

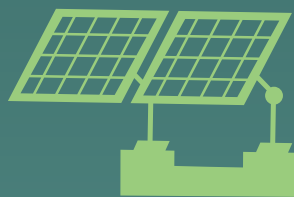


European
Commission

Quarterly report

On European electricity markets

With focus on the impact of wholesale
electricity prices on household retail prices



Market Observatory for Energy
DG Energy

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CONTENT

HIGHLIGHTS OF THE REPORT	3
1 ELECTRICITY MARKET FUNDAMENTALS.....	4
1.1 Demand side factors	4
1.2 Supply side factors	8
2 EUROPEAN WHOLESALE MARKETS	12
2.1 European wholesale electricity markets and their international comparison ..	12
2.2 Traded volumes and cross border flows	21
3 FOCUS ON THE IMPACT OF WHOLESALE ELECTRICITY PRICES IN HOUSEHOLD RETAIL PRICES.....	24
3.1 Main components of electricity retail prices	24
3.2 The pass through effect of electricity prices	24
3.3 Market conditions.....	27
3.4 The gap between wholesale prices and household retail energy component per Member State	29
4 REGIONAL WHOLESALE MARKETS.....	36
4.1 Central Western Europe (Austria, Belgium, France, Germany, Luxembourg, the Netherlands, Switzerland)	36
4.2 British Isles (GB, Ireland)	38
4.3 Northern Europe (Denmark, Estonia, Finland, Latvia, Lithuania, Sweden, Norway).....	40
4.4 Apennine Peninsula (Italy, Malta).....	42
4.5 Iberian Peninsula (Spain and Portugal).....	44
4.6 Central Eastern Europe (Czechia, Hungary, Poland, Romania, Slovakia, Slovenia).....	47
4.7 South Eastern Europe (Bulgaria, Croatia, Greece and Serbia).....	49
5 RETAIL MARKETS.....	52
5.1 Retail electricity markets in the EU	52
5.2 International comparison of retail electricity prices.....	59
GLOSSARY	60

HIGHLIGHTS OF THE REPORT

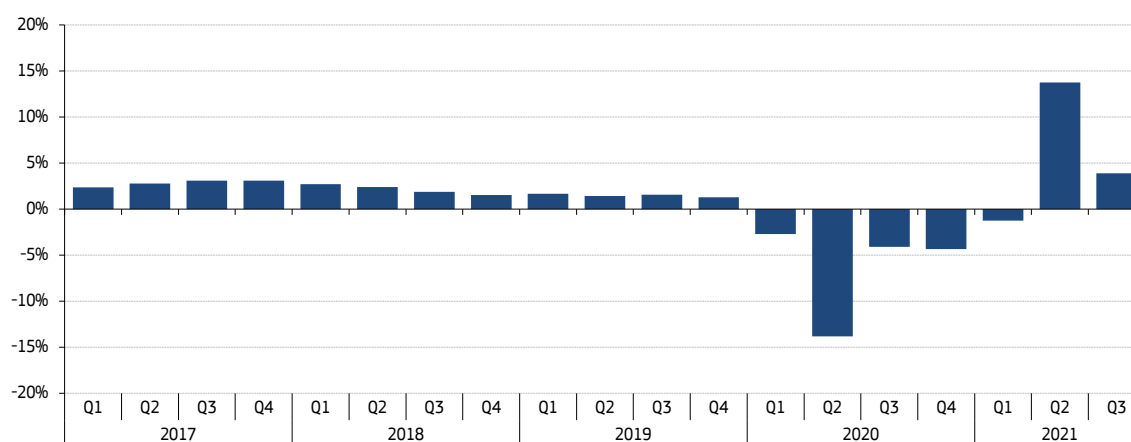
- **The third quarter of 2021 brought electricity consumption in Europe at pre-pandemic levels (Q3 2019)**, driven by a steady economic recovery and ease of lockdowns. **EU-wide consumption increased by 3% year-on-year in Q3 2021**, thanks to recovering industrial and labour activity. Warmer-than average weather also contributed driving cooling demand during the quarter.
- **Wholesale electricity prices reached all-time highs in European markets, registering a sharp increase compared to the same quarter of the previous year (Q3 2020)**. The post-pandemic economic recovery has significantly disrupted global supply chains, having a direct impact on the price of gas in Europe. The sustained rise in this commodity is driving record highs of electricity prices in European markets. The largest year-on-year price increases in the European Union were registered in Ireland (+323%), Portugal (+215%) and Spain (+214%), as a result of rising gas prices in the context of economic recovery. Prices continued the rally during the following months, reaching new historical records in October and December, under high price volatility as Europe enters into the winter. The European Power Benchmark averaged 105 €/MWh in Q3 2021, 211% higher on yearly basis. Compared to Q3 2019, the quarterly average price rose by 164%.
- The rise of gas prices has reversed the coal-to gas switching observed in the previous year, boosting coal generation gains in spite of increasing carbon prices during Q3 2021. Coal and lignite generation rose by 15% (+17 TWh), whereas less CO₂-intensive gas generation fell at 18% (-33 TWh). However, despite unfavourable conditions in some regions, the **share of renewables still managed to reach 37%, beating again fossil fuels (35%)**. This was possible thanks to an increase of 11% in solar generation (+5 TWh), 4% of biomass (+1 TWh) and 2% hydro (+1 TWh) on a yearly basis. Conversely, onshore wind generation decreased by 1% (-0.5 TWh), partially compensated by 8% of improved offshore wind generation (+0.7 TWh). Nuclear generation increased by 20% (+27 TWh), compensating for the reduced levels of gas generation.
- Based on preliminary estimates, **the carbon footprint of the EU power sector rose by 1% in Q3 2021 compared to Q3 2020**, and 13% compared with Q2 2021. **However, emissions were still 6% lower than in the third quarter of 2019**. Despite high carbon prices, carbon emissions are expected to rise this year due to high commodity prices, especially gas, which has triggered a wider use of coal-fired generation at the detriment of gas-fired generation.
- Wholesale electricity prices have been reaching all-time highs, triggering considerable political and social concerns in an increasing number of Member States. **During the last years, wholesale prices have been passed through faster to household retail prices in some countries** (zero to one month e.g. BE, DK, EE, ES, SE), **while in others takes a longer period of time** (one to two years e.g. BG, MT, PL). The use of future contracts is also a strategy used to hedge prices by utilities (BE, CZ, IT, NL) with a considerably level of responsiveness found with the retail energy component. In general, **in markets with high levels of competition, retail prices tend to correlate best (follow the movements) with the wholesale market**.
- **The speed of the pass through effect of wholesale to household retail prices may depend on factors such as the competitive structure of the market, pricing system and the level of public price intervention**. Competitive markets registered lower prices than markets with higher indexes of concentration. The level of dispersion of prices may suggest structural barriers that are present in more concentrated markets. Changes in wholesale prices are reflected more rapidly in retail tariffs in less concentrated markets. **Higher levels of competition in retail markets are the most effective way to reduce household retail prices**. Markets with high shares of dynamic pricing contracts have shown lower prices than those with fixed contracts and are passed through more rapidly than in markets prone to fixed rates. It should be noted that several countries with high penetration of dynamic prices have in general cheap wholesale electricity prices as a result of their energy mix (hydro/nuclear) that could distort the overall picture. Markets without price intervention had delivered lower prices than those with public price intervention, whereas changes in wholesale prices are passed through more swiftly under the former. Nevertheless, other factors have to be taken into account before drawing conclusions into the behaviour of certain markets (energy mix, number of suppliers, offers, price transparency, switching behaviour).
- **In the retail market**, the largest year-on-year **increases** in the **household** category in September were assessed in **Estonia (+53%), Cyprus (+48%) and Spain (+30%)**. The biggest year-on-year falls were estimated for Czechia and Hungary (-3%) and Slovakia (-1%).
- Demand for electrically chargeable vehicles (ECVs) kept growing in Q3 2021. Fiscal support measures (tax benefits) and purchase incentives (bonuses or premiums) provided in seventeen Member States continued to boost sales during 2021. As a result, **almost 410,000 new ECVs were registered in the EU in the third quarter of 2021 (+50% year-on-year)**. ECV sales translated into an impressive 19% market share. ECV sales in Europe were slightly below ECV sales in China and almost four times higher than in the United States.

1 Electricity market fundamentals

1.1 Demand side factors

- **Figure 1** shows in Q3 2021 the economic recovery from the pandemic shock which swept across Europe during 2020 and 2021. The gradual lift on restrictions on economic and social activity and the massive roll out of vaccination, had a palpable impact on the daily lives of millions of citizens and operations of the majority of business. According to an estimate published by Eurostat in September 2021, seasonally adjusted GDP in the EU increased by 4.1% year-on-year between July and September 2021. Although not as impressive as the GDP growth registered during Q2 2021 (13.8%), the growth of the reference quarter is an example of the scale of the economic recovery. This is the second quarter with positive growth since five consecutive negative growth quarters following the start of the pandemic. A rise in output was observed in every Member State. The highest increases were reported in Croatia (+15.5%), Greece (+13.4%), Ireland (+11.4%), Malta (+9.8%) and Estonia (+9.2%). The lowest year-on-year growths were observed in Slovakia (+1.3%), Germany (+2.6%) and Spain (+2.7%).

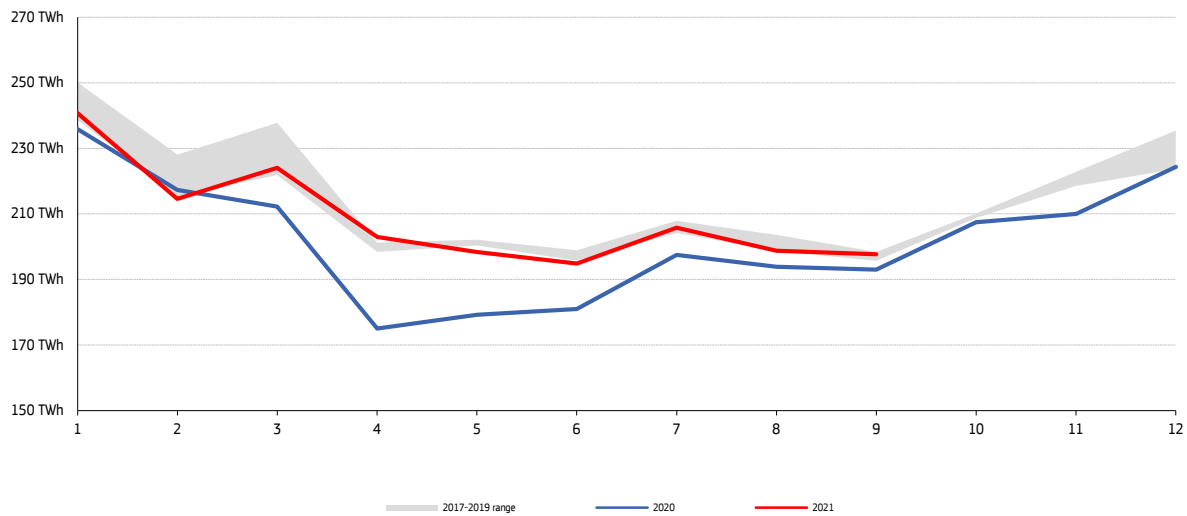
Figure 1 – EU GDP annual change (%)



Source: Eurostat

- According to Eurostat, the electricity consumption in the EU rose 3% above last year's levels in Q3 2021, following the steady economic and social activity recovery. Demand returned to pre-pandemic levels, being slightly over the historical range during July and September and practically at the same level during August. However, the EU average hides wide differences in developments in individual Member States. While almost every Member State saw increases in consumption year-on-year, those range from considerable grows in Poland (+16%), Malta (+11%), Denmark (+8%) to the small increases reported in Slovenia (+1%), Czechia (+1%) and Estonia (+2%). Moreover, Portugal, France, and Spain remained practically unchanged and the Netherlands presented a decrease of electricity consumption during the reference quarter (-1%).

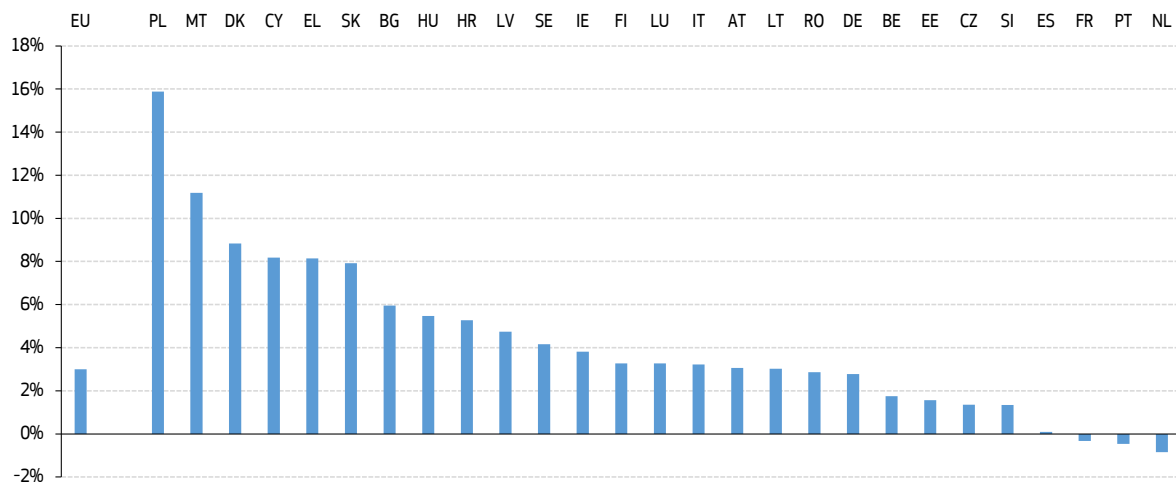
Figure 2 – Monthly EU electricity consumption



Source: Eurostat

- **Figure 3** sums up changes in electricity consumption between the third quarter of 2020 and Q3 2021. Large increases in electricity consumption occurred in Central Eastern and Southern European regions. EU-wide consumption rebounded by 3% on the back of the steady recovery on industrial activity and ease of lockdowns. Cooling demand also influenced the rise in demand during the quarter.

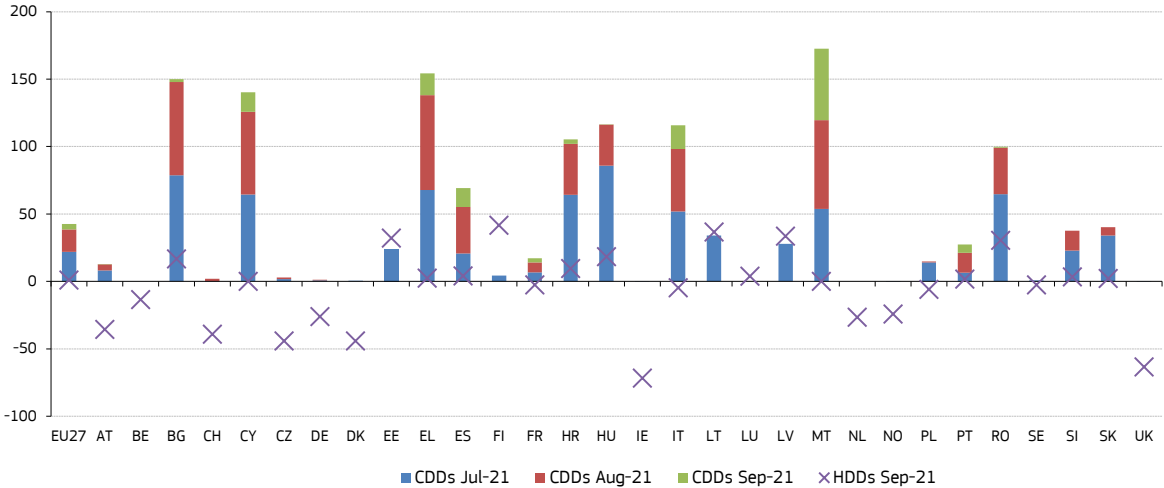
Figure 3 – Annual changes in electricity consumption in Q3 2020 and Q3 2021 by Member State



Source: Eurostat

- **Figure 4** illustrates the monthly deviation of actual Heating Degree Days (HDDs) and Cooling Degree Days (CDDs for September) from the long-term average (a period between 1978 and 2018) in Q3 2021. EU-wide, the reference quarter was hotter than usual, registering 43 CDDs above the long-term average. This means that temperatures were about a half degree Celsius higher than usual. Most of the deviations took place in July, and to a lower extent in August; meaning that the first part of the European summer was warmer-than average. The Iberian Peninsula, Greece and Malta were a notable exception, registering a relatively hot August. In addition, Malta went through heat waves in September. On the heating front, September did not bring major deviations in both directions, with the exception of the British Isles where the weather turned warmer than usual. In general, warmer-than average weather increased electricity demand and prices during Q3 2021.

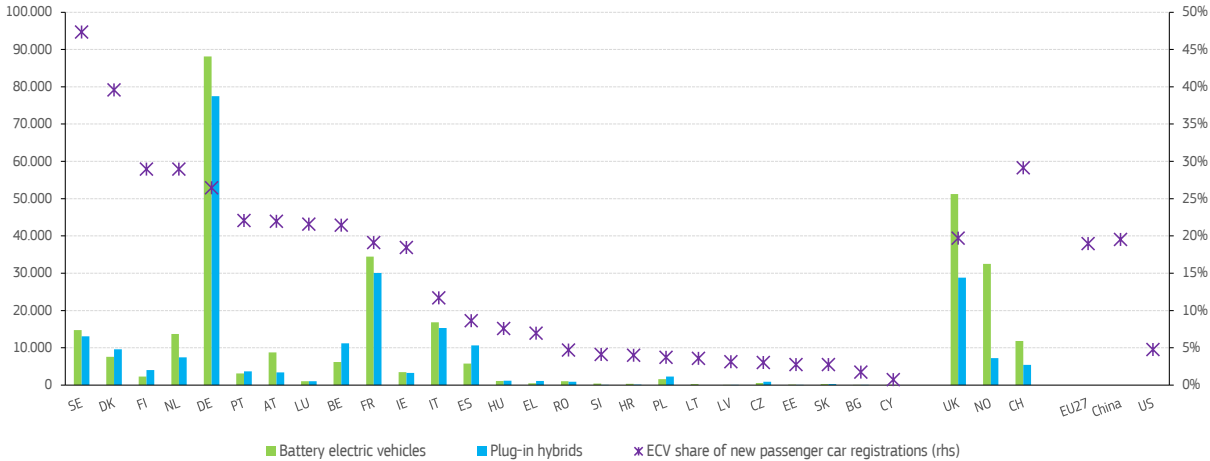
Figure 4 - Deviation of actual heating days from the long-term average in July-September 2021



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

- Figure 5** shows that demand for electrically chargeable passenger vehicles (ECVs) kept growing in thanks to efforts by major automobile manufacturers to meet stricter emission targets and also thanks to support policies of some Member States aimed at incentivising ECV purchases. Additionally, higher number of models are being advertised at more affordable prices, and uncertainty around the use of the combustion engine increases. Germany, Sweden, Denmark, Ireland and the Netherlands plan to end the sale of new internal combustion cars by 2030. In addition, Austria, Croatia, Cyprus, Denmark, Finland, Ireland, Lithuania, Luxembourg, Netherlands, Poland, Slovenia and Sweden (among other non EU 27 MS) signed a declaration to work towards sales of new cars being zero-emissions by 2040 and 2035 in leading markets, during the COP 26 in Glasgow. Almost 410,000 new ECVs were registered in the EU in Q3 2021 (+50% year-on-year). These numbers translated into an impressive 19% market share, slightly below ECV sales in China and almost four times higher than in the United States. ECV sales figures represent the third highest quarterly figure on record (close to the record numbers of Q4 2020 and Q2 2021). Although growth of ECV sales during Q3 2021 did not show impressive numbers compared with Q3 2020, the plug-in hybrid segment continued to grow (+43% year-on-year to 197,000) while demand for battery electric vehicles grew to a higher pace (+57% year-on-year to 212,000). The ECV category beat the hybrid electric vehicles (not chargeable) for the first time since Q4 2020.
- The highest ECV penetration was once again observed in Sweden, where almost half of the passenger cars sold could be plugged, thanks to significant policy changes. From 1 April, battery-powered electric vehicles (BEV) owners in Sweden are being supported by a climate bonus of EUR 6800, for new zero-emission cars and light trucks. Relatively high ECV market shares were observed in Denmark, Finland, the Netherlands and Germany. The 40% share in Denmark is all the more impressive since it is taking place against the backdrop of zero direct purchase incentives (only tax benefits). Germany retained the position of the largest individual market. Its generous incentive programme, which offers up to 9,000 EUR in direct purchase bonuses, keeps driving up ECV sales to 165,000 in Q3 2021, an increase of 50% over the third quarter of 2020. Growth numbers in BEVs were supported most notably by Germany and France, where sales grew 63% and 35% respectively year-on-year.
- As noted by the [European Automobile Manufacturers' Association \(ACEA\)](#), 17 EU Member States offer incentives in the form of fiscal support (tax benefits related to vehicle acquisition and ownership, as well as company cars) or purchase incentives (bonuses or premiums) for buyers of electric vehicles in 2021. In 2020, 20 Member States provided incentives for electric vehicles. Moreover, 10 Member States do not provide any type of purchase incentives (four more than in 2020), although most of them grant tax reductions or exemptions for EVs.

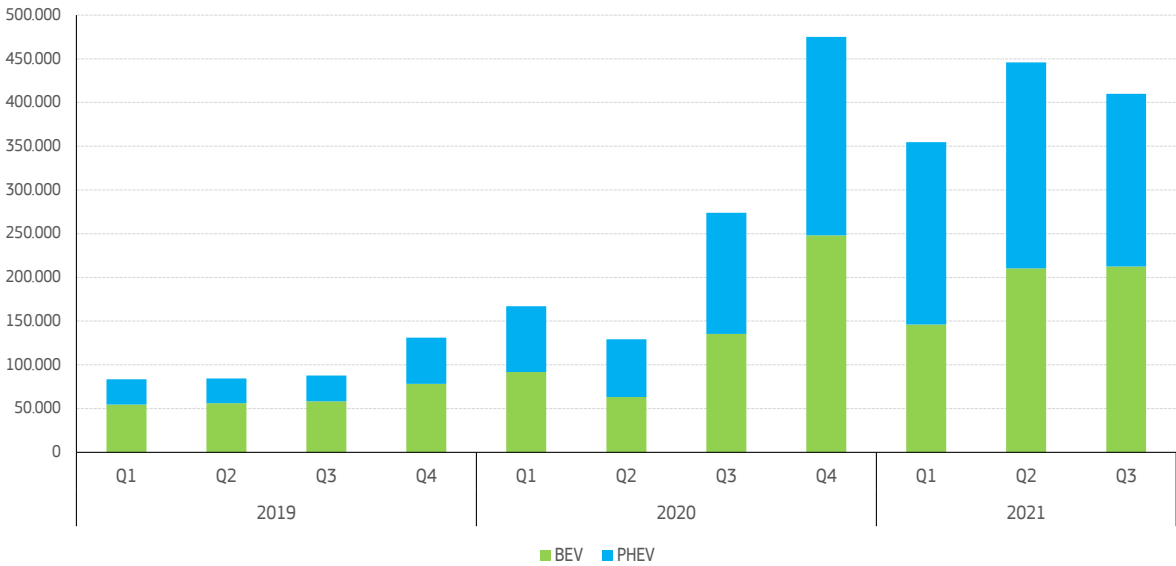
Figure 5 – Electrically chargeable passenger vehicle (ECV) sales in selected countries in Q3 2021



Source: ACEA, CPCA, BloombergNEF

- **Figure 6** shows how the rapid expansion of electric vehicles in Europe unfolded during the last quarter of 2020 has been keeping good track in 2021. Policy support and additional stimulus measures, and steady recovery in activity after the pandemic have contributed to the impressive increase in ECV numbers. Overall, almost 2 million new ECVs were sold in the EU in the year between Q3 2021 and the same quarter in 2020 (compared to X million cars with a plug sold in China), more than doubling the existing electric fleet. As the number of ECVs on European roads is expected to continue growing fast in the years ahead, so will its impact on electricity demand and on network load.

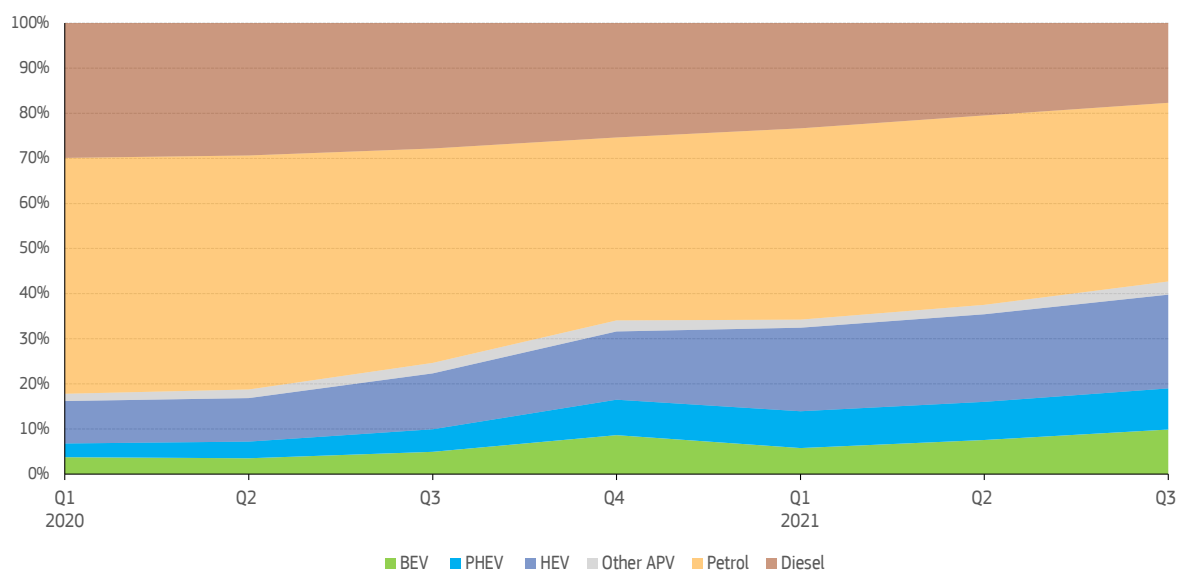
Figure 6 – Quarterly ECV sales in the EU



Source: ACEA

- **Figure 7** shows the decline of diesel cars, which saw their market share fall to 18% in Q3 2021, from 28% in Q3 2020. Petrol cars experienced a fall in their share to 40% in Q3 2021, from 48% in the third quarter of the previous year. On the other hand, the shares of new Hybrid electric vehicles (HEV) in the market increased from 12% in Q3 2020, to 21% in Q3 2021. The shares of new ECVs have almost doubled year-on-year (from 10% in Q3 2020 to 19% in Q3 2021). In July, the European Commission presented the proposals to deliver the Green Deal, proposing among other initiatives, strong reduction of CO2 emissions for cars and the support to the growth of the market for zero- and low- emissions vehicles.

Figure 7 – Evolution of quarterly drivetrain shares in the EU

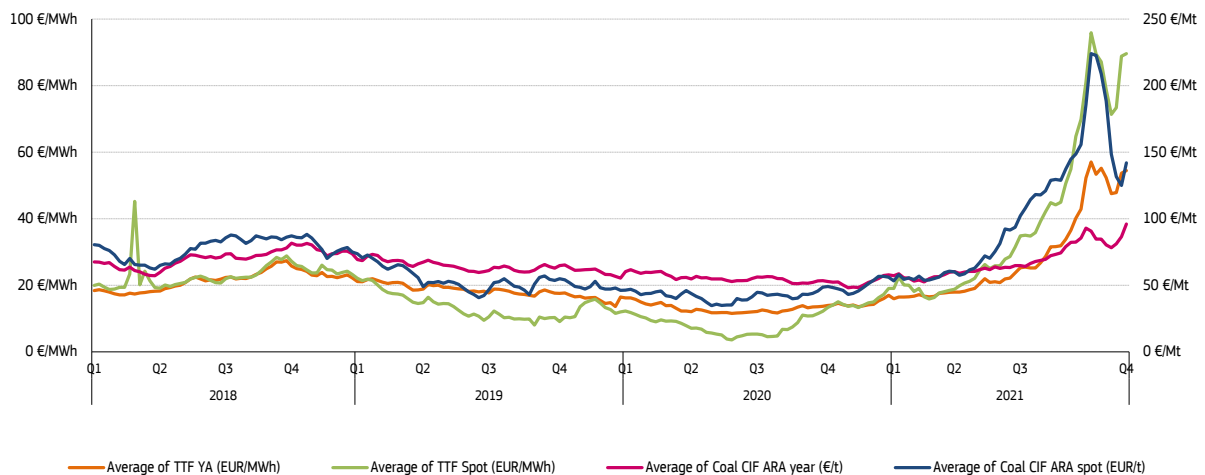


Source: ACEA

1.2 Supply side factors

- Figure 8** reports on developments in European coal and gas prices. In Q3 2021, prices of coal and gas have been rising to record levels in the spot market and way above from their year-ahead peers. The situation follows the trend of increasing demand registered during the previous quarter, linked to tighter global supply as economic recovery is peaking up. Rising demand for gas has not been matched by increasing supply with effects felt not only in the EU, but also in other regions of the world. In addition, lower-than-expected gas volumes have been observed from main suppliers, tightening the market as the heating season arrives, offering little or no extra capacity to ease pressure on the EU gas market. Delayed infrastructure maintenance during the pandemic has also contributed to constrain gas supply.
- The rising trend of spot gas prices (represented by the TTF day-ahead contract) during this year has been strengthened as a result of increasing demand, tight Liquefied Natural Gas (LNG) and pipeline supplies, uncertainty over pipeline projects and high CO₂ prices during Q3 2021. This trend has intensified into the fourth quarter of the year, during mid-October, price rocketed reaching almost 100 €/MWh at the TTF hub and several new records were established in quick succession. This situation has significantly undermined the competitive edge of gas-fired power plants in Europe and allowed their coal and lignite competitors to regain some of the lost ground.
- Spot gas prices averaged 48 €/MWh in Q3 2021, an all-time record high. Prices are 91% higher than the previous quarter (Q2 2021) and represent a 522% increase compared to Q3 2020, which reflects level of tightness of the gas market. While in 2020, cheaper gas and the resilience of the carbon market contributed to intensified coal-to-gas and lignite-to-gas switching, driving down the carbon footprint of EU electricity sector to record lows, current high prices could be detrimental to the reduction of emissions during the current year. 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, were steadily climbing since March with values over 60 €/t until mid-October, reaching a peak price of 225 €/t. This impressive surge can be explained by supply tightness, increasing demand and higher freight rates. As Chinese economy started to rebound from COVID-19, demand for electricity was enhanced by a warmer-than-average summer, which followed cold spells during last winter in the region. However, prices started to ease as China announced plans to put a cap on coal prices. Prices were also partially helped by the pledge of more than 40 nations to phase out coal and a commitment to cut methane emissions, a movement led by the EU during the recent COP26 in Glasgow. While the market remains tight in the short term, the medium term outlook points to low prices as supply factors normalise after the post-covid demand shock and economies continue to phase-out coal from their power grids. The average CIF ARA spot price averaged 132 €/t in the third quarter of 2021, up 206% compared to Q3 2020 and 77% to the second quarter of 2021.

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



Source: S&P Global Platts

- The European market for emission allowances, shown in **Figure 9**, registered important price gains throughout Q3 2021, although at a slower pace than during the previous quarters of the year. Several new records were established in quick succession, culminating in a peak at the end of September when the closing price climbed above 64 €/tCO₂ for the first time, thanks to rising gas prices and the expectation of upcoming market reform to the Emissions Trading Scheme (ETS), which would tighten supply-demand balance. High gas prices contribute to rising carbon price since they lead to an increased use of coal for power generation and consequently higher demand for emission allowances. In October, high power emissions continued to support the carbon price, but the risk of curbed industrial demand maintained prices around 60 €/tCO₂. Prices surged again in November, reaching levels around 75 €/tCO₂ at the end of the month, thanks to the tightness of the market and the release of a preliminary analysis by the [European Securities and Markets Authority \(ESMA\)](#) of the EU ETS, which confirmed that so far no specific cases of market manipulation have been detected. Prices in December reached a new historical peak of 89 €/tCO₂, on the back of cold weather and enhanced coal-fired generation, increasing demand for allowances.
- The average CO₂ spot price in Q3 2021, at 57 €/tCO₂, represented an increase of 14% with respect to Q2 2021 and a change of 169% year-on-year. Higher carbon prices put coal and lignite power plants at a greater disadvantage against their less polluting gas-fired competitors. However, under the current situation of exceptionally high gas prices, the European Union Allowances (EUA) price is not enough to support coal-to-gas fuel switching in power generation (see **Figure 19**). They also tend to drive wholesale electricity prices higher (see **Figure 14**). Nevertheless, as noted in the European Commission Communication "[Tackling rising energy prices: a toolbox for action and support](#)", the effect of the gas price increase on the electricity price is nine times bigger than the effect of the carbon price increase.

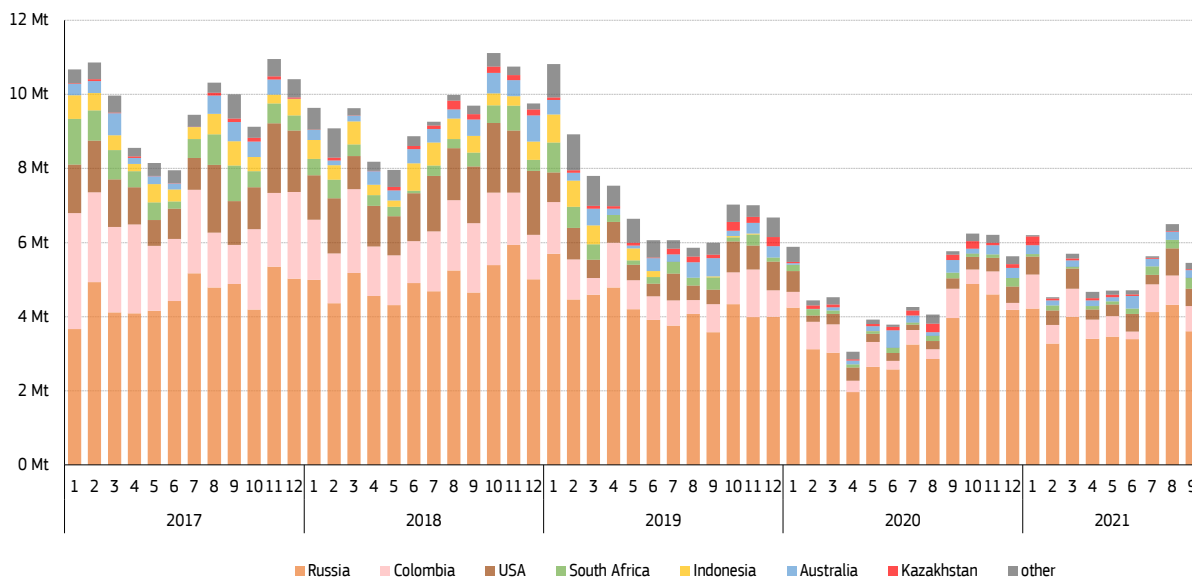
Figure 9 – Evolution of emission allowance spot prices from 2018



Source: S&P Global Platts

- As visible from **Figure 10**, monthly thermal coal imports into the EU held at roughly 5.9 Mt in Q3 2021 as electricity demand increased and made more space for fossil fuels in the mix. The total volume of imports increased by 25% year-on-year to 18 Mt in the third quarter of 2021. The estimated EU import bill for thermal coal amounted to €1.9 billion in the reference quarter, 11.3% higher compared to Q3 2020 enhancing the year-on-year increase in imported volumes of this commodity.
- The largest part of extra-EU thermal coal imports in Q3 2021 came from Russia which accounted for 69% of the total. Russian traders managed to achieve the highest share of the market, despite a decrease in the share (-3%) with respect to Q3 2020, as most of their rivals find it difficult to compete in the tough low-price, low-demand environment. Colombia saw its market share going up to 13% compared with 10% in the previous quarter. The position of Australia and Kazakhstan shrunk from 5% and 4% in Q3 2020, to 4% and less than 1%, respectively. The share of deliveries from US ports increased from 5% to 8%. Shares of other trading partners were not relevant.

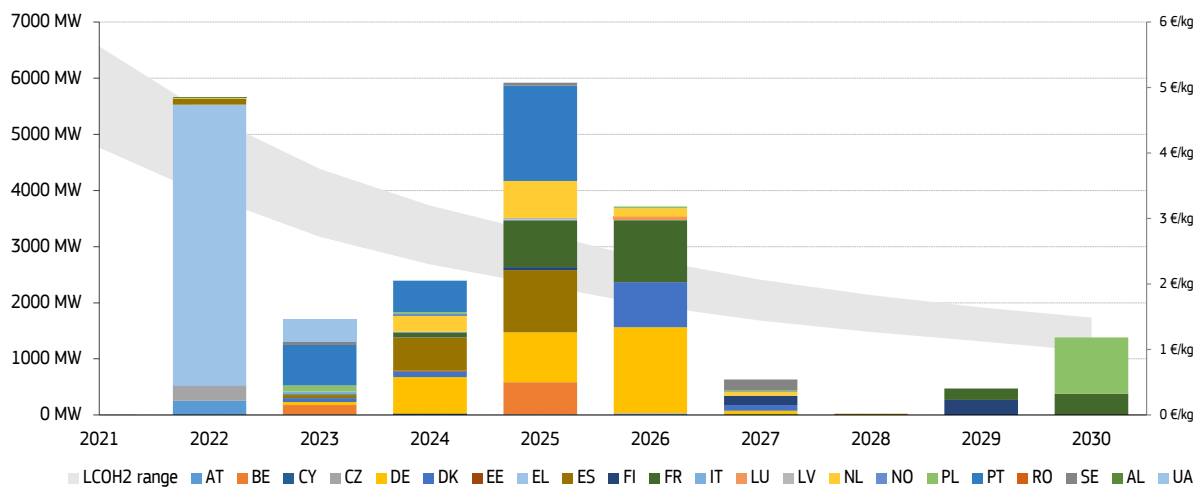
Figure 10 – Extra-EU thermal coal import sources and monthly imported quantities in the EU



Source: Eurostat

- **Figure 11** presents a pipeline of hydrogen production projects from members of the [European Clean Hydrogen Alliance](#). Projects were assessed by the European Commission against a set of defined criteria, including scope, size, greenhouse gases emission reduction and project maturity. The database of projects include 446 hydrogen production projects of different capacities and maturity years in Europe. The graphic also presents a range of Levelised Cost of Hydrogen (LCOH₂) values from the analysis of hydrogen production costs in selected European countries (Germany, Spain, France, Italy, Netherlands, Poland, Sweden and the United Kingdom)¹. LCOH₂ is set to fall from 4.1 €/Kg – 5.6 €/Kg in 2021, to 1 €/Kg – 1.5 €/Kg in 2030, assuming the lowest LCOH₂ value using alkaline electrolyzers in Europe.
- The two most mature hydrogen electrolyser technologies are Alkaline and proton exchange membrane (PEM). Both share the same principles of electrolysis. Alkaline water electrolysis is characterised by having two electrodes operating in a liquid alkaline electrolyte solution of potassium hydroxide (KOH) or sodium hydroxide (NaOH). A proton exchange membrane (or polymer-electrolyte membrane) is the electrolysis of water in a cell equipped with a solid polymer electrolyte that is responsible for the conduction of protons, separation of product gases, and electrical insulation of the electrodes.

Figure 11 – Pipeline of hydrogen production projects and lowest LCOH₂ using alkaline electrolyzers in Europe



Source European Clean Hydrogen Alliance, BloombergNEF

Note: The graphic includes only announced projects that have disclosed production capacity. Unknown means that the developer has not disclosed the project's maturity year

¹ BloombergNEF. 2H 2021 Hydrogen Levelised Cost Update.

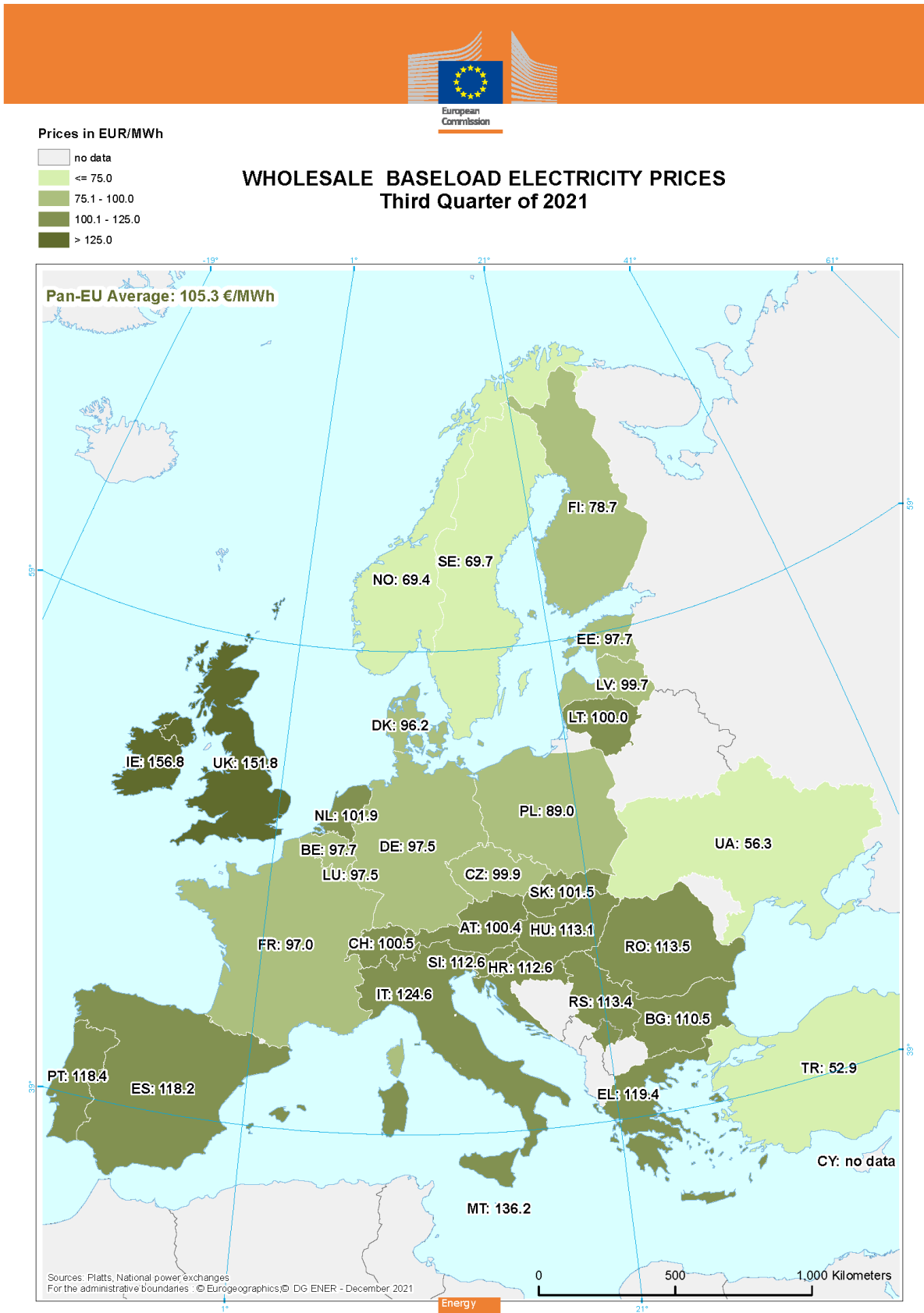
2 European wholesale markets

2.1 European wholesale electricity markets and their international comparison

- The map on the next page shows average day-ahead wholesale electricity prices across Europe in Q3 2021. The reference quarter saw a sharp increase compared to Q3 2020, as prices reached all-time highs in many European markets, on the back of high commodity prices (mainly gas, but also coal and CO₂) and increasing demand due to the steady but strong recovery of industrial and labour activity and seasonal temperatures. Practically every European Union Member State experienced a considerable surge in prices (changes over 100%, 200% and even 300%²). Ireland reported the highest quarterly average price (157 €/MWh), which was 323% higher than in Q3 2020 (236% above Q3 2019 levels). The United Kingdom became the second most expensive market with an average baseload price of 152 €/MWh, which was 277% higher compared to the same period last year (256% above Q3 2019 levels). Italy registered quarterly prices of 125 €/MWh and the Iberian Peninsula reported prices of 118 €/MWh during the same period.
- The European Power Benchmark averaged 105 €/MWh in Q3 2021, 211% higher on yearly basis. Compared to Q3 2019, the quarterly average price rose by 164%.
- The largest year-on-year price increases were registered in Norway (+1256%), Ireland (+323%), United Kingdom (+277%), Portugal (+215%) and Spain (+214%), on the back of rising gas prices in the context of economic recovery. Conversely, Poland experienced the least increase in prices during Q3 2021 (+72%). Poland has lower dependence on gas in their power mix. As such, prices increased (yet less) due to its high reliance on coal and lignite in the mix and the need to pay more for their higher emissions. It should be noted that the prices during the pandemic last year were unusually low (including during Q3 2020 and especially in the case of Norway, with an average price of 5 €/MWh during that quarter of 2020).
- Member States are already taking steps to mitigate the effects of rising energy prices, especially to reduce the impact on households' electricity bills. The European Commission adopted a [toolbox for action](#) on 13 October 2021, which includes a structured set of short and medium-term tools that could be used by Member States to alleviate the situation. The document also provides suggestions to further expand the legislative package on Delivering the European Green Deal.
- The European Commission asked the Agency for the Cooperation of Energy Regulators (ACER) for an assessment of the current wholesale electricity market design by April 2022 and a preliminary assessment by mid-November 2021. [ACER's preliminary report](#) shows that the energy market has delivered benefits to Member States and consumers over the past decade thanks to market-based pricing and market integration. It finds no obvious evidence of systematic manipulation of EU energy markets.

² Twenty-six MS experienced increases over 100%, three MS above 200% and one MS beyond 300%, compared to Q3 2020

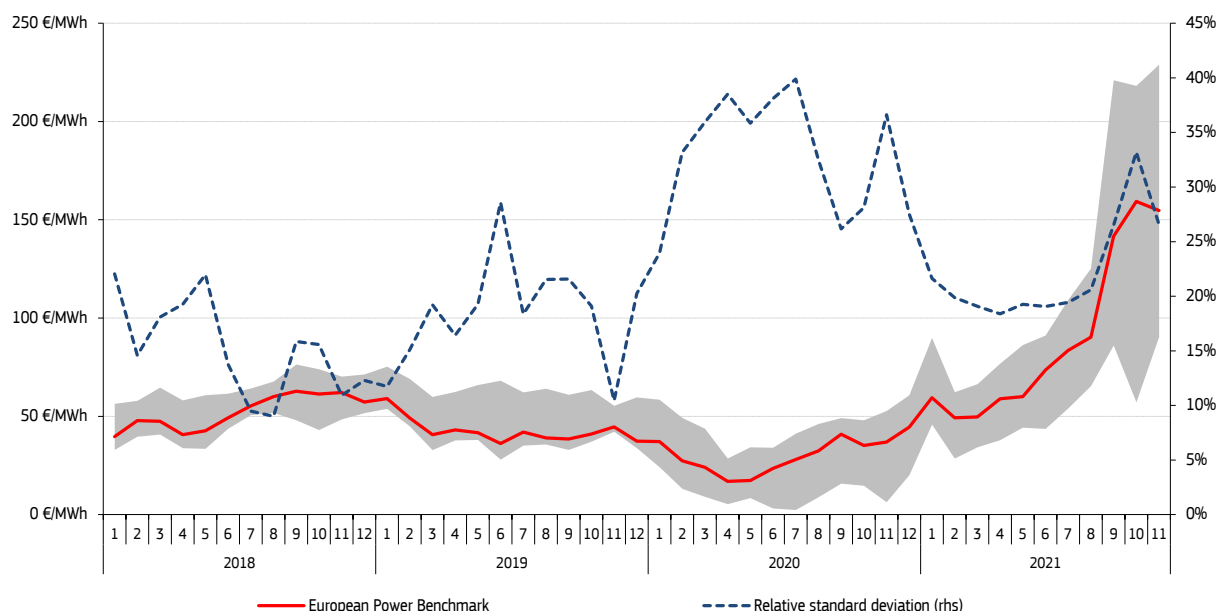
Figure 12 – Comparison of average wholesale baseload electricity prices, third quarter of 2021



Source: European wholesale power exchanges, government agencies and intermediaries

- Figure 13** shows the European Power Benchmark of nine markets and, as the two lines of boundary of the shaded area, the lowest and the highest regional prices in Europe, as well as the relative standard deviation of regional prices. Both the shaded band and the relative standard deviation metric show divergence levels started to surge again in Q3 2021, after a period of relatively stable value of convergence of prices during the first half of 2021. Average prices in countries and regions have been reaching all-time records during the reference quarter, driven by a sustained increase in gas prices. Central Western Europe, Great Britain and the Iberian Peninsula, among others, have experienced a surge in prices linked to the variations in gas prices. The phase-out of coal and nuclear capacity is increasing the sensitivity of power prices to the developments of the gas market. Subdued wind and hydro generation amplified the impact of gas prices in the regions. The Nordic region experienced dry weather condition reducing hydropower output, which combined with the tightness of the continental European markets, resulted in a steep increase in prices. Soaring gas prices in Great Britain, combined with tight supply margins, low wind availability, robust demand, unplanned interconnector outages and reduced nuclear output, made Britain the most expensive market in Europe during the third quarter of 2021. The European Power Benchmark averaged 105 €/MWh in Q3 2021. This was 211% higher than in the same quarter last year. Prices were still 164% higher than Q3 2019 (pre-pandemic levels). The rising trend continued in the following months on the back of extremely high gas prices. In October and later in December, electricity prices in many markets, including Spain, France and Germany, reached new all-time record highs.

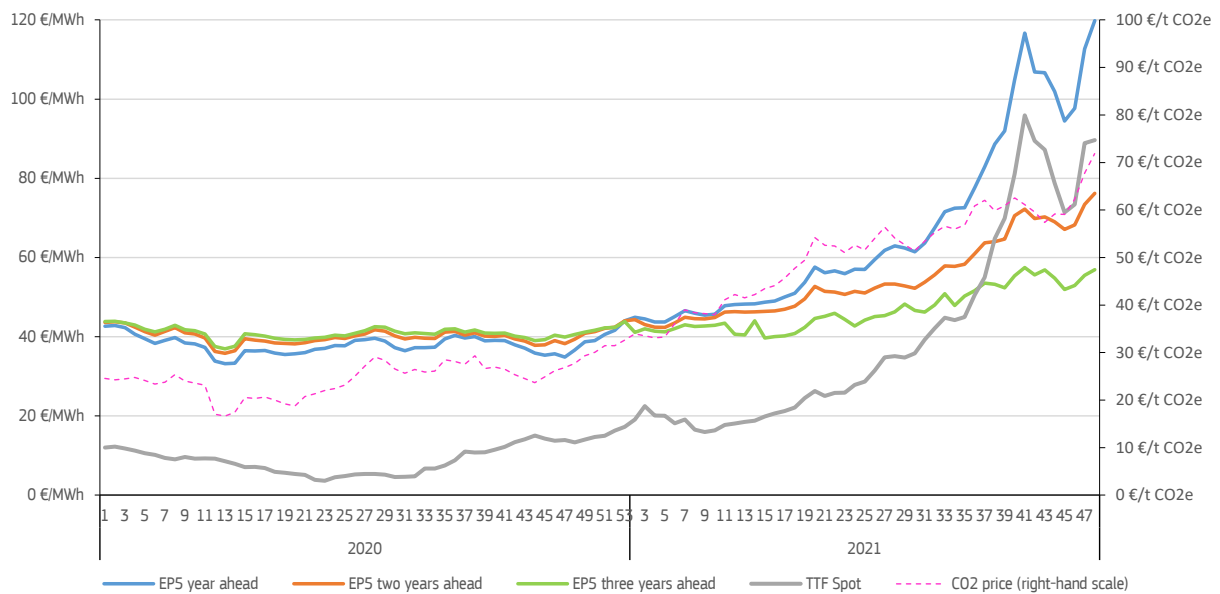
Figure 13 – The evolution of the lowest and the highest regional wholesale electricity prices in the European day-ahead markets and the relative standard deviation of the regional prices



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

- Figure 14**, reveals that notably gas prices have been the main driver behind changing expectations of future electricity prices since the first quarter of the year. The rally in gas that has been taken place since March 2021, lifted the benchmark above pre-crisis levels and into all-time record highs. The TTF spot price surged 91% during the third quarter of the year, whereas the year ahead benchmark increased 57% in the same period. Carbon prices have also been rising since the last months of 2020, registering a 14% increase during Q3 2021. This increase has also influenced electricity prices, but to a far lower extent than gas prices.
- During the first week of Q3 2021, the electricity year-ahead, two-year ahead and three-year ahead contracts were respectively 60 €/MWh, 52 €/MWh and 45 €/MWh; whereas at the end of September, these three values reached 92 €/MWh, 65 €/MWh and 52 €/MWh. In addition, the discount of the year-ahead contract to the spot market indicates a strong backwardation which has been developing in parallel with the latest price increase in spot markets. The discount of the year-ahead contract to the spot market grew from 12 €/MWh to 47 €/MWh during Q3 2021 (reaching a peak during week 47 in line with developments in the gas market), and by the end of November this difference rose to 53 €/MWh, underlying that the market anticipates a correction of the price levels in the mid-term future.

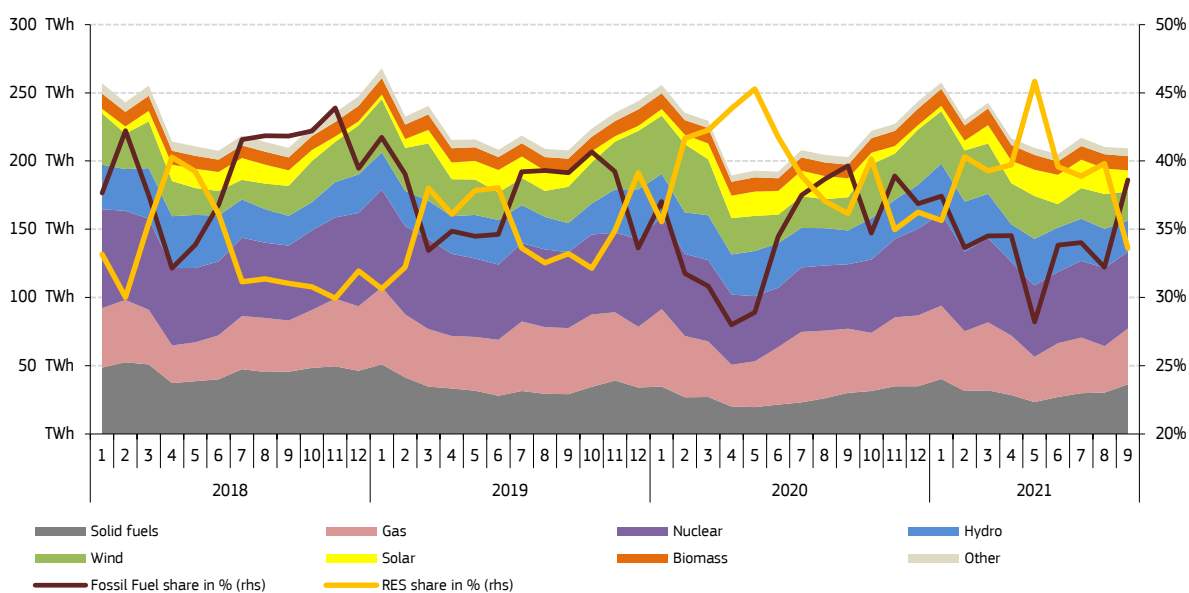
Figure 14 – Weekly futures baseload prices – weighted average of selected European markets



Source: Platts.

- Figure 15** shows the monthly evolution of the electricity mix in the EU. A combination of recovering industrial activity and increasing electricity demand supported by higher-than usual temperatures during the summer months made more space for fossil fuels in the mix. However, the share of energy produced by renewables still managed to reach 37% in Q3 2021 (unchanged from the share of renewables in Q3 2020), while fossil fuel generation (coal, gas and oil) stayed below registering 35% of the share during the quarter. Fossil fuel generation decreased its share in the mix compared with the 39% observed in Q3 2020. Nuclear generation increased its share of generation (27%) compared with the reference quarter in 2020 (25%).
- Within the fossil fuels complex, coal gained terrain both in absolute and relative terms compared to Q3 2020 due to rising demand (higher than a year earlier), but mostly as a reaction to the rally of gas prices which has reversed the coal-to gas switching registered in previous quarters, despite rising carbon prices. Coal's share in the mix rose to 15%. Meanwhile, less CO2-intensive gas generation practically saw its share fell at 18% in the reference quarter. In absolute terms, coal-based generation rose by 17 TWh year-on-year, while gas-fired power plants' output decreased by a significant volume of 33 TWh. Renewables, generated 8 TWh of surplus electricity year-on-year on the back of higher solar and offshore wind generation, despite a slight reduction in onshore wind output.
- Between hard coal and lignite (the distinction between them is not visible in **Figure 15**), the latter tends to be more resilient in the face of changing market environment, as lignite generation traditionally displays more competitive marginal costs per unit of energy produced even facing the current level of CO2 prices. This stems mainly from low production costs of the input fuel, which is usually mined in close proximity to power plants that use it. Conversely, lignite generators have a larger carbon footprint per generated MWh (by about 20% compared to coal), which penalises them more when emission allowances become costlier. Emission allowances were 169% more expensive in Q3 2021 compared to Q3 2020, but this was compensated by rising gas and hard coal prices, which meant that lignite power plants weathered the reference quarter in a significant better shape. In the end, lignite-based generation in Q3 2021 rose by 12% year-on-year (more than 5 TWh), while hard coal-fired generation increased by 34% year-on-year (or 12 TWh).

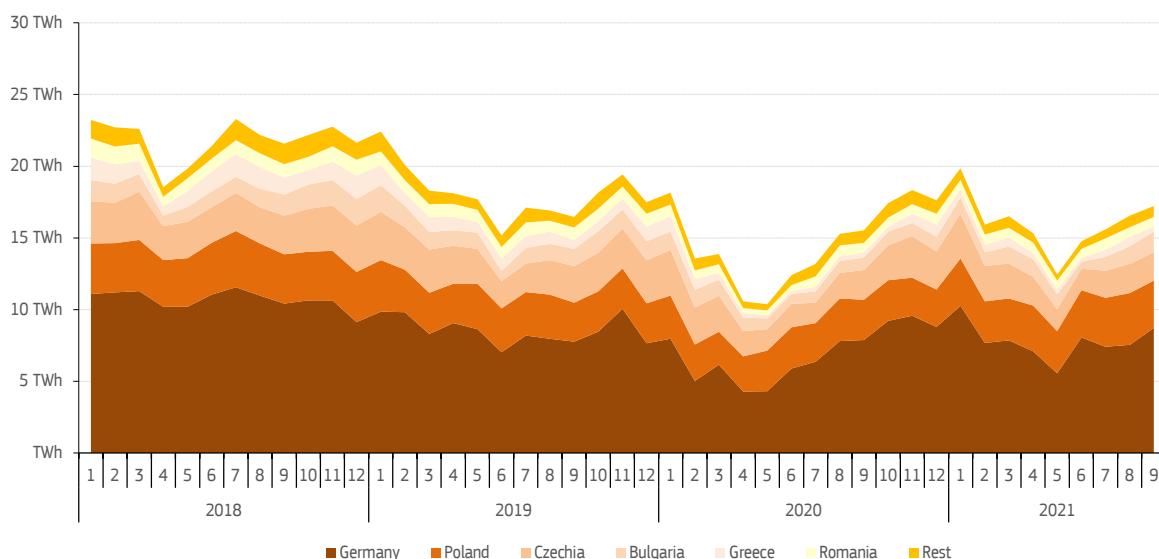
Figure 15 – Monthly electricity generation mix in the EU



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

- Figure 16** shows that after a large covid-related drop during 2020, lignite generation has staged a powerful comeback in 2021 and especially during the third quarter of the year, helped by soaring gas prices (which decreased the competitive edge of gas-fired power plants). Most Member States with lignite-fired capacity increased its output during Q3 2021. Monthly output rose through Q3 2021 and peaked in September at roughly 17 TWh. In Germany, home to the largest lignite fleet, generation from the dirtiest fuel rose by 7% year-on-year in Q3 2021, due to falling gas and wind output, supported by increasing demand. Lignite-fired generation in Poland increased 22% year-on-year in Q3 2021. The output of the Czech lignite fleet rose by 12% year-on-year. The three Member States accounted for 81% of the total lignite-based generation in the EU in Q3 2021. In Greece, lignite generation increased by 53% year-on-year on the back decreased biomass and wind output, and rising demand. In Bulgaria, growing demand facilitated the generation of additional volumes of lignite (46%) compared to Q3 2020. Lignite power plants reached an 8% share in the EU generation mix in Q3 2021 (up from 7% on Q3 2020) and were responsible for approximately 32% of the electricity sector’s total carbon emissions.

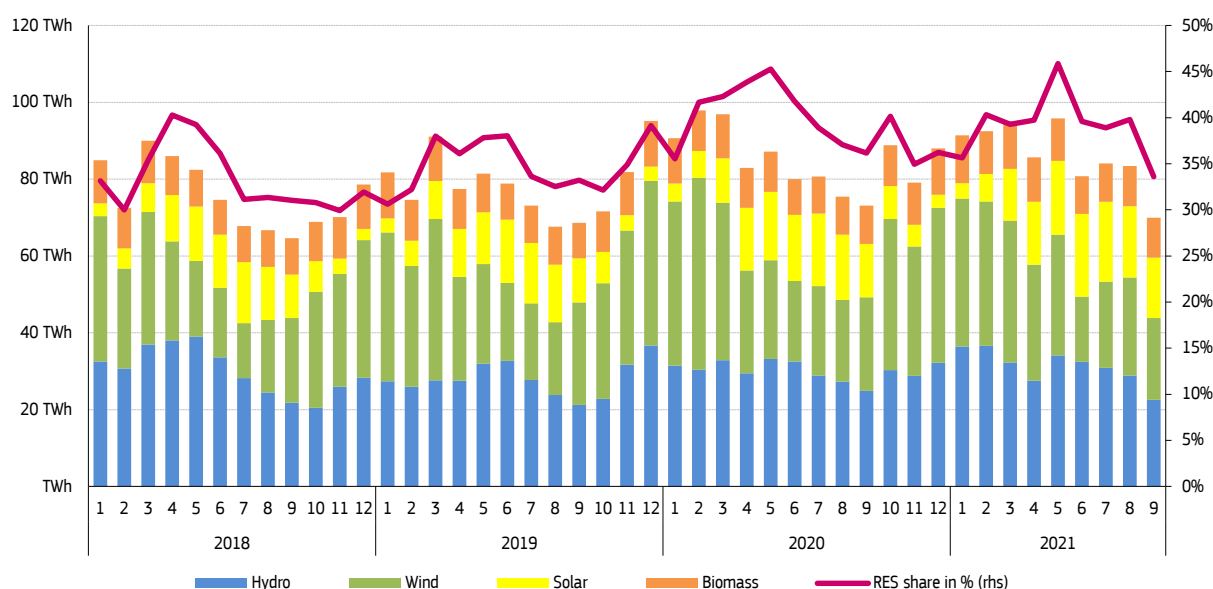
Figure 16 – Monthly generation of lignite power plants in the EU



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

- **Figure 17** depicts the evolution of monthly renewable generation in the EU, alongside its share in the electricity generation mix. Renewable penetration reached 37% in Q3 2021, unchanged from Q3 2020, but lower than the second quarter of 2021 (42%).
- Most of the gains in renewable generation came from solar (+5 TWh), hydro (+1 TWh) and biomass (+1 TWh) compared with the reference quarter in 2020. Thanks to newly added panels, solar PV generation rose by 11% in Q3 2021 to 5 TWh, more than five times than oil-fired generation. The increase was mostly driven by Spain, where solar generation rose 22% year-on-year. Also the share of solar generation in Spain reached 14% in Q3 2021, putting it within striking distance of hard coal (2%).
- Main hydro generation volumes were registered from gains in France (+14%) and Germany (+11%). Overall, hydro output increased by 2% during Q3 2021. Conversely, the largest decreases in hydro generation came from Romania and Slovenia, where hydro generation fell by 13% and 22% respectively compared with Q3 2020, as a result of low stock levels and limited precipitations. Italy and Finland also registered declines in hydro generation compared with Q3 2020. In addition, biomass increased its generation by 4% during the reference quarter. Main gains were reported in France (+95%), Denmark (+81%) and the Netherlands (+35%).
- Overall, wind output remained with a small surplus (+0.2 TWh) in Q3 2021. Wind gains during the reference quarter were reported in the Netherlands (+24%) and Denmark (+11%), thanks to their offshore fleet and the onshore output in Italy (+9%), among other Member States. Conversely, the UK experienced calm weather, which resulted in a decline of wind generation by 40% and 24% respectively (onshore and offshore). Likewise, Germany registered less output from their offshore wind fleet during the quarter (-7%).

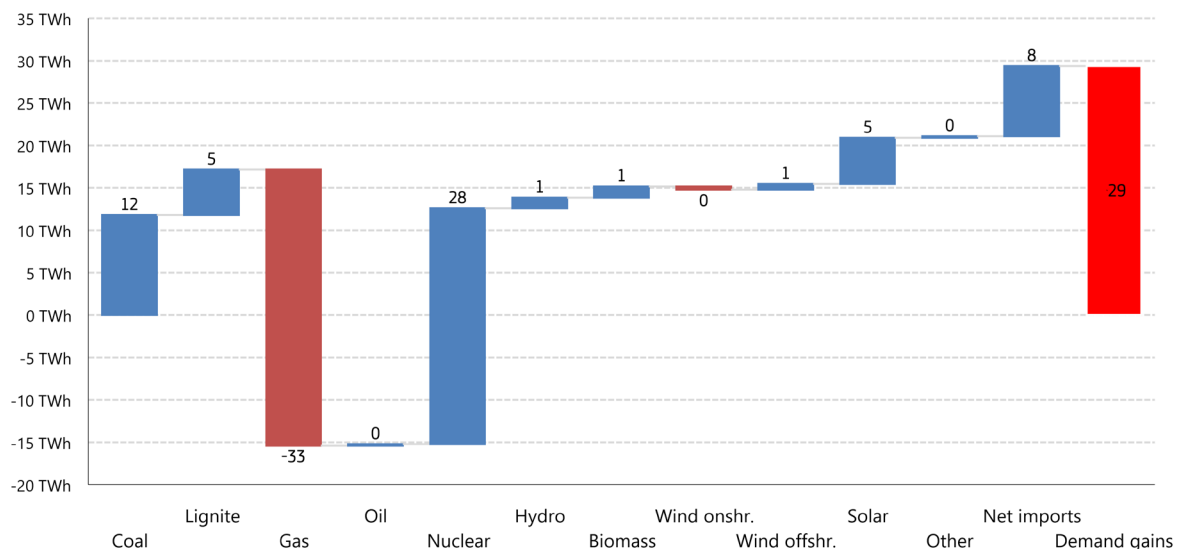
Figure 17 – Monthly renewable generation in the EU and the share of renewables in the power mix



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

- **Figure 18** visualises changes in the EU27 electricity generation balance in the reference quarter compared to the same quarter a year before. The space for conventional power plants' running hours was augmented by increases on the demand side. The steady but strong economic recovery from the coronavirus pandemic and temperatures above average, increased power demand by 29 TWh. Fossil fuels decreased their generation (-15 TWh) while nuclear considerably grew its output (+28 TWh). Renewable sources generation also rose (+8 TWh), whereas net imports increased (+8 TWh) compared with Q3 2020. An increase in power demand during the quarter strengthen more polluting technologies of fossil fuel generation. All in all, coal increased its output by 12 TWh, lignite by 5 TWh, gas fell significantly by 33 TWh as a result of high prices, while oil slightly remained practically unchanged in Q3 2021. Based on preliminary estimates, the carbon footprint of the power sector in the EU rose by 1% year-on-year in Q3 2021 and 13% compared with Q2 2021, due to the larger use of fossil fuels. However, emissions were still 6% lower than in Q3 2019.
- Most of the main drivers behind the Q3 2021 increase in carbon emissions can be traced to the influence of the high prices of commodities (mainly gas), which has increased the output of more polluting fossil fuel technologies, combined with the increasing demand in line with the return to normal industrial and labour activity in Europe. It is likely that both the power sector's average carbon footprint and carbon intensity will rise overall in 2021.

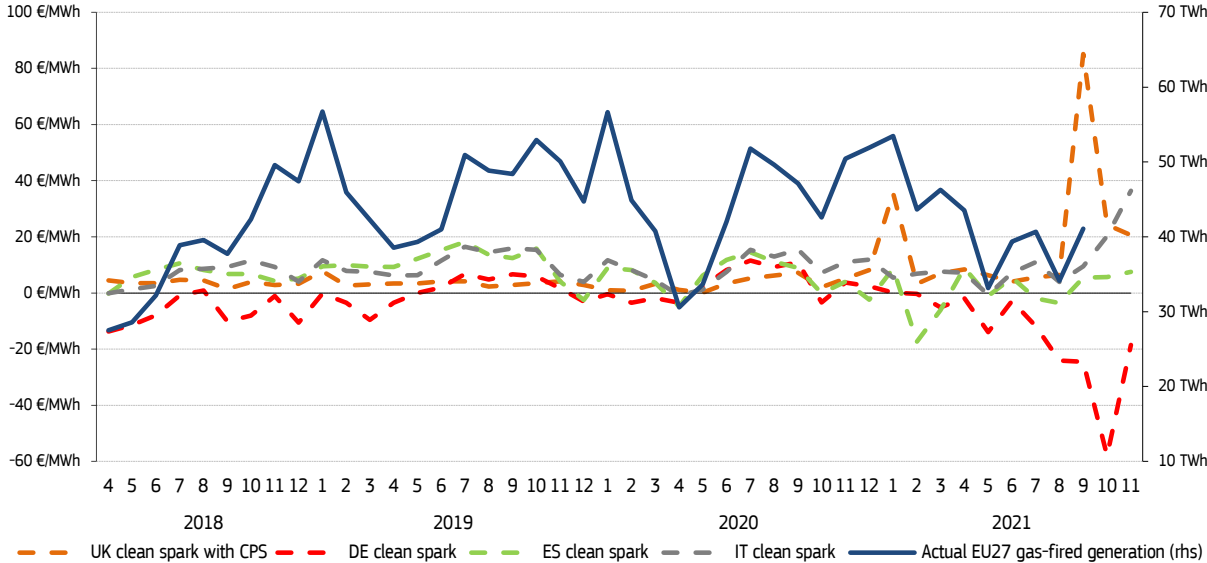
Figure 18 – Changes in power generation in the EU between Q3 2020 and Q3 2021



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

- The following two figures report on the profitability of gas-fired and coal-fired electricity generation in Germany, the UK, Spain and Italy by looking at their clean spark indicators. Gas reduced its traditional competitiveness advantage to coal for a second quarter in a row in Q3 2021. During the whole quarter of reference, rapidly rising gas prices resulted in coal gaining the upper hand, despite high carbon prices. Overall, mix clean spark spread in the UK, Spain and Italy was driven by rising electricity and gas prices. High prices created health margins not only for gas, but also for coal generators, as the spark spreads climbed into the positive area during the reference quarter (with the notorious exception of Germany). The increasing rally in gas prices during 2021 ought to a combination of rising global demand and low storage levels. As such, coal usage has been increasing throughout the year to reach electricity demand.
- As shown in **Figure 19**, in the UK and Italy, the profitability of gas firing for electricity generation remained mostly in positive territory for a plant with an average efficiency during Q3 2021 (as opposed to the German clean spark spread who has not been in positive territory since January 2021). In September, the UK clean spark skyrocketed to 85 €/MWh. The Spanish market started with positive number in July, only to fall into negative territory during August and September. The highest [clean spark spreads](#) in Q3 2021 were assessed in the UK (32 €/MWh), followed by Spain (8 €/MWh). The lowest was presented in Germany (-20 €/MWh), registering a minimum of -58 €/MWh in September. Gas-fired generation volumes largely corresponded to the movement of spreads in respective markets. The total EU gas generation reached 116 TWh in the reference quarter, down by 22% compared to Q3 2020.

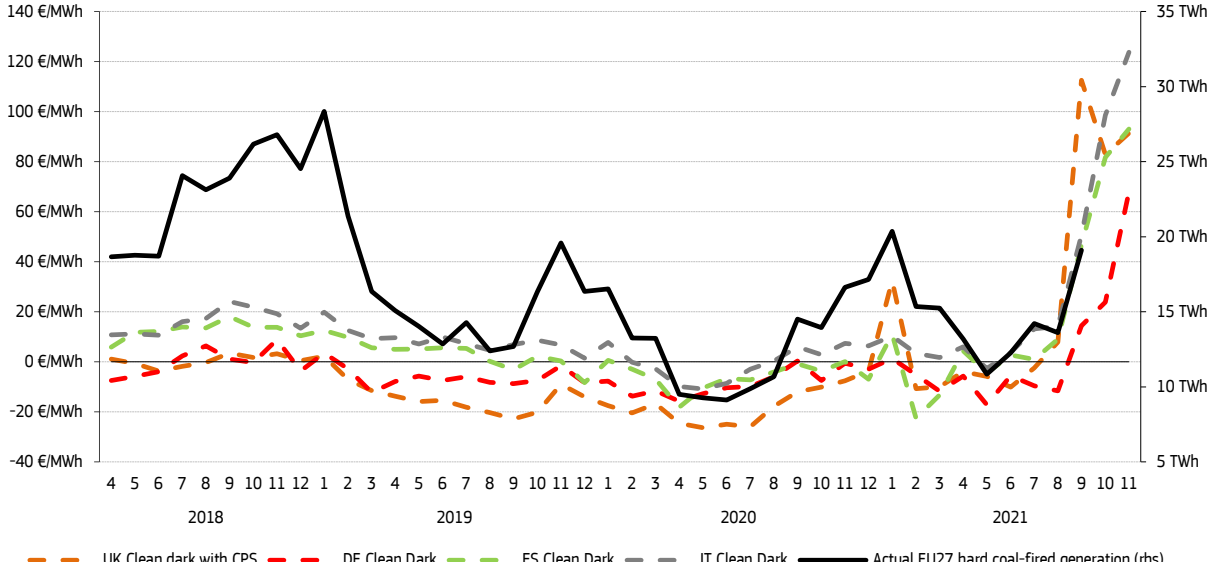
Figure 19 – Evolution of clean spark spreads in the UK, Spain, Italy and Germany, and electricity generation from natural gas in the EU



Source: ENTSO-E, Eurostat, Bloomberg

- Figure 20** shows that UK, followed by Italy, experienced the most profitable coal-fired power generation in Q3 2021. In September, the UK and Italy presented spikes in the profitability indicator for an average plant, despite rising coal and carbon prices. [Clean dark spreads](#) in the UK averaged 39 €/MWh in Q3 2021, higher than in the case of gas-fired power plants. Coal generation in Spain increased by 12% year-on-year in Q3 2021, with only few units remaining in the market. German coal generators, increased their output by 58% year-on-year in Q3 2021, as nuclear generation has been gradually fading in accordance with the German nuclear phase-out plan and no other conventional capacities were available as replacement to meet increasing electricity demand.

Figure 20 – Evolution of clean dark spreads in the UK, Spain, Italy and Germany, and electricity generation from hard coal in the EU

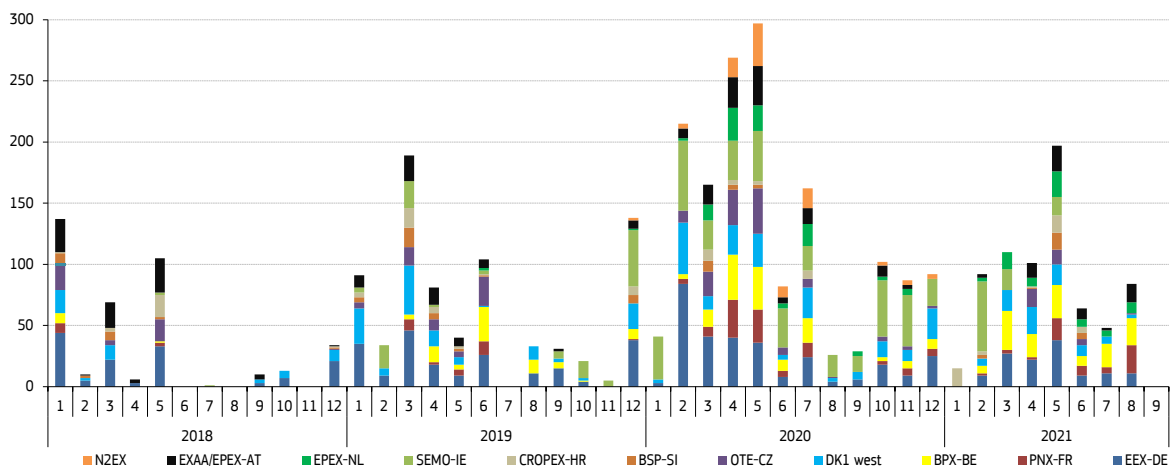


Source: ENTSO-E, Eurostat, Bloomberg

- Figure 21** 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 2021 (132) was 39% lower in the observed bidding zones than in the previous Q3. Most of the falls into negative territory occurred in August of the reference quarter and took place mostly during weekends when low consumption coincided with high renewable generation. It should be noted that no negative hours were registered during the month of September. The highest number of negative prices was recorded on Sunday 8 August, when strong wind speed combined with strong solar generation and weak demand, pushed most of Central Western Europe markets (German, French, Dutch, Belgium, Austrian, and Swiss) prices below zero during several hours of the day. Wind generation covered a large part of the German consumption during that day.
- The Belgium zone recorded the highest number of negative hourly prices (41) in Q3 2021 and it was followed by France (28), Germany (22), and Austria (17). The East Denmark (DK2) zone recorded an increase of 400% of negative hourly prices in Q3 2021. The aftermath of the pandemic has made balancing the grid a harder task and accentuated the need for more flexibility in the European power system in both directions. It has also intensified the search for market instruments that would find a proper value of flexibility. Flexibility will gain importance as we transition to a renewable-based energy system.

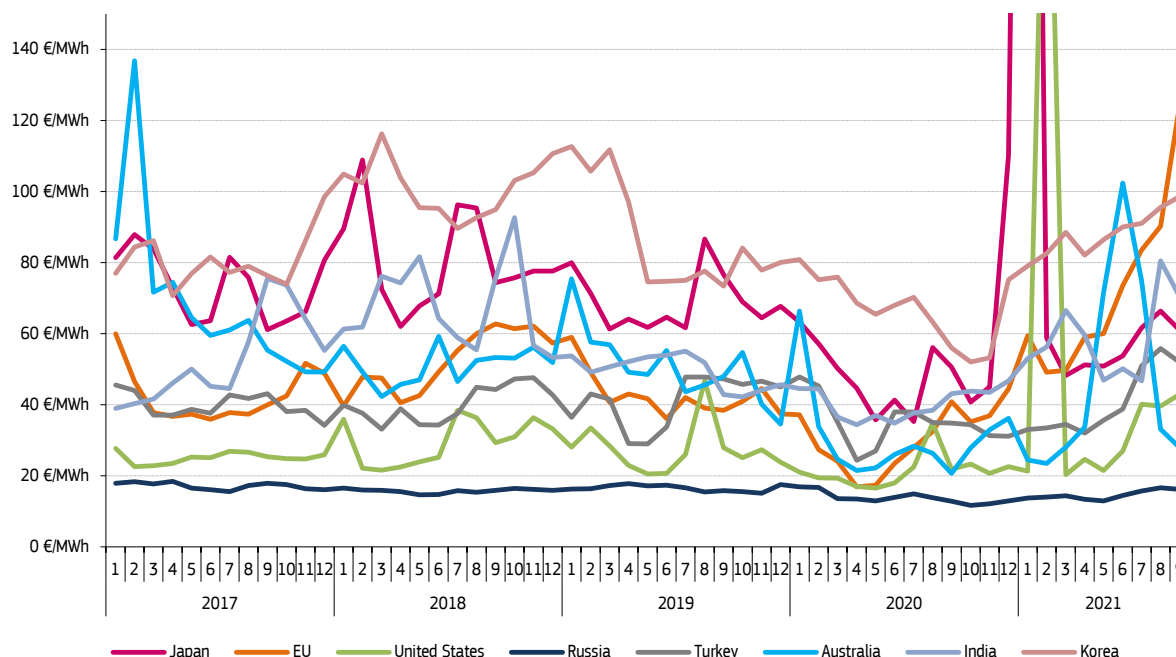
Figure 21 – Number of negative hourly wholesale prices on selected day-ahead trading platforms



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

- **Figure 22** compares price developments in wholesale electricity markets of selected major economies. Most markets saw prices rising as a result of the steady recovery from the pandemic in Q3 2021. In the U.S., in the aftermath of the dramatic price spikes during the last winter in Texas (ERCOT), wholesale electricity prices rose through the reference quarter by 55% in comparison with Q3 2020. The increase was influenced by rising natural gas prices at the U.S. benchmark (Henry Hub), leading to high prices and augmented utilisation rate of coal-fired plants. According to the [EIA \(Energy Information Agency\)](#) 22% more coal-fired generation is expected in 2021 compared with 2020. High natural prices in the U.S. have increased the running hours of coal-fired plants at almost 2018 levels.
- Japan experienced an increase of 21% in prices during Q3 2021. Limited gas supply due to steep LNG prices, led to low gas-fired electricity generation. China and South Korea have been equally exposed to tightening LNG market fundamentals, turning the gas scarcity into a regional issue. Prices in South Korea increased by 10% in the reference quarter. Large-scale power shortages affected ten provinces in China during September. The event drove Chinese authorities to raise the cap on electricity prices to give more incentives to generate. The strength of the recovery in India led to a shortage of coal, plant shutdowns and a surge in power prices during Q3 2021.
- European wholesale prices were the highest of the observed economies in Q3 2021, reaching 105 €/MWh. Russia remained at the other end of the spectrum with 16 €/MWh, which was still 19% higher than in the same quarter last year. Despite a volatile July, Australian prices fell by 35% year-on-year across regional markets throughout Q3 2021. Increased renewable generation, combined with falling gas prices and lower demand due to milder weather in August, led to a fall in prices in the National Electricity Market (NEM). Prices in India rose by 26% in Q3 2021.

Figure 22 – Monthly average wholesale electricity prices in international markets (D-A markets)

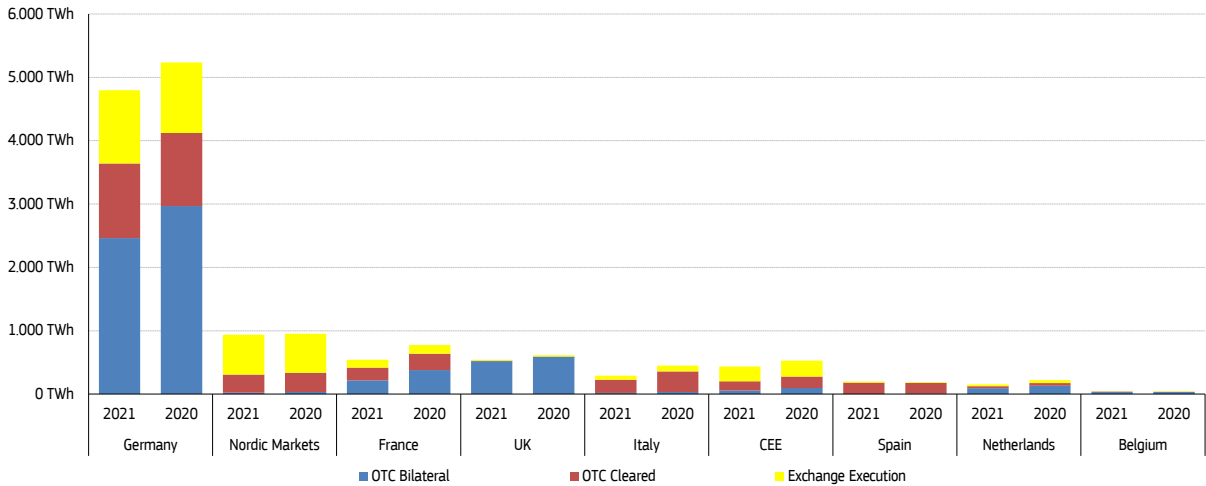


Source: European Power Benchmark, JPEX (Japan), AEMO (Australia), JCS ATS (Russia), Energy Exchange Istanbul (Turkey) and the average of selected PJM West, ERCOT, MISO Illinois and CAISO regional wholesale hubs in the United States. BloombergNEF (India and Korea).

2.2 Traded volumes and cross border flows

- Figure 23** shows annual changes of traded volumes of electricity in the main European markets, including exchange-executed trade and over-the-counter (OTC) trade. Most markets and regions witnessed a year-on-year decline in trading activity in Q3 2021. The largest annual falls in total traded volumes were registered in Italy (-35%), the Netherlands and France (-30%), split approximately equal by the OTC and Exchange sectors (except in France where losses were driven mainly by the OTC sector). The total traded volume in all markets under observation fell by 12% to 7942 TWh in Q3 2021.
- Despite falls in traded volume, Germany was by far the largest and most liquid European market, total volumes reached 4796 TWh (equivalent to 60% of the total traded volumes under observation in Q3 2021). Activity fell in OTC contracts (-12%) and increased at exchanges (+4%) in 2021. Overall, total activity fell (-8%) in Germany during 2021. The market share of exchanges experienced a slight increase (+3%) and the OTC contracts share decreased (-3%) compared to 2020. Relative decreases in activity were visible in the UK where total volumes fell (-11%) to 543 TWh. Similar relative decreases were also visible in the CEE region where total volumes fell by 17%. Increases in activities were reported in Spain where total volumes rose by 5% to 197 TWh and in Belgium (+1%) to 45 TWh.
- Overall, the market share of power exchanges expanded from 25% to 29%. The largest falls in exchange-based volumes were reported in the Netherlands (-37%) and Italy (-31%). Overall, exchange-based trading volumes decreased by 19 TWh in Q3 2021 and increased their share of the market to 29%. The OTC segment traded 1048 TWh less of electricity in 2021 compared to 2020, as a result of lower volumes changing hands in Germany, France and Italy. OTC volumes reduced their share off the market to 71%. Spain, France and CEE markets registered the largest decrease in bilateral OTC deals (-66%, -42%, and -40% respectively).

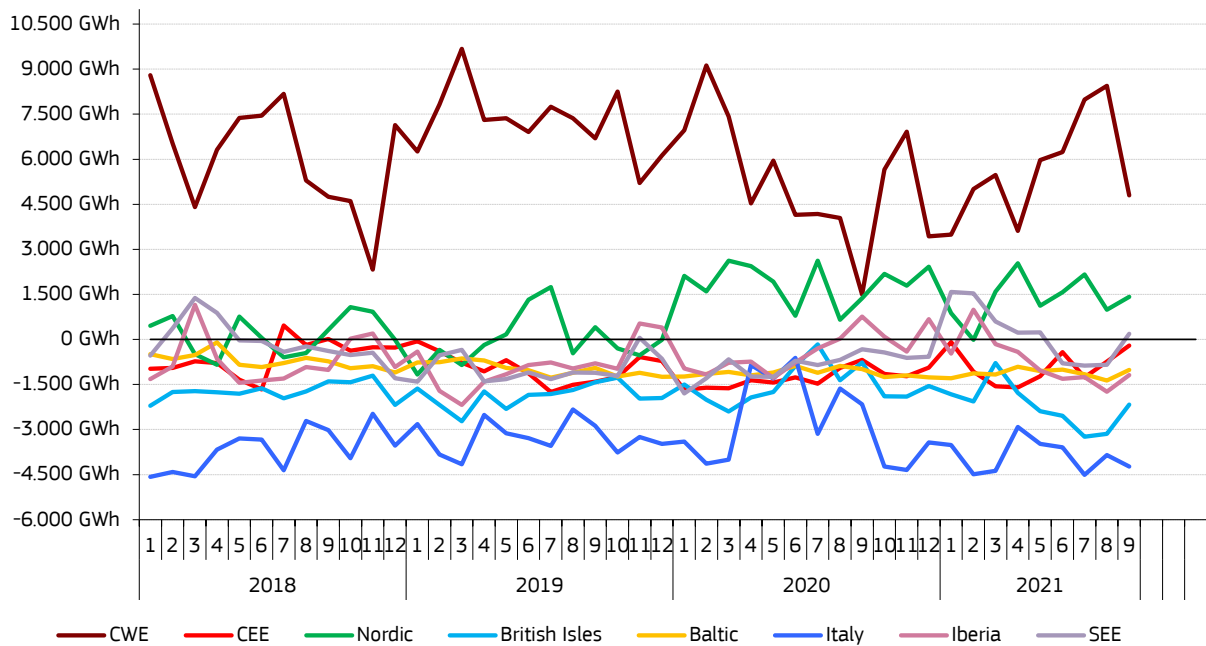
Figure 23 – Annual change in traded volume of electricity on the most liquid European markets



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

- Figure 24** reports on the regional cross-border flows of electricity. Central Western Europe retained its position of the main exporting region, having plentiful and diverse generation capacities and a central position suitable to supply other regions. During the third quarter of 2021, CWE exploited its strong potential with 21 TWh of net exports and was again the largest source of outflows, surging flows by 118% in comparison with Q3 2021. The increase can be traced mainly to higher generation within CWE market, which increased the availability of exports. The Nordic region recorded a surplus of 4.5 TWh in the reference quarter, 2% below from the net exports in Q3 2020. South Eastern Europe registered the return to its condition of net importer (-1.5 TWh), still a significant improvement compared to Q3 2020 (-1.8 TWh). The Iberian Peninsula fell back to its traditional condition of net importer, as high gas prices and increasing power demand resulted in a shortfall of -4 TWh during the reference quarter.
- The rest of the regions ended up in deficit. Net flows to the British Isles increased compared to Q3 2020 at -8.5 TWh, rising 274% on yearly basis, supported by high gas prices, a shortfall in renewables output (mainly wind) and increasing demand due to post-pandemic recovery. Italian net imports rose by 81% year-on-year to -12.5 TWh in Q3 2021. The CEE region's net position (-2 TWh) worsened by 29% in Q3 2021 compared to Q3 2020.

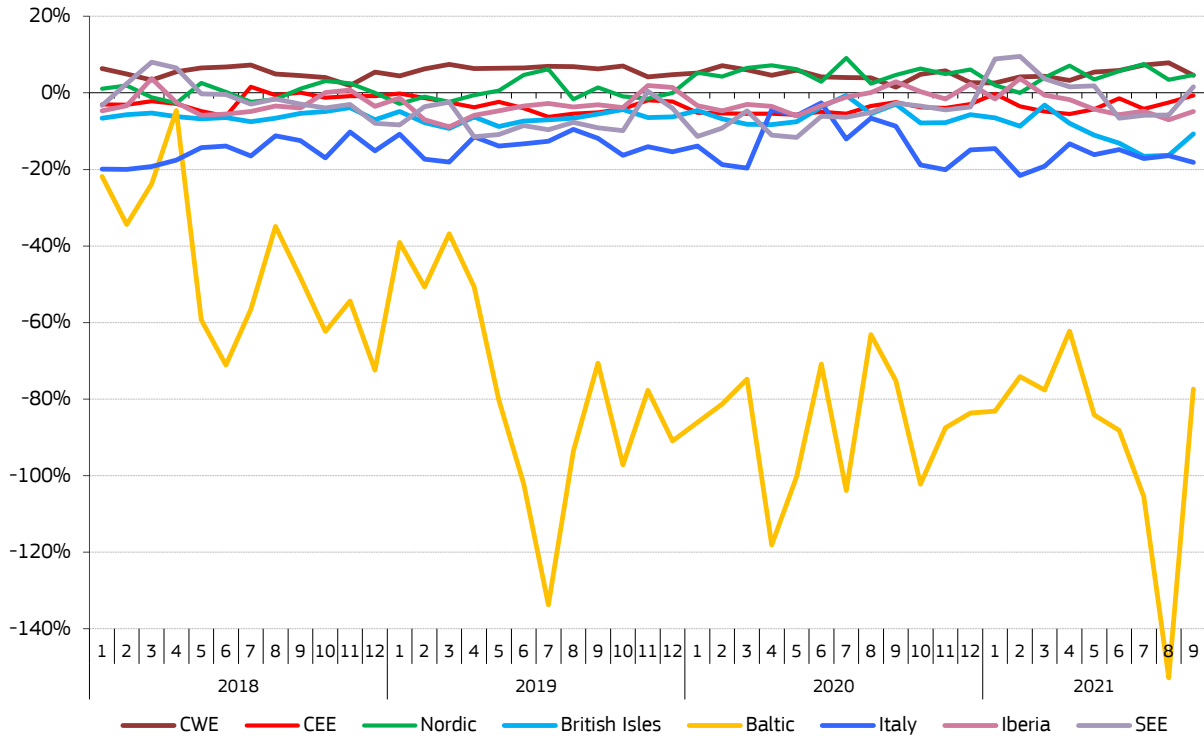
Figure 24 – European cross-border monthly physical flows by region



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 25** 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 2021 compared to the same quarter a year ago. Net imports (3.5 TWh) reached about 112% of domestic generation. Italy became the second largest importer relative to its domestic generation (17%), followed by the British Isles (15%). For the rest of the regions, net imports (or exports) did not exceed 7% of domestic generation.

Figure 25 – The ratio of the net electricity exporter position and the domestic generation in European regions



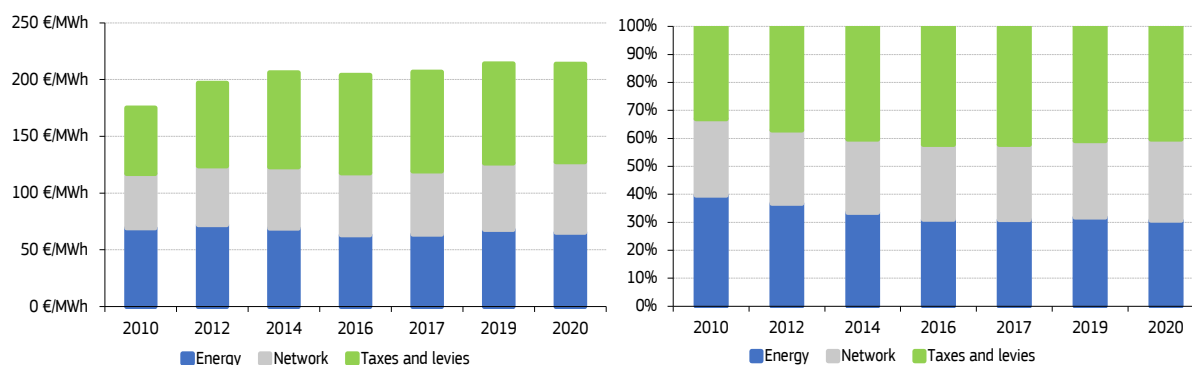
Source: ENTSO-E. Country distribution in regions is the same as in the previous figure. The -100% level means the same amount of electricity is imported as produced domestically. Source: ENTSO-E, TSOs, Eurostat, DG ENER calculation

3 Focus on the impact of wholesale electricity prices in household retail prices

3.1 Main components of electricity retail prices

- The unprecedented increase in wholesale electricity prices has raised concerns among Member States, due to its knock-on effects on retail energy prices. In the case of retail prices closely following spot wholesale markets, such as dynamic contracts, or some types of regulated prices (e.g. PVPC³ in Spain), the effects have been felt earlier. Other Member States, where long-term hedging in wholesale markets and contracts with fixed prices are more common (e.g. Germany), are likely to see retail price increases in the upcoming months.
- Electricity retail prices can be disaggregated into three main components: energy (tied to the commodity itself), network charges and taxes & levies. The energy component includes cost elements such as the wholesale price of electricity, operational costs and profit margins of supply companies, balancing energy, metering and billing charges. They also include the ETS costs, which electricity generators pass on in their bids in wholesale electricity markets. The network component includes transmission and distribution tariffs. It could also include other cost elements like ancillary services. Finally, the taxes and levies component consists of a wide range of fiscal instruments and levies designated for specific technology, market or social policies. In 2020, the subcomponents of Value Added Tax (VAT) and renewable taxes represented two thirds of the whole taxes and levies component. They vary highly from country to country. It is important to note that while taxes and levies and network charges are directly set by regulators and governments, the price of the energy component depends mainly on wholesale prices and the structure of market regulation.
- **Figure 26** shows how the evolution of household electricity prices in the EU for the DC band, covering annual consumption of 2500 to 5000 KWh, which is the most common volume of households. The energy component has been relatively stable between 2010 and 2020, falling behind the general inflation rate. The fact that wholesale electricity prices were kept under pressure was helped by EU energy policies such as increased competition as a result of market coupling, unbundling of electricity generation from system operation, the growth of generation capacity with low operation and maintenance costs (renewables like wind or solar PV), among others. In 2010, the energy component represented a 40% of the total household retail electricity prices in the EU, while in 2020 this value was reduced to 31%. This was mainly due to increasing importance of taxes in the energy bill.

Figure 26 – Evolution and composition of the EU household price (DC band)



Source: EUROSTAT

3.2 The pass through effect of electricity prices

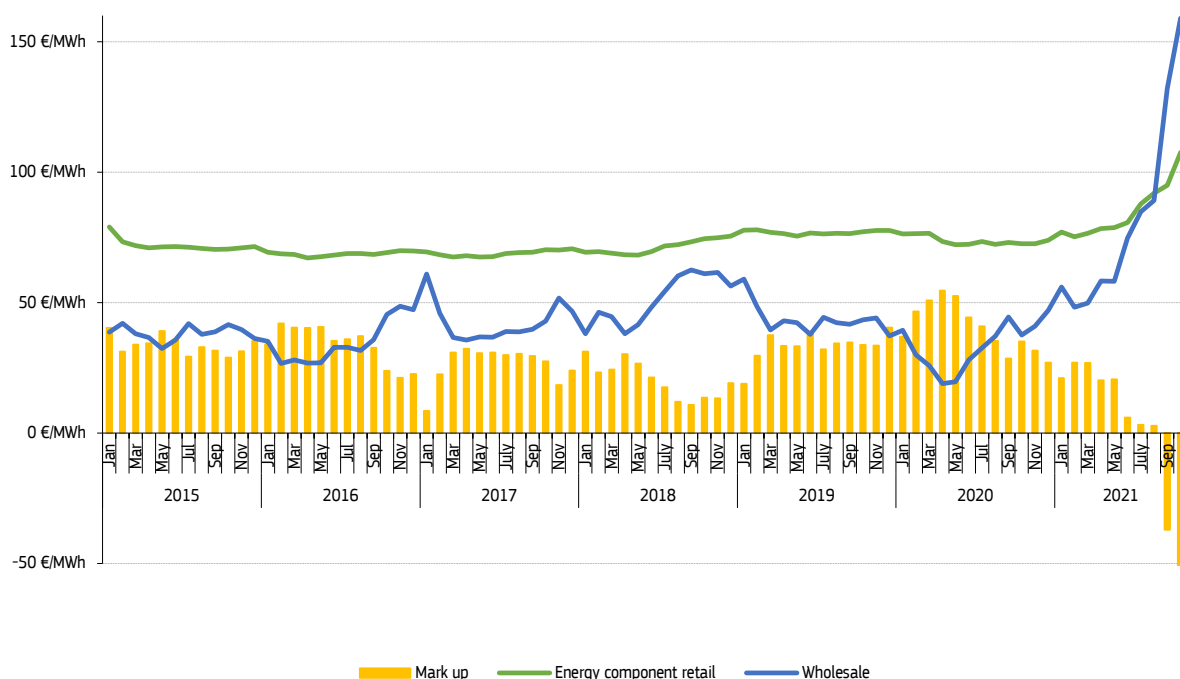
- In order to assess the level of responsiveness of the energy component of final prices to wholesale prices (i.e. the pass through effect) it is important to take a close look at the speed with which they interact. The speed of the pass

³ Voluntary Price for the Small Consumer (PVPC in Spanish)

through effect could be assessed by using a correlation analysis with lags between the retail price component and the wholesale price⁴.

- The difference between the energy component in household electricity prices and wholesale prices in the EU is called mark-up (or margin) and is sometimes used as a gross “profitability” indicator of suppliers. However, it would not be correct to present mark-ups as profits, as suppliers still have to pay for operational costs in bringing the product to the market⁵. Moreover, the degree of alignment between the evolution of the energy component of retail prices and wholesale prices could be used as a proxy of the effectiveness of competition in retail markets.
- **Figure 27** shows the responsiveness of the energy component of retail electricity prices to the variations in the wholesale electricity price and the evolution of mark-ups over 2015-2021 (October). Overall, a degree of convergence can be observed between 2017 and 2018. However, divergence can be detected from 2019 until the low of prices reached during the pandemic in 2020. The convergence between the two factors improved in 2021 together with record-high levels of wholesale electricity prices in the EU.

Figure 27 – Level of responsiveness of the energy component of household retail electricity prices to changes in wholesale electricity prices in the EU.



Source: Platts, European Power Exchanges, VAASAETT, ACER, ENER

- **Figure 28** presents the different correlation coefficients⁶ adjusted by time lag (measured in months) between the energy component and wholesale electricity prices. The time lag between these two factors in the EU varies between 0 and 24 periods (months) and the average correlation is 0.6. Nevertheless, to address the speed of the responsiveness of the energy price component to wholesale electricity prices, it is necessary to focus on each particular Member State. High correlations with zero to one lag can be found in Spain, Denmark, Sweden, Estonia and Belgium (correlation between 0.9 and 0.8), and Romania, Finland, Netherlands, Italy and Latvia (between 0.8 and 0.7). Poland, Malta and Bulgaria display a relatively high correlation (0.8-0.7) with 20, 14 and 24 lags respectively. Between 0.65 and 0.5 is Greece and Czechia situated with zero lag. At 0.6, Austria displays a correlation coefficient with 3 periods of lag, while Slovakia presents a lag at 20 periods. The rest of the Member States present lower values.
- The difference in time lag (speed) and how well both variables correlate could be explained by several factors. For example, in some countries, the degree of competition in the market can play an important role in the speed of the

⁴ Prices and costs of EU energy – Ecofys BV study. [Annex 2](#).

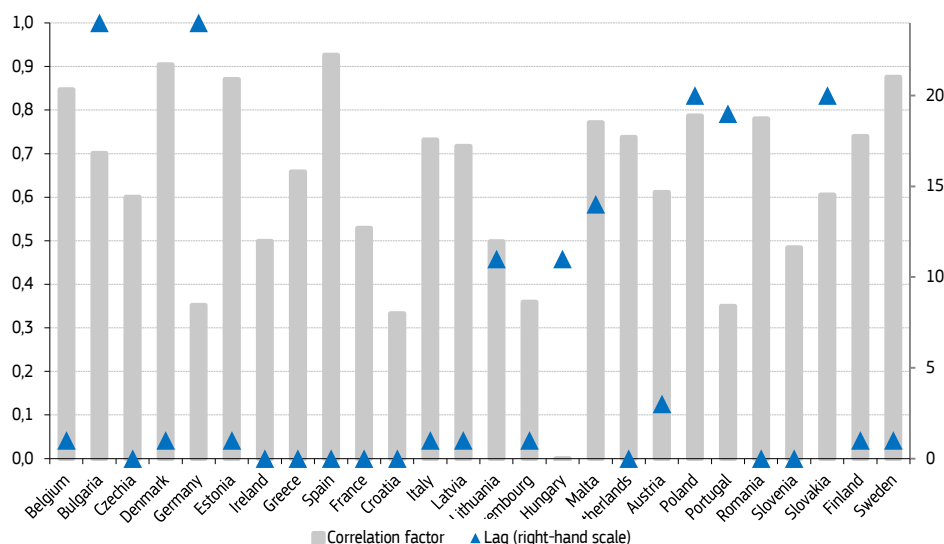
⁵ ACER Market Monitoring Report 2015. [Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2014](#).

⁶ The correlation coefficient is a measure of the strength of the linear relationship between two variables. A value of 1 indicates a strong positive relationship. A value of -1 indicates a strong negative relationship and a result of zero indicates no relationship at all.

pass-through of prices. If the concentration in a certain market is high, this could also mean a slow pass through of price drops or larger mark-ups than in more competitive markets. Additionally, in some Member States, prices are fixed for a given period of time, while in others many clients use dynamic contracts (linked to the wholesale market). Another factor that can be mentioned is that in some Member States household retail prices are still subject to price intervention, while in others, prices are not subject to intervention. Thus, the speed of pass through relies on the specificities of each market and how different tariffs are designed within the retail market.

- For instance, Sweden presents a high correlation (0.9) with one month of time lag between the energy component and wholesale electricity prices. Sweden falls in the category of countries with the lowest levels of concentration in the electricity market in the EU, dynamic contract pricing system and without price intervention. As such, a link can be suggested between these three variables, which combined, reflect a direct level of pass through of wholesale prices into the energy component. Conversely, countries like Czechia, which have medium values of correlation (0.6), a market without price intervention, but a high proportion of fixed prices and levels of concentration of the market suggest that there may be other variables in play that are not reflected in the relation wholesale-retail. Another interesting case is Hungary. A market with public price intervention, plenty of fixed rate contracts and high levels of market concentration, presents almost no correlation between the evolution of the retail component and wholesale prices. An outlier case can be found in Spain, which shows a high level of correlation (0.9) between the two studied variables. Approximately 40% of the domestic consumers of electricity in Spain have the regulated prices of PVPC, which act as a de facto dynamic pricing system. In general, a high level of correlation reflects a speed pass through of prices.

Figure 28 – Correlation and lag between the household retail energy component and wholesale price of electricity (2015-2021) in the EU.

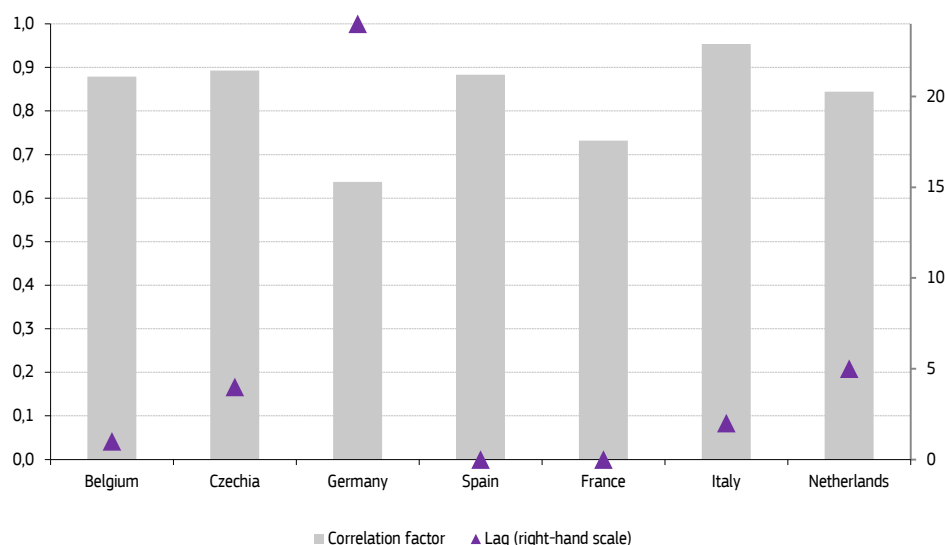


Source: Platts, European Power Exchanges, VAASAETT, ENER

- In spite of the previous analysis, plenty of utilities usually hedge⁷ prices, dampening the impact of price spikes (up to a certain point). One example of the hedging performed by utilities is through the futures market. Therefore, it is also interesting to analyse the role of future prices (where available) and their impact on the energy component of retail prices. **Figure 29** illustrates the different correlation coefficients adjusted by time lag (measured in months) between the energy component and future electricity prices. It is interesting to observe that most of the studied markets presented improved correlation factors when using future contracts instead of wholesale prices. Belgium (+4%), Czechia (+49%), Germany (+81%), Spain (-5%), France (+38%), Italy (30%) and the Netherlands (14%). High correlation values could be found in Italy (larger than 0.9 with 2 lags) and also in Belgium, Czechia and Netherlands (0.8 and 0.9) with 1, 4 and 5 lags, respectively. France registered a correlation valued between 0.7 and 0.8 while Germany presented values in the range of 0.6-0.7 with 24 lags. All in all, results suggest that hedging prices through long term financial instruments is a strategy that many utilities use in Europe.

⁷ The practice of taking an offsetting financial position designed to protect itself against fluctuations in a commodity price.

Figure 29 - Correlation and lag between the household retail energy component and futures of electricity (2015-2021) in the EU



Source: Platts, VAASAETT, ENER

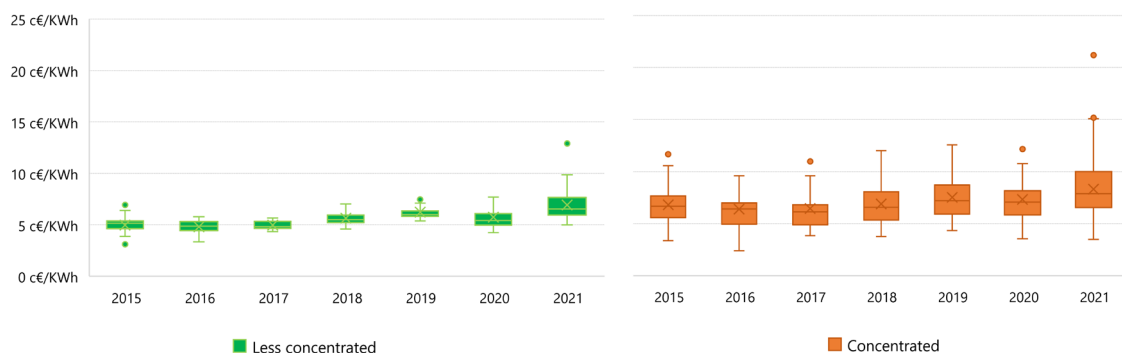
3.3 Market conditions

- The speed of the pass through effect of wholesale to retail prices may depend on factors such as the level of public price intervention, pricing system and the competitive structure of the market. There are further market characteristics (e.g. energy mix, number of suppliers, offers and price transparency) or consumer behaviour (i.e. switching between suppliers) that can influence the energy component and are not included in this analysis.
- An important factor that can have a substantial influence on retail prices is the level of competition in markets. Overall, a competitive market structure is commonly measured by the level of market concentration and the number of suppliers. To measure market concentration the Herfindahl-Hirschman-index (HHI) is commonly used. Another measure of market concentration is assessed by the concentration ratio (CR3), which entails the sum of the market shares of the three largest suppliers in a market. ACER annually informs on these two indicators as part of its Monitoring Market Report.
- **Figure 30** presents the energy component of two groups of markets. Those that have an HHI index lower than 2000 and with a CR3 smaller than 70% (less concentrated markets⁸) and another group with HHI index higher than 2000 and CR3 ratio greater than 70% (concentrated markets⁹). Both HHI and CR3 indexes for MS were obtained from the 2020 ACER MRR. A comparison of average prices between the two groups reveals that less concentrated markets have prices 21% lower than Member States with higher concentration in their markets. Moreover, the dispersion levels of each group may suggest that established incumbents in more concentrated markets can afford to keep larger price distance from smaller competitors, without being afraid of losing market share is an interesting sign of the level of structural barriers that play a part in the market.

⁸ Less concentrated markets: DK, AT, SI, FI, SE.

⁹ Concentrated markets: BE, CZ, EE, IE, EL, ES, FR, HR, IT, LT, LU, HU, NL, PL, PT, RO, SK.

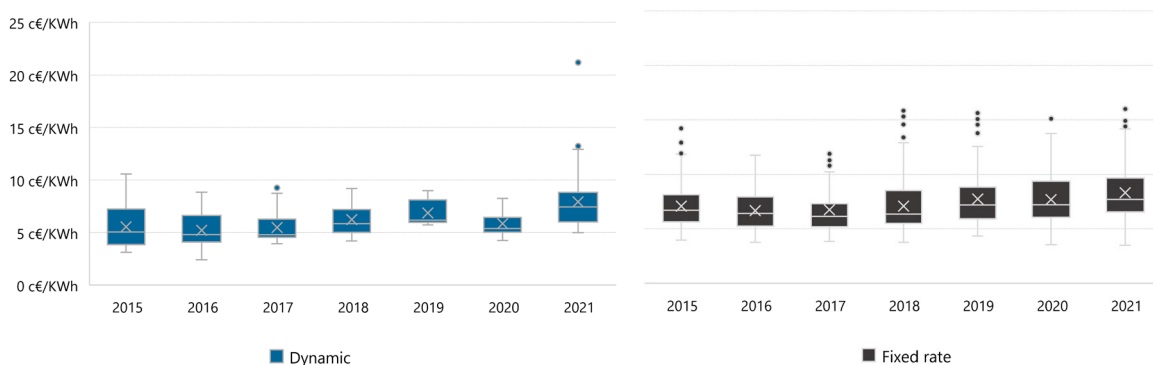
Figure 30 – Energy component by degree of competition in the market



Source: VAASAETT, ACER, ENER

- Another relevant factor to consider is the analysis of the impact of dynamic pricing system in comparison with fixed price contracts. By closely following daily developments in volatile spot markets, dynamic contracts create incentives for customers to react flexibly to variations in the wholesale market prices and adapt electricity consumption habits. On the other hand, customers instantly feel the impact of large-scale or long-lasting shifts in wholesale market prices. Conversely, fixed price contracts reduce the uncertainty associated with daily price fluctuations in prices and offer better mid-term visibility of energy costs, but incorporate a premium for this reduction of the risk. ACER/CEER report in its Annual Report on the Results of Monitoring the Internal Electricity and Gas Markets in 2020, that electricity consumers in 11 Member States can choose real-time or hourly energy pricing.
- **Figure 31** compares the evolution of electricity prices in two different groups of Member States. Those with a high share of consumers under systems based on dynamic pricing¹⁰ and those with a high proportion of flat-rate contracts¹¹. Results indicate that the average price across Member States and years (2015-2021) in markets with dynamic pricing systems was found to be 16% lower than in markets with predominantly fixed rates. Nevertheless, it is also important to consider that an important share of countries with high penetration of dynamic prices (e.g. Nordics) have in general cheap wholesale electricity prices as a result of their energy mix (hydro and/or nuclear). This of course could be a distortive effect beyond the option of dynamic or fixed prices.

Figure 31 – Energy component by system of pricing, electricity DC band



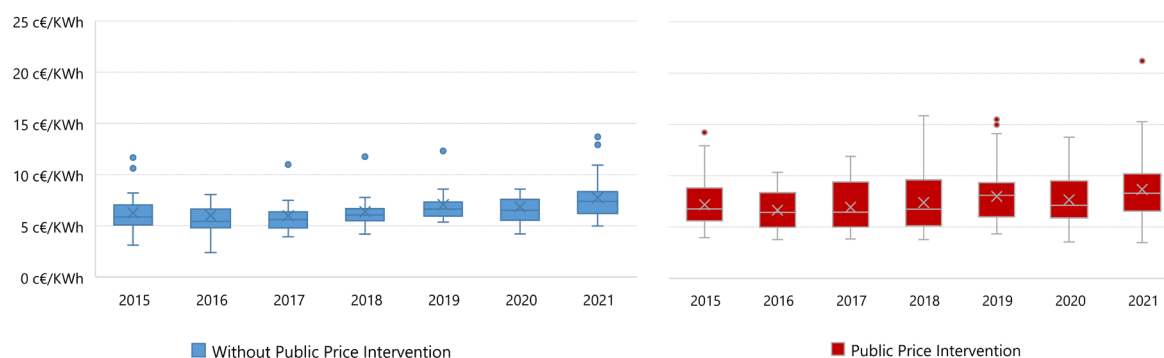
Source: VAASAETT, ENER

¹⁰ Dynamic pricing: DK, EE, ES, NL, FI, SE, as reported in [SWD/2019/1](#)

¹¹ Fixed rate: BE, BG, CZ, DE, IE, EL, FR, HR, IT, CY, LV, LT, LU, HU, MT, AT, PL, PT, RO, SI, SK.

- Public price intervention (PPI) on the energy component in the household market is a price subject to regulation or control/intervention by public authorities (e.g. National Regulatory Authority (NRA) or governments)¹², contrary to those being determined by market dynamics of supply and demand. Public price intervention includes price regulation, price cap, price approval or social tariffs. The level of public price intervention can have different impacts on end-user prices.
- Fourteen Member States have some sort of electricity public price intervention. In markets where regulated and non-regulated prices co-exist, consumers can choose to switch between them. Spain, France, Italy, Lithuania, Poland, Portugal and Romania reported such switching activities in 2020¹³.
- **Figure 32** illustrates the differences registered between the two categories of markets with Public Price Intervention (PPI)¹⁴ and without Public Price Intervention (WO PPI)¹⁵ for the energy component in the EU. For the purpose of this analysis, the Member States were allocated in each category according to the information provided by the latest ACER Market Monitoring Report¹⁶. Overall, the average price of the energy component across Member States and years (2015-2021) in markets without public price intervention was found to be 11% lower than in PPI markets. MSs that have PPI are commonly less exposed to ebbs and flows of markets without PPI. Nevertheless, it is important to consider the distortive effect that some markets (e.g. Nordic) may have on this analysis, as some of them already benefit from cheap hydro and nuclear power, and therefore, their lack of public intervention might not be the main reason for lower prices. The energy mix of the studied markets plays an important role as well in the level of prices.

Figure 32 – Energy component by status of Public Price Intervention, electricity DC band



Source: VAASAETT, ACER, ENER

3.4 The gap between wholesale prices and household retail energy component per Member State

- The following graphs present different groups of Member States and the evolution of wholesale prices in comparison to the energy retail price component according to the different market conditions previously explained. Wholesale and the energy component of retail prices are presented without a lag. The gap between the two very roughly indicates the potential profits/losses for suppliers (mark-ups).
- **Figure 33** and **Figure 34** compare examples of competitive markets with another group of countries with concentrated markets. The graphics suggest that the impact of wholesale prices in more competitive markets is higher than in concentrated markets, as changes are incorporated more rapidly in the energy component of retail prices. In addition, the first group of markets showed 8% lower mark-ups than in the second group. Higher mark-ups signal less competitive markets, while low mark-ups suggests effective competition.

¹² ACER Market monitoring Report 2020 – [Energy retail and consumer protection volume](#).

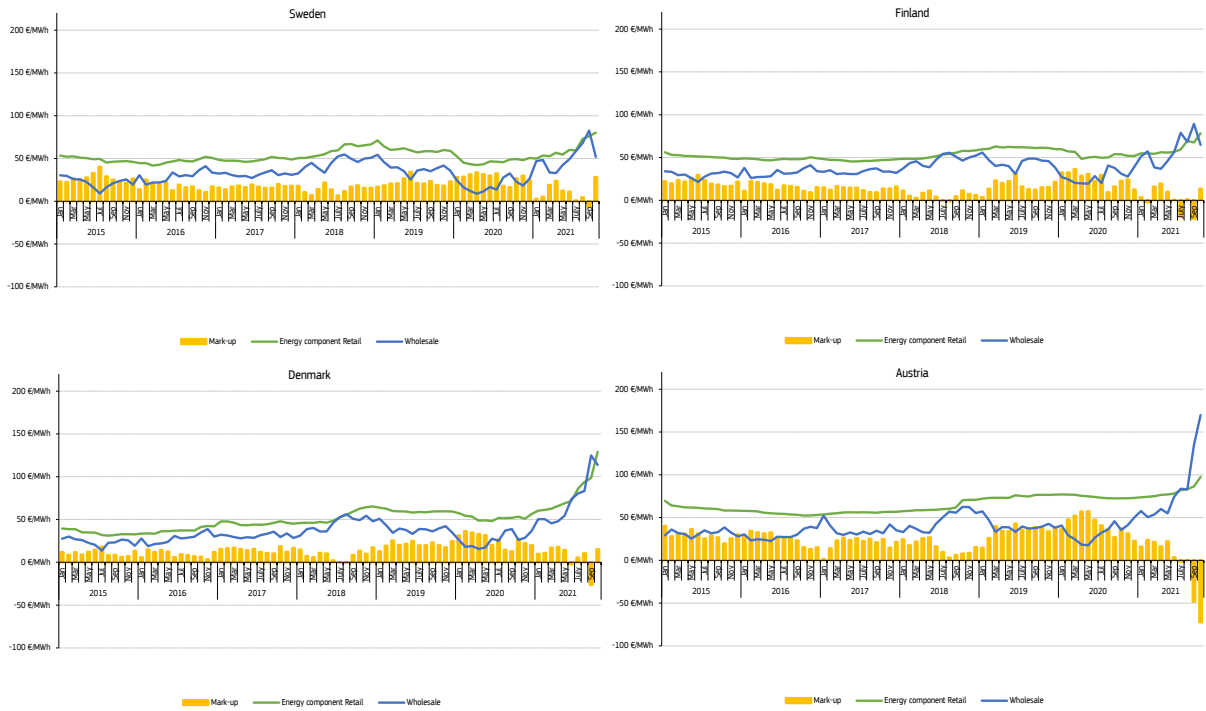
¹³ ACER Market monitoring Report 2020 – Energy retail and consumer protection volume.

¹⁴ Public Price Intervention (PPI): BE, EL, ES, FR, IT, CY, LV, LT, HU, MT, PL, PT, RO, SK.

¹⁵ Without Public price intervention (WO PPI): BG, CZ, DK, DE, EE, IE, HR, LU, NL, AT, SI, FI, SE.

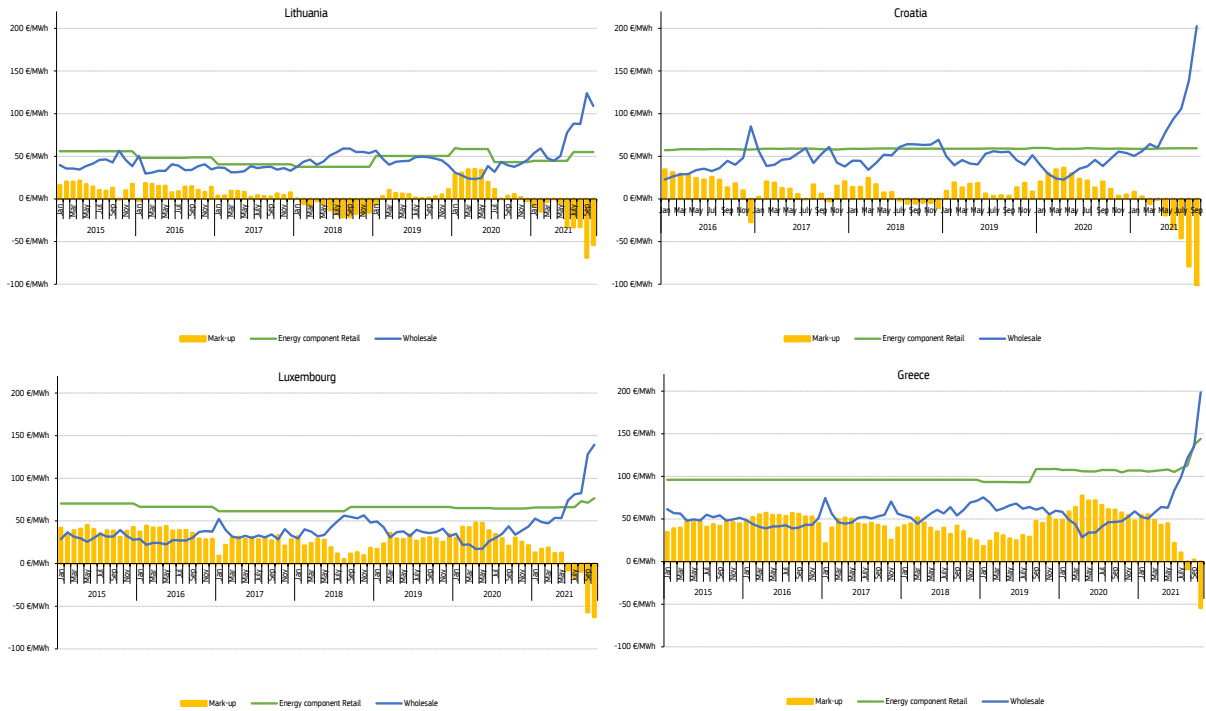
¹⁶ ACER Market monitoring Report 2020 – Energy retail and consumer protection volume.

Figure 33 – Household electricity retail energy component and wholesale prices, low concentration level markets



Source: Platts, European Power Exchanges, VAASAETT, ACER, ENER

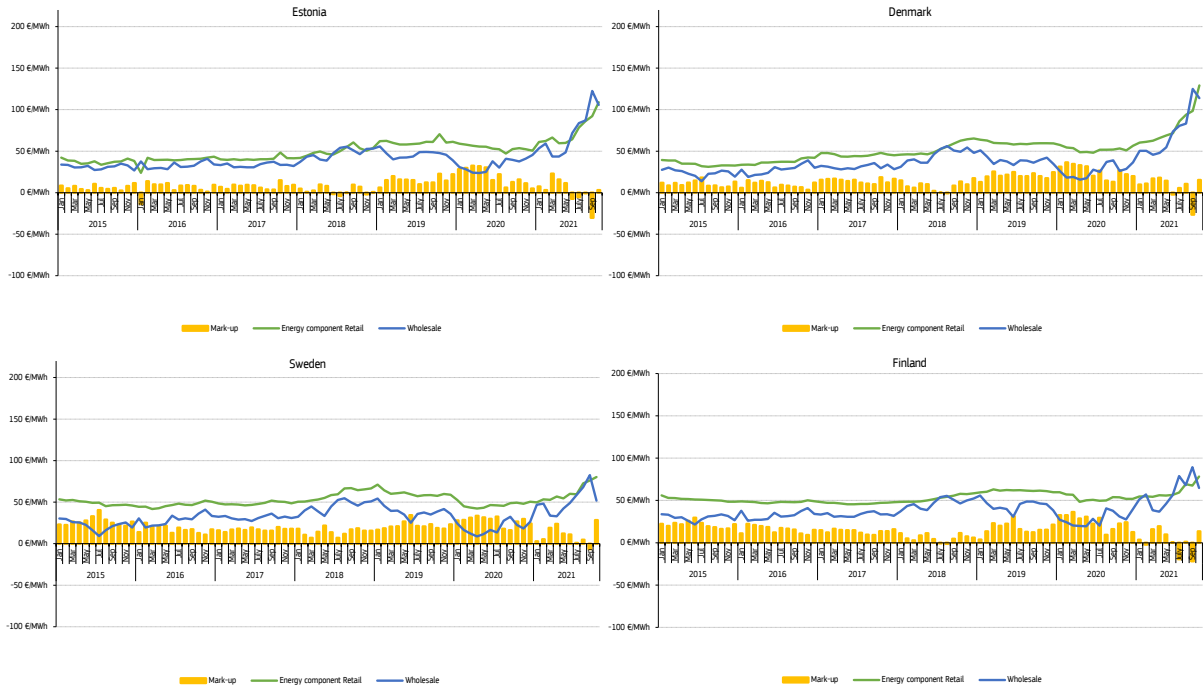
Figure 34 – Household electricity retail energy component and wholesale prices, markets with high levels of concentration



Source: Platts, European Power Exchanges, VAASAETT, ACER, ENER

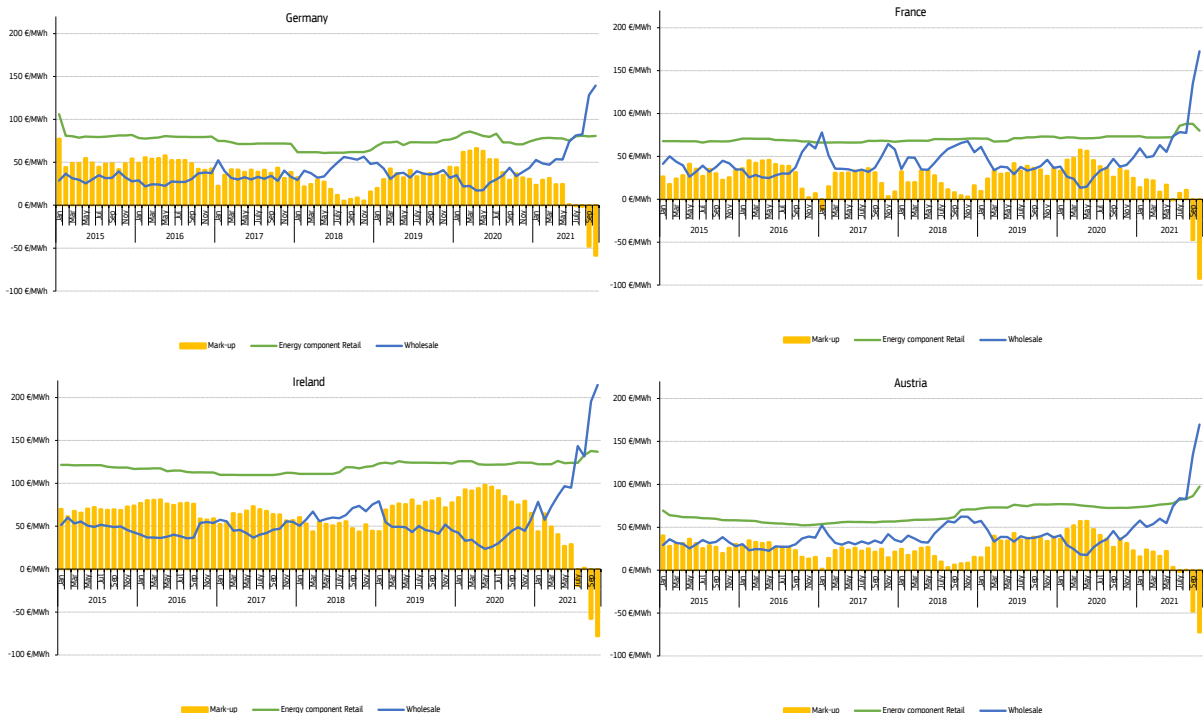
- **Figure 35** and **Figure 36** illustrate the first group of markets with a high penetration of dynamic prices and a second group with more presence of fixed rate contracts. The energy component of retail prices tends to follow rapidly developments in wholesale prices. In addition, the graphs present low mark-ups in this first group of markets (14 €/MWh in average – 60% lower than in the second group), which suggests strong market competition in comparison with the second group of predominant fixed rates markets.

Figure 35 – Household electricity retail energy component and wholesale prices, dynamic pricing



Source: Platts, European Power Exchanges, VAASAETT, ACER, ENER

Figure 36 – Household electricity retail energy component and wholesale prices, fixed rate pricing



- Figure 37** and **Figure 38** show the evolution of wholesale prices and the retail energy component in household electricity prices for two groups of markets. The first group takes a sample of markets without price intervention, while the second group presents a group of markets with public price intervention. In some Member States with PPI, mark-ups could be negative as a result of setting the energy component of retail prices at lower levels than wholesale prices. However, this effect has been extended also to markets without PPI and accentuated for PPI markets during the current period of high energy prices. In addition, a graphic analysis suggests that the impact of wholesale prices variations is more relevant in markets without public price intervention than in markets with PPI.

Figure 37 – Household electricity retail energy component and wholesale prices, markets without public price intervention

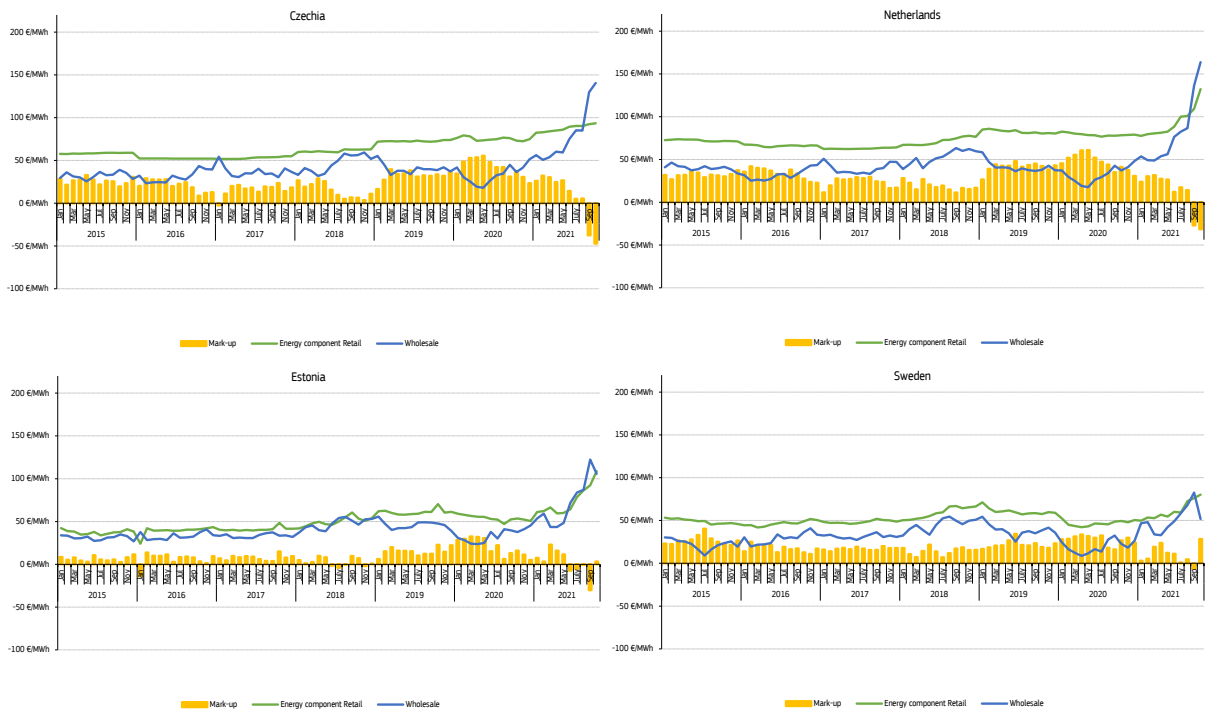
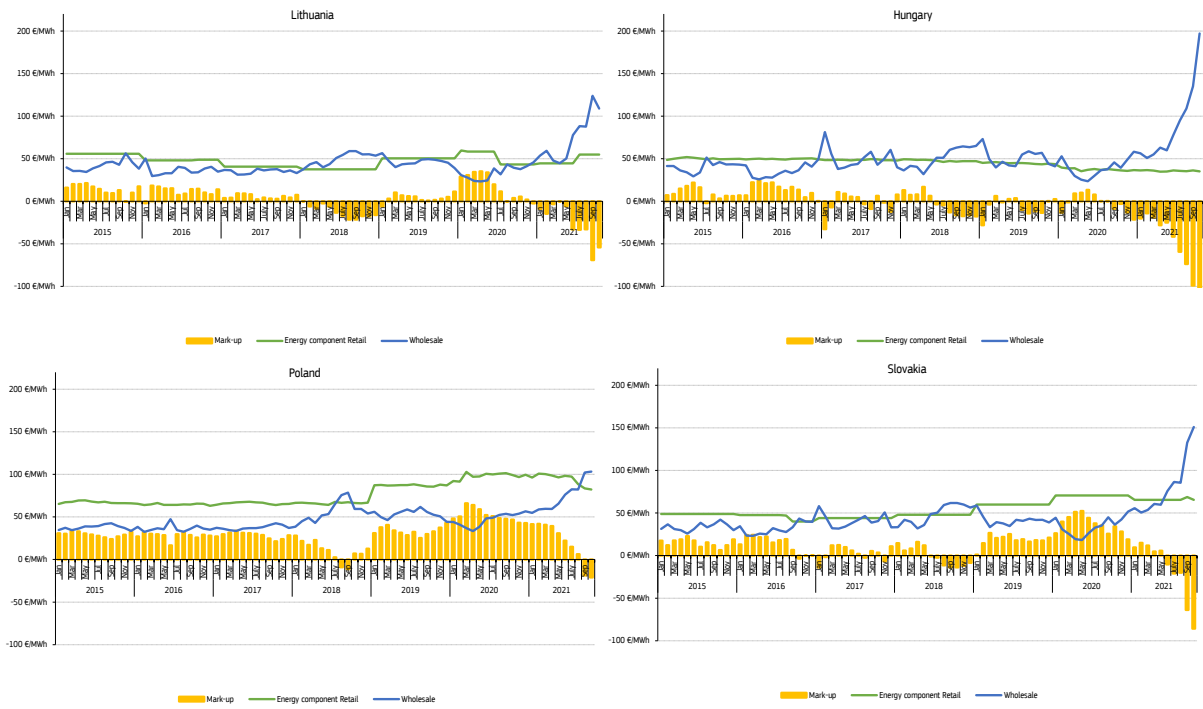


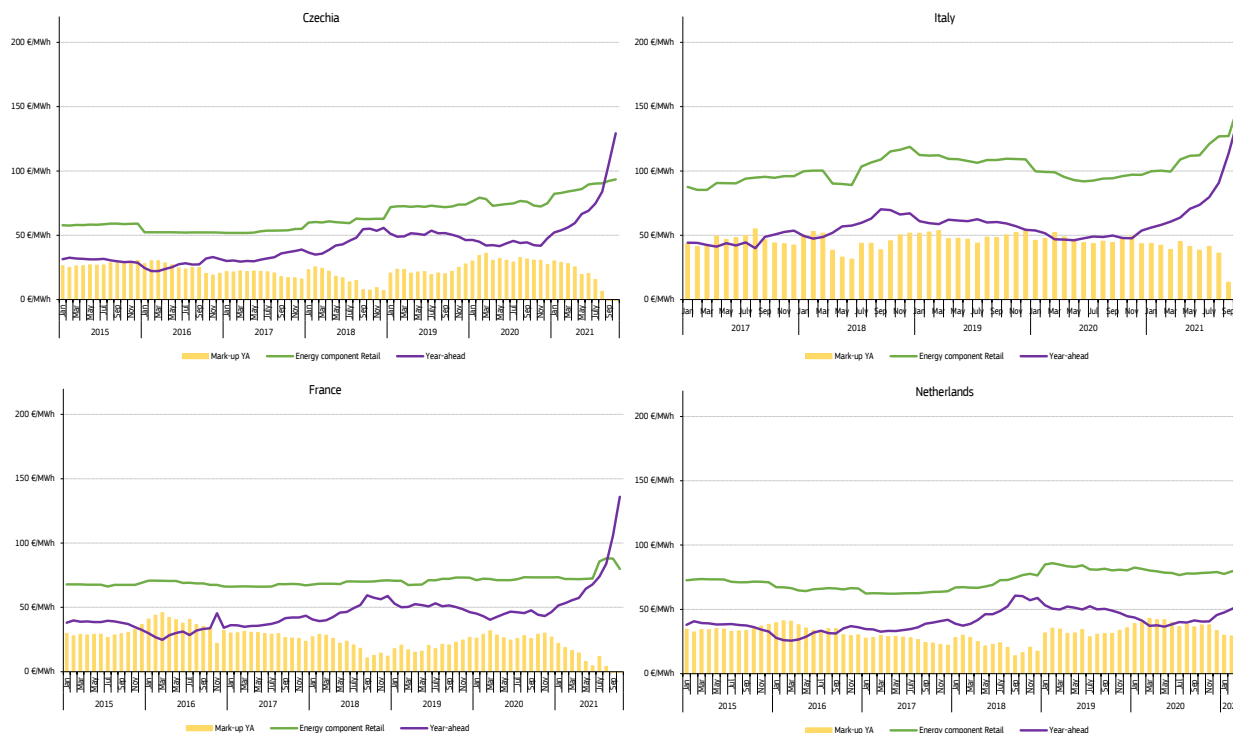
Figure 38 – Household electricity retail energy component and wholesale prices, markets with public price intervention



Source: Platts, European Power Exchanges, VAASAETT, ACER, ENER

- In addition, the evolution of future prices and the energy retail price component for selected Member States are presented without a lag in **Figure 39**. It can be observed the improved correlation between futures and the energy component when compared with the effect of wholesale prices. This signals the use of long term financial instruments to hedge electricity prices. The mark-ups are 3% higher than in the case of wholesale prices for the selected markets.

Figure 39 – Household electricity retail energy component and future prices, use of long term financial instruments



Source: Platts, VAASAETT, ENER

- Bearing in mind multiple caveats of the present analysis, results may suggest that the speed of the pass through between wholesale prices and the energy component of household retail prices, is faster in some Member States than in others. While these are not the only factors, the degree of market concentration, preference for certain types of contracts and public price intervention appear to play an important role in the pass through effect at household level. Spain, Denmark, Sweden, Estonia and Belgium have shown higher correlation levels with zero or one month of delay on the impact of wholesale prices over the energy component of retail prices. In general, prices correlate best in markets with high levels of competition where retail prices tend to follow the movements of the wholesale market.
- In addition, it is also interesting to analyse the role of financial instruments, such as hedging through future contracts and their impact on the energy component. Belgium, Italy, Czechia and the Netherlands showed high correlation values in the analysis of future contracts. High levels of correlation in some markets may suggest that hedging through long term financial instruments is a strategy that is used by utilities.
- The results suggest that markets with high levels of concentration have shown higher prices (21%) than those more competitive markets. The level of dispersion of prices may suggest structural barriers that are present in more concentrated markets, where incumbent suppliers can afford to keep larger prices distance from small competitors without being afraid of losing market share. Changes in wholesale prices are reflected more rapidly in retail tariffs in less concentrated markets. Mark-ups in the sample of less concentrated markets were found to be 8% lower than in the sample of concentrated markets. Higher levels of competition in retail markets are the most effective way to reduce household retail prices.
- In general, markets relying on dynamic contracts (e.g. Estonia, Sweden, Denmark and Finland) have shown lower prices (16%) on average throughout the past years. However, we have to be cautious to state plainly that dynamic prices may always deliver lower prices, as it is relevant to consider that several of the markets with high penetration of dynamic pricing, have at the same time an energy mix based on technologies with low short run marginal costs (e.g. hydro). Moreover, in markets where fixed rates are more prevalent, wholesale prices are passed through to the energy component of retail rates with more delay than in markets prone to dynamic contracting, but at the same time retailers' margins tend to be smaller in a more dynamic contracting environment (half the value of the mark-ups with fixed contracts in the sample of markets).

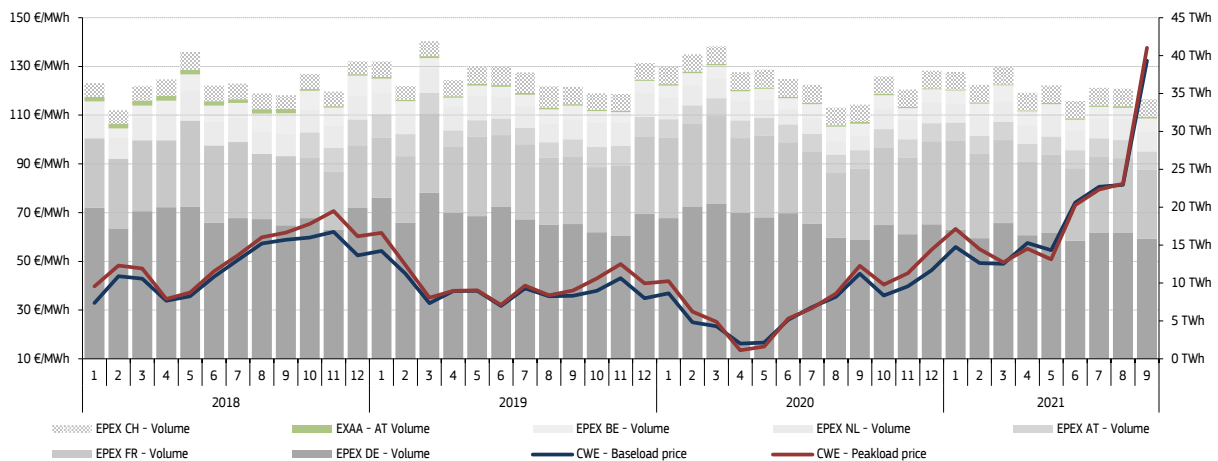
- Finally, the results indicate that markets with public price intervention presented higher prices (11%) than markets without price intervention and changes in wholesale prices are passed through to household retail prices more swiftly under the latter. However, differences in the energy mix are important and could distort the picture when comparing these two groups (for instance the fact that high levels of hydro generation deliver cheaper wholesale prices in some Nordic countries).

4 Regional wholesale markets

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

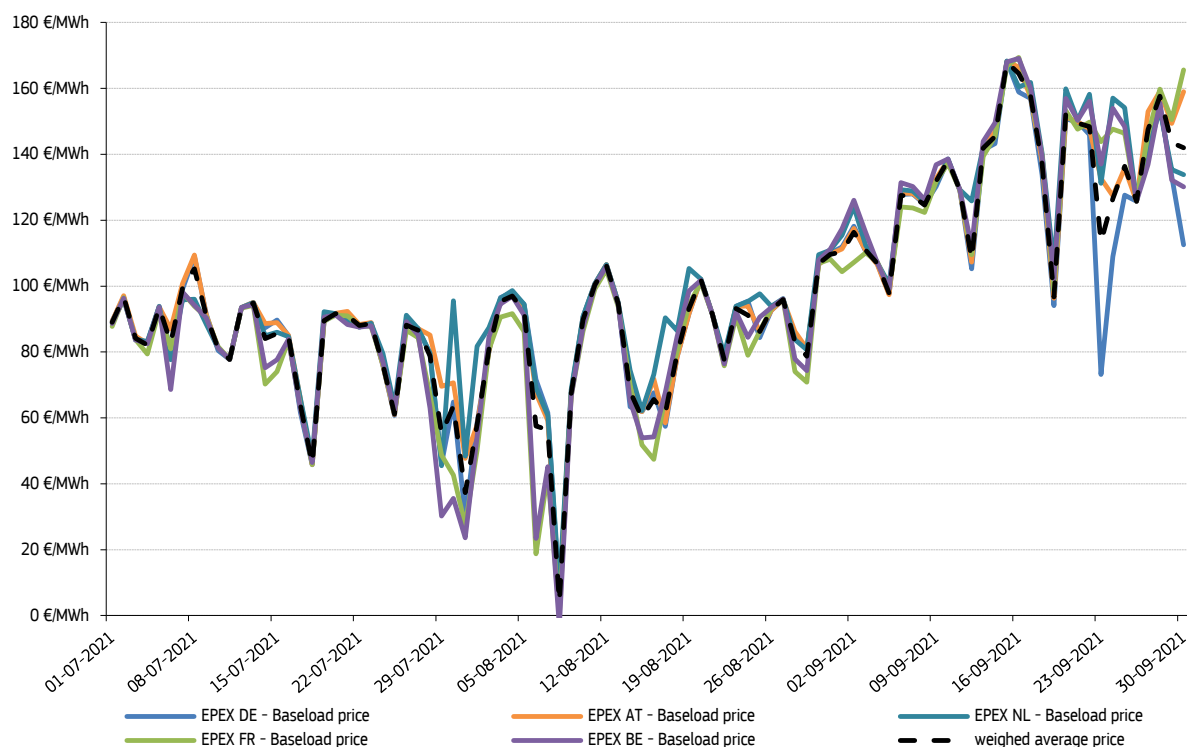
- Following the rally in prices in the previous quarter, monthly average wholesale baseload electricity prices in Central Western Europe (CWE) continued to rise in the third quarter of 2021. The increase in spot prices has intensified, amid expensive gas, growing power demand due to the relaunch of the economic activity and to a lesser extent, high CO₂ prices. Wholesale electricity prices reached a peak in September (132 €/MWh), on the back of the previously mentioned factors. The rally in baseload electricity prices briefly stalled in August increased renewable generation. The monthly average price for baseload power in September, reached all-time highs, reflecting levels of demand at pre-pandemic times. Compared to Q3 2020, the average baseload price in the region increased by 164% to 98 €/MWh in the reference quarter. Meanwhile, average peakload prices increased by 158% to 158 €/MWh. The rally of prices continued through the fourth quarter of the year, reaching new historical highs in October throughout European countries.
- In France, following the major reshuffle of annual maintenance of the nuclear fleet as a result of the pandemic, the French nuclear operator lifted its 2021 generation target at 345-365 TWh, due to an improved performance of the nuclear fleet during the summer. All in all, nuclear generation rose 29% year-on-year during Q3 2021, facilitating exports during the quarter (22 TWh), combined with subdued demand. However, the outage of the 1 GW IFA 2 cable to the UK on 15 September, resulted in lower net exports and reduced nuclear output (below 39 GW) during week 38.
- In Germany, decreased levels of wind reduced the output of renewable generation. Against the backdrop of renewables, hard coal and especially lignite generation were called to meet the gap of improved power demand, adding further running hours of thermal generation. Germany's exposure to variations in wind generation could increase high price volatility during the upcoming winter. In addition, nuclear output increased +1.6 TWh during the reference quarter. Gas prices have impacted the German generation mix by lifting competitiveness of coal and lignite versus gas-fired generation. As a result, gas-fired generation fell by 30% in Q3 2021. Germany is set to retire 10 GW of traditional capacity by the end of 2021. 6 GW of coal and 4 GW of nuclear (three of remaining six generators) will be decommissioned. Germany was a net importer of power during Q3 2021. The new German government has announced plans to accelerate coal exit ideally by 2030 (instead of 2038), while rapidly speeding up the rollout of renewables.
- The Netherlands, experienced a 16% year-on-year decrease in generation (-4.8 TWh) due to reduced gas generation (-49%), despite considerable increase of wind and solar output. Rather reduced levels of Alpine hydro and gas generation in Austria were supported by increased coal and wind generation. Austria announced a new CO₂ tax starting in July 2022 at 30 €/tCO₂ which would gradually raise to 2025. Switzerland reported improved solar generation (+52% in Q3 2021) thanks to the record addition of 493 MW of new solar capacity during last year. Belgium's electricity capacity mechanism was approved under state aid rules by the European Commission at the end of August. The capacity auction aims to compensate for the phase-out of 6 GW of nuclear capacity by 2025.

Figure 40 – Monthly exchange traded volumes of day-ahead contracts and monthly average prices in Central Western Europe



- **Figure 42** shows the daily average day-ahead prices in the region in the reference quarter. The third quarter of 2021, was marked by a sustained increase in prices from mid-August onwards. In July, daily average prices held mostly between 75 and 90 €/MWh. Volatility increased during August, driven by high gas prices and increased demand due to above-average temperatures, with prices in the range of 65-95 €/MWh. Prices continued to rise during September registering prices between 115-150 €/MWh, due to high commodity prices and variations in wind generation.
- All-time highs were registered over 160 €/MWh around mid-September. In particular, on 15 September, prices spiked to 168 €/MWh, due to an outage of the UK-French 2 GW IFA interconnector, combined with high prices of gas and subdued renewable generation. On the bottom side of the price spectrum, Germany, France, the Netherlands, Belgium, Austria and Switzerland saw prices sinking below zero during some hours on 8 August, owing to weak demand and a surge in wind and solar generation.

Figure 41 – Daily average power prices on the day-ahead market in the CWE region



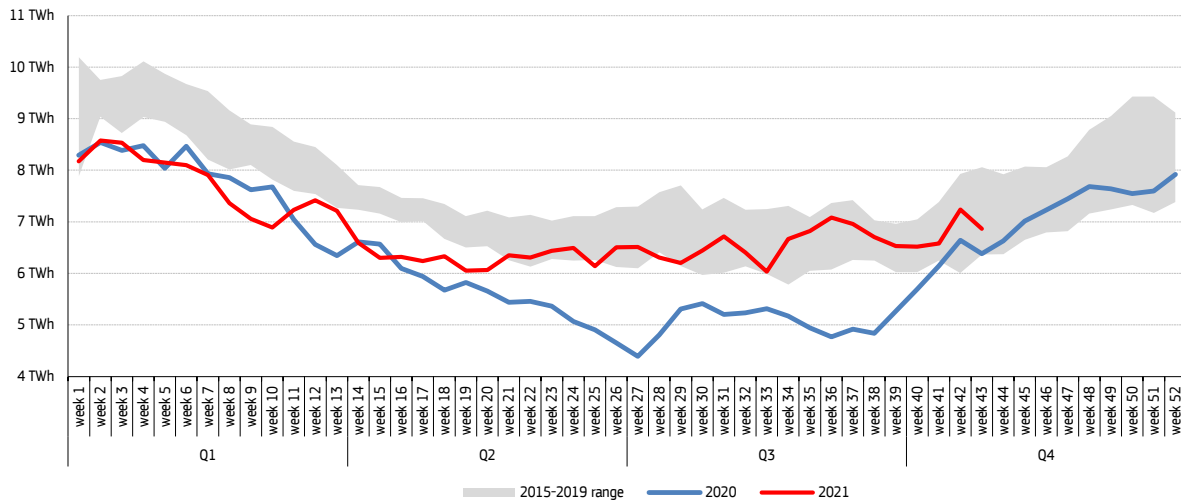
Source: Platts.

- In July, French nuclear generation continued to recover from the lows of the previous quarters, as shown in **Figure 43**. In 2020, French nuclear output fell to a record-low of 335 TWh, due to the economic recession, planned maintenance, closure of assets and extended outages. However, following a major reschedule of annual maintenance of the nuclear fleet as a result of the pandemic, French nuclear output was up 30% (20 TWh) year-on-year in Q3 2021, close to levels seen in previous years. During the quarter, EDF delayed some planned reactor returns and registered brief unplanned outages at Paluel 4, Cruas 3 and Tricastin 2. French nuclear forecast to the four quarter of the year is at 44 GW, a significant recovery from last year. In addition, the French nuclear operator maintained the 2022 target of nuclear generation at 330-360 TWh and estimates the 2023 output at 340-370 TWh. The new French reactor Flamanville 3 (1.6 GW) has been delayed to start commercial operations around mid-2023. The French government announced to relaunch the construction of nuclear reactors while continuing to develop renewables in the country. France's 2030 growth plan has a focus on the support of small modular reactors (SMRs), with an indicative decision on whether to build more EPR reactors, which should be taken in the near term. EDF noted that the first of six EPRs could start operating in 2035.
- Improved nuclear availability was at 39 GW in average during Q3 2021. Nuclear availability in September 2021 stood at 40 GW. The nuclear output peaked at 7.1 TWh during week 37, in stark contrast with levels seen during the same week in 2020 (4.8 TWh). The maximum daily availability was registered on 7 September (43 GW), while a low was recorded on 8 August at 30 GW. French nuclear output during September was the best since 2015. Due to the good performance in the summer, the 2021 estimated output was upgraded to the range of 345-365 TWh. Capacity improved due to the return of reactors from maintenance before the summer (Flamanville 1 and Paluel 2 in early May, Tricastin 3 and St Alban 2 in mid-May) and the return of Chooz 2 from extended maintenance (online since December 2020) and Cattenom unit 3 from a 10-year overhaul at the end of August. In addition, Chooz 1 started

planned maintenance in September, with unit 4 scheduled for such an overhaul in early 2022. However, in November, defaults were detected in Civaux 1 and Civaux 2, which will delay their return by Q2 2022. In addition, EDF decided to take offline Chooz 1 and 2 reactors for preventive maintenance in December. Chooz 1 and Chooz 2 are scheduled to be offline until 23 January. The unavailability of the reactors will impact nuclear availability during Q1 2022.

- Belgium has plans to decommission the existing nuclear capacity (6 GW) by 2025. The plan involves the closure of Doel 3 from October 2022 and Tihange 2 from February 2023. The remaining (five) reactors are scheduled to close between February and December 2025.

Figure 42 – Weekly nuclear electricity generation in France

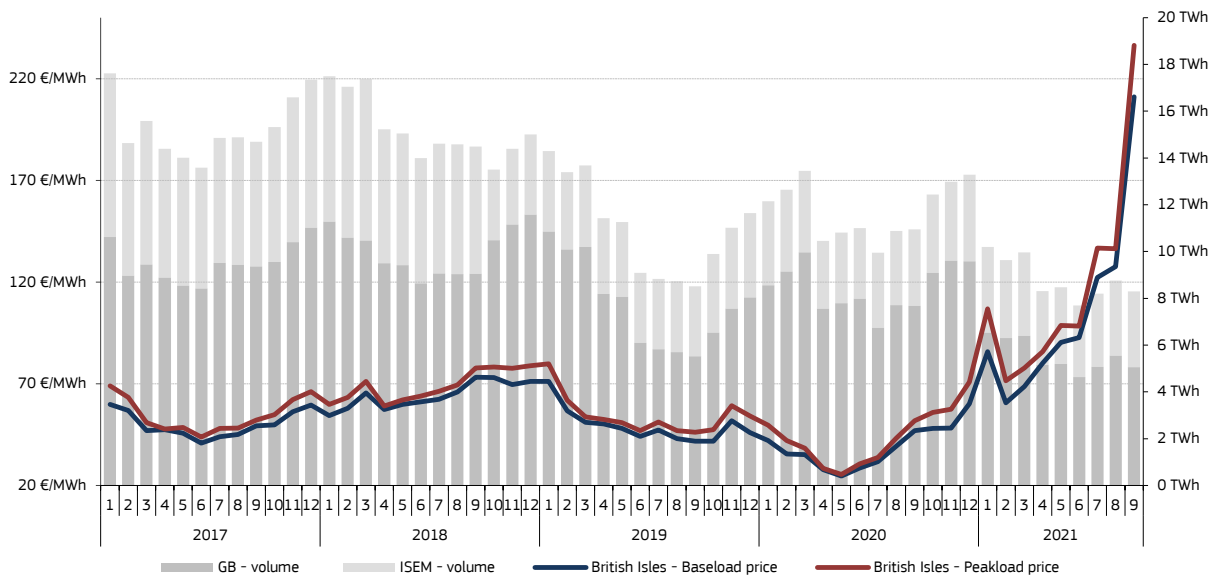


Source: ENTSO-E

4.2 British Isles (GB, Ireland)

- **Figure 44** illustrates monthly volumes and prices on the day-ahead markets in Great Britain and in the all-island integrated market in Ireland. Monthly averages for both baseload and peakload power rose again reaching all-time highs during the last month of Q3 2021. The surge was driven mainly by soaring gas prices, combined with tight supply margins, low wind availability, robust demand, unplanned interconnector outages and reduced nuclear output. Great Britain had insufficient spare capacity to meet demand, resulting in gas, coal and even oil plants ramping up to meet the demand during the quarter. In July high temperatures impacted the operation of gas and nuclear power stations, forcing imbalance prices to rise as the system operator called operating reserves. A fire at the IFA 2GW interconnector with France resulted in a soar in prices, as the lack of imported flows saw the UK more reliant on expensive gas-fired generation in a situation of tight supply-demand balance. The interconnector was partially back online on 20 October, whereas National Grid informed that the remaining 1 GW of the IFA capacity will be unavailable until 27 March 2022. Compared to Q3 2020, the average baseload price on the British Isles rose by 290% to 154 €/MWh during Q3 2021 and was 114% above the level from Q2 2021. Trading activity on the British day-ahead market decreased by 29% in Q3 2021 compared to the same quarter last year, whereas Ireland reported a 1% decrease during the reference quarter. As a result of high energy prices, ten suppliers ceased trading during Q3 2021 affecting 1.8 million customers in the UK. In December the number of suppliers that went bust increased to thirty. Prices surged reaching new highs during November and December, on the back of extreme gas prices, tight supply margins and cold weather.
- In its [Winter Outlook](#) released in early October, the National Grid forecasts sufficient capacity available and the tools needed to meet demand during the winter 2021/2022. System margins are expected to be well within the reliability standard. On the supply side, slightly more available generator capacity is expected to be available, due to a higher number of CCGT and biomass power plants being available.

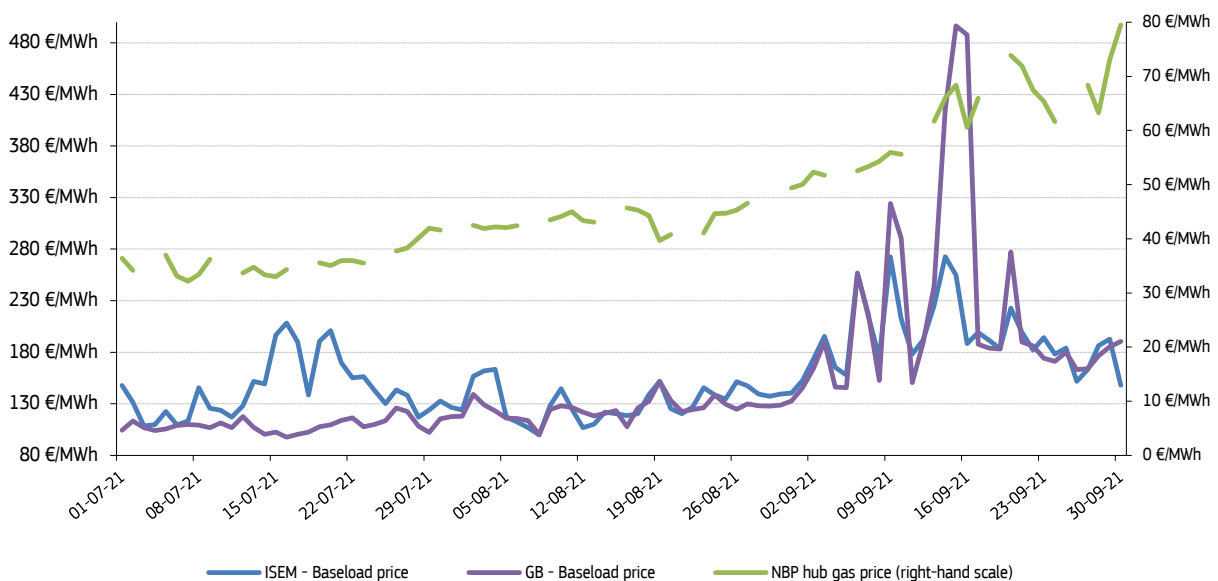
Figure 43 – Monthly exchange traded volumes of day-ahead contracts and monthly average prices in Great Britain and Ireland



Source: Nord Pool N2EX, SEMO, Utility Regulator

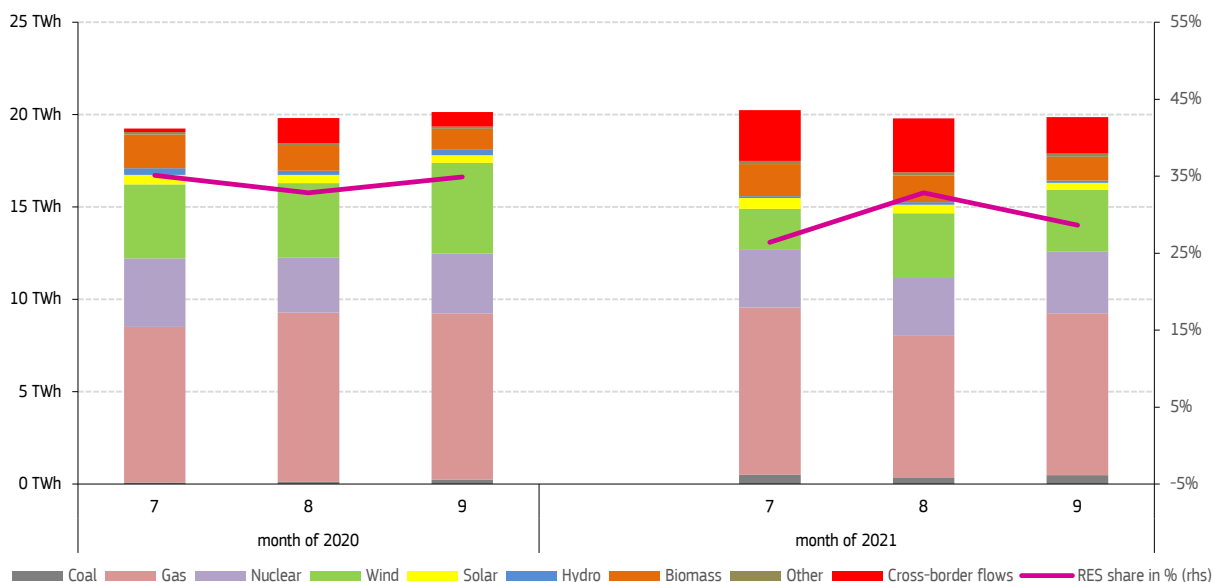
- Figure 45** follows the developments of daily average baseload electricity prices in Great Britain (N2EX) and Ireland (ISEM). British baseload prices experiencing soaring prices during Q3 2021, with increased volatility and spikes registered during September. High gas prices, low wind generation and tight margins of spare electricity capacity saw the increase of running hours of the coal fleet to meet the demand. In July, daily average prices held mostly between 100 and 110 €/MWh. In August, prices fluctuated among 120-130 €/MWh, climbing during September to prices in the range of 160 and 250 €/MWh due to supply tightness and a surge in gas prices. The Irish market registered spikes on 14 September (272 €/MWh), whereas prices in Great Britain registered a peak of 497 €/MWh on 15 September, amid low winds and an unplanned outage that affected the 2GW capacity IFA 1 cable infrastructure between the UK and France. Baseload wholesale prices were higher than in any previous quarter.
- Prices in the all-island Irish market generally followed the UK contract, albeit less volatility during September. Low winds contributed to a 32% year-on-year output decline during the quarter, while coal generation saw an increase in its output by 230%, amid high gas prices which reduced gas-fired generation by 10% on yearly basis.

Figure 44 – Daily average electricity prices on the day-ahead market in Great Britain and Ireland



- Figure 46** shows that coal-fired plants were the main winners of generation mix during Q3 2021, as they were required to fill the gap due to low wind generation and decreased gas-fired output due to soaring gas prices (especially during September). Imports from the continent increased by 227% on a net basis. The quarter saw the highest volume of imports seen in any previous quarter, with +7.6 TWh of net imports registered. Coal-fired output increased remarkably (230%) to cover the gap in demand of low winds. Coal is now mainly used to cover demand peaks at times of low renewable availability and should leave the mix by 2024. However, its contribution was almost negligible in absolute terms compared with gas. Extremely high gas prices at the NBP resulted in a decrease on gas-fired output by 10%. Nevertheless, the share of gas generation was still at 49% during Q3 2021. Biomass output registered a decline of 15% during the quarter. The renewable share decreased to 29%, up from 34% in the reference quarter during 2020, as July and September saw important wind lulls. Conversely, fossil fuels covered 52% of the total electricity generation, compared with 48% registered during Q3 2020.
- The early closure of nuclear reactors Hunterston B and Hinkley Point B by mid-2022, combined with the closure of Dungeness B nuclear power plant (1 GW) will remove nuclear installed capacity by two thirds by the end of 2022 (6 GW will remain). All existing UK reactors are schedule to shut down by the end of 2031, with the exception of Sizewell B, which should be in operation until 2055. The exit date for coal generation was moved forward to October 2024. Ratcliffe power plant will be the last remaining unit from September 2022. The recent resurgence of coal generation in the UK has been fuelled by the surge in gas prices. However, it is expected that by 2023, coal generation will be consistently not profitable. Considering the nuclear and coal phase-out, the UK would become more reliant on electricity imports and flexible use of capacity to meet demand.
- The UK is a net importer of electricity. Existing infrastructure links with EU Member States provide up to 10% of UK's electricity supply. Great Britain has 5 GW of interconnection capacity to other Member States (France, Belgium and the Netherlands). The 1 GW Eleclink interconnector via the channel tunnel to France registered its first import test on 18 September. Commercial operations are expected from mid-2022. The North Sea Link to Norway (1.4 GW) came online during on 1 October limited to a maximum flow of 700 MW. The Viking link to Denmark (1.4 GW) should further increase interconnectivity between the UK and the continent in 2023. In addition, another 1.4 GW power cable is due to be built in 2023-2024, connecting the Isle of Grain in the UK with Wilhemshaven in Germany. The UK government plans to become a net exporter of electricity by 2040, thanks to a surplus of electricity coming from 20 GW of wind capacity (mainly offshore).

Figure 45 – Changes in the UK electricity mix between Q3 2020 and Q3 2021



Source: BEIS

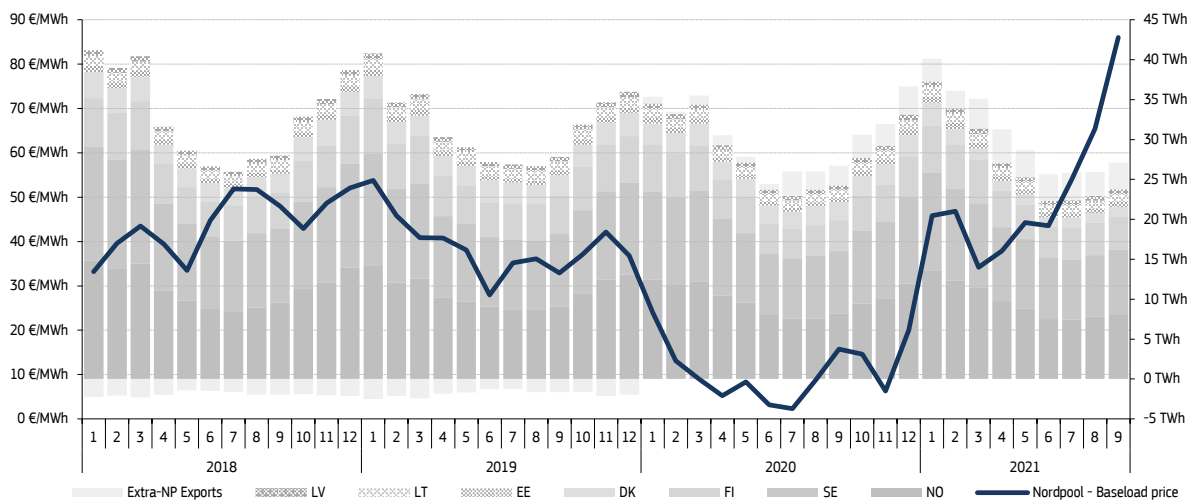
4.3 Northern Europe (Denmark, Estonia, Finland, Latvia, Lithuania, Sweden, Norway)

- As shown in **Figure 47**, Nord Pool prices rose again throughout the third quarter of 2021, after more or less stable prices in the previous quarter. Spot prices rose during July and August reaching 54 €/MWh and 65 €/MWh respectively. Baseload prices continued to rise until September, reaching an all-high price of 86 €/MWh on the back of a steep rundown in hydro reservoir stocks and low wind speeds. The interconnection to continental Europe has im-

proved the power flows between markets, bringing Northern Europe closer to prices in continental markets. Compared to Q3 2020, the average system baseload price surged by 654% to 68 €/MWh in the reference quarter. Very low prices in the third quarter of 2020 helped to amplify the increasing effect of prices during the reference quarter. Trading activity remained at the same levels as to the previous Q3.

- A new 400 kV power link between Sweden and Finland is on track to boost interconnection capacity by 65% between the two countries in 2025. The 380-km cable from Lapland in Sweden to the Finnish Baltic shore is expected to start the construction in 2024. The link will allow to balance the grid taking advantage of Swedish and Finnish enhanced wind capacity. Sweden is on track to exceed 17 GW of wind capacity by 2024, whereas Finland's wind sector is growing thanks to 6 GW of projects fully permitted. Finland is expected to improve its condition of net importer of electricity when Olkiluoto-3 nuclear power plant is commissioned during 2022, expecting to ease the pressure on Nordic power markets.

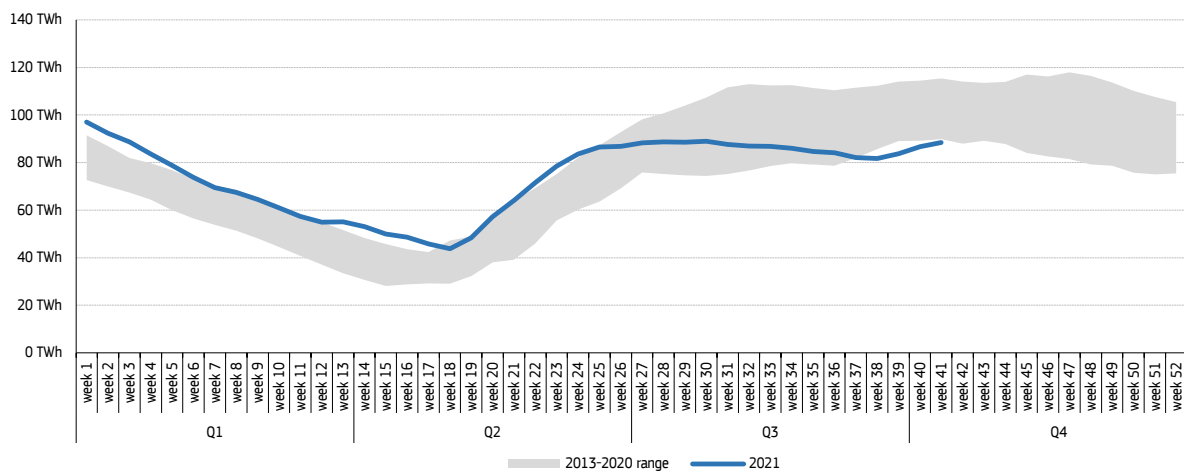
Figure 46 – Monthly electricity exchange traded volumes and the average day-ahead wholesale prices in Northern Europe



Source: Nord Pool spot market

- **Figure 48** shows the weekly evolution of the combined hydro reservoir levels in the Nordic area (Norway, Sweden and Finland) in 2021 compared to previous eight years. Hydroelectric stocks fell steadily throughout the quarter, on the back of dry weather and rising spot prices in the region. Dry weather condition reduced reservoir and river inflows through most of Q3 2021 in Norway. Overall, hydro generation in the region registered a decline during Q3 2021, driven by Norway's 7% decrease (- 2.1 TWh) and Finland's 4% losses (- 0.1 TWh), which could not be compensated by Sweden's 2% year-on-year upturn (+ 0.4 TWh).

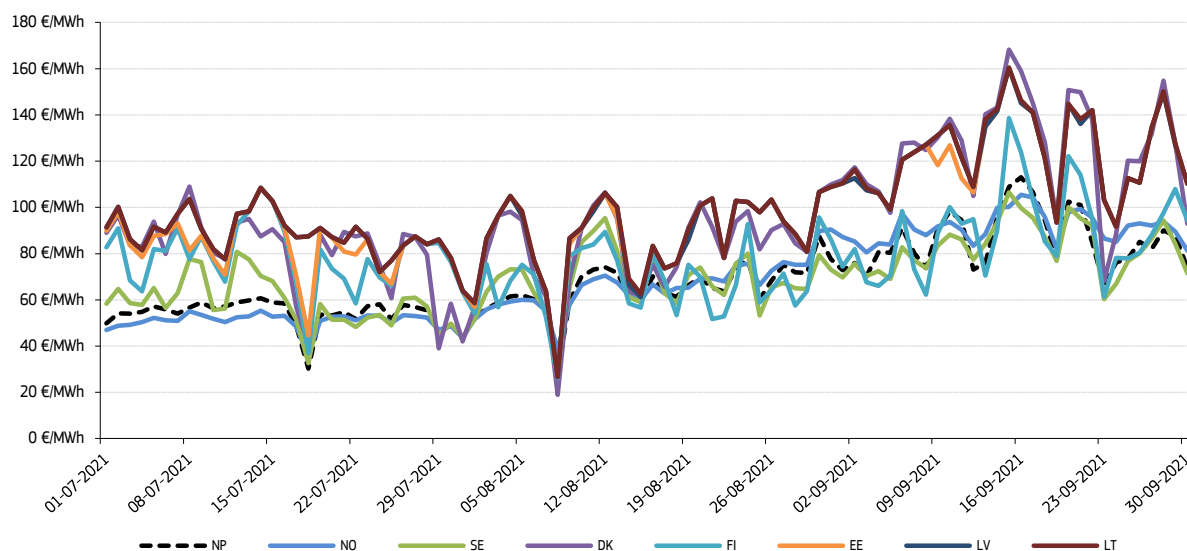
Figure 47 – Nordic hydro reservoir levels in 2021, compared to the range of 2013-2020



Source: Nord Pool spot market

- **Figure 49** shows that average daily prices across Northern Europe continued to display a high degree of divergence throughout Q3 2021. System prices fluctuated among 50-80 €/MWh during the reference quarter. Continued lack of rainfall and below-average weather caused electricity demand to hit record highs in the Nord Pool system on 16 September (113 €/MWh). Increased electrification of industry, transportation, and home energy use has boosted energy demand in the region, especially during cold periods. The Baltic region and Finland, which both suffer from considerable structural deficits (see **Figure 25**), registered nearly permanent premiums over the system contract. The Nordic region was affected dry and colder-than average temperatures, while also fell the impact of high fuel prices, which increased system prices during Q3 2021.

Figure 48 – Daily average regional prices and the system price on the day-ahead market in the Nordic region

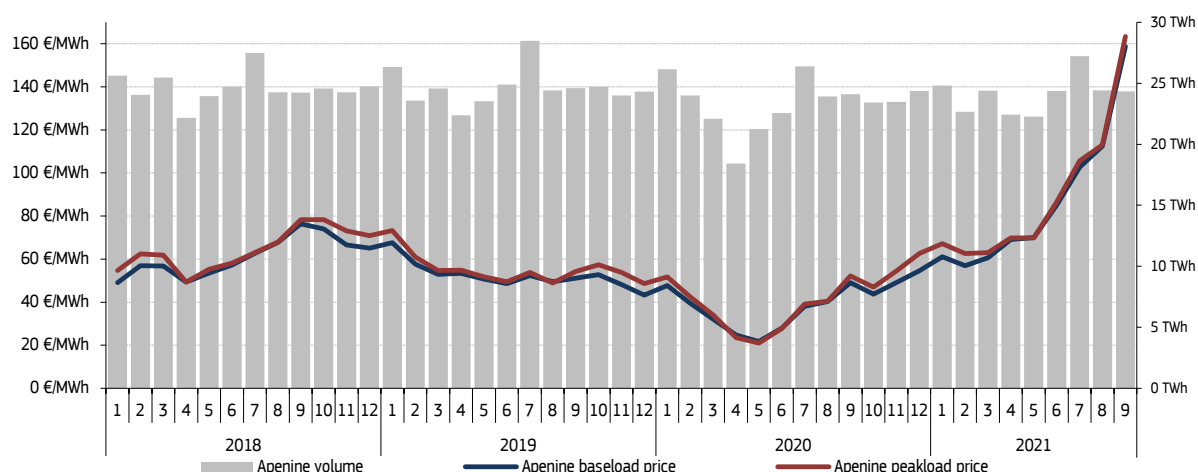


Source: Nord Pool spot market

4.4 Apennine Peninsula (Italy, Malta)

- Rising Italian monthly average baseload electricity prices (**Figure 50**) reached an all-time peak in September (158 €/MWh), driven by rising commodity prices (mainly gas). The Italian market recorded one of the largest increases in Europe. The average baseload price in Q3 2021 rose by 67% to 125 €/MWh compared to Q2 2021, and was 194% above Q3 2020 levels. Trading volumes increased by 2% compared to the previous Q3. The rally of prices continued through the following months, registering prices close to and above 220 €/MWh during October and November in the Apennine Peninsula.
- The Italian regulator announced at the end of September that electricity tariffs were due to increase by 30% during the last quarter of the year, a situation that affects 17 million customers. As a result, the Italian government announced 4 billion euros to reduce the impact of high prices on consumers in the fourth quarter of the year, 2 billion euros for the first quarter of 2022, and additional 500 million euros for the budget of 2022 to cope with the rise of cost of energy.
- Italy will hold an auction for the addition of 60 GW of new renewable capacity to support the delivery of the European Green Deal objectives. 55 GW of solar PV and wind are expected by 2030 in the country.

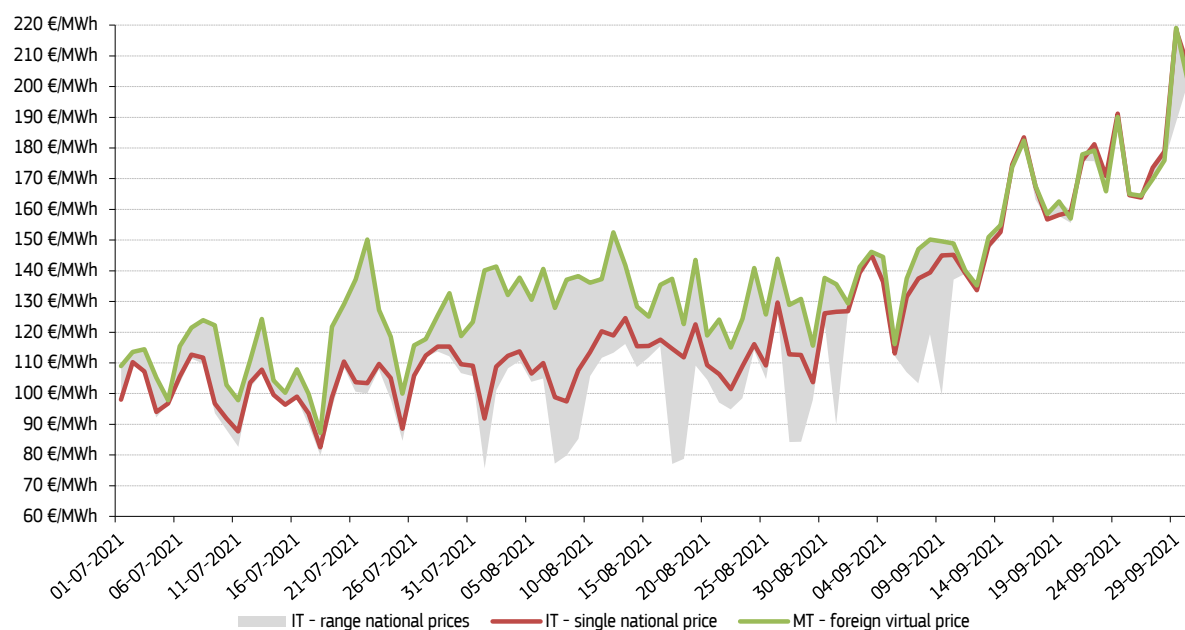
Figure 49 – Monthly electricity exchange traded volumes and average day-ahead wholesale prices in Italy



Source: GME (IPEX)

- **Figure 51** 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 100 and 115 €/MWh during July and August. In September, the prices moved above in the range of 140-175 €/MWh and kept rising during the following months.
- Italy is one of the largest producers of electricity from gas in the EU (gas represented 52% of the total generation in Italy during Q3 2021). Rising commodity prices, especially gas, played an important role in the surge in prices, in the context of continent-wide supply tightness (see **Figure 42**). Italian spot prices surged significantly in September, as record gas and carbon prices kept wholesale prices high, supported by a fall of wind and solar output year-on-year. As a result, net power imports increased to close the demand gap. Combined wind and solar output decreased in September. Thermal generation and imports from the northern borders were able to offset losses in renewable generation. The return of the 500 MW IT-EL interconnector online in early September saw the link operating as net importer, a reversal of its usual position. Italy joined the European Single Intraday power Coupling system (SIDC) on 22 September, via a cable to France. A second phase of the project will seek to integrate the Greek borders (with Italy and Bulgaria) into the SIDC.
- The Italian Power Exchange provides data on foreign price zones such as Malta, in addition to individual regional markets in Italy. The island is a net electricity importer from Italy (through Sicily) and thereby daily prices from the Italian power exchange (especially the Sicilian price zone) influence the Maltese wholesale electricity market. As visible in **Figure 51**, prices in the Maltese zone mostly formed the upper boundary of the band of regional prices in the reference period.

Figure 50 – Daily average electricity prices in the Italian day-ahead market, within the range of different area prices

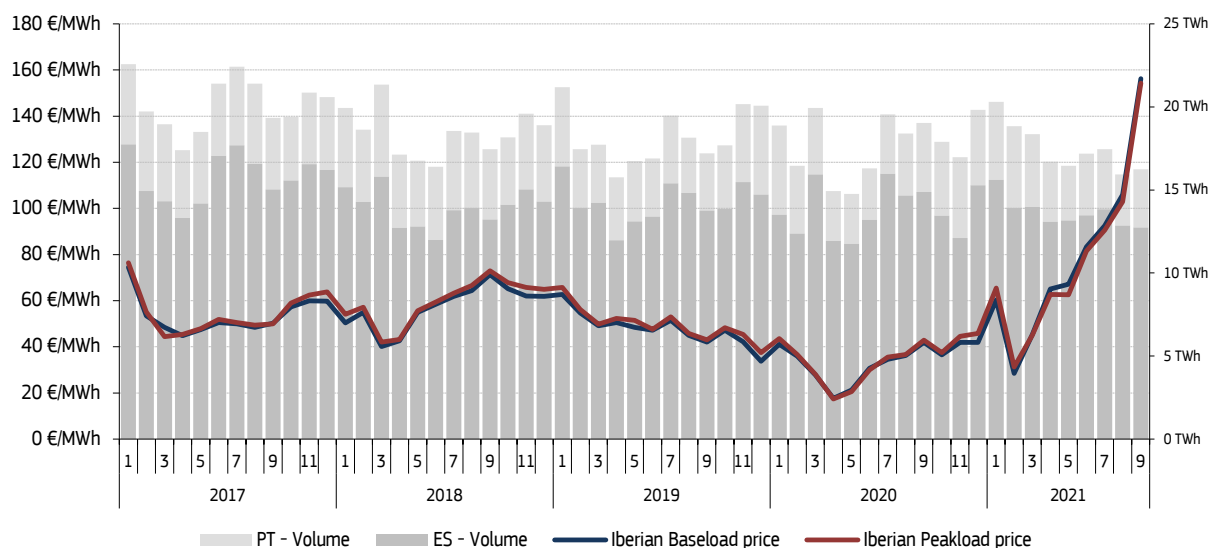


Source: GME (IPEX)

4.5 Iberian Peninsula (Spain and Portugal)

- Figure 52** reports on monthly average baseload and peakload contracts in Spain and Portugal. During the third quarter of 2021, prices recorded all-time highs, mainly driven by gas prices. The average baseload electricity prices surged to 92 €/MWh in July and rose in May to 103 €/MWh. In September, prices spiked to 156 €/MWh, due to increasing thermal generation and low wind output. During the quarter, power imports from France played a key role thanks to improved French nuclear availability. Compared to Q3 2020, the average baseload price rose by 214% to 118 €/MWh in the reference quarter. Peak prices increased by 202% to 115 €/MWh. Trading activity was 13% lower compared to the previous Q3.
- Nearly 10 million customers (40% of consumers in Spain) are on tariffs directly linked with the wholesale electricity market. In light of the surges in wholesale prices that took place during Q3 2021, the Government announced a full package of measures that seek to tackle the social and economic effects of rising energy prices. First, a set of fiscal measures adopted already in June (reduced VAT and suspension of tax on generation units in the electricity market at 7%). In September, the Royal Decree 17/2021 added a battery of measures to reduce household electricity monthly bills by 22%. These measures will remain in effect until 31 March 2022. Spain has also adopted a series of legislative measures which aim at charging excess rents from generators. In October, the Council of Ministers approved a new emergency energy package to protect consumers who are vulnerable to the current situation of high gas and electricity prices. The aim of this new package is to introduce more transparency in energy markets, facilitate decision-making, and help industry to conclude long-term electricity supply contracts.

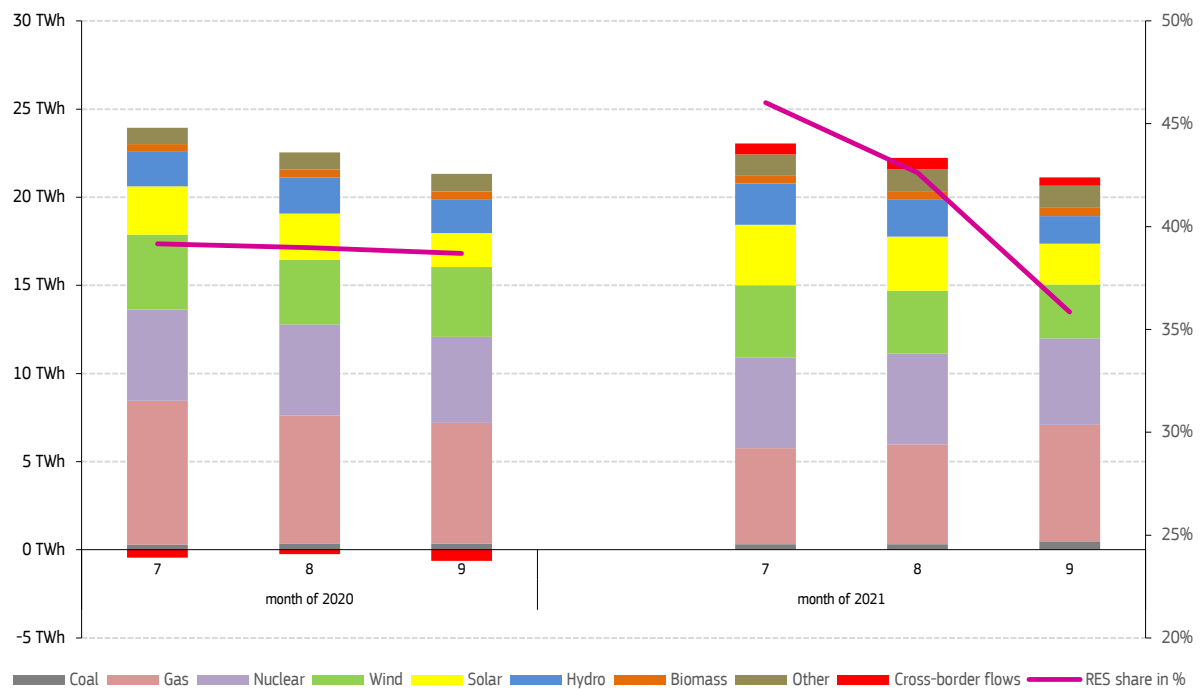
Figure 51 – Monthly electricity exchange traded volumes and average day-ahead prices in the Iberian Peninsula



Source: Platts, OMEL, DGEG

- Figure 53** displays the evolution of the monthly electricity generation mix in Spain during the second quarter of 2021, as well as during the same period of the previous year. Net generation decreased by 5% year-on-year, in line with a decline in gas and wind generation. Rising solar and biomass generation caused the share of renewable electricity sources to reach 41% during the reference quarter, slightly up from 39% a year before. Wind generation decreased by 10%, whereas solar output rose by 22%. Gas generation fell by 21% and coal output increased by 12% year-on-year in Q3 2021. Nuclear generation remained practically unchanged during Q3 2021, and covered a share of 24% of the total generation, slightly higher than in the previous year. Spain switched from net exporter in Q3 2021, to net importer during Q3 2021, with 1.8 TWh of net imports accounting for 3% of the total generation during the quarter.
- In Spain, only two coal power plants are expected to remain online by the end of 2021: two units in the Balearic Islands and Abono power plant, which is integrated with steel manufacturing facilities. The rest of the fleet is scheduled to close by the end of 2021. Between 2025 and 2030 the nuclear plants of Almaraz, Asco I and Cofrentes are scheduled to shut down, leaving Asco II, Vandellos and Trillo which will close between 2030 and 2035.
- Gas-fired generation decreased by 29% (- 1.6 TWh) during the reference quarter in Portugal. The gap in generation was partially replaced by hydropower which registered a 16% year-on-year increase (+0.3 TWh), Solar with 40% higher output (+0.2 TWh) and 10% more biomass generation (+0.1 TWh). The rest was covered by net imports.

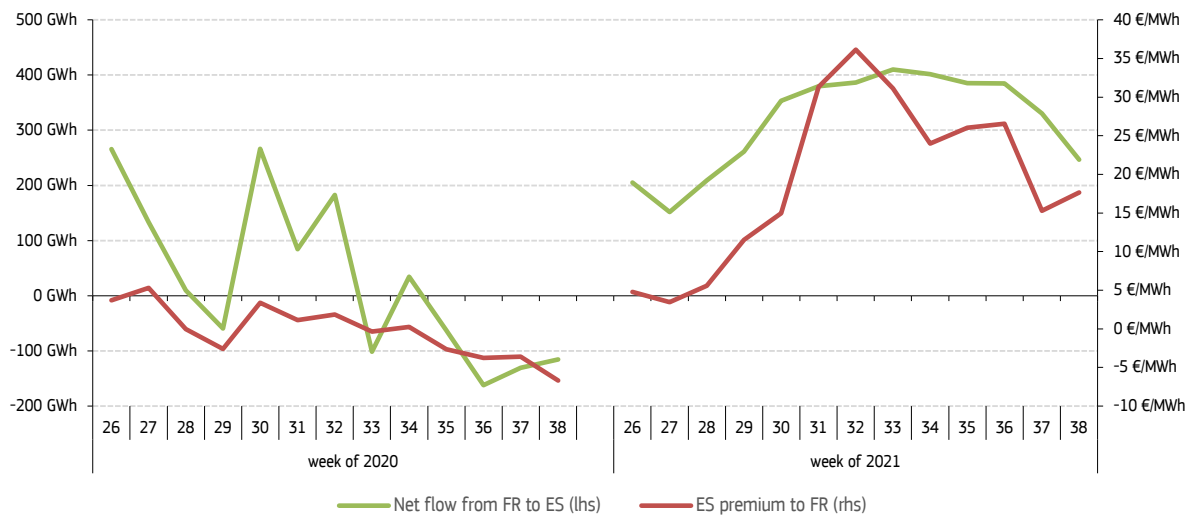
Figure 52 – Monthly evolution of the electricity generation mix in Spain in Q3 of 2020 and 2021



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

- **Figure 54** shows weekly electricity flows between France and Spain and price differentials between the two bidding zones. With the exception of the first weeks of the quarter, Spain kept its usual premium over the French day-ahead price throughout Q3 2021. As from the third week of July, Spain turned into a net power importer on the back of high gas prices and low wind generation, depending mainly on French nuclear availability. The differential reached its maximum (36 €/MWh) during the first week of August amid the improvement of the French nuclear availability, a reliance on Spanish gas-fired output and low wind generation in Spain.
- Record-high prices have boosted power flows from France amid a widening spread. In addition, the 2 GW Biscay interconnector project with France was delayed to 2027 (from the original date of 2025). Once completed, this new interconnector will double the interconnection capacity between Spain and France. Spain needs 10 GW of cross border links to meet the EU target of interconnection capacity equal to the 10% of installed generation capacity. Currently, limited interconnection capacity with France is a bottleneck in the European power market as both sides could further benefit from complementary seasonal generation.
- Bilateral trade with Morocco in Q3 2021 resulted in net imports of 129 GWh from Morocco. A third interconnection link with Morocco (700 MW) is expected to be online by 2026.

Figure 53 – Weekly flows between France and Spain and price differentials between them

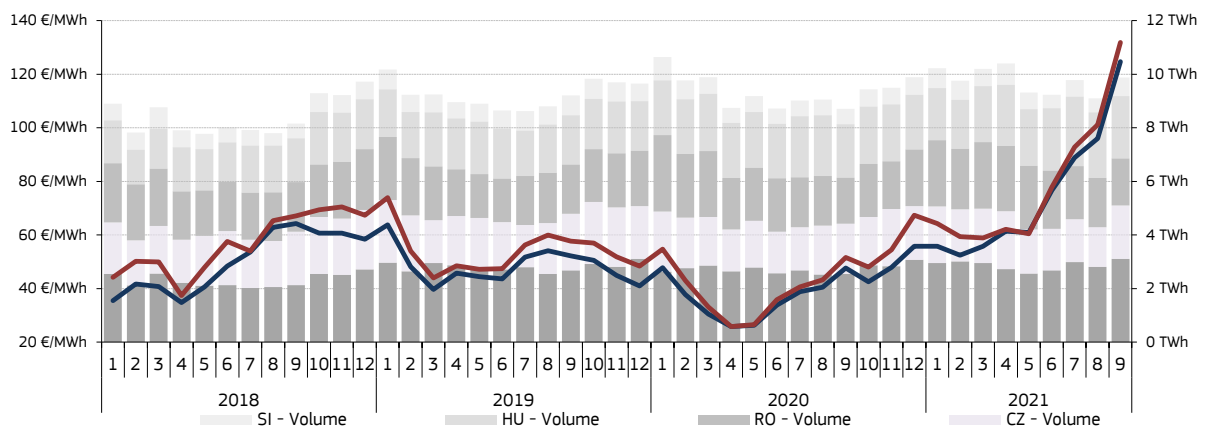


Source: ENTSO-E, OMEL, Platts

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

- **Figure 55** shows that average monthly prices for baseload power in Central Eastern Europe exceeded historical levels, reaching 125 €/MWh in September. Baseload prices escalated throughout the third quarter of the year, mainly driven by rising price in fuels and also tighter supply-demand balance, combined with a recovery in demand. The gap between baseload and peakload monthly averages increased from 4% in July to 6% at the end of the Q3 2021. When compared to Q3 2020, the average baseload price in the reference quarter rose by 144% to 103 €/MWh. Traded volumes in the reference quarter increased by 8% compared to the previous Q3.
- Polish electricity demand rose considerably during Q3 2021 in comparison with the previous year (see **Figure 3**). Economic recovery and seasonal demand supported the increase. The gap was filled by increased coal generation and net imports. A HDVC 700 MW interconnector of 290 kilometres is expected to connect Poland and Lithuania by 2025. A combination of unplanned coal unit outages at Opole and Bełchatów, high demand and reduced wind output boosted prices at the end September to values over 120 €/MWh. Nevertheless, while the September average reached 102 €/MWh in Poland, prices are still at discount to most of neighbouring countries thanks to lower generation costs of the Polish coal fleet.

Figure 54 – Monthly electricity exchange traded volumes and average day-ahead prices in Central Eastern Europe (CEE)



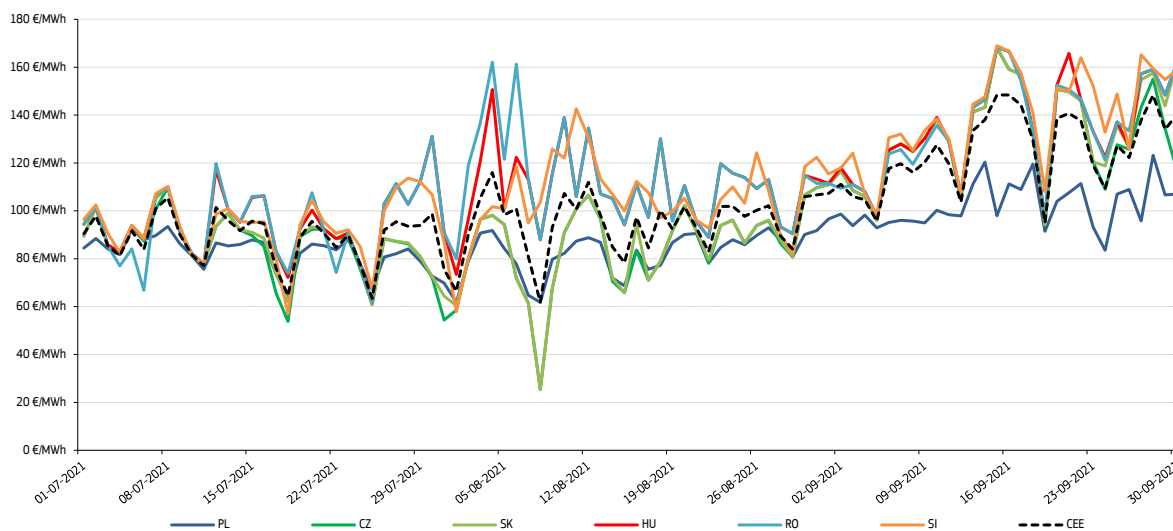
Source: Regional power exchanges, Central and Eastern Europe (CEE), CEE: PL, CZ, SK, HU, RO, SI

- **Figure 56** shows that daily average baseload prices in the coupled markets (CZ, SK, HU, RO, PO) saw an increase in prices during Q3 2021, on the back of rising commodity prices (mainly gas, but also coal and EU ETS), tightening supply-demand balance and ebbs and flows of wind availability. Prices moved between 55 and 70 €/MWh between April and May and among 80 and 95 €/MWh in June, growing through the quarter reaching prices between 110 and 140 €/MWh in September. The Polish market, having started a day-ahead market in February 2021, reversed its

typical premium towards CEE prices from an average of almost +10 €/MWh in Q3 2020, to a discount of -14 €/MWh in Q3 2021. The large coal-fired fleet in Poland has also been taking the impact of high commodity prices (coal and also CO₂), as high electricity prices have also affected Member States with reduced exposure to gas, such as Poland. This is an interesting signal towards renewables, as high penetration levels of solar and wind would reduce exposure of electricity prices to commodities (gas and carbon).

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

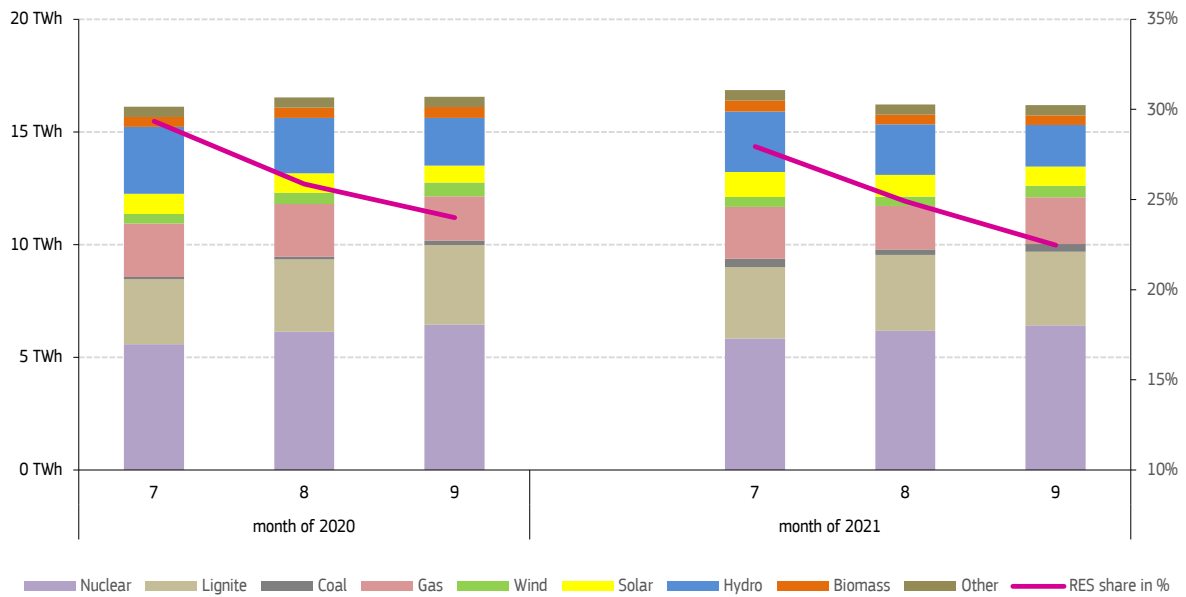
Figure 55 – Daily average power prices on the day-ahead market in the CEE region



Source: Regional power exchanges

- **Figure 57** compares the combined electricity generation mix of the reference quarter of the CEE region (excluding Poland) and the quarter a year before. The most substantial change took place in hydro generation with a lost output of 0.8 TWh, due to reduced Romanian generation (- 0.5 TWh). Coal experienced an increase of 0.5 TWh, while lignite rose to 0.2 TWh of additional generation. The share of renewables slightly decreased from 26% to 25% as result of lower hydro and wind generation in Romania, Czechia, Slovenia and Slovakia. Nuclear remained the dominant generation technology with a 37% share in the mix, unchanged when compared with Q3 2020. Total generation remained unchanged during the reference quarter.

Figure 56 – Changes in the electricity mix in the CEE region (excluding Poland) between Q3 2020 and Q3 2021



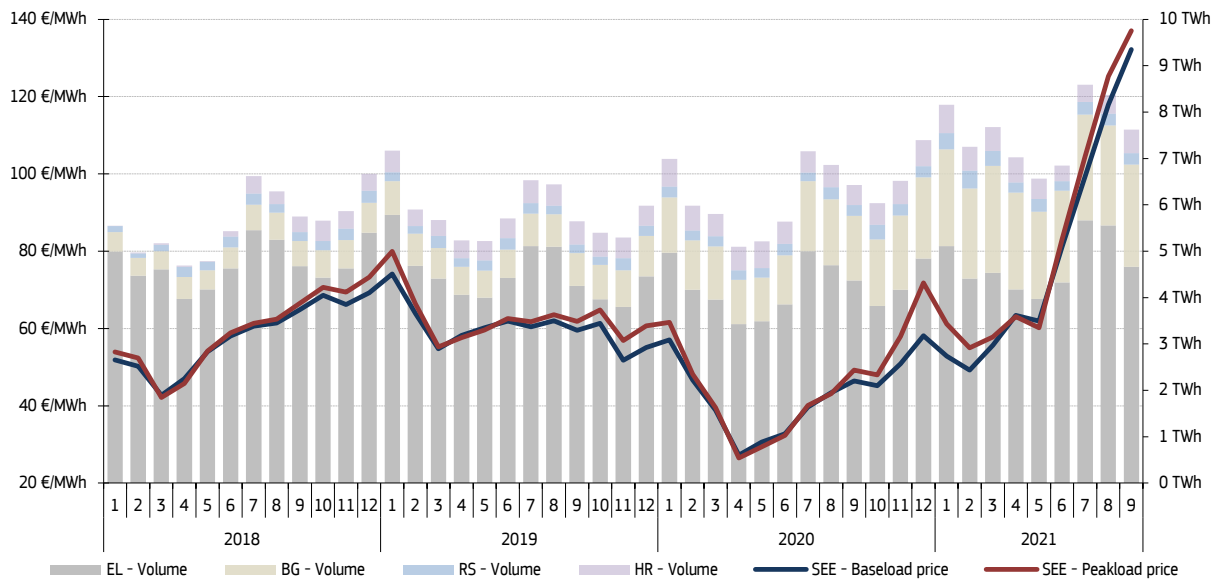
Source: ENTSO-E.

- In Poland, which is analysed separately due to significant differences in the size and structure of its generation base, the combined share of coal and lignite in its mix slightly increased to 74% in Q3 2021 (compared to 72% in Q3 2020), thanks to improved demand. Renewables maintained their share at 16% year-on-year. Gas decreased its share in the mix to 4% year-on-year. The share of coal in Poland's mix should decrease to 56% by 2030 thanks mainly to significant wind capacity additions (especially in the offshore segment). Additionally, Europe's largest coal-fired plant, Bełchatów (5 GW), is planned to cease operations by 2036.

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

- **Figure 58** shows that trade-weighted monthly average baseload prices in the SEE region have been rising steadily throughout the reference quarter. Baseload average prices reached 132 €/MWh in September, exceeding previous monthly record prices from the past years. Baseload prices in the region were driven by Greek prices (by far the most liquid market in the region). Strong gas prices combined with increased demand drove electricity prices up. The average quarterly baseload price rose by 170% year-on-year to 117 €/MWh in Q3 2021, 69% above Q2 2021 and 92% higher than Q3 2019. The average quarterly peakload price, rose 177% above Q3 2020 levels to 122 €/MWh.

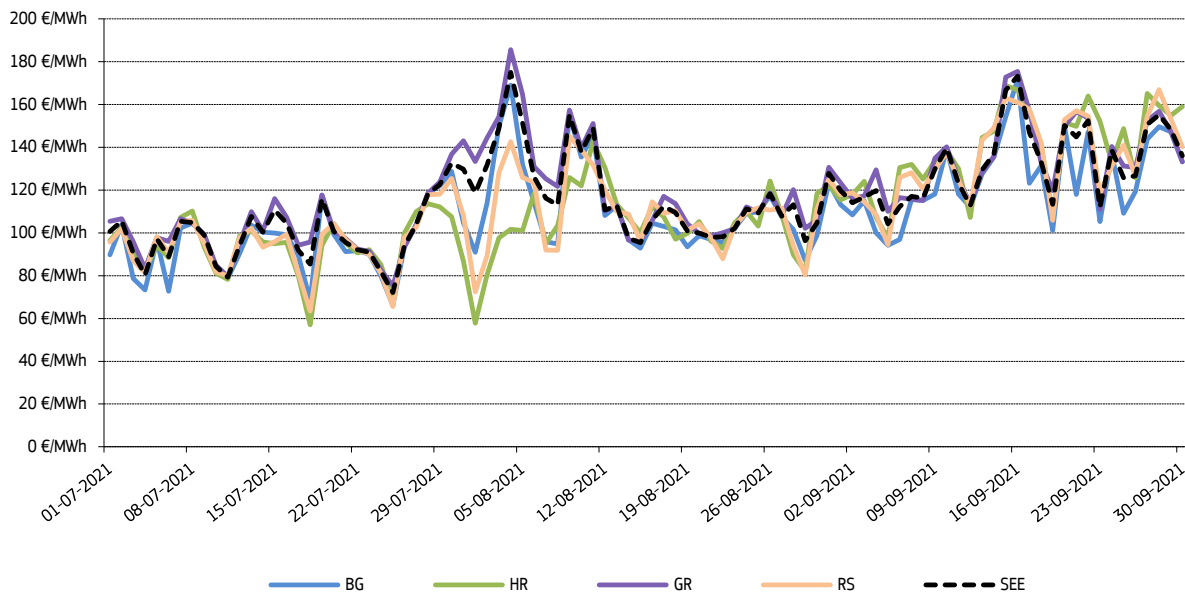
Figure 57 – Monthly traded volumes and baseload prices in South-Eastern Europe (SEE)



Source: IBEX, LAGIE, CROPEX, SEEPEX

- Daily baseload price movements in individual markets were relatively well synchronised during Q3 2021, as shown in **Figure 59**. Prices moved between 90 and 105 €/MWh in July, until they started to increase volatility on the back of developments in the Greek market (extensive fires in the first week of August damaging electricity infrastructure and risked outages to the Greek capital and other parts of the country) combined with high gas prices, led to a range of 100-130 €/MWh prices in August. Baseload prices reached a peak of 175 €/MWh on 4 August. In September, prices rose again moving between 115 and 150 €/MWh. A new peak was reached on 16 September at 173 €/MWh, on the back of general tightness of supply in Europe due to high gas prices and low RES generation.
- Since the last quarter, the [Bulgarian day-ahead market is integrated](#) via the Greek border in the Pan-European day-ahead power market. Greece completed the first interconnector link to the island of Crete through a 400 MW cable. The link can cover a third of Crete's electricity demand with the aim to prevent electricity insufficiencies and decrease oil-fired generation in the island.

Figure 58 – Daily average power prices on the day-ahead market in Bulgaria, Croatia, Greece and Serbia

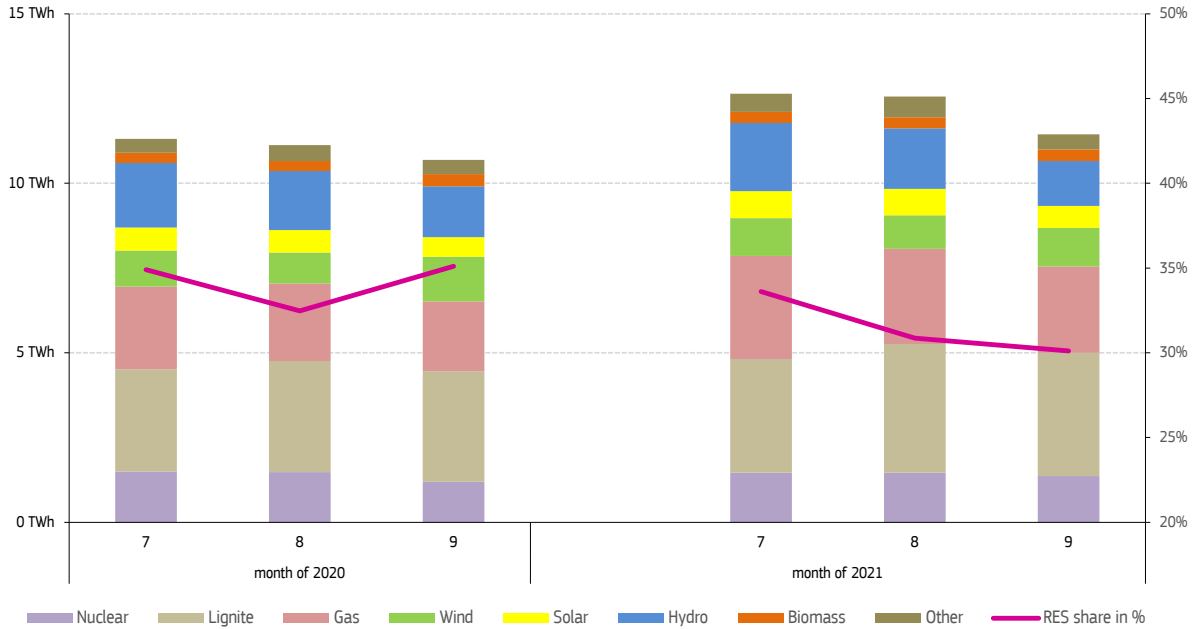


Source: IBEX, LAGIE, SEEPEX, CROPEX

- **Figure 60** compares the combined electricity generation mix of the SEE region between Q3 2020 and Q3 2021. Lignite output increased in Greece (+53%), Bulgaria (+46%) and Croatia (+8%), although the share of lignite remained unchanged at 29% year-on-year. The share of gas generation increased to 23% from 20% during the

quarter, rising its output levels by 24% compared with Q3 2020. Renewable penetration fell from 32% to 34% due to reduced wind output across the region. The draft of the Climate Law presented by Greek authorities included the decommissioning of lignite plants by 2028, and could even bring forward the target to the end of 2025. Ptolemaida V power plant (660 MW) will be converted to natural gas by 2025. Mytilineos new CCGT will supply power to the aluminium manufacturing industry from 2024.

Figure 59 – Changes in the electricity generation mix in the SEE region between Q3 2020 and Q3 2021



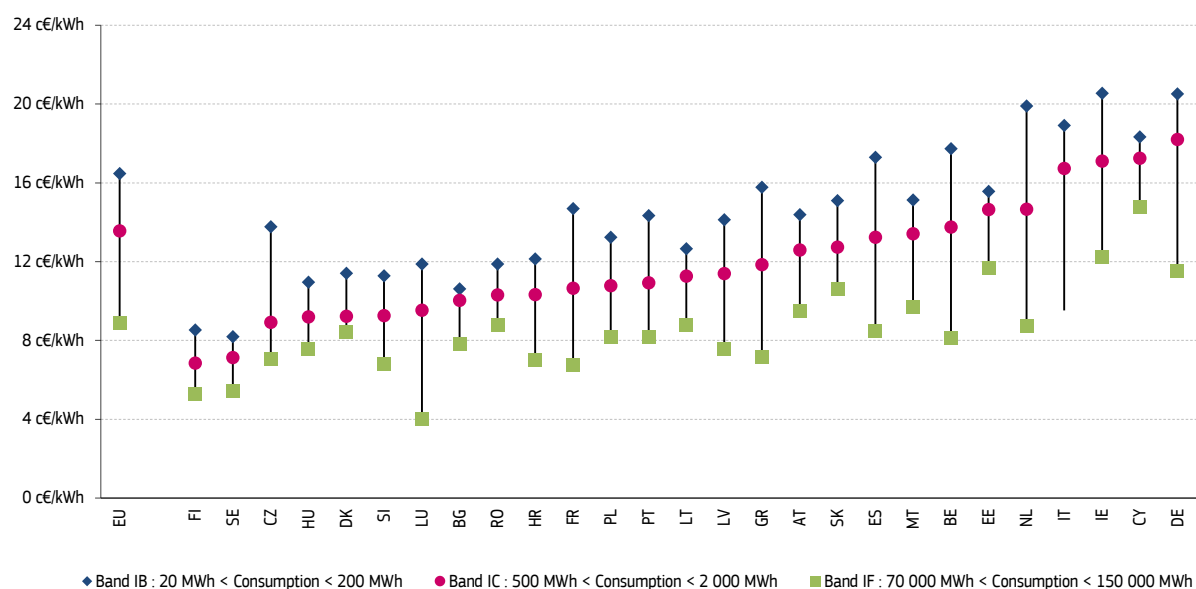
Source: ENTSO-E

5 Retail markets

5.1 Retail electricity markets in the EU

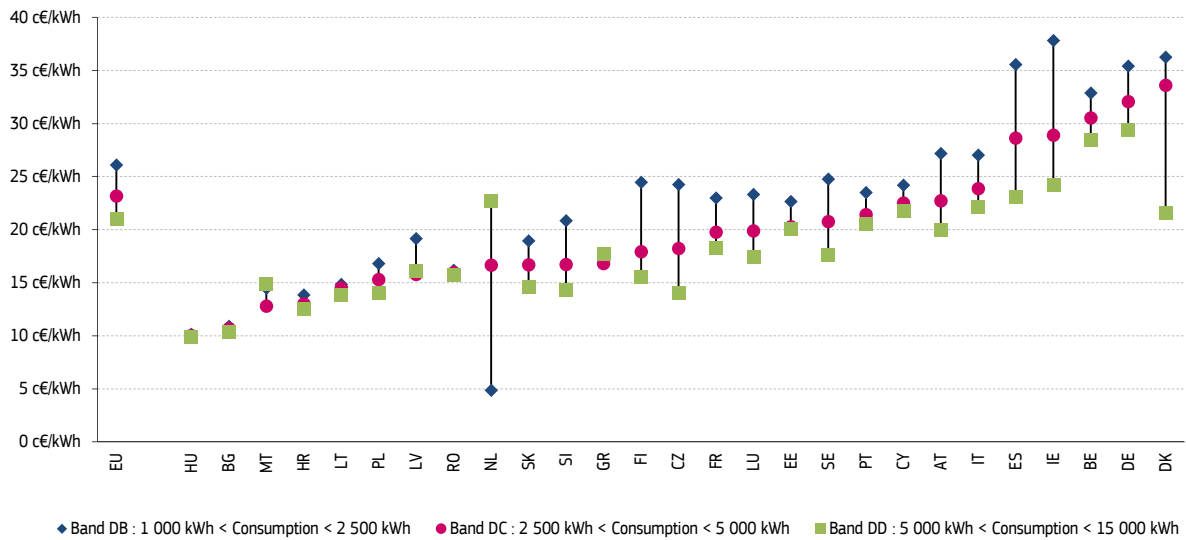
- Figures 60 and 61** display the estimated retail prices in September 2021 in the 27 EU Member States for industrial customers and households. Monthly and quarterly retail prices are estimated by using half-yearly prices from Eurostat (with the latest available figures relating to the first half of 2021) and Harmonised Consumer Price Indices (HICP) for both the household prices and industrial consumers. Prices are displayed for three different levels of annual electricity consumption for both consumer types (Eurostat bands IB, IC and IF for industrial customers and bands DB, DC and DD for households). In most cases it holds for both consumer types that the lower the consumption, the higher the price of one unit of electricity (per MWh consumed). Dutch, Maltese, Greek and Latvian household prices are a notable exception.
- Smaller industrial consumers (band IB) were assessed to pay the highest prices in Ireland (20.6 c€/kWh) and Germany (20.5 c€/kWh), followed by the Netherlands and Italy (19.9 and 18.9 c€/kWh respectively). The lowest prices in the same category were assessed to be in Sweden (8.2 c€/kWh) and Finland (8.5 c€/kWh). The ratio of the largest to smallest reported price was above 2:1. Compared to September 2020, the average assessed EU retail price for the IB band rose by 5% to 16.5 c€/kWh. On the other side of the consumer spectrum, industrial companies with large annual consumption (band IF), including most energy-intensive users, paid the highest prices in Cyprus (14.8 c€/kWh), followed by Ireland (12.2 c€/kWh), Estonia (11.7 c€/kWh) and Germany (11.5 c€/kWh). Luxembourg (4.0 c€/kWh) was assumed to have by the lowest prices, with Finland and Sweden (5.3-5.4 c€/kWh) coming close behind. The ratio of the highest to lowest price for large industrial consumers was above 2:1 for this consumer type. Compared to September 2020, the average assessed EU retail electricity price for the IF band rose by 16% to 8.9 c€/kWh.
- In the household segment, Germany (29.4 c€/kWh) was assessed to have the highest electricity price for large consumers (band DD), followed by Belgium (28.5 c€/kWh), and with Ireland (24.2 c€/kWh) in the third place. The lowest prices for big households were calculated for Hungary (9.9 c€/kWh) and Bulgaria (10.3 c€/kWh). Compared to September 2020, the average assessed EU retail electricity price for the DD band rose by 7% to 21.0 c€/kWh. In the case of small households, Ireland saw the highest prices (37.8 c€/kWh), followed by Denmark (36.3 c€/kWh) and Spain (35.6 c€/kWh), while Netherlands (4.9 c€/kWh), Hungary (10.1 c€/kWh) and Bulgaria (10.7 c€/kWh), found themselves on the other side of the price spectrum. Compared to September 2020, the average assessed EU retail electricity price for the DB band rose by 7% to 26.1 c€/kWh.

Figure 60 – Industrial electricity prices, September 2021 – without VAT and recoverable taxes



Source: Eurostat, DG ENER.

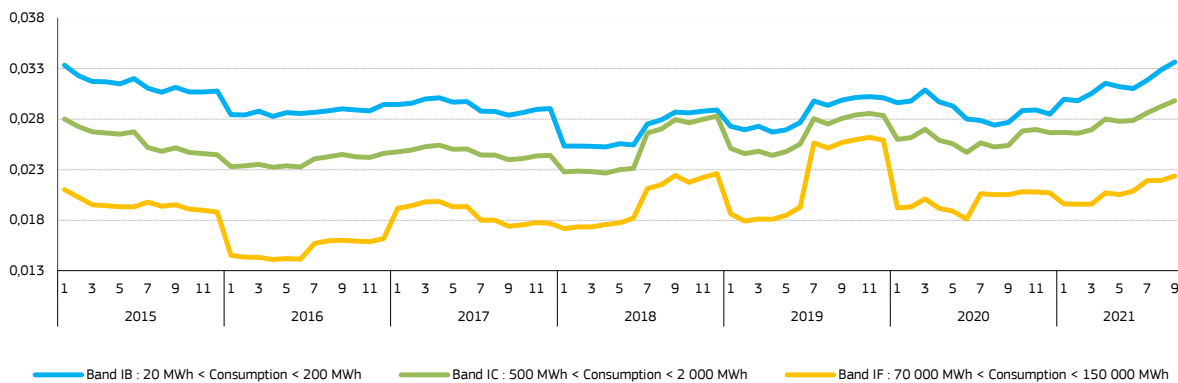
Figure 61 – Household electricity prices, September 2021 – all taxes included



Source: Eurostat, DG ENER

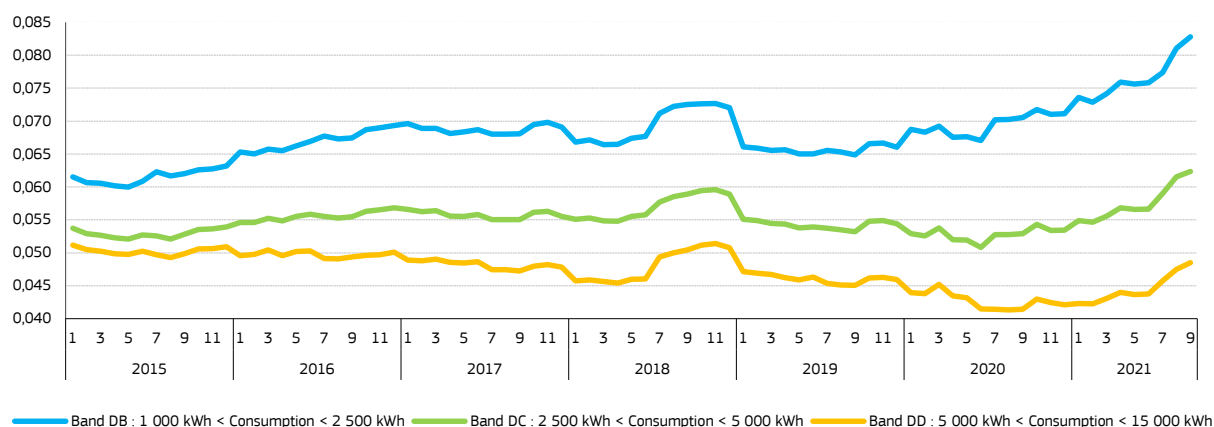
- **Figure 63 and Figure 64** display the convergence of retail prices across the EU over time, by depicting their standard deviation. Industrial prices for small and medium-sized businesses showed increasing divergence in Q3 2021, at a higher pace than in the previous quarter. In the case of retail prices for medium businesses, the divergence levels reached the highest register of the series.
- In the household sector, price divergence increased during Q3 2021. In fact, besides from prices for large consumption households, household prices reached the highest level of divergence on record. Household prices tend to be more impacted by regulated elements (network charges, taxes and levies) so their variation across Member States is greater than in the case of industrial consumers.

Figure 62 – Standard deviation of retail electricity prices in the EU for industrial consumers



Source: Eurostat, DG ENER

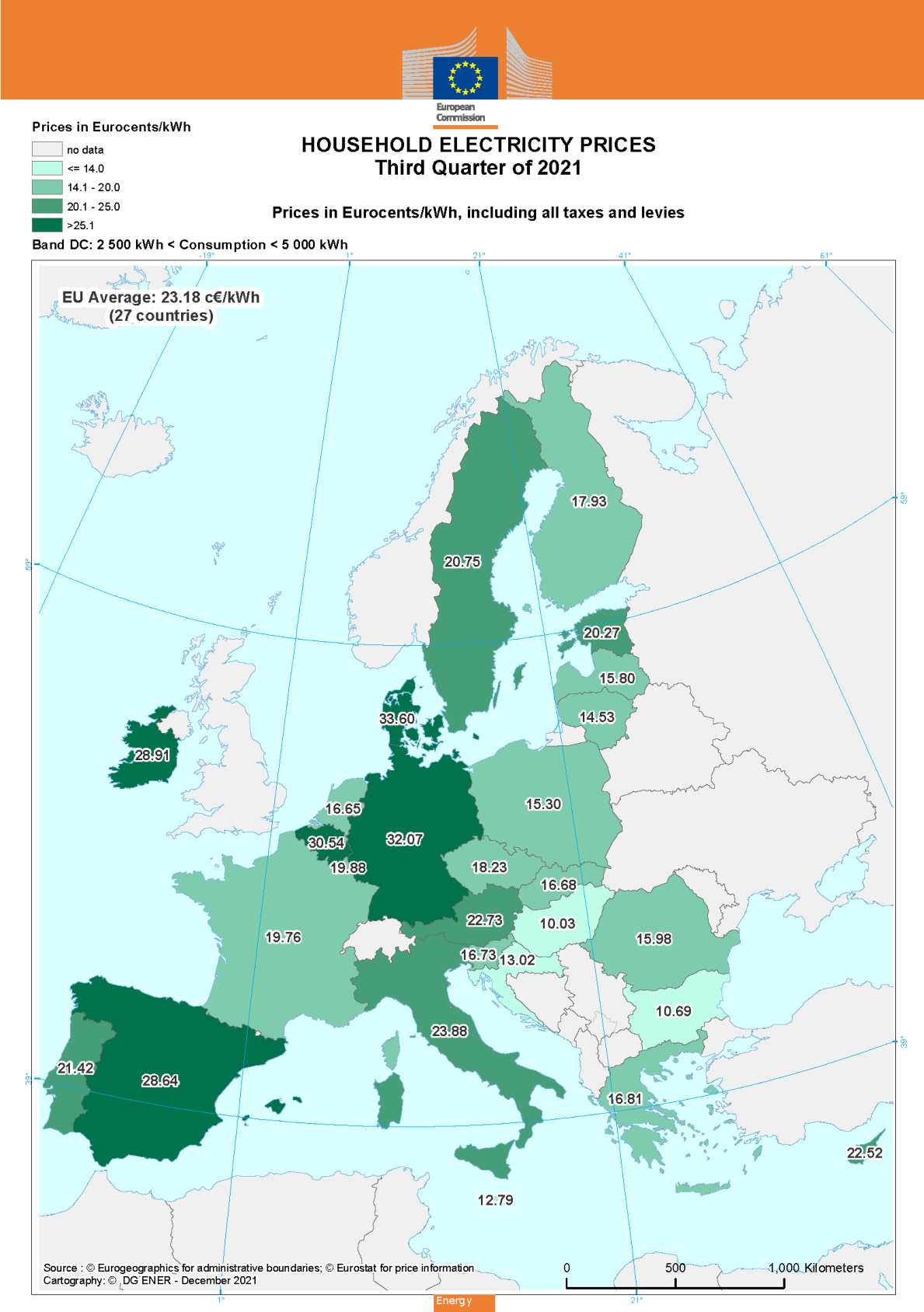
Figure 63 – Standard deviation of retail electricity prices in the EU for household consumers



Source: Eurostat, DG ENER

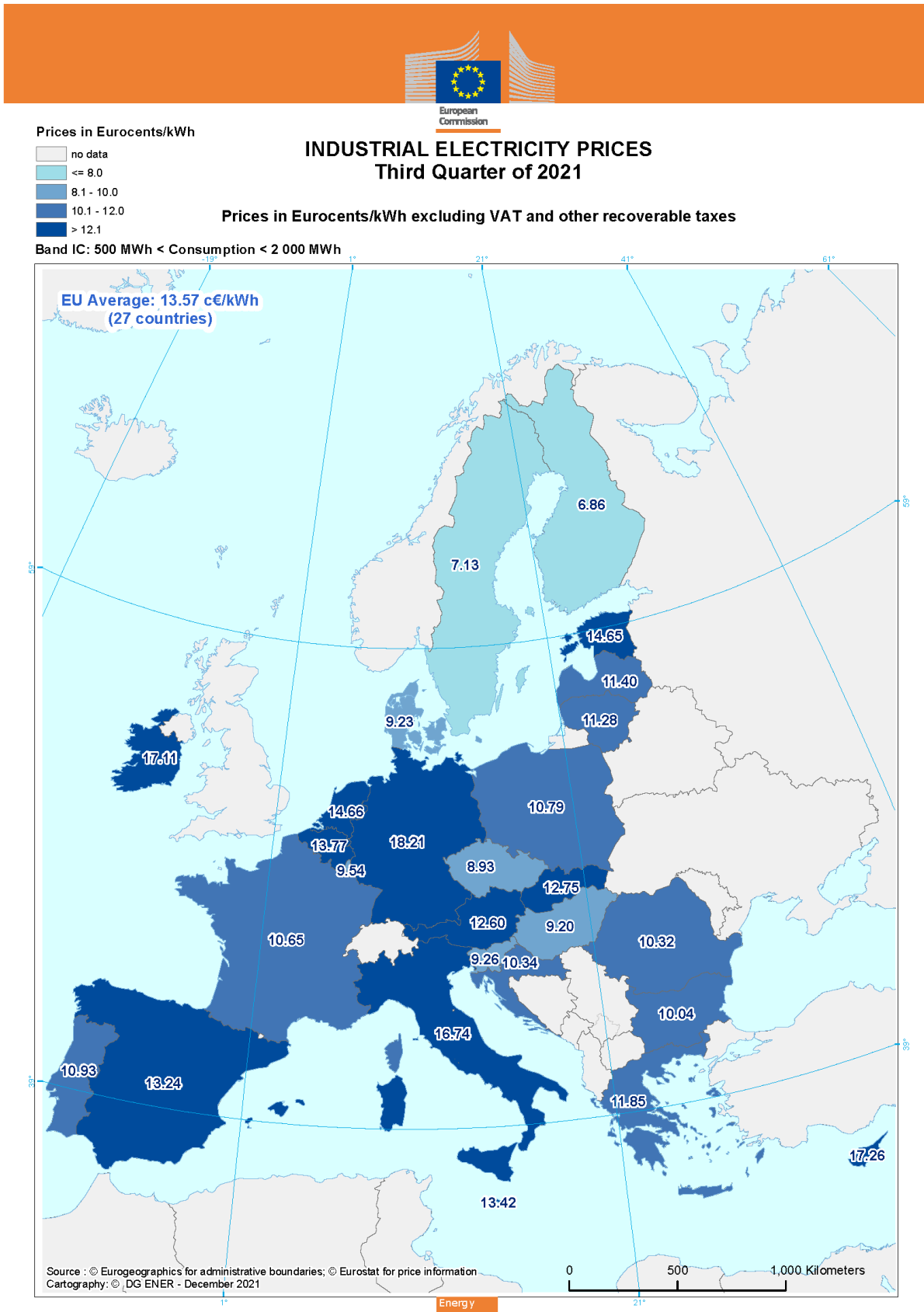
- Figures 62 and 63** display the estimated electricity prices paid by EU households and industrial customers with a medium level of annual electricity consumption in the last month of Q3 2021. In the case of household prices, Denmark topped the list (33.6 c€/kWh), followed by Germany (32.1 c€/kWh) and Belgium (30.5 c€/kWh). As was the case in previous quarters, Hungary (10.0 c€/kWh) and Bulgaria (10.7 c€/kWh) retained their position as Member States with the cheapest household electricity prices. The EU average increased by 8% to 23.2 c€/kWh in the reference quarter compared to September 2020. The largest year-on-year increases in the household category were assessed in Estonia (+53%), Cyprus (+48%) and Spain (+30%). The biggest year-on-year falls were estimated for Czechia and Hungary (-3%) and Slovakia (-1%). See **Figure 67** for more details.
- In the case of mid-sized industrial consumers, Finland was assessed to have the most competitive price in Q3 2021 (6.9 c€/kWh), followed by Sweden (7.1 c€/kWh), and with Czechia (8.9 c€/kWh) taking the third place. Meanwhile, Germany (18.2 c€/kWh) and Cyprus (17.3 c€/kWh) stood at the other end of the spectrum. At 13.6 c€/kWh, the average retail price for industrial customers in the EU in the reference period rose by 7% compared to Q3 2020.

Figure 64 – Household Electricity Prices, third quarter of 2021



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

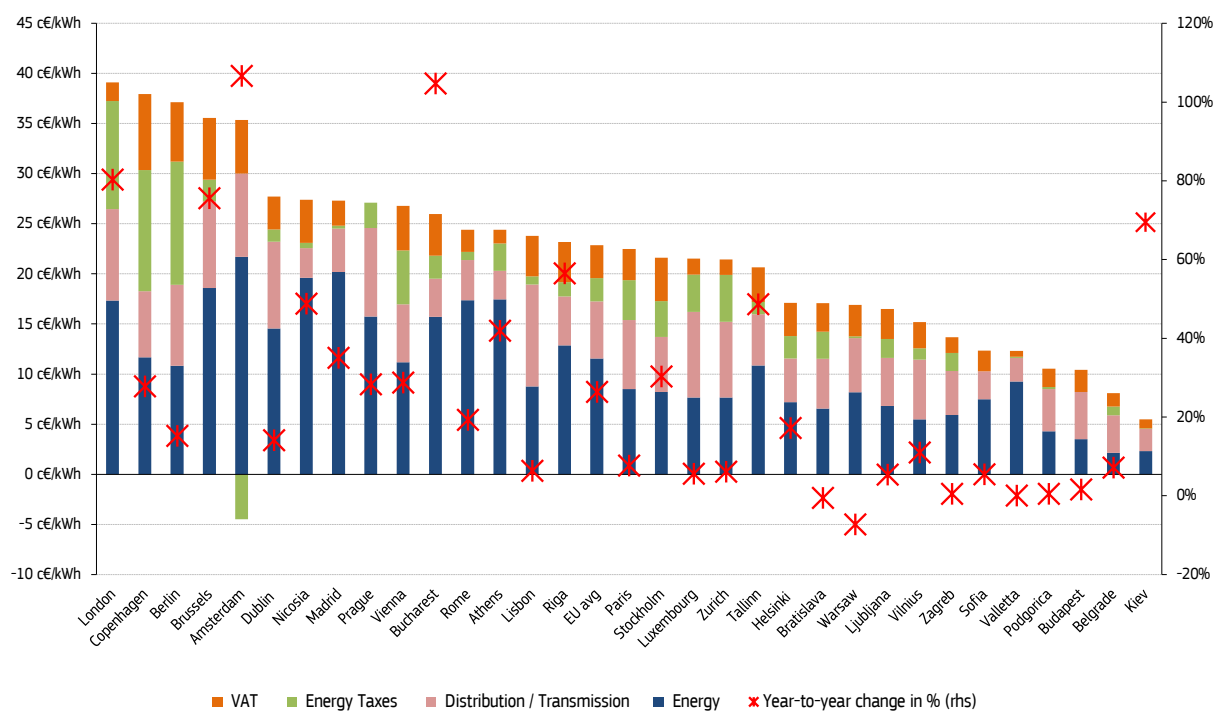
Figure 65 – Industrial Electricity Prices, third quarter of 2021



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

- Figure 67** shows retail electricity prices for representative household consumers in European capital cities and their composition divided into four categories (energy, network charges, energy taxes and the value added tax). In November 2021, the highest prices were observed in London, Copenhagen and Berlin (39.1, 38.0 and 37.1 c€/kWh, respectively) In the case of London, the energy component share was 44% of the final bill, while in the case of Copenhagen and Berlin, energy taxes accounted for more than a third of the final bill. The lowest prices among EU capitals were recorded in Budapest and Valletta (10.4 c€/kWh and 12.3 c€/kWh, respectively). This corresponds to the Eurostat data analysed in **Figure 62**. EU-wide, retail prices have been climbing since the end of 2020. Inflation pressures have intensified throughout the year, due to rising wholesale prices, which have been driven largely due to high gas prices, increased demand, and to a lesser extent, more expensive emission allowances.
- The highest levels of the energy component in Europe were reported from Amsterdam, Madrid, and Nicosia (21.7, 20.2 and 19.6 c€/kWh). The lowest levels of the energy component (2-4 c€/kWh) were recorded in the capitals of countries with stronger forms of price regulation (Belgrade, Kiev and Budapest). The EU average for the energy component was 11.6 c€/kWh (up from 7.2 c€/kWh in November 2020). Out of the 27 capitals, 23 had a more expensive energy component than the EU average.
- The highest network charges were recorded in Lisbon (10.2 c€/kWh), Prague and Brussels (8.8 c€/kWh and 8.7 c€/kWh, respectively) where they accounted between 33%-43% of the total price and in some of the cases were higher than the energy component. The lowest network fees were collected in Valletta (2.3 c€/kWh) and Sofia (2.8 c€/kWh). The EU average in the reference quarter was 5.7 c€/kWh (up from 5.4 c€/kWh in November 2020).
- Apart from Berlin and Copenhagen (12 c€/kWh), the highest energy taxes were paid by households in London (10.8 c€/kWh). Sofia and Budapest stood at the other end of the range, with zero energy taxes collected by local authorities. The average energy tax component reached 2.3 c€/kWh (down from 2.7 c€/kWh in November 2020). Varied VAT rates applied to electricity, ranging from 5% in Malta and London to 21% in Hungary, also contribute to differences in household prices across Europe.
- The tax reduction subcomponent (tax credit) that applies to electricity customers in the Netherlands is currently higher than the annual energy tax amount that corresponds to a typical residential customer in Amsterdam. Even in cases when the tax credit is higher than the tax amount, the customers still receive the full credit as a discount from their overall annual bill. In practice, this has resulted in a negative value of the Dutch tax component in the price breakdown. This development has also significantly reduced household electricity prices countrywide, which is visible in **Figure 62**, and contributed to the unusual effect in which the lower the consumption, the lower the price per kWh.

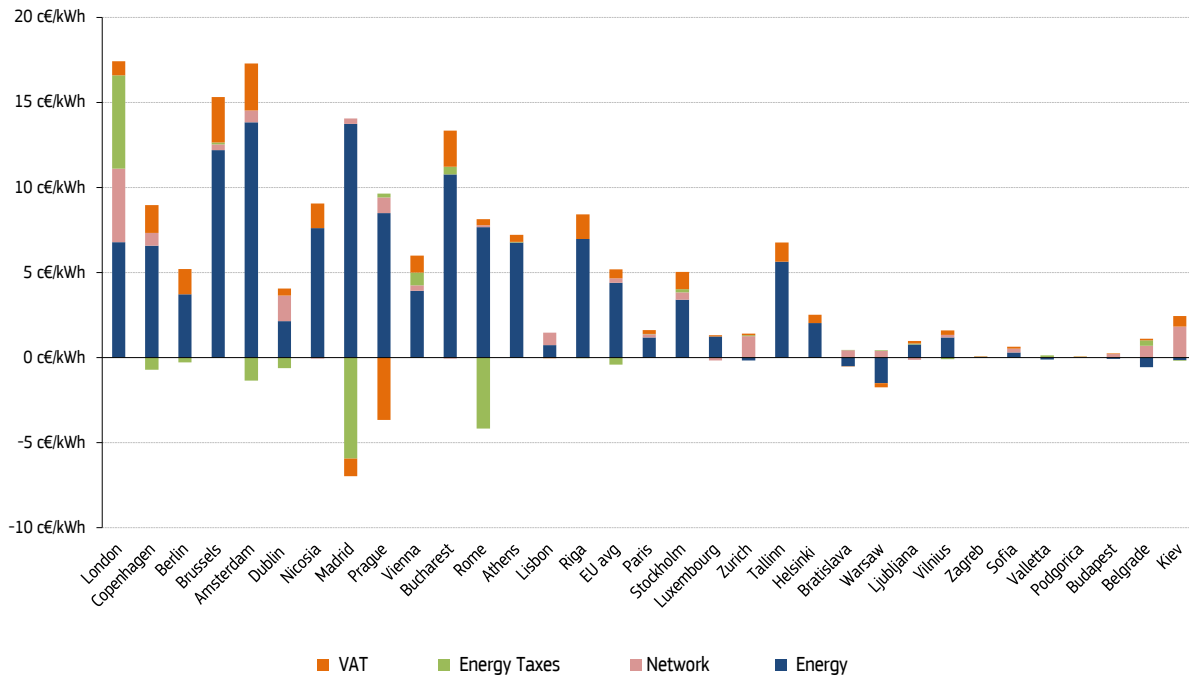
Figure 66 – The Household Energy Price Index (HEPI) in European capital cities in Eurocents per kWh, November 2021



Source: Vaasaett

- Compared to the same month of the previous year, the largest price increases in relative terms in the European Union in November 2021 were observed in Amsterdam and Bucharest (+107% and +105% respectively) and Brussels (+76%). As shown in **Figure 68**, rising prices were driven by increasing wholesale prices in Netherlands, Romania and Belgium. In fact, the rise of wholesale prices was the most important factor for the increase of end user prices in 21 of the 27 EU capitals. 5 of the 27 EU capitals reported prices lower or unchanged compared to the same month of the previous year, with Warsaw (-16%) and Bratislava (-7%) posting the largest relative drops. Households in the Polish and the Slovak capitals benefited mainly from lower energy and VAT components.

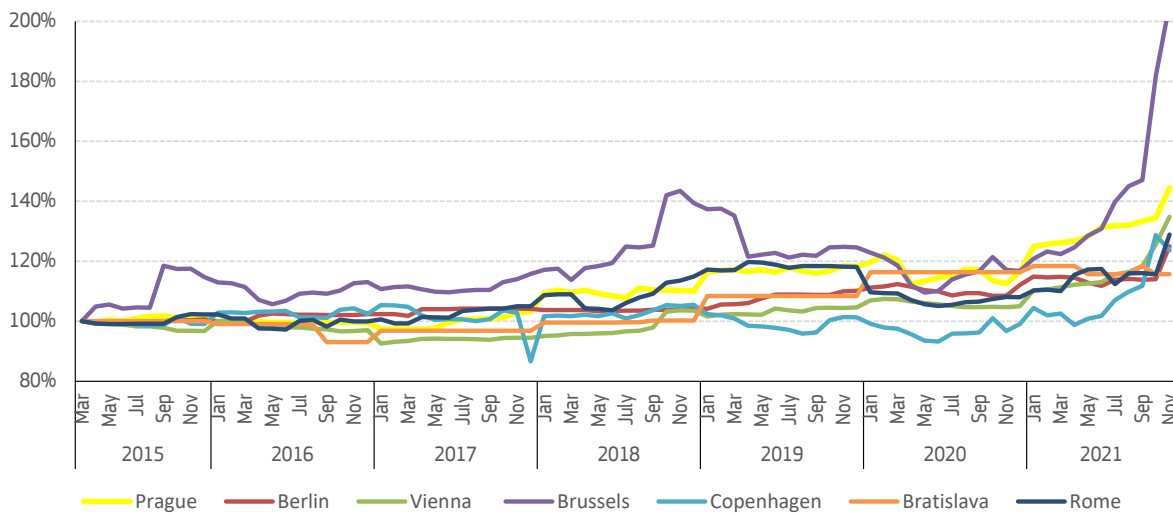
Figure 67 – Year-on-year change in electricity prices by cost components in the European capital cities comparing November 2021 with November 2020



Source: Vaasaett

- Figure 69** compares how household retail prices in selected EU capitals changed in relative terms over the last six years. The biggest increase (+106%) was registered in Brussels and was driven mainly by a rising energy component (32% of the change). Prague came in second with a 44% increase since February 2015, followed by Vienna (+35%) and Rome (+29%). Retail prices for households in Copenhagen, which have been roughly the same as six years ago, have recently seen an increase (+24% compared to February 2015) due to a rise in the energy component.

Figure 68 – Relative changes in retail electricity prices in selected EU capitals since 2015

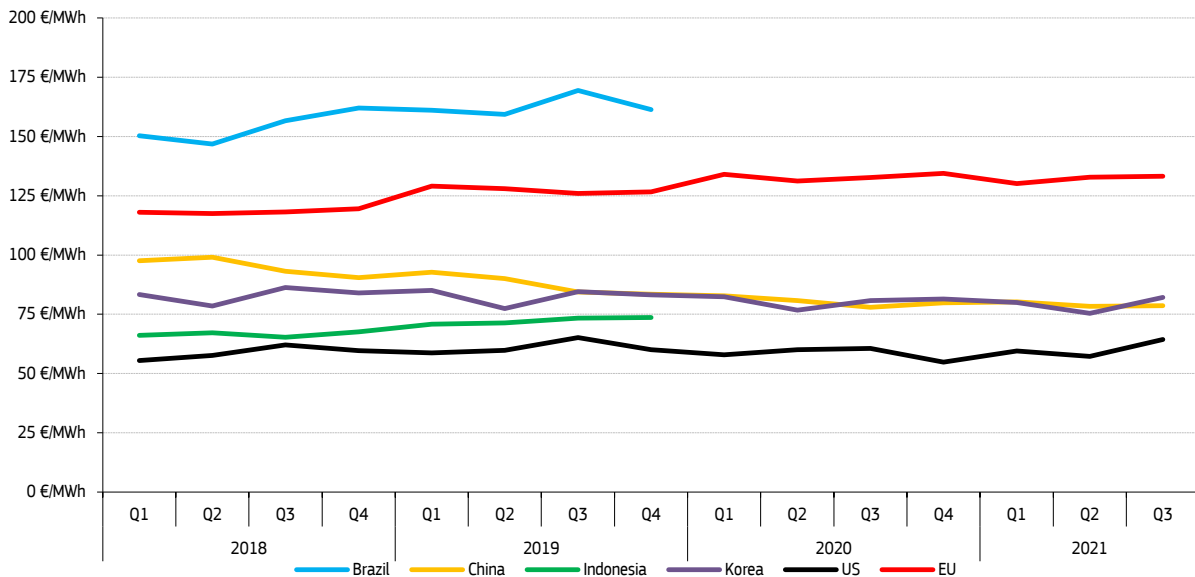


Source: Vaasaett

5.2 International comparison of retail electricity prices

- **Figure 70** 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 remained practically unchanged in Q3 2021 compared to the equivalent quarter in 2020. Meanwhile, Chinese industrial prices increased by 1%, halting the steady downward trend observed over the past two years. Industrial electricity prices in the United States increased by 6% quarter-to-quarter in Q3 2021.

Figure 69 – Retail electricity prices paid by industrial customers in the EU and its main trading partners



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

Glossary

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

Clean dark spreads are defined as the average difference between the price of coal and carbon emission, and the equivalent price of electricity. If the level of dark spreads is above 0, coal power plant operators are competitive in the observed period. *See dark spreads.*

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

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

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

Dark spreads are reported as indicative prices giving the average difference between the cost of coal delivered ex-ship and the power price. As such, they do not include operation, maintenance or transport costs. Spreads are defined for a coal-fired plant with 36% efficiency. Dark spreads are given in this publication, with the coal and power reference price as reported by *Bloomberg*.

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

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

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

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

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

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

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

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

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

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

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

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