Weather and Geopolitics Are Stress-Testing Europe's Clean Energy Transition

Wind, Water, and the Price of the European Evening

Evidence from 2026

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Rivers shaded by flow against their 1991-2025 normal for the date. The redder the river, the drier it ran.

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Abstract

European power prices are usually judged by an annual average. Read instead at the resolution the system runs at, one price per bidding zone per hour on a panel of 3.9 million zone-hours ending 10 August 2026, the clean transition has moved Europe's economic cycle in between a weather cycle and a political one. Summer 2026 had fifteen days on which ten or more of the 39 zones were hot at once against five in 2022, and heat reaches supply as well as demand. Fifteen of 35 river cooling sites ran at their lowest in 35 years, hydro's contribution to the evening climb halved from 8.9 to 4.3 GW, and gas covered the difference. Russian gas meanwhile fell from 42 per cent of extra-EU imports to about a tenth while liquefied gas rose to 44 per cent, a real diversification into a different form of exposure, and the defence budgets the same geopolitics requires draw on the fiscal space the grid needs. Solar carried the daytime this summer and cannot carry the evening, which falls to wind, hydro or fuel. Wind is the renewable whose share tracks national income, from 60 per cent of generation in Denmark to 1.4 in Hungary, so the member states with the widest gap between a cheap midday and a dear evening are the ones that have not built it. Adjacent zones clear at the same price in only 26 per cent of hours. Expanding wind, and building the wires and the agreement between zones that would let it be shared, is the binding constraint on completing the transition. This paper identifies that constraint from price and operating evidence, and it does not estimate the environmental or the total system cost of resolving it.

Summary

Europe has been trying to make energy one market since 1951. Coal and steel came first, gas and electricity in the 1990s, coupled day-ahead markets after 2006. In 2026 the electricity price is moving the other way.

The price Europe pays for leading the clean energy transition is usually read off one number, the average electricity price set against its trading partners. That average conceals the two dimensions along which the price now moves, the hour of the day and the bidding zone. The stresses testing the system come from two directions it cannot capture, the weather and geopolitics.

A fully renewable system returns an industrial economy to something older, with output governed by what the sky delivers, much as a rain-fed farm is governed by the monsoon. Generation follows the weather, and dispatch, price and trade have to arrange themselves around what it delivers. When Europe began this transition, both conditions were benign. The weather was not yet extreme, the geopolitics were friendly, and each cushioned the other. A wind drought, a dark and calm week, a dry year could all be absorbed. The anchor was gas, mostly cheap pipeline gas, cleaner than coal in both carbon and particulates, and abundant enough that some countries could close their nuclear plants as well. Affordable power was the condition on which Europe's industrial competitiveness rested.

The capital programme is still running. Europe leads in parts of the clean-technology supply chain, but its balance of payments carries a heavy, front-loaded bill for imported capital goods such as turbines, cells and transformers. When the weather turns, the failures compound. A heatwave limits the cooling water that thermal and nuclear plants depend on, hydro and wind cannot cover the evening, and the fastest substitute is gas. Since the war in Ukraine that gas arrives by ship rather than pipeline, at a higher delivered cost. Diversifying LNG supply is the obvious answer, though the sea lanes carry their own geopolitical risk, and leaning on United States cargoes swaps one concentrated dependence for another.

Inside Europe the picture is equally uneven. The Coal and Steel Community was built on the theory that integrating a sector integrates the politics behind it. Seventy-five years later the sector is pulling in the opposite direction. Countries sit at different stages of the transition, the wires between them are incomplete, and zones with cheap power have a rational interest in keeping that advantage local. Market coupling, redispatch and contracts for difference all exist to manage the resulting gaps, yet the gaps remain large enough to be worth lobbying over. Europe must now balance three things at once, the weather, its external dependencies, and its internal divisions.

Trading has moved with the market. Predicting prices zone by zone was specialist work ten years ago and is now within reach of any team with public data and a machine learning stack. A market built to deliver electricity is increasingly a market for taking positions on what a zone's price will do next.

This report documents how a European power price is now formed and why the transition has made that mechanism harder to read. For anyone forecasting it, an annual average no longer carries enough information, and the unit that does is the zone and the hour.

1. The transition has to adapt to the weather and renew what it runs on

The evidence from summer 2026.

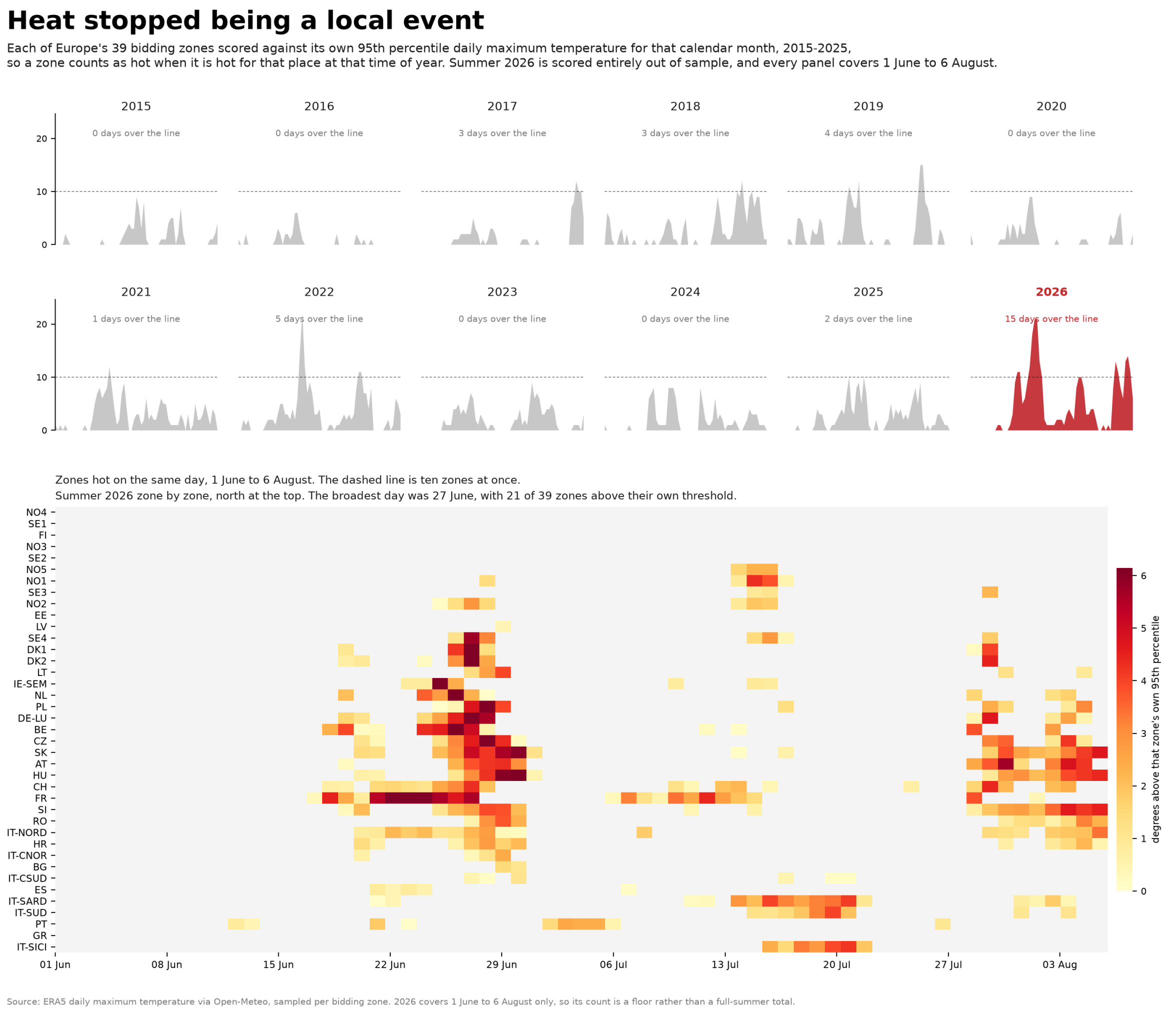


Figure 1. Every summer since 2015 on the same axes, counting how many of the 39 zones are above their own 95th percentile on the same day. Earlier years spike and pass. 2026 stays over the line for fifteen days, and the carpet below shows which zones.

A heatwave raises consumption and cuts production in the same week, and the two sides get very different amounts of attention.

Consumption is the side everyone watches. Air conditioning turns a hot afternoon into extra load, and Europe is getting more of those afternoons. Across the 39 bidding zones,[1] the stretch from 1 June to 6 August 2026 averaged 18.7 degrees, the warmest of the twelve years in the daily record and above the 18.6 of 2022. In 2015 the same weeks averaged 17.2. This side is largely handled,

[1] Thirty-nine is the number of zones live in 2026, Switzerland included. The price panel carries a fortieth label, DE-AT-LU, which is the joint German-Austrian-Luxembourg zone split into DE-LU and AT in October 2018. That is history rather than a gap, and it is dropped from every figure after that date so the two halves are not counted twice. Figures drawn on the EEA perimeter drop Switzerland as well, which leaves 38.

and by accident rather than by design. Solar peaks in the same hours as the cooling load, and it was mostly built where the load is, on roofs and in the industrial south, so the electricity shows up in the same place as the air conditioner. The midday price falls in most of Europe instead of rising.

Production is the side that gets almost no attention. The plants that carry the rest of the day, once the sun is off and the load is still there, need cooling of their own, and they take it from rivers. Nuclear and thermal stations draw river water and return it warmer, under licences that cap how much they may take and how hot they may leave the river. When the river falls, the plant reduces output. There is no fault and no outage notice, and capacity the market counts as always available stops being available. The water comes from rainfall and snowmelt rather than from a supply contract, and this summer there has been less of it than in any of the previous 35 years.

A third effect removes the usual answer. A hot zone buys from a cool neighbour, which is what market coupling is for, and that works while the heat stays regional. Taking daily maximum temperatures for every zone from the ERA5 reanalysis through Open-Meteo, and scoring each of the 39 zones against the 95th percentile of its own 2015 to 2025 daily maxima for that calendar month, summer 2026 has had 15 days on which ten or more zones were hot at the same time. In 2022 there were 5 such days, and in six of the eleven earlier summers there were none. The threshold is built without 2026 in it, so this summer is scored out of sample, and the count runs only to 6 August.

2022 touched 22 zones on a single day and 2019 touched 15, both narrow spikes that passed within the week. 2026 has stayed over the line for a fortnight. One sharp day can be ridden out by leaning on a neighbour and buying back later. A fortnight has to be covered from a zone's own plant.

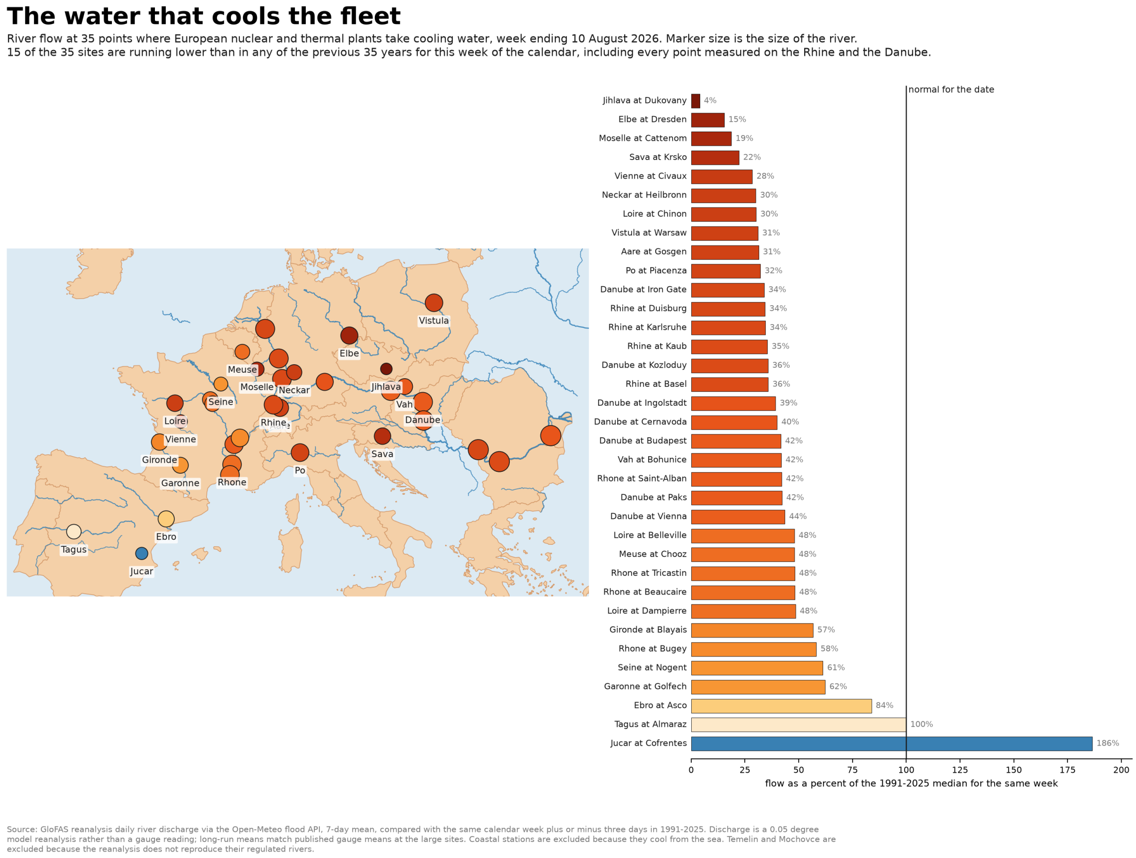


Figure 2. Nuclear and thermal stations inland run on river water. Of the 35 points where they take it, one was above its normal flow for the date in August 2026 and 15 were at their lowest in 35 years.

I measured daily discharge at 35 points where European plants take that water, from the Rhine and the Danube down to the Jihlava, the small regulated river that cools Dukovany, using the GloFAS reanalysis through the Open-Meteo flood API. Every site is scored against its own history and against no other river, by ranking its seven-day average flow against the same seven calendar days in each year from 1991 to 2025. In the week ending 10 August 2026, 15 of those points were running lower than in any of the previous 35 years for that week of the calendar. That includes every point measured on the Rhine and every point on the Danube. The Rhine at Kaub was at 35 per cent of its normal flow for the date. The Danube at Vienna was at 44 per cent, the Po at Piacenza 32, the Elbe at Dresden 15.

Across all 35 sites, exactly one was running above its normal flow for the date, the Jucar in eastern Spain. One more, the Tagus at Almaraz, sat level with normal, and that reading is a regulated release rather than a river finding its own level. The remaining 33 were below, and in August 2026 28 of them were below half.

1.1 Rivers dried almost everywhere

Europe has had these summers. 2003, 2015, 2018 and 2022 all forced cooling restrictions somewhere on the continent, and 2022 is the one the industry still refers to. Measured the same way across the same 35 sites on the same date, the median flow was 57 per cent of normal in 2003, 64 in 2015, 63 in 2018 and 47 in 2022. In 2026 it is 40. In 2022, 19 of the 35 sites were below half their normal flow. In 2026, 28 are.

So the pattern is familiar and the severity is new. That distinction matters for what Europe does next, because a recurring problem that is getting worse is a design question rather than an emergency.

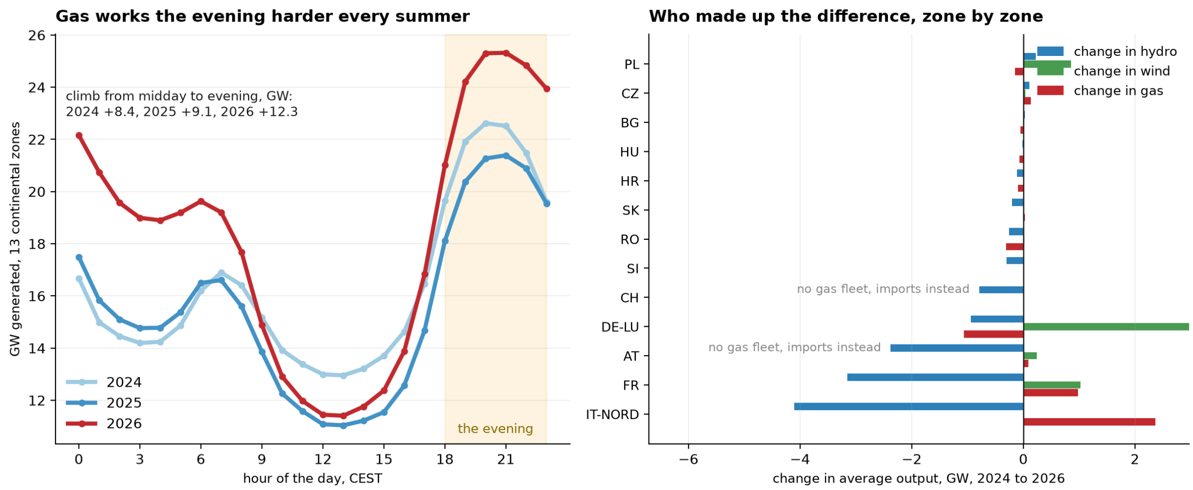
1.2 The evening is where the water is missed

A dry river reaches the price at a particular hour. Solar covers the middle of the day and covers more of it every year, so what the system has to find is the evening ramp, the climb out of that middle from about six to about ten, after the sun has gone and before the load has. Hydro used to supply a large share of that ramp, because a reservoir is the cheapest way there is of moving a megawatt-hour from noon to nine o'clock. This summer it could not.

ENTSO-E publishes actual generation by production type for every zone and hour, which lets the fuels be read against the clock rather than against a monthly total. Take the same six weeks in three consecutive summers, 1 July to 10 August, across thirteen continental zones, with hours shifted from UTC to CEST so the evening is the evening. Rivers at the cooling sites in those zones ran at 125 per cent of their normal flow in 2024, 69 per cent in 2025 and 43 per cent in 2026. Two years is short enough that the fleet has not turned over, so the comparison is close to like for like.

In the evening hours, hydro across those zones produced 40.4 GW in 2024, 32.6 in 2025 and 28.0 in 2026. That is 12.4 GW of evening output gone in two summers. Wind put back 9.1 GW of it and solar 4.6, gas rose 2.5 and coal fell 2.6, against a load that rose 6.4. In energy terms the water was covered, and covered by weather of a different kind.

The energy balance answers a different question from the one the evening poses. What moved is the ramp. Hydro's contribution to the climb from midday to evening was 8.9 GW in 2024 and 4.3 GW in 2026. The gas ramp over the same hours went from 8.4 GW to 12.3. Wind's evening contribution grew as well, from roughly nothing to 5.8 GW, which is real and which no dispatcher can call on in advance. Wind replaced the water's energy. Gas replaced the dispatchable half of the water's job, and nothing else did.



ENTSO-E actual generation per production type, A75, for 13 continental zones, 1 July to 10 August of each year. Hours are UTC shifted to CEST, and each series is the group's total output in that fuel averaged across every day in the window. Rivers at these zones' cooling sites ran at 125 per cent of their normal flow in 2024, 69 per cent in 2025 and 43 per cent in 2026.

Figure 3. Left: the average day in gas output across thirteen continental zones, three summers on the same calendar dates. Right: what each zone lost in hydro over that window, and what it gained in wind and in gas.

The zone detail answers the next question, which is where the replacement came from, and the answer is different in each place. Northern Italy lost 4.1 GW of average hydro output, has almost no wind, and raised its own gas by 2.4 GW while buying the rest. France lost 3.2 GW of hydro and covered it about evenly between gas and wind, 1.0 GW each. Germany lost 0.9 GW of hydro, added 3.1 GW of wind and 4 GW of solar, cut its own gas by 1.1, and sent 5.2 GW more out to its neighbours than it did in 2024. Austria lost 2.4 GW and Switzerland 0.8, and neither has wind or a gas fleet worth the name, so both covered the gap on the wires, with Austrian net imports up 2.0 GW and Swiss up 1.6.

So a dry Alpine summer is not a local event. It puts gas into Italian machines, splits the French answer between a turbine and a wind farm, and pulls German wind and solar south across the interconnectors. Whether that reads as a success or a warning depends on whether the energy or the ramp is the number taken.

One number belongs beside this. As solar builds, the fall from the midday peak into the evening steepens on its own, and across these zones that fall deepened from 63 GW to 83 GW between 2024 and 2026. Part of the evening ramp's new size is therefore solar's doing and part is the water's. What the water explains is the hydro side of it, and the zones that lost the most water are the zones whose evening supply changed most.

1.3 The fleet total hid what the reactors did

Nuclear output across those thirteen zones barely moved, 52.9 GW in the evening hours of 2024 against 52.1 in 2026. Read as a fleet total, nothing happened. That reading is wrong twice over, and both reasons are ordinary features of how a nuclear fleet is operated.

The first is that France cools thirteen of its eighteen stations from a river and five from the sea. A drought cannot reach the second group, so a single fleet number averages an exposed population against an unexposed one and returns a null by construction.

The second is availability. France came into this summer in better shape than into either of the last two, running about 39 GW of nuclear through the second half of June against roughly 36 GW in the same fortnight of 2024 and of 2025. The cooling curtailments came out of that surplus. An output series compares what ran against what ran, whereas a derate removes megawatts from what was available, and those are different baselines. On the first, French nuclear had a good summer. On the second, it lost capacity it would otherwise have sold.

That is why the measure here is load factor conditional on running. ENTSO-E publishes actual generation for each named generation unit hour by hour, so every reactor can be measured against its own highest recorded output across the three summers rather than against a nameplate rating. Summer output at a European reactor is set mainly by refuelling and maintenance, scheduled into the months when demand is low, so a unit at zero in July is usually on an outage rather than short of water. Every figure below is computed on online days only, meaning days the unit generated in all 24 hours, which excludes outages instead of counting them as a shortfall, and a station appears only if it has at least five such days in both summers. The baseline is 2025 rather than 2024, because French units spent most of July 2024 on maintenance and half the fleet has fewer than ten online days that year.

Measured that way the differences appear. Between last summer and this one the fourteen river-cooled French stations lost 4.4 points of load factor on the days they were running, while the four sea-cooled stations gained 1.6. Across all ten countries in the data, a river-cooled reactor held 89.8 per cent of its own maximum on an online day this summer against 92.8 per cent at a sea-cooled one.

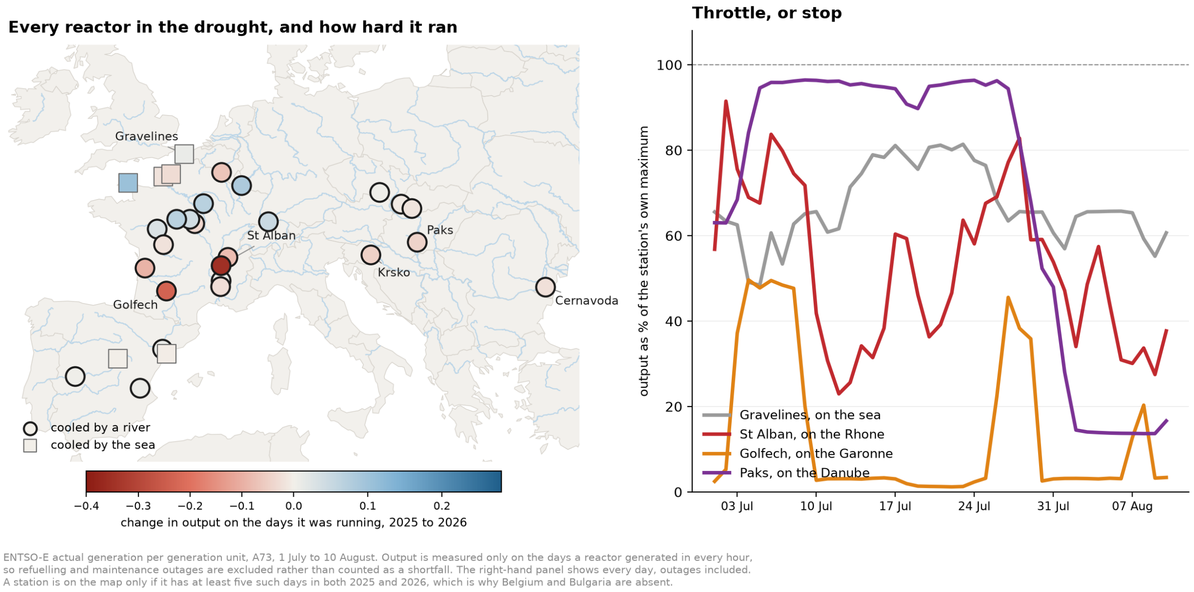


Figure 4. Left: every reactor with enough running days to compare, coloured by how its output changed between the two summers. Circles cool from a river, squares from the sea. Right: the whole of this summer for four stations, including the days they were shut.

1.4 The constraint that binds is temperature, and flow is what sets it up

The licence condition that stops a reactor is a thermal discharge limit rather than a volume of water. A station may not lift the receiving river above a stated temperature, and on the Garonne, the Rhone and the Seine that ceiling sits at around 28 degrees. Low flow matters because it removes the dilution. The same quantity of rejected heat lands in less water, the river reaches its ceiling sooner, and the operator derates to stay inside the licence. Flow and temperature are therefore one constraint rather than two, which is why the driest rivers and the derated reactors are the same list.

Late June tested it. A blocking high over western Europe took riverside air temperatures at the French sites to 42.5 degrees. EDF cut of the order of 6 GW of nuclear, close to a tenth of the fleet, to hold the discharge limits, and the regulator granted temporary derogations from those limits to keep the system supplied. Reported unit actions included Golfech 2 off from 22 June with a return scheduled for 22 July, Bugey 3 to 19 July and Chooz 2 to 25 July, with Tricastin 4 and both Saint-Alban units derated rather than stopped. Those are declared actions taken from press and regulator reporting rather than from this panel.

1.5 Some throttle, some stop

The per-unit series records the same summer from the other side, as megawatts rather than as announcements, and it separates two distinct operating responses.

Saint-Alban sits on the Rhone, which ran at the lowest flow in 35 years for almost every day of the window. It ran on all 41 days and never disconnected. What it did instead was slide, between 21 and 91 per cent of capacity, holding near 21 per cent through the second week of July and again in early August and recovering between. Its load factor on the days it ran fell from 89 per cent last summer to 54 this one.

Golfech sits on the Garonne, a smaller river with less to give. It held above 90 per cent through the first week of July, then fell to about 3 per cent and stayed there, with two brief returns to full load at the end of the month. Its load factor on the days it ran fell from 91 per cent to 67. Inside this summer the split is sharper. On days when the Garonne was above its own 20th percentile Golfech ran at 96 per cent, and on the days below it, at 51.

So both responses are present. A large station on a large river derates, holds a reduced load for days, and recovers. A station on a smaller river runs at full load until the river reaches its ceiling and then comes off within the day. Neither reaches the market as a failure, and neither is an outage in the sense a capacity adequacy study uses, which is part of why the exposure is not priced.

The Danube shows the milder version. Paks ran every one of the 41 days with the river at its lowest flow in the record and held 92 per cent against 96 last summer. Cernavoda, far downstream, held 94 against 96. Krsko on the Sava went from 98 to 94. These are small numbers next to Saint-Alban and they all point the same way.

One limit belongs with all of it. A73 reports what each unit produced and not why it produced it. Declared causes sit in the REMIT urgent market messages and in ENTSO-E's unavailability data, neither of which I have pulled, so the attribution here rests on the derating tracking the river beside each plant and on the sea-cooled control group not moving. The June actions listed above supply the declared cause independently.

1.6 The plants were licensed on flows that no longer occur

The plants on these rivers were sited, licensed and cooled on the assumption of a flow regime that held. That assumption has changed, and the research has been consistent about it for more than a decade. van Vliet et al. (2012) projected summer generating capacity in Europe falling 6.3 to 19 per cent under warming, from the combination of lower river flows and warmer river water. Behrens et al. (2017) put the same question to 1,326 individual European plants across 818 water basins, and found the number of basins facing reduced power availability rising from 47 to 54 between 2014 and 2030, concentrated in the Mediterranean with further exposure in France, Germany and Poland.

Read against this August, that literature no longer looks like a projection.

1.7 The Draghi report leaves water out

The reference document for the coming investment push is the Draghi report on European competitiveness, which asks for the total investment-to-GDP rate to rise by around 5 percentage points a year and compares that with the 1 to 2 per cent the Marshall Plan delivered. I read both volumes for this constraint and it is absent. Part A does not use the word water. In Part B it is almost always an inland waterway, and the single appearance that touches power runs the other way, naming the Water Framework Directive among the environmental laws to relax so that grids and renewables permit faster. Water enters as a source of delay rather than as an operating input. Other bodies are already correcting this. ACER's market monitoring reports elevated river temperatures limiting cooling at thermal and nuclear plants during peak demand, and puts French cooling demand at roughly 600 MW of extra load for each degree above 20. A summer like this one makes water harder to leave out, and the likely outcome is a consensus that weather and water belong in the design of the energy system alongside cost and speed.

What has not caught up is procurement. An investment appraisal tests cost, delivery time and supply-chain origin, and it should test whether the capital good fits the climate it will run in for forty years. Systems hold contingency plans for a hot week, and a contingency plan assumes an exception. Fifteen days with ten or more zones hot at once reads as a season, and so does a summer with every measured point on the Rhine and the Danube at a 35-year low. At that scale the answer is a specification change rather than a procedure, which means cooling design, siting and water rights belong in the investment decision itself.

1.8 Every part of the system loses capacity in heat, including the wires

The same week does something similar to the network. Conductors carry less current when the surrounding air is hot, losses rise with conductor temperature, and transformers derate. Bartos et al. (2016), working on the United States network, projected average summertime transmission capacity falling 1.9 to 5.8 per cent by mid-century while peak per-capita summer load rose 4.2 to 15 per cent. Both sides of that ledger move the same way as the rivers. Capacity contracts in the week demand expands.

Europe already applies this logic to agriculture, where the advice to a farmer is to plan for the weather that is coming rather than the weather that was. The power system is being built now, for forty years, on the older assumption.

1.9 New load is being sited without water data

There is an awkward corollary, and it is worth stating before anyone reaches the obvious policy conclusion. The exposure this summer measured falls hardest on the plant that Europe most needs more of. The reason is the ratio of heat rejected to power sold. A pressurised water reactor converts about a third of its heat into electricity and rejects the rest, nearly all of it through the condenser. A combined-cycle gas plant converts about 60 per cent and sends much of what it wastes up the stack, and its gas turbine takes no cooling water at all.

Two quantities get conflated here and they behave differently. On consumption, meaning water evaporated and not returned, published figures put nuclear at roughly 2.1 litres per kWh against about 1.2 for a combined-cycle plant. That is a real gap and a modest one. On withdrawal and on the heat carried back to the river, which is what a discharge licence actually regulates, the gap is an order of magnitude, because a once-through station takes tens of thousands of gallons per MWh and returns them warmer. The 28 degree ceiling constrains the second quantity and is indifferent to the first.

So the exposure follows cooling design and siting rather than the technology in the abstract. A coastal reactor, a reactor with a cooling tower and a reactor cooled with air do not meet this constraint the way a once-through river station does. Firm low-carbon capacity is what the evening needs, and the firmest kind Europe knows how to build is the one a dry August constrains hardest unless it is sited and cooled for the climate it will run in. That is settled at the point the site is chosen, which is the same point at which the water question is currently not being asked.

The existing fleet is stuck with the cooling it has, and changing that costs output. Qin et al. (2023) put the energy penalty of dry cooling at 1 to 15 per cent depending on site and climate, and the penalty runs highest on hot days, when the plant is most needed. Lohrmann et al. (2019), working from a satellite-derived database of 13,863 thermal units, find most of that water demand can be designed out by 2050, largely by building fewer thermal plants.

The live decision is the new load. Europe is siting datacentres, electrolysers, green steel and battery plants now, several of them water-cooled at scale, and the water they will draw goes unmeasured. Mytton (2021) found that fewer than a third of datacentre operators measure their water consumption, and that the published totals rest on a handful of derived estimates. A siting decision cannot weigh a constraint that almost nobody measures.

So the siting question is concrete. A plant placed on the cheap-power map alone has been sited on the price and not on the water, because the zone price says nothing about whether the river beside it will be there in August. A gigawatt station on a river that runs low every August is a gigawatt that is only partly there in the weeks the system needs it most.

1.10 Capital goods need a weather test

Three things arrive in the same week, and each has a number behind it. Heat lifts demand, and solar covers most of that lift because it was built where the load is. Heat and drought cut what the rest of the fleet can produce, with 33 of 35 cooling points below their normal flow this August and 15 at a 35-year low. And the heat now covers the continent rather than one corner of it, which takes away the cool neighbour a zone would otherwise buy from.

The planning question that follows is narrow and answerable. A capital good is already tested for cost, delivery time and where it was made. The test still missing is whether it performs in the weather it will actually meet over forty years, and that test is what decides the cooling system, the site and the water rights a project is bought with.

2. What Europe depends on to build it and to run it

Geopolitics hits the energy sector directly, and is expected to crowd out the money that would build it.

The 2022 crisis is usually told as a gas story, and the retelling has become a success story. The gas half of it is real. On Eurostat's monthly extra-EU trade values, Russian-origin gas, counting the volumes that crossed Ukraine and Belarus and adding them back to Russia, fell from 48 per cent of extra-EU imports in 2019 and 42 per cent in 2021 to about 11 per cent in 2026. Norway holds 27 per cent. The United States went from 3 per cent to 18. Liquefied gas rose from a fifth of extra-EU imports to 44 per cent. Every share in this section is a share of value rather than of volume.

Much of that is a genuine gain. New liquefaction capacity in the United States, Qatar and west Africa arrived in time to be useful, and the terminals Europe built in 2022 and 2023 are the reason the switch was possible at all. It is also a trade rather than a favour. Exporting countries need the revenue and the long-term contracts as much as Europe needs the molecules, which is what makes the arrangement durable and what gives both sides something to lose.

What changed is the form of the dependence. A pipeline monopoly became a shipping market, which is more diverse in principle and more exposed to freight, weather and politics at the loading end. ACER makes the same point from the other direction, noting that the United States now supplies more than half of EU LNG, and that long-term contracts consolidate a relationship carrying price and tariff risk. Russia has not left either, still supplying roughly a tenth of extra-EU gas imports, with the 2026 share slightly above 2025.

That remaining tenth is held by a small number of member states rather than spread across the union. Almost all Russian LNG arriving in the EU lands in three countries: in 2025 Belgium took 5.9 billion cubic metres, Spain 3.8 and the Netherlands 2.5, and the same three account for the 2026 volumes. Part of the Belgian figure is transhipment at Zeebrugge for onward export rather than European consumption. The union-wide total has not fallen at all. EU imports of Russian LNG were 12.8 bcm in 2021, 14.6 bcm in 2024 and 12.7 bcm in 2025. The rest of the Russian flow arrives by pipeline through Turkey, at roughly 1.5 to 1.7 bcm a month.

The phase-out is now law. The regulation banning Russian gas entered into force on 3 February 2026 and applies stepwise from 18 March, with short-term LNG contracts prohibited from 25 April 2026, long-term LNG contracts from 1 January 2027 and pipeline gas from autumn 2027. The volumes had not turned by May. Russian LNG arrivals ran at 1.27, 1.25, 1.73, 1.29 and 1.65 bcm through the first five months of 2026, with May the highest of them. What is left is contracted supply rather than opportunistic buying, which is what the 2027 date exists to close.

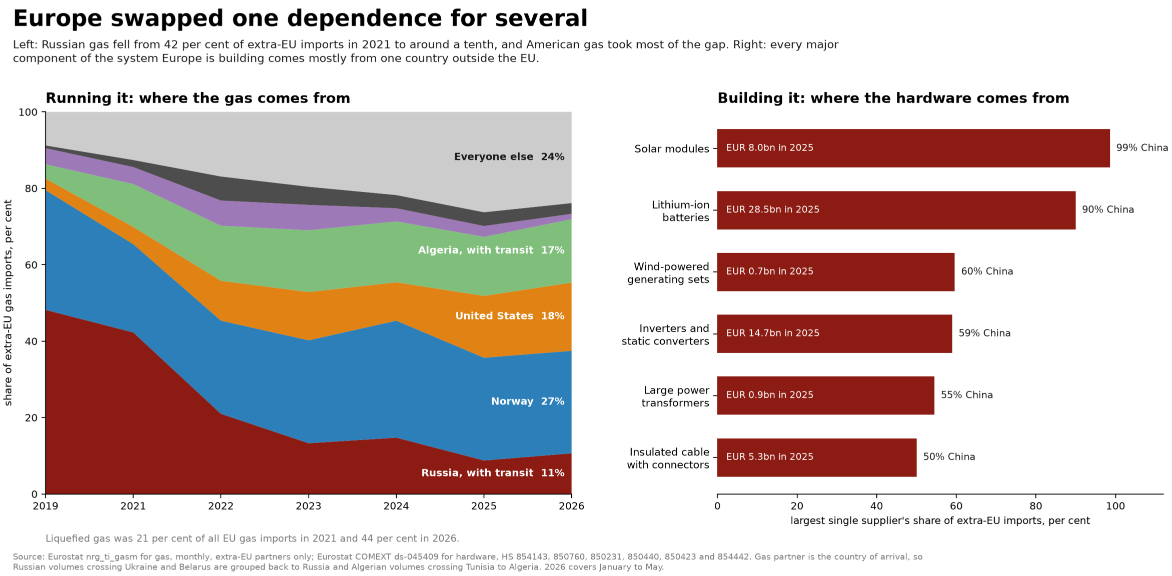


Figure 5. Left: Russian-origin gas fell from 42 per cent of extra-EU imports in 2021 to around a tenth, and American gas took most of the gap. Right: every major component of the system Europe is building comes mostly from one country outside the EU.

The building side went the other way. Every major component of a modern power system is bought outside the EU and bought largely from one country. In 2025, China supplied 99 per cent of EU solar module imports, 90 per cent of lithium-ion batteries, 60 per cent of wind-powered generating sets, 59 per cent of inverters, 55 per cent of large power transformers and 50 per cent of insulated cable. Batteries alone came to 28.5 billion euros, inverters to 14.7 billion.

The dependence deepened while Europe was diversifying its gas. China's share of EU battery imports rose from 48 per cent in 2019 to 90 per cent in 2025, and its share of large power transformers from 9 per cent to 55. ACER reports the same concentration for 2024 from the same trade data, so the direction is not in dispute.

One number in that series is easy to misread. EU solar module imports fell from 19.5 billion euros in 2023 to 8.0 billion in 2025, which reads as exposure falling by more than half. The tonnage tells a different story: 4.61 million tonnes in 2023 and 4.46 million in 2025. Europe imported the same physical quantity of modules and paid 59 per cent less for it. A shrinking import bill can mean a cheaper supplier rather than a smaller dependence.

Each conflict reaches this system by a different route. The Ukraine transit contract ended on 1 January 2025, and the trade data records Ukraine at exactly zero from that month. A tariff dispute with the United States would reach the gas bill and the hardware bill in the same quarter. A disruption in the Gulf reaches the LNG cargo before it reaches anything else. None of this is a new observation. Draghi's report names critical raw materials as Europe's external vulnerability, and ACER names the energy-side version of it. This chapter is context, and the figures above are my own calculation of it rather than a citation.

The argument worth adding is about the money. The same geopolitics that raises these risks is also the reason European defence budgets are rising, and the Commission's own estimate, quoted in the Draghi report, puts additional defence investment at around 500 billion euros over the decade. That sits beside a call for total investment to rise by roughly 5 percentage points of GDP a year. Both draw on the same fiscal space, the same borrowing capacity, and in places the same supply chains and ports. So geopolitics reaches the grid twice over, taking money that would otherwise have gone to it and raising the price of the equipment it still has to buy.

3. The market in transition, and who is carrying it

What the hourly price says about where Europe's market has got to.

A national average price tells you what a country paid. The hourly zonal price tells you how the system works, and that is the one that has changed. Read at that resolution, three things are true at once across almost every zone in Europe.

Two sources carry the whole chapter. Prices are ENTSO-E day-ahead clearing prices, one number per zone per hour. Generation is ENTSO-E actual generation by production type over the same hours, which covers 34 of the 39 zones rather than all of them, because the aggregated series only reports units above a size threshold and the Netherlands and Ireland account for barely a third of their own load that way. Any figure that needs the fuel mix uses those 34. Where the chapter says midday it means 11:00 to 15:59 and where it says evening it means 18:00 to 22:59, both in central European summer time.

The middle of the day is cheap, and solar did it. Across the 34 zones whose generation can be measured this summer the median midday price is 44 euros per MWh. Solar supplies a median 45 per cent of midday generation, and in Latvia 89 per cent. This is the transition working.

The morning and the evening are expensive, in every zone that can be measured. The median evening price is 155 euros against that midday 44. In all 34 zones the evening costs more than the middle of the day, from 3 euros more in northern Norway to 154 more in Hungary. These are the residual-load peaks. Residual load is the term the sector uses for demand net of wind and solar, and it is the quantity the rest of the fleet has to meet.

What covers those hours is largely the fleet that was there before. The plan was hydro, wind and storage. Grid-scale batteries supply a median of zero per cent of evening generation across these zones. Europe operates just over 10 GW of them, and at the two-and-a-half hour duration the industry currently builds to that is about 25 GWh, or roughly five minutes of average European demand. Pumped hydro remains the continent's real store, and it sits where the mountains are. So the residual-load peaks are met by hydro where a zone has it, and by nuclear, coal and gas where it does not.

That is where the zones separate, because the price in those hours is a statement about what a zone owns and the fleets have little in common. Trade is meant to close that gap, and the chapter takes that claim seriously enough to test it. The rest of the chapter works through five questions in order: what the day has done, where it is steep and where flat, whether the generation mix explains the difference, who can afford the answer, and where trade actually harmonises the price.

3.1 The European day turned over

The clearest single fact about the European price is what happened to the shape of its day. It inverted.

In 2015 the cheapest hour of the average European day was three in the morning, at 74 per cent of that day's own average price, and the whole daytime from seven to seven sat above the average in a broad plateau. That is what a thermal system looks like. Demand is low at night, the expensive plant comes off, and the price follows the load.

In 2026 the cheapest hour is one in the afternoon, at 65 per cent, and the night is no longer cheap at all. Midnight now prices at 1.03 times the daily average and three in the morning at 0.96. The evening peak has risen from 1.21 to 1.49 times the average. Load barely moved. Supply did.

The transition between the two shapes was not gradual. The cheapest hour of the day sat at three in the morning in every year from 2015 to 2022 and moved to the middle of the afternoon in 2023, where it has stayed. One year separates the two regimes.

Two things about that reshaping are worth stating before the chapter goes on.

The first is that it happened in almost every zone. Take each zone on its own and compare its average daily swing, trough to peak, against its own average price. In 2021, one zone out of 38 had a daily swing larger than its own average price. In 2026, 27 of the 38 did. The day steepened right across the continent, in zones of every size and every fuel mix. A handful of volatile markets pulling a European mean around would not produce that count.

The second is that the day widened at both ends, and that needs a word explaining first. The standard account of what solar does to a price is called cannibalisation. Every solar plant in a zone generates in the same hours as every other, so each new plant pushes the price down in exactly the hours it earns its money, and the technology eats its own revenue. Read that way, the day should widen downward only, with the middle falling and the rest of the clock standing where it was.

That is not what the record shows. In Figure 6 the afternoon fell from 0.74 to 0.65 of the day's own average and the evening rose from 1.21 to 1.49, so both ends moved and the evening moved the further of the two. In euros the two are almost identical, the peak up 337 per cent since 2015 and the trough deeper by 343, and the share of the day's swing lying below the average has held at 47 per cent for twelve consecutive years. Scarcity at the top has contributed as much as surplus at the bottom, and an account built on cannibalisation alone accounts for only half of what happened.

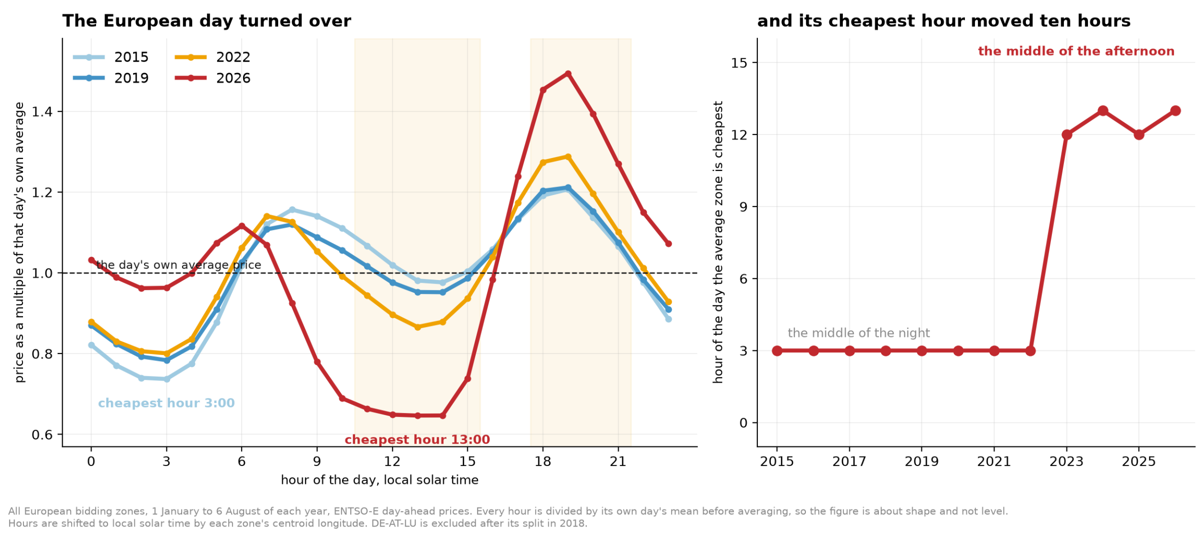


Figure 6. The average European day in four years. Each hour is divided by the mean price of its own day, so that 2015 at 36 euros and 2026 at 98 euros can share an axis and the picture is about shape rather than level. Hours are shifted to local solar time, so noon means noon in Lisbon and in Bucharest alike. Right: the hour at which the average zone is cheapest, one value per year.

3.2 Prices are still far above where they started

One conclusion carries this section. European power is dear against its pre-crisis level and has stayed dear. Measured in real terms against 2020, industrial gas is up 104 per cent and industrial electricity 29 per cent, against 10 per cent for household electricity.

That distribution is the finding. The same crisis raised what a factory pays by roughly three times what it raised a household bill by, because household prices were held down and industrial ones were not. Political attention went to households. The cost went to industry.

Year-on-year movement since then is small enough to ignore, and reading it as recovery would be a mistake. The commodity has come down while network charges have risen and crisis-era tax relief has expired, so the bill has barely moved. What changed is the composition of the price rather than its level.

3.3 What an hour actually costs, and who pays it

A day shape says how far the price travelled. It does not say what anybody paid, because it counts no megawatt-hours. So bring in the third series, the load ENTSO-E reports for the same zone and the same hour, split each day at its own average price, and on each side divide total spend by total consumption. That gives the price a megawatt-hour actually paid in the dear half of the day and in the cheap half. Ireland is left out throughout, because it publishes no load for 2026 and this measure needs load in every hour.

That gap has doubled in eleven years. In 2015 the dear half cost 45 euros per MWh and the cheap half 32, a ratio of 1.41. In 2026 the dear half costs 126 and the cheap half 62, a ratio of 2.02. The ratio held between 1.35 and 1.47 in every year from 2015 to 2023, through the gas crisis and out the other side, then moved in three steps to double. Figure 7 runs the same calculation zone by zone, where the median zone went from 1.36 to 1.96.

That ratio is the price of being unable to move, and it is a transfer between buyers rather than a cost to the system. A buyer who can shift consumption into the middle of the day pays the trough price, and one who cannot pays the peak.

Read across the zones it doubles as a reading of who has built solar. Spain runs at 3.98 and Portugal at 3.81, Greece at 2.79, Latvia and Estonia at about 2.6. Solar supplies between a fifth and two fifths of midday generation in all of them. At the other end the ratio falls to 1.22 in western Norway and 1.29 in northern Italy. Across the 33 zones where both can be measured, a percentage point of extra midday solar share adds 0.02 to the ratio, with a t statistic of 2.5. The relationship is real and it is loose, an R^2 of 0.17, so it is a tendency rather than a rule.

The looseness is itself informative, because a flat day means two different things. Norway and northern Sweden have almost no solar and a great deal of hydro, so nothing pulls the middle of the day down and the reservoirs cover the evening cheaply. Italy has as much midday solar as Germany and still runs flat, because gas sets its price in most hours and the floor under the middle of the day never falls far. A steep day is evidence that a zone has adopted solar. A flat day says nothing either way.

Where the argument is usually taken next is that price signals, storage and smarter scheduling will pull consumption into the cheap hours, so that what the average buyer pays converges on the trough even as the two prices separate. That argument has a physical ceiling which is rarely stated. Most European load cannot move to the middle of the day, whatever the price does. Aluminium electrolysis, cement milling and electric arc furnaces are candidates for load shedding rather than load shifting, because the process cannot simply be run four hours later. Chlor-alkali is one of the few chemical processes with genuine shifting potential, and even there Germany's 1,350 MW of installed chlorine capacity is credited with roughly 169 MW of flexibility, about an eighth of it. Cooling, refrigeration and data centres run around the clock, and what they can offer is the thermal inertia of a building or a cold store, which buys hours rather than a working day. Household demand sits in the evening by construction, in cooking, lighting and hot water. What can genuinely move is a shorter list than the argument assumes: batteries and pumped hydro, vehicle charging if it happens at work rather than at home, water heating, some cold storage, and electrolysers.

So the transfer runs from households, whose demand sits in the evening, and from continuous processes that have to run at the same rate around the clock, towards pumped hydro, batteries, electrolysers, cold stores and any plant that can be interrupted.

The hours priced above the daily mean now take 52 per cent of Europe's electricity against 55 in 2015, which reads at first like the shift the reforms were meant to produce. It is mostly the boundary moving rather than the consumer. As solar deepens the trough, more hours of the clock fall below the day's own mean, so the cheap set grows without anybody rescheduling anything.

Measured against the clock instead of against the price, demand has not moved into the middle of the day at all. Across the whole panel, the share of each day's consumption falling between 11:00 and 16:00 was 23.2 per cent in 2015 and 22.1 per cent in 2026, while the 18:00 to 23:00 share rose from 21.9 to 22.3. Load drifted slightly away from midday and slightly towards the evening. Rooftop solar netting off behind the meter would explain a fall in the solar-heavy south, and it does not explain this one, because the decline is the same in Iberia, Italy and Greece as in the rest of the panel, 1.06 points against 1.08.

So the transfer is not being competed away. Those same dear hours take 69 per cent of the money against 64 in 2015. The cheap half of the day does not pay for the dear half, the gap between what an inflexible buyer pays and what a flexible one pays is wider than at any point in the record, and eleven years of price signal have not moved the load curve enough to register.

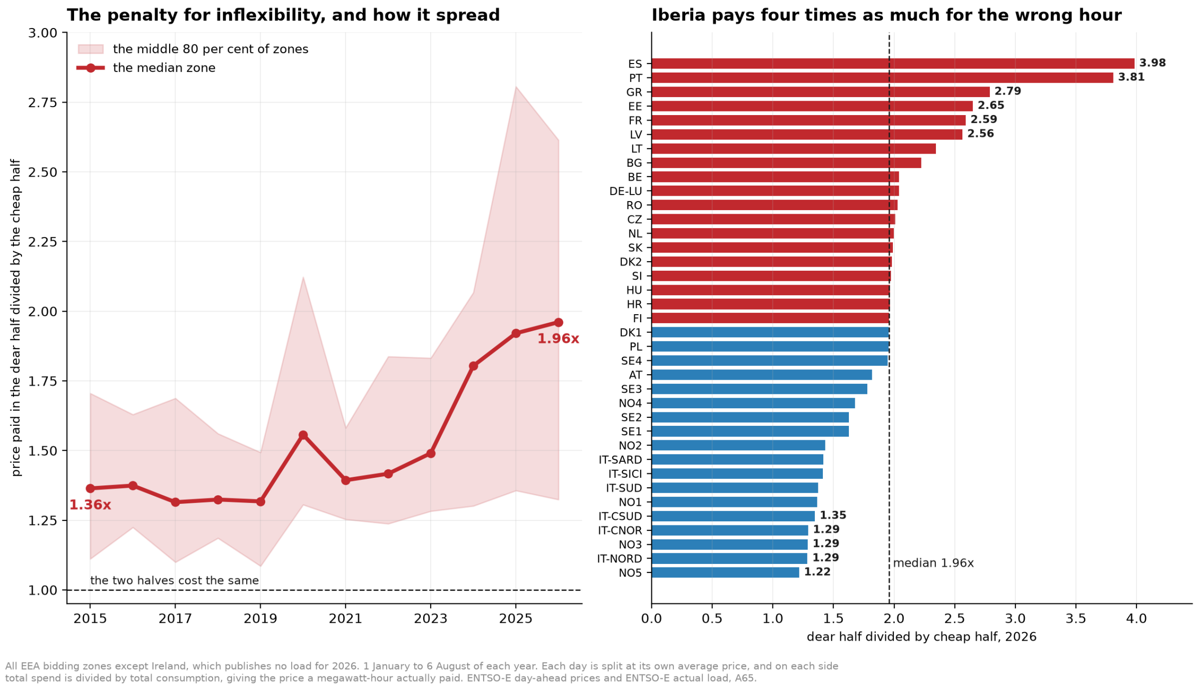


Figure 7. The ratio between what a megawatt-hour actually costs in the dear half of the day and in the cheap half. Each day is split at its own average price and, on each side, total spend is divided by total consumption. Left: the median zone, with the middle 80 per cent of zones shaded. Right: every zone in 2026, ranked.

3.4 Does the generation mix explain the difference?

Solar made the middle of the day cheap and left the evening as the most expensive hours of the clock. Wind and hydro do the opposite, and the small group of countries that have them have made their evening cheap as well. Everywhere else the evening is covered by fossil generation or by nuclear, and fossil generation is the expensive way to do it. So the mix explains both halves of the picture, and it explains them in opposite directions.

That makes the next European price question a question about what happens after sunset. Solar has done most of its work on the middle of the day, and outside the gas-set zones there is not much more price to win there. What is left is the evening, and the zones that still burn coal and gas to cover it are the zones where transformation has the most price to gain. The order of the build is solar first, because it is cheapest and fastest, then wind, because wind is the only renewable that generates when the sun has gone.

Where nature already did it. Four zones have both a cheap evening and almost no gap. Northern Norway prices its evening at 15 euros per MWh, northern Sweden at 18, central Sweden at 19 and Finland at 20, with the evening costing between 3 and 7 euros more than the middle of the day. In the Norwegian and Swedish zones hydro and wind supply 94 to 100 per cent of evening generation, and reservoir hydro is the one renewable that can be held back until it is wanted. Finland gets there by a different route, with nuclear at 48 per cent of its evening and wind at 23. These are the systems the rest of Europe is trying to imitate, and none of them can be copied by decision.

Where solar was built well and the evening was left behind. The widest gaps in Europe belong to the zones that have taken solar furthest. Hungary and Romania run 154 euros between evening and midday, Poland 138, Greece 135 and Germany 134. Solar supplies between two fifths and two thirds of midday generation in most of them, and in Latvia 89 per cent. Their middays have collapsed accordingly, to 21 euros in Latvia, 23 in Lithuania, 26 in Germany and 24 in France. Their evenings have not moved, because what covers the evening is coal, gas and nuclear at whatever those cost. Across the 34 zones with usable generation data, each extra point of midday solar share adds about 1.1 euros per MWh to the evening premium. The fossil share of evening generation adds nothing measurable, and adding it to the equation leaves the solar term where it was. The dear evening and the cheap afternoon are the same event read at the two ends of the clock.

Where the whole day is expensive and the gap is small. The five Italian zones with usable generation data look calm and are the most in need of change. Their evening premiums run from 58 to 79 euros, less than half Hungary's, and yet their midday prices of 123 to 134 euros are the highest middays in Europe and their evenings reach 191 to 210. Gas sets the Italian price in most hours of most days, so the floor under the middle of the day never falls far and the day stays flat at a high level. Renewables cover only 21 to 31 per cent of Italian evening generation against 54 to 71 per cent from fossil fuel. Hungary, Czechia and Poland sit at the other extreme of the same problem, with renewables covering 11 to 23 per cent of the evening, which is why their gaps are the widest on the continent.

The level and the shape are separate problems. Fossil share sets how expensive a zone is. Across the same 34 zones each extra percentage point of fossil generation adds about 1.1 euros per MWh to the average price, from Switzerland and northern Sweden at nothing through Germany at 27 per cent to Poland at 60. It does not set how uneven the day is, and solar share does. A zone can score well on one and badly on the other, and most of them do. Austria burns almost no fossil fuel and still carries a 121 euro gap. Poland burns the most and carries 138. Decarbonising a fleet lowers the bill and widens the day, and those are two problems needing two instruments. (ACER's 2026 monitoring reports the level result at country resolution, under the heading "High carbon intensity means high electricity prices"; the same relationship holds zone by zone here. On the shape, Pesenti and O'Sullivan find solar explains more of the variation in European prices than any other single driver despite supplying the least generation.)

A clean fleet and a clean price are two different things. Switzerland generates no fossil power at all and prices at 108 euros. Austria is at 1.3 per cent fossil and prices at 110. Southern Norway is almost entirely hydro and prices between 90 and 101 while northern Norway prices at 25, because the export cables land in the south. A zone can decarbonise its own fleet completely and still pay a fossil price if it is tightly coupled to somebody who has not. That is the integration argument arriving from the other side, and it is what the next section tests.

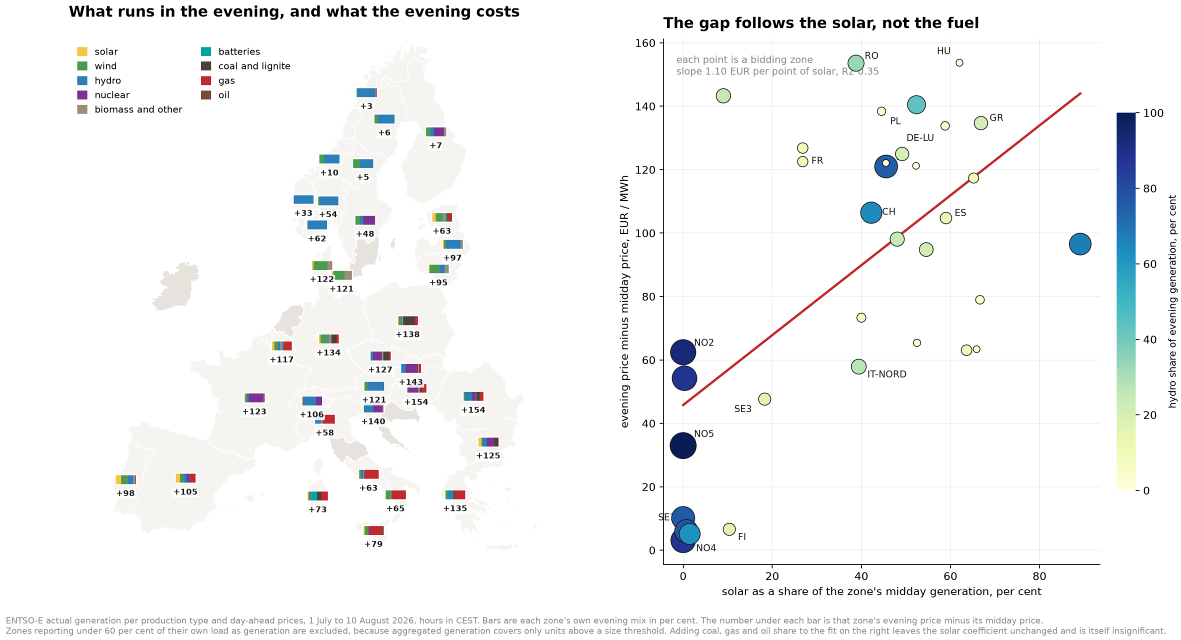


Figure 8. Left: each zone's generation mix in the evening hours as a percentage of its own evening output, with its evening price premium underneath. Right: the premium against midday solar share, sized and coloured by hydro.

3.5 Who can afford it, and who built which renewable

Every gap in this chapter is quoted in euros, and that invites a fair objection. A euro gap is a smaller thing in a country where everything costs less, so a narrow evening premium in a poorer member state might be arithmetic rather than a working system. The objection has to be tested rather than waved away, because if it holds then section 3.4 has ranked countries by their price level twice over.

It does not hold, for two reasons. The absolute premium turns out to correlate with the evening price at 0.78 and with the midday price at essentially zero, so what a wide gap measures is a dear evening rather than a dear day. And rerunning the same relationship on a scale-free measure, the evening price divided by the midday price instead of subtracted from it, leaves the solar result where it was. Nor do the poorer member states sit at the flat end. The three widest gaps in Europe belong to Hungary, Romania and Slovakia, and the four narrowest to northern Norway, northern and central Sweden and Finland, which is the opposite of what the objection predicts.

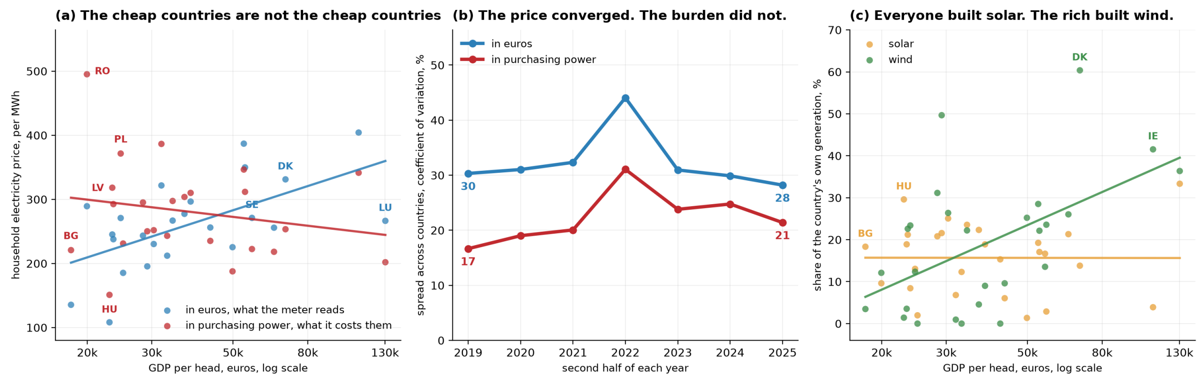
The objection is still worth having, because following it leads somewhere the euro price cannot go. Eurostat publishes the household electricity price twice, once in euros and once in purchasing power standards, the unit in which a thousand PPS buys the same basket of goods in every country. The second number is what the electricity costs a household relative to everything else it buys, and it reorders Europe.

Panel (a) of Figure 9 plots both. In euros, Romanian households pay 289 per MWh and German households 387, so Germany looks like the expensive country. In purchasing power Romania pays 495 and Germany 347, and Romania becomes the most expensive place in the European Union to buy household electricity. Poland moves from tenth to third, Latvia from fifteenth to sixth. Luxembourg and Sweden each fall ten places and Denmark nine. The correlation between income and the euro price is positive and clear, richer countries paying more per unit, and in purchasing power it disappears entirely. The apparent discount that poorer member states enjoy is spent in full on their lower purchasing power. Hungary is the exception that proves the instrument works, cheapest in the Union on both measures because its retail price is administered.

Panel (b) follows that over time, and the two units move in opposite directions. Across the 21 member states reporting in every period since 2019, the spread of the euro price narrowed from 30.3 per cent to 28.2. The spread of the same price in purchasing power widened from 16.7 per cent to 21.4. Europe's household electricity prices have converged slightly and the burden of paying them has come apart. That is the report's central thesis appearing in the one place where the wholesale market cannot be blamed for it.

Panel (c) says what each group built, and it is the sharpest result in this section. Solar's share of a country's generation has no relationship to income whatsoever. Hungary runs 30 per cent solar on 23,000 euros a head, Bulgaria 18 per cent on 18,000, Latvia 19 and Greece 21, against 7 per cent in Czechia and 2 in Slovakia at higher incomes. Wind is a different matter. Its share rises firmly with income, from 60 per cent in Denmark and 42 in Ireland down to 3.5 in Bulgaria and Latvia, 1.4 in Hungary and nothing at all in Slovakia and Slovenia. The pattern survives dropping Luxembourg and Ireland, whose GDP per head is inflated by activity that does not consume much electricity.

Put that beside section 3.4 and the three groups stop being a coincidence. Solar is cheap, quick, and can be built a roof at a time, so every member state has built it and every member state now has a cheap middle of the day. Wind is capital heavy, slow to permit and offshore in the places with the best resource, so it has been built by the countries that could finance it, and wind is the only renewable that generates after the sun has gone. The poorer member states have installed the technology that deepens the midday trough and not the technology that would cover the evening. Their evening is left to coal, gas and nuclear, they carry the widest day-night gaps on the continent, and their households pay the heaviest real price for it. This is where the case for European rather than national financing of the evening is strongest, and it is what the last section of this chapter returns to.



Left and centre: Eurostat nrg_pc_204, household electricity, consumption band 2,500 to 5,000 kWh a year, all taxes included. A purchasing power standard is the unit in which a thousand PPS buys the same basket of goods in every country, so the PPS price is what the electricity costs a household relative to everything else it buys. Centre uses the 21 countries that report in every period, so the series is not moved by entry and exit. Right: Ember monthly generation, twelve months to June 2026. GDP per head is Eurostat nama_10_pc.

Figure 9. (a) Household electricity price against income, the same countries plotted twice, once in euros and once in purchasing power. (b) How far those prices are spread across countries in each unit, year by year. (c) Solar and wind share of each country's own generation against income.

3.6 Where trade harmonises the price, and where it cannot

Trade is the mechanism that is supposed to close all of this. Under market coupling two adjacent zones clear at the same price in any hour when the interconnector between them is not congested, so the price gap across a border is a direct reading of whether the wire is doing its job.

Across 67 adjacent pairs this year, taking land borders from the zone geometry and adding the main sea cables by hand, they clear at the same price in 26 per cent of hours, counting any pair within one euro per MWh as sharing a price. That is trade working, and it is worth stating before the failure. Where two zones share a price, congestion is absent and the cheaper zone's plant is setting the dearer zone's price.

The failure is timed rather than general. The average gap between adjacent zones is 16 euros at two in the morning, climbs through the day, and peaks at 27 euros at eight in the evening. The wires bind hardest at the residual-load peak, which is the hour when closing the gap would be worth most.

The reason is in the weather rather than in the network, and it is the finding that shapes what to build. Taking every pair of zones and correlating their hourly output, solar moves together at 0.94 between neighbours and is still at 0.80 for zones 2,700 km apart. Wind starts at 0.51 and reaches zero beyond 1,500 km. The sun rises on the whole continent at once. The wind does not.

So a cable between two zones absorbs a wind surplus and merely relocates a solar one. A still hour in Denmark is a windy hour in Romania, and that is a trade. A sunny hour in Germany is a sunny hour in Poland, and that is not. This is my own data arriving where Stiewe, Xu, Eicke and Hirth arrived from a different direction: across 30 zones from 2015 to 2023, interconnection stabilises the market value of wind and does not stabilise the value of solar. A percentage point of extra solar at home costs 1.39 points of solar value and a percentage point in the neighbouring zones costs 2.38, so when both rise together, which is what a European solar build looks like, solar value falls by almost four points.

The implication for investment is specific. More copper between neighbours on the same clock buys less than it appears to. What pays is transfer capacity that reaches a different weather system, a different time zone, or a reservoir, and storage that moves the surplus in time rather than in space.

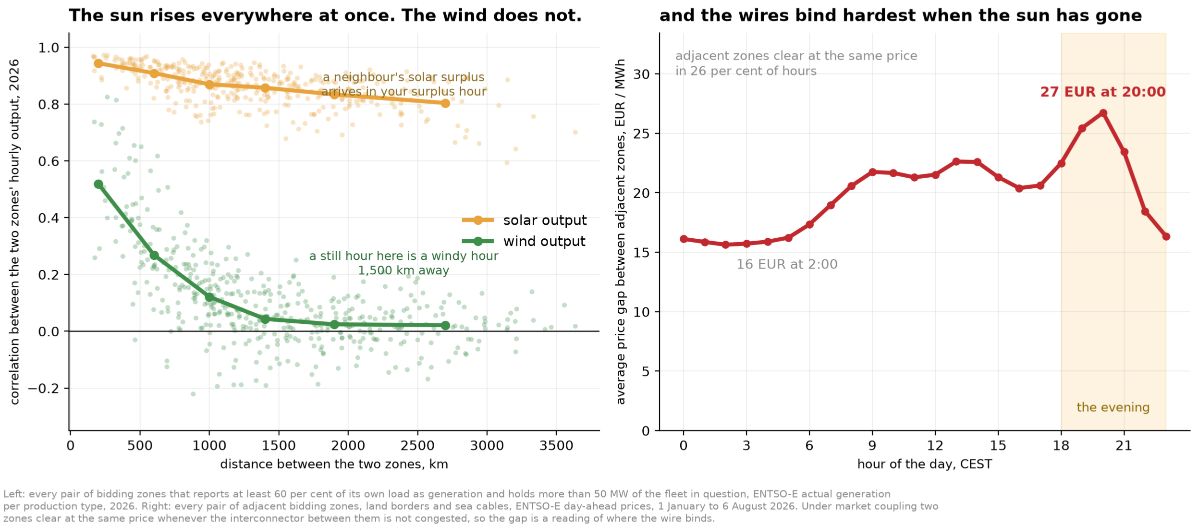


Figure 10. Left: every pair of bidding zones, by distance and by how closely their solar and wind output move together. Right: the average price gap between adjacent zones, by hour of the day.

3.7 Europe is now four markets rather than one

Six numbers are computed for each of the 39 zones over 1 January to 6 August 2026, all of them averages of its own hourly day-ahead prices: the mean price, how far the day travels, that distance relative to the mean, the share of hours priced below zero, the depth of the midday trough and the size of the evening peak. Each is standardised so that none of them dominates through its unit, and k-means then sorts the zones into groups. It separates the continent into four regimes running from 36 to 135 euros per MWh, a 3.7-fold gap.

Two things stand out. Level and shape are unrelated. The most expensive regime is also the flattest, and the second-cheapest has the most extreme daily shape. National borders do not survive the exercise either. Norway spans two regimes, its far north sitting with the cheap hydro group and its south grouped with Italy, because the export cables land in the south. Sweden splits the same way.

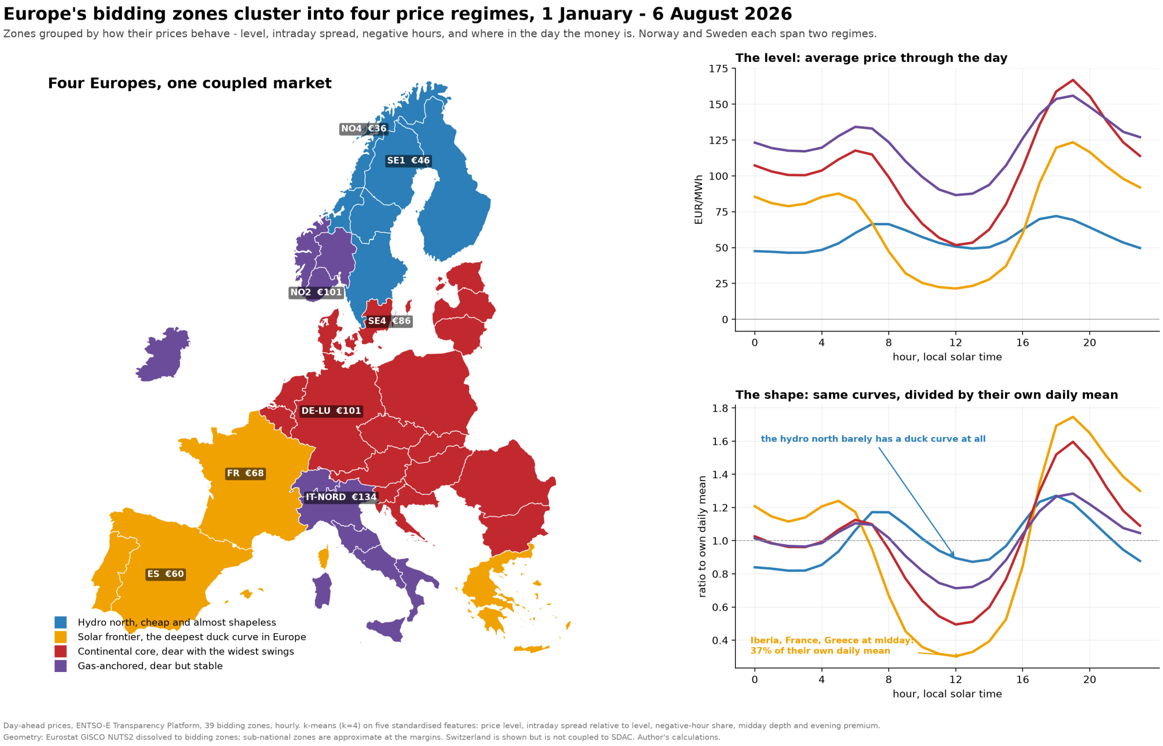


Figure 11. Clustering all 39 zones on how their prices behave separates Europe into four regimes.

3.8 A common shock, a divergent price

The zones remain tightly coupled. Cevik and Zhao, working across 24 EU countries from 2014 to 2024, find that 73 per cent of the forecast error variance in price volatility is cross-border rather than domestic, and that the share has grown over time. The disturbances, one gas price and one weather system, arrive everywhere on the same afternoon.

What differs is the conversion. A zone's price is its own merit order applied to a common shock, and the merit orders have little in common. Gas set 58 per cent of Dutch generation in 2019 and none of Estonia's. The impulse is shared. The transfer function is not, and 39 of them are running at once.

3.9 Who is actually exposed to this price

One word carries this section, so it is worth fixing first. Dispersion is how far apart a set of prices are from each other, measured as a percentage of their own average so that a cheap year and a dear year can be compared. Rising dispersion means the prices are separating, the gap between the cheapest and the dearest growing faster than the average is. Falling dispersion means they are converging on each other. It says nothing about whether prices are high or low, and the average can fall while dispersion rises, which is roughly what has happened since 2023.

There are three of them in this study and they answer three different questions. Cross-zone dispersion is how far apart the 38 bidding zones are within the same hour, which is a question about places. The intraday spread is how far apart the hours of a single day are, which is a question about time. Cross-country dispersion of retail prices is how far apart the member states are, and it is the only one that reaches a person.

While the wholesale market pulls apart, the retail market pulls together. On the same 21 member states that report in every period, the cross-country spread of household electricity prices was 30.3 per cent in 2019 and 28.2 in 2025. For industry, on the 500 to 2,000 MWh band excluding recoverable VAT and across all 27, it was 24.1 and is 23.0. Neither has risen, in a period when the day-ahead market separated on every measure in this paper.

That has a consequence for the competitiveness argument that is usually stated backwards. European industrial prices are not diverging from each other. They moved together and they moved up, 29 per cent in real terms on electricity since 2020 and 104 on gas, so European industry lost ground against the rest of the world as a bloc rather than against its neighbours. What diverges at zone level decides where new capacity is built, not what an existing plant pays this year.

Households look protected on the same test, and section 3.5 shows they are protected only in the unit that is easiest to hold together. Their euro dispersion fell from 30.3 to 28.2 while the dispersion of the same price in purchasing power rose from 16.7 to 21.4. The tariff and tax layer held the euro prices in line and did nothing about what those prices cost people relative to their incomes.

The wholesale and retail series are not the same object in any case, and the difference is part of the answer. Wholesale is measured across 38 bidding zones at hourly resolution, as the standard deviation of price across zones within each hour divided by the average price in that hour. Retail is Eurostat's own coefficient of variation across member states, published by country and twice a year, because tariffs have no zonal dimension to de-average along. Italy runs six wholesale prices and one household tariff. Norway runs five and one. A bill cannot show a spread the tariff does not contain.

Pass-through fails at every layer between the two. Network costs and redispatch are socialised into tariffs paid regardless of when or where anyone consumes. Contracts for difference move generators onto a fixed strike and off the market price. Norway's Norgespris, taken up by more than half of households since September 2025, does the same at the consumer end. Regulated and default tariffs absorb what is left.

What survives is a price that very few buyers or generators actually face. A signal reaching so few of them cannot site a battery, shift a load or retire a plant, and that is a design problem quite apart from the level of the price.

3.10 Weather has become the binding constraint

The daytime absorbed what Europe built. Across the thirteen continental zones it added 6.2 GW of solar this summer and used almost all of it where it was generated, because the heat raised load by 5.8 GW and put that demand in the middle of the day, which is exactly when the new solar arrives. The drought helped as well, by creating a buyer. Austria and Switzerland lost 1,168 and 810 MW of hydro and have no gas fleet to replace it, so they covered the gap on the wires, and Germany sent 5.2 GW more out to its neighbours than in 2024.

Where the daytime failed, it failed on the wires and not on the panels. A negative price is what a surplus does when it cannot be consumed locally and cannot leave. Greece gained 9.6 percentage points of negative hours on last summer, Portugal 5.9 and Spain 4.9, and these are the zones with the thinnest way out, one cable from Greece to Italy and a Pyrenean border that has never carried much. Greece is the clearest case of a threshold crossed rather than a trend continued. Its midday solar rose a fifth in a single year to two thirds of midday generation, and in 2025 it had 115 negative hours across the whole year without one of them falling between June and August, because summer is when Greek cooling demand is highest. This is the first summer the surplus was large enough to survive that demand.

Everywhere else the count fell, and it fell for reasons that will reverse. Counting every zone-hour priced below zero between 1 June and 6 August, there were 2,942 last summer and 1,792 this summer, a fall of 39 per cent, while the average summer price rose from 68 to 101 euros per MWh. Across the Nordic and Baltic zones hydro fell from 22.5 GW to 20.2 and nuclear from 7.4 to 6.2, so 3.5 GW of must-run output left the stack, and a dry year raises the water value, so reservoirs hold back for winter instead of spilling. Wet Nordic hydro is the classic source of a negative hour and there was less of it. No storage was added and no wire was built.

This matters because every published statement about 2026 rests on the first quarter, in which negative hours roughly doubled year on year and the commentary extrapolated. Anyone who annualised that will publish the wrong number. One caveat belongs with the six-year count as well. Iberia and Greece could not print a negative day-ahead price at all before 2024, because their floor was zero, and it now sits at about minus ten to minus fifteen euros in Spain and Portugal and minus fifty in Greece. Part of the step from 2023 to 2024 is a change in market rules rather than in physics. The 2025 to 2026 comparison is clean, since the floors did not move between those two years.

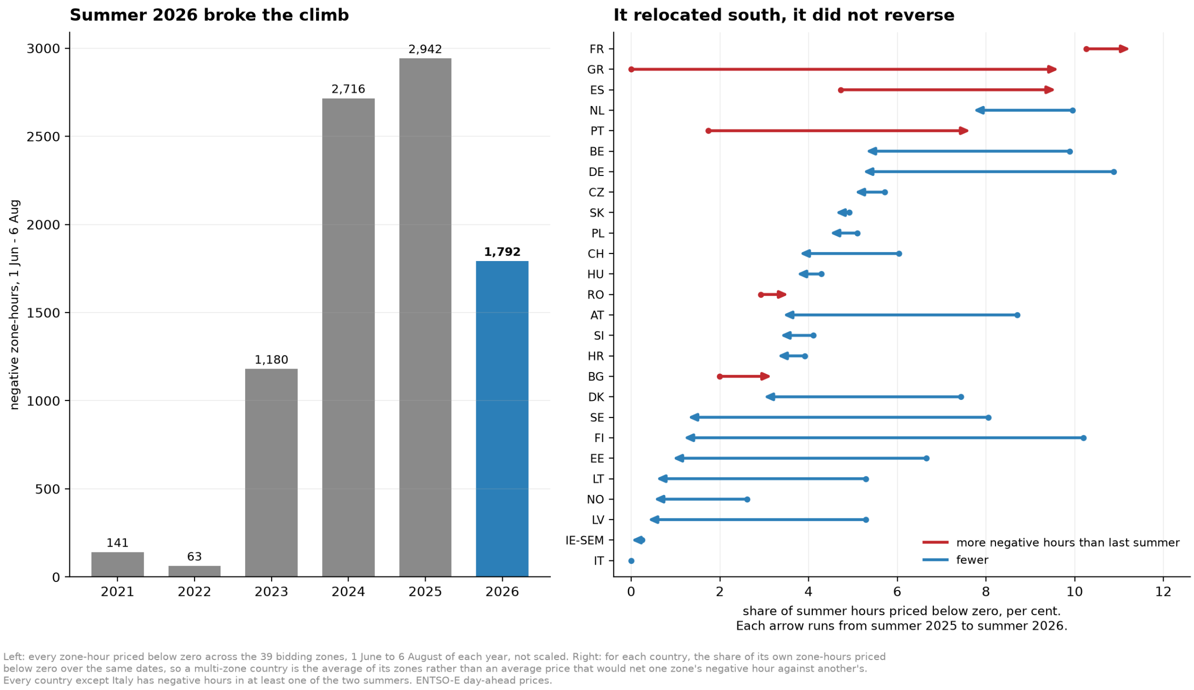


Figure 12. Summer 2026 broke the climb in negative hours, though the hours relocated south rather than disappearing. On the right, each arrow runs from last summer to this one along the share of that country's own zone-hours priced below zero. Red points right and means more negative hours than last summer, blue points left and means fewer. Every country except Italy has them in at least one of the two summers.

Nothing comparable was added for the night, because the technology that would cover it has not been built. Wind is the only renewable that generates after the sun has gone, and section 3.5 showed it is the one that tracks national income, from 60 per cent of generation in Denmark down to 1.4 in Hungary and nothing in Slovakia. It is capital-heavy, slow to permit and offshore where the resource is best, so it is not something a zone can add in a season the way it adds panels. Offshore additions across Europe have in any case fallen from about 3 GW a year to 0.5, and hours of very low wind across the continent have risen from 10.3 to 16.6 per cent of the year. Batteries cover roughly five minutes of European demand.

So the evening falls back on hydro, and the reservoirs are low. Of the 26 bidding zones that publish reservoir levels, 19 sat below their own 2015 to 2025 median at their latest reading, in the week of 27 July or 3 August depending on the zone, and the shortfalls sit where the rest of Europe leans hardest. Northern Italy held 46 per cent of its eleven-year maximum against a normal 83 for that week, southern Italy 10 against a normal 46, and southern Norway, the zone that exports to Germany, the Netherlands and Britain, 49 against 77. Spain and northern Norway were the exceptions, both wetter than usual.

A dry reservoir does not raise the price by itself. What it raises is the water value, the opportunity cost an operator attaches to releasing a megawatt-hour this evening rather than holding it for the winter. A higher water value means the plant bids higher and holds back, and that withholding is how a dry summer reaches the evening price. Reservoirs are only the generation side of water in any case. The cooling side is the one under real strain, and it is the subject of the opening chapter.

Meanwhile Europe is designing its future market boundaries using weather drawn from 1987 to 2016. The design weather stops ten years before the summer this report measures, and the summers since are the ones that have moved.

Conclusion

Europe has brought the price of the middle of the day down and has not done the same for the end of it. Solar made midday cheap in every member state regardless of income, while the median evening still costs 155 euros per MWh against 44 at noon, and that is where the fossil generation, the price and the emissions now sit. Whether wind and hydro can take the evening off coal and gas is the question of the next five years, and today's answer is not encouraging, with batteries covering five minutes of European demand, 19 of 26 reservoir zones below their own norm, and wind the one renewable whose share tracks national income. Policy decides that rather than technology, because the member states carrying the widest day-night gaps are the ones least able to finance the wind that would close them. An industrial economy that spent a century insulating itself from the weather now has to watch it again, and watch it hourly. Of the pillars this rests on, coordination between zones is getting the least attention and is the one everything else is waiting on.

Every path through this carries an environmental cost of its own, in land taken for wind and solar, in rivers drawn down and returned warmer, in the material mined for batteries and cables, and in what a gas fleet emits while it covers the evening. The tightrope Europe is walking between the weather cycle and the political one has to be walked over that cost as well as over the financial one. This report measures prices and does not weigh those costs. They belong in the choice of path ahead, and they belong in it strongly.

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Appendix A. Data

Every input to this paper is listed below. Table A1 gives the source and coverage of each series and Table A2 the descriptive statistics for the same rows in the same order. The construction notes in section A.3 are numbered to match. Series are grouped into five panels: the European wholesale market, European retail prices and income, generation mix and fuel benchmarks, weather and hydrology, and a United States control panel.

Descriptives are computed in each series' own unit over the full pooled sample of that series, with no weighting and no conversion. They are not restricted to the windows used in individual results, and they do not substitute for the sample definitions given in each chapter. Their purpose is to make the scale and the unit of every input legible.

A.1 Sources and coverage

Table A1. Provenance, frequency and coverage of each series.

Asset	Source	Freq	Coverage	Geography
Panel A. European wholesale market				
Day-ahead price	ENTSO-E Transparency, A44	hourly	2014-2026	40 zones
Actual load	ENTSO-E Transparency, A65	hourly	2015-2026	40 zones
Actual generation	ENTSO-E Transparency, A75	hourly	2024-2026	39 zones
Reactor output	ENTSO-E Transparency, A73	unit-day	2024-2026	36 stations, 10 zones
Intraday spread	derived from A44	zone-month	2014-2026	40 zones
Negative-price share	derived from A44	zone-month	2014-2026	40 zones
Within-country spread	derived from A44	country-month	2014-2026	DK, IT, NO, SE
2026 zone features	derived from A44	zone	2026	39 zones
Panel B. European retail prices and income				
Retail electricity	Eurostat nrg_pc_202-205	semestral	2007-2025	43 countries
Retail gas	Eurostat nrg_pc_202-205	semestral	2007-2025	36 countries
Retail components	Eurostat nrg_pc_*_c	annual	2017-2025	EU-27
Retail dispersion	derived from nrg_pc_204	annual	2019-2025	EU-27
Retail electricity, PPS	Eurostat nrg_pc_204	semestral	2007-2025	38 countries
GDP per head	Eurostat nama_10_pc	annual	2025	40 countries
Panel C. Generation mix and fuel benchmarks				
VRE share	Ember monthly electricity	country-month	2015-2024	29 countries
Gas (TTF)	World Bank Pink Sheet	monthly	2015-2024	EU benchmark
Panel D. Weather and hydrology				
Reservoir fill	ENTSO-E Transparency, A72	zone-week	2014-2026	26 zones
River discharge	GloFAS via Open-Meteo flood API	site-day	1991-2026	37 cooling sites
Zone daily maximum	ERA5 via Open-Meteo	zone-day	2015-2026	39 zones
Temperature	ERA5 via Open-Meteo	country-month	2015-2024	29 countries
Wind speed	ERA5 via Open-Meteo	country-month	2015-2024	29 countries
Solar radiation	ERA5 via Open-Meteo	country-month	2015-2024	29 countries
Heating degree-days	ERA5 via Open-Meteo	country-month	2015-2024	29 countries
Cooling degree-days	ERA5 via Open-Meteo	country-month	2015-2024	29 countries
Panel E. United States control panel				
US retail price	EIA-861M	state-month	2010-2026	51 states + DC
Henry Hub	EIA	monthly	2010-2026	US benchmark
WTI crude	EIA	monthly	2010-2026	US benchmark

A.2 Descriptive statistics

Table A2. Each series in its own unit, over its full pooled sample.

Asset	Variable	Unit	N	Mean	SD	Min	Max
Panel A. European wholesale market							
Day-ahead price	price	EUR/MWh	3,917,067	74.7	77.8	-500.0	4,000
Actual load	load_mw	MW	3,952,901	8,177	12,639	0.00	94,492
Actual generation	total	MW	386,644	7,128	11,794	0.00	85,056
Reactor output	lf	share of own max	6,701	0.92	0.13	0.05	1.00
Intraday spread	intraday_spread	EUR/MWh	5,432	65.2	62.4	0.00	573.0
Negative-price share	neg_share	% of hours	5,432	0.98	2.70	0.00	32.1
Within-country spread	mean_spread	EUR/MWh	563	20.0	37.5	0.00	440.2
2026 zone features	level	EUR/MWh	39	98.5	26.4	36.4	134.6
Panel B. European retail prices and income							
Retail electricity	eur_mwh	EUR/MWh	1,592	133.3	76.8	11.6	537.0
Retail gas	eur_mwh	EUR/MWh	2,075	56.0	32.6	11.7	275.1
Retail components	eur_mwh	EUR/MWh	100	43.2	36.7	1.70	167.6
Retail dispersion	CV %	%	21	35.4	5.48	28.4	47.4
Retail electricity, PPS	PPS/MWh	PPS/MWh	1,298	203.1	57.6	28.9	495.2
GDP per head	gdp_pc	EUR/person	40	43,748	27,720	760.0	130,300
Panel C. Generation mix and fuel benchmarks							
VRE share	vre_share	% of generation	3,101	18.7	16.5	0.00	82.6
Gas (TTF)	gas_eur_mmbtu	EUR/MMBtu	3,224	11.3	11.8	1.58	70.0
Panel D. Weather and hydrology							
Reservoir fill	fill	% of zone max	15,463	60.6	22.2	1.13	100.0
River discharge	discharge	m3/s	400,118	1,135	1,800	0.03	19,587
Zone daily maximum	tmax	degrees C	165,204	13.0	9.80	-31.6	45.0
Temperature	temp	degrees C	3,422	11.5	7.66	-8.82	30.3
Wind speed	wind	km/h	3,422	11.9	3.79	2.93	26.6
Solar radiation	solar	MJ/m2/day	3,422	12.8	7.39	0.34	28.5
Heating degree-days	hdd	HDD/month	3,422	227.9	192.8	0.00	831.4
Cooling degree-days	cdd	CDD/month	3,422	30.0	61.5	0.00	381.4
Panel E. United States control panel							
US retail price	price	US cents/kWh	10,047	14.2	5.21	6.73	52.0
Henry Hub	henry_hub_usd_mmbtu	USD/MMBtu	197	3.38	1.27	1.49	8.81
WTI crude	wti_usd_bbl	USD/barrel	197	71.9	20.8	16.6	114.8

A.3 Variable construction

Panel A. European wholesale market

1. **Day-ahead price**, `price`. ENTSO-E Transparency, A44. floor -500; DE-AT-LU dropped from 2019 to avoid double-counting
2. **Actual load**, `load_mw`. ENTSO-E Transparency, A65. consumption met in the hour; zones publishing at 15 or 30 minutes are averaged to the hour; Ireland publishes none for 2026
3. **Actual generation**, `total`. ENTSO-E Transparency, A75. summed over the production types, pumping excluded; May to September of 2024, 2025 and 2026 only; aggregated generation covers units above a size threshold, so the Netherlands reports 37 per cent of its own load and is left out of the figures that use this series

4. **Reactor output**, `lf`. ENTSO-E Transparency, A73. one row per reactor per day it generated in every hour, so maintenance outages are excluded; measured against that unit's own highest recorded output; 1 July to 10 August only
5. **Intraday spread**, `intraday_spread`. derived from A44. mean daily peak-to-trough within the month
6. **Negative-price share**, `neg_share`. derived from A44. the share of the month's hours that cleared below zero, reported here in per cent rather than as a fraction
7. **Within-country spread**, `mean_spread`. derived from A44. same hour, different zone of one country
8. **2026 zone features**, `level`. derived from A44. five features behind the k-means regimes; local solar time

Panel B. European retail prices and income

9. **Retail electricity**, `eur_mwh`. Eurostat nrg_pc_202-205. gas converted from EUR/GJ at 3.6 GJ = 1 MWh
10. **Retail gas**, `eur_mwh`. Eurostat nrg_pc_202-205. gas converted from EUR/GJ at 3.6 GJ = 1 MWh
11. **Retail components**, `eur_mwh`. Eurostat nrg_pc_*_c. energy / network / taxes; TOT_KWH here is the across-band average
12. **Retail dispersion**, `CV %`. derived from nrg_pc_204. cross-country coefficient of variation
13. **Retail electricity, PPS**, `PPS/MWh`. Eurostat nrg_pc_204. the same price in purchasing power standards, the unit in which a thousand PPS buys the same basket in every country; band DC, 2,500 to 5,000 kWh a year, all taxes included
14. **GDP per head**, `gdp_pc`. Eurostat nama_10_pc. current prices, B1GQ per head; Luxembourg and Ireland are inflated by activity that consumes little electricity and are checked separately in every regression that uses this series

Panel C. Generation mix and fuel benchmarks

15. **VRE share**, `vre_share`. Ember monthly electricity. wind + solar as a share of domestic generation
16. **Gas (TTF)**, `gas_eur_mmbtu`. World Bank Pink Sheet. converted at the ECB monthly USD/EUR rate

Panel D. Weather and hydrology

17. **Reservoir fill**, `fill`. ENTSO-E Transparency, A72. stored energy in MWh, expressed against each zone's own 2015-2025 maximum because installed reservoir capacity is not published
18. **River discharge**, `discharge`. GloFAS via Open-Meteo flood API. model reanalysis on a 0.05 degree grid, snapped to the main channel; long-run means match published gauge means at the large sites
19. **Zone daily maximum**, `tmax`. ERA5 via Open-Meteo. one point per bidding zone, the equal-area centroid of the same NUTS2 dissolve used for the maps, so SE1 and SE4 do not share Stockholm's weather; each day is scored against the 95th percentile of that zone's own 2015-2025 distribution for the calendar month

20. **Temperature**, `temp`. ERA5 via Open-Meteo. capital-city point, not population-weighted; a five-point national average was built as a robustness check and does not change the reported results
21. **Wind speed**, `wind`. ERA5 via Open-Meteo. 10 m wind speed, not hub height
22. **Solar radiation**, `solar`. ERA5 via Open-Meteo. Open-Meteo shortwave_radiation_sum, which is a daily MJ total, not kWh
23. **Heating degree-days**, `hdd`. ERA5 via Open-Meteo. base 18 C
24. **Cooling degree-days**, `cdd`. ERA5 via Open-Meteo. base 18 C

Panel E. United States control panel

25. **US retail price**, `price`. EIA-861M. cents/kWh, NOT EUR/MWh; 1 c/kWh = 10 USD/MWh
26. **Henry Hub**, `henry_hub_usd_mmbtu`. EIA.
27. **WTI crude**, `wti_usd_bbl`. EIA. included as a control, not a driver of power prices

A.4 A note on units

Three unit families appear in this paper and they are not interchangeable. Wholesale and European retail prices are in **EUR/MWh**. Eurostat publishes household gas in **EUR/GJ**, converted here at 3.6 GJ = 1 MWh. The US control panel is in **US cents/kWh**, the unit EIA publishes; 1 cent/kWh = 10 USD/MWh, so a US residential price of 10.3 c/kWh is roughly 103 USD/MWh. Fuel is in **USD or EUR per MMBtu** for gas and **USD per barrel** for crude. No series is converted into a common unit anywhere in the paper: comparisons are made within a unit, or in logs and percentages.

Two units are easy to misread and are flagged here rather than in a footnote. Solar radiation is a daily **megajoule** total rather than kilowatt-hours, so the mean of 12.8 MJ/m2/day is about 3.6 kWh/m2/day. The negative-price share is reported in per cent of hours, so the 0.98 in Table A2 is 0.98 per cent of hours and not 98 per cent.

The weather variables come at two frequencies and the difference matters. The zone daily maximum, the river discharge and the reservoir series are daily or weekly, and the heat, drought and hydro results in this paper are built on those. The country panel of temperature, wind, radiation and degree-days is monthly. A wind lull is a one-to-three-day event, so a monthly mean cannot see it, and any result drawn from that panel establishes that a weather channel exists without measuring its size.

A.5 Data availability

All sources are public and free. ENTSO-E Transparency requires a registered account for its API and serves the same data without one through its web interface. Eurostat, Ember, the World Bank Pink Sheet, the EIA and Open-Meteo require neither. No series in this study is proprietary, licensed or purchased, and none is subject to an embargo.

Two consequences follow for replication. ENTSO-E revises recent months, so a figure drawn on 2026 will move slightly when the panel is refetched, which is why this report states a cut-off date rather than "latest". And every figure and every number in the text is produced by code that reads only the raw downloads listed above and applies the constructions described in section A.3. The assembled panels and the code that builds them are available from the author on request.