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# Flexibility at a cost: Industrial battery storage and the breakdown of grid fee fairness in Germany

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## HIGHLIGHTS

- Optimization of over 800 real industrial load profiles using battery energy storage systems.
- Analysis of the impact of individual optimization on grid fees and grid operators.
- Current grid fee policies may not promote grid- and system-friendly behavior.

## ARTICLE INFO

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## ABSTRACT

The transformation of the electricity system towards higher shares of renewable energy necessitates increased flexibility on the demand side. The industrial sector, which accounts for over 40% of Germany's total electricity demand, exhibits significant heterogeneity in terms of production processes, load characteristics and grid use patterns. Consequently, it is considered a primary source of such flexibility. This study examines the economic and regulatory implications of deploying battery energy storage systems (BESS) in industrial settings, focusing on how different grid fee policy frameworks influence operational strategies, total costs of companies as well as their impact on grid operators. Using a mixed-integer linear programming model applied to more than 800 real-world industrial load profiles, we explicitly capture the diversity of industrial electricity demand and assess three regulatory scenarios: the current framework with incentives for atypical and intensive grid usage, and two proposed reforms incorporating dynamic energy prices and revised capacity prices. The objective of the model is a minimization of each company's annual total costs, with the model deciding how many BESS modules should be built. Results show that BESS adoption leads to an average cost reduction in electricity procurement costs of 14.3%, with some companies reaching cost reductions of over 30%. At the same time companies that make use of atypical grid usage increase their maximum peak load on average by 51.7%, while the average grid fee payments are reduced by 41.6%. It is shown that by removing capacity price components of grid fees and by fully dynamizing energy price components, cost and grid fee payment reductions as well as peak loads are increased significantly. This raises concerns about unintended system effects such as increased network congestion or transformer overloading. In contrast, retaining capacity components supports more equitable cost allocation and reduces the risk of cross-subsidization, whereby smaller consumers subsidize larger, more flexible ones. These findings underscore the importance of cost-reflective grid tariffs that align network charges with underlying system costs, and incentivize grid-friendly behavior. From a policy perspective, economic efficiency ought to be balanced with potential distributional effects, taking into account temporal and locational price signals enabling the efficient deployment of industrial flexibility.

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## 1. Introduction

The industrial sector plays a critical role in the decarbonization of electricity systems globally. In many advanced economies, industry accounts for a substantial share of electricity demand making it a key actor in the transition towards a more flexible, renewable-based energy system. As energy systems evolve to integrate higher shares of intermittent renewable energy sources (vRES), demand-side flexibility becomes increasingly important for ensuring system stability and cost efficiency. Industrial consumers, with their large and often shiftable loads, represent a particularly promising source of such flexibility.

System-friendly behavior enables a more efficient utilization of available network capacities and minimizes the need for grid expansion (Brucke et al., 2026). In doing so, system-friendly behavior can reduce both investment requirements and operational costs, e.g., by lowering the need for congestion management, and thus lower overall system costs of the future energy system. Besides financing network operation and investment, grid fees should also reflect congestion situations in the power grid, while the market components of end-user prices should reflect scarcity in the wholesale market. When both signals are properly aligned, their combination can incentivize all actors towards system-friendly behavior, although the two price signals need not move in lockstep. In particular, in load-intensive grid regions, market components and grid fees can even provide opposing incentives. Actors with significant potential for system-friendly behavior include not only consumers but also generators and storage operators (ENTSO-E et al., 2016). As grid users, they too can be incentivized through appropriately designed grid fee components. Crucial for all actors are the incentive effects of the combined signal from (time-varying) grid fees and market-based price components. The current grid fee system in Germany with flat-rate and static capacity and energy price components does not take into account the specific grid situation when purchasing electricity (European Association for Storage of Energy (EASE), 2025). Furthermore, it does not create any incentives for system-beneficial flexibility. On the contrary: the current design of the capacity price component actually inhibits the provision of flexibility.

However, the competitiveness of industrial enterprises is closely tied to electricity price developments, which have become increasingly volatile in recent years (ACER and CEER, 2024). Dynamic pricing structures can expose firms to greater cost uncertainty, especially when operational flexibility is limited. Nevertheless, for companies with suitable technological and organizational capabilities, these structures can provide substantial cost-saving opportunities. One key enabler of this flexibility is the deployment of battery energy storage systems (BESS), which allow firms to decouple consumption from production processes and respond to price or grid signals.

Policy frameworks in various countries are beginning to reflect the potential of flexible electricity consumption for improving grid efficiency and reducing system costs. In parallel, there is an increasing emphasis at European level on using network tariffs to encourage flexibility from both households and industry, while avoiding cross-subsidies between consumer groups (FTI Consulting LLP and smartEn, 2025). Across Europe, grid fee designs increasingly combine capacity-based charges, peak-related components, and targeted relief mechanisms to better align cost recovery with system stress and cost causation. Countries such as France and Spain rely on time-differentiated network tariffs to incentivize load shifting away from peak periods, while Belgium and Norway explicitly link transmission charges to system peak demand, thereby strengthening incentives for peak shaving (Cambridge Economic Policy Associates (CEPA), 2019). Recent reforms in France go even further by linking tariff components more directly to locational and temporal congestion signals. Under the TURPE 7 framework, for example, battery storage assets can opt into an 'injection–consumption' tariff. Under this optional tariff, bonuses are granted for charging during local solar surplus hours at injection points, while surcharges are imposed for discharging into already stressed grid sections at consumption points (Lauvergne, 2025). Zonal classifications are fixed until 2030, whereby only assets connected at the designated points are eligible for the optional grid tariff. Furthermore, it is stated in the regulation that batteries under this tariff cannot earn more in bonuses than they pay in grid fees over the year (Lauvergne, 2025). Similarly, Ireland has recently adapted its market rules to allow battery units to be fully integrated into the real-time electricity market (SDP-02). Previously, grid-scale batteries were used primarily to provide stability services. Under SDP-02, TSOs benefit from greater visibility of the state of charge of each battery, enabling them to issue negative dispatch instructions and settle bids within negative ranges (Single Electricity Market Operator (SEMO), 2025). The Netherlands and Italy have shifted a substantial share of network cost recovery toward capacity-based charges, reflecting concerns over declining volumetric revenues due to decentralised generation (Cambridge Economic Policy Associates (CEPA), 2019). Several countries, including France, Norway, and the Netherlands, additionally grant significant grid fee reductions to large or stable industrial consumers, justified by system stability benefits and international competitiveness (Cambridge Economic Policy Associates (CEPA), 2019). Despite this, recent EU debates have begun to question whether such extensive reliefs adequately reward genuine flexibility, or whether discounts should be more closely linked to quantifiable contributions to peak reduction, congestion relief, or renewable integration (European Commission, 2025). In Germany the Electricity Grid Charges Ordinance (§19 StromNEV) offers substantial grid fee reductions for large-scale consumers with atypical or intensive usage patterns. These reductions are embedded within the broader framework surrounding grid fees, which are levied on all electricity consumers to finance the construction, operation and maintenance of electricity grid infrastructure. As a central cost recovery mechanism, grid fees are currently borne entirely by end users and are allocated based on a regulated methodology that considers individual consumption characteristics and contributions to peak loads. The system thus serves two interrelated purposes. Economically, it ensures long-term financing of rising infrastructure and operational costs. Regulatorily, it aims to incentivize grid-friendly consumption behavior. BESS can assist industrial users in meeting the necessary thresholds by shaping their load profiles. However, the current approach to grid fee reductions, particularly when granted to select customer groups such as large industrial consumers, raises questions of distributional fairness. As of 2024, §19 StromNEV had granted reduced charges to approximately 400 permanent-load customers and 4200 atypical users. This resulted in over €1 billion of foregone network revenue, which was socialised via a levy on all grid users (Bundesnetzagentur, 2024). This preferential tariff structure has the potential to shift disproportionate cost burdens onto smaller consumer groups or less flexible users. These users frequently lack the financial resources to adapt their load profiles or invest in enabling technologies. It is therefore becoming increasingly important that grid cost allocations are not only efficient but also equitable, especially as the electricity system transitions toward a more decentralized and dynamic architecture. While this study focuses on the German context, the underlying mechanisms, cost drivers, and policy questions are highly relevant in an international context, particularly for countries modernizing their grid fee structures or encouraging industrial flexibility through regulatory reform.

### 1.1. *Atypical and intensive grid usage*

Under §19 of the German Electricity Grid Charges Ordinance (StromNEV), consumers with atypical or intensive electricity usage patterns may be eligible for significantly reduced grid fees. Specifically, network operators are required to offer individualized grid tariffs to consumers whose peak demand deviates substantially from the system-wide peak load or whose annual consumption exceeds 10 GWh with a high number of full load hours (FLH). In such cases, grid charges can be reduced to as low as 10% of the standard published tariff, provided that

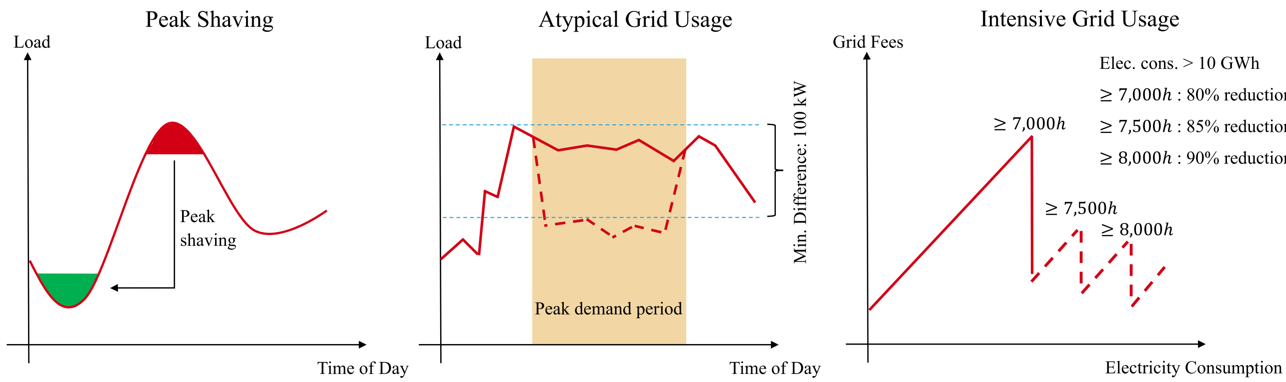


**Fig. 1.** Regulatory Policies in Germany.

the usage exceeds 8000 FLH annually (Bundesministerium der Justiz, 2023). BESS installations can support the operational patterns required to meet these thresholds by shaping the load profile and reducing peak demand, thus enabling substantial cost savings and improving overall energy cost efficiency. Therefore, both atypical and intensive grid usage could be viable options apart from pure peak shaving.

The structure of grid fees changes depending on whether a company exceeds a threshold of 2500 FLH per year. If the threshold is not reached, the energy price component of the grid fee is relatively high, while the capacity price is comparatively low. In contrast, for consumers exceeding 2500 FLH annually, a lower energy price component is applied, but the capacity price component increases significantly. This tariff structure is designed to reward consistent electricity usage, while penalizing low FLH profiles. While effective in an era dominated by large, baseload power plants, the transition to a generation mix with a high share of vRES in Germany now calls for a far more flexible demand side.

Due to the lower energy price component, peak shaving, as shown in Fig. 1 can be profitable. The aim of this concept is to decrease occurring peaks during the day, shifting the load to lower consumption times and therefore increasing FLH. This strategy seeks to maximize utilization of baseload generators and minimize reliance on expensive peaking plants, ultimately lowering wholesale electricity costs for society as a whole.

If companies manage to decrease their peak demand during the grid operator defined peak demand periods by at least 100 kW compared to their maximum peak load outside this time window, they are eligible for atypical grid usage, as shown in Fig. 1. The benefit is that companies now only have to pay the capacity price component of the grid fees on their peak load during the peak demand periods, rendering their overall maximum peak load outside this time frame economically irrelevant. This concept would result in reduced costs for companies and grid operators alike by reducing the overall peak load when there is low vRES generation and flexible demand in the energy system.

Similar to the atypical grid usage, the intensive grid usage is dependent on the amount of FLH per year. Fig. 1 depicts the thresholds needed to be eligible. According to §19 StromNEV, the grid fee reduction increases from 80% at 7000 FLH, over 85% at 7500 FLH to 90% at over 8000 FLH. Another criteria for intensive grid usage is the total electricity consumption, which needs to be above 10 GWh per year. Once both criteria are met, the corresponding reduction is applied to the total grid fee payment.

In an electricity system that is witnessing an increasing share of variable renewable generation, static FLH thresholds for intensive grid usage are becoming increasingly misaligned with the temporal volatility in supply. Against this background, the German Federal Network Agency is currently discussing a more dynamic framework governing intensive grid usage. The Kopernikus project “SynErgie” has proposed a revised model that aims to move away from rigid usage FLH thresholds and instead reward grid- and market-oriented flexibility (Buhl et al., 2025). Their proposal includes replacing the fixed full-load hour requirement with dynamic load windows determined by local grid operators, offering a more adaptive and renewables-aligned approach to incentivizing industrial flexibility. These developments underscore the urgency to reassess how BESS can be deployed to support not only cost reduction for individual companies, but also evolving policy objectives.

### 1.2. Literature review

Lithium-ion BESS has rapidly matured over the past decade, becoming the dominant technology for stationary applications due to continuous improvements in cost and performance. Recent reports estimate current costs between roughly 120€/kWh (IEA, 2024) and 400€/kWh (European Commission: Joint Research Centre, Clean Energy Technology Observatory, 2022).[1] From a technical perspective, lithium-ion batteries show high round-trip efficiencies of about 85–95% and typical lifetimes of 5–15 years (Kebede et al., 2022). These characteristics make BESS an increasingly viable solution for industrial flexibility, particularly where peak load reduction or tariff-based incentives enable economic value streams.

Several studies have investigated the cost-saving potential of BESS in industrial settings, particularly through load management and participation in incentive schemes. (Park and Lappas, 2017) demonstrated that combining solar photovoltaic with a 12 kWh battery system led to an additional 1.3–2.0% reduction in peak demand across several Australian electricity networks, with demand charge savings reaching over $1300 per year in some regions. The study also emphasized that optimized battery control strategies significantly improve financial performance. Similarly, Hartmann et al. (2018) found that BESS could be financially viable for specific industrial and commercial use cases, depending on local tariff structures and battery investment costs.

Braeuer et al. (2019) found that BESS becomes economically viable for small and medium-sized German enterprises primarily when several revenue streams—including peak shaving, frequency control, and arbitrage—are combined. Their analysis revealed that peak shaving was typically the dominant contributor to cost savings. In contrast, DiOrio et al. (2015) highlighted that achieving a reasonable payback period for battery investments in U.S. industrial applications depends heavily on stacking services across multiple use cases, especially under static pricing assumptions.

Focusing on battery dispatch behavior, Henni et al. (2022) showed that overly risk-averse strategies for peak shaving could reduce economic performance by up to 10%, while moderate risk tolerance maintained or improved returns. In a similar vein, Dougherty et al. (2021) evaluated real-world data from two U.S. manufacturing facilities and concluded that financial incentives alone are insufficient to justify BESS

[1] Values converted using December 2025 exchange rate of 1 USD = 0.86 € where applicable.

adoption unless paired with smart control and use-case alignment. Their findings stress the importance of context-specific dispatch strategies and policy support.

From a broader policy perspective, Billings et al. (2022) found that facility-controlled dispatch led to nearly nine times higher cost savings than utility-controlled scenarios, underlining the economic benefits of giving industrial users autonomy over storage operations. Likewise, Fisher et al. (2018) proposed a simple regression-based metric ("threshold ratio") to help non-experts predict revenue potential from demand charge reductions, facilitating faster screening of viable storage applications across commercial users.

Within the specific context of Germany's §19 StromNEV, several studies have investigated how industrial BESS can be used to meet the requirements for intensive or atypical grid usage. Tiemann et al. (2020) analyzed 5300 load profiles and found that BESS profitability improves markedly when regulatory incentives are taken into account, particularly under the intensive use scheme. Weinand et al. (2021) also observed that many companies currently benefiting from atypical usage tariffs could further increase savings by actively managing their load with storage systems.

Zimmerman et al. (2020) directly compared BESS for peak shaving and atypical grid usage, concluding that the latter offered higher savings potential but required larger storage capacities and more precise dispatch. This was confirmed by Zimmermann et al. (2020), who reported that atypical usage necessitates longer energy discharge durations to reliably shift demand outside peak windows. In a sector-specific application, Eskander et al. (2023) found that large-scale bus depots in the city of Hamburg could also meet atypical grid usage requirements through a combination of BESS and load management, highlighting the broader applicability of the incentive across non-traditional industrial sites.

A comparative study of different battery chemistries by Zimmerman et al. (2020) revealed that lithium-ion systems yielded the highest net present value for both peak shaving and atypical grid usage scenarios. Notably, achieving eligibility for the atypical usage tariff required nearly six times more energy capacity than the peak shaving configuration, reflecting the need to sustain load reduction over extended periods.

Despite the growing body of research, there is still a lack of integrated studies that address how industrial batteries can be optimally operated to meet the specific criteria of §19 StromNEV while balancing other services such as peak shaving or arbitrage trading. Existing studies either evaluate these strategies separately or do not capture the impact of large-scale BESS adoption on grid fee revenues and its impact on load consumption behavior. Furthermore, it remains unclear whether the current regulatory incentives genuinely promote grid-friendly behavior or may unintentionally lead to increased system peak loads, counteracting broader goals of decarbonization and demand-side flexibility.

In the following, we address these gaps by analyzing the implications of large-scale industrial battery adoption under the current §19 StromNEV framework. Specifically, we investigate (i) whether current tariff structures incentivize consumption behavior that aligns with grid stability and renewable integration, (ii) how widespread deployment of BESS would affect total grid fee payments and revenue flows to grid operators, and (iii) what revised policy designs could better promote system-friendly flexibility without jeopardizing grid financing. By explicitly modeling both existing and proposed policy structures, this work offers novel insights for policymakers and system planners on how to realign industrial incentives with the needs of a decarbonized and dynamic electricity system.

## 2. Methodology and data

In this section the input data sets for our optimization model are described as well as the mathematical formulation of the model.

**Table 1**
Statistics of analyzed companies.

| Metric | Value |
|---|---|
| Mean power [kW] | 168.45 |
| Standard deviation [kW] | 388.92 |
| Minimum power [kW] | 0.00 |
| Maximum power [kW] | 7260.00 |
| Average battery capacity [kWh] | 1044.75 |

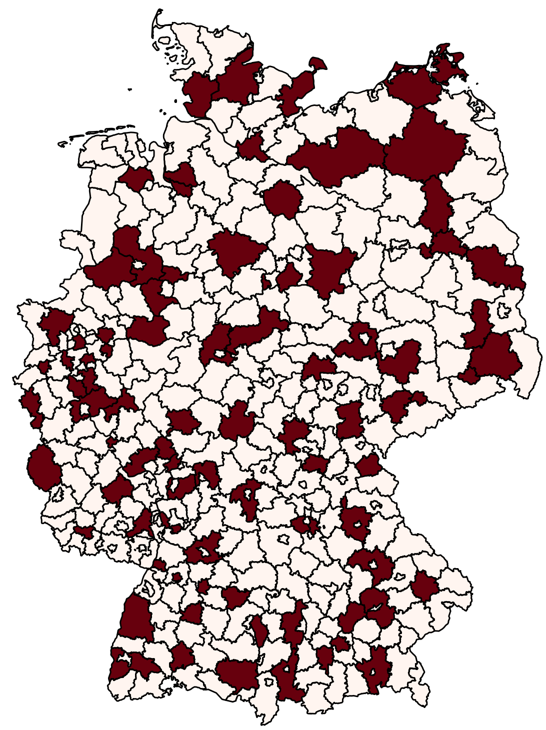

**Fig. 2.** Regional distribution of analyzed companies across Germany (NUTS-3 level).

### 2.1. Data sets

The input data for this study consist of 5359 industrial electricity load profiles with 15-minute resolution over a full year (2016), published by the German industry association VEA in 2024 (Tiemann, 2024). The dataset spans a diverse range of sectors, including mining, electricity supply, logistics, and health care. In addition to the load profiles, each entry includes company-specific parameters such as energy and capacity price structures, as well as the time windows for peak demand periods as defined by the respective distribution system operator. To ensure computational tractability, the original quarter-hourly profiles were aggregated to hourly resolution. A stratified sample of over 800 load profiles was selected for the optimization analysis, with 50 representative companies drawn from each sector to preserve sectoral diversity. Table 1 shows key summary statistics for the set of analyzed companies, including their mean, standard deviation, minimum and maximum observed grid power (in kW), as well as the average installed battery capacity (in kWh). Geographical representativeness was also maintained, as illustrated in Fig. 2, which shows the spatial distribution of companies across Germany at the NUTS-3 regional level. Day-Ahead market prices from 2024 were used for modeling electricity procurement, sourced from the European Energy Exchange (EEX) database (EEX AG, 2025).

### 2.2. Model formulation

The optimization model developed for this study is formulated as a mixed-integer linear program (MILP) and implemented using Gurobi. A

**Table 2**
Battery storage parameters used in the optimization model.

| Parameter | Value | Unit |
|---|---|---|
| $C_{bt}$ | 100 | kWh |
| $P_{bt}$ | 50 | kW |
| $\mu_{bt}$ | 95 | % |
| $L_{bt}$ | 10 | years |
| $I_{bt}$ | 250 | €/kWh |
| $M_{bt}$ | 5 | €/kWh/year |

preliminary version of this model was presented at the 21st International Conference on the European Energy Market (EEM), where the focus was limited to atypical grid usage and based on a small subset of company load profiles (Beranek et al., 2025). The present study significantly extends this work by incorporating intensive grid usage mechanisms, expanding the dataset to over 800 companies, and introducing multiple different regulatory frameworks. It determines the optimal amount of battery modules to be installed as well as the dispatch strategy for industrial electricity consumers aiming to minimize total electricity costs, including spot market expenditures, grid fees, and battery investment, while accounting for potential revenues from regulatory incentives as well as arbitrage trading on the Day-Ahead market, excluding participation in Redispatch and balancing markets. The model incorporates detailed operational constraints for battery charging and discharging, state-of-charge dynamics, and binary control of mutually exclusive tariff options. Furthermore, it explicitly models eligibility thresholds for atypical and intensive grid usage under §19 StromNEV, enabling a comparative assessment of the economic and regulatory benefits of each strategy under varying load profiles and pricing schemes.

The model consists of 114,477 equations, 70,499 variables and 77,485,779 non-zeros. Running 50 optimizations in parallel, the average computation time equals 18 minutes and 38 s. The machine used for the computations utilizes 2.45 GHz on 128 cores and 1024 GB of RAM.

Table 2 presents the model assumptions. Each battery module has a capacity $C_{bt}$ of 100 kWh with a power $P_{bt}$ of 50 kW. Furthermore, it is assumed that each module has a charging and discharging efficiency $\mu_{bt}$ of 95%. Additional parameters are lifetime $L_{bt}$ of 10 years, investments $I_{bt}$ of 250 €/kWh as well as operation and maintenance costs $M_{bt}$ of 5 €/kWh/year.

In the following, the most important constraints are explained. A full overview of the model can be found in Appendix A.

### 2.3. Objective function

The objective of the optimization model is to minimize the annual full costs incurred by each industrial consumer, as shown in Eq. (1).

$$\min\left(\kappa_{bt} + \kappa_{elec} + \phi\right) - R \tag{1}$$

Here, $\kappa_{bt}$ denotes the annualized investment and operating costs of the BESS, $\kappa_{elec}$ represents the annual electricity procurement costs from the spot market, and $\phi$ captures total grid fee payments. The total revenue $R$ accounts for returns from electricity arbitrage as well as cost reductions achieved through eligibility for atypical and intensive grid usage tariffs under §19 StromNEV.

The annual investment and operating cost of the BESS $\kappa_{bt}$ is defined in Eq. (2). Herewith, the linearly annualized investment considering the number of battery modules $N_{bt}$ and the capacity of each battery module $C_{bt}$ is added to the annual maintenance costs for the BESS. Eq (3) defines the annual electricity procurement cost $\kappa_{elec}$ which is derived by multiplying the hourly energy drawn from the grid, $E_t^{grid}$, with the corresponding hourly Day-Ahead spot market price $p_t^{spot}$, plus an additional surcharge $\chi$ to reflect non-energy price components. This surcharge was set to 1.49 ct/kWh, consistent with average procurement-related fees reported by BDEW for 2024 (BDEW, 2025).

$$\kappa_{bt} = \frac{I_{bt} \cdot N_{bt} \cdot C_{bt}}{L_{bt}} + M_{bt} \cdot N_{bt} \cdot C_{bt} \tag{2}$$

$$\kappa_{elec} = \sum_{t=1}^{T} \left[ E_t^{grid} \cdot \left( p_t^{spot} + \chi \right) \right] \tag{3}$$

Revenues are calculated by the amount of electricity that is sold from the BESS into the grid $x_t^{grid}$ multiplied by the corresponding hourly Day-Ahead spot market price $p_t^{spot}$ as well as the reductions from atypical and intensive grid usage, $R_{atyp}$ and $R_{intensive}$ respectively.

$$R = \sum_{t=1}^{T} \left( x_t^{grid} \cdot p_t^{spot} \right) + R_{atyp} + R_{intensive} \tag{4}$$

To prevent the optimization model from unrealistically oversizing the BESS purely for arbitrage trading, an upper bound on the number of battery modules, $N_{bt}^{ub}$, was introduced. This upper limit was heuristically defined based on the original peak load of each company, $P_{max,0}$, given in kW, reflecting typical space, cost, and use-case constraints in industrial settings as given in Eq. (5).

$$N_{bt}^{ub} = \begin{cases} 2, & \text{if } 0 \leq P_{max,0} < 100, \\ 10, & \text{if } 100 \leq P_{max,0} < 500, \\ 20, & \text{if } 500 \leq P_{max,0} < 1000, \\ 40, & \text{if } 1000 \leq P_{max,0} < 2000, \\ 60, & \text{if } 2000 \leq P_{max,0} < 3000, \\ 100, & \text{if } P_{max,0} > 3000. \end{cases} \tag{5}$$

### 2.4. Battery constraints

The amount of power that can be charged into the BESS from the grid at each time step, $y_t^{grid}$, given in kWh, is limited by two constraints. First, it must not exceed the remaining available capacity in the battery, which is the difference between the maximum state of charge (SoC) and the current SoC from the previous time step, as shown in Eq. (6). Second, the power drawn from the grid is restricted by a maximum charging rate, $y^{max}$, also given in kWh, imposed by technical limits of the battery system (cf. Eq. (7)).

$$y_t^{grid} \leq \frac{SoC^{ub} \cdot C_{bt} \cdot N_{bt} - SoC_{t-1} \cdot C_{bt} \cdot N_{bt}}{\mu_{bt}} \quad \forall t \in T \tag{6}$$

$$y_t^{grid} \leq y^{max} \quad \forall t \in T \tag{7}$$

A similar logic is applied to the battery's discharging behavior. The total discharge into the load and the grid, represented by $x_t^{load} + x_t^{grid}$, both given in kWh, must not exceed the usable energy available in the battery at time $t-1$, considering the lower SoC bound and discharge efficiency (Eq. (8)). Additionally, a technical upper limit for the discharging rate $x^{max}$ is imposed in Eq. (9).

$$x_t^{load} + x_t^{grid} \leq \mu_{bt} \cdot \left( SoC_{t-1} \cdot C_{bt} \cdot N_{bt} - SoC^{min} \cdot C_{bt} \cdot N_{bt} \right) \quad \forall t \in T \tag{8}$$

$$x_t^{load} + x_t^{grid} \leq x^{max} \quad \forall t \in T \tag{9}$$

### 2.5. Grid fees

Grid fees in Germany are determined based on both the total electricity procured from the grid, $E_{total}^{grid}$, and the maximum observed grid load, $P_{max}$. The ratio of these two values defines the number of FLH $\tau$, as shown in Eq. (10).

$$\tau = \frac{E_{total}^{grid}}{P_{max}} \tag{10}$$

Since the calculation of FLH $\tau$ involves a division in which both the numerator and denominator are decision variables, the expression is inherently nonlinear and therefore had to be linearized for use within

**Table 3**
Policy Framework Parameters.

| Feature | Current Regulation | Regulation 1 | Regulation 2 |
|---|---|---|---|
| Energy Price | Fixed | Dynamic (Day-Ahead-based) | Dynamic (Day-Ahead-based) |
| Capacity Price | Fixed | – | Fixed |
| FLH Requirement | ≥ 7000 h/a | – | – |
| Reduction Trigger | Atypical/Intensive ≥ 10 GWh | Intensive ≥ 10 GWh | Atypical/Intensive ≥ 10 GWh |

the MILP framework. The full linearization procedure is provided in Appendix B.

In this study, the grid fees $\phi$ are first calculated under standard tariff conditions. The revenue from atypical grid usage, $R_{atyp}$, is then estimated based on the difference between the overall peak load and the peak load during the high-load window, denoted by $P_{diff}$. As shown in Eq. (11), this revenue is bounded by the product of $P_{diff}$ and the applicable capacity price $p^{cp}$:

$$R_{atyp} \leq P_{diff} \cdot p^{cp} \tag{11}$$

Eq. (12) assigns the grid-fee discount according to the FLH threshold specified in Section 1.1. After a company exceeds the respective FLH threshold, its total grid-fee payments are reduced by 80%, 85%, or 90% depending on the achieved FLH level.

$$R_{intensive} = \begin{cases} 0.9 \cdot \phi, & \text{if } \tau > 8000 \\ 0.85 \cdot \phi, & \text{if } \tau > 7500 \\ 0.8 \cdot \phi, & \text{if } \tau > 7000 \\ 0, & \text{otherwise} \end{cases} \tag{12}$$

It is important to note that a company can only be eligible for one policy at a time.

## 3. Results

In this chapter, we present the results of the optimization model. We begin by analyzing the effects of the current as well as proposed regulatory frameworks on their impact on individual companies, after which we study their influence on total grid fee payments and shifts in electricity consumption patterns.

For the proposed regulation, we implemented two different approaches, depicted in Table 3. The first focuses on a dynamic energy price component that mirrors fluctuations in the Day-Ahead market. This approach aims to better reflect real-time market conditions and implicitly accounts for renewable energy feed-in by incentivizing electricity consumption during periods of high renewable availability. Inspired by the recommendations of Buhl et al. (2025), the capacity-based component of the grid fee was removed, along with the full load hour thresholds previously required for intensive grid usage eligibility. Under this revised framework, only a minimum annual consumption threshold of 10 GWh remains as the eligibility criterion for grid fee reductions, resulting in a reduction of 80% for all grid fees above 10 GWh.

The second regulatory model is based partly on the framework proposed by Weidlich et al. (2025). Similar to the first approach, it incorporates a dynamic energy price component. However, instead of abolishing the capacity-based element entirely, this approach recalculates its value to ensure revenue neutrality. Specifically, the capacity price is adjusted such that the total grid fee payments under the revised scheme match those under the current regulation, based on existing consumption patterns. This preserves the incentive structure while aligning tariff revenues with the status quo.

### 3.1. Impact on companies

Fig. 3 illustrates the total cost reduction potential achieved through the use of BESS across all analyzed companies, plotted against the corresponding change in grid power consumption. The results are shown for three distinct scenarios: atypical grid usage, intensive grid usage, and a baseline case involving only peak shaving or even no form of adaptation.

It is evident that in nearly all cases where companies opt for atypical grid usage, their maximum grid power consumption increases markedly. While this is the economically optimal solution for the companies in the model, it might not necessarily be feasible. Since no information is available regarding the size and power of each company's grid connection point, costs of a potentially needed larger connection point are not considered. In contrast, intensive grid usage typically results in a reduction of peak demand. Regardless of the chosen policy, companies benefit from significant total cost reductions, with some achieving savings of over 30% of their annual energy-related expenditures.

The figure also presents the total cost reduction potential under both proposed regulatory frameworks. In both scenarios, companies achieve significantly greater savings compared to the existing regulation. However, these cost reductions are often accompanied by an increase in maximum grid power consumption. This effect is particularly pronounced in Regulation 1, where the removal of the capacity-based grid fee component eliminates any incentive to limit peak demand. The effect of this is especially clear in companies that use intensive grid usage. With capacity prices, they clearly decrease the peak load substantially, whereas in Regulation 1, almost all companies increase it.

Despite the overall trend of cost reductions, a small number of companies experience an increase in total costs under Regulation 2, likely due to their consumption characteristics no longer aligning with the revised tariff structure.

The total cost reduction can also be partly explained by the trading activities of the companies using the BESS. Table 4 shows the trading

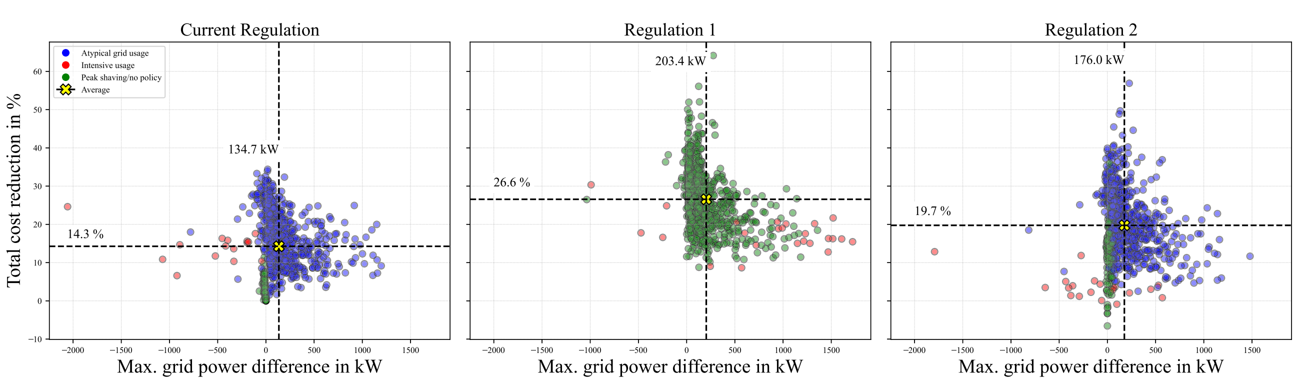


**Fig. 3.** Cost reduction potential compared to the change in grid power consumption.

**Table 4**
Trading behavior of BESS used for load coverage and arbitrage trading.

| | Load | Trading |
|---|---|---|
| Power bought [kWh] | 508,993 | 553,654 |
| Power sold [kWh] | 101,804 | 500,172 |
| Power bought [€] | 30,680 | 34,956 |
| Power sold [€] | 19,450 | 69,618 |

activities of an exemplary company, displaying the total traded sum of electricity with the current load as well as the trading strategy if the BESS were used for pure arbitrage trading.

It is clear to see that the BESS still sells electricity in the load covering case, and does not allocate all purchased electricity solely to meet on-site demand. However, the majority of profit does not stem from pure arbitrage trading. This underscores that the primary driver of cost reduction is the strategic use of the BESS for load management rather than market-based trading.

A deeper understanding of the relationship between grid fee reductions and changes in maximum grid load is provided in Fig. 4. Similar to Fig. 3 it shows the absolute difference in peak power compared to the percentage reduction in grid fee payments.

It depicts a clear divergence in strategy and outcome depending on the policy chosen. For companies pursuing intensive grid usage, grid fee reductions consistently cluster around 80–85%, corresponding to the fixed reduction thresholds defined by §19 StromNEV. These firms achieve such savings by significantly reducing their peak loads.

In contrast, companies exploiting atypical grid usage display much greater variation. While some achieve grid fee reductions comparable to intensive users, reaching up to 80%, this is often accompanied by a substantial increase in peak power. This counterintuitive trend results from the structure of atypical tariffs, where only the peak load during predefined peak demand periods determines capacity price payments, whereas there is no incentive to reduce the maximum load outside of these windows. This may ultimately undermine grid stability.

Companies not using either policy or relying solely on peak shaving demonstrate limited reductions in grid fees and minimal variation in peak power, highlighting the limited economic effectiveness of pure load-shaping strategies in the absence of policy support. On average, companies applying atypical grid usage can reduce their grid fee payments by almost 50%, whereas peak shaving or no policy reduces these payments by less than 10%.

These results emphasize the strong influence of regulatory design on operational behavior and system-wide impacts, raising questions about whether current policy structures truly align economic incentives with broader grid-friendly objectives.

A substantially higher reduction potential can also be observed for the proposed regulations. In both scenarios, average grid fee savings increase significantly compared to the current framework. An especially noteworthy outcome under Regulation 2 is that a small number of companies achieve grid fee reductions of almost 100%. This counterintuitive result arises from the structure of the revised tariff: since the energy price component of the grid fee is dynamically linked to the Day-Ahead market price, it can become negative during periods of high renewable generation and low demand. Consequently, instead of incurring costs, companies may effectively receive implicit profit on their grid fee component. When combined with the benefits of atypical grid usage, this mechanism can result in net grid fee payments falling to almost zero.

### 3.2. Impact on grid operators

The behavior of companies leveraging atypical grid usage becomes even more pronounced in Fig. 5, which displays the relative change in maximum grid power (in %) as a function of the maximum grid power difference (in kW) under different regulatory frameworks. A large cluster of companies operating just below the 100 kW threshold clearly shifts their consumption to exactly meet or slightly exceed this cutoff. This pattern reflects a strategic response to the eligibility condition for atypical grid usage.

The vertical clustering at the 100 kW mark underscores how regulatory design can inadvertently incentivize companies to increase their maximum grid power to qualify for the tariff. The reason for this steep vertical cut lies in the model assumptions, where each battery module has a power of 50 kW and small companies can build a maximum of two modules. This effect appears to override otherwise grid-friendly behavior, illustrating a potential misalignment between policy intent and system-level outcomes. In contrast, companies pursuing intensive grid usage show a more uniform reduction in peak demand.

Due to the elimination of capacity prices, Regulation 1 offers no incentive anymore to decrease peak load for companies utilizing intensive grid usage. Compared to the current policy, where intensive grid usage companies reduce their maximum grid power by about 13%, in Regulation 1 they increase it by over 36%. Regulation 2 shows that keeping a capacity price component, even in a changed structure, still reduces peak loads for these companies. Fig. 5 also shows that removing the capacity price component eliminates atypical grid usage.

Fig. 6 illustrates the average daily electricity load profiles for companies located in northern and southern Germany, respectively, along with corresponding regional renewable generation levels. The red line represents the original, unoptimized load curve, while the blue line indicates the optimized load after BESS deployment. Renewable generation

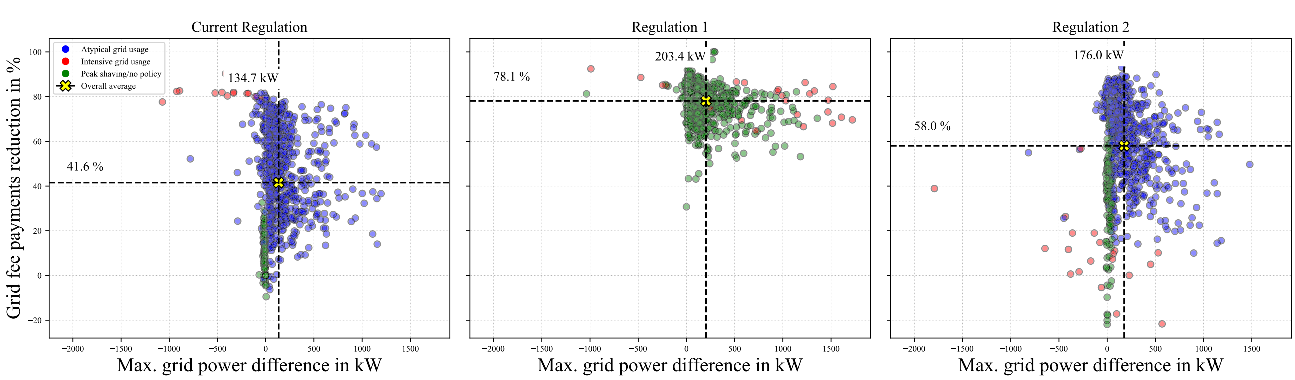


**Fig. 4.** Grid fee payment reduction potential compared to the change in grid power consumption.

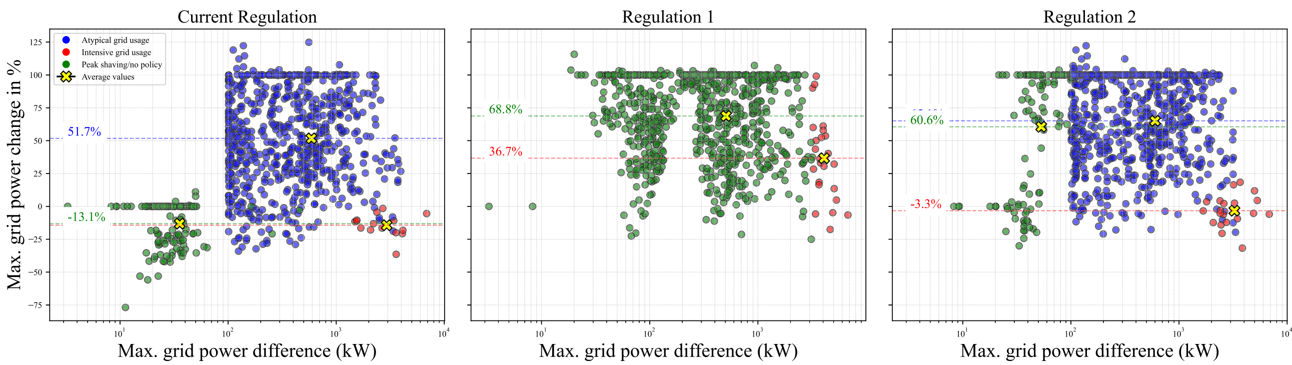


**Fig. 5.** Change in maximum grid power consumption compared to original grid power.

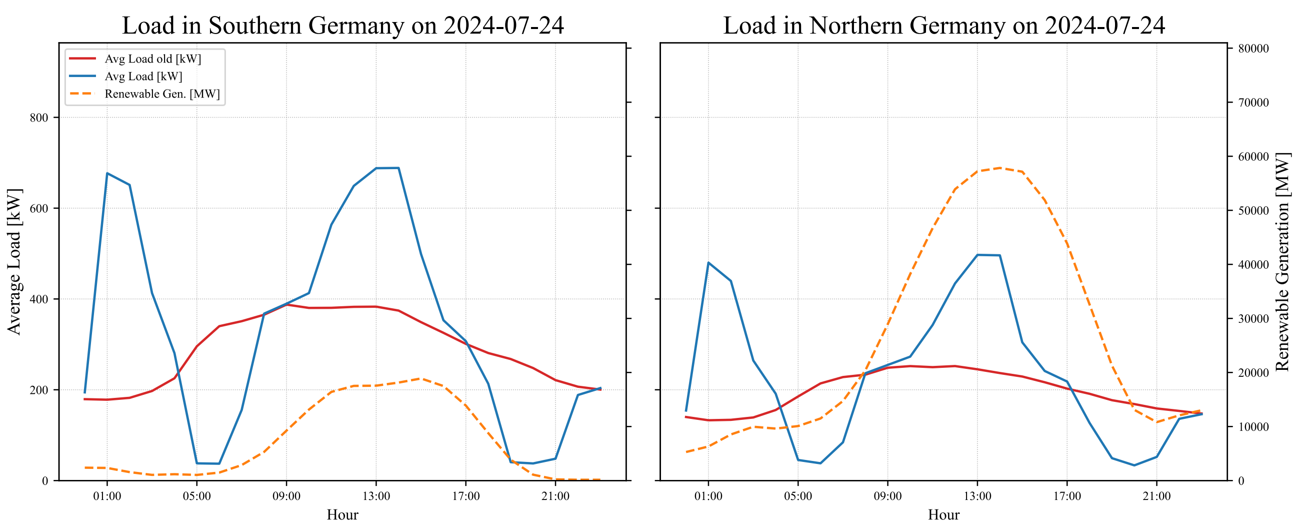


**Fig. 6.** Load change behavior in Northern and Southern Germany for Regulation 2.

data were sourced from the respective transmission system operators: 50Hertz for North-East Germany and TransnetBW for Southern Germany (ENTSO-E, 2025).

It is clear to see that the optimized load profiles show a distinct peak during noon, coinciding with the maximum in renewable energy generation and consequently low Day-Ahead market prices. In addition to this midday peak, the profiles also show a significant increase in electricity consumption during nighttime hours, which can be attributed to BESS charging activities. During generally more expensive morning and evening hours, the load is significantly decreased by discharging. The plot also shows a generally higher electricity consumption by companies in southern Germany, while the renewable generation is generally lower compared to northern Germany.

## 4. Discussion

### *4.1. Get the incentives right*

The observed load-shifting behavior under the proposed regulations highlights a fundamental challenge in tariff design: ensuring that economic incentives for individual actors align with overall system efficiency and grid stability. While the dynamic energy pricing mechanisms successfully incentivize electricity consumption during midday they also lead to significant increases in grid power consumption during nighttime hours due to battery charging. This behavior, while system-friendly in terms of temporal alignment with renewable generation and market signals, may not necessarily be grid-friendly, particularly if it worsens local network congestion or transformer loading.

Furthermore, the removal or weakening of capacity-based grid fee components diminishes the financial signal to limit peak loads. This erodes incentives for possible grid-friendliness, as companies no longer face cost penalties for sharp load increases, potentially contributing to localized grid stress.

The current policy also lacks cost-reflexivity. As such, companies are not financially motivated to adjust consumption in ways that mitigate operational burdens on the grid. This absence of dynamic price signals leads to a disconnect between individual consumption patterns and collective grid optimization, undermining system efficiency.

Finally, the principle of cost-by-cause participation is only partially fulfilled. While large consumers benefit from reduced fees under intensive or atypical usage classifications, these reductions are not always tied to actual reductions in grid strain or avoided infrastructure investments. In fact, as shown in the results, some companies increase their maximum load outside designated periods without an economic penalty, effectively shifting rather than avoiding grid stress. This contradicts the intent of grid-friendly behavior and can lead to cross-subsidization from more grid-compliant consumers.

Taken together, these findings highlight general principles for grid tariff design that extend beyond the German context. First, incentives for flexibility must remain tied to peak-related cost drivers, as peak demand continues to determine infrastructure investment needs in most European grids. Second, dynamic energy-based price signals alone are insufficient if not complemented by capacity-based components that reflect local grid constraints. Third, preferential treatment of large or flexible consumers should be conditional on verifiable reductions in grid strain, rather than on consumption patterns alone. Finally, tariff structures should be designed to avoid systematic cross-subsidisation, particularly where smaller or less flexible consumers lack access to enabling technologies such as BESS.

### *4.2. Proposed regulations*

The two analyzed proposed regulatory changes aim to address the structural weaknesses of the current grid fee regime. Both introduce a dynamic energy price component tied to the Day-Ahead market, thus aiming to align grid fees with real-time market conditions and renewable feed-in. Proposed Regulation 1 simplifies eligibility and implementation by eliminating the full load hour threshold for intensive grid usage. It furthermore allows companies to achieve a significant cost reduction, improving economic attractiveness of flexible technologies and possibly increasing competitiveness of said companies. One disadvantage of the proposal could be the removed capacity price, which encourages companies to increase their peak load significantly. Furthermore, by eliminating the capacity price component, there is no basis for atypical grid usage anymore, from which mostly smaller companies could benefit. Therefore it may unfairly exclude these smaller consumers and favor already large consumers regardless of their actual contribution to grid load.

With the second proposed regulation retaining the capacity price it can provide fairer cost allocation by allocating the cost for the needed infrastructure to the actual consumer. It also allows grid operators revenue stability. On the downside it would require the grid operator to dynamically recalculate the capacity price in order to maintain revenue neutrality. Especially smaller distribution system operators could face potential issues here, as they may not have the capacity for continuous recalculation. Furthermore, the results show that while most companies gain a clear benefit in total cost reduction, some companies that cannot optimize themselves sufficiently might find themselves object to increased costs.

### *4.3. Further development and considerations*

The results suggest that further regulatory development should move toward strengthening cost-reflexivity and system-oriented incentives. Especially, peak loads continue to drive grid extension costs, yet the existing framework inadequately incentivizes their reduction. Locational and temporal price signals, as well as grid congestion patterns and renewable generation availability should be incorporated and used for calculating both energy and capacity price components to better guide demand-side flexibility in line with both system efficiency and grid friendliness. Moreover, policies should ensure that financial participation follows the cost-by-cause principle, avoiding cross-subsidization between grid-friendly and grid-intensive consumers. However, electricity grid infrastructure is unlikely to be financed solely through strictly incentive-compatible tariff components, suggesting a certain degree of non-linear or residual cost allocation may be inevitable.

Further research could extend the current analysis by incorporating multiple electricity price scenarios, as the present study relies on a single year of Day-Ahead market prices. Varying price trajectories could significantly influence the operational behavior of BESS, as well as the resulting economic outcomes. Moreover, the interaction between BESS and photovoltaic (PV) systems has not been considered. Future studies could assess which companies already operate PV installations, how these are remunerated, and under what conditions it would be economically viable to invest in new PV systems. Another important avenue for future research concerns the implications for grid operators. It is essential to investigate how grid operators must respond to individual company-level optimizations and to assess the potential emergence of feedback loops between grid operators and companies.

## 5. Conclusion and policy implications

This study analyzes the economic and system-level implications of BESS under current and proposed grid tariff regulations in Germany. Using a dataset of over 800 industrial load profiles, the results show that BESS deployment can substantially reduce electricity-related costs for industrial consumers. However, the structure of regulatory incentives critically determines how these cost reductions are achieved and whether they align with grid stability objectives. Under the current framework, grid fee reductions via atypical or intensive usage can incentivize counterproductive behavior, particularly increases in peak load outside designated periods, highlighting a misalignment between private optimization and system-level efficiency.

Two alternative regulatory designs were evaluated to address these shortcomings. Both introduce dynamic energy pricing linked to the Day-Ahead market and improve alignment with renewable generation patterns, notably through increased BESS charging during midday solar peaks. The first proposal removes capacity-based charges and full-load-hour thresholds, yielding strong cost reductions but weakening incentives to limit peak demand and potentially disadvantaging smaller consumers. The second retains a capacity component while recalibrating it to ensure revenue neutrality, resulting in a clearer link between peak demand and infrastructure costs, albeit at the expense of higher administrative complexity for grid operators.

Although the analysis focuses on Germany, the identified incentive mechanisms and distributional effects are relevant for other European countries reforming grid tariff structures, particularly those expanding capacity-based charges, introducing dynamic pricing, or granting preferential treatment to energy-intensive industries. Across these contexts, the results underscore the importance of tariff designs that remain cost-reflective, preserve incentives to limit peak demand, and avoid systematic cross-subsidization between flexible and inflexible consumers.

Overall, the findings suggest that combining dynamic energy-based price signals with capacity-based grid fees can better align industrial flexibility with system needs. While such designs may increase regulatory and operational complexity, they offer a more robust framework for integrating BESS and other flexible technologies in a way that supports grid stability, equitable cost allocation, and long-term infrastructure financing.

## CRediT authorship contribution statement

**Julius Beranek:** Writing – original draft, Visualization, Validation, Software, Methodology, Investigation, Formal analysis, Conceptualization. **Nicole Niesler:** Writing – review & editing, Validation, Investigation. **Patrick Jochem:** Writing – review & editing, Validation, Investigation. **Armin Ardone:** Writing – review & editing, Supervision, Project administration, Funding acquisition. **Wolf Fichtner:** Writing – review & editing, Supervision, Funding acquisition.

## Declaration of generative AI and AI-assisted technologies in the writing process

During the preparation of this work the authors used ChatGPT to improve readability and language of the work. After using this tool, the authors reviewed and edited the content as needed and take full responsibility for the content of the publication.

## Declaration of competing interest

The authors declare the following financial interests/personal relationships which may be considered as potential competing interests:

Julius Beranek reports that financial support was provided by German Federal Ministry of Research, Technology and Space (BMFTR). Patrick Jochem reports that financial support was provided by DLR-VIMITRANS. Nicole Niesler reports that financial support was provided by German Federal Ministry of Research, Technology and Space (BMFTR). If there are other authors, they declare that they have no

known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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## Appendix A. Full optimization model

$$\min. \quad (\kappa_{bt} + \kappa_{\text{elec}} + \phi) - R \tag{A.1}$$

$$[1ex]\text{s.t.} \quad \kappa_{bt} = \frac{I_{bt}\, N_{bt}\, C_{bt}}{L_{bt}} + M_{bt}\, N_{bt}\, C_{bt}, \forall t \in T \tag{A.2}$$

$$\kappa_{\text{elec}} = \sum_{t \in T} \left[ E_t^{\text{grid}} \cdot (p_t^{\text{spot}} + \chi) \right] \tag{A.3}$$

$$R = \sum_{t \in T} \left( x_t^{\text{grid}}\, p_t^{\text{spot}} \right) + R_{\text{atyp}} + R_{\text{intensive}} \tag{A.4}$$

$$SoC_t = SoC_{t-1} + \left( \mu^c \cdot y_t^{grid} - \frac{x_t^{grid} + x_t^{load}}{\mu^d} \right), \forall t \in T \tag{A.5}$$

$$SoC_0 = SoC^{start} \cdot C^{max} \cdot N^{bt} \tag{A.6}$$

$$SoC_t \le SoC^{ub} \cdot C^{max} \cdot N^{bt}, \forall t \in T \tag{A.7}$$

$$SoC_t \ge SoC^{min} \cdot C^{max} \cdot N^{bt}, \forall t \in T \tag{A.8}$$

$$x_t^{grid} \le \frac{SoC^{ub} \cdot C_{bt} \cdot N_{bt} - SoC_{t-1} \cdot C_{bt} \cdot N_{bt}}{\mu^c}, \forall t \in T \tag{A.9}$$

$$y_t^{grid} \le y^{max}, \forall t \in T \tag{A.10}$$

$$y_t^{load} + y_t^{grid} \le \mu^d \cdot \left( SoC_{t-1} \cdot C_{bt} \cdot N_{bt} - SoC^{min} \cdot C_{bt} \cdot N_{bt} \right), \forall t \in T \tag{A.11}$$

$$x_t^{load} + x_t^{grid} \le x^{max}, \forall t \in T \tag{A.12}$$

$$y_t^{load} + g_t^{load} = E_t, \forall t \in T \tag{A.13}$$

$$y_t^{grid} \le BigM \cdot b_{cd,t}, \forall t \in T \tag{A.14}$$

$$x_t^{grid} + x_t^{load} \le BigM \cdot (1 - b_{cd,t}), \forall t \in T \tag{A.15}$$

$$E_{grid}^{total} = \sum_{t \in T} (g_t^{load} + y_t^{grid}) \tag{A.16}$$

$$P_{max} \le P_0^{max} + C_{bt} \cdot cr_{bt} \cdot N_{bt} \tag{A.17}$$

$$\tau \cdot P_{max} = E_{total}^{grid} \tag{A.18}$$

$$\tau - 2,500 \le BigM_\tau \cdot b_\tau \tag{A.19}$$

$$\tau - 2,500 \ge \epsilon - BigM_\tau \cdot (1 - b_\tau) \tag{A.20}$$

$$P_{max} \cdot cp_h + E_{total}^{grid} \cdot ep_h - GF \le BigM_\tau \cdot (1 - b_\tau) \tag{A.21}$$

$$P_{max} \cdot cp_h + E_{total}^{grid} \cdot ep_h - GF \ge -BigM_\tau \cdot (1 - b_\tau) \tag{A.22}$$

$$P_{max} \cdot cp_l + E_{total}^{grid} \cdot ep_l - GF \le BigM_\tau \cdot b_\tau \tag{A.23}$$

$$P_{max} \cdot cp_l + E_{total}^{grid} \cdot ep_l - GF \ge -BigM_\tau \cdot b_\tau \tag{A.24}$$

$$cp \le cp_h + BigM_\tau \cdot (1 - b_\tau) \tag{A.25}$$

$$cp \ge cp_h - BigM_\tau \cdot (1 - b_\tau) \tag{A.26}$$

$$cp \le cp_l + BigM_\tau \cdot b_\tau \tag{A.27}$$

$$cp \ge cp_l - BigM_\tau \cdot b_\tau \tag{A.28}$$

$$R_{atyp.}^{aux.} \ge P_{Diff} \cdot cp_l - BigM_{atyp.} \cdot b_\tau \tag{A.29}$$

$$R_{atyp.}^{aux.} \le P_{Diff} \cdot cp_l + BigM_{atyp.} \cdot b_\tau \tag{A.30}$$

$$R_{atyp.}^{aux.} \ge P_{Diff} \cdot cp_h - BigM_{atyp.} \cdot (1 - b_\tau) \tag{A.31}$$

$$R_{atyp.}^{aux.} \le P_{Diff} \cdot cp_h + BigM_{atyp.} \cdot (1 - b_\tau) \tag{A.32}$$

$$R_{atyp.} \le R_{atyp.}^{aux.} \tag{A.33}$$

$$R_{atyp.} \le 0.8 \cdot GF \tag{A.34}$$

$$P_{Diff} \le P_{max} - P_{max}^{PDP} \tag{A.35}$$

$$P_{max}^{PDP} \ge y_t^{load} + y_t^{grid}, \forall t \in PDP \tag{A.36}$$

$$E_{total}^{grid} \ge 10,000,000 - BigM_{int.} \cdot (1 - b_{80}) \tag{A.37}$$

$$E_{total}^{grid} \ge 10,000,000 - BigM_{int.} \cdot (1 - b_{85}) \tag{A.38}$$

$$E_{total}^{grid} \ge 10,000,000 - BigM_{int.} \cdot (1 - b_{90}) \tag{A.39}$$

$$b_{int.} \ge b_{80} \tag{A.40}$$

$$b_{int.} \ge b_{85} \tag{A.41}$$

$$b_{int.} \ge b_{90} \tag{A.42}$$

$$\tau \ge 7000 - BigM_{int} \cdot (1 - b_{80}) \tag{A.43}$$

$$\tau \ge 7500 - BigM_{int} \cdot (1 - b_{85}) \tag{A.44}$$

$$\tau \ge 8000 - BigM_{int} \cdot (1 - b_{90}) \tag{A.45}$$

$$b_{80} + b_{85} + b_{90} \le 1 \tag{A.46}$$

$$GF_{80} \le BigM_{int} \cdot (1 - b_{80}) \tag{A.47}$$

$$GF_{85} \le BigM_{int} \cdot (1 - b_{85}) \tag{A.48}$$

$$GF_{90} \le BigM_{int} \cdot (1 - b_{90}) \tag{A.49}$$

$$R_{intensive} = GF_{80} + GF_{85} + GF_{90} \tag{A.50}$$

$$R_{aytp} \le BigM_{exclusive} \cdot b_{exclusive} \tag{A.51}$$

$$R_{intensive} \le BigM_{exclusive} \cdot (1 - b_{exclusive}) \tag{A.52}$$

## Appendix B. Linearization of full load hours

To linearize the nonlinear full load hour constraint, we begin by transforming the fractional expression from Eq. (10) into a multiplicative form:

$$\tau \cdot P_{max} = E_{total}^{grid} \tag{B.1}$$

This expression is quadratic and thus incompatible with mixed-integer linear programming. To enable linearization, we introduce two auxiliary variables, $y_1$ and $y_2$, defined as:

$$y_1 = \frac{1}{2}(\tau + P_{max}) \tag{B.2}$$

$$y_2 = \frac{1}{2}(\tau - P_{max}) \tag{B.3}$$

These substitutions allow the original product to be expressed as a difference of squares:

$$y_1^2 - y_2^2 = \tau \cdot P_{\text{max}} \tag{B.4}$$

The bounds for $y_1$ and $y_2$ are derived from known lower and upper bounds of $\tau$ and $P_{max}$, denoted by $\underline{\tau}$, $\overline{\tau}$, $\underline{P_{max}}$, $\overline{P_{max}}$, respectively

$$\frac{1}{2}(\underline{\tau} + \underline{P_{max}}) \le y_1 \le \frac{1}{2}(\overline{\tau} + \overline{P_{max}}) \tag{B.5}$$

$$\frac{1}{2}(\underline{\tau} - \overline{P_{max}}) \le y_2 \le \frac{1}{2}(\overline{\tau} - \underline{P_{max}}) \tag{B.6}$$

Finally we replace $\tau \cdot P_{max}$ with $y_1^2 - y_2^2$ and use Special Ordered Sets of type 2 (SOS2), based on piecewise interpolation over breakpoints in the feasible ranges. This enables a fully linear reformulation of the original full load hour equation:

$$E_{total}^{grid} = y_1^2 - y_2^2 \tag{B.7}$$

$$y_1 = \frac{1}{2}(\tau + P_{max}) \tag{B.8}$$

$$y_2 = \frac{1}{2}(\tau - P_{max}) \tag{B.9}$$

$$\frac{1}{2}(\underline{\tau} + \underline{P_{max}}) \le y_1 \le \frac{1}{2}(\overline{\tau} + \overline{P_{max}}) \tag{B.10}$$

$$\frac{1}{2}(\underline{\tau} - \overline{P_{max}}) \le y_2 \le \frac{1}{2}(\overline{\tau} - \underline{P_{max}}) \tag{B.11}$$

## Data availability

The data supporting the findings of this study are publicly available at the source cited in the manuscript.

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