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Explaining the emergence and expansion of negative electricity prices across Europe

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ABSTRACT

Negative electricity prices have become increasingly frequent across European power markets in recent years, raising critical challenges for market participants, policymakers, and researchers. While much of the existing empirical literature has focused on Germany, where negative prices first appeared in 2008, this study systematically analyzes and compares their drivers across 20 European electricity markets. Using hourly data for the period 2015–2024, we employ both country-specific and panel logistic regression models to identify the fundamental determinants of negative price events. The results reveal broad commonalities across markets, complemented by notable country-specific deviations. Negative prices exhibit strong persistence and pronounced seasonal patterns, while higher electricity demand systematically reduces their likelihood. The generation mix proves decisive: higher combined wind and solar generation is positively associated with the probability of negative price, whereas the effects of other renewables (e.g., biomass, geothermal, hydro) vary by country. By contrast, non-renewable generation is generally associated with a lower probability of negative prices, although the strength of this relationship varies across countries, while the role of cross-border electricity flows remains heterogeneous and context-dependent.

1. Introduction

In recent years, negative electricity prices have become a recurring phenomenon in many European power markets. Originally considered rare and exceptional, they have become increasingly frequent across European power markets, raising critical questions for market participants, policymakers, and researchers alike. From the perspective of standard microeconomic theory, negative prices should not occur, as no rational seller would willingly dispose of a good at a loss. However, electricity markets differ fundamentally from typical goods markets: negative prices are not inherently irrational but instead reflect the specific characteristics and technical constraints of power systems.

Indeed, over the past decade, the occurrence of negative electricity prices in European markets has already risen markedly, with the trend pointing to a growing relevance of this phenomenon across countries. In 2015, fewer than 500 hourly intervals across all monitored markets recorded negative prices, corresponding to only about 0.24% of all observed hours. By 2024, that number had surged to more than 6000, corresponding to roughly 3.45% of all observed hours, reflecting a more than tenfold increase and underscoring a major transformation in market dynamics. What was once an extremely rare phenomenon, largely confined to a few countries like Austria, Czech Republic, Denmark, Germany, and Slovakia, has now become a frequent feature across nearly all major European electricity markets, whereby markets like Spain and Portugal only encountered negative prices for the first time in 2024, see Fig. 1.

This development has important welfare and market-design implications. While negative prices can constitute efficient market signals under specific operational constraints and institutional settings, persistently frequent negative-price episodes may also indicate insufficient system flexibility and distorted incentives. Such episodes can affect short-run dispatch decisions as well as longer-term investment incentives for generation, storage, demand response, and other flexibility assets. Understanding the conditions under which negative prices emerge is therefore important for evaluating the efficiency and resilience of European electricity markets and for informing policymakers' efforts to preserve efficient price signals while facilitating the energy transition.

This shift has far-reaching implications. From a welfare and market-design perspective, frequent negative-price episodes may signal allocative inefficiency, implying inefficient resource use: in such hours, marginal generation exceeds contemporaneous marginal willingness to pay, and resources are allocated to electricity that cannot be absorbed economically through storage or flexible demand. Persistent negative prices therefore point to coordination frictions and insufficient system flexibility, and they can distort both short-run dispatch decisions and

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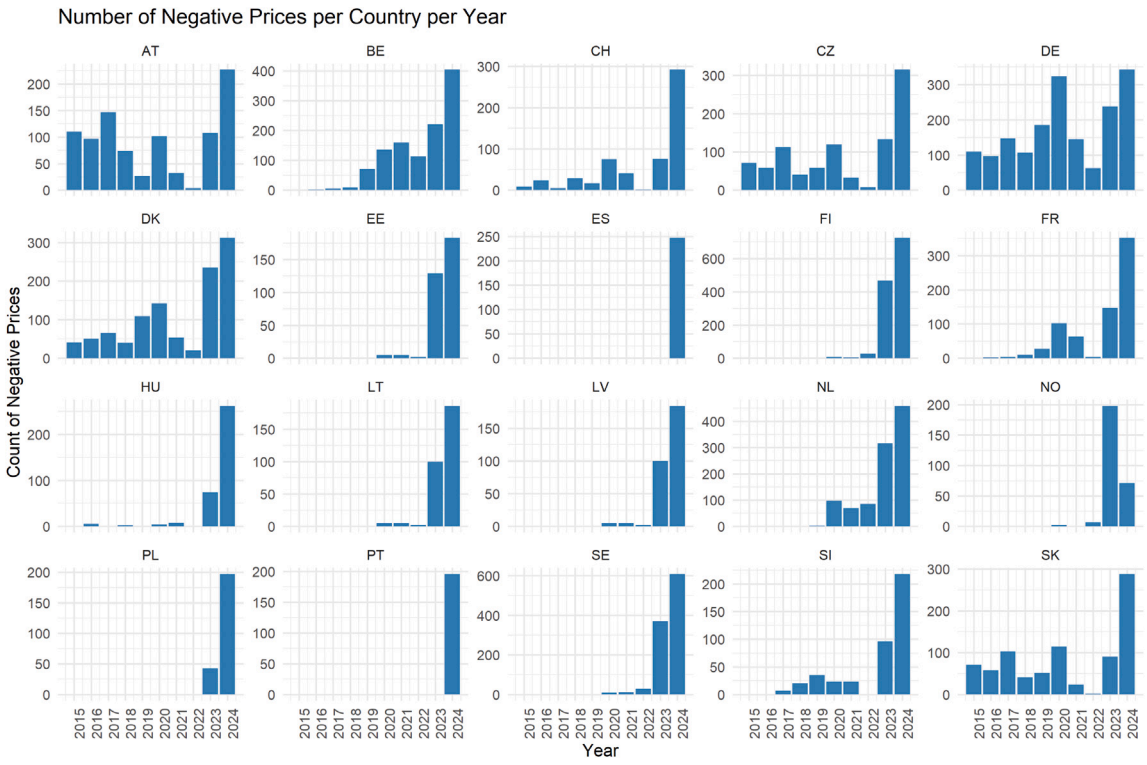


Fig. 1. Annual distribution of negative price occurrences in European electricity markets,2015–2024.
Notes: The figure displays, for each country in the sample, the total number of hourly intervals with negative day-ahead market prices in each year from 2015 to 2024. Data are based on hourly day-ahead price series from ENTSO-E Transparency Platform (2024).

long-run investment incentives for generation and flexibility assets. This underscores the importance of mitigating allocatively inefficient negative price episodes and calls for a deeper investigation into their underlying drivers, including temporal patterns, technological determinants, and cross-country variation. Understanding when and why prices turn negative is essential for evaluating the efficiency and resilience of current market structures and for shaping future energy policy across Europe. This knowledge is critical for market participants, who must adapt their risk management and operational strategies; for grid operators, who face growing challenges in balancing supply and demand; and for policymakers, who must address market signals that risk discouraging investment in flexibility, storage, and demand response.

Against this background, our study addresses two central research questions. First, which seasonal, demand-side, generation-related, and persistence factors determine the probability of negative electricity prices across European electricity markets? Second, to what extent can cross-border electricity flows mitigate or amplify negative-price events, and how do these relationships differ across national markets?

Despite the increasing prevalence of negative prices across Europe, much of the existing empirical evidence is necessarily based on earlier periods and remains concentrated on Germany, where negative prices emerged comparatively early. As a result, systematic cross-country comparisons remain rare, and no study to date comprehensively analyzes and contrasts the drivers of negative price events across a broad set of European electricity markets using a unified empirical framework. This gap is particularly relevant given the pronounced heterogeneity in renewable expansion, market regulation, generation portfolios, and system flexibility across countries, alongside the European Union's objective of deepening cross-border integration toward a single European electricity market.

To address this gap, this study makes three main contributions to the literature on negative electricity prices. First, we substantially broaden the empirical scope beyond the predominantly Germany-focused literature by providing a systematic analysis of 20 European electricity markets. Importantly, we combine country-specific logistic regressions with a complementary panel model, allowing us to identify both market-specific determinants of negative prices and relationships that hold systematically across European markets. This dual-model design therefore provides a more comprehensive assessment of negative-price formation across heterogeneous electricity systems than single-country analyses. Second, beyond domestic demand and generation, we explicitly incorporate cross-border electricity flows, enabling us to assess whether international electricity trade mitigates or amplifies the likelihood of negative price events. This extends the set of potential drivers considered in the existing literature and is particularly relevant given the European Union's objective of deeper market integration and expanding interconnection. Third, we introduce a more flexible representation of recurring temporal patterns by modeling intra-day, intra-week, and intra-year seasonality using cyclical sine-cosine transformations rather than conventional seasonal dummy variables. This specification explicitly accounts for the cyclical nature of electricity-market seasonality, avoids artificial discontinuities between adjacent periods, and provides a smooth and economically interpretable representation of recurring temporal patterns.

Using hourly market and system data from 2015 to 2024, we estimate logistic regression models to explain the occurrence of negative electricity prices as a function of seasonal patterns, the persistence of negative prices, domestic electricity load, cross-border electricity flows (exports and imports), and the technology mix of generation (e.g., solar and wind, other renewables, non-renewables, and nuclear). Hereby, our approach allows for isolating the effects of each explanatory factor on the likelihood of a negative price hour, while also controlling for systematic seasonal variation in price behavior. Importantly, our study goes beyond the German case, which has experienced negative prices since 2008, due to its early expansion of renewable capacity combined with inflexible conventional generation. In contrast, other markets,

such as Spain and Portugal, have only recently seen negative prices, with the first occurrences observed in 2024. This heterogeneity provides a unique opportunity to investigate the underlying mechanisms behind negative price events and whether they differ across markets.

Overall, our results indicate broad commonalities in the determinants of negative prices across European electricity markets, alongside some notable country-specific deviations. Seasonal patterns emerge as a key driver, while the occurrence of a negative price in the preceding 24 h strongly increases the likelihood of another, indicating pronounced persistence. In addition, higher electricity demand consistently reduces the probability of negative prices. Moreover, the generation mix plays a central role: higher combined wind and solar generation is positively associated with the probability of negative prices in the baseline specification, although technology-specific robustness analyses indicate that this relationship is more consistently driven by solar generation, while the wind effect is more heterogeneous across countries. In addition, the influence of other renewable sources, such as biomass, geothermal, and hydro, varies across countries. Further, non-renewable generation is generally associated with a lower probability of negative prices, although the strength of this relationship varies across countries. Further, the panel logistic regression model is estimated over the common sample period from January to December 2024, ensuring full cross-country comparability, and additionally over the unbalanced sample from 2015 to 2024 as a robustness check. The results of both specifications largely confirm the country-specific findings, reaffirming the importance of seasonal patterns, demand levels, wind and solar generation, and the persistence of negative-price events across European electricity markets.

By systematically comparing the drivers across countries, this study contributes to a better understanding of the market dynamics that lead to negative prices and highlight how national electricity systems respond differently to structural and operational stress. Hereby, the Europe-wide analysis does not only identify common drivers but also uncovers regional specificities shaped by differences in generation portfolios, interconnection capacity, and market design. This insight is crucial not only for market participants and system operators, but also for policymakers aiming to design more resilient electricity markets amid the ongoing energy transition.

The remainder of the paper is structured as follows. Section 2 reviews the economic mechanisms underlying negative electricity prices and the related empirical literature. Section 3 outlines the empirical framework, detailing the country-specific and panel logistic regression specifications. Section 4 describes the data sources and the explanatory variables capturing demand conditions, generation by technology, cross-border flows, persistence, and seasonal patterns. Section 5 presents and discusses the main estimation results, contrasts cross-country and panel findings, and reports a set of robustness checks to assess the stability of the conclusions. Finally, Section 6 summarizes the main insights and derives policy implications.

2. Literature review and background on negative electricity prices

2.1. Economic mechanisms of negative electricity prices

Negative electricity prices arise when the physical and institutional characteristics of power systems prevent supply and demand from adjusting sufficiently to temporary imbalances. In particular, limited storage capacity and inflexible load adjustments restrict the system's ability to balance fluctuations in generation in real time, as emphasized by Keles et al. (2012). In practice, negative prices emerge when limited short-run demand flexibility meets supply that cannot be adjusted quickly enough.

On the supply side, such conditions can arise through two main mechanisms. First, weather-dependent renewables such as wind and solar generate according to meteorological conditions and, under many support schemes (e.g., priority dispatch or fixed remuneration), may be insulated from short-term market prices. As a result, renewable output can remain high even during periods of weak demand. Second, conventional generation may be unable or unwilling to reduce output rapidly because shutting down and restarting units involves technical constraints, start-up costs, and minimum downtime requirements, making it economically preferable to remain online even at negative prices, as argued by Davi-Arderius and Jamasb (2026), Genoese et al. (2010) and Schneider (2010). Institutional features can further reinforce these mechanisms by weakening incentives to curtail generation when prices fall below zero, according to Aust and Horsch (2020).

However, negative prices should not necessarily be interpreted as a sign of market inefficiency. In particular, Rafizadeh (2026) argues that, in the presence of operational constraints and production subsidies, allowing prices to become negative can facilitate welfare-maximizing market clearing by providing an efficient signal of temporary excess supply. At the same time, Davi-Arderius and Jamasb (2026) show for the Spanish electricity market that zero and negative day-ahead prices can coincide with additional system-balancing costs, indicating that wholesale price signals do not necessarily reflect the full operating costs of increasingly renewable-based power systems. Hence, the relevant policy concern is not the occurrence of negative prices per se, but whether their increasing frequency reflects persistent system inflexibilities or distorted incentives. Such episodes can arise from the interaction of limited demand flexibility, weather-driven renewable surpluses, and the operational inflexibility of conventional generation. The extent to which these imbalances can be mitigated, however, also depends on the institutional conditions under which flexibility resources can participate in electricity markets. Pedro et al. (2023), for example, document substantial cross-country differences in market access and regulatory conditions for small-scale flexibility across European markets. More broadly, Tutar and Štreimikienė (2026) show for the EU-27 that renewable integration is itself shaped by heterogeneous policy and system conditions, particularly market design and grid flexibility, with differing effects across wind and solar technologies. Against this background, continued growth in variable renewable generation is likely to increase the relevance of negative-price episodes unless flexibility options expand in parallel.

2.2. Empirical evidence on negative-price determinants

The empirical literature has examined the market conditions under which negative electricity prices arise and sought to disentangle their underlying drivers. At the core lies the merit-order effect, whereby renewable energy sources with near-zero marginal costs shift the supply curve outward and thereby exert downward pressure on market-clearing prices. Numerous studies confirm the price-depressing effect of wind and solar generation in various European markets, including Spain Ballester and Furió (2015), the United Kingdom (Brancucci Martinez-Anido et al., 2016), Italy (Clò et al., 2015; Sapio, 2019), Germany (Dillig et al., 2016; Ketterer, 2014; Maciejowska, 2020; Paraschiv et al., 2014; Würzburg et al., 2013), Turkey (Gökgöz and Yücel, 2024), Portugal (Macedo et al., 2020), the Iberian market (Figueiredo and da Silva, 2019), and Greece (Maniatis and Milonas, 2022).

Beyond the general influence of renewables on price levels, several studies focus explicitly on the occurrence of negative price events. Using historical data from the German electricity market, Bublitz et al. (2017), Genoese et al. (2010), and Paraschiv et al. (2014) document recurring patterns in hourly day-ahead spot prices based on descriptive evidence, offering an initial characterization of negative-price episodes. Specifically, Bublitz et al. (2017) identify low system load as a key driver of negative price hours over 2011–2015, while Paraschiv et al. (2014) emphasize that negative spot prices over 2010–2013 tend to occur when high wind generation coincides with weak demand. Focusing on an earlier period from 2008 to 2009, Genoese et al. (2010) provide a more nuanced characterization, showing that negative prices typically arise either when low demand coincides with moderate wind output or

when moderate demand aligns with high wind generation, highlighting the interaction between supply- and demand-side imbalances. Taken together, these findings confirm that negative prices are fundamentally the result of oversupply situations in Germany, when large volumes of wind and solar generation with near-zero marginal costs and supported by guaranteed feed-in tariffs confront insufficient demand. Extending this perspective, Gerster (2016) estimates a regime-switching model for German day-ahead prices over 2009–2012, focusing on off-peak hours (8 p.m.-8 a.m.), and finds that more ambitious renewable expansion is associated with a higher frequency of low or negative price episodes. However, the study also finds that complementary measures, such as nuclear phase-outs or the expansion of storage capacity, can offset these effects by enhancing system flexibility.

Building on these contributions, Aust and Horsch (2020), Biber et al. (2022), and Hagfors et al. (2016) use logistic regression to perform statistical inference on the determinants of negative-price events exclusively in the German day-ahead market, i.e., they model how market fundamentals affect the probability that an hourly price turns negative. Using hourly spot prices from January 2010 to May 2014, Hagfors et al. (2016) model each delivery hour separately to analyze extreme price occurrences and focus, in particular, on trading period 3 to identify the determinants of negative prices. Their specification includes technology-specific generation, fuel prices, emission allowance prices, and price volatility, and their results indicate that negative prices are closely associated with the combination of low demand and high wind generation. Building on this approach, Aust and Horsch (2020) analyze hourly spot prices from 2013 to 2016 and model the probability of negative prices as a function of wind and solar generation, residual load, and seasonal controls. They find a significant negative relationship between residual load and the incidence of negative prices, while reporting less robust evidence for a causal role of renewables infeed alone or lagged price-related components. More recently, Biber et al. (2022) estimate logistic regression models for low (below 10 Euro/MWh) and negative electricity prices over 2019–2021, using a set of fundamentals that includes technology-specific generation, system load, fuel prices, CO_2 allowance prices, and seasonal controls. Their results indicate that greater system tightness and flexibility, captured by higher load, higher conventional output, and the availability of flexible gas-fired generation, are associated with higher and more stable prices. While higher CO_2 allowance prices tend to reduce the likelihood of negative prices by shifting dispatch away from relatively inflexible coal toward more flexible gas units, greater wind and solar infeed increases the probability of negative-price events. Their forward-looking scenario analysis further indicates that, absent additional flexibility on the supply and demand side, the frequency of low and negative price events is likely to increase by 2030.

Taken together, the German evidence suggests that negative-price episodes are likely to become more common as renewable penetration rises. However, while negative prices have only recently become widespread across European power markets, much of the existing empirical evidence is necessarily based on earlier periods and is concentrated on Germany, where negative prices emerged first. The resulting lack of systematic cross-country evidence motivates the Europe-wide empirical analysis developed in the following sections. As a result, systematic cross-country comparisons remain rare, and no study to date comprehensively analyzes and contrasts the drivers of negative price events across multiple European electricity markets. This gap is particularly relevant given the growing heterogeneity in renewable expansion, market regulation, and generation portfolios, alongside the EU policy objective of deepening cross-border market integration toward a single European electricity market and motivates the Europe-wide empirical analysis developed in the following sections.

3. Methodology

To identify and quantify the key drivers of negative electricity prices in European day-ahead markets this study applies logistic regression models, which are a well-established statistical technique for modeling the probability of a binary outcome as a function of one or more explanatory variables, see Aust and Horsch (2020), Biber et al. (2022) and Hagfors et al. (2016). In this context, the model does not predict the exact price level; rather, it estimates the likelihood that a negative price occurs.

Our dependent variable, $neg_price_{i,t}$, is defined as 1 if the day-ahead price in country i at time t is negative, and 0 otherwise. Then, the general specification of the logistic regression model is:

$$\Pr(neg_price_{i,t} = 1 \mid \mathbf{X}_{i,t}) = \frac{\exp\left(\beta_0 + \beta_1 X_{1,i,t} + \beta_2 X_{2,i,t} + \cdots + \beta_K X_{K,i,t}\right)}{1 + \exp\left(\beta_0 + \beta_1 X_{1,i,t} + \beta_2 X_{2,i,t} + \cdots + \beta_K X_{K,i,t}\right)} \tag{1}$$

where $\Pr(neg_price_{i,t} = 1 \mid \mathbf{X}_{i,t})$ denotes the probability of a negative price in country i at time t. Moreover, the coefficients $\beta_{1,i}, \beta_{2,i}, \ldots, \beta_{K,i}$ measure the marginal impact of the explanatory variables $\mathbf{X}_{i,t} = (X_{1,i,t}, X_{2,i,t}, \ldots, X_{K,i,t})'$ on the log-odds of a negative price event, allowing us to assess both the direction and relative importance of the different market factors. Overall, the country-specific logistic regression models capture the unique characteristics and dynamics of each individual electricity market. This approach provides detailed insights into how the explanatory variables affect the probability of negative prices at the national level.

To assess whether these relationships hold more generally across markets, we extend the analysis to a panel logistic regression framework. This approach exploits both cross-country and time-series variation, thereby increasing statistical power and improving the robustness of the results. The panel specification controls for unobserved heterogeneity between countries through fixed effects, thereby capturing persistent, country-specific characteristics, such as regulatory frameworks, market design, or structural differences in generation portfolios, that may be correlated with the explanatory variables. This approach ensures that our estimates rely on within-country variation over time, isolating the impact of load, cross-border flows, and generation mix on the probability of negative prices while netting out time-invariant cross-country differences.

Given that cross-border electricity dynamics and market structures evolve over time, the fixed effects specification provides a rigorous framework for identifying common drivers of negative prices across countries while fully controlling for time-invariant, country-specific heterogeneity. By focusing on within-country variation, this approach ensures that the estimated coefficients are not biased by unobserved structural differences, such as regulatory settings, generation portfolios, or long-run market design, that remain constant over time. The general form of the panel logistic regression model with country fixed effects is given by:

$$\Pr(neg_price_{i,t} = 1 \mid \mathbf{X}_{i,t}) = \frac{\exp\left(\alpha_i + \beta_1 X_{1,i,t} + \beta_2 X_{2,i,t} + \cdots + \beta_K X_{K,i,t}\right)}{1 + \exp\left(\alpha_i + \beta_1 X_{1,i,t} + \beta_2 X_{2,i,t} + \cdots + \beta_K X_{K,i,t}\right)}, \tag{2}$$

where α_i denotes the country-specific fixed effect, capturing all unobserved, time-invariant factors at the country level. This panel framework enables us to identify generalizable patterns in the occurrence of negative prices and to assess the relative importance of supply, demand, and seasonal factors across multiple electricity markets simultaneously.

By estimating both country-specific and panel logistic regression models, we can disentangle market-specific dynamics from general patterns that apply across Europe. The country-level estimations highlight how the drivers of negative prices differ depending on each market's generation mix, demand profile, and institutional framework. The panel

model, in turn, provides a broader perspective by quantifying the average effects of these drivers across all countries while controlling for persistent market heterogeneity. Comparing the two sets of results allows us to identify which determinants are robust across markets and which are highly context-dependent, an important distinction for policymakers, market operators, and investors seeking to design measures that are effective both locally and at the European level.

4. Data

The objective of this study is to explain the occurrence of negative electricity prices. Hereby, we examine hourly electricity prices from 20 European day-ahead markets spanning Northern, Western, Southern, and Central-Eastern Europe. The data, obtained from ENTSO-E Transparency Platform (2024), consist of standardized spot prices expressed in EUR/MWh and harmonized to a uniform time zone to ensure full cross-country comparability. Although the raw dataset covers the period from 1 January 2015 to 31 December 2024,[1] negative price events did not occur throughout the entire horizon in every market, see Fig. 1. In several countries, particularly those where negative prices are a more recent phenomenon, the early years contain too few events to yield reliable statistical inference. To address this, we define market-specific sample periods based on a "one-in-ten" rule, i.e., ensuring a sufficient number of negative-price events relative to the number of explanatory variables. In practice, this implies restricting each country's sample so that negative prices account for at least 1% of hourly observations. This approach preserves the longest feasible time span for each country while ensuring model stability and statistical robustness. The resulting sample periods, the total number of observations as well as the number of negative prices for each market are reported in Table IV.

To capture the fundamental dynamics of real-time supply–demand balancing, we include a set of explanatory variables that reflect both demand- and supply-side conditions in electricity markets. On the demand side, we incorporate total system load for each country as a proxy for overall electricity consumption. On the supply side, different technologies are characterized by highly heterogeneous marginal costs and technical flexibility: while renewable sources such as wind and solar typically operate at (near) zero marginal cost and cannot easily be curtailed without support schemes, conventional plants differ widely in their shutdown costs and ramping capabilities, which directly affects their contribution to the emergence of negative prices. Therefore, we account for actual generation by major technology categories: nuclear; weather-dependent renewables such as solar and wind; other renewables including biomass, geothermal, and hydro; and non-renewable technologies such as gas, coal, and other fossil-based generation (e.g., oil, waste). More importantly, we capture the role of international electricity trade by including aggregated hourly cross-border flows for each country, distinguishing between exports and imports. Since these flows can either mitigate or amplify domestic supply–demand imbalances by transmitting scarcity and surplus conditions across borders, accounting for them is essential in increasingly integrated European power markets, where cross-border spillovers and volatility transmission have grown over time, see Cevik and Zhao (2025) and Schischke and Rathgeber (2025). These continuous explanatory variables are all mean-centered prior to estimation to facilitate interpretation of the logistic regression models.

In addition, we account for the persistence of negative price events, which can arise mechanically because the underlying drivers are not hour-specific: weather conditions affecting wind and solar output often persist over several hours, and conventional plants frequently operate with intertemporal constraints, making rapid shutdown and restart costly and thereby prolonging negative-price episodes, see Genoese et al. (2010) and Schneider (2010). Therefore, we include as an explanatory variable the number of negative-price hours observed during the preceding 24 h. Thus, the persistence measure is constructed exclusively from lagged outcomes and does not contain contemporaneous information.

Finally, we control for seasonal effects to reflect the recurring temporal patterns in electricity demand and renewable generation. Hereby, a more detailed examination of the timing of negative price events reveals clear temporal patterns. Negative prices occur disproportionately on weekends, periods typically associated with reduced electricity demand, see Figure IIa. They also tend to cluster during the early morning hours (around 2 a.m.) and around midday, aligning with troughs in consumption and peaks in solar generation, respectively, see Figure IIb. Therefore, we model seasonality using cyclical sine and cosine transformations, which allow for smooth, continuous representation of intra-day, intra-week, and intra-year cycles. For the hourly cycle, we include both first and second harmonics to capture the two typical daily peaks in price patterns. For the weekly and annual cycles, we use only the first harmonic, as these effects generally display a single dominant fluctuation per period.

While additional market variables, such as fundamental energy price drivers (e.g., fuel and CO_2 prices) or financial indicators like STOXX indices, may also influence electricity price formation, they are typically available only during trading hours and are not reported for weekends or public holidays. As our analysis is conducted at an hourly resolution and covers the full week, including non-trading days, such variables cannot be incorporated consistently without introducing significant gaps or interpolation bias. Focusing on variables with complete and high-frequency coverage ensures the robustness and comparability of our results across countries and time.

5. Results and discussion

Negative electricity prices have become a recurring problem in many European power markets. To understand the underlying drivers and reasons for this phenomenon and the increasing occurrence, we analyze and compare the determinants of negative electricity prices across multiple European electricity markets. Hereby, we first report the results of the country-specific logistic regression models, which capture how the probability of negative prices is shaped by domestic load levels, the technology mix of electricity generation, cross-border electricity flows, and seasonal patterns in each market. This step allows us to identify the most influential drivers within individual countries and to detect differences in the magnitude and direction of effects. Second, we turn to the panel logistic regression results, which exploit both cross-country and time-series variation to estimate the average impact of these drivers across Europe, while controlling for unobserved heterogeneity through country fixed effects. Comparing the country-specific and panel estimates enables us to distinguish between robust, Europe-wide determinants of negative prices and factors whose influence is market-specific.

Table 2 presents the estimation results from the country-specific logistic regression models, while Table 1 summarizes the main findings. The models are estimated by maximum likelihood, and statistical inference is based on heteroscedasticity- and autocorrelation-consistent Newey–West standard errors with a truncation lag of 48 h, without prewhitening and with finite-sample adjustment. Hereby, the 48-hour lag is chosen to allow for serial dependence in the hourly observations over up to two daily cycles.

As explanatory variables, we include the persistence of negative prices, measured by the number of preceding hours with negative

[1] The sample ends in 2024 because the European Single Day-Ahead Coupling transitioned from hourly to 15-minute Market Time Units on October 1, 2025. Extending the analysis through 2025 would therefore introduce a structural change in the temporal market design, limiting comparability with the hourly observations used in this study.

prices, total system load, cross-border electricity flows, and the generation mix across different technologies.[2] To avoid perfect collinearity with total generation, one generation category is omitted from each country-specific regression: nuclear generation is used as the reference category where available; otherwise, non-renewable generation serves as the reference category, see Table IV. Accordingly, the estimated coefficients of the included generation technologies capture their effects relative to the respective omitted generation category.

Given the time-series structure of the data, we additionally assess the stationarity of the continuous explanatory variables using Augmented Dickey–Fuller tests, see Table V. The unit-root null is rejected at conventional significance levels for almost all series entering the regression models. The few exceptions comprise the country-specific series for other renewable generation of Latvia, while two additional non-stationary nuclear generation series of Spain and Slovenia serve as omitted reference categories and therefore do not enter the respective regressions directly. To assess potential multicollinearity, we calculate variance inflation factors (VIFs) for all country-specific specifications, see Table VI. The large majority of VIFs remain below 5, while elevated values are confined to a limited number of country-variable combinations. Only two VIFs slightly exceed 10, indicating that stronger multicollinearity is localized rather than systematic across the models. Moreover, recurring temporal patterns are explicitly modeled, consistent with previous studies that model the occurrence of low or negative price events using high-frequency market fundamentals with logistic regressions, including Biber et al. (2022) and Bello et al. (2016). In contrast to approaches relying on conventional seasonal dummy variables, we model recurring temporal patterns in our specification through cyclical sine-cosine transformations for intraday, intra-week, and intra-year seasonality. This representation preserves the cyclical structure of electricity-market patterns and avoids artificial discontinuities between adjacent hours, weekdays, or months. Overall, the results reveal broad similarities in the determinants of negative prices across European electricity markets, although some country-specific differences remain.

First of all, our results indicate that seasonal patterns exert a consistent and statistically significant influence on the probability of negative price events. Hereby, the estimated seasonal effects shown in Figures III–XXII are mostly in line with the descriptive evidence presented in Figures IIa and IIb. Across most countries, the hourly profiles reveal a pronounced bimodal pattern, with the probability of negative prices peaking during the late night and early morning hours, typically between midnight and 2 a.m., and again around midday. These patterns closely reflect periods of structurally low demand coinciding with high supply from inflexible conventional units and weather-dependent renewable generation. With respect to the intra-week dimension, negative price events are most likely to occur on weekends, particularly on Saturdays and Sundays, consistent with reduced industrial and commercial electricity demand. While this weekend effect dominates in the majority of markets, a small number of countries exhibit slightly shifted patterns toward the end of the working week: Spain, Portugal, and Sweden show elevated probabilities already on Thursdays, while Finland and France display higher probabilities on Fridays, reflecting country-specific differences. Seasonal variation over the year displays greater cross-country heterogeneity. For most markets, including Austria, Czech Republic, Denmark, Finland, France, Hungary, Latvia, the Netherlands, Norway, Sweden, Slovenia, and Slovakia, the probability of negative prices is highest during the winter months, particularly from December to February, while for Switzerland, Estonia, Spain, and Portugal the occurrence of negative prices is more likely in the summer. A plausible interpretation is that winter peaks are driven by a combination of seasonally high must-run generation and reduced flexibility in certain systems, whereas summer peaks may reflect periods of high solar availability and frequent midday surplus, especially in markets with a comparatively larger solar share and limited short-run absorption through demand, storage, or exports. By contrast, Belgium exhibits a peak in spring, with the highest likelihood occurring in April, while Germany, Lithuania, and Poland display elevated probabilities in early autumn, around September or October; these shoulder-season patterns are consistent with transitional periods in which demand weakens while renewable output remains substantial, and system flexibility constraints or export conditions become binding. Overall, these differences point to country-specific interactions between seasonal demand profiles, renewable generation patterns, and system flexibility, underscoring that while intra-day and intra-week effects are remarkably uniform across Europe, annual seasonality remains more market-specific.

Another robust finding across all models is the strong persistence of negative prices: a negative price within the preceding 24 h significantly increases the probability of a negative price in the current hour. This persistence is consistent with the fact that the underlying drivers are not hour-specific: weather conditions shaping wind and solar output often remain stable over several hours, demand adjusts only gradually, and conventional generation is subject to intertemporal operating constraints that limit rapid output reductions. Therefore, oversupply situations can persist rather than being confined to isolated hours.

In contrast, higher electricity demand, proxied by total system load, is significantly associated with a reduced likelihood of negative prices, consistent with the evidence reported by Aust and Horsch (2020), Biber et al. (2022), Bublitz et al. (2017), Genoese et al. (2010), Hagfors et al. (2016), and Paraschiv et al. (2014), which is based on Germany and sample periods prior to 2021, while our results show that this inverse demand-negative-price relationship extends robustly across a broad set of European markets and more recent years. This indicates that stronger demand conditions might mitigate the risk of oversupply in the system, thereby stabilizing prices and lowering the probability of them turning negative. The only exception is Switzerland, where the high share of cross-border electricity trading renders domestic prices less dependent on internal demand conditions.

Furthermore, he generation mix is another key driver. Across most markets, a higher share of wind and solar generation is significantly associated with a higher probability of negative prices, corroborating prior German-focused results in Aust and Horsch (2020), Biber et al. (2022), Genoese et al. (2010), Gerster (2016), Hagfors et al. (2016), and Paraschiv et al. (2014). This pattern is economically intuitive: wind and solar enter the merit order with near-zero marginal costs and therefore shift the supply curve outward, exerting downward pressure on market-clearing prices. Moreover, their weather-dependent and non-dispatchable nature can amplify short-run supply fluctuations, see e.g. Cevik and Ninomiya (2023), Johnson and Oliver (2019), and Schischke and Rathgeber (2026), and increase the likelihood of temporary oversupply, thereby raising the incidence of extreme low-price outcomes, including negative prices. However, the impact of other renewable sources (including biomass, geothermal, hydro, and other renewables) varies considerably across countries. In Austria, Belgium, Czech Republic, Germany, France, Lithuania, and Slovakia, a greater share of these renewables is associated with a higher probability of

[2] When the contribution of a generation technology was negligible relative to total system load, we excluded it from the regression specification to ensure statistical feasibility and interpretability. Negligibility was assessed based on both the average and the median share of the respective technology in total load. If both measures remained at only a few percent, the technology was excluded, even if occasional peak values were higher. Specifically, this applies to: Estonia (other renewables, average 6%, median 6%), Finland (non-renewables, average 5%, median 4%), Latvia (solar and wind, average 7%, median 4%), Slovakia (solar and wind, average 2%, median 0.1%), and Slovenia (solar and wind, average 4%, median 0.3%). Including such variables not only led to numerical instability and disproportionately large coefficient estimates, but also added limited explanatory value, given their minor role in shaping aggregate market outcomes.

Table 1
Summary of country-specific logistic regression results.

	AT	BE	CH	CZ	DE	DK	EE	ES	FI	FR	HU	LT	LV	NL	NO	PL	PT	SE	SI	SK
Price persistence	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Load	–	–	+	–	–	–	–		–	–	–	–	–	–	–	–	–	–	–	–
Export	–	+		–	+	–	–		–	–	–		–	+	–			–	–	–
Import	+	–	–	+	–	+	+		+	+	+	+	+	–		+		+	+	+
Non-renewables		–			–			–		–	–			–						+
Other renewables	+	+	–	+	+	–			–	+		+			–			–		+
Solar and wind	+	+	+	+	+	+	+		+	+	+	+				+	+	+		

This table summarizes the results of the country-specific logistic regression models. A statistically significant positive (negative) coefficient is indicated by + (–), while blank cells denote statistically insignificant coefficients.

negative prices. Conversely, in Switzerland and the Nordic countries (Denmark, Finland, Norway, and Sweden), which exhibit comparatively high shares of renewable generation, greater output from these sources, particularly hydropower, is associated with a reduced likelihood of negative prices. This effect is likely attributable to the dispatch flexibility and storage capacity associated with hydropower systems. Moreover, non-renewables are consistently associated with a reduced likelihood of negative prices in all countries, except for Slovakia. This is consistent with the merit-order effect: increased fossil-based generation, with its higher marginal costs, tends to raise wholesale prices and counteract downward price pressures from excess renewable generation.

The effects of cross-border electricity flows are heterogeneous across countries. For Austria, the Czech Republic, Denmark, Estonia, Finland, France, Hungary, Lithuania, Latvia, Norway, Poland, Sweden, Slovenia, and Slovakia, higher imports and lower exports are associated with a higher probability of negative prices. This pattern is consistent with the idea that imports add to domestic supply, while reduced exports weaken the role of interconnectors as a relief valve for surplus generation, both of which can increase the likelihood of local oversupply and thus negative prices. In contrast, for Belgium, Switzerland, Germany, and the Netherlands, higher exports and lower imports are linked to a higher probability of negative prices. This suggests that in these markets cross-border exports tend to be pro-cyclical, particularly, they increase precisely in hours when domestic prices are already very low, so they may reflect (rather than prevent) surplus conditions. A plausible explanation is reverse causality that exports respond to low domestic prices and/or binding interconnector constraints, which can limit the extent to which exports can offset oversupply during extreme renewable output or low-demand periods.

To assess the adequacy of the country-specific models, we evaluate standard measures of predictive performance. The McFadden pseudo-R^2 values range between 0.42 and 0.78, suggesting a satisfactory overall explanatory power. Based on a classification threshold of 50%, overall accuracy is uniformly high (above 95%), indicating that the vast majority of outcomes are correctly predicted. Specificity, the correct identification of non-negative price hours, exceeds 98% in all cases, highlighting the strong predictive performance for the dominant class of non-negative price observations. By contrast, sensitivity and precision vary more widely across countries, ranging from 17% to 74% and from 46% to 87%, respectively. This implies that the models perform less reliably in predicting negative price events. Such differences are largely attributable to the rarity of negative price occurrences compared to the prevalence of non-negative prices, underscoring both the inherent difficulty of forecasting rare events and the comparatively greater success of the models in capturing "normal" market conditions.

In summary, beyond demonstrating strong predictive performance, the country-level regressions also point to several common drivers of negative electricity prices across Europe: low demand, high shares of wind and solar generation, and the persistence of negative price events over short horizons. While the role of other renewables and cross-border flows varies by market, reflecting differences in generation portfolios, storage capacity, and interconnection patterns, these findings collectively underscore the central influence of supply–demand imbalances and renewable variability in shaping price dynamics. This provides a strong basis for the subsequent panel analysis, which examines whether these patterns hold across countries and over time.

To further validate the findings from the country-specific regressions, we estimate a panel logistic regression model with country fixed effects, whereby we restrict the sample period from January to December 2024 ti ensure that all countries included observe negative prices. The model is estimated as a binomial generalized linear model with a logit link, including a separate fixed effect for each country. In particular, the country fixed effects absorb unobserved, time-invariant heterogeneity across electricity markets, including persistent differences in generation structures, regulatory frameworks, and market design, such that the coefficients are identified from within-country variation over time. This complementary specification therefore assesses whether the relationships identified in the country-specific models also hold systematically across markets when controlling for time-invariant country heterogeneity. To avoid perfect collinearity with total generation, nuclear and non-renewable generation are omitted from the panel specification. Statistical inference is based on standard errors clustered at the country level, allowing for arbitrary heteroscedasticity and within-country serial correlation. The results of this analysis are presented in Table 3.

In general, the results of the panel logistic regression model corroborate the main insights derived from the country-specific estimations. First, seasonal patterns exert a consistent and statistically significant influence on the probability of negative price events. Importantly, these panel estimates align closely with the country-specific seasonal profiles discussed earlier, indicating that the estimated intra-day and intra-week regularities reflect broad cross-country commonalities rather than being driven by a small subset of markets. In line with the descriptive evidence, see Figures IIa and IIb, the probability of negative prices exhibits a pronounced bimodal intra-day pattern, peaking around early-morning hours and again around lunchtime. Moreover, negative price events are significantly more likely on weekends, especially Saturdays and Sundays, consistent with systematically lower demand. By contrast, the seasonal component over the year is less uniform across markets, so the panel seasonal effects should be interpreted as an average pattern that masks meaningful cross-country heterogeneity in the timing of peak risk.

The panel results also reinforce the strong persistence effect: the occurrence of a negative price within the preceding 24 h markedly increases the likelihood of another negative price in the current hour. Moreover, higher electricity demand is significantly associated with a reduction in the probability of negative prices, while greater wind and solar generation are significantly associated with a higher probability across European markets. While the country-specific regressions reveal heterogeneous effects of cross-border electricity flows, the panel regression results point to a more consistent pattern: higher exports are generally associated with a lower probability of negative prices, whereas higher imports tend to increase this probability, broadly in line with the majority of country-level findings. However, these average effects are not statistically significant in the panel specification. This

Table 2
Results of the country-specific logistic regression models.

	Austria			Belgium			Switzerland			Czech Republic			Germany			Denmark			Estonia			Spain			Finland			France			Hungary			Lithuania			Latvia			Netherlands			Norway			Poland			Portugal			Sweden			Slovenia			Slovakia		
	Est.		Std. E.	Est.		Std. E.	Est.		Std. E.	Est.		Std. E.	Est.		Std. E.	Est.		Std. E.	Est.		Std. E.	Est.		Std. E.	Est.		Std. E.	Est.		Std. E.	Est.		Std. E.	Est.		Std. E.	Est.		Std. E.	Est.		Std. E.	Est.		Std. E.	Est.		Std. E.	Est.		Std. E.	Est.		Std. E.	Est.		Std. E.	Est.		Std. E.
(Intercept)	−8.48	***	(0.27)	−9.34	***	(0.35)	−10.63	***	(0.79)	−8.72	***	(0.31)	−11.99	***	(0.48)	−7.86	***	(0.21)	−6.35	***	(0.27)	−16.22	***	(1.45)	−5.12	***	(0.21)	−10.55	***	(0.56)	−11.98	***	(0.81)	−7.07	***	(0.28)	−6.98	***	(0.36)	−7.71	***	(0.28)	−10.27	***	(0.55)	−9.67	***	(0.61)	−13.41	***	(1)	−7.79	***	(0.42)	−10.28	***	(0.81)	−8	***	(0.25)
Price persistence	0.5	***	(0.03)	0.41	***	(0.03)	0.75	***	(0.08)	0.42	***	(0.03)	0.31	***	(0.02)	0.45	***	(0.03)	0.46	***	(0.04)	0.79	***	(0.09)	0.28	***	(0.02)	0.49	***	(0.04)	0.57	***	(0.08)	0.45	***	(0.05)	0.48	***	(0.06)	0.57	***	(0.04)	0.41	***	(0.05)	0.5	***	(0.08)	0.9	***	(0.09)	0.24	***	(0.03)	0.58	***	(0.1)	0.44	***	(0.03)
Load	−1.21	***	(0.18)	−0.9	***	(0.14)	0.78	***	(0.23)	−1.91	***	(0.2)	−0.08	***	(0.02)	−2.15	***	(0.28)	−2.1		(1.32)	−0.62	***	(0.16)	−0.85	***	(0.26)	−0.1	***	(0.03)	−3.93	***	(0.52)	−6.87	***	(1.37)	−10.23	***	(2.16)	−0.19	***	(0.05)	−0.93	***	(0.3)	−0.73	***	(0.14)	−1.98	***	(0.38)	−0.97	***	(0.15)	−6.25	***	(1.06)	−5.65	***	(0.41)
Export	−0.25	*	(0.13)	0.36	***	(0.1)	0.28		(0.17)	−0.66	***	(0.17)	0.22	***	(0.04)	−1.33	***	(0.16)	−2.98	*	(1.53)	0.09		(0.25)	−0.57	*	(0.33)	−0.42	***	(0.04)	−1.6	***	(0.52)	0.57		(1.02)	−4.59	***	(1.5)	0.84	***	(0.09)	−0.68	*	(0.38)	0.39		(0.27)				−0.27	*	(0.15)	−1.18	***	(0.36)	−2.68	***	(0.38)
Import	1.37	***	(0.11)	−0.45	***	(0.11)	−0.77	***	(0.14)	1.26	***	(0.19)	−0.36	***	(0.05)	1.7	***	(0.14)	1.87	**	(0.85)	0.38		(0.24)	0.59	**	(0.25)	0.28	***	(0.06)	2.12	***	(0.34)	2.19	***	(0.83)	3.1	*	(1.61)	−0.29	**	(0.12)	−0.42		(0.26)	0.96	**	(0.4)	0.35		(0.27)	0.73	***	(0.23)	1.68	***	(0.39)	2.14	***	(0.28)
Non-renewables				−1.28	***	(0.33)				0.18		(0.15)	−0.34	***	(0.04)							−1.5	**	(0.64)				−1.46	***	(0.18)	−2.27	*	(1.19)							−0.31	***	(0.07)										−0.53		(0.97)	−0.02		(1.36)	1.71	***	(0.6)
Other renewables	0.92	***	(0.11)	1.44	***	(0.24)	−1.67	***	(0.29)	0.99	***	(0.25)	0.44	***	(0.06)	−2.7	***	(0.55)				0.12		(0.29)	−1.2	***	(0.24)	0.27	***	(0.06)	0.2		(6.08)	1.76	**	(0.79)	0.06		(1.6)	1.02		(6.14)	−0.67	***	(0.18)	−1.06		(2.15)	0.38		(0.3)	−0.68	***	(0.15)	−0.96		(0.9)	2.94	***	(0.38)
Solar and wind	1.23	***	(0.11)	0.81	***	(0.1)	0.59	**	(0.27)	2.89	***	(0.31)	0.08	***	(0.02)	1.21	***	(0.09)	4.61	***	(0.99)	0		(0.16)	0.63	***	(0.15)	0.17	***	(0.03)	1.56	**	(0.61)	2.93	***	(0.81)				0		(0.08)	−0.3		(0.27)	0.69	***	(0.12)	0.52	*	(0.28)	0.55	***	(0.14)						
Sine hour	1.47	***	(0.21)	1.65	***	(0.17)	3.08	***	(0.43)	0.93	***	(0.22)	1.32	***	(0.14)	1.44	***	(0.17)	1.22	***	(0.27)	0.91	***	(0.33)	0.23	*	(0.13)	2.22	***	(0.35)	1.97	***	(0.54)	1.06	***	(0.23)	1.37	***	(0.3)	2.09	***	(0.23)	0.27		(0.43)	2.13	***	(0.48)	0.64	*	(0.35)	0.09		(0.14)	3.28	***	(0.59)	2.06	***	(0.2)
Cosine hour	−0.65	***	(0.19)	−0.93	***	(0.22)	−1.47	**	(0.73)	0.04		(0.22)	0.07		(0.14)	−0.96	***	(0.17)	0.2		(0.31)	−8.45	***	(0.92)	0.33	**	(0.16)	−0.76	**	(0.33)	−2.35	***	(0.91)	−0.39		(0.32)	−1.14	***	(0.37)	−2.17	***	(0.27)	−0.79	**	(0.37)	−0.96	*	(0.52)	−8.25	***	(0.98)	−0.75	***	(0.21)	−2.12	***	(0.56)	−1.51	***	(0.19)
Sine hour 2	0.19	*	(0.12)	0.44	***	(0.11)	0.83	***	(0.2)	0.24	**	(0.09)	0.49	***	(0.08)	0.35	***	(0.09)	0.01		(0.15)				−0.27	***	(0.07)	1.54	***	(0.21)	−0.18		(0.31)	−0.08		(0.16)	−0.24	*	(0.15)	0.66	***	(0.13)	−0.25	*	(0.15)	−0.25		(0.23)				−0.51	***	(0.11)	0.04		(0.28)	−0.29	***	(0.11)
Cosine hour 2	1.25	***	(0.15)	0.99	***	(0.11)	1.79	***	(0.28)	0.55	***	(0.15)	1.09	***	(0.1)	1.57	***	(0.13)	1.54	***	(0.18)				0.96	***	(0.1)	1.43	***	(0.2)	1.38	***	(0.29)	0.62	***	(0.23)	1.11	***	(0.19)	1.76	***	(0.14)	0.93	***	(0.33)	1.86	***	(0.31)				0.86	***	(0.12)	1.56	***	(0.35)	0.94	***	(0.13)
Sine weekday	0.36	**	(0.18)	−0.09		(0.12)	0.38		(0.31)	0.36	**	(0.16)	0.11		(0.12)	0.14		(0.13)	0.26		(0.18)	−0.63	**	(0.32)	−0.12		(0.12)	−0.29		(0.19)	−0.11		(0.22)	0.18		(0.27)	−0.09		(0.31)	−0.13		(0.11)	−0.09		(0.32)	0.12		(0.28)	−0.3		(0.28)	−0.31	*	(0.17)	0.65	**	(0.3)	0.25		(0.16)
Cosine weekday	0.51	**	(0.2)	0.48	***	(0.15)	1.91	***	(0.49)	0.7	***	(0.21)	0.29	**	(0.13)	0.36	**	(0.17)	0.92	***	(0.29)	−0.34		(0.48)	0.21		(0.15)	0.25		(0.2)	0.81	**	(0.32)	0.47		(0.31)	0.6		(0.39)	0.36	***	(0.12)	0.27		(0.36)	0.51		(0.32)	0.23		(0.42)	0.03		(0.18)	1.25	***	(0.43)	0.7	***	(0.21)
Sine month	0.62	***	(0.14)	0.37	***	(0.12)	−0.39	*	(0.2)	0.76	***	(0.16)	−0.14		(0.12)	0.76	***	(0.14)	−0.23		(0.25)	−0.47		(0.5)	−0.03		(0.2)	−0.09		(0.17)	0.09		(0.34)	−0.4	*	(0.23)	0.82	**	(0.33)	0.04		(0.11)	0.37		(0.52)	−0.02		(0.29)	0.53		(0.44)	0.7	*	(0.36)	0.53	**	(0.26)	0.69	***	(0.17)
Cosine month	0.13		(0.19)	−0.26	*	(0.14)	−0.59	*	(0.33)	0.91	***	(0.18)	−0.17		(0.14)	0.59	***	(0.16)	−0.46		(0.3)	−1.39	***	(0.45)	0.47		(0.32)	0.68	***	(0.2)	0.22		(0.35)	0.08		(0.25)	0.55	**	(0.28)	−0.11		(0.15)	3.01	***	(0.86)	0.23		(0.35)	−1.21	**	(0.56)	1.65	***	(0.4)	0.14		(0.35)	1.03	***	(0.18)
McFadden R^2	0.59			0.63			0.68			0.61			0.7			0.54			0.42			0.78			0.5			0.64			0.74			0.51			0.47			0.56			0.64			0.61			0.76			0.62			0.68			0.56		
Accuracy	0.99			0.99			0.99			0.99			0.99			0.99			0.98			0.99			0.95			0.99			0.99			0.98			0.98			0.99			0.98			0.99			0.96			0.99			0.99		
Sensitivity	0.41			0.49			0.6			0.45			0.6			0.34			0.17			0.74			0.45			0.51			0.7			0.32			0.24			0.42			0.46			0.4			0.7			0.56			0.58			0.36		
Specificity	1			1			1			1			1			1			1			1			0.99			1			1			1			1			1			1			1			0.99			1			0.99			1		
Precision	0.72			0.73			0.87			0.72			0.78			0.65			0.46			0.86			0.72			0.78			0.85			0.61			0.58			0.75			0.73			0.63			0.85			0.73			0.77			0.66		

This table reports the estimated coefficients from the country-specific logistic regression models explaining the probability of negative electricity prices. Newey–West standard errors are shown in parentheses besides the coefficient estimates. Significance levels are indicated by asterisks, where *** denotes significance at the 1% level, ** at the 5% level, and * at the 10% level. The models include various explanatory variables. First, we capture seasonal patterns by cyclical sine and cosine transformations with the first harmonic for weekly and annual cycles and both first and second harmonics for the hourly cycle. Second, we account for the persistence of negative price events by incorporating the number of hours with negative prices during the preceding 24-hour period. Third, we proxy the electricity demand by the total system load. Fourth, we include the cross-border electricity flows (exports and imports), as well as the generation by technology (non-renewables, solar and wind, other renewables). Finally, we control for seasonal effects using cyclical sine and cosine transformations to represent intra-day, intra-week, and intra-year cycles. Hereby, we include both first and second harmonics for the hourly cycle and the first harmonic to reflect the weekly and annual cycles.

Table 3
Results of the panel logistic regression model.

	Est.	Std. E.
Price persistence	0.4206***	(0.0735)
Load	−0.4723***	(0.1424)
Export	−0.1332	(0.1692)
Import	0.1902	(0.1448)
Other renewables	−0.2815	(0.1751)
Solar and wind	0.4426***	(0.1368)
Sine hour	1.0159***	(0.2794)
Cosine hour	−1.1227**	(0.4433)
Sine hour 2	−0.2129**	(0.0876)
Cosine hour 2	1.5353***	(0.1069)
Sine weekday	0.0123	(0.058)
Cosine weekday	0.7264***	(0.1271)
Sine month	0.1015	(0.0863)
Cosine month	−0.5287***	(0.0935)
McFadden R^2	0.51	
Accuracy	0.98	
Sensitivity	0.42	
Specificity	1	
Precision	0.75	

This table presents the estimated coefficients from the panel logistic regression with fixed effects, explaining the probability of negative electricity prices across 20 European day-ahead markets. Hereby, we omit nuclear power and the generation of non-renewables, similar to the country-specific models to avoid perfect collinearity. The standard errors, which were clustered by individual country ID to account for potential heteroscedasticity and autocorrelation within subjects, are reported in parentheses besides the coefficient estimates. Significance levels are indicated by asterisks, where *** denotes significance at the 1% level, ** at the 5% level, and * at the 10% level.

finding indicates that, on average, exporting electricity raises effective demand in the domestic market, thereby alleviating oversupply pressures, while imports add to domestic supply, increasing the likelihood of prices falling below zero. Overall, the panel logistic regression model demonstrates satisfactory explanatory power. Similar to the country-specific models, it exhibits strong predictive performance for the dominant class of non-negative price observations, indicated by an accuracy of 98%. However, the model's reliability in predicting negative prices is notably lower, which can be attributed to the rarity of negative price occurrences compared to the prevalence of non-negative prices.

Taken together, both the country-specific and panel results provide a coherent picture of the drivers of negative electricity prices in Europe. Seasonal demand cycles, persistence effects, and the generation mix, particularly the contribution of variable renewable sources, emerge as the most robust determinants, while the influence of cross-border trading remains highly context-dependent. These findings underline the importance of integrating flexibility measures and demand-side responses into market design to mitigate the risk of negative prices in an increasingly renewable-dominated electricity system.

5.1. Robustness and sensitivity analyses

We perform several additional analyses to assess the robustness of our findings with respect to the sample specification, the representation of renewable generation, and the specification and scaling of the explanatory variables. The corresponding results are reported in Appendix C.

5.1.1. Alternative sample specifications

First, while the country-specific logistic regressions were initially estimated over the longest feasible sample period available for each market, this approach inevitably yields differing time spans across countries. By contrast, the panel regression analysis is restricted to the common period from 1 January 2024 to 31 December 2024. To ensure full comparability, we therefore re-estimate all country-specific models using this shorter, harmonized subsample. Overall, the main findings remain robust, although the statistical significance of some effects diminishes due to the reduced sample size. Notably, in the more recent period non-renewables are also found to reduce the probability of negative prices in the Czech Republic, an effect that did not emerge in the longer samples.

Moreover, we re-estimate the panel model over the full available sample period beginning in January 2015, thereby allowing for an unbalanced panel across countries. This broader specification includes early sample years in which negative-price events were still very rare and, for some markets, did not occur at all. Despite this pronounced heterogeneity in event frequencies and country-specific sample availability, the estimated relationships remain largely consistent with the baseline 2024 panel results. The main exception concerns cross-border exports: over the full sample period, higher exports are associated with a higher probability of negative prices, similar to the effect of imports, whereas the baseline 2024 specification indicates a negative relationship. Overall, the robustness exercise suggests that the main panel results are not driven by the restriction to the common 2024 sample, although the role of exports appears to vary across sample periods.

5.1.2. Alternative specification of wind and solar generation

Second, because the strong correlation between solar and wind generation may complicate the identification of their individual effects, we re-estimate the models using technology-specific specifications. We therefore estimate one specification including solar generation and another including wind generation instead of their aggregated contribution. The results broadly support the importance of variable renewable generation, but reveal considerable heterogeneity between the two technologies. Solar generation is significantly and positively associated with the probability of negative prices in the majority of countries, a finding that is also reflected in a significant positive coefficient in the panel model. Spain constitutes a notable exception, where higher solar generation is associated with a lower probability of negative prices. One possible explanation is the comparatively active curtailment of solar generation during periods of high renewable output and low demand by the Spanish system operator (Micheli et al., 2025). By contrast, the association with wind generation is considerably less robust. In Germany, Estonia, Hungary, Latvia, the Netherlands, and Norway, the wind coefficient becomes statistically insignificant in the technology-specific specification, and the panel estimate likewise indicates no significant overall association with wind generation. These differences may reflect technology-specific generation profiles and their interaction with demand, system flexibility, forecasting, and market adaptation. In particular, solar output is highly concentrated around midday and can coincide with low-demand periods, especially on weekends, whereas wind generation is temporally less concentrated and more geographically dispersed. Accordingly, the robustness analysis suggests that the positive baseline association of combined wind and solar generation is more consistently supported for solar than for wind generation.

5.1.3. Alternative model specifications

Third, we assess the robustness of our findings with respect to the inclusion of the price-persistence measure and the scaling of the explanatory variables. First, we re-estimate all country-specific and panel models without the 24-hour price-persistence measure, which is constructed from lagged realizations of the dependent variable. Overall, the main findings remain robust to its exclusion. In the country-specific models, only a limited number of previously significant relationships become statistically insignificant, including some of the negative load effects and the positive effects of solar and wind generation in Germany and Portugal. In the panel model, the estimated relationships likewise

remain largely unchanged, while other renewable generation additionally becomes statistically significant with a negative coefficient. However, excluding the persistence measure results in somewhat lower sensitivity and precision, indicating that information on preceding negative-price events contributes to the models' ability to identify negative-price episodes.

Second, to facilitate comparisons of coefficient magnitudes across explanatory variables measured on different scales, we re-estimate the models after standardizing the continuous regressors to zero mean and unit standard deviation. As expected, this rescaling does not affect the statistical significance, model fit, or substantive conclusions of the estimations, but expresses the coefficients in terms of a one-standard-deviation change in the respective explanatory variable. The standardized estimates reveal some additional patterns regarding the relative strength of the estimated relationships. The persistence effect is particularly pronounced in Switzerland, Spain, and Portugal, while electricity load exhibits comparatively large standardized coefficients in the Czech Republic, Spain, Hungary, Norway, Sweden, and Slovakia. The positive relationship between wind and solar generation and the probability of negative prices is particularly pronounced in the Czech Republic, Denmark, Hungary, Poland, and Sweden. Within individual country specifications, load frequently exhibits one of the largest standardized coefficients, while non-renewable generation also shows comparatively strong relationships in several markets where it is included. At the same time, the standardized estimates do not reveal a clear geographical clustering of coefficient magnitudes, suggesting that the relative importance of individual drivers is more strongly market-specific than regionally structured. Overall, the standardized estimates therefore complement the baseline results by illustrating differences in the relative magnitude of the estimated relationships while confirming their qualitative robustness.

Overall, the robustness checks mainly confirm the findings: negative prices in European electricity markets are strongly shaped by seasonality, persistence, demand levels, and renewable generation, particularly solar, while fossil fuels play a stabilizing role and cross-border trade effects remain country-specific.

6. Conclusion and policy implications

While negative electricity prices have been originally considered as rare and exceptional, they have become a recurring phenomenon in many European power markets in more recent periods. This study provides a first comprehensive, cross-country analysis of the drivers of negative electricity prices across 20 European day-ahead markets. Using both country-specific and panel logistic regression models, we examine how domestic demand, generation mix, cross-border electricity flows, and seasonal patterns shape the likelihood of negative price events.

Our results reveal several robust and consistent patterns. Seasonal effects exert a strong and statistically significant influence, with negative prices more likely during early morning hours, around midday, and on weekends. Negative prices also display pronounced persistence: the occurrence of a negative price within the previous 24 h substantially increases the probability of another. Moreover, higher electricity demand is systematically associated with a reduced likelihood of negative prices, underscoring the stabilizing effect of strong load conditions. In contrast, higher combined wind and solar generation is significantly positively associated with the probability of negative prices across most markets, although technology-specific robustness analyses indicate that this relationship is more consistently driven by solar generation. The effect of other renewable sources varies across countries, with hydropower-dominated systems often showing the opposite pattern, reflecting the operational flexibility of such assets. However, the generation of non-renewables is generally associated with a lower likelihood of negative prices, in line with the merit-order logic, although the strength of this relationship varies across countries. The influence of cross-border electricity flows remains heterogeneous, reflecting differing interconnection structures and trading roles among countries.

By comparing results from both modeling approaches, we demonstrate that these core drivers are largely consistent across Europe, while also identifying important market-specific deviations. This highlights the dual nature of negative price events as both a Europe-wide challenge linked to common structural trends, such as the rapid expansion of variable renewable energy, and a phenomenon shaped by country-specific generation portfolios and flexibility resources.

While this study provides evidence on the drivers of negative electricity prices across Europe, several limitations should be acknowledged. First, despite strong overall explanatory power and excellent performance in predicting non-negative price outcomes, the models exhibit more limited predictive accuracy for negative price events themselves. This reflects the inherent rarity of negative prices and the resulting class imbalance, which poses well-known challenges for standard logistic regression frameworks. Second, data availability constrains the set of explanatory variables to consistently available market-level fundamentals observed at an hourly frequency across all 20 markets. As a result, potentially relevant factors such as fuel prices, reserve constraints, redispatch measures, and plant-level operational decisions cannot be explicitly incorporated. This also applies to electricity storage. While installed storage capacity alone does not capture the flexibility available in a specific hour, consistently harmonized information on actual charging and discharging, available charging capacity, and state of charge is not available across all markets and sample periods considered. Consequently, the potentially mitigating effect of storage on negative-price events cannot be identified separately in our empirical framework. In addition, some explanatory variables, most notably electricity generation and cross-border flows, may be jointly determined with electricity prices, implying potential endogeneity and limiting a strictly causal interpretation of the estimated relationships. Third, the country-specific regressions are estimated over market-specific sample windows, which differ across countries depending on the availability and frequency of negative-price observations. While this ensures sufficient event counts for reliable estimation, it limits the direct comparability of coefficient estimates across countries because they are based on different time periods. Moreover, although the country-specific models allow the estimated effects of market fundamentals to differ across national settings and the panel specification controls for persistent country-specific heterogeneity, our analysis does not explicitly identify the effects of individual institutional features, such as renewable support schemes, or their interactions with renewable generation. Relatedly, our analysis focuses on prices formed in the day-ahead spot market and does not capture the effective prices or revenues faced by individual market participants. Generators and consumers may be partially insulated from contemporaneous spot-price movements through power purchase agreements, contracts for difference, futures, or other hedging arrangements. Consequently, the occurrence of a negative spot price should not be interpreted as implying that all electricity produced or consumed in the respective hour is settled at a negative price. Fourth, the use of country-level aggregates may mask intra-zonal congestion and regional heterogeneity, particularly in larger or structurally diverse electricity systems. Finally, the baseline panel analysis is restricted to the common sample period from January to December 2024. Although this harmonized window ensures full cross-country comparability, the single-year panel cannot capture longer-term structural adjustments or regime changes associated with the energy transition. To address this limitation, we additionally estimated an unbalanced panel over the full available sample period from 2015 to 2024 as part of the robustness analysis. The results of this extended specification largely confirm the findings of the baseline panel model, suggesting that the main relationships are not driven by the restriction to the common 2024 sample.

Future research could address these limitations by applying rare-event or machine-learning classification techniques, using identification strategies that better address endogeneity, explicitly incorporating time-varying institutional and renewable support frameworks, exploiting nodal or plant-level data where available, extending the panel analysis over longer harmonized time periods, analyzing negative-price formation at higher temporal resolutions such as 15-minute market intervals, and embedding negative price formation in structural or equilibrium models that explicitly account for market design, flexibility options, and strategic behavior. A further promising extension would be to explicitly model spatial dependencies across interconnected bidding zones, including correlated meteorological conditions, renewable generation patterns, and simultaneous negative-price events, to examine their role in the occurrence and cross-border propagation of negative prices. In addition, incorporating harmonized high-frequency information on storage operation and available storage flexibility would allow future research to assess to what extent storage can absorb temporary generation surpluses and reduce the probability of negative prices.

From a policy, welfare, and market-design perspective, frequent negative-price episodes may signal allocative inefficiency and thus inefficient resource use. Against this backdrop, our evidence on the drivers of negative electricity prices suggests that meeting climate targets through continued renewable expansion requires parallel investments in system flexibility, particularly demand response, and adequate interconnection to limit an inefficient increase in negative-price events and the associated risks to market stability and investment incentives. These implications are consistent with the recommendations of European Union Agency for the Cooperation of Energy Regulators (ACER) (2024), which identifies limited system flexibility as an important contributor to very low and negative electricity prices and emphasizes stronger demand-side flexibility and further cross-border market integration as key elements of an efficient European energy transition. A particularly effective near-term lever is the wider adoption of time-varying retail pricing schemes, which strengthen incentives to shift consumption toward low-price hours (e.g., EV charging or electric heating) and thereby enhance demand-side flexibility. Finland illustrates the feasibility of this approach: dynamic electricity contracts are widely used, and negative-price hours fell markedly between 2024 and 2025, see Finnish Energy Authority (Energiavirasto) (2025), Finnish Energy (2025) and Finnish Energy (2026). While not causal evidence, this pattern is consistent with research showing that dynamic pricing supports demand response and system flexibility under high renewable penetration, see Numminen et al. (2022) and Haakana et al. (2025). Beyond retail pricing, expanding storage, especially technologies suited for intra-day and intra-week balancing, can absorb surplus generation and reduce the persistence of oversupply episodes. On the supply side, greater operational flexibility can be achieved through a more geographically diversified wind fleet, more effective curtailment and system integration of solar output when needed, and enhanced cross-border interconnector capacity to share flexibility across markets, consistent with ACER's emphasis on increasing cross-zonal trading capacity to improve the efficient allocation of renewable generation across interconnected European markets (European Union Agency for the Cooperation of Energy Regulators (ACER), 2024). Overall, these results suggest that aligning renewable expansion with timely investments in flexibility and demand-side market design is essential to ensure that negative prices remain a manageable feature of an efficient, decarbonized power system.

CRediT authorship contribution statement

Amelie Schischke: Writing – original draft, Validation, Software, Project administration, Methodology, Formal analysis, Data curation. **Andreas Rathgeber:** Writing – review & editing, Supervision, Conceptualization.

Declaration of competing interest

The authors have no competing interest to declare.

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Appendix A. Supplementary data

Supplementary material related to this article can be found online at https://doi.org/10.1016/j.jup.2026.102361.

Data availability

Data will be made available on request.

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