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Offshore or onshore hydrogen production? A critical analysis on costs and operational considerations for the Dutch North Sea

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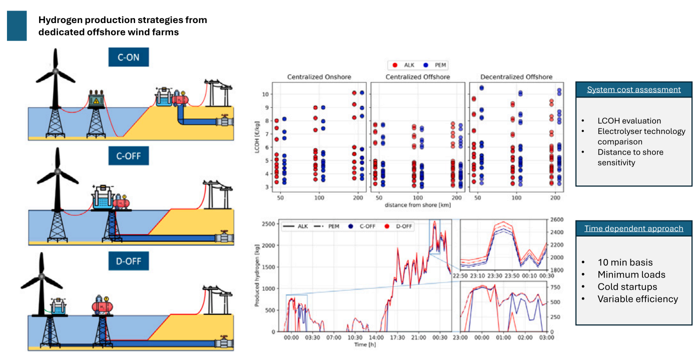
HIGHLIGHTS

- Cost and operational analysis of centralized and decentralized offshore hydrogen systems.
- Innovative modelling enables detailed analysis for decentralized electrolysis.
- Future cost and technology input data result in LCOHs ranging from 3.0 to 10.5€/kgH_2.

GRAPHICAL ABSTRACT



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ABSTRACT

Ambitious offshore wind energy targets in the North Sea necessitate innovative solutions for efficiently delivering energy to onshore demand locations. Wind-to-hydrogen systems offer a promising pathway, with three archetypes of system configurations: centralized onshore electrolysis (C-ON), centralized offshore electrolysis (C-OFF), and decentralized offshore electrolysis at each wind turbine (D-OFF). This study introduces a high-resolution, time-dependent simulation framework capable of analyzing offshore wind-to-hydrogen systems with a focus on operational dynamics and comprehensive cost estimation. The framework enables detailed analysis of D-OFF, capturing its unique dynamics driven by direct connections to individual wind turbines, including the impacts of dynamic operation. A comprehensive system analysis, spanning from the wind farm to the hydrogen offtaker, reveals a wide cost range, with Levelized Cost of Hydrogen (LCOHs) ranging from 3.0 to 10.5€/kgH_2 post 2030. Among the different scenarios analyzed, C-OFF with proton exchange membrane electrolysis achieves the lowest LCOHs due to a reduced need for offshore electrical infrastructure, economies of scale, and efficient dynamic operating characteristics. D-OFF with alkaline electrolysis incurs the highest costs and faces operational challenges, such as electrolyzers shutting down when they occasionally fail to reach the minimum load thresholds, lowering hydrogen production. We illustrate the trade-offs between system configurations' cost, production rate, and electrolyzer stack lifetime across configurations. Insights from this study can be utilized as a starting point for informed decision-making for large-scale wind-to-hydrogen deployment in the Dutch North Sea region.

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1. Introduction

The North Sea region hosts a large wind energy potential. The European Union, Norway, and the UK have a combined 2050 target of nearly 500 GW of offshore wind in the North Sea [1]. The Netherlands alone aims to expand its offshore wind capacity to 50 GW by 2050 and to 70 GW by 2070 [2]. These ambitious targets for offshore wind energy may necessitate partially converting the produced electricity to hydrogen offshore to efficiently deliver this wind energy to onshore demand locations [3], although the desired ratio between offshore hydrogen and electricity remains the subject of debate [4,5].

Green hydrogen will be required to de-carbonize hard-to-abate sectors and industries [6]. For the production of low-emission hydrogen, water electrolysis is the most anticipated and promising conversion method [7,8]. Key challenges arise in increasing the capacity of electrolyzers to GW-scale and developing the upstream supporting infrastructure. Moreover, there are difficulties in financing the projects [9].

Against this background, this study provides a comprehensive framework to explore the economic characteristics and operational dynamics of different offshore wind-based hydrogen production system configurations. The three analyzed configurations include:

1. Onshore centralized electrolysis (C-ON): Offshore wind-based hydrogen production occurs entirely onshore, with wind-generated electricity transported via high-voltage cables to shore.
2. Offshore centralized electrolysis (C-OFF): This approach involves offshore hydrogen production at a single centralized platform where electricity from nearby turbines is converted to hydrogen and piped to shore.
3. Offshore decentralized electrolysis (D-OFF): Each offshore wind turbine platform hosts an individual electrolysis system, producing hydrogen locally and eliminating the need for offshore electricity transmission infrastructure.

The D-OFF system configuration may have five major advantages over the two centralized alternatives. Firstly, Timmers et al. [10] conceptually showed that it is possible to modify wind turbine (WT) power systems to minimize the number of power conversion steps, i.e., by bypassing one conversion step (direct current (DC)-alternating current (AC)) and using less electric transmission infrastructure to reduce conversion losses. This approach may reduce power conversion losses since the WT and electrolyzer are at the same site [11,12] and may both operate on the same DC-voltage level. Secondly, offshore decentralized electrolysis replaces all electrical export infrastructure (inter-array (IA) cables, high voltage (HV)AC/DC-cables, substations, and converter stations) with pipeline transmission infrastructure [11,12] which may result in lower costs and lower transmission losses. Thirdly, decentralized brine disposal has a lower environmental impact and lower costs [11]. Fourthly, the WT and electrolyzer can be integrated into a single modular system [11,12], rather than using two independent systems. Fifthly, Ibrahim et al. [11] state that D-OFF has more manageable failure events due to the modular system and there is no need for additional support structures.

In this context, we aim to answer the following research question: How do different offshore wind-based hydrogen production system configurations in the Dutch North Sea region affect the Levelized Cost of Hydrogen (LCOH), considering the effects of operational behavior, energy flows, and production rates under intermittent wind energy inputs?

We introduce an innovative modular simulation, time-dependent model based on a Python-environment that allows analyzing the hydrogen production systems with multiple levels of detail. It enables quasi-steady state modelling, analysis of operational dynamics, energy flows, material flows, and economic assessments. The model combines high-detail modules for the main system components (the wind farm (PyWake) [13] and electrolyzer (physically accurate electrolyzer model) [14]) and the lower-detail modules for the modelling of other system components. The higher detail level modules are required for conducting a detailed analysis of the D-OFF configuration, as it captures the unique dynamics driven by direct connections to individual wind turbines. As our results will illustrate, this is crucial for examining the impacts of wind energy fluctuations and intermittency on system performance, hydrogen production rates, and overall efficiency.

To feed this framework, we first compile an extensive techno-economic dataset, validated by industrial and scientific experts, for the full upstream hydrogen system spanning from the wind farm to injection into the onshore Dutch hydrogen backbone which is expected to be developed in the upcoming years [15]. Second, we perform a comprehensive economic analysis by determining the LCOH for different scenarios across three system configurations. Third, we assess and analyze the operational dynamics and time-dependent energy flows for each system configuration, including start-stop frequency, degradation rates, and minimum load thresholds, to provide critical insights into the lifetime and efficiency of electrolyzers under different conditions.

1.1. Contribution

First, we compile a validated dataset incorporating projected costs and technological advancements from 2030 onward, ensuring alignment with current knowledge. Expert validation of economic data for key components enhances the reliability and relevance of the cost modelling.

Second, this research presents a detailed analysis of the system costs for a range of scenarios for both centralized and decentralized offshore hydrogen production systems. A total of 432 scenarios based on lower, mean, and higher bounds for input parameters are included to address the wide range of potential future costs and technological developments. Typically, the literature relies on single-point estimates as input data, overlooking the inherent uncertainty in both economic and technological parameters, particularly for future systems.

Third, the presented framework is, to the best of the authors' knowledge, the most comprehensive open-source framework to date. In contrast to many existing approaches in the literature [12,16,17], this study incorporates a detailed assessment of energy production at the individual wind turbine level, integrating the effects of wind speed variability, wake losses, and other spatiotemporal factors. This approach enables a more time and location-specific evaluation of wind energy generation, addressing limitations in prior studies that often rely on aggregated or simplified assumptions. Existing studies that often exclude [12,16,18–20] or only partially incorporate [21–24] detailed electrolyzer operations. In contrast, our study fully considers operational dynamics and component interdependencies of the hydrogen production system. By providing outputs on interconnections, energy flows, and costs, along with flexibility in time steps from annual to 10-minute intervals, the model captures the effects of intermittent energy inputs.

1.2. Structure of the paper

The paper is organized as follows. After the introduction and literature review (Section 2), the methodology section (Section 3) describes the simulation model by elaborating the models of each system component. This is followed by the case study (Section 4), which includes data on the system boundaries and analyzed region. Next, the results (Section 5) consist of the economic and technical outputs of the simulation model. The outcomes are placed in the context of existing literature in the discussion (Section 6), highlighting implications for stakeholders, and reflecting on the limitations of the analysis. Finally, the paper concludes with key findings (Section 7).

2. Literature review and knowledge gaps

In Table 1, we present an overview of the literature on system simulation models for offshore wind-powered hydrogen production, highlighting several omissions in the literature. In contrast, in our study, wake losses and per-turbine energy production, minimum load thresholds for

Table 1
Overview of techno-economic simulation models of offshore wind energy-based electrolysis in the literature.

Source	Temporal resolution	Measured wind data input	Production per wind turbine	Detailed electrolyzer operation (load range, effects of temperatures, etc.)	Stack degradation (decreasing efficiency)	Economies of scale
This study	10 min	✓	✓	✓	✓	✓
Rogeau et al. [12]	Annual	x	x	x	x	x
Egeland and Sartori [21]	Hourly	✓	x	Partly	x	x
Komorowska et al. [16]	Annual	x	x	x	x	x
Vu Dinh et al. [18]	Hourly	✓	✓	x	x	x
Singlitico et al. [25]	Hourly	✓	x	✓	✓	✓
Hill et al. [22]	hourly	✓	x	Partly	x	x
Calado et al. [23]	Hourly	✓	x	Partly	x	x
Jang et al. [17]	Annual	x	x	✓	✓	✓
Song et al. [19]	Hourly	✓	x	x	x	x
Zhuang et al. [20]	Hourly	✓	x	x	x	x
Mehta et al. [24]	Hourly	✓	✓	Partly	x	x
Rezaei et al. [29]	Hourly	✓	✓	Partly	✓	✓

electrolyzers, detailed component representation, and comprehensive modelling of component interactions are key aspects to analyze and compare the system configurations in cost and operational performance. To capture these key aspects, a detailed geographical and temporal resolution is required. In many existing studies [12,16,17,19,20], few of these aspects are incorporated or are not combined, as their primary aim is not to analyze the consequences of the operational-level interaction between the different components on the performance and cost of the systems.

Firstly, most studies utilize an hourly temporal resolution and incorporate either actual or empirical wind data [20–25] or data derived from existing models or datasets [12,16,17]. Despite the reliance on real-world wind data, few studies account for production per WT considering wake losses and other aspects [18,24]. This is crucial for D-OFF, given expected interactions with operational characteristics of the electrolyzer [11,17].

Secondly, some studies detail electrolyzer operations [17,25], while others partially address this by including minimum load requirements [21,24] or operating temperature considerations [22,23]. However, stack degradation is rarely included. Kojima et al. [26], Kuhnert et al. [27], and Nguyen et al. [28] have studied the effects of intermittent power input on electrolyzers, finding that degradation rates can drastically increase for both Alkaline (ALK) and Proton exchange membrane (PEM) types.

Thirdly, only Singlitico et al. [25], Jang et al. [17], and Rezaei et al. [29] consider the economies of scale for the electrolyzers, which refer to the cost benefits associated with centralized large-scale electrolytic hydrogen production over a decentralized approach, consisting of multiple facilities with smaller capacities.

The work by Singlitico et al. [25], Jang et al. [17], and Rogeau et al. [12] is closest to the analysis presented in this paper. These authors analyze comparable system configurations and consider the North Sea region for hydrogen production. We discuss how they address key modelling challenges central to our work: the dynamic behavior of wind farms and electrolyzers over time, the influence of geographic conditions, the role of economies of scale, and comprehensive cost estimation. Together, they provide a strong foundation for comparison and help clarify how our approach advances the current state of the art.

The study by Singlitico et al. [25] provides a cost estimation of three system configurations in the North Sea region. Their analysis includes dynamic modelling of the wind farm and the electrolyzer. The study highlights the strong influence of economies of scale, particularly for small electrolyzer capacities that incur higher specific costs. However, the study employs two operating strategies: a 'hydrogen-driven' operation mode, where the electrolyzer is operated at fixed power rating, and an 'electricity-driven' operation mode, where only excess electricity is used for hydrogen production. In contrast, we study the dedicated wind-based hydrogen production systems. Furthermore, the study relies on an hourly temporal resolution, which may be insufficient for capturing the operational dynamics of D-OFF. Our work addresses this by using a finer temporal resolution (10-minute timesteps) to enhance modelling accuracy. In our study, we leverage a more advanced wind farm model and extend Singlitico et al.'s electrolyzer model model to represent the dynamic interaction between these key components. Singlitico et al. [25] highlight the strong influence of economies of scale, i.e., small electrolyzer capacities exhibit higher specific costs.

Jang et al. [17] assess C-ON, C-OFF, and D-OFF configurations to estimate the LCOH and net present value (NPV). Their study includes a detailed cost breakdown that incorporates fixed operating cost assumptions and a predefined, static capacity factor. While this approach provides clear cost comparisons across system configurations, it limits the representation of operational dynamics by not accounting for temporal fluctuations in wind power generation or electrolyzer operations. As a result, system constraints on dynamic operations and real-time performance are underrepresented, which our study incorporates. Nonetheless, the study confirms that electrolyzers for D-OFF system configuration face higher specific costs, due to their smaller capacities at each turbine, which underscores the anticipated cost disadvantage associated with reduced economies of scale in decentralized configurations.

The North Sea region is also the focus of the study by Rogeau et al. [12], which presents a detailed techno-economic analysis of C-ON, C-OFF, and D-OFF configurations for the years 2020, 2040, and 2050. Their work offers an in-depth breakdown of the cost components across the entire value chain, including turbines, substations, pipelines, and infrastructure. However, the study does not apply the same level of detail to the operational side of hydrogen production as we have in our analysis. Hydrogen yields are based on fixed conversion efficiencies and predefined loss factors, without considering the dynamic behavior of the electrolyzer or the variability in wind generation.

Across all three studies, only a single set of input data is used. While they include sensitivity analyses to illustrate the influence of individual components on overall cost estimates, they do not incorporate a broader range of data points that could better reflect the uncertainty surrounding future costs of key technologies such as wind turbines and electrolyzers. In contrast, our study integrates a wide set of input parameters drawn from both scientific literature and industry data. However, even with more comprehensive input data, there remain notable gaps in how these systems are modelled.

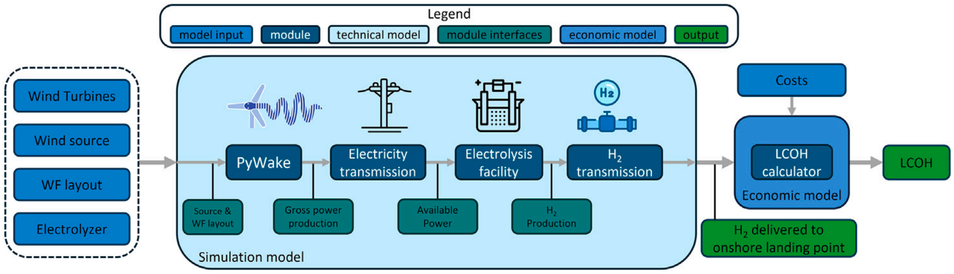


Fig. 1. Simulation model workflow.

Several authors indicate knowledge gaps related to the modelling of the costs of these system configurations. Rogeau et al. [12] state that a harmonized comparison of onshore electrolysis considering HVAC and HVDC export and offshore electrolysis, including both centralized and decentralized configurations, is lacking. Komorowska et al. [16] highlight that a detailed consideration of geographical effects for offshore wind locations is (often) not (fully) included in the cost assessment. This is also acknowledged by Vu Dinh et al. [18], who emphasize that there is a gap in the literature for a technically rich, location-dependent cost model for green hydrogen production. Hill et al. [22] point out that there is limited consideration of dynamic electrolyzer operation and its impact on efficiency, as well as a lack of focus on offshore wind farms as a primary energy source for hydrogen production. Additionally, few studies examine the lack of reliable data on the cost of offshore renewable hydrogen production projects.

3. Methodology

This section outlines the modelling approach, the description of the main system components, the economic assessment framework, and the data collection process. The simulation framework presented in this work is available open-source on Github [30].

We developed an engineering model to assess the performance and costs of electrolytic hydrogen production from dedicated wind farms. This framework describes the operation of the different hydrogen production configurations, starting from components that comprise the system, focusing on energy and physical flows, such as hydrogen and water, resulting from an intermittent power input. This engineering model forms the heart of our model workflow (Fig. 1). After the estimation of the energy and physical flows, we calculate the LCOH, considering the production of hydrogen and costs over the lifetime of the assets.

Delving deeper into details, the engineering model can be described as follows: after calculating the gross wind farm power production, the model estimates the electricity transmission losses to evaluate the power available to the electrolyzer per timestep. The hydrogen that can be fed into the hydrogen grid is then calculated through a detailed module of the electrolysis facility that reproduces the behavior of the stack and the auxiliary systems. For the wind farm and the electrolysis facility, detailed simulation models are utilized, but components such as pipelines, electric transmission infrastructure, and auxiliaries such as compressors and the desalination unit are handled with a simplified—low-fidelity—method. This assumption is justifiable based on the minor impact of these components on the system's behavior at the adopted time scales.

As shown in Fig. 1, physical and energy flows represent the interconnections between the components. The output of each module is utilized as input for the next. Regarding the time resolution for the simulations, 10-minute-based wind speed and direction data have been selected. This resolution allows modelling the operation of the electrolyzer, including degradation and temperature effects and variability of offshore wind energy. This time step size allows analyzing the effects of cold startup time for the electrolyzers. Additionally, wind power curves provided by wind farm manufacturers are typically averaged over 10-minute intervals [31]. A coarser time resolution would have led to overestimating the production [32].

Each component is sized to the peak output of the upstream component. As such, the definition of the wind farm installed capacity determines the size of all the components of the electrolysis facility and the hydrogen production potential. The wind farm's characteristics, such as the layout and the WT type, and the component costs are set as boundary conditions.

3.1. System components

3.1.1. Wind power production

PyWake [13] has been utilized to assess the wind farm's performance due to its large adoption in the design, development, and evaluation processes of wind projects. PyWake is an open-sourced and Python-based wind farm simulation tool that is capable of computing flow fields and the power production of a wind farm. The main potential of this tool is the ability to calculate the wake interactions within a wind farm for a range of steady-state conditions with a low computational cost. This enables the integration of different Python-based modules, such as the electrolysis facility and the transmission infrastructure, within the same numerical model using the wind power output to model the interfaces. Moreover, it allows for time-dependent analyses to evaluate the power production of the single wind turbines within the wind farm.

In PyWake's architecture, the primary object is the Wind Farm module, which includes two key components: a site and a wind turbine object. The site object defines local wind conditions based on given turbine positions, reference wind speed, and reference wind direction. The wind turbine object, defined for each turbine type and effective wind speed, provides the power curve, thrust coefficient curve, hub height, and rotor diameter of the wind turbines. Upon calculation, the Wind Farm module generates the results in terms of the calculated effective wind speed, power production, and thrust coefficient for each turbine.

Concerning the wake effects, the N.O.J. wake deficit model [33], based on the assumption of a linearly expanding wake diameter with a constant wake decay coefficient, has been adopted. In order to deal with the marine environment of the Dutch North Sea, the DTU guidelines for offshore installations have been adopted, neglecting factors such as surface roughness and orography due to the offshore site [34].

3.1.2. Electrolyzer

To account for the effects of intermittent power input, time-dependent hydrogen production requires a model that can provide a variable efficiency of the component depending on power inputs, temperature, and load hours for the different electrolyzer technologies considered in this study—ALK and PEM. The approach proposed in Superchi et al. [14] has been adopted and expanded to include PEM electrolysis. This module mimics the electrolyzer stack in terms of hydrogen production through implementation of the polarization curve of the cell. This curve describes the relationship between the cell's voltage and current, depicting the efficiency of the component by including

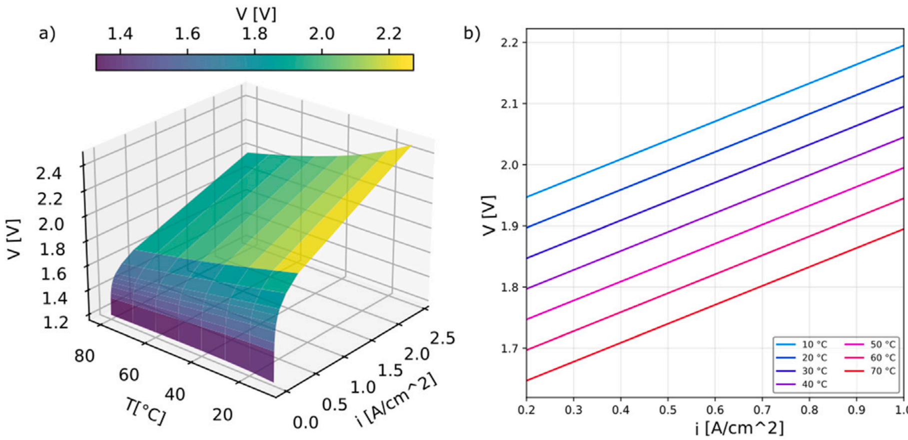


Fig. 2. Polarization curve of the PEM electrolyzer (a) [36] and ALK electrolyzer (b) [14].

the system's irreversibilities. Specifically, the actual operating voltage of the cell consists of the thermoneutral voltag—the theoretical minimum voltage needed for water splitting—and additional overpotentials. These overpotentials arise from three types of losses: activation (due to reaction kinetics) that mostly affects the hydrogen production curve for low power inputs, ohmic (due to resistance in the electrolyte and other cell components) prevailing in the inner part, and, finally, concentration losses (due to mass transport limitations). Together, these factors influence the efficiency and power requirements of the electrolysis process [35]. Furthermore, this approach addresses the effects of the thermal variation of the stack thanks to the computation of the heat generation and dispersion to the environment based on the geometry of the electrolyzer itself.

Regarding the power source, this module enables addressing the impact of variable operation on system productivity when connected to non-dispatchable power sources. The modelling strategy mimics a management system that seeks to maximize the number of active modules within the electrolyzer by distributing the minimum required power across as many modules as possible.

Fig. 2(a) and (b) show the link between the voltage and the current density (i) of the electrolyzer at different temperatures for the PEM [36] and ALK [14]. The control system of the ALK allows a minimum power input of 20 % of the nominal power. The low-voltage region of the operational curve is not modeled in the analysis, forcing the component to work in the linear part of the polarization curve. On the other hand, the PEM also enables the operation in the area affected mostly by activation overvoltages, which leads to strongly nonlinear behavior. To assess the impact of the temperature variation, the modelling of this initial portion of the curve requires a 3-D approach. While the ALK efficiency has been modeled with a linear curve—see Fig. 2(b)-, the behavior of the PEM is reproduced with a surface, see Fig. 2(a).

The impact of temperature on the stack efficiency can be observed in Fig. 2. A decrease in temperature due to heat losses leads to a shift of the curve towards higher voltages of 0.5 mV [14] and 0.4 mV [36] per °C for the ALK and PEM. This leads to a decrease in the efficiency of the component. Adopting this modelling strategy leads thus to the assumption that the hydrogen flow rate is proportional to the current density of the cell. An enhanced working voltage at the same current density results in a higher power input needed to produce the same amount of hydrogen. Finally, an efficiency degradation mechanism that accounts for the operating hours is considered. A linear relationship between degradation and operating hours has been considered, setting a constant increase in the overvoltage per working hour for both technologies. However, although the intermittent operation of the electrolyzer strongly affects the lifetime of the component itself [27,28,37], incorporating this aspect into a parametric model remains an unresolved gap in the literature. To address this challenge, several degradation factors have been tested, as extensively depicted in Section 4, to reproduce the mimic of a lower electrolyzer lifetime on the revenues of the plant.

To quantify the variation of the voltage, Eq. (1) is employed per time-step. Here, V_{OP} represents the operating voltage, V_{id} the voltage of the new electrolyzer working at design temperature, ΔV_{time} the time degradation overvoltage, h the cumulative number of operating hours, ΔV_T the thermal overvoltage, and T_{rated} and T_{el} the design and working temperatures.

$$V_{OP} = V_{id} + \Delta V_{time} \cdot h + \Delta V_T \cdot (T_{rated} - T_{el}) \tag{1}$$

As described in Superchi et al. [14], the operating voltage leads to the estimation of the conversion factor (Ω) and the heat generated by the component. Ω represents the link between the power input to the component and hydrogen production. This coefficient is evaluated per time-step through the ratio between the maximum hydrogen production ($H_{2,id}$) and the product of the number of cells (n_{cell}), the operating voltage and the ideal current (I_{id}), as shown in Eq. (2).

$$\Omega = \frac{H_{2,id}}{n_{cell} \cdot V_{OP} \cdot I_{id}} \tag{2}$$

Hydrogen production is estimated by multiplying Ω and the electrolyzer input power provided by the renewable source. The definition of the correct working temperature is required to match the correct operating point on the polarization curve. Heat generation (Q_{Gen}) and dissipation (Q_{Diss}) are estimated following the approach mentioned in the reference model [14], adapting the geometries to the ones described in Tiktak [36] for PEM.

Regarding the electrolysis facility, a few assumptions have been made. Considering the thermal model reproduces the heat exchange between the gas-liquid separator and the environment (ALK), and between the whole stack and the environment (PEM), a realistic thermal capacity should be set. For both electrolyzers, a reference size of 1 MW has been set for the stack. This leads to the possibility of scaling up the whole electrolysis facility by adding 1 MW modules, resulting in homogeneous heat generation and loss for each stack. Moreover, considering a control strategy that keeps the temperature at a maximum value equal to the nominal one to avoid overheating, the cooling required (Q_{Cool}) is evaluated as shown in Eq. (3):

$$Q_{Cool} = Q_{Gen} - Q_{Diss} \tag{3}$$

This cooling requirement is then converted into the power required by the chiller by adopting a coefficient of performance (COP), set to 3.5 [38].

Extended periods of no power input result in an electrolyzer temperature drop due to heat dissipation, leading to reduced efficiency as indicated by the upward shift of the polarization curve. 30 °C has been set as the target value at which the shutdown of the component occurs. To restore the operation of the electrolyzer, an approach similar to Singlitico et al. [25] has been adopted, considering a cold startup time of five and twenty minutes for the PEM and ALK, where the power input to the electrolyzer is used to increase the temperature, and no hydrogen is produced.

The simulation of the whole lifespan of the plant leads to the possibility of assessing the real replacement time for the electrolyzer stacks. According to manufacturers, the component replacement should occur when the cell voltage at nominal temperature exceeds 2.3 V for the ALK stack [14]. Starting from this assumption, also for the PEM a maximum voltage of 2.23 V, equivalent to an increase of 21 % at rated temperature and current density, has been assumed. Therefore, by monitoring the increase in overvoltage induced by degradation, it is possible to evaluate the component's end of life.

3.1.3. Auxiliaries

Adopting a time-dependent approach allows for the evaluation of the energy availability of the electrolysis facility powered by a specific wind farm. This is key for assessing the physical flows, such as oxygen, brine, and heat production or water feed. Auxiliary components such as compressors and reverse osmosis units have been included in the analyses. However, due to the minor role of these technologies, a simplified approach has been adopted. A brief description of the technologies adopted and the modelling assumptions made is provided in Supplementary Appendix A.

3.2. Economic assessment

Hydrogen production cost assessments are typically conducted through techno-economic assessments utilizing the LCOH as the main cost metric. This metric evaluates the annualized cost of hydrogen produced at a specific installation site over its economic lifetime. The LCOH considers the capital expenditures (CAPEX) of each component, the operational and maintenance costs (OPEX), discount rates, and inflation. The LCOH is calculated following the approach shown in Singlitico et al. [25] and Rogeau et al. [12] and depicted in the equation below.

$$\mathrm{LCOH} = \frac{\sum_{y=1}^{n} \frac{\mathrm{CAPEX}_y^{\mathrm{Total}} + \mathrm{OPEX}_y^{\mathrm{Total}}}{(1+r)^y}}{\sum_{y=1}^{n} \frac{\mathrm{H_2 production}_y}{(1+r)^y}} \tag{4}$$

The n in Eq. (4) represents the economic lifetime, y is the year, $\mathrm{CAPEX}_y^{\mathrm{Total}}$ and $\mathrm{OPEX}_y^{\mathrm{Total}}$ represent the total system capital and operational expenditures for each y and r is the discount rate.

Economies of scale and scale factor. In the studies by Singlitico et al. [25] and Jang et al. [17], the economies of scale benefit centralized configurations more than decentralized ones. Even though electrolyzer stacks are modular, centralized system configurations consolidate all electrolysis components at a single location. As Cooper et al. [39] highlight, larger electrolyzer plants allow for a cheaper balance of plant—which is part of the CAPEX of the electrolyzer—which reduces the specific cost as system size increases. A scale factor of 0.69 is introduced in Travaglini et al. [32] based on scientific literature [40] and correspondence with industrial experts, resulting in cost benefits for electrolysis, as shown by Eq. (5). Conversely, due to its decentralized setup, the D-OFF configuration, which employs smaller electrolyzers distributed across multiple wind turbines, does not realize the same cost advantages.

$$CAPEX_{Electrolyzer} = C_0 \cdot \left(\frac{X}{X_0}\right)^{0.69} \tag{5}$$

This equation shows how, taking a reference cost (C_0) and size (X_0), the CAPEX of the electrolyzer can be scaled, according to the actual size of the component (X). In this work, while C_0 depends on the economic scenario, the X_0 has been set to 15 MW.

4. Case study

For each combination of system configuration and selected wind farm location in the North Sea, different scenarios have been simulated. Both economic and technical data are gathered to develop a large dataset. This is done by executing a desktop study on the existing literature from academia and industry. The analysis focused on data for 2030 and beyond. The most recent data were selected when projections were available for this period.

Based on interviews and communications with experts in the fields of wind energy, electrolysis, hydrogen infrastructure, and electricity infrastructure, the data are validated for the core components. For confidentiality reasons, most of the references are excluded (Supplementary Appendix B). Together, these values make up the benchmark scenarios for the combination of each system configuration and the predefined location of the offshore wind farm.

4.1. North sea region specifications

Measured wind data are obtained for the Dutch North Sea region, more particularly for the Nederwiek [41] and Ten Noorden van de Waddeneilanden (TNW) [42], located 100 and 50 km from the assumed landing area. Additionally, to assess the robustness of the findings, the wind resources for this study two additional sites are included: Hollandse Kust Zuid (HKZ) and IJmuiden Ver (IJV) [42]. These offshore sites are located 20 km and 60 km from the assumed landing area.

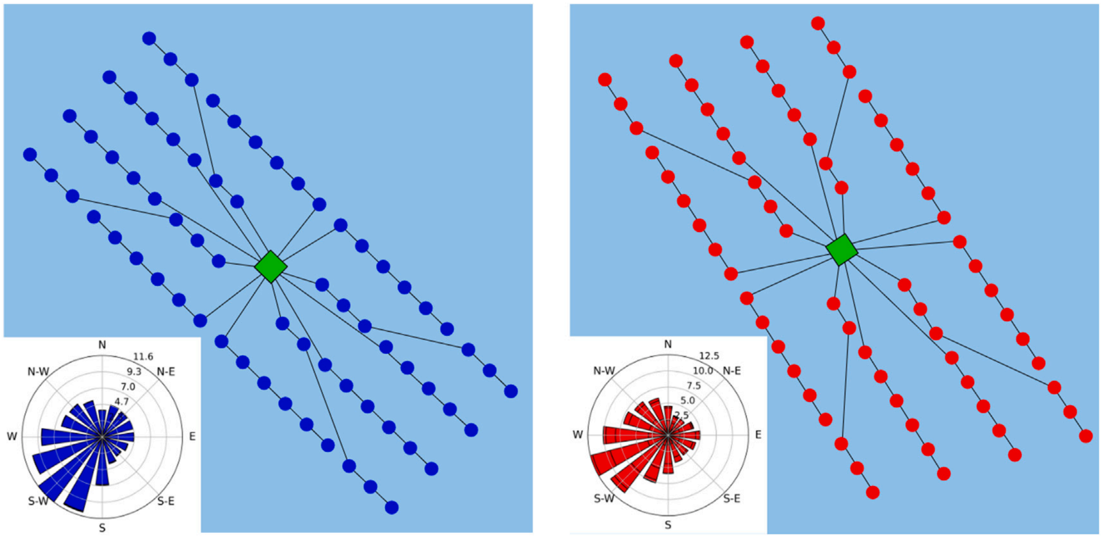
Real-life data with the required 10-minute timestep resolution for locations at 200 km from shore are currently unavailable. Considering the reduced variation in the wind source for distances from shores higher than 80 km, as depicted by the online database Global Wind Atlas [43], the same wind speed and direction series as the 100 km case have been adopted.

Two different wind farms have been designed. Both wind farms show a similar layout, obtained by the trade-off between wake losses and cable cost reduction, characterized by IA turbine distances of 14 and 5 wind turbine diameters in along-wind and cross-wind directions. Upon examination of the wind rose (Fig. 3a and b), the prevalent wind direction at the installation site is South-West for Nederwiek (a) and West-South-West for TNW (b), considering both wind frequency and energy. These directions have been adopted to define the wind farm orientations to maximize the parks' energy production. As HKZ and IJV experience a wind rose similar to Nederwiek, as shown in detail in Supplementary Appendix C, the same wind farm layout has been adopted. Fig. 3a and b depict the relative positions between wind turbines and the electrical scheme for the wind farms located at 50 and 20/60/100 /200 km from shore. Further specifications can be found in Supplementary Appendix C.

4.2. System configurations

For each system configuration, the offshore wind farm is composed of sixty-seven 15 MW wind turbines, for a cumulative installed capacity of 1.005 GW. We assume that the electricity produced is dedicated to hydrogen production and the auxiliary processes. The produced hydrogen is transported via an onshore pipeline to an onshore hydrogen backbone network, which is assumed to be situated 10 km inland. It is assumed that the backbone can accommodate fluctuating hydrogen input, allowing our analysis to focus on the production aspect of the hydrogen chain while excluding storage facilities.

The system configurations—C-ON, C-OFF, and D-OFF—differ in the electrolysis facility location, resulting in different energy requirements,



(a) Wind farm layout at 50km from shore with corresponding wind rose

(b) Wind farm layout at 100 and 200km from shore with corresponding wind rose.

Fig. 3. The dots represent the wind turbines, and the lines represent the IA cables (centralized system configurations) or pipelines (decentralized system configuration). The green square in the middle represents the centralized substation for electrical or hydrogen transmission to shore.

hydrogen production rates, and associated costs. Several operational aspects of the electrolyzer, such as start-stop frequency, degradation rates, and minimum load thresholds, affect each system configuration.

C-ON. This is the conventional system configuration, considering that the components in the system have the highest TRLs and most are already commercially available on a larger scale or are expected to be in the nearby future (Fig. 4 top). The offshore wind farm is connected through IA cables that lead to an HVAC or HVDC export infrastructure, depending on the distance to the onshore landing area. At the landing area, the electrolyzer is located together with the desalination unit and compressors, and it is connected to the national hydrogen grid. The onshore compressor is assumed to be powered by the grid and a cost of 100€/MWh is assumed for the electricity.

C-OFF. Individual WTs are connected through IA cables (Fig. 4 center). The IA cables are connected to an offshore structure or platform where a centralized electrolysis plant is stationed, including a seawater desalination system and a compressor. The hydrogen export infrastructure requires offshore and onshore hydrogen compression. The onshore and offshore compressors are connected to the power grid, assuming a cost of 100€/MWh and an additional cost per km/MW for the offshore cables required to transmit the power to the compressor.

D-OFF. D-OFF is the most innovative configuration with the lowest TRL. Each WT powers an on-site electrolyzer plant that is scaled to the WT power output (Fig. 4 bottom). The D-OFF configuration utilizes DC output at the turbine, reducing half of the conversion steps [10]. A direct coupling between the wind turbine and the electrolyzer located on its foundation has been considered, neglecting any potential interaction between other wind-electrolyzer configurations. In this configuration, half of the losses are prevented, resulting losses at the rectifier by 1 % compared to the centralized system configurations [44]. A co-located desalination unit is present, but it is assumed that an additional compressor per turbine is not required. IA pipelines connected to a large export hydrogen pipeline deliver hydrogen to shore. Due to the simplified modelling approach adopted for the pipelines, no mass flow interactions have been accounted for between the electrolyzers, which operate independently within the wind farm. Both offshore and onshore compressors are required to increase the hydrogen pressure for hydrogen transmission. The compressors are powered in a similar way to the C-OFF configuration.

4.3. Scenarios and databases

This study evaluates three system configurations across 432 scenarios. The scenarios consist of the combination of data for economic and technical parameters. For each economic and technical parameter, we obtained data using a literature review to create a lower, average, and upper bound. An additional value incorporates expert-validated economic data. Experts from industry and academia provided validated the economic data of the key system components. This provides an extra economic scenario, resulting in a total of four economic configurations.

Key variables include electrolyzer type, pipeline options—new vs. repurposed—and distances to shore. Each scenario was constructed as follows: One of the three different system configurations is the basis: C-ON, C-OFF, and D-OFF. Each system configuration is evaluated for three distances to shore (50 km, 100 km, and 200 km) and two types of electrolyzers (ALK and PEM). For each combination, both economic and technical parameters are systematically considered by applying three different scenarios (lower bound, average, and upper bound) for cost and performance parameters. The economic data refer to projections for the year 2030 and beyond (Table 2). An overview of the technical data for 2030 and beyond is presented in Table 3.

5. Results

This section compares different system configurations in terms of cost and operational performance. The economic analysis results in LCOHs spanning from 3.0 to 10.5€/kgH_2 with C-OFF obtaining the lowest outputs and D-OFF the highest, as presented in Section 5.1. In this case, technical results such as hydrogen production and energy efficiency have not been included to evaluate the best configuration. The expert-validated scenarios show smaller ranges from 4.1 to 5.5€/kgH_2. Additionally, offshore electrolysis offers lower costs due to the use of hydrogen transmission infrastructure, centralized system configurations benefit from economies of scale, and PEM outperforms ALK electrolyzers as presented in Section 5.1. On the other hand, although D-OFF

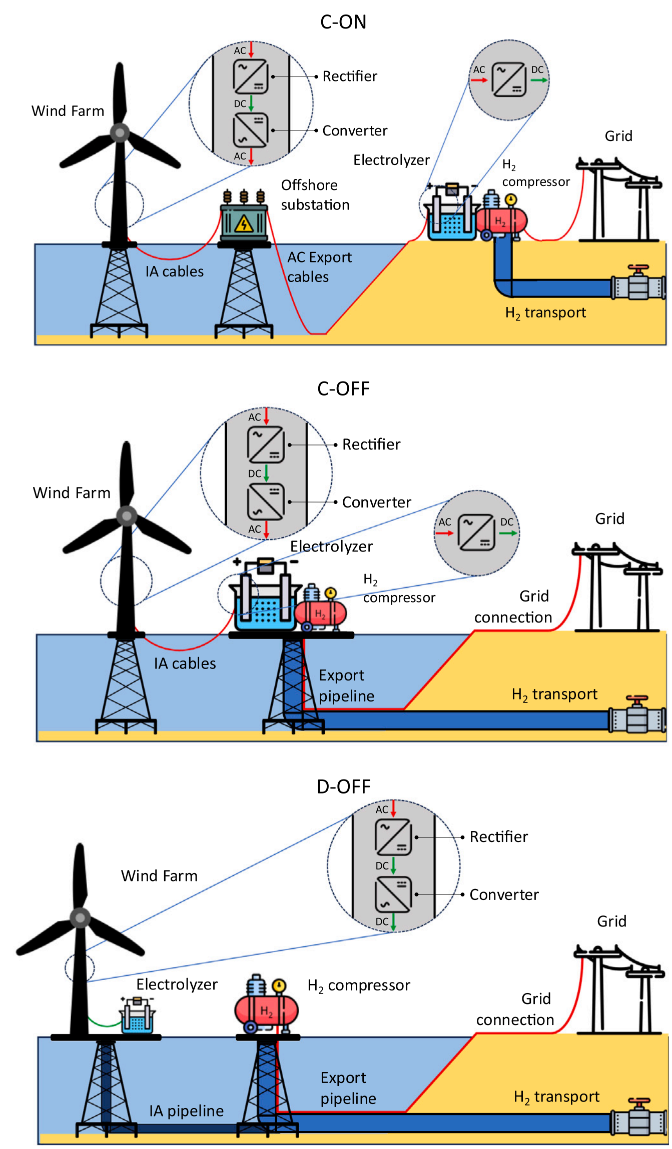


Fig. 4. Schematic representation of the C-ON, C-OFF and D-OFF system configuration.

has the highest LCOH for the different scenarios, it has the highest annual production rate and system efficiency (Section 5.2.1). Therefore, when the focus is put on the technical performance, the decentralized configuration benefits from the lower power losses. Additionally, the time-dependent analysis in Section 5.2.2 shows that PEM electrolyzers benefit from a wider power range in comparison to ALK electrolyzers, resulting in more hydrogen production.

5.1. Economic analysis of system configurations

For the C-ON configuration, a wide LCOH range is found (Fig. 5): from 3.3€/kgH_2—for PEM electrolysis at 50 km, assuming lower bound economic costs, upper bound technological input data, and repurposed onshore pipelines—to 10.1€/kgH_2, which represents ALK electrolysis at 200 km with upper bound economic costs, more conservative technological assumptions, and new onshore pipelines.

The LCOH outcomes for C-OFF configurations span from 3.0€/kgH_2—for PEM electrolysis at 100 km under lower bound economic costs, upper bound technology input, and repurposed onshore pipelines—to 7.8€/kgH_2 for ALK electrolysis at 200 km, incorporating higher economic costs, more conservative technological assumptions, and new pipelines.

The LCOH for D-OFF configurations ranges from 3.2€/kgH_2—achieved with PEM electrolysis at 100 km using lower bound economic conditions, advanced technology assumptions, and repurposed pipelines—to 10.5€/kgH_2, for the scenario with PEM electrolysis at 50 km with upper bound economic cost inputs, conservative technology assumptions, and new offshore and onshore pipelines.

Fig. 6 presents the LCOH breakdown for two benchmark scenarios—with expert-validated costs and mean technology input data—for each system configuration: a 50 km offshore distance using an ALK electrolyzer, and a 200 km offshore distance using a PEM electrolyzer. Across all system configurations, the largest contributor to the LCOH is consistently the wind farm, accounting for ≈60 to ≈80 % of the LCOH. Other components include the electrical transmission infrastructure—notably in the C-ON configuration (≈15–30 %)—and the electrolyzers (≈9 % for centralized configurations and up to ≈35 % for D-OFF). In contrast, the hydrogen transmission infrastructure, both onshore and offshore, accounts for less than 1 % of the LCOH for 50 km and around 3 % for distances up to 200 km.

Onshore vs. offshore electrolysis. C-OFF shows lower LCOH values than C-ON configurations, especially for distances farther from shore, indicating that offshore systems may be more cost-effective. This cost advantage is largely due to differences in transmission infrastructure costs. The analyzed data reveal that the 36-inch hydrogen export infrastructure—which can transmit 15 GW of hydrogen—CAPEX ranges from 3.6 M€/km to 5.8 M€/km or about 0.24 to 0.39 M€/km/GW [57] for new pipelines and 0.36 M€/km to 1.09 M€/km [58] for repurposed pipelines. In contrast, electricity export infrastructure costs are higher, with HVAC cable costs ranging from 3.0 M€/GW/km [48] to 6.8 M€/GW/km [49], HVDC cable costs from 0.8 M€/GW/km [48] to 6.8 M€/GW/km [51]. These values differ greatly, but the sources lack detailed explanations for their selected cable costs. Additionally, expenses for substations and platforms contribute to the overall cost.

For C-ON, the increasing distance affects the LCOH linearly, resulting from the cost per km of the HVAC or HVDC transmission infrastructure. This increase ranges from 3 % per 100 km to 10 % per 100 km. This effect is less pronounced for C-OFF and D-OFF due to the low cost of the hydrogen transmission infrastructure. Moreover, a decrease in LCOH is observed between 50 and 100 km for all offshore system configurations of ≈4 %, attributed to higher wind speeds that boost hydrogen production rates. This advantage, however, does not persist at distances of 200 km, as the modeled wind speeds reach their maximum beyond 100 km offshore [41,42]. Beyond 100 km, the LCOH increases by 2 to 3 % for both C-OFF and D-OFF configurations across all scenarios.

Centralized vs. decentralized. Across all distances and for both electrolyzer types, the C-OFF configuration consistently demonstrates the lowest LCOH. Notably, it achieves the lowest LCOH not only in the most lower bound cost and upper bound technology scenarios −3.0€/kgH_2 versus 3.5€/kgH_2 for both C-ON and D-OFF with PEM electrolysis at 100 km, but also in the mean and upper-cost bound cases −7.4€/kgH_2 versus 9.0€/kgH_2 for C-ON and 10.1€/kg$H_2$for D-OFF with PEM electrolysis at 100 km. This is attributed to two major advantages: economies of scale and minimal reliance on external electrical transmission infrastructure. Using the LCOH metric, C-OFF outperforms other system configurations for dedicated hydrogen production.

In summary, the centralized configurations are likely the most cost-effective option. In our simulations, D-OFF is the least cost-effective system configuration in most scenarios. While it benefits from fewer losses in transmission due to hydrogen production directly at the turbine, it is more affected by minimum load requirements, particularly for ALK electrolysis, as discussed in Section 5.2. The primary driver of its higher LCOHs is the lack of economies of scale [32].

To assess the effects of economies of scale, the same specific cost per unit size has been assumed across all configurations, setting the

Table 2
Overview of the economic specifications of all components of the considered system configurations. *Excluding platform cost. **Only for D-OFF systems. ***Including structure and development cost.

Component	Specification	Unit	Lower bound	Average	Higher bound	Expert-validated value
Wind turbine	CAPEX	[EUR/kW]	870 [45]	1073	1547 [46]	2400***
	OPEX	[%/CAPEX/year]	1.9 [25]	2.6	3 [17,45]	
Monopile structure	CAPEX	[EUR/kW]	503 [25]	535	567 [45]	
	OPEX	[%/CAPEX/year]	1.9 [25]	2.6	3 [17,45]	
IA cables	CAPEX	[k€/km]	194 [22]	290.5	500 [47]	
	OPEX	[%/CAPEX/year]	0.2 [25]	1.2	2.2 [22]	
HVAC export cables	CAPEX	[k€/MW/km]	3 [48]	5.06	6.84 [49]	5.33
	OPEX	[%/CAPEX/year]	0.5 [50]	1.5	2.5 [48]	
HVAC substation	CAPEX	[EUR/kW]	178.5 [46]	236	345	345
	OPEX	[%/CAPEX/year]	1.5 [48]	2	2.5 [12]	
HVDC export cables	CAPEX	[k€/MW/km]	0.8 [48]	2.8	6.8 [51]	1.54
	OPEX	[%/CAPEX/year]	0.2 [25]	1.5	3 [48]	
HVDC substation	CAPEX	[EUR/kW]	565 [49]	686	808	808
	OPEX	[%/CAPEX/year]	1.5 [49]	1.9	2.3 [48]	1.5
ALK electrolyzer plant	CAPEX	[EUR/kW]	350 [11]	664	1000 [22]	728
	OPEX	[%/CAPEX/year]	2 [12]	3	4 [12]	
	Replacement	[%/CAPEX]	40 [52]	47.5	55 [53]	
PEM electrolyzer plant	CAPEX	[EUR/kW]	500 [54]	825	1400 [52]	873
	OPEX	[%/CAPEX/year]	1.5 [48]	2.6	4 [12]	
	Replacement	[%/CAPEX]	40 [52]	47.5	55 [53]	
Reverse osmosis	CAPEX	[€/m^3/day]	1212.3	1212.3	1212.3	1212.3
	OPEX	[%/CAPEX/year]	2 [55]	2.17	2.5 [25]	
Brine disposal	CAPEX	[€/m$^3_{brine}$]	0**	0.073 [25]	0.073 [56]	
Offshore hydrogen platform	CAPEX	[EUR/kW]	110 [48]	194	287 [17]	
	OPEX	[%/CAPEX/year]	1 [17]	1	1 [17]	
Offshore hydrogen platform electronics	CAPEX	[EUR/kW]	30 [49]	30	30 [49]	
	OPEX	[%/CAPEX/year]	1 [17]	1	1 [17]	
Offshore infrastructure (new)	CAPEX	[M€/km]	3.6	4.7	5.8 [57]	3.6
	OPEX	[%/CAPEX/year]	0.8 [58]	2.7	7 [50]	
Offshore infrastructure (repurposed)	CAPEX	[M€/km]	0.36	0.64	1.09 [58]	0.36–0.54
	OPEX	[%/CAPEX/year]	0.8 [58]	2.7	7 [50]	
Onshore infrastructure (new)	CAPEX	[M€/km]	3.2 [58,59]	3.2	3.2 [58,59]	
	OPEX	[%/CAPEX/year]	0.8 [58]	2.7	7 [50]	
Onshore infrastructure (repurposed)	CAPEX	[M€/km]	0.64 [58]	0.74	0.84 [59]	
	OPEX	[%/CAPEX/year]	0.8 [58]	2.7	7 [50]	
IA pipeline	CAPEX	[M€/km]	0.2	0.55	0.9	0.2–0.9
	OPEX	[%/CAPEX/year]	0.5 [47]	0.5	0.5 [47]	
Hydrogen compressor (onshore)	CAPEX	[M€/MWe]	0.8 [48]	2.9	4 [58]	
	OPEX	[%/CAPEX/year]	1.7 [57]	2.2	4 [48]	
Hydrogen compressor (offshore)	CAPEX	[M€/MWe]	2.2 [57]	4.5	6.7 [57]	
	OPEX	[%/CAPEX/year]	1.7 [57]	2.2	4 [48]	

Table 3
Overview of the technical specifications of all components of the considered system configurations.

Component	Specification	Unit	Lower bound	Average	Higher bound
HVAC export cables	Transmission losses	[%/1000 km]	6.7 [60]	6.7	6.7 [60]
HVAC substation	Power conversion losses	[%/station]	1 [48]	1	1 [48]
HVDC export cables	Transmission losses	[%/1000 km]	3.5 [25,50,60]	3.5	3.5 [25,50,60]
HVDC substation	Power conversion losses	[%/station]	1 [12,25]	1.67	2 [48]
ALK plant	Energy requirement	[kWh$_e$/kg]	47 [52,54]	51.8	55.6
	Stack degradation	[V/h]	4.00e-6 [14]	5.04e-6	6.85e-6 [14]
PEM plant	Energy requirement	[kWh$_e$/kg]	49 [52,54]	52.6	58.1 [54]
	Stack degradation	[V/h]	4.29e-6 [14]	4.85e-6	6.60e-6 [14]
Desalination unit	Energy requirement	[kWh$_e$/m^3]	3 [55,61,62]	3	3 [55,61,62]
Hydrogen pipelines	Transmission losses	[%/1000 km]	0 [48]	0.03	0.05 [50]

scaling factor equal to one. This leads to LCOHs of 4.0€/kgH_2 for C-ON, 3.5€/kgH_2 for C-OFF, and a lowest of 3.3€/kgH_2 for D-OFF in the lower bound cost and upper bound technology scenario (ALK, 200 km offshore).[2] In worst-case scenarios, LCOHs increase to 13.7€/kgH_2 for C-ON, 12.6€/kgH_2 for C-OFF, and 10.8€/kgH_2 for D-OFF. For D-OFF configurations, the inability to exploit the benefits of scaling results in electrolyzer plant costs three to four times higher compared to centralized systems under similar production rates for both ALK and PEM electrolyzers. In other words, D-OFF can become the most cost-effective solution for all scenarios, distances, and electrolyzer types only if cost scaling effects were not available. However, as Cooper et al. [39] have pointed out, the balance of plant for the electrolyzer facilities benefits from centralized setups for large-scale electrolytic hydrogen production, resulting in a higher specific cost for decentralized over centralized configurations.

ALK vs. PEM. PEM electrolyzers consistently outperform ALK electrolyzers in terms of cost-efficiency across all configurations and distances. For example, for the mean cost and technology performance scenario at 50 km, the LCOH for C-ON PEM is 4.4€/kgH_2, making it 6 % cheaper than C-ON with ALK at 4.7€/kgH_2.

[2] Note that these results are not included in Fig. 5.

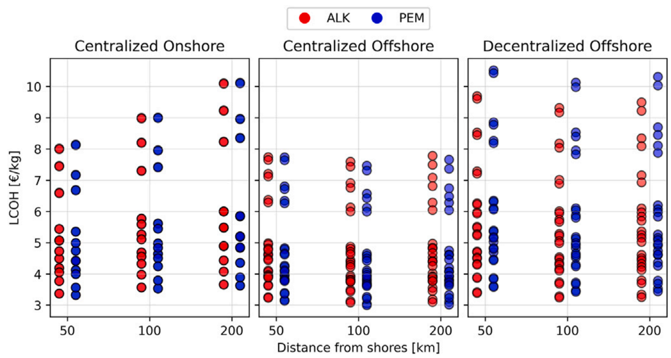


Fig. 5. Range of LCOH found for each system configuration for three wind park sites (characterized by their distance to shore).

While PEM electrolyzers have a higher CAPEX than ALK electrolyzers, they demonstrate superior performance under intermittent operating conditions. This enhanced performance results in lower degradation rates in most scenarios, subsequently reducing replacement costs. Additionally, the wider operational load range of PEM electrolyzers facilitates increased hydrogen production across all system configurations.

However, there is still a lot unknown about the degradation rate of electrolyzer stacks under dynamic operational conditions, potentially leading to a higher degradation rate in comparison to that under a stable power input [26–28]. To analyze the impact of the degradation of the stacks, additional simulations were run for both PEM and ALK electrolyzers with degradation rates twice as high as for scenarios visualized in Fig. 5. At multiple distances, the LCOH increases by 2–4 % for ALK electrolyzers under lower bound and mean cost and technology scenarios. For PEM electrolyzers, the LCOH rises more, with a 5–7 % increase, primarily due to higher stack degradation rates. In higher bound cost and lower bound technology scenarios, the cost differences are more pronounced: ALK electrolyzers experience a 4–8 % increase in LCOH, while PEM electrolyzers face a rise of 10–15 %. This difference arises from the higher CAPEX of PEM electrolyzers, meaning more frequent replacements have a greater impact on overall costs than ALK electrolyzers. However, these analyses mimic the degradation of the electrolyzer per hour of operation, disregarding the impact of *dynamic* loading.

Table 4 shows the average lifetime for each system configuration and technical scenario. The higher bound cost and lower bound technology scenarios lead to a higher number of replacements. The D-OFF configuration experiences a reduced lifetime compared to the centralized setups if the ALK technology is deployed. This is due to the higher average capacity factor of the electrolyzer, which is related to a higher number of hours of operation.

For all scenarios, PEM stacks require more frequent replacement than ALK stacks. This is due to two reasons. First, as shown in Table 3, in the lower bound technology scenarios, ALK has a lower degradation rate (4.00e-6 V/h) than PEM (4.29e-6 V/h). However, this difference does not hold in the mean and higher bound scenarios. The main reason for the higher replacement rate of PEM is its higher number of load hours, resulting from its wider operational range (0–100 %) compared to ALK (20–100 %). Consequently, the PEM stacks experience more degradation per year due to the modelling approach adopted and must be replaced more often.

The salvage value of the stacks has been excluded in our analysis. However, the residual value of the stacks at the end of their operational life could contribute to lowering the LCOH. For D-OFF employing ALK electrolyzers, the remaining lifetime extends at most to seven years, representing 88 % of the total operational life. Accounting for its salvage value can lower the LCOH by over €0.5/kg, bringing it to approximately 9€/kgH_2. For C-ON and C-OFF systems using ALK electrolysis, the remaining operational lifetime of the stacks is at

Table 4
Electrolyzer lifetime per technology and technical scenario.

System configuration	C-ON		C-OFF		D-OFF		Unit
Electrolyzer	ALK	PEM	ALK	PEM	ALK	PEM	
Upper bound technology scenario	15	10	15	10	14	10	Years
Mean technology scenario	12	9	12	9	11	9	Years
Lower bound technology scenario	9	7	9	7	8	7	Years

most 11 years, exceeding 90 % of their total lifetime. When these salvage values are incorporated, the LCOH for C-OFF systems decreases from 4.3–4.5€/kgH_2 to 4.2–4.4€/kgH_2, and for C-ON systems from 4.7–5.5€/kgH_2 to 4.7–5.4€/kgH_2. The inclusion of salvage values can have a measurable effect on reducing LCOH, but does not change the relative order of the configurations.

5.2. Operational differences across configurations

Firstly, we discuss annual hydrogen production, efficiency and the impact of wake effects (Section 5.2.1). Secondly, we illustrate how system configurations interact with the operational limitations of electrolyzer technologies (Section 5.2.2).

5.2.1. Hydrogen production and system efficiency

Depending on the selected scenario, the yearly production ranges between 76.2 and 95.8 kton for C-ON, between 76.4 and 96.2 kton for C-OFF, and between 80.3 and 99.9 kton for D-OFF. Fig. 7 shows the comparison between the different system configurations in the mean technical scenario. PEM electrolyzers always result in higher hydrogen production, regardless of distance from shore. This results in lower LCOH values for PEM compared to ALK (Section 5.1).

Focusing on the impact of the length of electrical and hydrogen transmission infrastructure, Fig. 7 shows how the increased distance from shore leads to more hydrogen delivered to the backbone due to more favorable wind conditions, despite the losses related to energy and hydrogen transmission. Note that this effect does not persist beyond 100 km offshore due to the assumption of an unchanged wind source. The electricity transmission losses that affect the C-ON result in a decreased energy input to the onshore electrolyzer, and thus less hydrogen production. PEM electrolysis enables higher production rates. This is due to the higher efficiency and large operating range of this technology, which allow for the exploitation of almost all the available wind energy. The D-OFF experiences the highest production due to the higher overall conversion efficiency compared to the other configurations.

The overall system conversion efficiency can be estimated as the energy content of the produced hydrogen over by all the input energy (Fig. 8). D-OFF experiences the highest system efficiency—resulting from the lowest losses—while C-ON has the lowest production and system efficiency. PEM is less affected by fluctuations in the wind energy source than ALK, as highlighted by the light green bars in Fig. 9(a). Finally, accounting also for the impact of distance to shore on the conversion efficiency (Fig. 9(b)), it is apparent how it adds at most 1 p.p. and does not affect the relative performance of configurations. Despite the higher amount of produced hydrogen, an increase in the length of the cables or pipelines results in lower efficiency due to the reduced exploitation of the available source. This effect is particularly evident for the C-ON, which experiences the highest energy transmission losses, as depicted by the comparison between Fig. 9(a) and (b).

Fig. 9 shows the aggregated impact of the electrolyzer constraints, namely minimum stable loads, cold startups, and power electronics on

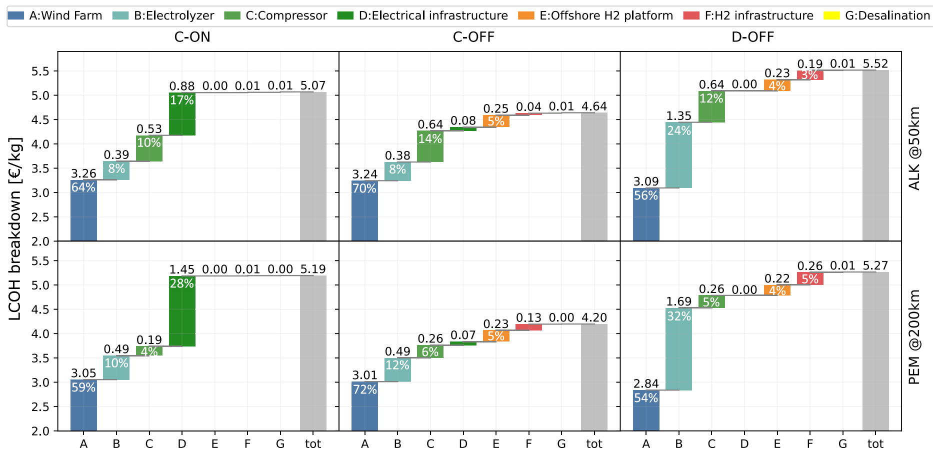


Fig. 6. LCOH breakdown for two scenarios (under expert validated cost and mean technology input data) for each system configuration: a 50 km offshore distance using an ALK electrolyzer, and a 200 km offshore distance using a PEM electrolyzer.

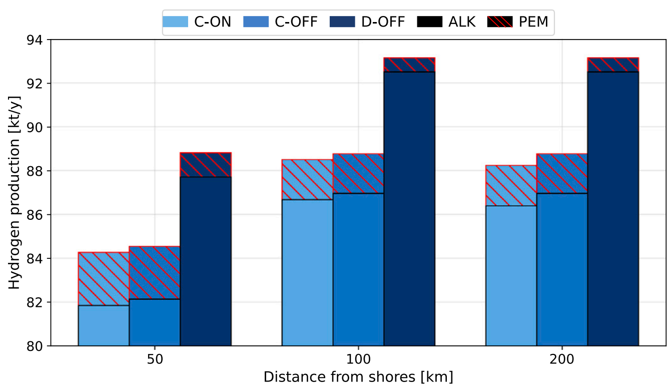


Fig. 7. Annual hydrogen delivered to the backbone for C-ON, C-OFF, and D-OFF for different distances to shores and electrolysis technologies in the mean technical scenario.

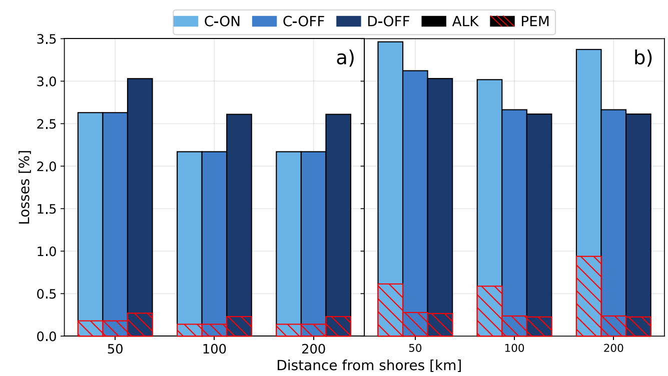


Fig. 9. Losses due to electrolyzer constraints (a) (minimum load requirements, cold startups, and power electronics) and total losses (b) (including distance from shores) per system configuration.

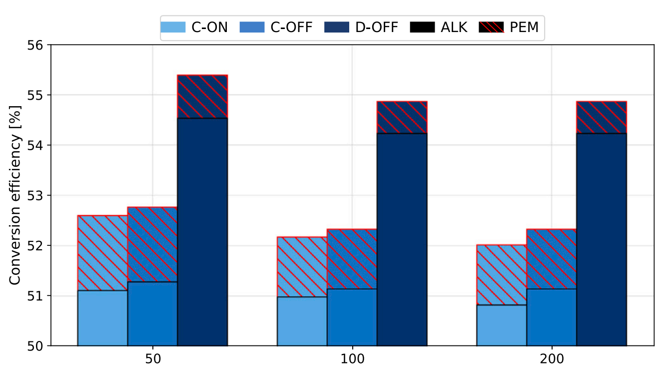


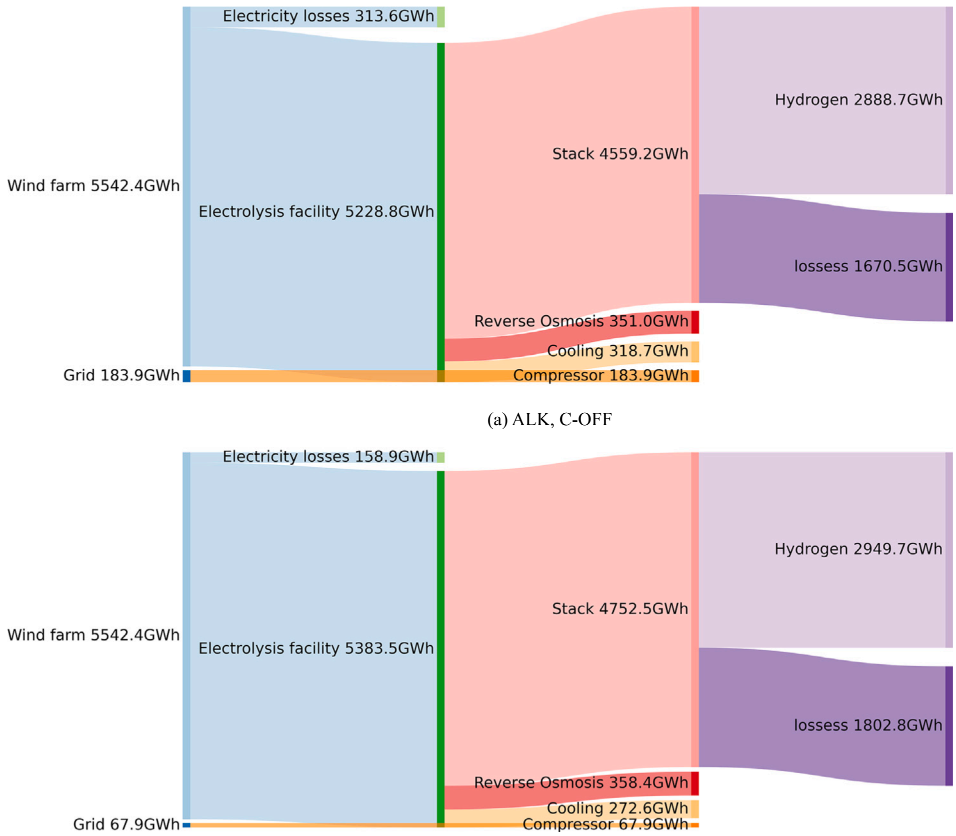
Fig. 8. Mean overall system efficiency across all scenarios and configurations.

losses. These losses are estimated as the ratio between the energy available to the electrolyzer and the energy converted to hydrogen. While the D-OFF configuration has the highest curtailments due to the technical constraints of the electrolyzer, it has the highest overall system efficiency (Fig. 8). The centralized configurations experience lower system efficiencies, due to losses in electricity transmission and conversion. Increasing the distance to shore reduces the effects of minimum loads and cold startups due to the improved wind resources. Finally, looking at the comparison between electrolyzer technologies, PEM shows losses below 1 % compared to up to 3.5 % for ALK, which is consistent with the higher hydrogen production shown in Fig. 7.

To provide an overview of the system operation, the links between the components can be depicted as energy flows in a Sankey diagram (Fig. 10(a) and (b)). Fig. 10(a) and (b) show the differences between the operation of the system for the C-OFF configuration with the two electrolyzer technologies, in terms of total yearly energy. Starting from the same wind farm power production, the PEM offers a more efficient solution. Fewer curtailments occur due to the components constraints, leading to about 447 GWh per year of additional energy available to the electrolyzer. Furthermore, despite the higher stack conversion efficiency of the ALK—testified by the ratio between produced hydrogen and losses of the stack—the scenario with PEM provides a higher amount of hydrogen and, hence, an increased system efficiency.

In the D-OFF configuration, the loading of each individual electrolyzer varies based on its position in the wind farm due to wake effects. This is illustrated via the electrolyzers' capacity factors (CF), estimated as the ratio between the produced hydrogen and the nominal capacity of the electrolyzer. Fig. 11 illustrates the variation of the CF throughout the wind farm in the mean technical scenario. As a point of reference, we remind the reader that centralized configurations offer the worst CFs, ranging from 55 % to 58 % for ALK and PEM.

In D-OFF, PEM outperforms ALK, which is affected by higher losses and, thus, shows lower CFs. On average, CFs range from 61 % for PEM



(a) ALK, C-OFF

(b) PEM, C-OFF

Fig. 10. Sankey diagrams for the ALK and PEM electrolyzers in the C-OFF system configuration.

and 59 % for ALK. The inner arrays of the wind farm face wake effects, hence, the outer electrolyzers show better performance and higher CFs. Furthermore, the comparison between the two plots depicts how inner electrolyzers are more disadvantaged with ALK technology due to the more strict technical constraints. The higher difference between the electrolyzer CFs—shown by the colors of the single wind turbines—observed between outer and inner WTs in Fig. 11(a) highlights a larger impact of the wake effect for this technology.

5.2.2. *Operational behavior*

Fig. 12 shows the hydrogen production of the offshore configurations with both electrolysis technologies during one day with a 10-minute resolution in the mean technical scenario at 100 km from shore. The variability in the wind power input results in periods of low and high hydrogen production within the same day, represented by the magnifications in the lower and upper right of the image. Focusing on the comparison between the system configurations during periods of low wind power output, several differences can be observed. PEM's wider operating range is beneficial for hydrogen production (dashed lines). The minimum power input of ALK—set at 20 % of the nominal power—results in higher losses due to the constraints of the electrolysis facility, as illustrated in the aggregated results shown in Fig. 9.

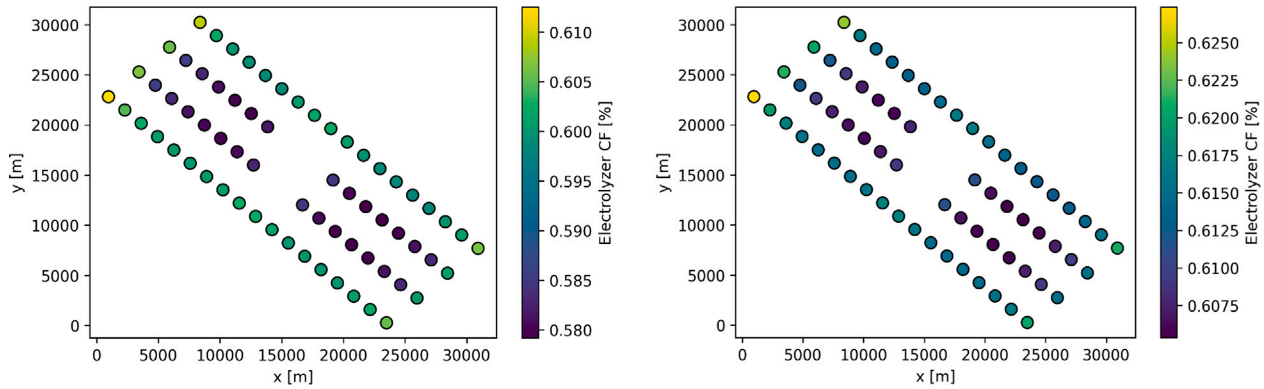
While C-OFF experiences a higher hydrogen production with ALK during low wind periods, as shown in the first hours of the selected day, when the power input to the electrolysis facility is higher than the minimum allowed D-OFF experiences improved performance. The wake losses affect the available power for the electrolyzers located on the inner WTs, triggering the minimum load constraint more often compared to centralized configurations. This is again consistent with Fig. 9 due to the lower conversion and transportation electricity losses.

The close-up of the last hours of the day depicts the system's behavior during operation far from the minimum load. D-OFF outperforms C-OFF for both electrolyzer technologies. Close to the nominal input, the ALK shows a higher hydrogen production. However, this is representative of the behavior of a new electrolyzer, when degradation has not yet set in.

5.2.3. *Impact of the selected site in the Dutch North Sea*

We analyze two additional offshore wind sites to provide better insight into the performance of the hydrogen production configurations. One of these sites is situated closer to shore, approximately 20 km from the landing area (HKZ), and is characterized by lower wind speeds. The other is located at a distance of 60 km (IJV), between the primary test sites (NED and TNW). These supplementary analyses capture the influence of site-specific factors such as wind availability and distance from shore on both technical performance and economic viability. From a cost perspective, as shown in Fig. 13, the outcomes from these additional sites are generally less favorable than those of the primary reference case.

Despite experiencing poorer wind conditions, the HKZ site (20 km from shore) achieves lower LCOHs compared to the IJV site (60 km from shore) for C-ON configurations. This is primarily due to the shorter distance for energy transmission, which reduces transmission infrastructure-related costs and losses, compensating for the reduced energy yield. On the other hand, the IJV site results in improved economic performance for the offshore configurations. This is attributed to the technical and economic advantages of deploying pipelines at longer distances offshore over cables. Therefore, the cost increase due to the larger transmission distance is balanced by the increased hydrogen production due to the beneficial wind source.



(a) CF per wind turbine with ALK

(b) CF per wind turbine with PEM

Fig. 11. Capacity factor (CF) per wind turbine in the D-OFF configuration for the mean technical scenario in the 100 km offshore site.

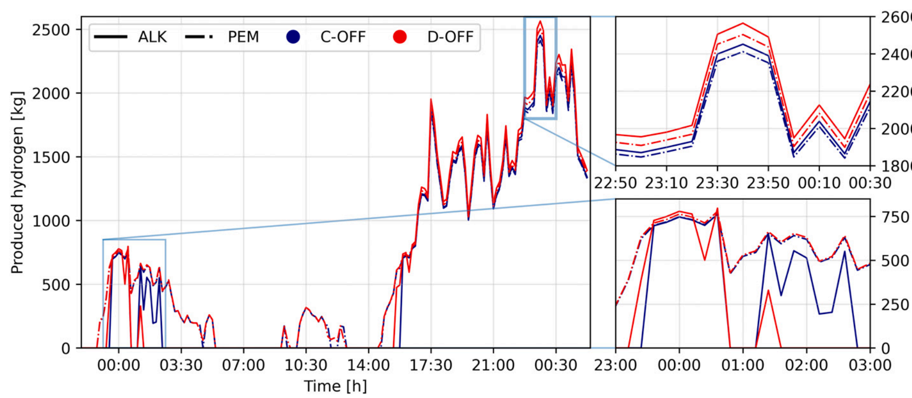


Fig. 12. Comparison between the operational behavior of the offshore configurations with PEM and ALK.

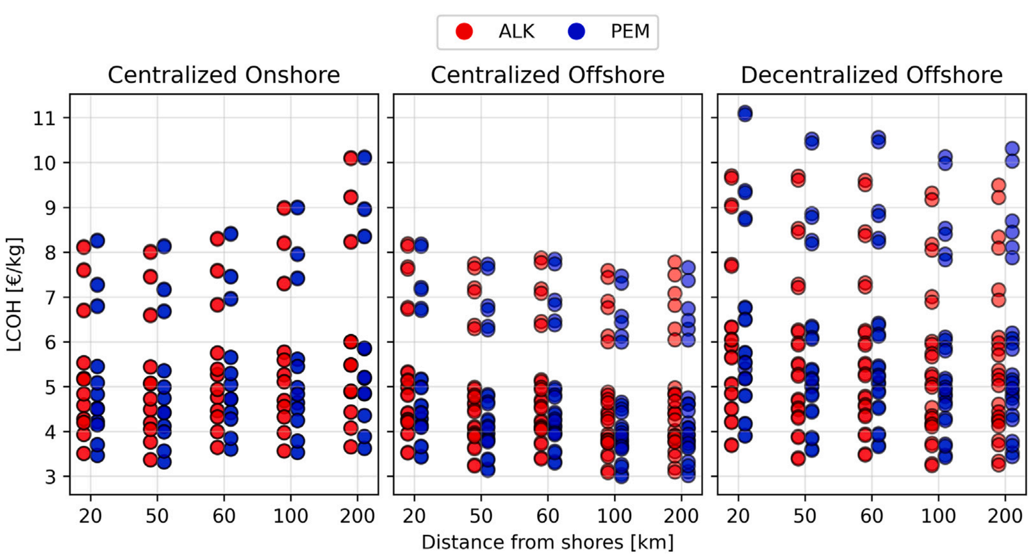


Fig. 13. Range of LCOH for each system configuration for five wind park sites, characterized by their distance to shore.

As shown in Fig. 14, the findings for the two additional sites show that increasing the distance from shore, resulting in better wind sources, can reduce conversion losses due to operational constraints of the electrolyzer systems. This confirms our findings in Section 5.2.

PEM consistently demonstrates higher efficiency compared to ALK, reinforcing earlier conclusions on the superiority of PEM technology in applications with fluctuating power input. The total system losses in the C-OFF configuration are affected by electricity transmission losses,

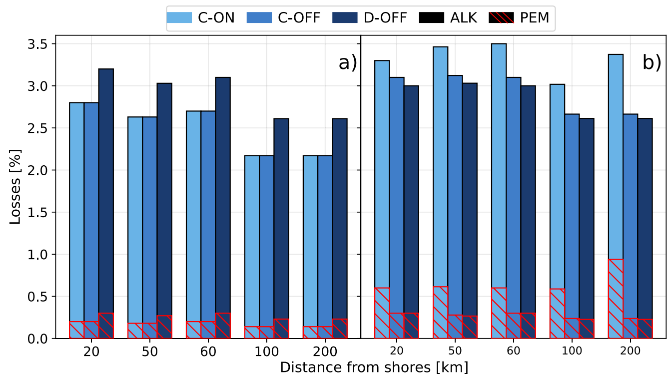


Fig. 14. Overview of the operational behavior of the offshore configurations with PEM and ALK with the inclusion of additional wind park sites HKZ (20 km) and IJV (60 km).

which increase with distance and can outweigh gains in conversion efficiency, particularly for configurations relying on power transmission rather than direct hydrogen transport.

6. Discussion

After a short reflection on our results in relation to the scientific literature (Section 6.1), we discuss the implications of our work for stakeholders (Section 6.2). Section 6.3 offers a reflection on the limitations of our study.

6.1. Comparison to literature

Compared to the literature, the LCOH estimates of our expert-validated benchmark scenarios align with studies that project 5–6€/kgH_2 in favorable scenarios [16,63]. For C-ON, our findings are generally lower than the values reported by Hill et al. [22], which are similar to the higher bound scenarios in this study. Many studies report LCOHs of 2–4€/kgH_2, aligning with lower bound cost and higher bound technology scenarios in this research, while our higher bound cost and lower bound technology scenarios, particularly for D-OFF and C-ON, are up to 10.1€/kgH_2 for C-ON and 10.5€/kgH_2 for D-OFF. Frowijn et al. [64] recently estimated the LCOH of three system configurations, finding an LCOH range of 1.5–10.8€/kgH_2 across scenarios, with D-OFF as the most competitive. The study focuses on analyzing the assumed benefits of D-OFF. As a result, it uses a less detailed modelling approach, excludes economies of scale, and assumes a constant offshore energy input, which contributed to lower LCOHs in some scenarios.

As a reference, the average European competitive bids for green hydrogen production range from 5.8 to 13.5€/kgH_2, with an average of 9.8€/kgH_2 for the Netherlands [65]. In a recent study by TNO, the current LCOH for green hydrogen production was found to be 12–14€/kgH_2 for the Netherlands [66]. This highlights the critical role of selected input data and detailed, location-specific modelling, as the difference in configurations translates into different hydrogen production rates, energy flows and transmission infrastructure needs, and ultimately LCOHs.

In our study, PEM electrolyzers are the most cost-effective option for all scenarios. However, other studies have reported different findings. Some do not address the debate and select only one of the two or do not specify which electrolyzer is included [12,16,29]. Hill et al. [22] found that PEM is outperformed by ALK, which is also the conclusion of Lei et al. [67] and Singlitico et al. [25]. These diverging outcomes are explained by the lower TRL of PEM, with correspondingly less beneficial parameters, and higher CAPEX costs. However, Lei et al. [67] and Singlitico et al. [25] do not consider the difference in operational characteristics between electrolyzer technologies. We show that PEM electrolyzers perform better with the variable wind energy input due to their wider operational range, resulting in a lower LCOH.

In most studies centralized offshore electrolysis achieves the lowest LCOH [17,25,68], as in our study. However, Calado et al. [23] found onshore electrolysis more cost-effective due to the option to purchase low-cost grid electricity, this was disabled for their C-OFF system configuration analysis. The choice between onshore and offshore electrolysis extends beyond the economic potential and operational dynamics, especially at larger scales. Besides cost implications, installing several offshore cables compared to a single pipeline may delay or halter development, with permitting—potentially taking multiple years per cable or pipeline—being a potential bottleneck. Potential delays in project development for onshore electrolysis may be more substantial than for offshore system configurations, especially when considering repurposed existing pipelines. Repurposing may entail a cost decrease of three to four times compared to new pipelines [57,59], but the benefits in terms of LCOH are negligible, with improvements from 0.1 to 4 %. Repurposing natural gas pipelines for hydrogen transmission faces potential challenges, such as embrittlement [69].

As hypothesized by Jang et al. [17], many technical and economic benefits may arise from implementing D-OFF. In contrast to their work, however, we do not find D-OFF to be the most cost-efficient configuration. We show that the economies of scale impact the LCOH more than the increased hydrogen production, the reduced need for electrical transmission infrastructure and absence of additional infrastructure to host the electrolyzers in the D-OFF. Consequently, the centralized offshore configuration is the most cost-effective in our analysis, as in Singlitico et al. [25].

6.2. Implications for stakeholders

For stakeholders—including energy producers, policymakers, and investors—understanding the implications of power input intermittency on the cost of renewable hydrogen is crucial. This study enables assessing cost and operational performance in different system configurations, moving forward the existing debates on onshore versus offshore and centralized versus decentralized hydrogen production.

While the outcomes presented in this study depict offshore electrolysis as an interesting and viable solution, they show that policymakers should focus on centralized configurations. Besides the economic results—which present this configuration as the most cost-effective—the C-OFF offers several advantages, such as higher technology readiness and reduced challenges for the system development over D-OFF.

To inform investment decisions for large-scale production, further in-depth analysis is required to identify cost-optimal conditions and ensure the technical feasibility of each configuration. This underscores the need for a cautious approach when making decisions about hydrogen projects, as varying assumptions and configurations can lead to widely different economic results. Moreover, the variability in the outcomes highlights the risks of oversimplifying the complexities of production technologies, as such simplifications may not fully capture the variability and nuances that influence the production cost for each system configuration.

Equally important is the need for targeted incentives—such as subsidies, tax benefits, or other (financial) mechanisms—to kick-start the upscaling of the green hydrogen supply chain and close the competitiveness gap. Introducing green hydrogen into our energy system depends on developing large-scale, integrated supply chains that align production with demand. Investments in these supply chains and offtake installations are capital-intensive and risky, which makes industrial parties hesitant to invest without government support.

6.3. Limitations

This study does not include the costs or operational considerations of hydrogen storage. Instead, we focus on the production, assuming hydrogen is delivered directly to the future Dutch hydrogen backbone. We assume the onshore hydrogen transmission infrastructure can accommodate variable production [70]. We acknowledge that hydrogen storage is an important system component, but it is out of scope for our analysis. This allows focusing on the performance of the hydrogen production system, without accounting for supply-demand dynamics.

We evaluate the cost of hydrogen rather than the value. This choice has been made to provide guidance on the costs associated with the hydrogen production configurations. While the value of hydrogen could have led to different results, we do not believe that the relative differences between system configurations would be affected. A value-oriented perspective would allow shedding light on hybrid solutions—combining electricity and hydrogen production offshore [68]. This offers possibilities for arbitraging between these two energy vectors and overplanting of wind farms.

Our economic findings confirm the uncertainty surrounding offshore wind-based hydrogen production, driven by the wide range of input parameters and the need to include multiple assumptions. Expert-validated scenarios are incorporated into our analysis, aiming to enhance the robustness of our cost projections. While our analysis considers over 400 scenarios, this represents only an initial step toward exploring the full uncertainty space. A more comprehensive treatment of uncertainty remains an important direction for future research.

Similarly, the most cost-efficient system configuration for large-scale green hydrogen production is wind source and location-dependent. The Dutch North Sea wind conditions are characterized by a favorable Weibull distribution. Different wind energy input profiles from other sea basins may lead to different conclusions.

This study focuses on the techno-economic evaluation of offshore hydrogen production configurations, highlighting the impact of the choice of electrolyzer technology, distance to shore, the choice for hydrogen pipelines or HVDC infrastructure, etc. The environmental impact of these technology choices and configurations is out of scope due to the complexity of these assessments. For example, when considering the electrolyzer choice, PEM electrolyzers use of rare materials like platinum-group metals [25]. However, due to other factors such as system lifetime, efficiency differences, and manufacturing impacts, no clear winner emerges between ALK and PEM technologies in terms of overall environmental impact [71]. Similarly, a comparison between the environmental impact of electrical cables and hydrogen pipelines may be challenging. Multiple factors, such as material requirements, installation procedures, and impact on local biodiversity contribute to the overall environmental impact of the system. Optimizing the wind farm layout may reduce the inter-array distance and thus the footprint of the farm. The benefits related to this optimization may limited if one considers, e.g., influence on biodiversity. A comprehensive analysis of trade-offs between cost, efficiency, environmental impact, and other factors would require an explicit multi-objective optimization approach, which we identify as a promising topic for future work.

7. Conclusions

The study aims to contribute to the ongoing discourse on selecting an approach to producing green hydrogen based on offshore wind on a GW-scale: Onshore centralized electrolysis (C-ON), Offshore centralized electrolysis (C-OFF), and Offshore decentralized electrolysis (D-OFF). An innovative high-resolution, time-dependent simulation framework was employed to accurately analyze the operation of the system configurations, with a particular focus on the decentralized one. Unlike centralized systems, D-OFF has unique dynamics driven by the direct connection of electrolyzers to individual wind turbines. The proposed modelling framework allows analyzing system costs and the impact of operational behaviors under intermittent energy inputs, providing a robust foundation for informed decision-making.

For all system configurations, the wide range of estimated LCOHs—spanning from 3.0 to 10.5€/kgH_2—reflects a wide variety in future costs and potential technological development. Benchmark scenarios were developed using expert-validated economic input data. The resulting LCOHs exhibited a narrower range, between 4.1 and 5.5€/kgH_2. For all system configurations, the most significant cost driver was the wind farm cost, followed by the electrolyzer costs, and, in the case of C-ON, the electrical transmission infrastructure costs. The latter strongly depend on the distance to shore.

Our analysis identifies offshore electrolysis—specifically C-OFF—as the most cost-competitive option, driven by the cost advantage of hydrogen transmission infrastructure over electrical export transmission infrastructure. This advantage grows with increasing distance from shore. Centralized configurations outperform decentralized ones, which are limited by the economies of scale. While D-OFF boosts hydrogen production rates, the gain is insufficient to achieve the lowest LCOH. Across all system configurations, PEM emerges as the most suitable choice. Both ALK and PEM face challenges due to intermittent supply. Under the assumptions made, enabled by the proposed framework based on time-dependent analyses and detailed wind data analysis, ALK is characterized by more strict technical constraints, resulting in worse performance and a higher LCOH than PEM. However, the long-term effects of intermittency on stack behavior, particularly for large-scale systems, remain uncertain.

The operational analysis realized due to the adoption of a time-dependent approach reveals how fluctuations in wind power, minimum load requirements of the electrolyzer, and stack degradation for each electrolyzer technology impact the energy losses for each system. The proposed model enables a detailed analysis of the differences between C-ON, C-OFF, and D-OFF. Results show that, while the decentralized configuration experiences relevant losses related to the operative constraints of the electrolyzers, it is characterized by the highest system-level efficiency, given the reduced energy conversion steps and transmission losses. This is emphasized by adopting PEM, which ensures continuous operation even with low power inputs. Stack degradation decreases the performance, decreasing hydrogen production, and increasing of the LCOH.

The study underscores the need for a detailed, time-dependent modelling framework combined with system designs tailored to specific offshore wind energy conditions. Researchers and policymakers should focus on developing adaptive operational strategies that have maximizing value as the starting point, going beyond cost. Integrating these insights into techno-economic models and energy system modelling frameworks will ensure that large-scale green hydrogen production aligns with the energy transition.

CRediT authorship contribution statement

R. Travaglini: Writing – original draft, Visualization, Software, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **L.S.F. Frowijn:** Writing – original draft, Visualization, Software, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **A. Bianchini:** Writing – review & editing, Resources, Project administration, Funding acquisition, Conceptualization. **Z. Lukszo:** Writing – review & editing, Resources, Project administration, Funding acquisition, Conceptualization. **K. Bruninx:** Writing – review & editing, Supervision, Project administration, Methodology, Investigation, Conceptualization.

Declaration of generative AI and AI-assisted technologies in the writing process

During the preparation of this work the author(s) used ChatGPT in order to streamline writing. After using this tool/service, the author(s) reviewed and edited the content as needed and take(s) full responsibility for the content of the publication.

Declaration of competing interest

The authors declare the following financial interests/personal relationships which may be considered as potential competing interests:

Laurens Frowijn reports financial support was provided by Dutch Research Council. If there are other authors, they declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Appendix A. Supplementary data

Supplementary data for this article can be found online at doi: 10.1016/j.apenergy.2025.126290.

Data availability

Data will be made available upon request.

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