LSEG Commodities Research
Power

The state of the European power transition 2040

May 2026

LSEG Power Research has expanded the European forward price model to run until 2040. In this report we present our key assumptions and some key findings about where the European power transition will stand by 2040, what the state of the decarbonization process will be and what challenges remain 10 years before the 2050 EU carbon neutrality target year.

How does the renewable power capacity develop? How well will renewable power be integrated and what role will batteries play in this? What will be the power mix in 2040? How do relative power prices change over time and where do we see the price peak?

LSEG Power Research: Long term power system model

We refer to the assumptions of our in-house forward price model, which simulates the hourly electricity dispatching from the front month until 2040. This covers about 86% of the current EU27 electricity demand, in addition to the British, Swiss and Norwegian systems. The coverage of the European continent is close to 90%. The model delivers hourly market clearing prices for the countries highlighted in dark green in this map. For all modelled areas we compute the generation by technology, cross-border flows and emissions.

We apply real-observed weather (temperature, wind speeds and solar radiation) from 1991-2020, "re-played" in future years, resulting in 30 different price scenarios. We suggest that within 30 years of weather data a wide - though not exhaustive - range of possible constellations of temperature, wind speeds and solar radiation can be observed, including extreme weather moments.

For a detailed view on our assumptions, we refer to our input pages and the methodology document for the LSEG Forward Model.[1]

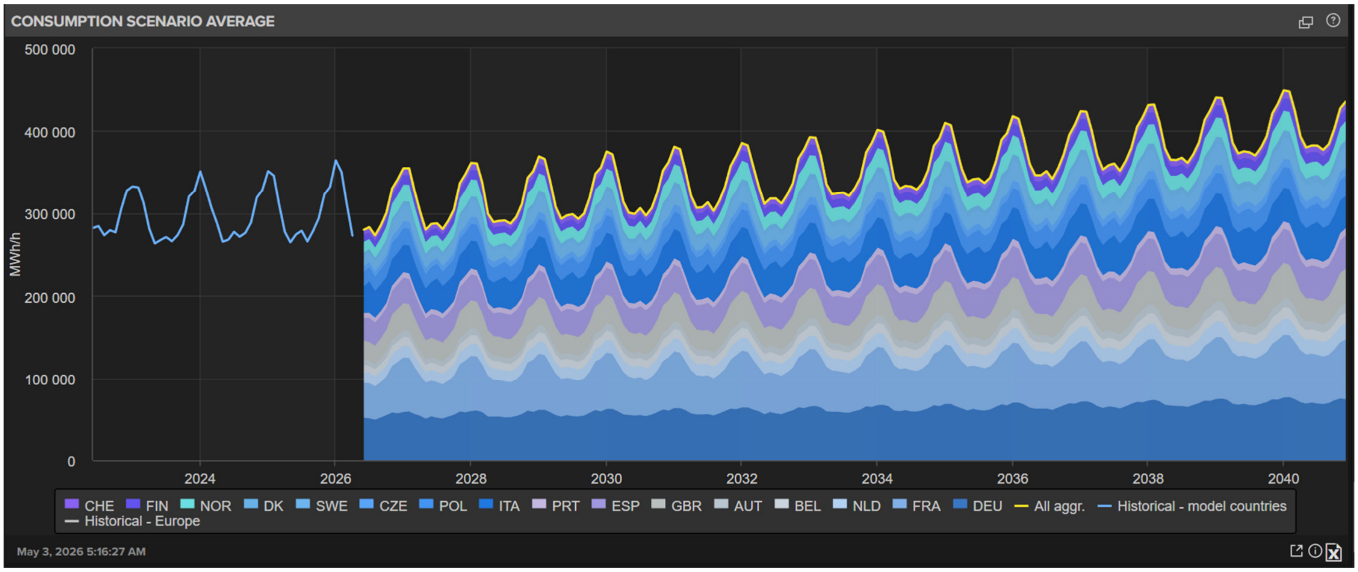
[1] See Workspace POWER > Europe > Long Term for our assumptions, and POWER > Europe > Tools for our methodology document

Power Fundamentals

Demand

After a rather stagnant decade ahead of Covid-19, both the pandemic and the 2022 energy crisis led to significant demand disruption and a significant degree of permanent demand destruction, especially in the industry sector. By 2026, power consumption has not reached the pre-crisis level yet, even though there is visible electrification-driven growth in the mobility and heating sectors and new data centre demand.

We use a bottom-up forecast in which we project the consumption growth in electromobility, heating, new industry (mainly giga factories and data centres), and electrolyser consumption. One very strong growth sector is **electromobility:** we expect the power consumption from electric vehicles to grow to around 170 TWh in 2030, and close to 300 TWh in 2040. 300 TWh compares to the current consumption in Iberia.



The chart above shows the total demand history for the past four years and our forecast country-by-country. We expect that it will take until 2027/28 for the demand destruction from 2022 to be compensated by demand from the new sectors. The compound annual growth rate for the entire region is 2.1% for the 2025-40 period. With that, the total demand would grow by a total 36% between 2025 and 2040. For comparison: The IEA World Energy Outlook's Net-zero 2050 scenario ("NZE") foresees 45%-55% power demand growth for the EU 2040 (WEO 2025).

Supply

Our power generation forecast is one of the outputs of the market simulation model. The installed generation capacity results from each country's known plans or targets for decommissioning and new-build of thermal and renewable capacity. The dispatching of renewable sources has priority, and the thermal plants dispatch according to their relative short run generation costs. We abstain from taking a market view on fuels. Instead, we apply the market fuel and carbon prices from current forward curves for as much as there is liquidity (approx. three years). Beyond that time horizon we assume that fuel & carbon prices remain constant while applying the target inflation rate of 2%.[2]

Nuclear Power

Some nuclear unit **closures** within our forecast horizon are not certain, so we had to make assumptions. For example, the current Swiss policy allows the operation of existing units for as long as they pass safety inspections. However, the "Energieperspektiven 2050+" report sets the expectation that there will be decommissionings before 2040, which we partially implemented. We also assumed a few plant decommissionings in France by 2040 (total -4.5 GW), assuming that not all reactors will pass the test for a lifetime extension to 60 years. This is in line with RTE's current baseline scenario. The Spanish nuclear phaseout (7.3 GW today) is set to be completed by 2035. Borssele (500 MW) in the Netherlands is scheduled to decommission by 2033, and the remaining reactors in Belgium will end operation in 2035. A large nuclear reactor replacement is undergoing in Great Britain: before new reactors come online in the 2030ies, Heysham,

[2] Find the fuel price inputs under Workspace POWER > Europe > Long Term > Fuels

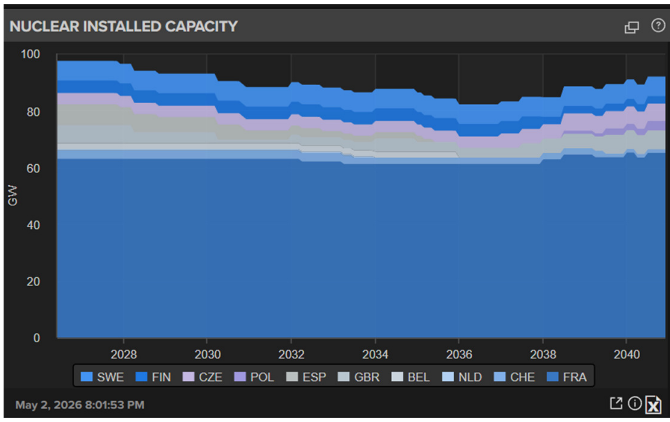
Hartlepool and Torness will reach end of lifetime, bringing British nuclear capacity to a low point of 1.3 GW in the early 2030ies. The decommissioning of Sizewell B follows in 2035. The Finish Olkiluoto 1+2 units will run until 2038 unless they pass lifetime extension tests.

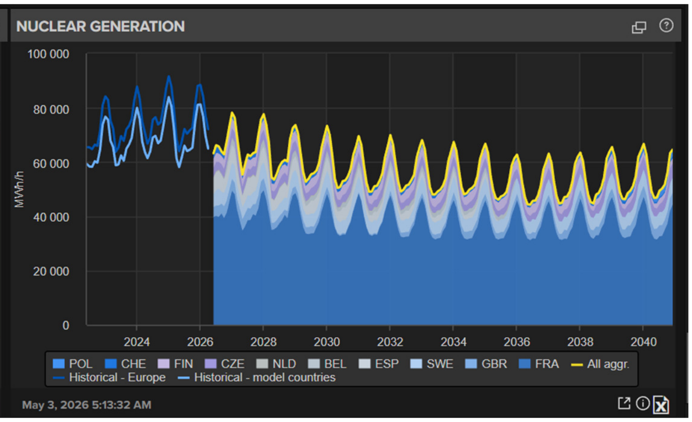
The **new nuclear commissioning** we expect before 2040 are Hinkley Point C in Britain by 2034 and Sizewell C by 2039. Dukovany will add 2 GW of nuclear capacity in the Czech Republic by 2038. The introduction of nuclear power in Poland starts in 2038, adding 3.3 GW generation capacity of the new Liubatowo-Kopalino plant in three steps.

We consider the French plans to add build new EPR reactors at existing sites that have already been determined. We include a part of these newbuilds within our forecast horizon, adding 6.6 GW of capacity until the end of 2040. Considering the decommissionings mentioned above, **today's 63 GW French nuclear fleet grows to 65 GW in 2040.**

In our assumptions for newbuilds we did not consider Small Modular Reactors (SMR). We believe there could be SMR commissionings in Europe before 2040, but we don't expect that in our base case until the ripeness of this technology becomes more evident. If there is a breakthrough in the SMR sector within the next 15 years it would likely replace some of the assumed EPR capacity above, leading to an overall neutral effect on our nuclear capacity assumptions. For example, the Sizewell C EPR reactors might not get Final Investment Decision (FID), and instead SMR reactors would start up by the late 2030ies.

All the mentioned changes combined lead to an interesting picture for European nuclear power: The installed operational capacity is 97 GW in the present and would drop moderately to 92 GW in 2040. As decommissionings and new starts do not take place seamlessly there will be a low point phase around 2036, with a capacity drop to 82 GW, before new reactors add back capacity.





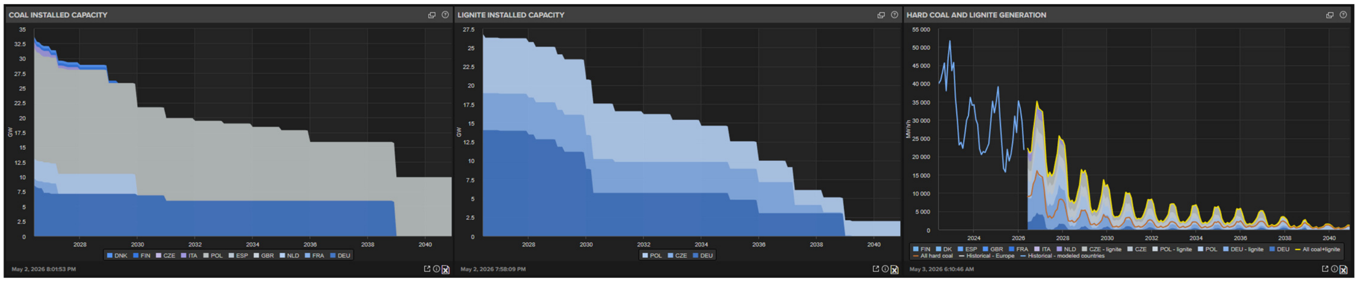
Our generation forecast declines over time, from 610 TWh in 2025 to a low point of 452 TWh in 2036, before rising to 485 in 2040. On one side, this reflects the net reduction of available capacity, but it also reflects a reduction in the nuclear load factor: The increased renewable power supply, leads to more frequent (partial) ramp-down of the nuclear reactors. This is particularly the case in France, given that the nuclear fleet makes up a very high share of the total power supply, therefore French units need to frequently down-regulate already today when renewable intermittent supply is plenty.

Coal and Lignite

Most countries will have finalized their coal & lignite phaseout by 2030. Beyond that date we only expect DEU, POL and CZE to continue firing coal. The official phaseout date for the Czech Republic is actually in 2033, but the plant decommissioning is conditional on the start of the nuclear unit Dukovany 5, which we only expect to happen in steps in 2037/38. Therefore, we estimate the full phaseout to occur by 2039 for lignite plants in the Czech Republic, whilst hard coal plants have already been phased out. Polish hard coal and lignite continue to run until past 2040. The plant decommissionings go in tandem with respective coal mine closures, which is what we aim to estimate. Compared to today's 27 GW combined operational capacity, we expect 12 GW to remain by 2040.

The German coal phaseout is completed by end of 2038. However, there is one legally stated mid-step in April 2030, by when the West German lignite plants must shut down, leaving 5.7 GW remaining lignite power capacity in East Germany and a total 5.9 GW of hard coal in 2030 – a strong drop compared to today's combined 23 GW coal and lignite capacity.

In all three countries, due to rising relative costs of coal firing, the capacity drop and limited flexibility restrictions, we foresee a strong decline in the use of coal & lignite units towards 2030. During 2031-2040 the generation only drops at slow rate. This reflects that in periods with unfavourable conditions solar & wind power, there will still be reliance on the fossil fuel fleet. However, after 2030 the coal-fired generation in the summer season is quite limited, whilst in the winter periods it is to average between 5-10 GW for the entire region observed.



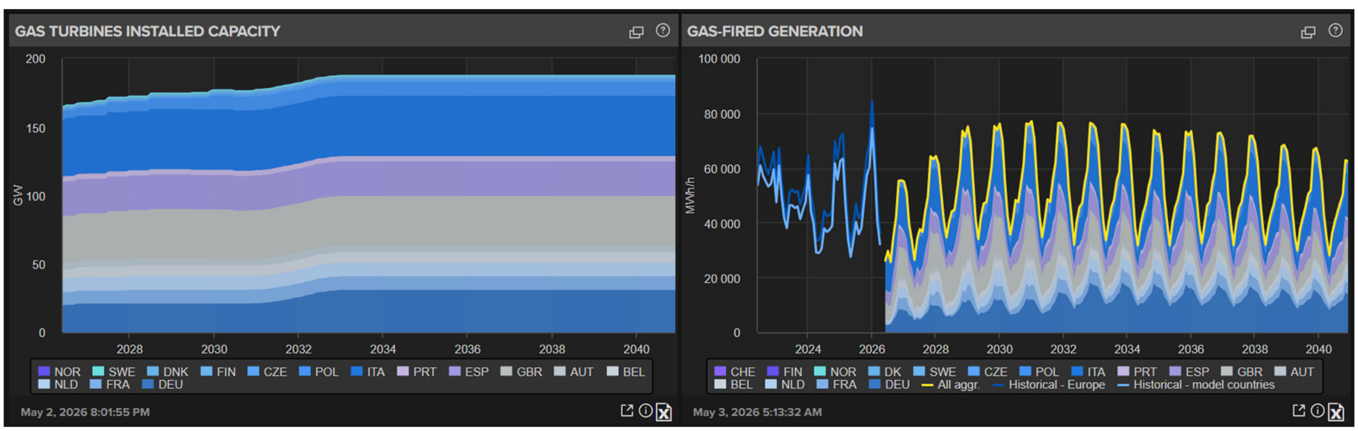
The combined annual coal & lignite generation in our model area is expected to decrease from 222 TWh in 2025 to 60 TWh in 2030 and merely 6 TWh in 2040, which would mean a 97% decrease in that timespan. We acknowledge that in Europe outside our modelled area, especially in the Balkan region, the reliance on coal & lignite is relatively stronger and the substitution by lower-emission power might go at slower pace than in our representative region.

Gas and hydrogen power

For gas-fired capacity we expect an increase in the coming decade of more than 20 GW, of which 10 GW are added in Germany alone. In Poland the gas fleet is set to increase from 5 GW today to 10 GW in 2030. The German power station strategy will significantly raise the role of Germany as flexibility provider for the rest of Europe, for which we have published analysis before.

We only considered new gas units that are under construction or in concrete planning steps. It is likely that more countries will plan for further (possibly hydrogen-ready or CCS-capable) gas generation units.

The figure below shows that gas-fired generation increases in the coming years, up from 400 TWh in 2025, peaking in 2031 (503 TWh) and declining thereafter to 414 TWh in 2040. This reflects that gas-fired power increasingly replaces retiring coal and/or nuclear units. The increasing power consumption is covered by rising renewables, but the use of gas can only drop slowly as it substitutes other thermal supply and the flexibility of gas plants is needed to meet intermittent solar & wind. In the 2031-40 period we expect continuedly strong renewable power generation growth, but also the storage capability will have developed, allowing to shift more of the renewable supply into hours of higher demand and therefore achieving significant savings in gas-to-power.



As of now, the only concretely planned **hydrogen-based power** generation capacity is in Germany, which is why we have only considered H2-capacity in DEU as of now. These will produce up to 0.5 TWh in 2040. We expect that other countries could start specifying hydrogen-to-power strategies (e.g. in GBR), which we will adopt in our modelling accordingly.

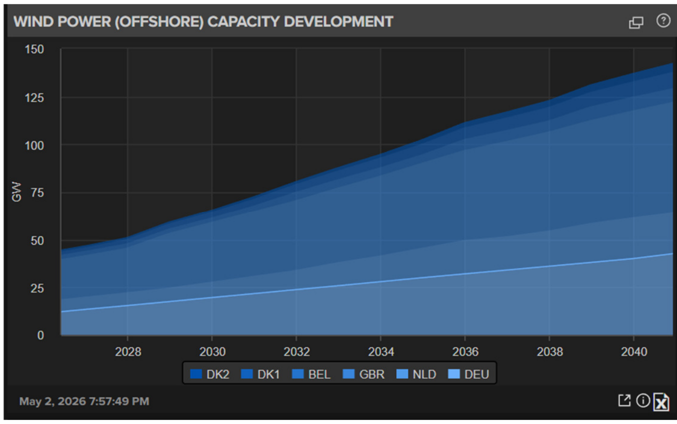
Solar and wind power

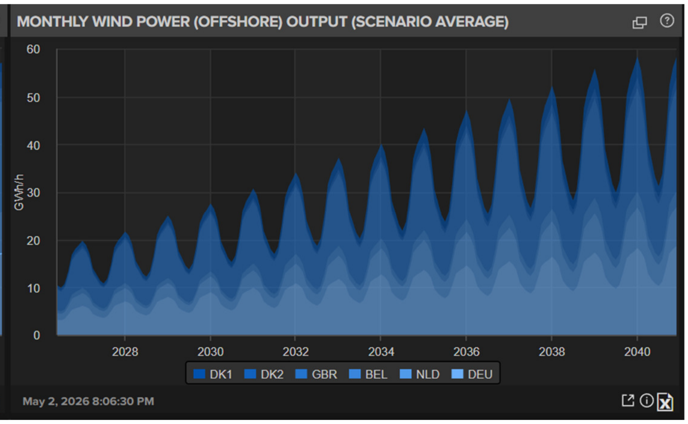
To estimate the future capacity of intermittent renewables our first reference are the targets from current national legislation, on which we discuss how realizable those targets are. We often apply the given GW targets to a later point in time, indicating that many countries' targets can be achieved, but most likely with delays, given the current pace of renewables deployment and known bottlenecks.

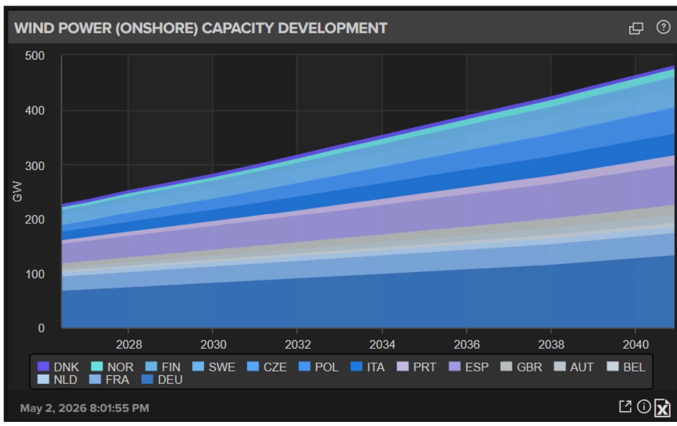
Compared to today, the solar capacity in the countries we model more-than doubles from 340 to 960 GW in 2040, and wind power more-than doubles from 270 GW to 640 GW in 2040.

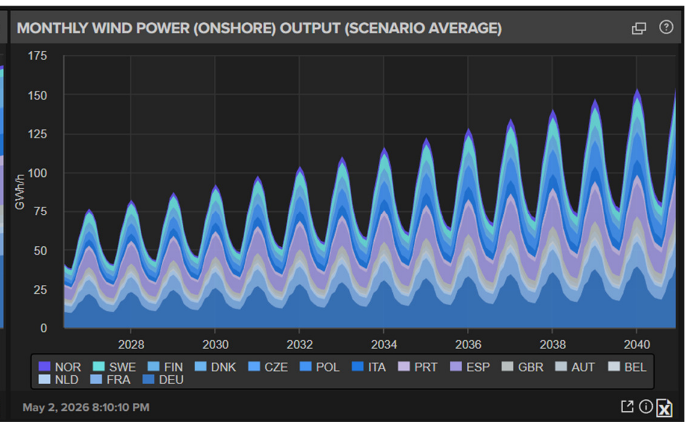
In terms of generation, we expect the overall supply of wind & solar power to rise from 775 TWh in 2025 to **2278 TWh in 2040, meaning almost three-times higher supply than today.** The figures below display our buildout assumptions, together with the potential wind and solar potential renewable production.

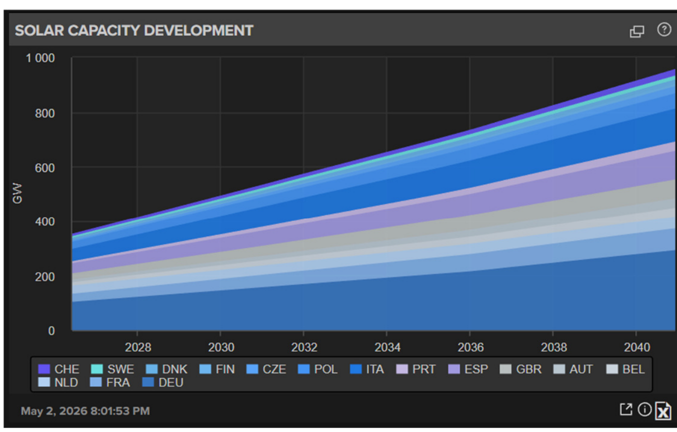
We assume that renewables (wind and solar) participate in the market similarly to today, by bidding at or close to the market floor to ensure they remain “in the money.” However, as private contracts (PPAs) and subsidy schemes become stricter regarding remuneration during negative price hours, renewable generators are being incentivised to participate more actively in power markets. To reflect this, we model a gradual reduction in negative bidding from renewables, stabilising at around zero by 2028.

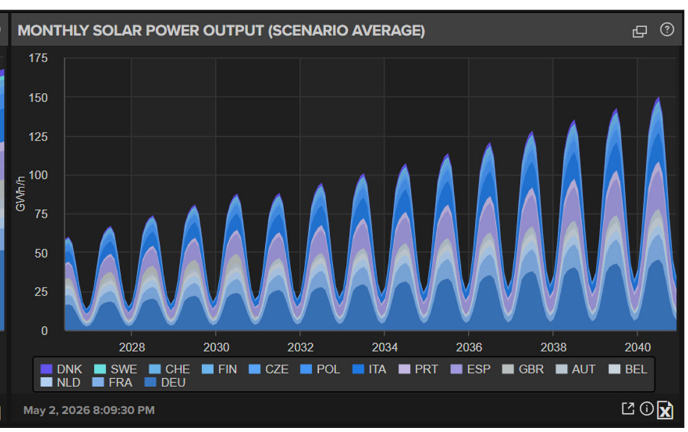












Curtailment

The intermittent nature of wind and solar generation makes curtailment inherent to power systems, as supply and demand must be matched in real time. To capture this effect, we feed into our model the potential wind and solar generation profiles for each weather year. We then identify periods in which this potential generation exceeds domestic demand and available export capacity and classify the surplus as curtailment.

As the renewable fleet expands, the volume of potential wind and solar generation that cannot be integrated into the system also increases. We estimate that curtailment rises significantly from 24 TWh in 2030 to 68 TWh in 2035 and reaches around 150 TWh by 2040. By 2040, the level of curtailment across the modelled countries is significant and could almost cover the expected demand in the Netherlands if enough flexibility and interconnection capacity were in place. We examine flexibility, interconnections and the integration of renewables in detail in the following sections.

It is important to note that we only account for curtailment driven by temporal supply–demand imbalances. We do not account for additional sources of curtailment, such as voluntary reductions due to low price expectations or constraints imposed by grid limitations and maintenance. As a result, actual curtailment levels could be even higher than our estimates.

Biomass

We do no regard biogas-powered generation a growth area and assume the current capacity to remain constant. We do see some changes happening in the wood-fired electricity sector though: The British plants will be phased out of their current Contract-for-Difference (CfD) schemes and go into cost competition with gas power plants, which will lead to decreasing generation over time as wind and solar replaces the demand for dispatchable generation in general.

In the Netherlands and Denmark the remaining hard coal capacity will in part switch to wood-firing, which will be mostly free of governmental support. In Denmark wood-fired power already makes up for the majority of thermal generation and by 2040 that share will be of two thirds, however the total generation is projected to shrink to less than 1 TWh or less than 2% of total Danish generation.

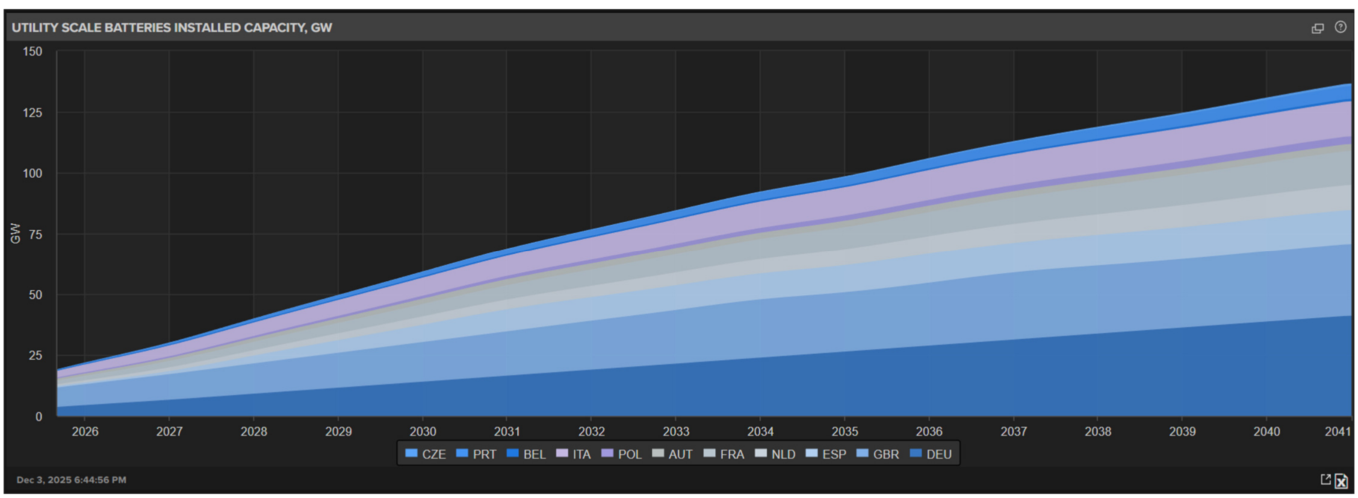
Hydro power

We have the rather conservative assumption of insignificant growth of hydro power generation capacity in Europe. With that, the share of hydro power on the generation mix declines over time from approximately 16% in the present to around 12% in 2040.

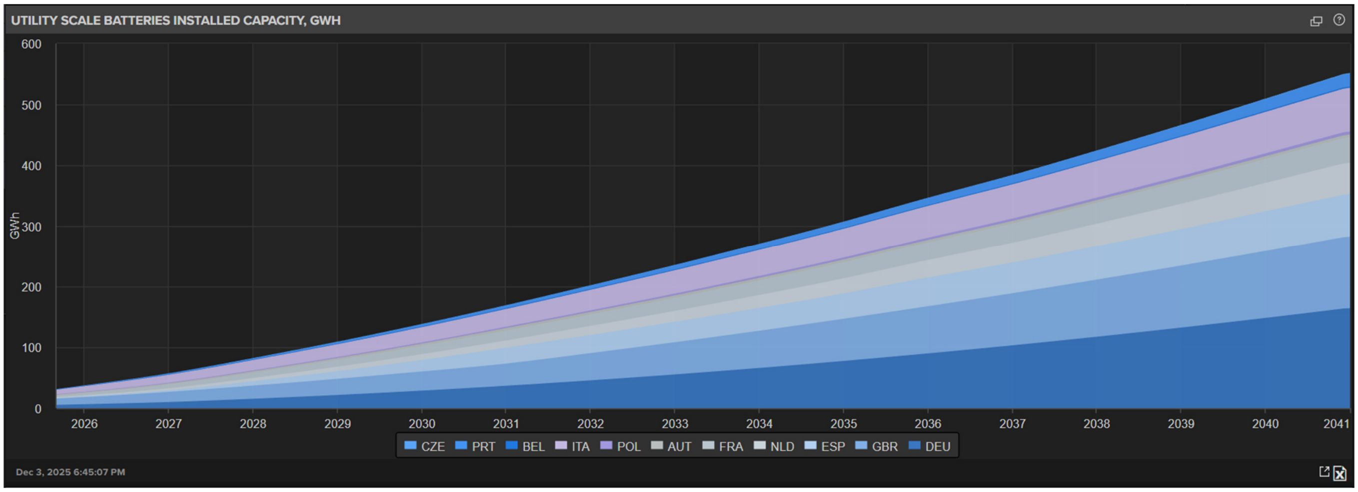
Flexibility and Storage

For utility-scale battery capacity, we also consider the national targets (both in terms of duration in GWh/GW, and power in GW) and our own market analysis. Where we consider official targets to be outdated, we adjust them based on our assessment of project pipelines and recent market developments. To ensure they make enough profit, batteries are charged during periods of low or negative residual demand, and then discharged during peak hours, also supporting renewable power integration by reducing curtailment.

We expect utility-scale battery capacity to grow significantly, from less than 25 GW today to more than 100 GW by 2035 and close to 140 GW by 2040 across the main countries covered in our analysis shown below.



In parallel, we expect average battery duration to increase to more than 4 hours by 2040, driven by declining costs and ongoing technological improvements. We also expect average durations to vary across countries, depending on the subsidy schemes and market incentives in place.



Great Britain has been a front-runner in battery deployment, but we expect strong growth across other major markets, particularly Germany, Spain, and Italy.

While we consider utility-scale batteries as a key source of system flexibility, other flexibility sources will also play an important role in the long term. These include demand-side response, flexible conventional generation, and interconnectors between regions with complementary generation profiles.

Interconnection and Cross-border Flows

We track the interconnection projects that will add to cross-border transmission capacity between markets for the next 15 years. Detailed lists for the capacity additions can be found on the Interconnectors pages[3]. Some highlights include the new direct interconnection of Germany and Great Britain with the Neuconnect cable in 2028 (1.4 GW), further strengthening of the British-French interconnection with an additional 4.5 GW by end-2040, and a near-doubling of the Spanish-French interconnection to over 6 GW.

The exact start date for new transmission lines has to be estimated, as available public information can be scarce, and announced start dates are usually met with long delays. We usually add 1-3 years to announced start dates to reflect a more realistic buildout schedule and constantly track schedule changes.

The long-term evolution of a market's total net import or net export is often related to its relative standing in renewable power deployment and possibly other large supply-side enhancements, like new nuclear power units. For example, French net exports, which are very strong today, are set to decline, as France has a relative excess of lower-cost electricity (nuclear, solar and wind) for exports today, but a slower deployment of new low-cost power in the future. Norway and Sweden will also see a shrinking power surplus over time and export less electricity by the next decade, as the power generation growth will increasingly be consumed internally. On the other hand, we foresee Germany's net import position to flip back to net exports early next decade, which is in part due to relatively rapid renewable deployment, but primarily due to the addition of 10 GW new flexible gas-fired generation. This is a security of supply and flexibility measure for Germany, but all surrounding countries will end up benefitting from enhanced German supply and import when convenient, while Germany will rely less on gas-fired power from abroad.

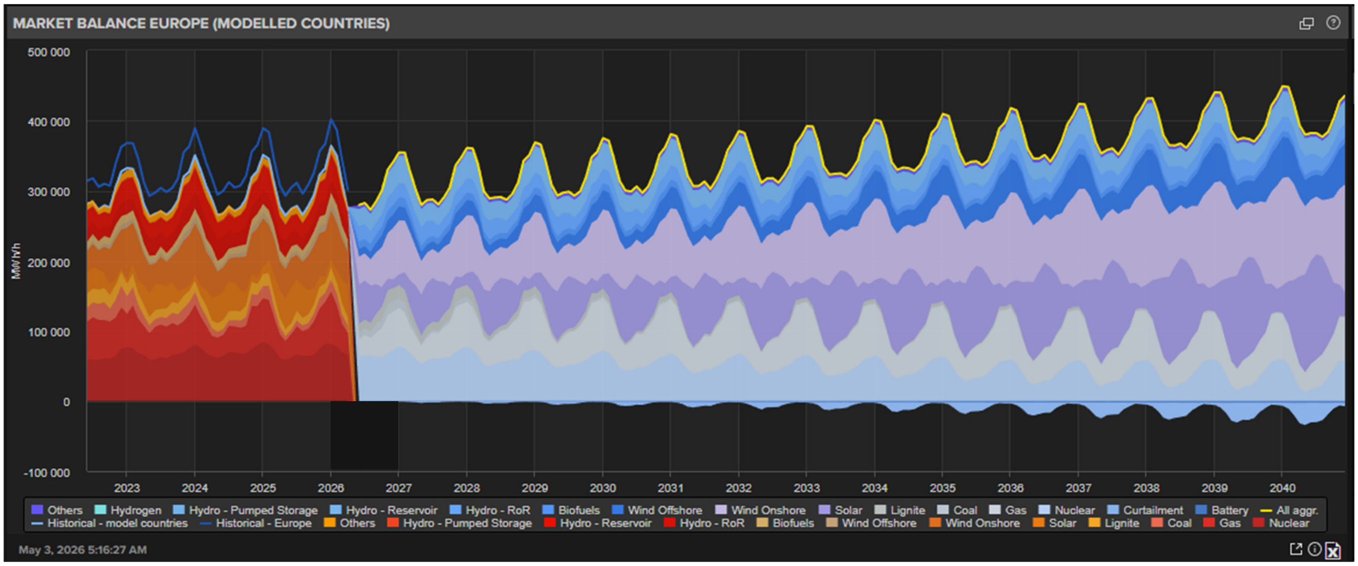
Our price discussion below will show that whilst by 2040 we expect more interconnector capacity, there will still be significant price differentials within Europe.

[3] See POWER > Europe > Long Term > Fuels

Market Balance and generation mix

Below we can see how renewable (includes wind, solar, hydro and biomass) and clean (includes renewable and nuclear) generation shares rise steadily, setting the prospect for a 77% renewable and 92% emission-free grid in 2040. However, as discussed previously, curtailment of potential renewable production occurring during periods of insufficient demand limits the effective integration of new generation and slows down the growth of the renewable share.

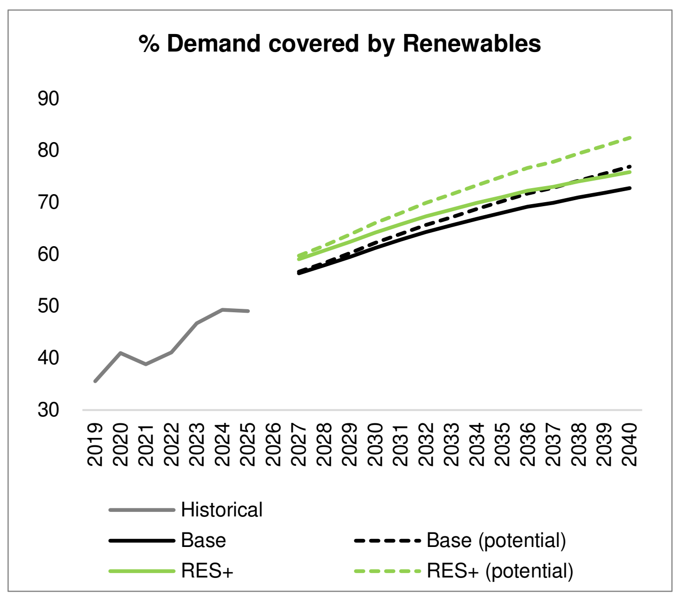
Wind and solar generation is to make up for around 60% of total demand in 2040. If all wind and solar generation was effectively integrated into the system their share could increase to 64%.



We also assessed a more ambitious scenario with a 10% increase in wind and solar buildout compared to our Base Case (RES+ scenario). In this case, 82% of demand could potentially be covered by renewables, but only around 76% after accounting for curtailment (compared to 77% and 73% respectively, under the Base Case). As we can see from the chart on the right, the additional ambition for wind and solar deployment of the RES+ scenario, would result in almost the same share of demand covered by renewables, as if all their potential generation was effectively integrated into the system in the Base Case with 10% lower capacities for wind and solar

Under the RES+ scenario, the total share of emission-free generation (including also nuclear) could reach 96% but would be 90% once curtailed energy is excluded.

These results highlight that, without additional flexibility solutions, a significant share of incremental renewable capacity cannot be fully utilised, limiting the effective decarbonisation impact of further buildout.



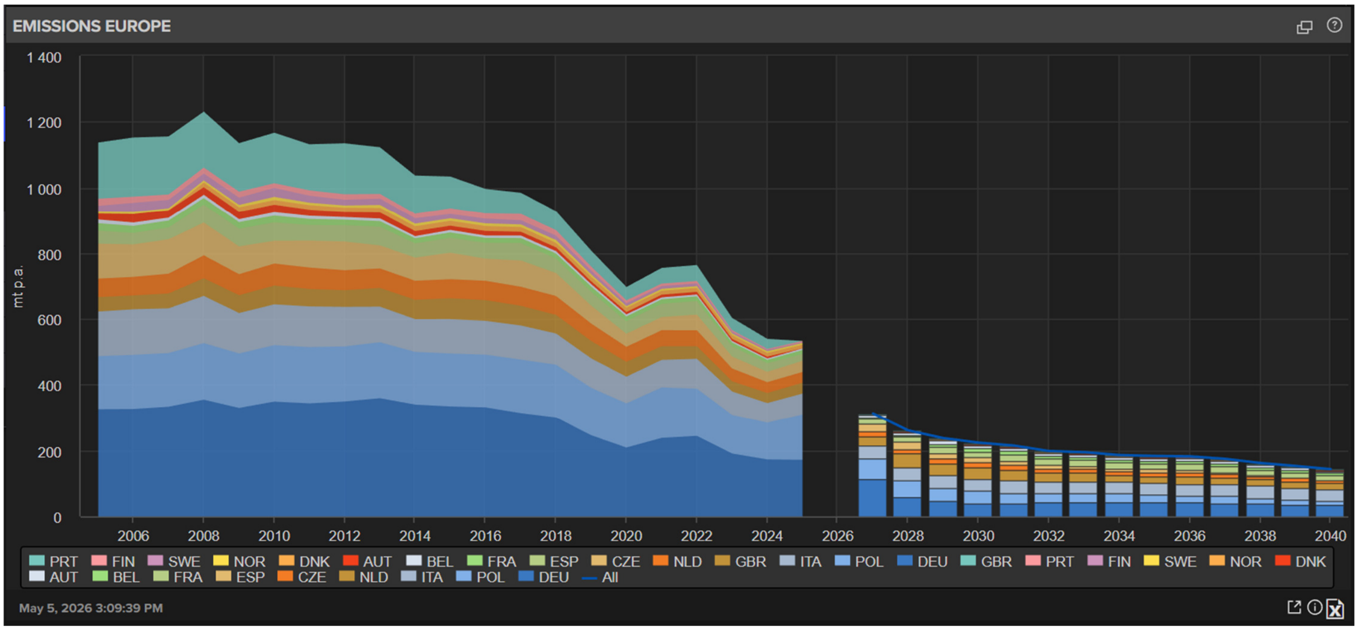
Power Emissions

We currently cover about 87% of the EU-ETS countries' power sector emissions – EU13+NOR[4], in addition to the British power emissions.

Applying our EU13+NOR forecast as proxy for the EU-ETS, we can derive that the **2040 emissions are set to drop to 126mt – an up to 87% decrease vs. 2005 levels.** In Britain the corresponding 2040 emissions would fall by 90% vs. 2005 levels.

Nearly all fossil-fuelled generation in 2040 will come from the **gas-fired sector**. In our model area, the 2027 power emissions from gas plants are still expected to make up for 36% of EU-ETS power emissions. This share will increase drastically to 74%/87%/97% in 2030/2035/2040.

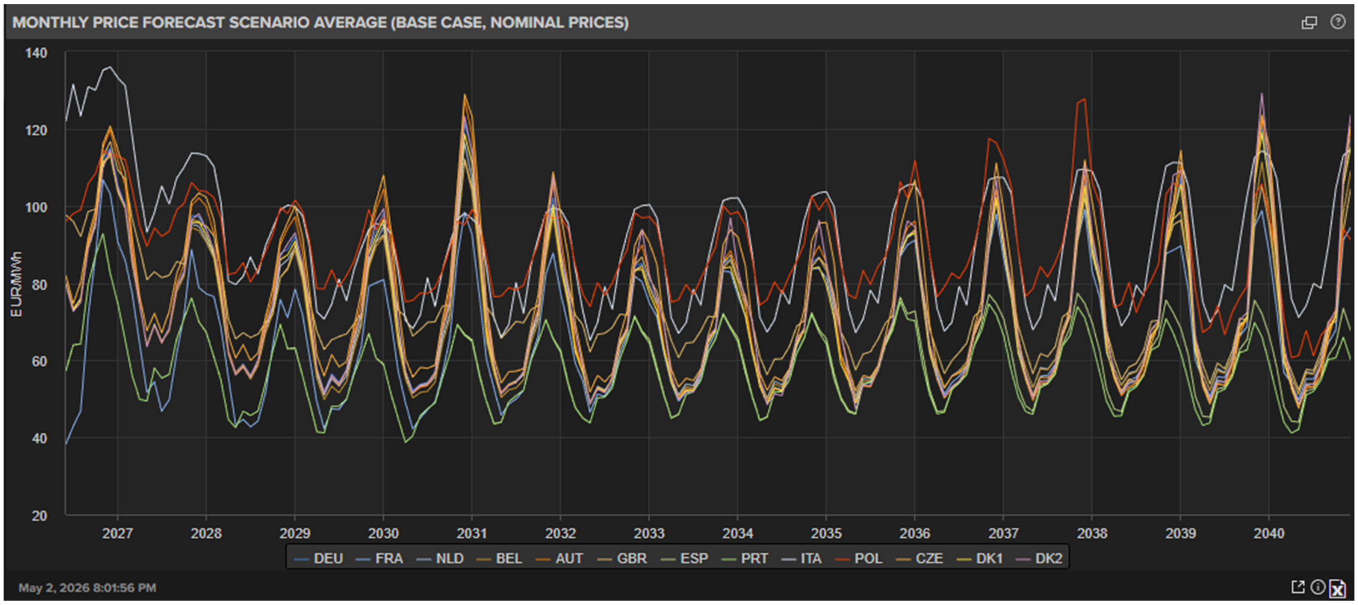
Germany, Poland and Italy currently make up for about two thirds of total emissions in our modelled area, while in 2040 we expect the share to be drop to 58%, i.e. for power emissions to be less concentrated than today.

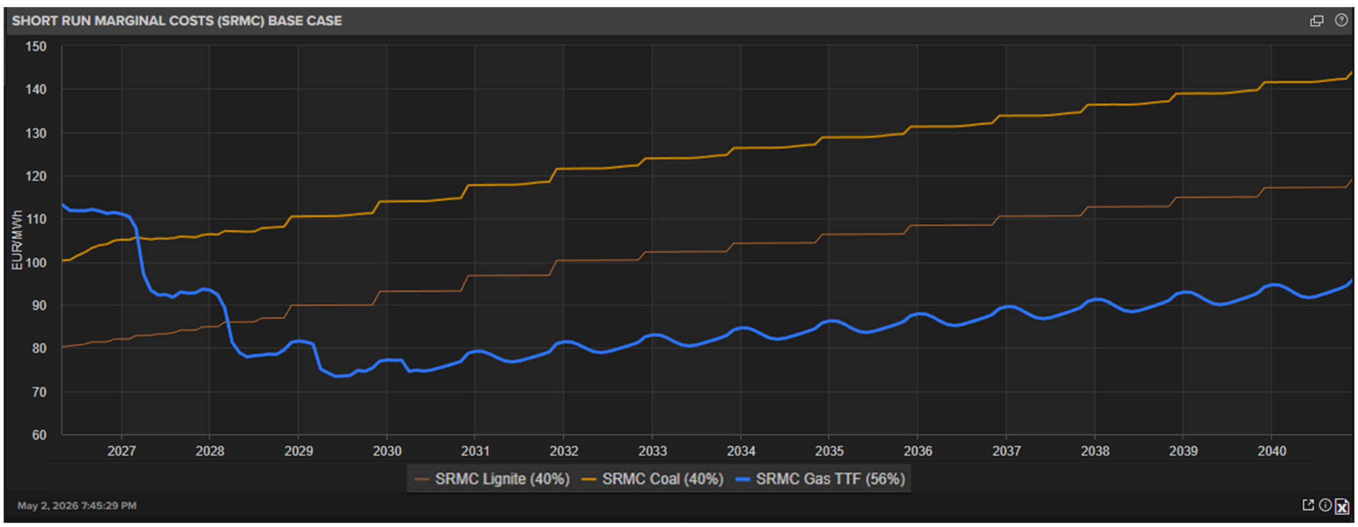


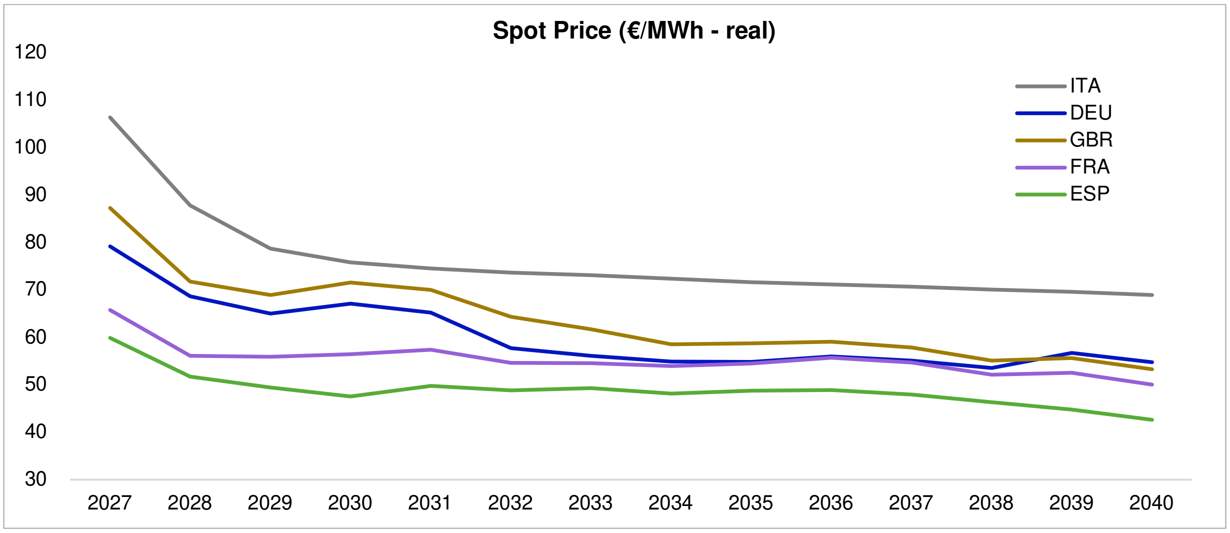
[4] DEU, FRA, BEL, NLD, DNK, SWE, FIN, AUT, CZE, POL, ESP, PRT, ITA + NOR

Price Discussion

Our nominal price forecast shows a nearly sideways trajectory for most countries, however the real prices chart shows that overall market tightness drops over time.







Key drivers for our price forecasts are:

- Consumption growth outpaced by renewable power growth
- Low-marginal cost renewable power sources setting the price in an increasing amount of hours
- Gas forward prices are in backwardation, putting gas-fired generation in the money from 2028
- Increasing interconnection slowly closing location spreads

From the monthly profile we learn that the months Dec-Jan-Feb maintain the strongest potential for price spikes.

The annual trend shows some interesting trends: **Iberia** continues to be the discount region in Europe with prices below 61 €/MWh from 2028 onwards.

By 2040 we see growing convergence of **Central-Western European** countries to a mostly coupled priced are, at least in monthly granularity: Germany, Austria, the Netherlands, Belgium, Denmark and Czech Republic average closely together at around 74 EUR/MWh in 2040. **France** is expected to maintain the discount to the CWE neighbours, though the discount narrows towards 2040 to about 6 €/MWh or 9%.

British prices are particularly higher in the summer compared to neighbours, though more coupled in winter months. With the continued rollout of solar power capacity, the summer gap closes gradually towards 2040.

Italy stays on the relatively high-price end with more than 93 €/MWh in 2040: the renewable power deployment is slower than it would need to be to keep up with demand growth. There is also a decreasing supply of cheap(er) electricity from the classical exporters Switzerland and Austria.

Poland is also mostly on the high side: We do expect rather strong deployment of solar, onshore and offshore wind, and relatively strong expansion of the gas power fleet. Yet, the coal phaseout is in the beginnings and there are several coal mine and coal plant closures ahead which will provide quite some price upside, especially in the winter. The startup of the first Polish nuclear plant Liubatowo-Kopalino in 2038 would have a significant impact in bringing prices closer to the Western-European country group.

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