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When gas costs rule power prices

Merit order pricing, Europe's energy crisis and reform options

As gas prices have doubled since the beginning of the war in the Middle East, concerns about electricity costs are returning across Europe. Why, despite the rapid growth of low-cost renewables, do gas prices still have such a strong impact on power prices? Mostly because of merit order pricing, which implies that flexible gas-fired power plants often set market prices when demand exceeds non-fossil supply. Yet it was designed to encourage investment in low-cost power sources and efficient technologies. Short-term fixes such as subsidies or price caps may provide temporary relief but also carry risks. To keep (wholesale) electricity prices durably low, the electricity system must be decarbonised further and made more flexible, while electricity markets must become more competitive.

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Gas still rules Europe's power prices

Gas-fired power plants generate less than one-fifth of EU electricity but set wholesale power prices in more than twice the percentage of hours. Gas accounted for 85% of Europe's power price surge in 2022. Even as renewables grow, flexible gas remains dominant. Without adequate storage, grids, demand flexibility and a balanced wind-solar mix, low-carbon energy transition remains fragile.

Short-term fixes also carry significant risks

The Iberian model (gas subsidies) works only in isolated markets, while Italy's refunding of ETS carbon costs risks locking in gas reliance. Austria's transparency push and WIFO's proposal to refund the portion of wholesale power prices attributable to ETS carbon costs above a specified threshold could risk distorting futures markets. Greece's dual pricing shields consumers but adds complexity.

A flexible low-carbon electricity system keeps prices low

Renewables acceleration and demand flexibility that shift electricity use to periods of abundant non-fossil generation are important steps forward. But Europe must also scale power storage and grids to break the pricing grip of gas. Otherwise, power price volatility and fossil fuel reliance will persist, threatening both affordability and climate goals.

1 Summary

- The European electricity market sets prices based on marginal costs according to the merit order principle, which has been designed to promote efficiency and investment. Power prices often track those of gas-fired power plants even though renewables power plants with lower production costs are dispatched first.
- In 2022, according to Mier (2025), gas prices drove 85% of Europe's power price surge. Transmitted via electricity prices, gas was also a key driver of euro area inflation between 2021 and 2023. Although renewables supplied around 47% of electricity in 2025 – nearly three times the share of gas – EU power prices remain dependent on gas in the short term.
- To stabilise electricity market prices, the EU introduced Contracts for Difference (CfDs) and other long-term market tools. However, also further alternatives like the ones outlined here – such as the Iberian model's subsidised gas price caps or WIFO's proposal to partially refund carbon costs – should reduce power generation costs in the short run but risk market distortions or over-complexity.
- A comprehensive transition to a flexible low-carbon power system would make electricity prices less dependent on gas costs. Such a transition requires an expanded deployment of non-fossil energy, a balanced wind-solar mix, greater storage capacity, stronger power grids and smart demand management. Austria's latest energy legislation takes steps in this direction. At the same time, higher competition could encourage electricity suppliers to pass on cost savings from renewable energy to customers.
- Eventually, low-carbon energy transition should deliver lower and stable (wholesale) electricity prices. In the short run, however, the variable power output of wind and solar plants may cause electricity prices to fluctuate. Nevertheless, greater system flexibility may prove more effective over time than short-term fixes that add regulatory complexity and risk distorting electricity markets.

2 The merit order dilemma: Costly gas dominates EU power pricing

The doubling of gas prices since the beginning of the war in the Middle East has put electricity costs back at the top of Europe's agenda. Despite the rapid growth of low-cost renewables, wholesale electricity prices continue to closely track gas prices. The fact that electricity prices in Europe are even higher than in other regions of the world puts Europe's industry at a disadvantage compared to producers in cheaper-energy markets. Furthermore, rising power bills make it harder for households to afford essential energy needs. At least partly, these dynamics stem from the way European electricity markets are designed.

The merit order is the wholesale electricity market's version of marginal cost pricing.[1] It means that power plants are dispatched in order of their short-run marginal costs, from cheapest to most expensive (see figure below).[2] The market operator accepts the most expensive supply bid that still meets demand, which thus sets the wholesale electricity price for all plants whose bids were accepted for each quarter

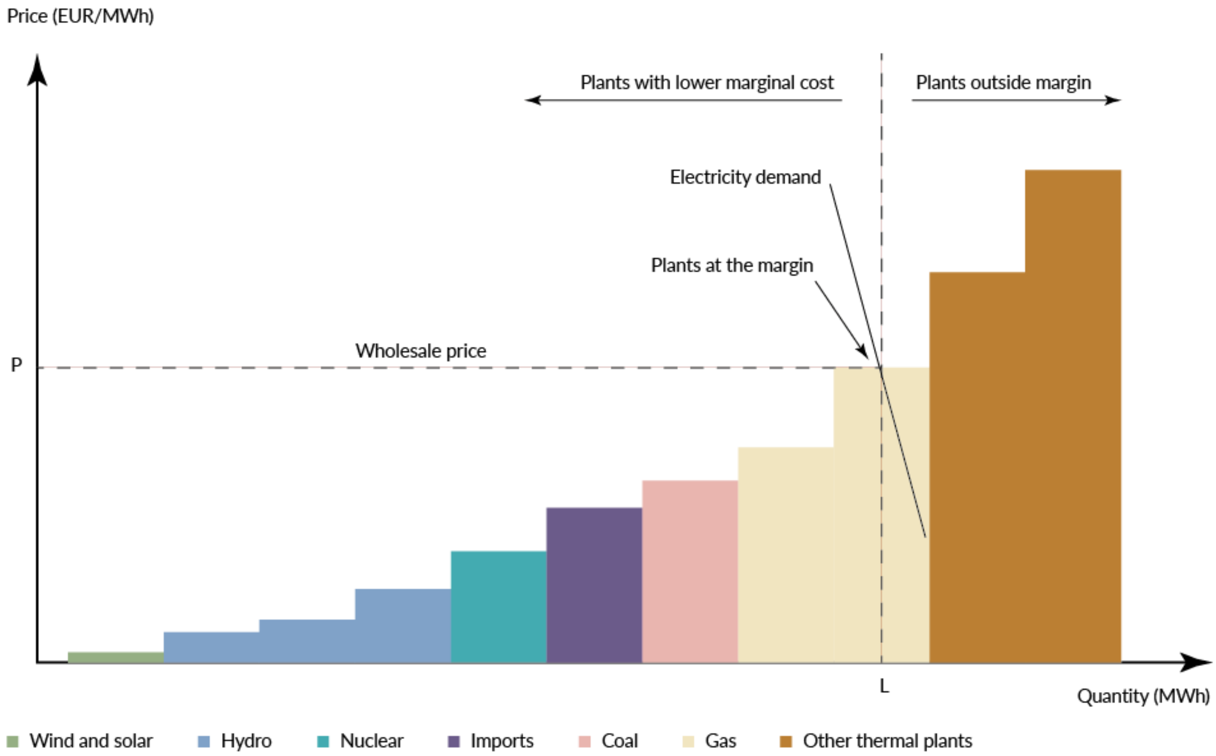
[1]Note that the electricity sector extends far beyond merit order-based wholesale markets. For instance, it also covers regulated grid networks, retail markets, balancing and ancillary-service markets, capacity and flexibility mechanisms as well as a growing range of long-term contracting arrangements. Beyond electricity markets, merit order principles are used in other markets such as in gas pipeline capacity allocation, hydroelectric reservoir operations and freight rail scheduling.

[2] Grid infrastructure, capacity payments and other system costs are allocated separately and are not part of the dispatch hierarchy.

hour of the following day. Since renewables power plants have near-zero variable costs, they are always dispatched first. This means that average wholesale electricity prices are dampened in the long term as renewable energy capacity and system flexibility expand.

In the short term, however, more costly gas-fired power plants often set European electricity prices, despite their declining share in EU power generation (16.7% in 2025). Their flexibility enables them to increase output quickly when wind and solar output is low or demand spikes. During periods of power scarcity, gas prices have a disproportionate influence on wholesale electricity costs across much of the EU. The extent of this merit order dilemma varies by country. For example, gas sets wholesale electricity prices in almost 90% of hours in Italy but only in 15% of hours in Spain, although the two countries' renewables shares lie much closer together (40% and 55%, respectively). This suggests that the frequency with which gas sets prices depends not only on the size of the share of renewables itself but also on the flexibility of the wider power system.

How the merit order principle works



Source: OeNB based on Zakeri et al. (2023)

However, counterintuitively, expanding renewables may temporarily strengthen rather than weaken the role of gas in electricity price formation. As wind and solar energy first displace coal and nuclear energy, gas becomes the dominant balancing technology. This means that it sets the quarter-hourly marginal wholesale electricity price more often than other technologies, even though its share in power generation is falling.

Merit order pricing is widely regarded as the most efficient mechanism for short-term electricity market operation. By dispatching the lowest-cost generators first and using a single market-clearing price, it promotes efficient allocation, competition, transparency and cross-border electricity trade (Gasparella et al., 2023). However, Christophers (2024) argues that the resulting price volatility creates a paradox in which electricity prices are either too high, fuelling affordability concerns, or too low (sometimes even negative), undermining profitability and investment incentives. At high levels of renewables penetration, the merit order effect may evolve into a cannibalisation effect causing abundant wind and solar energy generation to suppress electricity prices during the very periods in which they generate the most output.[3]

Breaking these dynamics requires a more flexible system supported through

- diversified non-fossil energy sources, in particular a balanced wind-solar mix, as the complementary output profiles of wind and solar power within a day and between seasons can reduce variability and strengthen the security of supply;
- storage capacity, such as grid-scale batteries and pumped-hydro storage, to absorb the output variability of renewables;
- demand-side flexibility, enabled by smart meters, smart appliances, charging infrastructure and dynamic retail pricing, to shift consumption away from peak-price hours;
- stronger transmission grids that interconnect regional power networks to move surplus power to where it is needed.

Completing low-carbon energy transition in this way will help balance the electricity system without defaulting to gas in periods when wind and sunshine are low.

Recognising these challenges, the International Energy Agency (IEA, 2026) called on Austria to close the gap between ambition and delivery by accelerating investment in renewables, grids, storage and flexibility, while strengthening electricity market competition to enhance affordability, security of supply and industrial competitiveness. Austria has taken important steps in this direction through the Electricity Industry Act (ElWG)[4] and the Renewable Energy Expansion Acceleration Act (EABG)[5], which modernise electricity market rules and accelerate investment in renewable energy, storage and grid infrastructure.

3 Proposals to amend or replace the merit order

The paradoxical merit order dilemma has sparked a broad debate on the design of electricity markets. In 2022, Ursula von der Leyen, President of the European Commission, declared, "This market system does not work anymore. We have to reform it." Subsequent debates on reforming the design of the EU electricity market resulted in the 2024 EU Electricity Market Directive. The directive, however, left the merit order largely unchanged while adding mechanisms to reduce volatility and improve flexibility. In this vein, the EU introduced Contracts for Difference (CfDs), which stabilise revenues for electricity produced by new non-fossil power plants by guaranteeing a predefined strike price. Producers receive public compensation when market prices fall below the strike price and pay back excess revenues when prices rise above it. The EU also introduced a framework for private long-term power purchase agreements (PPAs) between companies and power producers, aimed at reducing price risk. Furthermore, it created incentives for electricity companies to invest in new power generation capacity even when full utilisation is not guaranteed and to increase the flexibility of the electricity system (e.g. through storage). Additionally, the EU has required member states to strengthen consumer protection during energy crises. All this leaves the wholesale price mechanism itself unchanged – gas-fired power plants can still set the

[3] Voicing similar criticism, Preinstorfer (2026) and Schleicher (2026) call for a fundamental debate on a broader reform of the electricity market system.

[4] https://www.parlament.gv.at/aktuelles/pk/jahr_2025/pk1179.

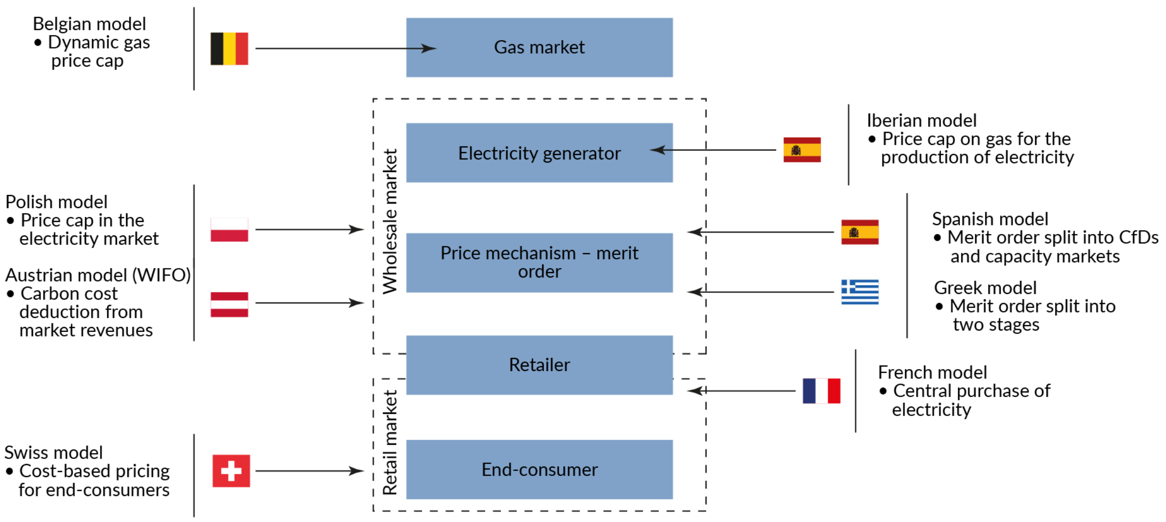
[5] https://www.parlament.gv.at/aktuelles/pk/jahr_2026/pk0622#XXVIII_I_00449.

marginal price – but shields producer revenues from its volatility, supporting investment in low-carbon capacity.

Alternative reform models proposed by member states, such as replacing the current pay-as-clear system with a pay-as-bid system, were rejected for fear of non-linear effects and perverse incentives that would benefit free-riders. For example, generators would have incentives to inflate bids towards the expected clearing price while firms with better market intelligence could capture disproportionate rents without contributing additional efficiency. National intervention models offer targeted relief as the chart below illustrates. These models range from price caps in Belgium, Poland and on the Iberian peninsula to more structural interventions such as France's centralised purchasing of electricity, Greece's dual pricing and Italy's ETS carbon cost reimbursement. However, they have been criticised for distorting market signals, weakening investment incentives and creating coordination problems. Neither has proven to be easily scalable as an EU-wide structural reform as they rely on local conditions that are difficult to replicate elsewhere.

In early 2026, Austria revived the debate with a non-paper proposal presented at the EU Energy Council. The proposal aimed at enhancing electricity market transparency by identifying which technologies set power prices and by breaking down CO_2 costs. This would help to ensure that fossil fuel and carbon allowance costs do not inflate electricity prices despite abundant renewable power generation.[6] Finster et al. (2026) from the Austrian Institute of Economic Research (WIFO) go beyond merely enhancing transparency by proposing a direct CO_2 proxy deduction from infra-marginal rents above a certain price threshold. This threshold could be implemented either at EU level (through the electricity exchange) or at the national level (through the tax system). Finster et al. (2026) effectively reject the "law of one price", arguing that renewables require stable revenue streams rather than emergency price caps (e.g. Austria's electricity price cap, the Strompreisbremse). This approach is based on compelling economic arguments for reducing windfall profits driven by fossil fuels. Implementing it would introduce additional complexity, however.

Overview of proposed models and impact on market functioning



Source: OeNB based on Wendtner (2023).

[6] https://www.bmwet.gv.at/Presse/Archiv/BMWET-Pressemeldungen-2026/pa-bmwet-2026-04/Strommarktreform.html.

One underdeveloped aspect of the reform debate in Austria is that energy providers are not legally required to charge the full marginal price. Their reluctance to pass on cost advantages to customers might signal weak competition. In that sense, the IEA (2026) noted in its report on Austria that “further action is needed to strengthen competition in the electricity market”. Some utilities, such as TIWAG-Tiroler Wasserkraft AG in western Austria, have experimented with more competitive pricing (e.g. a EUR 0.049/kWh summer tariff) to ease the price burden on consumers.

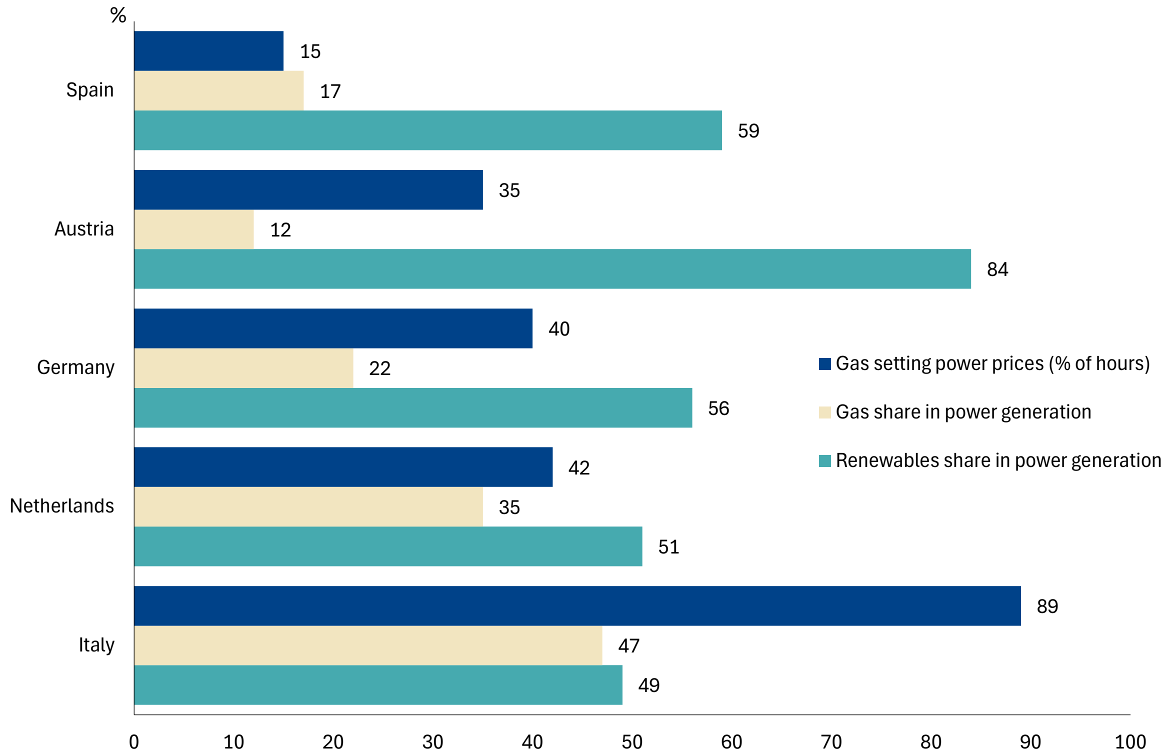
The trade-offs involved in the various proposals are summarised in the first table in the annex. Notably, the Nordic countries stand out as the only case without direct market intervention. The second table in the annex gives an overview of alternative electricity market structures, ranging from centrally planned systems in China and India to liberalised wholesale markets in the USA and Japan and from contract-dominated models in France and the Nordics to cost-based dispatch in Latin America. None of these has proven clearly superior to Europe’s liberalised electricity market architecture as each involves its own trade-off between price efficiency, investment incentives, consumer protection and public finance costs.

4 Empirical evidence of the gas-electricity price nexus

Gas-fired power plants set electricity prices far more often than their share in power generation would suggest. Zakeri et al. (2023) show that, for the EU-27 plus the United Kingdom and Norway between 2015 and 2021, natural gas generated only 18% of electricity in Europe, yet gas-fired power plants set around 39% of hourly wholesale prices. Fossil fuel plants taken together were responsible for 58% of hourly prices despite producing no more than 34% of power output. This asymmetry reflects the interaction between renewables and the merit order: Wind and solar technologies displace coal and other baseload technologies but do not eliminate the need for flexible power generation during hours of low renewables output or high demand. As a result, gas-fired power plants – the dominant flexible technology – remain decisive in price formation even as their share in total power generation declines.

Global energy think tank Ember’s recent country comparison (Rosslowe and Petrovich, 2025) of the influence of gas on power prices identifies Italy as the country with the highest percentage of hours in which gas sets the power price (89%), while this share is lowest in Spain at 15%. However, the gap between the two countries’ renewables shares in power generation (40% and 55%, respectively) is nowhere near as wide.

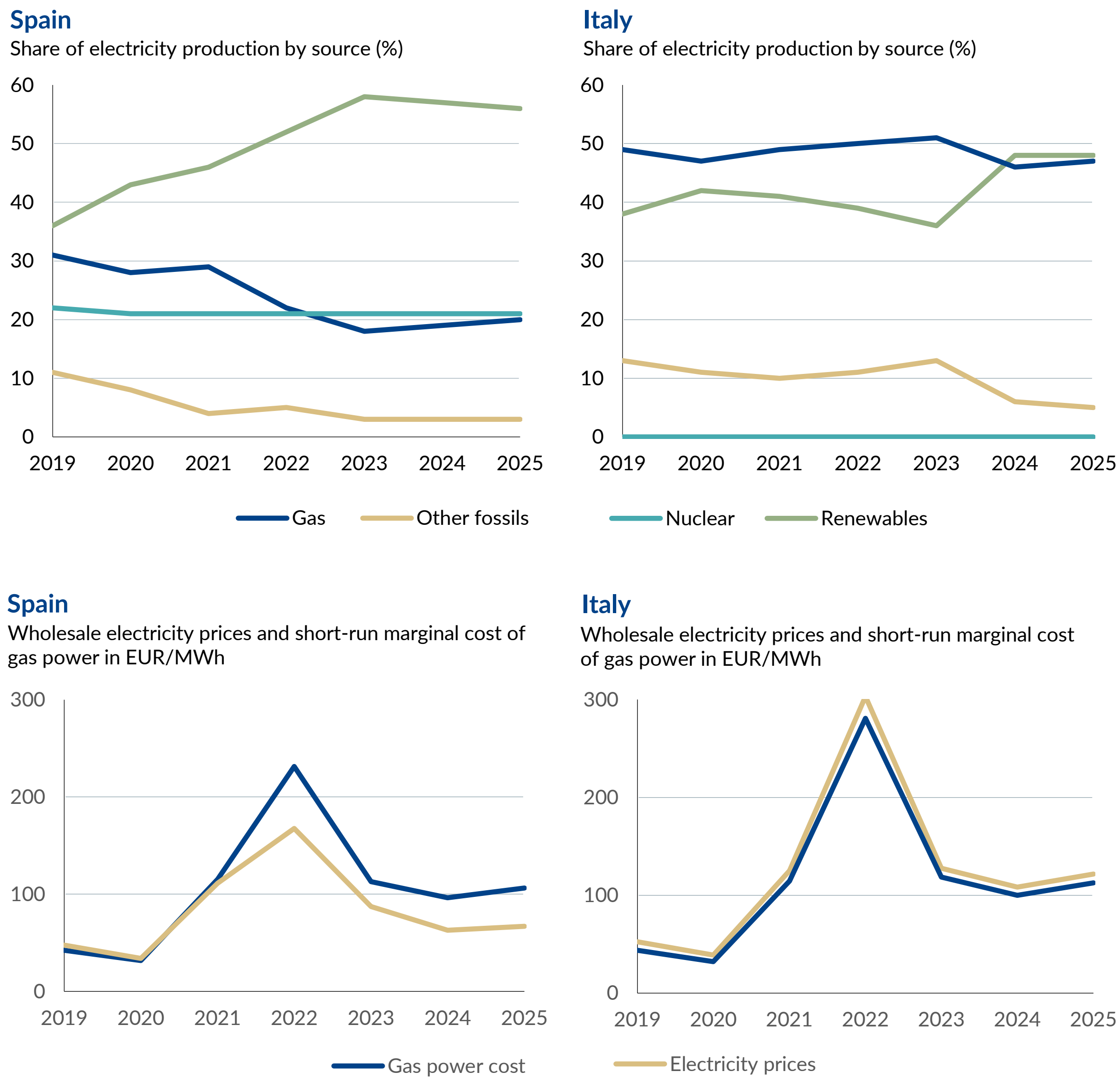
Gas price influence on wholesale electricity prices and gas share in power generation (2025–2026)



Source: Ember (2026; gas price influence); OeNB estimate (2025; Austria); Our World in Data (2025; shares in power generation).

So why do relatively similar power generation mixes lead to such different prices? The answer lies in system flexibility. Spain benefits from pumped-storage hydro power, a diversified wind fleet and a strong interconnection between the two, which together reduce residual electricity demand met by gas. As Rosslowe and Petrovich (2025) document, renewables in Spain increasingly displace gas directly – a result of the country's capacity of pumped-storage hydro power and interconnection, which lets solar and wind technologies cover the balancing role that gas still plays elsewhere. In Italy, by contrast, which lacks a comparable capacity for flexibility, renewables have primarily displaced coal, leaving gas as the dominant marginal technology. Zakeri et al. (2023) confirm that the frequency with which gas determines prices depends less on the market shares of renewables as such than on the availability of flexible non-fossil fuel capacity. The charts below show that declining gas generation tends to reduce the price-setting power of gas, although not automatically or proportionally.

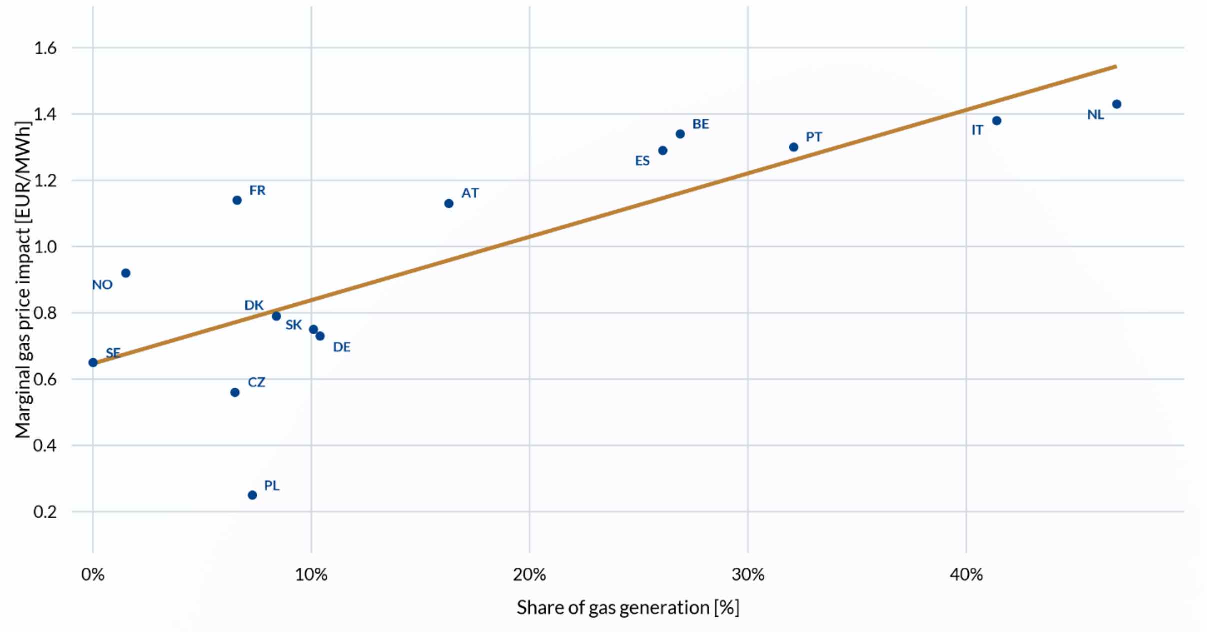
Comparing electricity sources and prices in Spain and Italy from 2019 to 2025



Source: Top panels: Our World in Data (Ember, 2026; Energy Institute – Statistical Review of World Energy, 2025); bottom panels: Rosslowe and Petrovich (2025; Ember, ENTSO-E, LCCC).

Empirical literature quantifies the respective gas-to-electricity price pass-through. Kosch et al. (2022) estimate that a EUR 1/MWh increase in gas prices raised electricity prices by EUR 0.2–1.4/MWh across 14 European countries around 2020, with the highest pass-through in systems with a high share of gas in their power generation mix, such as in Italy and the Netherlands (see chart below). Countries with substantial hydro or nuclear capacity – such as Sweden – exhibit a lower sensitivity to gas price rises. Furthermore, the same study attributes the 2021 electricity price surge in Europe overwhelmingly to gas: Rising gas prices accounted for an average increase in power prices of approximately EUR 110/MWh across their sample, while carbon price increases contributed only around EUR 20/MWh. This finding underscores that, although the EU's Emission Trading System (ETS) influences marginal costs, market-driven fuel prices dominate short-run electricity price dynamics. These pass-through estimates line up with more recent macroeconomic evidence: Colombo and Toni (2025) confirm that gas price shocks transmit almost one-to-one to electricity prices in markets where both demand and supply are inelastic in the short run.

Impact of gas and carbon prices on electricity prices from 2018 to 2021



Source: Kosch et al. (2022).

The 2022 energy crisis further exposed the central role of gas in European electricity pricing. Mier (2025) finds that of the increase in European wholesale electricity prices from about EUR 80/MWh to EUR 270/MWh, 84.7% were attributable to higher gas prices, while reduced French nuclear availability and lower hydro energy output accounted for 9.4% and 5.9%, respectively. In France, nuclear outages explained nearly 23% of the domestic power price rise, whereas in Germany, 83% of the power price increase was driven by gas. These results confirm that Europe's electricity price surge in this period was fundamentally a gas price shock transmitted through the marginal pricing mechanism. That shock was compounded by outages in the French nuclear fleet and drought-induced declines in European hydro power generation, which increased the reliance on gas-fired generation.

System flexibility is again the decisive factor: Without it, renewables expansion initially displaces coal or nuclear technologies rather than gas. This temporarily increases the frequency with which gas sets the price of electricity even as its share in power generation is falling. Grid-scale batteries, pumped-hydro storage, interregional transmission capacity, demand-side responsiveness and dynamic retail pricing all help absorb the variable output of wind and solar power plants and reduce residual demand peaks, limiting the role of gas-fired plants during hours of scarcity.

The short-run demand and supply inelasticity found by Colombo and Toni (2025) shows up at the macro level, too: Alessandri and Gazzani (2025) show that gas supply shocks accounted for a significant share of euro area inflation between 2021 and 2023, with the electricity sector acting as the key transmission channel. These dynamics were further strengthened after 2022 by precautionary inventory accumulation and heightened financial volatility following the sharp reduction in Russian pipeline flows. Uribe et al. (2022) add that this co-movement is asymmetric: Upward gas price shocks transmit more strongly to electricity prices than downward shocks, reinforcing the vulnerability of European electricity markets during crises.

Cross-country variation reflects differences in flexibility and interconnection. In Belgium, the United Kingdom, Greece, Italy and the Netherlands, gas set the power price in more than 80% of hours in 2021 (Zakeri et al., 2023). In contrast, the Nordic countries, combining high renewables shares (including hydro power) and strong cross-border power interconnections, and Spain with its focus on solar and wind power and on system flexibility, record a much lower frequency. Austria does not obviously fit this pattern: Despite its high share of renewables in power generation, wholesale electricity prices remain strongly correlated with natural gas prices at the Dutch Title Transfer Facility (TTF). This is mainly because Austria's and Germany's electricity markets are interconnected, so Austria imports Germany's gas-driven price signals even in hours when domestic renewables output alone would be sufficient. As a result, electricity prices in both countries moved almost in line with natural gas prices, and this gas-driven co-movement intensified during the 2021–2022 power price surge.

Although expanding renewables lowers average electricity costs in the long run through the merit order effect – provided the system is sufficiently flexible – it does not automatically reduce the short-run influence of gas prices on electricity prices. Initially, as renewables displace coal and other conventional power generation, gas remains the balancing technology and sets the marginal electricity price. For a genuine decoupling of gas and electricity prices, growing renewables deployment must be accompanied by greater system flexibility. Increased storage capacity, stronger demand-side response and improved grid interconnection can reduce the number of hours in which gas sets the marginal electricity price – as Spain's experience suggests. As long as non-fossil flexibility is insufficient, however, energy security will continue to depend on gas, its storage capacity and diversified supply sources as well as temporary demand reductions in case of power shortages. In the meantime, enforced price transparency may encourage electricity suppliers to pass on the lower costs of producing renewable energy to consumers.

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6 Annex

Proposals to reform or amend merit order pricing in Europe

Proposal	Features	Pros	Cons	Policy implications
Iberian model (Spain/Portugal)	Temporary cap on gas (and coal) input costs for power generation Compensation via congestion rents and consumer charges	Rapid price reduction Targeted crisis relief	Distorts investment signals Requires compensation Cross-border spillovers	Only possible in closed regional markets; short-term emergency tool, not a structural reform
Greek model	Ex post revenue recovery using administered reference prices by technology	Protects households from price spikes Maintains market design, EU-compatible	High administrative complexity Regulatory uncertainty	Requires clear governance and sunset clauses
Italian reform (2026)	Reimbursement of ETS carbon costs for gas-fired power plants, reducing CO_2 pass-through into marginal electricity prices	Strong wholesale price reduction Targeted relief for industry	Weakens ETS price signal Distorts investment incentives	Direct challenge to merit order pricing and EU ETS compatibility
French proposal	Central agency purchases all wholesale electricity at spot prices and auctions capacity contracts for fossil-powered plants	Stable procurement Reflects cost structure	Market fragmentation Raises EU competition concerns	Challenges the internal electricity market
Swiss model	Heavy reliance on long-term contracts; limited exposure to spot markets and retail competition; regulated consumer prices	Low price volatility Industrial predictability	Limited transparency Weak price signals	Highlights role of contractual de-risking
WIFO paper (Finster et al., 2026)	Above-threshold deduction of average carbon cost from infra-marginal rents to consumers	Reduces gas price pass-through Cost-reflective	Complex redesign Bidding risk	Implies EU market overhaul or national workaround
Belgian proposal (2022–2023)	EU-wide dynamic gas price cap; temporary trading suspension rules	Harmonised windfall profit capture Consumer relief	Weakens investment incentives if permanent	Appropriate only as temporary EU safeguard
Polish proposal (2022)	Gas price cap on imports; shift to pay-as-bid; ex ante bid review; spot price cap with ex post surplus redistribution	Limited market intervention Energy security focus	High-emission conflicts with EU climate law	Incompatible with EU de-carbonisation path
Electricity price cap (Austria/Germany)	Revenue caps plus consumer price relief funded by infra-marginal revenue levy	Effective crisis protection	Distorts price signals Only implicitly socially targeted	Crisis management tool, not a market reform
Nordic model (Denmark/Sweden/Finland)	No price intervention, high renewable share Strong cross-border integration and zonal pricing	Efficient dispatch EU-compatible	High price volatility Geography-dependent (hydro reliance)	Long-term benchmark, not a short-term fix

Source: OeNB.

Comparative overview of electricity market structures outside Europe

Model	Countries	Market character	Role of marginal pricing	Core distinction	Policy implication
Regulated or vertically integrated systems	China, India, USA (non-ISO areas), South Korea	Administrative or single-buyer	Largely absent; prices set by regulator or utility	Centralised planning replaces competitive bidding	Ensures supply security but discourages efficiency and innovation; limited transparency
Liberalised ISO markets	USA (PJM, CAIS, MISO); Japan	Competitive wholesale markets	Fully applied	Standard merit-order dispatch; fuel costs drive prices	Efficient dispatch but vulnerable to input-price shocks
Contract-dominated systems	France, Nordic countries, parts of Latin America	Markets exist but long-term contracts dominate	Present only at the margin	Long-term contracts or regulated procurement (e.g. French nuclear, Nordic hydro) decouple generator revenues from spot prices	Offers stability for consumers; reduces price signals for new investment
Cost-based centralised dispatch	Brazil, Chile, Colombia	Centrally optimised with verified cost data	Implicit; prices are derived administratively	Based on audited production costs, not market bids	Enhances transparency; limits strategic bidding; less dynamic efficiency
Hybrid single-buyer models	Malaysia, Vietnam, Thailand	Transitional or mixed regimes	Minimal; contractual scheduling prevails	Central procurement with limited market trading	Facilitates investment in early stages of liberalisation; restricts competition and flexibility

Source: OeNB.

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