Energy & Materials Transition
www.tno.nl
+31 88 866 80 00
info@tno.nl

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Optimizing Hybrid Power Plants: Revenue Growth and Grid Efficiency via Multi-Market Participation

Author(s)	Max Houwing, Bas de Jager, Bart Klootwijk, Iratxe Gonzalez Aparicio
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Contents

Executive summary

Offshore renewable energy plays a vital role in transforming Europe's energy sector to be self-sufficient, affordable, and climate-neutral. The Netherlands, targeting a 50% reduction in CO2 emissions by 2030 and 80% by 2040, plans to install 21.5 GW of offshore wind capacity by 2030. Combining offshore wind with floating solar energy can further optimize infrastructure use, reduce investment costs, and address seasonal intermittency by leveraging the complementary nature of these resources.

TNO’s case study on a hybrid power plant—featuring solar PV, wind, battery storage, and power-to-hydrogen conversion—demonstrates the potential for significant revenue increases. The integration of flexible assets allows participation in short-term different electricity markets, resulting in monthly income boosts of over 100% in some cases, compared to relying solely on day-ahead markets. Additionally, the hybrid system reduces export cable utilization, showing that existing infrastructure can accommodate more generation capacity without requiring costly upgrades.

This flexibility, when properly designed, not only enhances the financial viability of renewable projects but also contributes to greater energy security and optimization of market operations.

1 Introduction

Offshore renewable generation is a key component for transforming the European energy sector to become self-sufficient, affordable and climate neutral in the next decades. A massive up-scale is needed to achieve the objective of a fivefold increase by 2030 and a 25-fold increase by 2050 in the North Sea. The Netherlands has set ambitious targets: to decrease CO_2 emissions by 50% by 2030 (compared to 1990 levels), and by 80% in 2040 [1].

Offshore wind energy will be the main supplier for the power market, aiming towards 22 GW of installed capacity by 2032 [2]. Floating solar energy is an additional promising offshore technology, and the complementary nature of the wind and solar resources can increase the total amount of exported energy using the same infrastructure, thereby lowering initial total investment cost, and reducing the seasonal intermittency of the combined power profile.

The large-scale integration of renewable energy sources will increase the need for flexibility in the energy system in terms of electricity transport, energy conversion and storage, and demand-response. The option to integrate power-to-hydrogen conversion and electricity storage with renewable generation in a hybrid power plant, can significantly mitigate the need for curtailment and unlock new market opportunities, thereby enhancing the overall business case [3]. Specifically, incorporating these flexible assets can enable greater participation in short-term electricity markets beyond the traditional day-ahead market, less conservative bidding and provide general energy security. This flexibility, if designed properly, allows power producers to optimize their operations and capture additional value streams.

To address these design considerations, TNO has developed a cross-departmental tool that combines market mechanism modelling with the operational optimization of hybrid power plants. This revenue-stacking tool provides valuable insights into the various income sources that can be tapped by a given hybrid power plant configuration, enabling a comprehensive understanding of the economic potential across multiple markets.

This report presents an exemplary case study of a MW scale hybrid power plant, consisting of solar photovoltaic (PV) and wind power generation, battery energy storage, and power-to-hydrogen conversion. Using TNO's multi-market tool, we explore the financial viability of this configuration by evaluating income potential across different market segments, including the Frequency Restoration Reserve (FRR) and passive balancing markets.

The report is organized as follows: Chapter 2 outlines the methodology applied in the case study and details the functionality of the TNO multi-market tool. Chapter 3 presents the results of the case study, focusing on the financial and operational outcomes of the proposed hybrid power plant. Lastly, Chapter 4 provides key conclusions and offers recommendations for future research to further enhance the performance and profitability of hybrid power systems.

2 Methodology

The introduction of flexibility assets such as electrolyzers and battery energy storage, as well as their combination with renewable generation in a hybrid power plant has been widely researched [4], [5], [6]. In this study, the possibilities of such a combination operating on multiple electricity markets is studied. This chapter details the tooling and modelling approach, presented in Section 2.1, which is used to evaluate a hybrid power plant case study, as discussed in Section 2.2.

2.1 Modelling approach

In order to model the operational characteristics of a hybrid power plant and study its impact under optimal operation, a cross-departmental tool was developed by TNO in 2022. This tool, the Energy management system for combined renewable generation, storage and conversion (EMERGE) tool [7], consists of different modules that aim to provide insight in the scheduling and operational side of hybrid power plants. The optimizer module, as used in this study, is described in Section 2.1.1. Additionally, the different markets used as inputs to the optimizer module are described in Section 2.1.2.

The model description and further assumptions are included in the annexes of this document.

2.1.1 Hybrid power plant configuration & optimization

The optimizer integrates power prediction time series with day-ahead market prices to determine optimal set points for generation, storage, and conversion assets, maximizing overall profit. These set points are normalized between 0 and 1, where 0 indicates no generation or load and 1 represents full generation or load for each asset. The battery system is an exception, with set points ranging from -1 (full charging) to 1 (full discharging).

The optimization model is implemented in Python using mixed-integer linear programming (MILP) and incorporates simplified models for wind and solar PV generation, battery storage, and hydrogen production assets. This approach allows for effective decision-making regarding the operation of each component, ensuring an optimal balance between energy generation, storage, and conversion to maximize revenue. A more detailed description of the (multi-market) optimization approach can be found in Appendix A.

2.1.2 Markets & products

A brief overview and description of each of the considered markets is presented below. First, the day ahead electricity market is described in Section 2.1.2.1. Next, the aFRR market is discussed in Section 2.1.2.2. Finally, a brief detail of the passive imbalance market is laid out in Section 2.1.2.3.

2.1.2.1 Day ahead electricity market

Bidding on the day-ahead market begins 45 days in advance and closes at 12:00 on the day before delivery (D-1). The process involves blind bidding with uniform price clearing to match the buying and selling of energy. Participants can submit bids to buy or sell electricity in increments of 0.1 €/MWh. Based on all buy bids, a demand curve is created, and based on all sell bids, a supply curve is formed for each time slot. These curves are plotted against volume (MWh) and price (€/MWh) to determine the equilibrium point, which establishes the market clearing volume (MCV) and the market clearing price (MCP).

The MCP is the uniform price at which all electricity, whether bought or sold, is traded. It represents the point where supply and demand are in balance, but it does not imply that all demand is fully met or that all available supply is utilized. Instead, it signifies the price at which the quantity of energy demanded matches the quantity offered. The EPEX SPOT Day-Ahead market is coupled across Europe, facilitating efficient cross-border electricity trading and price convergence.

2.1.2.2 Automatic Frequency Restoration Reserve (aFRR) market

For the aFRR market, the TSO is obliged to procure the minimum level required for each imbalance settlement period (ISP), i.e., 15 min in order to assure grid security. Thus, the attainment of aFRR is done in two stages, a capacity auction to contract BSPs (Balancing service providers) and a market clearing for balancing services during the corresponding ISP to determine price and selection of reserve.

Two types of BSPs participate in the balancing stage:
- Contracted (TSO obliged to keep minimum level)
- Free

For Contracting BSPs, the capacity auction starts at 9:00 (D-1) and ends with the selection of energy bids for each ISP for D until 14:45 (D-1).
To determine the price of balancing energy per ISP, TenneT compiles an aFRR merit order list of all aFRR energy bids (contracted and free).
- The balancing energy price is based on the highest activated FRR bid for upward regulation and lowest activated FRR bid for downward regulation.
- In upward regulation the BSPs receive the above-mentioned price and for downward regulation BSPs also offer to pay TenneT, for example if power for downward regulation is delivered with resources that have fuel costs.

2.1.2.3 Passive imbalance market

Every Programmaverantwoordelijke (PV) needs to submit its E-programma to the Transmission System Operator (TSO). In the E-program the PV informs how much energy it in sum will produce or consumer from the grid. The E-program must be approved by the TSO. When the PV produces more/consumes less energy than the E-program states, the energy is sold/bought virtually to/from the TSO. The prices for which this energy is bought or sold are determined the day after delivery, for every Programma Tijdseenheid (PTE) (15 minute interval), and are based upon the costs the TSO has for maintaining balance in the grid (e.g. through aFRR). When actively participating in the passive imbalance market, the goal is to forecasts these prices, and try to "sell" energy to the TSO when you expect the prices to be positive, and/or to "buy" energy from the TSO when you expect prices to be negative. [8]

2.2 Case study description

The case study selected is of a small size - MW scale. This onshore hybrid power plant was selected in order to demonstrate how even a relatively small collection of generation assets, as commonly found onshore, can have significant gains from a hybrid approach. Additionally, a system of this size can be assumed to be a price-taker, significantly simplifying its market interactions.

TNO's in-house energy management tool, described in Section 2.1.1, optimises the scheduling of a given hybrid power plant configuration based on this data.

The hybrid power plant considered in this case study consists of the configuration specified below:

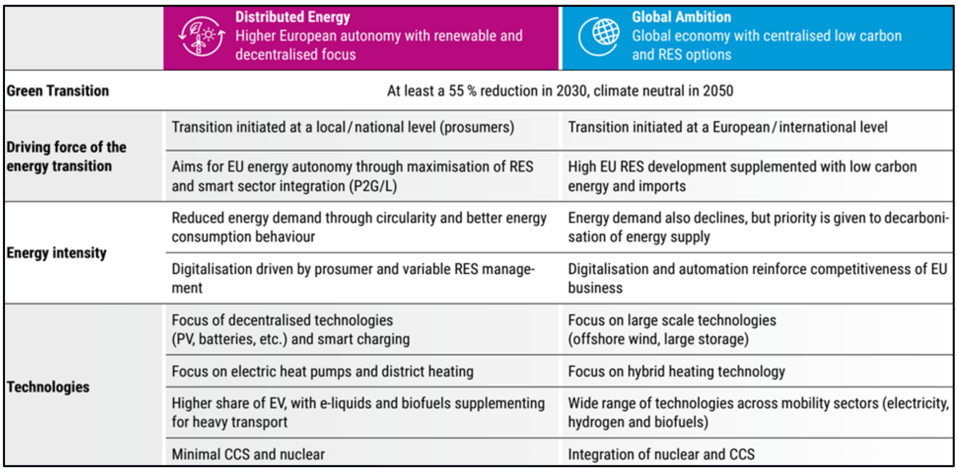
- 22 MW wind farm
- 38 MWp solar PV farm
- 6 MW / 12 MWh battery energy storage
- 6 MW electrolyzer
- 22 MW grid connection

As a representative recent period that does not suffer from strongly deviating energy prices, the second half of 2023 is selected for study - from September to December, at hourly resolution. Weather data from this period is applied as normalised wind and solar energy production profiles. This weather data is also used to generate the projected 2030 market prices, assuming a similar weather year as 2023 would occur again in 2030. This approach is chosen to ensure market prices are time correlated with the meteorological condition – which is an essential consideration in a renewable dominated energy system.

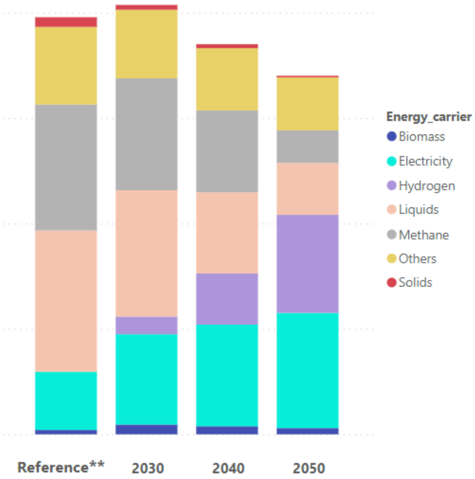
These market prices for the 2030 scenario are then generated using a TNO European power market model (OPERA model) based on the Ten-Year Network Development Plans (TYNDP) – Global Ambition (GA) 2030 scenario. The Ten-Year Network Development Plans (TYNDP) of ENTSO-E and ENTSOG are a set of ambitious and technically robust development scenarios for the EU energy system that are fully compliant with the Paris Agreement and with the European ambitions for achieving climate neutrality by 2050.
They aim to provide a quantitative basis for infrastructure investment planning and insights into the evolution of integrated energy system perspectives, while remaining both technology- and energy-carrier neutral.

- The Global Ambition (GA) scenario is more technology-driven, includes a hydrogen market, puts focus on more centralized production and use, and assumes a big role for imports. It uses a wide range of renewable and low-carbon technologies (many being centralized), and global energy trade to accelerate decarbonization. Economies of scale lead to cost reductions in emerging technologies (e.g. offshore wind), imports of decarbonized energy viable option.
- The Distributed Energy (DE) scenario is population-driven, puts focus on maximizing electrification, and has more decentralized production and use. It assumes a willingness of society to achieve energy autonomy based on widely available indigenous renewable energy sources, a way-of-life evolution, a strong decentralized drive to decarbonize, with local initiatives (citizens, communities and businesses) supported by authorities.

This study has been performed under the Global Ambition scenario, where the ratio between electricity and hydrogen in Europe is 50:50.



	Distributed Energy Higher European autonomy with renewable and decentralised focus	**Global Ambition** Global economy with centralised low carbon and RES options
Green Transition	At least a 55 % reduction in 2030, climate neutral in 2050	
Driving force of the energy transition	Transition initiated at a local / national level (prosumers)	Transition initiated at a European / international level
	Aims for EU energy autonomy through maximisation of RES and smart sector integration (P2G/L)	High EU RES development supplemented with low carbon energy and imports
Energy intensity	Reduced energy demand through circularity and better energy consumption behaviour	Energy demand also declines, but priority is given to decarbonisation of energy supply
	Digitalisation driven by prosumer and variable RES management	Digitalisation and automation reinforce competitiveness of EU business
Technologies	Focus of decentralised technologies (PV, batteries, etc.) and smart charging	Focus on large scale technologies (offshore wind, large storage)
	Focus on electric heat pumps and district heating	Focus on hybrid heating technology
	Higher share of EV, with e-liquids and biofuels supplementing for heavy transport	Wide range of technologies across mobility sectors (electricity, hydrogen and biofuels)
	Minimal CCS and nuclear	Integration of nuclear and CCS



** Most of the current hydrogen produced locally in the industrial clusters is not included in the hydrogen figures, since they are not connected to any regional or national networks. These figures are shown as methane demand.*
*** The historic values are based on 2018 for residential and tertiary sectors, 2015 for the other sectors (industry, agriculture, energy branch, mobility)*

Description of the Global Ambition scenario and the targets by 2030 for each energy carrier.

3 Results

From the case study, the grid connection utilisation rates were analyzed first. The results of this analysis is shown in Figure 1 and Figure 2 below. The results of the analysis indicate that a hybrid power plant configuration reduces the average utilization of the grid connection by over 10% compared to scenarios involving only wind power or a combination of wind and solar PV. This reduction in grid utilization can be attributed to two main factors. Firstly, the production of hydrogen via the electrolyzer offsets the need to export electricity during periods of excess generation, effectively diverting energy that would otherwise require grid capacity. Secondly, the inclusion of an energy storage system contributes to the reduction by smoothing out production peaks, thus minimizing instances of high-power output that would typically necessitate increased use of the export cable. This could also mean that more wind and/or solar production could be added with the same capacity of the export cable.

Furthermore, adopting a multi-market strategy, in addition to the base day-ahead market interactions, leads to an even greater reduction in average export cable utilization. By participating in multiple markets, such as balancing and reserve markets, the hybrid power plant gains additional flexibility in managing its output, allowing it to optimize the timing of electricity exports and thereby decrease peak utilization of the grid connection.

The benefits of the multi-market strategy are also evident when examining power imports. As shown in Figure 1, the amount of imported power—which is used, for instance, to supply the electrolyzer during periods of low renewable generation—decreases significantly in the multi-market scenario. This decrease indicates that the hybrid plant is able to better match its internal energy demand with its own generation, leading to more efficient use of locally produced renewable energy. A similar trend can be observed in Figure 3, where the reduction in power imports of approximately 50% is clearly illustrated, highlighting the improved self-sufficiency of the hybrid system.

In summary, the hybrid power plant configuration, especially when combined with a multi-market strategy, demonstrates several key advantages over more conventional configurations. By reducing reliance on the grid for both exports and imports, the hybrid system not only alleviates grid congestion but also maximizes the utilization of renewable energy for on-site hydrogen production and energy storage. This integrated approach not only strengthens the economic viability of the hybrid power plant but also contributes to a more stable and resilient power grid, with the added benefit of reducing the carbon footprint associated with energy imports.

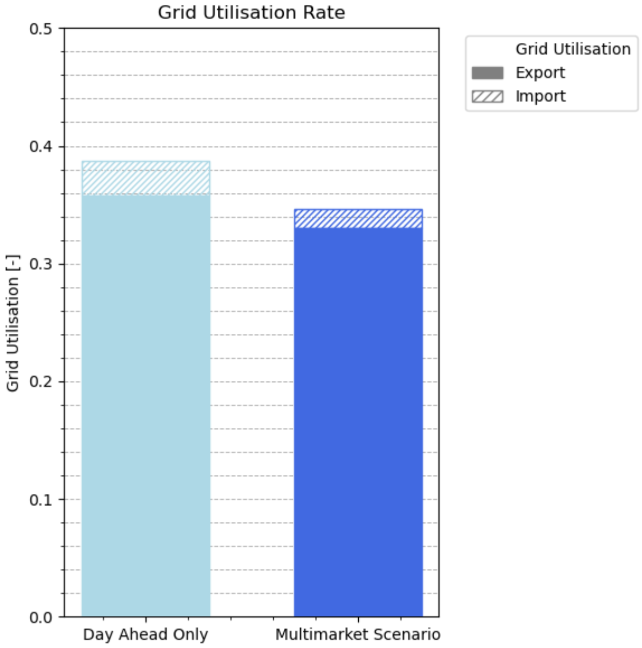


Figure 1: Grid connection utilisation rate of the considered hybrid power plant of the case study, for the day-ahead only and multi-market cases.

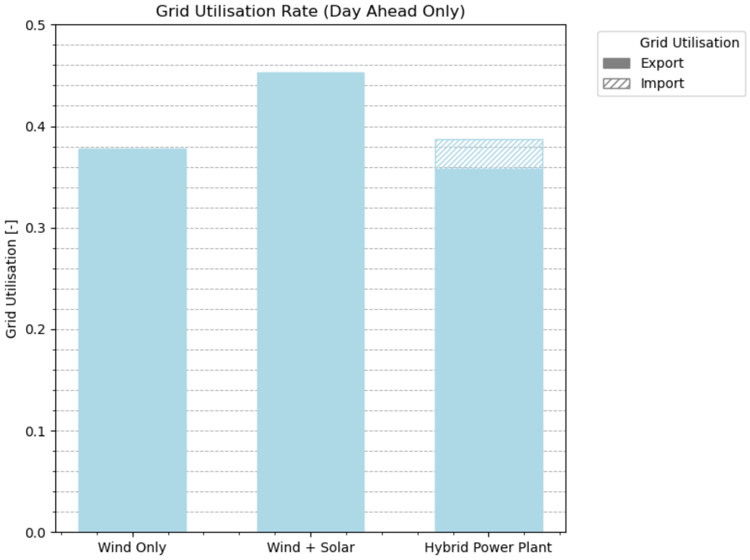


Figure 2: Grid connection utilisation rate comparison of a wind-only, wind and solar PV, and hybrid power plant configuration.

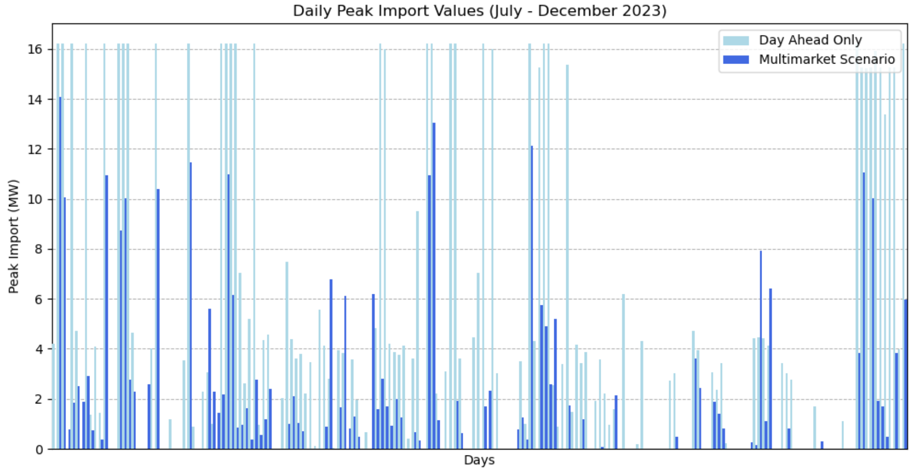


Figure 3: Resulting case study overview of all days from July to December 2023, with their total daily electricity import indicated for the day-ahead and multi-market scenario.

The reduction of imported power can be seen in the Figure 3, both in amount of size of the peak import. This result indicates that more of the locally generated power is used instead imported. However, this leaves out a key component: generated revenue from the energy production. An overview comparing the day-ahead case with the addition of aFRR, as well as aFRR and imbalance markets, is presented in Figure 4.

The reduction in imported power is seen in Figure 3, both in terms of the total amount imported and the size of peak imports. This result suggests that a larger portion of the energy demand is being met by locally generated renewable power rather than relying on imported electricity. This enhanced self-sufficiency is crucial for improving the economic performance of the hybrid power plant, as it reduces dependency on external power sources and minimizes associated costs.

However, focusing solely on the reduction in imported power overlooks a key aspect of the hybrid power plant's performance: the revenue generated from energy production. The economic viability of the system depends not only on optimizing energy usage but also on maximizing income streams through strategic market participation.

Figure 4 compares the generated revenue across different market participation scenarios, highlighting the benefits of expanding beyond the day-ahead market. In the base case of day-ahead market participation only, revenue is limited to the fluctuations of day-ahead prices. However, by adding automatic Frequency Restoration Reserve (aFRR) and further incorporating the imbalance markets, the hybrid power plant is able to capitalize on additional revenue opportunities, up to over 75% increase in the considered period.

The inclusion of aFRR allows the plant to provide ancillary services that help stabilize the grid, offering a valuable source of income beyond just selling electricity. The plant's fast-responding assets, such as battery storage and hydrogen conversion, enable effective participation in these balancing services, which are typically rewarded with higher remuneration due to their role in maintaining grid reliability.

Moreover, participating in the imbalance market provides further revenue potential by enabling the plant to adjust its generation or consumption in response to real-time deviations between forecasted and actual supply and demand. By leveraging this market, the hybrid power plant can earn additional income while also contributing to the overall stability of the electricity system.

The comparison in Figure 4 clearly demonstrates that the adoption of a multi-market strategy results in a substantial increase in revenue compared to relying solely on the day-ahead market. This additional revenue not only strengthens the business case for the hybrid power plant but also supports its long-term sustainability by providing multiple income streams that reduce financial risk.

All in all, the results indicate that the hybrid power plant's ability to reduce imported power and utilize more locally generated energy is complemented by significant revenue gains from multi-market participation. The combination of optimized energy usage and diversified income streams makes the hybrid configuration a compelling solution for enhancing both economic returns and operational efficiency. Future studies should further explore these dynamics, particularly under different market conditions and regulatory environments, to fully realize the potential of hybrid power plants in contributing to a resilient and sustainable energy future.

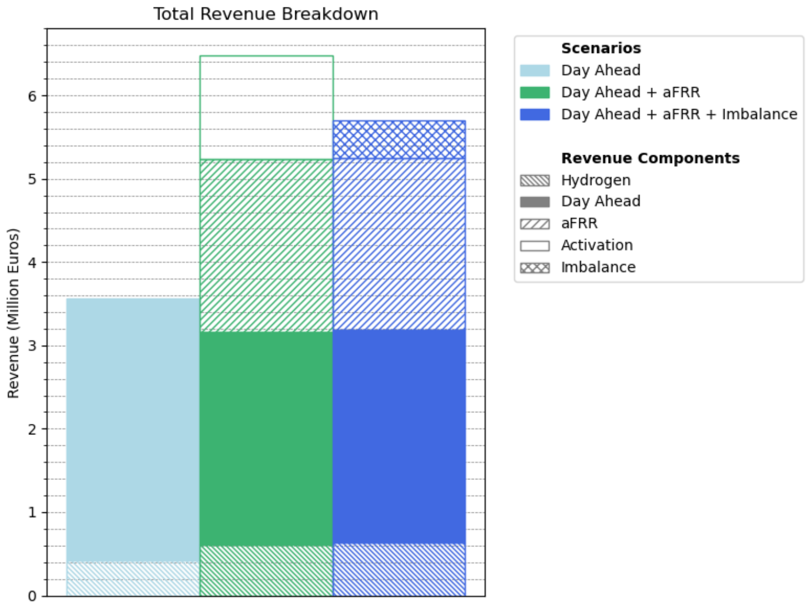


Figure 4: Breakdown of the total revenue of the cases for the day-ahead only, day-ahead and aFRR, and day-ahead, aFRR and imbalance markets.

This breakdown shows the opportunity present in participating in markets beyond just the day-ahead market. The aFRR potential is approximately equal to the amount of revenue generated by the day-ahead market, even without considering any aFRR activation. At the same time, the addition of the imbalance market can add more revenue than the share of hydrogen revenue in the base case. Finally, it can be seen that the share of hydrogen revenue is increasing in both of the multi-market cases. This indicates that the decrease in imported power, as seen in Figure 1 and Figure 3, is not simply caused by a decrease in hydrogen production, but instead by increased use of local generation.

A monthly overview of the generated revenue for each of the scenarios can be seen in Figure 5. It can be seen that in the multi-market cases, the variation – both in percentage and absolute value - in generated revenue between the considered months is higher than in the day-ahead case. However, these results also show that the generated revenue is always higher, in all months and for all cases.

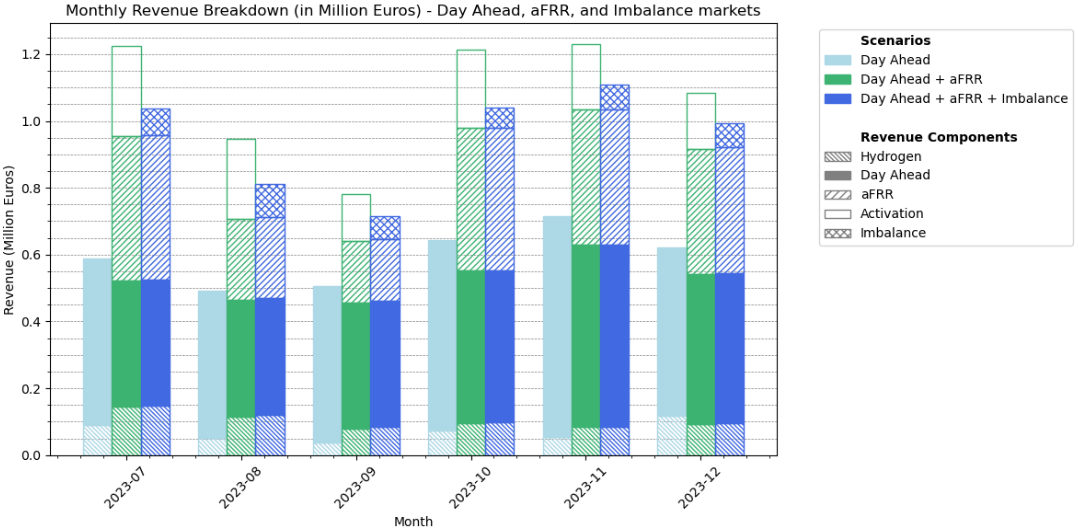


Figure 5: Breakdown of the generated revenue for each month in the considered case study, showing the hydrogen, day ahead, aFRR (activation) and imbalance market prices.

4 Discussion and conclusions

This case study evaluated the performance and economic potential of a small-scale hybrid power plant (MW-scale) composed of wind power and solar photovoltaic (PV) generation, combined with battery energy storage and hydrogen conversion using an electrolyzer.

The study explored several scenarios for the sale of the generated electricity, with the goal of optimizing revenue streams and maximizing the utilization of renewable energy. Specifically, three scenarios were considered: a base case where electricity is sold exclusively on the day-ahead market; a scenario involving participation in both the day-ahead and the automatic Frequency Restoration Reserve (aFRR) markets; and a comprehensive scenario incorporating the day-ahead, aFRR, and passive imbalance markets.

The results of the analysis demonstrated notable benefits for the hybrid power plant under the multi-market participation scenarios. There was a marked reduction in the average utilization rate of the grid connection, which suggests improved efficiency in the use of the existing infrastructure. This reduction in grid dependency could also indicate the potential for increasing the generation capacity of the hybrid system without additional grid expansion costs. Moreover, revenue generation increased significantly—up to 100%—in both of the multi-market scenarios, emphasizing the financial advantages of expanding market participation beyond the traditional day-ahead market.

In addition, the share of hydrogen production in the multi-market scenarios experienced a significant rise, while the amount of imported power decreased. This implies that a greater portion of the locally generated renewable energy was used for hydrogen production, which not only enhances the sustainability of the system but also provides an additional revenue stream through the sale or use of hydrogen. The improved utilization of renewable power for local hydrogen production contributes to minimizing energy wastage and enhancing the overall efficiency of the hybrid power plant.

The promising outcomes of this study highlight the need for further research, particularly in the context of scaling up these findings to larger hybrid power plants. The current case study assumes that the hybrid power plant acts as a price-taker, meaning it does not influence market prices. However, for larger hybrid power plants—such as those on the gigawatt (GW) scale—this assumption is likely invalid, as such plants could potentially impact market dynamics due to their significant generation capacity. Therefore, understanding the market influence of larger hybrid plants and optimizing bidding strategies accordingly will be essential to ensure profitability.

Additionally, further exploration of available ancillary services and electricity markets is needed to determine how these opportunities could enhance the business case for hybrid power plants even further. Expanding the scope to include services such as voltage support, black start capabilities, and other grid-balancing services could provide additional income streams and enhance system reliability. By identifying and incorporating more value-adding services, the economic viability and attractiveness of hybrid power plants can be further strengthened, ultimately supporting the transition to a more resilient and sustainable energy system.

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6 Annexes

Multi-market strategy methodology [9]

A.1.1 Power balance and objective function

The wind power and solar power are optimized using setpoints in the form:

$$P_t^{wind} = S_t^{wind} \cdot P_t^{w,pred} \cdot P^{wind,rated}$$

The solar power has a similar formulation

$$P_t^{solar} = S_t^{solar} \cdot P_t^{solar,pred} \cdot P^{solar,rated}$$

The powerbalance is the following:

$$P_t^{\mathrm{wind}} + P_t^{\mathrm{pv}} + P_i^{\mathrm{bat}} + P_t^{\mathrm{h2}} + P_t^{\mathrm{imp}} = P_t^{\mathrm{exp}}$$

The objective function of the problem is the maximization of the profit.

$$\max_{\Theta} \sum_{t \in T} R_t - C_t$$

$$\mathrm{R}_t = P_t^{\mathrm{export}} \cdot T \cdot \lambda_t^{DA} + P_t^{\Delta+} + Q_t^{H2,\mathrm{export}} \cdot \lambda_t^{H2}$$

$$\mathrm{C}_t = P_t^{import} \cdot T \cdot \lambda_t^{DA} + C^{bat}$$

$$\Theta_t = \{S^{wind}, S^{solar}, S^{bat,in}, S^{bat,out}, S^{H2}\, P^{exp}, P^{imp}, optimizationvariablesbattery, \}$$

$$\mathbf{x} = \{Q_t^{H2,prod}, Q_t^{H2,out,total}, Q_t^{H2,out,direct}, P_t^{\mathrm{comp}}, p_t^{\mathrm{in}}, \hat{P}_{ts}^{\mathrm{e}}, s_t^{\mathrm{in}}, s_t, s_t^{\mathrm{out}}, z_t^{\mathrm{su}}, z_{ts}^{\mathrm{h}}, z_t^{\mathrm{on}}, z_t^{\mathrm{off}}, z_t^{\mathrm{sb}}\}.$$

A.1.2 aFRR Market

The total reserve from the storage and the electrolyzer is given by Equation 28 and Equation 29:

$$r^{\text{AFRR}\uparrow} = r_t^{\text{AFRR}\uparrow,H2} + r_t^{\text{AFRR}\uparrow,bat} \quad \forall t \in \mathcal{T} \tag{28}$$

$$r^{\text{AFRR}\downarrow} = r_t^{\text{AFRR}\downarrow,H2} + r_t^{\text{AFRR}\downarrow,bat} \quad \forall t \in \mathcal{T} \tag{29}$$

$$\text{where} \quad r^{\text{AFRR}\uparrow},\ r_t^{\text{AFRR}\uparrow,H2},\ r_t^{\text{AFRR}\uparrow,bat},\ r^{\text{AFRR}\downarrow},\ r_t^{\text{AFRR}\downarrow,H2},\ r_t^{\text{AFRR}\downarrow,bat} \geq 0 \quad \forall t \in \mathcal{T} \tag{30}$$

Where: $r_t^{\text{AFRR}\uparrow,H2}$ and $r_t^{\text{AFRR}\uparrow,bat}$ denote the upward AFRR provided by the hydrogen storage and the battery, respectively. $r_t^{\text{AFRR}\downarrow,H2}$ and $r_t^{\text{AFRR}\downarrow,bat}$ denote the downward AFRR provided by the hydrogen storage and the battery, respectively. Regarding the indexing, aFRR total capacity should be the same for every ISP in the 24 hours and thus is not indexed with t. However how the capacity is regulated in the HPP itself can be varied and thus are the capacity of the electrolyzer and battery indexed with t.

The total reserve values are defined as integer values:

$$r^{\text{AFRR}\uparrow}, r^{\text{AFRR}\downarrow} \in \mathbb{Z}$$

A.1.2.1 aFRR battery constraints

The first two constraints Equation 31 and Equation 32 are on how much room in the state of charge is left to either charge or discharge the battery, providing upregulating energy in the form of discharging and providing downregulating energy in the form of charing:

$$\text{SOC}_t^{\text{bat}} \cdot P^{\text{bat,cap}} - r_t^{\text{AFRR}\uparrow,bat} \cdot T \geq \text{SOC}^{\text{bat\_min}} \cdot P^{\text{bat,cap}} \tag{31}$$

$$\text{SOC}_t^{\text{bat}} \cdot P^{\text{bat,cap}} + r_t^{\text{AFRR}\downarrow,bat} \cdot T \leq \text{SOC}^{\text{bat\_max}} \cdot P^{\text{bat,cap}} \tag{32}$$

The amount of upregulating power be provide by reducing the planned output of the battery or by increasing the amount of energy inputted. If the planned setpoint of the battery was already inputting the energy the battery can only output so much more till it reaches the max discharge rate. Downregulating power in works the other way around, providing downward aFRR by either reducing the amount of discharging energy, or increasing the intake of energy. With the amount of being limited by the maximal charging rate.

$$-P_t^{\text{bat,in}} + P_t^{\text{bat,out}} + r_t^{\text{AFRR}\uparrow,bat} \leq P^{\text{bat,dis,max}} \cdot \eta^{\text{bat}} \tag{33}$$

$$P_t^{\text{bat,in}} - P_t^{\text{bat,out}} + r_t^{\text{AFRR}\downarrow,bat} \leq P^{\text{bat,ch,max}} \cdot \eta^{\text{bat}} \tag{34}$$

A.1.2.2 aFRR State-of-charge dynamics

The state of charge of the battery over time, considering the AFRR, is given by Equation 35:

$$SOC_t^{\text{bat}} = SOC_{t-1}^{\text{bat}} + \left(P_t^{\text{bat, in}} - P_t^{\text{bat, out}} - \beta_t^{\uparrow} r_t^{\text{AFRR}\uparrow\text{,bat}} + \beta_t^{\downarrow} r_t^{\text{AFRR}\downarrow\text{,bat}}\right) \cdot \Delta T \quad \forall t \in \mathcal{T} \tag{35}$$

This equation models the change in the state of charge of the battery, factoring in the energy input and output as well as the AFRR adjustments. Here we are introducing the activation parameters $\beta_t^{\downarrow}$ and $\beta_t^{\uparrow}$, which are in the interval [0,1].

A.1.2.3 aFRR Electrolyzer constraints

The following equations define the constraints for reserving AFRR from the electrolyzer: For simplification and better computability we drop the segmentation of the electrolyzer Now without segments Equation 10 becomes:

$$S_t^{\text{H2}} \cdot P^{H2_{\text{max}}} = P_t^{H2} = \hat{P}_t^{\text{e}} + P^{\text{sb}} z_t^{\text{sb}} \quad \forall t \in \mathcal{T} \tag{36}$$

With $\hat{P}_t^{\text{e}}$ being the power used to generate hydrogen.

The power constraint for the electrolyzer during upward AFRR is given by Equation 37 [5]:

$$P_t^{\text{H2}} - r_t^{\text{AFRR}\uparrow} \geq P^{H2\text{min}} z_t^{\text{on}} + P^{H2\text{,sb}} z_t^{\text{sb}} \quad \forall t \in \mathcal{T} \tag{37}$$

The power constraint for the electrolyzer during downward AFRR is given by Equation 38:

$$P_t^{\text{H2}} + r_t^{\text{AFRR}\downarrow} \leq P^{\text{H2,max}} z_t^{\text{on}} + P^{\text{sb}} z_t^{\text{sb}} \quad \forall t \in \mathcal{T} \tag{38}$$

Notice that for both aFRR up and down reserve, if the elecrolyzer is standby no afrr can be delivered. This is due to the fact of safety issues of operating an electrolyzer in the phase between standby and on [6]. Also when the electrolyzer is in off state both z^{on} and z^{sb} are zero, constraining both Equation 37 and Equation 38 to be zero.

The hydrogen production dynamics, taking AFRR into account, are modeled by Equation 39:

$$h_t^{\text{prod}} = A \cdot \left(\hat{P}_t^{e} - \beta_t^{\uparrow} \cdot r_t^{\text{AFRR}\uparrow} + \beta_t^{\downarrow} \cdot r_t^{\text{AFRR}\downarrow}\right) + B \quad \forall t \in \mathcal{T} \tag{39}$$

This equation describes how hydrogen production is influenced by the AFRR, where $e_t^{\text{H}_2}$ represents the base hydrogen power production and the AFRR terms adjust the production accordingly.

A.1.2.4 aFRR Monetary

The total income from the system on the day-ahead, including the AFRR reserve, is described by Equation 61:

$$\mathrm{R}_t^{aFRR,DA} = r^{\mathrm{AFRR}\uparrow}\lambda^{\mathrm{AFRR}\uparrow} + r^{\mathrm{AFRR}\downarrow}\lambda^{\mathrm{AFRR}\downarrow} \quad \forall t \in \mathcal{T} \tag{40}$$

Additional income on the day it self comes from the activation

$$R_t^{aFRR,ID} = \beta_t^{\uparrow} \cdot r_t^{\mathrm{AFRR}\uparrow} \cdot \lambda_t^{\mathrm{AFRR,act}\uparrow} + \beta_t^{\downarrow} \cdot r_t^{\mathrm{AFRR}\downarrow} \cdot \lambda_t^{\mathrm{AFRR,act}\downarrow} \tag{41}$$

A.1.2.5 aFRR Activation

The activation of aFRR is significantly influenced by the bidding strategy employed by the BSP. A well-defined strategy is crucial for determining the effective activation of aFRR, as it aligns the activation decisions with market conditions. Taking into account activation revenue in the first stage optimization can be done in order to find a balance between amount offered as DA energy and aFRR capacity.

A preliminary aFRR activation strategy can be expressed mathematically to guide the decision-making process:

$$\text{if } \lambda_t^{\mathrm{AFRR,act}\uparrow} > \lambda_t^{\mathrm{DA}}, \text{ then } \beta_{\mathrm{real}}^{\uparrow} = 1 \tag{42}$$

$$\text{if } \lambda_t^{\mathrm{AFRR,act}\downarrow} < \lambda_t^{\mathrm{DA}} \text{ and } \lambda_t^{\mathrm{AFRR,act}\downarrow} < 0 \text{ then } \beta^{\downarrow} = 1 \tag{43}$$

$$\text{Else } \beta_{\mathrm{real}}^{\uparrow} = 0 \text{ and } \beta^{\downarrow} = 0 \tag{44}$$

The activation strategy is based on leveraging day-ahead prices. Activation is only undertaken when prices are higher than the day-ahead prices, which results in less energy being reserved for later utilisation in activation in order to obtain activation revenue rather than day-ahead revenue. For activation down only negative prices are considered, as not to pay for the aFRR energy we are providing. With this strategy realistic amounts of activation can be derived by analyzing historic price data. It should be noted that this strategy is relatively simple and straightforward. For further optimality of aFRR profits, a more sophisticated strategy may be required, however finding this optimility is

A.1.3 Passive imbalance market

When considering the decisions on the day-ahead market and the imbalance decisions to be independent of each other we have to following power balance:

$$P_t^{\Delta} = P_t^{imp} - P_t^{exp} + P_t^{bat} + P_t^{H2} + P_t^{wind} + P_t^{solar} \quad \forall t \in \mathcal{T} \tag{45}$$

With P^{imp} and P^{export} being fixed parameters and an output of the DA offering.

Different prices are in place for the situations of having either surplus or insufficient energy. And thus the balance energy is split into its negative and positive part.

$$P_t^{\Delta} = P_t^{\Delta+} - P_t^{\Delta-} \quad \forall t \in \mathcal{T} \tag{46}$$

$$P_t^{\Delta+} \geq P_t^{\Delta} \quad \forall t \in \mathcal{T} \tag{47}$$

$$P_t^{\Delta-} \geq -P_t^{\Delta} \quad \forall t \in \mathcal{T} \tag{48}$$

$$P_t^{\Delta+} \leq M \cdot u_t^{imb} \quad \forall t \in \mathcal{T} \tag{49}$$

$$P_t^{\Delta-} \leq M \cdot (1 - u_t^{imb}) \quad \forall t \in \mathcal{T} \tag{50}$$

The optimized profit is than the following.

$$\max \sum_{t \in T} \mathrm{R}_t - C_t \tag{51}$$

$$\mathrm{R}_t^{ID} = P_t^{\text{export}} \cdot T \cdot \lambda_t^{DA} + P_t^{\Delta+} \cdot \lambda_t^{\Delta \text{ up}} - P_t^{\Delta-} \cdot \lambda_t^{\Delta \text{ down}} + Q_t^{H2,\text{export}} \cdot \lambda_t^{H2} \tag{52}$$

$$\mathrm{C}_t = P_t^{import} \cdot T \cdot \lambda_t^{DA} + \mathrm{C}^{\mathrm{H2}} + C^{bat} \quad \forall t \in \mathcal{T} \tag{53}$$

A.1.4 Market combination – aFRR and passive imbalance

When operating in the aFRR market and passive imbalance one should consider a few things. First of all you should always be able to deliver the capacity and the constraints from Equation 28 to Equation 39 still hold. However when aFRR is activated the balance provider is not allowed to increase imbalance in the other direction

$$P_t^{\Delta+} = 0 \quad \forall \beta_t^{\downarrow} \neq 0 \quad \forall t \in \mathcal{T} \tag{54}$$

and

$$P_t^{\Delta-} = 0 \quad \forall \beta_t^{\uparrow} \neq 0 \quad \forall t \in \mathcal{T} \tag{55}$$

The other way is combined maximization where the import and export are optimized at the same time where P_t^{export} and P_t^{import} are not fixed.

Optimizing again has not only the fixed energy import and export but also the predetermined aFRR capacity. As optimizing again different activation parameters of aFRR can be inputted. As could be used in the case of forecasted activation and actual activation. Different activation parameters might render the problem infeasible. E.g. when the battery might be discharged more than expected due to many full upward activated aFRR. The battery might not be able to deliver more upward activated aFRR. To measure this we introduce slack variables for the aFRR equations.

$$r^{\text{AFRR}\uparrow} = r_t^{\text{AFRR}\uparrow,H2} + r_t^{\text{AFRR}\uparrow,\text{bat}} - \text{slack}_t^{\text{AFRR}\uparrow,neg} + \text{slack}^{\text{AFRR}\uparrow,\text{pos}} \tag{56}$$

$$r^{\text{AFRR}\downarrow} = r_t^{\text{AFRR}\downarrow,H2} + r_t^{\text{AFRR}\downarrow,\text{bat}} - \text{slack}_t^{\text{AFRR}\downarrow,\text{neg}} + \text{slack}_t^{\text{AFRR}\downarrow,\text{pos}} \tag{57}$$

- $\text{slack}_t^{\text{AFRR}\uparrow,\text{neg}}$: Accounts for any shortfall in the upward aFRR capacity.
- $\text{slack}_t^{\text{AFRR}\uparrow,\text{pos}}$: Accounts for any excess in the upward aFRR capacity.
- $\text{slack}_t^{\text{AFRR}\downarrow,\text{neg}}$: Accounts for any shortfall in the downward aFRR capacity.
- $\text{slack}_t^{\text{AFRR}\downarrow,\text{pos}}$: Accounts for any excess in the downward aFRR capacity.

with

$$\text{slack}_t^{\text{AFRR}\uparrow,\text{neg}},\ \text{slack}_t^{\text{AFRR}\uparrow,\text{pos}},\ \text{slack}_t^{\text{AFRR}\downarrow,\text{neg}},\ \text{slack}_t^{\text{AFRR}\downarrow,\text{pos}} \geq 0 \quad \forall t \tag{58}$$

They are introduced in the objective with use of slack penalty $\mathcal{N}$

$$Obj_t = \text{Profit}_t - \left(\text{slack}_t^{\text{AFRR}\uparrow,\text{neg}} + \text{slack}_t^{\text{AFRR}\downarrow,\text{neg}} + \text{slack}_t^{\text{AFRR}\downarrow,\text{pos}} + \text{slack}_t^{\text{AFRR}\uparrow,\text{pos}}\right) \times \mathcal{N} \tag{59}$$

A.1.5 Market combination - monetary

The total income on D-1 when combining the day-ahead and afrr income is the following:

$$\text{R}_t^{DA} = P_t^{DA} \cdot T \cdot \lambda_t^{DA} + r^{\text{AFRR}\uparrow}\lambda^{\text{AFRR}\uparrow} + r^{\text{AFRR}\downarrow}\lambda^{\text{AFRR}\downarrow} \quad \forall t \in \mathcal{T} \tag{60}$$

The total extra income of the within-day revenue is:

$$\begin{aligned} \text{R}_t^{ID} = P_t^{\Delta +} \cdot \lambda_t^{\Delta\text{ up}} - P_t^{\Delta -} \cdot \lambda_t^{\Delta\text{ down}} + Q_t^{H2,\text{export}} \cdot \lambda_t^{H2} \\ + r^{\text{AFRR}\uparrow}\lambda^{\text{AFRR}\uparrow} + r^{\text{AFRR}\downarrow}\lambda^{\text{AFRR}\downarrow} \quad \forall t \in \mathcal{T} \end{aligned} \tag{61}$$

Here we assume that the income of the hydrogen is received on the day itself.