European Price Sensitive Curtailment Report

About this report

This report tracks price sensitive curtailment of renewable generation at the day-ahead stage of European power markets. It measures the volume of power offered into the day-ahead auction at prices between the technical minimum and zero, exclusive, that does not clear when the price settles below zero. We call this commercial, or market-based, curtailment. It is a business decision not to produce, not an instruction from a grid operator.

Where last year's edition looked back over a full calendar year, this mid-year edition compares the first half of 2026 against the first half of 2025 on a like-for-like basis, then uses the model's own extrapolation to sketch where the full year might land. The point is to catch the direction of travel while the year is still running.

The analysis covers ten monitored markets. Germany and France are the two heavyweights and get the closest attention. Austria, Belgium, Finland, Great Britain, Hungary, the Netherlands, Poland and Switzerland round out the set. Spain, Italy and the other Nordic zones are still outside the commercial model because the data publications don’t fit with our methodology. This edition adds a short contextual section on Spain, Portugal and Italy built from grid operator data, which measures a different thing and is kept firmly apart from the commercial numbers.

Executive summary

Commercial curtailment retreated across most of Europe in the first half of 2026. It fell in seven of the nine markets where we measure volume, and negative price hours fell in nine of ten.

Germany and Austria are the exceptions that continued to see rising numbers of negative price hours. What stands out is how. Commercial curtailment in Germany rose 20 percent, from 1,216 to 1,463 GWh, even as negative price hours in the country fell from 389 to 299. So even with fewer hours where prices were below zero, more volume was withdrawn. When the German market goes negative, more renewable capacity now switches off, and does so more completely as the tighter subsidy rules push newer assets to bid at zero and stop. Germany is now curtailing deeper, not more often.

France is the mirror image of this, and the central puzzle of this edition. Its curtailment fell 32 percent to 700 GWh, yet its negative price hours rose, from 363 to 413. Despite more hours with prices below zero, less volume was curtailed. In short, more must-run nuclear and more solar pushed the French market negative more often, but French assets increasingly produce through those shallow negatives rather than withdrawing, and the late-June heatwave switched the surplus off altogether on the hottest days. We unpack all three threads below.

The genuine retreat is broad. The level of commercial curtailment in the Netherlands roughly halved, it collapsed in Finland due to the Nordic hydro deficit and Belgium also saw a reduction as renewables delivered as its nuclear reactors went into maintenance. The ten markets covered here are swimming against the European tide: across the EU negative price hours roughly doubled in the first quarter, driven by a pronounced Iberian and south-eastern oversupply. The retreat is a northern and central European story, not a continental one.

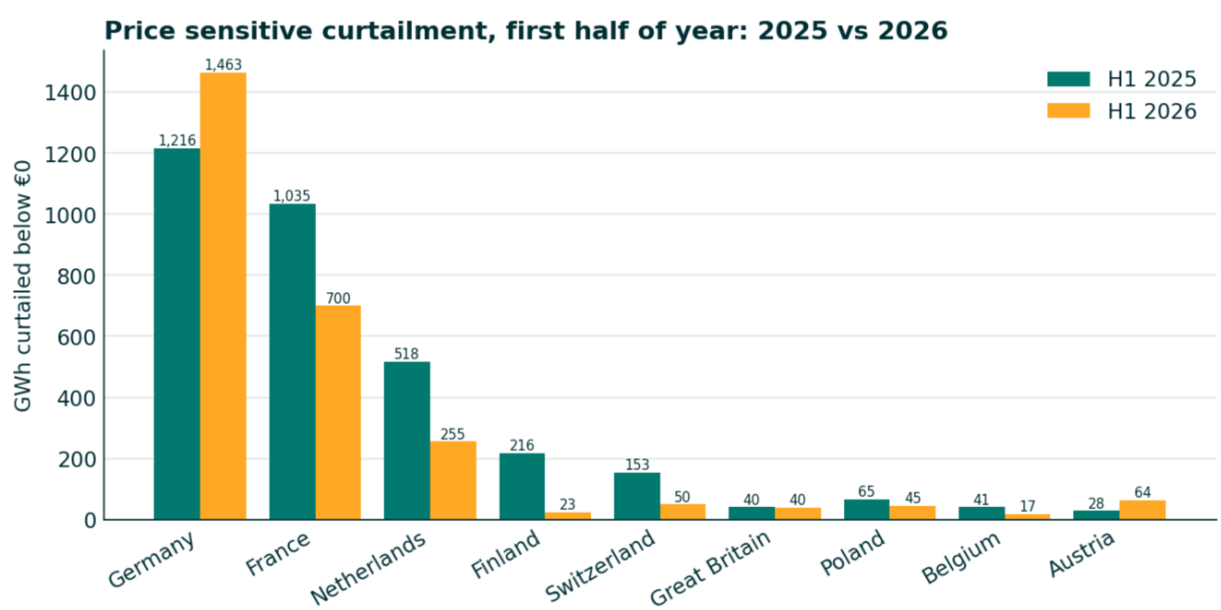

Figure 1. Price sensitive curtailment below zero euro, first half of 2025 versus first half of 2026.
Source: Montel EnAppSys day-ahead curve model

Pan-European view: H1 2026 versus H1 2025

The table sets the two half years side by side for every market where we measure curtailment volume. The figures are cumulative gigawatt hours offered below zero and left uncleared, from 1 January to 30 June of each year.

Country	H1 2025 (GWh)	H1 2026 (GWh)	Change
Germany	1,216	1,463	**+20%**
France	1,035	700	**-32%**
Netherlands	518	255	**-51%**
Finland	216	23	**-89%**
Switzerland	153	50	**-67%**
Great Britain	40	40	**-1%**
Poland	65	45	**-31%**
Belgium	41	17	**-58%**
Austria	28	64	**+129%**

Seven markets saw commercial curtailment fall, while two saw commercial curtailment rise. Germany and Austria are the only risers, and Austria only because a few spells of imported German surplus lifted a tiny base. Germany aside, the first half unwound a good part of the curtailment growth of the previous two years. The falls are real and, in Finland and the Netherlands, large.

Negative prices: a proxy under strain

The count of negative price hours is usually our best single guide to curtailment. This year, the link between negative price hours and commercial curtailment volumes came apart, most notably in opposite directions in the two big markets. Germany's negative price hours fell, while its commercial curtailment rose. France's negative price hours rose while its commercial curtailment fell. In both countries, the cause is the same thing: the rules and behaviour that decide how much renewable volume actually leaves the market in each negative price hour. The counts below are computed from quarter-hourly day-ahead prices, taking an hour as negative when the average of its quarter-hour prices is below zero.

Country	< 0, 2025	< 0, 2026	Change	≤ 0, 2025	≤ 0, 2026	Change
Germany	389	299	**-23%**	427	307	**-28%**
France	363	413	**+14%**	483	474	**-2%**
Netherlands	408	250	**-39%**	436	255	**-42%**
Finland	337	40	**-88%**	441	47	**-89%**
Switzerland	237	186	**-22%**	241	188	**-22%**
Great Britain	68	50	**-26%**	70	55	**-21%**
Poland	251	225	**-10%**	278	233	**-16%**
Belgium	361	221	**-39%**	382	226	**-41%**
Austria	290	220	**-24%**	317	223	**-30%**
Hungary	209	198	**-5%**	231	204	**-12%**

Table 1. Negative price hours below zero (columns 2 and 3) as well as negative price hours including zero (columns 5 and 6) cumulative to 1 July. Source: Montel EnAppSys, from quarter-hourly day-ahead prices.

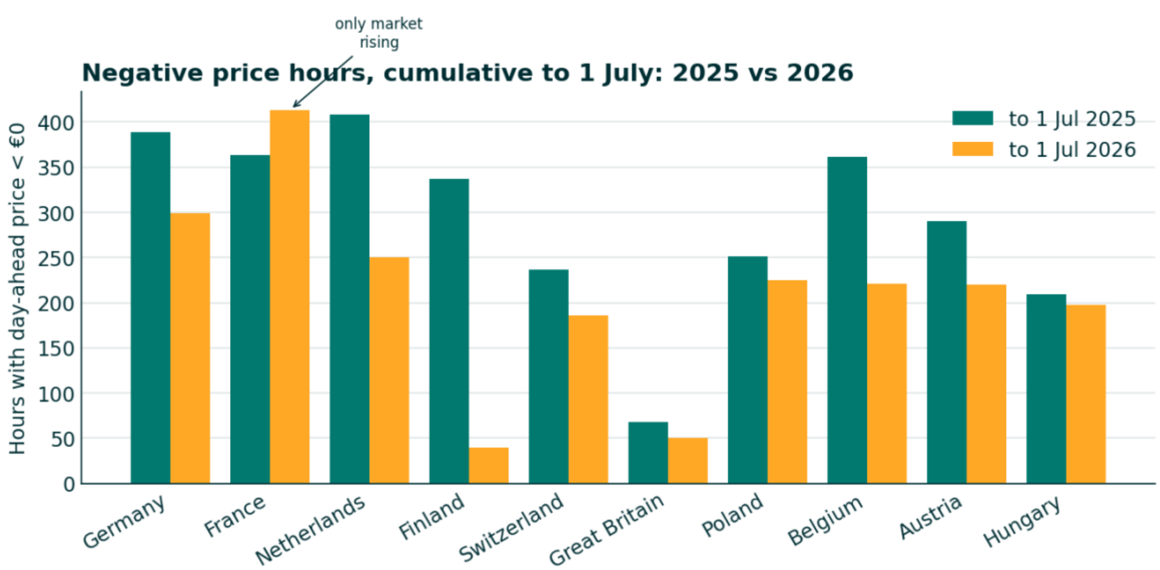

Figure 2. Negative price hours below zero, cumulative to 1 July. Source: Montel EnAppSys, from quarter-hourly day-ahead prices.

Negative price hours fell in nine of the ten markets. Finland is the extreme case, collapsing from 337 hours to just 40. Belgium and the Netherlands each fell by about 40 percent, while Austria and Switzerland dropped by roughly a quarter. Only France went the other way, its hours rising from 363 to 413, even as its commercial curtailment fell. This is further explained in the dedicated France section.

On the hours alone, the ten markets tracked here diverge from the rest of the continent. Across the EU, negative price hours roughly doubled in the first quarter of 2026, driven by a surging Iberian oversupply, with Spain alone running over 600 negative hours in the first half of 2026, compared to c. 460 in the first half of 2025.

How the year built up

The cumulative curves show the shape of each year, not just the endpoint. The 2026 line runs only to the end of June, so read it against where the 2024 and 2025 lines sat at the same point, not against their full-year totals.

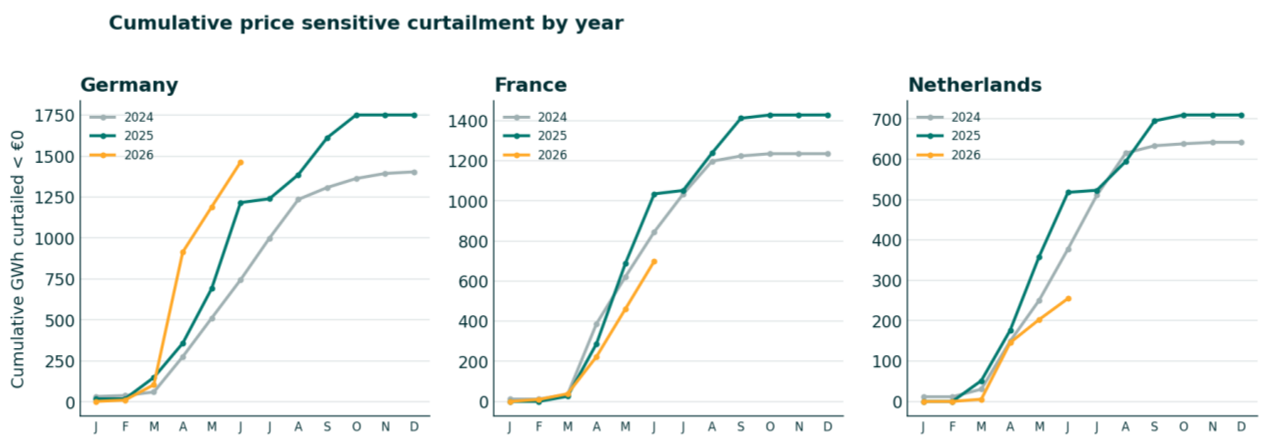

Figure 3. Cumulative curtailment below zero euro by year for Germany, France and the Netherlands. 2026 to end June. Source: Montel EnAppSys.

Germany's 2026 line runs a little above its 2025 self, the modest 20 percent lift in one picture. France and the Netherlands both track clearly below their 2025 curves, France easing back and the Netherlands falling further. The big continental markets are no longer moving together.

By country

Germany

Commercial curtailment in Germany is deeper than ever before. H1 closed at 1,463 GWh (against 1,216 GWh a year earlier). Modelling extrapolates the full year to roughly 1,985 GWh, up from 1,751 in 2025, which would rank among the highest on record. Given that negative price hours in the country fell, it is clear to see that this is due to the volume withdrawn per negative hour, not the number of negative price hours.

Germany has more solar than its midday demand can absorb in spring and summer, a still partly inflexible thermal fleet and, since the Solarspitzengesetz, or Solar Peak Act which took force in February 2025, a subsidy regime that switches off support for newer assets the instant prices go negative. The switch to a quarter-hourly day-ahead market in October 2025 lets that bite in fifteen-minute slices. So even as the number of negative hours falls, more capacity is pushed to the exit the moment the price crosses zero. You could call it a shift from negative prices to zero prices. Limited-marketing bids are set to reinforce this, moving from the current -100 to -200 euro band toward zero (or a small negative figure, near minus eleven cents in line with EDF's Obligation d'Achat (OA)). Germany also remains the most mature market in dealing with this. It has the deepest intraday liquidity, as well as the most active optimisers and direct marketers. Where Germany goes, others tend to follow.

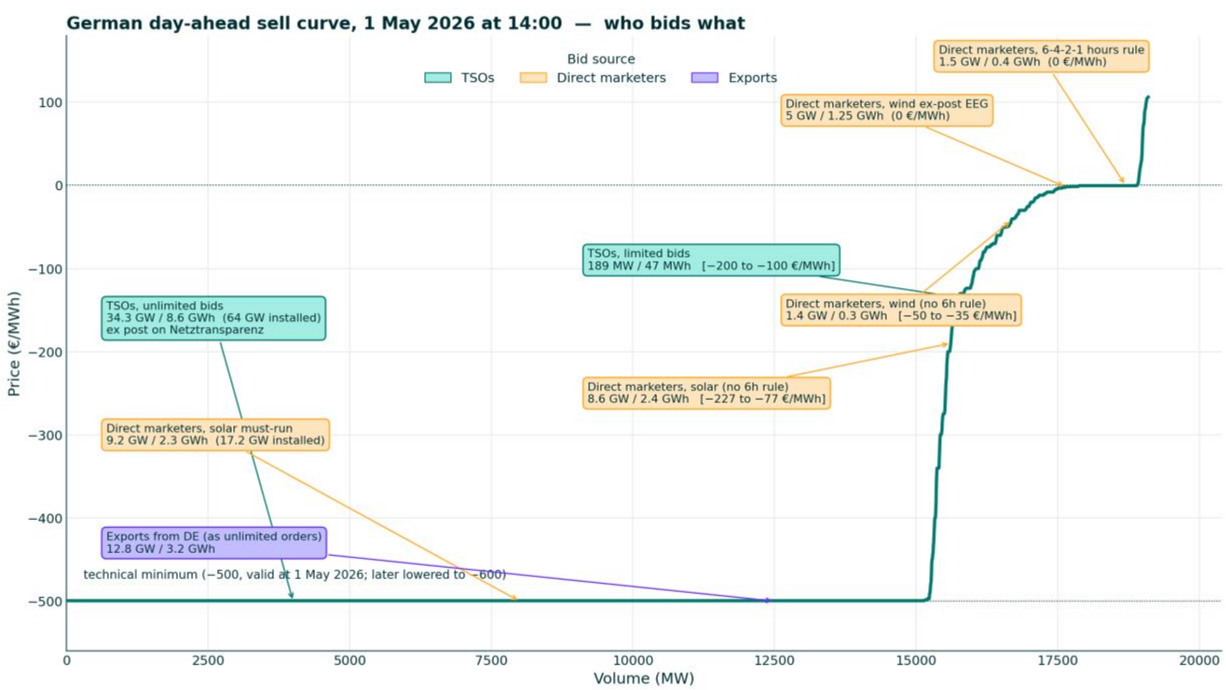

Figure 4. Germany's aggregated day-ahead sell curve for 1 May 2026 at 14:00. Price-insensitive volume, meaning TSO feed-in and exports, sells down to the −500 €/MWh technical minimum, while plants under the 6-4-2-1-hour rule and post-EEG assets withdraw at zero. Source: Montel internal analysis, V. Thevenin.

Renewable generation grew modestly. German solar output rose about 6 percent in H1 2026 compared to H1 2025 (from 41.3 to 43.7 TWh) while wind output rose about 12 percent, from 60.8 to 67.9 TWh. A 6 percent lift in solar, alongside a 20 percent rise in commercial curtailment, is what stands out. Commercial curtailment does not scale with generation, it amplifies it. A little more midday solar added to an already saturated market (under rules that force withdrawal at zero) pulls out disproportionately more volume.

France

France pulled back on commercial curtailment volumes while its market spent more time priced below zero, the widest divergence seen in the first half of 2026. Commercial curtailment fell 32 percent to 700 GWh. Modelling extrapolates the full year down to around 986 GWh (from 1,429 in 2025). However, negative price hours rose from 363 to 413, and the negative prices grew deeper with them as hours priced below minus ten euros rose from 58 to 93. More hours below zero, less volume withdrawn. That inversion is the real puzzle observed in H1 2026, pointing away from prices and toward behaviour, rules and weather.

The reason the negative prices rose is more nuclear. French nuclear ran higher in the first half of 2026, up 8.1 TWh or 4.4 percent compared to the first half of 2025. It still load-follows, backing down through the middle of the day, but from a higher base, so midday output actually rose. Greater nuclear output collided with more solar, French solar was up about 15 percent year on year to 17.3 TWh, is what pushed prices below zero more often and more deeply. The rise in French negative hours is no mystery. It is a fuller baseload meeting a bigger solar peak.

Why then did curtailment fall while the negative price hours rose? Because a large share of French renewable capacity sits on obligatory purchase and feed-in premium contracts whose negative-price rules only come into effect well below zero. Under the arrêté of 8 September 2025, feed-in premium plants earn a premium for halting output during negative hours only once the day-ahead price falls below -10 cents per megawatt hour, which leaves a buffer band between zero and the level where producing still pays. The parallel power to force large plants off the system, under Article 175 of the 2025 Finance Law, only affects wind above 10 megawatts and solar above 12 megawatts-peak, with the solar threshold cut to 10 megawatts-peak in April 2026. The 2026 Finance Law, enacted in February 2026, lowers that floor to one megawatt. EDF OA, the obligated buyer, has itself begun offering flexible wind and solar volume into the day-ahead auction at a price limit of minus eleven cents per megawatt hour. This first occurred on 13 May 2026, with that flexible capacity growing toward 7.4 gigawatts. In the shallow band just below zero, where a growing share of French negative hours sit, much French capacity keeps producing rather than withdrawing. It pushes the price down further, and because it is not withdrawing, commercial curtailment volumes fall. Germany is the contrast. Under the Solarspitzengesetz of February 2025, new German plants lose their support the moment prices turn negative, yet at exactly zero they are still paid in full. Germany withdraws at zero, France produces through it. And, as the next section shows, the late-June heatwave removed the surplus entirely on the hottest days.

Iberia is a supporting actor, not the lead. When France is negative, Spain is negative in the same hour about 79 percent of the time. Generally, the two move together, but that is mostly the same solar weather landing on both sides of the Pyrenees rather than Spain setting the French price. The border stays congested most of the time, the average price gap runs near thirty euros, and Spanish negatives are shallow, rarely below minus twenty-five euros, whereas France's deep negatives are its own. The France-Spain link is under three gigawatts (against French demand in the hundreds of gigawatts) and the Bay of Biscay cable that nearly doubles it does not switch on until 2028. Iberia nudges the shallow negative price hours, but it does not flood the country.

Demand, weather and the nuclear balance

Two forces sit behind the French and German picture: how much demand grew, and how much of that was simply weather. Both markets saw demand firm through the spring, but only in the low single digits, until the late-June heatwave. When Paris and Berlin touched 40 degrees in the week of 22 June, cooling demand jumped, and the June demand step moved with it.

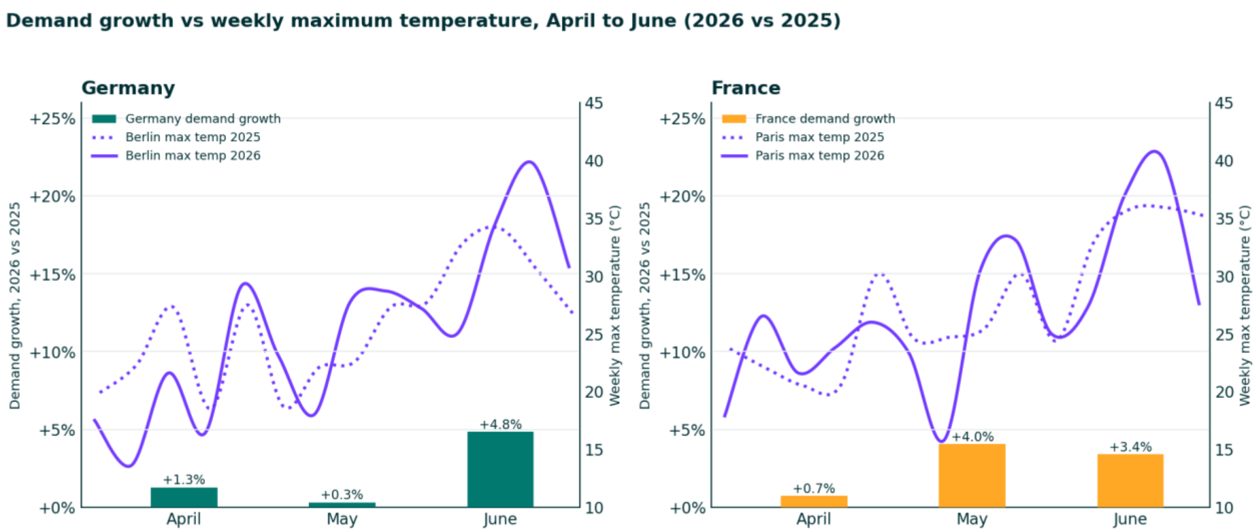

Figure 5. Demand growth versus weekly maximum temperature for Germany and France, April to June. Dotted lines are 2025, solid lines 2026. Source: Montel EnAppSys demand data, Open-Meteo temperatures.

The tailwind is real but small, and mostly attributable to a June weather event rather than structural growth. A few percent of extra demand cannot absorb a solar fleet growing so fast, so demand relieves the midday surplus only at the margin, except in extreme heat.

France shows the clearest interaction between heat, nuclear and demand. Two particular days show this, a mild April weekday compared against the 24 June heatwave peak.

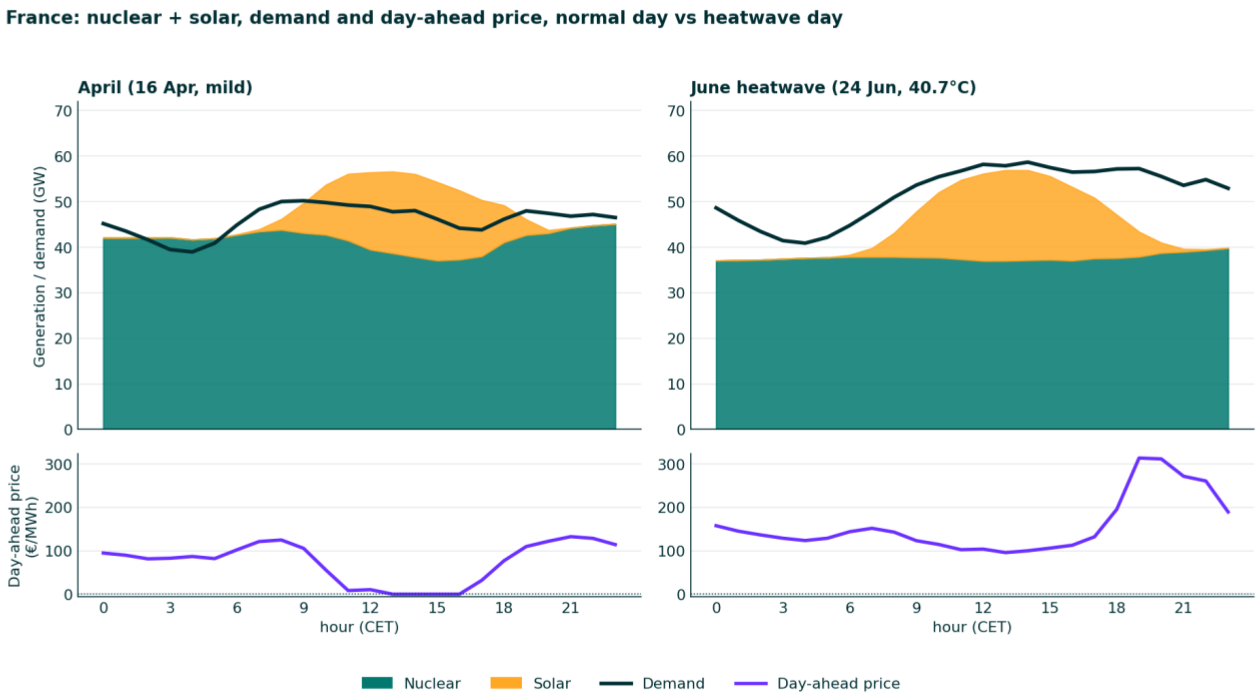

Figure 6. France, two days compared: nuclear and solar stacked against demand, with the day-ahead price. On the mild April day the price falls to zero at midday; on the 24 June heatwave it stays positive, near 95 euro at midday and spiking in the evening. Source: Montel EnAppSys, French nuclear availability, demand and day-ahead prices.

On the mild day, nuclear did what it usually does, backing down about 2 GW through the middle of the day to make room for solar. It was not enough. Nuclear plus solar still sat roughly 8 GW above demand at midday and the French price duly touched zero. On the heatwave day, the picture inverts. Nuclear began the day already limited, around 37 GW rather than 42, because the heat had eaten into river-cooling headroom. Being already capped, it had nothing left to flex, and with cooling demand some 9 GW higher it had no need to. Demand up, baseload down, no flex needed, no surplus. The French price never went near zero. It sat near 95 euro through the middle of the day and spiked above 300 in the evening, as solar faded while cooling demand held, so nothing was curtailed due to prices.

That is the counterintuitive heart of the French story. The hottest, sunniest days of the half produced no curtailment, while mild, unremarkable spring days did. Extreme heat curbs the surplus, lifting demand and trimming nuclear at the very moment solar peaks. Stack up enough of those hot June days and the half-year volume falls, even as the tally of negative hours, dominated by ordinary spring days, keeps climbing. The curtailment risk lies on the ordinary sunny days, not the record-breaking ones.

The smaller markets

Finland fell steeply, from 216 GWh to 23 GWh, an 89 percent drop, with negative hours down from 337 to 40. The cause is hydrology, not renewables. The Nordic water balance swung from a comfortable surplus a year ago to a deep deficit in 2026, with Norwegian snowpack near a twenty-year low and reservoirs well below normal. That lifted Nordic prices and all but erased the negative hours that drive curtailment there. Switzerland, Poland and Great Britain also fell, on lower imported surplus and, for Great Britain, its usual reliance on forced grid curtailment rather than the price-driven kind.

Belgium deserves its own line, because its grid operator has effectively named the cause. Elia's summer outlook points to the Doel 4 and Tihange 3 reactors, (accounting for roughly 2 GW) going into maintenance from April to November 2026, and links this directly to a lower risk of oversupply this spring and summer. Strip out that much inflexible must-run nuclear from underneath the renewables and there is less generation to push prices below zero. Curtailment duly fell about 58 percent.

The Netherlands, until recently one of the big three in commercial curtailment terms, has cooled enough to sit with the smaller markets. Curtailment fell about 51 percent to 255 GWh and negative hours fell from 408 to 250. The cause is a solar boom reaching its peak. Dutch solar output was essentially flat in the first half of 2026, up just 2 percent (the weakest of any market in this report) as both subsidy and grid-cost changes slowed new buildout. Behind-the-meter storage started to absorb some of the midday surplus too. Wind rose 8 percent in the Netherlands. Demand has firmed as well, up roughly 3 to 4 percent year-on-year across the spring, so more of the midday surplus is absorbed at home rather than curtailed. A market in which solar has stopped growing is one where curtailment can finally begin to level off.

Austria is the exception among the smaller markets, with commercial curtailment up roughly fivefold to 64 GWh. That is off a base so small that a few spells of imported German surplus in a big solar June explain most of it, and it behaves like a satellite of the German market rather than a story in its own right. Hungary, which we track for negative price hours but not yet for curtailment volume, saw its negative hours ease slightly from 209 to 198.

Case study: the deepest days versus the heaviest days

It is tempting to assume the days with most negative price hours see the biggest volumes of commercial curtailment. The data says otherwise, and the gap is instructive. The graph below shows the days that stood out on price in the first half of 2026 alongside the German curtailment volume. The number of negative hours is labelled on each bar, whilst the daily minimum price is plotted in orange.

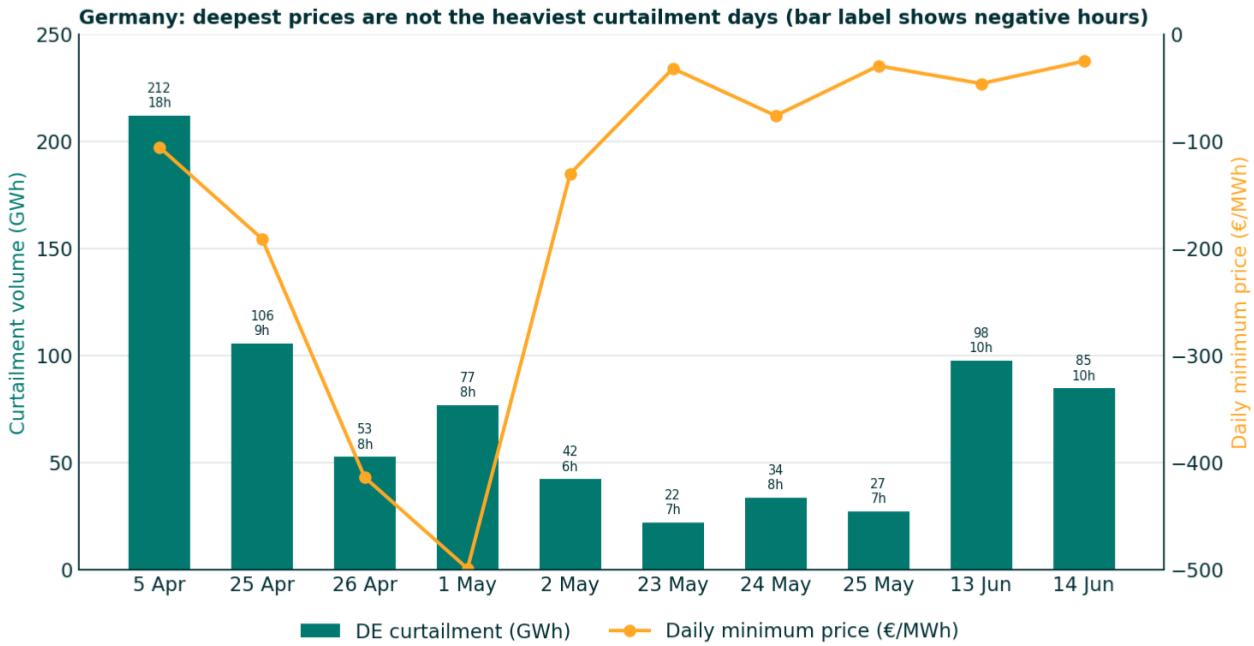

Figure 7. Germany, selected days in 2026. Bars are daily curtailment volume with the count of negative hours; the line is the daily minimum day-ahead price. Source: Montel EnAppSys.

More deeply negative prices and commercial curtailment volumes do not line up. The single deepest day, 1 May, fell to -499 euros but curtailed only 77 GWh across eight negative hours. The 26 April dip to -414 euro delivered even less, 53 GWh. The heaviest day in H1 2026 was 5 April, at 212 GWh, where prices bottomed out at a comparatively mild -105 euro. What set it apart was breadth, eighteen hours below zero, rather than a brief, violent plunge.

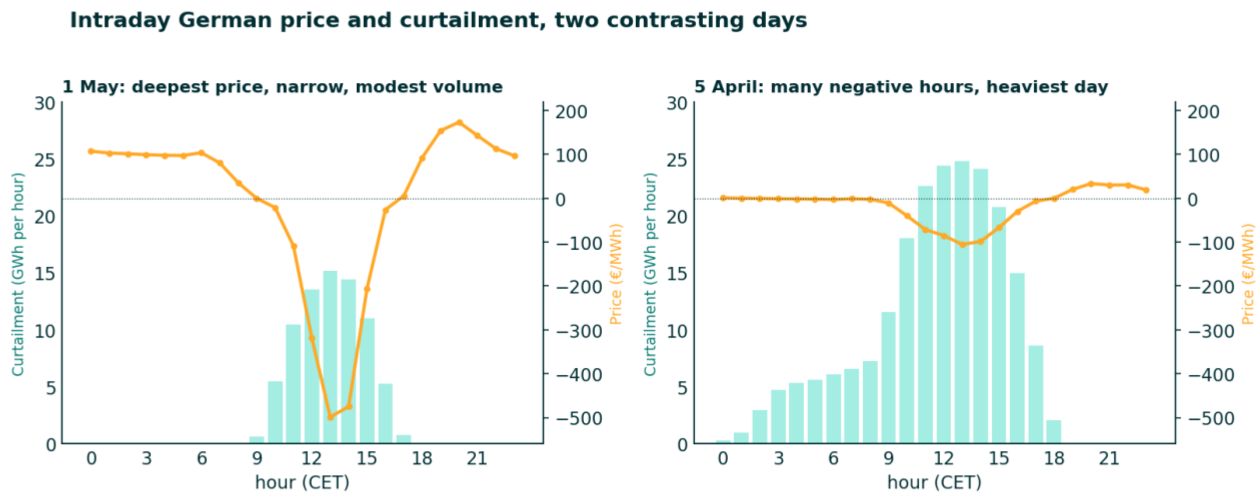

Figure 8. Intraday German price and curtailment on 1 May and 5 April 2026. Source: Montel EnAppSys.

The detailed view shows why. On 1 May the price craters during a narrow window around midday and commercial curtailment spikes briefly, then it is over. On 5 April the price sits below zero across most of the daylight hours, all the whilecommercial curtailment accumulates steadily through all of them. Volume tracks the breadth of the negative-price window, how many hours the market spends below zero, far more than the depth of the worst quarter-hour. A long, shallow negative day removes more renewable energy than a short, severe one.

That recasts the French picture once more. France gained negative hours in 2026, but many were the shallow, heat-shortened kind, and its must-run fleet produced through them. Breadth without withdrawal does not curtail much. It is the ordinary, cloudless, long-negative spring days, not the record-breaking price crashes, that fill the curtailment account.

Full year outlook: 2025 actual versus 2026 extrapolated

The chart below puts last year's actual full-year curtailment next to the model's extrapolation for 2026, for the six markets where the model runs the projection. The extrapolated bars are the workbook's own estimate based on the year to date, not a hand-drawn forecast and should be read as directional.

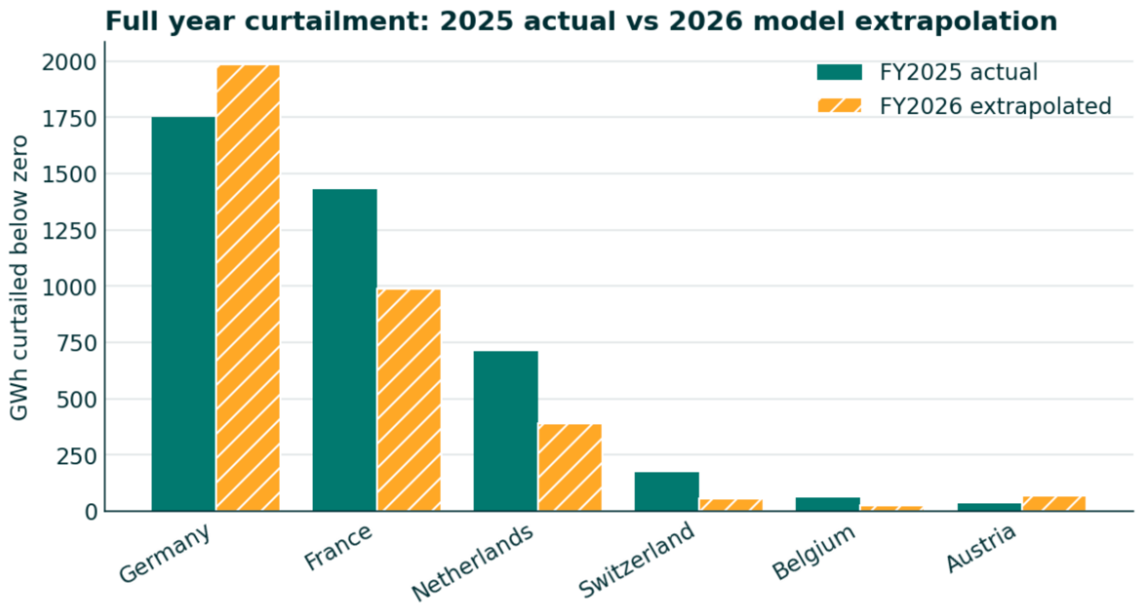

Figure 9. Full year curtailment, 2025 actual versus 2026 model extrapolation. Source: Montel EnAppSys.

The extrapolation says Germany up, everyone else down. Germany would set a fresh record near 2.0 TWh while France, the Netherlands, Switzerland and Belgium all retreat and Austria climbs off its small base. If it plays out this way, 2026 will become the year the big continental markets stop moving in lockstep, with Germany decoupling upward on the back of its tighter rules while France and the Netherlands ease.

Every projection leans on a first half that was, on the price evidence, quiet in our markets (even as Iberia set records). If the second half brings a run of sunny low-demand weekends, or the Iberian oversupply pushes further north, the projections could shift. And for France, remember the volume fall sits alongside rising negative hours, so a chunk of the commercial curtailment may simply have moved above the zero line, or been swallowed by heat, where this model does not fully count it. Extrapolation draws a straight line through a curve. It is useful for direction but should not be read as a firm forecast.

Southern Europe: a different kind of curtailment

This section adds Spain, Portugal and Italy, but it comes with a health warning, so read it as context rather than as more rows in the table above. Everything up to this point measures commercial curtailment, the voluntary price-driven withdrawal of renewables at the day-ahead stage, estimated from the sell curve. The public numbers available for Southern Europe measure something different. They measure system curtailment, renewable energy a grid operator cannot integrate because of network security limits. That is closer to the forced, grid-driven curtailment previously flagged in Great Britain, rather than the commercial curtailment behind the German and French numbers. Mixing the two would flatter the totals and mislead, so we keep them apart.

Spain is the one market of the three that publishes a clean, recurring number. Red Eléctrica's monthly ERNI series measures renewable energy that could not be integrated because of day-ahead network security constraints. It also splits the cause between the transport grid and the distribution grid. It is unambiguously a network story. Across the first half of 2026 it totals about 2,391 GWh, roughly 3 percent of available renewable generation. In most months between 77 and 93 percent of it comes from transport grid constraints. The trajectory is steep. June 2025 saw 193 GWh curtailed for grid reasons. June 2026 saw 1,112 GWh, very nearly six times as much. May and June 2026 together account for about three quarters of the half-year total.

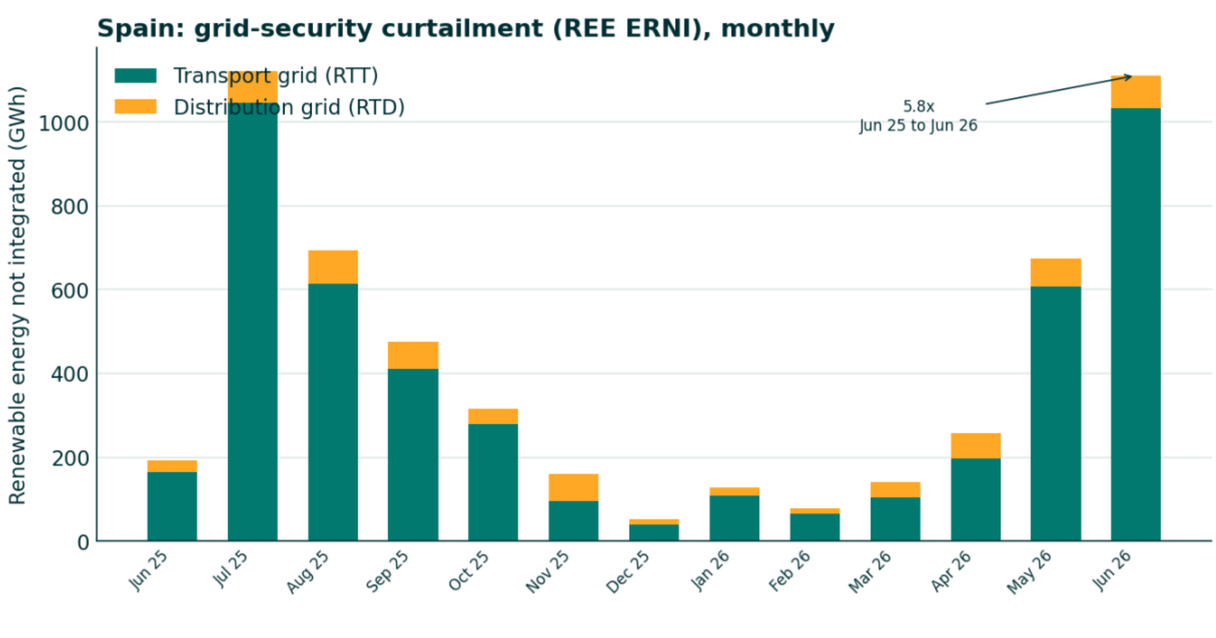

Figure 10. Spain grid-security curtailment (Red Eléctrica ERNI), split by transport and distribution grid. This is system curtailment, not the commercial curtailment measured elsewhere in this report. Source: Red Eléctrica / ESIOS.

To repeat caution on the Spanish figure: It is grid-security curtailment, not the commercial curtailment this report is built around, so it does not belong in the same league table as Germany or France. And there is no clean like-for-like first half of 2025 to set against it, because the public monthly series only reaches back to mid-2025, so the honest comparison is June against June, not half-year against half-year. What the number does tell you is that Spain's problem in 2026 is increasingly the wires, not the price. A rough financial proxy, applying Red Eléctrica's average downward restriction price to the curtailed volume, points to something like 133 million euro of curtailed energy value in H1 2026. That is an order-of-magnitude marker rather than an exact settlement figure.

Portugal and Italy do not publish a comparable national curtailment series. For Portugal, the operator data shows record renewable output and record hydro pumping, the tell-tale signs of a system working hard to swallow its surplus, but no published monthly curtailment volume. For Italy, the framework is visible even where the outturn is not. Terna's RiGeDi procedure for reducing distributed generation on security grounds was updated in August 2025.The day-ahead market then moved to fifteen-minute products in October 2025 and, along with the rest of the coupled markets, saw its minimum clearing price drop to minus 600 euro from late May 2026. All of that sharpens the exposure of Southern European renewables.

The consistent reading is that Southern Europe's surplus is showing up first in the network and in prices, rather than in voluntary commercial curtailment. This is the same Iberian oversupply that spills shallow negatives into southern France.

What this says about flexibility, storage and demand response

A retreat in curtailment volume is not the same as a solved problem. The oversupply that drives commercial curtailment is structural, and this half year's fall owes more to weather, hydrology and plant availability than to any lasting shift. Negative price hours, the underlying pressure, remained relatively stable, even rising in France. What changes from one half year to the next is the weather and the rules, not the mismatch between when renewables generate and when we use power.

The German signal is the clearest argument for storage. A market that commercially curtails more renewable power every time it goes negative, even as it goes negative less often, is a market leaving cheap, zero-carbon energy on the table. That is precisely the energy a battery, an electrolyser or a heat store is designed to absorb. The charging side of the storage business case looks healthy wherever commercial curtailment or negative pricing is rising. Taking a longer-term view, it does not yet appear to be cannibalising itself. Demand response is the natural complement, though it still carries an inconvenience cost that limits how far it scales beyond industrial users.

The Netherlands offers the one hint of the other path, where curtailment eases as storage and behind-the-meter flexibility grow into the surplus. One easing market does not prove flexibility is winning, but it is the trajectory the whole system needs, and it is worth watching whether it holds.

Weather as a structural risk

The June heatwave had a paradoxical effect on the market. By lifting demand and clipping both nuclear and conventional power at the same moment, it held prices positive through the sunniest hours and spared France a bout of commercial curtailment. That relief carries a cost, because the same heat that relieves the midday surplus is also drawing down the system's reserves.

Europe's hydropower reservoirs are the sector's savings account. Water is deposited in the wet months and withdrawn in the dry ones. The real test is not surviving the summer but arriving in winter with enough left in the account. Europe entered this summer in reasonable shape, with Spain unusually well stocked after a wet winter and spring, though southern Norway and the Balkans carried thinner margins. A run of hot, dry weeks is a withdrawal from that account, and the withdrawals are coming more often.

The heatwaves are no longer anomalies. 2003, then 2018, 2019, 2022, 2023 and now 2026. Each starts from a slightly higher baseline, so records that once seemed extraordinary become merely notable. For a commercial curtailment report, that matters, because the relief we saw in late June is not a one-off quirk of the calendar. It is a pattern, extreme heat repeatedly turning would-be negative-price days into positive ones, while at the same time straining the hydro and cooling margins that keep the wider system secure.

The nuclear cooling limits behind the French relief are the clearest example. Hot rivers force thermal plants to cut output at precisely the moment demand peaks, and EDF has repeatedly flagged restrictions when river temperatures climb, as has Switzerland. In our data, that showed up as a fleet already capped at the start of the heatwave day. The drivers of commercial curtailment and the drivers of summer supply risk are increasingly the same weather.

The practical takeaway is that weather is no longer just a short-term forecasting variable for this market. It is becoming a structural feature of generation economics and security of supply. For curtailment it cuts both ways. Warm, sunny springs swell the solar surplus that drives negative prices, while the hottest summer spells briefly switch that surplus off. Neither is going away, and every heatwave now matters a little more than the one before.

Methodology

We estimate price sensitive curtailment from the sell curve of the day-ahead auction. For every settlement period, hourly before 1 October 2025 and quarter-hourly from that date, we measure the volume offered in the sell curve between the market clearing price and zero. That is the volume willing to generate only above where the market cleared, and therefore did not produce. The lower bound of that band is the technical minimum, the floor price of the day-ahead auction. We reference the technical minimum rather than a fixed number on purpose, because the floor was minus 500 euro through most of the period and moved to minus 600 euro across the coupled markets from late May 2026.

This is deliberately a simplification. Depending on subsidy rules, the number of consecutive negative price periods, and plain commercial judgement, participants may start curtailing above zero, or hold on to more negative prices than we assume. Montel's own work has flagged generators switching off between zero and five euro as balancing risk and market-access costs rise, which our below-zero metric does not capture, so the true commercial curtailment may be somewhat higher than reported here. There is renewable capacity in the buy curve too, and intraday trading reshuffles positions after the auction closes. The model does not separate wind from solar, because bids are anonymous. Curtailment for redispatch or balancing is out of scope, since every country handles those differently.

Two practical notes. The like-for-like curtailment comparison uses 1 January to 30 June for both years. The negative price hour counts are computed from the quarter-hourly day-ahead price series, cumulative to 1 July, with an hour counted negative when the mean of its quarter-hour prices is below zero.

Sources and further reading

All curtailment volumes and full-year extrapolations are drawn from the Montel EnAppSys day-ahead curve model, with data to 1 July 2026. Negative and zero price hour counts are computed from the quarter-hourly day-ahead price series for the same period.

Germany: subsidy rules and curtailment

From Negative Prices to Zero Hours, Montel (25 March 2026). Supports the shift from negative to zero-price hours and the quarter-hour averaging rule.

Germany Ends Remuneration of Negative Price Periods Under the EEG, Pexapark (19 February 2025). Supports the Solarspitzengesetz (Solar Peak Act) mechanics, the 2 kWp threshold and the co-location changes.

15-minute products live on EPEX SPOT Day-Ahead markets, EPEX Spot (2025). Supports the 1 October 2025 quarter-hourly day-ahead go-live.

France: nuclear, support rules and the Iberian link

Operational Performance, EDF (updated 15 July 2026). Supports French nuclear output up 8.1 TWh, or 4.4 percent, in the first half of 2026 versus 2025.

New record of negative electricity prices in France, pv magazine and Storio Energy (7 May 2026). Supports reduced nuclear flexibility, the March 2026 RTE-EDF minimum-output agreement and the rise in negative and near-zero hours.

Arrêté du 8 septembre 2025 (Article 175, 2025 Finance Law), Légifrance. Supports the minus ten cents per MWh shutdown trigger for obligatory purchase and feed-in premium contracts, applied from 1 October 2025.

Loi de finances 2026, revision des mecanismes de soutien aux EnR, Cerfrance and Editions Legislatives (27 March 2026). Supports the lowering of the shutdown threshold from ten megawatts to one megawatt and the move to fifteen-minute settlement.

From night to noon: France's reactors are now bending for European solar, pv magazine and Ricardo WSP (14 May 2026). Supports France importing cheap Spanish solar in spring and bending nuclear to make room.

The electricity interconnection across the Biscay Gulf, INELFE. Supports the France-Spain capacity of about 2.8 GW, the border congestion and the 2028 commissioning of the Bay of Biscay cable.

Curtailment above zero and balancing risk

European Price Sensitive Curtailment Report 2025, Montel. Supports generators switching off between zero and five euro per MWh as balancing risk and market-access costs rise.

Southern Europe: system curtailment (context, different methodology)

Publicacion mensual de la Energia Renovable No Integrable (ERNI), Red Eléctrica and ESIOS (monthly, 2025 to 2026). Supports Spain's grid-security curtailment volumes, the transport versus distribution split and the June 2025 to June 2026 surge.

Data Hub and monthly balances, REN Portugal (2025 to 2026). Supports Portuguese renewable output and hydro-pumping records, used qualitatively.

RiGeDi (Allegato A.72) and TIDE dispatching notices, Terna, with zonal day-ahead prices from GME (2025 to 2026). Supports Italy's security-driven reduction framework, the fifteen-minute products from October 2025 and the minus 600 euro floor from May 2026.

Nordic hydro balance

Europe's negative electricity price hours double in Q1, pv magazine and Ricardo WSP (8 May 2026). Supports the Nordic negative-hour collapse against the EU-wide doubling.

Varens elpriser 2026, Vattenfall Energy Plaza (31 March 2026). Supports the Nordic hydrological deficit and the lowest snow and ground water in ten years.

Weather as a structural risk

Heat eats into Europe's electricity savings account, Montel News, Jean-Paul Harreman (24 June 2026). Supports the framing of heatwaves as a recurring structural risk, hydropower reservoirs as the system's savings account, and thermal cooling limits on nuclear during heat.

Belgian nuclear maintenance

Elia Summer Outlook 2026, Elia (26 March 2026). Supports the Doel 4 and Tihange 3 maintenance from April to November 2026 and the operator's own link to lower surplus risk.

Restart and extended operation of Belgian reactor approved, World Nuclear News (7 July 2025). Supports the 2025 outage dates that qualify the year-on-year comparison.