

Simulated Day-Ahead Prices with Additional Battery Storage

Description of the Method (v1.0, 24 September 2026)

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Abstract

The Energy-Charts page “Simulated spot market prices” shows which day-ahead prices would have resulted in the bidding zone Germany–Luxembourg (DE-LU) if additional battery energy storage systems (BESS) had taken part in the auction. The calculation is based on the aggregated supply and demand curves published by EPEX SPOT for every market time unit. The BESS fleet is dispatched with the objective of maximum profit over one calendar week, and the market is cleared again with the resulting bids. Block orders and the exchange with the neighbouring bidding zones react to a changed price. Both effects are therefore modelled explicitly: block orders by a mixed-integer program per delivery day which follows the EUPHEMIA rules, the cross-zonal exchange by an import response curve per market time unit which is built from public JAO and ENTSO-E data. This documentation describes the input data, the equations of the individual model parts, the scenarios, the operational calculation, the limitations of the method and its relation to fundamental electricity market models.

Revision history

Version	Date	Changes
v1.0	24 September 2026	Initial version

1 Introduction

1.1 Motivation

The installed BESS capacity in Germany is growing fast, and a large part of it is operated for arbitrage: the storage is charged at low prices and discharged at high prices. With a small capacity this has no visible influence on the market. With several gigawatts the storage changes the prices itself. Charging at noon increases the demand and therefore the price, discharging in the evening increases the supply and lowers the price. The price spread within a day becomes smaller, the market value of solar power rises, fewer hours with negative prices occur, and the revenue of each additional storage unit decreases.

The size of these effects cannot be read from a historical price time series, because the price in every market time unit (MTU) is the result of an auction. To answer the question which prices would have resulted with a given BESS fleet, the auction has to be calculated again with the additional bids of the fleet. The simulation does this for every MTU on the basis of the published order curves. It therefore needs no assumptions on power plant costs, availabilities, fuel and CO₂ prices, bidding strategies or the feed-in of renewable energies. Their effect is already contained in the published curves, and without additional storage the published prices are reproduced exactly.

A common approach is to shift the published demand and supply curves by the charging and discharging energy of the fleet and to determine the new intersection. This approach overestimates

the price effect, because the published curves do not contain the complete order book in its original form. Two parts of the market are included only with their historical result and do not react when the curves are shifted: the block orders and the exchange with the neighbouring bidding zones. The following two subsections explain why both have to be considered.

1.2 Why block orders have to be considered

In the Single Day-Ahead Coupling (SDAC) the market clearing prices (MCP) of all bidding zones are determined by the EUPHEMIA algorithm, which maximises the total social welfare over all MTUs of the delivery day and all bidding zones at once, under consideration of the order books and the available transmission capacities [1, 2]. Besides the simple orders per MTU, which are aggregated into the demand and supply curves, the participants can submit block orders. A block order covers several MTUs and is accepted or rejected as a whole, depending on the average price over its periods. Linked block orders and exclusive groups add further conditions. Power plants use block orders to represent start-up costs and minimum run times.

The published aggregated curves are distorted with respect to the block orders [3]: accepted blocks are contained as price-independent volume at the minimum or maximum price, and rejected blocks are not contained at all. If the curves are only shifted, every block keeps its historical status. In reality a changed price can change the status. Table 1 shows an example with a sell block over two hours and a limit price of 65 €/MWh.

Case	MCP hour 1	MCP hour 2	average MCP	limit price	status of the block
without BESS	60 €/MWh	80 €/MWh	70.0 €/MWh	65 €/MWh	accepted
with BESS	60 €/MWh	55 €/MWh	57.5 €/MWh	65 €/MWh	rejected

Table 1: Example for a change of the acceptance status of a sell block order over two hours.

Without BESS the average MCP of 70 €/MWh is above the limit price and the block is accepted. If the fleet discharges in hour 2 and lowers the MCP to 55 €/MWh, the average falls below the limit price and the block is rejected. The supply of the block is then missing in both hours, so the price rises again. The same applies in the opposite direction: if the fleet charges and raises the price, rejected sell blocks can become accepted and accepted buy blocks can be rejected, which limits the price increase. The MCP depends on the acceptance of the blocks and the acceptance depends on the MCP. Prices and acceptances have to be determined together. Without this step the price reduction in expensive hours and the price increase in cheap hours are both overestimated.

1.3 Why the electricity exchange has to be considered

DE-LU is coupled with its neighbouring bidding zones. The transmission system operators provide the available transmission capacities, and EUPHEMIA uses them to exchange energy between the zones as long as this increases the welfare, i.e. until the prices have converged or a capacity limit is reached. The realised net import or export of DE-LU is contained in the published curves in the same way as an accepted block, as a fixed volume which does not depend on the price.

If the fleet raises the price at noon, DE-LU becomes more expensive compared to its neighbours. In the real market this leads to higher imports or lower exports, which limits the price increase. In the evening the opposite happens: a lower price in DE-LU reduces the imports. The neighbouring zones therefore take over a part of the price effect. The size of this part depends on the free transmission capacity in the respective hour. For a small fleet the damping is strong. When the capacities are exhausted, additional BESS power acts on the DE-LU price almost without

damping. A constant damping factor cannot represent this behaviour, therefore the response of the imports is calculated per MTU from the capacities and prices of the individual borders.

1.4 Scenarios and structure of this documentation

To show the influence of both effects separately, four scenarios are calculated: **base** (published curves only), **mc** (with market coupling), **cb** (with block orders) and **mc_cb** (with both). All scenarios use the same BESS dispatch and differ only in the clearing function. With 100 effective power levels (fleet power multiplied by the day-ahead share, section 4.4), five storage durations and four scenarios, 2000 combinations are calculated for every week.

Section 2 lists the input data. Section 3 describes the market model, section 4 the dispatch of the BESS fleet, sections 5 and 6 the block orders and the market coupling. Sections 7 to 9 deal with parameters and outputs, the operational calculation and the validation. Section 10 describes the limitations, and section 11 relates the method to fundamental electricity market models.

2 Input data

All input data are published market data or freely available transparency data (table 2). Confidential data are not used.

Quantity	Source	Use
Aggregated supply/demand curves	EPEX SPOT	clearing functions
Block order files (bbof 15/30/60 min)	EPEX SPOT	re-clearing of block orders
Max. bilateral exchanges (MaxBex)	JAO Core publication tool	headrooms (Core borders)
Day-ahead prices of all zones	ENTSO-E transparency (12.1.D)	price level of the neighbours
Day-ahead load forecasts	ENTSO-E transparency (6.1.B)	market size of the neighbours
DA commercial schedules	ENTSO-E transparency (12.1.F)	historical cross-border flows
DA transfer capacities / offered cap.	ENTSO-E transparency (11.1.A/12.1.A)	headrooms (other borders)
Total nominated capacity	ENTSO-E transparency (12.1.B)	explicit border (CH)
Feed-in potential, forecasts, load	Energy-Charts	display only

Table 2: Input data. If a transparency feed is not published for a border, static interconnector ratings are used. The series in the last row are shown next to the prices and are not part of the price calculation.

3 Market model

3.1 Clearing function from the published curves

An MTU has a length of one hour until 30 September 2025 and of 15 minutes since the introduction of the 15-minute products in the SDAC on 1 October 2025. For every MTU t EPEX SPOT publishes two aggregated curves as functions of the price p . From these the excess supply is calculated:

$$E_t(p) = S_t(p) - D_t(p) \quad (1)$$

with

$S_t(p)$ supply: sell curve, i.e. the total volume of all sell orders which are executed at the price p (orders with a limit price of p or lower). S_t increases with the price.

$D_t(p)$ demand: purchase curve, i.e. the total volume of all buy orders which are executed at the price p (orders with a limit price of p or higher). D_t decreases with the price.

$E_t(p)$ excess supply: the volume by which the supply exceeds the demand at the price p . E_t is negative below the MCP, positive above it and increases monotonically with the price.

All three functions are piecewise linear. The zero of E_t , i.e. the intersection of the sell and the purchase curve, is the official MCP p_t^0 . An additional net demand w_t shifts the intersection and results in the price

$$p_t(w_t) = E_t^{-1}(w_t), \quad w_t = c_t - d_t + \delta_t, \quad (2)$$

where c_t and d_t are the charged and the discharged energy of the fleet at the grid connection point (section 4) and δ_t is the response of the block orders (section 5), which is zero in the scenarios without block orders. All further calculations use these piecewise linear functions directly, no functional form is fitted. Weeks with hourly and quarter-hourly delivery days can be calculated together. Energy per MTU, curve shifts and state-of-charge steps scale with the length of the MTU.

3.2 Historical volumes and their response

The published curves are consistent with the historical result. Accepted block orders and the realised net position are contained as price-independent volumes. Therefore neither the blocks nor the exchange have to be reconstructed in absolute terms. Only their response to a price change caused by the BESS is modelled, and every model part is formulated such that without BESS the published MCP is reproduced exactly. This property is checked numerically for every MTU during the calculation.

4 Dispatch of the BESS fleet

4.1 Competitive equilibrium

The additional fleet has the power P , the storage duration τ (usable energy capacity divided by the power, in hours), the round-trip efficiency η and degradation costs c^{deg} per discharged MWh. It is modelled as a large number of small units without market power. Charging and discharging take place at full rated power at the grid connection point. The losses are assigned to the charging process, i.e. only the share η of the charged energy can be discharged later. With the purchased energy c_t and the sold energy d_t in MTU t the state of charge is

$$s_{t+1} = s_t + \eta c_t - d_t, \quad 0 \leq s_t \leq P \tau. \quad (3)$$

The dispatch of the whole fleet corresponds to the competitive equilibrium. It is the solution of the optimisation problem

$$\max_{c,d} - \sum_t W_t(c_t - d_t) - c^{\text{deg}} \sum_t d_t \quad \text{subject to equation (3) and } 0 \leq c_t, d_t \leq P \Delta t_t, \quad (4)$$

where Δt_t is the length of MTU t and

$$W_t(w) = \int_0^w E_t^{-1}(v) dv. \quad (5)$$

$W_t(w)$ is the cost of the net demand $w = c_t - d_t$ in MTU t : the integral of the price $p_t(v) = E_t^{-1}(v)$ of equation (2) from zero to w , i.e. the area under the inverse excess supply curve. It can be read as follows. The fleet places its energy one MWh after the other, and every MWh is valued at the price which holds once the previous MWh are already in the market. For $w > 0$ (net purchase) W_t is the money paid for the w MWh at a rising price, for $w < 0$ (net sale) $-W_t$ is the revenue for the $|w|$ MWh at a falling price. The objective is therefore the revenue from discharging minus the expense for charging, each MWh valued at its own marginal price, minus the degradation costs. The sum of $-W_t$ over all MTUs is at the same time the welfare which the fleet adds to the market.

This objective differs from the cash flow of the fleet, $\sum_t p_t(w_t) (d_t - c_t)$, in which every MWh is settled at the uniform clearing price. A single participant which maximised the cash flow would withhold power, because every additional MWh lowers the price of all MWh it sells. With the integral the derivative of W_t at w is exactly the current price $E_t^{-1}(w)$, so the optimality condition reads: shift one more MWh from MTU t_1 to MTU t_2 as long as $p_{t_2} > p_{t_1}/\eta + c^{\text{deg}}$ at the resulting prices. This is the decision of a small unit without market power. In the optimum no unit can improve its result by deviating, which is the definition of the competitive equilibrium. It is also the objective which the auction algorithm would apply to the fleet if it were submitted as storage orders (section 10.3).

A numerical example with the synthetic delivery day of section 9: a linear curve with a slope of 10 €/MWh per 1000 MWh and a published price of 20 €/MWh at noon. If the fleet buys $w = 1000$ MWh, the price rises to 30 €/MWh, and

$$W(1000) = \int_0^{1000} (20 + 0.01 v) dv = 25\,000 \text{ €}.$$

The fleet actually pays $30 \cdot 1000 = 30\,000$ €. The difference of 5 000 € is its own price impact, which a participant with market power would take into account and a competitive fleet does not. In the evening at 120 €/MWh the same happens with the opposite sign when the fleet sells.

W_t is convex, because E_t^{-1} increases with w , and piecewise quadratic, because E_t^{-1} is piecewise linear; hence the problem is convex. In the equilibrium the prices within the charging and within the discharging periods are equalised as far as the curve steps and the power limit allow. A cycle is only carried out if the price spread covers the losses and the degradation costs, $p^{\text{sell}} > p^{\text{buy}}/\eta + c^{\text{deg}}$.

4.2 Solution method

Problem (4) is solved with the Frank–Wolfe algorithm. The linearised subproblem at the current prices is the profit maximisation of a single storage unit against fixed prices, which is solved exactly by dynamic programming over discrete state-of-charge levels. The efficiency is represented as a ratio of integers. For the value $\eta = 86\%$ of the published results (section 7) one MTU of charging raises the state of charge by 43 levels and one MTU of discharging lowers it by 50 levels. The duality gap of the Frank–Wolfe iterations gives an upper bound for the distance to the optimum, and the iteration is stopped below a relative tolerance.

For the scenarios without block orders a faster incremental method is used. Storage units of 1 MW are dispatched one after the other, each against the curves which already contain the bids of the previous units. For small increments the result converges to the same equilibrium. The scenarios with block orders use the Frank–Wolfe method, because it can be combined with the iteration described in section 5.

4.3 Optimisation horizon of one week

Curves, coupled curves and block orders are prepared per delivery day, as they are published per delivery day. The BESS fleet is optimised over a complete ISO week (Monday to Sunday) in one step. The state of charge is carried over midnight and is not reset every day.

The week was chosen as horizon for the following reasons. A separate optimisation of every delivery day with a return to the initial state of charge at midnight is the simplest choice, but it distorts the dispatch at the day boundary: a real storage does not empty or fill at midnight because the delivery day ends, and the cheap hours of the night belong to two delivery days. A horizon over the whole history would remove every boundary, but it would give the fleet perfect knowledge over months, and the result of every day would change with every new day. The week

is a compromise. Within the week the boundary effects at midnight are eliminated, and the weekend, where the prices are low and the storage is used differently than on working days, is contained completely. At the same time the perfect knowledge of the fleet is limited to seven days, and the weeks are independent of each other, so that a single week can be calculated on its own and several weeks in parallel.

Every week starts with a state of charge of 50 % of the usable capacity and must not end below this value. The energy which is in the storage at the beginning can therefore not be sold. A surplus at the end of the week has no value in the objective function, therefore no energy is stored without a corresponding revenue. With this condition the weeks are independent of each other.

In operation the current week is not yet complete. It is then optimised over the delivery days which have been auctioned so far, and the condition on the final state of charge applies to the last available day. When the next delivery day is added, the whole week is optimised again (section 8).

4.4 Share of the fleet on the day-ahead market

In practice only a part of a storage portfolio is traded on the day-ahead market. The remaining power is used in the intraday markets and for balancing services. A fleet with the power P and the day-ahead share s shifts the curves in the same way as a fleet with the power sP . Every product of the selectable fleet powers (0 to 20 GW) and shares (10 to 100 %) is therefore calculated as a separate effective power level. The 20 fleet powers in steps of 1 GW and the 10 shares in steps of 10 % give 200 products, of which 100 are distinct (e.g. 2 GW at 50 % and 1 GW at 100 % are the same level of 1 GW). These 100 levels between 0.1 and 20 GW are calculated. They lie 0.1 GW apart up to 2.2 GW and become sparser above, up to 1 GW apart above 17 GW; a power such as 2.3 GW is not a product of the two sliders and is not calculated. The web page selects the calculated level which corresponds to the chosen combination.

The default value is derived from the Battery Revenue Index of RWTH Aachen University (ISEA) [8]. This index gives the revenue potential of a large-scale BESS in Germany separately for the individual markets: day-ahead auction (DA), intraday auction (IDA1), continuous intraday trading (IDC), frequency containment reserve (FCR) and automatic frequency restoration reserve (aFRR). For a system with 2 h storage duration and two cycles per day, the share of the day-ahead revenue R in the sum of the single-market revenue potentials is calculated for every month:

$$s_{DA} = \frac{R_{DA}}{R_{DA} + R_{IDA1} + R_{IDC} + R_{FCR} + R_{aFRR}}. \quad (6)$$

The mean of the last twelve monthly values is rounded to the 10 % grid of the selectable shares. For September 2025 to August 2026 the monthly values lie between 14 and 20 %, and their mean is 16.5 %. This gives the default of 20 %. The value is checked every month with the new index data and adapted if the rounded result changes. It is a share of the revenue, which is used as an approximation for the share of the power. This corresponds to the assumption that every megawatt of the fleet earns the same revenue in each market, i.e. that the arbitrage between the markets equalises the revenues, so that the revenue share and the power share coincide. The limits of this assumption are discussed in section 10.

5 Block orders

5.1 Re-clearing relative to the historical result

Every block b with the volumes q_{bt} per MTU, the limit price P_b , the minimum acceptance ratio MAR_b and the historical acceptance ratio AAR_b from the published files is decided again by a

mixed-integer program per delivery day. Its acceptance ratio $x_b \in \{0\} \cup [\text{MAR}_b, 1]$ enters the clearing as deviation from the historical result,

$$\delta_t = \sum_b q_{bt} (x_b - \text{AAR}_b), \quad (7)$$

which is added to the net demand of MTU t . For $x_b = \text{AAR}_b$ for all b the published MCP is reproduced. This is checked for every delivery day, and a remaining price deviation or changed volume is reported.

5.2 Formulation of the mixed-integer program

With the binary variables u_b and the ratios x_b ($\text{MAR}_b u_b \leq x_b \leq u_b$) the program maximises the surplus of the blocks plus the piecewise linear welfare of the resulting shifts. The constraints for the order types follow EUPHEMIA [1]:

$$\text{exclusive groups (C04): } \sum_{b \in G} x_b \leq 1 \quad \text{for every group } G, \quad (8)$$

$$\text{linked block orders (C02): } x_{\text{child}} \leq x_{\text{parent}}. \quad (9)$$

For blocks with $\text{MAR} = 1$ the first constraint means that at most one block of the group can be accepted. Paradoxically accepted blocks are removed iteratively: an accepted block with a negative surplus at the resulting prices is excluded and the program is solved again. As in EUPHEMIA, linked blocks are assessed by the surplus of the whole family, so that a child order with a positive surplus can compensate a parent order with a negative one. Paradoxically rejected blocks are permitted. In the scenario with market coupling the blocks are cleared against the coupled curves of section 6.

5.3 Selection of the relevant blocks

To limit the computing time, only those blocks receive decision variables whose status can change at all. For this purpose the curves are cleared with the maximum charging and the maximum discharging energy of the largest simulated fleet. This gives the price range which can be reached in the MTUs of a block. The range is widened by a margin for the interaction between blocks. Blocks whose limit price is outside this range keep their historical acceptance. The members of an exclusive group are checked individually, and members which are not relevant enter the group constraint as a constant. Linked blocks always stay together. On delivery days with 15-minute MTUs the three published files (15, 30 and 60 minutes) are merged. A 60-minute block covers four quarter hours.

5.4 Iteration between BESS dispatch and block orders

BESS dispatch and block acceptance influence each other via the prices. They are calculated alternately: the dispatch for the current block response δ , then the block program for the current dispatch, until the new block response changes the price in no MTU by more than a tolerance. Both steps start from the solution of the previous iteration and of the neighbouring power level. The programs of the individual delivery days are independent and are solved in parallel. The removal of paradoxically accepted blocks is carried out once per power level after the iteration has converged.

The complete iteration is carried out only at anchor power levels: at the first level, at every multiple of 0.5 GW and at the largest level. At the levels in between the block response of the last anchor level is kept and only the BESS dispatch is calculated again. The values at the anchor levels are therefore the fully calculated ones. The round fleet sizes of the web page (1, 2, 5, 10, 20 GW etc.) are anchor levels.

6 Market coupling

6.1 Coupled excess supply

The excess supply of every MTU is replaced by a coupled function

$$\tilde{E}_t(p) = E_t(p) + M_t(p), \quad M_t(p_t^0) = 0. \quad (10)$$

$M_t(p)$ is a monotone, piecewise linear import response curve. It gives the additional net import into DE-LU if the price changes from the published MCP p_t^0 to p . As $\tilde{E}_t$ is again monotone and piecewise linear, the BESS dispatch and the block program can be used without changes. The scenarios with market coupling receive $\tilde{E}$ instead of E . In contrast to a constant damping factor, M_t saturates when the transmission capacities are exhausted.

6.2 Model of the neighbouring bidding zones

Complete order curves are only available for DE-LU. A neighbouring zone z is therefore approximated by the DE-LU curve of the same MTU, scaled with the market size and positioned at the day-ahead price p_z^0 of the zone:

$$E_z(p) = \kappa_z \frac{L_z}{L_{\text{DE}}} (E_t(p) - E_t(p_z^0)). \quad (11)$$

L denotes the day-ahead load forecast. The economic interpretation is that the neighbouring zone is assumed to have the same supply and demand structure and the same bidding behaviour as DE-LU, only with a different market size and a different price level. The factor $\kappa_z \geq 1$ accounts for zones through which further markets are connected and respond together with the zone: $\kappa_z = 1$ for AT, BE, NL and PL, 1.2 for CZ (gateway to SK and HU) and FR (gateway to the Iberian peninsula and Italy), 1.3 for CH (gateway to Italy), 1.5 for DK1 and DK2 and 2.0 for SE4 and NO2 (gateways to the Nordic system). The values are estimates and are listed in table 3. Due to the positioning on the price axis the response depends on the market situation. A neighbour with a price in the flat part of the curve responds with a large volume, a neighbour in a scarcity situation with a small one. The error of this approximation is discussed in section 10.4.

6.3 Headrooms and treatment of price differences

Every border can contribute at most its remaining capacity in the respective direction, related to the historical result. This remaining capacity is the headroom h_z of the border: $h_z^\uparrow = X_z^\uparrow - F_z^0$ for additional imports into DE-LU and $h_z^\downarrow = X_z^\downarrow + F_z^0$ for additional exports, where $X_z^\uparrow$ and $X_z^\downarrow$ are the maximum bilateral exchanges in the import and in the export direction and F_z^0 is the historical day-ahead commercial schedule of the border, positive for imports into DE-LU. The maximum bilateral exchanges are taken from JAO (MaxBex) for the Core borders [4] and from the ENTSO-E capacities for the Hansa borders [5]. The response of a zone is the limited curve $\Delta I_z(p) = \text{clip}(E_z(p), -h_z^\downarrow, h_z^\uparrow)$, where $\text{clip}(x, a, b)$ limits x to the interval $[a, b]$. If the historical prices of z and DE-LU had not converged, the direction in which an exchange would have been profitable is treated as exhausted. In flow-based market coupling a critical network element is then binding, which is not visible in the bilateral capacity data. With this rule $M_t(p_t^0) = 0$ holds for every border, and the one-sided behaviour in hours without price convergence is reproduced. The total response is $M_t(p) = \sum_z \Delta I_z(p)$.

6.4 Explicit border to Switzerland

Switzerland does not take part in the SDAC, so EUPHEMIA does not allocate the capacity between DE and CH together with the energy. Instead the TSOs let JAO auction the capacity

separately as physical transmission rights, per hour and direction, in yearly, monthly and daily explicit auctions; the daily auction takes place on the morning of D-1, before the day-ahead gate closure. The holder of a right has to procure the energy itself, e.g. with a buy order in the DE-LU day-ahead auction and a sale in Switzerland, and then nominates the cross-border schedule to the TSOs after the auction results are known. A right which is not nominated expires (daily rights) or is resold in the daily auction (long-term rights). The nominated schedules are published by ENTSO-E as total nominated capacity.

For the simulation this has two consequences. The buy and sell orders of the rights holders are ordinary orders in the DE-LU auction and are therefore already contained in the published curves. And the rights are fixed before the German auction, so within a delivery day the border can only respond with capacity which has not been nominated. To avoid double counting, the range in which a response would only reverse existing nominations is excluded. With the nominations F^0 and the capacities $C^\uparrow, C^\downarrow$ the response is

$$\Delta I_{CH}(p) = \text{clip}(r(p), -(C^\downarrow + F^0), C^\uparrow - F^0) - \text{clip}(r(p), -\max(F^0, 0), \max(-F^0, 0)), \quad (12)$$

where $r(p)$ is the scaled curve positioned at p_t^0 . Only additional exchange on unused capacity enters M_t . The observed price difference between CH and DE is kept constant, as it reflects the price of the capacity in the explicit auction.

6.5 Scope of the approximation

The coupling model treats the borders separately. The common network constraints of the flow-based domain, i.e. critical network elements which are used by several borders, are only considered by the rule for non-converged prices. A complete flow-based representation with the PTDF and RAM data of the JAO final computation is planned as an extension. It would only change the calculation of M_t . The coupling data are downloaded once per delivery day and stored.

7 Parameters and outputs

Table 3 contains the parameters of the published results. For every scenario, effective power level and storage duration the new price series as well as the power and the state of charge of the fleet are written into the weekly files of the Energy-Charts web page. In addition, summary files with the profit of the fleet (gross, degradation costs, net), the discharged energy and the number of cycles are created. The profit is calculated with the new prices and thus includes the price effect of the fleet itself.

The solar and wind series shown next to the prices represent the volumes which were available for grid feed-in and not the generation after curtailment (market and grid induced). For every time step the first available value of the following sources is used: final grid feed-in potential, preliminary potential, day-ahead forecast, actual generation. The load is the measured load and is extended by the day-ahead load forecast where no measurement is available yet. All series end at the last simulated MTU. They are not part of the price calculation.

8 Operational calculation

In operation the calculation follows the daily auction. As the BESS dispatch is one problem per week, the week is the unit of calculation. The market data are retrieved automatically. As soon as the data of a new delivery day are available after the auction, the current week is calculated again and the results on the web page are updated. This normally happens in the night before the day of delivery.

Parameter	Value
Effective fleet power on the day-ahead market	0.1 to 20 GW, 100 levels
Storage duration	2, 3, 4, 5, 6 h
Round-trip efficiency η	86 % (losses assigned to charging)
Degradation costs c^{deg}	10 €/MWh discharged
State of charge at the week boundary	50 % of the usable capacity
Increment of the incremental method	1 MW
Stopping criterion Frank–Wolfe	duality gap below 1 % of the initial gap
Tolerance of the block iteration	0.5 €/MWh
Distance of the anchor power levels	0.5 GW
Margin for the selection of blocks	25 €/MWh
Relative gap of the mixed-integer program	10^{-5}
Hinterland factor κ_z of the neighbouring zones	1.0 (AT, BE, NL, PL), 1.2 (CZ, FR), 1.3 (CH), 1.5 (DK1, DK2), 2.0 (SE4, NO2)

Table 3: Parameters of the published results.

An example: on a Wednesday the auction for Thursday takes place. After it the current week contains the delivery days Monday to Thursday, and the fleet is optimised over these four days. On Thursday the delivery day Friday is added, and the week is optimised again over five days. The dispatch and the prices of Monday to Thursday can change slightly in this step, because the fleet now knows the prices of Friday as well. With the auction on Saturday for Sunday the week is complete, and its result does not change any more unless late input data arrive. While a week is running, the displayed results of its earlier days are therefore the result of the optimisation over the days known so far.

Some input data, e.g. the block order files or the coupling data, can be published later than the curves. In this case the result of the week is provisional, and the week is calculated again when the missing data have arrived.

The generation and load series which are shown next to the prices are updated regularly and independently of the price calculation, as soon as better data are published.

9 Validation

Three properties are checked during the calculation of every delivery day: the intersections of the curves reproduce the official MCP, the coupled curves reproduce it without shift ($M_t(p_t^0) = 0$), and the block program with the historical acceptance reproduces it as well. A deviation in the last check indicates inconsistent AAR data and is reported with the largest price deviation and the changed volume. For every dispatch calculation the number of Frank–Wolfe iterations and the largest duality gap are logged, for every block calculation the number and duration of the solved programs and the convergence at every anchor level.

In addition, the method was tested with a synthetic delivery day for which the result can be calculated by hand: 24 hourly MTUs, a linear curve with a slope of 10 €/MWh per 1000 MWh, a BESS with 1 GW and 4 h, $\eta = 100$ % and degradation costs of 10 €/MWh. The published price is 20 €/MWh at noon (hours 11 to 14), 120 €/MWh in the evening (hours 18 to 21) and 60 €/MWh otherwise. The expected dispatch is one full cycle. In the block scenario eleven synthetic block orders were added (regular, linked and exclusive), of which blocks with 400 MWh per hour change their status. In the coupling scenario one neighbouring zone with half the market size and sufficient capacity was added. Table 4 compares the results. All values agree with the analytical expectation, including the acceptance status of every single block, the linked and exclusive constraints, the state of charge and the profit.

Quantity	base	cb	mc
Price at noon (published 20 €/MWh)	30.00 €/MWh	26.00 €/MWh	26.67 €/MWh
Price in the evening (published 120 €/MWh)	110.00 €/MWh	114.00 €/MWh	113.33 €/MWh
Price spread	80.00 €/MWh	88.00 €/MWh	86.67 €/MWh
Gross profit	320 000 €	352 000 €	346 667 €
Degradation costs	40 000 €	40 000 €	40 000 €
Net profit	280 000 €	312 000 €	306 667 €

Table 4: Results for the synthetic delivery day. With block orders and with market coupling the price effect of the BESS is smaller than in the **base** scenario, and the profit of the BESS is higher accordingly.

The test covers one day with hourly MTUs and one BESS configuration. The exported week files are additionally checked for groups of scenario and storage duration without any dispatch and for implausible changes of the weekly mean price.

10 Limitations

The simulation answers one question: which day-ahead prices would the auction of a past delivery day have given if an additional BESS fleet had submitted bids and all other bids had remained unchanged? The results have to be read with this question in mind. The most important limitations are summarised in the following box and explained in the subsections.

Limitations at a glance

1. **Only the day-ahead auction is calculated.** Intraday markets, balancing markets and redispatch are not part of the model.
2. **The constant day-ahead share (default 20 %) is not realistic.** A real fleet distributes its power over several markets, and this distribution changes from hour to hour and with the size of the fleet. A correct treatment requires a multi-market optimisation, which the tool does not contain. The quantity which determines the result is the effective power on the day-ahead market. The default value assumes that the arbitrage between the markets is complete, so that the revenue share of the day-ahead market equals its power share.
3. **All other bids are unchanged.** Only block orders and cross-zonal exchange react to the new prices. The result is a short-term sensitivity and not a new long-term market equilibrium.
4. **The fleet is idealised:** perfect foresight over one week, no market power, no technical restrictions apart from power, capacity, efficiency and degradation costs. Efficiency (86 %) and degradation costs (10 €/MWh) are fixed and are an uncertain input with a large influence on the result.
5. **Block orders and market coupling are approximations** of the EUPHEMIA algorithm and of the flow-based capacity calculation. The neighbouring zones are assumed to have the same supply and demand structure as DE-LU (section 10.4).
6. **The physical system is not modelled.** Curtailment, generation mix, emissions and system costs cannot be derived. For these quantities fundamental market models are required (section 11).
7. **The simulation is not a forecast** and not a statement on the total revenue of a BESS project.

10.1 Only the day-ahead auction, constant day-ahead share

The simulation calculates one market stage again, the day-ahead auction. Intraday auctions, continuous intraday trading, balancing markets, redispatch and countertrading are not considered. A real BESS is marketed on several of these markets at the same time. The web page represents this by the constant day-ahead share s of section 4.4 with a default value of 20 %. This is a strong simplification for the following reasons:

- **The share is not constant over time.** An operator decides for every MTU on which market the power is offered, depending on the expected prices. On a day with a large day-ahead price spread a larger part of the fleet is offered in the day-ahead auction than on a day with a flat price profile. Power which was sold as balancing capacity before the day-ahead auction is not available at all during the respective product period.
- **The default value is a share of the revenue, not of the power.** If the arbitrage between the markets works and a BESS is not built for one specific market, every megawatt earns the same revenue in each market in the long term, and the revenue share is equal to the power share. This is the assumption behind the default value. In the short term it does not hold: the revenues per megawatt differ between the markets from month to month, and the single-market revenue potentials of the index are each calculated for the exclusive participation in one market. They cannot be reached at the same time and are not additive.
- **The share depends on the size of the fleet.** The default value is derived from today's revenues with today's fleet. With a growing fleet the revenues decrease in all markets, but not to the same extent. The balancing markets have a volume of only a few gigawatts and are saturated first. A fleet of 10 or 20 GW has to place a growing part of its power in the day-ahead and intraday markets. A share of 20 % therefore tends to underestimate the day-ahead power of a large fleet. The share is a free parameter of the web page: for large fleets a higher share is appropriate, and the user can set it according to own assumptions.
- **The markets influence each other.** A position from the day-ahead auction is optimised again in the intraday markets, and the intraday prices follow the day-ahead price. A changed day-ahead price would therefore also change the prices and the revenues of the other markets. This feedback is not modelled.

A consistent treatment requires a multi-market optimisation. In such a model the fleet is optimised jointly over the balancing capacity auctions, the day-ahead auction, the intraday auctions and continuous intraday trading, in the chronological order of the gate closure times and with the price response of the fleet in each of these markets. The day-ahead share would then be a result of the calculation and not an input. The necessary order data are only partly public: aggregated curves are published for the day-ahead auction and the intraday auctions, but for continuous intraday trading only the executed trades are published and not the order book, and for the balancing markets anonymised bid lists are published, but not the joint restrictions of bidders which are active in several markets. In addition, the problem is considerably larger than the one described here. It is not part of this tool.

The day-ahead share is therefore a sensitivity parameter and not a prediction of the trading behaviour. The quantity which determines the result is the effective power sP on the day-ahead market. A result of the tool has to be read as “a BESS power of x GW which acts in the day-ahead auction changes the prices by y ” and not as “an installed BESS power of x/s GW changes the prices by y ”.

10.2 Unchanged bids of the other market participants

The historical bids are assumed to be unchanged. Only the block orders and the cross-zonal exchange react to the new prices. In a competitive market the bids of power plants correspond to their marginal costs and do not depend on the price level, so for them the assumption is justified in the short term. It is not justified for participants whose bids depend on the expected prices of other MTUs: pumped hydro storage, existing BESS and flexible loads bid on the basis of the expected price differences within the day, and a changed price profile changes their bids. They are contained in the historical curves with their historical bids and would be partly displaced by a large additional fleet. The relevant point, however, is the long term. With permanently smaller price spreads, investment and decommissioning decisions change, in the storage fleet itself as well as in the power plant park. The results for large fleets therefore show the short-term effect on a given delivery day and not a new market equilibrium. The simulated fleet is always additional to the BESS which already took part in the historical auction.

Strategic behaviour is not considered. The fleet is modelled as a large number of small units without market power, and the other participants keep their bids, which is consistent with a competitive market. This gives the largest possible equalisation of the prices.

A special case of unchanged bids is the behaviour of renewable plants at negative prices. Under § 51 EEG these plants receive no market premium in periods with negative prices, so they curtail rather than produce at a loss. This behaviour is contained in the published curves as price-dependent sell orders close to zero. The simulation therefore reproduces how much renewable supply withdraws when the price turns negative and returns when the fleet lifts the price above zero, and the simulated prices show directly how many periods with negative prices remain with a given fleet. What the simulation cannot show is the long-term effect of these periods on the revenues and the investment risk of new plants, which the study [9] examines.

10.3 Idealised dispatch of the fleet

The fleet is optimised with perfect knowledge of all prices of the week, while in reality the auction takes place day by day on the basis of forecasts. The simulated fleet can therefore shift energy between days better than a real portfolio, and the simulated day-ahead profit tends to be too high. The fixed state of charge at the week boundary prevents a shift of energy between weeks. The reasons for the horizon of one week are given in section 4.3.

This idealisation would be partly removed by the storage orders which the NEMOs and TSOs plan to introduce in the SDAC [7]. With a storage order the participant does not submit price-dependent bids per MTU but the technical parameters of the storage: the maximum energy stored, the maximum input and output power, the cycling costs and optionally the starting energy, the efficiency and a value for the energy stored at the end of the day. The auction algorithm then determines the charging and discharging over all MTUs of the delivery day with knowledge of the complete order book, such that the order does not lose money. The dispatch of the fleet in this simulation is calculated in the same way, as a welfare maximisation against the order curves with the parameters P , $P\tau$, η and c^{deg} . Within one delivery day the result therefore corresponds to a fleet which is offered as storage orders. If storage orders are introduced, which is planned for the fourth quarter of 2027, the assumption of perfect knowledge of the prices would be realised for the part of the fleet which uses them. The remaining idealisation is the optimisation over the whole week, as a storage order covers one delivery day.

The fleet operates at full power per MTU on an integer grid of state-of-charge levels, which is coarse for short storage durations and hourly MTUs. The efficiency is constant and does not depend on the power or the state of charge. Auxiliary consumption, availability and grid connection restrictions are not considered. The number of cycles is only limited by the degradation

costs and not by warranty conditions.

The efficiency and the degradation costs deserve a separate remark. Both are fixed for the published results, at 86 % and 10 €/MWh, and cannot be changed by the user. They determine the minimum price spread at which the fleet trades and therefore the number of cycles, and they are more uncertain than the mutual influence of the markets discussed in section 10.1: the values differ between systems, change with age and improve with every technology generation. The efficiency also decides how much of the price effect is lost as heat. With $\eta = 86\%$ the fleet buys about 16 % more energy than it sells, which raises the mean price. A fleet with a different efficiency or different degradation costs gives a different result.

10.4 Approximations for block orders and market coupling

Between two anchor power levels of the block scenarios the block response is kept constant, so the damping by the blocks is slightly underestimated at these levels. At the anchor levels it is calculated completely. Further EUPHEMIA order types (flexible blocks, minimum income condition, load gradient condition) are not modelled. Block orders of the neighbouring zones are not available and do not react.

The neighbouring zones in the coupling model use the shape of the DE-LU curve, i.e. the same supply and demand structure and the same bidding behaviour (section 6). This is an approximation for systems with a different structure. The error concerns the slope of the neighbour's curve at its own price, i.e. the volume with which the zone responds to a price change before its border is congested. France, with a high share of nuclear power and electric heating, and the Nordic zones, whose prices are set by the opportunity costs of hydro reservoirs, have curves whose slope at the respective price can differ considerably from the slope of the DE-LU curve in the same hour. The direction of the error is not systematic: a neighbour whose supply is more elastic than DE-LU at its price responds more strongly than modelled, one with a less elastic supply more weakly. The error is limited by the headroom of the border, because no slope can produce a response beyond the free capacity, and it vanishes in hours in which the border is congested. It is therefore largest for small fleets in hours with free capacity and does not affect large fleets, for which the transmission capacities determine the response. These capacities are taken from data. The network constraints of the flow-based market coupling in the Core region are only represented by their bilateral projection and the rule for non-converged prices. The additional fleet is located in DE-LU only. Additional storage in the neighbouring zones, which would reduce the damping by the exchange, is not simulated.

11 Relation to fundamental electricity market models

The effect of additional storage on the electricity prices is usually examined with fundamental electricity market models. Two examples are given here. The first is the short study “Die nächste Phase der Energiewende: Flexibilität” of Fraunhofer IEE on behalf of the German Renewable Energy Federation (BEE) [9]. It uses the European electricity market model SCOPE-EM, a mixed-integer linear optimisation (unit commitment and economic dispatch) which minimises the operating costs of the generation system in hourly resolution with a rolling horizon. Germany and its direct neighbours are modelled endogenously with flow-based or NTC market coupling. For the period from January 2025 to May 2026 additional storage of 10 to 40 GW with 2 to 8 h is added in Germany. The study finds the largest additional benefit at about 20 GW with 4 h (80 GWh). With this fleet the number of hours with negative prices decreases by about 70 % (from 845 to 276 in the model), the market-based curtailment of renewable energies decreases by about 55 %, and the market values of wind and solar power increase.

The second example is the short study “Wert von Großbatteriespeichern im deutschen Strom-

system” of Frontier Economics [10], commissioned by several storage companies. It uses a fundamental model of the day-ahead wholesale market with an investment calculation for the years 2030 to 2050. The battery fleet is not an input but a result of the model. It grows from 15 GW with 57 GWh in 2030 to 61 GW with 271 GWh in 2050, mostly with a storage duration of 4 h. In the scenario without batteries the market builds about 9 GW of additional gas-fired power plants by 2030 instead. Compared with this scenario the batteries lower the mean wholesale price by about 1 €/MWh in the average of the years 2030 to 2050, reduce the price spread within the day and save about 12 billion € of system costs until 2050. If the batteries could not be replaced by gas-fired power plants, the price effect would be about 4 €/MWh.

The two studies differ from each other in the degree of market adaptation. The IEE study keeps the power plant park of the years 2025 and 2026 and adds storage. The Frontier study lets the power plant park and the fleet itself adapt. Both examine the same question as the simulation described here, with different methods. Table 5 compares the approaches.

Aspect	This simulation (based on orders)	Fundamental model (e.g. [9, 10])
Basis of the prices	published orders of the real auction (aggregated curves, block orders)	costs of the power plants, feed-in and load; price = marginal costs of the cost-minimal dispatch
Case without additional storage	historical MCP, reproduced exactly	model result, validated with historical data (in [9]: 97 % of the mean day-ahead price, 845 instead of 819 hours with negative prices)
Time resolution	MTU of the auction (15 min since October 2025)	hourly
Real bidding behaviour (block orders, mark-ups, scarcity prices, negative bids)	contained in the data	not contained or only in simplified form
Response of the other participants	bids fixed, only block orders and exchange react	power plants, storage and exchange are dispatched again; with an investment calculation the power plant park adapts as well
Neighbouring zones	response curve per border	modelled endogenously
Storage dispatch	profit maximisation of a fleet without market power, only day-ahead auction	cost-minimal dispatch of the whole fleet by the model
Curtailment, imports and exports, emissions, system costs	not available yet, but possible to implement	available
Future years, other expansion of renewables	possible if coupled to energy system models	possible (in [10]: 2030 to 2050)
Range of storage	up to 20 GW, 2 to 6 h	in [9]: 10 to 40 GW, 2 to 8 h; in [10]: result of the investment calculation, 15 GW in 2030 to 61 GW in 2050
Update	every day after the auction	per study

Table 5: Comparison of the simulation described here with a fundamental electricity market model.

What both methods have in common. Both describe the same mechanism: charging raises low prices, discharging lowers high prices. In both cases the storage is dispatched in a welfare-maximising way. The competitive equilibrium of section 4 is the market-side equivalent of the cost-minimal dispatch in a fundamental model. The results are therefore expected to agree in direction and order of magnitude: fewer hours with negative prices, smaller price spreads,

higher market values of solar power and a decreasing additional benefit with a growing fleet.

How the results have to be compared. A fundamental model dispatches the complete storage fleet against the wholesale price. For a comparison the effective power on the day-ahead market of this simulation has to be set equal to the storage power of the fundamental model, which corresponds to a day-ahead share of 100 %. The case of 20 GW with 4 h of the study [9] corresponds to the largest power level of this simulation. The larger fleets of the study are outside its range.

Where systematic differences are expected. Fundamental models reproduce the mean price level well, but they tend to underestimate extreme prices, because bids above the marginal costs and negative bids are not part of a cost-based model. The simulation based on orders contains these bids. In hours with very high or negative prices the price effect of storage can therefore differ between the two methods. In the other direction, a fundamental model lets the complete system react to the storage, including power plants and storage in the neighbouring zones, while this simulation keeps all other bids fixed and approximates the neighbours. The hourly resolution of the fundamental model does not show the price differences between quarter hours, which are an additional source of revenue for BESS since October 2025.

How both methods complement each other. The two methods differ in what they take from data and what they take from assumptions. The simulation described here is tied closely to the real behaviour of the market. The prices without additional storage are the published prices, and the bids of all participants are the real bids of the respective delivery day. Power plant costs, availabilities, fuel and CO₂ prices, bidding strategies and the feed-in of renewable energies do not have to be assumed, because their effect is contained in the order curves. The assumptions are limited to the additional fleet and to the response of the block orders and the exchange. The result is therefore close to what the auction would have given on that day with the additional fleet. The price of this is that the market cannot adapt. All other bids are fixed, so the simulation describes the immediate effect of an additional fleet on a given order book and not a market which has adjusted to the fleet.

A fundamental model takes the opposite approach. It builds the market from its components: power plants with their costs and technical restrictions, feed-in of renewable energies, load, storage and grid capacities. Every result depends on these assumptions, and the historical prices are only reproduced approximately. In return all components react to the additional storage. Power plants change their dispatch, other storage and flexible loads adapt, the neighbouring systems respond, and in scenarios of the future the generation mix and the fleet itself can change. A fundamental model can therefore describe the adaptation of the market and the long-term effect, which the simulation cannot. The study of Frontier Economics [10] shows what this means for the result: because the market without batteries builds additional gas-fired power plants instead, the long-term price effect of the batteries is small, about 1 €/MWh. Such a value answers a different question than the short-term effect on a given order book which is calculated here, and the two must not be compared directly.

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