Le réseau
de transport
d'électricité

2024 ELECTRICITY REVIEW

FULL REPORT

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2024 Electricity Review

SUMMARY

The full report and data are available at https://analysesetdonnees.rte-france.com/

1. CONSUMPTION

2. GENERATION

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Consumption

2024 ELECTRICITY REVIEW

In 2024, electricity consumption stopped falling and rose slightly, though it still remained well below pre-crisis levels

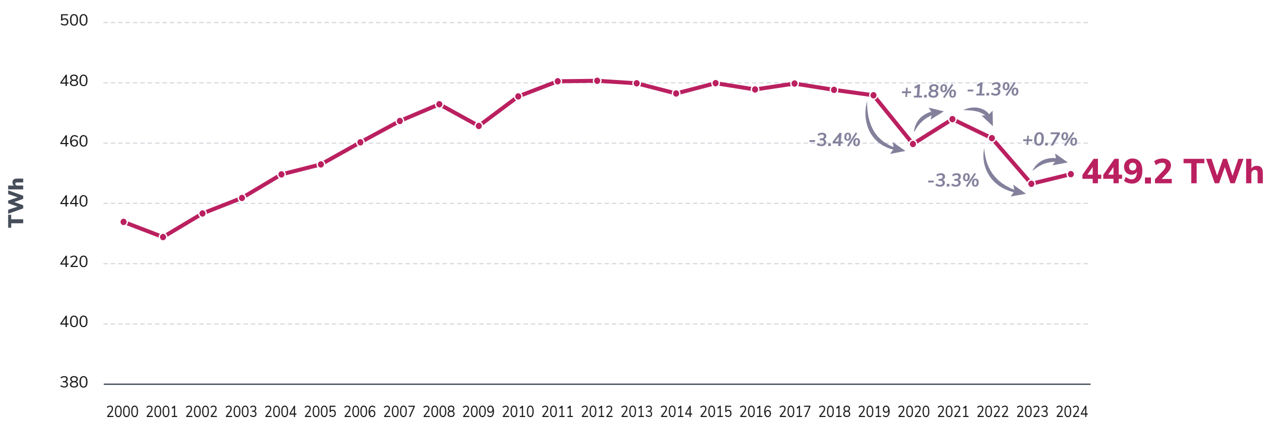
Consumption moves away from the downward trend seen in 2022 and 2023

In 2024, French electricity consumption (adjusted for weather contingencies) totalled **449.2 TWh.**

This level marks a very slight increase (+3 TWh, or +0.7%[1]) over 2023 and a break away from the downward trend seen in recent years, due to a slightly more favourable macroeconomic climate[2].

However, it remains **well below** the level seen in the 2010s (around -30 TWh, or **-6%, compared with average consumption between 2014 and 2019)**. These low levels result from the combined effects

Figure 1.1 – Consumption adjusted for weather and calendar effects between 2000 and 2024



1. These values include the volumes of electricity self-consumption in France.
2. In particular, gas and electricity prices fell sharply, nearing the levels seen between 2014 and 2019 (see the *Prices* chapter), and inflation fell to a level close to 2% in 2024, after hovering around 5% over the previous two years.

of rising electricity prices and the energy sobriety measures during the energy crisis (which are having a lasting impact), as well as continued progress in energy efficiency over the last decade.

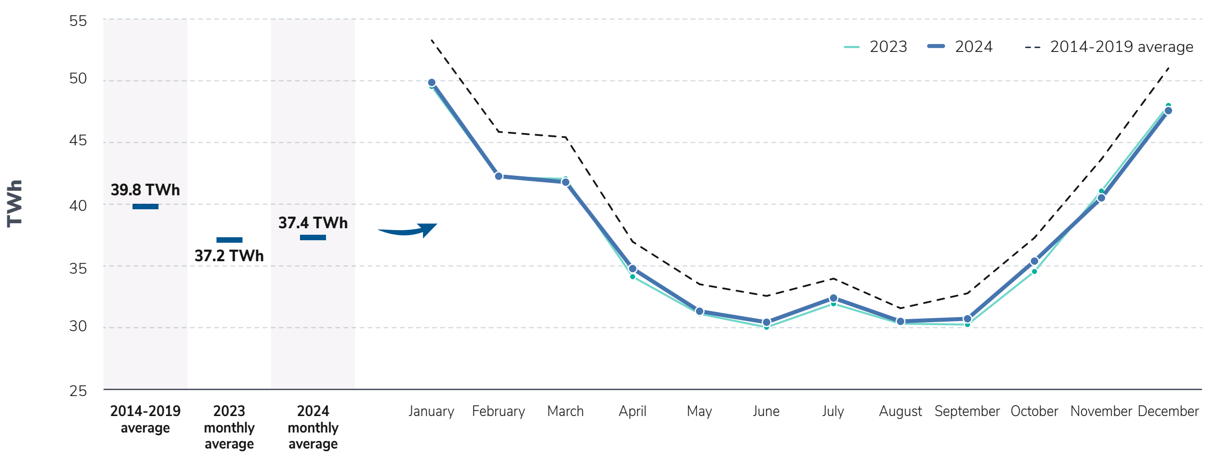
As in 2023, the difference relative to the 2014-2019 period was highest in winter, when heating in buildings provides an additional lever for energy savings, and lowest in July and August. These months correspond to periods when economic activity usually slows down: the drop in industrial consumption, significant during both the pandemic and the energy crisis, is therefore less visible, which helps to reduce the gap from the pre-crisis period. In particular, electricity consumption by large industrial consumers[3] was around 7.8% lower in August 2024 than the average for August between 2014 and 2019, whereas it was 13% lower in the other months of 2024 compared with the same months between 2014 and 2019.

Electricity consumption in 2024 thus ended the sharp downward trend in consumption seen since 2020, due to the pandemic and then the energy crisis. These were the biggest falls in consumption since the end of the Second World War.

The pandemic pulled consumption downwards, mainly during the first lockdown in 2020, which interrupted much of the country's economic activity. Once the lockdown was lifted, consumption returned to a level close to the 2014-2019 period. In particular, the economic recovery seen from the end of 2020 and during 2021 brought consumption back to levels close to historical norms; by the beginning of 2022, it was even slightly above past levels.

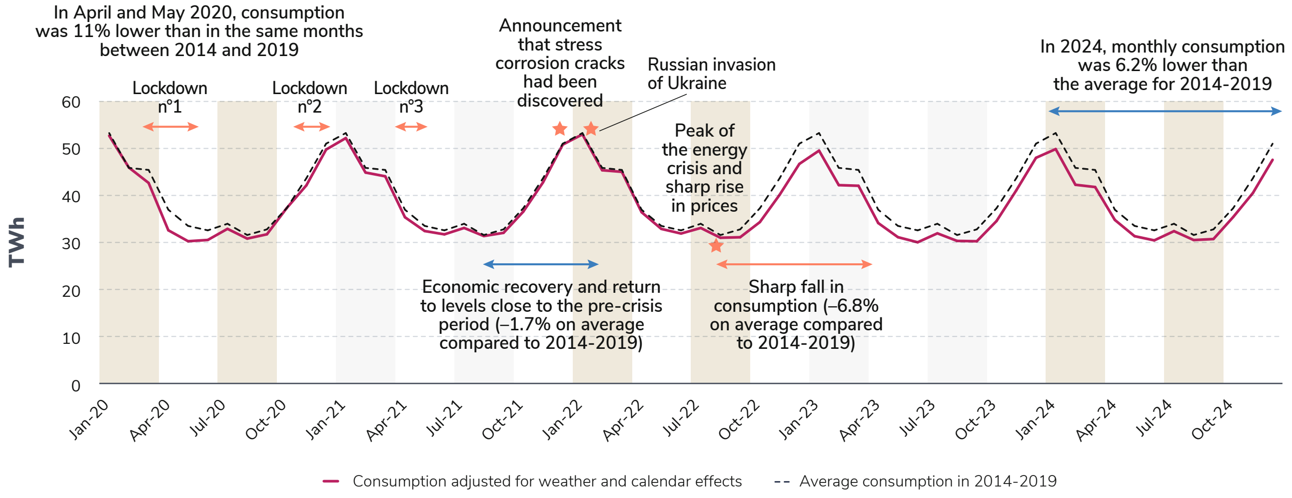
Then 2022 brought a threefold energy crisis caused by the reduction in nuclear availability due to stress corrosion checks and repairs, the drought that severely affected hydroelectric generation in Europe, and the Russian invasion of Ukraine, which led to a sharp rise in fossil fuel prices. From August 2022, when electricity prices reached historically high levels, electricity consumption fell significantly compared with historical figures. This fall was less intense than during the first lockdown in 2020, but lasted much longer, since consumption fell for two consecutive years (2022 and 2023). The year 2024 thus marks a break in the trend, even if electricity consumption has still not returned to 2014-2019 levels despite the relative improvement in the macroeconomic climate and the drop in wholesale electricity prices in 2023 and 2024.

Figure 1.2 – Monthly consumption adjusted for weather contingencies in 2024 and from 2014 to 2019



3. Consumers connected to the transmission network (high and extra-high voltage) managed by RTE (see focus). These are mainly large industrial consumers, but they also include some large tertiary consumers.

Figure 1.3 – Monthly trend in consumption adjusted for weather and calendar effects between 2020 and 2024



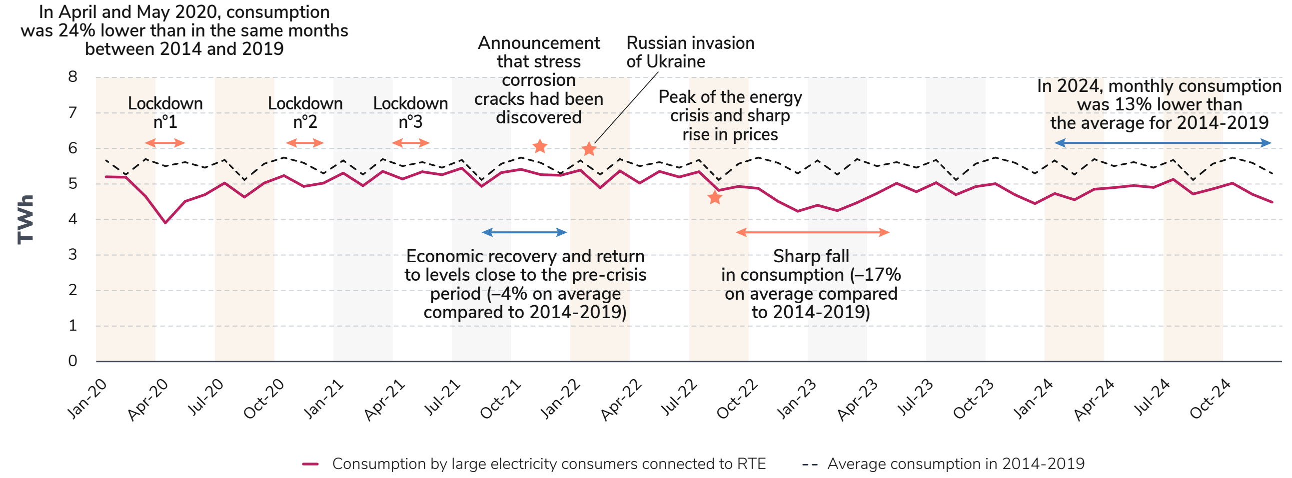
After two years of decline, consumption by major industrial consumers rose by 2.4% on the previous year

In 2024, consumption by major industrial companies increased by around 2.4% on the previous year

In 2024, electricity consumption by major industrial consumers increased by around 2.4% compared with 2023. Electricity-intensive industries were the hardest hit by the energy crisis: the increase in consumption by these economic players is a significant sign that their activity is picking up.

However, like the country's overall consumption, it remains well below historical levels: 12.7% below the average for 2014-2019 (and 8.2% below the 2021 level).

Figure 1.4 – Monthly consumption between 2020 and 2024 by major electricity consumers connected to the RTE network



The effects of the pandemic and the energy crisis on consumption by large-scale industry follow the same pattern as their effects on French consumption as a whole. There was a very significant drop concentrated during the first lockdown in 2020, followed by a partial recovery, and a further major drop from the summer of 2022, which was less marked than in April-May 2020 but much longer-lasting.

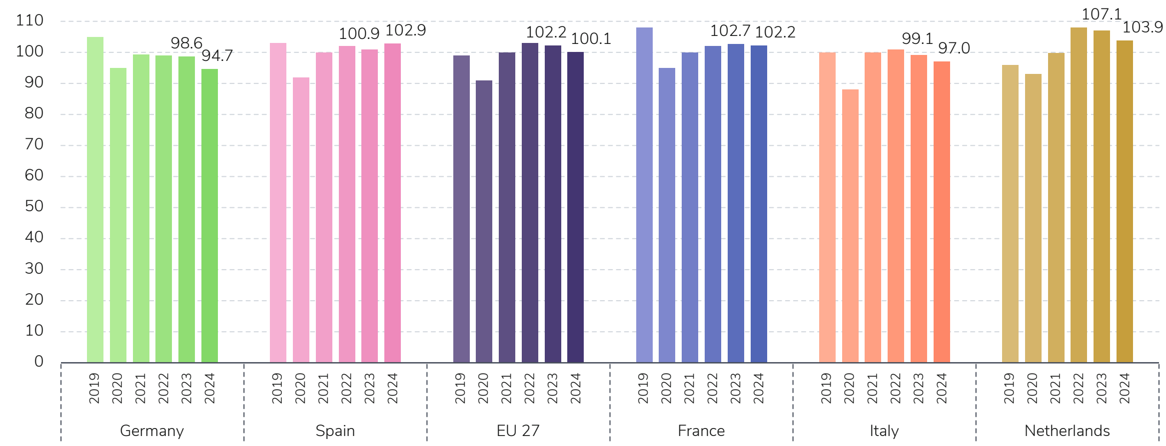
Some sectors were more affected by the pandemic (such as car manufacturing and rail transport). Others, which consume more energy, were more affected by the energy crisis: the chemical industry, metallurgy and the paper and cardboard sector all saw their electricity consumption fall by around 20% at the height of the energy crisis compared to the 2014-2019 average.

Paper and cardboard, hit hard by the energy crisis, is the sector that showed the strongest signs of recovery in consumption in 2024 (+9.6% compared with 2023). The transport sector (particularly rail) also saw its consumption increase by 2.7%, slightly more than the average for large consumers connected to the RTE network. The chemical and metal industries, also heavily affected by the crisis, saw their consumption increase by around 1%. On the other hand, other sectors, such as the manufacture of non-metallic mineral products and the automotive industry, have continued to see their consumption fall (by around 5% and 2.9% respectively compared with 2023), despite the overall upward trend.

Industrial production held up better in France than in other European countries

The French industrial production index was slightly lower in 2024 than in 2023. Despite the slight rise in raw material prices in 2024 and the downward trend in the business climate identified by INSEE surveys[4], industrial output in France remained close to the previous 'ear's level, in contrast to other European countries. In particular, Germany and Italy, the two countries with the European Union's highest levels of industrial production, saw a significant drop in output in 2024 (-4 and -2 index points respectively, compared to less than one point in France).

Figure 1.5 – Average annual industrial output, base 100 (2021)



Source: Eurostat

first 11 months of 2024

4. In December 2024, the business climate in industry was stable – Informations rapides – 316 | Insee

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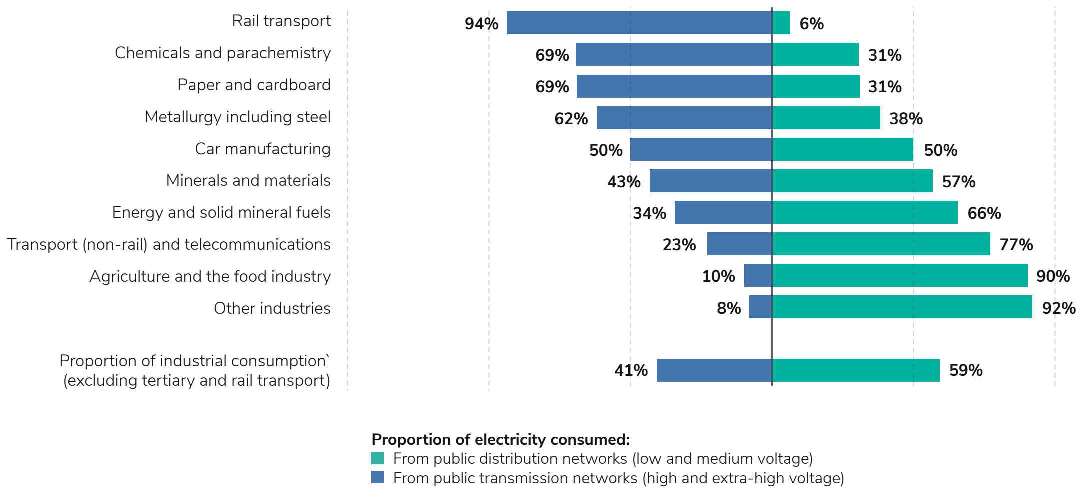
Forty percent of industrial consumption is drawn from the transmission network (high and extra-high voltage), with marked differences between sectors

Forty percent of industrial electricity consumption is supplied by the high- and extra-high-voltage transmission network (managed by RTE) and 60% by the low- and medium-voltage distribution networks (managed mainly by Enedis, but also by local distribution companies). Industrial companies connected to the transmission network are major consumers of electricity, such as manufacturers in the chemicals, paper and cardboard or steel industries. Industrial sectors with relatively more numerous plants that consume less, such as the agri-food sector, are supplied mainly by the distribution networks. The transmission network also supplies a number of companies in the tertiary sector and the railways, which draw 94% of their electricity consumption from this network

Figure 1.6 - Proportions of electricity consumption by French industry supplied from the transmission and distribution networks in 2023 (segmented according to NAF REV2)



The electrification of uses is a major challenge for the long term

Even if the electrification of uses has begun, particularly in transport, its effects are not yet sufficiently visible to offset this fall. Firstly, because the electrification of current uses – such as mobility, heating (still largely reliant on fossil fuels) or certain industrial processes – is a long-term process within systems that are subject to a degree of inertia (renewal of the vehicle fleet, housing renovations etc.). And secondly, because the emergence of new energy uses (such as the construction of electrolysers) also involves a certain lead time. The abundance of low-cost, low-carbon generation in France in 2024 (which created value through exports) shows that the country already has the capacity to accommodate significant electrification. This will be a major asset in responding to the challenge of the energy transition, as well as the growing geopolitical tensions and the rise of new forms of protectionism that could affect oil and gas supplies and the costs of these fuels.

Due to high temperatures, the difference between weather-adjusted consumption and gross consumption is significant

Gross consumption was among the lowest in the last ten years

Gross electricity consumption in 2024 amounted to 442.2 TWh, slightly higher (+0.9%) than in 2023 (438.5 TWh), though both years were among the five hottest since measurements began in France[5]. Part of the increase is due to calendar effects, since 2024 was a leap year. Excluding consumption on 29 February (1.4 TWh), the increase is 0.5%.

On average, temperatures in 2024 were higher than the seasonal norms, which reduced electricity consumption for heating in winter and increased electricity consumption for air conditioning in summer. The effect of reducing heating demand in winter was predominant, since electricity consumption is more temperature-sensitive in winter than in summer.

The weather conditions in 2024 thus led to non-adjusted consumption values that were lower than the adjusted consumption.

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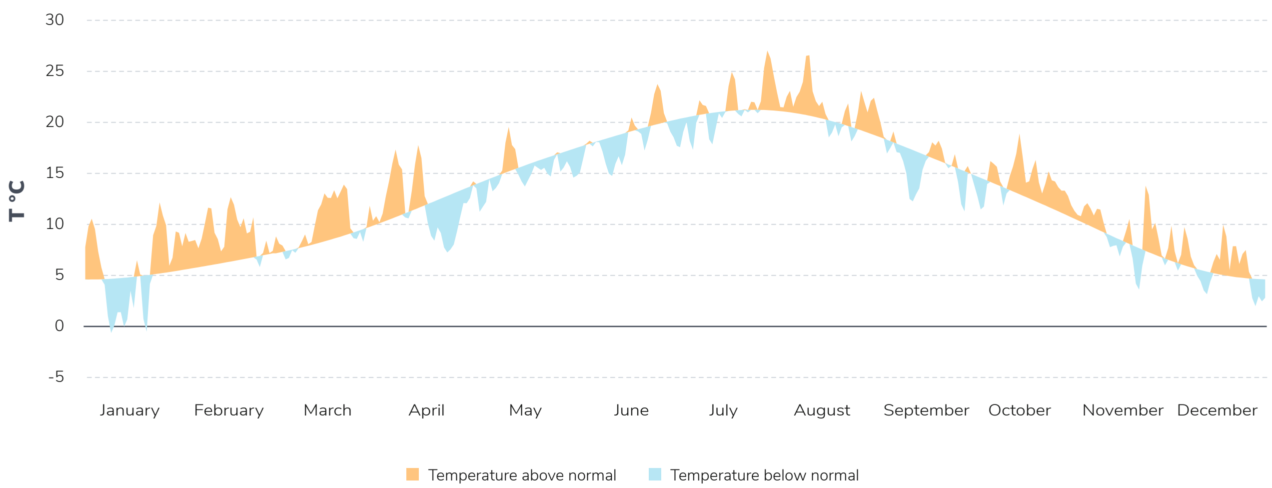
Why adjust consumption for weather?

RTE always adjusts its gross electricity consumption measurements to allow a comparison from one year to the next regardless of weather variability, and an identification of the structural effects that affect the level of consumption. Weather-adjusted consumption is the electricity consumption that would have occurred if temperatures had been in line with the reference temperatures for the period. The calculation is carried out on the basis of consumption and temperature data. For example, if during a winter week temperatures are higher than normal for the season, gross consumption (i.e. unadjusted) will be lower than consumption based on normal temperatures. An adjustment is also carried out for leap years.

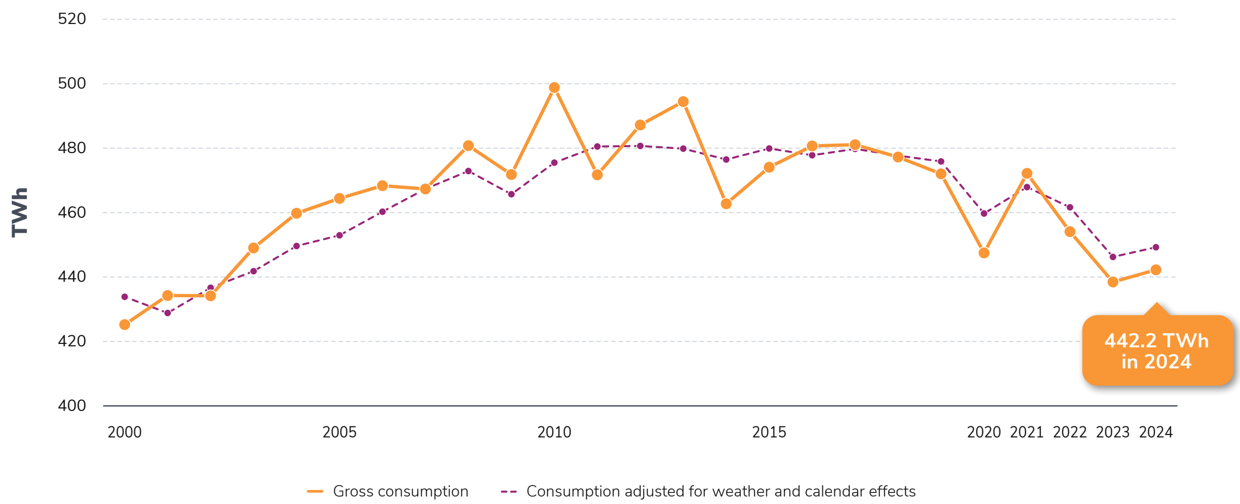
5. 2024 French Climate Review | Météo-France

Figure 1.7 – Normal temperature and actual temperature in 2024



These low levels were significantly below those seen in the 2010s.

Figure 1.8 – Consumption not adjusted for weather and calendar effects between 2000 and 2024

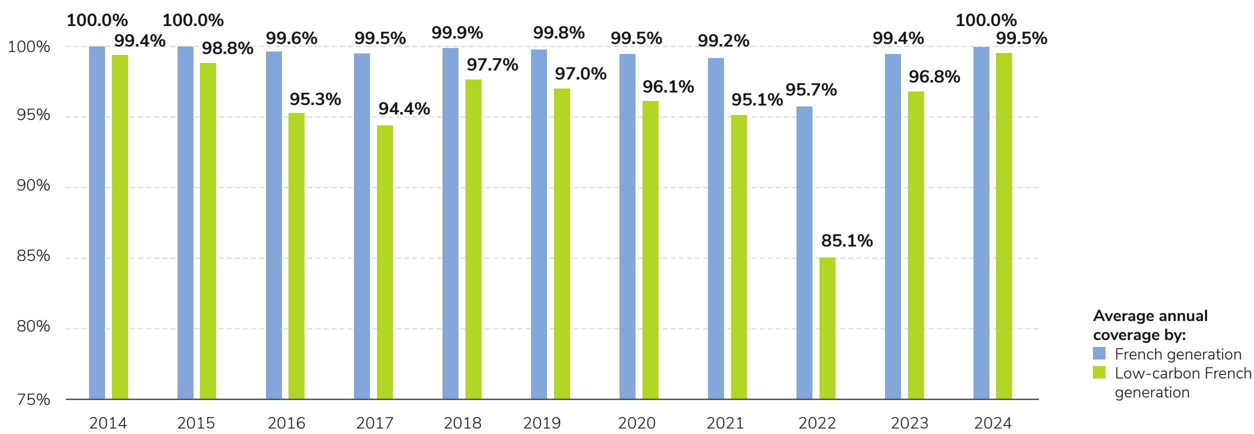


French generation almost always covered consumption in full

So 2024 was simultaneously marked by a slight increase in consumption and by very abundant generation, particularly low-carbon[6] (nuclear generation at its highest level for five years, hydropower at its highest level since 2013, wind and solar power continuing to develop – see the *Generation* chapter). As a result, the average rate at which French consumption was covered by French generation reached 100% in 2024, and for low-carbon generation it rose to 99.5% for the first time in a decade.

For example, 2014 and 2015 were characterised by relatively low gross consumption (462 TWh and 474 TWh) and high nuclear power output (415.8 TWh and 416.8 TWh)[7]. However, thermal generation was higher in both these years than in 2024.

Figure 1.9 – Average half-hourly coverage of consumption by French generation (blue) and by French low-carbon generation (green)



Peak consumption in 2024 was among the lowest of the decade

The highest levels of daily consumption in 2024 were recorded between 8 and 20 January. During this period, the temperature was 3°C below the seasonal norms, which led to an increase in daily electricity consumption. The electrical power demand at any one time was also very high: the top 1% of the year's consumption levels were all recorded on these days. Annual peak consumption was recorded on Wednesday 10 January at 7 p.m., at 86.0 GW. This is a higher level than the previous year, but – along with the consumption peaks of 2014 and 2020 (which both had mild winters) – one of the lowest in the last ten years.

6. The generation mix was 95% low-carbon, another all-time high.
7. In addition, 2015 was the last year to date in which Fr'nce's annual nuclear generation exceeded 400 TWh.

Figure 1.10 – Maximum weekly consumption in 2024

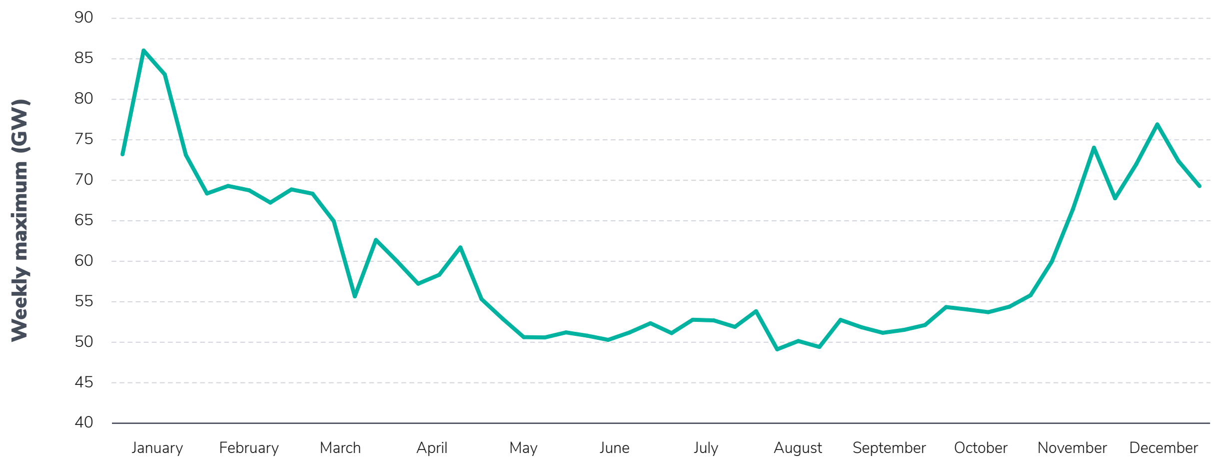
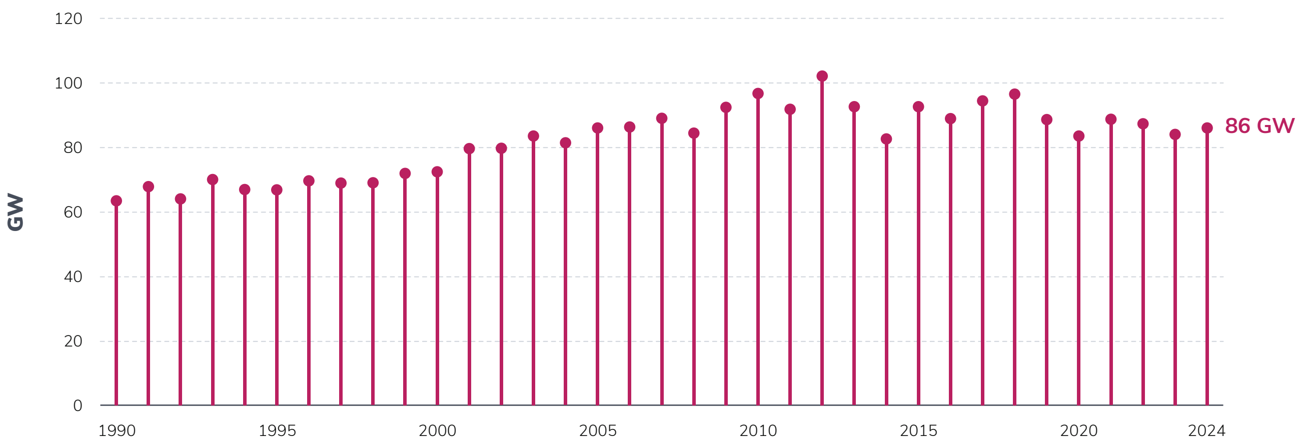


Figure 1.11 – Trends in peak values between 1990 and 2024



Even when consumption was high, it was mostly covered by low-carbon generation

The year's highest levels of electricity consumption were largely covered by low-carbon generation. Nuclear and hydropower output together covered more than 85% of consumption during the 10% of hours in the year with the highest consumption (a rate not seen since 2015, when it stood at around 89%).

During these same hours, wind generation reached 6.3 GW and covered 9% of consumption on average (slightly higher than the average for thermal generation during the same periods).

Generation

2024 ELECTRICITY REVIEW

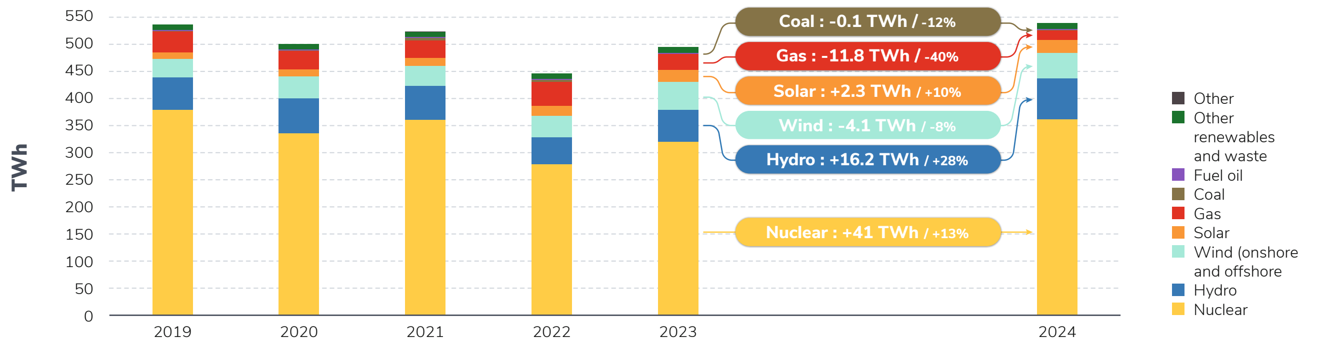
French electricity generation continued to grow in 2024, reaching unprecedented levels of low-carbon generation

Taking all energy sources together, the volume of electricity generated in France rose for the second year running in 2024 (+9% compared with 2023). This represents a similar proportion to 2023, when production was 10.8% higher than in 2022. Electricity generation reached 539 TWh in 2024, exceeding its pre-crisis level for the first time (537.5 TWh on average over the 2014-2019 period).

The rise in electricity output in 2024 was mainly due to the increase in nuclear and hydropower generation (+41.3 TWh and +16.2 TWh respectively) and, to a lesser extent, solar generation (+2.3 TWh). At the same time, electricity generation from fossil fuels fell significantly in 2024 (–11.6 TWh compared with 2023), reaching its lowest level since 1952. **The volume of low-carbon generation has never been**

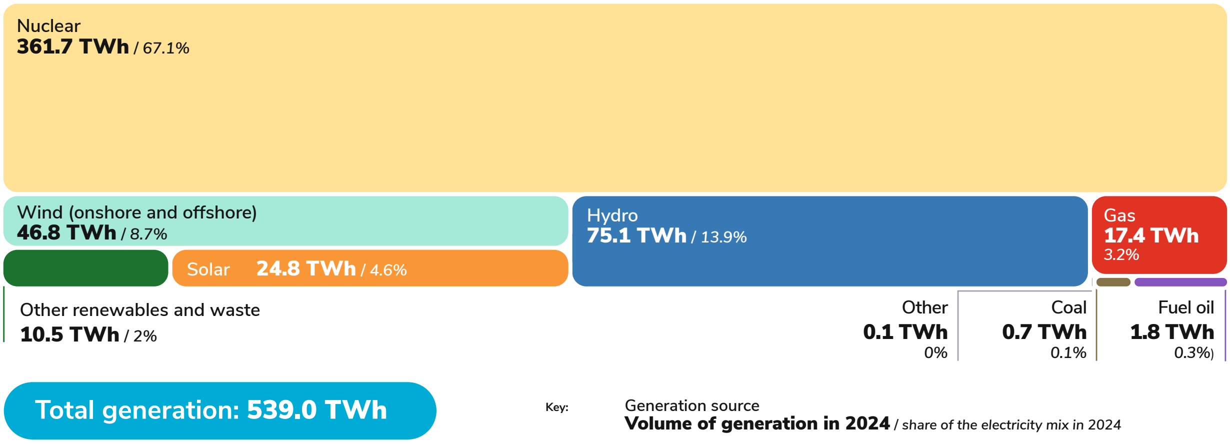
Figure 2.1 – Electricity generation in France by energy source between 2019 and 2024

	2019	2020	2021	2022	2023	2024
Total generation (TWh)	536.1	500.1	523.1	446.5	494.7	539.0
Low-carbon proportion (%)*	91.0	91.2	91.4	87.4	92.4	94.9
Renewable proportion (%)	20.2	24.2	22.5	24.9	27.6	27.8



Power generated from household waste is considered 50% renewable. Seventy percent of PSP pump consumption is deducted from hydropower generation in accordance with European Directive 2009/28/EC.

Figure 2.2 – Total electricity generation in France in 2024 and breakdown by source



higher, thanks to the recovery of nuclear power, a rainy year that boosted hydropower output and the development of wind and solar generation over the last ten years. The proportion of low-carbon generation thus reached an all-time high of 95% in 2024.

After reaching its lowest level since 1988 in 2022, nuclear generation began to revive in 2023 and completed its recovery in 2024 (reaching 361.7 TWh), as maintenance outages and stress corrosion checks came to an end. The year 2024 also saw a record level of renewable generation, reaching 150 TWh, or almost 28% of total French generation. This record results from an unprecedented level of renewable hydropower generation[1] (69.8 TWh) combined with growth in wind and solar output over the years (71.6 TWh in 2024 compared with 45.8 TWh in 2019).

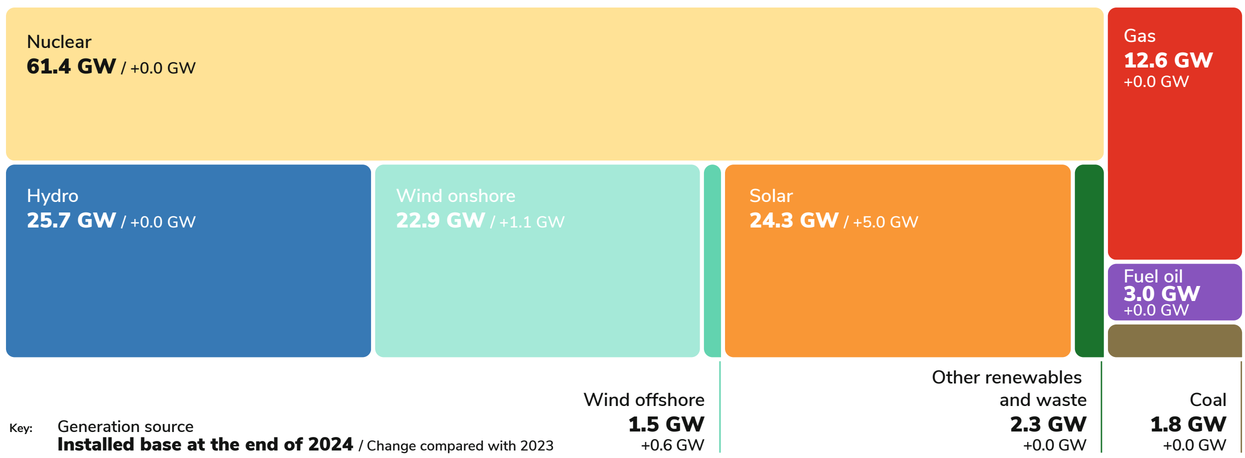
France's electricity generation capacity grew at an unprecedented rate in 2024 with the commissioning of new offshore wind farms and record growth in photovoltaic installations

The electricity generating fleet continued to expand in 2024, reaching 155.5 GW of installed capacity at the end of December, an increase of 6.7 GW compared with the installed capacity at the end of 2023. This rise was driven by growth in solar and, to a lesser extent, wind capacity. France's electricity generation fleet has not expanded so significantly since the nuclear fleet was developed in the early 1980s. This figure does not include the new nuclear reactor at the Flamanville power station (with a capacity of 1.6 GW). The reactor was connected to the grid on 21 December 2024, but is due to enter commercial service during 2025, which will bring the nuclear fleet to 63.0 GW (see the Focus in the section on nuclear power), close to its level before the closure of the two Fessenheim reactors (63.1 GW).

Almost three-quarters of the new generation capacity installed in 2024 consists of solar photovoltaic installations, which saw record growth (+5.0 GW)

1. Renewable hydropower generation corresponds to hydropower generation minus 70% of pumping consumption by PSH, in accordance with European Directive 2009/28/EC. It has never been so high (while total hydropower generation in 2024 was the highest since 2013).

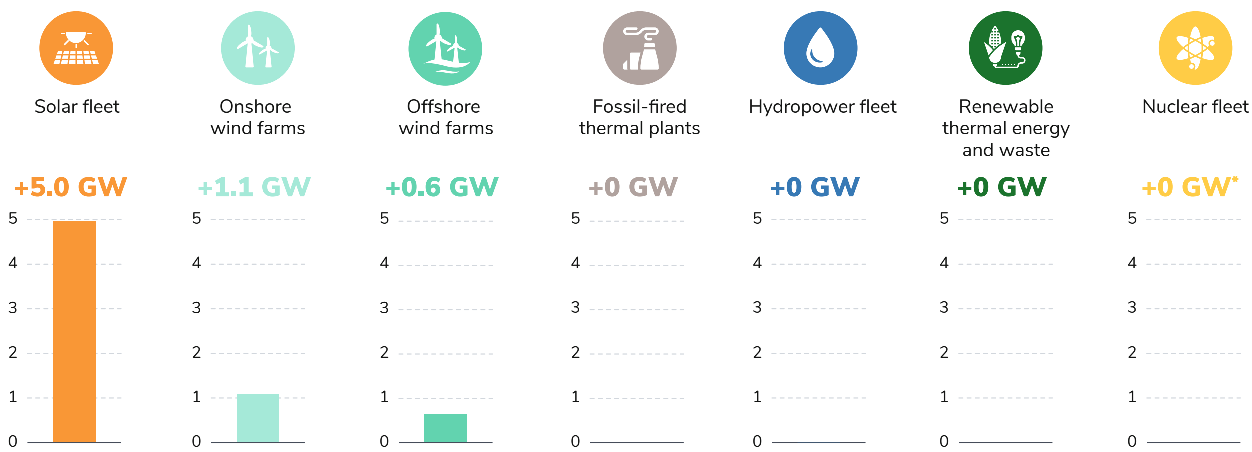
Figure 2.3 – Electricity generation capacity in France at the end of 2024 and breakdown by source



for the second year running, further accelerating the pace compared with 2023 (+3.3 GW). The capacity of solar PV installations in France (24.3 GW) now exceeds onshore wind farms, whose growth rate slowed for the second year in a row. Newly installed onshore wind generation capacity in 2024 (1.1 GW) is the lowest since 2020. Offshore, the Fécamp and Saint-Brieuc wind farms were completed and entered full operation in May 2024: they bring French offshore wind capacity to 1.5 GW.

The capacity of the French thermal and hydropower fleet did not change in 2024.

Figure 2.4 – Change in French electricity generation capacity by source in 2024



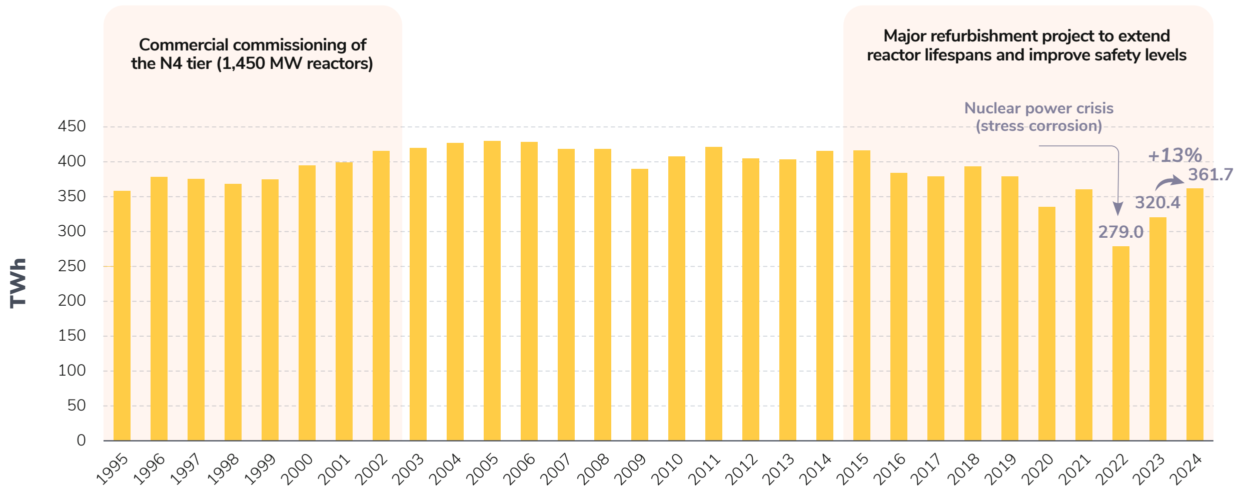
* Excluding Flamanville 3, which will be commissioned in 2025

Nuclear generation is now back to normal after the crisis

The generation volume increased by 13% in 2024 compared to the previous year, completing its recovery from the low point of 2022

Nuclear electricity generation stood at 361.7 TWh in 2024, an increase of almost 13% compared with nuclear output in 2023 (320.4 TWh), continuing the sharp increase in volume that began in 2023 (+15% compared with 2022). The year 2022 was characterised by a serious crisis in the nuclear sector after faults linked to stress corrosion cracking (SCC) were identified in many reactors. The level of generation in 2024 exceeded the total achieved in 2021 (360.7 TWh), making it the highest since the closure of the Fessenheim nuclear plant in 2020. In 2024, nuclear power accounted for 65% of the French generation mix.

Figure 2.5 – Nuclear power generation in France between 1995 and 2024



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Connecting the Flamanville EPR

On 21 December 2024, the Flamanville EPR (European pressurised reactor), the plant's third reactor and the first EPR-type reactor to be built in France, was connected to the grid. According to EDF, the reactor should remain in the test phase for several months before it is commissioned commercially[2]. With a net installed electrical capacity of 1,620 MWe[3], it is the most powerful reactor in the French fleet, and the largest electricity production facility in Europe, just ahead of the Olkiluoto EPR in Finland. It is also the first reactor to be connected to the grid in France since the Civaux 2 reactor in 1999 (commissioned commercially in 2002). This will be the fourth EPR to be commissioned worldwide, following the two reactors at Taishan in China (1,660 MWe) in 2018 and 2019 and the one at Olkiluoto in Finland (1,600 MWe) in 2023.

Construction of this reactor began in 2007, and the grid connection was originally scheduled for 2012. Several events have contributed to the delay. In particular, defects were discovered during construction in the welds of the steam transfer pipes running through the two walls of the containment. In addition, a manufacturing anomaly was identified in the reactor vessel cover, which will have to be replaced when the reactor is shut down for the first time for refuelling. This is scheduled for 2026 according to information provided by EDF under the European REMIT regulation. According to the same information, the reactor should produce 14 TWh before this first shutdown.

2. See'EDF's message of 18/12/2024 on the Inside Information Platform and'EDF's press release of 21/12/2024.
3. Most recent value declared by the operator via the ENTSO-E transparency platform at the end of 2024.

The availability of the nuclear fleet was higher in 2024 than in the previous two years, but remains lower than in the more distant past

The availability rate of the nuclear fleet[4], i.e. the ratio between the capacity available for electricity generation and the installed capacity of the fleet, was 71.5% in 2024. This figure was deduced from the oper'tor's declarations on the ENTSO-E transparency platform. The capacity available for generation is the capacity remaining once reactor shutdowns and reactors with limited generating capacity have been accounted for, based on the operator's declarations. The level of availability in 2024 represents a clear improvement on 2023 (62.9%) and 2022 (54.1%, an all-time low) and is slightly higher than in 2021 (69.7%), approaching the average for 2015-2019 (73.6%).

Figure 2.6 – Trend in average daily nuclear availability in 2024 and comparison with previous years

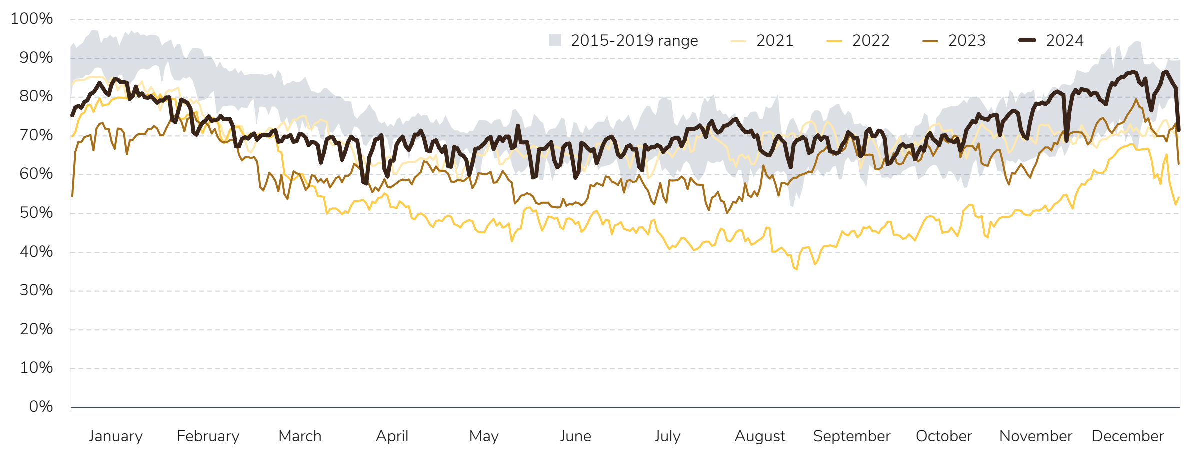
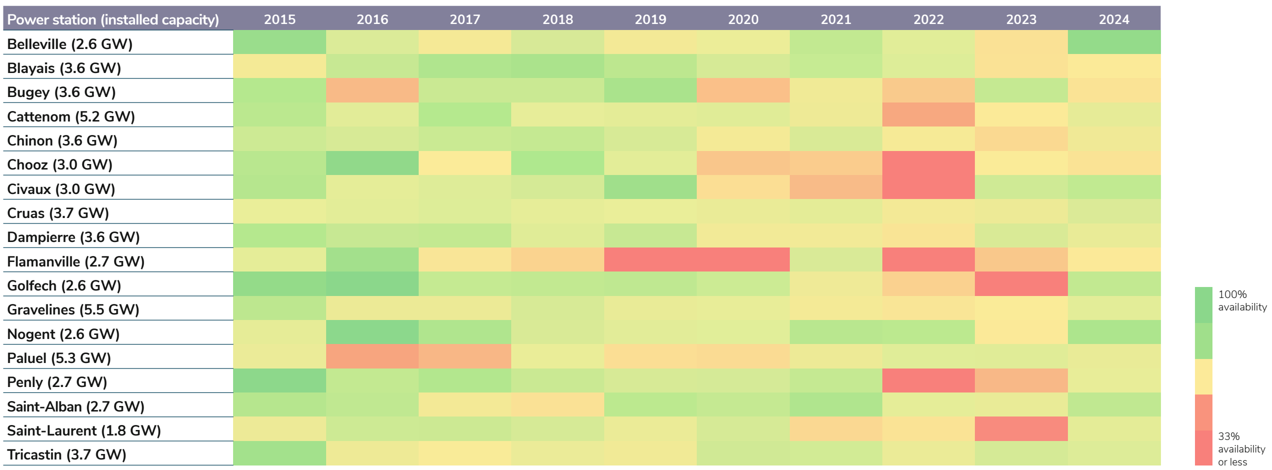


Figure 2.7 – Average availability rate of each nuclear power plant by year



4. This is slightly lower than the availability coefficient (Kd) reported by EDF in its annual publications, because it includes all types of unavailability regardless of their causes. In its annual publications, EDF reports certain shutdowns (to save fuel, for example) and certain power limitations (to comply with temperature limits for cooling water discharged by the reactor, for example) as modulations rather than unavailability. We include all unavailability, whatever its origin, as it is not always possible to identify the precise cause.

The recovery in the volumes generated in 2024 compared with the two previous years is largely explained by the increase in availability. However, compared with the more distant past (before 2015), the availability rate in 2024 is still lower. Particularly in the late 2000s and early 2010s, the average availability rate of the fleet was considerably higher. The “Grand carénage” (major refurbishment) industrial programme, which aims to extend the operating life of facilities and enhance their safety, had not yet begun at that point, and the fleet in operation was more recent.

The effects of stress corrosion on generation almost disappeared in 2024

The volume of repair work related to stress corrosion in the nuclear fleet was much lower in 2024 than in 2022 and 2023: the total volume of unavailability in 2024 related to this work was around 2 TWh, compared with several dozen TWh in the two previous years. However, the number of checks (not leading to unavailability) on welds identified as being at risk remained very high. These checks were carried out using non-destructive testing techniques developed by EDF specifically to deal with suspected stress corrosion. They took place during scheduled maintenance, so no special shutdowns were necessary.

In 2024, the only stress corrosion-related repair work planned and carried out was the preventive replacement of sensitive pipes in the Cattenom 4 reactor during its third ten-yearly maintenance at the beginning of the year and in the Nogent 2 reactor during a partial shutdown in the autumn. It was possible to carry out these repairs in parallel with other maintenance work, without causing any loss of output[5].

With regard to unscheduled repair work, the operator put forward a list of 13 reactors at the end of 2023 where there was a one-in-three chance that weld inspections could lead to pipe replacements and an additional month’s shutdown, based on experience. In this context, following the identification of defects during weld inspections, sections of piping were replaced at the Blayais 4 and Paluel 2 reactors, with around a month’s additional shutdown for each of these operations. In the end, these were the only reactors out of the 13 initially identified that required extended maintenance operations, resulting in the 2 TWh of unavailability mentioned above.

As announced by EDF, the inspection of welds subject to risk is set to continue during scheduled shutdowns until the end of 2025, and monitoring should then be integrated into the reactors’ long-term maintenance programme. For 2025, as in 2024, EDF has provided a list of 23 reactors whose welds will be inspected during scheduled maintenance, with a one-in-six chance that the shutdown will be extended by one month.

5. The maintenance operations on the two reactors affected were also shorter than initially planned.

Hydropower generation at its highest level for ten years

The level of generation from hydropower plants reached 75.1 TWh in 2024[6], an increase of 28% compared to the 58.9 TWh generated in 2023. This is the highest level since 2013 (75.5 TWh), achieved thanks to abundant rainfall, with 2024 being one of the ten wettest years since 1959[7]. The increase was greater for reservoir and pondage generation (+33% and +36% respectively) than for run-of-river

Figure 2.8 – Hydropower generation in France between 1995 and 2024

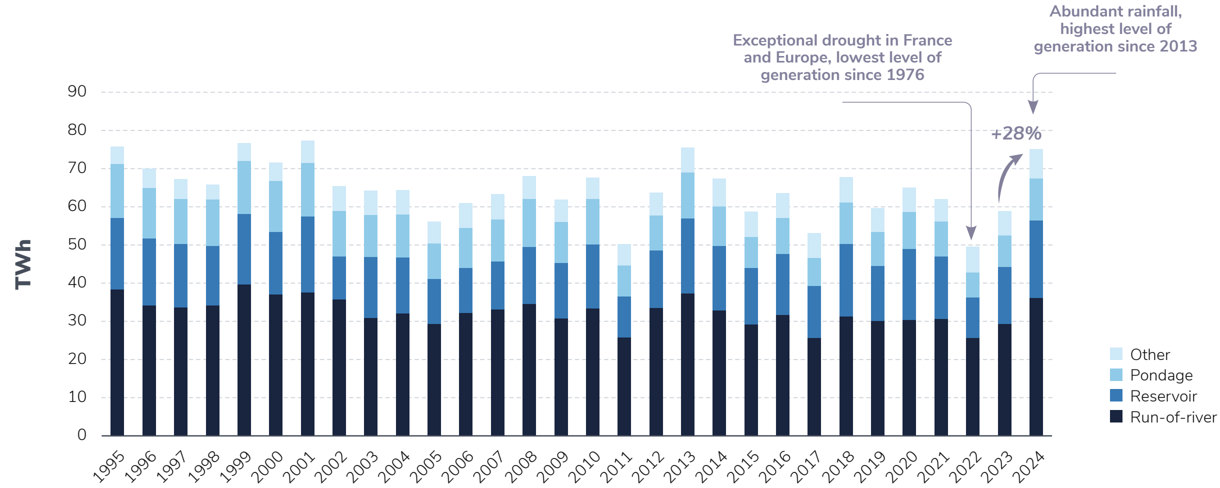
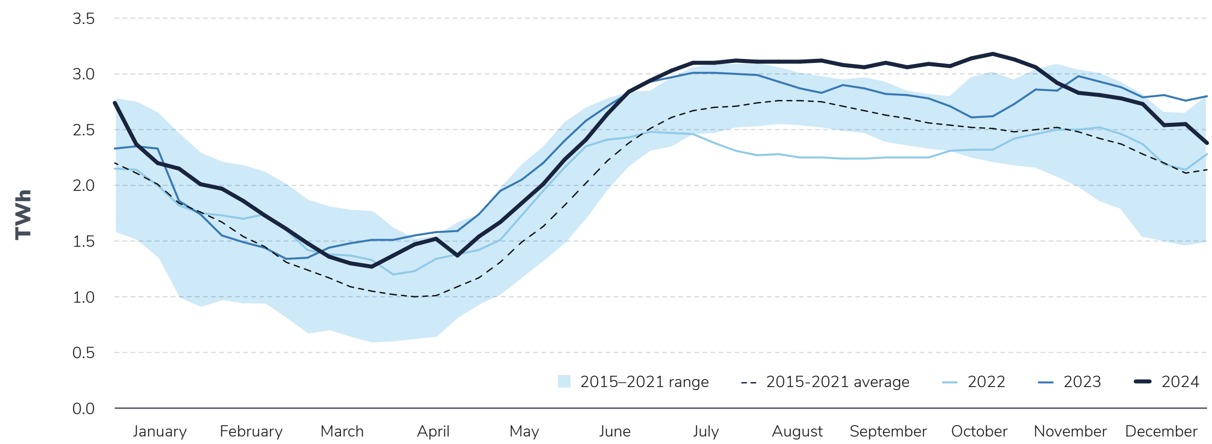


Figure 2.9 – Weekly changes in hydraulic stock in 2024 and comparison with previous years



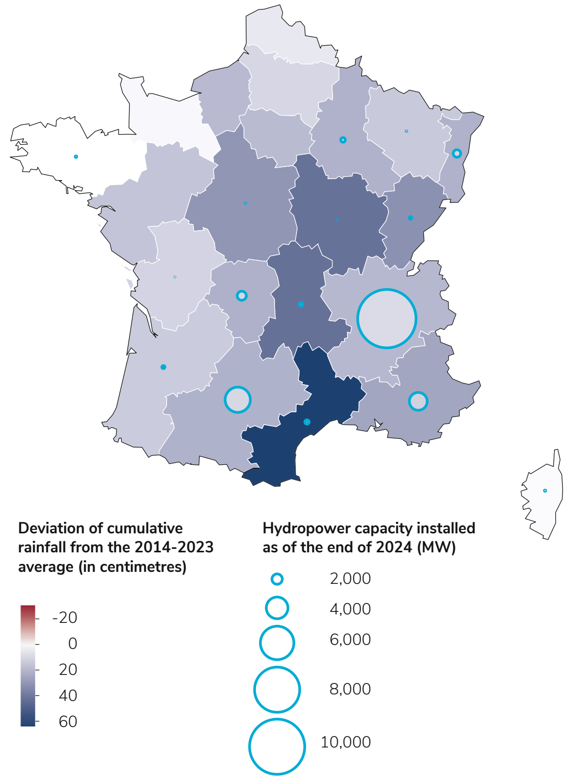
6. Of this quantity, 69.8 TWh was renewable (to obtain the renewable hydropower figure, 70% of consumption from PHP pumping is deducted from the total output in accordance with European Directive 2009/28/EC).
7. See the 2024 French Climate Review | Météo-France

generation (+23%). This level contrasts with 2022 (49.6 TWh), a year marked by very low rainfall, which saw the lowest output since 1976.

Hydropower accounted for 13.9% of all the electricity generated in France in 2024, remaining the second largest power source after nuclear power, and the largest renewable source. This exceptional yield meant that hydropower exceeded the combined output of solar and wind power (71.6 TWh) for the first time since 2021. As the installed base of wind and photovoltaic power continues to grow, this is unlikely to happen again in the coming years.

Hydraulic stock (a measure of reservoir and river levels based on the power generation they enable) remained high compared with historical figures throughout 2024 due to very heavy rainfall in the Alps and the Pyrenees . Between June and October it even reached record values that had never been seen over the last ten years.

Figure 2.10 : Excess rainfall in France in 2024 compared with the average for 2014-2023



Data sources: Copernicus Climate Change Service* et RTE

* *Copernicus Climate Change Service(2020): Climate and energy indicators for Europe from 1979 to present derived from reanalysis.*
Copernicus Climate Change Service (C3S) Climate Data Store (CDS)

8. 2024 French Climate Review | Météo-France Relative to a 1991-2020 baseline, the climate review shows precipitation up 16% and 21% respectively in Auvergne-Rhône-Alpes and Provence-Alpes-Côte d'Azur, and 4% and 18% in Occitanie and Nouvelle Aquitaine.

A poor year for onshore wind, with a low load factor and a slowdown in capacity growth

Onshore wind generation was down in 2024 compared with 2023, despite the growth in the turbine fleet

French onshore wind generation totalled 42.8 TWh in 2024, down 12.6% on its level in 2023 (–6.1 TWh).

This decline partly reflects a shortage of wind in 2024 compared with the previous year[9]. However, the storms at the end of 2024 enabled the sector to set a new output record (almost 18 GW), which was achieved on 24 November 2024.

Figure 2.11 – Onshore wind generation over time

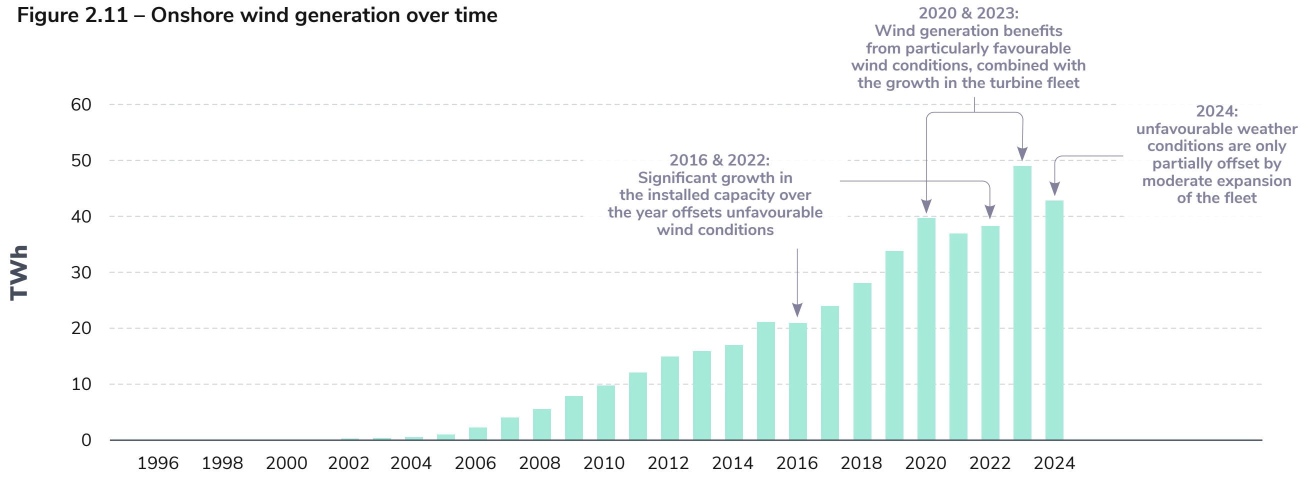
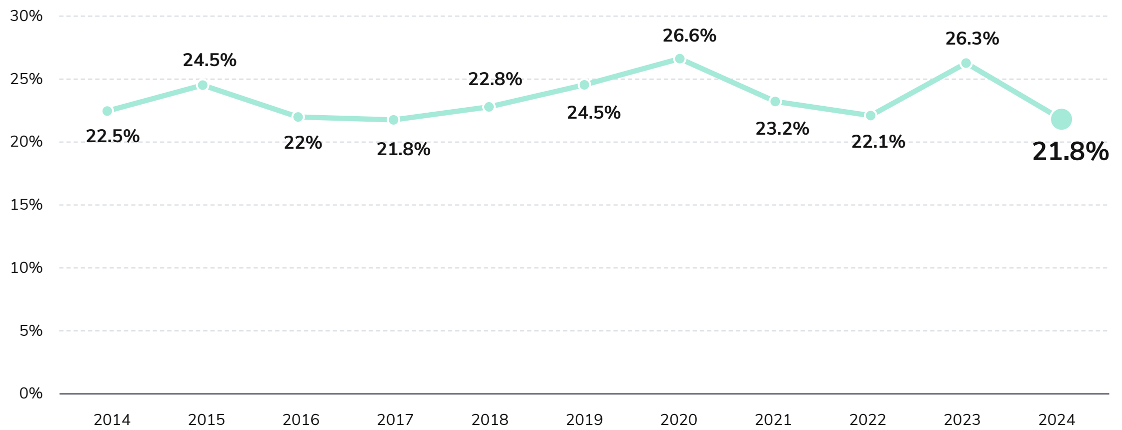
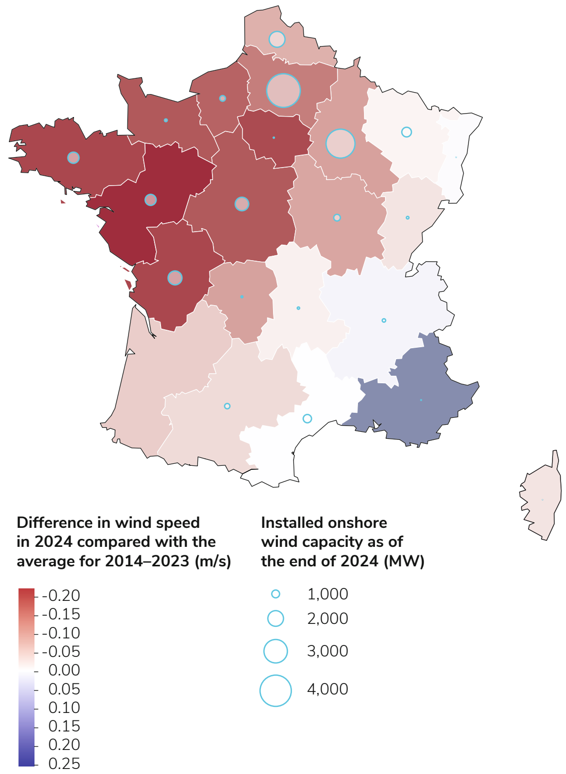


Figure 2.12 – Change in annual load factor for onshore wind power between 2014 and 2024 and installed onshore wind capacity as of the end of 2024



9. The ERA5 weather data shows that average wind speeds in 2024 were around 6% lower than in 2023 across mainland France.

Figure 2.13 – Difference in wind speed in France in 2024 from its average value between 2014 and 2023, and installed onshore wind capacity as of the end of 2024



Source: Copernicus Climate Change Service* and RTE

* *Copernicus Climate Change Service(2020): Climate and energy indicators for Europe from 1979 to present derived from reanalysis. Copernicus Climate Change Service (C3S) Climate Data Store (CDS)*

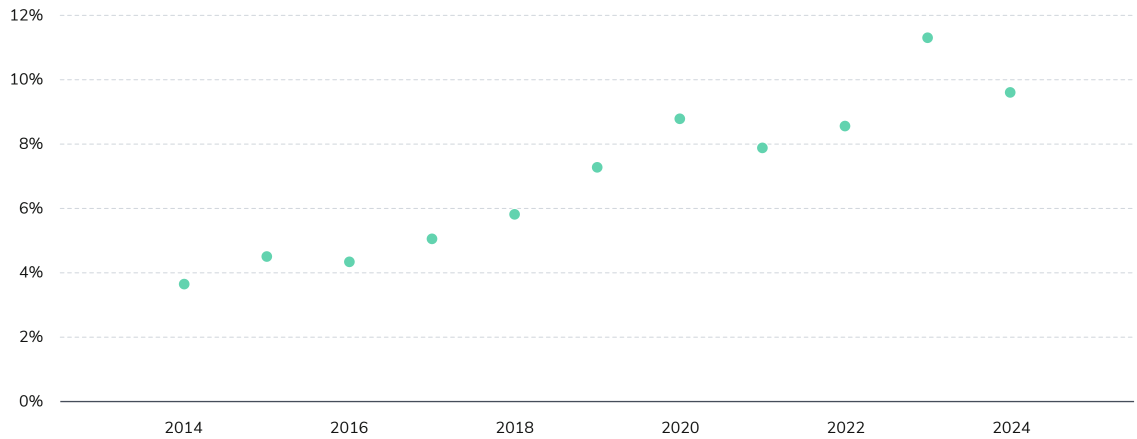
The average annual load factor for French onshore wind reached 21.8%, equalling its all-time low in 2017. This low load factor is primarily due to unfavourable wind conditions over the past year: the average wind speed in mainland France in 2024 was lower than its average over the last decade. This wind deficit was particularly marked in the northern and western regions of France, where most of the onshore wind capacity installed by the end of 2024 is concentrated (see Figure 2.12).

In addition to the unfavourable weather conditions in 2024, wind generation was also lowered, though to a lesser extent, by episodes of negative prices, which occurred much more often this year than in previous years (see *Prices* chapter). When prices are negative, facilities benefiting from the "*complément de rémunération*" premium scheme, as well as those that do not receive support, have an economic incentive to cease production. In 2024, onshore wind installations likely to shut down during negative price episodes represented around 60% of installed onshore wind capacity[10]. Onshore wind generation foregone during negative price periods totalled 0.9 TWh in 2024[11], or around 2% of output. This is around two and a half times the volume in 2023. In addition, RTE ordered reductions in the output of wind power plants during episodes of plentiful generation during 2024 in order to guarantee the real-time balance of the power system, in accordance with the current provisions of the French Energy Code (see section 7). This curtailment represented around 0.01 TWh of onshore wind generation over the year. Overall, onshore wind curtailment was responsible for a drop of around 0.5 points in the wind power load factor.

On average over the year, output from onshore wind covered around 9.6% of national consumption. This coverage rate rose steadily between 2014 and 2024, by around 0.7 percentage points per year. However, the rate of coverage of consumption by wind generation in 2024 is down compared to its level in 2023 (11.3%) as a result of the decline in onshore wind generation and the slight increase in consumption relative to the previous year (consumption not adjusted for weather effects rose by 0.9% in 2024 compared to its 2023 level).

10. The rest of the facilities are subject to a purchase obligation contract, which provides no economic incentive to interrupt generation during periods of negative prices.
11. RTE estimate.

Figure 2.14 – Average coverage rate of consumption by onshore wind generation in France

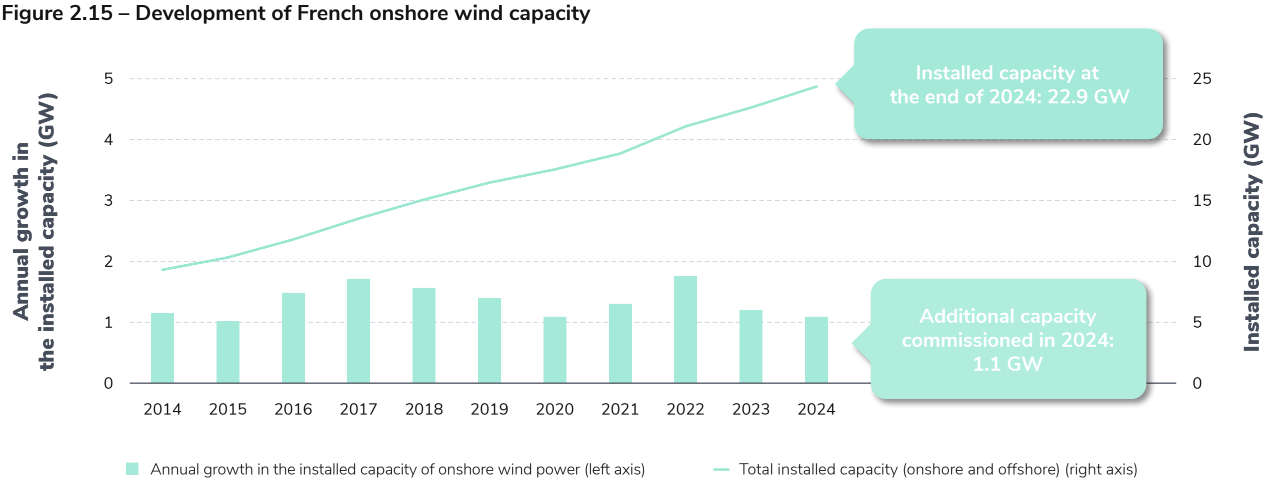


Installed capacity for onshore wind generation continued to grow, but at the slowest rate since 2005

On 31 December 2024, onshore wind capacity in France stood at 22.9 GW. It grew by 1.1 GW in 2024, the smallest increase since 2020. As a result, in 2024, the pace of development of onshore wind farms slowed for the second year running, following an initial slowdown in 2023.

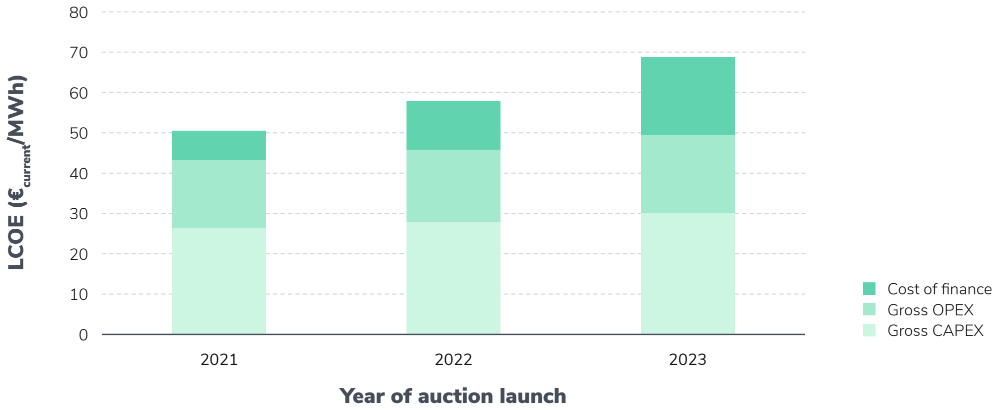
The installed capacity of onshore wind in 2024 thus remained below the target of 24.1 GW set for 2023 by the 2020 Multi-year Energy Planning Act (PPE)[12]. Given the average rate of development of onshore wind farms over the last five years, the onshore wind farm development targets set by the PPE for 2023 could be achieved by the end of 2025.

Figure 2.15 – Development of French onshore wind capacity



12. Decree no. 2020-456 of 21 April 2020 on multi-year energy planning.

Figure 2.16 – Estimated total generation costs for onshore wind projects that have won CRE auctions



Data sources: RTE estimate based on CRE data

The slower growth of onshore wind power over the last two years coincides with a worsening of the economic climate for this sector. Between 2021 and 2023, the investment and operating costs declared by the successful bidders for CRE onshore wind auctions rose by around 15%, faster than inflation (10% over the period in question). In addition to these rising costs, average interest rates for financing these projects have doubled[13]. Based on the costs declared by the players, the estimated overall generation costs[14] of onshore wind installations rose by around 34% (in current euros)[15] between the successful bidders for the 2021 CRE auctions and those in the 2023 auctions[16]. This same economic context has also had an impact on wind projects being developed outside the auctions organised by the CRE.

In the highly inflationary context of the 2021-2022 period, support schemes for wind power lost some of their appeal (see Focus). By the end of 2022, these schemes had been significantly adapted, and the auction results since May 2023 suggest that the slowdown in the growth of onshore wind farms in France in 2023 and 2024 may be temporary.

In addition to the economic context, the regulatory and societal context can act as a brake on project development in some cases. Before the law to accelerate renewable energy generation (known as the APER law) was enacted in 2023, 75% of authorisations issued for onshore wind projects were the subject of an appeal[17].

13. CRE, *Etat des lieux et premiers enseignements tirés à fin 2023 des résultats des appels d'offres " PPE2 " éoliens terrestres et photovoltaïques* (review and initial lessons at the end of 2023 from the results of "PPE2" onshore wind and solar auctions), September 2024.
14. This estimate is based on the costs, load factors and average borrowing rates declared by the successful bidders. To calculate the full cost of these facilities, RTE assumes a lifespan of 25 years, in line with the assumptions made in the 2023 Generation Adequacy Report and by ADEME in its report "*Évolution des coûts des énergies renouvelables et de récupération en France entre 2012 et 2022*" (trends in the cost of renewable and recovered energy in France between 2012 and 2022). The estimate identifies the cost of the capital required to finance these projects at the average interest rate declared by the successful bidders in the auctions. However, an average of 20% of the finance for the successful bidders came from equity capital, for which the expected return was not disclosed.
15. This estimate thus includes the effect of inflation, which accounts for around a third of the increase.
16. These estimates reflect the costs of onshore wind projects that bid successfully for the CRE auctions launched in 2021 and 2023. The costs therefore differ from those of the onshore wind installations commissioned in 2021 and 2023, as estimated by ADEME in the report "*Évolution des coûts des énergies renouvelables et de récupération en France entre 2012 et 2022*" (trends in the cost of renewable and recovered energy in France between 2012 and 2022), published in January 2025.
17. French Senate, *Etude de l'impact du projet de loi relatif à l'accélération de la production des énergies renouvelables* (impact study of the bill to accelerate renewable energy generation), 23 September 2022.

FOCUS

Impact of public support schemes on the development of onshore wind farms in 2024

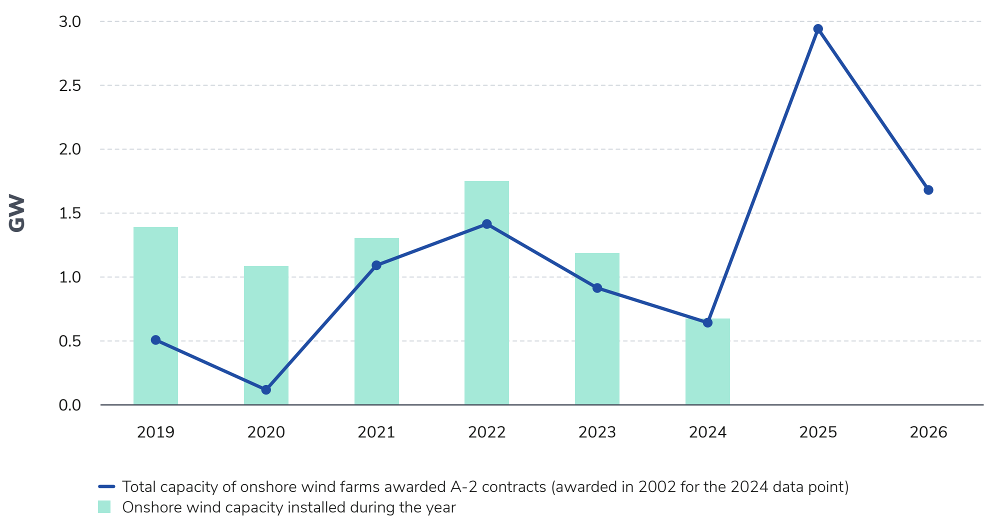
The development of onshore wind power is supported by a premium scheme (*"complément de rémunération"*), which guarantees that projects will be profitable. Since 2017, there have been two ways to benefit from these contracts:

- A competitive bidding procedure based on multi-year auctions organised by the French Energy Regulation Commission (CRE).
- An "open window" (*"guichet ouvert"*) for small-scale facilities (with the framework for this changing in 2022).

Empirically, a correlation can be seen between the capacity of the installed base of onshore wind power and the volume bid for during auctions, with a time lag of around two to three years. This is consistent with the time taken to meet the specifications of these auctions[18]. As a result, the slowdown in the growth of onshore wind power over the last two years is due – at least partly – to the reduction in the cumulative capacity of the onshore wind projects selected in auctions opened between 2020 and 2022.

This reduction is linked to sharp rises in costs and interest rates for onshore wind projects between 2021 and 2022. In this context, the economic viability of the projects, even if they were selected, was uncertain. From 2023 onwards, however, the cumulative capacity of the onshore wind projects with winning bids has increased significantly. Given the time required to complete each installation, this increase could boost the growth rate of onshore wind power over the next few years.

Figure 2.17 – Onshore wind power growth compared with the total capacity of successful bids in CRE auctions



18. The theoretical maximum time for completing a facility selected in an auction is 36 months from its designation. The specifications for the "onshore wind" auctions also include specific conditions for extending this deadline.

FOCUS

Several changes to the support mechanisms for onshore wind power have contributed to the increase in capacity bid for through the 2023 and 2024 auctions.

Firstly, the economic attractiveness of the auctions has been improved. At the end of 2022, the conditions offered to successful bidders were adjusted to reduce the risk faced by candidates due to inflation. The tariff offered is now tied to a price index[19] as soon as the winners are announced, including during the period before the installation is commissioned. In addition, since 2023 auctions have offered access to higher tariffs than those available through the "open window".

Secondly, the Order of 27 April 2022 restricted access to the "open window" to community projects or projects that could prove a height limit linked to avigation easements or radar constraints. As a result, the majority of projects now bid for contracts through auctions.

It is worth noting, however, that the increase in capacity bid for in the 2023 and 2024 auctions will not all correspond to an increase in the actual capacity of new onshore wind projects. As a result of the new auction conditions, which take better account of inflation, projects that won previous contracts were authorised to abandon their position in order to bid for new contracts from the end of 2023.

19. This price index is defined in the auction specifications as a weighted average of price indices relating to generation costs in the French market, hourly labour costs and an index of company financing costs.

Two new offshore wind farms commissioned and a clearer path for growth

France's offshore wind capacity and output continued to grow, with two wind farms entering service in 2024

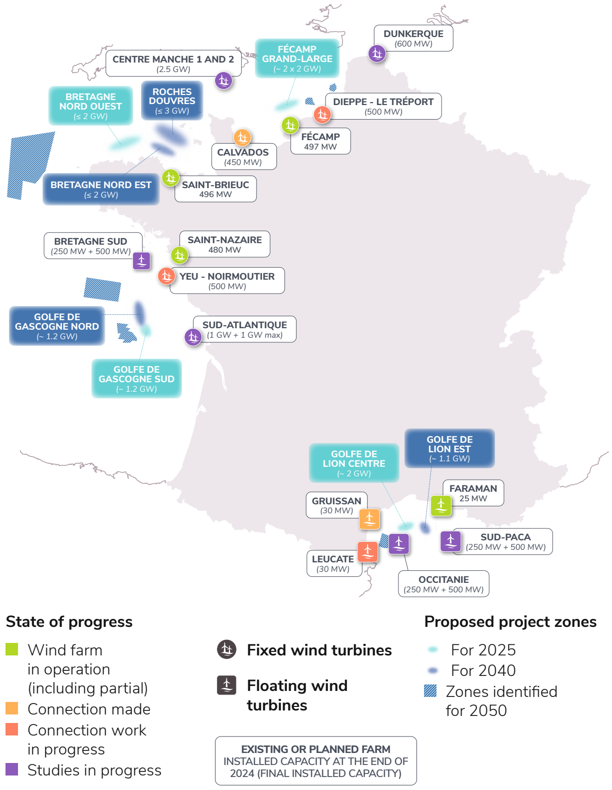
The Saint-Brieuc and Fécamp offshore wind farms (each with a capacity of almost 500 MW) were commissioned in May 2024. These two wind farms were already partially operational in 2023, with a total capacity of 360 MW. With the Saint-Nazaire wind farm (480 MW), commissioned in 2022, the installed capacity of French offshore wind power reached 1.5 GW by the end of 2024, an increase of 0.63 GW on its 2023 level. The three wind farms in service were among the successful bidders in the first offshore wind auction, launched in 2011, along with the Courseulles-sur-Mer wind farm (currently under construction).

Offshore wind generation stood at 4 TWh in 2024, more than double its level in 2023. The load factor for the Saint-Nazaire wind farm, the only offshore wind farm operating at full capacity throughout 2024, was around 31.6%. The load factor for this wind farm was down on the previous year (33.3%), due to less favourable wind conditions in 2024 than in 2023 and a temporary increase in downtime in 2024.

Installed capacity remains below the target of 2.4 GW set for 2023 in the 2019-2028 PPE. However, this target should be reached in 2025 following the commissioning of the Courseulles-sur-Mer wind farm (450 MW), the last project from the first auction to enter service, and the Île d'Yeu and Île de Noirmoutier wind farms (488 MW).

These first offshore wind farms consist of wind turbines fixed on the seabed. This technology is limited to sites located at depths that allow subsea foundations to be built[20]. Depending on the characteristics of the coastline, the development of the planned

Figure 2.18 – Map of existing and planned offshore wind farm projects at the end of 2024



offshore wind capacity will also require the deployment of floating wind farms.

The commissioning of France's first pilot floating wind farm is currently being finalised off Faraman and Port-Saint-Louis-du-Rhône. This is a small-scale wind farm with a capacity of 25 MW, the winner of a call for projects launched by ADEME in 2015 to support the development of the sector in France. The first commercial floating wind farm (South Brittany), with a capacity of 250 MW, is due to come on stream in 2031.

20. These sites are limited to a depth of around fifty metres.

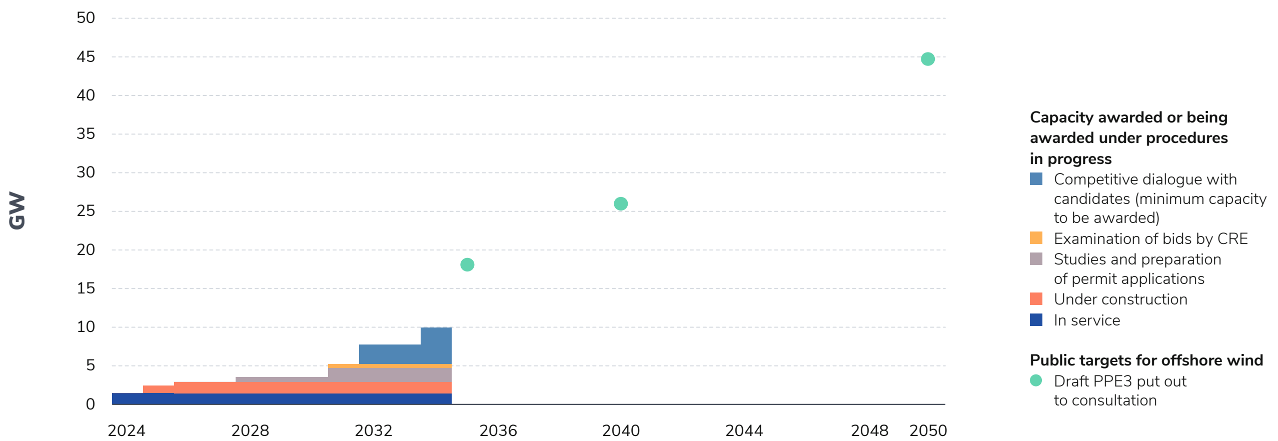
The growth rate of offshore wind power is set to accelerate between now and 2035

Offshore wind capacity has been growing in France since 2011 through competitive bidding procedures. In 2024, the winners of the auctions for floating wind farms south of Brittany (AO5) and in the Mediterranean (AO6) were announced, and a ninth auction round was launched. In total, the competitive bidding procedures already launched or closed represent around 10 GW of offshore wind capacity (awarded or in the process of being awarded). This capacity is expected to come on stream in stages between now and 2035.

The French National Commission for Public Debate (CNDP) organised a public debate on maritime spatial planning entitled *"La mer en débat"* ("The sea under debate") from 20 November 2023 to 26 April 2024. This debate covered both the planning of offshore wind development and updates to the coastal strategy documents (DSF) for each coastline. Following this debate and regional consultations on each coast, the French government has identified priority zones for the development of offshore wind power over the next decade and up to 2050[21]. Within these priority zones, the development of offshore wind capacity will be the subject of a tenth auction round, due to be launched in 2025, to allocate 9.2 GW of new capacity. Subsequent rounds are also planned, with the aim of commissioning a further 6.3 GW by 2040.

In line with these objectives, and the targets in the offshore wind pact signed in 2022 between the French government and the wind power sector, the draft multi-year energy plan (PPE) submitted for consultation in November 2024 modifies the development ambitions for the French offshore wind fleet compared with the previous plan. The ambition set out in the draft document is to achieve 18 GW of offshore wind capacity in service by 2035, 26 GW by 2040 and 45 GW by 2050.

Figure 2.19 – Offshore wind capacity commissioned and planned, by stage of development



21. Decision of 17 October 2024 following the *"la mer en débat"* public debate on updates to strategic sections of the coastal strategy documents and the mapping of priority sea and land areas for offshore wind power.

Solar photovoltaic output continued to grow, driven by record growth in generating capacity

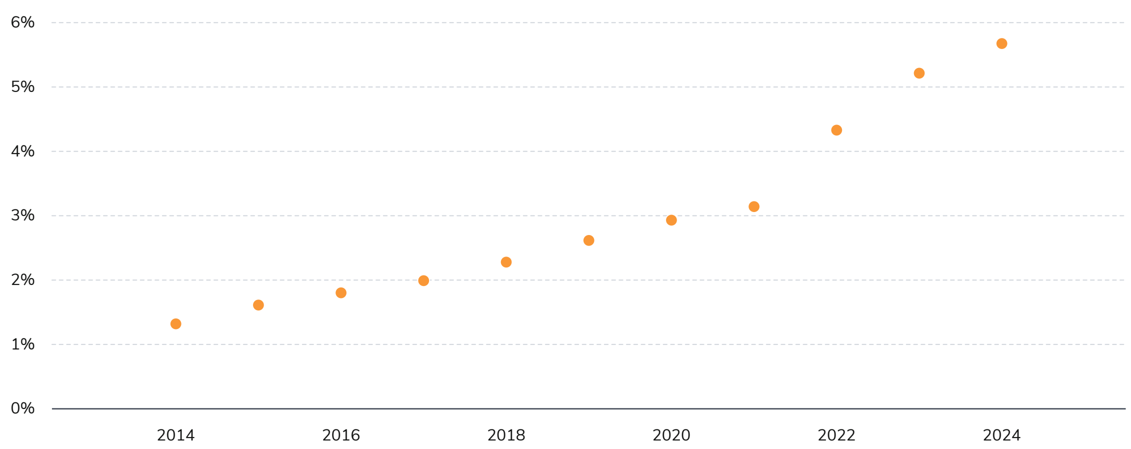
Solar PV generation set a new record in 2024 despite unfavourable weather conditions throughout the year

Solar electricity generation reached an all-time high in 2024 (as it has every year since 2006), with 24.8 TWh produced. This represents an increase of 2.3 TWh (+10%) on the 2023 level, driven by growth in installed capacity, despite the fact that last year France saw the least sunshine in almost thirty years[22]. In 2024, annual solar PV electricity generation exceeded fossil-fired generation for the first time.

Solar PV covered 5.7% of French electricity consumption in 2024. This coverage rate has increased in recent years as solar output has grown, while French electricity consumption has remained stable since 2014, with short-term decreases between 2020 and 2023. Since 2021, the year when the growth of the solar PV fleet accelerated significantly, the rate of coverage of consumption by solar PV generation has increased by around 0.8 points per year.

The record level of solar PV generation in 2024 was achieved despite a historically low load factor: 13% on average, down on its level in 2023 (14.5%) and its average value between 2014 and 2023 (14.5%). This low load factor is mainly due to the lack of sunshine in 2024, and to a lesser extent to generation curtailments during periods when spot prices were negative. Part of the fleet has an economic incentive to reduce its production during these episodes, and this is what happened in 2024, when around 0.8 TWh of production was lost (according to RTE's estimate). However, almost two-thirds of solar PV generation is still supported by feed-in tariffs, which do not provide any financial incentives to reduce output when prices are negative[23].

Figure 2.20 – Average coverage rate of consumption by photovoltaic generation in France



22. CRE, *Analyse de la CRE sur le phénomène de prix de l'électricité négatifs et recommandations relatives aux dispositifs de soutien aux énergies renouvelables* (CRE analysis of the negative electricity price phenomenon and recommendations on support measures for renewable energy), November 2024.
23. Météo France, *op. cit.*

Figure 2.21 – Change in annual solar power load factor between 2014 and 2024

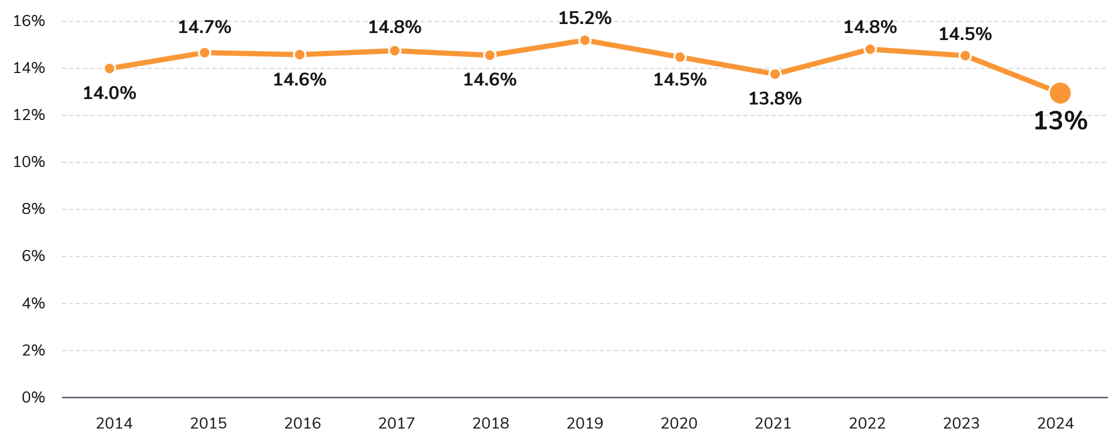
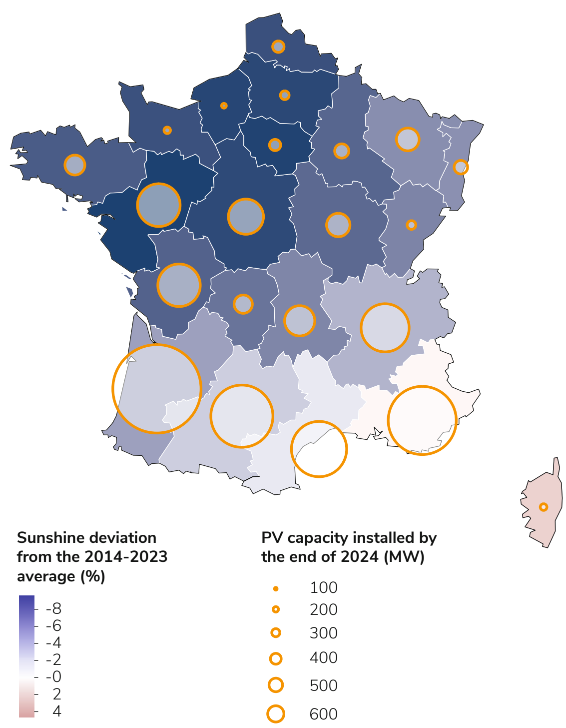


Figure 2.22 – Sunshine deficit in France in 2024 compared with the average for 2014-2023



Data source: Copernicus Climate Change Service* and RTE

* Copernicus Climate Change Service(2020): *Climate and energy indicators for Europe from 1979 to present derived from reanalysis.* Copernicus Climate Change Service (C3S) Climate Data Store (CDS)

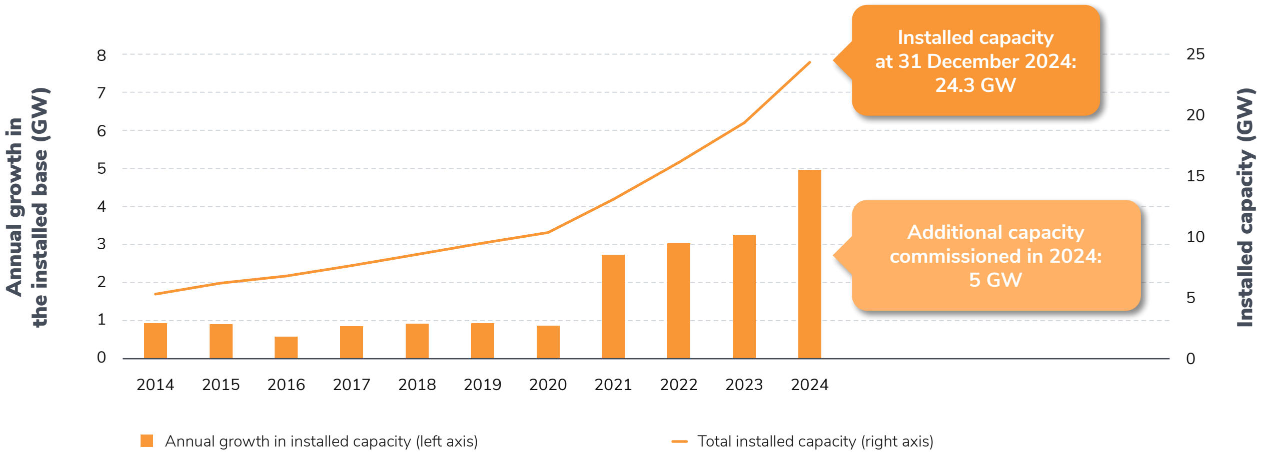
Solar PV capacity grew at an unprecedented rate in 2024

By the end of 2024, installed solar photovoltaic capacity had reached 24.3 GW, representing almost 16% of the country's installed electricity generation capacity.

Solar power was the generating source with the highest capacity growth in France in 2024, with an increase of 5 GW over the year. This is a record for French solar capacity, following the previous record set in 2023 (3.3 GW). It underlines the new momentum in solar growth that began in 2021, since when solar power has grown at an average rate of almost 3.4 GW/year.

Compared with onshore wind power, the development of solar PV seems to have been more resilient to inflation and the rise in interest rates. Current cost trends show an improvement in the economic competitiveness of these installations.

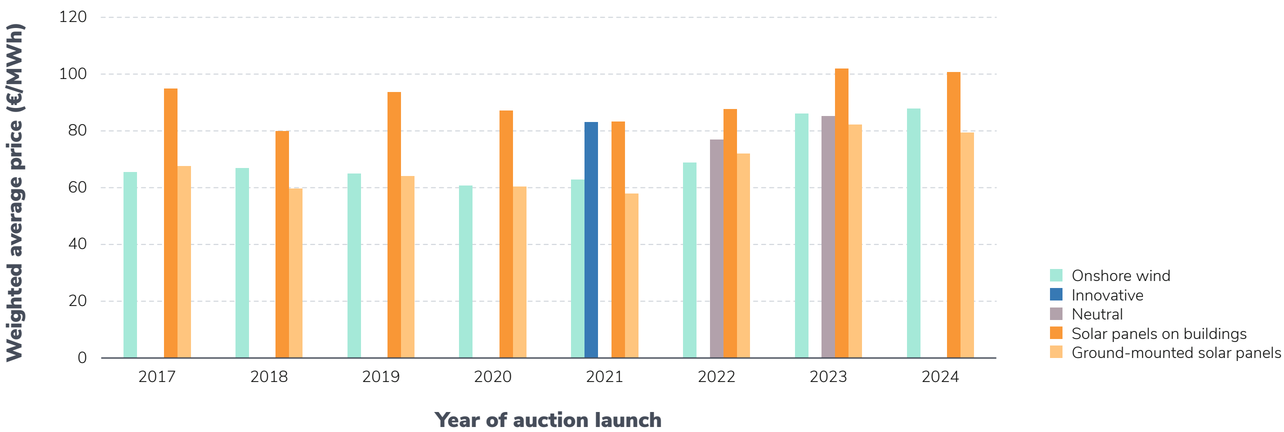
Figure 2.23 – Growth in the French solar power installed base



Finally, the differences in the growth dynamics between solar PV and onshore wind capacity are consistent with the energy planning objectives. In this respect, over the period from 2021 to 2023, the capacity offered through CRE auctions was greater for solar (7.5 GW in total over the period) than for onshore wind (5.3 GW in total).

If the consultation launched in November 2024 confirms the objectives in the new multi-year energy plan, the growth rate of the solar PV installed base will have to accelerate further from the record reached in 2024. The document submitted for consultation proposes a central scenario of 54 to 60 GW of solar PV capacity by 2030.

Figure 24 – Trend in the weighted average price for auction winners



Data source: CRE

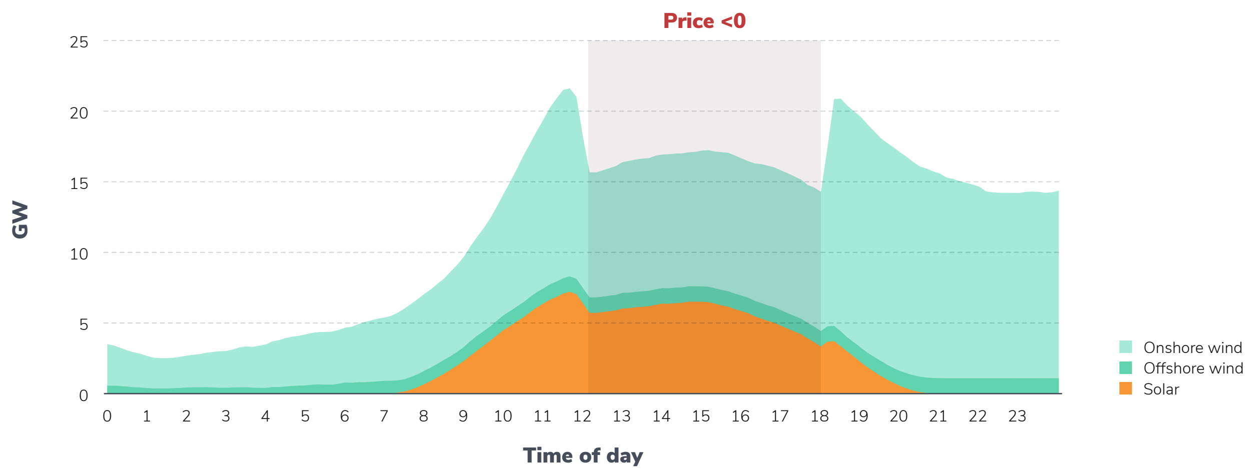
Wind and solar curtailment was higher in 2024 than in the past

During periods of plentiful renewable generation, a proportion of renewable capacity is incentivised to reduce output

With the growth of wind and solar generation capacity, France and other European countries have seen an increasing number of episodes of plentiful low-carbon generation at low or zero cost, particularly on spring and summer afternoons. During these periods, the normal operation of the market incentivises producers to stop generating – or at least to reduce output as far as possible – when the equilibrium market price does not cover the variable costs of production (see the "Negative prices" section in the Prices chapter). This affects all the power generation sectors, including fossil-fired generation, dispatchable hydropower production, nuclear power stations and a significant proportion of wind and solar capacity, including the most recent large-scale onshore wind farms. Installations that benefit from a premium scheme contract, or that sell their output without support, are subject to an economic incentive to cut their production in the event of negative prices. By the end of 2024, this capacity represented around 60% of the onshore wind fleet and 30% of the photovoltaic fleet, totalling almost 20.5 GW. This type of operation contributes to optimum use of the generating fleet for the community: installations offer their production at a price close to zero, and stop operating when demand is too low for these volumes to be viable.

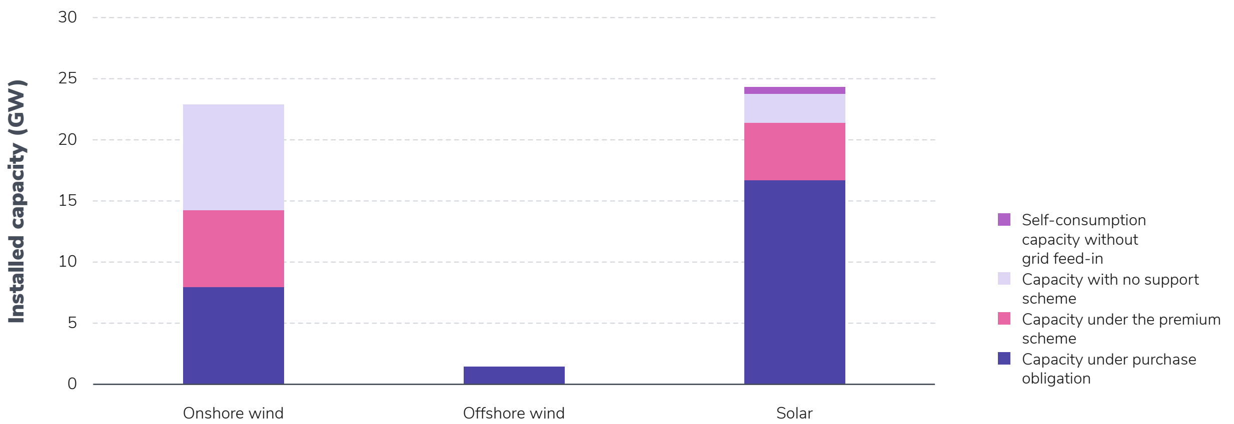
During 2024, the curtailment of French wind and solar power generation during episodes of negative spot prices in France represented around 1.7 TWh (or 2.4% of cumulative wind and solar generation over 2024)[24], including around 0.9 TWh of curtailed wind generation and around 0.8 TWh of solar generation.

Figure 2.25 – Wind and solar generation on 15 April 2024 (spot price negative between midday and 5 pm)



24. This figure is based on an estimate of the difference between the solar and wind generation observed during periods of negative prices and a forecast by RTE of what this generation would have been at those times if prices were positive.

Figure 2.26 – Breakdown of wind and solar capacity according to how its output is used



In a power system with a growing renewable share, the occurrence of negative prices is likely to increase, with implications for the smooth operation of the power system (need to encourage all producers to modulate, development of flexible consumption and storage, etc. – see the Prices chapter). In particular, renewable power generators currently benefiting from purchase obligation contracts have no incentive to reduce or halt generation in the event of negative prices, since their income is not sensitive to market conditions. At the end of 2024, 100% of offshore wind capacity, 40% of onshore wind capacity and almost 70% of photovoltaic capacity, totalling almost 28 GW, was covered by a purchase obligation contract.

In the long term, the development of solar and wind power remains an essential means of supporting the electrification of uses, the development of new uses such as data centres and electrolysers, and the reindustrialisation of the country as part of a strategy to decarbonise the French economy and move away from fossil fuels. At the same time, there will be a need for ways of ensuring that renewables are properly integrated into the system, first and foremost by increasing demand flexibility (in France and Europe), but also by developing support mechanisms for renewable energy producers to encourage them to adjust their output in line with market prices (as is already the case with the premium scheme).

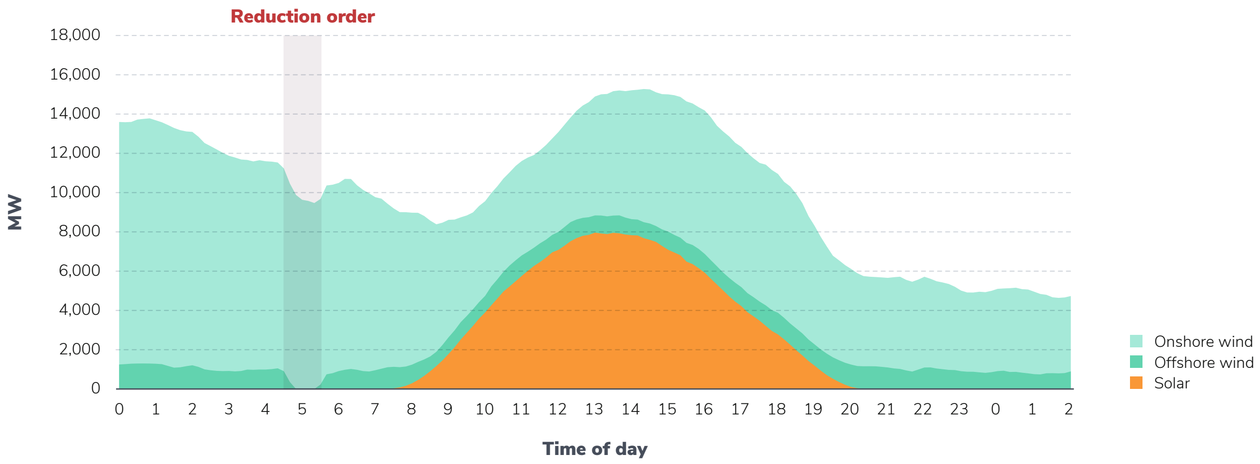
Wind and solar generation had to be adjusted in 2024 to guarantee the safety of the electrical system

To ensure the operating safety of the power system, RTE is authorised to adjust the scheduling of electricity generation facilities in almost real time if the normal operation of the market has failed to achieve a balance.

In accordance with the French Energy Code, these adjustments are made in order of economic precedence. In particular, when the electricity supply exceeds demand, these adjustments prioritise the demand schedules of the generation units with the highest variable costs (thus avoiding generating costs). Wind and photovoltaic capacity, whose variable costs are close to zero, are therefore among the last resources called on to make such adjustments, but they are among the methods that can be used. During 2024, RTE adjusted wind and, to a lesser extent, solar generation downwards by 18 GWh[25]. Although these volumes are still small compared with the total volume of downward adjustments made to maintain the supply-demand balance, they represent a clear increase compared with previous years. Prior to 2024, no adjustments had been made to photovoltaic generation schedules, and downward adjustments to wind power had always been below 2 GWh per year.

25. Including 10 GWh under the balancing mechanism and 8 GWh under safeguard orders.

Figure 27 – Wind and solar generation on 11 September 2024 (power reduction order at 5 am)



For example, on 11 September 2024 at 5 a.m., RTE ordered seventeen renewable energy generators (offshore and onshore wind farms with a total capacity of around 1.3 GW) to reduce their output to meet a temporary requirement to balance electricity supply and demand.

Completing the work in progress to develop support mechanisms for renewable energy by incentivising output adjustment based on market prices would be beneficial in all cases, and would avoid the need to make near-real-time adjustments through the balancing mechanism. In addition, greater participation by renewable generation resources in the balancing mechanism would make it possible to adjust these same resources upwards during negative price episodes (when some renewable generation stops producing, but RTE may still need to request increases in generation almost in real time), which would avoid having to resort to fossil-fired generation to meet this need.

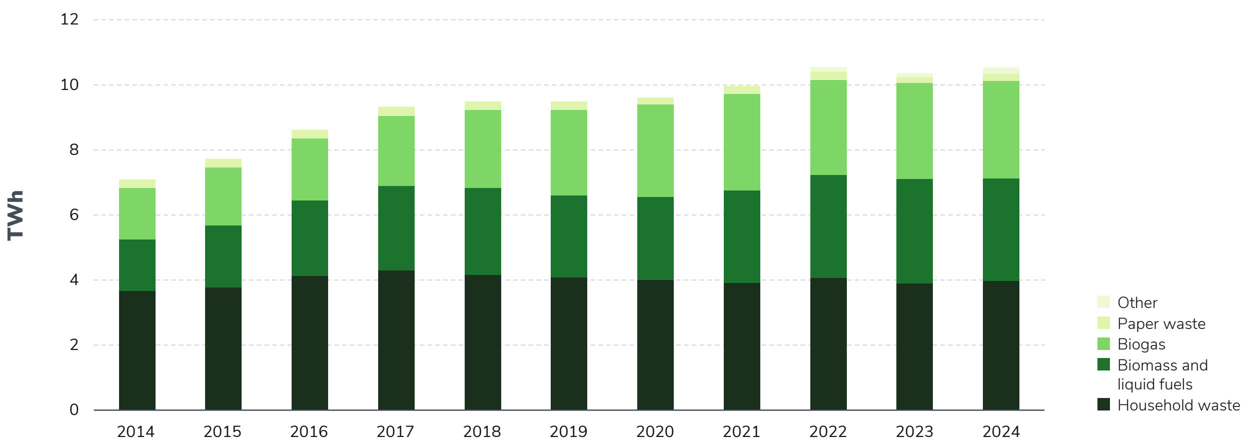
Production from other renewable sources and waste remained stable in 2024

'Other renewables and waste' includes electricity generated from biomass (wood and plant waste, including agricultural waste), biogas (obtained from the fermentation of organic waste) and waste incineration. The sector generated 10.5 TWh in 2024. Over three quarters of this output came from renewable sources within the meaning of the current regulations[26]. Installed capacity in this sector stood at 2.3 GW on 31 December 2024.

After two decades of significant growth (around 7% per year between 2002 and 2022), output in this area has stabilised since 2022, partly because installed capacity has changed little since 2021.

This dynamic is consistent with the ambitions in the multi-year energy planning bill submitted for consultation at the end of 2024. The bill aims to focus the development of biogas production capacity on direct injection into gas networks, limiting its use for electricity generation (through cogeneration) to very specific cases (such as farms located far from electricity connection sites).

Figure 28 – Other renewable and waste generation between 2014 and 2024



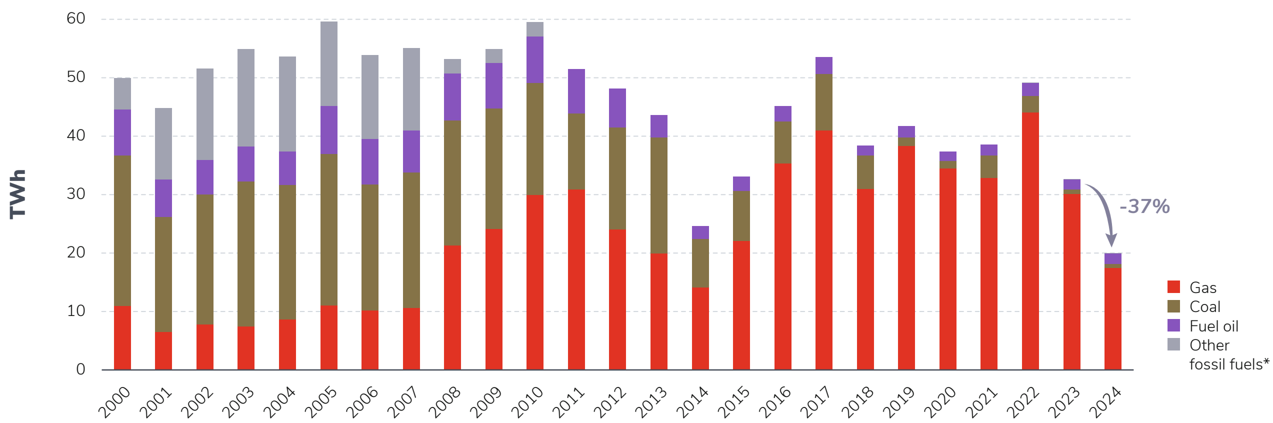
26. The order of 8 November 2007 stipulates that only 50% of the electricity generated by incinerating household waste should be considered renewable.
27. Including 71.6 TWh generated by solar and wind power in 2024.

Fossil-fired electricity generation reached its lowest level since 1952

Total generation from fossil-fired sources fell significantly in 2024 (20.0 TWh) compared with 2023 (31.6 TWh). This is the lowest volume since 1952 (18.3 TWh). The fall, largely driven by gas, is explained by the abundance of low-carbon production (increased nuclear and renewable power volumes), while consumption remained at a relatively low level, despite rising slightly compared with the years before the pandemic. Generation in 2024 also represented a clear break with 2022 (49.2 TWh), when gas-fired power stations were used extensively to compensate at least partially for the unavailability of nuclear power stations, and continued the downward trend that began in 2023.

Compared with historical figures, fossil-fired output in 2024 could represent a new structural shift in fossil-powered electricity generation. Falling from 121 TWh at the end of the 1980s to 46 TWh by the end of the 1990s thanks to the development of the nuclear fleet, the figure is now following a similar downward trajectory due to the development of the renewable fleet , falling from an average of 55 TWh at the end of the 2000s to 20 TWh in 2024[28]. In the short term, the proportion of fossil-fired generation in the electricity mix will depend on how consumption and low-carbon generation evolve. It could remain low (or even decrease) as long as low-carbon production increases faster than consumption. Low-carbon generation is set to grow in the near future: the Flamanville EPR should be fully commissioned in 2025[29] and the volume of renewable generation will continue to grow as the installed base expands. Together, these factors will limit the need to rely on fossil fuels for generation[30], all other things being equal.

Figure 29 – Electricity generation from fossil fuels in France between 2000 and 2024



Until 2010, the "Other fossil fuels" category included derived gases, miscellaneous fuels and distribution network generation. As a result of methodological changes, these sources have gradually been incorporated into the other sources, partly in 2008 and fully in 2011.

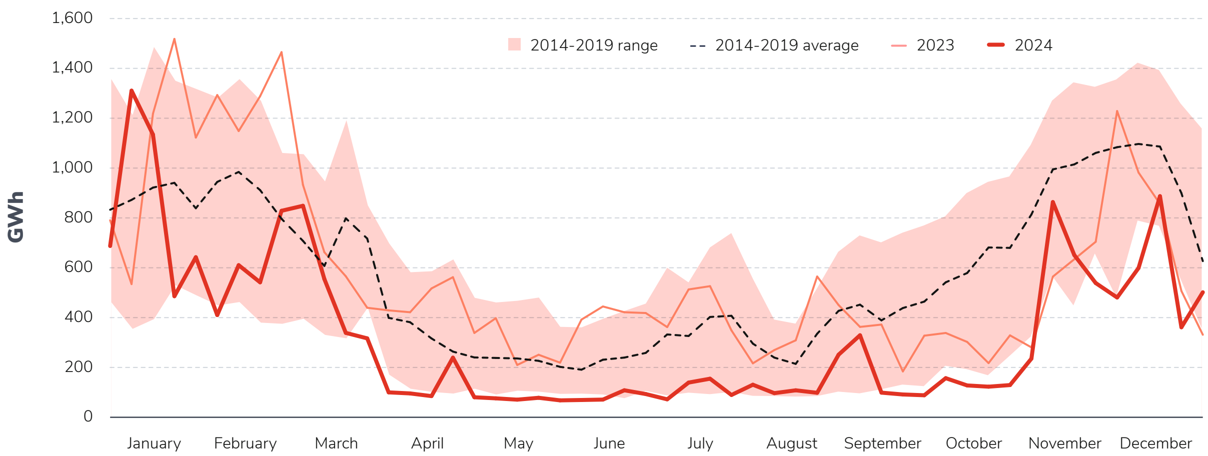
28. An average over recent years would be misleading. In 2022 and 2023, the fall in nuclear generation due to stress corrosion checks and repairs meant the reduction in fossil-fired generation seen in other European countries (see Europe chapter) was not possible in France. Part of the fossil fuel output had to be used to compensate for the lower nuclear generation.
29. This represents annual output of around ten TWh.
30. Fossil fuels are generally the last to be called on in the order of economic priority, even if, from time to time, load shedding or generation sources that depend on stocks of generation capacity, such as reservoir hydropower or batteries, can be more costly.

Gas-fired generation at its lowest for eleven years

In 2024, the level of generation from gas was 17.4 TWh, compared with 29.2 TWh in 2023 (–40%), even though gas prices fell compared with the previous year (see the Prices chapter). This is the lowest level since 2014 (14.1 TWh). In both cases, the reduction in the use of gas-fired generation units was made possible by the abundance of low-carbon generation: 361.7 TWh of nuclear power, 75.1 TWh of hydropower and 71.6 TWh of wind and solar power altogether in 2024, compared with 415.8 TWh of nuclear power, 67.4 TWh of hydropower and 22.9 TWh of wind and solar power in 2014. Gas-fired generation was low throughout the year, below the 2014-2019 average in every month, and particularly low in the period from April to October.

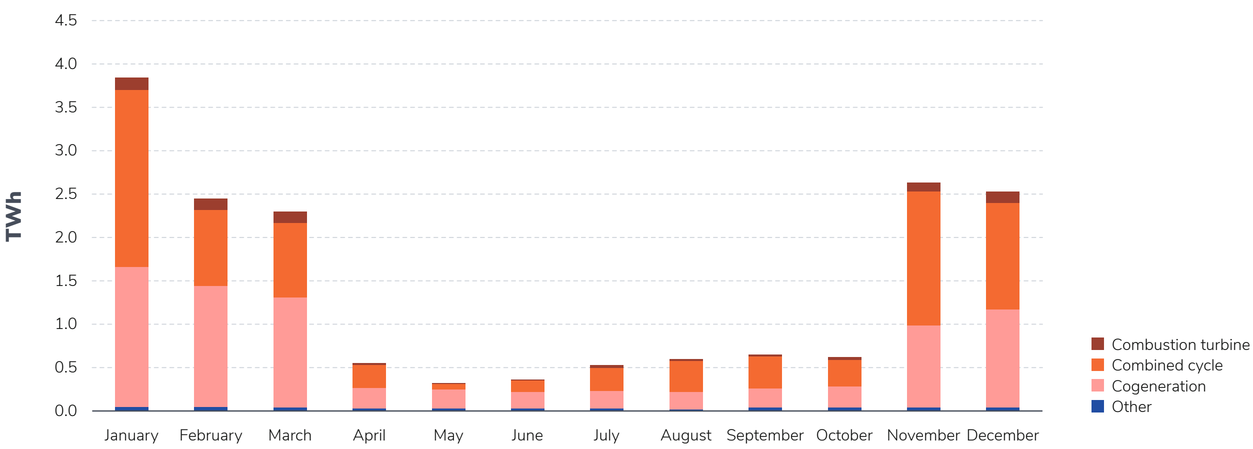
Almost half (45%) of the volume generated from gas in 2024 came from cogeneration plants. These plants not only generate electricity; they also recover the heat produced in the process that is not converted into electricity. This heat can be used in industrial processes or heating networks, providing economic and climate co-benefits[31], whereas it is not recovered in other thermal generation units (for example, even though the best-performing CCGT plants can achieve efficiency levels of over 60%, any heat that is not transformed into electricity is lost). Some cogeneration plants (1.7 GW) still benefit from a historic feed-in tariff during the winter, though this is being phased out[32]. This volume of annual generation at the feed-in tariff can be seen as relatively incompressible, and partly explains the reserve of fossil-fired generation that sometimes persists even during periods of high low-carbon generation.

Figure 30 – Weekly generation by gas-fired power plants in 2024 and comparison with previous years



31. Compared with a separate gas boiler combined with an electricity production unit. Although they are gas-fired, they are still carbon-based sources of electricity production.
32. This type of historic contract, which used to run for 15 years, is no longer available since 23 February 2021.

Figure 31 – Monthly output of gas-fired power stations in France in 2024 with breakdown by type of power station



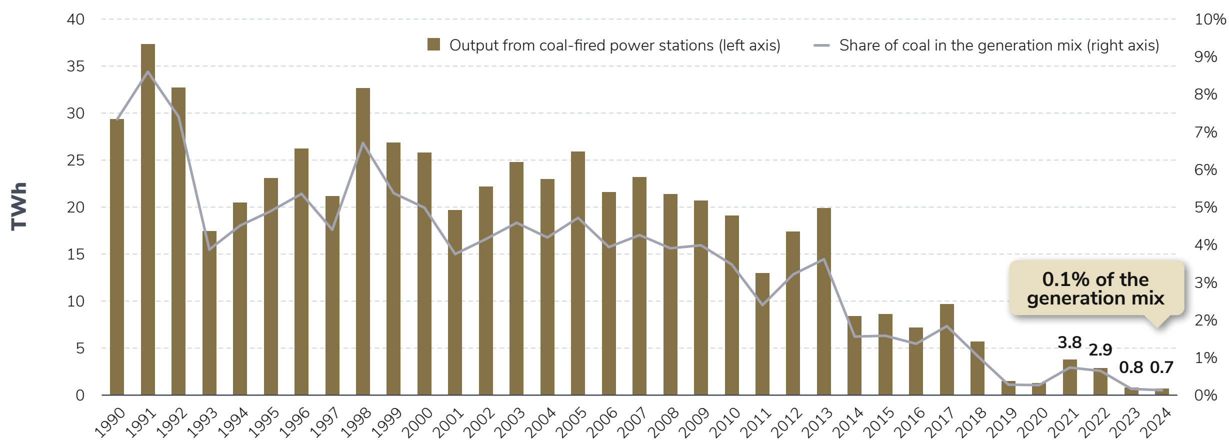
Coal-fired power generation, already anecdotal in 2023, continued to decline

Volumes of electricity generated from coal continued to fall, reaching 0.7 TWh in 2024, after hitting a previous all-time low in 2023 (0.8 TWh). In mainland France, in terms of volumes, electricity generation through burning coal has virtually come to an end. Coal's share of the French electricity mix was 0.13% in 2024, even lower than in 2023 (0.17%).

Annual output in 2023 represented a load factor for the coal fleet of 4.4%, corresponding to around 390 hours of production (at maximum power-equivalent) out of the 8,760 hours in a year.

From 1 January, coal-fired generation is capped at 700 hours of full-power generation per year until this power source is phased out, by 2027 at the latest. In 2024, as in 2023, coal-fired power stations remained below this ceiling.

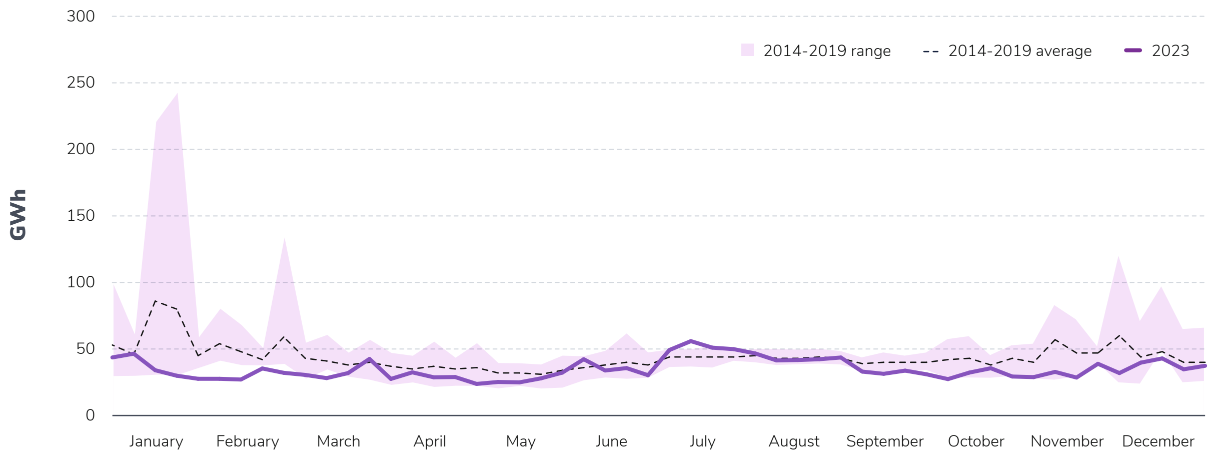
Figure 32 – Coal-fired electricity generation in France between 1990 and 2024



Fuel oil-fired generation remained stable in 2024

Electricity generation from fuel oil represented 1.8 TWh for the year 2024, or 0.3% of total production. This volume has remained relatively stable over the last ten years, with average annual output of 2.1 TWh. These generation resources are mainly used to balance the power system in near-real time and during winter consumption peaks. The outlines of the next multi-year energy plan, submitted for public consultation at the end of 2024, set a target for replacing oil with low-carbon fuels, including biofuels, by 2030.

Figure 33 – Weekly generation by fuel oil-fired power plants in 2024 and comparison with previous years



Electricity prices

Spot electricity prices in France returned close to pre-crisis levels in 2024, continuing the fall that began in 2023

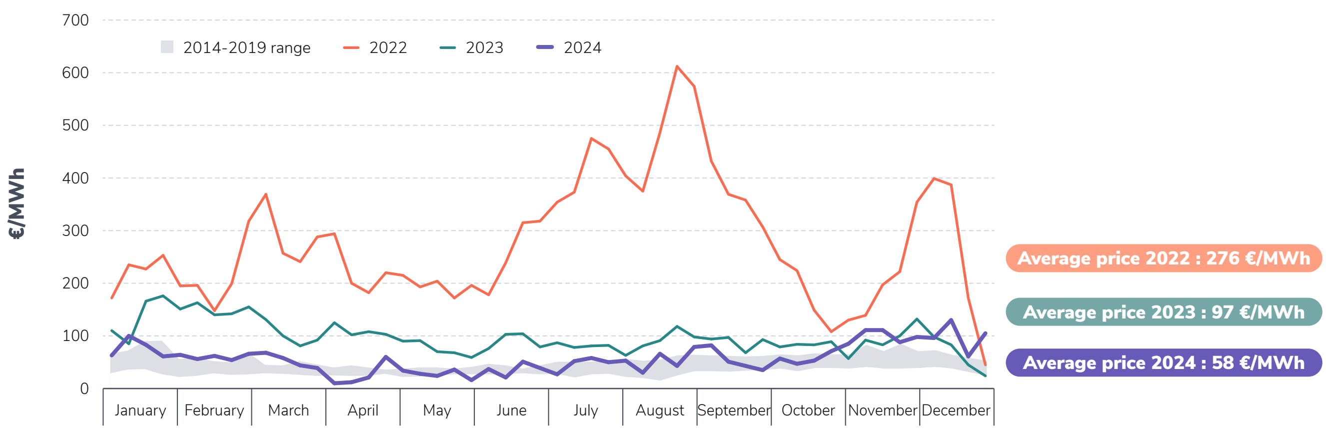
In 2024, prices on the wholesale electricity markets continued their fall from the highs of the 2022 energy crisis. **The average annual spot price in France fell by 40% compared with 2023, from €97/MWh in 2023 to €58/MWh in 2024, and fivefold compared with 2022, when it stood at €276/MWh.** On average, spot prices have now returned to a similar level to where they were before the pandemic and the energy crisis, thanks to subsequent improvements in the determinants of the supply-demand balance compared with 2023, when the crisis was already subsiding and a new balance had been reached in terms of the system's economic fundamentals, though prices had not returned to the levels of the late 2010s.

Even though average spot prices in 2024 remained within the range seen between 2014 and 2019, their volatility increased. In particular, the number of hours of negative spot prices more than doubled compared with the previous year (361 hours in 2024 compared with 147 in 2023).

Forward prices also fell significantly in 2024, in line with the trend in forward gas prices. The French price for electricity to be delivered the following year was halved, from €161/MWh for products traded in 2023 to €77/MWh for products traded in 2024. Despite this significant fall, forward prices remained higher than before the crisis, unlike spot prices: for example, the average forward price in 2019 for delivery in 2020 was €51/MWh. Forward prices are of major importance, because they influence the electricity prices paid by end consumers. In particular, they are used to calculate regulated sales tariffs, and generally provide the basis for calculating the suppliers' share of the tariffs offered to customers in the free market (see the "Background" section).

In line with the changes seen in 2023, the main factors behind these trends are a consumption level that is still lower than before the pandemic and the energy crisis, and the abundance of low-cost, low-carbon production.

Figure 3.1 – Weekly average spot prices in France in 2024 and comparison with previous years



Source: EPEX

Market fundamentals favourable to a fall in prices

The economic fundamentals of the power system have continued to improve since the energy crisis peaked in the summer of 2022.

Climate-adjusted electricity consumption rose slightly in 2024, after two consecutive years of decline, but remains lower than before the crisis (see Consumption section). At the same time, the volume of low-carbon generation in France was very high, thanks to the recovery in nuclear generation, a very good year for hydropower and the continued growth of wind and solar capacity.

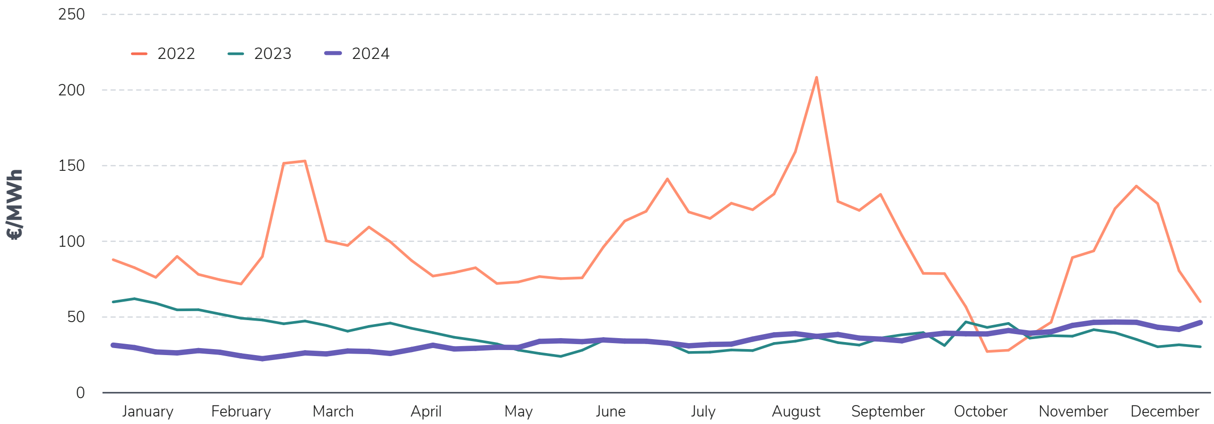
On the fuel markets, the downward trend that began in 2023 also continued in 2024. The average annual spot price for gas in France fell by 12% in 2024 compared with 2023, from €38.8/MWh to €34.2/MWh: this is the lowest average annual price since 2020, although it is still higher than before the crisis (€13.6/MWh in 2019, for example).

The continued fall in gas prices on the wholesale markets is due to a favourable context, with consumption still relatively low and no major disruption to European gas supplies. Pipeline deliveries accounted for 62% of total European gas supplies (EU 27) in 2024, a share that has been declining since the energy crisis in favour of LNG supplies[1]. The volumes delivered through pipelines rose slightly in 2024 compared with 2023, however, with almost a third of the volume supplied by Norway, which has retained its position as the leading pipeline supplier since Russia invaded Ukraine in 2022 (as far as France is concerned, Norway was already the leading supplier of natural gas before 2022). European gas supplies from Russia accounted for 18% of the total supplied by pipeline in 2024, compared with 51% in 2021. However, they increased slightly in volume between 2023 and 2024 despite the sanctions against Russia. European LNG supplies remained much higher in 2024 than before the crisis, despite a 15% drop in deliveries compared with 2023. The United States remains the main supplier of LNG, covering 48% of total deliveries in 2024. Like pipeline flows, Russian LNG supplies also increased slightly year-on-year, despite the sanctions, accounting for 19% of the total.

European gas storage facilities reached a 90% fill rate by the end of August in 2024, well ahead of the deadline (1 November). This minimum level required before the start of winter to guarantee the security of the European supply was introduced in 2022 in

1. Source: Bruegel (for data on EU gas supplies).

Figure 3.2 – Weekly average spot prices for gas in France in 2024 and comparison with previous years



Source: EEX Group

response to the invasion of Ukraine. Filling the storage facilities early was made easier by the fact that they had remained at a very high level (at least 40% of capacity) after the two previous winters.

Finally, gas consumption remained below pre-crisis levels, with a 25% drop[2] between 2021 and 2024. This trend, resulting mainly from the economic pressures on households and businesses, exceeds the European Union's gas consumption reduction targets (–15%) introduced in response to Russia's invasion of Ukraine. High temperatures in Europe, particularly during the winters of 2022/2023 and 2023/2024, also contributed to the reduction in demand.

Even though gas prices fell on average in 2024 compared with 2023, the trend over the year was upwards, responding to concerns about the conflicts in the Middle East and the anticipated non-renewal of the contract for Russian gas to transit via Ukraine, which expired at the end of 2024. Gas prices in December 2024 were therefore higher than in December 2023.

2. Source: Eurostat.

French wholesale market prices were once again among the most competitive in Europe

Futures markets

Electricity forward prices fell significantly but, unlike spot prices, they remained above historical pre-crisis levels. The French price for delivery the following year fell from €161/MWh for products traded in 2023 to €77/MWh for products traded in 2024. The French price for delivery in the first quarter of the following year fell from €229/MWh to €97.2/MWh.

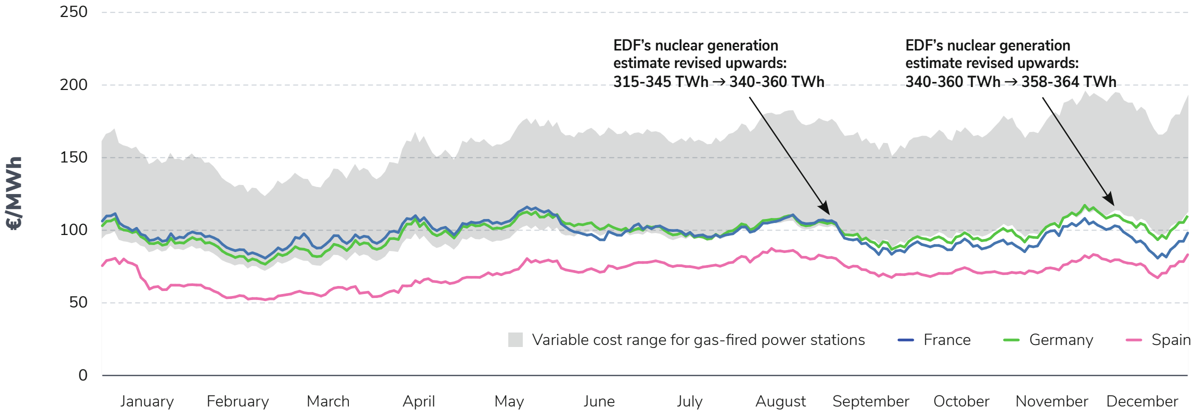
These are the lowest prices since 2020 (prices of 2021 products negotiated in 2020), but the fact that they are still relatively high compared with those at the end of the 2010s shows that there is still some uncertainty about the end of the energy crisis, together with a context of stubbornly high inflation and fossil fuel prices that have not returned to their pre-crisis levels. Adjustments to gas supplies due to the war in Ukraine on one hand, and greenhouse gas reduction targets on the other, kept the respective prices of gas and CO_2, which influence forward prices, at higher levels than those seen before 2020. However, the range of variation in forward prices is much smaller than was seen in the previous two years. Although the market is still relatively volatile, with geopolitical factors regaining importance due to the conflicts in the Middle East, the movements observed are consistent with the fundamentals.

French forward prices were lower than in all the neighbouring countries except Spain. This is due to plentiful low-carbon electricity generation in Spain (56% renewable and 20% nuclear in 2024) combined with the geographical position of the Iberian Peninsula, characterised by limited interconnections with other European countries. The installed base of wind and solar power rose from a total of 34.5 GW in 2019 to 63.1 GW in 2024, for example, gradually reducing dependence on higher-cost fossil-fired generation. The so-called "Iberian exception" mechanism for capping gas prices for electricity generation, which limited the rise in Spanish prices in 2022, has had no effect since 2023.

In France, the successive upward revisions to EDF's nuclear output forecasts at the beginning of September 2024 and again at the beginning of December helped to make forward prices more competitive with those of neighbouring countries. The risk premium that characterised the French market in 2022 had already been reduced in 2023, and it disappeared altogether in 2024. Throughout the year, prices for delivery in the first quarter of 2025 remained at the lower end of the variable cost range for natural gas-fired generation. The price for delivery in 2025 was even well below this range from the spring onwards, when the effect of renewable generation on mid-day prices became particularly visible on the French spot market. The effect of renewable penetration is beginning to be seen on seasonal forward products. In fact, over the next annual periods for summer products, "base" prices (24 hours) are higher than "peak" prices (8 a.m. – 8 p.m.). This means that market players are expecting higher prices at night than during the day, due to plentiful solar generation in summer.

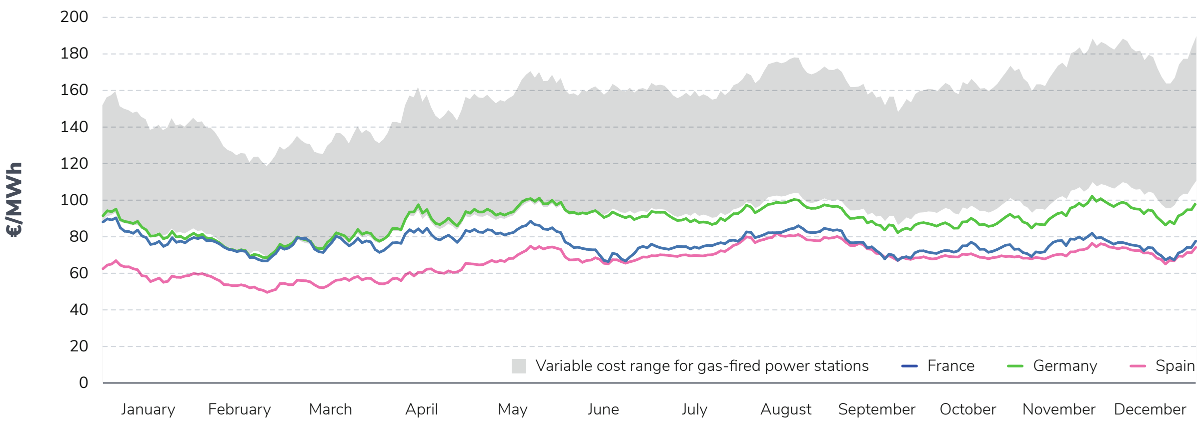
3. From 315-340 TWh to 340-360 TWh at the beginning of September 2024, then from 340-360 TWh to 358-364 TWh at the beginning of December.

Figure 3.3 – Trend in 2024 of forward prices for delivery in the first quarter of 2025, in France, Germany and Spain, and comparison with the variable costs of gas-fired power plants



Source: RTE calculations based on EEX Group data

Figure 3.4 – Trend in 2024 of forward prices for delivery in 2025, in France, Germany and Spain, and comparison with the variable costs of gas-fired power plants



Source: RTE calculations based on EEX Group data

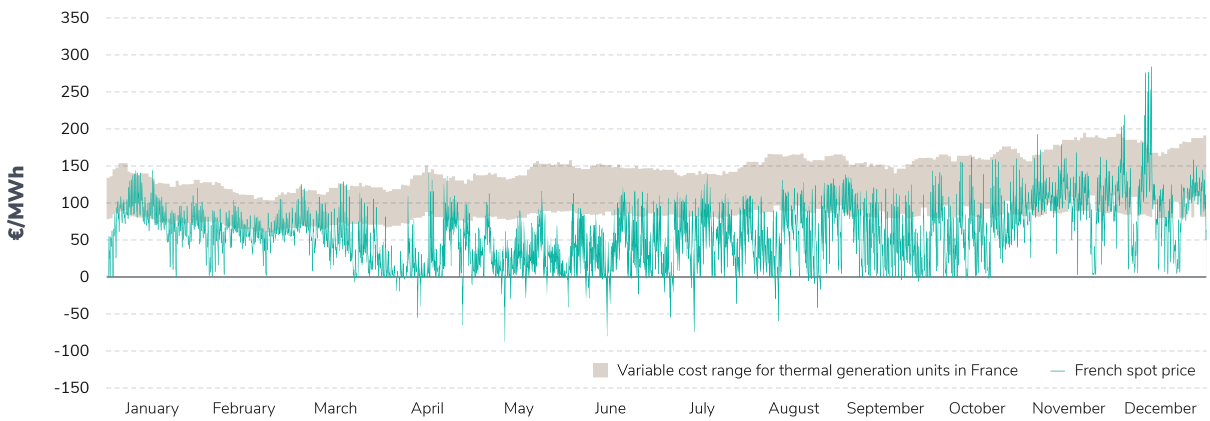
Spot market

As mentioned above, the average annual spot price was €58/MWh in France in 2024, representing a 40% reduction on the 2023 price and a return to average levels close to those seen in the late 2010s.

The momentum at the start of 2024 continued the overall downward trend that began in 2023. As a result, average monthly prices fell in May to their lowest level since June 2020 (affected by the pandemic), at €27.2/MWh. Prices then followed an upward trend, with a slight pause in September and an acceleration from November onwards. Prices in the last two months of the year were well above those for the rest of the year. In fact, the average price doubled between the January-October period (€49.5/MWh on average, the same level as before the crisis) and the November-December period (€99.3/MWh). This acceleration in prices towards the end of the year was due to a number of episodes in which low temperatures were accompanied by very low levels of renewable generation, while consumption was sustained, meaning that fossil-fuelled generation had to be used to a greater extent. Fuel and CO_2 prices, already high due to the geopolitical context, rose further at the end of the year in line with this increase in demand, contributing to the rise in electricity prices.

French spot prices were very often below the variable cost range of thermal power stations (71% of the time). This is a major change compared to 2023, when the rate was 48%. This situation, mainly due to the increase in low-carbon generation in France, could change in the coming years, however, if consumption increases.

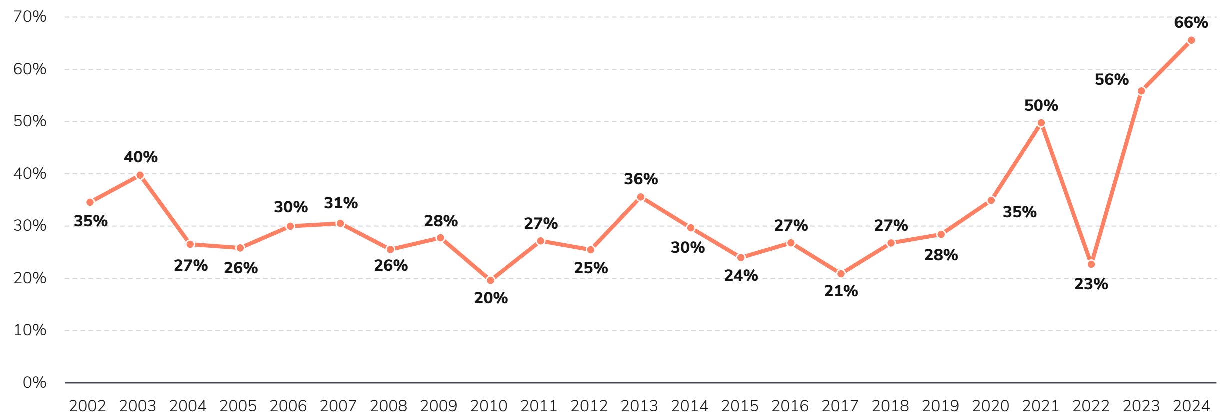
Figure 3.5 – Hourly spot electricity prices in France in 2024 and comparison with the variable costs of fossil-fired thermal power plants



Source: RTE calculations based on EEX Group and EPEX data

The fall in prices was accompanied by a significant increase in their volatility compared with the pre-crisis years due to the growth of non-dispatchable renewable generation: despite an annual average close to the 2014-2019 values, prices in 2024 were only within the range of variation in hourly prices between 2014 and 2019 for 31% of the time, compared with 21% of the time below and 48% of the time above. This level of volatility[4] is one of the highest seen over the last 10 years. It is well above the level in 2021, which was affected by the start of the energy crisis at the end of the year, and in 2022, the peak of the crisis. In fact, volatility was relatively low in 2022 as price levels were very high throughout the year.

Figure 3.6 – Historical volatility index for spot prices in France by year

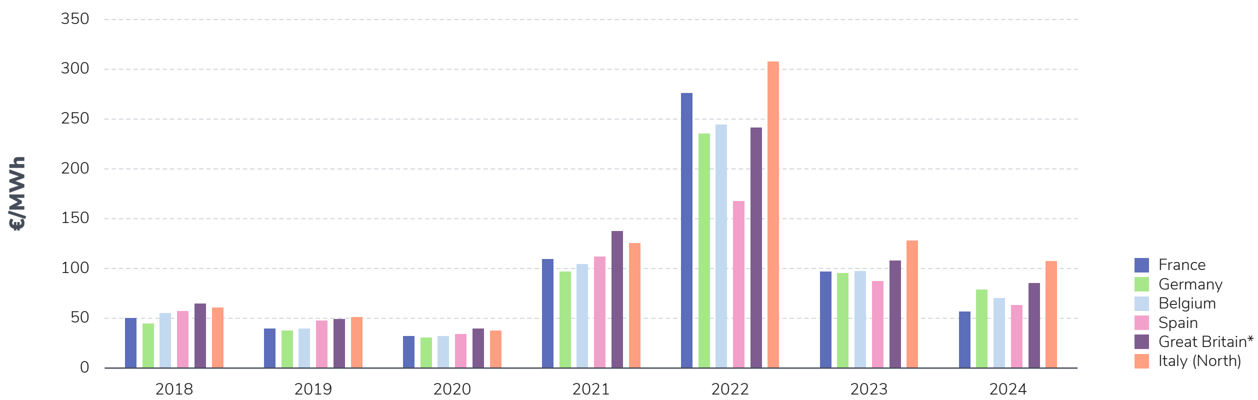


Source: RTE calculations based on EPEX data

4. The historical volatility is the standard deviation over the year of the daily variation in spot prices.

A general fall in prices across Europe, though less marked in the countries most dependent on gas

Figure 3.7 – Annual averages of hourly spot prices for several European countries over the period 2018-2024



* As Great Britain and Northern Ireland belong to separate market areas, the data displayed here relate only to Great Britain and not to the United Kingdom

Source: EPEX

Elsewhere in Europe, prices followed a similar pattern to France, with reductions in all countries and average spot prices for most reaching their lowest levels since 2020. However, the extent of the decline varies from country to country. On one hand, it was weakest in countries where fossil-fired generation accounted for at least a third of the national electricity mix in 2024. This was the case in Italy, Germany and the UK. All these countries also have significant renewable generation, but when this type of generation is inadequate to cover consumption, much more expensive fossil fuels are used to supplement it. In particular, the variable costs of these generation sources (linked to fuel costs and the cost of CO_2 quotas) are still higher than before the pandemic and the energy crisis, though they have been falling since 2023. On the other hand, the fall in prices compared with 2023 was greatest in France's neighbouring countries where the majority of generation is low-carbon (over 75%), such as Spain, where the average price reached €63/MWh, relatively close to the French price (€58/MWh).

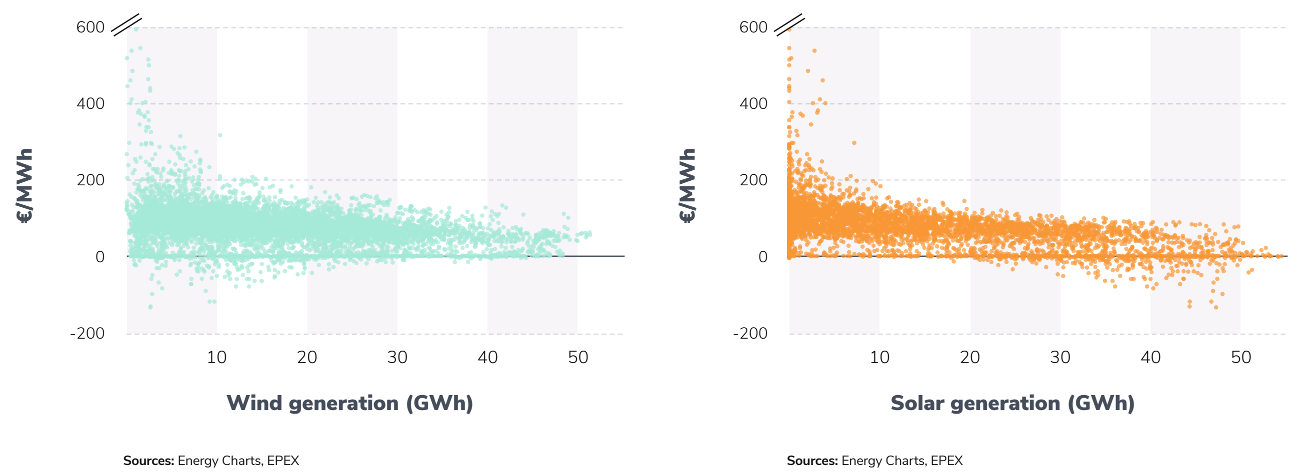
For the first time since 2011, the French spot price fell below the German price on average over the year. In fact, the fall in prices in France was more significant than in Germany, where average prices were down 18% on the previous year. Germany also saw an increase in price volatility compared with previous years, linked to the development of renewable generation, the closure of the last nuclear power station (in 2023), and the reduction in coal-fired generation capacity. Between November 2023 and November 2024, 7.9 GW[5] of coal-fired generation capacity was withdrawn from the market (from 17.5 GW to 9.6 GW) along with 3.9 GW of lignite-fired generation capacity (from 18.4 GW to 15.2 GW). The influence of renewable generation, particularly solar, on German prices was particularly visible in 2024, with a sharp fall in prices and the arrival of negative prices as soon as solar output exceeded 20 GW.

5. Source Bundesnetzagentur (for coal and lignite capacity data).

In addition, prices rose sharply during morning and/or evening consumption peaks when renewable generation was low, as was the case during certain periods at the end of the year[6]. On Thursday 12 December at 5pm, the German hourly price reached its highest level since 2006 at €936.3/MWh, having already reached €820/MWh on Wednesday 6 November at 5 p.m.. Outside the energy crisis, these price levels had previously been very rare in Germany. The circumstances leading to high prices over these two hours were similar, with very low wind generation – 1.3 GW on 12 December at 5 p.m. and 0.2 GW on 6 November at 5 p.m. – and zero solar generation at these times, while consumption was high, at over 65 GW, requiring greater use of German fossil-fired generation and imports.

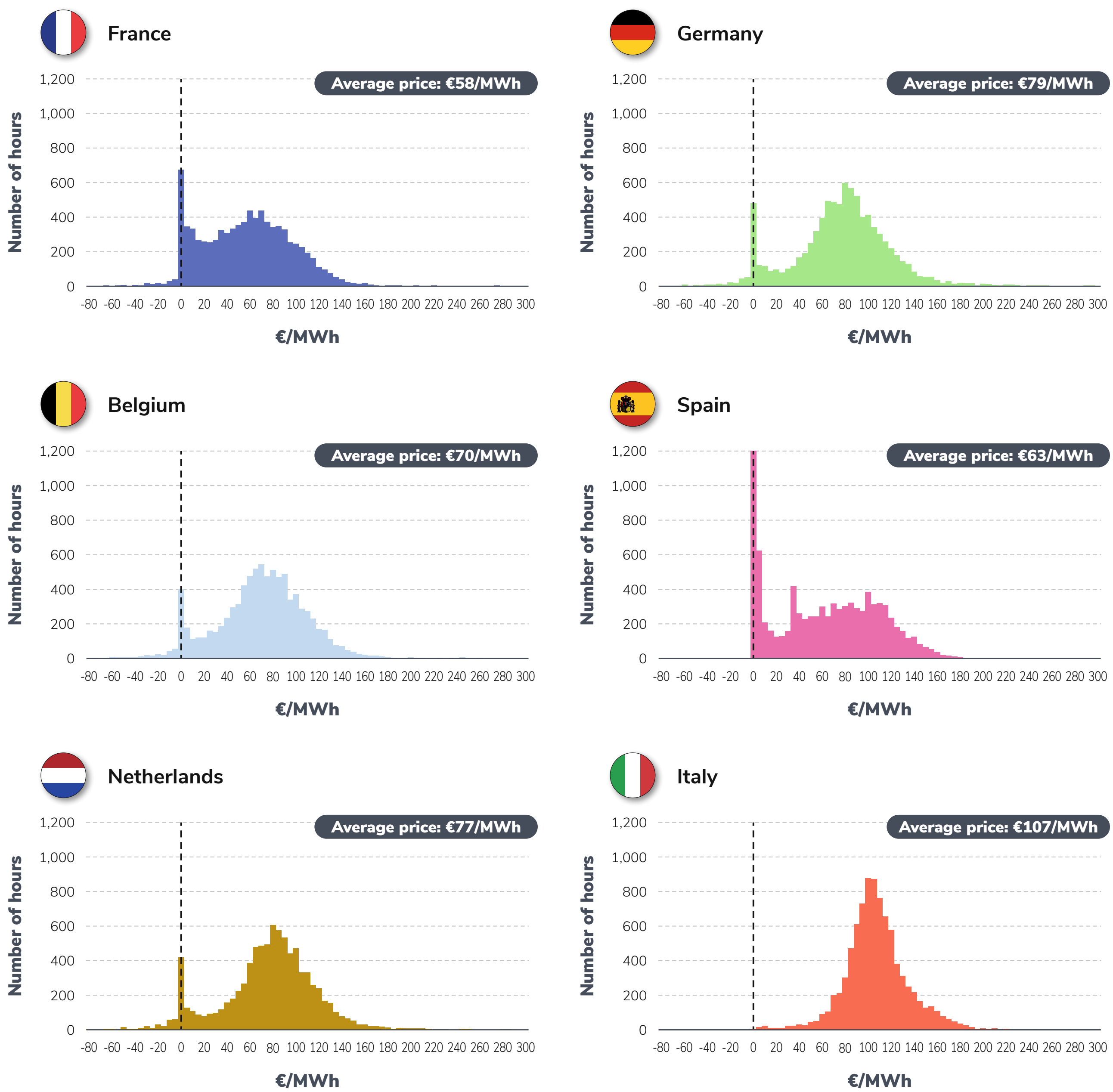
The Spanish price fell by 28% compared to the previous year, almost as far as the French price. It stayed very close to the French annual average price and returned, as in France, to levels similar to those seen before the crisis. Prices were even lower in Spain than in France during the first five months of the year, with a reversal from the summer onwards. The reduction in Spanish prices was mainly due to the abundance of wind generation and, to a lesser extent, hydropower, thanks to high rainfall and ample stocks (mainly until April). As a result, wind power was the leading source of generation in Spain in a mix that was 76% low-carbon, while gas-fired generation accounted for 20% of the Spanish energy mix in 2024. The fall in the Spanish gas price also contributed to the reduction in the spot price for electricity. As a reminder, the "Iberian mechanism" has no longer had an effect on electricity prices in Spain since 2023. This mechanism, introduced in 2022 in the wake of the energy crisis, consisted of a cap on the price of gas used for electricity generation in Spain. As gas prices fell on the markets from 2023, the mechanism was no longer effective. Prices (€39/MWh on average in 2023) were well below the defined ceilings (€56.1/MWh from April 2023 and €65/MWh from December 2023). The mechanism came to an end on 31 December 2023.

Figure 3.8 – Hourly spot prices in Germany as a function of wind or solar PV generation in Germany in 2024



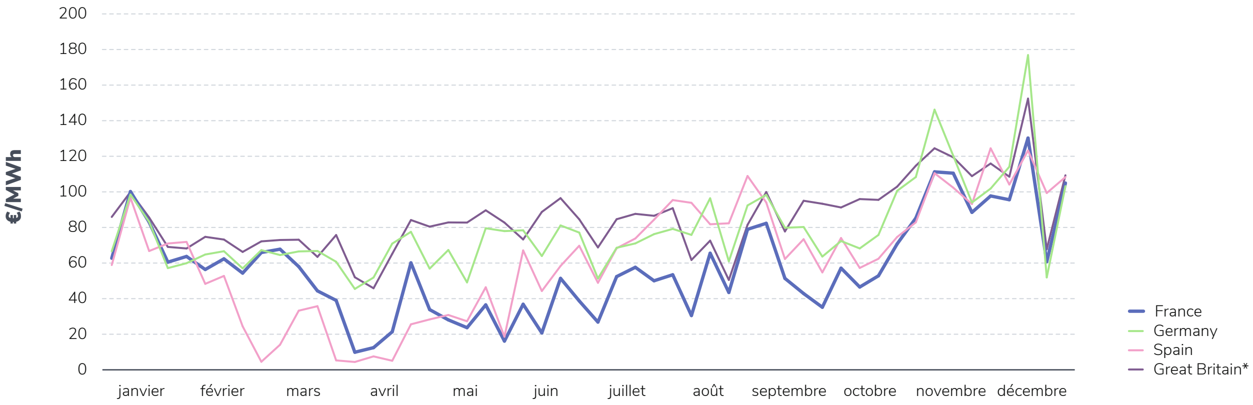
6. Known as "*Dunkelflaute*", these are prolonged periods (several days) when weak wind is combined with insufficient sunshine, resulting in very low wind and solar generation.

Figure 3.9 – Distribution of hourly spot prices for various European countries in 2024 (the bar corresponding to the 0 €/MWh price indicates the number of hours when the price was between €–2.5 and €2.5/MWh, etc.)



Source: EPEX

Figure 3.10 – Average weekly spot prices in France and selected European countries in 2024



* As Great Britain and Northern Ireland belong to separate market areas, the data displayed here relate only to Great Britain and not to the United Kingdom

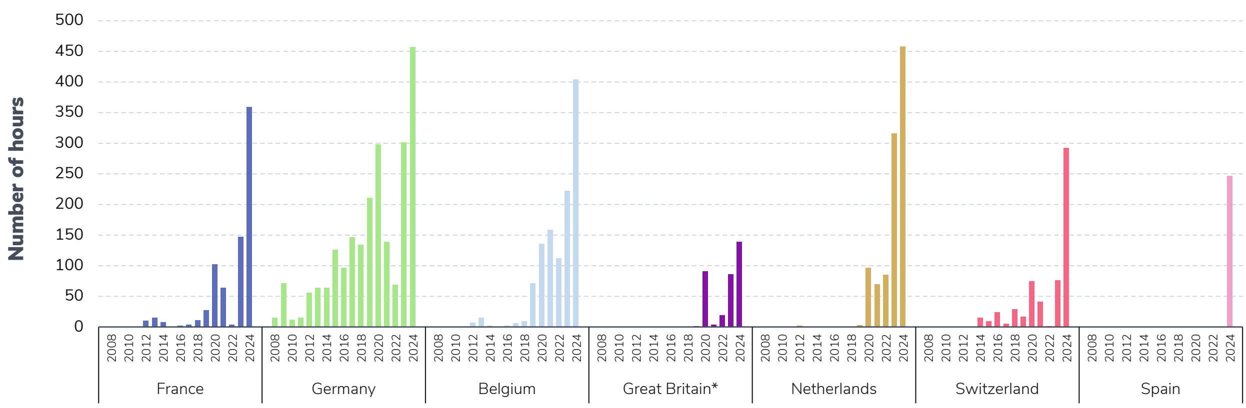
Source: EPEX

Occurrences of negative prices doubled on the French spot market

The number of occurrences of negative spot prices rose sharply in 2024, with 361 hours over the year (4% of the time). This is double the number of occurrences the previous year (147 hours), which was already a record level in France. The number of negative price episodes has accelerated in recent years due to the increase in renewable electricity generation capacity, the recovery in nuclear power and the fact that consumption has remained at a lower level than between 2014 and 2019.

The number of occurrences of negative prices in France was similar to neighbouring European countries where the pace of renewable energy growth is greater than in France. Germany recorded 457 hours of negative prices, Belgium 404 hours and the Netherlands 458 hours. Negative prices occurred most frequently in Finland, with 722 occurrences. Spain saw its first negative spot prices in 2024, with 247 occurrences (Spanish electricity market regulations did not allow negative prices until 2020).

Figure 3.11 – Number of hours over the year when electricity prices were negative in a selection of European countries



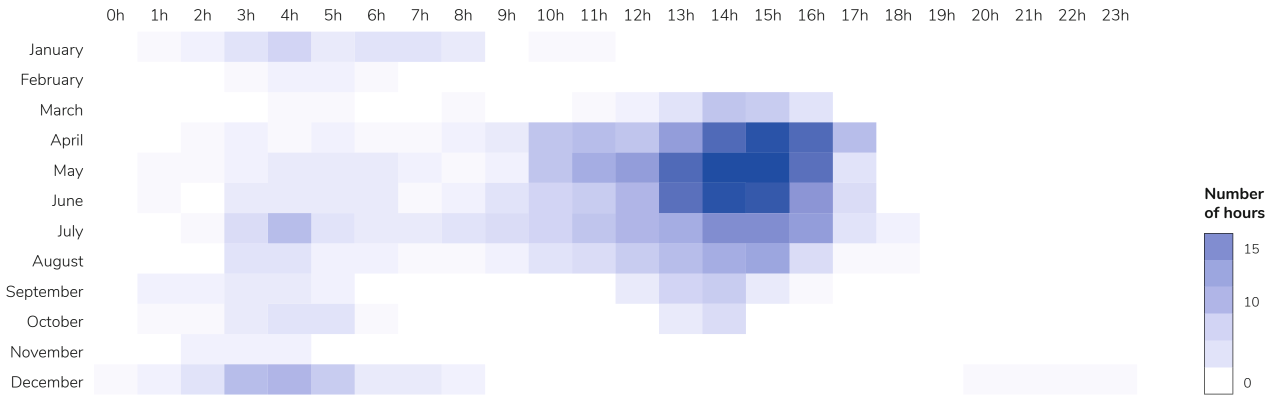
* As Great Britain and Northern Ireland belong to separate market areas, the data displayed here relate only to Great Britain and not to the United Kingdom

Source: EPEX

Slightly negative prices generally occurring on weekend afternoons

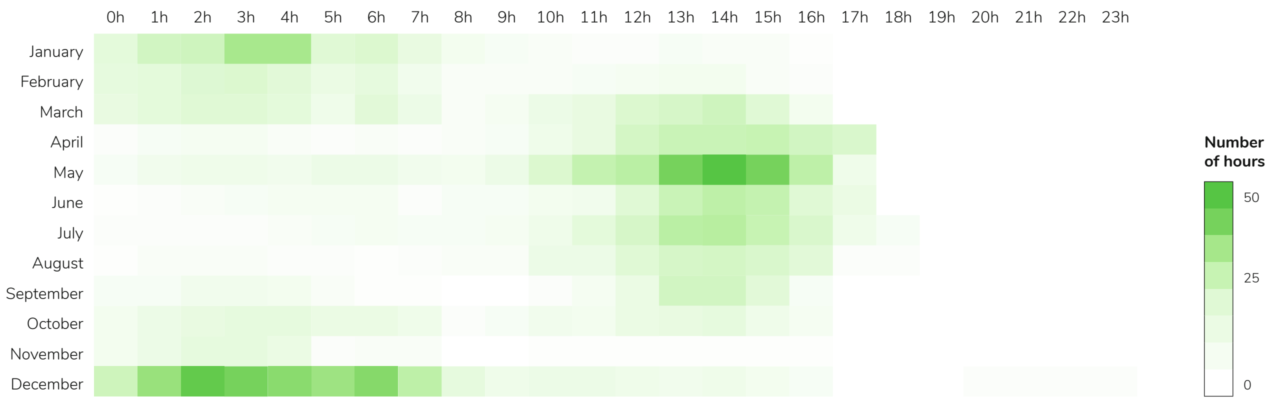
Despite the increase in the number of occurrences, negative prices still had the same characteristics as previously. Negative prices most often occur in sequences of several successive hours, at night between 2 a.m. and 7 a.m., in the afternoon between 11 a.m. and 4 p.m. and at weekends from March to August. During the winter, regular occurrences can be seen at the end of December and the beginning of January during the school holidays, but only at night.

Figure 3.12 – Hourly distribution, by month, of negative spot prices in France over the period 2002-2024



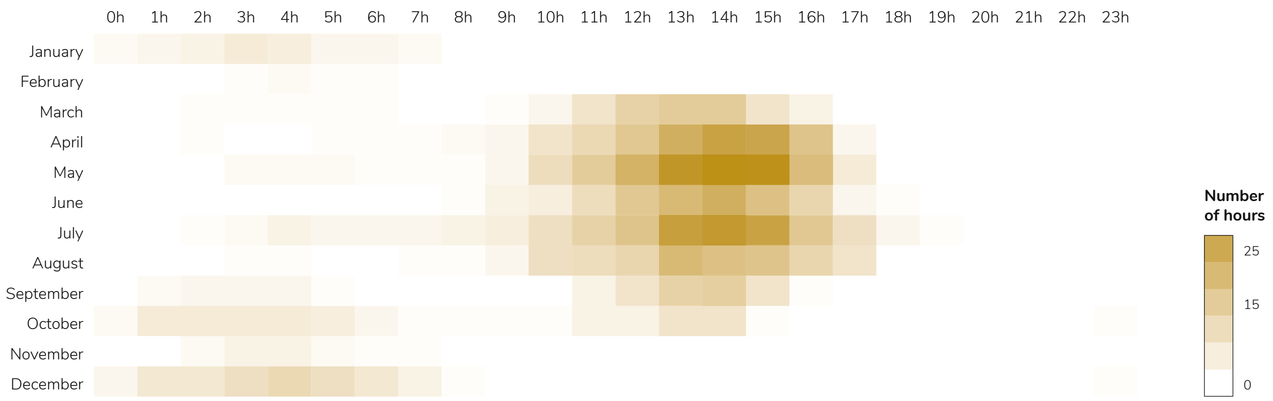
Source: EPEX

Figure 3.13 – Hourly distribution, by month, of negative spot prices in Germany over the period 2002-2024



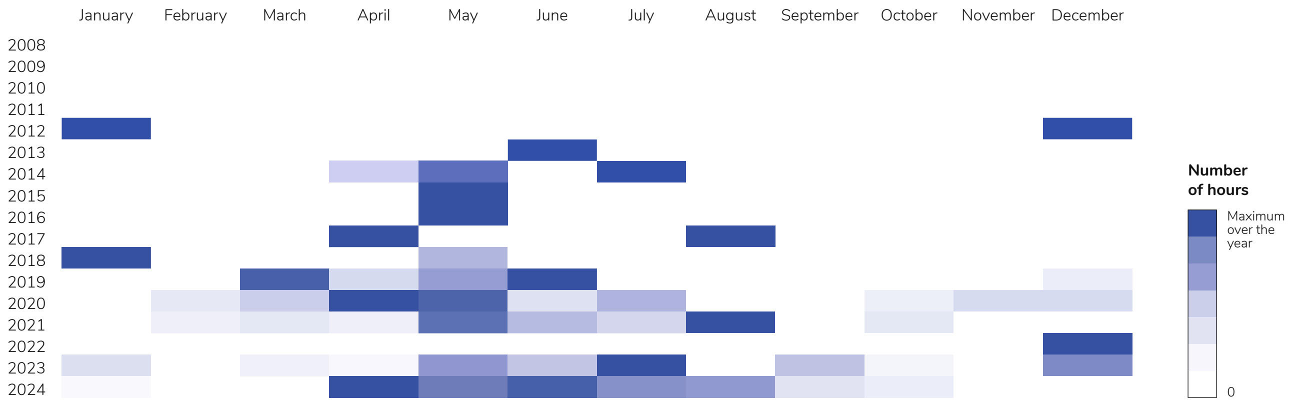
Source: EPEX

Figure 3.14 – Hourly distribution, by month, of negative spot prices in the Netherlands over the period 2002-2024



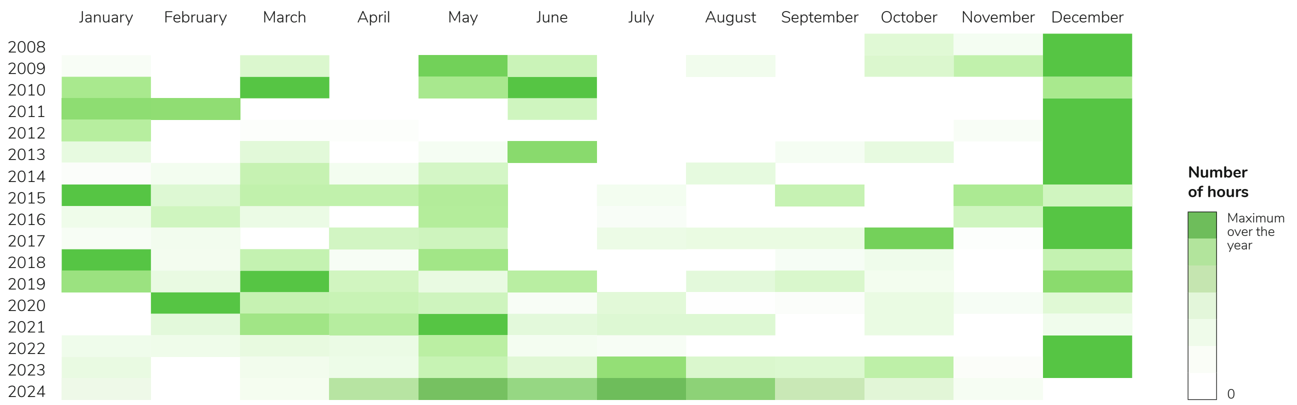
Source: EPEX

Figure 3.15 – Monthly distribution, by year, of negative spot prices in France



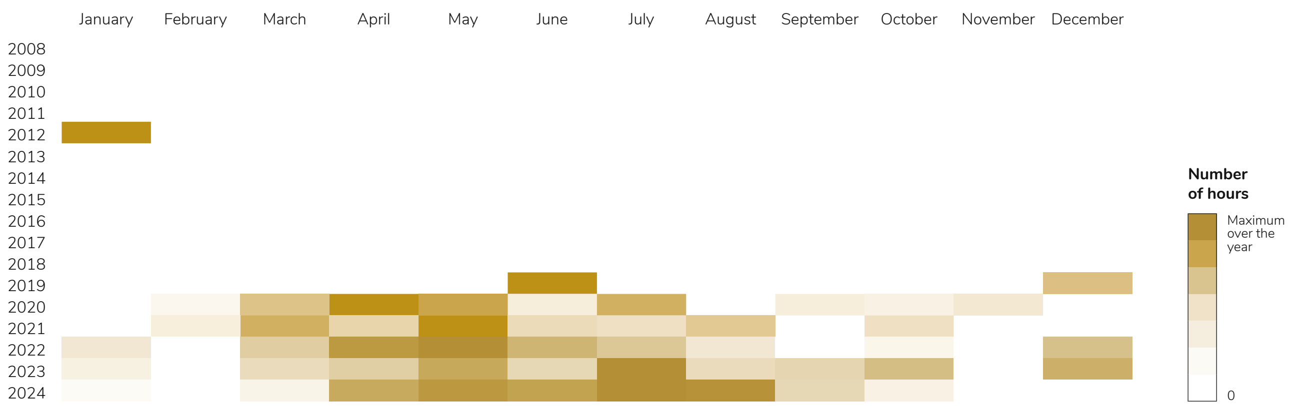
Source: EPEX

Figure 3.16 – Monthly distribution, by year, of negative spot prices in Germany



Source: EPEX

Figure 3.17 – Monthly distribution, by year, of negative spot prices in the Netherlands

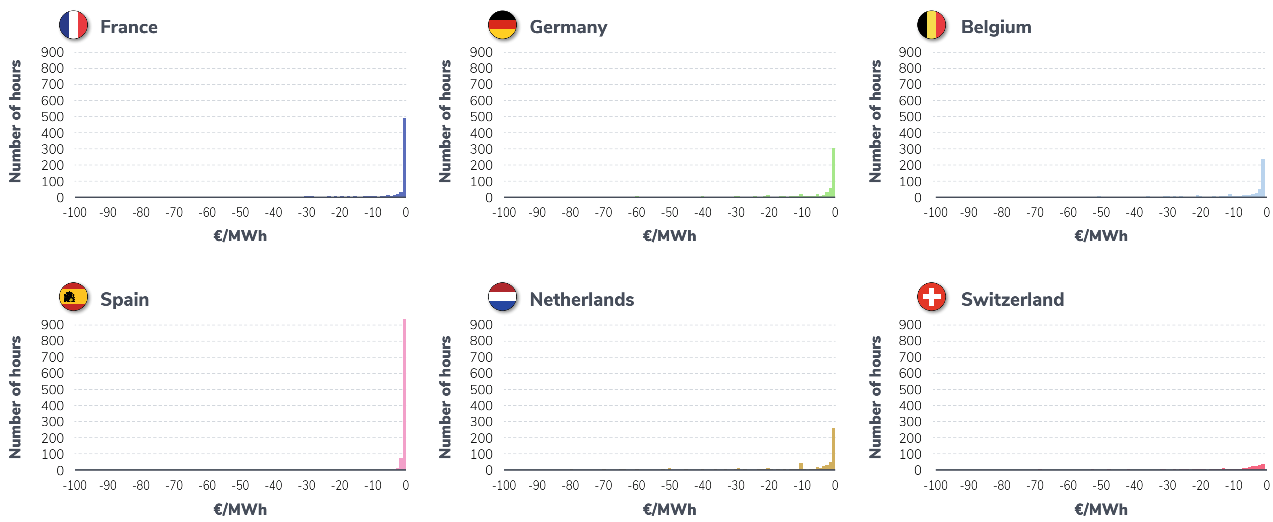


Source: EPEX

Negative prices are usually only very slightly negative: prices between €–0.01/MWh and €–1/MWh accounted for 61% and 46% of occurrences in 2023 and 2024 respectively in France. However, the proportion of more strongly negative prices (between €–5/MWh and €–30/MWh) increased in 2024 compared with 2023, rising from 20% to 30% of occurrences. The remainder are prices below €–30/MWh. In France's neighbouring countries, at least a third of negative prices were in the range of €–0.01/MWh to €–1/MWh, with the notable exception of Spain, where most of the negative prices were at this level (89%). Looking at zero prices, the French and Spanish spot markets had the highest number of occurrences, with 195 hours of zero prices in France and 537 in Spain.

It is interesting to analyse the position of French electricity trade during episodes of negative prices. In 2024, France was a net exporter 83% of the time during negative price times: across all its borders, the balance was most often positive (i.e. exporting), with the exception of the German and Belgian borders, where it was more often negative (71% of the time during negative price hours). In this way, France "exported" its negative prices to all its neighbours around 15% of the time. Just under 40% of the time, it "imported" negative prices across its eastern borders (Germany and Belgium), often only to re-export them across other borders. This is due to episodes of very high renewable generation in Germany, but also in its neighbouring countries (the Netherlands in particular). The rest of the time, negative prices were "imported" across one of the other borders (Switzerland, Spain, Great Britain), apart from Italy, where market rules do not allow for negative prices. Even in these cases, they were frequently "re-exported".

Figure 3.18 – Distribution of zero (below €0.5/MWh) or negative spot prices for various European countries in 2024



Source: EPEX

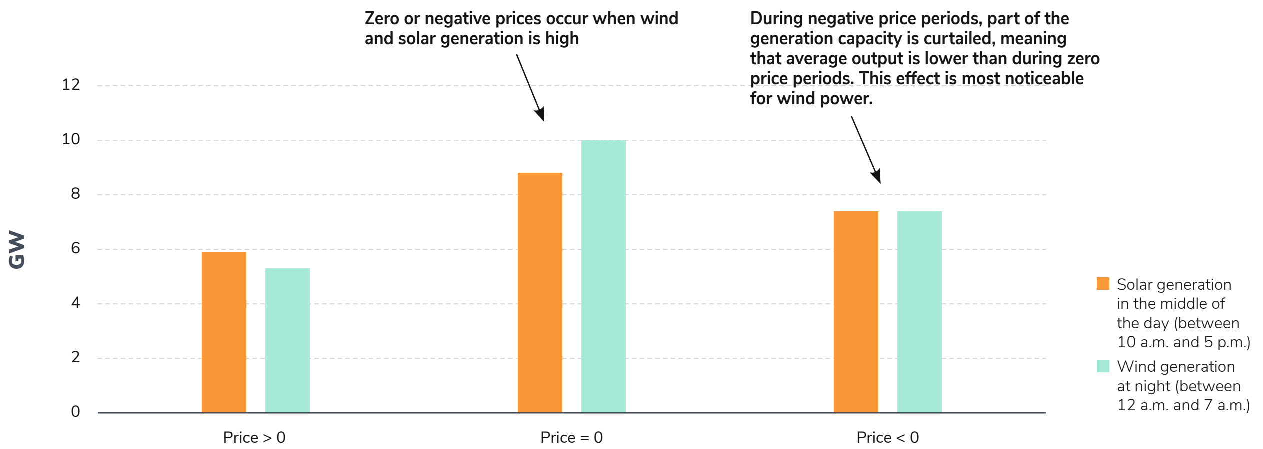
Why do negative prices happen?

Negative prices generally occur during times of low consumption combined with high renewable energy generation. When renewable production exceeds consumption, controllable units, particularly non-flexible thermal units, should stop producing. They may, however, prefer not to stop, and offer negative price deals, i.e. choose to pay buyers for a few hours to consume (or resell) this surplus electricity. The reason for this is that shutting down a thermal unit temporarily can be costly due to technical and economic constraints (start-up costs, minimum technical requirements, minimum shutdown time, etc.). Thus, consumers are paid to consume electricity produced in quantities that are too abundant compared to consumption needs at these specific times.

Negative prices are not in themselves an anomaly in the functioning of the market. In theory, the negative price is a legitimate economic signal, encouraging consumers to increase their consumption during periods of high renewable production, and producers with controllable units to lower their production levels. In fact, however, as only a small part of electricity consumption at a given time is covered by volumes traded at the spot price (or whose price is indexed to it) , the incentive effect of this signal on the level of consumption is reduced. In addition, a large part of renewable production is also not exposed to market prices, having direct power purchase agreements through the feed-in tariff mechanism. The negative price does not then act as an incentive to reduce this production. On the other hand, facilities on the premium scheme have an incentive not to produce if prices are negative. The mechanism does not provide for any remuneration for generation during these episodes, but it provides compensation if the total number of hours the facility is shut down over the year exceeds a threshold defined for each generation source.

In particular, wind and solar output during periods of negative prices was generally lower than during periods of zero prices. This difference clearly shows the effect of the curtailment of price-sensitive renewables (plants on the premium scheme or exposed to market prices) at negative price times, which is estimated to amount in total to 1.8 TWh over the course of 2024 (see the *Generation* chapter).

Figure 3.19 – Wind and solar generation at specific times of the day for different market prices



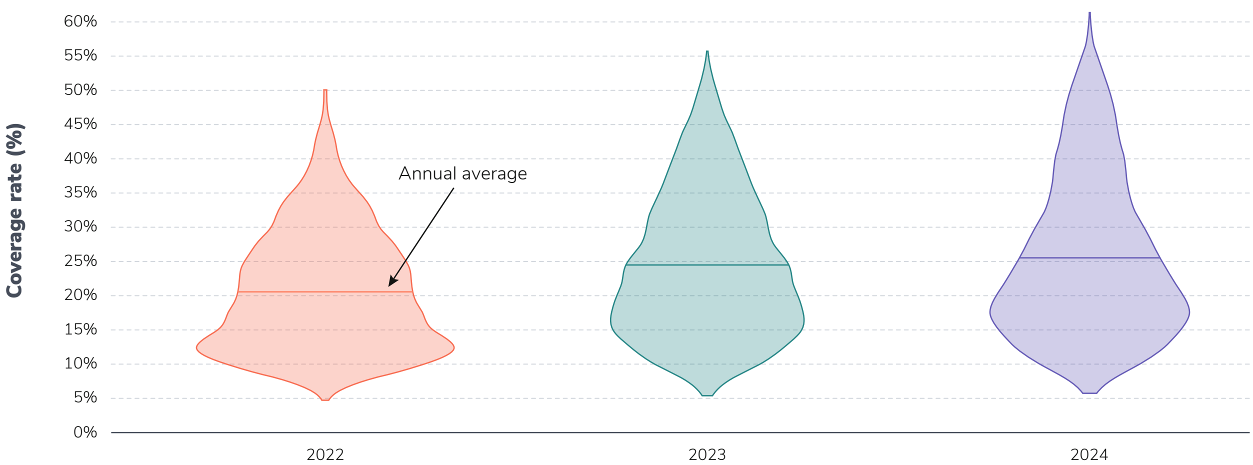
7. The retail price paid by consumers is generally different from the wholesale price (see “The different concepts of electricity prices”).
8. The premium scheme (“*complément de rémunération*”) is a support system for renewable electricity generation facilities (for new contracts, it covers onshore wind, hydroelectricity and biogas, for facilities with a capacity below certain thresholds).

In a power system where the share of renewable energy is growing, negative prices are likely to occur more frequently, particularly if the electrification of uses is delayed and electricity consumption is slow to rise. The resources for dealing with these situations are clear:

- The flexibility of the generating fleet: the manoeuvrability of France's nuclear fleet is an essential source of flexibility;
- The development of support mechanisms for renewable energy: the premium scheme provides support for generating sources while encouraging modulation;
- The development of demand flexibility and storage. Generally speaking, certain uses of electricity (such as recharging electric vehicles or water heaters) could take place during the periods of the day most likely to experience negative prices, with no effect on user comfort and extremely competitive economic conditions for the consumer.

In this context, it is also worth recalling the usefulness of cross-border trade and the integration of European markets: the operation of the European electricity market enables optimum use to be made of the generating capacity available, within the limits of the trade capacities between the various countries. Trade makes it possible to take advantage of the variability of production and consumption profiles in different market areas, while minimising the cost of production on a European scale. In a purely theoretical situation in which there are no limits on trade in Europe, the price would be the same everywhere (negative or not), and all generation across the continent could be matched with all consumption in an optimised way. In this hypothetical situation, negative prices would only be possible if the non-dispatchable renewable output of the whole of Europe were greater than the whole of Europe's consumption at a given moment. But total wind and solar power output is nowhere near the level of European consumption on an hour-by-hour basis. Over the last three years, as negative prices have multiplied, the average coverage rate has risen from 21% to 26%, and the maximum rate from 50% to 61%. This is purely theoretical, but it shows the advantages, in terms of managing the power system and minimising generating costs, of being able to "pool" generation and consumption across different countries via an interconnected power system and an integrated European electricity market.

Figure 3.20 – Distribution of the rate of coverage of European consumption (EU 27) by wind and solar power generation



Source: ENTSO-E

Key: the wider the shape, the larger the number of time intervals in the year characterised by the rate shown on the y-axis. For example, in 2024, there were a large number of time periods where the coverage rate was between 15% and 20%. The average coverage rate was 26%, with the highest rates close to 60% for a few hours during the year.

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The different concepts of electricity prices (spot, forward, etc.)

In practice, the term "electricity price" covers different concepts that are often confused. In particular, it is necessary to distinguish between the price of electricity on wholesale markets, on the one hand, and the "retail price" charged to the consumer, on the other.

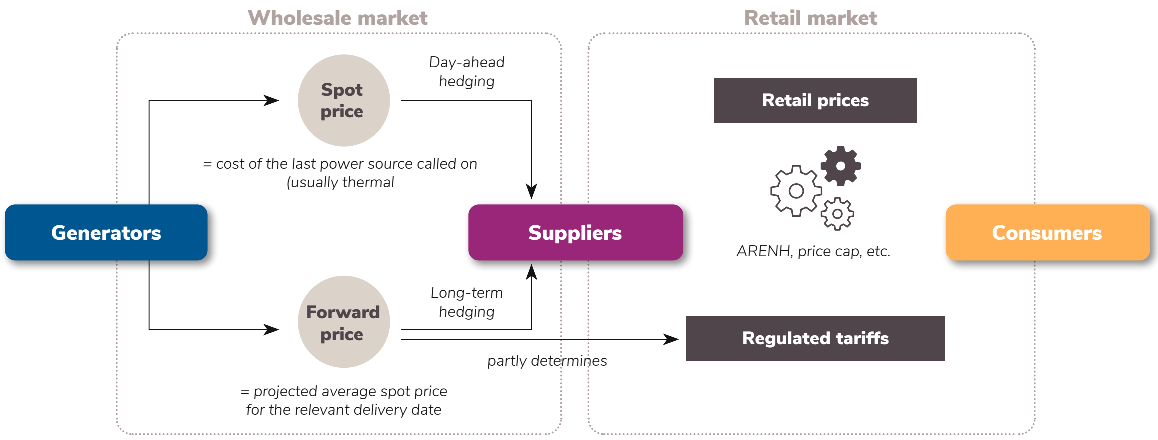
The concept of "wholesale price" itself covers multiple ideas depending on the timeframe to which it refers: it can be either the spot price, corresponding to the price of one megawatt-hour of electricity for physical delivery at a given time, the day before for the following day (constructed on daily markets according to the principle of economic precedence illustrated below) or a few hours later (intraday markets), or a forward price with a longer delivery timeframe, ranging from one week to one year.

Futures markets allow producers and suppliers to hedge against the "price risk" of the daily market, i.e., against the hourly price volatility that forms there. The producers, on the one hand, and the suppliers or large consumers, on the other, respectively sell or buy a large part of their production and consumption, to, as the case may be, define their margin or determine a rate for their customers, several months, or even several years upstream (with only a residual part of their production or consumption being sold or bought on the spot market).

Forward prices thus reflect a trade-off between selling or buying electricity in advance and waiting until the last moment to hedge (at the time of the daily market). Forward prices are therefore generally based on expectations of average spot prices, including a possible risk premium which may depend on the uncertainty and/or risk aversion of the various players involved. In particular, risk premiums can reach very high levels when a crisis occurs, reflecting players' perceptions of a shortage or pressure on supply.

Forward prices are one of the components of the price of electricity paid by end consumers (they are used in particular to construct regulated sales tariffs and to supply consumers

Figure 3.21 – Operation of the wholesale and retail electricity markets



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who are not eligible for these tariffs, such as industrial customers) alongside other components. In addition to this supply on the forward markets, the retail price shown on consumers' electricity bills includes a component corresponding to the costs of the network needed to transport the electricity, a tax component, a component linked to regulatory mechanisms such as the ARENH and other various components (marketing costs, capacity mechanism, etc.). These principles are common to regulated sales tariffs and to the market offers that compete with them.

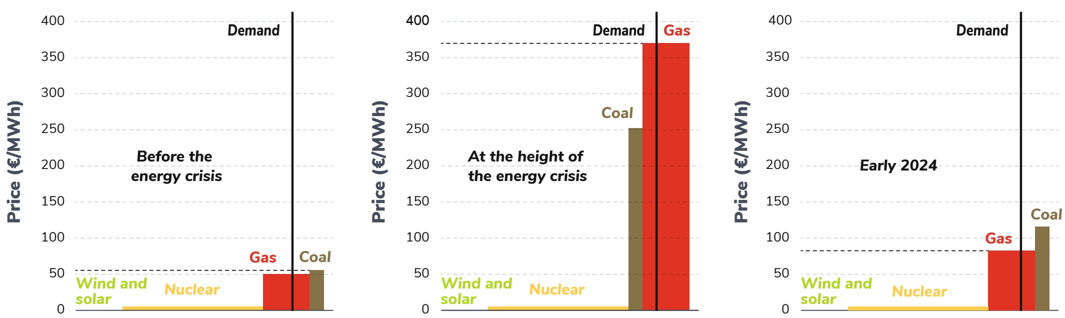
In short-term physical markets (daily markets – with next-day delivery – but also intraday markets), weather conditions play an important role. On the other hand, in the futures markets, which have a longer delivery date, prices are more strongly dependent on the outlook for gas prices over the medium term and the supply and demand situation.

Why can electricity prices depend on gas prices?

The European electricity market is based on the principle that the price of electricity is fixed at each moment at the level of the variable production cost of the last unit called upon to cover electricity demand. In other words, for each hour, everything happens as if the production facilities were "stacked" in order of economic merit until they reached a sufficient volume to supply the demand for electricity: the last facility called upon in this stack, described as "marginal", then determines the price of electricity for the given hour. In practice, market players optimise their purchases/sales at the level of their production and consumption portfolio, and not at the level of each individual unit, but the price still tends to form around the offer price of the marginal unit necessary to satisfy the supply-demand balance. This ensures an economically optimal allocation of production.

At the European level, this price formation mechanism takes into account the balance between supply and demand in each price zone (which generally corresponds to a country), as well as the exchange capacity between these zones. The result is an optimisation, on a European scale, of the use of the resources available in the short term. As fossil-fired generation is needed most of the time to balance supply and demand on a European scale (despite a marked reduction

Figure 3.22 – Illustrative example of the order of economic precedence and electricity price formation: before the energy crisis, at the height of the energy crisis in 2022, and in early 2024. The diagram is just a guide – the generation volumes are not to scale



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in the European generation mix in recent years), the hourly spot price is generally based on the variable cost of the corresponding generation resources. For example, changes in the price of electricity are correlated with changes in the price of fuels such as gas and with the price of CO_2. Even if the proportion of fossil-fired production in French electricity generation is low, it still plays an important role in electricity pricing, because interconnection with the rest of the European grid means that electricity prices in France also depend on fossil-fired generation located abroad and traded on the market. In 2024, however, spot prices in France were often below the production costs of fossil-fired plants, reflecting both the exceptional decarbonisation of the French mix and the gradual decarbonisation of the mix in other European countries.

Electricity trade

2024 ELECTRICITY REVIEW

The years from 2021 to 2024 demonstrated the capacity of the European power system and its market architecture to ensure optimum resource use, making it a major asset in the continent's energy transition

The power systems of the different European countries are now widely interconnected. Most countries in continental Europe are part of the synchronous continental power system, which shares the same 50 Hz electrical frequency at all times.

The development of interconnections between member states has long been a priority of the European Union's energy policy. By making it possible to take advantage of the synergies between national energy mixes by pooling generating capacity, electricity trade benefits the European community in three ways: by reinforcing the security of the electricity supply and the operational security of interconnected systems, by reducing production costs on a continental scale through the use of the least expensive (and lowest-carbon) production resources at any given time, and by making it possible to integrate greater volumes of decarbonised energy, a factor that is now essential for the continent's energy transition.

This pooling makes it possible to benefit from the differences in consumption profiles between European countries. Consumption peaks do not occur at the same time of day or in the same season in different countries, for example (peaks on summer afternoons in Spain, on winter evenings in France, on winter mornings in Scandinavian countries). To a lesser extent, pooling also enables full advantage to be taken of the abundant production of variable renewable energy.

The European electricity market helps to minimise the cost of operating the power system at the European level. However, the very high levels of electricity prices reached in 2022, which exerted intense pressure on consumers, public finances and the economy in general, led to the emergence of a debate at the European level on the subject, which culminated at the end of 2023 in an agreement on a reform of the organisation of markets in Europe[1]. The aim was to bring the bills paid by electricity consumers more into line with production costs while maintaining the efficiency of the short-term market and strengthening incentives for investment in the new electricity generation facilities required for decarbonisation. The foundations of the short-term spot market remain unchanged, and the emphasis

1. The reform was published in the Official Journal of the European Union in July 2024. Certain provisions adopted through the Regulation are directly applicable; others adopted through the Directive have yet to be transposed into national law. Directive (EU) 2024/1711 of the European Parliament and of the Council of 13 June 2024, and Regulation (EU) 2024/1747 of the European Parliament and of the Council of 13 June 2024.

is on developing futures markets and regulations to encourage public or private guaranteed price contracts between generators and consumers.

The operation of the power system on a European scale is now a reality, which has proved essential when the French power system has found itself in a situation of supply pressure, as was the case in the autumn and winter of 2022/2023. Over the past ten years, the strengthening of interconnections between countries and the development of variable renewable energy have led to a significant increase in electricity trade between European countries, and France is no exception. Located at the intersection of several electrical peninsulas (Iberian Peninsula, Italy, Great Britain) and with significant installed generating capacity, **France participates fully in European trade.** France's energy mix, made up mainly of nuclear, hydro and other renewables, is on the whole more competitive than that of most of its neighbours. As a general rule therefore, in the absence of pressures on the national supply-demand balance, the power system is a significant exporter across the scale of a year: supply from French nuclear and renewable generating capacity is called on by the markets before thermal production units, including those in neighbouring countries (within the limits allowed by interconnection capacity).

From both the technical and economic points of view, it would not be optimal to size the production fleet to systematically and fully cover periods of high consumption. This is all the more true in France, where consumption is highly sensitive to temperatures (see the Consumption chapter). So if there is tension in the supply-demand balance, even outside a crisis situation, it is normal for the country to find itself in an importing position from time to time. This is also the case when it is simply cheaper to import, as happens across certain borders when renewable generation is high, particularly with Spain and Germany, and more rarely with Great Britain (see below, Details by border). France's interconnection with other European countries, and its full integration into the market mechanisms governing trade, mean that it can:

- Find economic outlets for its low-carbon generation and contribute to decarbonising the European mix on one hand;
- Ensure its security of supply at a much lower cost than if the country had to rely solely on national generation resources at all times, on the other.

The series of events seen in France since the end of 2021 points to a clear conclusion: the European short-term electricity markets have demonstrated their efficiency, their responsiveness, and their ability to reconfigure trade rapidly in response to the physical needs of the system in times of crisis, as well as to direct electricity flows in an economically optimal way, even when the fundamentals are more favourable.

During 2022, for example, flows aligned themselves with the physical needs of the power system: the balance of French trade tipped towards imports during the year, as national generation fell due to the unavailability of a large number of nuclear reactors and reduced hydropower generation. In 2023, the improvement in the fundamentals of the supply-demand balance in France led to an equally rapid reversal in the direction of trade, enabling France to regain its role as Europe's leading electricity exporter as quickly as it had been lost. **Once again in 2024, France took full advantage of its status as Europe's leading generator, deeply integrated into the internal energy market: the country recorded the highest annual export balance in its history, just two years after one of the most serious crises ever to affect its generating fleet.**

Over the last few years, the European short-term electricity market has given rise to legitimate questions about its ability to support a large-scale, economically and socially sustainable electrification policy. One of these questions concerns the link between the short and the long term, and specifically the ability of short-term prices to provide the signals needed for long-term investment to ensure both the optimal development of the fleet in the context of the energy transition and security of supply. The second concerns the link between the wholesale and retail markets, i.e. protection for consumers from shocks affecting wholesale prices, and the introduction of instruments to make electricity prices less dependent on the price of fossil fuels.

Though these questions need to be addressed, they should not obscure the essential result of twenty years of integration of Europe's power systems: with the internal electricity market and the infrastructure that underpins it, France and the European Union have a physically and economically efficient tool that enables them to ensure their security of supply at the best possible cost. Faced with the challenge of the energy transition, growing geopolitical tensions and the rise of new forms of protectionism, this is a major asset.

In 2024, France recorded the highest net export balance in its history

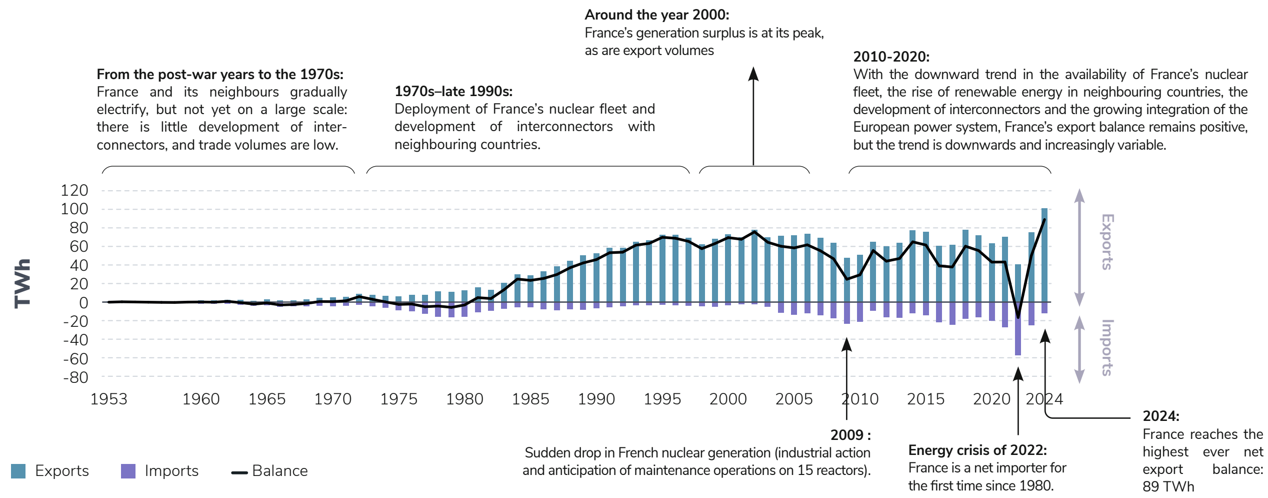
France's net balance in 2024 was 89.0 TWh of exports. This is the highest annual balance ever recorded; the previous record, set in 2002, was 76 TWh. France was a net exporter to all its neighbours: to Germany and Belgium (27.2 TWh), Italy (22.3 TWh), Switzerland (16.7 TWh) and Great Britain (20.1 TWh); and to a lesser extent to Spain (2.8 TWh).

There are many factors that have led to such a high volume of exports. In the short term, the primary determinant is the level of competitive, low-carbon domestic generation (see the Generation chapter, forthcoming): the continuing recovery in nuclear output, abundant hydropower and an increasingly important contribution from wind and solar power in recent years. The second determinant is domestic electricity consumption, which, although its downward trend has stopped and consumption levels stabilised in 2024, is still below pre-crisis levels (see the Consumption chapter, forthcoming).

In the longer term, the record balance for 2024 also reflects the development of interconnections and the growing integration of the internal electricity market. Between 2002 (the year of the previous record) and 2024, as a result of European integration, the capacity for trade between France and its neighbours has increased considerably, providing ever more outlets for French generation when there is a surplus.

On a monthly scale, France maintained a clear export position throughout 2024, continuing the trend observed since mid-2023. Between January and the end of April, trade was mainly export-oriented, in the usual proportions. From May onwards, however, historically high levels of exports were recorded. This jump was the result of particularly favourable fundamentals in France: the seasonal fall in consumption as winter ended; good nuclear availability; particularly abundant hydro generation; a significant contribution from wind and solar. From mid-November, the time of year when French consumption picks up again, exports returned to the level of the first quarter: high, but with occasional imports, particularly from Germany, the UK and Spain, and especially during periods of very high wind production in these countries.

Figure 4.1 – Electricity trade between France and its neighbours between 1953 and 2024



When we compare 2024's flows with the previous export record of 2002, we see a variation in their geographical distribution. The borders where exports have increased are those with Great Britain and, above all, with Germany and Belgium. **On the British border,** this is largely due to the fact that exchange capacity almost doubled between 2002 and 2024, with the construction of two new direct current interconnectors. **On the border with Germany and Belgium,** as well as infrastructure development, the integration and strengthening of trade mechanisms have enabled trade to increase and flow more smoothly.

Figure 4.2 – Monthly electricity trade between France and neighbouring countries in 2024

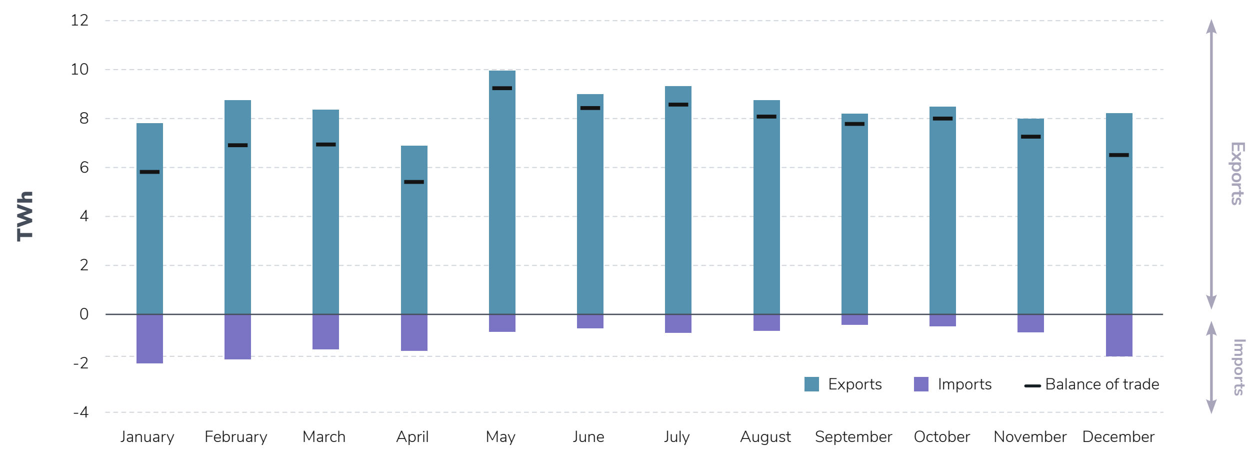
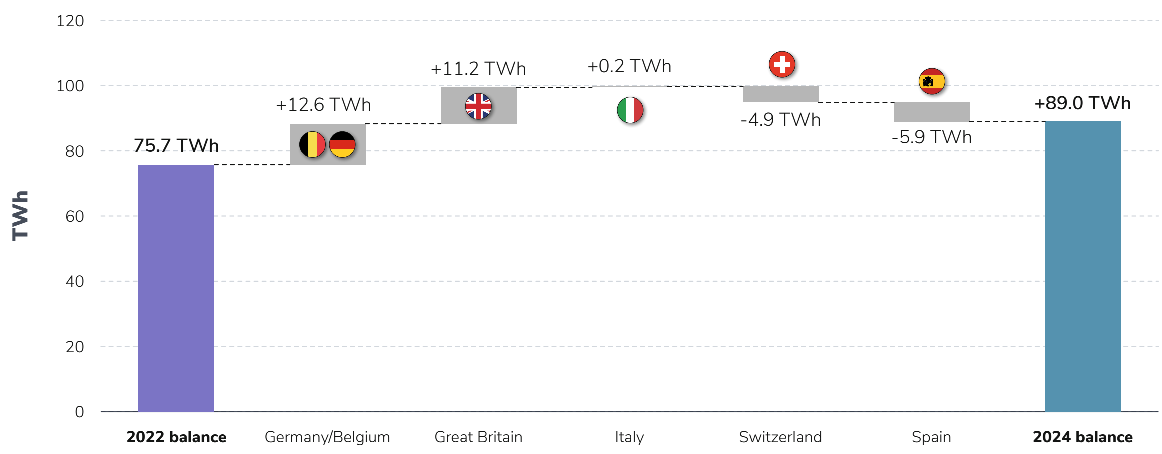


Figure 4.3 – Contribution of the various borders to the development of the balance of French electricity trade between 2002 and 2024

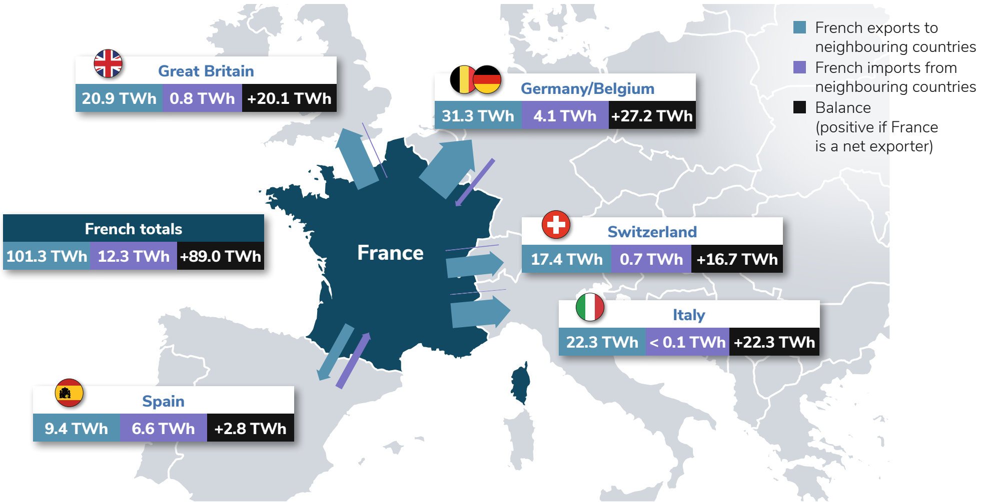


On the borders with Italy and Switzerland, trade volumes in 2024 were respectively equal to and lower than in 2002. In the case of Switzerland, this is partly a reflection of the increased competitiveness of the Swiss generating fleet (see below).

Finally, on the Spanish border, the trends over the last 20 years have been particular and composite: there has been significant growth in interconnectors between the two countries, but at the same time the Spanish mix has become much more competitive thanks to the development of renewable generation capacity. As a result, trade volumes have risen sharply, but have also largely rebalanced, leading to a reduction in France's net export balance across this border between 2002 and 2024.

France was an exporter across all its borders

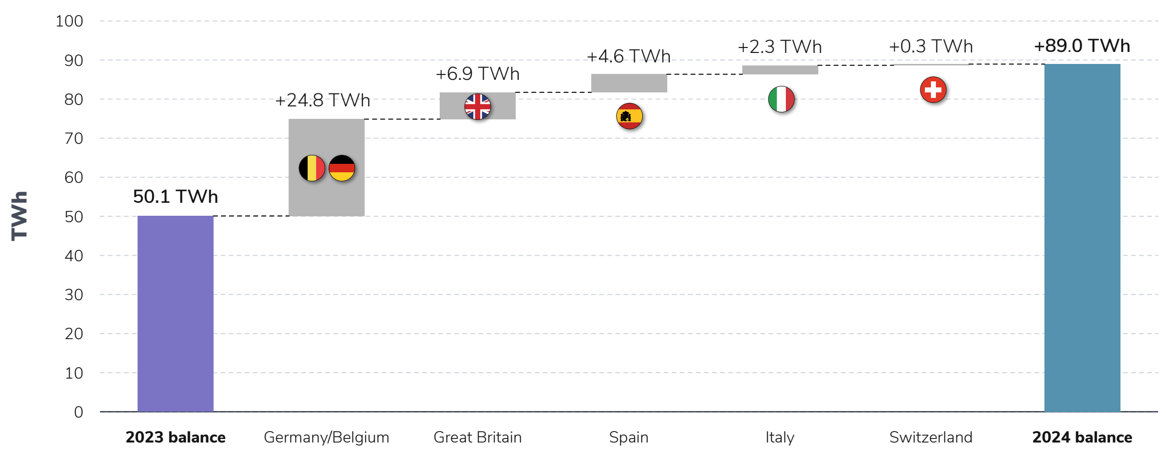
Figure 4.4 – Electricity trade between France and neighbouring countries in 2024



France was an exporter across all its borders: exporting strongly to Germany and Belgium, Switzerland, Italy and Great Britain; also exporting across the Spanish border, but to a lesser extent due to more balanced trade.

Most of the growth in electricity exports from France between 2023 and 2024 was driven by exports to Germany and Belgium (+24.8 TWh compared with 2023). To a lesser extent, trade with Great Britain, Spain and Italy also contributed to the increase in

Figure 4.5 – Contribution of the various borders to the development of the balance of French electricity trade between 2023 and 2024



the annual balance (+13.8 TWh between them compared with 2023). At the Italian border, the increase in exports was partly the result of increased trade capacity. Finally, exports to Switzerland were very close to those seen in 2023.

Spain

French and Spanish electricity consumption is countercyclical on an annual scale. For example, France usually exports large volumes to Spain in the summer, when consumption is at its highest in Spain, mainly due to the use of air conditioning. In winter, the situation tends to be slightly more balanced: France regularly imports from Spain during peaks in French consumption, but overall remains a net exporter in terms of volume.

However, the dynamics of trade across the Spanish border have been changing rapidly in recent years. Until the mid-2010s, France was a net exporter. Trade then gradually began to balance out, leading to an annual net balance close to equilibrium by 2023. This rebalancing is essentially due to rapid changes in the Spanish generation mix: between 2014 and 2024, Spanish wind generation capacity increased from 22 GW to almost 32 GW, and solar generation capacity from 7 GW to 31 GW (see the Europe chapter, forthcoming). It has also been facilitated by the growing integration of trade across this border, as well as by the significant development of connection capacity, which almost doubled in 2015 with the commissioning of the Baixas–Santa Llogaia direct current interconnector. In addition to the increase in capacity made possible by the new transmission infrastructure, the mechanisms governing trade on the Franco-Spanish border are increasingly coordinated and flexible, and trade is therefore increasingly fluid. All these factors – new infrastructure, market integration, profound transformation of the generation mix – apply at all the borders (with the notable exception of Great Britain as far as market integration is concerned – see below), but they are particularly marked in Spain.

Figure 4.6 – Annual distribution of electricity trade between France and Spain over the period 2001-2024

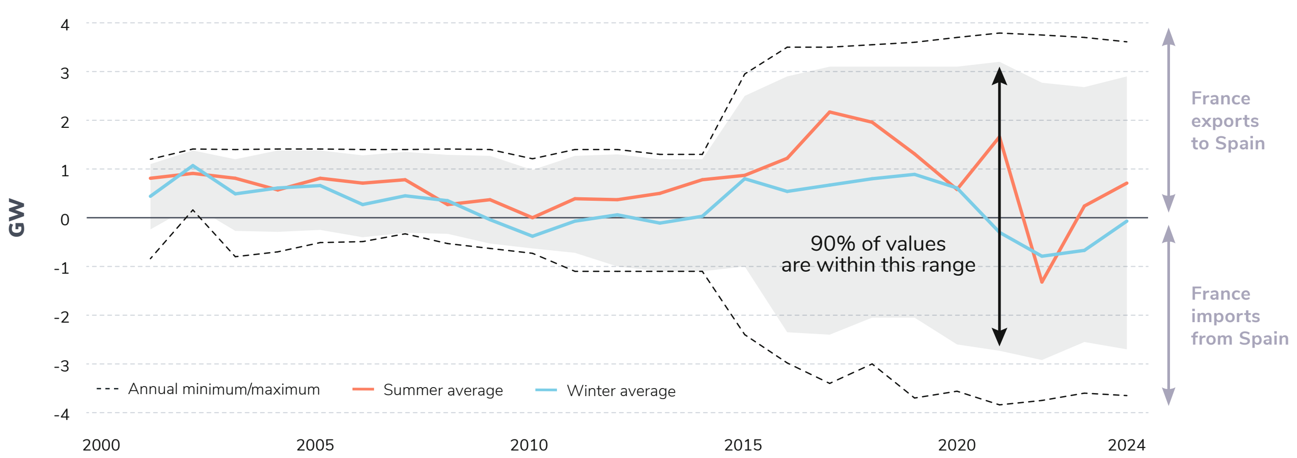
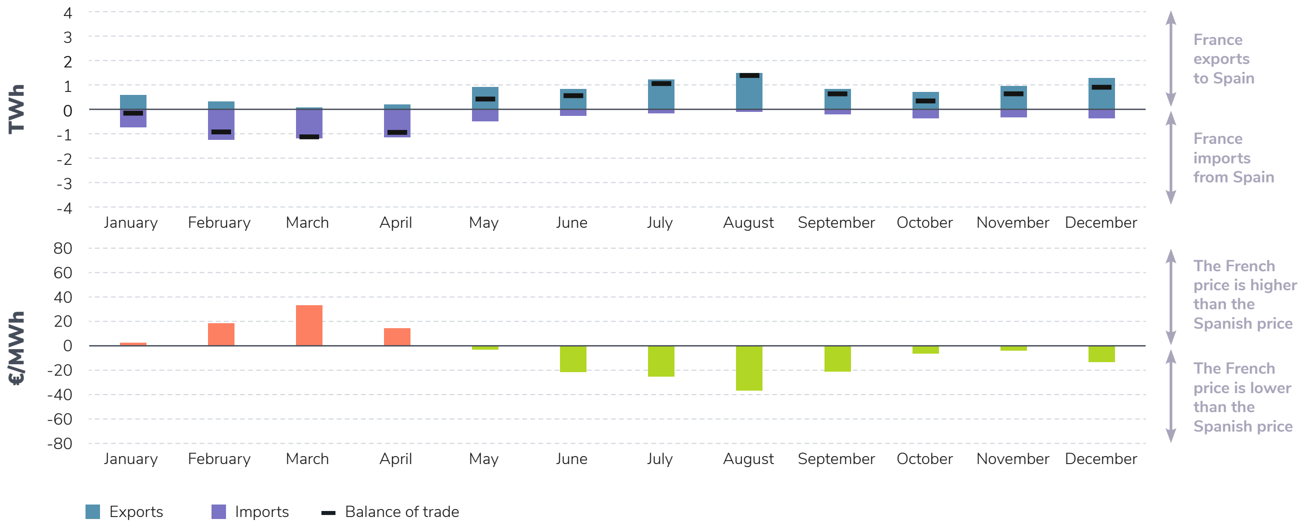


Figure 4.7 – Monthly volumes of electricity trade between France and Spain (top) and monthly average differences between French and Spanish spot prices (bottom) in 2024



In 2024, France regained a net export position over the year in relation to Spain, with a balance of +2.8 TWh.

However, the dynamic shifted over the course of the year: until April, France was a net importer from Spain on a monthly basis, in line with the position at the end of 2023. The main reason for this situation in the first third of the year was the extremely high level of wind generation throughout the Iberian Peninsula (see the Europe chapter), with the surplus exported at full capacity to France and beyond.

From May onwards, the direction of trade was reversed due to increased consumption in Spain for seasonal reasons and lower consumption in France at the end of the heating season, as well as continued high nuclear availability and extremely abundant hydropower output in France (see the Generation chapter, forthcoming).

The rapid transformation of Spain's electricity mix, its unique position as a peninsular country and the frequent reversals in the direction of trade between France and Spain raise questions about the determinants of energy flows between the two countries. As we might expect, the direction of trade with France is regularly influenced by the volume of solar generation in Spain, although this is not systematic. Wind power on the peninsula has a more decisive effect on the direction of flows across the Franco-Spanish border, in terms of both frequency and volume. When wind generation is high in Spain, the country is mostly a net exporter.

Figure 4.8 – Volumes of trade between France and Spain according to Spanish wind generation

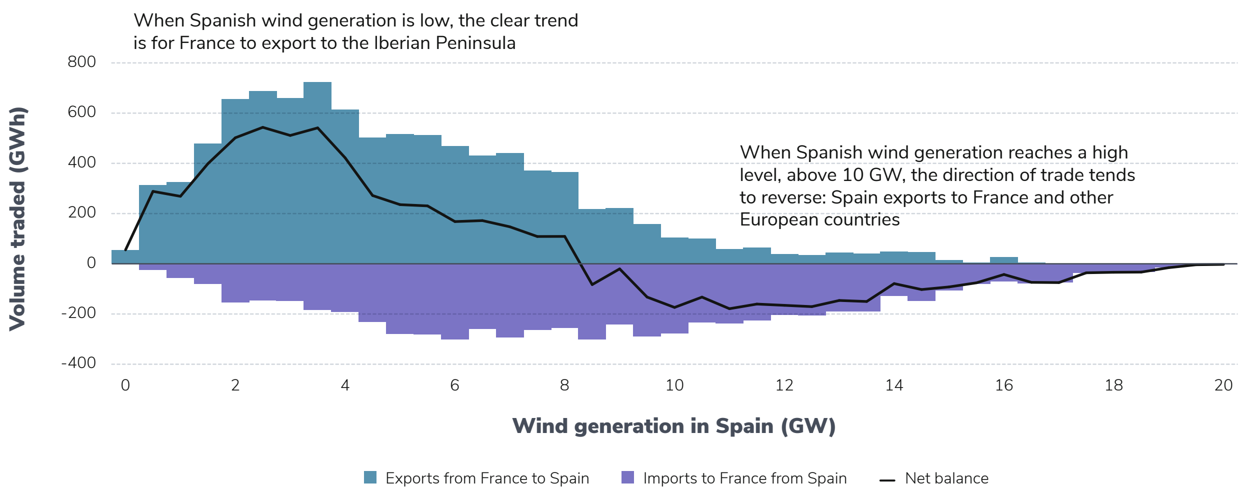
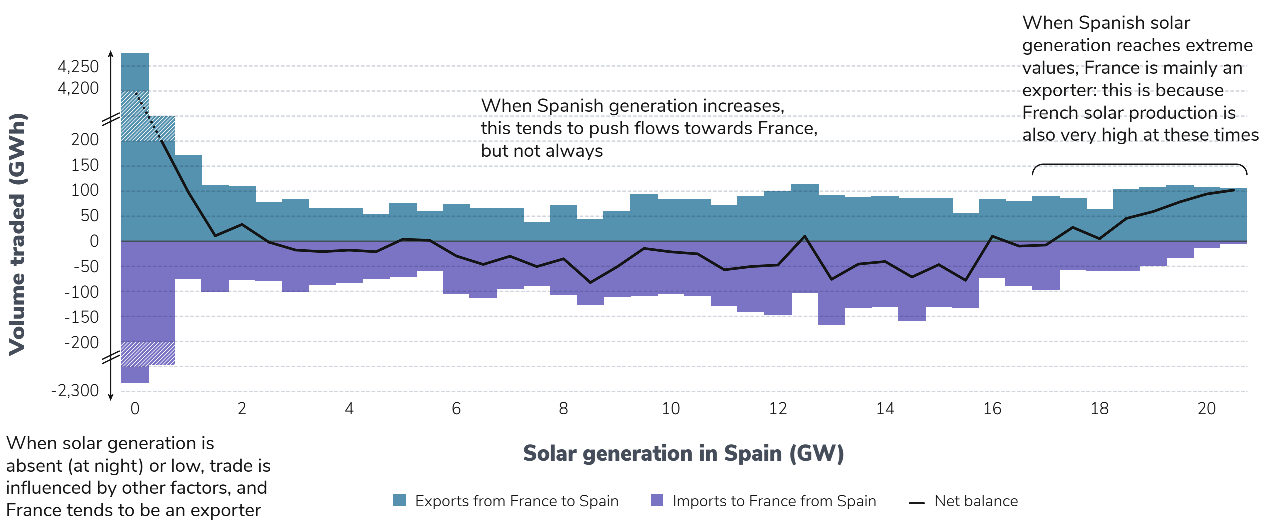


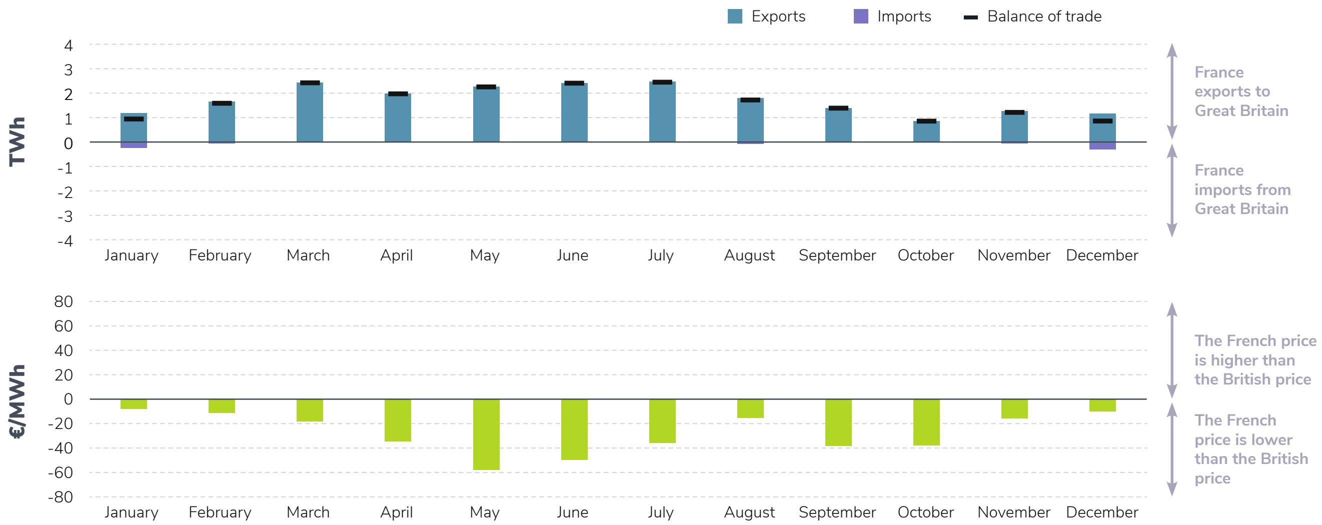
Figure 4.9 – Volumes of trade between France and Spain according to Spanish solar generation



Great Britain

The British power system is unique in that it is both insular and asynchronous with its neighbours. This leads to specific, significant constraints, which limit the overall competitiveness of British electricity generation. Despite a mix that includes a rapidly growing proportion of low-carbon energy (mainly wind, but also nuclear and, to a lesser extent, solar, hydro and biomass), the UK only exports to France when there is significant pressure on the French supply-demand balance. This was the case, for example, at the height of the French energy crisis

Figure 4.10 – Monthly volumes of electricity trade between France and Great Britain (top) and monthly average differences between French and British spot prices (bottom) in 2024



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Background: Why do we talk about the "British" power system?

We refer to trade with Great Britain, and not with the United Kingdom, because the power systems of the island of Great Britain and of Northern Ireland are not synchronous, are not managed by the same transmission system operator (National Grid for Great Britain and SONI for Northern Ireland), and do not belong to the same market area. The Northern Irish power system is integrated with the Republic of Ireland's system; the two Irish transmission system operators (EirGrid for the Republic of Ireland and SONI for Northern Ireland) have jointly operated a single market area for the entire island of Ireland, the Single Electricity Market, since 2007. The Irish network is interconnected with the British network by two DC links with a capacity of 500 MW each: the East-West Interconnector, between the Republic of Ireland and Wales, and the Moyle Interconnector, between Northern Ireland and Scotland. A third interconnector, Greenlink, between the Republic of Ireland and Wales, is due to come on stream in early 2025, with a capacity of 500 MW. A fourth HVDC link is also planned, between the Republic of Ireland and France this time: the Celtic Interconnector, capacity 700 MW, with commissioning scheduled for 2027.

in the summer of 2022. Outside these periods, Great Britain is generally a net importer from France.

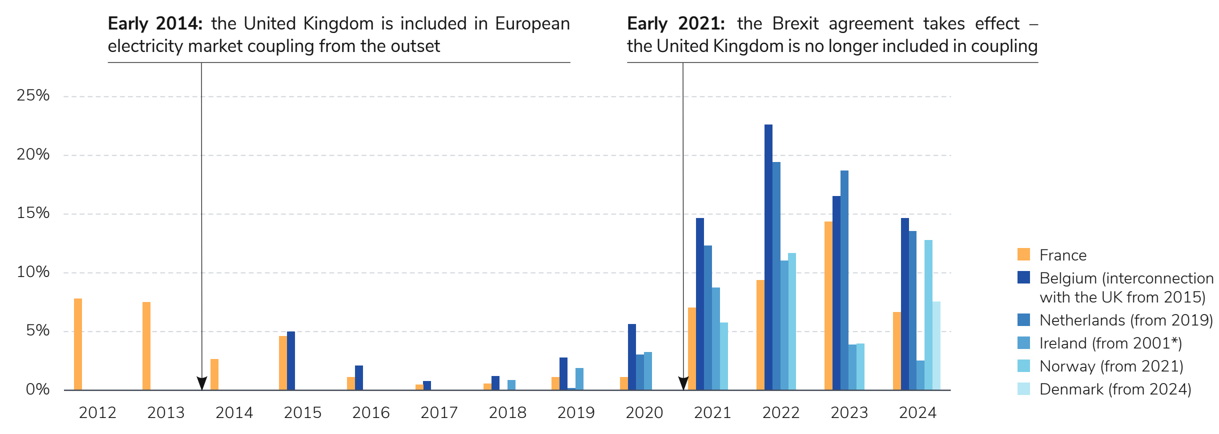
In 2024, as there was a considerable surplus of French generation, trade across the British border was almost unilaterally in the direction of exports. The annual balance amounted to 20.1 TWh, the highest annual total since trade between the two countries began in 1986[3]. This record owes much to the increase in trade capacity since 2022.

Since the United Kingdom's exit from the European Union in 2020, another peculiarity of trade with Great Britain is the lack of coupling with continental markets. Among other things, this de-optimises trade compared with the implicit coupling that exists between the other market areas in Europe (this is also the case for Switzerland; Norway, on the other hand, by virtue of its Association Agreement with the European Union, is integrated into the coupling of the short-term markets).

By comparing trade and spot prices in each country for each hour and for each of Great Britain's borders, we can determine the proportion of the time for which trade is "correctly" oriented, i.e. from the zone with the lowest price to the zone with the highest price. Where this is not the case, the trades are said to be economically "counter-intuitive", and therefore sub-optimal: energy is being imported from where it is more expensive to where it is cheaper.

This type of situation is likely to occur on all borders, at the margins, including borders that are highly integrated with optimised trade mechanisms; one of the main reasons for this is the coexistence of several trade time scales, which can lead to a reversal in the direction of trade across the border if there is significant variation in the determinants of the supply-demand balance in near-real time. However, it is clear that this phenomenon is much more frequent at the British border than across the others: the absence of integrated, optimised and coordinated trade mechanisms reduces the ability of players to respond correctly to economic signals, and thus to the physical underpinnings of the system. This is true for trade with France, but also with its other neighbours. We can clearly see the effects of introducing market coupling in 2014, on one hand, and the United Kingdom's withdrawal from it in 2021, on the other.

Figure 4.11 – Proportion of the value traded by the United Kingdom in the opposite direction to the economic logic (from the country with the highest price to the country with the lowest price), by border, as a proportion of the total value of energy traded across the border concerned



* Interconnection from 2001, but price data for Ireland are only available from 2018

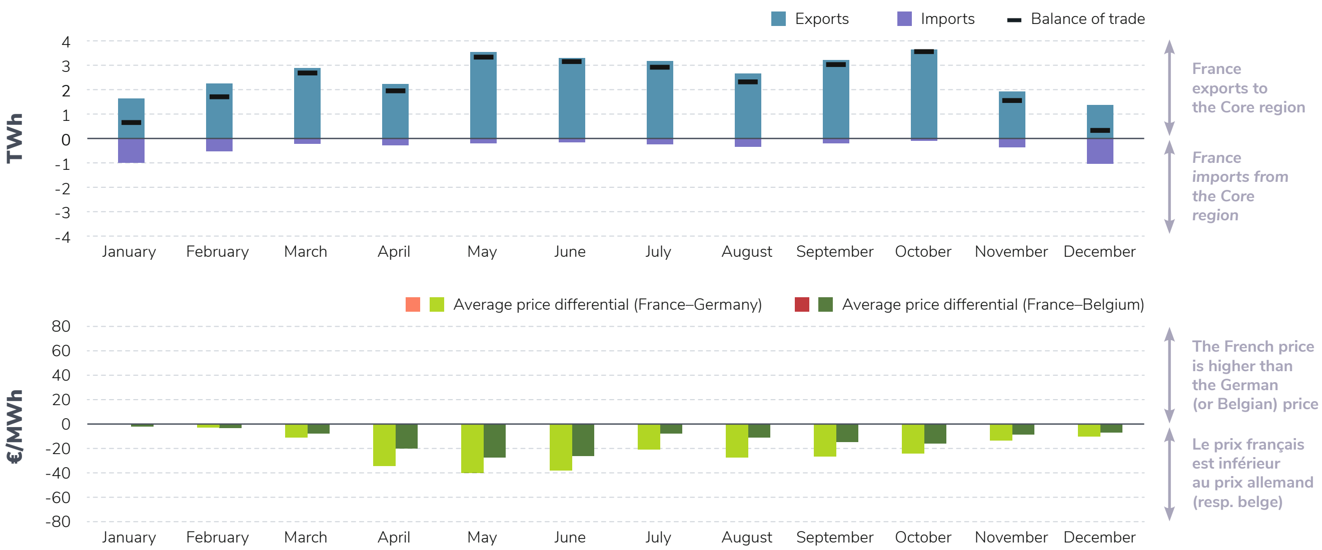
Core region (Germany and Belgium)

Trade between France and its neighbours in the Core region, i.e. Germany and Belgium, is by far the largest in terms of volume; this is also the border where trade capacity is the highest, and where market integration is the most advanced[2]. Lastly, trade with this region is also the most variable: this is partly due to the high degree of integration of trade mechanisms, and partly to the generation mix in the region, which includes a high proportion of variable renewable energy.

Since 2001, France has traded 580 TWh with Germany and Belgium; for comparison, the total volume traded with Italy over the same period was 449 TWh, 429 TWh with Switzerland, 302 TWh with Great Britain and 247 TWh with Spain. The variability of trade between France and Germany and Belgium, as well as the complementary nature of their respective generation mixes over the long term, is clear from the net cumulative trade balance between the two regions over the entire period: between 2001 and 2024, it amounts to a mere +57 TWh, compared with the almost 600 TWh traded.

On more granular time scales, trade between France and the Core region is characterised by greater volatility than across other borders. Depending on the supply-demand balance situation and the generating costs on either side of the border, trade is likely to change direction quickly and significantly; in 2024, for example, around thirty situations arose where France's trade with Germany and Belgium varied by nearly 10 GW over the course of a three-hour period[3]. This trend has been accentuated since 2015 as part of the integration and increasing fluidity of exchanges in the *Central Western Europe* zone first, then in the Core region from June 2022. On an annual basis, since 2001, France has oscillated between a position of being a net importer and a net exporter vis-à-vis Germany and Belgium. It is usually in summer, when available production in France far exceeds consumption, that exports to this region are highest. In winter,

Figure 4.12 – Monthly volumes of electricity trade between France and the Core region member countries (top) and average monthly differences between French spot prices and spot prices in these countries (bottom) in 2024



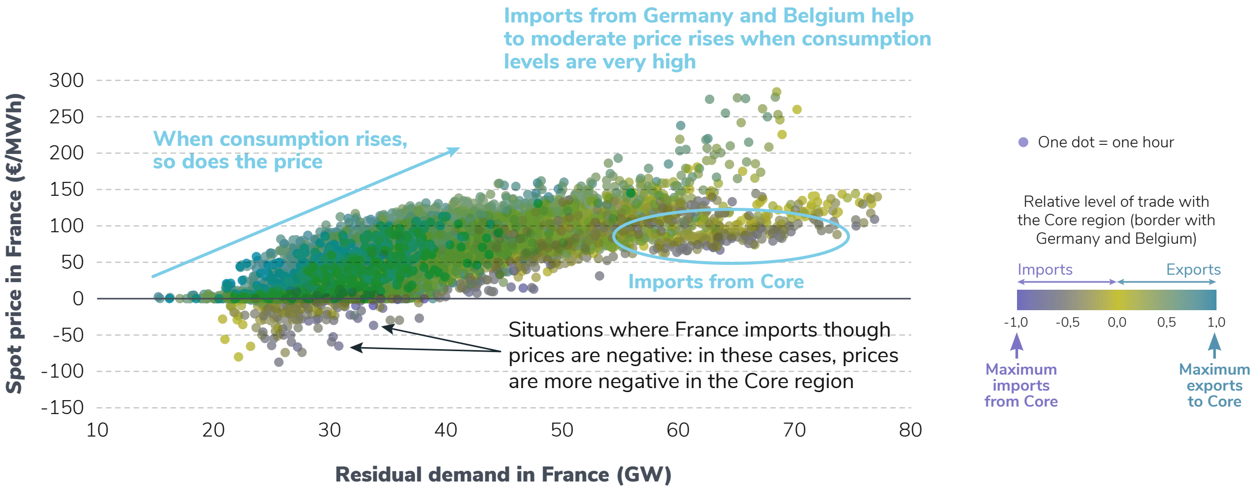
2. The border with the Core region is the only French border on which exchange capacity is determined using a so-called "flow-based" approach, which maximises capacity compared with the simpler approaches used on the other borders.
3. For comparison, the maximum variation in the balance over three hours observed on the other borders is 7 GW on the British border, and less than 6 GW on the others. The average variation in the balance over a period of three hours at the border with the Core zone is 1.6 GW, while it is less than 800 MW on the others.

on the other hand, France tends to be an importer – the winter of 2023-2024 being the exception for the first time since the winter of 2006-2007.

In fact, France exported a historically high volume of energy to Germany and Belgium in 2024, with a net balance of +27.2 TWh (the highest annual net export balance recorded from 2001 to 2023 was 15.9 TWh, in 2003). Between February and November, France exported massively; trade was most balanced in mid-winter, in January and December, but the balance remained slightly positive.

In general, the highest spot prices occur when the level of residual demand, which has to be covered by dispatchable resources, is high. In these high-consumption situations, trade with neighbouring countries helps to limit the rise in prices, both for France and for the other countries, by ensuring that the least costly generating resources are used throughout the interconnected system. In 2024, trade between France and the German/Belgian borders was frequently close to saturation in the export direction, when nuclear and renewable generation was abundant and consumption normal in France. These exports helped to limit the rise in prices in the neighbouring countries. Conversely, when consumption in France was at its highest, trade with the Core region was reversed and France was able to import significant volumes as needed to satisfy its own consumption or to re-export to other countries, thus avoiding the need to use less competitive resources in France or in third countries. **This brief analysis illustrates an important point: imports/exports between European countries, which vary hour by hour, are essentially part of a logic of economic optimisation on the scale of the European grid. They should not be interpreted in terms of security of supply (an import does not generally reflect a "physical need" on the part of the importing zone).**

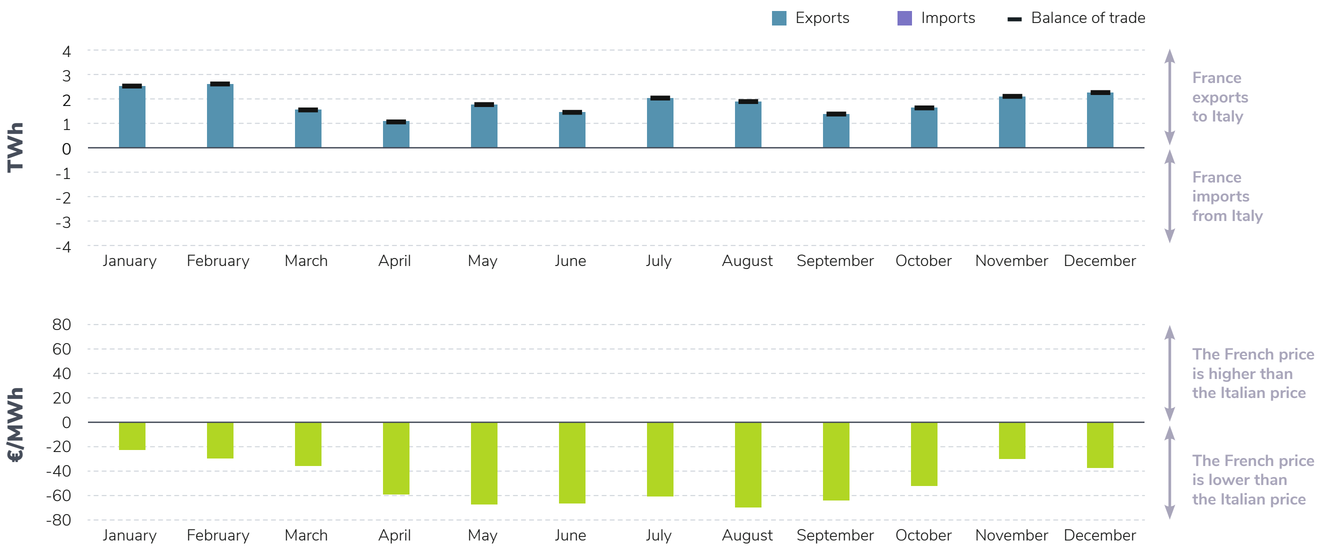
Figure 4.13 – Analysis of the influence of residual demand and the level of trade with the Core region on the French spot price in 2024



Italy

Historically, trade between France and Italy has generally flowed towards Italy. Across this border, France has been a net exporter every year since 1979. Italian generation is still very dependent on fossil-fired thermal plants, particularly gas, and is structurally less competitive than its neighbours'. One of the reasons for this is the price of gas supplies on the peninsula, which is consistently higher than in neighbouring countries. Since the late 1980s, electricity imports have accounted for between 10 and 15% of Italy's domestic electricity consumption[4]. In 2024, the dynamic was in line with historical trends: France exported massively to Italy, with a net annual balance of 22.3 TWh.

Figure 4.14 – Monthly volumes of electricity trade between France and Italy (top) and monthly average differences between French and Italian spot prices (bottom) in 2024

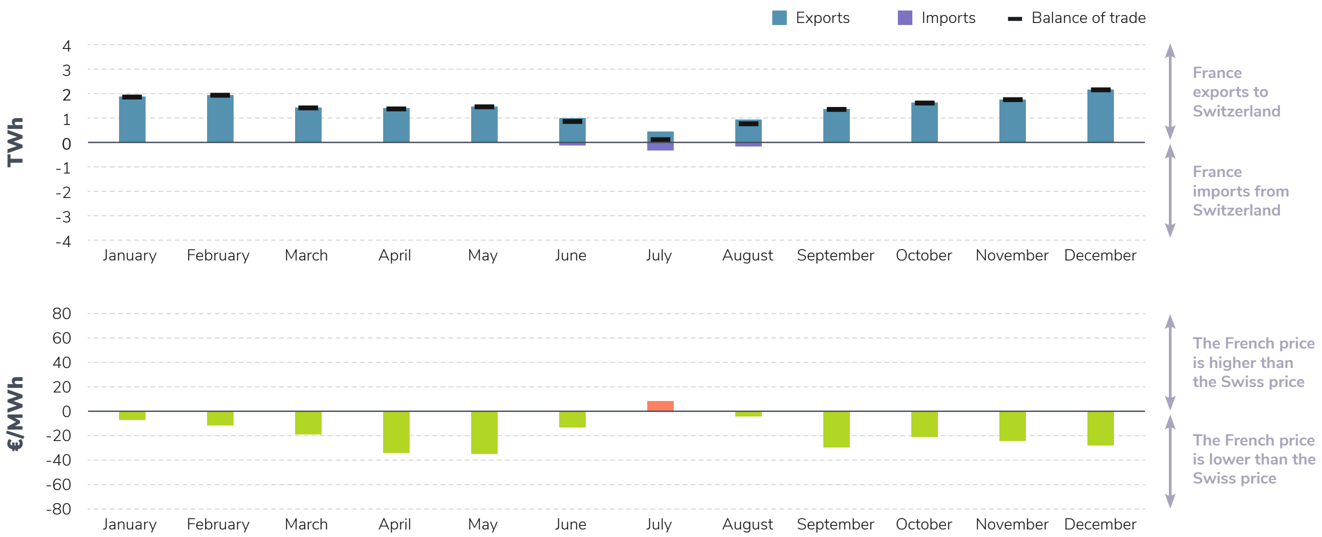


4. Terna, *Dati Storici 2023*.

Switzerland

France has usually been a major exporter to Switzerland since the early 2000s. From the mid-2010s onwards, the competitiveness of the Swiss generating fleet, which was already high due to the predominance of hydro and nuclear power, increased further, partly through the development of solar capacity. This has led France to import more often, particularly in summer. Over the course of 2024, trade across the Swiss border was still strongly oriented towards exports, with an annual balance of 16.6 TWh. In addition, Switzerland plays the role of a "transit country", given its central position in Europe: a proportion of the flows exported to Switzerland was directed to other neighbouring countries, such as Italy (for more on this point, see the analysis in the next section). From March to June, export volumes to Switzerland were below the usual maximum levels. There was also a marked dip between June and August. In July, the net balance was even close to equilibrium. This trough can be explained by the fundamentals in Switzerland – particularly hydropower and, to a lesser extent, solar generation, which is now substantial in the country in summer.

Figure 4.15 – Monthly volumes of electricity trade between France Switzerland (top) and monthly average differences between French and Swiss spot prices (bottom) in 2024

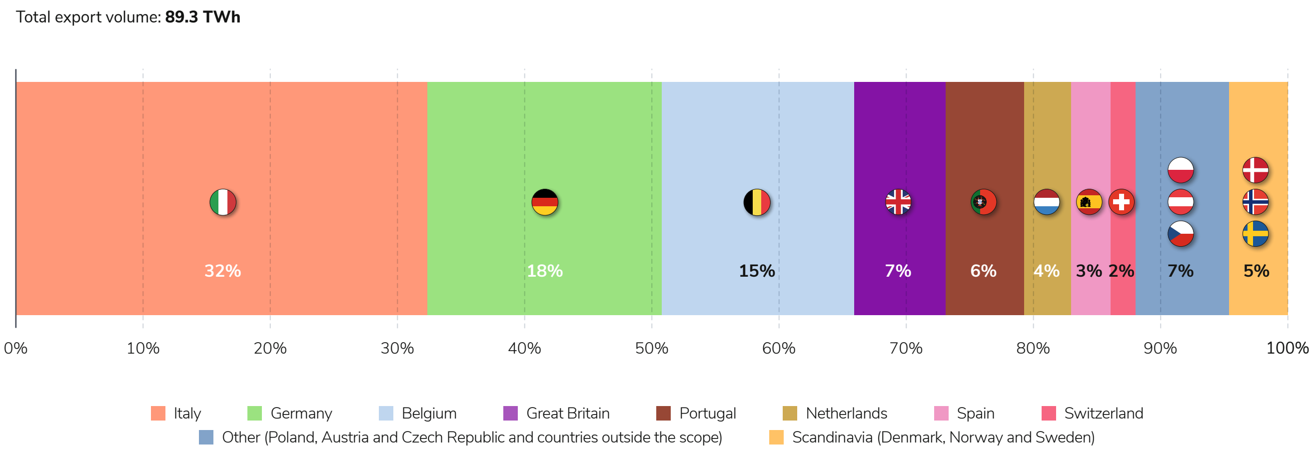


French exports spread beyond the neighbouring countries

As the European network is interconnected, we might intuitively assume that France's trade with its direct neighbours, as presented in the analysis by border, has components originating in or destined for more "distant" countries. Schematically, if, over a given period of time, France imports electricity from Spain but Spain imports it from Portugal at the same time, then it may be legitimate to consider that, over the period in question, part of the electricity exchanged between France and Spain is attributable to production in Portugal. Similarly, if France exports electricity to Italy but imports it at the same time from Germany, it may be legitimate to consider part of these exports as coming from Germany and not from French production. The results of the analysing the trade using this approach, known as "flow tracing", with a European scope extended to 15 countries[5], are presented here. These are not measured data but the results of modelling[6], which can however provide additional information useful for understanding the operation of the European power system.

This analysis shows, firstly, that a large proportion of France's imports "pass through" the country, and do not supply French consumption. When France imports from certain neighbours while being a net exporter, i.e. re-exporting a higher volume to other neighbours, we consider in this analysis that the volumes imported are re-exported to these neighbours. The volume of imports supplying French consumption, as defined by this approach, is thus extremely low: less than 1 TWh over the year, given that France was a net exporter almost 98% of the time.

Figure 4.16 – French exports within the extended scope in 2024



5. The 15 countries are: Spain, Portugal, Italy, Switzerland, Austria, Germany, the Czech Republic, Poland, Belgium, the Netherlands, Sweden, Norway, Denmark, Great Britain and Ireland, but Ireland was excluded due to the insufficient quality of the data available. A wider group of countries, extending as far as Greece and Finland, was also studied: the inclusion of countries further away than the 15 selected, and whose power systems are relatively small compared with France's, does not substantially alter the results presented here.
6. The foundations of the approach used in this section are set out in detail in Bialek, J., *Tracing the flow of electricity*, 1996.

Looking in more detail, we can see that exports to Switzerland are much lower according to the "flow tracing" analysis than those identified in the bilateral analysis for borders with direct neighbours. Switzerland is a transit country[9]: the energy exported from France is largely re-exported to Italy. Taking this into account, Italy accounts for 32% of French exports (29 TWh), compared with 22% if we only consider direct bilateral flows. The leading non-contiguous country importing from France is Portugal, with 6% of the volume (5.5 TWh), i.e. more than French exports to Spain. This indicates that Spain frequently acts as a transit country between France and Portugal. To a lesser extent, the situation is similar for Belgium, which handles flows from France to the Netherlands and Germany[7]. Finally, around 12% of France's exports, or 11 TWh, are destined for the rest of Europe, and particularly Central Europe and Scandinavia: Denmark, Norway, Poland, Austria, Czech Republic, etc.

All these considerations underline once again the highly interconnected nature and the specifically European operation of the electricity network and energy trade in Europe.

7. See the *Europe* chapter.

With the transformation of the French and European electricity mix, the French power system is playing an increasingly important role as an "electricity crossroads"

The transformation of European countries' generation mixes is likely to lead to a variety of trade regimes across the continent. These regimes will be determined by each country's mix and the synergies between them, particularly in terms of variable renewable generation. Because of its position as an "electricity crossroads" between its neighbours to the north, south-west and east, France is likely to play the role of a transit country for these different trade systems. The prime example is the trade between the Iberian Peninsula and the Germany/Benelux region, both of which already have significant installed solar and wind capacity.

Between 2001 and 2020, through traffic was concentrated mainly in a loop from Germany to Italy and Switzerland via France. The 2010s saw the beginnings of new, more numerous and diversified schemes. In the 2020s, and particularly 2024, these new trade patterns developed further; the emergence of trade through France from Spain to the rest of Europe was particularly notable in 2024.

The proportion of imports from the Iberian Peninsula passing through France on their way to other European countries has been high since 2016: in 2024, it reached 98% (93% considering only re-exports across borders other than those with Switzerland and Italy). Even in 2022, at the height of the energy crisis, more than half of all imports from Spain were re-exported – that year mainly to Switzerland and Italy.

Figure 4.17 – Trends in flows transiting the French power system over recent decades (averages over the period in question)

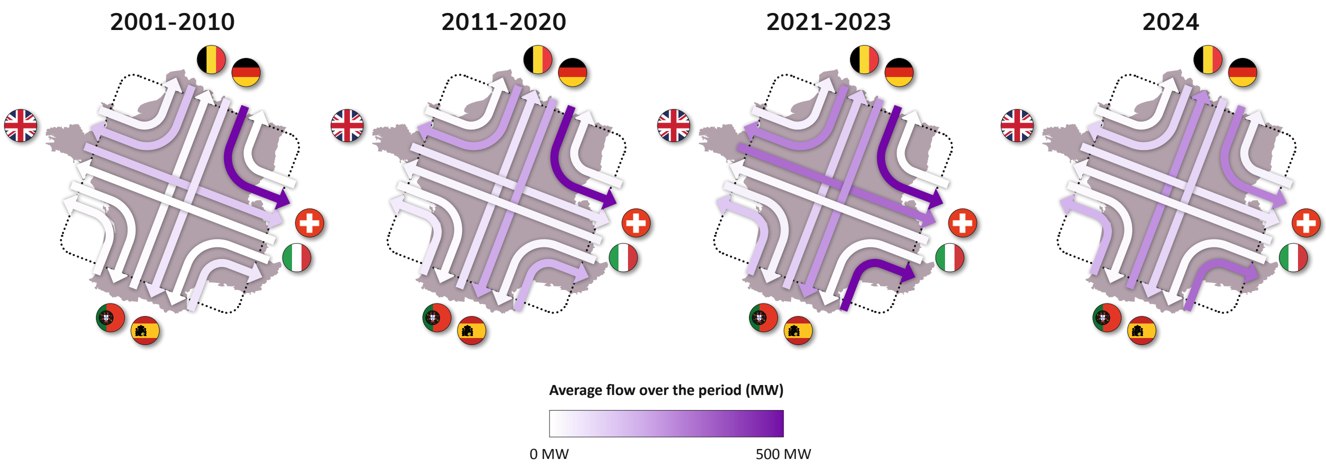
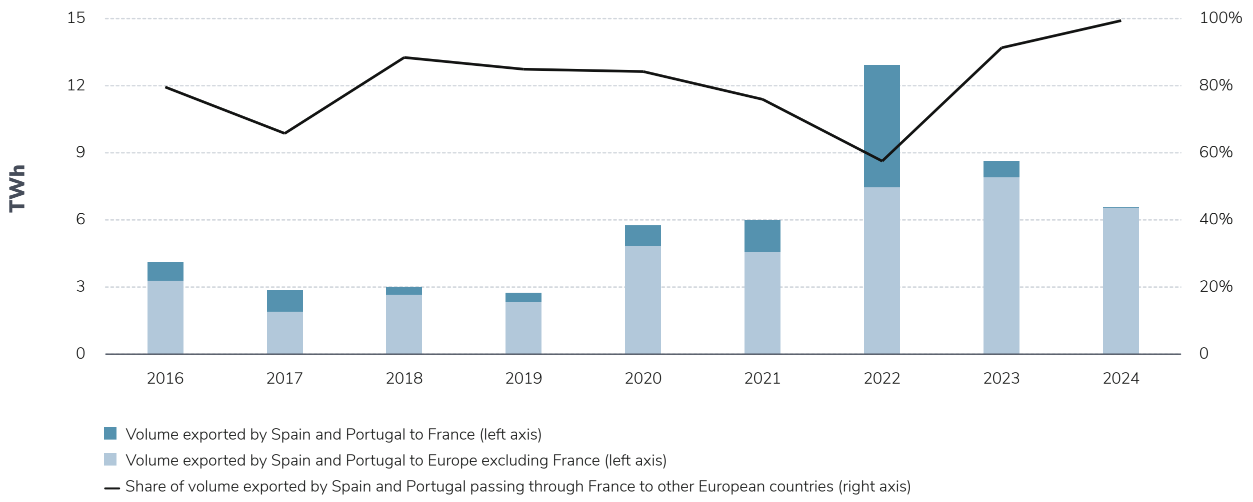


Figure 4.18 – Exports from the Iberian Peninsula to France and the rest of Europe



FOCUS

The increase in renewable production in Europe presents growing challenges for the management of the power system

The transformation of generation mixes in European countries is changing electricity flows in the European grid, and in particular leading to an increase in trade between the countries of northern and eastern Europe and the countries of southern and western Europe, due to the synergies between generation mixes dominated by renewable energy. Because of its position as an "electricity crossroads" between northern, southern and eastern Europe, France is increasingly playing the role of a transit country as these different trade systems become established. A concrete example is the trade between the Iberian Peninsula and the Germany/Benelux region, both of which already have significant installed solar and wind capacity. This "through trade" is increasingly significant in terms of both volume and frequency, and is in addition to the volume of exports arising from French generation. In March and April, there was a brief fall in volumes exported across the eastern borders (Germany, Belgium, Switzerland and Italy). This relative decrease resulted from the combined effect of (i) strong low-carbon generation in France and the Iberian Peninsula, (ii) the reorganisation of flows within France in this context of strong low-carbon generation, particularly visible in the south-west of France, (iii) necessary maintenance work on the main transmission infrastructure, leading to constraints on the network. This work was part of RTE's vast programme to renew and reinforce its network in order to meet European and national energy transition targets. The programme is causing an increase in the unavailability of electrical facilities, and thus an increase in flows on the rest of the network. **Against this backdrop, RTE made exceptional reductions in exports to countries to the east of France in April and May.** These measures were taken after all the conventional resources had been put in place and additional maintenance work had been cancelled.

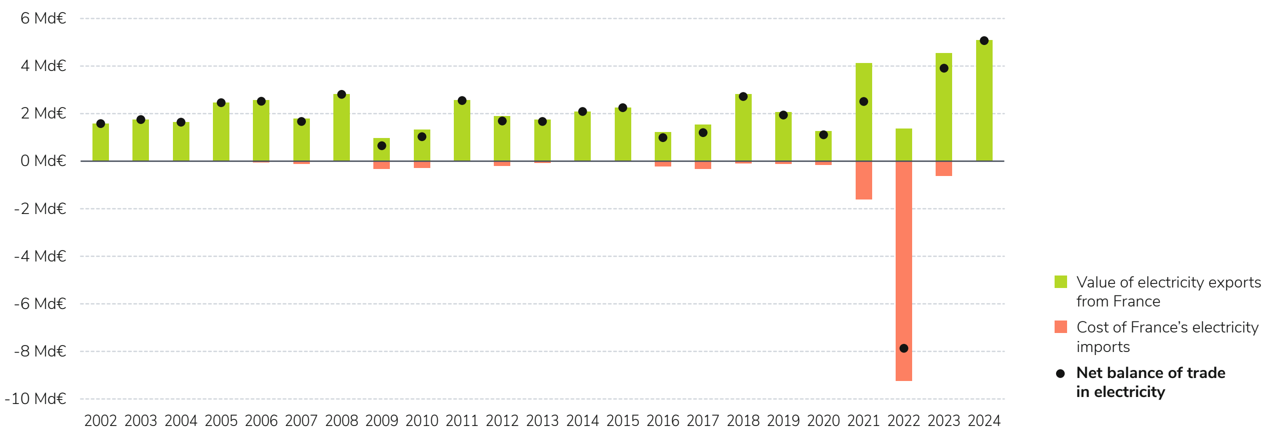
However, **even during this period, the export balance to Germany and Belgium exceeded the maximum levels seen over the last ten years, and it remained close to the average values on the Italian and Swiss borders.** From May onwards, the constraints on the transmission network close to these borders eased, though they remained significant. In the summer of 2024*, RTE anticipated that such situations would be likely to recur between August and October; in the end, conditions were more favourable than expected, and there was no need to take exceptional action again.

* see RTE, Bilan du premier semestre 2024 (review of the first half of 2024) and RTE, French eastern borders : situation update on 23th July 2024.

The value of electricity exports in 2024 amounted to several billion euros

In 2024, **the total net value of France's electricity exports was €5 billion,** its highest level since the wholesale markets were opened up in 2000.

Figure 4.19 – Value of electricity traded between France and its neighbours

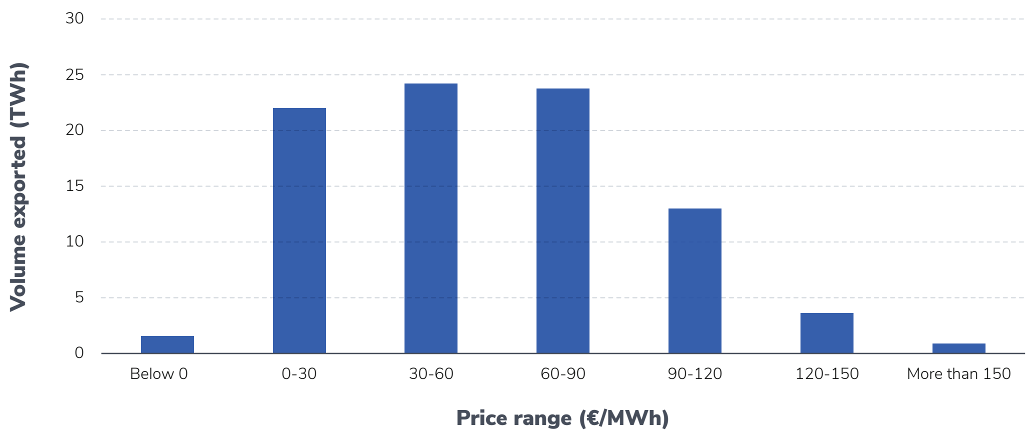


** in current euros*

Between 2002 and 2019, the annual net value of France's electricity trade fluctuated between €1 billion and €3 billion at current prices. The 2010s were characterised by a gradual shift in the French and European energy mix, with the development of renewable energy and a reduction in the share of fossil-fired generation, particularly coal (see the Europe chapter, forthcoming). Over this decade, the net value remained at the same level as in the previous decade, despite an increase in the volumes imported and exported. Then, from 2021 onwards, the impact of the energy price crisis in Europe was clearly visible. Although annual volumes were not much higher, the value of the electricity traded by France rose sharply, mainly due to the price effect. In 2024, the effect of lower prices partly offset the higher export volumes: despite a 78% increase in the export balance compared with 2023, the net value was only 30% higher than in 2023.

In addition, it is interesting to consider the market prices at which exports took place. France was an exporter over a wide range of prices, with high volumes during both periods of relatively low prices and relatively high prices. The average French spot price in 2024 was €58/MWh; **France exported a total of 46 TWh below the average price, and 44 TWh above the average price, i.e. volumes of the same order of magnitude.**

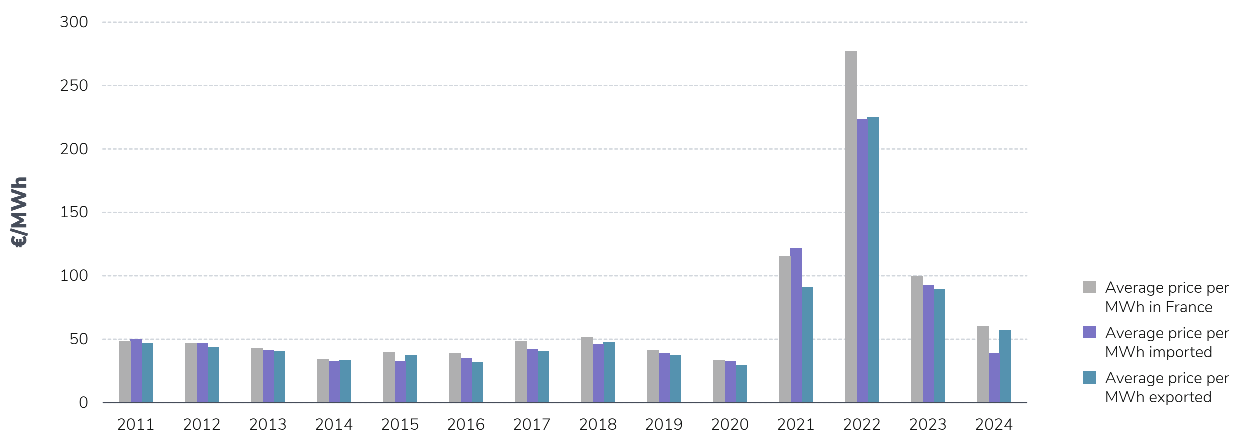
Figure 4.20 – Volume exported by France in each French spot price range in 2024



The average price per MWh exported is generally slightly lower than the average French spot price, but still relatively close. In 2024, although this price was down on the previous two years, it remained slightly higher than in the 2010s. **France did not "dump" its electricity: it exported almost continuously its competitive surplus production, which would otherwise have had no outlets, according to the economic optimum at European level.**

Furthermore, the average price per MWh imported was also generally close to but slightly lower than the average price; in 2024, it was even significantly lower (almost 30% lower). This means that during the rare periods when France was importing, this was essentially to take advantage of abundant, cheap, low-carbon electricity from its neighbours. It should be noted that this was also the case in 2022: imports from neighbouring countries helped to limit the cost of France's electricity supply at a time when it was under great strain, avoiding the use of additional, more costly and more carbon-intensive generation resources in France.

Figure 4.21 – Average price per MWh exported, imported and generated in France, between 2011 and 2024



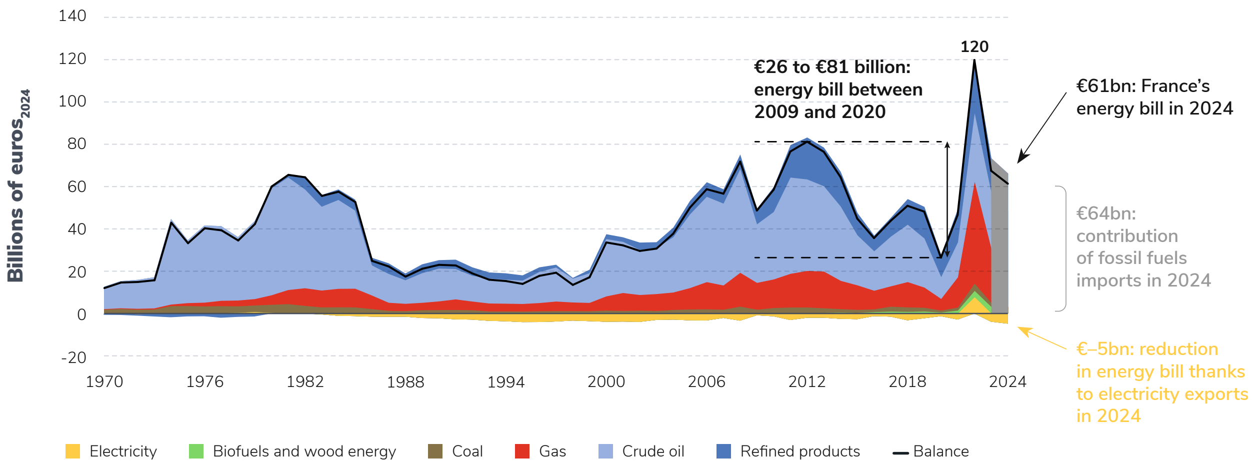
* in current euros

In terms of foreign trade, electricity is minor compared with fossil fuels

France's energy bill corresponds to the balance between the values of energy imports and energy exports across all energy sources (including electricity and fossil fuels).

Outside exceptional situations such as the 2022 energy crisis, France is a major exporter of electricity, which helps to reduce the country's energy bill. **In 2024, France's large export balance helped to decrease this bill by around €5 billion.** However, this contribution remains small compared with the weight of fossil fuel imports, which constitute the largest item in France's trade deficit; in 2024, imports cost more than $€_{2024}$60 billion[8]; in 2022, this cost was more than $€_{2024}$110 billion. In comparison, although exceptional, the cost to the national economy of electricity imports[9] that same year was less than $€_{2024}$10 billion. One automatic consequence of the energy transition, based on a massive switch from fossil fuels to low-carbon electricity, will be a significant reduction in the energy bill linked to fossil fuels. The amount paid each year by the country is highly volatile, depending on the major events affecting the global economy and the price of hydrocarbons. In comparison, the share linked to electricity remained limited even during the major crisis that affected France in 2022: the electrification of uses also protects the French and European economy better against external shocks. **As well as being imperative for the climate, this is also an asset in terms of French and European sovereignty** (most fossil fuels are imported from third countries).

Figure 22 – Trends in the French energy bill between 1970 and 2024



8. Source: Customs
9. The energy bill calculation is based on bilateral trade with direct neighbours rather than trade analysed through flow tracing.

Emissions

2024 ELECTRICITY REVIEW

Greenhouse gas emissions from the French power system reached a historic minimum for the second year running in 2024

Emissions related to electricity generation in France amounted to 11.7 Mt_{CO2eq} in 2024, their lowest level since the end of the Second World War. This represents a reduction of almost 30% compared with 2023, when emissions from French generation had already reached a historically low level (16 Mt_{CO2eq}). This fall occurred even though domestic generation increased at the same time. **As a result, the carbon intensity of French electricity generation fell by almost a third compared with 2023,** to 21.7 g_{CO2eq} per kilowatt-hour produced in 2024. Fossil-fired electricity generation was used very infrequently, which explains these particularly low emission levels (see the Generation chapter); in particular, the use of the highest-emitting fossil-fired generation sources, coal and oil, was virtually zero. In 2024, emissions from the French power system remained among the lowest in Europe; this was also the case in 2023, and even in 2022, at the height of the crisis that affected the French generating fleet and led to greater reliance on fossil-fired generation. Despite relatively high per capita electricity consumption compared with comparable European countries[1], electricity generation represents only a small proportion of the national carbon footprint: less than 5% in France, compared with 22% in Germany, 19% in Spain and 21% on average in the European Union[2,3].

The carbon intensity of the French generation mix in 2024 is already of the same order of magnitude as the intensity RTE has forecast for 2030. **As a result, even though the French electricity mix is already largely low-carbon (95%), the challenge for the coming years lies in increasing the volume of low-carbon electricity generated to supply growing electricity requirements, which will result from the gradual phasing out of fossil fuels in all sectors (transport, industry, tertiary and residential buildings – see the Electrification chapter) and new energy uses (data centres, electrolysers).** For 2030, the draft multi-year energy plan submitted for consultation at the end of 2024 forecasts over 620 TWh of generation; in 2050, in all the scenarios studied by RTE, generation exceeds 680 TWh; in 2024, French electricity generation amounted to less than 540 TWh.

1. Due in particular to the high proportion of electric heating. In 2021, consumption was about 7,200 kWh/capita in France, compared to 6,000 kWh/capita in Germany, 5,500 kWh/capita in the European Union and less than 5,000 kWh/capita in Spain and Italy (source: Eurostat).
2. Sources: CITEPA, Secten Report 2023; European Environment Agency; Eurostat; ENTSO-E; calculations: RTE.
3. The territorial emissions of the European Union amounted to 3,735 $MtCO_2eq$ in 2021 (source: European Environmental Agency). Emissions due to electricity generation in the European Union reached 783 $MtCO_2eq$ (source: Ember Climate, Yearly electricity data, 2024).

French electricity generation has been largely decarbonised since the end of the 1980s, and has become even more so since the 2010s

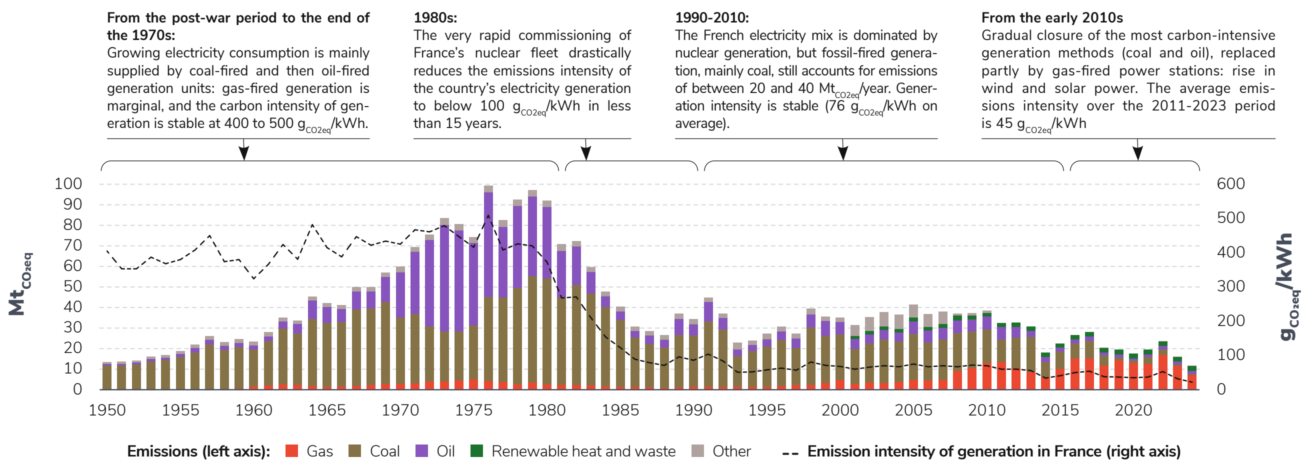
From the second half of the 20th century, it is possible to identify four major periods for the French power system from the point of view of greenhouse gas emissions[4]:

- **Before 1945,** electricity played a relatively minor role in the country's energy system. It became widely used over the first half of the 20th century, particularly for lighting, but there was still no unified transmission grid, and generating facilities were mostly private, for industrial use. The bulk of electricity generation came from coal and hydropower;

- **From the post-war period until the end of the 1970s,** generation was highly carbon-based; the significant growth in electricity consumption (+1% per year on average), in a context of strong economic development and electrification of the country, was mainly covered by hydropower, coal and oil-fired power plants. The average intensity of electricity generation in France thus remained between 400 and 500 g_{CO2eq}/kWh. In 1976, annual emissions related to electricity generation in France reached nearly 100 Mt_{CO2eq};

- **During the 1980s,** the rapid commissioning of the nuclear reactors that make up the current fleet, in parallel with the continued growth in national electricity consumption (+0.4% per year on average over the decade), resulted in a very rapid decarbonisation of the French electricity mix[5]. This deployment saw the fuel-oil fleet almost disappear and emissions related to coal

Figure 5.1 – Direct greenhouse gas emissions related to electricity generation in France and emission intensity of French electricity generation between 1950 and 2024



Calculated using current assumptions for fuel emission factors and plant efficiency, which may lead to a slight underestimation of historical emission volumes.

4. The emission factors of the different generation sources used to calculate the emissions over the entire period 1950-2024 are the current emission factors (see Appendix). Strictly speaking, it should be taken into account that emission factors tend to decrease (very slowly) over time with improvements in plant efficiency, changes in the quality of fossil fuels, etc. However, the approximation made here is not likely to substantially modify the results of the analysis.
5. The main objective at the time was the improvement of energy sovereignty and not the decarbonisation of the mix.

halve between 1980 and 1990. As a result, the carbon intensity of French production has been divided by four in ten years: in 1990, it was less than 100 g_{CO2eq}/kWh;

- **Between 1990 and the late 2000s,** emissions and the emission intensity of production remained relatively stable. The electricity mix was dominated by nuclear power, but a proportion (between 10 and 20 GW) of the fossil-fuel thermal plants, particularly coal-fired, were still in operation. Greenhouse gas emissions (between 20 and 40 Mt_{CO2eq}) and carbon intensity (around 75 g_{CO2eq}/kWh) remained stable over the period;

- **From the early 2010s,** with the increase in targets for reducing greenhouse gas and pollutant emissions, oil and coal-fired production plants were gradually reduced. At the same time, gas-fired power plants, with lower emissions per unit of energy generated, have replaced them as state-of-the-art production facilities. The 2010s were also marked by the strong development of wind and solar power. All these factors together contributed to further reducing the intensity of French electricity generation, which reached 45 g_{CO2eq}/kWh on average over the period 2010-2024.

Today, the French electricity mix is one of the most low-carbon in Europe, due to the predominance of low-carbon generation sources: nuclear, hydro and more recently wind and solar power. In addition, some of the highest-emitting generating facilities (coal and fuel oil) have been gradually shut down over the last twenty years. Furthermore, France's traditionally strong export position means that interconnected European countries can import low-carbon electricity to cover part of their consumption, thereby improving the carbon balance on a European scale.

Historically low emissions despite a slight upturn in domestic consumption and a massive increase in exports

In 2022, the crisis in electricity generation in France led to a real but limited increase in emissions from the French electrical system (see the Emissions chapter of the 2022 Electricity Report). After this atypical episode, emissions quickly returned to a particularly low level: between 2022 and 2023, generating emissions fell by almost a third to 16 Mt_{CO2eq}, their lowest level since 1953. This drop was mainly due to the upturn in low-carbon generation, and particularly the recovery in nuclear power. **In 2024,**

Figure 5.2 – Direct greenhouse gas emissions related to electricity generation in France (left axis) and emission intensity of French electricity generation (right axis) between 2014 and 2024

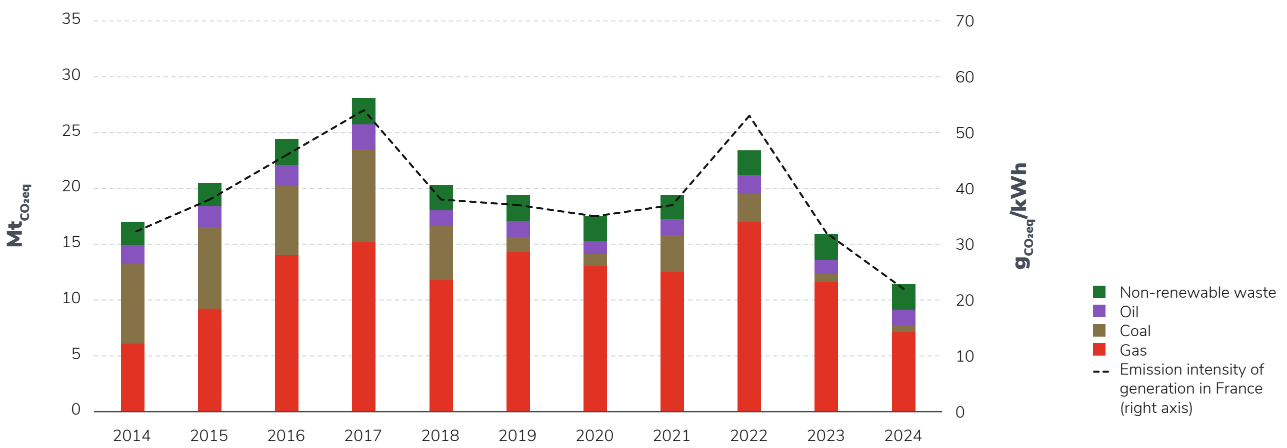
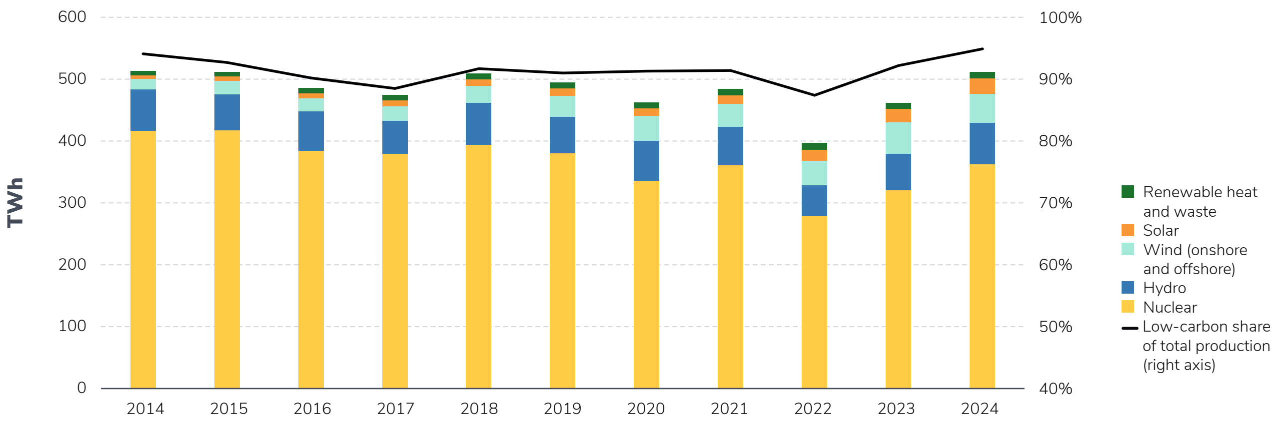


Figure 5.3 – Decarbonised electricity generation in France (left axis) and decarbonised share of total electricity generation (right axis) between 2014 and 2024



Power generated from household waste is considered 50% renewable. Seventy percent of PHP pump consumption is deducted from hydropower generation in accordance with European Directive 2009/28/EC.

this trend continued and even intensified: total direct emissions linked to national electricity generation amounted to 11.5 Mt$_{CO2eq}$; this is once again a historically low level, even corresponding to the levels of the early 1930s (electricity generation, entirely coal-fired, was then almost 30 times lower than today).

Just under three quarters of generating emissions come from gas-fired power plants, which help to balance the system during periods of high consumption. These "residual" emissions from the French mix should be put into perspective, at least in the short term, in that they allow the system to function properly and the low-carbon generation fleet to develop, thereby decarbonising the mix as a whole; the operating times of carbon-based resources are low and limited to the times when they are needed to balance supply and demand. These emissions are extremely low in relation to the service provided to the system. Around a quarter of the volume of emissions comes from electricity generation by incinerating non-renewable waste, a highly inflexible sector. Coal-fired generation was hardly used in 2024, and therefore the associated emissions were negligible: less than 300 kt$_{CO2eq}$ over the year as a whole – this is roughly the equivalent of one day's road transport emissions in France.

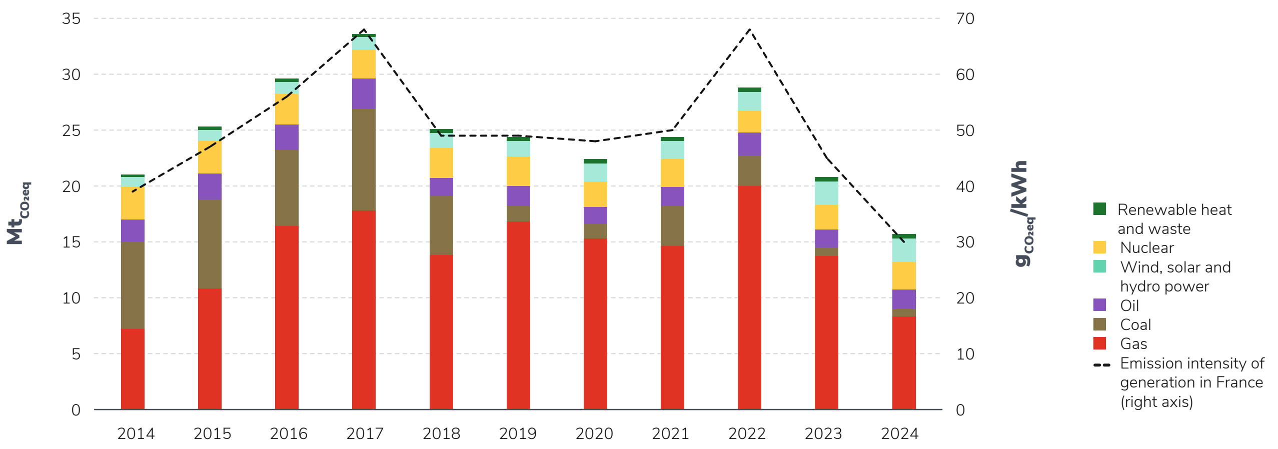
Even taking into account life-cycle emissions, emissions related to the French power system remain very low

The carbon intensity related to electricity generation can be calculated by considering only direct emissions, as in the previous paragraphs, or by including all emissions related to electricity generation over the life cycle. As well as the direct emissions related to combustion in power plants (for fossil fuel-fired power plants), this second approach includes all the emissions related to the life cycle of generating facilities: from the extraction and transport of fuels and raw materials or equipment to the construction of infrastructure allowing the generation of a given amount of energy. Some generation sources, such as wind, solar and hydro power, do not cause direct emissions, but the construction of dams, the manufacture and transport of solar panels and wind turbines and their installation generate indirect emissions that are taken into account in this approach[6].

Including life-cycle emissions, the total emissions related to electricity generation in France reached 15.9 Mt_{CO2eq} in 2024, compared to 23 Mt_{CO2eq} in 2023, a decrease of 27%. Just like direct emissions, life-cycle emissions remain much lower in France than in other countries. Life cycle intensity reached 30.2 g_{CO2eq}/kWh, a historically low value, as was the case for direct emissions intensity.

As the share of fossil-fired generation in the production mix decreases, the proportion of emissions linked to direct emissions from combustion decreases,

Figure 5.4 – Life-cycle greenhouse gas emissions related to electricity generation in France (left axis) and emission intensity of French electricity generation (right axis) between 2014 and 2024



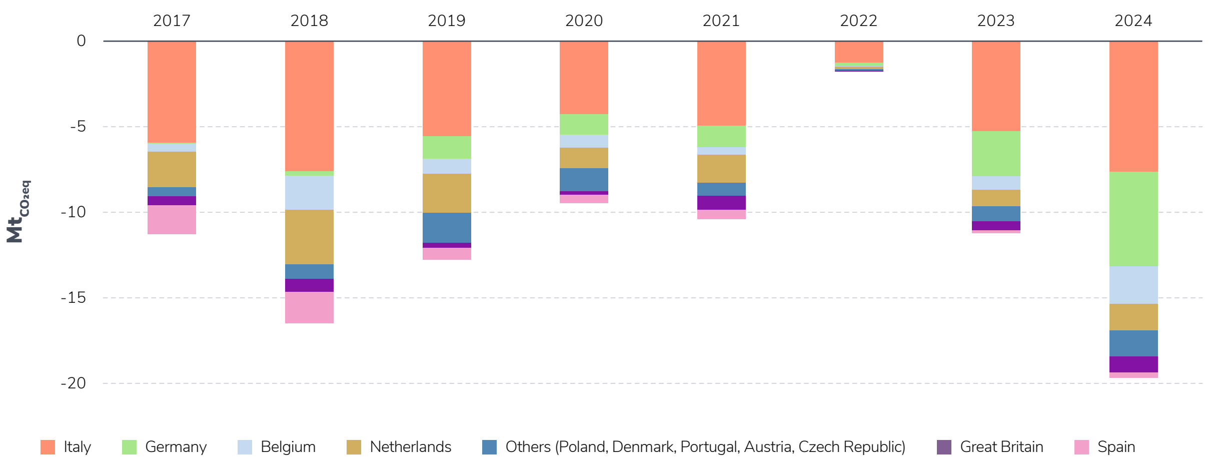
6. Greenhouse gas emissions over the life cycle of low-carbon energy sources remain very low compared to those of fossil-fuel thermal facilities: 16 g_{CO2eq}/kWh for onshore wind power, 17 g_{CO2eq}/kWh for offshore wind power, 43 g_{CO2eq}/kWh for photovoltaic solar power, 7 g_{CO2eq}/kWh for nuclear power, 6 g_{CO2eq}/kWh for hydropower, compared to 941 g_{CO2eq}/kWh for coal-fired power plants, 928 gCO_2eq/kWh for oil-fired power plants and 389 g_{CO2eq}/kWh for combined cycle gas power plants, which are the most efficient gas-fired power plants.

and the share of emissions linked to the rest of the life cycle of the generating plants automatically increases. These emissions are still low: despite their now-significant share of the electricity mix, the combined contribution of wind, solar and hydropower to life-cycle emissions from electricity generation remains very low. In 2024, they accounted for around 15% of the total life-cycle emissions related to electricity generation in France (1.9 Mt_{CO2eq}), while their contribution to the national electricity mix was 28%; as a guide, this is less than 0.5% of the country's carbon footprint[7].

7. The carbon footprint refers to all emissions, both domestic and foreign, that are attributable to the national consumption of a given country. This therefore counts emissions generated abroad by the production of goods or services consumed in the country in question, but not emissions generated in the country in question by the production of goods or services that are consumed abroad. It is a concept close to the life cycle, but distinct: the carbon footprint is based on the attribution of emissions to the consumption of a given territory, while the life cycle analysis is based on the attribution of emissions to a given energy use, activity or object. The proportion of the carbon footprint made up of life-cycle emissions from renewable power is given here as a guide, as the value of the footprint for 2024 is not yet known.

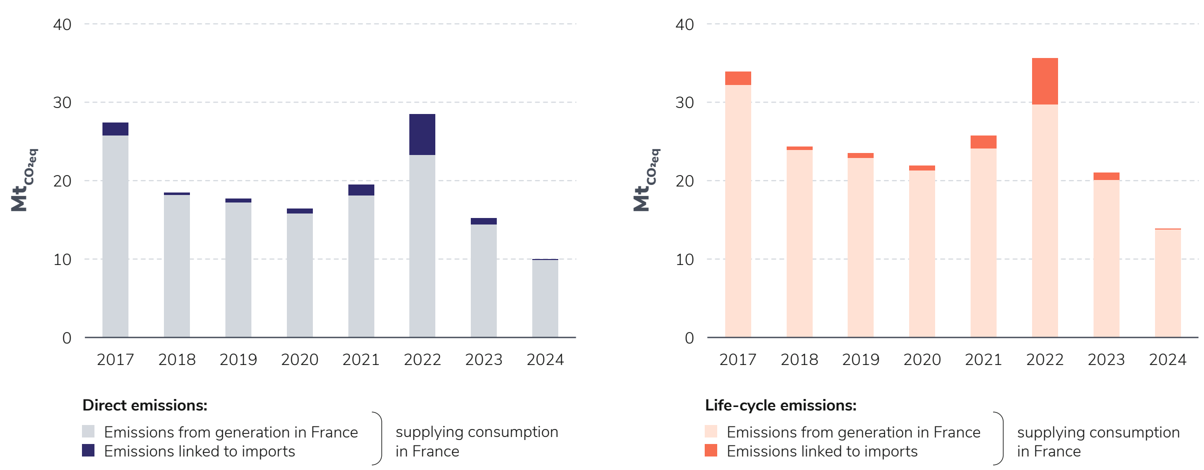
French low-carbon electricity exports are an asset for the European power system

Figure 5.5 – Emissions avoided by exports from France to European countries over the period 2017-2024



As French electricity generation is already largely low-carbon, the country's electricity exports, which reached a record level in 2024 (89 TWh, see the Trade chapter), are helping to avoid emissions elsewhere in Europe. To evaluate these emissions, we can compare the intensity of French generation with that of the countries to which the electricity is exported, for each hour. The emissions avoided thus depend on the carbon intensity differential between the generation mixes of France and the other countries on one hand, and on the quantity of electricity exported on the other. In 2024, exports from France prevented

Figure 5.6 – Greenhouse gas emissions related to electricity consumption in France between 2017 and 2024



the emission of almost 20 Mt_{CO2eq} in Europe. More than a third of these emissions were avoided in Italy, and a quarter in Germany. This record level is largely due to the volumes involved: the very high level of exports offset the effect of the gradual decarbonisation of power generation elsewhere in Europe (see the Europe chapter) – and therefore the fall in the carbon intensity differential between France and other countries.

Almost 15% of the emissions from electricity generation in France were linked to electricity that was exported. Emissions linked strictly to French electricity consumption amounted to 10.0 Mt_{CO2eq}, equivalent to less than three weeks of road transport emissions in France[8], or less than the annual emissions of a country like Luxembourg[9].

8. CITEPA, Monthly Secten Report 2022.
9. Joint Research Centre of the European Commission, IEA-EDGAR CO_2 database.

Even on an hourly basis, the carbon intensity of the French power system remained limited throughout the year

Even in a low-carbon power system, there are likely to be occasional spikes in the intensity of generation and consumption. These occur mainly in winter, during periods of high consumption, when it is necessary to call on fossil-fired generation and possibly imports from countries whose power is more carbon-intensive. In 2023, for example, despite very good overall performance, the carbon intensity of consumption exceeded 100 g_{CO2eq}/kWh around 3% of the time.

In 2024, intensity remained limited even during periods of high consumption: its maximum value was 67 g_{CO2eq}/kWh, which is less than the average intensity of French generation in 2010.

The intensity of both generation and consumption was below 10 g_{CO2eq}/kWh almost half the time, a value that is practically irreducible. This level, which can be seen as the system's "background intensity", corresponds to emissions from sectors where electricity generation is independent of the system's overall operation; these are essentially waste incineration on one hand, and cogeneration on the other, which produces heat for district heating networks or industry and feeds electricity into the grid as a by-product. This "background intensity" can be compared with the residual intensity linked to the power system in the prospective scenarios (see the introductory section of this chapter).

Figure 5.7 – Monotonic intensity of direct greenhouse gas emissions from French electricity consumption over different periods

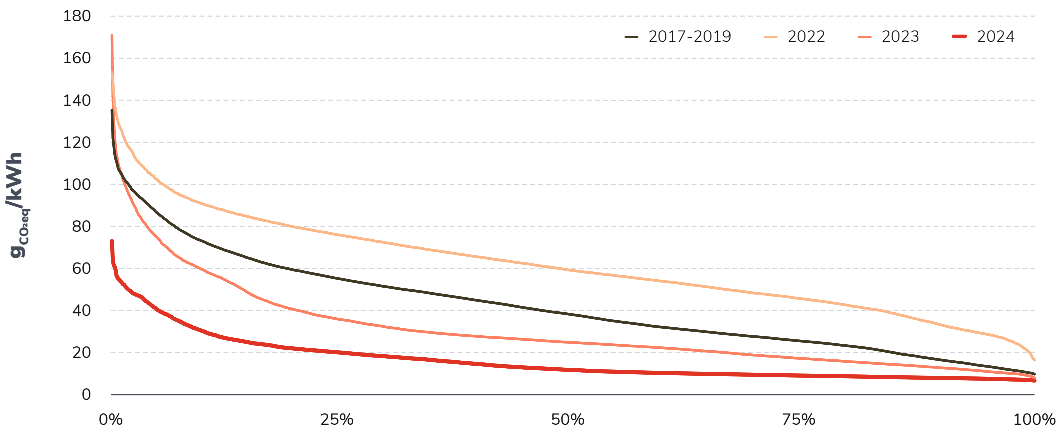
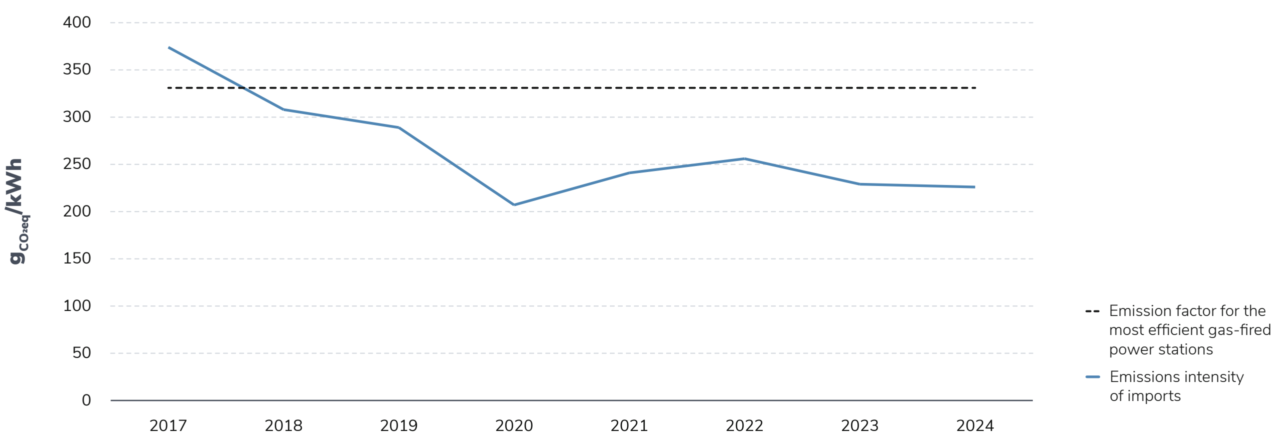


Figure 8 – Summary of the concepts involved in the calculation of greenhouse gas emissions related to electricity

			Type of emissions	
			Direct emissions	**Life-cycle emissions**
			For electricity generated in fossil-fired power plants, these are emissions related to combustion. Electricity generation resources that do not use fossil fuels (wind, solar, nuclear and hydro power) do not generate direct emissions.	Life-cycle emissions assessment or LCA includes all the emissions generated to make a certain amount of electricity available: these include all the emissions related to the extraction and transport of materials used for the construction of power plants, equipment and infrastructure in France or abroad. These emissions can take place upstream or downstream of electricity generation facilities. Emissions related to the life cycle (excluding combustion) can take place abroad.
Scope	Elec. gen.	This concerns the electricity generated by the facilities present on the national territory	Direct emissions from electricity generation plants located on the national territory.	Life-cycle emissions attributable to electricity generated on French territory. Some of the emissions related to the upstream or downstream of the life cycle (excluding combustion) can take place abroad.
Scope	Electricity consumption	This concerns electricity consumed on French territory: this is the share of French generation that is not exported, as well as imports.	Direct emissions from electricity generation plants located on the national territory, minus emissions from the generation of exported electricity, and direct emissions from plants located abroad that supply electricity consumption in France (via imports).	Life-cycle emissions attributable to electricity consumed on French territory. Life-cycle emissions of electricity generated in France but exported are not counted; life-cycle emissions of imports that supply electricity consumption in France are counted.

Thanks to the gradual decarbonisation of the European electricity mix over the last few years, the little electricity that France imports from its neighbours is now much less carbon-intensive than the electricity generated by the most efficient gas-fired power stations. This shows that a significant proportion of this electricity is generated by low-carbon means

Figure 5.9 – Average annual carbon intensity (direct emissions) of France's imports



Europe

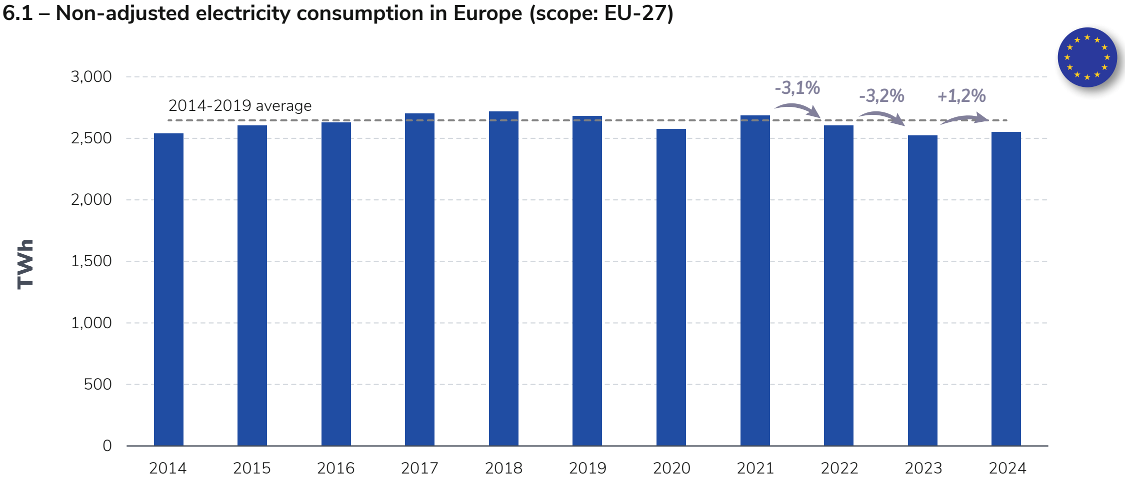
2024 ELECTRICITY REVIEW

European electricity consumption rose slightly after two consecutive years of decline

Gross electricity consumption, i.e. not adjusted for weather effects[1], increased slightly in 2024 (+1.2%) within the European Union[2] compared with 2023, putting an end to the downward trend observed since the start of the energy crisis.

European consumption fell sharply in 2022 and 2023, by 3.1% in 2022 compared to 2021, and by 3.2% in 2023 compared to 2022. Between late 2021 and early 2023, all European countries were affected by the energy crisis linked to lower hydropower production as a result of low rainfall and higher fuel prices following Russia's invasion of Ukraine. The crisis in nuclear generation in France also played a role due to a reduction in exports. Rising energy and commodity prices had both direct effects on household and business

Figure 6.1 – Non-adjusted electricity consumption in Europe (scope: EU-27)



Data sources: Eurostat, ENTSO-E, RTE

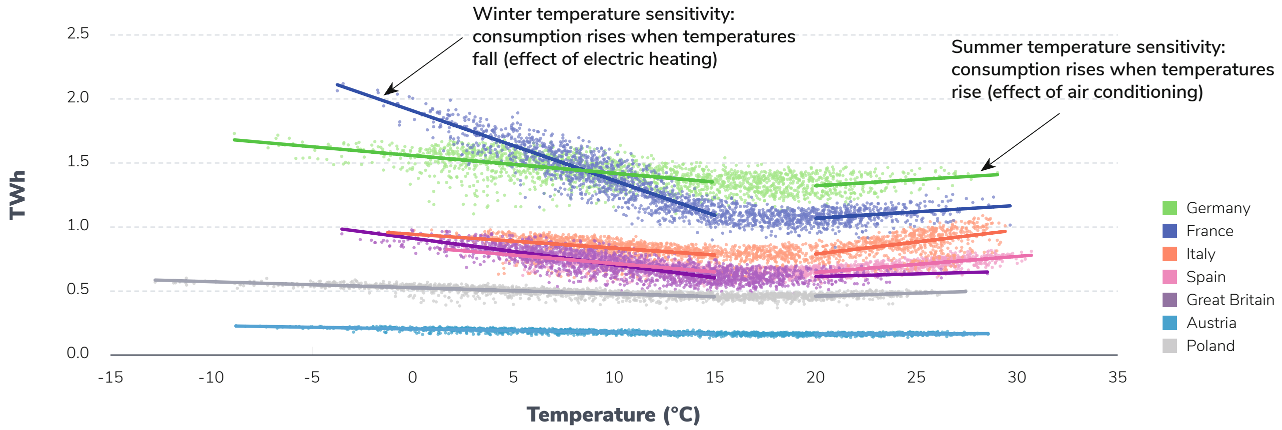
1. Gross consumption, i.e. not adjusted for weather and calendar effects. Consumption data adjusted for these effects are not available for other European countries. As 2024 was warmer than normal (as was 2023), the slight upward trend should remain even after adjusting for weather effects. The year 2024 also includes an extra day (29 February): without this extra day, the increase in consumption would have been 0.9%.
2. The scope considered here is the European Union of 27 member states. The United Kingdom is not included, even in the pre-Brexit years, in order to maintain a constant scope and facilitate analysis.

energy consumption and indirect effects linked to the reduction in economic activity against a backdrop of global inflation. The rise in electricity prices particularly affected electricity-intensive industries in France and Europe3. The actions taken by several countries to save energy in response to the crisis, and temperatures well above normal that reduced heating needs, also contributed to the fall in consumption in 2022 and 2023, albeit to a lesser extent.

Consumption in 2024 remained lower than before the pandemic and the energy crisis, demonstrating that some of the effects of the 2021-2023 economic crisis are still present (as shown by electricity forward prices and fuel prices, which have not returned to pre-crisis levels). **However, the trend showed signs of reversing across the continent in 2024, with a slight increase in consumption against a backdrop of lower prices and more favourable fundamentals for electricity generation.** The fall in fossil fuel prices, the rise in solar and wind generation thanks to growth in installed capacity, the increase in hydropower production due to favourable weather conditions and the recovery in French nuclear generation all contributed to a general fall in electricity prices in Europe (see the Prices chapter).

The increase in consumption in 2024 compared with 2023 was mitigated by a very warm winter in 2024, as mentioned above, since several European countries have a high level of temperature sensitivity in winter (e.g. France and Germany). Temperatures from January to March were significantly higher than in 2023, by between 0.8 and 1.4°C in Germany, France, Italy and Spain, an average increase of 14%. **Globally, 2024 was the hottest year on record, with global warming exceeding 1.5°C above pre-industrial levels for the first time[3].** In France, the winter of 2023-2024 was the third-warmest on record. Unlike other European countries, average consumption in Germany rose during the winter months between 2023 and 2024, despite the rise in temperatures. This may be partly due to the fact that the fall in consumption between the first quarters of 2022 and 2023 was significantly sharper in Germany (6%) than in other countries (e.g. 3% in Spain): the recovery in consumption, excluding weather effects, was therefore likely to be higher in Germany than elsewhere.

Figure 6.2 – Daily consumption according to temperature for a selection of European countries between 2017 and 2024 (working days only)

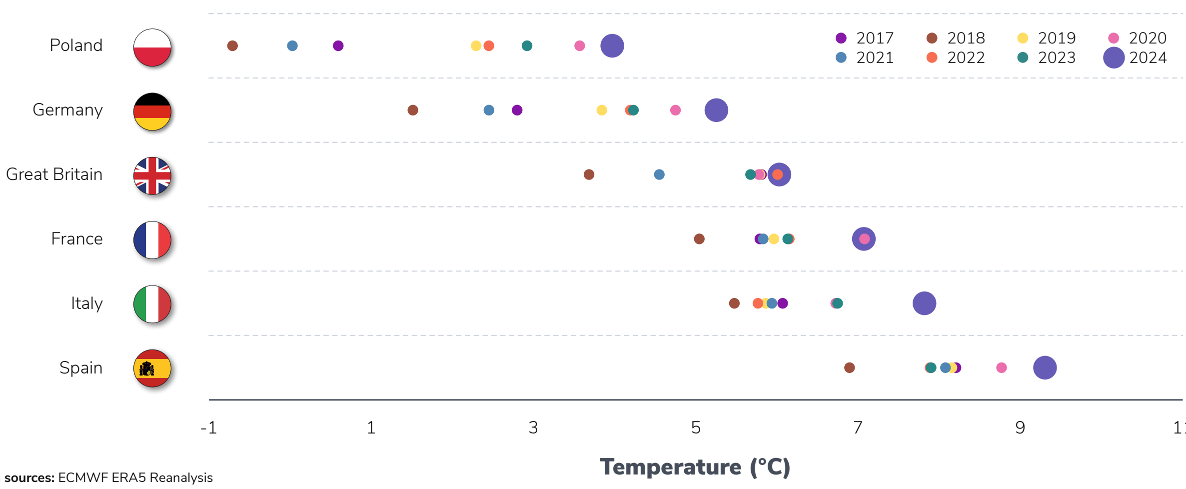


Data sources: ECMWF ERA5 Reanalysis, ENTSO-E, RTE

3. IEA, Electricity 2024, 2024

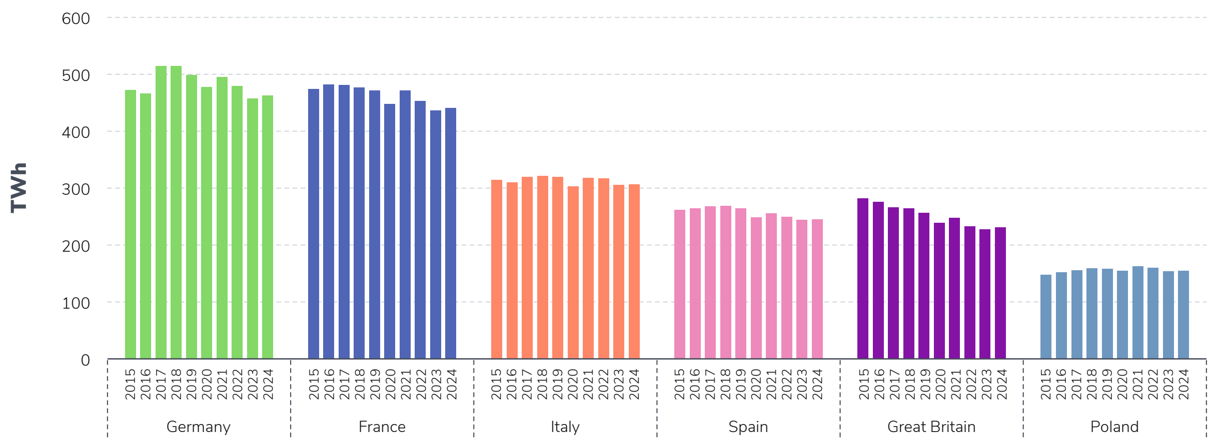
The year 2024 could be a turning point signalling a potential rise in consumption in the coming years. The IEA forecasts a 2.4% annual increase in European consumption between 2024 and 2026[4], driven by a revival in industrial activity, growth in the number of electric vehicles, the installation of heat pumps and an increase in the number of data centres. In the longer term, consumption could rise even further due to the electrification of uses as set out in the energy strategies of European countries.

Figure 6.3 – Average temperatures on working days during the January-May period, for a range of years



Data sources: ECMWF ERA5 Reanalysis

Figure 6.4 – Unadjusted electricity consumption for the six highest-consuming countries in Europe



Data sources: Eurostat, ENTSO-E, National Grid, RTE

4. World Meteorological Organization, WMO confirms 2024 as warmest year on record at about 1.55°C above pre-industrial level, 2025

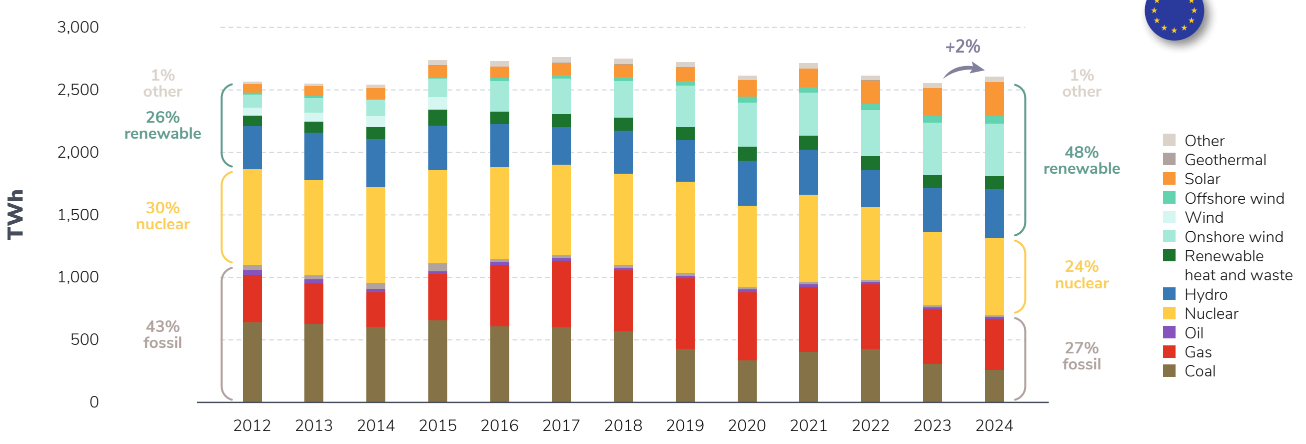
Rising generation, with growth in low-carbon sources gradually replacing fossil fuels

Electricity generation in the EU-27 increased by 2% in 2024 compared with 2023[5], reaching a level close to 2022 and 2020 while remaining lower than output in 2021. Generation was mainly driven upwards by low-carbon sectors, while fossil-fired generation fell sharply, continuing the trend of the previous year. **Solar generation (271 TWh) overtook coal-fired generation (258 TWh) for the first time. Wind (422 TWh for onshore wind, 62 TWh for offshore wind) remained the EU's second-largest power source behind nuclear (619 TWh, 58% of it in France), having overtaken gas-fired generation (411 TWh in 2024) in 2023.**

Hydropower production rose by 11.7% thanks to abundant rainfall. Rainfall in Europe in 2024 was 7% higher[6] than the average for 1990-2023, and 15% higher than in 2022, a year characterised by particularly low rainfall. **Nuclear output rose by 4.8% (+29 TWh), entirely due to the growth of nuclear generation in France (+41 TWh),** where the increase in volume more than offset the reduction in other European Union countries (–12 TWh). In fact, 2024 was the first full year of nuclear-free generation in Germany since the last power station was shut down in April 2023 (Germany still produced 6.7 TWh in 2023). Slight reductions in nuclear generation were also recorded in other countries. The Finnish Olkiluoto 3 EPR, commissioned in 2023, produced 9.2 TWh in 2024 (down 0.8 TWh on the previous year) due to annual maintenance scheduled between March and May. This first maintenance since the reactor was commissioned, the only major element affecting the plant's output, took twice as long as planned[7]. Lastly, **the rise in solar generation continued, with an increase of 21% in 2024 compared with 2023,** even higher than 2023's rise over 2022 (18.9%). **The volume of solar generation in Europe has accelerated sharply over the last five years: after growing at an average rate of 5.6% a year between 2014 and 2019, this rate rose to 19.5% between 2020 and 2024,** driven by the increased pace of solar panel installation in many countries (e.g. Austria, Poland and the Netherlands). By the end of 2024, installed capacity in the European Union was 338 GW (+66 GW compared with 2023)[8]. **Wind generation also increased, by 2.0% between 2023 and 2024, thanks to wind farm growth and despite unfavourable wind conditions across the continent.** In the European Union as a whole, 14 GW[9] of wind power capacity, both onshore and offshore, was installed in 2024, an increase of 7% compared with 2023. The top three countries are Germany (72 GW[10] installed), Spain (32 GW[11] installed) and France (24 GW installed). In total, wind and solar output reached 754 TWh in the European Union in 2024, almost twice the level of hydropower. The average hourly coverage rate of consumption by solar and wind generation increased to 25.5% in 2024 (compared with 24.5% in 2023)[12]. Finally, fossil-fired generation continued to fall sharply (–10% in 2024 after a 21% reduction in 2023). All fossil fuels were affected: gas (down 6%), coal (down 16%) and oil (down 13%).

5. The increase was 1.7% if 29 February 2024 is excluded.
6. Source: ERA5 data from the Copernicus Climate Change Service
7. TVO, First annual outage starts at Olkiluoto 3 on Saturday, 2024
8. Source: Solar Power Europe.
9. Source: ENTSO-E.
10. Source: Energy-Charts.
11. Source: Red Electrica de España.
12. Source: Entso-e; calculations: RTE.

Figure 6.5 : Electricity generation in the European Union by power source (scope : EU)

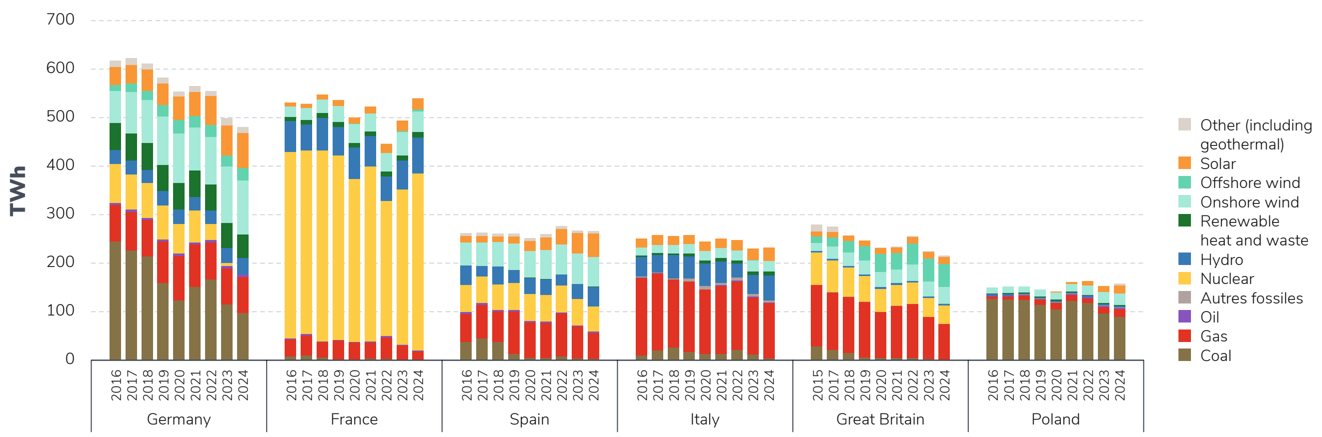


Data sources: ENTSO-E, Energy-Charts, CBS & NedNL, REE, RTE

In several EU countries, the share of renewable energy (solar, wind and hydropower[13]) in the electricity generation mix is now over 50%. Austria and Latvia reached this threshold several years ago, thanks to their large historic hydroelectric fleet. With the development of wind and solar power, Portugal and Spain have also passed the threshold in the last two years.

With the increase in installed capacity, most countries set new records for solar power generation (in terms of instantaneous power).

Electricity generation, by type, for Europe's six main producer countries



Data sources: ENTSO-E, National Grid, Energy-Charts, REE, RTE

13. Bioenergy is excluded from the analysis because data on its production, depending on the country, are not always available separately from non-renewable thermal production.

In Germany, for example, solar output reached 54.5 GW on 25 June 2024, beating the previous record of 44.3 GW set in 2023. However, there were also periods of very low renewable generation, particularly in the autumn (see the focus on Dunkelflaute episodes below).

Analysing the dynamics by country, total German output fell, contrasting with the trend in other countries, due to the increase in imports. The main reduction was in coal, followed by nuclear power, with the last reactor shutting down in April 2023. Output from the solar sector rose the most.

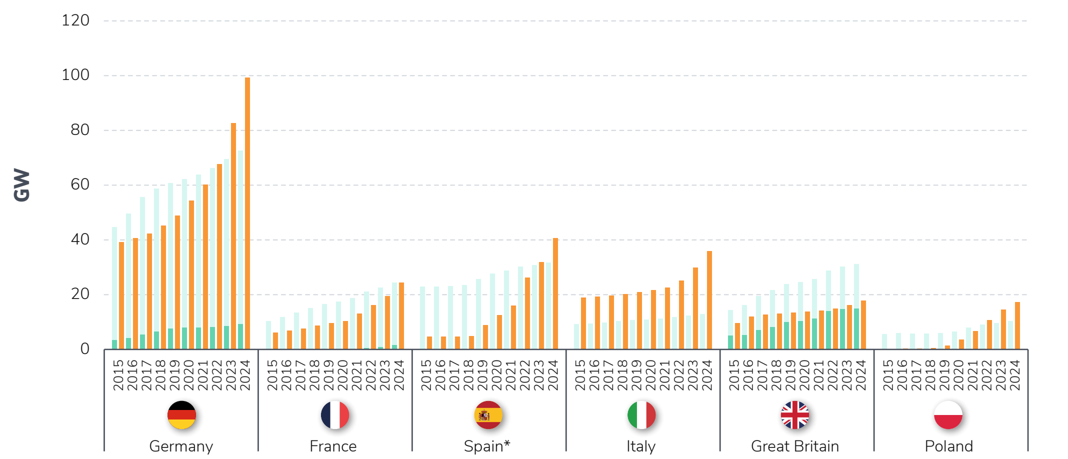
Austria also saw an unprecedented increase in its solar generation, continuing 2023's trend of new momentum resulting from significant new capacity in the sector. In Belgium, gas-fired generation fell without being significantly offset by growth from other sources, while consumption increased, the difference coming from imports (see the detailed analysis of these three countries later in the chapter).

In Switzerland, abundant rainfall had a particularly significant effect on hydropower generation, which rose by 28% compared with 2023 to 26 TWh, 6.4 TWh more than the average for the last six years.

In the Netherlands, the fast pace of solar panel installations in recent years slowed in 2024, though it remained very high in relation to the size of the country. Compared with 4.8 GW in 2022 and 4.4 GW in 2023, around 3 GW of capacity was installed in 2024[v]. On a per capita basis, this installed capacity (0.17 kW/capita) is much higher than many other countries, including France (0.05 kW/capita). Solar generation rose sharply again, by 3.6 TWh or 18% between 2023 and 2024.

In Italy, solar output was up 19% on the previous year, thanks partly to significant growth in the installed base (+6.8 GW). Hydropower generation increased by 30% due to heavy rainfall, while wind generation fell, as elsewhere on the continent (–6%). Fossil-fired generation decreased by 6%, with coal-fired generation in particular down 71% on the previous year, to a level that is now negligible[15].

Figure 6.7 : Wind and solar power fleets in a selection of European countries at the end of 2024



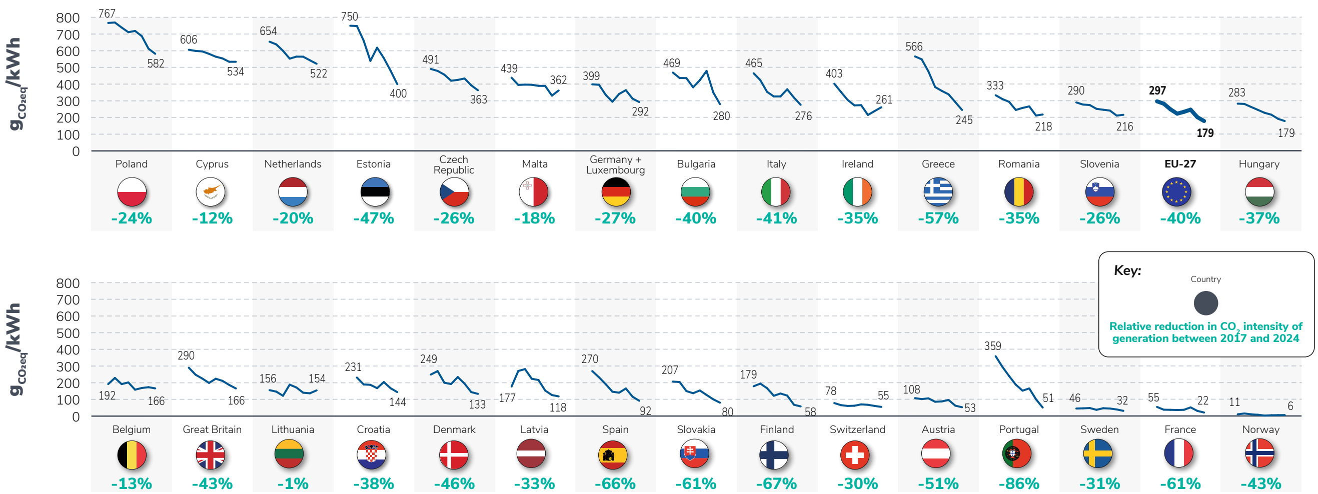
Data sources: Energy Charts, REE, Terna, Department for Energy Security and Net Zero, ENTSO-E, Eurostat, RTE

* The Spanish solar fleet includes thermodynamic solar installations, which accounted for around 2 GW in 2024

14. Source: Energy-Charts for all generation and fleet data for Germany, excluding coal.
15. SMARD, 2024

The carbon intensity of electricity generation has fallen by almost 30% in Europe since 2017

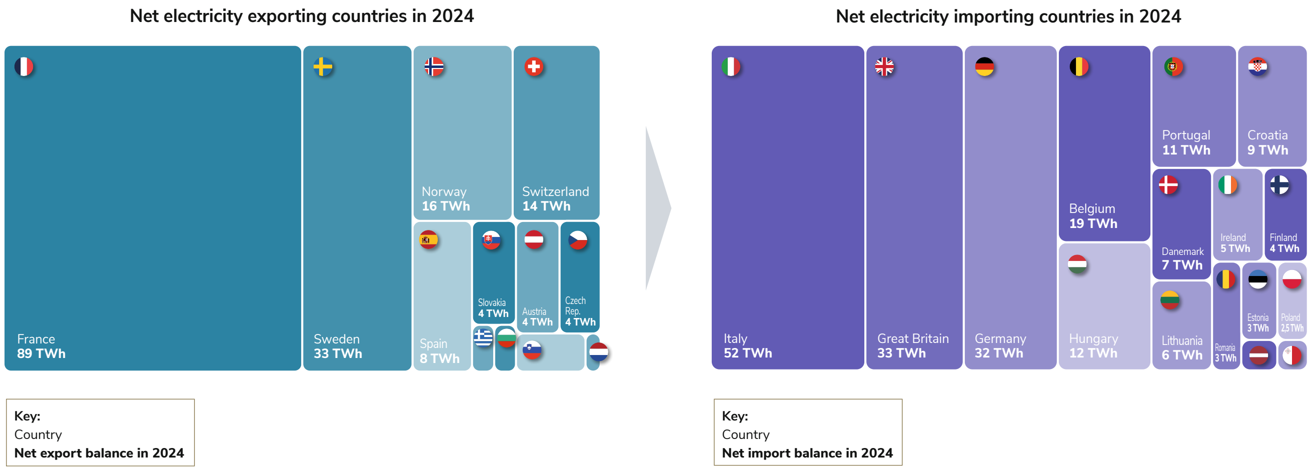
Figure 6.8 – Average carbon intensity of electricity generation in the countries of the European Union, the United Kingdom, Norway and Switzerland



The decarbonisation of Europe's power system is continuing. Between 2017 and 2024, the average carbon intensity of electricity produced in the 27 European Union member states fell by 40%, from 297 gCO_2/kWh to 179 gCO_2/kWh in 2024. Over this period, carbon content fell in all member states (but also in other European countries such as Great Britain, Norway and Switzerland). French electricity generation has long been among the lowest-carbon in Europe, and thanks to the further reduction between 2023 and 2024 due to the abundance of low-carbon generation, it is now second only to Norway. In some countries, the speed of decarbonisation is spectacular. Thanks to the massive development of renewable energy, particularly wind, and the closure of most of their coal-fired power stations, Spain and Portugal reduced the carbon intensity of their electricity generation by 66% and 86% respectively over the period. The closure of coal-fired power stations has enabled countries such as Greece, Bulgaria and Great Britain to halve the carbon intensity of their generation mix.

France was the leading net exporter of electricity in Europe in 2024, thanks to its low-carbon generation fleet, a feature shared by the main exporting countries in Europe

Figure 6.9 – Origin and destination of electricity trades in Europe in 2024



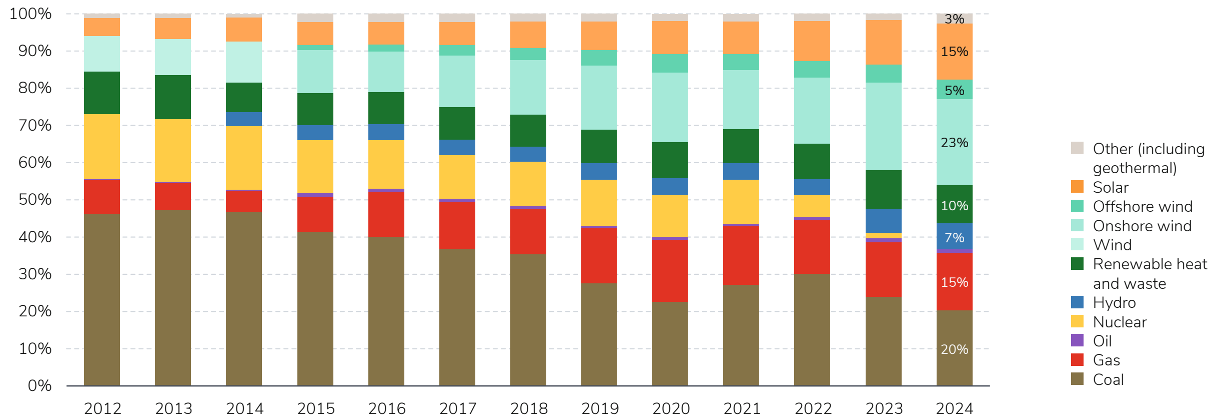
France was Europe's leading net exporter of electricity in 2024, with a higher trade balance than all the other net exporting countries combined. Italy was the biggest importer, with almost 50 TWh of net imports over the year, representing nearly 15% of the country's consumption (see the analysis by border in the Trade chapter). Germany was in second place, with a net import balance of 32 TWh over the year (see the section on Germany in this chapter).

In general, countries whose electricity production is low-emission have been the leading exporters, and conversely, importing countries are generally countries with a higher carbon intensity. This is partly due to the fact that most electricity is traded on the basis of price (from the country where the price is lowest to the country where it is highest) and that the cheapest sources of energy are also generally the least carbon-intensive.

Finally, the net trade balance is not always correlated with the size of the countries' power systems, with Sweden among the main exporters and Germany having a balance close to that of Belgium.

In Germany, wind remains the leading generation source in the mix, despite a few periods of very low wind speeds

Figure 6.10 – German electricity mix between 2012 and 2024



Data sources: Energy-Charts

While Germany's annual consumption increased by 1% in 2024, in line with the European trend, generation fell by 4% due to a rising import balance, benefiting in particular from the abundance of low-carbon French production (see the Trade chapter). This balance reached 29 TWh, representing 6% of consumption in 2024, more than two times the import balance in 2023.

As in the rest of Europe, weather conditions were characterised by more rain in 2024 than in previous years, and by a reduction in wind and sunshine. **Despite unfavourable weather conditions, which led to a slight fall on the previous year (–3 TWh), wind remained the leading source of electricity generation, accounting for 28% of the mix (111 TWh for onshore wind, 26 TWh for offshore wind[14]). Solar generation continued to grow significantly, with 72 TWh generated (15% of the mix, +13 TWh compared with 2023), driven by the expansion of the installed base, which more than compensated for the lower level of sunshine.** The average hourly rate of coverage of German consumption by wind and solar generation also rose, reaching 41% in 2024 (compared with 40% in 2023 and 35% in 2022). Thanks to higher rainfall, hydropower output reached 33.9 TWh, an increase of 2.3 TWh on the previous year (7% of the mix).

The increase in solar generation and imports enabled a significant reduction in fossil-fired generation while offsetting the fall in nuclear production. The last reactor, shut down in April 2023, still produced 6.7 TWh in 2023. Coal-fired generation fell the most (-14% or -16 TWh compared with the previous year), with its share of the mix down to 20%, compared with 24% in 2023. Coal-fired generation has halved since 2018 due to the development of wind and solar generation. Germany has set itself the target of phasing out coal by 2038, and the country closed 3.3 GW of lignite-fired capacity and 2.6 GW of coal-fired

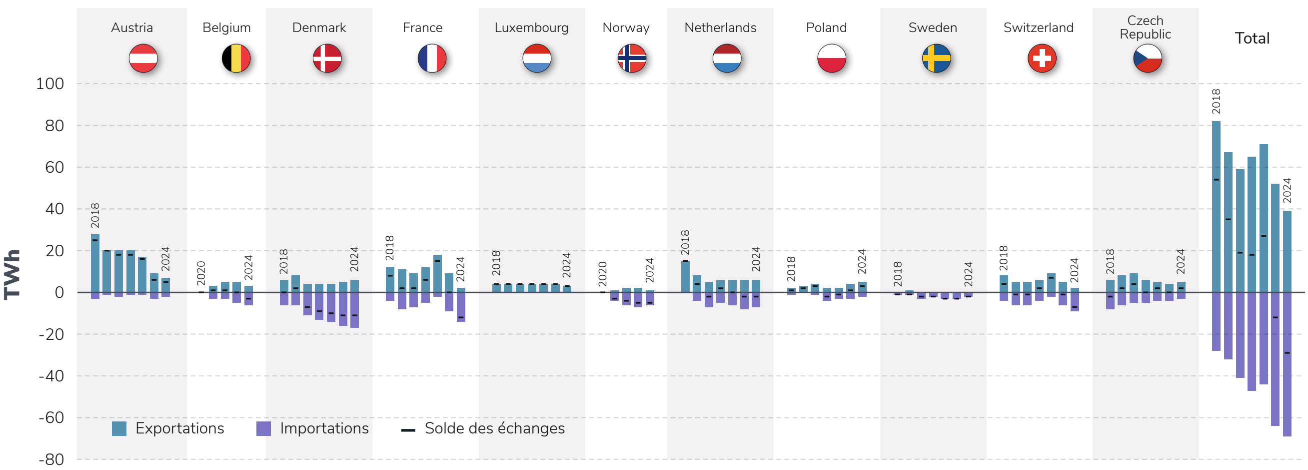
16. The second decile is the value below which 20% of the average daily load factors recorded between 2016 and 2024 lie, for each generating source and

capacity in 2024[15]. The size of these fleets thus fell by 18% and 14% respectively, to 15 GW and 16 GW. Plant closures had been slowed down in 2022 and 2023 in response to the gas supply crisis caused by the war in Ukraine. The main development in the German power generation fleet was the increase in installed solar capacity: 16.5 GW in 2024, a higher rate than in 2023 (15.1 GW installed). **Germany's solar capacity now stands at 99.2 GW, almost half the figure for the whole European Union.** For wind power, 2.9 GW of capacity was installed in 2024.

Germany's net trade balance was heavily skewed towards imports in 2024, at 29 TWh (6% of consumption), up on 2023 (11 TWh, 2% of consumption).

While the net balance relative to certain countries did not change significantly (Austria, Denmark, Luxembourg, Norway, the Netherlands, Sweden, the Czech Republic), this was not the case for the other countries interconnected with Germany. Imports from Belgium, France and Switzerland rose sharply compared with 2023. In particular, the balance with France moved from zero in 2023 to an import balance of 12 TWh (3% of German consumption) in 2024 due to the abundance of low-carbon generation in France. The trade with Belgium and Switzerland was also due to this French momentum, as these countries often act as relays for through trade from France (see the section on Belgium).

Figure 6.11 – Electricity trade between Germany and its neighbours



Data sources: ENTSO-E

each country. The solar load factor was below the second decile of solar load factors during the three days from 11 to 13 December in Germany, and the

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Dunkelflaute episodes in Germany

At the end of 2024, Germany was hit by several periods of a number of consecutive days combining low solar and wind generation (known as "*Dunkelflaute*" in German). Weather conditions of this kind can occur infrequently anywhere, though their effects are more visible in countries where solar and wind energy account for the largest share of the electricity mix, such as Germany. **One example of this situation was the period from 11 to 13 December 2024 in Germany. On 12 December in particular, the country's total solar and wind generation amounted to 55 GWh, compared with an average of 570 GWh/day over the course of 2024.** This was the lowest daily level since 16 November 2021 (48 GWh), despite the fact that solar and wind capacity increased significantly (+48 GW) between these two dates, underlining the exceptional nature of the phenomenon. Daily consumption was 1.4 TWh on 12 December, in line with the average for a working day in December. Given the conditions, the German spot price reached its highest level of the year at 5 p.m. on that day, at €818/MWh, and its highest average daily price at €395/MWh, due to the strong demand for gas-fired generation (see also the *Prices* chapter).

Germany also imported its highest daily volume of the year on 12 December (325 GWh over the day). These imports took place across all borders:

- Countries from which Germany usually imported electricity in 2024, such as Switzerland (import balance of 64 GWh on 12 December, compared with an average of 16 GWh on autumn working days), Denmark (50 GWh, compared with an average of 41 GWh), the Netherlands (44 GWh, compared with an average of 10 GWh) and, to a lesser extent, France (37 GWh, compared with an average of 34 GWh),
- Countries to which it usually exported electricity, such as Poland (import balance of 29 GWh, compared with an export balance of 8 GWh on average) and the Czech Republic (29 GWh, compared with 7 GWh exported on average).

It is also interesting to look at Germany's trade over the period from 11 to 13 December across the "extended European scope" (see the Trade chapter for more details). This involves tracking electricity trade flows beyond Germany's direct neighbours. In particular, net exports from France to Germany between 11 and 13 December using this approach (240 GWh total) were much higher than bilateral exports (103 GWh total): this indicates that a large part of the volume exported from France to Germany passed through third countries, including Switzerland and Belgium. **Taking this broader view, the countries that exported the most to Germany during the three-day *Dunkelflaute* episode in December were France (240 GWh), Norway (168 GWh) and the Netherlands (157 GWh).** Norway in particular was able to draw on its large hydropower stocks to meet Germany's increased import requirements.

Elsewhere in Europe, the phenomenon was also pronounced in Belgium, the Netherlands and Denmark, where wind generation between 11 and 13 December was around ten times lower than on other days in December, and to a lesser extent in Norway and Poland (production around two to five times lower). France also saw low wind output over these three days, combined with high consumption due to below-seasonal temperatures. Against this backdrop, France experienced increased demand for nuclear, hydro and, to a lesser extent, thermal generation. The French price increased, but by much less than the German price, reaching a daily average of €173/MWh on 12 December and €177/MWh the following day, when French wind and solar generation was even lower (69 GWh compared with 107 GWh on 12 December – the lowest value across 2024 was 54 GWh on 9 November).

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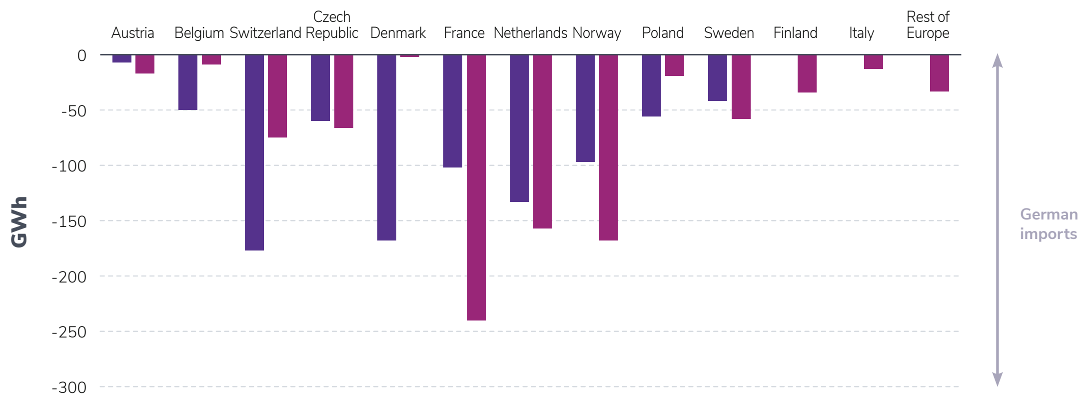
Figure 6.12 – Net trade between Germany and other European countries from 11 to 13 December 2024



Data sources: ENTSO-E

For comparison, the French price also reached high levels in 2024 outside the periods of very low renewable generation in Germany, such as on 4 December, at €145/MWh, which was due to low temperatures leading to higher consumption and relatively low renewable generation in France. In addition, French gas-fired generation (186 and 188 GWh on 12 and 13 December) was also higher at other times of the year, such as from 9 to 12 January, during the coldest days of the year, when it exceeded 200 GWh per day. It should be remembered that despite a few days of high demand from thermal plants, annual gas-fired generation continued to fall, reaching its lowest level since 2014 in 2024.

In Germany, the Dunkelflaute episode in December was the most significant of 2024 because of its duration and its effect on prices. This is not a new phenomenon: using an (arbitrary) definition based on the combination of both wind and solar load factors below the second decile at the same time[16], episodes lasting no more than two days have occurred 10 times since 2016 in Germany. Longer episodes are rarer: since 2016, there have been six three-day episodes and only one four-day episode in 2022.

Episodes with low load factors are rarer in France: over the same period, there were eight two-day episodes, one three-day episode and three four-day episodes with load factors below the second decile, i.e., 12 episodes of two days or more since 2016, compared with 17 in Germany. They are also less intense, with France experiencing just one episode lasting two days or more with load factors below the first decile (in 2017), while Germany experienced four over the same period.

The *Dunkelflaute* phenomenon is generally regional, and diminishes the larger the area

same applied to wind. The deciles for the average daily load factors are:

	Germany		France	
	Solar	Wind	Solar	Wind
First decile	1.9%	6.0%	5.1%	6.9%
Second decile	3.1%	8.7%	7.1%	9.6%

17. Proyectos estratégicos para la recuperación y transformación económica (PERTE).
18. Ministerio para la Transición Ecológica y el Reto Demográfico (MITECO).

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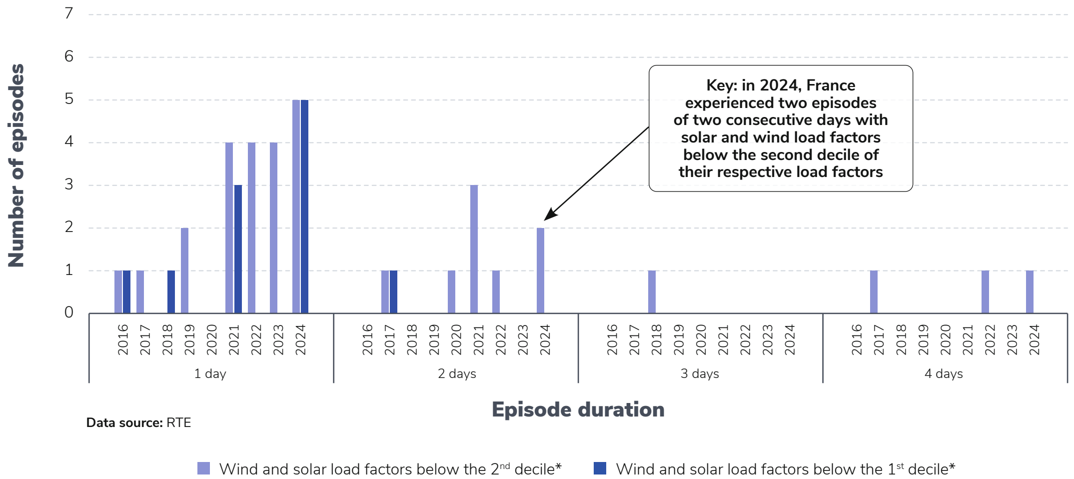
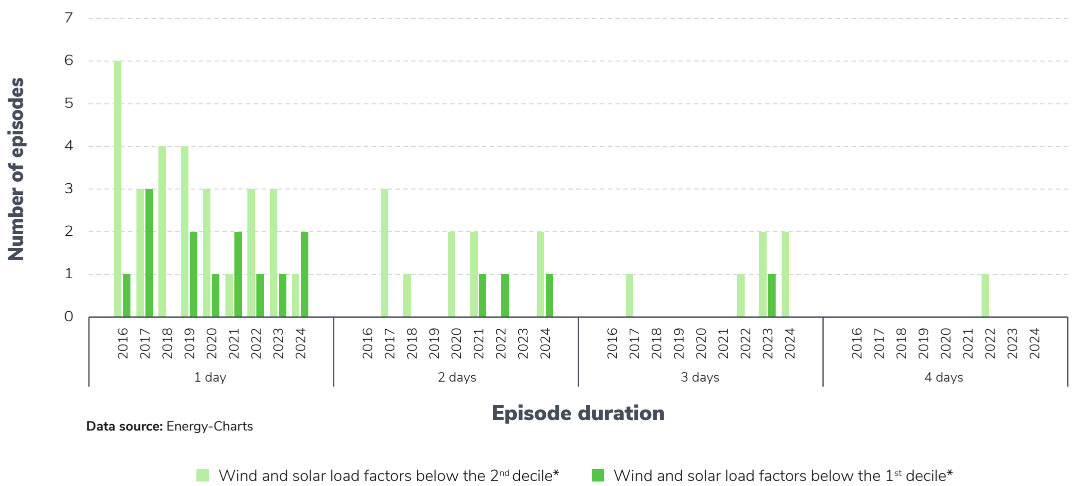
Figure 6.13 – Number of episodes of low wind and solar output in France, per year, by duration



* Situations where the average daily load factors for wind and solar are simultaneously under 10% (1st decile) or 20% (2nd decile) of the lowest daily values observed for these power sources between 2016 and 2024 in France.

Figure 6.14 – Number of episodes of low wind and solar output in Germany, per year, by duration



* Situations where the average daily load factors for wind and solar are simultaneously under 10% (1st decile) or 20% (2nd decile) of the lowest daily values observed for these power sources between 2016 and 2024 in Germany.

under consideration. Across the European Union, even if wind and sunshine patterns are partially correlated, the average load factors for the entire fleet do not remain very low over the long term.

Episodes of low wind and solar production at the same time are not new, though they do occur infrequently; moreover, they are included in the weather scenarios used to assess the security

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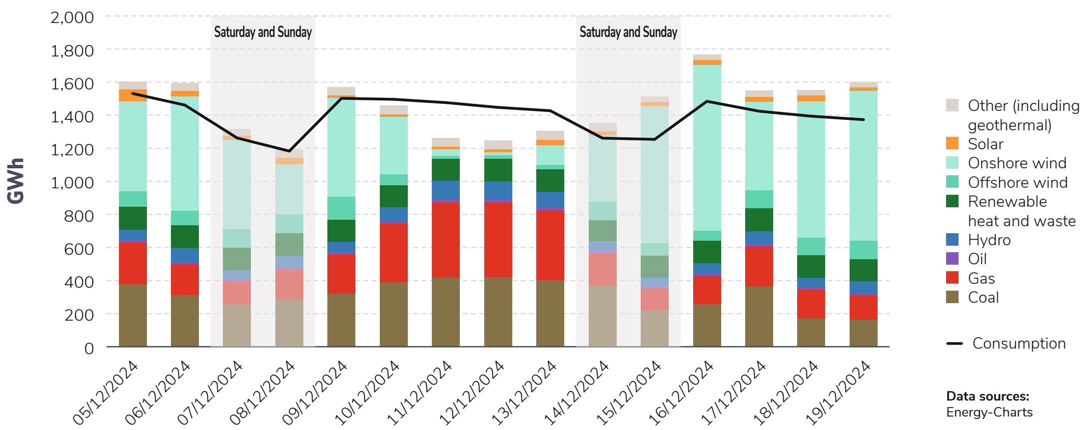
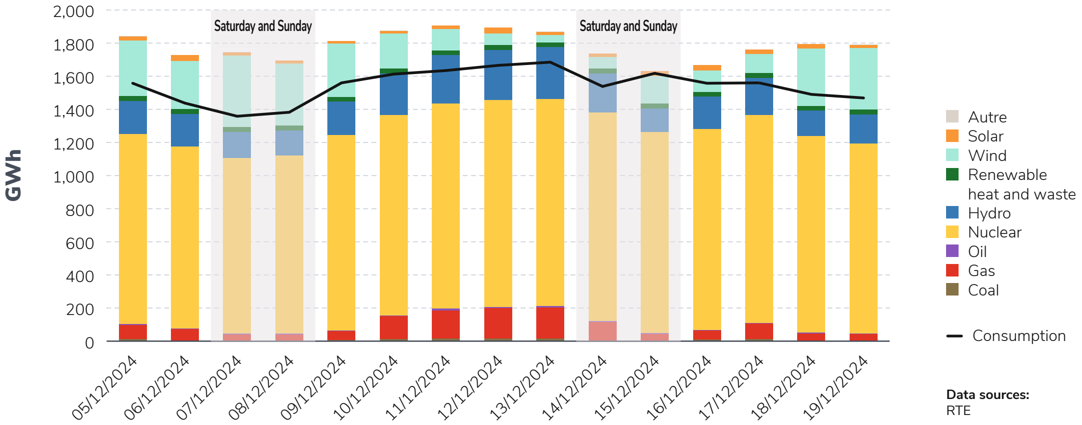
Figure 6.15 – Daily electricity generation in Germany, by source, between 5 December and 19 December 2024



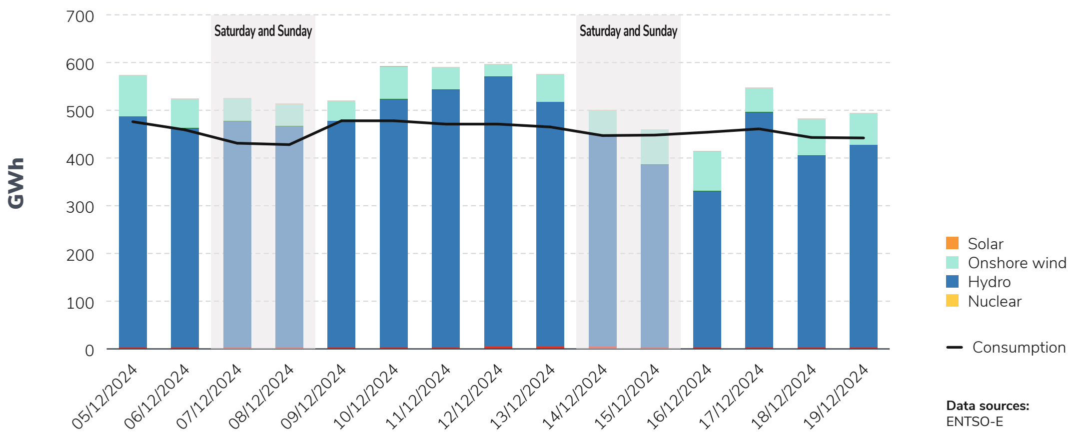
Data sources:
Energy-Charts

Figure 6.16 – Daily electricity generation in France, by source, between 5 December and 19 December 2024



Data sources:
RTE

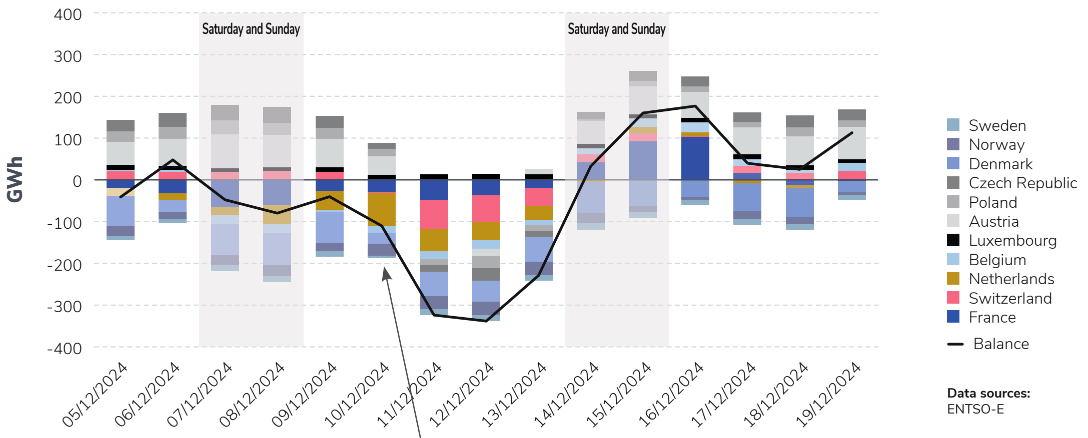
Figure 6.17 – Daily electricity generation in Norway, by source, between 5 December and 19 December 2024



Data sources:
ENTSO-E

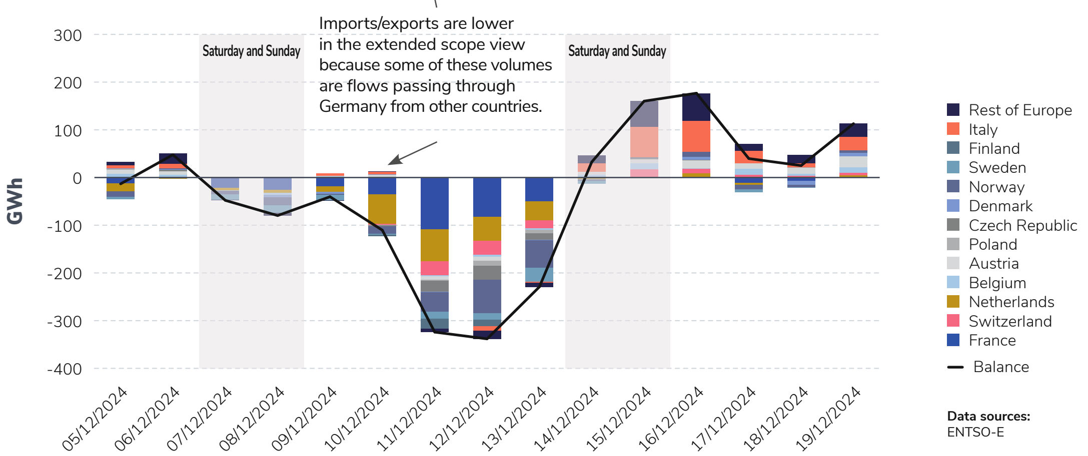
FOCUS

Figure 6.18 – Daily trade between Germany and its direct neighbours between 5 and 19 December 2024



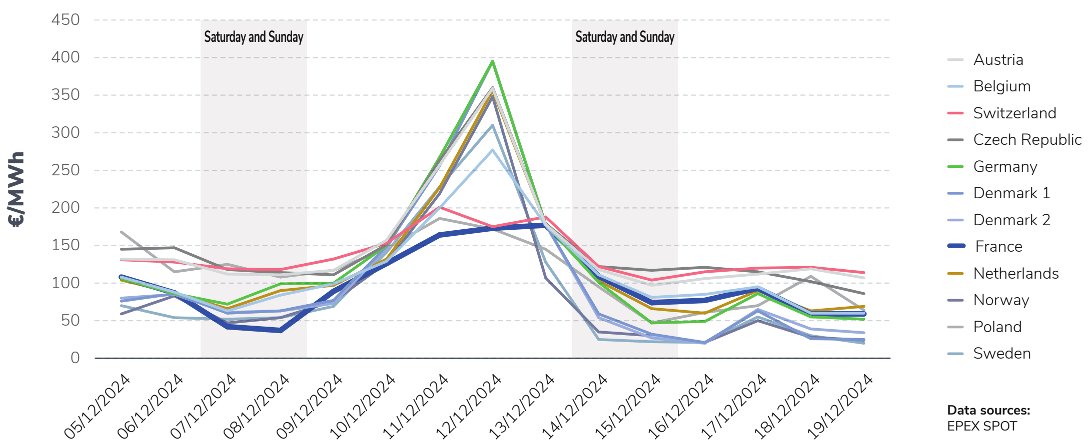
Data sources: ENTSO-E

Figure 6.19 – Daily trade between Germany and other countries (in the "extended scope")



Data sources: ENTSO-E

Figure 6.20 – Average daily spot prices in Germany and neighbouring countries between 5 and 19 December 2024



Data sources: EPEX SPOT

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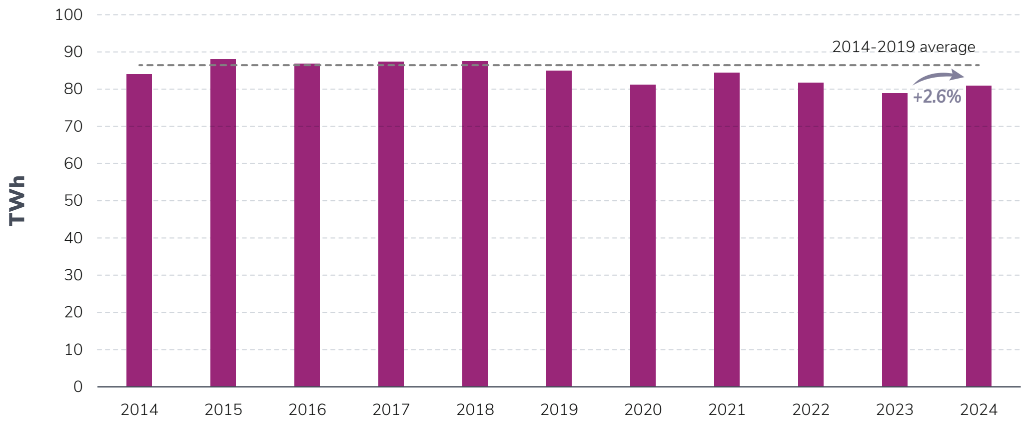
of the electricity supply in each country, as is the case with RTE's winter season analyses and the Generation Adequacy Report, which also includes specific stress tests. Increasing the share of variable renewable power sources in the French and European electricity mix does, however, present challenges for system and grid operation. The development of consumption flexibility (see the Flexibility chapter) could enable full advantage to be taken of low-carbon power when it is abundant and help to reduce consumption during periods of low generation.

Low-carbon imports enabled Belgium to reduce its fossil fuel generation in 2024

Figure 6.21 – Non-adjusted electricity consumption in Belgium



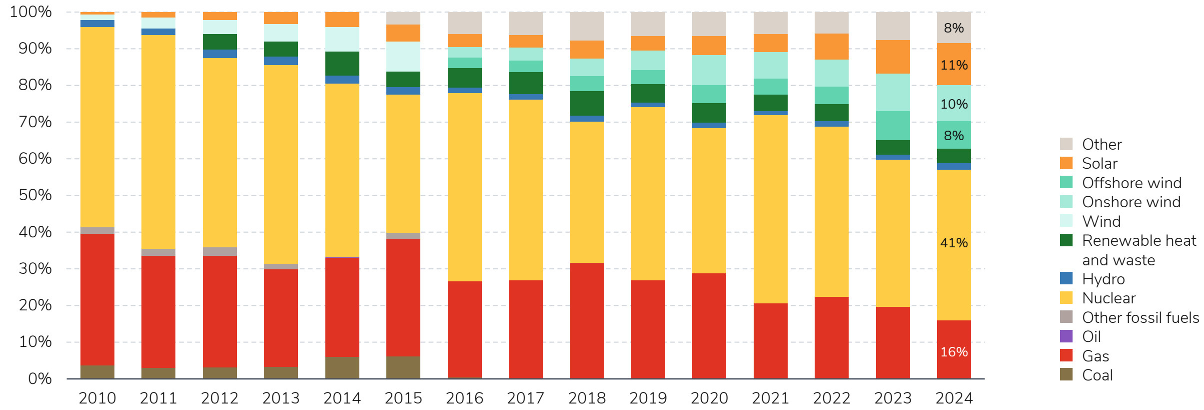
Data sources: ENTSO-E

Belgium's electricity consumption rose by 2.6% in 2024 compared with 2023, reaching 81 TWh, due to a slightly more favourable macroeconomic context[31]. As in France and most other European countries, consumption in 2023 reached its lowest level in recent years, at 79 TWh. In 2024, it remained low compared to the pre-crisis years, and compared to 2021 (post-Covid recovery). Its level was close to that of 2020, when consumption was particularly low in the spring during the first lockdown, then higher during the rest of the year; consumption in 2024 was higher than in 2020 in the spring (March, April and May), but lower during the rest of the year. According to the Belgian grid operator's press release reviewing 2024, the low level of consumption is likely to be temporary: consumption could increase significantly in the coming years as a result of the electrification of uses, and could even double by 2050[32].

Significantly, electricity generation fell by 7.4% (or 5.8 TWh) between 2023 and 2024, to 72.2 TWh, despite the increase in consumption. This was because **the increase in imports, particularly from France (see below), reduced demand for thermal resources: the drop in generation mainly concerned gas, down 4 TWh (–25%), whose share of the mix fell from 20% to 16%.** Wind generation was also down, by 1.6 TWh, due to unfavourable weather conditions, but still accounted for 18% of total generation, as in 2023. Solar generation increased by 1.1 TWh thanks to the expansion of the solar fleet, reaching 11% of the mix. Output from other sources changed little between 2023 and 2024. Nuclear generation remained stable, for example, representing 41% of the generation mix. Following the closure of the Doel-3 nuclear power station in 2022 and Tihange-2 in 2023, the Belgian nuclear fleet remained unchanged in 2024. Further closures are planned in stages in 2025: Doel-1 (February), Tihange-1 (October) and Doel-2 (December). These reactors generated 10.3 TWh in 2024, or 14.3% of total output. The other two reactors in operation (Tihange-3 and Doel-4) were also initially due to close in 2025, but a project to extend

33. Ouest France, La France et la Belgique pourront s'échanger plus d'électricité dès cet hiver (France and Belgium will be able to trade more electricity from this winter), 2022

Figure 6.22 – Belgian electricity mix between 2010 and 2024



Data sources: ENTSO-E

their life until 2035 is under way. **Structurally, as in other European countries, fossil-fired generation has fallen sharply in recent years, from 33% of the mix in 2014 to 16% in 2024, replaced by renewable generation, whose share of the mix has risen from 11% to 29% over the same period.**

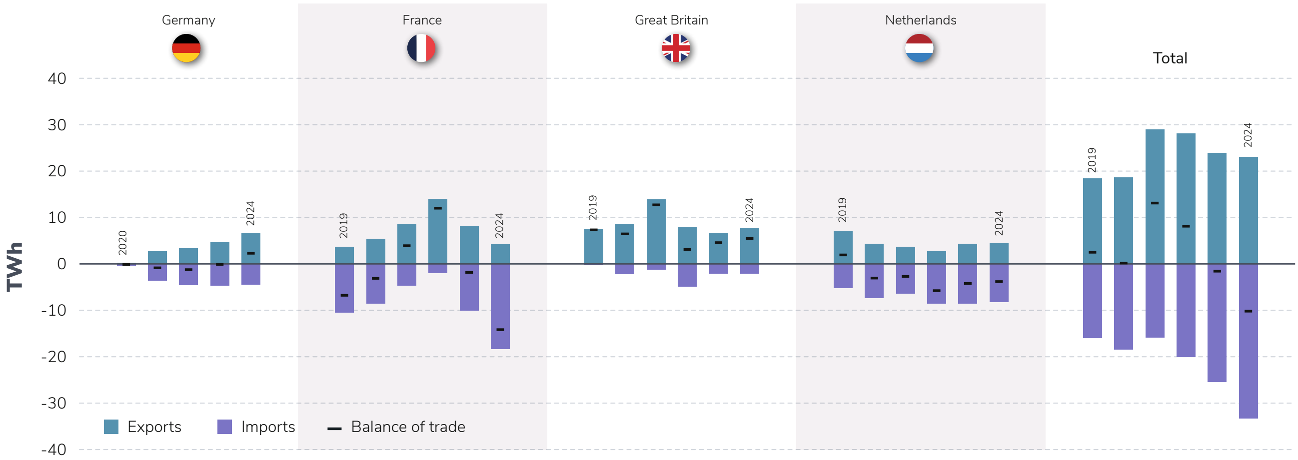
As the Belgian power system is relatively small compared with its neighbours France, Germany or the UK, it is common for the volume of electricity generated to vary significantly from one year to the next, depending on electricity trade with other countries. Over the period from 2010 to 2024, the variation between the lowest annual generation (2015) and the highest annual generation (2021) was 28 TWh, a volume equivalent to around 40% of total generation in 2024. Over the same period, the variation between the lowest and highest annual generation volumes was 104 TWh for France, which represents 24% of 2024 output. For France, therefore, the variation is less significant in proportion to the total, despite the historic fall in generation in 2022 as a result of the crisis affecting nuclear and hydropower. In addition, Belgium exported 32% of its generation in 2024, compared with 20% for France, despite France reaching an all-time export record in 2024.

The volume of imports reached 33 TWh in 2024, a record for Belgium, which is not a structural importer (between 2020 and 2022, the trade balance was positive). Analysing trade by border, the main change compared with the previous year concerns the balance of trade with France, which was strongly negative in 2024. The net volume imported by Belgium from France was equivalent to almost 18% of Belgian consumption, whereas the balance between the two countries was almost neutral in 2023. Since 2020, Belgium's balance with Germany has gradually become positive. Trade with Great Britain and the Netherlands has changed little over the years. Great Britain is a structural importer from all continental European countries, including Belgium, due to higher prices than on the continent; conversely, Belgium has been an importer from the Netherlands since 2020. The development of trade has been influenced by the relatively recent installation of interconnection capacity at the Belgian borders. For example, capacity for trade with France was doubled in 2022[33], the first interconnection with Germany dates from 2020[34] and the interconnection with Great Britain opened in 2019.

Given its geographical position, a proportion of Belgium's trade consists of "through" flows, from

34. RTBF, Interconnexions des réseaux électriques (Interconnections between electricity grids), 2020
35. Elia, Summer Outlook, 2024
36. Elia, Mesures d'urgence sur le réseau électrique belge évitées pendant l'été grâce au comportement adapté des acteurs de marché, aux conditions météo

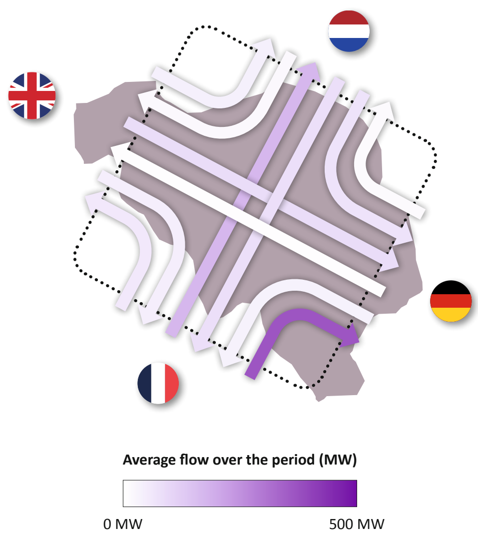
Figure 6.23 – Trade between Belgium and its neighbours



Data sources: - Elia, the first Belgium/Germany interconnection, dates back to 2020

one neighbouring country to another. In particular, the bulk of exports across the German border in 2024 was due to through trade from France, i.e. imports from France that are simultaneously re-exported to Germany. Other flows cross Belgium towards the Netherlands. The volume of cross-border flows from France to the Netherlands and Germany in 2024 totalled 4.7 TWh, or 20% of Belgium's exports.

Figure 6.24 – Trade through Belgium in 2024

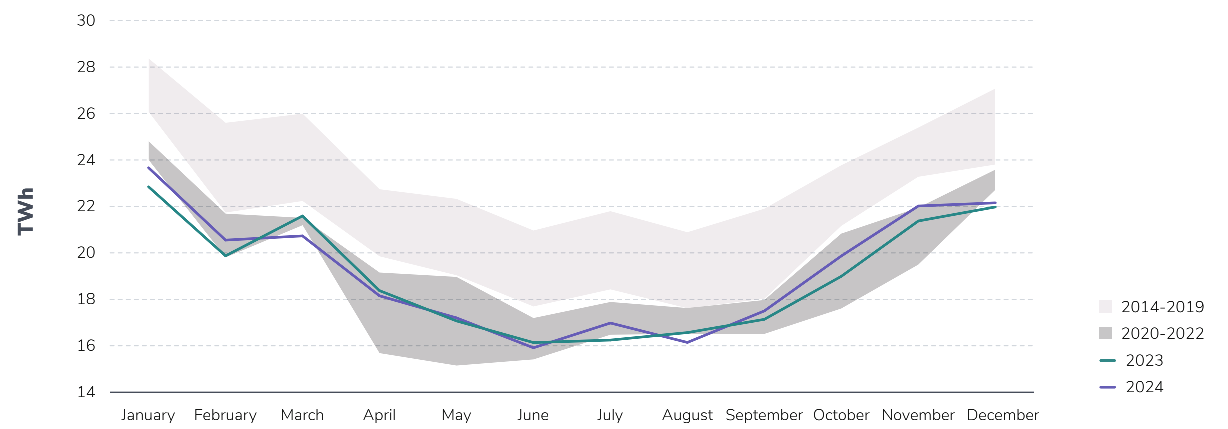


The increase in the share of renewable generation is creating the same challenges in Belgium as in France and other countries with regard to the operation of the power system, particularly in terms of the need to develop flexibility, which can be seen in the increase in negative price episodes (see the *Prices* chapter). For example, in its outlook for the summer of 2024, the Belgian grid operator Elia anticipated the risk of a supply-demand imbalance caused by low consumption in a context of high solar output and high availability of the nuclear fleet, which would have required large-scale exports to restore the balance[35]. In the end, these fears did not materialise, and in the autumn Elia noted that there were no problems, thanks to well-functioning markets, rising consumption and lower-than-expected solar production due to "gloomy" weather. The grid operator says it is working on measures to further develop flexibility in the market over the coming summers[36].

et à la consommation en hausse (Emergency measures on the Belgian electricity grid avoided during the summer thanks to market players adapting their behaviour, weather conditions and increased consumption), 2024

Great Britain completed its phase-out of coal in 2024

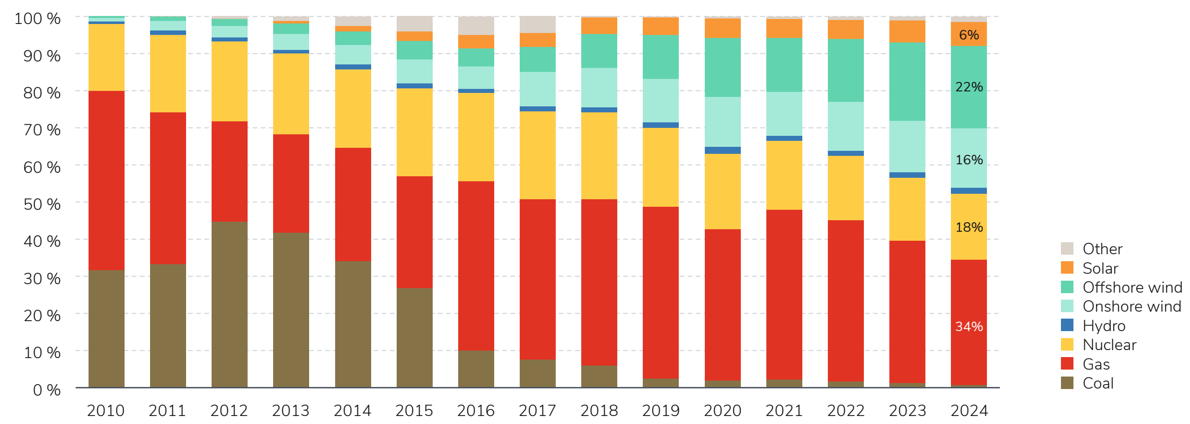
Figure 6.25 – Monthly non-adjusted electricity consumption in Great Britain between 2010 and 2024



Data sources: National Grid

Electricity consumption rose slightly in Great Britain in 2024, reaching 231 TWh (+1% compared with 2023). This increase was driven in particular by the residential and tertiary sectors, as a result of the improvement in the economic climate, while the industrial sector saw consumption fall in the second and third quarters[27,28,29].

Figure 6.26 – Great Britain's electricity mix between 2010 and 2024



Data sources: National Grid

29. Department for Energy Security and Net Zero, UK Energy Trends, Q3 2024
30. National Grid, The history of energy in the UK, 2024.
31. For example, inflation was 3.1% in 2024 compared with 4.1% in 2023 and 9.6% in 2022 (source: Federal Planning Bureau).

British electricity generation was 4.3% lower in 2024 than in 2023, at 215 TWh. This decrease was linked to the increase in imports (see below).

The evolution of the electricity mix continued the trend of previous years: the share of fossil-fired generation continued to fall, compensated by the increase in output from renewable sources. While Great Britain has seen a rising trend in its imports in recent years, due partly to growth in trade capacity, these imports rose sharply in 2024 (see figure), which also made it possible to reduce the use of fossil fuels with high marginal costs.

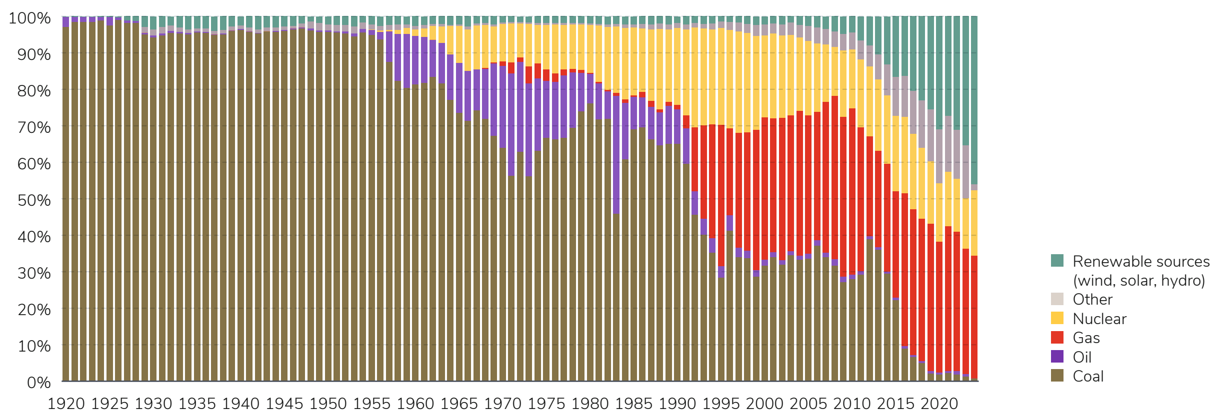
The last remaining coal-fired power station in the UK, at Ratcliffe-on-Soar, was shut down for good on 30 September, marking the end of coal-fired power generation in the country. Coal accounted for almost 100% of Great Britain's electricity mix until the mid-1950s, and more than a quarter until 2015. It was also in Great Britain that the first coal-fired power station, with an output of 93 kW, was commissioned, in London in 1882[30]. In 2024, Ratcliffe-on-Soar still generated 1.6 TWh, or 0.7% of the mix. For comparison, the two power stations still in operation in France accounted for less than 0.2% of the generation mix in 2024 (0.7 TWh).

Electricity generated by gas-fired power stations (73 TWh) fell sharply in 2024 compared with the previous year (86 TWh), from 38% to 34% of the mix. This power source, which developed from the 1990s as a substitute for coal, is now less in demand thanks to the development of solar and wind energy.

Wind generation saw the biggest increase in output between 2023 and 2024, rising from 79 to 82 TWh (35% to 38% of the mix) and becoming the leading generation source ahead of gas. Onshore wind capacity of 640 MW and offshore of 55 MW were installed during the first nine months of 2024, bringing the totals to 16.1 GW of onshore wind capacity and 14.8 GW of offshore wind capacity at the end of September. Although solar power is a lower development priority than wind in the UK, output has continued to grow, reaching 14 TWh in 2024. As a result, its share of the mix rose from 6% to 6.5%. The UK had installed 1.2 GW of solar photovoltaic capacity by September 2024, bringing the total to 17.4 GW.

Prices in the UK are structurally higher than in neighbouring countries, making the country a structural importer. In 2024, the net annual import balance rose by 42% on the previous year to 33 TWh, corresponding to 14% of consumption. The breakdown by

Figure 6.27 – Great Britain's electricity mix between 1920 and 2024

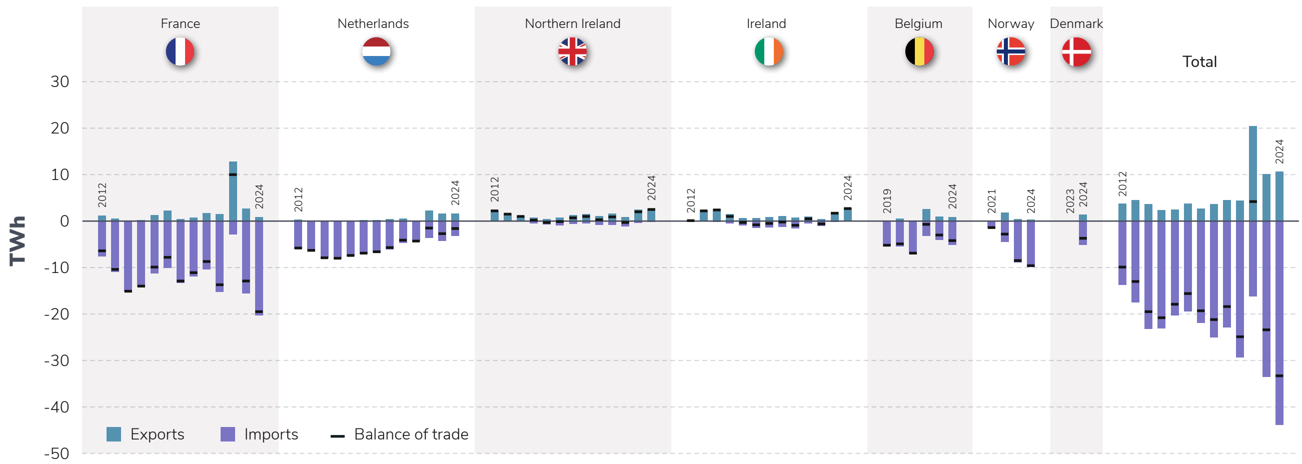


Data sources: Department for Energy Security and Net Zero, National Grid

32. Elia, press release, 2025

border remained similar to 2023, though at different levels. Net import balances from the interconnected countries with the least carbon-intensive and least costly mixes, namely France, Norway and Denmark, reached their highest levels ever, at 19.5 TWh, 9.6 TWh and 3.7 TWh respectively. The UK has developed its interconnections in recent years, with those with Norway and Denmark becoming operational in 2021 and 2023. An increase in capacity from 800 to 1400 MW on the Viking Link interconnection with Denmark is planned for 2025 thanks to adjustments to the Danish network.

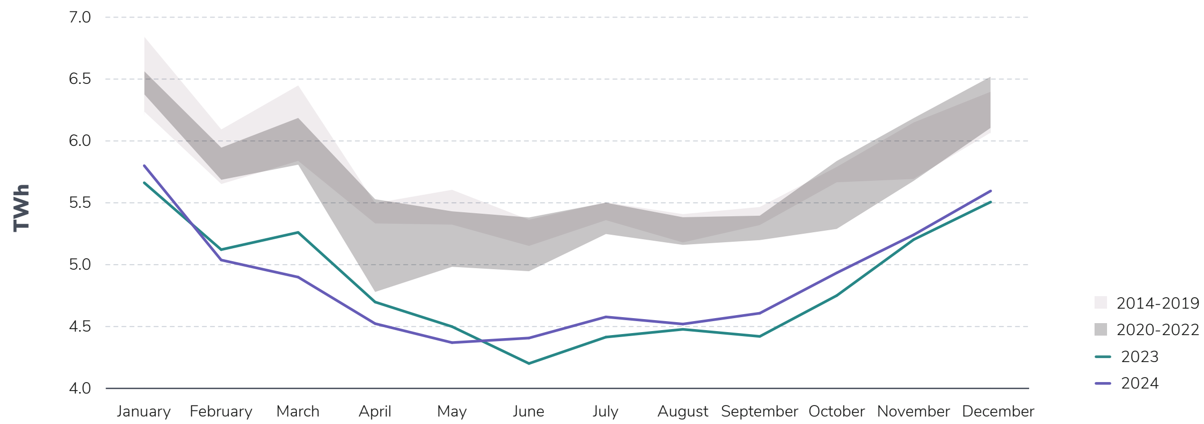
Figure 28 – Physical exchanges of electricity between Great Britain and its neighbours



Data sources: National Grid

Austria saw a jump in solar generation in 2024

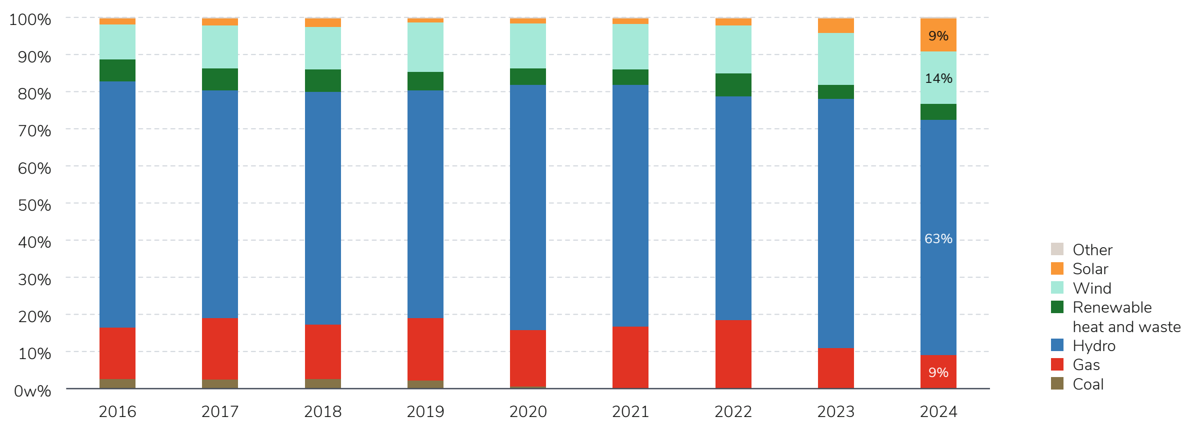
Figure 6.29 – Monthly non-adjusted electricity consumption in Austria between 2014 and 2024



Data sources: ENTSO-E, Eurostat

At 63.5 TWh, Austrian electricity consumption remained relatively stable between 2023 and 2024 (with a slight decrease of less than half a percentage point), still well below the levels of the pre-crisis years. This relative stability masks larger seasonal variations. Between February and May, consumption in 2024 was well below the 2023 level, mainly because of high temperatures – up to 4.4°C higher on average in February than in 2023. In the following months, however, consumption rose higher than in 2023, driven by lower prices, before returning to almost the same level as in 2023 in November and December.

Figure 6.30 – Austrian electricity mix between 2016 and 2024



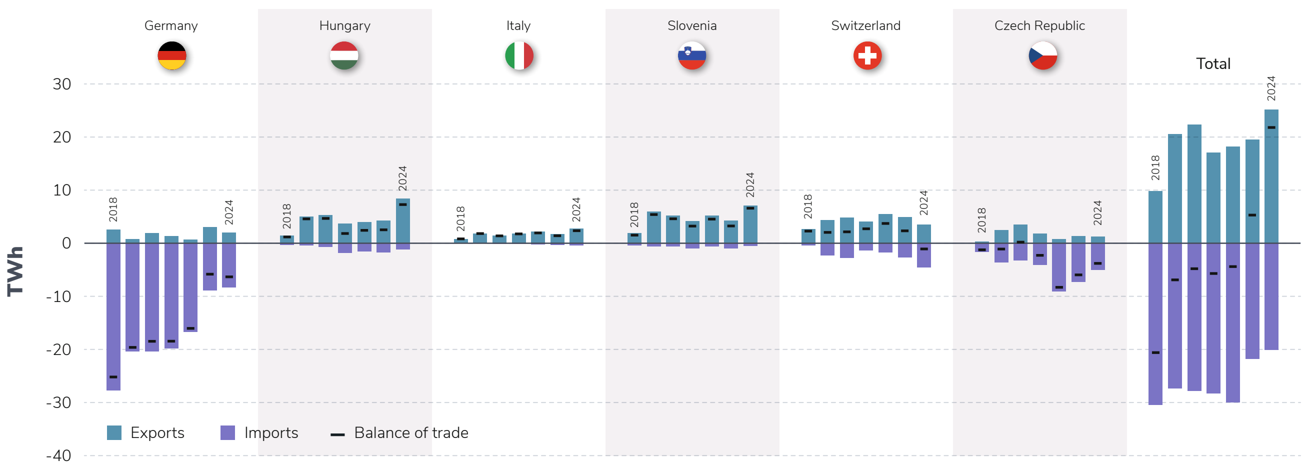
Data sources: ENTSO-E

Austrian generation increased by 11% between 2023 and 2024. Solar output saw a spectacular leap in 2024, rising from 2.3 TWh and 4% of the mix in 2023 to 5.8 TWh and 9% of the mix in 2024. In fact, 2.6 GW of solar capacity was installed in 2023, representing growth of 68%. Although the rate of installation slowed slightly in 2024, the solar fleet continued to expand by a further 2 GW, bringing total installed capacity to 8.4 GW[23]. The majority of installations were roof-mounted panels rather than photovoltaic power plants[24]. Hydropower production, historically the largest component of the Austrian mix, increased by 1.9 TWh in 2024 thanks to a 10% increase in rainfall. However, as a result of solar growth, its share of the mix fell from 67% to 63%.

This drive to install solar capacity was boosted by the Austrian parliament's vote in July 2021 to adopt a new law on renewable energy development. The law sets a target for 100% of its electricity to be generated from renewable sources by 2030, more ambitious than Germany's target (80% by 2030). Austria already has a largely renewable generation mix thanks to its hydropower capacity. New installations benefit from a feed-in premium mechanism[25], similar to the French premium scheme, particularly for photovoltaic installations of more than 10 kW. Investment support is also included for small installations, with bonuses if they are equipped with a storage system.

Austria's net balance of electricity trade in 2024 amounted to 5 TWh of exports, corresponding to 8% of the country's generation. The trade balance had been strongly negative in 2018, was slightly negative between 2019 and 2022 and became slightly positive in 2023. There are two main factors behind this development. Firstly, the net volume of imports from Germany has fallen sharply in recent years, dropping from 25 TWh to 6 TWh between 2018 and 2024. The fact that Austria is generally an importer from Germany reflects the price differential between the two countries, as the German price is generally lower than the Austrian price. However, this price differential narrowed in 2024 to €3/MWh, compared with €10/MWh in 2021, €25/MWh in 2022 and €7/MWh in 2023. The reason for the closing of the gap in 2023 and again in 2024 is the fall in Austrian prices due to growth in solar power and the general reduction in

Figure 6.31 – Electricity trade between Austria and its neighbours



Data sources: ENTSO-E

25. E-Control, Renewable Energy Expansion Act, 2021
26. Balkan Green Energy News, What is behind electricity price spike in SEE: grid issues, and something more, 2024
27. Department for Energy Security and Net Zero, UK Energy Trends, Q1 2024

prices following the energy crisis of 2021-2022. The second determining factor in Austria's shifting trade balance is the considerable increase in the export balance to Hungary in 2024. Austria is generally an exporter to Hungary, where market prices are usually higher. The price differential between the two countries rose sharply in 2024, from €4.7/MWh in 2023 to €19.3/MWh. In particular, Hungarian prices were very high during the summer of 2024, for three reasons[26]:

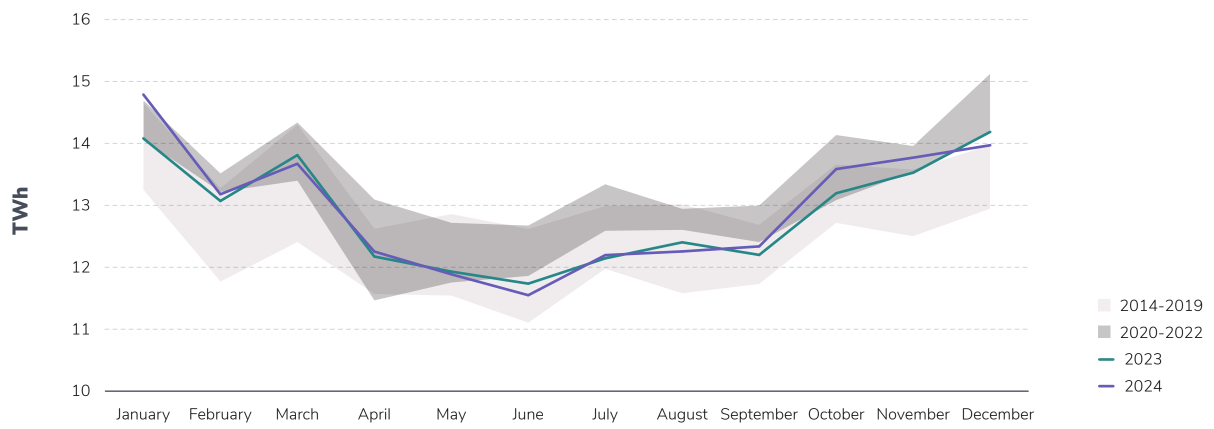
- A heatwave in Eastern Europe, with temperatures over 40°C for several days in Hungary, leading to an increase in peak summer consumption of almost 1 GW, or 18% of demand;
- The delayed return to availability of a nuclear power station and reduced output from coal-fired power stations;
- Constraints on Hungary's import capacity.

Trade across the Italian, Slovenian and Czech borders changed little between 2023 and 2024, with the net balance remaining positive to Italy and Slovenia and negative from the Czech Republic. However, the situation reversed for Switzerland in 2024. The net trade balance was slightly positive in 2023, at 2.3 TWh, then became negative at -1.1 TWh in 2024.

28. Department for Energy Security and Net Zero, UK Energy Trends, Q2 2024

In Poland, the decline in coal-fired generation, historically the majority source, is continuing

Figure 6.32 – Monthly non-adjusted electricity consumption in Poland between 2015 and 2024



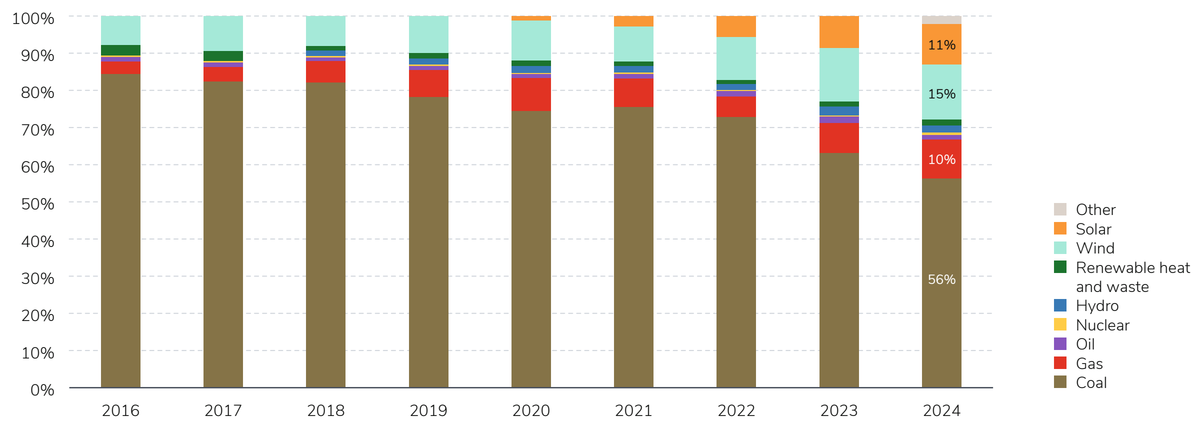
Data sources: ENTSO-E, Eurostat

Electricity consumption in Poland rose slightly in 2024 to 155 TWh, 1 TWh more than in 2023 (+0.7%). As in other European countries, however, it remains below the level of the years before the pandemic and the energy crisis. At 9 a.m. on 9 January 2024, Poland experienced a historic consumption peak of 28.4 GW due to a cold snap, when temperatures reached -20°C[21]. Polish electricity consumption is slightly temperature-sensitive (see Fig. 2), which meant that consumption in January was higher than the range for January in previous years since 2015.

Generation rose by 5 TWh in 2024 to 158 TWh (+3% compared with 2023). Despite the fact that coal is still a significant part of the generation mix (56% in 2024, 89 TWh), electricity generation in Poland is following a clear trajectory of low-carbon development: in 2016, coal still accounted for 84% of the mix. Since then, wind and solar farms have expanded to account for 26% of generation in 2024, at 41 TWh. The solar sector in particular has grown rapidly from a still-negligible figure in 2019 to 11% of generation in 2024 (17 TWh). In its national energy and climate plan submitted to the European Commission in 2019, Poland set a target of 32% for electricity generated from renewable sources by 2030[22]. This target has been raised to 56% in a new version of the plan currently being validated. New capacity is installed via auctions, which operate in a similar way to the French premium scheme and are held every year. A rule introduced in 2016, requiring a minimum distance of 2,000 metres between wind farms and homes, has in the past limited the participation of wind projects in these auctions, favouring photovoltaic projects. This distance was reduced to 700 metres in 2023, and a bill proposes to reduce it further to 500 metres.

23. SolarPower Europe, EU Market Outlook for Solar Power, 2025
24. IEA, National Survey Report of PV Power Applications in Austria 2023, 2024

Figure 6.33 – Polish electricity mix between 2016 and 2024



Data sources: ENTSO-E

Poland also plans to install between 6 and 9 GW of nuclear capacity over the next 20 years. The American company Westinghouse has been selected to build the first reactor, with construction due to start in 2026.

Poland's overall trade profile has changed significantly in recent years. From record imports in 2020, the country became a net exporter in 2022, before becoming an importer again in 2023 and 2024. The balance amounted to 2.5 TWh of imports in 2024, a relatively low volume compared with the country's consumption (1.6% of consumption). Poland continued to import heavily from Sweden (3.3 TWh over the year) and exported little (0.5 TWh), while exporting to Slovakia and Lithuania (net balances of 1 TWh and 3 TWh respectively). Imports from Germany (6 TWh) accounted for almost half of total imports in 2024, up on previous years. Imports from Germany were particularly high (over 0.5 TWh/month) during periods of high renewable generation: in January and February (high wind output) and from May to August (high solar output).

In Spain, renewables now account for the majority of the generation mix

Spanish consumption increased by less than 1% between 2023 and 2024, reaching 249 TWh. It followed the same momentum as the rest of Europe, with a reversal of the downward trend observed in 2022 and 2023, while remaining below the consumption levels of the years before the pandemic and the energy crisis.

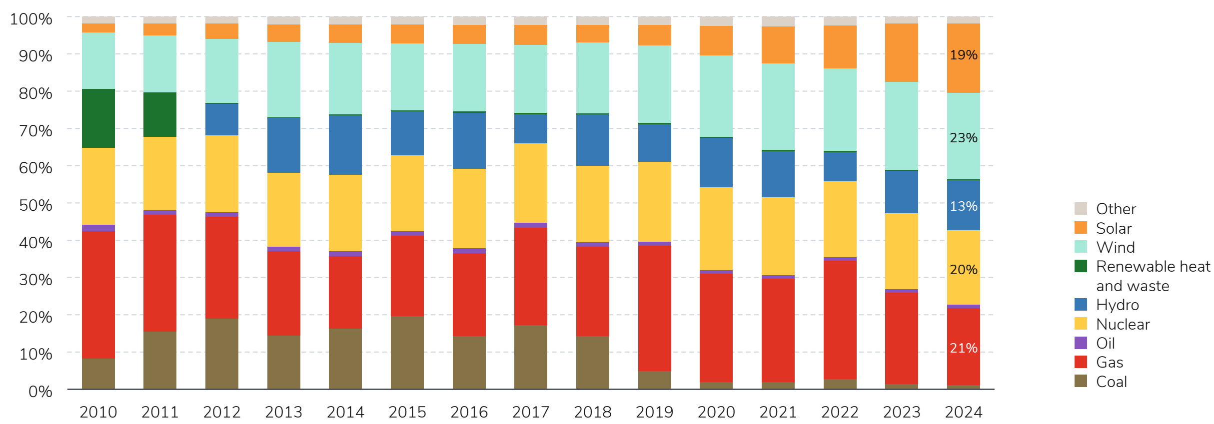
Total electricity generation in Spain remained particularly stable between 2023 and 2024, at 262 TWh, while the mix varied significantly. The share of hydro and solar power increased, leading to a fall in the share of gas. Other sources remained stable.

Solar generation rose by 15% to 49 TWh in 2024, thanks to 6 GW installed in 2023 and 9 GW installed in 2024, bringing the total to 38 GW. The solar share of the Spanish mix reached 19%, doubling in four years. Hydropower generated 40 TWh, or 13% of the mix, the first time this has been achieved since 2016, due to a sharp rise in rainfall, as in the rest of Europe. Wind generation fell by 1.8 TWh year-on-year to 60.9 TWh, a drop of 3%, due to less favourable weather conditions. The 832 MW of new capacity installed (bringing the total to 31.7 GW) only partially compensated for the poor wind conditions. Thanks to the overall increase in renewable power, the volume of gas-fired generation fell by 11 TWh (–17%) between 2023 and 2024, with 54 TWh generated in 2024.

In total, low-carbon generation exceeded 76% of the generation mix (56% renewable and 20% nuclear), compared with 71% in 2023 (51% renewable and 20% nuclear). In neighbouring Portugal, the share of renewable generation reached 89% in 2024. This abundance of low-carbon generation on the peninsula (which can also be exported to France or other European countries via France) pushed Spanish wholesale prices to relatively low levels, comparable with French prices (see the *Prices* chapter). As a result, trade between Spain and France was much more balanced than between France and its other neighbouring countries, which imported large quantities of French electricity.

In September 2024, the Spanish government submitted an update of its integrated National Energy and Climate Plan to the European Commission, accelerating the pace of the transition. Compared with the previous version in 2019, the share of

Figure 6.34 – Spanish electricity mix between 2010 and 2024



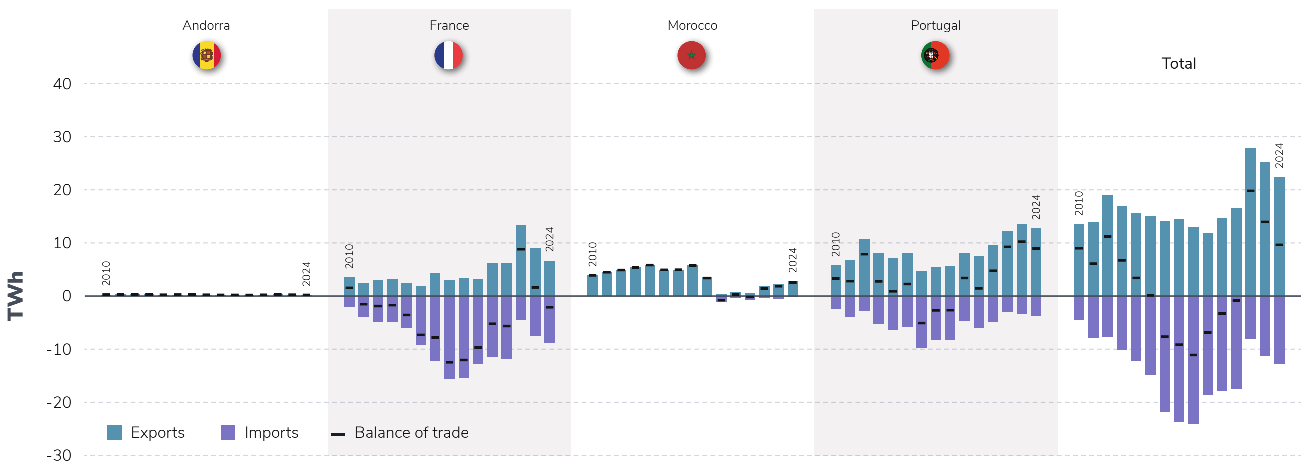
Data sources: REE

renewable energy in the electricity mix by 2030 has been increased from 74% to 81% (remaining at 100% by 2050). Coal will have to be phased out in 2025, though production from this resource was 3 TWh (1% of the mix) in 2024.

To facilitate the integration of renewable energy into the electricity grid and meet the resulting need for flexibility, the Spanish NECP aims to achieve 22.5 GW of electricity storage capacity by 2030, all technologies combined. Spain currently has around 8 GW of storage installed. One way of achieving this target is through calls for PERTE project tenders[17]. The Ministry for the Ecological Transition and the Demographic Challenge[18] used these calls for tender to select storage projects totalling 904 MW in 2023[19] and 690 MW of batteries in 2024[20], which will receive a total of €300 million in grants. The first case mainly involves batteries that can deliver their maximum capacity for two to three hours, coupled with solar or wind installations. The second case consists of independent batteries with around four hours' storage capacity. Installation of these batteries is scheduled for 2025 and 2026.

Spain's trade balance varies from year to year: the country was a net exporter in the early 2010s, before becoming an importer in 2016 and then an exporter again from 2022. The export balance remained positive in 2024 at 9.6 TWh, a slightly lower volume than in 2023. In particular, the export balance with France was slightly positive in 2023 (1.9 TWh), before turning slightly negative in 2024 (–2.8 TWh), which explains most of the variation. Spain became a significant exporter to France in 2022 as a result of the energy crisis, with net exports of 9.1 TWh. France was hit harder than Spain because of the crisis in French nuclear generation, which compounded the rising gas prices and drought.

Figure 6.35 – Physical exchanges of electricity between Spain and its neighbours



Data sources: REE

19. Gobierno de España, Conoce los proyectos financiados en la primera convocatoria para impulsar el almacenamiento conectado con plantas de generación renovable, 2024
20. Gobierno de España, Transición Ecológica allocates 156 millones to 45 innovative independent and thermal storage projects, 2024
21. Warsaw Business Journal, Historic power demand in Poland recorded on January 9, 2024
22. Ministry of Climate and the Environment, National Energy and Climate Plan, 2021

Flexibility

2024 ELECTRICITY REVIEW

Introduction

An increase in flexibility requirements driven by renewable energy development

The operation of the power system requires a constant balance between electricity generation and consumption. Until now, maintaining this balance has mainly relied on the flexibility offered by dispatchable generation resources (particularly nuclear, fossil-fired and reservoir hydro power plants). Other mechanisms, such as adjustments to consumption or the use of storage facilities, also help to ensure the balance between supply and demand, but to a lesser extent than generation flexibility. Trade with neighbouring countries, which optimises the operation of the power system on a European scale by pooling resources, is also an important factor in balancing the power system in real time.

Adapting the consumption profile to the generation profile, or "demand flexibility", is thus one of the levers available for balancing supply and demand, and is becoming increasingly necessary with the growth in the volumes of inflexible renewable electricity generated (wind and solar). However, this is not a new concept: the spread of "off-peak" tariffs from the 1960s onwards made it possible to shift a proportion of consumption away from daytime hours, when it is higher, to night-time hours, when it is generally lower, thanks to a more attractive electricity tariff for consumers. This smoothing of demand is very well suited to France's historic mix, which is mainly based on nuclear power, because on one hand it means that less of the more expensive carbon-based generating resources are required during the day, and on the other it reduces the need to modulate nuclear power downwards during the night. Hot water tanks triggered by the "off-peak" signal were developed in the 1980s partly to provide an outlet for abundant nuclear generation at night.

Today, the development of wind and solar capacity is leading to an increase in the need for flexibility, which may involve "structural" adaptations to the consumption profile (to take advantage of plentiful solar generation in the early afternoon, for example), in a similar way to the adaptation that accompanied the development of nuclear power. There are also more specific potential adaptations, as well as other mechanisms such as the development of storage solutions, batteries for the very short term and power-to-gas for inter-seasonal storage.

Different types of flexibility make it possible to address these varied requirements. They can be classified sequentially over time, with the volume of energy displaced decreasing as they approach real time:

- **Structural and regular flexibility** accounts for the bulk of flexibility requirements, which are largely predictable far in advance (based on the natural shape of the load curve, solar power generation during the day, etc.). The challenge lies in scheduling shutdowns of dispatchable generation facilities in relation to periods of lower consumption (summer, weekends) and in structurally modifying load curves to position consumption when low-carbon electricity is abundant.

- **Dynamic flexibility** addresses requirements that are predictable with a lead time ranging from a few days to a few hours (intraday), particularly in response to uncertainty about weather conditions (wind generation, temperature sensitivity of consumption);

- **Balancing flexibility** is used to compensate for unforeseen events (breakdowns, incidents) or uncertainty about sudden changes in the weather, which represent a challenge for managing the balance between supply and demand in real time; the total requirement represents no more than a few GW, and will only increase marginally despite changes in the generation mix;

- **Safeguarding flexibility** concerns the requirements for dealing with exceptional situations affecting the supply-demand balance. This type of flexibility is currently based mainly on the Ecowatt system reporting the days and times of highest risk.

The first three types of flexibilities are used every day and can be valued within the context of wholesale and balancing markets, while safeguarding flexibilities meet exceptional, one-off requirements.

Demand flexibility: a major source of flexibility that can be harnessed now

Flexible consumption can meet different types of flexibility needs. It is easy to schedule certain types of consumption to take place during off-peak hours (see focus below) several months or even years in advance, but it is also possible to optimise the scheduling of certain energy uses up to the day before for the following day, thanks in particular to the development of technologies such as the Internet of Things (IoT).

Flexibility of consumption is therefore a key priority in the management of a power system with a high proportion of renewable energy. It enables the system's operation to be optimised by positioning consumption when low-cost, low-carbon generation (renewable and nuclear) is abundant, reducing consumption at times when the use of fossil-fuel thermal generating units, which are more costly and polluting, would be necessary.

In addition, demand flexibility is an effective and relatively inexpensive method, since in many cases it does not require major investment and involves less consumption of materials. This represents an advantage over battery storage, which can provide a similar flexibility service (shifting generation or consumption profiles by a few hours).

Figure 7.1 – Different types of flexibility, according to need and timeframe

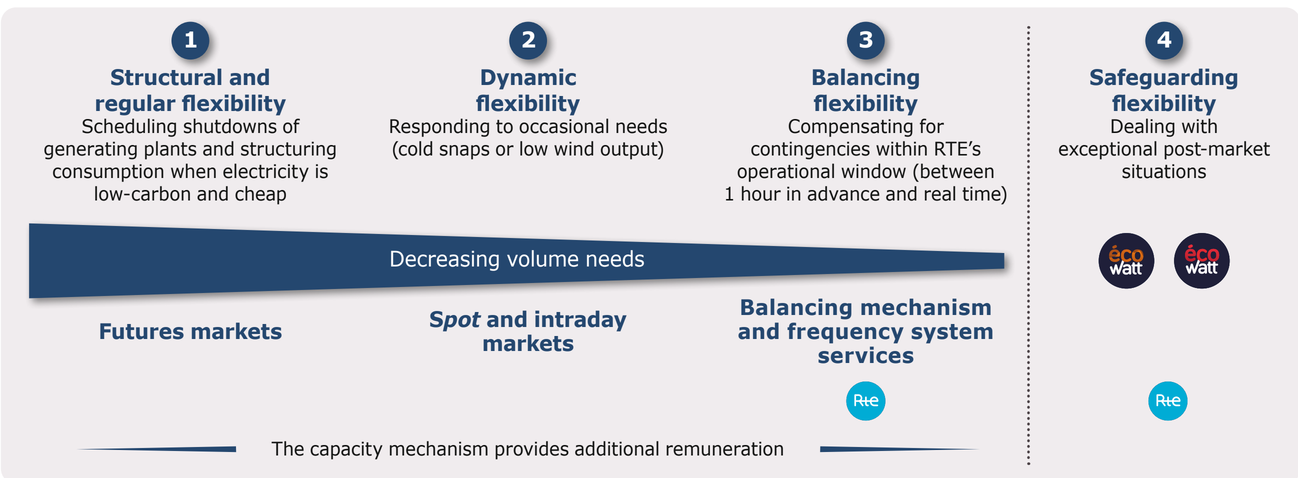
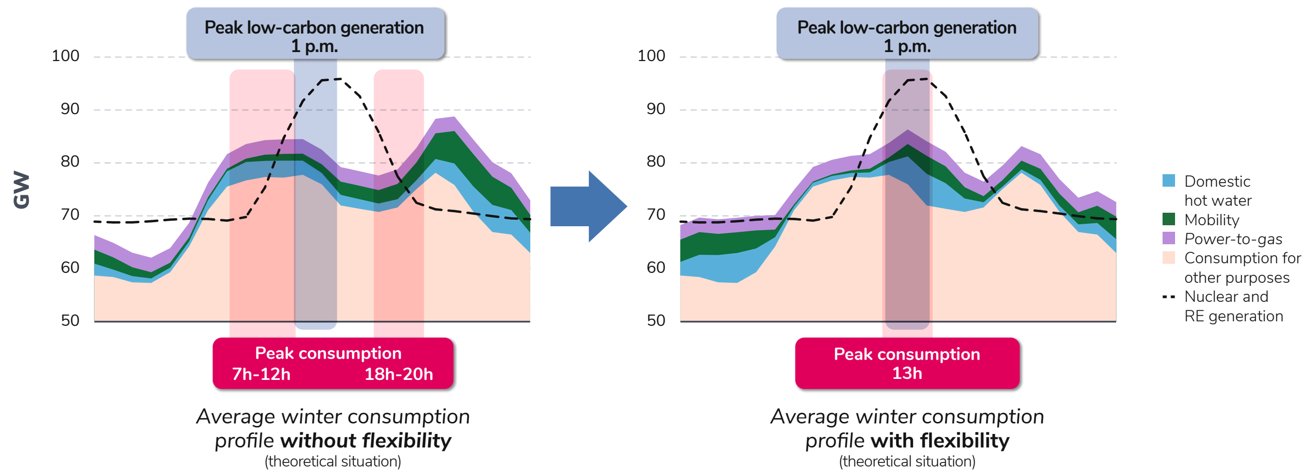


Figure 7.2 – (Prospective) illustration of the effect of flexibility on the positioning of consumption during peaks in low-carbon generation



Several energy uses, whether in the residential, commercial or industrial sectors, can be flexible, and in many cases already are, such as domestic hot water, dishwashers, washing machines and tumble dryers, heating/air conditioning and certain industrial processes. The electrification of consumption now largely covered by fossil fuels (mobility, industrial processes, heating) and the emergence of new energy uses (such as electrolysers) present a major challenge in terms of system flexibility. These are large volumes of additional consumption, but they will be at least partly controllable. Electric mobility, hydrogen production by electrolysis and electric heating in buildings make it possible to adapt the consumption profile at least in part to low-carbon generation and to periods when electricity prices are lowest on the wholesale markets. Electric vehicle batteries can store energy, which means that recharging can be postponed to a certain extent; hydrogen can be stored using suitable infrastructure and heating can be adjusted or postponed using the inertia inherent in buildings. These energy uses thus represent an opportunity to make the consumption profile more flexible, optimising the operation of the system.

A useful indicator for analysing flexibility needs is the residual demand curve, i.e. consumption minus inflexible generation with zero marginal cost (see the rest of this chapter).

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The reform of the peak/off-peak system

The French energy regulation commission (CRE) recently approved[1] a reform of peak and off-peak times, which will be implemented between November 2025 and the end of 2027. **The aim is to bring the off-peak periods[2] into line with the needs of the power system, particularly as a result of the development of solar generation.**

The "peak/off-peak" system divides the hours of the day into two categories: 16 "peak" hours and eight "off-peak" hours, enabling consumers to benefit from reduced rates during off-peak hours.

Currently, for 5.7 of the 14.5 million customers who benefit from this tariff, off-peak hours are divided between the afternoon[3] and the night[4]. For the remaining 8.8 million customers, the off-peak hours are concentrated solely at night. The positioning of these hours is determined by the distribution network operator, taking local network constraints into account. As a result, the distribution of peak and off-peak hours varies from one area to another.

The reform of off-peak times is designed to bring them into line with the new realities of the electricity grid and the increase in solar generation. Some of the night-time off-peak hours will be shifted to the afternoon, to take advantage of cheap and plentiful solar output, particularly in spring and summer. For some customers, off-peak times may change between winter and summer[5]. As a result of these changes, around 13.1 million households will benefit from off-peak hours divided into two periods (afternoon[6]/night[7]), at least in summer, while 1.4 million households will retain off-peak hours at night only. The plan is for five off-peak hours always to be placed at night, leaving a maximum of three off-peak hours in the afternoon.

In 2024, for the 8.8 million customers on the peak/off-peak tariff who only have off-peak hours at night, only 15% of the 5% lowest spot prices occurred during hours that could be off-peak[8]. With the new hours, this percentage would have been 93%. This demonstrates the misalignment that existed between wholesale and retail prices and the considerable benefits of aligning off-peak times better with periods of high solar output. This repositioning of peak and off-peak hours will help optimise the operation of the system, reducing the occurrence of negative spot prices and the volume of renewable generation curtailed during these episodes. The last section of this chapter provides details on the curtailment of renewable generation.

1. In its TURPE 7 tariff deliberation ("tariff for using public electricity networks").
2. This only applies to the "peak/off-peak" tariff, not the "Tempo" tariff, for example.
3. From 8 p.m. to 8 a.m.
4. From 8 p.m. to 8 a.m.
5. From 1 April to 31 October.
6. 10 a.m. to 6 p.m. in summer, 11 a.m. to 5 p.m. in winter.
7. 11 p.m. to 7 a.m. in summer, 9 p.m. to 7 a.m. in winter.
8. For the 60% of customers who only have night-time off-peak hours, there are 12 hours that could be off-peak. After the reform, this number will increase to 16 hours.

Storage: a useful lever, but with cost and/or availability constraints

Storage is another source of flexibility for the power system, providing a response to various needs. The principle of storage is to absorb surplus energy, particularly when consumption is low, and release it when consumption peaks. This can be done on a regular, recurring basis, for example by storing energy in the afternoon in summer and releasing it in the evening, or dynamically, depending on the spot prices available the previous day for each hour of the following day. Technologies with fast response times, such as batteries, can also contribute to balancing flexibility, whether via the balancing mechanism or by participating in frequency system services. In particular, batteries account for a growing proportion of automatic frequency maintenance services in Europe each year, for both primary and secondary reserves.

In France and around the world, almost all installed electricity storage capacity is divided between two technologies: **pumped storage hydropower** (PSH), which transfers large volumes of water between two lakes at different altitudes, and **batteries,** mainly lithium-ion batteries. Worldwide, PSH has long provided the vast majority of capacity, but the rapid development of batteries in recent years means that the ratio is now more balanced[9]. If the recent rate of battery installation continues, this technology could overtake PSH in terms of installed capacity within one or two years.

Other storage technologies are emerging, but are still at an experimental stage. These include thermal batteries, which can store surplus electricity in the form of heat and then redistribute it, still as heat, mainly to industrial processes with continuous needs. Other notable examples are storage using compressed air and storage in the form of hydrogen (through water electrolysis). Alternative battery technologies to lithium-ion are also being developed, including the first battery powered by sodium[10], an abundant and less expensive material, connected to the electricity grid in China in 2024.

In France, pumped storage hydropower provides the largest installed storage capacity, amounting to 5.0 GW of turbines and 4.3 GW of pumping in 2024. This capacity has hardly changed since the last PSH plant was commissioned in the late 1980s. The potential for new installations in France is limited, but a moderate increase in capacity could still be possible in the future according to the players involved (RTE's 2023-2035 Generation Adequacy Report includes 0.5 GW to 1.5 GW of additional PSH capacity in its scenarios for 2035). France has six major pumped storage plants. Most of the PSH plants[11] are "daily", meaning that they can store a quantity of energy that corresponds to a few hours of turbine operation (around five hours, for example). In France, there are also two "weekly" PSH plants (Grand'Maison and Montézic, with a total pumping capacity of 2.1 GW), which can store larger volumes[12], making it possible, for example, to store some of the energy generated over the weekend and use it during the following week. They can also help to smooth out variations in wind power generation over the course of a given week.

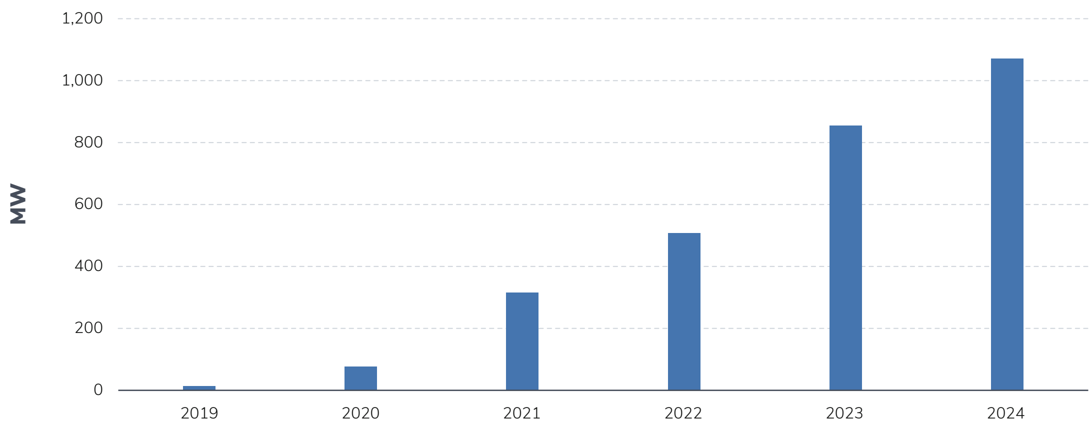
Meanwhile, batteries are designed to store a volume of energy that can be restored for just a few hours (less than four hours or even less than two hours, depending on the type of system), due to the high costs associated with their storage capacity. They can store this energy and return it to the system a few hours or a few dozen hours later[13]. This service is similar to demand-side flexibility (such as controlling the recharging of electric vehicles or the positioning of domestic hot water production during hours of high photovoltaic output), and is particularly useful in scenarios of accelerated photovoltaic development in Europe. The benefits of deploying batteries are therefore largely dependent on the extent to which consumption flexibility is mobilised, and vice versa. The analyses in "*Futurs énergétiques 2050*" (Energy

9. World Energy Outlook 2024 - Analysis - IEA. At the end of 2023, there were around 90 GW of batteries installed worldwide (with around 40 GW installed during 2023) and around 160 GW of PSH (stable over the last ten years).
10. World's biggest sodium-ion battery switches on, able to power 12,000 homes | The Independent
11. The four PSH plants at Revin, Super-Bissorte, Cheylas and La Coche.
12. Ratio between storable energy and power of the order of several dozen hours.
13. This is also a service provided to the French power system by daily PSH.

Futures for 2050) highlighted the strong competition between these two types of solution, which is confirmed by the studies in the 2023-2035 Generation Adequacy Report.

At the end of 2024, battery storage in France amounted to 1,071 MW. This represented an increase of 216 MW over the year, a lower rate of installation than in 2023 (+317 MW).

Figure 7.3 – Total power of grid-connected batteries installed in France between 2019 and 2024

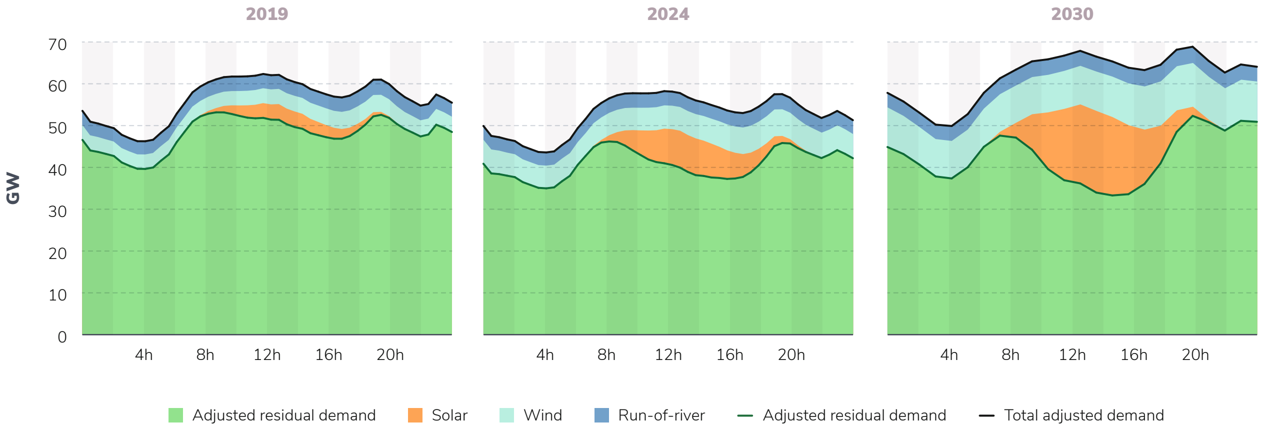


Analysis of the residual load curve shows the challenges associated with flexibility

Residual demand is the demand that remains to be met by dispatchable generation, once non-dispatchable renewable generation has been taken into account: run-of-river hydropower, solar and wind[14]. The non-weather-adjusted figure is a **key indicator for the real-time operation of the power system,** as it determines which dispatchable generation units are mobilised to meet demand. For analysis or forecasting purposes, in order to monitor trends and project them into future years, it is possible to "adjust" residual demand based on weather effects, which makes it easier to compare one year with another[15]. This is known as weather-adjusted residual demand. **The deformation of the residual load curve over time reflects changes in the power system, highlighting the integration of new generation and consumption resources.** In particular, if the profile becomes "flatter", this shows that new uses of electricity are taking place during periods of abundant low-carbon generation, or that existing uses are being shifted[16].

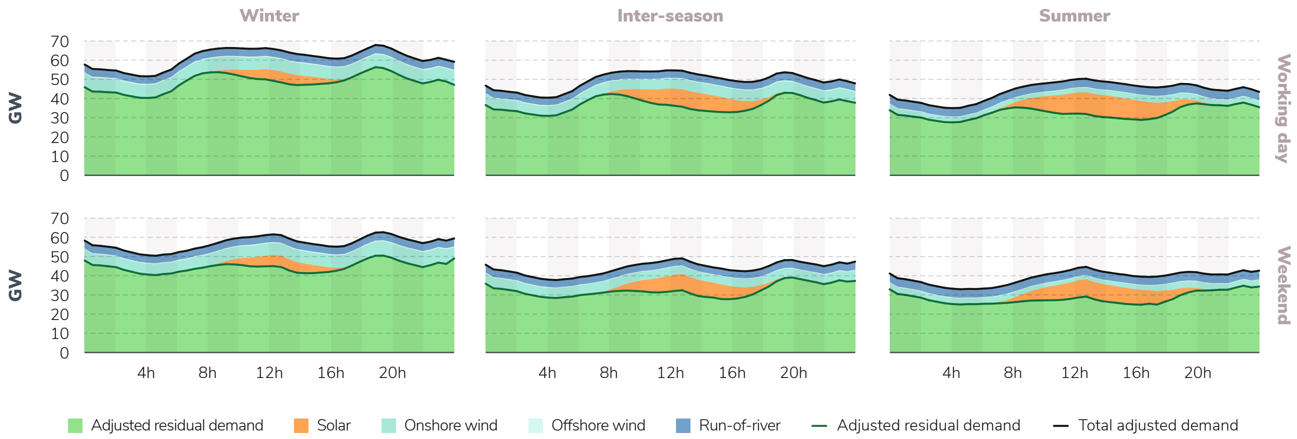
Until recently, the shape of residual demand was very similar to that of total demand: a plateau in the morning, a small dip in the afternoon before peak consumption in the evening and a larger dip at night. All other things being equal, **the development of non-dispatchable renewable energy significantly changes this shape.** Over the last ten years, the average level of residual demand has gradually fallen under the combined effect of increased renewable generation (mainly wind, as far as the average effect is concerned) and, over the last four years, lower consumption than in the 2010s (see the *Consumption* chapter). The residual demand curve has also changed shape, mainly in the middle of the day as a result of increasingly high solar photovoltaic generation: the "plateau" that used to be seen in the morning is gradually disappearing, and the residual curve is now marked by two short peaks lasting a few hours (in the morning and evening) and two troughs (at night and in the afternoon). In the absence of additional flexibility, this trend is likely to

Figure 7.4 – Daily profile of total and residual demand in 2019, 2024 and 2030
Adjusted generation and demand



14. The residual demand is thus the total demand minus inflexible renewable energy generation (photovoltaic, wind and run-of-river hydropower).
15. In particular, the Baromètre des flexibilités de consommation d'électricité (Barometer of electricity consumption flexibility) published by RTE, Enedis, GIMELEC, IGNES and Think Smartgrids in autumn 2024 considers adjusted residual demand.
16. Indicators to be monitored are defined in the Barometer of Flexibility.

Figure 7.5 – Daily profile of total and residual demand in 2024
Unadjusted generation and demand

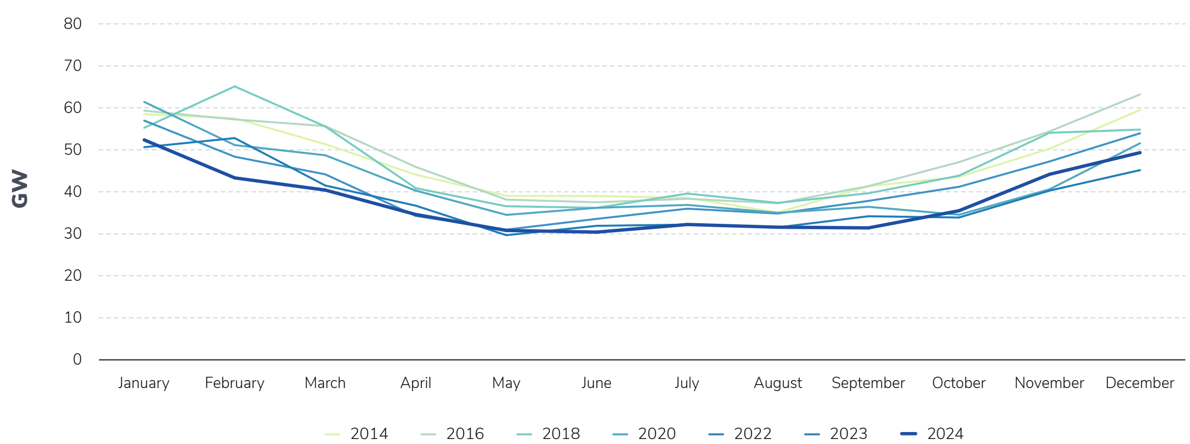


Winter: November–February; summer: May–August; inter-season: March–April and September–October

increase, and the deformation that can be projected for 2030[17] highlights the importance of developing new flexibility tools today.

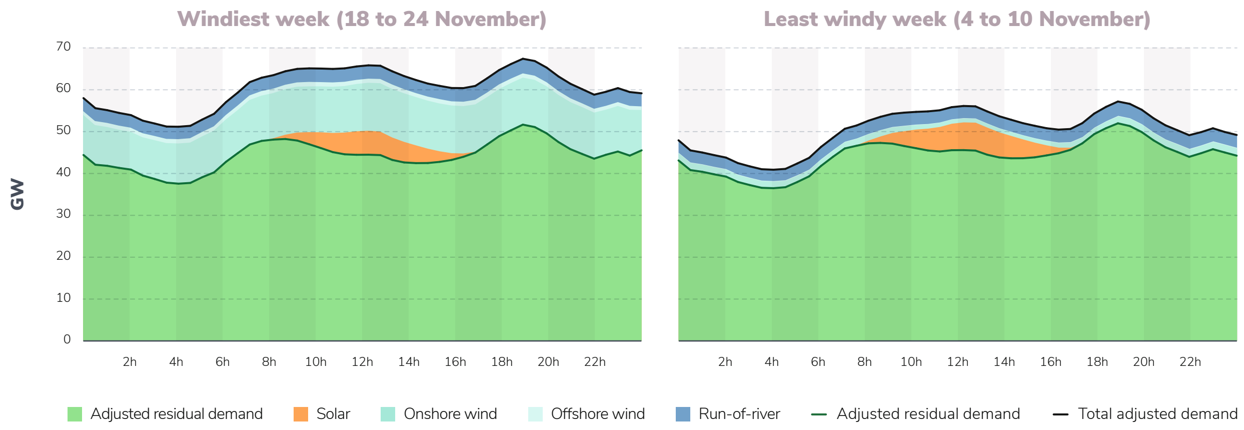
As a result of weather conditions and more structural factors, residual demand varies over different time scales, from intraday (from one hour to the next) to interannual (from one year to the next). For example, solar output is highest in the middle of the day, (total) demand is higher on weekdays than at weekends, wind output is generally higher in winter than in summer, and wind generation and consumption volumes may vary from one winter to the next depending on weather conditions and the economic climate.

Figure 6 – Average monthly residual demand in France (not adjusted for weather and calendar effects)



17. See also the Barometer of Flexibility.

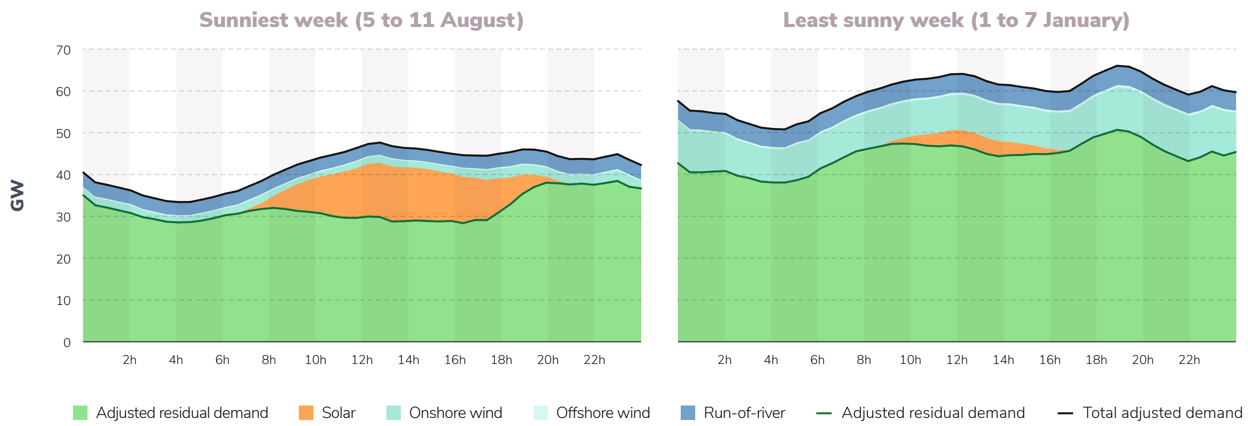
Figure 7.7 – Total and residual demand in the windiest and least windy weeks in 2024
Unadjusted generation and demand



Over the course of the year, the lowest levels of residual demand generally occur between April and October. This is due to traditionally lower consumption in summer (mainly because there is no heating and air conditioning is not widely used in France), coupled with high levels of photovoltaic generation. In the inter-season periods, lower photovoltaic output than in summer is offset by higher wind generation over this period, resulting in relatively low levels of residual demand. The lows are concentrated on spring, summer and autumn weekends, when consumption is lower than on weekdays. In 2024, the minimum level of residual demand occurred on Saturday 15 June at 5 a.m. (15.3 GW), and the maximum was reached on Wednesday 10 January at 7 p.m. (77.8 GW).

Unusually, the least windy week in 2024 was in November – the least windy weeks are usually in the summer. Paradoxically, the windiest week of the year also occurred in November, demonstrating the challenges facing the wind sector in terms of inter-week

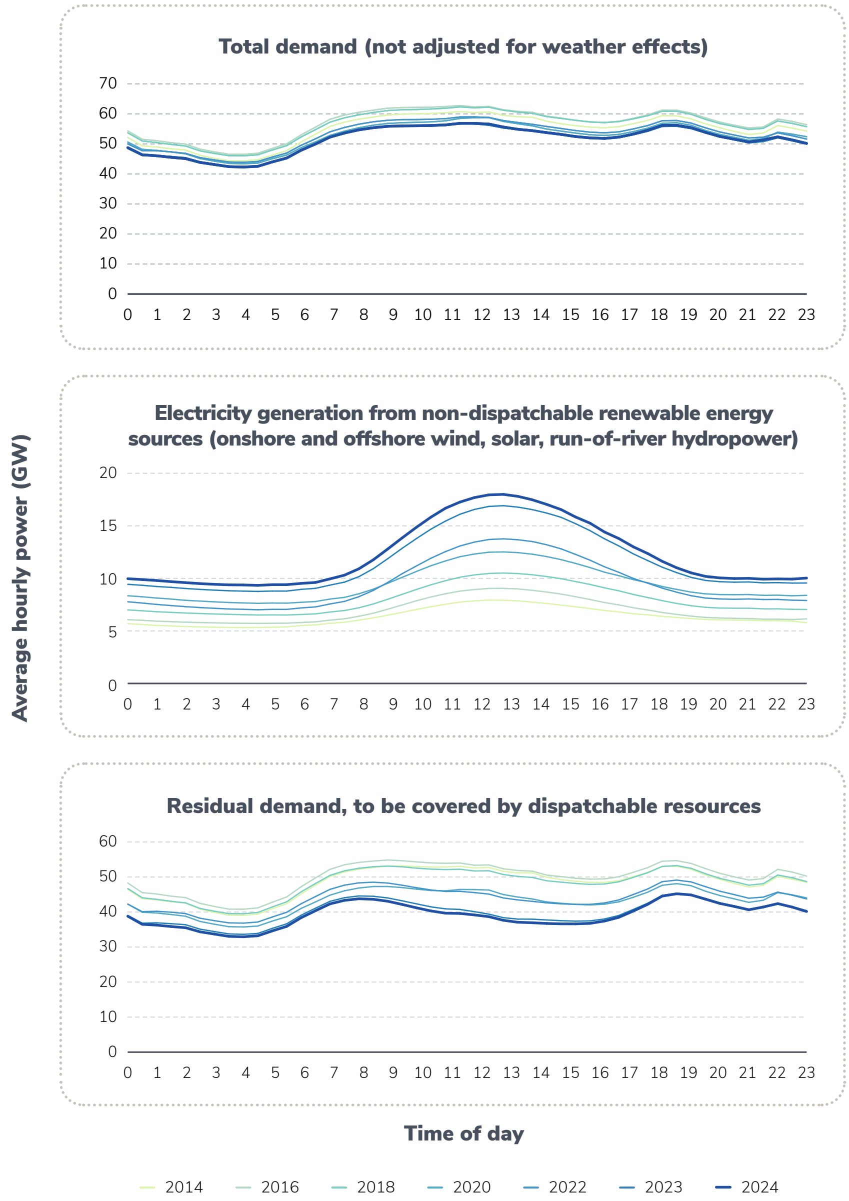
Figure 7.8 – Total and residual demand in the sunniest and least sunny weeks in 2024
Unadjusted generation and demand



flexibility and the need for dynamic flexibility in response. More typically, the sunniest week was the second week in August, and the least sunny was the first week in January.

The average hourly residual demand curve for 2024 remained at a similar level to the previous year. Two phenomena explain this result. On one hand, renewable generation was very similar in both years (a larger renewable fleet in 2024 offset less favourable weather conditions than in 2023 – see the *Generation* chapter), and on the other hand, total consumption was also very similar (even if adjusted consumption increased slightly – see the *Consumption* chapter).

Figure 7.9 – Deformation of total and residual demand on an"average" working day over time



Consumption (not adjusted for weather and calendar contingencies) varies from year to year. It was very similar in 2024 to 2023.

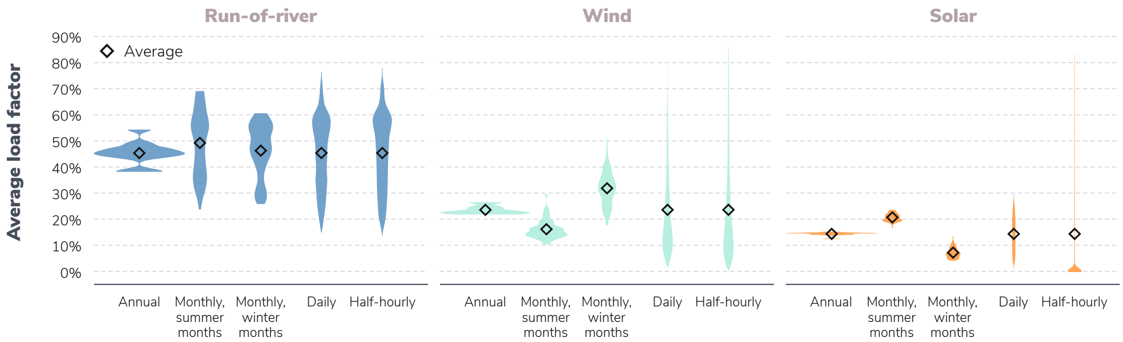
Renewable generation is increasing steadily as the installed capacity grows. Wind power is generated throughout the day, translating the curves upwards. Solar generation is concentrated around 1–2 p.m., creating a “hump” in the middle of the day.

The residual demand curve shifts downwards when wind generation increases. In the middle of the day, it moves further down due to solar generation

FOCUS

The variability of load factors for inflexible renewable energy sources

Figure 7.10 – Distribution of average load factor between 2015 and 2024
Unadjusted values



Key to the graph: for each type of inflexible renewable energy, this graph shows the distribution of the average load factor according to the time interval on the x-axis. For the "annual" interval, for example, the distribution is constructed from the average load factors calculated for each year between 2015 and 2024. The concentration of points towards 0% for solar (for the half-hourly interval) is due to the zero load factor at night.

Inflexible renewable energy generation (run-of-river hydropower, onshore and offshore wind and solar) varies according to weather conditions. However, the amplitude of the variation depends on the time scale: the longer the time scale, the lower the variability. For example, over the last decade, the load factors (generation relative to installed capacity) for wind and solar power have remained within fairly narrow ranges on an annual average basis, whereas the fluctuations are wider when all the half-hourly load factors are considered over the decade. Looking at averages by year and by season, the variability is higher than for the annual scale, but much lower than for the half-hourly scale.

This is because interannual differences in weather conditions are relatively small; in this sense, annual renewable generation volumes are guaranteed within a certain range around the average annual volume for a given level of installed capacity.

On the other hand, instantaneous generation volume from renewable energy sources can vary from one hour to the next or from one day to the next, with times of the year when output is plentiful and other times when wind and solar generation are very low. These situations are normal, and are taken into account in analyses of short and medium-term security of supply such as RTE's winter analysis and Generation Adequacy Report (see also the focus on episodes of low wind and solar generation in the Europe chapter). However, this variability clearly highlights the flexibility challenges for the system, both in terms of the "structural" deformation of the load curve (to meet "average annual" generation) and in terms of dynamic adaptations of consumption or the development of storage to cope with variability ranging from a few hours to a few days.

The increase in the volume of renewable energy curtailment reinforces the importance of developing demand flexibility now

As mentioned in the Prices chapter, the number of occurrences of negative spot prices rose sharply in 2024, with 359 hours over the course of the year (or 4% of the time). This is more than double the number of occurrences the previous year (147 hours).

Episodes of negative spot prices generally occur at times of low consumption combined with high levels of renewable energy generation, mainly on spring and summer afternoons, and to a lesser extent at night. They are more frequent at weekends, when consumption is generally lower than during the week. On average during 2023 and 2024, consumption was 15% lower during hours with negative prices than during hours with positive or zero prices. At the same time, **solar and wind generation was 29% higher than during the hours when prices were positive or zero. It would even have been 83%**

Figure 7.11 – Daily profile of the French spot price on an "average" day in 2024

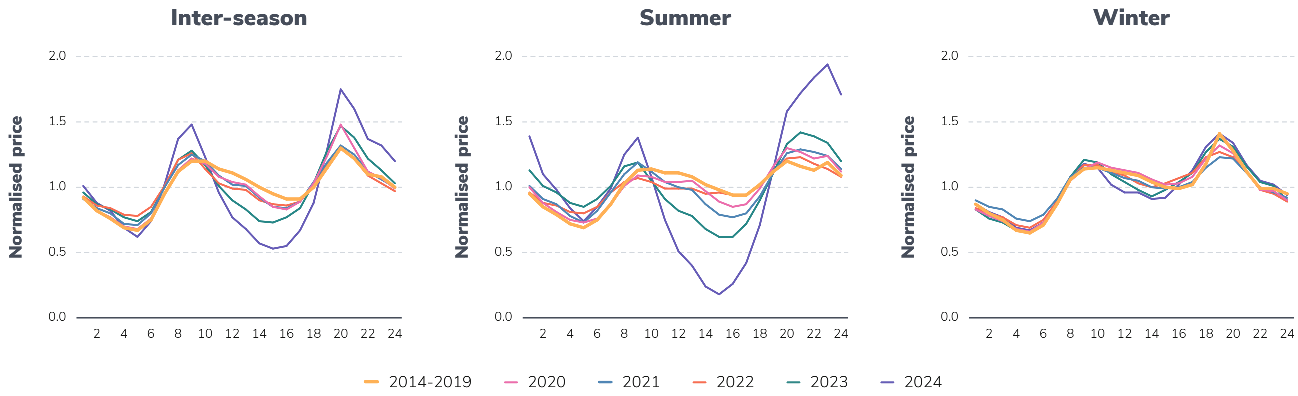
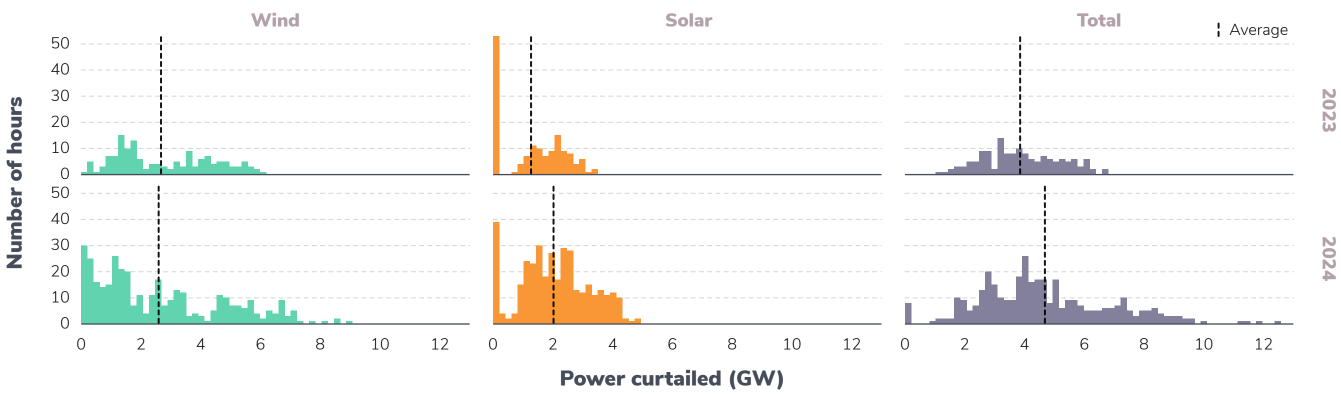


Figure 8.12 – Distribution of wind and solar capacity curtailed during hours when spot prices were negative in 2023 and 2024
Estimates by RTE



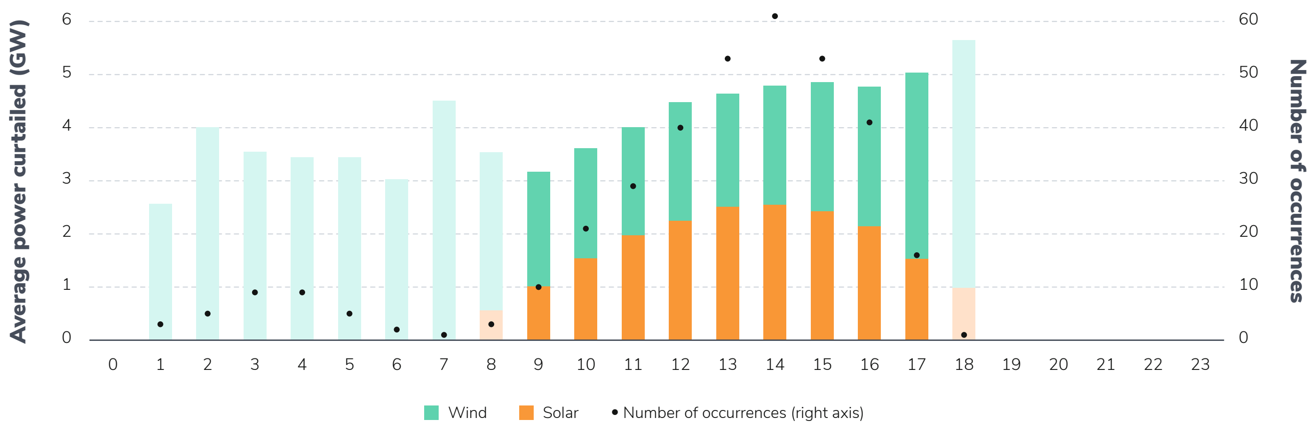
Key to the graph: this graph shows the distribution of wind and solar capacity curtailed (in GW) during hours with negative spot prices over 2023 and 2024 and the totals. For each level of power curtailed, in 200 MW steps, the bars show the number of hours a corresponding power level was curtailed. In the case of solar power, there are a large number of hours when no power was curtailed during a negative price episode: these are mainly episodes that took place at night.

higher if part of this output had not been curtailed. During periods of negative prices, a significant proportion of wind and solar farms cap their output (see the "Curtailment" section in the Generation chapter). **In 2024, the total curtailment of renewable generation due to negative prices is estimated at around 1.7 TWh**[18] (2.4% of the annual output of these energy sources), compared with 0.6 TWh in 2023. Combined wind and solar generation was curtailed at an average of 4.5 GW during negative price hours in 2024, compared with 3.9 GW in 2023. **The maximum power curtailed was around 12 GW in 2024,** compared with 7 GW in 2023. This increase results partly from growth in the installed renewable power capacity (all other things being equal) and partly from the increase in the proportion of plants on the premium scheme, which have a financial incentive to curtail their production in the event of negative prices.

Large amounts of wind power are curtailed in autumn and winter when the winds are strongest, but as consumption is generally high in winter, the number of occurrences of this type of event is low. Most of the instances of curtailment concern both solar and wind, with power distributed relatively evenly between the two.

The levers for reducing the occurrence of negative prices are clear: the development of demand-side and storage flexibility on one hand, and the flexibility of the generation fleet on the other. This is mainly based on the modulation of the nuclear and hydropower fleets, but renewables will be able to play an increasing role, provided that the legislative and regulatory framework provides appropriate incentives.

Figure 7.13 – Average wind and solar power curtailed and number of occurrences per hour of negative spot prices in 2024
Estimates produced by RTE



Key to the graph: in 2024, there were 53 occurrences of negative prices at 3 p.m. (i.e. between 3 p.m. and 4 p.m.). The average power curtailed at that time was just under 5 GW in total, split equally between wind and solar. The lighter bars show results for which the number of occurrences is too low to be significant.

18. 0.9 TWh for wind power and 0.8 TWh for photovoltaic solar power.

Electrification of uses

2024 ELECTRICITY REVIEW

Fossil fuels account for almost 60% of French energy consumption, while electricity provides less than 30%

Energy consumption in France is still heavily dependent on fossil fuels, most of which are imported. These represent almost 60% of the country's final energy consumption (57% in 2023, the last year for which data are available), while electricity accounts for only around 27%.

France's strategy for reducing greenhouse gas emissions and combating climate change over the coming years involves first reducing energy consumption, thanks in particular to progress in energy efficiency but also to energy sobriety measures, while at the same time replacing fossil fuels with low-carbon energy sources, including a significant proportion of electricity. This is what is meant by the term "electrification of uses": using electricity to replace fossil fuels wherever this is possible and has no major impact on the end use (for example, switching from a gas boiler to a heat pump for heating, or from a combustion engine to an electric vehicle). This strategy, which is similar to those of other European countries, will involve increasing electricity's share of final energy consumption. At a time when the geopolitical context is increasingly uncertain, electrification is also a way of strengthening French sovereignty.

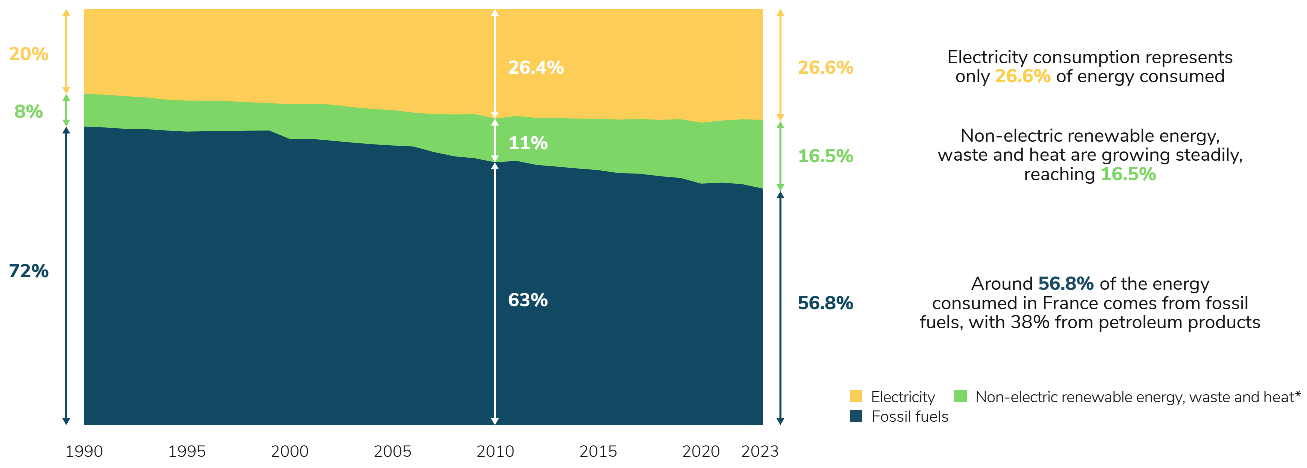
This transfer from fossil fuels to electricity is all the more attractive in France, given that the power system is already largely low-carbon and the country's electricity generation is abundant: greenhouse gas emissions per kWh generated and consumed are among the lowest in Europe, and growth in installed capacity essentially focuses on low-carbon resources.

The share of fossil fuels has been declining over the last 30 years, driven by the rise of the service sector and the growth of bioenergy

Between 1990 and 2023, fossil fuels as a proportion of final energy consumption in France fell from 72% to 57%. This decline was mainly concentrated in petroleum products (down from 50% to 38%) and coal (from 4% to less than 0.5%). The gas share remained stable over this period. Two main factors explain this development. Over the first two decades, between 1990 and 2010, it was the rise of the service sector that led to an increase in the share of electricity (+5.9 percentage points). Since the end of the 2010s, the development of non-electric renewable energy[1] and waste-to-energy have played a major role in reducing the share of fossil fuels.

1. These energy sources are used in particular in the building sector as fuel for heating.

Figure 8.1 – Share of different energy sources as a proportion of final consumption



Data sources: SDES

* Heat included from 2000

Petroleum products are mostly used in transport, while natural gas is used in buildings and industry

In 2023, around 60% of France's energy consumption still came from fossil fuels, including 38% from petroleum products and 19% from natural gas. Petroleum products, which include all refined fuels derived from oil, are used almost exclusively in the transport sector, which alone accounts for around a third of France's final energy consumption. Gas is mainly used to heat homes and offices or to produce high temperatures in industrial processes. Coal consumption accounts for less than 1% of final energy consumption, driven mainly by the steel industry.

Figure 8.2 – Breakdown of French energy consumption by energy source and sector in 2023

FRENCH CONSUMPTION
1,534 TWh

Petroleum products account for more than a third of French energy consumption.

BUILDINGS (residential + tertiary)
684 TWh

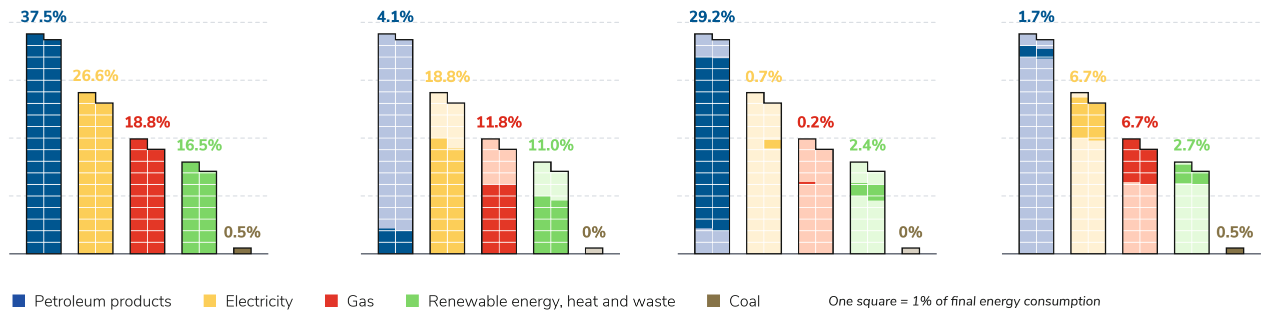
The buildings sector mostly consumes electricity, followed by gas and non-electric RE. It is responsible for over **60% of France's electricity consumption** and **60% of its gas consumption.**

TRANSPORT
504 TWh

The transport sector is almost entirely dependent on petroleum products, **consuming almost 80% of the petroleum products** used in France.

INDUSTRY
283 TWh

Industry is the second largest consumer of **electricity** and **gas.** In addition to this consumption for energy purposes, it also consumes energy as a raw material (such as petroleum products for petrochemicals).



One square = 1% of final energy consumption
The remaining energy is consumed by the agriculture and fisheries sector

Data sources: SDES

As well as reducing emissions, the electrification of energy consumption also addresses economic and sovereignty issues

In addition to the benefits in terms of pollution and emissions reductions, the move away from fossil fuels also has economic and sovereignty implications: France's energy bill has fluctuated between €40 and €80 billion since the early 2000s, even topping €120 billion at the height of the energy crisis in 2022. The main item of expenditure in the energy bill is imports of fossil fuels, which accounted for around €64 billion in 2024. In comparison, electricity exports, which reached a record net volume in 2024, earned France around €5 billion.

Clearly, gradually replacing fossil fuels with electricity largely produced in France would reduce this bill, and possibly even generate net profits in the longer term. France already has the competitive generating capacity needed to supply an increase in electricity

Figure 8.3 – Trends in the French energy bill between 1970 and 2024

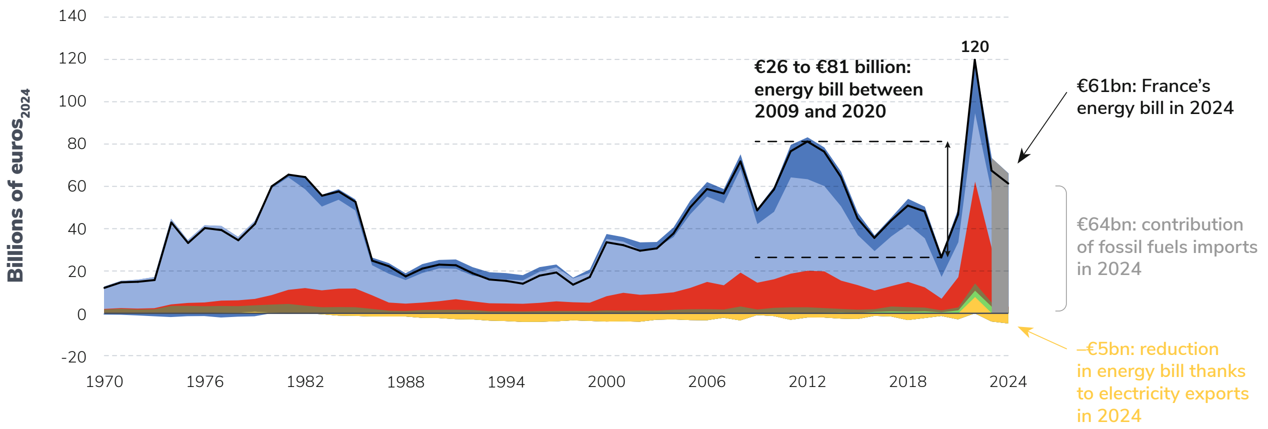
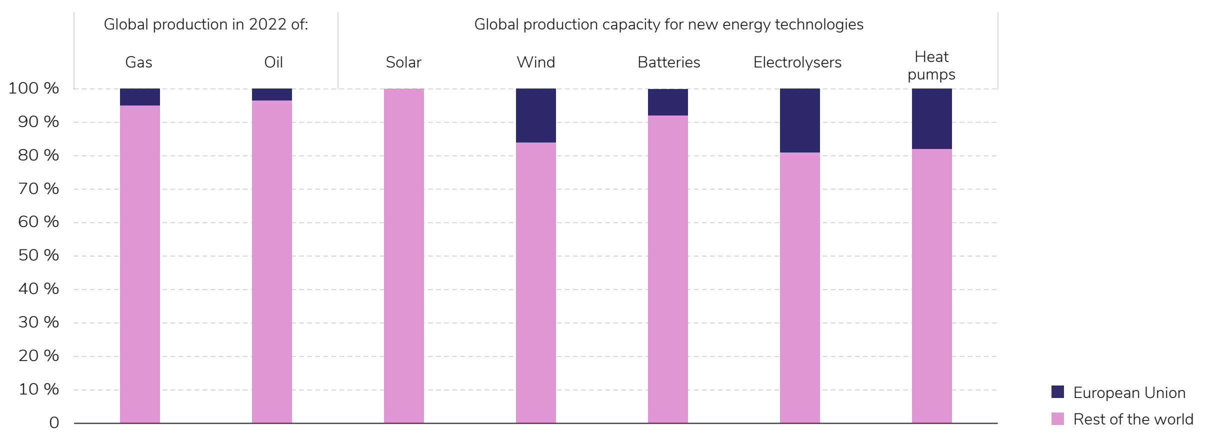


Figure 8.4 – Global oil and gas production in 2022 and global distribution of production capacity for new energy technologies



Data sources : RTE calculations based on SDES and IEA data consumption linked to new uses and electrification, as shown by the balance of electricity trade, which is usually very positive. In the medium and long term, the challenge for the French power system will be to ensure the continued availability of competitive, low-carbon electricity while increasing generation volumes to enable large-scale electrification.

Apart from the financial implications, replacing fossil fuel consumption with electricity reduces France's dependence on non-European exporters of fossil fuels. The energy transition also presents its own challenges of dependence in terms of the technologies needed to achieve it. That said, even if the value chains for these technologies also depend on foreign countries, they are more differentiated and can lay claim to a stronger European component than fossil fuel supplies (with the main exception of photovoltaic panel manufacturing).

Electrification of transport

The transport sector accounts for around a third of France's final energy consumption. Almost all the sector's consumption, dominated by road transport for passengers and goods, is fuelled by petroleum products.

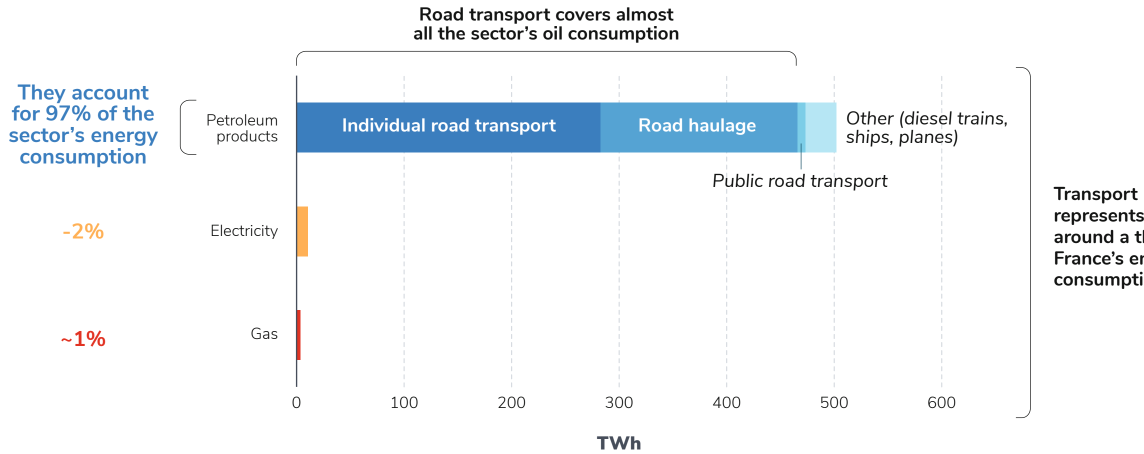
Decarbonising road transport is thus the major challenge facing the sector. There are currently several alternatives to petrol and diesel engines, with varying degrees of technological and industrial maturity. In the case of private cars, which account for more than 39 million vehicles in France, the two main low-carbon solutions are electric vehicles[2] and hydrogen-powered vehicles.

The former are much more widespread, with more than 1.2 million units[3] in France at the end of 2024 (plus around 700,000 plug-in hybrids). Hydrogen-powered vehicles are currently more limited, with around 1,000 on the road in France and around 5,000 in Europe.

Electric car sales made up almost 17% of new passenger car sales

In 2024, sales of new electric cars reached around 290,000 units[4], a slightly lower level than the previous year; this trend was consistent with the car market as a whole, as new car sales were down by 3.4% over the year[5]. The market share of electric vehicles remained stable compared with the previous year, at almost 17%, after several years of significant increases. The green grant ("bonus écologique") offered by the government to encourage people to replace internal combustion vehicles with electric vehicles was reduced slightly in 2024 from €5,000 to €4,000 for around half of households (the most affluent). On the other hand, these grants can increase up to €7,000 for more modest households, reducing the barrier to entry for the purchase of an electric vehicle compared with an equivalent internal combustion model[6].

Figure 8.5 – Breakdown of final consumption in the transport sector by energy source and mode of transport

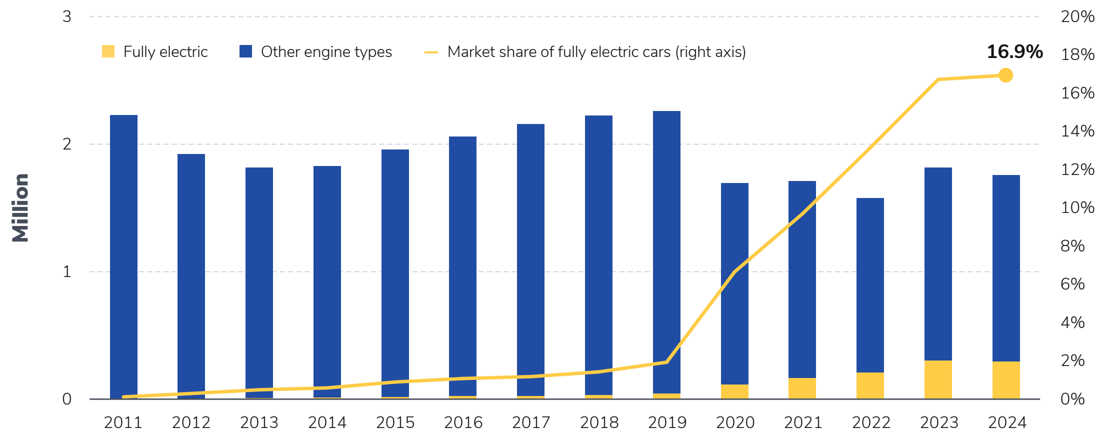


Data sources: SDES

Here, oil consumption includes biofuels

2. In the rest of this chapter, unless stated otherwise, the term electric car refers to fully-electric passenger cars.
3. Vehicles and fleet | European Alternative Fuels Observatory
4. Source: Vehicles and fleet | European Alternative Fuels Observatory
5. Immatriculations des voitures particulières en 2024 : baisse dans le neuf et léger rebond pour l'occasion (Passenger car registrations in 2024: decline for new cars and slight bounce-back for used cars) | Statistical Data and Studies Department (SDES)
6. On the other hand, running and maintenance costs are lower for electric vehicles.

Figure 8.6 – Sales of new fully-electric cars in France between 2011 and 2024

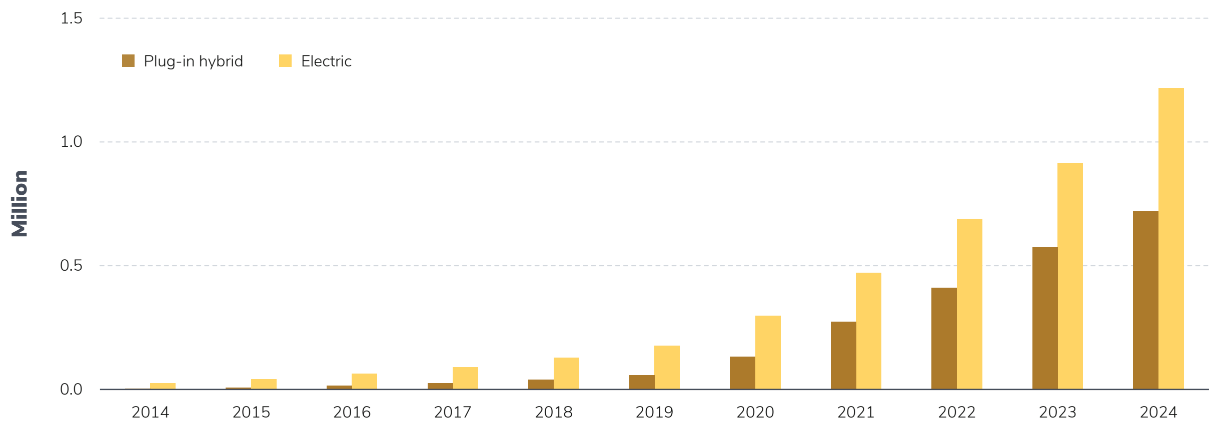


Data sources: European Alternative Fuels Observatory, SDES, RSVERO

The number of electric vehicles on the road has risen sharply in recent years, more than tripling between 2020 and 2024, which brought the total number of fully-electric cars on the road to over 1.2 million by the end of 2024[7] and the number of light commercial vehicles to over 125,000.

At the beginning of 2024, electric cars accounted for 2.3% of the total of more than 39 million cars on the road. This proportion is lower than the share of sales, because the renewal of the car fleet is subject to a degree of inertia: as an illustration, new car sales[8] represent around 5% of the total car fleet each year

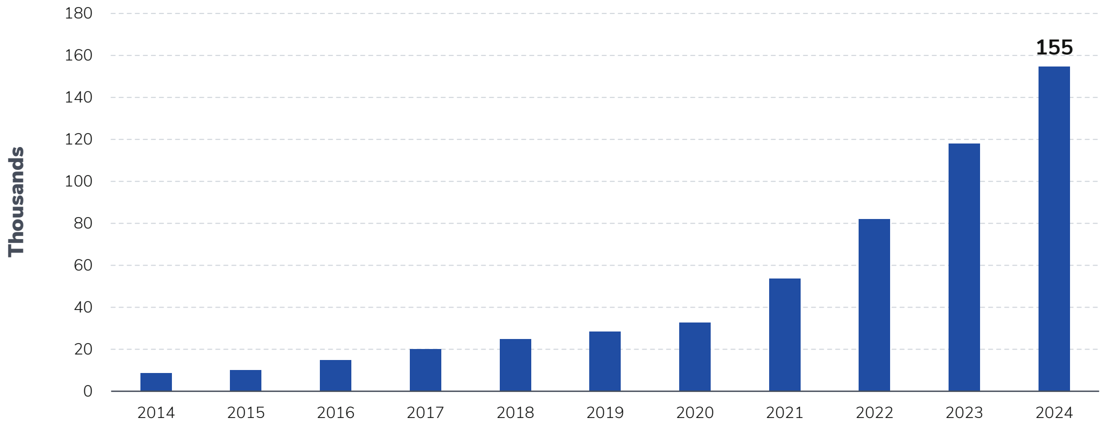
Figure 8.7 – Growth in the number of electric and plug-in hybrid passenger cars between 2014 and 2024



Data sources: European Alternative Fuels Observatory

7. Vehicles and fleet | European Alternative Fuels Observatory
8. Sales on the second-hand market account for around three quarters of vehicle sales.

Figure 8.8 – Number of charging points open to the public over time in France



Data sources: AVERE France

(around 1.8 million car sales in 2024 for a total fleet of 39.3 million cars on 1 January 2024).

It is interesting to note that once they change engine type, the majority of users are satisfied (91% of users according to the Enedis barometer[9], which seems to be confirmed by the IPSOS–Avere France survey[10] of April 2024).

All in all, electricity consumption by electric and plug-in hybrid vehicles (cars and light commercial vehicles) was around 3 TWh in 2024, the vast majority of which was consumed by electric cars.

As the number of electric vehicles grows, so does the coverage of the charging network across the country. The number of charging points open to the public exceeded 150,000 in 2024 and is continuing to rise.

The rest of the road transport sector is comparatively late in decarbonising

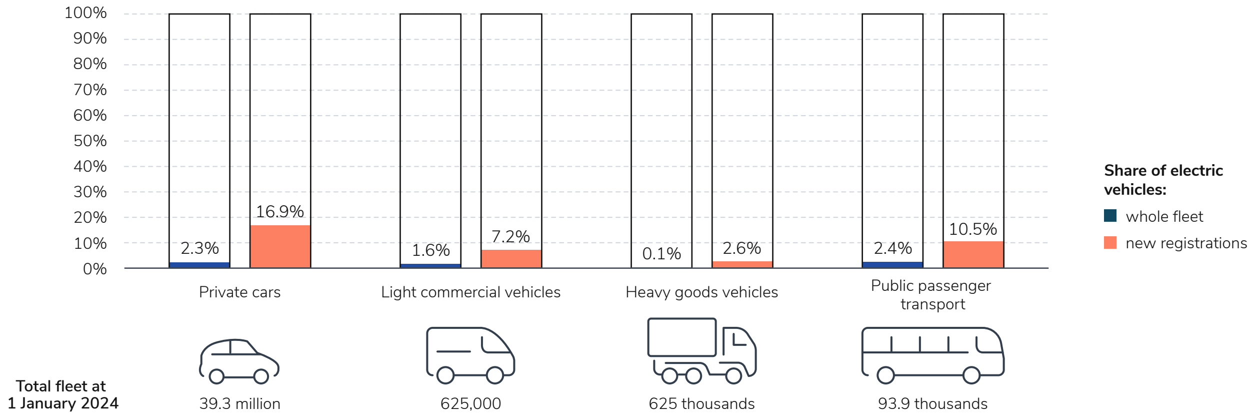
Compared with the electrification of passenger cars, heavier vehicles (light commercial vehicles and heavy goods vehicles) are less advanced, with the exception of public passenger transport.

Sales of electric light commercial vehicles in France represented around 7% of the new vehicle market in 2024. By the end of 2024, more than 125,000 vehicles were in circulation, out of a total fleet of around 6.5 million.

The electrification of road haulage, which accounts for almost half of the sector's energy consumption, has barely begun, as electric HGV models have only appeared more recently. There were over two thousand HGVs in circulation in France by the end of 2024, out of a total fleet of more than 624,000. Sales of electric HGVs doubled between 2023 and 2024, reaching 2.6% of new vehicles.

9. Link to the Enedis barometer
10. Link to Avere survey

Figure 8.9 – Electric vehicles as a proportion of the whole fleet and of new registrations



Data sources: European Alternative Fuels Observatory, SDES. **Calculation:** RTE

Lastly, the market share of electric vehicles in public passenger transport exceeded 10% for the first time in 2024. These vehicles already represent just over 2.4% of the fleet, a slightly higher proportion than for private cars.

Energy consumption in the residential sector is driven by heating, which is still highly carbon-intensive

The residential sector is the second-largest energy consumer in France after transport, with consumption of over 450 TWh in 2023. Energy consumption in the country's 38.2 million homes[11] can be broken down into five main uses: heating, domestic hot water, cooking, air conditioning and specific uses (uses that can only be met by electricity: household appliances, computers, televisions, etc.).

Heating alone accounts for 70% of residential energy consumption[12]. Nearly half comes from fossil fuels: a third is gas and 10% is heating oil. At the start of 2023, oil was still the main heating method for 10.5%[13] of primary homes in mainland France. Decarbonising this use of energy represents a twin challenge: firstly, increasing energy efficiency, mainly through thermal insulation, and secondly, replacing fossil fuels with low-carbon energy sources, particularly electricity via the installation of heat pumps.

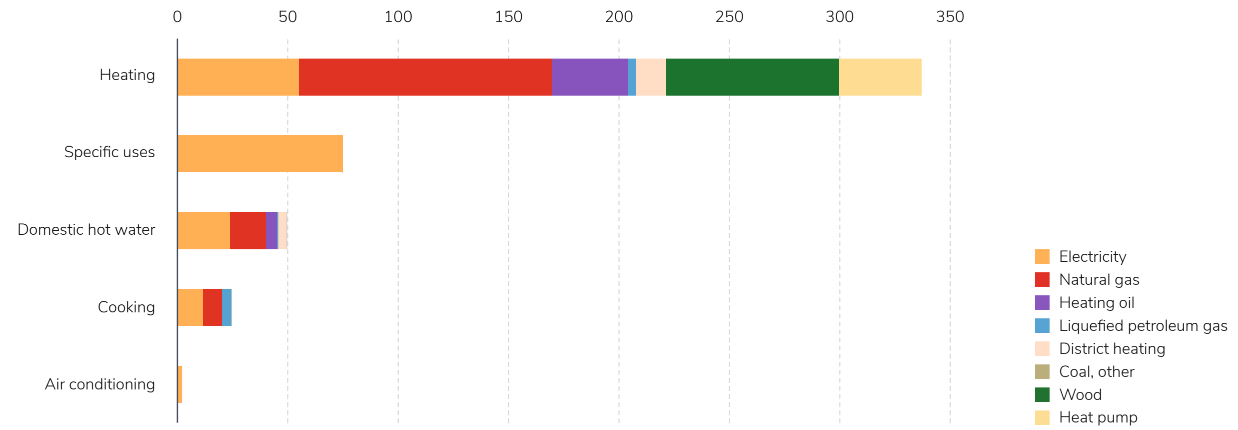
The total number of major renovations rose sharply in 2024

Home heating and insulation upgrades are a significant source of energy savings: according to an estimate by the Agence nationale de l'habitat (the French national housing agency), the measures put in place by the government have enabled savings of around 17.6 TWh[14] per year since 2020.

The government currently supports heating and insulation upgrades through the MaPrimeRenov' scheme. This system helps to finance part of the renovation work, whether this is a single action, such as changing the heating system or insulating the building, or a "major renovation", the most effective type of upgrade, with tailored support.

In 2024, grants were mainly directed towards major renovations. As a result, the number of renovations

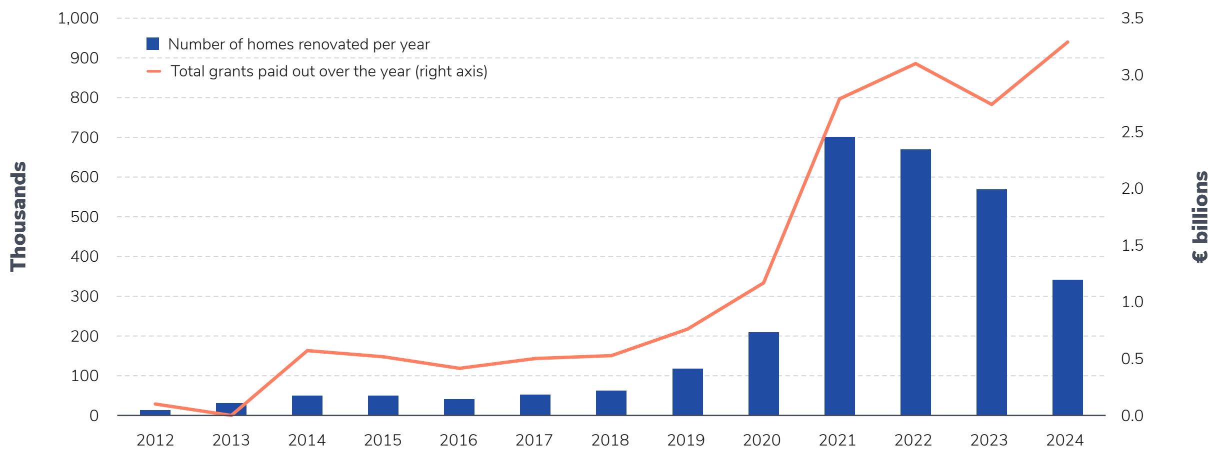
Figure 8.10 – Breakdown of final energy consumption in homes in 2021 by energy use and source



Data sources: SDES

11. On 1 January 2024.
12. Le chauffage au fioul, encore très répandu en zone rurale - Insee Flash Bourgogne-Franche-Comté - 163 (Oil heating still widespread in rural areas)
13. Data for 2021. This is the last year for which a breakdown of residential consumption by use is available on the SDES website.
14. Agence nationale de l'habitat, *Les chiffres clés de l'Anah, 2024 edition* (National housing agency key figures, 2024 edition), 2024

Figure 8.11 – Number of renovation actions per year and grants paid



Data sources: Anah

fell sharply (–40%), but the grant amount paid out increased by almost 20% to €3.3 billion. The total number of major renovations thus increased significantly in 2024 (+20,000 homes).

On 1 January 2024, 14% of primary residences were poorly insulated

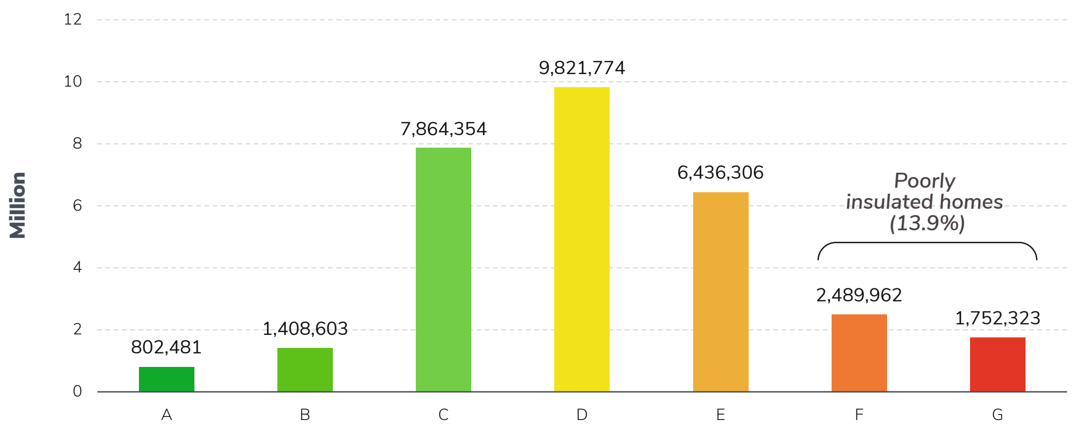
In order to target thermal upgrade policy more effectively and inform buyers and tenants in property transactions, the government has introduced an energy performance diagnostic system (DPE). DPE labels rate homes according to two criteria: greenhouse gas emissions (CO_2) and energy consumption.

For a home to be classified in a certain category, its emissions and energy consumption must both be below the threshold for the category in question. For example, for a home to be classified in category A, its annual energy consumption must be less than 70 kWh/m² and its annual emissions must not exceed 6 $kgCO_2/m^2$.

On 1 January 2024, most of the housing stock consisted of buildings with an energy performance rating of D. The worst-performing homes, rated F and G, are often referred to in France as "heat sieves"[15]. These homes still accounted for 4.2 million primary residences (around 13.9% of the housing stock) in 2024, and are the priority targets for thermal upgrade policies. Regulatory measures, such as a ban on renting out G-rated homes from 2025 and F-rated homes from 2028, and financial measures, such as additional grants to upgrade homes out of the F and G classes, are being introduced to encourage homeowners to carry out renovations and thus improve the overall performance of the housing stock.

15. Energy performance diagnostic - DPE | Ministries for spatial planning and the ecological transition

Figure 8.12 – Number of main residences by DPE class on 1 January 2024

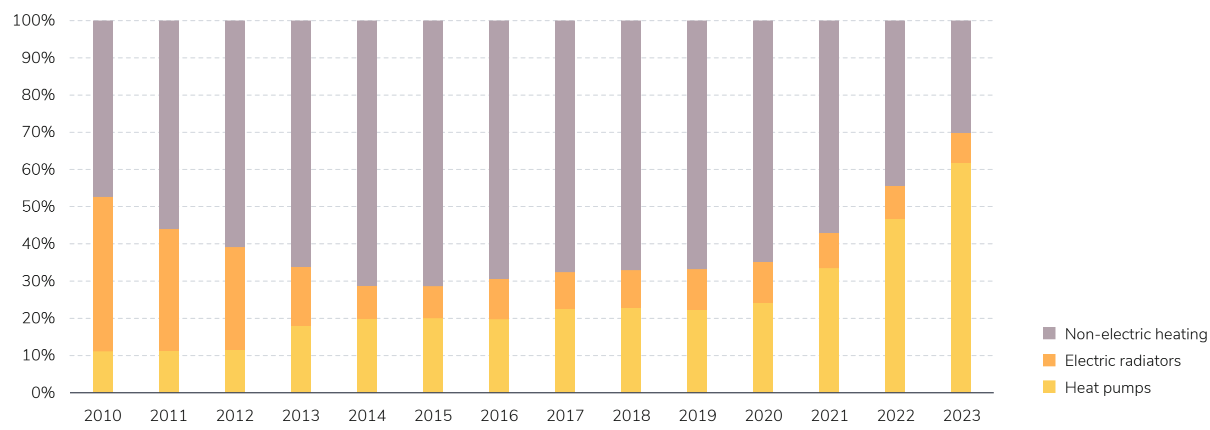


Data sources: SDES

Heat pumps are the main heating method in new buildings from 2023

Over the last few years, electric heating has once again become the predominant form of heating in new buildings, mainly due to the development of heat pumps. In 2023, heat pumps accounted for 60% of all new-build heating systems. Initial figures for heat pump sales in 2024 show a drop in the number of sales compared with the previous year. One of the reasons for this is the slowdown in new-build construction against a backdrop of unfavourable economic conditions. The number of new housing projects fell by around 12.3% year-on-year[14].

Figure 8.13 – Breakdown of heating systems in new buildings



Data sources: Bati-étude

16. Statinfo – Housing construction

Decarbonising industry – an opportunity for the French economy

The decarbonisation of French industry depends partly on electrification of uses

Around half the energy used by industry today comes from fossil fuels. Decarbonising[17] this sector involves transferring energy use to low-carbon energy, but also on replacing fossil fuels used as raw materials with low-carbon alternatives.

In France, the 50 sites that emit the most greenhouse gases have signed a contract with the government to reduce their emissions by 2030, setting out greenhouse gas reduction targets and some of the solutions that have been identified to achieve them. Some sectors, including the cement and steel industries, have highlighted the possibility of transforming some of their processes to use lower-emission raw materials or reduce their reliance on fossil fuels. All sectors have emphasised the key role to be played by two technologies that are not yet available on a large scale: carbon capture from flue gas and the use of low-carbon hydrogen. Lastly, industrial companies are stressing the importance of high-voltage connections to the electricity transmission network to enable certain processes to be electrified.

FOCUS

RTE is receiving large numbers of connection requests

As the operator of the high- and extra-high-voltage transmission network, RTE has signed contracts for 6.2 GW of network access rights for around 60 projects involving manufacturing industries between now and 2030. These projects involve either new sites or increases in connection capacity for existing sites.

There are also a number of electrolyser projects: indirect electrification through hydrogen production from low-carbon sources is part of France's climate and energy strategy, which sets a production target of 600 kt/year by 2030. Around 40 projects have signed grid access contracts for 9.6 GW over the same timeframe.

Finally, the transmission network is also preparing to supply power to new data centres, which will support the country's digital sovereignty as demonstrated by the artificial intelligence summit in February 2025. This digital infrastructure will benefit from abundant electricity delivered by a network capable of handling large capacities. At the start of 2025, 40 new projects requiring additional capacity of 5.3 GW have already been granted grid access rights.

These numerous requests have led RTE to propose different connection strategies depending on whether the project is located in an area that is favourable to new consumers, and on the capacity of the project in question. The various industrial connection strategies envisaged by RTE are presented in sheet 5 of the French network development plan (NDP), which RTE submitted to the competent authorities in February 2025.

17. As well as electrifying existing industry, France will need to decarbonise new industrial sites. Some of these new sites result from the move to reindustrialise. While this will necessarily increase industrial energy consumption, returning industrial production capacity to France means a reduction in France's carbon footprint, as well as a gain in sovereignty. Finally, new industrial activities are developing in France. These include new energy technologies (such as electric vehicles, batteries and hydrogen), which will help to increase France's share of the added value from delivering the energy transition.

Appendices

2024 ELECTRICITY REVIEW

Glossary

Mot clé	Définition
Adjusted (for weather and/or calendar effects) consumption	The consumption that would have been observed if temperatures had been normal (as defined below "Normal temperatures") and excluding the consumption of 29 February for leap years.
ASN	The Nuclear Safety Authority *(Autorité de sûreté nucléaire)* is the public entity which carries out, on behalf of the French state, the missions of nuclear safety control, radiation protection (workers in the nuclear industry, environment, local communities) and the public's information, "to protect workers, patients, the public and the environment from the risks associated with nuclear activities".
Auto-consumption	Consumption, by a consumer, of all or part of the electricity generated by their own production installation. Closely related to the English-language concept of "prosumer".
Balancing mechanism	The mechanism whereby RTE procures dispatchable reserves of supply to balance supply and demand close to real time. RTE can activate production and/or load ramp-up and/or ramp-down offers from participants in the mechanism.
Capacity factor	For a given production type, the capacity factor is defined as the ratio between production and installed capacity. In RTE's Electricity report, the monthly and yearly capacity factors correspond to the monthly or yearly average of the half-hourly capacity factors.
$CO_{2eq.}$	Carbon dioxide equivalent – a comparative emissions measurement index of different greenhouse gases representing their global warming potential. The volume of gas emitted is converted into the equivalent quantity of carbon dioxide needed to reach the same global warming potential.
Commercial exchanges	Commercial exchanges are the result of a commercial transaction bewteen market participants which are located in different countries (or bidding zones).
Core	Capacity calculation and market coupling region. The member countries are: France, Germany, Belgique, the Netherlands, Austria, Slovenia, Poland, the Czech Republic, Slovakia, Croatia, Hungary and Romania.
Coverage rate	The ratio between the output of a given generation type, and demand. In the Electricity review, the monthly and yearly coverage rates correspond to the average of half-hourly coverage rates.

Mot clé	Définition
Demand peak	The hours where electricity demand is highest.
Dispatchable production unit	A production unit which can be started up and/or modulate its output on demand (thermal and nuclear power plants, hydroelectric plants with pumped storage...).
EPEX SPOT	One of the power exchange operator among those designated by regulators. Power exchange operators are tasked with the organisation of market coupling, and provide insurance for transactions on the day-ahead and intraday markets. The operators approved for France by the *Commission de régulation de l'énergie* are EPEX SPOT and Nord Pool.
EPR	The European Pressurized Reactor, or EPR, is a nuclear reactor design of the pressurized water reactor (PWR) type. The EPR is part of the so-called 3rd generation of PWR.
Fossil-fired thermal/fossil fuels	Electricity generation from thermal power plants running on gas, coal or oil.
Grand Carénage	An large industrial programme designed to upgrade the safety of existing nuclear plants.
Gross consumption	Countrywide electricity consumption (Corsica included, overseas territories not included), taking into account transmission losses but not the consumption of pumped-storage plants.
Intraday prices	The prices of electricity transactions for delivery on the same day.
LNG	Liquefied natural gas
Lock hydropower plants	Mostly located in lakes downhill from mid-altitude mountains, those plants have a filling duration of 2 to 400 hours. They provide daily or, more rarely, weekly flexibility to the power system (daily demand peak, between business and non-business days...).
NEBEF	The French demand-respond products trade mechanism *(Notification d'Échange de Bloc d'Effacement)*
Normal temperatures	Average of past temperature timeseries that are considered representative of the current decade. They are based on Météo France data, and are computed by RTE at the country level thanks to a panel of 32 meteorological stations across France.
Other hydro power plants	The plants in the "other" category are tidal energy plants and pumped-storage plants. Tidal energy plants harvest the energy from the tides in coastal areas where the tidal range (the height difference between high- and low-tide) is large. This range is used to generate electricity by exploiting the height difference between two basins separated by a dam. Pumped-storage plants, operating in pumping-generation cycles between a downhill and an uphill reservoir, thanks to reversible turbines-pumps, are efficient storage assets which contribute to the balance of the power system. When the reservoirs also have natural inflows, the turbine is categorized as "mixed pumped storage", otherwise as "pure pumped storage".
Physical exchanges	Physical exchanges account for the actual electricity flows on interconnectors between countries, and can differ from commercial exchanges.
PPE	The French Multiannual Energy Plan *(Programmation Pluriannuelle de l'Énergie)*
Renewable thermal and waste	Electricity generation from thermal power plants running on fuels such as: bioenergy, paper waste, renewable household waste, non-renewable household waste...

Mot clé	Définition
Reservoir hydropower plants	Located downhill from mid- and high-altitude mountains, those plants have a filling duration of over 400 hours and provide seasonal flexibility and storage to the power system.
Run-of-river hydropower plants	Mostly located in plains, those plants consist in a small-height dam and can be filled in under two hours. Therefore, their flexible potential is small and their production depends on the river's flow rate.
SFEC	French Strategy on Energy and Climate *(Stratégie française énergie-climat)*
SNBC	National Low-Carbon Strategy *(Stratégie nationale bas-carbone)*.
Spot prices	The electricity prices set by the day-ahead market coupling, for each hour of the next day
STEP	Pumped hydro storage plants *(stations de transfert d'énergie par pompage)* are hydroelectric power plants that have the ability, during off-peak hours, to pump water from a lower basin to an uphill lake. The water is then released downhill during peak hours to produce electricity.
Supply-demand balance	The possibilities for storing electricity are limited. Therefore, supply and demand must match at every instant, which is RTE's responsibility to ensure. An imbalance between supply and demand causes the power system's frequency to deviate from its nominal value of 50 Hz.
Temperature-sensitivity of consumption	Refers to the variation of electricity demand linked to the variation of temperature. For example, demand increases in winter, when the weather is cold, due to the high prevalence of electric heating in France.
Water reserves	Countrywide French water reserves represent the aggregate weekly filling level, in %, of reservoirs and lakes where there are hydropower production assets. Water reserves are expressed in terms of "producible energy"», in MWh, given the reservoir filling.
Wholesale prices	Can refer either to the spot price (*cf.* definition), or to forward prices, for which the delivery date ranges from the next week to the next year.

Assumed emission factors used to calculate greenhouse gas emissions from electricity generation and consumption

	Direct emission factor (g_{CO2eq}/kWh)	Life-cycle emission factor (g_{CO2eq}/kWh)
Nuclear	0	7
Gas – combined cycle	331	389
Gas – combustion turbine	497	583
Gas – cogeneration	461	540
Gas – undetermined	435	471
Hydrogen – combined cycle	0	35
Hydrogen – combustion turbine	0	34
Coal	855	941
Lignite	961	1 040
Oil	769	928
Other fossil fuels	855	941
Hydro – Run-of-river	0	6
Hydro – PSH	0	6
Hydro – reservoir	0	6
Onshore wind	0	16
Offshore wind	0	17
Solar photovoltaic	0	43
Wood	0	66
Biogas	0	70
Biomass	0	70
Renewable waste	0	0
Industrial waste	988	0
Household waste (non-renewable portion)	988	0
Other renewable energy	0	70
Batteries	0	67
Electric vehicles	0	0

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