Capgemini

POINT OF VIEW · BATTERY ENERGY STORAGE

Beyond the battery

Winning the next phase of the BESS market



Contents

OVERVIEW

Key messages 03

Executive summary 04

CHAPTERS

01 Saturation is real, but uneven 06

02 The thin-margin trap 08

03 One assumption decides most business cases 13

04 What a winning BESS looks like 15

05 The BESS mortality test 17

06 How operations and contracts change returns 19

07 Data and AI turn operations into margin 22

08 Market design and security now move returns 26

FURTHER READING

What this means for investors and asset owners 28

How Capgemini helps 29

Methodology 31

References 34

Authors and contacts 36

About Capgemini 37

Key messages

01 A battery bought on a thin margin can become a stranded asset.

In Capgemini's base case, a merchant two-hour battery whose revenue in today's market exceeds its annualised cost by 10% loses about a fifth of its capital in present-value terms over 15 years, and close to 40% in a stressed market. To earn its cost of capital it needs revenue in today's market about 37% above annualised cost. A battery earning today's German benchmark clears that bar; one bought at the margin of today's market does not.

02 Spread compression moves returns twice as much as capex, yet business cases take it on trust.

A 10% change in capex moves the project IRR by about 3 points. Spread compression moves it by about 6, underlying spread growth by more than 5 and the operator's spread capture by almost 4. The first two come with the revenue forecast, while the third is decided after the investment.

03 Better operations raised returns in every scenario we tested. A fairly priced toll mainly buys downside protection.

Better spread capture, lower operating costs and a good site add 3.3 to 3.6 points of project IRR in every scenario. A toll priced on the base case barely changes expected returns: tolling 40% of capacity for 15 years cuts the gap between the best and worst outcomes by about 40%, a seven-year toll by about 13%. No fairly priced toll rescues a battery bought on a thin margin.

04 Real fleets show a wider operating gap than our model assumes, and closing it depends on data and AI.

In California, the best battery captured 71% more of its benchmark spread than the median one, about four times the edge in our model, where each 5% of capture is worth about 0.6 points of IRR. Forecasting, bid optimisation, state estimation and predictive maintenance can narrow that gap, and at fleet scale they depend on AI. Few owners have the data access to use AI this way.

05 Grid access, grid fees, auctions and inverter rules now shape returns.

Germany is rationing grid access and resetting grid fees for storage. Italy's first storage auction cleared at about a third of its ceiling price. The EU has restricted funding for projects that use inverters, including battery power conversion systems, from high-risk suppliers.

Executive summary

Most battery business cases are argued over capex and EPC terms. Once the price is agreed, other inputs matter more. How fast storage compresses price spreads, an assumption usually inherited from the revenue forecast, and the quality of operations, which now depends on data and AI, each move a battery's return more than the last 10% of capex.

Battery storage is still growing fast, but the market is becoming less forgiving. Some 108 GW was deployed worldwide in 2025, 40% more than the year before.[1] In the markets that opened first, revenue per kilowatt is falling: in Texas it fell by 37% in 2025 alone, while battery capacity grew by almost 80%.[2] Most European batteries still earn well: a two-hour battery in Germany could earn about €155k/MW over the twelve months to July 2026.[3]

Our view is that **the batteries most likely to become the next stranded assets were bought on thin margins and are run by average operators,** especially when they depend on one revenue stream. They will keep running and serving the grid without paying back their capital. Capgemini modelled a two-hour battery over 15 years under three market futures built on public build-out targets and price outlooks. Our reference battery is deliberately a thin-margin project: its revenue in today's market covers its annualised cost with a 10% margin. In the base case, where storage capacity grows by a quarter a year until 2030 before slowing, it loses about a fifth of its capital in present-value terms. In a stressed market it loses close to 40%, and even in a favourable one it only just misses its cost of capital.

How much it loses depends above all on one assumption: how fast additional storage compresses price spreads. Across public estimates, the base-case loss runs from 3% to a fifth of capital, and to a third under a steeper assumption ($\beta = 0.6$). Across that range the assumption moves the project IRR by about 6 points, twice as much as a 10% change in capex. Most business cases embed it without stating it. Making it explicit is the starting point of the BESS mortality test: five stress questions every investment case should answer before capital is committed.

Operational performance raised returns in every scenario we tested: better spread capture and lower operating costs add about 2.5 points of project IRR, and a good site close to one more. Real assets already differ far more: in California, the best battery captured 71% more of its benchmark spread than the median one.[4]

Contracting mainly narrows the range of outcomes. A toll priced on the base case leaves expected returns almost unchanged. Its value depends on its tenor and, above all, on whose view of saturation sets its price. Italy's first storage auction, which cleared at about a third of its ceiling price, shows how hard contract prices are competed.[5]



57.6%

Share of downtime attributed to small, recurring outages in a study of over 50 operating projects.

The operating edge rests on data and AI. Re-optimising bids across several markets every few minutes, or following the condition of every cell and inverter, cannot be done by hand. Spread capture and availability depend on forecasting, bid optimisation, state-of-charge estimation, degradation-aware dispatch and predictive maintenance, and at fleet scale each of these is a data and AI problem. According to a recent study of more than 50 operating projects, 57.6% of downtime comes from small, recurring outages, which early detection can catch thanks to data and AI.[6] Few of the owners we work with have the data access and AI capabilities this requires, and fewer still measure what these deliver in money.

An investment case should state its compression assumption and test it across the range, judge contracts on price and tenor, and assess data and AI readiness as carefully as capex and grid connection. The data rights an asset needs are best secured at commissioning.

CHAPTER 01

Saturation is real, but uneven

Battery storage is scaling fast as power systems take on more wind and solar. In the markets that opened first, it has already outgrown the services that paid for the first projects.

China installed 136 GW / 351 GWh of new-type storage by sthe end of 2025, about half of the world total, and targets around 300 GW by 2030.[7] The United States installed a record 18.9 GW / 51 GWh in 2025.[8] In Germany, grid operators signed connection agreements for 54.2 GW / 142.4 GWh of batteries in 2025 alone, against around 6 GW of large batteries connected today.[9]

Ancillary revenue falls first

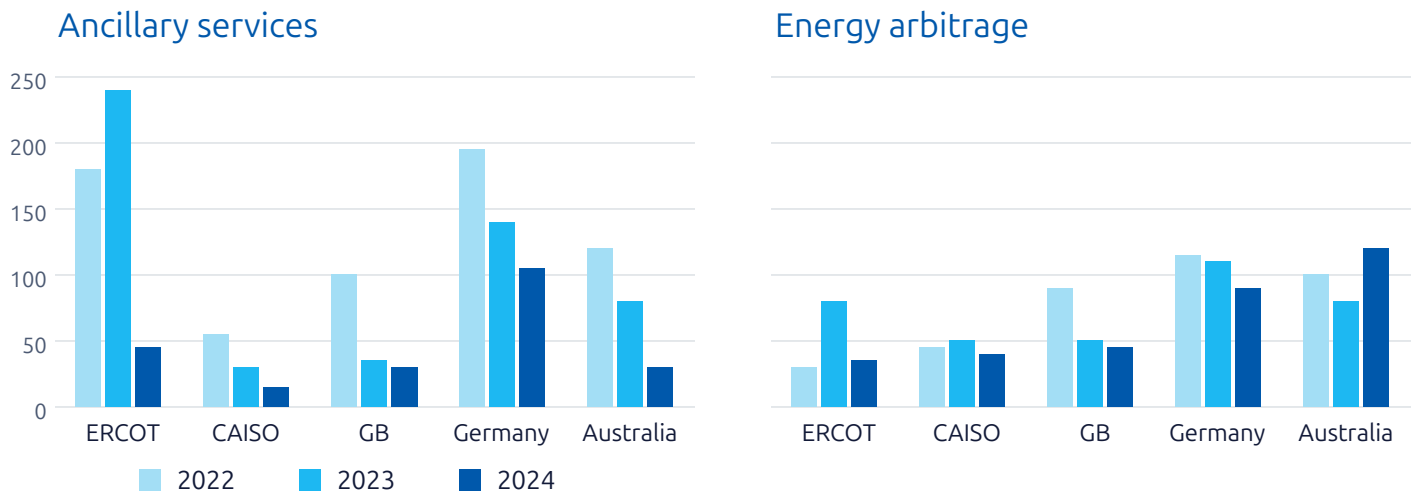
The first utility-scale batteries entered markets where balancing services were undersupplied and batteries were often the cheapest providers. Those markets have a ceiling. System operators procure what the system needs and no more. Once the battery fleet exceeds that volume, more assets bid for the same contracts and clearing prices fall.

Texas shows how quickly this can happen. Enverus estimates that average battery revenue in ERCOT fell from $149/kW in 2023 to about $17/kW in 2025, with the share from ancillary services falling from 84% to 48%.[10] ERCOT's market monitor found that revenue per unit of battery capacity fell by a further 37% in 2025, as ancillary revenue fell by the same amount, while capacity grew by almost 80% to more than 17 GW.[2] In California, battery net market revenue fell from about $78/kW-year in 2023 to $53/kW-year in 2024, as capacity reached 13 GW, up from 0.5 GW in 2020.[11]

FIGURE 1

Ancillary revenue fell in all five early markets between 2022 and 2024

Average annual revenue for a two-hour battery by market and revenue source, 2022–2024, USD/kW



Source: S&P Global Commodity Insights (October 2025). The series ends in 2024; the 2025 figures for Texas in the text show the fall continued.

67%

Upper estimate of the share of a typical German two-hour battery's income from ancillary services.

In Germany, ancillary services can provide up to 67% of a typical two-hour battery's income,[12] but saturation is already visible. Battery capacity prequalified for primary reserve (FCR), about 1.35 GW, is more than twice the 0.53–0.56 GW required.[13] In aFRR, around 1.2 GW of battery capacity was prequalified by early 2026 against about 1.9 GW procured in each direction: more headroom, but saturation pressure is spreading to the larger balancing markets. Energy spreads averaged €80–90/MWh in 2025, against €120/MWh in 2022.[12]

Value is moving to trading

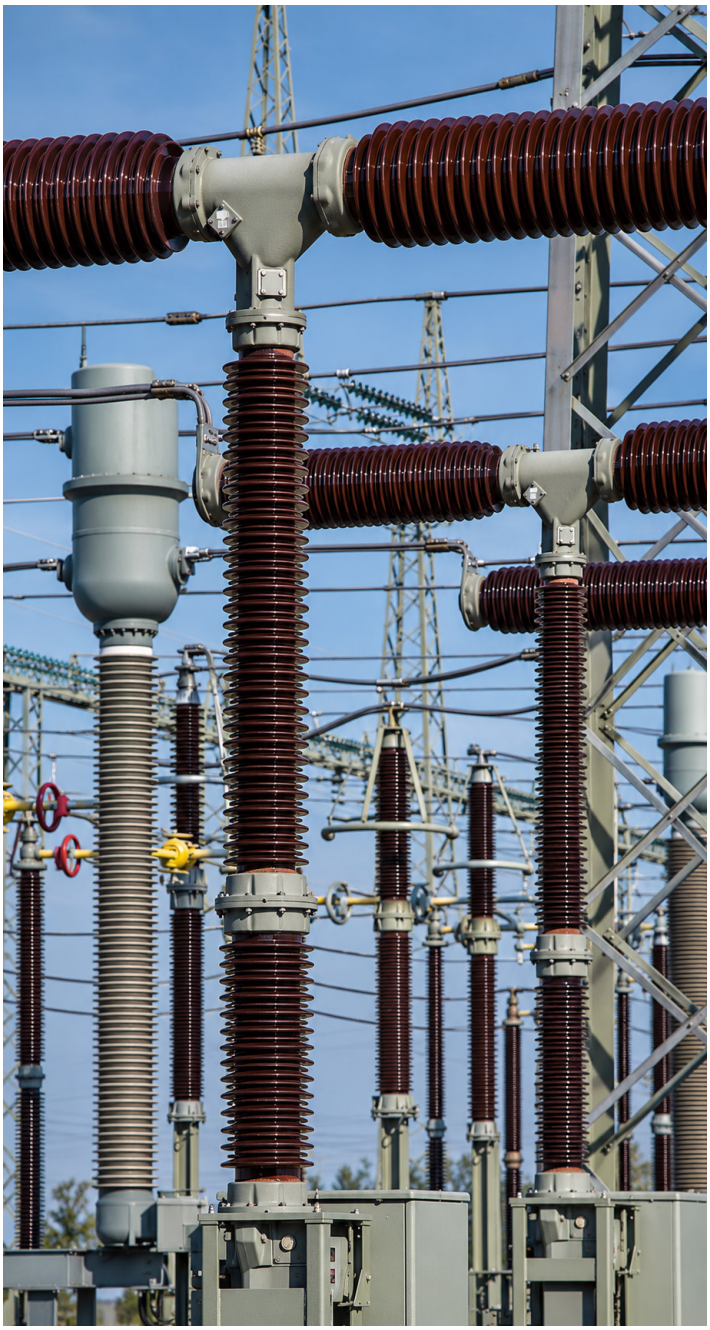
Saturation also changes where batteries earn their money. In ERCOT, operators shifted towards energy arbitrage as ancillary prices fell,[14] and the market redesign live since 5 December 2025 (real-time co-optimisation plus batteries, RTC+B) lets suitably equipped batteries optimise ancillary services and energy together in real time.[15] As revenue moves to trading, it becomes more volatile and more dependent on how well each asset is operated.

The case against: European revenues are still high

Not everyone shares our concern. The optimiser enspired Trading argues that revenues in continental Europe will not crash as they did in Great Britain, and the data supports part of that view. Clean Horizon's index ranks Poland and Italy as Europe's highest-earning battery markets,[16] and Enervis's July 2026 revenue for Germany was about 40% above July 2025.[3]

Why we still see a stranding risk

The drivers of saturation are visible: the German connection pipeline is roughly nine times the large-battery fleet in operation. Revenue is also volatile: Enervis's monthly index ranged from €5,700/MW in December 2025 to €18,900/MW in September 2025. And the benchmarks used to build business cases disagree. For a German two-hour battery, Enervis implies about €155k/MW over the twelve months to July 2026, while another analysis puts the marginal merchant asset nearer to €80k.[12] The choice of benchmark alone can decide an investment case.



CHAPTER 02

The thin-margin trap

To test how far returns can move, Capgemini modelled a stylised two-hour battery cycling 1.5 times a day over 15 years. It is a battery bought at the margin of today's revenue (Table 1).

The model compresses arbitrage spreads as storage capacity grows relative to market depth, erodes ancillary revenue as saturation rises and derates capacity revenue by duration. Results are project IRRs and net present values before tax and debt, at an 8% cost of capital; the Methodology gives the assumptions and their limits.

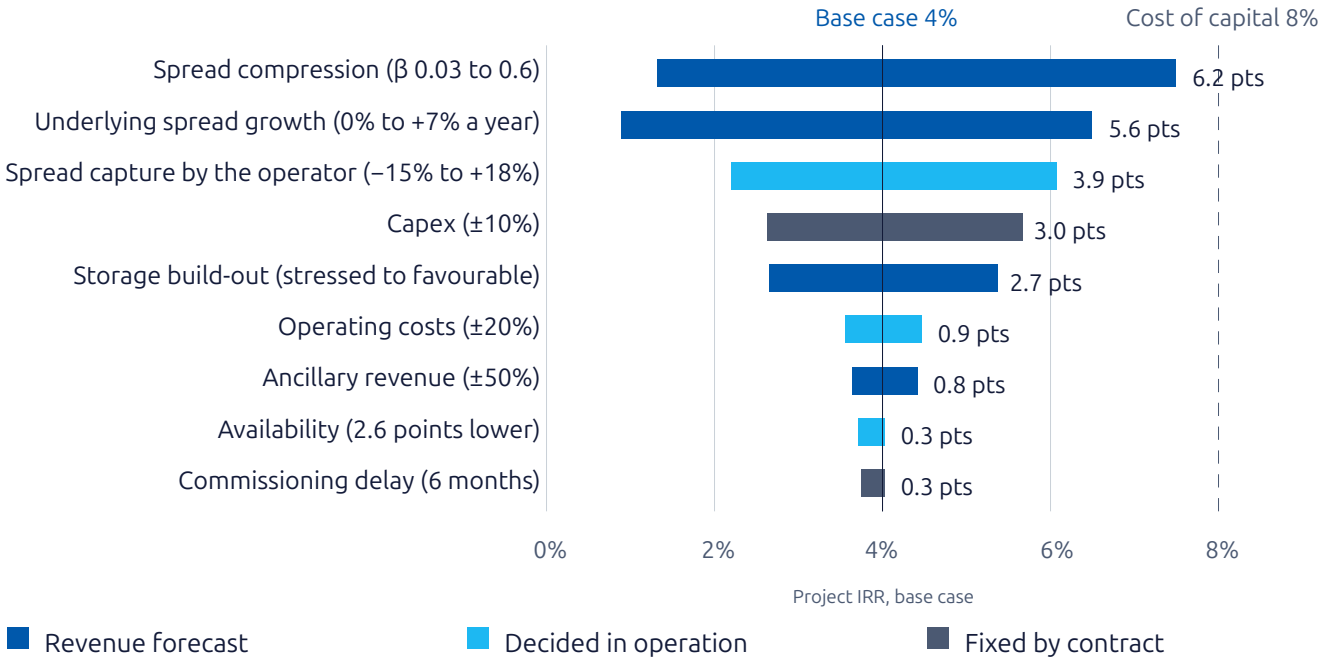
What moves its return

Figure 2 moves each input of the reference battery across a plausible range, one at a time. A 10% change in capex moves the project IRR by about 3 points. The spread-compression assumption moves it by about 6 and underlying spread growth by more than 5: both are inherited from the revenue forecast, usually bought from a forecaster and rarely debated.

FIGURE 2

Once the price is agreed, the revenue forecast and the operator move a battery's return more than capex

Project IRR of the reference battery in the base case as each input moves across a plausible range, others held constant



Source: Capgemini analysis. Spread compression from β = 0.03 (EWI) to 0.6; spread growth and build-out from the stressed to the favourable scenario; capture from a 15% shortfall to an operational leader; capex ±10% around €260/kWh.

The operator's spread capture moves it by almost 4 and is decided after the investment, by the quality of forecasting, bidding and the data and AI behind them. Ancillary revenue, the focus of many early business cases, moves it by less than a point, because in the base case most of it has gone by 2030.

Moving one input at a time understates combined risk. In a weak market, faster build-out, slower spread growth and a weaker operator tend to arrive together; the stressed and favourable scenarios used throughout this paper move several inputs at once for that reason.

TABLE 1

The reference battery, line by line

€/kW per year, today	How it is built	Value
Trading	1.5 cycles × 365 days × 2 hours = 1.1 MWh per kW a year, at a daily spread of €51/MWh net of today's storage, 70% captured by a standard operator	€39
Ancillary services	Today's level, eroding as the battery fleet outgrows the volumes procured	€20
Capacity payments	€28/kW for a four-hour equivalent, derated to 57% for two hours (France's capacity mechanism applies a coefficient of 0.5817)	€16
Revenue today		€75
Annualised capex	€260/kWh × 2 hours = €520/kW, × a capital recovery factor of 11.7% (8%, 15 years)	€61
Operating costs	Fixed, per kW	€7
Annualised cost	Revenue today exceeds it by 10%: a thin margin, by design	€68

Source: Capgemini BESS model. Figures rounded. The reference is stylised and is not a forecast for any one market. Revenue today is what the battery would earn in today's market, the figure a business case starts from; cash flows start a year later, after a further year of storage build-out (€66/kW in the base case).

Three market futures

We built three scenarios from two variables: the gross build-out of storage capacity, which drives saturation, and the annual change in raw price spreads, which reflects renewable growth and the system's rising need for flexibility before any effect of storage. In all three futures, build-out follows an S-curve: fast until 2030 while connection queues clear, then slower as targets are met and markets reach their depth. A market can move from one scenario to another during the life of an asset.

TABLE 2

Three market futures for a merchant battery

Scenario	Gross storage build-out	Spread change from renewables	Ancillary services	Merchant outcome
FavourableFCR largely saturated, but value shifts towards aFRR (and mFRR), where BESS still has value; demand and prices in these products hold	+20% a year to 2030, then +7%	+7% a year	Ancillary services remain valued; TSO/DSO demand and prices hold	Merchant model viable; energy, ancillaries and capacity stack positively
Base caseAncillary prices converge towards the opportunity cost of energy arbitrage; they remain part of the stack but no longer earn a premium, so value shifts from ancillaries to arbitrage	+25% a year to 2030, then +9%	+4% a year	Prices fall but remain part of the revenue stack; price-sensitive but still material	Returns compress; merchant alone is marginal and partial contracting (hedging, tolling or PPAs) becomes prudent
StressedFlexibility overshoots	+30% a year to 2030, then +11%	None	Ancillary markets saturated; battery capacity reaches several times the requirement and clearing prices collapse	Merchant model deteriorates rapidly; assets without an edge in trading or contracts lose money

Source: Capgemini analysis. The raw spread change excludes the effect of storage, which the model captures through the saturation index; a negative value would require another source of flexibility, such as interconnection or demand response. The basis for each parameter is set out in the Methodology.

What stranded means for a battery

We use the term in its financial sense: an asset that, before the end of its economic life, can no longer earn the return assumed when the investment was made. A stranded battery keeps running, covers its operating costs and supports the grid, but does not pay back its capital.

Our reference battery is deliberately a thin-margin project. Its revenue in today's market, €75/kW, exceeds its annualised cost of €68/kW by only 10%. In the base case, as spreads compress and ancillary revenue erodes, it returns 4.0% a year over 15 years against an 8% cost of capital. That is a loss of about €110/kW, or a fifth of its capex, in present-value terms. In the stressed case the loss reaches 39% of capex. Even in the favourable case, a merchant battery run by an average operator only just misses its cost of capital, with a project IRR of 7.9%.

4.0%

Project IRR of the reference merchant battery in the base case, against an 8% cost of capital

−22%

Share of capex lost in present-value terms, base case

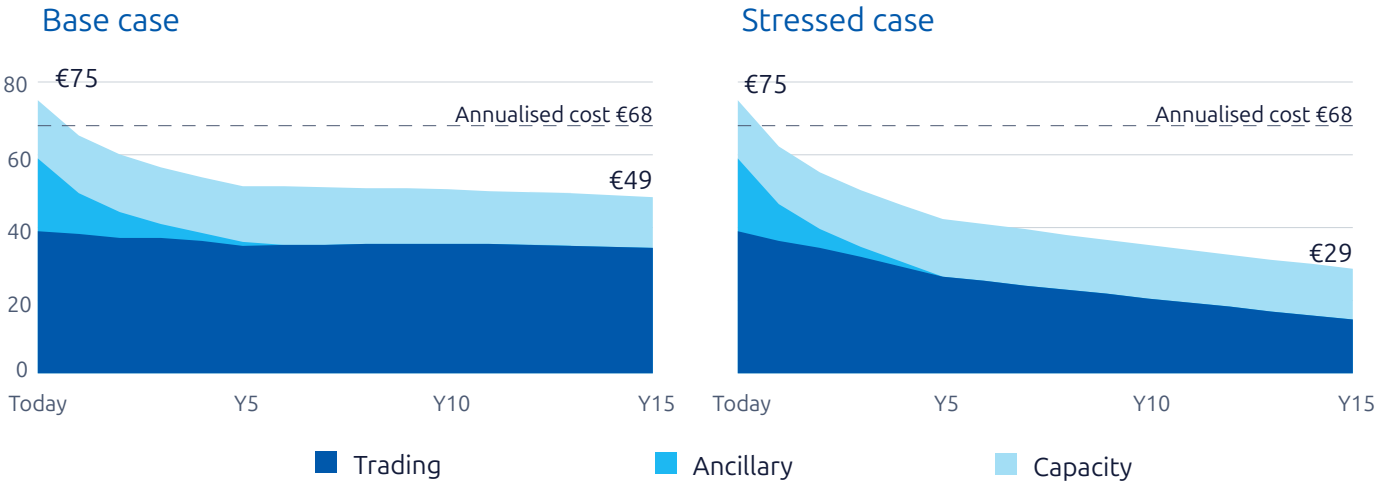
−39%

Share of capex lost in present-value terms, stressed case

FIGURE 2

Once the price is agreed, the revenue forecast and the operator move a battery's return more than capex

Project IRR of the reference battery in the base case as each input moves across a plausible range, others held constant



Source: Capgemini analysis.

Ancillary services provide 27% of today's revenue but only about €1/kW by year 5 in the base case, as the fleet outgrows the volumes procured (Figure 3). Trading revenue holds up only because underlying spreads keep widening. In the stressed case, where they do not, it falls by more than half.

Build-out and spread growth drive most of the outcome

The merchant battery's project IRR differs by around 8 percentage points between the favourable and stressed scenarios. Most of that gap comes from the two variables in Table 2, storage build-out and raw spread growth. Precision on every other input does not make up for an error on either. Every project should therefore be tested against all three futures.

Today's revenue is a poor guide to lifetime returns

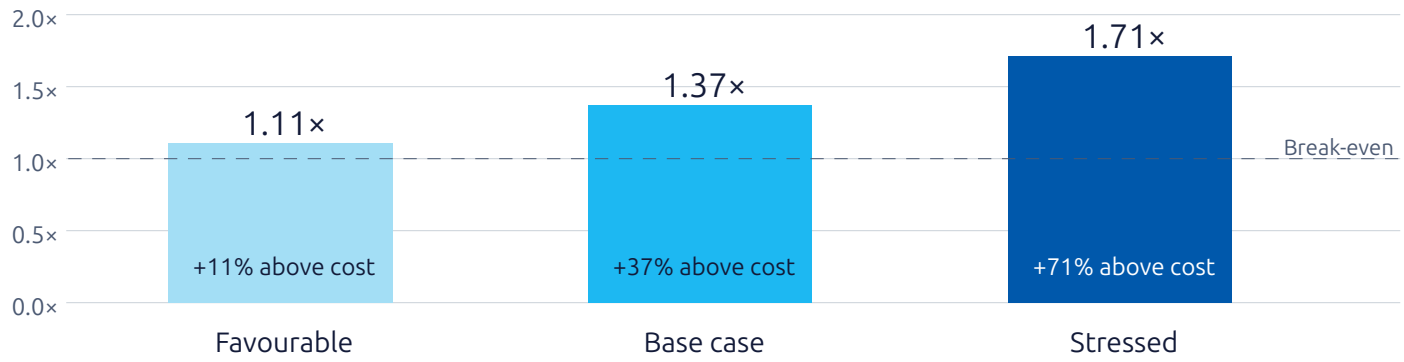
To earn 8% over its life, the reference battery would need revenue in today's market about 37% above its annualised cost in the base case and around 70% in the stressed case. Even the favourable case needs a margin of about 11% (Figure 4).

This ratio does not depend on capex or operating costs: in the model it is set only by how fast revenue declines. It gives investors a simple screen: a project whose revenue in today's market only just covers its annualised cost falls short of its cost of capital even in the favourable scenario.

FIGURE 4

In the base case, a merchant battery needs today's revenue about 37% above annualised cost to earn its cost of capital

Merchant revenue in today's market needed to earn an 8% project IRR over 15 years, as a multiple of annualised cost. In each scenario the revenue path keeps the same profile; only its starting level changes.



Source: Capgemini analysis. Two-hour battery, 1.5 cycles a day, standard operator.

Who is exposed

A battery earning today's German benchmark is not in this position. At a capex of €200/kWh, a two-hour battery earning Enervis's benchmark of about €155k/MW would have revenue close to three times its annualised cost; even the marginal merchant asset at €80k/MW reaches about 1.5 times, enough for the base case but not for the stressed one.[3, 12] The exposure sits with projects bought on thin margins: built at higher capex, priced on optimistic benchmarks, or entering the market after revenues have compressed.

CHAPTER 03

One assumption decides most business cases

Battery business cases are usually argued line by line on capex and EPC terms. Once those are agreed, the spread-compression assumption moves the return most (Figure 2).

Spread compression: the input few business cases state

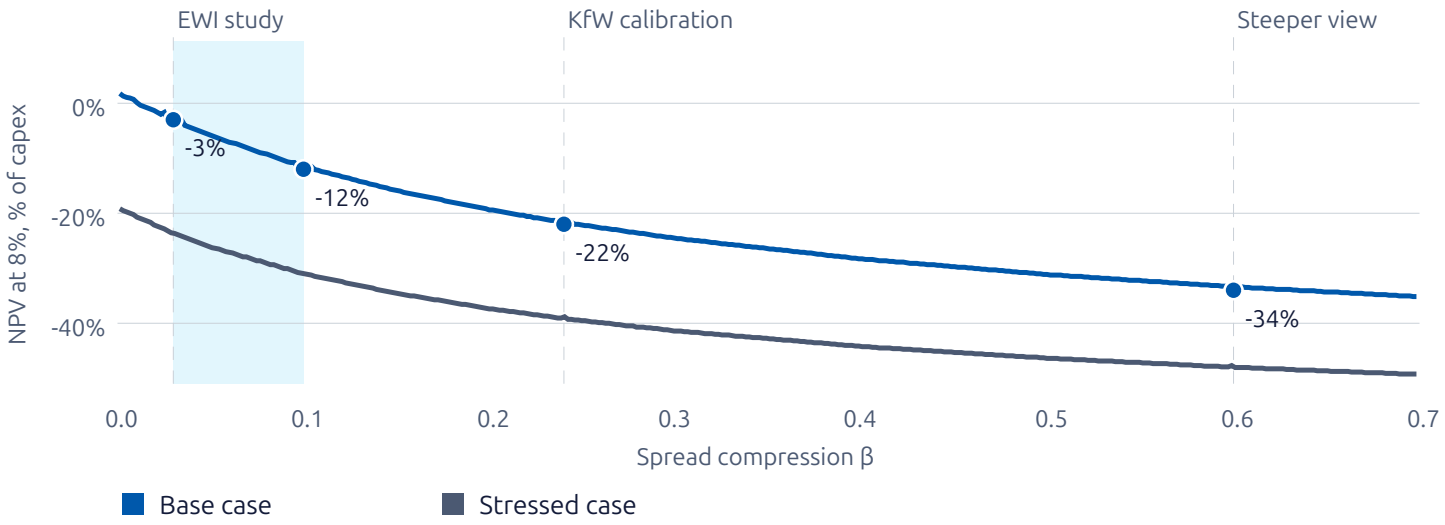
Public estimates differ widely. KfW Research estimates that batteries built in Germany in 2023–25 already cut the daily spread between the highest and lowest prices by €18–20/MWh, about a sixth.[18] A study by EWI finds a much weaker effect at larger scale: a fast build-out to 32 GW by 2030 narrows the daily spread by only 18% compared with a slow one to 12 GW.[19] Our model expresses this effect as a single compression factor, β. We calibrate it on KfW's estimate (β = 0.24). EWI's results imply 0.03 to 0.1, depending on the capacity taken as today's reference.

With no compression at all, the reference battery would earn its cost of capital in the base case (Figure 5): the loss comes from compression, not from the fall in ancillary revenue. Calibrated on EWI, it loses 3% to 12% of its capital; on KfW, 22%; with a steeper compression (β = 0.6), a third. The stressed case loses about a fifth even with no compression, because ancillary revenue collapses there.

FIGURE 5

The same battery loses between 3% and a third of its capital, depending on how fast storage compresses spreads

NPV at 8% as a share of capex, merchant two-hour battery, standard operator, by spread compression factor β



Source: Capgemini analysis; calibration on KfW Research and EWI estimates (see Methodology).

Both public estimates measure the gap between the highest and lowest daily prices. A two-hour battery competing with others captures a narrower spread, which can compress faster. That is the argument for staying above the EWI range. A business case that relies on it should say so explicitly.

A project that only works at the mild end of the range is a bet on the market absorbing storage more easily than the first markets did.

Asset life and duration

Two other assumptions are often debated: how long the battery lasts and how many hours it stores (Table 3).

At 1.5 cycles a day, a 20-year life means about 11,000 cycles, against about 8,200 over 15 years. If the battery holds its nameplate capacity at no extra cost, the extra years add 2.2 points in the base case. That is an upper bound. Discounted at 8%, a euro earned in years 16 to 20 is worth 0.29 to 0.21 today, and it is earned when revenue is most compressed, about €46–48/kW a year. With capacity fading 2% a year, the maximum manufacturers typically guarantee,[20] and one augmentation in year 10, the 20-year battery earns 3.9%, about what the 15-year reference earns: the extra years pay for the capacity they require. Fade also matters on its own: without augmentation it costs the 15-year battery 2.7 points. Our reference assumes the battery holds its nameplate capacity, as NREL's Annual Technology Baseline does. NREL budgets fixed operating costs of 2.5% of capex a year to cover augmentation, against about 1.3% in our model.[21] On this point the reference is generous.

At one cycle a day, a four-hour battery discharges a third more energy than the two-hour battery at 1.5 cycles, at a spread per MWh about 14% narrower,[22] and receives full capacity credit: revenue in today's market rises from €75 to €93/kW. It also costs more. Ember finds equipment 10–15% cheaper per kWh at four hours than at shorter durations.[20] We take the upper end, €221/kWh, so capex per kW is 70% higher. At one cycle a day the four-hour battery's revenue in today's market covers 80% of its annualised cost and it earns −0.3% in the base case. At 1.5 cycles a day it earns 4.0%, the same as the two-hour battery. The capex assumption is cautious: grid connection and part of installation scale with power, so the all-in gap per kWh is probably wider. At 20% below the two-hour capex, a four-hour battery cycling 1.5 times a day earns 5.0%. The market is moving to longer durations nonetheless. Centrica Energy has signed a toll for a 99 MW, three-hour battery in Lower Saxony,[23] and the projects named in the ENGIE–Flower agreement store about four hours.[24] Buyers are pricing two effects our single compression factor misses: a growing fleet of two-hour batteries compresses the shortest spreads first, and capacity mechanisms reward duration. France's mechanism applies 17 a coefficient of 0.86 to a four-hour battery, against 0.58 for two hours.

TABLE 3

Asset life and duration: project IRR of the reference battery

Variant (merchant, standard operator)	Favourable	Base case	Stressed
Reference: two hours, 15 years, nameplate capacity held	7.9%	4.0%	−0.4%
20 years, nameplate capacity held at no extra cost	10.2%	6.2%	1.8%
15 years, capacity fading 2% a year, no augmentation	5.3%	1.4%	−3.1%
20 years, fading 2% a year, augmentation in year 10 (€50/kW)	8.2%	3.9%	−1.0%
Four hours, 1.0 cycle a day	3.1%	−0.3%	−4.0%
Four hours, 1.25 cycles a day	5.6%	1.9%	−2.1%
Four hours, 1.5 cycles a day	7.8%	4.0%	−0.3%

Source: Capgemini analysis; Ember (fade, equipment cost by duration); Stratergy (spreads by duration). Four-hour battery: capex €221/kWh, 15% below the two-hour battery; spread per MWh 86% of the two-hour spread; full capacity credit; operating costs in proportion to capex.

CHAPTER 04

What a winning BESS looks like

A battery that wins is bought cheaply enough against today's revenue, has part of its capacity under contract and is run by a top operator. On our reference battery, the three together turn a 4.0% return into 10.6% in the base case and keep it close to 8% in a stressed market. Each alone falls short.

TABLE 4

Three levers, added one at a time to the reference battery

Lever	What it means	Project IRR, base case	In the market
1. Cheaper purchase	A purchase price low enough that today's revenue is about 1.4 times annualised cost (Figure 4), here €203/kWh instead of €260/kWh	4.0% to 8.0%	A battery earning today's German benchmark clears this bar (Section 2)
2. Top operator	Higher spread capture, availability in high-value hours and lower costs, built on owned data and AI (Section 7)	8.0% to 12.0%	In California, the best battery captured 71% more of its benchmark spread than the median one[4]
3. Contract on part of the capacity	A toll on 40% of the capacity for 15 years, priced at the base-case value for an average operator (€55/kW a year)	12.0% to 10.6%; stressed case 7.2% to 7.8%	Real tolls are shorter: Next Kraftwerke tolls 80% of Eco Stor's Förderstedt battery for five years;25 ENGIE holds a seven-year virtual toll on 126 MW of Flower's batteries[24]

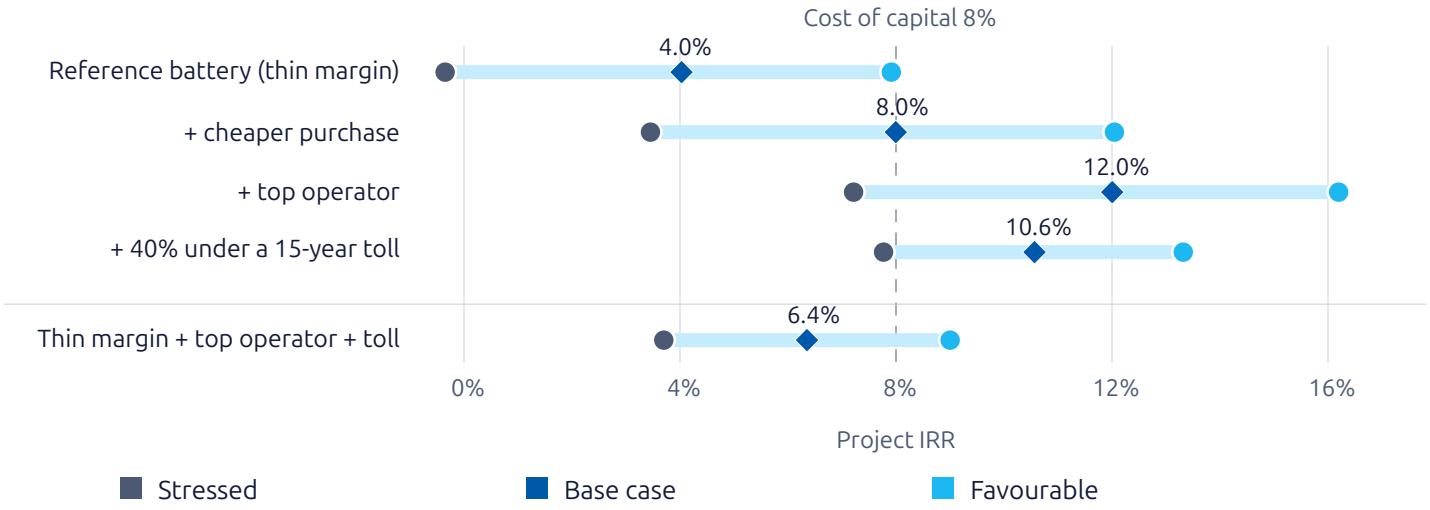
Source: Capgemini analysis, sources as noted. Top operator: +18% spread capture, +8% siting, –20% operating costs.



FIGURE 6

Return of the reference battery as each lever is added

Project IRR in the stressed, base and favourable cases, two-hour battery, 15 years



10.6%

Base-case project IRR after all three levers are applied.

The purchase price comes first. A top operator and a toll lift the thin-margin battery only to 6.4% in the base case (bottom row of Figure 6). Bought cheaply enough, the same battery earns 8.0% before anything else is added, and a top operator takes it to 12.0%.

The contract costs 1.4 points in the base case, because its price reflects an average operator. In exchange, it lifts the stressed case from 7.2% to 7.8%, narrows the range of outcomes by about 38% and, outside our project-level model, supports debt: lenders size loans on contracted revenue. Each lever is decided at a different time, from investment decision to operations (Sections 5 to 7), and Capgemini works with investors and owners on each of them.



CHAPTER 05

The BESS mortality test

Every investment case should answer five questions before capital is committed. Our model quantifies the first two, gives a lower bound for the third, and leaves the last two to due diligence.

TABLE 5

Five stress questions for every BESS investment case

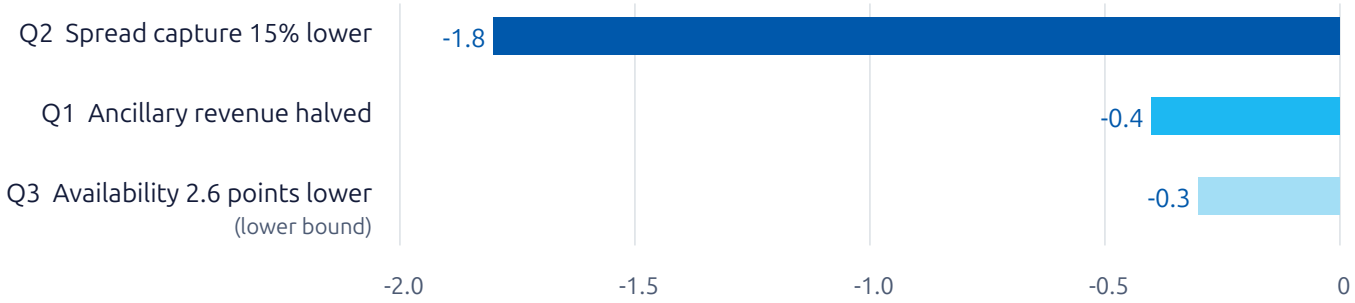
Stress question	What it tests	Impact on project IRR (base case, two-hour battery)
1. If ancillary-service revenue falls by 50%, does the project still work?	Exposure to saturating revenue pools	−0.4 points
2. If the optimiser captures 15% less of the available spread, what happens to returns?	Dependence on trading quality	−1.8 points
3. If availability runs 2 to 3 points below plan and outages fall in high-value hours, does the case survive?	Operational resilience	At least −0.3 points (timing of outages not modelled)
4. If cycling increases to capture smaller spreads, who bears the degradation, cooling and auxiliary energy, and do noise limits hold?	Fit between warranty, contracts, dispatch strategy and site permits	Not modelled. Requires degradation and auxiliary costs
5. If merchant markets weaken and a cheaper generation of batteries enters, can the project still be refinanced?	Refinancing and vintage risk	Not modelled. Requires the debt structure

Source: Capgemini analysis.

FIGURE 7

Losing 15% of spread capture costs more than four times as much as halving ancillary revenue

Change in project IRR from each stress, base case, percentage points



Source: Capgemini analysis.

Halving ancillary revenue costs little in the base case, because ancillary prices there already fall by about 40% a year until 2030 and by about a fifth a year after that, and account for only around 5% of the battery's discounted lifetime revenue. A further 50% cut costs just 0.4 IRR points. The exposure is much larger if a business case assumes flat ancillary prices.

Spread capture matters more because it affects the whole arbitrage stream over the asset's life. A 15% shortfall costs 1.8 IRR points, which makes the choice of optimiser and operational data quality as important as capex scrutiny.

The availability result is only a floor: the model spreads lost hours evenly, while real outages during peak-price hours would cost much more.

Question 4 goes beyond cell wear: heavier cycling means more cooling and auxiliary energy and, near homes, can breach the noise limits in the permit.

In a representative financing model, a 2% revenue reduction moves a loan sized at 1.30 times debt-service cover to about 1.26 times.[6] Question 5 is where a thin margin becomes a refinancing problem.

Co-located projects face two more questions: do curtailment, low prices or connection limits justify the battery, and do dispatch rights let it keep a fair share of the value it creates?

CHAPTER 06

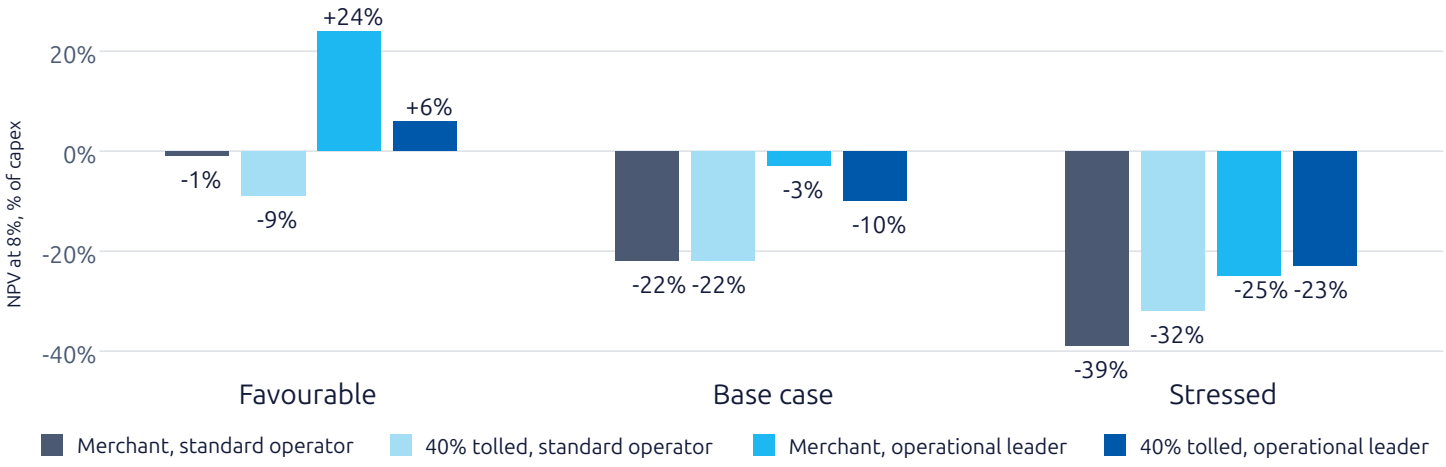
How operations and contracts change returns

We compared the same battery in the same three markets under four strategies: fully merchant or with 40% of capacity under a fixed-price toll, each run either by a standard operator or by an operational leader with 18% better spread capture, 8% better siting and 20% lower operating costs. The toll is priced at €55/kW a year: the level payment worth as much as base-case merchant revenue over 15 years.

FIGURE 8

An operating edge is worth 3.3 to 3.6 IRR points in every market future; a toll priced on the base case mainly narrows the range

Net present value at 8% as a share of capex, two-hour battery, 15 years



Project IRR (change vs merchant, standard operator)	Favourable	Base case	Stressed
Merchant, standard operator	7.9%	4.0%	–0.4%
40% tolled, standard operator	6.5% (–1.4)	4.1% (+0.1)	1.7% (+2.1)
Merchant, operational leader	11.5% (+3.6)	7.5% (+3.5)	2.9% (+3.3)
40% tolled, operational leader	9.0% (+1.1)	6.4% (+2.3)	3.7% (+4.0)

Source: Capgemini analysis. Changes in percentage points, computed before rounding.

3.3–3.6

Percentage points of project IRR added by the operational edge across the three scenarios.

Operations add value in every scenario

The operational edge adds between 3.3 and 3.6 points of IRR in all three scenarios. In the model it raises revenue by about 15%. Real assets differ far more: across 30 Californian batteries, revenue ranged from under $1 to over $6 per kW-month in 2024–25.[4] In the base case, operations account for about 2.5 points of the 3.5-point edge, mainly through spread capture, and siting for about 0.9 (Figure 10, Section 7). That edge is built with data and AI: better forecasts and adaptive bidding raise capture, and anomaly detection and predictive maintenance protect availability in the hours that matter.

At a fair price, a toll mainly buys downside protection

A toll priced on the base case leaves expected returns almost unchanged: tolling 40% of capacity moves the base-case IRR from 4.0% to 4.1%. It costs 1.4 points in the favourable case and adds 2.1 in the stressed one. The owner gives up upside in good markets for protection in bad ones, and the gap between best and worst outcomes narrows from 8.3 to 4.8 points.

Tenor matters as much as share: saturation bites hardest in the later years, so a short toll protects the years that need it least. A seven-year toll on the same 40%, priced on the base case over its own tenor, narrows the range by only about 13%, and a ten-year toll by about 23%, against 42% for 15 years (Figure 9).

Lenders favour the same structures that our model finds narrow the range least. At a battery-finance conference in March 2026, NORD/LB described typical German structures as a 12-month merchant phase followed by about 80% tolling for five to seven years, which "works for projects with high gearing", and advised against tolling 100%. Santander said tolling agreements are needed, "in part, to spread the risk". A toll moves risk rather than removing it: RWE pointed to mark-to-market penalties and Terralayr to sanctions for underperformance, so the owner takes on delivery and availability risk.[26] Debt is sized on the contracted years, while saturation bites after they end.

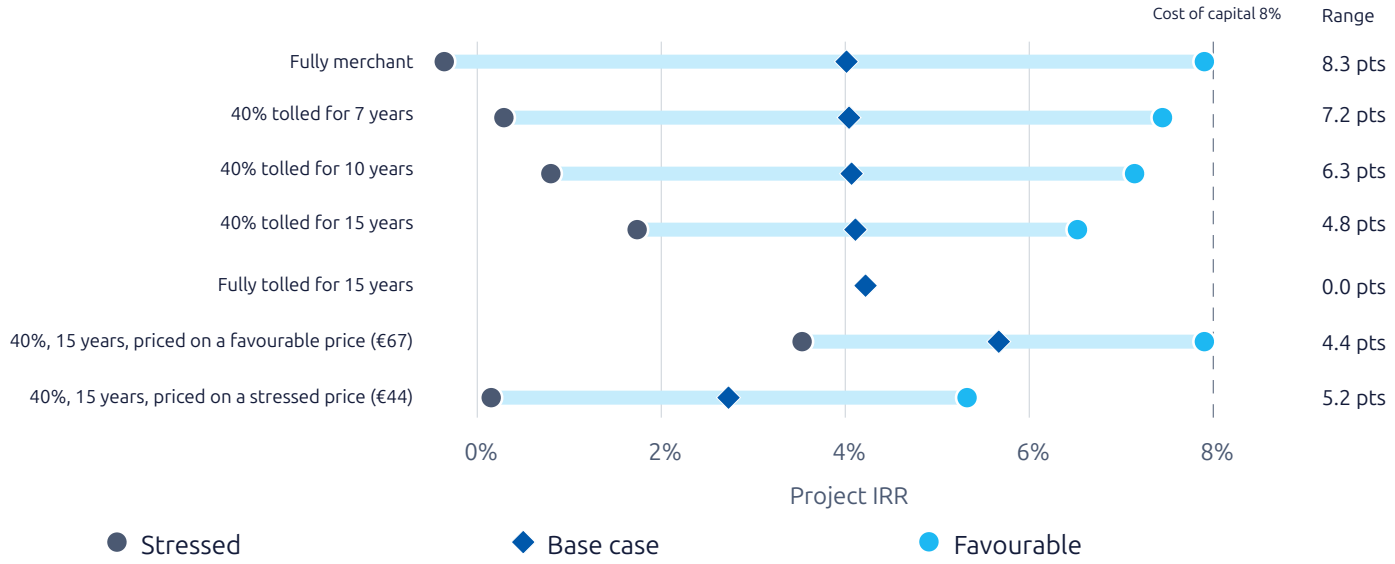
The toll price matters most. The same 15-year toll priced on a favourable view (€67/kW a year) adds 1.7 points in the base case; priced on a stressed view (€44), it costs 1.3 points (Figure 9). Competitive procurement pushes towards the second: Italy's first MACSE auction, for 15-year storage contracts, cleared at an average €12,959/MWh a year against a ceiling of €37,000.[5, 27]

No fairly priced toll rescues a battery bought on a thin margin. Fully tolled for 15 years, the reference battery earns 8% only if the toll reaches €68/kW a year, about a quarter above the base-case value of its capacity. An operational leader should not toll at prices set by average operators either: in the base case, tolling 40% of its capacity at €55 lowers its IRR from 7.5% to 6.4%, because the capacity is worth about €65/kW a year in its hands.

FIGURE 9

A 15-year toll narrows the range of outcomes, a seven-year toll barely does, and the toll price shifts the whole range

Project IRR in the stressed, base and favourable cases, standard operator. Unless stated, each toll is priced at the base-case value of merchant revenue over its tenor (€55/kW a year for 15 years)



Source: Capgemini analysis.

Location and grid connection, power and duration, grid-forming capability and qualification for several markets are fixed before construction, are costly to reverse and limit what operations can achieve later. Design should keep several value pools open, since the stream that pays best today may be the next to saturate. Co-located projects should be designed and contracted as one system, with trading rights secured at design stage. Section 3 tests a four-hour battery.

CHAPTER 07

Data and AI turn operations into margin

Our model gives an operational leader 18% better spread capture than an average operator. Real batteries already differ by far more: in California, the best captured 71% more of its benchmark spread than the median one in 2024–25.[4] Closing part of that gap is largely a data and AI task, and it falls to the teams that run batteries: trading, asset operations, data and IT.

In our model, each 5% of spread capture is worth about 0.6 points of project IRR, and each 10% of operating costs about 0.2 points. These are modelled sensitivities, but they put a price on what data and AI do in operations. In the base case, operations account for about 70% of the edge of a well-sited, well-run battery, and spread capture for most of that (Figure 10).

Where value leaks

Fleet data from California show how much is at stake. Across 30 batteries representing 2.3 GW, the median asset captured 82% of its benchmark spread over 2024–25 and the best 141%. Only five beat their benchmark. Twenty kept a static regulation bid curve in at least three-quarters of active months, and fleet availability averaged 80%.[4]

Across more than 50 operating projects in four markets, availability reported by energy management systems exceeded measured availability by 2.6 points on average, and three sites in four over-reported. Small recurring outages caused 57.6% of downtime, and ACCURE finds that early detection and predictive maintenance can catch them. Power conversion systems were the largest single source of unavailability, at 36.4%.[6] A wider review of 18 GWh found that one in five hardware components caused problems that directly cut performance.[28] Revenue is also lost in a few hours: in a study of an Australian battery, most of the revenue lost to imperfect price forecasts was lost on a small number of days with extreme prices.[29]



TABLE 6

Data and AI uses mapped to returns

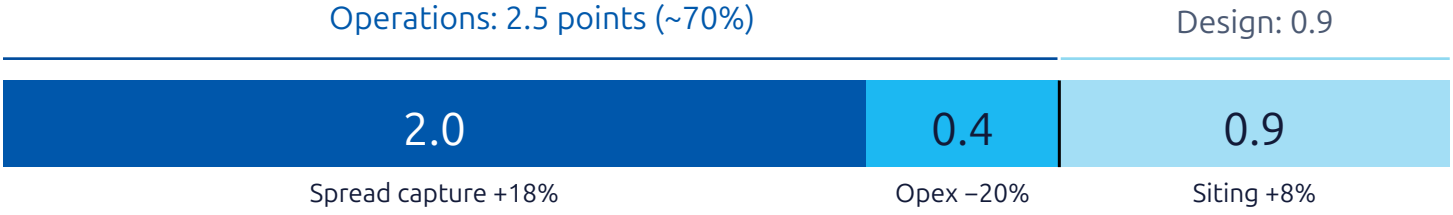
Use	What it improves	Mortality-test question	Evidence
1. Price, renewable and activation forecasting	Positions and bids ahead of delivery	Q2	Stochastic forecasts produced 53% more revenue than a persistence forecast in an ERCOT backtest (vendor)[30]
2. Multi-market bid optimisation	Revenue stacking across trading, ancillary and capacity markets	Q1, Q2	In California, 20 of 30 batteries kept a static regulation bid curve in most months; the median captured 82% of its benchmark spread, the best 141% (vendor)[4]
3. State-of-charge and state-of-health estimation	Usable capacity and warranty evidence	Q2, Q4	State-of-charge errors of ±15% are common in LFP; around ±2% with advanced analytics (vendor)[28]
4. Anomaly detection and predictive maintenance	Availability in high-value hours and operating costs	Q3	Small recurring outages caused 57.6% of downtime across 50+ projects; the power conversion system was the largest single source (vendor)[6]
5. Degradation-aware dispatch	Value of each cycle and warranty throughput	Q4	Allocating capacity with battery ageing in view raised lifetime revenue by up to 32% in research[31]
6. Business-case screening	Lifetime returns before investment decision	Q1 to Q5	Revenue in today's market must be about 1.4 times annualised cost to earn 8% in our base case (Figure 4)
7. Portfolio orchestration	Allocation and learning across sites and manufacturers	All	RWE pools batteries at two sites (117 MW) with its run-of-river plants, raising the capacity it can offer for grid stabilisation by up to 15%[32]

Source: Capgemini, sources as noted. Four of the seven evidence items come from vendor analyses.

FIGURE 10

Operations account for about 70% of the advantage, and spread capture for most of that

Contribution of each lever to the IRR advantage of a battery with a good site and strong operations, base case, percentage points. Together: 3.5 points (includes a small interaction effect)



Source: Capgemini analysis. Each lever applied on its own; the total includes a small interaction effect.

Why most operators struggle

The data often stays with the manufacturer. BMS and EMS data sit in OEM platforms, with access, resolution and retention set by contracts signed before anyone asked what the data would be used for. Owners then cannot check what they are told: availability reported by the EMS can exceed measured availability by several points.

Trading, asset management and O&M also tend to use separate systems and definitions, which hides the true cost of outages and derating. Models trained on a few months of data from one site rarely hold up across a fleet of mixed manufacturers, so AI often stays in pilots. New rules on inverters and remote control (Section 8) restrict how data leaves the site and who can act on it.

Data foundations are set at commissioning

Commissioning sets telemetry, naming conventions, data standards, baseline performance and data-access rights. It is also often late: delays of one to two months are typical, and some projects slip by eight months or more.[28] Getting telemetry and data rights right at commissioning avoids costly retrofits.

A data and AI agenda for battery operations

Most of the levers sit with five roles, and AI moves each of them (Table 7). At fleet scale, re-optimising bids every few minutes and reading the telemetry of hundreds of thousands of cells cannot be done by hand. It pays only if the owner holds the data, since none of these measures can be produced from performance reported by an OEM or an optimiser alone, and if control is clearly set: safety, warranty and grid limits are hard-coded, and people approve changes to dispatch limits and maintenance plans.



TABLE 7

A data and AI agenda for battery operations: who decides what, and what to measure

Role	Decisions that move the return	Where AI moves it	What to measure
Head of trading	Optimiser model and contract; how often bids adapt to market conditions; degradation priced into each bid	Probabilistic price and activation forecasts; multi-market bid optimisation that adapts continuously	Spread capture against a transparent benchmark, month by month; months with unchanged bids
Head of asset operations	Maintenance timing against market value; early fault detection; power conversion system reliability	Anomaly detection and predictive maintenance on cell, thermal and inverter data	Availability measured at the asset, in the highest-value hours; recurring small outages
Chief digital or information officer	Data ownership and access in OEM, EPC and optimiser contracts; one data model from cell to profit and loss; secure remote access	The data platform and semantic layer that let models run across sites and manufacturers	Share of telemetry owned and accessible at full resolution; time from fault to diagnosis
Head of portfolio	Allocation of capacity and learning across sites, markets and manufacturers	State-of-health estimation and fleet-level learning across assets	Spread of capture and availability across the fleet, and how fast it narrows
CFO and investment committee	Spread-compression assumption; toll price and tenor; operator selection	Revenue scenarios tested across the compression range; AI performance measured in money	Business-case IRR across the compression range; IRR points gained from each AI use

Source: Capgemini.

What an AI-ready battery operation looks like

- independent performance data, measured at the asset and not only reported by the EMS;
- one data model from cell to profit and loss, linking telemetry to contracts, market positions, work orders and warranties;
- forecasting and optimisation that price degradation and opportunity cost into every bid;
- maintenance planned against the market value of the hours it takes out;
- AI uses tied to the IRR levers they move and measured in money, with human approval for changes to dispatch limits or maintenance plans.

The optimiser contract decides who keeps the data and the upside, so it belongs with the board. Trading in-house keeps both but needs scale and skills. An optimisation service is faster to set up, but the owner may then be unable to judge its performance, and a floor or toll from the optimiser transfers market risk at a price. Whichever model is chosen, the owner should keep full access to dispatch and market data, pay fees linked to a transparent benchmark such as RWTH Aachen's ISEA Battery Revenue Index,[33] and keep the right to switch provider.

CHAPTER 08

Market design and security now move returns

In Europe, returns now also depend on grid access, grid fees, auction design, security rules and the falling cost of new batteries.

Grid access is no longer first come, first served

German transmission operators received around 545 large battery connection requests, totalling roughly 211 GW. Since April 2026 connections have been allocated through a maturity-based procedure.[34] Connections go to the most advanced projects, whatever their place in the queue.

France is moving the same way. Close to 15 GW of battery projects were in RTE's connection queue at the end of 2025, against about 1.5 GW connected, and the CRE asked RTE to propose by 1 October 2026 a procedure that takes better account of project maturity. RTE has also introduced a connection offer for storage whose injection and withdrawal limits are fixed in advance by season and time of day.[35]

In Italy, requests to connect storage to the transmission grid reached 300 GW by the end of 2025, against 7.4 GW installed.[36] The February 2026 "Bollette" decree targets this "virtual saturation": connection solutions for projects that are not yet authorised will lapse once the regulator's implementing rules are published.[37] A ministerial decree of 8 September 2026 has Terna publish available capacity by microzone, allocate it through an "Open season" and confirm each selected connection with a "Benestare".[38]

Grid fees are being reset

Under Germany's AgNes reform, batteries keep their 20-year grid-fee exemption only if they reach final investment decision before the new rules take effect, expected around late 2026 or early 2027, and are commissioned before August 2029. Later projects are expected to pay around €4–7/kW a year.[39] Wood Mackenzie finds that grid fees alone can push a Dutch battery to near-zero returns while the same asset earns double-digit returns in Belgium.[40]

Contract prices are set in competitive auctions

Italy's first MACSE auction procured all 10 GWh on offer, for delivery in 2028, at an average €12,959/MWh a year against a reserve price of €37,000.[5] A second auction, for 16 GWh, is scheduled for 24 November 2026.[27] Long-term contracts bring visibility, but competition prices most of the saturation risk into them (Section 6).

Security rules reach the power conversion system

In May 2026 the European Commission moved to restrict EU funding, including through the European Investment Bank and European Investment Fund, for solar, wind and storage projects that use inverters from high-risk suppliers. China, Russia, Iran and North Korea are named, and battery power conversion systems are explicitly included. Projects that can still change supplier do not qualify for grandfathering.[41] The PCS supplier therefore affects access to EU-backed financing, and remote-access rules limit who can operate the asset.



Cheaper batteries erode the returns of older ones

BNEF's surveys found European turnkey system prices at $275/kWh in 2024 and $177/kWh in 2025, against $73/kWh in China in 2025.[42, 43] In our base case, revenue for today's battery falls by 35% over 15 years, while the annualised cost of a new battery falls by 59% as capex declines. Each cheaper generation can accept lower prices, eroding the position of older, higher-cost assets. These figures show the direction of the effect. Its size is uncertain.

What this means for investors and asset owners

Battery storage will keep growing as power systems take on more wind and solar. The conditions that rewarded the first projects, undersupplied ancillary markets and few competitors, are disappearing in the markets that opened first and will fade elsewhere as deployment catches up.

Average returns will fall and the gap between the best and worst assets will widen. Five levers decide which side of that gap an asset ends up on (Table 8). can operate the asset.

TABLE 8

Five levers that shape BESS returns

Lever	When it is taken	What investors should test
Business case	Before investment decision	The spread-compression assumption, stated and tested across the public range. The five mortality-test questions answered. Today's revenue against annualised cost, with a margin that matches the investor's view of saturation (Figure 4).
Design	Before construction	Access to several value pools over the asset's life. Resilience to saturation, market-design changes and cheaper future batteries. PCS supplier and remote-access set-up compatible with financing and security rules.
Contracts	At financing	Toll price against the value of the capacity under the owner's own saturation view, and under its own operating capability. Tenor that covers the years when saturation bites. Dispatch, cycling and availability terms that fit the warranty.
Operations	Over the asset's life	Spread capture against a market benchmark. Availability measured independently, in high-value hours. Maintenance planned against market value.
Data and AI	From investment decision onwards	Independent performance data. Data-access rights in OEM and EPC contracts. AI uses tied to the levers that move IRR and measured in money. Cybersecurity and decision rights assessed with the same rigour as capex.

These levers are closely linked. A well-designed battery underperforms if its contracts are badly priced or its operations weak. Better software cannot make up for a purchase price that left no margin (Section 4), nor for a restrictive grid connection.

In our model, a battery bought with enough margin, partly contracted and run by a top operator stays close to 8% even in the stressed case. A thin-margin battery does not, whoever runs it.

How Capgemini helps

Capgemini works with utilities, renewable developers, IPPs and industrial energy users across the life of a battery, from the investment case to construction and operations, and builds the data and AI platforms that run the portfolio.

TABLE 9

How Capgemini helps across the asset life

Phase	The question	What we do
Investment strategy	Will this battery earn its cost of capital?	Apply the BESS mortality test and scenario modelling using the Capgemini BESS model, calibrated to the client's market and tested across the range of spread compression. Test toll and floor offers on price and tenor. Assess revenue-stacking assumptions, merchant exposure, grid constraints and technology risks. Perform commercial, technical and operational due diligence for investors, lenders and asset owners.
Development	Is this the right project, in the right location, with the right business model?	Assess market attractiveness, grid connection constraints, route-to-market options and revenue opportunities. Define the deployment roadmap, evaluate technology choices and identify the operating model required to deliver long-term value.
Build	Will it be delivered on time and ready for data-driven operation?	Deliver the feasibility and engineering studies needed to reach FID. Identify and select EPC contractors, run project management and coordinate interfaces across EPC contractor, OEM, integrator and grid operator. Support commissioning, capacity tests and telemetry acceptance. Secure data-access, ownership, retention and interoperability clauses in EPC and OEM contracts from the start.
Operate and optimise	Is every megawatt earning what it should?	Build the data platform and semantic layer from cell to profit and loss. Deploy AI for forecasting, bid optimisation, state-of-health estimation, anomaly detection and predictive maintenance. Integrate BMS, SCADA, EMS, trading and maintenance systems into a single operational view. Benchmark assets across the portfolio and set up the governance that carries what works at one site to the others.
Monetise	Are we capturing all available value streams?	Optimise participation in energy, capacity, ancillary service and flexibility markets. Improve dispatch decisions, revenue stacking and portfolio performance. Use advanced analytics and AI to continuously adapt bidding and operating strategies to changing market conditions.

Client examples

RENEWABLE DEVELOPER & OPERATOR

Design for optionality

For a €38 million project in Spain (2024), we designed the hybridisation of a 40.56 MW wind farm with 40.14 MWp of solar PV and an 80.24 MWh, four-hour BESS, all connected through a single grid injection point. Our team delivered permitting and flood-risk studies, PV design, BESS sizing recommendations and the hybrid control architecture. A power plant controller receives commands from the grid operator (REE) and coordinates dispatch across the three assets.

The plant is ready for permitting, meets grid requirements and runs wind, solar and storage as one system. The four-hour battery and single plant controller keep access to several revenue pools: energy shifting, ancillary services and renewable shaping.

BESS OPERATOR

Closing the data and control gap

For a US-based operator, we are integrating utility-owned batteries at three remote sites located hundreds of miles apart into a unified control-room view alongside existing generation assets. The work includes remote monitoring, NERC CIP compliance and integration of battery data with the client's cloud reporting platform. This will improve reliability and supportability, standardise reporting, and reduce operating and staffing costs by limiting site travel.

Battery data previously held in separate OEM systems will sit in one model that links cell-level performance to financial results. It is being built in from the start, so no retrofit will be needed after deployment.

LEADING EUROPEAN ENERGY UTILITY

EMS for BESS benchmark

A major energy utility acquired a unified SCADA, EMS and fleet-visibility platform for utility-scale BESS and plans to deploy it across future assets. The EMS market is crowded, and regulation is tightening, notably through EU RfG 2.0. The client asked Capgemini for a neutral assessment against leading market solutions.

In four weeks, we built a 47-criteria evaluation framework with a pricing template, collected expert-validated evidence, then scored eight solutions across seven axes. Deliverables included eight vendor one-pagers, a fully sourced scoring file and a consolidated report with recommendations. The client can now check what the platform covers, where the gaps are and where a complementary solution or partner is needed.



Methodology

The Capgemini BESS cannibalisation model

The model extends the backward-looking logic of the ISEA Battery Revenue Index (RWTH Aachen)44 with a forward-looking cannibalisation function.

It works per kilowatt of power and per year, and is designed to compare scenarios and strategies rather than to value individual assets.

- **Arbitrage revenue** equals annual discharge (cycles × 365 × duration) multiplied by the raw daily spread, a compression factor of 1 / (1 + β × saturation index) and the share of the spread the operator captures (70% for a standard operator). The raw spread is the spread before any effect of storage; it changes each year with renewable growth and the system's need for flexibility. The saturation index grows with the gross build-out of storage.
- **Scenarios.** Gross build-out grows by 20%, 25% and 30% a year until 2030 in the favourable, base and stressed cases, then by 7%, 9% and 11%. The first phase brackets the path in Great Britain's Clean Power 2030 plan, from 7.5 GW of grid-scale batteries at the end of 2025 to the 23–27 GW it requires by 2030, or 25–29% a year; growth in 2025 itself was about 44%.[45,46] The second phase matches the growth of large batteries between 2037 and 2045 in German grid-planning scenarios, 8–11% a year.[47] Raw spreads change by +7%, +4% and 0% a year. The favourable rate follows Montel's forecast that GB day-ahead spreads may widen by up to 47% by 2030, mostly as wind and solar are added.[48] The base rate reflects a slowdown in structural widening: German spreads rose sharply between 2019 and 2025, a one-off step that should not be extrapolated, but relative to gas prices they widened by only about 3% in 2024–25 (Capgemini analysis).
- **Spread compression** (β = 0.24) is calibrated so that today's fleet narrows the spread by about 16%, in line with KfW Research's estimate that batteries built in 2023–25 cut the German daily spread by €18–20/MWh.[18] Today's spread net of that effect, about €51/MWh, sets revenue in today's market at €75/kW; in the first year of operation, after a further year of build-out, it is €66/kW in the base case.
- **Ancillary revenue** falls as the saturation index rises, with an elasticity of 2.5.
- **Capacity revenue** is derated by duration, as (duration / 4)^0.8, and declines by 1% a year.
- **Cost of new entry** is the annualised capex of a battery built in that year, using a capital recovery factor at the cost of capital over the asset's life, plus operating costs. Capex falls by 7% a year.
- **Project IRR** is calculated from capex in year 0 and net revenue in years 1 to 15, with no tax, debt, inflation or terminal value.

Decomposing the operating edge

Each lever was applied on its own. In the base case, +18% spread capture adds 2.0 points of IRR and –20% operating costs add 0.4 points; together they add 2.5 points, the operations edge used throughout this paper. A site worth +8% spread capture adds 0.9 points, and all three together add 3.5 points. A change of 5% in spread capture moves IRR by about 0.6 points, and a change of 10% in operating costs by about 0.2 points.

How to read the results

Absolute returns are sensitive to inputs. In the base case, the merchant battery's project IRR moves from 1.0% to 8.3% when capex changes from €320/kWh to €200/kWh. The stranding figures (share of capital lost) describe a battery whose revenue in today's market exceeds its annualised cost by 10%. A battery with a larger margin loses less: at €200/kWh, the base-case merchant battery roughly earns its cost of capital instead of losing a fifth. The required multiple of today's revenue (Figure 4) does not depend on capex or operating costs.

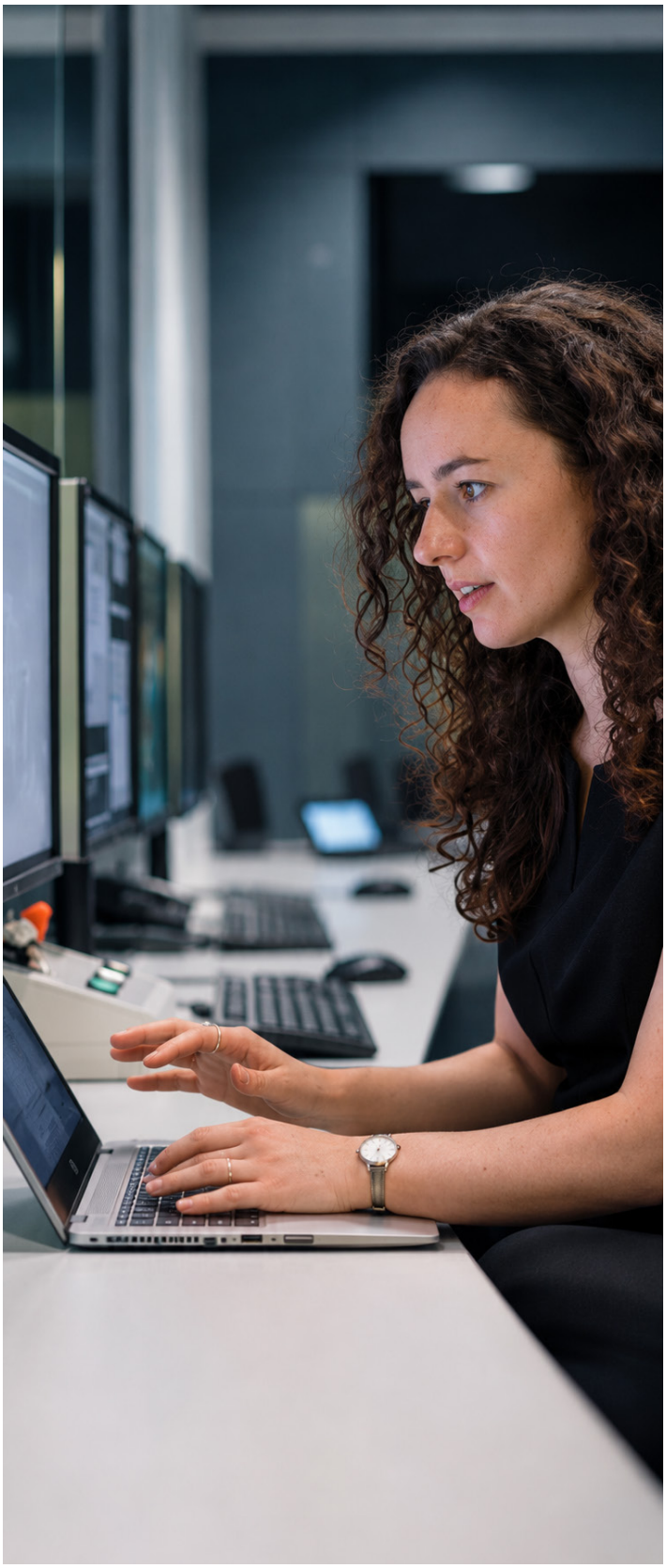
Toll. The toll price is the level annual payment with the same present value at 8% as merchant revenue for a standard operator over the toll's tenor, in the scenario named (base case unless stated). It is fixed, with no indexation, availability penalty or offtaker margin; real tolls priced with an offtaker margin would be worth less to the owner. A toll of €70/kW a year, close to the favourable-case value, would overstate the protection a toll gives.

Spread compression is the least certain parameter (Section 3). Across the range from β = 0.03 to 0.6, the base-case operating edge stays between 3.3 and 3.7 points and the ranking of the stress questions does not change; the size of the stranding loss does.

The differences between scenarios and strategies are more stable. Across the variations we tested (capex of €200 and €320/kWh, today's spread a third higher and an ancillary elasticity of 1.5), operations added between 2.2 and 2.9 points, siting between 0.8 and 1.1 points, and a 15% capture shortfall always cost more than halving ancillary revenue (–1.7 to –2.2 points against –0.3 to –0.7 points).

The reference battery is stylised. Its revenue in today's market was set to exceed annualised cost by 10%, so that it represents a battery bought at the margin of today's revenue in a market with a capacity mechanism. It is not a forecast for any one market.

Life and duration. Capacity fade reduces usable energy by 2% of nameplate a year, which scales trading and capacity revenue; ancillary revenue depends on power and is unaffected. Augmentation in year 10 restores nameplate energy at that year's capex (€50/kW). The four-hour battery has capex of €221/kWh, a spread per MWh 86% of the two-hour spread, full capacity credit and operating costs in proportion to capex; its cycling is tested at 1.0, 1.25 and 1.5 cycles a day.



Limits

The model does not include a degradation cost per cycle, so its returns rise with cycling; we draw no conclusion on cycling from it. It has no availability parameter, so the availability stress is approximated as a loss of capture and understates the cost of outages in high-value hours. It has no debt or tax, so it produces project IRRs, not equity returns or debt-service ratios. The toll is a fixed price with no indexation or performance terms. Duration is tested with a single compression factor, which probably understates the advantage of longer batteries as two-hour fleets grow. Storage growth follows a set path and does not respond to prices. Co-location is not modelled. Round-trip efficiency is reflected only through the capture rate.

TABLE 10

Main assumptions

Parameter	Value
Duration / cycles	2 hours / 1.5 cycles a day
Capex / annual decline	€260/kWh / 7% a year
Operating costs	€7/kW per year
Asset life / cost of capital	15 years / 8%
Daily spread today: net of today's storage / raw	€51/MWh / €60/MWh
Saturation index today / compression β	0.8 / 0.24
Gross storage build-out to 2030, then after: favourable / base / stressed	20% then 7% / 25% then 9% / 30% then 11% a year
Raw spread change: favourable / base / stressed	+7% / +4% / 0% a year
Ancillary revenue today / elasticity	€20/kW per year / 2.5
Capacity revenue (4-hour equivalent) / decline	€28/kW per year / 1% a year
Toll price	€55/kW per year (base-case value of merchant revenue), fixed; 15 years unless stated
Strong operations	+18% spread capture, –20% operating costs
Good site (design)	+8% spread capture

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Primary source for all modelled results unless otherwise noted: Capgemini BESS cannibalisation model (see Methodology).

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