Journal of Physics: Conference
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To cite this article: K Brunik *et al* 2024 *J. Phys.: Conf. Ser.* **2767** 062017

Journal of Physics: Conference Series **2767** (2024) 062017 doi:10.1088/1742-6596/2767/6/062017

Potential for large-scale deployment of offshore wind-to-hydrogen systems in the United States

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Abstract.
This study explores the role of producing low-carbon hydrogen using water electrolysis powered by offshore wind in facilitating the United States' transition to a net-zero emissions economy by 2050. This research introduces an open-source scenario analysis tool for offshore wind-to-hydrogen systems, aiming to assess the impact of technology, regional considerations, and policy incentives on the cost of producing low-carbon hydrogen through offshore wind. Conducting a regional techno-economic analysis at four U.S. coastal sites, the study evaluates two energy transmission configurations and examines associated costs for the years 2025, 2030, and 2035. The results highlight that locations using fixed-bottom technology may achieve cost-competitive water electrolysis hydrogen production by 2030 through leveraging geologic hydrogen storage and federal policy incentives. Furthermore, floating technology locations are expected to see an average 38% reduction in the levelized cost of hydrogen from 2025 to 2035.

1. Introduction

The United States has pledged to reach net-zero emissions economy-wide by 2050 [1], but as of now, only 8.5% of the nation's total energy production comes from renewable sources [2]. Offshore wind energy and clean hydrogen production are two pathways that together could facilitate U.S. decarbonization through bulk energy production and fueling hard-to-abate industries. The global offshore wind industry is set to grow substantially in the coming decade [3], benefiting from stronger winds [4] and reduced land use conflicts compared to onshore sites. In the United States, this expansion is supported by government initiatives, notably the U.S. Department of Energy's (DOE) Floating Offshore Wind Energy Shot goal, which aims to reduce the cost of floating offshore wind by at least 70% by 2035 [5]. Despite these large-scale initiatives, the offshore wind sector faces challenges, including the capital-intensive nature of projects, constraints in energy transmission, and variability in energy generation.

One potential solution to these challenges is producing low-carbon or clean hydrogen (H_2) using renewably powered water electrolysis. Low-carbon H_2 can reduce dependence on extensive electrical transmission infrastructure by leveraging pipelines as an alternative means of energy transport and H_2 potentially offers bulk energy storage to mitigate variability. Further, integrating clean H_2 with offshore wind in a hybrid plant not only takes advantage of policy incentives for wind energy but also unlocks additional tax benefits from the Inflation Reduction

Journal of Physics: Conference Series **2767** (2024) 062017 doi:10.1088/1742-6596/2767/6/062017

Act (IRA) [6], which aim to enhance performance and reduce costs in low-carbon H_2 technology. The DOE's goal is to cut clean H_2 costs to \$1/kg-H_2 [5], but even reaching \$2/kg-H_2 could make it cost-competitive with current carbon-intensive methods of H_2 production [7]. The unique possibilities of offshore wind-to-hydrogen systems are of increasing interest to research and industry sectors.

Recent research has explored technology advancements and coupling configurations in offshore wind-to-hydrogen systems [8, 9, 10]. Initial techno-economic analyses favor centralized offshore electrolysis with alkaline electrolyzers for cost-effective clean H_2 production with fixed-bottom offshore wind [11, 12]. However, uncertainties remain, especially regarding alkaline electrolyzer efficiency with variable power [13] and limited research on proton exchange membrane (PEM) electrolysis. While much research focuses on the post-electricity production phase, factors like wind speed, the number of turbines, distance from shore, and substructure technology are crucial considerations in the wind farm design. Existing studies on offshore wind-to-hydrogen system design primarily concentrate on fixed-bottom technology [11, 12, 14, 15], with limited attention to floating technology [10, 16]. Current research tends to assess system viability and hydrogen cost but overlooks broader technology performance advancement and cost reduction trends.

Building on an initial U.S. case study [14], this work conducts an in-depth techno-economic analysis showcasing the impact of technology, region-specific characteristics, and policy incentives on the levelized cost of (clean) hydrogen (LCOH) from offshore wind across the United States. In Section 2 of this paper, we introduce a techno-economic analysis methodology for offshore wind-to-hydrogen systems using an open-source scenario analysis tool and we cover individual models, site selection criteria, and cost assumptions. Section 3 demonstrates the effects of region-specific characteristics and the influence of performance and cost assumptions over time on the LCOH. In Section 4, we summarize key analysis outcomes and discuss their implications for the design and placement of offshore wind-to-hydrogen systems.

2. Methods

This section outlines the modeling methodology for offshore wind-to-hydrogen hybrid plants and determines associated costs at four U.S. coastal sites. The study evaluates two energy transmission configurations – centralized onshore and offshore electrolysis – for technology cost years 2025, 2030, and 2035. The techno-economic analysis uses an adapted version of the Hybrid Optimization Performance Platform (HOPP) [17], incorporating future wind energy cost projections from a nationwide analysis [18]. HOPP, a Python-based tool, enables modeling, design, and optimization of utility-scale hybrid plants.

2.1. Site Selection

We identified four representative U.S. coastal locations for wind-to-hydrogen hybrid plants, capturing spatial variations influencing technology choices, costs, and performance (see figure 1). For fixed-bottom technology sites, criteria included abundant wind resources and proximity to the DOE's Regional Clean Hydrogen Hubs (H2Hubs) [19], which connect hydrogen producers and consumers through dedicated infrastructure. Additionally, we selected two sites in water depths (>60 m) that likely require floating offshore substructures with existing or near-term Bureau of Ocean Energy Management (BOEM) leasing activity [20].

During site selection, we assessed coastal bathymetry to determine the most suitable substructure technology, opting for either the most common fixed-bottom (monopile) or floating (semisubmersible) substructure[21]. Traditionally, depths that exceed 60 m are considered less economically viable for fixed monopile substructures, although recent projects challenge this limitation [21]. Locations such as the Gulf of Mexico and the New York Bight, with depths of less than 60 m, favor the use of current technology for fixed offshore turbines and offshore H_2 production infrastructure. In contrast, the majority of the western U.S. coast drops quickly to

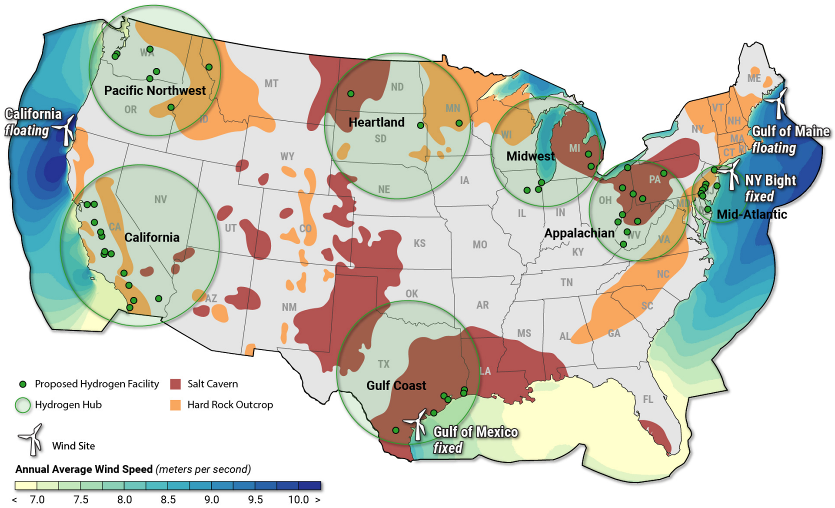

Figure 1: Map of selected representative sites and the offshore wind resources within U.S. maritime limits. H2Hubs and strategic hydrogen development areas are in green, and potential geologic hydrogen storage sites across the contiguous United States are in maroon and orange.

significant depth, favoring the use of floating turbines and offshore H_2 production infrastructure, as seen in the chosen California site. The Gulf of Maine site was selected to explore the feasibility of floating technology along the Eastern Seaboard. Table 1 provides an overview of representative site characteristics.

Table 1: Physical site parameters for the four representative sites [18]. Note: "Energy Export Distance" – straight line distance a subsea electrical export cable or hydrogen pipeline will travel to shore. "CF '25/'30/'35" – wind capacity factor for years 2025/2030/2035.

Region	Gulf of Maine	New York Bight	Gulf of Mexico	California
Substructure	Semi-submersible	Monopile	Monopile	Semi-submersible
Depth	184 m	34 m	45 m	905 m
Energy Export Distance	212 km	71 km	45 km	41 km
Avg. Wind Speed	9.91 m/s	9.64 m/s	8.46 m/s	9.46 m/s
CF '25/'30/'35	49/49/45 %	49/49/44 %	41/44/44 %	45/45/41 %

2.2. Hybrid Plant Modeling

2.2.1. Layout Configuration Two energy transmission configurations were considered based on their technical readiness level (figure 2).

Configuration one consists of an offshore wind plant connected to centralized onshore electrolysis. Renewable electricity generated offshore is sent to an offshore substation using

AC cables, then transmitted through high-voltage cables to an onshore location. There, a PEM electrolyzer uses the electricity to produce H_2 from fresh water onshore. This represents a conventional approach of offshore wind paired with onshore electrolysis, as all current electrolysis takes place on land.

Configuration two shifts centralized low-carbon H_2 production from onshore to an offshore platform, resembling a conventional offshore substation but enlarged (approximately 250m by 250m) to accommodate the equipment for H_2 production. Renewable energy is centralized to the offshore platform via AC cables. A PEM electrolyzer on the platform uses desalinated seawater to produce H_2, which is then transported to shore for storage through pipelines. Note the platform's size exceeds typical offshore constructions, and its technical feasibility is uncertain. Further research should determine if scaling the platform is viable or if other alternatives like floating production storage and offloading vessels would be more suitable.

Substructure technology is site specific and is used for the turbines, electrical substation and platform. Both configurations use onshore hydrogen storage, either manufactured vessel storage or geologic storage near the site. In each configuration, we calculate the initial annual energy production and hydrogen production from electrolysis. Subsequently, we use an iterative approach to allocate sufficient power to the peripheral equipment and then recalculate the hydrogen production accordingly.

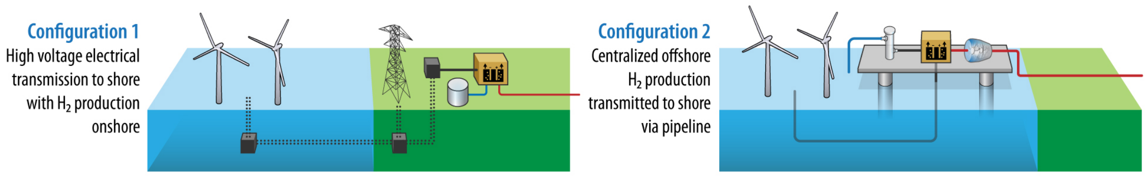

Figure 2: The two modeled configurations for clean hydrogen production with offshore wind.

The wind plant's nominal capacity at each site is approximately 1 GW; specific plant ratings are adjusted according to changes in turbine ratings over time (table 2), reflecting the trajectory outlined in [18]. This resulted in fewer turbines as the turbine power rating increased. For each rating, a generic gridded plant layout is used, maintaining a distance of 7 rotor diameters between turbines in north-south and east-west directions. The electrolyzer's capacity is sized at a 1:1 ratio with the wind plant capacity.

2.2.2. Wind Energy We employed the FLOw Redirection and Induction in Steady State (FLORIS) [22] wake modeling tool for wind plant energy yield calculations. FLORIS captures and models wake deficits—areas with lower wind speeds—due to turbines extracting energy from the wind. It quantifies both the magnitude of these deficits and their accumulation across a wind farm. The turbines in the FLORIS analysis are the same as those used by Fuchs et al. [18] and shown in table 2, based on publicly available turbine models [23, 24].

Using wind resource time series data from the WIND Toolkit [25], the simulation generated a time-dependent, steady-state farm power prediction. The simulation applied the Gaussian wake deficit model, along with the Crespo Hernandez wake-added turbulence intensity model and the sum-of-squares superposition model [26, 27]. Wake deflection and wakes from external wind plants were not considered. The wind farm power output calculation incorporates not only the wake losses calculated in FLORIS but also additional operational losses. These operational losses, which encompass system availability, electrical efficiencies, environmental factors, and curtailment actions, are applied to the wind farm output at a rate of 12.83% [28].

Table 2: Assumed turbine technology trajectory, reproduced from Fuchs et al. [18]. Note: COD – commercial operation date, GoM – Gulf of Mexico.

COD	Region(s)	Turbine Rating [MW]	Rotor Diam. [m]	Hub Height [m]	Specific Power [W/m^2]
2025	All	12	216	137	327
2030	All except GoM	15	242	150	326
	GoM	17	278	168	280
2035	All except GoM	20	252	168	401
	GoM	17	278	168	280

2.2.3. Cost Contribution of the Offshore Wind Plant We determined the individual offshore wind plant component costs at each site using the Offshore Renewables Balance-of-System and Installation Tool (ORBIT) [29]. ORBIT operates as a design trade-off tool integrated with HOPP, evaluating different wind plant design and installation choices. The tool does not predict costs through time, so we adjusted the ORBIT results using a multiplier to align the offshore wind plant costs with future projections [30] while preserving the flexibility to replace components for different system configurations. The multiplier represents the ratio of expected wind plant capital costs from the nationwide analysis by Fuchs et al. [18] to the ORBIT total capital cost at each site. Installed wind system capital costs can be seen in table 3. Additionally, operational costs identified in the nationwide analysis are used as inputs to the ORBIT model.

2.2.4. Electricity Transport In configuration one, electrical energy is transported via high-voltage subsea cables. The choice between high-voltage alternating current (HVAC) and high-voltage direct current (HVDC) cabling, based on a simplified approach outlined in Fuchs et al. [18], depends on the site's proximity to the shore. HVAC is typically more cost-effective for nearshore applications (Gulf of Mexico and California sites), especially for offshore substations, despite higher electrical losses per unit length of cable. Beyond approximately 70 km from the shore (Gulf of Maine and New York Bight sites), HVDC electrical export becomes the more cost-effective choice [18]. High-voltage export cabling costs are extracted from ORBIT.

2.2.5. Water Modeling Water usage is based on annual electrolysis water requirements. For configuration one, we use regional water feedstock costs from the Annual Energy Outlook 2022 [31]. For configuration two, we apply HOPP's desalination model using 50% for seawater recovery and 4.0 kWh/m^3 for energy conversion [32, 33]. Desalination costs (capital and operational) are from Ruth et al. [34].

2.2.6. PEM Electrolyzer The PEM electrolyzer, which is expected to operate favorably in dynamic conditions, is modeled at the cell level using first-principle equations, details of which can be found in [35]. Stack replacement is assumed to be every 7 years [36]. The uninstalled system costs of the electrolyzer are based on the Hydrogen and Fuel Cell Technologies Office's 2022 uninstalled system cost ($1000/kW in 2020USD) [37] and future projections from the Office of Clean Energy Demonstrations[38]. Configuration 2 cost modeling is based on [12] and assumes a 33% higher capital cost and 74% higher operational cost. Electrolyzer installed capital costs can be seen in table 3.

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2.2.7. Hydrogen Compressor In configuration two, the H_2 produced is transmitted to shore via pipeline, which requires compression from atmospheric pressure to 68 bar [39]. The HOPP's H_2 transport compressor model is derived from the compressor model in the Hydrogen Delivery Scenario Analysis Model (HDSAM) [39]. The required number of compressors and the power rating of each compressor depend on the H_2 flow rate. We use an H_2 compressor flow rate that is equal to the maximum hourly production of H_2 by the PEM electrolyzer. Due to the high failure rates of compressors [36], a backup compressor is factored into the costs.

2.2.8. Hydrogen Transport Pipeline In configuration two, once the produced H_2 is compressed, it is transported to the shore through a pipeline. The transport pipeline model in HOPP determines the most cost-effective specifications, including grade, diameter, and thickness, while adhering to ASME B31.12 and B31.8 standards [40]. The model calculates the minimum pipe diameter required to meet the pressure drop criteria based on the specified inlet (68 bar) and outlet (10 bar) pressures, pipe length and depth (site-specific), and flow rate (maximum hourly H_2 production rate). Costs, categorized into material, labor, miscellaneous, and right-of-way, are obtained from industry insights and correlations [41, 42]. These costs are aggregated to determine the installed capital cost of the pipeline.

2.2.9. Hydrogen Storage The modeling encompassed three types of onshore hydrogen storage: underground pipe storage, hard rock outcrop storage, and salt cavern storage. Onshore underground pipe storage, separate from the transport pipeline, appears to be feasible at all four locations. In contrast, salt cavern storage and hard rock outcrop storage, also known as lined rock cavern storage, are geological formations distributed based on the U.S. geology, as illustrated in figure 1. We implemented salt cavern storage at the Gulf of Mexico site and hard rock outcrop at the other three sites. The installed capital cost curves of the underground pipe storage, hard rock outcrop storage, and salt cavern storage models are based on bottom-up cost modeling in [43]. The models require the storage capacity of the hydrogen storage and the system flow rate. These values are based on the maximum hourly hydrogen production from the PEM electrolyzer and the days of hydrogen storage, which we assumed to be 11 days to represent long-duration storage. The operations and maintenance models are based on HDSAM [39].

2.3. Financial Modeling

We used ProFAST [44] a financial tool based on the Generally Accepted Accounting Principles method, to calculate levelized cost of energy (LCOE) and LCOH for evaluating different designs. The LCOE reflects costs exclusively for the electrical infrastructure, encompassing the wind system and electrical transmission. The LCOH accounts for the entirety of the integrated system, including the wind system, electrical transmission, and hydrogen system. This analysis includes financial parameters outlined in table 4, along with capital expenditures, operation and maintenance expenditures, feedstock costs (water in configuration one), and policy incentives. Policy incentives, from the IRA [6], were incorporated to evaluate their effects on offshore wind-to-hydrogen systems. Provision 45Y, the technology-neutral production tax credit (PTC), is applied to the electricity generated for the first 10 years of plant operation, while provision 45V, the clean hydrogen production tax credit (H_2 PTC), applies to the hydrogen produced for the first 10 years – the 45Y credit phase out is expected to begin in 2032, or when emissions levels reach a 75% reduction to those in 2022. The prevailing wage and apprenticeship (PWA) utilization 5X credit multiplier is modeled and applied to the technology-neutral PTC and H_2 PTC. Facility credit eligibility, any bonus credits, or incurred labor costs for PWA utilization are not addressed in this research. Both provision 45Y and 45V are implemented as reflected within the IRA. The newly proposed 45V guidance as of December 2023 is not addressed, as it is only proposed guidance rather than actual law. Costs were modeled using nominal values in 2020 U.S. dollars (USD), with project commissioning occurring three years after the technology cost year [45], and a project lifetime of 30 years.

Table 3: Installed capital costs of wind system and PEM electrolyzer in 2020USD/kW. Electrolysis costs are ordered Configuration 1/Configuration 2.

Technology	Wind System				Electrolysis
Year	Gulf of Maine	New York Bight	Gulf of Mexico	California	All Sites
2025	10226	4266	4731	10930	900/1197
2030	6308	3008	3312	6678	540/718
2035	4860	2765	3164	5081	445/592

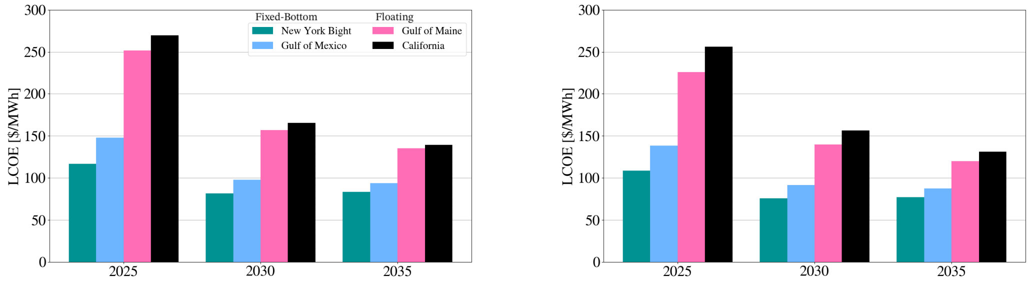
Table 4: Financial and policy assumptions. Technology-neutral PTC value is in 1992 USD valuation and H_2 PTC value is in 2022 USD valuation, adjusted to 2020 USD in analysis. Note: PWA – prevailing wage and apprenticeship, PTC – production tax credit.

Parameter	Value	Parameter	Value
Wind Return on Equity	11%	H_2 Return on Equity	10.89%
Wind Debt-Equity Ratio	2.82	H_2 Debt-Equity Ratio	0.62
Wind Debt Interest Rate	4.39%	H_2 Debt Interest Rate	5.00%
Debt Type	Revolving Debt	Depreciation	7-year MACRS
PWA technology-neutral PTC	\$0.015/kWh	PWA H_2 PTC	\$3.00/kg

3. Results

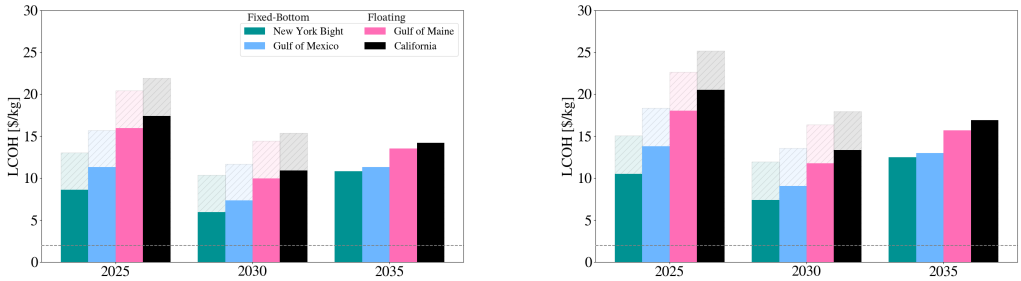
This section presents techno-economic analysis of offshore wind-to-hydrogen plants at four U.S. coastal locations, illustrating the impact of regional-specific characteristics on clean H_2 costs. Figure 3 shows the LCOE for only the offshore wind plant and electrical infrastructure costs without policy incentives within the wind-to-hydrogen system (excludes H_2 system costs) across all locations through time. Configuration two (offshore electrolysis) has lower LCOE values than configuration one because the electrical export infrastructure is replaced by hydrogen pipelines (figure 3b). The fixed-bottom sites, New York Bight and Gulf of Mexico, demonstrate lower LCOE compared to their floating counterparts. Floating technology with its greater uncertainty around capital, installation and maintenance costs, contributes to increased LCOE [30]. Between the fixed-bottom sites, the New York Bight exhibits lower LCOE than the Gulf of Mexico, partially due to its higher wind capacity factor. Similarly, between the floating locations, the Gulf of Maine has a lower LCOE than California due to its higher wind capacity factor and shallower site depth, which reduces technology costs. Over time, the LCOE largely decreases as a result of the learning curve and economies of scale. Further insights into offshore wind specific trends can be found in [18].

Figure 4 shows the LCOH, which incorporates all system costs, including long-duration hydrogen storage, at each location. Across all locations, configuration one (onshore electrolysis) yields lower LCOH than configuration two. This is attributed to higher costs and reduced available power for electrolysis in configuration two, which is allocated to peripheral equipment, resulting in about 7% less hydrogen produced annually. The LCOH trends, without policy

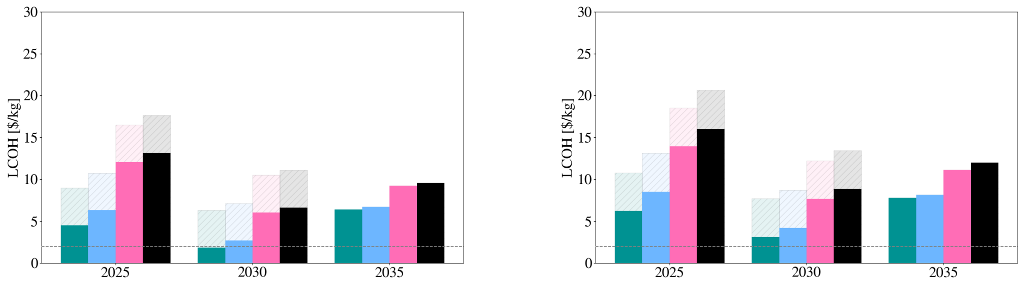


(a) Configuration one. (b) Configuration two.

Figure 3: LCOE (wind plant and electrical infrastructure costs) at each location.



(a) Configuration one with pipe storage. (b) Configuration two with pipe storage.



(c) Configuration one with geologic storage. (d) Configuration two with geologic storage.

Figure 4: LCOH with long-duration hydrogen storage at each location. Dashed line at \$2/kg-H_2. Hatched bars represent LCOH in the absence of PWA policy in years 2025 and 2030.

incentives, parallel those of the LCOE for both fixed-bottom and floating technologies. The Gulf of Mexico LCOH decreases over time, with a more significant decrease observed from 2025 to 2030 than from 2030 to 2035. In contrast, the LCOH for the New York Bight follows a similar pattern to its LCOE, decreasing from 2025 to 2030 but then slightly increasing from 2030 to 2035, despite lower system costs, attributed to a lower wind capacity factor in 2035. The LCOH for floating locations decreases over time, even though the systems have a lower capacity factors in 2035. This is because system costs, which account for the pre-commercial nature of the floating systems, outweigh the reduced capacity factor. The stacked implementation of the technology-neutral PTC and clean hydrogen PTC with the PWA multiplier for wind and low-carbon hydrogen results in an approximate \$4.5/kg reduction in LCOH in both 2025 and

2030. The choice of hydrogen storage significantly impacts the cost, with a 20–35% decrease in LCOH achievable if geologic storage is used at each location (figure 4c,4d). When configuration one (onshore electrolysis) is combined with policy incentives and geologic storage, hydrogen production may be cost-competitive (approximately \$2/kg) at fixed-bottom locations by 2030. It is important to note that provision 45Y and 45V incentives may not available in 2035, although historical trends suggest renewable energy credits are often renewed.

4. Conclusion

This paper details an open-source scenario modeling tool aimed at creating transparent and accessible models for analyzing the techno-economics of offshore wind-to-hydrogen systems. Our analysis suggests that by 2030, combining fixed-bottom offshore wind with onshore electrolysis and geologic storage, leveraging IRA policy incentives, may achieve hydrogen production costs of less than \$2/kg-H_2, competing with current carbon-intensive methods. It's important to highlight that the technology in this analysis is rapidly evolving and may undergo significant changes within the timeframe considered in this analysis. Our simplified system designs facilitate easy location and year comparisons, yet optimizing designs, including the electrolyzer to wind plant sizing ratio and scenario-matched hydrogen storage, along with operational dynamics remains essential. While our research favors an onshore electrolysis configuration, further exploration of alternative configurations, such as decentralized hydrogen production repurposing existing oil and gas infrastructure for hydrogen production, or considering alternate off-take vectors could enhance system efficiency and cost-effectiveness. Furthermore, leveraging additional policies from the IRA could also contribute to reducing project costs.

Acknowledgments

This work was authored in part by the National Renewable Energy Laboratory, operated by Alliance for Sustainable Energy, LLC, for the U.S. Department of Energy (DOE) under Contract No. DE-AC36-08GO28308. Funding provided by the U.S. Department of Energy Office of Energy Efficiency and Renewable Energy Wind Energy Technologies Office and Hydrogen and Fuel Cell Technologies Office. The views expressed in the article do not necessarily represent the views of the DOE or the U.S. Government. The U.S. Government retains and the publisher, by accepting the article for publication, acknowledges that the U.S. Government retains a nonexclusive, paid-up, irrevocable, worldwide license to publish or reproduce the published form of this work, or allow others to do so, for U.S. Government purposes.

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