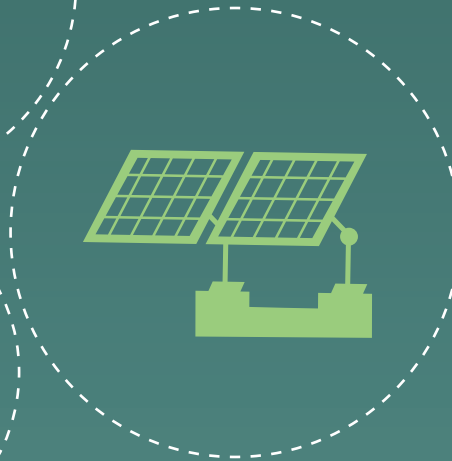




European
Commission

Quarterly report

On European electricity markets



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Energy

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HIGHLIGHTS OF THE REPORT

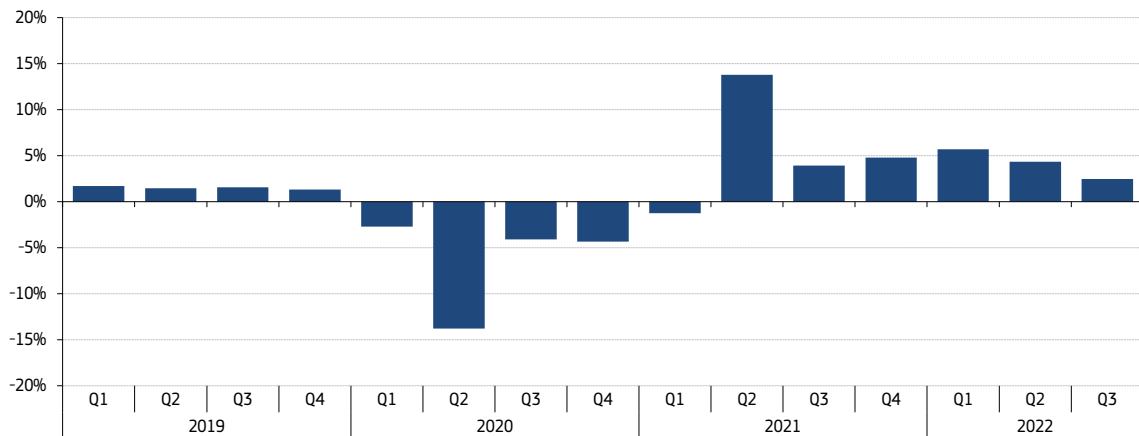
- **The third quarter of 2022 was marked by further reductions and the following total cut in gas supply from the Nord Stream 1 pipeline in early September.** The consequent **high gas prices**, combined with **reduced availability of nuclear power plants** and weak hydroelectric production due to droughts, exerted additional pressure on the already tight wholesale electricity market. **Skyrocketing prices were recorded at the end of August in almost every power market in the European Union.** The market continued reacting to events affecting the price of gas in Europe. The higher-than-usual temperatures that delayed the start of the heating session and the high levels of underground storages supported the fall in the price of gas and, consequently, of electricity in the first months of the following quarter. However, prices have bounced back with the start of the first cold snaps in Europe.
- **High energy commodity prices, especially gas** (marginal fuel setting the wholesale electricity prices in most regions), **supported unprecedented high prices and volatility in Q3 2022.** Low nuclear fleet availability and reduced hydro output, increased the pressure on the already tight market. The largest year-on-year price increases in Member States were registered in France (+342%), Austria (312%), and Slovakia (+310%). Prices in France were influenced by low nuclear generation that led to net imports from other European markets. **The European Power Benchmark was 339 €/MWh on average in Q3 2022**, 222% higher on yearly basis. Prices rose considerably in almost every market in Europe (price changes ranged from 25% to more than 300%). The highest prices during the quarter were recorded in Italy and Malta (472 and 460 €/MWh, respectively) and were 279% and 238% higher than in Q3 2021.
- **Electricity consumption in the EU registered a 2% decrease compared with last year's levels in Q3 2022**, following the impact of high electricity prices and the subsequent industrial demand reduction, despite the increase of economic activity. Electricity consumption levels for the third quarter of 2022 were below the 2017-2019 range, recording the lowest value in September (lower than in September 2020).
- **The share of renewables increased to 39% during the third quarter of 2022.** Renewable generation rose by 1% (+3 TWh) year-on-year. On yearly basis, solar generation rose by 28% (+16 TWh), onshore wind by 7% (+4 TWh) and biomass by 2% (+0.5 TWh) offsetting a bad quarter in hydro generation, which fell by 21% (-17 TWh). Nuclear generation remained under pressure for another quarter due to outages and scheduled maintenance in France, decreasing its output by 24% (-41 TWh) in Q3 2022.
- **Reduced nuclear and hydro generation resulted in fossil fuel generation to increase by 11% (+24 TWh) year-on-year in Q3 2022**, despite high energy commodity prices. Coal and lignite saw its generation increase in many Member States during Q3 2022. In total, coal-fired generation rose by 8% (+8 TWh), whereas less CO₂-intensive gas generation still managed to grow by 14% (+15 TWh). Based on preliminary estimates, the Q3 2022 carbon footprint of the EU power sector rose by 10% compared to Q3 2021, due to larger use of fossil fuels.
- **Carbon prices registered high volatility during Q3 2022**, hovering around 70-90 €/tCO₂, and reaching a new all-time high of 97 €/tCO₂ on 19 August. Carbon prices were driven up by greater coal-fired generation (pushed by high gas prices) despite low industrial demand (also due to high energy prices). The interaction between these factors has contributed to the decoupling between EU ETS and TTF price observed in previous quarters. The average spot price of CO₂ in Q3 2022 (80 €/tCO₂) registered an increase of 16% compared with Q3 2021.
- **Temporary emergency intervention policy measures were adopted to tackle high electricity prices**, including electricity demand reduction measures and revenue cap on inframarginal electricity producers. Revenues above the cap will be collected by MS governments to help energy consumers with their energy bills.
- **Electricity traded volumes on the European markets fell by 41% (-3242 TWh) in Q3 2022 year on year**, reflecting the magnitude of the downward trend of trading in the electricity sector. Activity dropped significantly in OTC contracts (-43%) and decreased widely at exchanges (-35%). Decreased trading liquidity has been attributed to the situation of high prices and increased volatility in the energy market.
- **Retail electricity prices for household costumers in EU capital cities were up by 49% in November 2022**, compared with the same month in 2021. Highest increases in EU Member States prices were registered in Italy (+64%), Belgium (+59%) and Germany (+58%). The energy component share surpasses 50% of the total retail price in twenty-two EU capitals, up from thirteen in November 2021. Retail electricity prices for mid-sized industrial consumers were also estimated to increase at 43% higher year-on-year in Q3 2022. Industrial retail electricity prices in the EU were higher compared to many trading partners, implying cost disadvantages, especially for energy intensive industries.
- Demand for electrically charged vehicles (ECV) positioned Q3 2022 as the fourth highest quarterly figure on record. **More than 443,000 new ECVs were registered in the EU in Q3 2022**, an increase of 8% in comparison with same quarter in 2021. EU proposals linked to Green Deal initiatives and national policies continue to support the adoption of ECVs in Europe. Q3 2022 numbers translated into a 20% of market share, more than two times higher than in the United States, but still lower than in China.

1 Electricity market fundamentals

1.1 Demand side factors

- **Figure 1** shows the GDP annual growth in the European Union. According to the December 2022 Eurostat estimate, seasonally adjusted GDP increased by 2.5% year-on-year in the EU between July and September 2022 (after +4.3% in the EU in Q2 2022). The economic recovery registered in the first half of 2022 has slowed down in Q3 2022, amid high energy pressure and elevated inflation (10.9% of EU annual inflation in September 2022). Moreover, as high electricity prices prompted the decreased use of electricity in energy-intensive sectors, the increase in economic activity did not really translate in higher electricity consumption in the EU. Compared with Q3 2021, annual growth registered positive figures in 25 of 27 Member States. The highest annual rates were reported in Ireland (+10.6%), followed by Croatia (+5.5%) and Cyprus (+5.4%). The highest year-on-year decreases were observed in Estonia (-2.3%) and Latvia (-0.4%).

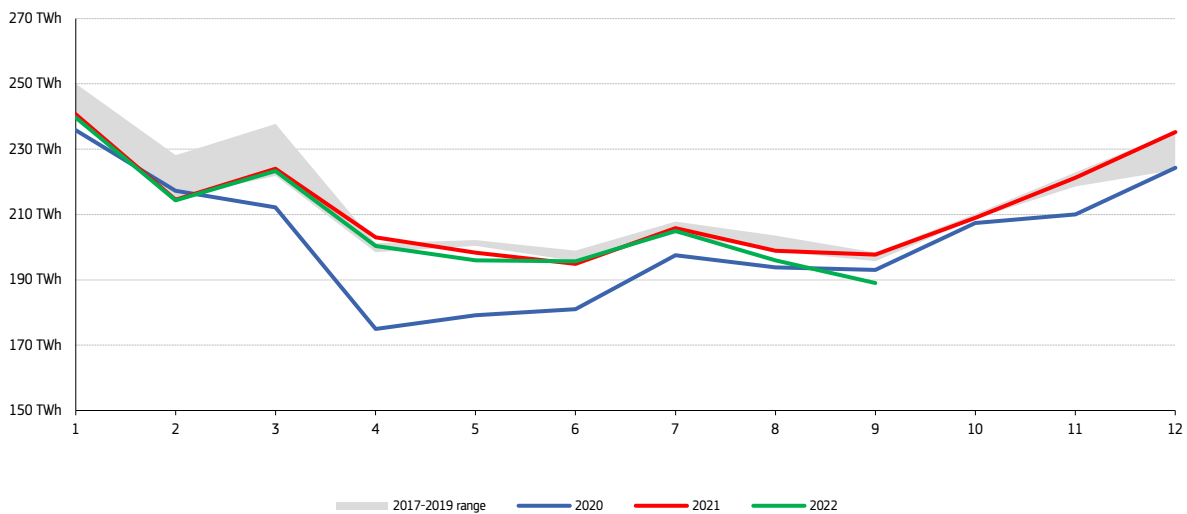
Figure 1 – EU GDP annual change (%)



Source: Eurostat

- According to Eurostat, the electricity consumption in the EU fell 2.2% compared with last year's levels in Q3 2022, following the impact of high electricity prices and the subsequent industrial demand reduction. Demand levels for the third quarter of 2022 were below the 2017-2019 range, registering the lowest value in September (even lower than September 2020) and the highest in July (within the 2017-2019 range).

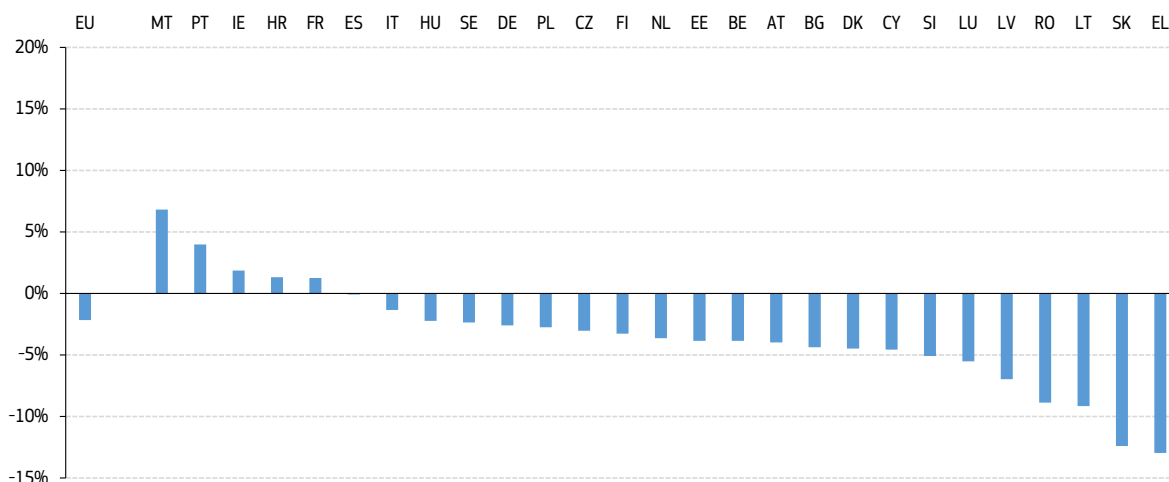
Figure 2 – Monthly EU electricity consumption



Source: Eurostat

- Figure 3** sums up changes in electricity consumption over the third quarter of 2022, compared to Q3 2021. EU average hides wide differences of developments in individual Member States during the reference quarter. Only five Member States saw an increase in consumption year-on-year, registering relevant grows in Malta (+7%) and Portugal (+4%). In addition, twenty-two Member States registered a drop in consumption, led by Greece (-13%), Slovakia (-12%), Lithuania and Romania (-9%). Of the major economies, power consumption went up slightly in France (+1%), while decreases were registered in the Netherlands (-4%) and Germany (-3%). Overall, large industrial consumers, responsible for the biggest portion of the demand, are already struggling with high energy prices, resulting in a decrease of the consumption.

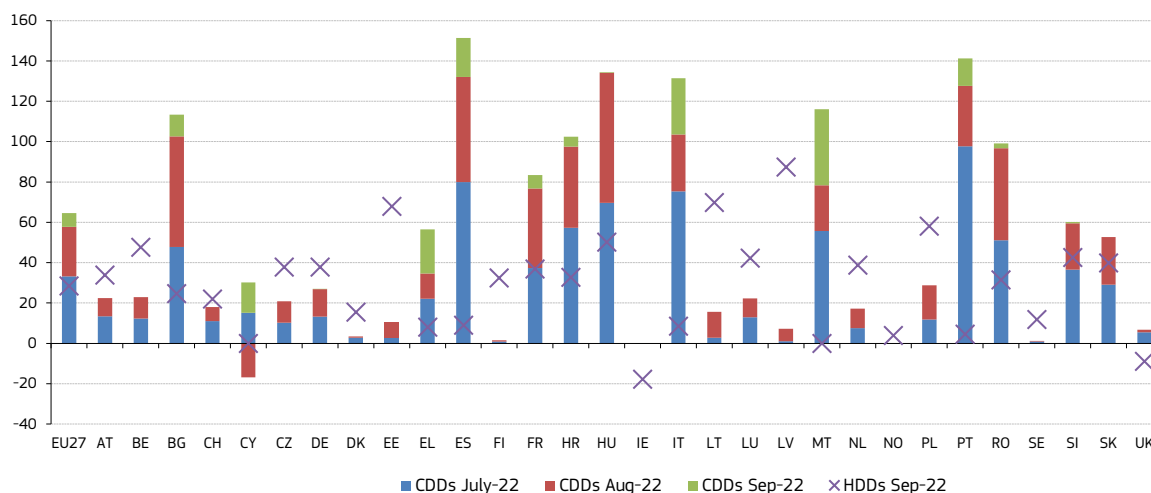
Figure 3 – Annual changes in electricity consumption in Q3 2021 and Q3 2022 by Member State



Source: Eurostat

- Figure 4** illustrates the monthly deviation of actual Cold Degree Days (CDDs) and Heating Degree Days (HDDs) from the long-term average (a period between 1979 and the last calendar year completed) in Q3 2022. EU-wide, the reference quarter was slightly warmer than the historical range, registering 65 CDDs above the long-term average (concentrated mainly in July) and 29 HDDs in September. In general, temperatures during Q3 2022 were higher than usual, mainly due to warmer weather in July and August. Some Mediterranean countries experienced hot temperatures in July and August (Portugal, Spain, Italy, Croatia and Malta), while warm temperatures were also observed in some countries from Central and South-Eastern Europe (Hungary, Bulgaria and Romania). Higher temperatures imply additional cooling needs, having a potential impact on gas-fired generation due to increased electricity demand. Conversely, HDDs were higher in some Nordic countries during September. Overall, July and August were warmer than the historical average, while September registered slightly colder-than-usual temperatures.

Figure 4 - Deviation of actual heating days from the long-term average in July-September 2022



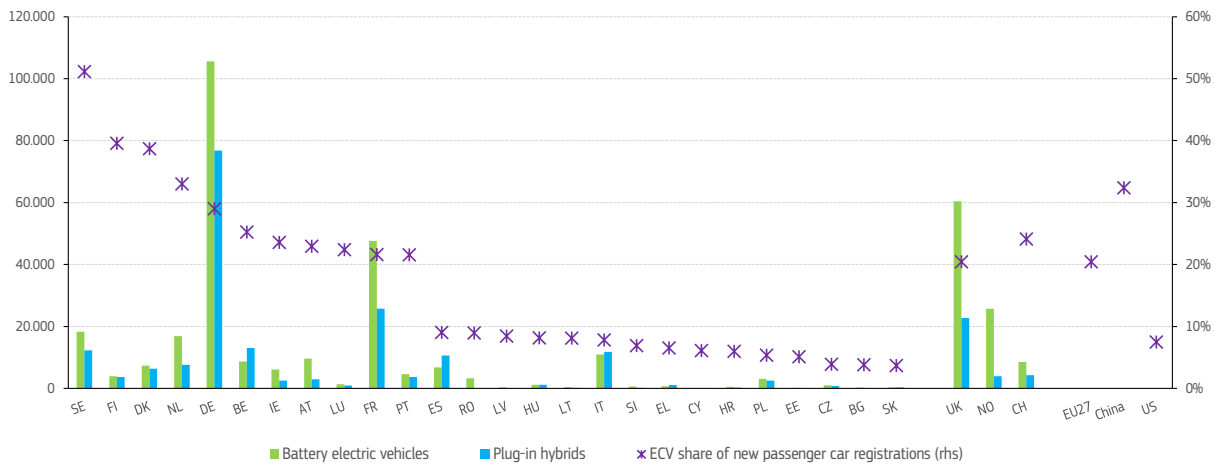
Source: JRC. The colder the weather, the higher the number of HDDs. The hotter the weather, the higher the number of CDDs

- Figure 5** shows that more than 443,000 new ECVs were registered in the EU in Q3 2022 (+1% compared with Q2 2022 and +8% year-on-year). This is the fourth highest quarterly figure on record (after sales in Q4 2021, Q2 2021

and Q4 2020) and translates into a 20% market share; lower than China (32%), but higher than in the United States (8%). The battery electric vehicles segment continued to grow (+22% year-on-year close to 260,000) while demand for plug-in hybrid vehicles decreased for another consecutive quarter (-7% year-on-year to almost 184,000). Hybrid electric vehicles (not chargeable) sales amounted to 492,000, higher but not far from the ECV category. EU proposals linked to Green Deal initiatives and national policies continue to support the adoption of ECVs in Europe.

- The highest ECV penetration was observed in Sweden for another consecutive quarter, where more than half (51%) 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. From January 2023, new CO2 limits for the climate bonus will take place, increasing the emissions requirement to opt for this bonus. In addition, almost 40% of the Q3 2022 car sales in the Finland and Denmark were ECVs, followed by the Netherlands (33%). Germany retained the position of the largest individual market (more than 182,000 ECV sales in Q3 2022) thanks to its generous incentive programme, which since 2020 and until the end of 2022, offered up to €9,000 in direct purchase bonuses. After Germany, numbers in ECVs were also supported by France, where sales amounted to more than 73,000 new ECVs in the reference quarter.

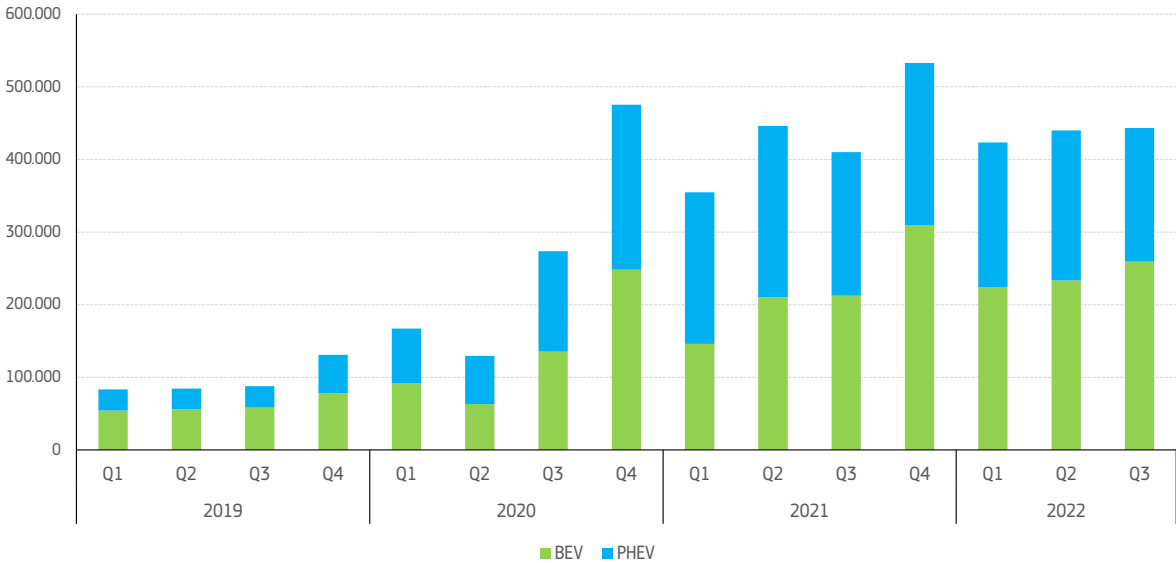
Figure 5 – Electrically chargeable passenger vehicle (ECV) sales in selected countries in Q3 2022



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, and the economic recovery in activity following the pandemic peak, have contributed to the increase in ECV numbers. 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. In addition, the increase in demand and further constraints in the supply chain of batteries risk slowing the rollout of ECVs in the near future.

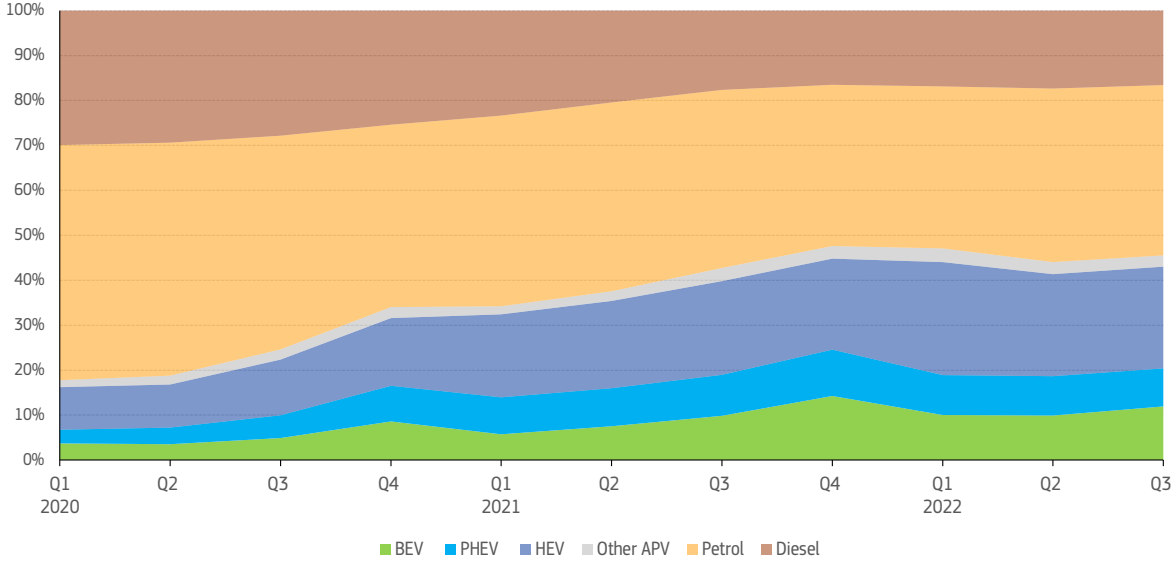
Figure 6 – Quarterly ECV sales in the EU



Source: ACEA

- Figure 7** shows the decline of sales of diesel cars, which saw their market share fall to 17% in Q3 2022, from 18% in Q3 2021. Petrol car sales experienced a fall in their share to 38% in Q3 2022, from 40% in the third quarter of the previous year. On the other hand, the share of new Hybrid electric vehicles (HEV) in the market increased from 21% in Q3 2021, to 23% in Q3 2022. The share of new ECVs has also risen year-on-year (from 19% in Q3 2021 to 20% in Q3 2022).

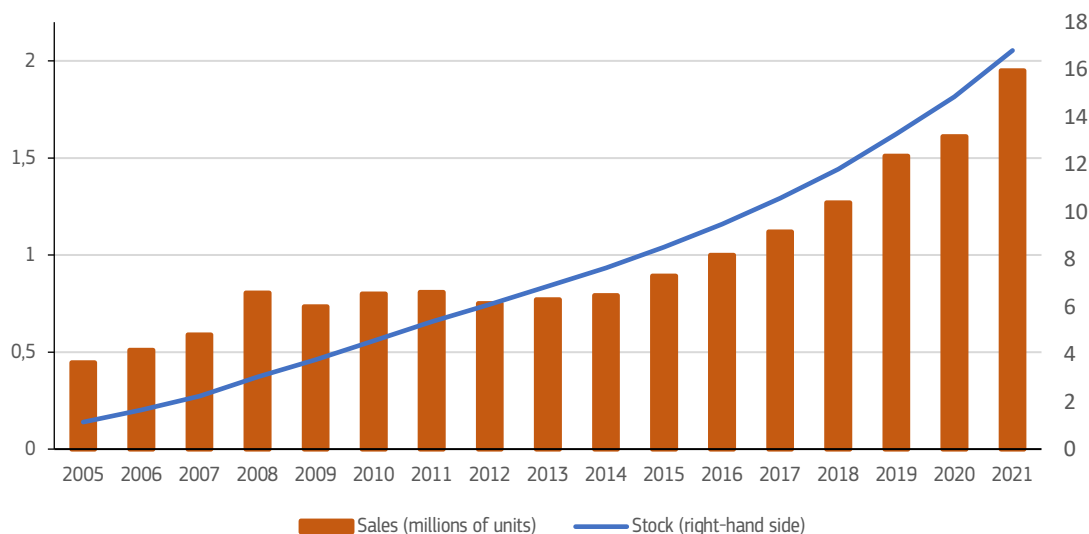
Figure 7 – Evolution of quarterly drivetrain shares in the EU



Source: ACEA

- Figure 8** shows the evolution of Heat Pumps sales across Europe reported by Joint Research Centre (JRC) in its [Heat Pumps in the European Union 2022 report](#). Heat pumps are commonly used for heating, hot water and even in some cases, for cooling. Heat pumps enable the use of renewables (ambient heat) in the heating sector and are more efficient than boilers. In addition, REPowerEU plans to double the annual pace of deployment, mainly replacing gas boilers in an additional 10 million buildings over the next five years, and 30 million by 2030.
- In total, the current heat pump stock amounted to 16.8 million in Europe, by the end of 2021. Annual sales grew around 34% in 2021 (close to 2 million new heat pumps).

Figure 8 – Yearly Heat Pump sales in Europe



Source: JRC based on EHPA data

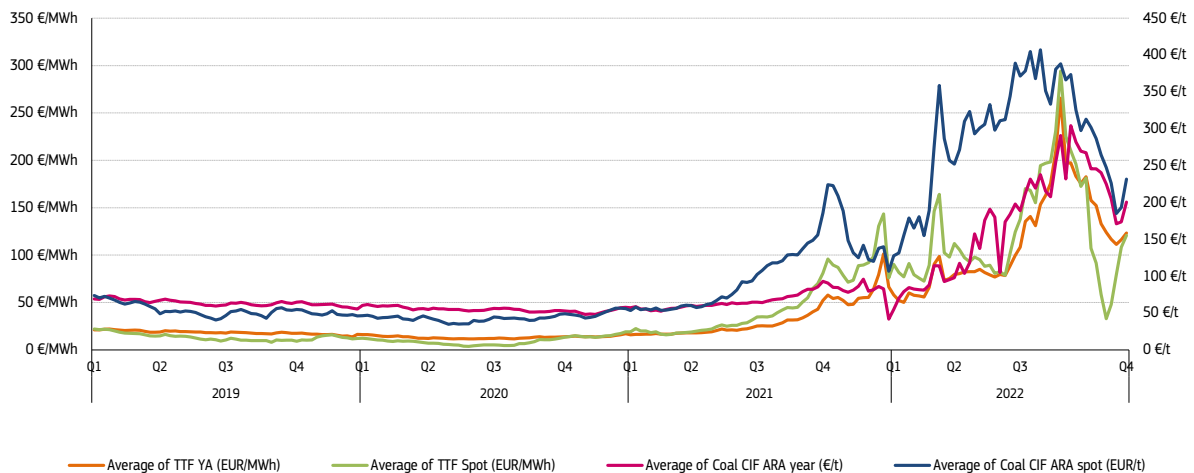
1.2 Supply side factors

- Figure 9** reports on developments in European coal and gas prices. In Q3 2022, prices of gas and coal skyrocketed to new record highs. Both markets remained subject to volatility in the spot market, way above their year-ahead peers. The Russian invasion in Ukraine and related international sanctions (including reluctance from companies to purchase Russian fossil fuels) affected already tight energy markets resulting in substantial increases in prices, volatility and uncertainty on energy supply.
- The worsening of the geopolitical picture has had a direct impact on the gas market. The drop in Russian pipeline gas deliveries to Europe and potential woes of gas deficit during the winter heavily impacted the market. Moreover, other international developments such as a fire at an important LNG facility in the US and disruptions in Norwegian flows (due to strikes and field maintenance) contributed to put upward pressure on top of the situation with Russian gas flow. The announcement of the cut-off of Nord Stream flows (not operational since end of August) by Gazprom had a substantial impact on gas prices at the TTF. Summer heat waves increased the hours of operation of gas-fired generation to offset reduced nuclear and hydro generation. However, prices fell in the following months thanks to favourable fundamentals: underground storages being at high levels in most Member States, continued deliveries of LNG at prices lower than TTF and reduced demand in line with policy action, supported by warmer-than average temperatures during the Autumn and demand destruction.
- The Commission adopted a legislation setting [minimum EU gas storage obligations](#) (80% of capacity filled by 1 November 2022) and [gas demand reduction targets](#) (15% compared with the average winter gas consumption of the previous 5 years) to ensure supply for the coming winter. In October, the Commission proposed [new emergency regulation](#) to address high gas prices strengthen security of supply of gas via joint purchasing, default solidarity, a new pricing reference benchmark for LNG, and a temporary collar to prevent extreme spikes in derivative markets. It also proposed a [Market Correction Mechanism](#) to protect consumers from episodes of excessively high gas prices. Gas storage levels were at 88% of total EU capacity at the end of Q3 2022, at a higher level than in 2021, meeting in most of the Member States the 80% target ahead of the initial deadline of 1 November.
- Spot gas prices averaged 199 €/MWh in Q3 2022, reaching a new record high. Prices increased by 103% compared with the previous quarter (Q2 2022) and amounted for a 310% increase compared with Q3 2021, signalling the unprecedented level of tightness of the market. On 26 August, gas prices closed at 316 €/MWh reflecting the risk of additional Russian supply cuts (Nord Stream 1), growing competition with Asia for seaborne cargoes of LNG, announcements of maintenance of Norwegian gas assets, high demand for cooling due to high temperatures, on top of the overall tight supply situation. Gazprom halted all Nord Stream 1 pipeline flows since the end of August. On 27 September, prices increased by 10-15% compared to the previous day following pipeline sabotages reported

on both Nord Stream 1 and Nord Stream 2 pipeline, compromising any potential future deliveries, and turning Russian gas a marginal supply in the western European markets. Forward prices registered a contango during the first part of Q4 2022, corrected with the delayed start of the heating season translating into higher gas demand and storage withdrawals. Nevertheless, EU storages reached a peak of 95% during the second week of November.

- The evolution of gas prices in Q3 2022 continued to support the gas-to-coal switching observed in the previous quarters, boosting coal generation gains despite rising coal and relatively 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 record high in Q3 2022 (362 €/t). Prices rose by 13% compared with the previous quarter (Q2 2022) and amounted for a 174% growth compared with Q3 2021. Coal price registered new record highs at the end of July (425 €/t on 28 July) and August (418 €/t on 22 August) due to the strong demand in European and Asian markets, and supply constraints in the global market.
- In April, 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. As a result of sanctions, imports of coal from Russia halted since 10 August, although suppliers were already looking for alternative sources to replace Russian coal in the previous months. Some Member States are allowing the use of more coal for producing electricity to replace Russian gas used for power generation. The German government approved the return of five lignite-fired plants (1.9 GW of combined capacity) from October to June 2023. Moreover, hard-coal plants in the reserve will be enabled to return to the market until end of March 2024. In total Germany plans to reopen 6.7 GW of hard coal capacity. Similarly, Italy has revived 2.3 GW of coal capacity. Likewise, the Dutch government lifted on 20 June the production restrictions for coal-fired generation, as part of the country's gas crisis plan.
- Coal prices registered a fall in the following months (Q4) despite tight energy market, supported by increased levels of imports in line with the supply diversification efforts, as well as the improvement of local coal production in some Member States (e.g. Poland) and near-full underground gas storages which supported lower gas prices in the EU.

Figure 9 – 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 10**, registered high levels of price volatility in Q3 2022 driven by two main forces: on one hand an upward pressure from greater coal-fired generation which increases demand for emission allowances, and on the other hand, a downward pressure from industrial demand destruction due to high energy prices. Carbon prices hovered around 70-85 €/tCO₂ during Q3 2022. They reached a new all-time high at 97 €/tCO₂ on 19 August, as high temperatures and drought led to rising cooling demand, increasing in fossil fuel generation to offset the subdued hydro and nuclear output. Elevated gas prices have contributed to rise carbon prices as they lead to an increased use of coal for power generation and consequently higher demand for emission allowances. However, as mentioned earlier, the curbed levels of industrial demand due to high energy prices represent less demand for allowances, and therefore, are putting downward pressure on carbon prices. The interaction between these factors has contributed to the decoupling between EU ETS and TTF price observed in the first part of 2022 and previous quarters in 2021. Prices started to fall in September averaging 70 €/tCO₂, reaching

a low of 65 €/tCO₂ on 28 September. Carbon prices remained highly volatile in the following months, continuing around 67-77 €/tCO₂ in the context of downward factors such as industrial demand destruction, the discussion at the European Union level to sell surplus permits to alleviate the impact of the energy crisis, the announcement in REPowerEU to increase Market Stability Reserve auction volumes and the announcement of the EU demand reduction plan, linked to high prices and recession woes. On the upward side, high gas prices and cold weather in the last part of the year are pushing for higher coal consumption leading to higher demand for EU ETS allowances.

- The average spot price of CO₂ in Q3 2022 (80 €/tCO₂) registered an increase of 16% compared with Q3 2021, recording a 4% in relation to the previous quarter (Q2 2022). Under the current situation of exceptionally high gas prices, the European Union Allowances (EUA) price is not high enough to support coal-to-gas fuel switching in power generation (see **Figure 21**). In recent years (2020) high carbon prices put coal and lignite power plants at a greater disadvantage against their less polluting gas-fired competitors.

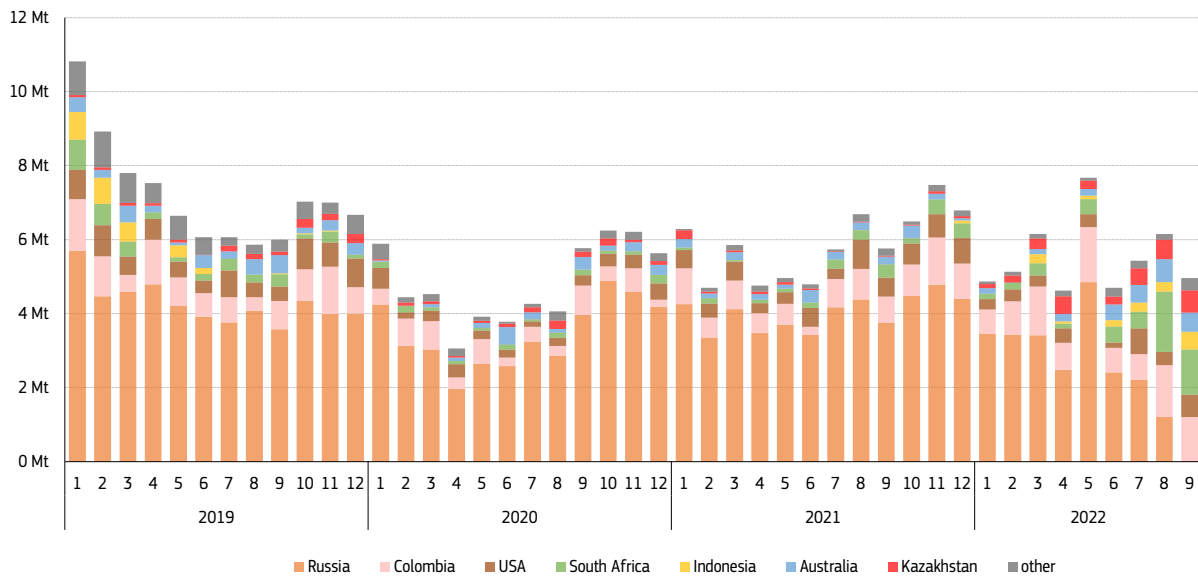
Figure 10 – Evolution of emission allowance spot prices from 2019



Source: S&P Global Platts

- As visible from **Figure 11**, monthly average thermal coal imports into the EU held at roughly 5.5 Mt in Q3 2022. The total volume of imports fell by 9% year-on-year to 17 Mt in the third quarter of 2022. Imports in September recorded a decrease of 14% year-on-year, on the back of the impacts of the sanctions to Russian. The estimated EU import bill for thermal coal amounted to €5.5 billion in the reference quarter, 167% higher compared to Q3 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 Q3 2022 came from Russia which accounted for 21% of the total, amounting to a 47% decrease compared with Q3 2021. However, coal imports from Russia fell by 99.6% year-on-year in September. The 5th package of sanctions adopted by the EU, in light of the invasion of Russia in Ukraine, 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 exports, amounting to around €8 billion loss of revenue per year for Russia. Events are currently changing the distribution of EU coal imports, as it was too difficult for many international competitors to compete in a low-price/low-demand environment in the past. Consequently, South Africa registered an increase of 15% of deliveries in Q3 2021 (20% of the total imports), while Colombia saw its market share grow to 20% compared to 13% in the third quarter of 2021. The share of deliveries from US ports increased from 8% to 10%, while the share of imports from Kazakhstan and Australia reached 10% each during the reference quarter.

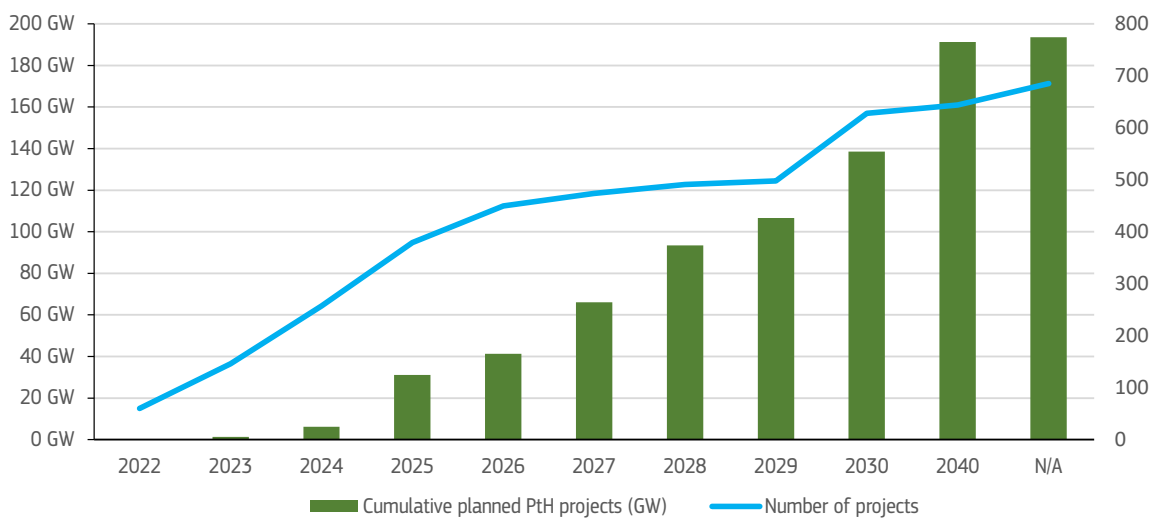
Figure 11 – Extra-EU thermal coal import sources and monthly imported quantities in the EU



Source: Eurostat

- Figure 12** presents the numbers of the total planned capacity of Power-to-Hydrogen (PtH) projects in Europe (including EU27 Member States, EFTA countries and the UK) as reported by Hydrogen Europe in its [Clean Hydrogen Monitor 2022](#). In total, there are 644 PtH planned project by 2040 (191 GW), with an extra of 41 project (2 GW) with an unspecified start date. In terms of mid-term projects, 628 PtH projects are planned with start dates by 2030 (amounting to 138 GW). In the short-term, 60 projects (0.165 GW) are expected to come online by the end of 2022 and an additional number of 146 projects (1.2 GW) by 2023.
- As noted by Hydrogen Europe, the mid-term period up to 2030 is a critical objective for [REPowerEU plan](#) and the [European Hydrogen Strategy](#). The average capacity growth rate tracked between 2022 and 2030 has been reported at 111% per year, which, if achieved, would result in 138 GW of installed electrolysis capacity by 2030. This installed capacity could be enough to meet REPowerEU target to produce ten million tonnes of renewable hydrogen in the EU by 2030.

Figure 12 –Cumulative planned Power-to-Hydrogen projects in Europe (EU27, EFTA countries and the UK)



Source: Hydrogen Europe. Clean Hydrogen Monitor 2022.

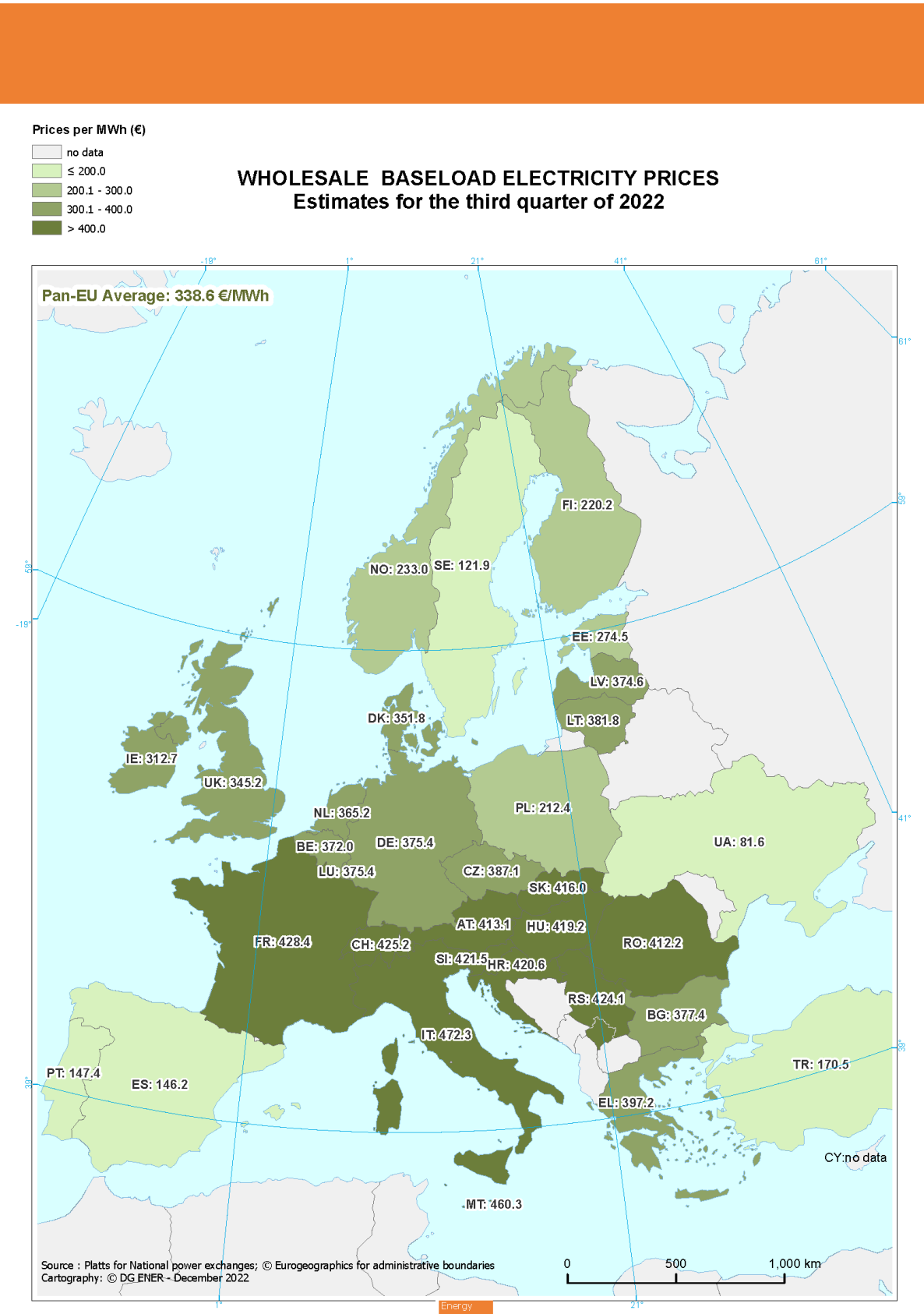
Note: Planned projects considers projects in construction, preparatory stage, under feasibility study or in the concept stage.

2.1 European wholesale electricity markets and their international comparison

- The map on the next page (**Figure 13**) shows average day-ahead wholesale electricity prices across Europe in Q3 2022. Prices reached new unprecedented high levels across Europe, due to the effect of cut-off of pipeline gas flows (Nord Stream 1), the uncertainty of the markets around European security of gas supply and the role of gas prices on wholesale electricity markets (marginal fuel used in the price setting). The Russian invasion in Ukraine and related international sanctions are affecting energy markets resulting in substantial increases in prices, volatility and uncertainty on energy supply. On top of the mentioned factors, the lower availability of the nuclear fleet and the weak hydroelectric power production due to droughts, put additional pressure on wholesale electricity markets. In the following months, the wholesale electricity market has continued reacting to announcements impacting the price of gas in Europe and policy responses from the EU and its Member States in the context of the upcoming winter. The delay in the start of the heating session and the filling of underground storages supported the fall in the price of gas and, consequently, of electricity in the first months of the following quarter. However, prices have bounced back with the start of the first cold snaps in Europe.
- On a yearly basis, practically every wholesale electricity market in Europe experienced a surge in prices (changes ranged from approximately 25% to more than 300%¹). Italy and Malta reported the highest quarterly average price (472 and 460 €/MWh, respectively), 279% and 238% higher than in Q3 2021. France became the third most expensive market with an average baseload price of 428 €/MWh, which was 342% higher compared to the same period last year. Switzerland reported prices of 425 €/MWh, while Slovenia registered quarterly prices of 422 €/MWh.
- The European Power Benchmark averaged 339 €/MWh in Q3 2022, 222% higher on yearly basis. Compared to Q2 2022, the quarterly average price rose by 77%.
- The largest year-on-year price increases in Member States were registered in France (+342%), Austria (312%), and Slovakia (+310%). Prices in France were influenced by the low nuclear output and the reversal of net export power flows in the context of unprecedented high gas prices. Conversely, Portugal and Spain experienced the lowest increase in prices during Q3 2022 (+25%) followed by Sweden (+75%).
- Following the adoption of the [REPowerEU plan](#) to rapidly reduce dependence on Russian fossil fuels and fast-forward the green transition and other measures for gas storage and reduction target, the Commission proposed in September [new emergency market intervention measures](#). The package of measures included exceptional electricity demand reduction action and measures to redistribute the energy sector's surplus revenues to final costumers. As the first response to the crisis should be reducing the demand, the Commission proposed an obligation to reduce electricity consumption by 5% during selected peak hours. The Commission also proposed that Member States should reduce overall electricity demand by at least 10% until end of March 2023. The Commission also proposed a temporary revenue cap on inframarginal electricity producers, at 180 €/MWh. As part of the package, the Commission proposed a temporary solidarity contribution on excess profits generated from activities in the oil, gas, coal and refinery sectors (which are not covered by the inframarginal revenue cap). The proposed measures were [adopted by the Council](#) on 6 October 2022. On 18 October, the Commission proposed [additional measures](#) to address high gas prices and a [new instrument to limit excessive gas price spikes](#) on 22 November. In addition, the [20-21 October European Council](#) invited the Commission to speed up the work on the structural reform of the electricity market. The Commission will propose in early 2023, amongst other initiatives, a reform of the EU electricity market, which includes the effect of gas prices on electricity and adaptation to a decarbonised system.

¹ Three EU MS experienced increases over 300% and nineteen above 200%, compared to Q3 2021.

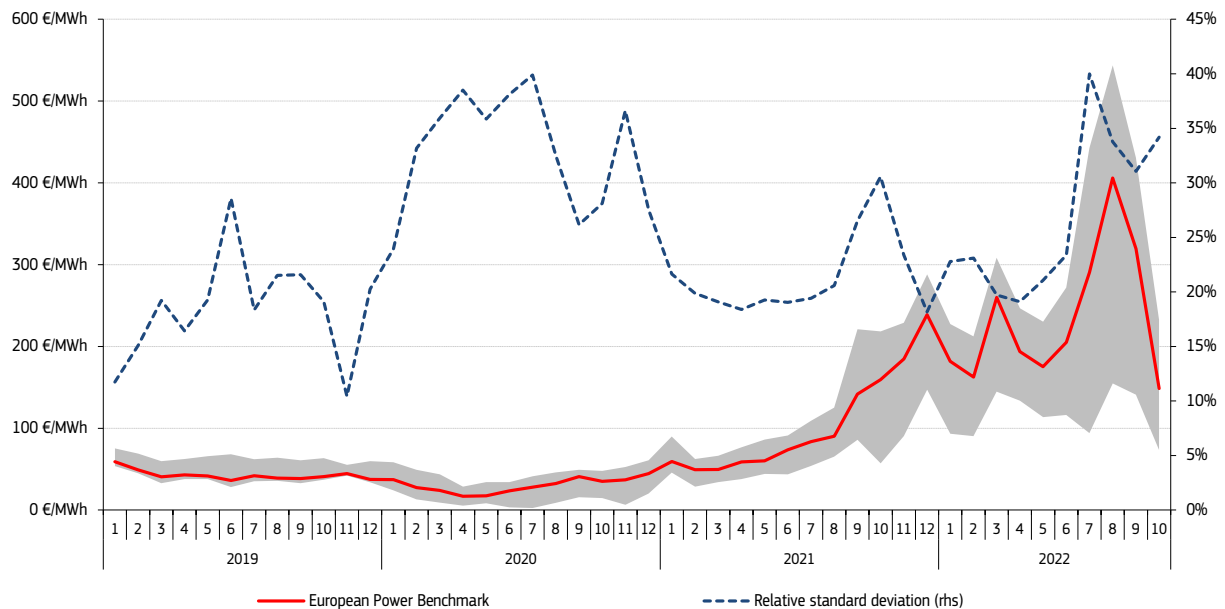
Figure 13 – Comparison of average wholesale baseload electricity prices, third quarter of 2022



Source: European wholesale power exchanges, government agencies and intermediaries

- Figure 14** 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 remain high, despite a short fall registered during Q3 2022, as prices in the regional markets diverged less than in the previous quarter. Q3 2022 was marked by prices reaching new all-time peaks at the end of August, due to further disruptions of Russian gas supplies, increased demand due to record-breaking temperatures, maintenance of power stations (in particular nuclear) and lower output from hydropower generation. Central Western European markets increased their coal-fired generation over gas-fired output. The lower availability of the French nuclear fleet continues to put upward pressure on prices and reversing power flows away from the historical net exporting position of France. The phase-out of coal and nuclear capacity is increasing the sensitivity of power prices to the developments of the gas market. A drought in the Nordic region reduced hydropower output, which combined with the tightness of the continental European markets, resulted in an increase in prices. Soaring gas prices in Italy, combined with tight supply margins, made Italy the most expensive market in Europe (together with Malta). In the autumn, prices fell on the back of annual record-low gas prices (due to oversupplied market with high storage volumes) until prices bounced back on the start of increasing gas prices, reflecting the delayed start of the heating session and intensifying storages withdrawals in mid-November.

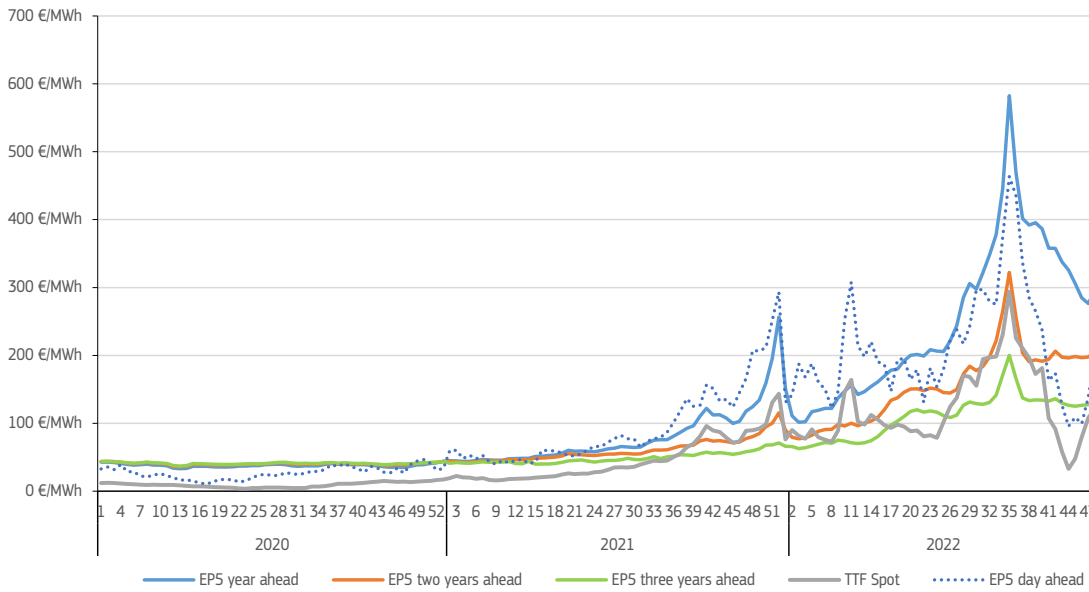
Figure 14 - The evolution of the lowest and the highest regional wholesale electricity prices in the European day-ahead markets and the relative standard deviation of the regional prices



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

- Figure 15**, shows the effect of gas prices (TTF spot price) driving changing expectations of future electricity prices already since the first quarter of 2021. The rally in gas prices that started in 2021, lifted the benchmark above pre-crisis levels and into record highs. TTF spot price started climbing again in summer, reaching a new weekly all-time high of 294 €/MWh during the last week of August. Consequently, the year ahead power benchmark rose to unprecedented prices during the same week in August. Future contracts surged, reaching 727 €/MWh on the year-ahead benchmark during 26 August. During the same day, the year-ahead contract of France skyrocketed to 1130 €/MWh. From that point, year-ahead power benchmark prices started to fall again thanks to an oversupplied gas market with high storage volumes, which lasted until the actual start of the heating session with the first cold snaps of the session.
- During the first week of Q3 2022, the electricity year-ahead, two-year ahead and three-year ahead contracts were respectively 284 €/MWh, 172 €/MWh and 126 €/MWh, whereas during the last week of August, these three values reached weekly record-highs of 582 €/MWh, 322 €/MWh and 200 €/MWh. The significant increase of forward curves in Q3 2022 suggests 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 -150 €/MWh during Q3 2022.

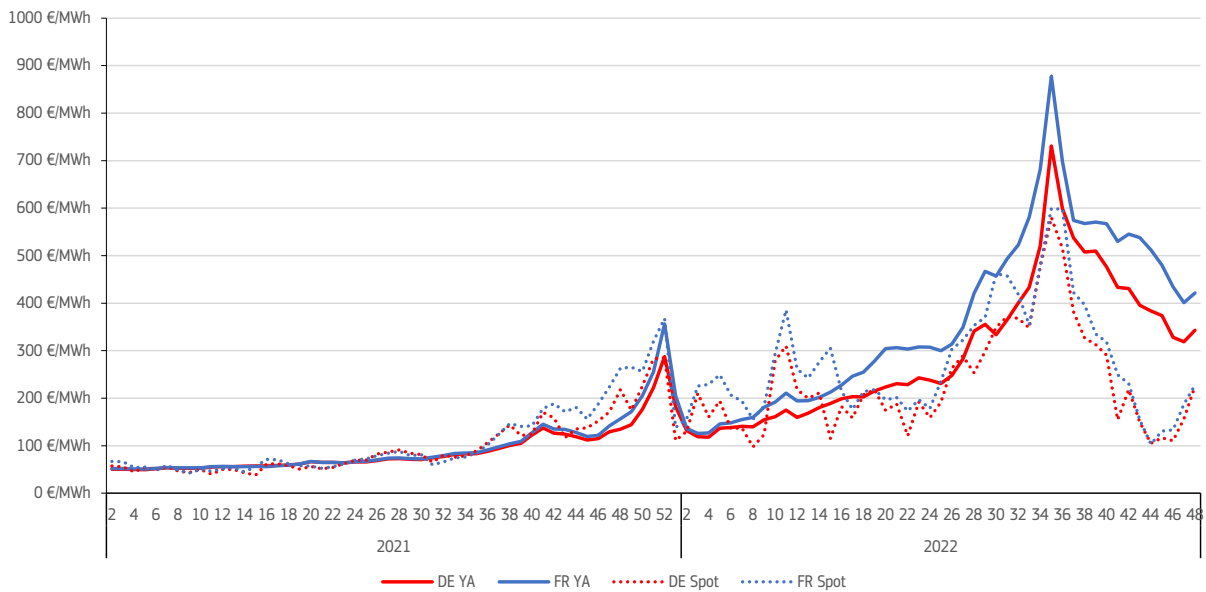
Figure 15 – Weekly futures baseload prices – weighted average of selected European markets



Source: S&P Global Platts.

- Figure 16** 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 2022, reflecting structural differences between the two markets (i.e. the high proportion of French nuclear power plants under maintenance and the relevance of wind generation when can cover a significant part of the demand at times in Germany). The French premium over the German forward contract also reflects worries over the availability of the French nuclear fleet. The premium of the French contract over their German equivalent contract started at 66 €/MWh in the first week of the reference quarter and it peaked at 161 €/MWh during the third week of August.

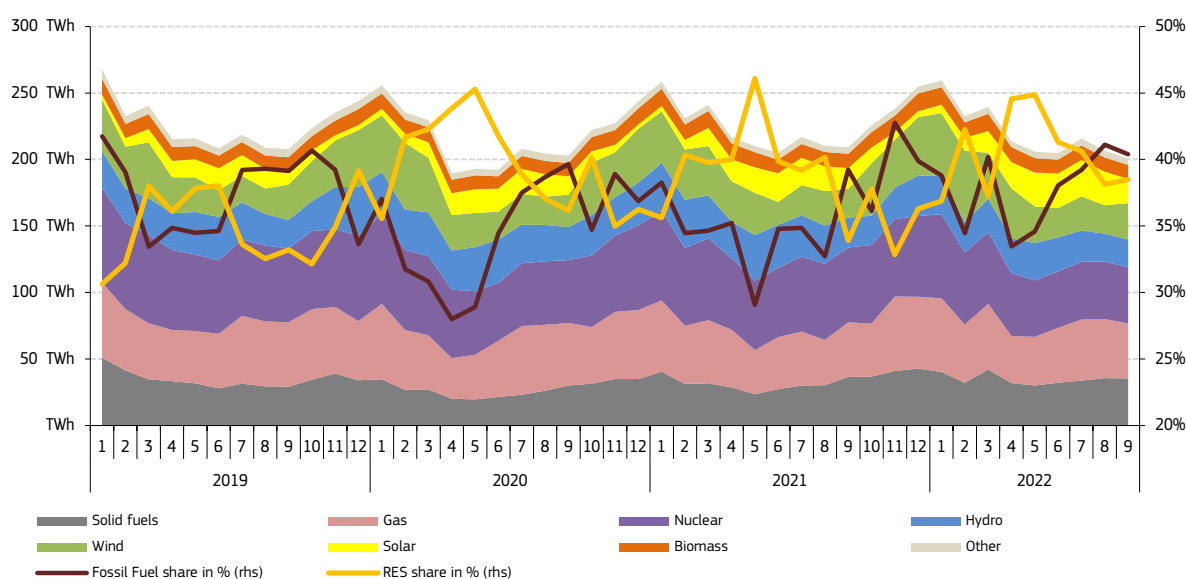
Figure 16 – Weekly German and French year ahead contracts



Source: S&P Global Platts.

- Figure 17** shows the monthly evolution of the electricity mix in the EU. As a result of decreased nuclear and hydro generation during Q3 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) rose to 40% in Q3 2022 (from 36% in Q3 2021). Nevertheless, renewables manage to increase their share to 39% (from 37% in Q3 2021). Nuclear generation remained another quarter under pressure, due to unplanned outages and delayed scheduled maintenance in France, decreasing its share of generation in Q3 2022 to 21% (from 27% in Q3 2021). Nuclear output fell by 24% (-41 TWh) in Q3 2022.
- Within the fossil fuels realm, coal gained ground for another consecutive quarter, both in absolute and relative terms, mainly due to the rally of gas prices which has been reversing the previous coal-to-gas switch registered in 2020, despite relatively high carbon and coal prices. Overall, fossil fuel generation registered an increase of 24 TWh y-o-y (+11%). Coal's (hard coal and lignite) share in the mix rose to 17%, whereas less CO₂-intensive gas generation still managed to grow at 21% in the reference quarter. In absolute terms, coal-based generation rose by 8 TWh year-on-year (+8%), while gas-fired power plants' output rose by 15 TWh (+14%). Renewables generated 3 TWh (+1%) more of electricity year-on-year mainly thanks to improved solar and onshore wind generation, despite low levels of hydro output. Hard coal generation increased by 13% in Germany, 14% in the Netherlands, 111% in Spain, 13% in Czechia and 58% in Italy.
- Between hard coal and lignite (the distinction between them is not visible in **Figure 17**), lignite generation traditionally displays more competitive marginal costs per unit of energy produced even facing the current high 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 16% more expensive in Q3 2022 compared to Q3 2021, although rising gas and hard coal prices were able to counterweight the effect of high carbon prices. In the end, lignite-based generation rose by 9% year-on-year (close to 5 TWh) and hard coal-fired generation increased by 7% year-on-year (3 TWh) in Q3 2022.

Figure 17 – Monthly electricity generation mix in the EU

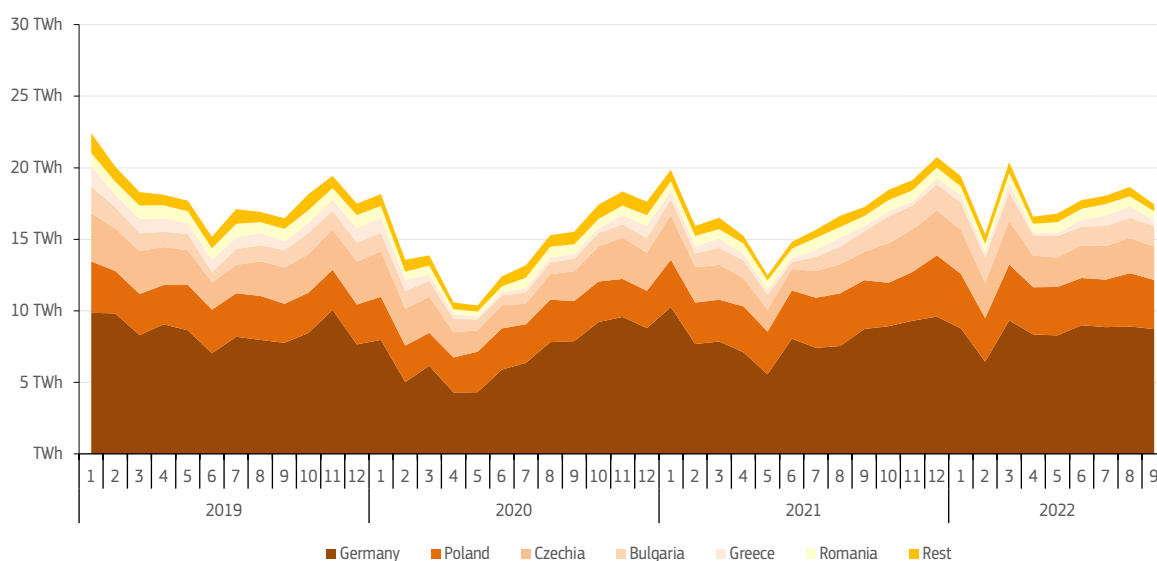


Source: ENTSO-E, Eurostat, DG ENER. Data represent net generation. Fossil fuel share calculation covers power generation from coal, lignite, gas and oil.

- Figure 18** shows the comeback of lignite generation helped by soaring gas and hard-coal prices, decreasing the competitive edge of gas- and hard coal-fired power plants, in the context of the energy crisis. Most Member States with remaining lignite-fired capacity increased its output during Q3 2022. Monthly output peaked in August at roughly 19 TWh. In Germany, home to the largest lignite fleet, generation from the dirtiest fuel rose by 12% year-on-year in Q3 2022, potentially due to the impact of high gas prices (i.e. gas-to-lignite switching) combined with the scheduled reduced nuclear capacity. Lignite-fired generation in Poland remained practically unchanged a year-on-year in Q3 2022. The output of the Czech lignite fleet rose by 21% year-on-year. The three Member States accounted for 81% of the total lignite-based generation in the EU in Q3 2022. In Greece, lignite generation rose by 34% year-on-year on the back of enhanced use of the lignite fleet combined with decreased oil- and gas-fired generation. In Bulgaria, decreased gas-fired output enabled the generation of additional volumes of lignite (+16%) compared to Q3 2021. Lignite power plants reached an 9% share in the EU generation mix in Q3 2022 (up from 8% in Q3 2021)

and were responsible for approximately 33% of the electricity sector's total carbon emissions in the reference quarter.

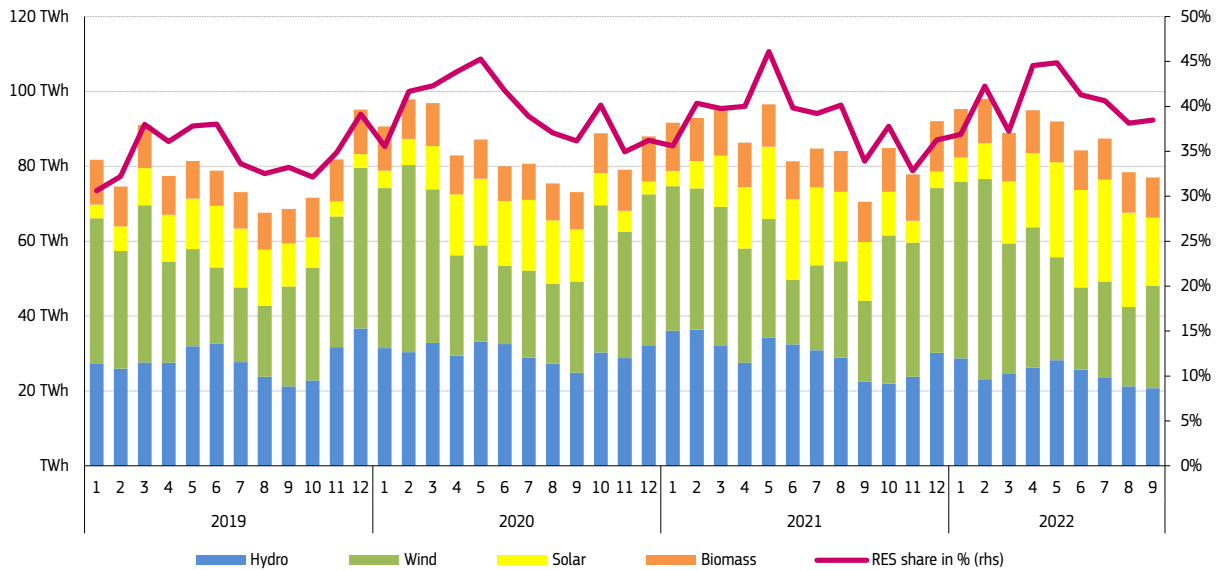
Figure 18 – Monthly generation of lignite power plants in the EU



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

- **Figure 19** depicts the evolution of monthly renewable generation in the EU, alongside its share in the electricity generation mix. The share of renewables reached 39% in Q3 2022, slightly higher than the 38% share of Q3 2021. An increase of 3 TWh in renewable generation contributed to the growth in renewable penetration during Q3 2022.
- The main gains in renewable output came from solar (+16 TWh), wind onshore (+4 TWh), and biomass (+0.5 TWh) in comparison to the reference quarter in 2022. Thanks to an increasing installed capacity, solar PV generation rose by 28% in Q3 2022 to a total of 71 TWh, six times more than oil-fired generation and higher than other technologies such as hydro, hard coal and lignite. In absolute terms, the increase was mostly driven by +4 TWh in Germany (+23%), +2 TWh Spain (+24%) and the Netherlands (+52%). For another quarter, Poland registered impressive solar output figures with an additional +1.5 TWh (+106%). In addition, the share of solar generation in Germany reached 18% in Q3 2022, surpassing the share of all other technologies, except lignite (22%).
- Thanks to the rapid development of new capacity, onshore wind gains during the reference quarter (+7%) were reported mainly by almost +2 TWh in Spain (+15%) followed by 0.5 TWh on Sweden and Finland (+10% and +34%, respectively). Conversely, France registered calm weather, which resulted in a slight decline of wind generation by 1%. Wind offshore experienced a slight fall in its output (-1%). Overall, wind output remained with a surplus (+4 TWh) in Q3 2022, increasing its generation by 6%. Biomass gains (+2%) during Q3 2022 were reported mainly by +0.5 TWh in Germany (+8%).
- However, for another quarter, the brunt of the losses in renewable generation came from hydro (-17 TWh), falling by 21% during Q3 2022. Main hydro generation volume losses were registered in France (-5 TWh), Italy (-4 TWh), Austria (-3 TWh) and Spain (-2 TWh) as a result of low stock levels and limited precipitations. Croatia, Czechia, Germany, Finland, Greece, Hungary, Ireland, Lithuania, the Netherlands, Portugal, Romania, Slovenia and Slovakia also registered declines in hydro generation compared to Q3 2021.

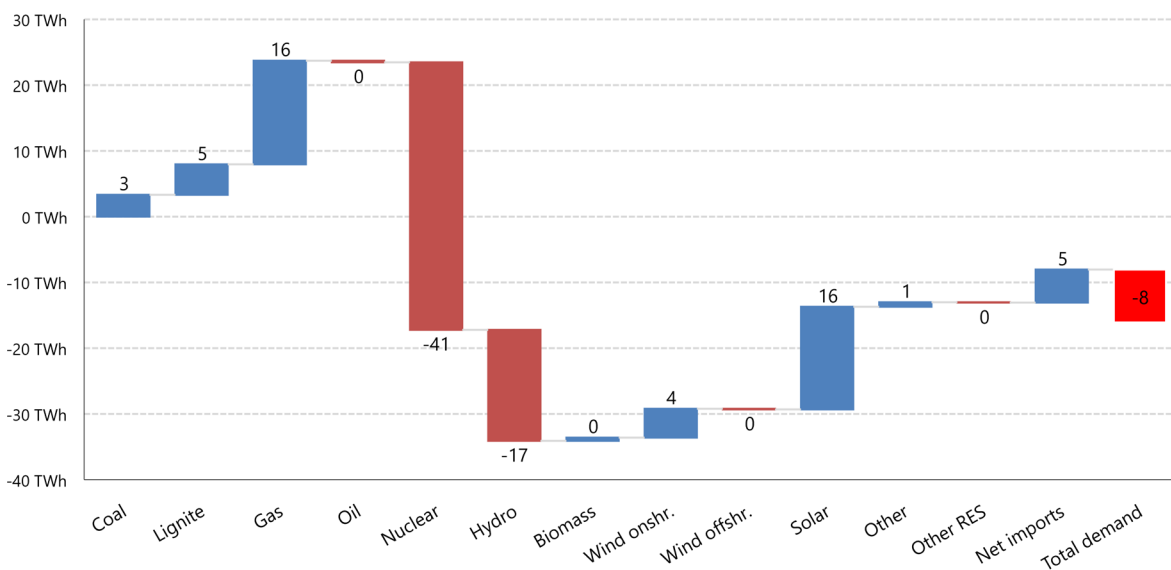
Figure 19 – Monthly renewable generation in the EU and the share of renewables in the power mix



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

- Figure 20** visualises changes in the EU27 electricity generation, imports and consumption in the reference quarter (Q3 2022) compared to Q3 2021. The space for conventional thermal power plants' running hours was augmented, following the trend of previous quarter. Fossil fuels boosted their generation by +24 TWh. Renewable sources generation rose (+3 TWh), despite significant falls in hydro generation (-17 TWh). Net imports rose (+5 TWh) compared to Q3 2021. Nuclear generation registered a large drop (-41 TWh) on the back of reduced fleet availability due to maintenance and phase out policies in some Member States. All in all, hard coal increased its output by 3 TWh, lignite by 5 TWh, whereas gas-fired generation rose by 16 TWh. Oil generation remained practically unchanged compared to Q3 2021. The increase of gas-fired generation despite skyrocketing gas prices, signals the difficulty for further fuel switch for power generation to replace nuclear and hydro subdued output. Based on preliminary estimates, the carbon footprint of the power sector in the EU rose by 10% year-on-year in Q3 2022, due to a larger use of more carbon-intensive fossil fuels. If the current trend continues, it is likely that both the power sector's carbon footprint and carbon intensity will rise in the year 2022.

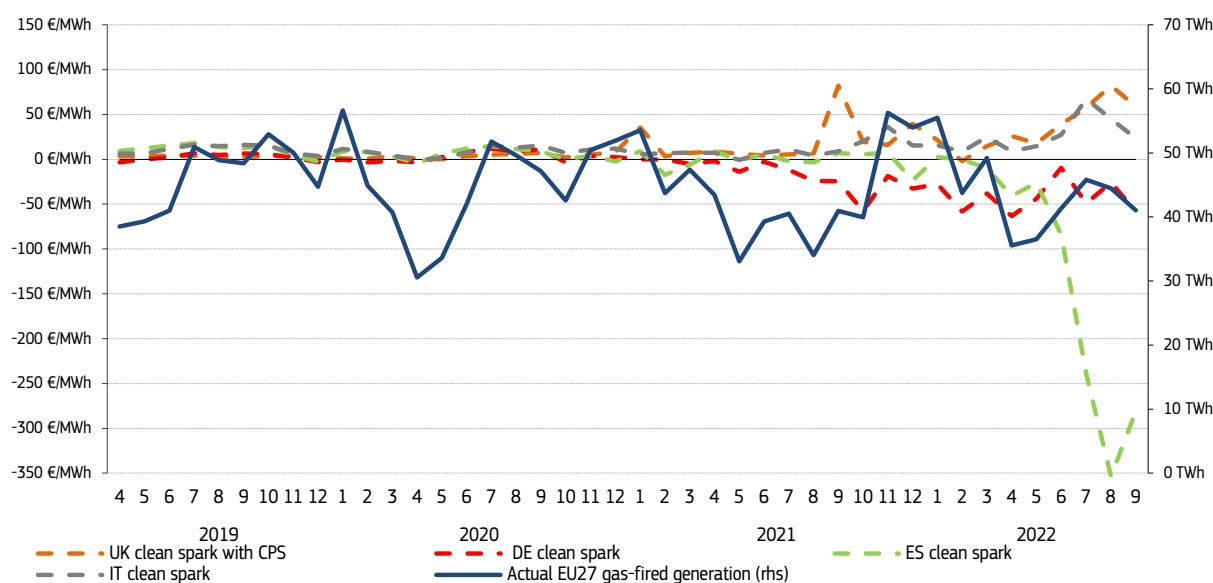
Figure 20 – Changes in power generation in the EU between Q3 2021 and Q3 2022



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. Despite high coal prices, coal-fired generators were able to improve their position in the profitability zone vis-à-vis gas-fired plants. High prices have created healthy margins mainly for coal, but in some markets, also for gas generators. The Italian, German and UK [clean dark spreads](#) remained on average positive during Q3 2022. Likewise, [clean spark spreads](#) remained at positive levels in the case of UK and Italy. Coal usage has been increasing to compensate for high gas prices and subdued hydro and nuclear generation in Europe. However, as registered during Q3 2022, despite higher levels of profitability of coal-fired generation, the fuel switching capacity is limited by the scarcity of coal-fired plants still in operation due to the decommissioning of the fleet over the last years, despite efforts of some MS to bring back some extra capacity to the market.
- As shown in **Figure 21**, the profitability of gas firing for electricity generation remained in the UK and Italy in positive territory for a plant with an average efficiency during Q3 2022. The positive profitability levels of gas-fired generation in Italy are likely due to much higher wholesale electricity prices and much higher number of hours when gas is the marginal technology, setting the electricity generation costs and wholesale market prices. In Germany, the profitability of gas-fired generation has remained in the negative zone, due to high gas prices outpacing the rise in wholesale electricity prices. German clean spark spreads have not been in positive territory since January 2021. Conversely, the Spanish equivalent registered a steep drop during the quarter. The abrupt fall in profitability might be related to the impact of the [‘Iberian exception’](#), that subsidises gas-fired generation. In August, the UK clean spark climbed to 82 €/MWh. The highest clean spark spreads in Q3 2022 were assessed in the UK (66 €/MWh), followed by Italy (45 €/MWh). The lowest was registered by far in Spain (-291 €/MWh), recording a low of -280 €/MWh in September. Gas-fired generation volumes largely corresponded to the movement of spreads in respective markets (with the notorious exception of Spain). The total EU gas generation reached 131 TWh in the reference quarter, up by 14% compared to Q3 2021.

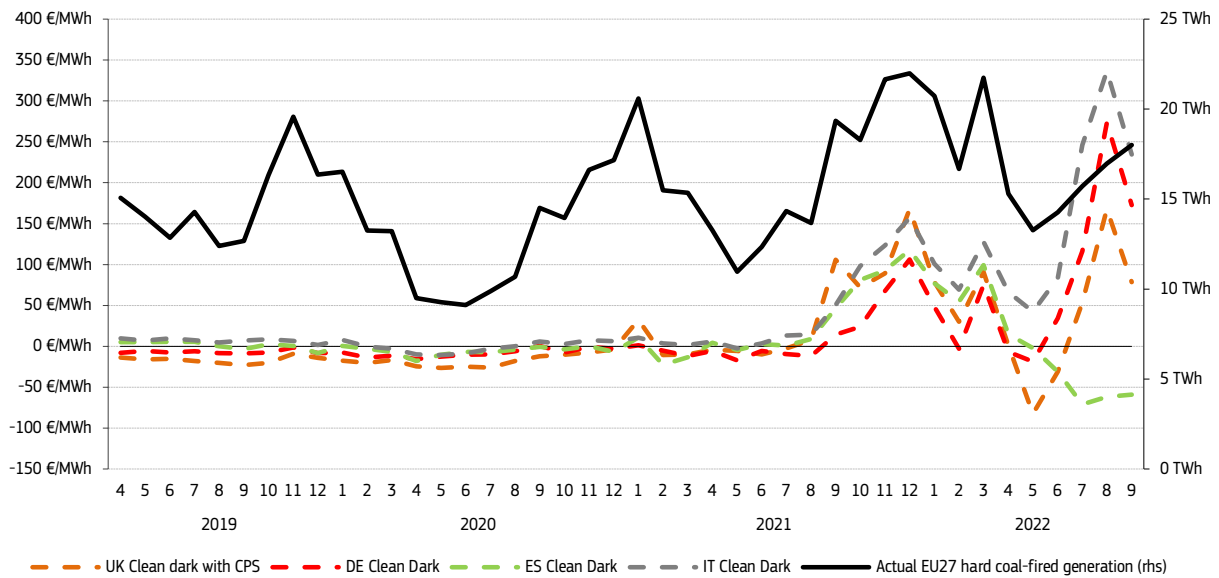
Figure 21 – Evolution of clean spark spreads in the UK, Spain, Italy and Germany, and electricity generation from natural gas in the EU



Source: ENTSO-E, Eurostat, Bloomberg

- **Figure 22** shows that Italy, followed by Germany, experienced the most profitable coal-fired power generation in Q3 2022. In August, most of the selected markets recorded highs in the profitability indicator for an average plant, due to new all-time record high gas prices, despite very high coal prices. [Clean dark spreads](#) in Italy averaged 272 €/MWh in Q3 2022, roughly six times more than in the case of gas-fired power plants. Spain was the only selected market registering negative profitability of coal-fired plants, likely as a side effect of the [‘Iberian exception’](#), subsidising not only gas, but also coal for power generation. Coal generation in Spain increased by 111% year-on-year in the third quarter of 2022, with only few units remaining in the market. German hard coal generators increased their output by 25% year-on-year in Q3 2022, as nuclear generation has been gradually fading in accordance with the German nuclear phase-out plan and gas-fired plants have not been running as many hours as they did in Q3 2021. Current plans to temporarily return some coal capacity to the market could support increased coal-fired generation.

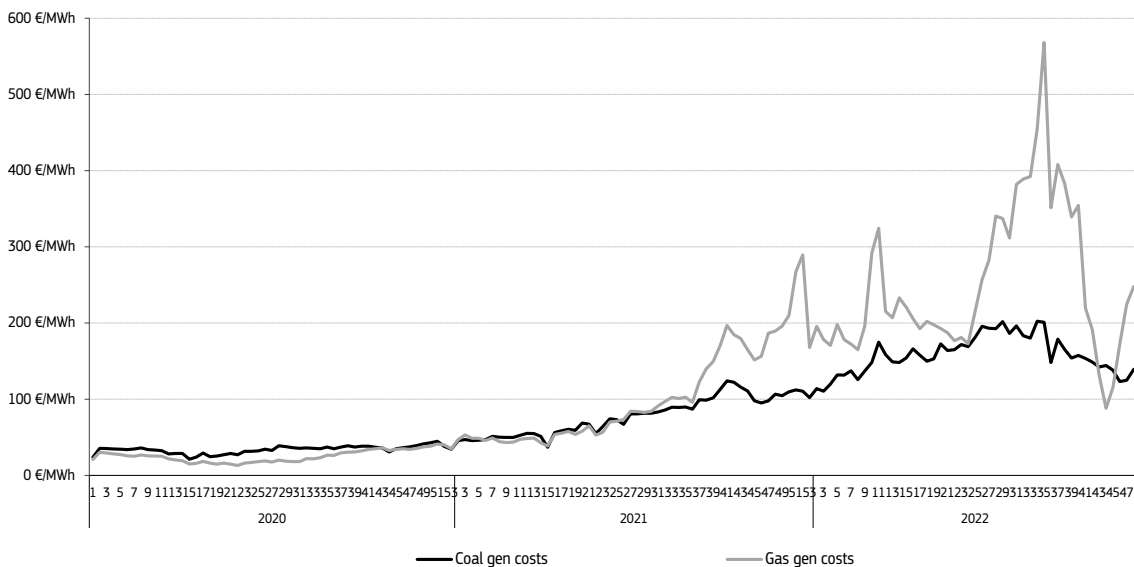
Figure 22 – Evolution of clean dark spreads in the UK, Spain, Italy and Germany, and electricity generation from hard coal in the EU



Source: ENTSO-E, Eurostat, Bloomberg

- Figure 23** shows the impact of gas prices on gas and coal-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). This was the case in 2020, where a combination of low gas prices and increasing prices of emissions allowances supported coal-to-gas switch. However, unprecedented gas prices have a more relevant impact on gas-fired generation costs, than the increase in coal and carbon prices on coal-fired generation costs. However, low gas prices during the last weeks of October, first week of November, combined with elevated coal prices briefly supported coal-to-gas switching for the first time since May-June 2022. Nevertheless, bouncing back gas prices at the start of the 2022-2023 heating session and further storage withdrawals, supported the widening of the variable generation cost gap in favour of coal.

Figure 23 – Variable generation costs of coal- and gas-fired power plants

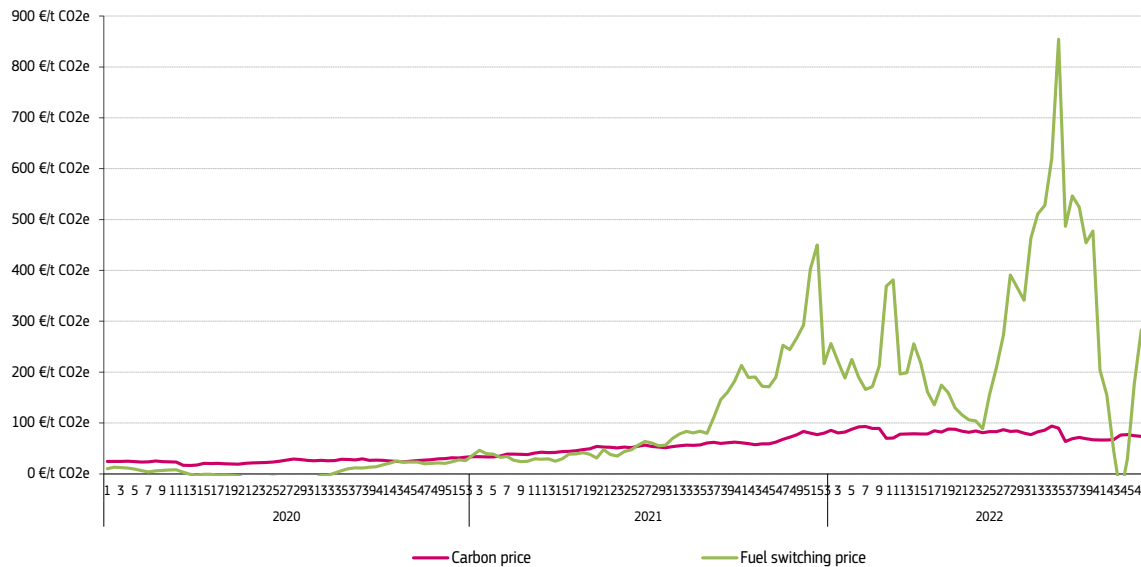


Source: S&P Platts, ENER.

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 24** shows how the reduced gas prices during October, combined with a still high coal prices improved the economics of gas-fired plants for the first time since May-June. The estimated average fuel switching price required to make gas-fired plants economically viable vis-à-vis coal fell below EU ETS prices (roughly at 70 €/tCO₂) during the last weeks of October and the first week of November. However, the fuel switching price stood on average at 300 €/tCO₂ during the last week of November on the back of bouncing back gas prices. New all-time high gas prices and weather-related demand for gas could contribute to increase the fuel switching price in the winter.

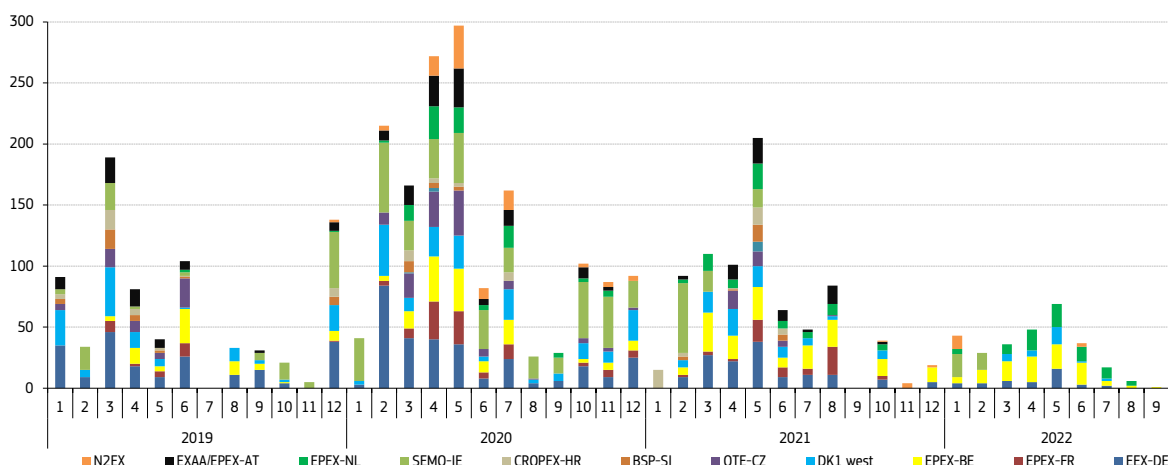
Figure 24 – Coal-to-gas fuel switching



Source: S&P Platts, ENER.

- **Figure 25** 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 Q3 2022 (24) was 82% lower in the observed bidding zones than in the previous third quarter. Most of the falls into negative territory occurred in July 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 16 July, when strong wind speed combined with weak demand, pushed some Central Western Europe markets (German and Dutch) and some Nordic markets (Sweden and Denmark) below zero during several hours of the day. Wind generation covered a large part of the Danish consumption during that day.
- The Netherlands recorded the highest number of negative hourly prices (13) in Q3 2022, followed by Belgium (7). However, the Netherlands still recorded a decrease of 7% in negative hourly prices in Q3 2022. The current situation of high energy commodity prices is temporarily decreasing the occurrence of negative prices on wholesale electricity markets. However, the higher level of penetration of variable renewables is introducing new challenges to the grid balance and is 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.

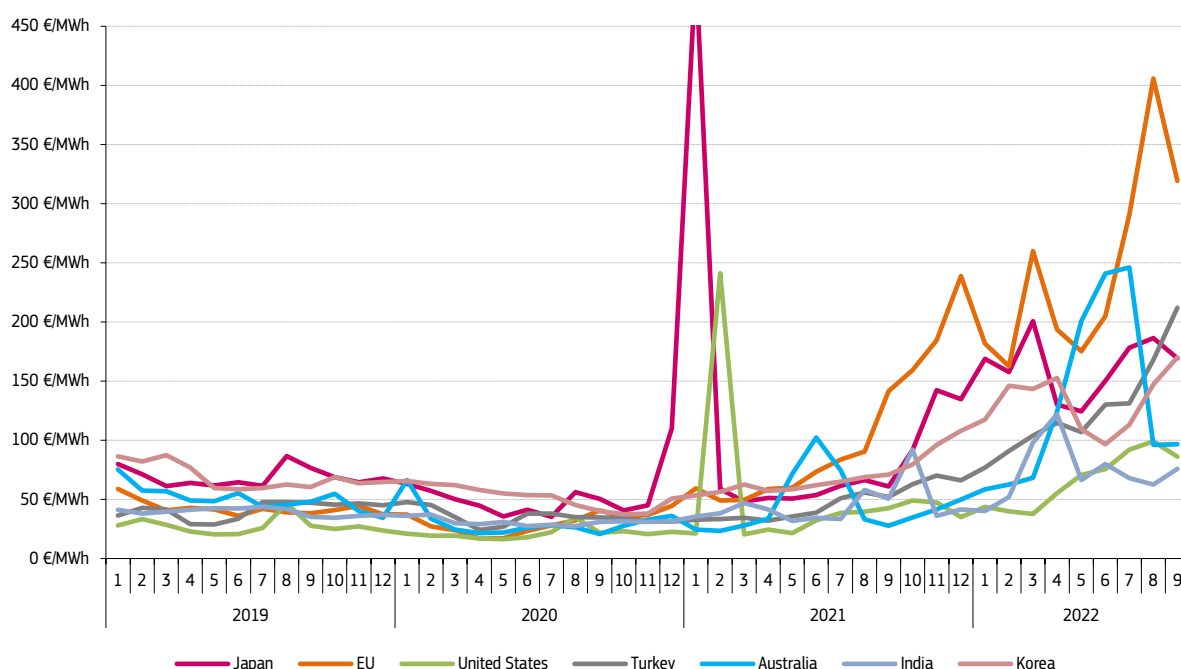
Figure 25 – Number of negative hourly wholesale prices on selected day-ahead trading platforms



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

- Figure 26** compares price developments in wholesale electricity markets of selected major economies. Most markets saw prices mounting due to tight global markets, exacerbated by the global impact on commodities (mainly gas, but also coal) by the impact of the Russian war in Ukraine and associated sanctions. In the U.S., wholesale electricity prices increased in most of the analysed regional wholesale markets. Rising natural gas prices at the U.S. Henry Hub and the warm weather-related demand led to high wholesale electricity prices in many of the regional benchmarks. Overall, the U.S. price benchmark increased by 130% in Q3 2022 compared with Q3 2021. The December edition of the EIA's [Short Term Energy Outlook \(STEO\)](#) expects the price of Henry Hub to rise during the last part of 2022 and beginning of 2023 due to higher winter demand and rising LNG exports. EIA expects Henry Hub prices to fall after January as domestic natural gas production increases and storage gets filled. However, prices are likely to remain volatile.
- In Japan, warm temperatures and the higher LNG and energy commodities prices, contributed to high prices during Q3 2022 (+183%). Japan relies heavily on fossil-fuel power generation, and it is one of the most important LNG buyers in the global market. The Japan-Korea Marker (JKM), LNG benchmark fell further in November dragging down electricity prices. However, elevated coal and gas prices, combined with winter temperatures could drive power prices higher during the upcoming months. South Korea have been equally exposed to tightening LNG market fundamentals and warm weather driving prices 110% higher in the reference quarter.
- European wholesale prices were once again, the highest of the observed economies in Q3 2022, reaching 339 €/MWh. In Australia, following the June market intervention events (triggering of safety nets - price cap and temporary suspension of the market) prices were consistently higher and volatile in all the NEM regions, during Q3 2022. Despite the critical situation in June, the Australian operator was able to avoid any significant load shedding or blackouts in the grid. Australian prices rose 223% year-on-year in Q3 2022. July prices registered an equivalent of 246 €/MWh, but prices fell below 100 €/MWh in August and September as milder weather and a drop in demand decreased pressure on power prices. Prices in India rose by 45% in Q3 2022 on the back of milder weather.

Figure 26 – Monthly average wholesale electricity prices in international markets (D-A markets)

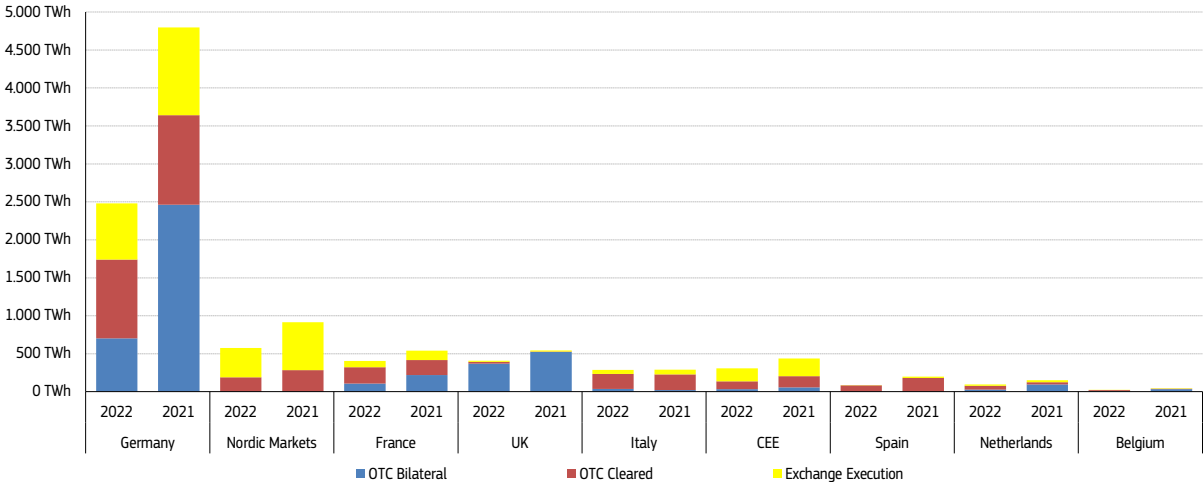


Source: European Power Benchmark, JPEX (Japan), AEMO (Australia), JCS ATS (the latest data for Russia is not available), Energy Exchange Istanbul (Turkey) and the average of selected PJM West, ERCOT, MISO Illinois and CAISO regional wholesale hubs in the United States. BloombergNEF (India and Korea).

2.2 Traded volumes and cross border flows

- Figure 27** shows annual changes of traded volumes of electricity in the main European markets, including exchange-executed trade and over-the-counter (OTC) trade. For another consecutive quarter, most markets and regions witnessed a year-on-year decline in trading activity up to September 2022. The decrease in total traded volumes (-41%) up to the third quarter of 2022 (-3242 TWh) reflects the magnitude of the falling trend in trading activity on the electricity sector. Decreased over-the-counter and exchange liquidity has been attributed to the situation of high prices and increased volatility in the energy market. Activity dropped significantly in OTC contracts (-43%) and also decreased widely at exchanges (-35%) in the total traded volumes under observation during the reference period.
- The largest annual falls in total traded volumes were registered in Spain (-56%), Germany (-48%) and Belgium (-45%). 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 41% to 4675 TWh during the reference period (-3242 TWh compared with Q3 2021).
- Despite falls in traded volume, Germany was by far the largest and most liquid European market, as total volumes reached 2480 TWh (equivalent to 53% of the total traded volumes under observation in Q3 2022). Overall, total activity fell (-48%) in Germany in Q3 2022. In Germany, the market share of exchanges experienced an increase (+6 p.p.) while the OTC contracts share decreased compared with Q3 2021. Spain and Belgium markets registered a drop in activity of 56% and 45%, to 87 TWh and 25 TWh, respectively. Relative decreases in activity were also visible in the Netherlands where total volumes fell (-37%) to 96 TWh. Moreover, relative decreases were also visible in the Nordic and CEE markets where total volumes fell by 37% to 575 TWh and by 30% and 308, respectively.
- Overall, the market share of power exchanges expanded from 29% to 32%. The largest increase in exchange-based volumes were registered in the UK (+14%), while the largest falls were reported in Spain (-75%) and the Nordic markets (-39%). Overall, exchange-based trading volumes decreased by 794 TWh in Q3 2022 (-35%). The OTC segment traded 2448 TWh less of electricity in the reference quarter compared with the same period in 2021, as a result of lower volumes changing hands in Germany, Spain and Belgium. OTC volumes reduced their share of the market to 68%. Spain, Germany, Belgium and the Netherlands registered the largest decrease in bilateral OTC deals (-54%, -52%, -47% and -38% respectively).

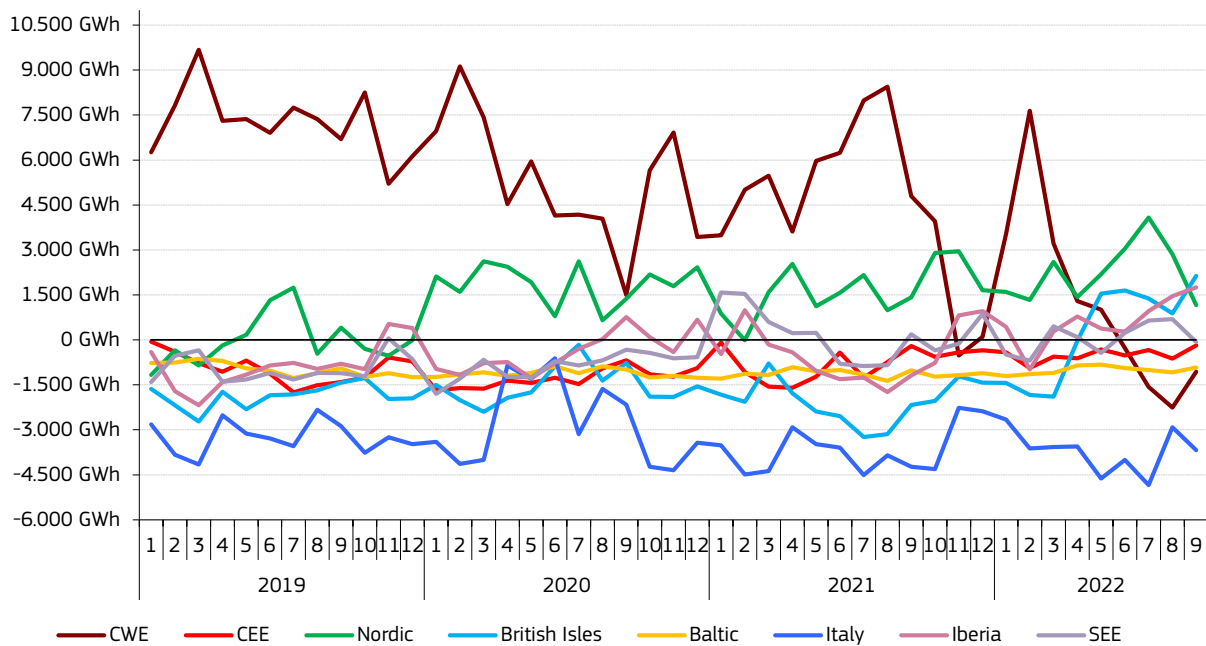
Figure 27 – Annual change in traded volume of electricity on the most liquid European markets



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

- Figure 28** reports on the regional cross-border flows of electricity. Central Western Europe registered a drop in its traditional position as the main exporting region during Q3 2022. 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. However, intensifying the trend registered in the previous quarter, CWE registered almost 5 TWh of net imports, reversing its traditional outflows in comparison to Q3 2021. The drop can be traced mainly to high gas prices, lower nuclear availability in the CWE main markets (maintenance or scheduled phase-out), combined with subdued hydropower generation, which decreased the availability of exports. Conversely, net flows in the British Isles changed their traditional direction (net imports) compared to Q3 2021, in line with the trend registered during Q2 2022. In Q3 2022, the British Isles recorded 4 TWh in net exports. The Nordic region recorded a surplus of 8 TWh in the reference quarter, 77% above from the net exports in Q3 2021. The Iberian Peninsula also registered a change in the direction of traditional quarterly flows, supported by the subdued nuclear generation in France and the impact on prices of the 'Iberian exception'. Spain recorded 4 TWh of net exports in Q3 2021, compared with 4 TWh of net imports in Q3 2021. Likewise, SEE registered 1 TWh of net exports, reversing the direction of flows in comparison with Q3 2021.
- 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. Italian net imports decreased by 9% year-on-year to -11 TWh in Q3 2022. The CEE region's net position (-1 TWh) improved by 48% in Q3 2022 compared to Q3 2021.

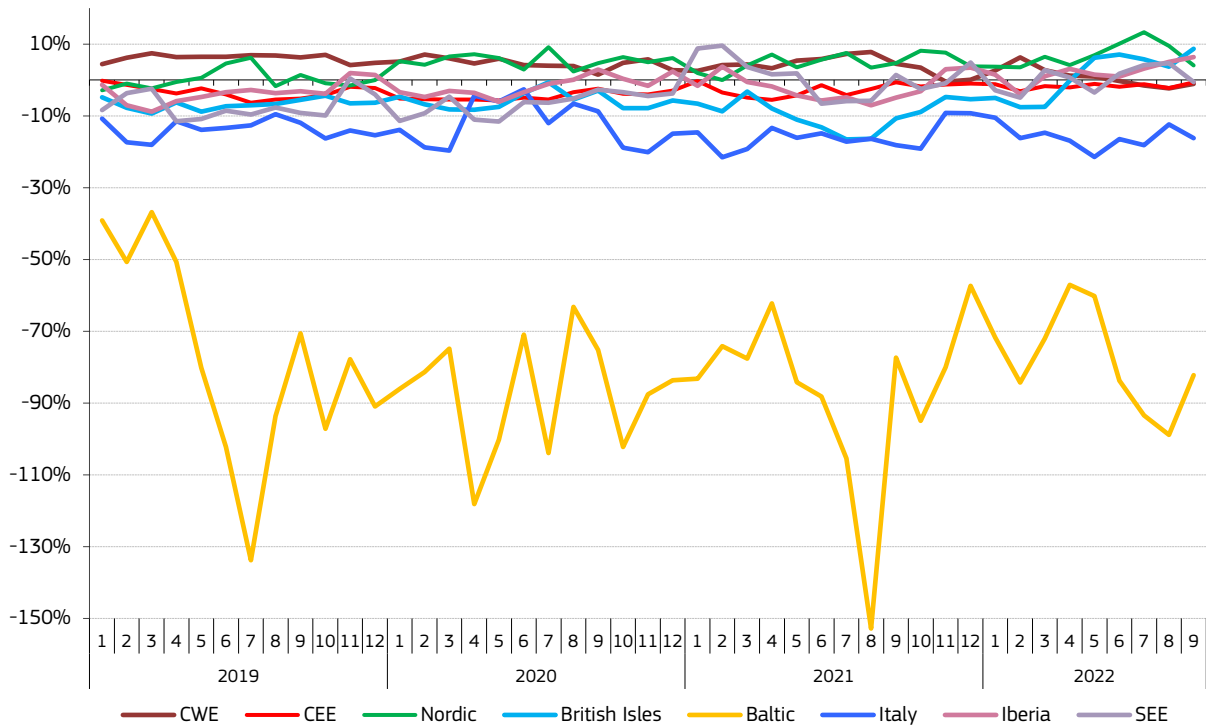
Figure 28 – European cross-border monthly physical flows by region



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 29** 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 Q3 2022 compared to the same quarter a year ago. Net imports (3 TWh) reached about 92% of domestic generation. Italy became the second largest importer relative to its domestic generation (16%). For the rest of the regions, net imports (or exports) did not exceed 9% of domestic generation.

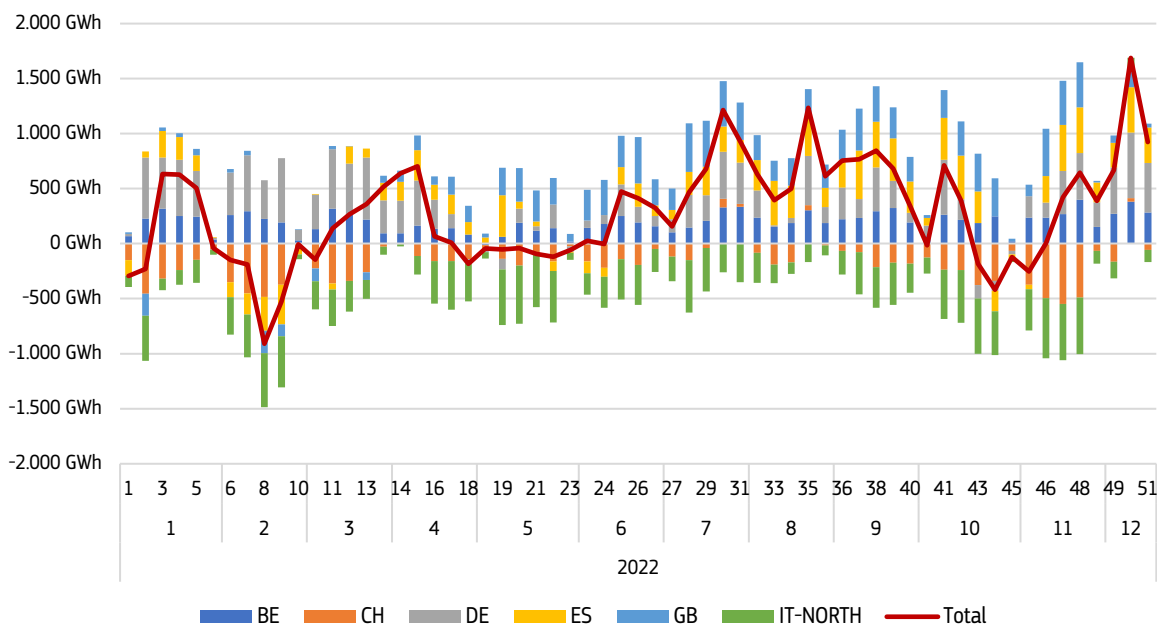
Figure 29 – The ratio of the net electricity exporter position and the domestic generation in European regions



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

- Figure 30** compares France’s net cross border scheduled flows from neighbour markets during most of the weeks of 2022. Positive values indicate flows going into France (net imports). The low availability of the French nuclear fleet has caused a reversal of traditional position of France as net exporter in the region. France imported electricity from all neighbouring bidding zones, except from the North of Italy. Net imports of France in Q3 2022 recorded 10,207 GWh, a staggering difference compared with the net exports registered during Q3 2021 (-20,812 GWh). Moreover, January to November 2022 French net imports amounted to 14,380 GWh, while registering net exports of 45,412 GWh, in the same period in 2021.

Figure 30 - French cross-border weekly scheduled flows



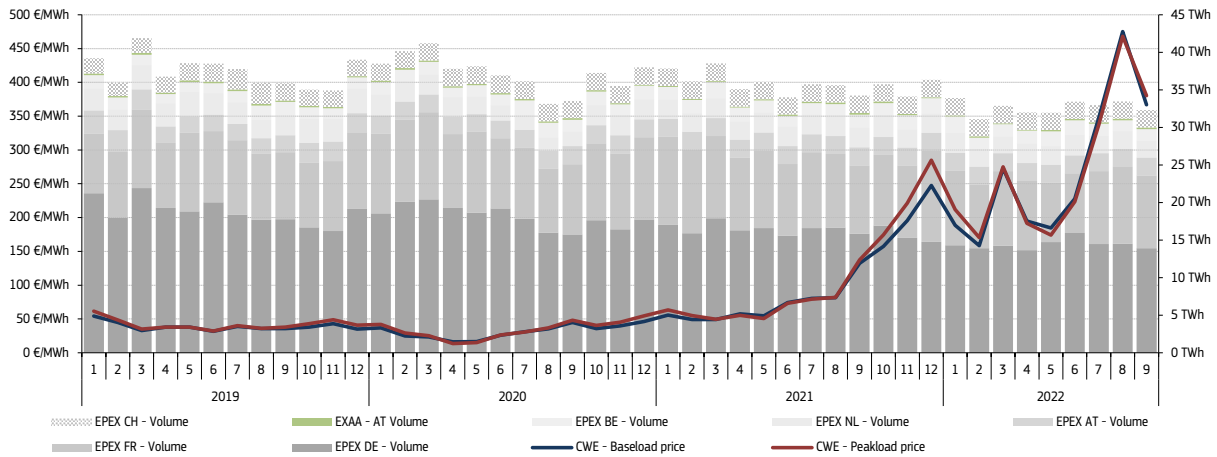
Source: ENTSO-E

3 Regional wholesale markets

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

- Wholesale electricity prices in Central Western Europe (CWE) showed record levels of prices during Q3 2022, peaking in August amid an increasingly tight energy market and related gas supply disruptions by Russia (Nord Stream pipeline) and increase of gas prices. Compared to Q3 2021, the average baseload price in the region increased by 304% to 397 €/MWh in the reference quarter. Meanwhile, average peakload prices increased by 297% to 395 €/MWh.
- In France, nuclear generation availability has drastically decreased, reaching a new record low during the last week of August 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, due to corrosion problems or scheduled maintenance. Among other factors, the reduced nuclear fleet availability is keeping the French forward contracts in premium over Germany (see **Figure 16**). On 9 December, five nuclear reactors (5.3 GW in total) were still pending to return before the end of the 2022. More recently, on 15 December, EDF announced the extension of the maintenance of two nuclear plants (Flamanville-1 by 19 February 2023 and Penly-1 to restart by 20 March 2023).
- The latest ENTSO-E [Winter Outlook 2022-2023](#) points out that the adequacy risks in France for the winter 2022/2023 are greater than the previous winter due to the low availability of the French nuclear fleet. Moreover, RTE, the French power grid operator warned of a period of tight electricity supply during January and February in the [latest winter outlook](#), without ruling out the possibility of power outages.
- Available France – UK interconnection would amount to 4 GW in January 2023, thanks to the new 1 GW ElecLink via the Channel Tunnel that started operations during the summer and with the expected return of the 2-GW IFA-1 link on 27 January.
- In Germany, the government passed a regulation in September extending the life of hard-coal power plants (6.9 GW), enabling the return into the market until 31 March 2024, as a result of the disruption in global markets as a result of the Russian war in Ukraine in an effort to use less gas. Moreover, Lignite plants (total capacity of 1.9 GW) in the reserve were enabled to start operating in October. The country had previously planned to end the coal reserve by end of April 2023.
- In addition, Germany has approved the extension of the use of the three remaining nuclear reactors (Isar-2, Neckarwestheim-2 and Emsland) until April 2023, to secure the security of supply during the winter season. As part of the scheduled nuclear phase-out plan, these plants were expected to cease operation at the end of 2022. Germany already closed three reactors at the end of 2021. The nuclear closures added extra tightness and combined with expensive gas prices, are supporting elevated German power prices.
- Germany is to set a windfall tax for inframarginal generators, with price levels where revenues are to be capped at 130 €/MWh for offshore wind and nuclear, 60 €/MWh for lignite (plus EU ETS costs) for most of the units and 82 €/MWh (plus EU ETS costs) for lignite plants coming back from the reserve. The temporary measures would take place until end of June 2023, potentially subject to extension. Germany is also working to implement a cap on gas and electricity prices from 2023. Electricity for the industry sector would be capped at 130 €/MWh for 70% of the total consumption and 400 €/MWh for 80% of the consumption of households in 2021. The income from the tax on inframarginal power revenues is set to partially support the reduced electricity tariffs.
- The Netherlands is also implementing a tax on inframarginal power revenues above the threshold of 130 €/MWh, to start from December 2022 until end of June 2023. The tax will apply to inframarginal generation with some caveats applied to certain technologies (e.g. 240 ceiling €/MWh for biomass plants).

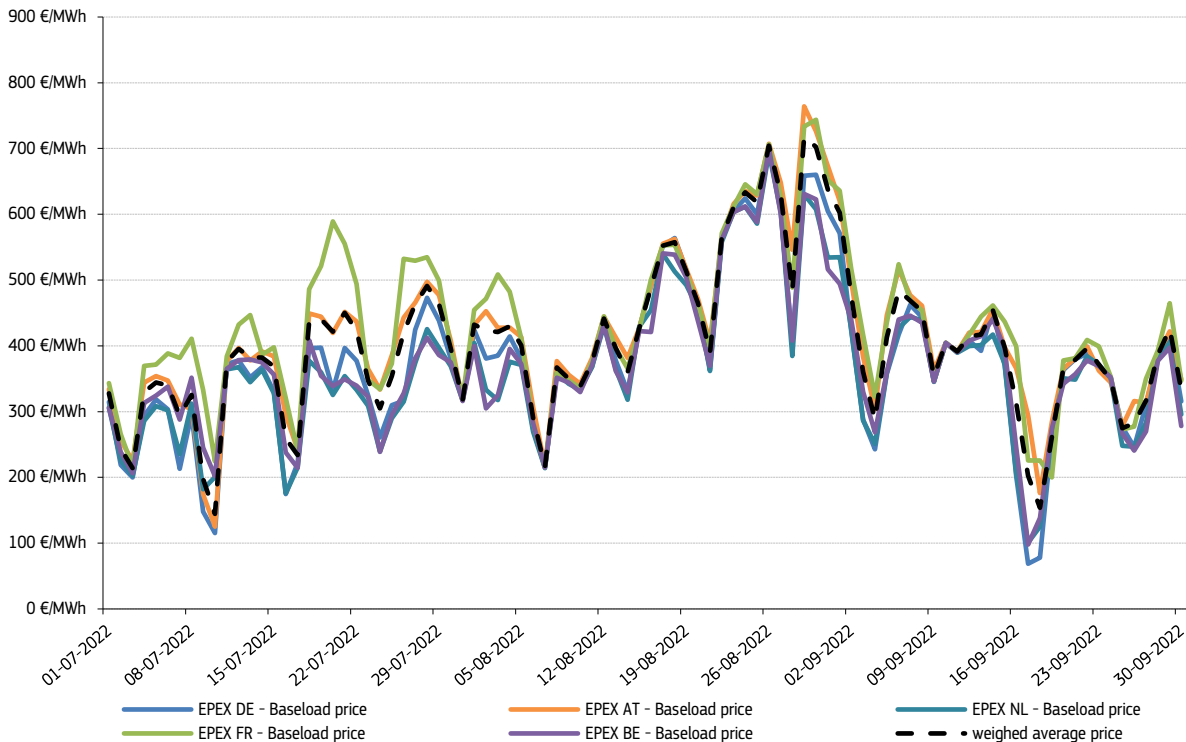
Figure 31 – Monthly exchange traded volumes of day-ahead contracts and monthly average prices in Central Western Europe



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

- Figure 32** shows the daily average day-ahead prices in the region in the reference quarter. Daily average prices in CWE reached new all-time peaks in Q3 2022, after having reached previously record levels in Q1 2022. On 29 August, CWE prices skyrocketed to 718 €/MWh following the corresponding increase of gas prices on the main European hubs. On that day, Austrian day-ahead prices recorded 764 €/MWh, while on the following day (30 August) French day-ahead prices registered 744 €/MWh, with some hourly peaks over 1,000 €/MWh. The tightness of the gas market, the lower-than-average outputs from French nuclear power plants and the consistent droughts hitting large part of Europe in 2022, supported high power prices in the CWE region.

Figure 32 – Daily average power prices on the day-ahead market in the CWE region

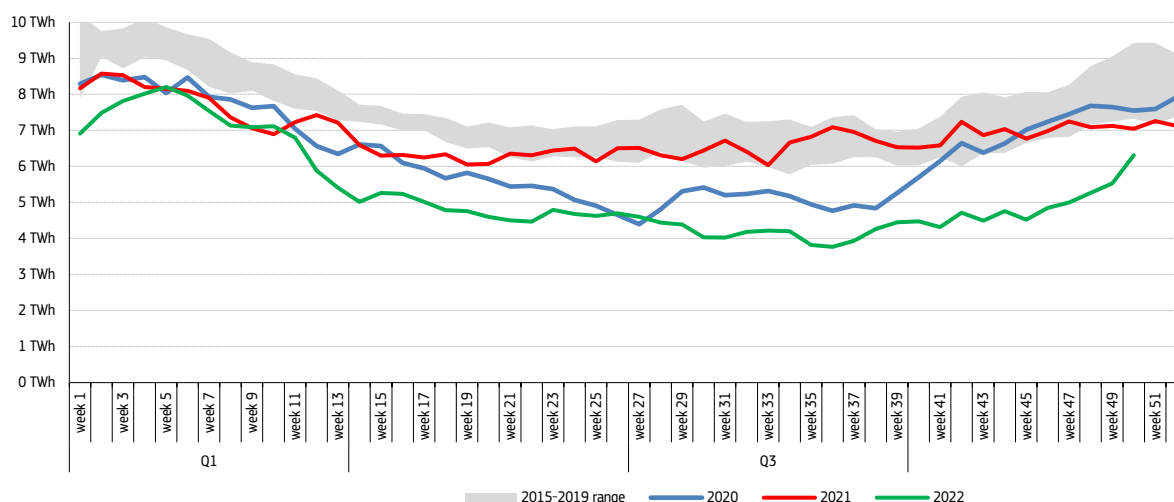


Source: S&P Platts.

- As shown in **Figure 33**, French nuclear output was significantly down by 36% (-31 TWh) year-on-year in Q3 2022. Nuclear generation drastically decreased, from 4.6 TWh in the first week of July 2022 to a new low during the last week of August (3.8 TWh) and then bounced back to around 4.5 TWh in the last week of September 2022. Subdued nuclear generation continued into Q4 2022, registering an increase in its output to 6.3 TWh during the second week of December. However, the output remained below historical levels.

- EDF has lowered the nuclear availability for 2022, as the fleet experienced a high number of outages combined with scheduled maintenance in 2022 (the latest estimated 2022 output is between 275 and 285 TWh). During mid-December France registered 41 reactors available (out of 56). EDF recently announced delays in the return of Flamanville 1 and Penly 1 reactors by some weeks. Of the remaining 15 reactors to come back, three are scheduled to return before the end of 2022, six before the end of January, five before the end of February and the remaining in March 2023.
- In Belgium, after 40 years of operation, Doel 3 nuclear generator was permanently disconnected from the grid on 23 September, in agreement with the scheduled phase-out plan of nuclear energy. Doel 3 is the first nuclear reactor to be shut down as part of the phase out plan. The Belgium federal government had 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 33 – Weekly nuclear electricity generation in France

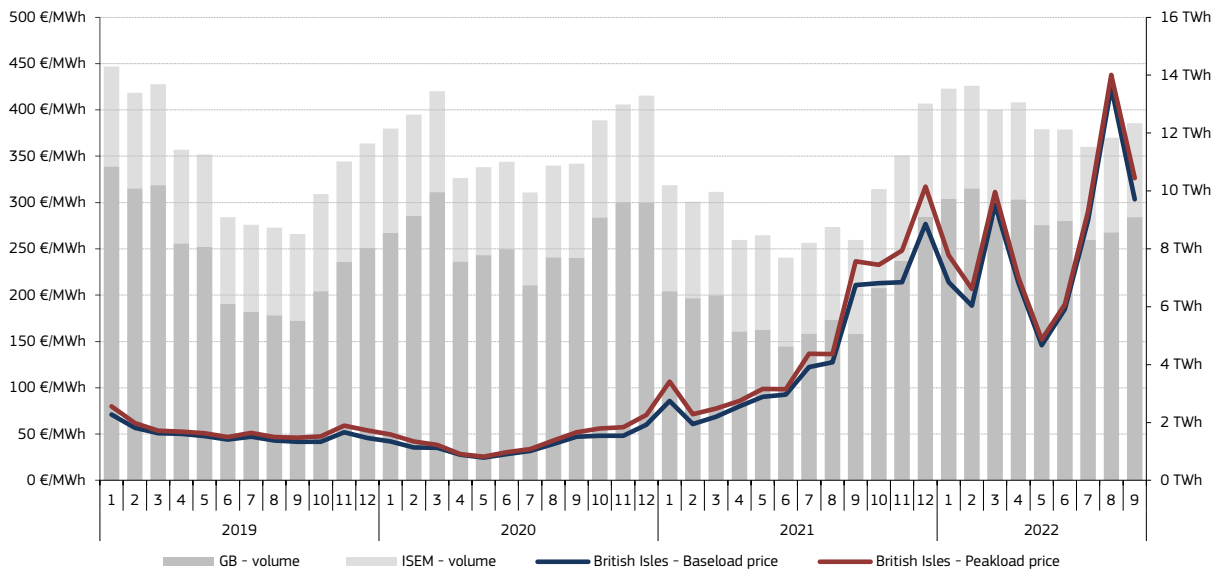


Source: ENTSO-E

3.2 British Isles (GB, Ireland)

- **Figure 34** illustrates monthly volumes and prices on the day-ahead markets in Great Britain and in the all-island integrated market of Ireland. Following the ease in the price rally during Q2 2022, monthly averages for both base-load and peakload power rose again reaching new record highs during August (monthly average at 425 €/MWh). The favourable position of the British Isles, less dependent than mainland Europe from Russian energy commodities and increased LNG imports, supported lower prices of gas in the British Isles compared with mainland Europe. Thus, Q3 2022 wholesale electricity prices rose less than in the continent, supporting for a second quarter the change of traditional direction of flows between the British Isles and the continent. Q3 2022 saw the British Isles acting as a net exporter to mainland Europe. Compared to Q3 2021, the average baseload price on the British Isles rose by 119% to 336 €/MWh during Q3 2022 and increasing by 85% from Q2 2022.
- The UK government launched the [Review of Electricity Market Arrangements \(REMA\)](#) in July, based on the [British Energy Security Strategy \(BESS\)](#) presented to the UK parliament. The reform process seeks to outline the necessary updates to the electricity market to deliver a fully decarbonised electricity system by 2035, while securing the required supply. The process also encompasses the role of Contracts for Difference (CfD) and the Capacity Markets.
- The Celtic Interconnector between France and Ireland is one of the projects recognised as a project of common interest (PCI) by the EU. The new link is scheduled to be commissioned by 2027, for a cable of 575 kms joining La Martyre in France with Knockraha in Ireland for a total installed capacity of 700 MW.

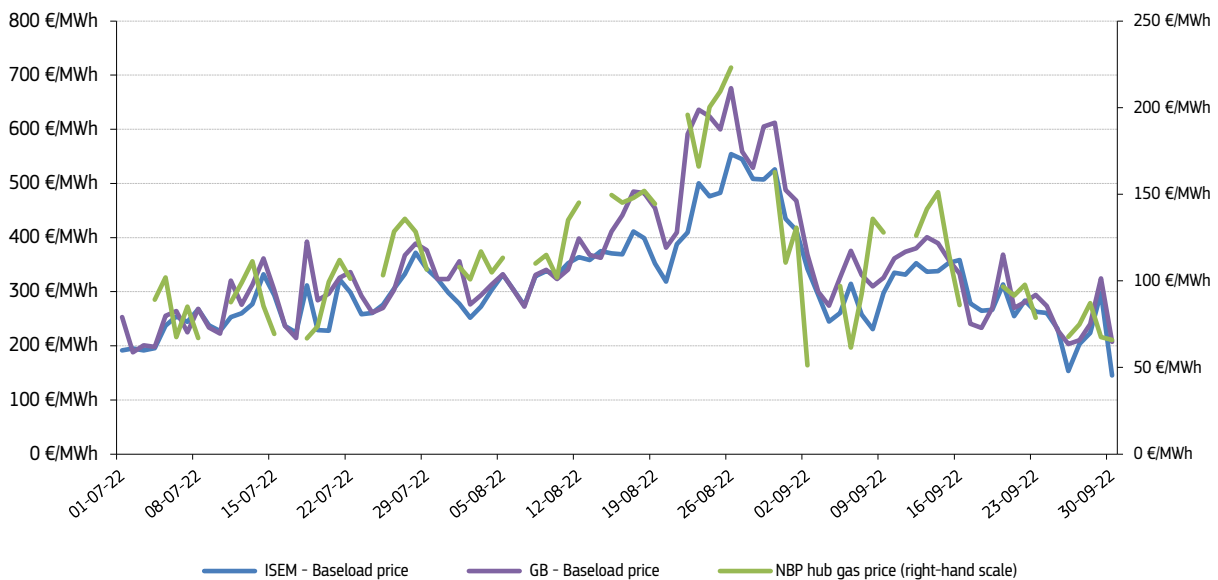
Figure 34 – Monthly exchange traded volumes of day-ahead contracts and monthly average prices in Great Britain and Ireland



Source: Nord Pool N2EX, SEMO, Utility Regulator

- **Figure 35** follows the developments of daily average baseload electricity prices in Great Britain (N2EX) and Ireland (ISEM). British baseload prices experienced strong volatility along Q3 2022, in line with other European markets. The highest values were registered at the end of the August driven by NBP prices following the geopolitical situation and the resulting tight gas market. On 26 August, Great Britain recorded a new all-time high of 676 €/MWh, while during that day, the Irish market registered also its highest value (554 €/MWh).

Figure 35 – Daily average electricity prices on the day-ahead market in Great Britain and Ireland



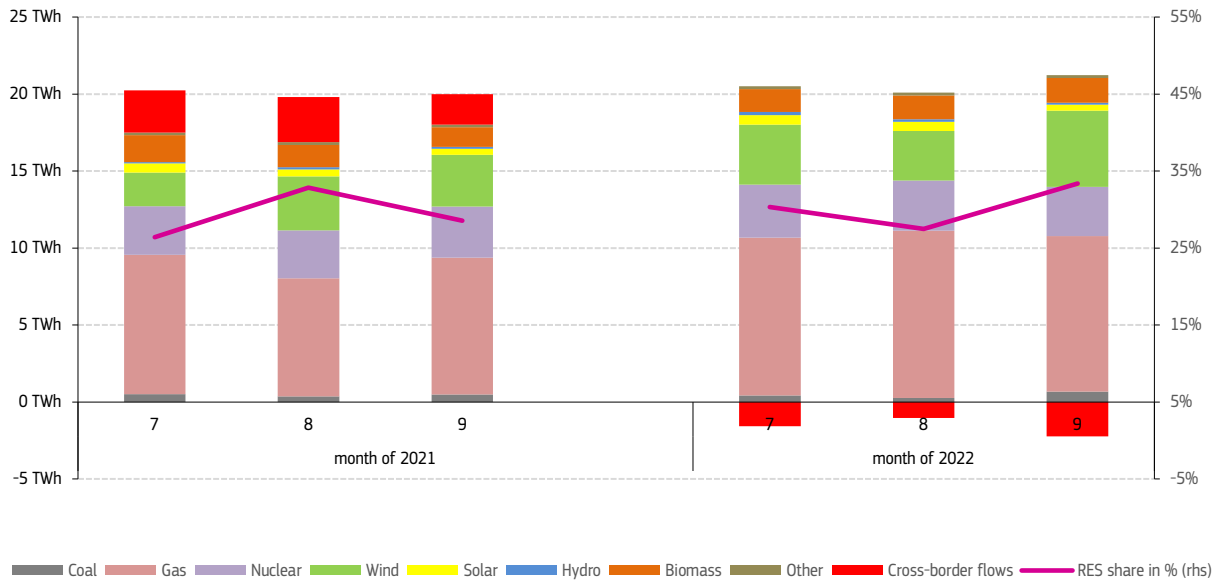
Source: Nord Pool N2EX, SEMO

- **Figure 36** shows the impressive increase of electricity net exports during Q3 2022, changing UK's traditional net importer position. UK also registered significant increases in gas and wind (both onshore and offshore) generation between Q3 2021 and Q3 2022. The renewable share increased from 29% in Q3 2021 to 30% in Q3 2022, supported by a surge in wind output (+33%). Nuclear generation was 2% higher during Q3 2022. The share of net imports from the continent compared with total generation decreased from 15% in Q3 2021 to -8% in Q3 2022

(net exports). The position of coal drop slightly (-1%). Gas generation registered a relevant increase of 22% compared to Q3 2021. Gas-fired generation remained the largest share of generation mix (51%) during Q3 2022.

- Two nuclear power plants ended generation between 2021 and 2022 (Dungeness B in 2021 and Hunterston B in Q1 2022). The nuclear fleet of the UK is set to be retired by 2028 (Torness, Hinkley Point B, Heysham 1, Heysham 2 and Hartlepool), with the exception of Sizewell B, to be closed in 2035. However, the new nuclear plant Hinkley Point C is now expected to come online in June 2027. EDF is planning to extend the life of Hartlepool and Heysham I nuclear reactors beyond the current expected end date of March 2024 (2 GW of capacity altogether).

Figure 36 – Evolution of the UK electricity mix between Q3 2021 and Q3 2022

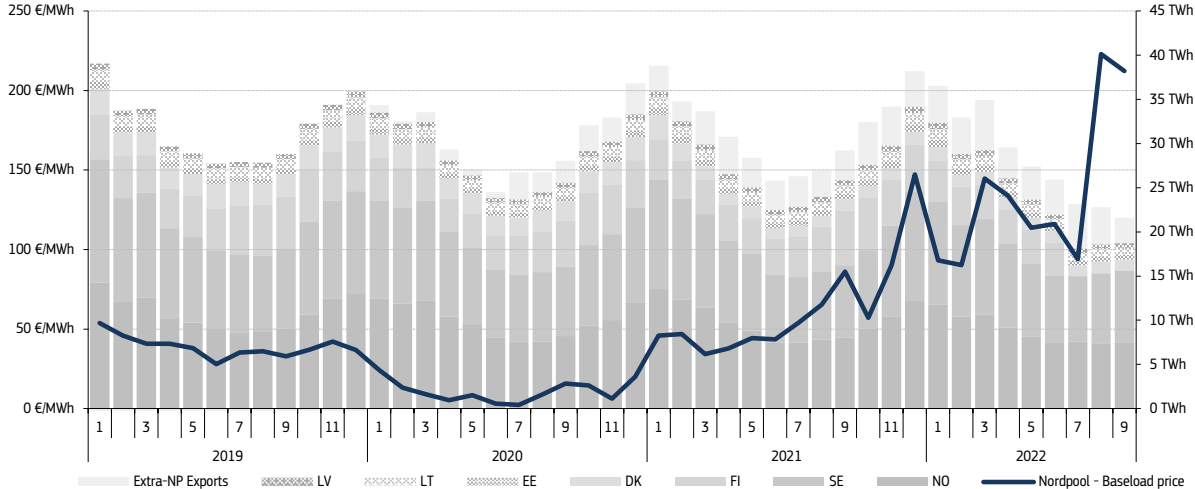


Source: BEIS. Positive values of cross-border flows indicate net imports

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

- As shown in **Figure 37**, Nord Pool prices baseload prices reached new historical peaks in Q3 2022. Prices reached a new all-time high of 223 €/MWh during August (+54% from the high in March 2022). Compared to Q3 2021, the average system baseload price surged by 158% from 68 €/MWh in the equivalent reference quarter.
- Finland is expected to improve its condition of net importer of electricity when Olkiluoto-3 nuclear power plant is commissioned. Olkiluoto-3 will significantly improve Finland's position, especially after Russian exports of electricity were suspended to Finland on 14 May. The start date of the reactor has been recently postponed again to February 2023, as the plant was scheduled to come online in December 2022. The delay obeys some damage detected in Olkiluoto-3's turbine island. As part of the commissioning tests, the nuclear plant reached full electrical power (1600 MW) for the first time at the end of September. Finland also 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.

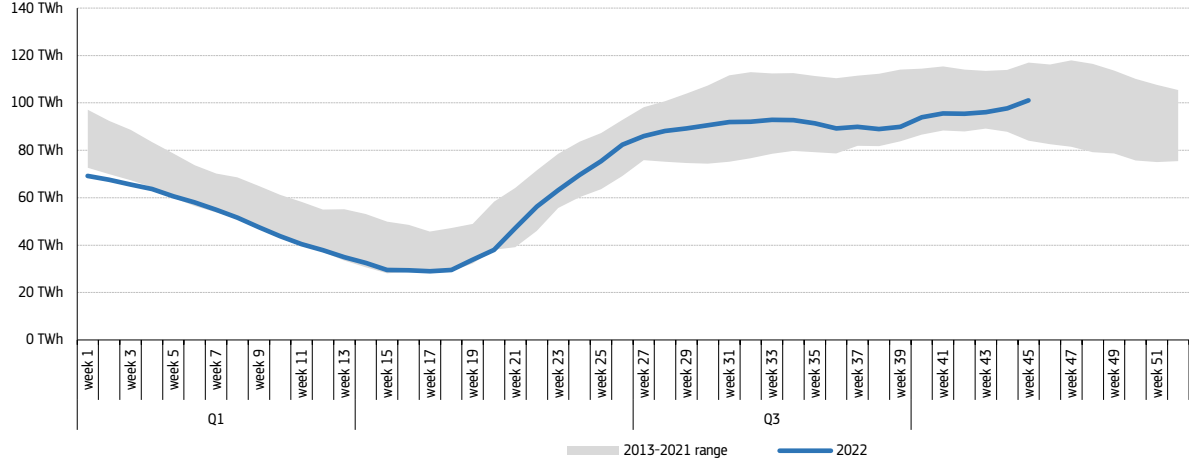
Figure 37 – Monthly electricity exchange traded volumes and the average day-ahead wholesale prices in Northern Europe



Source: Nord Pool spot market

- **Figure 38** 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. After a dry summer, hydro stocks started to mildly increase during Q3 2022. Hydroelectric stocks reached a quarterly high of 93 TWh during the second week of August, within the range of historical levels. Since then, stocks have increased to above 100 TWh, during the start of November. Overall, Nordic hydropower generation recorded a 6% improvement in Q3 2022 compared to Q3 2021.

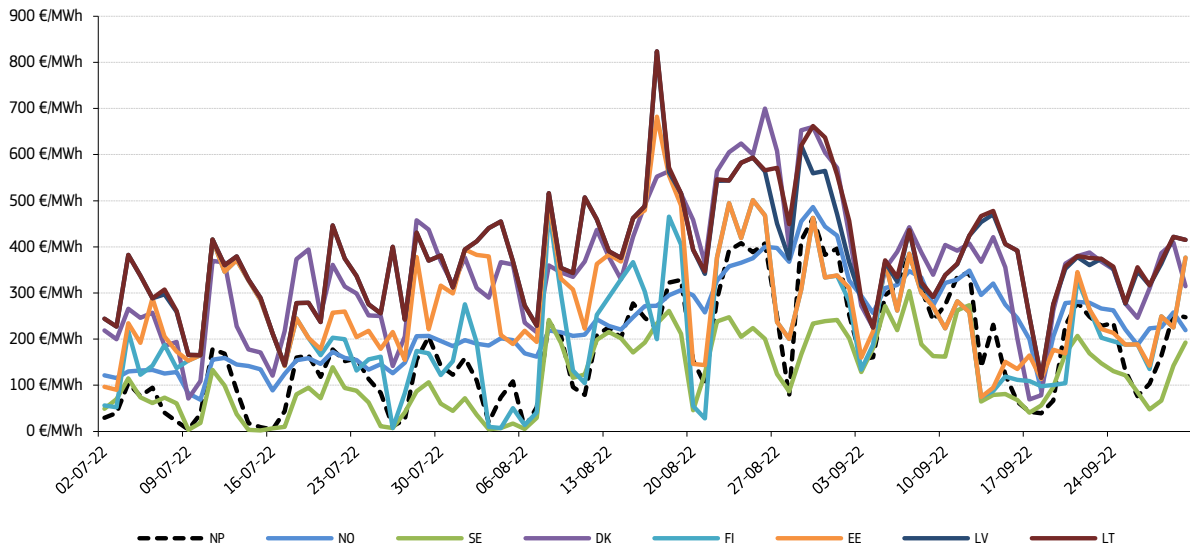
Figure 38 – Nordic hydro reservoir levels in 2022, compared to the range of 2013-2021



Source: Nord Pool spot market

- **Figure 38** shows that average daily prices across Northern Europe continued to display an unprecedented degree of divergence and volatility throughout Q3 2022. The highest daily regional price registered in the reference quarter reached an all-time high at 462 €/MWh on 30 August, whereas the lowest daily regional price registered dropped to 13 €/MWh on 16 July. The highest spike was recorded in Lithuania and Latvia on 17 August (824 €/MWh). Hourly prices hit the maximum Single Day-Ahead Coupling clearing price (SDAC) of 4,000 €/MWh in the three Baltic bidding zones on 16 August. The main factors enabling this event were reduced cross-border transmission capacity and tight supply margins, including subdued wind generation. In Estonia, the Finnish cross-border link was under maintenance on 17 August and the Lithuanian-Polish interconnection was to be cut for maintenance. Furthermore, the suspension of Russian imports from Kaliningrad to Lithuania on August 11 also supported tight margins on the supply side.

Figure 39 – Daily average regional prices and the system price on the day-ahead market in the Nordic region

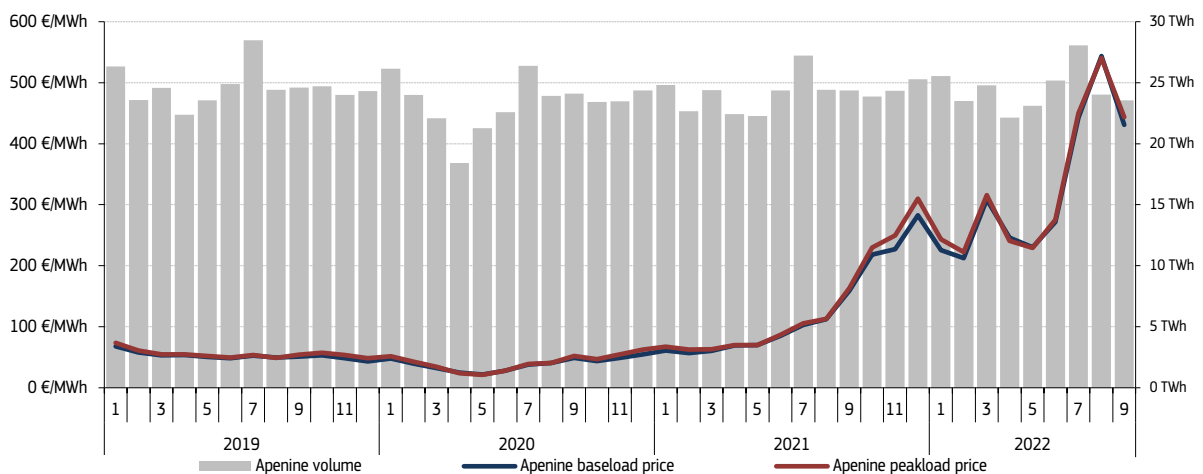


Source: Nord Pool spot market

3.4 Apennine Peninsula (Italy, Malta)

- Following a drop in the previous quarter, the Italian monthly average baseload electricity prices (**Figure 40**), experienced a new all-time high in August (540 €/MWh) supported by the developments on the gas market. At 472 €/MWh, the Italian market recorded the largest average baseload price in Europe during Q3 2022 (followed by Malta). The average baseload price rose by 279% compared to Q3 2021. Trading volumes practically unchanged with respect to the previous third quarter.
- Italy, like other Member States, has been taking measures to alleviate the effect of high energy prices to end-consumers. The Italian government has been putting in place several emergency packages to mitigate the impacts of the energy prices surge. In September and November, new measures were put in place to mitigate the impact of the energy crisis on consumers and businesses.
- The 1.2 GW Savoy-Piedmont link between Italy and France became half operational on 7 November (equivalent to 500 MW in the Italy-France direction and 600 MW in the reverse direction). The link will be fully operational in 2023. The link (1 GW in the Italy-France direction and 1.2 GW in the other direction) will boost the interconnection between France and Italy to 4.4 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 40 – Monthly electricity exchange traded volumes and average day-ahead wholesale prices in Italy



Source: GME (IPEX)

- **Figure 41** 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 300 and 700 €/MWh during the reference quarter. Prices reached an all-time high value at 740 €/MWh on 29 August, due to skyrocketing gas prices following the worsening of the geopolitical picture around the cut-off of flows via the Nord Stream 1 pipeline.
- Italy is one of the largest producers of electricity from gas in the EU (gas-fired generation represented 54% of the total generation in Italy during Q3 2022). Rising commodity prices, especially gas, played an important role in the surge of prices. The impact of the Russian invasion of Ukraine and the uncertain political situation connected to the war, have heavily impacted gas prices in Italy. In addition, the cut-off of deliveries to Italy by main the Russian gas company increased pressure on an already tight energy market, as a result of a drought which has reduced hydro output by 34% year-on-year in Q3 2022.
- 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 41**, the trend has shown an intermittent development in Q3 2022, as prices in the Maltese area not always stayed in the upper bound of regional prices. On the other hand, the Sardinian zone has been forming the lower boundary, quite far away from the Italian single national price (PUN), supported in part, by the isolated effect of the island zone with respect to the continent.

Figure 41 – Daily average electricity prices in the Italian day-ahead market, within the range of different area prices

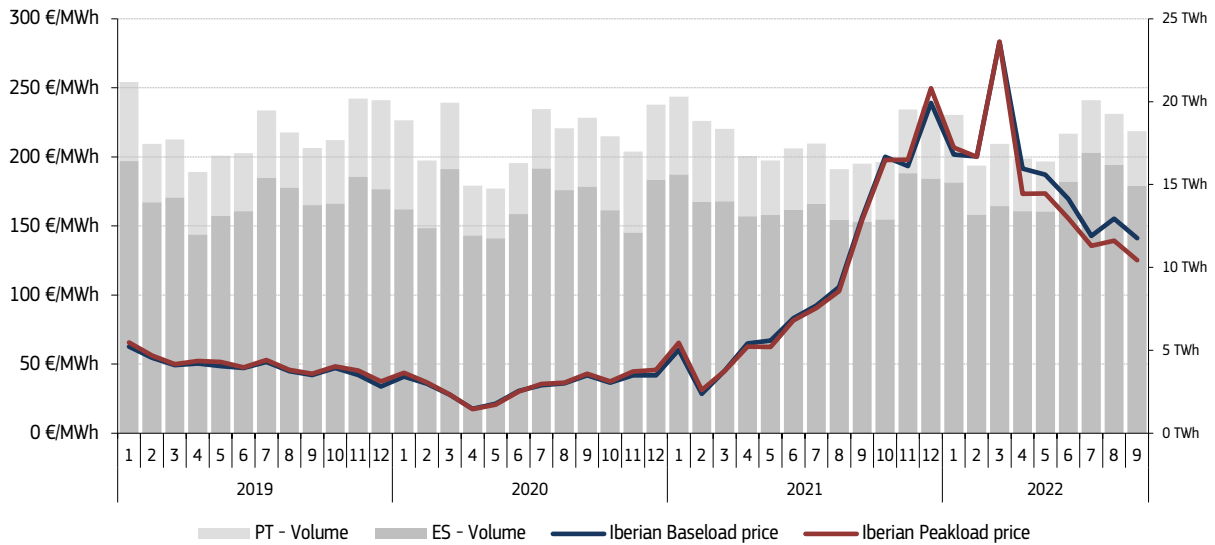


Source: GME (IPEX)

3.5 Iberian Peninsula (Spain and Portugal)

- **Figure 42** reports on monthly average baseload and peakload contracts in Spain and Portugal. After the March peak (283 €/MWh) prices fell until July (143 €/MWh) supported by the start of the 'Iberian exception' in mid-June. Prices rose in August, however, to a much lower level than in the rest of Europe. Prices fell again in September to 141 €/MWh, at a lower level than September 2021. Compared to Q3 2021, the average baseload price rose only by 24% to 146 €/MWh in Q3 2022. Peak prices increased by 15% to 133 €/MWh. Trading activity registered an increase (+22%) compared with the previous Q3.

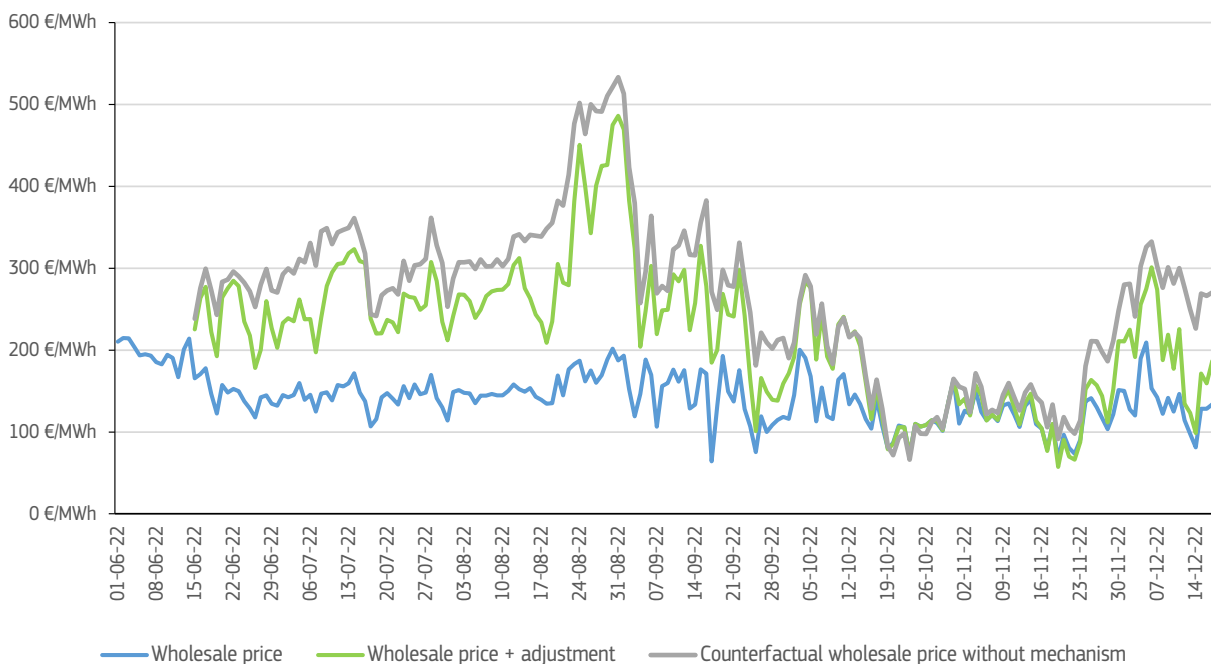
Figure 42 – Monthly electricity exchange traded volumes and average day-ahead prices in the Iberian Peninsula



Source: Platts, OMEL, DGEG

- Nearly 10 million customers (40% of consumers in Spain) are on tariffs directly linked with the wholesale electricity market. Considering the surges in wholesale prices, the Government issued an exceptional cap on the price of gas used for power generation as of 14 June in the day-ahead markets of the Iberian Peninsula. The measure has resulted in lower wholesale prices in the Iberian market while at the same time, it has partially contributed to reverse power flows between Spain and France and increase gas-fired generation. However, these developments need to be seen in the context of increasing imports of electricity in France due to low nuclear generation and subdued hydro-power generation in Spain.
- **Figure 43** reports on the developments in wholesale prices since the start of the mechanism (15 June 2022) up to mid-December. Overall, since the start of the exception, the wholesale electricity price has averaged 138 €/MWh, registering a 48% decrease in comparison with the average counterfactual wholesale price without the mechanism. Also, final consumers with tariffs linked with the wholesale price have paid an average compensation of 83 €/MWh, thus these consumers have benefitted by 16% from the measure.

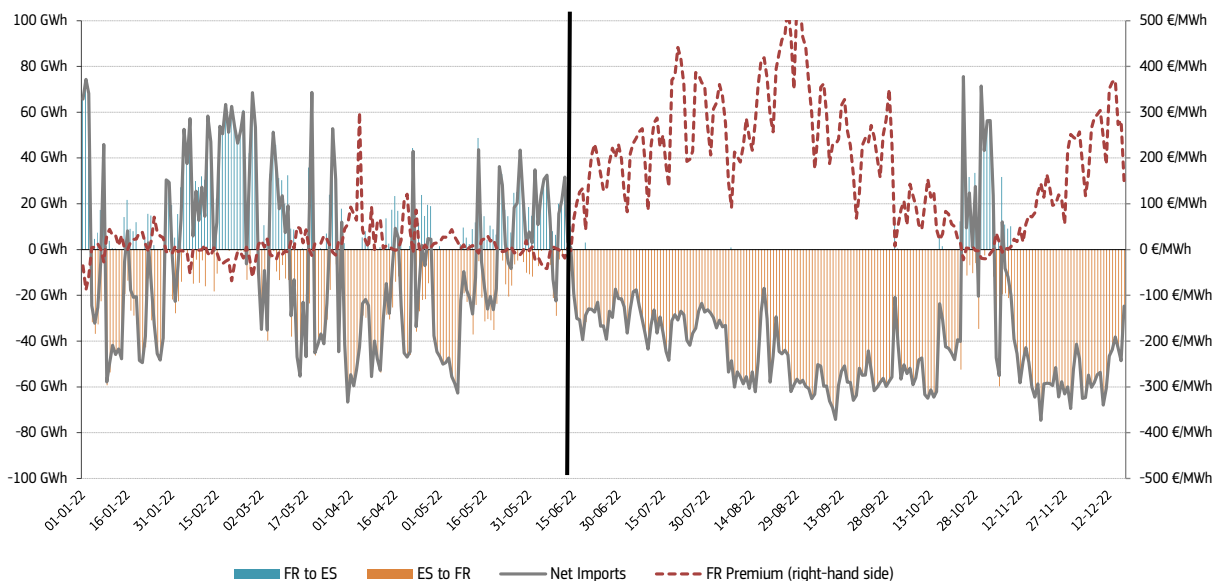
Figure 43 – Iberian market day-ahead electricity prices



Source: OMIE, DGEG

- Figure 44** shows daily electricity flows between France and Spain and price differentials between the two bidding zones from January to mid-December 2022. Since the introduction of the measure and along with the reduction of the traditional French premium, exports from France to Spain practically disappeared, while flows from Spain to France have risen. In general, the subdued nuclear availability of the French nuclear fleet has made electricity prices higher in France. Thus, changing France's traditional net exporter into a net importer role, not only from Spain but also from other Member States and the United Kingdom (see **Figure 30**). A notorious exception to this trend occurred between 23 October and 9 November, when lower power demand in France due to mild weather supported French net exports to Spain. During these days, the French premium over Spain was severely reduced and even reversed on certain days.

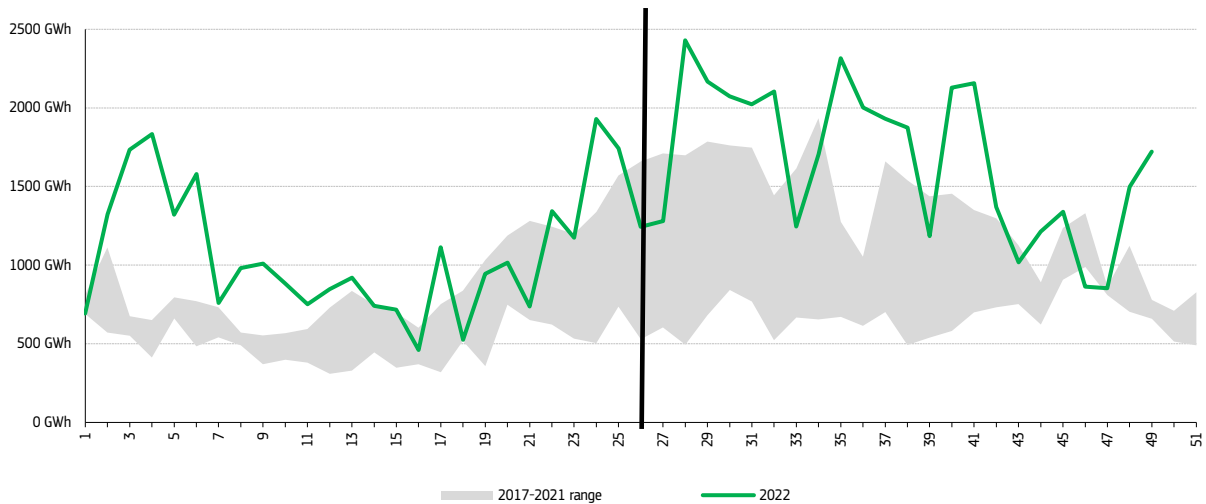
Figure 44 – Daily electricity import balance for Spain and France and price differentials between them in 2022 (January – mid-December)



Source: ENTSO-E

- Figure 45** reports the evolution of gas-fired generation in Spain during 2022 (January – mid-December) compared to a range of the previous five years (2017-2021). From 15 June to mid-December, gas-fired generation rose by 51% compared with the average value during the same period between 2017-2021. However, gas-fired generation levels were already 50% higher during the period before the introduction of the measure (January to mid-June), in comparison with the same period in 2017-2021 (Q1 2022 recorded an increase of 69% in gas-fired generation year-on-year). The levels of gas consumption in the period under study were also influenced by weather conditions, with higher-than-usual electricity demand for cooling compounded with severe droughts that led to lower electricity generation from hydropower. All this, led to a resort to gas for electricity production above normal levels.

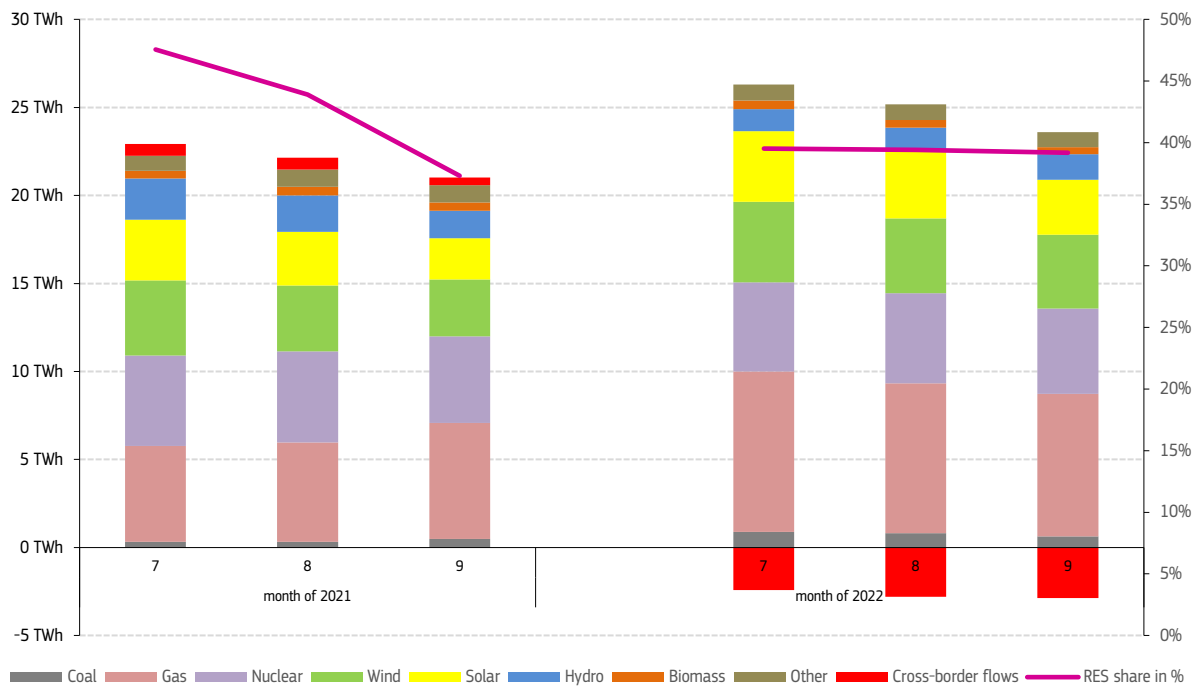
Figure 45 – Weekly gas-fired electricity generation in Spain



Source: REDEE

- Figure 45** displays the evolution of the monthly electricity generation mix in Spain during the third quarter of 2022, as well as during the same period of the previous year. Net generation increased by 17% year-on-year. The share of renewable electricity sources fell to 39% in Q3 2022 from an average of 43% in Q3 2021. Wind generation increased by 15%, whereas solar output rose by 24%. Gas generation rose by 45% (+8 TWh), covering a share of 34% of the total generation in Q3 2022. The reduced remaining coal capacity registered a 111% increase in output (+1.2 TWh) year-on-year in Q3 2022. Nuclear generation decreased slightly its output by 1% and covered a share of 20% of the total generation. In Spain, net exports accounted for 11% of the total generation during the third quarter of 2022.

Figure 46 – Monthly evolution of the electricity generation mix in Spain in Q3 of 2021 and 2022

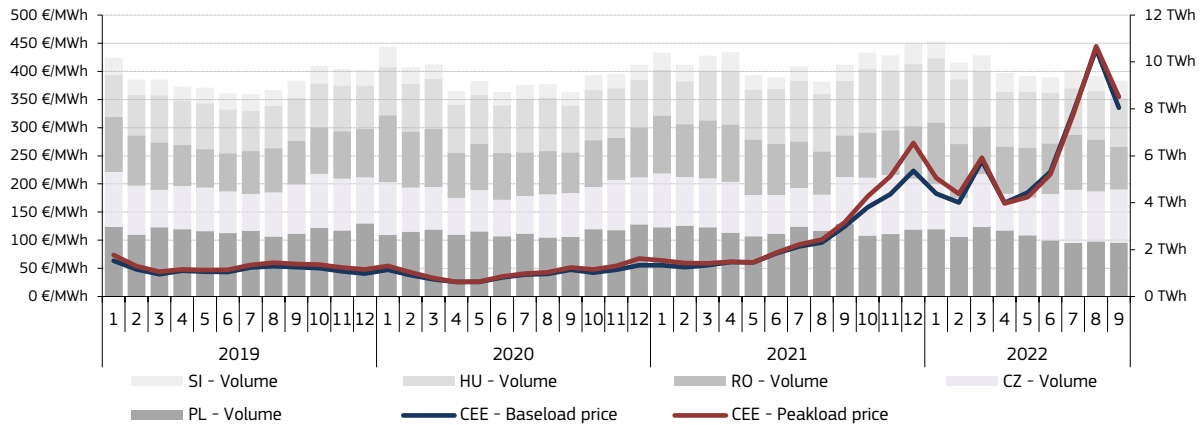


Source: ENTSO-E, Eurostat. Positive values of cross-border flows indicate net imports. Data represent net generation.

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

- **Figure 46** shows that average monthly prices for baseload power in Central Eastern Europe reached new historical high levels in Q3 2022. After the peak in March (241 €/MWh), baseload prices continued to rise in July to 327 €/MWh, reaching a new historical peak in August at 439 €/MWh, decreasing to 335 €/MWh in September. When compared to Q3 2021, the average baseload price in the reference quarter rose by 256% to 367 €/MWh, 92% higher than the average in Q2 2022. Traded volumes in the reference quarter fell by 4% compared to the previous Q3.

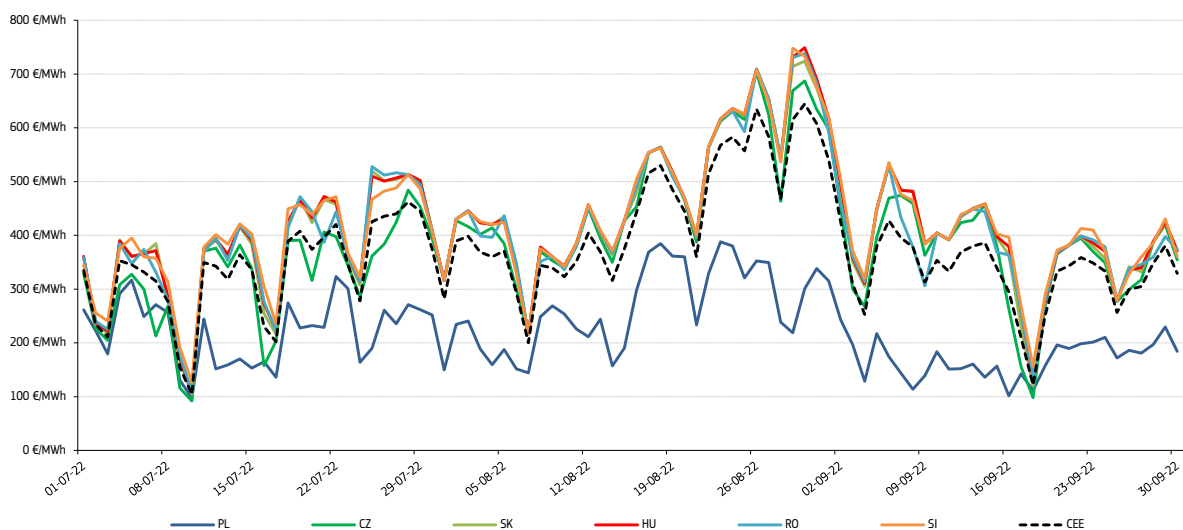
Figure 47 – Monthly electricity exchange traded volumes and average day-ahead prices in Central Eastern Europe (CEE)



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

- **Figure 47** shows that daily average baseload prices in the markets (CZ, HU, RO, PL, SK, SI) reached unprecedented levels together with high volatility during Q3 2022. CEE prices moved between 200 and 450 €/MWh in July. In August, prices continued to rise until they reached a new all-time high on 30 August (644 €/MWh). The Polish market significantly increased its discount towards CEE prices from an average of -42 €/MWh in Q2 2022 to -149 €/MWh in Q3 2022. High electricity prices have also affected Member States with reduced exposure to gas, such as Poland (although to a lesser extent than markets relying on gas). This is an interesting signal towards renewables, as high penetration levels of solar and wind could reduce exposure of electricity prices to scarce energy commodities (gas and coal).
- The 600 MW SwePol link was temporarily shut down on 12 September due to planned maintenance and a further unplanned outage, returning to service on 9 October. The maintenance forced the Polish network operator to import larger volumes from Germany and the Czechia.

Figure 48 – Daily average power prices on the day-ahead market in the CEE region

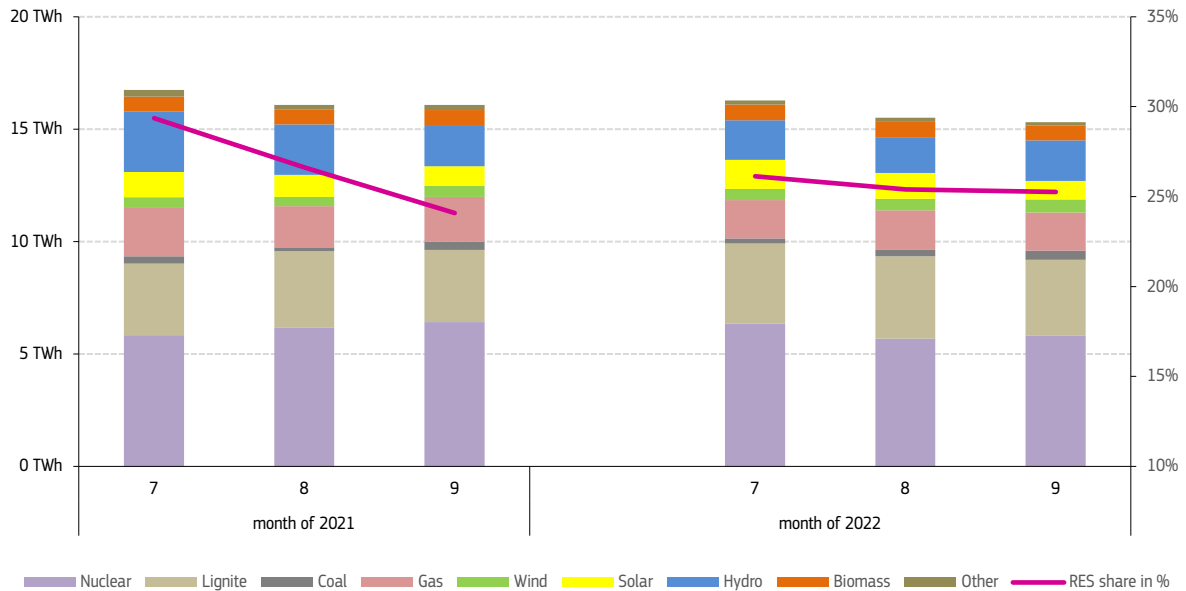


Source: Regional power exchanges

- **Figure 49** compares the combined electricity generation mix of the CEE region (excluding Poland) in Q3 2022 and Q3 2021. Hydro-power generation fell considerably (-24%) in Q3 2022 (especially in Slovakia registering -39%

output). A rise in wind (+18%) and solar (+10%) generation were not enough to compensate hydro losses during the reference quarter. This caused the renewable energy share to slightly drop compared with Q3 2021 (from 27% to 26%). Wind generation registered a surge in Romania and Slovenia. Nuclear remained the dominant generation technology (38% share of the total generation), despite reducing its output by 3% in Q3 2022, with a considerable presence in all five markets.

Figure 49 – Evolution of the electricity mix in the CEE region (excluding Poland) between Q3 2021 and Q3 2022



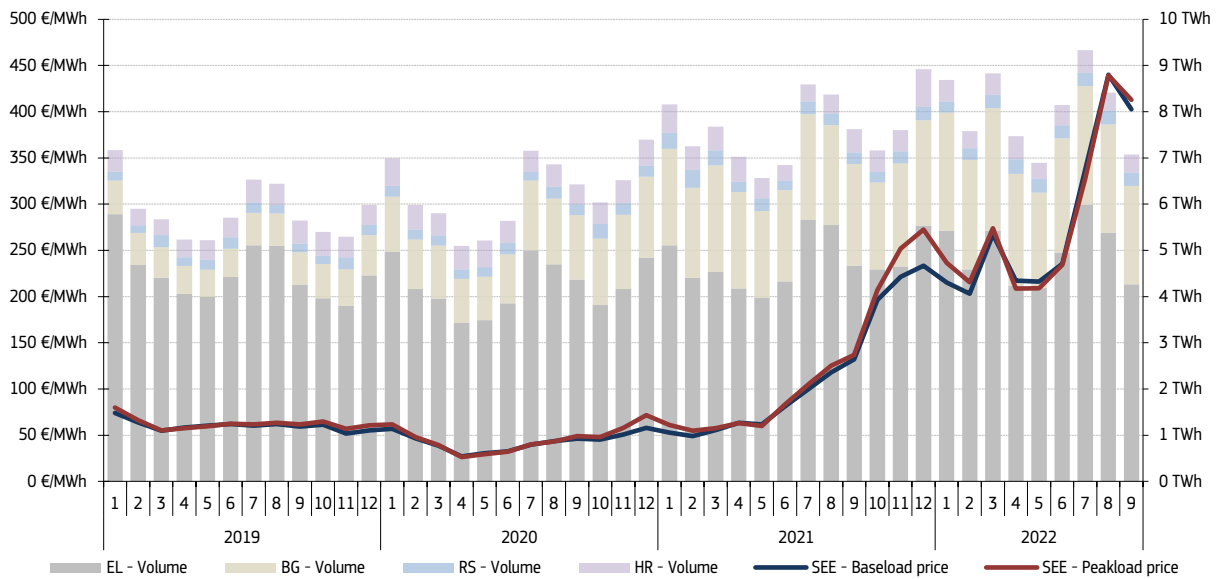
Source: ENTSO-E.

- 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 slightly to 73% in Q3 2022 compared to 74% in Q3 2021. Renewables increased their share from 16% in Q3 2021 to 21% in Q3 2022, thanks to booming solar generation (+106%) and the increase in wind (+11%), despite a drop in hydro (-16%) and biomass (-15%) generation. Gas decreased its share in the mix from 9% in Q3 2021 to 5% in Q3 2022, underlining the limited short-term potential for coal-to-gas switching (or vice versa) and recent economic disadvantage of gas compared with 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 (hard coal and lignite) in Poland's mix, at 73% in Q3 2022, should decrease to 56% by 2030 thanks 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 50** shows that baseload prices rose in July and August to 337 €/MWh and 440 €/MWh, respectively. Prices then fell to 402 €/MWh in September. Strong gas prices in the context of cut-offs of Russian gas supplies to Europe influenced new all-time high electricity prices in August. Marginal costs of gas generation in countries like Greece, with high levels of gas-fired generation supported high energy prices, especially in August. The average quarterly baseload price rose by 238% year-on-year to 393 €/MWh in Q3 2022, 72% above Q2 2022 levels. The average quarterly peakload price rose 222% above Q3 2021 levels to 393 €/MWh.

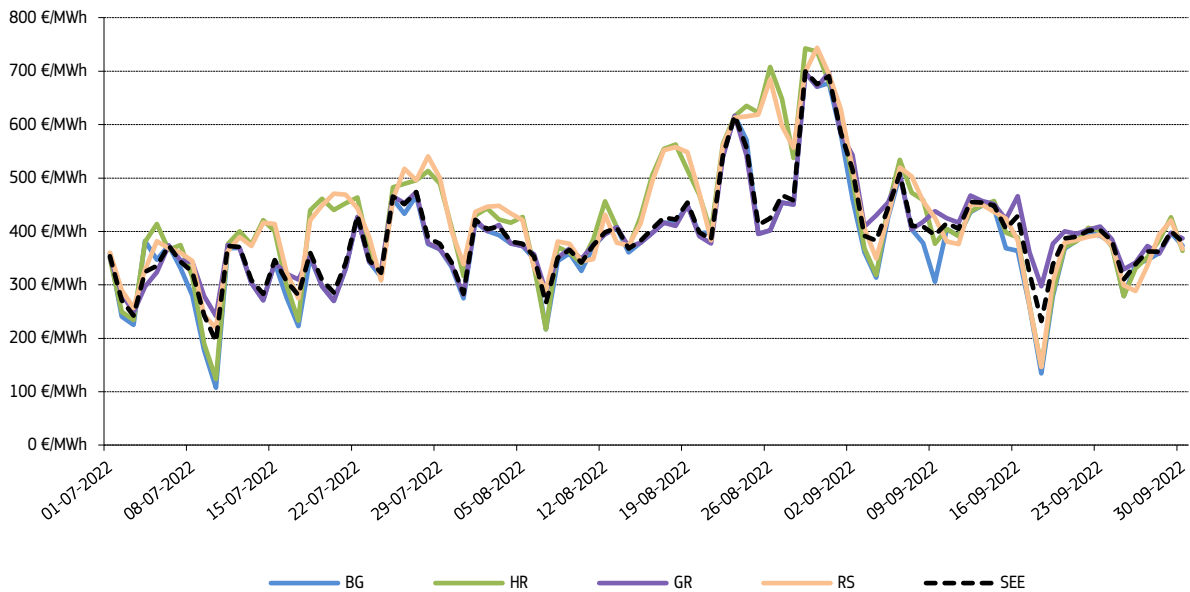
Figure 50 – Monthly traded volumes and baseload prices in South-Eastern Europe (SEE)



Source: IBEX, LAGIE, CROPEX, SEEPEX

- As shown in **Figure 51**, Greek and Croatian day-ahead prices remained mostly at a premium on the daily baseload price of South-Eastern Europe markets during Q3 2022. Prices increased and remained volatile during July (between 200 and 450 €/MWh) and August (between 350 and 700 €/MWh). Prices started to fall in September, moving between 200 and 550 €/MWh. In line with the rest of Europe, wholesale electricity prices reached a new all-time high on 29 August at 700 €/MWh, on the back of the effects of high gas prices due to cuts of Russian gas supply.

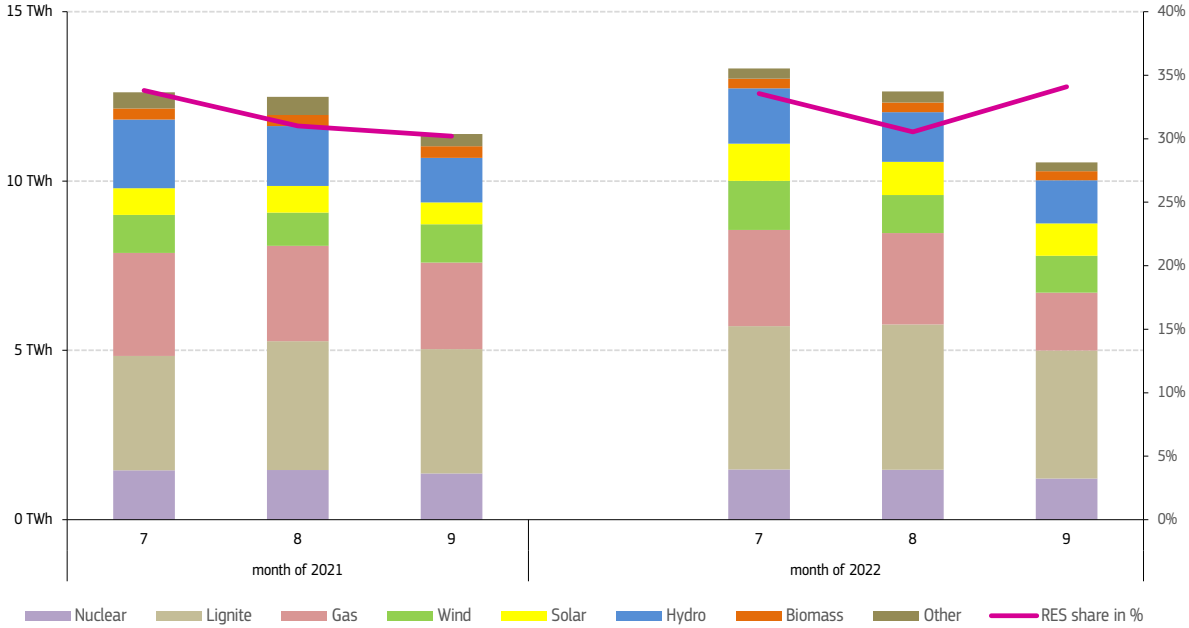
Figure 51 – Daily average power prices on the day-ahead market in Bulgaria, Croatia, Greece and Serbia



Source: IBEX, LAGIE, SEEPEX, CROPEX

- Figure 52** compares the combined electricity generation mix of the SEE region between Q3 2021 and Q3 2022. In Q3 2022, coal and lignite generation increased by 13% its year-on-year output (+1 TWh). Gas output fell by 1 TWh, while nuclear generation remained practically unchanged. Hydro output experienced a setback with 1 TWh less year-on-year. The share of lignite in the regional mix increased from 30% in Q3 2021 to 34% in Q3 2022. Renewable penetration rose from 32% in Q3 2021, to 33% in Q3 2022 due to increased solar (+36%) and wind (+13%) output, despite subdued hydro generation in the region (-14% on yearly basis). European countries are putting measures in place to manage without gas supply from Russia. Greece has extended the life of Melti 1, Agios Dimitrios 3 and 4 lignite power plants from 2023 to 2025, to support security if supply in the country. Moreover, the original plan to convert the Ptolemaida 5 lignite plant to natural gas by 2025 is now in doubt. In addition, lignite mining is being boosted in the country with the aim to increase the lignite-fired output,

Figure 52 – Evolution of the electricity mix in the SEE region between Q3 2021 and Q3 2022



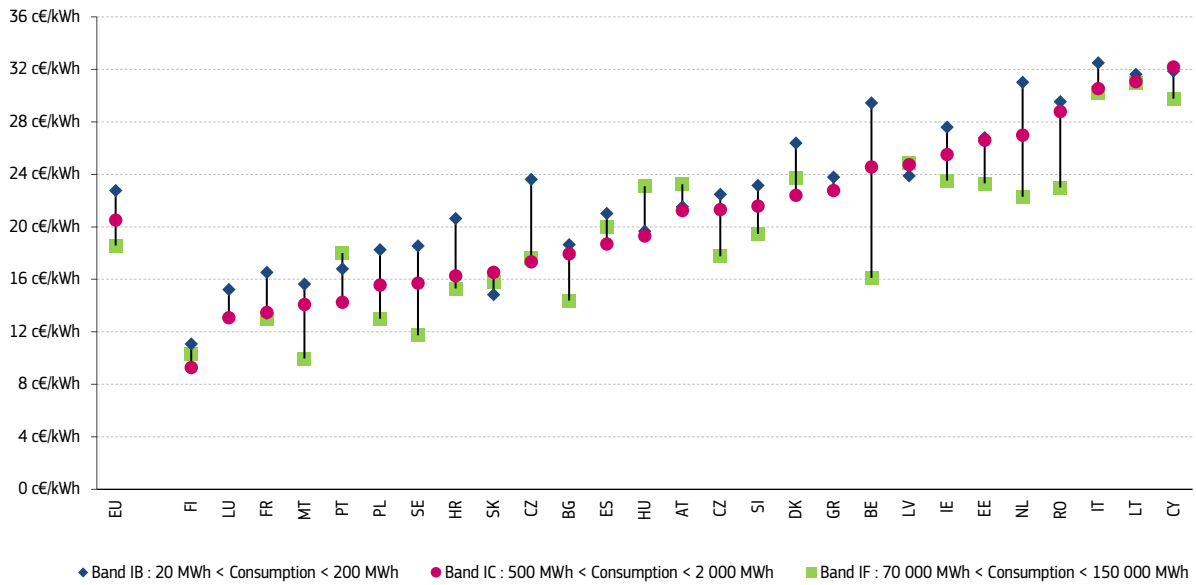
Source: ENTSO-E

4 Retail markets

4.1 Retail electricity markets in the EU

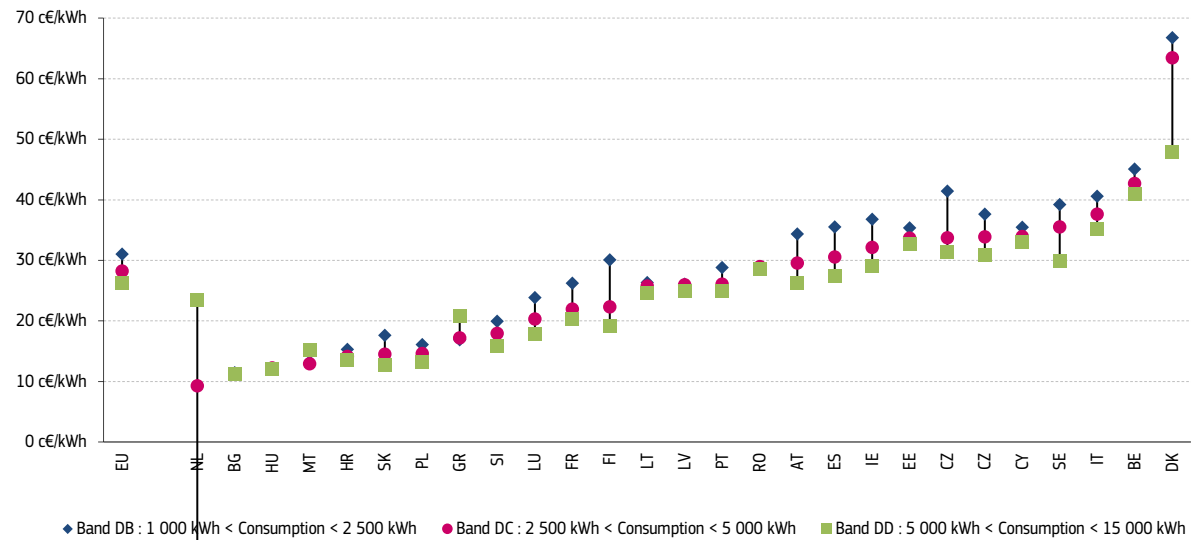
- High wholesale electricity prices have resulted in rising consumer bills for households, impacting the industry sector as well. Increasing wholesale prices are putting upward pressure on retail prices, while government interventions in some Member States are helping to alleviate the bill for consumers. The increases in retail prices could continue ahead the next heating season, as there is still room for wholesale prices to be passthrough into consumer contracts.
- **Figures 53 and 54** display the *estimated* retail prices in September 2022 in the 27 EU Member States for industrial customers and households. The monthly and quarterly retail prices are estimated based on the semi-annual Eurostat prices (with the latest figures available corresponding to the first half of 2022) and the variation of the Harmonized Consumer Price Indices (HICP) of electricity for both household prices and industrial consumers as a multiplier. 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). Hungarian, Portuguese, Austrian, Latvian 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 estimated to pay the highest prices in Italy (32.5 c€/kWh) and Cyprus (31.9 c€/kWh), followed by Lithuania and the Netherlands (31.6 and 31.0 c€/kWh respectively). The lowest prices in the same category were estimated to be in Finland (11.1 c€/kWh) and Slovenia (11.1 c€/kWh). The ratio of the largest to smallest reported price was at 3:1. Compared to September 2021, the average estimated EU retail price for the IB band rose by 40% to 22.8 c€/kWh. On the other side of the consumer spectrum, industrial companies with large annual consumption (band IF), including most energy-intensive users, paid the highest prices in Lithuania (31.0 c€/kWh), followed by Italy and Cyprus (30.2 and 29.8 c€/kWh). Malta and Finland (10.0 and 10.3 c€/kWh) were assumed to have the lowest prices, with Sweden and France (11.7 and 13.0 c€/kWh) coming close behind. The ratio of the highest to lowest price for large industrial consumers was coming close to 3:1 for this consumer type. Compared to September 2021, the average estimated EU retail electricity price for the IF band rose by 64% to 18.6 c€/kWh.
- In the household segment, Denmark (47.8 c€/kWh) was estimated to have the highest electricity price for large consumers (band DD), followed by Belgium (41.0 c€/kWh), and Italy (35.2 c€/kWh) in the third place. The lowest prices for big households were estimated for Bulgaria (11.2 c€/kWh), Hungary (12.1 c€/kWh) and Slovenia (12.7 c€/kWh). Compared to September 2021, the average estimated EU retail electricity price for the DD band rose by 31% to 26.5 c€/kWh. In the case of small households, Denmark was estimated to have the highest prices (66.6 c€/kWh), followed by Belgium (45.1 c€/kWh) and Czechia (41.5 c€/kWh), while Bulgaria (11.5 c€/kWh), Hungary (12.1 c€/kWh) and Malta (14.7 c€/kWh) were on the other side of the price spectrum. In the Netherlands, a price of -16.3 c€/kWh was estimated for small size consumers, connected to government subsidies and allowances. Compared to September 2021, the average estimated EU retail electricity price for the DB band rose by 25% to 26.3 c€/kWh.

Figure 53 – Industrial electricity prices, September 2022 – without VAT and recoverable taxes



Source: Eurostat, DG ENER. Data for the IF band for LU and EL are either confidential or unavailable.

Figure 54 – Household electricity prices, September 2022 – all taxes included

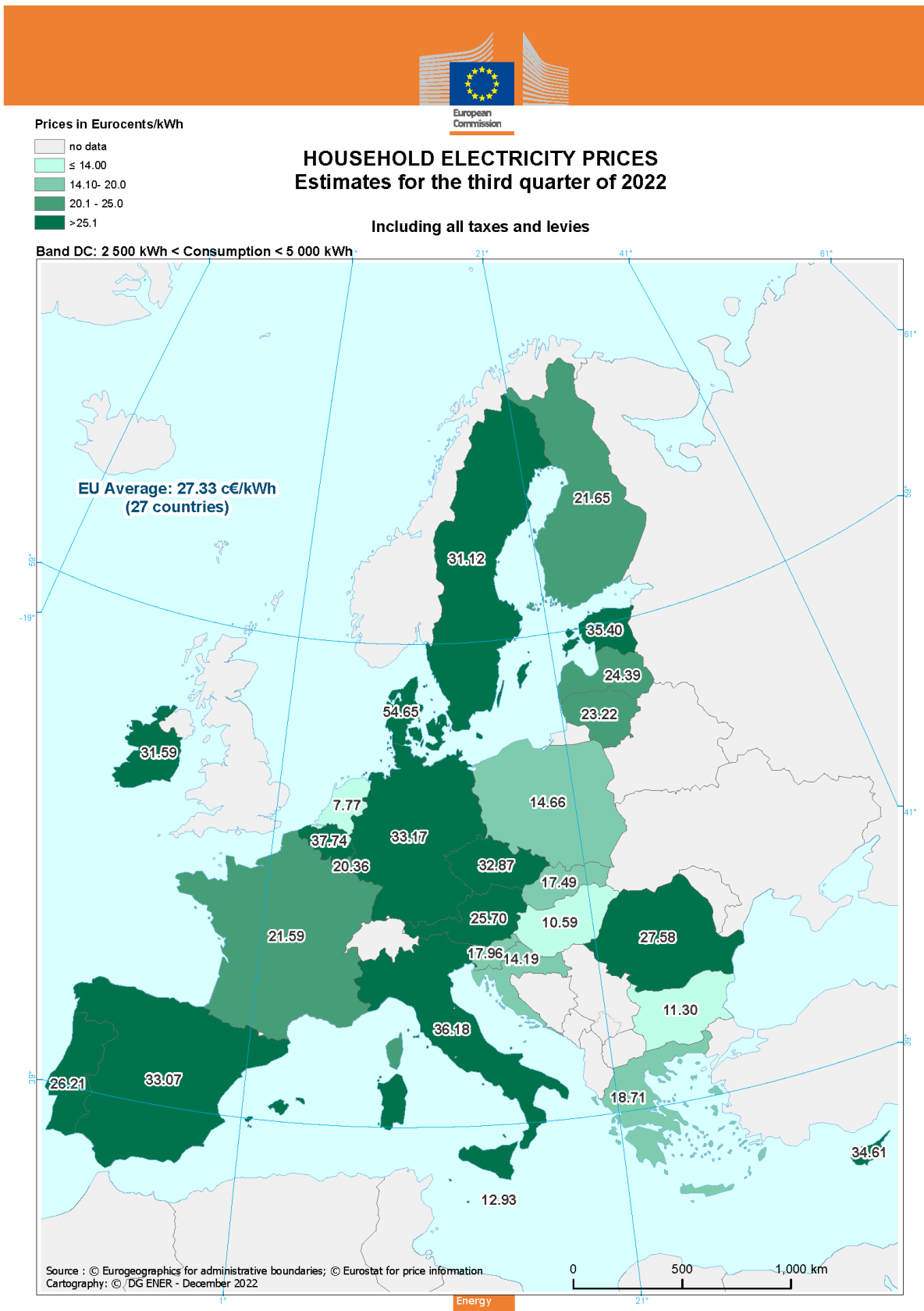


Source: Eurostat, DG ENER

- Figures 55 and 56** display the **estimated** electricity prices paid by EU households and industrial customers with a medium level of annual electricity consumption in the third quarter of 2022. In the case of household prices, Denmark topped the list (54.6 c€/kWh), followed by Belgium (37.7 c€/kWh) and Italy (36.2 c€/kWh). The Netherlands was estimated to have the lowest quarterly prices (7.8 c€/kWh). Hungary (10.6 c€/kWh) and Bulgaria (11.3 c€/kWh) followed the list of Member States with the cheapest estimated household electricity prices. The EU average increased by 21% to 27.3 c€/kWh in the reference quarter compared to Q3 2021. The largest year-on-year increases in the household category were estimated in Estonia (+97%), Denmark (+69%) and Italy (+68%). Year-on-year falls were estimated for the Netherlands (-34%), Poland (-7%) and Malta (-2%). See **Figure 57** for more details on household prices in EU capitals.

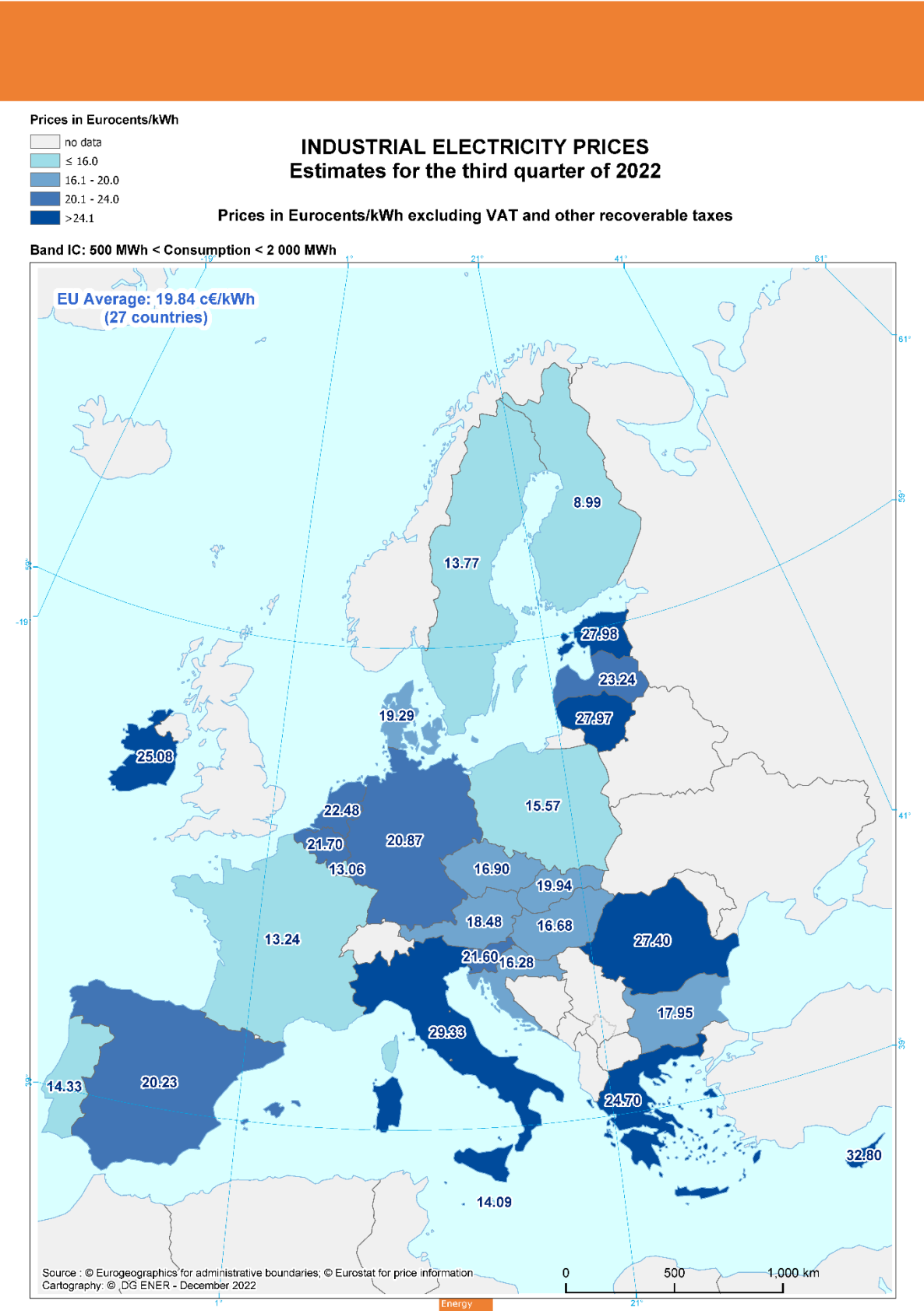
- In the case of mid-sized industrial consumers, Finland was assessed to have the most competitive price in Q3 2022 (9.0 c€/kWh), followed by Luxembourg and France (13.6 and 13.2 c€/kWh, respectively). Meanwhile, Cyprus (32.8 c€/kWh), Italy (29.3 c€/kWh) and Estonia (28.0 c€/kWh) stood at the other end of the spectrum. At 19.8 c€/kWh, the average retail price for industrial customers in the EU in the reference period rose by 43% compared to Q3 2021. The Netherlands (+124%), Romania (+105%) and Lithuania (+100%) marked the largest year-on-year increases in the industrial consumer category. Prices in Malta remained practically unchanged.

Figure 55 – Estimated household Electricity Prices, third quarter of 2022



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

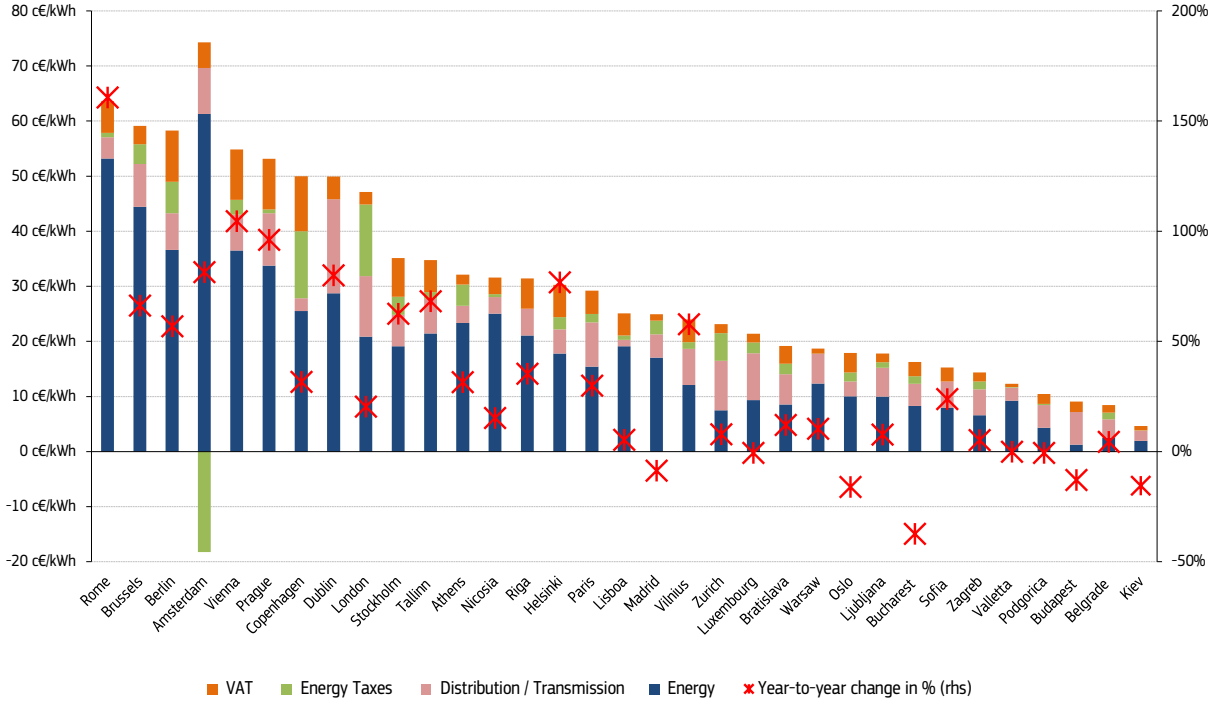
Figure 56 – Estimated industrial Electricity Prices, third quarter of 2022



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

- **Figure 57** 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 49% in November 2022, compared to the same month in 2021. The highest prices were observed in Rome, Brussels, Berlin and Amsterdam (63.6, 59.1, 58.3 and 56.0 c€/kWh, respectively). Following the increase in wholesale energy prices, the energy component share increased in the vast majority of EU capitals. It now surpasses 50% of the total retail price in 22 EU capitals, up from 13 in November 2021. The energy component share is highest in Rome (82%) and Nicosia (79%). Amsterdam represents a special case as explained below. The lowest prices among EU capitals were recorded in Budapest (9.1 c€/kWh), Valletta (12.3 c€/kWh) and Zagreb (13.7 c€/kWh). EU-wide, retail prices have started a steep climb since September 2021. Moreover, pushed by high wholesale prices, retail prices kept increasing throughout the year, intensifying the pressure on inflation throughout 2022. However, the decrease in wholesale prices registered in October alleviated pressure on retail prices, which resulted in a decrease of 7% of prices in November when compared with October 2022. Nevertheless, bouncing back wholesale prices in December might soon reverse the decreasing trend in retail prices.
- The highest levels of the energy component in Europe were reported in Amsterdam, Rome, and Brussels (61.3, 53.2 and 44.5 c€/kWh). The lowest levels of the energy component (1-3 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 21.7 c€/kWh (up from 11.1 c€/kWh in November 2021).
- The highest network charges were recorded in Dublin (17.1 c€/kWh), London and Prague (11.0 c€/kWh and 9.5 c€/kWh, respectively) where they accounted between 34%-18% of the total price. The lowest network fees were collected in Lisbon (1.1 c€/kWh), Kiev (1.8 c€/kWh) and Copenhagen (2.3 c€/kWh). The EU average in the reference quarter was 5.8 c€/kWh (slightly up from 5.6 in November 2021).
- Apart from London (13.0 c€/kWh), the highest energy taxes were paid by households in Copenhagen (12.1 c€/kWh) and Berlin (5.7 c€/kWh). Dublin, Sofia, Budapest and Riga stood at the other end of the range, with practically zero energy taxes collected by local authorities. The average energy tax component stood at 1.2 c€/kWh (down from 2.3 c€/kWh in November 2021). Varied VAT rates applied to electricity, ranging from 5% in Madrid, Valletta, Warsaw and London to 21-20% in Budapest, Copenhagen and Stockholm, also contribute to differences in household prices across Europe. Member States continue to use 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 54**, and contributed to the unusual effect in which the lower the consumption, the lower the price per kWh.

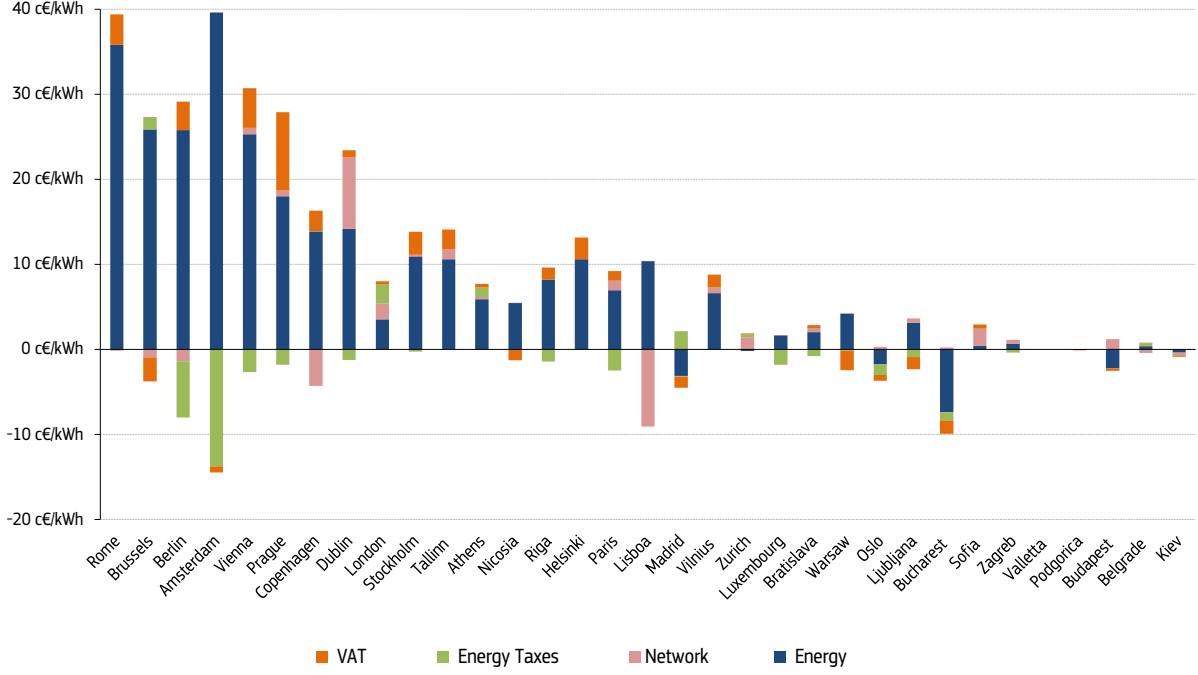
Figure 57 – The Household Energy Price Index (HEPI) in European capital cities in Eurocents per kWh, November 2022



Source: Vaasaett

- Compared to the same month of the previous year, the largest price increase in relative terms in Europe in August 2022 was observed in Rome (+161%), Vienna (+105%) and Prague (+96%). As shown in **Figure 58**, rising prices were driven by increasing wholesale prices in practically every EU capital. Four of the twenty-seven EU capitals reported prices lower or unchanged, compared to the same month of the previous year, with Bucharest (-37%) and Budapest (-13%) posting the largest relative drops. Households in the Hungarian and the Romanian capital benefited mainly from a reduction in the energy component.

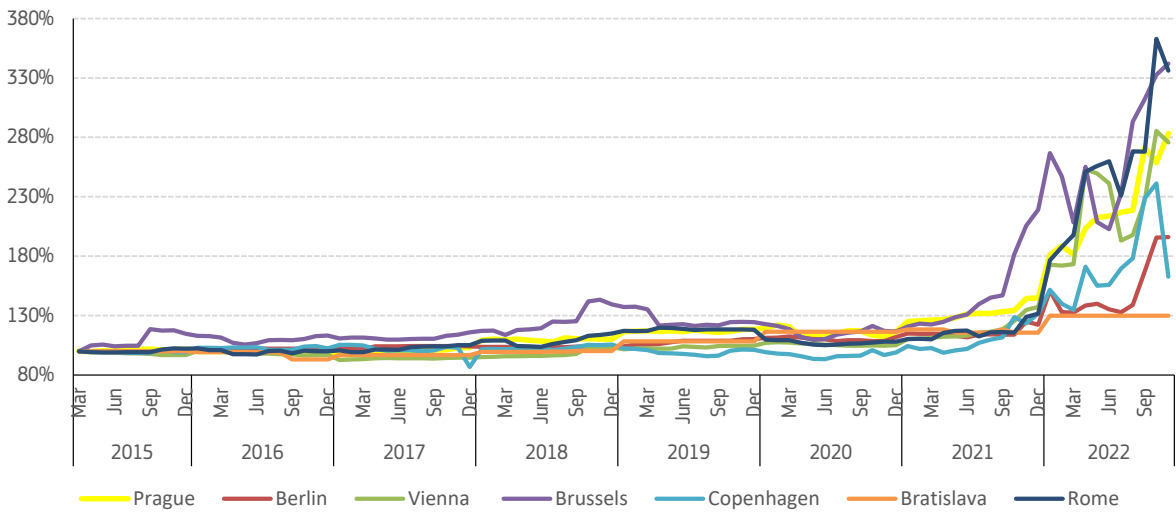
Figure 58 – Year-on-year change in electricity prices by cost components in the European capital cities comparing November 2022 with November 2021



Source: Vaasaett

- **Figure 59** compares how household retail prices in selected EU capitals changed in relative terms over the last seven years. The biggest increase in November 2022 (+342%) was registered in Brussels and was driven mainly by a rising energy component. Rome followed closely with a 336% increase since February 2015, followed by Prague (+283%) and Vienna (+276%). Retail prices for households in Copenhagen, which have been roughly the same as until the second half of 2021, have recently seen a steep increase (+163% compared to February 2015) due to a rise in the energy component. Bratislava and Berlin mark the smallest increases of the selected capitals (130% and 196% respectively).

Figure 59 – Relative changes in retail electricity prices in selected EU capitals since 2015



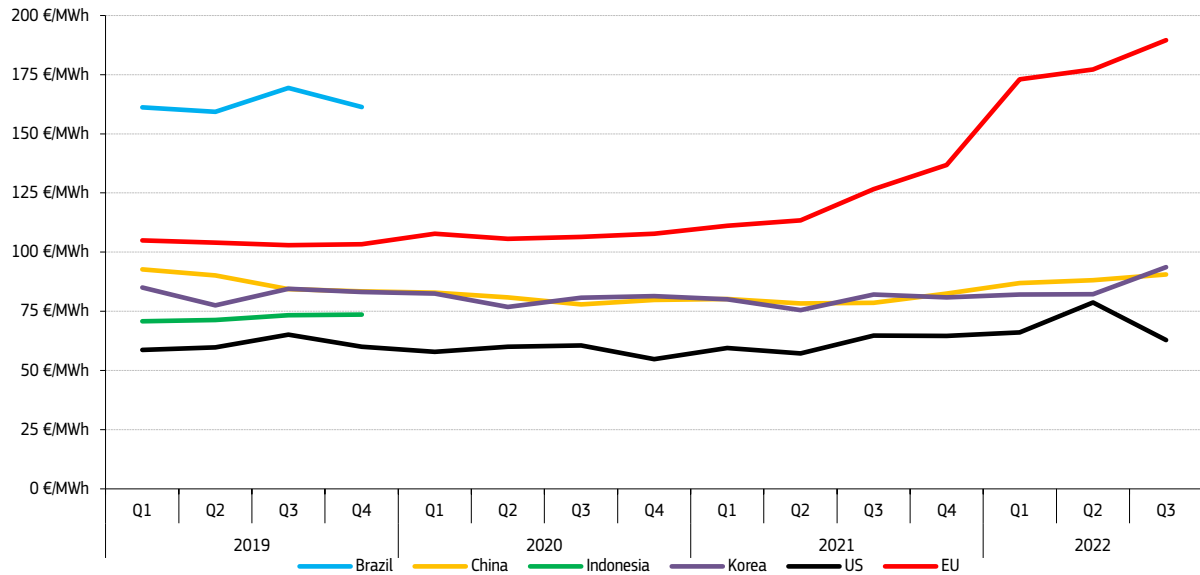
Source: Vaasaett

4.2 International comparison of retail electricity prices

- **Figure 60** 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 registered an increase of 50% in Q3 2022 compared to the equivalent quarter in 2021 and by 7% compared to Q2 2021. Meanwhile, Chinese industrial prices increased 15% year-on-year, continuing an upward trend after the fall in prices observed before 2021. Industrial electricity prices in the United States drop by 3% year-on-year in Q3 2022, falling by 20% compared to Q3 2021. As it can be observed, industrial retail electricity prices in the EU were significantly higher compared to many of the trading partners, implying cost disadvantages for energy intensive industries.

Figure 60 – 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.