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Market-Based Optimization of a 140 MW Wind Turbine Farm Integrated with Pumped Hydro Storage Under Negative Day-Ahead Prices

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Abstract

The increasing penetration of renewable energy sources (RESs), such as solar and wind power, introduces significant operational and economic challenges due to their variability and the rising frequency of negative day-ahead electricity price hours in recent years. Negative price conditions lead to substantial revenue losses when wind turbines deliver power during hours of negative prices. This study combines mixed-integer linear programming (MILP) optimization of pumped hydro storage (PHS) operation with a revenue assessment of a 140 MW wind farm consisting of twenty Siemens Gamesa 7.0 MW wind turbines. Historical hourly day-ahead prices for 2024 and measured wind data are used to quantify PHS market revenue and the revenue and energy effects of a prescribed wind-curtailment rule. Three scenarios are analysed: PHS revenue alone, PHS revenue plus wind revenue without curtailment, and PHS revenue plus wind revenue with wind injection set to zero during negative-price hours. The results show that injecting wind power during negative-price hours reduces the wind farm's annual day-ahead market revenue. Price-based curtailment avoids these negative-revenue injections, while optimized PHS scheduling exploits temporal price differences through pumping and generation. These findings concern market-participant revenues under exogenously specified historical prices; they do not quantify effects on market-clearing prices, grid balancing, or system reliability.

Keywords: pumped hydro storage; wind turbine; day-ahead prices; optimization

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1. Introduction

The rapid expansion of wind power capacity in recent years has significantly increased the electricity production variability and uncertainty of electricity systems. Due to winds' fluctuating availability, wind and other renewable energy sources (RESs) frequently lower day-ahead market prices and contribute to price volatility, which includes prolonged periods of very low or negative market prices [1,2]. The merit-order effect, where wind displaces conventional baseload generators, amplifies these price fluctuations and reduces revenue predictability for market participants [3,4]. The consequences are especially visible during periods of low demand and high RES generation, which eventually lead to frequent occurrences of negative electricity prices, especially visible in countries with substantial wind or solar installed capacity [2,5].

Recent studies have increasingly addressed the optimization and market-oriented scheduling of wind-based energy systems under uncertain operating conditions. For example, Zhu et al. (2025) [6] proposed a day-ahead planning and scheduling framework for wind-storage systems based on multi-scenario generation and Conditional Value at Risk (CVaR), emphasizing the role of uncertainty-aware dispatch and risk control in improving economic performance. Li et al. (2025) [7] developed a multi-objective day-ahead optimization scheduling model for active distribution networks with distributed wind and photovoltaic integration, showing that economic and operational objectives can be coordinated under uncertain renewable output. In addition, Aghamohammadloo et al. (2026) [8] investigated multi-market revenue optimization for integrated wind and hybrid energy storage systems, highlighting the importance of coordinated market participation, revenue stacking, and flexibility in maximizing the economic value of wind generation under evolving electricity market conditions.

As RES penetration levels continue to rise, the mismatch between wind production and electricity demand is reaching problematic levels, which subsequently creates an even higher need for flexibility and controllability in power system operation. This challenge is also reflected in long-term energy system studies. Large-scale optimization analyses of the European energy transition indicate that wind and solar power will become the dominant sources of electricity generation [9].

Pumped hydro storage (PHS) is known to be one of the oldest, most mature, and efficient technologies for large-scale energy storage and has proven to be one of the best technologies for integrating variable renewable energy sources into future power systems. PHS has a very important role in integrating intermittent RES into the power grid and does so by absorbing excess electricity and releasing it during peak demand [10,11]. With its high, non-degradable round-trip efficiency (from 70% to 85%), PHS systems provide operational flexibility and economic viability under increasingly volatile market conditions [12–16].

Among grid-scale energy storage technologies, lithium-ion batteries are currently widely used because of their high energy density, fast response, and modular scalability, which makes them particularly suitable for short-duration balancing applications [17]. However, review studies also emphasize that their economic and material constraints become more pronounced when moving toward larger-scale and longer-duration storage applications [17,18]. In contrast, mechanical storage technologies, such as pumped hydro storage and compressed air energy storage, are considered especially relevant for bulk and long-duration energy shifting over time scales from several hours to multiple days [19–21]. Within this context, pumped hydro storage retains a particular advantage as the most established large-scale storage technology, combining high installed power, long lifetime, negligible self-discharge, and proven suitability for balancing variable renewable electricity generation in real power systems [14,16,20]. These characteristics make PHS especially relevant for the type of large-scale market-based wind integration problem considered in the present study, where multi-hour storage capability and high energy output are more important than very fast short-duration response.

From a market point of view, PHS absorbs low-value or negative-valued (surplus) energy through pumping, potentially generating revenue pumping during periods of negative prices, and generates electricity during high-price periods, thereby increasing revenue and enhancing system reliability and stability. When day-ahead prices are negative, electricity consumption when pumping water into the upper reservoir can itself produce a positive market cash flow. This payment for electricity consumption is separate from the revenue earned through subsequent generation. Pumping nevertheless remains an electricity-consuming process. Previous research on PHS scheduling has demonstrated that mixed-integer linear programming (MILP) works very well at modelling the binary

operating modes, operational constraints, and temporal coupling of reservoir dynamics that characterize PHS plants [22–24].

Previous studies have considered uncertainty-aware wind-storage scheduling [6], multi-market revenue optimization [8], and capacity planning of wind–PV–PHS systems [24]. These studies address different aspects of renewable generation and storage, including operating risk, market participation, and the selection of installed capacities.

The present study focuses on a retrospective Slovenian case study using 2024 day-ahead prices, measured wind data, and a commercial turbine power curve. It quantifies PHS arbitrage revenue and wind-farm revenue separately and assesses the gross revenue and energy effects of a prescribed negative-price curtailment rule. The direction of the curtailment effect follows directly from the revenue assumptions; its magnitude depends on the timing and magnitude of negative prices and their coincidence with available wind generation.

The case study evaluates PHS operation and the revenues of a 140 MW wind farm consisting of twenty Siemens Gamesa 7 MW wind turbines [25].

Choosing 140 MW as the power for the wind farm capacity follows the trajectory set by the National Energy and Climate Plan [26], which entails gradual wind power installation during the course of the following years, reaching a peak in 2030.

The wind component is modelled using a turbine-specific power curve and real hourly wind availability, while day-ahead prices are taken from 2024 market data. The proposed MILP scheduling model evaluates three scenarios:

1. Standalone PHS operation;
2. PHS + wind without curtailment;
3. PHS + wind with price-based curtailment, where wind production is halted during negative-price hours.

This comparison quantifies PHS arbitrage revenue, wind-farm revenue, and the gross revenue and energy effects of the prescribed curtailment rule. The wind operating rule does not alter the PHS optimization.

This enables an analysis of how price volatility, negative prices, and wind variability influence PHS operation, wind utilization, and annual revenue.

This study provides the following case-specific results:

1. A retrospective estimate of PHS day-ahead market revenue under the adopted technical and storage constraints, using Slovenian electricity prices for 2024.
2. Monthly and annual revenue estimates for a 140 MW wind farm, calculated using measured wind data, hub-height extrapolation, and a commercial turbine power curve.
3. A quantitative comparison of wind revenue and generated energy with and without prescribed negative-price curtailment, establishing the magnitude and monthly distribution of the gross revenue benefit.

This study was conducted independently. Publicly available sources were used for the PHS project information and electricity prices, while wind-speed measurements were supplied by a private company. It was not prepared in cooperation with the investor or project developer of the PHS Kozjak project [27], and it does not include any confidential technical, financial, commercial, or strategic information related to the project. All assumptions, calculations, interpretations, and conclusions presented in this paper are, therefore, solely those of the authors.

2. Materials and Methods

The case study focuses on Slovenia. In 2009, Slovenia committed to achieving a 25% share of renewable energy sources (RESs) in final energy consumption by 2020, in line with the EU Directive 2009/28/EC on the promotion of renewable energy use. This target

will not be met by 2025. According to the updated National Energy and Climate Plan [26], Slovenia has set highly ambitious goals of increasing the overall RES share in gross final energy consumption to 33% by 2030, with sectoral targets of 55% for electricity generation, 45% for heating and cooling, and 26% for transport. Furthermore, the country aims to expand installed wind power capacity from the current 3 MW to 150 MW by 2030. As the share of electricity generation from intermittent and variable renewable sources grows, the plan also includes the construction of the Kozjak pumped-storage hydropower plant, with a nominal turbine capacity of 2 × 219.8 MW, 2 × 213 MW pump capacity and an effective storage capacity of 5644 MWh, which will be analysed in the following sections.

The case study evaluates PHS operation and the revenues of a 140 MW wind farm under the same historical 2024 day-ahead prices [28]. The MILP determines the PHS schedule, while wind injection is prescribed by the selected operating rule and its revenue is added to the optimized PHS revenue. The day-ahead prices used in the analysis are historical hourly market-clearing prices for the year 2024, directly obtained from BSP Southpool [28]. Therefore, no price forecasting model is used in this study, and the analysis is performed as a retrospective evaluation under realized market conditions. Hourly day-ahead prices are shown in Figure 1.

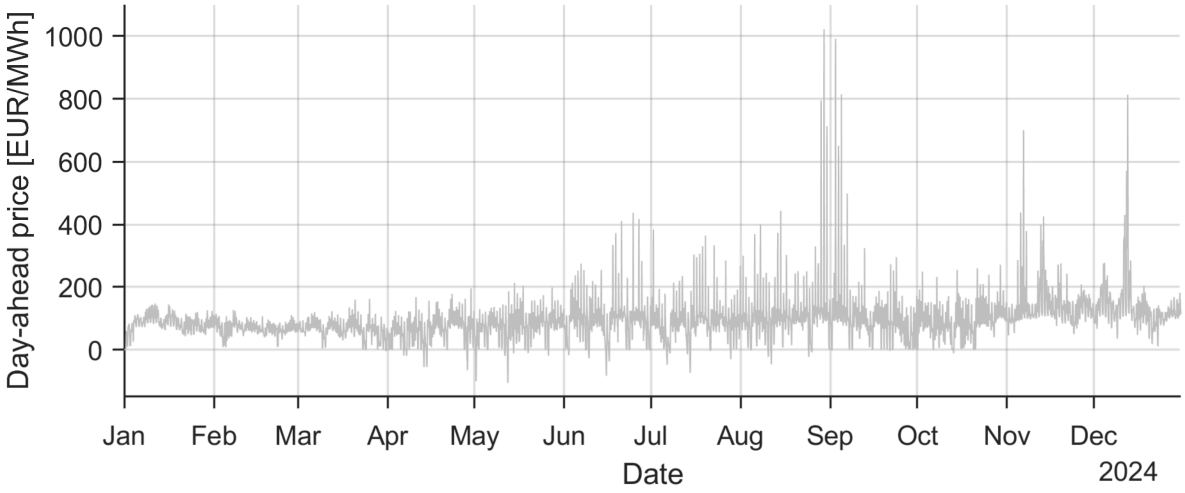

Figure 1. Hourly day-ahead prices in Slovenia for the year 2024.

Wind speed measurements for 2024 were aggregated to hourly resolution and extrapolated from the measured height of 8 m to the hub height of $H_{\text{hub}} = 170$ m using the following standard power-law relation:

$$v_{\text{hub}}(t) = v_{\text{ref}}(t)\left(\frac{H_{\text{hub}}}{H_{\text{ref}}}\right)^{\alpha}, \tag{1}$$

where α is the wind shear exponent, and for the purpose of this study, its value was set to $\alpha = 0.13$. The available wind power was computed by applying the Siemens Gamesa 7 MW power curve interpolated in MATLAB® 2024b, yielding the hourly available wind energy $P_{\text{avail}}(t)$. Wind generation is subject to the standard definition of a multi-MW turbine:

$$0 \leq P_{\text{w}}(t) \leq 7\,\text{MW} \tag{2}$$

Extrapolation from 8 m to 170 m using a fixed shear exponent introduces uncertainty into the estimated hub-height wind speed. Kelly et al. (2019) [29] develop and test methods for evaluating uncertainty associated with shear-based vertical extrapolation. No site-specific uncertainty interval is assigned to the estimates in the present study. Wind-generation and revenue results therefore remain conditional on the adopted vertical wind profile.

2.1. Pumped Hydro Storage Model with Mathematical Formulation

The PHS model follows the MILP methodology optimization study of PHS Kozjak [10,20,30]. In pumped hydro storage systems, electrical energy is stored as the gravitational potential energy of water. In this study, the storage state variable $V(t)$ represents energy-equivalent storage (MWh) rather than geometric water volume (m^3), assuming constant hydraulic head and steady operating conditions. Under this assumption, hydraulic parameters are lumped into fixed efficiencies, enabling a linear energy-based reservoir balance suitable for market-oriented MILP scheduling. At the current planning stage of the PHS Kozjak project, detailed unit-specific data such as head-dependent efficiency curves, start-up cost coefficients, and partial-load operating characteristics are not publicly available. Therefore, the PHS plant is represented using aggregated technical parameters and constant efficiency assumptions.

$$V(t+1) = V(t) + \eta_{\text{pump}} P_{\text{pump}}(t)\Delta t - \frac{P_{\text{turb}}(t)}{\eta_{\text{turb}}}\Delta t. \tag{3}$$

Typical technical characteristics of PHS are shown in Table 1.

Table 1. Typical technical characteristics of pumped hydro storage (PHS) systems [14–16].

Parameter	Typical Value or Range
Power	10–4000 MW
Discharge duration at rated power	1–24+ h
Round-trip efficiency	70–85%
Self-discharge	Generally negligible
Response time	minutes
Power capital cost	1700–3800 EUR/kW
Energy capital cost	4–90 EUR/kWh
Lifetime	40–60+ years
Suitable storage duration	Hours–days

Reservoir operational limits are enforced for all time steps:

$$V_{\min} \le V(t) \le V_{\max}. \tag{4}$$

Turbine and pump powers must remain within nominal bounds and be consistent with binary operating modes:

$$0 \le P_{\text{turb}}(t) \le u_{\text{turb}}(t) P_{\text{turb}}^{\max} \tag{5}$$

$$0 \le P_{\text{pump}}(t) \le u_{\text{pump}}(t) P_{\text{pump}}^{\max} \tag{6}$$

Mutual exclusivity of turbine and pump operation is ensured through

$$u_{\text{turb}}(t) + u_{\text{pump}}(t) \le 1. \tag{7}$$

In addition, the model supports daily start-up limits, represented by

$$u_{\text{turb}}(t) - u_{\text{turb}}(t-1) \le s_{\text{turb}}(t), \tag{8}$$

In addition, we have

$$\sum\nolimits_t s_{\text{turb}}(t) \le N_{\text{start}}^{\max}, \tag{9}$$

with a corresponding limit for pumping mode, limiting excessive cycling.

2.2. Wind Turbine Integration and Curtailment Logic

Wind injection is bounded by the available wind power, with its value prescribed by the selected operating rule:

$$0 \leq P_{\mathrm{w}}(t) \leq P_{\mathrm{avail}}(t). \tag{10}$$

The revenue assessment considers the following two prescribed wind operating rules:

1. No-Curtailment Regime:

$$P_{\mathrm{w}}(t) = P_{\mathrm{avail}}(t), \tag{11}$$

Wind is always injected, even if price$(t) < 0$.

2. Price-Based Curtailment Regime:

$$P_{\mathrm{w}}(t) = \begin{cases} 0, & \mathrm{price}(t) < 0, \\ P_{\mathrm{avail}}(t), & \mathrm{price}(t) \geq 0, \end{cases} \tag{12}$$

The gross revenue benefit of this rule is calculated directly from the wind revenues avoided during negative-price hours. This calculation is independent of the PHS MILP.

2.3. MILP Optimisation Model

The operational planning of the hybrid PHS–wind system is formulated as a mixed-integer linear programming problem, where the objective is to determine the hourly schedule that maximizes the annual market revenue of PHS under real 2024 price conditions. For each analysed operating scenario, the MILP model is formulated over the hourly time horizon of the year 2024. The optimization variables include pumped hydro storage turbine power, pump power, reservoir state, binary operating variables for turbine and pump modes, and the corresponding startup indicators. A schematic overview of the MILP framework is shown in Figure 2.

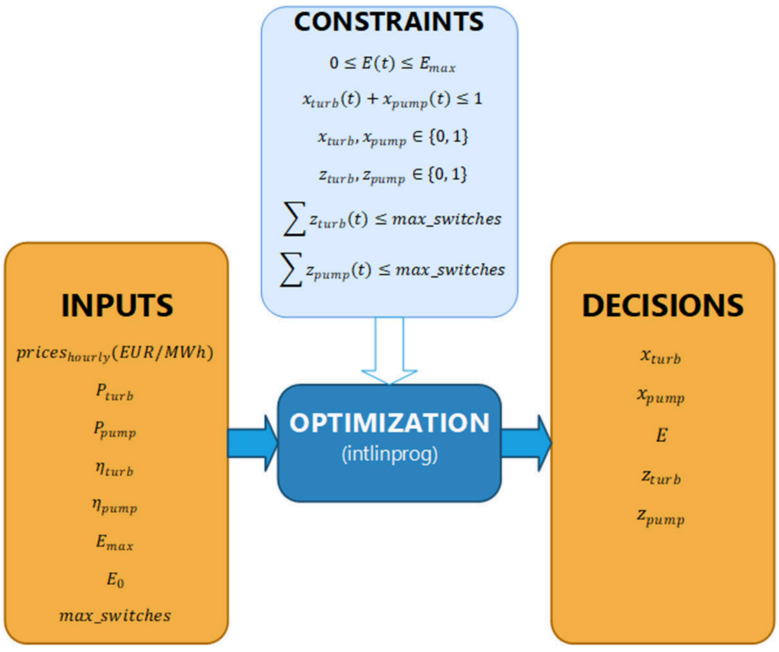

Figure 2. Schematic overview of the MILP framework, showing the main input parameters, operational constraints, optimization block, and decision variables.

Wind power injection is treated in a scenario-dependent manner according to the selected wind operating regime. The objective function maximizes the market-based revenue

of the hybrid system, subject to storage balance, reservoir limits, turbine and pump operating bounds, mutual exclusivity, startup limitations, and scenario-specific wind operating rules. Accordingly, the optimization problem can be written in compact form as follows:

$$\max \sum_{t=1}^{8760} \text{price}(t)(P_{\text{turb}}(t) - P_{\text{pump}}(t) + P_{\text{w}}^{(s)}(t))\Delta t. \quad (13)$$

where the three terms represent turbine generation, pumping consumption, and predetermined wind power generation in scenario (s). The objective function is evaluated under the selected operating scenario, while the corresponding feasible solution space is defined by Equations (3)–(12).

The objective combines PHS revenue with wind-farm revenue under the selected operating rule. Wind injection is prescribed by Equation (11) or Equation (12), so its revenue contribution is constant with respect to the PHS decision variables. The MILP determines the PHS schedule, while wind revenue is calculated from the prescribed injection and the same hourly electricity prices. Under identical PHS parameters and constraints, the same PHS optimization applies in all three scenarios. Comparing scenarios 2 and 3 therefore isolates the revenue effect of the prescribed wind-curtailment rule.

The optimization problem is solved using MATLAB's *intlinprog*, which applies a branch-and-bound strategy supported by cutting planes, heuristics, and presolve reductions to reduce problem complexity [31–34]. The implementation procedure consists of the following steps: preprocessing of hourly market prices and wind-speed data; calculation of scenario-dependent wind power; formulation of the MILP objective function and constraints; solution using MATLAB's *intlinprog*; and post-processing of the resulting hourly schedules, energy balances, and revenues.

3. Results

The results are presented for three operating modes of the system:

1. Pumped hydro storage (PHS) operating alone;
2. A hybrid configuration with PHS and a 140 MW wind turbine farm without curtailment;
3. A hybrid configuration with price-based curtailment of the wind turbine during negative day-ahead prices.

The results are analysed for the month of May 2024. Figure 3 represents day-ahead prices for the month of May. Using those prices, we calculated hourly income for the PHS operation with optimized pump and turbine regimes, wind farm revenue, and wind farm revenue when enabling curtailment logic.

As can be seen from modest price fluctuations for the month of May in Figure 3, we obtained 42 h of negative prices, which represents 5.6% of the month's hours; therefore, during negative price hours, revenue was generated by pumping water to the higher reservoir. Negative price hours in May can be seen in Table 2.

Table 2. Day-ahead electricity price statistics for May 2024.

Month	Positive Price Hours [h]	Negative Price Hours [h]	Positive Peak [EUR/MWh]	Negative Peak [EUR/MWh]
May	702	42	212.52	−105.88

Figure 4 shows the daily production of a wind farm calculated based on wind measurements.

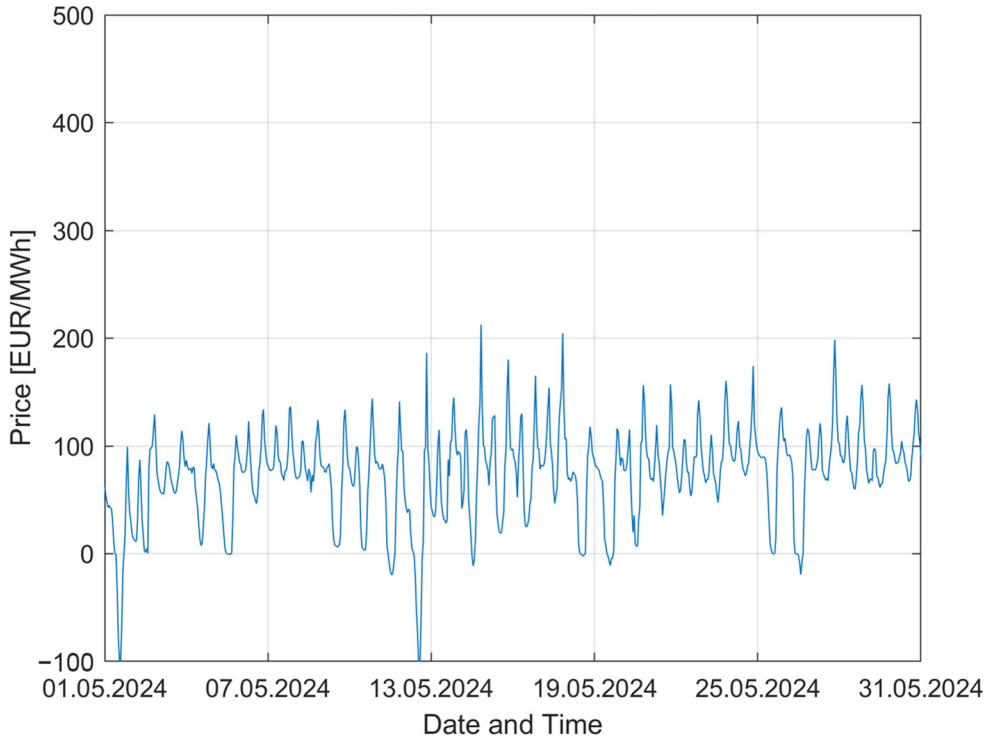

Figure 3. Hourly day-ahead electricity prices, May 2024.

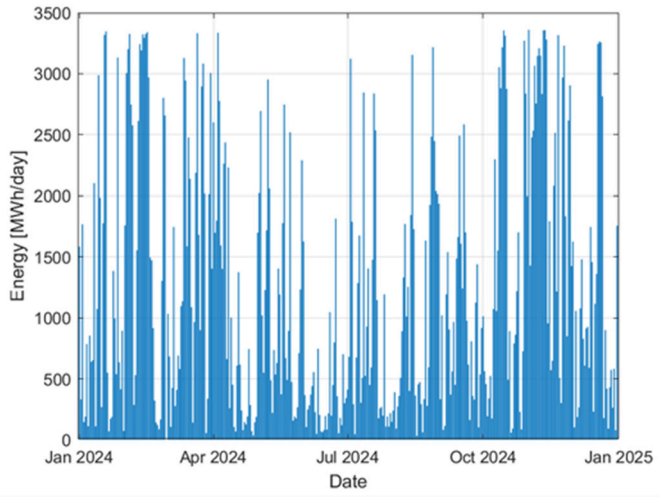

Figure 4. Calculated daily wind farm energy generation based on the extrapolated measurements for 2024 and the selected power curve.

The baseline operation of the PHS plant, obtained from the MILP optimization without wind, shows a typical arbitrage pattern. The plant primarily carries out pumping operations during low-price night hours and generation operations during higher daytime prices, thereby smoothing price variability over the year. Daily revenue values remain positive for almost all days of the optimization horizon, and almost no negative-revenue days are observed in the PHS-only case. This confirms that the underlying PHS model behaves as expected and provides a robust reference against which the hybrid scenarios can be evaluated.

Next, we calculated the hourly cash flow of the wind turbine over the year 2024, obtained by combining the calculated wind farm output, which uses the wind turbine

power curve [25] and location-extrapolated wind data (Figure 4) with the rebased 2024 day-ahead prices (Figure 1).

Figure 5 represents hourly wind turbine production in MWh and day-ahead prices for the month of May. It can be seen that production and day-ahead price spikes are rarely aligned, meaning that wind turbines do not produce energy when needed, but just the opposite, it produces energy when the demand is low or even when the price of energy is negative. This is evidently visible in Figure 5, where the power output is close to zero during high day-ahead electricity price periods and only rises during negative price hours.

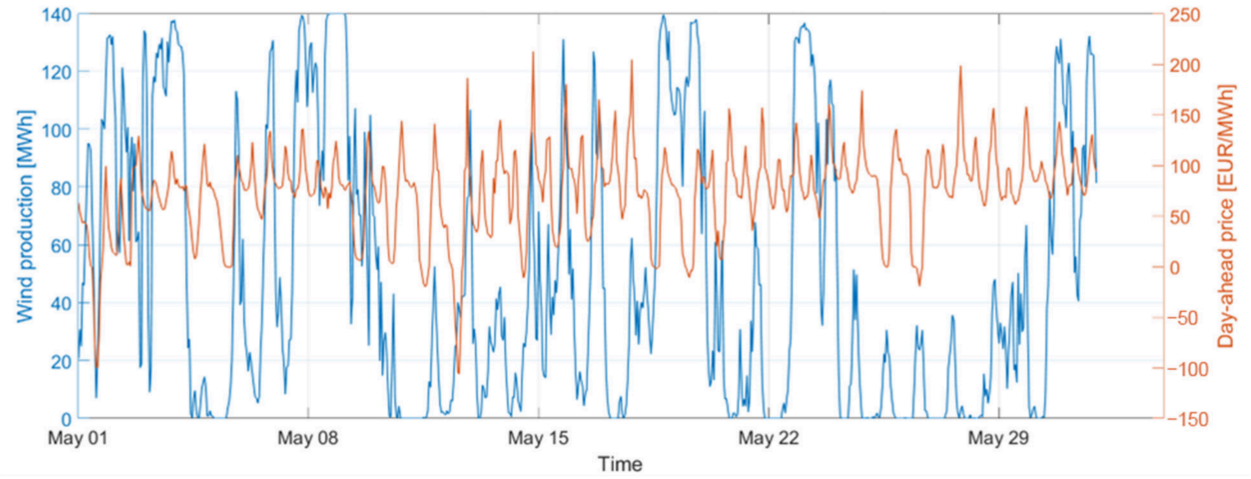

Figure 5. Hourly wind farm generation (blue, left axis) and day-ahead prices (orange, right axis) for May 2024.

Figure 6 provides a closer view of hourly wind farm generation and day-ahead prices on 26 May 2024.

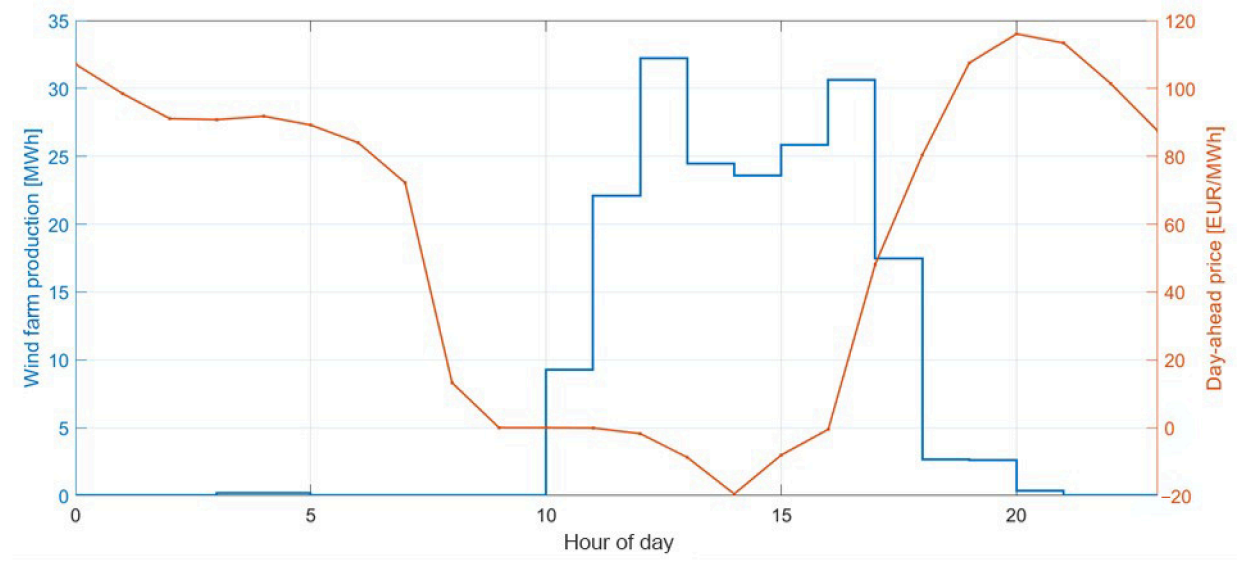

Figure 6. Hourly wind farm generation (blue, left axis) and day-ahead electricity prices (orange, right axis) on 26 May 2024.

Therefore, in the last step, we added curtailment logic to the wind farm. When the day-ahead prices were negative, we shut down the wind turbines in order not to incur losses at those specific hours. In Figure 7, this extra income, due to enabled curtailment, is shown

as extra revenue (with the orange colour bar). This is the revenue that would otherwise be a loss. It was calculated using

$$\text{Extra income (curt)} = \\ = \sum_{t=1}^{t=t_{\text{month}}} (P_{\text{w}}^{\text{curt}} \cdot \text{price}(t) - P_{\text{w}}^{\text{no curt}} \cdot \text{price}(t)) \quad (14)$$

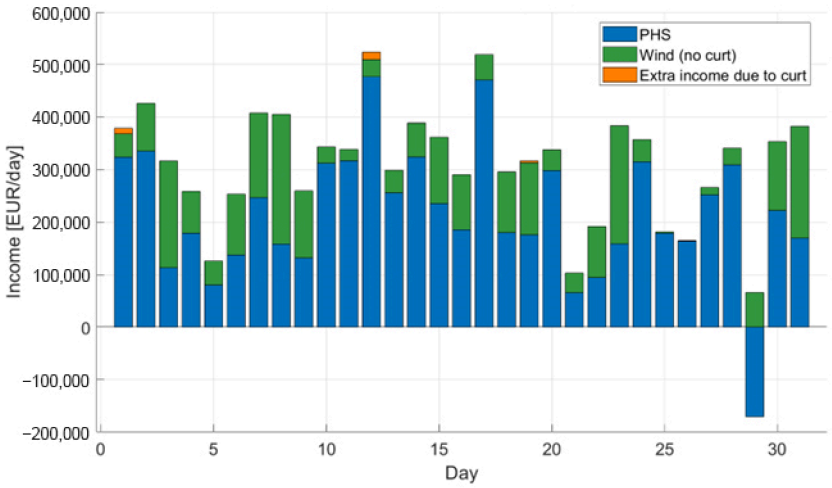

Figure 7. Daily market revenue in May 2024: PHS revenue (blue), wind farm revenue without curtailment (green), and additional wind revenue from negative-price curtailment (orange).

Table 3 shows detailed results of PHS optimization, PHS + wind without curtailment, PHS + wind farm with curtailment, and loss due to not using curtailment logic for May 2024. Monetary values are rounded to the nearest euro. Consequently, the difference between the two displayed rounded revenue values may not exactly equal the separately rounded revenue difference.

Figure 8 shows monthly revenues, while Table 4 reports monthly and annual energy and revenue totals.

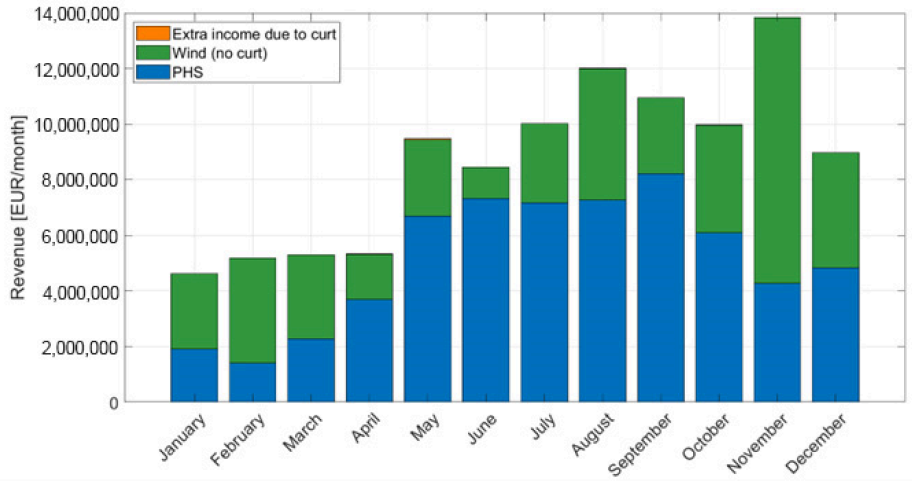

Figure 8. Monthly market revenue in 2024: PHS revenue (blue), wind farm revenue without curtailment (green), and additional wind revenue from negative-price curtailment (orange).

Table 3. Daily PHS and wind farm energy and market revenue in May 2024, with and without wind curtailment.

Day	PHS [EUR]	PHS Produced [MWh]	PHS Consumed [MWh]	Wind Farm (No Curtailment) [EUR]	Wind Farm (No Curtailment) [MWh Produced]	Wind Farm (Curtailment) [EUR]	Wind Farm (Curtailment) [MWh Produced]	Loss Due to No Curtailment [EUR]
1	323,743	1978	5858	44,502	1699	55,095	1413	10,594
2	335,132	4352	5325	91,183	2022	91,183	2022	0
3	112,930	3165	3195	203,525	2694	203,525	2694	0
4	178,772	3165	4260	79,895	1020	79,895	1020	0
5	80,059	1583	5858	45,704	550	45,710	530	7
6	137,332	2769	3195	115,880	1228	115,880	1228	0
7	246,576	2374	533	161,200	1719	161,200	1719	0
8	158,027	2374	1598	247,370	2953	247,370	2953	0
9	131,700	1583	4260	127,877	2059	127,877	2059	0
10	312,196	3561	3728	30,987	488	30,987	488	0
11	316,796	2769	4260	21,730	221	21,778	205	48
12	476,768	2769	6390	32,834	736	47,017	512	14,183
13	255,605	3956	4793	43,120	536	43,120	536	0
14	323,984	3956	5858	64,592	630	65,066	564	474
15	235,243	3165	4793	126,434	1404	126,434	1404	0
16	185,223	2769	4260	105,019	1192	105,019	1192	0
17	470,575	4352	2130	48,414	373	48,414	373	0
18	179,943	2374	4793	115,570	1777	115,899	1511	329
19	175,601	1978	5325	137,454	2748	141,011	2123	3557
20	298,127	3561	4260	39,697	670	39,697	670	0
21	65,332	2374	3728	37,662	491	37,662	491	0
22	94,312	2374	3195	97,333	894	97,333	894	0
23	158,527	3165	3728	225,079	2519	225,079	2519	0
24	314,762	2769	533	42,362	475	42,362	475	0
25	178,663	1978	4260	2774	157	2774	157	0
26	163,476	1583	5325	463	192	1415	33	952
27	251,891	3165	2663	14,131	176	14,131	176	0
28	309,096	3561	2130	31,815	266	31,815	266	0
29	−170,761	1978	6390	65,770	710	65,770	710	0
30	222,040	2769	1598	131,444	1234	131,444	1234	0
31	169,390	2769	2130	213,032	2290	213,032	2290	0
SUM	6,691,060	87,041	120,345	2,744,849	36,125	2,774,993	34,462	30,144

From Table 4, it is evident that the PHS produces the most energy in the months of May, July, September, and October. The results show that year-round operation of the PHS is economically reasonable. The highest revenues occur in the summer months, as electricity price fluctuations are greatest during that time. The operation of the PHS complements the operation of wind farms well, since wind generation is higher when PHS generation is lower and vice versa. Using curtailment logic further increases the revenue from wind farms, especially in the spring and summer months.

Table 4. Monthly and annual PHS and wind farm energy and market revenue in 2024, with and without wind curtailment.

Month	PHS Energy Produced [MWh]	PHS Energy Consumed [MWh]	PHS Revenue [EUR]	Wind Farm Energy Produced [MWh]	Revenue Wind [EUR]	Wind Farm Energy Produced—Curt On [MWh]	Extra Revenue Wind Farm—Curt On [EUR]
January	62,115	85,733	1,913,352	33,083	2,718,151	33,083	0
February	59,346	82,538	1,404,409	55,774	3,790,979	55,774	0
March	62,115	85,733	2,282,662	45,567	3,026,517	45,460	215
April	62,115	85,733	3,697,237	29,533	1,625,514	28,206	11,595
May	87,041	120,345	6,691,060	36,125	2,744,849	34,462	30,144
June	62,115	85,733	7,316,727	12,286	1,123,635	11,628	9426
July	87,041	120,345	7,159,506	28,399	2,847,736	27,464	9997
August	62,115	85,733	7,270,864	33,897	4,724,772	33,265	11,062
September	87,041	120,345	8,218,920	29,624	2,731,908	29,474	87
October	87,041	120,345	6,095,524	43,188	3,869,058	41,755	3414
November	62,115	85,733	4,282,178	67,687	9,559,290	67,687	0
December	62,115	85,733	4,844,534	33,426	4,118,755	33,426	0
SUM	842,318	1,164,045	61,176,976	448,588	42,881,164	441,685	75,942

4. Discussion

Lorenzo Dambrosio et al. conducted a comprehensive multi-objective sensitivity analysis of a wind turbine equipped with a pumped hydro storage system using a reversible hydraulic machine, commonly referred to as a Pump as Turbine (PAT). Their research introduced an innovative wind system configuration that eliminates or significantly reduces the need for battery storage by enabling bidirectional operation of a single hydraulic machine. By reversing the impeller's rotation, the PAT operates either in pumping or generating mode, allowing flexible energy storage and recovery. The primary objective of their study was to assess the robustness of different PAT configurations under stochastic variations in wind speed and AC generator power, identifying solutions that maintain stable performance under uncertain operating conditions [12].

While the study by Dambrosio et al. focused on component-level sensitivity and hydraulic-machine-based storage concepts, the present work extends the scope of analysis to a system-level, market-oriented framework. In contrast to idealized or probabilistic wind scenarios, this study employs real hourly wind measurements from a selected location in Slovenia and applies a turbine-specific power curve corresponding to wind turbines planned for installation under national development strategies. Furthermore, technical characteristics of a large-scale pumped-storage hydropower plant scheduled for construction by 2030 according to the National Energy and Climate Plan are incorporated. This enables an assessment that reflects realistic operational constraints, storage capacities, and market participation conditions.

In line with findings reported by Kulpa et al. [35], which emphasize that pumped hydro storage cannot be evaluated solely through energy price arbitrage, the results of this study confirm the strategic importance of storage flexibility in systems with a growing share of intermittent renewable energy sources. The optimization results demonstrate that pumped hydro storage significantly benefits from negative electricity price periods by converting excess low-value electricity into stored potential energy. At the same time, uncontrolled wind power injection during negative-price hours leads to direct revenue losses, reinforcing observations from earlier market studies on the merit-order effect and price volatility induced by wind generation [1,4].

The case study quantifies PHS arbitrage revenue and wind-farm revenue under the same historical price series. The gross annual benefit of wind curtailment is 75,942 EUR, approximately 0.18% of wind revenue without curtailment, while wind generation decreases by 6903 MWh, approximately 1.54%. These results establish the modest magnitude of the benefit for the investigated price and wind series. The wind-curtailment calculation does not change PHS scheduling, which is optimized independently of wind injection.

The modest curtailment benefit obtained for 2024 should not be interpreted as a fixed expectation for future market conditions. If variable renewable generation expands without sufficient investment in energy storage and other sources of flexibility, negative-price events could become more frequent, longer, or more pronounced. Under such conditions, the gross revenue benefit of avoiding negative-price wind injections could increase substantially. Its magnitude would nevertheless depend on the coincidence of negative prices with available wind generation and on the costs and operational restrictions associated with curtailment. These future effects are not quantified in the present study.

Beyond its market value, the role of pumped hydro storage should also be considered from the perspective of public resilience and the continuity of vital services. In practical energy-system planning, part of the available storage capacity or operational flexibility may need to be reserved for critical infrastructure such as hospitals, emergency telecommunications, data centers, civil protection systems, and public safety services. The present study does not explicitly model reserved capacity or priority supply constraints for such services, as its main objective is to assess market-based operation under real day-ahead price conditions. Nevertheless, the obtained results indicate that large-scale pumped hydro storage can provide an important flexibility buffer that is relevant not only for economic optimization but also for broader security of supply and public interest planning.

5. Conclusions

The results represent three working regimes: optimized PHS operation using the MILP optimization algorithm, optimized PHS results with wind farm production not using curtailment, and optimized PHS results with wind farm production using curtailment.

Day-ahead prices for May are moderately fluctuating, spanning from positive 220 EUR/MWh to negative 100 EUR/MWh. This positively affects total PHS revenue, since it enables many opportunities to sell electricity at periods of high prices and profit from negative price hours; this is because PHS generates revenue when using electricity to pump water into higher reservoirs. The total PHS monthly revenue for May was 6,691,060 EUR, with 87,041 MWh of produced energy and 120,345 MWh of consumed energy.

Added to the PHS monthly revenue is wind farm revenue without using curtailment logic. The wind farm used available wind power to generate electricity based on the Siemens-Gamesa 7.0 MW turbine power curve [25]. Wind speed was extrapolated from the measured height of 8 m to a hub height of 170 m using standard power law relations. The installed wind farm power is 140 MW, in correspondence with the National Energy and Climate Plan [26]. For the historical 2024 price series and wind profile considered, price-based curtailment increases annual wind-farm revenue by approximately 76,000 EUR, corresponding to about 0.18% of the revenue without curtailment. Annual wind-energy generation decreases from 448,588 to 441,685 MWh, a reduction of approximately 1.54%. The relatively small revenue increase is an outcome of the analysis and indicates that the economic value of curtailment was modest under the conditions examined.

This increase represents a gross day-ahead market benefit under idealized assumptions. Shutdown and restart costs, transition times, and minimum shutdown durations are not included; therefore, the results do not establish the net profitability of implementing the

strategy under practical operating conditions. Total wind farm revenue in May without using curtailment logic was 2,744,849 EUR while producing 36,125 MWh.

In contrast to PHS, the wind farm incurred losses when operating during negative day-ahead price periods. The logic is to implement curtailment during those hours. There were 42 negative price hours in May 2024, which cumulatively increased the revenue of PHS + wind farm using curtailment by 30,144 EUR. The total revenue was 2,774,993 while producing 34,462 MWh.

Cumulative energy production for 2024 was 842,318 MWh, and using MILP optimization, we managed to gain 61,176,976 EUR in revenue. Without using curtailment logic, the wind farm produced 448,588 MWh, yielding revenue of 42,881,164 EUR, while using curtailment produced less energy at 441,685 MWh but increased revenue to 42,957,105 EUR.

The results demonstrate the economic value of price-responsive operation for the investigated PHS–wind portfolio under historical 2024 day-ahead market conditions. PHS scheduling exploits temporal price differences, while wind curtailment during negative-price hours avoids negative day-ahead revenues from wind generation. These findings are conditional on the assumed technical parameters and exogenous price series.

The analysis does not establish effects on the frequency or magnitude of negative electricity prices, grid balancing, network stability, or security of supply. Evaluating these effects would require additional modelling of market-price formation, system-wide generation and demand, network constraints, and the relevant operational or reliability criteria.

The results show that wind farm revenue using curtailment logic aligns with day-ahead electricity market conditions. During periods of stable or positive prices, curtailment is not required, whereas under increasing price volatility, especially in summer months, negative-price hours occur more frequently and make curtailment economically beneficial.

In the context of market-based operation, the coordinated behaviour of the wind–PHS system follows system needs reflected through electricity prices. When electricity generation exceeds demand and prices become low or negative, pumped hydro storage consumes electricity for pumping, thereby reducing surplus energy in the system. Conversely, when electricity becomes scarce and prices increase, the system generates electricity, supplying energy back to the grid.

While the present study does not include a detailed power system model, such price-driven operation represents system-supportive behaviour that contributes to balancing supply and demand at the market level. Future research should extend the model by incorporating power system constraints and dynamic stability analysis in order to quantify these effects more explicitly. Particular emphasis will be placed on hourly-resolution modelling of electricity generation, storage, and demand in order to assess the combined impact of new renewable capacities and storage facilities on system autonomy, market behaviour, and grid stability. Such analyses will enable a more comprehensive evaluation of long-term energy transition pathways and support strategic planning of future investments in flexible generation and storage technologies. We should also examine the role of pumped hydro storage in ensuring the continuity of vital services and critical infrastructure, including the possible reservation of part of the available storage capacity or flexibility for emergency supply and security of supply purposes.

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Abbreviations

The following abbreviations are used in this manuscript:

AC	Alternating current
MILP	Mixed-integer linear programming
MW	Megawatt
MWh	Megawatt hour
PHS	Pumped hydro storage
PV	Photovoltaic
RES	Renewable energy sources
PAT	Pump as turbine

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