Journal of Physics:
Conference Series

The Impact of Multi-Market Operational and Sizing Optimisation for Upcoming Offshore Energy Areas

To cite this article: Bart Klootwijk *et al* 2026 *J. Phys.: Conf. Ser.* **3185** 012008

9th Offshore Energy and Storage Symposium (OSES 2025) IOP Publishing
Journal of Physics: Conference Series **3185** (2026) 012008 doi:10.1088/1742-6596/3185/1/012008

The Impact of Multi-Market Operational and Sizing Optimisation for Upcoming Offshore Energy Areas

Bart Klootwijk[1]*, Dimitris Ntagkras[1], Max Houwing[1], Javier Fatou Gómez[1]

[1] Energy & Materials Transition, TNO, Rijswijk, The Netherlands

*E-mail: bart.klootwijk@tno.nl

Abstract. The adoption of renewable energy technologies presents challenges in balancing variable energy supply with demand and ensuring grid stability. Hybrid Power Plants (HPPs) with flexible assets like energy storage and conversion can engage in multiple markets for these purposes, thereby accessing diversified revenue streams (revenue stacking). The dynamic nature of HPP operations complicates the application of theoretically optimal setpoints to real asset constraints. This study presents two key contributions. The first is a quantitative assessment of the added value of revenue stacking, specifically through participation in the day-ahead market and automatic Frequency Restoration Reserves (aFRR). The hypothetical offshore hybrid system is located in the Dutch part of the North Sea, including offshore wind and solar power, a battery storage system and an electrolyser. The analysis is performed using a nested optimisation framework, integrating both sizing and operational decision-making. The second contribution quantifies the added value of incorporating a physics-based correction step to refine linearised setpoints. The results show consistent improvements in profit by revenue stacking (5-6%) compared to the single-market approach. Potential for higher profits was limited by an increase of grid tariffs in the multi-market cases and the relatively limited aFRR market volume. The proposed physics-informed sizing and operational optimisation approach is broadly applicable to both onshore and offshore systems, providing valuable insights for both private and public stakeholders.

1. Introduction

The increasing penetration of renewable energy technologies introduces challenges in matching fluctuating energy supply with demand, and maintaining grid stability. With ambitious targets set for offshore wind energy development, focus has shifted towards efficient system integration of offshore renewable resources. Hybrid Power Plants (HPPs) offer benefits in this context, as they can enhance grid reliability and stability by integrating multiple renewable energy sources, energy storage systems, and power conversion technologies. This integration facilitates more consistent power output, addressing intermittency issues associated with renewable energy sources and optimising overall energy system performance.

HPPs enable participation on additional markets at different time scales due to the flexibility introduced by the storage and conversion assets. These additional markets can unlock supplementary sources of revenue, improving the overall business case. This approach is often referred to as *revenue stacking*, where the HPP assets capture multiple revenue streams by participating in different electricity- (or hydrogen) market services (e.g. spot market, ancillary services, etc.), either concurrently or in succession. As an example, [1] showed that, for battery energy storage systems, revenue stacking can substantially increase the revenue streams in a case study located in Northern Ireland. In [2], a sizing optimisation of a system with both wind and energy storage systems showed that simultaneous sizing of different elements of the system could provide a 50% increase in the Net Present Value (NPV).

Revenue stacking can result in more dynamic operations, as grid balancing markets tend to be more volatile than day-ahead markets. However, this depends on the specific conditions of the country or bidding zone. For instance, the Netherlands had decreased volatility in imbalance in the first months after joining the cross-border automatic Frequency Restoration Reserve (aFRR) balancing platform PICASSO [3], whereas Italy had increased volatility [4].

The operational complexity under this volatility is often underrepresented in literature. Studies mainly aim to capture dynamics associated with the participation in multiple markets [5], and not necessarily with the response of the physical components. The work in [6] linearised parts of the system to use a commercial solver in a hydrogen and methane plant, modelling these assets with constant efficiency. Limited attention has been given in these academic studies to operational constraints of the HPP, after a certain strategy has been optimally prescribed. Due to effects such as ramp-up/ramp-down, dynamic efficiency levels or minimum load factors, the linearised setpoints may result in infeasible operations. Correction steps in real-time operation could potentially result in reduced revenue compared to the (simplified) simulations. Assessing the effects of constraining a theoretical optimum to more realistic performance can result in closer approximations of revenue streams and decrease the uncertainty of the business case calculations.

In this study, two main contributions are presented. The first one comprises a comparison of the revenue streams of an offshore HPP composed of an offshore wind farm, floating PV, a battery and hydrogen production, when participating in a single or multiple markets for power (day-ahead and aFRR capacity reservation and activation), with a single market for hydrogen. The second contribution is the assessment of the effects of establishing physical, non-linear constraints to the optimal operational strategy, comparing the deviations between the theoretical case and the physics-based one. A sizing optimisation of different components of the HPP was performed to optimise the business case. The combination of both contributions goes beyond the current state of the art, which commonly focuses on only one of them.

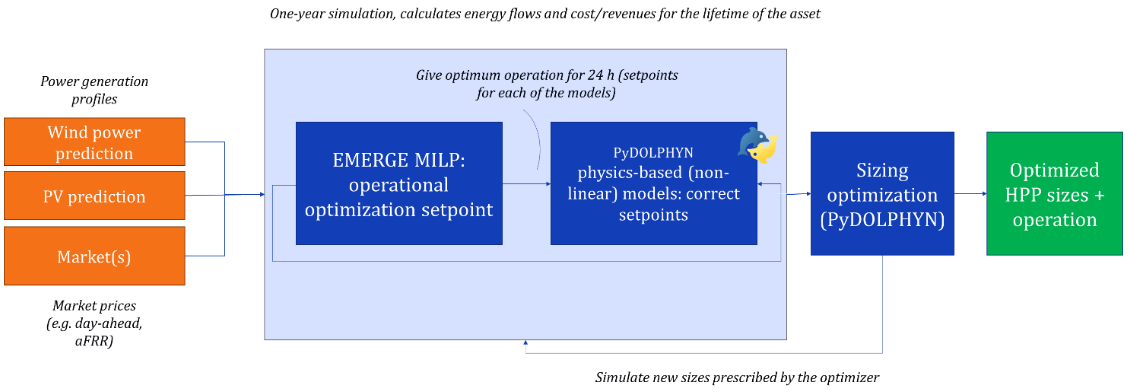

Figure 1. Schematic overview of the workflow for the nested sizing + operational optimisation.

To fulfil these goals, simulations on 15-minute time steps with a one year time horizon were performed, by coupling two TNO in-house tools, as shown in Figure 1. These tools use power and Dutch market predictions as input, by first computing a day-ahead operational optimisation using a Mixed-Integer Linear Programming (MILP) approach, EMERGE [7], determining optimal setpoints of linearised models of the considered assets in these 24 hours. These setpoints are then used in a non-linear, higher-fidelity representation of the assets and constraints, PyDOLPHYN [8]. Furthermore, the physical constraints at component- and system level are accounted for using this model, to correct the prescribed setpoints. An outer sizing optimisation layer was built on top of these blocks. The final result was a close-to-optimal corrected MILP-given operation with the optimal ratio between installed wind, floating solar, battery storage- and electrolyser capacity. The objective function was profit maximisation, with the utilisation of the export infrastructure and curtailment as other key performance indicators.

2. Methodology

2.1 Case studies

The configuration of the case studies was inspired by the upcoming IJmuiden Ver Gamma wind offshore area in the Netherlands [9], co-locating different offshore assets with it, as observed in Figure 2. The capacity of the wind farm was fixed to 2 GW, and the meteorological conditions and power production are based on this geographical location. Two sets of case studies were performed, using an objective function based on profit maximisation and 25 years of operation. The simulations were performed over a full year, calculating operational expenditures (OPEX) and revenues for this timeframe, and extrapolating them for the lifetime of the system.

The first case study aimed to optimise a power-based system, optimising the size of offshore solar and an offshore battery. Two subsets were calculated, using only the day-ahead market and also using aFRR reservation and activation. The second case study fixed the optimum offshore solar size of the first case, and then optimised the sizes of the battery and offshore proton-exchange membrane (PEM) electrolyser.

In all cases, the battery was modelled with a C-rate of 0.5 (i.e. its maximum capacity could be discharged in 2 hours). Furthermore, the power import and export were restricted physically by the HVDC export cable, with capacity of 2 GW. As the focus of this study is on the HPP itself, the power flows through the export cable are not physically modelled; instead the power losses, based on the distance to shore, are assumed to be 2%.

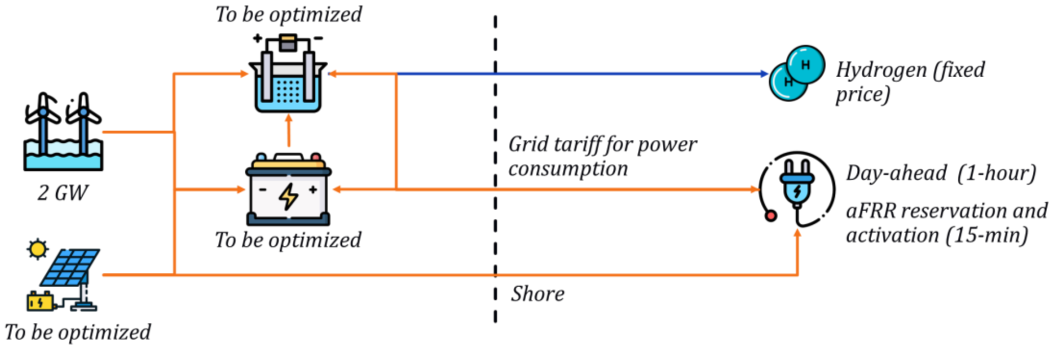

Figure 2. Schematic overview of the case study, inspired by the IJmuiden Ver Gamma offshore wind area in The Netherlands [9]. The wind farm size is fixed to 2 GW, and the sizes of different elements of the system are optimised using a profit-based objective function.

2.2 Techno-economic data, boundary conditions and assumptions

The data used to simulate the system was a combination of internal assumptions and other projections for 2030. An overview of the techno-economic parameters used can be found in Table 1. The system contained cost and revenues for the assets, market data obtained from 2024 for the Netherlands, and grid tariffs for the Extra High Voltage (EHV) level [10]. In the current Dutch regulation, these grid tariffs are only applied for power consumption (to the battery or the electrolyser), and not for exporting power to the transmission system. However, this assumption may not hold in future wind tenders [11].

The wind and solar power profiles were obtained from data presented in [12] and [13], accessed via the web interface of [14]. These profiles were recorded on an hourly basis for the year 2024 and subjected to linear interpolation to produce the 15-minute interval data required for the aFRR case studies. Furthermore, the wind power profiles were corrected for wake- and inter-array losses. The hydrogen price was assumed to be a fixed value of 8 EUR/kg, which aligns with values tested in other studies for configurations in the Netherlands for onshore [15] and offshore [16] electrolysis configurations. This assumption does not distinguish between cost components paid directly by the off-taker and those covered through alternative mechanisms (e.g. subsidies). Furthermore, a sensitivity analysis was performed for a selected configuration. The relatively high capital expenditures (CAPEX) for the battery and the electrolyser include the installation offshore.

Table 1. List of techno-economic values used in this study.

Component	Variable	Value	Source
Offshore wind farm	CAPEX	2.5 EUR/W	TNO data
	OPEX	1.6 % of CAPEX/year	TNO data
Offshore floating PV	CAPEX	0.725 EUR/Wp	[28]
	OPEX	4.75 % of CAPEX/year	[28]
Battery Storage	CAPEX	1.4 EUR/Wh	[29], [30], [31]
	OPEX	0.5 % of CAPEX/year	[29], [30], [31]
Electrolyser	CAPEX	4.0 EUR/W	TNO data
	OPEX	4.0 % of CAPEX/year	TNO data
Grid connection	Standing fee EHV	12479 EUR	TenneT
	kW contracted rate	60.65 EUR/W	TenneT
	kW peak rate	6.91 EUR/kW	TenneT
Power market	Day-ahead	2024 values for NL	ENTSO-E
	aFRR	2024 values for NL	ENTSO-E
Hydrogen market	Revenue per kg	8 EUR/kg	[34]

2.3 Characteristics of the considered electricity markets

The Dutch electricity market operates across multiple timeframes, balancing supply and demand through various stages, such as long-term contracts, day-ahead markets, intra-day markets, and ancillary services. The interaction of these markets is crucial for maintaining grid stability especially with the increased penetration of renewable energy sources [17]. The scope of this study was limited to the day-ahead market and the aFRR market. Table 2 offers an overview of the aFRR market in comparison with other balancing markets in the Netherlands.

Table 2. Overview of the Dutch balancing markets and their characteristics [32], [33]. Only the aFRR market is considered in this study.

Product	FCR (primary reserve)	**aFRR** (secondary reserve)	mFRR (tertiary reserve)
Market type	Capacity bids (EUR/MW)	Capacity bids (EUR/MW) and energy bids (EUR/MWh)	Capacity bids (EUR/MW)
Remuneration	Contracted capacity	Contracted capacity and activated energy	Contracted capacity and activated energy
Minimum availability	4 hours	24 hours	24 hours
Minimum capacity	1 MW (symmetric)	1 MW (asymmetric)	1 MW (asymmetric)

aFRR capacity is secured by the Transmission System Operator (TSO) on the day before delivery through a capacity bidding mechanism. In the Netherlands, in 2024, TenneT procured at least 350 MW of aFRR capacity daily [18]. This capacity is procured through capacity bids, which define the volume of balancing power each Balancing Service Provider (BSP) commits to make available in both upward or downward direction. The capacity bids establish physical availability – i.e. reserved capacity – rather than energy delivery itself. When accepted, these capacity bids convert into obligatory energy bids, which establish the price at which the BSP is willing to provide upward or downward aFRR (activation of reserved capacity). The window of the procured aFRR capacity spans 24 hours and bids must be in integer multiples of 1 MW.

Electricity market data for both day-ahead and aFRR markets were obtained from the ENTSO-E Transparancy Platform [19]. The distribution of day-ahead prices is illustrated by the price-duration curve in Figure 3. The average day-ahead electricity price in 2024 was 77.29 EUR/MWh, while the number of negative price hours was 458.

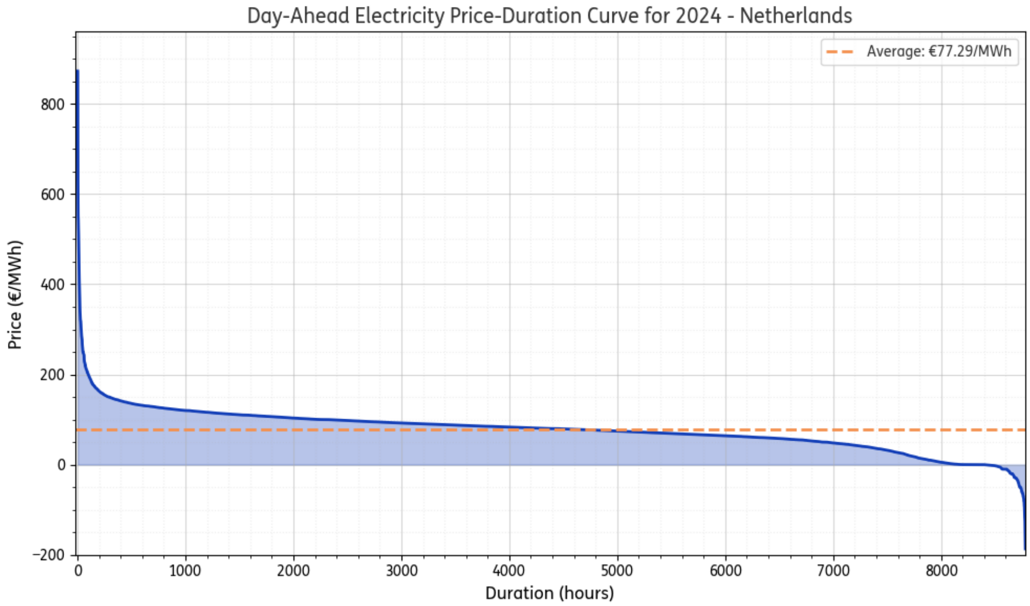

Figure 3. Price-duration curve of the day-ahead market electricity prices used as input to the model. The data represents the full year of 2024 in the Netherlands and was obtained from ENTSO-E's transparency platform [19].

2.4 Operational optimisation and setpoints: EMERGE setup

Mixed-integer Linear Programming (MILP) methods are widely used in operational optimisation of HPPs, and are well suited for evaluation of revenue stacking potential. MILP optimisation frameworks are highly flexible and are therefore applicable from urban energy systems with heat networks [20] or community energy storage [21] all the way down to single (co-located) HPPs [22]. Thereby, a MILP optimisation can help study the potential of revenue stacking options for HPPs.

The energy management system for combined renewable generation, storage and conversion (EMERGE) model [7] is an operational profit-based optimisation model that uses MILP to optimally schedule operation of HPPs. To this end, a profit objective function is used as the core of the optimisation, maximizing the profit as a function of revenue and cost. The revenue and cost components are computed for each asset of the HPP, based on weather- and market input data, linearised asset characteristics and operational decision variables. The objective function is evaluated for each period of 24 hours, which yields a time series of optimised setpoints for every asset within the HPP, optimising daily profits.

2.5 Revenue stacking in multi-markets using the EMERGE framework

The EMERGE framework was adapted for use in multi-market scenarios, as detailed in [23]. The aFRR market, as considered in this study, operates on 15-minute intervals known as the Imbalance Settlement Period (ISP), which contrasts with the day-ahead market that uses hourly intervals. However, certain metrics like day-ahead power export and prices remain at hourly resolution. Consequently, in order to effectively merge schedules across these different timelines, a dual time-indexing method was used, indexing MILP variables over both hours and quarters.

Moreover, the adoption of a multi-market approach introduced the reserved capacity as a new optimisation variable, which could be divided over both the battery and the electrolyser, while imposing additional constraints on the storage and conversion assets.

As previously outlined, the aFRR market comprises two components: capacity reservation and activation. Capacity reservation was incorporated into the EMERGE framework by imposing further constraints on the battery state of charge, thereby limiting its available capacity for day-ahead market operations. The amount of reserved capacity is subject to the maximum charge- or discharge rate, ensuring the provision of up- or down-regulating energy while maintaining the battery state above the minimum threshold necessary during activation.

The electrolyser employed a similar strategy, by limiting the bandwidth of the operational load range. To ensure it remains available and responsive to aFRR activations, the electrolyser must remain in online mode, avoiding standby or shutdown states due to their transition risks and start-up delays.

The total revenue generated from the aFRR market was derived from both capacity reservation income, secured the day prior to delivery, and activation income during real-time operations. The revenue from capacity reservation was calculated by multiplying the total reserved capacity (in MW) with the capacity price (EUR/MW/ISP). This calculation assumed perfect information, utilising historical data under a price-taker assumption, and employed average procured capacity prices. Given the limited market volume—approximately 400 MW for upward capacity and 740 MW for downward capacity—an upper limit of 50 MW was imposed on the maximum reserved capacity (in both upward and downward direction) to prevent scenarios wherein the full market position was unrealistically occupied.

The revenue generated from aFRR activations is significantly influenced by the bidding strategy employed. This study adopted a pragmatic approach that leverages the relation between real-time (historical) activation prices and day-ahead market prices, initiating activations only when higher revenue was anticipated relative to selling in the day-ahead market. This method initiated upward activation during price surges in the aFRR market and considered downward activation solely when prices are negative, thereby avoiding additional costs. While this approach generates realistic activation patterns based on historical data, it does not fully optimise aFRR profits nor address all market uncertainties. Furthermore, it was assumed that the full volume of capacity is offered all at once at a fixed price, without considering bidding curves.

2.6 Sizing optimisation and physics-based setpoint confirmation: PyDOLPHYN setup

As seen in Figure 1, the setpoints computed in each set of 24 hours in the operational optimisation step are an input to the (potentially non-linear) physics-based solver. The solver corrects the energy flows, taking into account additional constraints and performance. If there was a discrepancy between the linearised and the non-linear solutions, a rule-based strategy was followed, always attempting to fulfil the aFRR reservation/activation setpoints, while correcting the day-ahead actions. This was chosen for both interpretability and simplicity, assuming that, on average, the specific revenues (in EUR/MWh) of the aFRR are higher than on the day-ahead for this particular asset. Providing an additional feedback loop to change the operational strategy if this assumption does not hold was out of scope of this study.

The operational optimisation, including the correction steps, was coupled to a sizing optimisation algorithm. This was performed using a modified version of Particle Swarm Optimisation (PSO), as seen in [24]. For all optimisation exercises in this study, three iterations were applied in the PSO, with 320 particles per iteration.

The PEM electrolyser model followed a similar approach as in [8], with overpotentials based on different physical effects. Both PyDOLPHYN and EMERGE models aimed to use a similar electrolyser configuration, and were calibrated with a similar nominal power consumption (57 kWh/kg of hydrogen produced). The differences rely on the linear approach followed in EMERGE compared to the non-linear polarisation curve and specific power consumption from PyDOLPHYN.

The battery model followed a similar structure with a linear state of charge calculation when performing the nested sizing and operational optimisation. An additional simulation was performed with more complex physics, using the Python Battery Mathematical Modelling (PyBaMM, version 25.4.2). This consists of a broad python framework which is defining the discretised domain where the differential equations will be solved (i.e. energy conservation, charge conservation, mass conservation etc.). The user has the flexibility to use different battery models. For this study, the battery cell is solved based on the Doyle-Fuller-Newman model [25].

3. Results

The simulation outcomes of the reference case, involving solely the 2 GW wind farm, are detailed in Table 3. Projected profits amount to 9630 MEUR over the span of its 25 year lifetime, resulting from day-ahead market transactions. With the export cable dimensioned to match the wind farm's capacity, the observed curtailment rate of 7.92 % is purely economic, and attributed to periods of negative electricity prices. Despite this curtailment, the export capacity factor reaches approximately 50%.

Table 3. Simulation results of the 2 GW reference wind farm, with 2 GW export cable capacity.

	CAPEX [MEUR]	OPEX [MEUR]	Revenue [MEUR]	Profit [MEUR]	Curtailment [%]	Cable Utilisation [%]
Reference case	5000	2000	16630	9630	7.92	49.63

3.1 HPP containing wind, solar and battery

With additional renewable generation and storage added to the reference wind farm, an improvement is observed in terms of profits. Furthermore, the optimal size of the HPP is contingent upon market participation strategy. As illustrated in Table 4, engaging in both the day-ahead and aFRR markets results in higher profits and favours greater solar and battery capacities compared to participation in the day-ahead market alone.

Table 4. Simulation results of the HPP including wind, solar and battery energy storage, comparing the single market approach against the multi-market scenario.

	Solar Capacity [MWp]	Battery Capacity [MWh]	Total Revenue [MEUR]	Total Profit [MEUR]	Curtailment [%]	Cable Utilisation [%]
Single market	979	90	18800	9998	8.50	56.80
Multi-market	1047	217	19833	10608	8.52	57.34

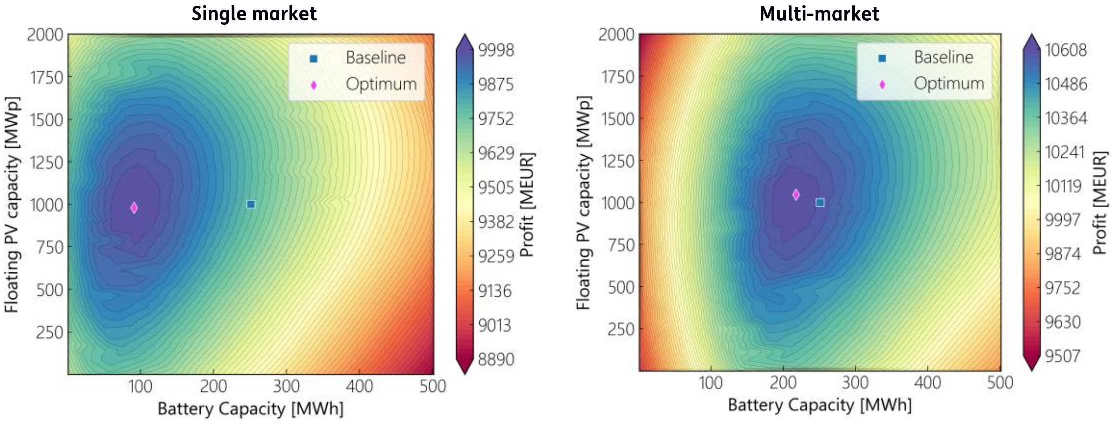

Figure 4. Optimisation results of the HPP case with wind, solar and battery, where the capacity of the latter two are the sizing degrees of freedom. The multi-market case on the right shows an optimal solution with higher profits compared to the single market case, with higher asset capacities for the solar and storage systems.

Figures 5 and 6 show a detailed financial breakdown of the optimal HPP configurations for the single- and multi-market case. It can be observed that for identical asset capacities, engagement in the aFRR market results in reduced day-ahead revenues due to the allocation of battery capacity for up- and downregulation, leaving less capacity available for e.g. arbitrage. Nevertheless, Figure 4 demonstrates a greater potential for solar generation and battery storage capacities within the multi-market scenario, which explains the increased day-ahead revenue in this case.

The aFRR revenues in Figure 6 reveal a notable difference in activation revenue between up- and downregulation, driven by several factors. Firstly, the bidding strategy in EMERGE involves offering reserved capacity at negative energy bids for downregulation, whereas in 2024, the average price for activated downward capacity was slightly positive. Secondly, downregulation occurred less frequently and exhibited a lower activation percentage compared to upward capacity. Finally, prices for activated upward capacity were both higher and more volatile. Consequently, these conditions enabled the HPP to generate greater revenue from upward activation within the aFRR market under the modelled assumptions.

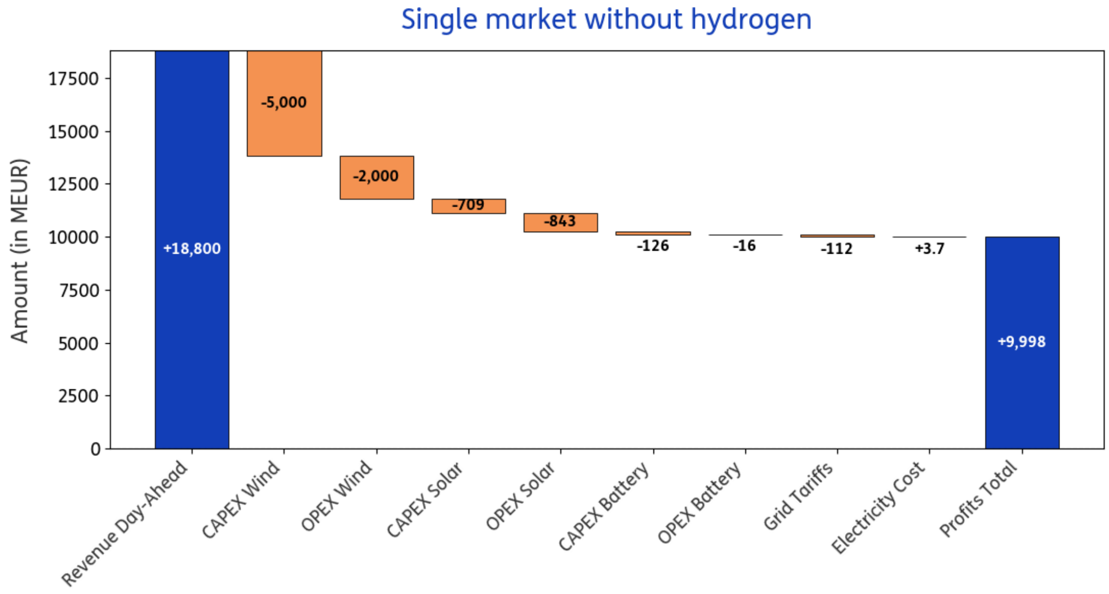

Figure 5. Financial breakdown of the optimal solution for a hybrid power plant including wind, solar, and battery storage, participating only on the day-ahead market.

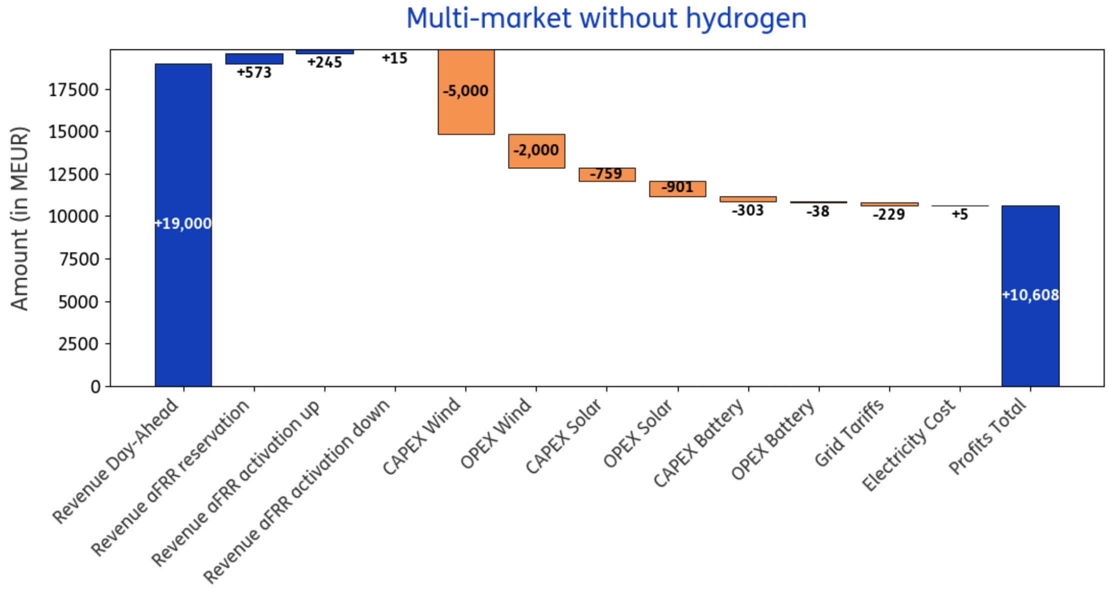

Figure 6. Financial breakdown of the optimal solution for a hybrid power plant including wind, solar, and battery storage, participating on the day-ahead market and the aFRR market.

Electricity import costs in Figures 5 and 6 point out a substantial relative variation between the single-market and multi-market scenario, primarily due to differences in battery capacities. In the multi-market scenario, the higher optimal battery capacity increases the charge/discharge power due to maintaining a constant C-rate. Although importing electricity during periods of negative pricing can generate revenue, it concurrently increases grid tariffs applicable to consumption. The elevation in grid tariffs is more pronounced for higher battery capacities, influenced by both contracted rates and peak rates.

Figures 7 and 8 show the curtailment and cable utilisation values for the sizing optimisation. Overall, the differences between the single- and multi-market approach are minimal for both parameters. Generally, it is observed that the integration of solar generation substantially increases utilisation of the existing electrical infrastructure (up to a total of ca. 60% for a 1:1 ratio between wind and solar capacity), against only a modest increase in curtailment (less than 7% increase for a 1:1 wind/solar ratio). This phenomenon is attributed to the complementary nature of wind and solar resources in The Netherlands, highlighting the potential for cable pooling. The increase in curtailment resulting from additional solar generation is mitigated by the integration of battery storage, which functions as a buffer.

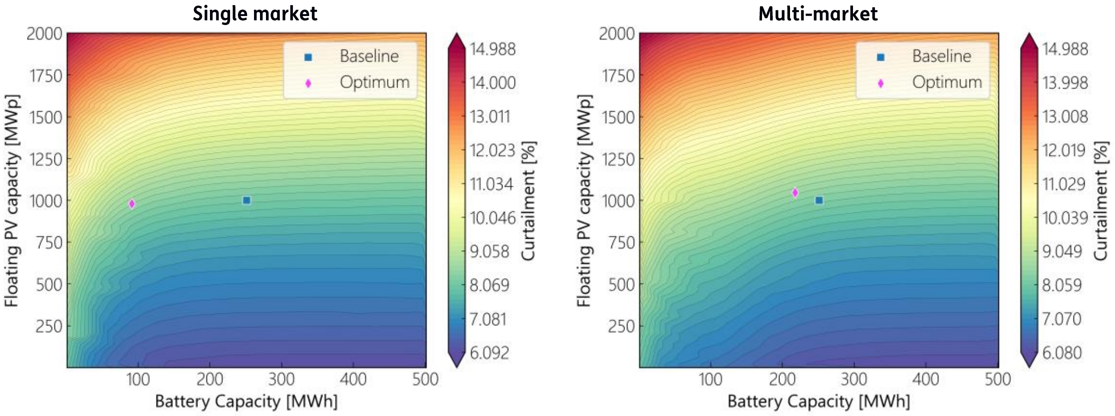

Figure 7. Optimisation results for the HPP comprising wind, solar and battery storage, showing the total curtailment for various combinations of floating PV- and battery capacities.

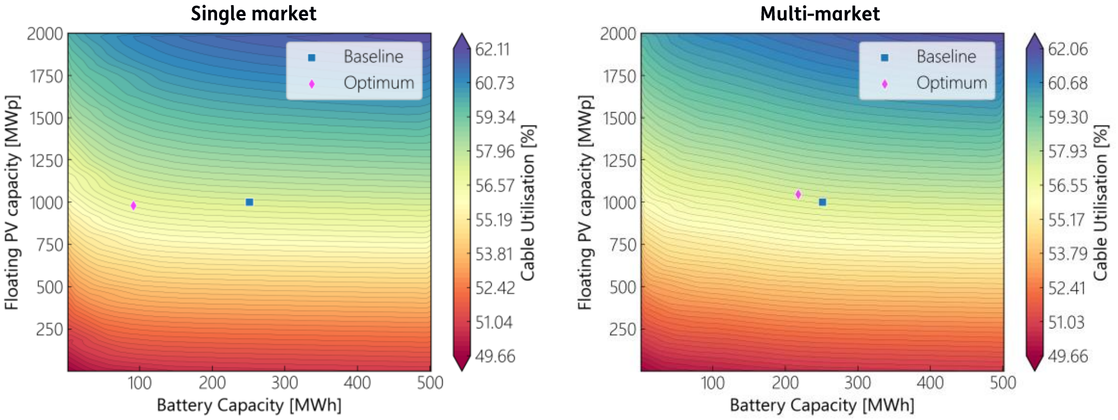

Figure 8. Optimisation results for the HPP comprising wind, solar and battery storage, showing the export cable utilisation for various combinations of floating PV- and battery capacities.

In Figure 7, the effects of reduction of curtailment remain minimal due to the optimal dispatch model's emphasis on profit maximisation, which excludes consideration of grid tariffs. The battery system charges using grid power during periods of negative electricity prices to optimise profits, thereby neglecting import tariffs. In practice, HPP operators may prioritise buffering energy from renewable power generation instead of curtailing; however, this aspect is not accounted for in the EMERGE model, leading to persistent curtailment.

3.2 HPP containing wind, solar, battery and hydrogen production

The integration of an electrolyser into the HPP introduces an additional revenue stream from selling hydrogen, while enhancing operational flexibility. Combining storage and conversion assets behind the meter not only enhances the economic viability of the power plant by diversifying income sources but also optimises the responsive capacity of the system in frequency regulation tasks, enabling both upward and downward aFRR activations to be distributed between the battery and the electrolyser.

To find the optimal sizing combination for the HPP including battery storage and hydrogen conversion, an optimisation study has been performed, keeping the renewable generation capacity constant at 2 GW wind and 1 GW solar, while varying the capacities of the battery and electrolyser. The main results are summarised in Table 5.

Table 5. Simulation results of the HPP including 2 GW wind, 1 GW solar, battery energy storage, and PEM electrolysis, comparing the single market approach against the multi-market scenario.

	Battery Capacity [MWh]	Electrolyser Capacity [MW]	Total Revenue [MEUR]	Total Profit [MEUR]	Curtailment [%]	Cable Utilisation [%]
Single market	0	243	21808	10338	7.99	50.39
Multi-market	0	316	23949	10903	8.16	47.99

Similar to the previous optimisation case, the multi-market scenario results in higher total profits compared to the single market, along with increased optimal capacities. Notably, the optimal battery capacity is zero in both scenarios, suggesting that an electrolyser is more profitable than electricity storage given the current cost and price assumptions. Nevertheless, the economic feasibility of offshore electrolysis is highly dependent on the hydrogen offtake price. Figure 9 illustrates that offshore storage still enhances the business case for offshore renewable generation; an effect which is more pronounced when engaging in multiple markets.

The financial breakdown of the scenarios in Figures 10 and 11 demonstrates several insights. Firstly, the multi-market scenario, with higher optimal electrolyser capacity, exhibits lower revenues from the day-ahead market as compared to the single market scenario, but increased revenues from selling hydrogen, while reserving some capacity for the electrolyser to respond to aFRR activations. This suggests that overall, selling hydrogen at a price of 8 EUR/kg is often more profitable than selling electricity in the day-ahead market, based on the assumptions made.

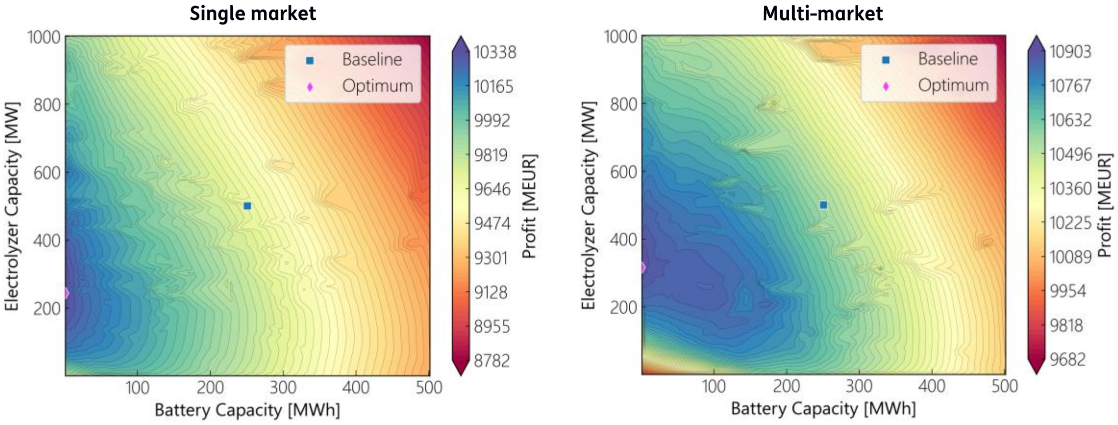

Figure 9. Optimisation results of the HPP case with wind, solar, battery and hydrogen production, where the capacity of the latter two are the sizing degrees of freedom. Again, the multi-market case shows an optimal solution with higher profits compared to the single market case, with a higher electrolyser capacity compared to the single market case. *Note*: the contours are linearly interpolated from the sampled locations, showing irregularities in regions that have not been densely sampled within the optimisation.

Observing the aFRR revenue, the income from reserved capacity is lower compared to the previously considered case where the hybrid power plant (HPP) consists solely of wind, solar, and battery storage. This suggests that, according to the assumptions, selling hydrogen directly is often more profitable than earning from capacity reservation. Notably, this trend is more significant for downward regulation (i.e., increasing electrolyser load) than for upward regulation (i.e., decreasing electrolyser load), due to the necessity of adhering to reserved capacity limits. Consequently, the revenue from downward aFRR activations is negligible compared to the revenue from upward activations.

When comparing the single- and multi-market scenarios, grid tariffs rise with the increased electrolyser capacity, because more hydrogen is being produced and thus greater grid imports occur. Notably, the cost of electricity also decreases. This indicates that either the electrolyser might consume electricity from the grid even when prices aren't negative—this could happen e.g. during aFRR activations— or the electrolyser consumes power directly from the renewables more often.

Another aspect worth noting is the utilisation of the export cable in both scenarios. Despite the addition of 1 GW of solar capacity to the HPP, the export cable utilisation remains comparable to the reference case in the single-market scenario and is lower in the multi-market scenario. This is primarily attributable to the power consumed by the electrolyser, either through self-consumption of the power generated offshore, or from grid imports. Figure 12 illustrates that the effect is more pronounced with higher electrolyser capacities, although it is somewhat diminished as battery capacities increase. These findings suggest that there is potential for overplanting of additional renewable generation capacity, or conversely, the export cable capacity could be reduced.

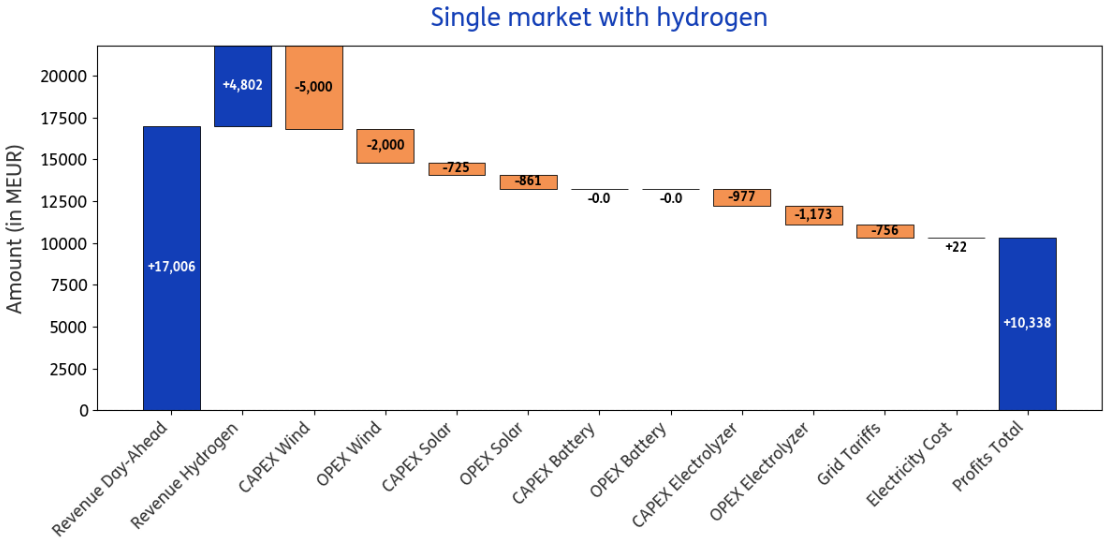

Figure 10. Financial breakdown of the optimal solution for a hybrid power plant including wind, solar, battery and hydrogen, participating on the day-ahead market alone.

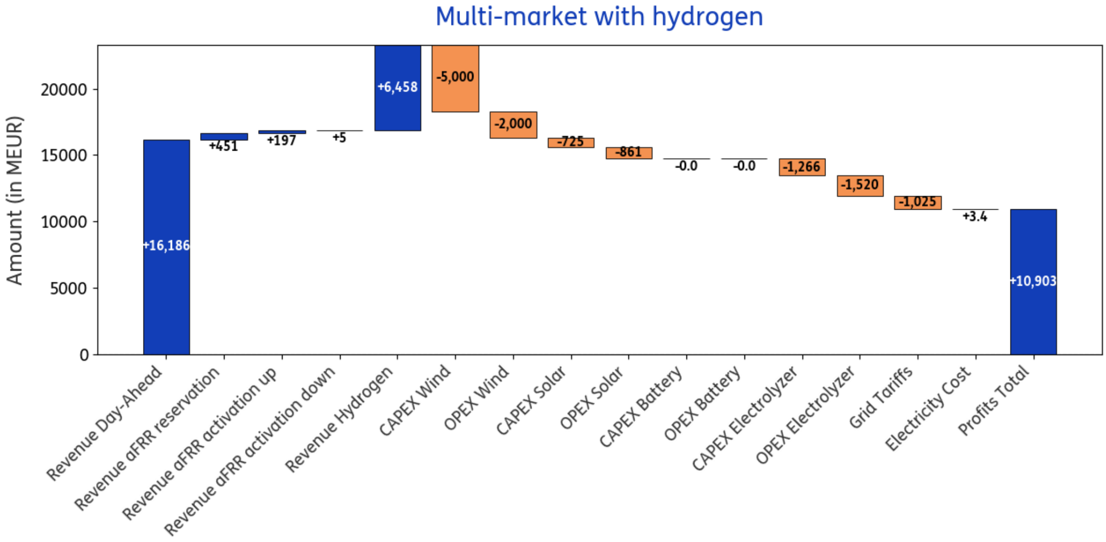

Figure 11. Financial breakdown of the optimal solution for a hybrid power plant including wind, solar, battery and hydrogen, participating on the day-ahead market and the aFRR market.

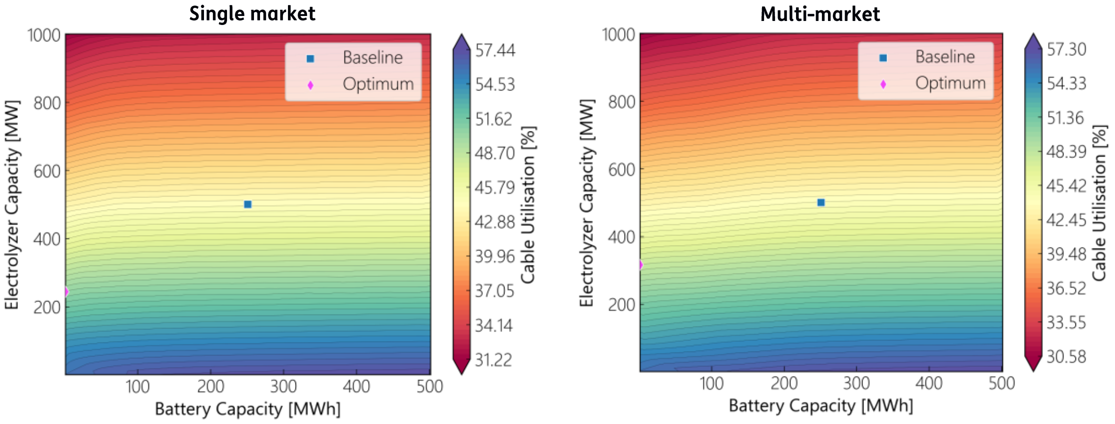

Figure 12. Optimisation results for the HPP comprising 2 GW wind, 1 GW solar, battery storage and hydrogen conversion. The contour plots show the export cable utilisation for various combinations of battery and electrolyser capacities.

A main benefit often mentioned for offshore storage and conversion is that it allows the curtailment of offshore renewable generation to be reduced. This effect is not observed from the results presented in the study. Although Figure 13 demonstrates a slight decrease in curtailment for elevated battery and electrolyser capacities, the effect is minimal as curtailment percentages stagnate at around approximately 7.7%. As mentioned in the previous section, this result is due to EMERGE's dispatch model, prioritizing grid imports over self-consumption during periods of negative electricity prices to optimise profits. This highlights a main limitation of the optimal dispatch model, which neglects the impact of grid imports on grid tariffs. As demonstrated in Figure 5, 6, 10 and 11, the grid tariffs may be in the order of 75-85% of the electrolyser- or battery CAPEX.

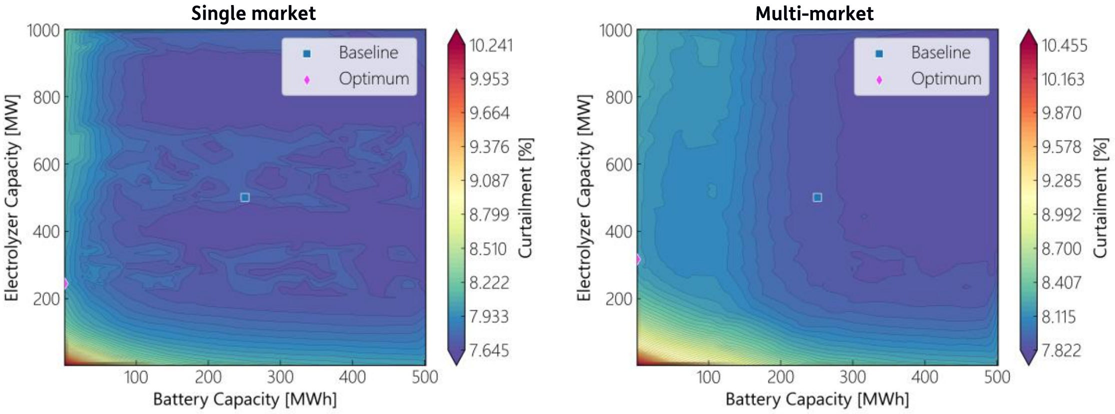

Figure 13. Optimisation results for the HPP comprising 2 GW wind, 1 GW solar, battery storage and hydrogen conversion. The contour plots show the total curtailment for various combinations of battery and electrolyser capacities.

Table 6. Sensitivity of hybrid power plant sizing and profitability to variations in fixed hydrogen price for the multi-market case. Electrolyser- and battery capacity reflect optimal sizing results. Profit change is relative to the case with fixed price of 8 EUR/kg.

H_2 Price [EUR/kg]	6	6.5	7	7.5	**8**	8.5
Electrolyser Capacity [MW]	0	12	32	71	**316**	1000*
Battery Capacity [MWh]	212	195	169	124	**0**	0
Total Cost [MEUR]	9157	9252	9410	9739	**12393**	21310
Revenue Day-Ahead [MEUR]	18926	18791	18599	18231	**16186**	11704
Revenue aFRR [MEUR]	829	830	823	799	**653**	561
Revenue Hydrogen [MEUR]	0	233	616	1409	**6458**	20872
Total Profit [MEUR]	10598	10602	10628	10700	**10903**	11827
Profit Change	-2.80 %	-2.76 %	-2.52 %	-1.86 %	**-**	+8.47 %

To assess the sensitivity of system sizing and the overall business case to hydrogen price, the optimisation was repeated across a range of hydrogen prices for the multi-market scenario, with results summarised in Table 6. As previously discussed, at a hydrogen price of 8 EUR/kg, selling hydrogen regularly yields higher profits than participation in the day-ahead electricity market or reserving electrolyser capacity for the aFRR market. This incentivises a sizing strategy favouring substantial electrolyser capacity, while the optimal battery size remains negligible. As the hydrogen price decreases, this trend reverses. For instance, at 7.5 EUR/kg, the optimal electrolyser capacity drops to approximately 22% of its value at 8 EUR/kg, whereas the battery reaches an optimal size of 124 MWh.

Further reductions in hydrogen price continue this pattern, with decreasing electrolyser capacity and increasing battery capacity. Notably, as battery capacity increases, revenue from aFRR market participation also rises. This highlights the battery's ability to generate more direct income from the aFRR market, which can be attributed to its bidirectional operation. However, it should be noted that electrolysers can still contribute to aFRR revenues with sufficient frequency, particularly by reserving upward capacity while continuing hydrogen production and sales. Nonetheless, at higher hydrogen prices, the financial incentive to reduce hydrogen output diminishes, making it less attractive to divert capacity away from hydrogen generation.

As hydrogen prices rise, the revenue share from hydrogen sales increases exponentially, while electricity market revenues decline. Although the reduction in profits at lower hydrogen prices is moderate, profit growth becomes pronounced above 8 EUR/kg, with a total profit increase of 8.47% at a hydrogen price of 8.5 EUR/kg. Furthermore, the effect of greater hydrogen prices promote self-consumption of renewable power, resulting in reduced export cable utilisation.

3.3 Comparison between linearised setpoints and physics-based corrections

The optimal sizing studies previously discussed have been conducted using a combination of linearised models and simplified physics, particularly concerning battery dynamics, to manage computational complexity. This simplification impacts the operational characteristics of the assets as well as their financial metrics. A final simulation involving a 2 GW wind farm, 1 GW offshore solar array, 250 MWh battery storage system, and a 250 MW electrolyser was conducted. Figure 14 illustrates a comparison between the behaviour of the battery (left) and the electrolyser (right) when subjected to non-linear physical dynamics versus the linearised dispatch model.

The linear model provides optimal setpoints that serve as inputs for the physics-based models. Nevertheless, edge cases necessitate corrections to ensure the operational schedule does not violate constraints imposed by accepted aFRR capacity bids or activations. For instance, they may be violated due to discrepancies in battery state of charge values produced by the physical models compared to the linearised dispatch model. Here, the time resolution is in steps of 15 minutes, which is equivalent to the ISP. However, as the resolution increases, the consideration of physics-based models becomes more critical, as dynamic characteristics like ramp rates become non-negligible.

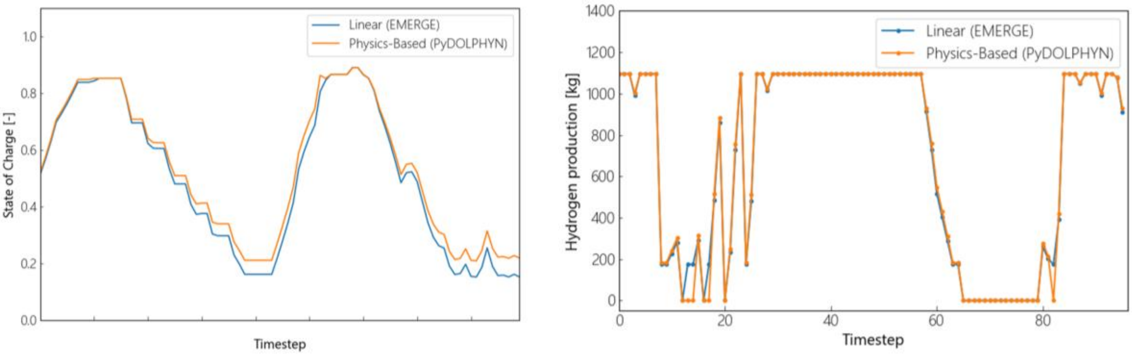

Figure 14. Comparison of the state of charge of the linearised battery model and the physics-based battery model.

Table 7 provides a comparison of the financial results from both linearised and physics-based models, and reveals a slight variation in revenue streams, with the physics-based models offering a small decrease in profit. This was resulting from considerable differences in individual components (grid tariffs, electricity costs and revenue from hydrogen), ranging from -0.32 to -22%. In other cases, with a different distribution of these cost/revenue differences, there could be even larger shifts in profit. While this comparison analysis is limited in this study, it highlights the importance of using higher-fidelity physics-based models to simulate the hybrid power plant operations. These models can enhance the accuracy of financial assessments and reinforce the reliability of the business case conclusions.

Table 7. Summary of the techno-economic results, comparing the use of only linearised models against using physics-based models in the simulation.

	Linear Model	Physics-Based Model	Difference
Assets CAPEX [MEUR]	7075	7075	-
Assets OPEX [MEUR]	4105	4105	-
Grid tariffs [MEUR]	1115	1043	-6.5 %
Electricity cost [MEUR]	-20.9	-16.3	-22 %
Revenue day-ahead [MEUR]	17322	17024	-1.7 %
Revenue aFRR reservation [MEUR]	588	588	-
Revenue aFRR activation [MEUR]	284	284	-
Revenue Hydrogen [MEUR]	4737	4722	-0.32 %
Profits [MEUR]	10658	10411	-2.3 %

4. Conclusions, limitations and recommendations for future work

4.1 Conclusions

In this study, the combination of two solvers (linearised and physics-based) for a nested operational and sizing optimisation of a hybrid power plant has been presented. This formulation was tested for case studies comprising single- and multi-market strategies (day-ahead, aFRR and hydrogen), with dual-time indexing (15 minutes and one hour). The case studies were based on an offshore wind farm in the Netherlands, using weather and market data from 2024.

The participation in multiple markets when optimising the size of offshore solar and a battery system showed an improvement of 6.1% in profit. This was accompanied by a larger battery size compared to the single-market case. When adding an offshore electrolyser, a 5.5% increase in profit was obtained for the multi-market case, although the profitability of green electrolysis exhibited high sensitivity to hydrogen prices. Battery systems were promoted for 6 EUR/kg, whereas electrolysers became the optimal choice at 8 EUR/kg under the tested assumptions.

It was also highlighted that modelling the complexities of the system can be impactful to obtain the right business case conclusions. In particular, the case including hydrogen showed that grid tariffs can represent a cost stream in a similar order of magnitude as the CAPEX of the electrolyser or the aFRR revenues. The comparison between linearised and non-linear physics also showed differences in the costs related to electricity import, day-ahead electricity revenues and revenue from hydrogen production, resulting in a 2.3% decrease in overall profits.

The flexible formulation presented can be expanded and used for different applications within the energy sector, such as decarbonisation of an industrial off-taker or local grid congestion analysis onshore. This can provide useful considerations for asset owners and developers in an exploratory phase for potential investments. In addition, public stakeholders can benefit from a better understanding of the cost and revenue levers that affect the attractiveness of the business case. This can be used to draft policies that benefit both societal and private interests, accelerating the penetration of sustainable assets.

4.2 Limitations of the study and recommendations for future work

The approach and results of the study are associated with several limitations that could be tackled in future work. Firstly, the combined sizing and operational optimisation algorithm was tested with a simplified model for the battery, due to the computational expense of using the higher-fidelity model for all the samples. While the exploratory trends may hold, the exact optimum may be different in some cases. An additional sensitivity analysis could be established in the vicinity of the calculated point with higher-fidelity physics.

In the models used, no degradation was established in the battery and the electrolyser. This can affect the business case (OPEX, replacements), and the performance for the components and the system. There may be situations where strategies with similar revenue lead to different degradation rates, leading to different costs and profit.

The grid tariffs were only included outside of the operational optimisation. As one of the components of these tariffs depends on the consumption during a whole month, this is a challenging implementation for daily dispatching strategies.

Looking at longer time horizons could help to capitalise in greater profits for systems with a battery or an electrolyser. This would however result in greater computational cost.

Uncertainty in the difference between predicted and actual supply and demand was outside the scope of the study. An additional source of uncertainty is the development of the different markets. The market data used in this study were based on 2024 values for the Netherlands. For the annual simulation, December 31st was excluded to ensure a consistent 365-day year, and leap year adjustments were applied for lifetime extrapolation. With rapid development in the markets and increased penetration of renewable energy sources, large uncertainties on their dynamics exist. This may change the tipping point where operating in multiple markets becomes more profitable, and also the volumes that can be accessed in each of these markets.

In this study, the profit increase from participating in the aFRR market was found to be in the order of 5-6%. The revenue potential is limited because the HPP with GW-scale generation assets faced a relatively shallow aFRR market volume. Conversely, smaller-scale HPPs may exhibit a greater proportional increase in profitability when they engage in the same market.

As for the multi-market optimisation strategy, the assumption of perfect foresight, using historical market data, represents a considerable simplification. In reality, market prices are uncertain and subject to volatility, which can lead to suboptimal decisions if not properly accounted for. Future work could incorporate stochastic or robust optimisation approaches to better reflect real-world decision-making under uncertainty.

Regarding the revenue stream of the hydrogen, the fixed value of 8 EUR/kg may be uncertain, and subjected to off-taker agreements. When consuming power from the grid without taking into account the principles of additionality, geographical correlation and temporal correlation, the hydrogen cannot be considered green with the current European regulation schemes [26]. This may lead to a lower off-take price than the one presented in this study. Conversely, this study did not include an analysis of additional markets, contractual arrangements, or ancillary services (such as contracts for differences or power purchase agreements), which could potentially offer further revenue streams.

References

[1] A. A. R. Mohamed, R. J. Best, X. Liu, D. J. Morrow, J. Pollock and A. Cupples, "Stacking Battery Energy Storage Revenues in Future Distribution Networks," *IEEE Access,* vol. 10, pp. 35026-35039, 2022.

[2] A. Bechlenberg, E. A. Luning, M. B. Saltık, N. B. Szirbik, B. Jayawardhana, A. I. Vakis, "Renewable energy system sizing with power generation and storage functions accounting for its optimized activity on multiple electricity markets," *Applied Energy,* vol. 360, 2024.

[3] Timera Energy, "Netherlands joins PICASSO aFRR platform, imbalance volatility falls by almost 50% in the first period.," 31 10 2024. [Online]. Available: https://timera-energy.com/blog/netherlands-joins-picasso-afrr-platform-imbalance-volatility-falls-by-almost-50-in-the-first-period/. [Accessed 28 05 2025].

[4] Timera Energy, "Italy suspends Picasso aFRR participation," 06 03 2024. [Online]. Available: https://timera-energy.com/blog/italy-suspends-picasso-afrr-platform-participation/. [Accessed 28 05 2025].

[5] Á. Paredes, J. A. Aguado, C. Essayeh, X. Y. I. Savelli and T. Morstyn, "Stacking revenues from flexible DERs in multi-scale markets using tri-level optimization," *IEEE Transactions on Power Systems,* 2023.

[6] G. Pan, Y. Lu and S. Lu, "Accurate Modeling of a Profit-Driven Power to Hydrogen and Methane Plant Toward Strategic Bidding Within Multi-Type Markets," *IEEE TRANSACTIONS ON SMART GRID,* vol. 12, 2021.

[7] M. Houwing, N. Cassamo and E. Wiggelinkhuizen, "Energy management system for combined renewable generation, storage and conversion (EMERGE model): Renewable Hybrid Power Plant Optimization," July 2022. [Online]. Available: https://publications.tno.nl/publication/34639960/0EZ0ct/TNO-2022-R10402.pdf.

[8] J. Fatou Gómez, A. Martín-Gil and S. Dussi, "PyDOLPHYN: Dynamic simulations and optimization of multi-energy assets," Accepted in Energy, 2025.

[9] Rijksdienst voor Ondernemend Nederland, "Wind op zee - IJmuiden Ver kavels Gamma-A en Gamma-B," June 2022. [Online]. Available: https://www.rvo.nl/onderwerpen/bureau-energieprojecten/lopende-projecten/woz-ijmuiden-ver-kavels-gamma-en-gamma-b. [Accessed 2025].

[10] TenneT, "Tarieven | TenneT," [Online]. Available: https://www.tennet.eu/nl/de-elektriciteitsmarkt/regulering/tarieven. [Accessed 2025].

[11] Autoriteit Consument & Markt, "ACM start met voorbereiding van invoedingstarief voor grote producenten van elektriciteit," 02 10 2024. [Online]. Available: https://www.acm.nl/nl/publicaties/acm-start-met-voorbereiding-van-invoedingstarief-voor-grote-producenten-van-elektriciteit. [Accessed 05 0 2025].

[12] S. Pfenninger and I. Staffell, "Long-term patterns of European PV output using 30 years of validated hourly reanalysis and satellite data," *Energy,* vol. 114, pp. 1251-1265, 2016.

[13] I. Staffell and S. Pfenninger, "Using Bias-Corrected Reanalysis to Simulate Current and Future Wind Power Output," *Energy,* vol. 114, pp. 1224-1239, 2016.

[14] Renewables.ninja, [Online]. Available: https://www.renewables.ninja/. [Accessed May 2025].

[15] J. Fatou Gómez, A. Raja and I. González-Aparicio, "FlexH2 Work Package 4.2.2: FlexH2 system sizing optimisation (in review)," GROW, 2025.

[16] I. González-Aparicio, M. Wevers and A. Raja, "North Sea Energy 2023-2025 D3.2A: Scaling Offshore Wind-to-Hydrogen Systems: A Pathway to Feasibility and Integration by 2050," North Sea Energy, 2025.

[17] C. Weber,, "Achievements and Challenges in European Energy Markets," *Journal of Modern Power Systems and Clean Energy,* vol. 11, no. 3, pp. 698-704, 2023.

[18] TenneT, "aFRR documents," [Online]. Available: https://www.tennet.eu/node/321. [Accessed May 2025].

[19] ENTSO-E, "Transparancy Platform," [Online]. Available: https://transparency.entsoe.eu/. [Accessed May 2025].

[20] B. Morvaj, R. Evins and J. Carmeliet, "Optimising urban energy systems: Simultaneous system sizing, operation and district heating network layout," *Energy,* vol. 116, no. 1, pp. 619-636, 2016.

[21] M. Houwing, I. Dukovska and N. G. Paterakis, "A Reputation Management System for the Fair Utilization of Community Energy Storage Systems," *IEEE Transactions on Smart Grid,* vol. 14, no. 1, pp. 582-592, 2023.

[22] M. De Eusebio Cobo, "Optimal revenue strategies for hybrid power plants in the Dutch wholesale energy market," 2022. [Online]. Available: https://resolver.tudelft.nl/uuid:247a8e13-c07c-4358-8b53-31182e5c49a8. [Accessed 2025].

[23] L. de Jager, "Optimizing Portfoliomanagement of Hybrid Power Plants under Uncertainty," 2025. [Online]. Available: https://resolver.tudelft.nl/uuid:f849d08c-90c3-42f5-95c4-8cdd51529359. [Accessed 2025].

[24] J. Fatou Gómez, P. Shoeibi Omrani and S. P. C. Belfroid, "Data-Driven Optimization of Intermittent Gas Production in Mature Fields Assisted by Deep Learning and a Population-Based Global Optimizer," in *SPE Annual Technical Conference and Exhibition*, 2021.

[25] M. Doyle, T. F. Fuller and J. Newman, "Modeling of galvanostatic charge and discharge of the lithium/polymer/insertion cell," IOP Publishing, 1993.

[26] European Parliament (Gregor Erbach with Sara Svensson), "EU rules for renewable hydrogen - Delegated regulations on a methodology for," EPRS | European Parliamentary Research Service, 2023.

[27] F. Ahmed, R. Al-Abri, H. Yousef and A. M. Massoud, "An Optimal Energy Dispatch Management System for Hybrid Power Plants: PV-Grid-Battery-Diesel Generator-Pumped Hydro Storage," *IEEE Access,* vol. 12, pp. 143307-143326, 2024.

[28] ECN-TNO, "SOLAR PV, FLOATING > 1 MWp, ORIENTED EAST/WEST," July 2019. [Online]. Available: https://energy.nl/wp-content/uploads/solar_pv_floating_above_1_mwp_east-west-1-7.pdf. [Accessed 2025].

[29] Y. Arellano-Prieto et al., "Energy Storage Solutions for Offshore Applications," *Energies,* vol. 15, no. 17, p. 6153, 2022.

[30] F. Salvatori Maldonado, "Techno-Economic Assessment of Lithium Ion Batteries for Utility Scale Purpose in The Italian Market," 2023. [Online]. Available: https://www.politesi.polimi.it/retrieve/f93f26c3-4326-447d-8e10-6090d90adf2e/2023_05_Salvatori_Maldonado.pdf. [Accessed 2025].

[31] European Association for Storage of Energy, "Energy Storage Technology Descriptions: Lithium-Ion Battery," 2023. [Online]. Available: https://ease-storage.eu/wp-content/uploads/2016/03/EASE_TD_LiIon.pdf. [Accessed May 2025].

[32] TenneT, "Imbalance Pricing System," 21 October 2024. [Online]. Available: https://tennet-drupal.s3.eu-central-1.amazonaws.com/default/2024-10/Imbalance%20Pricing%20System.pdf. [Accessed May 2025].

[33] Rabobank, "The Dutch electricity sector - part 2: How do the different electricity markets work?," 14 May 2024. [Online]. Available: https://www.rabobank.com/knowledge/d011424506-the-dutch-electricity-sector-part-2-how-do-the-different-electricity-markets-work. [Accessed May 2025].

[34] A. Christensen, "Assessment of Hydrogen Production Costs from Electrolysis: United States and Europe," 2020.