

An aerial photograph of a solar farm with rows of photovoltaic panels. A large, light-colored rectangular container, likely a Battery Energy Storage System (BESS), is situated in the lower-left area. The entire image is overlaid with a semi-transparent green grid pattern and several white diagonal lines.

FORRS

Co-locating BESS with renewable generation

Setups, optimization, revenue models,
and bankability

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1 Introduction

The European power sector is undergoing one of the most profound transformations in its history. Driven by ambitious decarbonization targets, declining technology costs, and increasing energy independence objectives, renewable generation capacity has expanded rapidly across Europe. Solar and wind power account for the vast majority of newly installed generation assets and are expected to continue growing significantly over the coming decades. While this transition is essential for achieving climate goals, it fundamentally changes the way electricity systems operate.

Unlike conventional power plants, renewable generation depends on weather conditions and therefore cannot be dispatched according to demand. As a result, electricity markets are increasingly characterized by periods of surplus generation and periods of scarcity. This growing mismatch between generation and consumption creates volatility in power prices, increases balancing requirements, and places additional stress on existing grid infrastructure. At the same time, developers and investors face new challenges in securing stable revenues and ensuring the long-term profitability of renewable energy projects.

Our first whitepaper, Battery Energy Storage Systems (BESS) as a Key Flexibility Provider, examined these structural changes and their implications for European power systems. We discussed the growing flexibility requirements resulting from the energy transition and compared different flexibility technologies. Due to significantly decreased turnkey costs, BESS

currently offers the most immediate and scalable solution. We explored the role of such batteries in supporting grid stability and renewable integration, and highlighted how the increasing penetration of renewable generation is changing market dynamics and creating new opportunities for flexible assets.

Building on this foundation, our second whitepaper, Making BESS Happen: Turning Energy Storage Potential into Grid-Scale Reality, shifted the focus from technology and market fundamentals to practical implementation. The paper explored how battery assets can be integrated into modern trading organizations and energy markets, covering topics such as trading architecture, Energy Trading and Risk Management (ETRM) systems, market participation and multi-market optimization, while taking battery degradation into account. The objective was to demonstrate how the technical flexibility provided by battery storage can be translated into operational and commercial value.

This third whitepaper focuses on the next stage in the evolution of battery storage projects: co-location. BESS combines the asset diversity of renewable generation with the optimization complexity of thermal power plants, and this complexity multiplies once a battery shares its grid connection with another asset instead of operating on its own. BESS projects therefore follow one of two fundamental setups: standalone or co-located. A standalone BESS operates as a pure merchant asset, trading independently across markets without constraints from a host asset.

A co-located BESS, in contrast, shares its grid connection with another asset, typically a wind or solar generator, which creates operational dependencies around charging sources, dispatch rights, and revenue sharing.

BESS shows particular promise in co-located projects, where storage operates alongside a generation or consumption asset at a shared grid connection point. These configurations enable more efficient grid utilization and unlock additional revenues. Co-located BESS is not a

single, uniform model. The specific setup depends on the type of host asset and the contractual arrangement between the parties involved. These arrangements determine core aspects of BESS operation, including permitted charging sources, dispatch rights, and the allocation of revenues between the battery and its host. This directly feeds into the availability of core (trading) capabilities of the institution. This whitepaper focuses on co-location with a producer and distinguishes by grid impact, namely green and grey setups.



2 Co-location setups

There are various setups for co-located energy storage. The two main configurations are a BESS co-located with a consumer, typically an industrial or commercial site, and a BESS co-located with a producer, typically a renewable generation asset.

The former allows for improved energy usage and is primarily motivated by the consumer's energy cost structure. Key advantages include peak shaving to reduce capacity-based grid charges, increased self-consumption of on-site generation, price-driven load shifting against day-ahead and intraday spot prices, and reduced exposure to grid fees and levies on grid-supplied electricity. In addition, the storage asset can

provide backup power and, depending on the setup, participate in ancillary services markets with the capacity not reserved for on-site optimization.

In industrial settings, the storage medium is not limited to electrochemical batteries. Figure 1 shows a co-located heat storage, which converts low-price electricity into process heat.

A comprehensive discussion of all potential co-location architectures is beyond the scope of this paper. The remainder of this paper therefore focuses on the producer-side configuration: a BESS co-located with a renewable generation asset.

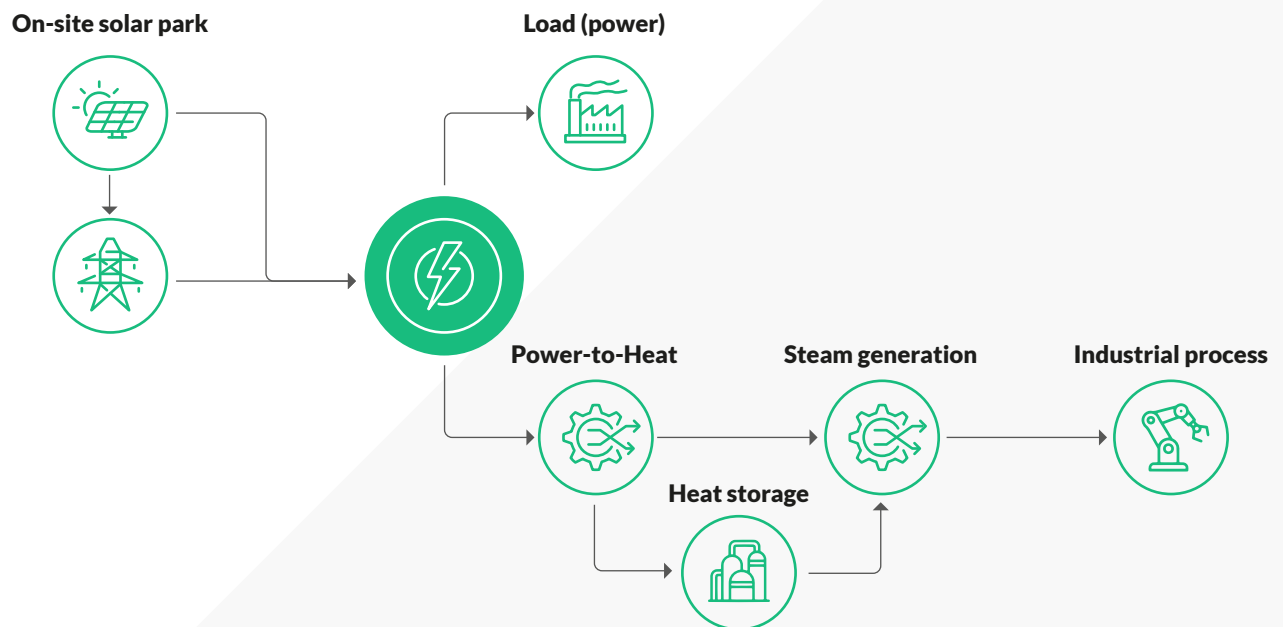


Figure 1:
Illustrative
industrial setup
with a co-located
heat storage

3 Varieties of co-location with a producer

There exists a broad spectrum of different setups of energy producers and large-scale batteries. In this section, we will not look into detailed technical setups like the number of grid connection points, etc., but show categories of setups concerning market access and support regimes/subsidies.

3.1 Renewable support regimes

Most European power markets operate support regimes to underpin renewable investment, ranging from feed-in tariffs and sliding premiums to contracts for difference, and these schemes increasingly shape how storage can be integrated with subsidized generation. Germany's instrument is the Renewable Energy Sources Act¹ (EEG), which guarantees operators a plant-specific applicable value, i.e. the reference value against which the sliding market premium is calculated, set administratively for small installations and via competitive tenders for larger ones. Since direct marketing became mandatory, most plants sell their output on the wholesale market through a direct marketer and receive the sliding market premium, which tops up the achieved market value to the plant's applicable value. The premium is paid only on electricity actually fed into the public grid, and it is suspended when day-ahead prices turn negative: older installations lose it only after a defined run of consecutive negative hours, whereas newer ones lose it for every affected interval, with the unpaid periods added to the end of the support period. The regime rests on a strict attribution logic: only electricity of demonstrably renewable origin qualifies, and supported volumes are barred from additional green marketing via Guarantee

of Origin (GOO) under the double marketing ban. This attribution logic is precisely where storage becomes sensitive, because once a battery sits between generation and grid feed-in, the renewable quality and thus the support entitlement of the discharged energy must be preserved, which leads directly to the distinction between grey and green co-location.

In the following, this whitepaper focuses on the German support scheme EEG.

3.2 Green vs. grey co-location

In a green co-location setup, the battery charges exclusively with electricity generated by the co-located wind or PV plant, so the stored energy retains its renewable quality and, decisively, the plant's entitlement under the EEG support regime. In a grey co-location setup, the battery may additionally charge from the grid, which turns the stored energy into non-attributable "grey" power and forfeits EEG eligibility for the affected volumes, with the risk of jeopardizing the support entitlement of the entire installation if metering does not cleanly separate the flows (see 3.2.4). The market access consequences follow directly: a grey battery can run the full revenue stack, including bidirectional wholesale arbitrage and balancing products that require grid charging, while a green battery is essentially limited to time-shifting the plant's own generation and to system services that do not involve grid imports. In return, the green configuration preserves the market premium on discharged energy, keeps the electricity marketable as green power and avoids the more complex levy and metering treatment of mixed operation.

¹Erneuerbare-Energien-Gesetz

In Germany, green co-location has therefore often been the more feasible entry point: it protects the existing EEG business case and shares a single grid connection point in a market where connection capacity is the scarcest resource.

The project's starting point matters. A green-field hybrid project designs the renewable plant and the battery together, so the charging source, the curtailment rights, and the marketing contract can all be structured for joint operation from the outset. Adding a battery to an existing PV or wind plant is more constrained, since the direct-marketing contract and any offtake terms are already in place and were not written with a co-located battery in mind. Two points therefore require clarification up front, before signing a new contract or extending an existing one: whether drawing electricity from the local generation into the battery is permitted at all, and, where a contract already exists, whether the renewable asset can be made curtailable. Curtailment is not a precondition for joint optimization. Without it, the plant and the battery are still optimized together, subject to the constraint that all renewable output must flow either to the grid or into the battery. The right to curtail adds flexibility, mainly as a relief valve when export capacity and available storage cannot absorb generation, for example, during negative prices or when the battery is full.

Table 1 below shows three representative specifications. While not by any means extensive, they demonstrate the core differences between the setups.

3.2.1 Hybrid green co-location

The hybrid green setup allows for joint optimization and co-located renewable energy sources (RES) charging and is the only one of the three in Table 1 that remains EEG premium eligible. In a hybrid, green-only setup, discharging the BESS into most markets is possible. Since the green nature of the electricity must be preserved, grid charging is ruled out, which in turn excludes any product that depends on it, such as the frequency containment reserve (FCR) or the negative automatic frequency restoration reserve (aFRR). Another difference from grey setups is the generally lower number of cycles, for example in winter, when PV production is at its lowest.

3.2.2 Subordinated grey co-location

The easiest setup is to make use of a grid connection and share the costs. In that case, the battery is optimized in a subordinated manner. After the trading decisions on the locally produced energy are taken across markets such as the day-ahead auction and the intraday continuous market, the remaining capacity of the grid connection point is available for battery schedule decisions. The battery sits next to the

Table 1:
Most common
setups of
producer site
co-located BESS

Item	Hybrid green	Subordinated grey	Hybrid grey
Joint optimization	Yes	No	Yes
Curtailment fully flexible	Yes / No	Yes / No	Yes / No
Co-located RES charging	Yes	No	Yes / No
Grid charging	No	Yes	Yes
EEG premium eligible	Yes	No	Yes ²

²Pre-conditioned MiSpeL (see 3.2.4) is implemented

RES park without the option to store locally generated power, so it needs market access to buy electricity, which makes it a grey BESS. All this means that the storage can only discharge if the RES asset does not utilize the available grid connection capacity. Given its subordinate nature, ancillary market participation is of lesser importance.

3.2.3 Hybrid grey co-location

In the true hybrid setup, both components are optimized jointly. The BESS can charge by buying from the markets, which qualifies the setup as grey. The configuration may additionally allow co-located green energy to be stored. Where it does and where the generation is subsidized, the resulting mixed inventory raises the question of how much of the feed-in still earns the EEG premium, a question that does not arise in a green-only setup. In Table 1 terms, this is the hybrid grey column, with joint optimization and grid charging, and co-located RES charging optional. Joint optimization does not require the renewable asset to be curtailable. Without curtailment, both components are still optimized together, subject to the constraint that all renewable output must flow either to the grid or into the battery. Curtailment adds a degree of freedom rather than serving as a precondition.

3.2.4 Market integration of storage and charging points (MiSpeL³)

If a BESS can also charge from the grid, this raises the question of how much premium the electricity it feeds in should earn. The Federal Network Agency's⁴ MiSpeL specification addresses this question. The 2024 EEG amendment already introduced the rules for mixed and co-located storage. These rules take effect on October 1st 2026. Simply put, once a battery holds both green

and grey electricity, only the eligible green share of its feed-in still earns the market premium. MiSpeL sets out two ways to determine that share: the delimitation option, which allocates it precisely from quarter-hourly (15-min) metering, and the simplified flat-rate option, which uses flat-rate caps based on installed capacity for small solar-plus-storage setups.

Under the delimitation option, the green share is derived from the metered flows: a statutory priority rule pairs charging with grid consumption and discharge with feed-in in each interval, and the renewable share of storage output follows from those pairs and the round-trip efficiency. That share keeps its eligibility for the market premium; the remainder counts as grid-based feed-in and reduces the levy owed on the matching grid consumption.

3.2.5 AC vs. DC coupled BESS

In an AC-coupled configuration (see Figure 2), the battery system and the PV plant each connect to the grid through their own inverters.

Charging the battery from PV therefore requires two conversion steps (DC to AC to DC), with each step incurring losses of roughly 1-2% in modern utility-scale inverters. This results in a round-trip efficiency disadvantage of approximately 2-4% compared to DC coupling, depending on the operating profile. The separate power conversion system also adds capital costs of indicatively EUR 50-100k⁵ per MW, including the associated electrical balance of system, depending on scale, sourcing, and scope. In return, the AC-coupled design offers higher resiliency, since inverters sit at different locations and a single failure does not take the full system offline, and it is more flexible for retrofitting batteries to existing PV plants.

³Marktintegration von Speichern und Ladepunkten (MiSpeL) | ⁴Bundesnetzagentur (BNetzA) | ⁵Efficiency and cost figures are market estimates as of 2025/2026. Actual values may vary with project scale, equipment sourcing, and scope.

Figure 2:
AC coupling

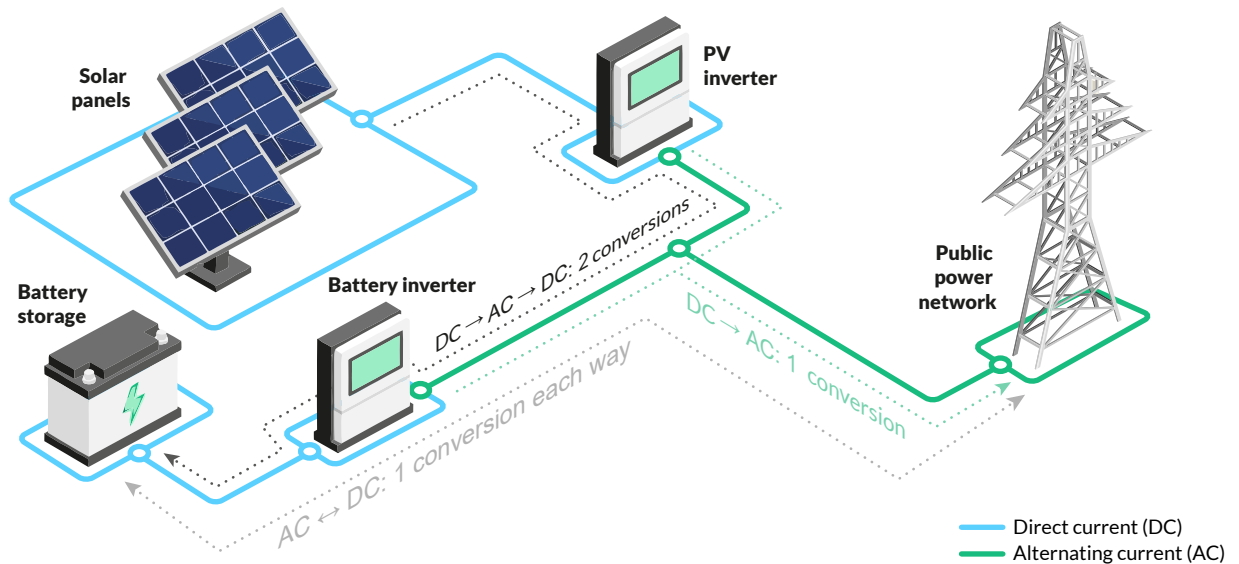
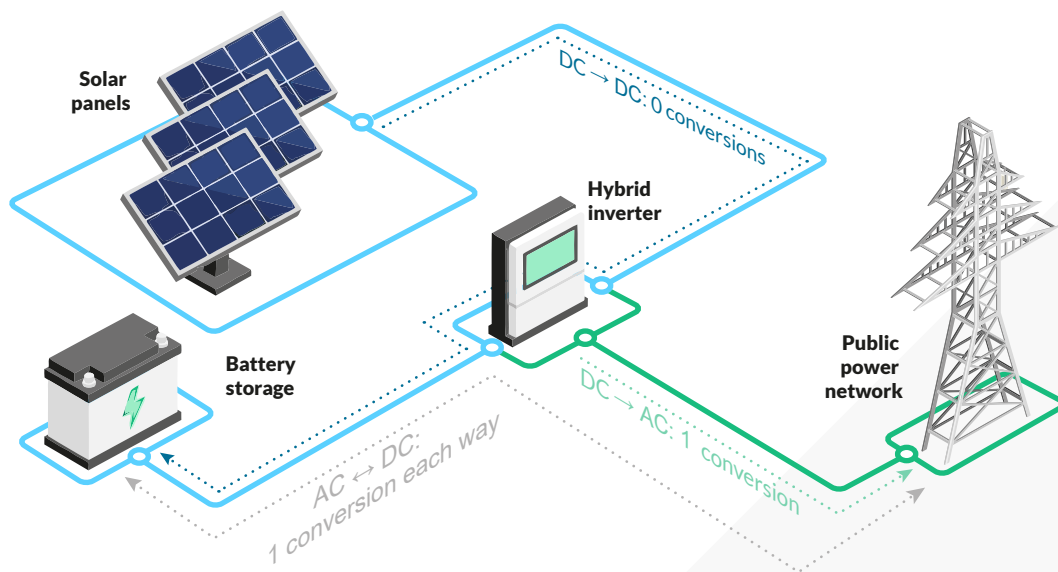


Figure 3:
DC coupling



A DC-coupled system (as shown in Figure 3), in contrast, connects the battery and PV behind a shared inverter, so charging from PV requires no AC conversion at all.

DC-coupled BESS yields higher round-trip efficiency and lower capital costs, as fewer inverters and less balance-of-system equipment are needed. The trade-off is reduced resiliency, since the shared inverter constitutes a single point of failure, and limited flexibility in sizing and later expansion. The choice between the two architectures therefore depends on whether the project prioritizes efficiency and cost (DC) or operational robustness and retrofit capability (AC).

Beyond efficiency and cost, the German support regime materially influences the coupling choice: EEG eligibility has traditionally required exclusive charging with renewable electricity, and the emerging mixed-flow options to be concretized by the BNetzA's determination rest on calibrated, interval-based metering concepts that are considerably easier to implement in AC-coupled architectures. DC coupling remains attractive for pure green-storage strategies and innovation tenders, where clipping capture and a shared grid connection point play to its strengths.

4 Optimized trading of a hybrid asset

The preceding sections described how a co-located battery can be built and what the support regime allows it to do. The commercial question follows from there: how is such a hybrid asset actually traded? Throughout this section, we assume co-location with a producer, as introduced above, and set aside batteries sited with a consumer or prosumer, whose business case is driven mainly by the site's own energy cost structure rather than by wholesale market access. Revenue stacking refers to the strategic approach of maximizing financial returns by participating in multiple energy markets and services simultaneously. Instead of relying on a single revenue stream, energy assets can be utilized across various market segments, including wholesale energy markets, ancillary services, and capacity markets, to generate diversified income.

A key component of revenue stacking is arbitrage, which can be categorized into inter-market and temporal arbitrage. Inter-market arbitrage involves exploiting price differences between different markets; for example, buying energy in a low-priced wholesale market and selling it in a higher-priced market. Temporal arbitrage focuses on time-based price fluctuations within the same market. This includes purchasing electricity during off-peak hours when prices are low and selling during peak demand periods when prices surge. Both forms of arbitrage require precise forecasting, real-time market access, and a robust IT infrastructure to execute trades efficiently and profitably.

While for standalone BESS, maximizing financial returns by participating in multiple energy markets and services simultaneously is a valid strategic approach, which, depending on risk appetite, can lead to intensive inter-market arbitrage trades, the situation is slightly different for co-located assets. Depending on the exact

setup, access to certain markets is limited or prohibited. Additionally, the use of a BESS could be less flexible than in the standalone case. On the other hand, local production adds another layer of potential revenue (for example, charging at the plant's marginal cost rather than at the market price) to the optimization approach. Where the renewable plant is EEG-supported, all of this has to be achieved without putting its support entitlement at risk.

Mathematically, the optimization can be written as a mixed-integer linear program. Models can be myopic or fully coordinated. The problem retains the familiar constraints, such as state-of-charge limits, and adds constraints linked to the forecasted and realized production of local power, together with binary constraints that depend on which of the three setups of Table 1 applies.

As in the standalone BESS case, revenue maximization must account for degradation costs. Degradation is the gradual, irreversible loss of a cell's performance over its service life, seen as capacity fade (less energy stored) and rising internal resistance (less efficient charge and discharge). Each cycle therefore consumes part of a finite asset, so the optimization weighs short-term margin against the lifetime it uses up. The drivers split into calendar ageing, which depends on time, temperature, and resting state of charge, and cyclic ageing, which depends on the number of full equivalent cycles, the depth of cycle, and the charge and discharge rate (Collath et al., 2022). The trade-off also depends on the cell chemistry: lithium iron phosphate reaches round-trip efficiency near 90% but fades measurably, whereas iron-air cells degrade far less yet return only roughly 40% to 60% of the energy input and suit multi-day backup rather than the high-throughput arbitrage relevant here (Zhao et al., 2026).

5 Revenue models

Section 4 described how value is created by trading a hybrid asset. The revenue model determines how that value is divided between the asset owner, optimizer and offtaker, and how much of it is contractually secured rather than left to the market. This section begins with power purchase agreements, the instrument through which renewable output is already monetized and into which any co-located battery has to be fitted, before turning to the contract structures used for standalone batteries and then to the models specific to co-located assets. The choice is not purely commercial: as Section 6 shows, it also determines what a lender is willing to finance.

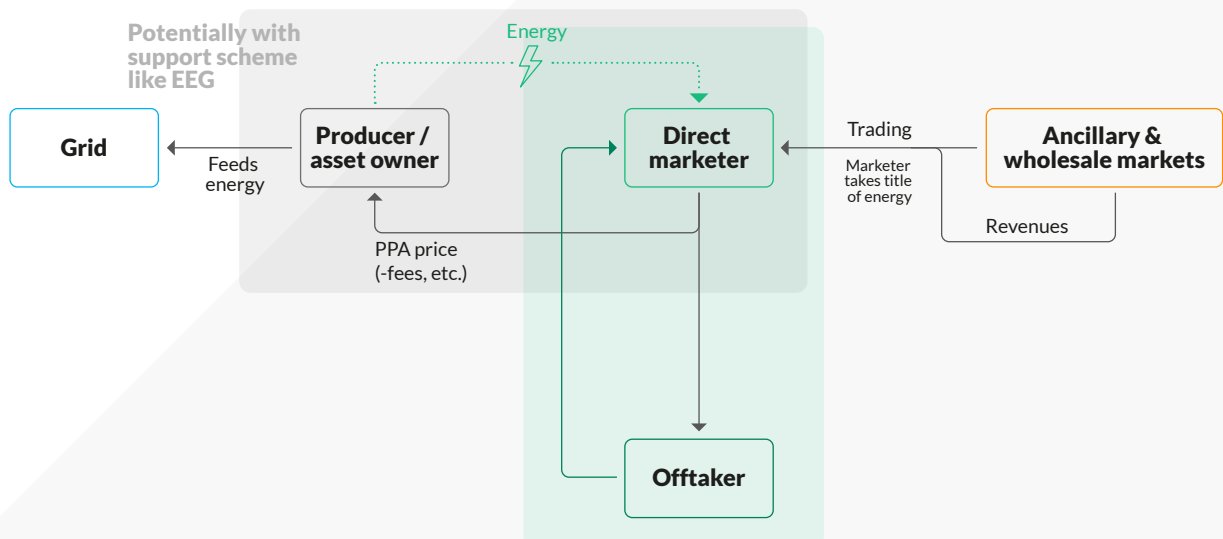
5.1 Power purchase agreements

Power purchase agreements (PPAs) are the central contractual instrument for monetizing renewable generation. Figure 4 illustrates one of many possible configurations. On the physical side, the producer feeds its energy into the grid, while a direct marketer takes title to the energy and trades it in the wholesale and ancillary

service markets. The producer receives the agreed PPA price, net of marketing fees, and the arrangement can coexist with a support scheme such as the EEG, for example through the market premium model.

The figure also shows that the physical PPA may not be the end of the chain. In parallel, the direct marketer could hold a purely financial contract with an offtaker, shown as the virtual PPA layer. No energy is delivered under this leg. Instead, the parties settle the difference between the agreed PPA price and a market reference price, while the trading revenues from the physical energy remain with the direct marketer. This financial leg is economically a contract for difference (CfD) or fixed-for-floating swap. It allows offtakers without their own market access, typically corporates, to hedge power prices and secure green attributes, and it allows the direct marketer to pass on price risk from its physical position while earning a margin for intermediation, profile, and balancing risk. Structures of this kind are known in the market as sleeved or back-to-back PPAs.

Figure 4:
Generalized
graphical
representation
of a PPA



5.2 Models for standalone BESS

The commercial arrangement between a BESS owner and its route-to-market partner determines how cash flow and market risk are allocated. Figure 5 shows three structures that dominate the market today.

5.2.1 Merchant optimization

In a merchant setup with revenue share, the asset owner mandates a battery optimizer to handle dispatch and trading across the agreed markets. Realized revenues are divided according to a contractual ratio, and the optimizer's remuneration frequently combines this share with a fixed optimization fee for its trading and dispatch services. There is no guaranteed minimum, so the owner carries the full upside and downside of market performance. Contract terms are short, typically one to three years.

5.2.2 Floor structures

A floor plus revenue share structure adds downside protection to the merchant model. The optimizer guarantees the owner a minimum annual revenue and, in exchange, retains a larger share of the earnings above that level, sometimes subject to a cap. The owner trades part of the upside for revenue certainty, while the optimizer absorbs the risk of weak market years. Terms of up to five years are common.

5.2.3 Tolling agreements

Under a tolling agreement, an offtaker pays the owner a fixed capacity-based fee and in return obtains the right to dispatch and market the asset, in full or for a defined share of its capacity. The fee is owed regardless of the trading result, so market risk shifts entirely to the offtaker, while the owner receives predictable, bankable cash flows. Tolls can be structured physically, where

Figure 5:
Main revenue models for BESS between asset owner (AO) and optimizer

	BESS optimization	BESS flexibility purchase agreements	
	1 Merchant (revenue share)	2 Floor + revenue share	3 Tolling agreements
Revenue & operation	- Counterparty is Battery Optimizer (BO) and takes over operational dispatch - Revenues are split according to a pre-agreed ratio - No minimum guaranteed payment - AO and BO decide in which markets the BESS will be traded	- AO is the battery operator, and the counterparty is Battery Optimizer - Asset owner receives a guaranteed minimum amount (the floor price) - Floor amount can be fixed for a certain period of time or flexible - Any additional revenues above threshold are split between operator and the optimizer or capped	- Counterparty is an Offtaker, who takes over the operational dispatch and marketing of BESS - Asset owner receives a pre-agreed payment (the tolling fee) - Tolling varies between full and partial tolling.
Risk & exposure	- Full Market Risk for AO and BO - Full downside and upside exposure for AO	- High Market Risk for BO - Limited downside and full/limited upside potential for AO	- Full Market Risk on Offtaker - No downside (full) and possible upside potential (partial) for AO
Duration	1-3 years	Up to 5 years	5-7 years

the offtaker takes over dispatch and operational risk, or virtually, where the owner continues to operate the asset against the offtaker's nominations. Typical terms run five to seven years, with longer tenors emerging as the market matures.

5.3 Models for co-located BESS

Revenue contracts for co-located generation and storage assets must resolve a set of structural questions before any commercial term is negotiated. The starting point is market access. The parties must establish which of them, the producer, offtaker, direct marketer, or optimizer, holds the exchange memberships, balancing group contracts, and prequalifications for ancillary services, and therefore in whose name the asset trades. Closely linked is the question of title and agency, namely who holds the entitlement to the power and whether the trading party acts on its own behalf, as principal taking title, or on someone else's behalf, as a service provider against a fee. This distinction drives the entire cash flow logic, from physical delivery with pass-through of revenues to purely financial or cash-settled arrangements.

The technical setup constrains what the contract can promise. The metering concept, the shared or separate grid connection, and the ability to charge the BESS from local production or from the grid define which flows can be delimited, remunerated, and evidenced. Where a support scheme such as the EEG applies, the contract must reflect its conditions, in particular the green and grey charging rules and the associated measurement requirements, since these determine whether storage operation endangers the plant's support entitlement. Curtailment deserves explicit treatment: the contract should fix which trading signals the optimizer may execute, including economic curtailment and downward dispatch, how grid-operator-in-

structed curtailment and redispatch compensations are allocated, and how availability, degradation, and round-trip efficiency affect guaranteed payments.

5.3.1 Existing PPA without modification

A common starting point in practice is a renewable plant whose output is already contracted under a physical PPA with a direct marketer, often in combination with EEG support. Renegotiating the PPA to integrate a battery is frequently unattractive or simply not feasible, so the BESS is added downstream of the existing marketing arrangement. This is what is typically meant by a true hybrid: the renewable optimization comes first and remains untouched, and the battery operates on what is left after it. Concretely, the direct marketer continues to trade the plant's generation and pays the PPA price as before, while the BESS, steered by its own optimizer, which may well be a third party, works within the residual grid and market constraints after renewable marketing. Since the battery in this configuration primarily charges from the grid, it operates as a downstream grey-power storage⁶ and does not participate in the plant's EEG support. The commercial upside instead comes from arbitrage and ancillary services, while the full range of revenue models discussed above, from merchant and floor structures to tolling, remains available for the BESS itself. The critical contractual interfaces are the energy schedules exchanged with the grid operator and the delimitation of dispatch rights, so that the battery's signals cannot interfere with the direct marketer's delivery obligations under the PPA. The price of this simplicity is efficiency: shared value pools such as clipping capture or joint profile shaping remain unexploited, which is the core trade-off against a fully integrated co-location model.

⁶Nachgelagerter Graustromspeicher

5.3.2 Existing PPA with adjustments

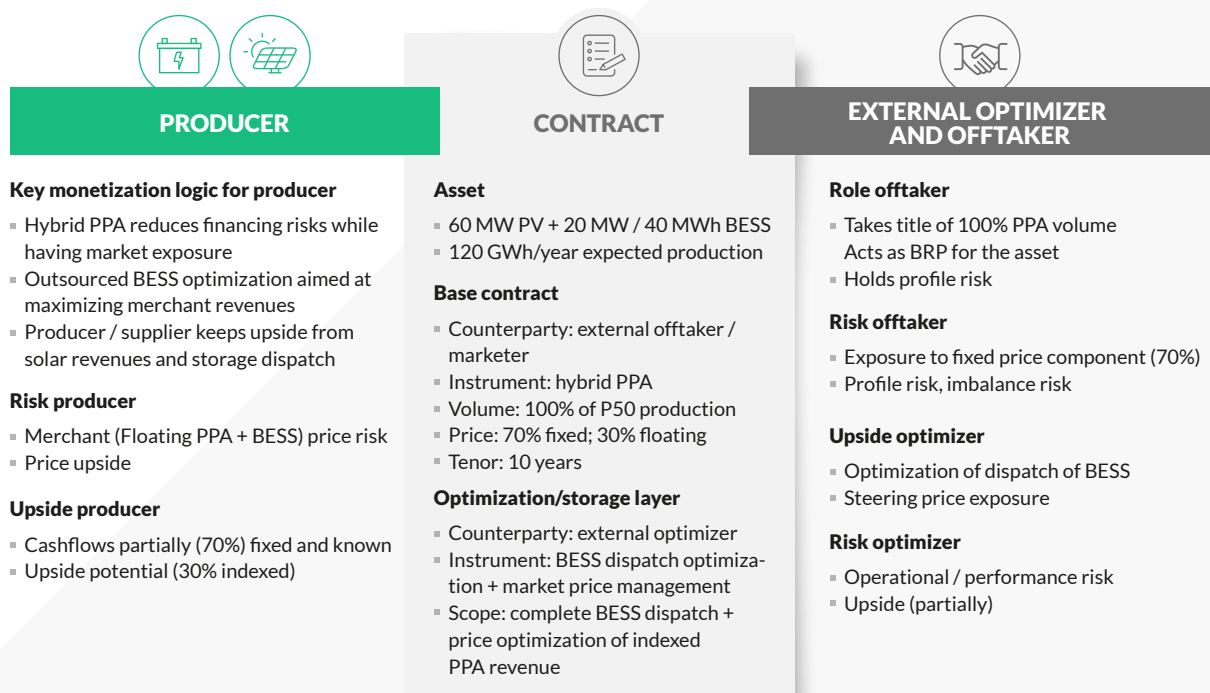
The PPA is replaced by some revenue-off-setting contract, which may or may not include the handover of the entitlement to the power generated locally to the marketing party. The optimizer may participate in the upside but generally receives a fee for the optimization service provided.

A concrete variant of this adjusted arrangement is the hybrid PPA (see Figure 6), combined with outsourced BESS optimization. The utility contracts the full PV volume to an external marketer but splits the price: in the illustrative case below, around 70% of the volume is sold at a fixed price, and the remaining 30% is settled against a market index. The fixed tranche secures cash flow and reduces financing risk, while the indexed tranche preserves exposure to price upside. The battery is not marketed by the utility itself; its dispatch optimization is handed to the same external party in order to maximize merchant revenue.

The external marketer takes 100% of the PPA volume, acts as the balance responsible party for it, and assumes the PV profile risk. Its own exposure is therefore threefold: fixed-price risk on the contracted 70%, profile and imbalance risk on the delivered volume, and operational and performance risk on the battery optimization it has taken over. In exchange it earns the dispatch margin from the BESS and can steer its price exposure through the indexed PPA leg without taking physical delivery.

For the utility, the structure resolves the trade-off that runs through this chapter. It keeps cash flow certainty from the fixed share, retains upside from the indexed share and from storage dispatch, and it converts the battery into a merchant revenue stream operated by a party better equipped to monetize it. What remains with the utility is merchant price risk on the floating PPA share and on the BESS, which is precisely the exposure that determines the coverage ratio a lender will require.

Figure 6:
Example for a monetization structure: hybrid PPA with outsourced BESS optimization for solar and co-located storage



6 Bankability and the impact of the revenue model

The revenue model does not only determine how much a project earns; it determines how much of that revenue a lender is willing to count on. Bankability is therefore the point where the contractual structures discussed above translate into financing terms, and where the difference between a merchant position and a contracted one becomes visible in the capital structure.

6.1 The cash flow forecast as the central input

Banks cannot size BESS debt without a credible revenue forecast. Unlike solar or wind, where generation profiles are well understood and largely weather-driven, BESS revenue depends on market price dynamics, the trading strategy and revenue model, and the degradation profile of the cells. The cash flow forecast is consequently the main determinant of a project's bankability, and lenders review it as a distribution rather than as a single number.

A simplified cashflow model rests on five elements. The first is revenues, either as a contracted tolling fee or as P90 expected revenues in a merchant model. The second is the state of health and the planned refurbishment at end of life, typically at 80% remaining capacity, including refurbishment cost. The third is operating expenditure (OPEX), fixed and variable, together with annual capital expenditure (CAPEX). The fourth is the interest rate. The fifth is the minimum required debt service coverage ratio (DSCR).

Each element carries its own uncertainty. Revenues from spot and ancillary markets must be projected over the full asset lifetime under realistic market scenarios, that is, without assuming perfect foresight, and banks review the resulting P50 and P90 distributions. The degradation trajectory determines when augmentation CAPEX is triggered and how capacity, and therefore revenue, declines over time; a battery digital twin can be used to simulate this future behavior. Items include fixed and variable operation and maintenance (O&M) costs, grid charges and network tariffs. The DSCR, finally, measures the project's ability to service debt out of operating cash flow and must remain above a minimum threshold that depends on the revenue structure.

6.2 P90 as the standard for debt sizing

Project finance practice distinguishes two points of the revenue distribution. P50 reflects the base scenario and is used for equity returns and investor presentations while P90 reflects the downside. Because debt service must be coverable even in the downside case, P90 is the reference for sizing the loan. Providing lenders with robust P90 simulations is therefore not a formality but the precondition for a competitive financing package.

6.3 Tolling versus merchant

The effect of the revenue model on financing capacity can be significant: a secured revenue stream lets the bank accept a lower coverage ratio, and a lower required DSCR converts the same operating cash flow into a larger loan. The tolling case could support roughly 30% more debt than the merchant case, which reduces the equity ticket and improves the return on the equity actually deployed. The price is the upside foregone under the toll.

For co-located assets, the same logic applies, with two additional levers. First, the configuration decides which revenue streams are available at

all: a subordinated grey battery can only discharge when the renewable asset leaves grid capacity unused, which widens the gap between P50 and P90 and thus depresses the debt-sizing case, whereas a green hybrid retains the EEG market premium as a partly contracted, regulated cash flow. Second, the contractual interface with the direct marketer determines who bears volume and curtailment risk, and lenders will price that allocation into the coverage ratio they require. Bankability is therefore decided well before the financing stage, in the choice of setup and the drafting of the marketing contract.

Simulation: renewable vs. co-located BESS

As discussed in Section 6, the core inputs for a sensible bankability analysis are the future cash flows. Starting from an exemplary solar park with 60 MW peak and an expected production profile similar to the average German solar production over the years 2027-2041, we show that while the advantages of storage co-located with production seem obvious, the economics do not always follow. Whether a co-located BESS is viable depends on CAPEX, on the chosen duration, and on whether the asset is set up as green or grey.

increases revenue, with the impact being greater when installing a 4h BESS rather than a 2h BESS and when allowing full arbitrage across all markets (grey storage).

Even though CAPEX has dropped significantly in recent years, higher revenues alone do not necessarily justify the investment. The derivation of the internal rate of return of an investment is highly dependent on CAPEX and OPEX assumptions for the period of operation, which makes a prudent estimation paramount in edge cases.

Table 2 shows the impact of adding storage to the solar park on the expected undiscounted revenues over the 15 years⁷. Adding storage

Table 3 shows that adding a BESS with solely green energy does not increase the internal rate of return (IRR), given the limited use cases of the

Table 2:
Simulation
results:
undiscounted
revenues

Configuration	Duration	Type	% change to solar only
20 MW - 40 MWh	2h	Green	23%
20 MW - 40 MWh	2h	Grey	40%
20 MW - 80 MWh	4h	Green	37%
20 MW - 80 MWh	4h	Grey	56%
60 MW - 120 MWh	2h	Green	75%
60 MW - 120 MWh	2h	Grey	132%
60 MW - 240 MWh	4h	Green	110%
60 MW - 240 MWh	4h	Grey	179%

Table 3:
Storage and IRR

Configuration	Duration	Type	% change in IRR
20 MW - 40 MWh	2h	Green	-5%
20 MW - 40 MWh	2h	Grey	23%
20 MW - 80 MWh	4h	Green	-18%
20 MW - 80 MWh	4h	Grey	8%
60 MW - 120 MWh	2h	Green	-6%
60 MW - 120 MWh	2h	Grey	62%
60 MW - 240 MWh	4h	Green	-34%
60 MW - 240 MWh	4h	Grey	24%

⁷We calculated revenues using long-term price forecasts, marketing the co-location on the day-ahead and intraday continuous markets as well as on the FCR and aFRR markets.

storage. Doubling the duration is counterproductive: costs rise, while the locally produced volume and the shape of the daily price curve do not support a 4h BESS.

In contrast, grey storage has a positive impact on the IRR. The numbers also show, however, that a 2h BESS exhibits better economics than a 4h BESS. Longer duration is not automatically better, as the additional energy capacity only pays off if the daily price spread is wide enough to monetize it.

A further caveat concerns the price forecasts underpinning these figures. Long-term price curves embed structural assumptions, the coal phase-out, the pace of renewable build-out and demand electrification, as well as assumptions about how crowded the ancillary service markets will become. As storage capacity enters the system, these markets are widely expected

to saturate and become less attractive, shifting value towards wholesale arbitrage. Where a configuration sits close to the investment threshold, a single base-case curve is therefore not sufficient: a scenario-based price calculation is required to test how robust the IRR is to these assumptions.

A final aspect to take into consideration is that, at the time of writing, official approval for a green storage installation is more likely to be granted than for a grey one. The choice between the two is therefore not purely economic: a green configuration that looks marginal on a stand-alone IRR basis may still be the right strategic decision. Tactically, given ongoing legislative discussion, installing a green storage can create the foundation for harvesting further revenues in grey storage mode.

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