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on European Electricity Markets

with focus on the developments in annual
wholesale prices

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HIGHLIGHTS OF THE REPORT

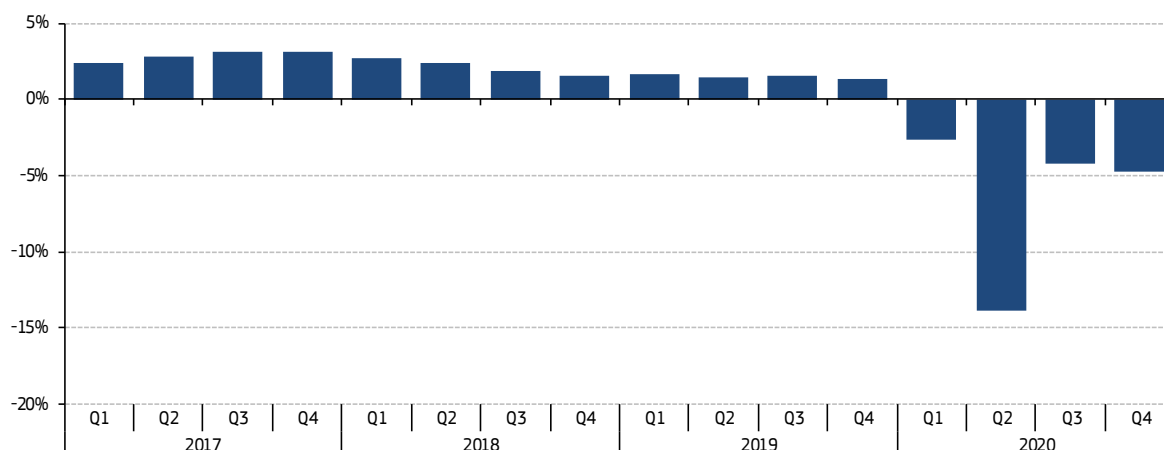
- The fourth quarter of 2020 brought electricity consumption close to pre-pandemic levels, despite continuing restrictions on economic and social activity. However, part of the recovery stemmed from colder temperatures compared to 2019. In the whole year 2020, EU-wide consumption decreased by 4% year-on-year, as rising demand by households could not reverse falls in other sectors of the economy.
- 2020 was an exceptional year in several aspects. The warm winter of 2019/2020, the demand shock caused by the pandemic and good weather conditions supporting renewable generation combined to substantially change the structure of the mix and corner conventional generators. As a result, coal and lignite generation fell by 22% (-87 TWh) and nuclear output dropped by 11% (-79 TWh). Gas came out relatively less affected due to its very favourable price which intensified coal-to-gas and lignite-to-gas switching. The share of renewables in the mix rose to 39%, beating fossil fuels (36%) for the first time. Based on preliminary estimates, the carbon footprint of the power sector in the EU dropped by 14% in 2020, similar to the development in 2019, when fuel switching was the main factor behind the decarbonisation trend. However, most of the drivers in 2020 were exceptional or seasonal (the pandemic, warm winter, high hydro generation). First months of 2021, with relatively cold weather, lower wind speeds and higher gas prices, suggest that the CO₂ emissions and intensity of the power sector could rise in 2021.
- Rising renewable generation in the EU was greatly assisted by 29 GW of solar and wind capacity additions in 2020, which is comparable to 2019 levels. This shows that the pandemic has not derailed renewable expansion substantially, although supply chain disruptions and logistical challenges did cause some delays in the onshore wind sector. However, meeting more ambitious 2030 climate targets will require a significantly increased tempo of additions in the coming years.
- Carbon prices moved decidedly above 30 €/tCO₂ in the final month of 2020 and surged to more than 40 €/tCO₂ in March 2021, putting coal and lignite power plants at a greater disadvantage against their less polluting gas-fired competitors. As the outlook for emission-intensive technologies worsens, more and more early coal retirements are announced. Sweden and Austria shut down their last coal-fired capacities in 2020. Ireland disconnected its last peat-fired power plant from the grid at the end of 2020. Hungary brought forward its coal exit date by five years to 2025. Greece aims to put all existing lignite capacities out of operation by 2023. Coal generation in Bosnia and Herzegovina, in contrast, rose by 8% in 2020.
- In recent months, more expensive emission allowances, along with rising gas prices, have driven up wholesale electricity prices in many European markets to levels last seen at the beginning of 2019. The effect was most pronounced in Member States dependent on coal and lignite. Poland had the highest baseload electricity prices (47 €/MWh on average) in 2020, beating even relatively isolated Malta. Higher wholesale electricity prices filter through to retail prices after a while. However, consumers can mitigate the impact by switching to a cheaper supplier. A typical German household can save up to €500 in its annual electricity bill, if it chooses the most advantageous offer on the market. Belgium, Finland, Slovenia and Norway offer best examples of hassle-free market environment for switching.
- Rising levels of renewable penetration, magnified by covid-related demand destruction, brought instances of negative electricity prices to new records in 2020, essentially doubling them compared to 2019. In contrast, wholesale prices surged above 100 €/MWh for several hours on 9 December amid low wind speeds, reduced availability of dispatchable capacities and relatively high demand levels during a cold spell. A similar scarcity event took place in the middle of September. Such episodes are likely to proliferate as conventional power plants are retired and renewable sources, despite their rising presence, cannot be relied upon all the time due to their intermittency. This will place more emphasis on cross-border trade and better coordination of generation adequacy planning among Member States.
- Demand for electrically chargeable vehicles (ECVs) kept on rising over Q4 2020 thanks to carmakers' efforts to meet stricter emission targets and expanded support policies by Member States. Almost half a million new ECVs were registered in the EU in the final quarter of 2020. This was the highest figure on record and translated into an unprecedented 17% market share, more than two times higher compared to China and six times higher compared to the United States. It also brought the annual total to one million new ECVs, which means that the existing electric fleet doubled in just 12 months. The rapid sales growth in the ECV sector was accompanied by expanding charging infrastructure. The number of high-power charging points per 100 km of highways rose from 12 to 20 in 2020. Despite widely different home charging prices across Europe, ECVs are still cheaper to drive than conventional ICE vehicles.

1 Electricity market fundamentals

1.1 Demand side factors

- Figure 1** shows that the second wave of the pandemic which swept across Europe in Q4 2020 partially reversed the recovering trend of the previous months. Restrictions on economic and social activity, although generally less strict than during spring, still had a palpable impact on the daily lives of millions of citizens and operations of the majority of business. According to an estimate published by Eurostat in March 2021, seasonally adjusted GDP in the EU decreased by nearly 5% year-on-year between October and December 2020. This meant a fourth consecutive quarter of negative growth and added up to a 6.2% contraction of the EU GDP in the whole year 2020, the largest fall on record. The only Member State with a growing economy in Q4 2020 was Luxembourg (+1.4%). The highest year-on-year declines in Q4 2020 were reported in Spain, Greece and Croatia.

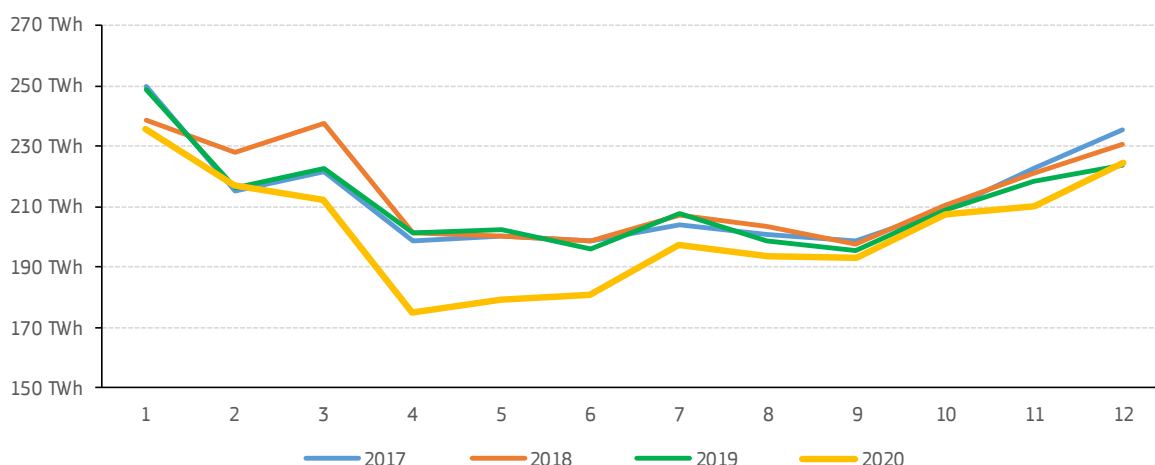
Figure 1 – EU GDP annual change (%)



Source: Eurostat

- Electricity consumption in the EU stayed only 1% below last year's levels in Q4 2020, helped by recovering industrial activity and strong household demand. Despite a small setback in November, influenced by a second wave of lockdown measures, demand returned to pre-pandemic levels in December, helped by a colder start of winter than in 2019. The EU average hid wide differences in developments in individual Member States. While ten of them saw consumption going up year-on-year, sometimes considerably (Hungary +5%, Romania +3%, Poland +1%), the rest remained in negative territory. Scandinavian countries experienced notable falls in consumption on the back of very warm weather (Denmark -8%, Sweden -6%, see **Figure 4**). Major economies witnessed declines between 1-3%.

Figure 2 – Monthly EU electricity consumption

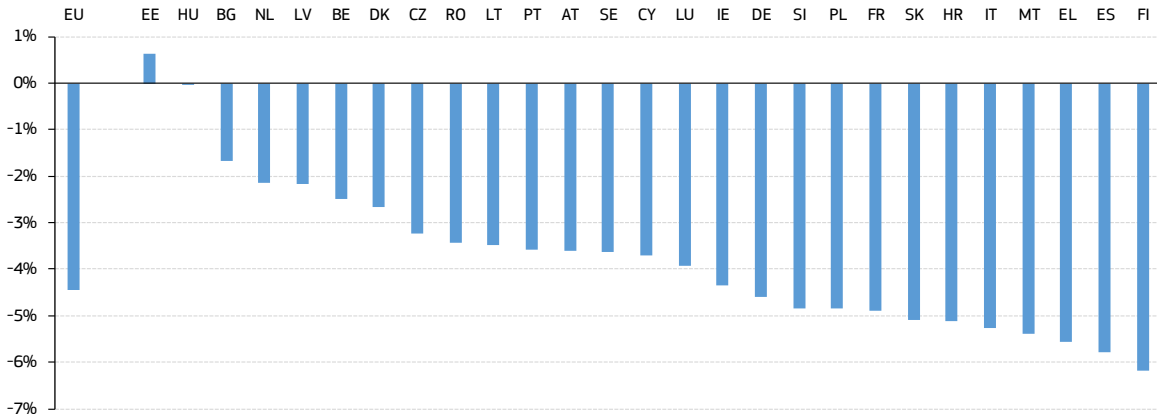


Source: Eurostat

- Figure 3** sums up changes in electricity consumption over the whole exceptional year 2020. Only Estonia and Hungary escaped declines, the biggest of which occurred in southern regions. Finland's sharp fall was influenced more by strikes at large energy-intensive factories rather than by the impact of the pandemic. EU-wide consumption decreased by 4%. Total figures conceal structural changes in energy use across the economy which could be long-

lasting. Large industrial consumers, responsible for the biggest portion of total demand, apparently reduced their demand noticeably, especially during the spring lockdown period. This was only partly compensated by rising residential consumption caused by people spending much more time at home. Household electricity consumption in Czechia grew by 5% year-on-year in 2020 for instance. But since households are only responsible for a fifth of the total Czech consumption, they could not reverse the general trend.

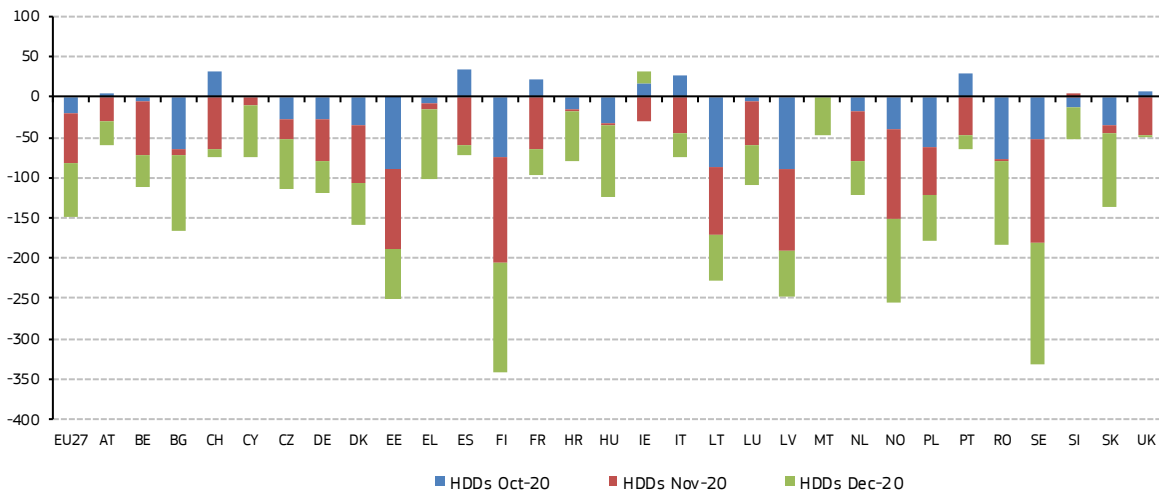
Figure 3 – Annual changes in electricity consumption in 2020 by Member State



Source: Eurostat

- **Figure 4** illustrates the monthly deviation of actual Heating Degree Days (HDDs) from the long-term average (a period between 1978 and 2018) in Q4 2020. EU-wide, the reference quarter was warmer than usual, registering 148 HDDs below the long-term average. This means that temperatures were about 1.6 degree Celsius higher than usual. Most of the deviations took place in November and December. The Nordic and Baltic regions experienced very warm weather conditions, which dampened electricity demand. The impact was pronounced especially in Norway where the heating sector is highly electrified. Low consumption kept prices in Nord Pool markets in check, especially in November.

Figure 4 - Deviation of actual heating days from the long-term average in October-December 2020

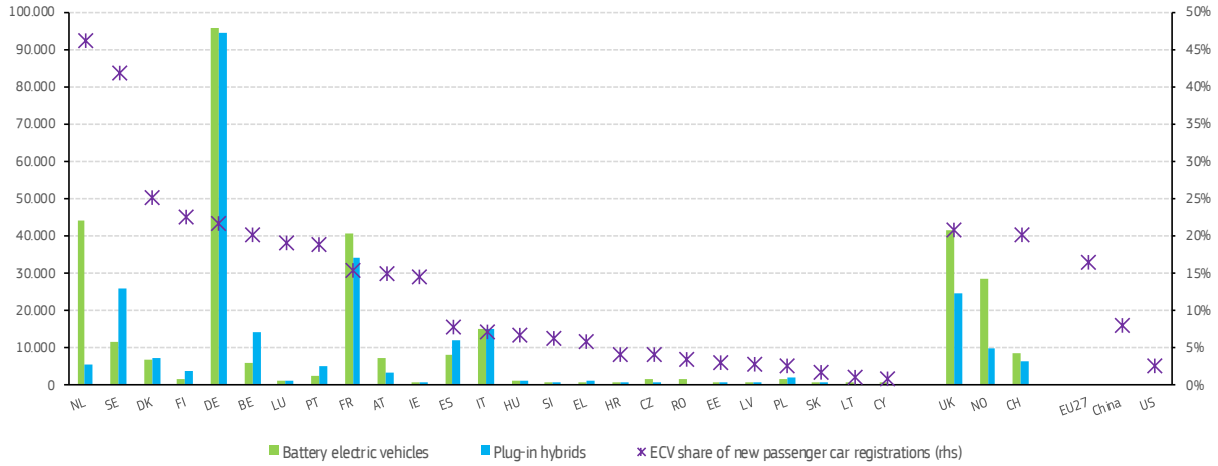


Source: JRC. The colder the weather, the higher the number of HDDs. The hotter the weather, the higher the number of CDDs

- **Figure 5** shows that demand for electrically chargeable passenger vehicles (ECVs) reached new heights in Q4 2020 thanks to efforts by major automobile manufacturers to meet stricter emission targets for 2020 and also thanks to expanded support policies of some Member States aimed at incentivizing ECV purchases. Almost half a million new ECVs were registered in the EU in Q4 2020 (+263% year-on-year). This was the highest quarterly figure on record and translated into a 17% market share, two times higher compared to China and six times more than in the United States. The plug-in hybrid segment continued to grow strongly (+331% year-on-year to 249,000), while demand for battery electric vehicles grew at a slower but still impressive pace (+217% year-on-year to 227,000). The ECV category beat the hybrid electric vehicles (not chargeable) for the first time in Q4 2020.
- The highest ECV penetration was again observed in the Netherlands and Sweden where almost half the passenger cars sold could be plugged. Apart from registration and ownership benefits, the Dutch state also offers direct purchase subsidies of up to 4,000 EUR to ECV buyers. Relatively high ECV market shares were observed in Denmark,

Finland, Germany and Belgium. The 25% share in Denmark is all the more impressive since it took place against the backdrop of zero direct purchase incentives (only tax deduction benefits). Germany retained the position of the largest individual market. Its generous incentive programme, which offers up to 9,000 EUR in direct purchase bonuses, drove up ECV sales to 190,000 in Q4 2020, an increase of more than 500% over the last quarter of 2019. Seven Member States did not provide any substantial incentives for ECV purchases in the reference quarter.

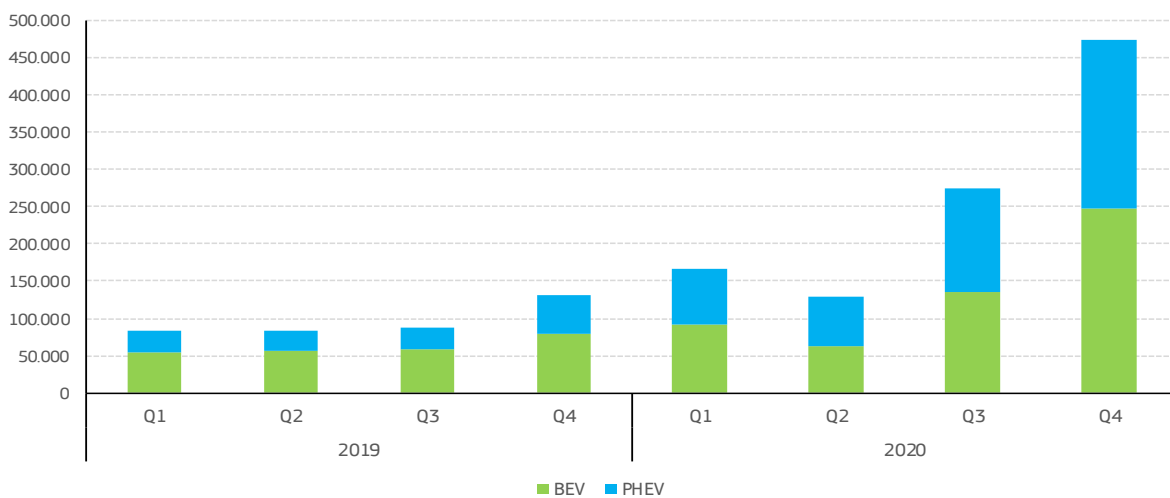
Figure 5 – Electrically chargeable passenger vehicle (ECV) sales in selected countries in Q4 2020



Source: ACEA, CPCA, BloombergNEF

- **Figure 6** shows how the rapid expansion of electric vehicles in Europe unfolded in 2020. Lockdown measures in Q2 2020 curtailed manufacturing capacities, strained supply chains and dampened consumer demand. However, the effect was only temporary and the sector went back on its feet in the second half of the year, underpinned by existing policy support and additional stimulus measures. In the end, a million new ECVs were sold in the EU in 2020 (compared to 1.2 million cars with a plug sold in China), doubling the existing electric fleet. The 2020 addition brings about 2.5 TWh of new electricity demand, which represents around 0.1% of annual EU consumption. As the number of ECVs on European roads is expected to continue growing fast in the years ahead, so will its impact on electricity demand and on network load.
- The quick sales growth tempo in the ECV sector was accompanied by the expansion of charging infrastructure, especially in Member States with high ECV market shares. EU-wide, the number of public charging points increased by 36% to 225,000 in 2020. As sales of new electric vehicles grew quicker than the build-up of charging points, the number of ECVs per one connector increased from 7 to 9. The segment of fast charging stations, often installed at existing highway rest stations, has made considerable progress. The number of high-power charging points per 100 km of highways rose from 12 to 20 in 2020.

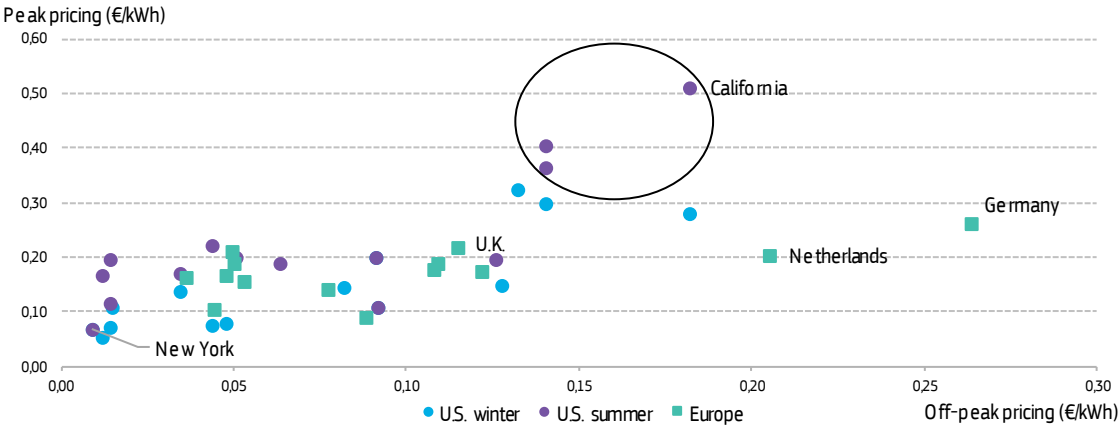
Figure 6 – Quarterly ECV sales in the EU



Source: ACEA

Figure 7 shows the results of a survey about home charging prices available to ECV owners in Europe and the US¹. Home charging is the most widely available method to ECV owners and as electric mobility grows, ECV-tailored electricity tariffs are one way retailers are trying to attract new customers and manage the increasing influence of ECVs on the power system. Time-of-Use (ToU) tariffs, where lower prices are charged during off-peak hours at night, are the most common option (55% of surveyed utilities) offered in Europe. Other home charging tariff types include flat rates or real-time pricing following wholesale markets. Annual home charging costs were assessed to be 40% higher in Europe than in the US. However, this difference is equivalent to the gap between wholesale electricity prices in Europe and the US (see **Figure 24**). Additionally, the US displays higher seasonal differences in prices than Europe. In the summer, when the American grid load is more affected by cooling demand, the average on-peak tariff in Europe is 0.04 €/kWh cheaper than its equivalent in the US. On the other hand, during the winter, American electric vehicle owners pay €0.33/kWh less than their European counterparts.

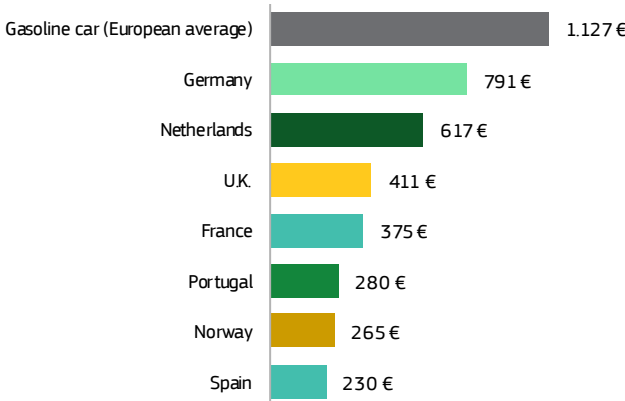
Figure 7 – On-peak and off-peak EV-specific charging tariffs by region and season



Source: BloombergNEF, various utilities.

Figure 8 presents estimated annual costs of charging an ECV using surveyed home charging tariffs in Europe. European annual home charging costs range from €230 to €790. The highest levels were observed in Germany which corresponds to the ranking of household electricity prices (see **Figure 55**). Reduced availability of cheaper off-peak tariffs was another contributing factor. This is somewhat unexpected since the long-term average peakload premium over baseload prices in Germany, France and Netherlands is the same (8%). European electricity prices are generally higher than in the US, but as petrol and diesel are also more expensive in Europe due to higher taxation, ECVs still offer more attractive operating terms than conventional ICE vehicles. ECV charging costs range between €0.01 and €0.05 per kilometre, depending on the market and the retailer. The cost for refuelling a comparable petrol vehicle ranges between €0.07 and €0.08 per kilometre in surveyed countries.

Figure 8 – Annual cost of EV home charging tariffs by selected utilities in Europe



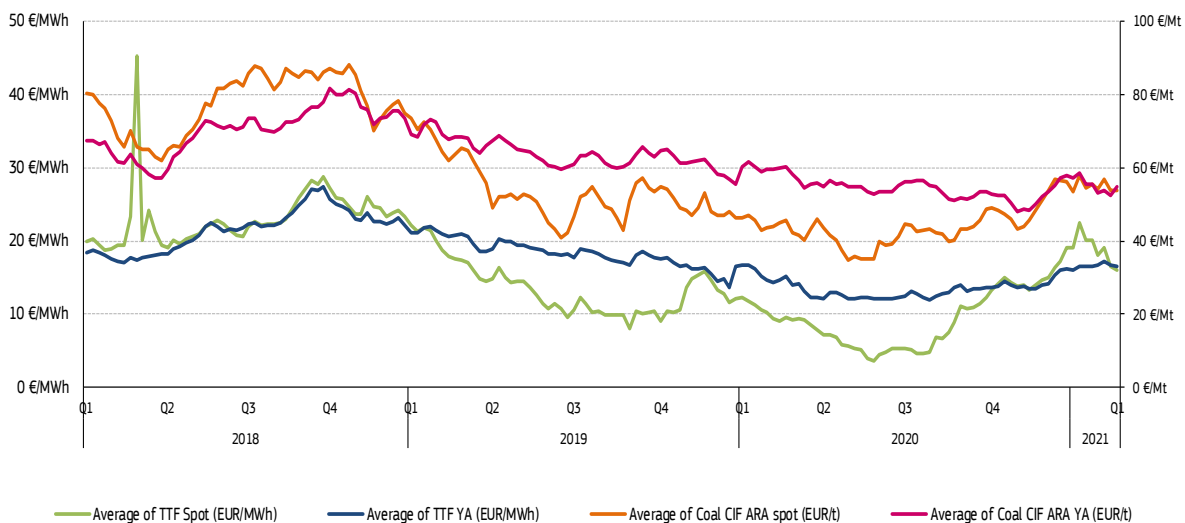
Source: BloombergNEF. Note: Annual cost assumptions are only for hourly charging and do not include fees or additional fees. Calculations uses efficiency rates for new 2020 vehicles from BloombergNEF's 2020 Road Fuel Outlook.

¹ BloombergNEF. EV home charging tariffs – 2021.

1.2 Supply side factors

- Figure 9** reports on developments in European coal and gas prices. Thanks to recovering economic activity and increasing demand tied to the incoming winter, prices of coal and gas in the spot market caught up with their year-ahead peers in Q4 2020. While relatively stable during October and November, spot gas prices (represented by the TTF day-ahead contract) started to climb in December on the back of forecasts of colder weather and rising storage withdrawals. The trend intensified in January 2021 as cold spells affecting the whole Northern Hemisphere increased demand and sent spot prices sharply up, especially in the LNG segment. This significantly undermined the competitive edge of gas-fired power plants in Europe and allowed their coal and lignite competitors to regain some of the lost ground. The price rally largely dissipated by the end of January as conditions returned to normal.
- Spot gas prices averaged 9.4 €/MWh in the whole 2020, 30% less than in 2019, which reflects the impact of the pandemic on energy demand. Cheaper gas and the resilience of the carbon market contributed to intensified coal-to-gas and lignite-to-gas switching in 2020, driving down the carbon footprint of EU electricity sector to record lows. In the first two months of 2021, spot gas prices averaged 19 €/MWh, a level last seen in 2018.
- Thermal coal spot prices, represented by the CIF ARA contract, stagnated in October and November, but began to climb up in December amid supply disruptions in Australian ports and colder weather conditions which stimulated more coal burn. However, rising carbon prices at the beginning of 2021 and warmer temperatures in February limited coal's potential and kept its prices under 60 €/t. The average CIF ARA spot price reached 44 €/t in 2020, down 19% compared to 2019. The lower decrease in spot coal prices compared to their gas peers reflects that fact that coal use had already been under pressure in 2019 and that prices could not fall much lower in 2020 despite the pandemic.

Figure 9 – Weekly evolution of spot and year-ahead coal and gas prices



Source: S&P Global Platts

- The European market for emission allowances, shown in **Figure 10**, saw significant price gains throughout Q4 2020 which continued well into 2021. Several new records were established in quick succession, culminating in the middle of March when the closing price climbed above 40 €/tCO₂ for the first time.
- The rally started in November when a delay to the start of 2021 auctions was announced, meaning a longer-than-expected break in fresh supply from auctions in January. Prices continued to head higher in December and clearly broke through the 30 €/tCO₂ barrier in the aftermath of the European Council 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 as cold and calm weather necessitated the start-up of more emission-intensive power plants, increasing CO₂ emissions and demand for allowances. Allowances held their gains even after temperatures rose, indicating a shift in market expectations and more bullish long-term outlook. This can be traced down to reforms of several key aspects of the EU ETS which are planned to be introduced in 2021 and which are expected to lead to a tighter supply-demand balance.
- The average CO₂ spot price in 2020, at 25 €/tCO₂, was little changed compared to 2019. However, in January and February 2021 the average price jumped to 36 €/tCO₂. Higher carbon prices put coal and lignite power plants at a greater disadvantage against their less polluting gas-fired competitors (see **Figure 20**). They also tend to drive wholesale electricity prices higher (see **Figure 14**).

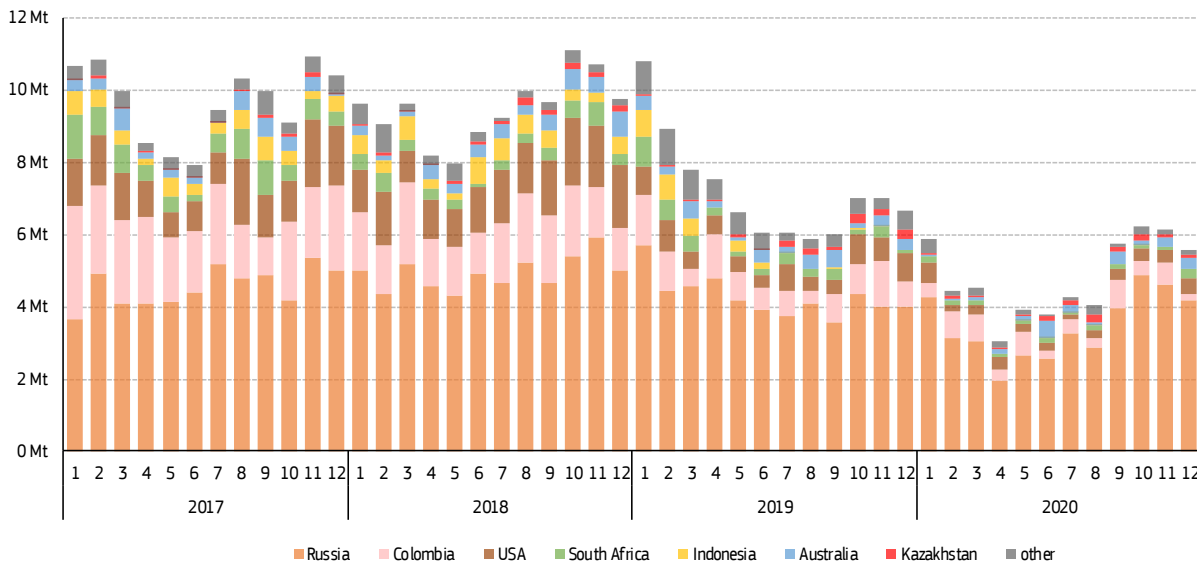
Figure 10 – Evolution of emission allowance spot prices from 2018



Source: S&P Global Platts

- As visible from **Figure 11**, monthly thermal coal imports into the EU held at roughly 6 Mt in Q4 2020 as electricity consumption recovered and made more space for fossil fuels in the mix. The total volume of imports nevertheless fell by 13% year-on-year to 18 Mt in the final quarter of 2020. For the whole year 2020, EU thermal coal imports decreased by a third to 58 Mt compared to 2019 due to the effects of the pandemic on power demand and fuel switching. The estimated EU import bill for thermal coal amounted to €1.1 billion in the reference quarter, 27% lower compared to Q4 2019 and exceeding the year-on-year decline in imported volumes due to lower contracted prices of the commodity. The total 2020 import bill for thermal coal decreased nearly by half to €3.7 billion.
- The largest part of extra-EU thermal coal imports in Q4 2020 came from Russia which accounted for 76% of the total. Russian traders continued to cement their dominant position as most of their rivals find it difficult to compete in the though low-price, low-demand environment. Colombia saw its market share going down to 7% from 10% in the previous quarter. The position of Australia and Kazakhstan worsened as well (4% and 2% shares respectively). The share of deliveries from US ports increased from 5% to 6%. Shares of other trading partners were insignificant.

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



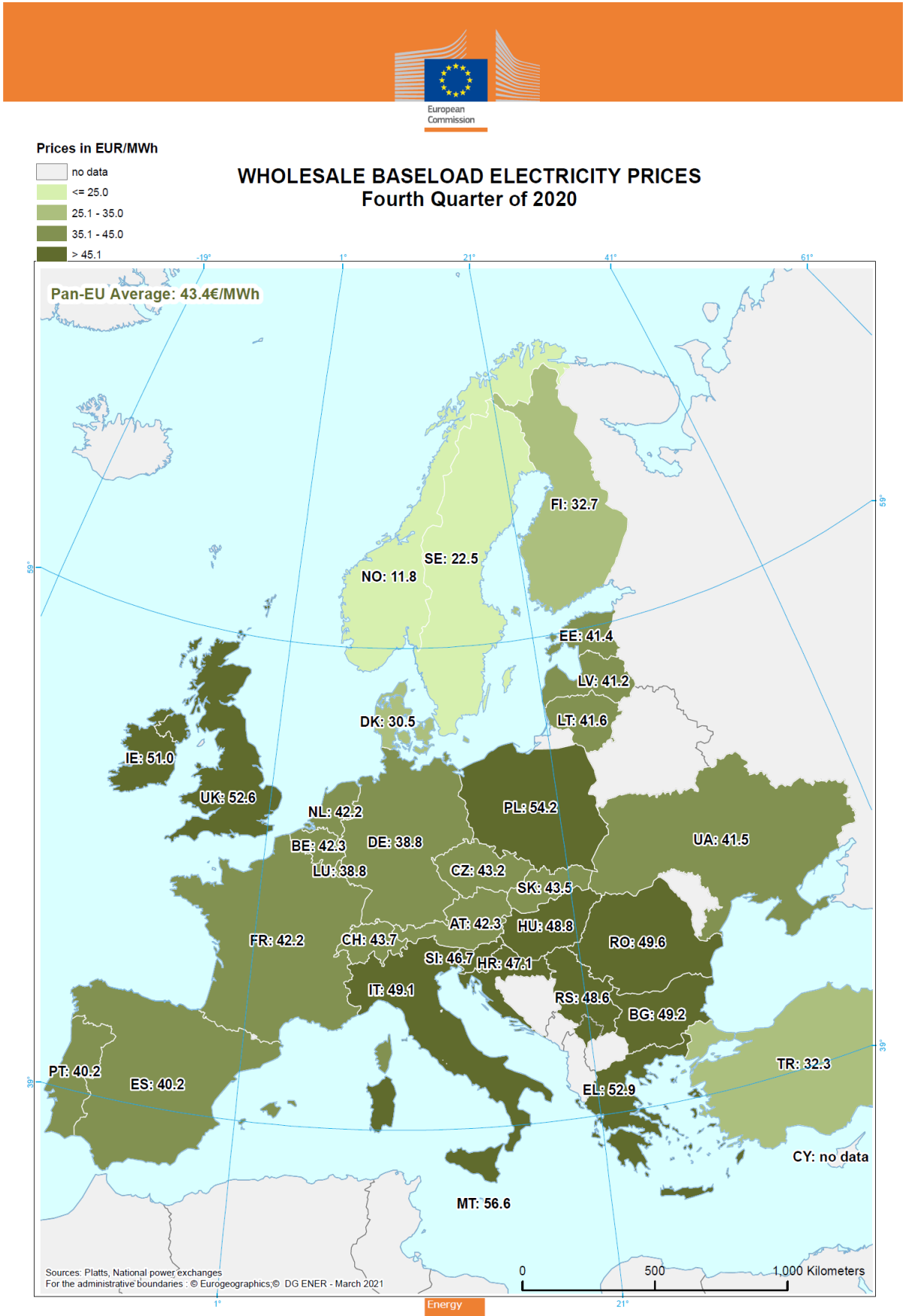
Source: Eurostat

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 Q4 2020. The reference quarter saw a mix development. Prices rose on average compared to Q3 2020, but to a different extent, depending on the structure of the mix, renewable and nuclear availability and the severity of restrictive measures during the second wave of the pandemic. Most countries experienced higher electricity prices than in the same quarter last year, notably Czechia, Ireland and Poland (+10%), on the back of rising carbon and fuel prices. The cheapest baseload power on the day-ahead market was available in the Nordic region where record high hydro reserves, rising wind generation and weak demand due to warm weather kept prices under pressure. The lowest prices were found in Norway, with values as low as 12 €/MWh on average. Sweden reported prices around 23 €/MWh on average. Most markets moved between 40 and 50 €/MWh. Poland became the second most expensive market with an average baseload price of 54 €/MWh, which was 10% higher compared to the same period last year. Malta reported the highest quarterly average price (56 €/MWh).
- The pan-EU average of day-ahead baseload prices reached 43 €/MWh in the reference quarter, down 1% in a year-on-year comparison. Compared to Q3 2020, the quarterly average rose by 12%.
- The biggest year-on-year price decreases were registered in Norway (-69%), Sweden (-42%), Finland (-25%) and Denmark (-21%).

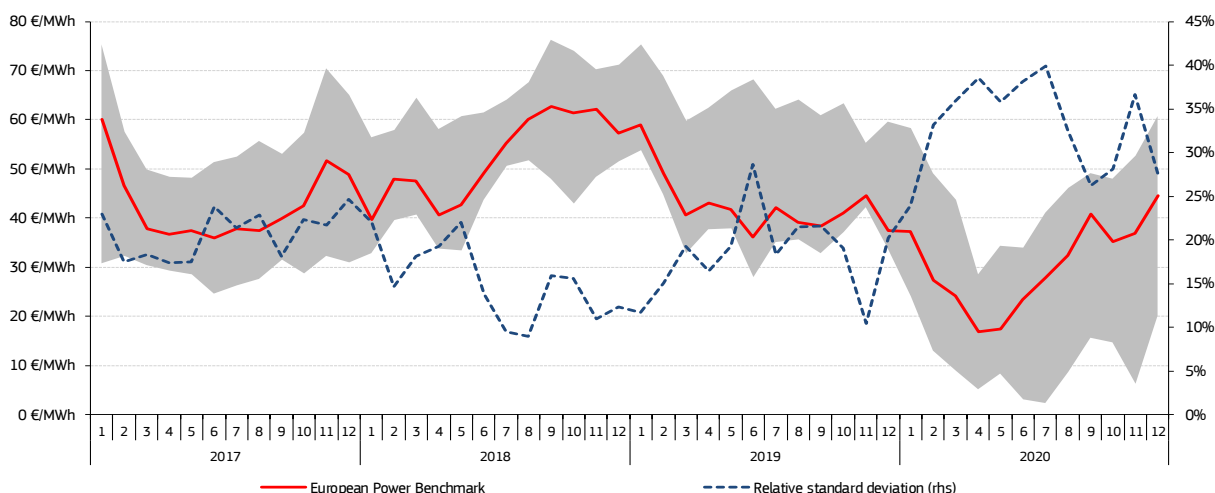
Figure 12 – Comparison of average wholesale baseload electricity prices, fourth quarter of 2020



Source: European wholesale power exchanges, government agencies and intermediaries

- Figure 13** shows the European Power Benchmark of nine markets and, as the two lines of boundary of the shaded area, the lowest and the highest regional prices in Europe, as well as the relative standard deviation of regional prices. Both the shaded band and the relative standard deviation metric show that divergence levels remained elevated at the end of 2020, as the supply-demand balance developed differently in individual regions. Central Western and Eastern Europe experienced rising prices on the back recovering demand and rising fuel and carbon costs. The Iberian Peninsula witnessed stable prices due to weak demand and rising renewable penetration. The Nordic region, on the other side of the spectrum, was overflowing with cheap electricity thanks to cheap hydro generation and warm weather which dampened demand. Great Britain went through a tight December with average prices climbing above Greek levels. This made Britain the most expensive market in Europe that month. The European Power Benchmark averaged 39 €/MWh in Q4 2020. This was 5% less than in the same quarter last year.

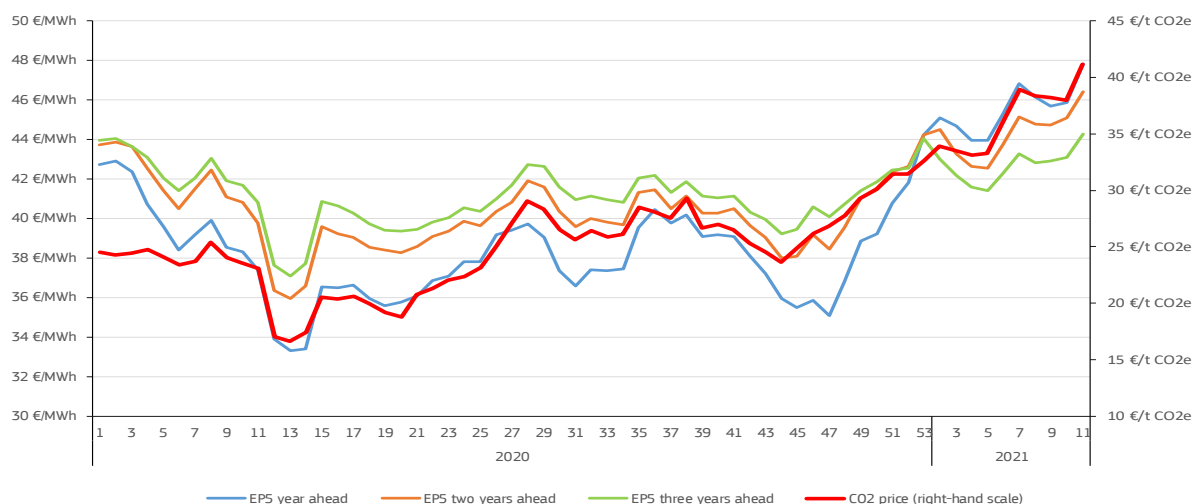
Figure 13 – The evolution of the lowest and the highest regional wholesale electricity prices in the European day-ahead markets and the relative standard deviation of the regional prices



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

- A consumption-weighted futures benchmark (EPS) of five markets, shown in **Figure 14**, reveals that carbon prices have been one of the main drivers behind changing expectations of future electricity prices since the beginning of the spring lockdown. The rapid rise in CO₂ prices that took place between November 2020 and February 2021 lifted the benchmark above pre-crisis levels. On average, 1 €/tCO₂ adds roughly 0.6 €/MWh to electricity prices, which reflects the average carbon content of fossil-based electricity generation in the EU (0.6 tCO₂/MWh). Thus, higher carbon costs factored in future generation costs have outweighed the effect of lower demand expected in the years ahead as a result of lasting covid-related shifts in the structure of the economy.

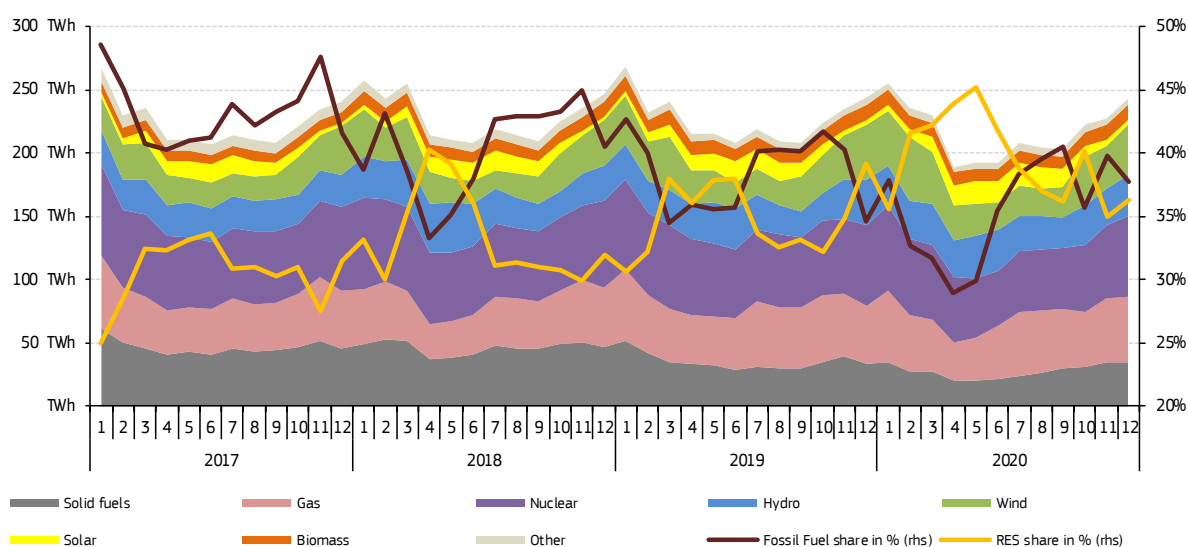
Figure 14 – Weekly futures baseload prices – weighted average of 5 European markets



Source: Platts.

- **Figure 15** 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 wind and solar generation put a cap on their expansion. Renewables and fossil fuels were competing neck to neck for primacy in the mix. In the end, the share of electricity generated by burning coal, gas and oil reached 38% in Q4 2020, while renewables scored one percentage point lower. Nuclear generation remained under pressure due to rising renewable penetration in Sweden. Its share fell to 25% in the reference quarter (from 26% in Q4 2019).
- Within the fossil fuels complex, coal suffered losses both in absolute and relative terms compared to Q4 2019 due to weak demand, which was still lower than a year earlier, and rising carbon prices. Coal's share in the mix fell to less than 15%. Meanwhile, less CO₂-intensive gas generation saw its share unchanged at 21% in the reference quarter. In absolute terms, coal-based generation fell by 6 TWh year-on-year, while gas-fired power plants' output decreased by 3 TWh. Renewables, in contrast, generated 8 TWh of electricity more year-on-year.
- Between hard coal and lignite (the distinction between them is not visible in **Figure 15**), the latter tends to be more resilient in the face of changing market environment, as lignite generation traditionally displays more competitive marginal costs per unit of energy produced. 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 11% more expensive in Q4 2020 compared to Q4 2019, but this was more than compensated by rising hard coal prices, which meant that lignite power plants weathered the reference quarter in a better shape. In the end, lignite-based generation in Q4 2020 fell only by 3% year-on-year (or 2 TWh), while coal-fired generation decreased by 8% year-on-year (or 4 TWh). Wind generation in Q4 2020 surpassed coal generation volumes.

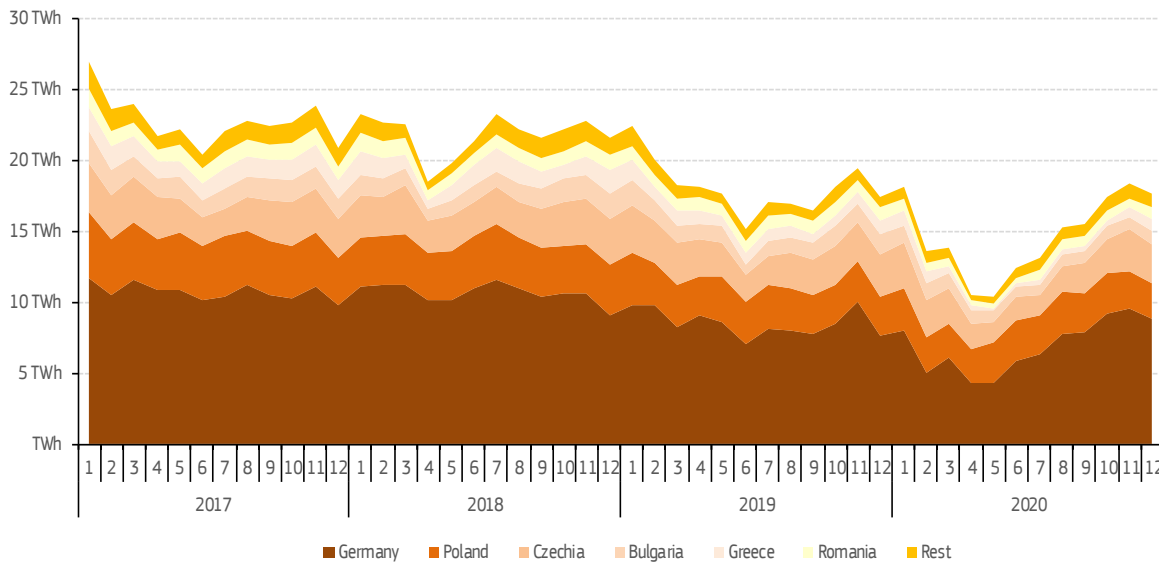
Figure 15 – Monthly electricity generation mix in the EU



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

- **Figure 16** shows that after a big covid-related drop during spring and summer months, lignite generation staged a powerful comeback in Q4 2020, helped by rising gas prices (which decreased the competitive edge of gas-fired power plants) and recovering demand. Monthly output peaked in relatively windless November at 18 TWh, the highest figure since January 2020. In Germany, home to the largest lignite fleet, generation from the dirtiest fuel even rose by 5% year-on-year in Q4 2020, due to falling nuclear output. Lignite-fired generation in Poland decreased 4% year-on-year in Q4 2020. The output of the Czech lignite fleet fell by 6% year-on-year, and was partly replaced by increased biomass, hydro and gas generation. The three Member States accounted for 82% of the total lignite-based generation in the EU in Q4 2020. The largest fall in lignite generation (-30% year-on-year) was observed in Bulgaria where rising gas and biomass output were able to compensate for only a third of the shortfall. Significant drops in lignite generation were also observed in Romania (-20%) and Greece (-27%). In Greece, renewables and gas stepped in to make up for the missing lignite volumes. Romania benefited from high hydro generation. Lignite power plants reached a 7% share in the EU generation mix in 2020 (down from 8% a year earlier) and were responsible for approximately 30% of the electricity sector's total carbon emissions.

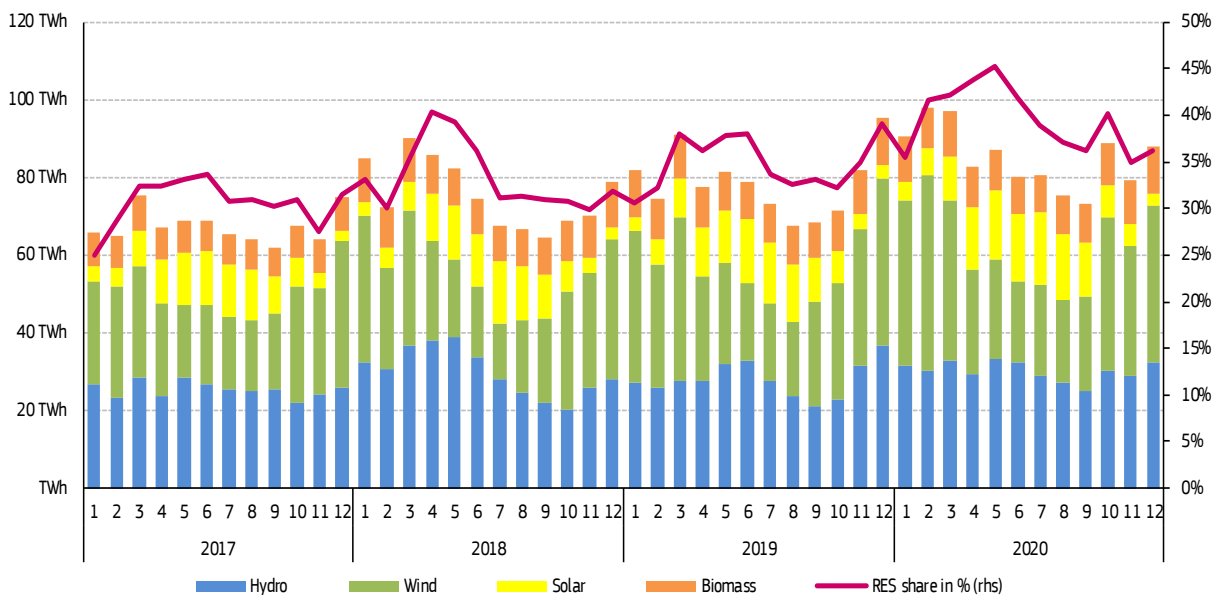
Figure 16 – Monthly generation of lignite power plants in the EU



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

- **Figure 17** depicts the evolution of monthly renewable generation in the EU, alongside its share in the electricity generation mix. Renewable penetration reached 37% in Q4 2020, unchanged compared to Q3 2020, but was still measurably higher than during the same quarter last year (35%). Weaker demand and a 3% year-on-year rise in renewable generation contributed to the increase in renewable penetration.
- Most of the increase in renewable generation came from wind (+5 TWh) and solar (+2 TWh) segments. Offshore wind farms experienced a 25% jump in output thanks to new capacities brought online in the Netherlands and Belgium (see **Figure 19**). Over the entire year 2020, the share of wind generation in the mix reached 15% (compared to 13% in 2019), which was more than that of coal and lignite put together (13%). The average capacity factor for onshore installations rose slightly to 25% (from 24% in 2019) and increased also for offshore units to 42% (from 38% in 2019), making 2020 a relatively windy year.
- Thanks to newly added panels, solar PV generation rose by 12% in Q4 2020 to 18 TWh, double that of oil-fired generation. The increase was almost singlehandedly driven by Spain. The share of solar in the mix rose to 5% in 2020, up from 4% in 2019, putting it within striking distance of hard coal (6%).

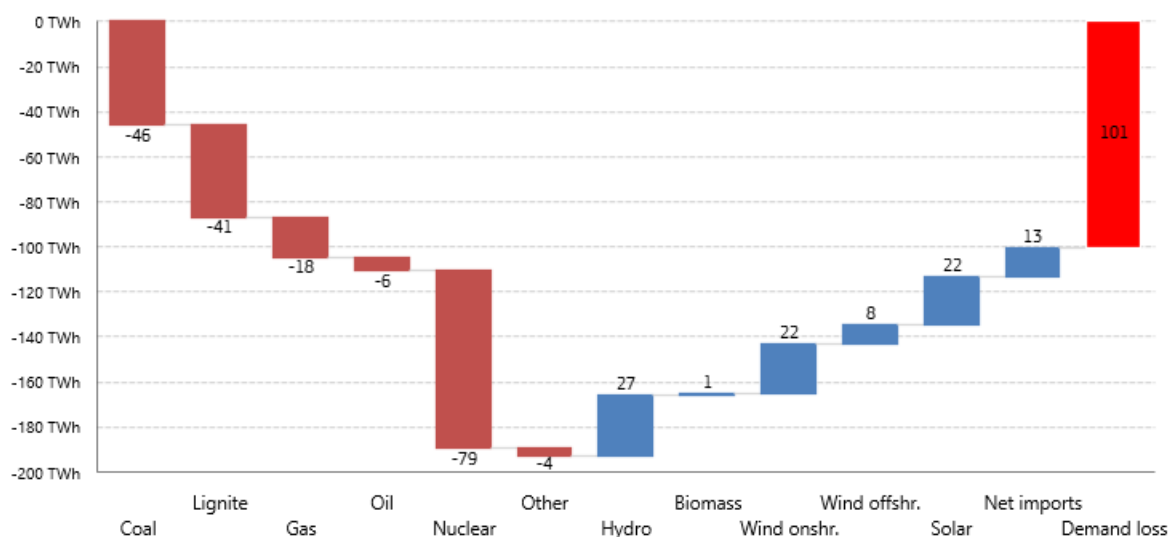
Figure 17 – Monthly renewable generation in the EU and the share of renewables in the power mix



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

- **Figure 18** visualises the dramatic changes in the EU electricity generation, imports and consumption in 2020 compared to 2019. The space for conventional power plants' running hours was restricted by major shifts both on the supply and demand side. The warm winter of 2019/2020 and the coronavirus pandemic cut power demand by more than 100 TWh. Additional crowding out came from rising renewable generation (+80 TWh) and more net imports (+13 TWh), which flowed in mainly from Norwegian hydro power plants (see **Figure 29**). While coal and lignite together with nuclear bore the brunt of the losses, gas came out relatively less scathed due to its very favourable price which intensified coal-to-gas and lignite-to-gas switching in 2020 (see **Figure 20**). Decreases in nuclear output were concentrated to France (-43 TWh), Sweden (-17 TWh), Germany (-10 TWh) and Belgium (-9 TWh). Some of these stemmed from planned phase-outs (Germany, partly Sweden), while some were caused by one-off events such as demand destruction during lockdowns and maintenance overruns and rescheduling or postponed refuelling (France, Belgium, Sweden). Based on preliminary estimates, the carbon footprint of the power sector in the EU dropped by 14% year-on-year in 2020 due to the lower use of fossil fuels.
- As most of the main drivers behind the 2020 decrease in carbon emissions were exceptional or seasonal (the covid-related demand shock, warm weather, very high hydro generation), a temporary reversal in the carbon emissions trajectory can be expected going forward. As wind generation in the first months of 2021 was relatively low and weather turned significantly colder than in 2020, it is likely that both the power sector's carbon footprint and carbon intensity will rise in 2021.

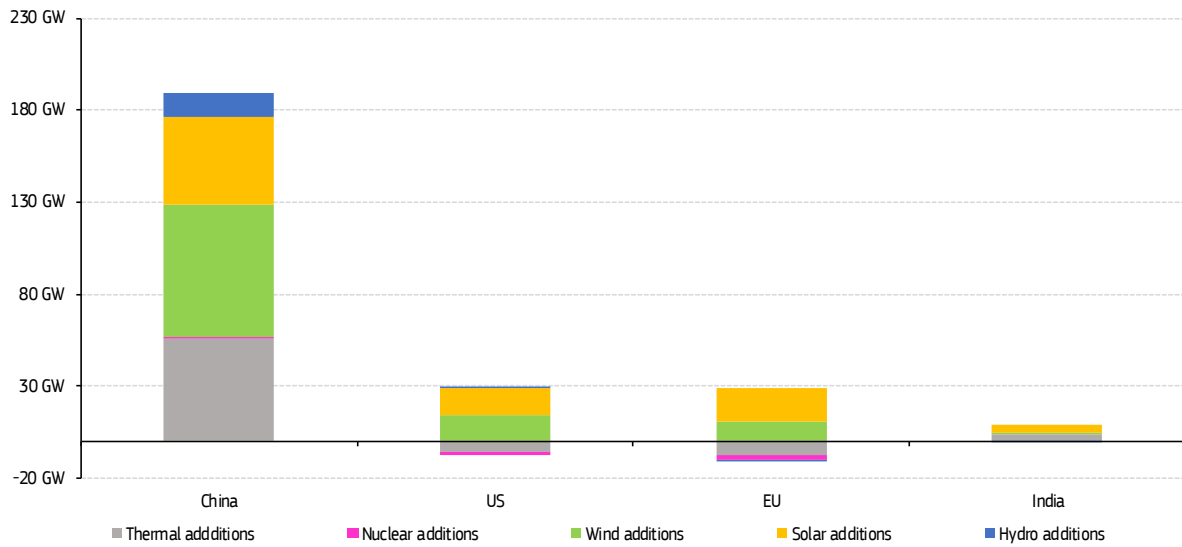
Figure 18 – Changes in power generation in the EU between 2019 and 2020



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

- **Figure 19** maps newly installed power capacities on a net basis in the EU in 2020 and, for the sake of comparison, in other major economies. Rising carbon-free generation in the EU was greatly helped by 29 GW of renewable additions (11 GW of wind and 18 GW of solar PV), which is comparable to 2019. This shows that the pandemic has not derailed renewable expansion substantially, although supply chain disruptions and logistical challenges did cause some delays in the onshore wind sector. However, meeting more ambitious 2030 climate targets will require a significantly increased tempo of renewable additions.
- The largest increases in the renewable capacity were registered in Germany (+6.6 GW), where solar PV was the main driver, and Netherlands (+4.9 GW), where both solar and wind sectors contributed to the result. Spain (+4 GW) and Poland (+3.3 GW) also saw significant renewable capacity additions, followed by France (+2.3 GW) and Belgium (+1.9 GW). Greece (+0.9 GW) was also among Member States making notable progress. Two nuclear reactors in France and one in Sweden were shut down during the year, removing 2.7 GW of carbon-free capacity from the grid. Roughly 8 GW of thermal (mostly coal- and lignite-fired) capacity was retired on a net basis. This includes a 1.1 GW hard coal unit commissioned in Germany. The figure does not include 5 GW of hard coal capacities in Germany which left the market at the end of 2020 following an auction for compensation. The awarded units can be disconnected from the network only after the approval of the national regulatory authority.
- Outside Europe, the largest renewable additions were registered in China (72 GW of wind, 48 GW of solar and 13 GW of hydro) which also put 56 GW of additional thermal capacities online in 2020. The US experienced a similar development in net additions as the EU, witnessing 7 GW of thermal and nuclear retirements put together and 29 GW of additions in the renewable segment.

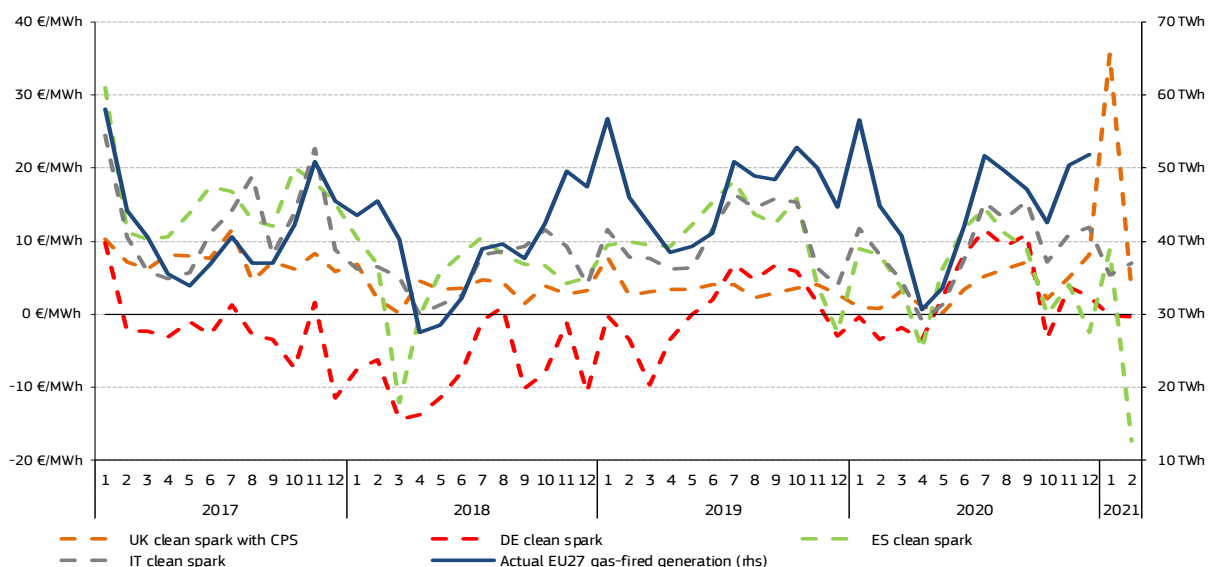
Figure 19 – Net capacity additions across major economies in 2020



Source: China Electricity Council, Central Electricity Authority of India, FERC. For the EU, ENTSO-E figures were used for thermal, nuclear and hydro additions; latest estimates from WindEurope and SolarPower Europe for wind and solar additions.

- 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 Q4 2020, continuing the trend of the last two years. That changed in January 2021 when rapidly rising gas prices resulted in coal gaining the upper hand, despite rising carbon prices. However, the reversal was only temporary and as gas prices deflated in February, gas-fired power plants regained their competitive edge. The spike in the January clean spark spread in the UK was driven by extremely high prices during scarcity events in the first two weeks of the month.
- As shown in **Figure 20**, with the exception of Spain, the profitability of gas firing for electricity generation remained mostly in positive territory for a plant with an average efficiency during Q4 2020, bottoming out in October on the back of falling power prices. The highest [clean spark spreads](#) in Q4 2020 were assessed in Italy (10 €/MWh), followed by the UK (5 €/MWh) and Germany (1 €/MWh). Gas-fired generation volumes largely corresponded to the movement of spreads in respective markets. The total EU gas generation reached 145 TWh in the reference quarter, down by 2% compared to Q4 2019.

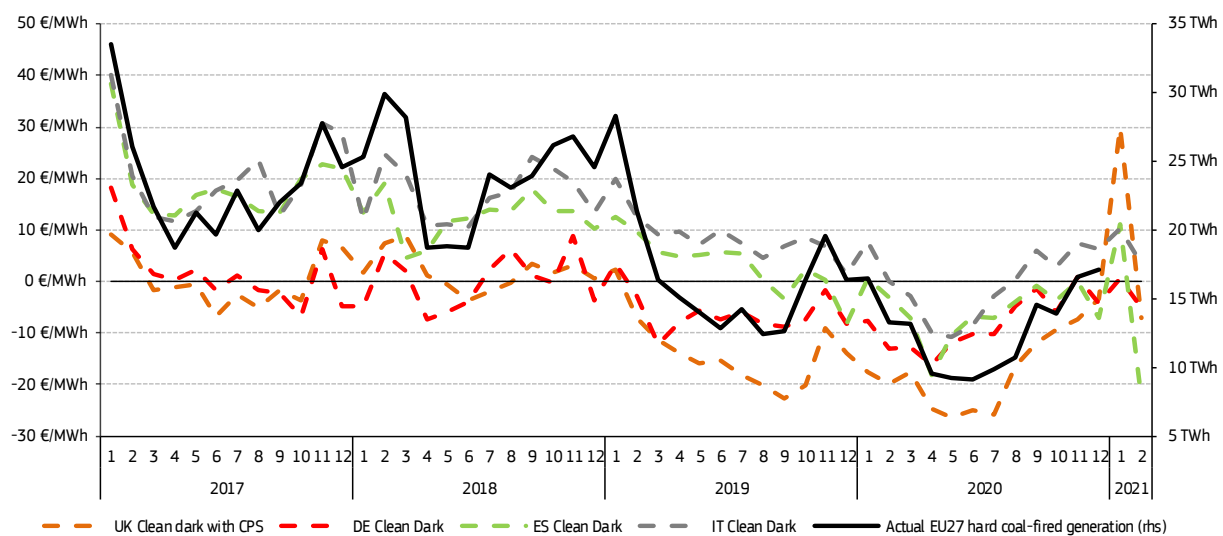
Figure 20 – Evolution of clean spark spreads in the UK, Spain, Italy and Germany, and electricity generation from natural gas in the EU



Source: ENTSO-E, Eurostat, Bloomberg

- For the whole year 2020, gas generation fell by 18 TWh EU-wide. The fall was driven almost exclusively by Spain and Italy where gas is already the dominant fuel and was affected by the covid-related demand shock. In other markets where coal still has a sizeable presence, such as the Netherlands, Greece, Czechia or Germany, coal-to-gas or lignite-to-gas switching continued and intensified, meaning that gas-fired power plants were able to increase their running hours at the expense of coal competitors even though the space for fossil fuels in the mix shrunk considerably. The outlook for gas generation remains positive thanks to the prevailing expectations of rising carbon prices in the months and years ahead.
- **Figure 21** shows that with the exception of Italy, coal-fired power generation was not profitable in Q4 2020 for an average plant due to rising coal and carbon prices. [Clean dark spreads](#) in Italy, where power prices were relatively higher, averaged 6 €/MWh in Q4 2020, which was lower than in the case of gas-fired power plants. Coal generation in Spain declined by 50% year-on-year in Q4 2020 to the point of irrelevance, with only few units remaining in the market. German coal generators, in contrast, increased their output by 7% year-on-year in Q4 2020, as nuclear generation gradually faded in accordance with the German nuclear phase-out plan and no other capacities were available as replacement.

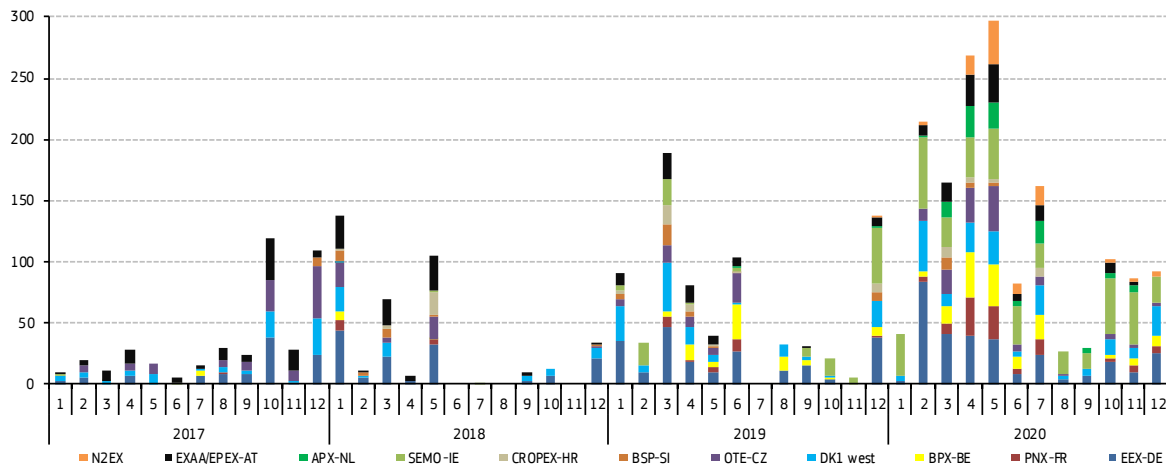
Figure 21 – Evolution of clean dark spreads in the UK, Spain, Italy and Germany, and electricity generation from hard coal in the EU



Source: ENTSO-E, Eurostat, Bloomberg

- **Figure 22** shows the 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 281, the number of hours with negative wholesale prices in Q4 2020 was 71% higher in the observed bidding zones than in the previous Q4. Falls into negative territory were evenly spread among the three months of the reference quarter and occurred mostly during weekends when low consumption coincided with high renewable generation. Strong wind speeds on 27 December (Sunday) pushed German and Danish (DK1 zone) prices below zero for most of the day. This capped a record-breaking year for negative prices which numbered almost 1600 in the 11 bidding zones under observation, double the amount from 2019.
- The integrated Irish zone recorded the highest number of negative hourly prices (382) in 2020 and was trailed by Germany (298) and the Danish mainland (DK1) zone (192). Low electricity consumption and rising renewable penetration brought negative prices even to markets which traditionally do not display many such instances, such as France or Great Britain. The Netherlands saw the number of falls below zero jump from 3 in 2019 to almost 100 in 2020 amid a dramatic increase in solar PV capacity. Greece experienced first-ever negative prices in December, four weeks after it started day-ahead trading. The pandemic and its aftermath 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.

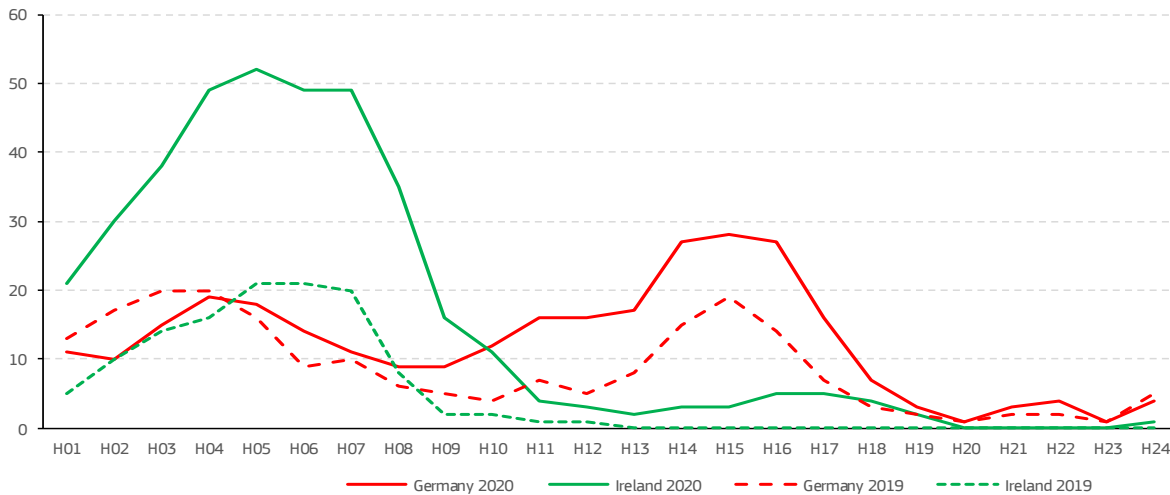
Figure 22 – Number of negative hourly wholesale prices on selected day-ahead trading platforms



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

- Figure 23** displays the distribution of negative wholesale power prices throughout the day in Germany and the integrated Irish market over the course of 2020 and, for comparison, in 2019. Both markets saw the number of negative hours go up significantly year-on-year. On the Irish island, negative prices occurred almost exclusively during the night when demand was low and wind generation reached high levels. Most of the annual increase came during the same period, even though there were already some instances of negative prices during the afternoon when solar generation contributes to renewable penetration. Germany, in contrast, experienced an interesting shift in which the highest concentration of negative hourly prices moved from night-time to the afternoon on the back of rapidly rising solar PV capacity, which coincided with sunny weather and low consumption during the spring lockdown. Thus, solar PV became the main driver behind prices falling into negative territory in the German market in 2020 and also put afternoon prices under pressure generally. While the average baseload price in the German market decreased by 19% in 2020 year-on-year, prices between 13:00 and 16:00 pm fell by a quarter on average.

Figure 23 – Hourly comparison of the occurrence of negative prices on selected day-ahead trading platforms in 2020 and 2019



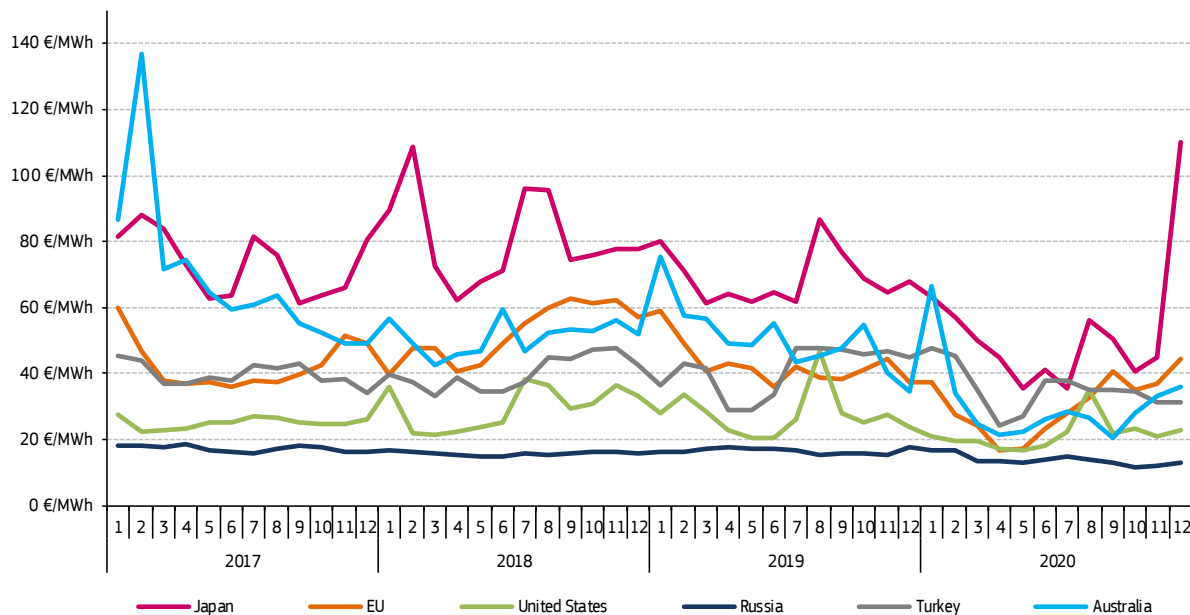
Source: Platts, ENTSO-E.

- Figure 24** compares price developments in wholesale electricity markets of selected major economies. While most markets saw prices returning to pre-pandemic levels in Q4 2020, Japan experienced a sharp increase in December which escalated further in January when prices surged to 2000 €/MWh on some occasions, above levels reached in the aftermath of the Fukushima disaster. The primary driver behind the price spike was very cold weather which boosted electricity demand to ten-year highs. This prompted a scramble for LNG, a major fuel for the country’s power plants. Utility companies urged customers to ration electricity to prevent blackouts, although no outages occurred. A similar story played out in China and South Korea, turning the gas scarcity into a regional issue. Many Japanese generators were unprepared for such high demand and had insufficient LNG stocks ahead of winter. The

event demonstrated the risk of high dependency on one particular fuel. Of the 33 currently operable nuclear units in Japan, nine have been restarted since 2015.

- With the exception of Japan, European wholesale prices were the highest of the observed group in Q4 2020, reaching 39 €/MWh. Russia remained at the other end of the spectrum with 12 €/MWh, which was 24% lower than in the same quarter last year. The decrease was mainly driven by the weakening rouble.
- For the whole year 2020, wholesale prices in the EU averaged 30 €/MWh, similar to Australia and below Turkey (35 €/MWh) and Japan (53 €/MWh). At the same time, European prices were 41% higher than in the US.

Figure 24 – Monthly average wholesale electricity prices in Europe, US, Japan and Australia (D-A markets)

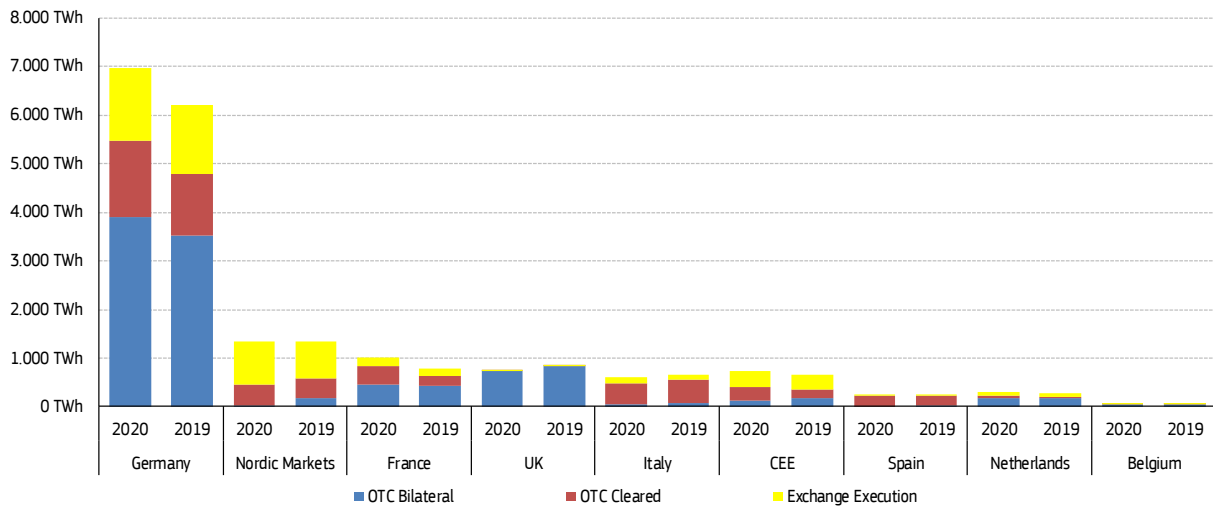


Source: European Power Benchmark, JPEX (Japan), AEMO (Australia), JCS ATS (Russia), Energy Exchange Istanbul (Turkey) and the average of selected PJM West, ERCOT, MISO Illinois and CAISO regional wholesale hubs in the United States.

2.2 Traded volumes and cross border flows

- **Figure 25** shows annual changes of traded volumes of electricity in the main European markets, including exchange-executed trade and over-the-counter (OTC) trade. Increased price volatility induced by the pandemic generally lifted trading activity. Most markets and regions witnessed an increase in volumes in 2020, with the UK and Italy being the exceptions. The largest annual rises in total traded volumes were registered in France (+29%), Belgium (+17%) and Germany (+12%), driven mainly by the OTC sector. The total traded volume in all markets under observation rose by 8% year-on-year to 12,008 TWh in 2020.
- Germany cemented its position as by far the largest and most liquid European market, with more activity both at exchanges (+5%) and in OTC contracts (+14%) in 2020. Total volumes reached 7000 TWh, the highest figure since 2016 and 1000 TWh shy off the all-time high from 2011. The market share of exchanges remained unchanged compared to 2019. Similar relative increases in activity were visible in the CEE region where total volumes rose by 10% to 727 TWh. Nordic markets registered a large decrease in bilateral OTC deals (-80%) at the expense of rising exchange-based volumes (+16%). The net impact on total volumes was zero, but the market share of power exchanges expanded from 56% to 65% year-on-year. The largest falls in exchange-based volumes were reported in Belgium (-18%) and the Netherlands (-14%). Overall, exchange-based trading volumes increased by 253 TWh in 2020 and kept their share in the market at 26%. The OTC segment traded 674 TWh of electricity more in 2020 compared to 2019, mainly thanks to greater volumes changing hands in Germany and France.

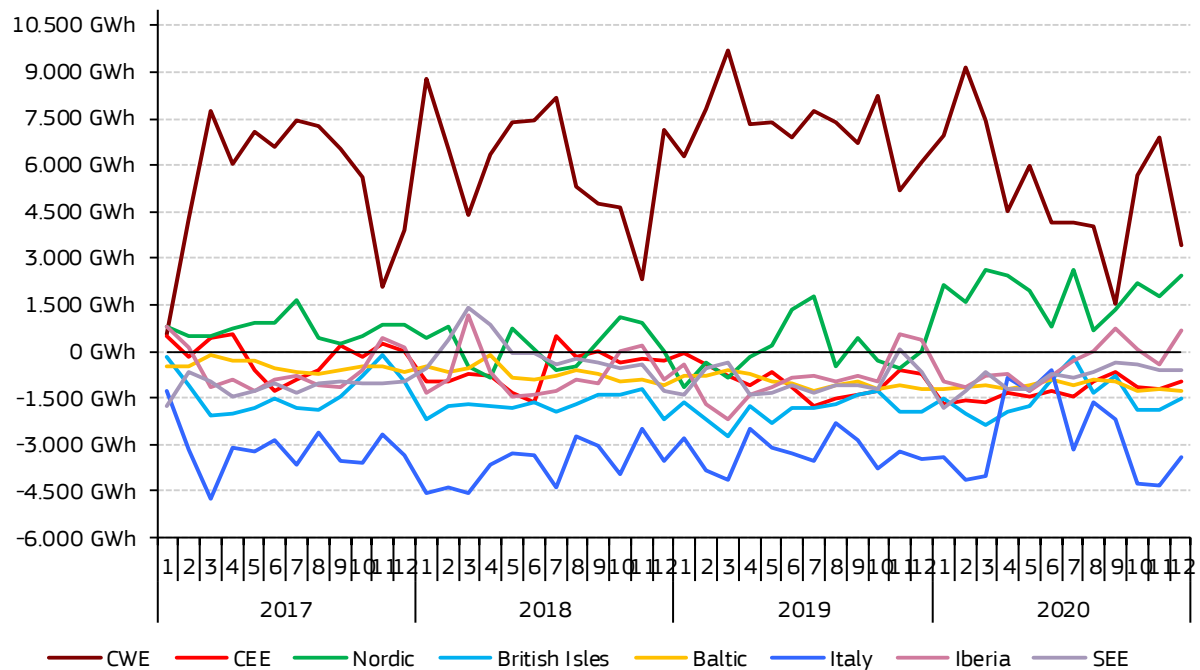
Figure 25 – Annual change in traded volume of electricity on the most liquid European markets



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

- Figure 26** reports on the regional cross-border flows of electricity. Central Western Europe exploited its strong potential and with 16 TWh of net exports was again the largest source of outflows in the final quarter of 2020, but this was still 18% lower than in Q4 2019. The decrease can be traced mainly to lower overall consumption and extremely high Scandinavian exports (mainly from Norway). Thanks to overflowing hydro reservoirs and rising wind generation, the Nordic region recorded a surplus of 6 TWh in the reference quarter, a large swing compared to nearly 1 TWh of net imports in Q4 2019. The Iberian Peninsula also emerged as a net exporter, even though only by a slight margin. This fits into a typical pattern in which Spanish generation increases towards the end of the year thanks higher wind speeds and rising hydro generation in winter.
- The rest of the regions ended up in deficit. Italian net imports rose by 15% year-on-year to 12 TWh in Q4 2020, returning to pre-pandemic levels for the first time. Net flows to the British Isles remained roughly unchanged compared to Q4 2019 at 5 TWh. The CEE region's net position (-3 TWh) worsened in Q4 2020 compared to Q4 2019 lower nuclear availability in Czechia and Hungary. South Eastern Europe's balance remained unchanged (-2 TWh) compared to the previous Q4.

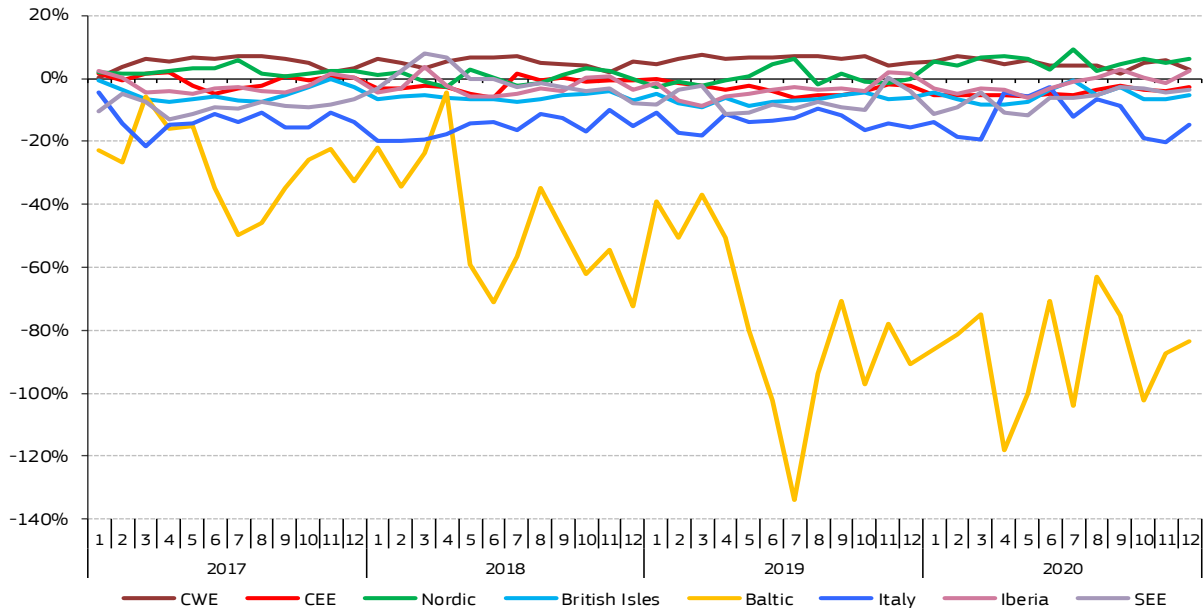
Figure 26 – European cross-border monthly physical flows by region



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 27** compares net cross border flows to regional power generation to give a better comparative perspective on the flows and their size. Positive values indicate a net exporter. The position of the Baltic region, which has the biggest deficit compared to the size of its power sector, remained largely unchanged in Q4 2020 compared to the same quarter a year ago. Net imports (4 TWh) reached about 91% of domestic generation. Italy became the second biggest importer relative to its domestic generation (18%). For the rest of the regions, net imports (or exports) did not exceed 7% of domestic generation.

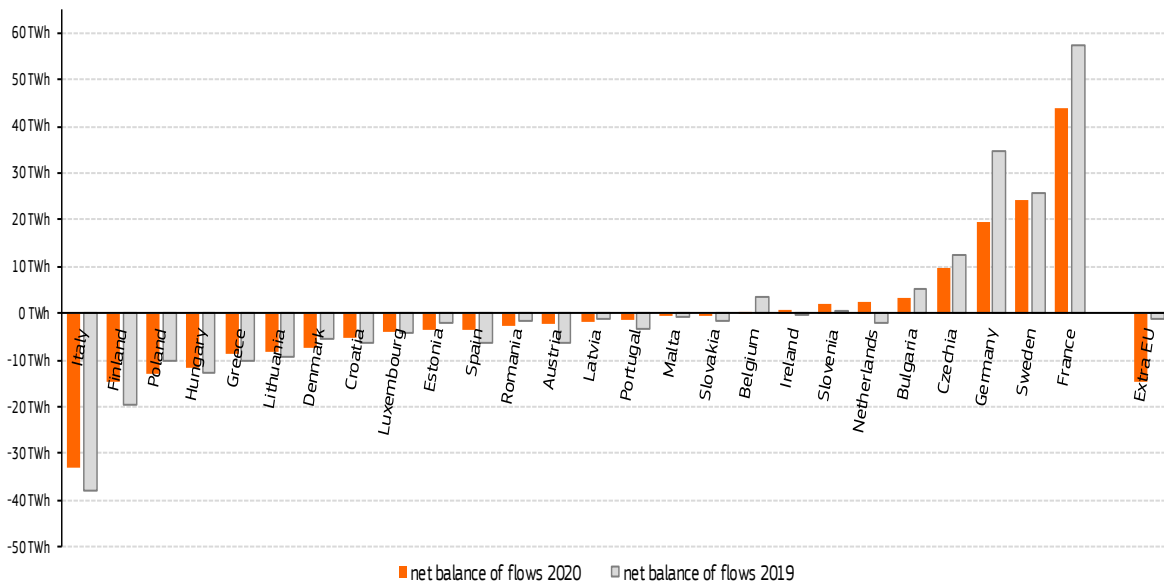
Figure 27 – The ratio of the net electricity exporter position and the domestic generation in European regions



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

- **Figure 28** compares net balances of physical electricity flows among EU Member States in 2019 and 2020. The pandemic, coal-to-gas switching and rising renewable generation in certain regions combined to make net trading positions more balanced than in previous years.
- France topped the list of net exporters with 44 TWh of net surplus, which was 23% below the 2019 level. This was driven mainly by lower consumption and higher renewable generation abroad, and by lower availability of the French nuclear fleet, which generated 45 TWh less than in the previous year (see **Figure 36**). German net exports fell by 44% to 19 TWh (the lowest net surplus in a decade) on the back of collapsing coal- and lignite-fired generation, which was replaced by cheaper gas plants or renewables elsewhere or crowded out by low demand. As it retires roughly 20 GW of dispatchable nuclear, lignite and coal capacities in the next two years, Germany is expected to shift to being a net importer of electricity in 2023. Bulgaria and Czechia also saw their surpluses slide on the back of falling domestic lignite output.
- After being in deficit for many years, the Netherlands swung to a net surplus in 2020 on the back of rapidly rising renewable and gas generation. In just two years, annual Dutch solar output more than tripled to 8 TWh. Italy, traditionally the largest importer, decreased its net deficit by 14% to 33 TWh as domestic generation fell to a smaller extent than consumption. Finland, Spain and Austria reduced their net imports for the same reason. Hungary, where consumption remained unchanged, saw its balance boosted thanks to expanding solar PV capacities.

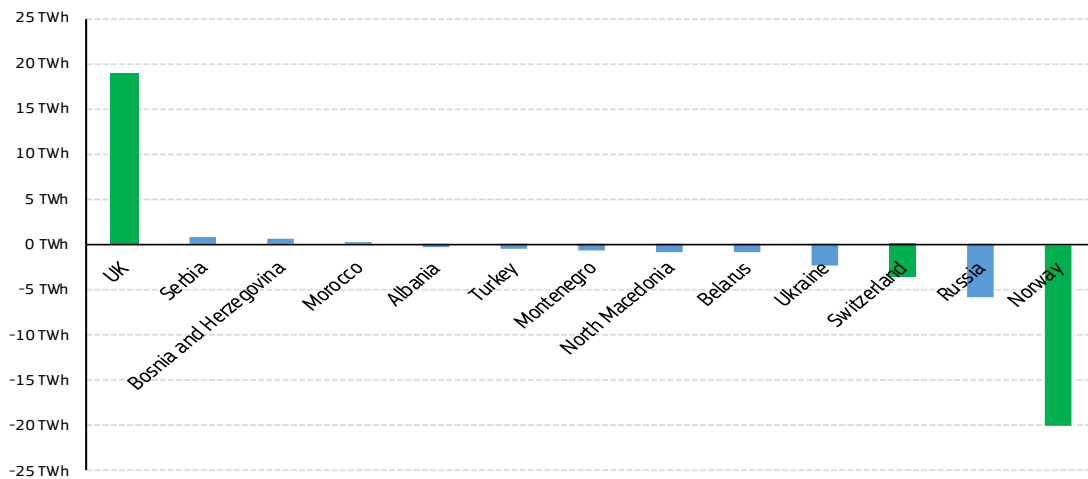
Figure 28 – Member States’ net export/import positions within the EU in 2020 and 2019



Source: ENTSO-E, TSOs, Eurostat

- Figure 29** shows netted electricity exchanges with EU neighbours in 2020. Most of the trade took place with just two partners. Great Britain became EU’s biggest export market with 19 TWh of net outflows from the continent, which was 16% lower than in 2019 due to the impact of the pandemic on British consumption. Norway stood at the opposite side with 20 TWh of net exports into the EU, powered by record hydro generation and rising wind output. This was a stark contrast to 2019, when the net result of bilateral trade was an even zero. Russian exports the EU decreased by 56% year-on-year to 6 TWh, crowded out by cheaper Norwegian flows and falling consumption in Finland (see **Figure 3**). Net imports from Ukraine also decreased substantially (-44% compared to 2019) in 2020, as low electricity prices in Hungary and Romania during the lockdown period discouraged cross-border trade. Exchanges with countries not applying similar level of carbon pricing resulted in net import of 9 TWh (down from 20 TWh in 2019). Coal generation in Serbia and Bosnia and Herzegovina rose by 4% and 8% respectively in 2020. Nevertheless, both countries imported more from the EU than exported in 2020.

Figure 29 – Extra-EU electricity exchanges in 2020 – netted



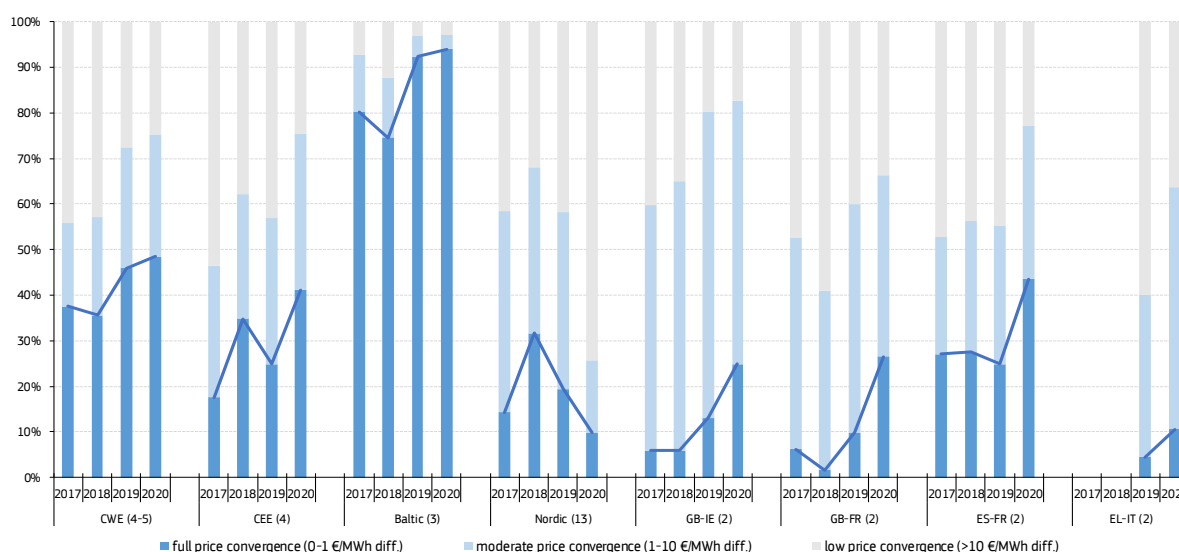
Source: ENTSO-E, TSOs, Eurostat, Inter RAO. Negative values indicate net imports to the EU. Green colour denotes neighbours with similar or identical levels of carbon pricing.

3 Focus on developments in annual wholesale prices

3.1 Day-ahead price convergence

- Figure 30** illustrates the degree of price convergence in day-ahead markets within selected European regions expressed in percentages of hours in a given year. Price convergence provides an indication of the level of market integration. Its longer-term drivers are market coupling initiatives or the expansion of interconnection capacities. In the short term, fluctuations in convergence may also be caused by factors not necessarily related to the level of market integration, such as changes in the amount of cross-zonal capacity designated by TSOs for commercial purposes, long-lasting outages of transmission lines, significant shifts in the power mix or in consumption patterns. Several of these one-off factors influenced developments in convergence in 2020, the covid-related demand shock being one of them.
- Overall, there was more convergence in 2020 than in the previous year. In the CWE region, which is the only one where flow-based market coupling has been applied since 2015, the number of occurrences of full price convergence (when the difference between hourly prices in all bidding zones is lower than 1 €/MWh) increased slightly (from 46% to 49% of hours). The exact causes are dissected in the following figures, but the impact of the pandemic was double-sided. A considerable increase in full price convergence occurred within the four coupled markets in Central Eastern Europe (CEE), reaching more than 40% of hours. Higher convergence levels in the region were observed especially in the second part of the year. The three Member States in the Baltic region remained highly convergent in 2020, with hourly prices nearly identical 94% of the time. Price convergence continued to rise across the British Isles, following the implementation of market coupling between Great Britain and the Irish Integrated Single Electricity Market. However, the two islands, connected by two interconnectors, were decoupled in 2021 because of Brexit. The British day-ahead order books are no longer coupled with other European markets, which could also affect the positive trend of rising convergence between Great Britain and France observed in the last three years. On the other hand, a new 1 GW interconnector linking Great Britain and France (IFA2), operational since January 2021, should mitigate the effects of the decoupling.
- The significant increase in convergence between Spain and France in 2020 can be attributed mainly to rising renewable generation and low consumption levels in Spain going up against reduced nuclear availability in France. This resulted in Spanish prices falling more than their French counterparts and moving closer to French levels both on average and hour by hour. Even though Italy and Greece were coupled only in the middle of December 2020, the results are already visible in an annual overview, with convergence levels doubling year-on-year. In December alone, prices were fully convergent 31% of the time. Electricity market reforms introduced in November, rising renewable generation and intensive lignite-to-gas switching in Greece contributed to the positive development. The Nordic region became the only one registering a significant drop in convergence levels in 2020. This marked a continuation of a trend visible since 2018, driven by growing trade imbalances of the four Scandinavian countries not matched by an expansion of interconnection capacity. In 2020, record high Norwegian hydro generation, which put local prices under heavy pressure, played a crucial role in driving hourly prices in the region further apart.

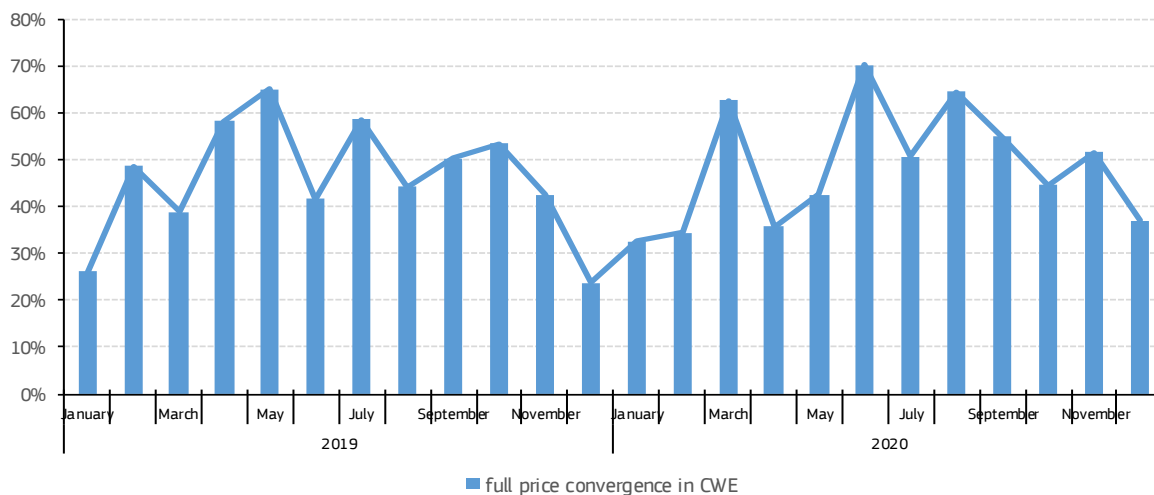
Figure 30 – Price convergence on day-ahead markets in selected regions as percentage of hours in a given year



Source: ENTSO-E, OTE, Nord Pool, Platts. The numbers in brackets refer to the number of bidding zones included. The CWE region comprises of BE, FR, NL and DE-LU-AT zones until October 2018, and separate DE-LU and AT zones since then. The CEE region includes CZ, SK, HU, RO bidding zones which are coupled. The Baltic region includes EE, LV, LT bidding zones. The Nordic region includes 13 bidding zones of Norway, Sweden, Finland and Denmark.

- Figure 31** demonstrates that price convergence is subject to seasonal fluctuations and that it changes from month to month. In the case of the CWE region, lower price convergence is observed during winter months when electricity consumption increases and the grid is under greater stress due to higher loads. At the same time, periods of exceptionally low consumption with fewer dispatchable capacities online and higher shares of renewable penetration can also push convergence levels lower. The period of spring 2020 is a case in point. Convergence levels were relatively low in April and May 2020 when the most stringent and widespread social distancing measures were in place. Despite record falls in electricity demand, hourly prices across the CWE region were moving further apart.

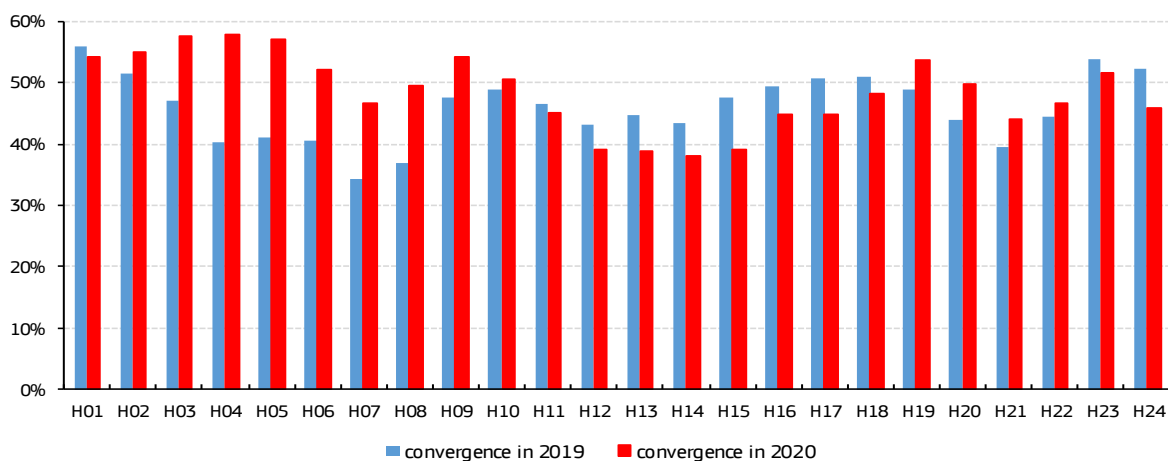
Figure 31 – Monthly full price convergence in the CWE region in 2020 and 2019



Source: ENTSO-E

- Figure 32** investigates how price convergence developed throughout 24 hours of the average day in 2019 and 2020, offering additional clues about possible sources of changes. It is visible that hourly prices were more convergent in the early morning hours in 2020, which could be the result of slower starts of workdays as more people worked from home and did not have to commute. A comparison between average daily consumption patterns shows that the biggest annual drops in network load in most CWE countries in 2020 occurred between 5 a.m. and 9 a.m. when the load usually increases quickly. This would confirm the assumption that the lower morning load (and lower ramping demands) led to greater price convergence. Lower convergence in afternoons in 2020 was probably caused by unevenly rising solar penetration in the CWE region, especially during the spring lockdown when falling consumption and sunny weather allowed solar PV generators to take over larger shares of the mix than usual and press down prices. In France, which has small solar capacities relative to its consumption, prices in the afternoon fell by 17-20% year-on-year on average in 2020. In contrast, average afternoon prices in Belgium, Germany and the Netherlands, where solar generation plays a bigger role, fell by 22-27% year-on-year in 2020. Growing disparities between generation bases in the CWE region have thus driven local electricity prices further apart. That is one of the factors behind low convergence levels in April and May 2020 when solar penetration reached record highs.

Figure 32 – Average hourly full price convergence in the CWE region in 2020 and 2019



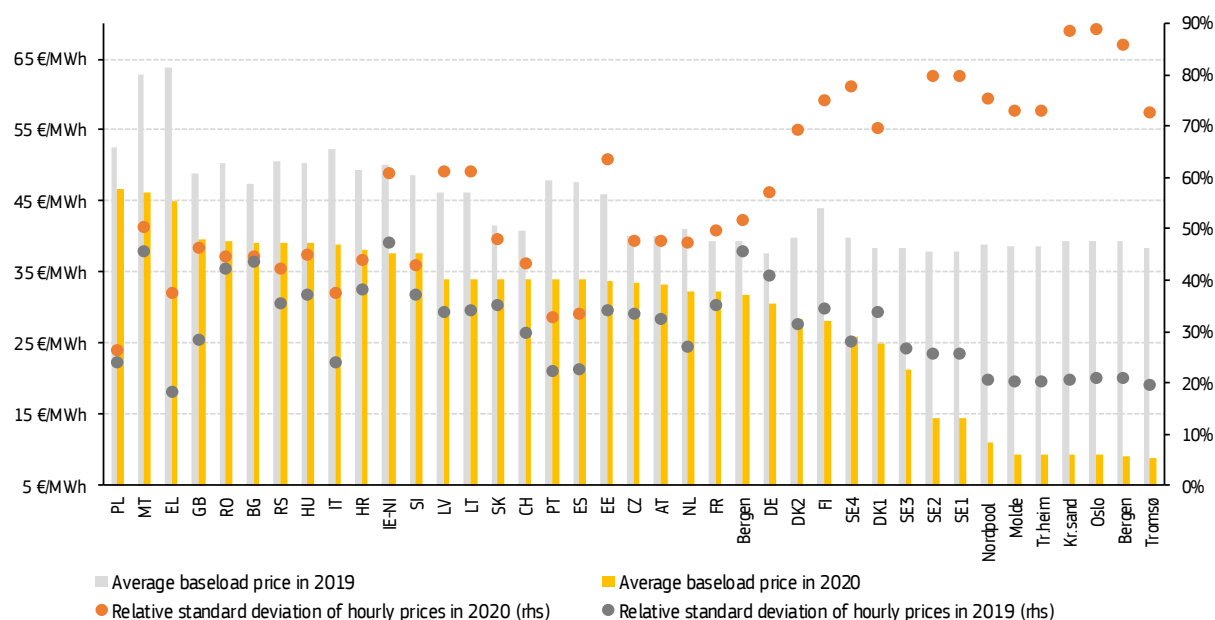
Source: ENTSO-E

- Expected adjustments in the capacity calculation methodologies and the application of the cross-zonal capacity targets set by [Regulation \(EU\) 2019/943](#) on the internal market for electricity, together with the completion of market coupling, are expected to increase price convergence across Europe. Another strong impetus towards greater convergence should be provided by a number of interconnectors scheduled to come online in the next few years. The Nordic border transmission capacity should expand from 7 GW at the beginning of 2020 to 14 GW by 2030. Half of that capacity should be linked to Germany.

3.2 Average annual price levels and volatility

- **Figure 33** maps annual changes in average day-ahead baseload prices and in hourly price dispersion across European day-ahead markets. Emission allowances were on average traded at the same price in 2020 as in 2019. The universal decrease in the price of baseload electricity observed in 2020 can be attributed to lower fuel costs and the covid-related demand shock (see **Figure 3** and **Figure 9**). Wholesale prices did not fall to the same extent, however. Poland, greatly dependent on coal-fired generation, became the most expensive European market (47 €/MWh) and at the same time experienced the lowest annual decrease in prices (-11%), despite the fact that its power demand fell more (-5%) than the EU average. Greece, in contrast, experienced a 29% drop in wholesale prices as it increased renewable generation (see **Figure 19**), intensified lignite-to-gas switching (**Figure 20**) and progressed in market reforms (**Figure 30**). Markets at the higher end of the spectrum are typically energy islands or relatively isolated areas dependent on imports (MT, GB, IT), or have a significant presence of emission-intensive lignite generation in their mix (PL, EL, RO, BG, RS, HU). The lowest prices were observed in the Nordic region, but even there the differences were large. Norwegian bidding zones were on average below 10 €/MWh thanks to record high hydro generation and rising wind output (see **Figure 41**). Bidding zones in Denmark, Finland and southern Sweden with a different mix consisting also of fossil fuels and nuclear could not match such low levels.
- All markets experienced higher levels of price volatility in 2020 (measured as relative standard deviation of hourly prices and plotted on the right-hand scale of the chart). This could be the result of the pandemic which affected consumption patterns and brought prolonged periods of very low or even negative prices into the market. Also, generally lower price levels can be conducive to greater relative jumps in both directions. Extremely high volatility was observed in Nordic markets with below-average prices. Poland, Romania and Bulgaria, on the other hand, saw only small changes in price volatility. Volatility can greatly influence asset profitability in the electricity sector. For storage technologies, for instance, the greater the absolute spread between minimum and maximum prices in a day, the more they can earn by buying low and selling high.

Figure 33 – Changes in average baseload prices and hourly price volatility in European day-ahead markets between 2020 and 2019



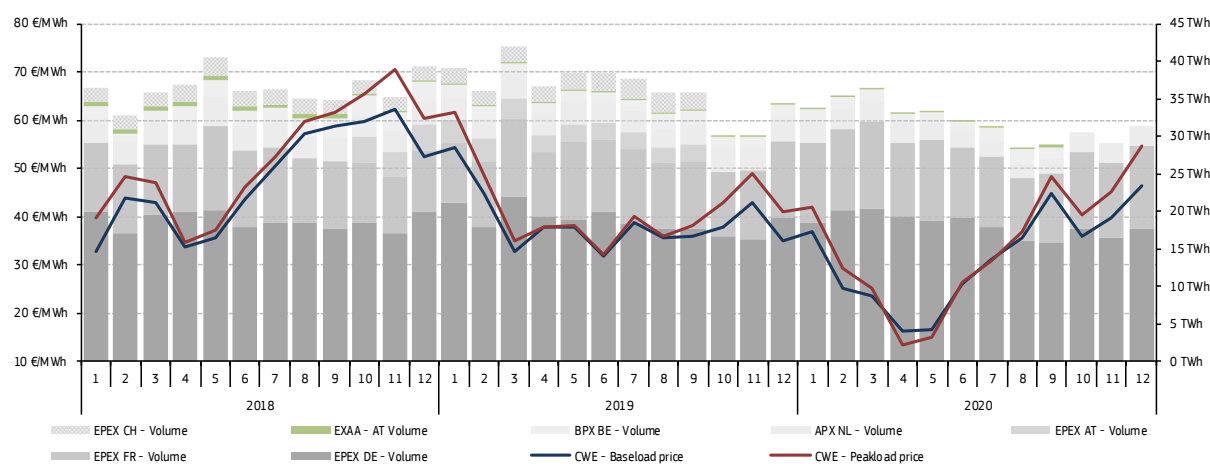
Source: ENTSO-E, OTE, Nord Pool, Platts. Italy is represented by the national average (PUN), the rest of the markets under observation correspond to bidding zones. Ireland has a common bidding zone with Northern Ireland (ISEM). Prices in Great Britain are represented by the N2EX power market.

4 Regional wholesale markets

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

- After reaching peak levels in September, baseload electricity prices in Central Western Europe (CWE) experienced a drop during October due a lower electricity demand as a result of the second European lockdown. However, prices went up again in November and took a steady upward direction amid increasing gas prices as a result of cold weather and concerns over supply. The monthly average price climbed to 46 €/MWh for baseload power in December, representing the highest price experienced during 2020, due to low wind speeds, rising carbon prices and relatively high demand levels during cold spells. Compared to Q3 2020, the average baseload price in the region increased by 9% to 41 €/MWh in the reference quarter. Meanwhile, average peakload prices increased by 21% to 47 €/MWh.
- For the first time in the year, the availability of the nuclear French fleet experienced levels close to the historical ranges. Relatively low wind availability increased space fossil-based capacities. French exports rose strongly during November, thanks to recovering nuclear availability, which did not last in December. However, after seeing its export fall in spring and summer on the back of adverse conditions for coal and lignite generation, Germany returned to a surplus status, typical of it in the winter period. German exports were again driven by rising levels of lignite and hard coal generation which also had to replace part of the falling nuclear output. The Netherlands, experienced a 5% year-on-year decrease in generation (-2 TWh) due to decreased gas, coal, biomass and solar output. Higher offshore wind generation could not make up for lower output of thermal and other renewables. Hydro generation rose in Austria (+1 TWh year-on-year), pushing out gas and coal generation from the merit order.
- German cross-border transmission capacity received a considerable boost thanks to several projects completed in Q4 2020. In October, the world's first hybrid interconnector (CGS) between offshore wind farms in Germany and Denmark started operations. The 400 MW subsea cable will allow electricity from the wind farms to be delivered to both countries and will also serve for electricity trade when the wind does not blow at the often-congested border. In November, a 1000 MW underground high-voltage connection between Germany and Belgium was inaugurated, representing the first direct high-voltage link between the two countries. Finally, a 1400 MW subsea cable between Germany and Norway was brought online, connecting Nordic hydropower with German wind energy. However, the capacity of the link will be restricted in the first years of operation due to limitations of the German grid which is beset by internal bottlenecks and saturation zones.

Figure 34 – Monthly exchange traded volumes of day-ahead contracts and monthly average prices in Central Western Europe

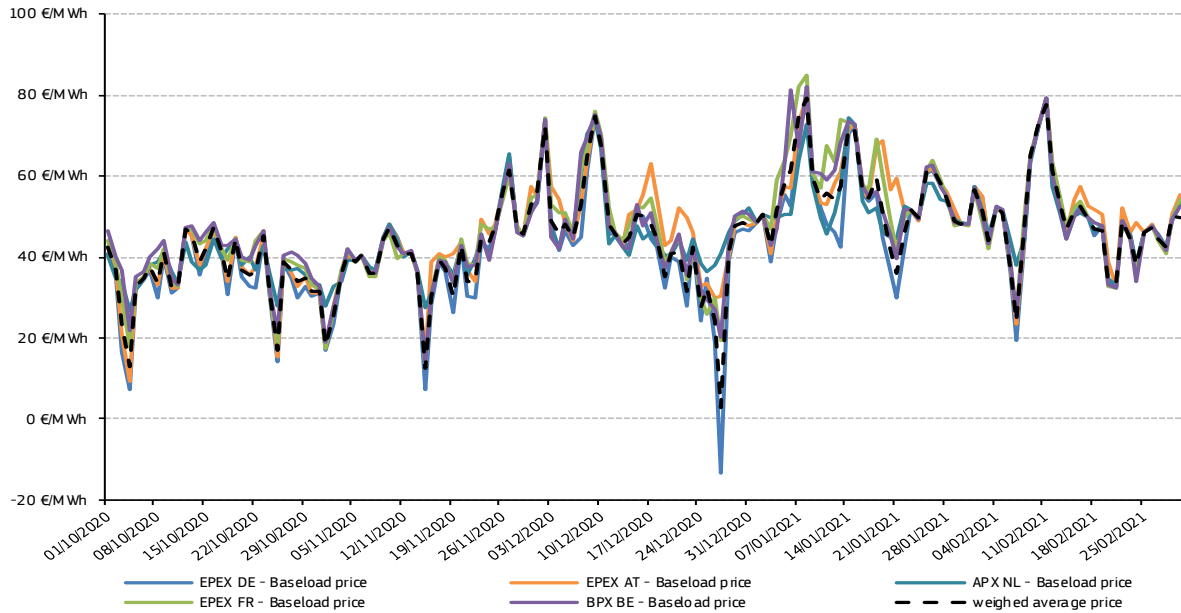


Source: Platts, EPEX. Volumes for EPEX-CH and EPEX-AT are missing.

- **Figure 35** shows the daily average day-ahead prices in the region in the reference quarter. Daily average prices held mostly 20-30 €/MWh in October and moved above 40 €/MWh in mid-November with a peak during the second week of December (79.2 €/MWh), before they started plummeting towards the end of the year, reaching a low value of close to 3 €/MWh on 27 December. A combination of strong wind speeds and low weekend consumption drove hourly prices below zero for most of the last Sunday of 2020 in Germany. For the fourth time in the year, wind generation in Europe peaked above 100 GW. Wind covered almost a third of continent's demand that day.
- In contrast, prices peaked on 9 December when extremely low wind generation, insufficient nuclear availability in France and Belgium and a cold spell required large imports from other regions. Hourly prices on the day-ahead market across many bidding zones surged above 110 €/MWh for the evening peak, which was still lower than during a similar scarcity event in September. However, as the supply tightness lasted longer this time, the German peakload

price climbed to a four-year maximum of 104 €/MWh. French demand peaked at 80 GW during this December day and had to be met with the help of imports.

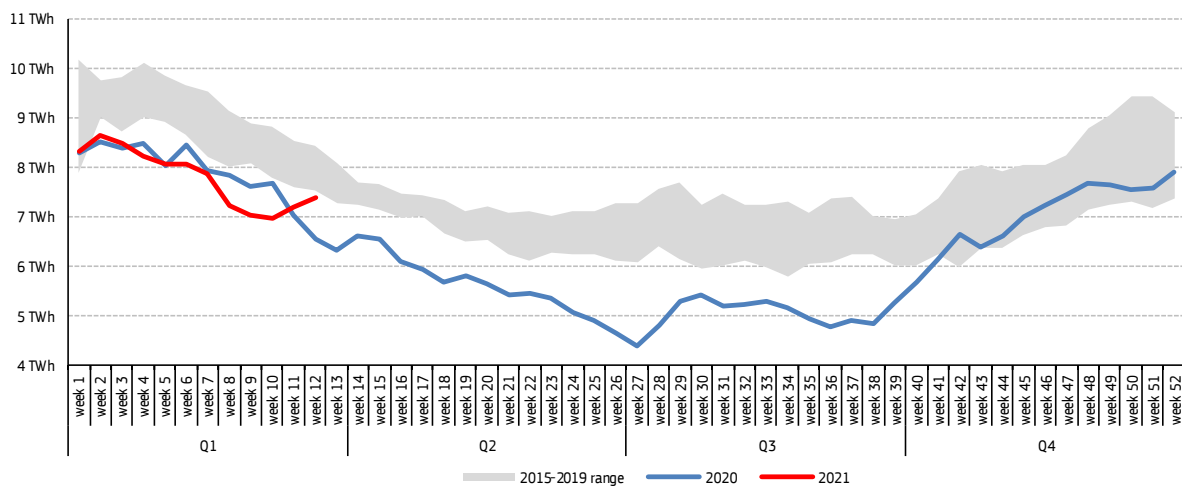
Figure 35 – Daily average power prices on the day-ahead market in the CWE region



Source: Platts.

- After reaching record monthly lows in Q3 2020, French nuclear generation returned to the historical average output range from October onwards, as shown in **Figure 36**. The available capacity climbed to 46 GW in December (compared with 44 GW in the same month of 2019). Total nuclear output in 2020 was slightly above the target (335 TWh), but still 45 TWh below the previous year.
- Nuclear availability in January 2021 held close to weak 2020 levels. A prolonged outage at Chooz 1 and a delayed return of Flamanville 1 negatively impacted generation volumes. In February, output fell to record low levels as 11 reactors started maintenance before spring. The 2021 output is estimated in the range of 330-360 TWh, which is still measurably lower than in the years before the pandemic.
- Nuclear availability in Belgium suffered from unplanned outages and lifespan extension works. Early 2021, the Belgium nuclear regulator (FANC) approved the restart of Tihange-2 which was shut in December for maintenance works. Belgian nuclear output fell almost 25% (9.7 TWh) year-on-year in Q4 2020. The nuclear phase-out plan foresees the first retirement in 2022. The last units are scheduled to be shut down in 2025.

Figure 36 – Weekly nuclear electricity generation in France

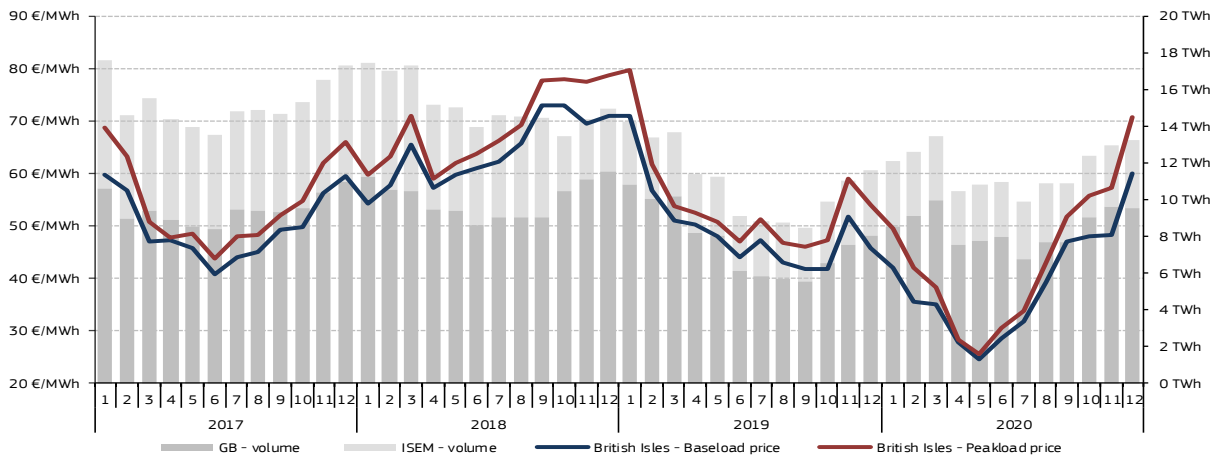


Source: ENTSO-E

4.2 British Isles (GB, Ireland)

- Figure 37** illustrates monthly volumes and prices on the day-ahead markets in Great Britain and in the all-island integrated market in Ireland. Monthly averages for both baseload and peakload power rose throughout the reference quarter reaching the highest level since January 2019 at the end of the period. The surge in wholesale power prices at the end of the quarter was driven by relatively low wind availability, rising gas prices, robust demand and a tightening balance on the continent. Compared to Q3 2020, the average baseload price on the British Isles rose by 33% to 52 €/MWh in the reference quarter and was 12% above the level from Q4 2019. Trading activity on the British day-ahead market increased by 28% in Q4 2020 compared to the same quarter last year and was unchanged in Ireland.
- Ireland closed its last peat-fired power plant at Lanesborough at the end of 2020. All peat harvesting was stopped and a peatland restoration project was launched in its place, which can secure and store over 100 million Mt of CO₂.

Figure 37 – 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 38** follows the developments of daily average baseload electricity prices in Great Britain (N2EX) and Ireland (ISEM). British baseload prices moved between 40 and 60 €/MWh during October and November, but climbed up close to 60 €/MWh during December as power demand and gas prices rose and wind speeds fell. Day-ahead prices spiked on 9 December amid calm weather, high demand and a warning of the grid operator about tight margins of spare electricity capacity. Intraday prices for the evening peak period surged to 248 €/MWh and recorded 11 hours of prices above 100 €/MWh. The Irish market generally followed the British contract albeit with larger volatility. As wind generation constitutes a more important part of the electricity mix on the Irish island, ebbs and flows of wind availability tend to make prices jumpier there than in Britain (see **Figure 22**).

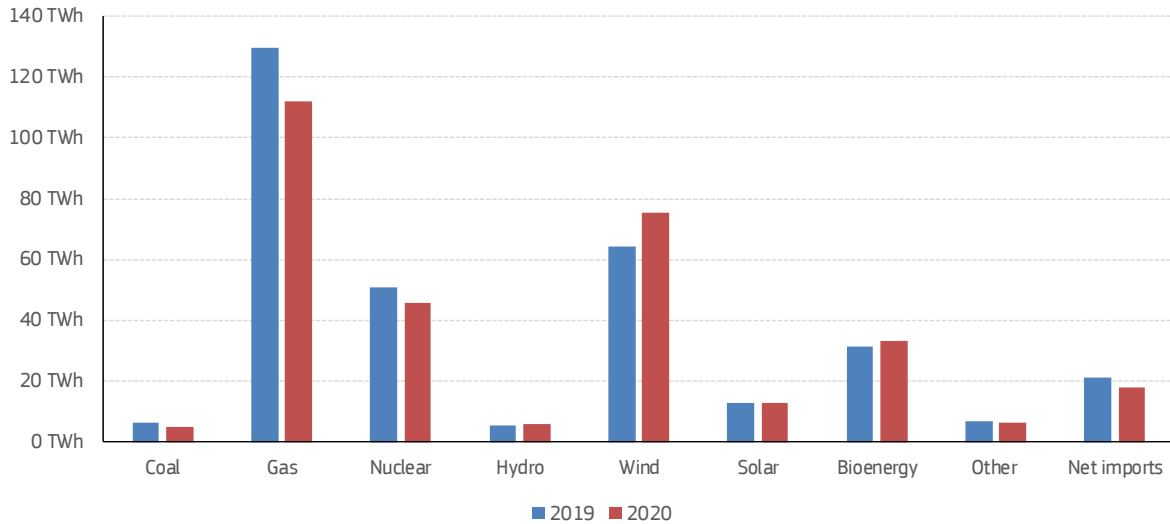
Figure 38 – Daily average electricity prices on the day-ahead market in Great Britain and Ireland



Source: Nord Pool N2EX, SEMO

- **Figure 39** shows that gas and nuclear generation were the main losers of the coronavirus pandemic and rising renewable generation in 2020. Imports from the continent were also affected, falling to their lowest level since 2017 on a net basis. The position of coal has not changed significantly, as the fuel is now used mainly to cover demand peaks at times of low renewable availability and should leave the mix soon. The renewable share rose sharply to 43%, up from 37% in 2019. This exceeded the share of generation from fossil fuels (39%) for the first time. The main driver behind rising renewable output was wind energy, especially in the offshore segment.

Figure 39 – Changes in the UK electricity mix between 2019 and 2020

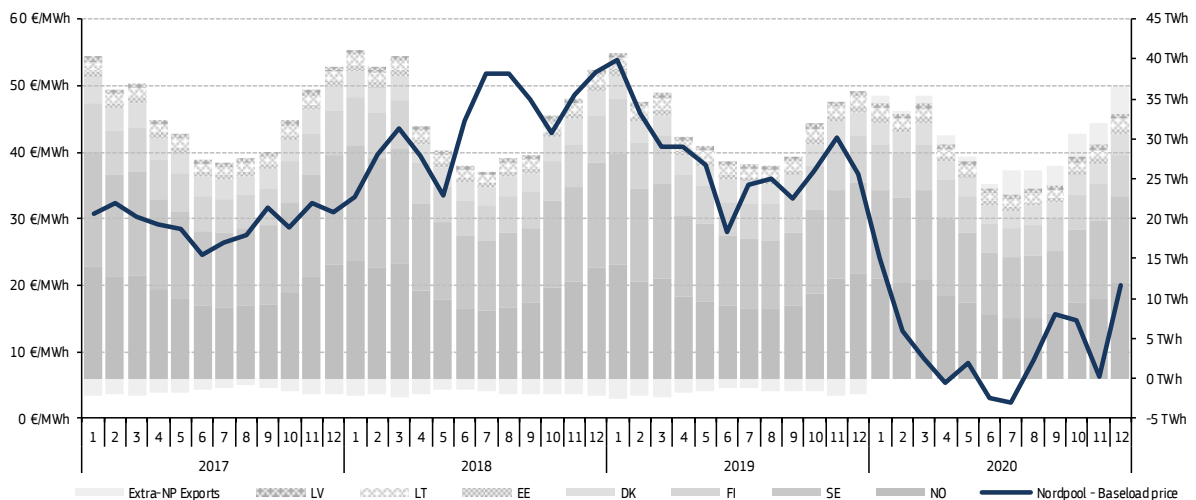


Source: BEIS

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

- As shown in **Figure 40**, after reaching a record of yearly low system prices during July, Nord Pool prices began to recover in August and September, only to fall again in November (6 €/MWh) on the back of high wind generation and warm conditions dampening demand. Prices rose again during the second week of December, lifted by the start of operations of a new 1.4 GW interconnector (NordLink) between Norway and Germany, increasing Norwegian export potential. Compared to Q4 2019, the average system baseload price tumbled by 65% to 14 €/MWh in the reference quarter. Trading activity was slightly higher compared to the previous Q4.

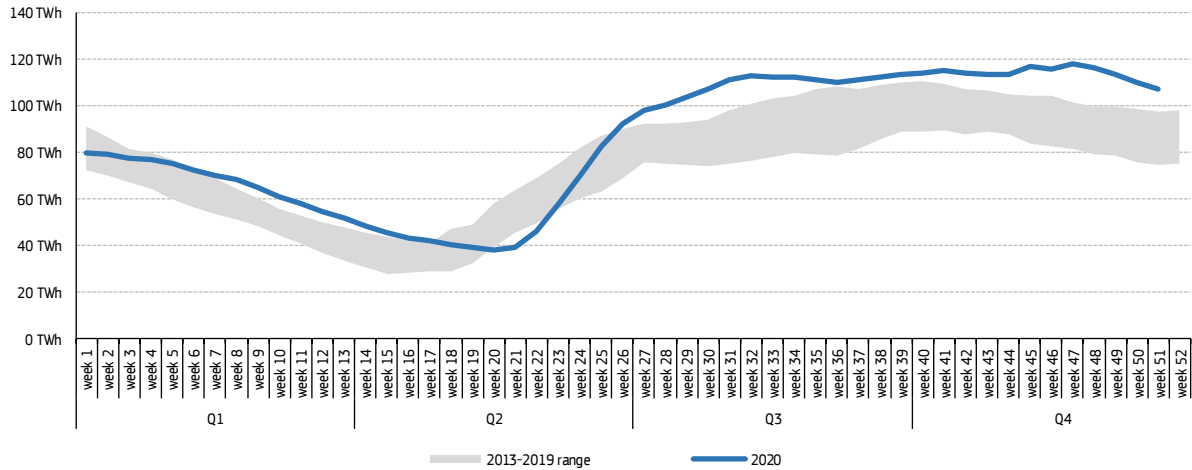
Figure 40 – Monthly electricity exchange traded volumes and the average day-ahead wholesale prices in Northern Europe



Source: Nord Pool spot market

- **Figure 41** shows the weekly evolution of the combined hydro reservoir levels in the Nordic area (Norway, Sweden and Finland) in 2020 compared to previous seven years. Hydro stocks in the region were overflowing during Q4 2020, holding above 110 TWh practically until the end of the year on the back of high precipitation and low consumption caused by warm weather. A noticeable drawdown in stocks took place only in December as tighter supply conditions due to colder weather and rising carbon prices increased prices on the continent and prompted a rise in Nordic exports. The total hydro generation in the region increased by 12% (or 7 TWh) year-on-year to 63 TWh in Q4 2020, contributing to relatively high net exports of the region in the period (see **Figure 26**).

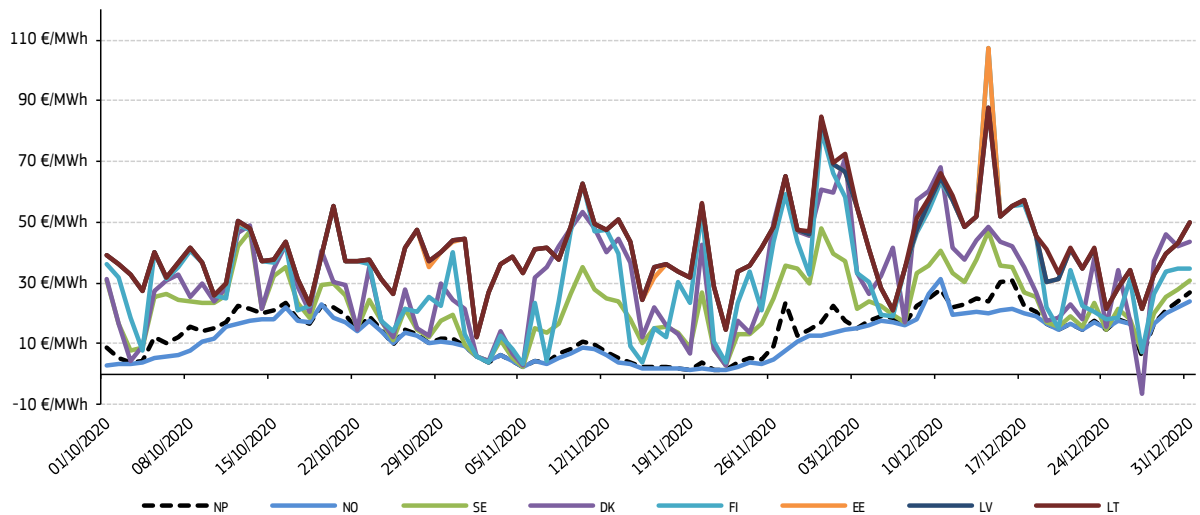
Figure 41 – Nordic hydro reservoir levels in 2020, compared to the range of 2013-2019



Source: Nord Pool spot market

- **Figure 42** shows that average daily prices across Northern Europe continued to display a high degree of divergence in Q4 2020, as in previous quarters. The Baltic region and Finland, which both suffer from considerable structural deficits (see **Figure 27**), registered nearly permanent premiums over the system contract. Temporarily reduced transfer capacities and lower nuclear availability lifted prices in Sweden above system levels in Q4 2020. Swings in wind generation and the necessity to rely on imports drove volatility in the Danish market. Norway reported daily baseload prices at or below the system price during the reference quarter. Cooler temperatures, rising export opportunities and lulls in wind availability increased system prices in the second half of Q4 2020.

Figure 42 – Daily average regional prices and the system price on the day-ahead market in the Nordic region



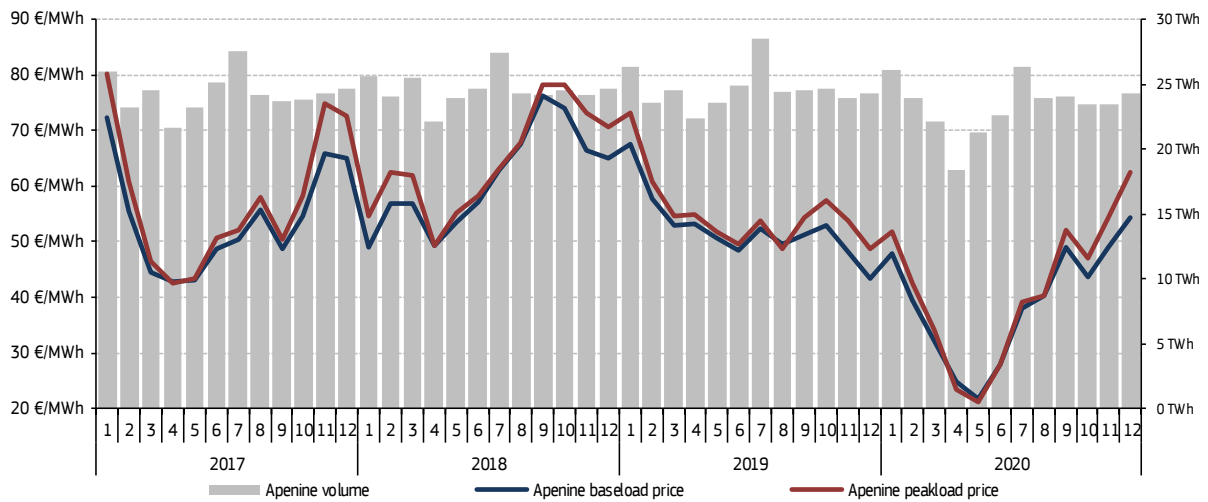
Source: Nord Pool spot market

4.4 Apennine Peninsula (Italy, Malta)

- Italian monthly average baseload electricity prices (**Figure 43**) fell in October from the previous peak in September. Colder temperatures combined with relatively low renewable generation and rising gas prices to drive day-ahead prices during the rest of the reference quarter. Baseload electricity prices averaged 55 €/MWh in December, the highest level since February 2019, as demand recovered to the full extent and gas prices rose further. The average

baseload price in Q4 2020 rose by 16% compared to Q3 2020 to 49 €/MWh, and was 2% above Q4 2019 levels. Trading volumes decreased by 2% compared to the previous Q4.

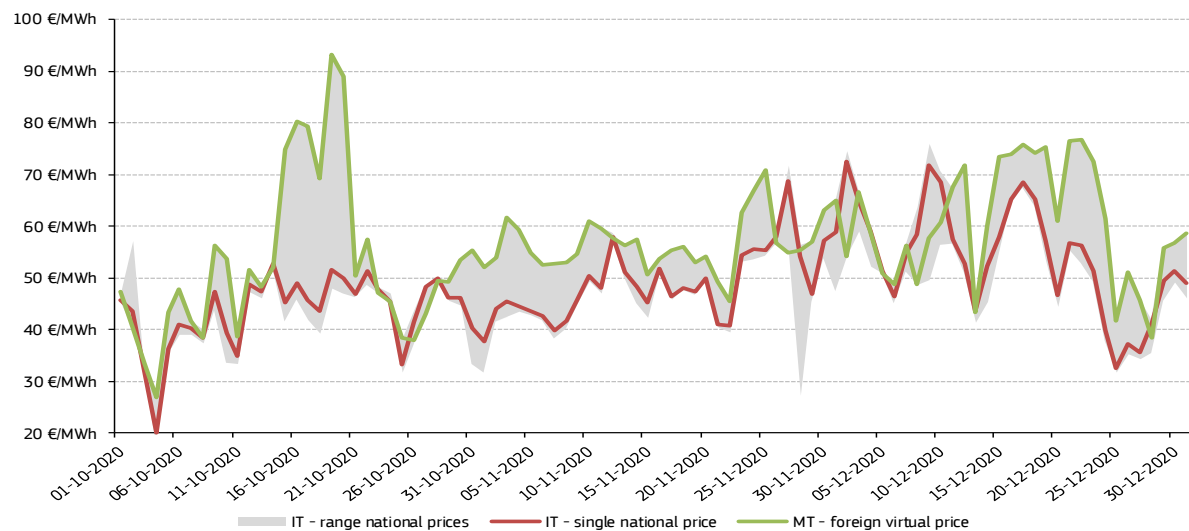
Figure 43 – Monthly electricity exchange traded volumes and average day-ahead wholesale prices in Italy



Source: GME (IPEX)

- **Figure 44** 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 50 €/MWh during the first half of reference quarter and moved above 50 €/MWh in December on the back of cold weather, low renewables and higher gas prices. The peak came on 9 December amid a continent-wide supply tightness (see **Figure 35**).
- 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 44**, prices in the Maltese zone mostly formed the upper boundary of the band of regional prices in the reference period with a few exceptions at the beginning of December.

Figure 44 – Daily average electricity prices in the Italian day-ahead market, within the range of different area prices



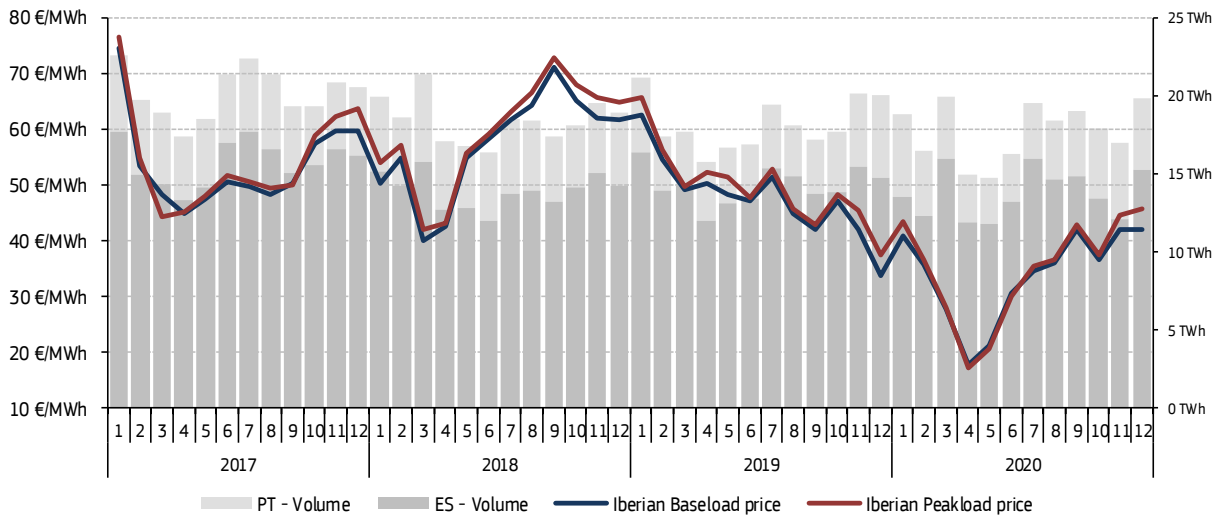
Source: GME (IPEX)

4.5 Iberian Peninsula (Spain and Portugal)

- **Figure 45** reports on monthly average baseload and peakload contracts in Spain and Portugal. Average baseload electricity prices fell to 37 €/MWh in October on the back of strong hydro and wind generation and new social distancing measures. Prices went up in November and stayed stable in December as weak demand and strong wind output largely compensated for rising gas prices. Compared to Q4 2019, the average baseload price declined by 2%

to 40 €/MWh in the reference quarter. Peak prices increased by 3% to 43 €/MWh. Trading activity was 10% lower compared to the previous Q4.

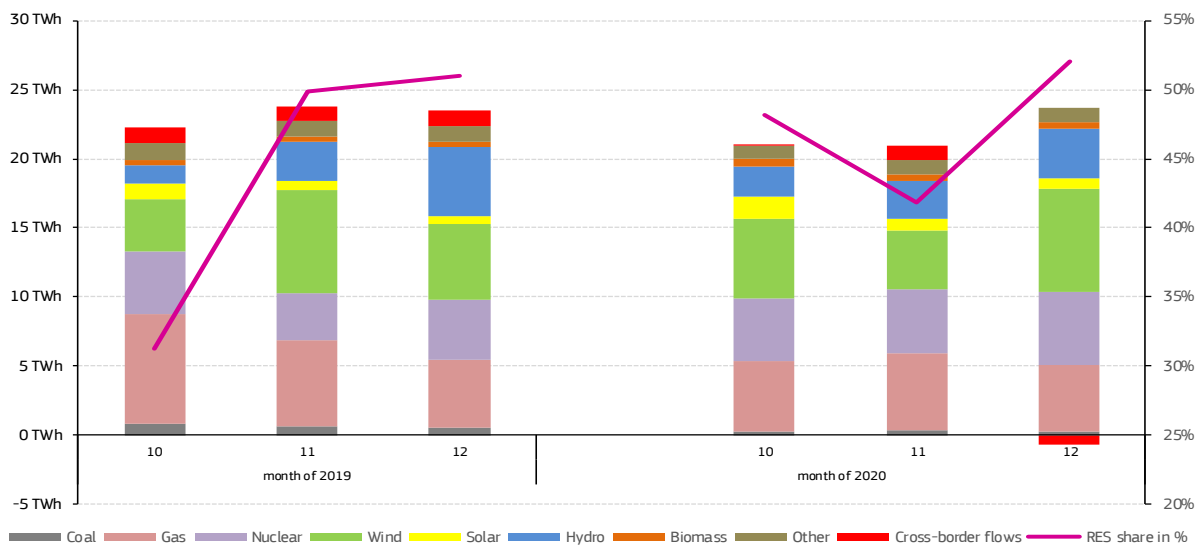
Figure 45 – Monthly electricity exchange traded volumes and average day-ahead prices in the Iberian Peninsula



Source: Platts, OMEL, DGEG

- Figure 46** displays the evolution of the monthly electricity generation mix in Spain during the fourth quarter of 2020, as well as during the same period of the previous year. Net generation decreased by 3% year-on-year, in line with a decrease in consumption. Spain remained a net importer during the first two months of the quarter and turned into a net exporter in December, when renewables hit a penetration record of 52% of the supply mix, on the back of very high wind generation and weak demand. This allowed Spanish renewable generation to reach an average of 47% in Q4 2020, up from 44% a year before. Squeezed out by low demand and surging renewables, gas generation fell by 19% year-on-year in Q4 2020. Thus, the share of gas in the mix shrank from 29% in Q4 2019 to 24% in Q4 2020. Coal has virtually disappeared from the mix. The share of nuclear energy increased from 19% in Q4 2019 to 22% in the last quarter of 2020.
- Spanish renewable capacity expansion slowed in 2020, with around 4 GW of solar PV and wind additions registered (compared to 7.4 GW of new capacity installed 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.

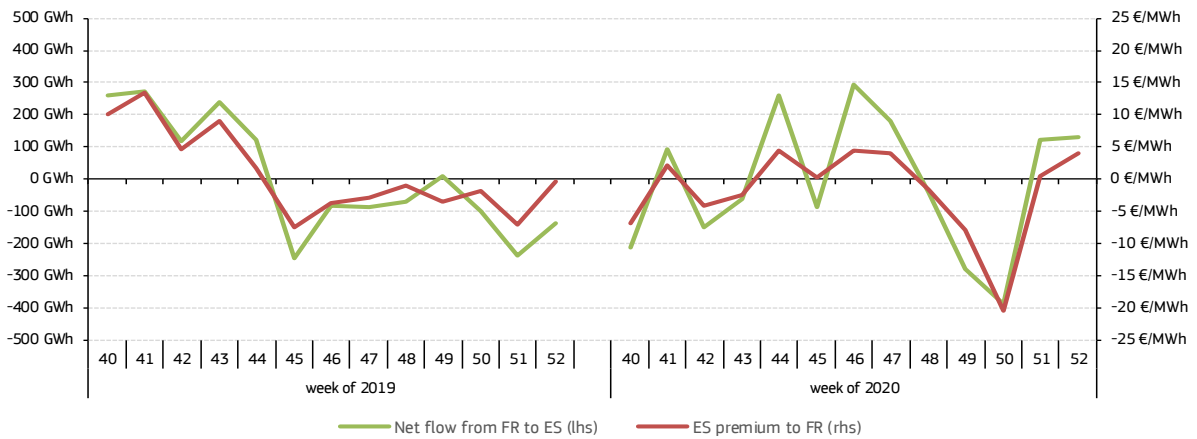
Figure 46 – Monthly evolution of the electricity generation mix in Spain in Q4 of 2019 and 2020



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

- **Figure 47** shows weekly electricity flows between France and Spain and price differentials between the two bidding zones. The balance of prices between the two markets shifted repeatedly in Q4 2020, depending mainly on French nuclear availability and Spanish wind speeds. The differential reached its maximum (20 €/MWh) at the beginning of December when the French nuclear fleet experienced outages and Spanish wind generation reached record levels. Cross-border flows generally followed price differentials, adding up to 0.2 TWh of net exports to France. Spain and France are connected through five high-voltage power lines of combined 2.8 GW capacity.
- Bilateral trade with Morocco in Q4 2020 developed in Spain's favour and resulted in net exports of 114 GWh to Morocco.

Figure 47 – Weekly flows between France and Spain and price differentials between them

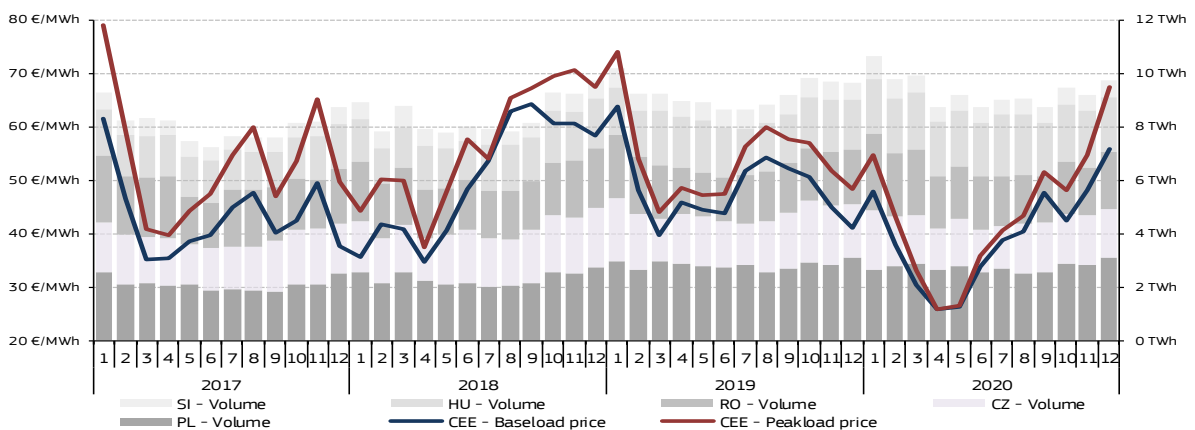


Source: ENTSO-E, OMEL, Platts

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

- **Figure 48** shows that average monthly prices for baseload power in Central Eastern Europe copied the downward move of their peers in the CWE region in October as the second wave of the pandemic brought new lockdowns. Prices then recovered strongly and rose decidedly above 50 €/MWh in the second half of Q4 2020, driven by a tighter supply-demand balance and rising carbon prices. The average monthly price reached a two-year high in December both for baseload and peakload contracts. The gap between baseload and peakload monthly averages grew to 21% at the end of the reference quarter as solar PV output waned and peakload demand recovered due to falling temperatures. When compared to Q4 2019, the average baseload price in the reference quarter was rose by 7% to 49 €/MWh. Traded volumes in the reference quarter were broadly unchanged compared to the previous Q4.
- Hungary brought forward its coal phase-out plan by five years, aiming to shut the last lignite-fired unit at Matra power plant in 2025. The government plans to achieve 90% carbon neutral electricity generation by 2030 by maintaining its nuclear capacity and adding 5 GW of new solar PV capacity.

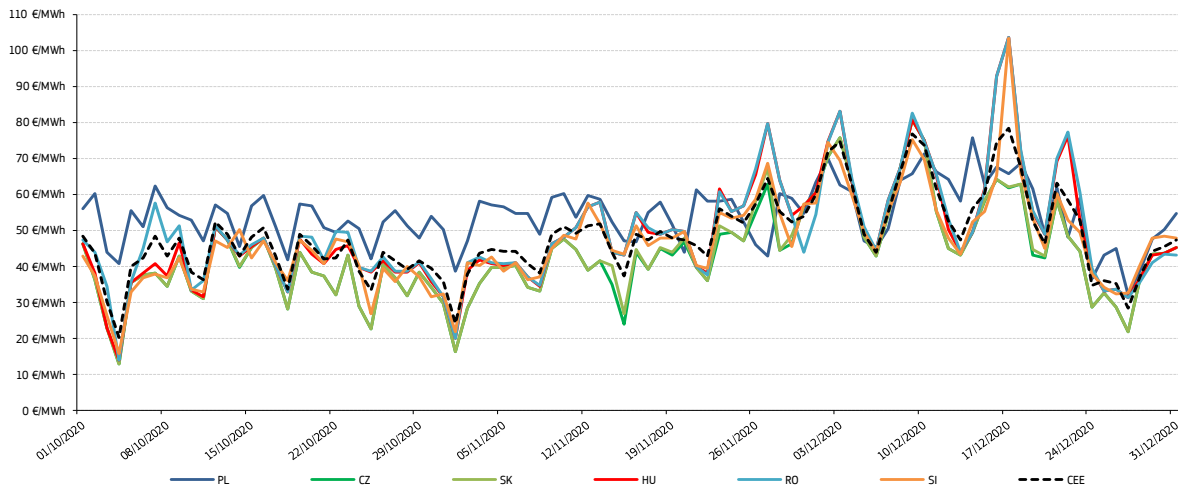
Figure 48 – Monthly electricity exchange traded volumes and average day-ahead prices in Central Eastern Europe (CEE)



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

- **Figure 49** shows that daily average baseload prices in the four coupled markets (CZ, SK, HU, RO) were relatively stable during the first half of Q4 2020, holding under 50 €/MWh, while the Polish market retained its typical premium. Prices moved universally higher and became more volatile since the end of November on the back of tightening supply-demand balance caused by cold spells, interconnector and plant outages and ebbs and flows of wind availability. Polish peakload demand hit an all-time high of nearly 27 GW on 10 December thanks in part to an estimated 3.8 million students taking part in online classes. Booming industrial activity also contributed to the record. The electricity system coped with the strain thanks to emergency supplies from Lithuania, amid interconnector outages at the German and Swedish border, 7 GW of hard coal capacity missing from the market and low wind availability.

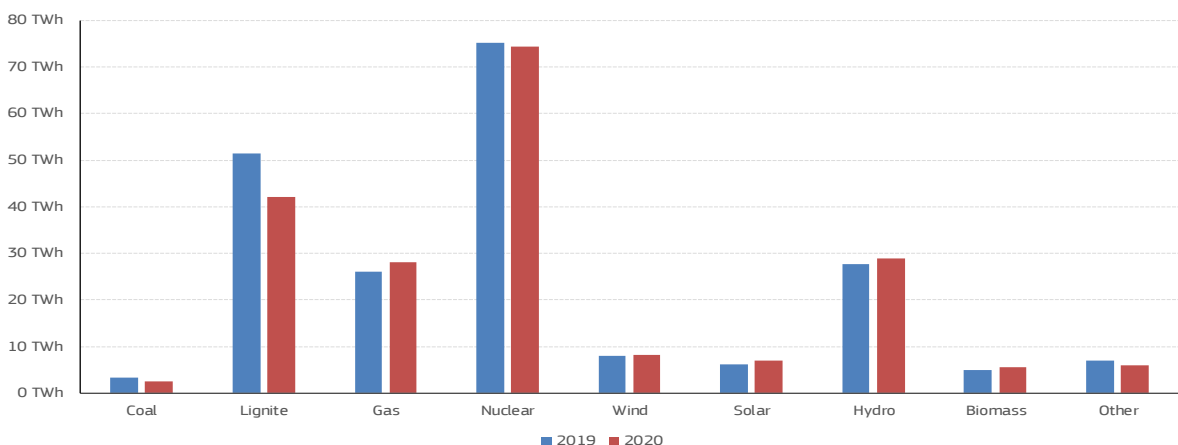
Figure 49 – Daily average power prices on the day-ahead market in the CEE region



Source: Regional power exchanges

- **Figure 50** compares the combined electricity generation mix of the CEE region (excluding Poland) between 2019 and 2020. The most substantial change took place in the lignite segment which bore the brunt of the covid-related demand shock and experienced a 9 TWh drop in output. This was mainly driven by falling generation in Czechia (-5 TWh) and Romania (-3 TWh). The missing lignite volumes were only partly replaced by higher gas generation (+2 TWh) in Czechia, Slovakia and Hungary. The share of renewables increased from 22% to 24% thanks to higher hydro generation in Czechia and Slovenia and thanks to a solar boom in Hungary and Poland. Nuclear remained the dominant generation technology with a 37% share in the mix and a considerable presence in all five markets. Total generation fell by 3%, in line with the fall in demand.

Figure 50 – Changes in the electricity mix in the CEE region (excluding Poland) between 2019 and 2020



Source: ENTSO-E.

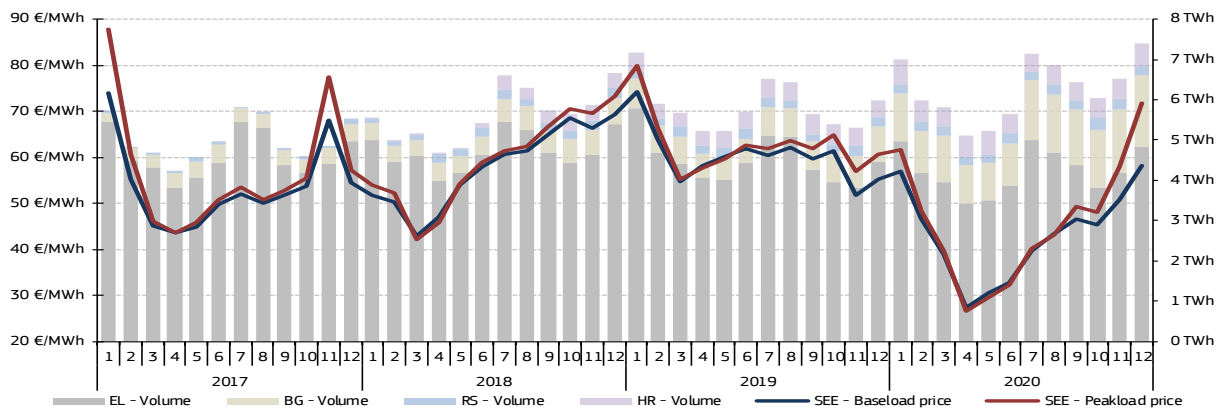
- In Poland, which is analysed separately due to significant differences in the size and structure of its generation base, the combined share of coal and lignite in its mix decreased to 69% in 2020 (compared to 73% in 2019), while renewables increased their share from 16% to 19% year-on-year thanks to rising solar, wind and biomass generation. Gas increased its share in the mix from 10% to 11% year-on-year, underlining the limited short-term potential for coal-to-gas switching. 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). The share of coal in Poland's mix should decrease to 56% by 2030 thanks mainly to significant wind capacity additions (especially in the offshore segment), according to a strategy document approved in February 2021 by the Polish government.

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

- **Figure 51** shows that after pausing in October, trade-weighted monthly average baseload prices in the SEE region went back on their upward trajectory and in December reached levels last seen in 2019. Peakload contracts climbed up even faster and their premium over baseload rose to 24% in December, the highest figure on record. This could be partly a result of market reforms in Greece which altered the way prices are discovered. The average quarterly baseload price rose by 19% year-on-year to 51 €/MWh in Q4 2020, which was still 8% below Q4 2019. The average quarterly peakload price, however, rose 3% above Q4 2019 levels to 61 €/MWh.

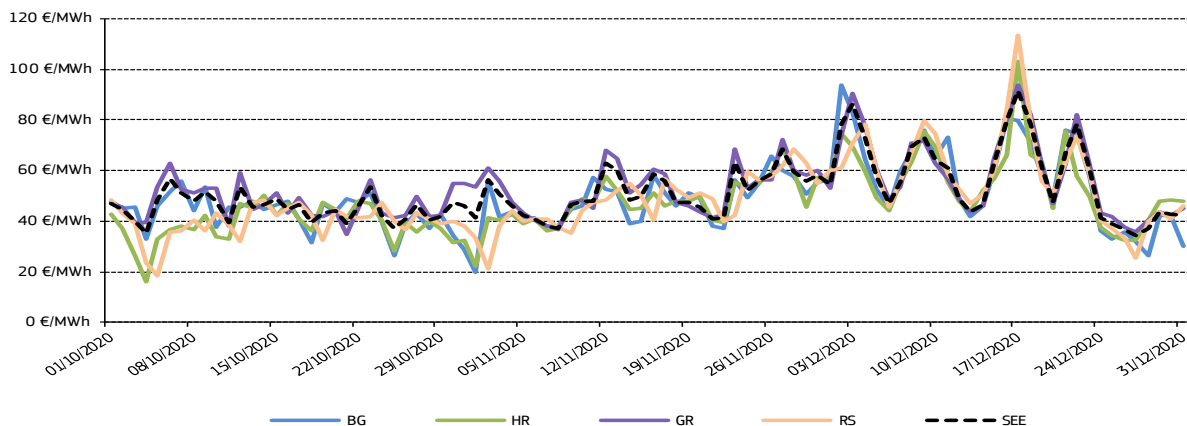
Figure 51 – Monthly traded volumes and baseload prices in South-Eastern Europe (SEE)



Source: IBEX, LAGIE, CROPEX, SEEPEX

- Greece began real time trading on the day-ahead, intraday and balancing markets on 1 November, the last EU Member State to do so. It also liberalized the market for bilateral contracts and power purchasing agreements. Thanks to this, Greece was able to couple with the Italian market in December. Market coupling with Bulgaria is planned for May 2021. The reform will increase competition and transparency and reduce energy costs for consumers and businesses. Coupled cross-border trading limits the ability of incumbents to hoard interconnector capacity. A well-functioning intraday market in turn allows wind and solar generators to correct their position as their actual output deviates from their forecast. As renewables gradually lose priority dispatch, the intraday market will allow them to optimize their trading strategy and maximize output sold. The balancing market is also an important precondition for growing renewable penetration, as it gives generators the ability to actively participate in correcting imbalances in supply and demand in real time. It also promotes the deployment of flexible technologies, such as batteries, which will be crucial to the success of renewables-centred electricity system.
- As shown in **Figure 52**, Greek day-ahead prices were relatively elevated on some occasions in November on the back of maintenance of key interconnectors with Italy and Bulgaria, but were more convergent with the rest of the region in December. That month, the usual Greek premium over Bulgaria narrowed to just 4%.

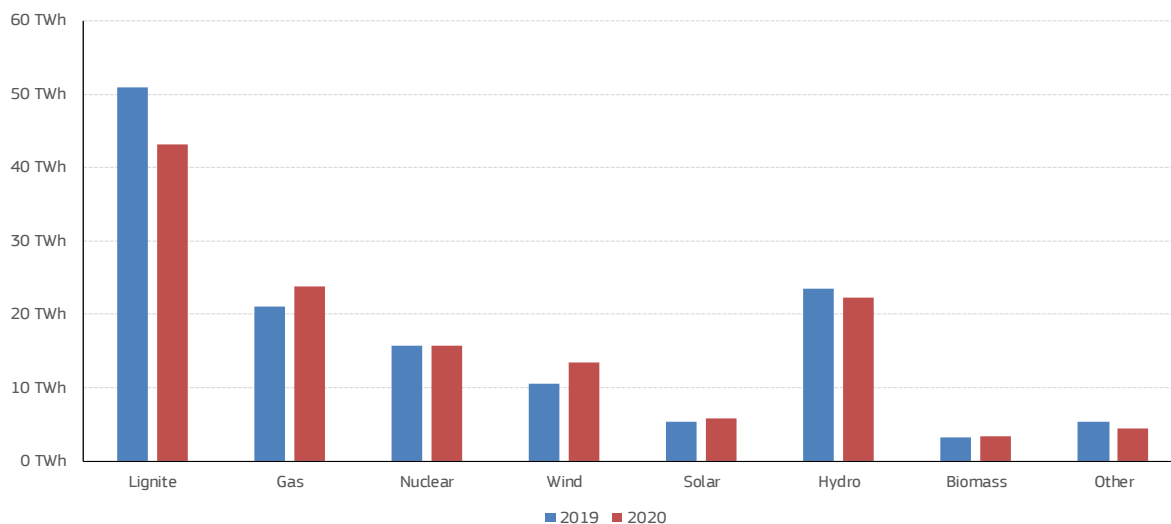
Figure 52 – Daily average power prices on the day-ahead market in Bulgaria, Croatia, Greece and Serbia



Source: IBEX, LAGIE, SEEPEX, CROPEX

- Figure 53** compares the combined electricity generation mix of the SEE region between 2019 and 2020. Lignite generation suffered losses mainly in Greece (-5 TWh), where it was replaced by gas and wind, and also in Bulgaria (-3 TWh). In Serbia, where fossil-based generators do not face carbon costs borne by their EU-based competitors, lignite generation increased by 4% to 24 TWh. The share of lignite in the regional mix fell from 38% to 33% year-on-year. Increased gas generation in Greece (+2 TWh) and Croatia (+1 TWh) drove up the share of gas from 16% to 18%. Renewable penetration rose from 31% to 34% thanks to rising wind output in Greece and lower consumption in the region.

Figure 53 – Changes in the electricity generation mix in the SEE region between 2019 and 2020



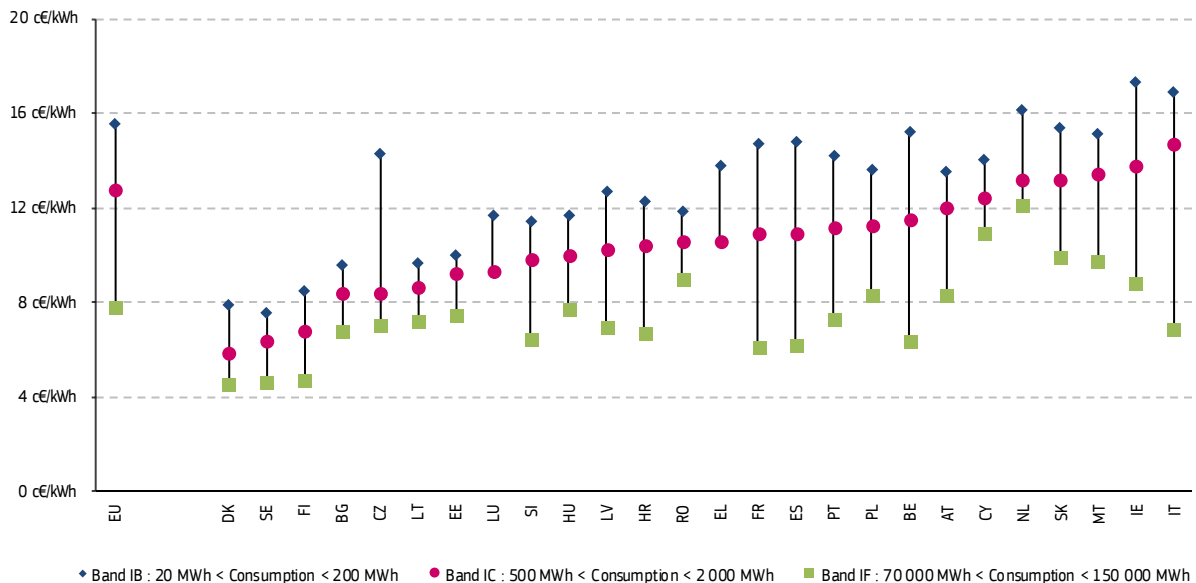
Source: ENTSO-E

5 Retail markets

5.1 Retail electricity markets in the EU

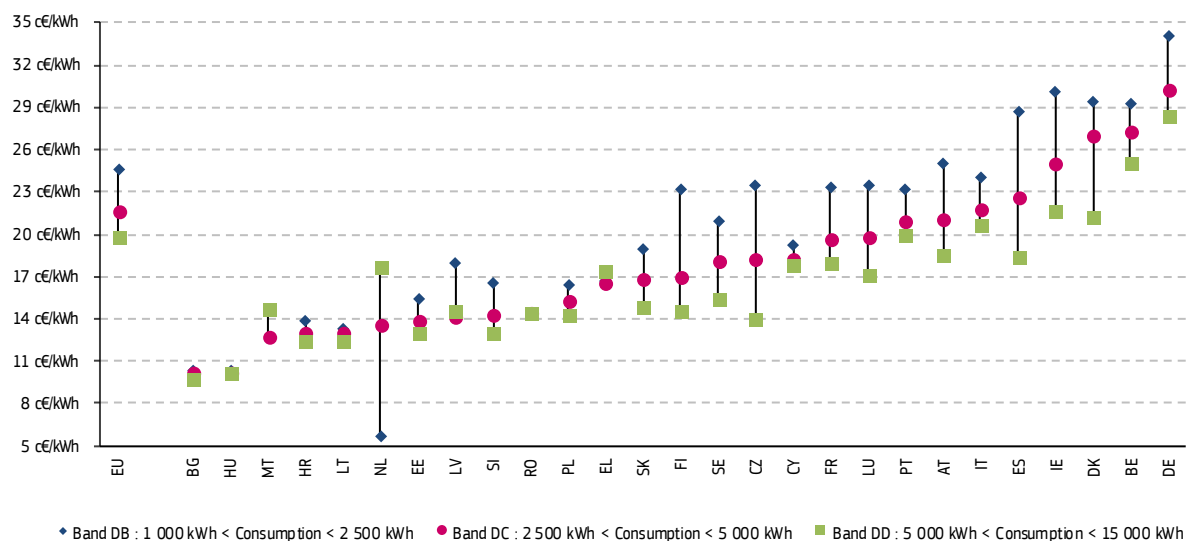
- Figures 54 and 55** display the estimated retail prices in December 2020 in the 27 EU Member States for industrial customers and households. Prices are displayed for three different levels of annual electricity consumption for both consumer types (Eurostat bands IB, IC and IF for industrial customers 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 and Greek household prices are a notable exception.
- Smaller industrial consumers (band IB) were assessed to pay the highest prices in Germany (20.0 c€/kWh) and Ireland (17.3 c€/kWh), followed by Italy and the Netherlands (16.9 and 16.1 c€/kWh respectively). The lowest prices in the same category were assessed to be in Sweden (7.6 c€/kWh) and Denmark (7.9 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 the Netherlands (12.1 c€/kWh both), followed by Cyprus (10.9 c€/kWh) and Germany (10.0 c€/kWh). Denmark (4.5 c€/kWh) was assumed to have by the lowest prices, with Sweden and Finland (4.6-4.7 c€/kWh) coming close behind. The ratio of the highest to lowest price for large industrial consumers was below 3:1 for this consumer type. Compared to December 2019, the average assessed EU retail electricity price for the IF band rose by 4% to 7.8 c€/kWh.
- In the household segment, Germany (28.5 c€/kWh) was assessed to have the highest electricity price for large consumers (band DD), followed by Belgium (25.1 c€/kWh), and with Ireland (21.6 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 (34.1 c€/kWh), followed by Ireland, while Bulgaria and Hungary found themselves again on the other side of the price spectrum. Compared to December 2019, the average assessed EU retail electricity price for the DD band rose by 1% to 19.9 c€/kWh.

Figure 54 – Industrial electricity prices, December 2020 – without VAT and recoverable taxes



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

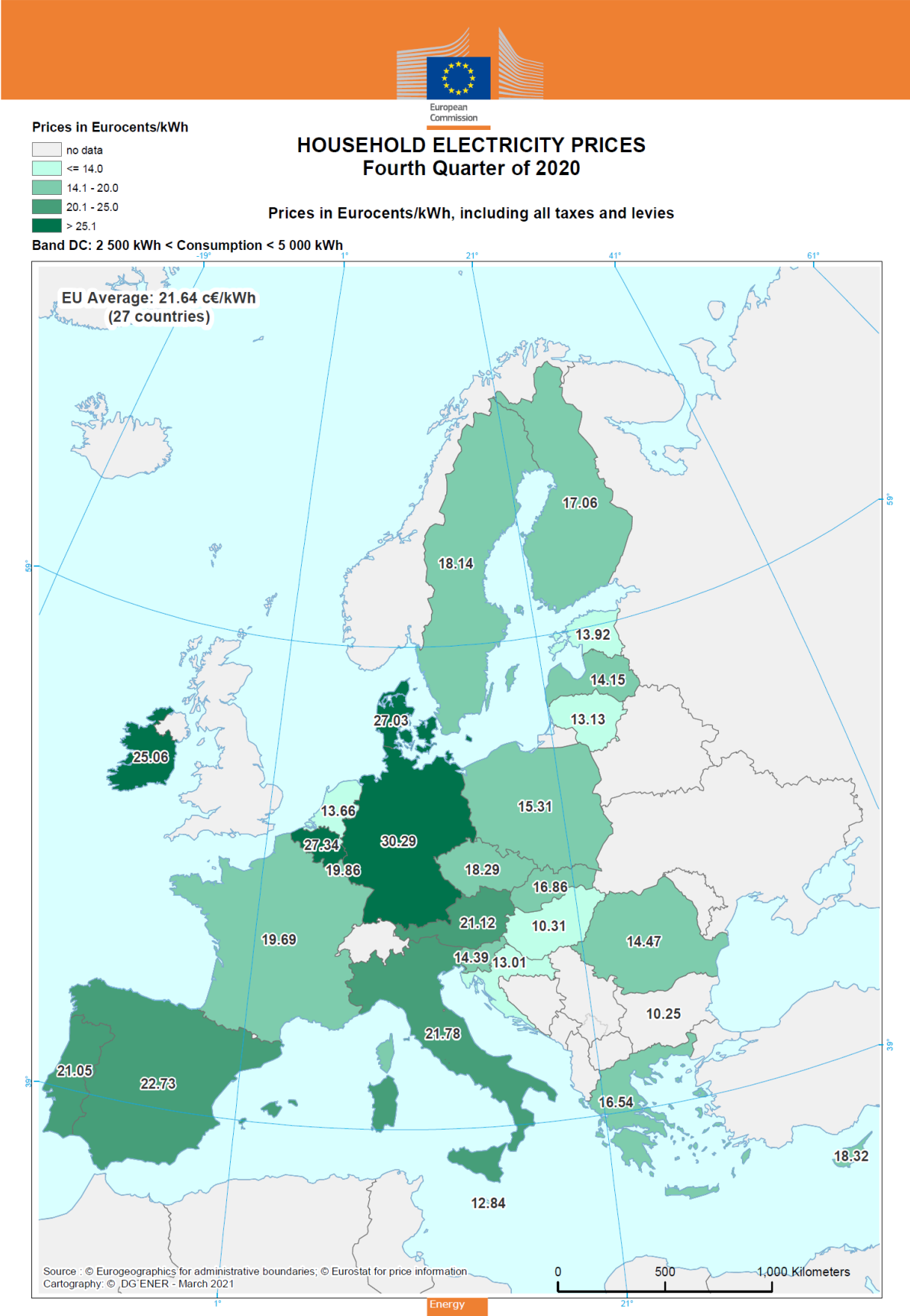
Figure 55 – Household electricity prices, December 2020 – all taxes included



Source: Eurostat, DG ENER

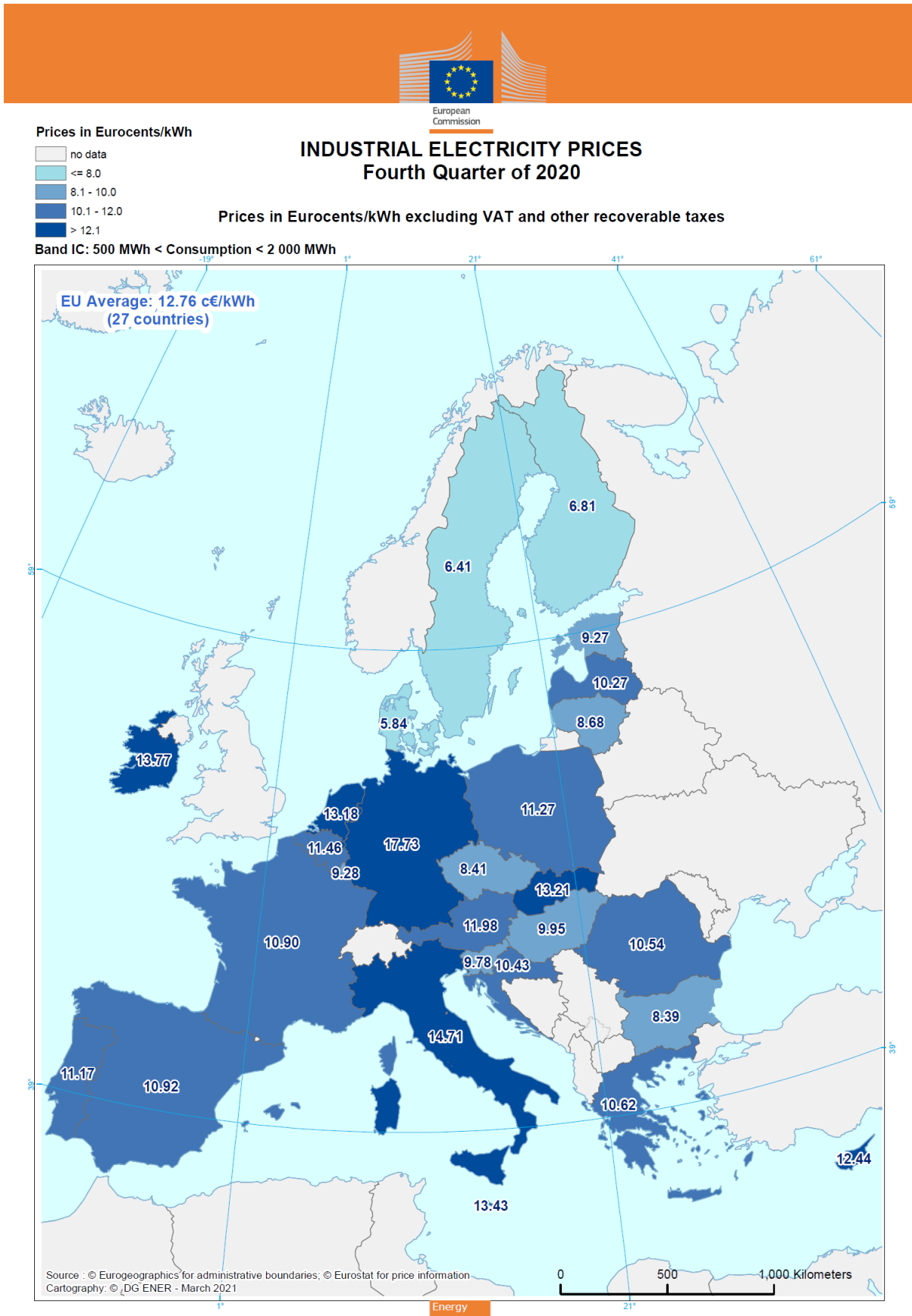
- Figures 56 and 57** display the estimated electricity prices paid by EU households and industrial customers with a medium level of annual electricity consumption in the last month of Q4 2020. In the case of household prices, Germany topped the list (30.3 c€/kWh), followed by Belgium and Denmark. As was the case in previous quarters, Bulgaria and Hungary retained their position as Member States with the cheapest household electricity prices. The EU average remained broadly unchanged in the reference quarter compared to December 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 (-33%, see **Figure 58** for more details) and Cyprus (-20%).
- In the case of mid-sized industrial consumers, Denmark was assessed to have the most competitive price in Q4 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 Q4 2019.

Figure 56 – Household Electricity Prices, fourth quarter of 2020



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

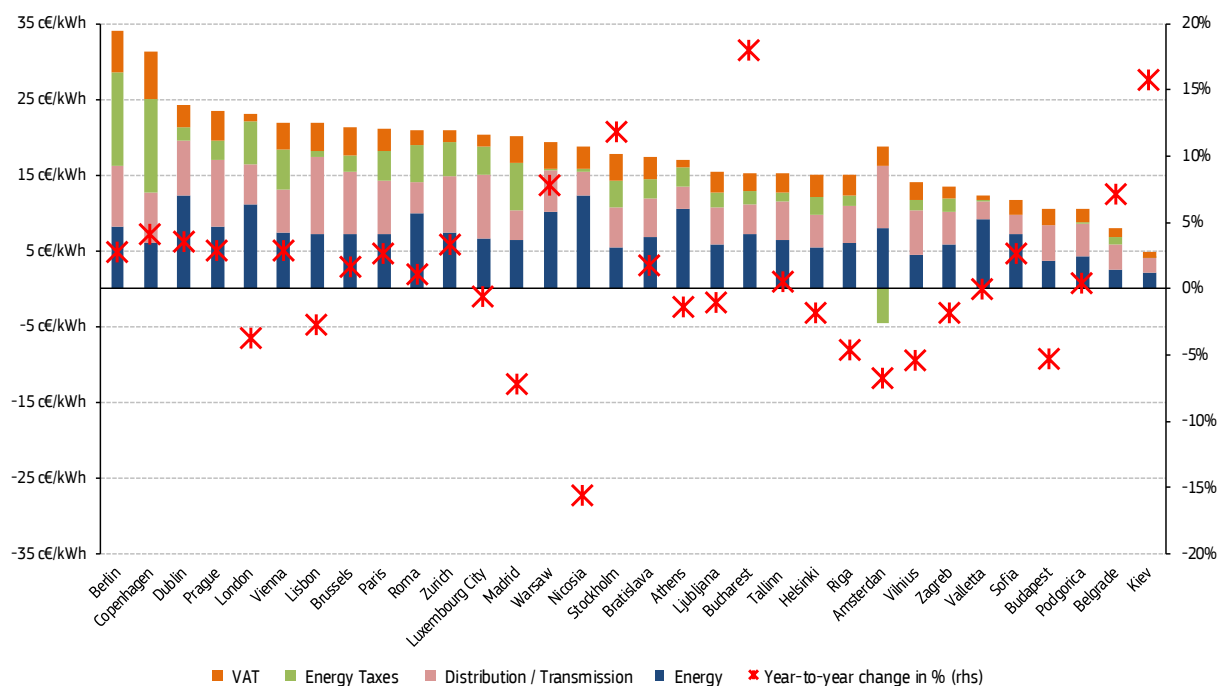
Figure 57 – Industrial Electricity Prices, fourth quarter of 2020



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

- **Figure 58** 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 February 2021, the highest prices were observed in Berlin and Copenhagen (34.1 and 31.3 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 55**. EU-wide, retail prices started climbing at the end of 2020, after being largely stagnant during the spring and summer of 2020. Inflation pressures intensified in January due to rising wholesale prices, which were driven by cold weather, low wind availability and more expensive emission allowances.
- The highest levels of the energy component in Europe were reported from Nicosia, Dublin, and London (11-13 c€/kWh), cities in relatively isolated island markets. The lowest levels of the energy component (3-6 c€/kWh) were recorded in the capitals of countries with stronger forms of price regulation (Budapest, Belgrade, Vilnius) or with a high degree of renewable generation (Copenhagen, Stockholm). The EU average for the energy component was 7.6 c€/kWh (unchanged from February 2020). Out of the 27 capitals, 18 had a cheaper energy component than the EU average.
- The highest network charges were recorded in Lisbon (10.2 c€/kWh), Prague and Luxembourg City (8.7 c€/kWh and 8.5 c€/kWh, respectively) where they accounted for roughly 40% of the total price and were higher than the energy component. The lowest network fees were collected in Valletta (2.4 c€/kWh) and Sofia (2.6 c€/kWh). The EU average in the reference quarter was 5.7 c€/kWh (up from 5.6 c€/kWh in February 2020).
- Apart from Berlin and Copenhagen (12 c€/kWh), the highest energy taxes were paid by households in Madrid and London (5-6 c€/kWh). Sofia and Budapest stood at the other end of the range, with zero energy taxes collected by local authorities. The average energy tax component reached 4.0 c€/kWh (down from 3.9 c€/kWh in February 2020). 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 55**, and contributed to the unusual effect in which the lower the consumption, the lower the price per kWh.

Figure 58 – The Household Energy Price Index (HEPI) in European capital cities in Eurocents per kWh, February 2021

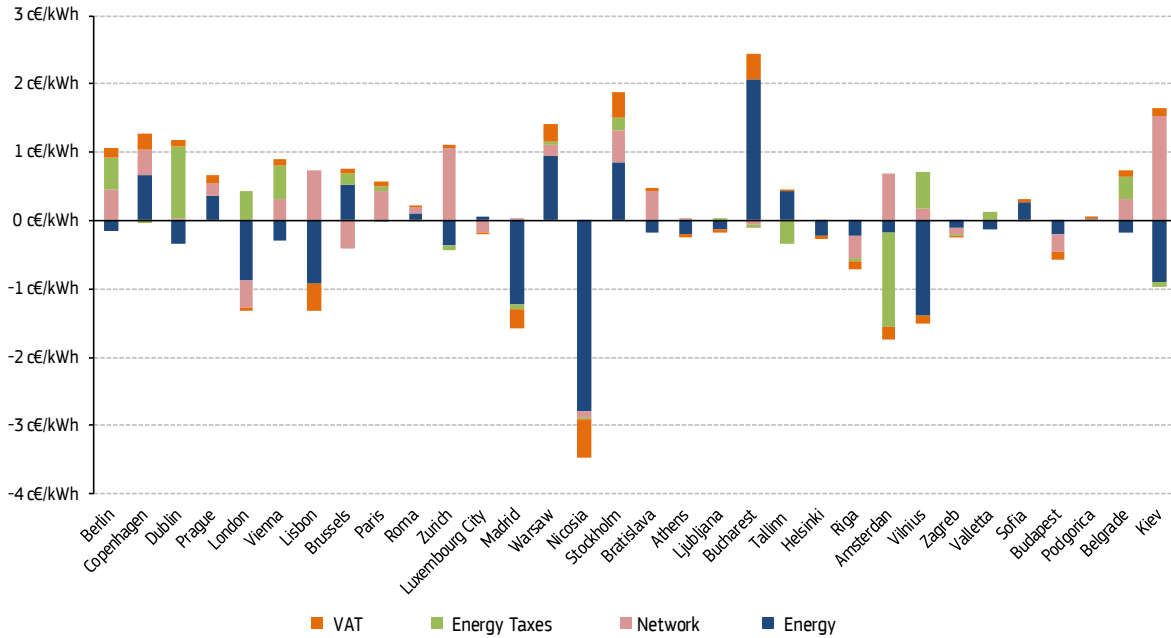


Source: Vaasaett

- Compared to the same month of the previous year, the largest price increases in relative terms in February 2021 were observed in Bucharest (+18%) and Kiev (+16%). As shown in **Figure 59**, the distribution component was the

biggest contributor to rising prices in the Romanian capital. In Kiev, rising prices were driven by network charges. 13 of the 27 EU capitals reported prices lower or unchanged compared to the same month of the previous year, with, Nicosia (-16%), Madrid (-7%) and Amsterdam (-7%) posting the largest relative drops. The price fall in the Cypriot capital was driven mainly by a lower energy component, whereas households in the Dutch capital benefited mainly from lower energy taxes.

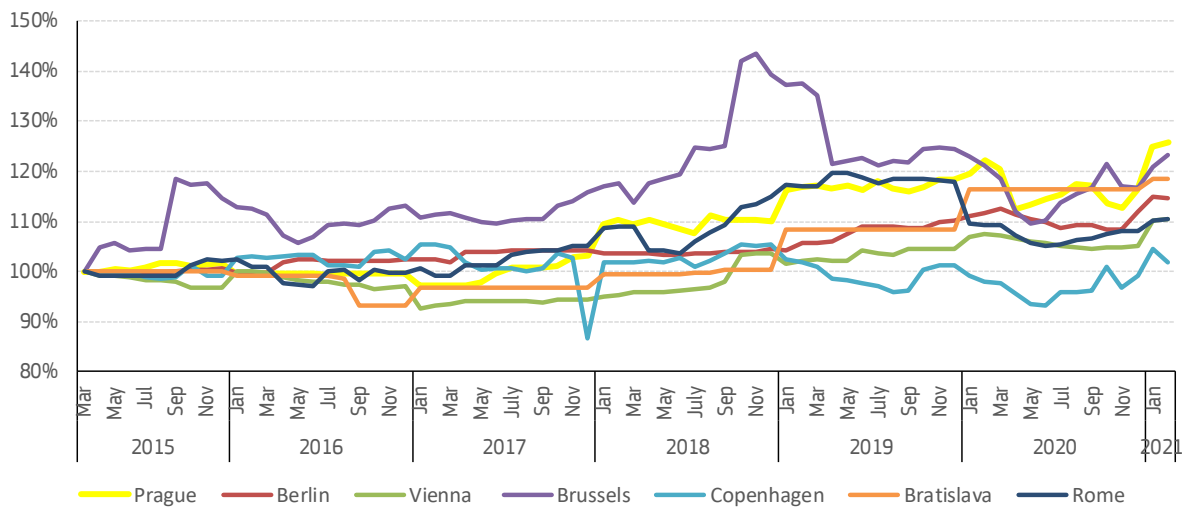
Figure 59 – Year-on-year change in electricity prices by cost components in the European capital cities comparing February 2021 with February 2020



Source: Vaasaett

- Figure 60** compares how household retail prices in selected EU capitals changed in relative terms over the last six years. The biggest increase (+26%) was registered in Prague and was driven mainly by a rising energy component (50% of the change) and more expensive network charges (20% of the change). Brussels came in second with a 23% increase since February 2015, followed by Bratislava (+18%) and Berlin (+15%). On the other end, retail prices for households in Copenhagen are now more or less the same they were six years ago, as a rise in the local energy component was compensated by falling energy taxes in Denmark.

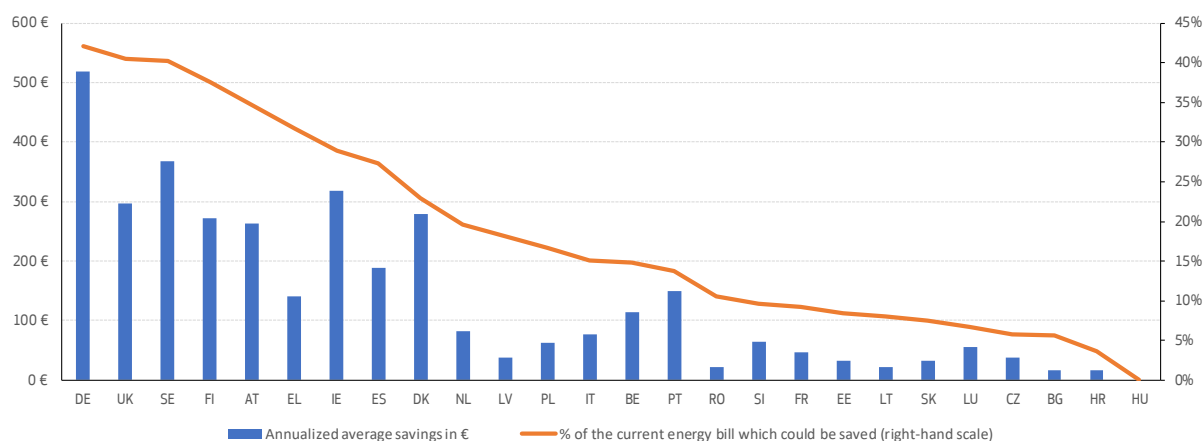
Figure 60 – Relative changes in retail electricity prices in selected EU capitals since 2015



Source: Vaasaett

- **Figure 61** shows the annualized average savings both in absolute terms and as a percentage of the energy bill available to typical households who switched away from their local by-default contract to the cheapest offer available in December 2020. Temporary discounts and rebates were taken into account for this analysis. Prices in capital cities were used as a proxy to assess prices at national level. While having the highest electricity prices in the EU, German households have also the possibility to save the most in terms of their energy bill (energy component of the retail price) if they choose the best option available in the market. This combination translates into the highest absolute savings possible (€519). In six other markets, annual savings between €200 and €300 (or between 25% and 40% of the bill) were possible. High relative savings despite below-average retail electricity prices were assessed in Greece, Sweden and Finland, a sign of healthy competition in the sector.

Figure 61 – Average annualized savings from switching retail electricity providers across Europe

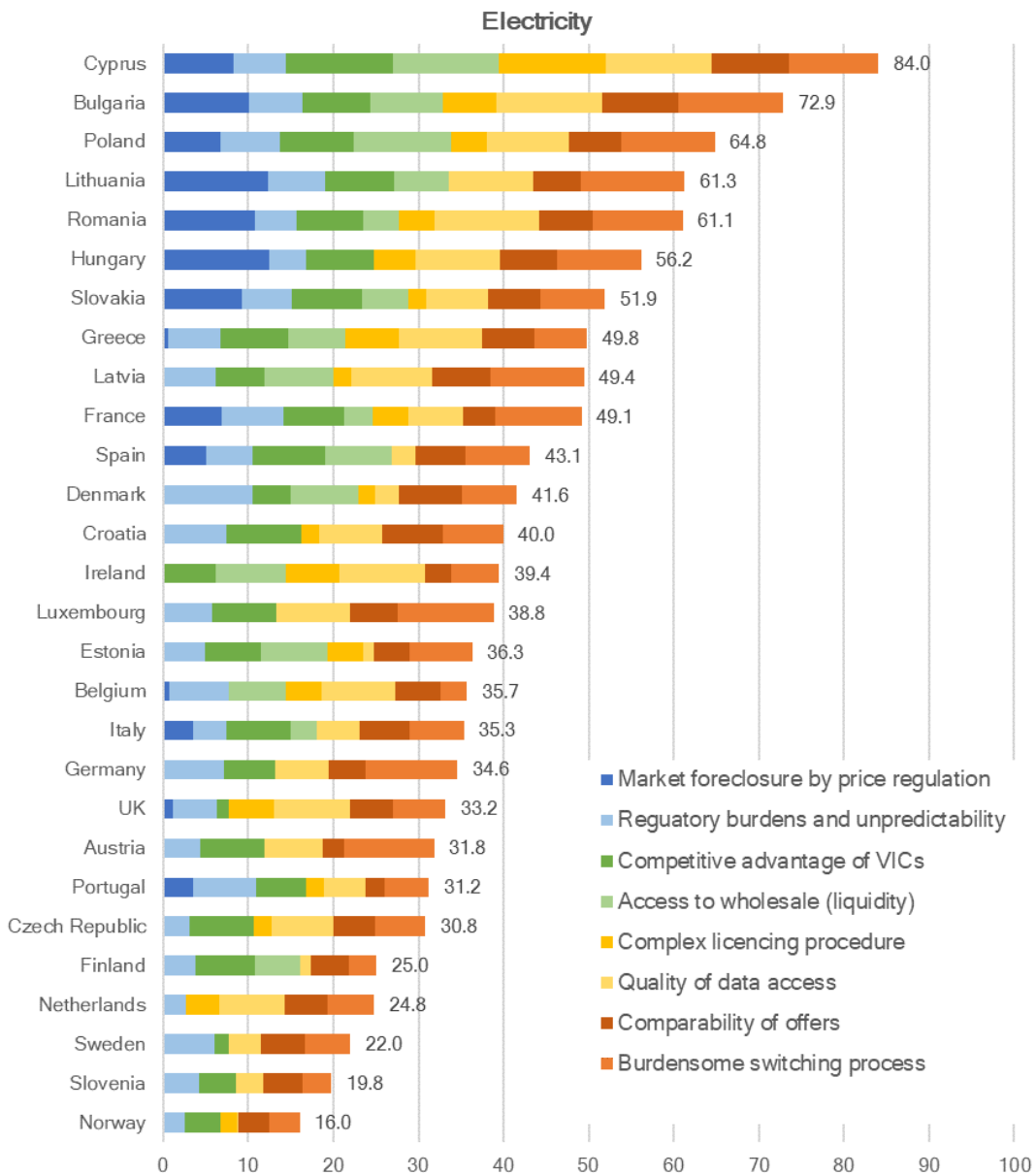


Source: Vaasaett

- **Figure 62** displays the results of the [European Barriers in Retail Energy Markets](#) project established to research the extent to which energy suppliers across Europe face a variety of barriers to enter and compete in the market; to identify which barriers exist and to provide some suggested solutions to those barriers. It was conducted under the auspices of the Commission for over a year over with the cooperation and assistance of nearly all of the relevant national regulatory authorities, around 150 suppliers and many other stakeholder organizations across all focus markets. Among the most important barriers identified by the study were: 1] the advantage of vertically integrated market players; 2] low customer awareness or interest; 3] uncertainty around regulatory future or digitalization; 4] uncertainty around current regulatory environment or its development; 5] strategic behaviour of incumbent or other market players.
- In order to add a quantitative aspect to the study and enable additional comparability between the markets, indicators measuring the countries performance in selected categories have been developed. These indicators are the basis of the Barriers Index. The overall score of the Barriers Index in the electricity sectors show that entrants to Scandinavian, Slovenian and Dutch markets face the fewest barriers. The common feature of these countries is that they do not regulate end-user prices and that there is no licencing obligation for new suppliers (except in the Netherlands). In contrast, Cyprus is the toughest market to enter for a supplier, while Bulgaria, Poland, Lithuania and Romania are also among the high-barrier countries. In general, countries with extensive price regulation (the dark blue bar) are at the top of the list. Some sort of price regulation was found to be present in 14 out of the 28 analysed electricity markets.
- When it comes to access to wholesale markets, which was measured by their liquidity, 12 countries had no entry barriers, while only moderate barriers were observable in another 3-5 countries. Cyprus and Poland displayed the worst results as most of the local wholesale trading takes place outside organised marketplaces (long-term contracts or other bilateral deals).
- The perceived difficulties of switching were measured based on DG Justice's survey. The indicator incorporates the experience and opinions both of customers who have switched, and also of those who have not because they faced obstacles or thought it might be too difficult. On average, approx. 60% of the customers have had a bad experience or opinion of the switching process in electricity and gas, which is a quite high number. In relation to electricity markets, three groups of countries can be separated. Ten countries received close to, or above, eight points (indicating very high barriers), twelve countries achieved an intermediate score and four countries (Belgium, Finland, Slovenia and Norway) registered very low barriers in this respect.
- The extensive findings of the project indicate that while barriers are being reduced and retail energy markets are generally heading in the right direction, many serious obstacles to better functioning remain and need to be addressed if potential benefits or free and fair competition are to be realised. Many such barriers are very specific to

each individual market, but many are pan-European and could therefore be reduced by appropriate policies at EU level.

Figure 62 – The Barriers Index

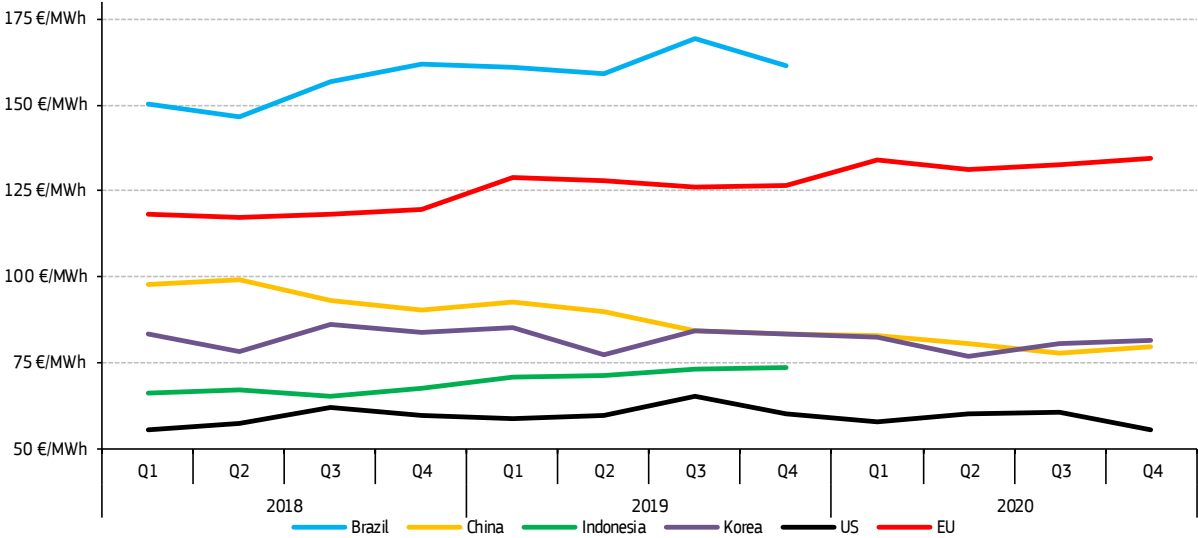


Source: European barriers in retail energy markets: Index report

5.2 International comparison of retail electricity prices

- **Figure 63** 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 Q4 2020 compared to the previous quarter, similar to the developments in South Korea. Meanwhile, Chinese industrial prices increased by 1%, reversing a steady downward trend observed over the past two years. Industrial electricity prices in the United States fell by 8% quarter-to-quarter in Q4 2020 in euro terms to their lowest level since 2017.

Figure 63 – Retail electricity prices paid by industrial customers in the EU and its main trading partners



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

Glossary

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

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

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

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

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

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

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

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

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

