Energy Community Secretariat

2026/2

CBAM Quarterly report

27 July 2026

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Introduction

Following its report on the first quarter of 2026, the Energy Community Secretariat continues to publish regular overviews of the main trends and movements in electricity markets in Energy Community Contracting Parties and neighbouring Member States with special focus on the potential policy and market impacts triggered directly or indirectly by the European Union's Carbon Border Adjustment Mechanism (CBAM).
This edition includes an additional chapter providing details of implementation questions raised by stakeholders in renewable energy.

Scope of assessment

The analysis focuses on the six Western Balkans Contracting Parties (WB6, i.e. Albania, Bosnia and Herzegovina, Kosovo*[1], Montenegro, North Macedonia, and Serbia) and their neighbouring EU Member States (Bulgaria, Croatia, Greece, Hungary, Italy, and Romania). Regarding the remaining three Contracting Parties, Ukraine and Moldova are not covered due to limited data availability, while Georgia is not included because it currently has no interconnections with any Contracting Party or Member State, meaning that CBAM has no direct impact on its electricity market. The Q2 2026 assessment covers developments in electricity generation, day-ahead prices, cross-border price spreads, price correlations, cross-border average daily capacity prices, power exchange (PX) liquidity, as well as scheduled and physical electricity flows. Compared with the Q1 2026 report, the analysis on electricity generation has been expanded to cover the full production mix available on the ENTSO-E Transparency Platform, and the assessment now also includes cross-border average daily capacity prices.

[1] Throughout this report, this designation is without prejudice to positions on status, and is in line with UNSCR 1244 and the ICJ Opinion on the Kosovo* declaration of independence.

CBAM Quarterly report

Q2 2026 is the second quarter under CBAM's definitive period, and the first interval that allows both a quarter-on-quarter comparison within the definitive period and an initial half-year (H1 2026) view. As in the previous edition, the findings should be read as preliminary observations of emerging patterns, not as definitive conclusions. One important caveat remains: CBAM started on 1 January 2026 at the same time as the emergence of exceptionally favourable hydrological conditions across the region, so the effects of CBAM and the hydro surplus in Q1 2026 cannot be fully separated. Seasonal factors and changing market conditions continued to play an important role in Q2 2026: the developments described in this edition were shaped by the fading of that hydro surplus and by a decrease in the average day-ahead prices in the neighbouring EU Member States. Therefore, the outlined developments should not be attributed solely to CBAM.

Highlights

01. The price spreads between Member States and Contracting Parties narrowed but remained below the level of convergence recorded in 2025.

02. Price correlations improved due to the region being a price taker in Q2, turning into a net importer with minimum exports due to the depletion of hydro surplus.

03. The commercial exchanges between Member States and Contracting Parties showed a sign of recovery, but remained at lower levels than recorded 2025, accompanied by increasing intra-regional commercial activity.

04. Ukraine might be emerging as a primary destination market for surplus electricity from the Western Balkans while electricity within the region is increasingly channelled northwards through Serbia towards the Hungarian border rather than being absorbed within the region.

05. The persistent divergence between commercial and physical flows suggests that it will make it more expensive/complex to maintain grid stability.

06. Default emission factors still appear to influence cross-border flows. However the recovery on some corridors (such as Montenegro→Italy) suggests that some market participants may be taking into account a broader scope of expectations in addition to price spreads and CBAM-induced costs when conducting commercial operations. Such considerations may include the relative stability of the quarterly EU ETS price and the anticipated policy changes stemming from the revision of the CBAM Regulation.

07. Producers of renewable electricity and project developers in Contracting Parties are facing objective challenges and increased uncertainty in projected revenues seeking to meet the CBAM conditions for the use of actual emission values. Further guidance regarding the implications of the conditions on various types of power purchase agreements (PPAs) would help renewable operators and project promoters better plan their business strategies.

Detailed observations and potential implications of CBAM on EU Member States' and Energy Community Contracting Parties' electricity markets in Q2 2026

Q2 2026 provides the first view of whether the electricity market patterns observed at the start of CBAM's definitive period continued, faded, or evolved as the exceptional hydrological conditions of early 2026 weakened. The data suggest a mixed picture: several Q1 frictions eased, while others persisted or emerged in a different form. Hydrology, price movements in neighbouring EU markets, and CBAM all contributed to shaping these developments.[2]

1. *The price spreads between Member States and Contracting Parties narrowed but remained below the level of convergence recorded in 2025*

The pronounced Q1 2026 price divergence narrowed clearly in Q2 2026, mainly because EU benchmark prices declined, with Hungary falling from €127.5/MWh to €109.2/MWh and Italy from €130.3/MWh to €120.9/MWh. By contrast, prices in the observed Western Balkans zones changed only marginally. Albania and Kosovo*, both observable for the first time, averaged €88.6/MWh and €89.0/MWh, respectively, placing them within the lower-priced Western Balkans cluster. Serbia effectively realigned with Bulgaria, while North Macedonia kept close to Greece. The widest residual gaps remained on the Italian (around €27/MWh above Montenegro) and Hungarian (around €13/MWh above Serbia) borders. Such a narrowing reflects lower EU demand, decreased gas-linked generation costs, and stronger spring renewables production rather than a recovery of cross-border trade. Average prices over H1 2026 the neighbouring EU bidding zones remained well above the Western Balkans (Italy being the highest at €125.5/MWh versus Albania being the lowest at €86.3/MWh), whereas the average prices in the bidding zones of both Western Balkan Contracting Parties and EU neighbouring Member States had been broadly aligned in H1 2025. The H1 year-on-year gap has therefore widened, and the Q2 price spread narrowing is best interpreted

[2] Q1 2026 figures cited in this edition reflect the data available at the time of preparation, including subsequent resubmissions to the ENTSO-E Transparency Platform, and may therefore differ marginally from the figures published in the Q1 2026 edition.

as an easing within 2026, rather than a return to the pre-CBAM relationship. Nor should it be read in isolation as evidence of CBAM's effect in either direction.

2. *Price correlation recovered, but unevenly*

The rolling 30-day correlation with the Hungarian benchmark, near zero in January 2026, recovered to around 0.91 for Serbia and 0.82 for Montenegro by the end of June, close to their 2025 baseline. However, North Macedonia, and coupled Albania and Kosovo*, fell to roughly 0.33 in early June before rebounding only partly, to around 0.77 and 0.70 respectively. In well-integrated markets, correlations would normally stay consistently above 0.80. The rebound is most plausibly linked to the fading hydro surplus, which returned the region to its seasonal position of net-importer and price taker thereby strengthening its exposure to the prices in the EU benchmark zones.

3. *The region returned to net imports, while WB6–EU exchange remained lower*

The region reverted from the atypical Q1 net-exporter position (approximately 1,247 GWh) to net imports of around 1,048 GWh in Q2 2026, which is close to the level of Q2 2025. Regardless of the region again becoming a net importer in Q2 2026, the balance of H1 2026 shows a minimal net export position of 199 GWh against a 1,609 GWh of net imports in H1 2025. Such a change was expected following the exceptional hydrology in Q1 2026 in Contracting Parties. The level of commercial activity adds an important element to this picture. Gross WB6–EU exchange fell by roughly 15% year-on-year in Q2, after the 23% drop registered in Q1 2026. This leaves H1 2026 some 19% below H1 2025 levels. At the same time, day-ahead trading across all four power exchanges in the Western Balkans Contracting Parties moved in the opposite direction, rising in Q2 2026 about 19% to 2.70 TWh. The increase took place on all exchanges – including SEEPEX, which registered reductions earlier in Q1 2026 –, therefore overall trading activity in the region appears to pick-up. The simultaneous reduction in cross-border exchanges between Member States and Contracting Parties, may be attributed to multiple drivers such as CBAM-related costs, residual regulatory uncertainty, hydrology and price levels, without the possibility to pinpoint either of those as major triggers for such a development. However, if this pattern persists, it could weaken regional trade depth and slow market integration between the markets of EU Member States and Contracting Parties even as domestic liquidity improves.

4. *Trade flows shifted towards new demand and supply centres*

Trade consolidated around two centres, rather than reverting to its 2025 configuration. Serbia→Hungary more than doubled (+111%) in comparison with Q2 2025, and Romania→Hungary rose 156%, which is consistent with Ukraine's import needs being served through the Hungarian hub. Greece maintained its role as a supply source towards Bulgaria (+139%), North Macedonia (+70%) and Albania (+6%), while Albania→Greece fell to 196 GWh after its hydro-driven Q1 2026 surge. Other transit-linked routes showed no recovery. The shift seems to be driven by solar output, Ukrainian demand, fuel costs and emission-factor economics, so the redirection seems to be catalysed rather than exclusively caused by CBAM. The changes suggest that the Q1 2026 reallocation of flows across the region might have already been showing the early signs of structural reformulation rather than just accidental changes. If that shift is consolidated, it may have a lasting effect on the use and valuation of cross-border capacity.

5. *Commercial schedules and physical flows continued to diverge*

The divergence identified in Q1 2026 persisted and widened on some borders: on BA→HR, scheduled flows fell about 43% while physical flows rose roughly 270% (824 GWh crossing against 282 GWh scheduled), on Albania→Greece schedules held (+3%) while physical flows fell about 63%, and physical flows generally intensified along the south-to-north axis feeding the EU borders. Normally, schedules and physical flows should move broadly together since schedules are the key input for operational planning and operational security analysis performed by TSOs. If persistent, the mismatch reduces flow predictability, requires larger security margins and more frequent redispatch and countertrading, with costs ultimately borne through network tariffs, and weakens the link between where congestion arises and where congestion income accrues. These effects are regional and reinforce the case for coordinated capacity calculation and congestion management.

6. CBAM default emission factors varying impact on competitiveness

In Q2 2026, the widest residual spreads remained on corridors with high default emission factors, led by Montenegro–Italy at around −€27.2/MWh, [3] where Montenegro's default factor of 0.979 tCO_{2eq}/MWh implies a CBAM cost of the order of €74/MWh. Exports nevertheless held where the remaining gap could potentially absorb this wedge (Montenegro→Italy recovered by around 19% compared to Q2 2025) or are driven by transit towards Ukraine (Serbia→Hungary more than doubled compared to Q2 2025). Albania, with a zero factor, maintained exports (+3%) at a spread of only −€1.6/MWh, while North Macedonia→Greece fell 78% as the opposite direction rose around 70% compared to Q2 2025. This two-tier pattern supports that the cost wedge remains material for arbitrage, however, generation mix, plant availability and hydrology also play an important role. If the phenomenon persists, it may entrench uneven competitive positions, with consequences for regional investment signals.

7. EU ETS price and CBAM certificate costs stabilised

The price of CBAM certificates[4], based on the average EU ETS auction price, was €75.28/tCO_2 in Q2 2026, almost unchanged from Q1 (€75.36/tCO_2). The daily price narrowed from approximately €62–91 in Q1 to €70.6–80.4/tCO_2 in Q2. As the default emission factors are also unchanged, the implied CBAM cost per imported MWh remained stable across H1 2026, even though this could not yet be known at the time of imports. Nevertheless, the expectations for stable CBAM costs temporarily removed one source of uncertainty and coincided with a partial recovery in exports through carbon-intensive corridors. The experience of Q1 2026 also shows how strongly the profitability of electricity exports from Contracting Parties can depend on EU ETS prices.

[3] Consolidating at −€35.8/MWh over H1 2026, from roughly −€44/MWh in Q1 2026

[4] https://taxation-customs.ec.europa.eu/carbon-border-adjustment-mechanism/price-cbam-certificates_en

The lower price volatility observed in Q2 should therefore not be assumed to continue, particularly in view of the ongoing reform of the EU ETS.

8. *Amendments to the CBAM Regulation may result in lower default emission values and more realistic conditions to use actual emission values*

The interinstitutional negotiations in the EU regarding the amendments to the CBAM Regulation are reaching a mature stage with a political decision expected towards the end of 2026. The current positions of the co-legislators – the Council and the European Parliament – leave the relevant proposals of the European Commission unchanged. Those proposals include considering the emission intensity of the whole electricity mix for calculating default emission factors instead of focusing only on the fossil-fuel-based part, and adjusting the conditions for using actual emission values. Regarding the latter, the removal of the criterion of no congestion at the time of the electricity exports is essential for facilitating the use of this opportunity. Those changes could take effect retroactively – i.e. from 1 January 2026 – if the Commission's proposals are adopted without changes.

To sum up, Q2 2026 points to a partial easing of the frictions observed at the start of CBAM's definitive period. As hydrology normalised, prices partly reconverged, correlations recovered, the region returned to its seasonal net-importer position, and exports resumed on corridors where the remaining price spreads could absorb costs implied by the default emission factors. The data, do not, however, show a full return to the 2025 pattern, Gross WB6–EU electricity exchange remained lower, trade continued to consolidate around new channels, commercial and physical flows remained divergent, and the widest spreads persisted on corridors exposed to high implied CBAM costs. Compared with H1 2025, price spreads were wider and cross-border exchanges lower despite the easing observed in Q2 2026. Data from further quarters will be needed to determine whether these developments are temporary or signal a more structural change in regional electricity trade.

The financial impact of using national emission factors in CBAM

The price of CBAM certificates for Q2 2026 electricity imports, was **€75.28/tCO_2**. This was essentially unchanged from the €75.36/tCO_2 recorded for Q1 2026. The stable quarterly average, however, masks a clear reduction in short-term volatility: the daily auction price ranged between €70.60 and €80.43/tCO_2 in Q2 2026, is much narrower than the €62.19–€91.34/tCO_2 range observed in Q1.

Figure 1. Primary EU ETS auction price (EEX)

Volume-weighted mean of EEX primary auction clearing prices · shaded band = reporting window (Q2 2026)

Source: European Energy Exchange (EEX) primary auction benchmark. Aggregated by the Energy Community Secretariat.

Using the default values published in the European Commission's relevant implementing regulation,[5] the specific CBAM-related costs for importing electricity from Contracting Parties to the EU in Q2 2026 are shown below, almost unchanged from Q1.

[5] Commission Implementing Regulation (EU) 2025/2621 laying down rules for the application of Regulation (EU) 2023/956 of the European Parliament and the Council as regards the establishment of default values

Origin of imported electricity	Default value (tCO_2/MWh)	CBAM cost per imported MWh (€)
Albania	0	0
Bosnia and Herzegovina	1.148	86.421
Kosovo*	0.984	74.076
Moldova	0.530	39.898
Montenegro	0.979	73.699
North Macedonia	0.887	66.773
Serbia	1.041	78.366
Ukraine	0.907	68.279

Electricity generation and market prices in Q2 2026

Generation mix

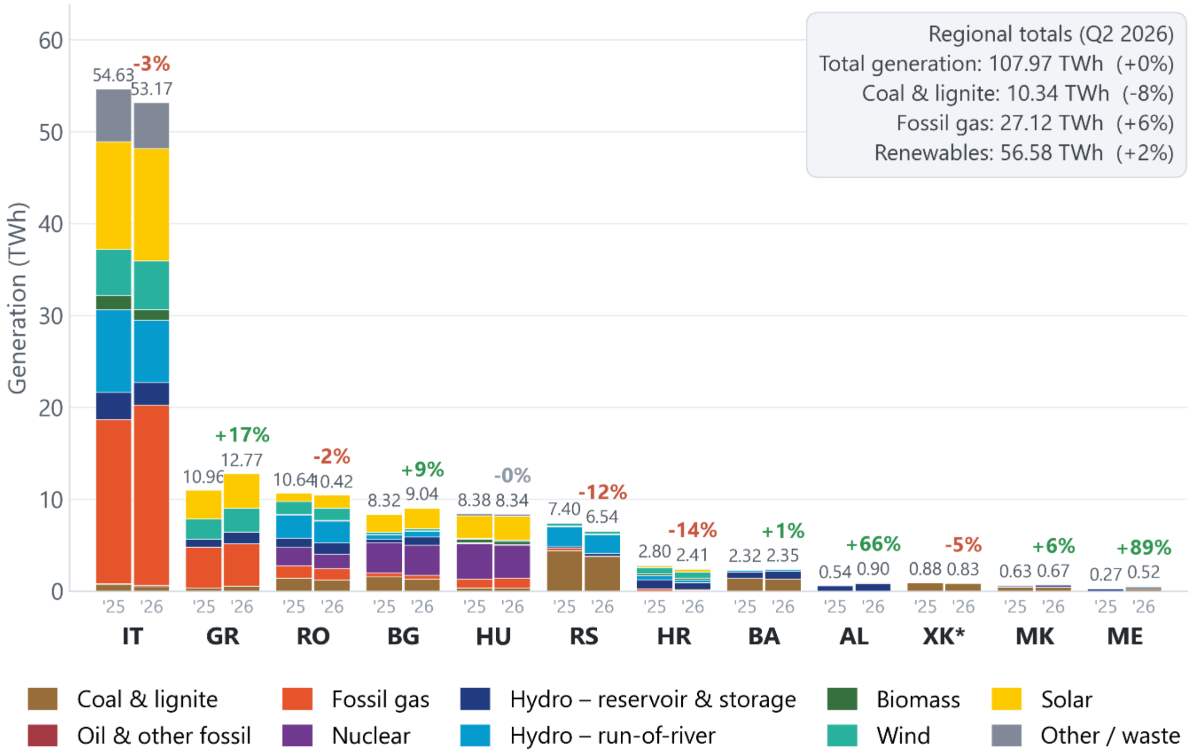
The figure below presents the full electricity generation mix in the Western Balkans Contracting Parties and neighbouring EU Member States in Q2 2026, rather than the narrower hydro-and-coal focus used in the previous edition of the CBAM Quarterly Report.[6] This broader view is needed because the defining feature of Q2 2026 was the fading of the exceptionally high hydro generation that dominated Q1. Only the full production mix shows which technologies filled the resulting gap. Total observed

[6] In the Q1 2026 edition, gas-fired generation, which plays only a minor role in the Western Balkans mix and typically contributes during peak hours, had been largely displaced by the exceptionally strong hydro output and was therefore not separately analysed. In Q2 2026, with hydro output normalising and gas-fired generation rising, the full production mix is included.

generation across the region in Q2 2026 was 107.97 TWh, essentially unchanged year-on-year (+0%), compared with a 5% increase in Q1 2026.

Figure 2. Electricity generation mix

Full generation mix in TWh · left bar = Q2 2025, right bar = Q2 2026 · WB EnC Contracting Parties and neighbouring EU MSs



Note: Based on ENTSO-E Actual Generation per Production Type data, reported at bidding zone/control area level. For EU Member States, the dataset may include estimated small-scale and distribution-connected generation, depending on national reporting arrangements. For Western Balkan Contracting Parties, distribution-connected generation, such as rooftop solar and small hydro, is largely not reported; therefore, the figures may understate total national generation. Italy is aggregated across its bidding zones. Solar PV for North Macedonia is available only under the Generation Forecast for Wind and Solar dataset and is therefore excluded from this analysis. Data are complete up to 30 June 2026 for most bidding zones, except for Albania, where data are available up to 22 June 2026. Source: ENTSO-E Transparency Platform, aggregated by the Energy Community Secretariat.

At the regional level, the three main aggregates moved in different directions. Coal- and lignite-fired generation continued to decline, falling to 10.34 TWh (−8% year-on-year),

while natural gas generation rose to 27.12 TWh (+6%) and renewables increased modestly to 56.58 TWh (+2%). As noted under the figure, distribution-connected renewables in the Contracting Parties, such as rooftop solar and small hydro, are largely not reported. This means renewable output in those countries is likely understated.
At the country level, the aggregate figures hide considerable differences. Italy remained by far the largest system at 53.17 TWh (−3%), with a mix led by fossil gas and complemented by a substantial and growing solar contribution, alongside hydro and wind. Among the other EU neighbours, Greece recorded the largest relative increase (+17%, to 12.77 TWh), mainly driven by solar and wind, as was also the case in Bulgaria, which rose by 9% (to 9.04 TWh). Romania (10.42 TWh, −2%) and Hungary (8.34 TWh, broadly unchanged) remained anchored by their nuclear fleets.

Within the Contracting Parties, the structural contrast underpinning the CBAM discussion remained clear. Serbia remained the region's dominant coal producer, with output falling by 12% to 6.54 TWh as lignite generation eased. Kosovo* (0.83 TWh, −5%), Bosnia and Herzegovina (2.35 TWh, +1%) and North Macedonia (0.67 TWh, +6%) also retained coal-based mixes. The reported total for North Macedonia is understated because its solar output is reported only as forecast, and its distribution-connected generation is largely unreported, as is also the case in the other Contracting Parties. Albania (0.90 TWh) remained almost entirely hydro-based, while Montenegro's output (0.52 TWh) was driven primarily by the Pljevlja lignite-fired power plant, as opposed to Q2 2025 when it was offline. The large percentage increases recorded for Albania (+66%) and Montenegro (+89%) should be read with caution, as they come from small absolute bases and, in Albania's case, from an incomplete reporting period.

The half-year view places these movements within a decarbonisation trend that remains clear but moderated in Q2. Over H1 2026, coal-fired generation fell by 13% (to 26.13 TWh), renewables rose by 11% (to 109.10 TWh), and natural gas increased by 3% (to 72.23 TWh) in the entire region, resulting in total generation of 237.57 TWh (+3%). The comparison between the two quarters suggests that Q1 amplified the underlying trend because of exceptional hydrology. Over the half-year, the overall direction remained towards lower coal and higher renewable output, but Q2 shows that the momentum weakened as hydrology normalised and gas re-entered the mix.

Day-ahead price developments

The following heatmap compares average day-ahead prices in Q2 2026 with Q1 2026 and Q2 2025 across the bidding zones of the relevant Contracting Parties and neighbouring EU Member States.[7] It shows a marked compression of the price differential that characterised the opening quarter of CBAM's definitive period. The EU benchmark zones recorded substantial quarter-on-quarter declines: Italy from €130.3/MWh to €120.9/MWh, Hungary from €127.5/MWh to €109.2/MWh, Romania from €119.1/MWh to €109.4/MWh, Croatia from €120.7/MWh to €103.3/MWh, and Bulgaria from €117.8/MWh to €96.8/MWh. The observed Western Balkans zones moved comparatively little, with Serbia from €94.7/MWh to €96.3/MWh, Montenegro from €85.8/MWh to €93.6/MWh, North Macedonia from €96.7/MWh to €91.6/MWh, Kosovo* from €87.4/MWh to €89.0/MWh and Albania from €83.9/MWh to €88.6/MWh. Greece, although an EU Member State, remained the exception: it eased from €94.6/MWh to €90.2/MWh and stayed aligned with the lower-priced Western Balkans range, as already observed in the previous edition.

Figure 3. Average day-ahead prices by bidding zone

Main reporting window 1 April – 30 June 2026 · columns: Q2 2026, Q1 2026, Q2 2025 (€/MWh)

	Q2 2026	Q1 2026	Q2 2025
IT	120.9	130.3	102.3
RO	109.4	119.1	86.2
HU	109.2	127.5	83.5
HR	103.3	120.7	84.9
BG	96.8	117.8	85.2
RS	96.3	94.7	87.2
ME	93.6	85.8	94.2
MK	91.6	96.7	84.8
GR	90.2	94.6	85.4
XK*	89.0	87.4	97.7
AL	88.6	83.9	97.7

EUR/MWh (avg daily price): 90, 100, 110, 120, 130

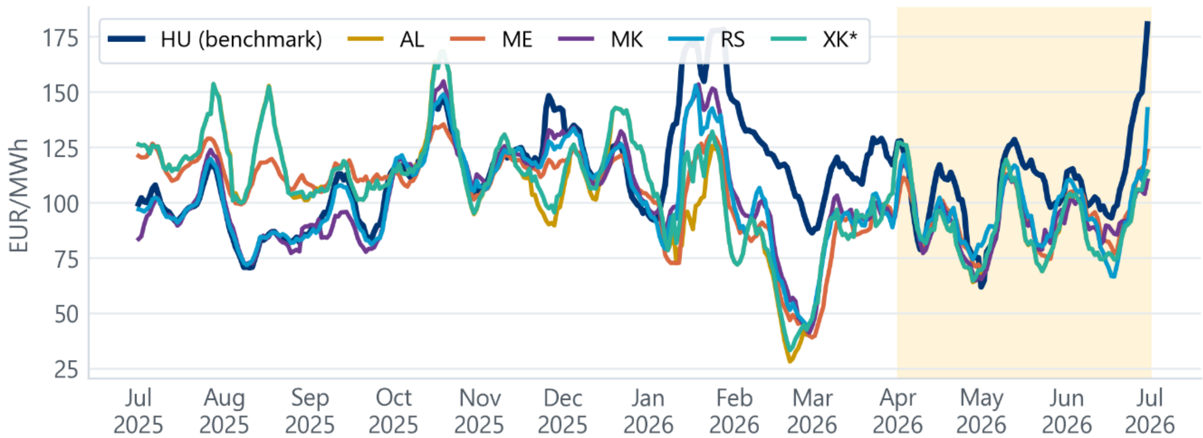
Source: ENTSO-E Day-ahead prices. Aggregated by the Energy Community Secretariat.

Normally, a compression of this size would be read as a return towards price convergence. Here, however, the adjustment was driven mainly by falling EU prices, consistent with softer seasonal demand, lower gas-linked marginal costs, and improved solar and wind generation. Prices in the observed Western Balkans zones mostly increased quarter-on-quarter: Montenegro by about €7.8/MWh, Albania by €4.7/MWh, and Serbia and Kosovo* by €1.6/MWh. North Macedonia was the only one to decline, by around €5/MWh. The convergence was also incomplete: Italy still averaged some €27/MWh above Montenegro and Hungary around €13/MWh above Serbia, while Serbia had effectively realigned with Bulgaria (€96.3/MWh against €96.8/MWh) and North Macedonia with Greece (€91.6/MWh against €90.2/MWh). This pattern coincides with the second quarter of CBAM but is more plausibly linked to the normalisation of exceptional Q1 hydrology and to EU wholesale price movements. It should not be read on its own as evidence of CBAM's effect one way or the other.

The daily price series supports this interpretation. In Q1 2026, the Hungarian benchmark pulled sharply away from the Western Balkans zones. During Q2 2026, prices tracked each other much more closely, mostly moving in a range of €70–110/MWh for much of the quarter before rising together towards the end of June, when demand increased during a strong heatwave across Europe.

Figure 4. Daily day-ahead prices: HU benchmark vs Western Balkans

Daily average, 7-day moving average · shaded band = reporting window (Q2 2026)



Source: ENTSO-E Day-ahead prices. Aggregated by the Energy Community Secretariat.

The half-year comparison adds important context to this apparent convergence. Averaged over H1 2026, the EU zones remained well above the observed Western

Balkans/SEE cluster: Italy averaged €125.5/MWh, Hungary €118.3/MWh, and Romania €113.6/MWh, compared with Albania at €86.3/MWh and Kosovo* at €88.2/MWh, Montenegro at €89.7/MWh, and, among EU Member States, Greece at €93.5/MWh. This also marks a wider year-on-year gap than in H1 2025, when Western Balkans zones averaged around €108–114/MWh and were broadly aligned with neighbouring EU markets.

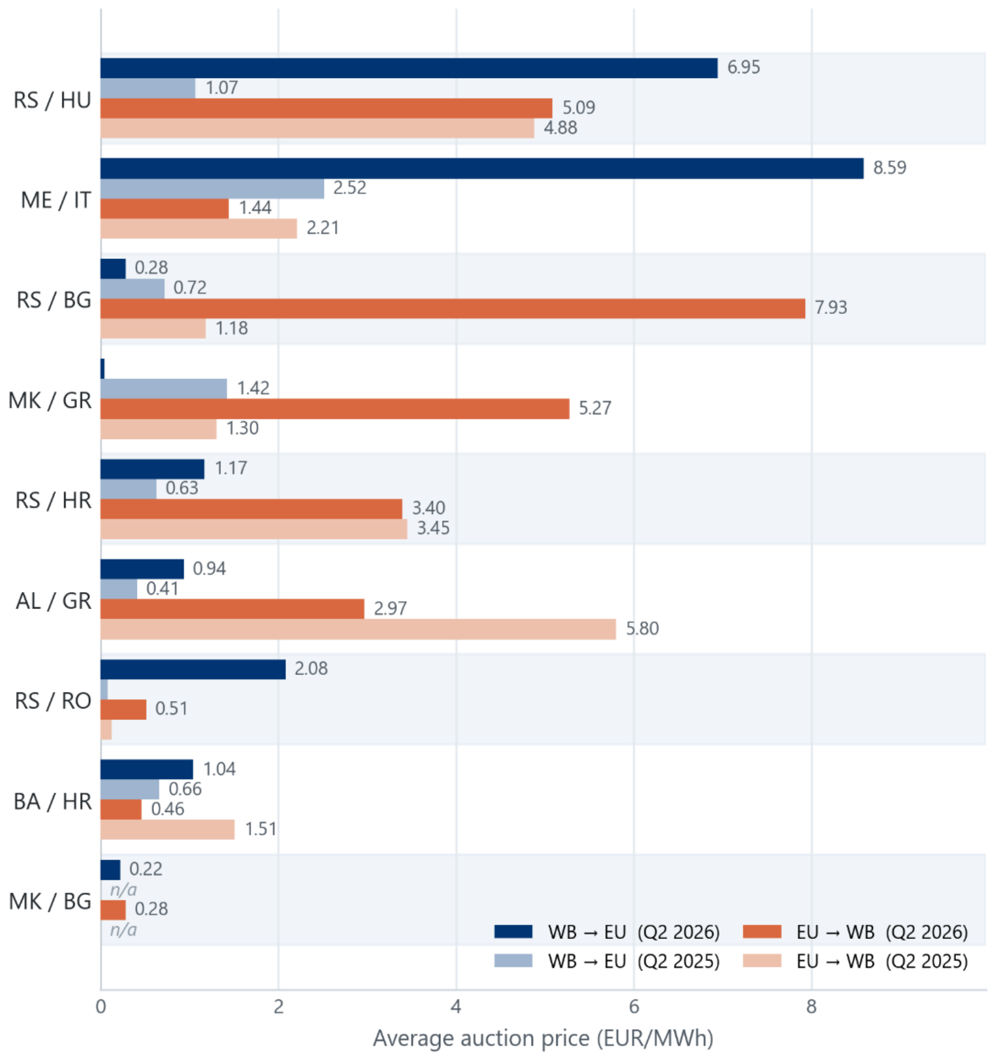
The Q2 2026 movement is therefore best understood as an intra-year narrowing of prices, not as a return to last year's level of regional alignment. If the wider H1 gap persists as hydrology normalises, it may point to a more durable separation between EU and non-EU price levels than the Q2 2026 convergence alone would suggest.

Cross-border capacity allocation

The average daily cross-border capacity auction marginal prices are a useful proxy for the short-term market value of cross-border capacity on WB6–EU borders. This Q2 2026 analysis complements the published Q1 assessment, which focused mainly on 2026 annual auction results and indicated a weaker forward valuation of capacity amid CBAM-related uncertainty. Although the Q1 average daily auction prices were not presented separately in that report, they are used here as a baseline for comparison with Q2 2026 and the corresponding 2025 period. The baseline confirms that the strongest year-on-year increases in Q1 were concentrated on borders already identified in the Q1 analysis as relevant for definitive CBAM price and flow developments, notably Serbia–Hungary, North Macedonia–Greece, and Albania–Greece. In directional terms, these increases were mainly observed on Serbia→Hungary, Greece→North Macedonia and Albania→Greece, while the overall capacity-price signal remained uneven across corridors.

Figure 5. Average daily-auction prices on WB ↔ EU borders in Q2 2026

Daily cross-border capacity auctions · average clearing price per direction



Source: JAO, SEE CAO and Transelectrica DAMAS daily auction results. Aggregated by the Energy Community Secretariat.

In Q2 2026, average daily auction prices increased across several WB6–EU corridors. The increase in the value of cross-border capacity appears to coincide with growing interest from market participants in certain corridors, which was also reflected in higher scheduled exchanges in some of the corridors. In the WB6→EU direction, the increase was most pronounced on Serbia→Hungary and Montenegro→Italy[8], with a further sharp rise on Serbia→ Romania from a very low base.

On the North Macedonia–Greece and Serbia–Bulgaria borders, by contrast, the increase was concentrated in the import direction, namely Greece→North Macedonia and Bulgaria→Serbia. This is consistent with the seasonal return of EU-to-WB6 flows, while the average daily auction prices in the opposite flow direction at these two borders declined. The strengthening of the Greece→North Macedonia direction appears to continue the trend, since the same corridor was also among those recording the strongest average daily auction price increases in the Q1 baseline, again in the import direction.

Normally, the value of capacity rights should broadly track the underlying day-ahead price spread, as market participants bid for capacity based on the arbitrage value it is expected to unlock. Compared with the weaker forward valuation observed in the yearly auctions, the daily-auction data show a more mixed short-term picture across corridors. For the WB6–EU borders with larger price differentials, average daily capacity prices increased compared with Q2 2025.

The interpretation of these data should take into account that daily auction prices reflect not only expected price spreads, but also auction competition, available transmission margins and market participants' expectations at the time of bidding. If the Q2 realignment continues, it would point to a gradual restoration of functioning cross-border price signals. If it proves temporary or limited to specific corridors, it will instead reinforce the concern that capacity on WB6–EU borders continues to be priced unevenly in the definitive CBAM environment.

[8] For Montenegro→Italy, export-direction capacity was offered in around 84% of the hours in Q2 2026, reflecting periods of genuine unavailability of the link in that direction. When capacity was offered, it was almost fully allocated.

Market analysis

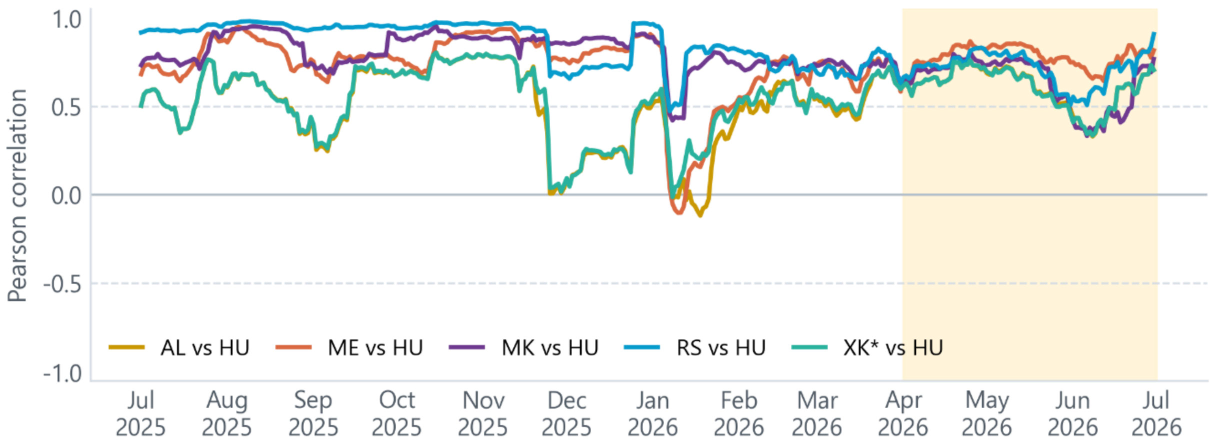
Price correlation

The rolling 30-day Pearson correlation[9] between the observed Western Balkans bidding zones and the Hungarian benchmark continued to recover in Q2 2026, but at different speeds across zones. After falling close to zero and briefly turning negative in January, correlations had only partly recovered by the end of Q1. In Q2, Serbia and Montenegro strengthened further, reaching around 0.91 and 0.82, respectively, by the end of June. This brought them close to, but not consistently back to, their 2025 baseline. North Macedonia and Albania showed a less stable recovery. Both fell sharply in the first week of June, to around 0.33, before partially rebounding. By the end of the quarter, North Macedonia had recovered to roughly 0.77, while Albania and Kosovo* remained the least correlated and most volatile of the observed series, at around 0.70. The shared early-June setback, most visible in North Macedonia, Albania, and Kosovo*, shows that the recovery remained fragile and does not follow a steady upward path.

[9] Pearson correlation measures how closely two data series move together. A value of 1 means the two series move in perfect lockstep; a value of 0 means no systematic relationship; a negative value means they tend to move in opposite directions. In well-integrated electricity markets, day-ahead prices in neighbouring zones typically show correlations above 0.80.

Figure 6. Rolling 30-day price correlation to HU

Daily prices · shaded band = reporting window (Q2 2026)



Source: ENTSO-E Day-ahead prices. Aggregated by the Energy Community Secretariat.

In well-integrated neighbouring markets, day-ahead correlations would normally be expected to remain consistently above 0.80. The observed path, a sharp dislocation at the start of 2026 followed by progressive recovery over the half-year, is most plausibly linked to the fading of exceptional hydro production from its January peak. This also returned the region to its seasonal net-importer position in Q2 and increased its reliance on priced imports from benchmark zones. The available data do not yet show whether the recovery reflects a durable restoration of integration or mainly the fading hydrological anomaly.

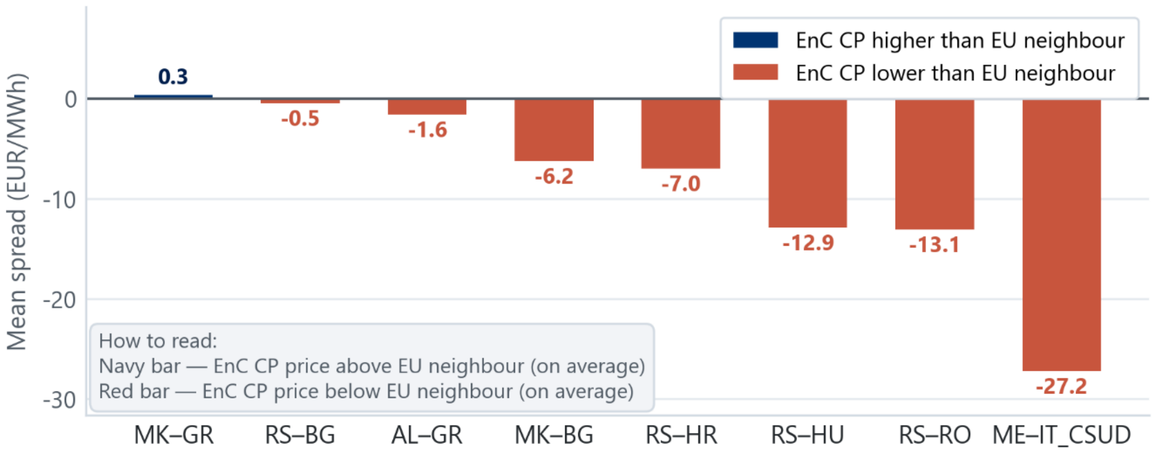
Directional price spreads

Directional day-ahead price spreads, expressed as the Contracting Party price minus that of its EU neighbour and averaged over Q2 2026, narrowed significantly relative to Q1 while keeping a clear structure. The widest spread remained Montenegro–Italy, at approximately −€27.2/MWh, down from roughly −€44/MWh in Q1. The Serbia–Hungary and Serbia–Romania spreads stood at around −€12.9 and −€13.1/MWh respectively, against roughly −€33/MWh for Serbia–Hungary in Q1. Serbia–Croatia (−€7.0/MWh, from −€26.0/MWh) and North Macedonia–Bulgaria (−€6.2/MWh, from −€21.1/MWh) narrowed further, while Serbia–Bulgaria showed the strongest convergence of all borders, from −€23.1/MWh in Q1 to near parity at −€0.5/MWh. The North Macedonia–Greece border remained marginally positive (+€0.3/MWh, from +€2.2/MWh), and the Albania–Greece spread narrowed to −€1.6/MWh from −€10.6/MWh.

The Kosovo*–Albania pair averaged +€0.1/MWh, reflecting an intra-EnC coupled market, where the near-zero spread confirms full price convergence within the ALPEX coupling. Kosovo* is therefore exposed to EU price signals only indirectly through neighbouring markets, despite having one of the region's highest CBAM default emission factors (0.984 tCO_{2eq}/MWh, equivalent to around €74/MWh).

Figure 7. Directional day-ahead price spreads

EnC Contracting Party minus EU neighbour, mean over Q2 2026



Source: ENTSO-E Day-ahead prices. Aggregated by the Energy Community Secretariat.

The Q2 data indicate that estimated price spreads between lower-priced Western Balkans zones and neighbouring EU Member States narrowed compared to Q1 2026 but remained material on several corridors. Under normal market conditions, such spreads would be expected to support exports from the WB6 towards higher-priced EU markets and contribute to price convergence.

On carbon-intensive export corridors, the largest residual differentials remained. Exports nevertheless continued, where the remaining price gap was still wide enough to absorb the additional cost wedge. Scheduled exports on Montenegro→Italy recovered by around 19% year-on-year where the stabilisation of the ETS price and thus CBAM costs in H1 2026 is assumed to have contributed as a positive impact, while Serbia→Hungary more than doubled, increasing by 111%, even as spreads on both corridors narrowed from Q1 levels. This suggests that trade partly recovered once the remaining differentials became sufficient to support exports.

The Greece-facing corridors show a clear contrast. On the Albania–Greece border, the price spread has almost disappeared, while exports from Albania to Greece have remained broadly unchanged, increasing by around 3% year-on-year. This is consistent with Albania's hydro-based export position and its zero CBAM default emission factor, which keeps exports competitive even with a narrow spread. By contrast, exports from North Macedonia to Greece fell sharply, by around 97% year-on-year in Q1 and 78% in Q2, while flows in the opposite direction increased significantly, with Greece→North Macedonia rising by around 70% in Q2. This points to a loss of competitiveness for North Macedonia's exports, linked partly to the country's relatively high fossil-based CBAM default emission factor and partly to Greece's changing regional role, as it has increasingly shifted from a net importer to a net exporter in recent years.

Overall, these developments are consistent with CBAM default emission factors continuing to act as a cost wedge on carbon-intensive routes, while not affecting the hydro-based Albanian corridor in the same way. The pattern should not, however, be attributed only to CBAM, as generation mix, plant availability, hydrology and wider market conditions also matter. The H1 averages, at around −€35.8/MWh on Montenegro–Italy and −€22.8/MWh on Serbia–Hungary, confirm that spreads were widest in Q1 and narrowed through Q2. If sustained, this emerging two-tier pattern may entrench uneven competitive positions across the region, allowing low-carbon exporters to retain market access at narrow spreads while weakening investment signals in carbon-intensive systems. This could, in turn, slow the energy transition and reinforce negative externalities for regional decarbonisation.

Energy Community Secretariat

Spotlight: Ukraine's import demand and the Hungarian hub

The strength of the Serbia–Hungary corridor appears to reflect more than the WB6–EU price signal alone. Cross-border capacity data indicate that Hungary was the most important route for the electricity imports to Ukraine during the quarter. Capacity totalling roughly 1,546 GWh was allocated on the Hungary→Ukraine border through daily auctions over the quarter as a whole, equivalent to about 17 GWh per average day and some 247% more than in Q2 2025. The daily auctions alone generated revenue of around €12.5 million, on almost fully allocated capacity. Ukraine has remained a substantial net importer of electricity, and this demand, transmitted through the Hungarian hub, may help explain why commercial exports from Serbia to Hungary more than doubled even as gross Western Balkans-to-EU trade dropped. Under typical conditions, a corridor would be expected to respond mainly to its own price signal; here, the increase also appears to reflect onward demand further east. Transit cannot be separately quantified from the aggregate scheduled exchanges available, so this reading remains provisional. Still, it is consistent with the observed pattern and, if sustained, points to a growing role for the region in supplying a Ukrainian system that remains short of domestic generation.

Scheduled commercial exchanges and net trade position

Scheduled commercial exchanges between the Western Balkans and the EU in Q2 2026 show a dual development: the region returned to its usual net-importer position, but overall exchange continued to decrease. Scheduled imports from the EU into the WB6 fell by 14% year-on-year to 4,271 GWh, while scheduled exports from the WB6 to the EU declined by 16% to 3,223 GWh. As a result, the region's aggregate net position reverted from the net-exporter position of approximately 1,247 GWh in Q1 2026 to a net-importer position of around 1,048 GWh in Q2 2026, close to the 1,136 GWh net-import balance recorded in Q2 2025.

Figure 8. WB ↔ EU scheduled commercial electricity exchanges

Total scheduled commercial exchanges across all WB ↔ EU borders, with net trade position

Period: 1 April – 30 June 2026 (compared with 1 April – 30 June 2025). Source: ENTSO-E scheduled commercial exchanges. Aggregated by the Energy Community Secretariat.

Under normal seasonal conditions, the Western Balkans typically import from the EU when hydrology weakens, so the return to a net-importer position in Q2 is consistent with expectations. The more important signal is the lower level of commercial activity. In Q2 2026, gross scheduled exchange across the WB6–EU borders dropped by roughly 15% year-on-year, from 8,828 to 7,494 GWh, after a decrease of around 23% in Q1. Across H1 2026, this amounted to a fall of around 19% compared year-on-year (from 19,323 to 15,567 GWh). The region was close to balance over the half-year 2026 a net export of only 199 GWh, compared with a net import of 1,609 GWh in H1 2025. Under comparable price and hydrological conditions, cross-border volumes would normally be expected to remain broadly stable. The persistence of a double-digit reduction in gross exchange, even as prices reconverged and the net position normalised, occurred despite almost full allocation of the capacity that was offered. Allocation rates stayed close to 100% on the main WB–EU export corridors, so the reduction reflects lower scheduled energy volumes rather than unsold capacity rights. This reduced intensity of commercial exchange is the development most plausibly connected to CBAM-related costs and residual regulatory uncertainty, although hydrology and price levels also contribute, and the effect cannot be isolated with confidence.

Spotlight: Traded volumes on the Western Balkans power exchanges

While cross-border scheduled exchange dropped, trading on the region's power exchanges moved in the opposite direction. Day-ahead traded volumes across the four Western Balkans power exchanges rose by about 19% year-on-year in Q2 2026, from 2.26 to 2.70 TWh. Unlike in Q1, all four exchanges grew: ALPEX (Albania-Kosovo*) by 52%, MEPX (Montenegro) by 49%, MEMO (North Macedonia) by 31% and SEEPEX (Serbia) by 7%.
SEEPEX's return to growth is a notable change from the first quarter, when it was the only exchange to shrink (−11%). The decline in the previous period was linked to its greater exposure to transit-based trading. Its recovery in Q2, as the EU ETS price stabilised and directional price gaps narrowed, would be consistent with participants regaining confidence in trading through the Serbian hub, although this reading remains provisional. Taken together, the two quarters point in the same direction: liquidity appears to be deepening within the region's domestic day-ahead markets even as the commercial link with the EU carries less volume. This suggests that the reduction is concentrated on the cross-border side, rather than in overall trading activity.

Changes in scheduled flow patterns

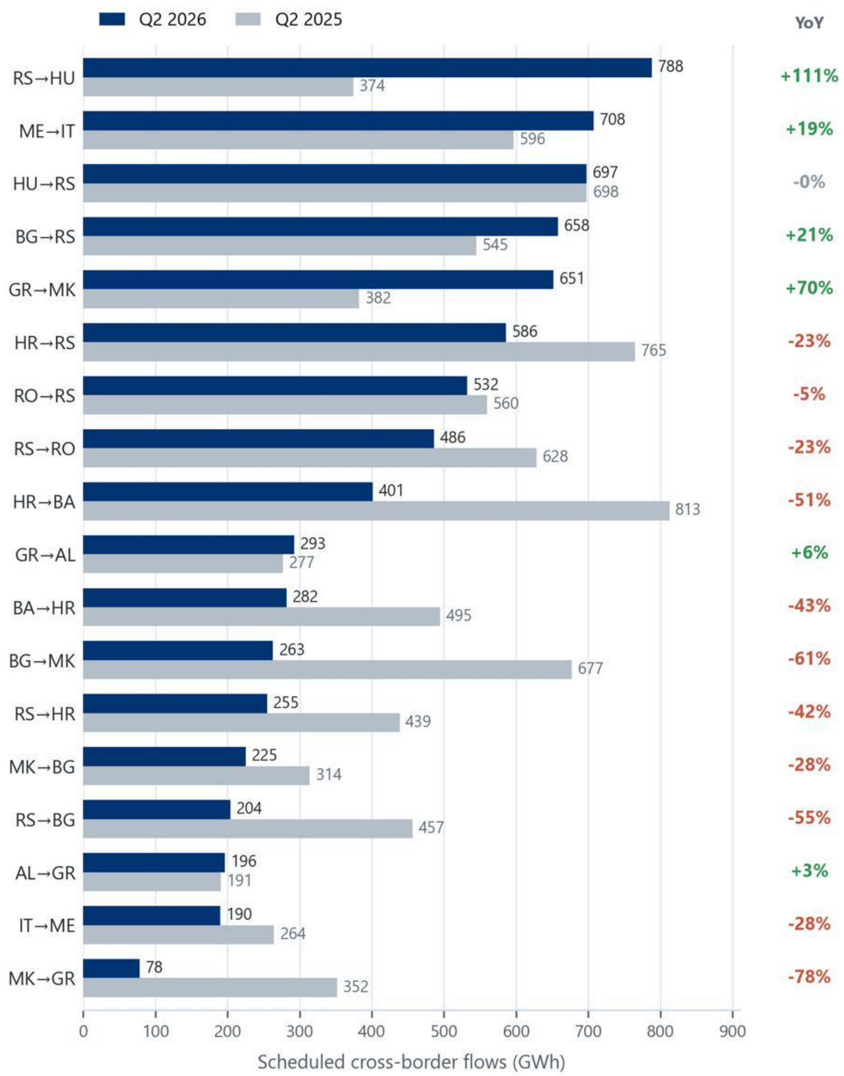
A comparison of scheduled commercial exchanges in Q2 2026 with the same period in 2025 indicates continued redirection of regional trade, with a corridor composition that differs from that in Q1. Several corridors carrying electricity towards EU markets strengthened markedly: scheduled flows on Serbia→Hungary more than doubled (+111%), Greece→North Macedonia increased by around 70%, Bulgaria→Serbia by 21%, and Montenegro→Italy recovered (+19%). At the same time, a number of corridors that had carried commercial transit through the Western Balkans[10] declined sharply, including North Macedonia→Greece (−78%), Bulgaria→North Macedonia (−61%), Serbia→Bulgaria (−55%) and Croatia→Bosnia and Herzegovina (−51%). The Croatia–Serbia border also dropped in both directions, with Croatia→Serbia down 23% and Serbia→Croatia down 42%, so one of the two largest EU-to-WB6 import routes in Q2 2025 carried materially less commercial volume.

Albania→Greece warrants particular attention. This corridor had been one of the main drivers of the Q1 reconfiguration, when scheduled exports nearly tripled year-on-year to 569 GWh, a development then linked to exceptional Albanian hydro output and to the route's zero CBAM default factor. In Q2 2026, the corridor returned to typical levels, at 196 GWh, broadly in line with the same period of 2025 (+3%). This normalisation suggests that the Q1 surge was a hydro-driven episode rather than a durable shift in trading patterns, although the corridor's zero-factor status may regain relevance in future periods of renewed hydro surplus. Beyond the WB–EU corridors, the single largest increase in the wider dataset was on the EU-internal Romania→Hungary route (+156%), showing that the redirection also extended into the surrounding EU network and was not limited to the WB–EU borders.

[10] Transit flows cannot be separately quantified from aggregate scheduled exchanges in the available data.

Figure 9. WB ↔ EU cross-border scheduled flows

Q2 2026 vs Q2 2025, by corridor, with year-on-year change (GWh)



Source: ENTSO-E scheduled commercial exchanges. Aggregated by the Energy Community Secretariat.

The corridors within the Western Balkans do not appear in the figure above, but the underlying data show a clear direction of movement in Q2 2026 vs Q2 2025: commercial exchange inside the region shifted northwards. Scheduled flows increased on

Albania→Kosovo* (+153%), Kosovo*→North Macedonia (+110%), Montenegro→Serbia (+56%), North Macedonia→Serbia (+46%) and Albania→Montenegro (+45%). Several southbound and westbound routes dropped, including Serbia→North Macedonia (−51%), Serbia→Bosnia and Herzegovina (−40%) and Bosnia and Herzegovina→Montenegro (−27%). These movements suggest that, relative to the same quarter a year earlier, the intra-regional trade reoriented. Compared with Q2 2025,, commercial volumes moved from the hydro-rich south towards Serbia and onwards to the Hungarian border, a pattern consistent with the doubling of Serbia→Hungary schedules noted above.

Normally, cross-border trade would be expected to follow relatively stable and economically efficient pathways shaped by price differentials and available interconnection capacity. The recovery of Montenegro→Italy scheduled flows is notable: in Q1, this corridor had provided the clearest example of suppressed commercial activity, when the widest spread in the region coincided with declining scheduled flows. Its partial recovery in Q2, as the ETS price stabilised and the spread narrowed, is consistent with an easing of the frictions observed at the outset of the definitive period. The broader picture, however, points to a reconfiguration rather than a restoration of trade. In the north-east, Ukraine's sustained import requirements appear to be drawing volumes towards the Hungarian hub, as evidenced by the increases in Romania→Hungary and Serbia→Hungary, as examined in the spotlight above. In the south, Greece shifted from a net destination to a source on several routes, with scheduled exports rising towards Bulgaria (+139%), North Macedonia (+70%) and Albania (+6%), most plausibly reflecting strong spring generation led by its expanding solar and wind fleet. Meanwhile, transit routes through the Western Balkans that decreased in Q1, such as North Macedonia→Greece (−78%) and Bulgaria→North Macedonia (−61%), showed no recovery. Each of these shifts has its own drivers, including seasonal solar output, Ukraine's import demand, relative fuel costs, and the emission-factor economics of individual exporters, so the redirection cannot be attributed solely to CBAM. Still, the fact that trade is settling into new channels rather than returning to its 2025 configuration suggests that the Q1 reconfiguration was more than a passing anomaly. Subsequent quarters will show whether these patterns consolidate.

Divergence between commercial schedules and physical flows

The divergence between commercially scheduled exchanges and actual physical flows, identified in Q1 2026, persisted in Q2. The clearest example is the Bosnia and Herzegovina–Croatia border, where scheduled commercial flows on BA→HR fell by about 43% year-on-year while physical flows in the same direction rose by roughly 270%. This pattern is not new, but it has intensified: the same border had already diverged in Q1, when scheduled flows fell by 27% while physical flows increased by 146%. Electricity continued to move across the interconnected network towards EU borders even where it was no longer commercially scheduled to do so. The Albania–Greece border shows the same divergence in the opposite configuration for the second consecutive quarter. In Q1, scheduled flows on AL→GR nearly tripled while physical flows slightly declined; in Q2, scheduled flows held at ordinary levels (+3%) while physical flows fell by about 63%. Across both quarters, commercial bookings towards Greece and the electricity actually crossing that border moved largely independently, with the energy contracted southwards appearing instead to travel north through Montenegro and Bosnia and Herzegovina.

Figure 10. WB ↔ EU cross-border physical flows

Apr–Jun 2026 vs Apr–Jun 2025, by corridor, with year-on-year change (GWh)

Source: ENTSO-E physical cross-border flows. Aggregated by the Energy Community Secretariat.

The same tendency for physical flows to outpace commercial schedules was observed along the south-to-north axis feeding the EU borders: Greece→North Macedonia

(+216%), North Macedonia→Serbia (+226%) and Montenegro→Bosnia and Herzegovina (+235%).

Normally, commercial schedules and physical flows should move broadly together. Schedules are the operational plan used by transmission system operators to secure the grid. In Q2 2026, the two again diverged materially, and on some corridors the gap was pronounced: on the Bosnia and Herzegovina→Croatia route, the 824 GWh that physically crossed the border was almost three times the 282 GWh that was commercially scheduled. In practice, electricity continued to follow the physical path of least resistance through the meshed Western Balkans network, most visibly along the south-to-north corridor from Greece and Albania through Montenegro and Bosnia and Herzegovina towards Croatia, regardless of where the underlying transactions were booked. If persistent, this mismatch could cause tangible operational and financial consequences. Transmission system operators must plan around flows that are not visible in the schedules, maintain larger security margins and resort more frequently to remedial actions such as redispatch and countertrading, the costs of which are ultimately reflected in network tariffs on both sides of the border. The divergence also weakens the link between where congestion arises and where congestion income accrues, diluting the locational signal that such income is intended to provide. These effects are regional and cannot be addressed by any single operator alone. They reinforce the case for coordinated cross-border capacity calculation and congestion management between the Contracting Parties and their EU neighbours, so that the capacities offered to the market more accurately reflect the actual operating conditions of the interconnected network.

Policy implications – the case of renewable electricity

The assessment of publicly available, standardised data represents the core of the Secretariat's quarterly CBAM reports. At the same time, there are issues, which do not appear in structural market trends, but they still significantly influence the changes in stakeholder decisions and strategies. Portraying these issues is relevant for the policy makers and the authorities involved in the implementation and enforcement of CBAM.

Spotlight: The ongoing revision of the CBAM Regulation

The European Commission proposed to amend the CBAM Regulation including certain rules on electricity in December 2025. The main proposed changes – which are not yet in force as they are undergoing the ordinary legislative procedure of the EU – include:

- Introducing the possibility for the Commission to conclude a Memorandum of Understanding with a third country that has requested to integrate its electricity market into that of the Union through market coupling pursuant to an international agreement, set the timeline for the application of the exemption foreseen in Article 2(7) and the timeline for the implementation of a carbon pricing instrument equivalent to the EU ETS, insofar as electricity generation is concerned;
- Changing the calculation of the default emission factors from taking into account the fossil-fuel-based part of the electricity mix to considering the weighted average of the CO2 intensity of the electricity produced within a geographic area;
- Clarification that only physical PPAs are covered by CBAM;
- Amendments to the criteria for using actual values – a.) possibility to use intermediaries in power purchase agreements (PPAs) as long as a verifiable contractual relationship between the producer of electricity, the intermediaries, and the importer, or CBAM declarant, can be demonstrated; b.) removal of the condition to demonstrate that there was no physical network congestion at any point in the network between the installation and the Union transmission system.

The Commission proposed that the new rules regarding the calculation of default emission factors for electricity and the criteria for using actual emission values be applicable from 1 January 2026, which appears unchallenged at the current state of interinstitutional negotiations.

The European Parliament has proposed to take into account the target date for accession aligning with the Union's enlargement policy towards the relevant third country, when setting the timeline for the application of the exemption in Article 2(7) and for the implementation of a carbon pricing instrument equivalent to the EU ETS in the Memorandum of Understanding.

While Q1 2026 was characterised by robust hydro output, the production from other sources of renewable electricity – such solar PV – picked up in Q2. At the same time, market participants continued to adapt to the new conditions created by CBAM and to explore how its rules can be applied in practice. This process has brought several unresolved compliance issues to light. The topics below have been communicated to the Secretariat by stakeholders with the aim to flag the challenges they are facing in ensuring compliance. The aim of operators of existing renewable installations and the renewable project developers in Contracting Parties is to ensure access to the EU market (and the EU price benchmarks) via using actual emission values or via an exemption through Article 2(7).

That route, however, is challenged in several ways:

1. Absence of verifiers – a materially impossible compliance for using actual values
   One of the conditions to use actual emission values for electricity as an imported good is to ensure that *the fulfilment of the [other] criteria is certified by an accredited verifier, who shall receive at least monthly interim reports demonstrating how those criteria are fulfilled*.[11] National accreditation bodies in EU Member States started to roll out the accreditation programmes for CBAM verifiers at the beginning of the summer 2026. Expectations are that the first accredited verifiers would be available at the end of 2026 or early 2027. CBAM declarants thus are objectively unable to comply with one of the criteria to use actual emission values. It also remains a question whether retroactive certification of the fulfilment of the conditions for imports in 2026 will be possible once a verifier is contracted.

2. Uncertain price convergence between Contracting Parties' and EU Member States prices making revenue planning for projects more difficult
   While price convergence partly recovered in Q2 2026 compared to Q1, it cannot yet be confirmed whether this is a sign of structural re-alignment or a momentary phenomenon linked to the region becoming net importer from EU markets. The disappearance of the predictable link between the day-ahead prices of the EU

[11] Regulation (EU) 2023/956 Annex IV, point 5(e).

markets and those of Contracting Parties represent an uncertainty factor for the revenue planning of renewable projects. As an illustration, if the spread returns to the level in Q1 2026 setting prices in Contracting Parties at a substantial discount compared to neighbouring EU markets, and the electricity is limited to be sold only on the local market (being unable to use actual emission values for EU exports) an onshore wind farm of 130 MW would accrue opportunity costs of €8.9 mln just in 6 months.[12]

3. Requirement for a PPA vs. the ability to service that PPA fully with electricity from renewable sources

   The CBAM Regulation requires that the amount of electricity for which the use of actual embedded emissions is claimed, is covered by a PPA between the authorised CBAM declarant and a producer of electricity located in a third country. In the case of PPAs with fixed quantities – such as baseload or shaped PPAs – any shortfall in the planned/contracted production is mitigated from additional transactions from the intraday market or from the balancing market. Regardless of whether the production and profile risk is assumed by the generator or the offtaker (CBAM declarant), the resulting imports into the Union may include electricity, which has not been generated from renewable sources, or the source of which may be impossible to track. In both cases, that part of the electricity, which is delivered via the PPA, but is not produced in the installation of the renewable producer, is expected to be subject to CBAM costs based on the default emission factor. This represents potential additional costs for servicing such a PPA – instances of which already exist today – making its implementation less economical. Such a risk may be mitigated via the conclusion of Pay-as-Produced PPAs where the entire production risk is assumed by the offtaker.

[12] The €8.9 million figure represents the opportunity cost accrued by a 130 MW onshore wind farm over January–June 2026, calculated as the difference between actual revenues realised on the domestic non-EU market by the producer (investor) and the revenues that would have been achieved had the same electricity volumes been sold on the Hungarian day-ahead market (HUPX) in the identical delivery hours (including capacity costs).
The hourly production profile for the project was estimated by scaling the measured output of a neighbouring wind power plant of known capacity to the 130 MW installed capacity of the project, and applying a proportional adjustment factor for each hour of the January–June 2026 period.

Reflecting electricity market realities, several PPAs are concluded via aggregators or other intermediaries that connect producers and consumers via the pooling of supplies. The current rules, which require that *where the PPA was concluded through an intermediary, the contractual evidence shall demonstrate that only one single contract was concluded between the three contracting parties*,[13] remove the possibility of portfolio optimisation, even if the intermediary's entire pool of supplies is based on renewable electricity. The European Commission's proposal which amends the PPA criterion in the CBAM Regulation by allowing PPAs involving intermediaries *as long as a verifiable contractual relationship between the producer of electricity, the intermediaries, and the importer, or CBAM declarant, can be demonstrated*,[14] is a step in the right direction if it allows intermediaries to take positions on EU and Contracting Party markets simultaneously and to aggregate volumes and manage price and balancing risk, while making it possible to use actual emission values for the exported renewable electricity.

PPAs are flexible instruments aiming to serve various contractual and market needs. In order to preserve their flexibility the European Commission issued a Recommendation on removing barriers to their development. In that Recommendation, it is explicitly recognised that *The Energy Community contracting parties have the objective of decarbonising power systems and integrating with the Union internal electricity market, resulting in eventual market coupling.* ***Cross-border PPAs between market operators in Energy Community contracting parties and in Union Member States can thus support gradual market integration and investments in clean energy production, while mitigating price volatility.***[15]

[13] Annex II, Point D.2.4 (a) of Commission Implementing Regulation (EU) 2025/2547 laying down rules for the application of Regulation (EU) 2023/956 of the European Parliament and the Council as regards the methods for the calculation of emissions embedded in goods

[14] Annex II, point 6 of the Annexes to the Proposal for a Regulation of the European Parliament and of the Council amending Regulation (EU) 2023/956 as regards the extension of its scope to downstream goods and anti-circumvention measures COM(2025) 989 final Annexes 1 to 3

[15] Commission Recommendation (EU) 2026/917 of 22 April 2026 on removing barriers to the development of power purchase agreements and other energy purchase agreements – Preamble, point (11)

The variety of PPA types ensures agility, but it represents uncertainty when it comes to CBAM compliance. Stakeholders are facing the problem of having no indication what minimum requirements and standard elements a PPA should have in order to be considered compliant for the use of actual emission values. While it is clear that the principle of CBAM is to track the origin of imported goods, a too restrictive approach (e.g. PPA concluded for an installation, rather than for the renewable portfolio of a producer) could overall kill incentives for any export of renewable energy into the EU.

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