Techno-economic assessment of offshore wind-to-hydrogen scenarios: A UK case study

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HIGHLIGHTS

- The potential of using offshore electricity for hydrogen production is investigated.
- Data for capital and operating costs of the technologies are collected.
- Scenarios for hydrogen production, storage and transport are evaluated.
- Levelised costs of hydrogen for the different scenarios are calculated.

ARTICLE INFO

ABSTRACT

The installed capacity, electricity generation from wind, and the curtailment of wind power in the UK between 2011 and 2021 showed that penetration levels of wind energy and the amount of energy that is curtailed in future would continue to rise whereas the curtailed energy could be utilised to produce green hydrogen. In this study, data were collected, technologies were chosen, systems were designed, and simulation models were developed to determine technical requirements and levelised costs of hydrogen produced and transported through different pathways. The analysis of capital and operating costs of the main components used for onshore and offshore green hydrogen production using offshore wind, including alternative strategies for hydrogen storage and transport and hydrogen carriers, showed that a significant reduction in cost could be achieved by 2030, enabling the production of green hydrogen from offshore wind at a competitive cost compared to grey and blue hydrogen. Among all scenarios investigated in this study, compressed hydrogen produced offshore is the most cost-effective scenario for projects starting in 2025, although the economic feasibility of this scenario is strongly affected by the storage period and the distance to the shore of the offshore wind farm. Alternative scenarios for hydrogen storage and transport, such as liquefied hydrogen and methylcyclohexane, could become more cost-effective for projects starting in 2050, when the levelised cost of hydrogen could reach values of about £2 per kilogram of hydrogen or lower.

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Introduction

In the UK, wind constitutes approximately 18% of the total renewable primary energy supply [1] in line with the installed capacity of onshore and offshore wind farms in the period of 2011−2021 [2] shown in Fig. 1. The current number of offshore wind farms is remarkably lower compared to onshore wind farms but they are of a larger size i.e. mainly greater than 500 MW and offer the potential to produce more energy per turbine due to more consistent and speedy offshore wind [3]. Nonetheless, wind energy development is still constrained by multiple factors such as curtailment of wind farms [4], limited interconnections among existing national grids [5], unpredicted and fluctuating electricity prices [6], as well as policy and regulatory barriers [5] in addition to being intermittent and fluctuant without inherently regulated power output nor correlation with demand.

Curtailing wind farms is a common practice, i.e. wind turbines are shut down at certain times over a period, for instance, to deal with issues related to turbine loading, electricity export to the grid, unfavourable wind conditions (either too weak or too strong beyond the pre-defined speed range) or environmental circumstances such as birds and bats. Location, grid infrastructure, wind speed, demand, and storage capability are the main factors that affect the curtailment of offshore wind energy [7]. Fig. 2 presents the UK statistics for the curtailment of wind power [8,9] and electricity generated from wind power over the same period [2], showing that the increase in electricity generated from wind sources in the last decade is accompanied by an increase in energy that is curtailed, although a decrease was observed in the year 2021 due to low wind speed.

Following this trend, the penetration levels of offshore wind energy will continue to increase in future (as represented by the strategy of the UK government to achieve 50 GW of offshore wind installed capacity by 2030 [10]), resulting in an increase of the amount of energy that is curtailed without significant grid improvement. In this regard, deploying wind energy from offshore wind farms for hydrogen production is advantageous as fossil fuel is not consumed [5] whilst resolving the issues associated with fluctuating power [11] and curtailment of wind farms [4] as well as offering the opportunity to utilise electricity that otherwise would be curtailed [12]. This is not a new idea but has recently revitalised great interest again, as evidenced by Hydrogen Strategy [13] and projects (e.g. Dolphyn (£3.12 m) [14] and Gigastack (£7.5 million) [15]) in the UK. Similarly, Japan, Australia, Chile, Finland, Portugal, Spain, France, Norway, Germany and the Netherlands have also strategised their national plan to adopt blue and/or green hydrogen at different ambition levels and scales in short, medium and long term whereas Portugal, Ireland, Belgium, and Denmark have commissioned hydrogen projects, for instance.

As alternatives to sole selling to the grid at a wholesale rate, electricity generated by offshore wind farms can be used for the offshore/onshore production of.

i. hydrogen through electrolysis (known as "power-to-gas") where the produced hydrogen is sold immediately or stored (until electricity prices go up) and then converted by fuel cells back into electricity for sale at the market price (known as "power-to-power"); or
ii. hydrogen carriers (such as ammonia) or liquid organic hydrogen carriers (LOHC) (such as toluene/methylcyclohexane (MCH)).

Hybrid production from offshore wind farms (i.e. electricity and hydrogen/hydrogen carriers/LOHC reacting to real market price and energy demand whilst utilising wind energy that is otherwise curtailed) will increase system flexibility but they warrant additional capital investments in technology and infrastructure such as desalination, electrolysis, air separation, compression, liquefaction, storage, and transmission, to name a few, depending on business goals and system designs. Which alternative is more technically strategic and cost-effective has motivated techno-economic assessment in research, as summarised in Table 1. Research gaps exist as a
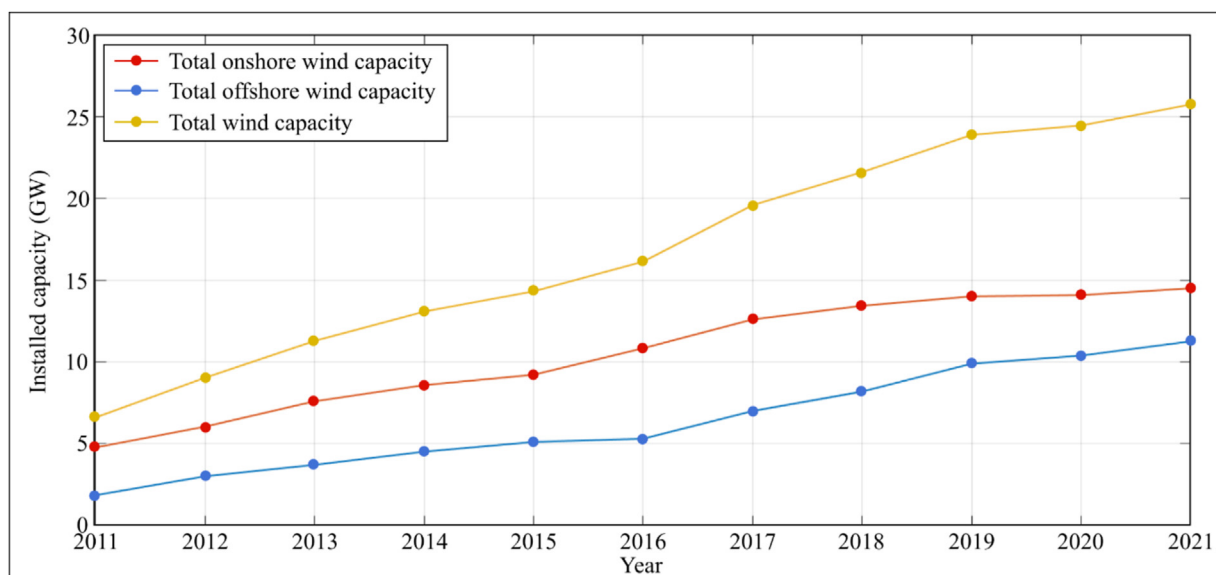

Fig. 1 − UK onshore and offshore installed wind capacity for the period 2011−2021 [2].
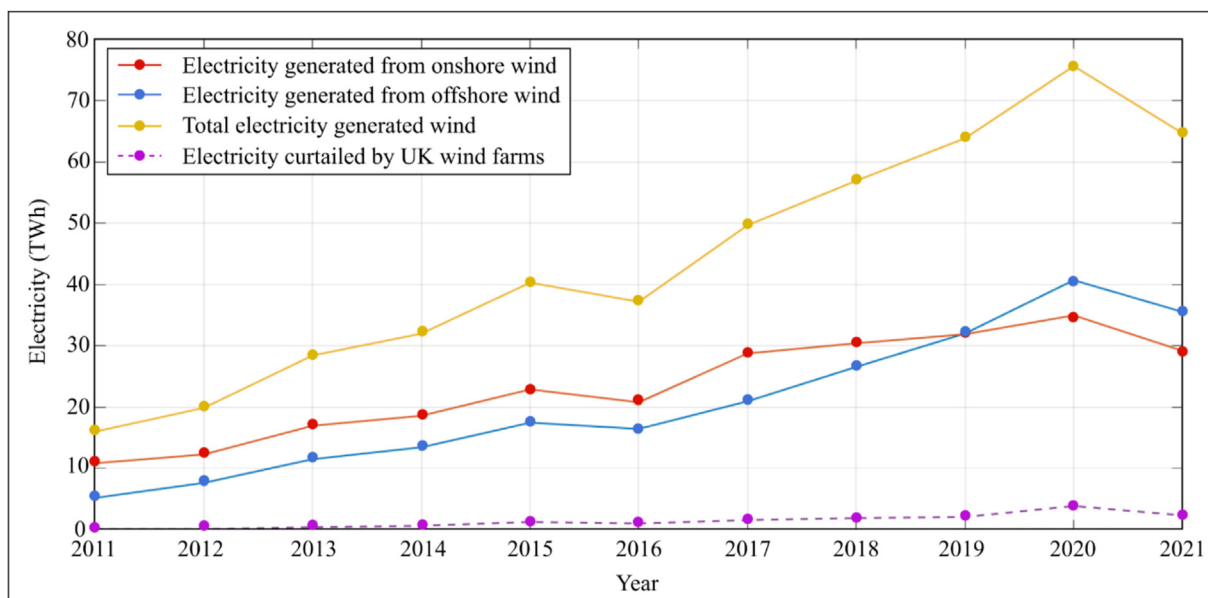
Fig. 2 – UK wind electricity generation and curtailment, obtained from Refs. [2,8,9].

result of limited system boundary covered by previous techno-economic assessments — most studies in Table 1 focused on specific scope without comparing hydrogen with hydrogen carriers nor assessing the full supply chain from hybrid production to delivery of electricity, hydrogen and/or hydrogen carriers where the curtailment of offshore wind farms, desalination, high-voltage direct current (HVDC) transmission, and converters were not considered. This study is therefore novel as it bridges existing research gaps by comparing hydrogen, ammonia and MCH from hybrid production to delivery extensively where the curtailment of offshore wind farms and all relevant components were taken into account.

The manuscript is organised as follows. Scope and Methodology defines the scope of this study, outlining the wind-to-hydrogen production scenarios assessed and the methodology applied. Techno-economic analysis: consideration and assumptions explains consideration and assumptions made relevant to the main components involved in the study. Results and discussion shows the results of the techno-economic analysis for these scenarios and sensitivity analysis for key parameters, followed by discussion of the results and limitations of the study in Further discussion: comparisons with other studies, policy implications, and limitations of the study and conclusions drawn in Conclusion.

Scope and Methodology

In line with research gaps identified from literature review as reported in **Introduction**, a research question was defined: if offshore wind farms implement hybrid production of electricity and hydrogen/hydrogen carriers/LOHC, which pathway would be more technically strategic and cost-effective? The research question was addressed by conducting a techno-economic assessment in this study following methodological

steps illustrated in Fig. 3. During scope definition, a reference case i.e. compressed hydrogen produced offshore and transported to shore by pipeline and 6 possible alternative scenarios were defined. The alternative scenarios included (i) compressed hydrogen produced onshore utilising electricity transmitted from offshore wind farms (to allow for a comparison between offshore or onshore hydrogen production); (ii) liquefied hydrogen produced offshore and transported to shore by maritime transport e.g. liquid hydrogen tanker; (iii) ammonia produced offshore and transported to shore by tanker; (iv) ammonia produced offshore and transported to shore by pipeline; (v) MCH produced offshore and transported to shore by tanker; and (vi) MCH produced offshore and transported to shore by pipeline, as shown in Fig. 4. The year in which the system proposed in each scenario would be constructed was set as 2025, 2030 and 2050. Pessimistic, average, and optimistic cases were defined based on the analysis of the range of data collected from literature for the assessed components for each year of construction. Input data required for the assessment were gathered from literature (see **Techno-economic Analysis: Consideration and Assumptions** for the details) parallel to the design and modelling of the systems investigated in the reference case and 6 alternative scenarios. Parameters related to the chosen technologies and components were determined during technical analysis. This was followed by economic analysis where future capital expenditure (CAPEX) and operational expense (OPEX) of the systems were estimated. The levelised cost of hydrogen, $LCOH$ (£/kg$_{H2}$), was calculated using Equation (1):

$$LCOH = \frac{\sum_{i=0}^{T} \frac{CAPEX+OPEX}{(1+r)^i}}{\sum_{i=0}^{T} \frac{M_{H_2,i}}{(1+r)^i}} \qquad (1)$$

where CAPEX included capital and replacement costs whilst OPEX accounted for operation, maintenance and electricity cost. The parameter r represented an interest rate that applied for an investment, which was assumed as 7% in this study. T

Table 1 – Scope, key findings, and limitations of previous study.

Previous study	Scope	Components assessed	Economic assessment method	Key findings	Limitations	Year
Babarit et al. [16]	• Production of hydrogen from offshore wind by energy ships (which attached a water turbine to the hull for electricity generation) or sailing wind turbines	• Wind converters, alkaline electrolyser (AEL), liquefaction unit, storage, and distribution via pipeline, ship and truck	• Levelised cost of hydrogen (LCOH)	• The LCOH ranged €7.1–9.4 and €3.5–5.7 per kg hydrogen in the short and longer term respectively	• Effect of curtailment and NPV were not assessed	2018
Glenk and Reichelstein [17]	• Production of hydrogen from a hybrid energy system integrating wind and solar with a power-to-gas facility	• AEL, polymer electrolyte membrane (PEM) electrolyser, and solid-oxide electrolyser cells	• LCOH	• The produced hydrogen would be economically viable if it is sold at €3.23 or US$3.53 per kg in Germany or Texas	• The study was only compatible with hydrogen supply on small- and medium-scale	2019
Taieb and Shaaban [18]	• Production of hydrogen from an offshore wind farm located in Germany	• PEM electrolyser, high-voltage direct current (HVDC) transmission line, hydrogen pipeline	• Total cost	• HVDC would be preferable if transmission distance was up to 60 km whereas 510 km would be required to make pipeline transmission cost-effective	• Effect of curtailment, LCOH and NPV were not included	2019
McDonagh et al. [19]	• Production of hydrogen from a hybrid energy system integrating offshore wind using historical wind data	• Wind turbines, PEM electrolyser, hydrogen compression, hydrogen storage	• LCOH, NPV	• The produced hydrogen would be economically viable compared to producing electricity only if the price of hydrogen was more than €4 per kg in Ireland	• Effect of grid expansion, storage and demand response on the curtailment of electricity that would be produced from offshore wind were not assessed	2020
Crivellari and Cozzani [20]	• Use of offshore wind in various pathways for power-to-gas and power-to-liquid application	• Electrolyser, desalination unit, CO_2 capture, compression, storage, methanol and synthetic natural gas production, transport by pipeline and shipping	• LCOH, NPV	• Compressed hydrogen and blending hydrogen into natural gas were the most cost-effective strategies	• Effect of curtailment, LCOH, future cost and future energy consumption were not included	2020
Franco et al. [21]	• Evaluation of different pathways to produce and transport hydrogen or hydrogen carriers from offshore to shore	• HVDC transmission line, electrolyser, desalination, hydrogen and oxygen compression, hydrogen storage, hydrogen liquefaction, ammonia production, methylcyclohexane (MCH) production, shipping, pipeline, reconversion	• LCOH, NPV	• Compressed hydrogen would be the most cost-effective strategy (between £2.15 and £5.35 per kg)	• Effect of curtailment and future cost for different pathways were not projected	2021
Singlitico et al. [22]	• Production of hydrogen from a hybrid energy system integrating offshore wind	• Wind farm, HVDC transmission line, voltage source converter (VSC), electrolyser, desalination, hydrogen compression, and pipeline	• LCOH, NPV	• The LCOH of the produced hydrogen could be as low as €2.4 per kg for application in the North Sea	• Only compressed hydrogen was assessed where effect of curtailment, future cost and future energy consumption of the components, and hydrogen transport alternatives were not assessed	2021

Semeraro III [23]	• Comparison of HVDC and pipeline as hydrogen transmission alternatives	• HVDC transmission line, converters, PEM electrolyser, hydrogen storage, hydrogen compression, solid oxide fuel cell (SOFC)	• Total cost (CAPEX and OPEX)	• Hydrogen pipeline transmission could be cost-competitive with HVDC transmission, although unfavourable under some circumstances	• LCOH, future cost and future energy consumption of components, effect of curtailment and hydrogen transport alternatives were not included	2021
Song et al. [24]	• Comparison of production and transport of liquid hydrogen, MCH and ammonia	• Electrolysers (AEL, PEM, SOEC), hydrogen compression, hydrogen storage, hydrogen liquefaction, ammonia production, MCH production, shipping, reconversion	• LCOH	• Hydrogen produced in China transported in the form of MCH to Japan by ship would be the most cost-effective pathway, which could be as low as $1.8 per kg in 2050	• Transport option was limited to shipping • Effect of curtailment and NPV were not assessed	2021
Dinh et al. [5]	• Production of compressed hydrogen from a hypothetical offshore wind farm considering the size of the storage tank and decommissioning expenditure	• Wind farm, PEM electrolyser, hydrogen storage	• LCOH, NPV	• A LCOH of €5 per kg would be required to ensure economic viability	• LCOH was not calculated but obtained from literature • Effect of curtailment and hydrogen transport alternatives were not assessed	2021
Papadias et al. [25]	• Comparison of hydrogen carriers i.e. methanol, ammonia and MCH produced in a central location and transported by pipeline, truck or train	• Hydrogen, methanol, ammonia and MCH production, transport, reconversion	• LCOH	• Methanol showed the lowest LCOH ($4.63 per kg), followed by MCH ($6.17 per kg) and ammonia ($6.44 per kg)	• NPV, future cost and future energy consumption of components were not included	2021
Gea Bermudez et al. [26]	• Investigation of offshore hydrogen production in future integrated energy systems	• Wind farm, electrolyser, desalination unit, compressor, storage, fuel cell, methanation	• Minimisation of fixed, variable and discounted costs	• Transmission of electricity produced by offshore wind to shore has higher value than offshore production of hydrogen	• NPV and LCOH were not assessed	2021
Lucas et al. [27]	• Production of hydrogen and oxygen from the WindFloat Atlantic offshore wind farm	• Wind farm, PEM electrolyser, hydrogen storage, hydrogen compression, oxygen liquefaction and storage	• Total cost, LCOH, NPV	• The LCOH ranged €4.25–8.25 per kg depending on the capacity of the offshore wind farm	• Hydrogen transport alternatives and effect of curtailment were not assessed	2022
Baldi et al. [28]	• Production of hydrogen from an offshore wind farm located in North Scotland	• Wind farm, PEM electrolyser, ammonia production, liquefaction unit, fuel cell, storage of electricity, compressed and liquid hydrogen, ammonia	• Revenues and costs	• A cost for hydrogen of £0.08/kWh at a 60% penetration of renewable energy would make the process economically viable	• Effect of curtailment, future cost and future energy consumption of components were not included	2022
Scolaro and Kittner [29]	• Production of hydrogen from an offshore wind farm located in North Germany	• PEM electrolyser, hydrogen storage, PEM fuel cell	• LCOH, NPV	• The project would be economically viable (NPV>0) when LCOH was greater than €4.9 per kg in 2025	• Effect of curtailment, future cost and future energy consumption of components were not included	2022

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Table 1 – (continued)

Previous study	Scope	Components assessed	Economic assessment method	Key findings	Limitations	Year
Okunlola et al. [30]	• Transport of low-carbon hydrogen from Canada via national, international, and intercontinental routes	• Hydrogen production, liquefaction, ammonia production and reconversion, pipeline, shipping	• Delivered cost of hydrogen	• The cost-competitiveness of exporting hydrogen over large distances would be influenced by the specific cost of domestic supply of hydrogen for each country	• LCOH, NPV, future cost and future energy consumption of components were not included	2022

was the lifetime of the system, which was assumed as 40 years. $M_{H2,i}$ was the amount of hydrogen produced by the electrolyser (kg/y) for a particular year, i.

To assess whether electricity generated by offshore wind farms should be sold directly or utilised fully or partially for the production of hydrogen/ammonia/MCH, and whether energy curtailed from offshore wind farms could be utilised to produce hydrogen/ammonia/MCH, the reference case and alternative scenarios were further evaluated following 7 possible production profiles. They include: (i) 100% electricity production; (ii) 100% hydrogen production; (iii) 100% ammonia production; (iv) 100% MCH production; (v) co-production of hydrogen and electricity; (vi) co-production of ammonia and electricity; and (vii) co-production of MCH and electricity.

Techno-economic analysis: consideration and assumptions

The full dataset used for the main components of the techno-economic analysis is shown in Table 2 and further described in the next sections.

Offshore wind farm

A list of installed and under construction wind farms in the UK can be found in Ref. [48]. The speed of the wind affects the amount of electricity that can be produced by a wind turbine. The common behaviour for the power produced by the wind turbine, $P(U_{wind})$, depending on the wind speed, U_{wind}, can be described as in Equation (2):

$$P\left(U_{wind}\right) = \begin{cases} 0 \; when \; U_{wind} < U_{cut-in} \\ P(U_{wind}) \; when \; U_{cut-in} < U_{wind} < U_{rated} \\ P_{rated} \; when \; U_{rated} < U_{wind} < U_{cut-off} \\ 0 \; when \; U_{cut-off} < U_{wind} \end{cases} \tag{2}$$

where U_{cut-in} represents the wind speed at which the wind turbine starts to produce power, U_{rated} is the wind speed at which the wind turbine can produce its rated power output, P_{rated}, and $U_{cut-off}$ is the wind speed at which the wind turbine must be shut down to avoid damage to the turbine equipment.

A linear relationship between the data supplied by the manufacturers of the wind turbines was assumed in order to calculate $P(U_{wind})$ for different values of U_{wind}, as shown in Equation (3) [49]:

$$P\left(U_{wind}\right) = \frac{P_{i+1} - P_i}{U_{i+1} - U_i} \left(U_{Wind} - U_i\right) + P_i \tag{3}$$

where P_{i+1} and P_i represent the power output data supplied by manufacturers for the wind speed U_{i+1} and U_i given two points of the power curve, i and $i + 1$.

To estimate the power available from the offshore wind farm, hourly data for the wind speed at the wind farm at a reference height, U_{Ref}, were collected from Ref. [50] and adjusted to account for the height of the hub of the wind turbine, $Z_{HubHeight}$, using Equation (4) [51]:

$$U_{HubHeight} = U_{Ref} \left(\frac{z_{HubHeight}}{z_{Ref}}\right)^a \tag{4}$$
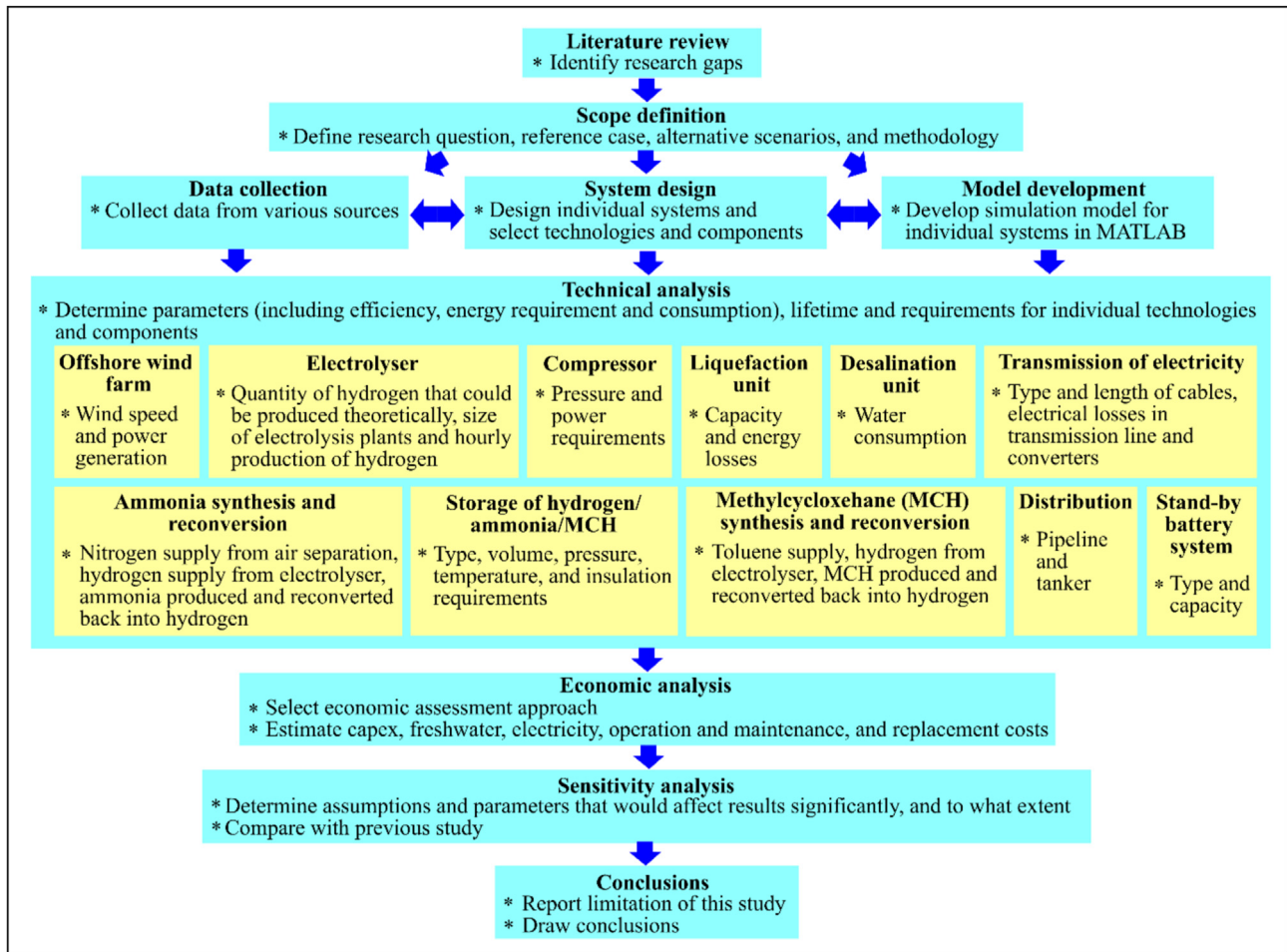
Fig. 3 — Methodological steps applied in this study.

where Z_{Ref} represents the reference height (assumed as 50 m in this study) while $U_{HubHeight}$ represents the wind speed at the hub height. The constant a represents an empirical coefficient, which was assumed as 0.15 [51] in this study. The total power output from the offshore wind farm, P_{farm} (t), was then calculated as in Equation (5):

$$P_{farm}(t) = \sum_{i=1}^{N_{WT}} P\,(U_{wind})_i \qquad (5)$$

where N_{WT} represents the total number of wind turbines.

HVDC transmission line and converters in substations

The electric energy generated by the offshore wind farm is transmitted to the shore (for hydrogen production or to be sold to the grid) by means of HVDC interconnectors. While HVAC systems are preferred for the transmission of electricity over short distances, HVDC transmission is favoured for long-distance distribution because of its smaller transmission losses and the lower cost of DC cables, although expensive power converters are required [52]. These power converters are associated with losses, which results in additional costs [53]. A value ranging between 50 and 100 km for underground and underwater cables would make HVDC more advantageous than HVAC [3].

In this model, the offshore wind farm would generate AC, which was converted into DC and used for the production of hydrogen/ammonia/MCH or transmitted to the shore by two 300 kV cables and then reconverted to AC by a grid-scale converter for sale. The CAPEX and OPEX of transmission cables, AC/DC inverter and DC/AC rectifier with data for overhead, underground and sub-sea configurations were acquired from Ref. [54]. The electrical losses in the HVDC transmission line and converters were included in the model in line with [54] together with the cost associated with electrical losses [53]. Table 3 shows the electrical losses considered in the model. For 2025, 2030 and 2050, it was assumed that the CAPEX of HVDC, $CAPEX_{HVDC}$, would remain the same for the pessimistic case and reduce steadily by 5%, 10%, and 15% for the average case and 10%, 20%, and 30% for the optimistic case, respectively.

The main converters used in HVDC transmission lines are current source converters (CSCs) and voltage source converters (VSCs), each with its own characteristics and cost. VSC converters are regarded as the most promising for application with offshore wind farms due to their better characteristics in terms of active and reactive power control; however, their performance is characterised by larger losses and higher capital costs [23]. The CAPEX of CSC, $CAPEX_{CSC}$ (M£), and the CAPEX of VSC, $CAPEX_{VSC}$ (M£), were calculated using Equations (6) and (7) [54]:
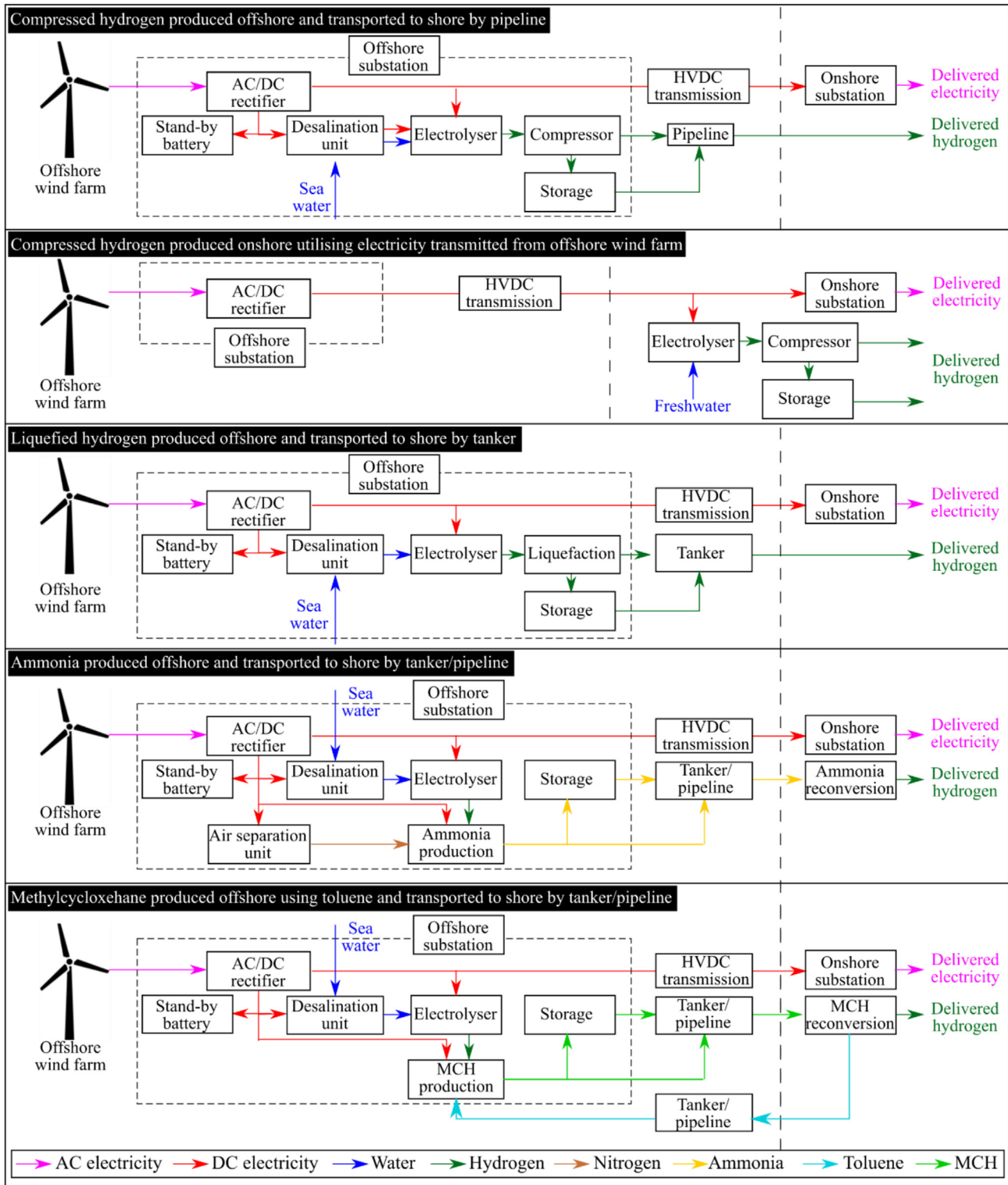
Fig. 4 — Schematic diagram of hydrogen, ammonia and toluene/MCH production utilising electricity from offshore wind farms.

$$CAPEX_{CSC} = (0.067 \cdot P_{Conv} + 33) \cdot C_{£,\$} \quad (6)$$

$$CAPEX_{VSC} = (0.083 \cdot P_{Conv} + 28) \cdot C_{£,\$} \quad (7)$$

where P_{Conv} is the power converted from AC to DC. $CAPEX_{CSC}$ and $CAPEX_{VSC}$ applied the same assumptions made for the estimation of $CAPEX_{HVDC}$ for 2025, 2030 and 2050 i.e. no reduction for the pessimistic case and steady reductions for the average and optimistic cases.

Table 2 – Dataset used for the techno-economic analysis.

	2025			2030			2050		
	P[a]	A[b]	O[c]	P[a]	A[b]	O[c]	P[a]	A[b]	O[c]
Offshore wind farm [8,31]									
Capacity factor (%)	31	47.5	54	36	52	58	43	55	60
Curtailed energy (% total)	5	6.8	8.5	5	9	13.1	5	18.2	31.5
Electrolyser [32–34]									
Efficiency (%, LHV)	60	64	66	63	65	68	67	70.5	81
Operating lifetime (h)	45,000	67,500	90,000	60,000	75,000	90,000	100,000	125,000	150,000
CAPEX (£/kW)	1204.5	748.25	565.75	1095	511	474.5	657	328.5	146
O&M (% CAPEX/y)	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Replacement (% CAPEX)	14.5	14.0	12.0	14.0	12.0	12.0	12.0	12.0	12.0
Max. output pressure (MPa)	4.5	6.3	9.0	6.0	7.0	10.0	8.0	10.0	14.0
Stand-by battery (£/kW)	50.2	41.9	33.5	42.6	35.5	28.4	23.2	19.3	15.4
Desalination system and freshwater [35]									
$CAPEX_{Desalination}$ (£/(m^3/d))	1284.8	1240.6	1196.5	1170.2	1081.9	993.5	657	585.8	423.4
$Electricity_{Desalination}$ (kWh/m^3)	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Operating lifetime$_{Desalination}$ (y)	30	30	30	30	30	30	30	30	30
Freshwater (£/m^3)	1.38	1.38	1.38	1.38	1.38	1.38	1.38	1.38	1.38
Hydrogen compressor [36–39]									
O&M (% CAPEX/y)	3	3	3	3	3	3	3	3	3
Operating lifetime (y)	10	10	10	10	10	10	10	10	10
Replacement (% CAPEX)	100	100	100	100	100	100	100	100	100
Liquefaction unit [24,34,40–42]									
$CAPEX_{Liquefaction}$ (£/(kg/h))	45,504	35,971	31,682	37,108	28,713	22,411	25,124	20,926	13,140
$Electricity_{Liquefaction}$ (kWh/kg$_{H2}$)	13.6	10.3	9.5	10.6	7.6	5.4	7.3	5.8	4
Liquid hydrogen yield (%)	50	75	100	75	100	100	100	100	100
$O\&M_{Liquefaction}$ (% CAPEX/y)	4	4	4	4	4	4	4	4	4
Operating lifetime$_{Liquefaction}$ (y)	20	20	20	20	20	20	20	20	20
Ammonia synthesis and reconversion [21,24,34,42–45]									
$CAPEX_{Air separation unit}$ (£/(kg$_{N2}$/h))	1247	1247	1247	1247	1247	1247	1247	1247	1247
$E_{Air separation unit}$ (kWh/kg$_{N2}$)	0.108	0.108	0.108	0.108	0.108	0.108	0.108	0.108	0.108
$CAPEX_{Ammonia, synthesis}$ (£/(kg$_{H2}$/h))	61,959	41,352	33,647	51,655	23,842	18,588	31,120	17,214	10,585
$Electricity_{Ammonia, synthesis}$ (kWh/kg$_{H2}$)	4.8	4	3.5	4.1	3.4	2.8	3	2.7	2
Efficiency of synthesis (%)	90	90	90	0.9	0.9	0.9	0.9	0.9	0.9
$O\&M_{Ammonia, synthesis}$ (% CAPEX/y)	4	4	4	4	4	4	4	4	4
Operating lifetime$_{Ammonia, synthesis}$ (y)	20	20	20	20	20	20	20	20	20
$CAPEX_{Ammonia, reconversion}$ (£/(kg$_{H2}$/h))	12,167	8852	5804	9156	6144	2373	4906	3401	657
$Electricity_{Ammonia, reconversion}$ (kWh/kg$_{H2}$)	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
$Q_{Ammonia, reconversion}$ (MJ/kg$_{H2}$)	36	31.68	26.64	32.76	29.52	20.88	23.76	22.32	15.12
Efficiency of reconversion (%)	84	86	86	86	87	88	88	89	90
$O\&M_{Ammonia, reconversion}$ (% CAPEX/y)	4	4	4	4	4	4	4	4	4
Operating lifetime$_{Ammonia, reconversion}$ (y)	20	20	20	20	20	20	20	20	20
MCH synthesis and reconversion [21,24,25,34,41,42,45]									
$CAPEX_{MCH, synthesis}$ (£/(kg/h))	6598	4212	3234	4377	2156	1430	2453	1342	529
$Electricity_{MCH, synthesis}$ (kWh/kg)	1.5	1.3	1.1	1.4	1.2	0.9	1	0.9	0.7
Toluene cost (£/kg)	0.7	0.6	0.5	0.6	0.5	0.4	0.5	0.4	0.3
Ratio H$_2$/toluene	4	4	4	4	4	4	4	4	4
Efficiency of synthesis (%)	90	90	90	90	90	90	90	90	90
$O\&M_{MCH, synthesis}$ (% CAPEX/y)	4	4	4	4	4	4	4	4	4
Operating lifetime$_{Ammonia, synthesis}$ (y)	20	20	20	20	20	20	20	20	20
$CAPEX_{MCH, decomposition}$ (£/(kg/h))	1540	1177	1095	1216	891	803	863	701	511
$Eelectricity_{MCH, decomposition}$ (kWh/kg)	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
$Q_{MCH, decomposition}$ (MJ/kg)	54	48.6	45	50.04	45.72	41.76	46.08	42.12	38.16
Efficiency of reconversion (%)	0.88	0.89	0.89	0.89	0.89	0.9	0.89	0.9	0.9
$O\&M_{MCH, reconversion}$ (% CAPEX/y)	4	4	4	4	4	4	4	4	4
Operating lifetime$_{MCH, reconversion}$ (y)	20	20	20	20	20	20	20	20	20
Storage [21,24,28,34,42–44]									
$CAPEX_{Comp, storage}$ (£/kg$_{H2}$)	430	391.1	367.5	401.9	373.7	348	365.2	351.1	328.5
$O\&M_{Comp, storage}$ (% CAPEX/y)	2	2	2	2	2	2	2	2	2
Operating lifetime$_{Comp, storage}$ (y)	30	30	30	30	30	30	30	30	30
$CAPEX_{Liq, storage}$ (£/kg$_{H2}$)	76.9	53.3	41.2	55.2	33.5	22.5	34.2	23.3	13.1
$O\&M_{Liq, storage}$ (% CAPEX/y)	2	2	2	2	2	2	2	2	2
Operating lifetime$_{Liq, storage}$ (y)	20	20	20	20	20	20	20	20	20
$CAPEX_{Ammonia, storage}$ (£/kg$_{H2}$)	7.6	5.6	5.2	5.8	3.9	3.5	3.8	2.9	1.9

Table 2 – (continued)

	2025			2030			2050		
	P[a]	A[b]	O[c]	P[a]	A[b]	O[c]	P[a]	A[b]	O[c]
O&M$_{Ammonia, storage}$ (% CAPEX/y)	2	2	2	2	2	2	2	2	2
Operating lifetime$_{Ammonia, storage}$ (y)	20	20	20	20	20	20	20	20	20
CAPEX$_{MCH, storage}$ (£/kg$_{H2}$)	7.8	5.9	5.4	6.1	4.4	3.8	4.2	3.3	2.2
O&M$_{MCH, storage}$ (% CAPEX/y)	2	2	2	2	2	2	2	2	2
Operating lifetime$_{MCH, storage}$ (y)	20	20	20	20	20	20	20	20	20
Pipeline [38,46]									
O&M (% CAPEX/y)	5	5	5	5	5	5	5	5	5
EU H$_2$ backbone length (km)	1598	1649	2499	1598	1700	3400	1598	5725	19,500
Materials cost @ 8% LR[d] (%)	100%	100%	95%	100%	99%	91%	100%	85%	73%
Labour cost @ 14.2% LR[d] (%)	100%	99%	91%	100%	99%	85%	100%	74%	55%
Liquid ship tanker [24,34,42,47]									
CAPEX$_{Liquid\ hydrogen\ ship\ tanker}$ (£/m³)	2139.9	1804.3	1607.9	1857.8	1575.7	1289.8	1414.8	1273.8	971.8
O&M (% CAPEX)	4	4	4	4	4	4	4	4	4
Operating lifetime (y)	25	25	25	25	25	25	25	25	25
CAPEX$_{Ammonia\ ship\ tanker}$ (£/m³)	998.9	911.3	846.6	936.3	873.6	794.1	839	807.6	741.7
O&M (% CAPEX)	4	4	4	4	4	4	4	4	4
Operating lifetime (y)	25	25	25	25	25	25	25	25	25
CAPEX$_{MCH\ ship\ tanker}$ (£/m³)	578.3	489.2	440.6	503.7	429.1	360.7	392.2	354.9	280.8
O&M (% CAPEX)	4	4	4	4	4	4	4	4	4
Operating lifetime (y)	25	25	25	25	25	25	25	25	25
Electricity price [31]									
Offshore electricity (£/kWh)	0.102	0.08	0.055	0.066	0.051	0.037	0.051	0.037	0.022

[a] Pessimistic case (P).
[b] Average case (A).
[c] Optimistic case (O).
[d] Learning rate (LR).

Electrolyser

AC generated by the offshore wind farm will be converted to DC by an AC/DC converter. Electrolysers will consume part of DC to split water into hydrogen and oxygen. The amount of hydrogen that could be produced using electricity supplied by the wind farm on an hourly basis, $W_{H_2,theoretical}$ (kg$_{H2}$), was estimated using Equation (8) [5]:

$$W_{H_2,theoretical}(t) = \frac{P_{farm}(t)}{\frac{E_{elec}}{\eta_{conv}} + E_{aux}} \tag{8}$$

where η_{conv} is the conversion efficiency, E_{elec} is the electricity consumed in producing 1 kg of hydrogen (MWh/kg H$_2$), and E_{aux} is the electricity consumed by auxiliary components (i.e. desalination, hydrogen compression, hydrogen liquefaction, etc.).

The model used in this study was based on a PEM electrolyser plant, which, can be modularly 'stacked' to achieve the desired scale without sacrificing efficiency or output pressure, despite its current low capacity as evidenced by the current maximum capacity of the largest PEM electrolyser plants i.e. 20 MW [34]. PEM electrolysers are highly flexible with significant changes in operational parameters, making them ideal for intermittent inputs such as the power generated by offshore wind farms [56].

The size of the electrolyser plant, $P_{H2,\ plant}$ (MW), is affected by the quantity of offshore wind electricity allocated to hydrogen production, and its maximum value could be obtained by considering the product of the maximum amount of hydrogen that could be theoretically produced, $maxW_{H_2,theoretical}$, and the energy consumed by the electrolyser, E_{elec}, as in Equation (9) [5]:

$$P_{H_2,plant} \leq max\ W_{H_2,theoretical}(t) \cdot E_{elec} \tag{9}$$

The operation of the electrolyser would be interrupted when wind energy available from the offshore wind farm was too low due to the potential ineffectiveness of the electrolysers, which would eventually shorten its lifetime. A value of 5% of the rated power of the wind farm, $P_{farm,low}$, was assumed as the threshold for the operation of the electrolyser [5].

If the power output of the offshore wind farm is larger than the energy demand of the electrolyser plant at its rated capacity (i.e. if $P_{farm}(t) \geq P_{H2,plant} + W_{H2,prod}(t) \cdot E_{aux}$), the amount of hydrogen produced per hour, $W_{H2,prod}$ (kg/h), is calculated using Equation (10):

$$W_{H_2,prod}(t) = \frac{P_{H_2,plant} \cdot 1\ hour}{E_{elec}} \eta_{conv} \tag{10}$$

The operation of the electrolyser depending on the power output of the offshore wind farm is summarised in Equation (11):

Table 3 – Electrical losses in HVDC transmission [53,55].

Component	Loss
HVDC underground transmission	0.3% per 100 km
HVDC overhead transmission	0.4% per 100 km
HVDC submarine transmission	0.3% per 100 km
CSC converter	0.75%
VSC converter	1.5%

$$W_{H_2,prod}(t) = \begin{cases} 0 \ when \ P_{farm}(t) < P_{farm,low} \\[2mm] \dfrac{P_{farm}(t)}{\dfrac{E_{elec}}{\eta_{conv}} + E_{aux}} \ when \ P_{farm,low} < P_{farm}(t) < P_{H_2,plant}\left(1 + \dfrac{E_{aux}}{E_{elec}} \cdot \eta_{conv}\right) \\[4mm] \dfrac{P_{farm}(t)}{E_{elec}}\eta_{conv} \ when P_{farm}(t) > P_{H_2,plant}\left(1 + \dfrac{E_{aux}}{E_{elec}} \cdot \eta_{conv}\right) \end{cases} \quad (11)$$

The specific CAPEX of PEM electrolysers based on the cost per kW of input electricity was estimated using data from Refs. [32–34]. The future decrease in CAPEX of PEM electrolysers was expected to be driven primarily by scaling up production over time, learning rate, technological improvements and increase in the module size of the electrolysers [57,58].

To estimate the replacement costs of the electrolyser, the operating lifetime was assumed as the lifetime of the electrolyser stack, which would be prolonged with technological improvements over time. It was also assumed that a complete replacement of the PEM electrolyser was not necessary at the end of life. Instead, the replacement cost was taken as a percentage of CAPEX required to replace and/or repair the electrolyser stack, with this value decreasing over time in line with improvements in resiliency. The total replacement cost was calculated based on the CAPEX per kW for each replacement year, interpolating between data provided for 2025–2050.

The OPEX of the electrolyser was comprised of input electricity as well as operation and maintenance (O&M) costs, where different cases of electricity cost were considered. Technological improvements in terms of the increase in the maximum output pressure of the hydrogen produced by the electrolyser were also considered. If the output pressure of the hydrogen produced by the electrolyser could achieve the desired pressure at the inlet of the pipeline, it would exclude the need for additional compression, resulting in limited or no requirement for compression in 2050. If hydrogen is produced offshore, a battery is required as a backup power source when the electrolyser is in a stand-by mode [3]. The specific CAPEX (£/kW) of the stand-by battery was estimated based on [32], while the total CAPEX was calculated by assuming that 5% of the electrolyser capacity would be required for stand-by Ref. [32].

Desalination unit

From a stoichiometric point of view, 9 kg of water is required per kg of hydrogen produced [59]. Water consumption of 15 kg per kg of hydrogen produced by the electrolyser system, Q_{H2O}, was considered to account for water losses [22]. The daily volume of water required by the electrolyser plant, V_{H2O} (m³/d), can be calculated using Equation (12) [22]:

$$V_{H_2O} = \sum_{i=1}^{24} W_{H_2,prod,i}(t) \cdot Q_{H_2O} \cdot \rho_{H_2O} \quad (12)$$

where ρ_{H2O} is the density of water (kg/m³). For offshore hydrogen production, the water required by the electrolyser is supplied by a desalination unit. Although different types of

desalination technologies are available in the market, mainly based on processes of evaporation and condensation, filtration and crystallisation [60], reverse osmosis (RO) desalination was considered in this study. The daily energy consumption of the desalination unit, E_{des} (kWh/d), was calculated according to Equation (13):

$$E_{des} = V_{H_2O} \cdot e_{des} \quad (13)$$

where e_{des} is the specific energy consumption of the desalination unit, assumed as 3.5 kWh per m³ of desalinated water [34]. The CAPEX of the desalination unit was estimated based on the daily volume of water required by the electrolyser plant, in line with [35]. The O&M costs of the RO desalination unit (with a capacity larger than 100,000 m³/d) included labour, maintenance, chemical and membrane exchange [61], while the replacement costs were calculated considering a 30-year lifetime of the desalination unit [35].

Freshwater could be used as an alternative to seawater. A constant rate, £1.38/m³, was assumed for the cost per cubic meter of freshwater, $C_{freshwater}$ (£/m³). A 60% discount for large consumers was considered [22], as presented in Equation (14) for the annual cost of freshwater:

$$CAPEX_{freshwater} = C_{freshwater} \cdot (1 - 0.6) \cdot \sum_{i=1}^{365} V_{H_2O,i} \quad (14)$$

Compressor

The produced hydrogen may be compressed, stored or distributed via pipeline. The CAPEX of the hydrogen compressor was estimated based on the power required at the shaft to pressurise the incoming hydrogen, as shown in Equation (15) [62]:

$$P = Q \cdot \frac{ZTR}{M\eta} \cdot \frac{N\gamma}{\gamma - 1} \cdot \left(P_{outlet}^{\frac{\gamma-1}{N\gamma}} \bigg/ P_{inlet} - 1 \right) \quad (15)$$

where P is the required shaft power for a compressor with N stages, P_{inlet} and P_{outlet} represent the inlet and outlet pressure (MPa), respectively, Q is the hydrogen flow rate (kg/s), T is the inlet temperature (considered as 298.15 K, corresponding to the outlet pressure of the electrolysis plant), Z is the compressibility factor, M is the molecular mass of hydrogen (g/mol), γ is the ratio of the specific heat (1.4), R is the universal ideal gas constant (8.314 J/mol·K) and η is the efficiency of the compressor (assumed as 88% in this study).

PEM electrolysers produce high purity hydrogen at pressures ranging between 2 and 6 MPa, resulting in the need to compress the produced hydrogen up to 10–20 MPa at the

pipeline inlet for offshore application, depending on the flow rate that is required in the pipeline. Being commonly used with natural gas pipelines, centrifugal compressors were considered [63] with a pressure ratio of 2:1 per compressor stage [39]. The choice of the location of the electrolyser (onshore or offshore) was included to determine the pressure required at the outlet of the compressor. The pressure required at the pipeline inlet was assumed as 10 MPa and 7 MPa for the offshore and onshore scenarios, respectively [22]. The CAPEX of the hydrogen compressor was determined by using the functions reported in Refs. [36–39].

Liquefaction unit

Liquefaction of hydrogen is an alternative to the transport of compressed hydrogen by pipelines, capable of increasing the energy density of hydrogen. The specific CAPEX (£/(kg/h)) of liquefaction units was obtained from Refs. [21,24,34], taking account of a decline in CAPEX in the long term, as reported in Ref. [24]. To liquefy 1 kg of hydrogen, the energy required for the process varies with the capacity of the liquefaction system, ranging between 8 and 12 kWh for liquefaction systems with a daily capacity of 200 tonnes of hydrogen or less, respectively [64]. More recent projects were reported to liquefy hydrogen at a lower energy requirement, for instance, 6.4 kWh/kg with integrated design [65] and 5–6 kWh/kg with optimal design [40,66] while the theoretical minimum energy requirement for hydrogen liquefaction is 2.88 kWh/kg (in a reversible Carnot process considering an inlet pressure of 2 MPa [64]). The high energy consumption required by the liquefaction process represents an issue for offshore hydrogen production as it would significantly reduce the energy available to run the PEM electrolyser, resulting in a lower hydrogen output. The liquid hydrogen yield, y, which is defined as the total liquid hydrogen produced per total hydrogen supplied to the liquefaction unit [67], is affected by the hydrogen liquefaction cycle. A diversified range of y has been reported: 8% for simple Claude cycles, 12–17% for precooled Linde-Hampson cycles, 41% for precooled dual-pressure Linde-Hampson cycles, 16–20% for precooled simple Claude cycles, and 100% and 54% for helium-precooled Claude cycles for "normal" and for parahydrogen respectively whilst 100% has been proposed for future hydrogen liquefaction cycles [40,67]. The lifetime of the liquefaction unit and its O&M were assumed as 20 years and 4% of CAPEX, respectively [24].

Hydrogen carriers

Fig. 5 presents the energy demand for hydrogen storage and transport through different approaches [41], showing that liquefaction, adsorption of hydrogen, aluminium hydride (AlH_3), and formic acid are the four largest electricity consumers among all possible approaches for hydrogen storage, conversion and reconversion. When more electricity is consumed by these approaches, less electricity would be available for hydrogen production by electrolysers. As such, these approaches limit offshore hydrogen production, resulting in a lower hydrogen output. This study focused on the use of ammonia and MCH as potential hydrogen carriers.

Ammonia synthesis and reconversion

Ammonia (NH_3) shows high volumetric density, energy efficiency and flexibility (as ammonia can be directly used as fuel, fertiliser or decomposed to hydrogen). Based on the percentage composition by weight i.e. 82.4% nitrogen and 17.6% hydrogen [43], the ammonia synthesis process requires an air separation unit (ASU) and a Haber-Bosch reactor for nitrogen and ammonia production, respectively [21]. Cryogenic air
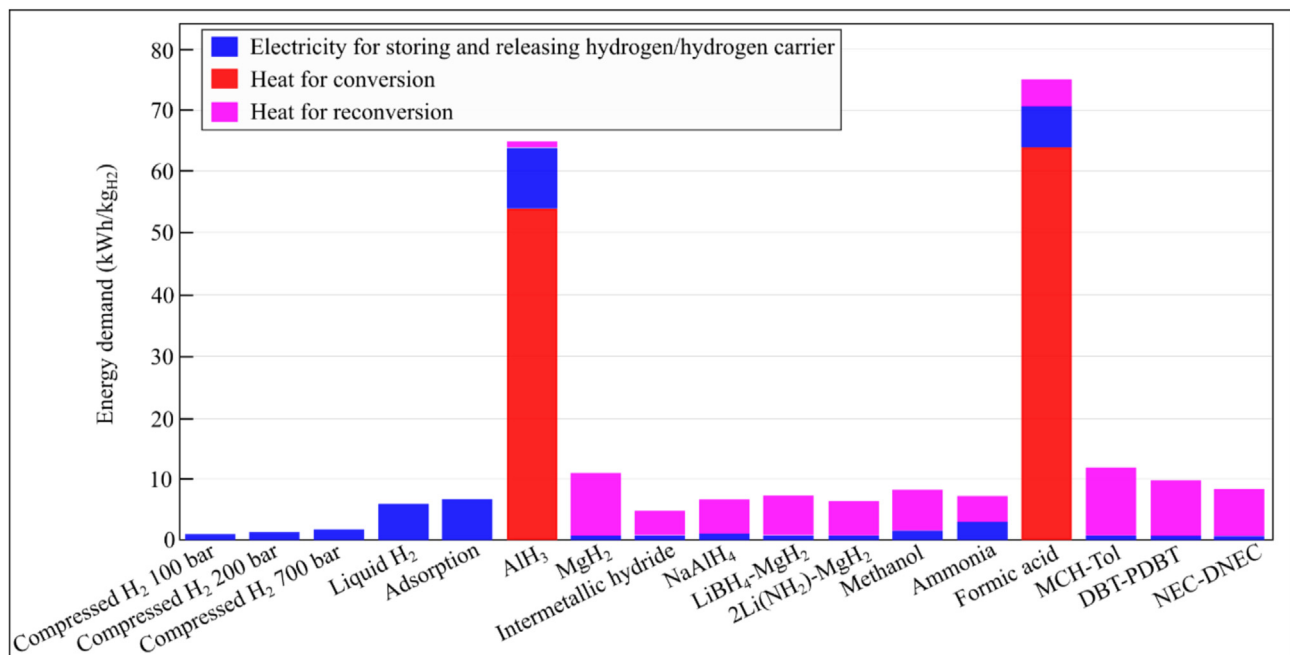

Fig. 5 – Energy demand for hydrogen storage, conversion and reconversion with different approaches, obtained from Ref. [41].

distillation is the only technology available for large-scale ASUs [44]. It requires CAPEX of £1247 per kg of nitrogen produced per hour whereas its specific energy consumption was assumed as 0.108 kWh per kg of nitrogen produced [28].

The reaction of ammonia synthesis (as reported in Equation (16) for 25−35 MPa and 500 °C in the presence of an iron-based catalyst such as Fe_3O_4) is an exothermic process, which releases 2.6 MJ of heat per kg of ammonia produced [44,45]:

$$N_{2(gas)} + 3\,H_{2(gas)} \rightarrow 2\,NH_{3(gas)}, \Delta H_r = -92.4\,kJ\,/\,mol \qquad (16)$$
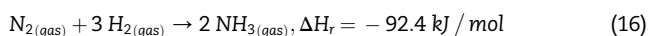
The specific CAPEX (£/(kg/h)) of the ammonia synthesis unit was collected from Refs. [21,24,44,68]. Its specific electricity consumption ranged between 2 and 4.8 kWh per kg of hydrogen supplied to the ammonia synthesis unit, based on the data collected from Refs. [21,24,41−43]. The lifetime and the O&M cost of the ammonia synthesis unit were assumed as 20 years and 4% of CAPEX per year, respectively [24]. The conversion rate for the ammonia synthesis reaction was considered as 90% [45]. Gaseous ammonia was cooled to −33.3 °C for liquefaction for easier handling, storage and transport [25,45].

If ammonia is not used directly, additional costs are required for the reconversion of ammonia into high-purity hydrogen onshore. The ammonia cracking process is a highly endothermic process that works at high pressures and temperatures (2 MPa and 800 °C) [25], as shown in Equation (17):

$$2\,NH_{3(gas)} \rightarrow N_{2(gas)} + 3\,H_{2(gas)}, \Delta H_r = 92.4\,kJ\,/\,mol \qquad (17)$$
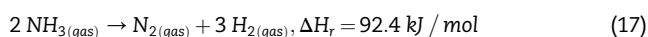
The specific CAPEX (£/(kg/h)) for the ammonia decomposition unit was collected from Refs. [21,24,34]. The electricity consumption of the ammonia decomposition process was considered as 1.5 kWh per kg of hydrogen [21,24,34], while its heat consumption was considered to range between 15.12 and 36 MJ per kg [21,24,34,41]. The cost of the natural gas required for the ammonia decomposition process was assumed as £0.05/kWh. The lifetime and the O&M cost of the ammonia decomposition unit were assumed as 20 years and 4% of CAPEX per year, respectively [24]. The efficiency of the ammonia decomposition process included was taken from Refs. [34,45], ranging between 84% and 90%.

MCH synthesis and reconversion
The transport of hydrogen by LOHCs is based on the "loading" of a "carrier" molecule, which is transported in a liquid form to the final application point and then converted back into hydrogen. Compared to hydrogen, "hydrogen-loaded" LOHCs show a higher volumetric energy density and the advantage of being stored at ambient conditions without energy losses [69].

The production of methylcyclohexane (MCH or $C_6H_{11}CH_3$) from toluene ($C_6H_5CH_3$), also called the hydrogenation process, is an exothermic process at 50−100 °C and 1−5 MPa in the presence of a platinum group metal-free (PGM-free) catalyst [25,70], as shown in Equation (18) [45]:

$$C_6H_5CH_{3(gas)} + 3\,H_{2(gas)} \rightarrow C_6H_{11}CH_{3(gas)}, \Delta H_r = -205\,kJ\,/\,mol \qquad (18)$$
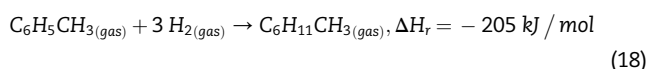
After producing gaseous MCH, it is condensed at 25 °C and 0.1 MPa [45] before being transported in a liquid form to shore (by pipelines or tankers). The specific CAPEX (£/(kg/h)) for the hydrogenation unit was collected from Refs. [21,24,34]. The heat released during the hydrogenation process requires accurate cooling to sustain the reaction [45], consuming 0.7 kWh of electricity per kg of hydrogen. The lifetime and the O&M cost of the hydrogenation unit were assumed as 20 years and 4% of CAPEX per year, respectively [24]. The characteristics of the catalysts will influence the conversion ratio, which was considered as 90% if palladium deposited on acidic hierarchical faujasite (Pd-HFAU) zeolite was used as the catalyst for the synthesis of MCH [45].

After the reconversion of MCH into hydrogen, toluene would be transported or shipped back to the MCH production unit. Such transport or shipping as well as toluene itself will incur additional costs, which could be significant. A cost of £0.3−0.7 per kg of toluene [34] with a ratio of hydrogen to toluene consumption of 4:1 [71] were considered. Toluene needs to be topped up regularly as some toluene molecules will be lost during storage and transport due to side reactions [69]. The toluene markup was considered as 22% [72]. The lifetime and the O&M cost of the MCH production unit were assumed as 20 years and 4% of CAPEX per year, respectively [24].

The reconversion of MCH or dehydrogenation process is endothermic and requires a significant amount of energy to release hydrogen [70], as shown in Equation (19) for a temperature of 320 °C and a pressure of 0.1 MPa [45]:

$$C_6H_{11}CH_{3(gas)} \rightarrow 3\,H_{2(gas)} + C_6H_5CH_{3(gas)}, \Delta H_r = 205\,kJ\,/\,mol \qquad (19)$$

Being in a gaseous form, the dehydrogenation process is preceded by the evaporation of liquid MCH and followed by the evaporation of toluene [45]. After dehydrogenation, the produced toluene will be liquefied before being sent back to the offshore wind farm by pipelines or ship tankers. The specific CAPEX (£/(kg/h)) for the MCH dehydrogenation unit was collected from Refs. [24,34]. Dehydrogenating MCH would consume 1.5 kWh electricity [21,24,34] and 38.16−54 MJ heat [21,24,34,41,42] in producing 1 kg of hydrogen. It was assumed that the heat required for the MCH dehydrogenation process was supplied by natural gas at £0.05 per kWh. The lifetime and O&M cost of the dehydrogenation unit were assumed as 20 years and 4% of CAPEX per year respectively [24]. Similar to the hydrogenation reaction, the rate of dehydrogenation reaction depends on the activity, selectivity and stability of the catalyst chosen for the process. For the MCH dehydrogenation process in the study, its efficiency of conversion was collected from Refs. [34,45].

Storage

Depending on the pressure at which hydrogen is stored, the CAPEX of compressed gas hydrogen storage was calculated based on the amount of hydrogen produced per day, M_{H2} (kg/day), as reported in Equation (20) with the storage capability, $t_{Storage}$ (days of storage required) indicating the size of the storage tank:

$$CAPEX_{Storage} = CAPEX_{Spec,storage} \cdot M_{H_2} \cdot t_{Storage} \qquad (20)$$

where the specific cost of the compressed hydrogen storage tanks, $CAPEX_{Spec,\,storage}$ (£/kg), was collected from Refs.

[21,24,28]. The lifetime and the O&M cost of the compressed hydrogen storage tanks were assumed as 30 years and 2% of the CAPEX per year, respectively [24]. Storing a large volume of compressed hydrogen in tanks on offshore platforms could present an additional issue due to the space occupied by the tanks. For instance, tanks required for storing the hydrogen produced by a 1 GW electrolyser for 24 h would take up a space of 56,000 m^3 at minimum [3].

Specially insulated cryogenic containers can be used for storing liquid hydrogen, which has a density nearly twice of that of compressed hydrogen at 70 MPa (71 kg/m^3 vs. 42 kg/m^3) [73]. The insulation in the cryogenic tank is achieved by evacuating the space between the double wall of the tank and placing several reflective heat shields between them. Cryogenic storage tanks are usually spherical to limit the surface-to-volume ratio [74]. The CAPEX of the cryogenic storage tank varies with the size of the storage tank (£/kg), which was considered using data collected from Refs. [21,24,28]. The lifetime and the O&M cost of the cryogenic storage tank were assumed as 20 years and 2% of the CAPEX per year, respectively [24]. The storage of liquid hydrogen is subject to losses due to evaporation, also called boil-off. In general, these losses will be affected by the size and insulation of the cryogenic storage tank. For instance, liquid hydrogen will be lost by 0.4% per day in a 50 m^3 storage tank whereas the loss will be 0.06% for a 20,000 m^3 storage tank [70]. Reduced or zero boil-off could be achieved through active and passive approaches by (i) accelerating the transition from ortho-to para-hydrogen during liquefaction, (ii) further reducing the surface-to-volume ratio of the storage tank, and (iii) developing better insulation and cryocooling [75].

Commercially, bulk liquid ammonia storage using standard crude oil tanks is well established [24]. The specific CAPEX (£/kg) of ammonia storage tanks was collected from Refs. [21,24,28,42−44]. Its lifetime and the O&M cost were assumed as 20 years and 2% of the CAPEX per year, respectively [24]. At −33 °C, liquid ammonia storage also presents boil-off but the issue is not as critical as that of liquid hydrogen storage. This is because the evaporated ammonia can be recovered through condensation and feeding back to the storage tank [43]. Similarly, LOHCs can be stored in conventional crude oil storage tanks as LOHCs and crude oil share similar properties. The specific CAPEX (£/kg) for MCH storage was collected from Refs. [21,24,42]. Its lifetime and the O&M cost were assumed as 20 years and 2% of the CAPEX per year, respectively [24].

Distribution

Pipelines
In this study, hydrogen distribution pipelines were assumed to be made of API 5L Grade X52 carbon steel with an internal diameter which varied in line with the flow rate of hydrogen. The outlet pressure was 7 MPa, and the inlet pressure was controlled to achieve the desired flow rate of the system. The dimension of the pipeline was determined based on the energy flow from the electrolyser, considering 142 cm as the maximum diameter of the pipeline and 20 m/s as the maximum velocity of the compressed hydrogen in the pipeline [25].

An increase in pipeline construction was assumed in this study in line with the EU Hydrogen Backbone, which envisaged new hydrogen pipelines would make up 50% of the global hydrogen networks by 2040. The construction cost of the hydrogen pipelines was estimated by adjusting the construction cost of a natural gas pipeline, which included: (i) materials; (ii) labour; (iii) miscellaneous including regulatory filing fees, administration and overhead, surveying, supervision, contingencies and allowances for construction funds [76]; and (iv) right of way. The cost equations in Ref. [76] were used to calculate the total CAPEX of the hydrogen pipelines. The cost of materials was increased by 50% to account for greater wall thicknesses (to reduce embrittlement) whereas labour costs were raised by 25% in line with the higher cost for welding (to reduce leakage).

The O&M cost is expected to comprise predominantly of the cost of 'pigging' the pipeline to detect leaks and defects. Learning rates were also applied: a doubling of pipeline construction could lead to an 8.0% and 14.2% reduction in the materials and labour costs respectively [46]. The losses in transporting hydrogen by pipelines, which was considered as 0.01% in this study, are less significant than long-distance transmission of electricity (both AC and DC) [3]. Three cases were considered for the pipeline construction: (1) an average case assuming that hydrogen pipelines construction would take place but stop expanding by 2040; (2) an optimistic case assuming a continued expansion of hydrogen pipelines until 2050; and (3) a pessimistic case assuming that no pipeline would be built, resulting in no learning rate applied to the pipeline costs.

With higher energy density compared to hydrogen, ammonia pipeline distribution is well established and applied by industry, resulting in cheaper costs for ammonia transport [25]. On the contrary, LOHC pipelines have not been developed yet, although they could be similar to crude oil pipelines because the physical and chemical properties of LOHCs are comparable to those of crude oil [77]. Compared to hydrogen and ammonia pipelines, extra costs are incurred in returning the toluene produced by the MCH dehydrogenation process back to the offshore platform through pipelines [77]. The CAPEX of the pipelines for ammonia, MCH and toluene was estimated by adjusting the CAPEX of hydrogen pipelines in line with [25] where the maximum velocity of liquid ammonia, MCH and toluene inside the pipelines was assumed as 2 m/s [25]. The electricity consumption, CAPEX, O&M and the lifetime of the pumps required for the distribution of ammonia and MCH were obtained from Ref. [24].

Shipping
Alternatively, ship tankers could be used for transporting liquid hydrogen, ammonia and MCH, which would become more cost-effective for distances longer than 1800 km [34]. As such, liquid hydrogen ship tankers could be more appealing for continental and intercontinental journeys. Meanwhile, conventional ship tankers used for transporting oil and chemicals could be used to distribute ammonia and MCH [24]. After delivery, ship tankers will return to the offshore platform without carrying any cargo, which presents a disadvantage of distributing liquid hydrogen, ammonia and MCH by ship tankers, unless another application is found [34].

Table 4 — Characteristics of Hornsea Two offshore wind farm considered in the reference case study [79,80].

Parameter	Value
Location	Latitude 53.9658
	Longitude 1.89694
Turbine type	Siemens Gamesa SG 8.0—167 DD
Rated power output	8 MW
Cut-in speed	3 m/s
Rated speed	12 m/s
Cut-off speed	25 m/s
Survival speed	70 m/s
Hub height	92 m
Number of turbines	165
Total power output	1320 MW
Distance to shore	89 km

The specific CAPEX (£/m^3) considered for liquid hydrogen, ammonia and MCH ship tankers were collected from Refs. [24,34,42,47]. To estimate and compare the total CAPEX for liquid hydrogen, ammonia and MCH distribution by ship tankers, the capacity of the ship tankers was assumed the same as 1600,000 m^3 based on the current and future capacity of the ship tankers [47]. The speed of the ship tankers was assumed as 30 km/h and the data for fuel consumption of the different ship tankers were sourced from Ref. [34]. The propulsion of the ship tankers would be provided by prime movers run by heavy fuel oil (HFO) at a cost of £0.0142 per MJ [78]. Liquid hydrogen would be lost by 0.2% per day whereas there was no loss for ammonia and MCH [24]. The lifetime and the O&M cost of liquid hydrogen, ammonia and MCH tankers were assumed as 20 years and 4% of the CAPEX of the tanker per year, respectively [24]. Some studies have also included the possibility of using the boil-off of liquid hydrogen as the propulsion fuel [34], which was not considered in this techno-economic analysis.

Results and discussion

Reference case and alternative scenarios

The offshore wind farm Hornsea Two [79] was considered in this project as a baseline case study. Located in the North Sea off the Yorkshire coast and adjacent to Hornsea One, this wind farm became fully operational on the August 31, 2022 and has a total capacity of 1320 MW employing 165 wind turbines Siemens Gamesa SG 8.0—167 DD with a power output of 8 MW each. The main characteristics of the offshore wind farm are summarised in Table 4.

The power curve of the Siemens Gamesa SG 8.0—167 DD wind turbines was obtained from Ref. [80], as illustrated in Fig. 6 for the power output of a single turbine up to 8 MW depending on the wind speed.

Fig. 7 shows the hourly wind speed data at the Hornsea Two Wind Farm [50], together with the values of cut-in, rated and cut-off wind speed of the considered wind turbine.

Based on the power curve, the estimated wind speed, and the total number of wind turbines, the power that could be potentially produced by the entire wind farm, $P_{farm}(t)$, was calculated, as shown in Fig. 8.

Fig. 9 shows the maximum theoretical production capacity of Hornsea Two for the scenarios of 100% conversion of offshore wind electricity into hydrogen, ammonia, or MCH. If each production system in the reference case and the alternative scenarios was constructed in 2025, the estimated total production over the full lifespan of each offshore system would be 4,659,921,758 kg compressed hydrogen, 3,927,646,743 kg liquid hydrogen, 22,060,495,685 kg ammonia, or 5,172,045,442 kg MCH, as shown in Fig. 10 (i)—(v), utilising 100% electricity generated by the wind farm i.e. 274,191,876.5 MWh following an average case of cost and performance evaluation (as defined in Scope and Methodology). If each system was constructed
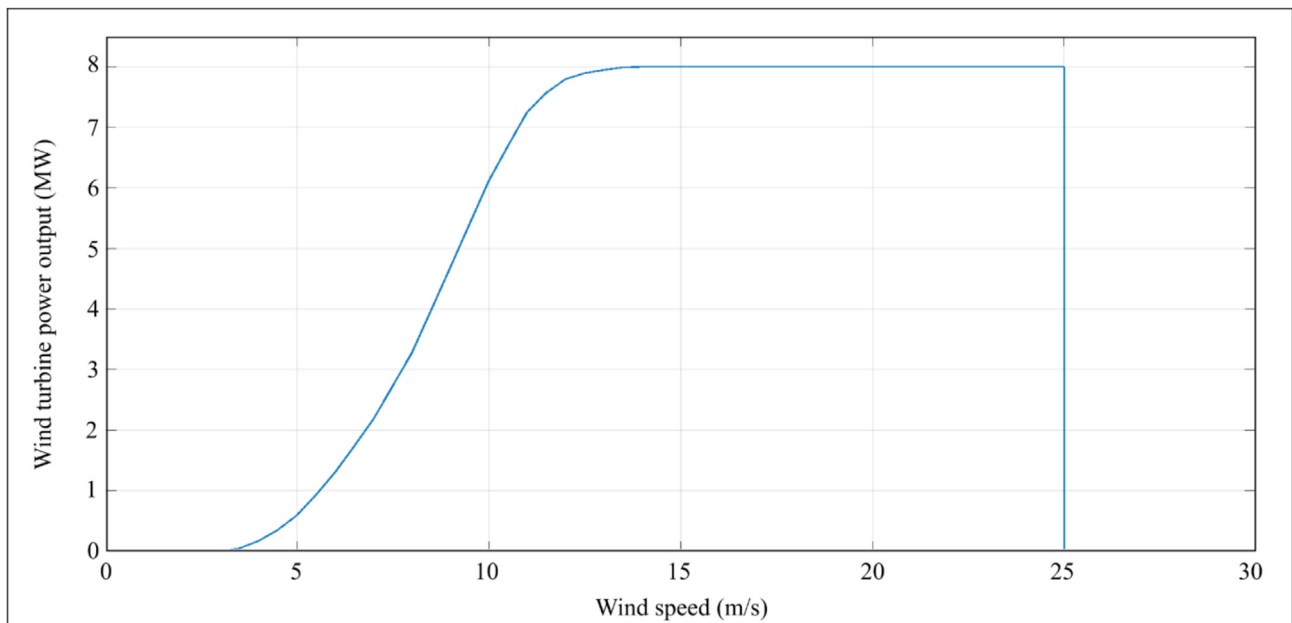

Fig. 6 — Power curve of Siemens Gamesa SG 8.0—167 DD wind turbine, adapted from Ref. [80].
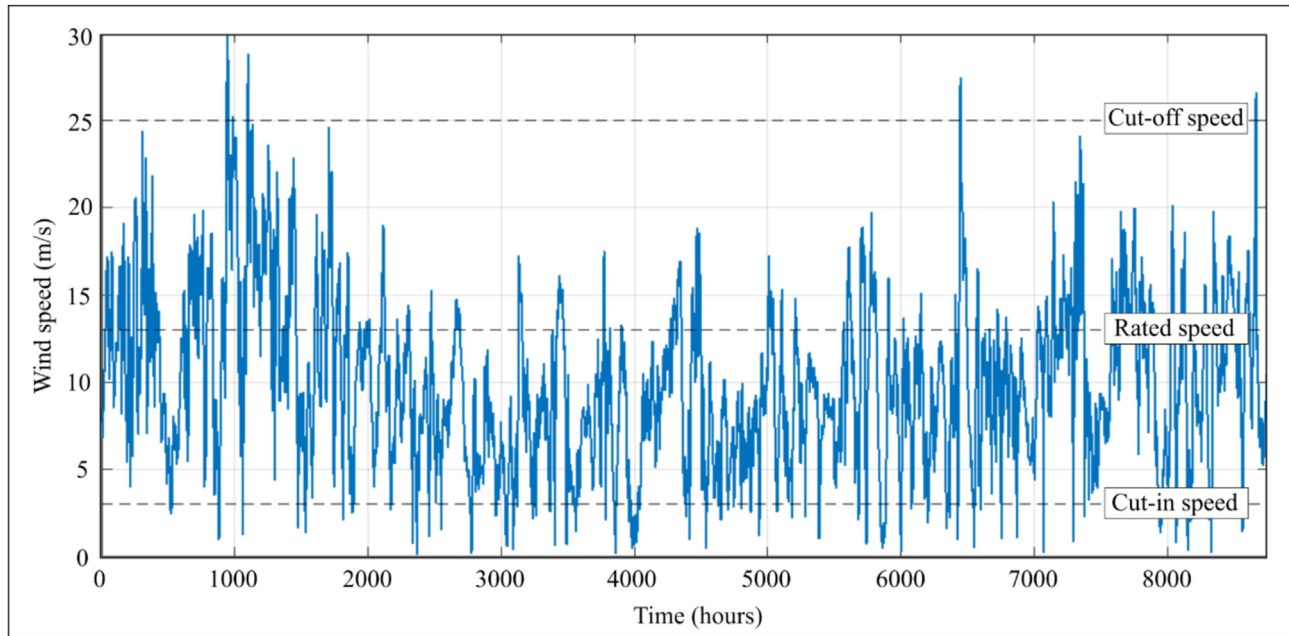
Fig. 7 – Estimated wind speed at Hornsea Two Wind Farm based on data available in Ref. [50].

and operated in 2050, the quantities would increase (producing 5,179,390,252 kg compressed hydrogen, 4,634,327,956 kg liquid hydrogen, 24,688,462,101 kg ammonia, or 5,725,798,835 kg MCH in total). On the other hand, if the electricity generated by the wind farm was fully consumed to produce compressed hydrogen onshore, the total production would reduce by 6.1% and 6.77% in 2025 and 2050 respectively compared to the quantities produced offshore. This was due to the electrical losses during electricity transmission from offshore to the shore by means of HVDC cables and the electrical losses for AC/ DC conversion whereas losses associated with hydrogen

distribution through pipelines were assumed as low as 0.01% in this study. If the electricity generated by the wind farm was fully consumed to produce hydrogen which was then converted into ammonia offshore and reconverted back into hydrogen onshore, the total production of hydrogen would reduce by 6.65% and 5.86% in 2025 and 2050 respectively compared to the quantities produced offshore when only compressed hydrogen was produced as a result of the electricity consumption required for the ASU and the Haber-Bosch reactor. Similarly, if the electricity generated by the wind farm was fully consumed to produce hydrogen which was then
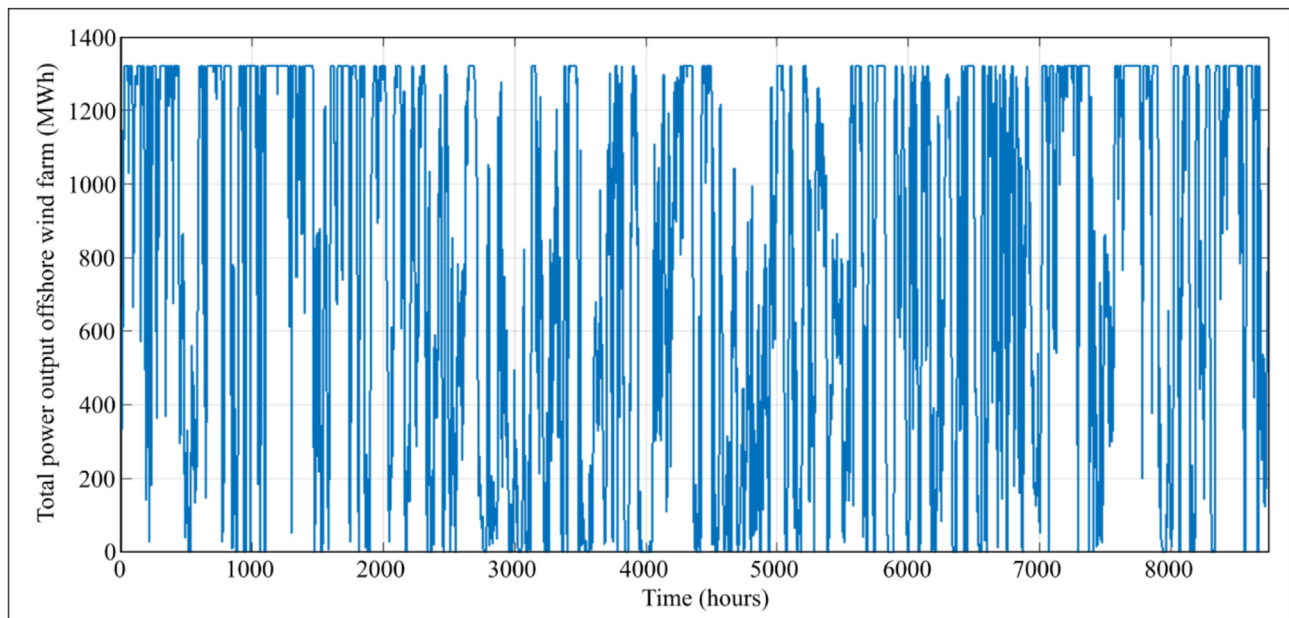

Fig. 8 – Total hourly power output estimated for Hornsea Project Two.
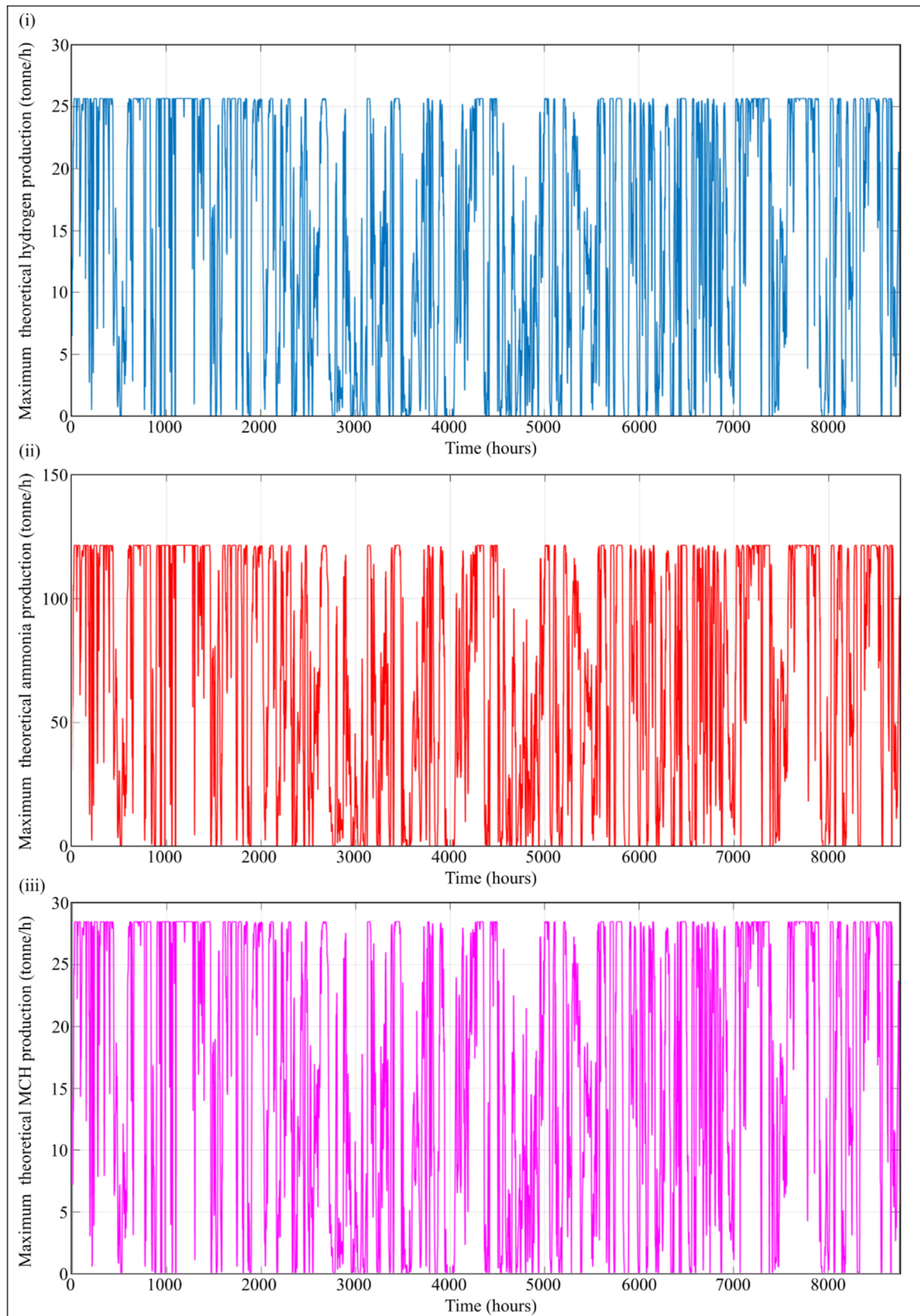
Fig. 9 — **Hourly maximum theoretical production in 2025 estimated for Hornsea Project Two for (i) hydrogen; (ii) ammonia; or (iii) MCH.**
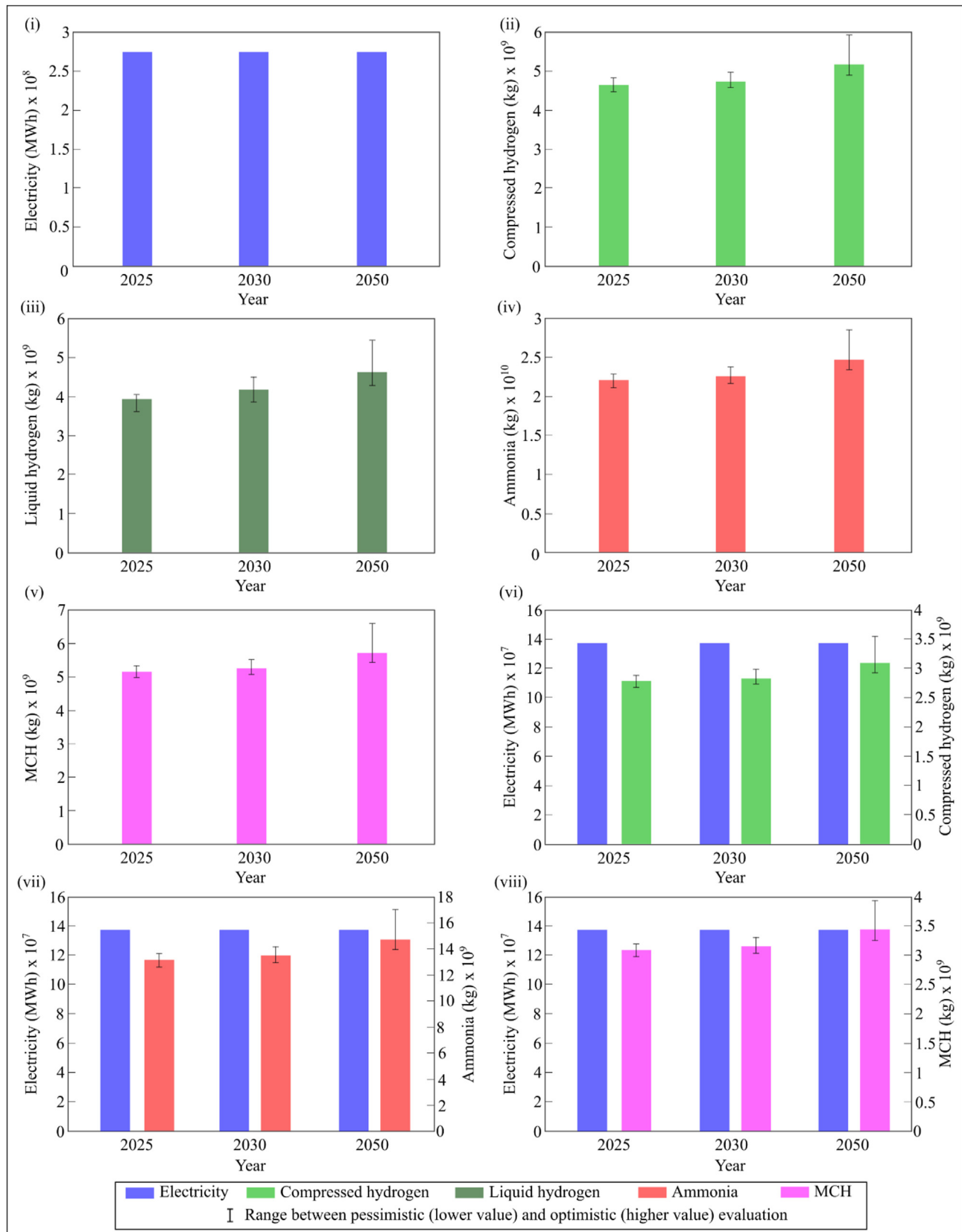
Fig. 10 — Total offshore production capacity over 40 years for (i) 100% electricity production; (ii) 100% compressed hydrogen production; (iii) 100% liquid hydrogen production; (iv) 100% ammonia production; (v) 100% MCH production; (vi) co-production of compressed hydrogen and electricity*; (vii) co-production of ammonia and electricity*; and (viii) co-production of MCH and electricity*. (*50% of the total generated electricity would be fed into the transmission grid for sale whereas the remaining would be used for producing hydrogen, ammonia, or MCH offshore.)

converted into MCH offshore and reconverted back into hydrogen onshore, the total production of hydrogen would reduce by 1.19% and 1.37% in 2025 and 2050 respectively compared to the quantities produced offshore when only compressed hydrogen was produced as a result of the electricity consumption required for the cooling of the hydrogenation reaction of the toluene. When the co-production scenarios were explored with different percentages of the generated electricity being utilised for the co-production scenarios of hydrogen, ammonia, or MCH, the analysis showed that the quantity of hydrogen, ammonia, or MCH produced would not be linearly proportional to the total electricity supplied by the offshore wind farm nor the increase in the capacity of the electrolyser, despite the total electricity being generated and the size of the electrolysis plant would significantly affect the feasibility of offshore wind to the production of hydrogen, ammonia, or MCH. It is worth noting that electrolyser units sized at 100% of the offshore wind farm capacity might not be as cost-effective as claimed because they could be oversized compared to the availability of wind power.

Fig. 11 shows a breakdown of the total cost (including electricity, CAPEX, O&M and replacement cost) estimated for different ratios of electricity-to-hydrogen production for 2025, 2030 and 2050, considering an average case of cost and performance of systems, considering HVDC underground transmission, VSC converters and a storage period of 14 days. A significant reduction in the total cost could be achieved in 2030 and 2050, ranging 28.5−30.4% and 36.6−42.2% respectively compared to 2025. The total cost of the system over a lifetime of 40 years would be dominated by the cost of the input electricity, as follows.

- When only electricity was produced by the offshore wind farm and transmitted to shore by HVDC transmission, the cost of input electricity would contribute to 86.3%, 80.3%, and 74.9% of the total cost in 2025, 2030, and 2050 respectively.
- When compressed hydrogen was produced offshore utilising 25%, 50%, 75%, and 100% of the electricity generated offshore, the cost of input electricity would contribute to 64.2−75.6%, 55.8−68.1%, and 48.9−61.7% of the total cost in 2025, 2030, and 2050 respectively.
- When compressed hydrogen was produced onshore utilising 25%, 50%, 75%, and 100% of the electricity generated offshore, the cost of input electricity would contribute to 70.7−79%, 62.9−72.1%, and 56.2−66% of the total cost in 2025, 2030, and 2050 respectively.
- When liquefied hydrogen was produced offshore utilising 25%, 50%, 75%, and 100% of the electricity generated offshore and transported to shore by tanker, the cost of input electricity would contribute to 75.3−78.1%, 71.2−72.8%, and 69.4−70.4% of the total cost in 2025, 2030, and 2050 respectively.
- When ammonia was produced offshore utilising 25%, 50%, 75%, and 100% of the electricity generated offshore and transported to shore by pipeline, the cost of input electricity would contribute to 69.2−78.1%, 66.1−73.6%, and 64.3−70.4% of the total cost in 2025, 2030, and 2050 respectively.
- When MCH was produced offshore from toluene utilising 25%, 50%, 75%, and 100% of the electricity generated

offshore toluene and transported to shore by pipeline, the cost of input electricity would contribute to 75.1−79.9%, 69.8−73.8%, and 65.9−69% of the total cost in 2025, 2030, and 2050 respectively.

In this study, offshore wind electricity price was considered fixed in line with [31]. However, the system could operate flexibly i.e., producing hydrogen, ammonia or MCH when electricity prices were low and selling the electricity from the offshore wind farm directly without hydrogen/ammonia/MCH production when the electricity prices were high. Whilst such flexible operation could significantly reduce the electricity cost of the system, using the curtailed wind energy and future PEM electrolysers with higher electrical efficiency, longer lifetime and higher maximum pressure output would have the potential to further improve the economics of the system. The CAPEX, O&M and replacement costs would contribute to less than 15% of the total cost in all scenarios assessed in this study. The fuel cost required to transport the liquid hydrogen, ammonia or MCH over the lifetime of the system was marginal for the reference case study due to the short distance to shore (89 km), contributing to values lower than 0.01% of the total cost over the lifetime of the technology. When MCH was produced offshore using toluene and transported to the shore by pipeline, the cost for heating would range 6.3−10.5%, 8.8−14.6%, and 11.4−19.1% of the total cost in 2025, 2030, and 2050 respectively. Compared to MCH production, the contribution of the heating cost to the total cost was slightly lower for ammonia production, i.e., 3.8−6%, 5.4−8.5%, and 5.9−9.4% in 2025, 2030, and 2050 respectively.

The total cost associated with each production and distribution scenario could be also broken down for each component, as shown in Fig. 12, for 2025, 2030 and 2050. Electrolysers, among all components, showed the most significant impact on the total cost, resulting in a significant increase in CAPEX when a larger amount of electricity produced by the offshore wind farm was used for hydrogen production. When hydrogen was produced offshore utilising 25%, 50%, 75%, and 100% of the electricity generated offshore, the cost of electrolysers would make up 45.2−69.5%, 40.7−60.3%, and 36.5−52.1% of the total cost in 2025, 2030, and 2050 respectively. By 2050, a significant reduction in CAPEX would be observed as driven by lower specific costs (CAPEX/kW) of electrolysers, increased efficiency (from 64% to 70.5% for the average case defined in Scope and Methodology **Scope and Methodology**), longer lifetime (from 67,500 h to 125,000 h for the average case) and reduced stack replacement costs (by 14.3%). The contribution of the cost of the HVDC transmission lines and converters could also be significant, for instance, 21.1−48.7%, 20.2−47.9%, and 19.5−47% of the total cost when compressed hydrogen was produced onshore utilising 25%, 50%, 75%, and 100% of the electricity generated offshore in 2025, 2030, and 2050 respectively.

For all considered cases, hydrogen pipelines would have a relatively low contribution to the total cost of the whole system, ranging 1.5−1.6%, 2−2.3%, and 2.1−2.5% in 2025, 2030, and 2050 respectively. A similar contribution to the total cost was observed for ammonia and MCH pipelines, lower than 1% and 2.4−4.1% of the total cost respectively. The analysis indicated that for shorter distances, pipelines would not
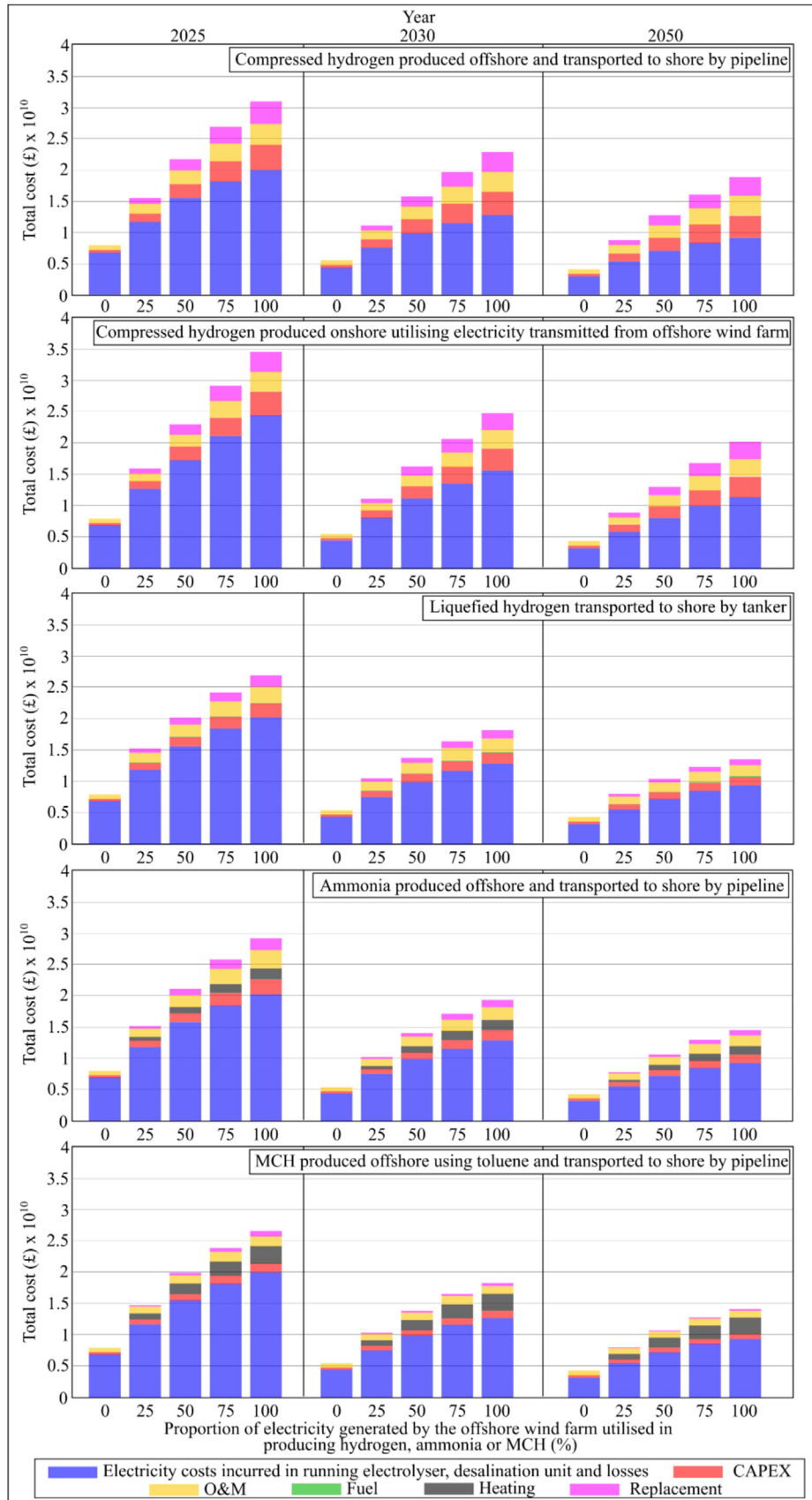
Fig. 11 — A breakdown of the total cost estimated for different scenarios of producing compressed and liquid hydrogen, ammonia, and MCH offshore utilising different proportions of electricity generated by the offshore wind farm and transported to the shore via pipelines or tankers in 2025, 2030, and 2050.
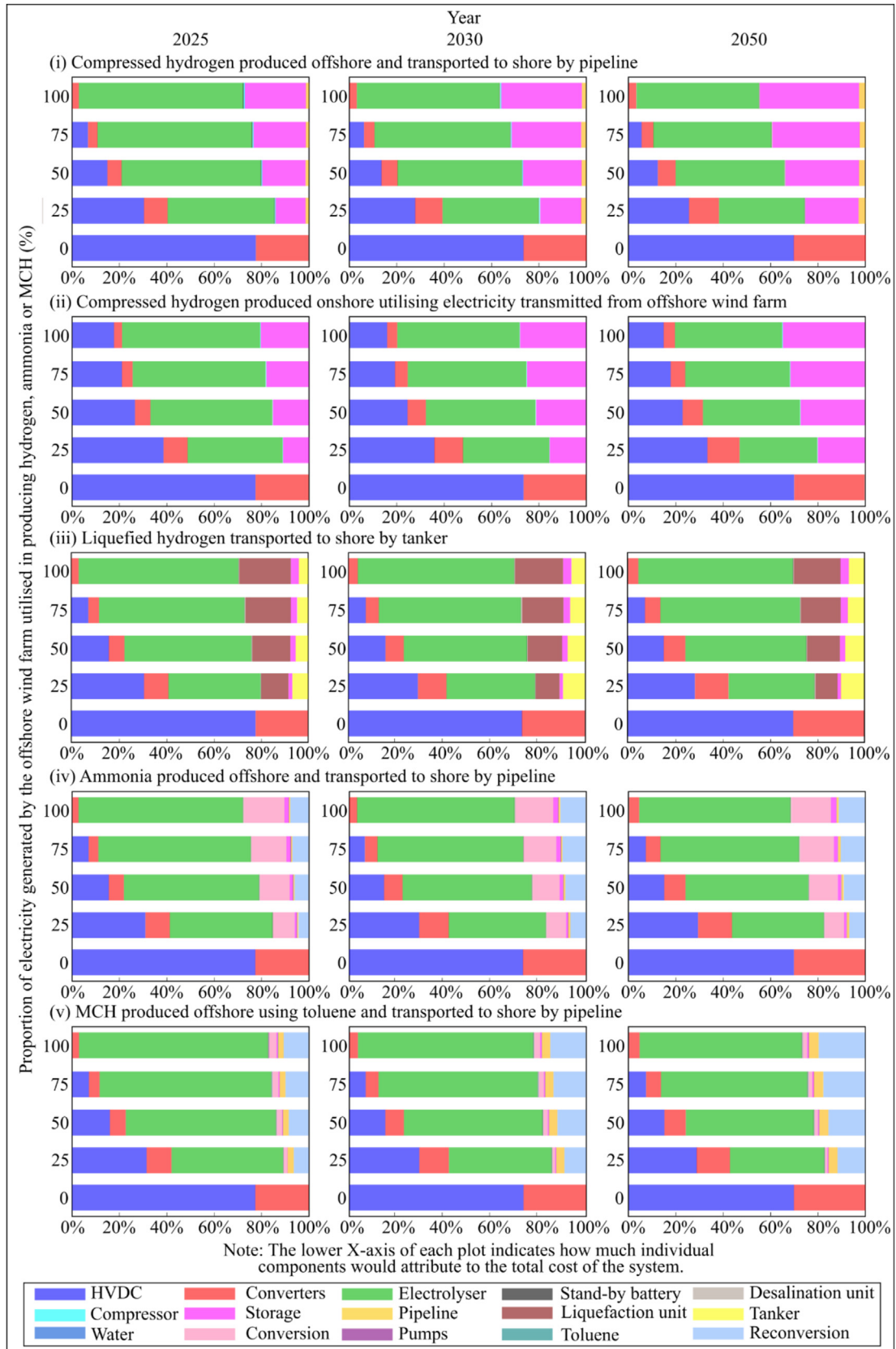
Fig. 12 − A cost breakdown of each system as per components.

significantly affect the economic performance of the whole system. For the reference case, the cost of transport by ships would not remarkably affect the total cost of the system, although the cost would be higher than the transport by pipeline. For a liquid hydrogen ship tanker, this would 3.9–6.8%, 5–8.7%, and 5.5–9.3% in 2025, 2030, and 2050 respectively. A similar trend was observed for ammonia and MCH tankers, i.e., lower than 10% of the total cost. Using a portion of the transported fuel, for instance by recovering boil-off gas or using ammonia directly, could further reduce costs.

Compressors also showed a low contribution to the total cost, i.e., 0.2–0.4% in 2025 which would decrease by 2030 and become negligible by 2050. Any future increase in the maximum output pressure of PEM electrolysers would eliminate the need for compression and improve the efficiency and reliability of the system whereas its future impact on the total cost of the system would be minimal. On the other hand, the choice of storage technology type would affect the contribution of the storage cost to the total cost, i.e., 12.8–25.8%, 17.6–34.1%, and 22.5–42.2% in 2025, 2030, and 2050 respectively for compressed hydrogen produced offshore. This was due to the combination of the high CAPEX of compressed hydrogen storage and the storage period considered in the analysis i.e., 14 days. Other storage choices in the form of liquid hydrogen, ammonia and MCH would contribute to less than 4% of the total cost for all scenarios assessed in this study.

The liquefaction process would involve expensive CAPEX and electricity consumption, making liquefaction units contributing 11.6–21.8%, 10.3–20.6%, and 9.5–19.9% of the total cost of the system in 2025, 2030, and 2050 respectively. The cost of the conversion and reconversion units for ammonia and MCH would have similar impact on the total cost. When ammonia was produced offshore and transported to shore by pipeline, the cost of the conversion and reconversion unit would contribute 13.9–25.2%, 14.7–26.7%, and 15.2–28.2% to the total cost in 2025, 2030, and 2050 respectively, with the majority of the cost was attributable to the ammonia synthesis process (ASU and Haber-Bosch unit). When MCH was produced offshore using toluene and transported to shore by pipeline, the cost of the conversion and reconversion unit would contribute to 8.1–13.8%, 10.3–17.5%, and 12.6–21.5% of the total cost in 2025, 2030, and 2050 respectively, with the majority of the cost attributable to heating required by the MCH decomposition process.

Fig. 13 shows the estimated LCOH for the assessed production and distribution scenarios for optimistic, average, and pessimistic cases utilising different proportions of electricity generated by the offshore wind farm. The analysis indicated high LCOH ranges for scenarios in 2025, which could be as low as £6.63/kg$_{H2}$ for the average case when 100% of the offshore wind electricity was used for the production of compressed hydrogen offshore. A significant reduction would be observed in 2030 and 2050 when liquefied hydrogen was transported to shore by tanker for the average case, i.e., as low as £3.04/kg$_{H2}$ and £1.54/kg$_{H2}$ respectively as offshore wind-to-hydrogen projects would become more efficient with more commercial applications by that time. An increase in the electrolyser efficiency would result in better utilisation of the electrical energy available from the offshore wind farm, leading to a higher hydrogen production output.

When the LCOH for different scenarios was compared, it was found that compressed hydrogen produced offshore utilising 100% electricity generated from offshore wind would have the lowest LCOH in 2025, i.e., £4.92/kg$_{H2}$ and £8.6/kg$_{H2}$ for the optimistic and pessimistic cases respectively. The LCOH could be further reduced to £4.65/kg$_{H2}$ and £8.28/kg$_{H2}$ for the optimistic and pessimistic cases respectively when curtailed energy was not charged at any price (because the electricity that would be curtailed otherwise was generated to supplement the power supply). The scenario of 100% offshore hydrogen production would benefit from a lower LCOH (as HVDC transmission cables were not required); however, it might not support flexible production of electricity and/or hydrogen in the UK when electricity costs and energy demand were low. When only a limited fraction of the offshore wind energy was utilised for hydrogen production (which could be driven by curtailed energy only) the LCOH would be higher if the curtailed energy was charged at a market price. As such, hydrogen production only utilising electricity that would be curtailed otherwise would not be cost-effective due to the high capital cost required compared to the amount of hydrogen produced. If the electricity generated from offshore wind was 100% used for hydrogen production, the magnitude of onshore hydrogen production assessed in alternative scenario (i) would be less than that of offshore hydrogen production assessed in the reference case due to the higher losses during conversion and HVDC transmission compared to the losses associated with pipeline transmission, leading to a higher LCOH i.e., £5.76–10.26/kg$_{H2}$ for the optimistic and pessimistic cases. The difference would be case-specific, varying with the power transmitted by the HVDC lines and distance.

In 2030, the LCOH of alternative scenarios, such as liquefied hydrogen produced offshore and transported to shore by tanker or ammonia/MCH produced offshore and transported to the shore by pipeline or tanker could become cost-competitive or cheaper than hydrogen produced offshore. By 2050, the LCOH of offshore wind-to-hydrogen/ammonia/MCH production scenarios would become cost-competitive with grey and blue hydrogen (£0.69–2.32/kg$_{H2}$ and £1.12–2.07/kg$_{H2}$ respectively, as shown in Fig. 13). Converters of higher efficiency and HVDC transmission of higher voltage could reduce transmission losses and associated costs, leading to a decrease in the LCOH. Additional revenue could be achieved by selling the oxygen produced from the electrolyser. Both were not considered in this study and should be further evaluated in future studies.

The results shown in Fig. 13 would be valid for a storage period of 14 days and the choice of the storage technology and period would have, in general, an important impact on the LCOH. To further clarify the effect of the storage period on the feasibility of offshore wind-to-hydrogen production, Table 5 presents the LCOH estimated for different storage periods when 100% of the offshore wind electricity was used for hydrogen/ammonia/MCH production in 2025, 2030 and 2050. Table 5 indicated the dominant effect of the storage period on the most cost-effective scenario. When one day of storage was considered, compressed hydrogen produced offshore would be the most cost-effective scenario in 2025, 2030 and 2050. When the storage period was extended, compressed hydrogen produced offshore would become less cost-effective because
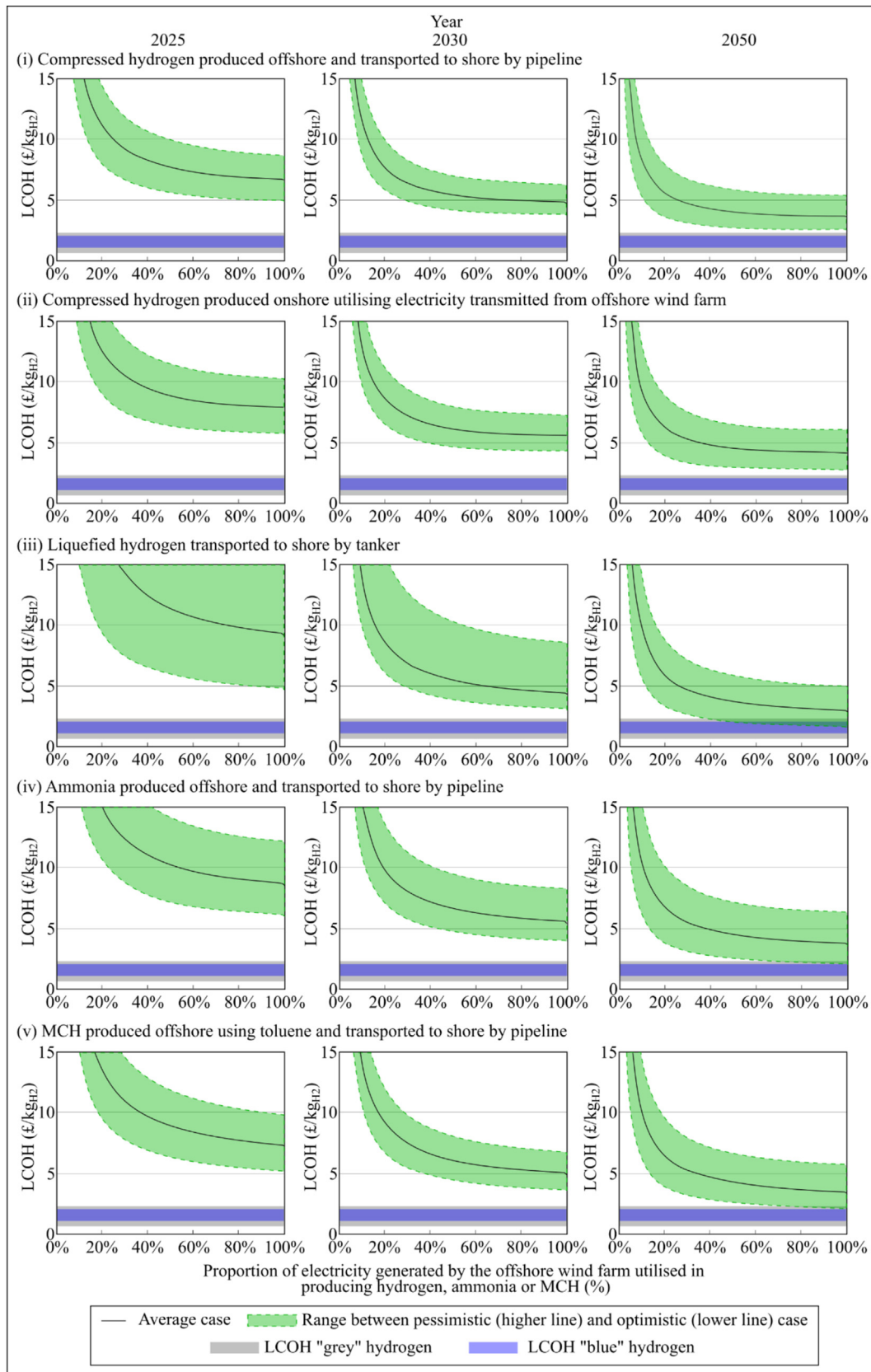
Fig. 13 – LCOH of the considered scenarios.

Table 5 – LCOH (£/kg$_{H2}$) estimated for the average (optimistic–pessimistic) cases when 100% of the offshore wind electricity was used for hydrogen/ammonia/MCH production and stored over different periods.

Pathway		Storage period			
		1 day	7 days	14 days	31 days
Year 2025	Reference Case	5.05 (3.43–6.85)	5.78 (4.12–7.66)	6.63 (4.92–8.6)	8.71 (6.87–10.88)
	Scenario (i)	6.38 (4.33–8.59)	7.08 (4.99–9.36)	7.89 (5.76–10.26)	9.88 (7.62–12.44)
	Scenario (ii)	8.84 (4.59–18.59)	8.97 (4.67–18.88)	9.13 (4.76–19.22)	9.5 (4.98–20.04)
	Scenario (iii)	8.55 (6–11.94)	8.62 (6.06–12.04)	8.7 (6.13–12.15)	8.9 (6.32–12.42)
	Scenario (iv)	8.45 (5.9–11.81)	8.52 (5.97–11.91)	8.6 (6.04–12.02)	8.79 (6.22–12.29)
	Scenario (v)	7.08 (4.96–9.6)	7.09 (4.98–9.62)	7.11 (4.99–9.64)	7.16 (5.03–9.7)
	Scenario (vi)	7.19 (5.06–9.7)	7.2 (5.08–9.72)	7.22 (5.09–9.74)	7.27 (5.14–9.8)
Year 2030	Reference Case	3.27 (2.37–4.59)	3.97 (3.03–5.34)	4.79 (3.79–6.22)	6.77 (5.63–8.36)
	Scenario (i)	4.11 (2.97–5.7)	4.78 (3.6–6.42)	5.56 (4.32–7.26)	7.46 (6.09–9.3)
	Scenario (ii)	4.2 (2.95–8.09)	4.26 (3–8.23)	4.33 (3.05–8.39)	4.51 (3.17–8.78)
	Scenario (iii)	5.53 (3.94–8.14)	5.58 (3.98–8.21)	5.63 (4.03–8.29)	5.77 (4.15–8.5)
	Scenario (iv)	5.43 (3.85–8.03)	5.48 (3.89–8.1)	5.54 (3.94–8.18)	5.67 (4.06–8.38)
	Scenario (v)	4.73 (3.48–6.52)	4.74 (3.49–6.54)	4.76 (3.51–6.56)	4.79 (3.53–6.6)
	Scenario (vi)	4.84 (3.59–6.63)	4.86 (3.6–6.65)	4.87 (3.61–6.67)	4.9 (3.64–6.71)
Year 2050	Reference Case	2.21 (1.22–3.87)	2.87 (1.83–4.55)	3.63 (2.55–5.35)	5.5 (4.3–7.29)
	Scenario (i)	2.8 (1.55–4.67)	3.43 (2.13–5.32)	4.16 (2.82–6.08)	5.95 (4.49–7.94)
	Scenario (ii)	2.78 (1.49–4.72)	2.82 (1.52–4.79)	2.88 (1.54–4.86)	3 (1.61–5.05)
	Scenario (iii)	3.7 (2.07–6.23)	3.73 (2.09–6.28)	3.77 (2.12–6.33)	3.87 (2.18–6.46)
	Scenario (iv)	3.62 (2–6.15)	3.65 (2.02–6.19)	3.69 (2.05–6.25)	3.79 (2.11–6.37)
	Scenario (v)	3.29 (1.98–5.48)	3.3 (1.99–5.49)	3.3 (1.99–5.5)	3.33 (2.01–5.53)
	Scenario (vi)	3.38 (2.05–5.6)	3.39 (2.06–5.61)	3.4 (2.07–5.62)	3.42 (2.08–5.65)

of the high cost associated with the storage tank compared to liquid hydrogen, ammonia, and MCH storage. For a storage period of 30 days, compressed hydrogen produced offshore would become significantly more expensive than the alternative scenarios.

Sensitivity analysis

The power output of the offshore wind farm and the distance from the shore to the offshore wind farm were the two key parameters in the study. By manipulating their magnitudes (power output: 150 MW, 500 MW, 1 GW, and 12 GW; distance: 60 km, 200 km, 1000 km and 10,000 km representing short, medium, long and international distances respectively), a sensitivity analysis was conducted to assess their influence on the findings of the study for pessimistic, average, and optimistic cases (see Scope and Methodology for the definition of these cases). The speed of the wind received and the power curve of the 8 MW S Gamesa SG 8.0–167 DD wind turbine used in estimating wind energy generation by the wind farm remained unchanged. Whilst the total cost and the LCOH for different power outputs and distances to the shore were estimated and compared in this sensitivity analysis, they did not reflect future technological advancements in wind turbine technology and the wind speed received by wind farms located more than 1000 km away from the shore. Table 6 summarises the LCOH estimated for the pessimistic, average, and optimistic cases for different power outputs of wind farms and distances from the shore when 100% of the electricity generated from offshore wind was utilised to produce hydrogen/ammonia/MCH.

For an offshore wind farm with a power output of 150 MW at 60 km to the shore, the total cost of the pipeline for compressed hydrogen would not be a significant factor, contributing to 3.5–5.3%, 4.7–6.9%, and 4.7–6.8% of the total cost in 2025, 2030,

and 2050 respectively when 25%, 50%, 75%, and 100% of the electricity generated offshore was utilised for hydrogen production. If the power output went up to 500 MW and the distance to shore reached 200 km, the total cost of the pipeline for compressed hydrogen would contribute to 5.3–6.3%, 7.3–8.6%, and 7.8–9% of the total cost in 2025, 2030 and 2050 respectively. Similar trends would be found for ammonia pipelines. Since the transport of MCH through pipelines would require delivering toluene back to the offshore wind farm, this would incur higher costs, i.e., 5.6–7.8%, 7.7–10.3%, and 8.1–10.5% of the total cost in 2025, 2030, and 2050 respectively for an offshore wind farm of 150 MW and at 60 km to shore, and 7.7–10.2%, 10.8–14.2%, and 11.7–15.7% in 2025, 2030, and 2050 respectively for an offshore wind farm of 500 MW at 200 km away from the shore. The contribution of the pipeline cost to the total cost would become more significant with distance to the shore, for instance, reaching 84.1%, 68.3%, and 91.2% of the total cost for compressed hydrogen pipelines, ammonia pipelines, and MCH pipelines respectively when the distance to the shore approaching 10,000 km.

The cost of transporting liquefied hydrogen/ammonia/MCH produced offshore to the shore by tankers would be worth noting. For an offshore wind farm of 150 MW at 60 km to the shore, the cost of liquid hydrogen tankers would contribute 25.3–37.3%, 30.3–41.7%, and 31.8–41.8% of the total cost in 2025, 2030, and 2050 when 25%, 50%, 75%, and 100% of the electricity generated offshore was utilised for hydrogen production. Similar trends were observed for ammonia and MCH tankers. The contribution of the tankers to the total cost would become less significant with the distance to the shore and the power output of the offshore wind farm, i.e., up to 7.3% of the total cost for offshore wind farms of 1000 MW located at 1000 km to the shore which would drop to 3.7% or lower for larger power outputs and farther distances.

Table 6 – LCOH (£/kg$_{H2}$) estimated for the average (optimistic–pessimistic) cases for different power outputs of wind farms and distances from the shore when 100% of the offshore wind electricity was used for hydrogen/ammonia/MCH production.

Year	Power output and distance	Reference Case	Scenario (i)	Scenario (ii)	Scenario (iii)	Scenario (iv)	Scenario (v)	Scenario (vi)
2025	150 MW; 60 km	7.06 (5.32–9.04)	8.45 (6.33–10.77)	12.33 (6.86–25.27)	10.3 (7.59–13.98)	9.04 (6.47–12.5)	8.06 (5.85–10.75)	7.84 (5.68–10.38)
	500 MW; 200 km	7.04 (5.31–9.01)	10.11 (7.34–13.35)	9.8 (5.2–20.49)	9.04 (6.44–12.53)	8.83 (6.26–12.28)	7.31 (5.17–9.88)	7.92 (5.74–10.48)
	1 GW; 1000 km	8.94 (7.05–10.99)	24.79 (17.1–34.68)	9.26 (4.85–19.47)	8.78 (6.2–12.23)	9.63 (7–13.13)	7.15 (5.03–9.69)	11.42 (8.98–14.15)
	12 GW; 1000 km	7.53 (5.74–9.53)	23.98 (16.36–33.8)	8.76 (4.53–18.53)	8.53 (5.98–11.95)	8.95 (6.37–12.4)	7.01 (4.89–9.52)	8.85 (6.62–11.45)
	12 GW; 10,000 km	30.61 (26.92–33.24)	184.53 (122.1–268.8)	8.8 (4.57–18.57)	8.61 (6.06–12.04)	18.87 (15.56–23)	7.02 (4.91–9.53)	50.19 (45.01–54.73)
2030	150 MW; 60 km	5.21 (4.17–6.66)	6.15 (4.87–7.85)	6.34 (4.62–11.74)	7.13 (5.33–9.95)	5.97 (4.34–8.64)	5.62 (4.24–7.54)	5.48 (4.16–7.28)
	500 MW; 200 km	5.2 (4.15–6.63)	7.09 (5.5–9.51)	4.75 (3.38–9.1)	5.95 (4.3–8.64)	5.76 (4.15–8.42)	4.94 (3.66–6.76)	5.55 (4.21–7.38)
	1 GW; 1000 km	7.05 (5.77–8.56)	16.38 (12.31–24.22)	4.42 (3.11–8.53)	5.7 (4.09–8.37)	6.53 (4.81–9.24)	4.79 (3.53–6.6)	8.98 (7.19–10.95)
	12 GW; 1000 km	5.67 (4.56–7.14)	15.62 (11.66–23.36)	4.11 (2.87–8.01)	5.47 (3.89–8.11)	5.88 (4.24–8.55)	4.66 (3.42–6.45)	6.46 (5.01–8.33)
	12 GW; 10,000 km	28.15 (24.24–30.4)	115.93 (84.71–184)	4.14 (2.91–8.05)	5.56 (3.97–8.2)	15.45 (12.6–18.63)	4.67 (3.43–6.46)	46.74 (40.29–50.39)
2050	150 MW; 60 km	4 (2.85–5.76)	4.71 (3.26–6.62)	4.39 (2.58–6.66)	5.04 (3.13–7.72)	4.07 (2.37–6.66)	4.01 (2.53–6.29)	3.92 (2.49–6.21)
	500 MW; 200 km	3.97 (2.81–5.75)	5.24 (3.47–8.27)	3.19 (1.76–5.24)	4.04 (2.33–6.63)	3.88 (2.2–6.47)	3.45 (2.11–5.67)	3.94 (2.49–6.28)
	1 GW; 1000 km	5.44 (3.93–7.55)	11.23 (6.48–22.7)	2.94 (1.59–4.94)	3.84 (2.17–6.4)	4.47 (2.63–7.2)	3.33 (2.02–5.53)	6.65 (4.55–9.62)
	12 GW; 1000 km	4.33 (3.08–6.21)	10.57 (6.01–21.89)	2.71 (1.43–4.66)	3.64 (2.01–6.18)	3.96 (2.24–6.58)	3.23 (1.93–5.41)	4.67 (3.02–7.19)
	12 GW; 10,000 km	22.13 (16.53–28.17)	74.31 (37.45–179.6)	2.74 (1.47–4.7)	3.72 (2.09–6.27)	11.42 (7.79–15.88)	3.24 (1.94–5.42)	36.59 (27.1–46.85)

The HVDC transmission line would also significantly affect the total cost of the system for long distances to the shore, as shown in Table 6 for the LCOH of the compressed hydrogen produced onshore, which would become too costly with the increase in the distance to the shore. Increasing the power output of wind farms would also magnify the total cost of the system (due to the higher cost of HVDC transmission, converters, electrolysers, desalination units, compressors, storage, etc.), which would be compensated by a larger scale of hydrogen/ammonia/MCH production, leading to trivial impact on the LCOH.

At far distances to the shore, the high cost of pipelines would increase the LCOH of hydrogen/ammonia/MCH production and transport, making it not as cost-competitive as transporting liquefied hydrogen, ammonia and LOHC by tankers. In other words, transport by tankers would make offshore hydrogen production more profitable at long distances and enable continental and intercontinental distribution. These scenarios should be further investigated in future studies, in particular when the costs of liquefaction and conversion/reconversion processes become cheaper.

For a small power output (150 MW) and a close distance to the shore (60 km), the reference case (compressed hydrogen produced offshore) showed the lowest LCOH in the average case in 2025 and 2030, i.e., £7.06 and £5.21 per kg of hydrogen, respectively. In this case, alternative scenarios for the transport of ammonia in Scenario (iv) and MCH/toluene in Scenario (vi) through pipelines could become cost-competitive or cheaper compared to compressed hydrogen produced offshore in 2050, i.e., as low as £2.37/kg$_{H2}$ and £2.49/kg$_{H2}$ for Scenarios (iv) and (vi) respectively. The high cost of the liquid hydrogen/ammonia/MCH tanker for Scenarios (ii), (iii) and (iv) would limit the cost-effectiveness of the offshore wind farms with small power output and located close to the shore. Compared to offshore hydrogen production, onshore hydrogen production would show slightly higher LCOH when the electricity generated by a 150 MW offshore wind farm located 60 km to the shore was utilised for hydrogen production. This indicated that onshore hydrogen production could be feasible for offshore wind farms relatively close to the shore due to the reduced costs required for the HVDC transmission line and the capacity to offer hybrid production and flexibility in selling electricity to the grid or producing hydrogen in line with energy market demand.

For offshore wind farms up to 500 MW located 200 km from the shore (or closer), the estimated LCOH could be £5–6 and £3–4 per kg of hydrogen produced in 2030 and 2050, respectively, as shown by the average case in the Reference Case, Scenario (ii), Scenario (iv), and Scenario (vi). For offshore wind farms located at long distances to the shore (such as 1000 km or farther), the transport of hydrogen/ammonia/MCH by tankers could offer a similar price, with the estimated LCOH of £4–5.7 and £2.7–3.8 per kg of hydrogen in 2030 and 2050, respectively, as shown by the average case in Scenario (ii), Scenario (iii) and Scenario (v).

Significant differences were observed between pessimistic and optimistic cases mainly due to the uncertainties in the technical characteristics of future components, such as PEM electrolysers (e.g., electrical efficiency, operating lifetime, and replacement cost), liquefaction unit (e.g. electrical

efficiency, liquid hydrogen yield, etc.), ammonia/MCH production and reconversion units as well as future costs of electricity, materials and labour associated with hydrogen/ammonia/MCH pipelines.

Further discussion: comparisons with other studies, policy implications, and limitations of the study

The study assessed and compared multiple scenarios for the production of electricity from offshore wind in combination with the production of hydrogen or hydrogen carriers. The results based on LCOH analysis showed that the distance to shore and the power output of the offshore wind farm affect the determination of the most cost-effective scenario for the use of offshore wind electricity for hydrogen production, storage and transport. As such, comparative analysis with other studies would be more relevant if the same conditions apply for distance to shore, power output of the wind farm, assessed components, year of construction and lifetime, storage period, etc. In comparison, Franco et al. [21] found that the lowest LCOH (£5.35/kg$_{H2}$) can be obtained for compressed hydrogen produced offshore by an offshore wind farm located 50 km from the shore and has a power output of 100 MW and transmitted to shore by pipeline, in which the cost could be reduced to £2.88/kg$_{H2}$ and £2.17/kg$_{H2}$ due to technological advancement and policy intervention, respectively. However, the year of construction of the offshore wind-to-hydrogen system was not specified. The results obtained in this study are in agreement with those in Ref. [21], as compressed hydrogen produced offshore and transported to the shore via pipeline is considered among the most cost-effective strategies for a wind farm located 60 km from the shore and with a power output of 150 MW, offering LCOH of £5.21/kg$_{H2}$ and £4/kg$_{H2}$ (which could be optimistically as low as £2.81/kg$_{H2}$) for the years 2030 and 2050, respectively. Franco et al. [21] also identified transportation via tanker as less cost-effective than transport via pipeline for relatively short distances to the shore (150–250 km). Meanwhile, Singlitico et al. [22] concluded that the lowest LCOH (€2.4/kg$_{H2}$) can be obtained for compressed hydrogen produced offshore by an offshore wind farm located in the North Sea at a distance to shore of 380 km and transmitted to the shore by pipeline. The reference case in this study presents LCOH of £3.27 and £2.21 per kg of hydrogen for the year 2030 and 2050, respectively, when a storage period of 1 day is considered. This result agrees with the LCOH value reported in Ref. [22], although the year of construction of the offshore wind farm was also not specified in Ref. [22].

This study showed that electrolysers are responsible for the largest cost of hybrid offshore wind/hydrogen production projects. In particular, the energy-intensive process of electrolysis strongly affects the economics of hybrid offshore wind/hydrogen production, as the cost of electricity required for the process presents the major share of the total cost of offshore wind-to-hydrogen projects. To scale up the deployment of electrolysers, reducing costs and improving the performance of electrolysers as well as developing international collaboration and national policies that favour green hydrogen produced by offshore wind farms would be essential, which in combination would prompt the demand for green hydrogen. Policies could favour green hydrogen produced from offshore wind farms by supporting the scale up and efficiency of the electrolyser manufacturing capacity by funding research on improved manufacturing processes and technological advancement [81]. This could be achieved either by providing direct financial support or financial incentives. Policies which (i) reduce the price gap between green hydrogen and fossil fuel alternatives, (ii) increase the market share of green hydrogen, (iii) support the development of hydrogen infrastructure, and (iv) support seasonal storage by use of green hydrogen [81] could further roll-out hydrogen produced by offshore wind farms. The supply of cheap green hydrogen produced by offshore wind electricity is fundamental for the deployment of the hydrogen economy. This could be achieved by enabling international collaborations for the transport of green hydrogen at long distances from sources capable of supplying a relatively cheap price, as investigated by Song et al. [24] for the transport of green hydrogen produced in China and supplied to Japan.

This study investigated the offshore wind farm, Hornsea Two, as a reference case for hybrid electricity/hydrogen production, which is constructed with a fixed-bottom foundation (i.e., the most used type of offshore wind farms in the UK) with limited application to shallow waters [82]. In recent years, floating wind farms (which are still in an early stage of development) have gained increasing interest due to their capacity to produce electricity from stronger winds in deeper water [83], as demonstrated by the floating wind farm in the UK, Hywind Scotland, which has the highest lifetime capacity factor among the UK wind farms [84]. However, floating wind farms are currently more expensive than fixed-bottom wind farms and their potential to achieve a very high capacity factor as well as their application are restricted by their stationary position that could be affected by weather conditions. An alternative for the conversion of offshore wind far from shore to electricity is the use of energy ships, as suggested by Babarit et al. [16]. Energy ships can be considered as a sort of mobile offshore wind farms that is smartly move in deep seas to harness the power of high-wind speed. This technology is promising because it would reduce costs for grid connection, installation and operation [85] while increasing the capacity factor [86]. Although still in the prototype stages, examples of energy ships have been identified in the literature [85–87]. Future studies should assess the techno-economic feasibility of using fixed-bottom wind turbines, floating wind turbines and energy ships for hydrogen production and compare the differences, in particular for offshore wind-to-hydrogen projects located at large distances from the shore.

The use of a fixed price for the electricity produced by the offshore wind farm presents another limitation in this study. Acting on real-time electricity pricing and energy demand could help improve cost effectiveness of the systems i.e., selling electricity to the grid when the electricity price is high and producing hydrogen or hydrogen carriers when the electricity price is low. The improved cost effectiveness of these flexible electricity-hydrogen systems could be further assessed in future study by net present value analysis, which would help identify the optimal ratio of offshore wind

electricity that should be utilised for the production of hydrogen or hydrogen carriers.

In this study, scenario analysis was applied as a means for sensitivity analysis to assess the effects of methodological choice (i.e., reference case vs. alternatives scenarios) and data (for pessimistic, average, and optimistic cases) on results. However, the uncertainty of input data due to possible variability in parameters presumably as a result of round-off or unrepresentativeness of data, unknown future circumstances and technology development, and unconscious inconsistency have not been quantified, which presents another limitation to this study. Future work in this area could be extended to address parameter uncertainty using stochastic modelling. This would involve the use of a uniform, normal, lognormal, triangular, beta or gamma probability distribution or a sampling technique e.g., Monte Carlo. Alongside stochastic modelling, Bayesian could also be applied to determine how much parameter uncertainty is reduced.

Conclusion

As green hydrogen production using offshore wind has the potential to unlock more renewable energy resources whilst producing (low- and) net-zero carbon fuel and feedstock for transportation and industrial processes, it is envisaged to grow rapidly in the UK, European, and global markets. Based on current and future costs of technologies for hydrogen production, storage and transport, a techno-economic appraisal of various scenarios of producing hydrogen (offshore and onshore) using offshore wind, including the use of hydrogen carriers, was performed. The analysis was primarily conducted based on a real reference case study using historical wind speed data and wind turbine generator power curves to estimate the total power output from the offshore wind farm, the potential curtailed energy and the resulting production of hydrogen or hydrogen carriers, such as ammonia or MCH. This helped to assess the most cost-effective scenario for the use of offshore wind electricity for hydrogen production, storage and transport. The techno-economic appraisal showed that.

- significant reduction in CAPEX and OPEX and increase in energy performance are expected for projects starting in 2030 and 2050
- electricity cost presents the largest cost item of the system, although future improvements in the electrolyser's efficiency and electricity price would lessen its impact on the total cost and the economic feasibility of offshore wind-to-hydrogen/hydrogen carriers production
- electrolysers are the most expensive component for all the scenarios, although a significant reduction in CAPEX and OPEX is expected by 2050 due to lower specific costs, increased efficiency, longer lifetime and reduced stack replacement costs
- compressed hydrogen produced offshore is the most cost-effective option for projects starting in 2025, in particular for relatively short distances to shore, in which case the cost of the pipeline does not significantly affect the cost-effectiveness

- alternative strategies for the storage and transport of hydrogen, such as liquefied hydrogen or MCH, are envisaged to have the potential to be more cost-effective for projects starting in 2050
- for offshore wind farms located at a significant distance to shore (more than 1000 km), offshore production of hydrogen or hydrogen carriers and transport to shore by pipeline is not cost-effective; shipping liquid hydrogen, ammonia or liquid organic hydrogen carriers for continental and intercontinental hydrogen transport should be evaluated as alternatives to onshore hydrogen production.

Declaration of competing interest

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

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