



# BATTERY CO-LOCATION AS A STRATEGIC PILLAR FOR ACCELERATING EV INFRASTRUCTURE AND STRENGTHENING EUROPE'S POWER SYSTEM

## Executive Summary

The rapid electrification of transport is a central pillar of Europe's decarbonization strategy. Turning transport electrification ambitions into reality requires not only the deployment of charging stations, but the deployment of reliable, high-power, grid-integrated charging infrastructure at scale.

Battery co-location in the EV charging industry refers to installing stationary battery energy storage systems alongside charging infrastructure so that electricity can be stored and dispatched when needed rather than drawn directly from the grid in real time.

Battery co-location at charging sites is a strategic enabler of this transition. By integrating stationary storage behind the meter of charging hubs, Europe can simultaneously accelerate infrastructure rollout, address potential lack of grid capacity, and enhance system optimization. Battery co-location can also allow to ideally utilize existing charging infrastructure despite grid constraints, improving the business case for operators. Battery co-location is not a substitute for grid reinforcement, but a complementary solution that allows Europe to move at the speed required by industrial policy objectives.

Today, however, battery co-location remains capital-intensive and constrained by fragmented regulatory frameworks, inconsistent permitting procedures, inefficient taxation models, limited access to flexibility markets, and insufficiently developed offers of Flexible Connection Agreements (FCAs). Without targeted policy action, the full system value of co-located storage will remain underutilized.

## Battery Co-Location as a Grid-Enabling Flexibility Resource

Battery co-location facilitates the deployment of charging infrastructure in areas where grid capacity is limited, or reinforcement timelines are long. By integrating storage, charging operators can deploy high-power charging hubs, keeping grid draw within the available grid capacity, while the network upgrades are carried out at a later date. In practice, batteries can allow charging installations to deliver peak charging power that exceeds the instantaneous grid capacity. Batteries allow to deliver the power of a station connected on medium or high-voltage, which typically require long lead times, but with a low or medium voltage connection, which available capacity is accessible in a shorter timeframe.

When integrated into broader congestion management frameworks, distributed storage can also unlock additional hosting capacity across the network. While grid reinforcements need to remain a priority, flexibility resources deployed at individual sites can help reduce stress at substations and enable further infrastructure deployment elsewhere before local grid reinforcements are in (1), effectively multiplying grid capacity in the short and medium term without disproportional investment in network reinforcement

At the site level, co-located storage enables peak shaving at the grid connection point without affecting individual charging sessions. During periods of network congestion or high system demand, system operators can send signals to reduce grid draw while the battery supplements the needed charging load. This ensures a reliable charging speed for EV drivers while mitigating unmanaged charging peaks.

(1) Pilot initiatives such as Euroflex demonstrate that distributed flexibility resources can unlock additional hosting capacity at substations. In practice, installing a battery at one site may enable further installations elsewhere, effectively multiplying infrastructure potential without proportional grid investment.

## Strengthening the Economic Case for Charging Infrastructure

Battery co-location also strengthens the commercial viability of charging infrastructure.

From an operational perspective, storage temporarily replaces the need for high contracted capacity levels, lowering upfront connection costs, and recurring peak-related network charges. From an investment perspective, storage allows developers to defer upstream grid reinforcements, such as new substations or cabling. This deferral of capital expenditure can determine whether a site is financially viable, particularly during early utilization phases when charging infrastructure utilization remains moderate.

Batteries can unlock new revenue streams for Charging Point Operators (CPOs) by enabling access to front-of-the-meter (FTM) wholesale and balancing markets. Operators can arbitrage energy charging when prices are low and discharge when they rise and, when aggregated, participate in ancillary services such as automatic and manual Frequency Restoration Reserve (aFRR and mFRR). (2)

In practice, however, most European CPOs have difficulties capturing this value. Market rules in many Member States set minimum bid sizes and prequalification requirements suited to large-scale assets, excluding smaller, distributed energy resources. Participation typically requires aggregation into Virtual Power Plants, but frameworks for independent aggregation remain underdeveloped, with unclear Distribution System Operator (DSO) – Transmission System Operator (TSO) coordination rules, inconsistent telemetry standards, and fragmented communication protocols. The classification of behind-the-meter storage further complicates access, as assets are treated differently across jurisdictions, creating legal uncertainty and limiting eligible services. Even where access exists, revenues are unpredictable and vary significantly between TSOs, making cross-border strategies difficult.

To unlock scale, policymakers need to align eligibility rules with distributed assets, lower minimum bid thresholds, clarify aggregation frameworks, and ensure consistent classification of behind-the-meter. These are essential conditions for making battery co-location financially viable.

(2) The automatic Frequency Restoration Reserve (aFRR), also known as secondary reserve, is a reserve in the power grid that helps to keep the grid frequency stable. To keep the frequency within certain thresholds, the Transmission System Operators (TSOs) activate balancing services like aFRR, which they acquire from Balancing Service Providers (BSPs). Countries differ in their specifications but after European harmonization of the balancing markets, BSPs need to ensure that they provide the reserve within 5 minutes (Full Activation Time). As the secondary reserve, aFRR replaces the FCR gradually after 30 seconds, the mFRR, the tertiary reserve, supports or partially substitutes the aFRR after 12.5 minutes.

## Additional revenue streams and business models enabled by battery co-location

Beyond local benefits, distributed batteries across charging hubs can be aggregated to provide demand-side flexibility at scale. By pooling storage assets across multiple sites, operators can create Virtual Power Plants capable of participating in balancing and ancillary services markets such as Frequency Containment Reserve (FCR). This significantly increases the volume of flexible capacity available to distribution and transmission system operators, contributing to congestion management, system balancing, and grid stability.

Battery co-location also supports renewable energy integration. By absorbing excess generation and reducing curtailment, storage assets help align EV demand with renewable production patterns. This temporal alignment strengthens the decarbonization impact of electrified transport.

Under RED III credit mechanism, however, regulatory clarity is needed to ensure that electricity drawn from the grid, temporarily stored, and subsequently delivered to vehicles retains its renewable accounting validity. Temporary storage should not undermine net metering or renewable credit eligibility. The fuel credit mechanism should explicitly recognize battery co-location and clearly define the proof points required from CPOs.

## The Essential Complementarity with Flexible Connection Agreements

Flexible Connection Agreements (FCAs) are increasingly proposed as a tool to support connection to the grid in congested areas. However, for public high-power charging hubs, flexible connections without storage often imply accepting curtailment during peak hours, directly conflicting with EV drivers' expectations of constant high-power availability.

Battery co-location and FCAs are therefore structurally complementary. An FCA can allow higher grid capacity during off-peak hours to charge the battery, while reducing grid draw during peak demand hours. The battery then supplements or replaces grid supply when contracted capacity is constrained.

Nevertheless, policy design matters. In certain Member States, dual FCA models applied simultaneously to chargers and batteries risk reducing power availability for both assets during congestion periods, thereby undermining incentives for voluntary grid support. FCA frameworks must be designed in a manner that rewards, rather than penalizes, integrated flexibility solutions.

In addition, to ensure the feasibility and attractiveness of FCAs, they must be implemented using open protocols. Schemes where the grid operators require direct control of the storage asset using proprietary solutions are not sufficiently scalable.

## Regulatory and Administrative Barriers

Despite its clear benefits, battery co-location faces significant regulatory obstacles at both EU and national levels.

Regulatory frameworks are not sufficiently established today. Across Member States, battery storage regulation is rather immature with fragmented definitions and inconsistent treatment. In the absence of clear regulation, even the operators are uncertain about how to proceed, which further extends waiting times. Moreover, access to real-time grid data remains uneven. On the EU level, there is no fully harmonized framework governing the connection of co-located storage installations. Medium-sized behind-the-meter batteries in the range of 200 kW to 1 MW are currently overlooked in legislation, despite representing the core segment for charging hubs. CPOs observe that the 200 kW to 1 MW battery segment is today the most complex to deploy in many cases because none of the processes, obligations, and procedures are standardized like is it done for residential storage or large-scale utility projects.

At national level, barriers multiply. Fire safety regulations and their interpretation vary significantly across Member States, creating uncertainty and redesign costs. Permitting delays are common, often compounded by additional administrative layers when projects are located on public land. Public tenders frequently fail to anticipate storage integration, omitting reserved space or modification pathways. Responsible authorities should instead design battery-ready tenders and explicitly reward congestion mitigation solutions.

In addition, pricing distortions in electricity market design further undermine the business case for battery co-location. When electricity is withdrawn from the grid, consumers are charged for both the energy component and applicable network tariffs. However, when electricity is injected into the grid, remuneration typically covers only the energy component. Consequently, full cost recovery is not achieved upon resale. Furthermore, double taxation of stored electricity persists in certain jurisdictions.

Finally, grid connection queues and unharmonized grid communication further delay deployment.

On grid queues, CPOs are experimenting with longer queues as the number of electrification projects is increasing. Combined assets are often misunderstood by DSOs and either require different connection procedures, may not be accepted in certain cases (France), or create a completely new process that increase connection times (Germany, Austria). The industry is also facing unharmonized grid communication standards across Member States that hinder interoperability and increase integration costs. The latter lack of harmonization opens the doors to local grid operators to impose local grid communication standards which could, in some cases, even lead to market-specific hardware changes which are economically unsustainable for mass market production. Harmonization at the EU level is essential to avoid these local lock-ins and to protect customers from being disadvantaged due to lack of choice of good quality products on the market.

## Recommendations

- The EU should recognize battery co-location as enabling infrastructure for EV fast charging in designing funding instruments such as future versions of AFIF, ensuring it is explicitly eligible for deployment support where it enables high-power charging under grid constraints, as storage is often the most capital-intensive component of constrained-grid sites. The EU must ensure that this funding strengthens European industrial resilience by financing exclusively projects that support a strong EU battery value chain.
- Under the Renewable Energy Directive and Guarantees of Origin frameworks, the EU should ensure that electricity stored in and discharged from co-located batteries retains its renewable attribution through standardized accounting rules.
- Co-located storage at EV charging hubs should be granted full and non-discriminatory access to balancing and ancillary services markets under the Electricity Market Design framework and relevant network codes, including the ability to aggregate into Virtual Power Plants for flexibility provision. The EU should align electricity market rules with distributed storage by lowering minimum bid thresholds, clarifying aggregation frameworks, strengthening DSO–TSO coordination, and ensuring consistent treatment of behind-the-meter batteries, so that co-located storage can access flexibility markets and improve the financial viability of EV charging infrastructure.
- Member States should streamline permitting, safety, and grid connection procedures for co-located EV charging and storage infrastructure.
- Co-located assets behind the meter are usually 200 kW–1.5 MW batteries. However, this segment has its own properties as it isn't residential storage or large utility scale. When developing regulation, the EU and Member States should ensure that this segment is properly covered and not over regulated or penalized because of regulatory red tape.



## Conclusion

If Europe is serious about achieving its electrification targets while preserving grid stability and cost efficiency, battery co-location must be recognized as a strategic infrastructure component rather than an optional add-on.

The European Union should harmonize storage definitions and connection requirements, clarify RED III treatment of stored electricity, eliminate double taxation, and ensure explicit eligibility of battery co-location under infrastructure funding instruments. Member States should streamline permitting procedures, harmonize fire safety interpretations, enable fair access to balancing markets, and design FCA frameworks that are compatible with public fast charging.

Battery co-location enables faster deployment, improves grid resilience, enhances renewable integration, strengthens the business case for operators, and safeguards customer experience. It represents a practical, scalable solution to bridge the gap between infrastructure ambition and grid constraints.

Without decisive action to remove regulatory and administrative barriers, Europe risks slowing down the very transition it seeks to accelerate. With the right framework, battery co-location can become a cornerstone of a flexible, resilient, and electrified European energy system.

## Annex 1: Examples of a successful project

Grid congestion in the Netherlands limits most new sites to a low-voltage 3×80A connection (~55 kVA). To still deliver High Power Charging on 6 charge points or plus, CPO builds battery-boosted hubs: an on-site Battery Energy Storage System (BESS) is slowly recharged by the grid and provides the peak power needed for fast charging, with an energy management layer arbitrating between the two sources.

Beyond solving the technical constraint, this model is a core growth lever: Low Voltage (LV) connections are granted far faster than Medium Voltage (MV) upgrades (few months vs few years), allowing sites to open years earlier, while load smoothing keeps the site grid friendly. Battery-boosted hubs are therefore primary vehicle for sustaining network expansion in the Netherlands under current infrastructure constraints.

In the Netherlands, these sites have to stay transitional solutions as they are limiting both revenue potential and return on investment. To unlock the full commercial value of these locations, it is therefore critical that sites operating under this model are prioritized for early access to dynamic MV connections as grid capacity becomes available, or that regulatory frameworks evolve to allow LV connections closer to 200 kVA.

## Annex 2: regulatory good practice example at Member State level

### Italian Regulatory Framework: ARERA Resolution 109/2021

A relevant good practice in the Italian regulatory context concerns Resolution 109/2021/R/eel (1) issued by ARERA (the Italian Regulatory Authority for Energy, Networks and Environment), which establishes a favourable tariff treatment for energy drawn from the public grid when it is functionally destined for subsequent re-injection.

The core principle underlying the resolution is that transmission and distribution tariffs, including components covering general system charges, should apply exclusively to energy drawn for final consumption, and not to energy withdrawn from the grid for storage and subsequent re-injection or for auxiliary generation services.

The mechanism through which this is operationalised is the concept of “Energia Immessa Negativa” (negative injected energy). The kWh absorbed by auxiliary services and storage charging are no longer treated as standard withdrawal items on the electricity bill, but are instead accounted for as negative injected energy, managed within the injection dispatching contract rather than through a conventional supply agreement. Energy drawn for other final consumption purposes at the same site remains subject to standard network tariffs, as it does not qualify as negative injected energy.

In a configuration combining EV charging infrastructure and a co-located battery storage system, this framework is particularly advantageous as this effectively eliminates the double-counting of grid costs that would otherwise arise when energy passes through the battery as an intermediary.

To access the benefit, the producer must submit a formal application to the relevant grid operator, accompanied by a certified assessment prepared by a qualified independent engineer, specifying the auxiliary systems and storage equipment with their associated maximum power absorption. The grid operator must issue a decision within four months of receiving the application, excluding the time required for any necessary technical modifications, such as the installation or replacement of metering equipment, and for any documentary integrations requested.

On the metering side, the producer must ensure that the withdrawal related to auxiliary services and storage can be measured separately. The responsibility for the additional meter required to attribute energy to the Auxiliary Services Production Unit follows ARERA's metering regulation: for plants connected to low-voltage public networks, the obligation falls on the DSO, while for medium- and high-voltage connections it falls on the producer, who may request installation from the DSO or Grid Operator depending on the voltage level.

From an economic standpoint, facilities that do not participate in the scheme continue to be charged for auxiliary and storage fees as standard electricity consumption. For an EV charging hub with battery storage, compliance with Resolution 109/2021 therefore results in a structurally significant cost reduction in operating costs, improving the profitability of flexible, grid-interactive charging configurations.

(1) <https://www.arena.it/atti-e-provvedimenti/dettaglio/21/109-21>

## Annex 3: regulatory bad practice examples at Member State level

### France - Arrete du 9 juin 2020

It classifies storage units as "generating machines", subjecting them to a maximum installed power of 250 kVA on low-voltage connections. In practice, a 500 kW battery paired with a 250 kVA LV connection is deemed non-compliant, even when configured with strict anti-injection controls. This forces operators to cap the battery at 250 kW, limiting total charging power to around 500 kW at the terminals, far below the intended capacity.

The consequence is counterproductive: sites specifically designed to relieve grid stress through local storage are instead pushed toward medium-voltage connections or oversized grid subscriptions, defeating the very purpose of the battery-boosted architecture. The regulation, designed to limit energy injection into the grid, fails to account for configurations where injection is physically and technically impossible, conflating the power delivered to internal loads with the power drawn from the grid.

### France - Environment protection provisions

France is currently looking into obligating all of stationary batteries >600kw, including the ones on charging site to fit into the ICPE (Installation Classée pour la protection de l'environnement). This would imply heavy security, prevention, and derisking measures to install BESS on charging sites. Imposing such regulation on batteries would make it nearly impossible to deploy BESS in urban areas due to distances constraints while this use case will be increasing in the coming years due to a reduction of the available power in certain zones.

If security measures must apply to Battery Energy Storage System (BESS) deployed on stations, public authorities should encourage their deployment along charging sites, especially if there're <1MW and imposing strict measures would only reduce the use cases for electric mobility.

## Germany and Austria - diversity of practices

In Germany and Austria, the deployment of batteries at charging stations faces significant regulatory and technical hurdles related to the Technische und organisatorische Regeln für Betreiber und Benutzer von Netzen – TOR (1) regulation, which requires Distribution Network Operators (DNOs) to remotely control battery systems by sending real-time commands to limit the power drawn from the grid.

It should be noted that the application of this regulation necessitates prior coordination with the relevant DNO, as the existing regulatory framework and associated documentation do not currently account for use cases in which energy is solely consumed without any re-injection into the grid.

Its implementation across Germany and Austria, where requirements are the same, is deeply inconsistent: across all the different DNOs, different communication protocols have been encountered, forcing CPO development teams to build custom solutions each time despite the underlying functional requirements being largely similar.

Beyond protocol fragmentation, DNOs diverge on the specific parameters they seek to control, ranging from active power limitations to measurement confirmation requirements, with some requesting capabilities that others do not even consider. A recurring challenge is DNO unreadiness: in several instances, DNOs initially made their validation a prerequisite for station or battery operation, only to later acknowledge they were not prepared to test compliance, ultimately allowing operations to proceed without the system in place.

In Germany, stationary battery storage systems do not fall automatically within the scope of Section 4(1) of the Federal Emission Control Act (Bundes-Immissionsschutzgesetz, BImSchG). A permit obligation under this legislation is triggered only where the installation in question is explicitly enumerated among permit-requiring systems in the Fourth Ordinance on Systems Requiring Permits (4. BImSchV).

At present, stationary battery storage systems are not explicitly listed in the 4th BImSchV. As a consequence, small to medium-sized installations, including those integrated into buildings or deployed as part of electric vehicle charging infrastructure, fall outside the permitting requirements of emission control law. This absence of explicit classification results in a regulatory gap: without a defined legal status, such assets operate in a zone of ambiguity that generates significant uncertainty for developers, operators, and competent authorities alike.

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1) <https://www.e-control.at/marktteilnehmer/strom/marktregeln/tor>