E3S Web of Conferences **727**, 02005 (2026) https://doi.org/10.1051/e3sconf/202672702005
EEPES 2026

Development of aggregators in micro grids in Eastern Europe

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Abstract. Aggregators bundle small distributed energy resources into a single market-facing unit capable of participating in wholesale electricity markets and providing system services. In Eastern Europe, increasing renewable penetration, ageing grid infrastructure and delayed transmission reinforcement create growing demand for distributed flexibility. This paper examines the development of independent aggregators in six Visegrad and Balkan states: Poland, the Czech Republic, Slovakia, Hungary, Romania and Bulgaria. It combines a concise regulatory and technical overview with a screening-level techno-economic assessment of a 150 MW / 450 MWh reference aggregator portfolio composed of battery energy storage, demand response and vehicle-to-grid resources. The model applies a levelized cost of storage (LCOS) approach calibrated against Bulgarian market data. Under a representative two-cycle-per-day operating pattern with 3-hour storage duration, the portfolio achieves an LCOS of 165.4 EUR/MWh against an average peak-hour price of 232.6 EUR/MWh, corresponding to an LCOS-based gross margin of 45.7 MEUR/year before network-fee adjustments. The corrected revenue-stack calculation gives total gross revenue of 89.1 MEUR/year and EBITDA of 34.9 MEUR/year under the stated assumptions. Sensitivity results indicate that the outcome is most affected by CAPEX, cycle density and the realized charge/discharge spread, while round-trip efficiency has a smaller effect within the 0.82–0.92 range. The findings suggest that aggregator deployment in Eastern Europe depends not only on technology costs, but also on market-access rules, prequalification procedures, baseline methodologies and DSO–TSO coordination. The results should be interpreted as indicative scenario-based estimates and provide a basis for future country-specific, full-year simulations.

1 Introduction

The transition away from synchronous thermal generation is reshaping electricity systems by reducing system inertia, increasing forecast uncertainty and increasing the need for flexible resources. In Eastern Europe, much of the replacement capacity is variable renewable generation, especially photovoltaic generation at distribution level and onshore wind at sub-transmission level. This shift balancing responsibility toward hydro resources, interconnectors, fossil-fuel peaking units, battery energy storage systems (BESS), demand

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response (DR) and other distributed energy resources (DERs). Aggregators operate at the interface of this transition by pooling small-scale DERs behind a single market-facing entity and enabling resources that are individually too small to participate in wholesale, balancing, ancillary-service or local flexibility markets.

Previous studies identify aggregators as an important coordination mechanism for distributed flexibility, but their value depends on market access, baseline design, dispatch uncertainty, communication reliability and the ability to combine several revenue streams. Although aggregator business models, prosumer bidding strategies, demand response, flexibility products and battery degradation have been widely discussed in the literature, Eastern European electricity markets remain less frequently analysed. This gap is relevant because the region combines rapid renewable expansion, ageing grid infrastructure and uneven implementation of market rules for independent aggregation.

At EU level, the regulatory basis for aggregation is linked to the Clean Energy Package and the internal electricity market framework. Regulation (EU) 2019/943 reinforced the principle for balancing and capacity markets. Article 6 requires that balancing markets be based on marginal pricing and that products be standardized and close to real time, enabling smaller bids to compete. The ENTSO-E platforms PICASSO (aFRR), MARI (mFRR) and TERRE (RR) now clear at 15-minute and 4-second resolution, which changes the bid size economics in favor of pooled resources [1, 2]. Poland transposed the Directive through successive amendments to the Energy Law. The 2021 revision introduced the definition of an aggregator and allowed independent aggregation into day-ahead and intraday markets; participation in balancing is still conditional on prequalification against PSE (the Polish TSO) technical codes, with minimum bid sizes that remain a barrier for pure demand-response portfolios below 1 MW. The Czech Republic's Energy Act amendment in 2023 defined the active customer and the aggregator and CEPS opened aFRR and mFRR to aggregated bids in pilot mode during 2024. Hungary introduced regulated aggregation roles in its 2021 grid code revision and runs a capacity-type remuneration for demand-side flexibility through the Capacity Market. Slovakia remains the most restrictive of the four: the 2022 amendment to the Energy Act recognized the aggregator role, but SEPS has kept the prequalification thresholds at levels that exclude most commercial-scale portfolios.

Bulgaria amended its Energy Act in 2023 to introduce the aggregator and to recognize energy storage as a distinct asset class. Ordinance №6 of 28 March 2024 on grid connection rationalized the procedural rules for storage, aligning thresholds (>10 MW to the transmission grid operated by ESO; up to 10 MW to DSOs) and introducing transitional arrangements for pre-13th of October 2023 grid agreements [3]. Independent aggregation of wholesale bids is now permitted on the Independent Bulgarian Energy Exchange (IBEX); participation in FCR and aFRR through an aggregator is still under technical prequalification review at ESO. Romania's ANRE Order 97/2022 opened the balancing market to aggregated bids with a 1 MW minimum; Transelectrica runs a monthly procurement for FCR that is accessible to aggregator pools. In both countries the gating problem is less legal than technical: baseline methodology and telemetry standards for demand-side assets are not yet fully codified.

Table 1 summarizes the market segments in which independent aggregation is currently operational, piloting or still gated. "Operational" means aggregator bids cleared at least once in 2024-2025 under a standard grid-code-compliant process; "Pilot" means a trial period or sandbox; "Gated" means the product is not yet accessible to independent aggregators, typically due to prequalification rules or minimum bid size.

Table 1. Independent aggregator access to electricity markets in six Eastern European countries, as of Q1 2026. O = operational; P = pilot; G = gated.

Country	DAM/IDM	FCR	aFRR	mFRR	Capacity	DSO services
Poland (PL)	O	P	P	P	O	P
Czech (CZ)	O	P	P	P	G	P
Slovakia (SK)	O	G	G	P	G	G
Hungary (HU)	O	P	P	P	O	P
Romania (RO)	O	P	O	O	G	P
Bulgaria (BG)	O	P	P	P	G	G

The pattern is clear. Wholesale energy markets are open across the region; balancing products are mostly in pilot mode; capacity and DSO-level services are where the regulatory backlog sits. An aggregator entering any of these six countries in 2026 can count on energy arbitrage as a firm revenue stream and should price balancing and capacity revenues as options rather than annuities.

From a technical perspective, the aggregator-controlled resource pool considered in this paper is located mainly at distribution level. In the Eastern European context, this usually corresponds to a medium-voltage distribution cell with local generation, storage, flexible demand and a single point of common coupling with the higher-voltage grid. Such distribution-level coordination is also relevant for smart-city power-supply systems, where reliable supply, smart-grid operation and local energy management are central challenges [3]. The term "micro grid" is therefore used here in a functional sense: the paper focuses on coordinated DER aggregation, market participation and flexibility provision rather than on detailed islanding studies, protection coordination or local power-flow analysis.

A typical aggregator portfolio may include behind-the-meter PV with small BESS, utility-scale BESS co-located with ground-mounted PV, commercial and industrial DR, EV charging fleets with smart charging or V2G and residential thermal flexibility from heat pumps and electric water heaters. The aggregator combines these heterogeneous resources into a dispatchable portfolio, allocates setpoints across assets, maintains technical and contractual constraints and submits bundled bids into wholesale, balancing, ancillary-service or DSO flexibility markets.

Figure 1 schematizes the three-layer structure used in the model. The bottom layer is the DER estate. The middle layer is the aggregator platform: a SCADA front-end, an energy management system (EMS) for optimization, a day-ahead and intraday bidding engine, a settlement back-office and a communications stack compliant with IEC 61850-7-420 for DER control and IEC 62056/DLMS for metering. The top layer is the market interface – wholesale exchanges, TSO ancillary platforms, DSO flexibility platforms and capacity procurements.

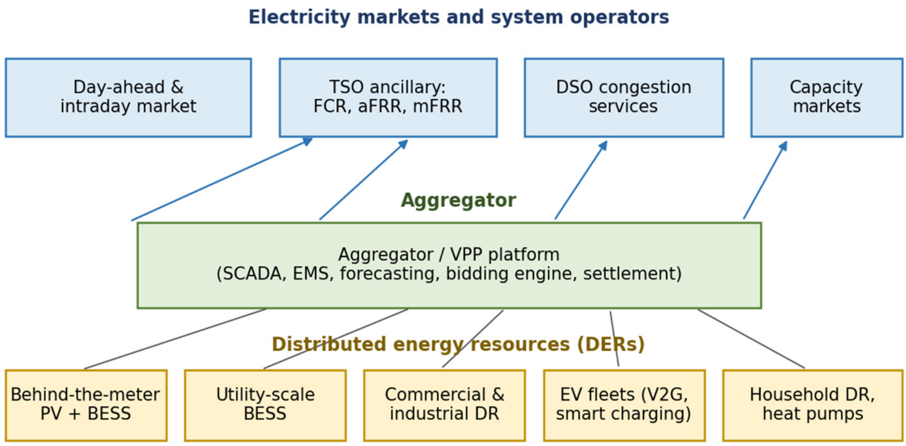

Fig. 1. Three-layer aggregator architecture. DERs are contracted and metered at the distribution level; the aggregator platform optimizes dispatch and submits bundled bids to the wholesale exchange, to TSO ancillary platforms (FCR/aFRR/mFRR), to DSO flexibility procurements and to national capacity markets.

A diversified aggregator can stack several revenue streams. Day-ahead and intraday arbitrage use low-price hours for charging or load shifting and high-price hours for discharge or consumption reduction. FCR and aFRR provide capacity and activation revenues, while mFRR and DSO services can create additional value where national rules allow aggregated participation. The practical challenge is that these revenue streams are not equally accessible across countries and often remain contingent on prequalification, telemetry standards, baseline methodologies and market-design reforms.

Against this background, the objective of this paper is to provide a screening-level techno-economic assessment of aggregator-based distributed flexibility in six Eastern European electricity markets: Poland, the Czech Republic, Slovakia, Hungary, Romania and Bulgaria. The paper combines a regional regulatory and technical overview with a deterministic reference-portfolio calculation for a 150 MW / 450 MWh aggregator pool composed of BESS, DR and V2G resources. The contribution is a transparent regional assessment linking market-access conditions, aggregator architecture, LCOS-based cost evaluation, revenue stacking and sensitivity analysis. The results should therefore be interpreted as indicative scenario-based estimates rather than as a full-year stochastic validation of aggregator profitability.

2 Materials and methods

2.1 Reference aggregator portfolio

To make the techno-economic analysis concrete, we specify a 150 MW / 450 MWh reference portfolio calibrated against the BESS inventory commissioned in Bulgaria between January and September 2025 [3, 4] and typical DER mixes in the region. The portfolio is treated as homogeneous at the market interface even though the underlying assets differ. Table 2 gives the composition.

Table 2. Reference aggregator portfolio used in the techno-economic model. MW values are grid-side AC connection power at the DER level; MWh values are usable AC-side energy for storage assets and reservoir estimates for DR and V2G.

Sub-portfolio	Power (MW)	Capacity (MWh)	Cycles/day	Contracted share
Utility-scale BESS (2-4 h)	60	180	1.6	40%
PV + BESS co-located	40	120	1.4	27%
Commercial & industrial DR	30	60	1.0	20%
EV fleets (smart + V2G)	20	90	0.6	13%
Total	150	450	1.3 (weighted)	100%

2.2 Cost assumptions

Battery cost is the dominant CAPEX term in the pool. We use the same benchmark as [5]: 250 EUR/kW of grid-side power plus 250 EUR/kWh of usable energy, plus a 15% balance-of-plant multiplier. Fixed operations and maintenance (FOM) is set at 1.5% of CAPEX per year. Round-trip efficiency η_($_{rt}$) is 0.88 at full load and 0.85 at partial-load weighted average. We use a 15-year asset lifetime, consistent with common BESS project-finance assumptions. For DR and V2G, no CAPEX is booked at the aggregator level – the asset sits with the customer, but a contractual payment of 35 EUR/MWh of activated energy is assumed (market-standard in CEE pilots). The weighted average cost of capital is set at 8%, reflecting the sovereign-plus-project-risk premium for the six jurisdictions in scope.

2.3 Revenue model

Three revenue streams are modeled explicitly. First, day-ahead arbitrage: the pool charges during the four cheapest hours and discharges during the four most expensive, subject to the SOC constraint

$$SOC_t = SOC_{t-1} + (\eta_{rt}.P^{charge} - P^{de}).\Delta_t \quad (1)$$

Second, FCR capacity payment: 18 MW of the pool is pre-qualified for FCR at an annual-average capacity clearing price of 130,000 EUR/MW/year. (three-year average across the six national FCR markets). Third, aFRR activation: 30 MW of the pool clears aFRR capacity at 8,500 EUR/MW/year, with an additional activation-energy payment of 2.1 MEUR/year in the base case. The charging-energy cost is the volume-weighted average of the four cheapest hours or 89.82 EUR/MWh on the reference day (30 September 2025 at IBEX) and the discharge price is the average of the four most expensive hours, 232.62 EUR/MWh [6].

2.4 Levelized cost of storage

LCOS is computed as:

$$LCOS = (CAPEX\ .CRF + FOM)/(E_e\ .365\ .N\ .A) + P^{charge}/\eta_{rt} \quad (2)$$

where CRF is the capital recovery factor at 8% over 15 years, E_e is the usable energy per cycle, N is the number of full cycles per day, A is availability (0.95) and P^{charge} is the charging price. Three LCOS points are computed, at 2, 3 and 4 h storage duration and for one and two cycles per day, to bracket the operating envelope reported in [3] for Bulgaria and to test the economics of a denser dispatch schedule.

2.5 Regional scale-up

For the regional projection, we adopt the NECP 2024 trajectories for installed PV and onshore wind capacity in each of the six countries and assume that aggregator-addressable flexibility scales at 0.3 MW per MW of PV capacity (consistent with the Bulgarian inventory in [3, 7]) plus the NECP-announced BESS procurement volumes. DR scales with industrial electricity demand; V2G scales with the EV stock projection from national transport plans. The resulting 2026 and 2030 volumes are reported in Figure 2.

3 Results

3.1 Dispatch on a representative day

Figure 2 plots the representative price-spread dispatch of the 150 MW pool against the IBEX hourly prices on 30 September 2025. The pattern is familiar from the reference paper: charge into the midday trough (10:00-14:00) and discharge into the morning and evening peaks, with the largest single-hour discharge at 19:00 when the spot price reached 367.91 EUR/MWh. Net dispatched energy is 670 MWh/day, corresponding to 1.49 full cycles on the 450 MWh capacity envelope.

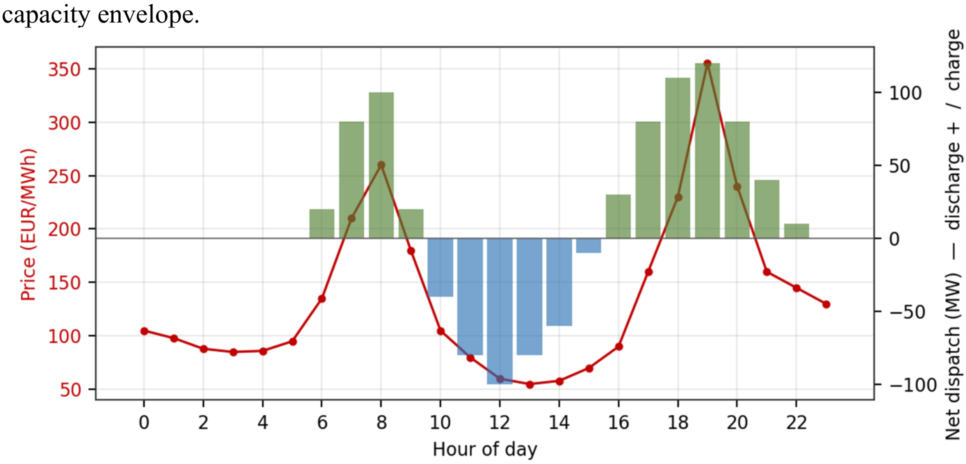

Fig. 2. Representative price-spread dispatch of the 150 MW aggregator pool against IBEX hourly prices on 30 September 2025. Negative bars indicate charging; positive bars indicate discharge. Red line is the hourly clearing price.

3.2 LCOS and gross margin

Table 3 gives the LCOS under six combinations of storage duration and cycles per day and the implied gross margin at the observed price spread. At one cycle per day the 2 h configuration loses 12.0 EUR/MWh; the 3 h and 4 h configurations clear positive margins of 3.8 and 11.7 EUR/MWh respectively. At two cycles per day all three durations clear comfortably: margins rise to 59.3, 67.2 and 71.2 EUR/MWh, because doubling the cycles halves the fixed-cost component of LCOS while the charging-cost component stays at p^{charge}/η_{rt}. The take-away for portfolio design in the region is that a denser dispatch schedule – achievable only where balancing-market access is open to aggregators – is the decisive economic variable, ahead of storage duration.

Table 3. LCOS (EUR/MWh) and portfolio gross margin under six operating configurations. Discharge price = 232.62 EUR/MWh; charging price = 89.82 EUR/MWh; η = 0.88; availability = 0.95.

Duration	Cycles/day	LCOS (EUR/MWh)	Margin (EUR/MWh)	Portfolio annual margin (MEUR)
2 h	1	244.6	−12.0	−4.1
3 h	1	228.8	3.8	1.3
4 h	1	220.9	11.7	4.0
2 h	2	173.4	59.3	40.3
3 h	2	165.4	67.2	45.7
4 h	2	161.5	71.2	48.4

3.3 Revenue stack

Table 4 decomposes the gross annual revenue of the 150 MW pool under the 3 h / 2 cycle-per-day configuration.

Table 4. Gross revenue stack for the 150 MW aggregator pool in the base case (3 h duration, 2 cycles/day). Prices in EUR; volumes in MWh/year.

Revenue stream	Allocated capacity (MW)	Price (EUR/MW or EUR/MWh)	Gross revenue (MEUR/year)	Share (%)
Day-ahead arbitrage	150	142.80/MWh spread	60.4	67.8
FCR capacity	18	130,000/MW/year	2.3	2.6
aFRR capacity + activation	30	8,500/MW/year + 2.1 MEUR/year activation	2.4	2.6
Intraday rebalancing	60	5.2/MWh avg	11.0	12.3
DSO local services	20	150/MWh conservative	3.0	3.4
Other (capacity, pilots)	-	-	10.0	11.2
Total gross			89.1	100

Day-ahead arbitrage contributes 60.4 MEUR/year or 67.8% of total gross revenue. FCR capacity contributes 130,000 EUR/MW/year x 18 MW = 2.34 MEUR/year or 2.6%. aFRR capacity contributes 8,500 EUR/MW/year x 30 MW = 0.26 MEUR/year, with an additional 2.1 MEUR/year of activation revenue, bringing the total aFRR contribution to 2.36 MEUR/year or 2.6%. Intraday rebalancing contributes 11.0 MEUR/year, DSO local services are booked conservatively at 3.0 MEUR/year and other capacity or pilot revenues contribute 10.0 MEUR/year. Total gross revenue is therefore 89.1 MEUR/year. Net of the stated LCOS and FOM cost component of 54.2 MEUR/year, EBITDA is 34.9 MEUR/year, corresponding to a first-year cash-on-cash return of 19.4% against the 180 MEUR CAPEX envelope.

3.4 Regional projection

Figure 3 projects aggregator-addressable flexibility by country for 2026 and 2030 under the NECP trajectories. Poland dominates the 2030 volume in absolute terms (3.86 GW across BESS, DR and V2G) because its grid is the largest in the region; Bulgaria and Romania show the fastest growth rates from a smaller 2026 base. The Czech Republic, Slovakia and Hungary trail because their 2024 regulatory transposition is more recent and because their balancing markets remain in pilot. The total 2030 pool-addressable capacity across the six countries reaches 11.5 GW or roughly 18% of the regional peak load – consistent with the flexibility share that ENTSO-E's ERAA 2024 identifies as sufficient to avoid structural curtailment [8].

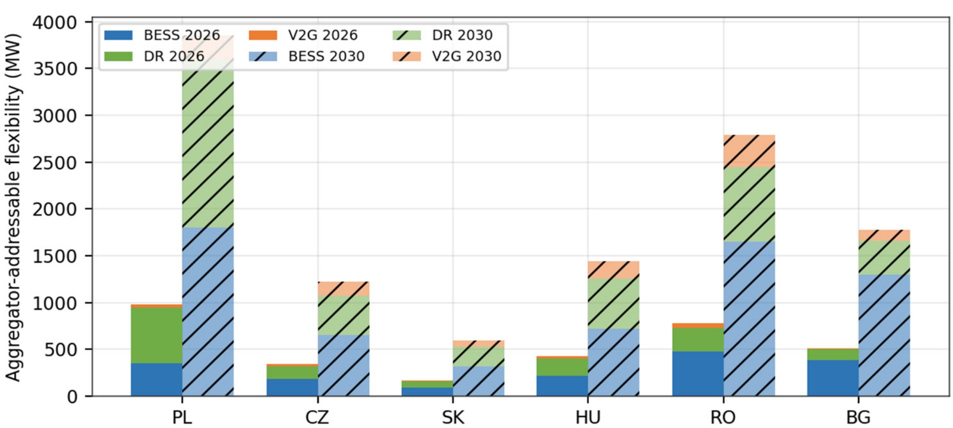

Fig. 3. Projected aggregator-addressable flexibility by country and technology, 2026 (solid) and 2030 (hatched) derived from NECP trajectories and calibrated against the Bulgarian BESS inventory: BESS – battery energy storage system; DR – demand response; V2G – vehicle-to-grid.

3.5 Sensitivity

Figure 4 reports a one-factor-at-a-time sensitivity on the base-case LCOS of 165.4 EUR/MWh. The widest bar is cycles per day: moving from 2 to 1 pushes LCOS to 228.8 EUR/MWh and flips the margin to negative. CAPEX variation of ±20% moves LCOS by roughly ±22 EUR/MWh. The charging-price assumption is almost as large: a 25% price increase during the midday trough raises LCOS to 188 EUR/MWh which shrinks margin to 44 EUR/MWh but does not break the business case. Round-trip efficiency (RTE) and lifetime are second-order within plausible bounds.

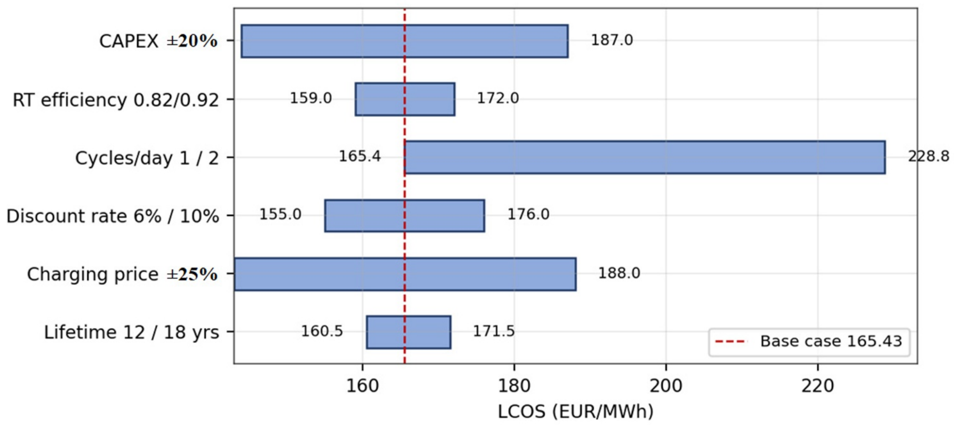

Fig. 4. One-factor-at-a-time LCOS sensitivity around the 3 h / 2 cycles-per-day base case of 165.43 EUR/MWh. Each bar shows the range of LCOS under the stated parameter swing; the dashed red line marks the base case.

4 Discussion and limitations

4.1 Interpretation of results

The results are consistent with the aggregator and storage-economics literature in showing that cycle density and CAPEX are the main drivers of LCOS, while round-trip efficiency has a smaller effect within the tested range [8, 9]. In the base case, the 3 h / 2 cycle-per-day configuration gives an LCOS of approximately 165 EUR/MWh and a positive LCOS-based gross margin under the observed Bulgarian reference-day price spread. This indicates that aggregator-controlled storage and flexibility portfolios may be economically viable under favourable spread conditions, but the result should be interpreted as a deterministic screening estimate rather than as evidence of general profitability across all market conditions.

The comparison between one-cycle and two-cycle operation highlights the importance of utilization. At one cycle per day, the fixed-cost component of LCOS remains high and the 2 h configuration becomes uneconomic under the assumed price spread. At two cycles per day, the fixed-cost burden is distributed over a larger discharged-energy volume, which improves the margin across all tested storage durations. This suggests that access to multiple revenue streams, including intraday rebalancing and balancing products, can materially affect aggregator economics. However, the ability to achieve such utilization depends on market access, asset availability, forecasting accuracy, degradation constraints and the operational rules imposed by TSOs and DSOs.

The corrected revenue stack shows that day-ahead arbitrage remains the dominant revenue source in the base case, contributing 60.4 MEUR/year or 67.8% of total gross revenue. FCR and aFRR capacity and activation revenues contribute a smaller but still relevant share, together accounting for approximately 5.2% of gross revenue. This reduces the dependence of the economic case on ancillary-service remuneration compared with the previous calculation, but it does not remove the importance of balancing-market access. Prequalification for FCR, aFRR and mFRR can still improve operational flexibility, reduce exposure to arbitrage-only business models and provide optional revenues when price spreads are weaker.

4.2 Market and regulatory implications

The regional comparison indicates that wholesale market access for independent aggregators is generally more advanced than access to balancing, capacity and DSO-level flexibility services. This supports the view that market-design and prequalification barriers remain important constraints on aggregator deployment in Eastern Europe. However, the results do not prove that regulatory barriers are the only or dominant limitation in all countries. They suggest instead that, under the assumptions used in this study, regulatory and technical-access conditions may be at least as important as technology cost in determining whether aggregator portfolios can reach sufficient utilization.

The most relevant practical implication is that aggregators should not be assessed only as arbitrage operators. Their value depends on the ability to combine BESS, DR and V2G resources, allocate dispatch across assets and participate in multiple market segments where rules permit. For TSOs and DSOs, this points to the importance of transparent prequalification procedures, clear baseline methodologies for demand response, lower minimum bid sizes where technically feasible and standardized local-flexibility products. These measures would not guarantee profitability, but they would reduce transaction costs and allow market participants to test aggregator business models under more predictable conditions.

V2G remains a potentially important but still uncertain component of the regional flexibility pool. In 2026, the dispatchable V2G volume is limited by EV stock, bidirectional-charging availability, user participation and retail-tariff design. The analysis therefore treats V2G as a smaller contributor in the reference portfolio rather than as a near-term dominant flexibility source. Its role may increase after 2028 if EV adoption, dynamic tariffs and bidirectional-charging standards develop as expected, but this requires country-specific validation.

4.3 Limitations and future research

The main limitation of the study is the use of a representative IBEX market day rather than a full-year simulation. The selected day captures a typical shoulder-season pattern with a midday price trough and evening peak, but it does not represent winter peak conditions, summer cooling demand, hydro seasonality, prolonged low-renewable periods or extreme price events. Consequently, the calculated margins should be interpreted as scenario-based indicators. A full-year simulation using hourly or 15-minute ENTSO-E and national market data would be needed to estimate annual profitability, volatility, downside risk and country-specific performance more robustly.

The dispatch model is also simplified. It assumes perfect price foresight, fixed cycling patterns, aggregate portfolio availability and a simplified treatment of degradation through annual capacity fade. In practice, forecast errors, imbalance prices, degradation-aware dispatch, state-of-charge reserve constraints, communication delays and asset-level contractual limits would reduce the captured spread and affect the optimal allocation between arbitrage and ancillary services. A more detailed model should include explicit SOC dynamics, reserve headroom constraints, cycle-dependent degradation costs, uncertainty treatment and solver specifications.

The regional scale-up estimates are indicative. They rely on simplified assumptions regarding PV-related flexibility, announced BESS volumes, industrial DR potential and EV/V2G adoption. These assumptions provide a transparent first approximation, but they do not represent confidence intervals or probabilistic forecasts. Country-specific studies should therefore recalibrate the model using national price series, grid-code requirements, smart-meter penetration, EV adoption, industrial-load structure and DSO congestion patterns.

Future research should also compare deterministic representative-day results with stochastic or scenario-based simulations and evaluate the option value of balancing-market prequalification under different regulatory pathways.

5 Conclusion

This paper presented a screening-level techno-economic assessment of aggregator-based distributed flexibility in six Eastern European electricity markets: Poland, the Czech Republic, Slovakia, Hungary, Romania and Bulgaria. The novelty of the study lies in combining a regional market-access comparison with a reference 150 MW / 450 MWh aggregator portfolio composed of BESS, demand response and V2G resources. Rather than proposing a new optimization algorithm, the contribution is a transparent regional assessment linking aggregator architecture, LCOS-based cost evaluation, revenue stacking and regulatory access conditions.

Under the base-case 3 h / 2 cycle-per-day configuration, the reference portfolio achieves an LCOS of approximately 165 EUR/MWh. The LCOS-based arbitrage margin is estimated at 45.7 MEUR/year before network-fee adjustments, while the corrected revenue-stack calculation gives total gross revenue of 89.1 MEUR/year and EBITDA of 34.9 MEUR/year under the stated assumptions. The results indicate that cycle density and CAPEX are the most influential economic parameters, whereas round-trip efficiency has a smaller effect within the tested range. Single-cycle operation is considerably less attractive, especially for shorter-duration storage, which suggests that aggregator profitability depends strongly on sufficient asset utilization and access to more than one market segment.

The regional projection indicates a potential aggregator-addressable flexibility volume of approximately 11.5 GW by 2030 across the six countries, although this estimate should be interpreted as indicative rather than predictive. Poland accounts for the largest absolute volume, while Bulgaria and Romania show stronger relative growth from a smaller base. The analysis suggests that regulatory and market-access conditions may be at least as important as technology costs in determining aggregator deployment. In particular, balancing-market prequalification, minimum bid sizes, baseline methodologies for demand response and standardized DSO flexibility products remain important practical barriers.

For market participants, the results provide a reference framework for evaluating mixed aggregator portfolios that combine BESS, DR and V2G assets. For TSOs, DSOs and regulators, the practical contribution is the identification of market-design measures that could improve aggregator participation: clearer prequalification procedures, lower minimum bid sizes where technically feasible, transparent baseline rules and local flexibility products compatible with behind-the-meter resources. Future research should extend the model to full-year country-specific simulations using ENTSO-E and national price data, include degradation-aware dispatch and test stochastic or scenario-based treatment of price uncertainty and balancing-market access.

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