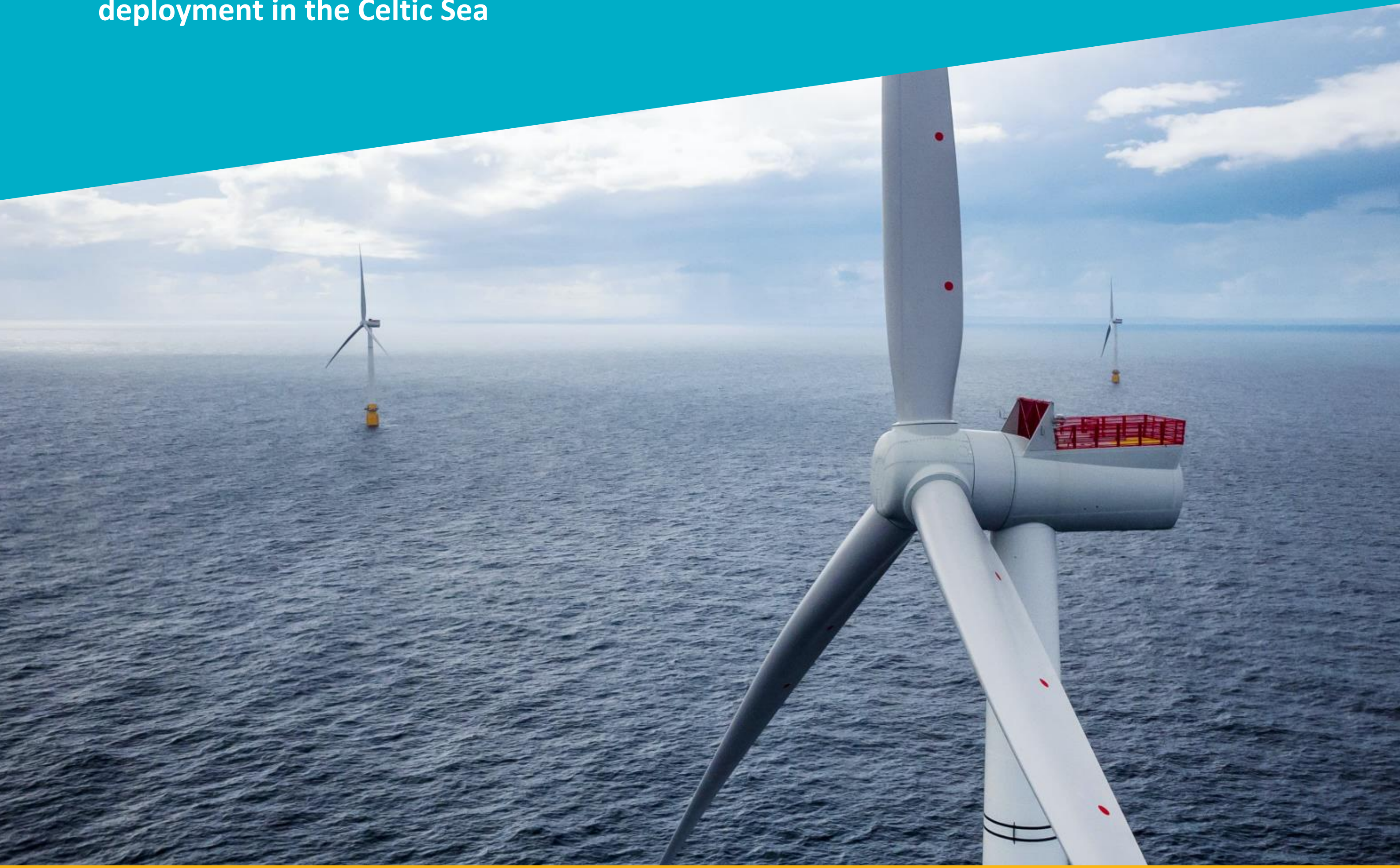
Offshore Renewable Energy

Milford Haven: Energy Kingdom Longer Time-Horizon Energy Generation Development

Enabling activity for multi-GW offshore wind and hydrogen deployment in the Celtic Sea



GENERIC REPORT

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AUTHORS INFORMATION

Name	
James Ferguson	**Scott Davie**
John Nwobu	**Chunjiang Jia**
Anup Nambiar	**Will Brindley**
Nathan Haley	

PREFACE

The Offshore Renewable Energy Catapult (ORE Catapult) is a leading technology innovation and research centre for offshore renewable energy. Our work covers several areas including: research and innovation, testing and validation, analysis and strategy, as well as supply chain growth. The Milford Haven: Energy Kingdom project (funded by Innovate UK) has been a key project for developing understanding around how hydrogen can fit into the future energy system and for undertaking enabling actions to unlock multi-GW offshore wind projects in key UK offshore locations such as the Celtic Sea.

This report focuses on preparing the Milford Haven region for longer term trends (longer time-horizon energy generation) and is part of a wider suite of documents related to this study. The other documents cover: modelling the flow of energy through integrated wind turbine – electrolyser systems (ORE Catapult, 2022); using renewable energy and hydrogen to decarbonise steel in the context of Wales (ORE Catapult, 2022); and identifying the hazards of integrating offshore wind with hydrogen (Abbott Risk Consulting, 2022).

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NOMENCLATURE

AC	Alternating Current
BESS	Battery Energy Storage System
CAPEX	Capital Expenditure
DC	Direct Current
DRI	Direct Reduced Iron
EAA	Equivalent Annual Annuity
FLOW	Floating Offshore Wind
HSS	Hydrogen Storage System
HV	High Voltage
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
IRR	Internal Rate of Return
LCOE	Levelised Cost of Energy
LCOH	Levelised Cost of Hydrogen
LHV	Lower Heating Value
MTBF	Mean Time Before Failure
MVAC	Medium Voltage Alternating Current
NPV	Net Present Value
OCP	Offshore Central Platform
ORE	Offshore Renewable Energy
O&M	Operations and Maintenance

PEM	Polymer Electrolyte Membrane
PEMB	Pembrokeshire
SOC	State of Charge
SW	South Wales
WT	Wind Turbine

EXECUTIVE SUMMARY

Offshore wind and hydrogen are expected to become important parts of the UK's energy future and the Celtic Sea, and the Milford Haven region in South Wales are potential hotspots for deploying technologies required to make this possible. To achieve this would require deploying future floating offshore wind farms with hydrogen-based systems and integrating these technologies with each other and the wider energy system will raise a number of technical questions. In this report, we address such questions under four themes: technology development; the techno-economics of the future energy systems; possibilities for larger scale demonstration projects; and the role of the Milford Haven region in the context of a global green hydrogen market. The summary of the four themes is described below.

Theme 1 focuses on technology development of the electrolyser system and associated infrastructure, with the main objective of reducing the levelized cost of energy. The target cost of hydrogen from electrolysis from various sources are discussed and so is the applicability of different economic metrics like net present value and levelized cost. The importance of developing varying-fidelity models of the integrated wind turbine-electrolyser system, to study its different aspects, was identified as a key requirement with details of the models developed and the studies completed reported in a separate, supplementary document. At the wind turbine level, how to optimally place electrolysers, and at a farm level, how to export hydrogen produced through a comparison with conventional electricity export are examined. The possibility of having several electrolysis technologies on a site to improve the overall capabilities and of potentially including water desalination into the integrated system are also discussed.

Theme 2 explores the possible energy timeline for the Celtic Sea with an understanding of how hydrogen from floating offshore wind farms can be utilised in Milford Haven and its neighbouring regions around South Wales. This takes into consideration the technology development topics from Theme 1 and goes further with a techno-economic study of the energy system around the Celtic Sea, Milford Haven and its neighbouring regions around South Wales. It starts with a general understanding of a local energy system roadmap and timeline for green hydrogen in the region and goes further to explore different green hydrogen configurations and timeline scenarios for potential future hydrogen production and use (offtake) within the region. This takes into consideration the required electrical and gas infrastructure required to make this possible.

Theme 3 outlines potential demonstration projects. These include:

- Potential for deploying hydrogen fuel cells for black start capability and backup power provision, which could lead to the provision of ancillary services on the electricity market
- Deployment of several hydrogen technologies to make a miniature hydrogen energy system
- A focus on hydrogen storage technologies, deploying several different kinds as part of the demonstration and investigating characteristics like response time (to supply/demand for energy) and leak rates
- Development of a dedicated hydrogen test facility, which would hydrogen technology
- The integration of hydrogen systems into a vessel for offshore wind operations and maintenance activity, and the deployment of a hydrogen refueler for marine applications

Theme 4 explores the role of Milford Haven in the context of a global green hydrogen market. This work included conversations with other research groups, to explain the Milford Haven: Energy

Kingdom project and understand the problems they are tackling. We also engaged stakeholders working around the Celtic Sea, from project and technology developers to utilities and reviewed the hydrogen activities of other ports around the world. Finally, we worked with Abbot Risk Consulting to undertake a hazard identification study for the use of offshore wind to produce hydrogen, which is then used in a region with large existing hydrocarbon facilities (such as Milford Haven/South Wales).

1 INTRODUCTION

Through both the Ten Point Plan for a Green Industrial Revolution (UK Government, 2020) and the British Energy Security Strategy (UK Government, 2022), the UK Government has outlined its ambition to have offshore wind and hydrogen technologies as pillars in the nation's energy future.

Through securing a local, low carbon energy supply, an expansion of offshore wind will solve many of the UK's energy challenges. However, it will raise other technical problems, such as how to integrate this new power supply into an energy system which was designed around a completely different paradigm, namely controllable fossil fuel production facilities and thermal power generation.

Solutions to such integration problems include smart local energy systems and energy storage technologies. In particular, hydrogen produced through water electrolysis has a unique offering as a renewable chemical fuel; it has implications for a wide range of end uses, storage and transport of energy, and 'hard to decarbonise' areas such as industry. Combining these smart energy systems and energy storage with wind power offers a holistic energy solution.

Milford Haven: Energy Kingdom (MH:EK) is one project which has worked to advance these solutions. It has explored the potential of renewable hydrogen and electricity to meet the future energy needs of Milford Haven. This region hosts an impressive range of hydrocarbon facilities while also neighbouring the Celtic Sea, which has the potential to host tens of gigawatts of new offshore wind. Using funding from Innovate UK, the project has deployed world-first hardware systems, developed investable propositions, and made inroads into planning the long-term energy transition.

This report addresses some of the barriers to the long-term transition, which has been the focus of ORE Catapult's Electrical Research Team on this project. This work has addressed four themes, each of which support the goal of large-scale offshore wind to hydrogen schemes in the Celtic Sea. Theme 1 covers technology development. Theme 2 covers key energy system questions, including the timeline of development in the Celtic Sea and a scenario review. Theme 3 outlines possibilities for larger scale demonstration projects that will help to accelerate technology development. Finally, Theme 4 looks at the role of Milford Haven in the context of a global green hydrogen market. This report covers the main findings of this work.

This report is also supported by separate, supplementary deep dive reports, which provide detail in the areas of: modelling of integrated wind turbine – electrolyser devices (ORE Catapult, 2022); the safety considerations around producing hydrogen from offshore wind and incorporating this into an area with large scale hydrocarbon facilities (Abbott Risk Consulting, 2022); and the use of hydrogen for steel production in Wales (ORE Catapult, 2022).

2 THEME 1 – TECHNOLOGY DEVELOPMENT

This section addresses some of the technical considerations around integrating offshore wind with hydrogen. The topics include: levelised cost of energy reduction; modelling the flow of energy through integrated wind turbine – electrolyser systems; a comparison of the reliability of pipelines and cables; possibilities for optimising electro-chemistry and electrolyser systems; and options for integrating electrolysers and desalination units into floating wind turbine platforms. These are likely to be relevant to the future of Wales and energy generation in the Celtic Sea.

2.1 Levelised cost of energy reduction

There are three areas to explore regarding levelised cost of energy reduction: the reduction in the cost of wind power, the reduction in the cost of hydrogen, and the potential for reducing costs in integrated systems. These will be explored in turn. Additionally, we consider how levelised cost gives us some information, but a holistic economic analysis also will consider the value added by the system as a whole.

2.1.1 Cost reduction of wind power

Onshore wind and solar power have shown the power of learning rates, which is the percentage cost reduction with each doubling of capacity. With their learning rates of 23% and 36% the cost of onshore wind and solar declined by 70% and 89%, between the years of 2009 and 2019, respectively (Roser, 2020).

There is evidence that offshore wind also follows a learning rate. This will have contributed to the 2019 Round 3 Contracts for Difference strike price of around £40/MWh (2012) for almost 6 GW worth of fixed offshore wind farms due to come online between 2023 and 2025 (BEIS, 2019). (This is equivalent to about £45/MWh (2020), with average inflation of 1.6% per year (Bank of England, 2022).)

A new development in offshore wind is the deployment of floating devices, which are likely to be relevant for the Celtic Sea. The cost of these devices is currently high; a high-level report from ORE Catapult projected those costs in 2027 would be about £125/MWh (2020). However, depending on deployment rates and innovation of new technology, this could be reduced to £40/MWh (ORE Catapult, 2021). The time frame for this reduction will depend on deployment rates. The 2022 ScotWind leasing round awarded seabed rights to about 15 GW of floating projects (Crown Estate Scotland, 2022), which is expected to trigger a rapid reduction in cost towards £40/MWh by the mid to late 2030s.

2.1.2 Cost reduction of hydrogen

The International Renewable Energy Agency (IRENA) has outlined a cost reduction pathway for green hydrogen from about $5/kg to about $1/kg (IRENA, 2020). One of the important drivers for this was an 80% reduction in electrolyser costs, contributed to by a number of improvements delivered with scale. This magnitude of reduction has also been found plausible by the National Renewable Energy Laboratory; they found that the cost of a 1 MW electrolyser could decrease by around 54% when production rates increased from 10 units per year to 50,000 units per year (Mayyas, Ruth, Pivovar, Bender, & Wipke, 2018).

Another important factor is the cost of electricity. IRENA found that reducing the cost of electricity from $53/MWh to $20/MWh cut the cost of hydrogen by about $1.30/kg. One of the advantages of having electrolysers onshore, and grid connected, is that they can access low-cost electricity from the energy market e.g., on a windy night. This could help to improve electrolyser economics.

2.1.3 Cost reduction for integrated wind turbine – electrolyser systems

The first projects coupling offshore wind and hydrogen are currently underway and will help to reduce the number of uncertainties involved.

Although the first integrated systems are likely to have high costs, early consultancy reports have projected costs of hydrogen produced from offshore wind to be about £2/kg to £3.50/kg between the years of 2025 to 2032 (Xodus, 2020) (ERM, 2019) (Roland Berger, 2021).

Depending on the specific set up, integration of these machines presents some specific challenges but also opportunities.

One of the opportunities is that, if a wind farm is electrically connected only to an electrolyser, there is potential to simplify the power electronics that would normally be needed to ensure that the turbine matches grid specifications and compliance requirements. It also reduces vulnerability to grid constraints. This opportunity was explored by ORE Catapult and power electronics manufacturer Dynex Semiconductor in a project called HyPER Wind (Dynex, 2022), which was supported by the Welsh Government.

Conventionally, power electronic converters are required for wind turbines to rectify variable electricity outputs (voltage and frequency) from turbine generators into direct current (DC) and invert into grid compliant voltage and frequency (50Hz). The regulated electric power is then collected and transmitted via either a high voltage AC (HVAC) or high voltage DC (HVDC) connection to the shore. Thereby, it can be distributed through the electricity network and then converted into DC to supply electrolysers, as shown in Figure 1.

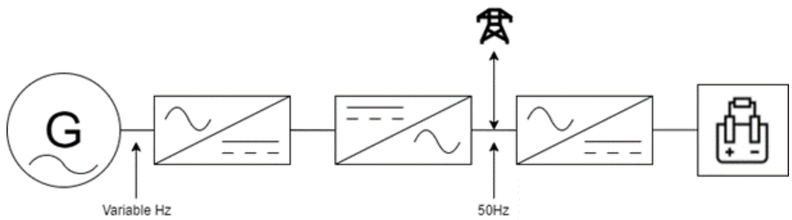


Figure 1 Conventional power circuit topology to supply electrolysers (Dynex, 2022)

Figure 2 illustrates an example of direct integration of a wind turbine/farm with electrolysers. This topology could eliminate/reduce the quantity of the required power electronics, which greatly reduces the CAPEX. Dynex and ORE Catapult joint research scrutinized a range of direct-conversion circuits in terms of size, weight and reliability through the HyPER Wind project. The project identified the most efficient and reliable converter topology to interface a wind turbine directly with an electrolyser. The properties and efficiency of this topology could be further improved by changing the kind of semiconductor used in the design. Although this approach may have some benefits, it also means that the turbine – electrolyser system is a micro-grid (i.e., off-grid), which requires energy storage for standby periods and black start capability so it can restart operation after a period of downtime.

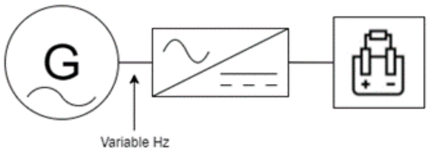


Figure 2 Topology of wind turbine integration with electrolysers

Another difference, that comes from landing hydrogen rather than landing electricity, is the characteristics of pipelines compared to cables. Some of the reported advantages of pipelines are that they have lower costs and are more reliable (explored in Section 2.3). There may also be the potential to export through existing pipelines if the associated challenges can be solved.

2.1.4 Adding value through technology and projects

The metric of levelized cost of energy (LCOE) allows us to compare between the costs of different energy sources. However, there are other aspects to consider, such as always being able to balance supply and demand and, with electricity specifically, balancing the network itself. This can be accounted for by looking at the cost of the overall energy system, rather than specific technologies. Then we can find the value of each individual technology/project. For example, the overall project economics could show onshore electrolysers coupled with fuel cells or hydrogen-based generators can add value through providing ancillary services to the grid.

Offshore turbine – electrolyser systems might also be able to add value through the inherent energy storage within a pipeline. Some studies have suggested that 1 km of pipeline could store 12 tonnes of hydrogen, equivalent to 400 MWh (Alverà, 2021). They may also be able to tie into large (TWh+) geological stores (Edlmann, Haszeldine, Heinemann, Hassanpouryouzband, & Thaysen, 2021).

Considering the value added by each technology will help to find the optimal mix for a low carbon future. Energy systems modelling tools (such as HySPOT, used in Section 3.5) are useful to find the value of these attributes.

Economic metrics which capture value in terms of revenue include net present value and payback period.

2.2 Energy flow model – modelling integrated wind turbine – electrolyser devices

With offshore wind and electrolysis/hydrogen on track to become important technologies for the UK's energy future, ORE Catapult is using data from existing assets and developing models of integrated systems to study the dynamics of these complex systems. The full results are documented in ORE Catapult's Energy Flow Model report (ORE Catapult, 2022).

To summarise, there are numerous ways to approach the problem of modelling integrated turbine – electrolyser systems and they can each be used to address different questions. At a high level, it is enough to specify a power capacity, capacity factor and electrolyser efficiency. For example, 40 GW of wind and electrolyser capacity, a wind capacity factor of 50% and an electrolyser efficiency of 75% by higher heating value would give an average stream of 15 GW of hydrogen.

The next level of detail takes into consideration wind turbine power curves and electrolyser operational envelopes/performance curves, quantifying the benefit of increasing electrolyser efficiency.

This is followed by higher-fidelity models of the integrated system, which includes the representation of the internal resistances, voltage and current flow in the electrolyser. These models can also consider control of the system e.g., to regulate the electrolyser power consumption. The controller aims to track the power output of the wind turbine while also protecting the electrolyser from sudden transients that might damage the cells.

These higher fidelity models can be used to quantify the energy storage required to compensate for any mismatch in energy between the wind turbine and the electrolyser and to quantify energy surplus when the wind turbine is rated higher than the electrolyser. Such energy surplus, if stored, would maximise the hydrogen production, however, at higher costs. Therefore, through the higher fidelity model developed, we studied the relationship between energy storage, hydrogen production and wind profiles.

2.3 Reliability of cables and pipelines

With increasing interest in offshore wind and hydrogen, some projects are investigating the possibility of creating integrated turbine-electrolyser devices which export hydrogen to shore, while others are interested in exporting electricity from the wind farm and producing hydrogen onshore. There are technical and economic aspects of each approach that need to be understood to know which option is favourable in a given situation. One technical aspect is the reliability of cables compared to pipelines, which is explored in this section.

Pipelines and cables are different types of equipment but are both critical for transporting offshore energy resources. Whether it may be pipelines for hydrocarbon export or subsea cables for the rapidly developing offshore wind industry, it is important to understand and compare the reliability of subsea pipelines and cables currently in service and identify where improvements can be made to reliability.

Pipelines typically come in two technologies: steel pipe and flexible pipe. With each type of pipeline comprising of different materials and used in different applications, the reliability rate and types of failure observed will also differ. Subsea cables make up just 10% of the initial cost of building an offshore wind farm but account for 75-80% of insurance claims in the offshore wind industry (ORE Catapult, 2020). With subsea cables being the primary cause of failures in the offshore wind industry, improvements to reliability must be made in order to help reduce the LCOE.

The choice between electricity or gas transmission systems is based on their suitability for the wind farm location and size. A variety of electricity transmission systems for offshore wind are available. Medium voltage alternating current (MVAC), and HVAC transmission systems are typically used when distance to shore is less than approximately 80 km. For greater distance to shore and cable lengths, HVDC becomes more economical. Each transmission system, whether MVAC, HVAC or HVDC, has its own pros and cons, e.g., reactive compensation for AC systems, and converter stations for DC systems, and each of these systems come with their own challenges to reliability (Warnock, McMillan, Pilgram, & Shenton, 2019).

Irrespective of the type of transmission system chosen for an offshore wind installation, significant lengths of subsea cables will be present. Hence, the reliability of these cables play an important role in the energy production by a wind farm over its lifetime and on the O&M costs. There will likely be scenarios where exporting electricity from the wind farm is favourable compared to exporting hydrogen. Still, in these cases, the growing demand for floating offshore wind in regions such as the Celtic Sea means there is an increasing need to develop offshore cable systems that can withstand more challenging conditions. Better understanding of the failure modes and rates for offshore cables will aid the development of future cable systems. There may be lessons to be learned from offshore pipeline failures that can add value to offshore wind cable systems going forward.

2.3.1 Reliability and Failure

The following statements help us to understand reliability and failure.

Reliability describes the ability of a system or component to function under stated conditions for a specified period of time. (IEEE, 1990).

In cables, the power system group CIGRE looked define failure as an "instantaneous failure leading to automatic disconnection" or an "occurrence requiring subsequent unplanned outage" (CIGRE, 2020).

In pipelines, failure may commonly refer to a leak. This can be associated with an equivalent hole diameter e.g., 10 mm. Another kind of failure is a split, which considers hole diameter up to 25 mm. Finally, there is a rupture, which is associated with hole diameters greater than 25mm.

Failures of pipes and cables may have different short-term consequences for an energy system. An instantaneous disconnection of a wind farm power cable may affect the power system. A leak in a pipeline will not cause an instantaneous system shock but can cause a local hazard and pollution.

2.3.2 Defining Failure Rate

Failure rate can be defined as the anticipated number of times that an item fails in a specified period of time." (Greeff & Ghoshal, 2004). Pipelines and cables may have four sections: a riser, sealine, land approach and landline. Depending on the type of failure to occur in the different sections of the pipeline or cable, the failure rate can be presented in different terms.

The failure rate for cables is often described in terms of the number of incidents per kilometre of cable per year of operation. This allows the length of cable to be factored into the failure rate, as a longer cable will potentially contain more joints and therefore could be at risk of suffering more failures than a shorter cable with less joints.

The failure rate for pipelines can also be described in terms of the number of incidents per kilometre of pipeline each year of operation. However, the SUREFLEX JIP 2017 report recommends that the failure rate should be based on the number of incidents per number of pipelines each year of operation. The main reason that the "per pipe" failure rate is deemed more representative is because the largest contributors to pipe damage and failure typically affect the pipe on a "per pipe" basis rather than a "per unit length" basis. The most common pipe damage mechanisms include annulus flooding, ancillary equipment defects and global pipe defects, while the most common pipe failure mechanisms for flexible pipes and risers include internal pressure sheath defects and armour wire degradation. These mechanisms for damage and failure typically affect the pipe on a "per pipe" basis (Wood Group, 2017).

In order to provide a comparison between the failure rates of offshore cables and pipelines, the "per km" metric must be used. However, a further comparison between the pipeline failure rates measured on a "per pipe" and "per km" basis is provided and the limitations of the "per km" metric for pipeline failures is discussed.

2.3.3 Cable Failures

A study of offshore wind transmission systems failure rates looked at the AC transmission system of 72 operational European wind farms, 22 of which had reported failures, not including the substations or arrays. The average failure rate was found to be 0.003 failures/km/year (Warnock, McMillan, Pilgram, & Shenton, 2019).

The CIGRE report details the service experience of HV underground and submarine cable systems installed at the end of 2015. The overall failure rate for submarine cables between 2006 and 2015 was found to be 0.00055 failures/km/year. This failure rate is significantly lower than the failure rate derived from the previous CIGRE survey which found the overall failure rate to be 0.0012 failures/km/year for the period 1991-2005. The main reasons for the reduced failure rate in more recent years are improved methods of surveying and cable routing, improved methods for cable laying, and increased focus on protection by burial or other protection methods at installation. From available data in the report, the cable configuration most relevant to the offshore wind industry was identified to be AC submarine cables with voltage range 33kV-220kV. The failure rate of cables at this voltage range was calculated to be 0.007 failures/km/year, which is a slightly greater failure rate than the overall failure rate for submarine cables (CIGRE, 2020).

2.3.4 Pipeline Failures

The PARLOC report, prepared for HSE, describes studies related to loss of containment from offshore pipelines and risers. The report has been updated since the early 1990s, with the most recently updated results taken from the 2012 version. PARLOC reports a failure rate of 0.000423 incidents/km/year for Steel pipelines and 0.00548 incidents/km/year for flexible pipelines. This shows that the failures/km/year for flexible pipelines is almost 13 times greater than for steel pipelines (PARLOC, 2012).

The failure rate for each type of pipeline failure that occurs is detailed in a previous version of the PARLOC report. For leaks (up to 10 mm), a failure rate of 0.00174 failures/km/year is observed. For splits (up to 25 mm), a failure rate of 0.000504 failures/km/year is observed. For ruptures (greater than 25mm), a failure rate of 0.000443 failures/km/year is observed. The overall pipeline failure rate at the time of the report is 0.00269 failures/km/year (PARLOC, 1996).

The CONCAWE database found the onshore pipeline failure rate to be 0.00026 failures/km/year, showing that the failure rate for offshore pipelines is 10 times greater than for onshore pipelines (CONCAWE, 2019).

2.3.5 Failure Rate Summary

The results provided in Table 1 show the failure rates for each cable and pipe type and show the corresponding failure frequency in terms of Mean Time Before Failure (MTBF). The MTBF is the predicted elapsed time before component failure occurs, expressed in years. The results show that steel pipelines generally have lower failure rates than transmission cables. It also shows that dynamic risers & flexible pipes have a similar failure rate to static cables. However, with limited data available, particularly for dynamic subsea cables, an improved understanding of this field would help to better understand the respective failure rates. Any field marked unknown means we did not find information on that parameter.

Table 1: Failure Rates for Cables and Pipelines

Connection Type	Description	MTBF/ 1GW Wind Farm (years)	Failure Rate (incidents/ km/year)	Failure Rate (incidents/ pipe/year)	Reference
Steel Pipeline	Loss of Containment period 2001-2012. 150 km route assumed.	≈15.8	0.000423	0.00563	(PARLOC, 2012)
Flexible Pipeline	Loss of Containment period 2001-2012. 66 x 2.2 km route assumed.	≈1.3	0.00548	0.00359	(PARLOC, 2012)
	Risers (dynamic) period 2011-2016. 66 x 2.2 km route assumed.	≈3.8	Unknown	0.004	(Wood Group, 2017)
	Flowlines & Jumpers (static) period 2011-2016. 66 x 2.2 km route assumed.	≈63.9	Unknown	0.000237	(Wood Group, 2017)
General Pipeline	For risers and the first 100m of sea-line (up to 1996). 150 km route assumed.	≈2.5	0.00269	Unknown	(PARLOC, 1996)
Offshore Cable	European windfarm AC transmission cable to shore. 150 km route assumed.	≈2.2	0.003	Unknown	(Warnock, McMillan, Pilgram, & Shenton, 2019)
	MV Inter-array cable (static). 66 x 2.2 km route assumed.	≈2.2	0.003	Unknown	(Warnock, McMillan, Pilgram, & Shenton, 2019)
	33kV-220kV AC submarine cables.	≈9.8	0.0007	Unknown	(CIGRE, 2020)

	66 x 2.2km route assumed.				
	MV Inter-array cable (dynamic)	Unknown	Unknown	Unknown	Unknown

The MTBF for the total cables or pipelines equivalent to a 1 GW wind farm (and pipeline/cable lengths given in the description in the table) was calculated based on the wind farm parameters shown in Figure 3 below.

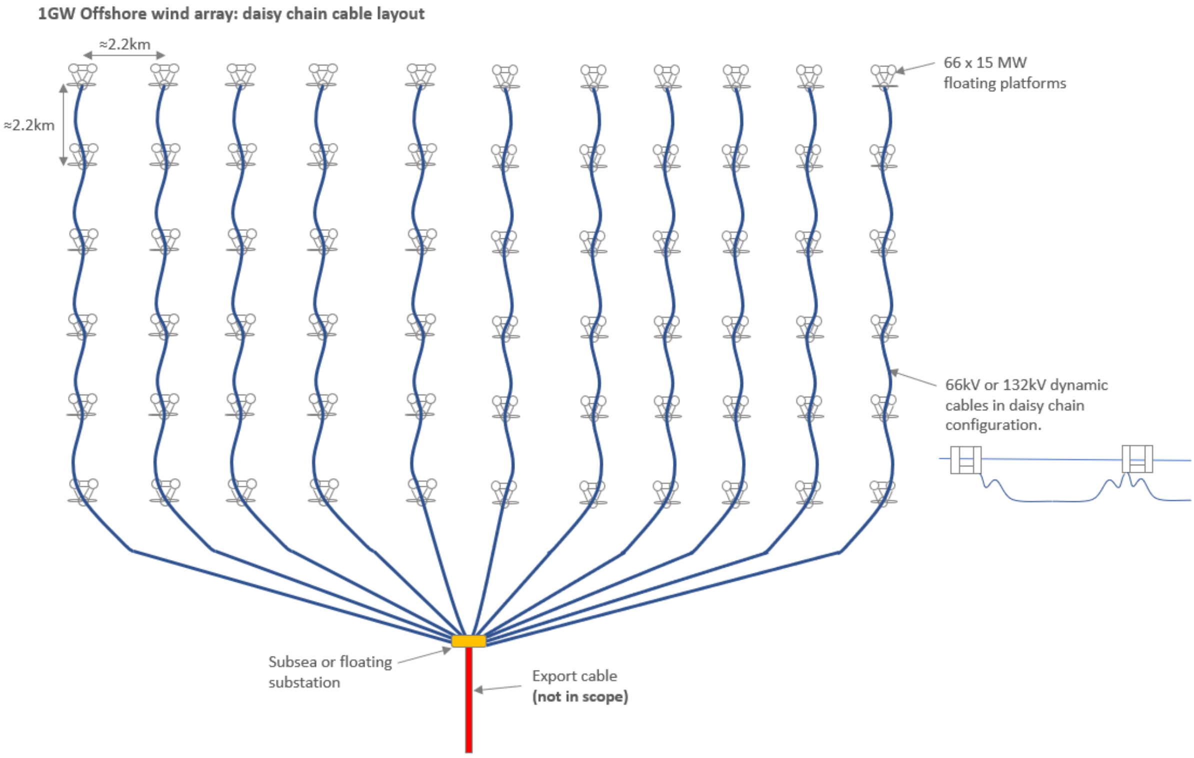


Figure 3 - 1GW Offshore Wind Farm Array: Daisy Chain Cable Layout

2.3.6 Limitations and Future Work

There are limitations to the conclusions that can be drawn from pipeline failure rates provided on a "per km" basis due to the typical failure modes of pipelines discussed. The pipeline failure rates provided by PARLOC suggest that flexible pipelines are approximately 13 times more likely to fail than steel pipelines. However, there are a relatively similar total reported number of flexible and steel pipelines in operation and the number of failure incidents for steel pipelines is almost twice the number for flexible pipelines. Using the PARLOC data, the SUREFLEX JIP report calculated the equivalent failure rate on a "per pipe" basis. The minimum failure rate was calculated to be 0.00563 incidents/pipe/year for steel pipes and 0.00359 incidents/pipe/year for flexible pipes, which translates to a flexible pipeline failure rate that is only 64% of the equivalent failure rate for steel pipelines (Wood Group, 2017).

The report also developed damage or failure rates/pipe/year for the population of pipelines during the period 2011-2016. It calculated the failure rate for Risers to be 0.004 failures/pipe/year, and the failure rate for Flowlines & Jumpers to be 0.000237 failures/pipe/year (Wood Group, 2017).

There are other barriers in making direct comparisons between failure rates established across different studies, such as the applied definitions for what constitutes a case of damage or failure and how these translate to the type of pipe in question, e.g., bonded/unbonded flexible pipes.

There is currently a lack of specific failure data recorded for offshore wind cables, particularly for inter array cables. It is recognised that failure data will be increasingly important for cables in the offshore wind industry, particularly for wind farms located in deeper, harsher waters. The ORE Catapult have developed a programme that will track subsea cable failures and provide insight to cable reliability. The programme called Electrical Cable Failure Trending & Reliability Analysis for Operational Developments (ELECTRODE) will involve collaboration with industry partners to continuously collect anonymous data with the goal of producing cable reliability insight that will; inform innovation and best use of technology, improve efficiency and drive down costs, and provide hard evidence for insurers and investors (ORE Catapult, 2020).

2.4 Possibilities for optimising electro-chemistry and electrolyser systems

The challenge of optimising electro-chemistry and the electrolyser system can be addressed at two levels of detail.

At a cell membrane level, there may be potential technical improvements which specifically suit electrolyser systems connected to renewable power generators. These cells/systems could be designed to deal with rapid fluctuations in power supply and frequent switching between idle and generation modes.

The second approach is to incorporate the specific advantages of alkaline, proton exchange membrane (PEM), anion exchange membrane (AEM) systems, and solid oxide electrolysers into single facilities. This approach raises system integration questions.

One general question is the mixture of lower cost, slower response machines (e.g., alkaline systems) and higher cost, faster response machines (e.g., PEM or AEM). For example, if powered with a 1 GW wind farm, there may be an economic advantage of deploying 0.9 GW of alkaline systems with 0.1 GW of PEM systems. The PEM system will be able to “soak up” the majority of the rapid fluctuations from the wind farm, allowing the alkaline system to be run with a smoother operational profile. Other energy storage devices and/or dump loads may help with any fluctuations that the PEM system couldn’t handle.

For larger systems, there may also be the potential to upgrade waste heat to electricity. For example, a 1 GW electrolyser with 75% efficiency, by higher heating value, will produce up to 250 MW of heat at full capacity. The current state-of-the-art of low temperature waste-heat-to-electricity machines could be investigated to understand the potential of upgrading this energy to electricity and sending it back to the electrolysers.

A related concept is to site solid oxide electrolysers in areas of high temperature waste heat (e.g., up to 850°C (IRENA, 2020)). With this technology, a larger proportion of energy required for the reaction is supplied by heat, meaning less electricity is required per kg of hydrogen. There may be potential for siting wind powered solid oxide electrolysers next to industrial clusters which can supply this heat.

Another possibility is the option to have different sizes of stacks. This could be relevant for systems that have relatively high minimum load factors. For example, a 1 MW system with a minimum load factor of 20% needs at least 200 kW to begin operation. A 100 kW system would only need 20 kW.

In order to find the optimal configuration in each of these cases, relatively detailed technical and economic information is required about the machines. For example, if a single electrolyser manufacturer supplies both the alkaline and PEM systems for a hybrid plant, are there economic benefits to placing a large order, and would this be significantly different if only one technology was ordered? What is the heat generation profile of an industrial cluster, and can it always maintain a solid oxide electrolyser's temperature, or would thermal cycling be a regular occurrence?

As the electrolyser market develops and the hydrogen sector makes links with other industries, the resulting information can be used in technoeconomic studies to optimise future site design.

2.5 Optimal placement of electrolyser systems on offshore wind turbine structures

If an electrolyser system is to be integrated into an offshore wind platform, where is the best location? One option is to have the electrolyser within a protective housing at the base of the turbine (ERM, 2019). For semi-submersibles, the deck between buoyancy elements (i.e., columns) or even the buoyancy elements themselves appear to be a straightforward option. However, there are alternatives, namely, to have the electrolysis and hydrogen equipment in the turbine tower, or the nacelle.

From an electrical point of view, there may be advantages to reducing the distance between the main electricity generator and consumer. Additionally, from a maintenance point of view, protecting the equipment from the bad weather may be favourable. However, moving the equipment inside the tower or nacelle may have implications for safety and other mechanical considerations may need to be made. On the safety side, hydrogen leaks in enclosed spaces are more dangerous than in open spaces and the presence of electrical equipment could further increase the risk. On the mechanical side, adding extra mass to the tower may require structural reinforcements. On the other hand, some wind turbines currently use the weight of electrical equipment in the nacelle as a cantilever to balance the weight of the blades, so existing designs may not need major changes.

A further consideration is that the water supply system may need a more powerful pump to send water up the tower.

Furthermore, the effect of increased movement at the top of floating devices, compared to their base, may need to be considered for liquid holding tanks in the electrolyser system e.g., sloshing may cause problems for level sensors. This could be more important for non-pressurised alkaline systems than for pressurised PEM machines.

2.6 Integration of desalination capability into offshore wind turbine infrastructure

The extraction of sea water onto an offshore wind platform to produce high purity water (up to type 2/nuclear grade for PEM systems) raises several new issues, listed below.

- One issue is that the extraction of water is likely to result in biofouling of the inlet pipes e.g., mussel growth. Thus, a pipe cleaning regime may become an important part of the platforms operation and should be considered during design.
- Another issue is that, for filtration/membrane technologies such as reverse osmosis, frequent replacement of the separation material will be required.

- The siting/routing of appropriately sized water tanks, pumps and pipes, are additional questions to be addressed.
- Finally, the brine outlet, which returns the rejected water to the sea, should be sited with the increased salinity in mind – this could accelerate the rate of corrosion on any exposed part of the platform.

2.7 Theme 1 Summary

We covered a wide range of technology questions, with main findings outlined below.

2.7.1 Levelised cost of energy reduction

We outlined the fall in the cost of renewables thus far, and the potential for the cost of floating wind to fall to £40/MWh (ORE Catapult, 2021). We also covered projections for the cost of hydrogen from electrolysis to fall to $1/kg (IRENA, 2020). Next, we looked at the potential advantages of integrating offshore wind with hydrogen systems, and how consultancy style reports predict costs of £2/kg to £3.50/kg between the years of 2025 to 2032 (Xodus, 2020) (ERM, 2019) (Roland Berger, 2021). Finally, we described how economic metrics such as net present value capture important information that is missed by levelised cost.

2.7.2 Modelling the flow of energy through integrated wind turbine – electrolyser systems

This subject is covered in a separate, supporting report. To summarise, there are different ways to approach modelling such integrated systems and they can each be used to answer different questions. We addressed questions of how much energy is produced by the wind turbine that the electrolyser cannot use, the standby energy requirements of the systems, how to optimise the electrolyser operation strategy and the response times of electrolysers compared to changes in wind turbine output.

2.7.3 Reliability of cables and pipelines

There is potential to deploy electrolysers at offshore wind farms and export hydrogen. Comparing such systems to wind farms which export electricity requires an understanding of the characteristics of the different technologies. A part of this is understanding the reliability of pipelines compared to cables. Our literature review suggested that static pipelines are more reliable than static cables. A lack of information on dynamic cables means we cannot yet compare them to dynamic pipes (such as risers).

2.7.4 Possibilities for optimising electrochemistry

Here we explored how it may be possible to couple the advantages of several electrolysis technologies on a site to improve the overall capabilities of the facility. One example is coupling a large quantity of relatively low cost, slow reacting electrolysers to a small quantity of higher cost, faster response electrolysers. These kinds of investigations can be undertaken when more technical and economic information on electrolysers becomes available.

2.7.5 Optimising the placement/location of electrolysers on offshore wind turbines

In this section, we outlined some of the possibilities for siting an electrolyser in an offshore wind turbine. The base of spar type substructures and the platform of semi-submersibles are straightforward options, but there may be advantages to installing the electrolyser in the turbine tower and nacelle.

2.7.6 Integration of desalination capability into offshore wind turbine infrastructure

Here we explored the potential design issues of incorporating a desalination unit in/on an offshore wind turbine.

3 THEME 2 – CELTIC SEA ENERGY SYSTEM TIMELINE AND SCENARIO REVIEW

Hydrogen is expected to play a significant role in the UK energy mix with the UK government aiming to produce up to 10 GW of hydrogen by 2030, with at least half of this being from electrolysis (Department of Business, Energy & Industrial Strategy, 2022). Globally, around 70 million tonnes of hydrogen are produced today with three-quarters of it from natural gas and the rest from coal (The International Energy Agency, 2019). Only close to 2% of the global hydrogen production is through electrolysis (The International Energy Agency, 2019). With the prospect of hydrogen playing a vital role in the global net zero ambitions and in decarbonising the energy system, it is expected that many more players would be involved in hydrogen production in the UK and in green hydrogen production from offshore renewables in particular.

The Celtic Sea is a hotspot for floating offshore wind activity in the UK at the moment with a pipeline of several 100 - 400 MW test-scale floating wind projects to be developed in the near future. The Crown Estate has also announced that up to 4 GW of floating offshore wind capacity is to be unlocked in the region by 2035 (The Crown Estate, 2021). The local electricity grid infrastructure in the region is poor with constraints (Western Power Distribution, 2022) and cannot take in all this generation. Hence, hydrogen production from the wind farms in the Celtic Sea is considered a good means to integrate these high levels of offshore wind power into the local energy system.

Taking the technology considerations highlighted in Section 2, this section goes further with a techno-economic study of the energy system around the Celtic Sea in the context of understanding how hydrogen from floating offshore wind (FLOW) can be utilised in Milford Haven and its neighbouring regions around South Wales. It starts with a general understanding of a local energy system roadmap and timeline for green hydrogen in the region and goes further to explore different scenarios for potential future hydrogen production and use (offtake) within the region including considerations around electrical and gas infrastructure required to make this possible.

3.1 Smart local energy system roadmap: green hydrogen pathway

The Milford Haven region in South Wales has a potential big role in aiding the UK towards meeting its net zero targets by 2050. As a part of the activities of the MH:EK project, a conceptual proposal for what a 2050 decarbonised Milford Haven energy system could look like was created (Arup, 2022). This proposal provided short to midterm options that could be adopted by the region to meet net zero by 2050. The long-term pathways in the proposal, provide a possible future with balanced green and blue hydrogen production, including the possibility of generating green hydrogen from the Celtic Sea. The pathways are consistent with the plans for the industries in Wales and the future energy system projections published by organisation such as the National Grid.

The Balanced Green Hydrogen roadmap from the Arup report is shown in Figure 4. This pathway is well aligned to the Climate Change Committee's (CCC) 'balanced pathway' demonstrating the potential balance of electric and hydrogen technologies in the future energy mix.

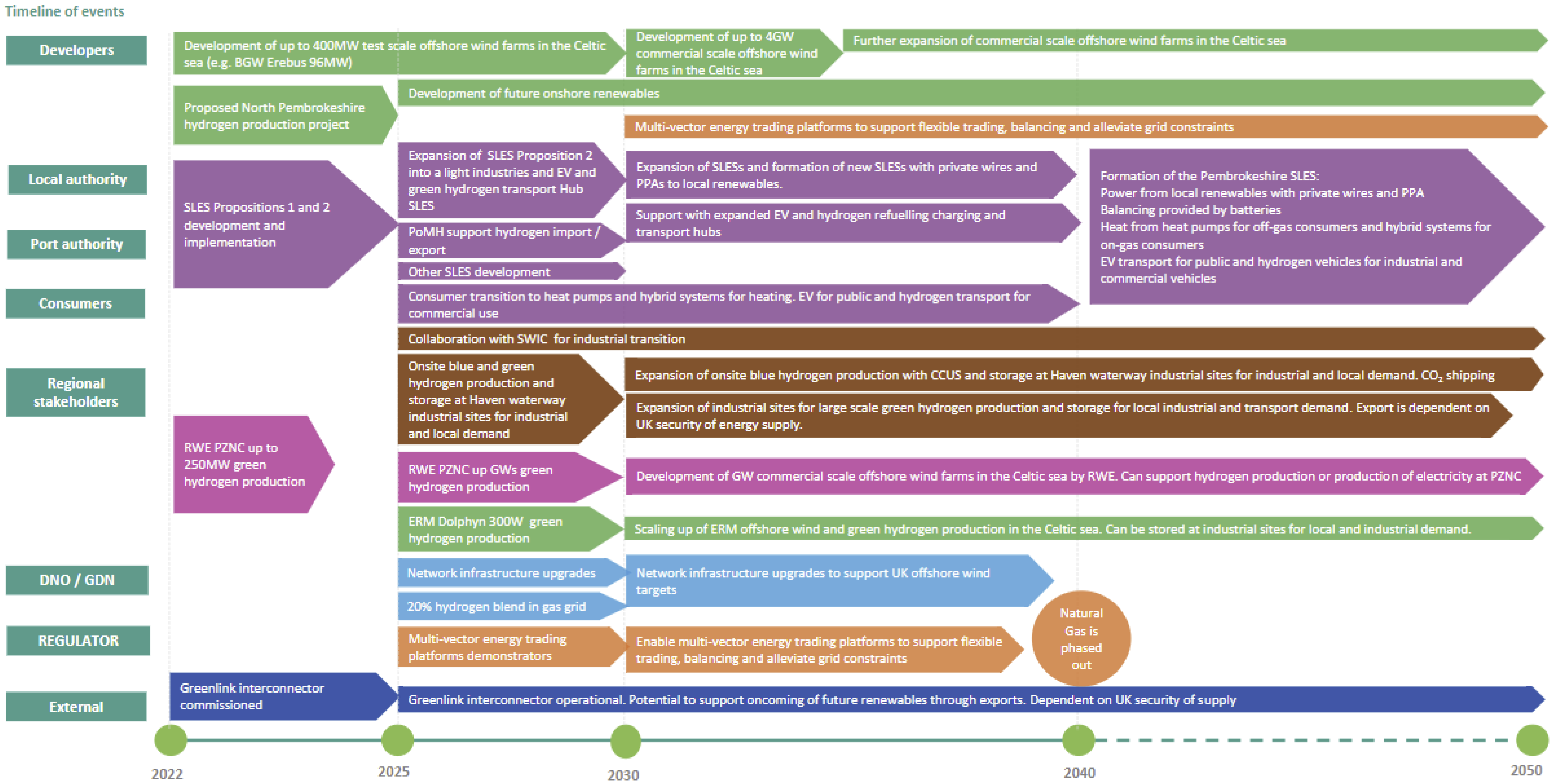


Figure 4: Timeline of events for the MH:EK Green Hydrogen Pathway (Arup, 2022)

3.2 Energy use in the Milford Haven and surrounding regions

To understand the potential role the Milford Haven region could play in the transition towards hydrogen, a general understanding is required to assess who could potentially use (offtake) hydrogen in the region. This estimate of future offtake helps inform the energy system modelling for the region discussed later in section 3.5 .

This section assesses the current energy use in Milford Haven and surrounding regions, identifies current and potential future hydrogen consumers and estimates their green hydrogen offtake. The following sub sections cover the selection of the project boundary as well as our approach to estimating the hydrogen offtake for this region. The general approach used to identify the main hydrogen consumers in a region can be found in Appendix A1.

3.2.1 MH:EK project boundary

The first step in the process was to identify the MH:EK project boundary, an area that could possibly use the hydrogen produced in the offshore wind farms in the Celtic Sea. For this study, the area within a 100 km radius from Milford Haven was chosen, which is shown in Figure 5. This area includes the nearby port towns of Port Talbot and Swansea city. Considering that some of the large energy demand centres in Wales are located further east in Cardiff and Newport, some of the hydrogen offtake options in these cities and the wider South Wales region were included too.

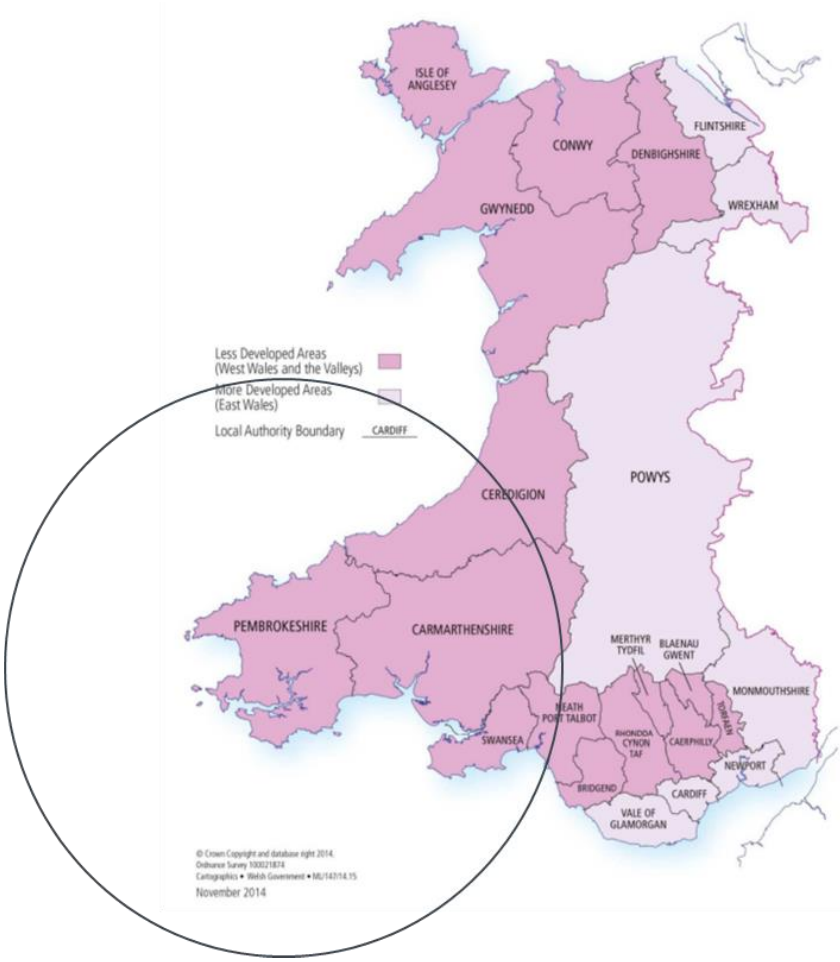


Figure 5: Neighbouring areas around Milford Haven considered in this work. Map obtained from (South East Wales Regional Engagement Team, 2022).

3.2.2 Potential hydrogen offtake in Milford Haven and neighbouring regions

Based on the possibility for hydrogen to be used in the industries and sectors discussed in Appendix A1, hydrogen consumers in Milford Haven and the neighbouring regions are presented here. The aim of this work was to estimate the hydrogen offtake potential of the region. This work expands an initial list of offtake options shown in Table 2 provided to the MH:EK project by ERM (ERM, 2022) during their South Wales feasibility study of green hydrogen from the Celtic Sea. The current study extends the list to include more hydrogen offtake options from the wider South Wales region. These are described in the following subsections.

Table 2: Potential for Hydrogen offtake in Milford Haven by ERM (ERM, 2022)

Offtake Option	Offtake Use	Hydrogen (t/day)	Wind Capacity (MW)	Estimated Timeline
Pembroke Council	Vehicle Fleet and Hydrogen refueling hub in Milford Haven	1-2	6	2024
Pembroke Dock	Supply of hydrogen to marine vessels (potentially including Pembroke to Rosslare)	4-8	25	2035
Milford Haven Port	Transport and heating requirements	2-3	10	2030
Pembroke Refinery (Valero)	Industrial Heat/grey hydrogen replacement	>200	800	2030
Pembroke Refinery (Valero)	Low Carbon Synthetic Fuels	>1500	>6000	2040
Pembroke Oil Terminal (Valero)	Bulk scale production and storage of LOHC or Ammonia for export	>1000	>4000	2040
Power Station (RWE)	Blend into single gas turbine (Trial)	20	80	2030
Power Station (RWE)	To fuel future hydrogen gas turbines	>1500	>6000	2040
Local Gas Network (Wales & West)	20% blend into local gas network. Potentially 100% into regional distribution system by early 2030's	9 (20%) 45 (100%)	36 180	2025 2032
National Grid	Potential to inject directly into 100% hydrogen 'backbone') by early 2030's	>250	1000	2030

3.2.2.1 Estimating hydrogen use for transport and heating requirements for ports

All ports within 100 km from Milford Haven were identified using (Compass Handbooks Ltd, 2022) and (World Port Source., 2022). Very small ports, small docks and marinas were not included, and can be covered in future work. Two ports, Pembroke dock and Fishguard have ferries to Ireland and the hydrogen demand of the ferries are dealt with later in Section 3.2.2.8

The focus here was on estimating the hydrogen transport and heat demand of Neath, Port Talbot, Swansea, Fishguard and Milford Haven. The hydrogen demand of Milford Haven port was estimated in the ERM study to be 2-3 tonnes of hydrogen per day. Using this value as the benchmark, the transport and heating hydrogen demand for the other ports were evaluated proportionally changing the demand based on the annual tonnage of each port. Table 3 shows the annual tonnage and the potential hydrogen demand of the 5 ports in the region.

Table 3: Annual tonnage of cargo handled by ports in the region and their potential hydrogen demand.

Port	Annual tonnage (million)	Reference	Hydrogen required (t/day)
Neath	0.35	(Compass Handbooks Ltd , 2022)	0.03
Swansea	0.52	(Compass Handbooks Ltd, 2022)	0.04
Port Talbot	6.6	(Compass Handbooks Ltd, 2022)	0.47
Fishguard	0.875	(Compass Handbooks Ltd, 2022)	0.06
Milford Haven	35	(Compass Handbooks Ltd , 2022)	2.5

3.2.2.2 Estimating hydrogen use for oil refining

There is one oil refinery in Milford Haven – the Pembroke Refinery, run by Valero Energy Corporation (Valero, 2022). In the near term, its industrial heat and grey hydrogen requirement could be partially met by green hydrogen, which will require more than 200 tonnes of hydrogen per day (see Table 2). Over the longer term, for producing low carbon synthetic fuels, the hydrogen demand would be greater than 1500 tonnes of hydrogen per day. The refinery is one of the biggest potential hydrogen demands in the region.

3.2.2.3 Estimating hydrogen use for ammonia production

The Valero Pembrokeshire Oil Terminal Ltd. provides petroleum products such as gasoline, diesel, ethanol, and jet fuel, as well as markets asphalt, propane, sulphur, naphthenic oils etc. to customers worldwide (Bloomberg, 2022). In the future there is a possibility that this terminal could be used for the bulk scale production of green ammonia with offshore wind from the Celtic Sea. Table 2 estimates this to be greater than 1000 tonnes per day.

In this study, we extended this to also consider additional ammonia production for the UK and global export and bunkering (refuelling) of ship vessels. This was based on the assumption that the oil terminal can provide all ammonia required and if not possible the region would require a newer facility. Assumptions for ammonia export were based on shipments to within a short distance (Grain LNG UK), medium distance (St. Nazaire, France) and long distance (Singapore LNG). This also considers aspects such as the number and size (tonnage) of ammonia carrier vessels and frequency of visits to the port.

From our analysis, we estimate the potential hydrogen offtake to be 4941 tonnes per day and assume the Valero Oil terminal would be able to handle this capacity in the future.

In addition to shipping ammonia and using it for bunkering, there is also a fertiliser plant, Origin fertiliser, at Newport. Details of the ammonia usage of the plant were not available and hence not included here. That said, this fertiliser plant is potentially another hydrogen offtake option in the region.

3.2.2.4 Estimating hydrogen use for steel industry

There are three iron and steel plants in the region: Tata Steel (Port Talbot), Celsa Manufacturing (Cardiff) and one processing plant at Liberty Steel (Newport). It is assumed here that the entire manufacturing process in these plants is converted to fossil-free operation as reported in (SSAB, LKAB, Vattenfall, 2017). Hydrogen electrolysis requires 0.05 GWh of electricity to produce 1 tonne of hydrogen (Hydrogen and Fuel Cell Technologies Office, Department of Energy, 2022). Energy required for the hydrogen plant in the HYBRIT system to produce 1 tonne steel is 0.00263 GWh (SSAB, LKAB, Vattenfall, 2017). From these figures, the assumption is that the hydrogen required to produce 1 tonne of steel is calculated to be 0.05266 tonnes.

Table 4 shows an estimate of the hydrogen demand in these steel plants over a day based on this simplified calculation. Although plans for the future of steel making in the UK are still being developed, it is possible to gain some insights as a start using high level numbers of production rates and hydrogen requirements. For more detailed information of our views regarding future of steel making in Wales, we have a separate supplementary deep dive report which provide more detail on our thoughts on possible routes for decarbonisation (ORE Catapult, 2022).

Table 4: Hydrogen demand in iron and steel plants.

Steel plant	Output steel (million t/year)	Hydrogen required (t/day)
Tata steel port Talbot	5 (Tata Steel, 2022)	721
CELSA manufacturing, Cardiff	1.3 (Celsa UK, 2008)	188
Liberty steel, Newport	1 (Liberty, UK, 2022)	144

3.2.2.5 Estimating hydrogen use for heat and power for industry

The 2.18 GW Pembroke gas-fired power station, owned by RWE, is the biggest power plant in the region. According to Table 2, hydrogen blending in the power station, which can occur in the near term, will require 20 tonnes of hydrogen per day. Converting the whole power station to run purely on hydrogen will require 1500 tonnes of hydrogen per day but is considered likely only after 2040. There are two other smaller gas-fired power plants in the region – the 520 MW Baglan Bay CCGT and the Severn Power 850 MW power plants. The hydrogen requirements of these power plants are assumed to be proportional to the power plant power rating based on the known hydrogen demand of the Pembroke power station. The near-term hydrogen demand for hydrogen blended operation of these power stations are 4.8 and 7.8 tonnes of hydrogen per day respectively. The hydrogen demand for the longer-term complete conversion to hydrogen operation for these power stations is listed in Table 5.

Table 5: Hydrogen offtake in power stations in the medium term (2040)

Offtake Option	Offtake Use	Capacity (MW)	Hydrogen required (t/day)
RWE Power Station	To fuel future hydrogen gas turbines	2180	1500
Baglan CCGT		520	357.8
Severn Power Station		850	584.9

3.2.2.6 Estimating hydrogen use for heat and power for buildings

There is potential for the hydrogen produced from offshore wind farms in the Celtic Sea to be blended into the West and Wales local gas network. 20% blending of hydrogen into the local gas network will require approximately 9 tonnes of hydrogen per day according to the ERM study while operating the local heat networks purely on hydrogen will require 45 tonnes of hydrogen per day. Extending this to a national grid-based hydrogen network, this estimates that injecting 100% hydrogen into the network will require 250 tonnes of hydrogen per day.

3.2.2.7 Estimating hydrogen use in vehicle fleets

As part of the activities within the MH:EK project, project partner Riversimple were tasked to assess the total vehicle hydrogen demand for all vehicle types in Milford Haven including light duty vehicles, heavy duty trucks, bus fleets, off highway vehicles. This more accurate piece of work showed the total hydrogen offtake to be approximately 1.65 tonnes per day, slightly higher than the ERM estimate of 1.5 tonnes per day as shown in Table 2. The hydrogen demand of the other local councils in South Wales were calculated based on this value for Pembrokeshire and their respective populations and is shown in Table 6.

Table 6: Hydrogen demand in Welsh councils for hydrogen fleets. Population obtained from (Stats Wales, 2022)

Council	Population	Hydrogen required (t/day)
Pembrokeshire	126751	1.65
Ceredigion	72895	0.95
Carmarthenshire	190073	2.47
Swansea	246563	3.21
Neath Port Talbot	144386	1.88
Bridgend	147539	1.92
Vale of Glamorgan	135295	1.76
Cardiff	369202	4.81
Rhondda Cynon Taf	241873	3.15
Merthyr Tydfil	60424	0.79
Caerphilly	181731	2.37
Blaenau Gwent	70020	0.91
Torfaen	94832	1.23
Monmouthshire	95164	1.24
Newport	156447	2.04
Total	**2333195**	**28.34**

3.2.2.8 Estimating hydrogen use for marine vessels

There are two ferry routes to Ireland that start from the region neighbouring Milford Haven. They are the Pembroke dock to Rosslare and the Fishguard to Rosslare routes. The former takes 4 hours one way and 2 return trips to Rosslare are completed every day (Irish Ferries, 2022), while the latter takes 3.5 hours and 2 return trips to Rosslare are completed every day (StenaLine, 2022).

The ferry that is used on the Pembroke dock to Rosslare route is the Blue Star 1 (NI Ferry, 2022), which has a power rating of 44 MW. Assuming a steady operation at 80% capacity for 16 hours operation per day, the total energy usage by the ferry is approximately 569 MWh. For an energy content in hydrogen of 33.33 kWh/kg by lower heating value, the total hydrogen demand of the ferry per day is 17.08 tonnes.

The ferry that is used on the Fishguard to Rosslare route is the MS Stena Europe (STENA EUROPE, 2022), which has a power rating of 15 MW. Assuming a steady operation at 80% capacity for 14 hours operation per day, the total energy usage by the ferry is approximately 172 MWh. For an energy content in hydrogen of 33.33 kWh/kg, the total hydrogen demand of the ferry per day is 5.16 tonnes. These figures are summarised in Table 7.

Table 2 shows the ERM estimates for ferry operation between Pembroke dock and Rosslare to be 4 to 8 tonne per day. For further analysis in this current work, the updated estimations from Table 7 have been used.

Table 7: Hydrogen offtake for marine vessels

Dock	Route	Total time travelled per day (hrs)	Power Rating (MW)	Energy use per day (MWh)	Hydrogen Required (t/day)
Pembroke	Pembroke - Rosslare	16	44	569	17.08
Fishguard	Fishguard - Rosslare	14	15	172	5.16

3.3 Potential green hydrogen production in the Celtic Sea

Once we had a better understanding of what the hydrogen offtake for Milford Haven and its neighbouring regions could look like, the next step was to understand the potential of hydrogen production from floating offshore wind (FLOW) in the Celtic Sea. To capture this, the following subsections set out to understand the following:

1. The potential generation (GW) that can be exploited from floating offshore wind in the Celtic seabed
2. The limitations of network capacity of the South Wales electricity grid in taking any additional offshore wind generation

3.3.1 Floating offshore wind potential in the Celtic Sea

Milford Haven will witness a significant penetration of offshore renewable generation in the Celtic Sea. It has been estimated that the Celtic Sea has a low-constraint area of over 25,000 km^2 in total, of which 18,000 km^2, within the South Wales (SW) Marine Plan offshore area, would be suitable for FLOW development (ORE Catapult, 2020). Figure 6 shows the five key zones identified by the ORE Catapult and ITPEnergised as promising regions with least constraints for initial FLOW development in the Celtic Sea. Table 8 lists these areas in order of possible FLOW capacity of each zone which is estimated based on a turbine deployment capacity of 2 MW/km^2 (low-case), 3 MW/km^2 (mid-case), and 4.8 MW/km^2 (high-case) respectively. This highlights the potential of between 43 - 86 GW worth of FLOW from the Celtic Sea.

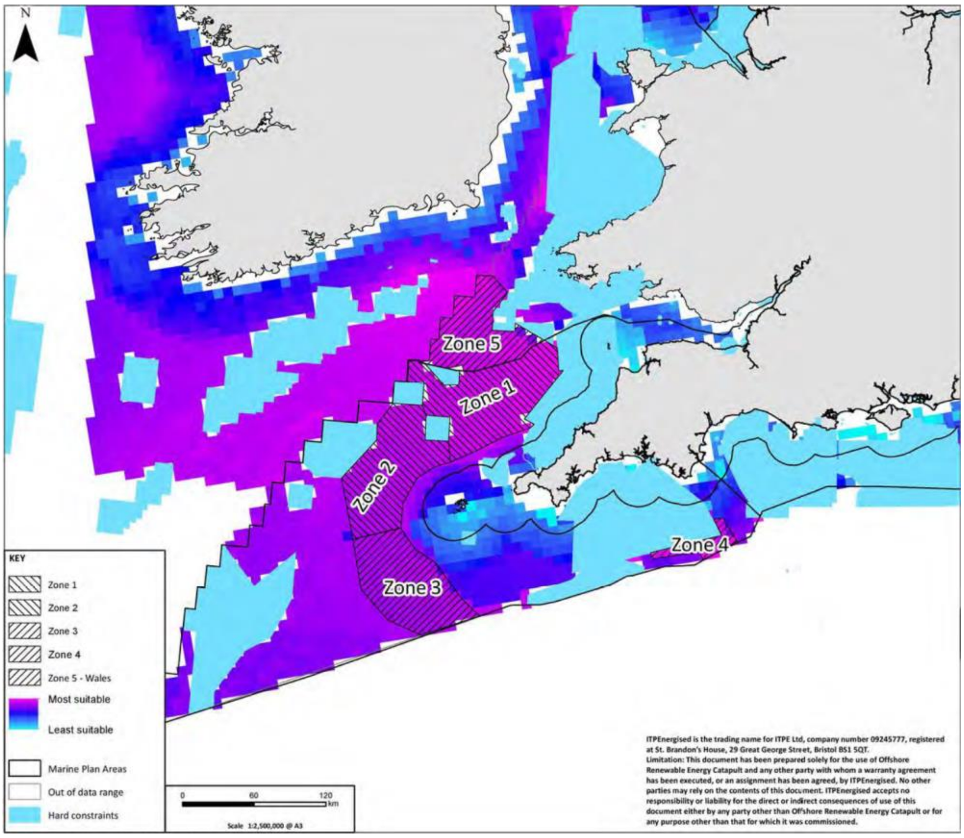


Figure 6: Five key zones for initial FLOW development in the Celtic Sea

Table 8: Five key zones for possible FLOW Capacity in the Celtic Sea

Zone Index	Area (km2)	Low-case FLOW Capacity (GW)	Mid-case FLOW Capacity (GW)	High-case FLOW Capacity (GW)
1	6,300	12.6	18.9	30.24
2	5,588	11.18	16.76	26.82
3	5,312	10.62	15.94	25.50
4	800	1.60	2.40	3.84
5	3,983	7.97	11.95	19.12
All Zones [1-5]	21,983	43.97	65.94	86.1

3.3.2 Electrical grid constraints – South Wales

The electrical grid in South Wales (SW) is as shown in Figure 7. The transmission infrastructure across the main network boundary SW1 comprises 400 kV double circuits from Pembroke to Walham, Rassau to Walham, Imperial Park to Iron Acton, and Whitson to Seabank, and double 275 kV circuits from Whitson to Iron Acton. Figure 8 shows the schematic of the existing SW grids along with present circuit ratings of those to be upgraded by 2035 (ORE Catapult, 2021). It is estimated that the total transmission ampacity across SW1 boundaries is currently around 8.7 GW.

Around 5.6 GW of generation is currently integrated within the SW grids, which is dominated by around 4 GW of thermal generation including the 2.2 GW Pembroke Power Station. The remaining 1.6 GW generation capacity is mainly from a 228 MW onshore wind farm (Pen Y Cymoedd) and around 1.3 GW of distribution generation primarily consisting of small solar and wind projects.

In addition to the existing 5.6 GW generation capacity, the SW grids will provide access to several new projects (excluding FLOW projects) with a total generation capacity of approximately 2.3 GW that are contracted to connect during the next decade. These include the 299 MW Open Cycle Gas Turbine power peaking plants at both Swansea North and Rhigos, solar and energy storage hybrid projects at both Aberthaw (57 MW) and Whitson (285 MW), 320 MW Swansea Bay Tidal Lagoon project at Baglan Bay, and approximately 1 GW of distributed generation. This brings the estimated total future generation capacity to be around 7.9 GW. Given a minimum electricity demand of around 1.3 GW within the SW region, the net generation capacity that will be exported to the rest of the GB across the SW1 boundaries is around 6.6 GW (ORE Catapult, 2021).

The total transmission capacity across the SW1 boundaries is currently around 8.7 GW, which suggest that the transmission capacity available for the new FLOW projects connecting to SW grids is around 2.1 GW only. This highlights that the present electrical transmission infrastructure across SW1 boundaries will find it difficult to handle the large-scale integration of FLOW in the Celtic Sea unless significant investments are made to upgrade the transmission system. This shows the need to consider alternative use of wind power from FLOW projects in producing green hydrogen in the region. Green hydrogen production from the Celtic Sea has the potential to reduce the consumption of natural gas in the heavy industries in the area and could be a cost-effective way to assist South Wales in the transition towards a low-carbon energy system.

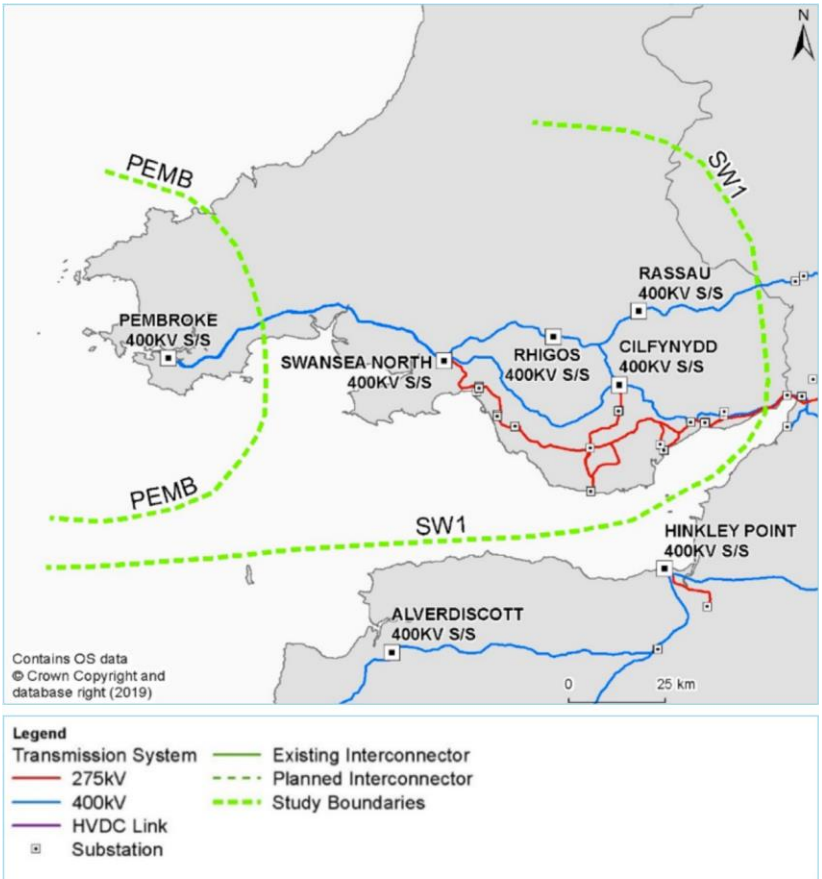


Figure 7: South Wales Grid Overview (ORE Catapult, 2021)

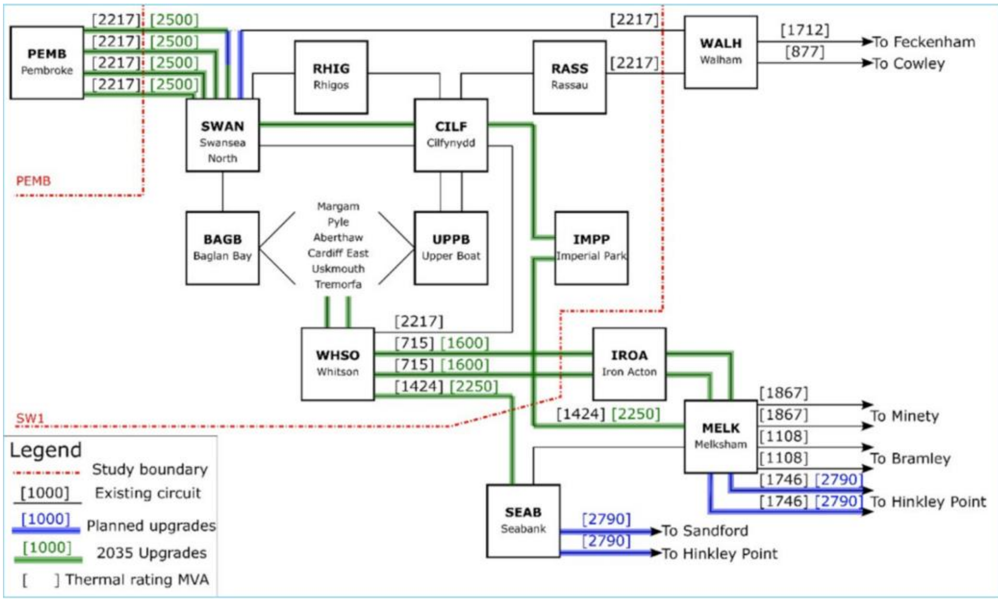


Figure 8: Schematic of the South Wales electrical grid with thermal rating (MVA) of circuits (ORE Catapult, 2021)

3.3.3 Grid capacity for current & future FLOW projects

The current list of planned and announced floating offshore wind projects in the region are summarised in Table 9. This highlights that a total capacity of around 2.2 GW has been planned in the Celtic Sea. The lease areas of some of these projects are shown in Figure 9.

Table 9: Technical information and grid access positions of planned FLOW projects in the Celtic Sea.

Project Name	Company	Total Capacity (MW)	WT Capacity (MW)	Distance to Shore (km)	Hub Height (above sea) (m)	Grid Access Point**
Erebus (Erebus, 2022)	Blue Gem Wind	96	9 – 12	45	~ 132	Pembroke, SW
Valorous (Valorous, 2022)	Blue Gem Wind	300	9 – 12	50	~ 132	Pembroke, SW
PDZ (PDZ, 2022)	Wave Hub Ltd	180	N.A.	15 – 21	N.A*	Pembroke, SW
Llŷr 1 (Llŷr, 2022)	Floventis Energy	100	12 – 20	45	Up to 156	SW
Llŷr 2 (Llŷr, 2022)	Floventis Energy	100	12 – 20	45	Up to 156	SW
Llywelyn (Llywelyn, 2022)	Falck Renewables & BlueFloat Energy	300	15	64.4	N.A*	SW
Petroc (Petroc, 2022)	Falck Renewables & BlueFloat Energy	300	15	59.5	N.A*	SW
Gwynt Glas (DPEnergy, 2022)	EDF Renewables UK & DP Energy	300 up to 1,000	N.A*	70	N.A*	SW*
Celtic Deep 1 (4Coffshore, 2022)	AWC Technology Ltd.	98	N.A*	N.A.	N.A*	SW*

Celtic Deep 2 (4Coffshore, 2022)	AWC Technology Ltd.	300	N.A*	N.A.	N.A*	SW*
White Cross [12] (Whitecross, 2022)	Flotation Energy & Cobra	Up to 100	12 – 24	52	Up to 195	East Yelland, England
Celtic Sea – Early Commercial Floating Release (4Coffshore, 2022)	Contender 1: Morwind Ltd. Contender 2 & 3: Celtic Sea Offshore Wind Farm Ltd	300	N.A*	N.A*	N.A*	Alverdiscott, England
Celtic Sea – Full Commercial Floating Release (4Coffshore, 2022)	Contender 1, 2 & 3: Simply Blue Energy Ltd.	350	N.A*	N.A*	N.A*	Alverdiscott, England

*N.A. - Information not available at the time of this study. **The grid access positions are estimated through comparing locations of FLOW projects with those that have confirmed connections to SW.

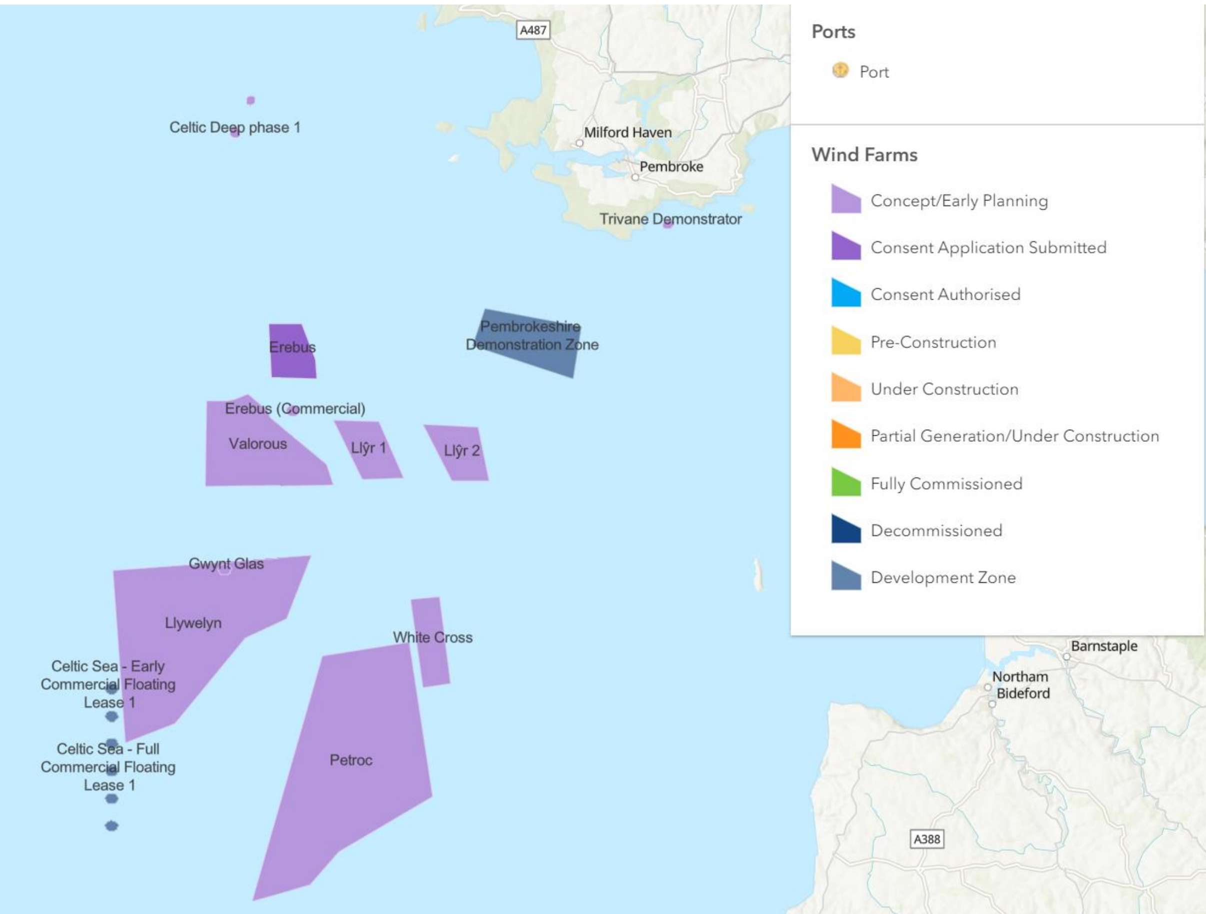


Figure 9: Map of planned FLOW projects in the Celtic Sea (4coffshore, 2022)

The generation of the 2.2 GW FLOW in Table 8 could be delivered via submarine cables to Pembroke substation and then transferred through 400 kV circuits to the rest of the GB, as shown in Figure 7. At Pembroke, both the Erebus (96 MW) and Valorous (300 MW) FLOW projects have grid connection agreements and the proposed 500 MW Greenlink interconnector will connect Ireland's and Great Britain's electricity networks.

The estimated future available connection capacity of 2.1 GW in the South Wales electrical grid leaves little or no room for further expansion of FLOW projects in the Celtic Sea. With the Crown Estate looking to unlock 4 GW of floating offshore wind capacity in the region by 2035, this still sits far off the future expectations of the transmission capacity of the electrical grid.

3.4 Green hydrogen layout and design

The previous sections discuss how much hydrogen can be produced from FLOW in the Celtic Sea and how much possible offtake within Milford Haven and neighbouring regions potentially exists. This picture is incomplete without considering the layout and design of the electrical and gas infrastructure required the make this possible.

In general, green hydrogen production from wind farms could follow any of the following three approaches:

1. an offshore centralised configuration where the hydrogen is produced offshore on a central platform,
2. an offshore distributed configuration where hydrogen electrolysers are placed on all wind turbines or,
3. an onshore configuration where the hydrogen production takes place onshore.

The onshore configuration was discussed as part of the short-term energy scenarios in the MH:EK project and was reported in (Arup, MH:EK strategic outline case for a smart local energy system - Prospering from the Energy Revolution , 2022) and is not discussed further in this report.

The current study focuses on green hydrogen production offshore and more details on the layout and design of these two offshore configurations are described in the following subsections. Both configurations are used and compared in the techno-economic study discussed later in Section 3.5.

3.4.1 Offshore centralised configuration

The layout of an offshore centralised FLOW hydrogen network is shown in Figure 10. The network shown comprises of 15 MW (V236-15.0 MW) Vestas FLOW turbines. The power outputs of the FLOW turbines within a wind turbine (WT) group are collected by 66 kV inter-array AC cables and transferred to an offshore central platform (OCP) where the hydrogen production occurs.

Considering that the expected energy output of an OCP is generally no greater than approximately 500 MW (S. Robak, 2018) and the wind resources are intermittent, the OCP is designed here to connect a 600 MW WT group consisting of 40 Vestas WTs (V236-15.0 MW). Since the layout optimisation of WTs and cables is not the focus of this study, the WTs are evenly distributed with a turbine spacing of 7 times the rotor diameter, i.e., around 2 km. The number of WTs along each string will depend on the rating of inter-array cables. Given the use of 630 mm^2, 81.7 MVA AC cables, the 600 MW WT group will comprise of eight strings, with each string consisting of five WTs.

The power output of the 600 MW WT group delivered to the OCP will be converted into DC power via an AC/DC converter and then consumed by the electrolyser. A desalination unit will purify seawater and provide freshwater supply to the electrolyser. Then the hydrogen production at low pressure (e.g., 70 bar at the output of a Proton Exchange Membrane (PEM) electrolyser) is pressurised by a 1-stage compressor to meet the required inlet pressure of the 12’’ export pipeline (i.e., about 90 bar in this study). If the hydrogen production exceeds the offtake demand, the excess hydrogen produced at low pressure can be further pressurised by a 2-stage compressor to reach a high pressure of 350 bar and stored in storage tanks, which will then be released into the 12’’ export pipeline when needed. In addition, an energy storage unit such as a Battery Energy Storage System (BESS) will be placed alongside the hydrogen system as a backup/standby power supply.

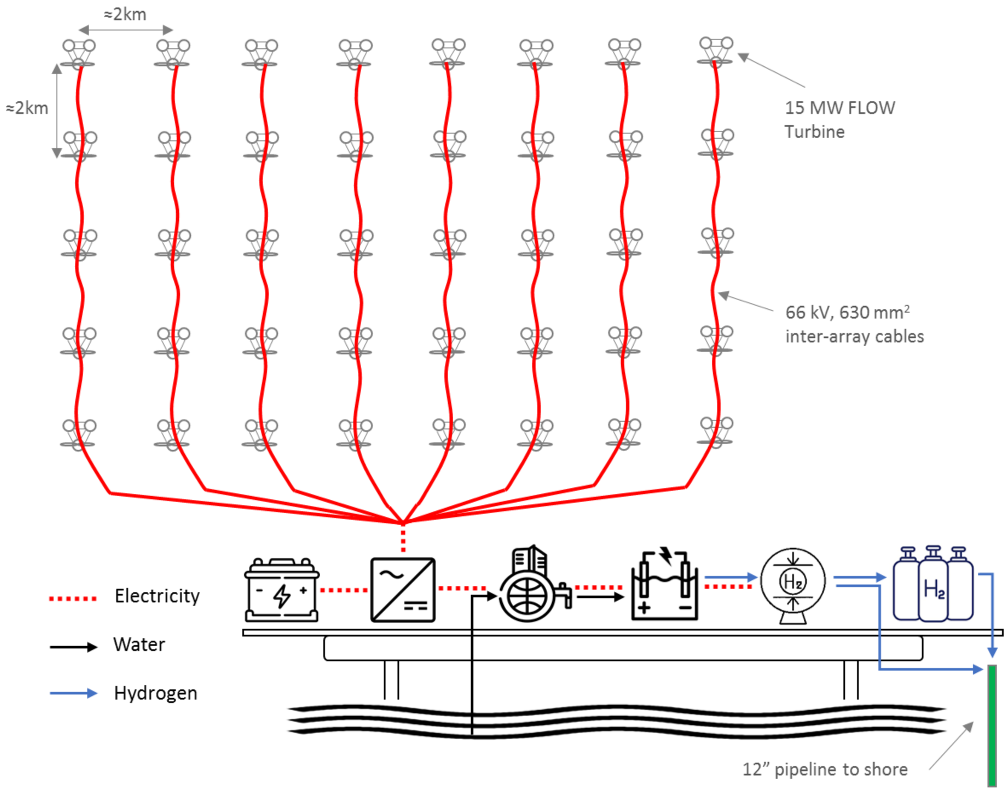


Figure 10: Layout of an offshore centralised FLOW hydrogen production system

3.4.2 Offshore distributed configuration

The layout of an offshore distributed FLOW hydrogen network is shown in Figure 11. Unlike the centralised configuration, this particular layout is not constrained by the OCP and the system consists of 60 WTs with a total capacity of 900 MW. The hydrogen system components including the AC/DC converter, desalination device, electrolyser, compressors and storage tanks together with the energy storage are integrated on each semi-submersible WT platform similar to that proposed for the Dolyphn project (ERM, 2019). The power generated at each wind turbine will be absorbed by the electrolyser located at each platform to produce hydrogen which is then pressurised to be injected into a 4'' dynamic hydrogen riser or stored in storage tanks.

The hydrogen flows through 4'' dynamic risers in a daisy chain configuration. The 10 WT strings will then be converged at a 10-slot manifold and then transmitted to shore through a 12'' pipeline. It is noted that some designs employ a floating compression unit to ensure sufficient inlet pressure at the 12'' pipeline (ERM, 2019). Here we assume the need of the floating compression unit is eliminated by appropriately increasing the inlet pressure of the 4'' dynamic risers to ensure their outlet pressure after the pressure drop still meets the required inlet pressure of the 12'' pipeline.

There are also other possible layouts for the hydrogen risers such as the fishbone arrangement or the star arrangement as shown in Figure 12 and Figure 13 respectively. The choice of riser configurations for hydrogen production would depend on the costs of additional hardware such as static jumpers, 3-slot or 5-slot manifolds and the associated costs of installation and systems integration testing. The cost drivers for the daisy chain and star arrangement are mostly driven by longer riser section lengths and that of the fish bone arrangement by the increased number of manifolds.

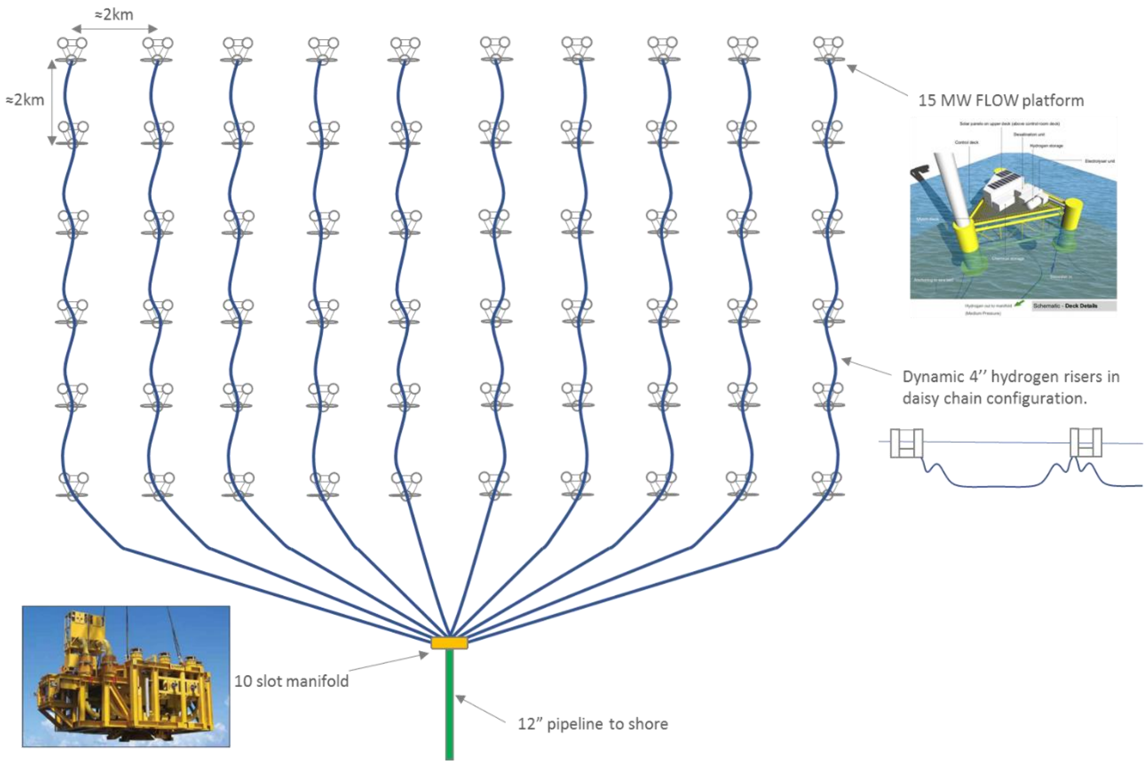


Figure 11: Daisy chain layout for offshore distributed FLOW hydrogen production

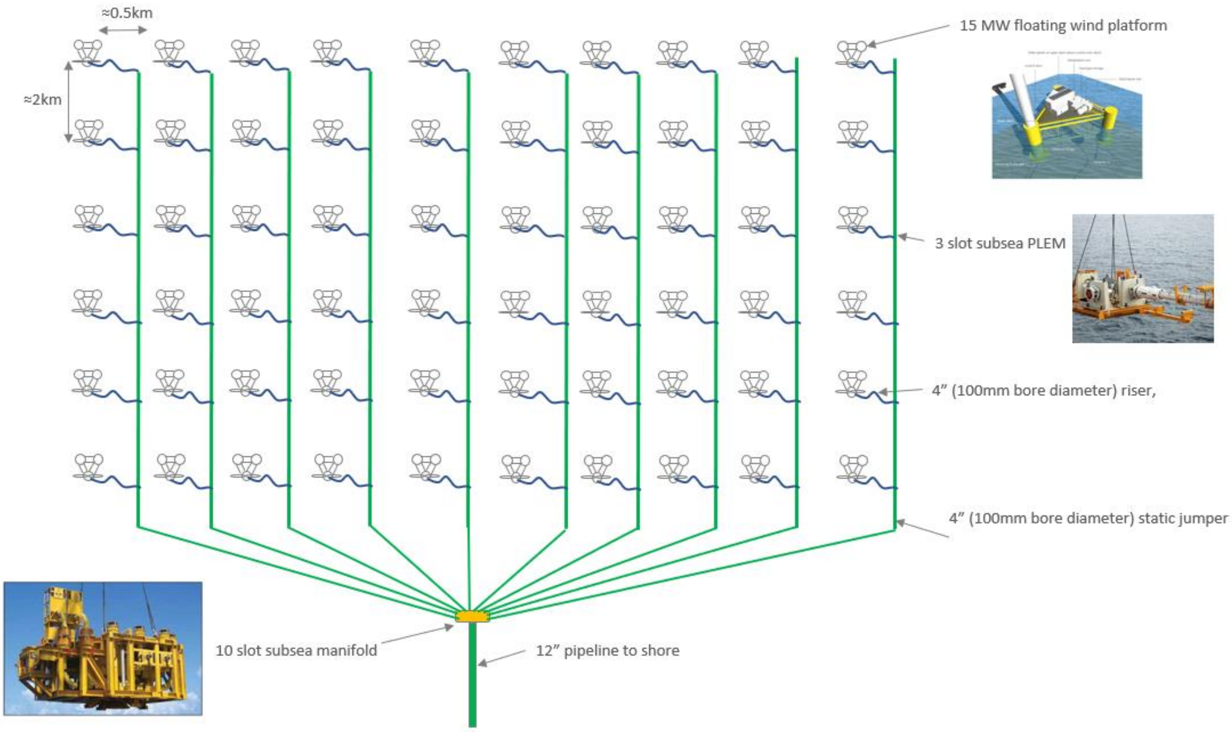


Figure 12: Fishbone layout for offshore distributed FLOW hydrogen production

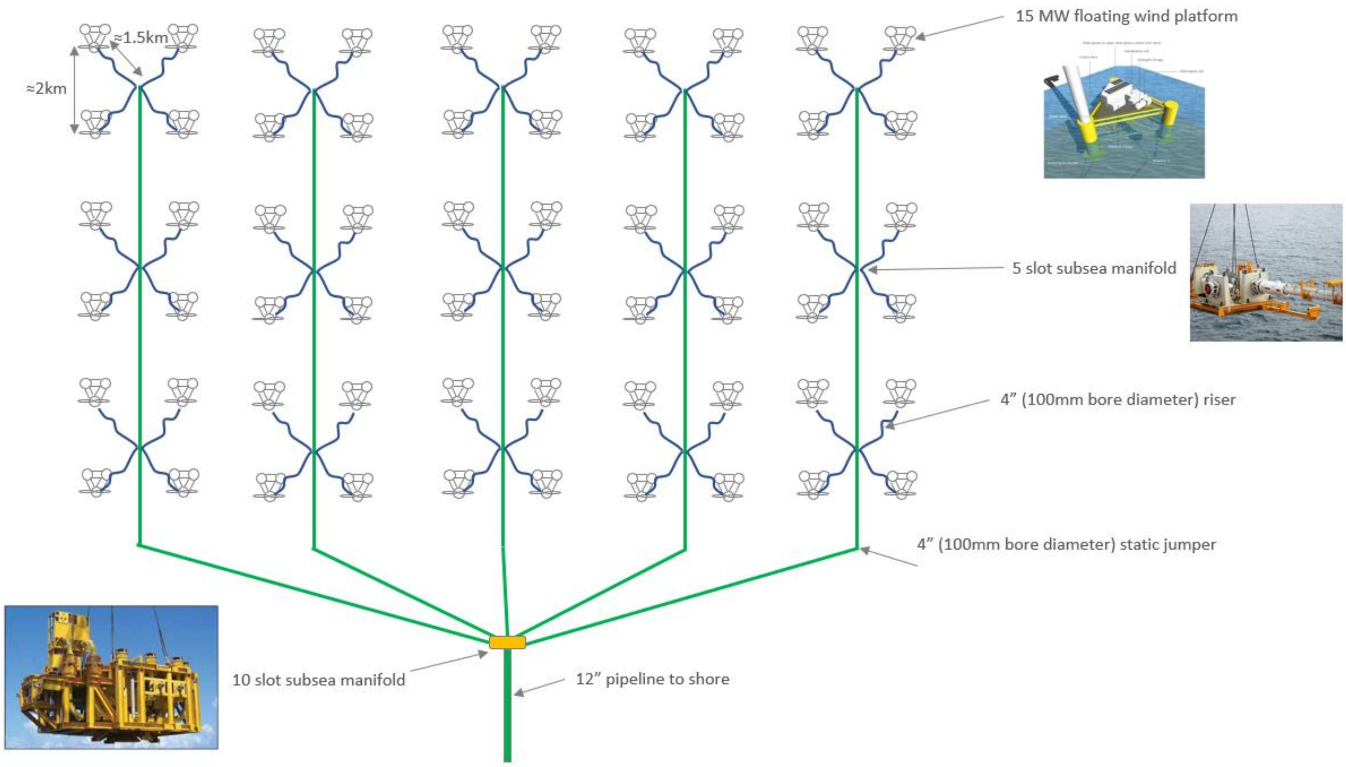


Figure 13: Star layout for offshore distributed FLOW hydrogen production

3.5 Celtic Sea scenarios: Modelling of energy system

The previous sections 3.2 - 3.4 detail the potential hydrogen produced from FLOW from the Celtic Sea, the hydrogen offtake in Milford Haven and neighbouring regions, and the design and layout of the offshore hydrogen production systems required to make this possible.

To develop a more detailed understanding of what the future use of hydrogen could look like in the region, we took all these into consideration in a techno-economic modelling assessment of the region transitioning towards being fully decarbonised by 2050. We adopted an approach using our internal modelling tool HySPOT to model the power produced from FLOW in the Celtic Sea, the hydrogen offtake options and associated costs and the offshore infrastructure costs in as much detail as possible. This was done for both the offshore centralised and distributed configurations discussed earlier.

The subsequent sections describe our approach to energy systems modelling and discuss some results from our assessment.

3.5.1 Data gathering and profiling

3.5.1.1 Celtic sea power time series profile

With the FLOW potential capacity estimated in Table 8 for Zone 1 and Zone 5 which are closer to the South Wales coasts, the total FLOW capacity to be integrated into the SW region is presumed here to range between 30.85 GW in the mid case and 49.36 GW in the high case.

The MERRA-2 (Modern-Era Retrospective Analysis for Research and Applications, Version 2) is a global atmospheric reanalysis based on satellite observations and offers a regularly-gridded, homogeneous record of the global atmosphere with a spatial resolution of 0.5° latitude (55 km) and 0.625° longitude

(69 km) (R. Gelaro, 2017), (MERRA, 2022). Considering that a MERRA Square of around 3.85 x 103 km^2 can contain approximately of 18.5 GW FLOW resources, two suitable MERRA Squares need to be adopted to account for the proposed 40 GW FLOW development in the region as shown in Figure 14.

Figure 14 shows the MERRA grids in the area and the approximate centres of the planned FLOW projects. The first MERRA Square (denoted by MERRA-S1) is selected as the one that intersects with the fitted trend line and is relatively closer to the SW coastlines. The adjacent MERRA Square to the left of MERRA-S1 is then adopted as the second MERRA Square (denoted by MERRA-S2). The two selected MERRA Squares highlighted in Figure 14 are expected to be located within Zone 1 and Zone 5 in Figure 6.

The straight-line distances to the Pembroke substation from the centres of MERRA-S1 and MERRA-S2 are estimated to be 122.5 km and 150.6 km respectively, which will be used to approximate the lengths of HVDC cables and hydrogen pipelines. The wind speed data for the two MERRA squares have also been extracted from the MERRA database and to synthesise the wind power time series for both squares, a common approach through the combination of wind speeds and a generic power curve that describes the relationship between wind speeds and power outputs of a wind turbine or a wind farm.

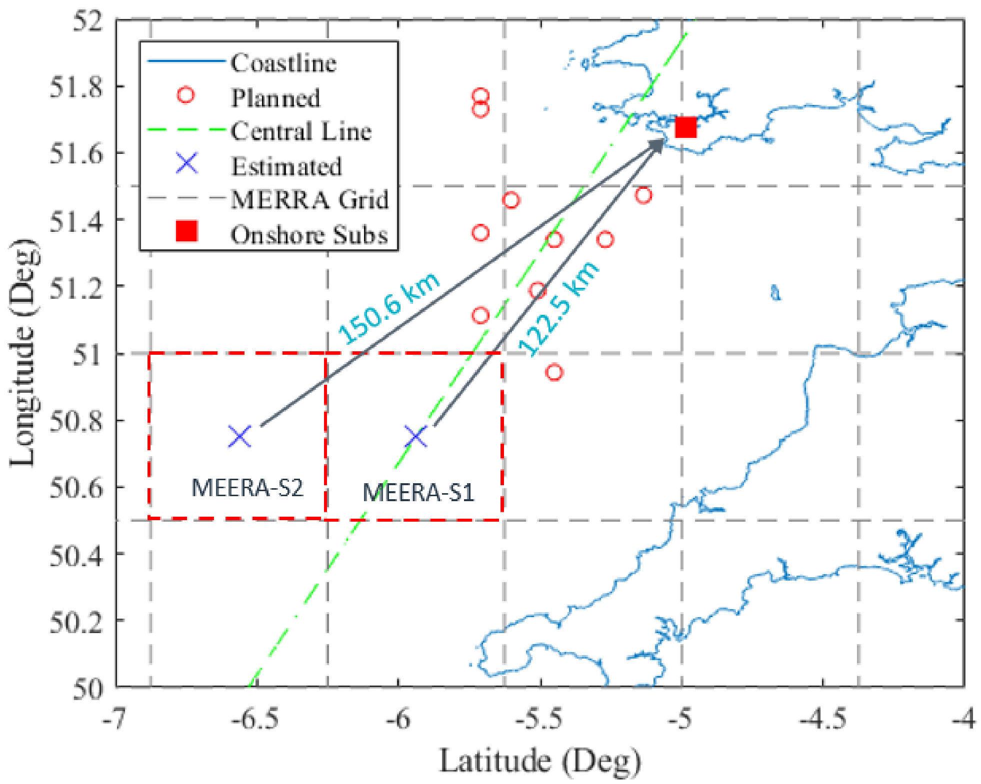


Figure 14: Map showing planned FLOW projects and two MERRA squares selected for future FLOW Model in the Celtic Sea

3.5.1.2 Hydrogen offtake profiles

The hydrogen produced from FLOW generation will not only be used locally within Milford Haven but can also be delivered to neighbouring regions. Table 2 in section 3.2.2 show hydrogen offtake options within Milford Haven and its neighbouring regions along with their estimated daily hydrogen usage. The following considerations were taken to create the hydrogen offtake profiles for both regions.

Hydrogen Refuelling: In order to reflect the time-varying nature of hydrogen offtake, the hydrogen demands of vehicle hydrogen refuelling within the region were synthesised based on their estimated daily usage. We have considered estimations from Riversimple as part of this MH:EK study which estimates an annual tonnage of approximately 1.65 t/day for the region. This data was combined with the busy hours of a typical petrol station within the Milford Haven region (BestTime, 2022) to give the hourly consumption of hydrogen in Pembrokeshire and its neighbouring regions.

Marine Vessels: To reflect the time varying nature of hydrogen offtake, the docking time slots for marine vessels were considered. According to the timetable of the marine vessel travelling between Rosslare and Pembroke Dock (Ferries, 2022) or Fishguard Dock (StenaLine, 2022), the vessels will dock at Pembroke Dock over 00:46 – 02:45 and 12:46 – 14:45 and at Fishguard Dock over 11:00 – 13:00 and 21:45 – 23:45. Assuming that the hydrogen demands required for a return journey are all supplied at Pembroke Dock or Fishguard Dock, the two 2-hour docking periods are assumed here to have a constant hydrogen supply rate which corresponds to the daily usage estimate in Table 7.

Power Stations: The hydrogen consumption profiles for the Pembroke Power Station, the Baglan Bay Power Station and the Severn Power Station were created based on historical data from the Elexon Balancing Mechanism Reporting Service (BMRS) (Elexon, 2022) of final physical notifications (FPN's). These were converted into hydrogen demand profiles under the assumption that these power stations are the fully decarbonised in the future.

Other options: Due to insufficient data and information for creating appropriate offtake profiles for the other hydrogen users in the region discussed in Section 3.2.2 their estimated daily hydrogen consumptions were assumed to be evenly distributed across 24 hours, i.e., constant hydrogen usage rates were assumed.

3.5.1.3 Hydrogen offtake costs

The price of each offtake option is determined by the corresponding break-even point where the specific hydrogen application becomes cost competitive relative to a zero-carbon alternative, as shown in Figure 15 (Offshore Renewable Energy Catapult, 2020).

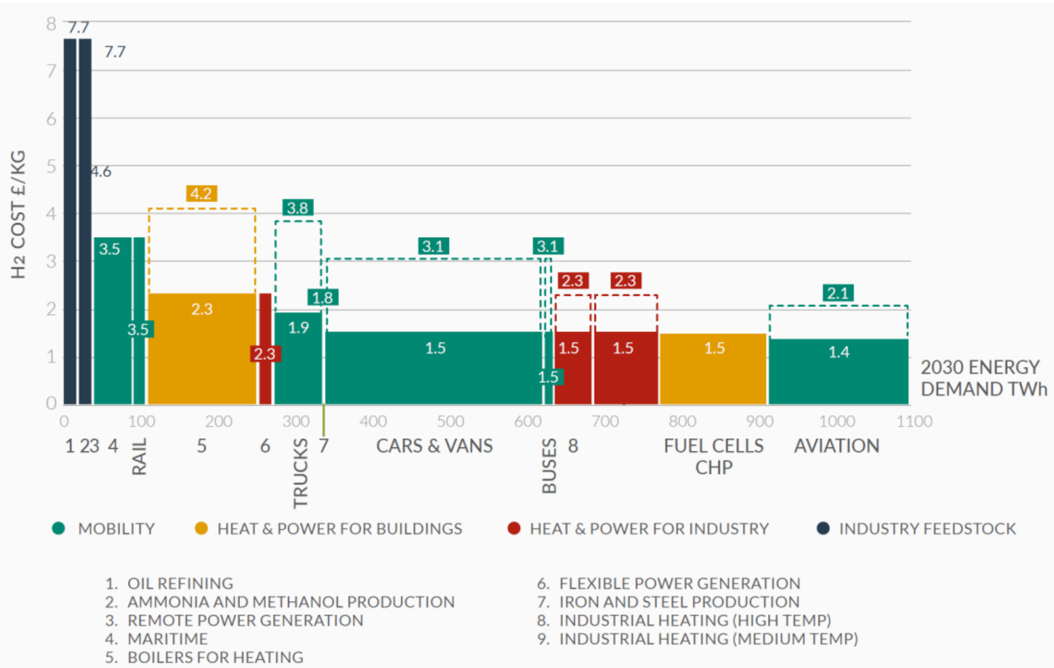


Figure 15: Break-even price points (GBP/kg) of different hydrogen applications (ORE Catapult, 2020)

Due to the intermittent nature of FLOW, the hydrogen production from FLOW may not always meet the required hydrogen demands. Therefore, it is necessary to prioritise these hydrogen offtake options based on their locations and prices. In this study, the hydrogen production from FLOW is assumed to supply to the offtake options within Pembrokeshire first in a price order from high prices to low prices, and then to the offtake options in neighbouring regions also in a price order. The priority of the offtake options is summarised in Appendix A2, with a smaller number representing a higher priority and vice versa.

3.5.2 Cost projections - longer term energy scenario

Table 10 summarises the key cost specification for the today (based on 2020), 2030 and 2050 scenarios. The values are determined through extensive literature review of possible future trends (IEA, 2019), (Caldera, 2017), (Stehly, 2020), (Fraile, 2021). The literature review suggests a potential improvement of up to 74% in PEM electrolyser efficiency by lower heating value (LHV), a reduction of CAPEX down to £429 /kW and an improvement of stack lifetime of the electrolyser of up to 120,000 hours by 2050. It also considers the potential reduction of FLOW capex by 51.6% and OPEX by 15.6 %.

Taking into consideration these projections, longer term energy scenarios are modelled using our internal HySPOT modelling tool, and results explained in the next Section 3.5.3.

Table 10: Cost Projection for Future Scenarios FLOW Hydrogen production

Unit	Item	2020 Scenario	2030 Scenario	2050 Scenario
PEM Electrolyser	Efficiency	18 kg/MWh (60% LHV)	20.4 kg/MWh (68% LHV)	22.2 kg/MWh (74% LHV)
	Operating pressure	30 bar	50 bar	70 bar
	Stack lifetime	60,000 hours (replace twice in 20 years)	90,000 hours (replace once in 20 years)	120,000 hours (replace once in 20 years)
	Replacement Cost	50% of CAPEX	45% of CAPEX	40% of CAPEX
	CAPEX	£1131 /kW	£838.5 /kW	£429 /kW
Desalination Device	CAPEX	£38.4 per L/h	£32.1 per L/h	£20.5 per L/h
FLOW Turbine	CAPEX	£3392 /kW	£2204.05 /kW (fall by 35%)	£1764.62 /kW (fall by 48%)

3.5.3 Modelling results

The following subsections summarise the results for the 2020, 2030 and 2050 Celtic Sea scenarios investigated. The 2020 Scenario represents the current state today and is based on limited information from literature available up to 2020. The two other scenarios consider the status in 2030 and 2050, which represent the future state again using available literature.

The results are based on optimisation using two economic metrics, the net present value (NPV) and the levelized cost of hydrogen (LCOH). Planning and optimisation analysis was undertaken using the HySPOT modelling tool and results of the cost benefit analysis, the optimal hydrogen system capacity and hydrogen supply split between offtakes in Milford Haven and neighbouring regions are presented here.

3.5.3.1 Cost benefit analysis

Figure 16 - Figure 18 summarise the results from the cost benefit analysis using HySPOT for both offshore centralised and distributed configuration. This analysis considers the CAPEX and OPEX of all infrastructure required and presents results of the optimal revenue from hydrogen production. Results are presented for two optimisation cases, one aiming to maximise the net present value (NPV) from a developer’s perspective and the other aiming to achieve minimal levelised cost of hydrogen (LCOH). Detailed results for all parameters can be found in Appendix A3.1.

From our assessment, in a centralised configuration the main cost drivers come from floating wind turbines and electrolysers, followed by the offshore central platform as illustrated in Figure 17. In the distributed configuration, the floating wind turbines and electrolysers still make the main contribution, but in this configuration, the costs of OCPs and AC/DC converters are avoided, and it is the use of dynamic risers that accounts for a considerable percentage of the overall project cost as highlighted in Figure 18.

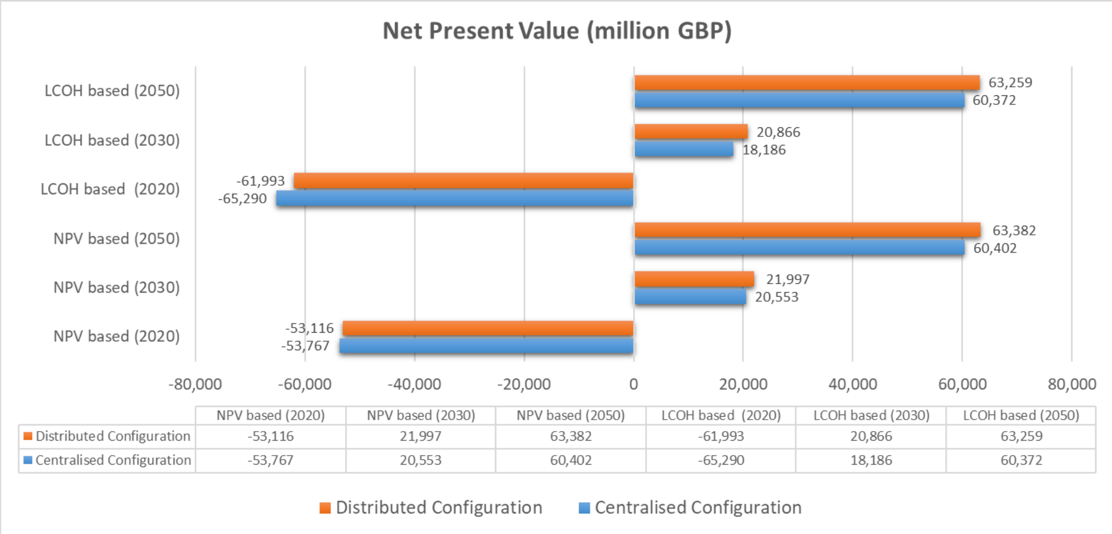
In both configurations, due to the current considerable costs of FLOW wind turbines and electrolysers, the overall project costs exceed the revenue generated by the hydrogen supplied to the offtake options, leading to negative NPVs as shown in the 2020 scenarios for both NPV and LCOH optimisation cases.

With the decline of electrolyser cost and the improvement of electrolyser efficiency, the CAPEX and OPEX of electrolysers are reduced in the 2030 and 2050 scenarios. Additionally, there is improvement in the electrolyser stacks lifetime from 60,000 hours in today’s scenario to 90,000 – 120,000 hours in 2030 and 2050 respectively. In our model, this suggests that the electrolyser would be replaced twice or once respectively in the 20-year project timescale. Therefore, the OPEX of the hydrogen systems dominated by the electrolyser’s OPEX and replacement costs would decrease in 2030 and 2050.

With the FLOW turbine costs dropping to 65% and 52% in 2030 and 2050 respectively (see Appendix A3.1), the CAPEX of WTs and the OPEX of wind farms dominated by the WT OPEX will significantly decline. The cost reductions of FLOW wind turbines and electrolysers, together with the growth of hydrogen supply revenue due to the greater hydrogen production and storage capability, result in profitable NPV for projects in the 2030 and 2050 scenarios.

For the centralised configuration, our results estimate the potential NPV from all wind farms in both MEERA-S1 and MEERA-S2 squares to be about £20.6 billion and £60.4 billion by 2030 and 2050 respectively throughout the projects’ lifetime. This is revenue slightly lower for situations where the optimisation objective is to minimise LCOH as shown in Figure 16.

Compared to the centralised configuration, in the distributed configuration the NPV from all wind farms are higher. In the 2030 and 2050 scenarios, this is estimated to be about £22 billion and 63.4 billion respectively with an IRR of around 18%, which is greater than that of offshore centralised projects. The corresponding LCOH would be around £3.8 /kg, which is lower than that of centralised projects. Therefore, the distributed offshore configuration is expected to be better with respect to both NPV and LCOH than the centralised offshore configuration. Further details of the analysis can be found in Appendix A4.4.



	NPV based (2020)	NPV based (2030)	NPV based (2050)	LCOH based (2020)	LCOH based (2030)	LCOH based (2050)
Distributed Configuration	-53,116	21,997	63,382	-61,993	20,866	63,259
Centralised Configuration	-53,767	20,553	60,402	-65,290	18,186	60,372

Figure 16: The equivalent NPV (million GBP) for offshore centralised configuration

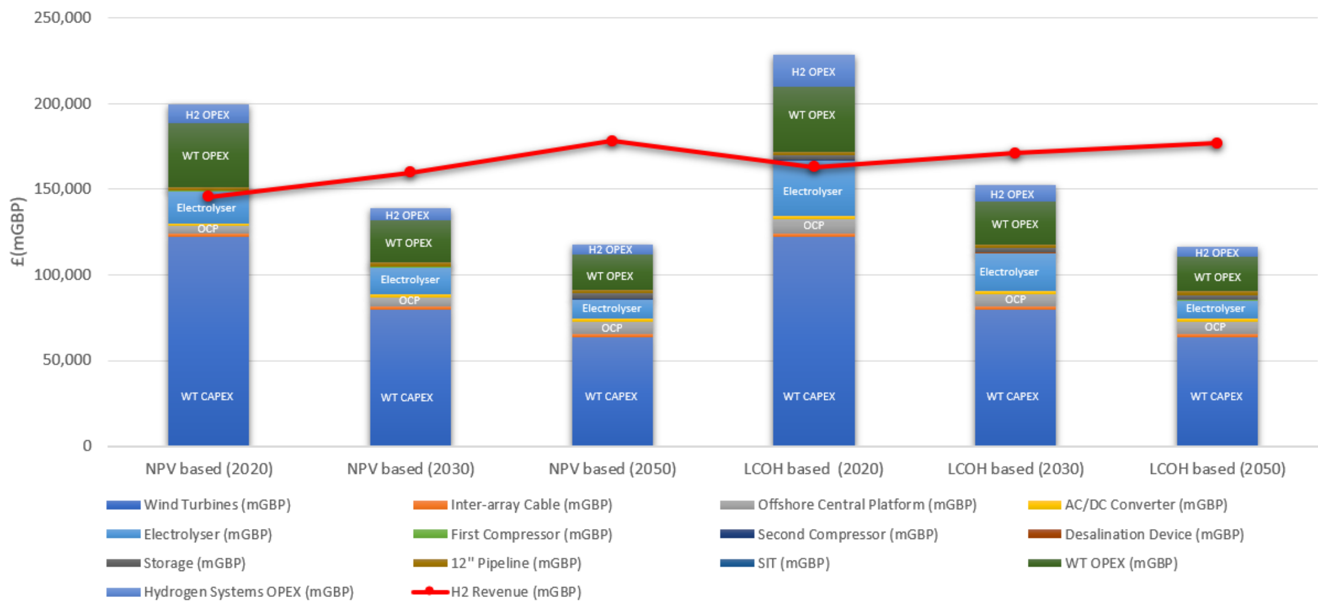


Figure 17: Breakdown of Costs (million GBP) for centralised configuration

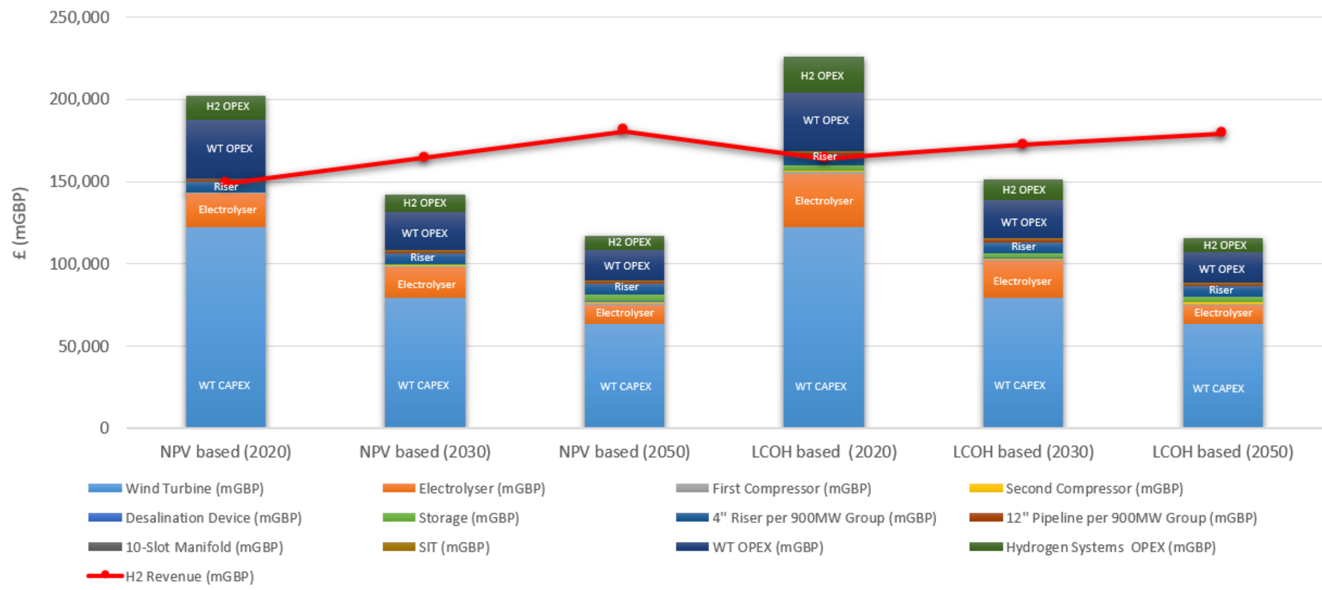


Figure 18: Breakdown of Costs (million GBP) for distributed configuration

3.5.3.2 Optimal hydrogen system capacity

Figure 19 summarises the results from the optimal hydrogen system capacity analysis performed using HySPOT for both the centralised and distributed configurations. The optimised variables are the electrolyser size (in MW) and the hydrogen storage capacity. These variables in turn define the co-dependent variables such as the offshore central platform size and the AC/DC converter capacity. Detailed results for all optimised parameters can be found in Appendix A4.2.

With a reduction in electrolyser costs and an increased electrolyser efficiency in the future, as shown previously in Figure 17, the hydrogen systems are optimised to have a higher hydrogen production rate together with a greater storage capability as shown in Figure 19. This is done in order to increase the hydrogen supply to offtake options and its associated revenue.

NPV Maximisation: When the optimisation objective is set to NPV maximisation, the hydrogen offtake prices priority list (see Appendix A2) is considered. Given that the hydrogen offtake options of lower priority generally have lower prices, it may be not economical to deploy larger hydrogen systems to receive payments from the low priority offtake options. This is reflected especially in the 2020 scenario where the electrolyser costs are still considerable. In addition, the use of a smaller electrolyser reduces the probability of the hydrogen production exceeding the offtake demands and thus mitigates the need of any hydrogen storage (which is zero in the 2020 scenario).

LCOH Minimisation: When the optimisation objective is set for LCOH minimisation, the hydrogen systems co-located with 600 MW WT groups are suggested to have hydrogen production rates between 8.5 tonne/hr and 9.1 tonne/hr and storage capacity between 96.3 tonnes and 102.6 tonnes. Although a higher hydrogen production rate is suggested in the 2030 and 2050 scenarios, the electrolyser size, which also affects the sizes of converter and OCP, is reduced due to the increased electrolyser efficiency.

In the 2050 scenario, the two optimisation objectives (NPV and LCOH) lead to very similar results. The optimal electrolyser sizes are around 67.5% - 68.8% and 68.2% - 69.5% of the FLOW capacity in both MERRA-S1 and MERRA-S2 squares respectively.

For the distributed configuration, the overall hydrogen production rates of are generally higher than those of centralised configuration. For example, in the 2050 scenarios, the optimal electrolyser sizes for offshore centralised hydrogen systems are around 67.5% - 69.5% of FLOW capacity, while the optimal sizes of distributed electrolysers are around 72.3% - 75.1% of FLOW capacity (i.e., 72.3% - 74.7% in MERRA-S1 and 72.7% - 75.1% in MERRA-S2). Further results on these assessments can be seen in Appendix A4.5.

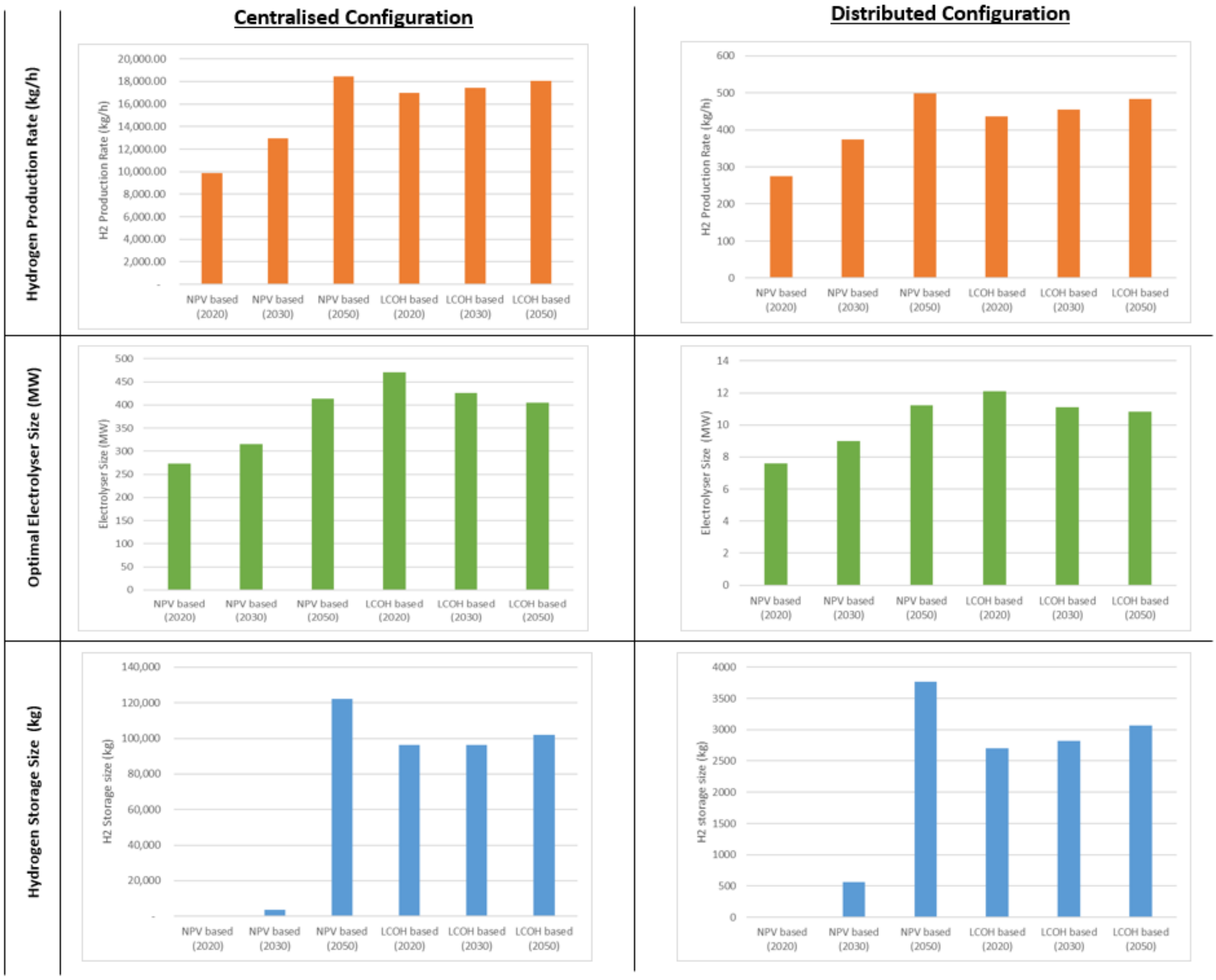


Figure 19: Optimal hydrogen production rate, electrolyser size and hydrogen storage size

3.5.3.3 Hydrogen supply split between offtake options

Figure 20 and Figure 21 summarise the results showing the hydrogen supply split to the different offtake options for offshore centralised and distributed configurations in Milford Haven and neighbouring regions. Results are presented for both the optimisation cases - maximise NPV and minimise LCOH. Further details of the results can be found in Appendix A4.3 and A4.6.

For the offshore centralised configuration, the annual hydrogen demand within Pembrokeshire and the neighbouring regions is around 3.84 million tons per annum. The hydrogen systems with higher hydrogen production rates and greater storage capacity in the 2030 and 2050 scenarios can supply more hydrogen to offtake options than those in the 2020 scenario. In general, more hydrogen will be produced and supplied in the LCOH-based optimisation than the NPV-based optimisation cases. In

2050 scenario, the total annual hydrogen supply is around 2.94 – 2.97 million tons which meets 76.6% - 77.3% of the total offtake demand.

Similar findings are seen for the distributed configuration, which will supply 2.99 – 3.03 million tons of hydrogen per annum on average in the 2050 scenarios, which meets 77.9% - 78.9% of the total annual offtake demands. The annual average hydrogen supply from distributed projects is slightly higher than that of centralised projects due to the higher hydrogen production rates as was noted in Section 3.5.3.2.

In both configurations, for both the NPV and the LCOH based optimisations, most of the hydrogen production is used to produce ammonia, which is dispensed through the Pembroke Oil Terminal, the Pembroke Refinery for low carbon fuel synthesis and the RWE power station due to their large demands for hydrogen. In the case of the NPV based optimisation these are at the top offtake priorities. This is highlighted in Figure 20 and Figure 21.

Furthermore, when the hydrogen production increases with the production rate and storage capability, e.g., in the 2030 and 2050 scenarios and with the LCOH-based optimisation, the remaining hydrogen production is supplied to the offtake options such as power stations and steel factories in neighbouring regions which have large demands for hydrogen.

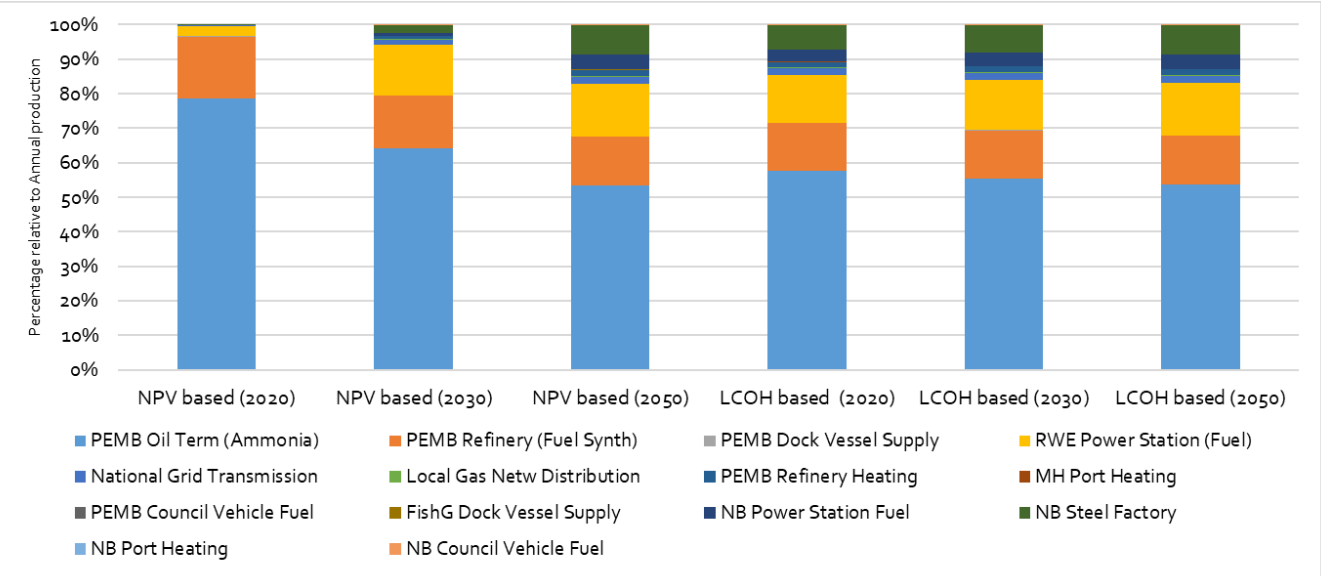


Figure 20: Annual hydrogen supply split compared to different offtake options for offshore centralised configuration.

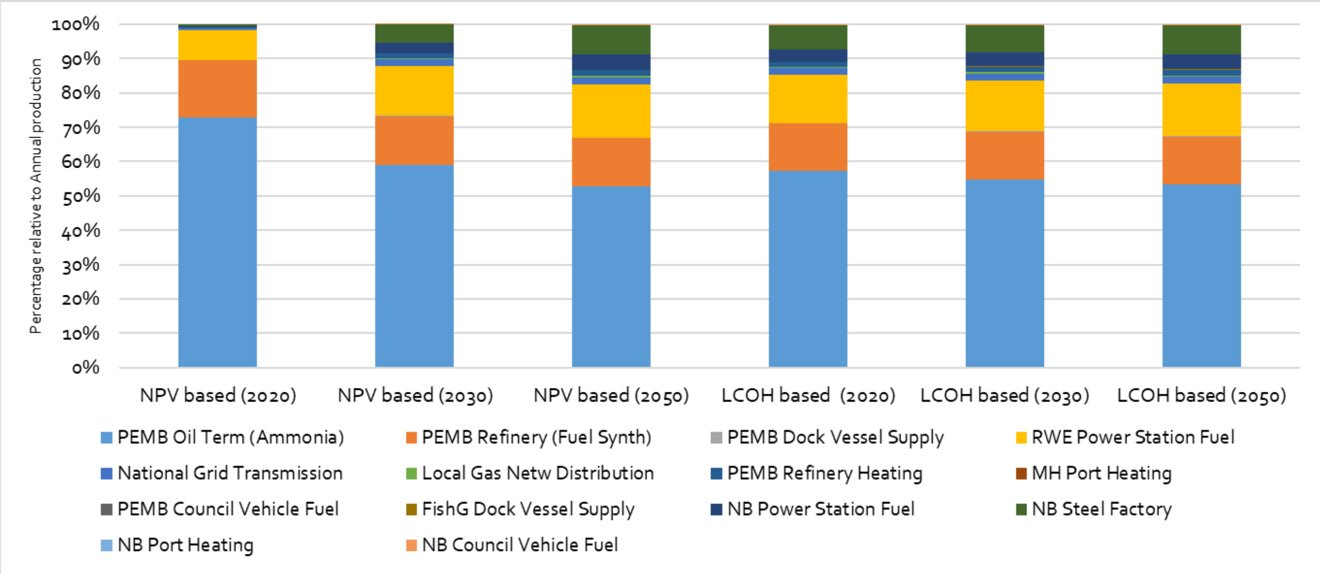


Figure 21: Annual hydrogen supply split compared to different offtake options for offshore distributed configuration

Figure 22 and Figure 23 show the annual average hydrogen supply for the offtake options relative to their actual annual demand for the centralised and distributed configurations respectively. Due to the time variations in production and demand profiles and the hydrogen supply at times being either in deficit or surplus of demand, the annual hydrogen offtake demands can't be met at all times. Given that the hydrogen production is supplied to offtake options based on priority order, the percentage of annual hydrogen demand met by the FLOW hydrogen production generally declines with decreasing priority. Around 80% – 90% of the annual demand of Pembroke Oil Terminal that has the highest offtake priority can be supplied by the FLOW hydrogen production. For most of the other offtake options, around 60% – 75% of their annual demands can be met by the FLOW hydrogen production in the 2050 scenarios.

Similar findings are seen for distributed projects which mostly supplies green hydrogen to Pembroke Oil Terminal for ammonia production, Pembroke Refinery for fuel synthesis and RWE power stations due to their large demands and top offtake priorities. These are followed by power stations and steel factories in neighbouring regions which also have relatively large hydrogen demands but lower offtake priorities. The percentage of annual hydrogen demand met by the distributed FLOW hydrogen production also generally declines with the decreasing priority of offtake options as shown in Figure 23.

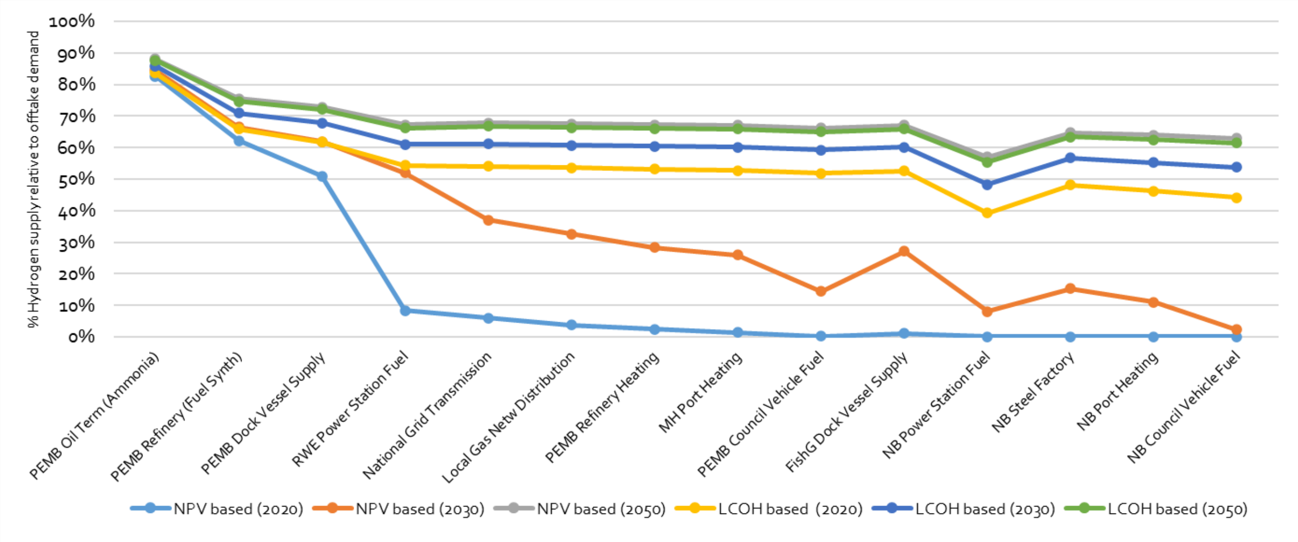


Figure 22: Annual average hydrogen supply relative to the actual annual hydrogen demand of each offtake option in centralised configuration

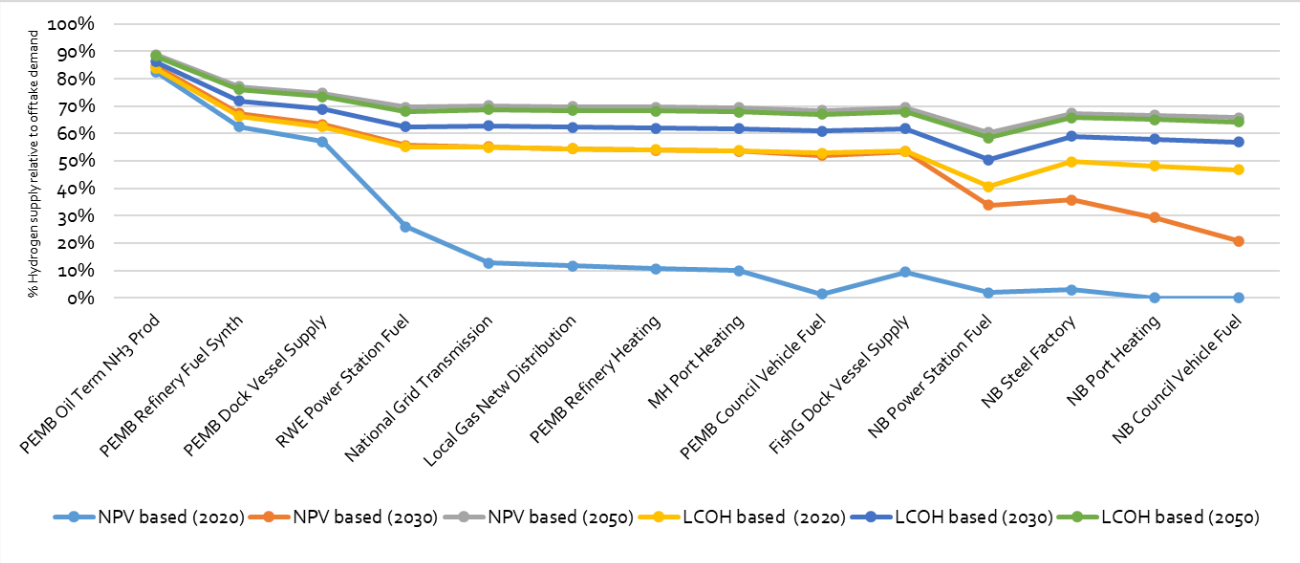


Figure 23: Annual average hydrogen supply relative to the actual annual hydrogen demand of each offtake option in distributed configuration

3.6 Future Challenges and Opportunities in the Celtic Sea

At a high-level, the Celtic Sea may become an important source of renewable energy for the UK, but there are still questions about exactly what this will look like. There are lots of factors which could influence the optimal mix of technologies, including minimising system costs, repurposing existing infrastructure and building in system resilience. As the UK's climate targets are timebound (i.e., Net Zero by 2050), the timeline of projects and the speed of deployment could be important factors.

With floating wind turbines there may be changes to the bottlenecks in deployment compared to fixed devices. Specifically, the deployment of the floating substructure could become a limiting factor. A potential reason for this is that the structures are so large that only a few can be stored in a given space at any one time. On the other hand, floating devices may be able to use smaller installation vessels (that are more readily available) that fixed wind turbines.

For integrated wind turbine-electrolyser devices, there could be limitations around the availability of electrolysers. This industry is aiming to rapidly scale up from producing a few MWs of electrolysis capacity per year to producing 10s of GWs per year. For example, ITM Power recently moved to a facility with a production rate of 1 GW electrolysis capacity per year but has plans to expand the company's overall capacity to 2.5 GW by the end of 2023 and 5 GW by the end of 2024 (ITM Power, 2021). Other manufacturers have similar ambitious plans. However, the current project pipeline for electrolysers now reaches into hundreds of GWs (specifically, in August 2021, Recharge reported a pipeline of 260 GW for gigawatt scale projects alone (Recharge, 2021)). This means that access to electrolysers could become a limiting factor for new proposals.

Another technology that could be a limiting factor for projects which export hydrogen is risers which can handle the gas. On the other hand, there is an establish gas riser supply chain, so the industry may be able to tackle this problem effectively.

From a techno-economic perspective, there lies a great opportunity from hydrogen production from the Celtic Sea. Our results from our study highlight a potential of up to £60 billion worth of revenue if most of the 40 GW Celtic Sea floating offshore wind (FLOW) generation potential is utilised for green hydrogen by 2050. This also points to some of the key drivers that would help achieve profitable projects in the future. The potential reduction in CAPEX and OPEX of the offshore FLOW platforms, hydrogen systems (including electrolyser) and hydrogen risers in distributed configuration would be key in achieving this goal. It is also noted that there is an opportunity for a large green ammonia market with the hydrogen produced from the Celtic Sea. Considering that there is already an established market in place for this and provided the breakeven price for offtake is high, there lies the opportunity for Milford Haven and the South Wales region to be key players in this market. Another aspect highlighted in the study is the opportunity of repurposing the oil refinery and the oil terminal to establish this region as a base for ammonia production for bunkering and export. This might also include the possibility for other hydrogen based synthetic fuels not covered as part of this study.

3.7 Theme 2 Summary

We covered a wide range of questions around the potential of the Milford Haven region including future green hydrogen roadmap, potential green hydrogen production and offtake, offshore layout and design for deployment, an energy system study of the techno-economics and challenges and opportunities hydrogen may bring into the region. Main findings are outlined below

3.7.1 Smart local energy system roadmap: green hydrogen pathway

We outlined a conceptual proposal by Arup for what a 2050 decarbonised Milford Haven energy system could look. This proposal provided short to midterm options that could be adopted by the region to meet net zero by 2050.

3.7.2 Energy use in the Milford Haven and surrounding regions

We outlined a project boundary for an energy systems study and estimated the potential offtake of hydrogen for different options within the region. This expanded on an initial list of offtake options provided to the MH:EK project by ERM to include more hydrogen offtake options from the wider South Wales region

3.7.3 Potential green hydrogen production in the Celtic Sea

Once we had a better understanding of what the hydrogen offtake for Milford Haven and its neighbouring regions could look like, we went further to understand the potential of hydrogen production from floating offshore wind (FLOW) in the Celtic Sea including considerations around potential generation (GW) that can be exploited the seabed and the limitations of electrical grid network capacity of the South Wales. The estimated future available connection capacity of 2.1 GW in the South Wales electrical grid leaves little or no room for further expansion of FLOW projects in the Celtic Sea.

3.7.4 Green hydrogen layout and design

Here we considered the layout and design of the electrical and gas infrastructure required the make the integration of hydrogen possible. We explored and discussed potential offshore configurations (centralised and distributed). These were also used for the modelling assessment of the energy system future scenarios in section 3.5.

3.7.5 Celtic Sea scenarios: Modelling of energy system

Here we undertook an energy system study to understand what the future use of hydrogen could look like in the region being fully decarbonised by 2050. Our study showed that there lies a great opportunity from hydrogen production from the Celtic Sea with the potential of up to £60 billion worth of revenue if most of the 40 GW Celtic Sea floating offshore wind (FLOW) generation potential is utilised by 2050. This also points to some of the key drivers that would help achieve profitable projects in the future including the potential reduction in CAPEX and OPEX of the offshore FLOW platforms, hydrogen systems (including electrolyser) and hydrogen risers.

3.7.6 Future Challenges and Opportunities in the Celtic Sea

Here we discussed the future challenges and opportunities that lie ahead for the Celtic Sea. It was also noted that there is an opportunity for a large green ammonia market for South Wales with the hydrogen produced from the Celtic Sea.

4 THEME 3 – DEVELOPMENT OF LARGER DEMONSTRATION PROPOSALS

This section outlines proposals for larger demonstration projects, with a focus on increasing knowledge around hydrogen technologies, including electrolysis, electrical integration and testing, fuel cells, storage and maritime use of hydrogen.

4.1 Deployment of hydrogen fuel cells, including for black start capability and ancillary service provision

One of the areas in which hydrogen technologies are closest to cost parity is in backup/remote heat and power generation (Hydrogen Council, 2020). Therefore, this is a promising area for demonstration projects. One possibility is to establish a demonstration project where a diesel backup generator and an equivalent hydrogen fuel cell system are deployed alongside one another so that their capabilities in a range of tests can be directly compared. This will allow organisations which rely on backup generators (such as hospitals and potentially industrial sites) to compare the systems and increase their confidence in pursuing decarbonisation strategies in this area. It also provides a potential solution for off-grid offshore wind hydrogen production.

Another promising area for hydrogen technologies is to provide ancillary services to the grid. Following sizing of the system, a small facility could be built to interact with the ancillary services markets. If this is successful, it would be possible to couple a similar kind of hydrogen system into existing wind farms in Wales, opening up new lines of revenue while helping to balance the grid.

One potential ancillary service is black start support, in case the electrical network trips or goes down. One way to introduce hydrogen technologies to this field would be to demonstrate the use of a hydrogen fuel cell to black start a micro-grid. This could be tied into a new proposed test facility described in Section 4.4. As well as the physical demonstration, it would be possible to investigate what is required for black start capabilities on offshore decentralised integrated turbine – electrolyser devices. Another possibility is to investigate the benefit of onshore hydrogen fuel cells for black starting new offshore wind farms, either for the first time or as a restart after a grid fault. The benefit of a mobile hydrogen fuel cell for black start services could also be investigated.

Running these kinds of demonstrations will incur costs in the procurement, installation and integration, operation, inspection and maintenance of the facilities. Where the goal is to demonstrate a small-scale black start facility, costs could be reduced by using an existing micro-grid.

4.2 Establishing a mini hydrogen eco-system, potentially powered by offshore wind

One potential demonstration is to build on the work of Arup in this MH:EK project (Arup, 2022) in identifying roles for smart local energy systems around Milford Haven and further these propositions by deploying hydrogen equipment and creating a miniature hydrogen eco-system. As offshore wind starts to come online in the Celtic Sea, there is potential to use the wind energy to help power the eco-system.

A number of demonstration projects around the world are showing how these kinds of demonstration projects can work. For example, the Wind2H2 demonstration project in Boulder, Colorado formed by NREL and Xcel Energy uses wind turbines and solar arrays to generate energy which is sent to electrolyser stacks to produce hydrogen which is then stored (Harrison, 2009).

In addition to deploying equipment, the offshore wind aspect could be simulated using grid emulation systems (described fully in Section *4.4.1*). This could replicate the output of an offshore wind turbine, with the resulting power sent to an electrolyser on site with the hydrogen produced stored or used directly.

The challenges around low wind speeds and the simulation of blackouts may be possible with this approach. Options to address these challenges include using a hydrogen fuel cell or backup generator to ensure the electrolyser is not cut off instantly. If a fuel cell is not utilized, then this demonstration could focus on measuring how much hydrogen is produced by a single turbine depending on the wind energy harvested. Using the hydrogen production data, the model can be scaled up to simulate an entire wind farm.

The produced hydrogen from the electrolyser could be stored (which links to the Hydrogen Storage demonstration proposal in Section 4.3), or directly used in a fuel cell (possible link to the Hydrogen Fuel Cell with black start demonstration proposal in Section 4.1) to be converted back to electricity and fed into the grid to provide power to nearby buildings.

Considerations for this demonstration would be how big/many electrolysers would be needed for the emulator supply? If the electrolyser is located onshore, will losses through cables be considered? Similarly, if located offshore, will hydrogen loss through piping/valves be considered? If stored, what size/type of storage is required?

Outcomes of the demonstration could indicate how much hydrogen potential there is for the power supplied, and a demonstration of a renewable energy (wind) to hydrogen to electricity to grid system solution.

4.3 Hydrogen storage technologies

Storage of hydrogen is a key technology for applications in stationary power like power stations, transportation and portable power like vehicle fuel cells.

Compared to other fuels such as gasoline, hydrogen has the highest energy content per mass. However, under ambient conditions of temperature and pressure, 1 kg of hydrogen will occupy 12.15 m^3 volume with energy content of about 33.5 kWh (lower heating value) (Andersson J. a., 2019) which means hydrogen has a very low energy density per volume. For effective use of hydrogen in applications such as vehicle fuel storage, this volume is too large and not feasible to store in such a way, compared to gasoline fuel which has an equivalent energy density of only $0.0038m^3$. Therefore, hydrogen must be stored in a way to increase the energy content in a reduced volume. This section discusses a few demonstration proposals related to hydrogen storage.

4.3.1 Compressed Gas Demonstration Proposal

Hydrogen storage in different types of gas cylinders (Types I – V) are described Appendix A5. Hydrogen can be stored in its gaseous state by using compression equipment and high-pressure cylinders. With a standard constant volume of a cylinder tank, hydrogen is pressurized into the tank which can support higher mass of the gas in a smaller volume, increasing the energy content per unit volume.

This proposal is to demonstrate and test the storage of hydrogen in its gaseous state and measure the mass loss after a period of time.

It is proposed to procure several storage cylinders of each type (Type I – V) and charge them with hydrogen gas to a pressure (e.g., 70% of the maximum pressure). The initial mass of the full tank will be recorded and then left in different temperature conditions. After a period of time (e.g., 8 weeks) the tanks will be weighed, and the loss of hydrogen will be measured. Tank pressure will also be monitored.

4.3.2 Liquid Hydrogen Demonstration Proposal

Hydrogen is gaseous at ambient room temperature but turns to its liquid state at 20 K (-253°C) and has a density of 71 kg/m^3 (Andersson, 2019). This is a much larger density than the gaseous state, which gets to about 42 kg/m^3 at 700 bar. This means less space is required to store the same amount of hydrogen and does not require the costs of compression to high pressures. However, for hydrogen to exist as a liquid the temperature must be kept below the boiling point which requires cryogenic equipment. This adds considerable cost to storage and increased safety risks with such low temperatures. The drawbacks of this type of storage are the safety, cost, and thermal losses resulting in evaporation of the hydrogen.

The proposal for demonstrating hydrogen storage in the liquid state is to procure a cryogenic storage tank which is a double walled vacuum insulated tank with a volume capacity of 3160 Litres (Linde, 2022). This has the potential to store up to 224 kg of hydrogen.

It is proposed to charge a cryogenic storage tank with liquid hydrogen to 70% capacity and measure the loss of hydrogen over a period (e.g., 8 weeks). As the temperatures are so low, the energy requirement to keep these temperatures constant would be measured. This energy requirement could be translated to a hydrogen requirement, which would help to indicate how much of the energy/hydrogen stored is required to keep the remaining energy/hydrogen stored. Based on the change in mass over time, the amount of hydrogen which evaporated could be calculated.

4.3.3 Solid-state Hydrogen Demonstration Proposal

Hydrogen can be stored in a solid-state using hydrides which is a metallic powder capable of absorbing hydrogen molecules to be bonded to the metal at ambient temperatures and pressures. This eliminates the need for compression or extreme temperature control and requires little volume for a relatively large hydrogen quantity, making it a relatively safe way to store hydrogen. The focus of this solid hydrogen storage is to increase volumetric capabilities. Metal hydrides can be used in applications such as electrochemical cycling, thermal storage, heat pumps and purification. Hydrides can be formed by hydrogen absorption with transition or group metals including iron (Fe), Nickel (Ni), Boron (B) or Aluminium (Al). However, an optimum solid metal hydride for hydrogen storage has not been discovered because of wide application potential for absorption/desorption rates.

Essentially, a metal hydride container is a rechargeable energy store with the ability to be "charged" with hydrogen. The metal hydride container is discharged when the pressure is reduced, or the temperature is increased (between 393 K and 473 K).

This proposal would demonstrate the solid-state storage of hydrogen after bonding with a metal hydride. A container of a metal hydride can be procured and tested by charging and discharging with hydrogen numerous times for a period of time (e.g., 8 weeks). Charging and discharging can take up to 24 hours each. The charge time and discharge time can be measured to see if these increase after 8 weeks or so. An example of one such container is the standard SOLID-H CL-series container (CL-400), which can hold up to 400 litres of hydrogen and requires hydrogen to be at 28 bar to charge.

4.3.4 Hydrogen Pipeline Storage Demonstration Proposal

Hydrogen can also be stored in the pipelines which contains the hydrogen being transported, much in the same way as how natural gas is transported. A cheaper option for the transportation and pipeline storage of hydrogen is to blend the hydrogen with natural gas in the existing infrastructure which can then be used in heating purposes (Melaina, 2013). If the electrolyser is located on an offshore platform, this pipeline can be kilometres long (Caldo, 2021) and "opened" when hydrogen is used for applications onshore. Having a long pipeline of hydrogen poses issues such as storage pressure, steel pipeline embrittlement, as well as leaks from pipeline connections and valves. Although when the electrolyser produces hydrogen in excess it is stored in tanks, the pipeline will be constantly full making the pipeline itself a storage vessel.

A demonstration of a length of the engineered pipeline holding hydrogen is proposed which is sealed at both ends with valves to imitate a period of time when hydrogen is not being used. This will demonstrate the integrity and feasibility of using a long pipeline from offshore or onshore and test if/how much hydrogen is potentially lost from connections and valves. Such pipelines would normally be subsea when used with offshore wind. Hence, the demonstration could take place in the Blyth dock where temperatures will be similar to the subsea temperatures from the offshore turbine to shore.

4.4 Hydrogen test and validation facility

ORE Catapult is developing a proposal for a new test facility that could support hydrogen and grid integration technology development. This could be deployed, in part, as a mobile facility, able to travel to all parts of the UK including Wales. It is composed of three phases, as outlined below. A list of potential test programmes is also included.

4.4.1 Phase One

Phase One would provide a 1 – 5 MW grid emulator. One option would be to utilise multiple modules, potentially 250 kW or 500 kW each. These would be able to simulate grids of different strengths and sizes e.g., mini-grids and national grids. The emulator could also generate numerous simulations/scenarios, including a large power output, back-to-back operation, and variable loads. It could generate direct current (DC) and alternating current (AC), and potentially both at the same time. This would allow testing of power converters and also allow generation of a wide range of AC frequencies during the test programme.

The facility would have the potential to contribute to an integrated hardware in the loop system, potentially using a digital twin of ORE Catapult's 7 MW demonstration offshore wind turbine as a realistic operational wind turbine profile. Additionally, this megawatt scale facility would be flexible and could be used for both component and systems testing. Also, it would be possible to make the grid emulator mobile, such that it can be deployed wherever novel technologies are being tried at other locations.

4.4.2 Phase Two

In Phase Two, ORE Catapult would purchase a 'megawatt' scale electrolyser for use in ORE Catapult test programmes. This would allow an increased understanding of operational performance, maintenance requirements, and the overall experience of owning and operating an electrolyser. A flexible electrolyser system that will allow testing of specific components, such as power supplies, with real machines would be the preferred option.

The experience gained in Phase Two will inform test programmes carried out on larger scale test facilities, and potentially the development of testing standards. It would also provide a real example of how electrolysers can be integrated with renewables, as simulated by the emulator. This could contribute to training activities for companies looking to integrate renewable sites with electrolysers. The companies could also use the facility to validate technoeconomic models of integrated systems.

4.4.3 Phase Three

In Phase Three, ORE Catapult would purchase a fuel cell, or similar, to generate electricity from hydrogen produced in Phase Two equipment, allowing direct power to feed through the test facility and use of the resulting electricity onsite. This would further increase the applicability of the facility for standards development, training and understanding the technical barriers to integrating renewables and hydrogen technology for several scenarios.

4.4.4 Potential test programmes

The new facility would aim to offer the following kinds of tests (not exclusive):

- Electrolyser interaction with the national grid, including grid compliance tests
- Hardware in the loop testing
- Verifying models for storage state-of-charge and filling and dispensing operations, potentially alongside curtailment simulations
- Harmonic profiling
- Simulating integrated wind turbine – electrolyser devices with black-start capability, including the micro-grid and energy storage device and/or hydrogen fuel cell
- Trying new control philosophies, especially for the micro-grid context
- Accelerated lifetime testing
- Individual component testing
- Simulating fuel cell vehicles and micro-grids, such as cars or ships

4.5 Clean maritime for hydrogen powered vessels for applications such as offshore wind operations and maintenance activity

Inroads are being made into developing battery powered vessels for offshore wind operations and maintenance (O&M) activity. On a separate front, there are a number of projects working on deploying hydrogen powered vessels, namely ferries (HySeas III, 2022) (Recharge, 2021) (H2 View, 2021). One possible demonstration is to combine these ideas to develop a hydrogen powered vessel designed for offshore wind O&M activity. This could be linked to plans to produce hydrogen offshore, allowing refuelling of the ships at the wind farm.

4.6 Marine refuelling/recharger technology

Hydrogen offers a potential route for decarbonising transport/mobility. An important part of this concept is refuelling the vehicles. Thus far, the focus has been on road vehicles, led by the J2601 standard series from the Society of Automotive Engineers (SAE, 2022). While there may be some applicable work in these standards, there will be differences in the characteristics of hydrogen systems on ships and that of road vehicles, and cars in particular; these may require new considerations. The differences could include:

- Size of hydrogen tanks and inventory of fuel
- Type of hydrogen tanks
- Storage pressure of tanks, if using compressed gas

- Refuelling mechanism (currently, ferries may be refuelled by a fuel truck which roles onto the vessel, whereas road vehicles visit a fuel station.)

A new demonstration project could investigate the best way to refuel marine vessels with hydrogen, considering the operational requirements of the ships and hydrogen refuelling operations. It could potentially tie in with the UK Government Clean Maritime Demonstration Competition (UK Governement, 2021). It could then work to build and demonstrate this optimal solution in an area with hydrogen ships. The deployment of such ships is currently also in the demonstration phase. The Orkney Islands are a base of such activity in the UK.

As hydrogen ships are likely to have a battery to help balance the electrical system, a demonstration project could also investigate the possibility of charging the battery at the same time as refuelling the hydrogen store.

4.7 Theme 3 Summary

We developed a number of proposals for larger demonstration projects that will deploy hydrogen technology and help to advance the sector.

4.7.1 Deployment of hydrogen fuel cells, including for black start capability and ancillary services

One of the areas in which hydrogen technologies are closest to cost parity is in backup/remote heat and power generation (Hydrogen Council, 2020), making this a promising area for demonstration projects. In particular, they could be used for black starting a micro-grid, or for providing ancillary services to the grid.

4.7.2 Establishing a mini hydrogen eco-system, potentially powered by offshore wind

It may be possible to take inspiration from the Milford Haven investible propositions developed by Arup and support these with demonstration proposals, where equipment for hydrogen production, storage/transport and use are deployed. Grid emulation technology could also be included, which would allow the power output of an offshore wind turbine to be simulated. A number of technical challenges could then be investigated, such as simulating black outs and understanding the response time of the electrolyser.

4.7.3 Hydrogen storage technologies

There are a number of technologies for storing hydrogen, including a range of types of compressed gas containers, liquid hydrogen, and solid-state hydrogen. A demonstration project could deploy a number of these technologies to document their characteristics in more detail, such as losses, exit conditions, and response time (i.e., how fast they can respond to a need to charge or discharge hydrogen).

4.7.4 Hydrogen test and validation facility

ORE Catapult is developing a proposal for a new test facility that would support hydrogen and grid integration technology development. The concept would be delivered in three phases. First, a 1 – 5 MW grid emulator for electrical testing of electrolysers and other electrical equipment. In Phase Two, ORE Catapult would purchase a 'megawatt' scale electrolyser for using in ORE Catapult test programmes. In Phase Three, a fuel cell would be purchased to use hydrogen to make electricity, allowing power to feed through the test facility, with use of the electricity generated onsite. Part of the facility could be mobile, and so carry out tests around the UK, including Wales.

4.7.5 Clean maritime for hydrogen powered vessels for applications such as offshore wind operations and maintenance activity

Hydrogen is a potential low carbon fuel for marine transport, including crew transfer vessels (CTV) that support wind farms. One potential demonstration is the development of a hydrogen powered CTV.

4.7.6 Marine refuelling/recharger technology

If hydrogen becomes an important transport fuel, then refuelling vehicles will become a common process. Thus far, the focus has been on light vehicles, especially cars. As marine vessels will have different characteristics to cars, there is more work to do on marine refuelling. A demonstration project could explore what marine refuelling could look like. As hydrogen ships will likely have a battery to balance their electrical systems, simultaneous refuelling and recharging could also be demonstrated.

5 THEME 4 – MILFORD HAVEN IN A GLOBAL GREEN HYDROGEN GENERATION CONTEXT

This section outlines our work in disseminating the Milford Haven: Energy Kingdom, our research activities, and our engagement with other research groups and stakeholders. It also covers the high-level outcomes of a study on safety around offshore wind and hydrogen.

5.1 Dialogue with EU and international research groups

ORE Catapult has been sharing the Milford Haven: Energy Kingdom project with organisations around the world in order to compare and facilitate global technology development. At a national level, the project has inspired mini-industrial challenges for the ReNU Centre for Doctoral Training (CDT), with a focus on understanding how offshore wind and hydrogen technologies can be integrated. We also presented this work at a stakeholder event hosted by the Sustainable Hydrogen CDT, which included participants from international research organisations and companies including Shell. Additionally, we documented the project in a blog for Renewable UK, in the run up to their Green Hydrogen Conference. ORE Catapult also presented this work at the 2022 All Energy conference, the UK's largest low carbon energy and full supply chain renewables event.

At an international level, ORE Catapult presented the Milford Haven: Energy Kingdom project to an International Energy Agency (IEA) Technology Collaboration Programme (TCP), specifically the wind TCP's Task 25, which aims to provide information to provide the highest economically feasible wind energy penetration within electricity power systems worldwide (IEA Wind TCP, 2022). Here, ORE Catapult's work on the long-term energy transition was presented alongside hydrogen presentations from colleagues from Sweden and Spain. The USA's National Renewable Energy Laboratory was also present.

5.2 Relevant stakeholder engagement to facilitate the Celtic Sea development

Through the Milford Haven: Energy Kingdom project, ORE Catapult has looked at using stakeholder engagement to facilitate the Celtic Sea development including site planning and landing areas as well as targeted technology developer engagements. ORE Catapult has established connections to numerous energy organisations working in Wales. This has included ERM, a sustainability consultancy with a novel concept for integrating offshore wind and electrolysis technologies on individual substructures (ERM, 2022). Another organisation has been RWE, which owns and operates a 2.2 GW gas power plant and has plans for both offshore wind power and a new, large scale electrolysis facility. These are key technologies in its Pembroke Net Zero Centre, which is a new initiative which will help guide the company's pathway to reaching carbon neutrality by 2040.

Through a safety study (documented in Section 5.4), we discussed landing hydrogen pipelines and electrical cables in Milford Haven with Milford Haven Port Authority. This provided useful insight into the existing infrastructure in the port and the most suitable routes, bearing in mind shipping routes and anchoring spots.

Through engagement with project partners Pembroke County Council, we learned about the plans of Celtic Sea Power regarding the Pembroke Demonstration Zone, an area of sea available for testing offshore devices off the coast of Pembroke (Celtic Sea Power , 2022). This could be a promising area for future technology demonstrations in Wales.

5.3 Establishing other port links and understanding the export hub potential for Milford Haven

Ports around the world are gearing up for hydrogen. The Port of London Authority, for example, is leading a consortium (which includes ORE Catapult) which aims to develop a UK hydrogen highway network (Port of London Authority, 2021). The project is working to establish the business case for back hauling hydrogen into central London.

In Europe, one of the major ports preparing for hydrogen is the Port of Rotterdam. It aims to be the leading port for sustainable energy. Their plans include importing hydrogen; so far, they have begun exploratory studies with more than ten countries, including nearby European nations as well as Iceland and Australia. They also have plans to host a GW scale electrolyser, and to build infrastructure inland to demand centres (Port of Rotterdam, 2022).

Beyond Europe, more ports are investigating the use of hydrogen technology. ORE Catapult reached out to the Port of Seattle, which is undertaking two studies into hydrogen (Port of Seattle, 2021). These are focused on reducing emissions through using hydrogen to fuel medium and heavy-duty vehicles. One study aims to develop a tool for optimal sizing of hydrogen fuelling stations, while the other aims to undertake a risk assessment around large scale hydrogen storage. Understanding such activities will help to guide projects in the UK.

The ports of countries with significant renewable resources are also preparing for hydrogen. Australia's Port of Newcastle aims to help the nation become a significant renewable exporter. As part of this ambition, the port has plans to develop an electrolysis facility, with an initial capacity of 40 MW and potential expansion beyond 1 GW (Port of Newcastle, 2022).

5.4 Investigating health and safety implications for hydrogen production

ORE Catapult worked with safety experts Abbot Risk Consulting to run three workshops which aimed to identify the hazards of integrating offshore wind with hydrogen. Topics considered included the application or otherwise of ATEX regulations, relevant standards and best practice from other industries/sectors. Further details of the study as be found in our supplementary safety study report (Abbott Risk Consulting, 2022). A wide number of stakeholders engaged with the study, including ERM, RWE, Port of Milford Haven Authority, Pembroke County Council, Simply Blue Group and electrolyser manufacturer CPH_2. The study covered both offshore and onshore production of hydrogen, although the focus was on offshore production as this is the more novel concept.

To pick a few highlights from the study, we anticipate that the main safety driver for offshore hydrogen production could be the maintenance activities, where crews are deployed onto devices to ensure the plant remains in a satisfactory condition and to carry out remedial work. For onshore production, we anticipate hazards around introducing additional explosive and potentially high-pressure gases to a region which already hosts a large number of hydrocarbon facilities. Additionally, if sited nearby, the oxygen production from a large scale (GW) electrolysis facility may have implications for the proportion of oxygen in air at the intakes of Pembroke Refinery and Pembroke Power Plant.

5.5 Theme 4 Summary

This area of work explored how Milford Haven could fit into a global market for green hydrogen generation.

5.5.1 Dialogue with EU and international research groups

ORE Catapult has presented this work to universities and conferences across the UK. It has also been presented internationally at the International Energy Agency's Technology Collaboration Programme on wind, specifically to a group which aims to provide information on the highest economically feasible wind energy penetration within the electricity power system worldwide.

5.5.2 Relevant stakeholder engagement

Through the Milford Haven: Energy Kingdom project, ORE Catapult has established connections to The ERM International Group Ltd. and learnt about their plans for integrated offshore wind turbine – electrolyser devices. We also engaged with RWE, which owns a 2.2 GW gas power plant in the region and are interested in electrolysis technology. We also discussed landing pipelines and cables with the Milford Haven Port Authority, and, through interactions with Pembroke County Council, learnt about plans for a new offshore test area from Celtic Sea Power.

5.5.3 Establishing links with other ports

ORE Catapult reviewed plans from national, European and international ports to understand how they plan to interact with hydrogen. This has included plans for export from countries with abundant renewables, such as Australia, and imports into regions with substantial energy use, such as Europe.

5.5.4 Undertake a hazard identification safety study on offshore wind to hydrogen and its use

We worked with Abbot Risk Consulting and a number of stakeholders to identify hazards when using offshore wind to produce hydrogen for use in a region with large existing hydrocarbon infrastructure. Our findings are covered in a separate, supporting report (Abbott Risk Consulting, 2022). To give an example of the material covered, we anticipate that maintenance activities will be an important safety driver for offshore hydrogen production. For onshore hydrogen production, the hazards include adding new high voltage infrastructure and fuel inventory to Milford Haven.

APPENDIX

A1. APPROACH TO IDENTIFYING HYDROGEN OFFTAKE

The first step in identifying hydrogen consumers in an area of interest would be to look for existing applications of hydrogen available nearby. An overview of applications in which hydrogen is currently used or could potentially be used is shown in (ORE Catapult, 2020). Some of these are existing applications, like oil refining (in hydrocracking and hydrotreating), ammonia and methanol production, direct reduced iron (DRI) production (The International Energy Agency, 2019). These existing applications could either partially or fully move to using green hydrogen. On the other hand, hydrogen could also be used in a range of new applications, like in transport, in the heat and power sector, in steel production and in electricity generation (The International Energy Agency, 2019).

This section lists and discusses the different sectors and industries that could potentially move to using green hydrogen. This list of possible hydrogen consumers is used to search for local and regional hydrogen consumers, and in turn to assess the suitability of generating hydrogen from wind farms in an area. This process in exemplified through the Milford Haven and neighbouring regions in the following section.

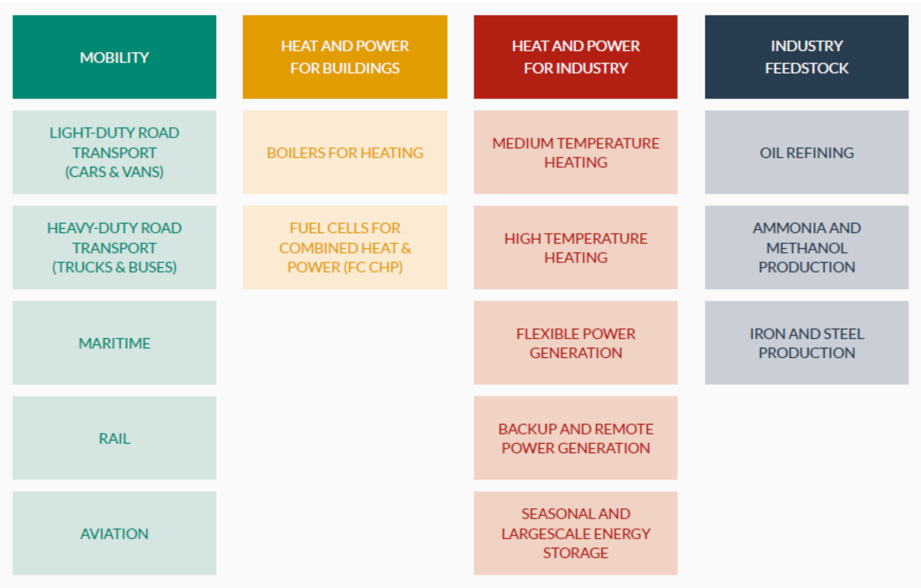


Figure 24: An overview of hydrogen applications (Offshore Renewable Energy Catapult, 2020).

This general approach is also applicable to identify potential hydrogen consumers in other areas where both onshore and offshore wind farms are being considered. This includes other areas in the UK such as parts of Scotland, where electrical constraints are present. After the recent ScotWind leases there is the potential of up to 25 GW of offshore wind capacity planned for the country (Crown Estate Scotland, 2022).

A1.1 Hydrogen use as industry feedstock

Hydrogen is used as an industry feedstock in multiple industries. This hydrogen demand could be potentially sourced by electrolysis from onshore and offshore wind farms and includes:

<u>**Industrial Ports:**</u> The International Energy Agency recommends industrial ports to be the first port of call for clean hydrogen demand. Many oil refining and chemical production units in the world are in

coastal zones, which make these areas of interest for green hydrogen. Green hydrogen could also feed nearby factories/steel plants and supply fuel to ships and other activities in the port.

Oil Refining: Oil refining uses approximately 33% of the hydrogen used today mainly in the hydrotreatment and hydrocracking processes (The International Energy Agency, 2019). Hydrotreatment is used to remove impurities from diesel oil (Ortega, 2022), while hydrocracking is the process to break petroleum into simpler fuels like gasoline and kerosene by the addition of hydrogen (McKinsey & Company, 2022). On average, one-third of the hydrogen demand of these processes is met by hydrogen produced as by-products during other chemical processes in the refineries; the remaining needs to be sourced, potentially using green hydrogen (The International Energy Agency, 2019).

Ammonia Production: Around 27% of today's hydrogen use is in ammonia production. 80% of the ammonia is used to manufacture fertilisers and the rest for other industrial applications (The International Energy Agency, 2019). Fertiliser plants and ammonia production facilities, thus, will require hydrogen in large quantities. There is also the potential for shipping ammonia from existing and new LNG shipping facilities.

Methanol Production: 11% of the hydrogen used today is for methanol production (The International Energy Agency, 2019). Methanol is used for a range of industrial applications and for producing other chemicals and solvents. Methanol also has fuel applications and has recently been used to manufacture some plastics (The International Energy Agency, 2019). Methanol production facilities, thus, would be relatively large hydrogen consumers.

Iron and Steel Production: Hydrogen also finds use in the iron and steel industry in steel production via direct reduction of iron ore (DRI) (The International Energy Agency, 2019). 7% of steel today is produced using this approach (The International Energy Agency, 2019). Expanding DRI further for steel production will increase hydrogen demand. Hence, iron and steel plants could become large consumers of green hydrogen too.

A1.2 Hydrogen use in heat and power for industry

Industry uses heat for various purposes like drying, aiding chemical reactions etc. Hydrogen for industrial low temperature (< 100°C), medium temperature (100–400°C) and high temperature (> 400°C) heat is a possible future application for hydrogen even though there is no hydrogen used this purpose at the moment. One easily attainable opportunity is to blend green hydrogen with natural gas to be used with industrial boilers, which may be achievable in the near term. Industries that use heating could potentially turn towards green hydrogen (and ammonia), but there are several operational and safety challenges to overcome (The International Energy Agency, 2019).

Hydrogen only plays a negligeable role in the power sector today. Co-firing of ammonia into existing conventional coal power plants can help reduce their carbon intensity (The International Energy Agency, 2019). Also, hydrogen-fired gas turbines and retrofitted combined-cycle gas turbines using hydrogen could become relevant in the power sector (The International Energy Agency, 2019). Compressed hydrogen or hydrogen in the form of ammonia could also be stored long-term to balance out variations in the generation and demand in electricity networks. Additionally, fuel cell systems could be used to provide off-grid power supplies.

Hence, both large industrial heat requirements and electrical power production could be potentially met by green hydrogen in the medium to long term.

A1.3 Hydrogen use in heat and power for buildings

The lowest cost option to use hydrogen for building heat supplies is to allow blending within the existing gas network. Blending ratios of between 5% and 20% are being considered at present (Energy Networks Association, 2022), (Northern Gas Networks, 2022). Methane produced from green hydrogen could also be used in existing gas infrastructure (The International Energy Agency, 2019). Full decarbonisation of heating is also possible by moving to 100% hydrogen, but that could involve an upgrade of the existing gas network.

A1.4 Hydrogen use in mobility

Practically, all modes of transportation could be run on hydrogen or hydrogen-based fuels, including light duty vehicles, heavy duty vehicles, maritime, rail and aviation sectors; some more easily than the others (The International Energy Agency, 2019). In the light duty vehicles sector, only a small penetration of 1% or less of hydrogen fuel cell vehicles is expected by 2050 with a major share of the market provided by EVs (Bloomberg NEF, 2022). That said, there might be a stronger case to diversify the light duty vehicles sector to get around possible material shortages and recycling issues with batteries.

On the other hand, the long-haul and heavy-duty applications where battery EVs are not competitive, are attractive for hydrogen. Public transport buses in cities and regions and long haulage transport are good examples of sectors where hydrogen could make inroads in the transport sector (Fuel Cell Electric Buses Knowledge Base, 2022), (Ewing, 2021), (Walker, 2021). Both these applications may not require a large network of hydrogen refuelling stations spread over large regions. Hydrogen refuelling stations could be placed more centrally - at the bus depots and at ports, for example, for long-haulage transport.

The maritime sector consumes around 5% of the global oil demand, 80% of which is used in international shipping of which 90% is used for maritime freight (The International Energy Agency, 2019). Hydrogen-based fuels could be used to tackle the carbon emissions from the international shipping industry and also some of the associated port activities. The latter ties in with the hydrogen use in industrial ports discussed in Section 3.2.2.1.

Hydrogen-powered passenger trains have been trialled over the past few years and have been in service in Germany and Austria (Alstom, 2022). Plans are in place to run hydrogen-powered trains in France, Japan and the UK too (Railway Technology, 2022), (Railway Technology, 2020). Hydrogen-powered trains will be most competitive in the long distance, cross-border rail freight sector (The International Energy Agency, 2019). Opting for hydrogen-powered trains will vary widely between regions based on the levels of railway electrification already achieved or planned.

The aviation sector could use synthetic hydrogen-based liquid fuels without many changes to the design of aircrafts and the airport infrastructure (The International Energy Agency, 2019). This move towards hydrogen could begin with blending of hydrogen based liquid fuels with conventional jet fuel.

A1.5 International shipping routes for trade

International hydrogen trade needs to start soon and could leverage the successful growth of the global LNG market. Hence, LNG terminals could be re-purposed for shipping of different forms of hydrogen fuels (The International Energy Agency, 2019).

A2. HYDROGEN OFFTAKE OPTIONS, PRIORITY AND COST

A2.1: Milford Haven region hydrogen offtake

Offtake Option	Purpose	Usage (t/day)	Timeline	Price (GBP/kg)	Priority
Pembroke Oil Terminal (Valero)	Bulk scale production and storage of LOHC or ammonia for export	4940.5	2040	7.7	1
Pembroke Refinery (Valero)	Low carbon synthetic fuels	1500.0	2040	7.7	2
Pembroke Dock	Supply of hydrogen to marine vessels	17.1	2035	3.5	3
2.18 GW Power Station (RWE)	To fuel future hydrogen gas turbines	1500.0	2040	2.3	4
Local gas network (Wales & West)	Potentially 100% into regional distribution system	45.0	2032	2.2	5
National Grid	Potential to inject directly to 100% hydrogen backbone	250.0	2030	2.2	6
Pembroke Refinery (Valero)	Industrial heat/grey hydrogen replacement	200.0	2030	1.5	7
Milford Haven Port	Transport and heating requirements	2.5	2030	1.5	8
Pembroke Council	Vehicle fleet and hydrogen refuelling hub in Milford Haven	1.7	2024	1.5	9

A2.2: Neighbouring regions hydrogen offtake

Offtake Option	Purpose	Usage (t/day)	Timeline	Price (GBP/kg)	Priority
Fishguard Dock	Supply of hydrogen to marine vessels	5.2	2035	3.5	10
520 MW Baglan Bay CCGT	To fuel future hydrogen gas turbines	357.8	2040	2.3	11
850 MW Severn Power		584.9	2040		
Tata Steel Port Talbot	Hydrogen requirement for steel production	721.4	2030	1.8	12
Celsa manufacturing, Cardiff		187.6	2030		

Liberty Steel New, Newport		144.3	2030		
Neighbouring Ports	Transport and heating requirement	0.6	2030	1.5	13
Neighbouring Councils	Vehicle fleet and hydrogen refuelling	28.7	2024	1.5	14

A3. MODELLING COSTS & ASSUMPTIONS

A3.1 Wind turbine exclusive of electrical (Stehly, 2020), (NREL, 2021)

Item	2020	2030	2050
CAPEX (% r.t. 2019 base year)	100%	65%	52%
CAPEX (GBP/kW)	3392.2	2204.4	1764.2
Annual OPEX (% of CAPEX)	2.5%	2.5%	2.5%

A3.2 Inter-array Cost (ABB, 2010), (TenneT, 2015)

Cross-section of Conductor (mm^2)	Thermal Rating (MVA) per Set	Resistance (ohm/km)	CAPEX (GBP/m)	Annual OPEX (% of CAPEX)
95	34.30	0.1815	109.1	3%
120	38.87	0.1437	122.7	3%
150	42.87	0.1149	138.9	3%
185	48.01	0.0932	157.8	3%
240	54.87	0.0718	187.6	3%
300	60.59	0.0575	220.1	3%
400	67.45	0.0431	274.2	3%
500	74.88	0.0345	328.3	3%
630	81.74	0.0274	398.6	3%
800	88.59	0.0216	490.6	3%
1,000	94.31	0.0172	598.8	3%

A3.3 Offshore Central Platform Cost

The CAPEX and annual OPEX of a new offshore central platform are assumed to be 264 GBP/kW and 1.1% of the CAPEX respectively. (ORE Catapult, 2020)

A3.4 Voltage Source Converter (VSC-HVDC) cost

The CAPEX and annual OPEX of a VSC-HVDC station are assumed to be 117.7 GBP/kVA and 2% of the CAPEX respectively. (X. Xiang, 2016)

A3.5 Submarine HVDC cable cost (X. Xiang, 2016)

Voltage (kV)	Cross-sectional Area (mm^2)	Thermal Rating (MVA)	Resistance (ohm/km)	CAPEX (GBP/m)	Annual OPEX (% of CAPEX)
±150	1000	493.2	0.0224	716.9	3%
	1200	537.3	0.0192	781.1	3%
	1400	588.6	0.0165	840.0	3%
	1600	636.9	0.0144	898.8	3%
	2000	722.1	0.0115	963.0	3%
±300	1000	986.4	0.0224	914.9	3%
	1200	1074.6	0.0192	1005.8	3%
	1400	1177.2	0.0165	1086.1	3%
	1600	1273.8	0.0144	1166.3	3%
	2000	1444.2	0.0115	1257.3	3%

A3.6 Electrolyser cost (IEA, 2019) (FCH, 2017)

Item	Today		2030		2050	
	Range	Adopted	Range	Adopted	Range	Adopted
Efficiency (kg/MWh)	16.8 – 18	18	18.9 – 20.4	20.4	20.1 – 22.2	22.2
Water Usage (L/kg)	15					
Load Range (% of Nominal)	0 – 160%					

Operating Pressure (bar)	30 – 80	30	30 – 80	50	30 – 80	70
Stack Lifetime (operating hours)	30,000 – 90,000	60,000	60,000 – 90,000	90,000	100,000 – 150,000	120,000
CAPEX (GBP/kW)	858 – 1404	1131	507 – 1170	838.5	156 – 702	429
OPEX (% of CAPEX)	2%					
Replacement (% of CAPEX)	30%					

A3.7 Desalination cost (Caldera, 2017) (A. Singlitico, 2021)

Item	2020	2030	2050
CAPEX (GBP per L/h)	38.4	32.1	20.5
Annual OPEX (% of CAPEX)	2.5%	2.5%	2.5%

A3.8 Compressor Cost

The CAPEX of a compressor, depending on its nominal flow rate and inlet/outlet pressure, is inferred from a reference 281,388.6 GBP compressor system which pressurises hydrogen at a nominal rate of 50 kg/h from 30 bar to 200 bar. The annual OPEX is assumed to be 4% of the CAPEX. (FCH, 2017), (A. Singlitico, 2021)

A3.9 AC/DC Converter Cost

The CAPEX and annual OPEX of an AC/DC converter are assumed to be 75,000 GBP/MW and 2% of the CAPEX respectively. (V. Jülch, 2016)

A3.10 Storage Tank Cost

The CAPEX and annual OPEX of steel cylinder bundles for hydrogen storage at 350 bar are assumed to be 440.8 GBP/kg and 2% of the CAPEX respectively. (FCH, 2017)

A4. RESULTS FROM CELTIC SEA SCENARIOS

A 4.1 Offshore Centralised Configuration – Cost Benefit Analysis

Item of MERRA-S1		NPV Maximisation based			LCOH Minimisation based		
		Current	2030	2050	Current	2030	2050
Wind Turbine	CAPEX (mGBP)	61,060	39,679	31,756	61,060	39,679	31,756
	OPEX (mGBP)	17,861	11,607	9,289	17,861	11,607	9,289
Inter-array Cable	CAPEX (mGBP)	1,085	1,085	1,085	1,085	1,085	1,085
	OPEX (mGBP)	381	381	381	381	381	381
OCP	CAPEX (mGBP)	2,284	2,635	3,471	3,949	3,574	3,406
	OPEX (mGBP)	294	339	447	508	460	438
Electrolyser	CAPEX (mGBP)	9,285	7,929	5,315	15,976	10,707	5,217
	OPEX (mGBP)	2,173	1,855	1,244	3,739	2,506	1,221
	Replacement (mGBP)	2,603	1,074	553	4,478	1,450	543
Compressor 1	CAPEX (mGBP)	83	100	129	122	124	128
	OPEX (mGBP)	39	47	60	57	58	60
Compressor 2	CAPEX (mGBP)	0	39	137	122	126	131
	OPEX (mGBP)	0	18	64	57	59	61
Desalination Device	CAPEX (mGBP)	85	93	85	146	125	83
	OPEX (mGBP)	25	27	25	43	37	24
Converter	CAPEX (mGBP)	649	749	986	1,122	1,015	968
	OPEX (mGBP)	152	175	231	263	238	226
Storage	CAPEX (mGBP)	0	47	1,615	1,274	1,274	1,346
	OPEX (mGBP)	0	11	378	298	298	315
12'' Pipeline	CAPEX (mGBP)	983	983	983	983	983	983
	OPEX (mGBP)	345	345	345	345	345	345
SIT	CAPEX (mGBP)	6	6	6	6	6	6
H2 Revenue (mGBP)		72,409	79,127	88,414	81,043	84,947	87,875
NPV (mGBP)		–26,985	9,901	29,829	–32,833	8,801	29,861

EAA (mGBP)	–2,744	1,007	3,033	–3,338	896	3,036
IRR (%)	N/A	11%	17%	N/A	10%	17%
LCOH (GBP/kg)	10.29	5.73	3.89	8.57	5.35	3.89

Item of MERRA-S2		**NPV Maximisation based**			**LCOH Minimisation based**		
		Current	2030	2050	Current	2030	2050
Wind Turbine	CAPEX (mGBP)	61,060	39,679	31,756	61,060	39,679	31,756
	OPEX (mGBP)	17,861	11,607	9,289	17,861	11,607	9,289
Inter-array Cable	CAPEX (mGBP)	1,085	1,085	1,085	1,085	1,085	1,085
	OPEX (mGBP)	381	381	381	381	381	381
OCP	CAPEX (mGBP)	2,297	2,682	3,508	3,976	3,606	3,433
	OPEX (mGBP)	296	345	452	512	464	442
Electrolyser	CAPEX (mGBP)	9,335	8,070	5,372	16,082	10,803	5,257
	OPEX (mGBP)	2,185	1,888	1,257	3,763	2,528	1,230
	Replacement (mGBP)	2,617	1,093	559	4,508	1,463	547
Compressor 1	CAPEX (mGBP)	84	102	131	124	126	129
	OPEX (mGBP)	39	48	61	58	59	61
Compressor 2	CAPEX (mGBP)	0	40	137	122	126	131
	OPEX (mGBP)	0	18	64	57	59	61
Desalination Device	CAPEX (mGBP)	86	95	85	147	127	84
	OPEX (mGBP)	25	28	25	43	37	24
Converter	CAPEX (mGBP)	653	762	997	1,130	1,024	975
	OPEX (mGBP)	153	178	233	264	240	228
Storage	CAPEX (mGBP)	0	48	1,632	1,282	1,285	1,357
	OPEX (mGBP)	0	11	382	300	301	317
12'' Pipeline	CAPEX (mGBP)	1,209	1,209	1,209	1,209	1,209	1,209
	OPEX (mGBP)	424	424	424	424	424	424
SIT	CAPEX	6	6	6	6	6	6
H2 Revenue **(mGBP)**		73,012	80,451	89,620	81,937	86,016	88,940

NPV (mGBP)	–26,782	10,652	30,573	–32,457	9,376	30,511
EAA	–2,723	1,083	3,109	–3,300	953	3,102
IRR (%)	N/A	11%	17%	N/A	10%	17%
LCOH (GBP/kg)	10.24	5.68	3.87	8.52	5.33	3.87

A 4.2 Offshore Centralised Configuration – Optimal Hydrogen Systems Capacity

Component		**NPV Maximisation based**			**LCOH Minimisation based**		
		Current	2030	2050	Current	2030	2050
Electrolyser (MW)	MERRA-S1	274	315	413	471	426	405
	MERRA-S2	275	321	417	474	429	409
Compressor 1 (kg/h)	MERRA-S1	4,926	6,430	9,618	8,475	8,683	9,000
	MERRA-S2	4,952	6,544	9,266	8,532	8,761	9,069
Compressor 2 (kg/h)	MERRA-S1	0	464	3,137	2,608	2,751	2,941
	MERRA-S2	0	472	3,171	2,625	2,776	2,964
Desalination Device (L/h)	MERRA-S1	73,888	96,447	137,522	127,131	130,246	134,997
	MERRA-S2	74,284	98,163	138,987	127,975	131,417	136,033
Converter and OCP (MW)	MERRA-S1	288	333	438	499	451	430
	MERRA-S2	290	339	443	502	455	433
Storage (kg)	MERRA-S1	0	3,581	122,097	96,340	96,338	101,814
	MERRA-S2	0	3645	123,398	96,980	97,204	102,595

A 4.3 Offshore Centralised Configuration – Hydrogen Supply to offtakes

Option	**NPV Maximisation based**			**LCOH Minimisation based**		
	Current (kg)	2030 (kg)	2050 (kg)	Current (kg)	2030 (kg)	2050 (kg)
Pembroke Oil Terminal (Valero)	1,491,275	1,525,802	1,588,461	1,509,329	1,550,404	1,582,286
Pembroke Refinery (Valero)	340,634	364,043	413,339	360,779	388,198	408,995
Pembroke Dock	3,181	3,865	4,549	3,857	4,231	4,499
2.18 GW Power Station (RWE)	56,313	349,335	451,535	364,881	409,566	444,266

Local gas network (Wales & West)	5,422	33,788	61,940	49,356	55,877	60,917
National Grid	628	5,357	11,095	8,800	9,985	10,908
Pembroke Refinery (Valero)	1,725	20,680	49,120	38,799	44,126	48,277
Milford Haven Port	12	237	612	482	549	601
Pembroke Council	1	87	399	312	357	392
Fishguard Dock	20	512	1,263	991	1,134	1,242
520 MW Baglan Bay CCGT	114	18,391	130,454	89,974	110,363	126,829
850 MW Severn Power	239	58,985	249,060	185,349	218,435	243,841
Tata Steel Port Talbot	0	24	140	101	121	137
Celsa manufacturing, Cardiff	0	238	6,601	4,635	5,642	6,443
Liberty Steel New, Newport	1,491,275	1,525,802	1,588,461	1,509,329	1,550,404	1,582,286
Neighbouring Ports	340,634	364,043	413,339	360,779	388,198	408,995
Neighbouring Councils	3,181	3,865	4,549	3,857	4,231	4,499

A 4.4 Offshore Distributed Configuration – Cost Benefit Analysis

Item of MERRA-S1		**NPV Maximisation based**			**LCOH Minimisation based**		
		Current	2030	2050	Current	2030	2050
Wind Turbine	CAPEX (mGBP)	61,060	39,679	31,756	61,060	39,679	31,756
	OPEX (mGBP)	17,861	11,607	9,289	17,861	11,607	9,289
Electrolyser	CAPEX (mGBP)	10,322	9,059	5,771	16,398	11,174	5,582
	OPEX (mGBP)	2,415	2,120	1,350	3,837	2,615	1,306
	Replacement (mGBP)	2,893	1,227	601	4,596	1,513	581
Compressor 1	CAPEX (mGBP)	324	404	518	463	479	503
	OPEX (mGBP)	151	198	242	217	224	236
Compressor 2	CAPEX (mGBP)	0	253	480	413	429	446
	OPEX (mGBP)	0	118	225	193	201	209
Desalination Device	CAPEX (mGBP)	95	106	92	150	131	89
	OPEX (mGBP)	28	31	27	44	38	26
Storage	CAPEX (mGBP)	0	297	1,991	1,431	1,490	1,622

	OPEX (mGBP)	0	70	466	335	349	380
4'' Riser	CAPEX (mGBP)	3,285	3,285	3,285	3,285	3,285	3,285
	OPEX (mGBP)	1,153	1,153	1,153	1,153	1,153	1,153
12'' Pipeline	CAPEX (mGBP)	656	656	656	656	656	656
	OPEX (mGBP)	230	230	230	230	230	230
10-Slot Manifold	CAPEX (mGBP)	108	108	108	108	108	108
	OPEX (mGBP)	38	38	38	38	38	38
SIT	CAPEX (mGBP)	244	244	244	244	244	244
H2 Revenue (mGBP)		74,153	81,204	89,858	81,464	85,751	89,003
NPV (mGBP)		–26,711	10,328	31,335	–31,249	10,107	31,264
EAA (mGBP)		–2,716	1,050	3,186	–3,177	1,028	3,179
IRR (%)		N/A	11%	18%	N/A	11%	18%
LCOH (GBP/kg)		9.68	5.41	3.80	8.41	5.24	3.80

A 4.5 Offshore Distributed Configuration – Optimal Hydrogen Systems Capacity

Component		**NPV Maximisation based**			**LCOH Minimisation based**		
		Current	2030	2050	Current	2030	2050
Electrolyser (MW)	MERRA-S1	8	9	11	12	11	11
	MERRA-S2	8	9	11	12	11	11
Compressor 1 (kg/h)	MERRA-S1	137	184	249	217	227	241
	MERRA-S2	138	189	250	219	228	242
Compressor 2 (kg/h)	MERRA-S1	0	30	83	65	69	74
	MERRA-S2	0	31	84	65	70	74
Desalination Device (L/h)	MERRA-S1	2,053	2,755	3,733	3,262	3,398	3,611
	MERRA-S2	2,063	2,842	3,751	3,279	3,419	3,630
Storage (kg)	MERRA-S1	0	562	3,765	2,706	2,817	3,066
	MERRA-S2	0	580	3,783	2,720	2,834	3,083

A 4.6 Offshore Distributed Configuration – Hydrogen Supply to offtakes

Option	NPV Maximisation based			LCOH Minimisation based		
	Current (kg)	2030 (kg)	2050 (kg)	Current (kg)	2030 (kg)	2050 (kg)
Pembroke Oil Terminal (Valero)	1,491,358	1,528,599	1,602,345	1,512,625	1,557,310	1,593,241
Pembroke Refinery (Valero)	342,043	368,949	422,945	363,494	393,553	416,865
Pembroke Dock	3,561	3,960	4,665	3,898	4,302	4,589
2.18 GW Power Station (RWE)	174,324	374,166	467,183	370,329	419,109	457,536
Local gas network (Wales & West)	11,602	50,287	64,058	50,186	57,312	62,758
National Grid	1,907	8,953	11,481	8,954	10,248	11,245
Pembroke Refinery (Valero)	7,778	39,446	50,850	39,496	45,313	49,793
Milford Haven Port	90	489	634	491	564	621
Pembroke Council	8	313	413	319	367	404
Fishguard Dock	178	1,005	1,309	1,010	1,163	1,279
520 MW Baglan Bay CCGT	4,271	77,299	138,140	92,867	115,527	133,624
850 MW Severn Power	11,556	137,553	259,208	191,403	227,049	253,173
Tata Steel Port Talbot	0	64	146	106	127	143
Celsa manufacturing, Cardiff	0	2,173	6,898	4,904	5,963	6,730
Liberty Steel New, Newport	1,491,358	1,528,599	1,602,345	1,512,625	1,557,310	1,593,241
Neighbouring Ports	342,043	368,949	422,945	363,494	393,553	416,865
Neighbouring Councils	3,561	3,960	4,665	3,898	4,302	4,589

A5. COMPRESSED GAS CYLINDER TYPES - STORAGE

The law relating pressure (p), volume (V), and mass (m_{H2}) of a gas is the ideal gas law using the temperature (in K), universal gas constant (R), number of moles (n) and molecular weight (M_{h2}). This can be used as a first approximation for the mass of hydrogen in a tank, given pressure and volume.

$$pV = nRT$$

$$m_{H_2} = nM_{h_2}$$

There are 5 tank types available each with different capabilities and maximum pressures and therefore different masses of potential hydrogen which increases the energy content of one cylinder. At a certain temperature, hydrogen density increases with pressure. Using the ideal gas law (for low pressures) stated above and the Hydrogen Analysis Resource Centre spreadsheet (h2tools, 2022) with interpolation calculations, cylinder types and their pressure can offer a theoretical mass of hydrogen available to be stored.

Type I cylinders are a steel seamless pressure vessel with a maximum pressure of 200 bar. With a total tank storage volume of 0.05 m^3, 0.82 kg of hydrogen can be stored at ambient temperature (298 K). h2tools spreadsheet states at 200bar, 0.71kg of hydrogen can be stored in a 0.05m^3 container due to the higher pressures of ideal gas.

Type II cylinders are an aluminium/steel pressure vessel with filament windings around the cylinder to strengthen with a maximum pressure of 300 bar. With a total tank storage volume of 0.05 m^3, 1.23 kg of hydrogen can be stored at ambient temperature (298 K). h2tools spreadsheet states at 300bar, 1.03kg of hydrogen can be stored in a 0.05m^3 container due to the higher pressures of ideal gas.

Type III cylinders are an aluminium/steel composite material with fiberglass or carbon fibre metal liner pressure vessel with a maximum pressure of 700 bar. With a total tank storage volume of 0.05 m^3, 2.87 kg of hydrogen can be stored at ambient temperature (298 K). h2tools spreadsheet states at 700bar, 1.91kg of hydrogen can be stored in a 0.05m^3 container due to the higher pressures of ideal gas.

The Type IV cylinders are a carbon fibre reinforced and polymer liner thermoplastic pressure vessel with a maximum pressure of 700 bar. With a total tank storage volume of 0.05 m^3, 2.87 kg of hydrogen can be stored at ambient temperature (298 K). h2tools spreadsheet states at 700bar, 1.91kg of hydrogen can be stored in a 0.05m^3 container due to the higher pressures of ideal gas.

The Type V cylinders are an all-composite pressure vessel with a maximum pressure of 1000 bar. With a total tank storage volume of 0.05 m^3, 4.11 kg of hydrogen can be stored at ambient temperature (298 K). h2tools spreadsheet states at 1000bar, 2.47kg of hydrogen can be stored in a 0.05m^3 container due to the higher pressures of ideal gas.

The drawbacks of this type of storage are the safety of pressurising to high pressures, high cost of compression, and embrittlement from the hydrogen reacting with the metal tank itself.

A5. DEMONSTRATION PROJECT COST DATA

A5.1 Mini hydrogen eco-system demonstration cost

The costing contributions for this demonstration proposal include the Hydrogen Test and Validation Facility with the power emulator, electrolyser, electrical infrastructure, and operation/maintenance/inspection costs. The application costs of the produced hydrogen must also be considered whether it is used for the storage tanks demonstration or if a fuel cell is required to directly use the hydrogen.

Hydrogen production electrolyser stacks are available from FuelCellStore.com with a range of stack sizes (Titan EZ-60 – Titan EZ-2000) costing between $600 - $6000 per stack for small scale hydrogen generation (FuelCellStore, 2022). Larger scale production systems cost in the region of £1,200/kWh for electrolysis, based on our conversations with electrolysers manufacturers.

A5.2 Hydrogen Storage Demonstration Cost

As a sustainable, environmental company with a pledge to reduce carbon emissions, ORE catapult will aim to buy from local, UK suppliers which reduces transportation and contributes to the UK economy.

The costing of the gaseous hydrogen storage demonstration breaks down into the hydrogen fuel costs, compression costs, storage costs of equipment for each type of cylinder tank, and operations, inspection and maintenance costs. Tanks can be bought with hydrogen already in them which would eliminate the fuel and compression costs, but if empty cylinder tanks are bought, compression equipment and the hydrogen fuel itself must be bought. The costs of the cylinder tanks are listed below with source:

- Type I – $500 (Alibaba, Cylinder gas hydrogen high pressure gas, 2022) 60 litres 325x325x1330mm with maximum pressure 300 bar.
  - Chesterfield Special Cylinders (CSC, 2022) offers Type I seamless pressure vessels for storage systems or to secure gas for processes.
- Type II – $500 (Alibaba, Factory direct scales type 2 CNG, 2022) 325x325x1330mm of 300 bar 50-200 Litres
- Type III – The UK Hydrogen and Fuel Cell Association showcase Luxfer Gas Cylinders (located in Nottingham) who offer Type III hydrogen storage cylinders (G-Stor H2).
- Type IV - $500 (Alibaba, 125L Type 4 carbon fiber cylinder carbon, 2022) 325x325x1330mm of 300 bar test pressure with a volume of 125 Litres
  - Luxfer Gas Cylinders also offer Type IV G-Stor Go cylinders for hydrogen storage.

Costing of the solid-state hydrogen storage demonstration consists of the hydrogen fuel itself, and metal hydride canisters available at FuelCellStore.com. They must be charged with hydrogen so this charging equipment must be bought. Operation and maintenance costs also need considering.

CL-400 Metal Hydride - $1053 (FuelCellStores, Hydrogen equipment hydrogen storage metal hydrides CL 400, 2022).

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GLASGOW

ORE Catapult
Inovo
121 George Street
Glasgow
G1 1RD

+44 (0)333 004 1400

BLYTH

National Renewable
Energy Centre
Offshore House
Albert Street, Blyth
Northumberland
NE24 1LZ

+44 (0)1670 359555

LEVENMOUTH

Fife Renewables Innovation
Centre (FRIC)
Ajax Way
Leven
KY8 3RS

+44 (0)1670 357649

GRIMSBY

O&M Centre of Excellence
ORE Catapult, Port Office
Cleethorpe Road
Grimsby
DN31 3LL

+44 (0)333 004 1400

ABERDEEN

Subsea UK
30 Abercrombie Court
Prospect Road, Westhill
Aberdeenshire
AB32 6FE

07436 389067

CORNWALL

Hayle Marine Renewables
Business Park
North Quay
Hayle, Cornwall
TR27 4DD

+44 (0)1872 322 119

PEMBROKESHIRE

Marine Energy Engineering
Centre of Excellence (MEECE)
Bridge Innovation Centre
Pembrokeshire Science
& Technology Park
Pembroke Dock, Wales
SA72 6UN

+44 (0)333 004 1400

CHINA

11th Floor
Lan Se Zhi Gu No. 15
Ke Ji Avenue,
Hi-Tech Zone
Yantai City
Shandong Province
China

+44 (0)333 004 1400

LOWESTOFT

OrbisEnergy
Wilde Street
Lowestoft
Suffolk
NR32 1XH

01502 563368