FLOATING OFFSHORE WIND POWERED HYDROGEN – CASE STUDY REVIEW FOR LOCAL SUPPLY CHAINS

ENERGY TRANSITION ALLIANCE

Offshore Wind Innovation Hub

Net Zero Technology Centre

Technology Driving Transition

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1 Key Findings

Following our investigations the key findings are:

Significant cost reductions are required to make floating offshore wind powered green hydrogen cost competitive.

51% Cost reductions and electrical loss improvements of 51% are required to reduce LCoE to levels predicted by the UK Government for 2050 (£40 /MWh).

The following levels of cost reduction and electrolyser efficiency improvements are required to reduce LCoH to levels predicted by the UK Government for 2050 (£70 /MWh):

52% Onshore hydrogen production.

55% Offshore hydrogen production from a repurposed facility, exporting through existing pipelines.

56% Offshore hydrogen production from a new build facility, exporting through a new pipeline.

72% Offshore hydrogen production from a new build facility, exporting via monthly tanker offload.

60% The UK would fail to meet the Government's target of 60% UK content for a 1 GW scale sample floating offshore windfarm.

60% The UK meets the Government's target of 60% UK content for the green hydrogen production facilities considered. This is largely driven by spending in operations and maintenance.

To reach 60% UK content over the lifetime of a floating offshore windfarm improvements to existing capability of varying degrees is required across all spending areas:

80% Jobs created in currently high capability areas (development and project management, installation and commissioning, and operations and maintenance).

80% Jobs created in improved capability in previously low / medium capability areas (Cables, floating substructure fabrication, moorings, offshore substation, decommissioning).

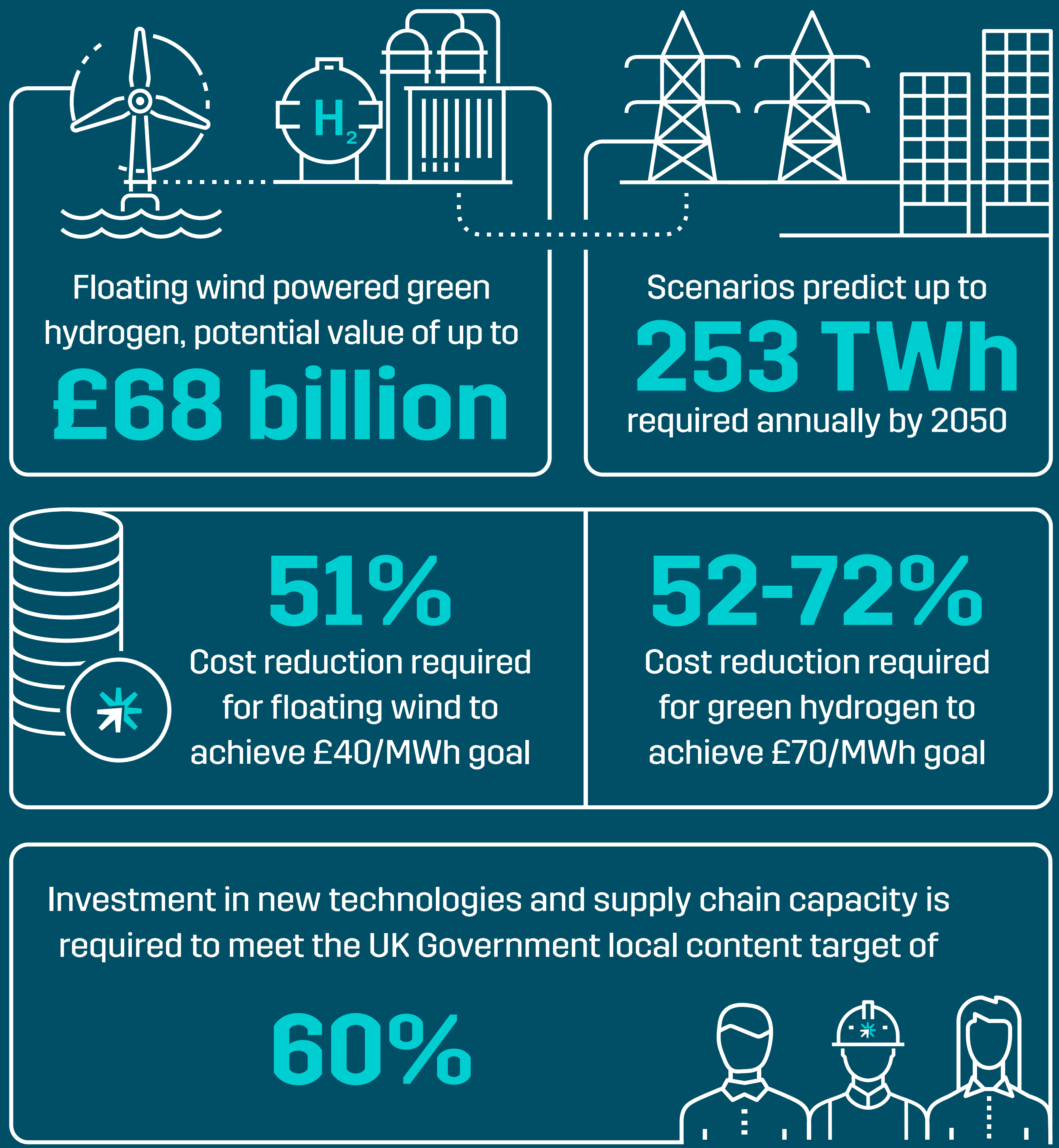
40% Jobs created in improved capability in previously low capability areas (Wind turbines and floating substructure material procurement).

To enhance UK content in CAPEX spending the following improvements should be targeted:

75% Jobs created in currently high capability areas (development and project management, installation and commissioning, and operations and maintenance).

75% Jobs created in improved capability in previously medium capability area of electrolysers.

40% Jobs created in improved capability in previously low capability area of compressors.



2 Executive Summary

Net Zero Technology Centre (NZTC) has completed a study commissioned by the Offshore Wind Innovation Hub (OWIH) to investigate the UK supply chain opportunity for floating offshore wind powered green hydrogen production projects. The study has been supported by the Offshore Renewable Energy (ORE) Catapult as part of the Energy Transition Alliance (ETA) between NZTC and ORE Catapult.

Building on previous work published by NZTC and ORE Catapult - “Reimagining a Net Zero North Sea: An Integrated Energy Vision for 2050” [1] the study comprises an assessment of the cost reductions required to make floating offshore wind powered green hydrogen projects viable and the UK supply chain’s ability to meet UK government targets for project local content.

Cost reduction assessments consider four case studies:

1. Onshore green hydrogen production powered by nearshore floating offshore wind, blending into National Transmission System (NTS).
2. Offshore green hydrogen production powered by nearby floating offshore wind, utilising repurposed oil and gas platforms and pipelines.
3. Offshore green hydrogen production powered by nearby floating offshore wind, utilising new build facilities and pipeline export to shore.
4. Offshore green hydrogen production powered by nearby floating offshore wind, utilising new build facilities and export tanker offload.

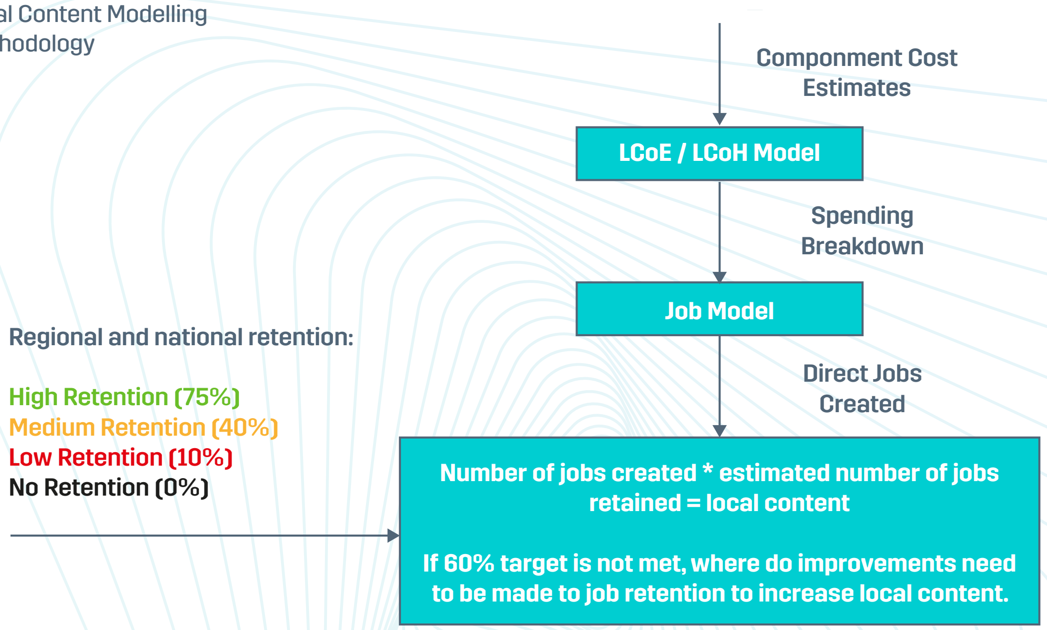
These case studies are intended to cover suitable means of producing and exporting green hydrogen near identified key regions for floating offshore wind. Key regions have been identified by comparing areas of the United Kingdom Continental Shelf (UKCS) with suitable water depths for floating offshore windfarms, with predicted available offshore wind resource. Key regions have been identified in North Scotland, North East England and the Celtic Sea.

Models to calculate both levelised cost of electricity (LCoE) and levelised cost of hydrogen (LCoH) have been developed. Modelling is first performed for current day pricing to determine the LCoH produced by each of the four case studies. Costs are then reduced to levels required to meet future prices predicted in 2050 to determine percentage reduction in costs required to make each case study viable.

From the LCoH models, spending breakdowns are output providing the levels of spend on each system component for viable projects. These spending breakdowns are used to calculate numbers of jobs created in each spending area using the same methodology as outlined in [1].

Calculated job numbers are combined with an assessment of local supply chain job retention in each region, and the UK national supply chain, for both floating offshore wind and green hydrogen production. The assessment applies multipliers to the number of jobs created by project spend to estimate the numbers of jobs that could be expected to be created in the UK by a floating offshore wind powered green hydrogen project.

Figure 1
Local Content Modelling Methodology



The key findings of the study are as follows.

The potential value of 60 per cent local content on floating offshore wind powered green hydrogen projects to the UK is up to £68 billion

Reimagining a Net Zero North Sea: An Integrated Energy Vision for 2050 [1] presents three future scenarios for the UK’s energy system. Two of these scenarios predict green hydrogen to make up a significant proportion of the UK’s energy mix. The progressive and transformational scenarios predict 75 TWh and 253 TWh required each year by 2050 respectively.

Meeting these scenarios would require between 9 and 31 projects of similar scale to those considered in the case studies herein to be producing green hydrogen in 2050. This assumes that 50 per cent of the electricity requirements for green hydrogen production are being met by floating offshore wind [2], reflective of an increase in floating offshore wind in the UK’s energy mix as nearshore fixed bottom opportunities are utilised.

Average present value lifecycle spending on one of the case study projects considered herein is circa £5.5 billion. Thus total lifecycle spending across the number of projects required is between £49 and £170 billion depending on the deployment scenario met.

Meeting the UK Government’s 60 per cent local content target therefore represents a £20 - £68 billion opportunity for the UK supply chain.

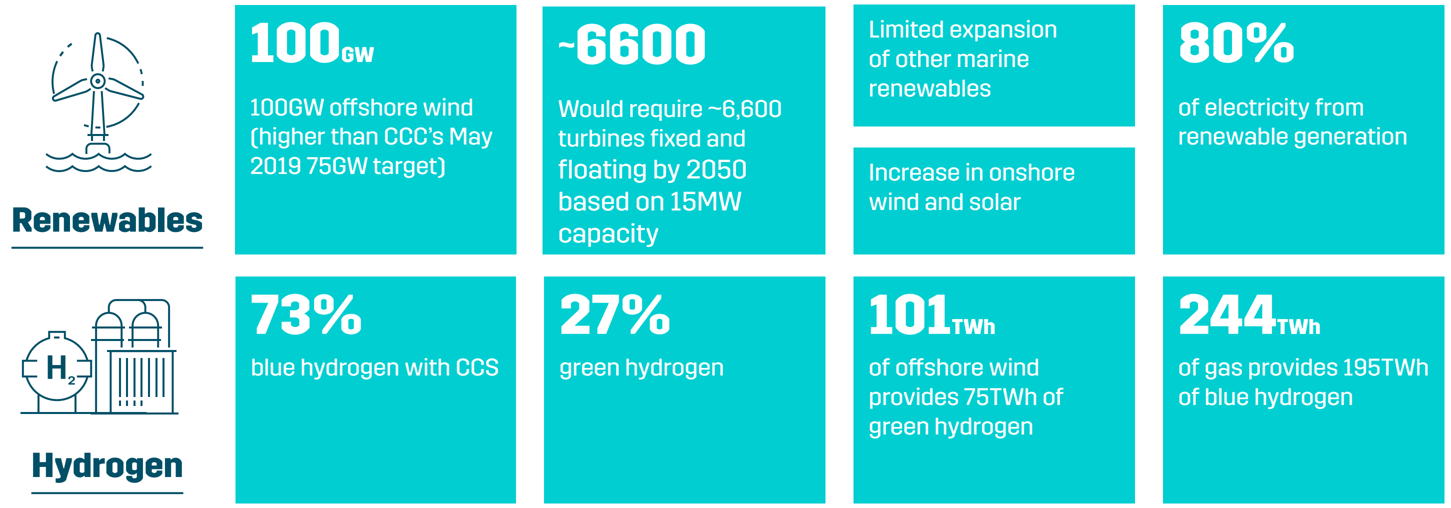


Figure 2
Integrated Energy Vision Progressive Scenario [1]

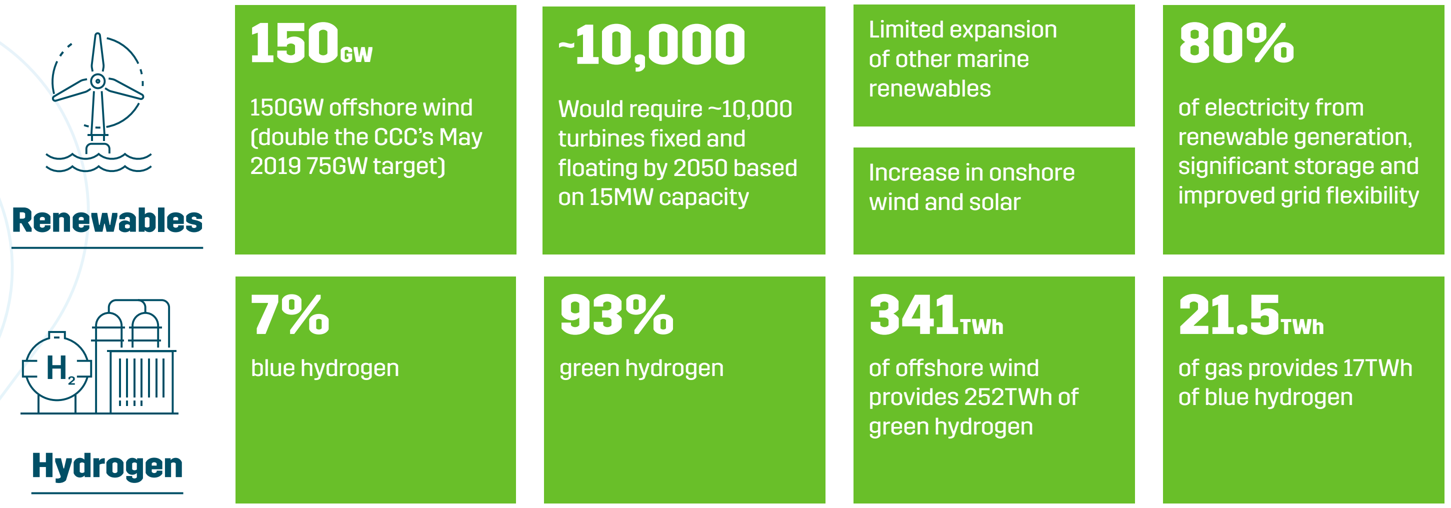


Figure 3
Integrated Energy Vision Transformational Scenario [1]

LCoH is heavily influenced by LCoE

The main driver of LCoH is the cost of electricity (i.e. the LCoE of the floating offshore windfarm).

Figure 4 presents the proportion of LCoH contributed by the LCoE of the offshore wind total expenditure (TOTEX) compared with green hydrogen capital expenditure (CAPEX), operating expenditure (OPEX), and decommissioning expenditure (DECEX). The example presented in Figure 4 is for case study one where green hydrogen is produced onshore. This is the lowest case study in terms of LCoH. Costs are representative of present day pricing.

LCoE is responsible for 72 per cent of LCoH in this example, which represents an LCoE of £91 / MWh. Reducing the LCoE to £40 / MWh – in parity with the current strike price for fixed bottom offshore wind – can reduce the associated LCoH by almost 60 per cent. This level of cost reduction would require a 51 per cent reduction in offshore wind costs and associated improvement in electrical losses to raise net capacity factors. Alternative solutions could come in the form of increased turbine capacities, improved gross capacity factors, or deployment of alternative turbine technologies to improve overall windfarm yield. Even after reductions of this level LCoE is still responsible for over half of LCoH (see Figure 5) and LCoE may need to fall further still, below the current strike price of fixed bottom offshore wind to make floating offshore wind powered green hydrogen projects viable.

Figure 4
LCoE Contribution to LCoH – Present Day Onshore Green Hydrogen

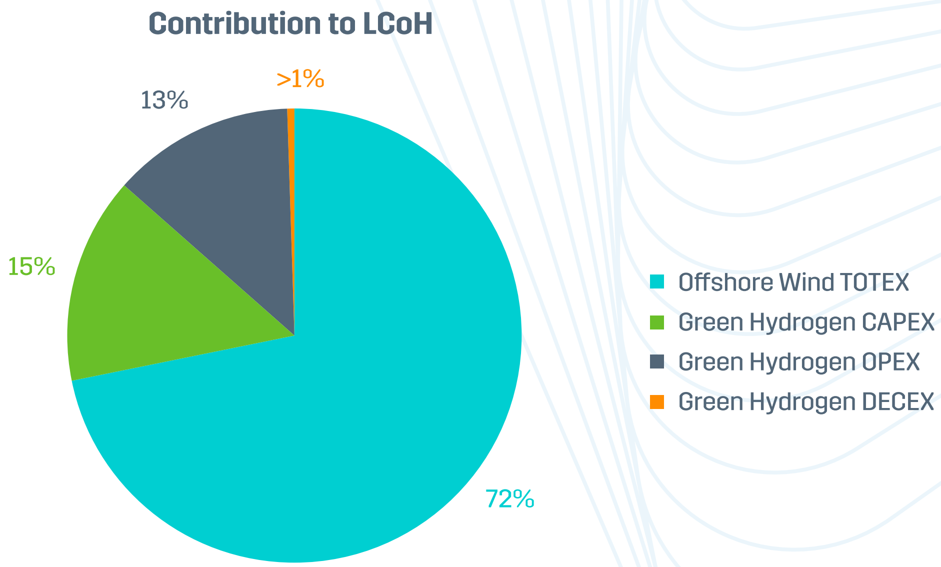
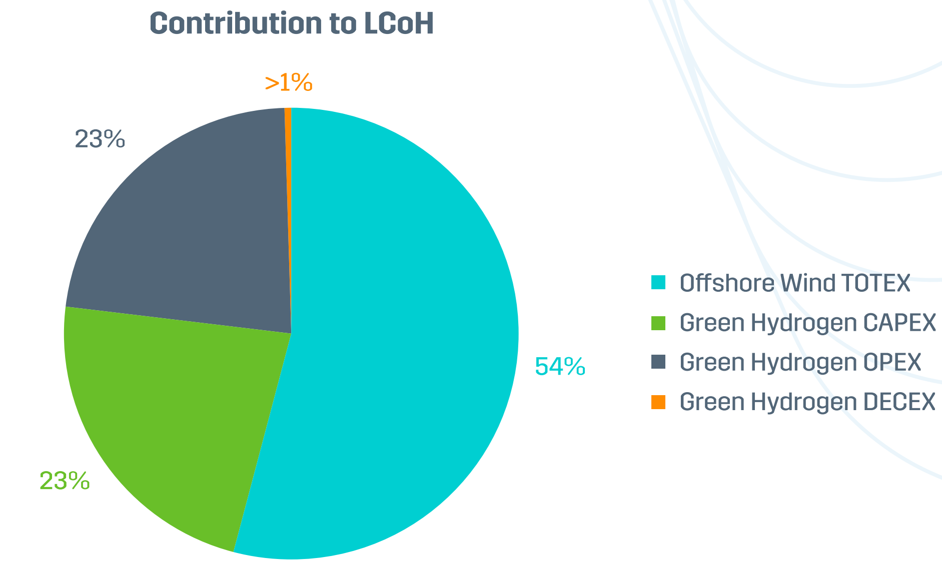


Figure 5
LCoE Contribution to LCoH – 2050 Target Onshore Green Hydrogen



Significant cost reductions and technological improvements are required to make green hydrogen production from floating offshore wind viable

Modelling of LCoH at present day prices estimates green hydrogen produced from floating offshore wind to cost between £204 and £259 /MWh (£6.81 and £8.63 /kg) depending on the case study considered. This is a significant uplift on UK Government projected costs of green hydrogen from all offshore wind (including cheaper fixed bottom offshore wind power) for 2025 of between £109 and £116 /MWh (£3.64 and £3.87 /kg).

LCoH modelling is repeated with cost reduction profiles applied across all areas of spending to reduce both LCoE and LCoH to £40 /MWh and £70 /MWh (£2.33 /kg) respectively. This requires cost reductions of 51 per cent for floating offshore wind and between 52 and 72 per cent for green hydrogen production (depending on the case study). Table 1 presents a summary of these findings.

Reductions of this scale represent a significant challenge to UK industry and indicate that substantial investment in finding new, disruptive technologies is required.

	Case Study One	Case Study Two	Case Study Three	Case Study Four
LCoE – Present Day (£/MWh)	90.75			
LCoH – Present Day (£/MWh)	204.37	214.20	217.00	258.85
LCoH – Present Day (£/kg)	6.81	7.14	7.23	8.63
Offshore Wind Reduction Rate (%)	51			
LCoE – 2050 (£/MWh)	40			
LCoH – 2050 LCoE (£/MWh)	120.24	129.02	130.99	174.18
LCoH – 2050 LCoE (£/kg)	4.01	4.30	4.37	5.81
Hydrogen Cost Reduction Rate (%)	52	55	56	72
LCoH – 2050 (£/MWh)	70.00	70.00	70.00	70.00
LCoH – 2050 (£/kg)	2.33	2.33	2.33	2.33

Table 1 – Required Cost Reduction Rates Summary

The UK supply chain requires investment in high spend areas to meet 60 per cent local content targets

The UK would fail to meet the Government's target of 60 per cent UK content in the sample floating offshore wind project considered without investment in the supply chain. Table 2 provides a summary of the improvements in job retention levels in each spending category required to meet the 60 per cent target for both TOTEX and CAPEX. These are split because the largest proportion of project spend is on operations and maintenance, which tends to be heavily localised. However, discourse around job creation tends to be focused on capital spend and manufacturing, so both are presented herein.

To reach 60 per cent UK content a high level of operations and maintenance jobs need to be secured locally, and steps taken to improve UK supply chain competitiveness in CAPEX areas with high proportions of jobs created.

The highest proportion of floating offshore wind CAPEX jobs is created by spending on the wind turbine. This is an area dominant by incumbent OEM's whose operations are based mainly overseas. Increasing levels of jobs created in this area in the UK will therefore require making the UK an attractive location for these OEMs to create manufacturing bases within, or disruptive technologies from UK SMEs invested in to provide alternative, cost competitive solutions.

A further 22 per cent of CAPEX jobs are created in the procurement and manufacture of the floating substructure. Thus, designs which can be fabricated locally at UK ports need to be harnessed.

The following would be required to meet the target of 60 per cent local content for floating offshore wind CAPEX and TOTEX spend:

1. 80 per cent jobs created in currently high capability areas (development and project management, installation and commissioning, and operations and maintenance).
2. 80 per cent jobs created in improved capability in previously low / medium capability areas (cables, floating substructure fabrication, moorings, offshore substation, decommissioning).
3. 40 per cent jobs created in improved capability in previously low capability areas (wind turbines and floating substructure material procurement).

Category	Rating		
	UK – Present	UK – 60% Overall	UK – 60% CAPEX
Development and Project Management	75%	80%	80%
Wind Turbine	10%	10%	40%
Array Cabling	40%	80%	80%
Export Cabling	40%	80%	80%
Floating Substructure Materials Procurement	10%	10%	40%
Floating Substructure Fabrication	10%	80%	80%
Moorings	40%	40%	80%
Offshore Substation	40%	40%	80%
Installation and Commissioning	75%	80%	80%
Operations and Maintenance	75%	80%	80%
Decommissioning	10%	80%	80%

Table 2 – Floating Offshore Wind Local Content Requirements Summary

The UK is projected to meet its local content targets for green hydrogen production if the supply chain assessment predictions are met. This is driven by the fact that an even larger proportion of jobs created by spending on green hydrogen production is in operations and maintenance. Thus, once more the levels of job creation required for both 60 per cent of TOTEX and CAPEX jobs are considered herein. Table 3 presents a summary of these requirements for green hydrogen production.

CAPEX job creation is mainly driven by electrolyser spend. This represents over half of CAPEX related jobs in all case studies. SMEs developing electrolyser technologies therefore need to be supported to create and develop manufacturing bases in the UK, anchoring this critical infrastructure both for local projects and export opportunities.

The other area of significant CAPEX job creation is in hydrogen compression systems. Increasing UK content this area would be required to meet the 60 per cent content target for CAPEX.

The following would be required to meet the target of 60 per cent local content for green hydrogen production CAPEX:

1. 75 per cent jobs created in currently high capability areas (development and project management, installation and commissioning, and operations and maintenance).
2. 75 per cent jobs created in improved capability in previously medium capability area of electrolysers.
3. 40 per cent jobs created in improved capability in previously low capability area of compressors.

Category	Rating	
	UK – 60% Overall	UK – 60% CAPEX
Development and Project Management	75%	80%
Substation	40%	40%
Electrolyser	40%	80%
Compressor	10%	40%
Desalination	10%	10%
Platform	10%	10%
Subsea Pipeline	40%	40%
High-Pressure Storage Tube Trailer	10%	10%
Installation and Commissioning	75%	80%
Operations and Maintenance	75%	80%
Decommissioning	10%	80%

Table 3 – Green Hydrogen Local Content Requirements Summary

3 Introduction

3.1 Energy Transition Alliance

In June 2019, the UK amended the Climate Change Act 2008, changing the target for reductions of emissions respective to 1990 levels from 80 per cent to at least 100 per cent by 2050 [3]. The UK is also trying to achieve net zero emissions by 2050, following recommendations by the Committee on Climate Change, to keep global warming levels to under 2 °C in line with the 2016 Paris Agreement [4].

To meet these ambitious targets, change to the UK's energy sector is needed – with growth of the renewables industry and a move to a more sustainable oil and gas industry. Collaboration across the energy sector is needed to meet the UK's emissions reduction goals.

The ETA has been formed by NZTC and ORE Catapult to support and accelerate the decarbonisation of the North Sea and the growth of fixed bottom and floating offshore wind in the UK. ORE Catapult and NZTC will collaborate with the energy sector to drive a focused, funded programme to develop advanced technologies, including the next generation of hydrogen production and floating offshore wind.

The ETA collaboration aims to transform the energy sector, accelerating the UK's transition to a net zero future, ensuring reliable and secure sources of energy for the UK, developed, constructed, and maintained by a globally competitive supply chain. Of vital importance to the future of the energy sector, specifically offshore renewable energy, and hydrogen, will be the transition of skills and workforce from the oil and gas industry supply chain.

THE ETA COLLABORATION AIMS TO TRANSFORM THE ENERGY SECTOR, ACCELERATING THE UK'S TRANSITION TO A NET ZERO FUTURE, ENSURING RELIABLE AND SECURE SOURCES OF ENERGY FOR THE UK, DEVELOPED, CONSTRUCTED, AND MAINTAINED BY A GLOBALLY COMPETITIVE SUPPLY CHAIN.

3.2 Project Overview

Several industry studies have been performed to date which have highlighted at a high level the opportunity that exists both for floating offshore wind and hydrogen production. These include Offshore Wind Industry Council (OWIC) and ORE Catapult's "Offshore Wind and Hydrogen – Solving the Integration Challenge" [5] and NZTC and ORE Catapult's "Reimagining a Net Zero North Sea: An Integrated Energy Vision for 2050" [1].

The ETA, funded through the OWIH, has performed a detailed, quantitative assessment of the opportunity for local supply chains in the UK. Consideration is given specifically to green hydrogen production powered using floating offshore wind. The project determines the local supply chain capability and technology gaps to be closed, and the economic opportunity that these present.

The project has been completed by NZTC, with support in developing the case studies from Wood, developing the LCoH models from Xodus, and in review of deliverables from ORE Catapult.

3.3 Scope of Work

The scope of the study includes:

- Development of relevant case studies for floating offshore wind powered green hydrogen production, with a focus on maximising UK content. Case studies to include all UK regions with water depths and wind resource suitable for floating offshore wind.
- Definition of technical requirements of each case study for both the floating offshore windfarm and selected green hydrogen production options.
- Economic modelling of each case study, considering industry cost reduction profiles [5, 6], to calculate LCoE and LCoH for each case study.
- Calculating jobs created based on spending profiles generated by LCoE and LCoH modelling.
- Determine likelihood of each region considered for floating offshore wind to meet content requirements locally.
- Determine likelihood of UK to meet content requirements.
- Identification of local supply chain capability or capacity gaps to be closed.
- Delivery of a final study report detailing the findings of the above.

The scope of the study does not include assessment of individual stakeholders to evaluate their business operations in detail. No interviews are performed, nor sites visited. The study also seeks to avoid repetition of work performed to date covering the high-level offshore wind and hydrogen opportunity. This includes but is not limited to:

- "Development and Integration of Early, Clean Hydrogen Production Plants in Scotland" [7] including:
  - Identification of potential hydrogen production sites in Scotland and their technology requirements.
  - Identification of potential collaboration models for supply chain companies.
  - Identification of hydrogen export markets and related stakeholders.
- "Scottish Offshore Wind to Green Hydrogen Opportunity Assessment" [8] including:
  - Establishment of hydrogen production and demand projections for Scotland.
  - Comparison of existing fuel costs by industry.
  - Mapping of Scottish offshore infrastructure.
  - Development of a supply chain database of Scottish companies active or with and interest in entering the green hydrogen industry.
- "Offshore Wind and Hydrogen – Solving the Integration Challenge" [5] including:
  - Calculation of hydrogen production required to achieve net zero by 2050.
  - Calculation of offshore wind produced green hydrogen costs compared with fossil fuel alternatives.
  - Identification of technology challenges required to drive down offshore wind produced hydrogen costs.
  - Defining the growth in hydrogen markets required to drive down costs.
  - Identification of promising sources of cost reduction market growth to 2030.
  - Defining the supply chain opportunity for UK manufactured electrolysers including exports.
  - Recommending policies for research and demonstration required for market scale up.
- "Reimagining a Net Zero North Sea: An Integrated Energy Vision for 2050" [1] including:
  - Calculating high level economic impact and job creation estimates for the hydrogen and offshore wind industries.

3.4 Acknowledgements

The ETA would like to thank Wood for their assistance in developing the case studies considered for the project and Xodus for providing guidance on the development of LCoE and LCoH models.

3.5 Abbreviations

AC	Alternating Current
CAPEX	Capital Expenditure
DECEX	Decommissioning Expenditure
ETA	Energy Transition Alliance
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
LCoE	Levelised Cost of Electricity
LCoH	Levelised Cost of Hydrogen
LNG	Liquified Natural Gas
NREL	National Renewable Energy Laboratory
NTS	National Transmission System
NZTC	Net Zero Technology Centre
ONS	Office for National Statistics
ORE	Offshore Renewable Energy
OWIC	Offshore Wind Industry Council
OWIH	Offshore Wind Innovation Hub
SIC	Standard Industrial Classification
TLP	Tension Leg Platform
TOTEX	Total Expenditure
UKCS	United Kingdom Continental Shelf

4 Case Study Development

4.1 General

The first stage of this review required the development of several case studies, comprising different combinations of floating offshore wind powered green hydrogen production. Development of these case studies has been performed by Wood who have a strong background in offshore field development as well as in the offshore wind and hydrogen industries.

This section provides a summary of the work performed by Wood. An overview of the background considered in the development of the case studies is followed by a summary of each case study considered for assessment.

4.2 Background Considerations

In developing the case studies consideration is given to the offshore wind resource, bathymetry, and availability of existing infrastructure in each region.

4.2.1. Offshore Wind Resource

Significant wind resource is required to provide enough wind power to produce green hydrogen at the requisite scale. Only regions with potential to access areas of the UKCS with wind resource potential of >1 000 W/m2 are considered. Figure 6 shows a map of offshore wind resource potential across the UKCS.

Greatest wind resource (>1400 W/m2) is available on the Atlantic Front off the coast of the Western Isles. This region is far from any existing offshore or onshore infrastructure. Large sections of this area are also restricted as designated by the Ministry of Defence. Some of this resource is available close to the emerging West of Shetland region of offshore oil and gas development. Existing developments are few, but the area should remain of interest in the future with several projects in development.

Off the East coast of Shetland and the North East of Scotland is the next strongest wind resource potential (1200 – 1400 W/m2). These areas are colloquially known as the Northern North Sea and Central North Sea and are home to the majority of the UK's offshore oil and gas facilities. As such this is a region with strong potential to utilise existing and previously decommissioned infrastructure to support hydrogen production. These areas host the majority of ScotWind's project areas.

Remaining regions of significant wind resource (1000 – 1200 W/m2) are found off the North East coast of England, in the Irish Sea, and in the Celtic Sea. The area off the North East coast of England is just to the north of the Dogger Bank round four project area which has a several fixed bottom offshore windfarms and many offshore gas facilities. Likewise the Irish Sea also has existing fixed bottom offshore wind and oil and gas infrastructure in place and is identified as a round four project area.

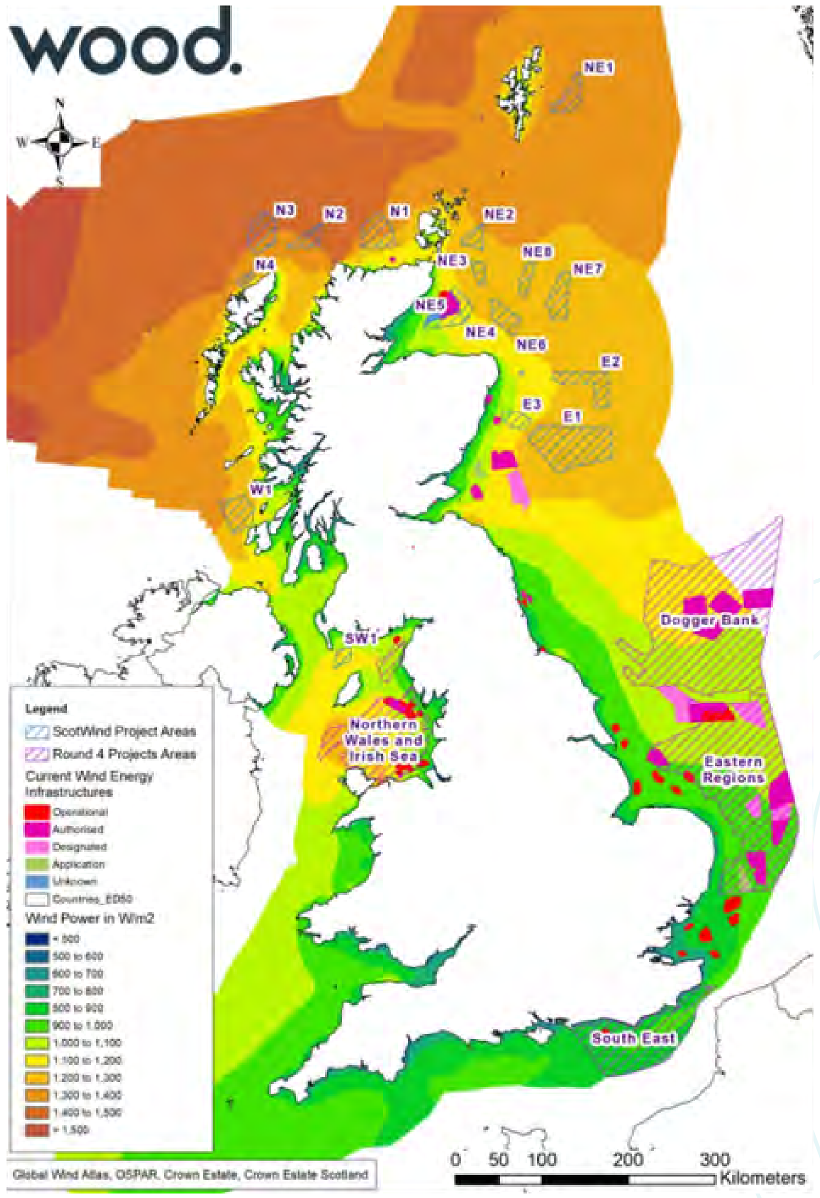


Figure 6
UKCS Offshore Wind Resource

4.2.2 Bathymetry

In line with previous work conducted by ORE Catapult [6], water depths of between 75 and 150 m are considered suitable for floating offshore wind developments. These depths are beyond the reach of fixed bottom offshore wind developments but avoid the significant increases in costs associated with deeper water. Figure 7 shows a map of UKCS bathymetry. These water depths are used as a filter on the regions with significant available wind resource in determining suitability for case study assessment.

Suitable water depths (75 – 150 m) are prevalent across the Northern and Central North Sea. Off the coasts of Shetland and North East Scotland there are suitable water depths available close to shore. These align with several ScotWind project areas. Smaller pockets of suitable water depths are found off the coast of North East England, some close to shore but most are further from shore to the north of Dogger Bank. In the Celtic Sea there are suitable water depths off the South West coasts of England and Wales, and along the maritime border with Ireland through the Irish Sea.

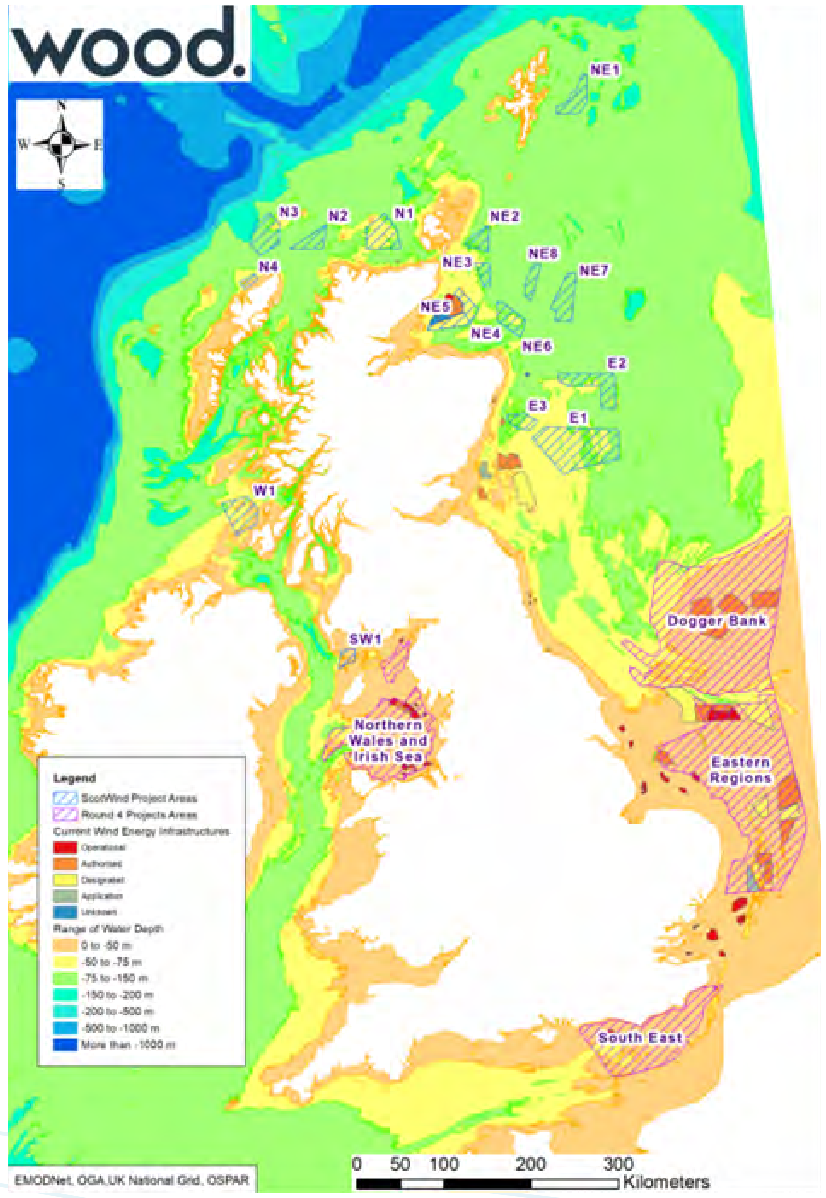


Figure 7
UKCS Bathymetry

4.2.3 Infrastructure Availability

Availability of existing infrastructure is considered in the development of the case studies. The UK has a mature oil and gas industry with several assets approaching the end of their design life. These could potentially be reused or repurposed for the transport of hydrogen. The UK is also the World leader in offshore wind generation capacity. As such there is already a significant amount of deployed generation and export equipment in the UKCS. Onshore there are critical tie in points to the National Transmission System (NTS) (Figure 8).

Oil and gas developments on the UKCS are clustered in five main regions: West of Shetland, Northern North Sea, Central North Sea, Southern North Sea and Irish Sea. Most assets are in the North Sea with a smaller number of developments in the Irish Sea and the West of Shetland. Oil and gas produced is transported to various terminals located across the UK. Major terminals include Bacton (Norfolk), Easington (Yorkshire), Flotta (Orkney), Kinneil (Falkirk), Mossmorran (Fife), Rampside (Barrow), St Fergus (Aberdeenshire), Sullom Voe (Shetland), Teesside (Middlesbrough), and Theddlethorpe (Lincolnshire). These are considered critical infrastructure points in the development of the case studies due to their ease of access to the NTS for hydrogen export. Another entry option to the NTS is through import terminals currently used for tanker offload of Liquified Natural Gas (LNG) from abroad. Such sites include the Grain LNG Terminal (Kent), Grangemouth (Falkirk), and South Hook (Pembrokeshire) which is the largest LNG terminal in Europe. Where offshore production of green hydrogen takes place away from shore, these terminals provide an option to bring the hydrogen to shore via tanker rather than export pipeline.

There is over 8 GW of operational offshore wind capacity in the UKCS with enough projects in development to double this figure by 2025. Developments to date have in all but two instances been fixed bottom, targeting water depth ranges of 0 – 75 m. These regions are covered by the round four project areas in Figure 7. The scope of this study is for developments in 75 – 150 m. There are beginning to be developments in suitable water depths as floating wind projects are commissioned. Hywind Scotland off the coast of Peterhead in North East Scotland is the UK's only fully commissioned floating windfarm at the time of writing. A further floating windfarm is currently under construction off the coast of Stonehaven, again in the North East of Scotland.

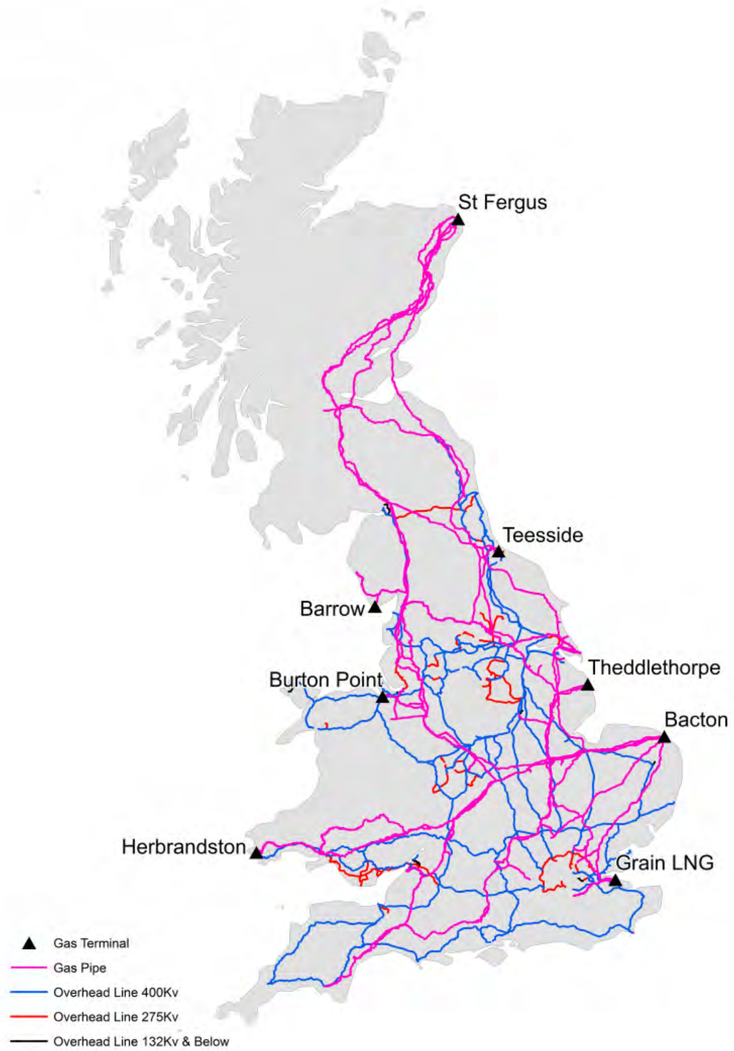


Figure 8
National Transmission System [9]

4.3 Key Region Summaries

4.3.1 North Scotland

The Shetland Islands have significant available wind resource and suitable water depths close to shore. Infrastructure is available at Sullom Voe Terminal which could be repurposed for green hydrogen production onshore. The terminal also has jetties which are currently used for oil export via tanker, providing an export route to international markets for produced hydrogen. Sullom Voe is also connected to the NTS via the SIRGE pipeline to St Fergus Gas Terminal. Shetland's local supply chain currently supports oil and gas operations and capital projects, along with emerging industries including onshore wind and wave and tidal energy.

Aberdeen and the wider North East region of Scotland is a global centre of excellence in offshore and subsea engineering. It has an incredibly strong local supply chain with decades of experience in the design, engineering and operation of offshore facilities. To the North of Aberdeen the St Fergus Gas Terminal handles the import of gas from several major pipelines from the Northern and Central North Sea. It is connected to the NTS via a National Grid facility on site. The North Sea is a mature oil and gas basin with several assets reaching the end of their life each year. This offers potential for repurposing as offshore hydrogen production facilities, managed by the local supply chain. Most oil and gas developments lie in regions of significant wind resource and suitable water depths for floating offshore wind developments.

4.3.2 North East England

Teesside is home to both a major gas terminal and the UK's largest hydrogen production facility. Further development is underway to build the UK's largest blue hydrogen plant on Teesside. Blue hydrogen differs from green hydrogen production considered herein. Blue hydrogen results in carbon emissions which are stored using carbon capture and underground storage technologies. Green hydrogen considered for this study utilises renewable energy to produce hydrogen by electrolysis rather than natural gas as a fuel, and thus results in zero carbon emissions directly from the production process. Suitable wind resource and water depths for floating offshore wind are available in pockets close to shore and further from shore. The region's coastline line between the Central and Southern North Sea regions of oil and gas development. Some facilities may be available for repurposing, but it is likely that a new build offshore facility would be required.

4.3.3. Celtic Sea

The Celtic Sea has strong available wind resource, particularly along the UK's maritime border with Ireland. This region away from the Bristol Channel is also more suited to floating offshore wind development as opposed to fixed bottom due to the available water depths. There is no existing offshore infrastructure in this region with no prior oil and gas production facilities. However, there is significant onshore infrastructure which makes the region attractive for green hydrogen production. The area is home to several large ports including Milford Haven and Falmouth. Two LNG terminals offer entry points to the NTS for tanker offloading of produced hydrogen. The region is also a significant industrial corridor which could be home to end users of hydrogen as companies endeavour to reach net zero targets.

4.4 Case Study Summaries

This section provides a summary of the case studies developed by Wood.

4.4.1 Case Study One
Onshore Green Hydrogen Production

The first case study is aimed at regions which have suitable water depths and available wind resource close to shore. This makes these regions particularly suited to onshore green hydrogen production powered by floating offshore wind. The case study considers:

- Floating offshore wind development close to shore (circa 25 km).
- Generated electricity exported to onshore substation.
- Onshore green hydrogen production at on onshore facility such as Sullom Voe Terminal or Teesside Terminal.
- Export option gas blend through NTS.

Figure 9
Onshore Green Hydrogen Production Schematic

4.4.2 Case Study Two
Repurposed Offshore Green Hydrogen Production

The second case study looks at making use of the existing oil and gas infrastructure. Suitable water depths and very high available wind resource are available further from shore in areas where oil and gas developments currently operate. Regions such as these can therefore look to use floating offshore wind power to produce green hydrogen offshore on repurposed oil and gas facilities. The case study considers:

- Floating offshore wind development far from shore (>100 km).
- Generated electricity exported to a repurposed oil and gas facility (within circa 25 km).
- Offshore green hydrogen production utilising redeployment of oil and gas facilities.
- Export option via gas blend through a repurposed existing pipeline to NTS via onshore terminal.

Figure 10
Repurposed Green Hydrogen Production Schematic

4.4.3 Case Study Three
New Build Offshore Green Hydrogen Production

Some regions have high available wind resource available in areas far from shore with no access to existing infrastructure. New infrastructure is therefore required to export offshore green hydrogen production. This can then be exported to shore via a new build pipeline in this case study. The case study considers:

- Floating offshore wind development far from shore (>100 km).
- Generated electricity exported to a new build offshore facility (within circa 25 km).
- Offshore green hydrogen production utilising new build facilities.
- Export option via new build pipeline to NTS via onshore terminal.

Figure 11
New Build Offshore Green Hydrogen Production Schematic

4.4.4 Case Study Four
New Build Offshore Green Hydrogen Production

Some regions have high available wind resource available in areas far from shore with no access to existing infrastructure. New infrastructure is therefore required to export offshore green hydrogen production. This can then be exported to shore via offloading tankers in this case study. The case study considers:

- Floating offshore wind development far from shore (>100 km).
- Generated electricity exported to a new build offshore facility (within circa 25 km).
- Offshore green hydrogen production utilising new build facilities.
- Export option via tankers to NTS via onshore LNG terminal.

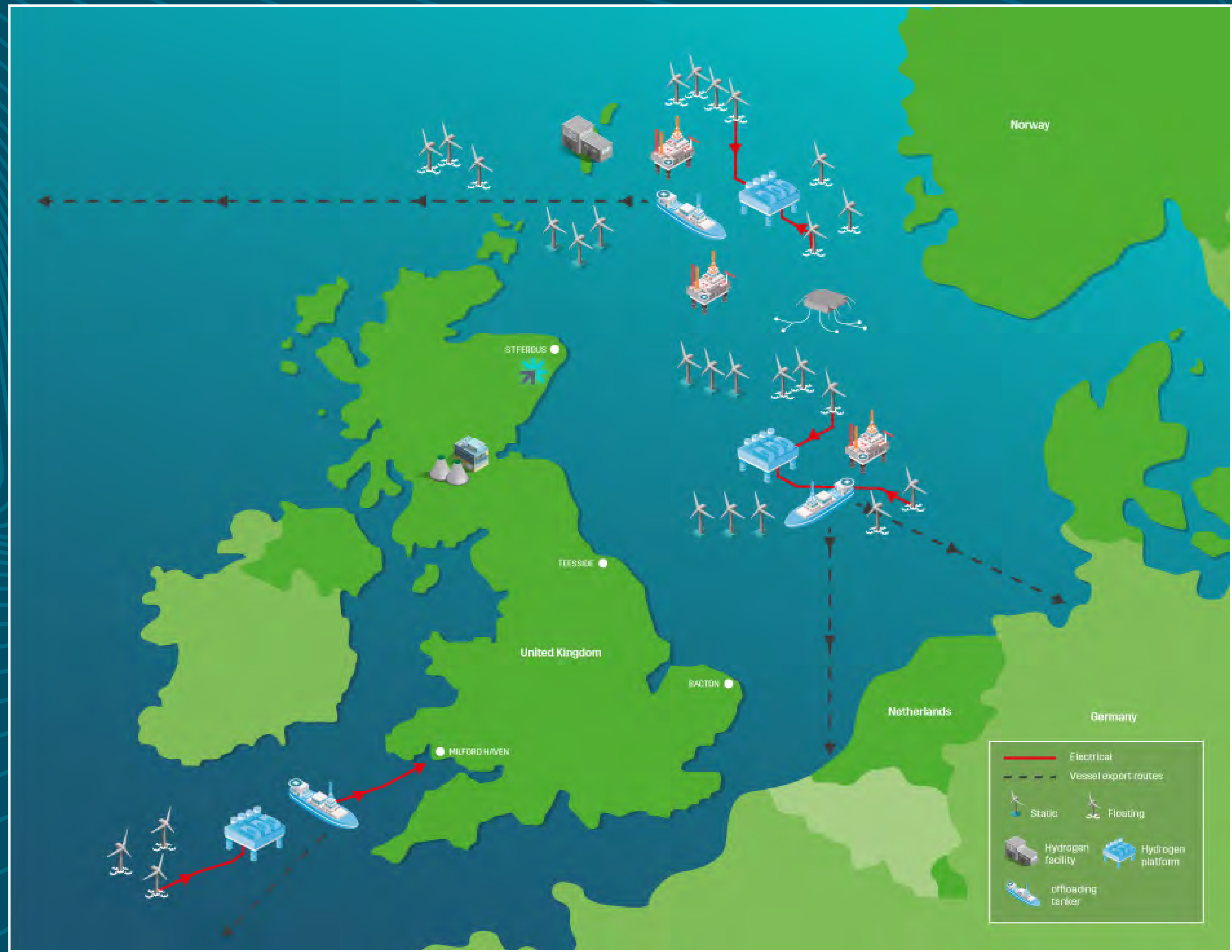


Figure 12
New Build Offshore Green Hydrogen Production Schematic

5 Levelised Cost of Electricity Model Basis

5.1 General

LCoE modelling is performed for a floating offshore windfarm to be commissioned in 2030. Development is assumed to begin in 2025, lasting five years. The design life of the floating offshore windfarm is assumed to be 30 years.

Future costs and revenue are both discounted at a rate of five per cent. Future costs are inflated at a rate of three per cent.
A contingency rate of 20 per cent is applied to all costs.
The windfarm is assumed to be 25 km from the green hydrogen production facility for all case studies. Where the green hydrogen production facility is onshore the floating offshore windfarm will be located close to shore, in regions such as the Shetland Islands where this is possible.

Total rated capacity of the windfarm is assumed to be circa 1 GW. This deployment size is reflective of commercial scale fixed bottom offshore windfarms currently in development and is reflective of the required scale required for floating offshore wind to be cost competitive.

Modelling assumes a gross windfarm capacity factor, before any electrical losses, of 60 per cent. Hywind Scotland has recorded capacity factors of 54 – 57 per cent in its first three years of operation [10]. With the potential for floating offshore windfarms to be deployed in ever higher yielding areas of the UKCS this assumed capacity factor is deemed suitable.

5.2 Development Costs

Development costs inclusive of consenting requirements, surveys, environmental assessments, engineering, and any other consultancy and project management are assumed at a rate of three per cent of total floating offshore windfarm capital expenditure (CAPEX). This is broadly in line with BVG Associate's guide to offshore windfarm costs [11] and reflects an average figure across several commissioned windfarms to date.

5.3 Wind Turbines

67, 15 MW capacity wind turbines are modelled to give the total required rated capacity of 1 GW.

Offshore windfarm deployments in the UKCS have been following a trend of increasing turbine capacity. Early fixed bottom offshore wind projects commissioned between 2003 and 2007 utilised wind turbines with gross capacities of 2 – 3 MW. Capacities have grown to 7 MW for example on the recently commissioned Beatrice Offshore Wind Farm in the Moray Firth [12]. Moray East Offshore Windfarm installed its first 9.5 MW turbine in January 2021 [13]. Windfarms currently under development including Dogger Bank Wind Farm [14] and Sofia Offshore Wind Farm [15] plan to utilise 14 MW designs from GE and Siemens Gamesa. Vestas have recently launched a 15 MW wind turbine design to enter production in 2024 [16].

Hywind Scotland, the UK's first floating offshore windfarm, utilises 6 MW capacity wind turbines [17]. Hywind Scotland has been producing electricity since 2017. Kincardine Offshore Wind Farm, under construction at the time of writing, is utilising 9.5 MW capacity wind turbines [18]. There are no other proposed floating offshore wind developments in the public domain at the time of writing, though this is likely to change with the conclusion of the ScotWind licensing programme.

Considering a windfarm to commence operation in 2030, and the current trend in increasing wind turbine capacity, it is considered reasonable to model 15 MW capacity turbines. This is also aligned with predictions made by ORE Catapult for ScotWind projects to be commissioned in 2030 [19].

Wind turbine CAPEX is modelled at £1 m/MW i.e. £15 m per 15 MW turbine.

5.4 Inter-Array Cabling

Each floating offshore wind turbine will require an inter-array cable including a dynamic cable, to export electricity generated by the wind turbine to an offshore substation.

66 kV, 50 MW capacity alternating current (AC) inter-array cables are assumed, with the required length of cable calculated as a function of the number of turbines arranged in each cable string, and the turbine spacing. Inter-array cable costs are assumed at a rate of £600 /m of cable and includes any costs associated with potential ancillary equipment for dynamic cabling including bend stiffeners and buoyancy modules.

5.5 Export Cabling

Each floating offshore windfarm requires export cabling to transmit the collected electricity from the offshore substation to the green hydrogen production facility. This facility may be onshore or offshore. Export is via high voltage alternating current (HVAC) cables over short distances and high voltage direct current (HVDC) over longer distances.

Export cabling is assumed to be via HVAC cables given the 25 km distance assumed between the floating offshore windfarm and green hydrogen production facility in each case study. 220 kV, 250 MW capacity cables are modelled. Export cable length required is calculated from the individual cable capacity and the rated capacity of the windfarm. Export cable costs are assumed at a rate of £1000 /m of cable and includes any costs associated with potential ancillary equipment for dynamic cabling including bend stiffeners and buoyancy modules.

5.6 Substructure

Each wind turbine requires its own floating substructure. There are many different floating substructure concepts in the public domain. These can be broadly categorised into four distinct typologies: spar, semi-submersible, barge and tension leg platform (TLP).

Spars are long vertical cylinders with ballast material within the cylinder providing a counterweight at the bottom of the substructure to resist overturning moments from wind and wave loading. The counterweight lowers the centre of gravity of the spar structure providing stability. Spar substructures have deep drafts which limits the ability of some ports to handle integration of wind turbines onto the substructure, requiring this operation to be performed offshore using heavy lift vessels. Spars are the most advanced substructure typology in terms of technological readiness. Hywind Scotland utilises spars to support its five 6 MW wind turbines. These have been producing electricity since 2017. As such the Hywind spar concept is well proven although has yet to complete a full design life deployment. Prior to Hywind Scotland a smaller 2 MW scale Hywind spar was deployed as a demonstrator unit [17]. Hywind Tampen will deploy 8 MW turbines when constructed in 2022 [20].

Semi-submersibles are multi-legged with legs joined together with horizontal members. The wind turbine itself is supported by either one of the outer legs or a central column depending on the design concept. Ballast material within each leg can be adjusted to either increase or decrease the substructure draft. This allows semi-submersible structures to utilise lower quayside drafts for turbine integration before utilising a deeper draft for stability in operation. Semi-submersibles are at a similar stage to spars in terms of technological readiness. Producing semi-submersible units are in place at Kincardine Offshore Wind Farm (2 MW scale) and WindFloat Atlantic (8.4 MW scale). Like Hywind Scotland these have been producing for short durations and are yet to complete a full design life deployment. Further semi-submersible substructures are being installed at Kincardine Offshore Wind Farm in 2021 (9.5 MW scale) [18].

Barges are shallow draft, large waterplane substructures. Stability of the substructure is provided by the large waterplane area, the weight of which provides sufficient righting moment to stabilise the substructure under loading. Their shallow draft makes barges suitable for quayside integration of wind turbines to the substructure whilst being stable during tow out to site. Barges have yet to be deployed commercially in an offshore floating wind development. Ideol's Damping Pool barge concept has been deployed in two 2 – 3 MW demonstrators. 10 MW scale units are planned for deployment in 2022/2023 as part of the Eolmed project [21].

TLPs are vertically moored using steel tendons at each of the substructure's corners. Tendons eliminate vertical motions of the substructure with buoyancy of the substructure sufficient to ensure that the tendons always remain in tension. There have been no deployments of TLPs for floating offshore wind developments to date. It is therefore the least mature typology in terms of technology readiness.

Whichever substructure is considered the design will have to be scalable to the capacity of the turbines considered (15 MW). Spars and semi-submersibles have proven their scalability in demonstrator and pre-commercial projects. Spars have accomplished this scaling by increasing the draft of the substructure. Semi-submersibles can do so by increasing the spacing between the pontoon legs, with draft less affected.

Case studies considered herein aim to maximise the opportunity for local supply chains. Therefore the opportunity to assemble the turbines and integrate them to the substructure at a local quayside is an important factor in substructure selection. All case studies herein consider a semi-submersible substructure.

Costs associated with the material procurement and substructure fabrication are estimated for the model based on substructure sizes deployed to date, scaled for increasing turbine size. Values of £7.5 m per unit and £12.5 m per unit are assumed for the material procurement and fabrication respectively.

5.7 Mooring System

Semi-submersible substructures can be moored using either a catenary or semi-taut mooring system. Three mooring lines are typically required for each semi-submersible substructure.

Catenary mooring systems are the most common system utilised in shallower waters. Free hanging catenaries of steel chain are hung off the substructure in a spread arrangement. The weight of the steel chain provides a restoring force on the substructure.

Semi-taut mooring systems are a combination of catenary and taut mooring systems. A midsection of steel chain is replaced by a taut section of synthetic fibre. This has the benefit of reducing the weight of the mooring system which is particularly suited to deeper water developments.

Steel chain, catenary mooring systems are considered appropriate for the UKCS water depths being considered for floating offshore wind. Each semi-submersible substructure is assumed to have three mooring lines.

Catenary mooring systems impart horizontal loading onto their anchors. For this reason catenary mooring systems typically use drag embedded anchors. Drag embedded anchors provide station keeping capacity from being buried or embedded within the seabed. As they undergo horizontal loading the anchor embeds further in the seabed providing further anchoring force. Drag embedded anchors are considered for each of the case studies herein. Each semi-submersible substructure is assumed to require three drag embedded anchors.

The total cost of the mooring system inclusive of chain and drag anchors is estimated at £2.7 m per substructure unit.

5.8 Substation

Substations are used to collect electricity generated from individual wind turbines prior to export to shore. In HVAC this is done by increasing the voltage.

Each case study herein only considers the transmission of power generated by the floating offshore windfarm over a short distance. This is either because the floating offshore windfarm is close to shore (circa 25 km) or is using the power locally for green hydrogen production at an offshore facility. Therefore LCoE modelling considers AC substations.

Due to the total size of windfarms considered in the case studies, i.e. in the order of GWs rather than MWs, multiple substations will be required for each floating offshore windfarm. It is assumed that an AC offshore substation is required for every 500 MW of windfarm capacity and substation CAPEX is modelled at a rate of £120 k/MW. Each of these assumptions is in line with [11].

5.9 Installation and Commissioning

Costs related to installation and commissioning of the floating offshore windfarm are modelled by considering the individual operations required to complete the full installation. This includes:

- Floating substructure installation (£1.15 m/unit).
- Mooring system installation (£2.98 m/unit).
- Cable lay (£400 /m).
- Quayside installation of the wind turbines on the floating substructure (£600 k/turbine).
- Offshore substation installation (£10m /substation).

Cost modelling also includes related costs including guard vessels, offshore reps and third-party verification. Modelling is completed using conservative estimates for vessels used and their rates, and operation durations.

5.10 Operations and Maintenance

Operations and maintenance costs for the floating offshore windfarm are modelled at a rate of £75 k/MW/year in line with [11]. The net present value associated with such costs is calculated using the rates outlined in Section 4.1.

5.11 Decommissioning

Decommissioning costs are modelled at a rate of £330 k/MW in line with [11]. The net present value associated with such costs is calculated using the rates outlined in Section 4.1.

6 Levelised Cost of Hydrogen Model Basis

6.1 General

For consistency with the floating offshore windfarm, LCoH modelling is performed for a green hydrogen production facility to be commissioned in 2030. Development is assumed to begin in 2025, lasting five years. The design life of the facility is assumed to be 30 years.

Future costs and revenue are both discounted at a rate of five per cent. Future costs are inflated at a rate of three per cent.

A contingency rate of 20 per cent is applied to all costs.

The facility is assumed to be within 25 km of the floating offshore windfarm regardless of whether the production facility is onshore or offshore.

6.2 Development Costs

Development costs inclusive of all engineering, and any other consultancy and project management are assumed at a rate of three per cent of total green hydrogen production facility CAPEX. This is consistent with the figure assumed for the floating offshore windfarm.

6.3 Substation

A substation is required at the hydrogen production facility to collect electricity exported from the floating offshore windfarm and convert it to the appropriate requirements of the hydrogen production equipment.

LCoH modelling assumes that the cost of the substation will be like that of the substations at the floating offshore windfarm in terms of £ /MW. The substation at the hydrogen production facility may be onshore or offshore depending on the case study considered. CAPEX costs models include only the electrical equipment, with any offshore structure costs captured under production facility CAPEX. CAPEX is modelled at a rate of £30 k/MW for all cases. Each of these assumptions is in line with [11].

6.4 Electrolyser

Even when operating at maximum wind yield, the power input to the electrolyser stack from the floating offshore windfarm will not be equivalent to 100 per cent of the rated capacity. Electrical losses and power consumption by other equipment will account for a portion of floating offshore windfarm output. Modelled electrolyser capacity is equal to the rated capacity of the windfarm, less electrical losses and power consumption of other hydrogen production equipment. This will be made up of many, smaller modular electrolyser units.

Various assessments of electrolyser CAPEX costs for different electrolyser types and commissioning years are outlined in [22]. For the purposes of this model, the IEA's 2030 figure for PEM electrolysers is considered. Electrolyser CAPEX is modelled at circa £650 k/MW.

Electrolyser efficiency is calculated from International Renewable Energy Agency (IRENA) data [23]. A learning rate of 10 per cent is applied to account for improvements in technology from the date of publication to the proposed 2030 commissioning date of the case studies. This results in a modelled electrolyser efficiency of 20.21 kg of hydrogen produced per MWh of electrical input.

Operational expenditure related to the electrolyser is modelled at two per cent of its capital costs as per [23].

6.5 Compressor

Compression systems are required at the green hydrogen production facility to pressurise the produced hydrogen for storage and export. [22] again provides a summary of previous studies considering hydrogen compression system CAPEX. [24] considers capital expenditure for hydrogen compression systems though they are often bundled together with costs related to storage and dispensing. An estimate of £2.5 k/kg of maximum potential annual hydrogen production capacity is considered appropriate and modelled herein.

6.6 Water Supply

Water supply shall be either from freshwater or desalinated seawater depending on the location of the green hydrogen production facility.

Any CAPEX related to freshwater intake has been deemed to be negligible. Where freshwater intake is modelled, an operational cost is levied based on Scottish Water charges. Though these charges will differ in different regions of the UK, this assumption is deemed applicable for the purposes of this model.

CAPEX for a desalination system is estimated at £1 m/MLD based on data presented in [25]. Operational costs for the desalination system are estimated by [25] to be £0.50 /m3.

6.7 Production Facility

An estimate of £100 m is modelled for the cost of an offshore platform to host the green hydrogen production facility offshore. This estimate is based on an increase in costs provided by [11] for an offshore substation jacket, to account for increased sizing required to accommodate hydrogen equipment. Where the facility is located onshore, there is no additional cost applied for the production facility itself. Operational costs are estimated at two per cent of platform CAPEX.

6.8 Export System

Export systems considered for the various case studies include direct blending into a pipeline system or shipping via an offloading tanker. The pipeline system in question could be the NTS, a repurposed oil and gas pipeline offshore or a new, purpose-built pipeline.

Where a new pipeline is considered a CAPEX value of £650 /m of pipeline is modelled, verified against previous subsea pipeline projects. In the case where a pipeline is being repurposed a reduction factor is applied to the CAPEX cost to account only for costs associated with repurposing rather than new construction. Operational costs related to the inspection of subsea pipelines are estimated based on 10 inspections being performed across the pipelines design life, with each of these costing £750 k. This operational cost is annualised in the model.

No additional capital expenditure is modelled for the offloading tanker case. Operational costs are modelled based on estimates for the cost of ammonia transformation and reconversion.

6.9 Storage

Where hydrogen export is being performed via an offloading tanker, high pressure storage will be required at the green hydrogen production facility for such a length of time as a tanker can access the facility. The time between offloads is estimated to be monthly, with 12 offloads a year. Hydrogen production is averaged across each month for the purpose of modelling, though it is likely that some months will see higher production than in others.

A CAPEX cost of £1 k/tonne of storage required is modelled based on costs provided in [24]. Operational costs associated with storage tanks are deemed to be negligible.

6.10 Installation and Commissioning

Estimates of costs associated with the following installation and commissioning procedures are included within the model:

- Substation construction
- Hydrogen facility construction / installation
- Export system installation

Substation and facility construction / installation costs are estimated based on similar costs for the installation of the floating offshore windfarm substation.

Installation costs associated with the installation of an export pipeline are assumed to be the same as for cable installation. A reduction factor is applied to this cost where only repurposing of an existing export pipeline is required.

6.11 Decommissioning

Decommissioning costs are modelled at a rate of two per cent of CAPEX. The net present value associated with such costs is calculated using the rates outlined in Section 5.1.

7 Job Creation Model Basis

7.1 Methodology

Job creation modelling for each of the case studies follows the same methodology as used in the NZTC and ORE Catapult's Integrated Energy Vision [1].

Spending breakdowns are pulled out of the LCoE and LCoH modelling for the following categories:

Each category is assigned an Office for National Statistics (ONS) Standard Industrial Classification (SIC) code based on a suitable industry approximation e.g. manufacture of electrical equipment for cabling.

Direct job numbers are calculated by dividing the share of spending assigned to labour by the average payroll cost for the assigned category.

Floating Offshore Wind

- Development and Project Management
- Wind Turbine
- Array Cabling
- Export Cabling
- Floating Substructure Material Procurement
- Floating Substructure Fabrication
- Mooring System
- Offshore Substation
- Installation and Commissioning
- Operations and Maintenance
- Decommissioning

Green Hydrogen

- Development and Project Management
- Substation
- Electrolyser
- Compressor
- Desalination
- Platform
- Subsea Pipeline
- High-Pressure Storage Tube Trailer
- Installation and Commissioning
- Operations and Maintenance
- Decommissioning

8 Supply Chain Assessment Basis

8.1 Methodology

Assessment of the UK's national and regional supply chains' ability to meet local content targets is performed by reviewing available literature and consultation with appropriate experts. The UK supply chain as a whole and the key regions identified are rated in each supply chain category outlined in Section 6.1. Multipliers for each rating are applied to the numbers of jobs created, and the totals summed to calculate the proportion of regional and UK content predicted to be met for each case study. Table 4 presents the multipliers used for each category. The calculation is performed first for each region, with calculated national numbers used to "top up" those created in the regions.

8.2 Floating Offshore Wind

Assessment of the UK's national floating offshore wind supply chain considers work performed previously by the ETA to identify relevant companies working in this area [26]. Companies were identified as having capabilities in designated floating offshore wind categories based on their demonstrated track record in other relevant industries such as fixed bottom offshore wind, oil and gas, marine, or other renewables such as wave or tidal.

Large numbers of companies were found to be active in development and project management, installation and commissioning and operations and maintenance. These are all areas of projects which tend to necessitate high volumes of local involvement and thus are rated high for the supply chain assessment for the UK.

Array cabling, export cabling, moorings and offshore substations are rated as medium for the UK supply chain assessment. The ETA found that around half of the electrical and cable supply chain needs for offshore wind are currently being met within the UK, so the medium multiplier of 0.4 is appropriate. Capability exists within moorings exists across other UK industries such as oil and gas though capacity was found to be limited with only a small number of companies active. The medium rating reflects this balance.

Wind turbine, floating substructure material procurement and fabrication, and decommissioning are rated as low for the UK. There is some limited capability for specific wind turbine component manufacture within the UK, though overall manufacturing is dominated by manufacturers outside of the UK. Availability of UK manufactured steel for substructures is low, this could rise should concrete substructure designs advance. Manufacture of substructures at the sizes required for 15 MW turbines is challenging at UK ports. Spar designs are also limited by available port depth. Barge and TLP designs are less proven. Decommissioning in the floating offshore wind industry is immature and thus it's hard to quantify current spending levels within the UK. The low rating is considered a conservative estimate.

Assessment of North Scotland's regional floating offshore wind supply chain identified companies within the national database in [26] by office locations, allowing for regionalisation of the database. Array cabling, export cabling and offshore substations are derated from medium to low reflecting lower availability within the region. Substructure material procurement is derated from low to zero as there is no availability of locally manufactured steel.

North East Local Enterprise Partnership reports "Research study into the North East offshore wind supply chain" [27] and "North East Energy for Growth" [28] have informed the assessment of its regional supply chain, along with interrogation of the publicly available supply chain database from NOF [29]. The North East already has a strong supply chain in fixed bottom offshore wind particularly in the provision of cables and manufacture of fixed bottom wind monopiles and jackets. There is also an experienced subsea engineering cluster crossing over from the oil and gas industry covering installation activities, and operations and maintenance.

Assessment of Celtic Sea's regional floating offshore wind supply chain considers work performed previously by ORE Catapult which looked at floating offshore wind case studies and the opportunities they offered to the region [30]. This work provides percentage ranges of local content created in each category and these are reflected in the ratings selected herein.

Table 4
Supply Chain Assessment Multipliers

Rating	Multiplier
High	75%
Medium	40%
Low	10%
Zero	0%

Table 5
presents the assessment of the floating offshore wind supply chain across key regions and the UK.

Category	Rating			
	North Scotland	North East England	Celtic Sea	UK
Development and Project Management	75%	40%	40%	75%
Wind Turbine	0%	0%	0%	10%
Array Cabling	10%	40%	40%	40%
Export Cabling	10%	40%	0%	40%
Floating Substructure Materials Procurement	0%	10%	10%	10%
Floating Substructure Fabrication	10%	10%	10%	10%
Moorings	40%	0%	0%	40%
Offshore Substation	10%	10%	10%	40%
Installation and Commissioning	75%	75%	75%	75%
Operations and Maintenance	75%	75%	75%	75%
Decommissioning	10%	10%	10%	10%

Table 5
Floating Offshore Wind Supply Chain Assessment

8.3 Green Hydrogen

Assessment of the UK supply chain is informed by the UK Hydrogen and Fuel Cell Association's Products and Services Matrix [31] along with judgements made on the potential for crossover from other industries such as oil and gas, and fixed bottom offshore wind.

Development and project management is rated as high. Several companies are already developing small scale green hydrogen projects in the UK. There is a strong supply chain of companies in oil and gas and fixed bottom offshore wind with the capability to make a transition to green hydrogen projects should the pipeline of projects appear. Installation and commissioning, and operations and maintenance are also rated as high. These categories are typically localised by nature and the UK again has a strong supply chain in other industries who can make the transition.

Substation, electrolyser, and subsea pipeline are rated as medium. EPC of subsea pipelines is an area in which the UK supply chain is very experienced and can expect to create a substantial number of jobs. However, there is a risk that material procurement and manufacturing is lost to other nations. Substation assessment is reflective of the floating offshore wind supply chain where around half of all electrical needs are currently met within the UK. It is anticipated this would be the same for the substation at the hydrogen facility. Several companies based in the UK are developing electrolyser technologies. Some of these are small scale now but with investment in large scale projects the potential for job creation in this area is high.

Compressor systems are available in the UK but only one organisation is represented in [31]. This is also true of water treatment systems and high-pressure storage tanks. EPC of offshore platforms is an area in which the UK supply chain has historical experience. Manufacturing now tends to be performed abroad and this is reflected by the low rating applied. As for floating offshore wind decommissioning is immature and thus it's hard to quantify current spending levels within the UK. The low rating applied is considered a conservative estimate.

Green hydrogen supply chain assessment for North Scotland uses information presented in the Scottish Governments assessment of the country's green hydrogen opportunity [8]. The assessment presents numbers of companies actively involved in various categories of the hydrogen supply chain within Scotland presently.

Substation and electrolysers are derated from medium to low reflecting the small number of companies active in these areas according to [8]. For the substation rating this is reflective of the findings for floating offshore wind. For electrolysers, none of the companies in [31] active in developing electrolyser technologies are based in North Scotland.

As for floating offshore wind the green hydrogen supply chain assessment is informed by information provided by the North East Local Enterprise Partnership [27, 28] and NOF's supply chain database [29]. There are some companies in the region related to the provision of materials for electrolysers who may generate jobs from hydrogen projects. Installation and commissioning, and operations and maintenance jobs are once more assumed to be created locally in high numbers.

Assessment of the supply chain in the Celtic Sea region is informed by the membership of regional organisations for the hydrogen industry such as HyCymru, along with judgements made on the potential for crossover from other industries such as oil and gas, and fixed bottom offshore wind. Most organisations with an interest in hydrogen in the area are either as end users of hydrogen or as project developers. There are very few companies included which are equipment manufacturers or suppliers. It is still assumed that a high number of jobs will be created locally because of installation and commissioning, and operations and maintenance of any facilities developed in the region.

Table 6 presents the assessment of the green hydrogen supply chain across key regions and the UK.

Category	Rating			
	North Scotland	North East England	Celtic Sea	UK
Development and Project Management	75%	40%	40%	75%
Substation	10%	10%	10%	40%
Electrolyser	10%	10%	0%	40%
Compressor	10%	0%	0%	10%
Desalination	10%	0%	0%	10%
Platform	10%	10%	10%	10%
Subsea Pipeline	40%	10%	10%	40%
High-Pressure Storage Tube Trailer	10%	10%	0%	10%
Installation and Commissioning	75%	75%	75%	75%
Operations and Maintenance	75%	75%	75%	75%
Decommissioning	10%	10%	10%	10%

Table 6
Green Hydrogen Supply Chain Assessment

9 Levelised Cost Modelling Results

9.1 Current Prices

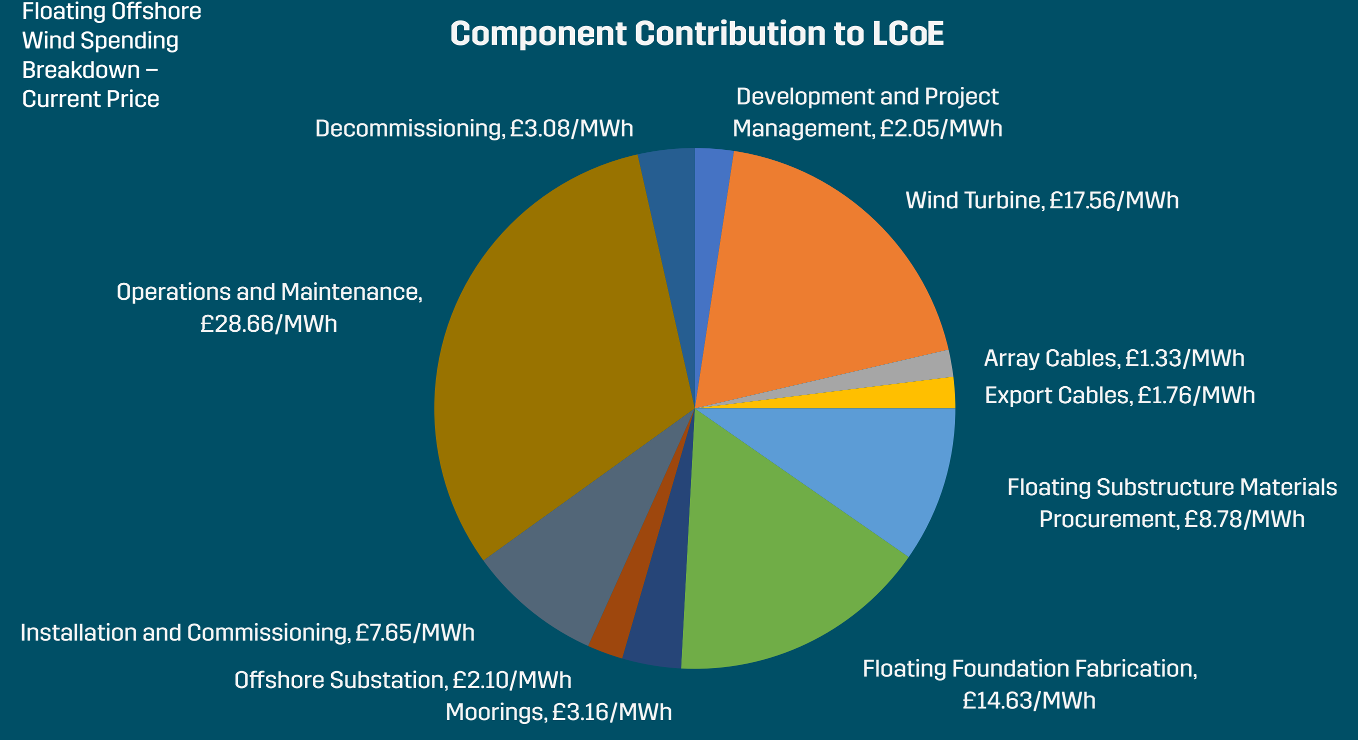
9.1.1 Floating Offshore Wind

Spending breakdowns and calculated LCoE are consistent across all four case studies, with the makeup of the floating offshore windfarm consistent throughout. Table 7 presents the calculated LCoE along with a spending breakdown of each component category to be considered in job creation modelling.

Modelled LCoE for the case study floating offshore windfarm is lower than the administrative strike price applicable to floating offshore wind in the Contracts for Difference (CfD) Round 4 [32]. This considers projects of smaller scale than modelled herein, with project scale and turbine rated capacity being significant contributors to LCoE. The modelled LCoE is however double that of the fixed bottom offshore wind strike price of £46 /MWh which is a better indicator as to the competitiveness of providing electricity for green hydrogen production from floating offshore wind.

Figure 13 shows the contribution to LCoE of each of the components considered. The bulk of project spending is concentrated on operations and maintenance (31.6 per cent), floating substructures (25.8 per cent), and wind turbines (19.3 per cent). Installation and commissioning (8.4 per cent) is another significant contributor to LCoE. The remaining components within the spending breakdown each contribute between one and three per cent of LCoE.

Figure 13
Floating Offshore Wind Spending Breakdown – Current Price



	Case Study One	Case Study Two	Case Study Three	Case Study Four
Development (£m)	141			
Wind Turbine (£m)	1,206			
Array Cables (£m)	91			
Export Cables (£m)	121			
Substructure Materials (£m)	603			
Substructure Fabrication (£m)	1,005			
Mooring System (£m)	217			
Substation (£m)	144			
Installation & Commissioning (£m)	525			
Operations & Maintenance (£m/yr)	90			
Operations & Maintenance (£m)	2700			
Decommissioning (£m)	398			
LCoE (£/MWh)	90.75			

Table 7 – Floating Offshore Wind Spending Breakdown – Current Price

9.1.2 Green Hydrogen

Table 8 presents the calculated LCoH along with a spending breakdown of each component category to be considered in job creation modelling.

Case study one predicts LCoH at £204 /MWh (£6.81 /kg). This is the cheapest of the four case studies with hydrogen production costs kept lower by producing the hydrogen onshore where equipment required, and construction costs are lower. LCoH is found to be heavily influenced by LCoE, which is predicted to be priced significantly higher than current fixed bottom offshore wind developments. Figure 14 shows the contribution of different areas of spending towards the LCoH total of case study one. The cost of the floating offshore wind farm represents 71.9 per cent of LCoH.

Moving the production offshore for case study two introduces new capital costs through desalination, and the repurposing of an offshore platform and subsea pipeline. These changes also impact operational costs with the addition of platform operations and subsea pipeline inspections. These raise the LCoH modelled to £214.20 /MWh (£7.14 /kg).

In case study three the capital costs associated with the platform and subsea pipeline are increased further still, accounting for the requirement of new build facilities rather than the repurposing of existing ones. These changes also have an associated increase in installation costs. Operational costs remain unchanged. LCoH modelled is raised in this case to £217.00 /MWh (£7.23 /kg).

The largest impact on LCoH aside from the cost of the electricity provided (LCoE) is found to come from the transportation costs involved in converting the hydrogen to ammonia and back again for tanker transport in case study four. This has a significant impact on operational costs. Figure 15 shows the LCoH contribution of area of green hydrogen production OPEX spend. Transportation costs represent 63.6 per cent of these operational costs, and 19 per cent of total LCoH. Capital costs are also increased with the need to store the produced hydrogen between each tanker offload. Modelled LCoH for case study four is £258.85 /MWh (£8.63 /kg).

Hydrogen being produced at these prices is not cost competitive. The UK Government's "Hydrogen Production Costs 2021" [33] predicts green hydrogen production costs from a dedicated offshore wind resource to the production facility at £109 – 116 / MWh. It should be noted that this dedicated resource can be fixed bottom or floating offshore wind. Levelised costs for fixed bottom offshore wind are significantly lower than for floating wind currently. Indeed the UK Government's electricity generation costs [34] put the levelised cost of fixed bottom offshore wind at £57 / MWh for the comparable period.

Regardless, none of these case studies would be sanctioned as projects for commissioning without either significant Government subsidy or cost reductions, to bring the LCoH produced down to levels predicted in [33] for future years. Future costs are predicted at £69 – 75 /MWh in 2050 [33]. Modelling of jobs created by projects which are unlikely to proceed is of no value. Therefore cost reduction profiles are applied to each case study to bring LCoH down to predicted future levels.

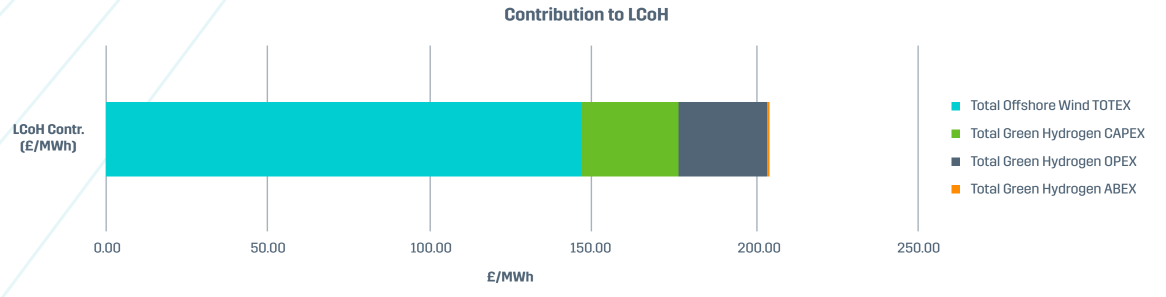


Figure 14
Spending Contribution to LCoH – Case Study One

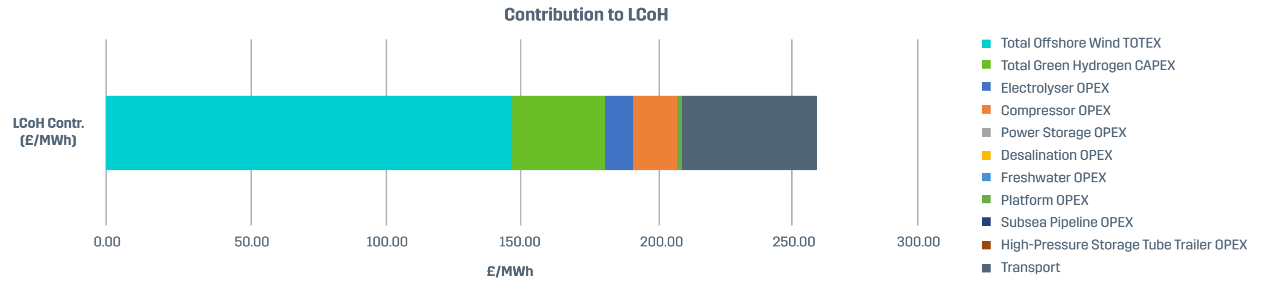


Figure 15
OPEX Focused Spending Contribution to LCoH – Case Study Four

	Case Study One	Case Study Two	Case Study Three	Case Study Four
Development (£m)	44	50	54	50
Substation (£m)	36			
Electrolyser (£m)	675			
Compressor (£m)	460			
Desalination (£m)	-	2		
Platform (£m)	-	80	120	
Subsea Pipeline (£m)	-	52	78	-
Storage (£m)	-			8
Installation & Commissioning (£m)	60	90	130	90
Operations & Maintenance (£m/yr)	53	64		55
Transportation (£m/yr)	-			96
Operations & Maintenance (£m)	1589	1920		1650
Transportation (£m)	-			2888
Decommissioning (£m)	26	29	31	29
LCoH (£/ MWh)	204.37	214.20	217.00	258.85
LCoH (£/kg)	6.81	7.14	7.23	8.63

Table 8 – Green Hydrogen Spending Breakdown – Current Prices

9.2 Future Prices

9.2.1 Floating Offshore Wind

As the cost of floating offshore wind is the largest contributor to LCoH, cost reductions are first modelled considering floating offshore wind exclusively, to quantify the impact on LCoH for each case study.

Cost reduction profiles are applied to bring the calculated LCoE inline with predictions in [34] for the cost of electricity generated by offshore wind 2050 (£40 /MWh). Cost reductions of 51 per cent are required to hit the 2050 target LCoE. Electrical loss rates are reduced by the same rate to account for improvements in this area. Table 9 presents the spending breakdowns resulting from the required cost reduction profiles to hit these LCoE targets. Table 10 presents the impact of the floating offshore wind cost reductions on case study LCoH.

Reductions in LCoE of this level bring the LCoH for the first three case studies close to current predictions for green hydrogen production from offshore wind in [33]. This is as expected with the LCoE values being more inline with those of fixed bottom offshore wind production. For the final case study the impact on LCoH is less pronounced, with the introduction of transport costs meaning floating offshore wind contributes a lower proportion of LCoH.

These improvements are still not sufficient to meet the 2050 target for LCoH alone and thus will need to be combined with cost reductions and technological improvements on the green hydrogen production equipment also.

Table 9 - Floating Offshore Wind Spending Breakdown – Reduction Profiles

	Current Prices	2050 Target
Development (£m)	141	69
Wind Turbine (£m)	1,206	592
Array Cables (£m)	91	45
Export Cables (£m)	121	59
Substructure Materials (£m)	603	296
Substructure Fabrication (£m)	1,005	493
Mooring System (£m)	217	107
Substation (£m)	144	71
Installation & Commissioning (£m)	525	261
Operations & Maintenance (£m/yr)	90	44
Operations & Maintenance (£m)	2700	1320
Decommissioning (£m)	398	195
LCoE (£/MWh)	90.75	40.00

Table 10 - Floating Offshore Wind Cost Reduction Impact on LCoH

	LCoH (£/MWh)		LCoH (£/kg)	
	Current Prices	2050 Target	Current Prices	2050 Target
Case Study One	204.37	120.24	6.81	4.01
Case Study Two	214.20	129.02	7.14	4.30
Case Study Three	217.00	130.99	7.23	4.37
Case Study Four	258.85	174.18	8.63	5.81

9.2.2 Green Hydrogen

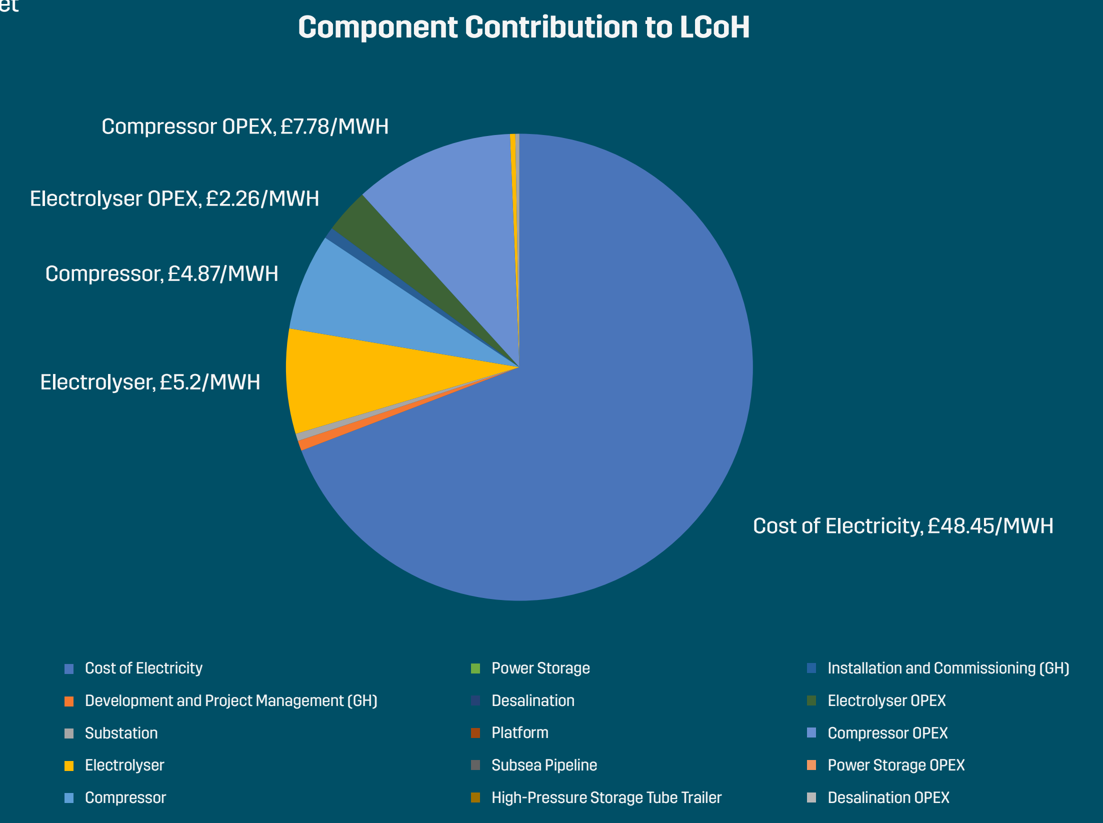
Table 11 presents green hydrogen component spending breakdowns required for each case study to hit a 2050 target of £70 /MWh (£2.33 /kg). Cost reduction rates presented are applied to green hydrogen costs only. Floating offshore wind costs are already reduced such that input LCoE to the LCoH model is £40 /MWh inline with predictions in [34]. An equivalent rate is also applied to uplift the efficiency of electrolysers to capture technological improvements required to reduce the cost of green hydrogen.

Significant cost reductions of at least 50 per cent are required for all case studies. This ranges from 52 per cent for case study one where hydrogen is produced onshore to 72 per cent where hydrogen is produced offshore. The addition of transport costs proving prohibitive to the cost competitiveness of case study four. Figure 16 and Figure 17 show this, with transportation making up a significant proportion of component contribution to LCoH for case study four. This requires the contributions of the other components, particularly other large contributors like LCoE, electrolyser and compressor costs, to reduce further to hit the same LCoH target. These findings reflect that priority should be given first to developing onshore green hydrogen production to unlock cost reductions which will benefit the implementation of offshore hydrogen production.

	Case Study One	Case Study Two	Case Study Three	Case Study Four
LCoE (£/MWh)	40			
Hydrogen Cost Reduction Rate (%)	52	55	56	72
Development (£m)	25	26	27	17
Substation (£m)	17	16	16	10
Electrolyser (£m)	328	302	296	188
Compressor (£m)	308	290	285	199
Desalination (£m)	-	2	2	1
Platform (£m)	-	36	53	34
Subsea Pipeline (£m)	-	23	34	-
Storage (£m)	-			4
Installation & Commissioning (£m)	29	40	63	25
Operations & Maintenance (£m/yr)	30	33	32	19
Transportation (£m/yr)	-			45
Operations & Maintenance (£m)	891	982	963	577
Transportation (£m)	-			1350
Decommissioning (£m)	14	15	15	10
LCoH (£/MWh)	70.00	70.00	70.00	70.00
LCoH (£/kg)	2.33	2.33	2.33	2.33

Table 11
Green Hydrogen Spending Breakdown – 2050 Target

Figure 16
Component Contribution to LCoH – Case Study One – 2050 Target



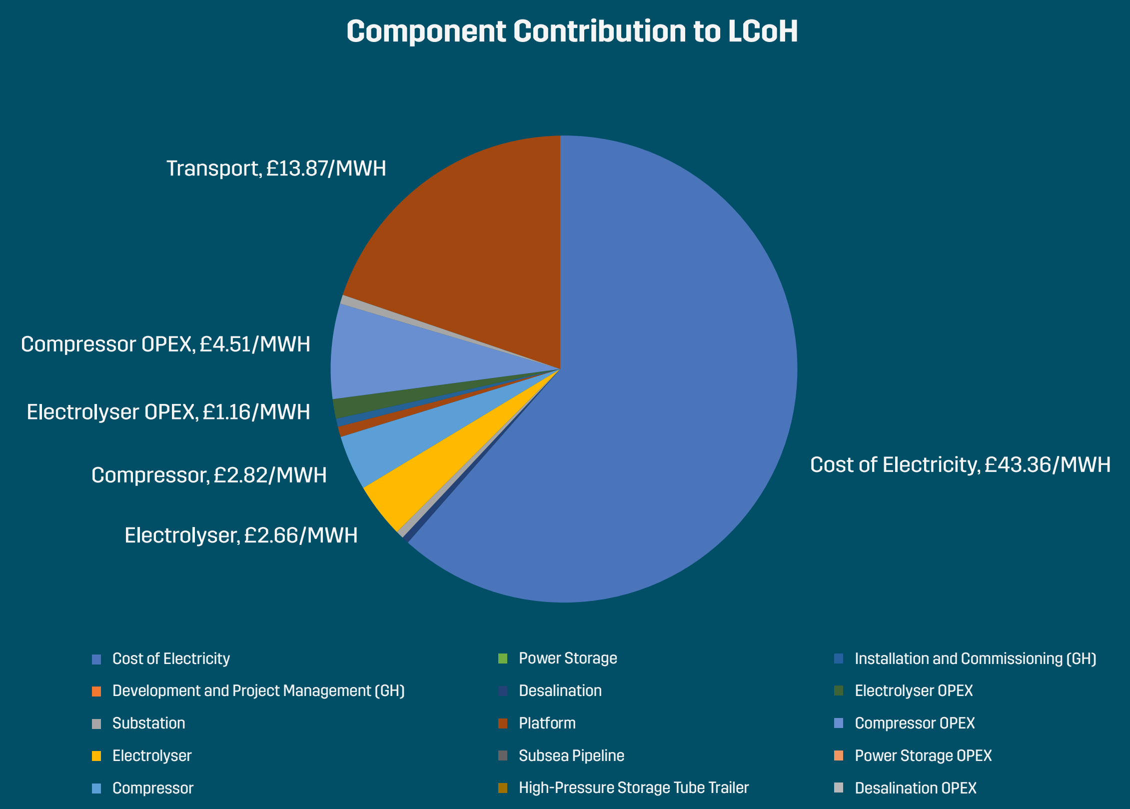


Figure 17
Component Contribution to LCoH – Case Study Four – 2050 Target

10 Supply Chain Assessment Results

10.1 Floating Offshore Wind

Table 12 presents calculated regional and national content percentages for floating offshore wind.

It is projected that the UK would fail to meet the Government's target of 60 per cent UK content in the sample floating offshore wind project considered for each case study.

The largest proportion of jobs created are in operations and maintenance over the life of the windfarm. Operations and maintenance accounts for circa 41 per cent of all jobs created by floating offshore windfarm spending. This is considered a high capability category as most of these jobs are expected to be created at bases close to the windfarm. High capability categories attribute 75 per cent of jobs created to UK content. When combined with other high capability categories such as development and project management, and installation and commissioning this accounts for just over half of all jobs created. Prioritising retaining as many jobs as possible in these areas remain in the UK is essential and would provide a strong footing to improving UK content ratios.

A significant proportion of jobs (approx. 22 per cent) are projected relative to the procurement and fabrication of the wind turbines themselves. This market is heavily dominated by incumbent manufacturers who are based overseas. These are categorised as low likelihood jobs and this is one factor in limiting UK content.

Substructure material procurement and fabrication accounts for circa 12 per cent of jobs created. Presently these are considered low capability areas (10 per cent of jobs retained) for the UK supply chain, due to low availability of UK manufactured steel and low capability in fabricating the sizes of structure required. Investment in port infrastructure and designs more suited to local manufacture (such as concrete foundations) could improve job retention.

Array cabling, export cabling, offshore substations and mooring systems comprise eight per cent of the remaining jobs and are medium capability categories. Although this is a lower proportion of jobs compared with substructures and turbines, having a capability base to start from may make investment in these areas more attractive. Improving retention in these areas would however only have a minor impact on overall UK content.

A more significant opportunity exists in growing a sustainable decommissioning industry in the UK. Decommissioning accounts for six per cent of jobs but is currently classed as low capability due to the relative immaturity of floating offshore wind decommissioning. Developing technologies to increase local capability to "high" levels would add four to five per cent to the UK's share of project content.

If operations and maintenance jobs are removed, and CAPEX jobs only are considered (shown in Table 13), the proportion of UK created jobs decreases significantly.

Regional content is consistent across the regions at between 17 and 19 per cent. Nationally this increases to 28 per cent. This is reflective of each region having differing strengths, as well as the ability to draw on expertise available in other parts of the UK.

Each region draws a high proportion of its retained contact through installation and commissioning.

North East Scotland retains a number of jobs in development and project management where expertise is strong particularly in the development and management of offshore projects in the UKCS. Small numbers of jobs are expected to be retained in cable ancillary components, electrical equipment provision and secondary steel fabrication.

North East England retains more jobs related to the provision of array and export cables than the other two regions. This balances out lower activity expected in development and project management when compared with North East Scotland.

The Celtic Sea region has lower capability in development and project management. There are several manufacturers of inter-array cabling in the region. Lower job retention is expected in substructure material procurement and fabrication.

To reach 60 per cent UK content high level of operations and maintenance jobs will need to be secured locally, and steps taken to improve UK supply chain competitiveness in CAPEX areas with high proportions of jobs created.

The following would be required to meet the target of 60 per cent local content:

1. 80 per cent jobs created in currently high capability areas (development and project management, installation and commissioning, and operations and maintenance).
2. 80 per cent jobs created in improved capability in previously low / medium capability areas (cables, floating substructure fabrication, moorings, offshore substation, decommissioning).
3. 40 per cent jobs created in improved capability in previously low capability areas (wind turbines and floating substructure material procurement).

This represents a significant challenge to the UK supply chain.

	Case Study One	Case Study Two	Case Study Three	Case Study Four
Regional - North Scotland	42%			
Regional - North East England	41%			
Regional - Celtic Sea	41%			
National	46%			

Table 12
Percentage of Regional and National Content – Floating Offshore Wind

	Case Study One	Case Study Two	Case Study Three	Case Study Four
Regional - North Scotland	19%			
Regional - North East England	19%			
Regional - Celtic Sea	17%			
National	28%			

Table 13
Percentage of Regional and National Content (CAPEX Only) – Floating Offshore Wind

10.2 Green Hydrogen Production

Table 14 presents calculated regional and national content percentages for green hydrogen production.

The UK is projected to meet its local content targets if the supply chain assessment predictions are met.

This is driven by the fact that an even larger proportion of jobs created by spending on green hydrogen production is in operations and maintenance. Operations and maintenance accounted for circa 41 per cent of floating offshore wind jobs created, whereas this rises to circa 58 per cent for case studies one, two and three, and 82 per cent for case study four (where there is additional operational spend on transportation of hydrogen to account for). As operations and maintenance is a high rated supply chain category this results in a significant amount of local job creation both for the UK and the key regions considered.

The second highest category in terms of jobs created is the electrolyser. Electrolyser spending accounts for a maximum of 25 per cent of jobs created for case study one (onshore hydrogen production with fewer areas of spending), reducing to a minimum of nine per cent of spending for case study four (offshore hydrogen production and tanker export with more areas of spending)
The category is rated as medium due to the UK having several companies developing electrolyser technology. Given the potential contribution to projects in terms of jobs created it is important that these technologies are supported, and production anchored in the UK. If the proportion of jobs created in the UK could be increased such that a high rating could be justified, this would increase UK content to around 70 per cent for each case study.

The reduction in North Scotland content versus the rest of the UK is reflective of the lower rating given to the regional supply chain for substations, and in particular, electrolysers. This further highlights the positive impact that creating a strong electrolyser production industry in the UK can have on local content figures.

Local content is circa two per cent lower in North East England vs North Scotland. Development and project management, and compression are predicted to result in fewer jobs created, but these are low number compared with installation and commissioning, and operations and maintenance so have a low impact on the overall figures.

The Celtic Sea region content creation is further evidence of the driving nature of installation and commissioning, and operations and maintenance spending. These were the only areas in which the region scored highly in the assessment, with development and project management rated medium. This is still sufficient to generate almost half of all content locally within the region, rising to above the target 60 per cent for case study four where there is the addition of high levels of local hydrogen transportation spend.

As operations and maintenance spend is so driving it is again important that jobs created by CAPEX spend are considered separately regarding local content targets. Table 15 presents the percentage of regional and national content created from CAPEX only.

Nationally between 35 and 37 per cent of CAPEX related jobs are projected to be retained.

This is mainly driven by electrolyser spend which represents over half of CAPEX related jobs in all case studies. Secondly, the two highly rated CAPEX areas nationally (development and project management, and installation and commissioning) represent between 10 and 15 per cent of jobs across the case studies.

The following would be required to meet the target of 60 per cent local content:

1. 75 per cent jobs created in currently high capability areas (development and project management, installation and commissioning, and operations and maintenance).
2. 75 per cent jobs created in improved capability in previously medium capability area of electrolysers.
3. 40 per cent jobs created in improved capability in previously low capability area of compressors.

	Case Study One	Case Study Two	Case Study Three	Case Study Four
Regional - North Scotland	54%	56%	56%	69%
Regional - North East England	52%	54%	54%	68%
Regional - Celtic Sea	49%	51%	51%	67%
National	62%	63%	62%	72%

Table 14
Percentage of Regional and National Content – Green Hydrogen

	Case Study One	Case Study Two	Case Study Three	Case Study Four
Regional - North Scotland	16%	18%	21%	18%
Regional - North East England	12%	13%	15%	13%
Regional - Celtic Sea	6%	8%	10%	8%
National	36%	36%	37%	35%

Table 15
Percentage of Regional and National Content (CAPEX Only) – Green Hydrogen

11 Conclusions

The following conclusions are drawn from the study:

1. Significant cost reductions are required to make floating offshore wind powered green hydrogen cost competitive.
2. Cost reductions and electrical loss improvements of 51% are required to reduce LCoE to levels predicted by the UK Government for 2050 (£40 /MWh).
3. The following levels of cost reduction and electrolyser efficiency improvements are required to reduce LCoH to levels predicted by the UK Government for 2050 (£70 /MWh):
   - 3.1. 52% for onshore hydrogen production.
   - 3.2. 55% for offshore hydrogen production from a repurposed facility, exporting through existing pipelines.
   - 3.3. 56% for offshore hydrogen production from a new build facility, exporting through a new pipeline.
   - 3.4. 72% for offshore hydrogen production from a new build facility, exporting via monthly tanker offload.
4. The UK would fail to meet the Government's target of 60% UK content for a 1 GW scale sample floating offshore windfarm.
5. To reach 60% UK content over the lifetime of a floating offshore windfarm improvements to existing capability of varying degrees is required across all spending areas:
   - 5.1. 80% jobs created in currently high capability areas (development and project management, installation and commissioning, and operations and maintenance).
   - 5.2. 80% jobs created in improved capability in previously low / medium capability areas (cables, floating substructure fabrication, moorings, offshore substation, decommissioning).
   - 5.3. 40% jobs created in improved capability in previously low capability areas (wind turbines and floating substructure material procurement).
6. The UK meets the Government's target of 60% UK content for the green hydrogen production facilities considered. This is largely driven by spending in operations and maintenance.
7. To enhance UK content in CAPEX spending the following improvements should be targeted:
   - 7.1. 75% jobs created in currently high capability areas (development and project management, installation and commissioning, and operations and maintenance).
   - 7.2. 75% jobs created in improved capability in previously medium capability area of electrolysers.
   - 7.3. 40% jobs created in improved capability in previously low capability area of compressors.

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