SHORT STUDY

Regulation of batteries for the transmission grid

A coherent set of tools for the economically sound grid integration of large-scale batteries

This is a machine-translated version of a study originally published in German. The original is available at neon.energy/regulierung-grossbatterien

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A coherent set of tools for the economically sound integration of large-scale batteries into the German transmission grid

The original study is available at neon.energy/regulierung-grossbatterien and the machine-translated English version at neon.energy/en/regulierung-grossbatterien

The study was prepared with the involvement of an expert advisory group comprising Dr. Christopher Koch, Jannis Brodmann (both 50Hertz Transmission GmbH), Dr. Andreas Maaz, Dr. Thomas Helmschrott (both Amprion GmbH), Dr. Friedrich Kunz (Tennet TSO GmbH), and Alexander Werling (Transnet BW GmbH). The advisory group provided guidance throughout the study's development process and contributed technical insights. The content, assessments, and conclusions presented in the study reflect solely the views of the authors and do not necessarily represent the opinions of the members of the advisory group or the organizations they represent.

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Summary

Background. Large-scale batteries have a wide range of impacts on power grids. For this reason, the Federal Network Agency, grid operators, and the federal government are simultaneously—but largely independently of one another—developing approaches to integrate large-scale batteries into the power system. These include, for example, grid fees for storage and various restrictions on storage operations within the framework of technical connection conditions, flexible grid connection agreements, and energy and building regulations. This carries the risk that uncoordinated measures will work against one another, result in unnecessary restrictions, or slow down the expansion of storage capacity. Furthermore, there is significant uncertainty regarding which restrictions and interventions will affect batteries. This uncertainty worsens the financing conditions for battery projects, leads to higher capital costs, and thus makes the energy transition more expensive.

This study. With this study, we aim to identify a coherent and consistent set of tools, incentives, and guidelines that ensures the grid and system benefits of battery storage while maintaining sufficient investment incentives. The goal is therefore a holistic set of tools that facilitates the sensible, system-beneficial integration of batteries into the electricity market and grid. In doing so, batteries should continue to leverage their strengths (particularly fast switching capability and high power), while simultaneously reducing their negative impacts (e.g., exacerbating grid congestion). From an economic perspective, the goal is to internalize effects in such a way that operators can make optimal investment and deployment decisions, e.g., deploying batteries to absorb local electricity surpluses. To this end, we examine approaches within the framework of the grid tariff system, the Technical Connection Rules (TAR), and flexible grid connection agreements. The focus of our analysis is on batteries connected to the transmission grid in the medium-term horizon of the 2030s, assuming a uniform price zone across Germany in the wholesale and balancing energy markets.

Challenges. We base our work on a comprehensive analysis of the impacts of large-scale batteries on the operation and financing of transmission grids. We identify four key challenges: predictable grid congestion (redispatch requirements), short-term grid congestion ("system stability"), frequency stability, and a politically desired contribution to grid financing. From the grid operator's perspective, the most urgent challenge is that batteries in the uniform price zone have no incentive to account for grid congestion (as all other market participants do). It is therefore left to chance whether their behavior exacerbates or reduces grid congestion. However, short-term grid congestion in particular poses a significant challenge for system management, as resolving congestion through redispatch is virtually impossible due to the short lead time. In addition to this challenge, the behavior of batteries also affects grid frequency, and batteries can contribute to grid financing.

Tools. Based on these four effects of large-scale batteries, we recommend five appropriate tools (Table1). A dynamic grid tariff provides incentives for batteries to take foreseeable congestion into account in their operational decisions. If congestion can be predicted with

sufficient accuracy, this should significantly reduce the need for redispatch on average. Remaining and short-term grid bottlenecks are very difficult to resolve while maintaining a single bidding zone. To address this, we recommend, on the one hand, better integration of large-scale batteries into the existing cost-based redispatch system and its continuous improvement and acceleration. Furthermore, we believe a moderate limitation of the maximum balancing capacity per grid connection point is sensible, with the aim of achieving a more even regional distribution. Ramp requirements between and within settlement periods appear indispensable for integrating the very fast systems into a system with a 15-minute settlement period. Through a capacity charge or a grid connection fee, batteries can contribute to the financing of grid fees in a way that largely avoids harmful distortions of battery operations. To avoid regulatory uncertainty and the associated higher capital costs, interventions with significant financial implications for the battery business model should be defined early on and in a binding manner.

Not recommended. Other restrictions and interventions have a major impact on batteries without guaranteeing sufficient benefits for grid operation. These include, for example, energy charge-based grid fees, general (unjustified) ramping restrictions, uncompensated redispatch, or general curtailment windows (“envelopes”). We advise against these interventions.

Table1 : Recommended Tools for Regulating Batteries in the Transmission Grid

Impact of large-scale batteries	Tools
1) Predictable grid congestion (redispatch requirement)	• Dynamic grid tariff (dynamic, regional, symmetric energy charge)
2) Short-term grid congestion ("System stability")	• Redispatch of large-scale batteries • Balancing reserves limit per plant
3) Frequency stability	• Ramp requirements between and within settlement periods
4) Contribution to grid financing	• Grid fee—capacity charge or grid connection fee (BKZ)

1 Introduction

Blind to the grid. The German electricity market, with its uniform price zone, generally provides no incentives to take the grid into account when making investments or during operations. This applies to generators, consumers, and storage facilities alike. Large-scale batteries therefore have no incentive to factor grid congestion into their operational decisions or to behave in a manner that benefits the grid in any other way. Like all other market participants, they are "blind to the grid."

Congestion effects. Even if they do not feel it financially, generators, consumers, and storage facilities naturally still have very real impacts on the power grid. In particular, they can reduce grid congestion and thus lower costs for redispatch and grid expansion—or exacerbate congestion and thereby cause additional costs. These effects can vary from quarter-hour to quarter-hour. In a study from last year, we showed that large batteries relieve the grid slightly more often than they burden it over the course of a year, meaning they are, in this sense, generally beneficial to the grid (Neon 2025). As further studies also demonstrate, this holds true largely regardless of location and applies to grid connections in both the transmission grid and the distribution grid. However, the positive effect on grid bottlenecks is small and purely coincidental, which is why, if regional wholesale markets continue to be politically rejected, we have proposed regional and dynamic grid tariffs, a suggestion that the Federal Network Agency has also taken up as part of the AgNes process.

Too fast for redispatch. Furthermore, large-scale batteries differ from other facilities primarily in their ability to adjust their output very quickly. While this is fundamentally a valuable feature that supports the energy transition, it presents grid operators with additional challenges in system operation. For example, large-scale batteries often respond to intraday price spikes just minutes before delivery or are activated to provide balancing energy. If this unexpectedly exacerbates grid congestion, TSOs cannot counteract it quickly enough because the redispatch process takes hours. The short-term congestion effect is currently the TSOs' greatest concern regarding secure system operation beyond 2030.

Grid tariffs. In the further development of the electricity market design—that is, the rules and incentives for market participants—the grid impact of large-scale batteries currently plays a significant role in two areas. First, it is the explicit wish of the Federal Network Agency to achieve two goals regarding storage as part of the AgNes grid tariff reform: to create incentives for grid benefits and to generate financial revenue ("financing contribution"). To this end, three tools are being discussed in the context of large-scale batteries: a potentially regionalized construction cost subsidy, a capacity price potentially based on grid connection capacity, and a regionally dynamic energy charge. The second area in which the grid impact of large-scale batteries is already being implemented in regulations today is flexible grid connection agreements.

FCAs. We are not aware of a single large-scale battery project in recent years that has received a grid connection without restrictions. Instead, grid operators restrict the operation of large-scale batteries, for example within the framework of the grid connection agreement. In some cases, such restrictions are also imposed during ongoing operation. From the battery's perspective, such "flexible" grid connection agreements (known by the English acronym FCA) are, of course, not flexible at all, but rather restrictive. FCAs vary significantly between storage projects and grid operators and today often include, for example, limits on ramp rates (active power gradients), prohibitions on charging or discharging at specific times, or a limitation on the provision of balancing energy. Requirements regarding the timing of market participation (binding dispatch schedules hours before fulfillment) and non-compensated redispatch are also being discussed.

Risks. This development poses a number of problems and risks:

- Proposals and interventions are not always preceded by a transparent problem analysis. Sometimes it is not even clear exactly which problems are supposed to be solved. This carries the risk that restrictions will go unnecessarily far, fail to achieve their intended goals, or overlook more cost-effective solutions. There is therefore a risk that ineffective measures will be implemented that fail to adequately address grid issues while simultaneously imposing unnecessary costs on battery operators and the electricity market. After all, any restriction on wholesale markets and balancing reserves always results in costs for both generators and consumers.
- Most interventions and restrictions worsen the economic viability of large-scale batteries. The public technical debate seems, in places, to be shaped by the implicit assumption that batteries are so profitable that they can financially withstand all conceivable restrictions. In fact, there is a real danger that the combination of interventions and grid fees will place such a heavy financial burden on batteries that the ramp-up of battery deployment will be stifled. This danger is further exacerbated by the fact that, at the time the investment decision is made, it is often not yet clear at all what restrictions and fees will apply. Such risks worsen financing conditions (less debt, higher interest rates) and thus increase the costs of battery projects.
- The fact that grid operators effectively have a great deal of autonomy in designing connection conditions and FCAs carries the risk of a hodgepodge of competing and inconsistent approaches, with each grid operator pursuing its own concepts. This complicates investments in and the operation of storage systems but also clouds energy policy discussions. In the worst-case scenario, there is a risk of an inconsistent set of tools, in which various tools (e.g., grid fees and FCAs) overlap in a redundant or contradictory manner.
- Finally, given the high degree of discretionary decision-making authority held by grid operators, there is a risk that this authority will be used to avoid batteries in their own grid area as much as possible. The main reason for this concern, particularly in the distribution grid, is the local reallocation of costs to consumers within their own grid area. Under the pretext of serving the grid, FCAs could thus become tools for obstruction.

This study. The aim of this study is to develop a coherent and consistent set of tools, incentives, and guidelines that ensures the grid and system benefits of battery storage while maintaining sufficient investment incentives. The goal is therefore to create a holistic toolbox that facilitates the sensible, system-beneficial integration of batteries into the electricity market and grid. In doing so, batteries should continue to be able to leverage their strengths (particularly fast switching capability and high power), their negative impacts should be reduced (e.g., exacerbation of grid bottlenecks), and effects should be internalized in such a way that operators can make optimal investment and deployment decisions (e.g., battery deployment that absorbs local electricity surpluses). To this end, we examine approaches within the framework of the grid tariff system, technical connection rules, and flexible grid connection agreements. The focus of our analysis is on batteries connected to the transmission grid in the medium-term horizon of the 2030s, assuming a uniform price zone across Germany in the wholesale and balancing energy markets. However, the implications extend beyond large-scale batteries—similar questions arise for a wide range of flexible installations, including (short-term curtailable) renewables. What we do not examine in detail in this study is the participation of batteries in the capacity market and other system services markets (reactive power, inertia, black start capability).

2 Benefits of Batteries

In this section, we briefly discuss where and in what form batteries create economic value. A more detailed discussion can be found in our study on the system utility of large-scale batteries.

2.1 SYSTEM SERVICES AND ECONOMIC VALUE

System services provided by batteries. Large-scale batteries can create economic value in the electricity market and within the power grid. The economic value in the electricity market arises primarily from shifting electricity consumption from hours with low electricity prices to hours with high electricity prices. Added value for the power grid arises when batteries reduce grid congestion or contribute in other ways to lowering grid costs. The sum of market and grid benefits can be considered a measure of a battery's system utility (Figure 1). From a macroeconomic perspective, it is fundamentally irrelevant in which area the added value is generated.

Welfare effect of a large-scale battery (illustrative)

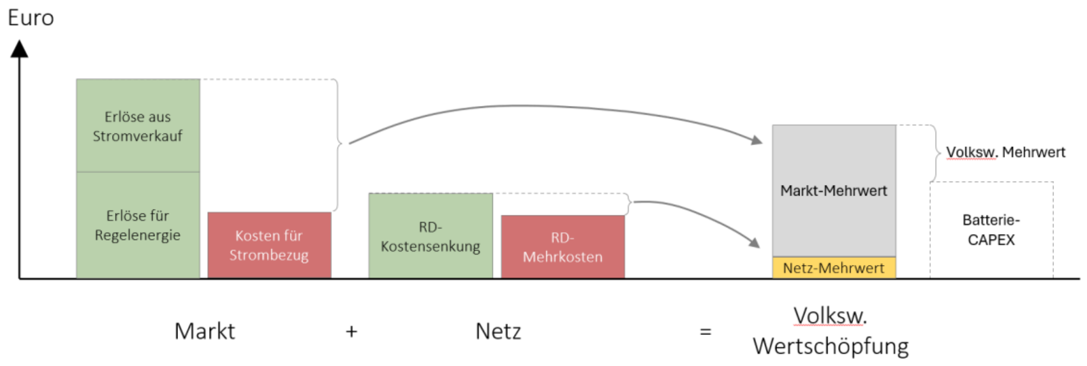


Figure 1: The difference between market revenues and costs yields the market value added. Grid value added (which can also be negative) results from cost reductions or increases in the grid. The sum of these two values yields the economic value added. If this exceeds the battery's investment costs (CAPEX), the project makes economic sense. (Figure from Neon's brief study for ECO STOR)

Example: Day-Ahead Market. By participating in electricity markets, the battery reduces the cost of electricity generation. This can be illustrated using the example of the day-ahead market. The battery charges at an electricity price of €10/MWh and discharges later at €100/MWh. The battery operator benefits from this. At the same time, however, this also reduces the economic costs of electricity generation. Charging the batteries activates additional low-cost generators. When discharging at high electricity prices, the necessary production from expensive peak-load power plants—such as gas-fired power plants—decreases. The economic value added results from the magnitude of the price difference. Specifically, it consists of lower gas consumption, lower CO_2emissions, and no wear and tear from the gas-fired power plant's e startup. Overall, the economic value added by batteries in the day-ahead market is significant, as we estimated in an earlier study for ECO STOR (Neon 2025). For example, a 100-MW battery would have generated approximately 9.1 million euros in value added in the electricity market in 2024 solely through its participation in day-ahead trading.

2.2 EXTERNAL AND INTERNAL EFFECTS

External effects. If the actions of a market participant cause costs or benefits for third parties that are not compensated through the price mechanism, an external effect exists. One example is the impact of the battery on grid congestion. In the unified German electricity price zone, batteries, like all other market participants, are "blind" to grid congestion—they have no incentive to factor the redispatch costs they cause into their investment and operational decisions. This is because the battery operator does not bear these costs; instead, they are socialized through grid fees. Such external effects prevent the full potential of batteries from being realized and the battery from being used in an economically efficient manner. The external effects of batteries occur primarily in the context of the power grid.

Internalized effects. Internalized effects occur when the consequences of an action are fully incorporated into the economic decision of the actor because they are reflected in prices or payments. For example, if a battery purchases electricity at a low price and sells it at a higher price, the price fluctuations are an internalized effect—they directly influence the battery's revenues and costs. The sale of balancing reserves is also internalized, as the battery is paid for this system service. The goal of the tools developed in this study is to internalize effects on the power grid that were previously external.

2.3 ADDED VALUE OF BATTERIES IN ELECTRICITY MARKETS

Participation in electricity markets. Large-scale batteries in Germany are currently operated primarily on a market-based basis: they respond to price signals in wholesale markets as well as in the markets for imbalance energy and ancillary services. In addition, new markets and remuneration mechanisms are currently being introduced for the provision of instantaneous reserve, black start capability, and reactive power, in which batteries can also participate. In the future, batteries will also be able to offer their capacity in the capacity market, provided that it is designed to be technology-neutral and batteries are not barred from participation by regulation. In all these markets, large-scale batteries reduce the cost of electricity generation through their participation.

Additional effects. In addition to these welfare effects, the participation of batteries in electricity markets has additional positive effects. It leads to a (slight) decrease in average electricity exchange prices, reduces price volatility, lowers the cost of supporting renewable energy, and results in less electricity generation from fossil fuel power plants, thereby reducing CO_2 emissions.

3 Impact of Batteries on Grid Operations

Need for action. We identify four key impacts of batteries on the electricity system that require regulatory action:

1) Predictable grid congestion (impact of battery deployment on redispatch)
2) Short-term grid congestion (not compensable through redispatch)
3) Changes in battery output affecting frequency stability
4) Contribution to grid financing

Motivation. The first three points concern external effects caused by batteries. Because the effects of batteries can potentially result in high costs for grid operation, these issues should be addressed. This point becomes increasingly relevant as more large-scale batteries are brought online. The fourth point, the contribution to grid financing, is not an external effect, however, but rather a political desire for redistribution. The rising grid fees for consumers are to be mitigated by spreading the costs across a broad base of payers.

3.1 PREDICTABLE GRID CONGESTION

Problem. Batteries are currently operated, as a rule, without taking grid bottlenecks into account. In the unified German bidding zone, electricity prices offer purely market-driven batteries no incentive to consider the current grid situation—just as is the case for all other market participants. The effect of battery storage on grid congestion is therefore purely random: its operation can both reduce and exacerbate foreseeable grid congestion, depending on how battery use and grid congestion coincide in time and space.

Redispatch. Dispatch decisions from the previous day (day-ahead dispatch schedules) that trigger congestion can generally be resolved through congestion management. This incurs costs that increase grid fees, but within the scope of current redispatch requirements, it is a fundamentally proven and robust process. However, peak redispatch demand is rising continuously, raising the question of whether there is sufficient redispatch capacity.

Current situation. In an initial study (Neon 2025) for ECO STOR, we estimated that large-scale batteries currently reduce congestion management costs on average at most locations in Germany: According to our calculations, each kW of battery capacity reduces redispatch costs by approximately 3–6 euros per year. However, this is purely an empirical finding regarding the status quo and not a systematic effect, as there are no corresponding incentives.

3.2 SHORT-TERM GRID CONGESTION

Forecasting errors. Weather forecasts are never perfect. They are continuously updated and refined in the days and hours leading up to their realization. Accordingly, generation forecasts for wind and solar energy are also constantly adjusted. As soon as it becomes apparent that an initial generation forecast was too high or too low, the direct marketers respond. This can happen in two ways: the excess or shortfall in electricity sold can be traded on the intraday market, or the forecast error is offset by adjusting other plants within the same balancing group. This helps balance the control area's net balance and prevents the need to compensate for forecasting errors with expensive balancing reserves. As renewable energy capacity expands, the need for such short-term flexibility increases.

Short-term grid congestion. Flexibility is essential to balance out the forecast error. This can be achieved by adjusting generation, consumption, or storage. In practice, such short-term flexibility is primarily provided by gas-fired power plants, pumped-storage facilities, decentralized flexibility sources, the curtailment of renewable energy, and, indeed, large-scale batteries. However, this flexibility response does not usually occur directly at the location of the renewable energy plants: for trading up to 30 minutes before delivery, balancing can take place anywhere within the German bidding zone; for trading within the last 30 minutes before delivery or for balancing within one's own balancing group, balancing occurs within the same control area. This can cause or exacerbate short-term grid bottlenecks.

Two examples. The problem of short-term bottlenecks can be illustrated using two examples. These occur when the transmission grid is already operating at its capacity limit in the north-south direction, and forecast errors regarding renewable energy then materialize (a power plant outage or a load forecast error would have similar effects).

Less solar. The first example is lower-than-expected solar generation, for instance due to unexpected cloud cover in southern Germany that is only detected one hour in advance. In this case, the lower generation leads to a short-term rise in intraday prices. Market participants, such as batteries or gas-fired power plants, respond to the higher prices by feeding additional power into the grid. In doing so, the electricity market does exactly what it is designed to do: it ensures short-term balance for Germany as a whole. Generation and consumption are back in balance. However, if these batteries or power plants are located in northern Germany, the change (less solar feed-in in the south, more battery feed-in in the north) results in a short-term increase in the north-south power flow beyond the available grid capacity. Normally, grid operators would respond with redispatch measures, but this may no longer be feasible in such a short time, meaning that, in the worst-case scenario, a grid overload cannot be prevented. If grid operators anticipate such effects, they must operate the grids with more buffer capacity, i.e., preventively curtail more generation than is actually necessary. A trading transaction isn't even necessary here: If the solar system and battery belong to the same balancing group, the balancing can simply take place within the balancing group—even into the current delivery period.

More wind. The second example concerns a comparable initial situation with high grid utilization. It now becomes clear at short notice that even more wind power will be produced than previously expected. As a result, the electricity price on the intraday market drops shortly before delivery. A large battery reacts by purchasing the electricity and storing it. In doing so, it helps compensate for this forecasting error—exactly as batteries should behave. However, if this battery is located in southern Germany, it thereby exacerbates the north-south grid bottleneck. This problem, too, is by no means limited to batteries—instead, for example, a solar park in southern Germany could also curtail output in response to the fallen intraday price. The consequences for the power flow would be the same. In both examples, the fundamental problem is that system balance is organized on a Germany-wide basis, whereas grid utilization actually requires a local solution (replacing the lost solar power in the south or absorbing the additional wind power in the north).

Impact. Short-term grid congestion poses a significant threat to the secure operation of the power system. TSOs are highlighting this issue with increasing urgency under the heading of "system stability" (Amprion 2025, Energate Messenger 2025). The biggest problem is that short-term grid congestion can no longer be "resolved" through redispatch, as this process, in its current form, requires approximately two hours of lead time according to TSOs—for instance, for load flow calculations to identify bottlenecks, determining countermeasures, notifying plant operators, and balancing the system.

3.3 FREQUENCY STABILITY

Balancing. In the European electricity market, a 15-minute settlement period applies, during which all balancing groups must be balanced on average—meaning generation, consumption, and trading must match. The power system, however, must be balanced at all times; it must therefore maintain a balanced system imbalance within the framework of frequency stability. Consequently, prices on the wholesale market provide a signal that is too coarse for the second-by-second balancing of the system imbalance.

Two challenges. The differing temporal resolution and the resulting incomplete incentives are particularly problematic for highly flexible assets such as batteries. They can lead to challenges in grid operation in two areas:

- Schedule jumps between settlement periods
- Schedule jumps within settlement periods

Between settlement periods. Batteries can execute very rapid power jumps at the transitions between settlement periods, while other market participants react more slowly. The interplay of abrupt power changes from batteries and slower reactions from other actors (e.g., rising solar generation in the morning) leads to temporary system imbalances, particularly at the transitions between two settlement periods.

Within the settlement period. Batteries can shift their output strategically within the settlement period, for example by charging or discharging at short notice to optimize balancing energy costs. While this ensures that the balancing group is balanced on average or offsets the system imbalance, it can cause significant temporary surpluses or deficits within the settlement period. The following example of a balancing group consisting of a battery and a PV park illustrates this: If it becomes apparent during the current settlement period that the PV park will generate less electricity than planned due to passing clouds, the battery can discharge at high power shortly before the end of the settlement period to compensate for the shortfall in its own balancing group. As a result, the balancing group is balanced on average, but within the quarter-hour it is first under- and then long. Both situations can lead to the need to activate balancing reserves, even though the balancing group is balanced on average.

Consequences. In both cases, the behavior of batteries can lead to a brief imbalance in the control area balance. This must be balanced by using balancing reserves and thus incurs additional system costs.

3.4 CONTRIBUTION TO GRID FINANCING

Grid costs. The operating and investment costs of the German power grid have risen significantly in recent years—and are likely to continue doing so in the coming years. This trend is driven by the rising costs of congestion management and increased grid expansion, particularly for the electrification of the energy system, the connection of offshore wind farms, decentralized generation facilities, and the greater European integration of power systems.

Rise in grid fees. Currently, grid costs are primarily borne by electricity consumers. Storage facilities have so far only contributed through the construction cost subsidy they provide. The cost increases of recent years have led to a sharp rise in grid fees, making the electrification necessary for the energy transition less attractive. Consequently, there is a political desire to curb the rise in grid fees. This is occasionally achieved through budgetary subsidies to transmission system operators.

More **fee payers.** The Federal Network Agency, which is responsible for grid fees, also intends to take a different approach and is proposing to expand the pool of fee payers. More grid users are to be involved in financing the power grids, including not only generators but also storage facilities. This is one of the central aspects of the AgNes reform process. However, the AgNes discussion does not always sufficiently take into account that, depending on their structure, grid fees may also be passed on—either via EEG levies to the federal budget (in the case of renewable energy) or via electricity prices to consumers (in the case of generators and storage facilities).

4 Market Design for Large-Scale Batteries

For the energy transition to succeed, a rapid ramp-up of large-scale batteries is needed. This is only possible if the impacts of batteries on the power grid are addressed. Put another way, if we internalize the external effects of batteries, we can extract significantly more economic value from this technology than we do today. In this chapter, we discuss five tools that address the four impacts of batteries on grid operations outlined in the previous chapter. These are:

- Dynamic grid tariffs
- Redispatch of large-scale batteries
- Regulating power limit per facility
- Limitation of power ramps
- Grid financing

We describe the five proposed tools and discuss sensible design options. We also quantify the impact of these tools on battery operation. To do this, we use market prices and grid congestion data from 2025 to assess the extent to which each tool would have restricted purely market-driven battery operation. We compare the effects for two different storage capacities: a 2-hour and a 4-hour storage system. The battery model used is described in the appendix. Before discussing the mechanisms in detail, we outline their role in the interaction of the tools.

4.1 TOOL BOX

Assignment. Each tool primarily addresses one of the challenges outlined in the previous section (Table 2). In most cases, one instrument per challenge is sufficient; however, a combination of several instruments is required, particularly when addressing the issue of short-term grid congestion.

Comprehensiveness. In our assessment, these tools can address the aforementioned problems in the operation of the transmission grid. Further restrictions on storage operations are, in our view, unnecessary and therefore undesirable.

Table 2 : Recommended tools for batteries in the transmission grid

Problem	Solutions (instruments)
1) Foreseeable grid congestion (Redispatch requirement)	• Dynamic grid fee (dynamic, regional, symmetric energy charge)
2) Short-term grid congestion ("System stability")	• Redispatch of large-scale batteries • Regulating power limit per plant
3) Frequency stability	• Ramp requirements between and within settlement periods
4) Contribution to grid financing	• Grid fee capacity charge or grid connection fee (BKZ)

Binding dispatch schedules. A much-discussed tool for resolving short-term grid congestion is plant-based binding dispatch schedules. The basic idea is to prohibit certain plants from making short-term adjustments to their dispatch schedules in order to avoid short-term grid congestion. To date, we are not aware of any concept for a concrete design of binding dispatch schedules. However, we have significant doubts that binding dispatch schedules can be implemented in a way that effectively prevents short-term grid congestion. They are therefore not included in the set of tools we propose for large-scale batteries. A more in-depth presentation and evaluation of this instrument can be found in the appendix.

Distribution grids. The focus of this study is on large-scale batteries in the transmission grid. In the distribution grid, the selection of battery restrictions may differ. This is due to two key differences in the operation of distribution grids compared to transmission grids. First, voltage maintenance in the distribution grid poses a particular challenge. This is because, due to the higher line resistances in the distribution grid, the voltage reacts more strongly to active power, and at the same time, fewer technical means for direct voltage control are available. Second, system control in the distribution grid relies much more heavily on measured values than in the transmission grid. Very rapid changes in the behavior of large-scale batteries may therefore not be detected and compensated for in a timely manner under certain circumstances.

Regional markets. The introduction of regional wholesale markets through the division of the single bidding zone would render most of the aforementioned instruments obsolete. By dividing the large bidding zone, all grid bottlenecks between zones would be reflected in wholesale prices. This applies at all times, from the day-ahead market through the intraday market to balancing and imbalance energy. Market prices would therefore ensure that all bottlenecks between bidding zones are avoided. As a result, restrictions on battery operation would no longer be necessary, or would be required to a much more limited extent; dynamic grid fees would not be needed, and redispatch would be significantly reduced. Regional markets could apply to all market participants or only to specific ones, e.g., only batteries (also discussed under the name “dispatch hub”). In general, regional markets are significantly superior to the tools discussed here because the resulting price signals would be equilibrium prices, and within the framework of intraday market coupling, an efficient balancing of alternative responses would be possible (Neon 2026). In addition, they increase the system's resilience, as the market would take grid constraints into account and system stability would no longer have to be ensured solely through the redispatch process.

4.2 DYNAMIC GRID TARIFFS

Background. Some grid bottlenecks can already be predicted well in advance, for example, large-scale north-south bottlenecks during periods of strong winds. Nevertheless, under the current market design, batteries (like all other market participants) have no incentive to take grid bottlenecks into account in their operational decisions.

Basic concept. Dynamic grid tariffs in the form of quarter-hourly, regionally varying energy charges could provide incentives for large-scale batteries to engage in behavior that reduces congestion. This could take the form of a general grid tariff system applicable to all grid users, as envisaged in the AgNes process by the BNetzA (Federal Network Agency 2026), or take the form of special grid tariffs applicable only to large-scale batteries, as proposed by us (Neon 2025). Dynamic grid tariffs apply to all forms of market participation, i.e., regardless of whether energy flows in the wholesale market or for the provision of system services such as balancing reserves.

Based on redispatch. Dynamic grid tariffs are based on the expected grid congestion situation: The grid tariff for drawing electricity from the grid would be high precisely when and where such withdrawal exacerbates congestion. At the same time, in these cases, feeding electricity into the grid would be rewarded, i.e., a negative grid fee would be applied. The dynamic grid fees thus compensate for the lack of local price signals in the day-ahead market within the single bidding zone.

Symmetry. From the grid's perspective, a reduction in grid feed-in by one MWh is equivalent to an increase in grid withdrawal by one MWh. Both have the same effect on the overloaded grid element. Therefore, we recommend the introduction of symmetric grid fees: at a given time and location, the grid fee for grid withdrawal is exactly as high as the grid fee for grid injection, but with the opposite sign.

Level of grid fees. The level of the dynamic grid fee should be based on the marginal cost of congestion management. In surplus regions where power is curtailed, grid fees should therefore be based on the (expected) electricity market price at the time of curtailment, as this is used to compensate curtailed renewable energy sources. In regions with a shortage, where power plants must be ramped up as part of redispatch to meet local demand, grid fees should instead be based on the marginal costs of these ramp-up power plants.

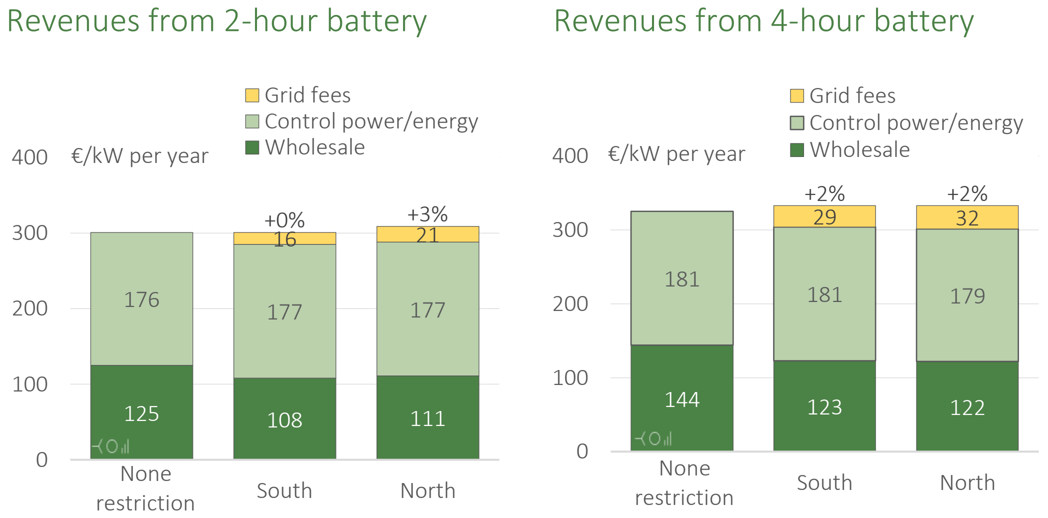
Economic efficiency. If dynamic grid fees correspond to the costs of avoided redispatch, a welfare-optimal trade-off between the costs and benefits of the behavioral change takes place. Battery storage should only be used to avoid grid congestion if the associated costs for the battery are lower than the resulting savings from redispatch. If this is not the case—for example, if redispatch by other market participants is a more cost-effective solution for the grid congestion—the battery will not be used to resolve the congestion ( ). This balancing of costs and benefits distinguishes dynamic grid tariffs from non-price-based tools, such as battery operation guidelines set the day before.

No short-term effect. If dynamic grid tariffs are set the day before the day-ahead auction and are not adjusted thereafter, they do not prevent grid congestion that arises only shortly before delivery.

Forecasting inaccuracy. Dynamic grid tariffs must be set based on congestion and redispatch forecasts. Therefore, there is a risk that dynamic grid tariffs based on incorrect forecasts may not accurately reflect the actual congestion situation. In the event of forecasting errors, it is thus possible that dynamic grid tariffs will not incentivize the optimal behavior for alleviating congestion. However, we expect that dynamic grid tariffs will reduce the need for redispatch on average, even though there will likely be individual quarter-hour periods in which the need for redispatch is also increased by dynamic grid tariffs.

AgNes. In the AgNes process, the Federal Network Agency advocates for the introduction of such dynamic grid tariffs for large-scale batteries. In the event of a promising pilot program, it aims to introduce dynamic grid tariffs for large-scale batteries as early as 2029 (Federal Network Agency 2026).

Financial implications. Dynamic grid tariffs vary not only over time but also across regions to reflect the specific grid conditions in each area. For this reason, the financial implications of dynamic grid tariffs also differ from one location to another. Our numerous analyses show that batteries generally benefit from symmetric grid tariffs, regardless of location and regardless of the grid level to which they are connected. This is because batteries can adapt their operational decisions to the dynamic grid tariffs. However, these additional revenues are low at all locations. With withdrawal grid tariffs of €100/MWh in shortage regions and -€40/MWh in surplus regions, dynamic grid tariffs lead to a maximum 3% increase in battery revenues (Figure 2).


Revenues from 2-hour battery

Revenues from 4-hour battery

Figure 2: Impact of dynamic grid tariffs on the revenues of a 2h and 4h battery in 2025 for a battery connected to the transmission grid and located in southern Germany (Bavaria / Baden-Württemberg) and northern Germany (Schleswig-Holstein, northern Lower Saxony), respectively.

4.3 REDISPATCH OF LARGE-SCALE BATTERIES

Current legal situation. Large-scale batteries with a capacity of over 100 kW are required to participate in redispatch. This means that grid operators are generally always permitted to intervene in the operation of these facilities for congestion management purposes. Exceptions to this rule apply only to the portion of the battery that provides system services, such as balancing reserves. In the event of a redispatch intervention, batteries are legally entitled to financial compensation, i.e., reimbursement for lost revenue and incurred costs. According to Section 13a(2) of the Energy Industry Act (EnWG), financial compensation is considered appropriate if, taking into account the balancing settlement, it leaves the plant operator in no better or worse economic position than they would have been in without the measure. For the specific calculation of this compensation, there is a practical solution: the BDEW Industry Compromise Redispatch 2.0 (BDEW 2020).

Actual status quo. In practice, large-scale batteries are de facto not used in redispatch. There are various explanations for this: On the one hand, batteries report themselves as unavailable because they do not wish to be activated for redispatch. On the other hand, grid operators shy away from redispatching large-scale batteries due to non-digitized processes and possibly also because of the risk of legal action if the flat-rate compensation falls short of the actual costs.

Basic idea. In the future, batteries should be better integrated into the redispatch process. To achieve this, the practical challenges must be addressed so that batteries can be reliably utilized in redispatch. Furthermore, the redispatch process should be made faster in general—and for highly flexible batteries in particular—so that even short-term grid bottlenecks can be eliminated.

Compensation. It is essential that the grid operator provide storage operators with appropriate and financially neutral compensation. If compensation is too high, there is a risk of so-called Inc-Dec gaming: the battery has an incentive to provoke an activation of the redispatch system in order to receive the high remuneration. This can lead to storage operations artificially exacerbating grid congestion. If compensation is too low, however, the battery has a structural incentive to avoid redispatch activations wherever possible, e.g., by reporting unavailability.

Issues with compensation. Calculating a financially neutral compensation for batteries is practically impossible for two independent reasons:

- Problem 1: A large portion of the revenue comes from short-term electricity market transactions on the intraday market. Here, it is virtually impossible to determine objectively in hindsight which transactions a battery would have executed had there been no redispatch intervention.
- Problem 2: A redispatch intervention alters the battery's charge level compared to the hypothetical level without intervention. This affects not only transactions during the intervention itself but (potentially) also those before or after. For example, if a redispatch intervention interrupts the battery's charging, it may be able to sell or feed less electricity into the grid at a later time.

Interaction with dynamic grid tariffs. Due to these problems, it will be de facto impossible in practice to determine an exactly neutral compensation. To minimize the resulting harmful incentives, redispatch of large-scale batteries should therefore be used as rarely as possible. The less predictable each redispatch activation is for storage operators, the less likely harmful strategic behaviors become. For this reason, we consider the interaction between redispatch and dynamic grid tariffs to be sensible. The redispatch of large-scale batteries is an essential component for effectively resolving grid congestion. Dynamic grid tariffs complement this tool and result in large-scale batteries being used less frequently for redispatch. This mitigates the disadvantages of compensation that is, in reality, impossible to achieve adequately.

Recommendations. The flexibility and high performance of large-scale batteries should also be utilized in practice for redispatch. To this end, financial compensation should be calculated as accurately as possible. This may require a revision of the industry regulations.

Non-recommendations. We strongly advise against uncompensated redispatch. Such considerations are already being made within the framework of FCAs. However, this approach is highly problematic for two reasons. On the one hand, an uncompensated activation would result in compensation that is far too low, creating the aforementioned incentives for harmful behavior. Furthermore, uncompensated redispatch would also create inefficient incentives for the grid operator. The operator would use free redispatch facilities for redispatch measures wherever possible, as these are always cheaper than facilities that receive compensation. This has the effect that the plant with the highest system benefit is not always used for redispatch, and leads to potentially significant revenue losses for the battery. Limiting the maximum possible activations would reduce this problem, but in turn gives battery operators an incentive to provoke redispatch activations when they incur low costs for them, in order to reduce the number of more costly activations.

4.4 BALANCING CAPACITY LIMIT PER UNIT

Background. Batteries are fundamentally well-suited technically to provide fast balancing capacity, particularly primary and Automatic Frequency Restoration Reserve (FCR and aFRR). In this role, they are exceptionally important for stable system operation in an electricity system increasingly dominated by wind and solar energy. Automatic Frequency Restoration Reserve, in particular, is currently financially attractive, which is why a significant portion of battery capacity is marketed for this purpose. With a trend toward large battery projects with capacities of up to 1 GW, this can lead to a strong spatial concentration of balancing capacity provision at a few grid connection points. This would be problematic for several reasons. On the one hand, the concentration increases the risks of a line failure for system management, because a failure of a grid connection line or busbar would result in the loss of a large portion of the total available balancing capacity. Furthermore, spatially concentrated activations for balancing reserves can exacerbate grid bottlenecks in the short term. This would be the case, for example, if a European frequency drop occurs while positive balancing reserves are primarily provided in a region with a significant generation surplus.

Approach. Limiting the amount of balancing capacity that can be marketed per unit restricts the geographical concentration of balancing capacity. Because this reduces the overall supply of balancing capacity, we propose a path whereby the maximum balancing capacity limit is gradually lowered over time—in parallel with the ramp-up of large-scale batteries. Initially, high shares apply to all batteries so that competition in the balancing capacity market is not overly restricted. The more large-scale batteries are connected to the grid, the lower the balancing capacity limit can be set without jeopardizing competition in the balancing capacity market. In addition to limiting balancing capacity per unit, open bidding on the balancing capacity market should also be restricted.

Design. We propose limiting the balancing capacity to a percentage of the battery's installed capacity, applied separately for positive and negative balancing capacity. With a balancing capacity limit of 50%, a 100-MW battery could thus simultaneously offer 50 MW of positive and 50 MW of negative Automatic Frequency Restoration Reserve, or alternatively 50 MW of (bidirectional) Frequency Containment Reserve. A gradual reduction of the limit over time would be conceivable. This limit would apply accordingly to all batteries connected to the transmission grid, i.e., both existing and newly connected systems. In doing so, the demand for balancing capacity and the competitive situation in the balancing capacity market should be kept in mind. Given potential outages and to ensure sufficient competitive pressure, the battery capacity available for balancing capacity should be significantly higher than the total demand for FCR and aFRR.

Practical implementation. The limits on the marketing of balancing capacity and their phasing-in could, in principle, be established as part of a uniform regulation in the Transmission System Operators' Technical Connection Rules (TAR). Despite the greater effort involved, this appears to be advantageous compared to a patchwork of FCAs, in which the limits vary depending on the grid operator, grid connection point, and year of commissioning.

Financial implications. By 2025, (unrestricted) batteries would have generated a large portion of their revenue through the provision of balancing capacity and energy. A restriction on balancing capacity provision therefore leads to substantial revenue losses for batteries (Figure 3), which can only be partially offset by higher wholesale revenues. This applies in particular to batteries with lower storage capacity. Batteries with higher charging hours, on the other hand, are less severely affected by a limitation on balancing capacity, as they can more easily switch to wholesale arbitrage. In the coming years, we estimate that the revenue potential from balancing capacity and energy will decline as the market becomes saturated. The relative impact of a cap on battery profitability will therefore tend to be smaller in the future.

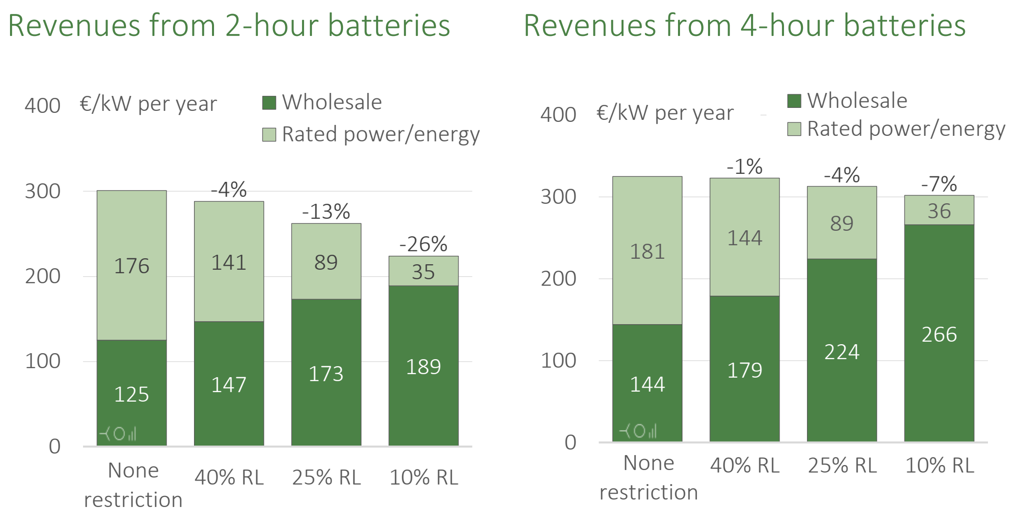


Figure 3: Effects of balancing capacity limits of varying levels on the revenues of a 2h and 4h battery in 2025.

4.5 LIMITATION OF POWER RAMPS

Background. Batteries can adjust their output much more quickly than almost any other technical component in the power system. In particular, batteries can make abrupt power changes at quarter-hourly intervals in accordance with the reported Dispatch schedules. Such abrupt transitions are, in themselves, fully consistent with current regulatory requirements. Because other market participants, however, operate with significantly flatter ramps, this results in deterministic balancing capacity requirements: Even with perfect quarter-hourly balancing, these differing speeds lead to systematic surpluses and shortfalls at the beginning and end of the settlement period. This results in frequency fluctuations and ties up valuable balancing capacity , making the system less resilient to unforeseen incidents. Shortening the settlement period would reduce these problems, but this is only feasible in the long term.

Design and Objective. Instead, we recommend limiting the maximum power change of the battery between settlement periods. This reduces structural system imbalances at the edges of the settlement periods. Furthermore, power jumps within the settlement period should also be prohibited. Both measures facilitate frequency control. The ramp limit, on the other hand, is not intended to increase the predictability of battery deployment, as the ramp specifications do not apply to the provision of system services.

Ramp limit. To achieve the specified targets, the ramp limit should be set so that it is compatible with power changes from other relevant players in the power system. Of particular relevance are solar ramps in the morning or afternoon, during which power continuously increases or decreases within a delivery period and therefore deviates significantly from the average power at the edges of the settlement periods. In the technical requirements, the TSOs therefore specify a ramp limit of 6 to 20% of the net rated power per minute (TSOs 2025). This would mean that switching between charging at full power and discharging at full power would take between just over 33 minutes (6%) and 10 minutes (20%).

Impact. A limit on power changes can affect battery revenues in two ways. First, with strict power limits, not all dispatch schedules are possible. For example, a battery with a limit of 10% per minute can only change its power by 150% from one quarter-hour to the next; it cannot discharge at full power in one quarter-hour and charge at full power in the next. Only ramp limits of at least 13.3% per minute allow for the execution of all possible dispatch schedules (200% in 15 minutes corresponds to 13.3% per minute). Second, the ramp limit reduces the amount of energy that can be sold. Due to the ramp, less electricity can be sold within a quarter-hour than would be technically possible.

Compensation. The energy sold in lesser quantities due to the ramp should be financially compensated by the grid operators through the balancing energy mechanism: The battery would be treated as if it had actually fed energy into the grid in a step-like manner according to the Dispatch schedule—which it could have done without any technical difficulty. In the event of a schedule deviation, the exact amount of energy resulting from the ramp as a “triangular area” around the quarter-hour change would be shifted in the balance sheet to the adjacent quarter-hour (Figure 4). Accordingly, any dynamic grid fees that may arise could also be compensated. Such a regulation would benefit grid stability without causing financial harm to batteries.

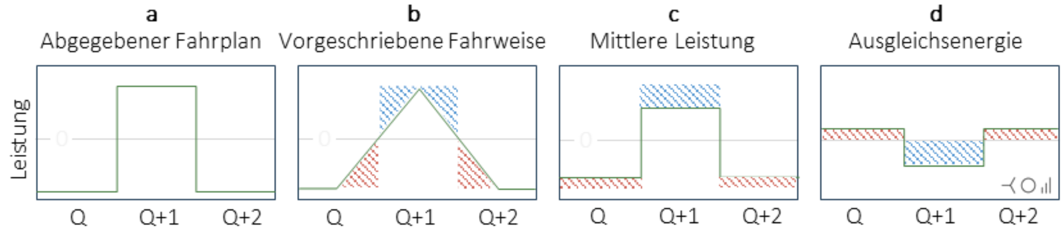


Figure 4: How compensation works with a ramp limit. **a** shows the dispatch schedule that the battery is allowed to follow despite the ramp limit. In the dispatch schedule shown, the battery switches from 100% charging to 100% discharging and back again. **b** shows the prescribed power profile, including the ramp limit (here 13.3% per minute). Due to the ramp limit, the battery deviates from the Dispatch schedule and actually feeds the average power shown in **c**. The deviation from the specified Dispatch schedule results in imbalance energy (**d**), which is compensated by the grid operator.

Practical implementation. The limitation of power ramps should apply not only to batteries but equally to all other market participants capable of responding quickly. Compensating for the ramp limit presents numerous practical challenges. Among other things, an adjustment to the balancing group contract would be necessary, as the balancing takes place at the balancing group level. Due to the complexity of implementation, the TSOs anticipate a timeframe of up to three years for the introduction.

Impact on battery cost-effectiveness. Ramp limits of at least 13.3% per minute allow for the execution of all possible dispatch schedules. With stricter limits, however, not all dispatch schedules are possible. If financial compensation is provided for losses resulting from ramp limits as proposed, there is no impact on the cost-effectiveness of the battery.

4.6 GRID FINANCING

Background and Objective. Against the backdrop of rising grid costs, the BNetzA aims to increase the participation of energy storage systems in grid financing. The financial contribution from batteries should be structured in such a way that it does not result in inefficient dispatch incentives for the battery.

No constant energy charge. A constant energy charge would fail to meet this requirement. It would incur costs for the battery with every storage cycle, thereby limiting battery usage. On the one hand, this would prevent economic value creation by batteries in electricity markets—electricity and balancing energy prices would rise. At the same time, this would also reduce the revenue of storage operators, which could then no longer be tapped elsewhere for grid financing.

Possible tools. Therefore, we recommend a one-time construction cost subsidy, payable upon commissioning of the storage unit, or an annual capacity charge based on the contracted grid connection capacity as tools for grid financing. A combination of both tools is also conceivable in principle. Unlike the constant energy charge under the " " model, neither approach would restrict battery operation, except that in the event of a strongly negative market development, a capacity charge could lead to projects exiting the market earlier than planned.

Uncertainty. From an economic perspective, there is no strong preference for either tool as long as the amount is fixed at the time of the investment decision. If there is uncertainty regarding the future introduction of a capacity charge or its level, this worsens the financing conditions for battery projects (less debt, higher interest rates) and thereby makes storage more expensive. On the other hand, a deferred payment facilitates financing. For this reason, a construction cost subsidy that is fixed in advance but spread over, say, 10 years seems sensible.

No regional differentiation. Our analyses to date have shown that the impact of large-scale batteries on congestion management varies only slightly from region to region (e.g., Neon 2025). Site selection based on regional differentiation of the financing contribution for large-scale batteries is therefore likely to be very limited and is probably not worth the effort. We therefore consider the planned abolition of differentiated construction cost subsidies to be sensible. This does not apply to the costs of the immediate grid connection, which can vary. However, these costs are already borne by the battery developers today.

Level of the financing contribution. Determining the level of the financing contribution from storage facilities—that is, setting the parameters for construction cost subsidies or capacity charges—is a delicate balancing act. On the one hand, the political desire to have profitable storage facilities contribute to the financing of grid costs is understandable. On the other hand, the financing contribution must not be set too high, as this risks stifling the expansion of storage capacity. This would not only be a disservice to the energy transition and affordable electricity prices, but ultimately also to grid fees: if no storage facilities are built, they cannot contribute to grid financing. A prohibitively high capacity charge would be, for example, the €53/kW per year cited by the TSOs for unlimited storage (Amprion 2026). Economically, this is equivalent to a one-time payment of €400/kW (assuming a 10% WACC and a 15-year lifespan). By comparison, the investment costs for a 2-hour battery currently amount to around €600–700/kW without a construction cost subsidy. Such a capacity charge would therefore make batteries a full 60% more expensive.

Interaction with restrictions. The financing contribution that would still be viable cannot be determined independently of the restrictions on storage operation. Our quantitative analyses have shown that restrictions such as mandatory Dispatch schedules, a balancing capacity limit, and a limit on power ramps (if uncompensated) can have significant impacts on the profitability of storage projects, depending on their design. The rule of thumb is: the stricter the restrictions, the lower the viable contribution to grid financing—in extreme cases, no financing contribution is possible at all. This argument supports standardizing storage restrictions wherever possible to better account for them when determining grid tariffs.

4.7 OBSOLETE TOOLS

No meaningful tools. In the public debate, other tools are emerging in addition to the approaches outlined above, which we consider obsolete if the described tools are introduced. These include, in particular, the following tools:

- Uncompensated redispatch
- General, strict ramp restrictions
- Prohibition on feeding into or withdrawing from the grid during certain hours (“envelope curves”)
- Complete ban on grid procurement (“green energy storage”)

Reasons. In our view, these tools do not provide a viable solution to the challenges outlined in the section “3 .” None of these tools are necessary if the set of tools we have proposed is implemented, and they are inferior to the alternative approaches described above. For example, uncompensated redispatch will always lead to more harmful incentives than compensation for redispatch interventions, even if this compensation does not exactly match the actual costs of the intervention. Furthermore, these tools impose disproportionately severe restrictions on storage operations, such as general, strict ramp restrictions to limit short-term grid congestion. Complete feed-in or feed-out bans also seem disproportionate to us, as these can generally be avoided through dynamic grid tariffs and the redispatch of other, cheaper plants. In the few situations where this is insufficient, direct redispatch of the storage facilities would still remain the better alternative. Therefore, the approaches mentioned here—especially in the transmission grid—should not be used.

Regulatory **uncertainty.** Investment decisions are currently being made for projects where it is by no means clear what restrictions might be imposed on battery storage at a later date. The mere possibility that the obsolete restrictions mentioned here could be introduced creates significant uncertainty. Even the mere possibility of these tools being introduced later—with potentially significant financial implications—increases the cost of capital and makes it harder for storage developers to secure financing. This can result in investments in sensible and, in fact, economically viable storage projects not being made. Keeping these options vaguely open thus causes significant harm, even if they are ultimately not implemented. We therefore recommend clearly and universally ruling out the introduction of the tools mentioned here in the transmission grid.

5 Conclusion

Consistent set of tools. This study develops a consistent set of tools for integrating large-scale batteries into the transmission grid. The proposed measures systematically address the four key challenges in grid operation and assign a suitable tool to each problem. For some challenges, the sensible solution is relatively clear: For frequency stability, bilancially compensated ramp requirements between and within settlement periods appear sensible. For grid financing, capacity charges or connection fees are better suited than energy charges, as the latter are more detrimental to battery operation.

Grid Congestion. The choice of tools to address grid congestion, however, is less clear-cut. The obvious solution lies in dividing the uniform German price zone and thereby establishing regional day-ahead, intraday, and balancing energy markets. This is not politically desirable, however, which is why we have not considered this approach further in this study. If the Germany-wide price zone is maintained, the price signals from the wholesale market will not reflect grid congestion. This can only be inadequately compensated for by additional tools, and even then with collateral damage. Regionally dynamic grid tariffs are likely to alleviate congestion, but they are only as good as the congestion forecasts. Furthermore, they cannot reflect short-term changes in grid utilization. Faster redispatch, which can draw on more generation facilities as well as large-scale batteries, can help address short-term perverse incentives created by the uniform bidding zone. However, providing fair financial compensation for redispatch interventions in battery operations is challenging.

Ineffective tools. In addition to appropriate measures, the current discussion is also considering tools that we consider ineffective. These include, in particular, blanket restrictions on battery operation or unrewarded redispatch interventions. At the same time, it is often unclear whether and in what form individual tools actually contribute to relieving grid operations.

Uncertainty. Uncertainty regarding future regulatory frameworks significantly undermines planning certainty. It leads to higher financing costs and can delay or prevent investments. In addition to costs borne by the private sector, this results in substantial economic damage, as it slows down the expansion of battery storage.

Impact on economic viability. Some of the recommended measures limit battery use, such as restrictions on the marketing of balancing capacity and (uncompensated) power ramps. This reduces the added value that batteries can generate on the wholesale market, diminishes the economic viability of storage projects, and results in these projects being able to make smaller contributions to grid financing. We therefore recommend, on the one hand, that restrictions on battery use be kept as moderate as possible and, on the other hand, that the impact of such restrictions be taken into account when setting grid tariffs.

Standardization. FCAs will play a central role in the integration of large-scale batteries, but their design is inconsistent. To create transparency and reduce costs, all aspects that can be standardized should be regulated in uniform technical connection rules. FCAs, on the other hand, should be clearly defined and limited. Uniform regulation helps reduce uncertainty and thereby creates significant economic value.

6 Appendix

6.1 BINDING DISPATCH SCHEDULES

Status quo. Today, plant operators are permitted to update their planned operations down to the delivery quarter-hour. Large-scale batteries can thus adjust plans for electricity withdrawal and injection in real time. This can occur either as part of intraday trading transactions or as part of the company's internal balancing group management. The only exceptions are plants used for redispatch. These may no longer change in a direction contrary to the redispatch.

Binding dispatch schedules. The idea behind binding dispatch schedules for large-scale batteries is that operators must, with a lead time of several hours, bindingly determine and report the physical feed-in and feed-out of each plant for every quarter-hour. Since balancing energy calls are not part of the dispatch schedules, they are exempt from this binding requirement. These dispatch schedules may subsequently be changed only to a limited extent or not at all; they are effectively "frozen." Binding dispatch schedules, however, do not prevent batteries from already taking positions in the day-ahead market that exacerbate grid congestion.

Expectation. The hope is that grid operators will be able to perform reliable load flow modeling based on binding Dispatch schedules and will subsequently no longer have to anticipate unexpected behavior that exacerbates congestion. So, for example, if even more wind power is expected in the north shortly before delivery during an existing north-south congestion, batteries in southern Germany can no longer react to this—because they can no longer adjust their operation.

Two options. There are two fundamentally different approaches to mandatory dispatch schedules. We refer to these as "unilateral mandatory dispatch schedules" and "bilateral mandatory dispatch schedules." Below, we explain why we have significant concerns about the effectiveness of these tools in both cases.

6.1.1 Unilaterally binding dispatch schedules

Approach. With unilaterally binding dispatch schedules, subsequent adjustments to the dispatch schedule are permitted if they alleviate congestion, i.e., if they go "in the right direction." Batteries in the surplus region may store more energy than planned, even in the short term. Batteries in the shortage region, on the other hand, may discharge more energy in the short term. A deviation in the opposite direction is prohibited. Which deviations are still permitted in the short term depends on the specific congestion situation. This must therefore be determined on a case-by-case basis (dynamically).

Idea. The idea behind unilaterally binding dispatch schedules is that flexible systems such as battery storage on the correct side of the grid congestion can continue to react to forecast changes . They would then contribute to balancing the grid without exacerbating grid congestion.

Strategic Behavior. However, unilaterally binding dispatch schedules can easily be circumvented. If, for example, it is foreseeable that additional discharge could be limited in the short term, the battery operator can report “100% discharge capacity” as the dispatch schedule. This preserves their full freedom to implement any physical battery operation—after all, they are free to reduce discharge or even switch to charging at short notice.

Example. The following example illustrates this logic. A storage unit in northern Germany must submit a binding Dispatch schedule by 4:00 p.m. for the delivery period from 6:00 p.m. to 6:15 p.m. It considers it possible that a north-south bottleneck may occur, in which case it would later be allowed to inject more energy than specified in the Dispatch schedule. Therefore, it reports that it will discharge as much as possible between 6:00 p.m. and 6:15 p.m. Shortly before delivery, it corrects the reported dispatch schedule to the actual planned level.

Negative effects. Incentives for such behavior undermine the primary goal of unilaterally binding dispatch schedules. In this form, the tool thus fails to create any binding effect. Consequently, it does not lead to greater planning security for the grid operators. Furthermore, strategic dispatch schedule submissions result in a further increase in the expected redispatch requirement—after all, the storage facilities report in advance more congestion-aggravating behavior than they actually plan. The fact that they then behave in a less congestion-aggravating manner during delivery hardly helps, because by that point the transmission system operators have already implemented other redispatch measures that cannot be reversed at such short notice.

Limits. There are aspects that make strategic behavior more difficult or less attractive under unilaterally binding Dispatch schedules. For example, 1-hour storage facilities cannot plausibly demonstrate that they intend to operate in the same direction over several hours. Furthermore, redispatch activations with cost compensation could make strategic behavior unattractive in individual quarter-hour intervals. This will help ensure that the manipulation of reported dispatch schedules is not as extreme in all cases as in the examples we have cited. However, it will not completely prevent strategic behavior.

6.1.2 Bidirectionally binding dispatch schedules

Approach. In the case of mutually binding dispatch schedules, operators are bound by the dispatch schedules they have submitted. Any subsequent deviation from the submitted dispatch schedule is penalized—even if such a deviation would reduce network congestion. Unlike unilaterally binding dispatch schedules, bilaterally binding dispatch schedules can apply throughout the entire year (statically) or be set dynamically only during peak hours.

Objective. The basic idea behind two-way binding dispatch schedules is that prohibiting short-term dispatch schedule changes increases the binding nature of the submitted dispatch schedules and thus avoids short-term grid congestion. Consequently, such a restriction would have to apply not only to large-scale batteries but to all facilities: gas-fired power plants, pumped-storage facilities, and the short-term curtailment of renewables can also cause short-term grid congestion.

Not a solution. Bilaterally binding dispatch schedules are not a solution to short-term grid bottlenecks. Forecasting errors in renewable generation or consumption will continue to occur and must be balanced out. A ban on short-term flexibility provision for batteries alone would result in other flexible generators, storage facilities, or consumers having to respond—and there is no guarantee that they would be on the “right” side of the congestion. Furthermore, this would increase the costs of balancing the grid if batteries were no longer available for this purpose. Two-way binding dispatch schedules for all facilities, on the other hand, would mean that forecasting errors could only be compensated for by the use of balancing reserves. This is expensive and inefficient, but even then it still does not solve the congestion problem. This is because there is no local control even when balancing reserves are activated. It therefore remains purely a matter of chance whether balancing reserves are provided on the “right” or the “wrong” side of the congestion.

6.2 BATTERY MODEL

Battery model. In our battery model, the battery is active on multiple markets simultaneously (see Table 3, which also includes further modeling assumptions). First, the model determines on which balancing market the battery will offer its power. Based on 2025 prices, Automatic Frequency Restoration Reserve is generally more attractive. For Automatic Frequency Restoration Reserve, bids are placed symmetrically in both the negative and positive directions, which leaves room for continuous intraday trading. On the balancing energy market, the battery offers its power linked to the prices of the IDA1 auction with a 50% premium. It repurchases the energy it has supplied on the continuous intraday market. In the final step, the model optimizes the battery for continuous intraday trading. In doing so, it re-optimizes the Dispatch schedule for the entire delivery day in 15-minute intervals based on new price information. Our model is based on the open-access optimization model of the Institute for Power Electronics and Electric Drives (ISEA) at RWTH Aachen University.

Table 3: Key modeling assumptions for battery optimization

Parameter	2-hour battery	4-hour battery
Charge/discharge efficiency	94%	95%
Location	Southern and Northern Germany	
Cycles	2 per day	
Markets	Continuous intraday trading, Frequency Containment Reserve, Automatic Frequency Restoration Reserve	
Model year	2025	

Dynamic grid fees. Building on our initial study for ECO STOR, we generated a time series for dynamic grid fees based on actual redispatch data at one location each in southern and northern Germany in 2025. Depending on whether positive or negative redispatch occurred at that location, the grid fee is determined by the amount of the corresponding marginal redispatch costs. The resulting time series is then added to all prices for a delivery period in continuous intraday trading.

Limitation of balancing capacity. Here, we reduce the marketable power by a specified factor. It should be noted that, due to symmetric bids, a restriction only takes effect when the limit falls below 50% of the installed capacity.