Energy Strategy Reviews 55 (2024) 101545

Contents lists available at ScienceDirect

Energy Strategy Reviews

journal homepage: www.elsevier.com/locate/esr

Evaluating the feasibility and economics of hydrogen storage in large-scale renewable deployment for decarbonization

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ARTICLE INFO

Keywords:
Net-zero transition
Decarbonized power system
Hydrogen energy storage
Renewable energy
Levelized cost of energy

ABSTRACT

Renewable energy (RE) is pivotal for achieving a net-zero future, with energy storage systems essential for maximizing its utility. This study introduces a modeling framework that simulates large-scale RE deployment in Taiwan, emphasizing hydrogen as a primary storage medium. Utilizing hourly time steps, the model assesses various energy generation and storage configurations to demonstrate the technical feasibility of meeting Taiwan's 2050 net-zero target, which calls for a 60 % RE share primarily through solar and wind resources. However, achieving this target and the ambitious goal of 100 % RE penetration requires substantial enhancements in both generation capacity and storage solutions. The research evaluates the economic impacts by analyzing the levelized cost of energy (LCOE), revealing that optimal configurations, such as a wind capacity of 30 GW with a 5 % minimum capacity factor constraint on electrolyzers, significantly reduce LCOE to $0.176/kWh, underscoring the cost-effectiveness of hydrogen storage compared to battery alternatives in large-scale settings. The study underscores the necessity for ongoing investigations into replacing thermal power plants and maintaining grid stability amidst high RE penetration. To fully harness Taiwan's RE potential and contribute to global sustainability, effective deployment of hydrogen storage will require robust stakeholder support, continual technological advancements, and enabling policies. This framework, while tailored to Taiwan's power system, offers insights applicable to various global contexts.

1. Introduction

Taiwan, recognized as highly vulnerable to climate change due to its geographical location and economic structure, has been actively implementing carbon reduction measures since 2005 [1–4]. In line with global climate change mitigation efforts, Taiwan enacted the "Greenhouse Gas Reduction and Management Act (GHG Act)" in 2015, which has now evolved into the "Climate Change Response Act," with a net-zero emission target by 2050 [3]. Remarkably, Taiwan has achieved a 24 % reduction in greenhouse gas (GHG) emissions, decreasing from 269 million tons of carbon dioxide equivalent ($CO2_e$) in 2005 to 205 million tons of CO2e in 2020, despite robust economic growth. Energy efficiency enhancement has emerged as a pivotal strategy in Taiwan's carbon reduction efforts [5]. Notably, the transportation sector has witnessed the promotion of green transportation, including the development of public transportation, vehicle energy efficiency standards, and electrification [6]. The industrial sector has also implemented various measures, such as appliance and equipment efficiency management, energy audits, achieving a 1 % energy reduction target, and industrial energy-saving incentives [7]. Moreover, Taiwan has made significant strides in reducing its reliance on coal in the power sector. Shifting from coal to natural gas has led to a substantial decline in power generation's carbon intensity. Coal's contribution to Taiwan's power generation decreased from 53 % in 2005 to 34 % in 2022 [4]. The transition to natural gas has played a pivotal role in reducing carbon emissions and promoting sustainable energy practices.

In addition to transitioning away from coal and towards natural gas, Taiwan's ongoing net-zero transition will be characterized by a rapid increase in renewable energy (RE), particularly solar and wind power. RE offers several advantages over fossil fuels, as it is derived from unlimited sources, produces minimal harmful emissions, and plays a crucial role in climate change mitigation [8,9]. Furthermore, RE contributes to enhanced resilience and energy security by diversifying the electricity generation portfolio, a vital aspect for Taiwan, where 98 % of energy consumption relies on imports. However, a major obstacle to RE adoption is the capital costs involved in installing solar and wind farms.

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https://doi.org/10.1016/j.esr.2024.101545
Received 29 December 2023; Received in revised form 16 September 2024; Accepted 20 September 2024
Available online 24 September 2024
2211-467X/

Although operating costs are minimal due to free fuel, significant expenses arise from technology construction. Nonetheless, RE capital costs have witnessed a remarkable decline since the early 2000s, with solar photovoltaic (PV) costs dropping by 83 % from 2009 to 2017 [10]. These cost reductions have stimulated RE penetration over the past decade, and further reductions are anticipated in the future [11,12]. Moreover, considering the levelized cost of energy (LCOE) over the lifespan, wind and solar technologies are poised to be economically competitive with fossil fuels in various conditions [13–17].

The increasing global shift towards clean energy sources, driven by ambitious climate change goals and declining technology costs, has notably increased the share of solar and wind in the world's power mix to 10.3 % in 2021 [18]. As nations strive for decarbonization, achieving a high or even 100 % renewable energy (RE) electricity supply is emerging as a long-term goal, generating significant research interest [19–30]. Studies like those by Mark Z. Jacobson et al. have shown that a substantial portion of global energy demands could potentially be met or even surpassed by 2050 through solar, wind, and hydroelectric power [30]. However, the reliability of renewable energy is closely tied to environmental conditions—for instance, solar panels produce electricity only during daylight hours and their output varies with cloud cover and atmospheric conditions [31]. Similarly, wind turbines require specific wind speeds to operate efficiently, which can fluctuate due to changing weather patterns [32,33]. As RE penetration increases, the power grid's stability is significantly impacted by its intermittency [34]. System inertia, a critical indicator of power system stability, is traditionally provided by the rotational kinetic energy of turbines, which corresponds to the grid's frequency. This kinetic energy acts as a buffer during frequency shifts, thereby stabilizing the system. However, most RE sources, such as solar and wind, lack inherent energy storage capabilities that contribute to system inertia, presenting unique challenges during power fluctuations [35]. To address these issues, integrating energy storage systems (ESS) is crucial not only to provide necessary system inertia but also to allocate additional backup power during grid faults, thereby ensuring grid stability [36]. These systems allow for the storage of excess energy for later use, enhancing the utilization of renewable resources and preventing wastage.

Subsequent studies provide a deeper understanding of ESS's role in energy system stabilization. S. Ould Amrouche et al. overviewed electrochemical, hydrogen, and mechanical storage and their role in stabilizing energy systems [37]. Djamila Rekioua expanded on the theoretical and practical advantages and disadvantages of various ESS technologies, including electrochemical, mechanical, and supercapacitor storage [38]. Currently, lithium-ion batteries (LIBs) dominate the market, but their performance is affected by factors such as charging and discharging frequency, discharge depth, and operating temperature [39–41]. To overcome these limitations, alternative materials like selenium-based batteries, sodium-ion batteries, and KOH catalyst materials have been developed [42]. However, high material costs for battery energy storage systems (BESS) for large-scale grid applications pose significant challenges [43]. Hydrogen, with its high gravimetric energy density, emerges as a viable energy storage solution for the grid. Studies by Hassan et al. have compared different hydrogen storage system (HSS) technologies and highlighted the advantages of hybrid systems combining HSS and BESS, leading to improved efficiency and reduced storage costs [44,45]. Colbertaldo et al. examined the reliance on hydrogen as a primary storage solution in California's power system with 100 % RE, underscoring the need for substantial increases in generation and storage installations for a successful clean transition [20].

The primary barrier preventing the widespread adoption of renewable energy technologies, including energy storage devices, is their high capital cost [43–45]. In power systems with a low share of RE, the cost of ESS is relatively insignificant. However, as the share of RE increases, the economic costs of ESS become more prominent and cannot be overlooked. To quantitatively assess the economics of different ESS based on upfront and operating costs, the levelized cost of storage (LCOS) is employed, similar to the concept of levelized cost of energy (LCOE) [45]. Several studies have evaluated LCOS under 100 % RE scenarios [21–28], focusing on various energy storage solutions like pumped hydro storage, thermal energy storage, and synthetic natural gas. These studies examined the economic feasibility of ESS under different power system conditions, including isolated or interconnected regions, and analyzed how the average total costs of energy systems change with the implementation of these storage solutions. Despite the existing research on LCOS and its impact on energy systems with high RE proportions, there remains a lack of comprehensive investigation into the influence of HSS on the costs associated with electricity generation, particularly when considering the required storage capacity for power systems heavily reliant on RE sources. Further research in this area is necessary to gain a deeper understanding of the economic implications of adopting HSS in a high-RE context.

Hydrogen has emerged as a promising solution to tackle the intermittent nature of renewable energy sources [46]. While above-ground hydrogen storage options like pipelines or compressed tanks encounter challenges in accommodating large-scale energy storage, underground hydrogen storage offers a range of viable alternatives. Lee et al.'s research has shed light on the potential of utilizing aquifers, depleted gas and oil fields, and salt caverns as natural underground gas storage sites [47]. Underground storage offers several advantages, including enhanced safety due to reduced vulnerability to fire, terrorist attacks, or military actions. Moreover, the spatial management benefits of underground facilities enable more efficient integration with existing infrastructure and landscapes compared to above-ground storage tanks. Additionally, underground gas storage construction is cost-effective in comparison to similar-capacity above-ground facilities. The prevalence of suitable geological structures in various countries further adds to the feasibility of underground storage solutions. However, despite the theoretical promise of hydrogen energy, large-scale implementation faces challenges due to limited empirical data and the need for effective assessment methods for identifying suitable hydrogen storage locations. Addressing gas losses in underground hydrogen storage and developing efficient planning strategies for the hydrogen value chain are also significant challenges [48].

Taiwan is actively pursuing a comprehensive transition to achieve net-zero emissions, with a significant focus on expanding RE sources, deploying ESS, and upgrading the power grid infrastructure [49]. Currently, RE accounts for a modest 3.6 % of Taiwan's total electricity generation, predominantly from solar and wind [4]. The nation's goal, as detailed in "Taiwan's Pathway to Net-Zero Emissions in 2050" [49], is to increase this share to 60 % by 2050, reflecting a bold commitment to decarbonizing the power sector. Despite these ambitious targets, there is a noticeable gap in research assessing the economic and societal impacts of such a profound energy transition. This study bridges that gap by evaluating the feasibility of using hydrogen as the primary energy storage solution to stabilize a power system undergoing substantial renewable integration, primarily through wind and solar technologies. Given Taiwan's limited water resources, the potential for expanding hydroelectric and pumped hydro storage solutions is constrained, necessitating extensive environmental assessments for new reservoir construction. Similarly, while geothermal energy presents an opportunity, its higher technological barriers and construction costs make it a less immediate solution compared to wind and solar. This research focuses on optimizing these two primary renewable sources and goes further by exploring the techno-economic viability of a power system achieving 100 % RE penetration. It compares these results against the current economics of fossil fuel-fired power generation, factoring in carbon emissions as a significant cost component. Our comprehensive analysis provides detailed system-level cost calculations under various configurations of renewable capacities and storage solutions— an aspect often overlooked in prior research. Additionally, our study does not limit itself to hydrogen storage; it also evaluates battery-based storage as a viable alternative, comparing the outcomes of both storage methods.

This dual approach allows for a balanced assessment of possible energy storage solutions, emphasizing the necessity of enhancing energy storage capabilities and auxiliary services to ensure grid stability and reliability in scenarios with high renewable penetration rates.

2. Methodology and data

This study employs a comprehensive large-scale electricity system simulation model to assess the impact of high RE penetration levels on the power grid and ESS at an hourly resolution. The simulation results provide a techno-economic overview of the optimal installed capacity combinations for RE generation and the required energy storage devices to achieve net-zero RE targets. To ensure efficient utilization of HSS and avoid curtailment of excess RE generation, no constraints are initially imposed on the power capacity of the hydrogen storage systems. This allows the HSS to have a power capacity equal to the peak of excess power generation from RE sources. However, to explore the effects of imposing capacity constraints on storage systems, the study also analyzes scenarios with capacity constraints, which could increase device utilization but may lead to curtailment. Furthermore, the study investigates a highly ambitious 100 % RE scenario and includes alternative battery-based storage systems for comparative analysis. Notably, this study assumes a single-node simulation structure, where there are no limitations in electricity transmission within the power grid.

2.1. Model overview

The simulation model operates on a time step of 1 h and is designed to maintain power balance within the system. Fig. 1 illustrates the concept of the power-to-power (P2P) system, which incorporates key components such as an electrolyzer for hydrogen production (P2G), a hydrogen storage tank, and a fuel cell generator for electricity production (G2P). In situations where RE generation exceeds electricity demand, the surplus electricity is utilized to produce hydrogen, which is then stored for future use. Conversely, during periods when RE generation and G2P capacity are insufficient to meet the national electricity demand, thermal generators are activated as backup sources to prevent power grid failures. The overall contribution of non-renewable energy (non-RE) amounts to 40 % of the yearly electricity consumption.

2.2. Modeling procedure

The simulation model is designed to ensure a balanced power system by meeting the national electricity demand through a combination of local RE resources (wind: 80 GW [50]; solar: 120 GW [51]) and appropriate storage capacities. The fundamental principle of the simulation is to balance the active power (Equation (1)) and electricity supply and consumption over each time interval (Equation (2)).

$$P_{\text{Load}} + P_{in} + P_{curl} = P_{RE} + P_{NonRE} + P_{out} \tag{1}$$

where P_{Load} is the load demand; P_{RE} is the generation from RE sources; P_{in} and P_{out} represent power flows into the electrolyzer and out from the fuel cell, respectively; P_{NonRE} is the non-RE power generation required to satisfy the demand after utilizing RE and extracting energy from storage; P_{curl} represents the curtailment, i.e., excess generation that cannot be accommodated by the storage.

$$E_t = E_{t-1}(1-\varepsilon_{sd}) + P_{in}\Delta t\,\eta_{in} + \frac{P_{out}\Delta t}{\eta_{out}} \tag{2}$$

where E_t is the energy storage at time t; ε_{sd} represents the rate of self-discharge losses (i.e., hydrogen leakage from the storage system), which is assumed to be 0 [45,46]; η_{in} and η_{out} are the charging and discharging efficiencies of the P2P system (65 % and 64 %, respectively) [1]; Δt is the fixed time step size of 1 h used in the model.

Fig. 2 illustrates the computational procedure of the simulation model. Positive residual load (i.e., RE greater than load) is stored in the storage system, while negative residual load (i.e., RE less than load) is met by storage or other non-RE dispatchable generating units. The simulation uses an optimization cycle to determine the required wind and solar installed capacities to achieve the desired RE share. The year-long profiles of energy generation and storage are then used to calculate the capacity sizes of the P2P systems. The sizing of the ESS is guided by a power balance model, as depicted in Fig. 1. This model operates under the assumption that the minimum hydrogen storage level throughout the year is zero, while the maximum storage level at equilibrium matches the installed capacity of the ESS. The storage capacity directly correlates with the proportion of RE sources utilized, forming a critical parameter in our optimization methodology. This method involves examining various configurations of solar and wind installations to

$$\begin{cases} \text{RE} > \text{Load} : \text{Hydrogen } (H_2) \text{produced via electrolysis and then fed into the storage systems} \\ \text{RE} + \text{Storage} < \text{Load} : \text{Other non} - \text{renewable energy serves as a backup} \end{cases}$$

identify scenarios where the installed capacity is minimized within a dynamically balanced system.

To increase the utilization of the storage systems, the concept of capacity factor (CF) is introduced. CF is defined as the ratio of actual energy generation/consumption over a year to the theoretical maximum possible generation/consumption in the same period (Equation (3)).

$$CF = \frac{\sum_{t=1}^{end} P_t \bullet \Delta t}{P_{install} \bullet T} \tag{3}$$

where P_t is the power generation/consumption at time t; $P_{install}$ represents the installed capacity of the device; T represents total periods in the simulation.

Given the high cost of electrolyzers and the necessity to manage instantaneous demand peaks, this study employs a minimum capacity factor (CF_{min}). CF_{min} restricts the electrolyzer size by ensuring that the electrolyzer operates no less than a predetermined proportion of full-load operating hours relative to the total simulation period. For

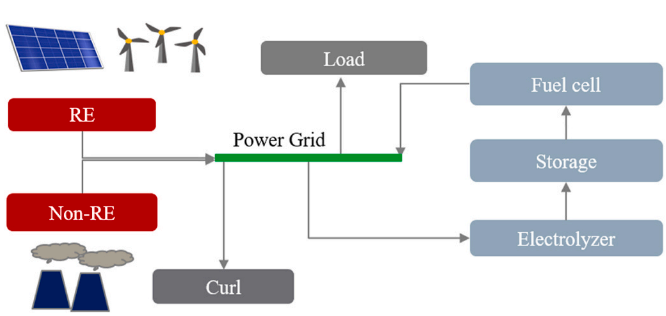

Fig. 1. Schematic diagram of the simulation model for the power system. RE: renewable energy; Non-RE: non-renewable energy (i.e., thermal power); Curl: curtailment; Load: electrical demand.

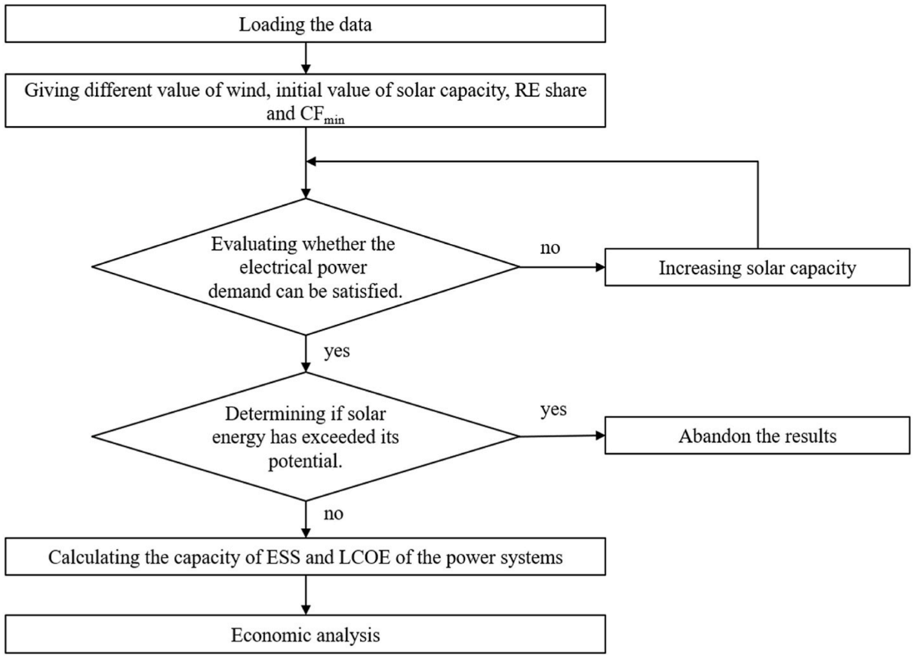

Fig. 2. Schematic diagram of the model procedure.

instance, a CF_{min} of 5 % implies that the device operates at full load for one-twentieth of the total time steps. Implementing CF_{min} helps mitigate the impacts of occasional extreme peaks and avoids operational inefficiencies. However, imposing CF_{min} can also lead to curtailment challenges, especially when higher installations of RE sources are necessary to meet targeted RE shares. This study, therefore, not only evaluates the technical feasibility but also provides a techno-economic analysis of different system evolution options for a future decarbonized power system. The focus remains on understanding the broader impacts rather than the precise numerical values, given the complexities inherent in the energy transition process.

Noted that in this study, fuel cells are sized to meet the electricity demand at every time step, specifically designed to handle Taiwan's peak electricity loads. This sizing strategy ensures that the fuel cells can convert all available hydrogen into electricity, particularly during high-demand periods, without the need for additional non-renewable energy support. We opt not to apply CF_{min} constraints to fuel cells to avoid the risk of insufficient capacity during peak times, which could force reliance on non-renewable sources. Maintaining fuel cell capacity at levels that meet or exceed peak demand aligns with our study's objective of promoting a substantial renewable energy integration, aiming for a 60 % renewable scenario without compromising energy reliability or increasing greenhouse gas emissions.

2.3. Techno-economic analysis

To evaluate the economic performance of different simulation scenarios, it is crucial to calculate the costs associated with each setting, including the installed capacities of RE sources and ESS. However, comparing systems with varying capacity settings, different periods of use, and operational costs can be challenging. To address this issue, we employ the concept of levelized cost in our economic analysis. The levelized cost calculation takes into account all costs associated with a particular energy technology over its lifetime, such as capital, operational, maintenance, and fuel costs. By dividing the total costs by the total amount of energy produced over the technology's lifetime, the levelized cost allows for a fair and accurate comparison between different clean power grid scenarios.

The widely accepted metric for comparing the costs of generating electricity over the lifetime of energy technologies is the levelized cost of electricity (LCOE) method [13,14]. For RE sources like wind or solar, upfront installation costs can be high, but the ongoing operational and maintenance (O&M) costs are typically lower than those of fossil fuel-based technologies. As a result, the levelized cost of RE may appear higher than traditional fossil fuel-based technologies in the short term but could be more cost-effective over the long term due to lower ongoing costs. While the LCOE is valuable, it has been criticized for not fully accounting for energy storage costs. Given the importance of storage in renewable energy systems, it is necessary to include storage costs when evaluating the cost-effectiveness of clean power systems. To address this concern, our study expands the LCOE to include the levelized cost of storage (LCOS) [34,36] and the levelized cost of curtailment (LCOC) [46–48], in addition to the levelized cost of renewable electricity (LCORE) and the levelized cost of non-renewable electricity (LCONRE), as shown in Equations (4)–(7).

$$LCOE = RES^*(LCORE + LCOS + LCOC) + (1 - RES)^*LCONRE \tag{4}$$

$$\text{with } LCORE = \frac{CAPEX_E + \sum_{t=1}^{t=n} \frac{O\&M_{E,t}}{(1+r)^t}}{E_{demand}} \tag{5}$$

$$LCOS = \frac{CAPEX_s + \sum_{t=1}^{t=n} \frac{O\&M_{S,t}}{(1+r)^t}}{E_{demand}} \tag{6}$$

$$LCOC = LCOE^* \frac{E_{curl}}{E_{demand}} \tag{7}$$

where *RES* represents the renewable energy share, indicating the proportion of RE electricity meeting total electricity demand either directly or through storage; *CAPEX* stands for capital expenditure, where subscript *E* refers to energy technology and *S* for energy storage; $O\&M_t$ represents operating and maintenance costs at year t; E_{curl} denotes to the curtailed excess energy; E_{demand} represents the demand of the power system at year t. The discount rate (r) dictates the relative importance of upfront CAPEX versus annual savings on O&M.

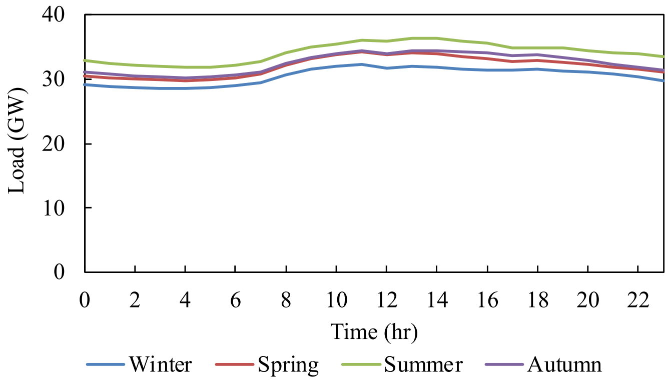

Fig. 3. Hourly load demand profiles of the four seasons in Taiwan. Note: Spring season is from Feb. to Apr., Summer is from May to Jul., Autumn is from Aug. to Oct., and Winter is Nov., Dec., and Jan.

2.4. Data assumptions

2.4.1. Load demand curve

The average hourly load demand curves for the four seasons in Taiwan used in this study are shown in Fig. 3, and the data are sourced from the Taiwan Power Company [4]. Electricity load exhibits variation due to various factors but generally follows predictable patterns throughout the year. In the summer months, characterized by high temperatures (often exceeding 30 °C) and humidity, electricity consumption increases significantly as households and businesses heavily rely on air conditioning for cooling. Conversely, during non-summer months, when temperatures are milder, the hourly load demand is generally lower as there is less need for heating. Moreover, the hourly load demand follows similar trends across all four seasons. Between 12:00 a.m. and 7:00 a.m., electricity demand is notably lower compared to daytime hours. Subsequently, electricity consumption gradually rises throughout the day, reaching its peak during evening hours when people return home and engage in activities that require the use of appliances and electronics, putting strain on the power grid if not managed effectively. Notably, there is a sudden decrease in the hourly load demand at 12:30 p.m., attributed to the common lunch break culture in Taiwan. During this time, many businesses switch off lights for a midday rest, resulting in a temporary reduction in electricity consumption. These load demand curves serve as the basis for evaluating the power system's ability to meet demand and optimize energy storage requirements under various RE capacity settings.

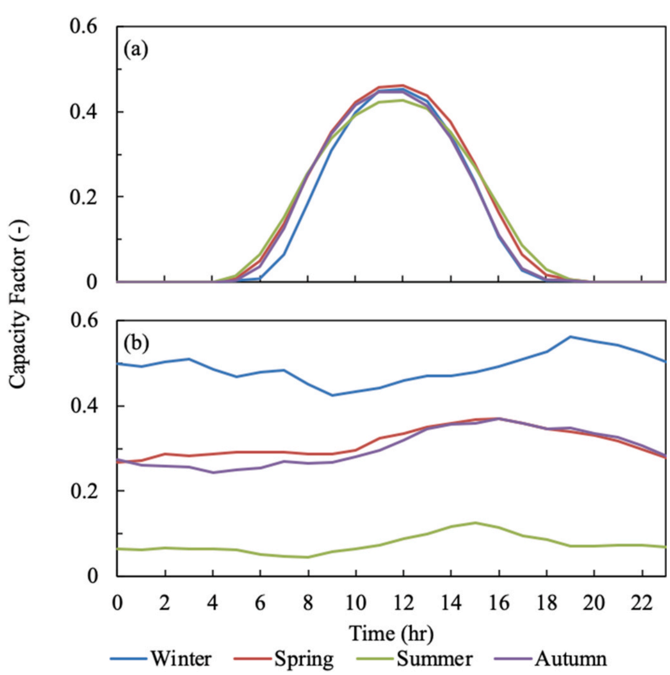

Fig. 4. Hourly capacity factors of the four seasons in Taiwan: (a) solar PV and (b) offshore wind power. Note: Spring season is from Feb. to Apr., Summer is from May to Jul., Autumn is from Aug. to Oct., and Winter is Nov., Dec., and Jan.

2.4.2. RE capacity factor

Fig. 4 illustrates the seasonal variations in the hourly capacity factors of solar power and offshore wind power. These capacity factors are computed by dividing the actual power generation by the installed capacity of the existing power plants in Taiwan [4]. Our analysis reveals that solar energy exhibits significant daily variability, with capacity factors showing an upward trend from 8 a.m. to 12 p.m., followed by a gradual decline until 4 p.m. This pattern corresponds to the availability of sunlight during daylight hours. However, the impact of seasonal variations on solar power performance is generally minor. On the other hand, offshore wind power demonstrates more pronounced seasonal variability in capacity factors compared to solar power. During the winter months, characterized by the strong northeast monsoon, offshore wind power exhibits considerably higher capacity factors than in other seasons. Notably, the lowest capacity factor of 0.045 is observed during the summer, whereas the highest capacity factor of 0.562 is recorded during the winter months. Understanding the seasonal variations in capacity factors is crucial for accurately assessing the contribution of solar and offshore wind power to the overall power system and optimizing the deployment of energy storage solutions to balance the grid under different scenarios of RE integration.

2.4.3. Techno-economic parameters

The primary objective of this study is to analyze the costs associated with electricity generation and storage in a power system with high RE penetration. Table 1 presents the essential parameters required for calculating the levelized costs of various RE generation resources, specifically utility-scale solar, offshore wind, and hydrogen produced through water electrolysis. These parameters are crucial in determining the levelized costs for each resource. The estimated LCORE values shown in Table 2 indicate that solar energy generation technologies in Taiwan are approximately 70 % more expensive than offshore wind—$0.124/kWh and $0.210/kWh, respectively. Additionally, the levelized costs of fossil fuels (i.e., LCONRE) in Taiwan are included for comparison, directly sourced from published reports by Taipower [4]. These LCONRE values serve as benchmarks for evaluating the economic viability and competitiveness of RE sources against conventional fossil fuel-based generation in Taiwan. It is observed that there is a significant difference between the LCONRE values in 2021 and 2022, primarily attributed to the significant increase in fuel prices during the Russia-Ukraine war in 2022 [52].

Table 3 summarizes the key techno-economic parameters used to compute the LCOS of various energy storage systems [20,55]. For hydrogen, our focus is solely on the costs associated with production, excluding post-production expenses like transportation to demand

Table 1
The techno-economic parameters for levelized cost of RE and non-RE technologies.

Energy Technology		CAPEX[1] ($/kW)	O&M ($/kW)	Discount Rate (%)	Lifetime (year)
2021 RE [53]	Solar PV	1448	50.5	5	25
	Offshore Wind	5189	144.7		20
2022 RE [53]	Solar PV	1427	50.5	5	25
	Offshore Wind	4996	144.7		20

Table 2
The estimated levelized cost of RE and non-RE technologies.

Energy Technology		Levelized Cost ($/kWh)	
Year		2021	2022
RE	Solar PV	0.124	0.123
	Offshore Wind	0.210	0.204
Non-RE [4]	Coal	0.053	0.120
	Natural Gas	0.065	0.111
	Oil	0.172	0.245

[1]The exchange rate between USD and NTD used in this study is 29.7 NTD per 1 USD, which is based on the average spot buying and spot selling rates provided by the Bank of Taiwan on May 20, 2021 [54].

centers. The electrolyzer and fuel cell technologies considered are proton exchange membrane (PEM) and combined cycle technologies, with costs determined by the various combinations of RE in Taiwan. Underground geological hydrogen storage is utilized as the storage vessel, with cost data sourced from a previous study [53]. The roundtrip efficiency of the hydrogen storage technology, which considers both charging and discharging, depends on the efficiency of the electrolyzer and fuel cell. The values of 93 % and 96 % in the charge efficiency refer to the amount of hydrogen lost during the transfer process to the storage tank. The economic and efficiency performances of different types of battery energy storage technologies are also presented for subsequent comparative analysis. Note that the self-discharge rates will be converted to a percentage per hour to align with the time step used in the simulations. These techno-economic parameters are essential for accurately evaluating the costs associated with energy storage and determining the economic feasibility of different storage solutions within the high-RE penetration power system.

3. Results and discussion

Applying the methodology and data outlined in Section 2, we utilize the developed model to simulate the Taiwan power system. The structure of this section is organized as follows: Section 3.1 discusses the outcomes of the optimization routine to achieve the net-zero target of 60 % RE penetration, both with and without capacity constraints imposed on the storage systems. Section 3.2 explores the consequences of the ambitious 100 % RE scenario to meet the electricity demand over the year. Section 3.3 examines the lowest LCOE under the constraints of electrolyzer and fuel cell systems for power systems with 60 % and 100 % RE contribution. Additionally, we evaluate the impacts of pricing carbon on the economics of high RE-based electricity generation. Section 3.4 compares the outcomes obtained using hydrogen energy storage with those using battery-based technologies to meet the storage capacity requirements.

3.1. Net-zero power systems with 60 % RE share

3.1.1. Unconstrained energy storage systems

The modeling process commences by assuming a specific wind installed capacity, followed by employing the optimization cycle to determine the required solar PV capacity to meet the 60 % RE target. In scenarios without constraints, the optimal sizing of the electrolyzer is based on the highest values of residual load observed during any 1 h throughout the year, ensuring that all excess electricity can be stored for later use to avoid curtailments.

Fig. 5 presents the simulation results without constraints, illustrating 30 potential combinations for wind capacity ranging from 20 GW to 50 GW (approximately 63 % of the estimated offshore wind potential in Taiwan [50]). The corresponding solar capacities for these combinations range from 126 GW to 44 GW, respectively. The results reveal a consistent trend of decreasing solar PV power requirements with increasing wind installations. The simulation shows that the minimum required electrolyzer power capacity (P2G) is 32 GW, achieved with an installed wind capacity of 50 GW and solar capacity of 44.8 GW. The purple triangle markers in the figure represent the minimum hydrogen storage size required for the proper yearly functioning of the system. To ensure non-negative net hydrogen generation over the year, the simulations ensure that the amount of hydrogen stored at the end of the simulated period equals the amount stored at the beginning of the subsequent period. The storage curve exhibits an upward trend as the proportion of wind energy increases, attributed to the seasonal variations in wind availability. The ample wind power supply in winter is stored and utilized in summer to compensate for the renewable energy deficit during that season.

Next, the levelized costs of generating electricity are computed based on the installed solar and wind capacities and the sizing of hydrogen storage systems, as indicated by the black circle markers. Initially, as the solar capacity decreases from 126 GW, the levelized costs decrease due to a reduction in the electrolysis system capacity. However, the cost

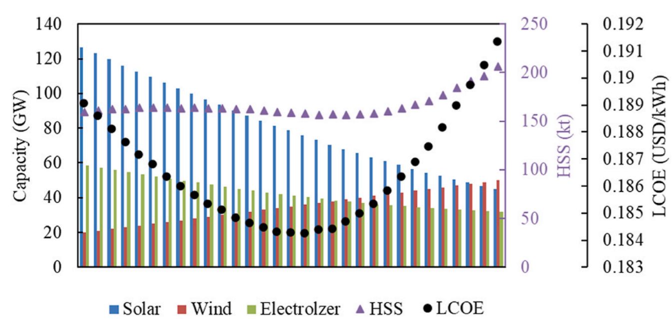

Fig. 5. Combinations of capacities (solar and wind generation with P2P storage) and the corresponding levelized costs of electricity for achieving 60 % RE share.

Table 3
The techno-economic parameters of various types of energy storage technologies with a discount rate of 5 % and a lifetime of 20 years [55]. Note that CAPEX and O&M costs for electrolyzers and fuel cells are presented per kW. Costs for hydrogen storage technologies are calculated per kWh. For battery storage, costs are detailed separately as capital expenditure for charging and discharging per kW, alongside the cost of storage capacity per kWh.

Energy Storage Technology			Discharge CAPEX ($/kW)	Storage CAPEX ($/kWh)	O&M ($/kW-year)	O&M ($/kWh-year)	Charge Efficiency (%)	Discharge Efficiency (%)	Self-Discharge Rate (%/mon)
Hydrogen	Electrolyzer		1771	–	75	–	65 [20]	–	–
	Fuel cell		1333	–	12.7	–	–	64 [20]	–
	Storage	Above-ground	–	8	–	0.08	96	–	–
		Under-ground	–	1.179	–	0.029	93	–	–
Battery	Lithium-ion		257	277	1.4	6.8	92	92	1.5
	Redux flow		620	171	4.1	0	92	88	0.0
	Metal-air		1100	3.7	27.5	0.1	72	60	7.3

reduction impact diminishes as the solar capacity continues to decrease. Rather than reaching progressively lower values, the LCOE starts to increase once a certain threshold of wind capacity is exceeded. The incremental costs associated with increasing storage tank and wind capacity contribute to the overall increase in the LCOE values. The intermediate cases prove to be more cost-effective in achieving a 60 % RE supply, considering the combined effects of electrolysis system capacity and hydrogen storage size for a given solar-wind ratio. The minimum LCOE (0.184 USD/kWh) is observed at a wind capacity of 33 GW, solar power of 84.4 GW, electrolyzer power capacity of 43.1 GW, and hydrogen storage vessel size of 161.4 kt.

3.1.2. Constrained energy storage systems

This section investigates the impact of different CF_{min} on the sizing of the electrolyzer capacity and its subsequent effect on the LCOE. CF_{min} refers to the minimum level of power generation that can occur within an hour across all time steps relative to the installed capacity. In the absence of constraints (as discussed in Section 3.1.1), electrolyzers tend to operate for only short durations, resulting in low-capacity factors that render their capacity economically impractical. Introducing CF_{min} constraints on the electrolyzer ensures that the system operates with a minimum threshold of utilization. By setting higher CF_{min} values, the utilization rate of the electrolyzer improves as it reduces instances of low utilization, thereby enhancing its efficiency. However, imposing constraints on the electrolyzer inevitably leads to a reduction in RE generation. To achieve the 60 % RE target with constrained electrolyzers, it becomes necessary to increase the capacity of solar PV installations while maintaining the wind capacity constant.

Fig. 6 illustrates the influence of different CF_{min} on the load duration curve of the electrolyzer system, using a specific wind capacity of 30 GW as an example. By imposing constraints, the power supplied to the electrolyzers is limited to a specific level corresponding to the installed capacity, which is quantitatively equal to the load curve value associated with the assigned CF_{min}. While the overall shape of the curve with constraints remains relatively consistent as CF_{min} increases, variations arise due to the reduction in electrolysis capacity and its effect on hourly balances. Consequently, there is a decrease in the availability of stored energy and an increased demand for RE installations. The leftward and downward shift of the curves in Fig. 6 with increasing CF_{min} signifies the necessity for expanding solar PV installations to compensate for the energy loss caused by imposing constraints on the electrolyzer system.

The introduction of constraints on the CF_{min} in the electrolyzer system results in significant changes to the system configuration, as illustrated in Fig. 7. Initially, imposing constraints in the range of 0 %–5 % CF_{min} leads to a substantial reduction in electrolyzer capacity of approximately 45 %. At the same time, the solar PV nominal power experiences a modest increase of around 4 %. As CF_{min} continues to increase beyond 5 %, the magnitude of capacity reduction in the electrolyzer system becomes smaller, while the demand for solar PV panels gradually grows. Specifically, as CF_{min} increases from 5 % to 10 %, the reduction in electrolyzer capacity is approximately 24.2 %, paired with a 7.2 % increase in solar PV nominal power. Continuing this trend, when CF_{min} rises from 10 % to 15 %, the electrolyzer capacity is further reduced by about 16.9 %, whereas solar PV nominal power experiences an increase of roughly 8.3 %. Similarly, as CF_{min} increases from 15 % to 20 %, the electrolyzer capacity decreases by approximately 14 %, while solar PV nominal power rises by about 10 %. The smaller reduction in electrolyzer capacity at a CF_{min} of 5 % compared to 0 % is attributed to the significant initial decrease in capacity and only a marginal increase in solar panel demand. However, as CF_{min} escalates from 5 % to 10 %, the decrease in electrolyzer capacity becomes less pronounced. This is accompanied by a higher increase in solar panel demand, resulting in a lower LCOE at CF_{min} of 5 % compared to both 0 % and 10 %.

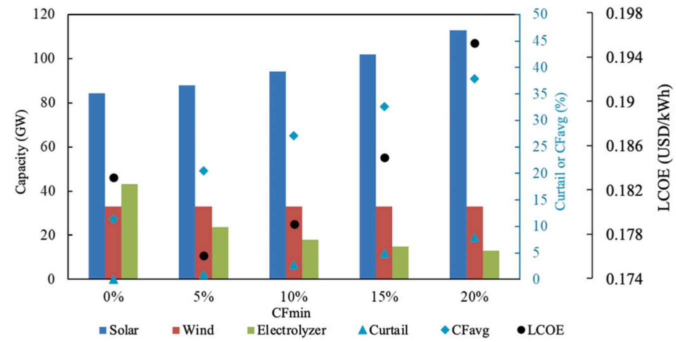

Fig. 7. Characteristics of the 60 % RE power system at different imposed minimum capacity factors (CF_{min}), given a fixed wind capacity of 30 GW. The left axis represents the installed capacity of RE generation and storage. The right first axis shows the average electrolyzer capacity factor (CF_{avg}) and the percentage of curtailed electricity. The right second axis represents the LCOE corresponding to the black circle marker on the graph.

Furthermore, as anticipated, the average CF of the electrolyzer system consistently exceeds the imposed CF_{min} and demonstrates an upward trend with increasing CF_{min}, as shown by the blue diamonds in Fig. 7. In the unconstrained case, the average CF stabilizes at approximately 14 %. However, when a CF_{min} value of 20 % is imposed, the average CF increases to 37.9 %. Additionally, Fig. 7 also depicts the curtailment caused by the constraints (shown as blue triangles), indicating the fraction of total excess electricity that remains unrecovered by P2G and is therefore lost. These fractions demonstrate an increasing trend as the CF_{min} is raised. The configuration that achieves the lowest LCOE of 0.176 USD/kWh corresponds to a CF_{min} of 5 %, consisting of a wind capacity of 33 GW, solar power capacity of 87.8 GW, electrolyzer capacity of 23.8 GW, and a hydrogen storage vessel capacity of 146.2 kt. This indicates that a moderate CF_{min} value strikes an optimal balance between enhancing the utilization of the electrolyzer system and

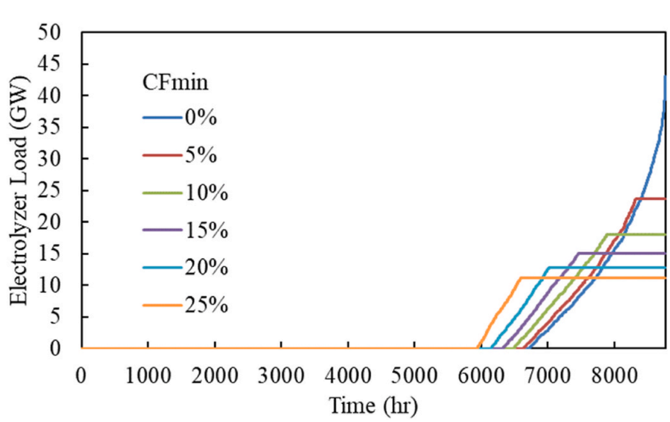

Fig. 6. Load duration curve of the electrolyzer system at various imposed minimum capacity factors (CF_{min}) given a wind capacity of 30 GW.

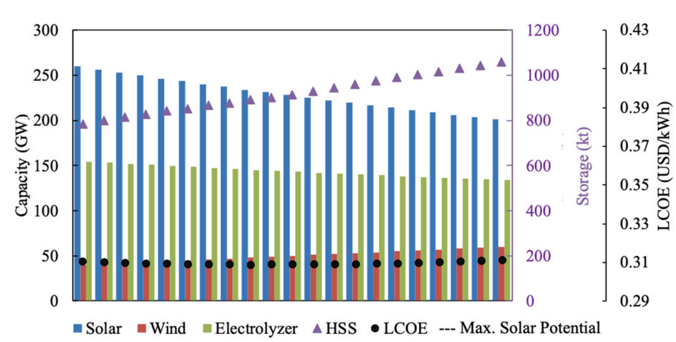

Fig. 8. Different combinations of capacities and LCOE achieving 100 % RE ecosystem.

minimizing curtailment, leading to the most cost-effective net-zero power system with 60 % RE penetration.

3.2. Ambitious fully renewable power system (100 % RE share)

3.2.1. Unconstrained energy storage systems

In this section, we explore the feasibility of achieving a fully renewable power system with 100 % RE penetration. Similar to the 60 % RE scenario, the simulation methodology assumes that all excess renewable energy is stored, and the electrolyzer systems are not subjected to any constraints initially. Fig. 8 presents the simulation results depicting various combinations of solar PV and wind installations under these conditions. The simulation begins with an initial wind capacity of 40 GW, resulting in a solar PV capacity of 260 GW and an electrolyzer requirement of 154.5 GW. As the installed solar PV capacity decreases, the wind capacity needs to be augmented to maintain a 100 % RE supply. Consequently, the required capacity of the electrolyzer system increases with the installed solar PV capacity, owing to the higher excess electricity peaks observed. Conversely, the required capacity of hydrogen storage exhibits a positive correlation with the installed wind power capacity, reflecting the heightened seasonal dependence on wind power observed in previous simulations.

To calculate the LCOE for various power generation combinations, we assess the capacities of solar PV, wind turbines, electrolyzers, fuel cells, and storage systems. The fuel cell system's capacity is designed to match the peak load demand, ensuring a real-time balance between supply and demand within the power system. The LCOE curve presented in Fig. 8 aligns closely with observations from the 60 % RE scenario, underscoring consistent characteristics. The optimal configuration for achieving the lowest LCOE, valued at $0.308/kWh, involves a wind capacity of 48 GW and a solar capacity of 234 GW. However, it is crucial to note that the estimated available reserves of wind and solar power in Taiwan are significantly lower, approximately 80 GW and 120 GW respectively. Therefore, achieving a fully renewable power system with these capacities will require the integration of additional power sources beyond the traditional reserves. Taiwan's limited land area further necessitates the diversification of renewable energy sources. Promising alternatives such as geothermal energy are currently being evaluated. To attain the lowest possible system LCOE and realize a 100 % renewable energy framework, it will be essential to fully exploit the potentials of both wind and solar, along with exploring other renewable options. This endeavor to pursue a complete RE scenario represents a formidable yet promising step toward establishing a sustainable and decarbonized power infrastructure in Taiwan.

3.2.2. Constrained energy storage systems

Similar to the previous 60 % RE scenario, the economic feasibility of the electrolyzer capacity may be compromised by a lower capacity factor. To address this issue and enhance the capacity factor, constraints are imposed in the simulation. The power system characteristics at various CF_{min} values are presented in Fig. 9, with the wind capacity kept constant at 50 GW, representing the most cost-effective option among all 100 % RE combinations in the unconstrained setting. The orange diamonds in Fig. 7, representing the average CF, consistently exceed the imposed CF_{min} and exhibit an increasing trend as the CF_{min} rises. This observation highlights the improvement in the utilization rate of the electrolyzer as the constraints are applied, resulting in higher capacity factors and enhanced efficiency. Similarly, the orange triangles, representing RE curtailment, align with the findings from the previous 60 % RE simulations, indicating the fraction of total excess electricity that remains unrecovered by the P2G system.

Furthermore, Fig. 7 displays the annual system-level levelized cost results, and the LCOE for each power combination can be calculated based on the capacities of all installations. At a CF_{min} value of 5 %, the LCOE reaches an optimal point of 0.295 USD/kWh. This optimal point is achieved by assigning specific capacities to solar PV (233.6 GW), wind (50 GW), and the electrolyzer (100.5 GW), with the storage vessel capacity set at 884.5 kt. Notably, the constraint imposed on the electrolyzer results in a reduction of 42 GW in its capacity, leading to an approximate 4.2 % decrease in the annual cost. When compared to the scenario without constraints (as discussed in Section 3.2.1), the LCOE with 5 % CF_{min} constraints experiences a moderate decrease of 0.0065 USD/kWh, representing a 3.5 % reduction. These results underscore the significance of capacity factors and their influence on the economic performance of high-RE power systems, where constrained energy storage systems can still achieve promising cost reductions while ensuring higher utilization rates and improved efficiency.

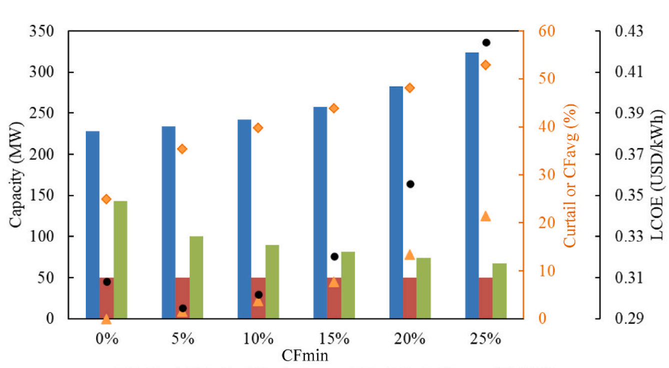

Fig. 9. 100 % RE Power system characteristic and LCOE imposing different CF_{min} at wind 50 GW.

3.3. Economic analysis

To assess the economic implications of power systems with high RE penetration, a levelized cost analysis is conducted, comparing the 60 % and 100 % RE scenarios, as depicted in Fig. 10. As expected, increasing the proportion of RE electricity supply from 60 % to 100 % results in higher levelized costs of storage (by 160 %) and RE installations (by 103 %). This increase in levelized costs can be attributed to the larger storage system capacity required for ensuring a stable energy supply within fully RE power systems. Additionally, curtailment costs also rise (by 500 %) due to the overall expansion of RE generation capacity. For the net-zero 60 % RE share power systems, the study also examines the impact of fossil fuel prices on the economic viability of the system. The analysis reveals that the increasing fossil fuel prices during 2022 would result in a significant 0.021 USD/kWh increase in system-level energy costs in Taiwan compared to the costs in 2021. This finding emphasizes the significance of transitioning to RE sources to mitigate the impact of volatile fossil fuel prices and achieve cost stability in the long term.

Furthermore, the study extends its analysis beyond fossil fuel prices and investigates the impact of carbon pricing on the economic viability of the system. Table 4 provides insights into the levelized costs of both RE and non-RE generation under various carbon price levels (commonly seen in the existing ETS price worldwide in 2021 [53]), including 0, 20, 60, and 100 USD/ton. In the absence of a carbon price, the levelized costs of non-RE generation in 2022, including coal (43.5 %), natural gas (54.2 %), and oil (2.2 %), experience a significant increase of 0.055 USD/kWh (88 %) compared to the 2021 levels. This increase can be primarily attributed to the rising energy (fossil fuel) prices during that period caused by Russia's war in Ukraine [52]. Introducing carbon prices further elevates the cost levels, such as imposing a carbon price of 40 USD/ton resulting in a 0.0253 USD/kWh increase in the LCONRE.

On the other hand, the levelized costs of RE generation exhibit a promising downward trend, decreasing by 0.0035 USD/kWh, or 1.9 %, over two consecutive years. This reduction reflects ongoing advancements in RE technologies and decreasing capital costs required for deploying solar and wind energy infrastructures [10–12]. Despite RE and associated storage systems remaining more costly than

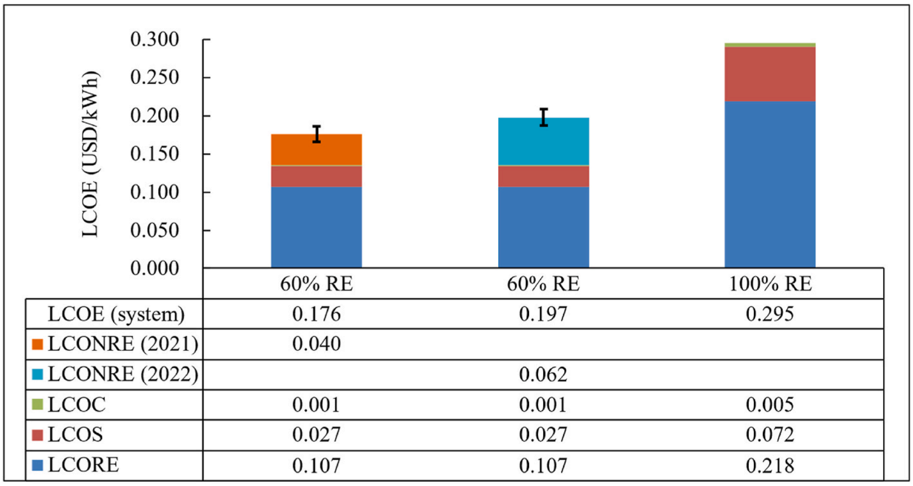

Fig. 10. The breakdown of system-level levelized cost of electricity (LCOE) under 60 % and 100 % RE power systems, including a comparison of the non-RE results between the fossil fuel prices in 2021 and 2022.

Table 4
The LCOE results of RE and non-RE with different carbon price and fuel price.

Levelized cost (USD/kWh)	Carbon Price ($/ton)	2021	2022 (High energy prices)
RE (LCORE)	-	0.1821	0.1764
Non-RE (LCONRE)	0	0.0623	0.1170
	20	0.0756	0.1296
	60	0.1009	0.1549
	100	0.1262	0.1802

non-renewable sources on a levelized cost basis, the imperative for transitioning to a higher proportion of renewables in the energy mix is increasingly evident, particularly as carbon pricing measures intensify. Notably, in 2022, amidst high fossil fuel prices, when carbon pricing surpasses 97.5 USD/ton, the economic benefits of shifting towards renewable sources become markedly clear as detailed in Table 4. This shift towards renewables is not merely a cost-saving measure but also a strategic response to the volatility of fossil fuel markets, enhancing overall market resilience and reducing long-term electricity costs. By transitioning away from fossil fuels, significant savings can be achieved in transportation and storage costs, as well as mitigating the external costs related to the environmental impact of fossil fuel combustion. Furthermore, this transition supports the localized development of small-scale renewable projects, significantly reducing transmission losses and further decentralizing energy production.

3.4. *Comparison between different storage options: hydrogen and battery*

As the global effort to reduce reliance on fossil fuels and transition to RE sources intensifies, the significance of energy storage systems has become increasingly prominent. In this section, we extend our research to thoroughly examine the role of hydrogen storage compared to battery energy storage options in grid-scale applications. While we have previously examined underground geologic storage facilities, this analysis delves into the economic aspects of aboveground hydrogen storage options and various electrochemical energy storage technologies, including lithium-ion, redox-flow, and metal-air batteries, within the context of the net-zero target of 60 % RE condition. To ensure a fair and comprehensive comparison, we employ the same simulation procedure and optimization routine used in the previous analysis. Specifically, we fix the system configuration at the one that achieved the lowest LCOE as depicted in Fig. 7. This configuration entails imposing a CF_{min} of 5 % for electrolyzer sizing, a wind capacity of 33 GW, and a solar power capacity of 87.8 GW. It is crucial to highlight that during this evaluation, no additional constraints are imposed on the operation of BESS, as the system solely relies on BESS for ensuring hourly electricity balance, without the need for electrolyzer and fuel cell systems.

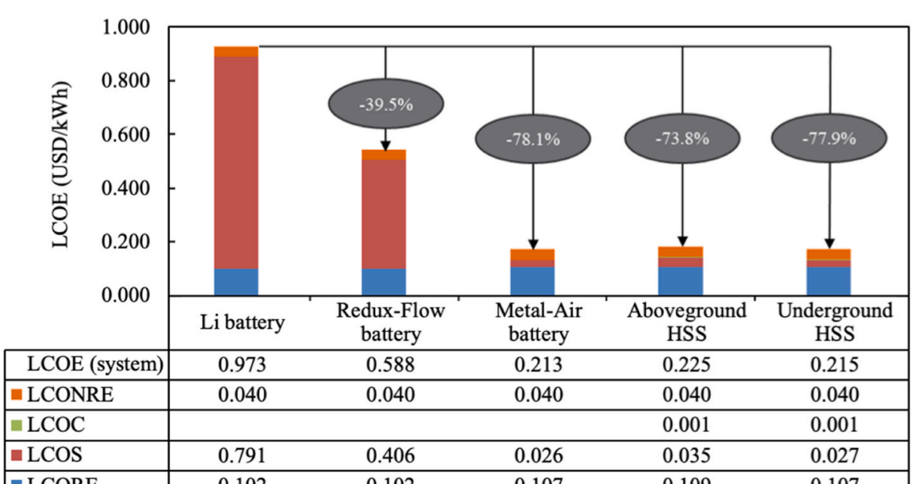

Fig. 11. The LCOE results of different types of storage system.

Fig. 11 illustrates the total electricity costs per kWh incurred by the entire power system while operating a 60 % RE grid, utilizing various energy storage technologies. The key observations are highlighted as follows. Lithium-ion batteries and redox flow batteries have demonstrated superior performance in fulfilling short-term energy storage requirements [55]. However, their high initial CAPEX makes them economically impractical for large-scale grid storage, leading to LCOE values that are 352 % and 173 % higher than those of underground hydrogen storage systems, respectively. In contrast, metal-air batteries offer a much lower CAPEX, making them a more economically promising option for grid-scale storage applications, with a cost advantage of two orders of magnitude compared to lithium-ion and redox flow batteries. The choice of battery technology significantly influences the system-level LCOE, causing up to 0.76 USD/kWh differences between various electrochemical options. Overall, the economic viability of BESS for long-term energy storage needs remains limited, mainly due to their high O&M costs over time.

On the other hand, hydrogen storage options are perceived as more suitable for addressing long-term energy storage needs and tend to have relatively lower recurring O&M costs. Currently, aboveground hydrogen storage systems find applications in various industrial sectors, such as bulk storage and pipeline storage [44]. However, implementing large-scale aboveground storage may pose challenges in terms of space requirements and safety concerns [47,48]. In response to these challenges, there has been a growing focus on exploring the feasibility of simulating underground hydrogen storage, as demonstrated in this study. The analysis reveals that underground hydrogen storage systems offer a cost advantage over aboveground systems, resulting in a reduction of 0.008 USD/kWh (33.3 %) in LCOS and a reduction of 0.01 USD/kWh (4.6 %) in the system-level LCOE. However, it is important to note that HSS presents certain challenges and is more expensive to install compared to BESS. These challenges arise from the complexity and infrastructure requirements associated with hydrogen storage and delivery systems, such as specialized storage vessels, pipelines, and safety measures for handling hydrogen [44]. Overall, both battery and hydrogen energy storage systems offer distinct advantages and face unique challenges, making them suitable for different applications based on specific needs and requirements. This section underscores the significance of carefully evaluating and selecting the appropriate energy storage technology to enhance the economics and performance of high-RE power systems.

4. Conclusion

In Taiwan, where the utilization of renewable energy remains limited, concerns about grid resilience are heightened due to the intermittent nature of these energy sources. This study addresses the implications of transitioning to a high-renewable energy power system, demonstrating that significant deployment of wind energy necessitates extensive energy storage infrastructure to achieve net-zero carbon emissions. Through comprehensive simulations of the entire power system, with a particular emphasis on evaluating hydrogen as a viable storage solution, this research provides insightful modeling outcomes beneficial to Taiwan's developing hydrogen industry. The model developed in this study focuses on achieving energy equilibrium primarily through wind and solar resources to meet the electric load. It incorporates residual load calculations and integrates hydrogen storage solutions including electrolyzers, fuel cells, and hydrogen storage facilities. Our simulation results confirm the technical feasibility of achieving Taiwan's 2050 goal of a 60 % renewable energy share, tapping into the country's full potential for renewable resources. However, to fully meet this ambitious target and eliminate fossil fuels from the power system, significantly greater levels of renewable energy generation and substantial electric energy storage capacities are required.

Hydrogen storage, in particular, plays a critical role in addressing the intermittency issues of renewables, by enabling the conversion of surplus electricity into hydrogen. This hydrogen can then be reconverted into electricity as needed, offering a robust solution to ensure a consistent and reliable energy supply. In the 60 % RE scenario, the optimal combination of 33 GW of wind power, 84.4 GW of solar power, 43.1 GW of electrolysis capacity, and 161.4 kt of hydrogen storage capacity achieves the lowest LCOE of 0.184 USD/kWh when there are no limitations imposed on the electrolyzers. However, to optimize electrolyzer utilization efficiency, practical considerations necessitate the restriction of their installed capacity. A sensitivity analysis incorporating CFmin reveals favorable cost variations. By implementing a 5 % CFmin, the electrolyzer capacity can be reduced by 45 %, with a compensatory increase of less than 5 % in solar panel capacity. This optimization, with just a 5 % CF_{min} constraint, leads to a substantial 4.3 % reduction in the LCOE, resulting in a final value of 0.176 USD/kWh. However, achieving a 100 % RE share in Taiwan poses significant challenges due to current technological limitations and the country's RE potential. Even with the maximum wind capacity of 80 GW, the required solar capacity exceeds Taiwan's maximum potential of 120 GW, highlighting the need for alternative strategies, including the development of other advanced clean energy sources such as geothermal and ocean energy [50].

The economic analysis suggests that while the cost of RE remains higher than that of non-RE sources currently, several factors should be considered. The increasingly volatile costs of fossil fuels and the learning effect benefits of RE technology play a crucial role in the overall cost dynamics. Over the past few years, the levelized costs associated with RE have gradually decreased due to the maturation of the technologies and the subsequent reduction in capital investments. In contrast, the introduction of carbon prices in the future is projected to increase the costs of non-RE electricity, serving as a significant economic incentive for the large-scale deployment of RE. As a result, transitioning to RE sources becomes economically more attractive over time, providing a pathway toward a sustainable and cost-effective energy future.

Moreover, the study compares hydrogen to battery-based ESS in the context of achieving the net-zero target of a 60 % RE share. While lithium-ion and redox flow batteries excel in short-term storage, their high initial costs limit their economic viability. In contrast, metal-air batteries show promise with lower capital costs but still face challenges for long-term storage. However, the overall economic viability of BESS for long-term energy storage remains limited due to its high O&M costs over time. On the other hand, HSS is better suited for addressing long-term energy storage needs with lower recurring costs. While aboveground hydrogen storage is prevalent in industrial applications, the study highlights the potential cost advantage of underground hydrogen storage systems. Careful selection of the appropriate storage technology based on specific requirements is crucial to enhancing the economics and performance of high-RE power systems.

While this study provides valuable insights into the potential and challenges of transitioning to a high proportion of RE sources within Taiwan's power system, it is important to recognize several limitations that warrant attention in future investigations. Our analysis primarily focuses on the broader outcomes rather than precise numerical values, primarily due to the model's emphasis on the capital costs associated with installations. These costs may vary significantly during actual implementation and differ based on equipment specifications. Additionally, the scarcity of localized data concerning electrolyzers necessitates reliance on international studies for reference points. The feasibility of implementing underground hydrogen storage in Taiwan remains to be thoroughly explored, reflecting the complex dynamics of the energy transition and underscoring the need for cautious interpretation of simulation results. Furthermore, Taiwan's offshore wind energy sector is still in its early stages of development, which underscores the importance of comprehensive data collection to enhance modeling accuracy. As offshore wind infrastructure continues to be deployed, considerable fluctuations and uncertainties arise in energy generation metrics and capacity factors. While data from offshore wind farm demonstration sites in Taiwan provide initial insights, they only offer a partial view. With the increasing distance from shore, potential escalations in operational costs and variations in capacity factors are anticipated, necessitating a thorough reevaluation.

Moreover, the hidden costs associated with grid upgrades under high RE penetration emerge as critical factors that must be carefully considered [56]. System inertia and the requirement for auxiliary services may necessitate substantial time and financial resources as part of Taiwan's energy transition strategy. Although our models are currently based on 2021 electricity demand levels and installed capacity calculations, the potential for significant increases in energy demand cannot be overlooked. Integrating forecasts of future energy demands is vital to ensure the resilience and adaptability of renewable energy systems during Taiwan's transition to net-zero emissions. Future research will expand these analyses to include detailed assessments of wind energy density variations across different locations and will comprehensively evaluate the hidden costs associated with energy transitions under scenarios of high renewable penetration. Additionally, our projected 2050 scenario indicates that increases in energy demand may necessitate the integration of additional renewable sources, such as geothermal energy, offshore solar energy, or imported green energy, to meet these expanded needs. Accurate and updated demand forecasts are essential for conducting robust analyses that can adapt to evolving energy requirements, ensuring a sustainable energy future for Taiwan.

CRediT authorship contribution statement

Yuan-Shin Fu: Data curation, Formal analysis, Investigation, Validation, Visualization, Writing – original draft. **I-Yun Lisa Hsieh:** Conceptualization, Methodology, Validation, Supervision, Funding acquisition, Writing – review & editing.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Data will be made available on request.

Acknowledgments

This work was supported by the National Science and Technology Council, Taiwan (NSTC 113-2621-M-002-006).

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