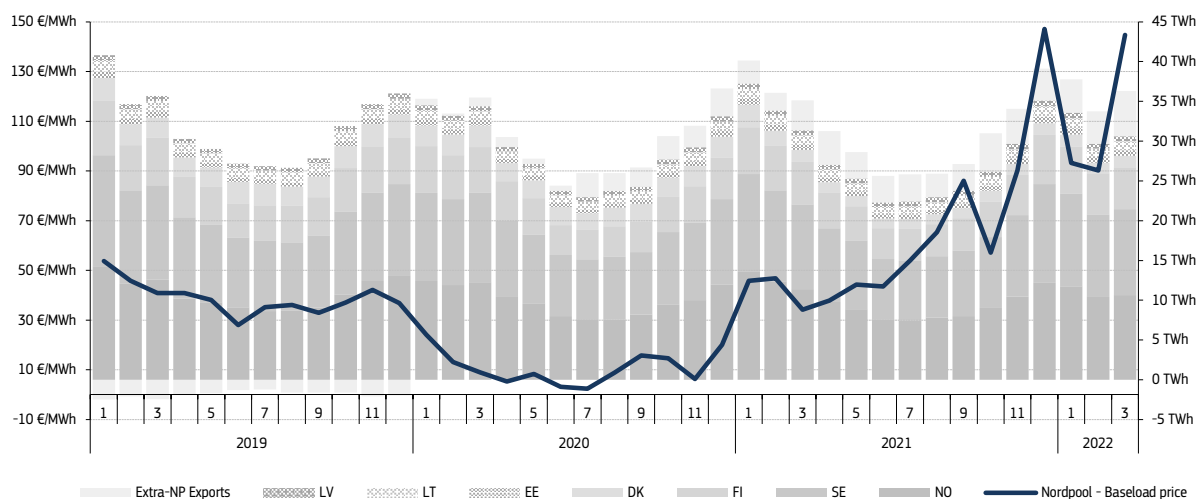


Source: BEIS. Positive values of cross-border flows indicate net imports

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

- As shown in **Figure 35**, Nord Pool prices strongly decreased in January and February 2022, after a peak reached at the end of Q4 2021. After the peak of 147 €/MWh in December 2021, baseload prices dropped to 93 €/MWh in January and 90 €/MWh in February. Baseload prices raised back to unprecedented highs in March, reaching 145 €/MWh (+61% from February 2022). Compared to Q1 2021, the average system baseload price surged by 159% from 42 €/MWh in the reference quarter.
- Finland is expected to improve its condition of net importer of electricity when Olkiluoto-3 nuclear power plant is commissioned during 2022, expecting to ease the pressure on Nordic power markets. The start of the commercial electricity production has been delayed from September to December 2022, amid technical issues during the test generation stage.
- On 14 May, Russian exports of electricity were suspended to Finland. In 2021, Finland imported 9 TWh from Russia, equivalent to approximately 13% of 2021 annual generation. [Fingrid](#) released a statement reporting that the lack of electricity imports from Russia will be offset by increased flows from Sweden and increased local generation. Finland expects to improve security of supply with the 440 kV interconnector Aurora Line between Sweden and Finland, which is expected to be completed in 2025. The new interconnection capacity is expected to enable the connection of 800 MW between the Finnish grid and the cheap north Sweden bidding zone.

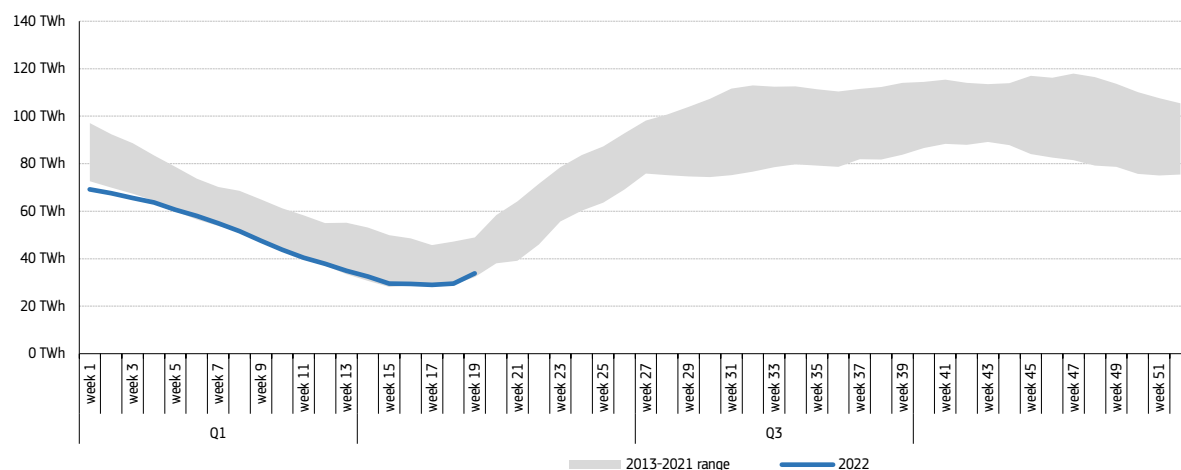
Figure 35 – Monthly electricity exchange traded volumes and the average day-ahead wholesale prices in Northern Europe



Source: Nord Pool spot market

- **Figure 36** shows the weekly evolution of the combined hydro reservoir levels in the Nordic area (Norway, Sweden and Finland) in 2022 compared to previous nine years. Hydroelectric stocks strongly decreased by 50% from the first week of January (69 TWh) to the last week of March 2022 (35 TWh), dropping below historical levels. Dry and cold weather condition in the area triggered this reduced reservoir in the end of Q4 2021 and the beginning of Q1 2022. Hydro stocks declined in line with seasonal demand and were exacerbated by below average temperatures during Q1 2022.

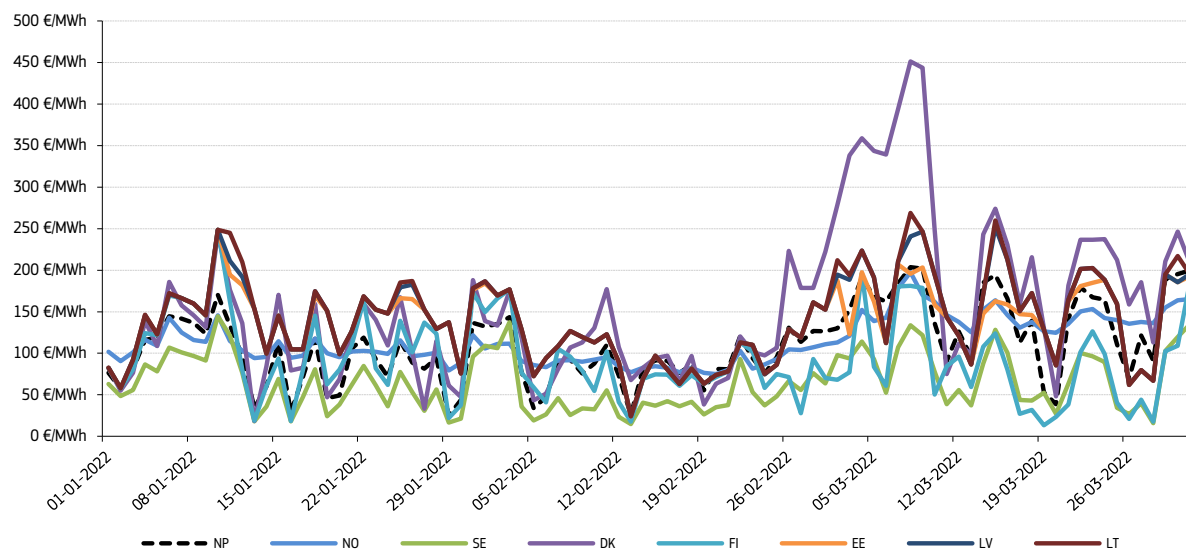
Figure 36 – Nordic hydro reservoir levels in 2022, compared to the range of 2013-2021



Source: Nord Pool spot market

- **Figure 37** shows that average daily prices across Northern Europe continued to display a high degree of divergence throughout Q1 2022. The lowest daily regional price registered in the reference quarter dropped to 39 €/MWh on 20 March, whereas the highest daily regional price registered reached 204€/MWh on 8 March. The highest spike was reached in Denmark on 8 March (451 €/MWh), as a consequence of the skyrocketing gas prices, amid international energy sanctions against Russia for the unjustified invasion of Ukraine, and subdued wind generation.

Figure 37 – Daily average regional prices and the system price on the day-ahead market in the Nordic region

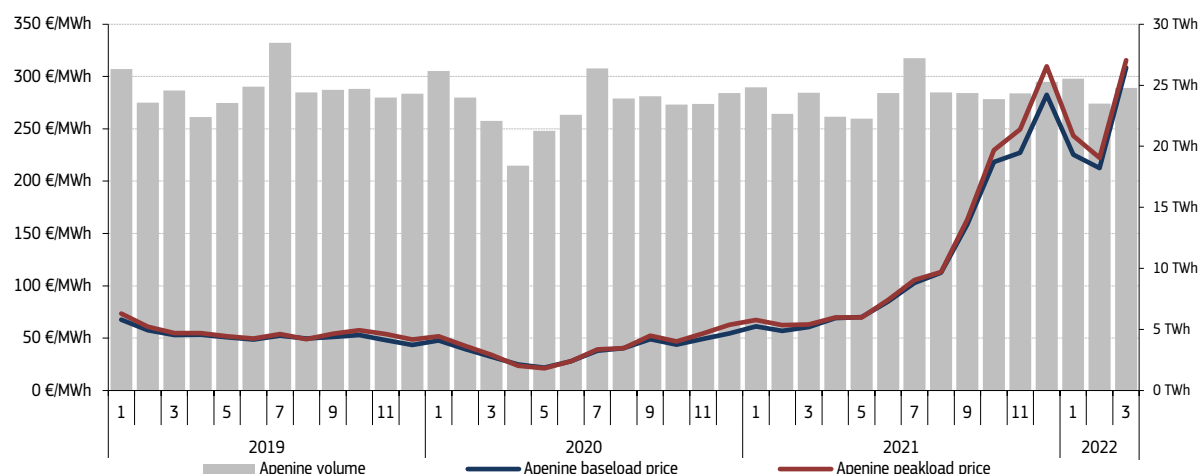


Source: Nord Pool spot market

3.4 Apennine Peninsula (Italy, Malta)

- Following a peak in December 2021 (282 €/MWh), Italian monthly average baseload electricity prices (**Figure 39**), experienced a drop in January (225 €/MWh) and February 2022 (212 €/MWh). Yet, the Italian market recorded a new all-time record in March 2022 (308 €/MWh) on the back of the Russian invasion of Ukraine. At 249 €/MWh, the Italian market recorder the largest average baseload price in Europe during Q1 2022. The average baseload price rose by 318% compared to Q1 2021 and was 2% above Q4 2021 levels. Trading volumes increased by 3% compared to the previous Q1.
- Italy has been taking measures to alleviate the effect of high energy prices to end-consumers. On the 27 February, Italy announced the activation of the “early warning” state, the first out of three possible alert levels in its Emergency Plan on natural gas. The government has increased monitoring of the gas market in view of possible effects of the energy crisis. The Italian government announced new measures to mitigate the impacts of the energy prices surge in [May](#).
- According to Italy’s strategy, the country needs to add 60 GW of new renewables to hit the 2030 target, including 43 GW of PV and 12 GW of wind. At the end of April 2022, Italy had already authorised around 3 GW of renewable additions and has started the process for further 4 GW that could be auctioned.
- The 1.2 GW link between Italy and France is expected to start its operations during the second half of 2022. The link will boost the interconnection between France and Italy to 4.3 GW and 2.2 GW in the opposite direction. Italy has eleven projects of interconnection planned by 2030, including increased capacities with Austria, Slovenia, Greece, Switzerland and Montenegro, and a new cable to Tunisia. A new link to Austria (300 MW) via Nauders is scheduled to start operating in 2023, while a new expansion at the Brenner Pass (100 MW) is set to go online during the same year.

Figure 38 – Monthly electricity exchange traded volumes and average day-ahead wholesale prices in Italy



Source: GME (IPEX)

- Figure 39** shows the daily evolution of the national average price and the range of the regional price areas in the Italian market. The national average stayed mostly between 200 and 300 €/MWh during January and February. In March, prices increased in the range of 250-350 €/MWh. Prices reach a peak value of 588 €/MW on 8 March, due to skyrocketing gas prices following the announcement of international energy sanctions against Russia.
- Italy is one of the largest producers of electricity from gas in the EU (gas represented 59% of the total generation in Italy during Q1 2022). Rising commodity prices, especially gas, played an important role in the surge of prices. In 2021, Italy imported 40% of its gas from Russia, the second highest ranking country in the EU. The impact of the Russian invasion of Ukraine and the uncertain political situation connected to the war, have heavily impacted gas prices in Italy. Moreover, the announcement in mid-June that the main Russian gas company will cut its deliveries to Italy by 50% is increasing the pressure on an already tight energy market.
- The Italian Power Exchange provides data on foreign price zones such as Malta, in addition to individual regional markets in Italy. The island is a net electricity importer from Italy (through Sicily) and thereby daily prices from the Italian power exchange (especially the Sicilian price zone) influence the Maltese wholesale electricity market. Traditionally, the Maltese zone forms the upper boundary of the band of regional prices. However, as visible in **Figure 39**, the trend has been reversed in Q1 2022, as prices in the Maltese area stayed most of the time in the lower bound of regional prices, as a direct result of the gap between prices in the north and south of Italy.

Figure 39 – Daily average electricity prices in the Italian day-ahead market, within the range of different area prices

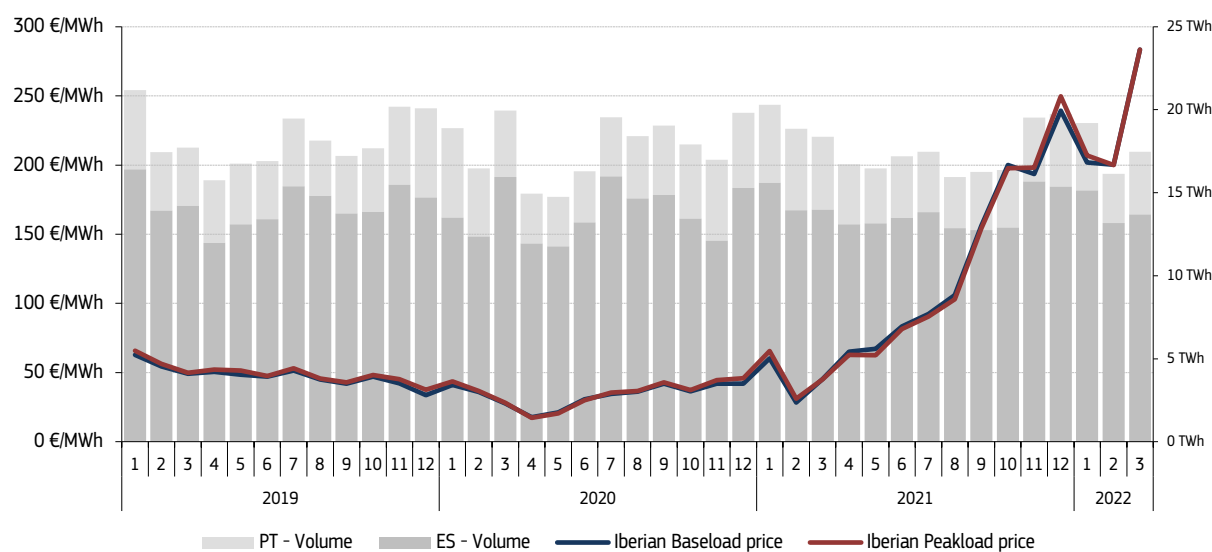


Source: GME (IPEX)

3.5 Iberian Peninsula (Spain and Portugal)

- **Figure 40** reports on monthly average baseload and peakload contracts in Spain and Portugal. During the first quarter of 2022, prices recorded new all-time highs, driven mainly by rising gas prices. Following a peak in December 2021 (239 €/MWh), baseload prices dropped to 207 and 201 €/MWh in January and February 2022, respectively. However, in March, prices reached historical levels up to 283 €/MWh, following the Russian invasion of Ukraine. Compared to Q1 2021, the average baseload price rose by 411% to 228 €/MWh in Q1 2022. Peak prices increased by 386% to 230 €/MWh. Trading activity was 8% lower than the previous Q1.
- Nearly 10 million customers (40% of consumers in Spain) are on tariffs directly linked with the wholesale electricity market. In light of the surges in wholesale prices, the Government has been reinforcing the measures taken in the last quarter to tackle the social and economic effects of rising energy prices. To that end, an exceptional cap on the price used for power generation came into force on 14 June in the day-ahead markets of the Iberian Peninsula. The measure, negotiated between Spain, Portugal, and the European Commission, was approved on 8 June 2022 by the Commission. Given the low interconnectivity of the Peninsula with the rest of Europe, measures allow for a temporary energy price cap on wholesale prices to mitigate the impact of soaring prices on end-consumers. The adjustment mechanism will be financed by the surplus in congestion rents obtained by the Spanish grid operator resulting from electricity trade with France and a charge imposed by the Iberian countries on buyers benefitting from the measure.

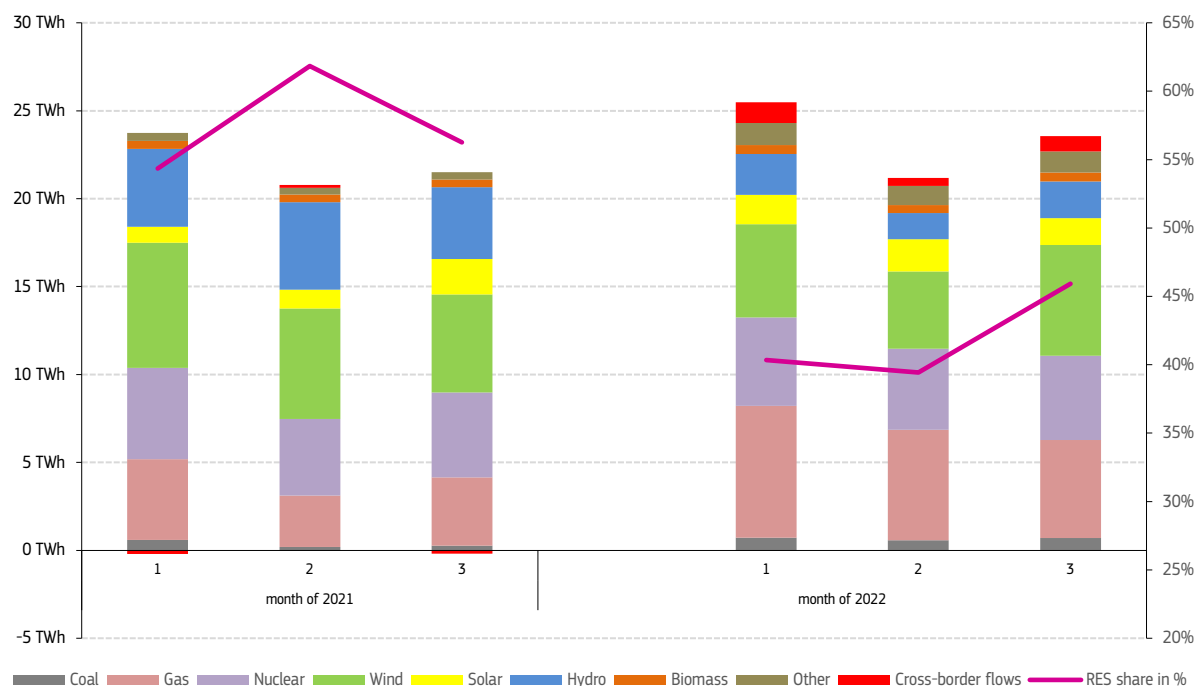
Figure 40 – Monthly electricity exchange traded volumes and average day-ahead prices in the Iberian Peninsula



Source: Platts, OMEL, DGEG

- **Figure 41** displays the evolution of the monthly electricity generation mix in Spain during the first quarter of 2022, as well as during the same period of the previous year. Net generation increased by 3% year-on-year. The share of renewable electricity sources reached 46% in March 2022 (average of 42% in the reference quarter), although down from an average of 57% in Q1 2021. Wind generation decreased by 16%, whereas solar output rose by 25%. Gas generation rose by 69% and the reduced remaining coal capacity increased its production by 92% (+1 TWh) year-on-year in Q1 2022. Nuclear generation remained practically at the same level than in Q1 2021 and covered a share of 21% of the total generation. In Spain, net imports accounted for 4% of the total generation during the first quarter of 2022.
- In Spain, two currently offline nuclear plants (Asco 2 and Trillo) are expected to return 7.3 GW of capacity in service. Despite the official closure of the Spanish coal fleet (with a few particular exceptions), Spain temporarily maintains four coal-fired plants operating (Abono, Soto de Ribera, Los Barrios and As Pontes). The As Pontes coal-fired plant started generating electricity at the end of November to contribute with the functioning of the Spanish electricity system in the context of the energy crisis. Currently, it is awaiting the end of the coal supplies to proceed with the administrative closure of the plant.

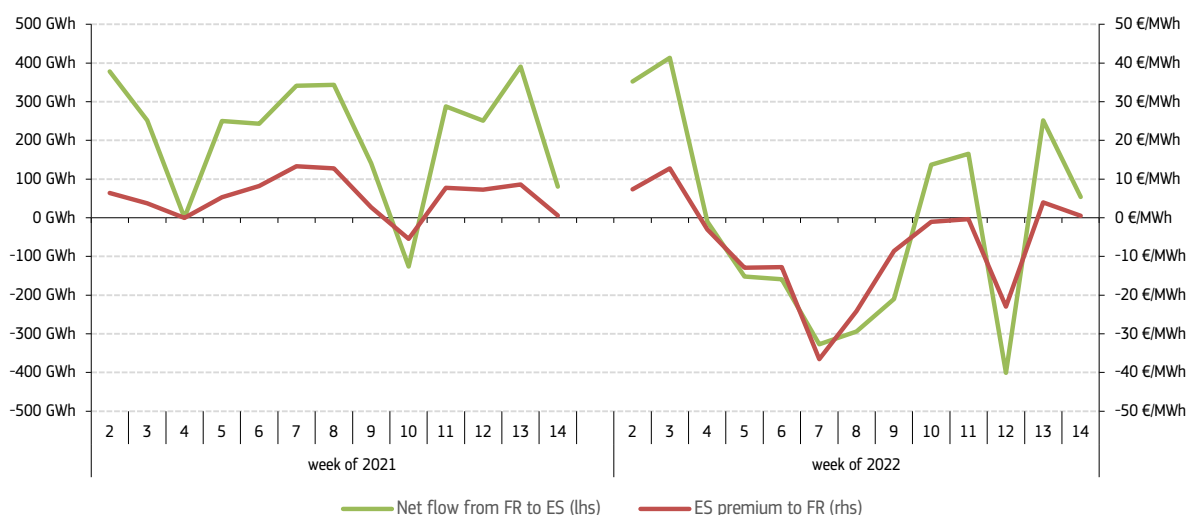
Figure 41 – Monthly evolution of the electricity generation mix in Spain in Q1 of 2021 and 2022



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

- **Figure 42** shows weekly electricity flows between France and Spain and price differentials between the two bidding zones. From week 4 to week 9, France experienced higher prices and Spain became net exporter. The differential reached its maximum (37 €/MWh) during the third week of February, amid low French nuclear availability. During the rest of the quarter, the price differential remained almost at zero, besides week 12 where the French prices were again in a premium. Consequently, electricity flowed back from Spain to France.
- Currently, limited interconnection capacity with France is a bottleneck in the European power market as both sides could further benefit from complementary seasonal generation. In the light of the events in Russian and Ukraine, Spain and Portugal have pushed for exceptional measures for the Iberian Peninsula regarding their lack of interconnection with the rest of Europe. Moreover, the 2 GW Biscay interconnector project with France, delayed to 2027, could double the interconnection capacity between Spain and France.
- Bilateral trade with Morocco in Q1 2022 resulted in net imports of 35 GWh from Morocco. A third interconnection link with Morocco (700 MW) is expected to be online by 2026.

Figure 42 – Weekly flows between France and Spain and price differentials between them

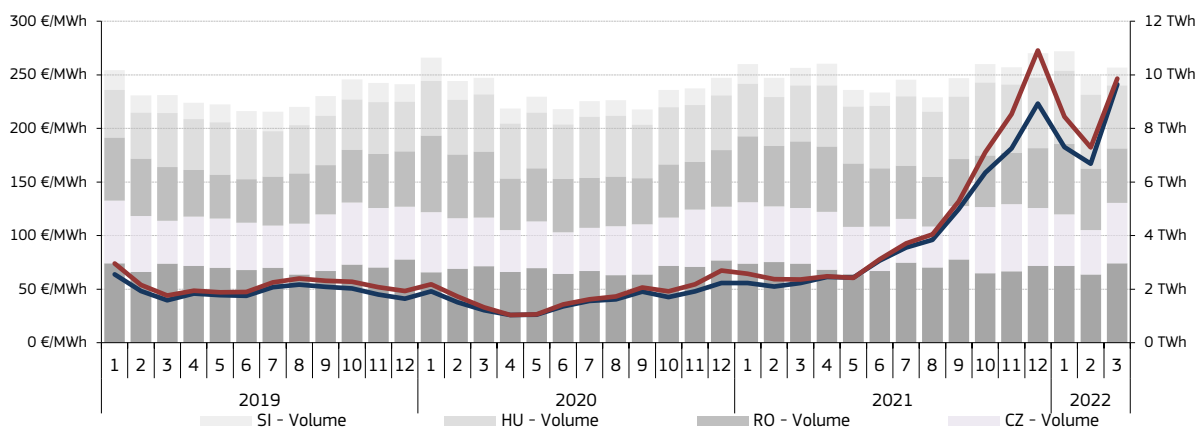


Source: ENTSO-E, OMEL, S&P Global Platts

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

- **Figure 43** shows that average monthly prices for baseload power in Central Eastern Europe remained at historically high levels. After a decrease from previously all-time-high levels at the beginning of the year, baseload prices escalated again in March 2022 to 241 €/MWh. Prices were mainly triggered by tightness of the gas markets and uncertainty connected with the Russian invasion of Ukraine at the end of February. The gap between baseload and peakload monthly averages decreased from 22% at the end of the Q4 2021 to 2% in March 2022. When compared to Q1 2021, the average baseload price in the reference quarter rose by 260% to 197 €/MWh. Traded volumes in the reference quarter increased by 4% compared to the previous Q1.
- At the end of March Poland announced actions intending to stop importing Russian gas, oil and coal by the end of the year. Despite the Q1 2021, 134 €/MWh average prices in Poland, baseload prices are still at discount to most of neighbouring countries thanks to current lower generation costs of the Polish coal fleet. This made Poland a net exporter of electricity during Q1 2022, increasing net exports to Slovakia and the Czech Republic, contrary to the norm of past years.

Figure 43 – Monthly electricity exchange traded volumes and average day-ahead prices in Central Eastern Europe (CEE)



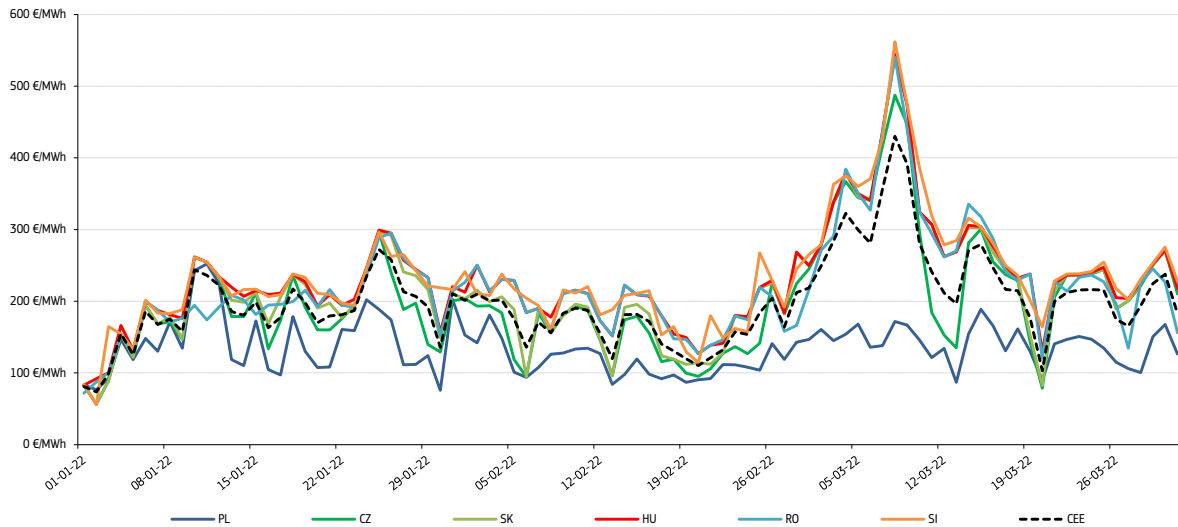
Source: Regional power exchanges, Central and Eastern Europe (CEE), CEE: PL, CZ, SK, HU, RO, SI

- **Figure 44** shows that daily average baseload prices in the markets (CZ, SK, HU, RO, PL) saw a dramatic increase in price and volatility during Q1 2022. The invasion of Ukraine by Russia at the end of February triggered prices around 500 €/MWh in all markets except Poland. This increase could be attributed mostly to rising commodity prices (mainly gas, but also coal), and indeed markets with higher dependence on gas (e.g. Hungary) were impacted more than markets relying on other sources (e.g. Poland). Volatility remained high, with CEE prices moving between 100 and 300 €/MWh in January and February, rising to peaks above 400 €/MWh in the first weeks of the invasion and then

decreasing again to values around 200 €/MWh at the end of March. The Polish market increased its discount towards CEE prices from an average of -53 €/MWh in Q4 2021 to one of -64 €/MWh in Q1 2022. The large coal-fired fleet in Poland has also been taking the impact of high commodity prices (coal and also carbon), as high electricity prices have affected Member States with reduced exposure to gas, such as Poland (although to a lesser extent than markets relying on gas). This is an interesting signal towards renewables, as high penetration levels of solar and wind would reduce exposure of electricity prices to scarce energy commodities (gas and carbon).

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

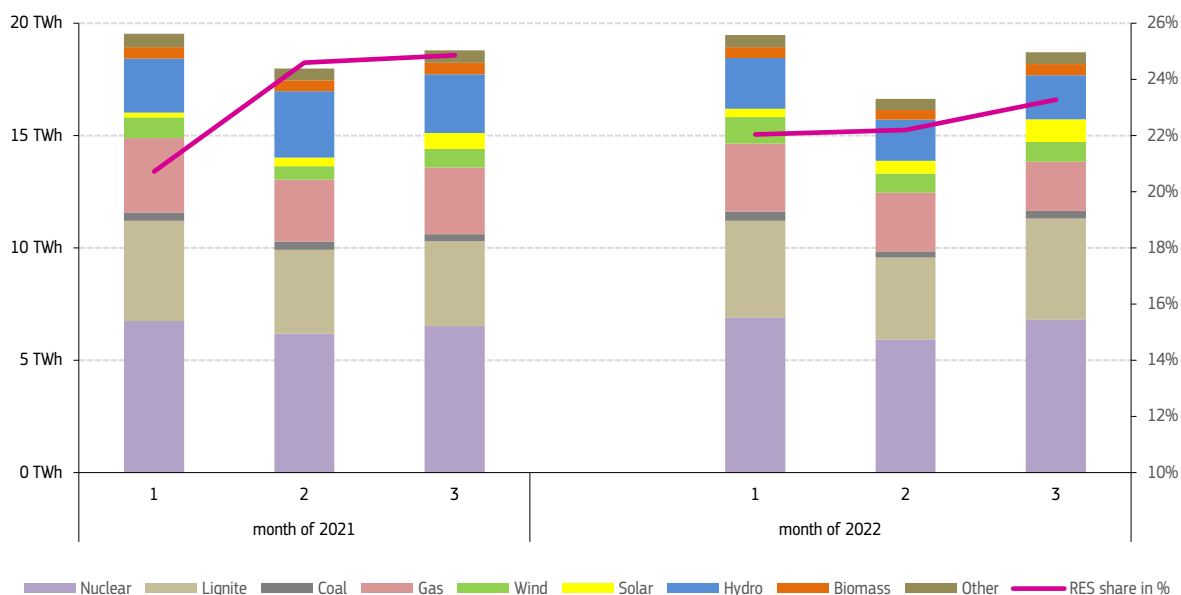
Figure 44 – Daily average power prices on the day-ahead market in the CEE region



Source: Regional power exchanges

- **Figure 45** compares the combined electricity generation mix of the CEE region (excluding Poland) in the first three months of 2021 and 2022. A significant reduction of the hydro-power generation (-24%) in 2022 (especially in Slovenia and Czechia) was only partially compensated by an increase in wind (+25%) and solar (+47%). This caused the renewable energy share to slightly drop by 1% compared to Q1 2021. All countries except Slovenia increased their wind production. While the solar generation had a boom in Poland, Hungary and Czechia. Nuclear remained the dominant generation technology with a considerable presence in all five markets.

Figure 45 – Evolution of the electricity mix in the CEE region (excluding Poland) between Q1 2021 and Q1 2022



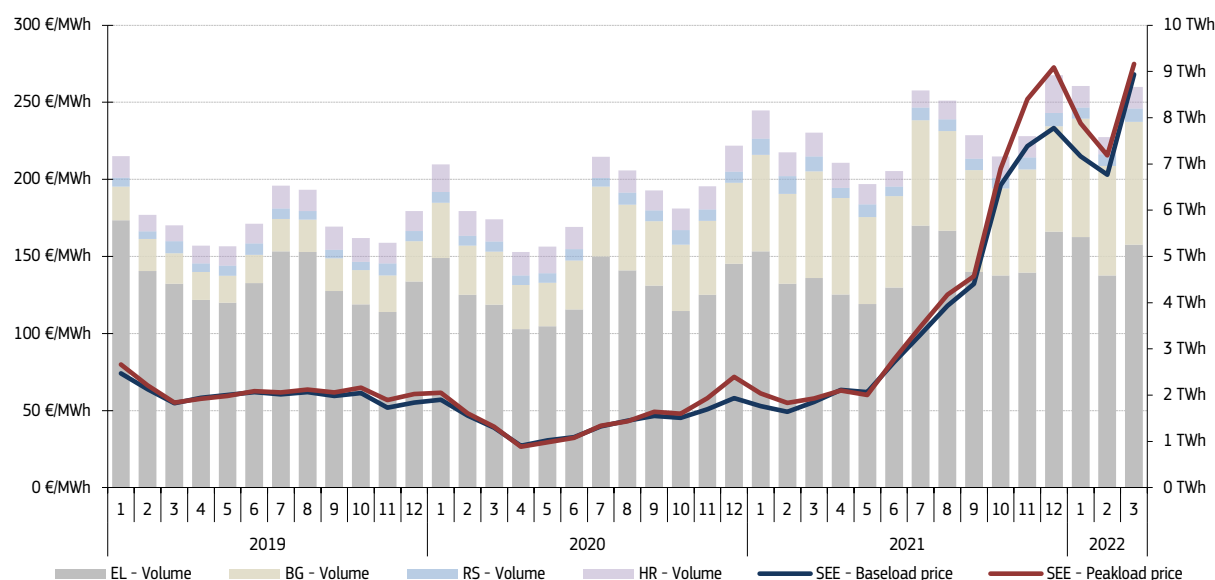
Source: ENTSO-E.

- In Poland, which is analysed separately due to significant differences in the size and structure of its generation base, the combined share of coal and lignite in its mix decreased to 68% in Q1 2022 compared to 68% in Q1 2021, while renewables increased their share from 17% in Q1 2021 to 23% in Q1 2022, thanks to booming generation of solar (+178%) and the increase in wind (+61%), biomass (+5%) and hydro (+5%) generation. Gas decreased its share in the mix from 10% in Q1 2021 to 8% in Q1 2022, underlining the limited short-term potential for coal-to-gas switching (or vice versa) and recent economic disadvantage of gas towards coal. Poland's solar PV capacities have been growing rapidly thanks to the introduction of an auction support system and grants for rooftop installations.
- The share of coal in Poland's mix, at 72% in 2021, should decrease to 56% by 2030 thanks mainly to significant wind capacity additions (especially in the offshore segment). Additionally, Europe's largest coal-fired plant, Bełchatów (5 GW), is planned to cease operations by 2036.

3.7 South-Eastern Europe (Bulgaria, Croatia, Greece and Serbia)

- **Figure 46** shows that trade-weighted monthly average baseload prices in the SEE region climbed steadily after an ease in February, during the reference quarter. Peakload contracts reduced their premium over baseload to 12% in Q1 2022. Baseload average prices reached 268 €/MWh in March, exceeding all previous monthly record prices from the past years. Strong gas prices in the context of the Russian invasion to Ukraine and the tightening of global markets influenced electricity prices up. Marginal costs of gas generation in countries like Greece, with high levels of generation from this energy commodity supported high energy prices, especially in March. The average quarterly baseload price rose by 335% year-on-year to 229 €/MWh in Q1 2022, 5% above Q4 2021 and 381% higher than Q1 2020. The average quarterly peakload price rose 318% above Q1 2021 levels to 242 €/MWh.

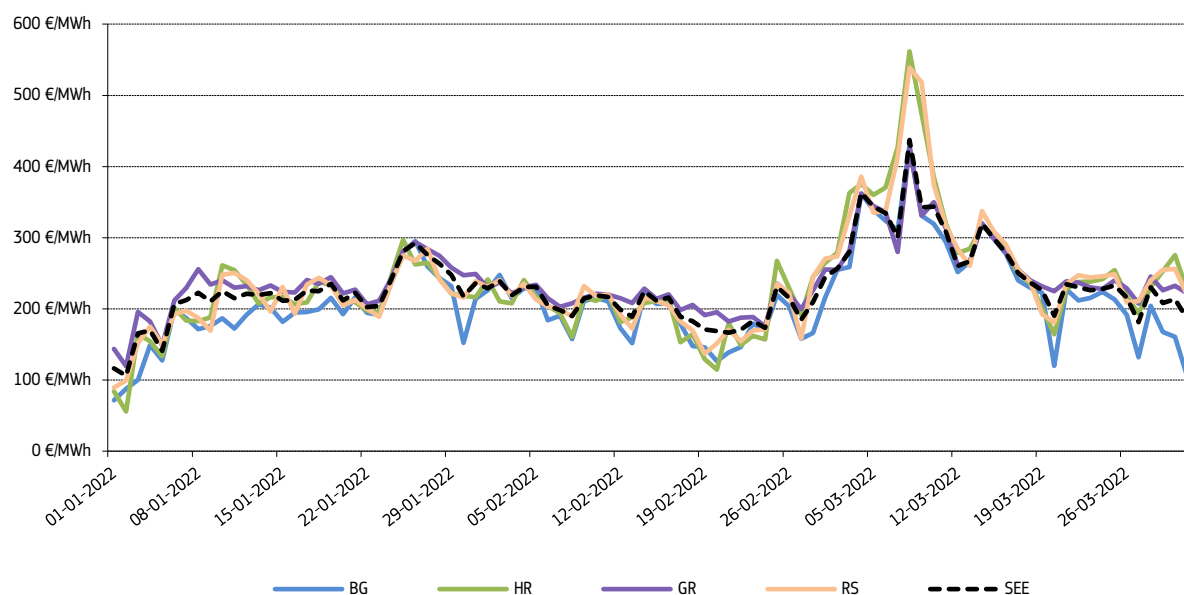
Figure 46 – Monthly traded volumes and baseload prices in South-Eastern Europe (SEE)



Source: IBEX, LAGIE, CROPEX, SEEPEX

- As shown in **Figure 47**, daily baseload price movements in individual markets were relatively aligned during Q1 2022, with the exception of elevated Greek and Croatian day-ahead prices in early March. Prices remain relatively stable during January (mostly between 200 and 240 €/MWh) and February (between 180 and 220 €/MWh). Volatility started to increase to high levels in the end of February and early March, on the back of the effects of the Russian war in Ukraine and the general tightness of supply in Europe due to high gas prices. Prices moved between 220 and 310 €/MWh in March. In line with the rest of Europe, wholesale electricity prices reached a new all-time peak on 8 March at 437 €/MWh, on the back of skyrocketing fuel prices as a result of the international energy sanctions against Russia. However, prices fell towards the end of the quarter reaching 182 €/MWh towards the end of Q1 2022 thanks to a drop in gas prices.

Figure 47 – Daily average power prices on the day-ahead market in Bulgaria, Croatia, Greece and Serbia

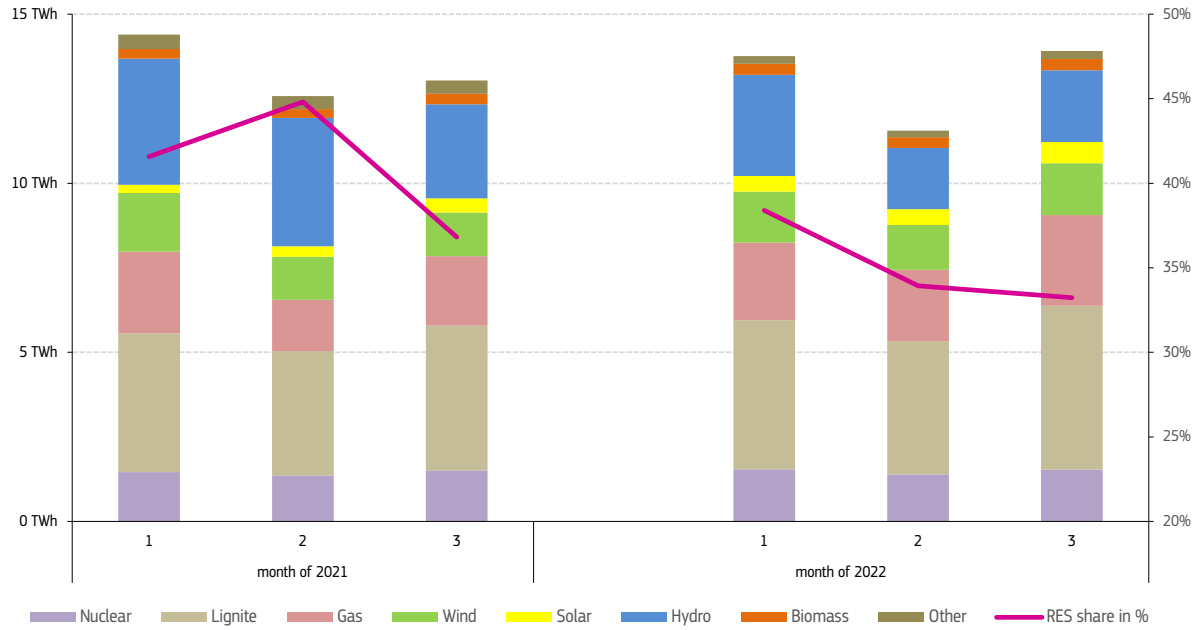


Source: IBEX, LAGIE, SEEPEX, CROPEX

- Figure 48** compares the combined electricity generation mix of the SEE region between Q1 2021 and Q1 2022. In Q1 2022, coal and lignite generation increased slightly its output (+1 TWh) year-on-year. Gas output increased by 1 TWh, while nuclear generation remained practically unchanged. Hydro output experienced a setback with 3 TWh less year-on-year. The share of lignite in the regional mix increased from 30% in Q1 2021 to 34% in Q1 2022. Increased gas generation in Greece (+1 TWh) drove up the share of gas from 15% in Q1 2021 to 18% in Q1 2022. Renewable penetration fell from 41% in Q1 2021, to 35% in Q1 2022 due to subdued hydro generation

in the region (-33% on yearly basis). As a temporary measure to reduce gas dependency, Greece is planning to increase lignite mining in the next two years. Greece continues with its plan to phase out lignite by 2025 with the conversion of Ptolemaida 5 to natural gas. However, as European countries are putting measures in place to manage potential gas supply disruptions from Russia, Greece may consider under a contingency plan, to ramp up lignite mining by 50% as a temporary measure in the next two years.

Figure 48 – Evolution of the electricity mix in the SEE region between Q1 2021 and Q2 2022



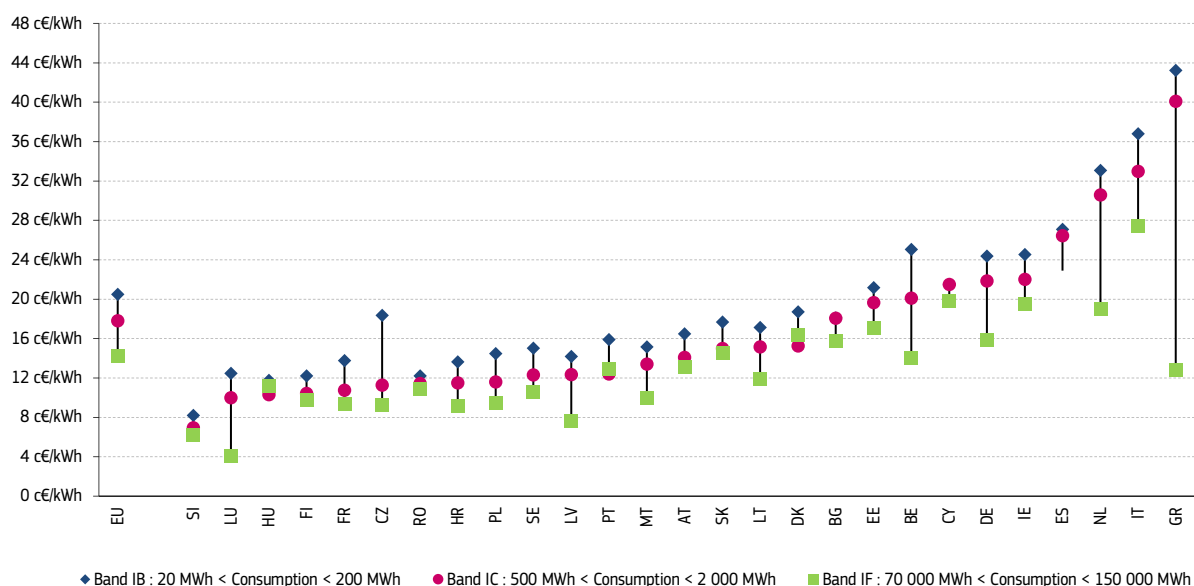
Source: ENTSO-E

4 Retail markets

4.1 Retail electricity markets in the EU

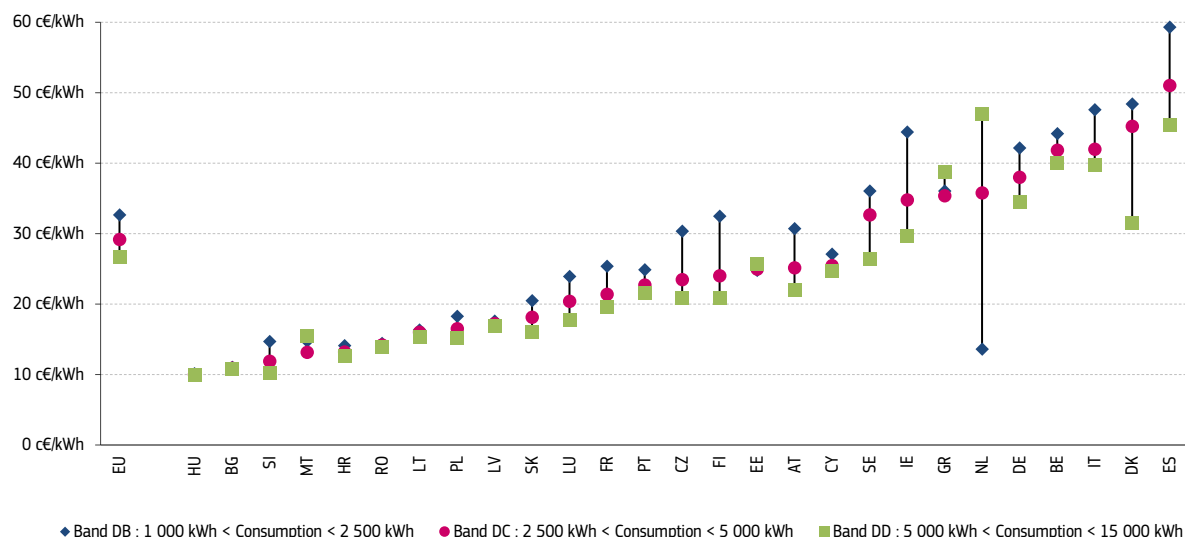
- High wholesale electricity prices have resulted in rising consumer bills for households, impacting the industry sector as well. Increasing wholesale prices is putting upward pressure on retail prices, while government interventions in some Member States are helping to alleviate the bill for consumers.
- **Figures 49 and 50** display the estimated retail prices in March 2022 in the 27 EU Member States for industrial customers and households. Monthly and quarterly retail prices are estimated by using half-yearly prices from Eurostat (with the latest available figures relating to the second half of 2021) and Harmonised Consumer Price Indices (HICP) for both the household prices and industrial consumers. It must be noted that by the time the next half-yearly price data will be available from Eurostat, monthly and quarterly figures might show different trends. 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 is (per MWh consumed). Cypriot, Estonian, Hungarian, Portuguese and Danish industrial prices are an exception, while Greece and the Netherlands prices are an exception for the household consumers.
- Smaller industrial consumers (band IB) were assessed to pay the highest prices in Greece (43.3 c€/kWh) and Italy (36.8 c€/kWh), followed by the Netherlands and Spain (33.1 and 27.1 c€/kWh respectively). The lowest prices in the same category were assessed to be in Slovenia (8.2 c€/kWh) and Hungary (11.8 c€/kWh). The ratio of the largest to smallest reported price was above 5:1. Compared to March 2021, the average assessed EU retail price for the IB band rose by 33% to 20.5c€/kWh. On the other side of the consumer spectrum, industrial companies with large annual consumption (band IF), including most energy-intensive users, paid the highest prices in Italy (27.4 c€/kWh), followed by Spain (22.9 c€/kWh), Cyprus (19.8 c€/kWh) and Ireland (19.5 c€/kWh). Luxembourg (4.1 c€/kWh) was assumed to have the lowest prices, with Slovenia and Latvia (6.2 and 7.6 c€/kWh) coming close behind. The ratio of the highest to lowest price for large industrial consumers was coming close to 7:1 for this consumer type. Compared to March 2021, the average assessed EU retail electricity price for the IF band rose by 76% to 14.3 c€/kWh.
- In the household segment, the Netherlands (47.0 c€/kWh) was assessed to have the highest electricity price for large consumers (band DD), followed by Spain (45.4 c€/kWh), and Belgium (40.0 c€/kWh) in the third place. The lowest prices for big households were calculated for Hungary (9.9 c€/kWh) Slovenia (10.2 c€/kWh) and Bulgaria (10.9 c€/kWh). Compared to March 2021, the average assessed EU retail electricity price for the DD band rose by 32% to 26.7 c€/kWh. In the case of small households, Spain saw the highest prices (59.3 c€/kWh), followed by Denmark (48.4 c€/kWh) and Italy (47.6 c€/kWh), while Hungary (10.2 c€/kWh), Bulgaria (11.0 c€/kWh) and the Netherlands (13.6 c€/kWh) were on the other side of the price spectrum. Compared to March 2021, the average assessed EU retail electricity price for the DB band rose by 30% to 32.7 c€/kWh.

Figure 49 – Industrial electricity prices, March 2022 – without VAT and recoverable taxes



Source: Eurostat, DG ENER.

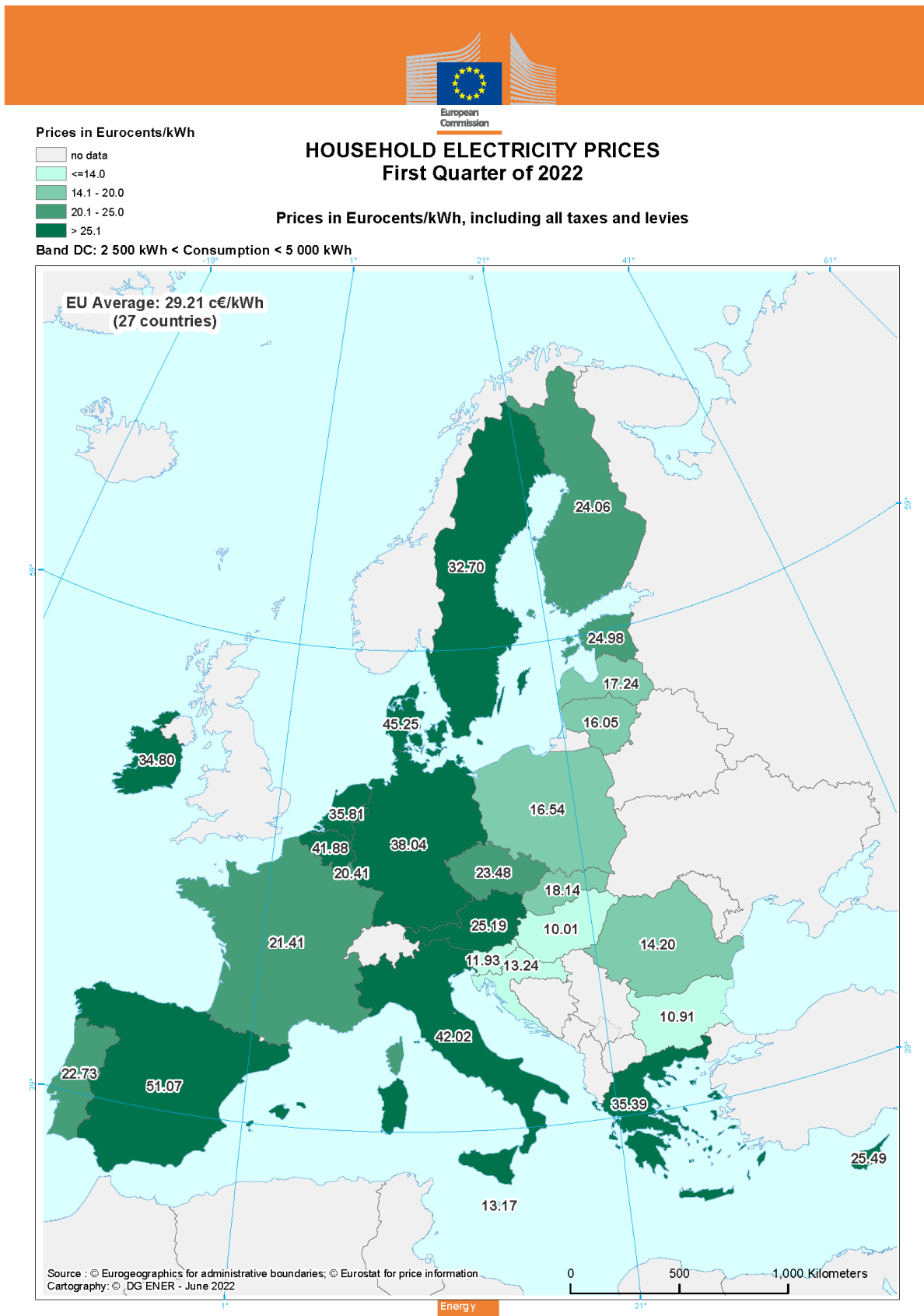
Figure 50 – Household electricity prices, March 2022 – all taxes included



Source: Eurostat, DG ENER

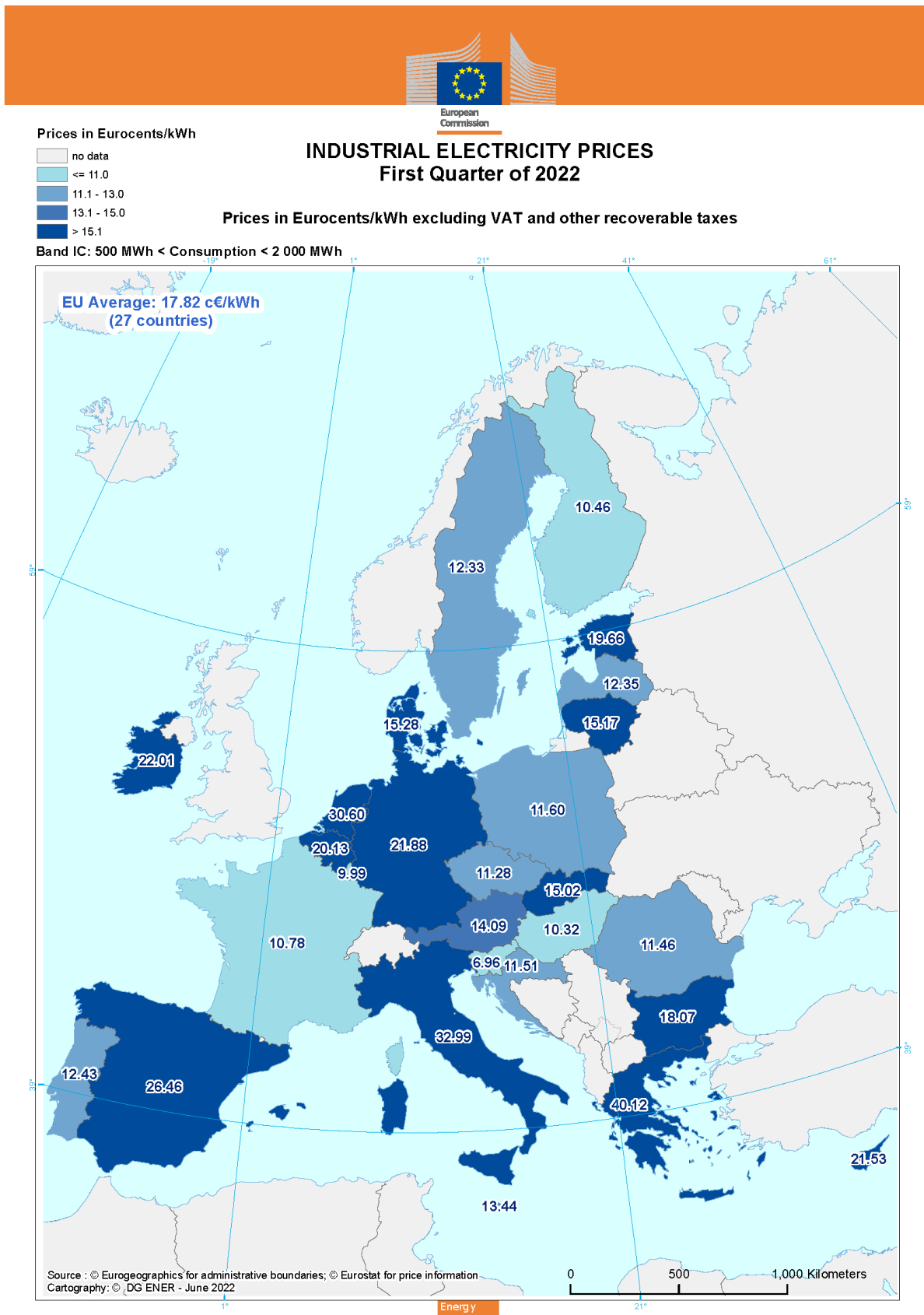
- Figures 51 and 52** display the estimated electricity prices paid by EU households and industrial customers with a medium level of annual electricity consumption in the first quarter of 2022. In the case of household prices, Spain topped the list (51.1 c€/kWh), followed by Denmark (45.3 c€/kWh) and Italy (42.0 c€/kWh). As was the case in previous quarters, Hungary (10.0 c€/kWh) and Bulgaria (10.9 c€/kWh) retained their position as Member States with the cheapest household electricity prices. The EU average increased by 32% to 29.2 c€/kWh in the reference quarter compared to March 2021. The largest year-on-year increases in the household category were assessed in the Netherlands (+174%), Spain (+120%) and Greece (+111%). The biggest year-on-year falls were estimated for Slovenia (-28%), and Romania (-7%). See **Figure 53** for more details on household prices in EU capitals.
- In the case of mid-sized industrial consumers, Slovenia was assessed to have the most competitive price in Q1 2022 (7.0 c€/kWh), followed by Luxembourg (10.0 c€/kWh), and with Hungary (10.3 c€/kWh) taking the third place. Meanwhile, Greece (40.1 c€/kWh), Italy (33.0 c€/kWh) and the Netherlands (30.6 c€/kWh) stood at the other end of the spectrum. At 17.8 c€/kWh, the average retail price for industrial customers in the EU in the reference period rose by 37% compared to March 2021. Greece (+242%), the Netherlands (+166%) and Spain (+147%) marked the largest year-on-year increases in the industrial consumer category. Slovenia and Sweden reduced prices by 24% and 2% respectively.

Figure 51 – Household Electricity Prices, first quarter of 2022



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

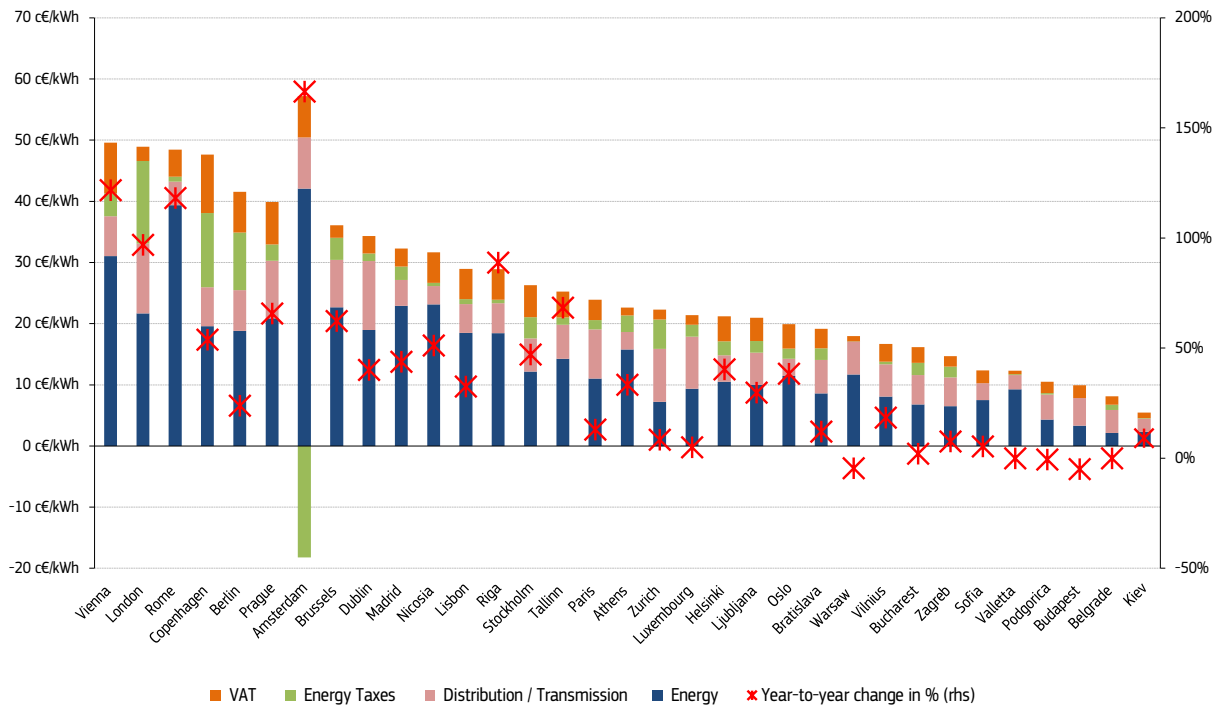
Figure 52 – Industrial Electricity Prices, first quarter of 2022



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

- **Figure 53** 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). Retail electricity prices for household costumers in EU capital cities were up by 44% in May 2022, compared to the same month in 2021. The highest prices were observed in Vienna, London and Rome (49.6, 48.9 and 48.4 c€/kWh, respectively). Following the increase in wholesale energy prices, in the vast majority of EU capitals, the energy component share increased. It now surpasses the share of 50% of the total retail price in 16 EU capitals out of 27, up from 8 out of 27 in Q1 2021. The energy component share is highest in Rome (81%) and Valletta (75%). Amsterdam represents a special case as explained below. The lowest prices among EU capitals were recorded in Budapest (9.9 c€/kWh), Valletta and Sofia (12.3 c€/kWh). EU-wide, retail prices have been rising since the end of 2020 and have started a steep climb since September 2021 which is still continuing. Inflation pressures have intensified throughout the year, due to rising wholesale prices, which have been driven largely due to high gas prices and energy commodities in general.
- The highest levels of the energy component in Europe were reported from Amsterdam, Rome, and Vienna (42.1, 39.4 and 31.1 c€/kWh). The lowest levels of the energy component (2-4 c€/kWh) were recorded in the capitals of countries with stronger forms of price regulation (Belgrade, Kiev and Budapest). The EU average for the energy component was 16.3 c€/kWh (up from 7.7 c€/kWh in May 2021). Out of the 27 EU capitals, twelve had a more expensive energy component than the EU average.
- The highest network charges were recorded in London (11.4 c€/kWh), Dublin and Prague (11.3 c€/kWh and 9.4 c€/kWh, respectively) where they accounted between 23%-33% of the total price. The lowest network fees were collected in Kiev (2.2 c€/kWh), Valletta (2.4 c€/kWh) and Sofia (2.8 c€/kWh). The EU average in the reference quarter was 5.6 c€/kWh (same as in May 2021).
- Apart from London (13.5 c€/kWh), the highest energy taxes were paid by households in Copenhagen (12.1 c€/kWh) and Berlin (9.4 c€/kWh). Sofia, Budapest and Warsaw stood at the other end of the range, with zero energy taxes collected by local authorities. The average energy tax component reached 1.5 c€/kWh (down from 2.7 c€/kWh in May 2021). Varied VAT rates applied to electricity, ranging from 5% in Valletta, Warsaw and London to 21-20% in Budapest, Copenhagen and Stockholm, also contribute to differences in household prices across Europe. Member States have already been using the measures included in the [Energy Prices Toolbox](#) to alleviate the effects of rising energy prices, in the form of lower energy taxes, levies and VAT applicable to household customers of energy.
- The tax reduction subcomponent (tax credit) that applies to electricity customers in the Netherlands is currently higher than the annual energy tax amount that corresponds to a typical residential customer in Amsterdam. Even in cases when the tax credit is higher than the tax amount, the customers still receive the full credit as a discount from their overall annual bill. In practice, this has resulted in a negative value of the Dutch tax component in the price breakdown. This development has also significantly reduced household electricity prices countrywide, which is visible in **Figure 50**, and contributed to the unusual effect in which the lower the consumption, the lower the price per kWh.

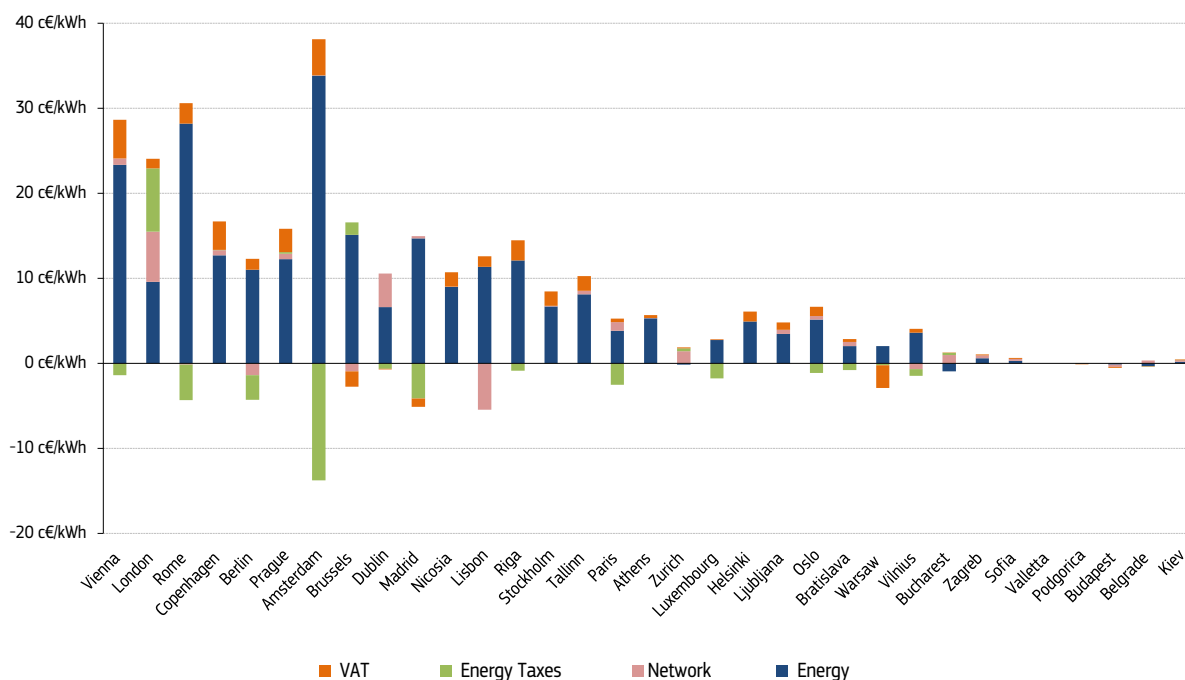
Figure 53 – The Household Energy Price Index (HEPI) in European capital cities in Eurocents per kWh, May 2022



Source: Vaasaett

- Compared to the same month of the previous year, the largest price increase in relative terms in Europe in February 2022 were observed in Amsterdam (+167%), Vienna (+122%) and Rome (118%). As shown in **Figure 54**, rising prices were driven by increasing wholesale prices in the Netherlands, Austria and Italy. In fact, the rise of wholesale prices was the most important factor for the variation of end user prices in 23 of the 27 EU capitals (Warsaw, Bucharest, Valletta and Budapest being the exceptions). 3 of the 27 EU capitals reported prices lower or unchanged, compared to the same month of the previous year, with Warsaw and Budapest (-5%) posting the largest relative drops. Households in the Polish capital benefited mainly from lower VAT components, while those in Budapest were mostly benefitting from lower network and energy components.

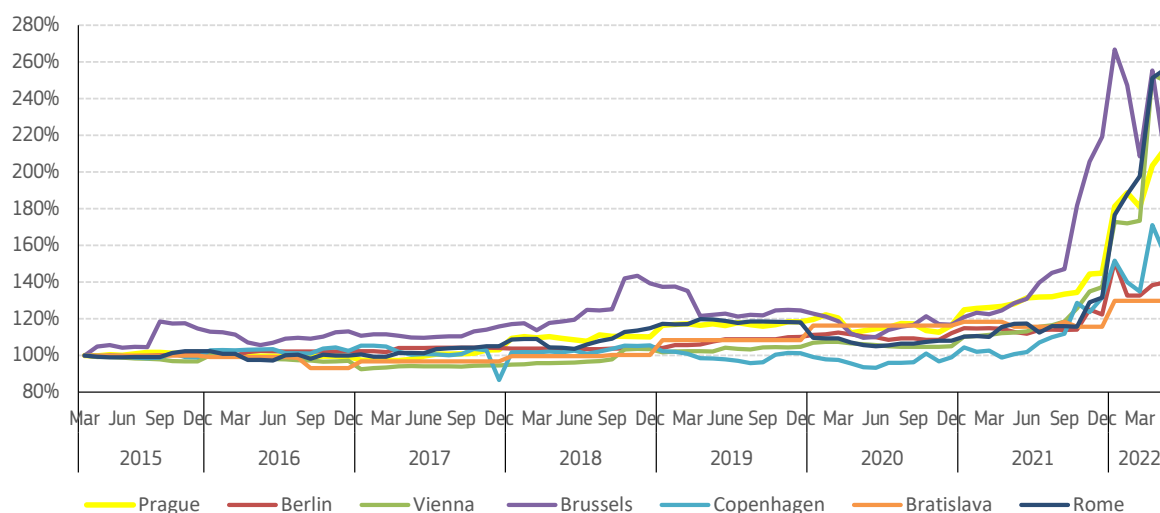
Figure 54 – Year-on-year change in electricity prices by cost components in the European capital cities comparing May 2022 with May 2021



Source: Vaasaett

- Figure 55 compares how household retail prices in selected EU capitals changed in relative terms over the last seven years. The biggest increase in May 2022 (+156%) was registered in Rome and was driven mainly by a rising energy component. Vienna followed closely with a 150% increase since February 2015, followed by Prague (+113%) and Brussels (+109%). Retail prices for households in Copenhagen, which have been roughly the same as until the second half of 2021, have recently seen an increase (+55% compared to February 2015) due to a rise in the energy component. Bratislava and Berlin mark the smallest increases (30% and 40% respectively)

Figure 55 – Relative changes in retail electricity prices in selected EU capitals since 2015



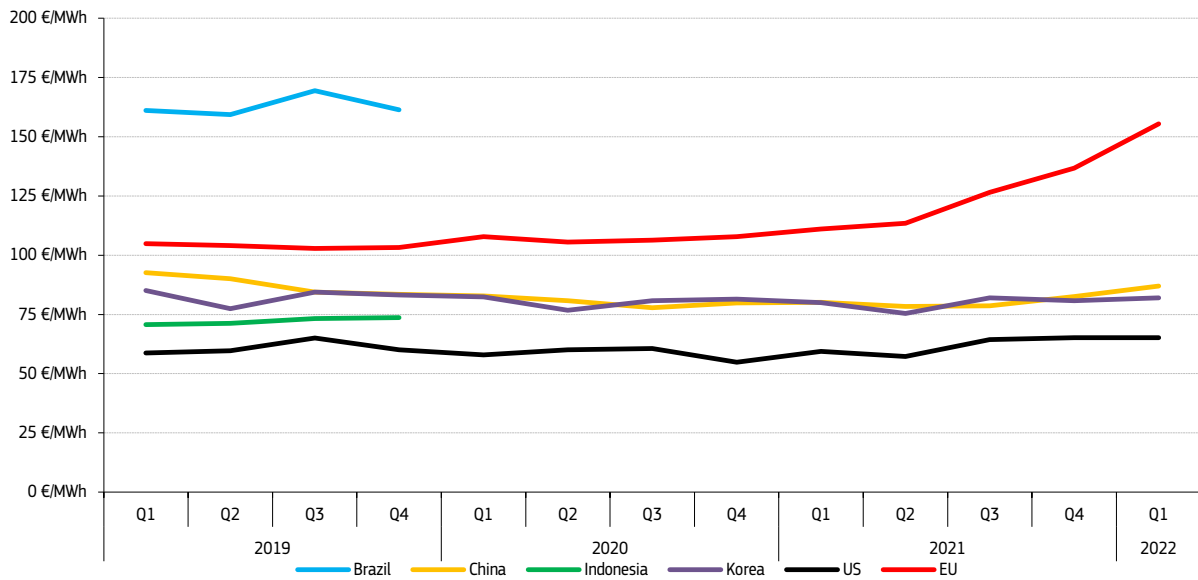
Source: Vaasaett

4.2 International comparison of retail electricity prices

- **Figure 56** displays industrial retail prices paid by consumers in the EU and in its major trading partners. Prices include VAT (with the exception of US prices) and other recoverable taxes for the purpose of comparability.

- Electricity prices for industrial users in the EU increased by 40% in Q1 2022 compared to the equivalent quarter in 2021 and by 14% compared to Q4 2021. Meanwhile, Chinese industrial prices increased by 8%, continuing to climb after a steady downward trend observed before 2021. Industrial electricity prices in the United States increased by 11% quarter-to-quarter in Q1 2022 but only grew by 2% compared to Q4 2021. As it can be observed, industrial retail electricity prices in the EU were higher compared to many of the global competitors, implying cost disadvantages for energy intensive industries.

Figure 56 – Retail electricity prices paid by industrial customers in the EU and its main trading partners



Source: Eurostat, IEA, CEIC, DG ENER computations. The latest data for Brazil and Indonesia is not available. Industrial prices in the EU are represented by the ID consumption band for the purposes of international comparison.

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.

EP5 is a consumption-weighted baseload benchmark of five most advanced markets offering a 3-year visibility into the future. Markets included in the benchmark are France, Germany, the Netherlands, Spain and Nord Pool. Prices are weighted according to the consumption levels in individual markets. Forward prices are rolled over towards the end of each year, meaning that the year-ahead benchmark in 2021 shows the price for 2022; and the year-ahead curve in 2022, in turn, shows baseload prices for delivery in 2023.

Flow against price differentials (FAPDs): By combining hourly price and flow data, FAPDs are designed to give a measure of the consistency of economic decisions of market participants in the context of close to real time operation of electrical systems.

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

Heating degree days (HDDs) express the severity of a meteorological condition for a given area and in a specific time period. HDDs are defined relative to the outdoor temperature and to what is considered as comfortable room temperature. The colder is the weather, the higher is the number of HDDs. These quantitative indices are designed to reflect the demand for energy needed to heat a building.

Long-term average for HDD and CDD comparisons: In the case of both cooling and heating degree days, actual temperature conditions are expressed as the deviation from the long-term temperature values (average of 1978-2018) in a given period.

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

Relative standard deviation is the ratio of standard deviation (measuring the dispersion within a statistical set of values from the mean) and the mean (statistical average) of the given set of values. It measures in percentage how the data points of the dataset are close to the mean (the higher is the standard deviation, the higher is the dispersion). Relative standard deviation enables to compare the dispersion of values of different magnitudes, as by dividing the standard deviation by the average the impact of absolute values is eliminated, making possible the comparison of different time series on a single chart.

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

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

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