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Price-setting tipping points in decarbonising EU electricity markets

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The role of fossil fuels, particularly natural gas, in setting clearing prices on the European Union's integrated electricity market is at the forefront of energy policy debates. Identifying price-setting technologies in electricity spot markets is, however, inherently complex due to cross-border trading, overlapping bidding strategies, and lack of granular plant-level operational data. Furthermore, empirical evidence remains limited on how the energy transition and the growing role of variable renewables may alter these price-setting dynamics. In this paper, we present an approach to reverse-engineer the most likely price-setting technology for each hour on the day-ahead market across EU bidding zones. Analysing a decade of data, our findings show distinct "tipping points" that indicate structural shifts in price-setting, moving from traditional fossil fuel dominance towards renewable-driven price-setting in highly nonlinear fashion.

Price formation on European wholesale electricity markets follows a uniform-price auction mechanism based on the merit-order principle, clearing the market in ascending order of submitted bid prices, which typically reflect short-run marginal costs (SRMC) of the respective technologies. The market-clearing price for any given bidding zone and period is then determined by the bid of the final, highest-bidding unit required to match total demand and supply. All accepted market participants receive this same clearing price regardless of their own bid, with the price-setting ("marginal") technology therefore driving the overall market value.

However, identifying the price-setting technology is complex. In most European Union (EU) wholesale electricity spot markets, traders submit aggregated portfolio-level supply curves rather than unit-specific bids, rendering individual price-setting technologies unobservable. Furthermore, actual SRMC values are not publicly disclosed: fuel procurement, hedging contracts, bidding strategies, plant heat rates, and maintenance and opportunity costs may be proprietary. Empirical identification of the marginal technology therefore typically requires using indirect proxies. So far, despite the public availability of data on wholesale prices and technology-level electricity generation at high spatio-temporal resolution (e.g. through the ENTSO-E Transparency Platform[1,2]), corresponding pan-European assessments of technology-level price-setting in space and time have been missing.

Following the increase in wholesale electricity prices in the EU during the last decade (Figure 1a-b), interest in reducing the influence of volatile fossil fuel costs, primarily natural gas (Figure 1c), has risen high on the political agenda[3,4]. However, the debate has been hampered by the absence of robust methods to identify price-setting technologies at sufficient granularity.

This paper introduces a comprehensive framework to reverse-engineer price-setting technologies based on observed generation, cross-border flows, wholesale prices, and commodity costs.

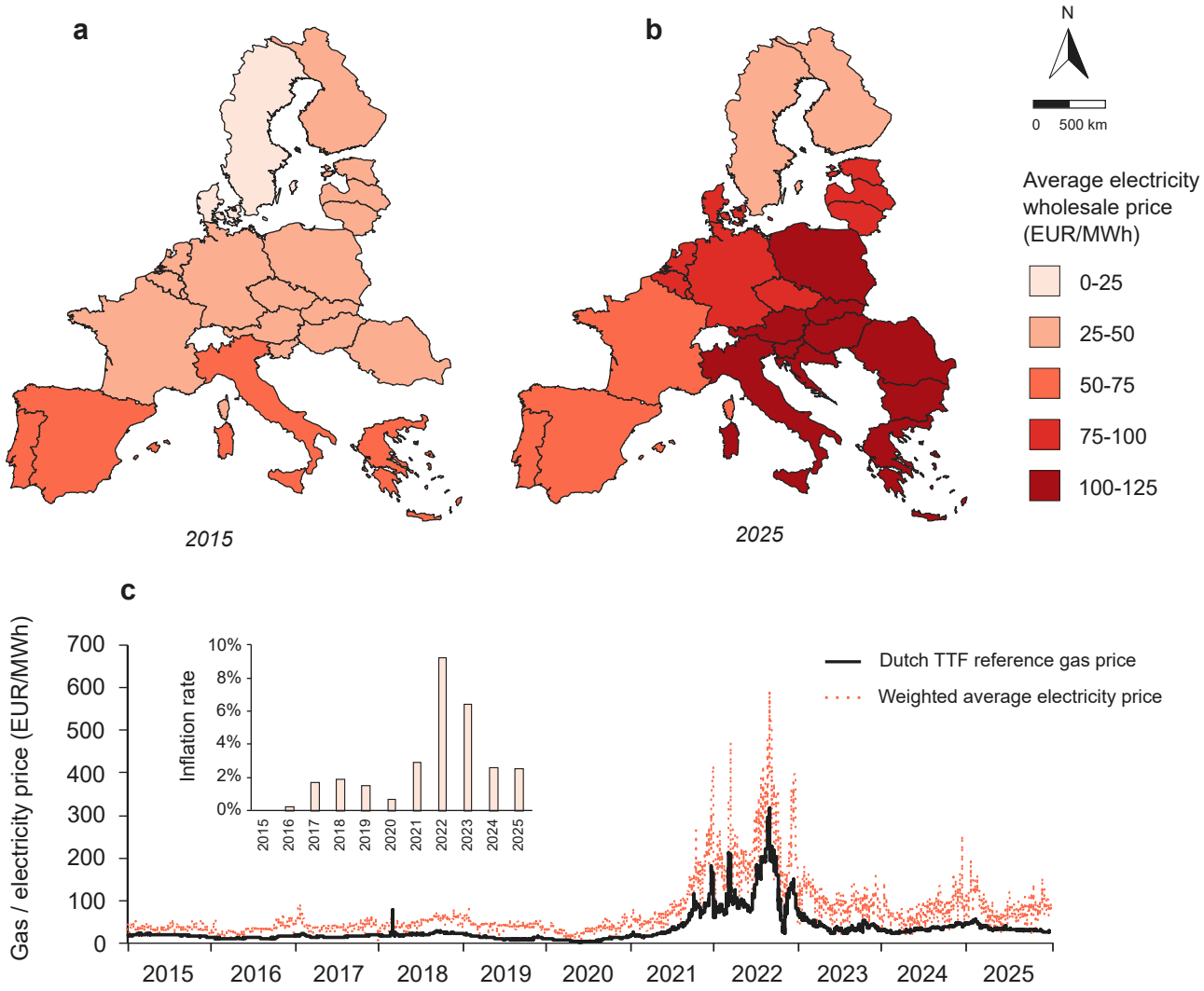


Figure 1: **Consequences of the energy crisis**. EU power markets have seen increased prices on the day-ahead market between 2015 (a) and 2025 (b). (Note that Bulgaria and Croatia had not yet joined the coupled day-ahead market in 2015, hence their data are missing in the left panel; note also that we limit our analysis to non-island states.) These increased wholesale prices (data from ref.[1]) are a consequence of the sharply risen price of fossil fuels, especially natural gas, caused by the 2021-22 energy crisis (c, showing the Dutch *Title Transfer Facility* [TTF] hub reference price[5] alongside demand-weighted EU-average electricity prices[1]); they also reflect increased inflation resulting from the energy crisis (inset to c, from ref.[6]).

This framework is used to assess a decade of hourly data across EU bidding zones and capture technological marginality across the full generation spectrum, from variable renewables (VRE, i.e. solar and wind power) and hydropower to nuclear and fossil-powered units. The gained empirical insights can inform energy policy across multiple domains: clarifying the influence of fossil fuel costs on electricity prices, quantifying the effect of increased VRE generation in displacing fossil fuel price-setters, and illustrating how interconnections affect price-setting.

Our results showcase how the EU energy transition has reduced the traditional fossil fuel dominance in price-setting, mitigating the impacts of energy crises. However, they also highlight the existence of several technology-related tipping points related to VRE uptake and non-fossil flexibility as the decarbonisation of the electricity system advances.

Estimating price-setting technologies

Existing studies on price formation in power systems have primarily focused on the perspective

of (1) fundamental cost and market mechanisms[7], including the "merit-order effect"[8,9], that drive price developments, (2) the interdependence between fossil fuel prices, carbon emission allowances, and electricity prices[10–12], and increasingly (3) the role of demand-side technologies (including flexibility solutions and storage technologies) as price-setting technologies[13,14]. While these streams of work establish a fundamental understanding of electricity price formation, they typically treat price-setting as an aggregate or systemic outcome[15].

Recent studies have more explicitly isolated the causal mechanisms of specific technologies on price-setting, establishing quantified shares of each generation type in setting electricity prices. First, the use of fundamental dispatch and multi-agent power system models, simulating plant-specific dynamics with high spatio-temporal resolution, is common, offering flexible scenario testing for price formation[16–20]. However, considerable drawbacks to this approach relate to their risk of structural modelling bias, the potential use of black-box modeling tools, and the failure to capture real-time operational shocks. Second, econometric and statistical methods can be applied to evaluate historical market time-series data to infer marginal technologies. However, existing studies are constrained by limited technological or geographical scope. For example, ref.[21] analysed actual generation alongside market clearance observations, but the study did not account for marginality across the full generation spectrum or through cross-border coupling. Similarly, refs.[22,23] estimate only the share of fossil fuel-powered generation in setting the electricity price, and only in a few EU bidding zones. While ref.[24] covers a comparatively extensive European scope, their framework relies on top-down regression proxies that correlate price variations with technology-aggregated generation changes, reducing the ability to capture cross-border market coupling and intra-technology efficiency spreads.

The approach presented in this paper combines the empirical approach of ex-post methods with the typical technological granularity of dispatch models. The methodology is based on an algorithm that matches observed day-ahead prices[1] (the day-ahead market is considered the reference spot market in EU electricity markets) with the closest estimated SRMC at each moment in time, identifying a price-setting technology for each hour across multi-year periods. This work thus aims at consistently reconstructing, from observed day-ahead prices, generation by technology, cross-border flows, and fuel and carbon costs, the "most likely" marginal technology across EU bidding zones, hour-by-hour from 2015 to the present.

The algorithm relies on informed assumptions around, inter alia, (i) the time-dependent SRMC of different technologies, affected by underlying commodity costs, (ii) assumptions on strategic bidding behaviour of hydropower reservoirs and pumped storage, (iii) the variation of thermal and nuclear efficiencies with generation, and (iv) the price-coupling of interconnected bidding zones. Details of the algorithm's implementation are given in Methods and Supplementary Note 1, and its code is available open-source (see "Code availability").

The decreasing role of fossil fuels

We find that, in most EU countries, reductions in the share of fossil fuels in power generation in the period 2015-2025 were correlated with a simultaneous reduction in the role of fossil fuels in price-setting (Figures 2a-b). In general, as should be expected, Member States (MS) with higher reliance on low-carbon technologies experience fewer hours during which fossil-fuel generation sets the market price. This pattern is particularly evident in Spain, Portugal, France, Austria, and the Northern European countries.

Figure 2c-d show how the generation mix and the price-setting mix have developed at the EU level in the last decade. The share of fossil fuels (primarily hard coal, lignite, and natural gas) in generation has dropped from 42% to 29% (Figure 2c). Fossil fuel price-setting has also decreased markedly relative to the pre-crisis period, falling from 68% to 50% (Figure 2d), largely driven by a reduction in the role of hard coal (from 20% to 11%) and natural gas (from 35% to 29%) as price-setting technologies. Compared to their contribution to generation, fossil fuels

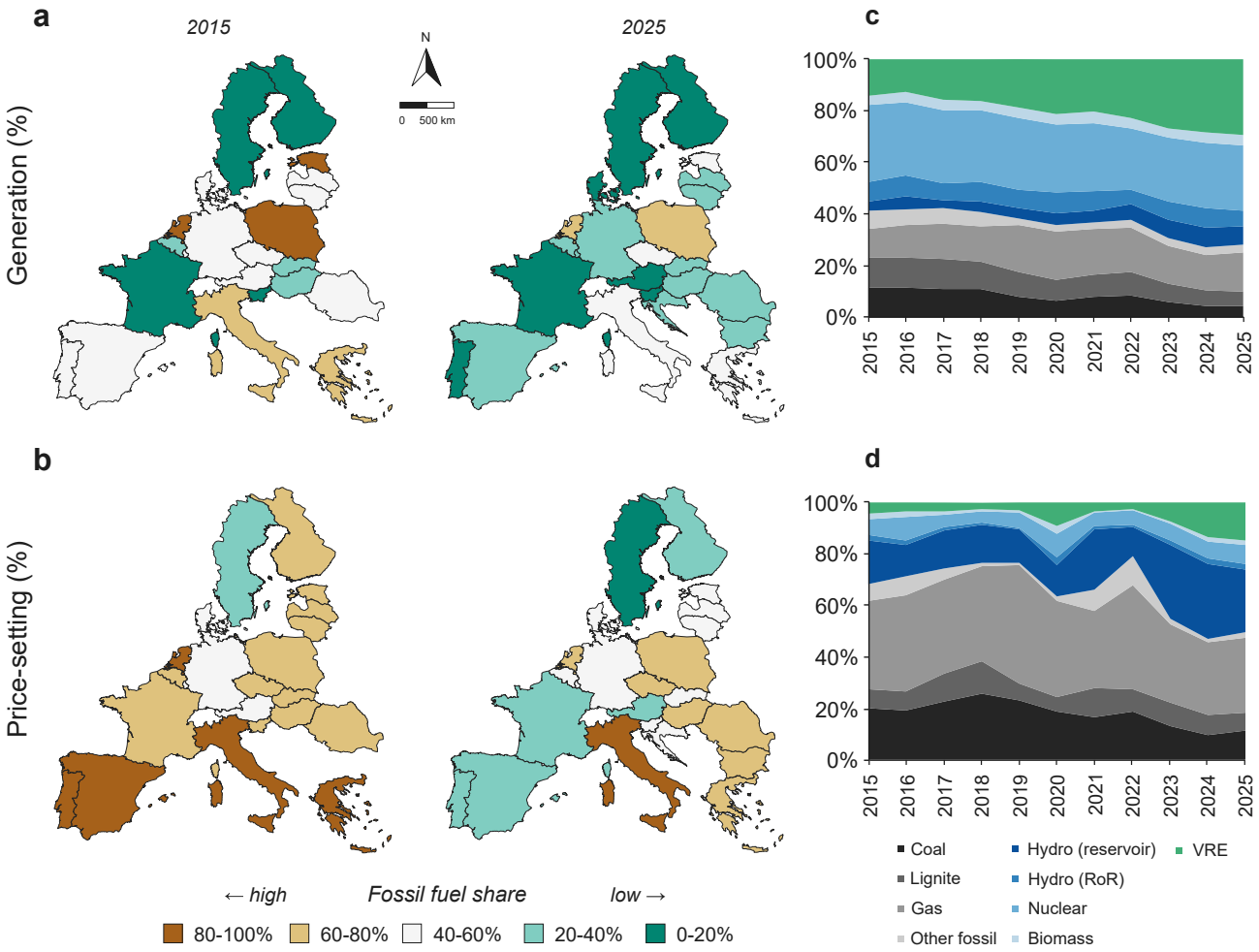


Figure 2: **Shifts in price-setting from 2015 to 2025**. (a,b) The relative share of fossil fuels in the power mix (a, from ENTSO-E[2]) and price-setting (b, as per our analysis) by country for 2015 (left) and 2025 (right). (c, d) The demand-weighted shares of generation (c) and price-setting (d) at EU-level across the period 2015-2025, split up by generating source. The category "Hydropower (reservoir)" includes both conventional reservoir hydropower and pumped storage hydropower. RoR = run-of-river; VRE = variable renewable electricity (solar and wind). For countries that share a bidding zone with neighbours, statistics are shown for the bidding zone, not the individual country. This applies to Luxembourg (part of DE-LU bidding zone) and Austria (part of DE-AT-LU bidding zone until 2018, when it split into DE-LU and AT). For countries with internal bidding zones, statistics are shown at country-level as weighted average.

are still disproportionally high price-setters; however, on average, every percentage point (p.p.) of lower fossil fuel generation share has translated into 1.4 p.p. lower fossil fuel price-setting share.

Despite a steady increase in the contribution of VRE to the power mix since 2015, from 14% to 29% (Figure 2c, with installed VRE capacity more than doubling[25]), it appears this has only recently started translating into increased contributions of VRE in price-setting (Figure 2d), which languished around ~3% in 2015-2022 but subsequently increased rapidly, reaching 15% in 2025. (The year 2020 was an anomaly in this trend, with the COVID-19 pandemic provoking demand reductions[26] which led to more VRE price-setting, but only temporarily.) Simultaneously, while hydropower generation has remained relatively steady (10%-15% of annual generation, depending on hydrology), with hardly any new capacity built (around 3% capacity added since 2015[25]), the role of hydropower in price-setting appears to have grown along with the increased role of VRE, from 15-20% before 2020 to 25-30% in 2023-25. In some MS, these dynamics

are even more pronounced: in Spain, the role of VRE grew from 19% to 42% in generation and from 1% to 21% in price-setting in 2015-2025; hydropower fluctuated between 8%-16% of generation in the same period, but more than doubled from 17% to 37% in price-setting. These dynamics are explored in more detail in the following sections.

Seasonal and diurnal patterns

The recent increasing influence of VRE on price formation is reflected in its temporal patterns (Figure 3). Seasonally, the role of VRE is especially pronounced in late spring and early autumn, when both solar and wind output are robust, heating and lighting demand is lower than during winter, and cooling demand is lower than in summer (Figure 3a). At hourly scale, VRE, especially solar, have become important price-setters during mid-day hours, where they reached an EU-weighted average of up to 37% of price-setting in 2025 (Figure 3b). This helps to consistently displace fossil fuel technologies from the merit order during those periods, especially in spring. Conversely, gas remains as the dominant price setter during peak demand hours, close to sunrise and sunset (Figure 3b). In those moments, more expensive fossil fuel peaking plants (such as heavy fuel oil plants, here grouped under "other fossil") also still consistently play a role as solar disappears from the mix.

Across bidding zones with vastly different power mixes, these dynamics manifest in "envelopes" of fossil fuel price setting in mornings and evenings across the year (Figure 3c), with VRE making seasonal inroads in the hours inbetween. Depending on power mix composition, these patterns may be complemented by price-setting from hydropower (e.g. in France and Spain) and/or coal (e.g. in Poland) during nights and low-VRE periods. (Additional visualisations are given in Supplementary Note 2.)

The role of interconnectors

Interconnectors contribute to price convergence across bidding zones and allow technologies in one bidding zone to set prices in neighbouring markets. Across EU countries, the rate of price-setting determined by neighbouring bidding zones varied from 12% to 68% in 2025 (Figure 4). Countries that frequently import a neighbour's marginal price include Portugal (68% in 2025), Denmark (61%), Sweden, Bulgaria (both 58%), Romania (57%), and Estonia (56%); these countries have in common that they are relatively peripheral in the EU electricity system. Conversely, countries often acting as price-setting exporters are Germany (9% of instances of cross-border price-setting), Spain (7%), Bulgaria, and Hungary (both 7%); these price-exporters reflect both regional hubs in the highly interconnected center (Germany, Hungary) as well as countries with specific transmission roles (Spain linking Portugal to Central Europe). Some countries play both roles: Bulgaria appears to act as "price bridge" between Romania and Greece, appearing both as substantial importer and exporter of prices. Conversely, France, despite being a net electricity exporter, is not a major price exporter, as its nuclear and hydro capacity usually clears below neighbouring gas prices. A detailed heatmap of price-setting interactions between countries is given in Supplementary Note 3. Overall, cross-border price-setting has increased somewhat since 2015 thanks to enhanced interconnection capacity and more countries joining the single electricity market, reaching a peak in 2021 just before the energy crisis, after which it started to decrease somewhat again, possibly due to more pronounced commodity cost disparities (Figure 4, inset).

Interconnection also amplifies the price impact of certain technologies, with gas, reservoir hydropower, and VRE being notable cross-border price-setters. Which one is dominant depends on the precise geographical and energetical circumstances. For instance, centrally-located, highly-interconnected Austria—with domestically >80% generation of hydropower and VRE—sees its wholesale price determined by up to 34% by its neighbours, and three-quarters of those price imports are set by fossil fuels from less-decarbonised neighbours (Figure 4). In contrast,

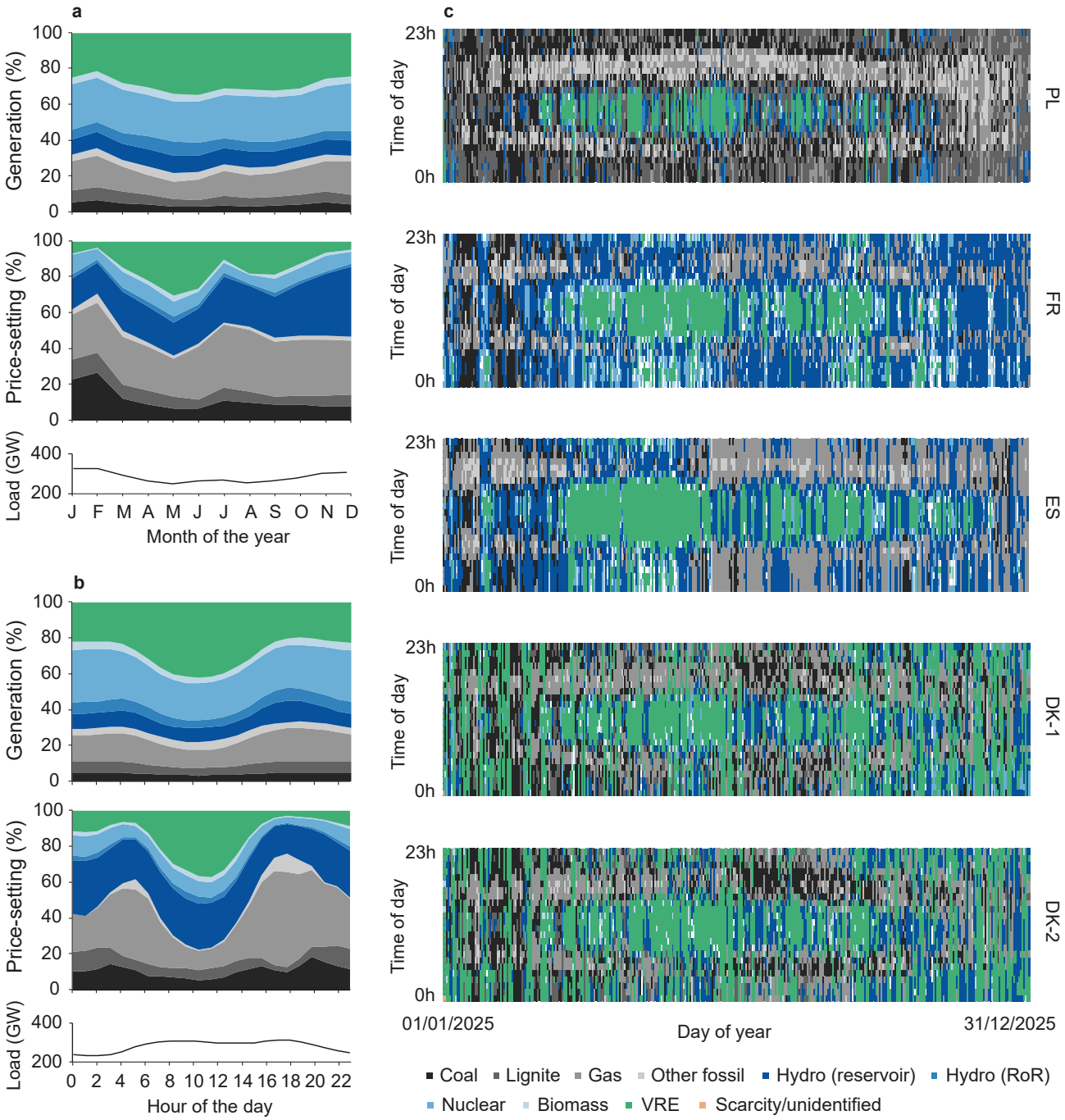


Figure 3: **Spatiotemporal trends in price-setting technologies.** Average seasonal (a) and hourly (b) profiles of generation (top) and price-setting (middle) technologies (grouped by fossil fuels, nuclear, hydropower, and other renewables) at EU-level for the year 2025, and compared to EU-wide average demand profiles per month and hour in 2025 (bottom). (c), Full hourly price-setting patterns for Poland (PL), France (FR), Spain (ES), and Denmark (DK-1 and DK-2) for each day of the year 2025, indicating the identified price-setting technology in each moment. Hours with more than one "co-marginal" technologies are shown in white; hours with scarcity pricing or otherwise unidentified price-setters are shown in red (see Methods).

Spain may import even more prices from its neighbours Portugal and France—up to 47%—but in two-thirds of cases, these are set by VRE, hydropower, and nuclear (Figure 4). Overall, interconnectors allow exporting low-price signals from clean techologies as well as high-price signals from fossil fuels, pointing to the importance of streamlining decarbonisation speeds across neighbours.

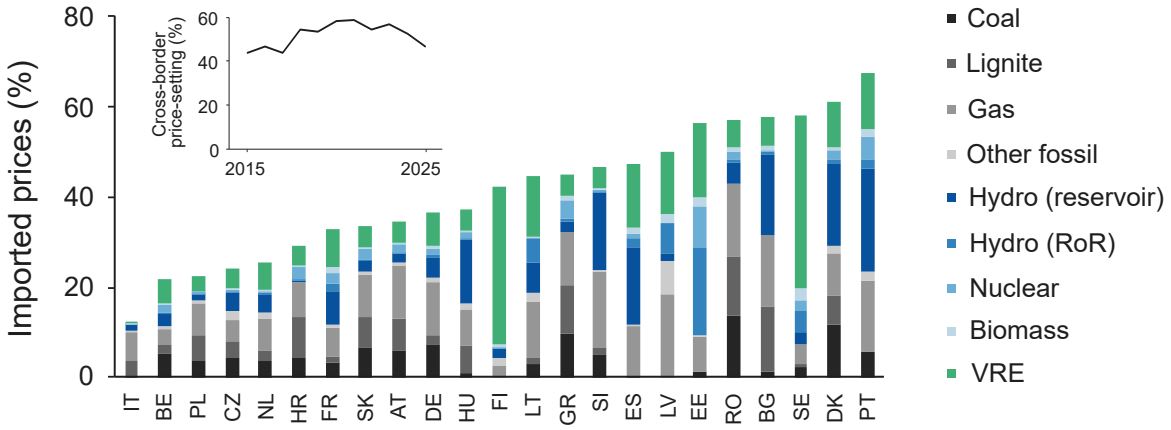


Figure 4: **The influence of interconnectors in price-setting.** Share of imported prices by member state for the year 2025, including the corresponding split of the specific technologies responsible for the cross-border price-setting. Countries are abbreviated by their alpha-2 ISO codes[27]. Inset: overall rate of cross-border price-setting from 2015 and 2025 at EU-level.

Tipping points in price-setting

Analysing the dynamics of price-setting shares over time, we identify three distinct "tipping points" of interest. Tipping points are here defined as situations where changes in a technologies' generation share have a clear non-linear effect on their own, or another technology's, share in price-setting, thus moving the overall price-setting mix to a new "state".

(1) *Critical mass for VRE.* With near-zero marginal cost, solar and wind power can only become price-setters in moments when they fully cover the demand. Since VRE production is intrinsically unsynchronised with demand, this effect can only manifest at scale once a certain VRE penetration is reached, at which peak VRE production (e.g. during mid-day sunshine) starts structurally exceeding demand. Figure 5a shows that a tipping point appears to have been reached at EU-level at a VRE penetration slightly above 20%. Until reaching those generation shares, no effect on price-setting was registered; once reached, VRE price-setting shares increased faster than generation shares. Between 2021 and 2025, each percentage point increase in VRE generation led to 1.3 p.p. increase in VRE price-setting. Figure 5b shows ranges of this effect across four areas (France, Poland, Spain, and Denmark), illustrating how regional differences in generation mixes, interconnections, and flexibility options may affect this tipping point. As mentioned, in Spain (ES), VRE increased from 19% to 42% in the electricity mix in 2015-2025 while VRE price-setting jumped from 1% to 21% (and gas price-setting dropped from 51% to 26%). In nuclear-dominated France (FR), although both gas and VRE have minor generation shares compared to nuclear and hydropower, VRE has overtaken gas in price-setting (17% versus 13%). In Poland (PL), too, VRE price-setting has increased—but less rapidly, with gas also increasing its price-setting role by similar proportions, as VRE and gas push coal out of the merit order.

(2) *Saturation of VRE.* The kind of VRE penetrations reached by Spain in 2025 were already common in Denmark (DK) a decade earlier, and have further increased since. However, Denmark's two bidding zones (DK1 and DK2) show signs of saturation of VRE price-setting. Despite VRE generation increasing from 56% to 80% (DK1) and 38% to 57% (DK2) in 2015-2025, price-setting in either region has not surpassed 40%. Partially, this may reflect how the growth of VRE has surpassed the concurrent increase in clean firm and/or flexible technologies needed to support high VRE integration. Additionally, even with sufficient flexibility technologies integrated (storage, electrolysers, demand response, etc.) to allow reaching (near-)100% shares of VRE, those flexibility technologies would eventually likely become the main price-setters

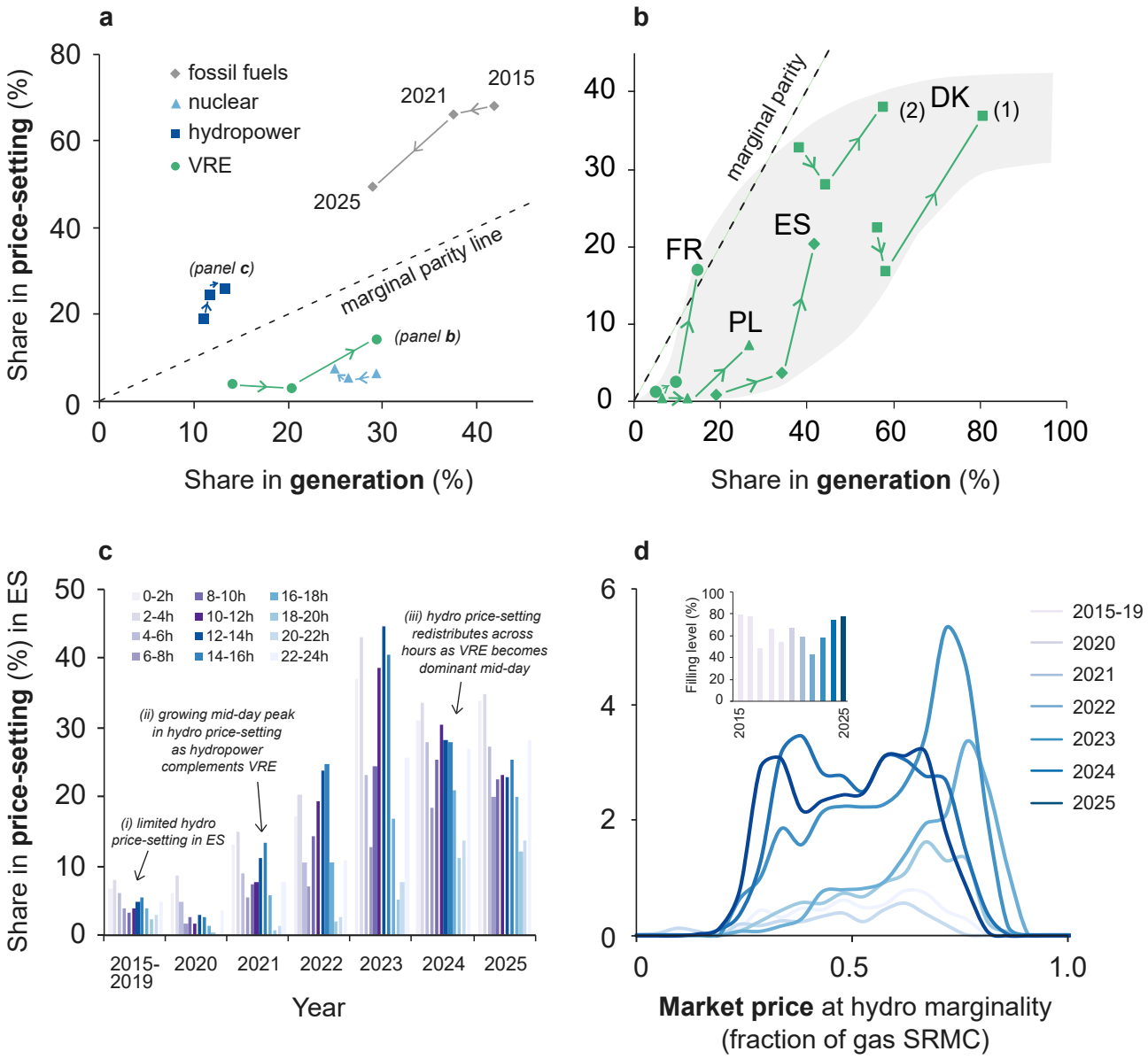


Figure 5: **Observation of tipping points in price-setting over time**. (a) The change from 2015 to 2021 and 2025 observed in the share of price-setting versus the share of generation across the EU, for fossil fuels, nuclear, hydropower, and VRE. The dashed line shows "marginal parity", i.e. if a technology's generation share equals its price-setting share ("proportional price-setters"). We use 2021 as "middle year" as 2020 statistics were affected by low demand owing to the COVID19 pandemic. (b) The same statistics for VRE for five bidding zones (FR, PL, ES, DK-1, DK-2). The gray area is an artist's impression of the "S-curve" behaviour expected under the presence of lower and upper "tipping points" as explained in the text. (c) Price-setting frequency of reservoir hydropower (including prices set from abroad; counting only conventional reservoirs, without pumped hydro) in Spain (ES) per two-hour block. Percentages refer to the frequency within each block. (d) Price-setting frequency of reservoir hydropower in ES as function of the observed marginal price[1]. Inset: average annual reservoir filling level in ES[28].

themselves[18,29]. For DK, interconnections with Norway, Sweden and Germany play an important role, but Nordic hydropower seemingly cannot offset this saturation effect, while Germany still relies strongly on fossil fuels and DK imports fossil fuel-set prices around 30% of the time (Figure 4). Thus, alongside the earlier curves from FR, PL, and ES (tipping point 1), this apparent saturation in DK (tipping point 2) gives the impression of an S-curve-type behaviour

in VRE price-setting, as illustrated schematically in Figure 5b. This S-curve would largely lie below the marginal parity line: the variable character of VRE may restrict its potential to become a proportional price-setter, even at high generation shares.

(3) *Hydropower flexibility.* According to Figure 5a, hydroelectric plants are increasingly setting the price without concurrently increasing generation. Here, this is investigated in more detail using the example of Spain as seen by our algorithm, where the trend is stronger than on EU average. We show the changing frequency of reservoir hydropower price-setting by hour of the day (Figure 5c), allowing to observe three phases. (i) In early years (pre-2020), reservoir hydropower was a limited price-setter. (ii) Subsequently (starting in 2021) hydropower appears to have progressively evolved from a non-marginal baseload provider to a flexibility provider role as VRE penetration increased. This increased price-setting manifested especially during mid-day hours, with hydropower becoming marginal upon complementing solar power generation. (iii) More recently (as of 2024), price-setting at mid-day has become increasingly saturated by VRE, now well past its tipping point (Figure 5b). In response, hydropower price-setting has redistributed, shifting more to low-VRE hours in which it is steadily more capable of pushing fossil fuels out of the merit order (Figure 5c). These trends form a third tipping point, representing changes in hydropower operation as VRE penetration grows. Related, we see a notable trend when analysing the *actual market price* in the moments that our algorithm identified as having had a hydro-set price (Figure 5d). The increased hydropower price-setting post-2020 appears to have initially shadowed gas prices: a peak in hydro price-setting close to gas SMRC appeared in 2021 and grew more pronounced in 2022 and 2023. As of 2024, this connection of hydropower to gas prices appears to have weakened again. The high-bid peak has receded, and a secondary peak has manifested at much lower bids, in what appears to be a progressive decoupling of hydropower bidding from gas prices as fossil fuels fall outside the merit order increasingly often. (The trends in Figure 5d also reflect, to a lesser extent, interannual hydrological variability, cf. inset. For instance, the bid distribution for 2022, the driest year in the series, registers the longest right-hand tail, reflecting high marginal bids under water scarcity. Similarly, 2024 and 2025 were wetter than the preceding years, and we logically see the peak of high-value bids shifting leftwards under reduced water scarcity.)

We conclude that VRE deployment needs to reach a certain critical mass before it can contribute meaningfully to set prices and have noticeable impact on wholesale prices. This tipping point has been observed indicatively at 20%-25% of VRE penetration at EU-level, but with considerable differences among bidding zones. Once reached, VRE price-setting can initially grow fast (as currently in FR, PL, ES), but in the absence of clean firm or flexible sources at scale, or sufficient interconnections to decarbonised neighbours, it is likely to eventually flatten off—with fossil fuels retaining substantial "latent" price-setting—even as VRE shares keep growing (as observed in DK). In this process, the role of existing flexible technologies, notably reservoir hydropower, also undergoes shifts reflected in price-setting.

Generally, a well-diversified energy mix, including not only VRE but also non-fossil firm capacity (notably hydropower and nuclear), can help mitigate the fossil fuel influence in price-setting. Displacing fossil fuels from the merit order is substantially easier when other firm or flexible power sources sit in between VRE and gas in the merit order. Greece (not shown here) had almost the same VRE penetration as Spain in 2025, but only half the VRE price-setting share—because Greece has much less hydropower capacity than Spain, and no nuclear plants, to occupy the space between VRE and fossil fuels in the merit order.

Comparison of outcomes

Only a few EU countries report price-setting technologies, notably Spain, Portugal, and Italy. Overall, comparisons are non-trivial: the Iberian market operator (OMIE) does not report a "VRE" category, counting solar/wind together with co-generation and waste; the Italian

market operator (GME) reports many hours (up to 20% in 2025) as "uncertain" with no uniquely identifiable technology. Interestingly, OMIE reports ∼20 p.p. higher price-setting for hydropower than our results, and 20 p.p. lower price-setting for gas, for the most recent full year available (2024)[30], but the aggregate gas-plus-hydropower price-setting matches our estimate within 5 p.p. (at ∼60%) for both Spain and Portugal. This appears to reflect the trends in Figure 5d where hydropower often sets prices close to gas SMRC, blurring the distinction between the two in price-setting. Our numbers also converge with Italian power exchange data on foreign price-setting[31] (∼4–8% in our results for 2025, against reported ∼3–4%).

When comparing with third-party studies, our marginality estimates for natural gas closely align with EMBER's[22] gas-SRMC benchmark, matching within 1 p.p. for Spain and the Netherlands in 2025, and with that of the European Central Bank[23], matching within 5 p.p. for Italy, Spain, and France in 2025. A main distinction with other studies relates to the assessment of cross-border price-setting: where imports are typically treated as unclassified "external" price-setter, our model traces cross-border price-setting back to specific marginal technologies in other zones, including non-EU countries within the internal electricity market (Norway) and outside (Switzerland, Western Balkans). Methodological differences in treating cross-border flows and plant-level constraints also explain divergences from ref.[24], suppressing VRE and foreign price-setting for their results.

Limitations and uncertainties

Our algorithm involves several structural uncertainties. First, most fuels for power generation are not procured on spot markets but through long-term supply contracts, which our model does not explicitly consider. Yet, spot prices are typically used as reference for such contracts, meaning they do serve as relevant proxy. Second, our approach provides a simplified view of hydropower's strategic bidding[32,33] (see Methods); while we assume that, on average (across seasons and years) our algorithm gives a representative view, "ad-hoc" decisions of reservoir management under e.g. contingency situations can not be captured. Third, while our analysis shows that (under the right circumstances) VRE can bring down day-ahead prices, increased VRE penetration may *increase* prices on ancillary service markets[34]. While volumes traded on those markets are substantially lower than on the day-ahead market, such that the positive effects of VRE on prices remain intact, such secondary impacts still merit further study. Fourth, CfDs (contracts-for-difference) will become the standard option for VRE support schemes in the future, which could permit a wider VRE bidding range[35]. Given these uncertainties, this analysis should be interpreted as providing proxies for marginal bidding, not exact outcomes.

Aside from the above-mentioned structural uncertainties, a sensitivity analysis of our algorithm was carried out to test the robustness of assumptions around important parameters (see Methods).

Discussion and conclusions

The transition toward a fully decarbonised electricity system is often conceptualised by a linear displacement of fossil generation by cleaner energy. However, our findings suggest that market price formation is governed by non-linear technology-related tipping points. Identifying and anticipating these price-setting inflection points can enhance the understanding of the conditions under which VRE can be expected to structurally lower prices.

First, while VRE expansion primarily pushes fossil fuels out of the merit order, its capacity to set marginal prices at scale requires reaching a critical penetration threshold. Below this tipping point, fossil thermal units continue to dominate marginality. Once the point is surpassed, low-marginal-cost renewables begin setting prices with sufficient frequency to put structural downward pressure on wholesale electricity prices, as already observed in various EU markets. However, in the absence of complementary flexibility technologies, VRE price-setting eventually

saturates, leaving substantial periods exposed to fossil fuel prices. Thus, while increased VRE price-setting in the EU has helped dampen the impact of the energy crisis on wholesale prices, it has not been sufficient to stop these prices from rising at all.

Second, clean firm resources and non-fossil flexible technologies can accelerate reaching these VRE tipping points. With more VRE in the system, we observe flexible hydropower to complement VRE by increasingly covering residual demand and setting market prices. Sufficiently high integration of flexible and firm clean assets in the system can thereby outcompete the fossil units as marginal technology, and lower the VRE volume required to displace fossil fuels from price formation. However, in the early stages of this displacement, it is likely that bids by hydropower (or other flexible technologies) keep mimicking fossil fuel costs, delaying the onset of downward pressure on wholesale prices. A *coordinated* uptake and operation of these assets along VRE integration is therefore crucial to decouple electricity prices from fossil fuel prices.

Third, cross-border interconnections expand the geographic reach of low-cost renewables and dampen price volatility, but may also extend gas price-setting to neighbouring bidding zones. For import-dependent countries, reducing the influence of gas in price-setting, even under the presence of domestic VRE, hydropower, and/or nuclear, can be challenging if neighbouring countries are not sufficiently decarbonised. A country that appears on course for the VRE tipping point, but that still imports from neighbouring zones far from reaching this "critical mass", will face limitations in reducing fossil fuel influence on electricity prices. This underscores the importance of cross-border energy policy cooperation in the context of a genuine Energy Union.

Understanding these non-linear market-clearing dynamics provides important insights for policymakers. Policies without a systemic approach, focusing only on volume targets for renewables instead of coordinating with the integration of firm and non-fossil capacity, the buildout of flexibility and storage solutions, and the strategic expansion of interconnections to other decarbonising markets, may risk overpaying for generation capacity without delivering proportional reductions in wholesale prices. Aligning investment incentives with the observed tipping points can drive and ensure the affordability of electricity prices.

Methods

Description of the algorithm

The price-setting algorithm designed in this study determines which generation technologies are "marginal" (i.e., likely setting the market price) for each hour of observed wholesale prices. The algorithm identifies the technology most likely to have set the wholesale electricity price on each bidding zone at hourly timescale, by combining observed generation and cross-border flow data with technology-specific Short-Run Marginal Costs (SRMC) ranges.

1. First, we construct estimated hourly SRMC intervals for all technologies. For fossil-fuel plants, these intervals are computed dynamically for the relevant day, using dynamic commodity price ranges, as well as dynamic efficiency ranges based on generation per production type from ENTSO-E[2], as input (see below, "Assumptions on technologies' SMRC"). Nuclear, biomass (understood to include waste), run-of-river hydropower, and VRE (covering onshore wind, offshore wind, and solar power) are assigned fixed SRMC ranges. Reservoir hydropower and pumped hydropower are treated separately through tailored functions intended to approximate their market bidding behaviour based on reservoir levels[28] and load[36] obtained from ENTSO-E (see below, "Modelling of strategic bidding by reservoir hydropower" and "Modelling of strategic bidding by pumped storage hydropower").

2. For each hour, we assess whether cross-zonal price coupling is likely to have occurred. For each bidding zone, neighbouring zones are classified as "coupled" when (a) their hourly prices differ by no more than ±0.5 €/MWh, and (b) scheduled commercial flows obtained from ENTSO-E[37] between bidding zones exceed 50 MW. Under these conditions, we assume that arbitrage across the respective interconnected zones can be considered plausible, and we extend the search for marginal technologies beyond the domestic zone to the SRMCs of technologies generating in coupled neighbours. This assumption does not account for transmission losses, congestion rents, loop flows, or internal grid constraints with coupled areas.

3. Marginal technologies are identified using a three-step selection. First, a technology must be actively generating in the relevant hour, with generation above a pre-defined threshold per technology and bidding zone. Here, we set the threshold to 10 MW for all technologies across all bidding zones, except for gas-fired power in a few zones whose gas-fired generation tends to be below 10 MW as a rule (EE, SE-3, SE-4, and NO-2); for these, we lowered the threshold to 1 MW. Second, the estimated hourly SRMC of the technology must fall within a range of ±10 €/MWh of the observed hourly market price obtained from ENTSO-E[1]. Third, among all qualifying technologies, the algorithm selects the one whose SRMC is closest to the observed hourly price. If several technologies are indistinguishable based on the difference between their SRMC and the observed hourly market prices, they are classified as "co-marginal". This reflects the possibility that multiple technologies can be setting the price in a given hour (e.g. in hours with high VRE infeed, it may be impossible to distinguish whether solar PV or wind power is setting the price; we classify such hours simply as "VRE" in this study). In calculations of average price-setting mixes in this paper, during hours of co-marginality, shares are allocated proportionally to the two or more technologies identified as co-marginal in the bidding zone in question.

4. If no technology satisfies these conditions, the algorithm applies two fallback rules. When the observed market price exceeds the SRMC of gas in a given hour by a factor of 1.5 or more, the hour is flagged as having its price set by "scarcity" instead of by a generating technology. This is intended to capture hours in which scarcity or demand curtailment may be setting the price. The share of scarcity values identified by the algorithm is very low (under 0.1% of hours at EU-level across the modelled period) and not visible in most graphs. Otherwise, the algorithm assigns the marginal role to the generating technology whose SRMC lies closest below the observed market prices. Finally, if no such technology is found by the algorithm, the cheapest technology with nonzero generation is selected, reflecting cases when the market price lies below all SRMCs (such as may occur during episodes of negative prices).

5. In very rare cases, the price data of certain bidding zones[1] contained NaN values for certain hours; for those hours, the algorithm does not identify a price-setter. Infrequently, such gaps may also occur in input time series for fuel prices. In such cases, it is theoretically possible that, in such an hour, no technology (domestic or in coupled neighbours) that is producing above the minimum generation threshold has a computable SRMC. For such instances, the algorithm does not identify a price-setter either.

The algorithm returns, for each bidding zone and each hour, a list of all marginal technologies setting the price, and the bidding zone (domestic or neighbour) responsible for setting the price.

Price-setting aggregates for the EU level and for countries comprising more than one bidding zone (IT, DK, SE) are computed using the annual electricity demand (sum of hourly ENTSO-E load) as weight for each bidding zone. Demand weighting aims at reflecting the electricity consumption exposed to the respective prices. Consequently, larger markets contribute proportionally more to the aggregate values.

A schematic diagram covering the steps and processes of the approach is shown in Supplementary Note 1.

Assumptions on technologies' Short-Run Marginal Costs (SRMC)

In the absence of public data on SMRCs and on the actual bids submitted by generators, identifying the price-setting technologies relies on several simplifying assumptions. The analysis is restricted to day-ahead markets and uses observable market commodity price benchmarks as proxies to estimate generators' SRMC. Specifically, gas prices are represented primarily by the Dutch Title Transfer Facility (TTF) prices[5], with local hub prices used for specific markets when available (Central European Gas Hub (CEGH)[38], Zeebrugge Trading Point (ZTP)[39], Virtual Trading Point CZ (VTP CZ)[40] and SK (VTP SK)[41], *Point d'Échange de Gaz* (PEG)[42], *Punto di Scambio Virtuale* (PSV)[43], Trading Hub Europe (THE)[44], *Punto Virtual de Balance* (PVP)[45] (we considered the *Iberian price cap* to be in place from mid-June 2022, up to end of the year 2023), National Balancing Point (NBP)[46] and German legacy hubs, such as NetConnect Germany (NCG)[47] and GASPOOL[48]. For the case of countries without a gas hub, TTF prices plus an estimated transport cost inspired by information from ACER[49] are used. Likewise, coal prices are proxied by CIF ARA benchmarks[50], oil prices by FO 1%S quotation[51], and carbon costs by European Union Emissions Trading System (EU ETS) allowance prices[52]. Hedging strategies, bilateral contracting and forward positions are not considered. For lignite, biomass, uranium, and VRE, cost assumptions are based on technological[53 54 55 56] and market judgment; these are given in Supplementary Note 4. These choices imply that estimated SRMCs should be interpreted as indicative approximations of bidding behaviour, rather than exact values. Where necessary, conversions of currencies to the Euro were done using conversion rates from the European Central Bank (ECB) [46].

For each technology f, the short-run marginal cost is defined as

$$SRMC_f(t) = \frac{p_f(t) + p_{CO_2}(t) \cdot \varepsilon_f}{\eta(t)} + p_{VOM}$$

where:

p_f : fuel spot price (€/MWh)
p_{CO_2} : carbon price (€/tCO_2)
ε_f : technology-specific emissions intensity (tCO_2/MWh)
η : plant efficiency
p_{VOM} : variable operation and maintenance costs (€/MWh)

Carbon costs are assumed to be passed-through fully into bids, implying a 100% pass-through rate and excluding any potential effects of free allowance allocation or strategic withholding of emissions costs. Variable operation and maintenance costs are assumed to be constant within each technology class and invariant to plant age, geographical location, and operating regime.

We consider that for thermal units (gas, coal, lignite, oil, combined heat and power (CHP), biomass, and nuclear), hourly SRMCs could vary with the aggregate output, reflecting the merit-order where lower generation levels use most efficient plants (high thermal efficiency), while high generation requires the dispatch of progressively less efficient plants. To represent this effect, a technology-specific generation factor is computed as:

$$g_f(t) = \frac{G_f(t) - G_f^{\min}}{G_f^{\max} - G_f^{\min}}$$

where:

$g_f(t)$: generation factor (dimensionless, $0 \leq g \leq 1$) of technology f (coal, gas, lignite, etc.) at time t
$G_f(t)$: generation (MWh) at time t
$G_f^{\min}, G_f^{\max}$: technology-specific minimum and maximum generation (MWh)

Minimum and maximum values are derived from the generation time series per year, per bidding zone, per technology. Dynamic efficiency is subsequently derived by linearly interpolating between the technology-specific upper and lower efficiency bounds:

$$\eta_f(t) = \eta_{\max} - g_f(t) \cdot (\eta_{\max} - \eta_{\min})$$

where:

$\eta_f(t)$: dynamic (load-dependent) plant efficiency for technology f at time t
$\eta_{\max}, \eta_{\min}$: technology-specific maximum and minimum efficiency

A list of the efficiencies used per technology and country is available in Supplementary Note 4.

By contrast, VRE and run-of-river hydropower are assigned static SRMC ranges to represent low marginal operating costs, while abstracting from curtailment and plant-specific heterogeneity.

Hydropower, both reservoir and pumped storage, requires a distinct treatment as the bidding behaviour of these technologies is shaped not only by operating costs, but also by opportunity cost values, i.e. the forgone value of turbining water in the present hour, instead of keeping it stored for later use when the hydropower could potentially have been sold at a higher price. This is explained in the sections "Modelling of strategic bidding by reservoir hydropower" and "Modelling of strategic bidding by pumped hydropower storage" below.

Modelling of strategic bidding by reservoir hydropower

Reservoir hydropower bidding is represented as a shadow-pricing (opportunity cost) function that varies inversely with reservoir filling levels and positively with residual demand and reference to gas SRMC[32,33]. The basic function used to estimate hydro reservoir SRMC reflects these considerations, and is capped at a fixed share of the gas SRMC:

$$SRMC_{\text{res}}(t) = \gamma\, SRMC_{\text{gas}}(t)\,[\phi_{\text{full}} + (1 - \ell(t))\,(\phi_{\text{empty}} - \phi_{\text{full}})] + \Delta_{\text{demand}}(t), \tag{1}$$

where $\ell(t)$ is the reservoir filling level (%)[28], $\gamma = 0.85$ caps the opportunity cost relative to the gas benchmark, $\phi_{\text{full}} = 0.25$ and $\phi_{\text{empty}} = 0.85$ bound the bidding range between full and empty reservoir conditions, and $\Delta_{\text{demand}}(t)$ is an adjustment factor that pushes the bid toward the gas ceiling under high residual demand. A full description of the function is provided in Supplementary Note 5.1.

Modelling of strategic bidding by pumped hydropower storage

Pumped hydropower is modelled through price-arbitrage logic, with pumping during cheap hours and generating during expensive hours. This is implemented with a time-of-day gating:

$$SRMC_{\text{PHS}}(t) = \begin{cases} \kappa_{\text{pumping}}\, SRMC^{d}_{\text{gas}}(t), & h(t) \in \mathcal{H}^{\text{pumping}} \\ \kappa_{\text{generating}}\, SRMC^{d}_{\text{gas}}(t), & h(t) \notin \mathcal{H}^{\text{pumping}} \end{cases} \tag{2}$$

where $h(t)$ is the hour of day, $\mathcal{H}^{\text{pumping}} = \{22, \ldots, 23, 0, \ldots, 4\}$ denotes night-time hours (22:00–04:59), and $SRMC^{\text{gas}}_{d(t)}$ is the mean gas SRMC over the calendar day $d(t)$ containing hour t. The night and day factors ($\kappa_{\text{pumping}} = 0.60$, $\kappa_{\text{generating}} = 0.85$) set pumping and generating bids as fixed shares of this daily benchmark. This logic reflects the traditional logic that pumping happened during night-time, but changing market conditions, such as increased daytime pumping to absorb solar surpluses, introduce potential uncertainties to this approach (see below, "Sensitivity analysis"). A full description of the function is provided in Supplementary Note 5.2.

Sensitivity analysis

The sensitivity analysis aimed at test broad sensitivity on certain areas that could impact the price-setting analysis. We looked into the following sensitivity scenarios:

1. SRMC selection range. We explored the effect of modifying the SMRC selection range window from ±10 €/MWh to ±5 €/MWh and ±15 €/MWh, allowing respectively fewer and more technologies to be covered by it before the algorithm passes to the scarcity criterion.
2. Interconnected price tolerance. We modified the maximum range for two or more bidding zones to be considered "coupled" (given a minimum flow of power between these zones) to ±1 €/MW and ±2 €/MW, thus modelling a more lenient view of when price-setting is deemed to flow across bidding zone borders.
3. Hydropower reservoir bidding range. We varied the parameters $[\phi_{\text{full}}, \phi_{\text{empty}}]$ from [0.25, 0.85] to [0.40, 0.70] (reducing the bidding range) and to [0, 1] (extending the bidding range).
4. Hydropower reservoir gas-ceiling factor. We varied the gas SMRC ceiling (γ) on the hydropower reservoir function around the base value of 85%, moving hydropower reservoirs closer to ($\gamma = 90\%$) the gas SRMC, and further away from it ($\gamma = 80\%$).
5. Minimum generation threshold. We adjusted the minimum threshold for a generating technology to set the price in a given hour from 10 MW to 1 MW for all technologies and bidding zones, potentially allowing a wider portfolio of technologies to be considered as price-setter.
6. Pumped hydro function charging window: We shifted the assumed pumped-storage charging window ($\mathcal{H}^{\text{pumping}}$) from night (22:00-04:00) to daytime (10:00-16:00), so that charging coincides with cheap solar generation and the technology is allowed to discharge (potentially setting the price) during night hours.

Details on the outcomes of the sensitivity analysis are provided in Supplementary Note 6.

Data availability

The ENTSO-E datasets are freely and openly available in the Transparency Platform [1,2,36,37,28]. The datasets used for fuel and emissions allowances commodity values used in this paper are available under commercial access via S&P Global Platts [5,50,51,52,38,39,40,41,42,43,44,45,46,47,48].

Code availability

The code used to run the algorithm, written in Python, is available open-source on GitHub (`https://github.com/imartinezn/price-setting`) alongside several supporting files. The datasets used to run the code for this paper are indicated in "Data availability", but the code can also be run with other third-party or "custom" data (see repository).

Correspondence and request for materials

All correspondence and requests for materials should be addressed to S.S.

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Author contributions

The algorithm was designed by I.M., D.K., and S.S, and coded by I.M. The paper was written by I.M. under supervision of D.K. and S.S. Data visualisations were conceived and designed by S.S. All authors contributed to the interpretation of results.

Competing interests

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper. The article represents the authors' viewpoints and not necessarily that of their institutions.

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