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Quarterly Report

on European Electricity Markets

with focus on the impact of rising CO2 prices on cross-border electricity trade

Market Observatory for Energy

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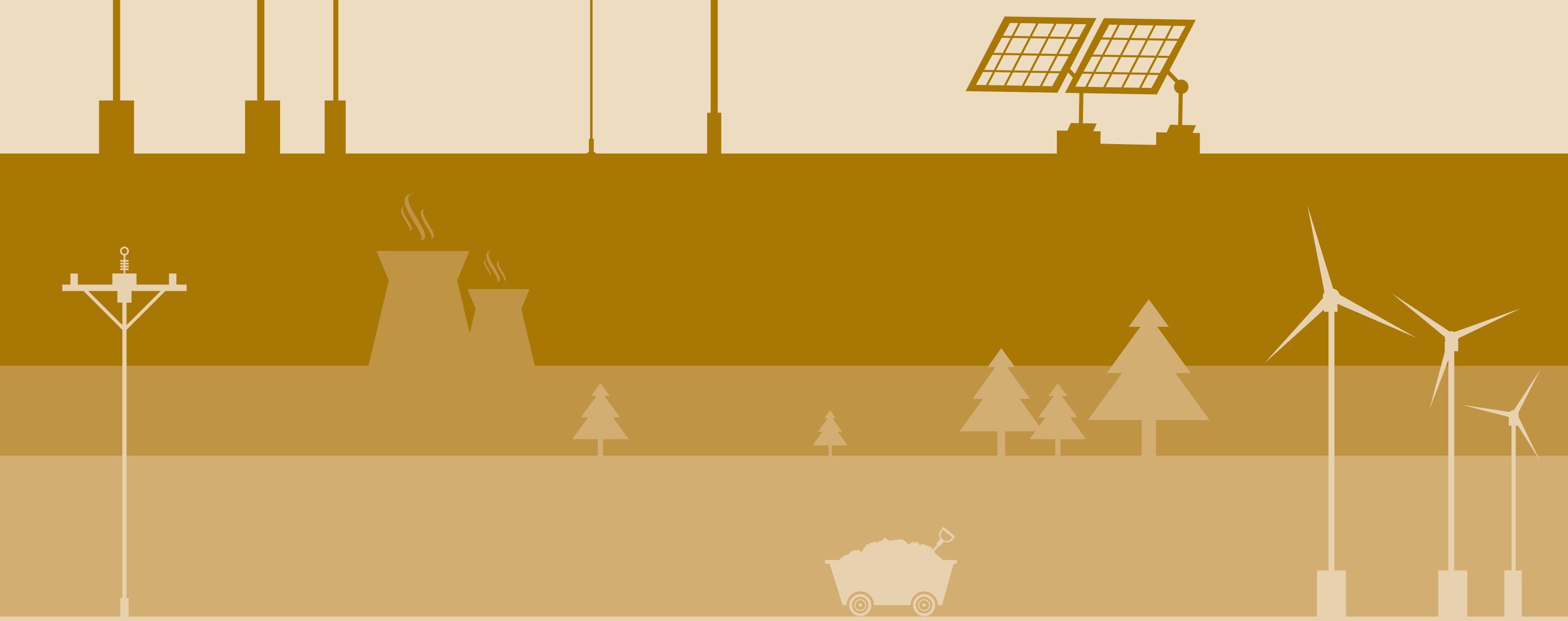

Energy

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CONTENT

HIGHLIGHTS OF THE REPORT

- **The third quarter of 2020 brought a gradual shift toward more normal conditions in European electricity markets. The lifting of lockdown measures and easing of restrictions on social and economic activity helped power demand to recover and reach pre-pandemic levels in September. However, the recovery was uneven and prone to setbacks amid rising infection rates towards the end of Q3 2020 which served as a warning that a second wave of the pandemic was inevitable. Overall, electricity consumption in the EU was 3% lower in Q3 2020 compared to the same quarter a year earlier, a big improvement in comparison with the 11% annual drop from Q2 2020.**

- **The structure of electricity generation was influenced by relatively high carbon prices, weak demand, improved hydro availability and rising solar generation which all combined to push out conventional fossil-based power plants. Nuclear generators were the main losers in Q3 2020 due to extended outages and maintenance overruns in France and Belgium and extremely low prices in Sweden which forced some units out of the market. As a result, nuclear generation fell by 16% year-on-year (-28 TWh) and its share in the mix, at 23%, dropped under that of gas (24%). Coal generation suffered losses as well, falling by 11% year-on-year (-11 TWh) due to rising carbon costs. Gas-fired power plants managed to keep their output unchanged thanks to continued coal-to-gas switching. High river and reservoir levels in the Balkans, France and Nord Pool markets and rising solar generation drove up renewable energy generation by 21 TWh year-on-year to reach a 37% share in the power mix in Q3 2020, up from 33% in the same quarter a year before. This was higher than in other major economies.**

- **The emission intensity of electricity generation in the EU continued to fall in Q3 2020 (-7% year-on-year according to preliminary estimates), but the pace slowed down considerably compared to double-digit rates from the first half of 2020. Recovering electricity demand and falling nuclear output acted as powerful counterweights to the decarbonisation trend.**

- **Demand for electrically chargeable passenger vehicles (ECVs) kept on rising over the summer as Member States expanded support policies aimed at incentivizing purchases. More than 273,000 new ECVs were registered in the EU in Q3 2020 (+212% year-on-year). This was the highest quarterly figure on record and translated into a jaw-dropping 10% market share, almost two times higher compared to China.**

- **Wholesale prices across the continent continued to recover from record lows reached in April and May as electricity demand gradually returned to normal levels. However, price dispersion was still relatively high even in September, with Nord Pool system price moving around 16 €/MWh at one end and Italy and Greece registering prices three times higher at the other end of the spectrum. The European Power Benchmark averaged 34 €/MWh in Q3 2020. This was 15% less than in the same quarter last year**

- **Rising levels of renewable penetration again brought more instances of negative electricity prices, which tripled compared to Q3 2019. In contrast, prices hit a multi-year high on 15 September when extremely low wind generation and a lack of dispatchable capacities due to regular maintenance and unplanned outages in Western Europe necessitated large imports from other regions. Hourly prices on the day-ahead market across many bidding zones surged to 189 €/MWh for the evening peak when solar irradiation wanes. Intraday prices on the day of delivery rose even higher as wind output during the evening peak period remained below expectations. The market signal of high balancing prices combined with a rapid correction of cross-border flows staved off the need for outside interventions and demonstrated the effectiveness of the current market mechanisms. As renewable penetration is expected to rise significantly in the years ahead and the number and capacity of conventional power plants to decrease, similar price spikes and episodes of high price volatility could become more frequent. This will present an opportunity for large-scale energy storage solutions and other providers of flexibility.**

- **Rising carbon prices have affected not only generation mixes of individual Member States, but also their balance of electricity trade as the sources replacing uncompetitive coal generators are not always located in the same Member State. This trend has enlarged the Polish trading deficit, turned Romania into a net importer of electricity and dramatically reduced German exports for instance. Wholesale electricity prices in Member States with significant presence of coal in their mix also tend to be more affected by CO2 price movements than markets with less emission-intensive generation sources. This is most visible in Poland where average baseload prices on the day-ahead market were 60% higher compared to the European Power Benchmark of nine markets in 2020.**

EXECUTIVE SUMMARY

- Electricity consumption in the EU declined by 3% year-on-year in Q3 2020, in line with developments in the wider economy which began to recover from the spring lockdown period. Declines were registered in all major consumption centres, including Germany (-4%), Italy (-3%) and France (-1%). Croatia experienced the largest power demand contraction (-7%). Growing power demand, in contrast, was recorded in Denmark, Estonia and Luxembourg.

- Thanks to a revival in economic activity, prices of coal and gas in the spot market continued to rise in Q3 2020, closing in on their year-ahead peers. In the gas market, spot prices increased more quickly and bridged their gap to future contracts completely. This diminished the competitive edge of gas and allowed coal generators to regain some of the lost ground in September. All in all, the average spot gas price reached 7.8 €/MWh in Q3 2020 (up 46% compared to Q2 2020). The average spot coal price was assessed at 43.2 €/t in Q3 2020 (up 13% compared to Q2 2020).

- CO2 prices held mostly above 26 €/t during Q3 2020, supported by expectations of more ambitious 2030 EU climate targets and further measures or reforms that could tighten the supply side. The spot contract settled above 30 €/t on 14 September for the first time in 14 years. The average CO2 spot price in Q3 2020 rose by 29% compared to Q2 2020 to more than 27 €/t. Several new price records were established in the aftermath of the European Council meeting on 11 December which endorsed the Commission proposal for a new EU target to reduce carbon emissions by at least 55% by 2030 (compared to 1990 levels). The maximum was reached on 28 December when allowances traded above 33 €/t. For the whole year 2020, the price of emission allowances reached 25 €/t on average, little changed compared to 2019.

- Highlighting the continuing decline of coal in the European power sector, thermal coal imports into the EU fell by 23% year-on-year to 13.8 Mt in Q3 2020. The estimated EU import bill for thermal coal amounted to €0.86 billion in the reference period, 40% lower compared to Q3 2019 and exceeding the year-on-year decline in imported volumes due to lower contracted prices of the commodity. The largest part of extra-EU thermal coal imports came from Russia which accounted for 73% of the total in the reference quarter.

- Recovering electricity demand made more space for fossil fuels in the mix, but rising solar generation and high hydro output put a cap on their expansion. In the end, the share of electricity generated by burning coal, gas and oil reached 39% in Q3 2020, only slightly lower than in Q3 2019. Nuclear generation remained under heavy pressure due to low availability of the French and Belgian fleets and fierce competition from renewables in Sweden. Its share fell to 23% in the reference quarter (from 27% in Q3 2019). Within the fossil fuels complex, coal suffered losses compared to Q3 2019 due to high carbon prices and its share fell to 13%. Meanwhile, less CO2-intensive gas generation saw its share of the mix going slightly up to 24% in the reference quarter (from 23% in Q3 2019).

- In line with the typical seasonal trend, the share of renewable energy sources declined in Q3 2020 compared to Q2 2020, but was still measurably higher (37%) than during the same quarter last year (33%). A 10% year-on-year rise in renewable generation contributed to the increase in renewable penetration. The highpoint, above 55%, was achieved on 5 July when a combination of windy and sunny weather coincided with low weekend demand. Renewable output across Europe peaked at 131 GW and in Germany it was large enough to cover the entire consumption between 7 am and 6 pm that day.

- Although wholesale electricity prices recovered from extremely low spring levels when lockdown measures substantially reduced electricity demand, they were on average still lower than during Q3 2019. The only exception to that were Belgium and France where lower nuclear availability propped up prices. The cheapest baseload power on the day-ahead market was available in the Nordic region which boasted unusually high levels of hydro reserves and rising wind generation. This was true especially for Norway where prices remained at single digits. Most markets moved between 30 and 40 €/MWh. Poland became the second most expensive market after Malta with an average baseload price of 52 €/MWh in Q3 2020. Day-ahead prices caught up with futures prices in September as electricity consumption largely returned to pre-pandemic levels. The year-ahead and spot contracts were on a declining trajectory in October and November as the second wave of coronavirus infections raised fears of another prolonged period of restrictive measures and economic uncertainty.

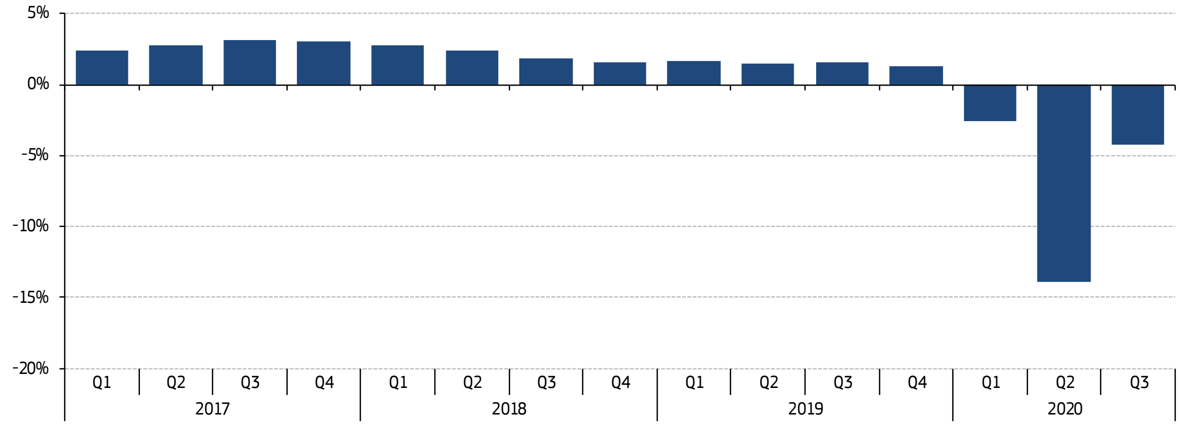
- Q3 2020 was marked by decreasing imbalances in regional cross-border trade. Central Western Europe retained its position of the largest exporter, but its net outflows decreased by 55% compared to the same quarter a year before to 10 TWh. This was due to lower nuclear availability in France, increased flows from Norway and rising renewable generation in other regions.

1 Electricity market fundamentals

1.1 Demand side factors

- **Figure 1** shows that the economic impact of the containment measures imposed to combat the spreading of the coronavirus, although much lower than in Q2 2020, was still being felt in Q3 2020. According to a December estimate published by Eurostat, seasonally adjusted GDP in the EU decreased by 4.2% year-on-year between July and September 2020. This was an improvement compared to the depths of the spring contraction, but nevertheless meant a third consecutive quarter of negative growth. The only Member State with a growing economy in Q3 2020 was Ireland (+8.1%), which has thus escaped a recession since it remained in negative territory only for one quarter in 2020. The highest year-on-year declines in Q3 2020 were reported in Greece, Croatia and Malta, affected by a very weak tourist season.

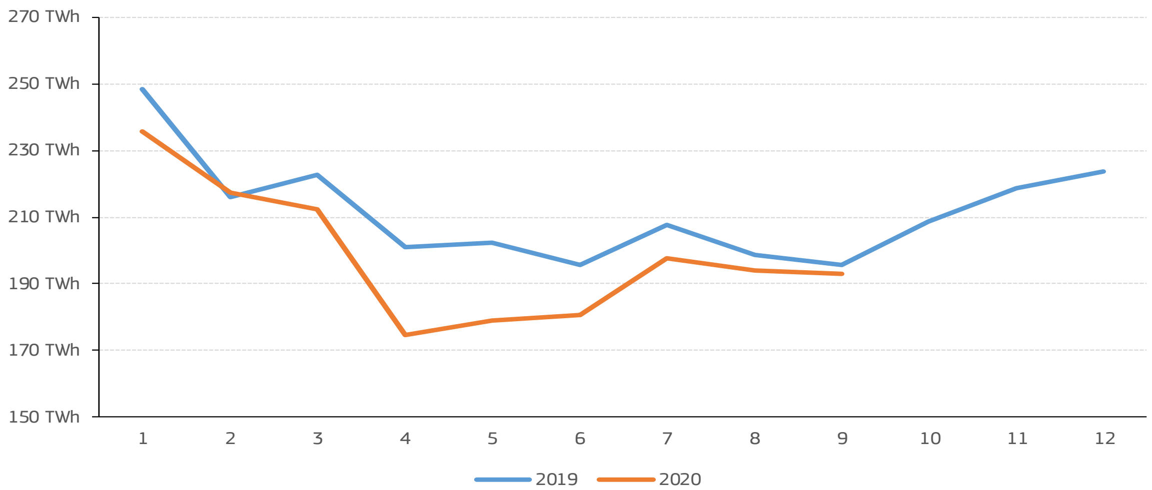
Figure 1 – EU GDP annual change (%)



Source: Eurostat

- According to Eurostat figures the consumption of electricity in the EU stayed 3% below last year's levels in Q3 2020, in line with developments in the wider economy. Declines were registered in all major consumption centres, including Germany (-4%), Italy (-3%) and France (-1%). Croatia experienced the largest power demand contraction (-7%) in Q3 2020. Growing demand, in contrast, was recorded in Denmark, Estonia and Luxembourg. European power demand approached last year's levels month by month in Q3 2020 and largely returned to normal by September.

Figure 2 – Monthly EU electricity consumption

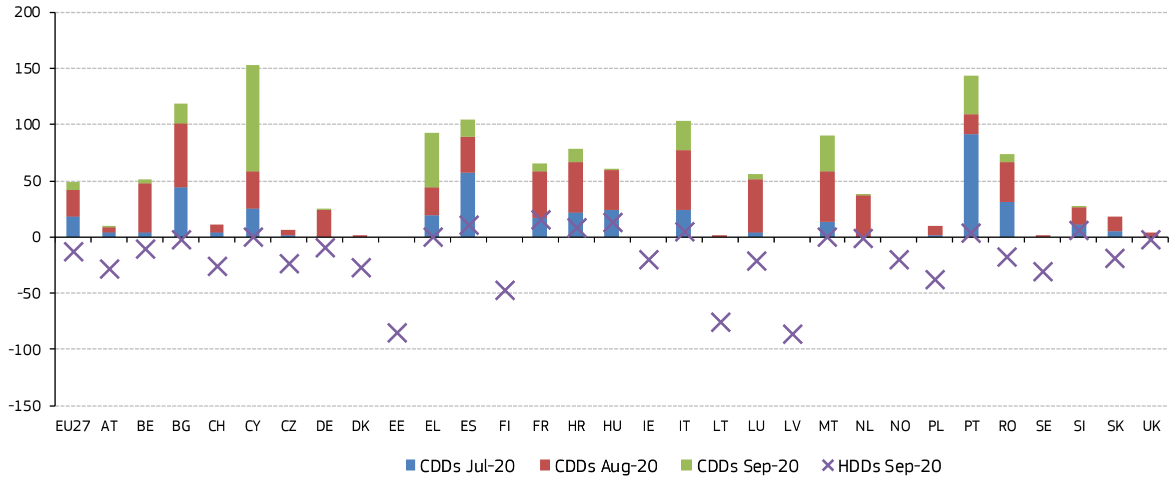


Source: Eurostat

- **Figure 3** 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 2020. EU-wide, the reference quarter was slightly hotter than usual, registering 50 CDDs above the long-term average. This means that temperatures were about half a degree Celsius higher than usual. Most of the deviations took place in August. The

Iberian Peninsula was a notable exception, registering a relatively hot July. Cyprus and Greece went through several heatwaves in September. On the heating front, September did not bring major deviations in both directions, with the exception of the Baltics and Finland where the weather turned warmer than usual.

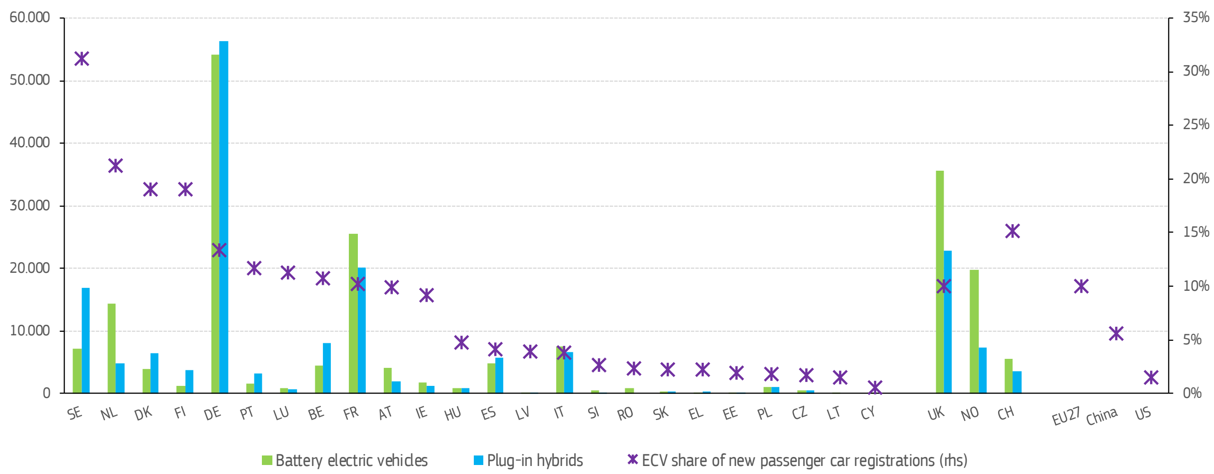
Figure 3 - Deviation of actual heating and cooling days from the long-term average in July-September 2020



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

- **Figure 4** shows that demand for electrically chargeable passenger vehicles (ECVs) kept on rising over the summer as Member States expanded support policies aimed at incentivizing ECV purchases. More than 273,000 new ECVs were registered in the EU in Q3 2020 (+212% year-on-year). This was the highest quarterly figure on record and translated into a 10% market share, almost two times higher compared to China. The plug-in hybrid segment boomed (+368% year-on-year to 138,000), while demand for battery electric vehicles grew at a more moderate but still impressive pace (+132% year-on-year to 135,000).
- The highest ECV penetration was again observed in Sweden where one in three new passenger cars sold could be plugged. The Netherlands came in second with a 20% ECV share, followed by Denmark and Finland. The relatively high Danish share is all the more impressive since it took place against the backdrop of zero government incentives. With more than 100,000 ECVs sold, Germany became by far the largest individual market in absolute terms. Its incentive programme offers up to 9,000 EUR in direct purchase bonuses. Seven Member States do not provide any purchase incentives for ECVs.

Figure 4 – Electrically chargeable passenger vehicle (ECV) registrations in selected countries in Q3 2020

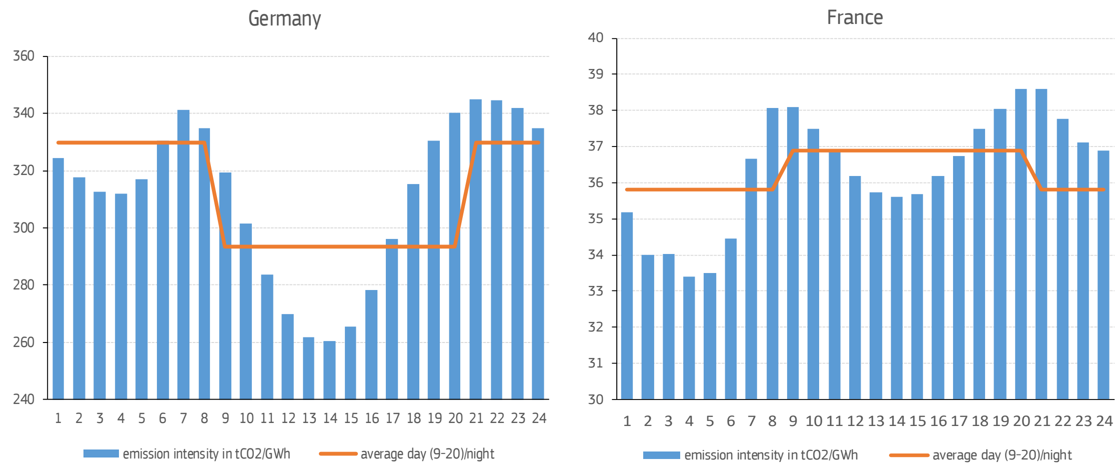


Source: ACEA, CPCA, BloombergNEF

- **Figure 5** maps how the environmental impact of ECV charging varies depending on the hour of the day on the example of France and Germany in the first 11 months of 2020. Thanks to the dominant role of nuclear energy in France, the local power sector generally produces much less emissions per MWh generated than its counterpart in Germany, where significant hard coal and lignite capacities are still in operation. Thus, carbon emissions stemming from the use of an ECV in France are about ten times lower than the use of the same ECV would cause in Germany. During the day (especially in the morning and evening) French gas-fired power plants ramp up to cover demand peaks, which pushes the average emission intensity slightly higher compared to night time. In the case of Germany, however, the much larger solar PV capacities (50 GW compared to 14 GW in France) depress the average emission intensity during the day by about 10% on average. A climate-conscious ECV driver should therefore pick different charging times in the two Member States.

- Germany introduced a 900 EUR home charger grant in November. In order to be eligible for funding, chargers need to have smart compatibility so that the grid operator can control and limit charging and a maximum output of 11kW. Chargers also need to be powered by a green electricity tariff or an onsite solar installation. There are around a hundred approved suppliers, which highlights the competitiveness of the market.

Figure 5 – Average hourly carbon emission intensity of power generation in France and Germany in 2020



Source: ENTSO-E, DG ENER calculations, 2020 data cover the first 11 months of the year.

1.2 Supply side factors

- **Figure 6** reports on the developments in European coal and gas prices. Thanks to recovering economic activity, prices of both commodities in the spot market continued to rise in Q3 2020, closing in on their year-ahead peers. In the gas market, spot prices increased more quickly and closed their gap to future contracts completely. This diminished the competitive edge of gas and allowed coal to regain some of the lost ground in September.

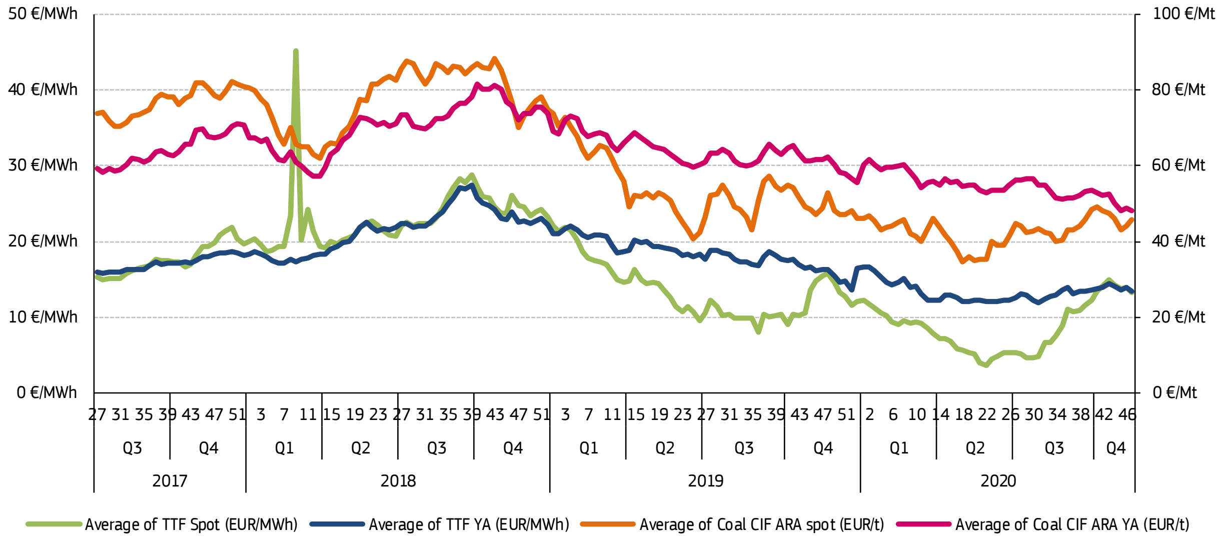
- Spot gas prices (represented by the TTF day-ahead contract) remained depressed in July but almost doubled to 10 €/MWh during August on the back of a number of unplanned maintenances across British and Norwegian gas fields and lower Russian pipeline imports, reduced by re-exports to Ukraine. The rising trend continued in September, although at a slower clip, amid reduced Norwegian flows, weak Dutch production and record high carbon prices. In the middle of October, just as the new heating season started, spot prices caught up with the forward curve and briefly pushed above it, on the back of relatively low temperatures, which increased heating demand, and further supply disruptions. Overall, the average TTF spot price reached 7.8 €/MWh in Q3 2020 (up 46% compared to Q2 2020, but down 24% compared to Q3 2019).[1]

- Thermal coal spot prices, represented by the CIF ARA contract, stagnated in July and August amid weak demand from coal-fired power plants which were being pressured by their gas-based competitors. A rebound took place in September as rising gas prices and recovering electricity demand induced some coal-fired capacities to return to the market and as concern mounted over strikes in Colombian mines. Spot coal prices peaked in the first half of October after which the supply fears eased. The average quarterly CIF ARA spot price was assessed at 43.2 €/t in Q3 2020 (up 13% compared to Q2 2020, but down 16% compared to Q3 2019).

- Year-ahead gas prices followed an upward trajectory in Q3 2020, rising by 6% compared to the previous quarter Meanwhile, year-ahead CIF ARA contracts were under pressure as prospects of coal burning in 2021 remained weak.

[1] For more information on gas markets see Quarterly Report on the European Gas Markets, Vol. 14, Issue 3.

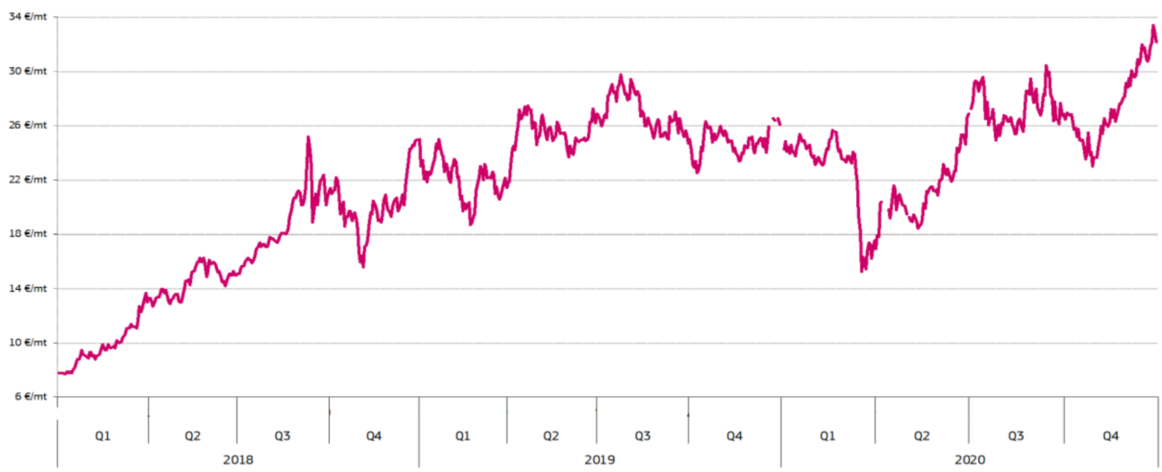
Figure 6 – Weekly evolution of spot and year-ahead coal and gas prices



Source: S&P Global Platts

- After a precipitous fall at the beginning of the lockdown period in March, the market for emission allowances, shown in **Figure 7,** recovered strongly during Q2 2020, as short-term demand weakness gave way to longer-term supporting factors. By the end of June, the carbon market recouped all of the losses suffered during the most acute phase of the pandemic, and reached even higher levels in Q3 2020.
- CO2 prices held mostly above 26 €/t during the summer of 2020 on the back of expectations of more ambitious 2030 EU climate targets and further measures or reforms that could tighten the supply side. The spot contract settled above 30 €/t on 14 September for the first time in 14 years. Prices then pulled back as traders started to take profit from the rally and, later, as the second wave of the coronavirus pandemic started to sweep across Europe, posing a threat of further economic disruption. The trend reversed in November when a delay to the start of 2021 auctions was announced, meaning a longer-than-expected break in fresh supply from auctions in January. Prices continued to head higher in December and clearly broke through the 30 €/t barrier in the aftermath of the European Council meeting on 11 December which endorsed the Commission proposal for a new EU target to reduce GHG emissions by at least 55% by 2030. Several new price records were established in the following weeks and allowances did not fall below 30 €/t ever since. The 2020 peak was reached on 28 December around 33 €/t.
- The average CO2 spot price in Q3 2020 rose by 29% compared to Q2 2020 to more than 27 €/t. This was the highest quarterly figure in more than a decade. In October and November 2020, the average CO2 spot price reached 25 and 27 €/t respectively. Spot prices averaged more than 30 €/t in December. For the whole year 2020, the price of emission allowances reached 25 €/t on average, little changed compared to 2019.

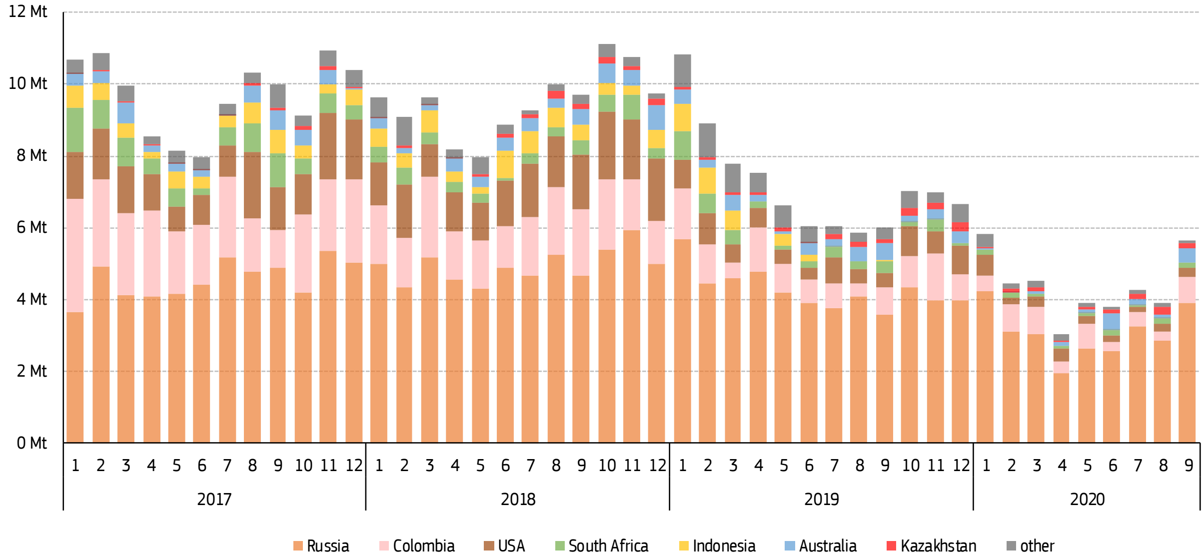
Figure 7 – Evolution of emission allowance spot prices from 2018



Source: S&P Global Platts

- As visible from **Figure 8**, monthly thermal coal imports into the EU held close to 4 Mt in July and August, before recovering to almost 6 Mt in September as conditions for coal-fired electricity generation improved. The total volume of imports fell by 23% year-on-year to 13.8 Mt in Q3 2020. The estimated EU import bill for thermal coal amounted to €0.86 billion in the reference period, 40% lower compared to Q3 2019 and exceeding the year-on-year decline in imported volumes due to lower contracted prices of the commodity.
- The largest part of extra-EU thermal coal imports came from Russia which accounted for 73% of the total in the reference quarter. Russian traders managed to achieve the highest share of the market yet as most of their rivals find it difficult to compete in the though low-price, low-demand environment. Colombia saw its market share going down to 10% from 11% in the previous quarter. The position of the United States and Australia worsened as well (5% shares both). Around 4% of thermal coal imports came from Kazakhstan. Shares of other trading partners were insignificant.

Figure 8 – Extra-EU thermal coal import sources and monthly imported quantities in the EU



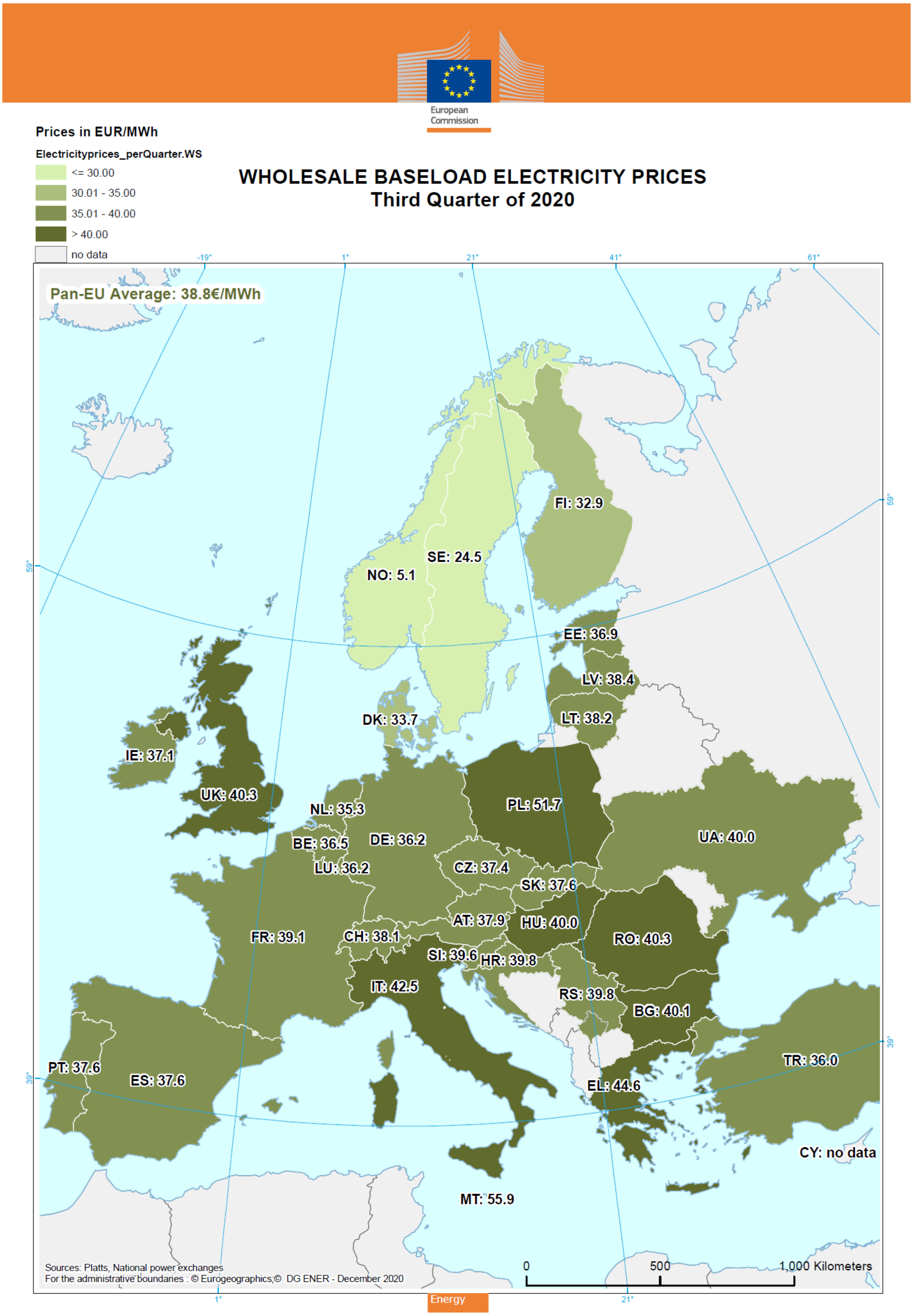
Source: Eurostat

2 European wholesale markets

2.1 European wholesale electricity markets and their international comparison

- The map on the next page shows average day-ahead wholesale electricity prices across Europe in Q3 2020. Although prices recovered from extremely low spring levels when lockdown measures substantially reduced electricity demand, they were on average still lower than during the same quarter last year. The only exception to that were Belgium and France where lower nuclear availability propped up prices. The cheapest baseload power on the day-ahead market was available in the Nordic region which boasted record high levels of hydro reserves and rising wind generation. This was true especially for Norway where prices remained at single digits. Sweden reported prices around 25 €/MWh on average. Most markets moved between 30 and 40 €/MWh. Poland became the second most expensive market with an average baseload price of 52 €/MWh, which was still 11% lower compared to the same period last year. Only Malta reported a higher quarterly average (56 €/MWh).
- The pan-EU average of day-ahead baseload prices reached 39 €/MWh in the reference quarter, down 18% in a year-on-year comparison. Compared to Q2 2020, the quarterly average rose by 61%.
- The biggest year-on-year price decreases happened in Norway (-85%), Sweden (-32%) and Romania (-31%).

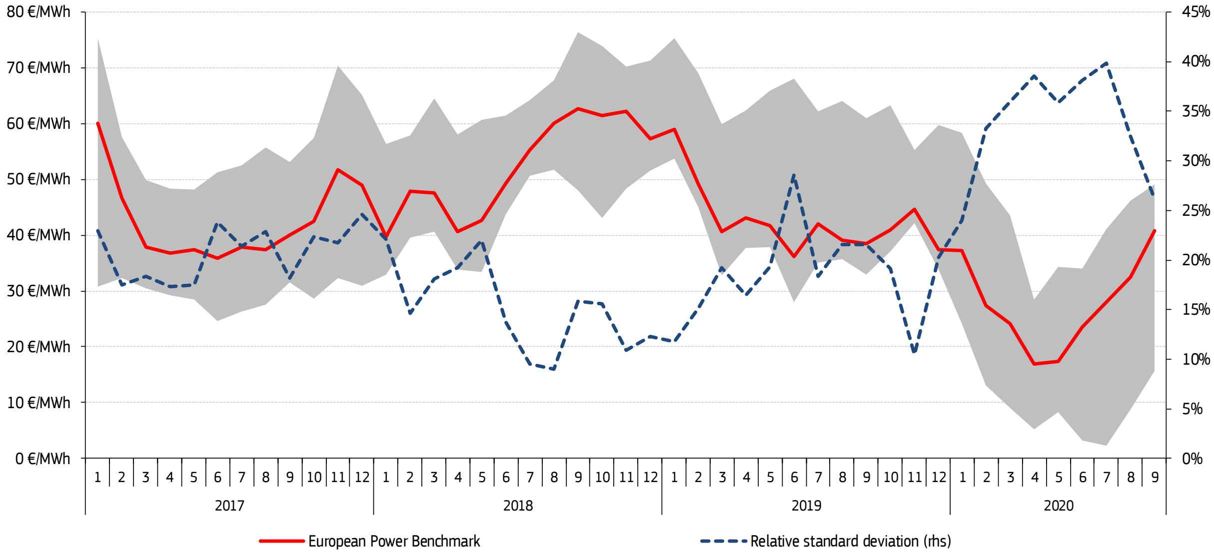
Figure 9 – Comparison of average wholesale baseload electricity prices, second quarter of 2020



Source: European wholesale power exchanges, government agencies and intermediaries

- **Figure 10** shows the European Power Benchmark of nine markets and, as the two lines of boundary of the shaded area, the lowest and the highest regional prices in Europe, as well as the relative standard deviation of regional prices. Both the shaded band and the relative standard deviation metric show that divergence levels, which increased considerably during the first half of 2020, climbed down in the course of Q3 2020. Wholesale prices across the continent continued to recover from record lows reached in April and May as electricity demand gradually returned to normal levels. However, price dispersion was still relatively high even in September, with Nord Pool system price moving around 16 €/MWh at one end and Italy and Greece registering prices three times higher at the other end of the spectrum. The European Power Benchmark averaged 34 €/MWh in Q3 2020. This was 15% less than in the same quarter last year.

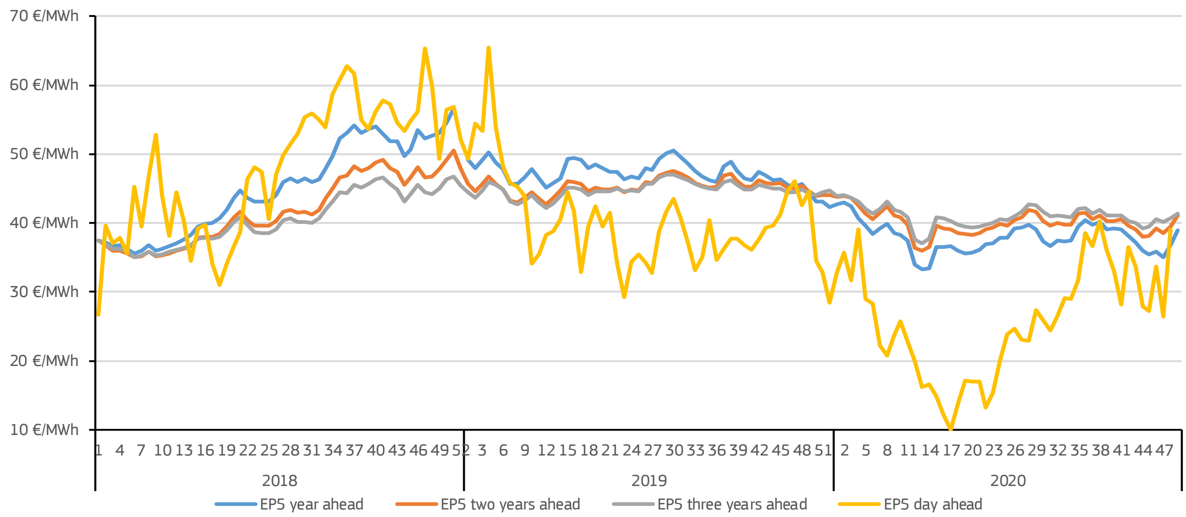
Figure 10 – The evolution of the lowest and the highest regional wholesale electricity prices in the European day-ahead markets and the relative standard deviation of the regional prices



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

- A consumption-weighted baseload benchmark (EP5) of 5 advanced markets, shown in **Figure 11**, reveals that day-ahead prices caught up with futures prices in September 2020 as electricity consumption largely returned to pre-pandemic levels. The year-ahead and spot benchmarks were on a declining trajectory in October and November as the second wave of coronavirus infections raised fears of another prolonged period of restrictive measures and economic uncertainty. Those fears subsided in December when infection rates plateaued and spot electricity prices began converging with long-term expectations again. The spot benchmark averaged 26 €/MWh in the first 11 months of 2020, a third lower compared to the last year. The year-ahead benchmark went down by 20% in the same period.

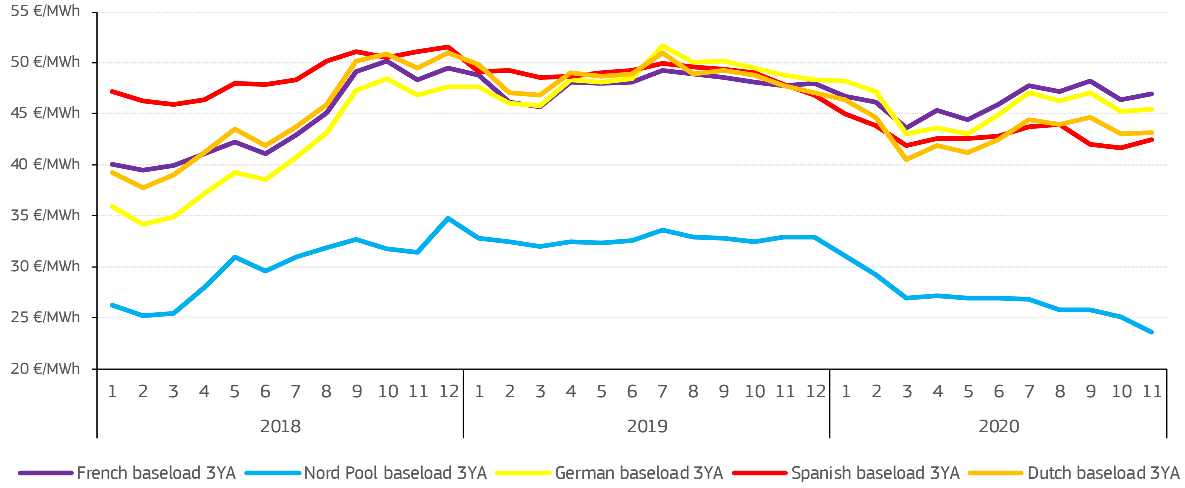
Figure 11 – Weekly spot and futures baseload prices – weighted average of 5 European markets



Source: Platts.

- A closer look at the five constituent markets of EP5 reveals changing expectations of future price developments in different European regions (**Figure 12**). Whereas Spain belonged to a group of relatively expensive electricity markets one or two years ago with futures prices assessed around 50 €/MWh, the long-term expectation has shifted considerably in 2020 to between 42 and 43 €/MWh, below German, Dutch and French levels. This is mainly thanks to a rapid expansion of Spanish renewable capacities, often built without financial incentives. Market expectations of wholesale prices in the years ahead decreased considerably also in the Nord Pool area, from levels between 30 and 35 €/MWh to around 25 €/MWh. The depressed outlook has been influenced by extremely high hydro reservoirs in the region which were filled by large amounts of melting snow. This is compounded by rising wind generation and relatively low consumption which exacerbates the surplus of supply. The Nord Pool region has become a significant net exporter of cheap electricity this year. This trend is expected to continue thanks to expanding renewable capacities and should be helped by several new interconnectors that are under construction or in the planning phase.

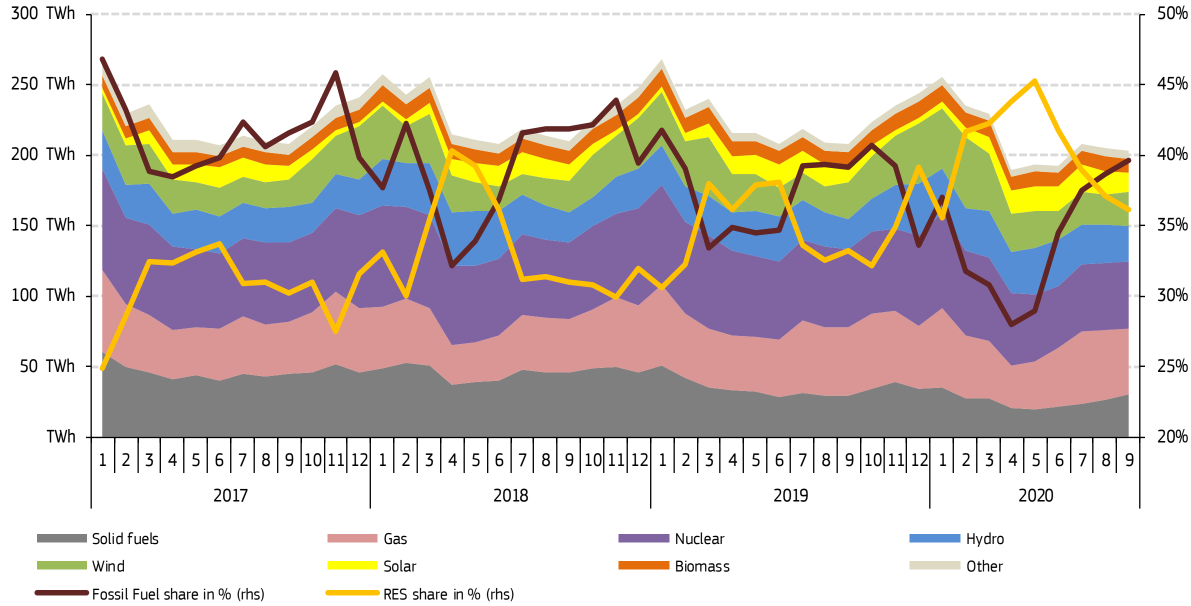
Figure 12 – Monthly baseload prices in selected markets – three years ahead



Source: Platts.

- **Figure 13** shows the monthly evolution of the electricity mix in the EU. Recovering electricity demand made more space for fossil fuels in the mix, but rising solar generation and high hydro output put a cap on their expansion. In the end, the share of electricity generated by burning coal, gas and oil reached 39% in Q3 2020, only slightly lower than in Q3 2019. Nuclear generation remained under heavy pressure due to low availability of the French and Belgian fleets and fierce competition from renewables in Sweden. Its share fell to 23% in the reference quarter (from 27% in Q3 2019). On the other hand, the share of renewables (hydro, biomass, wind and solar) climbed up from 33% to 37% during the same time, as green sources, boosted by rising solar output and good hydro generation, managed to take a larger portion of the consumption pie.
- Within the fossil fuels complex, coal suffered losses compared to Q3 2019 due to weak power demand and high carbon prices and its share fell to 13%. Meanwhile, less CO2-intensive gas generation saw its share of the mix going slightly up to 24% in the reference quarter (from 23% in Q3 2019). In absolute terms, coal-based generation fell by 13 TWh year-on-year, while gas managed to hold onto last year's volumes in Q3 2020. Renewables, in contrast, generated 21 TWh of electricity more in the reference quarter compared to the same quarter a year before.
- Between hard coal and lignite (the distinction between them is not visible in **Figure 13**), the latter tends to be more resilient in the face of changing market environment, as lignite generation traditionally displays more competitive marginal costs per unit of energy produced. This stems mainly from low production costs of the input fuel, which is usually mined in close proximity to power plants that use it. On the other hand, 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 only slightly more expensive in Q3 2020 compared to Q3 2019, but extremely low coal prices helped hard coal power plants maintain some profitability and led to limited lignite-to-coal switching. As a result, lignite-based generation in Q3 2020 fell by 13% year-on-year (or 6.5 TWh), while coal-fired generation decreased by 11% year-on-year (or 4.2 TWh). As was the case in Q2 2020, solar generation beat lignite in Q3 2020.

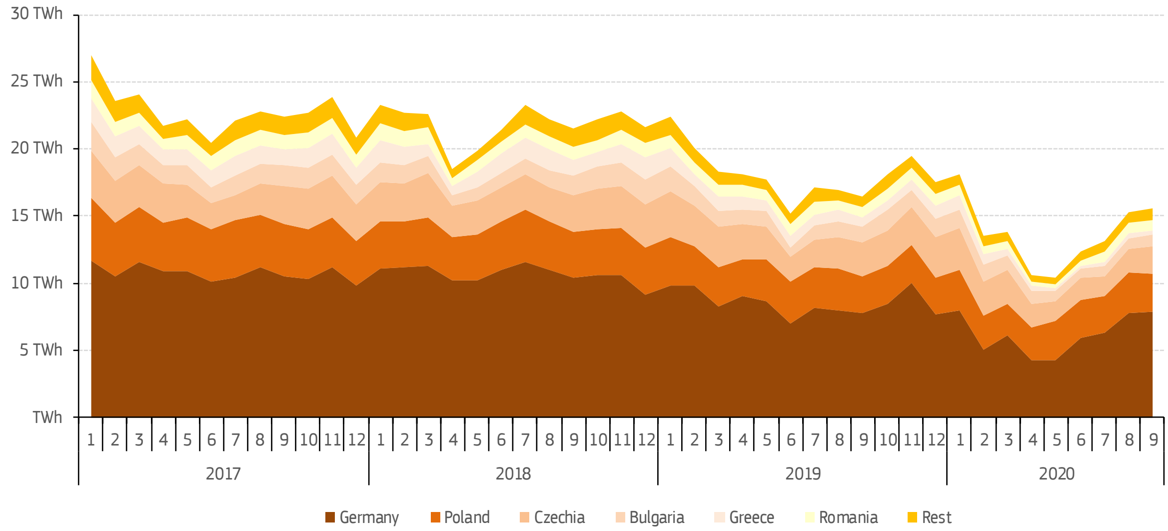
Figure 13 – Monthly electricity generation mix in the EU



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

- **Figure 14** shows that lignite generation in the EU rose during the summer, along with recovering electricity prices. For the first time since January, monthly output rose above 15 TWh in August and September. In Germany, home to the largest fleet of lignite units, lignite generation fell by 8% year-on-year in Q3 2020, displaced by weak demand, gas and rising solar penetration. Lignite-fired units in Poland displayed greater resilience due to a lower number of alternative sources. Thus, lignite generation fell only by 4% year-on-year in Q3 2020, which was one of the main factors behind relatively high wholesale electricity prices in Poland in the reference period. The output of the Czech lignite fleet, in contrast, decreased by 24% year-on-year in Q3 2020 on the back of good nuclear availability and high hydro generation. The three Member States accounted for 81% of the total lignite-based generation in the EU in Q3 2020. The largest fall in lignite generation (-58% year-on-year) was observed in Greece where gas and onshore wind made up most of the shortfall. A significant 27% year-on-year drop in lignite generation was also observed in Bulgaria with no substantial source acting as a replacement.

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

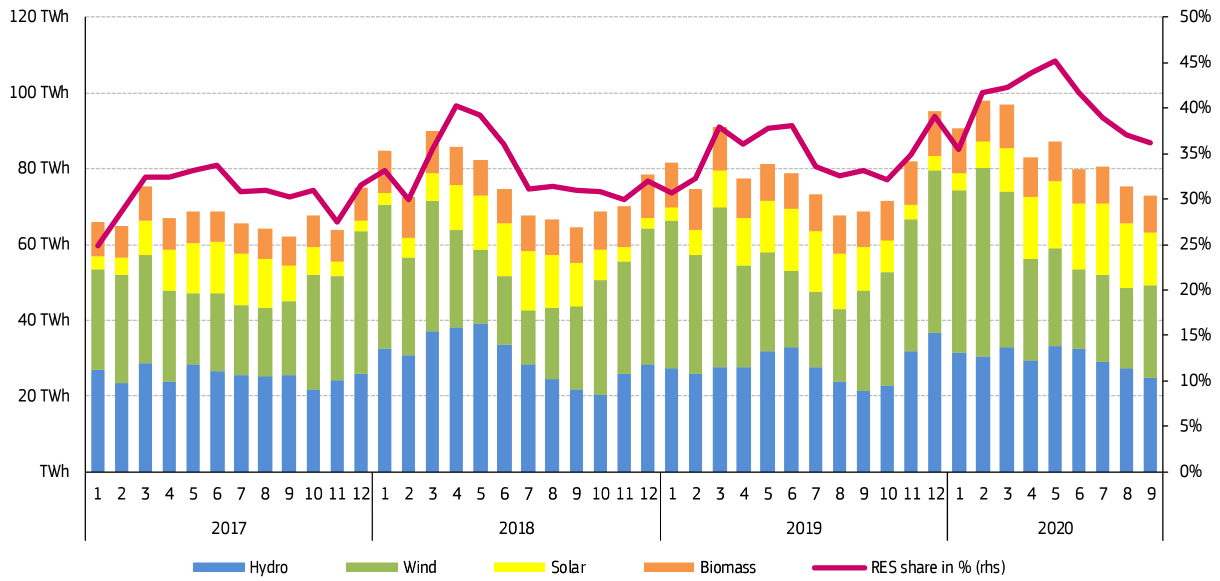


Source: ENTSO-E, Eurostat, DG ENER. Data represent net generation.

- **Figure 15** depicts the evolution of monthly renewable generation in the EU, alongside its share in the electricity generation mix. In line with the typical seasonal trend, the share of renewable energy sources declined in Q3 2020 compared to Q2 2020, but was still measurably higher (37%) than during the same quarter last year (33%). Weak demand, still affected by the pandemic, and a 10% year-on-year rise in renewable generation contributed to the increase in renewable penetration. On 5 July (Sunday), renewable energy covered more than 55% of EU's electricity demand.

- Apart from lower demand, the main drivers behind the increased presence of renewable power in the European mix in the reference quarter were good output volumes coming from hydro sources (up 9 TWh thanks mainly to increases in Austria, France, Spain, Sweden, Romania and Slovenia) and record high solar generation which increased by 18% year-on-year (up 7 TWh). Wind generation, which tends to taper off in the summer period, rose by 5% in Q3 2020 compared to a year before, taking an 11% share in the power mix. Biomass-based generation increased by 3% (or 1 TWh) year-on-year.
- Thanks to good weather conditions and expanding capacities, solar PV performed impressively in Q3 2020 and with an 8% share in the power mix became the third biggest contributor to the total renewable output (after hydro and wind). The largest increases in solar PV generation came from Spain (+2.3 TWh), Germany (+1.8 TWh), the Netherlands (+0.8 TWh), Italy and France (+0.5 TWh both). Polish solar PV output jumped by 190% year-on-year to 0.8 TWh in Q3 2020. Generation from solar panels in Hungary rose by 73% in the same period.
- At 37%, the combined share of hydro, biomass, wind and solar sources in the EU electricity generation in Q3 2020 was higher than in other major economies. The share of renewables in the US power mix in the reference quarter stood at 17%, whereas in China and India renewable energy constituted 29% and 27% of their respective total power generation during the same quarter.[2]

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

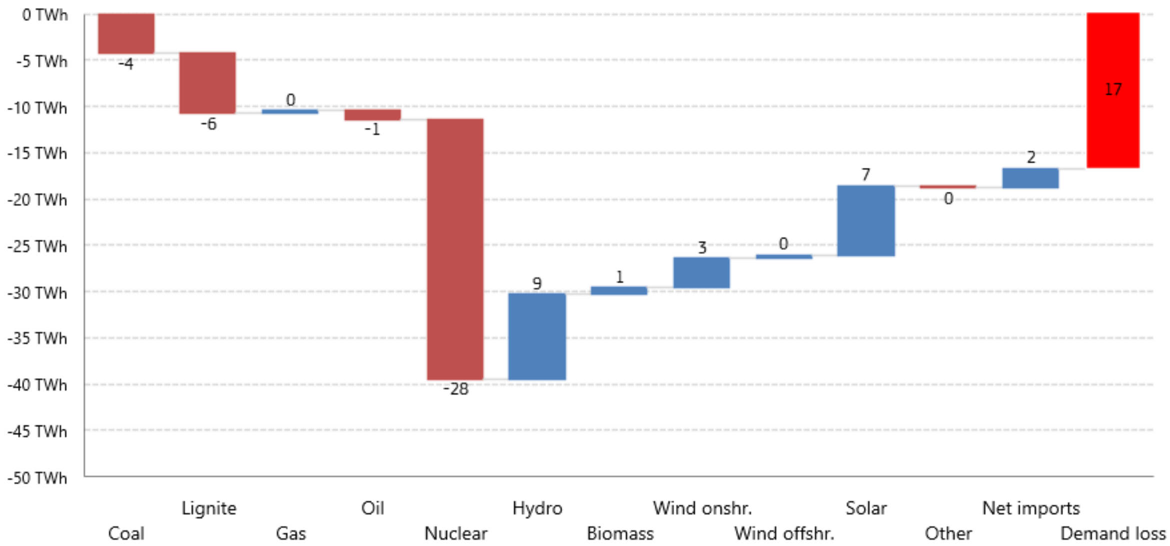


Source: ENTSO-E, Eurostat, DG ENER. Data represent net generation.

- **Figure 16** visualises changes in the EU electricity generation balance in the reference quarter compared to the same quarter a year before. The space for conventional power plants' running hours was restricted by low electricity consumption (-17 TWh) and rising renewable generation (+21 TWh). This time, however, the impact was most pronounced for nuclear energy, with power plants facing maintenance overruns due to covid-related restrictions (France) or having to shut down because of low demand and prices (Sweden). Net imports from third countries increased by 2 TWh mainly due to high inflows from Norway. Based on preliminary estimates, the carbon footprint of the power sector in the EU dropped by 7% year-on-year in Q3 2020 due to the lower use of fossil fuels.

[2] Calculations based on the data from Energy Information Administration in the US, China Electricity Council and Central Electricity Authority in India. The Chinese figure does not include biomass.

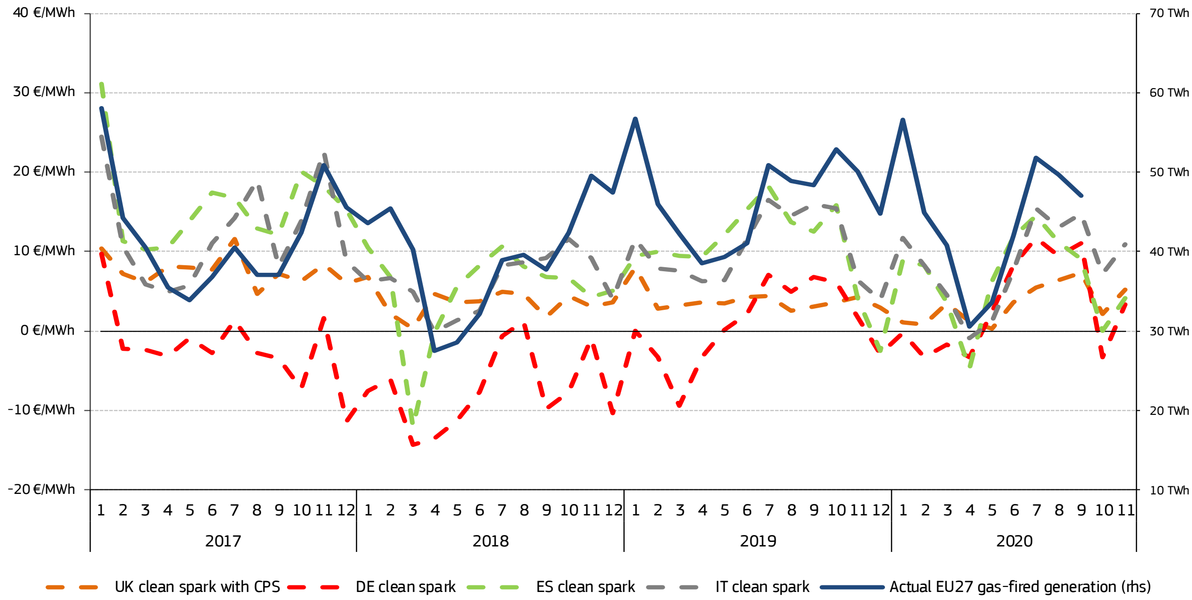
Figure 16 – Changes in power generation in the EU between Q3 2019 and Q3 2020



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

- The following two figures report on the profitability of gas-fired and coal-fired electricity generation in Germany, the UK, Spain and Italy by looking at their clean spread indicators. Gas remained more competitive than coal on average in Q3 2020 but rising gas prices and a pullback of carbon prices meant that this cost advantage diminished in October and November.
- As shown in **Figure 17,** the profitability of gas firing for electricity generation peaked in July when gas prices were still very low, but power prices were already recovering. Rising gas prices in August and September were to a large extent compensated by increasing wholesale electricity prices, which kept clean spark spreads in all four markets under observation at relatively high levels. The highest profit margins were assessed in Italy (14 €/MWh) in Q3 2020, followed by Spain (12 €/MWh) and Germany (11 €/MWh). Gas-fired generation volumes largely corresponded to the movement of spreads in respective markets. The total EU gas generation reached 148 TWh in the reference quarter, unchanged from Q3 2019. The outlook for gas generation remains positive thanks to the prevailing expectations of rising carbon prices in the months and years ahead.

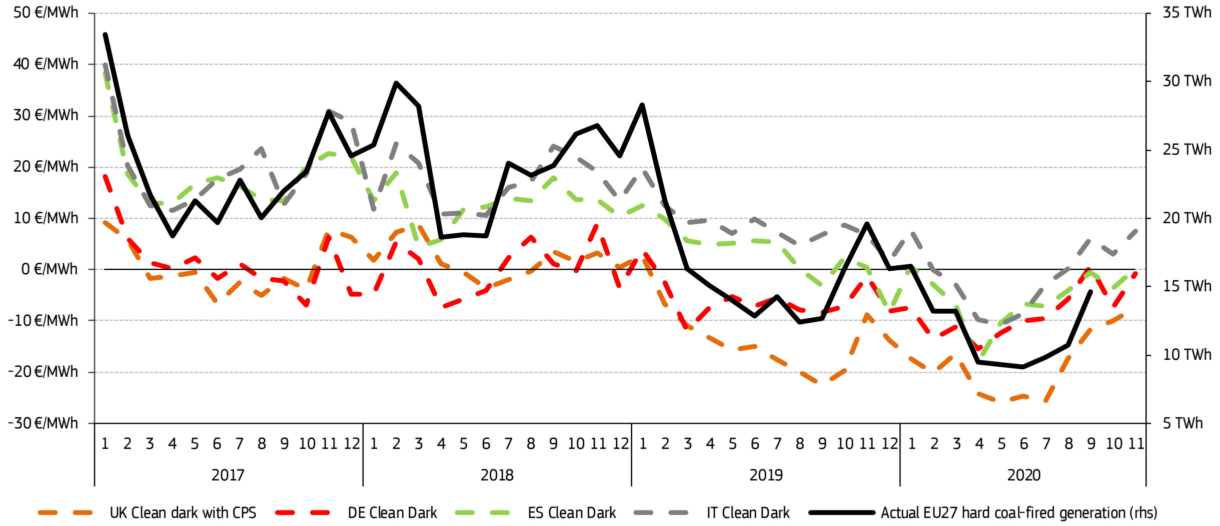
Figure 17 – Evolution of clean spark spreads in the UK, Spain, Italy and Germany, and electricity generation from natural gas in the EU



Source: ENTSO-E, Eurostat, Bloomberg

- **Figure 18** shows that the position of coal generators across Europe gradually improved in Q3 2020 thanks to rising power prices. Clean dark spreads in all markets under observation were on a rising trajectory. Italian clean dark spreads were positive already in August and remained above zero throughout the autumn. Spanish and German generators faced lower profit margins due to lower power prices. September marked the first month in 2020 when EU coal generation was higher than in the same month a year ago. This was mainly due to rising gas prices, low wind speeds and reduced availability of the French nuclear fleet. British dark spreads remained deep in negative territory in the second half of 2020. Nevertheless, September saw some UK coal generators firing up their units as other (mainly gas) sources were on maintenance or suffered from unplanned outages or were put into administration. The total EU coal generation reached 35 TWh in Q3 2020, down 11% compared to Q3 2019.

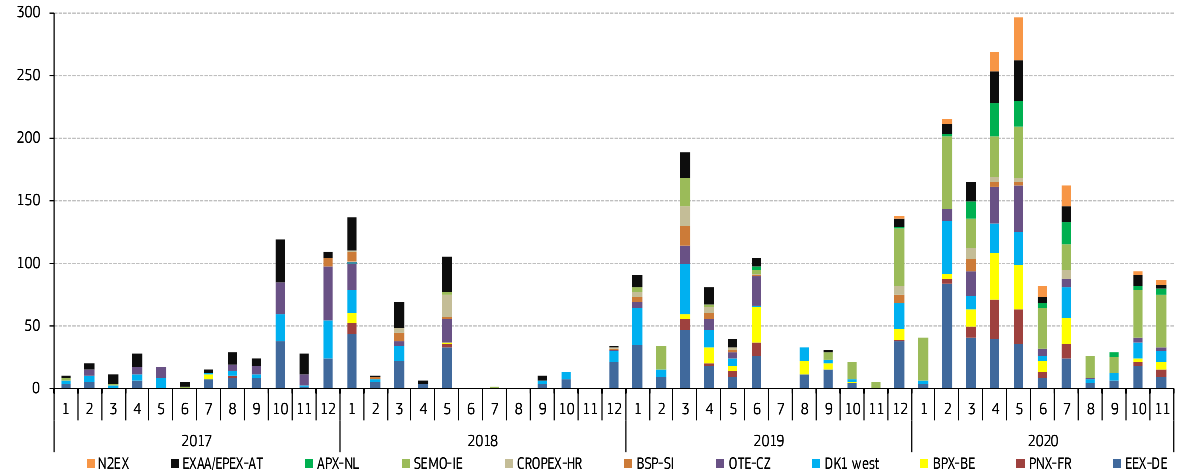
Figure 18 – Evolution of clean dark spreads in the UK, Spain, Italy and Germany, and electricity generation from hard coal in the EU



Source: ENTSO-E, Eurostat, Bloomberg

- **Figure 19** shows the monthly frequency of the occurrence of negative hourly wholesale electricity prices in selected European markets. Negative hourly prices usually appear when demand for electricity is lower than expected and when intermittent renewable generation is abundant, combined with ongoing relatively non-flexible large baseload power generation (e.g.: nuclear or lignite). In such cases, conventional power plants offer their output for a negative price in an effort to avoid switching the unit off and having to go through the costly and high-maintenance operation of restarting the facility when they want to enter the market again.
- At 217, the number of hours with negative wholesale prices in Q3 2020 was more than three times larger in the observed bidding zones than in the previous Q3. Most of the falls into negative territory occurred in July which is unusual in view of the past seasonal trends. The highest number of negative prices was recorded on 5 July (Sunday) when windy and sunny weather coincided with low weekend demand. Renewables covered the whole German consumption between 7 am and 6 pm that day.
- The integrated Irish zone recorded the highest number of negative hourly prices (51) in Q3 2020 and was trailed by Germany (34) and the Netherlands (22). Low electricity consumption and rising renewable generation brought negative prices even to markets which traditionally do not display many such instances, such as Norway and the Baltics. In the first 11 months of 2020 the number of negative hourly prices in markets under observation reached 1467 (up 133% compared to the same period in 2019). The pandemic has made balancing the grid a harder task and accentuated the need for more flexibility in the European power system in both directions. It has also intensified the search for market instruments that would find a proper value of flexibility.

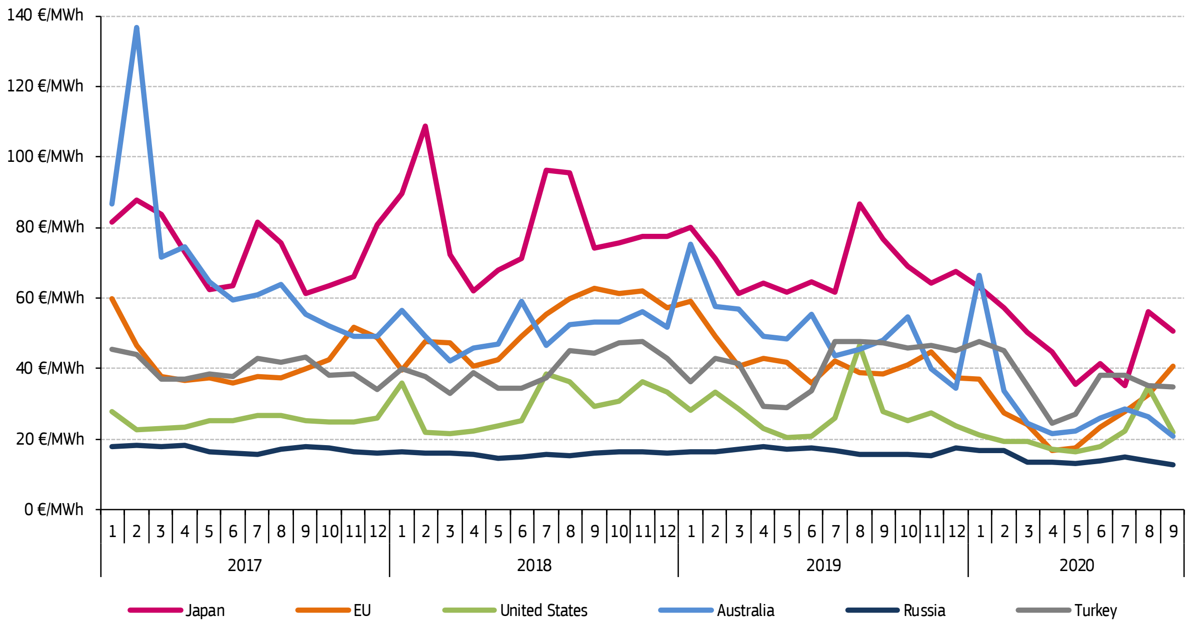
Figure 19 – Number of negative hourly wholesale prices on selected day-ahead trading platforms



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

- **Figure 20** compares price developments in wholesale electricity markets of selected major economies. In most markets prices recovered from extreme lows reached during the spring wave of the pandemic. Japan experienced a sharp uptick in August above 55 €/MWh as summer heat spurred more cooling demand. The country remained the most expensive of the markets under observation, with day-ahead prices reaching 47 €/MWh on average during Q3 2020. This was 17% higher than in Q2 2020. Heatwaves pushed wholesale power prices higher also in the United States, especially in California which also went through several rounds of rolling black-outs in August as increased cooling demand could not be met by a dwindled fleet of conventional sources. Power prices in Australia were on a downward trajectory in Q3 2020 on the back of weak demand and low coal and gas prices. Australian power prices were on average only 8% higher than in Q2 2020. Wholesale prices in Russia, at 14 €/MWh in Q3 2020, were the lowest of the observed group of markets and little changed from the previous quarter. Turkish power prices stabilized around 35 €/MWh in Q3 2020 (up 21% from Q2 2020).

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



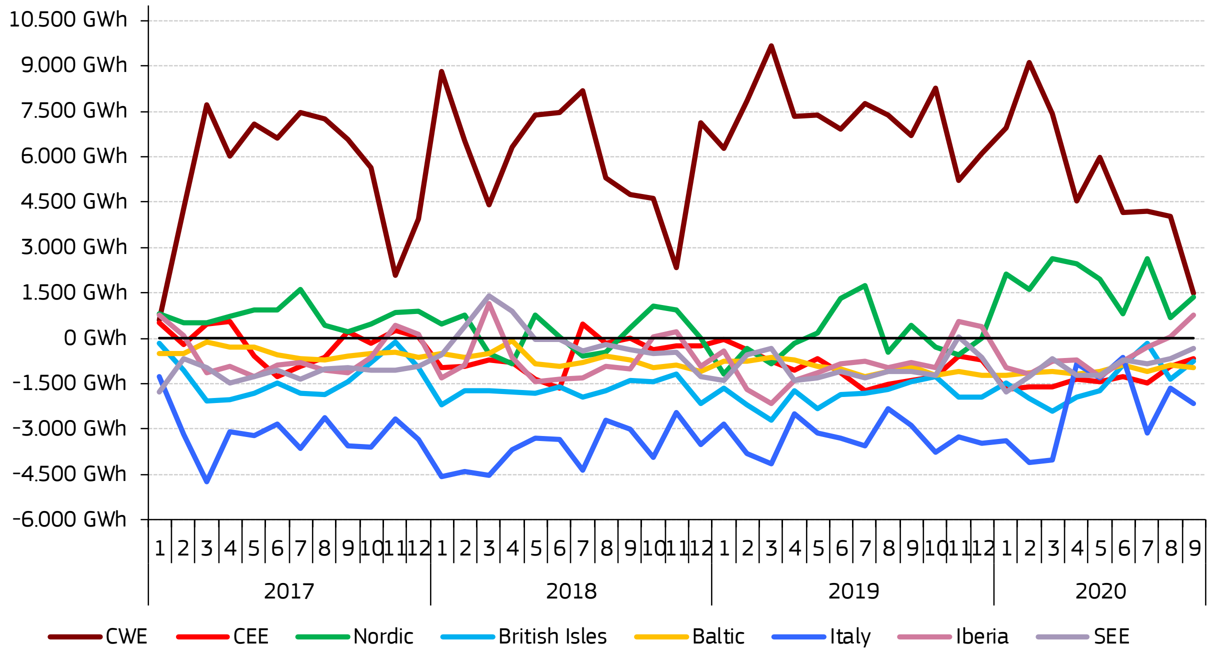
Source: European Power Benchmark, JPEX (Japan), AEMO (Australia), JCS ATS (Russia), Energy Exchange Istanbul (Turkey) and the average of PJM West, ERCOT, MISO Illinois and CAISO regional wholesale markets in the United States.

2.2 Cross-border flows

- **Figure 21** reports on the regional cross-border flows of electricity. Q3 2020 was marked by decreasing imbalances. Central Western Europe retained its position of the main exporting region, but with a much lower surplus than in the past quarters. Its net export flows decreased by 55% compared to the same quarter a year before to 10 TWh. This was due to lower nuclear availability in France and increased flows from the Nordic region (mainly Norway). Net outflows suffered particularly in September when they tumbled to a three-year low. France became a net importer of electricity that month. The Iberian Peninsula, in contrast, emerged as a net exporter in September thanks to improved hydro availability and increased coal and gas generation in Portugal. The region ended up with a net surplus of 0.5 TWh for the whole reference quarter (compared to a deficit of 2.5 TWh in Q3 2019).

- Italian net imports shrank by 21% year-on-year to 7 TWh in Q3 2020 as the fall in local consumption was greater than the decrease in generation. Net flows to the British Isles also decreased considerably (by 53% year-on-year to 2.3 TWh) on the back of a 6% drop in power demand in the UK. The CEE region's net position (-3 TWh) improved in Q3 2020 compared to Q3 2019 thanks to high levels on the Danube which boosted Slovak and Romanian hydro generation. South Eastern Europe's balance remained in negative territory (-1.9 TWh), but that was a noticeable improvement compared to Q3 2019 thanks to good hydro availability in Slovenia and Serbia and higher gas and wind generation in Croatia.
- The Nordic region retained it net exporting position as weak demand in Sweden and Finland combined with high hydro reservoir levels and rising wind generation. The total net surplus reached 4.7 TWh in Q3 2020 (up 174% compared to Q2 2019).

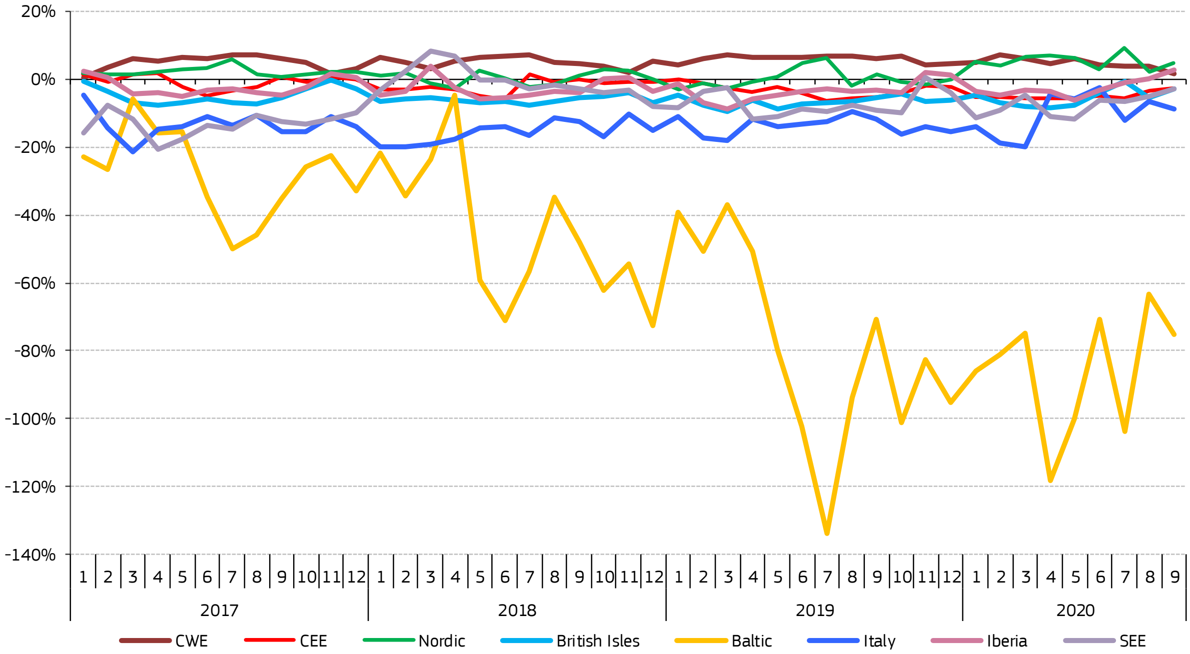
Figure 21 – European cross border monthly physical flows by region



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 22** 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 improved slightly in Q3 2020 compared to the same quarter a year ago thanks mainly to increased biomass co-firing in Estonia. Net imports (3 TWh) reached about 80% of domestic generation (compared to 100% in Q3 2019). Italy became the second biggest importer relative to its production (9%). For the rest of the regions, net imports (or exports) did not exceed 6% of domestic generation.

Figure 22 – The ratio of the net electricity exporter position and the domestic generation in European regions

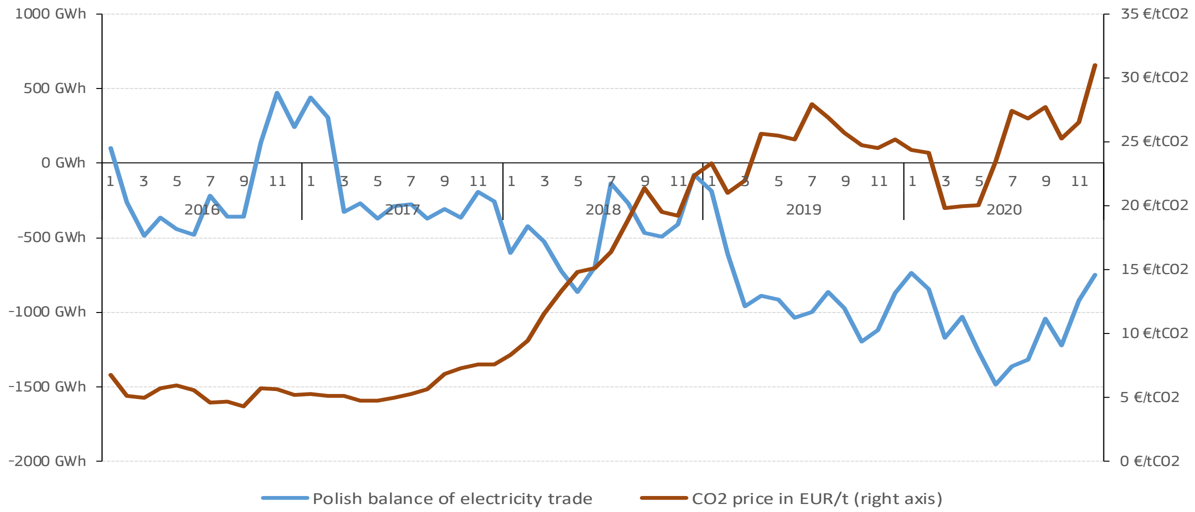


Source: ENTSO-E. Country distribution in regions is the same as in the previous figure. The -100% level means the same amount of electricity is imported as produced domestically. Source: ENTSO-E, TSOs, Eurostat, DG ENER calculation

3 Focus on the impact of rising CO2 prices on cross-border electricity trade

- The average price of emission allowances has risen considerably in the last few years – from 6 €/t in 2017 to 16 €/t in 2018 to 25 €/t in 2019 and 2020. Higher CO2 prices raise operating costs for fossil-based technologies, especially those with high carbon emissions intensity such as lignite or hard coal power plants. Gas-fired power plants, which emit a lower amount of CO2 per generated output, generally benefit from higher carbon prices and increase their share in the mix at the expense of their coal competitors. At the same time, both coal and gas generators are pushed out of the merit order by rising renewable generation. This interplay has affected the generation mix of individual Member States and also their balance of electricity trade as the sources replacing coal generation are not always located in the same Member State.
- **Figure 23** demonstrates this on the example of Poland. Its balance of trade was mostly negative between 2016 and 2017 but limited to no more than 500 GWh of net monthly imports, with occasional surplus periods around winter time. As carbon prices began to climb and local coal generators had to operate in a less hospitable environment since 2018, the Polish position deteriorated to the extent that net imports grew to more than 1000 GWh a month at times. The trend continued even as the coronavirus pandemic dampened electricity consumption. Polish net imports reached 13 TWh in 2020, compared to 11 TWh in 2019 and 6 TWh in 2018.

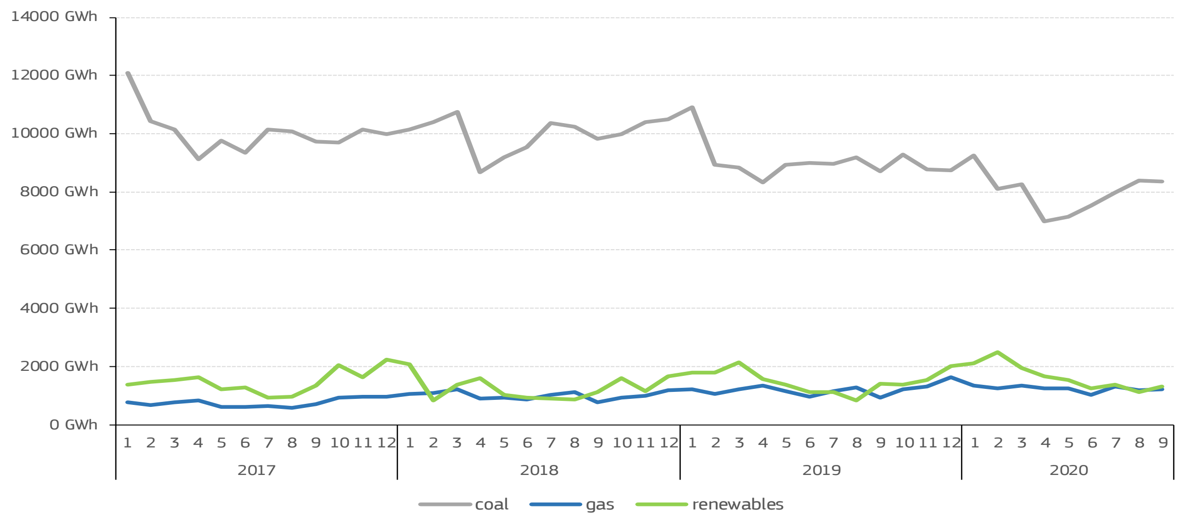
Figure 23 – Monthly Polish balance of electricity exchanges



Source: ENTSO-E, Eurostat, Platts

- **Figure 24** further explains the deteriorating Polish balance using the generation mix. As domestic coal generation declined from around 10,000 GWh a month in 2018 to around 8,000 GWh a month in 2020, there is only a limited potential to replace the missing volumes. Gas generation capacities, although rising (see **Figure 45)**, are still relatively small, excluding the possibility of stronger coal-to-gas switching. Renewable capacities have been expanding rapidly in the solar segment (from 1.3 GW in 2019 to 3.5 GW at the end of 2020), but the corresponding growth in solar generation has not been able to compensate for the whole loss of coal output.
- In the short-term, further replacement of coal generation could be possible with increased interconnection capacities with neighbouring countries and also with the removal of import and export restrictions the Polish TSO currently applies. In its implementation plan for the electricity market reforms, Poland has committed to achieve up to 4 GW of import capacities during extreme scarcity events by 31 December 2025. And as an interim step, assuming the implementation of flow-based market coupling in the CORE region, Poland has also committed to increase its import capabilities during scarcity events to reach up to 2.5 GW by 1 November 2021.
- A better access to generation sources in neighbouring markets and more efficient cross-border trade should also be achieved thanks to the Interim Coupling project that aims to connect the borders of the CEE region with the Europe-wide Multi-Regional Coupling zone by introducing NTC-based implicit capacity allocation on six borders (PL-DE, PL-CZ, PL-SK, CZ-DE, CZ-AT, HU-AT) for day-ahead trading. The project should go live in May 2021. An integrated day-ahead market increases the overall benefits of trading by promoting more competition, increasing liquidity and enabling a more efficient utilisation of generation resources across Europe.

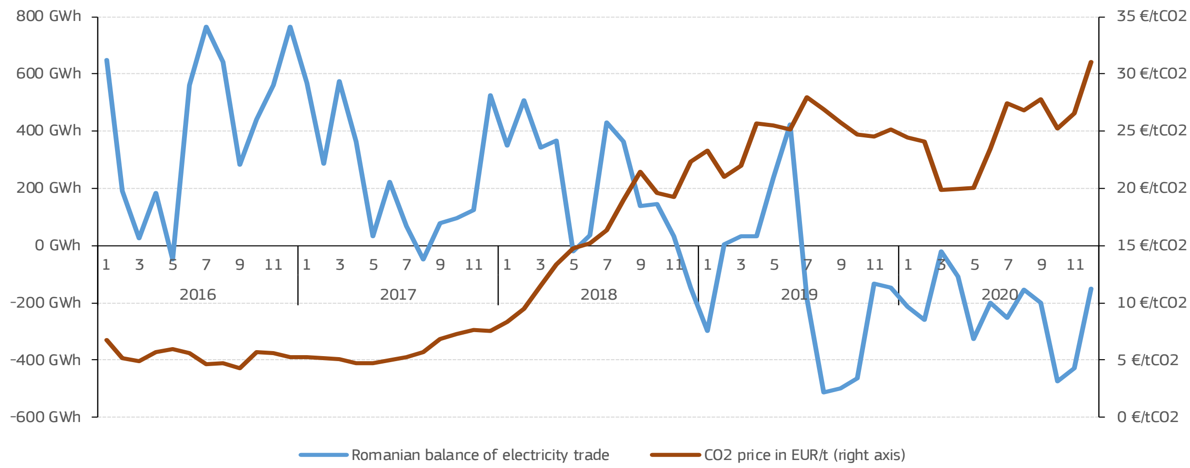
Figure 24 – Monthly development of Polish generation



Source: ENTSO-E, Eurostat. Coal includes both lignite and hard coal generation. Renewables include hydro, solar and wind generation.

- Romania's net position has also worsened noticeably with rising carbon prices. As shown in **Figure 25**, its balance gradually shifted from a surplus of 3 TWh in 2017 to a deficit of 3 TWh in 2020. Meanwhile, Romanian electricity consumption declined by 2 TWh year-on-year in the first three quarters of 2020. Falling hard coal and lignite generation, which struggle to come to terms with increased operating costs, and a lack of replacement capacities are again the main causes of the deteriorating balance of trade.

Figure 25 – Monthly balance of Romanian electricity exchanges

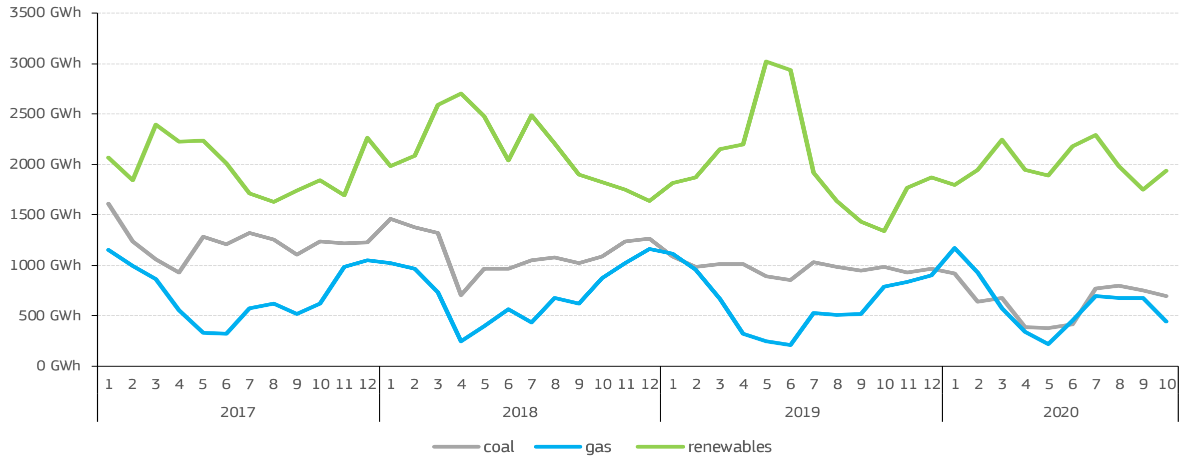


Source: ENTSO-E, Eurostat, Platts.

- **Figure 26** shows the fall of lignite and hard coal generation in Romania which accelerated in 2020. The trend has been accompanied by the decommissioning of older lignite units. The combined coal and lignite capacity decreased from nearly 6 GW in 2017 to 3.5 GW at the end of 2020. At the same time, the potential for coal-to-gas switching is restricted by limited gas-fired capacities which are partly mothballed. A new 430 MW CCGT expected to be commissioned soon in Iermut should broaden the switching channel. The development of new solar PV parks and onshore wind farms has stalled since 2014, limiting the possibility of higher renewable generation replacing the missing fossil-based volumes. Increased import needs have been partly sourced from the Burshtyn Island in neighbouring Ukraine. Ukrainian electricity exports to Romania grew from zero in 2018 to almost 1 TWh in 2020.

- If they want to operate after 2021, older power plants in the CEE region and beyond will need costly retrofitting to comply with EU best available technology standards for air pollution. Operating costs of these plants with more effective filters are likely to increase. Rising carbon costs will add an additional layer of financial burdens. It can be expected that some plants will not opt for upgrades and close earlier than planned.

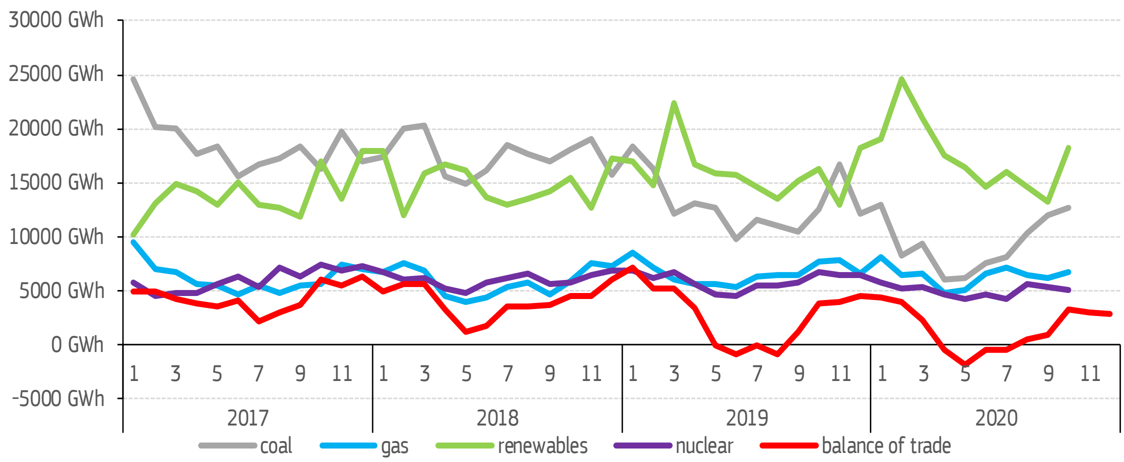
Figure 26 – Monthly production of selected Romanian generation sources



Source: ENTSO-E, Eurostat. Coal includes both lignite and hard coal generation. Renewables include hydro, solar and wind generation. Nuclear generation is not included as it was stable in the selected timeframe.

- Rising carbon prices have brought significant changes also to the German balance of electricity exchanges (**Figure 27**). As hard coal and lignite generation declined significantly in 2019 and 2020, German exports went down as well and not even rising renewable generation could compensate for it. Net electricity outflows from Germany peaked in 2017 at 52.5 TWh when they were the largest in Europe (and the second largest in the world, behind only Canada). One ton of carbon dioxide emissions cost 6 euros at the time. In 2020, with CO2 prices at 25 €/t and power demand and wholesale prices dramatically affected by the pandemic, German net exports dwindled to 17 TWh. In the space of three years annual German coal-fired generation fell by roughly 100 TWh. One third of that was pushed out of the merit order by rising domestic solar and wind generation, the rest succumbed either to falling power demand or more competitive generation sources abroad. Interestingly, coal-to-gas switching in Germany has so far been quite limited despite its relatively large potential (more than 30 GW of gas capacities are installed, although some of them are mothballed).
- The German balance of electricity trade should deteriorate further due to the planned phase-out of nuclear (2022) and coal (2038) generation sources. Around 19 GW of nuclear and coal power plants are expected to be retired by the end of 2022. The effect of reduced capacities should be mitigated by weak consumption which is not expected to recover to pre-pandemic levels before 2025 according to German TSOs' current predictions.

Figure 27 – Monthly production of selected German generation sources and balance of electricity trade



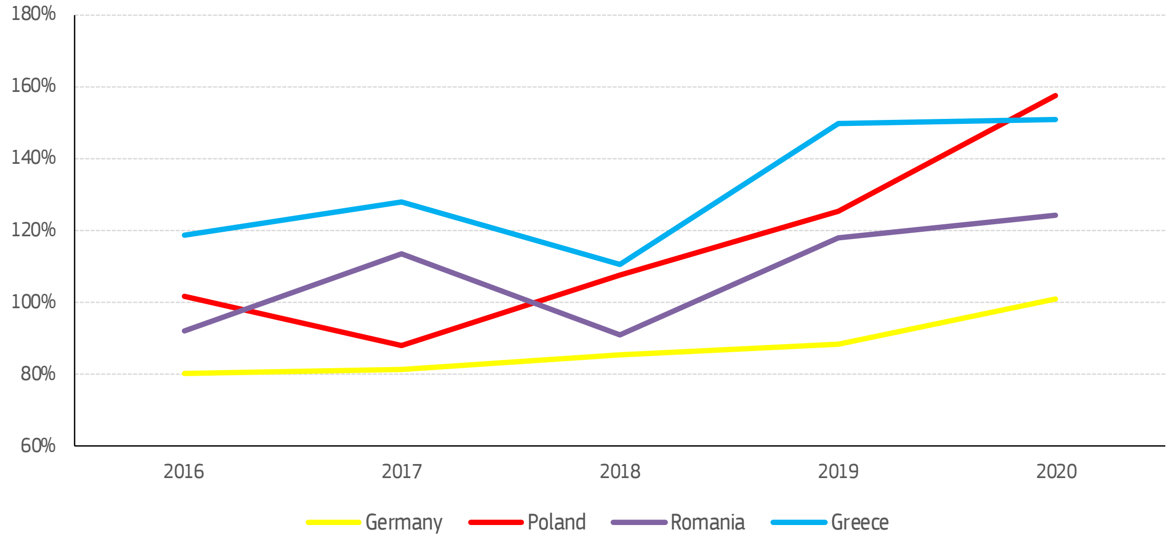
Source: ENTSO-E, Eurostat. Coal includes both lignite and hard coal generation. Renewables include hydro, solar and wind generation.

- Since not all markets can experience the worsening of their trade balance at the same time, there naturally arises a question of where the corresponding surplus comes from. As already mentioned in the German case, some of it can be traced to falling demand in structurally deficit markets such as Italy or Hungary which reduced their net imports. Part of the change in the trade patterns stems from rising renewable capacities which boosted generation especially in Western Europe. Over the first three quarters of 2020, wind, solar and biomass output in France, Spain and Italy rose by 17 TWh year-on-year, replacing domestic fossil-based sources and reducing import needs. Improved hydro generation across Europe compared to 2019 was also a significant factor in 2020.

Norway exported 20 TWh of mostly hydro-based electricity to the EU in 2020 on a net basis, compared to zero net outflows a year before.

- Even though their role in the generation mix has diminished across the continent, coal generators continue to influence wholesale electricity prices in many Member States due to their price-setting position in the merit order. Rising carbon costs tend to inflate electricity prices especially in Member States with significant presence of coal in the mix. **Figure 28** demonstrates this on the example of four markets by comparing their annual average day-ahead prices for baseload power with the European Power Benchmark (EPB9). Germany, Greece, Poland and Romania saw their wholesale power prices rise in relative terms in 2019-2020 compared to 2017-2018 when CO2 prices were much lower. The steepest increase can be observed in Poland where the share of coal in the mix (at around 75%) is the greatest. The premium over EPB9 also grew in Greece, although intensive coal-to-gas switching taking place over the last two years dampened the effect of rising carbon prices somewhat. Even Germany, which used to be a discount market, experienced a relative increase and was on par with EPB9 in 2020. This occurred despite the constant rise of renewable penetration in the German grid which in 2020 reached almost 50%.

Figure 28 – Day-ahead electricity prices in selected markets compared to European Power Benchmark



Source: ENTSO-E, Eurostat. Coal includes both lignite and hard coal generation. Renewables include hydro, solar and wind generation.

4 Regional wholesale markets

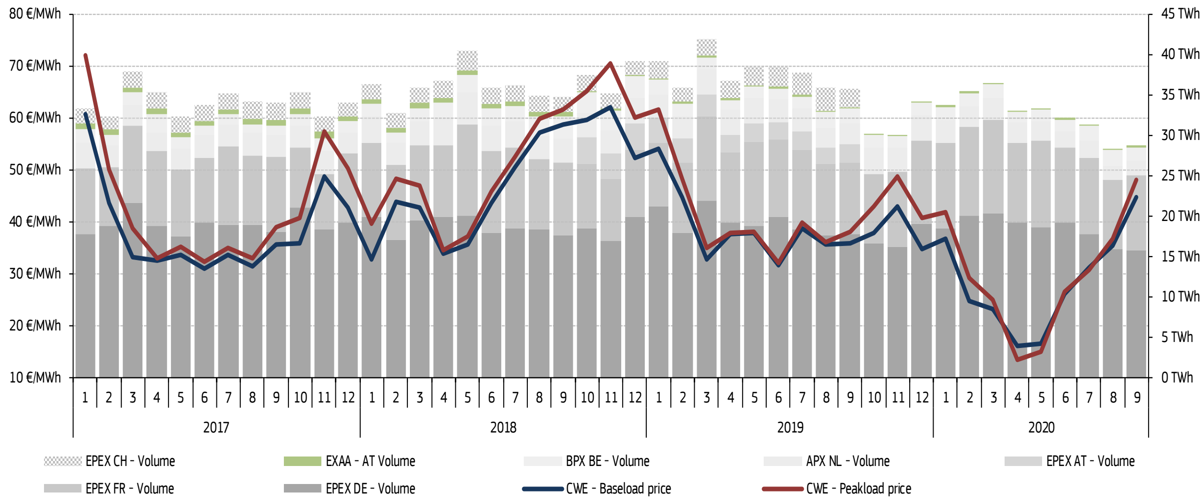
4.1 Central Western Europe (Austria, Belgium, France, Germany, Luxembourg, the Netherlands, Switzerland)

- After reaching multi-year lows in April and May, baseload electricity prices in Central Western Europe (CWE) took a steady upward direction and continued to rise in Q3 2020 amid recovering power demand and increasing gas prices. The monthly average price climbed to 45 €/MWh for baseload power in September, a level last seen in February 2019, as relatively low wind speeds and reduced availability of conventional power plants coincided with healthy demand levels. Compared to Q2 2020, the average baseload price in the region increased by 89% to 37 €/MWh in the reference quarter. Meanwhile, average peakload prices doubled to 39 €/MWh.

- Reduced generation of the French and Belgian nuclear fleets, decreased competitiveness of coal and lignite capacities, and rising solar penetration impacted production volumes and cross-border flow patterns in the region. Belgium, Germany and France experienced a combined year-on-year output loss of 22 TWh in Q3 2020, mainly due to falling nuclear and coal generation. For the first time since November 2017 France turned into a net importer of electricity in September. Germany was in deficit in July and registered only a slight surplus in August and September. The Netherlands, in contrast, experienced a 15% year-on-year rise in generation (+4 TWh) thanks to increased gas output and biomass co-firing and to booming solar generation (+41% year-on-year). Higher solar penetration was registered also in Switzerland, but this could not make up for lower hydro and nuclear generation volumes. Hydro generation rose considerably in Austria (+1.9 TWh year-on-year), pushing out a significant part of local gas generation (-0.9 TWh) from the merit order.

- Germany introduced a law in July 2020 that outlines the complete national phasing out of coal generation by 2038 at the latest, and potentially in 2035 if resource adequacy allows it. While lignite plants are to be decommissioned according to a predetermined schedule, hard coal capacity reductions will be implemented at first using auctions organised by the Federal Network Agency (BNetzA). The first auction ended in September with roughly 5 GW of hard coal capacity awarded compensation for closing by the end of 2020. The average compensation paid per megawatt of capacity was about €66,000.

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

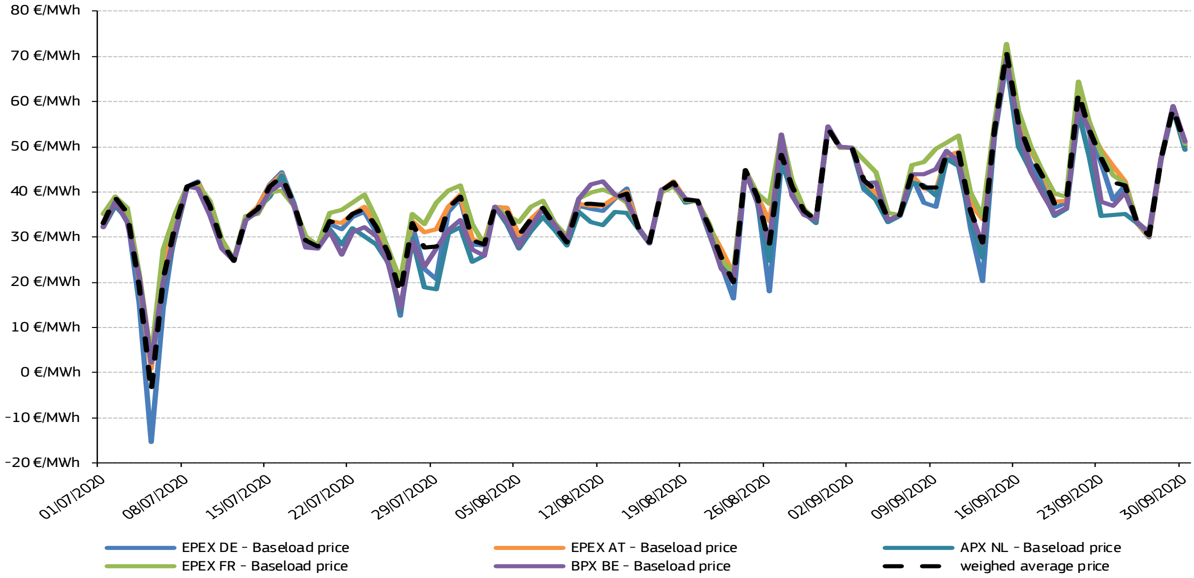


Source: Platts, EPEX. Volumes for EPEX-CH and EPEX-AT are missing.

- **Figure 30** shows the daily average day-ahead prices in the region in the reference quarter. A combination of stormy and sunny weather during the first July weekend drove hourly prices across the region below zero for several hours. Wind and solar generation in Europe peaked above 130 GW. As renewable penetration increased, French nuclear generation was ramped down to 20 GW in the morning of 5 July, a historic low for the current fleet of 61 GW. After that daily average prices held above 20 €/MWh and moved above 30 €/MWh in September when more volatility arrived amid fluctuating wind availability and recovering power demand.

- Prices hit a multi-year high on 15 September when extremely low wind generation and a lack of dispatchable capacities in Western Europe necessitated large imports from other regions. Hourly prices on the day-ahead market across many bidding zones surged to 189 €/MWh for the evening peak when solar irradiation waned, which was the highest level since February 2012 in the German market. At that point France needed to import about 5 GW from Switzerland, Italy and Spain as its nuclear generation was capped at 30 GW and all other available sources including oil were at their maximal output. Compounding this was the fact that 20 GW of dispatchable capacity was unavailable in Germany. As renewable penetration rises and the number and capacity of conventional power plants decreases, similar price spikes and episodes of high price volatility could become more frequent. This will present an opportunity for large-scale energy storage solutions and other providers of flexibility.

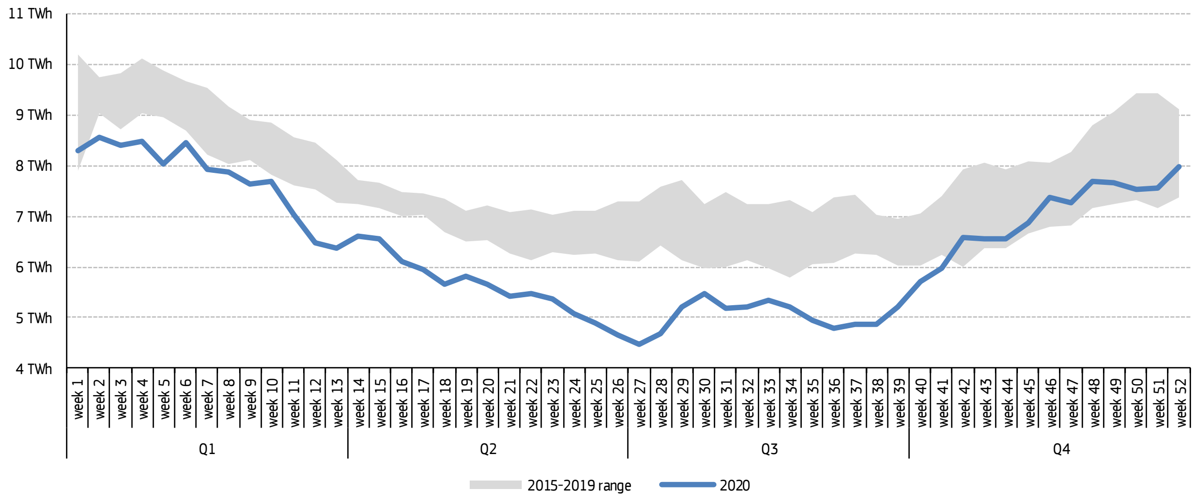
Figure 30 – Daily average power prices on the day-ahead market in the CWE region



Source: Platts.

- As shown in **Figure 31,** the French nuclear generation reached the lowest point of the year in early July but recovered quite quickly and somewhat unexpectedly in the following weeks as some reactors (Nogent 2) returned to operation earlier than previously announced. Thus, the year-on-year fall in average capacity available shrunk from 10 GW in July to 6 GW in August. However, the trend did not last in September as two units at Chooz (3 GW) had to be taken offline due to low levels on the river Meuse which is used for cooling purposes. In addition, the return of several other units was postponed (Penly 1, Flamanville 1). The total generation in Q3 2020 fell by 20% year-on-year (or 17 TWh). The availability of the fleet improved significantly in October when nuclear generation finally reached levels seen in previous years. This was also the first time since November 2019 that nuclear generation rose year-on-year. Average available capacity in November, at 43 GW, was 7% above 2019 levels. Strikes, small maintenance delays and unplanned outages dented output in December.
- The nuclear fleet Belgium suffered from extended outages. The restart of the Tihange 1 reactor was delayed from July to the end of the year due to a failure in a cooling water reservoir tank. This coincided with the planned maintenance of Tihange 3 from June until mid-October, altogether resulting in Belgian nuclear output falling by 43% (5 TWh) year-on-year in Q3 2020.

Figure 31 – The weekly amount of generated nuclear electricity in France

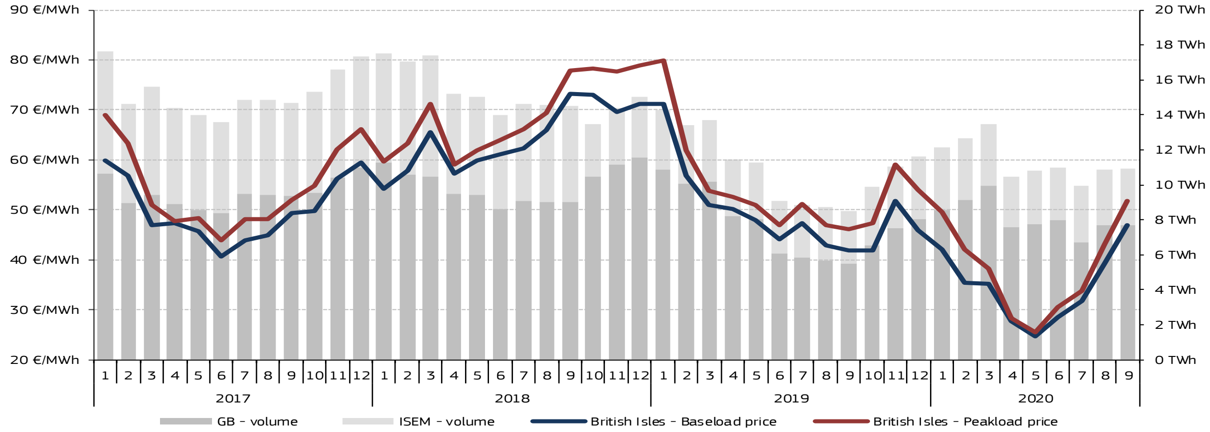


Source: ENTSO-E

4.2 British Isles (GB, Ireland)

- **Figure 32** illustrates the 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 copied developments on the continent, rising throughout the reference quarter and reaching the highest level since November 2019 at the end of the period. The recovery in wholesale power prices was driven by surging gas prices. Compared to Q2 2020, the average baseload price on the British Isles rose by 46% to 39 €/MWh in the reference quarter, but was still 11% below the level from Q3 2019.
- Trading activity on the British day-ahead market increased by 30% in Q3 2020 compared to the same quarter last year and was unchanged in Ireland.

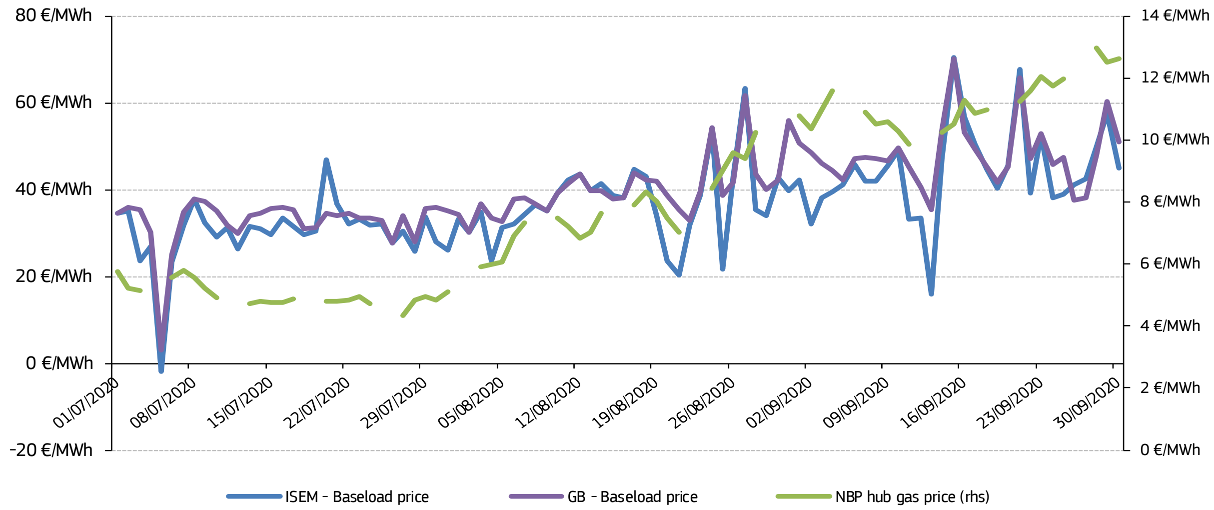
Figure 32 – Monthly exchange traded volumes of day-ahead contracts and monthly average prices in Great Britain and Ireland



Source: Nord Pool N2EX, SEMO, Utility Regulator

- **Figure 33** follows the developments of daily average baseload electricity prices in Great Britain (N2EX) and Ireland (ISEM). British baseload prices held close to 30 €/MWh during July as power demand recovered only slowly, wind speeds climbed up and gas prices hovered at multi-year lows. Britain even became a net exporter to France where low nuclear availability put a cap on generation. Rising gas prices and lower nuclear availability lifted day-ahead prices in August and September. Prices spiked on 15 September as the grid operator issued (and later cancelled) a capacity notice amid extremely low wind availability and outages at conventional power plants. Intraday prices for the evening peak period surged to more than 700 €/MWh, incentivizing all available coal-fired power plants to return to the market. Prices in the all-island Irish market generally followed the British contract albeit with larger volatility in the downward direction. As wind generation constitutes a more important part of the power mix on the Irish island, higher wind speeds tend to depress prices more than in Britain. Irish day-ahead prices went negative for a record number of hours in Q3 2020 (see **Figure 19**).

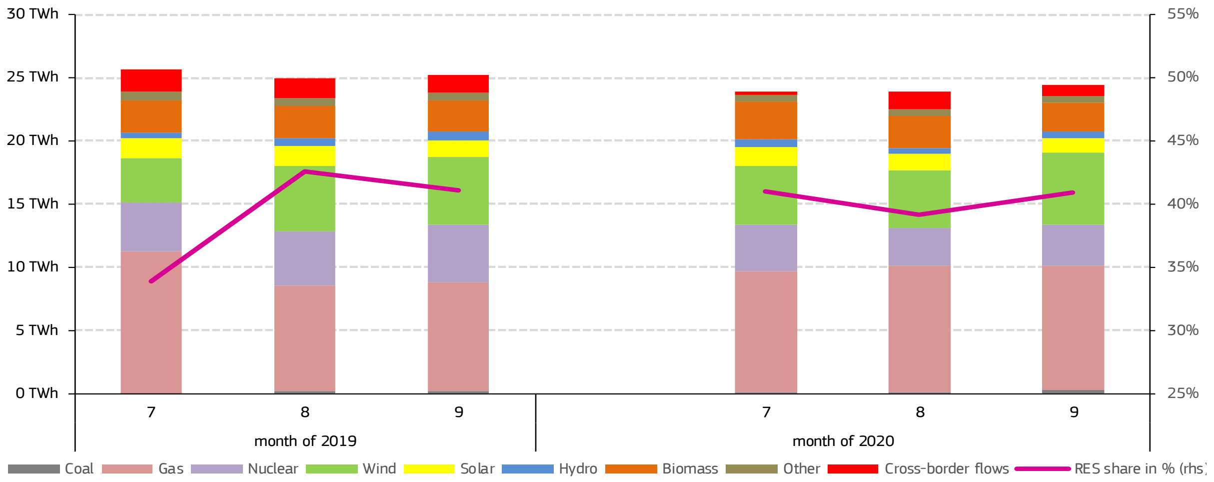
Figure 33 – Daily average electricity prices on the day-ahead market in Great Britain and Ireland



Source: Nord Pool N2EX, SEMO

- **Figure 34** compares the monthly electricity generation mix in the UK between the reference quarter and the quarter a year before. As British power demand remained depressed by the effects of the pandemic and generation held relatively steady, imports from the continent decreased measurably. Electricity generation fell by 2% year-on-year in Q3 2020. The main culprit was low nuclear availability which curbed nuclear generation by 22% year-on-year (or 2.8 TWh). Gas generation partially compensated for this, rising by 5% year-on-year (or 1.3 TWh). In the renewable domain, gains in offshore wind (+0.8 TWh) and biomass generation (+0.2 TWh) we partly reversed by lower solar PV output (-0.5 TWh). The share of renewable energy sources in the power mix increased to 40% in the reference quarter (from 39% in Q3 2019). The share of nuclear dropped from 18% to 14% year-on-year.

Figure 34 – Monthly evolution of the UK electricity generation mix in Q3 of 2019 and 2020

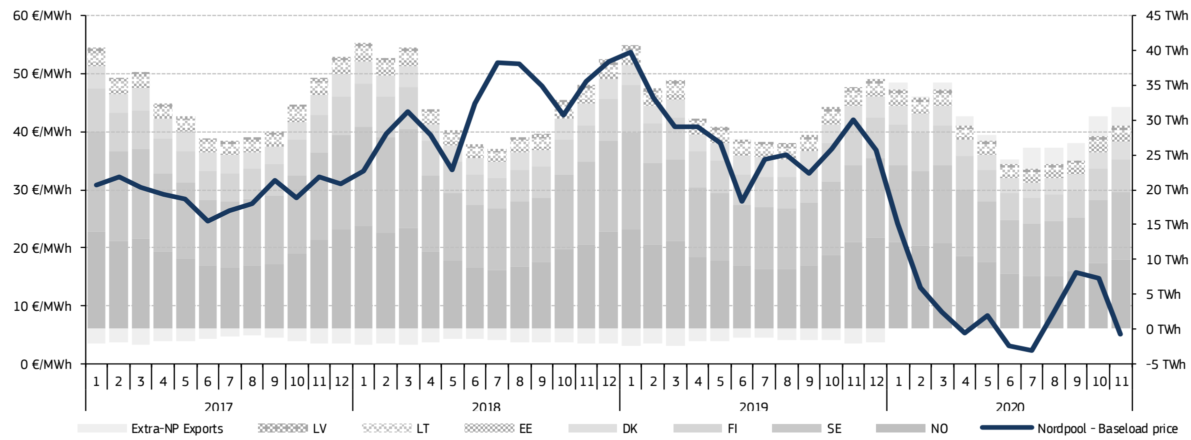


Source: ENTSO-E, Eurostat. Positive values of cross-border flows indicate net imports. Data represent net generation.

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

- As shown in **Figure 35,** system prices in the Nord Pool market bottomed out at 2 €/MWh in July and recovered slightly in August and September on the back of cooler temperatures and higher demand, only to fall again during windy November. The Nordic power market has seen the lowest power prices in 20 years in 2020 due to record high hydro reservoirs and rapidly rising wind generation. Compared to Q3 2019, the average system baseload price tumbled by 74% to 9 €/MWh in the reference quarter. Trading activity was slightly higher compared to the previous Q3.

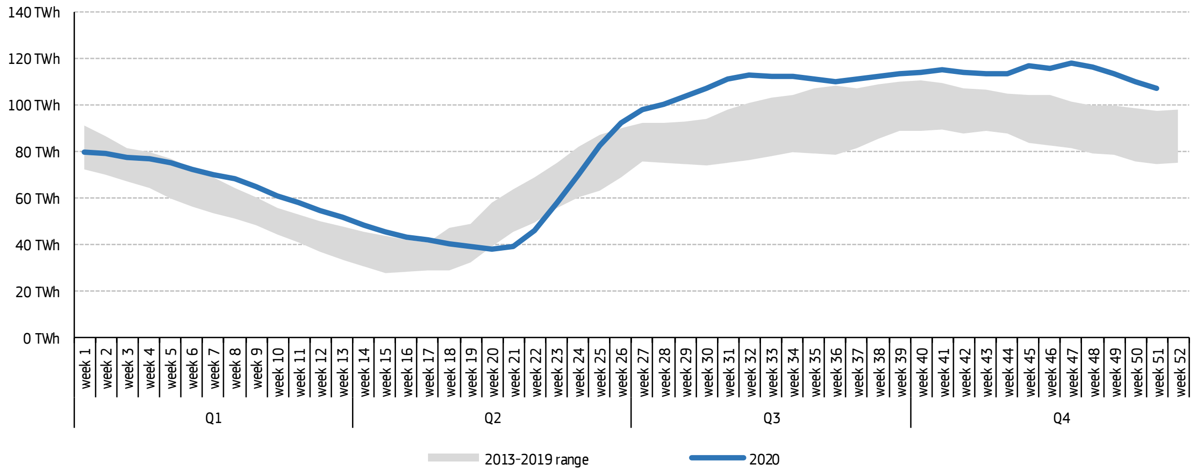
Figure 35 – Monthly electricity exchange traded volumes and the average day-ahead wholesale prices in Northern Europe



Source: Nord Pool spot market

- **Figure 36** shows the weekly evolution of the combined hydro reservoir levels in the Nordic region (Norway, Sweden and Finland) in 2020 compared to previous seven years. Nordic reservoirs were overflowing for much of the Q3 and Q4 2020, holding above 100 TWh since the middle of July on the back of record-breaking snowmelt, high precipitation and rising wind generation which locked hydro power plants out of the market. Hydro stocks held close to the maximum capacity assessed at 121 TWh for a few weeks. A slight draw-down in September, spurred by cooler temperatures and volatile wind availability, was followed by increases in October and November. This necessitated some running off of the reservoirs without any regard to the price and pressed prices lower. The total hydro generation in the region increased by 13% (or 6 TWh) year-on-year to 50 TWh in Q3 2020, contributing to relatively high net exports of the region in the period (see **Figure 21**). Unusually high hydro stocks have depressed even long-term electricity prices in the Nord Pool area (see **Figure 12**).

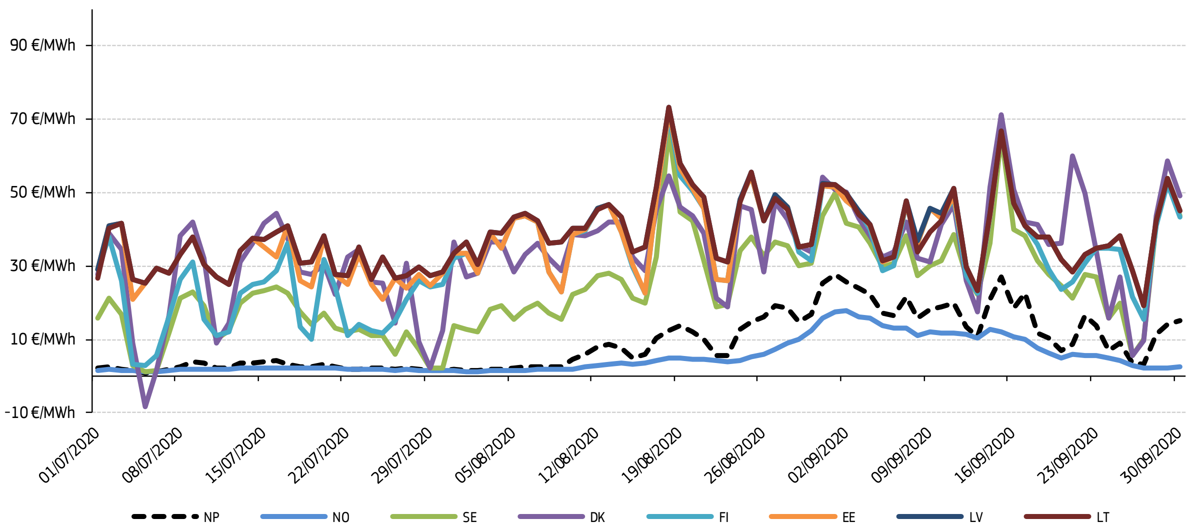
Figure 36 – Nordic hydro reservoir levels in 2020, compared to the range of 2013-2019



Source: Nord Pool spot market

- **Figure 37** shows that average daily prices across Northern Europe continued to display a high degree of divergence in Q3 2020, as in previous quarters. The Baltic region and Finland, which both suffer from considerable structural deficits (see **Figure 22**), registered permanent premiums over the system contract. Temporarily reduced transfer capacities and nuclear outages lifted prices in Sweden in the second part of Q3 2020. High wind generation and low demand brought daily Danish prices below or close to the system level on a few occasions. Norway reported daily baseload prices at or below the system price during the reference quarter. Cooler temperatures and lulls in wind availability increased system prices in the second half of Q3 2020.

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

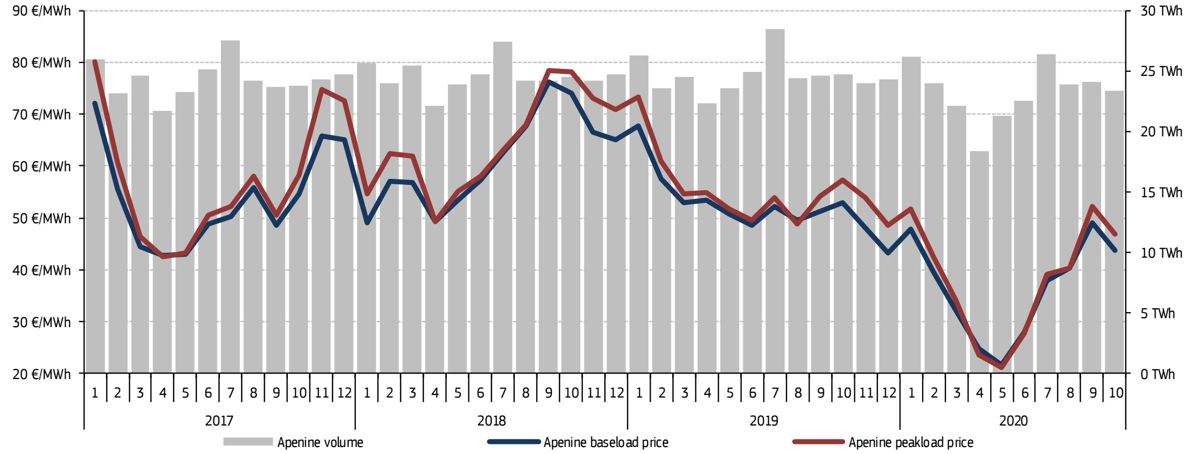


Source: Nord Pool spot market

4.4 Apennine Peninsula (Italy, Malta)

- Italian monthly average baseload electricity prices (**Figure 38**) reached pre-pandemic levels in July as power demand recovered and wind speeds stayed low. August saw a slight firming of the average price as many factories remained in operation to make up for earlier shutdowns during the spring lockdown, gas-fired electricity generation rose to last year's levels which lifted gas prices. In September, baseload electricity prices averaged 49 €/MWh, the highest level since October 2019, as demand recovered to the full extent and gas prices rose further. The average baseload price in Q3 2020 rose by 71% compared to Q2 2020 to 43 €/MWh, but was still 17% below Q3 2019 levels. Trading volumes decreased by 4% compared to the previous Q3.

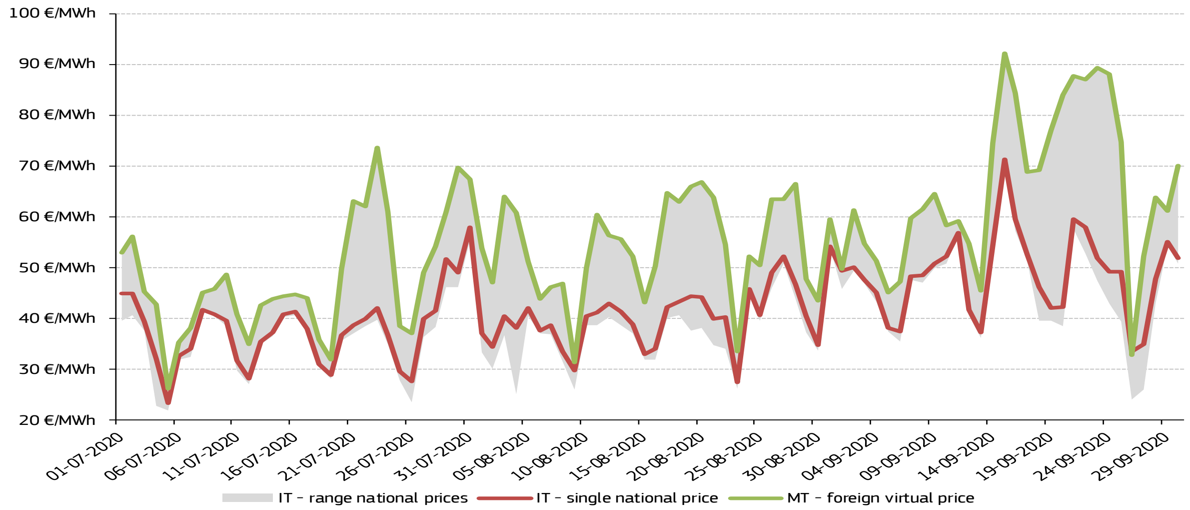
Figure 38 – Monthly electricity exchange traded volumes and average day-ahead wholesale prices in Italy



Source: GME (IPEX)

- **Figure 39** shows the daily evolution of the national average price and the range of the regional price areas in the Italian market. The national average stayed mostly between 30 and 60 €/MWh during the reference quarter and moved above 40 €/MWh in September on the back of higher gas prices. The peak came on 15 September amid a continent-wide supply tightness (see **Figure 30**).
- 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 39**, prices in the Maltese zone mostly formed the upper boundary of the band of regional prices in the reference period.
- In their power market implementation plan submitted at the end of June, the Italian authorities outlined plans to boost cross-border capacities to meet the 15% interconnectivity target set for 2030. New links to France and Austria with a combined capacity of 1.3 GW are expected to come online in the next months, and a further 4.1 GW by 2030, including new interconnectors with Austria, Montenegro, Tunisia, Slovenia and Switzerland.

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

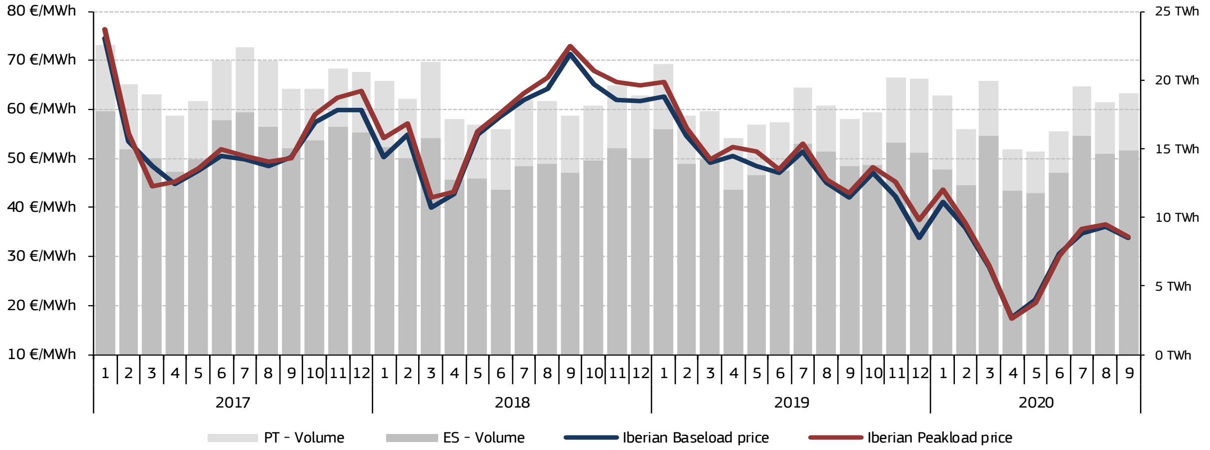


Source: GME (IPEX)

4.5 Iberian Peninsula (Spain and Portugal)

- **Figure 40** reports on monthly average baseload and peakload contracts in Spain and Portugal. Contrary to developments in other regions, spot electricity prices in the Iberian Peninsula peaked already in August, driven higher by rising gas prices and recovering demand. A decline came in September on the back of strong hydro and solar generation and rising cases of covid infections which muted demand again. Record-braking solar generation, spurred by new capacities added in 2019, kept peakload prices close to baseload contracts even in September. Compared to Q3 2019, the average baseload price declined by 24% to 35 €/MWh in the reference quarter. Trading activity was 4% higher compared to the previous Q3.

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

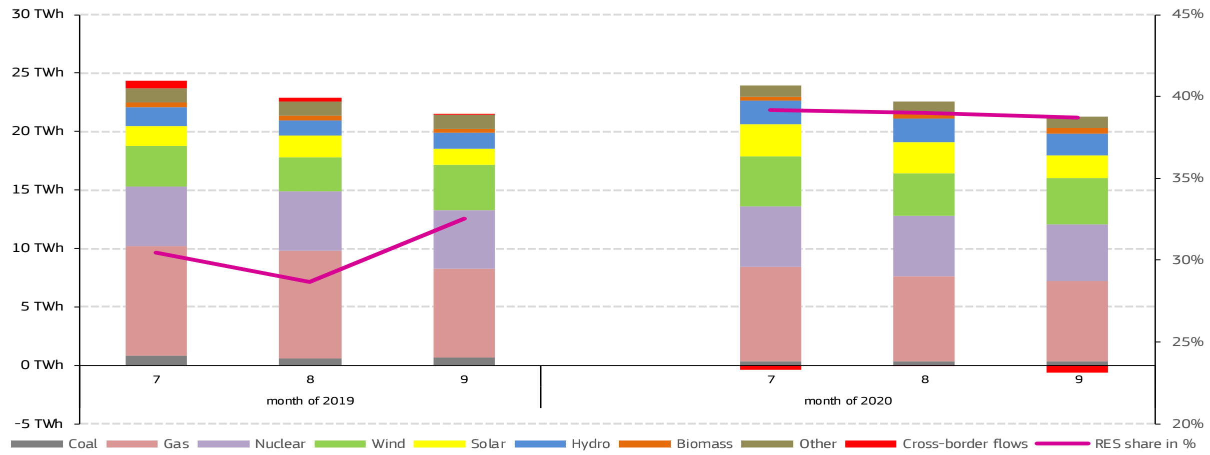


Source: Platts, OMEL, DGEG

- **Figure 41** displays the evolution of the monthly electricity generation mix in Spain during the third quarter of 2020, as well as during the same period of the previous year. Whereas generation remained unchanged year-on-year, consumption was still 4% below last year's levels. Thus, Spain became a net exporter in all three months of the reference quarter, which is unusual for summer. Improved hydro availability and record high solar and wind generation caused the share of renewable electricity sources to reach 40% in Q3 2020, up from 31% a year before. Squeezed out by weak demand and surging renewables, gas generation fell by 15% year-on-year in Q3 2020. Thus, the share of gas in the mix shrank from 39% in Q3 2019 to 31% in Q3 2020. Coal has virtually disappeared from the mix. The share of nuclear energy, at 22%, was unchanged year-on-year.

- Spanish renewable capacity expansion slowed in 2020 compared to 2019. In the first three quarters of 2020 over 1 GW of solar PV and 650 MW of wind were commissioned, compared to 5 GW of PV and 2.4 GW of wind additions in 2019. Given Spain's endowment of good wind and solar resources, and the government's forthcoming renewable capacity auctions, an acceleration of renewable capacity additions is expected in the coming years. Meanwhile in August, a new global fixed price low of 11.1 €/MWh was reached during a solar PV auction in Portugal. This was lower than 11.6 €/MWh achieved in Abu Dhabi just a month before.

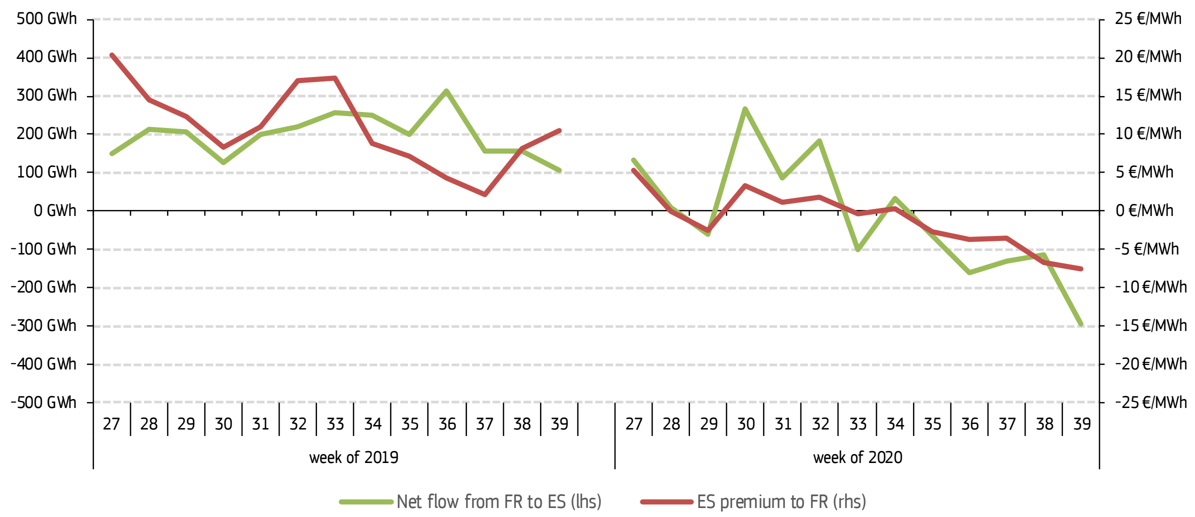
Figure 41 – Monthly evolution of the electricity generation mix in Spain in Q3 of 2019 and 2020



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

- **Figure 42** shows weekly electricity flows between France and Spain and price differentials between the two bidding zones. In the first half of the reference quarter, the usual Spanish premium over the French day-ahead price often reversed, depending on French nuclear availability and Spanish renewable generation. From the second half of August, however, strong Spanish renewable generation and weak demand drove local prices consistently below the French level, which is unusual for this time of the year. Cross-border flows generally followed price differentials, adding up to 0.2 TWh of net exports to France (compared to 2.5 TWh of net imports from France in Q3 2019). Spain and France are connected through five high-voltage power lines of combined 2.8 GW capacity.
- Bilateral trade with Morocco in Q3 2020 developed in Spain's favour and resulted in net exports of 120 GWh from Spain.

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

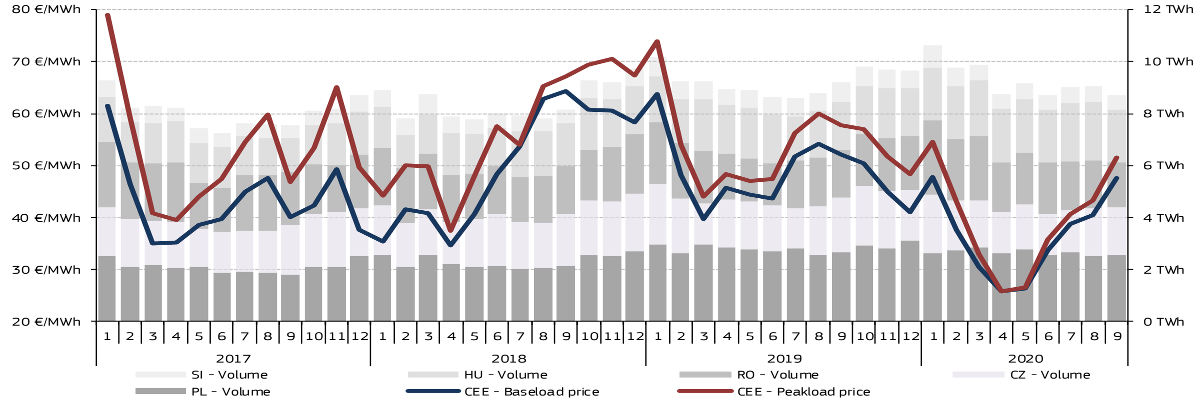


Source: ENTSO-E, OMEL, Platts

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

- **Figure 43** shows that despite an uneven recovery in power demand which was prone to setbacks, average monthly prices for baseload power in Central Eastern Europe rose to pre-pandemic levels in July, inching toward 40 €/MWh. Prices then moved decidedly above 40 €/MWh in September, in line with developments in the CWE region. The gap between baseload and peakload monthly averages grew wider throughout the reference quarter as solar PV output was gradually restricted by shortening days and peakload demand recovered. When compared to Q3 2019, the average baseload price in the reference quarter was still 20% lower, at 42 €/MWh. Traded volumes in the reference quarter slightly increased (+3%) compared to Q3 2019.
- High carbon prices continued to put a strain on local lignite and coal power plants. However, good nuclear availability in Czechia, high water levels on the Danube, rapidly rising solar generation in Poland and Hungary and lower consumption compensated for falling lignite and coal output, resulting in an improved net position of the region (-3 TWh in Q3 2020 compared to -5 TWh in Q3 2019). Poland, however, has increased its net imports to nearly 4 TWh in Q3 2020 (up from 3 TWh in Q3 2019). Germany, Austria, Nord Pool markets and Ukraine were the largest sources of inflows into the region.

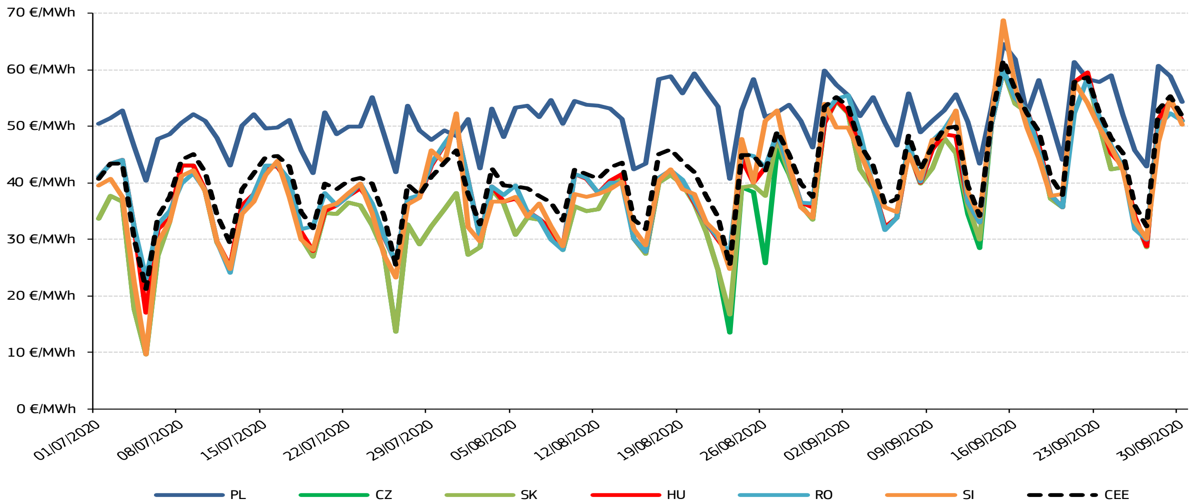
Figure 43 – Monthly electricity exchange traded volumes and average day-ahead prices in Central Eastern Europe (CEE)



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

- **Figure 44** shows that daily average baseload prices in the four coupled markets (CZ, SK, HU, RO) were relatively stable during the first half of Q3 2020, with occasional dips caused by windy days in Germany. Prices moved higher and became more volatile since the end of August on the back of repeated shifts in supply-demand balance. The premium of Polish baseload contracts over the regional average, which moved between 10-12 €/MWh during the summer holiday period, shrunk to 6 €/MWh in September on the back of rising wind availability in Poland. The supply tightness of 15 September (see **Figure 30**) had a lower impact on prices in the CEE region due to its lower dependence on wind sources. In fact, high prices during the most expensive hour (between 7-8 pm) enticed increased coal generation and saw Poland exporting power to Germany.

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

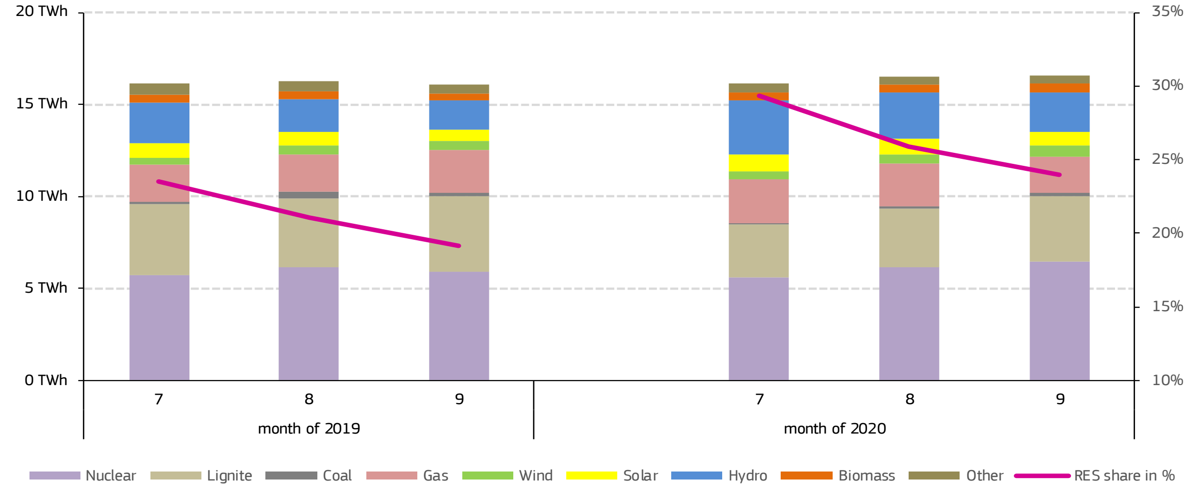


Source: Regional power exchanges

- **Figure 45** compares the combined electricity generation mix of the CEE region (excluding Poland) between the reference quarter and the quarter a year before. Thanks to high river levels, which boosted local hydro generation, and rising solar generation in Hungary the share of renewables in the mix rose to 26% in Q3 2020 (up from 21% a year before). Nuclear generation maintained a 37% share in the mix in Q3 2020, confirming its position as the single largest source of electricity for the four CEE Member States. The reduced competitiveness of lignite generation due to elevated CO2 prices caused the combined share of lignite and coal in the reference quarter to fall from 25% to 21% year-on-year, while gas managed to increase its share from 13% to 14% year-on-year.
- In Poland, which is analysed separately due to significant differences in the size and structure of its generation base, the combined share of coal and lignite in its mix decreased to 72% in the reference quarter (compared to 75% in Q3 2019), while renewables increased their share from 14% to 16% year-on-year thanks to much higher solar generation. Gas increased its share in the mix from 10% to 11% year-on-year. Poland's solar PV capacities have been growing rapidly thanks to the introduction of an auction support system and grants for rooftop installations. Around 3.5 GW were registered by the local TSO by the end of 2020 (up from 1.3 GW at the end of 2019). A new 450 MW combined cycle gas turbine power plant was commissioned in September at Stalowa Wola, replacing coal-fired units at the site in south eastern Poland. According to the latest version of the Polish Energy Policy to

2040 (PEP2040) the share of coal in the electricity mix should decline to 37.5-56% in 2030 and to 11-28% in 2040. Retired coal capacities should be replaced mainly by new offshore wind farms and nuclear reactors.

Figure 45 – Monthly evolution of the electricity generation mix in the CEE region (excluding Poland) in Q3 of 2019 and 2020

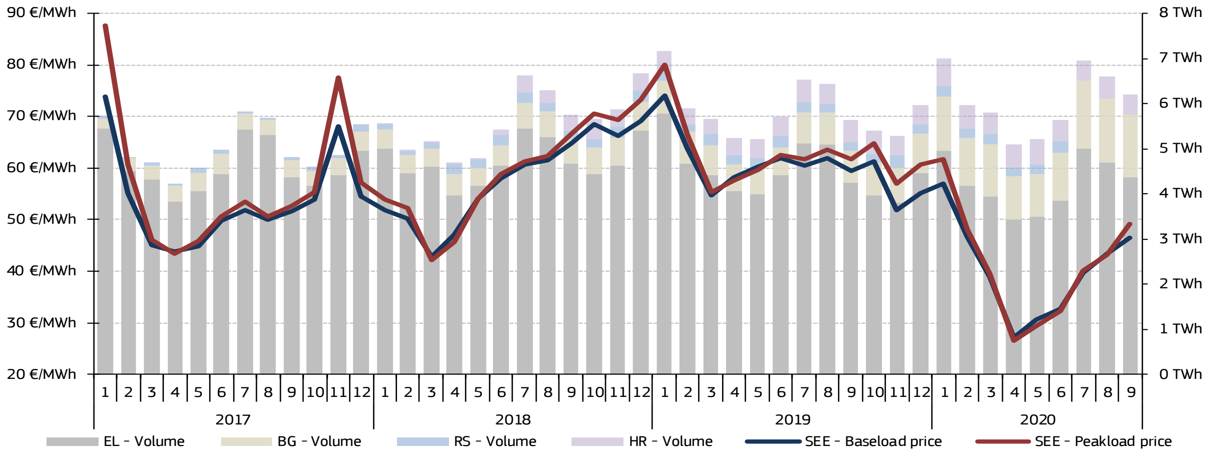


Source: ENTSO-E.

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

- **Figure 46** shows that trade-weighted monthly average baseload prices in the SEE region recovered more slowly than in other regions, reaching pre-pandemic levels only in September due to weak demand and high wind and hydro generation. Peakload contracts rose measurably above their baseload peers also only at the end of Q3 2020, highlighting weakness in peak demand in the summer period. The average quarterly price rose by 43% compared to Q2 2020 to 43€/MWh in Q3 2020, which was still 30% below Q3 2019.

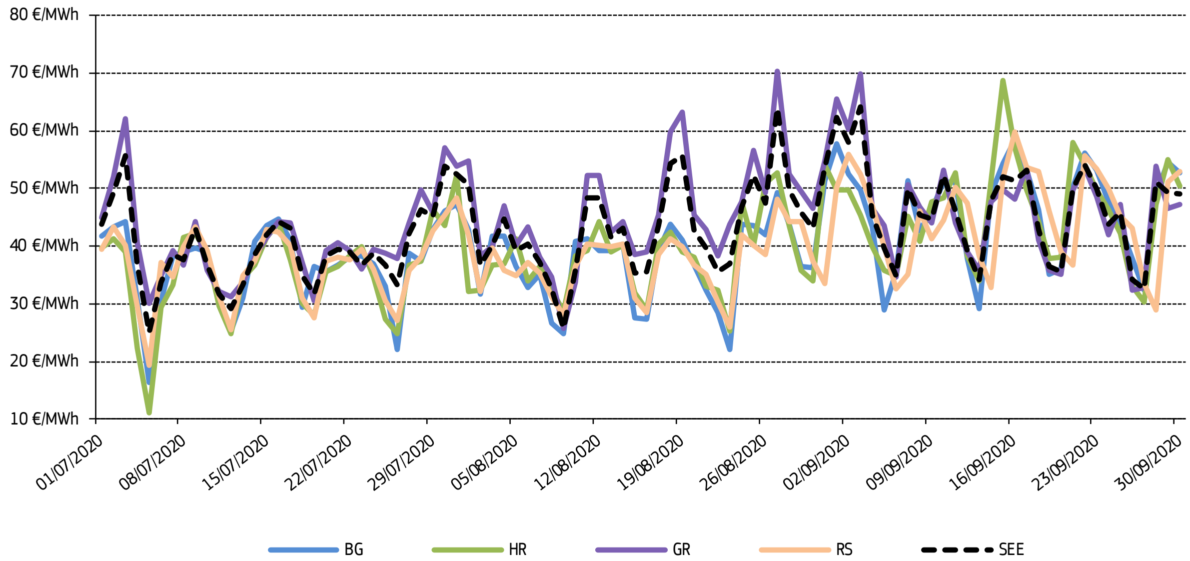
Figure 46 – Monthly traded volumes and baseload prices in South-Eastern Europe (SEE)



Source: IBEX, LAGIE, CROPEX, SEEPEX

- With a few exceptions in August, daily baseload price movements in individual markets were exceptionally well synchronized during Q3 2020, as shown in **Figure 47**. The usual Greek premium over the rest of the region decreased significantly in the reference quarter due to strong lignite-to-gas switching and weak demand in Greece. In September, the premium disappeared almost entirely due to windy weather as monthly wind generation rose to more than 1 TWh for the first time. As a result, baseload prices in all markets under observation reached between 46 and 47 €/MWh on average in September.

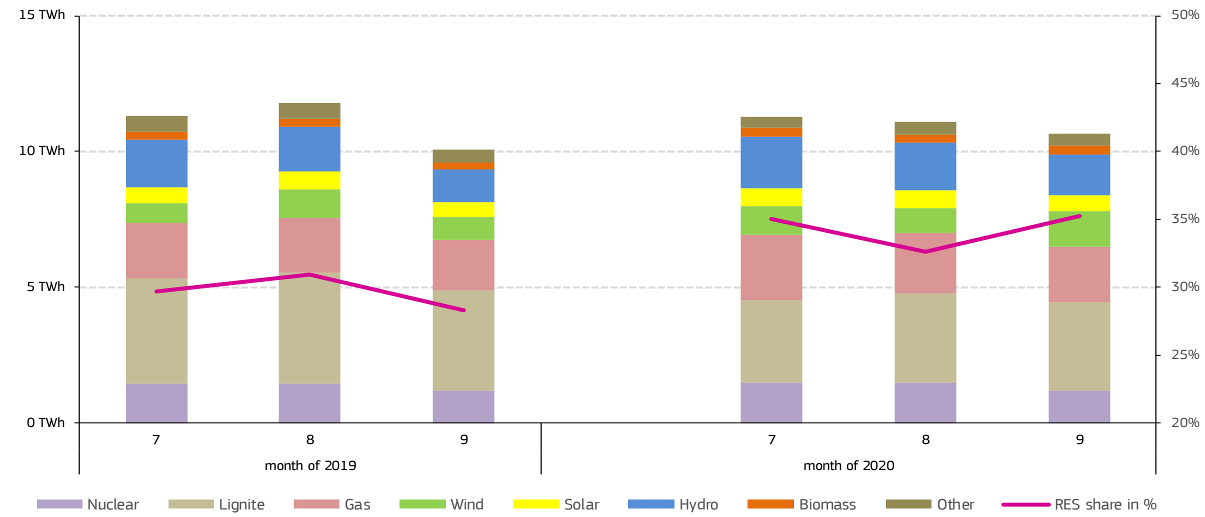
Figure 47 – Daily average power prices on the day-ahead market in Bulgaria, Croatia, Greece and Serbia



Source: IBEX, LAGIE, SEEPEX, CROPEX

- **Figure 48** compares the combined electricity generation mix of the SEE region between the reference quarter and the quarter a year before. Lignite generation suffered losses mainly in Greece, where it was replaced by gas and wind, and in Bulgaria. As a result, the share of lignite fell from 35% to 29% year-on-year in Q3 2020. Increased gas generation in Greece drove up the share of gas from 18% to 20% year-on-year in Q3 2020. Renewable penetration rose from 30% to 34% thanks to record wind output in Greece and high hydro generation in Serbia.

Figure 48 – Monthly evolution of the electricity generation mix in the SEE region in Q3 of 2019 and 2020



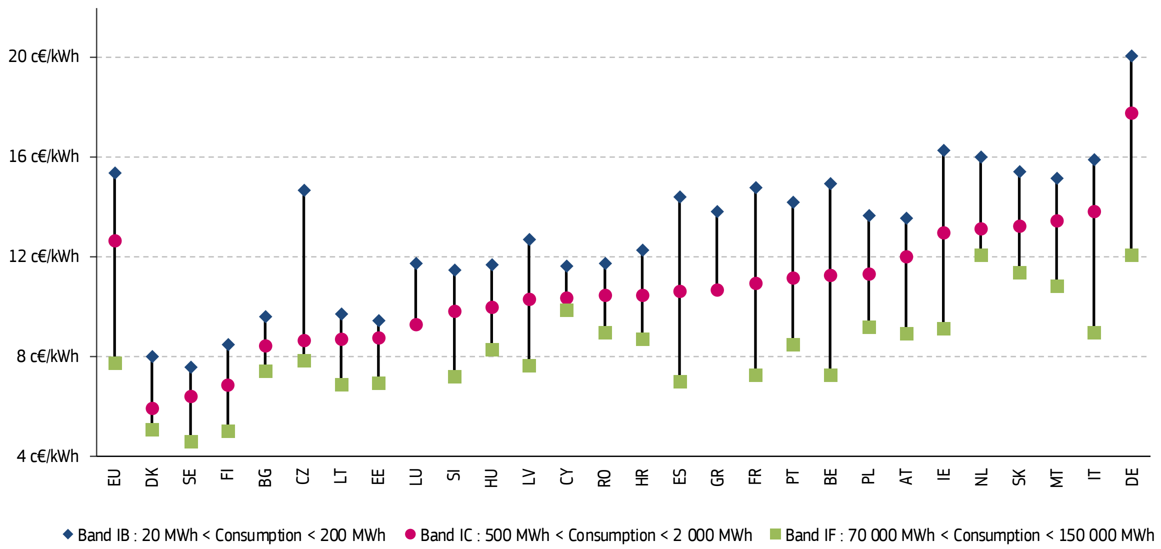
Source: ENTSO-E.

5 Retail markets

5.1 Retail electricity markets in the EU

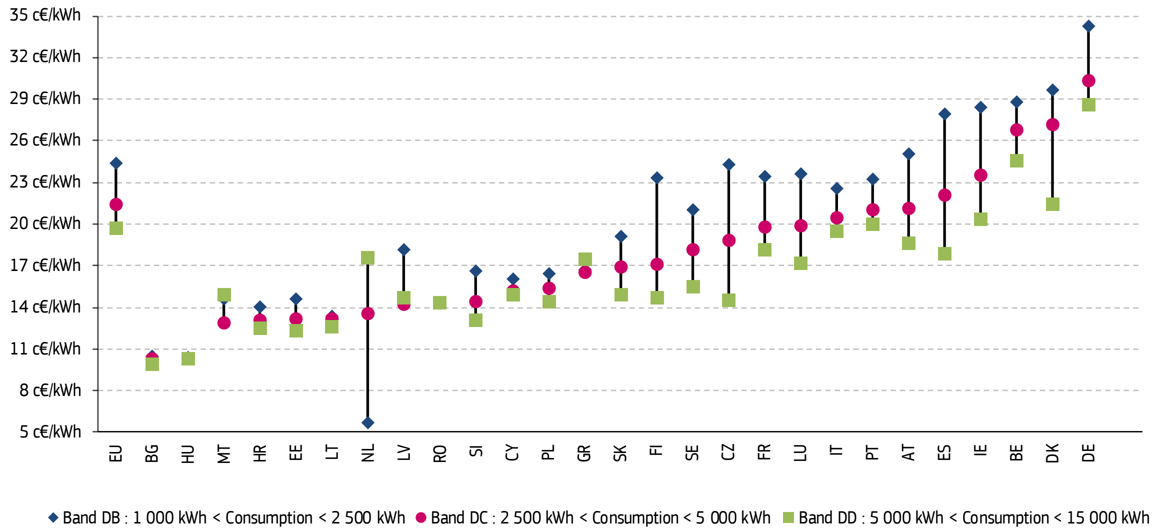
- **Figures 49 and 50** display the estimated retail prices in September 2020 in the 27 EU Member States for industrial customers and households. Prices are displayed for three different levels of annual electricity consumption for both consumer types (Eurostat bands IB, IC and IF for industrial customers and bands DB, DC and DD for households). In most cases it holds for both consumer types that the lower the consumption, the higher the price of one unit of electricity (per MWh consumed). Dutch household prices are a notable exception.
- Smaller industrial consumers (band IB) were assessed to pay the highest prices in Germany (20.1 c€/kWh) and Ireland (16.2 c€/kWh), followed by the Netherlands and Italy (16.0 and 15.9 c€/kWh respectively). The lowest prices in the same category were assessed to be in Sweden (7.6 c€/kWh) and Denmark (8.0 c€/kWh). The ratio of the largest to smallest reported price was nearly 3:1. On the other side of the consumer spectrum, industrial companies with large annual consumption (band IF), including most energy-intensive users, paid the highest prices in Germany and the Netherlands (12.0 c€/kWh both), followed by Slovakia (11.4 c€/kWh) and Malta (10.8 c€/kWh). Sweden (4.6 c€/kWh) was assumed to have by far the lowest prices, with Denmark and Finland (both 5.0 c€/kWh) coming close behind. The ratio of the highest to lowest price for large industrial consumers was again below 3:1 for this consumer type. Compared to September 2019, the average assessed EU retail electricity price for the IF band rose by 4% to 7.7 c€/kWh.
- In September 2020, Germany (28.6 c€/kWh) was assessed to have the highest electricity price for large household consumers (band DD), followed by Belgium (24.6 c€/kWh), and with Denmark (21.4 c€/kWh) in the third place. The lowest prices for big households were calculated for Bulgaria (9.9 c€/kWh) and Hungary (10.2 c€/kWh). In the case of small households, Germany was again evaluated as having the highest price (34.2 c€/kWh), followed by Denmark and Ireland, while Bulgaria and Hungary found themselves again on the other side of the price spectrum. Compared to September 2019, the average assessed EU retail electricity price for the DD band remained unchanged at 19.6 c€/kWh.

Figure 49 – Industrial electricity prices, September 2020 – without VAT and recoverable taxes



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

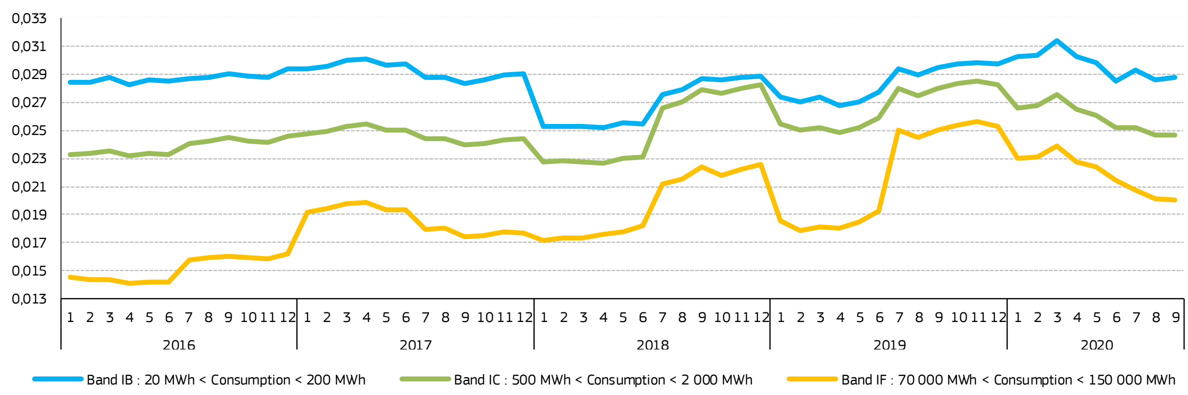
Figure 50 – Household electricity prices, September 2020 – all taxes included



Source: Eurostat, DG ENER

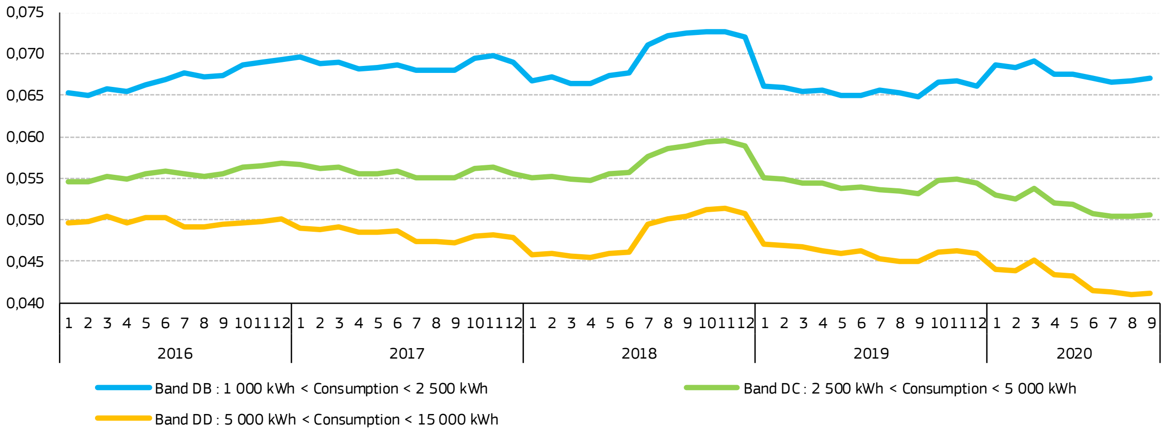
- **Figures 51 and 52** display the convergence of retail prices across the EU over time, by depicting their standard deviation. Industrial prices for large and medium-sized businesses continued to converge in Q3 2020, albeit at a slower pace than in the previous quarter. In the case of retail prices for small businesses, there was no change compared to the situation in June 2020.
- In the households sector, the trend of rising convergence stalled in Q3 3030. Prices for large and medium-sized households kept holding closer to each other than any at time before. 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 51 – Standard deviation of retail electricity prices in the EU for industrial consumers



Source: Eurostat, DG ENER

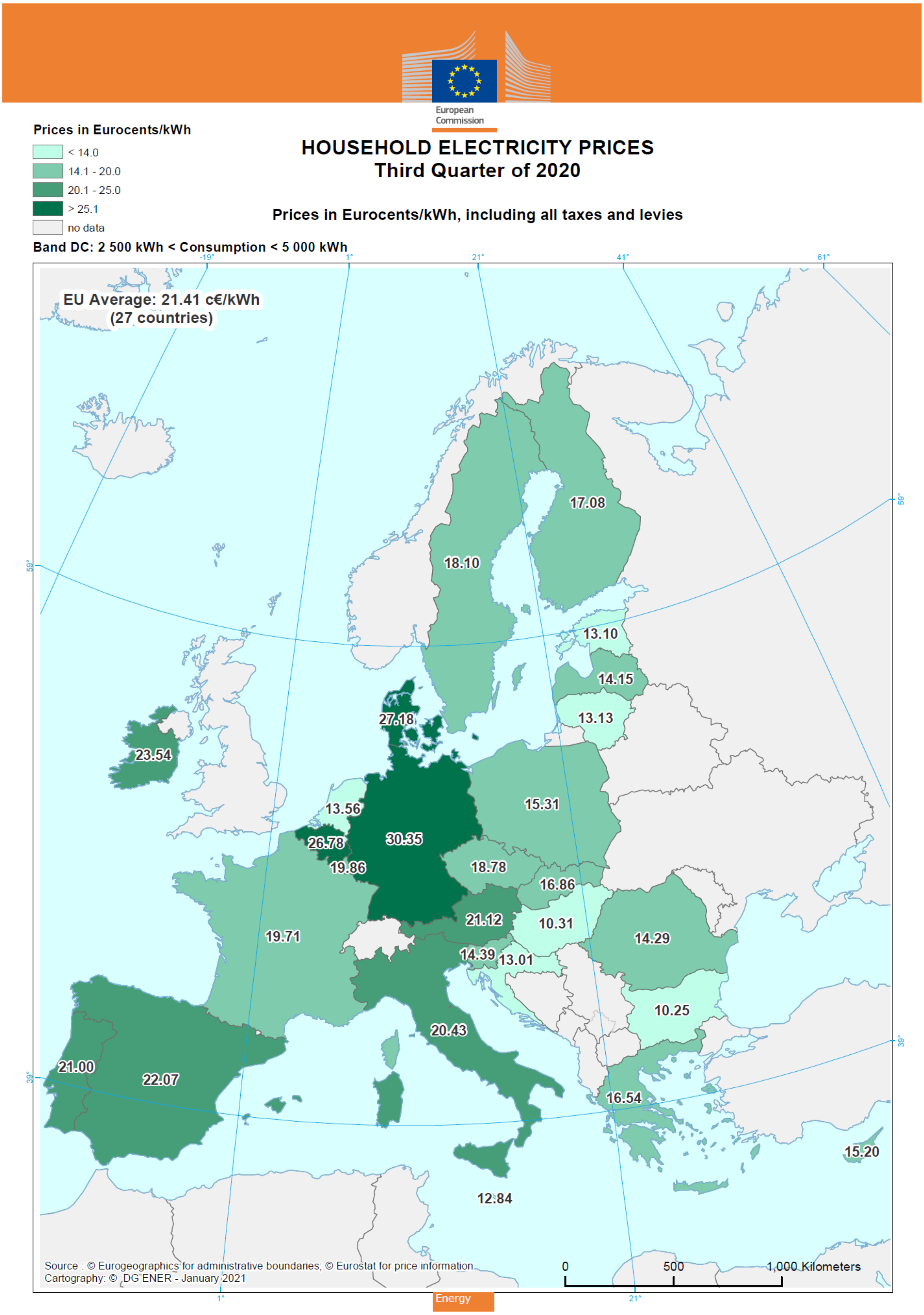
Figure 52 – Standard deviation of retail electricity prices in the EU for household consumers



Source: Eurostat, DG ENER

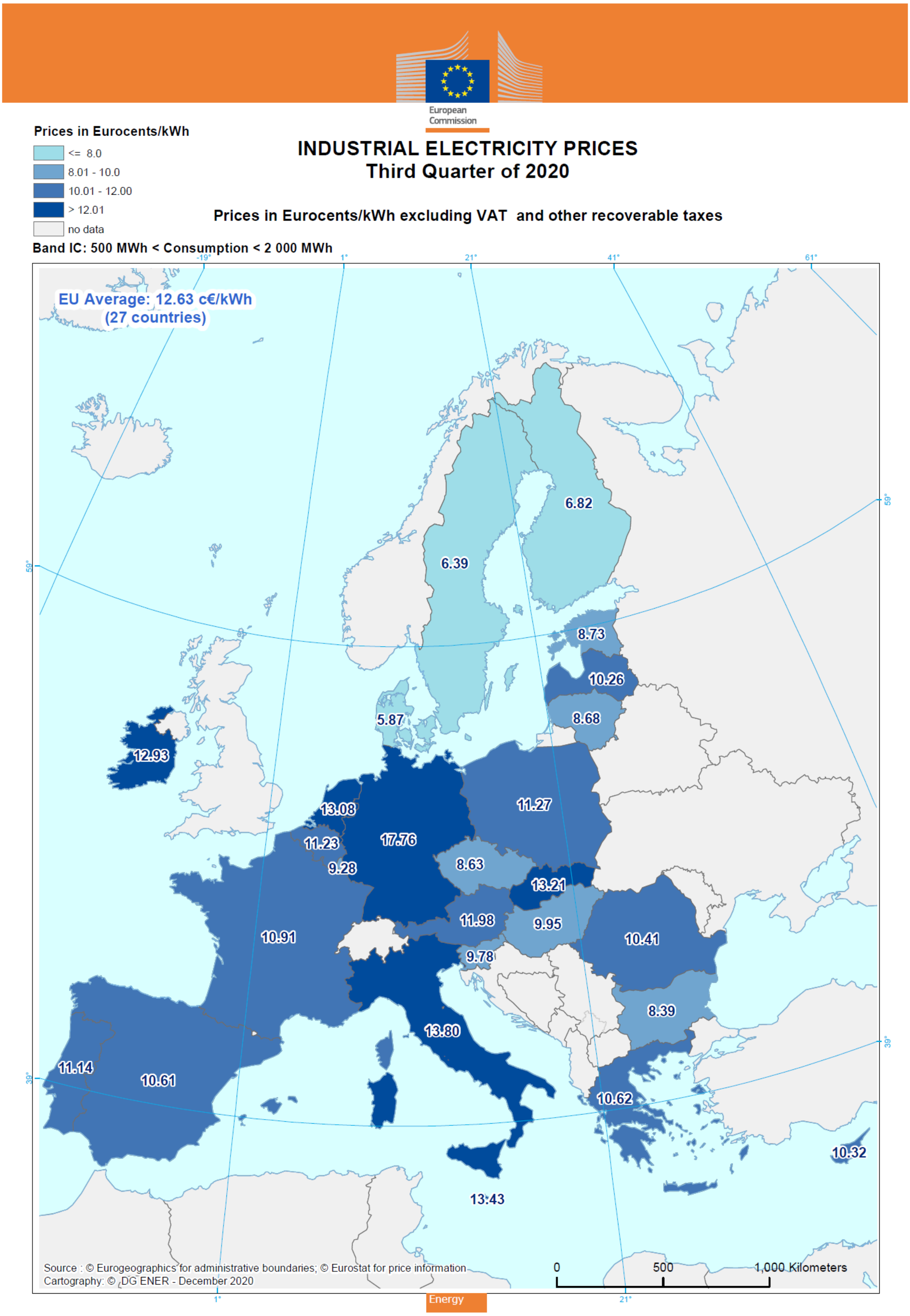
- **Figures 53 and 54** display the estimated electricity prices paid by EU households and industrial customers with a medium level of annual electricity consumption in the last month of Q3 2020. In the case of household prices, Germany topped the list (30.35 c€/kWh), followed by Denmark and Belgium. As was the case in previous quarters, Bulgaria retained its position as the country with the cheapest household electricity prices, with Hungary assessed to be in the second place. The EU average remained broadly unchanged in the reference quarter compared to September 2019. The largest year-on-year increases in the household category were assessed in Poland (+11%) and Luxembourg (+10%). The biggest year-on-year falls were estimated for the Netherlands (-34%, see **Figure 55** for more details) and Cyprus (-32%).
- In the case of mid-sized industrial consumers, Denmark was assessed to have the most competitive price in Q3 2020, followed by Sweden and with Finland taking the third place. Meanwhile, Italy and Germany stood at the other end of the spectrum. At 12.6 c€/kWh, the average retail price for industrial customers in the EU in the reference period rose by 8% compared to Q3 2019.

Figure 53 – Household Electricity Prices, third quarter of 2020



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

Figure 54 – Industrial Electricity Prices, third quarter of 2020



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

- **Figure 55** 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 September 2020, the highest prices were observed in Berlin and Copenhagen (32.5 and 29.6 c€/kWh, respectively) where energy taxes accounted for more than a third of the final bill. The lowest prices among EU capitals were recorded in Budapest and Sofia (10.6 c€/kWh and 11.7 c€/kWh, respectively). This corresponds to the Eurostat data analysed in **Figure 50**. The population-weighted EU average declined by 3% year-on-year to 19.8 c€/kWh. Non-Member States in Europe's east tend to have lower prices. Thus, electricity for an average household in Kiev was ten times cheaper than for one in Berlin in September.

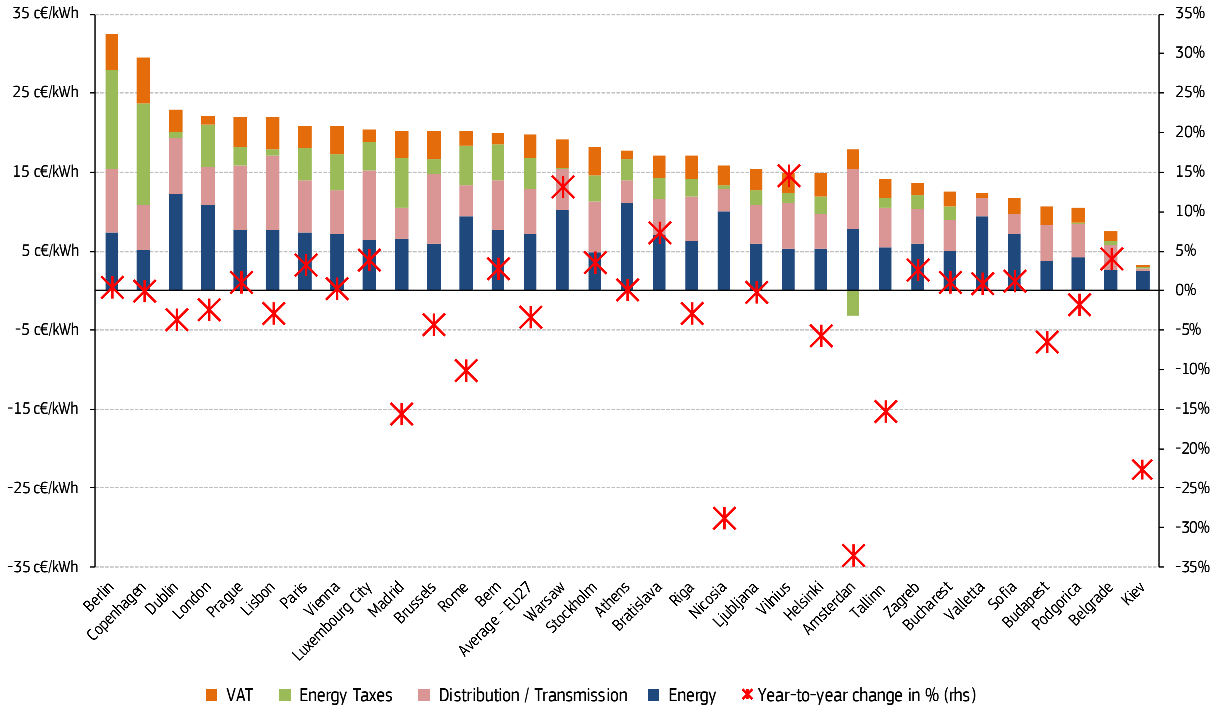
- The highest levels of the energy component in Europe were reported from Dublin, Athens and London (11-12 c€/kWh), cities surrounded by wholesale markets with higher prices compared to the EU average. The lowest levels of the energy component (3-5 c€/kWh) were recorded in the capitals of countries with stronger forms of price regulation (Budapest, Bucharest, Belgrade) or with a high degree of renewable generation (Copenhagen, Stockholm). The EU average for the energy component was 7.2 c€/kWh (down from 7.6 c€/kWh in September 2019). The general decrease in European wholesale prices witnessed over the last 18 months has started to be channelled into to retail prices. This could be explained by the fact that retailers usually buy electricity in advance before it is sold to customers, which results in a time lag between developments in wholesale and retail markets.

- The highest network charges were recorded in Lisbon (9.5 c€/kWh), Brussels and Luxembourg City (both 8.7 c€/kWh) where they accounted for more than 40% of the total price and were measurably higher than the energy component. The lowest network fees were collected in Valletta (2.4 c€/kWh) and Sofia (2.6 c€/kWh). The EU average in the reference quarter was 5.6 c€/kWh (unchanged from September 2019).

- Apart from Berlin and Copenhagen (13 c€/kWh), the highest energy taxes were paid by households in Madrid and London (5-6 c€/kWh). Valletta, 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 3.9 c€/kWh (down by 5% from September 2019 mainly thanks to the influence of negative taxation in Amsterdam). Varied VAT rates applied to electricity, ranging from 5% in Malta to 27% 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 was significantly increased as of January 2020 (by more than €200 annually) and is now higher than the annual energy tax amount that corresponds to a typical residential customer in Amsterdam. Even in cases when the tax credit is higher than the tax amount, the customers still receive the full credit as a discount from their overall annual bill. In practice, this has resulted in a negative value of the Dutch tax component in the price breakdown. This development has also significantly reduced household electricity prices countrywide, which is visible in **Figure 50**.

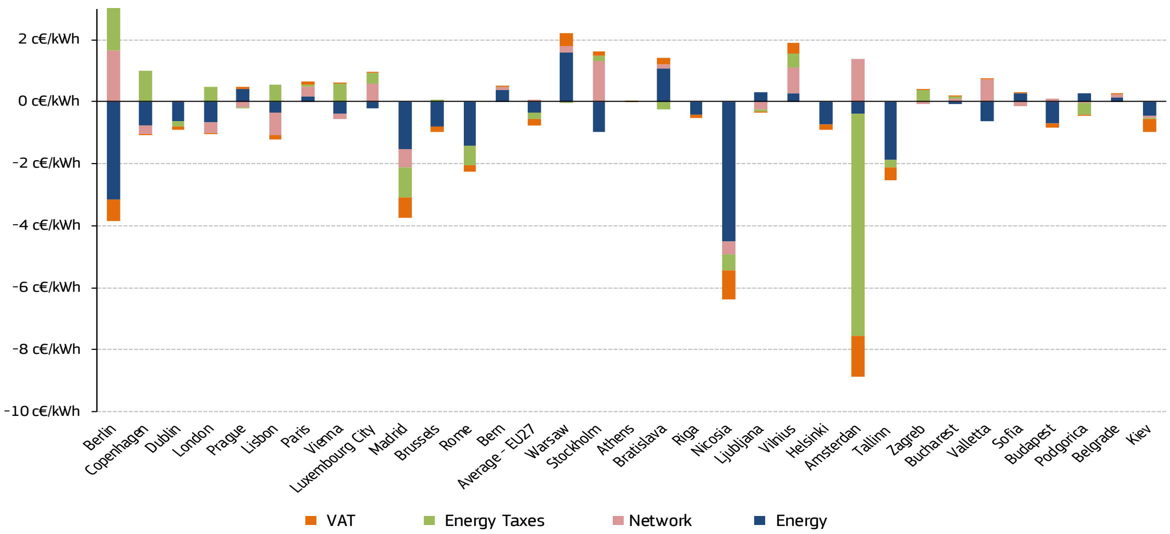
Figure 55 – The Household Energy Price Index (HEPI) in European capital cities in Eurocents per kWh, September 2020



Source: Vaasaett

- Compared to the same month of the previous year, the largest price increases in relative terms in September 2020 were observed in Vilnius (+15%) and Warsaw (+13%). As shown in **Figure 56**, the distribution component was the biggest contributor to rising prices in Vilnius. In Warsaw, rising prices were driven by the energy component. 16 of the 27 EU capitals reported prices lower or unchanged compared to the same month of the previous year, with Amsterdam (-34%), Nicosia (-29%) and Madrid (-16%) posting the largest drops. The price fall in the Dutch capital was driven mainly by a substantially raised tax credit (see previous figure), whereas households in the Cypriot capital benefited mainly from lower prices of the energy component. In Madrid, all components contributed to a decrease in the retail price for residents.

Figure 56 – Year-on-year change in electricity prices by cost components in the European capital cities comparing September 2020 with September 2019

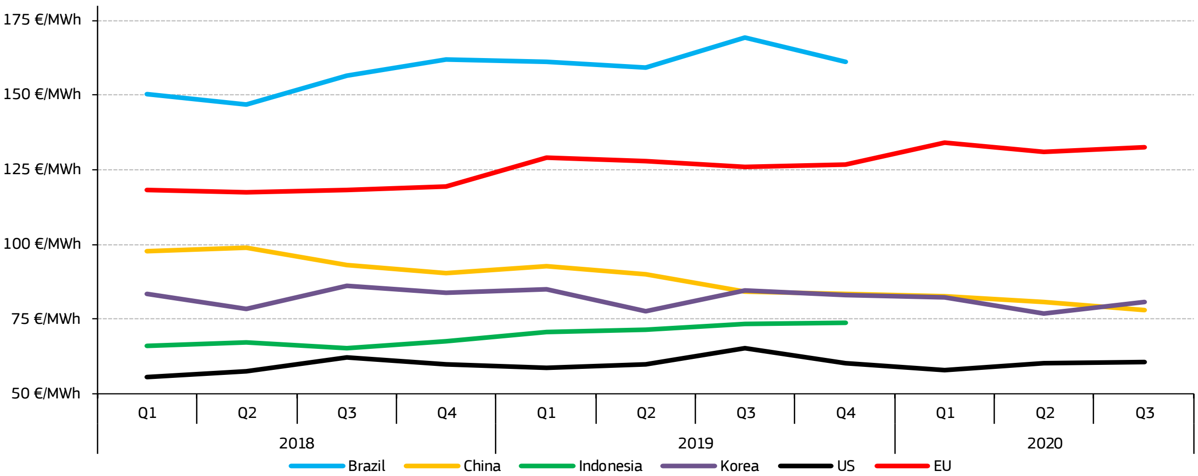


Source: Vaasaett

5.2 International comparison of retail electricity prices

- **Figure 57** 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 rose by 1% in Q3 2020 compared to the previous quarter. Meanwhile, Chinese industrial prices declined by 4%, continuing in their downward trend observed over the past two years. Prices for industry in South Korea, in contrast, went up by 5% compared to the previous quarter and for the first time clearly rose above their Chinese peers. Industrial electricity prices in the United States increased by 1% quarter-to-quarter in Q3 2020 in euro terms.

Figure 57 – Retail electricity prices paid by industrial customers in the EU and its main trading partners



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

Glossary

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

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

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

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

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

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

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

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

EP5 is a consumption-weighted baseload benchmark of 5 most advanced markets offering a 3-year visibility into the future Markets included in the benchmark are France, Germany, the Netherlands, Spain and Nord Pool. Prices are weighted according to the consumption levels in individual markets. Forward prices are rolled over towards the end of each year, meaning that the year-ahead benchmark in 2018 shows the price for 2019; and the year-ahead curve in 2019, in turn, shows baseload prices for delivery in 2020.

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

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

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

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

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

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

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

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