

STUDY

Dynamic Grid Fees for Batteries in the Distribution Grid

Quantitative assessment of the effects under realistic
conditions

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This study is available at neon.energy/netzentgelte-batterien-verteilnetz

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Neon conducted this study on behalf of E.ON, EWE NETZ, green flexibility, and enspire. The storage simulations were carried out by enspire; the participating distribution system operators provided redispatch data and grid loading data. Amprion accompanied the study in an advisory capacity and contributed technical input.

The content, assessments, and conclusions presented in this study reflect solely the views of the authors and not necessarily those of the commissioning parties.

Neon Neue Energieökonomik is an energy economics consultancy based in Berlin. As a boutique firm, we have specialized since 2014 in demanding quantitative and economic-theoretical analyses of the electricity market. With consulting projects, studies, and training, we support decision-makers in addressing the current challenges and future questions of the energy transition. Our clients include governments, regulators, grid operators, utilities, and electricity traders from Germany and Europe.

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Summary

Background. Battery storage in Germany is operated based on wholesale prices and balancing reserve activation. Shifting electricity from low-price to high-price hours saves generation costs and thereby creates economic value. However, battery dispatch ignores grid congestion. It sometimes relieves and sometimes aggravates congestion. In the absence of local price signals, there is no structural incentive to reduce grid congestion.

This study. This study examines whether dynamic grid fees in the distribution grid improve the system benefit of large-scale batteries. To this end, we compare different designs of symmetric, regional volumetric charges. We assess the effect of these grid fees quantitatively: we simulate storage operation for the year 2025 at three sites of the storage developer green flexibility in the distribution grids of E.DIS Netz, EWE NETZ, and Bayernwerk Netz, each with and without a dynamic grid fee.

Ideal case. The analyzed dynamic grid fees for storage in the distribution grid generate barely any additional benefit. In the theoretical ideal case, a continuous grid fee based on a perfect day-ahead congestion forecast, the dynamic grid fee does reduce redispatch costs by 3 to 15 EUR per kW of storage capacity and year. However, the dynamic grid fee also sometimes prevents the battery from shifting electricity from low-price to high-price hours. The resulting loss in the battery's market value is roughly as large as the redispatch cost savings, hence no significant net economic value is created.

Realistic conditions. Under realistic conditions, a dynamic grid fee in the distribution grid can even do more harm than good. In one of the three cases we examined, a simplified 3-step grid fee reduces the system benefit of the battery even under perfect foresight. Too often, it avoids cheap redispatch but causes more expensive redispatch instead. If the grid fee is calculated based on congestion forecasts from 10 a.m. the day before, the system benefit falls in all cases examined.

Recommendations. The dynamic grid fees we examined are hence not a suitable instrument to reduce congestion in the distribution grid. However, in most grid regions there is also little need for action: significant curtailment occurs at the sites examined in only 7 % to 16 % of the time, so the grid fee cannot avoid redispatch in more than 80 % of the time. Moreover, batteries at the sites examined already reduce redispatch needs more often than they increase them, even without dynamic grid fees.

Transmission grid. Dynamic grid fees for storage in the transmission grid were not at the core of this study, not least because congestion forecasts for the transmission grid were not available for a more detailed analysis. The findings from the distribution grid cannot simply be transferred to the transmission grid.

1 Introduction

Status quo. Battery storage in Germany is dispatched on a market-driven basis: batteries charge when wholesale prices are low and discharge when prices are high. In addition, they provide balancing reserves when activated by the transmission system operators. Grid congestion plays no role in these dispatch decisions: given the politically mandated uniform bidding zone, there is no financial incentive to take grid congestion into account, and in the absence of corresponding information on the grid state, there has so far been no direct way of doing so either.

Untapped potential. From a grid perspective, the behavior of storage is therefore random: depending on the market situation, it sometimes relieves and sometimes aggravates congestion. Its potential to contribute to relieving grid congestion in addition to its market value has thus remained untapped. In surplus regions, renewables are curtailed even though storage in the same region could absorb the electricity. Available green electricity is thus not put to productive use. In deficit regions, gas-fired plants must be ramped up for upward redispatch even though storage capacity would be available. This causes CO₂ emissions.

Dynamic grid fees. Locationally differentiated dynamic grid fees could create incentives for storage to align its dispatch more closely with foreseeable grid congestion. If this succeeds, grid operators need less redispatch and its costs fall.

System benefit as the yardstick. To assess the economic effect of dynamic grid fees, we examine the system benefit of batteries with and without a grid fee. The system benefit is the sum of the value batteries create in the electricity markets and their value for the grid (Figure 1). Market value arises from shifting electricity over time: storage charges at low prices and discharges at high prices. This replaces expensive generation with cheaper generation and lowers overall generation costs. This applies to spot markets as well as to system services such as the provision of balancing energy and balancing capacity. Grid value arises when storage shifts its dispatch such that redispatch needs fall. A dynamic grid fee is economically sensible if market value and grid value increase in sum. The grid effect alone, by contrast, is not the objective: a fee that slightly reduces redispatch costs but, as collateral damage, strongly reduces the battery's market value leads to higher system costs overall.

System benefit of a large-scale battery (illustrative)

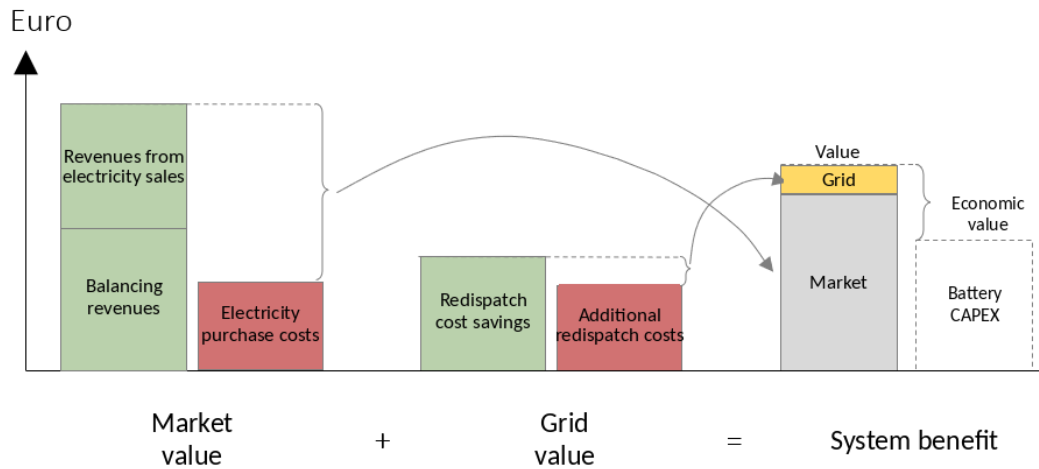


Figure 1: The system benefit of a large-scale battery is the sum of its market value and its grid value (conceptual illustration).

This study. This study examines dynamic grid fees for large-scale battery storage in the distribution grid. The aim of the grid fees is to reduce local redispatch needs at the respective substation. The grid fees examined are set at 10 a.m. on the day before delivery and not adjusted thereafter. To this end, we develop a calculation logic and discuss design options. We assess the effect of these grid fees quantitatively for example sites in the distribution grids of E.DIS, EWE NETZ, and Bayernwerk.

2 Grid fee calculation

In this chapter, we discuss different options for calculating dynamic grid fees. These include the basic structure and level of the fee, a minimum volume of redispatch needs above which the grid fee is activated, and cascading across grid levels.

2.1 BASIC IDEA: SYMMETRIC REGIONAL VOLUMETRIC CHARGES

Dynamic signal. We examine a grid fee in the form of dynamic, symmetric, and regional volumetric charges. These are based on the expected redispatch needs in the respective grid region. In hours in which a region generates more electricity than it consumes and the surplus cannot be transported away, this surplus must be curtailed (“downward redispatch”). This can be avoided if a local storage unit draws electricity from the grid. At those times and places, the grid fee makes grid withdrawal by storage cheaper and grid injection more expensive. Where and when, by contrast, local consumption exceeds local generation and not enough electricity can be procured from other regions due to grid congestion, grid operators ramp up additional generation (“upward redispatch”). This is generally the case only in the transmission grid. Here, the grid fee makes charging more expensive and discharging cheaper. If there are no redispatch needs, the grid fee is 0 EUR/MWh (Figure 2). The fee is symmetric because the grid fees for withdrawal and injection at a given location are equal in magnitude at any point in time but have opposite signs.

Price signal of the dynamic grid fee (illustrative)

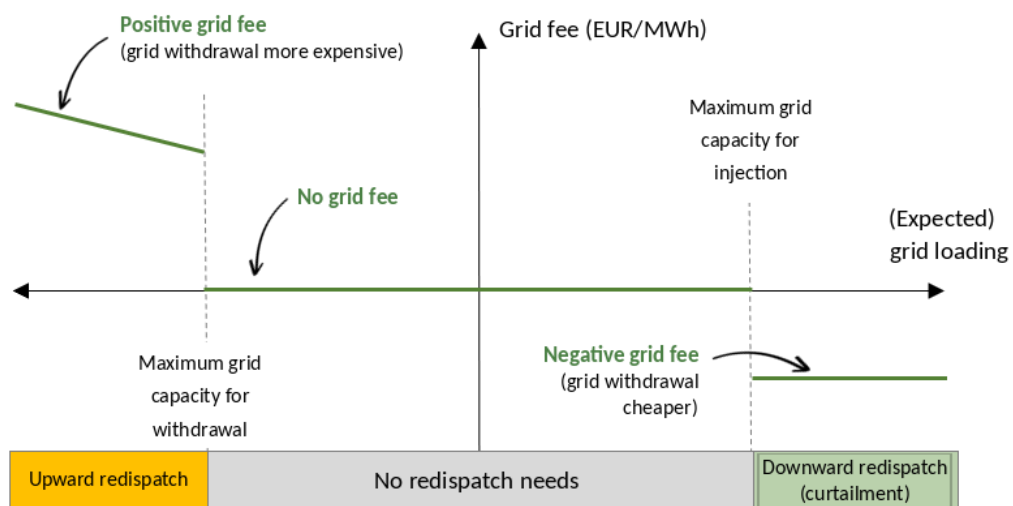


Figure 2: The grid fee at a given point in time depends on the redispatch needs in the respective region. It favors grid withdrawal by storage where and when electricity would otherwise be curtailed, and makes grid withdrawal more expensive where and when there is too little electricity in the grid.

2.2 LEVEL OF THE GRID FEE

Level of the grid fee. The grid fees we examine are based on the short-run marginal costs of congestion management. These marginal costs indicate the additional costs that withdrawing or injecting one additional kilowatt-hour of electricity causes in grid operation. The short-run marginal costs of grid operation are driven primarily by the costs of congestion management. They differ depending on local redispatch needs.

Upward redispatch. When upward redispatch is needed, grid operators generally ramp up power plants. The marginal costs of upward redispatch depend on the costs of the most expensive plant still required and on that plant's sensitivity to the congested element. If, for example, a plant must be ramped up that relieves the congestion only marginally, the marginal costs of redispatch can be well above the variable costs at which the activated plant is remunerated. The marginal costs of redispatch therefore vary strongly with the volume of redispatch needed: the more redispatch is required, the more expensive or more distant the plants that must be activated, with a smaller load-flow effect on the congested element. On average, the costs of ramping up conventional power plants (upward redispatch) amounted to 150 EUR/MWh in 2025.¹ In individual quarter-hours, however, costs can be considerably higher.

Downward redispatch. When downward redispatch is needed, grid operators curtail generation. In the distribution grids considered, this almost exclusively affects wind and PV plants. Under balancing-group compensation², the balancing group of the affected balance responsible party is treated as if the redispatch measure had not taken place. In addition, the grid operator reimburses the market premium for plants receiving renewable support. As a result, the plant operator or direct marketer suffers no financial disadvantage. The grid operator bears the costs of the balancing-group or financial compensation. These costs depend primarily on the time of procurement. At the time the grid fee is set, these costs are not yet known precisely. As a first approximation, they can be approximated by the day-ahead price. The marginal costs of curtailing renewables are therefore almost independent of how many plants are curtailed. Notable cost differences arise only if much more distant plants must be curtailed, for which considerably more capacity has to be curtailed to achieve the same effect on the congested element. In addition to balancing-group compensation, operators of renewable plants under the EEG support regime also receive compensation for the forgone market premium. Since this premium would also be paid without curtailment, we do not include it in the calculation of the marginal costs of downward redispatch.

¹ Own calculation based on [SMARD](#), "Netzengpassmanagement im Gesamtjahr 2025". In 2025, the deployment costs of conventional redispatch amounted to 1,176 million EUR for 7,732 GWh of upward redispatch (excluding grid reserve).

² Balancing-group compensation currently applies only to plants under the schedule-based model (Planwertmodell). For plants under the forecast-based model (Prognosemodell), replacement procurement in case of curtailment is carried out by the balance responsible party until 2031, which in return receives financial compensation from the grid operator based on short-term electricity prices.

Optimal incentive. We examine grid fees based on the marginal costs of grid operation in the respective region because an additional storage unit, depending on how it is operated, can avoid or cause exactly these costs. In this way, the grid costs avoided or caused by storage dispatch are taken into account in operating decisions. As a result, the storage unit is operated as if the electricity system as a whole were being optimized, with generation, storage, and grids in a joint optimization model. In addition to market prices, the storage unit thus also takes into account the costs that its behavior causes or avoids for the grid. Consequently, it relieves congestion whenever its contribution to avoiding redispatch costs exceeds the value of alternative uses. If, for example, the storage unit's short-term flexibility is worth more in other markets, it would not respond to the grid fee and other plants would be curtailed instead.

Continuous grid fee. The level of a fee defined in this way can change every quarter-hour, depending on the marginal costs of redispatch. We therefore refer to this variant as a continuous grid fee.

Floor at negative electricity prices. At negative electricity prices, the marginal costs of downward redispatch can also become negative. The compensation of curtailed plants is based on the forgone market value of the electricity; if this is negative, the direction of payment reverses and the grid operator receives compensation from the curtailed plants. If a battery charges from the grid in this situation, it prevents the curtailment and the grid operator forgoes this revenue. A strict marginal-cost logic would then charge a fee for charging. This, however, creates an incentive to increase the local electricity surplus. We therefore propose to floor the grid fee for grid withdrawal in surplus regions at 0 EUR/MWh when electricity prices are negative: the battery then receives no payment for withdrawing electricity, but does not have to pay for it either.

2.3 ACTIVATION THRESHOLD

Feedback. Ideally, the grid fee should be designed such that it already accounts for the expected storage response. For example, curtailment needs fall if storage in a surplus region draws considerably more electricity from the grid because of the grid fee. A grid fee that ignores this response can cause the storage unit to overreact.

Challenge. Predicting the storage response to a given price signal is challenging, however. It depends in particular on market prices and the state of charge and can therefore differ completely at different times. Estimating the storage response would face the same challenges as integrating storage into redispatch. If it were easy, there would be no reason not to adjust storage behavior exclusively via redispatch.

Activation threshold. Because calculating this optimal price signal will be difficult in practice, we choose an approach that is easier to implement. We calculate the grid fee without accounting for the storage response. To avoid the grid fee systematically providing excessive incentives for the storage unit to change its behavior, we introduce a minimum volume of

expected redispatch needs above which the grid fee for storage is activated. We call this minimum volume the “activation threshold”. In determining these redispatch needs, we do not account for the behavior of the storage unit. The threshold should be based on the expected storage response and should therefore increase with growing storage penetration.

2.4 CASCADING ACROSS GRID LEVELS

Challenge. Dynamic grid fees can be calculated for congestion at different voltage levels. A risk arises if the grid fee is passed down from higher to lower voltage levels. A storage unit connected to the distribution grid could cause or aggravate local congestion if it follows the signal from the transmission grid. A dynamic fee of the higher grid level should therefore not be passed on indiscriminately to assets at lower grid levels.

Go/no-go logic. Under the calculation method examined, the level of the grid fee is the same across grid levels. Since specific redispatch costs are of a similar magnitude at all voltage levels, there is no reason under this logic for fees to increase at lower voltage levels. Instead of a complex price cascade in which each grid level calculates its own fee, we therefore propose a simple logic analogous to clustering in Redispatch 2.0: if there is no local congestion, the grid fee of the higher grid level is passed through. If there is local congestion, the grid fee follows the redispatch needs of the connecting grid operator.

3 Methodology

Approach. We assess the effect of dynamic grid fees quantitatively by simulating the operation of battery storage based on historical data for the year 2025. In a first step, we calculate dynamic grid fees. In a second step, storage operation is calculated with and without grid fees. The storage unit is optimized across several markets: the wholesale market, in particular continuous intraday trading, the provision of balancing energy and balancing capacity, and grid fee payments. For our analysis, we assume that the storage unit is not used for redispatch. This optimization was carried out by the battery optimizer enspired. The result is the commercially optimal dispatch of the storage unit in each scenario. In a third step, we assess the differences between the scenarios with and without grid fee from three perspectives: the effect of the storage unit on the grid (“grid value”), its revenues in the electricity market (“market value”), and the sum of the two (“system benefit”).

Three sites. We carry out the calculations for example projects of the battery developer and operator green flexibility at three sites. At all three sites, 2-hour storage systems with approximately 10 to 20 MW of capacity were examined.

Redispatch needs. The three sites are HV/MV substations in the distribution grids of E.DIS, EWE NETZ, and Bayernwerk. In each case, substations were selected at which redispatch occurred between 7 % and 28 % of the time in 2025 (Figure 3). However, we apply a grid fee only if redispatch needs exceed 50 % of the installed storage capacity. At the E.DIS site, this corresponds to redispatch volumes above 6 MW, at EWE to about 8 MW, and at Bayernwerk to above 10 MW. The grid fee thus applies between 7 and 16 % of the time (Figure 3). The three grids have in common that upward redispatch is never required there, i.e., no consumption-driven congestion occurs. In all three grids, congestion is generation-driven. Its causes differ between the sites, however: at E.DIS and EWE NETZ, redispatch is triggered primarily by wind generation, at Bayernwerk by PV generation. In none of the grids does upward redispatch occur at the HV/MV level.

Frequency of local congestion

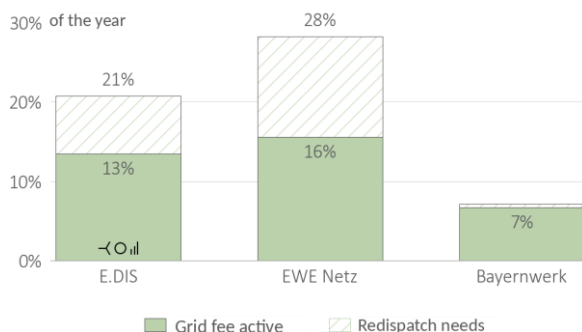


Figure 3: Share of quarter-hours in which curtailment occurs at the substation. The grid fee applies when curtailment exceeds the respective activation threshold.

Grid fee for the distribution grid. This study focuses on grid fees to reduce congestion in the distribution grid. The grid fees are thus intended to reduce local redispatch needs at the respective substation. To determine the grid fee, we therefore used only the curtailed energy at the respective HV/MV substation. Additional redispatch requests from the transmission grid are considered only in Section 4.5.

Level of redispatch costs. We derive the level of the grid fee examined from the marginal costs of redispatch. The actual redispatch costs in the regions are not available to us, so we make simplifying assumptions:

- The marginal costs of downward redispatch equal the spot price. This is based on the assumption that renewables are curtailed at the substations examined. The balancing-group compensation of curtailment causes costs roughly equal to the spot market price. The grid fee in these regions is floored at 0 EUR/MWh. Thus, even at negative electricity prices, no negative grid fee (in the withdrawal direction) is charged.
- We set the marginal costs of upward redispatch at 150 % of the day-ahead price. This yields a time series whose mean corresponds to the average costs of upward redispatch of around 150 EUR/MWh.

Determination the day before. We examine grid fees that are set at 10 a.m. on the day before delivery and not adjusted thereafter. This entails two decisive disadvantages.

No feedback. With grid fees that are set before delivery and not changed thereafter, there is no feedback from the behavior of market participants to the price signal, since the grid fee is already fixed. In this respect, dynamic grid fees differ fundamentally from market prices for electricity. This makes determining a suitable price signal challenging, all the more so the more storage units are affected by the grid fee. The problem can be mitigated with auxiliary constructs such as an activation threshold, but not avoided entirely.

No short-term adjustments. Grid fees set the day before cannot take into account information that materializes only after the grid fee has been set. The grid fees thus provide wrong incentives if the loading forecast of individual grid elements changes after the grid fee has been set, e.g., because weather forecasts have changed.

Forecast. We calculate grid fees based on the curtailed energy at the substation and based on loading forecasts for the respective substation provided to us by the grid operators. The forecasts are produced by an external service provider and are based on historical measurement data and weather forecasts. They are updated continuously over the course of the day; however, we use only the forecast available at 10 a.m. on the day before.

Methodological challenge. Using loading forecasts raises several methodological challenges. The available forecasts estimate the expected loading of the respective substation without, however, taking into account the (expected) redispatch requests from upstream grid levels. Such requests, however, change the measured values at the transformer. As a result, forecasts and measurements are not directly comparable at times when upstream grid operators request redispatch.

Approach. We addressed this challenge by selecting for the analyses a substation at which practically no redispatch is requested by upstream grid operators. Since this was the case only

at substations with few redispatch requests overall, we artificially reduce the capacity of the substation to generate additional congestion events. This approach yields comparable forecasts and measurements for assessing the magnitude of the fundamental forecast errors.

Marginal perspective. In calculating the grid fees, we consider only the historical redispatch needs that actually occurred. Logically, these do not reflect the effects of a storage unit that has not yet been built. For individual smaller storage units, this is a plausible approach. However, it cannot capture a future ramp-up of storage and the associated interactions among many storage units. With higher storage penetration, additional challenges arise in the fee calculation because storage behavior has an (even) stronger influence on the expected redispatch volumes needed for the calculation.

4 Results

In the following section, we present the results of our quantitative analyses. We show that the storage units examined already predominantly reduce grid congestion without a dynamic grid fee, and that the dynamic grid fee creates only a small additional benefit even in the theoretical optimum, which quickly turns into a welfare loss under more realistic conditions.

4.1 STORAGE OPERATION WITHOUT GRID FEE

Battery operation. A battery reduces redispatch needs if it charges from the grid while downward redispatch is required in the region. This allows local surplus electricity to be used and the curtailment of generation to be avoided. Conversely, the battery's withdrawal causes additional redispatch needs if upward redispatch is required in the region, since more power plant capacity then has to be ramped up. In total, there are nine conceivable combinations of battery dispatch and redispatch needs (Figure 4). In two of the nine combinations, the battery relieves congestion, in two others it aggravates congestion, and in five combinations it has no effect on redispatch needs, i.e., it is grid-neutral.

Congestion effect of a battery

Local scarcity (upward RD)	Aggravates congestion		Relieves congestion
No congestion (no RD)		No congestion effect	
Local surplus (downward RD)	Relieves congestion		Aggravates congestion
	Charging	Idle	Discharging
	Battery dispatch		

Figure 4: Congestion effect of a battery depending on its operating behavior and local redispatch needs.

Sites. At all three substations examined, the congestion-relieving effect of the storage unit on the distribution grid predominates even without a dynamic grid fee. However, the grid effect of a storage unit differs between the sites examined (Figure 5). It depends primarily on the congestion pattern of the site. At the E.DIS and EWE Netz sites examined, congestion is driven primarily by wind generation. It is long-lasting and only weakly correlated with market prices.

Market-driven storage dispatch relieves congestion here in 12 and 15 % of the year, respectively, but also causes higher redispatch needs in 7 and 11 % of the time. In about 80 % of the time, there is no local congestion and storage behavior therefore has no effect on the redispatch volume. At the Bayernwerk Netz site, by contrast, congestion is driven primarily by PV generation. Here, local congestion is strongly correlated with the electricity price: on sunny days, prices are low around midday and there is a local electricity surplus. Because of the low prices, storage frequently draws electricity from the grid in these hours and thus reduces the local surplus. This is the case in 6 % of the time. Storage dispatch, by contrast, almost never increases local redispatch needs. This is the case in only 1 % of the hours.

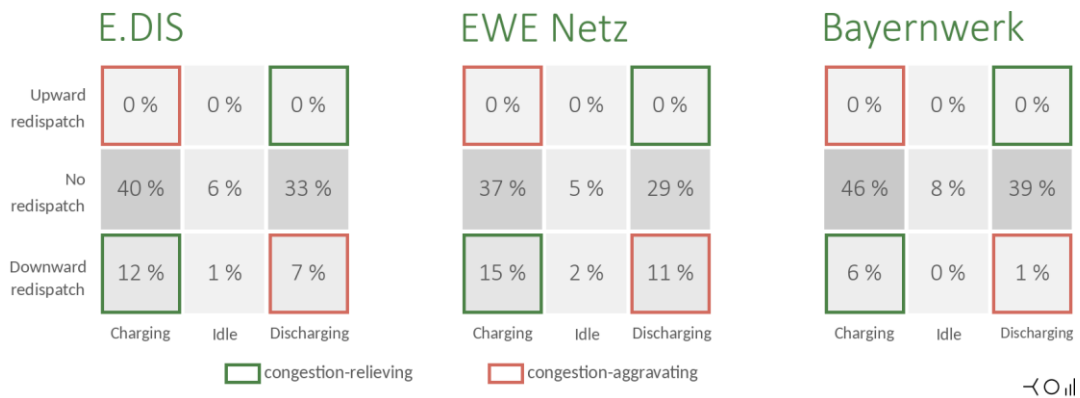


Figure 5: The grid effect of the storage units without a grid fee is predominantly positive at all sites examined: at all three sites, the storage units relieve congestion (green) more often than they aggravate it (red), by about 5 % of the year.

Redispatch costs. The grid effect of the storage unit can also be expressed as redispatch costs avoided by the storage unit. These result from the difference between the redispatch costs avoided by the storage unit and the additional redispatch costs it causes. To this end, we multiply the time series of the storage unit's redispatch effect by the time series of redispatch costs. For example, at the Bayernwerk Netz site, 1 kW of storage capacity avoids redispatch worth 1.6 EUR/kW per year and causes 0.4 EUR/kW of additional redispatch costs. In sum, the storage unit thus saves redispatch costs of 1.2 EUR per kW of storage capacity per year. For a 20 MW storage unit, this would correspond to net savings of about 25,000 EUR per year. EWE Netz shows a peculiarity. Without a grid fee, the storage unit avoids more redispatch than it causes in terms of volume. However, because it frequently avoids only cheap redispatch while causing expensive redispatch, it nevertheless leads to an increase in redispatch costs of around 2 EUR per kW of storage capacity per year. The key result, however, is not the positive or negative sign but the overall very small effect of storage on redispatch costs. Over the year, storage has no notable effect on redispatch costs at any of the sites.

4.2 HYPOTHETICAL IDEAL CASE

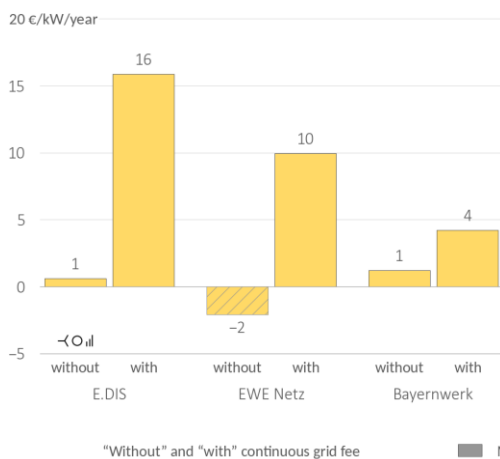
Ideal case. Dynamic grid fees would probably be set the day before, ahead of the day-ahead auction, so that market participants can take them into account in their day-ahead bids. At

that time, however, redispatch needs and their costs are not yet known. To show the maximum achievable benefit of dynamic grid fees in the distribution grid, we first examine the (hypothetical) ideal case. For this, we determine the grid fee at quarter-hourly resolution based on actual redispatch needs and their costs.

Result. Under these idealized conditions, the grid fee works as intended. The storage unit preferentially charges in hours in which electricity would otherwise have to be curtailed at the substation. The storage unit thereby reduces redispatch volumes and also redispatch costs at all three sites (Figure 6, left). With the grid fee, however, the value the storage unit creates in the electricity markets also falls, since it no longer optimizes its dispatch solely on the basis of market prices. In sum, the positive effect on grid value prevails and the system benefit increases (Figure 6, right).

Perspective. However, the added value of dynamic grid fees is small even in this hypothetical ideal case. At EWE Netz and Bayernwerk, the system benefit increases by less than 1 EUR/kW per year, which corresponds to less than 0.5 % of the storage unit's system benefit. At the E.DIS site, it is at least 8 EUR/kW per year (4 % of the storage unit's system benefit).

Grid value



Grid and market value

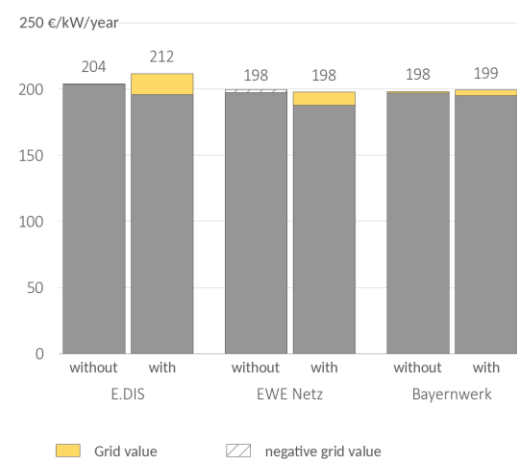


Figure 6: Grid and market value with a continuous grid fee under perfect foresight. With this best possible grid fee, the storage unit reduces redispatch costs at all three sites (left). This higher grid value is, however, largely offset by the lower market value. The system benefit, i.e., the sum of grid and market value, increases only minimally.

PV-dominated grids. The small effect of the dynamic grid fee has different causes depending on the grid area. At PV-dominated sites, such as in the Bayernwerk grid, storage already predominantly relieves congestion without a grid fee: it frequently charges in the sunny midday hours when there is a local electricity surplus. In these cases, the grid fee can hardly save additional redispatch costs (Figure 6, left). Moreover, with the calculation logic used, grid fees in these regions are relatively low. At the Bayernwerk Netz site, for example, the average grid fee during downward redispatch is only 24 EUR/MWh, compared with 61 EUR/MWh at EWE Netz. This is because the level of the grid fee is based on local redispatch costs. These correspond to the electricity prices at the time of curtailment, which are generally low in the case of PV.

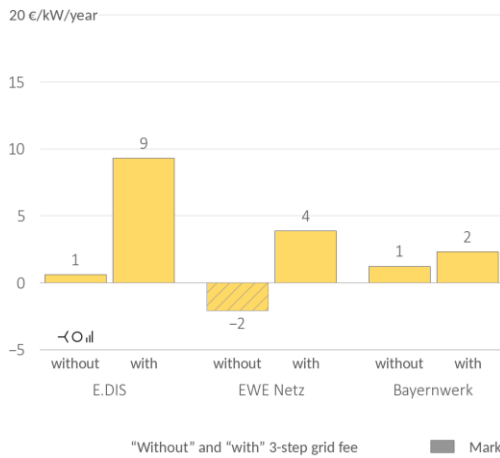
Wind-dominated grids. In the wind-dominated grids, the dynamic grid fee creates only a small additional system benefit for a different reason. In these regions, congestion periods often last many hours or even days. A storage unit can serve short congestion events well: it charges during the congestion and discharges as soon as it is over. If, by contrast, downward redispatch needs persist continuously, the grid fee is permanently active and therefore has hardly any influence on the storage unit's dispatch behavior.

4.3 3-STEP GRID FEE

Simplified grid fee. In the calculation variant discussed so far, the dynamic grid fee is a continuous quantity derived from redispatch costs that vary every quarter-hour. These costs, however, are not known at the time the fee is calculated. We therefore examine a much simpler variant with three fixed price steps. In times of curtailment, the storage unit receives, when withdrawing from the grid, the annual market value of the electricity curtailed in the region. We calculate this as the average day-ahead market value of electricity weighted by curtailment at the same substation. At the substations we examined, it ranges from 24 EUR/MWh at Bayernwerk to 61 EUR/MWh at EWE Netz. When injecting into the grid, the storage unit pays this value. If there is no congestion, the fee is 0 EUR/MWh. In times of upward redispatch needs, the grid fee would equal the average costs of upward redispatch in the region. However, since upward redispatch needs never occur at the distribution grid sites examined, the 3-step grid fee in our analyses *de facto* has only two steps.

Results. The grid fee simplified to three steps also leads the storage unit to avoid more redispatch than without a grid fee at all three sites (Figure 7, left). Compared with the continuous grid fee, however, grid value is 2 to 7 EUR/kWh per year lower. This is because the 3-step fee does not distinguish between expensive and cheap redispatch. It partly reduces redispatch needs in time windows with low redispatch costs and increases them in time windows with high redispatch costs, instead of specifically avoiding expensive redispatch. This lower grid value is also reflected in the system benefit. With the 3-step grid fee, the system benefit at the EWE Netz site is even lower than without a grid fee (Figure 7, right). There, the simplified grid fee thus makes the electricity system more expensive rather than cheaper overall, even though the grid fee was calculated assuming perfect forecasts.

Grid value



Grid and market value

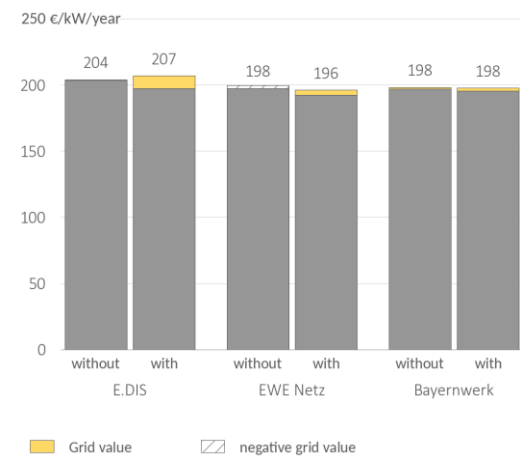


Figure 7: Grid and market value with a 3-step grid fee under perfect foresight. With this best possible grid fee, the storage unit reduces redispatch costs at all three sites (left). At the EWE Netz site, however, the storage unit's market value falls more sharply, so that the system benefit decreases. This is an example of how the 3-step grid fee can be harmful despite perfect foresight.

4.4 DETERMINATION BASED ON CONGESTION FORECASTS

Setup. In the analyses so far, we calculated the grid fees based on realized redispatch costs. These, however, are not known at the time the grid fee is determined. In this section, we therefore examine how the effect of dynamic grid fees changes when they are determined based on forecasts. To this end, we use grid loading forecasts for the respective connecting substations from 10 a.m. on the day before. We carry out the analyses only for the EWE Netz substation examined so far, as the corresponding forecast data are available to us only for this site. Methodological challenges of these loading forecasts and how we deal with them are described in more detail in the appendix.

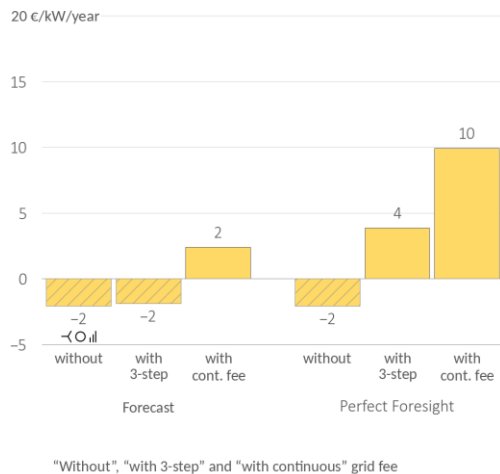
Forecast quality. The loading forecast is sometimes above and sometimes below actual grid loading. For the calculation of the grid fee, however, the exact level of grid loading is not relevant. What matters is whether or not the activation threshold of the grid fee is exceeded. The comparison of forecast and realized grid loading shows, however, that the forecasts predict exceedance of the activation threshold poorly (Table 1). In almost 80 % of the time, both realized and forecast redispatch needs are below the activation threshold. In the remaining time, the forecast is correctly above the activation threshold in 11 %, and the grid fee would rightly apply. However, in 4 % of the quarter-hours the forecast underestimates grid loading and wrongly fails to trigger a grid fee, and in 5 % of the time the forecast overestimates grid loading and triggers a grid fee even though actual loading is below the activation threshold. This example shows that a day-ahead forecast of wind generation at the spatial resolution of a single HV/MV transformer is subject to considerable uncertainty.

Table 1: Effect of forecast quality.

Realized grid loading ...	Forecast grid loading ...	
	... below the activation threshold	... above the activation threshold
... below the activation threshold	79% (true negative)	5% (false positive)
... above the activation threshold	4% (false negative)	11% (true positive)

More harm than good. Our analyses of storage behavior based on real forecasts show that the dynamic grid fee does more harm than good at the site examined. This applies to both the continuous and the 3-step grid fee. In both cases, the battery's grid value does increase and redispatch costs fall. But the grid fee reduces the battery's market value, and the system benefit falls overall when such a dynamic grid fee is introduced (Figure 8).

Grid value



Grid and market value



Figure 8: Grid and market value of a storage unit with forecast-based grid fees. The grid value from forecast-based dynamic grid fees is positive only with a continuous price signal and is lower overall than with perfect foresight. With both calculation methods, however, the system benefit with a forecast-based grid fee is negative.

4.5 GRID FEE FOR CONGESTION IN THE TRANSMISSION GRID

Congestion in the transmission grid. The grid fees we have examined so far aimed to reduce congestion at the HV/MV substation. In practice, however, a dynamic grid fee would likely target primarily congestion in the transmission grid, where redispatch volumes are considerably higher and occur more frequently.

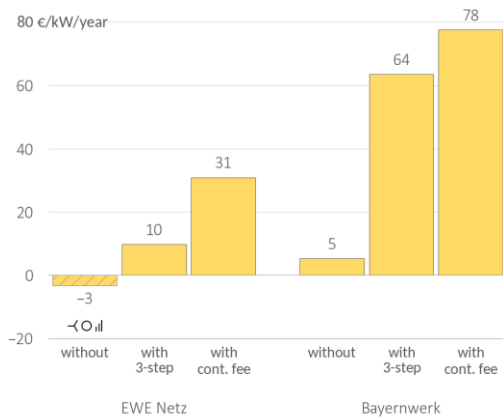
Second best. With regional electricity prices, for example through a split of the German bidding zone, the relevant congestion in the transmission grid would be reflected in wholesale

prices. Storage would take these into account in its dispatch decisions across all market stages (day-ahead, intraday, imbalance settlement, balancing capacity), and dynamic regional grid fees for the transmission grid would be superfluous. Even if perfectly designed, dynamic grid fees are clearly inferior to regional wholesale prices. Because grid fees are set *ex ante*, they do not constitute equilibrium prices. The grid fee remains in place even when the storage response has long since resolved the congestion or the grid loading forecast turns out to be wrong. Regional electricity prices, by contrast, would continuously adjust to changes in the behavior of storage (and other market participants) and to updated forecasts.

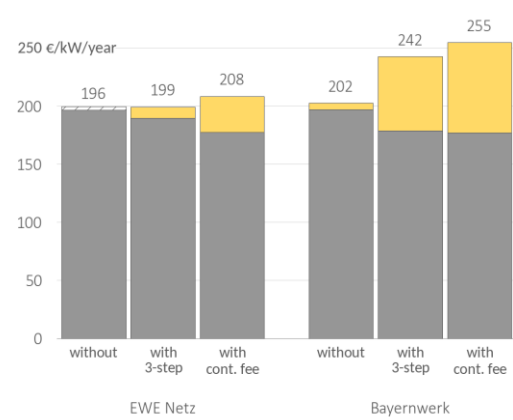
Approach. In this section, we analyze a dynamic grid fee that, in addition to congestion at the HV/MV substation, also accounts for congestion at the extra-high voltage level. To this end, we examine two sites in the grid areas of Bayernwerk and EWE Netz. At these sites, the grid fee is active around 40 % of the time, twice as often as when only local congestion is considered. In the absence of forecast data for the transmission grid, we could carry out this analysis only under the assumption of perfect foresight of redispatch volumes. It therefore remains an upper bound for estimating the benefit of dynamic grid fees.

Results. Under these theoretically ideal conditions, the effect of dynamic grid fees is much larger in the transmission grid than in the distribution grid. This is particularly evident at the Bayernwerk Netz site: under perfect foresight, introducing a continuous grid fee could save an additional 73 EUR of redispatch costs per kW of storage capacity and year (Figure 9). Even accounting for a reduced market value, this increases the battery's system benefit by about 25 %. At EWE Netz, grid value is also positive but remains considerably lower at 28 EUR/kW. The large difference between the two regions is largely explained by the fact that upward redispatch is much more expensive than downward redispatch; in the Bayernwerk grid, mainly upward redispatch occurs at the transmission grid level, and a grid-friendly operated storage unit can help reduce these high costs. We had not accounted for this effect in our previous studies (e.g., [Neon, 2025](#)).

Grid value



Grid and market value



"Without", "with 3-step" and "with continuous" grid fee

Market value

Grid value

negative grid value

Figure 9: Effect with and without the extra-high voltage level. Effect of the grid fee when the extra-high voltage level is taken into account (redispatch activations published via Netztransparenz for the respective grid area).

4.6 DISTRIBUTIONAL EFFECTS

Relevance. In the previous sections, we addressed the question of whether dynamic grid fees increase the system benefit of batteries, i.e., create economic value. What we have not examined is the distributional effect of dynamic grid fees, i.e., which actors benefit and which do not. In particular, the question arises whether dynamic grid fees reduce grid costs for end consumers.

Storage operators. Symmetric grid fees can increase the storage operator's revenues because grid-friendly behavior results in a net payment to the storage operator. In the cases we examined, this is the case even without any adjustment of operating behavior, since market-based storage dispatch already predominantly relieves congestion without a grid fee (see Section 4.1). Adjusting operating behavior further increases these additional revenues. Overall, in the cases examined, the storage operator earns about 1.5 to 5 % higher total revenues with the grid fee than without it (Figure 10, left).

Grid operators. From the grid operator's perspective, dynamic grid fees are generally not revenue-neutral. Net payments through grid fees often exceed the redispatch costs saved, as in the cases we examined. First, the grid operator pays out the grid fee even when the storage unit would have behaved in a grid-friendly manner anyway. Since the storage units at the sites examined here already predominantly relieve congestion without a grid fee, windfall effects arise: with the dynamic grid fee, grid operators pay batteries for grid services they previously provided for free (Figure 10, right).

Uncertainty. The second reason is likely that the storage response cannot replace redispatch one for one. Because grid operators cannot rely on the storage response, they will request

more redispatch as a precaution. This effect is not captured in our analyses. Because the dynamic grid fee generally does not save costs for the grid operator, taken in isolation it does not reduce grid fees for other consumers.

Funding component. If a dynamic grid fee reduces the total costs of the electricity system, it creates a welfare gain. Our analyses show that this gain accrues primarily to storage operators. The dynamic grid fee should therefore, as also planned by BNetzA, be introduced in combination with instruments for grid funding, such as a capacity charge for storage. This charge can be higher with a dynamic grid fee than without. Via this higher funding component, the required funding contribution of other grid users falls, and end consumers would benefit as well. The calculation of an appropriate recovery of the additional profits of storage operators was not examined further here. It does, however, entail further practical challenges, since storage units benefit from the dynamic grid fee to varying degrees, depending on how well the price signals of grid fee and electricity prices complement each other.

Impact on grid operator

Storage operator revenues



Figure 10: Effects of the continuous dynamic grid fee without forecast errors on the revenues of grid operator (left) and on the storage operator (right). In all three cases, grid fee payments exceed the avoided redispatch costs. The dynamic grid fees examined are thus not revenue-neutral for grid operators. They should therefore be combined with an instrument for grid funding, e.g., a capacity charge. Storage operators benefit from the dynamic grid fee at all three sites because they can adjust their behavior such that they receive net payments through the grid fee.

5 Summary and assessment

Objective. Battery storage currently creates market value by shifting electricity from low-price to high-price hours. Dynamic grid fees could additionally provide incentives for grid-friendly storage dispatch. In this study, we examined dynamic grid fees for resolving congestion in the distribution grid based on detailed historical grid loading data.

Ideal case. Our analyses show that dynamic grid fees for distribution grid congestion create value only in theory, namely if a continuous grid fee could be set under perfect foresight of the next day's grid congestion and electricity prices. And even in this hypothetical ideal case, the added value amounts to only 0 % to 4 % of the storage unit's existing system benefit. This small added value is mainly because, in the distribution grid, there are no redispatch needs most of the time and batteries already predominantly avoid congestion anyway. In a great many quarter-hours, the grid fee therefore cannot bring about any additional improvement. In the remaining quarter-hours, redispatch costs in the distribution grid are relatively low because only downward redispatch is activated.

Realistic conditions. Under more realistic conditions, the assessment of dynamic grid fees in the distribution grid is even negative. If the grid fee is set, as we examined, based on grid loading forecasts at 10 a.m. on the day before (rather than on actual congestion), the battery's system benefit falls considerably in all cases we examined. Too often, a grid fee based on wrong forecasts sends a wrong signal. A 3-step grid fee (instead of one that rises with current redispatch costs) also reduces the system benefit of storage in one of the three cases examined, even under perfect foresight. This is because this less complex signal frequently avoids cheap redispatch but causes more expensive redispatch.

Recommendations. Based on this study, we advise against introducing the dynamic grid fees for the distribution grid examined here. According to our results, such grid fees set the day before make the electricity system more expensive rather than cheaper. However, in most distribution grids there is also no acute need for action, since congestion occurs relatively rarely and batteries already behave predominantly in a grid-friendly manner anyway. Moreover, the effort of introducing and continuously calculating a dynamic grid fee has not even been taken into account. Challenges here include location-specific billing and clearing and the forecasting procedure, which is still being implemented. Given the lack of benefit of dynamic grid fees, these challenges were not analyzed further in this study.

Transmission grid. The results of this study cannot simply be applied to the transmission grid. At least in the ideal case, the potential benefit at the two sites examined in the grid areas of Bayernwerk and EWE is considerably higher. This is due to the larger and more frequent redispatch needs. It can be assumed that real forecasts would considerably reduce this theoretical added value. This effect, however, was not examined in the study for lack of forecast data. On the one hand, forecasts in the transmission grid may be better than in the distribution grid, because it is not the loading of individual transformers that must be predicted; rather, large-scale effects such as wind fronts drive redispatch needs. On the other

hand, grid loading forecasts in the transmission grid also depend heavily on load flows on interconnectors, which the German TSOs can forecast only with considerable uncertainty.

Distributional effects. In the design variants of dynamic grid fees examined, the payments from grid operators to storage operators exceed the savings in redispatch costs. This is mainly because the storage units predominantly relieve the distribution grid even without a dynamic grid fee. Remunerating grid-friendly behavior thus creates windfall effects. From an economic perspective, this is not an argument against introducing dynamic grid fees as long as they make the electricity system cheaper overall. For distributional reasons, however, it appears sensible to combine dynamic grid fees with a separate funding component, for example a capacity charge. This is also envisaged by the Bundesnetzagentur.