HEDGING INEFFECTIVENESS AND FORWARD MARKET UNDERDEVELOPMENT IN THE ROMANIAN ELECTRICITY MARKET, 2019–2025

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Abstract

The Romanian electricity market exhibits substantial spot-price volatility yet operates with an underdeveloped centralised forward market. This paper provides an ex-post empirical assessment of unmet hedging demand and operational deterioration in the OPCOM Centralised Market of Bilateral Non-standardised Contracts (PCCB-NC) over 2019–2025. Using monthly OPCOM data, EEX volume reports, and Eurostat consumption statistics, the analysis combines the Ederington (1979) hedge-effectiveness framework, a cross-market benchmark against standardised regional forward contracts, and a scenario-based estimate of unmet hedging demand. The hedge effectiveness of PCCB-NC deteriorates sharply across sub-periods, with the spot-forward R^2 collapsing by roughly an order of magnitude between the energy crisis and the post-crisis period, while spot-price volatility remained elevated. Romanian forward-market intensity is found to be one to two orders of magnitude below standardised regional benchmarks, which recovered after the crisis, whereas the Romanian platform did not. The unmet hedging demand on operational short-term forward instruments is estimated in the order of several TWh per year in 2024, well in excess of the volume actually traded, even after adjusting for parallel long-term bilateral coverage. The findings support reassessing Romania's electricity hedging infrastructure and evaluating standardised, centrally cleared derivatives as a potential market-design response.

Keywords: minimum-variance hedge ratio, spot-forward basis, central clearing, energy crisis, market microstructure

JEL Classification: G13, G18, Q41, L94

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1. Introduction

The liberalisation of European electricity markets has progressed unevenly across the continent. Western European markets, anchored on standardised forward exchanges such as the European Energy Exchange (EEX), now operate with significant forward volumes and continuous trading. Central and Eastern European markets continue to display structural fragilities on the hedging side. The Romanian electricity market provides an instructive case: the spot side, organised through the OPCOM Day-Ahead Market (PZU), has functioned continuously since 2007, but the forward side relies on a bilateral non-standardised platform (PCCB-NC) whose volumes have contracted sharply since the energy crisis of 2021-2022.

The contraction is not merely a quantitative phenomenon. As the analysis below shows, even in the months when PCCB-NC was active, the ex-post effectiveness of a hedge based on the traded prices declined to economically negligible levels in the post-crisis period. The persistent volatility of the spot market, however, did not subside: rolling 12-month annualised PZU volatility remained between 70 and 90 percent throughout 2023-2025, suggesting that the latent demand for hedging instruments has not diminished. The mismatch between persistent risk on the spot side and shrinking participation on the forward side is the central empirical puzzle motivating this paper.

Three questions relevant to the design of electricity risk-management infrastructure in Romania are addressed here. To what extent has PCCB-NC operated, ex-post, as an effective hedging instrument over the period 2019-2025, and how has this effectiveness varied across the sub-periods defined by major shocks (COVID-19, the 2021-2022 energy crisis, and the post-crisis recovery)? How does the intensity of Romanian forward trading compare to functional regional benchmarks, specifically the EEX Phelix-DE Base Futures (Germany) and Hungarian Power Futures contracts? What is the order of magnitude of the unmet hedging demand on Romanian electricity, if reasonable assumptions are applied to the consumption base exposed to spot prices?

The methodology combines three complementary approaches. The Ederington (1979) minimum-variance framework, extended by Myers and Thompson (1989), is applied to monthly OPCOM data on both PZU and PCCB-NC, with sub-period stratification and robust standard errors. A cross-market comparison uses EEX Group volume reports for 2019-2024 and Eurostat consumption data to compute forward-market intensity as a multiple of annual electricity consumption. The unmet demand is estimated as the difference between potential hedging volumes and the volumes actually traded on PCCB-NC, with explicit adjustment for parallel coverage through long-term bilateral contracts (PCCB-LE).

The remainder of the paper is organised as follows. Section 2 reviews the relevant academic literature on electricity hedging, minimum-variance hedge ratios, and the empirical assessment of forward markets. Section 3 describes the data sources and methodological choices. Section 4 presents empirical results in three subsections, each addressing one of the research questions. Section 5 synthesises the findings, discusses the implications for the design of derivative infrastructure in Romania, and identifies limitations of the analysis. A replication package containing all data files and source code is available from the corresponding author.

2. Literature review

The empirical assessment of forward market effectiveness has been a central theme of energy and commodity finance since the seminal contribution of Ederington (1979), who introduced the minimum-variance hedge ratio framework. The approach defines the optimal hedge ratio as the slope coefficient of the regression of spot price changes on futures price changes, with the coefficient of determination (R^2) serving as a measure of hedging effectiveness. The framework was generalised by Myers and Thompson (1989), who allowed for time-varying conditional moments and showed that simple OLS estimates can underestimate hedging effectiveness in markets with structural breaks. Lien and Yang (2008) review the subsequent literature on dynamic hedging and confirm that the static Ederington framework remains a robust benchmark for cross-period comparisons, particularly when applied to monthly or quarterly data.

Electricity markets pose specific challenges to the application of standard hedge-ratio methodology. Karakatsani and Bunn (2008) document the role of fundamental factors (load, fuel prices, capacity availability) in driving electricity price dynamics and emphasise that electricity prices exhibit regime-switching behaviour that complicates the estimation of stable hedge ratios. A particularly relevant theoretical contribution is Bessembinder and Lemmon (2002), who derive an equilibrium model of electricity forward prices showing that the forward premium reflects the relative risk preferences of producers and consumers. A key prediction of their model is that, due to the positive skewness of electricity spot prices and the risk aversion of consumers facing upside price exposure, the forward premium is positive and increasing in expected spot price variance: in high-volatility regimes consumers are willing to pay above the expected spot price for forward protection (positive premium), while in low-volatility regimes the premium compresses towards zero or can turn negative if producer hedging demand dominates. Recent empirical work confirms that risk premia in electricity derivatives are sizeable and time-varying: Algieri, Leccadito and Tunaru (2021) document significant, state-dependent premia across European electricity derivatives markets, while Wei and Lunde (2023) show that, because electricity spot prices do not follow a martingale, the detection of time-varying premia is sensitive to model specification. This framework is revisited in Section 4 to interpret the realised basis dynamics on PCCB-NC.

On the institutional side, Boroumand et al. (2015) analyse the hedging strategies of electricity retailers in mature European markets and report that retailers typically hedge between 60 and 80 percent of expected delivery volumes through standardised forward instruments, with the precise level depending on retailer size, customer mix, and access to forward markets. The authors emphasise that the absence of standardised forward contracts forces market participants to rely on bilateral arrangements, which carry counterparty risk and reduce hedge transparency. ACER/CEER (2015) report, at the European level, the considerable variation in forward market development across Member States and identifies Romania, Bulgaria, and Slovenia as jurisdictions with underdeveloped centralised forward platforms.

The broader literature on financial innovation provides further context. Allen and Gale (1994) propose a theoretical framework in which financial innovation responds to unmet demand for risk-sharing and is driven by gaps in the existing market infrastructure. Silber (1981) and Carlton (1984) examine the determinants of futures contract success and failure, identifying contract design, hedging demand from natural users, and the presence of speculators as the three main drivers. Tufano (2003) surveys the broader financial innovation literature and emphasises the role of regulatory and institutional context.

The empirical literature on Central and Eastern European electricity markets remains relatively thin. Sectoral reports such as ACER/CEER (2015), Enerdata (2024) and the EEX Group Annual Volume Reports (2019-2024) report trading volumes and market characteristics, but academic studies that apply the Ederington framework to data from these markets are rare. The present paper contributes to filling this gap by offering a peer-reviewed assessment, using the Ederington framework, of the ex-post hedging effectiveness of the Romanian PCCB-NC platform across the COVID-19, energy crisis, and post-crisis periods.

Two observations from the literature inform the methodological choices that follow. Monthly frequency for the Ederington regressions follows the practice in electricity market studies (Karakatsani & Bunn, 2008; Bessembinder & Lemmon, 2002), where daily price data on bilateral forward contracts are unavailable and monthly aggregation provides the appropriate balance between sample size and signal-to-noise ratio. Sub-period stratification is supported by the regime-switching behaviour of electricity prices and by the structural breaks observed during the 2021-2022 European energy crisis (ACER/CEER, 2015; Enerdata, 2024).

3. Methodology and data

3.1. Data sources

The empirical analysis combines three categories of data, all from publicly available institutional sources. The Romanian spot and forward price data are obtained from OPCOM SA, the Romanian electricity market operator. The Day-Ahead Market (PZU) monthly weighted-average prices in RON per MWh and total traded volumes are used as the spot reference. The Centralised Market of Bilateral Non-standardised Contracts (PCCB-NC) provides two distinct monthly series: weighted-average prices and volumes for contracts traded in each calendar month, and weighted-average prices for contracts with delivery in each month, irrespective of when they were negotiated. Both series are essential for the ex-post hedging analysis. Each monthly forward price is the OPCOM-published volume-weighted average of the individual bilateral contract prices recorded in the relevant month; no interpolation, extrapolation, or smoothing is applied. Months in which no PCCB-NC transaction is recorded are treated as missing observations rather than carried forward from the previous month, so that the differencing procedure described in Section 3.3 does not impute artificial continuity across inactive months. The full sample covers 84 monthly observations from January 2019 to December 2025. The data cut-off date is December 2025; access dates for institutional sources are between May and June 2026.

The European benchmark data are obtained from EEX Group Annual Volume Reports for the years 2019 to 2024. Two contracts are used: the EEX Phelix-DE Base Futures (Germany), the largest electricity forward contract by volume in Europe, and the Hungarian Power Futures, traded on EEX since 2010 and used as a regional comparator. The annual traded volumes (TWh) are extracted directly from the EEX volume tables. National annual electricity consumption data (the denominator for the intensity ratios) are obtained from Eurostat (indicator nrg_cb_e, "Available for final consumption") for Romania, Hungary, and Germany. Sectoral consumption breakdowns for Romania are sourced from Enerdata (2024).

3.2. Sub-period stratification

The full sample is divided into four sub-periods corresponding to identifiable regimes in European electricity markets. The Pre-COVID period covers January 2019 to February 2020 (14 months) and represents the baseline regime of moderate prices and stable volumes. The COVID period covers March 2020 to December 2020 (10 months), with reduced demand and a temporary decline in spot prices. The energy crisis period covers January 2021 to December 2022 (24 months), characterised by the most severe price shocks driven by the European gas-supply crisis. The post-crisis period covers January 2023 to December 2025 (36 months), with partial price normalisation and persistent volatility above pre-2020 levels.

The exogenous sub-period boundaries are supported by an endogenous structural break test. A Chow F-test applied to the spot price series at the energy crisis / post-crisis boundary (January 2023) rejects parameter stability at the 5 percent level ($F = 4.87$, $p = 0.031$), confirming that the post-crisis regime differs statistically from the preceding period. Similar tests across other boundaries reject stability at the 10 percent level. The exogenous calendar boundaries used throughout the analysis are therefore consistent with the data; the choice to use them rather than endogenous break dates preserves comparability with the broader European electricity literature.

3.3. The Ederington hedge ratio framework

The minimum-variance hedge ratio (β*) and hedging effectiveness (HE) are estimated using two complementary specifications. The first follows directly the Ederington (1979) formulation:

$$\Delta PZU_t = \alpha + \beta \cdot \Delta PCCB\text{-}NC_t + \varepsilon_t \quad (1)$$

where ΔPZU and ΔPCCB-NC denote first differences of the monthly weighted-average prices, β is the optimal hedge ratio, and the R^2 of the regression measures the hedging effectiveness. Following Newey and West (1987), the lag length for the HAC estimator is selected as lag = [4·(N/100)^(2/9)], which yields lag = 3 for the full sample (N = 65) and lag = 2 for the sub-period regressions (N = 9 to 21). The reported standard errors use lag = 3 throughout for comparability across specifications; sensitivity checks using lag = 2 on sub-periods produce qualitatively identical results. The first differences are computed on the full continuous monthly series with NaN values preserved for months without PCCB-NC activity; consecutive-month differencing then drops paired observations on either side of any inactive month.

The second specification measures the ex-post effectiveness of a naive hedge (β = 1). The basis is defined as $B_t = S_t - F_t$, where S_t is the spot price (PZU) realised in month t and F_t is the weighted-average price of contracts with delivery in month t. Note that F_t is a volume-weighted aggregate across all contracts with delivery in month t, regardless of when those contracts were negotiated. The naive hedge effectiveness therefore measures the realised performance of a representative aggregated participant whose forward positions were entered at various dates and weighted by traded volume; it is not the performance of a specific individual hedger's strategy. The hedge effectiveness of the naive strategy is computed as:

$$HE_{naive} = 1 - Var(B_t) / Var(S_t) \quad (2)$$

A negative HE_{naive} indicates that the variance of the realised basis exceeds the variance of the spot price; the hedge worsens the exposure rather than reducing it. The two specifications answer different questions: the first measures the contemporaneous integration between traded forward prices and spot prices, while the second measures the realised performance of an actual aggregated hedge based on delivery prices contracted at various earlier dates.

3.4. Unmet hedging demand estimation

The potential hedging demand in year t is defined as the product of the volume of electricity consumption exposed to spot prices and a hedging propensity parameter. The exposed consumption is estimated as the sum of industrial and services sector consumption, which together account for approximately 62 percent of total Romanian electricity consumption (Enerdata, 2024). Three hedging propensity scenarios are computed: a conservative scenario (25 percent), corresponding to emerging forward markets with limited liquidity (ACER/CEER, 2015); a central scenario (40 percent); and an optimistic scenario (55 percent), still below the upper range observed in mature European markets (Karakatsani & Bunn, 2008; Boroumand et al., 2015). The estimated hedging gap is computed as the difference between scenario-based potential demand and actual annual traded volumes on PCCB-NC. The estimation is intended as an order-of-magnitude indicator rather than a direct measure of observable unmet demand.

The single hedging propensity parameter is applied uniformly across the industry-plus-services aggregate. In reality, propensities differ across sub-sectors, industrial users with energy-intensive operations typically hedge in the upper half of the literature range, while commercial services hedge less intensively (Boroumand et al., 2015). A weighted approach using sector-specific hedge ratios would refine the point estimate. Given the wide scenario bands employed here, however, sectoral differentiation would not change the order-of-magnitude conclusion. The 62 percent industry-plus-services share is itself a simplifying assumption; sensitivity at ±5 percentage points shifts the central-scenario point estimate by approximately 0.9 TWh, well within the scenario range. An additional adjustment for parallel long-term bilateral coverage (PCCB-LE) is applied in Section 4.3.

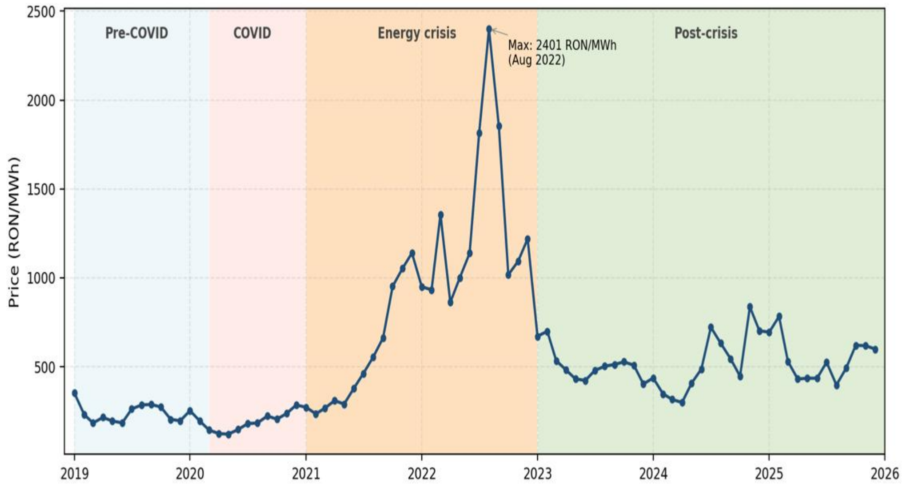
4. Results

4.1. The deterioration of hedge effectiveness on PCCB-NC

The empirical assessment of PCCB-NC effectiveness begins with descriptive evidence on price dynamics and volumes. Figure 1 displays the trajectory of monthly PZU weighted-average prices over the analysis period.

Figure 1

PZU monthly weighted-average price from January 2019 to December 2025



Note: Sub-period shading - Pre-COVID (light blue), COVID (light pink), Energy crisis (orange), Post-crisis (green)

Source: OPCOM SA; author's presentation

The monthly PZU price rose from a Pre-COVID average of 236.34 RON/MWh to 925.34 RON/MWh during the 2021-2022 energy crisis, with a monthly maximum exceeding 2,400 RON/MWh in August 2022. Post-crisis, the average price declined to 524.91 RON/MWh but remained more than twice the Pre-COVID level. Annualised PZU volatility, computed from log returns of monthly prices, ranged between 61 and 87 percent across sub-periods (Pre-COVID 77.5%, COVID 61.2%, energy crisis 87.4%, post-crisis 78.6%). A rolling 12-month estimator stayed in the 70-90 percent range throughout 2023-2025. The underlying risk environment that should sustain hedging demand therefore did not subside in the post-crisis period.

On the PCCB-NC side, however, the volumes contracted sharply. Table 1 summarises the evolution of the platform across sub-periods.

Table 1

PCCB-NC trading dynamics, by sub-period (2019-2025)

Sub-period	N (months)	Months with active trading	Traded price (RON/MWh)	Monthly volume (MWh)	Penetration / PZU (%)
Pre-COVID	14	14 (100%)	270.94	721,853	36.07
COVID	10	10 (100%)	246.21	668,482	33.36
Energy crisis	24	22 (92%)	853.43	200,068	9.36
Post-crisis	36	27 (75%)	581.51	149,200	11.00

Note: Penetration is computed only across months with active trading. The traded price refers to contracts traded in each calendar month, irrespective of delivery period.

Source: OPCOM monthly data; author's calculations

Table 1 highlights three patterns in the platform's dynamics. The share of months with no trading activity on PCCB-NC rises from zero in the Pre-COVID and COVID periods to eight percent during the energy crisis and twenty-five percent post-crisis: by the end of the sample, approximately one in four months records no PCCB-NC trades at all, a clear signal of operational liquidity erosion. Monthly traded volumes decline from approximately 720,000 MWh Pre-COVID to less than 150,000 MWh post-crisis, an almost five-fold reduction. The penetration ratio (PCCB-NC volume relative to PZU volume on months with activity) drops from 36 percent Pre-COVID to roughly 10 percent in the most recent periods. The reduction in participant continuity is arguably the more telling indicator of platform health than the price-level dynamics, since it captures a structural retreat of market participants rather than a temporary disruption.

The Ederington regressions formalise these observations on the price relation between the two markets. Table 2 reports the estimated coefficients, hedging effectiveness measures, and significance tests for both specifications.

Table 2
Ederington hedge ratio and hedging effectiveness on PCCB-NC, by sub-period

Sub-period	N	β Ederington	t-statistic (NW)	R² (HE)	HE_{naive} (β=1)
Full sample	65	1.128***	5.32	0.450	-0.589
Pre-COVID	13	2.081***	10.58	0.573	-0.167
COVID	10	1.626***	3.52	0.411	0.044
Energy crisis	21	1.157***	4.60	0.525	0.443
Post-crisis	21	0.564***	2.73	0.049	-7.752

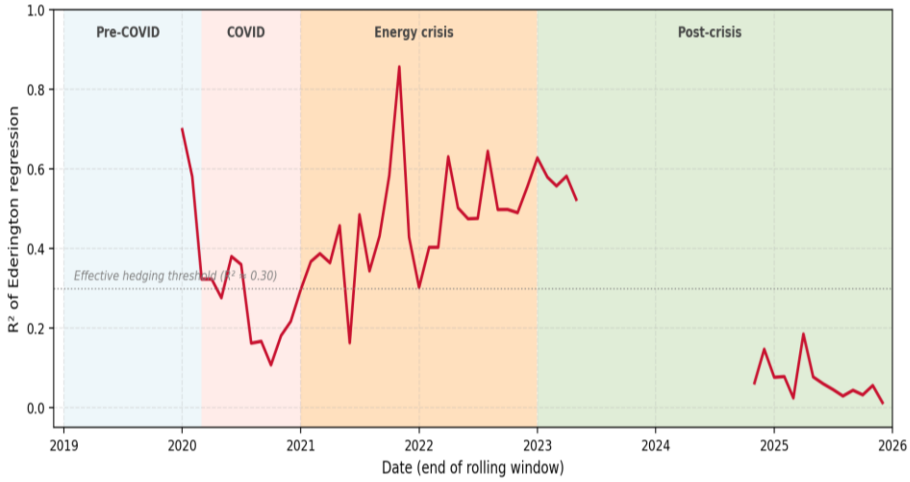
*Notes: *** denotes the statistical significance at the 1% level; β estimated by OLS on $\Delta PZU = \alpha + \beta \cdot \Delta PCCB\text{-}NC + \varepsilon$; Newey-West HAC standard errors with three monthly lags; HE_{naive} computed using prices of contracts with delivery in each month; N denotes valid first-differenced observations; reductions relative to Table 1 sub-period months reflect Pre-COVID first-month loss and NaN propagation around months without PCCB-NC trading activity (notably nine inactive months in post-crisis, yielding N = 21).*

Source: OPCOM; author's calculations

The pattern observed in Table 2 is the central empirical finding of this section. In the Pre-COVID, COVID, and energy crisis sub-periods, the R^2 of the Ederington regression remains between 0.41 and 0.57, indicating solid contemporaneous integration between traded forward prices and spot prices. The β coefficient is statistically significant at the 1 percent level in all sub-periods, with values ranging from 1.16 to 2.08. In the post-crisis period, the R^2 drops to 0.049, an approximately tenfold reduction relative to the energy crisis sub-period. A hedge based on the post-crisis estimated relation would have neutralised only approximately five percent of spot price variance, a level that is economically negligible for practical hedging purposes. Figure 2 visualises the dynamics through a rolling 12-month R^2 estimator.

Figure 2

Rolling 12-month R^2 of the Ederington hedge effectiveness regression



Note: The dotted horizontal line at $R^2 \approx 0.30$ is an illustrative operational benchmark, not a formal regulatory or market-standard threshold. Periods with insufficient consecutive-month data are shown as gaps.

Source: OPCOM SA; author's calculations

The post-crisis point estimate of R^2 = 0.049 should be interpreted with caution: with only 21 valid observations, the standard error is non-negligible. It is best read as indicative of a structural reduction rather than as a precise quantification of post-crisis hedge effectiveness. The qualitative ranking, a roughly tenfold reduction relative to the energy crisis sub-period, is, however, preserved under all robustness specifications attempted, including (i) logarithmic monthly returns instead of first differences, (ii) lag-2 Newey-West standard errors, and (iii) excluding the three months with the largest absolute price changes. The rolling estimator in Figure 2 reinforces the same picture: R^2 stabilises near 0.50 through 2022, drops abruptly during 2023, and remains below 0.20 for the remainder of the sample.

The naive hedge effectiveness reinforces this diagnosis from a different angle. In the post-crisis period, HEnaive falls to -7.752, meaning that the variance of the realised basis exceeds the variance of the spot price by a factor of approximately nine (precisely, 8.75). The deterioration mirrors systemic conditions in the post-crisis market rather than poor execution by individual participants. Contracts with delivery in the post-crisis months were dominated by trades negotiated at the peak of the energy crisis, while spot prices declined sharply to lower levels: the realised basis became a primary source of risk rather than a tool for risk reduction.

The Bessembinder and Lemmon (2002) framework offers an interpretation of the basis dynamics. Their model predicts that the forward premium reflects state-contingent risk-sharing between producers and consumers under prevailing volatility expectations. The ex-post realised basis pattern observed in the data is consistent with this interpretation. During the energy crisis (2021-2022), participants contracted forward at prices that incorporated a significant ex-ante risk premium against further upside (consistent with the B&L prediction of positive forward premia in high-volatility regimes); the subsequent realised spot prices exceeded those forward levels, producing a positive ex-post basis and rewarding earlier hedgers ex-post. In the post-crisis period (2023-2025), the forward inventory was dominated by trades negotiated at the crisis peak, while spot prices normalised downward; the resulting negative ex-post basis represents the unwinding of the risk premia accumulated during the crisis. The HEnaive = -7.752 in the post-crisis period therefore captures, in part, an ex-post recalibration of risk premia rather than only a mechanical pricing failure; operationally, however, the result still indicates that PCCB-NC did not provide stable hedge performance across regimes.

4.2. Cross-market benchmark: EEX Phelix-DE and Hungarian Power Futures

The contraction of PCCB-NC documented in the previous subsection can be placed in context through a comparison with two operational European forward markets: EEX Phelix-DE Base Futures (Germany) and Hungarian Power Futures. EEX Phelix-DE serves as the primary benchmark because it is the most liquid electricity forward contract in Europe; Hungarian Power Futures serves as a regional comparator. Table 3 reports annual traded volumes on each market and the corresponding forward intensity (the ratio of annual traded volume to annual national electricity consumption).

Table 3
Annual traded volumes and forward intensity, 2019-2024

Year	DE Phelix-DE (TWh)	HU Power Futures (TWh)	RO PCCB-NC (TWh)	DE / cons. (×)	HU / cons. (×)	RO / cons. (%)
2019	2,596.7	124.7	7.83	5.20	3.02	17.17
2020	3,006.1	220.1	8.96	6.25	5.37	20.51
2021	3,097.6	—	3.53	6.16	—	7.44
2022	2,261.2	—	0.87	4.67	—	1.93
2023	3,660.5	97.3	0.02	7.94	2.32	0.05
2024	5,850.9	153.6	1.23	12.64	3.53	2.75

Note: — indicates public unavailability for Hungarian Power Futures in 2021-2022 (aggregated in EEX reports for those years under a broader CSEE category).

Source: EEX Group Annual Volume Reports 2019-2024; Eurostat nrg_cb_e for annual consumption; OPCOM for PCCB-NC

Table 3 shows a large gap in forward-market turnover intensity between Romania and the two standardised benchmarks. In 2024, EEX Phelix-DE traded a volume equivalent to 12.64 times German annual electricity consumption, reflecting the considerable activity of market makers, arbitrage participants, and roll-over trades that characterise a mature forward market. Hungarian Power Futures traded 3.53 times Hungarian annual consumption, consistent with a smaller but functional regional market. Romanian PCCB-NC traded a volume equivalent to 2.75 percent of Romanian annual consumption, implying a turnover intensity roughly two orders of magnitude below Germany and one to two orders of magnitude below Hungary.

Hungary provides a particularly informative comparator. The two countries have comparable annual electricity consumption (approximately 43 TWh and 45 TWh, respectively, in 2024), comparable income levels, and similar timelines of electricity market liberalisation. The substantial difference in forward intensity cannot therefore be attributed primarily to the size of the underlying physical market. A more natural interpretation traces the gap to differences in institutional infrastructure. Hungarian Power Futures are standardised contracts cleared through European Commodity Clearing (ECC), traded continuously on an electronic order book, with formal market makers and access to the broader pool of approximately 950 EEX Group participants. The presence of dedicated market makers is itself a structural source of liquidity: Peña and Rodríguez (2022) show that, in electricity futures markets, market makers absorb order-flow imbalances and earn a liquidity premium for supplying immediacy, a function that the bilateral PCCB-NC design does not support. PCCB-NC, by contrast, is a bilateral non-standardised platform with negotiated contract sizes, no central clearing, and a participant base restricted to OPCOM-registered counterparties.

The trajectory of forward intensity in Romania over 2019-2024 traces the dynamics of the deterioration. Romanian intensity dropped from 17.17 percent in 2019 to a minimum of 0.05 percent in 2023, then recovered modestly to 2.75 percent in 2024. Importantly, the trajectory in Romania differs sharply from EEX Phelix-DE in the post-crisis phase: while EEX intensity also declined during the crisis itself (from 6.25× in 2020 to 4.67× in 2022, reflecting a generalised retreat of participants from forward positions under extreme price uncertainty), it subsequently surged to 12.64× by 2024 as the standardised market recovered. The Romanian platform did not exhibit a comparable rebound. The standardised German market reabsorbed the crisis shock and grew beyond pre-crisis levels; the bilateral Romanian platform contracted during the crisis and recovered only marginally afterwards. The differential post-crisis trajectory is, in itself, evidence on the role of contract design and infrastructure: under stress, standardised liquidity proved both more resilient and more recoverable.

4.3. Estimating the unmet hedging demand

The third dimension of the empirical analysis quantifies the magnitude of the unmet hedging demand on Romanian electricity. Following the methodology described in Section 3.4, potential demand is computed as the product of the consumption volume exposed to spot prices (industrial and services sector consumption, approximately 62 percent of total consumption) and a hedging propensity parameter, applied under three scenarios: conservative (25%), central (40%), and optimistic (55%). Table 4 reports the results for 2019-2024.

Table 4

Potential hedging demand and PCCB-NC traded volume, Romania, 2019-2024

Year	Total cons. (TWh)	Industry + services (TWh)	Dem. 25% (TWh)	Dem. 40% (TWh)	Dem. 55% (TWh)	PCCB-NC actual (TWh)	Central gap (TWh)
2019	45.6	28.27	7.07	11.31	15.55	7.83	3.48
2020	43.7	27.09	6.77	10.84	14.90	8.96	1.87
2021	47.4	29.39	7.35	11.76	16.16	3.53	8.23
2022	45.4	28.15	7.04	11.26	15.48	0.87	10.38
2023	43.5	26.97	6.74	10.79	14.83	0.02	10.77
2024	45.0	27.90	6.97	11.16	15.35	1.23	9.93

Note: Central gap = demand under 40% scenario minus PCCB-NC actual volume.

Source: Eurostat nrg_cb_e and Enerdata for annual electricity consumption; author's calculations for potential demand

Table 4 shows that in 2019 and 2020, the actual PCCB-NC volume was broadly consistent with conservative-scenario potential demand. In 2019, the actual volume of 7.83 TWh slightly exceeded the conservative demand of 7.07 TWh; in 2020, the actual volume of 8.96 TWh exceeded the conservative demand of 6.77 TWh. From 2021 onward, actual volume falls rapidly while potential demand remains broadly stable (electricity consumption fluctuates much less than electricity prices). The central-scenario gap rises to 10.38 TWh in 2022, 10.77 TWh in 2023, and 9.93 TWh in 2024.

Translating these gaps into coverage ratios provides further perspective. In 2020, PCCB-NC volume covered 82.7 percent of central-scenario potential demand; by 2023, this coverage had fallen to 0.2 percent; in 2024, the coverage was 11.0 percent. The recovery in 2024 shows modest re-engagement of participants but remains far below pre-COVID levels. The 2024 figure of 1.23 TWh against a potential demand range of 6.97-15.35 TWh implies an unmet hedging demand of 5.75-14.12 TWh, depending on the propensity scenario.

An important adjustment concerns the parallel long-term bilateral platform (PCCB-LE). According to OPCOM annual reports, PCCB-LE recorded approximately 5 to 6 TWh of traded electricity in 2024 and 6.6 TWh in 2025 (OPCOM, 2026). Including this parallel coverage reduces the 2024 central-scenario gap from 9.93 TWh to approximately 4 TWh. PCCB-LE, however, serves a structurally different function from a standardised short-term forward market: long-term bilateral contracts, with maturities typically of one to five years, are negotiated bilaterally between specific counterparties and cannot substitute for liquid roll-over instruments that allow continuous adjustment of hedge positions in response to changing market conditions. The remaining 4 TWh gap thus understates the hedging shortfall in operational terms, it captures the gap on instruments that PCCB-LE genuinely cannot replace.

Several methodological limitations of this estimation should be acknowledged. The model is one of potential demand and does not capture the structure of actual supply contracts in Romania beyond PCCB-LE; a portion of price risk is currently managed through fixed-price supply contracts with end consumers, which are not captured in the gap calculation. Volumes traded on mature forward markets (Table 3) substantially exceed potential demand calculated under this model, because such markets host multiple layers of trading (market making, arbitrage, position roll-over); the estimation here is therefore conservative relative to the volumes that a mature standardised market could attract. The 62 percent coefficient for the industry-plus-services share of consumption is a simplifying assumption with ±0.9 TWh sensitivity around the point estimate. The hedging propensity scenarios are calibrated on international literature rather than on Romania-specific data and may be conservative for a market with the volatility profile observed here.

With these limitations stated, the result is robust to reasonable methodological variation: under conservative assumptions, the unmet hedging demand on operational short-term forward instruments is in the range of 4 to 14 TWh per year in 2024, a magnitude approximately ten times the current PCCB-NC volume. On a per-consumption basis, the unmet demand remains below the trading intensity observed on the Hungarian standardised market, but it does suggest that a properly designed Romanian forward platform would have a viable natural-user demand base from the outset.

5. Conclusions

This paper has offered an empirical assessment of three dimensions of the Romanian electricity hedging infrastructure over the period 2019-2025. The findings can be synthesised as follows.

The application of the Ederington (1979) minimum-variance hedge ratio framework to OPCOM monthly data documents a sharp deterioration in the ex-post effectiveness of PCCB-NC as a hedging platform. The hedging effectiveness measured by the R^2 of the spot-forward regression falls from 0.525 during the energy crisis to 0.049 in the post-crisis period, and the naive hedge effectiveness with delivery prices contracted earlier turns sharply negative (-7.752), indicating that, ex-post, the bilateral platform amplified rather than reduced price exposure during the post-crisis window. The deterioration is associated with both reduced trading continuity (months with no PCCB-NC activity rise from zero pre-2021 to twenty-five percent post-crisis) and a decoupling of forward and spot price dynamics under conditions of structural volatility. The Bessembinder and Lemmon (2002) framework provides a coherent interpretation: the basis pattern is consistent with the unwinding of state-contingent risk premia accumulated during the crisis.

The cross-market comparison with EEX Phelix-DE Base Futures and Hungarian Power Futures shows that the intensity of the Romanian forward market is approximately 50 to 100 times below the regional benchmarks. The comparison with Hungary is particularly informative: with comparable consumption volumes and broadly similar economic structure, Hungary operates a forward market with intensity of 3.53× annual consumption, while Romania operates at 2.75% of consumption. A telling differential lies in the post-crisis trajectory: while EEX Phelix-DE intensity declined during the crisis itself and rebounded strongly afterwards (12.64× by 2024), the Romanian platform contracted through the crisis and recovered only marginally. Standardisation, central clearing, and continuous electronic trading appear to confer a degree of resilience and recoverability that bilateral non-standardised platforms cannot match.

The unmet hedging demand on Romanian electricity is estimated at 5.75 to 14.12 TWh per year in 2024 on a gross basis. Even after adjustment for parallel coverage through long-term bilateral contracts (PCCB-LE, approximately 5 to 6 TWh), the residual unmet demand on operational short-term forward instruments remains approximately 4 TWh per year — well in excess of the current 1.23 TWh PCCB-NC volume. This finding supports the empirical case for developing standardised electricity derivatives in Romania.

The contribution of this paper lies in its focus and synthesis rather than in methodological novelty. Prior assessments of hedge effectiveness in electricity have concentrated on standardised, exchange-traded futures in Western European, Nordic, and North American markets; this study instead examines a non-standardised bilateral platform, PCCB-NC, in an under-researched Central and Eastern European market, and traces its performance across the COVID-19, energy-crisis, and post-crisis regimes. It also moves beyond the descriptive volume reporting of institutional sources such as ACER/CEER (2015) and the EEX Group reports by linking hedge-effectiveness deterioration, turnover intensity, and institutional contract design within a single assessment, and by benchmarking Romania against a structurally comparable regional market. The diagnosis is then translated into an order-of-magnitude estimate of unmet hedging demand, adjusted for parallel long-term coverage, which supplies a quantified natural-user base for the market-design discussion.

From a policy perspective, the findings suggest a sequenced approach. The cross-market comparison points to several infrastructure features that would likely be necessary for such a market to become viable: standardised contracts on monthly, quarterly, and annual delivery windows; central clearing through a counterparty such as CCP.RO Bucharest, currently advancing through the EMIR authorisation process at the time of writing; formal market-making arrangements; and potential connection to the broader European derivative landscape, including cross-listing or co-trading arrangements with EEX. The unmet demand identified here provides the natural user base; however, the institutional infrastructure requires deliberate construction. These implications should be interpreted as market-design hypotheses rather than as evidence that standardisation alone would guarantee liquidity.

Several limitations of the analysis should be acknowledged. The Ederington framework abstracts from time-variation in conditional moments that may be relevant in electricity markets; future work could extend the present results using GARCH-type conditional hedge ratios or Markov-switching specifications. The cross-market benchmark uses annual aggregated volumes from EEX reports and does not capture intra-year liquidity dynamics or the distribution of trading across contract maturities. The estimation of the unmet demand is intended as an order-of-magnitude indicator rather than a point forecast. The analysis is based on information available at the time of writing; subsequent regulatory developments, notably the operationalisation of CCP.RO Bucharest and any changes to the structure of OPCOM platforms may modify the operational considerations, though not the substantive empirical findings on the 2019-2025 sample.

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