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Intermittent Renewables in the Italian Electricity Market: from LCOE to ECOE

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Intermittent Renewables in the Italian Electricity Market: from LCOE to ECOE

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Abstract

Intermittent renewable sources, most notably photovoltaic (PV) and wind, are capital-intensive and non-dispatchable. Long term contracts are often employed to support their deployment and insulate them from volatile spot markets. The framework developed by Ambec et al. (2025) finds that optimal pricing is obtained after adjusting the levelized cost of electricity (LCOE) with a technology-specific bonus-malus term, based on the covariance between renewable production (capacity factor) and wholesale prices. This component turns the LCOE into the Economic Cost of electricity (ECOE), to compare investment into different locations and intermittent sources. This is applied to the Italian zonal market, for which it is estimated and decomposed, using market data. Using hourly day-ahead prices, zonal load, and capacity factors for PV and wind over 2015–2024, two estimators are computed: the covariance between zonal prices and capacity factors, and a second-order Taylor decomposition that identifies the structural drivers of the adjustment. The results show that pricing for PV and wind should generally face a malus, yet has little policy implications by itself as the latest auctions to procure renewable capacity had substantially lower adjudication prices. More importantly, northern regions perform better than southern regions and islands, for both technologies. The decomposition of the bonus-malus shows PV generation is characterized by cannibalization across market zones, intensifying over the sample as installed capacity grows. Whereas the decomposition for wind generation shows both cannibalization and complementarity with PV's generation profile in northern zones, while southern zones display no such complementarity. The two estimators agree in sign for 12 of 14 zone-technology pairs, indicating consistency with minimal differences between the methods.

1 Introduction

The decarbonisation of electricity generation requires a large-scale reallocation of capital toward low-carbon technologies. Intermittent renewable energy sources, most notably wind and solar

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photovoltaics, combine near-zero marginal costs with high upfront investment requirements. As a result, the success of decarbonisation policies depends not only on technological feasibility but also on the ability of market and regulatory frameworks to induce sustained private investment in capital-intensive generation assets.

Wholesale electricity markets, however, provide limited revenue certainty for intermittent renewable producers. For technologies whose output is weather-dependent and largely non-dispatchable, revenues are strongly exposed to market volatility, which can deter investment even when renewable technologies are socially desirable. These features have long motivated public intervention aimed at stabilising revenues and accelerating the deployment of low-carbon generation. Fixed-price instruments, such as Feed-in Tariffs (FiT), Contracts for Differences (CfD), and Power Purchase Agreements (PPA), have played a central role in this process. By guaranteeing revenue certainty, they align private investment incentives with policy objectives, but may also distort investment choices across technologies and locations if contract prices are poorly calibrated.

Ambec et al. (2025) show that fixed-price contracts or auctions can implement the socially optimal portfolio of renewable technologies when the contract price is adjusted by a technology- and location-specific bonus–malus term. The bonus–malus reflects the covariance between renewable generation and wholesale market prices: it rewards a technology that produces in times of scarcity and penalises it when it produces in times of abundance. Equivalently, the Levelized Cost of Electricity (LCOE)[1] is turned into the Economic Cost of Electricity (ECOE) by adding the bonus–malus, so that ECOE > LCOE when the technology produces when prices are relatively low, and ECOE < LCOE when it produces when prices are relatively high.

This paper extends the bonus–malus framework to the Italian electricity market. Italy is a useful setting for two reasons. First, it has multiple bidding zones, a rare feature in Europe. Second, it exhibits a stark asymmetry between the location of renewable resources and the location of demand: the regions best suited for solar power are in the south, while the bulk of demand comes from the industries and urban centres in the north. Both features imply that locational heterogeneity in the bonus–malus should be empirically detectable and policy-relevant.

Two methods of estimations are employed: (i) the covariance between zonal prices and capacity factors, which yields a monetary value in €/MWh, and (ii) a second-order Taylor decomposition, which does not yield a monetary value but is informative to assess the main drivers — cannibalization, complementarity with other intermittent sources, and covariance with demand. The empirical analysis uses hourly zonal data from the Italian Day-Ahead Market, hourly capacity factors for PV and wind from Staffell and Pfenninger (2016), and installed-capacity data from Terna, over 2015–2024.

The main findings are as follows. The bonus–malus is negative across zones and technolo-

[1]The LCOE is the constant per-MWh price that equates the present value of lifetime costs of a generating asset (investment, fixed and variable operation and maintenance, fuel, decommissioning) to the present value of lifetime electricity production.

gies, with northern zones systematically closer to zero than southern zones and islands. PV displays cannibalization across the whole country, whereas Wind generation is more heterogeneous: northern zones display complementarity with PV and limited cannibalization, while southern zones display strong cannibalization. The two estimation methods agree in sign in 12 of 14 zone–technology pairs; the exceptions are those cases where the covariance-based estimate is closest to zero, suggesting broad consistency.

The contribution of the paper is twofold. First, it provides an empirical application of the framework by Ambec et al. (2025) to a multi-zone market. Second, it identifies the structural channels driving zonal differences through the decomposition, which separates cannibalization from cross-technology complementarity and demand alignment. The empirical results support the locational correction coefficients for PV introduced in the FER X decree (Ministero dell'Ambiente e della Sicurezza Energetica, 2024). Findings are similar for wind, which, unlike PV, did not have correction coefficients in the decree.

The remainder of the paper is organised as follows. Section 2 describes the Italian wholesale electricity market and renewable support schemes. Section 3 reviews related literature. Section 4 presents the theoretical framework. Section 5 describes the data. Section 6 presents certain descriptive statistics. Section 7 presents the empirical results. Section 8 discusses implications and limitations. Section 9 concludes.

2 Institutional setting

2.1 Zonal market design and the 2021 reform

The Italian wholesale electricity market is organised as a centralised, mandatory pool operated by the *Gestore dei Mercati Energetici* (GME), within a regulatory framework defined by ARERA and with system-operation responsibilities assigned to Terna. The core of price formation occurs in the day-ahead market (*Mercato del Giorno Prima*, MGP), where generators and buyers submit bids and offers for delivery on the following day. Market clearing follows a marginal pricing rule subject to transmission constraints, which implies that prices may diverge across geographic areas when inter-zonal congestion becomes binding.

Italy is composed of multiple bidding zones, which represents an intermediate solution between a single zone (the most common configuration in Europe) and fully nodal schemes (most popular in the US). In a zonal system, the transmission network is partitioned into a number of bidding zones, each characterised by a single market-clearing price. Within a zone, internal network constraints are ignored at the market-clearing stage and managed ex post by the system operator through redispatch.

The current zonal configuration splits Italy into Nord, Centro-Nord, Centro-Sud, Sud, Sicilia, Sardegna, and Calabria. Until 2020, the Italian market consisted of ten zones: six geographic zones and four "production zones." Starting in January 2021, a market redesign removed the production zones, created the Calabria zone, and moved the Umbria region from Centro-Nord to Centro-Sud, reflecting persistent congestion patterns and the growing geographic imbalance between generation and demand. This reform motivates the sample split adopted in this paper.

The application of zonal prices historically differed between the supply and demand sides. Producers were remunerated at the zonal price corresponding to their generation unit, while electricity purchases were settled at a uniform national price, the PUN (*Prezzo Unico Nazionale*), calculated as a demand-weighted average of zonal prices. Recent regulatory changes have progressively reduced this asymmetry, extending the application of zonal prices to both sides of the market, with full application from 2026 onwards (ARERA, 2024).

Italy's electricity generation mix in 2024 remained centred on natural gas, which accounted for 44.4% of generation, followed by hydropower (19.8%), solar PV (13.2%), wind (8.2%), biofuels (5.4%), and oil (3.1%) (IEA, 2024). The Italian power system operates under a marginal pricing regime in which thermal generation — particularly combined-cycle gas turbines — continues to play a dominant role in price formation: in 2024, gas-fired units were at the margin in 61.4% of total hours (GME, 2024).

2.2 Renewable support in Italy

Italy's renewable deployment has been supported through a set of remuneration schemes that differ in the degree of exposure of producers to wholesale prices: Feed-in Tariffs (FiT), fixed Feed-in Premia, one-way variable feed-in premium, and two-way variable feed-in premium (commonly described as two-sided Contracts for Difference). In 2024, the total cost of renewable support (not only wind and solar PV) in Italy is estimated at about €8.9 billion, up from roughly €7.1 billion in 2023, with year-to-year variation driven more by wholesale prices than by changes in incentivised output (ARERA, 2025).

Support instruments have increasingly relied on competitive auctions, as in the FER X decree (Ministero dell'Ambiente e della Sicurezza Energetica, 2024).[2] A notable feature of the FER X decree is the introduction of correction factors reflecting regional differences in solar irradiation: the support for PV is increased by +10 €/MWh in Northern regions and +4 €/MWh in Central regions, while no analogous differentiation applies to wind.

At the time of writing, a new instrument, the FER Z decree, has recently concluded the consultation phase. Instead of paying for production, traders and utilities would enter into CfDs toward the delivery of shaped consumption profiles (e.g., a baseload or peakload product) backed by a portfolio of assets (Decarolis, 2026). No definitive text exists at present.

[2] Decreto Ministeriale 30 dicembre 2024 (FER X).

3 Related literature

3.1 The Ambec–Crampes–Lamp framework

This paper builds on the framework by Ambec et al. (2025), they argue that a single auction with technology- and location-specific payments adjusted ex post via a *bonus–malus* term implements the socially optimal portfolio of renewable investment, and dominates both technology-neutral auctions and fully technology-specific designs. The bonus–malus is defined as the covariance between renewable capacity factors and wholesale prices, scaled by the average capacity factor. Equivalently, it transforms the LCOE into an Economic Cost of Electricity (ECOE) that reflects when, and not only how much, a technology produces. They also derive a decomposition of the bonus–malus that separates its drivers into three channels: own-variability of the renewable (cannibalization), covariance with other intermittent sources (complementarity), and covariance with demand.

Empirically, the framework requires only publicly available data: hourly day-ahead prices and hourly renewable capacity factors. The bonus–malus can be computed for any technology–location pair for which these two series are observed, without structural modelling of the supply side. The decomposition requires, in addition, an estimate of the derivative of the curvature of the supply curve, data on installed capacity and load.

Ambec et al. (2025) apply the framework to four markets: Germany, France, Spain, and California, using hourly data over 2015–2020 (2019–2020 for California). The bonus–malus is negative for both wind and solar in all four markets when computed over the full window, with one exception: Spanish solar, for which the 2015–2020 covariance is positive at +0.05 €/MWh. This exception, however, narrows over time. When the sample is restricted to 2020 alone, Spanish solar also turns negative at −1.06 €/MWh. The general pattern across markets is that solar penalties have grown year over year as installed capacity has expanded, consistent with the cannibalization channel identified in the decomposition. In terms of magnitudes, wind penalties range from about 1.6 to 5.8 €/MWh and solar penalties reach 8.4 €/MWh in California — the most solar-intensive of the four markets.

The decomposition in Ambec et al. (2025) adds further detail on the structural drivers of the bonus–malus. Across the four markets, cannibalization (term b) is the dominant component in magnitude, particularly in Germany and California; complementarity between wind and solar (term c) is negative everywhere, reducing the ECOE for both technologies. The demand-alignment term (term d) is positive in all markets except France for solar, where electric heating shifts peak load into winter evenings and produces a counter-cyclical pattern for solar generation. When the three terms are summed, the net decomposition is negative everywhere except for wind in France and solar in Spain. The positive value for French wind is at odds with the price-based estimate.

3.2 The market value of variable renewables

The bonus–malus is closely related to the broader literature on the market value of intermittent renewables. Borenstein (2012) argues that comparing technologies on a direct-cost basis is insufficient for electricity, because the value of generation depends on its time profile, its location, and its interaction with the rest of the system. Hirth (2013) shows empirically, combining European day-ahead market data with dispatch-and-investment modelling, that the market value of wind and solar declines with their penetration, with solar value declining faster because production is concentrated in fewer hours; Hirth and Radebach (2016) decompose this decline into a profile component and a residual-supply curvature component. The bonus–malus framework can be read as a contract-design counterpart to this positive literature: it converts the negative correlation between renewable output and prices, which the value-factor literature documents, into the corresponding adjustment to support prices.

3.3 Renewable support design, locational differentiation, and market integration

A third strand of literature concerns the design of renewable support and the spatial dimension of electricity markets, both directly relevant to the policy interpretation of the present paper's results. Fabra and Montero (2022) develop a theory of procurement comparing technology-neutral, technology-specific, and hybrid auction designs, showing that the ranking depends on cost heterogeneity, substitutability across technologies, and the shadow cost of public funds. Kröger et al. (2024) study resource differentiation in renewable auctions through an adjustment factor tied to site quality, using the German wind reference yield model; their numerical simulation suggests that such differentiation reduces consumer costs by roughly €21 billion ($\approx 11\%$) over 2025–2030 in Germany.

A separate but complementary contribution concerns the role of transmission infrastructure in shaping the spatial distribution of renewable value. Gonzales et al. (2023) exploit two major transmission expansions in the Chilean electricity market as a quasi-natural experiment, showing that market integration induces price convergence across zones, increases renewable entry, and reduces both generation costs and emissions. A substantial share of the renewable investment they document would not have occurred absent the transmission expansion, implying that the welfare gains of market integration are systematically understated when investment responses are ignored. This result is particularly relevant to Italy, where the TSO's Development Plan envisages an increase in inter-zonal transmission capacity from 16 GW to more than 35 GW. To the extent that such an expansion reduces structural congestion along the south–north axis, the cross-zone differences in the bonus–malus documented in the present paper should attenuate over time (another factor would be storage).

4 Theoretical framework

The framework follows Ambec et al. (2025), adapted to a zonal market.

Uncertainty is indexed by $\omega \in \Omega$, where each state summarises the realisation of all exogenous factors, including renewable availability. For each technology i and zone z, $\omega_{i,z}(\omega) \in [0,1]$ denotes the capacity factor associated with state ω. Demand uncertainty is taken as exogenous; no intertemporal substitution is allowed, and each state is treated independently.

Electricity can be produced using two classes of technologies: thermal generation and intermittent renewable generation. Thermal generation has a cost function $C(Q_z)$ that is increasing and convex in zonal thermal output $Q_z(\omega)$. Let $D(Q_z)$ denote total environmental damages with marginal damage $\delta_e(Q_z)$. The social cost of thermal generation is therefore

$$SC(Q_z) = C(Q_z) + D(Q_z). \tag{1}$$

A carbon price equal to marginal environmental damage ensures that market prices reflect the social marginal cost of thermal production.

Renewable technologies are indexed by $i \in \mathcal{I}$. For each technology and zone, installed capacity is $K_{i,z}$, and renewable output in state ω is $q_{i,z}(\omega) = \omega_{i,z}(\omega)K_{i,z}$. Renewable generation has zero marginal cost and is dispatched before thermal generation. In each zone and state, market clearing requires

$$\sum_i q_{i,z}(\omega) + Q_z(\omega) = D_z(\omega). \tag{2}$$

Zonal electricity prices arise as the shadow value of the market-clearing constraint. When thermal generation is required to meet residual demand,

$$p_z(\omega) = SC'(Q_z(\omega)). \tag{3}$$

When renewable output is sufficient to meet demand in a zone, thermal production is zero and prices are not pinned down by the model. The analysis therefore focuses on states where thermal generation is marginal.

4.1 Planner benchmark and the optimal fixed price

The social planner chooses renewable capacities $\{K_{i,z}\}$ and thermal output $\{Q_z(\omega)\}$ to maximise expected social welfare net of capital costs k_i per unit of capacity. The first-order condition with respect to renewable capacity $K_{i,z}$ is

$$k_i = \mathbb{E}_\omega[\, p_z(\omega)\, \omega_{i,z}(\omega)\,], \tag{4}$$

which states that the marginal cost of installing renewable capacity equals the expected value of its marginal contribution to meeting demand, evaluated at zonal scarcity prices. The expectation can be decomposed as

$$\mathbb{E}_\omega[p_z(\omega)\,\omega_{i,z}(\omega)] = \mathbb{E}[p_z]\,\mathbb{E}[\omega_{i,z}] + \mathrm{Cov}(p_z(\omega), \omega_{i,z}(\omega))\,. \tag{5}$$

A fixed-price contract paying $\psi_{i,z}$ per unit of output decentralises the planner's solution when

$$\psi^*_{i,z} = \frac{\mathbb{E}_\omega[p_z(\omega)\,\omega_{i,z}(\omega)]}{\mathbb{E}[\omega_{i,z}]} = \mathbb{E}[p_z] + \frac{\mathrm{Cov}(p_z(\omega), \omega_{i,z}(\omega))}{\mathbb{E}[\omega_{i,z}]}. \tag{6}$$

The optimal remuneration consists of two components: the expected zonal electricity price, and a technology- and zone-specific adjustment that depends on the covariance between renewable output and wholesale prices. This adjustment is the *bonus–malus*. Technologies whose output is positively correlated with high-price states receive a positive bonus; technologies that predominantly produce in low-price states receive a malus.

In a zonal market, the bonus–malus varies across locations due to differences in demand patterns, renewable availability, and network congestion. Efficient support is therefore technology- and location-specific.

4.2 Decomposition

The covariance-based estimator delivers a monetary value but does not separate the channels through which it operates. A second-order Taylor expansion of the zonal social marginal cost around its mean, used by Ambec et al. (2025), identifies these channels.

Let $Q^*_{0,z} \equiv \mathbb{E}[Q^*_z(\omega)]$ denote average thermal output at the optimum, and $\tilde{r}^*_{i,z}$ the levelised per-unit capacity cost for technology i in zone z. Approximating $SC'(Q_z)$ around $Q^*_{0,z}$ yields

$$\underbrace{\frac{\tilde{r}^*_{i,z}}{\mathbb{E}[\omega_{i,z}]}}_{\text{LCOE-type term}} + \underbrace{SC''\Big(Q^*_{0,z}\Big)}_{(a)} \left[\underbrace{\frac{\mathbb{V}[\omega_{i,z}]\,K_{i,z}}{\mathbb{E}[\omega_{i,z}]}}_{(b)} + \underbrace{\frac{\sum_{j\neq i}\mathrm{Cov}(\omega_{i,z},\omega_{j,z})\,K_{j,z}}{\mathbb{E}[\omega_{i,z}]}}_{(c)} - \underbrace{\frac{\mathrm{Cov}(\omega_{i,z}, D_z)}{\mathbb{E}[\omega_{i,z}]}}_{(d)} \right] \approx \mathbb{E}[\,SC'(Q^*_z(\omega))]\,. \tag{7}$$

The bracketed term represents the bonus–malus correction per MWh of average renewable output, while the curvature $SC''(Q^*_{0,z})$ scales its magnitude. Each term has a direct economic interpretation:

(a) Curvature of the supply schedule. The multiplier $SC''(Q^*_{0,z})$ captures the slope of social marginal cost around the average operating point. A steeper marginal cost schedule implies that a given amount of variability in residual demand translates into larger welfare-relevant price movements.

(b) Own-variability of renewable i (cannibalization). The term $\mathbb{V}[\omega_{i,z}]K_{i,z}$ measures the intermittency of technology i scaled by its installed capacity. It enters with a positive sign: by convexity of the cost function, higher variability in own production raises the expected ECOE, with the effect amplified by installed capacity.

(c) Covariance with other renewables (complementarity). The term $\sum_{j\neq i} \mathrm{Cov}(\omega_{i,z}, \omega_{j,z})K_{j,z}$ captures how technology i aligns with other intermittent technologies. If the covariance is negative, the technologies produce at different times, which mitigates fluctuations and reduces the ECOE. If positive, simultaneous production strengthens cannibalization, raising the ECOE.

(d) Covariance with demand. A positive covariance means production is tilted toward high-demand states, reducing the ECOE. A negative covariance means the technology produces little in high-demand hours, increasing the ECOE. The minus sign in equation (7) reflects that alignment with demand decreases the ECOE.

In a zonal market, all objects in equation (7) are in principle zone-specific. The bonus–malus can therefore differ across zones even for the same technology, because both scarcity conditions and the local mix of renewables differ. Empirically, this paper does not estimate term (a) — the slope of the supply schedule — and therefore the decomposition does not yield a monetary value. It does, however, identify the sign of the adjustment and the relative contribution of cannibalization, complementarity, and demand alignment, which serves as a diagnostic alongside the covariance estimate.

5 Data

Prices. Hourly zonal day-ahead prices $P_{z,t}$ (€/MWh) are taken from the day-ahead market published by GME. Prices are observed at the market-zone level and at hourly frequency for all Italian bidding zones (Nord, Centro-Nord, Centro-Sud, Sud, Sicilia, Sardegna, and Calabria post-2021).

Capacity factors. Hourly renewable capacity factors are available at the NUTS-2 (regional) level and are constructed separately for photovoltaic and wind technologies (Staffell & Pfenninger, 2016). Let $CF^{(k)}_{r,t} \in [0,1]$ denote the hourly capacity factor in region r for technology $k \in \{\mathrm{PV}, \mathrm{Wind}\}$. Regional capacity factors are aggregated to the zonal level using annual installed-capacity weights from Terna,

$$CF^{(k)}_{z,t} = \sum_{r\in z} \omega^{(k)}_{r,z,y}\, CF^{(k)}_{r,t}, \qquad \omega^{(k)}_{r,z,y} = \frac{Cap^{(k)}_{r,y}}{\sum_{r'\in z} Cap^{(k)}_{r',y}}, \tag{8}$$

where weights vary by technology and year but remain constant within each calendar year. The

Autonomous Provinces of Trento and Bolzano are treated as two distinct regional units prior to zonal aggregation, to preserve consistency with the original statistical reporting.

Installed capacity. Annual installed capacity data are sourced from Terna at provincial and regional level, then aggregated to market zones using the regional-to-zonal mapping.

Load. Hourly zonal load $Load_{z,t}$ (MWh) is observed at hourly frequency from GME and is used exclusively in the decomposition.

Time-zone harmonisation. GME hourly data include hours labelled 1 to 25 to account for daylight saving time adjustments, whereas the capacity-factor dataset follows a different convention. All observations are converted into a unique universal time identifier, so each record corresponds to one and only one time point across all sources.

Estimators. The bonus–malus is estimated, for each zone z and technology k, as the covariance between the zonal price and the corresponding zonal capacity factor:

$$BM_z^{(k)} = \mathrm{Cov}(P_{z,t},\, CF_{z,t}^{(k)}), \qquad k \in \{\mathrm{PV}, \mathrm{Wind}\}. \tag{9}$$

The decomposition estimates terms (b)–(d) of equation (7) using the same constructed series.

Sample. The empirical analysis covers 2015–2024 and is split into two sub-periods, 2015–2020 and 2021–2024. The split is motivated by two factors. First, the 2021 zonal reconfiguration — creation of the Calabria zone and reallocation of Umbria — modifies the geographic composition of certain bidding areas; separating the sample avoids mixing different zonal definitions. Second, the two sub-periods correspond to markedly different price regimes: a low-price environment in 2015–2020 and a high-price environment in 2021–2024 driven by the energy crisis.

6 Descriptive statistics

Tables 1 and 2 display summary statistics for zonal day-ahead prices in the two sub-periods. Pre-reform, Italian zones display a high degree of price convergence, with Sicilia as the main outlier (higher mean and dispersion). Post-reform, the single-outlier pattern weakens: dispersion across zones becomes more evenly distributed, Sardegna records the lowest mean price, and Nord and Centro-Nord exhibit the highest average prices and the largest standard deviations. The across-zone average rises from 50.70 €/MWh in 2015–2020 to 164.49 €/MWh in 2021–2024 (Figure 1).

Table 1: Zonal day-ahead prices: summary statistics (2015–2020)

	mean	sd	min	max	count
CentroNord	50.00	16.59	0.00	175.75	52608
CentroSud	49.48	15.80	0.00	170.00	52608
Nord	49.91	16.95	0.00	206.12	52608
Sardegna	49.26	16.31	0.00	449.01	52608
Sicilia	57.39	23.62	0.00	259.03	52608
Sud	48.13	15.22	0.00	170.00	52608
Total	50.70	17.91	0.00	449.01	315648

Table 2: Zonal day-ahead prices: summary statistics (2021–2024)

	mean	sd	min	max	count
Calabria	162.80	110.14	0.00	870.00	35064
CentroNord	167.69	116.37	0.00	871.00	35064
CentroSud	165.07	111.87	0.00	870.00	35064
Nord	167.01	116.48	0.10	871.00	35064
Sardegna	159.96	110.52	0.00	871.00	35064
Sicilia	165.55	110.81	0.00	870.00	35064
Sud	163.36	110.84	0.00	870.00	35064
Total	164.49	112.49	0.00	871.00	245448

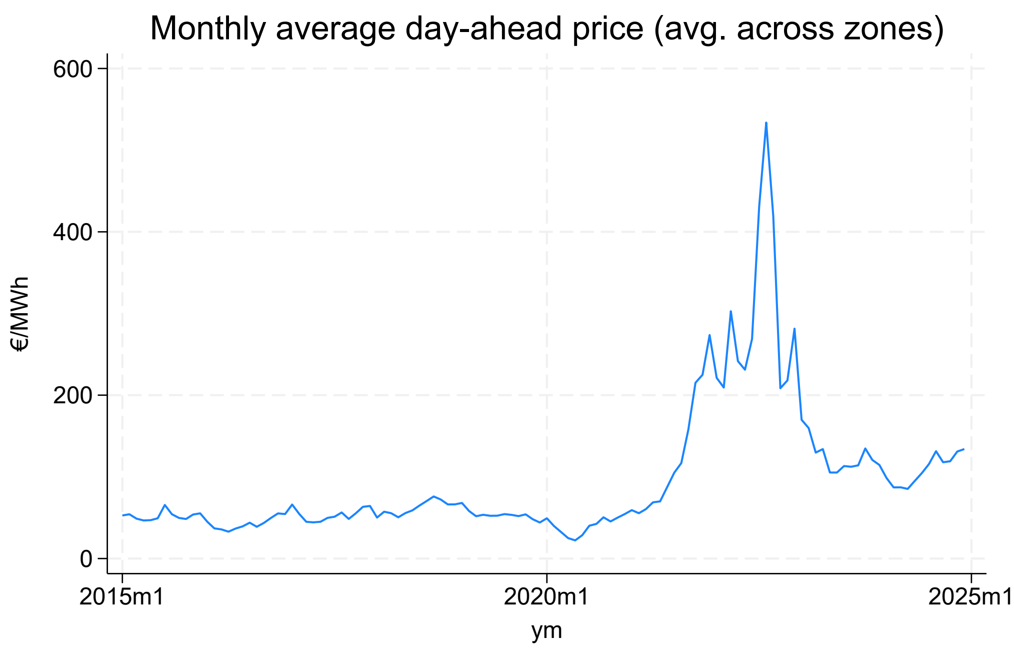

Figure 1: Monthly average price across zones

Tables 3 and 4 report zonal capacity factors for the post-reform sample. PV capacity factors are relatively homogeneous across zones, ranging from 0.146 in Nord to 0.174 in Sicilia, a difference of about three percentage points. Wind capacity factors are more dispersed: Sud (0.216) and

Sardegna (0.217) record the highest means, while Nord records by far the lowest (0.107), a gap of more than ten percentage points. Wind resources are markedly more concentrated geographically than solar.

Table 3: Zonal capacity factors: PV (2021–2024)

	mean	sd	min	max	count
Calabria	0.167	0.225	0.000	0.781	35064
CentroNord	0.152	0.209	0.000	0.754	35064
CentroSud	0.157	0.215	0.000	0.768	35064
Nord	0.146	0.201	0.000	0.741	35064
Sardegna	0.164	0.221	0.000	0.756	35064
Sicilia	0.174	0.233	0.000	0.785	35064
Sud	0.162	0.219	0.000	0.773	35064
Total	0.160	0.218	0.000	0.785	245448

Table 4: Zonal capacity factors: Wind (2021–2024)

	mean	sd	min	max	count
Calabria	0.179	0.163	0.000	0.944	35064
CentroNord	0.178	0.160	0.001	0.930	35064
CentroSud	0.174	0.175	0.000	0.940	35064
Nord	0.107	0.101	0.001	0.800	35064
Sardegna	0.217	0.204	0.001	0.972	35064
Sicilia	0.169	0.164	0.000	0.967	35064
Sud	0.216	0.180	0.000	0.953	35064
Total	0.177	0.170	0.000	0.972	245448

The two technologies follow opposite seasonal patterns (Figure 2): PV peaks in summer, wind in autumn and winter. This complementarity mitigates aggregate variability and motivates the cross-technology covariance term in the decomposition.

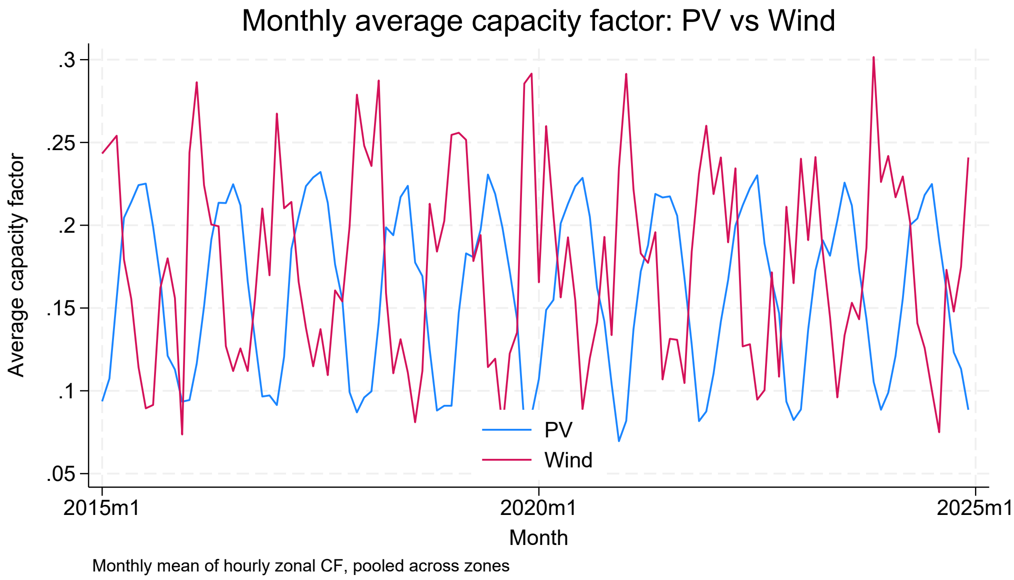

Figure 2: Monthly average capacity factor, pooled across zones

Demand is heavily concentrated in the North: Nord records an average hourly load close to 18,000 MWh, more than three times the second-largest zone (Centro-Sud, around 5,500 MWh) and roughly an order of magnitude above the islands. This north–south asymmetry between renewable resources and demand is the structural feature that motivates a zonal analysis of the bonus–malus.

Installed capacity for PV and wind grows over the sample, with PV accelerating sharply after 2021 (Figure 3). Between 2015 and 2020, installed PV capacity moves from roughly 19 GW to about 22 GW; from 2021 onward, it rises to nearly 37 GW by 2024. Wind follows a steadier path, reaching around 13 GW by 2024. The gap between the two technologies widens over time, which is directly relevant to the cannibalization channel in the decomposition.

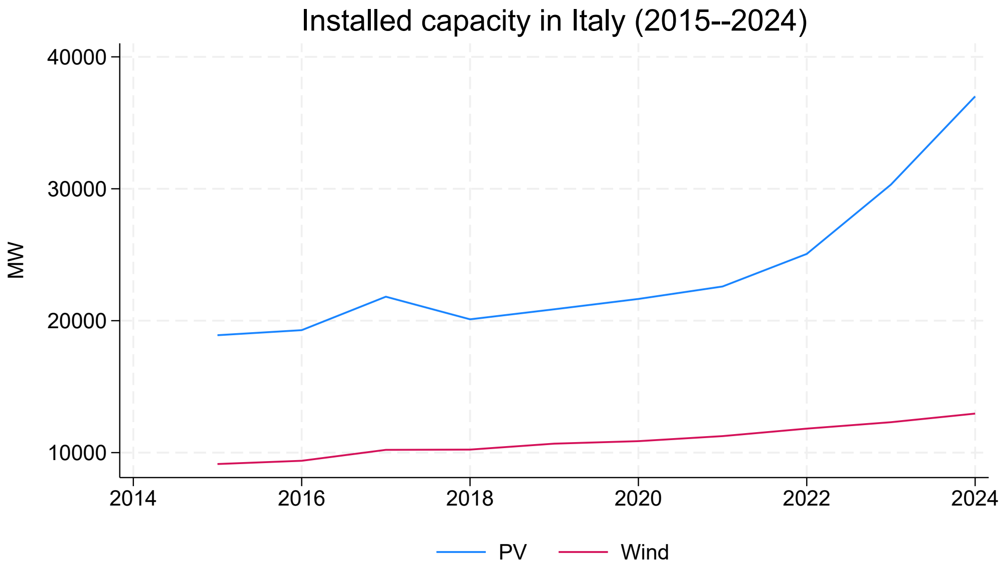

Figure 3: Installed capacity in Italy, 2015–2024

7 Results

7.1 Bonus-Malus

Tables 5 and 6 report the bonus–malus estimated as $\mathrm{Cov}(P_{z,t}, CF_{z,t}^{(k)})$ for the two sub-periods.

In the pre-reform period, the bonus–malus is negative across all zones and for both technologies, indicating that renewable generation is concentrated in hours with below-average prices. Substantial cross-zone heterogeneity emerges. For PV, Sicilia is the worst-performing zone (-6.52 €/MWh), despite recording both the highest mean capacity factor (0.175) and the highest average price (57.39 €/MWh); the magnitude of the penalty implies that solar production in Sicilia is strongly concentrated in low-price hours. Nord records the best performance (-0.55 €/MWh), notwithstanding the lowest mean capacity factor (0.148), indicating a more favourable alignment between generation and price realisations. Centro-Nord (-2.06 €/MWh) outperforms Centro-Sud, Sud, and Sardegna. For wind, the ranking is similar: Nord (-0.08 €/MWh) and Centro-Nord (-0.24 €/MWh) are essentially neutral, while Sicilia is again the worst performer (-6.13 €/MWh).

In the post-reform period, the bonus–malus remains negative across all zones and both technologies, and its absolute magnitude is substantially larger. For PV, Nord remains the best-performing zone (-4.80 €/MWh), followed by Centro-Nord (-7.48 €/MWh); all remaining zones exhibit double-digit negative values, with Sardegna performing worst overall (-17.12 €/MWh). For wind, Centro-Nord performs best (-6.07 €/MWh), Nord follows at -8.94 €/MWh, and Sardegna again records the largest penalty (-16.94 €/MWh). Dispersion across zones is sub-

Table 5: Bonus–Malus by zone and technology (2015-2020)

Zone	Tech	BM	Mean CF	Mean Price
CentroNord	PV	-2.0621	0.1539	50.00
CentroNord	Wind	-0.2386	0.1732	50.00
CentroSud	PV	-2.8844	0.1597	49.48
CentroSud	Wind	-2.8342	0.1723	49.48
Nord	PV	-0.5468	0.1478	49.91
Nord	Wind	-0.0833	0.1059	49.91
Sardegna	PV	-3.3374	0.1655	49.26
Sardegna	Wind	-2.0452	0.2176	49.26
Sicilia	PV	-6.5201	0.1748	57.39
Sicilia	Wind	-6.1274	0.1771	57.39
Sud	PV	-3.5606	0.1622	48.13
Sud	Wind	-3.2112	0.2077	48.13

Table 6: Bonus–Malus by zone and technology (2021-2024)

Zone	Tech	BM	Mean CF	Mean Price
Calabria	PV	-10.1752	0.1672	162.80
Calabria	Wind	-9.6149	0.1789	162.80
CentroNord	PV	-7.4767	0.1517	167.69
CentroNord	Wind	-6.0689	0.1785	167.69
CentroSud	PV	-9.8820	0.1568	165.07
CentroSud	Wind	-12.0315	0.1740	165.07
Nord	PV	-4.7950	0.1461	167.01
Nord	Wind	-8.9424	0.1074	167.01
Sardegna	PV	-17.1204	0.1637	159.96
Sardegna	Wind	-16.9373	0.2171	159.96
Sicilia	PV	-12.0223	0.1739	165.55
Sicilia	Wind	-14.0110	0.1690	165.55
Sud	PV	-10.9713	0.1622	163.36
Sud	Wind	-11.6268	0.2157	163.36

stantially wider than in the pre-reform period.

The shift in absolute magnitudes between the two sub-periods likely reflects the increase in prices in the wholesale electricity market, with intermittent renewables now "missing out" on higher prices. The percentage-of-mean-price representations in Section 7.3 show a more stable relative penalty. The ranking, however, is robust: Nord and Centro-Nord remain systematically less negative than southern zones and the islands across both technologies and both sub-periods.

7.2 Decomposition

Tables 7 and 8 report the three components of the Taylor decomposition — b (cannibalization), c (complementarity with other intermittent sources), and d (demand alignment) — for each zone–technology pair in the two sub-periods. As discussed in Section 4, these terms do not yield a monetary value because the supply-curve slope (term a) is not estimated, but the sign of $(b + c + d)$ identifies the direction of the effect on the ECOE, and the relative magnitudes identify the dominant channel. It is important to note that, unlike in the first estimation, a positive value raises the ECOE (malus), and a negative value decreases it (bonus).

Table 7: Main elements of decomposition (2015-2020)

	Wind			Solar		
	(b)	(c)	(d)	(b)	(c)	(d)
CentroNord	23.63	-44.87	2.07	719.18	-3.08	-263.61
CentroSud	321.05	-8.29	22.65	848.16	-5.68	-337.93
Nord	13.10	-199.81	-7.00	2517.28	-2.01	-2050.56
Sardegna	200.30	1.16	7.97	244.74	1.94	-23.02
Sicilia	319.00	-1.28	-3.37	436.84	-1.71	-66.40
Sud	721.68	-78.30	43.48	1164.70	-130.80	-79.88

Notes: The table reports estimates for the main elements (b) to (d) in equation (7). Positive values increase the ECOE, while negative values decrease it. Sample window: 01jan2015 00:00:00 to 31dec2020 23:00:00.

The pattern is largely consistent with the covariance-based estimates: across zones and for both technologies, the decomposition implies that intermittent renewables should be penalised. The only discrepancies arise for Wind in Nord across both sub-periods, and for Wind in Centro-Nord in 2015–2020. These are precisely the cases where the covariance-based bonus–malus is negative but very close to zero. Several factors may explain residual differences: the decomposition relies on the assumption of perfect competition, so if market power is present on the supply side, day-ahead prices may not coincide with the social marginal cost of electricity provision; small changes

Table 8: Main elements of decomposition (2021-2024)

	Wind			Solar		
	(b)	(c)	(d)	(b)	(c)	(d)
Calabria	178.64	-16.47	9.84	209.30	-30.78	-36.18
CentroNord	23.29	-44.10	21.51	713.46	-3.43	-345.37
CentroSud	401.84	-15.61	1.18	1423.59	-8.19	-501.98
Nord	18.47	-254.40	-67.70	3733.42	-2.69	-1910.89
Sardegna	218.40	-0.07	8.64	389.97	-0.08	-46.91
Sicilia	355.67	-6.85	27.42	633.84	-7.27	-126.03
Sud	729.00	-75.58	30.45	1162.24	-125.34	-119.39

Notes: The table reports estimates for the main elements (b) to (d) in equation (7). Positive values increase the ECOE, while negative values decrease it. Sample window: 01jan2021 00:00:00 to 31dec2024 23:00:00.

in the covariance between load and prices can generate noticeable differences in estimates; and the decomposition is a second-order approximation and is therefore, by construction, close to but not exactly equal to the exact value (Ambec et al., 2025).

To compare the relative magnitude of each driver within a given zone–technology pair, the decomposition is normalised. For each zone and technology,

$$s_x = \frac{|x|}{|b| + |c| + |d|}, \qquad x \in \{b, c, d\}, \tag{10}$$

so that $s_b + s_c + s_d = 1$. The sign in parentheses corresponds to the original (non-normalised) value, preserving the direction of the effect.

Table 9: Normalised decomposition with sign (2015–2020)

	Wind			Solar		
	(b)	(c)	(d)	(b)	(c)	(d)
CentroNord	0.3 (+)	0.6 (−)	0.1 (+)	0.7 (+)	0.0 (−)	0.3 (−)
CentroSud	0.9 (+)	0.0 (−)	0.1 (+)	0.7 (+)	0.0 (−)	0.3 (−)
Nord	0.1 (+)	0.9 (−)	0.0 (+)	0.6 (+)	0.0 (−)	0.4 (−)
Sardegna	1.0 (+)	0.0 (−)	0.0 (+)	0.9 (+)	0.0 (+)	0.1 (−)
Sicilia	1.0 (+)	0.0 (−)	0.0 (−)	0.9 (+)	0.0 (−)	0.1 (−)
Sud	0.9 (+)	0.1 (−)	0.0 (+)	0.8 (+)	0.1 (−)	0.1 (−)

Notes: Entries report $|x|/(|b| + |c| + |d|)$ with original sign in parentheses. Shares sum to 1 within each zone and technology.

Table 10: Normalised decomposition with sign (2021–2024)

	Wind			Solar		
	(b)	(c)	(d)	(b)	(c)	(d)
Calabria	0.9 (+)	0.1 (−)	0.0 (+)	0.8 (+)	0.1 (−)	0.1 (−)
CentroNord	0.3 (+)	0.6 (−)	0.1 (+)	0.7 (+)	0.0 (−)	0.3 (−)
CentroSud	1.0 (+)	0.0 (−)	0.0 (+)	0.7 (+)	0.0 (−)	0.3 (−)
Nord	0.1 (+)	0.7 (−)	0.2 (−)	0.7 (+)	0.0 (−)	0.3 (−)
Sardegna	1.0 (+)	0.0 (−)	0.0 (+)	0.9 (+)	0.0 (−)	0.1 (−)
Sicilia	1.0 (+)	0.0 (−)	0.0 (+)	0.8 (+)	0.0 (−)	0.2 (−)
Sud	0.9 (+)	0.1 (−)	0.0 (+)	0.8 (+)	0.1 (−)	0.1 (−)

Notes: Entries report $|x|/(|b|+|c|+|d|)$ with original sign in parentheses. Shares sum to 1 within each zone and technology.

The decomposition reveals two clearly distinct profiles for wind. In Sicilia, Sardegna, Sud, and Centro-Sud, the cannibalization term b dominates: terms c and d are close to zero in relative magnitude, indicating no economically meaningful benefit or penalty associated with complementarity or covariance with demand. By contrast, in Nord and Centro-Nord, the complementarity term c dominates and is negative, meaning that wind tends to produce when solar does not, mitigating cannibalization and reducing the ECOE. Cannibalization plays a comparatively minor role in these northern zones. The two profiles are essentially preserved in the post-reform period, with only marginal shifts: in Nord, the share associated with c slightly decreases while the share linked to d slightly increases, suggesting a modest strengthening of the demand-alignment channel.

For solar, the decomposition is considerably more homogeneous. Term b dominates in every zone, reflecting the structural concentration of solar output in a limited set of daylight hours that mechanically depresses prices when the technology produces. All zones also display a non-negligible contribution from term d with a negative sign, indicating some benefit from the covariance between solar production and demand. Nord is the most favourable case, combining the lowest relative cannibalization with the highest relative demand-alignment.

7.3 Trend in time

Figures 4–7 display the year-by-year bonus–malus for both technologies, in absolute values (€/MWh) and as a percentage of the mean zonal price.

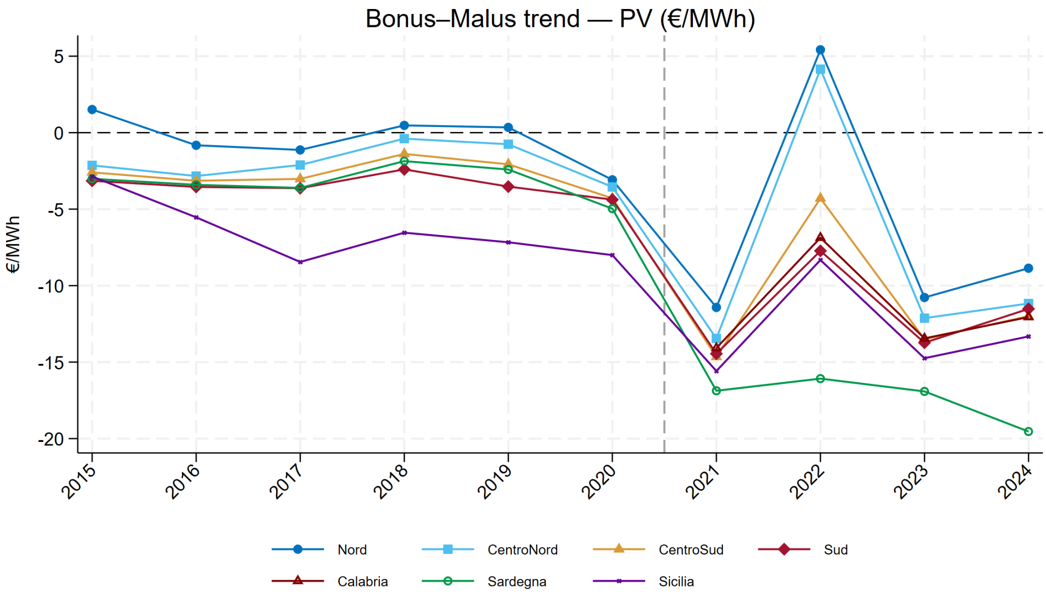

Figure 4: Bonus–malus trend for PV (€/MWh) — absolute values

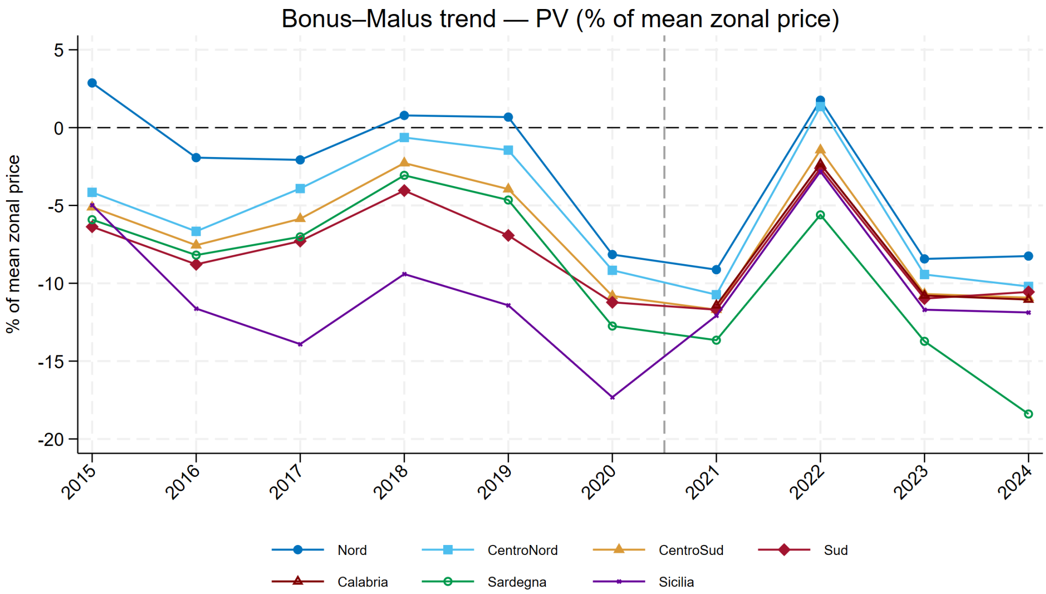

Figure 5: Bonus–malus trend for PV (% of mean zonal price)

For PV, the trend is moderately negative across all zones in both representations. Nord and Centro-Nord consistently outperform the other zones, reaching positive values in some years. Sicilia is the worst performer pre-reform; after the reform, Sardegna takes over that position. The negative trend could be consistent with the cannibalization mechanism identified in the decomposition: as installed capacity rises, the marginal value of solar generation declines during its own production hours. The 2022 spike probably reflects the extreme price level of that year rather than a structural shift. Price changes and the reconfiguration of zones in the 2021 reform are confounding factors.

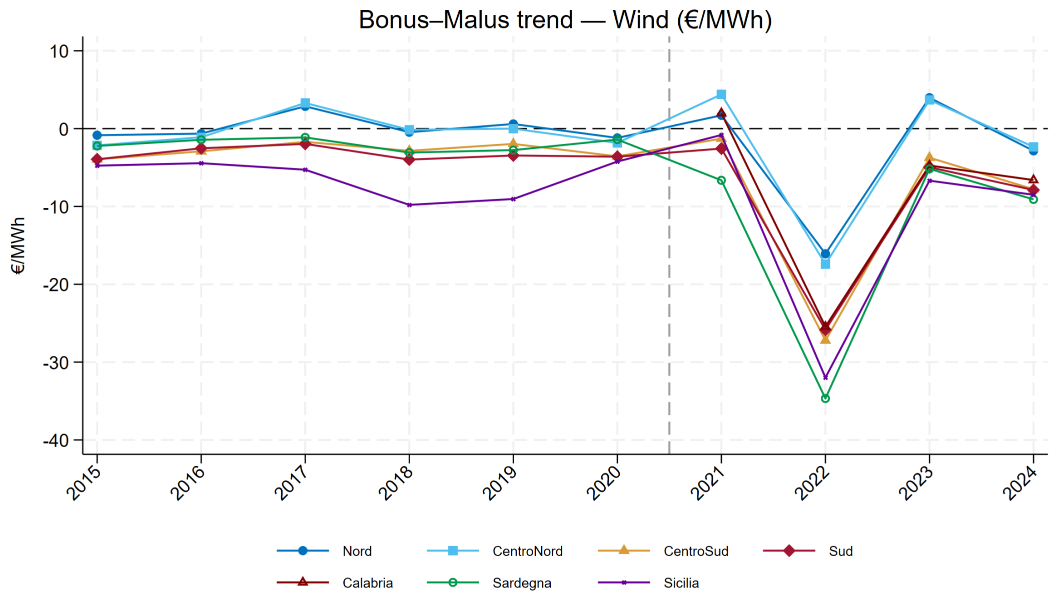

Figure 6: Bonus–malus trend for wind (€/MWh) — absolute values

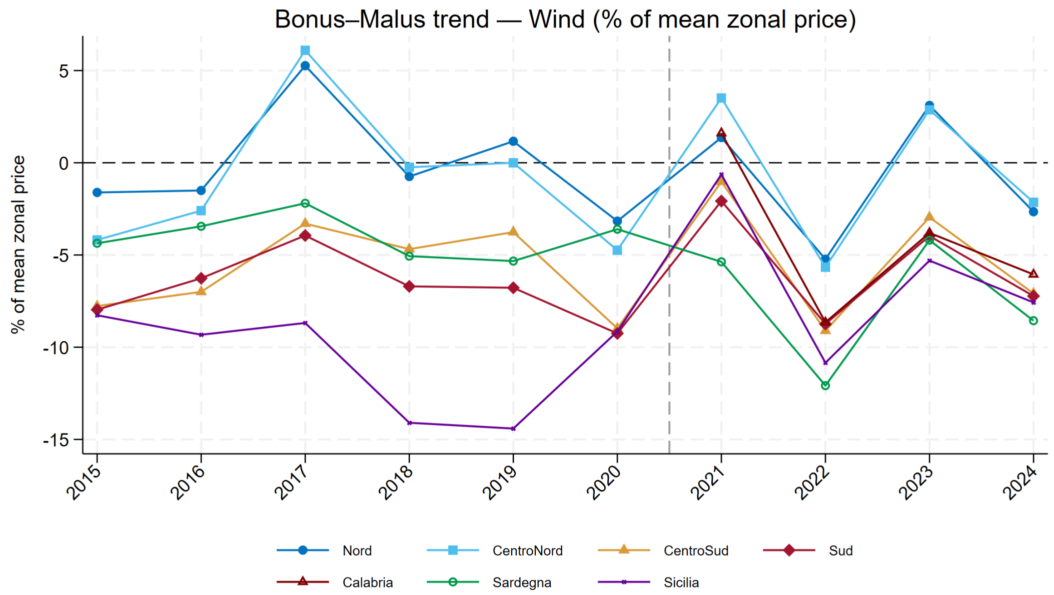

Figure 7: Bonus–malus trend for wind (% of mean zonal price)

For wind, the trend is more stable. Nord and Centro-Nord again remain the only zones with multiple positive bonus–malus values, and Calabria achieves a positive value in the first year after its creation as a standalone zone. Sicilia is the worst performer pre-reform, and after the reform Sardegna and Sicilia compete for the position. The absence of a clear deteriorating trend for wind, in contrast with PV, is consistent with the slower growth of installed wind capacity and therefore a weaker cannibalization channel. Interestingly, the exceptionally high prices of 2022 benefitted solar PV's bonus malus, while wind had its worst year in absolute terms and one of the worst relative to the mean zonal price.

7.4 Consistency across methods

The two estimators agree in sign in 12 of the 14 zone–technology pairs across the two sub-periods. The exceptions — Wind in Nord in both sub-periods, and Wind in Centro-Nord in 2015–2020 — are the cases in which the covariance-based bonus–malus is negative but quantitatively close to zero. This consistency suggests that the cross-zone differences documented above are not the result of either estimation method.

8 Discussion

Both the covariance estimates and the decomposition place Northern zones systematically closer to zero than Southern zones and the islands, across both PV and wind and across both sub-periods. This pattern reflects the structural mismatch in the Italian system between renewable resources and demand: Southern regions enjoy higher solar irradiation and stronger wind conditions, but they are relatively distant from the main industrial and urban load centres concentrated in the North. As a consequence, higher physical productivity, measured through capacity factors, does not translate into higher economic value.

This pattern is broadly aligned with the design of the support mechanism in the FER X decree (Ministero dell'Ambiente e della Sicurezza Energetica, 2024), which introduced correction coefficients favouring PV projects located in Northern and Central regions (+10 €/MWh and +4 €/MWh, respectively). The empirical evidence here supports the direction of those corrections and suggests an analogous locational differentiation is warranted for wind, which is not currently treated in the same manner under FER X. The decomposition shows that wind in Northern zones benefits from complementarity with solar and faces limited cannibalization, while wind in Southern zones suffers from strong cannibalization without offsetting complementarity.

Several caveats apply. First, the empirical strategy relies on ex-post market data, and implicitly assumes that future market conditions will resemble past ones, or that policymakers can approximate long-run expectations using historical distributions. Second, the analysis abstracts from risk aversion, assumes stable technological parameters, and does not explicitly model transmission constraints or congestion costs (Ambec et al., 2025). Third, the supply curve is not estimated, so the decomposition does not yield a monetary value but only signs and relative contributions.

PV and wind clearly should not receive a penalty, as the latest auctions show strike prices substantially lower than wholesale electricity prices in recent years (GSE, 2026). Environmental reasons or independence of supply could also be cited.

Several factors can affect future trends, including the following. Storage deployment, currently being procured through capacity-market auctions, will attenuate cannibalization by shifting renewable output across hours. Transmission expansion under Terna's Development Plan (Terna, 2025), which targets an increase in inter-zonal capacity from 16 GW to more than 35 GW, will reduce the price wedge between Southern generation and Northern demand. The proposed FER Z decree, which would shift support away from production-based remuneration toward profile-based contracts, will change the contractual environment in which these adjustments operate.

9 Conclusion

This paper applies the bonus–malus framework of Ambec et al. (2025) to the Italian zonal electricity market. Using hourly data over 2015–2024, the analysis combines two estimators: the covariance between zonal prices and capacity factors, which yields a monetary value, and a second-order Taylor decomposition, which identifies the structural drivers of the adjustment.

The estimated bonus–malus is negative across zones and technologies. Northern zones are systematically closer to zero, while Centro-Sud, Sud, Sicilia, Sardegna, and Calabria exhibit substantially larger penalties. For PV, cannibalization dominates everywhere. For wind, two profiles emerge: Northern zones display complementarity with PV and limited cannibalization, while Southern zones display strong cannibalization without offsetting benefits. The two estimation methods agree in sign in 12 of 14 zone–technology pairs, with disagreement confined to cases in which the covariance estimate is closest to zero.

The contribution is twofold. First, the paper provides an empirical application of the Ambec et al. (2025) framework to a multi-zone market with a stark north–south asymmetry between renewable resources and demand. Second, the decomposition identifies the channels driving the zonal differences, separating cannibalization from complementarity between technologies and demand alignment. The empirical pattern supports the locational correction coefficients for PV introduced in the FER X decree and suggests that an analogous treatment is warranted for wind. More broadly, renewable remuneration should reflect system value: otherwise, the risk is promoting deployment where there is more potential for production, which may not coincide with where that electricity is most valuable.

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