Techno-Economic Analysis of Hydrogen Storage Systems in Electricity Markets

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***Abstract*—Current day-ahead and time-of-use markets fail to fully capture hydrogen storage's economic potential for long-term storage. To better understand the economics of hydrogen storage, this paper presents a comprehensive techno-economic analysis of hydrogen storage in different energy markets using a perfect-foresight arbitrage model. Key influencing factors, including cost reduction and efficiency improvement, are identified to promote the deployment of hydrogen storage in power systems. In addition, a seasonal market is simulated and compared with day-ahead and time-of-use markets for different hydrogen storage technologies. The seasonal market exhibits a price gap two orders of magnitude larger than existing markets. Our findings reveal that current market prices hinder the development of hydrogen storage and that introducing seasonal prices is essential to unlock the potential of long-term energy storage in future low-emission energy systems.**

***Index Terms*—Hydrogen storage energy systems, Power markets, Seasonal energy storage**

I. INTRODUCTION

The penetration of intermittent renewable energy is increasing in the power grid inspired by the low-emission transition. More energy storage resources are required to balance volatile energy generation. Though battery energy storage systems (BESS) are now widely deployed, they are suited for short-term balancing with a typical duration of 2 to 4 hours [1]. Hydrogen has been widely considered a promising solution for long-term energy storage [2], [3], mainly due to its high energy density and low energy costs. When zero-emission renewable energy is powered to electrolysis, the process produces so-called green hydrogen with no emissions [4], [5]. Hydrogen could be stored for days, weeks or even months, making it suitable to offer seasonal energy transfer and balance long-term fluctuations in renewable energy generation [6].

However, the economic viability of hydrogen energy storage systems (HESS) remains lower than that of BESS, primarily due to the substantial capital and operational expenditures associated with electrolyzers (ELE), hydrogen storage (HS), and fuel cells (FC), as well as the considerable energy requirements. Komorowska [7] quantitatively evaluated and compared the economic feasibility of hydrogen storage systems and lithium battery storage systems in the day-ahead electricity market. The study reported net present values (NPV) of -4.85 million euros for hydrogen storage and 0.23 million euros for lithium batteries. The significant disparity is mainly attributed to the higher round-trip efficiency of lithium batteries. Hunter et al. [8] conducted a techno-economic comparison of various power technologies using the levelized cost of energy (LCOE) metric. Their analysis found that for a storage duration of 12 hours, the LCOE for hydrogen-based storage was nearly double that for battery storage.

To compensate for the low economic viability of hydrogen, value streams from hydrogen and auxiliary markets are also considered. Wu [9] investigated a hybrid energy storage system capable of participating in energy and hydrogen markets. Results showed such hybrid systems can take advantage of multiple opportunities by trading electricity and hydrogen to enhance overall profitability. Zheng [10] analyzed the techno-economic performance of hydrogen storage as a flexible resource in power systems, with a focus on frequency regulation and reserve markets in Denmark. The study incorporated multiple value streams from the day-ahead and auxiliary markets for hydrogen storage, finding that the reserve market alone contributed more than 50% of total revenues and the energy market alone is not profitable.

The economics of HESS in energy markets are the most crucial indicators for future commercialization. Despite the importance, little research has compared the economic viability of HESS within day-ahead and time-of-use markets. Furthermore, existing studies rarely offer a comparative analysis between different types of hydrogen storage technologies. Although policies and legislation support the integration of HESS in the power grid, low economic viability becomes the greatest obstacle. Therefore, identifying the economic feasibility of HESS is necessary. In this study, we performed a comprehensive economic evaluation of HESS in the energy markets. The contributions of this research are two-fold as follows:

1) We established an energy system dispatch model and constructed scenarios to simulate seasonal hydrogen storage operations to induce seasonal prices that aligns with the operational characteristics of long-term energy storage and transfer.
2) We performed a comprehensive evaluation and comparison of economic viability for different HESS in

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different markets using perfect-foresight prices to guide the future development of hydrogen technology and the enhancement of market designs.

The remainder of this research is organized as follows. Section II introduces the perfect-foresight arbitrage model in this study. Section III describes the technical parameters of various hydrogen storage technologies and compares the conventional electricity price markets with the proposed seasonal price profile. Section IV provides an economic analysis of different hydrogen storage systems in three different electricity markets. Finally, Section V summarizes the key findings and discusses the implications for the future integration of hydrogen storage in power systems.

II. Arbitrage Model

As illustrated in Fig. 1, ELE consumes electricity when prices are low, whereas FC draws hydrogen and convert it back into electricity when prices are high. Three distinct market prices are collected or simulated to explore HESS's profitability, namely day-ahead, time-of-use, and induced seasonal markets. Given annual hourly electricity prices with perfect foresight, the model determines the optimal configurations and operations of HESS to maximize profits. While this assumption is common in techno-economic studies, it represents an upper bound on achievable arbitrage profits. In practice, forecast errors or limited foresight would likely reduce realized profits due to suboptimal charging and discharging decisions, particularly in volatile day-ahead markets. A more explicit treatment of price uncertainty using rolling-horizon or stochastic optimization would be a valuable extension, but is beyond the scope of this study.

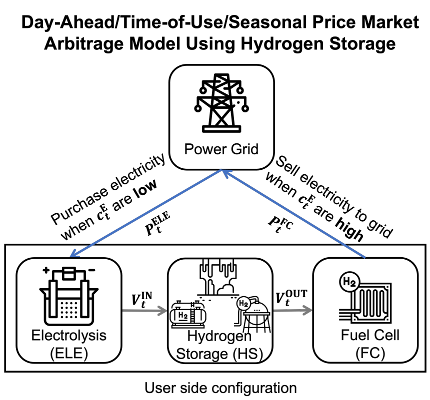

Fig. 1. Schematic of hydrogen storage economic analysis under day-ahead, time-of-use and seasonal markets using perfect-foresight arbitrage model.

A. Objective

For HESS, the objective consists of revenues from electricity sales and system costs, as expressed in (1). System costs include investment expenses of ELE, HS, and FC, as well as electricity bills. For simplicity, this study does not consider revenues or costs associated with the oxygen byproduct. Revenues are calculated as the product of the electricity price and the power output of fuel cells P_t^{FC} in (2).

$$obj = R - \mathrm{C}^{\mathrm{inv}} - \mathrm{C}^{\mathrm{om}} - \mathrm{C}^{\mathrm{op}} \tag{1}$$

$$R = \sum_{t=1}^{8760} P_t^{\mathrm{FC}} c_t^{\mathrm{E}} \Delta t \tag{2}$$

$$C^{\mathrm{inv}} = \gamma^{\mathrm{ELE}} c^{\mathrm{ELE}} P_{\mathrm{max}}^{\mathrm{ELE}} + \gamma^{\mathrm{FC}} c^{\mathrm{FC}} P_{\mathrm{max}}^{\mathrm{FC}} + \gamma^{\mathrm{V}} c^{\mathrm{V}} V_{\mathrm{max}}^{\mathrm{HS}} \tag{3}$$

$$\gamma^{(\cdot)} = \frac{w(1+w)^{\mathrm{T}^{(\cdot)}}}{(1+w)^{\mathrm{T}^{(\cdot)}} - 1} \tag{4}$$

$$C^{\mathrm{om}} = \theta^{\mathrm{ELE}} c^{\mathrm{ELE}} P_{\mathrm{max}}^{\mathrm{ELE}} + \theta^{\mathrm{FC}} c^{\mathrm{FC}} P_{\mathrm{max}}^{\mathrm{FC}} + \theta^{\mathrm{V}} c^{\mathrm{V}} V_{\mathrm{max}}^{\mathrm{HS}} \tag{5}$$

The investment costs for HESS are calculated as sum of annualized costs of ELE, HS, and FC. The annualized factor is presented in (4), where $\mathrm{T}^{(\cdot)}$ is the lifetime and w is the weighted average cost of capital (WACC). Operating and maintenance costs are calculated as a percentage of investment costs, specified by $\theta^{(\cdot)}$, as in (5).

$$C^{\mathrm{op}} = \sum_{t=1}^{8760} P_t^{\mathrm{ELE}} c_t^{\mathrm{E}} \Delta t + c^{\mathrm{W}} \sum_{t=1}^{8760} V_t^{\mathrm{ELE}} \Delta t \tag{6}$$

Primary feedstock of HESS is the electricity and water for ELE in hydrogen production. Water consumption rate is assumed to be 10 tons of fresh water per tonne of hydrogen produced with a water price of \$4.32 per ton, consistent with the value reported in [11]. Operating costs are calculated as in (6).

B. Constraints

The power inputs and outputs of ELE and FC are measured in kW and should be within a specific limit in each time interval, as in (7) and (8), respectively. ELE typically has a minimum operating level of 5-25% [12], [13].

$$\underline{\mathrm{R}}^{\mathrm{ELE}} P_{\mathrm{max}}^{\mathrm{ELE}} \leq P_t^{\mathrm{ELE}} \leq \overline{\mathrm{R}}^{\mathrm{ELE}} P_{\mathrm{max}}^{\mathrm{ELE}} \quad \forall t \in \mathbb{T} \tag{7}$$

$$\underline{\mathrm{R}}^{\mathrm{FC}} P_{\mathrm{min}}^{\mathrm{FC}} \leq P_t^{\mathrm{FC}} \leq \overline{\mathrm{R}}^{\mathrm{FC}} P_{\mathrm{max}}^{\mathrm{FC}} \quad \forall t \in \mathbb{T} \tag{8}$$

where $\underline{\mathrm{R}}^{(\cdot)}$ and $\overline{\mathrm{R}}^{(\cdot)}$ are the minimum and maximum operating levels with respect to the nominal capacity.

The storage level balance is influenced by the inflow and outflow of hydrogen measured in kg. Charging and discharging of hydrogen brings losses due to leakage in valves denoted with ϵ^{Dis} and ϵ^{Cha} and usually liquid hydrogen has a boil-off loss $\epsilon^{\mathrm{Boil\text{-}off}}$.

$$V_t^{\mathrm{HS}} - V_{t-1}^{\mathrm{HS}} = V_t^{\mathrm{ELE}} * \epsilon^{\mathrm{Dis}} - \frac{V_t^{\mathrm{FC}}}{\epsilon^{\mathrm{Cha}}} - \epsilon^{\mathrm{Boil\text{-}off}} * V_{t-1}^{\mathrm{HS}} \quad \forall t \in \mathbb{T} \tag{9}$$

$$V_t^{\mathrm{ELE}} = \frac{\eta^{\mathrm{ELE}} P_t^{\mathrm{ELE}}}{\mathrm{LHV}} \Delta t \quad \forall t \in \mathbb{T} \tag{10}$$

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$$V_t^{\mathrm{FC}} = \frac{P_t^{\mathrm{FC}}}{\eta^{\mathrm{FC}}\mathrm{LHV}}\Delta t \quad \forall t \in \mathbb{T} \tag{11}$$

(10) describes the conversion relationship between inflow of HS and inputs power of ELE, where η^{ELE} is the efficiency of ELE and LHV is the low heat value of hydrogen, taken as 33.3 kWh/kg (120 MJ/kg). Similarly, the relationship between outflow of HS and power outputs of FC is related by FC efficiency η^{FC} and LHV, as in (11).

The hydrogen storage level should not exceed the bounds decided by the volume capacity.

$$\underline{\mathrm{R}}^V V_{\mathrm{max}}^{\mathrm{HS}} \leq V_t^{\mathrm{HS}} \leq \overline{\mathrm{R}}^V V_{\mathrm{max}}^{\mathrm{HS}} \quad \forall t \in \mathbb{T} \tag{12}$$

where $\underline{\mathrm{R}}^V$ and $\overline{\mathrm{R}}^V$ are the minimum and maximum storage percentages with respect to the nominal allowable storage volume. The underground carvern needs 30% of the volume for cusion gas to maintain the reservoir pressure as hydrogen is withdrawn [14].

III. Market Prices

Existing electricity markets are not specifically designed to support hydrogen storage for long-term energy storage and transfer. Consequently, dedicated electricity price data for HESS are scarce, as these systems are rarely deployed in current energy infrastructures. Therefore, current markets could not reveal the economic viability of HESS in future energy systems. To address this gap, we adopted an energy system disptach model to induce seasonal prices.

By varying the carbon intensity of power generation from 1 kg/kWh to 0.1 g/kWh, penetrations of renewable energy are increasing dramatically and seasonal energy transfer could be observed when intensity is set to 0.1 kg CO_2/kWh as in Fig. 2. Excess renewable energy accumulates as hydrogen via ELE from spring to midsummer, when wind and solar resources are abundant, and is subsequently discharged from June to September. This process effectively shifts energy in hydrogen across seasons. We interpret the resulting shadow prices in this scenario as seasonal prices. The maximum price gap reaches about $27000/MWh, providing a sufficient price gap for hydrogen storage arbitrage.

A. Market prices

The day-ahead and time-of-use prices are collected from historical data in 2024. Specifically, day-ahead electricity prices are obtained from the California Independent System Operator (CAISO), with a supplementary monthly subsidy of $7.32/kW to compensate for power generation capacity. Meanwhile, time-of-use prices follows the two-part electricity tariff in Jiangsu, China, which not only reflects differentiated energy charges in peak and off-peak periods, but also includes an additional monthly demand charge of 44.8 RMB per kilowatt, equivalent to approximately $6.22/kW. Four levels are classified in time-of-use tariff into low, flat, high, and peak prices according to different time periods. The flat prices are set at 0.61 RMB/kWh ($84/MWh), and high electricity prices

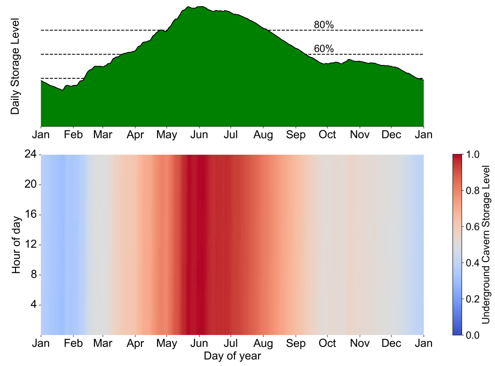

Fig. 2. Underground cavern shows seasonal energy transfer under carbon emission intensity constraint of 0.1 kg CO_2/kWh for electricity generation. Hydrogen was cumulated during spring and summer and then released in fall.

under the two-part tariff are 71.96% higher than the flat prices, while the low prices are 58.15% lower than the flat prices. The peak prices are set 20% higher than the high prices in summer and winter.

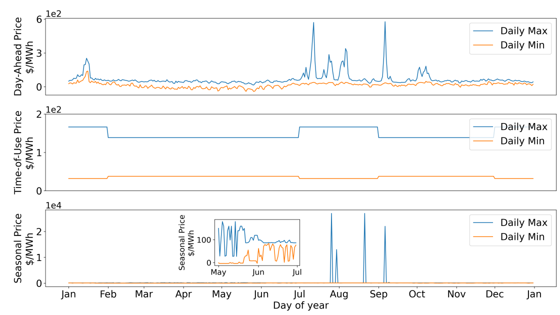

Fig. 3. Comparison between the day-ahead, time-of-use, and seasonal markets. Daily minimum and maximum prices for each market are plotted to show the price gaps.

Seasonal prices were induced from the dispatch model when long-term energy storage and transfer occurs. The comparison between the day-ahead, time-of-use and seasonal prices is presented in Fig. 3, with the daily minimum and maximum prices plotted for each market. The day-ahead market exhibits fluctuating daily price gaps, ranging from $12/MWh to $541/MWh. In contrast, the time-of-use market shows more stable price gaps, from $101/MWh to $134/MWh, due to fixed differences between peak and off-peak prices. The seasonal market shows a phenomenal price gap of $26916/MWh from August to September, which is two orders of magnitude greater than those observed in the day-ahead and time-of-use markets. The daily price gaps in other months are $73/MWh on average, which is close to those in the day-ahead and time-of-use markets.

B. Parameters

The economic and technical parameters of HESS are collected from Chinese manufacturers and summarized in Table I. Typical alkaline ELE is selected based on its commercial maturity and widespread use, characterized by an efficiency of

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TABLE I
PARAMETERS OF DIFFERENT HYDROGEN STORAGE SYSTEMS

Parameters	Electrolyzer	Fuel cell	Underground cavern	Aboveground tank	Liquid hydrogen tank
Investment costs	\$193/kW	\$448.4/kW	\$18/kg \$1500/(kg/hr) [11]	\$500/kg \$1500/(kg/hr) [11]	\$25/kg \$105000/(kg/hr) [11]
O&M costs	1.5%	3%	2%	2%	2%
Lifetime	10years	15years	30years	20years	20years
WACC	7%	7%	7%	7%	7%
Minimum	10%	0%	30% [14]	0%	0%
Maximum	100%	100%	100%	100%	100%
Efficiency	64%	50%	-	-	-
Loss	-	-	0.5%/discharge or charge	0.5%/discharge or charge	0.7%/day

64% and a capital expenditure (CAPEX) of \$193/kW. Whereas FC is assumed to have an efficiency of 50% and a CAPEX of \$448.4/kW, reflecting current technological and market conditions. The costs of HS are measured in mass of flowrate of hydrogen due to diverse storage phases. Each charge and discharge cycle of underground cavern and aboveground tank brings losses of nearly 1% due to leakage. While liquid hydrogen tank may avoid cyclic losses, boiloff rate is estimated to be 1% per day.

IV. RESULTS

The economic feasibility of three HS types is examined in the current day-ahead and time-of-use markets. Seasonal prices are induced from the simulation model and then compared with existing markets in terms of profitability.

A. Day-ahead market

Fig. 4 illustrates the impact of round-trip efficiency improvements and cost reductions on the profitability of HESS based on underground cavern. For example, an efficiency improvement of 20% means that the efficiency of the electrolyzer and fuel cell increases for 20% and a cost reduction of 20% means that the investment costs of the electrolyzer and fuel cell are reduced to 80% of the current level. Profitability is defined as the ratio of net profits to total system costs and net profits are shown with annotations.

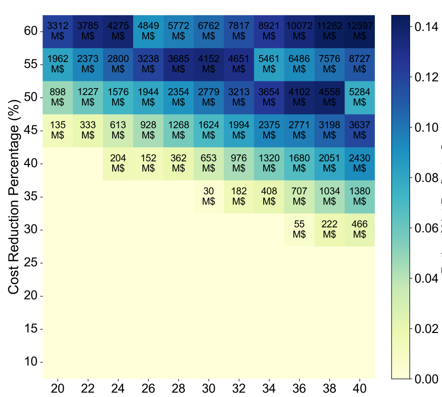

Fig. 4. Ratio of net profits to costs for underground cavern storage system in day-ahead market

In the heatmap, darker-colored blocks correspond to higher profitability ratios with greater profit potential; however, although HESS operators can still earn revenues through arbitrage in the lighter-colored areas, such operations are generally not deemed financially viable of recovering the expenditures within the project lifetime. The net profit ratio exhibits a pronounced sensitivity to technological improvements in efficiency, yet an interesting and somewhat counterintuitive pattern emerges when capital costs are reduced by more than 40%, as the corresponding profitability ratio no longer demonstrates a consistently increasing trend, despite the fact that absolute net profits continue to rise. However, the marginal revenue gained from capacity expansions does not always grow at the same rate as the investment, leading to a diminishing return in terms of profitability ratio. Therefore, while improvements in efficiency and costs clearly contribute to greater absolute profitability, they do not necessarily result in proportional increases in profitability ratios under optimized system configurations. When ELE and FC costs are reduced to 60% of current values and their efficiency increases by 40% (achieving a round-trip efficiency of approximately 63%), underground cavern and aboveground hydrogen tanks can achieve profit ratios of 14% and 6% in the day-ahead market, respectively.

B. Time-of-use market

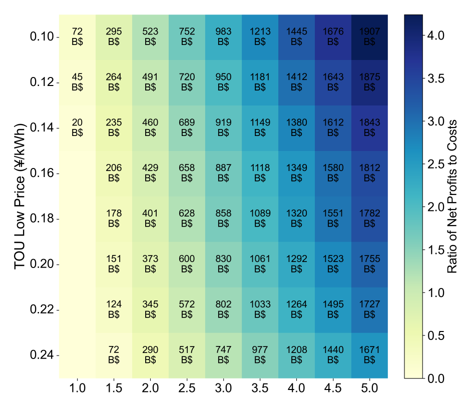

Fig. 5. Ratio of net profits to costs for gas hydrogen storage in Jiangsu's time-of-use market

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As illustrated in Fig. 5, the profitability of aboveground hydrogen in time-of-use market is predominantly governed by the magnitude of the price differential between high-price and low-price, such that when this gap widens to approximately 0.9 RMB/kWh, whether through a combination such as a high tariff of 1.0 RMB/kWh paired with a low tariff of 0.10 RMB/kWh, or alternatively a high tariff of 1.5 RMB/kWh coupled with a low tariff falling below 0.24 RMB/kWh, situations become favorable for arbitrage opportunities, allowing operators to strategically exploit the predictable intra-day price fluctuations to make profits. As high price goes up or low price goes down, the net profits increase.

C. Comparison

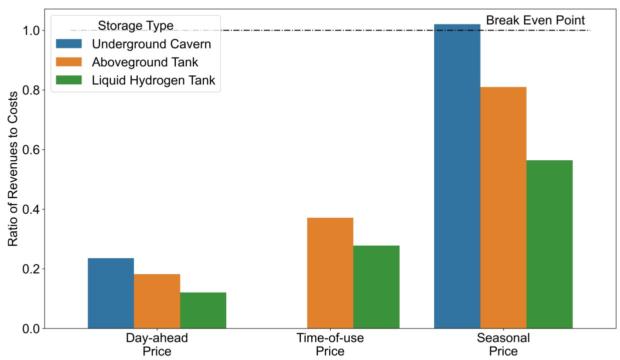

Fig. 6. Comparison of economic viability between three different price schemes for considered hydrogen storage types

Using seasonal electricity prices induced from the dispatch model, a comprehensive comparison is conducted across different types of storage technologies operating within various markets, in which the capacities of ELE, HS and FC are fixed to ensure consistency in the evaluation. As shown in Fig. 6, results reveal that under current cost and efficiency conditions, neither the day-ahead market nor the time-of-use market demonstrates profitability. Using the seasonal prices, a substantial increase in economic viability is observed, as the revenue-to-cost ratio for underground cavern increases markedly from 0.24 in day-ahead market to 1.02, indicating a strong potential for profitability. Similarly, aboveground tanks and liquid hydrogen tanks exhibit significantly improved financial performance under the seasonal price regime, with revenue-to-cost ratios reaching 0.81 and 0.56, respectively, suggesting that three storage technologies may become attractive in future energy systems that adopt market mechanisms designed to reward long-duration and seasonal energy storage capabilities.

V. Conclusions

In this study, we conducted a comparative analysis of day-ahead, time-of-use and seasonal price markets. Results demonstrate that the seasonal price market is particularly effective in encouraging hydrogen technologies deployment, especially in the context of long-term energy storage applications where traditional market signals fall short. The findings indicate that gaseous hydrogen storage, particularly in aboveground tanks, tends to be more economically advantageous in scenarios that demand frequent charge-discharge cycles because of its faster operational flexibility and moderate capital intensity. In contrast, underground cavern storage and liquid hydrogen tanks prove to be more profitable in markets characterized by significant seasonal or long-duration price variations, with the former benefiting primarily from exceptionally low energy storage costs afforded by natural geological formations, and the latter achieving favorable outcomes due to its low loss rate over extended storage durations, despite its higher upfront investment requirements.

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