

Impact of Grid Charge Regulation on Utility-Scale Front-of-the-Meter BESS Economics

A Quantitative Analysis of Germany's 2029 Transition with Focus on
Arbitrage

Master's Thesis Presented to
The Examination Board of the Graduate Program
Energy Management MBA

Under Authority of the
GKmE (Joint Commission with Decision Authority)
TU Campus EUREF
Technische Universität Berlin

in Partial Fulfillment of the Requirements for the Degree
Master of Business Administration

by

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March 20, 2026

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Declaration of Authorship

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- *Claude* (Anthropic; versions Opus 4.6, Sonnet 4.6): Development of the Python-based optimization and simulation codebase, including the linear programming model, Monte Carlo framework, and data processing pipeline. Language refinement, proofreading, and structural review of thesis text, as well as supporting systematic research for the methodology and results presentation.
- *Gemini* (Google; versions 3.1 Pro, 3 Thinking): Text review, formatting assistance, and cross-validation of analytical outputs.
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I further declare that I have not submitted the thesis in the same or similar form to any other examination authority.

Berlin, March 20, 2026

A handwritten signature in black ink, appearing to read 'Sorin Pascu', written over a horizontal line.

Pascu, Sorin

Abstract

The planned expansion of battery energy storage systems (BESS) in Germany amounts to 4.7 GWh by 2028, of which approximately 95% relates to utility-scale front-of-the-meter projects. The profitability of these systems critically depends on grid charge regulation, as the current exemption under § 118 (6) Energiewirtschaftsgesetz (EnWG) expires in 2029 without a defined successor regime.

This thesis quantitatively assesses the economic viability of utility-scale BESS under four post-2029 regulatory scenarios discussed in the Bundesnetzagentur (BNetzA) “AgNes” consultation process: the current exemption baseline (S0), full grid charges without exemption (S1), a static capacity charge as proposed by industry (S2), and a spot-market-oriented flexibility incentive informed by the BNetzA’s proposed dynamic pricing framework (S3). The analysis employs a linear programming optimization model under perfect foresight, combined with a Monte Carlo simulation framework using bootstrap-generated 20-year price scenarios derived from 2023–2025 German intraday market data. Three project configurations are evaluated: a standalone 3 MW system (Case A) and two co-located projects with photovoltaic (PV) and wind generation (Cases B1, B2).

The results demonstrate that the post-2029 grid charge regime is the determinant variable for BESS investment viability. Only the spot-market flexibility incentive (S3) achieves bankability across all configurations, with a net present value (NPV) exceedance probability — $P(\text{NPV} > 0)$ — of 100%. The current exemption (S0) yields marginal-to-robust profitability ($P(\text{NPV} > 0)$) ranging from 83% to 100%, while both the full grid charge default (S1) and the static capacity charge (S2) result in uniformly negative NPV outcomes. Sensitivity analysis confirms that regulatory design dominates all other tested parameters, including capital expenditures (CAPEX), weighted average cost of capital (WACC), and market revenue levels. Additionally, for severely grid-constrained co-located projects, the physical coupling topology is identified as financially comparable in impact to the regulatory regime choice itself.

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List of Abbreviations

Abbreviation	Meaning
aFRR	Automatic Frequency Restoration Reserve
AgNes	Allgemeine Netzentgeltsystematik Strom (BNetzA reform process)
BDEW	Bundesverband der Energie- und Wasserwirtschaft
BEE	Bundesverband Erneuerbare Energie
BESS	Battery Energy Storage System
BMWK	Bundesministerium für Wirtschaft und Klimaschutz
BNetzA	Bundesnetzagentur (Federal Network Agency)
CAPEX	Capital Expenditures
DCF	Discounted Cash Flow
DE-LU	Germany-Luxembourg (bidding zone)
DSO	Distribution System Operator
EnWG	Energiewirtschaftsgesetz (German Energy Industry Act)
FCR	Frequency Containment Reserve
FtM	Front-of-the-Meter
GMM	Gaussian Mixture Model
ID3	Intraday Continuous Price Index (3-hour window)
IRR	Internal Rate of Return

Abbreviation	Meaning
LFP	Lithium Iron Phosphate
LP	Linear Programming
NFA	Non-Firm Agreement (Netherlands)
NPV	Net Present Value
NVP	Netzverknüpfungspunkt (Grid Connection Point)
OBC	Operational Baseline Ceiling
OPEX	Operational Expenditures
ORC	Operational Revenue Ceiling
P(NPV>0)	Probability of Positive Net Present Value
PV	Photovoltaic
QH	Quarter-Hour (15-minute interval)
RaR	Revenue-at-Risk
RCR	Revenue Capture Rate
RE	Renewable Energy
RLM	Registrierende Leistungsmessung (Registered Load Measurement)
RTE	Round-Trip Efficiency
SoC	State of Charge
StromNEV	Stromnetzentgeltverordnung (Grid Fee Ordinance)
TCR	Targeted Charging Review (UK, Ofgem)
TNUoS	Transmission Network Use of System (UK)
TRC	Theoretical Revenue Ceiling
VWAP	Volume-Weighted Average Price
WACC	Weighted Average Cost of Capital



I. Introduction

The transition to a renewable energy (RE) system in Germany requires a significant expansion of flexibility options. According to a project pipeline analysis based on data from Energie & Management and Statista, the identified expansion of battery energy storage systems (BESS) in Germany until 2028 amounts to 4.7 GWh capacity [Bayern Innovativ, 2025]. Due to the nature of project tracking, which focuses on announced large-scale assets, approximately 95% of this identified volume relates to utility-scale front-of-the-meter (FtM) projects. This underscores the high relevance of large-scale FtM projects for the German energy market.

However, the profitability of these systems critically depends on the regulatory framework, specifically grid charge regulation. Under current German law (§ 118 Abs. 6 Energiewirtschaftsgesetz (EnWG)), utility-scale BESS are temporarily exempt from grid charges until 2029. Yet the BNetzA has signalled in its January 2026 orientation paper on storage grid charges that this exemption may not be maintained for its full 20-year duration, even for existing assets. Citing the European Court of Justice ruling on regulatory independence (C-718/18, 2021) and subsequent legislative amendments (December 2023), the BNetzA considers the legitimate expectation of continued exemption to be weakened, and a level-playing-field staggered phase-out for all storage assets — including those already in operation — to be legally permissible [Bundesnetzagentur, 2026]. The regulatory uncertainty regarding the post-2029 treatment creates significant investment risk, as grid charges can fundamentally undermine the business case for BESS deployment. This risk is structurally asymmetric: under capacity-based pricing regimes, a single charging event coinciding with the system load peak can trigger annual capacity charges that negate months of accumulated arbitrage revenue. The grid charge is determined by the highest 15-minute demand value observed in the entire billing period, creating a cost structure where one operational decision dominates the annual cost base. This asymmetry motivates the scenario-based approach adopted in this thesis, which evaluates how different regulatory designs distribute this risk. The ongoing reform process

(“AgNes”) conducted by the Bundesnetzagentur (BNetzA) has proposed several potential successor regimes. This thesis evaluates four scenarios spanning the regulatory design space: the current grid charge exemption (S0), full grid charges without exemption (S1), a static capacity charge as proposed by industry (S2), and a spot-market-oriented flexibility incentive as proposed by the BNetzA (S3). Despite the active regulatory debate, no quantitative assessment of these scenarios’ impact on BESS profitability has been published to date. The practical urgency of this regulatory gap is underscored by a joint industry appeal: as of March 2026, over 150 companies have formally urged the BNetzA to maintain the existing exemption framework, warning that retroactive changes would undermine planned investments at scale [Sagmeister, 2026].

This thesis does not aim to forecast future electricity prices or predict market outcomes — tasks that exceed academic scope and are addressed by specialized commercial tools (e.g., Aurora Energy Research). Instead, it provides a structured comparison of regulatory scenarios using historically observed market conditions as a stress-testing framework. The central question is not what will happen to BESS profitability, but how different regulatory designs perform across a wide range of plausible market environments derived from 2023–2025 intraday price data. This distinction is essential: conclusions drawn from this analysis are valid as regulatory comparisons, not as investment forecasts.

While perfect foresight optimization is an established benchmarking approach in industry practice, existing analyses typically rely on deterministic single-scenario assessments. This thesis extends the approach by systematically quantifying investment risk through Monte Carlo simulation of market price trajectories, capital costs, and technical degradation uncertainties — yielding full probability distributions rather than point estimates.

Research Objectives The core objective of this thesis is to quantitatively assess the economic viability of utility-scale, FtM BESS in Germany, specifically focusing on arbitrage revenues under the anticipated regulatory changes post-2029. This leads to the following research questions:

Main Research Question: How will the profitability of utility-scale FtM BESS arbitrage in Germany be affected by different potential grid charge regulations after the expiration of the current exemption in 2029?

Sub-Question 1 (Quantitative): What is the quantitative impact on the key profitability metrics, net present value (NPV) and internal rate of return (IRR), when comparing the most relevant post-2029 regulatory scenarios (S0–S3) against the current baseline regime?

Sub-Question 2 (Qualitative Benchmark): What alternative approaches to grid charge regulation for BESS can be identified in the UK and Netherlands, and what potential implications could inform Germany's post-2029 framework?

Structure of the Thesis Chapter II reviews the academic literature, establishes the regulatory context of German grid charges, and provides a comparative analysis of international frameworks (UK, Netherlands). Chapter III develops the quantitative methodology, including the block-bootstrap price simulation, the linear programming (LP) optimization model, and the Monte Carlo risk assessment framework. Chapter IV presents the results across four regulatory scenarios and three project configurations, analyzes co-location coupling effects, and discusses regulatory implications. Chapter V summarizes the findings, acknowledges methodological limitations, and outlines avenues for future research and commercial application.

II. State of Research & Regulatory Framework

This chapter provides the theoretical and regulatory foundation for the quantitative analysis. Section II.1 identifies the research gap, Section II.2 explains German grid charge mechanics, Section II.3 examines the AgNes reform debate, and Section II.4 contextualizes Germany's approach through international comparison.

II.1 Literature Review and Research Gap: Academic and Policy Discourse

The economic viability of BESS is a well-established subject in energy economics literature. However, existing research regarding the impact of grid charges focuses predominantly on *industrial behind-the-meter (BtM) applications*.

Recent reviews, such as Cottes et al. (2024), confirm that the majority of case studies analyze storage integration within industrial facilities to optimize internal energy efficiency or reduce peak load charges [Cottes et al., 2024]. In the German context, Fleschutz et al. (2022) provide a detailed analysis of how current grid fee regulations (specifically atypical and intensive grid usage under § 19 Stromnetzentgeltverordnung (StromNEV)) incentivize or hamper demand response in energy-intensive industries, using a chemical plant as a case study [Fleschutz et al., 2022].

Role of Non-Academic Literature Complementing this academic research, the specific German discourse on grid fee design and BESS economics is substantially influenced by 'grey literature'—including position papers from industry associations and techno-economic studies by specialized consultancies. Three categories of non-academic work are particularly relevant for contextualizing this thesis.

First, *system-level welfare analyses* assess the macroeconomic value of BESS deployment. Frontier Economics [2023], commissioned by a consortium of storage developers, employs a market

equilibrium simulation to project that grid-scale BESS capacity in Germany could reach 15 GW by 2030 and 72 GW by 2050, generating wholesale market savings of at least EUR 12 billion over the projection horizon. Similarly, the joint Consentec and Frontier Economics study [2025] models grid fee trajectories under different expansion scenarios through 2045. Both studies evaluate BESS from a system planner’s perspective—quantifying welfare effects and cost allocation—rather than from the investor’s perspective of project-level NPV and IRR under regulatory uncertainty.

Second, *proprietary asset valuation tools* provide revenue benchmarks for individual BESS projects. Aurora Energy Research offers its Chronos platform for bankable BESS valuations and publishes a European Battery Markets Attractiveness Report covering 28 markets [Aurora Energy Research, 2025]. Aurora has estimated that grid connection charges (Baukostenzuschüsse) alone can reduce a German BESS project’s IRR by up to four percentage points [Colthorpe, 2025]. Enervis Energy Advisors publishes a monthly BESS revenue index for Germany since 2025, reporting achievable net revenues of approximately EUR 148,500 per MW per year for a typical 2-hour standalone system based on intraday and ancillary service market participation [Schlossarczyk and Anthonioz, 2026]. Both provide point estimates under their respective proprietary price forecasts but do not model full probability distributions or systematic regulatory scenario comparisons.

Third, *market pipeline analyses* track announced BESS projects and capacity forecasts [Enervis Energy Advisors, 2024]. While valuable for market sizing, these do not assess project-level economic viability under alternative regulatory regimes.

While these reports offer critical insights into system-level efficiency, market revenue potential, and capacity forecasts, none provides a transparent, reproducible quantitative assessment of the investor’s business case under post-2029 grid charge scenarios—the specific gap this thesis addresses. The methodological distinction is threefold: this thesis (1) adopts the project investor’s perspective using NPV and IRR as primary metrics, (2) generates full probability distributions via Monte Carlo simulation rather than deterministic point estimates, and (3) systematically isolates the impact of regulatory design on bankability by comparing four grid charge scenarios under identical market conditions.

Identified Research Gap While these studies comprehensively cover the optimization of industrial loads under the *current* regulatory regime, a systematic Scopus search (2020–2025) confirms a significant lack of quantitative research addressing:

-
1. *Utility-Scale FtM projects*: Unlike industrial batteries, stand-alone BESS do not have a base load to optimize against; their business model relies entirely on market spreads and is thus far more sensitive to grid fee structures.
 2. *Future Regulatory Scenarios (Post-2029)*: No peer-reviewed study addresses the economic impact of the specific reform proposals currently discussed in the German AgNes debate (e.g., dynamic vs. capacity charges) on profitability using quantitative optimization methods (NPV/IRR).

This thesis closes this gap by being a quantitative assessment of these specific post-2029 regulatory scenarios for utility-scale BESS.

Literature Search Strategy To ensure economic relevance, this review focuses on publications from 2020 onwards. This temporal restriction is motivated by three structural shifts:

1. *CAPEX Decline*: Battery costs have dropped significantly (from >400 €/kWh pre-2020 to ~150 €/kWh at pack level in 2024), rendering older profitability analyses obsolete for current investment decisions [BloombergNEF, 2024].
2. *Market Regime Shift*: Prior to 2020, the German BESS market was dominated by Frequency Containment Reserve (FCR). The shift towards wholesale arbitrage as a primary revenue stream is a recent phenomenon—particularly since 2022 following the energy crisis-induced price volatility—and is thus not covered in older literature [Figgner et al., 2023].
3. *Regulatory Novelty*: The specific policy debate surrounding the expiration of the grid fee exemption in 2029 and the subsequent AgNes consultation process (initiated 2024) post-dates the 2020 search boundary.

II.2 Fundamentals of German Grid Charges

Before analyzing reform proposals, it is essential to understand the composition of the current grid fee system. In Germany, grid charges are not a single uniform tax but a stack of distinct components that vary by voltage level and by location.

The Dual-Component Structure For industrial consumers and grid-connected storage with registered load measurement (RLM), grid charges are fundamentally split into two logical components:

1. *Capacity Charge* (Leistungspreis): Charged in € per kW per year based on the annual peak demand (the highest 15-minute power interval registered by the meter). This component incentivizes a flat consumption profile (“Bandlast”) and penalizes single load spikes.
2. *Energy Charge* (Arbeitspreis): Charged in ct/kWh for the total energy volume drawn from the grid, regardless of when it is consumed.

The Price Stack: Local vs. Federal For the economic modeling of BESS, it is critical to distinguish between components that are set locally by the Distribution System Operator (DSO) and levies that are set federally.

Table II.1: Decomposition of German Grid Charges and Levies (Status Quo).

Component	German Term	Unit	Scope
Capacity Charge	<i>Leistungspreis</i>	€ / kW / a	Local (DSO-specific)
Energy Charge	<i>Arbeitspreis</i>	ct / kWh	Local (DSO-specific)
Levies	<i>Umlagen</i>	ct / kWh	National (Uniform)
Electricity Tax	<i>Stromsteuer</i>	ct / kWh	National (Federal)

The Current Exemption (§ 118 Abs. 6 EnWG) Currently, utility-scale storage facilities benefit from a specialized exemption regime. Facilities commissioned before the statutory deadline of August 4, 2029, are currently exempt from paying local grid charges (both capacity and energy price) for a period of 20 years [Bundesrepublik Deutschland, 2023, § 118 Abs. 6]. This privilege is tied to the condition that electricity is stored and subsequently discharged at the same connection point (physical congruence). This exemption is the central economic enabler for current projects; its expiration constitutes the core regulatory risk analyzed in this thesis.

II.3 The German Reform Debate (“AgNes”)

In anticipation of the 2029 deadline, the BNetzA initiated the consultation process AgNes (*Allgemeine Netzentgeltssystematik Strom*) to define a sustainable post-exemption framework [Bundesnetzagentur, 2025a]. In November 2025, the BNetzA published orientation points specifying the general tariff architecture, distinguishing between a financing function (cost recovery) and an incentive function (behavioral steering) as two separate pricing layers applicable to all grid users [Bundesnetzagentur, 2025b]. In January 2026, the regulator further specified how this architecture applies to storage assets [Bundesnetzagentur, 2026].

BNetzA Proposals: Flexibility Incentives The BNetzA’s discussion paper proposes three distinct flexibility models to integrate storage and flexible loads:

- *Option A (Spot Market-Oriented)*: This option introduces variable grid charges that are directly linked to spot market prices [Bundesnetzagentur, 2025a]. This constitutes a market-based dynamic pricing mechanism, where the spot price serves as the temporal price signal. The rationale is that spot prices serve as a proxy for general system scarcity. In times of low prices (high renewable feed-in), fees are reduced to encourage charging, whereas high spot prices trigger higher grid charges to discourage consumption.
- *Option B (Grid-Driven)*: Grid charges vary based on local congestion forecasts provided by the DSO [Bundesnetzagentur, 2025a]. This allows for precise local steering but requires complex data transparency. This represents a grid-based dynamic pricing approach, where the temporal signal is derived from local network conditions rather than wholesale market prices.
- *Option C (Contractual)*: This model relies on individual flexibility contracts where operators receive fee discounts in exchange for granting DSOs specific dispatch rights [Bundesnetzagentur, 2025a]. Unlike Options A and B, this model does not rely on a dynamic price signal but on contractual obligations — constituting a non-price-based flexibility incentive.

Regulatory Specification: Storage Grid Charges (January 2026) In January 2026, the BNetzA published its “Orientierungspunkte Speichernetzentgelte,” confirming the end of the blanket exemption (§ 118 Abs. 6 EnWG) beyond 2029 — aligned with European standards [BET Consulting and Aecoute, 2026] — and specifying a two-layer pricing architecture for storage [Bundesnetzagentur, 2026]:

The *financing function* comprises a capacity charge based on a user-selected demand threshold (“Bestelleistung”) and two work prices: AP1 applies to consumption within the selected capacity; AP2, set at a higher rate, applies to volumes exceeding it. For storage, the BNetzA proposes a netting mechanism (“Saldierung”): work prices would apply only to net grid withdrawal (total charging minus re-injection), effectively charging only round-trip losses rather than the full arbitrage cycle [Bundesnetzagentur, 2026]. The precise allocation of AP1 vs. AP2 to netted volumes remains subject to consultation.

The *incentive function* introduces a dynamic, sign-correct work price tied to local grid congestion rather than wholesale market prices. This component can be positive or negative: grid-relieving

behavior (e.g., charging during local oversupply) generates a payment to the operator, while grid-burdening behavior incurs a charge. The BNetzA targets introduction for storage at the transmission and high-voltage level by 2029 [Bundesnetzagentur, 2026]. The combined financing and incentive components may net to a value below zero, meaning storage operators could receive net payments from grid charges if their dispatch is sufficiently grid-serving. The incentive function is designed to be revenue-neutral in aggregate — payments to grid-serving operators are offset by charges on grid-burdening behavior — rather than as an additional cost-recovery instrument.

This two-layer architecture does not map one-to-one onto the scenarios modeled in this thesis. S3 (Spot-Flex) approximates the incentive function conceptually but uses spot prices as a proxy for unavailable congestion signals. S2 (Static-Cap) partially reflects the financing function's capacity component but lacks the AP1/AP2 mechanism. The BNetzA's combined model — moderate financing burden (losses only) plus dynamic incentive (potentially net-positive) — suggests that the regulatory outcome may fall between S0 and S3 in terms of economic impact. The scenario-based approach adopted here therefore brackets the plausible regulatory design space from both sides.

Industry Position: The Capacity Charge

In contrast to the regulator's push for dynamic signals, industry stakeholders such as the Bundesverband der Energie- und Wasserwirtschaft (BDEW) express concern regarding revenue stability for grid operators. They advocate for a *Static Capacity Charge* as the primary instrument to ensure cost recovery [BDEW Bundesverband der Energie- und Wasserwirtschaft e.V., 2025]. In this model, BESS would pay a reduced flat fee per installed kW.

Alternative Instruments: Dynamic Constraints Beyond price-based steering, alternative concepts focus on physical operational boundaries. A prominent proposal is the “Dynamic Grid Constraint” (also referred to as *Leitplanke*) analyzed by Neon [Lohr et al., 2025]. Instead of a monetary charge, this mechanism imposes a behavioral rule: storage units are prohibited from increasing grid load during specific congestion windows.

A comprehensive taxonomy of all discussed regulatory instruments, including additional industry proposals (e.g., connection charges), is provided in the scenario definition in Section III.2.

II.4 Comparative Analysis: International Regulatory Frameworks

To contextualize the ongoing German reform debate, it is instructive to analyze how neighboring markets have addressed the conflict between grid cost recovery and storage flexibility.¹ While Germany is currently searching for a new equilibrium (AgNes), the United Kingdom and the Netherlands have already implemented or piloted fundamentally different approaches. These distinct regulatory philosophies are summarized in Table II.2.

United Kingdom: Stability through Fixed Charges The UK market serves as a prominent case study for a regulatory shift from volatility to stability. Historically, BESS revenues in Great Britain were heavily driven by “Triad Avoidance”—a strategy where storage operators discharged during the three distinct half-hourly periods of highest winter demand to avoid transmission charges (Transmission Network Use of System, TNUoS) [GridBeyond, 2023]. This mechanism acted as a strong, albeit volatile, price signal. However, the Targeted Charging Review (TCR), fully implemented in April 2023, fundamentally altered this landscape [Ofgem, 2019]. The regulator identified Triad avoidance as a distortion — not because peak-load reduction was undesirable, but because the mechanism allowed certain flexible actors to systematically avoid residual cost contributions that were consequently borne disproportionately by inflexible consumers. For BESS specifically, the Triad signal had functioned as an effective incentive for peak shaving; its removal thus eliminated a revenue stream that was operationally aligned with grid needs. Ofgem replaced the volatile residual charges with fixed capacity-based levies, classifying standalone storage as ‘generation’ for this purpose and explicitly exempting BESS from these new charges [Ofgem, 2022].

Implication: While UK storage operators are shielded from high fixed grid charges, they have lost a significant “embedded benefit” revenue stream. Critically, this benefit applied not only to behind-the-meter installations (reducing consumption during Triads) but also to FtM assets: Distribution-connected FtM storage received payments (typically via suppliers) for actively discharging during Triad periods, compensating for transmission-level congestion relief [Ofgem, 2019, GridBeyond, 2023]. The regulatory signal has shifted from “grid-serving peak shaving” to a neutral position, forcing BESS to rely primarily on wholesale arbitrage and ancillary services.

1. The qualitative comparative analysis of international regulatory frameworks (Section II.4) draws on and extends the author’s prior seminar paper “New Trends in Global Energy: The Impact of Grid Charge Regulation on Utility-Scale BESS Business Models in Europe - A Comparative Study (DE, NL, UK)”, submitted in partial fulfillment of Elective Module Global Energy & Rural Electrification at TU Berlin (Academic Year: 2025/2026). The scenario taxonomy (Table III.1) was developed in that context and is here integrated into the quantitative framework.

The Netherlands: Flexibility through Contracts (Non-Firm Connections) In contrast to the UK’s rigid approach, the Netherlands is pioneering a model based on contractual flexibility to mitigate grid congestion. Facing severe capacity bottlenecks, Dutch grid operators utilize “non-firm grid connection agreements” (NFAs). Under this regime, BESS operators agree to mandatory curtailment during peak congestion hours in exchange for significantly reduced grid usage fees. Verhagen et al. (2026) demonstrate that such non-firm contracts can reduce grid charges by up to 65% compared to firm connections, creating a net positive business case despite the loss of revenue during curtailed hours [Verhagen et al., 2026].

Implication: This model explicitly trades “access security” for “OPEX reduction.” For utility-scale storage, which inherently possesses high flexibility, this creates a viable business case where the reduction in fixed costs overcompensates for the constrained operational hours.

Synthesis: Three Regulatory Philosophies The comparison highlights three distinct regulatory pathways currently co-existing in Northern Europe (see Table II.2). While the UK prioritizes cost recovery stability and the Netherlands focuses on physical congestion management via contracts, Germany’s ‘AgNes’ debate represents a search for a hybrid approach combining these elements.

Table II.2: Comparison of Grid Charge Frameworks for BESS in Northern Europe.

Feature	United Kingdom (Post-TCR)	Netherlands (NFA Model)	Germany (AgNes Proposals)
Regulatory Objective	Stability (Fixed Cost Recovery)	Physical Flexibility (Congestion Mgmt)	Hybrid Search (Incentive vs. Cost)
Grid Fee Structure	Fixed Residual Charges (Capacity-based)	Discounted Volumetric / Capacity Fees	<i>Specified (Jan 2026):</i> Financing (Capacity + AP) + Dynamic Incentive
Role of BESS	Exempt (treated as Generation)	Active Congestion Relief Provider	Active participant; netting on losses
Key Incentive	Neutral (Focus on Wholesale Market)	Reduced OPEX via Curtailment Risk	<i>Goal:</i> System-serving dispatch
Risk Profile	Low (Regulatory certainty, no fees)	Medium (Curtailment volume risk)	Medium-High (Direction set, details pending)

Source: Author's analysis based on Ofgem (2022), Verhagen et al. (2026), and BNetzA (2025; 2026).

Note: AgNes options are simplified here; see Chapter III for the full scenario taxonomy used in the model.

Lessons for the German Context The international experience reveals inevitable trade-offs. The UK example demonstrates that removing grid fee volatility (Triads) eliminates the asymmetric cost avoidance mechanism but also removes a revenue stream that was operationally aligned with grid needs for storage. The Dutch model shows that BESS can serve as a grid-booster if the regulatory framework allows for flexible (non-firm) contracts. For the quantitative analysis in this thesis, these findings underscore the necessity to model not just a single “post-exemption” price, but a range of scenarios reflecting these opposing regulatory philosophies (fixed vs. dynamic).

III. Methodology

This chapter establishes the quantitative framework for evaluating the impact of post-2029 grid charge reforms on BESS operations. It outlines the data foundation and simulation architecture (Section III.1), the regulatory scenarios (Section III.2) and the linear optimization model (Section III.3). Furthermore, it specifies the benchmark project configurations (Section III.4), the stochastic risk parameters (Section III.5), and the financial metrics (Section III.6). Finally, Section III.7 documents the model validation approach.

III.1 Data Foundation & Stochastic Modeling

III.1.1 Historical Market Data

To simulate the arbitrage potential of the BESS, high-resolution 15-minute time series for the German-Luxembourg (DE-LU) bidding zone were used for the period from January 1, 2023, to December 28, 2025.

- *ID3 Price Index*: The primary data source for the simulation is the continuous intraday ID3 price (the volume-weighted average price of all trades executed in the three hours prior to delivery). Originally defined and published by EPEX SPOT, this index was selected because it reflects the relevant liquidity and price volatility required for short-term flexibility dispatch. The 15-minute resolution ensures that sub-hourly price spreads are accurately captured.
- *Data Acquisition*: Historical price data were sourced from the public JSON data structures of the Energy-Charts platform (Fraunhofer ISE) [Fraunhofer Institute for Solar Energy Systems ISE, 2026], acting as the data aggregator. This approach allowed for the extraction of granular, quarter-hourly (QH) continuous trading data.
- *Data Integrity and Scope*: The final dataset comprises 104,832 data points. To ensure temporal consistency and mitigate daylight saving time anomalies, all timestamps were processed

in standard Coordinated Universal Time (UTC). Due to the weekly packaging of the source data, the observation period concludes on December 28, 2025; this minor truncation of the final three calendar days does not materially affect the annual profitability metrics of the simulation.

III.1.2 Descriptive Price Analysis

The economic viability of the BESS is fundamentally driven by the volatility structure of the underlying electricity market. Figure III.1 illustrates the frequency distribution of the ID3 prices over the 2023–2025 observation period.

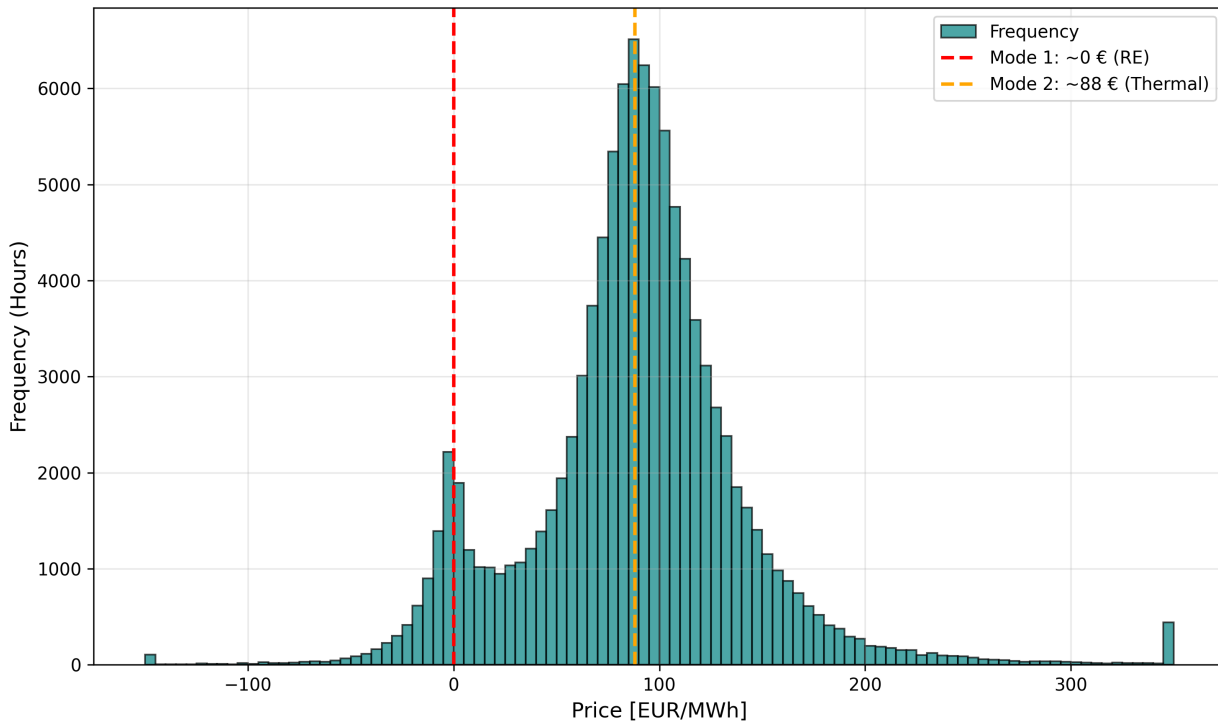


Figure III.1: ID3 price frequency distribution, DE-LU bidding zone (2023–2025).

The distribution reveals a distinct bimodal structure reflecting two dominant market regimes. The left peak (surplus regime, ≈ 0 €/MWh) captures periods of high renewable feed-in where zero-marginal-cost generation drives prices toward zero or negative values — a combined effect of renewable merit-order displacement (“price cannibalization”) and grid-driven feed-in priority. The right peak (dispatch regime, ≈ 80 – 100 €/MWh) reflects conventional thermal dispatch hours, where marginal costs are set by natural gas and coal prices plus CO₂ certificate costs. The resulting price

volatility — within and between both modes — creates the arbitrage opportunities exploited by the BESS optimization model.

The consistent persistence of this bimodal pattern throughout 2023–2025 represents a stable post-crisis structural regime and justifies its selection as the baseline for the bootstrap simulation. For a detailed analysis of the historical structural transformation since 2020 and the semi-annual stability of both modes, see Appendix A and B.

III.1.3 Generation of 20-Year Synthetic Price Scenarios (Block-Bootstrap)

To evaluate BESS profitability over the 20-year investment horizon under realistic market uncertainty, this study generates 10,000 synthetic price scenarios using a block-bootstrap resampling method applied to the 2023–2025 historical data pool. Unlike parametric models (e.g., ARIMA) that assume specific price distributions, the block-bootstrap preserves empirical market structures—including extreme price spikes, multi-day autocorrelation, and renewable-driven volatility patterns—without imposing distributional assumptions. This approach is consistent with established practice in probabilistic electricity price forecasting, where non-parametric and resampling-based methods are well-suited to capturing empirical fat tails and autocorrelation structures in volatile markets [Weron, 2014].

Block Dimensioning and Meteorological Realism

Rather than sampling individual hours, the algorithm randomly draws 14-day contiguous blocks from the historical pool. This duration was selected for three reasons:

- *Meteorological Coherence*: Extended weather events in Central Europe (e.g., “Dunkelflaute” periods) typically persist 10–14 days. Smaller blocks would fragment these phenomena, distorting the price volatility that drives arbitrage opportunities.
- *Weekly Market Cycles*: Fourteen days capture two complete weekly cycles, preserving systematic weekday-weekend price variations.
- *Sampling Efficiency*: The algorithm draws from 1,078 valid starting positions, utilizing daily offset sampling across the 104,832 QH historical pool to maximize statistical diversity.

Scenario Construction and Boundary Artifact Mitigation

Each synthetic 20-year timeline is constructed by randomly concatenating blocks from the historical pool. To eliminate fictitious arbitrage profits from artificial price jumps at non-sequential calendar

transitions, a 24-hour warmup period is applied at each block boundary. A post-hoc boundary analysis confirmed no systematic revenue bias from block transitions (see Appendix C). Consequently, no revenue exclusion is applied during warmup periods.

State of charge (SoC) remains continuous across all block boundaries to prevent artificial “free charging” artifacts; post-warmup SoC variability does not bias NPV outcomes due to random block sampling.¹

Integration with Monte Carlo Framework

The 10,000 bootstrap-generated price scenarios serve as deterministic inputs to the optimization model (Section III.3). By using identical price scenarios across all regulatory cases, differences in NPV distributions can be attributed exclusively to grid charge structures rather than random price variation.

III.1.4 Monte Carlo Simulation Architecture

Methodological Rationale

This study does not aim to forecast future electricity prices — a task beyond the scope of this study given the inherent complexity of long-term energy market dynamics (cf. commercial forecasting tools such as Aurora Energy Research). Instead, the Monte Carlo framework serves two distinct purposes:

- (1) enabling robust comparison of regulatory scenarios (S0–S3) under identical market conditions, such that NPV differences are attributable solely to grid charge structures rather than price assumptions; and
- (2) quantifying the sensitivity of investment outcomes to historically observed market variability. Unlike deterministic models, this yields full probability distributions of NPV and IRR — enabling revenue-at-risk (RaR) quantification across 10,000 scenarios. This is essential for BESS economics, where profitability is path-dependent: SoC at any point reflects all prior dispatch decisions, making closed-form analytical solutions infeasible over a 20-year horizon.

The use of block-bootstrapped price trajectories from 2023–2025 reflects a defensible modeling assumption: that near-term market conditions represent plausible realizations of the operating en-

1. To ensure cumulative accuracy over 700,800 intervals, all price data is processed using fixed-point arithmetic (Int32 cent-encoding), eliminating floating-point drift in long-term cash flow calculations.

vironment over the project horizon — not a prediction, but a scenario simulation across historically observed market states.

The Monte Carlo framework integrates the stochastic price trajectories (Section III.1.3) and parameter uncertainties (Section III.5) to quantify investment risk across a wide range of plausible future realizations. The deterministic optimization model (Section III.3) serves as the transfer function, calculating profit-maximizing dispatch strategies for each combination of price scenario and parameter draw.

Two-Phase Architecture and Computational Efficiency To manage the high dimensionality of 700,800 time steps per 20-year run across 10,000 iterations, the framework utilizes a high-performance two-phase architecture:

- *Phase 1 (Data Engine)*: Pre-computes the 10,000 synthetic price trajectories, stored in compressed Parquet format (~43 GB) for rapid access.
- *Phase 2 (Core Simulation)*: Executes the Monte Carlo runs by pulling one unique price scenario and pairing it with one independent set of stochastic parameters.

This design ensures statistical robustness while maintaining computational feasibility.²

Sampling Method and Integration For each iteration, variables are sampled independently to generate a representative project risk profile:

- *Market Risk*: Derived from one unique 20-year bootstrap realization (Section III.1.3).
- *Technical and Financial Risk*: Sampled from the distributions for degradation (Section III.5.1), capital expenditures (CAPEX), and weighted average cost of capital (WACC) (Section III.5.2).

Document Sample Size Reduction for Case B (B1/B2)

Due to significant computational constraints—specifically a persistent memory leak in the macOS virtual memory subsystem leading to excessive swap usage and system instability—the simulation scale for Cases B1 and B2 was adjusted. While Case A utilized 10,000 iterations, Cases B1 and B2 were simulated with 1,000 Monte Carlo iterations. This reduction is justified by the significantly higher computational complexity of the NPV-constrained dispatch and the integration of RE profiles in Case B. The 1,000-iteration sample remains representative and unbiased, as it was generated using a random block-bootstrap method from the historical dataset (2023–2025).

2. Computations were performed on an Apple Mac mini (M2 Pro, 12-core CPU, 32 GB RAM, NVMe SSD). No distributed computing environment was required.

Stochastic Stress Testing Beyond baseline distributions, the framework implements stochastic stress testing to assess resilience under adverse structural conditions. The expected means (μ) of parameter distributions are shifted to their boundary limits (e.g., CAPEX +15% or degradation +30%). A full 10,000-iteration simulation is then executed around these shifted baselines to quantify the residual probability of default (negative NPV) even under sustained market or technical stress.

III.2 Regulatory Scenarios

The profitability is compared across nine regulatory scenarios (Table III.1). These are derived from the broader AgNes regulatory debate and various stakeholder positions. Following the BNetzA's January 2026 specification of a two-layer tariff architecture (Section II.3), the quantitatively modeled scenarios (S0–S3) are positioned as boundary cases that bracket the plausible regulatory design space rather than as point predictions of the final regime.

Scenarios 0 and 1 represent the current baseline and the post-exemption status quo, respectively. Scenario 2 reflects the industry preference for a static capacity charge [BDEW Bundesverband der Energie- und Wasserwirtschaft e.V., 2025]. The variable grid fee options (Scenarios 3–5) follow the proposals by the BNetzA [Bundesnetzagentur, 2025a]. Additional concepts include dynamic constraints (Scenario 6) based on Neon [Lohr et al., 2025], feed-in charges (Scenario 7) discussed by BDEW [BDEW Bundesverband der Energie- und Wasserwirtschaft e.V., 2025], and connection charges (Scenario 8) reflecting recent regulatory discussions on Baukostenzuschüsse [Bundesnetzagentur, 2026].

Table III.1: Overview of regulatory scenarios for post-2029 BESS grid charge analysis.

Nr.	Scenario-ID	Full Name	Source	Description
0	Base-Exempt	Baseline	§118 EnWG	Current grid fee exemption for utility-scale BESS.
1	No-Exempt	Full Grid Charges	Status Quo	Standard work price (ct/kWh) + capacity price (€/kW).
2	Static-Cap	Static Capacity Charge	BDEW	Fixed fee based on grid connection capacity (€/kW).
3	Spot-Flex	Spot Market-Orient.	BNetzA (A)	Grid charges correlated with spot market prices.
4	Grid-Flex	Grid-Driven Flexibility	BNetzA (B)	Variable charges based on grid congestion signals.
5	Contract-Flex	Contractual Service	BNetzA (C)	Discounted fees in exchange for dispatch rights.
6	Dyn-Constraint	Dynamic Constraint	Neon	Behavioral rule: no grid-loading during congestion.
7	Feed-In-Charge	Feed-In Charges	BDEW	Fees applied to both consumption and injection.
8	Connect-Fee	Connection Charge	BEE/BDEW	One-time upfront fee (€/kW) for grid connection.

Note: Scenarios 0–3 are quantitatively modeled; 4–8 are qualitatively assessed.

Detailed Scenario Mechanics

Scenario 0: Baseline (*Base-Exempt*) This scenario represents the current regulatory framework in Germany defined by § 118 (6) EnWG. Under this rule, energy storage facilities constructed before 2029 are exempt from grid charges for a period of 20 years.

- Mechanism: The BESS operates free of any grid usage fees (neither capacity nor energy charges apply).
- Implication: This serves as the reference case (benchmark) for current project valuations. The only variable costs are market-related (e.g., taxes, levies if applicable), allowing arbitrage strategies to respond solely to market price signals. The BNetzA's proposed netting mechanism ("Saldierung") for the financing function, which would charge only round-trip losses rather than the full arbitrage cycle [Bundesnetzagentur, 2026], bears some resemblance to

this baseline: for a system with 90% round-trip efficiency, approximately 10% of throughput would incur work-price charges — a materially different regime from S0 but considerably closer to it than to S1 or S2. The additional incentive function (dynamic, congestion-based) would further modify the effective cost, potentially in either direction.

Scenario 1: Post-2029 Default (*No-Exempt*) This scenario models the regulatory fallback resulting from the expiration of the current privilege without a specific replacement regulation. It assumes a reversion to the standard grid fee methodology for final consumers, serving as the pessimistic baseline for the analysis.

- Mechanism: The BESS is charged a standard two-part tariff consisting of a capacity price (CP , €/kW/a) based on the annual peak load and a volumetric work price (WP , ct/kWh) for every unit of energy drawn from the grid [StromNEV, 2024, § 17]. The tariff components are set at 140 EUR/kW/a (capacity price) and 0.5 ct/kWh (energy charge), reflecting representative medium-voltage grid charges in Germany.
- Implication: This imposes a double burden: a high fixed cost block and a significant marginal cost for each charging cycle, heavily penalizing arbitrage strategies that rely on frequent cycling.

Scenario 2: Static Capacity Charge (*Static-Cap*) Reflecting the industry's preference for planning security and cost recovery [BDEW Bundesverband der Energie- und Wasserwirtschaft e.V., 2025], this scenario eliminates the volumetric working price entirely.

- Mechanism: Grid usage costs are determined solely by the installed grid connection capacity (P_{conn}), charged as a fixed annual fee (€/kW/a). The capacity charge is set at 80 EUR/kW/a, reflecting the BDEW's proposed benchmark for the AgNes framework. This charge applies regardless of the actual energy throughput or the operational peak load utilized. In co-location cases (B1, B2), the capacity charge for S2 is applied to the BESS rated power (P_{max}) rather than the shared grid connection capacity (NVP). This reflects the BDEW position that the charge targets the storage asset's own connection capacity, not the jointly-used grid connection point shared with the co-located generation asset.
- Implication: For the BESS business case, this converts grid charges into a pure fixed cost block (CAPEX-like OPEX), completely independent of the operational behavior. This removes the marginal disincentive to cycle frequently but imposes a high barrier to entry for projects with low utilization rates. The BNetzA's financing function shares the capacity-based logic of

S2 but differs in two respects: the capacity threshold is operator-selected rather than fixed to installed power, and volumes exceeding it incur a higher work price (AP2) rather than being cost-free [Bundesnetzagentur, 2026]. S2 thus approximates the fixed-cost character of the financing function but omits its variable-cost component.

Scenario 3: Spot Market-Oriented Flexibility Incentive (*Spot-Flex*) This scenario operationalizes the spot-market-oriented flexibility option (Option A) from the BNetzA's May 2025 discussion paper [Bundesnetzagentur, 2025a]. The January 2026 orientation paper [Bundesnetzagentur, 2026] has since shifted the regulatory emphasis toward grid-congestion-based signals (closer to Option B / S4 in this thesis); the spot-price-based construction is retained here as a modelable proxy. The BNetzA's May 2025 paper specified qualitative design criteria — orientation toward average redispatch costs, sign-correctness, symmetry — but no mathematical transfer function. This thesis operationalizes these criteria as the simplest mathematical specification consistent with the stated design principles. The construction follows from three requirements: (1) the effective price must retain the spot price as its basis, preserving the market price signal; (2) the incentive component must be sign-correct, i.e., reward counter-cyclical behavior by scaling with the deviation of the spot price from its annual mean; and (3) the incentive intensity must be adjustable via a single parameter. The resulting specification, $p_t^{eff} = p_t^{spot} + \alpha \cdot (p_t^{spot} - \bar{p}^{spot})$, is a linear form satisfying all three conditions.

- Mechanism: The effective price signal is defined as $p_t^{eff} = p_t^{spot} + \alpha \cdot (p_t^{spot} - \bar{p}^{spot})$, where \bar{p}^{spot} is the annual mean and $\alpha \geq 0$ scales the incentive magnitude. The spot price serves as proxy for unavailable congestion signals. For the baseline analysis, $\alpha = 0.3$ is applied; sensitivity runs use $\alpha = 0.1$ (conservative) and $\alpha = 1.0$ (upper bound). The spot price serves here as a proxy for local congestion signals, which the BNetzA's incentive function would derive from actual grid conditions rather than wholesale markets [Bundesnetzagentur, 2026]. The two approaches converge when market prices and grid congestion are correlated but diverge in hours where local network conditions deviate from the system-wide price signal — a non-trivial frequency in Germany's single-bidding-zone market, where persistent north-south congestion regularly decouples local grid conditions from uniform spot prices.
- Implication: For $\alpha > -1$, this positive affine transformation preserves the rank ordering of prices. Under perfect foresight, S3 dispatch is identical to S0; only revenue valuation differs. S3 is therefore computed as a post-hoc revaluation (see Section III.3 for formal proof). Under

perfect foresight, the incentive mechanism affects revenue valuation only, not operational behavior. Behavioral effects would only materialize under imperfect foresight (real-time trading). Linear specification only. Non-monotonic mechanisms (e.g., congestion step tariffs) would require separate optimization.

Scenario 4: Grid-Driven Flexibility (*Grid-Flex*) This scenario corresponds to “Option B” of the BNetzA proposal. Instead of following market prices, the grid usage charge becomes variable based on grid load forecasts provided by the DSO.

- Mechanism: The DSO defines time windows (e.g., red/yellow/green) with varying grid charges to signal local scarcity.
- Implication: This option is qualitatively assessed due to the lack of standardized, publicly available local congestion data required for quantitative modeling. The January 2026 orientation paper [Bundesnetzagentur, 2026] positions congestion-based dynamic pricing as the primary incentive mechanism for storage, making S4 the closest qualitative match to the BNetzA’s current regulatory trajectory.

Scenario 5: Contractual Grid Service (*Contract-Flex*) Reflecting “Option C” (BNetzA), this model relies on individual contracts.

- Mechanism: The BESS operator receives a discount on grid charges in exchange for granting the DSO specific dispatch rights (e.g., peak shaving capability upon request).
- Implication: Excluded from quantitative modeling as terms are bilateral and highly project-specific.

Scenario 6: Dynamic Grid Constraint (*Dyn-Constraint*) Based on proposals by Neon [Lohr et al., 2025], this approach replaces monetary incentives with operational boundaries.

- Mechanism: A behavioral rule prohibits grid-loading during specific congestion hours announced day-ahead (“dynamic constraint window”). Outside these windows, operation is unrestricted.
- Implication: Qualitatively compared as an alternative to price-based steering, focusing on the trade-off between grid security and market freedom.

Scenario 7: Feed-In Charges (*Feed-In-Charge*) A counter-proposal discussed by the industry to widen the cost base. The BNetzA explicitly rejects dual-sided financing charges for storage, stating

that storage operators should not pay financing-function charges on both withdrawal and injection [Bundesnetzagentur, 2026].

- Mechanism: Grid charges are levied not only on withdrawal (charging) but also on injection (discharging).
- Implication: This effectively adds a second marginal cost component per full cycle, creating a significant barrier for arbitrage business models.

Scenario 8: Connection Charge (*Connect-Fee*) Discussed by BEE and BDEW as a means to lower running costs.

- Mechanism: A one-time upfront contribution (€/kW) to grid construction costs replaces or reduces recurring running grid charges.
- Implication: This shifts costs from OPEX to CAPEX, potentially lowering the threshold for profitable operation once the investment is made.

III.3 Optimization Model

An LP optimization model is developed to determine the profit-maximizing charge/discharge strategy for a benchmark BESS under varying grid charge regimes. The model maximizes arbitrage revenues by optimizing operational decisions based on the synthetic price scenarios (Section III.1.3), while explicitly accounting for scenario-specific grid fee structures (capacity charges, energy charges, or dynamic tariffs) and cycle-dependent battery degradation costs.

Choice of Optimization Method

LP is selected for two reasons:

1. *Computational Efficiency*: The study includes a risk analysis via Monte Carlo simulation with thousands of iterative model runs. LP offers superior computational speed compared to mixed-integer or dynamic programming, ensuring the feasibility of the risk assessment [Bradbury et al., 2014].
2. *Model Suitability*: Utility-scale batteries operate as price-takers without significant start-up costs or discrete operational states. This allows the dispatch problem to be formulated as a convex linear problem, as established by Sioshansi et al. for arbitrage applications [Sioshansi et al., 2009].

This study employs a global 20-year optimization horizon, constituting the methodologically correct Theoretical Revenue Ceiling (TRC) — the primary quantitative benchmark of this thesis. The optimization framework additionally distinguishes Operational Revenue Ceiling (ORC, rolling 48-hour horizon) and Operational Baseline Ceiling (OBC, qualitative reference) as conceptual benchmarks; both are not computationally implemented due to scope and resource constraints. A rolling 14-day horizon was considered as a computationally lighter TRC alternative but equally excluded on these grounds.

Model Assumptions and Limitations. The model relies on the following abstractions from continuous trading reality:

1. *Price Index vs. Order Book Reality:* The model utilizes the Volume-Weighted Average Price (VWAP) index. This abstracts from the complexity of the continuous intraday market, specifically bid-ask spreads and limit order execution risk. By using VWAP, the model implicitly assumes guaranteed settlement at the average price, ignoring scenarios where specific limit orders (e.g., an offer to sell at 85 €/MWh) would remain unfilled because the market price peaked just below the target (e.g., at 84 €/MWh).
2. *Perfect Foresight (Global Optimum):* The optimization assumes full knowledge of future prices (“oracle” approach). While this abstracts from real-time trading uncertainty, it follows the established methodological standard for evaluating upper-bound economic potentials [Hornek et al., 2025]. Unlike Hornek et al. [2025], who apply perfect foresight within a rolling 8-hour window, this study computes the global optimum over the full projection horizon. This provides a stricter upper bound as it allows for long-term SoC positioning over multiple days or weeks.
3. *Operational Constraints:* While degradation costs are monetized to prevent excessive cycling, technical constraints like precise SoC drift or complex temperature dependencies are simplified.

Justification of the Approach Despite the abstraction from intraday uncertainty, the deterministic optimization offers distinct analytical value:

1. *Feasibility Ceiling (Necessary Condition):* The calculated revenue represents the theoretical economic maximum. If a business case proves unviable (negative NPV) even under these ideal “perfect foresight” conditions, it can be definitively ruled out for real-world implementation.

-
2. *Operational Benchmark*: The optimization results quantify the asset’s Revenue Potential (100% baseline). This aligns with the quality hierarchy for BESS-Benchmarks [Karimi and Swisher, 2026], which prioritizes a transparent, perfect-foresight baseline as the necessary starting point for quantifying the Revenue Capture Rate (RCR) in commercial assessments.
 3. *Isolation of Regulatory Impact*: By eliminating stochastic trading errors, the model isolates the financial impact of the regulatory regimes. Differences in NPV across scenarios (e.g., Spot-Flex vs. Static-Cap) can be attributed exclusively to the grid charge logic, rather than random forecast deviations.

Conservative Assumption: S1 Charging Base (Case B)

For Scenario 1 (*No-Exempt*) in Cases B1 and B2, all charging volume is treated as grid-sourced for the purpose of grid fee calculation, regardless of the actual share attributable to direct RE generation behind the metering point. Under real operating conditions, only the grid-sourced charging fraction ($ch_{grid}[t] = charge[t] - ch_{re}[t]$) would be subject to grid charges per StromNEV; RE direct-charging behind the Netzverknüpfungspunkt (NVP) does not constitute a “Bezug” in the regulatory sense.

An exact separation would require $ch_{re}[t] = \min(charge[t], RE_{gen}[t])$ — a non-linear expression infeasible in LP formulation. This conservative simplification slightly overstates S1 grid charge costs for Case B and is documented as a known modeling boundary.

For Case B2, the HiGHS solver returned a *warning* status for a subset of scenarios due to numerical conditioning at the constraint matrix scale (~2.8 million rows). Solutions with *warning* status were retained after plausibility verification, as HiGHS reports *warning* when feasibility tolerances are met but numerical precision is near solver thresholds. Scenarios without accessible solution vectors were excluded and reported separately.

Exclusion of Redispatch Measures: Furthermore, revenues from redispatch measures (Redispatch 2.0) are excluded from the model for two reasons. First, under the current German regulatory framework, redispatch interventions are compensated based on the ‘lost opportunity cost’ principle (Planwertmodell), rendering them theoretically revenue-neutral compared to the market scenario. Second, redispatch probability is highly site-specific and dependent on local grid topology data, which is not publicly available for a generalized benchmark analysis. Modeling it without specific nodal data would introduce speculative bias.

Dispatch Invariance of Linear Incentive Tariffs (Scenario 3) The Spot-Flex scenario (Section III.2) defines the effective price as $p_t^{eff} = p_t^{spot} + \alpha \cdot (p_t^{spot} - \bar{p}^{spot})$, which can be rewritten as $p_t^{eff} = (1 + \alpha) \cdot p_t^{spot} - \alpha \cdot \bar{p}^{spot}$, where $\alpha \geq 0$ and \bar{p}^{spot} is the annual mean. Since \bar{p}^{spot} is a scenario-specific constant, the objective function under S3 becomes:

$$\begin{aligned} \max \sum_t p_t^{eff} \cdot x_t &= \max \sum_t [(1 + \alpha) \cdot p_t^{spot} - \alpha \cdot \bar{p}^{spot}] \cdot x_t \\ &= (1 + \alpha) \cdot \max \sum_t p_t^{spot} \cdot x_t - \alpha \cdot \bar{p}^{spot} \cdot \sum_t x_t \end{aligned}$$

This property follows directly from the linearity of the arbitrage objective. For $\alpha > -1$, the first term is a positive scalar multiple of the S0 objective. The second term depends on the net energy balance $\sum_t x_t = SoC_0 - SoC_T$, which is bounded by the storage capacity E_0 since both terminal states lie in $[0, E_0]$. The term is therefore bounded by $|\alpha \cdot \bar{p}^{spot} \cdot E_0|$, which is negligible relative to total 20-year revenue.³ The optimal dispatch x_t^* (the solution to $\max \sum_t p_t^{spot} \cdot x_t$) is therefore identical under S0 and S3. Consequently, S3 revenues are computed as a post-hoc revaluation of the S0 dispatch solution.

III.4 Benchmark BESS Configuration

To ensure the practical relevance of the analysis, the model is parameterized using real-world project data provided by two industry partners developing utility-scale BESS projects in Germany. To ensure confidentiality, the data providers are anonymized as “Partner A” and “Partner B”. The study distinguishes between two fundamental configurations: a stand-alone commercial storage system (Case A) and utility-scale co-location projects (Case B).

Project Characteristics

Case A (Stand-Alone): Represents a typical commercial BESS located in an industrial zone in Southern Germany (Partner A). It is connected to the medium-voltage grid (20 kV) and operates without local generation constraints. The system has a power-to-energy ratio of roughly 0.4 (approx. 2.3-hour duration), targeting intraday arbitrage and peak shaving.

Case B (Co-Location): Represents utility-scale hybrid projects developed by Partner B.

3. For utility-scale configurations, this term remains below 0.1% of total project revenue over the 20-year horizon.

- *Case B1 (PV-Dominant)*: A large-scale 30 MW BESS co-located with a 70 MWp photovoltaic (PV) park in Brandenburg. The critical constraint is the grid connection point (NVP) of 54 MW, which is lower than the installed generation capacity, necessitating “clipping” or time-shifted feed-in.
- *Case B2 (Wind/PV Hybrid)*: A smaller 12 MW BESS in Northern Bavaria co-located with both Wind (13.9 MW) and PV (11.8 MW). Here, the grid connection is severely constrained (14 MW), allowing only ~54% of the installed generation capacity to pass through at peak times. For co-located configurations where RE generation can exceed the NVP limit (Case B2: RE peak 20.3 MW vs. NVP 14.0 MW), a curtailment variable $c_t \geq 0$ was introduced to ensure model feasibility:

$$r_t^{\text{net}} \geq RE_t - p_t^{\text{ch}} - c_t$$

Curtailment carries no cost in the objective function, as it represents modeled curtailment at the grid connection point (NVP) — endogenously determined when combined RE generation and BESS discharge exceed the NVP capacity limit — and does not affect BESS arbitrage revenue. The physical curtailment potential and its economic effect through coupling topology are quantified in Section IV.2.

Table III.2 summarizes the technical specifications used for the simulation.

Table III.2: Technical specifications of the benchmark BESS projects.

Parameter	Case A (Partner A)	Case B1 (Partner B)	Case B2 (Partner B)
Configuration	Stand-alone	Co-Location (PV)	Hybrid (PV + Wind)
Grid Level	Medium Voltage (20 kV)	High Voltage (110 kV)	Medium Voltage (20 kV)
Installed Power	3 MW	30 MW	12 MW
Capacity	7 MWh	60 MWh	24 MWh
Duration	~ 2.33 h	2.0 h	2.0 h
Grid Limit (NVP)	3 MW (Unrestricted)	54 MW	14 MW
Round-Trip Eff.	90%	90%	90%

Note: The 90% round-trip efficiency (RTE) represents a moderate estimate between battery-only efficiency (~97%, Partner A) and conservative system-level AC-to-AC performance (~85%), accounting for inverter losses without penalizing for extreme balance-of-plant inefficiencies.

Economic Parameters (CAPEX & OPEX) The economic viability analysis relies on current cost estimates for 2025 commissioning provided by the partners.

- Case A (Small Scale): Based on detailed quotation data from Partner A, the specific CAPEX is estimated at 357 €/kWh (Total: 2.5 M€). This includes the battery blocks, inverter, transformer, and grid connection costs. Fixed OPEX are calculated at approx. 3.9% of CAPEX per annum, covering maintenance, insurance, and land lease.
- Case B (Utility Scale): Due to significant economies of scale and shared infrastructure (grid connection already present for PV/Wind), Partner B estimates a lower CAPEX of 250 €/kWh. OPEX is estimated at 2.5% of CAPEX per annum.

Table III.3 summarizes the economic boundary conditions and financial assumptions used for the profitability simulation.

Table III.3: Economic parameters and financial assumptions for the benchmark BESS projects.

Parameter	Case A (Partner A)	Case B1 (Partner B)	Case B2 (Partner B)
Specific CAPEX	357 €/kWh	250 €/kWh	250 €/kWh
Total CAPEX	2.5 M€	15.0 M€	6.0 M€
Fixed OPEX	3.9% of CAPEX/yr	2.5% of CAPEX/yr	2.5% of CAPEX/yr
Discount Rate (WACC)	6.0% (real, post-tax)	6.0% (real, post-tax)	6.0% (real, post-tax)
Corporate Tax Rate	30.0%	30.0%	30.0%
Depreciation	20 years (linear)	20 years (linear)	20 years (linear)
Terminal Value	Zero	Zero	Zero

For the simulation of Case B, historical 15-minute generation profiles were simulated using satellite-based weather data (via Renewables.ninja) calibrated to the specific site coordinates and installed capacities.

Depreciation: CAPEX is depreciated linearly over the full 20-year project lifetime. This approach aligns the depreciation schedule with the technical operational period, consistent with IAS 16 guidance on the useful economic life of energy storage assets [International Accounting Standards Board, 2024]. While specific national tax tables (e.g., German AfA) might allow for shorter depreciation periods (10–12 years), this thesis adopts a conservative baseline to ensure the IRR reflects long-term asset value rather than short-term tax optimization strategies.

End-of-Life Treatment: The terminal value at the end of the 20-year project lifetime is conservatively set to zero. This “Net-Zero” assumption follows the precautionary principle, as current market analyses indicate that costs for decommissioning, electrical isolation, and logistics (“gate fees”) are likely to offset or even exceed the material recovery revenues [Sinovoltaics, 2025, Ramasamy et al., 2025]. Consequently, no positive salvage value is included in the cash flow analysis.

Financial Assumptions & Discounting: To determine the project’s NPV, the following financial boundary conditions are applied, consistent with the simulation parameters:

- *Real Terms Analysis:* The economic analysis is performed in real terms (€2025). General inflation is set to 0.0% for both revenue and operational expenditure projections. This approach maintains model simplicity and ensures that the IRR reflects the project’s intrinsic economic performance rather than monetary inflation effects.
- *Discount Rate:* A baseline WACC of 6.0% (real, post-tax) is applied, reflecting typical returns for RE infrastructure projects [International Renewable Energy Agency, 2023]. To account for market volatility and financing structure variations, this parameter is treated stochastically in the sensitivity analysis (Range: 4.0% – 8.0%).
- *Taxation:* A corporate tax rate of 30.0% is applied to taxable income, representing a standard combined trade and corporate tax burden.
- *Liquidity:* Working capital requirements are excluded from the model, assuming sufficient liquidity is provided through standard project finance structures.

III.5 Stochastic Parameters

Given the long investment horizon of 20 years and the volatility of the energy market, deterministic assumptions are insufficient for a robust valuation. To quantify the risk profile, this study transitions from static sensitivity analysis to a stochastic Monte Carlo simulation. While market-side uncertainty is inherently captured through the synthetic price scenarios generated via block-bootstrapping (Section III.1.3), this section defines the probability distributions for the remaining three critical technical and financial risk drivers identified in the case studies.

III.5.1 Battery Health & Degradation Risk

Battery degradation — the progressive, irreversible loss of usable energy capacity over time — directly reduces the revenue-generating capability of the BESS over its 20-year project horizon.

Rather than assuming a fixed annual fade rate, this study models degradation stochastically to capture the uncertainty inherent in real-world cell aging.

Degradation Model: The annual capacity fade rate d is drawn from a truncated normal distribution:

$$d \sim \mathcal{N}(\mu = 2\%, \sigma = 0.5\%), \quad d \in [0.5\%, 4.0\%]$$

The effective energy capacity available in year y is then:

$$E_{\text{eff},y} = E_0 \cdot (1 - d)^y$$

where E_0 denotes the nameplate capacity (MWh) at commissioning.

Parameter Justification:

- *Mean fade rate* ($\mu = 2\%/year$): This reflects published warranty-backed specifications for lithium iron phosphate (LFP) cells in utility-scale stationary storage applications, where manufacturers typically guarantee $\geq 60\%$ residual capacity after 20 years — implying an average annual fade of approximately 2.5% or less. The selected mean of 2% is moderately conservative.
- *Standard deviation* ($\sigma = 0.5\%$): Captures unit-to-unit variability within a single installation due to manufacturing tolerances and thermal gradients across container modules, without introducing extreme outlier scenarios.
- *Truncation bounds* ($[0.5\%, 4.0\%]$): The lower bound prevents implausibly low degradation (near-zero fade is inconsistent with electrochemical aging); the upper bound excludes catastrophic failure scenarios that would trigger warranty replacement in practice.

Integration with Monte Carlo Framework: In each of the 10,000 simulation iterations, one fade rate d_i is drawn and applied as a compound annual multiplier to the revenue stream over the full 20-year horizon. This captures the scenario where an investor receives a BESS installation with better or worse degradation characteristics than the population mean — a risk that is resolved at commissioning and persists for the project lifetime.

Note on Bimodal Degradation Hypotheses: During the research process, a bimodal Gaussian Mixture Model (GMM) was explored to account for the possibility of correlated batch defects —

where a subset of production batches exhibits significantly elevated capacity fade. This specification was ultimately excluded from the main analysis due to the absence of verifiable empirical data for calibration. The exploratory GMM analysis, including its motivation, parameterization, and reasons for exclusion, is documented in Appendix D.

III.5.2 Investment Metrics: CAPEX & WACC Uncertainty

Initial CAPEX Uncertainty: To isolate operational risks from construction timing complexities, this study employs the “Overnight Cost” method. The Initial CAPEX is modeled as a stochastic variable following a Log-Normal Distribution to reflect the risk of cost overruns:

$$\text{CAPEX}_0 \sim \text{LogNormal}(\mu_{\text{case}}, \sigma_{\text{cost}})$$

- *Mean* (μ_{case}): Defined by the specific case study parameters in Section III.4 (Case A: 357 €/kWh; Case B: 250 €/kWh).
- *Volatility* (σ_{cost}): Set to 10%, reflecting typical EPC contingency buffers.

Discount Rate (WACC): To assess the project’s economic viability independent of specific financing structures (e.g., debt-to-equity ratios) and resulting tax shields, the analysis utilizes a single WACC without explicit capital structure modeling. It is modeled as normally distributed around the utility-scale storage benchmark [Lazard, 2024]:

$$\text{WACC} \sim \mathcal{N}(\mu = 6\%, \sigma = 1\%)$$

Justification: A moderate volatility ($\sigma = 1\%$) captures variations in financing conditions (interest rate risk, equity premium fluctuations) without requiring explicit capital structure modeling.⁴

III.6 Financial Metrics

III.6.1 Discounted Cash Flow (NPV, IRR)

Net Present Value (NPV)

4. While the normal distribution theoretically permits negative values for the WACC, the probability of a draw below 0% under the $\mathcal{N}(\mu = 6\%, \sigma = 1\%)$ specification is statistically negligible ($P < 10^{-8}$). Utilizing a truncated or log-normal specification would not have materially altered the simulation outcomes.

The LP optimizer returns total arbitrage revenue aggregated over the full 20-year horizon per scenario (R_{20y}), with capacity degradation at a fixed rate $\delta_0 = 2\%$ applied endogenously via time-varying SoC limits. To derive the Year-1 equivalent revenue for the discounted cash flow (DCF) model, we invert the degradation summation, effectively removing the deterministic degradation assumption from the aggregated revenue to yield a degradation-free Year-1 baseline:

$$R_{y1} = \frac{R_{20y}}{\sum_{t=1}^{20} (1 - \delta_0)^{t-1}}$$

The DCF layer then reconstructs the annual profile using the stochastic degradation rate δ_i drawn per Monte Carlo iteration:

$$R_t = R_{y1} \cdot (1 - \delta_i)^{t-1}, \quad t = 1, \dots, 20$$

This introduces a minor inconsistency between the deterministic annualization ($\delta_0 = 2\%$) and the stochastic DCF projection (δ_i). This simplification was justified by computational constraints in the optimization layer and is acceptable given the study's focus on comparative scenario ranking rather than absolute cash flow precision.

Internal Rate of Return (IRR)

The IRR is derived endogenously from the same DCF stream used for NPV calculation. It represents the discount rate at which the NPV of the project would equal zero, offering a rate-of-return perspective complementary to the absolute value metric (NPV). While NPV isolates the impact of regulatory scenarios under a fixed WACC assumption (6%), IRR provides a scenario-agnostic benchmark for comparing project attractiveness across different financing structures. Both metrics are computed jointly for each Monte Carlo iteration using the reconstructed annual cashflow series $\{CF_0, CF_1, \dots, CF_{20}\}$.

III.6.2 Risk Metrics (Revenue-at-Risk)

To quantify downside risk beyond scenario means, the RaR at 95% confidence ($RaR_{0.95}$) is computed across the Monte Carlo distribution. This metric captures the potential loss relative to the expected mean in adverse realizations, providing a tail-risk measure analogous to Value-at-Risk in financial modeling:

$$RaR_{0.95} = \mathbb{E}[NPV] - q_{0.05}(NPV)$$

where $\mathbb{E}[NPV]$ is the expected NPV and $q_{0.05}$ denotes the 5th percentile of the simulated distribution.

III.7 Model Validation

To ensure the robustness of the optimization results, a deterministic shadow model was developed in Microsoft Excel. This tool serves a dual purpose in the methodological framework:

1. *Algorithmic Validation:* The spreadsheet functions as an independent “shadow calculation” engine. By importing sample dispatch schedules generated by the Python algorithm and recalculating the resulting revenues and specific grid charges line-by-line, the model validates the logical consistency of the optimization code, ruling out syntax errors or incorrect fee applications.
2. *Sensitivity Dashboard:* The model provides an auditable interface to verify base case assumptions. It serves to establish a deterministic financial “backbone,” ensuring that the transition from EBITDA to Free Cash Flow—including tax shields and depreciation—is mathematically sound. Furthermore, it allows for targeted sensitivity checks (e.g., WACC, CAPEX) to validate the model’s response before scaling into the stochastic Python framework.

IV. Results and Discussion

This chapter presents the quantitative results of the Monte Carlo simulation framework developed in Chapter III and interprets their implications for the post-2029 regulatory landscape. The analysis is structured in four parts. Section IV.1 evaluates the impact of the four quantitatively modeled regulatory scenarios (S0–S3) on BESS profitability across all three project configurations (Cases A, B1, B2), using NPV, IRR, and the probability of positive NPV as primary metrics. Section IV.2 isolates the financial effect of co-location coupling topology in Cases B1 and B2, comparing direct charging configurations against shared grid connection point (NVP) topologies. Section IV.3 subjects S0 (Baseline Exemption) and S3 (Spot-Market Flexibility) — the two scenarios yielding positive baseline NPV — to deterministic sensitivity analysis and stochastic stress testing to assess the robustness of investment outcomes under adverse parameter shifts. Finally, Section IV.4 discusses the regulatory implications of the quantitative findings, provides a qualitative assessment of the remaining scenarios (S4–S8) not captured by the model, and contextualizes the German debate through a brief comparison with the UK and Netherlands frameworks.

All quantitative results reported in this chapter are derived under the TRC assumption, i.e., a global 20-year perfect foresight optimization as defined in Section III.3. Realized revenues under real-world trading conditions will correspond to TRC revenues scaled by the operator's RCR (< 1). This distinction is critical for interpreting absolute NPV levels; however, since the RCR applies uniformly across all scenarios by assumption, the relative ranking of regulatory scenarios remains unaffected.

IV.1 Impact on Profitability Metrics

Under the current exemption regime (S0), the Monte Carlo simulation reveals a clear scale dependency in BESS profitability. The regulatory transition scenarios produce a stark bifurcation: the post-exemption fallback regimes (S1, S2) eliminate viability entirely, while the spot-market flexibil-

ity incentive (S3) restores and substantially improves the investment case. Table IV.1 provides an overview of the key metrics across all scenarios and project configurations.

Table IV.1: Summary of profitability metrics by scenario and project configuration (median values).

Scenario	Metric	Case A (3 MW/7 MWh)	Case B1 (30 MW/60 MWh)	Case B2 (12 MW/24 MWh)
S0: Baseline	NPV (M EUR)	0.35	12.91	3.33
	IRR (%)	7.8	16.1	12.8
	P(NPV > 0)	82.7%	100.0%	100.0%
S1: Full Grid	NPV (M EUR)	−3.31	−21.49	−11.25
	IRR (%)	n/a (no positive cash flow in any year)		
	P(NPV > 0)	0.0%	0.0%	0.0%
S2: Cap-Charge	NPV (M EUR)	−1.80	−6.97	−5.21
	IRR (%)	−8.1	−2.5	−9.1
	P(NPV > 0)	0.0%	0.0%	0.0%
S3: Spot-Flex	NPV (M EUR)	1.63	24.21	7.21
	IRR (%)	13.7	23.6	19.4
	P(NPV > 0)	100.0%	100.0%	100.0%

Scenario 0: Baseline

Case A, the standalone 3 MW/7 MWh system, achieves a median NPV of 0.35 M EUR with a probability of positive NPV of 82.7% (Table IV.1, Figure IV.2). While the median IRR of 7.8% exceeds the 6% WACC threshold, the distribution exhibits substantial downside exposure: the 5th percentile NPV falls to −0.26 M EUR. With $P(NPV > 0) = 82.7\%$, roughly one in six market realizations would result in a loss even under full grid charge exemption (Figure IV.3, Case A panel).

The co-located configurations demonstrate significantly stronger economics. Case B1 (30 MW/60 MWh, PV co-location) achieves a median NPV of 12.91 M EUR with $P(NPV > 0) = 100.0\%$ and a median IRR of 16.1%. Case B2 (12 MW/24 MWh, wind/PV hybrid) reaches a median NPV of 3.33 M EUR with $P(NPV > 0) = 100.0\%$ and a median IRR of 12.8%. This superior performance is driven primarily by the lower specific CAPEX of 250 EUR/kWh for Cases B compared to 357 EUR/kWh for Case A (Table III.3), reflecting economies of scale in utility-scale co-located projects. While the absolute NPV distributions of Cases B1 and B2 are wider due to their larger capacity, they exhibit lower relative dispersion compared to Case A (Figure IV.3). This is consistent with the lower

ratio of fixed costs to gross revenue in utility-scale configurations, though the reduced sample size (1,000 vs. 10,000 iterations) warrants caution in direct distributional comparisons.

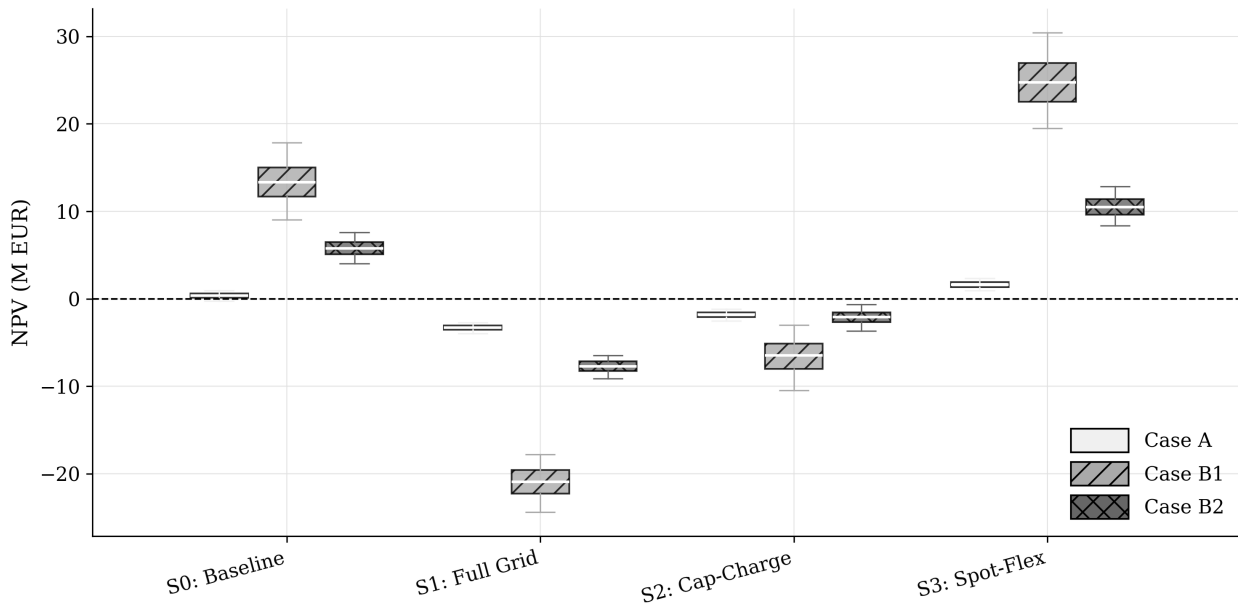


Figure IV.1: NPV boxplots by scenario and project configuration (P5/P95 whiskers).

Post-Exemption Fallback (S1, S2) Under Scenario S1 (Full Grid Charges), which models the post-exemption default of standard capacity and energy charges per StromNEV, the business case collapses entirely across all project configurations (Table IV.1). Case A reaches a median NPV of -3.31 M EUR, while Cases B1 and B2 fall to -21.49 M EUR and -11.25 M EUR, respectively. The probability of positive NPV is 0.0% for all three cases, with no single Monte Carlo iteration producing a profitable outcome. The IRR is undefined for all cases under S1, as no positive cash flow occurs throughout the project lifetime. This result is unambiguous: if the current exemption expires without a replacement mechanism, utility-scale BESS arbitrage becomes economically unviable under the standard grid charge regime. For Cases B1 and B2, the S1 grid charge burden is conservatively overstated due to the modeling simplification of treating all charging volume as grid-sourced (Section III.3); the actual outcome would be marginally less negative but remains deeply unprofitable.

Scenario S2 (Static Capacity Charge) imposes a fixed annual fee based on grid connection capacity, independent of energy throughput. While less destructive than S1, the outcome remains uniformly negative: $P(\text{NPV} > 0) = 0.0\%$ across all cases. An important structural observation is that S2 generates identical arbitrage revenue to S0, since the capacity charge does not depend on

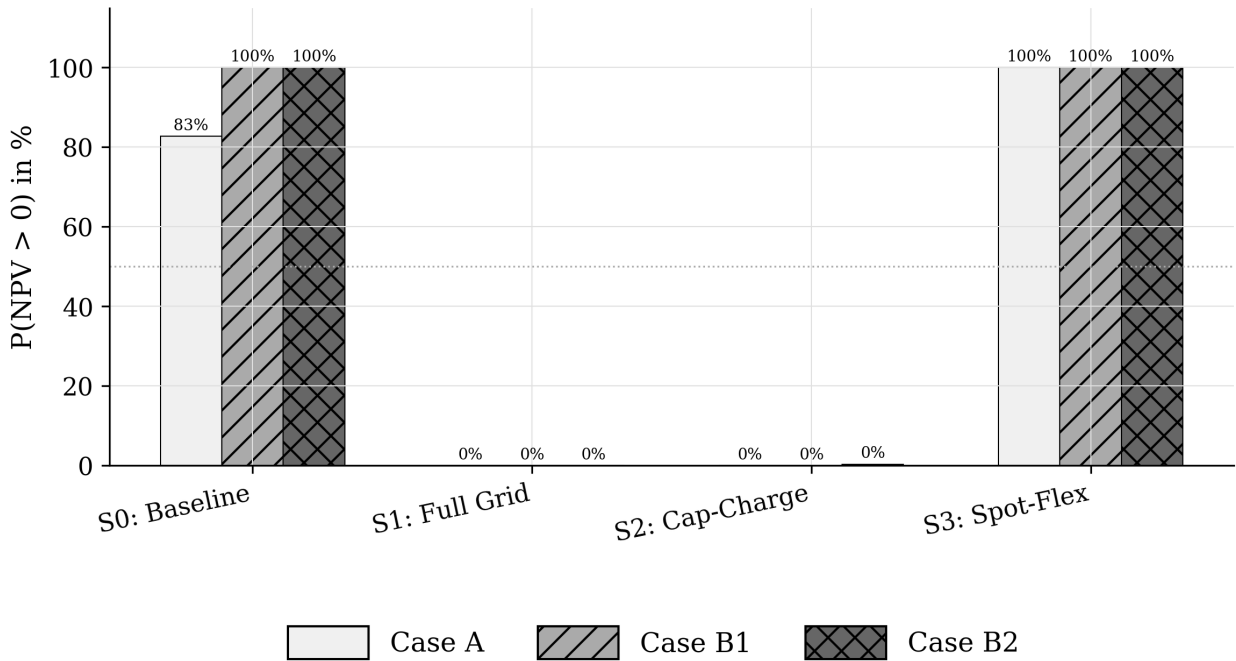


Figure IV.2: Probability of positive NPV by scenario and project configuration.

dispatch behavior. The NPV difference between S0 and S2 therefore reflects purely the annual fixed grid charge burden and resulting tax effects, not a change in operational strategy. For co-located projects, this fixed cost component scales with the NVP capacity and disproportionately penalizes projects with large grid connections relative to their storage capacity. However, if future regulation allows operators to nominate a contractual capacity below the physical NVP — as proposed in recent BNetzA orientation papers [Bundesnetzagentur, 2026] — this penalty could be substantially mitigated.

Spot-Market Flexibility (S3)

Scenario S3 represents the BNetzA’s proposed dynamic incentive tariff, operationalized as an affine price transformation with scaling parameter α (Section III.2). Under this regime, the effective price signal amplifies deviations from the annual mean spot price, rewarding counter-cyclical storage behavior. As demonstrated formally in Section III.3, this linear transformation preserves the rank ordering of prices under perfect foresight, rendering the optimal dispatch schedule identical to S0. The NPV difference between S0 and S3 is therefore purely valuational — reflecting the additional revenue from the α -scaled incentive component — with no change in physical battery operation.

S3 achieves $P(\text{NPV} > 0) = 100.0\%$ across all three project configurations (Table IV.1). Case A reaches a median NPV of 1.63 M EUR (median IRR: 13.7%), Case B1 attains 24.21 M EUR (median IRR: 23.6%), and Case B2 achieves 7.21 M EUR (median IRR: 19.4%). Even at the 5th percentile, all cases remain well above breakeven (Case A: 0.94 M EUR; B1: 19.06 M EUR; B2: 5.38 M EUR).

Cross-Scenario Comparison

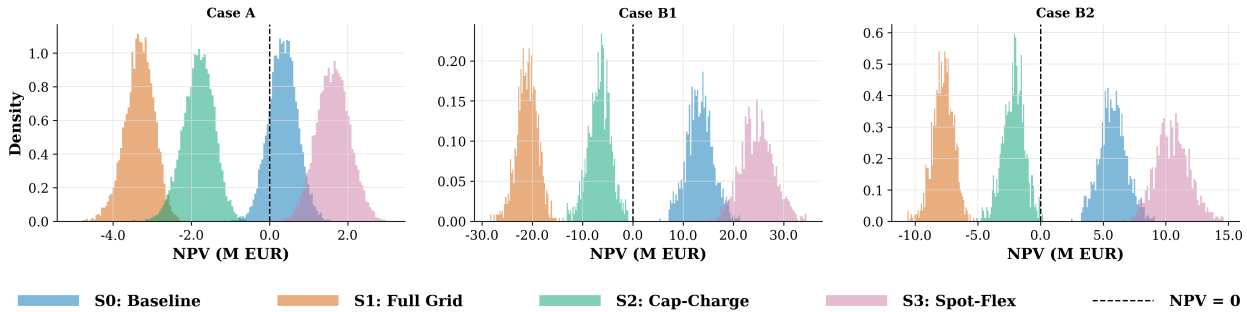


Figure IV.3: NPV distributions by scenario (S0–S3) and project configuration.

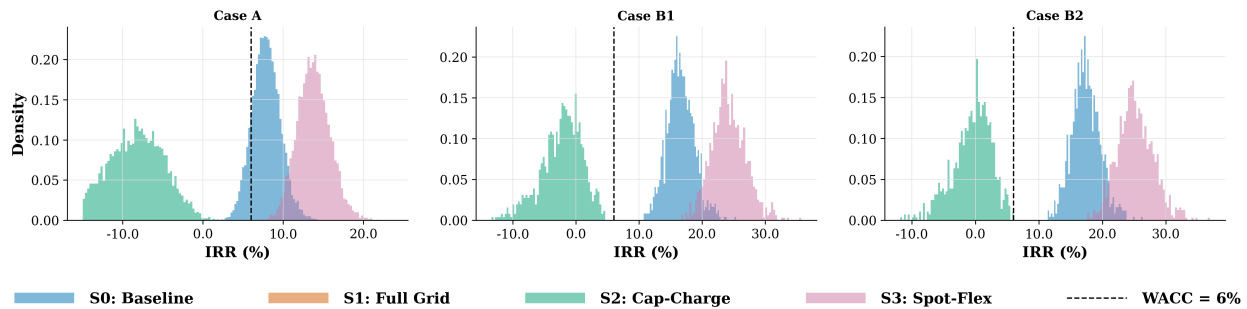


Figure IV.4: IRR distributions by scenario (S0–S3) and project configuration.

The NPV distributions (Figure IV.3) illustrate the bifurcation across scenarios. Under S0, the distributions for Cases B1 and B2 are concentrated in positive territory, while Case A straddles the breakeven line. Under S1 and S2, all distributions shift decisively into negative territory with no overlap with zero. Under S3, all distributions move well above breakeven.

The IRR distributions (Figure IV.4) confirm this pattern. Under S0, the IRR distributions for Cases B1 and B2 sit comfortably above the WACC = 6% threshold (median 16.1% and 12.8%, respectively), while Case A exhibits substantial probability mass closer to or below it (median 7.8%). Under S3, the entire distribution shifts decisively higher for all configurations, with median IRRs ranging from 13.7% (Case A) to 23.6% (Case B1). While co-located projects (B1, B2) outperform Case

A in absolute NPV terms due to lower specific CAPEX, the relative improvement from S0 to S3 is proportionally largest for Case A — where the baseline profitability is most marginal.

That S3 exceeds S0 in all metrics despite identical dispatch reflects the nature of the spot-market flexibility mechanism: the α -scaled incentive amplifies the effective price spread without imposing charges, generating additional revenue per cycle at no operational cost.

In summary, the scenario comparison reveals a three-tier outcome structure. The current exemption (S0) provides marginal-to-robust profitability depending on project scale, with standalone systems exhibiting meaningful downside risk. The post-exemption fallback scenarios (S1, S2) eliminate economic viability entirely — a finding that holds across all 10,000 (Case A) and 1,000 (Cases B1/B2) Monte Carlo iterations without exception. Only the spot-market flexibility incentive (S3) restores and substantially improves the investment case, achieving full bankability across all configurations. These results provide a direct quantitative answer to Sub-Question 1: the choice of post-2029 grid charge regime is not a matter of marginal adjustment but a binary determinant of BESS investment viability.

IV.2 Impact of Co-Location Coupling Topology

Beyond the regulatory scenario analysis, the simulation results reveal a significant financial dependency on the physical coupling topology in co-located projects. This section compares two configurations for Cases B1 and B2: a direct charging topology, where the BESS can absorb renewable generation behind the meter without routing through the grid connection point (NVP) limit, and a shared NVP topology, where all energy flows — including BESS charging from co-located RE — are constrained by the NVP capacity.

Table IV.2 summarizes the revenue and NPV differentials between both topologies across all scenarios; Figures IV.5 and IV.6 visualize the corresponding distributions.

Table IV.2: Financial impact of coupling topology: direct charging vs. shared NVP (median values).

Scenario	Δ Revenue (kEUR, 20 yr)		Δ NPV (MEUR)	
	Case B1	Case B2	Case B1	Case B2
S0: Baseline	934	5 821	0.39	2.44
S1: Full Grid	601	4 955	0.54	3.54
S2: Cap-Charge	934	5 821	0.49	3.13
S3: Spot-Flex	2 397	13 196	0.53	3.29

NVP binding: B1 < 0.1% of QH intervals (NVP 54 MW, BESS 30 MW);

B2 \approx 1.5% of QH intervals (\approx 4 200 MWh over 20 yr; NVP 14 MW, BESS 12 MW).

The revenue differential between both topologies is strictly positive across all scenarios and Monte Carlo iterations, confirming that direct charging never reduces profitability. However, the magnitude is highly sensitive to the NVP constraint ratio. For Case B1, the NVP is rarely binding relative to combined RE generation and BESS demand, resulting in a modest median revenue differential of 934 kEUR over 20 years under S0. For Case B2, where the grid connection is severely constrained, the median differential rises to 5,821 kEUR under S0 (Figure IV.5).

Two structural patterns in Table IV.2 merit explanation. First, the revenue differential under S2 strictly equals that under S0 — this is expected, as the static capacity charge does not affect dispatch and is assessed on identical installed BESS capacity in both topologies. However, the Δ NPV between S0 and S2 differs (e.g., Case B2: 2.44 vs. 3.13 M EUR). This difference in Δ NPV between S0 and S2 reflects the nonlinear interaction of the fixed capacity charge with the tax calculation: because direct charging generates higher operating revenues, EBIT is more frequently positive, allowing the fixed S2 grid charges to act as a differentiating tax shield across the topologies. Second, the Δ NPV under S1 exceeds that under S0 (e.g., Case B2: 3.54 vs. 2.44 M EUR) despite the lower absolute revenue. This reflects that under S1, direct charging partially avoids grid-sourced volume and the associated energy-based grid charges, adding a cost-avoidance component to the pure dispatch advantage.

Translating into discounted NPV terms (Figure IV.6), the coupling topology effect for Case B2 ranges from 2.44 M EUR (S0) to 3.54 M EUR (S1). For Case B2 under S0, the physical coupling decision thus carries a financial impact comparable in magnitude to the project's total NPV (median NPV S0: 3.33 M EUR). The narrow interquartile ranges visible in both figures confirm that this differential

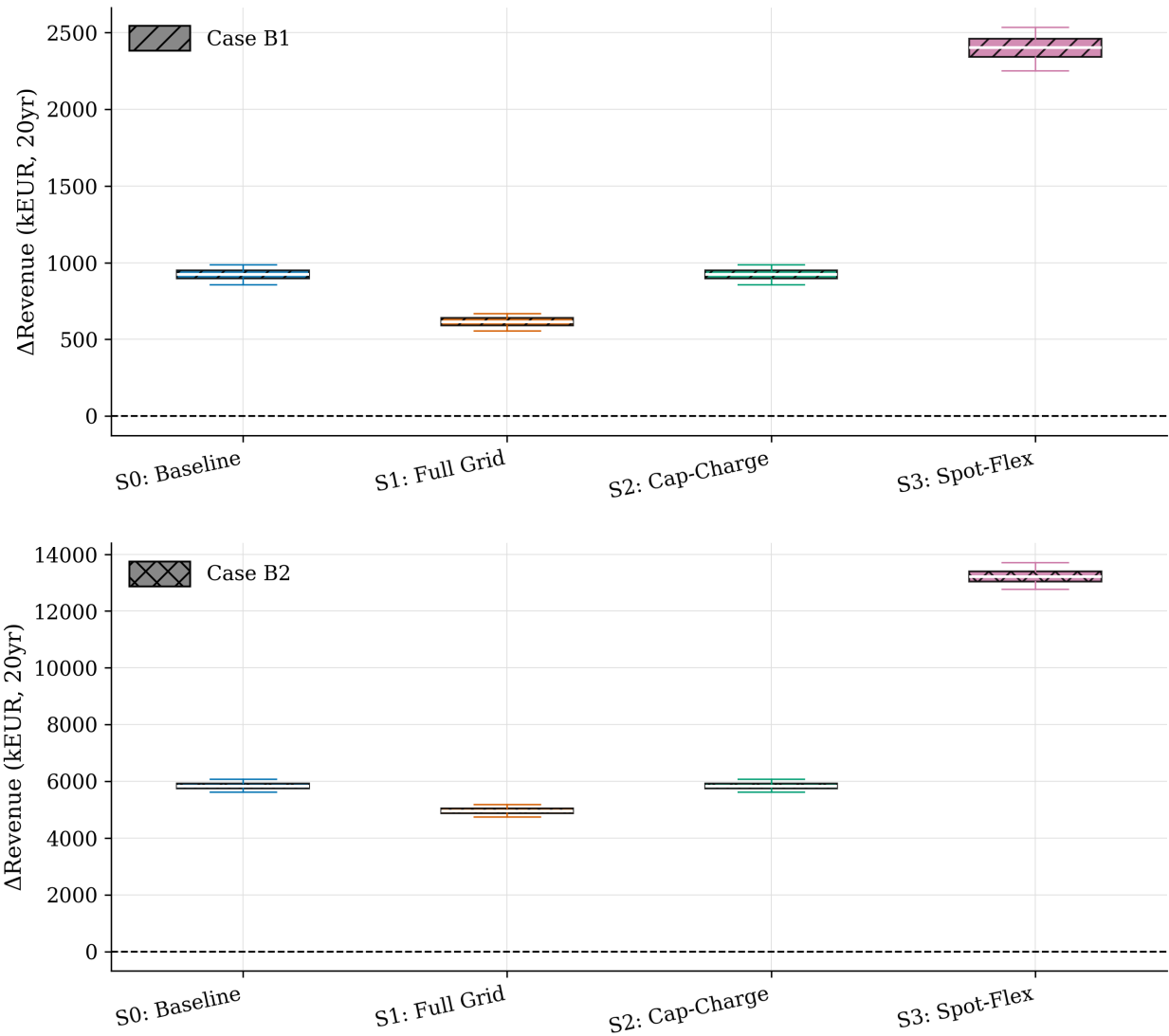


Figure IV.5: Revenue differential by coupling topology and scenario (P5/P95 whiskers).

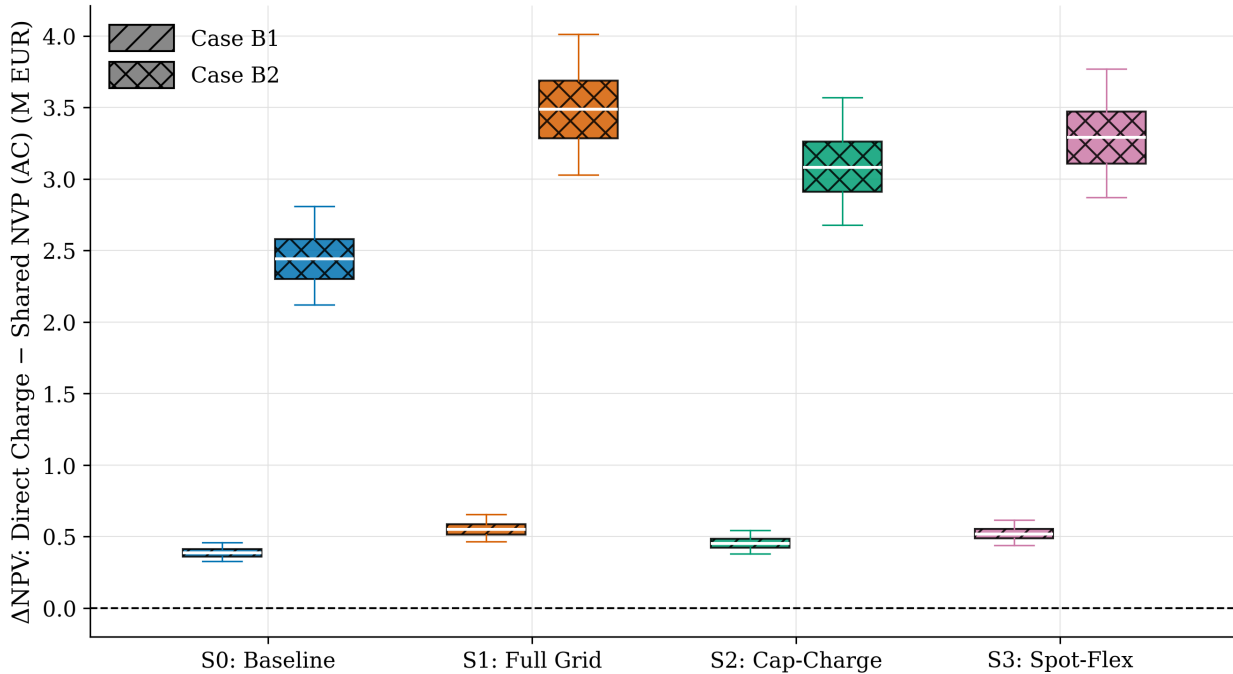


Figure IV.6: NPV differential by coupling topology and scenario (P5/P95 whiskers).

is driven almost entirely by the deterministic NVP constraint rather than by stochastic parameter variation, rendering the coupling topology a predictable design variable rather than a risk factor.

The financial advantage of direct charging amplifies under the spot-market flexibility regime (S3) in revenue terms: the α -scaled incentive multiplies the revenue from each additional MWh that direct charging makes accessible. For Case B2, the Δ Revenue under S3 reaches 13,196 kEUR — more than double the S0 value. In NPV terms, however, the amplification is more moderate (3.29 vs. 2.44 M EUR), as discounting compresses the long-horizon revenue gains.

IV.3 Sensitivity and Stress Testing

To assess the robustness of the profitability findings beyond the baseline Monte Carlo distributions, this section applies two complementary risk assessment methods. First, a deterministic analysis isolates the marginal impact of individual parameter shifts on NPV. Second, a stochastic stress test evaluates the probability of positive NPV when the centers of parameter distributions are shifted to adverse boundary values. Both analyses focus on the two scenarios with positive baseline NPV: S0 (Baseline Exemption) and S3 (Spot-Market Flexibility).

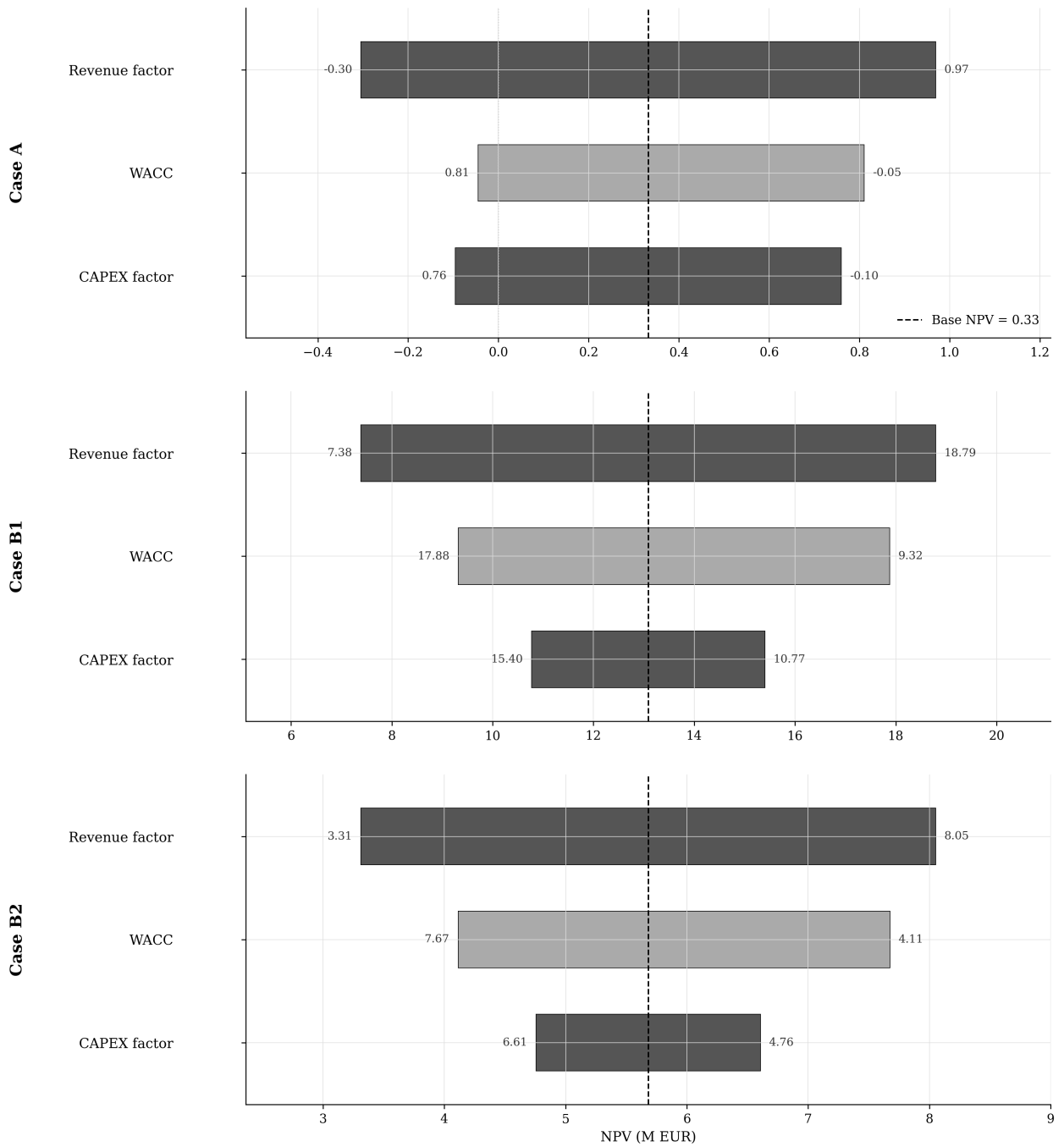


Figure IV.7: Sensitivity of NPV to parameter shifts under S0 (Baseline).

IV.3.1 Deterministic Sensitivity

The revenue factor represents a uniform scaling of all annual arbitrage revenues; a factor of 0.8 corresponds to a 20% reduction in realized market spreads relative to the historical baseline. Table IV.3 summarizes the deterministic NPV for all three cases at the upper and lower bound of revenue factor, WACC, and CAPEX; Figure IV.7 visualizes the corresponding tornado diagrams.

Table IV.3: Sensitivity of NPV to parameter shifts under S0 (Baseline).

Parameter	Shift	Case A (MEUR)	Case B1 (MEUR)	Case B2 (MEUR)
<i>Baseline</i>	—	0.33	13.09	5.68
Revenue factor	0.8	−0.30	7.38	3.31
Revenue factor	1.2	0.97	18.79	8.05
WACC	8%	−0.05	9.32	4.11
WACC	4%	0.81	17.88	7.67
CAPEX factor	+15%	−0.10	10.77	4.76
CAPEX factor	−15%	0.76	15.40	6.61

Under S0, the revenue factor emerges as the dominant driver across all cases. For Case A, the $\pm 20\%$ revenue shift spans the breakeven threshold IV.3, confirming the marginal nature of standalone profitability under exemption. WACC and CAPEX exert secondary but material influence; at WACC = 8%, Case A's median NPV turns slightly negative, while CAPEX +15% pushes it further into loss territory. For Cases B1 and B2, the same parameter ranking holds, but absolute NPV remains positive across all tested shifts, reflecting the greater financial buffer from lower specific CAPEX.

Under S3, the incentive scaling parameter α introduces an additional sensitivity dimension. Table IV.4 summarizes the deterministic NPV for all three cases at the upper and lower bound of α , revenue factor, WACC, and CAPEX; Figure IV.8 visualizes the corresponding tornado diagrams.

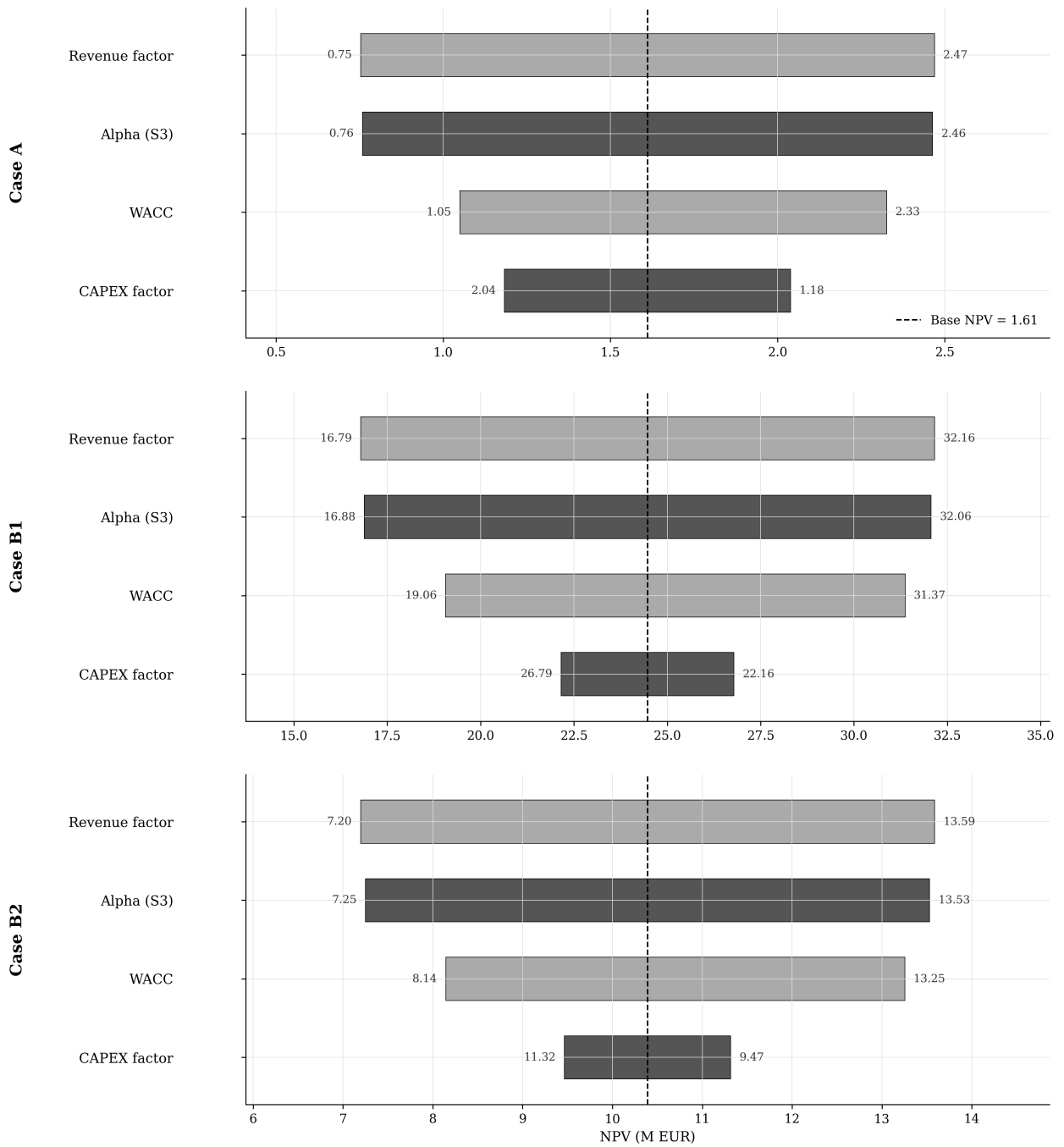


Figure IV.8: Sensitivity of NPV to parameter shifts under S3 (Spot-Flex).

Table IV.4: Sensitivity of NPV to parameter shifts under S3 (Spot-Flex).

Parameter	Shift	Case A (MEUR)	Case B1 (MEUR)	Case B2 (MEUR)
<i>Baseline</i>	—	1.61	24.47	10.39
α	0.1	0.76	16.88	7.25
α	0.5	2.46	32.06	13.53
Revenue factor	0.8	0.75	16.79	7.20
Revenue factor	1.2	2.47	32.16	13.59
WACC	8%	1.05	19.06	8.14
WACC	4%	2.33	31.37	13.25
CAPEX factor	+15%	1.18	22.16	9.47
CAPEX factor	−15%	2.04	26.79	11.32

For Case A, α is a primary driver: reducing it from the baseline (0.3) to 0.1 compresses NPV to 0.76 M EUR, while increasing it to 0.5 expands NPV to 2.46 M EUR. This pattern scales with project size — for Case B1, the α range spans 16.88 to 32.06 M EUR. Revenue factor remains equally significant, while WACC and CAPEX are secondary, underscoring that the calibration of the regulatory incentive parameter is a central design variable for the spot-market flexibility regime.

IV.3.2 Stochastic Stress Testing

The stochastic stress test shifts the expected means of parameter distributions to their adverse boundary values and executes a full Monte Carlo simulation around these shifted baselines. Table IV.5 defines these configurations and reports the resulting $P(\text{NPV} > 0)$ for each stress configuration; Figure IV.9 visualizes the comparison across cases and scenarios.

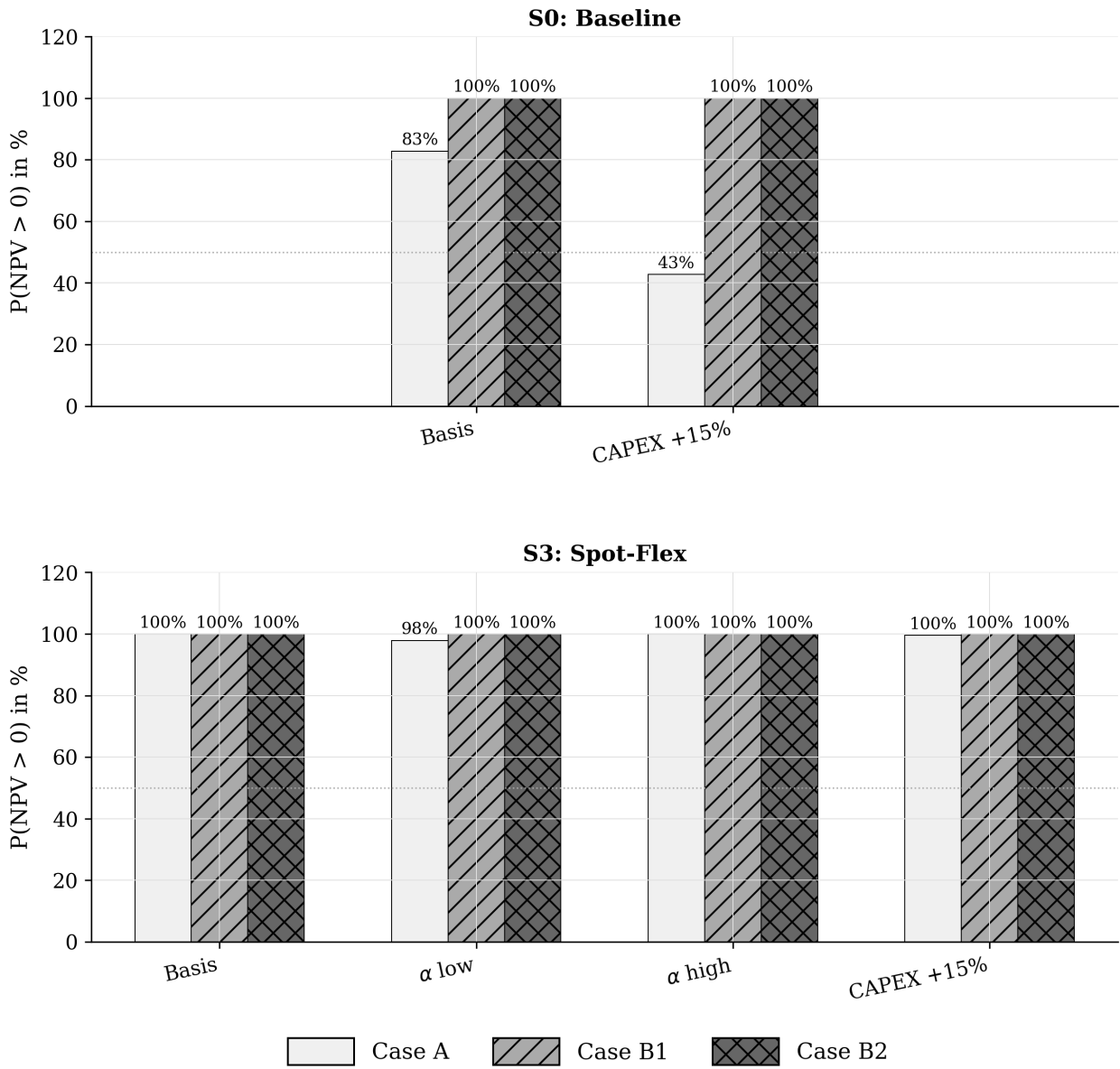


Figure IV.9: Stochastic stress test: $P(NPV > 0)$ under adverse parameter shifts.

Table IV.5: Stochastic stress test: $P(\text{NPV} > 0)$ under adverse parameter shifts.

Scenario	Stress case	Case A	Case B1	Case B2
S0	Basis	82.7%	100.0%	100.0%
S0	CAPEX +15%	42.7%	100.0%	100.0%
S3	Basis	100.0%	100.0%	100.0%
S3	$\alpha = 0.1$	97.8%	100.0%	100.0%
S3	$\alpha = 1.0$	100.0%	100.0%	100.0%
S3	CAPEX +15%	99.6%	100.0%	100.0%

Note: α is treated as a deterministic regulatory design parameter, fixed at the specified value across all iterations; CAPEX, WACC, and degradation rate continue to be drawn stochastically.

Under S0, the critical stress case is CAPEX +15%, which reduces Case A's $P(\text{NPV} > 0)$ from 82.7% to 42.7% — well below the 50% threshold that would already be insufficient for project finance standards. Cases B1 and B2 prove significantly more resilient, maintaining a $P(\text{NPV} > 0)$ of 100.0% even under these adverse conditions.

Under S3, the business case demonstrates broad robustness. Even under the most adverse configuration (α low for Case A), $P(\text{NPV} > 0)$ remains at 97.8%. For Cases B1 and B2, $P(\text{NPV} > 0)$ stays at 100.0% across all stress configurations. This confirms that the spot-market flexibility regime provides sufficient margin to absorb simultaneous adverse shifts in investment costs and incentive calibration.

IV.4 Discussion and Regulatory Implications

The quantitative results presented in Sections IV.1 through IV.3 provide a direct answer to the main research question. The post-2029 grid charge regime is not a marginal parameter in the BESS investment equation — it is the determinant variable. The difference between the worst-case (S1) and best-case (S3) regulatory outcome spans a median NPV range of approximately 5 M EUR for Case A, 46 M EUR for Case B1, and 18.5 M EUR for Case B2. No single parameter tested in the sensitivity analysis — including CAPEX, WACC, or market revenue levels — produces a comparable effect.

IV.4.1 Qualitative Assessment of Scenarios S4–S8

The five regulatory scenarios excluded from quantitative modeling (Table III.1) merit brief qualitative positioning relative to the modeled outcomes. The following assessment is qualitative and directional; no bankability conclusions can be drawn for S4–S8 without dedicated quantitative modeling. Scenarios S4 (Grid-Driven Flexibility) and S5 (Contractual Service) were excluded due to the absence of standardized, publicly available local congestion data required for credible simulation (Section III.2). Both would introduce dispatch constraints beyond pure market optimization, likely positioning their NPV outcomes between S0 and S1 — better than the full grid charge burden but worse than unconstrained exemption, depending on the frequency and duration of grid-driven curtailment windows. Scenario S6 (Dynamic Grid Constraint) imposes behavioral rules rather than monetary incentives; its impact would depend on the correlation between congestion hours and high-spread arbitrage windows — a relationship that cannot be quantified without nodal grid data. Scenarios S7 (Feed-In Charge) and S8 (Connection Charge) represent fundamentally different cost allocation philosophies: S7 would add a second marginal cost component per cycle, likely producing outcomes at least as severe as S1 or worse, as charges apply to both consumption and injection. S8 shifts costs from OPEX to CAPEX, potentially improving operational economics at the expense of higher upfront investment.

IV.4.2 Implications for the AgNes Debate

The results suggest that among the modeled options and under a pure intraday arbitrage assumption, only the spot-market flexibility approach (S3) preserves BESS investment viability while introducing a price-based incentive aligned with the BNetzA's stated objective of incentivizing system-serving behavior. Under the perfect foresight assumption of this model, S3 does not alter dispatch — its effect is purely valuational. Whether S3 produces behavioral steering under imperfect information is beyond the scope of this analysis but represents a critical question for regulatory design. The BNetzA's January 2026 orientation paper has since clarified that the incentive component would be tied to local grid congestion rather than spot prices, suggesting that the actual mechanism will differ from the spot-based proxy modeled here as S3 while retaining the sign-correct, dynamic structure that drives the S3 results. The static capacity charge (S2), despite its appeal as a predictable cost structure favored by industry stakeholders, fails to achieve bankability under the modeled cost assumptions. This finding is conditional on the specific CAPEX levels and intraday arbitrage market conditions underlying the simulation; lower future battery costs or the inclusion of additional

revenue streams (e.g., FCR, aFRR) could shift this viability threshold. However, under 2025 cost parameters, the capacity charge creates a fixed cost burden that exceeds the arbitrage margin available from intraday price spreads alone.

The sensitivity analysis provides a preliminary indication of the minimum calibration for α — the scaling factor within the minimal linear incentive form used to operationalize the BNetzA's qualitative criteria — required for project bankability. Even at $\alpha = 0.1$ — the lowest value tested — Case A achieves a positive median NPV of 0.76 M EUR under S3, suggesting that the threshold for investment viability lies below the tested range. For Cases B1 and B2, bankability is maintained across all tested alpha values. This implies that the BNetzA has considerable design latitude in calibrating the incentive magnitude without jeopardizing BESS investment cases, provided the mechanism retains the linear, sign-correct structure modeled here.

The comparative perspective from the UK and Netherlands frameworks (Section II.4) provides additional context. The UK's post-TCR approach of exempting FtM storage from residual charges aligns most closely with S0, prioritizing market access and investment certainty. The Netherlands' non-firm connection model introduces physical curtailment risk analogous to S4/S6. Germany's proposed incentive mechanism — approximated by S3 in this analysis — occupies a middle ground: it maintains full market access while introducing a monetary incentive layer — a design that, based on the quantitative evidence presented here, appears compatible with continued BESS deployment.

V. Conclusion

V.1 Summary of Findings

This thesis set out to quantify the impact of post-2029 grid charge regulation on the profitability of utility-scale FtM BESS in Germany, focusing on intraday arbitrage revenues. The main research question asked how different regulatory scenarios would affect BESS economics after the expiration of the current grid charge exemption under § 118 (6) EnWG.

The quantitative analysis, based on a Monte Carlo framework with bootstrap-generated price scenarios and LP optimization over a 20-year horizon, yields a clear answer: the post-2029 grid charge regime is the single most consequential determinant of BESS investment viability. Among the four quantitatively modeled scenarios, only the spot-market-oriented flexibility incentive (S3) preserves bankability, achieving $P(\text{NPV} > 0) = 100.0\%$ across all project configurations. The current exemption (S0) provides marginal-to-robust profitability depending on project scale ($P(\text{NPV} > 0)$ ranging from 82.7% for the standalone Case A to 100.0% for both Cases B1 and B2). Both the full grid charge default (S1) and the static capacity charge (S2) — the latter reflecting the industry's preferred alternative — result in uniformly negative NPV outcomes under intraday arbitrage alone, with zero probability of breakeven.

In response to Sub-Question 1, the median NPV spread between the worst-case (S1) and best-case (S3) regulatory outcome amounts to approximately 5 M EUR for Case A, 46 M EUR for Case B1, and 18.5 M EUR for Case B2. No parameter tested in the sensitivity analysis — including CAPEX, WACC, or market revenue levels — produces a comparable effect.

Beyond the regulatory analysis, the thesis identifies the physical coupling topology in co-located projects as a financially significant design choice. For Case B2, the NPV differential between direct charging and shared NVP topologies (median: 2.44 M EUR under S0) is comparable in magnitude

to the project's total NPV. This demonstrates that the technical configuration is a critical success factor with a financial impact similar in scale to that of the regulatory regime.

Regarding Sub-Question 2, the comparative review of UK and Netherlands frameworks positions Germany's proposed S3 mechanism as a middle ground between the UK's stability-oriented exemption approach and the Netherlands' physically constrained flexibility model.

V.2 Limitations of the Study

The following methodological boundaries must be considered when interpreting the results.

The optimization model operates under perfect foresight, computing the TRC — the maximum achievable arbitrage revenue given complete knowledge of future prices. Real-world trading involves forecast errors, execution latency, liquidity constraints, and partial or failed order execution that reduce realized revenues. The absolute NPV levels reported therefore overstate achievable profits; however, the relative scenario ranking remains valid, as the same foresight assumption applies uniformly across all scenarios and cases.

The use of the VWAP index abstracts from order book depth and bid-ask spreads. The model assumes price-taker behavior — neglecting potential market impact or endogenous price effects — which may slightly overestimate achievable spreads for very large portfolios in illiquid hours.

The analysis is restricted to intraday arbitrage as the sole revenue stream. Ancillary services (FCR; Automatic Frequency Restoration Reserve, aFRR), capacity market revenues, and potential redispatch compensation are excluded. This understates absolute profitability but is unlikely to distort the comparative ranking of grid charge regimes. Since ancillary service revenues are predominantly capacity-based, they remain largely independent of the energy-based charge structures modeled here; their inclusion would therefore shift absolute NPV levels upward without altering the relative economic hierarchy of the scenarios.

For co-located configurations (Cases B1/B2), both coupling topologies assume an identical round-trip efficiency of 90%. In practice, direct charging (typically DC-coupled) avoids AC conversion losses, implying that the topology advantage reported in Section IV.2 is conservatively understated. Similarly, potential CAPEX differentials between DC-coupled and AC-coupled system designs are not reflected in the analysis.

For Scenario S1 in Cases B1/B2, all charging volume is conservatively treated as grid-sourced, overstating the grid charge burden. The qualitative conclusion — that S1 is economically unviable — is not affected, as S1 also fails for Case A where this simplification does not apply.

The stochastic price scenarios are generated via block-bootstrap from 2023–2025 historical data, assuming that this post-crisis period is representative of future market conditions over the 20-year horizon. Structural shifts in the generation mix, interconnector capacity, or demand patterns are not captured.

Cases B1 and B2 utilize 1,000 Monte Carlo iterations compared to 10,000 for Case A, due to computational constraints documented in Section III.1.4. While the reduced sample is unbiased, direct comparison of distributional properties (e.g., tail quantiles) between Case A and Cases B requires caution.

The quantitative modeling was completed prior to the publication of the BNetzA's "Orientierungspunkte Speichernetzentgelte" (January 2026), which specifies mechanisms — notably the AP1/AP2 work price structure and the netting of arbitrage volumes to round-trip losses — that are not reflected in the scenario definitions. The scenario architecture nonetheless brackets the plausible regulatory design space, as discussed in Section II.3.

V.3 Outlook and Commercial Implications

The optimization framework developed in this thesis offers several avenues for practical application and academic extension.

For current market participants, the TRC framework enables ex-post performance benchmarking through the Revenue Capture Rate ($RCR = \text{realized revenue} / \text{TRC}$). This metric allows asset owners and route-to-market providers to evaluate trading algorithm performance against a transparent, reproducible baseline. In the context of project finance, the model provides a technology-agnostic liquidation floor: since it calculates the revenue potential independent of operator skill, banks and insurers can use it to define conservative debt-service coverage ratios under worst-case regulatory scenarios. Moreover, the full NPV distribution generated by the Monte Carlo framework enables the use of probabilistic risk metrics (e.g., Value-at-Risk analogues for revenue streams), aligning with standard project finance risk assessment practices. Finally, as the market shifts toward tolling agreements — where utilities lease battery capacity for fixed fees — the framework enables quantifi-

cation of the spread between theoretical maximum revenue and a proposed floor price, effectively pricing the optionality embedded in long-term offtake contracts.

The TRC computed here represents the upper bound of a three-level benchmark hierarchy for BESS performance assessment. Future research should implement the remaining tiers: the ORC, defined as the achievable revenue under a rolling horizon optimization with limited foresight (e.g., 48-hour windows), and the OBC, representing rule-based heuristic dispatch strategies reflecting current market practice. Specifically, replacing the perfect foresight assumption with stochastic price forecasting would enable direct quantification of the “forecast discount” relative to TRC. This would provide operators with a realistic revenue expectation that accounts for algorithmic limitations without the noise of idiosyncratic trading decisions. Additionally, the BNetzA’s proposed capacity-threshold mechanism with differentiated work prices (AP1/AP2) and netting to round-trip losses [Bundesnetzagentur, 2026] could be evaluated against the existing dispatch results without requiring new optimization, as the mechanism affects cost allocation rather than dispatch logic. This remains contingent on the BNetzA specifying numerical tariff parameters.

Beyond methodological refinements, integrating ancillary services (FCR, aFRR) would enable multi-market optimization and a more comprehensive investment assessment. Coupling this logic with the German Marktstammdatenregister would allow for capacity forecasts of actual planned projects grounded in economic viability rather than theoretical potential. Finally, the framework’s modular design remains adaptable to emerging revenue streams, such as grid-forming capabilities [Fraunhofer IEE, 2026], as technical and regulatory requirements evolve. For an exploratory projection of how the underlying bimodal price structure may evolve under continued decarbonization, see Appendix E.

The findings underscore that the post-2029 grid charge regime is not merely a cost parameter but the decisive gate for BESS investment viability. The framework developed in this thesis provides a quantitative basis for evaluating regulatory proposals against this threshold.

A. Supplemental Market Data Analysis

This appendix provides additional context for the price data foundation underlying the optimization model and long-term investment analysis.

To justify the selection of the 2023-2025 observation period as the representative baseline for the bootstrap simulation, Figure A.1 illustrates the structural transformation of the DE-LU intraday electricity market over six years.

Pre-Crisis Stability (2020-2021): The market exhibited a predominantly unimodal distribution centered around 30-50 €/MWh with limited volatility. This regime reflected the conventional merit-order dispatch with stable fossil fuel prices and moderate renewable penetration.

Energy Crisis (2022): The distribution flattened significantly, developing pronounced “fat tails” that extended price observations from deeply negative to extreme positive values (exceeding 300 €/MWh). This volatility was driven by the natural gas supply shock following geopolitical disruptions, which decoupled conventional price-setting mechanisms and introduced unprecedented market uncertainty.

New Normal (2023-2025): The market stabilized into the bimodal structure analyzed in Chapter III. This regime is characterized by two dominant phenomena: first, the “price cannibalization” effect where increasing renewable capacity drives prices toward zero during surplus hours (left mode); second, a floating fossil dispatch peak (right mode) determined by gas and coal marginal costs plus CO₂ certificate prices. The consistent bimodal pattern across 2023-2025 confirms that this period represents a stable post-crisis structural regime whose core bimodal features (renewable zero-floor + dispatchable marginal pricing) are expected to persist under continued renewable expansion, as evidenced by the modal-stability analysis in Section B.

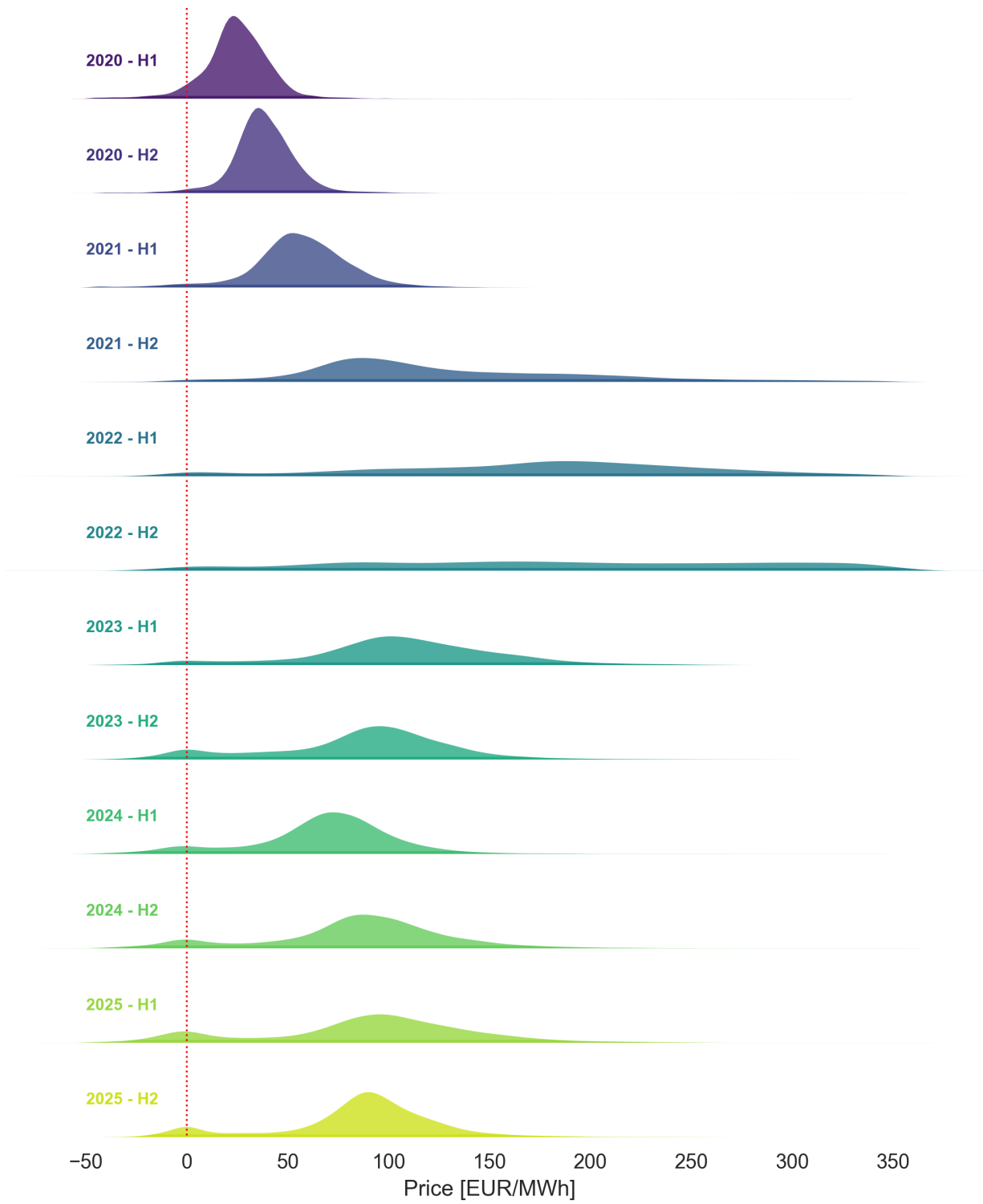


Figure A.1: Long-term evolution of price density distributions (2020–2025).

B. Modal Dynamics (2023-2025)

While the aggregate bimodal structure remained consistent across the 2023-2025 observation window, semi-annual variations reveal the differential dynamics of the two price modes. Figure B.1 overlays the price density distributions for each half-year period, highlighting the contrasting behavior of the renewable surplus mode versus the fossil dispatch mode.

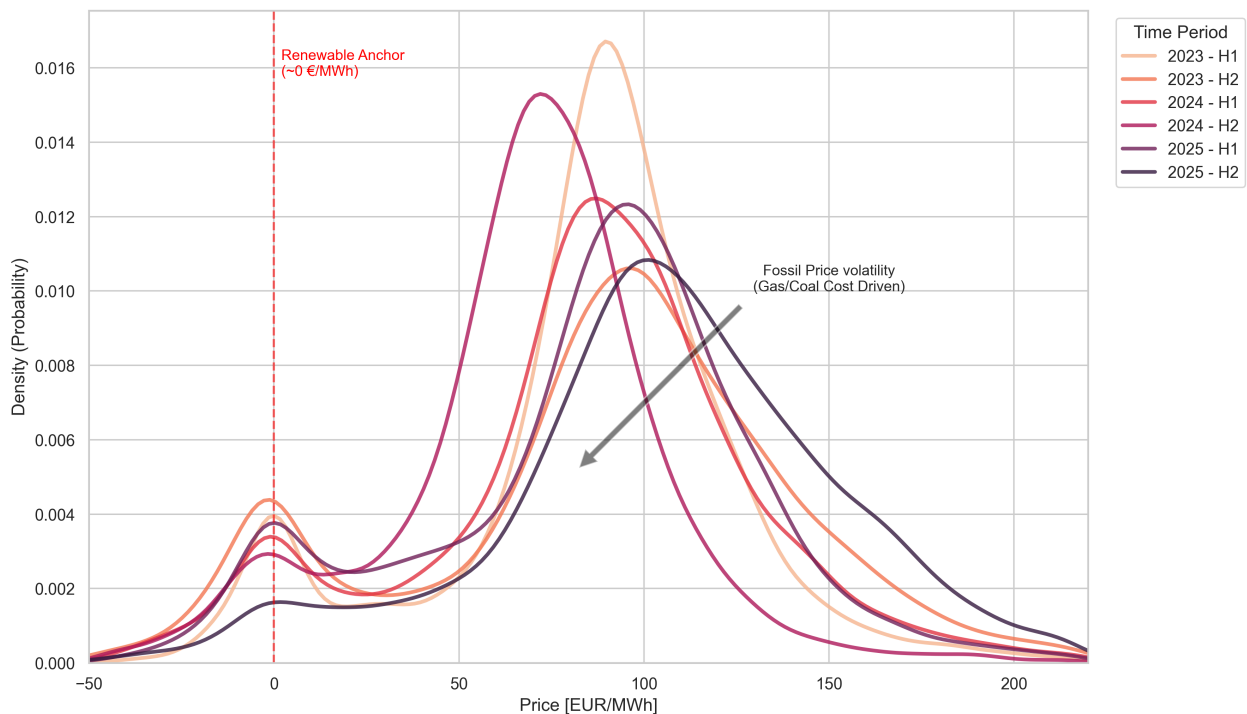


Figure B.1: Dynamics of price modes across semi-annual periods (2023–2025).

Renewable Anchor Stability: The left mode (surplus regime) exhibits remarkable stability across all six half-year periods, consistently anchored near 0 €/MWh. This persistence reflects the fundamental zero-marginal-cost nature of renewable generation, which acts as a structural price floor during hours of high solar and wind output. Minor variations in the left-tail density can be attributed

to seasonal patterns in renewable oversupply, with summer periods (H1/H2 of 2023–2024) showing slightly higher density in the near-zero range due to midday solar feed-in.

Fossil Price Volatility: In contrast, the right mode (dispatch regime) demonstrates significant temporal variation. The peak position shifts between approximately 60 €/MWh (2023-H1, light orange curve) and 110 €/MWh (2025-H2, dark gray curve), tracking fluctuations in natural gas spot prices and CO₂ ETS allowance costs. This volatility underscores the exposure of conventional generation to international commodity markets, while the renewable mode remains insulated from such external shocks.

Implication for Bootstrap Methodology: The divergent dynamics justify the 14-day block length employed in the bootstrap resampling (Section III.1.3). Extended meteorological periods (e.g., multi-day wind lulls or solar surplus events) persist long enough to affect both the renewable surplus frequency and the thermal dispatch necessity, making sub-weekly sampling insufficient to capture these correlated phenomena.

C. Block-Bootstrap Boundary Validation

To verify that block boundaries do not introduce systematic revenue bias, a post-hoc analysis compared the revenue density of boundary intervals against non-boundary intervals within a single representative scenario (S0).

Method: A dispatch-identical comparison was performed on one 20-year synthetic scenario using a global 20-year optimization (full revenue counting across all intervals). Post-hoc, the 700,800 QH intervals were classified as boundary (first 96 QH after each block transition, $n = 49,920$) or non-boundary ($n = 650,880$). Mean revenue per QH was computed for each group from the identical dispatch solution.

Result: Boundary intervals yielded a mean revenue of 10.69 EUR/QH versus 10.57 EUR/QH for non-boundary intervals, resulting in $R_{ratio} = 1.0106$ — within the $\pm 2\%$ tolerance threshold. Figure C.1 illustrates the revenue distributions and mean comparison.

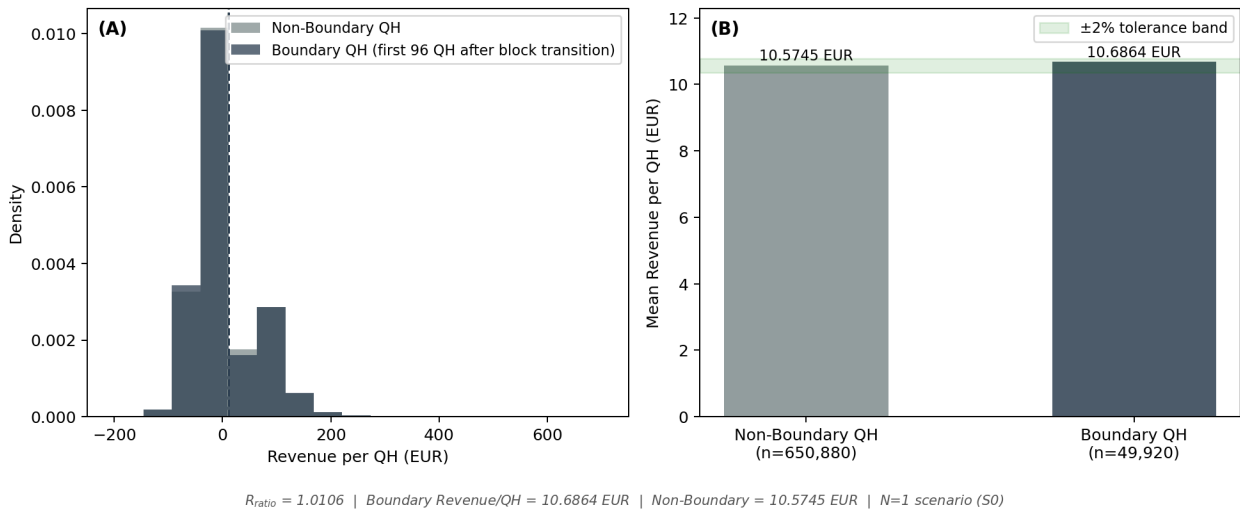


Figure C.1: Block-boundary revenue validation: QH distribution (A) and mean comparison (B).

Conclusion: No systematic upward bias from block-boundary price discontinuities is detectable. Revenue exclusion during boundary intervals is therefore not applied.

D. Exploratory Analysis: Bimodal Degradation Risk (Gaussian Mixture Model)

The main analysis (Section III.5.1) employs a unimodal normal distribution for battery degradation, reflecting the standard assumption in academic BESS valuation literature. This appendix documents an alternative bimodal specification that was explored during the research process but ultimately excluded from the core model due to insufficient empirical grounding.

D.0.1 Motivation

Conventional investment models assume a deterministic linear degradation path based on manufacturer warranties. This approach may underestimate the tail risk of asset underperformance. During the Enlit Europe 2025 trade fair (Dec 2025), a technical discussion with representatives of a battery diagnostics provider — specializing in rapid in-situ cell health assessment — yielded two qualitative observations:

1. **Manufacturing Variance:** Internal scrap rates in cell production were reported at approximately 30%, indicating process instability. While the exact field failure rate for deployed cells remains unknown, this figure suggests that a non-zero probability of latent defects reaching operational systems is plausible.
2. **Correlated Batch Defects:** Field diagnostics reportedly reveal that specific production batches can exhibit significantly higher capacity loss ($> 10\%$ deviation from specification). Since cells within a BESS container often originate from the same manufacturing batch, such failures would be correlated across modules — preventing risk diversification within a single installation (Since failures within a batch are correlated rather than independent, risk does not diversify across modules within a single installation).

These observations were presented informally via a slide deck. The underlying raw data was not subsequently made available for independent verification. The analysis below therefore constitutes a hypothetical stress scenario, not an empirically calibrated model.

D.0.2 Gaussian Mixture Model Specification

To explore the potential financial impact of bimodal degradation risk, a GMM was specified. The first-year capacity fade D_1 is drawn from a weighted sum of two normal distributions:

$$D_1 \sim (1 - w) \cdot \mathcal{N}(\mu_{\text{std}}, \sigma_{\text{std}}) + w \cdot \mathcal{N}(\mu_{\text{defect}}, \sigma_{\text{defect}})$$

Parameters:

- **Standard Cohort** (weight $1 - w = 98\%$): $\mu_{\text{std}} = 3\%$, $\sigma_{\text{std}} = 0.5\%$ — representing the compliant majority of cells operating within warranty specifications.
- **Defect Batch** (weight $w = 2\%$): $\mu_{\text{defect}} = 12\%$, $\sigma_{\text{defect}} = 2\%$ — representing a hypothetical “fat tail” scenario where a production batch exhibits accelerated degradation.

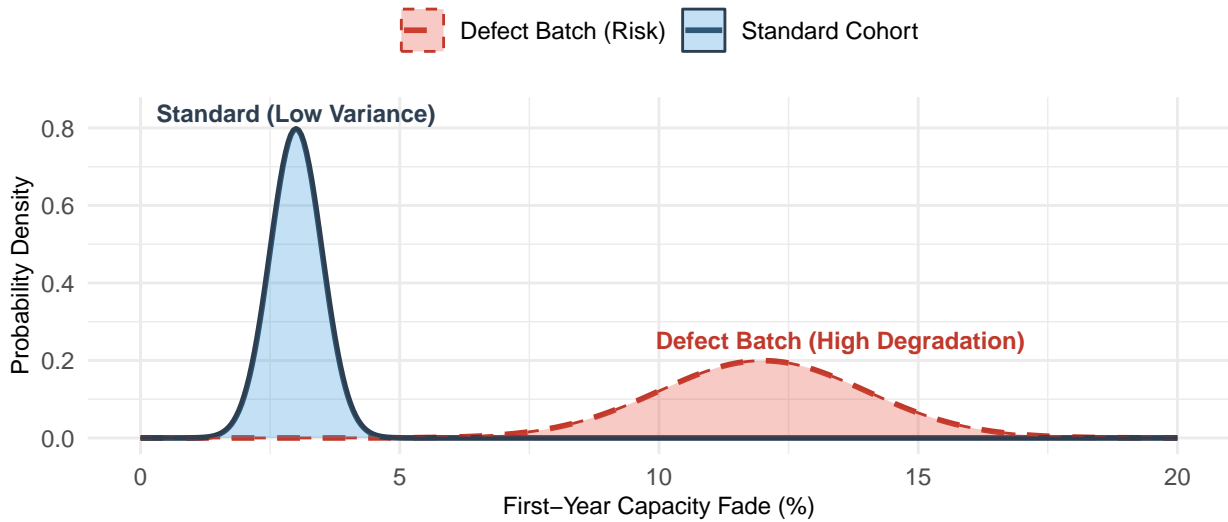
The defect probability $w = 2\%$ was set as an assumption without empirical calibration data. In the exploratory sensitivity runs, values of $w \in \{1\%, 2\%, 5\%\}$ were considered.

Figure D.1 visualizes the conditional component distributions.

D.0.3 Limitations and Rationale for Exclusion

The GMM specification was excluded from the core Monte Carlo analysis for three reasons:

1. **No verifiable data source.** The bimodal pattern was observed in internal company material shown informally during a technical discussion at the conference. The underlying measurement data were not shared, precluding independent replication or statistical validation of the mixture parameters.
2. **Questionable real-world persistence.** In operational practice, a defective battery module exhibiting 12% annual capacity fade would likely be identified through routine monitoring and replaced under warranty within 1–3 years — not operated for the full 20-year project horizon. Modeling a persistent defect batch without accounting for replacement overstates cumulative degradation losses.



Note: The plot shows conditional probability densities (unweighted) to clearly visualize both risk profiles. The Defect Batch component (w=2%) represents a hypothetical stress scenario without empirical calibration. This GMM specification was explored but excluded from the main Monte Carlo analysis in favor of a unimodal normal distribution.

Figure D.1: Degradation Risk: Conditional GMM component distributions.

3. **Parameter arbitrariness.** The 2% defect probability, the 12% mean fade rate, and the mixture weights lack empirical anchoring. Varying these parameters shifts NPV outcomes substantially, but the absence of calibration data makes any specific parameterization indefensible as a base case.

The main analysis instead uses a unimodal normal distribution $\mathcal{N}(\mu = 2\%, \sigma = 0.5\%)$, truncated to $[0.5\%, 4.0\%]$, which is consistent with published warranty-backed degradation ranges for LFP cells in utility-scale applications. This exploratory GMM analysis is retained here for transparency and as a reference point for future research should empirical fleet degradation data with bimodal characteristics become publicly available.

E. Future Price Projections

To contextualize the long-term persistence of arbitrage opportunities beyond the simulation horizon, this section presents speculative projections of how the bimodal price distribution may evolve under continued decarbonization. These scenarios serve to demonstrate structural market continuity rather than to inform the quantitative analysis, which relies exclusively on empirically validated 2023-2025 data.

2045 Transition Scenario (Figure E.1): This projection assumes a partial decarbonization pathway where natural gas peaker plants are progressively blended with hydrogen-ready turbines. The renewable surplus mode remains anchored near 0 €/MWh, while the dispatch mode shifts from the current ~88 €/MWh (fossil-dominated) to ~100 €/MWh, reflecting the higher marginal costs of gas/H₂ hybrid dispatch. The broadening of the right peak captures the transitional uncertainty in fuel mix and technology deployment rates during this period.

2065 Full Decarbonization Scenario (Figure E.2): This projection models a fully decarbonized system where hydrogen peaker plants serve as the sole dispatchable backup during renewable scarcity events (“Dunkelflaute”). The renewable surplus mode peaks at 0 €/MWh with a compressed negative tail—reflecting the expected absorption of surplus generation by large-scale BESS and electrolyzer fleets. The scarcity mode shifts to ~120 €/MWh, consistent with projected hydrogen-to-power marginal costs based on green H₂ import prices (7-9 ct/kWh_{th}) and turbine efficiency (~55-60%) [Fraunhofer ISE, 2021], aligned with the German National Hydrogen Strategy and Bundesministerium für Wirtschaft und Klimaschutz (BMWK) scenario frameworks. The compressed negative tail assumes that by 2065, sufficient flexible demand (battery storage, electrolyzers) prevents the deep negative price excursions observed in today’s market, establishing an effective price floor near zero €/MWh. This illustrates that arbitrage opportunities persist independent of the marginal technology setting the scarcity price (fossil vs. hydrogen). Critically,

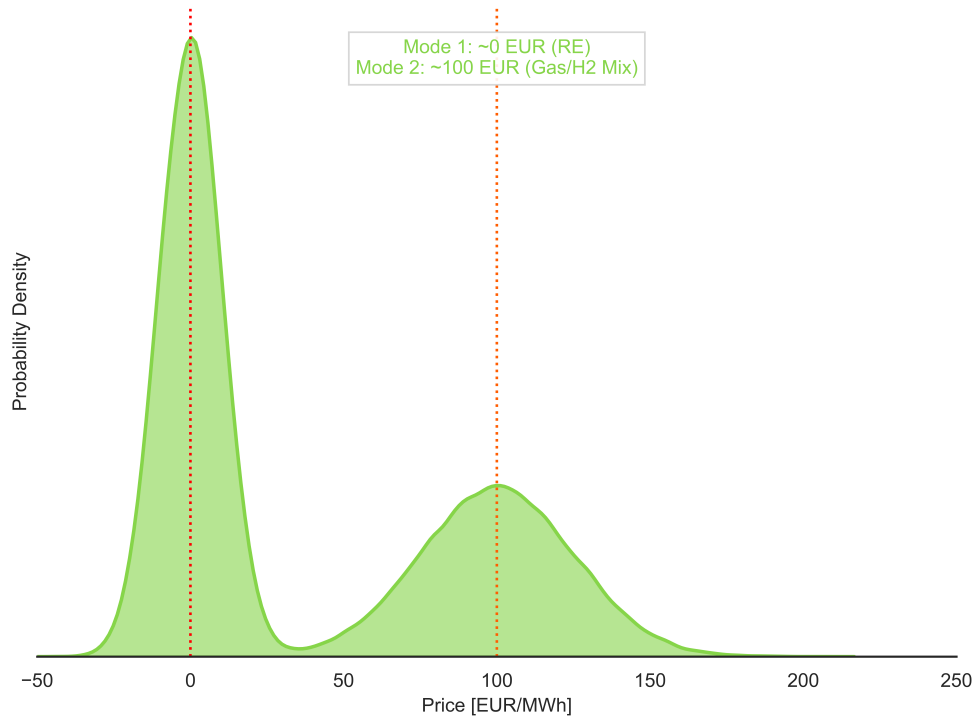


Figure E.1: Bimodal price distribution projection for 2045 transition scenario.

profitability is driven by the high-frequency surplus mode (left peak) creating daily low-price charging windows, not by waiting for rare multi-week scarcity events (right peak).

Methodological Note: These projections are speculative scenarios derived from synthetic GMM, not empirical forecasts. The 2065 scenario in particular reflects normative assumptions about flexibility deployment (BESS penetration, electrolyzer capacity) that remain uncertain. Actual market outcomes will depend on policy frameworks, infrastructure investment, and hydrogen supply chain development. The projections serve to demonstrate the structural persistence of price bimodality and arbitrage potential, rather than to predict specific future price levels. For conservative investment analysis, the 20-year simulation horizon (Section III.1.3) relies exclusively on validated historical data (2023-2025) without incorporating these long-term projections. The decision to exclude future projections from the Monte Carlo framework ensures that all profitability metrics reflect conservative, data-grounded assumptions rather than speculative price trajectories.

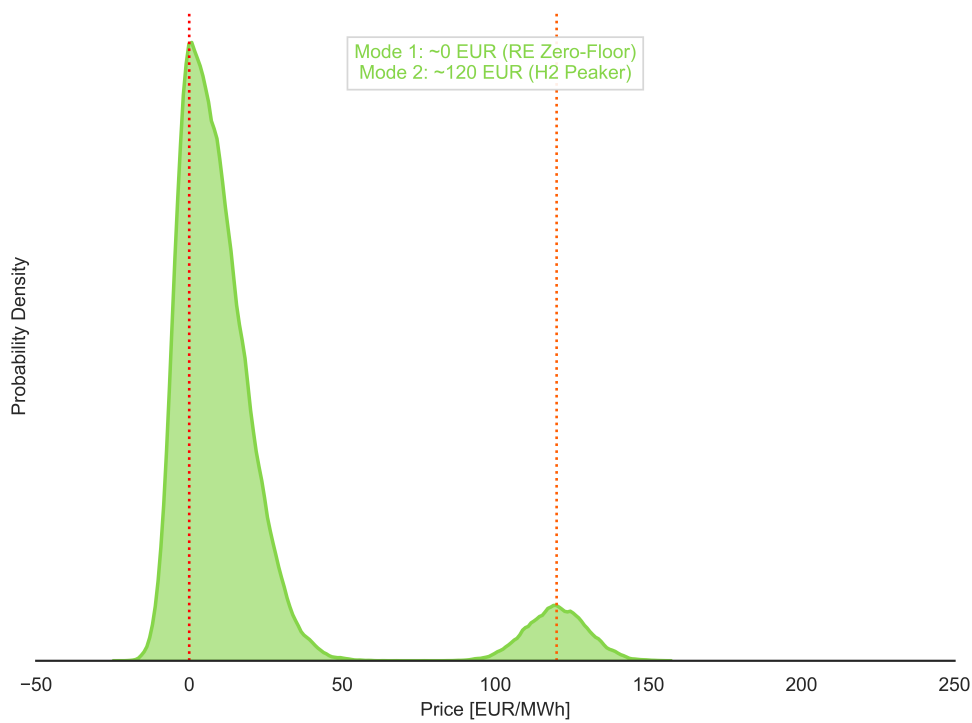


Figure E.2: Bimodal price distribution projection for 2065 full decarbonization scenario.

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