Department of Mechanical and Aerospace Engineering

Material considerations in the oil and gas industry adaptation for the production of green hydrogen at offshore platforms

Author: Sophie Garrett

Supervisor: Iasonas Zekos

A thesis submitted in partial fulfilment for the requirement of degree in

Master of Science in *Sustainable Engineering: Renewable Energy Systems and the Environment*

2021

202055419

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Abstract

The use of hydrogen as a fuel is debated and encouraged in the recent worldwide advance towards a greener future. With the United Nation's goal of reaching net zero carbon emissions by 2050, the race to hydrogen has begun. Several countries have begun implementing green hydrogen projects of which there are many that incorporate offshore oil and gas rigs. Repurposing these rigs as locations of green hydrogen production allows the integration with offshore renewable energy. Many projects have promoted offshore wind energy as a renewable source perfect for this integration with hydrogen production. As experiments and exploration of green hydrogen has progressed, there are many cost-reducing strategies being followed to compete with other renewable and non-renewable energies. Offshore green hydrogen would benefit from the vast resource of seawater that the oceans offer. Seawater electrolysis has been explored to reduce the use of freshwater sources and offer a green hydrogen production process for worldwide use.

This research explores offshore green hydrogen and considers the issues faced with seawater electrolysis, the options to repurpose oil and gas platforms and the viability of using existing infrastructure. A case study is used to determine the viability of offshore green hydrogen production at an abandoned platform in the North Sea using wind energy as a renewable source.

Acknowledgements

Firstly, I'd like to acknowledge the Sustainable Engineering teaching staff from Strathclyde University for their encouragement and support throughout this degree as they've inspired my interest in sustainability and made renewable energy a joy to learn.

I would like to thank my supervisor, Iasonas Zekos, for providing guidance and feedback throughout this research project. Thank you to Peter Alport from ITM Power, who provided key information on electrolyser cost projections.

I am also extremely grateful for my family's continuous support and encouragement along the way.

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Nomenclature

Symbol	Description	Units
A	Swept area of turbine blades	m^2
C_p	Power coefficient	
P	Power	W
ρ	Air density	kg/m^3
v	Velocity of the wind	m/s
v_{hub}	Velocity of the wind at the hub height	m/s
v_{anem}	Velocity of the wind at the anemometer	m/s
z_0	The surface roughness	m
z_{hub}	The hub height of the wind turbine	m
z_{anem}	The anemometer height	m

1.0 Introduction

The research and development of renewable energy technologies has become increasingly more important as climate change continues to affect the world. Technologies have advanced in order to provide systems of renewably sourced electricity and fuel. With the recent spotlight on climate change, driven at COP26, nations have come together to tackle the climate crisis with the main goals to achieve net zero emissions by 2050 and limit global warming to 1.5ºC [1]. The main way to induce this change is to develop commercially viable renewable energies. Renewable electricity is produced from intermittent sources such as wind, solar, wave and tidal. Intermittent energy results in an inconsistent production of electricity whereby there are periods of time of zero generation. As well as times of zero generation, there are also times of excess generation as demand is met and renewable generation is high. This causes times of carbon-based fuel usage and wasted renewable electricity, respectively. Energy storage solutions and smart grid systems will play a key role in a future energy system. Smart grids are systems which allow renewable energy to be managed and controlled to meet demand and will enable efficient use of renewable power to limit carbon-based fuel use and wasted renewable electricity [2]. Stored energy can be utilised in times of low renewable generation and distributed to consumers to meet demand and limit fossil fuel use. Energy can be stored using stationary batteries, thermal energy storage or Vehicle-to-Grid (V2G) connections [3]. V2G connections allow for optimum charging of electric vehicles (EVs).

In 2019, approximately 84% of global energy consumption came from coal, oil and gas [4]. This is represented in *Figure 1*, which shows that the proportion of renewable energy is little in comparison to fossil fuel use. These energy sources are predominantly used as fuels for industrial, commercial and residential uses that cannot be supplied by electricity. Hydrogen can be produced as an alternative fuel and provides a useful storage solution for renewable generation. It can be used as the fuel for fuel-cell electric vehicles (FCEVs), heating and industrial processes. Hydrogen has been researched in much debate termed the fuel of the future as it can be produced renewably through electrolysis [5] [6]. The current, most popular technology to produce hydrogen is through steam reforming of natural gas, and this is termed 'grey' hydrogen [7]. Carbon capture storage (CCS) is used as an option to reduce the carbon emissions of the process and if this is included in the system, 'blue' hydrogen is produced. 'Green' hydrogen is produced through electrolysis powered by renewable sources and there are zero emissions from this process. The production of green hydrogen could enable a hydrogen economy in which industries are transitioned to clean energy. In accordance with climate change and green policies, oil and gas rigs need to be repurposed or decommissioned at their end of life. The disused platforms offer a unique opportunity for offshore green hydrogen production using seawater and offshore renewable technologies such as wind and wave energy.

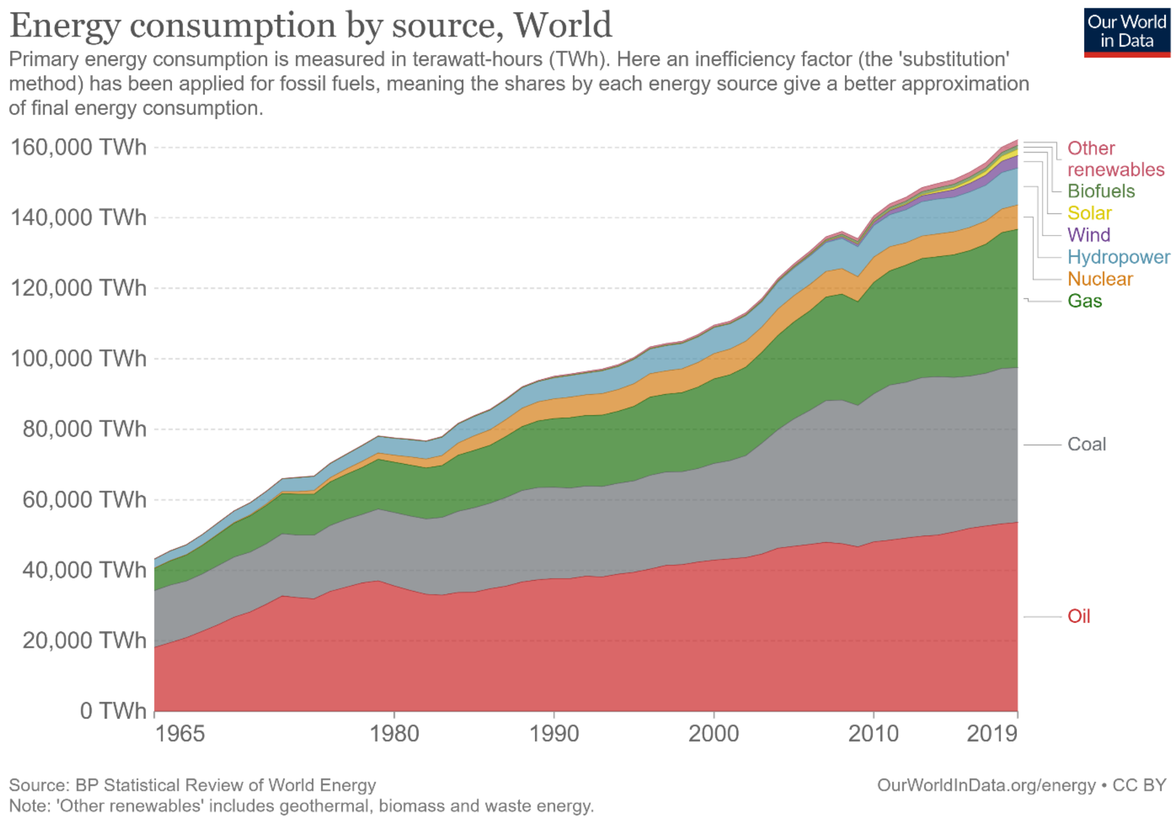


Figure 1: Graphical representation of the proportion of global energy consumption by fuel type. [8]

1.1 Why is hydrogen important?

In Scotland, wind has generated 73% of all the renewable electricity in 2020 [9]. There are plans to develop the country's offshore wind capacity and proposed projects have ensured an addition of 2.4GW [9]. The recorded worldwide wind capacity (onshore and offshore) in 2020 is about 733GW [8]. This has increased from 4GW in 1995 [8]. This has developed wind generation into an efficient and reliable renewable energy technology. Due to its advanced technology, it is the apparent choice for integration with hydrogen production. Green hydrogen has the ability to act as an alternative fuel to fossil fuels. If it is produced on a large scale, it has the opportunity to be cost competitive with other fuels whilst being renewably sourced.

1.2 How do oil and gas companies fit in to a green hydrogen future?

As oil and gas reserves are depleted, their subsea and surface infrastructure will be disused and abandoned. These rigs must be decommissioned in an environmentally-friendly way. This can incur some expense, so other options may be preferable. The rigs can be repurposed and used to promote renewable energy in the goal to become net zero. Oil and gas companies, such as Shell, must change their business to reduce carbon emissions and this may include transitioning to renewable power. Shell have recently designed an EV charging garage which will open in early 2022 and be the UK's first EV hub [10]. When rigs reach their end of life or become idle, platforms and their infrastructure will be abandoned. One way to extend their use is to concentrate hydrogen production on the platforms. This hydrogen system will prolong the life of platforms that would otherwise be left dormant or dismantled, and make use of the existing gas pipelines for hydrogen transportation. Hydrogen production can also be involved on operational oil and gas rigs where green hydrogen can be blended with natural gas to reduce the carbon footprint.

This research provides an overview of the technologies required for an offshore green hydrogen system to determine the material considerations in adopting seawater electrolysis and repurposing oil and gas platforms. Case study results are also used to show the renewable generation and hydrogen production potential of an area in the North Sea, based on offshore hydrogen production at an abandoned rig.

2.0 Hydrogen

2.1 A hydrogen economy

There is a worldwide effort to decarbonise economies in order to combat the effects of climate change. The issue with relying on renewable energy for power is its variable and inconsistent nature. Storage technologies can make a difference in the carbon footprint of an energy system. Providing a renewable energy storage system allows renewable energy to be utilised when the renewable generation is limited, by extreme wind speeds or low solar radiation, for example and this reduces the use of carbon-based fuels. Hydrogen provides many benefits for decarbonising an energy system and in particular can be utilised in the transport, residential, commercial and industrial sectors [11]. FCEVs provide a solution to decarbonise the transport sector by transitioning fuel use from petrol and diesel to hydrogen and electricity. The term 'hydrogen economy' was first used in 1970 [12] and has created interest in the possibility of hydrogen as a renewable fuel. In 2016, the European Marine Energy Centre (EMEC) installed hydrogen production in Eday, Orkney, which produces hydrogen from tidal energy and a community wind turbine [13]. The process of which is shown in ***Error! Reference source not f ound.***. In early 2021, BP proposed a project in Teeside, Scotland to produce up to 1GW of blue hydrogen by 2030 and develop the area as the UK's first hydrogen transport hub [14]. Developer Environmental Resources Management's Dolphyn project will see the "world's first" offshore floating wind farm (*Figure 3*) to produce green hydrogen and is due to provide hydrogen to Aberdeen in 2024 [15] [16]. So, why has it taken over 40 years to put the theory into practice? Hydrogen technologies have never been cost competitive with other renewable and non-renewable energies, and the transition to a hydrogen economy requires the consideration of changing production, storage, transportation and utilisation pathways [17].

Figure 2: EMEC's 'Surf 'n' Turf' project which is a hydrogen production system in Orkney involving tidal turbines, a community wind turbine and a 500kW electrolyser. The hydrogen is stored as compressed gas and transported to Kirkwall where it powers a fuel cell to generate electricity. [18]

Figure 3: A floating offshore wind turbine in the Kincardine Offshore Windfarm 15km off the Aberdeenshire coastline. An example of the type to be used in the Dolphyn project. [16]

2.2 Types of hydrogen

Water is the most abundant resource in the world and as such offers an excellent opportunity to exploit hydrogen as an energy carrier. The possibility of using hydrogen as an energy carrier (or fuel) has been debated for over 50 years. Research and development in the energy sector is progressing towards a hydrogen economy where hydrogen fuel is used in energy sectors. In the UK, for example, the government have published a policy on the country's hydrogen strategy which sets out to develop a hydrogen energy sector in the UK with the goal of creating a 5GW production capacity [19]. A future hydrogen economy involves exploration into emerging technologies which need to be understood to ensure a safe energy system. Hydrogen would play a key role in creating a 100% renewable energy system as it provides useful energy storage for variable renewable energy [20].

The energy industry uses a colour code to differentiate between the different types of hydrogen. The colour code denotes the different pathways for hydrogen production. Green hydrogen is produced with no greenhouse gas emissions. It is made through the electrolysis of water, which splits hydrogen and oxygen (*Equation 1*), using electricity generated from renewable sources, such as solar, wind or tidal power.

$$2H_2O \rightarrow 2H_2 + O_2 \tag{1}$$

Blue hydrogen is produced from natural gas through steam reforming. This process involves the reaction between methane (natural gas) and steam (*Equation 2*) at 3-25bar using a catalyst to produce hydrogen, carbon monoxide and carbon dioxide [21]. Further hydrogen is produced from the reaction between carbon monoxide and steam (*Equation 3*). Finally, any impurities such as carbon dioxide, are removed to leave pure hydrogen gas. Carbon capture storage (CCS) is used to reduce the harmful emissions from the process. Blue hydrogen is a 'low-carbon hydrogen'.

$$CH_4 + H_2O \rightarrow CO + 3H_2 \tag{2}$$

$$CO + H_2O \rightarrow CO_2 + H_2 \tag{3}$$

Grey hydrogen is currently the most widely produced. Its production is the exact same as blue hydrogen, however, CCS is not included in the process. This results in a high level of carbon emissions from production.

2.3 Production pathways

Hydrogen can be produced in a number of ways. It can be formed most commonly from fossil fuels, using hydrocarbon reforming methods, or water sources, using electrolysis as a water splitting technique [22]. Fossil fuels are the current dominant source for hydrogen production because there is still a requirement for natural gas as a fuel for power stations or residential heating, for example. Electrolysis provides a clean way of producing hydrogen from renewable sources and it is the most effective technique for splitting water [22]. Recent projects have shown advances in the energy industry transition to green hydrogen. Shell have started up

Europe's largest polymer electrolyte membrane (PEM) electrolyser to produce green hydrogen [23]. The components of an electrolyser are basic and this allows the system to be manufactured in a range of sizes fit for different conditions. There are several types of electrolysers however, all consist of a cathode and an anode, separated by an electrolyte (as shown in *Figure 4*) [22]. Electrolysers differ due to the material of the electrolyte. When an electrical current is passed through, the water splits, with hydrogen forming at the cathode (*Equation 4*) and oxygen forming at the anode (*Equation 5*). This emits zero emissions via the electrolysis reaction (*Equation 1*).

$$4H^{+} + 4Ee^{-} \rightarrow 2H_2 \tag{4}$$

$$2H_2O \rightarrow O_2 + 4H^{+} + 4e^{-} \tag{5}$$

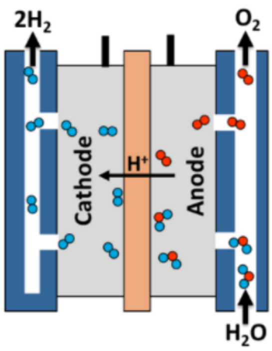


Figure 4: Diagram of the components and reactions within a simple electrolyser. [24]

2.4 Storage and delivery

Hydrogen can be stored as an energy carrier to utilise excess energy produced from variable renewable sources. Hydrogen provides a medium that can utilise the excess energy produced from the source at times of high generation. If hydrogen is produced in a central location, it can be distributed through existing pipeline infrastructure [25]. When hydrogen needs to be transported to disconnected areas, there needs to be storage options available for distribution. There are three main ways to distribute hydrogen: the transport of compressed hydrogen by road, the transport of liquefied hydrogen by road and the use of pipelines [25]. Cost is the deciding factor for the distribution of hydrogen with energy losses resulting in reduced revenue. Energy losses occur at each conversion step; production, storage and utilisation [26]. The industry choice for hydrogen storage is compressed gas. Due to the high pressures that hydrogen needs to be contained at, a well-engineered storage container is required. The materials of storage containers differ depending on if hydrogen is contained as a liquid or a gas and the pressure a gas is compressed to. High pressure containers, at 700bar, have a material composition of either all composite construction or have a metal liner and a full composite overwrap [26]. *Figure 5* shows an example and components of a high pressure hydrogen storage container.

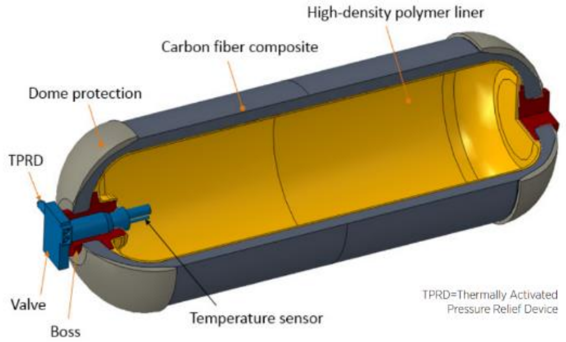


Figure 5: A diagram of a high pressure hydrogen storage container which is a composite overwrapped hydrogen pressure storage vessel. [27]

Hydrogen can also be stored as a liquid. This requires lowering the temperature to -253^{o}C [26]. This option presents a difficult issue to overcome as the container needs to withstand the low temperatures required to store the hydrogen liquid without heat transfer to or from the environment. As this involves energy losses and it also presents an issue for transportation, hydrogen liquid storage is not an ideal option.

Hydrogen can be distributed through a pipeline network, however building a new network would be a significant investment. This has urged the idea of using the existing natural gas network for hydrogen transmission. The current gas pipelines can be used for integrating hydrogen into the network as a component of a mixed gas. If hydrogen were to be transported as a pure gas, there would need to be an upgrade to the current infrastructure [25]. Transporting hydrogen through pipelines has the advantage of providing large volumes at a high efficiency however, the key disadvantage is that the network would require large volumes of hydrogen to justify the pipeline costs [28]. The UK National Grid has begun a project, named FutureGrid, in support of the path to net zero. This project aims to demonstrate how the gas network can be repurposed to transport hydrogen [29].

2.5 Hydrogen as a fuel

Hydrogen has more advantages to an energy system than only being a zero-carbon energy carrier. It has the potential to be a green fuel due to its clean burning qualities [30]. It has a place in the transport sector as fuel for FCEVs and it has 2-3 times higher efficiency than traditional gasoline [28]. Hydrogen can be used as a fuel for heating and power in industrial and residential sectors. It is an energy carrier and is therefore equipped to be an energy store for renewable generation. When renewable generation is produced at a high rate, sometimes, depending on the system, grid capacity is reached and there is excess generation. Hydrogen storage can be utilised in these instances to divert excess generation into hydrogen production. In smart grid systems, renewable energy can be stored in hydrogen to later be used. It is transformed back into power through the use of a fuel cell during periods of peak demand [31]. This therefore increases the use of renewable energy rather than reverting to fossil fuel based sources.

2.6 Limitations and development

The key limitation on the development of a hydrogen economy is the cost perspective of changing an energy system. Hydrogen has not been cost competitive with other renewable and non-renewable energies however, the cost of hydrogen solutions is expected to fall within the next decade. This comes about with an increase in hydrogen production, distribution, equipment and component manufacturing [25]. The cost is projected to decrease by up to 50% by 2030 which will make hydrogen competitive with other energy carriers [25].

Although hydrogen fuel has several advantages, its extreme low density creates a problem for its storage [32]. Storing hydrogen in containers as a compressed gas or liquid allows the option for international transport however, for national transport, pipeline transmission would be optimal to deliver a high volume efficiently [28]. For pipeline distribution to be viable, there needs to be a high production rate of hydrogen. It is apparent that the implementation of a hydrogen economy has been deferred because of the paradox between a hydrogen production system without the capability for distribution and the distribution network requiring a high hydrogen production rate.

3.0 Electrolysis

3.1 Types of electrolyser

Electrolysis is the process of splitting water into hydrogen and oxygen through electricity in an electrolyser unit (*Figure 4*). The process is important in the energy industry as it is a 100% renewable pathway to produce clean hydrogen which can be used as a fuel or a storage medium [33]. Electrolysis requires water, which is the world's largest resource, and electricity. Green hydrogen can be produced if electricity is renewably generated.

An electrolyser unit consists of an anode and a cathode separated by an electrolyte. Oxygen is formed at the anode and hydrogen created at the cathode. The electrolyte material can differ and hence different electrolysers exist. There are three main types of electrolyser: polymer electrolyte membrane (PEM), alkaline and solid oxide [34]. In a PEM electrolyser, the electrolyte is a solid plastic material. PEM electrolysers are a popular choice for coupling hydrogen production with renewable energy sources as they are well suited to do so [35]. They are able to do so because they can 'operate dynamically using varying loads of electricity' [36]. Most alkaline electrolysers use a liquid alkaline solution of either sodium or potassium hydroxide however, it is possible to use solid alkaline membranes [37]. Alkaline electrolysers usually operate below 100ºC. Solid oxide electrolysers use a solid ceramic material that conducts negatively charged oxygen ions. They produce hydrogen in a different way and require high temperatures, about 700-800ºC [34].

Hydrogen production using electrolysis is considered in partnership with renewable energy sources in order to have a zero-emission production. Currently, the most prominent production pathway for hydrogen is through natural gas reforming [38]. The main obstacle in the path to a hydrogen economy is the cost associated with implementing a hydrogen system. Electrolyser units are very expensive and hydrogen production using electrolysis is more expensive compared to carbon-based production pathways such as natural gas reforming [39].

In order to produce green hydrogen, electrolysers must be powered by renewable generation from sources such as wind or solar. Hydrogen production can be managed on-site, of wind farms for example, or at a centralised production site. Hydrogen can be utilised in a smart grid system where the production is controlled by demand. An electrolyser is capable of performing in this way as 'demand response devices' [40].

Cost reduction strategies for hydrogen production must be made for the progress towards a hydrogen energy system. In order for a hydrogen system to be cost competitive with other renewable energy systems, the processes need to be taken into account. The scaling up of electrolysers can result in a significant cost reduction [41].

3.2 Seawater electrolysis

A high volume of water would be required to produce hydrogen for a future hydrogen energy system, and purified water, which is currently the most prominent supply, is not unlimited. The oceans are the world's largest source of water and could supply the water required for electrolysis. Seawater electrolysis provides a solution for large scale carbon-free hydrogen production. The chemical makeup of seawater however, poses problems with the electrolysis reaction and electrolyser unit. The presence of sodium chloride (NaCl) in seawater causes an issue in the electrolysis process as chlorine can form at the anode and cause corrosion (described in *Section 3.2.1*).

Studies have shown that seawater electrolysis is possible via a selection of pathways. The processes are still being researched to determine the effectiveness of these pathways and other possibilities. To reduce the effects salt water has on the electrolyser, it can be treated to remove chlorine (Cl^-) before the electrolysis process. This is known as desalination or purification.

3.2.1 Material considerations with seawater electrolysis

Oceans offer a continuous source of water for electrolysis, however the electrolysis of salt water poses issues. During the electrolysis reaction of seawater, negatively charged chlorine (Cl^-) is produced at the anode and the seawater is actually desalinated whilst hydrogen is produced [42]. There have been numerous studies and experiments done to research the viable options for seawater electrolysis. The reaction can be coupled with catalysts that can sustain seawater splitting without a chlorine evolution reaction [42]. The formation of chlorine causes chlorine corrosion at the anode. A study on alkaline seawater electrolysis has shown that a new catalyst can help sustain seawater splitting without chlorine corrosion [42]. The catalyst is composed of inexpensive metal-nitrides on a porous nickel foam [43]. Reducing the effects of chlorine corrosion is very important as the corrosion limits the electrolyser life span. Research has also shown that the anode can be coated in layers rich in negatively charged materials. These layers would repel chlorine and reduce the decay rate of the anode itself [44]. A study on a small-scale seawater desalination and electrolysis system has shown that kinetic energy from flowing water, such as ocean water, can power the whole system [45]. The entire system is water-based and uses the present water for power and desalination. A recent study on electrolysis of natural water sources has shown that including a process called forward osmosis allows the water splitting of impure sources without the need for desalination or pre-treatment [46]. Forward osmosis is a water separation process which could be used to purify impure water sources (such as seawater) through a semi-impermeable membrane. During electrolysis of seawater, the formation of oxygen at the anode is the preferred reaction as chlorine is toxic and would decay the material [47]. Research has been done on the development of electrode materials that have a high selectivity for oxygen to promote the oxygen formation reaction rather than chlorine [47]. Most of this research is experimental and lab-based. It is expected that the near future will consist of electrolysis of desalinated or treated water until a commercial or industrial adaptation to the research is produced.

The seawater would be delivered to the electrolyser unit via a series of pumps and possible desalination units. The infrastructure in place would need to be treated or able to withstand the effects of saltwater corrosion. This can be reduced by improving the type of equipment material, such as a high grade stainless steel. Stainless steel is a popular alloy for pipeline material because it has a lower chance of corrosion [48]. Stainless steel has a high chromium content (Cr) compared to other alloys and hence, a lower iron (Fe) content. As it contains elements such as chromium (Cr), this acts as a protective layer and makes stainless steel resistant to corrosion [49].

3.2.2 Environmental considerations with seawater electrolysis

If seawater electrolysis is industrialised, the system will require a large volume of seawater. Although this system provides a zero-carbon alternative to fuel production, it could incur environmental issues as water is taken from a marine ecosystem. This involves the placement of infrastructure capable to deliver the seawater from the marine environment to the purification and electrolysis system. Issues could arise if there is a change in the sustainability of the environment and in the behaviour of the marine ecosystem [50].

There are environmental benefits to the process of seawater electrolyses. Desalination technologies allow water to be used in the electrolysis process that comes from a wide variety of sources [51]. This allows the use of freshwater resources, which are limited, to be reduced. The output of the system is the production of hydrogen for use as a low-carbon fuel to replace fossil-based resources and help reach the zero-carbon goal by 2050.

4.0 Offshore Green Hydrogen

Green hydrogen is seen as the fuel for the future and a solution to decarbonisation [52]. Whilst renewable technologies, such as wind and solar power, have offered a green solution for electricity generation, hydrogen can be used as a fuel. These renewable sources of energy are volatile and sometimes generate greater supply than demand, resulting in an excess of energy. Hydrogen production from renewable power allows this 'excess energy' to be fully utilised and furthers decarbonisation. Hydrogen is currently produced mainly by steam reforming for use by industry in refining petroleum and treating metals, for example [53]. Currently, 75 million tonnes of hydrogen is produced globally each year [52]. Green hydrogen only accounts for approximately 0.1% of the current global hydrogen production [54]. This is forecast to change however, as rapid growth in green hydrogen production is expected. The proportion of green hydrogen in the hydrogen market is due to increase to about 10% by 2030 [55].

4.1 Modelling the system

In order to produce hydrogen, a large amount of water is required for the electrolysis process. The world's oceans contain the largest source of water. Electrolysers currently on the market require fresh water, so the seawater would be treated for desalination and purification to remove all impurities. Wind power is one of the most popular renewable energy sources and offers opportunities onshore and offshore. This makes the technology suitable and popular for the integration of renewable generation and hydrogen production. In order to utilise the vast supply of water in the oceans for hydrogen production, offshore wind could be the renewable supply of electricity for the electrolysis process.

There are several modelling options for green hydrogen production and are categorised by their location, either onshore or offshore. Neptune Energy, a UK company, have launched an offshore green hydrogen project 'PosHYdon' which will be operated on an oil and gas platform in the North Sea, off the Dutch coast [56]. This will be the world's first offshore green hydrogen production on a platform and will be powered by offshore wind turbines. Seawater will be demineralised and used for electrolysis to produce hydrogen. The green hydrogen produced will be blended with natural gas extracted from the rig and transported using the existing gas pipeline. Environmental Resources Management (ERM) have begun a project 'Dolphyn' off the coast of Aberdeen, Scotland, which promises large scale green hydrogen from offshore floating wind turbines [57]. Each floating turbine platform will hold a 10MW turbine, a desalination system, an electrolyser unit and a hydrogen storage system (*Figure 6*). Seawater will be piped into the desalination unit and hydrogen gas will be transported through seabed pipelines to the mainland. The aim is to create full gigawatt scale hydrogen wind farms [57].

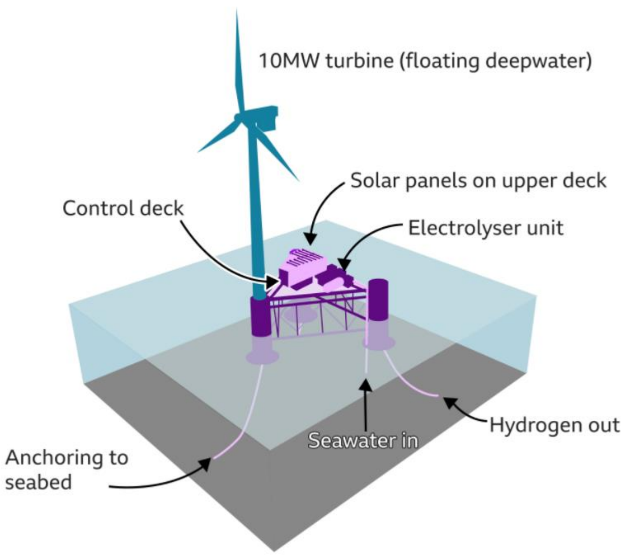


Figure 6: Diagram of the floating wind turbine design for ERM's Dolphyn project. [58]

An offshore hydrogen production system can be modelled differently depending on where the generation is produced, where the electrolyser facility can be operated and how the hydrogen is transported. *Figure 7* shows three options based on electrolyser location for offshore wind generation: an onshore, offshore and in-turbine electrolyser placement. Based on a techno-economic review of offshore green hydrogen designs, it was found that offshore electrolysis resulted in the lowest cost of hydrogen production [59]. The lowest cost was estimated to be 2.40€/kg of hydrogen [59]. This suggests that green hydrogen could be cost competitive with grey or blue hydrogen, which currently costs between $0.70 and $2.20/kg [60]. There is a range in cost due to the ranging price of coal or natural gas to produce the hydrogen.

An onshore electrolyser can be positioned in close proximity to existing gas pipelines and these can be used for hydrogen transmission. There would be little infrastructure required for this option as the only offshore component of the system would be the turbines, however, the power generated from the turbines would need to be delivered to the hydrogen production facility. Although in-turbine electrolysers are a relatively new concept, they would offer the ability for hydrogen production offshore with direct transmission from the turbine. This would incur costs for placement of sub-sea infrastructure. ITM Power and Ørsted have work on wind turbine and electrolyser integration to reduce overall costs of the system, as a hydrogen pipe network costs less per km than power cables [61]. An electrolyser located on an offshore substation allows for offshore hydrogen production and transmission directly to the gas network. Oil and gas platforms could be used as substations and offer the unique advantage of containing existing infrastructure. Gas pipelines that are already in place could be utilised for hydrogen transport direct into the grid system.

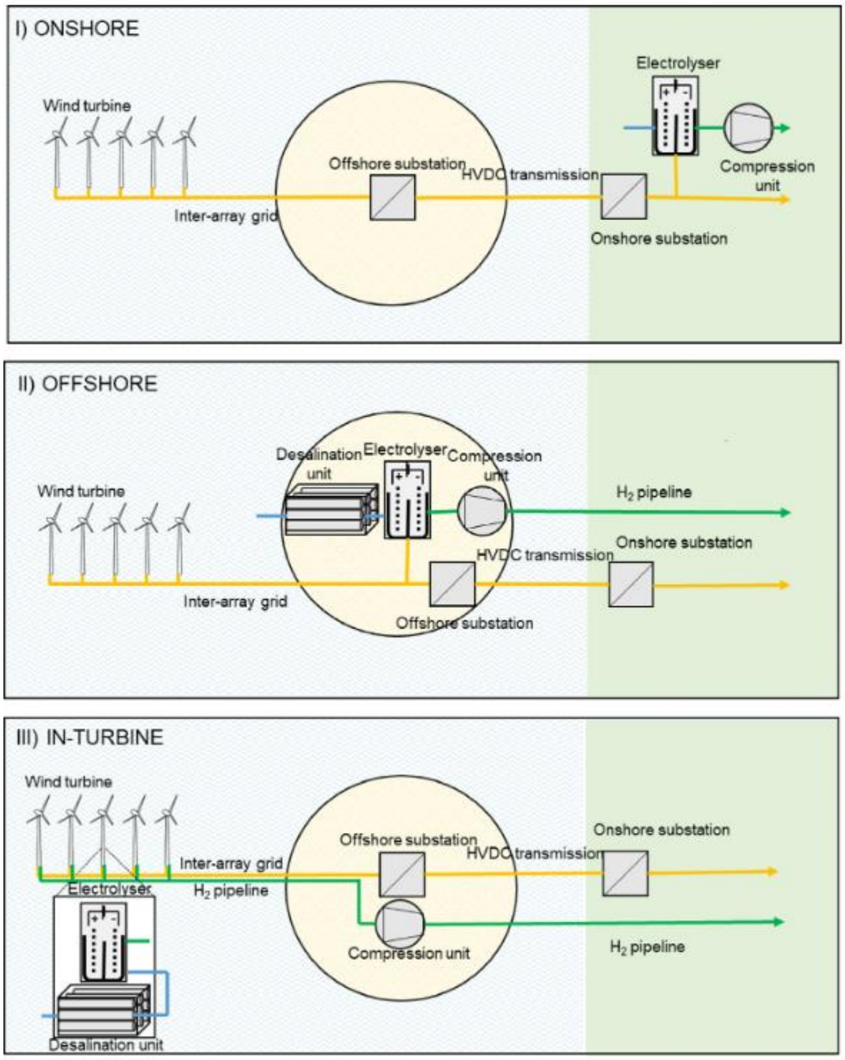


Figure 7: Diagram of the electrolyser placement options. [59]

4.2 Renewable generation

Energy from renewable sources is never constant but can sometimes produce excess energy when demand is low. Hydrogen provides an energy storage which can be utilised for times of low or zero generation. For a system to become 100% renewable, it must rely on a sufficient energy storage system to provide energy for times of zero production, for example, when there is insufficient wind or sunlight. There are advantages to marine technologies, such as tidal energy, to provide power for electrolysis as this would provide a constant power input. Tidal energy is still in experimental stages, where the ideal design of tidal turbines is still debated and there are few operational projects compared to wind or solar energy. Tidal turbines could be coupled with electrolysers to produce hydrogen from water flow and there have been lab-based studies to show the effectiveness of the system. A study of a hybrid tidal turbine and hydrogen micro-grid showed that hydrogen production can be used as an "energy buffer" for the variance in generation [62]. There have also been studies on the effect of hydrogen production from wave energy. A study based on an off-grid system showed that it is possible to produce hydrogen in a sustainable way using wave energy to power electrolysis. Seawater was used in the experiments and was fed directly into a PEM electrolyser using reverse osmosis to separate the impurities in the water [63].

4.3 Hydrogen production

Hydrogen is produced using an electrolyser unit which requires energy to split water into oxygen and hydrogen. Electrolysers are rated on their size and production capacity and can be a variety of sizes. The production rate varies depending on the electrolyser capacity. Hydrogen could be produced onshore or offshore (*Figure 7*). Offshore hydrogen production is favoured mostly due to cost factors. The production of hydrogen at sea allows for direct uptake of seawater with minimal costs regarding piping infrastructure. Although hydrogen pipelines would be required for the transportation of the gas, the cost of this is less than the cost to carry electricity to the mainland [64]. For an onshore production facility, subsea electricity cables would be required to transmit power from the turbines to the electrolyser(s). Electrolysers can be located onshore, offshore and in-turbine. The preference of each will be location and cost dependent but the option to have an electrolyser in each position gives an adaptable advantage for offshore green hydrogen production.

Rather than building substations for electrolysers, existing infrastructure can be utilised. In the North Sea, for example, the oil and gas industry exploit resources with 184 offshore rigs [65]. Globally, there are over 1,000 offshore rigs in the world's oceans, all of which will eventually reach end of use as resources are depleted [65]. These platforms could be repurposed to provide a place for electrolysers to operate and act as a hub for offshore energy.

4.4 Hydrogen transmission

Hydrogen can be stored and transported however it may be possible to repurpose existing natural gas pipelines for hydrogen transmission. In most countries, gas pipelines are nationwide and the inclusion of hydrogen into the network would allow for hydrogen integration into the energy system. There have been studies to show that hydrogen can be mixed with natural gas to lower the carbon footprint of the oil and gas industry however, it is also possible to transport green hydrogen alone to reduce the carbon emissions to zero [66] [67] [68].

If offshore rigs were to be repurposed and used for a green hydrogen system, existing gas pipelines could be used to transport hydrogen gas. This is a huge advantage for offshore hydrogen production as hydrogen can be transported directly from the source. Subsea electricity cables to the mainland may not be required as the electrolyser could receive power from neighbouring renewable sources and hence be 'off-grid' [69]. Offshore green hydrogen projects may involve production from excess renewable generation in which case the wind farm would be connected to the grid and also the electrolyser unit for production in periods of surplus generation [70].

4.5 Difficulties with implementing an offshore green hydrogen system

As with most projects, the major struggle with offshore green hydrogen is overcoming the cost obstacle [71]. Green hydrogen production costs are much higher than grey or blue hydrogen and in order to encourage the transition to green hydrogen, costs need to be reduced. A clear way to reduce costs, is to increase the production. This can be done through scaling up electrolysers to produce more hydrogen [72]. Construction of the required equipment and infrastructure to accommodate the hydrogen production system could be reduced by repurposing existing oil and gas platforms and pipelines. This would reduce the cost of production and enable the decarbonisation of the industry.

Producing green hydrogen offshore involves using seawater as the source. As salt water corrosion can affect equipment, material coating would be required to reduce its effects. Desalination, treatment or separation techniques would be required to remove impurities in the water source for electrolysis. A study found that PEM electrolysis would be the best option for offshore green hydrogen production based on economic and environmental factors and that it would not "suffer irreversible damage from impurities" in seawater [73].

5.0 Decommissioning and Repurposing of Offshore Oil and Gas Platforms

5.1 The energy industry transition

Although the energy industry is becoming ‘greener’, oil and gas are still the dominant fuel for energy consumption in the UK and worldwide [74]. The UK oil and gas authority will help the country to reach the net zero emissions goal by 2050 by employing the active decommission of infrastructure and appropriately repurposing the infrastructure to aid in green energy production [75]. Decommissioning will occur when the oil or gas field has reached its maximum economic potential whereby the resource is depleted. The industry will continue to support the energy system however the decommissioning of the UK’s offshore oil and gas production will occur in the next 30 years [75]. During this time, modifications will be made to the industry practice to include carbon capture storage (CCS) to reduce emissions and support renewable energy production by repurposing. The UK aims to encourage a green industrial revolution where renewable technologies will dominate the energy industry and ensure the goal of net zero is met [76]. The UK government has therefore proposed a ten-point plan to begin this green revolution (*Figure 8*).

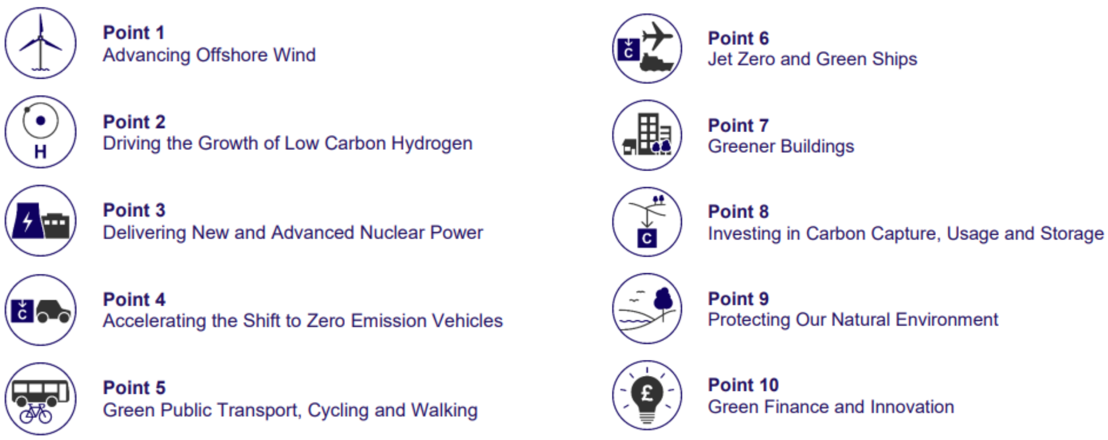


Figure 8: The UK Government’s ten point plan for a green industrial revolution. [76]

‘Gas goes Green’ is another project that aims to reduce carbon emissions from the oil and gas industry. The focus is to create the world’s first zero carbon gas grid by bringing together all five of the UK's gas network companies to provide bio-methane and hydrogen gas as alternatives to natural gas [77]. This energy transition will take time, significant investment and the involvement of oil and gas in the energy system will continue as demand remains.

5.2 Decommissioning oil and gas infrastructure

In areas such as the North Sea and the Gulf of Mexico, where oil and gas exploration and extraction is prominent, many oil and gas reserves are almost at their end of life. As reserves have been depleted over the last 50 years, the infrastructure in place will be abandoned. There are already several abandoned platforms in the North Sea (pictured in *Figure 9*). The decommissioning process involves removing all infrastructure in place, including the rigs, platforms, and pipelines. This involves plugging wells, cleaning and removing all pipelines, removing the platform from the foundations, disposal of the platform, and ensuring that the entirety of the infrastructure is cleared to reduce the risk of debris to the environment [78].

There are options to prolong the life of a platform (described in *Section 5.3 p.22*), however the infrastructure itself will eventually need to be removed as it reaches its end of life. They would no longer be suitable for their repurposed need and would incur safety concerns. There are several options for the complete removal. An artificial reef can be created from sinking infrastructure to the sea bed. The infrastructure can be disposed of in deep water or can be dismantled and recycled onshore.

Figure 9: Abandoned oil rigs in the Cromarty Firth, in the north of Scotland. [79]

The creation of artificial reefs is only applicable to certain structures and cannot be done in deep waters, however infrastructure can be moved and placed in shallower waters. The current processes of removing oil and gas rigs are unsustainable and cause ecological and economical imbalance [80]. Introducing an artificial reef minimizes the cost of decommission whilst offering an ecological benefit of improving the habitat and restoring biodiversity [80].

5.3 Repurposing oil and gas infrastructure

Decommissioning and total removal of the infrastructure may not always be the best option for abandoned rigs. Current practices in decommissioning follow a guide that prioritises the use of a structure. The guide follows the order: to prolong, reuse, repurpose, recycle and dispose [81]. If a platform is appropriate for further use, it can possibly be used to enable 'green' technologies. The 'jacket' of a rig is the underwater section that supports the platform and anchors it to the seafloor (*Figure 10*). If a platform's topside is dismantled and removed, the jacket can remain in place as an artificial reef and serve purpose to enrich the marine environment [82]. Platforms can be used in offshore renewable projects. They can act as sites for wind turbines or can be used to hold generating equipment for offshore wave or tidal energy projects. They could provide the infrastructure for offshore solar panel arrays and also sites for aquaculture projects [82].

The oil and gas demand will not suddenly stop therefore production is still required. In order to reduce the greenhouse gas (GHG) emissions of the process, CCS can be introduced. This would involve including CCS equipment on the platform to remove carbon dioxide (CO_2) from the natural gas. Studies have shown that this decreases the energy efficiency of the production however, it does significantly reduce the emissions [83]. A platform can be decarbonised by becoming a power plant to produce electricity from natural gas. A study has shown that the best CCS cycle for integration with an oil and gas power system, based on power output and system weight, is considered to be a back-pressure steam turbine [83]. This provides all the steam and power required for CO_2 capture and it is a relatively light system that can be added to the platform topside [84]. Reductions in the cost of clean natural gas are required to make this option cost competitive with other clean energies as a study found that the cost of production at an offshore site is more than double that of an onshore gas power plant [85].

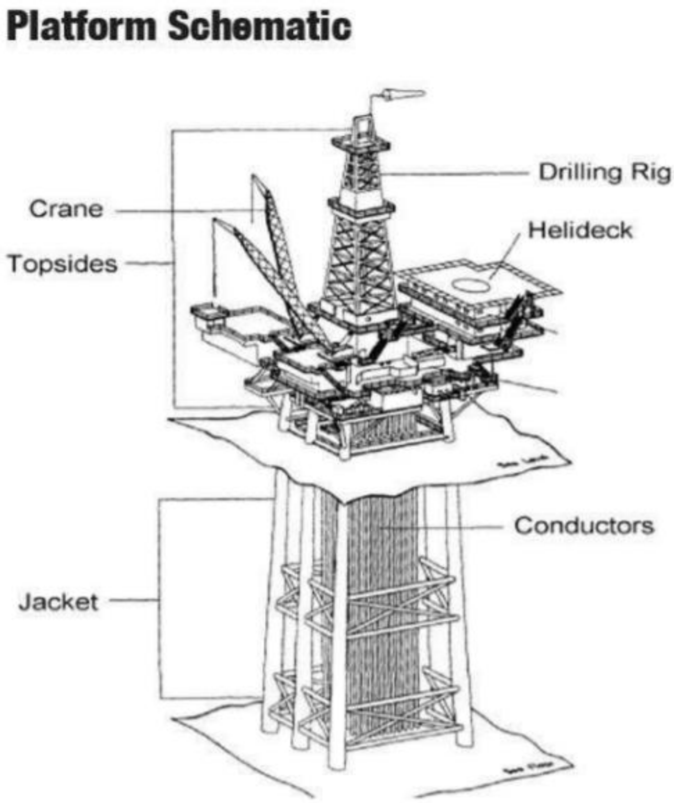


Figure 10: Diagram of a typical offshore platform showing the main sections. [82]

Most platforms have oil or gas pipelines connected to the mainland. These pipelines could be modified to transport hydrogen gas or a blended mixture of natural gas and hydrogen. The presence of a mainland pipeline connection allows a platform to be considered for hydrogen production (described in *Section 6.2 p.25*). Renewable generation from an offshore wind farm or wave/tidal energy array could power an electrolyser to produce hydrogen for integration into a gas grid [86].

6.0 Hydrogen Delivery

Storing and transporting hydrogen is perhaps the most difficult stage in a hydrogen energy system. It comes with many challenges due to the element's low volumetric energy density, high diffusivity and high flammability [87]. These chemical characteristics set challenges such as minimising hydrogen leakage and increasing energy efficiency through delivery [88]. Hydrogen can be transported in gaseous or liquid form however, it needs to be kept at an extremely low temperature (-253ºC) as a liquid. It requires energy to liquefy hydrogen, which 'consumes more than 30% of the energy content of hydrogen' [89]. This process is expensive and inefficient, so the delivery processes considered involve gaseous hydrogen.

6.1 Road transportation using tube trailers

Tube trailers contain pressurised containers for hydrogen storage and transport the gaseous hydrogen from distribution centres to hydrogen refuelling stations or end use industries [90]. Hydrogen is compressed to about 180bar and stored in metal containers that can be transported by road [91]. A certain risk factor is associated with transporting hydrogen as there is a chance of leakage and the gas is highly flammable. There are various types of pressurised containers and the material can affect the safety level of storage. An all-metal container has a relatively low cost however, the high container to hydrogen weight ratio can lead to the possibility of hydrogen permeation to the material and hydrogen embrittlement (described in *Section 6.3 p.27*) [90]. Hydrogen embrittlement occurs when the container material, such as steel, becomes brittle due to the diffusion of hydrogen into the metal [92]. Materials that characterise high strength, such as steel, have an increased susceptibility to embrittlement and hence, an all-metal container has a high risk of hydrogen leakage. Hydrogen leakage will occur if embrittlement causes cracking in the material. Containers composed of metal and carbon fibre have a lower container to hydrogen weight ratio and lower risk of embrittlement however are more expensive [90]. The most expensive container type is made of an all-composite construction [90]. These have a very low container to hydrogen weight ratio and a very low leakage risk.

6.2 Transmission through natural gas pipelines

Hydrogen gas could be transported via the existing natural gas pipeline network. *Figure 11* shows the UK National Grid network as an example. There are two options for incorporating hydrogen through the pipeline network; either blending hydrogen with natural gas or repurposing the existing infrastructure to manage hydrogen gas alone [67].

Blending hydrogen with natural gas allows hydrogen to be slowly introduced into the energy system however, it does not significantly reduce the greenhouse gas (GHG) emissions. In order to do so, hydrogen would need to be separated from the blended mixture to be used as a 'green' fuel. Hydrogen can be blended with natural gas at a proportion of up to 15% [93]. The hydrogen can either be extracted from the blend, to be used in FCEVs, or the combined gas mixture could be used to fuel industry or residential needs, for example. The UK National Grid has a hydrogen project with the aim to include hydrogen gas into the energy network. Current blending tests have been experimenting with hydrogen at a 5-15% inclusion proportion however the National Grid have already introduced a 20% blend to a small network in the UK [94]. Increasing the percentage of hydrogen in the mix does reduce the GHG emissions but also introduces more problems. As the proportion of hydrogen is increased, the pipeline material will become less effective, the chance of leakage increases and the safety of the system is reduced [95]. The pipelines would be more prone to hydrogen embrittlement as the hydrogen content of the mixture is increased. This would incur significant costs in the improvement of the infrastructure. If hydrogen is to be separated from the blend, extraction and purification process plants would need to be introduced close to the point of end use [95]. Membrane technology has been shown to effectively separate hydrogen from blended mixtures of natural gas using lead metal or lead metal alloys as hydrogen purification membranes [66].

The current natural gas grid cannot be used to transport 100% hydrogen gas due to the differences in physical and chemical properties of each gas. The pipelines would degrade after long exposure to hydrogen at a high pressure. The network would therefore have to be improved to handle the degrading effects of hydrogen transmission. This would be costly, however repurposing the existing network would be more cost-effective than constructing an entirely new hydrogen network [93]. The UK National Grid has started a project, named FutureGrid, which will consider the possibility of converting the national transmission system to transport hydrogen [96]. The project will operate in a facility that will represent a whole network system where blends of up to 100% hydrogen will be incorporated into the pipelines.

Figure 11: National Grid network route map of the UK. [97]

6.3 Hydrogen embrittlement and repurposing pipelines

Hydrogen embrittlement occurs when hydrogen is able to enter high strength materials, such as steel [98]. It causes damage to metals and reduces the strength of the material, making it brittle and prone to cracking. It can result from three main instances [99]:

- Hydride formation on the material. The presence in pipelines causes an increase in pressure at points of formation and an increase in the chance of cracking.
- A reaction between hydrogen and an impurity or alloy addition in the metal. This could form precipitates on pipeline material.
- Hydrogen can be adsorbed on or absorbed in the metal which can result in surface cracking.

Hydrogen damage can occur from hydrogen stress cracking (HSC). This occurs when acids corrode high strength materials. It is also known as sulphide stress cracking (SSC) when hydrogen sulphide (H_2S) gas is present [100]. The gas is produced from the breakdown of bacteria in the absence of oxygen and is often produced during crude oil and natural gas drilling [101]. When H_2S gas is present, it is known as a sour environment and these are typically found in oil and gas exploration and production lines.

Hydrogen embrittlement must be mitigated to increase the efficiency and safety of hydrogen transmission. A case study in Germany has defined four options of repurposing to reduce hydrogen embrittlement and pipeline cracking [102]. If pipelines are not modified in any way, hydrogen embrittlement is reduced through increased maintenance and repairs. The surfaces that are in direct contact with hydrogen can be coated to reduce adsorption or absorption of hydrogen into the pipeline material. Gaseous inhibitors can be added to the hydrogen gas to reduce the likelihood of reactions occurring between hydrogen and impurities in the pipeline. This is done to prevent H_2S corrosion. A pipeline specialised for hydrogen could be inserted into the existing pipeline, supplying a barrier to protect the existing pipeline.

7.0 UK Case Study: Offshore Green Hydrogen Production in the North Sea

7.1 Climate change targets and decommissioning

The UK government has set a goal of reaching net zero carbon emissions by 2050 [103]. In order to stay on track of reaching this target, the coming years have been separated into carbon budget periods. The Climate Change Committee has stated that the country is not on track to meet the targets set by the fourth, a 51% reduction compared to 1990 levels by 2025, and fifth, a 57% reduction compared to 1990 levels by 2030, carbon budgets [103]. If the carbon budgets are not met by 2030, it reduces the likelihood of reaching the ned goal in 2050. Policy initiatives have been promoted to encourage energy providers and consumers to reduce their carbon footprint. One of which is the Emission Trading Scheme, which is relevant for energy-intensive industries. It incentivises them to lower emissions and save money by charging for every unit of emissions. Another is the Climate Change Levy, which is a fee paid by polluters on every unit of energy consumed. There are several more policy initiatives that all have a similar aim – to reduce emissions. The energy sector must be changed to have a renewable energy focus and a transition towards renewable energy being the predominant source of fuel.

In order to become carbon neutral, some energy providers will need to change their business. Oil and gas distributors, such as Shell and BP, have been the main fuel providers for the UK [104]. Their main source of fuels are oil and gas from the North Sea's UK Continental Shelf (UKCS). This basin holds the most platforms in the world and can be referred to in *Appendix 1 (p.58)* which shows a map view of the UKCS infrastructure in quadrant 20 [105]. The North Sea Transition Deal has been created to tackle the challenges of reaching net zero whilst utilising the energy from the UKCS until the area reaches maturity. This will predominantly be done through carbon capture storage (CCS) and hydrogen production [106].

Platforms and infrastructure will need to be decommissioned to minimise environmental and safety concerns (as described in *Section 5 p.20*). In the UK, the Oil and Gas Authority (OGA) have produced a decommissioning strategy. This has a priority on cost certainty and reduction [107]. This has led to the creation of the North Sea Transition Decommissioning and Repurposing Task Force which aims to support industry with meeting the net zero target [108].

From the OGA's Energy Integration Project report, key uses of repurposing the platforms are CCS, easing the expansion of renewables, as well as blue and green hydrogen production [109].

The UK currently has over 10GW of offshore wind operational capacity. This contributed to 13% of the total electricity generation in 2020 [110]. There are more offshore wind projects planned to increase the capacity further. With an increasing interest in offshore wind, the decision between decommissioning or repurposing platforms is made easier. Platforms can act as hubs for offshore wind generation with infrastructure already in place for energy transmission. Platforms are equipped for large heavy machinery, some are equipped with living areas for maintenance crews and many are connected to the natural gas National Grid. With the clearance of refinery and oil machinery, other infrastructure can be brought in. The platforms could be repurposed for the placement of electrolysers from which green hydrogen could be produced.

The North Sea has been an area of intensive oil and gas industrial works, however with the rate of the energy transition, the goal of net zero, and the increase in available renewable energy production, these companies must consider different options to deliver power. The industry has to consider the decommission of infrastructure and the ways in which this can be done as well as repurposing platforms to introduce new, greener technologies for power generation. There have been studies to incorporate hydrogen production through gas reforming with the result of a mixed gas (natural and hydrogen) being delivered [111]. This helps in the path to net zero emissions however doesn't reduce the carbon emissions from the process entirely. Green hydrogen can be produced from the electrolysis of sea water using offshore wind power generation and can be used as a 100% renewable fuel.

7.2 Case study description

This case study explores the possibility of green hydrogen production at repurposed oil and gas platforms from offshore wind generation using floating wind turbines. The analysis has been done using generation from one turbine powering one electrolyser unit. Wind generation and hydrogen production have been calculated for a given year and the results have been discussed. The purpose of the case study is to determine whether offshore green hydrogen projects such as these are feasible and the impact green hydrogen would have on the energy system as a whole.

7.3 Case study location

This case study has been theorised using Shell's Goldeneye platform (pictured in *Figure 12*). Goldeneye exported gas and was operational from 2004 to 2010, finally being shut in 2011 [112]. Most platforms are situated over 100km from the coast of Scotland. Goldeneye was one of the closest platforms at a distance of 100km from the Aberdeenshire coast, located in between quadrants 14 and 20, in the Central North Sea (as shown in *Figure 13*). It was located near five major gas pipelines that transport to St Fergus, north of Peterhead, however the platform had a direct gas pipeline to St Fergus. The sea depth is approximately 120 metres at the platform. Goldeneye has recently been decommissioned following the approval from the Offshore Petroleum Regulator for Environment and Decommissioning (OPRED). The decommissioning programme for this platform was approved in November 2011 and the platform has been removed in October 2021 [113]. This platform has been chosen as the basis for analysis as it was an abandoned platform which had a direct gas pipeline connection to the mainland and was sizable to house hydrogen production equipment. This analysis should indicate whether Goldeneye could have been used as a hydrogen production hub.

Figure 12: Shell's Goldeneye platform [112].

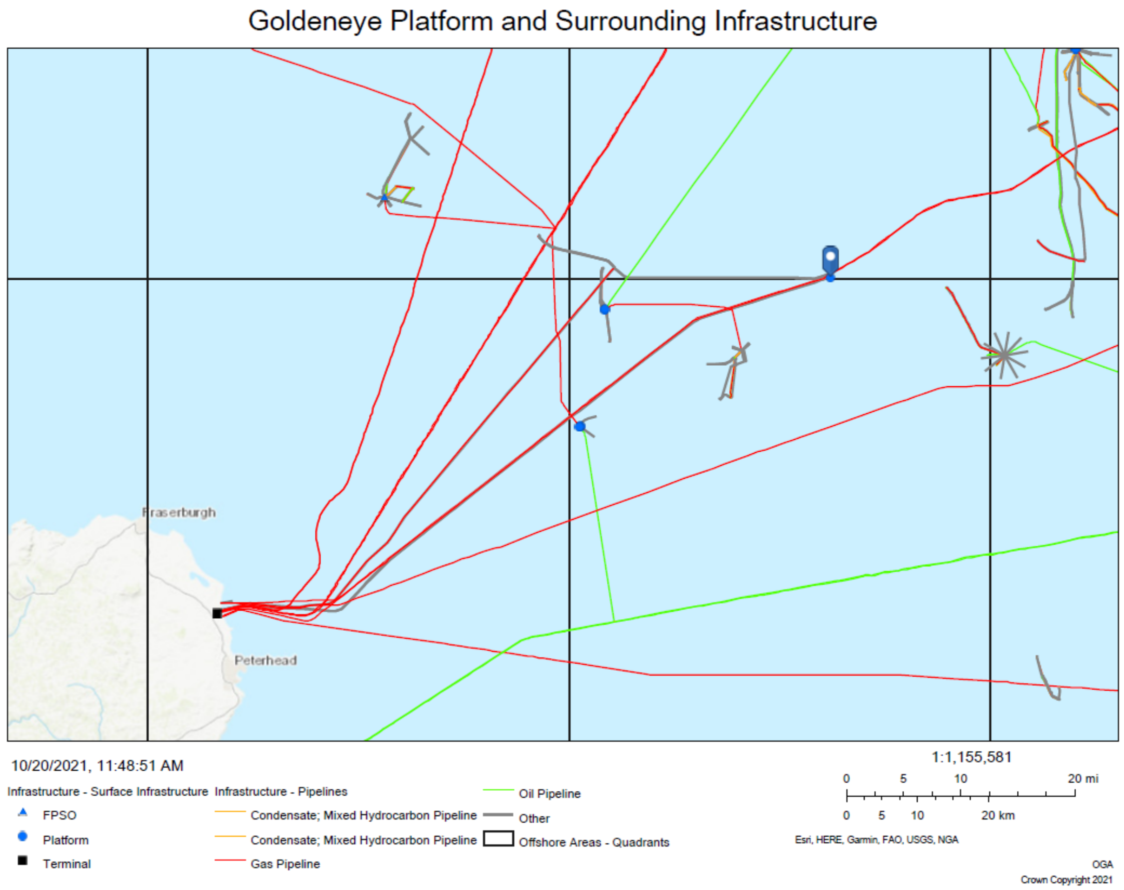


Figure 13: Map of the Goldeneye platform (marked) and surrounding infrastructure [114].

7.4 Wind generation

7.4.1 Wind generation as the renewable source

Offshore wind power is more reliable than onshore as there is a higher probability of adequate wind speeds at sea [115]. This statement is concurrent with the distance from the shore as well – the reliability of wind power increases as the distance from shore increases. As the distance from shore increases, so too does the water depth and this creates an issue for fixed turbines which cannot be constructed in deep seas. Floating turbines offer the chance to harness the wind from further off shore. The Kincardine Offshore Floating Wind Farm is currently operational 15km off the coast of Aberdeen, consisting of five 9.5MW Vestas turbines, and one 2MW Vestas turbine [116]. The 2MW turbine has been operational since October 2018 and so the calculations for wind generation at Goldeneye have been based on this turbine, as it is a known operational floating wind turbine. The Kincardine wind farm is located in waters ranging between 60 to 80 metres, compared to Goldeneye where the water depth is 120 metres. Floating wind turbines offer the exploration of production at deeper offshore sites and can be placed near abandoned platforms that can be repurposed as bases of power for wind farms. These platforms also offer a location for hydrogen production. The Goldeneye platform is a sizable normally unattended installation (NUI) with two accessible levels and is capable of housing an electrolyser. Utilising platforms gives the infrastructure a longer life whilst aiding in achieving the net zero carbon goal. Offshore wind generation is the ideal renewable energy option for producing green hydrogen as the technology has advanced to provide efficient power systems.

7.4.2 Wind generation calculations

The wind generation was calculated using the specifications of a 2MW Vestas (V80) turbine. The generation profile was based on one turbine to determine the possible hydrogen production quantity. The specifications for the turbine can be found in *Appendix 2 (p.59)*. Hourly wind speed for the year 2020 was used to create generation profiles and this was taken from NASA's Prediction of Worldwide Energy Resources data [117]. The wind speed was taken from the coordinates of the Goldeneye platform (58.002, -0.384). The wind speed was not averaged using several years' worth of hourly data because periods of low wind speeds would not be recorded and this would give deceiving results based on high wind speeds with few periods of low to zero generation. The data source provided wind speeds from a height of 10 metres above sea level. This was altered to the wind speed at the hub height of the turbine (which was 67 metres) using *Equation 6*. The surface roughness was determined to be 0.0005 as the terrain is expected to be a 'blown sea' [118].

$$v_{hub} = v_{anem}\left(\frac{\ln\left(\frac{z_{hub}}{z_o}\right)}{\ln\left(\frac{z_{anem}}{z_o}\right)}\right) \tag{6}$$

The power curve for this turbine can be found in *Appendix 3 (p.59)* [119]. The power coefficient (C_P) was calculated using values from the power curve, the known constants (detailed in *Appendix 4 (p.59)*) and *Equation 7*.

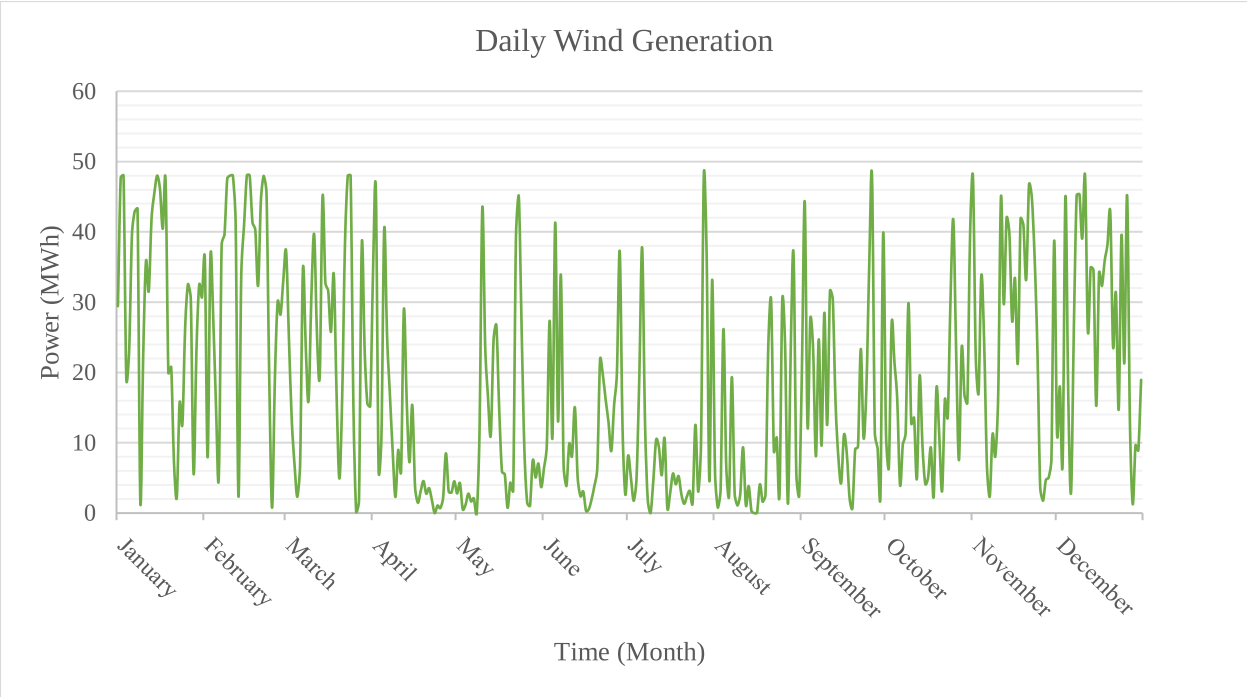
$$C_P = \frac{2P}{\rho A v^3} \tag{7}$$

Two criteria were formed to determine the power output of the turbine at different wind speeds. This was done using the altered hourly wind speed data. Since the turbine produces the rated power (2MW) at wind speeds between 14.5m/s and 25m/s, the first condition stated that if the wind speed at the hub height was less than or equal to the cut-out wind speed (25m/s) and greater than or equal to the rated wind speed (14.5m/s), the turbine would produce the rated power (2MW). The second condition stated that if the wind speed at the hub height was greater than or equal to the cut-in wind speed (3.5m/s) and less than or equal to the rated wind speed, the turbine would produce a power output using *Equation 8*.

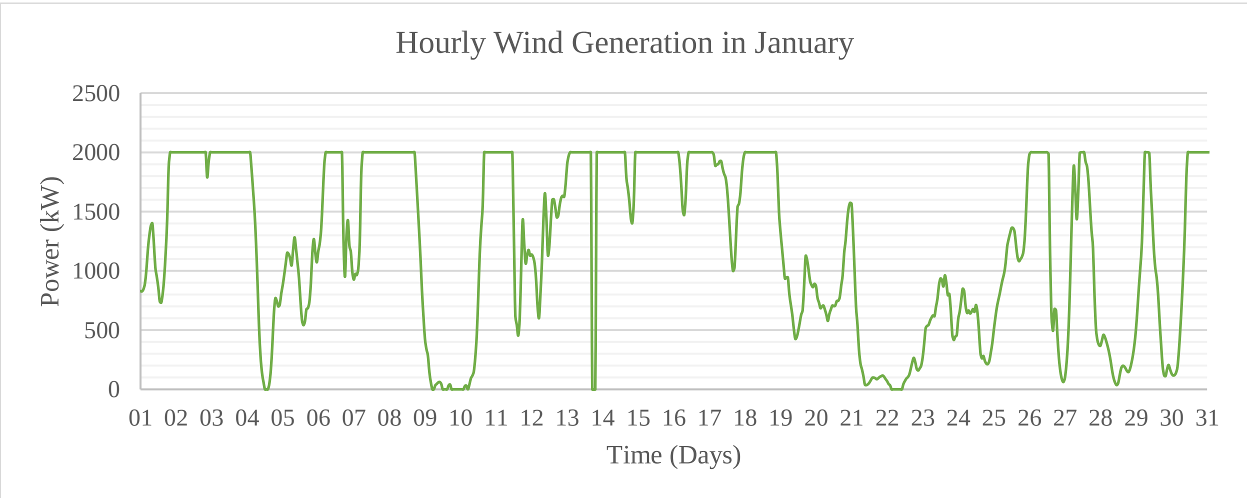
$$P = \frac{1}{2} C_P \rho A v^3 \tag{8}$$

7.4.3 Wind generation results

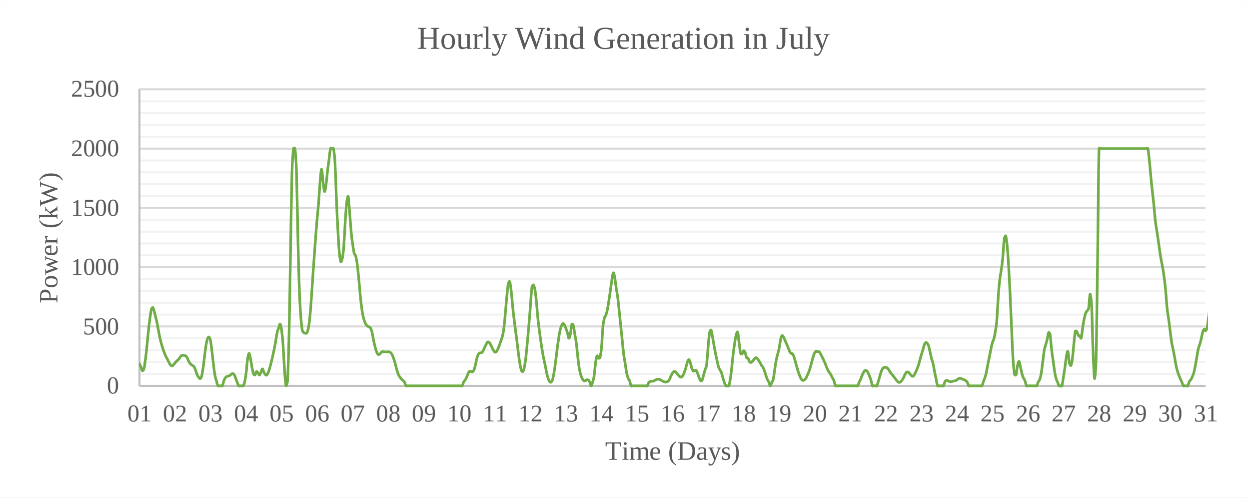
The wind generation was calculated in hourly increments over the course of a year. A generation profile was created using the daily average generation in 2020 (shown in *Graph 1*). The annual generation from one 2MW Vestas turbine has been calculated as 6.8GWh. There is however, a significant seasonal difference in generation rates. *Graph 2* and *Graph 3* show the monthly generation profiles of January and July using hourly data. There are noticeably fewer periods of peak generation in July than in January with the average daily wind generation in July (417kW) being less than half that of January (1227kW).



Graph 1: Wind generation profile for 2020 showing the daily average generation in MWh.



Graph 2: Wind generation profile for January 2020 showing the hourly generation in kW.



Graph 3: Wind generation profile for July 2020 showing the hourly generation in kW.

7.5 Hydrogen production

7.5.1 The electrolyser

The hydrogen production was based on polymer electrolyte membrane (PEM) electrolysis using an ITM Power PEM electrolyser (model HGAS3SP) which is a 60ft long container that produces hydrogen at 20barg (shown in *Figure 14*) [120]. The maximum input power is approximately 2,350kW, so the calculations were based on the power supply from one Vestas V80 (2MW) turbine. The maximum rate of hydrogen production is approximately 36kg/h. PEM electrolysis was chosen as it typically has a high rate of hydrogen production, has a compact design, can operate at low temperatures (80ºC), can quickly react to fluctuations typical of renewable power generation and is generally low maintenance [121]. A study on PEM electrolyser efficiency found that the efficiency can range between 70% to 90% [122]. An initial production calculation was done using an efficiency of 70% to set the lower production bound and reduce the uncertainty of over-exaggerating production rate. In order to test the difference in production depending on the electrolyser efficiency, a second calculation was based on an efficiency of 90% to set the higher production bound.

Figure 14: Model of an ITM Power PEM Electrolyser (Model HGAS3SP) [120].

7.5.2 Hydrogen production calculations

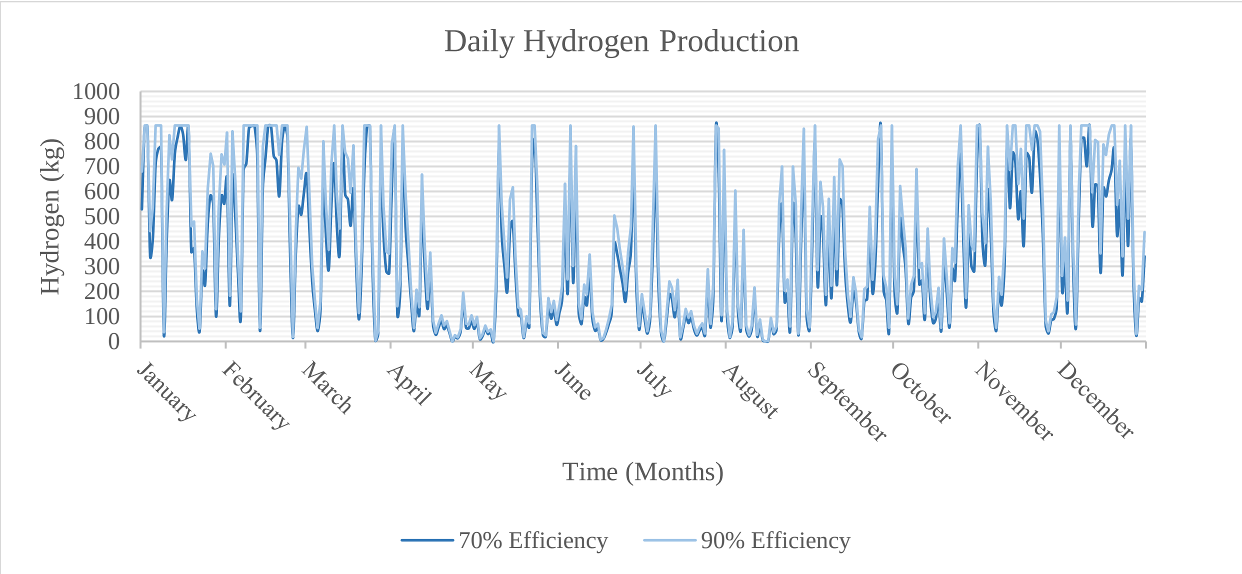
The specifications for the HGAS3SP PEM electrolyser can be found in *Appendix 5 (p.60)*. A wholly efficient electrolyser, that is an electrolyser with a 100% efficiency rating, can produce 1kg of hydrogen from 39kWh of energy [123]. Since the PEM electrolyser is assumed to have a low efficiency of 70% and a high efficiency of 90%, it can be assumed that this electrolyser can produce 1kg of hydrogen from 55.71kWh of energy at 70% or from 43.33kWh of energy at 90%. For the simplification of the calculations, it was assumed that all of the energy produced from the turbine would power the electrolyser each hour and was calculated using *Equation 9*.

$$Hydrogen\,production\,(kg) = \frac{Renewable\,Power\,Output\,(kW)}{\left(\frac{39}{Electrolyser\,Efficiency\,(\%)}\right)} \tag{9}$$

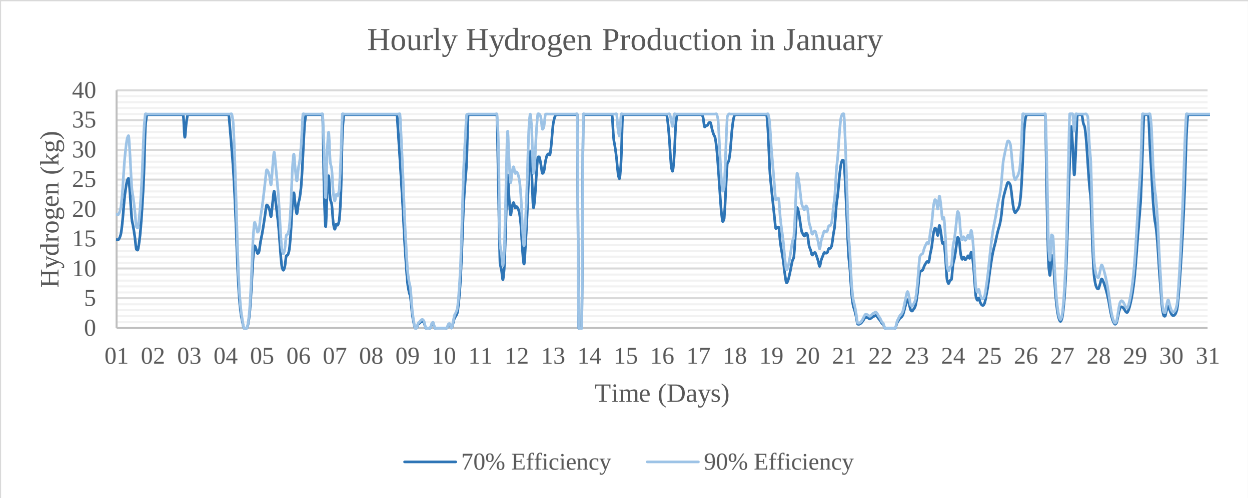
It was assumed that the hydrogen produced would be transported directly into the gas pipeline, therefore a storage option was not considered, and hydrogen production could be constant as long as there was a renewable power input. The electrolyser has a maximum production rate of 36kg/h so the production was set a condition whereby the hydrogen output was limited to 36kg/h. If there was a period where there was enough energy input to produce more hydrogen, this energy was calculated as excess generation from the turbine.

7.5.3 Hydrogen production results

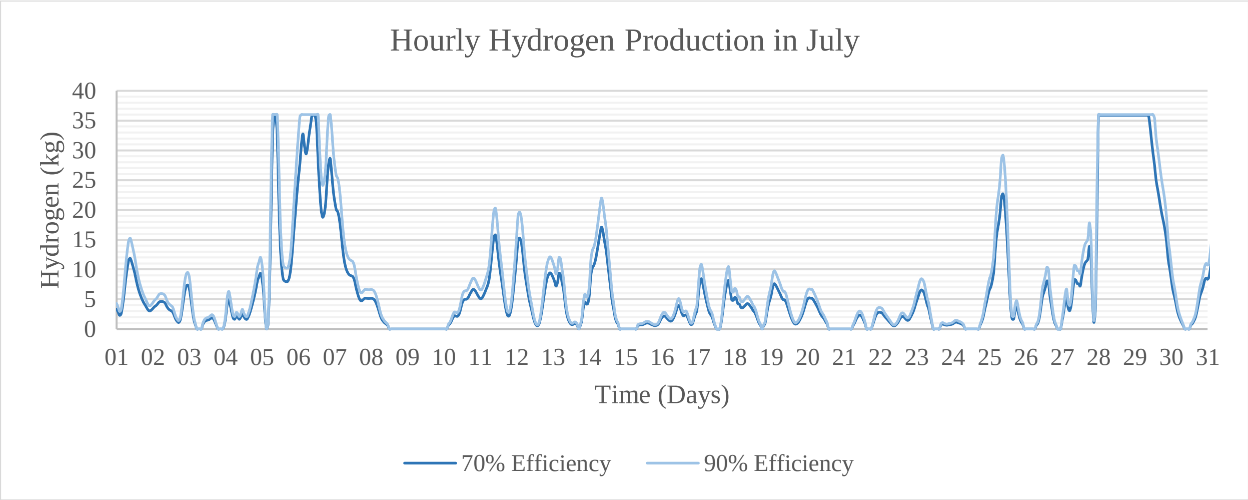
The hydrogen production was calculated on an hourly basis using the hourly wind generation results. Since only one turbine is being considered in this analysis, the hydrogen production rarely reaches production capacity (36kg/h). For the given year, total annual hydrogen production is approximately 123-149 tonnes depending on the electrolyser efficiency being between 70-90%. This is shown on *Graph 4*, where production is shown on a daily basis. *Graph 5* and *Graph 6* mirror the generation profiles (*Graph 2* and *Graph 3*) whereby there is a definite seasonal variance. Increasing the electrolyser efficiency from 70% to 90% increases the hydrogen production by an average of 25%.



Graph 4: Hydrogen production profile for 2020 showing the daily average production in kg.



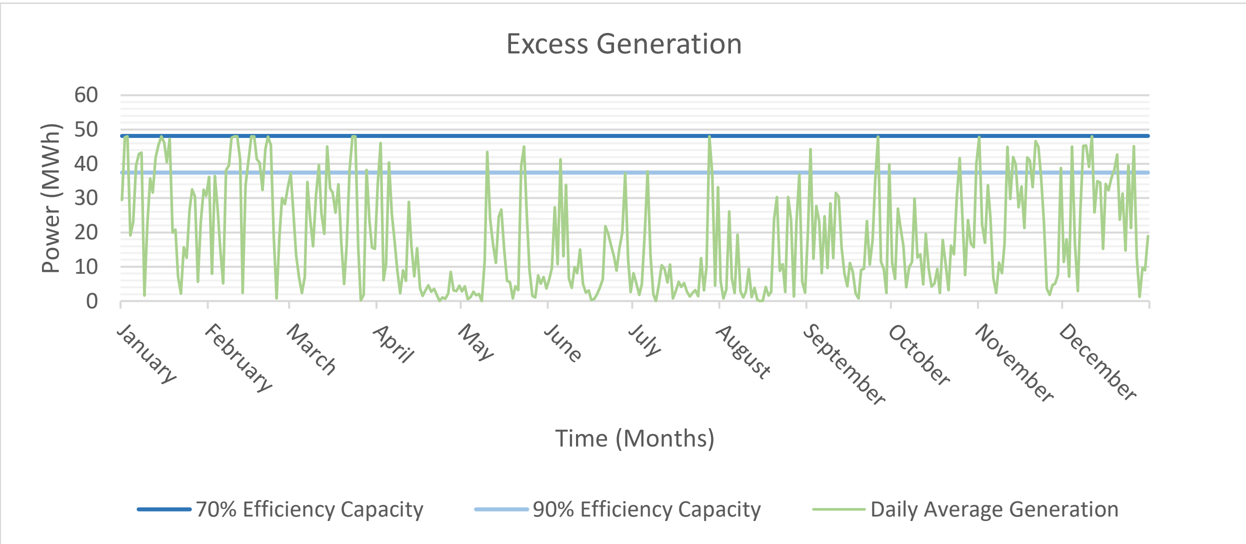
Graph 5: Hydrogen production profile for January 2020 showing the hourly production in kg.



Graph 6: Hydrogen production profile for July 2020 showing the hourly production in kg.

7.6 Excess generation

If the electrolyser is 70% efficient, the hydrogen production limit of 36kg/h is not reached, however if the electrolyser is 90% efficient, it can be reached. In this instance, there will be excess generation from the turbine (*Graph 7*). The daily average excess generation is only 1MWh which is less than 3% of the total generation produced. The excess power generated can either be stored and utilised for future hydrogen production during times of low renewable generation or it can be transmitted to the national grid as a renewable source of electricity. Considering that the average excess generation is only 3%, it may not be viable to store or transmit the energy. If more turbines were included, more electrolysers would need to be considered to optimise hydrogen production. Considering the size of the Goldeneye platform, however, the structure may not be able to house more electrolyser units. The size of the platform is therefore a limiting factor in the expansion of an offshore green hydrogen system.



Graph 7: Excess generation profile for 2020 showing the average daily generation in MWh. This occurs when the electrolyser is 90% efficient.

7.7 Selection of software

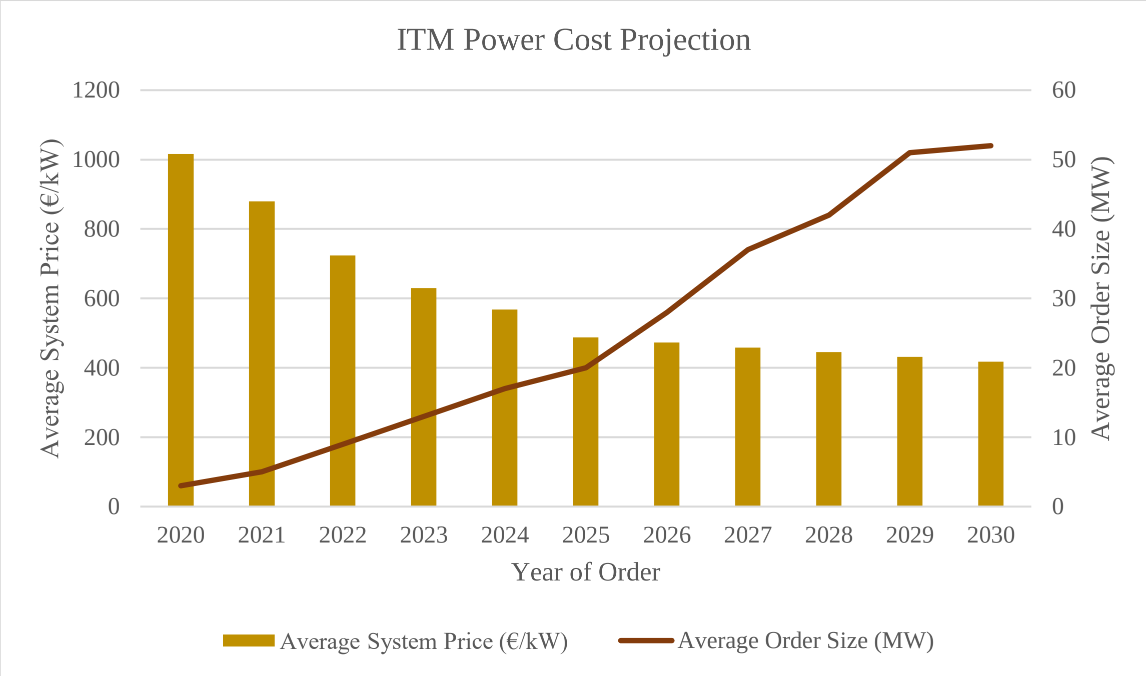
Microsoft Excel and HOMER Pro were considered to model the offshore green hydrogen production at Goldeneye. Excel was deemed more user-friendly and provided a platform where the calculations could be individually created and solutions easily tracked. HOMER Pro uses NASA weather data as a source, and this data was easily accessible so was used as the weather data source for the hourly wind speed at the Goldeneye coordinates. Excel provides a clear pathway of calculations that HOMER Pro did not. The data can easily be altered and amended for analysis of different wind turbines or for farms of different sizes, for example. Excel provided a simple way to look at the general trends of the offshore green hydrogen system.

7.8 Financial review

The installation of an offshore green hydrogen production site at the Goldeneye platform has been reviewed to determine the possible revenue and overall economic impact. The upfront cost of equipment and revenue from hydrogen fuel have been considered. Maintenance, construction, transportation and any other considerations have not been included in the analysis.

7.8.1 Equipment pricing

The turbine and electrolyser are considered the main pieces of equipment required for the green hydrogen system. Seawater inlet pipes would be required for the processing of the water. Desalination equipment may be required for the purification of the seawater. Modifications to the current gas pipeline would need to be considered to withstand the effects of hydrogen gas transmission. The typical cost of a turbine is $1.3m per MW of electricity-producing capacity [124]. The price of the Vestas 2MW turbine is therefore estimated to be £1.88m. In 2021, an ITM Power PEM electrolyser is priced at €880/kW (as shown on *Graph 8*) [125]. The electrolyser used in the case study calculations has an input power size of 2,350kW, therefore the approximate price of the electrolyser is €2.068m or £1.75m. The exchange rates used were concurrent with rates on the 22nd of October 2021.



Graph 8: ITM Power pricing outlook for electrolysers until 2030 [125].

7.8.2 Potential revenue

The current sell price of green hydrogen in the USA is \$5/kg [126]. Assuming the green hydrogen market is similar in the UK, the green hydrogen sell price is approximately £3.65/kg (using the exchange rate on the 22nd October 2021 of 0.73). From the hydrogen production results, approximately 123 – 150 tonnes of hydrogen can be produced annually depending on the electrolyser being 70-90% efficient. The annual revenue from hydrogen production can therefore range between £448,950 and £547,500.

7.8.3 Payback time of equipment

The total cost of the 2MW turbine and electrolyser is approximately £3.63m. *Equation 10* was used to determine the payback time of this investment.

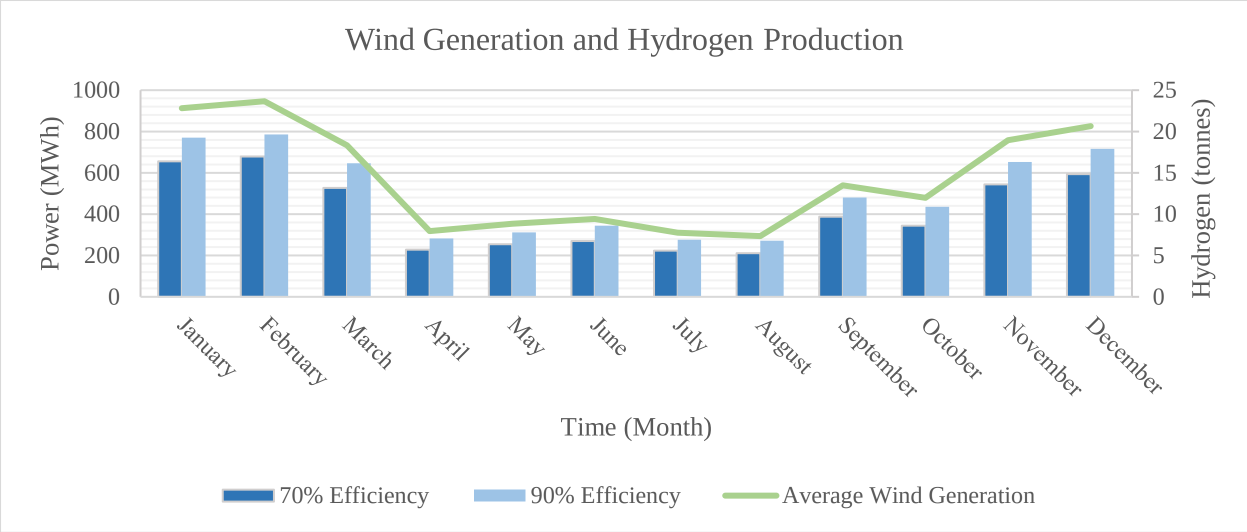
$$Payback\ time\ (years) = \frac{Investment}{Annual\ Revenue} \quad (10)$$

Since the case study was based on an PEM electrolyser which did not have a known efficiency, the efficiency was assumed to be between 70% and 90%. The annual revenue was calculated for both extremes and so the payback time was also calculated as a range dependent on the electrolyser efficiency. This was measured to be between 6.66 and 8.09 years, assuming the total revenue was only covering the cost of investment.

7.9 Discussion of case study results

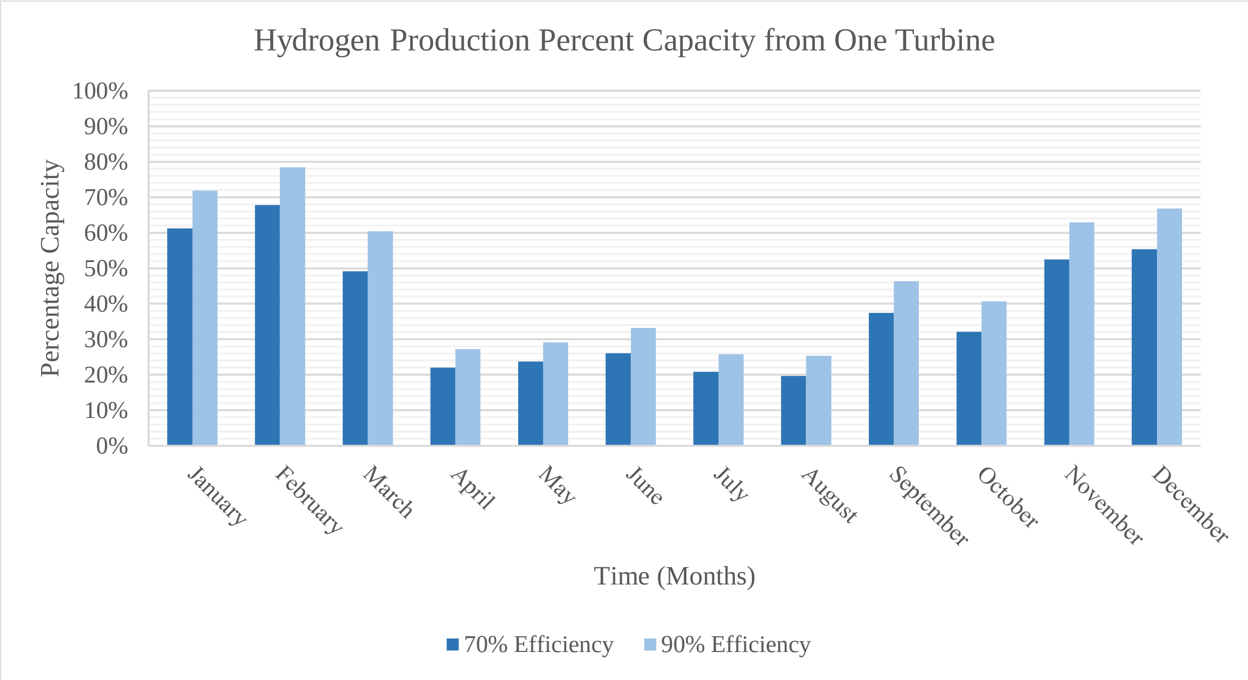
The results show that 123 tonnes of hydrogen can be produced annually if the electrolyser is 70% efficient. Assuming an average FCEV contains a 5kg fuel tank, this is enough hydrogen to fuel 24,600 cars. Assuming an average car user fills their vehicle once a month, the hydrogen produced could supply fuel for 2,050 users. In Scotland, as recorded in 2018, there are 2.9 million vehicles licensed for road use. If all vehicles were powered using hydrogen fuel, the annual production from Goldeneye would only generate enough fuel for less than 1% of the population. To fuel the 2.9 million vehicles in Scotland for a given year would require approximately 174 million tonnes of hydrogen. This shows that in order to promote a hydrogen economy, the production system needs to be on a large scale.

The hydrogen production capacity is never met when the electrolyser is 70% efficient, so the wind generation is being fully utilised by production requirements. *Graph 9* shows the drastic seasonal variance in wind generation and hydrogen production. Increasing the size of the wind farm and including more turbines would increase the power output and hydrogen produced, however, the same seasonal variance would occur. This is one of the most challenging factors to overcome as production is reliant on a variable source of energy. Although hydrogen production would increase over the summer months, when generation is typically lower, in the winter months, when generation is typically higher, the hydrogen production would only differ slightly as the electrolyser has a limiting capacity of 36kg/h. This equates to approximately 26 tonnes of hydrogen per month. In order to reach the production capacity, more generation is required to power the electrolyser. To achieve the maximum production output the required energy is 1.56-2MW depending on the electrolyser efficiency.

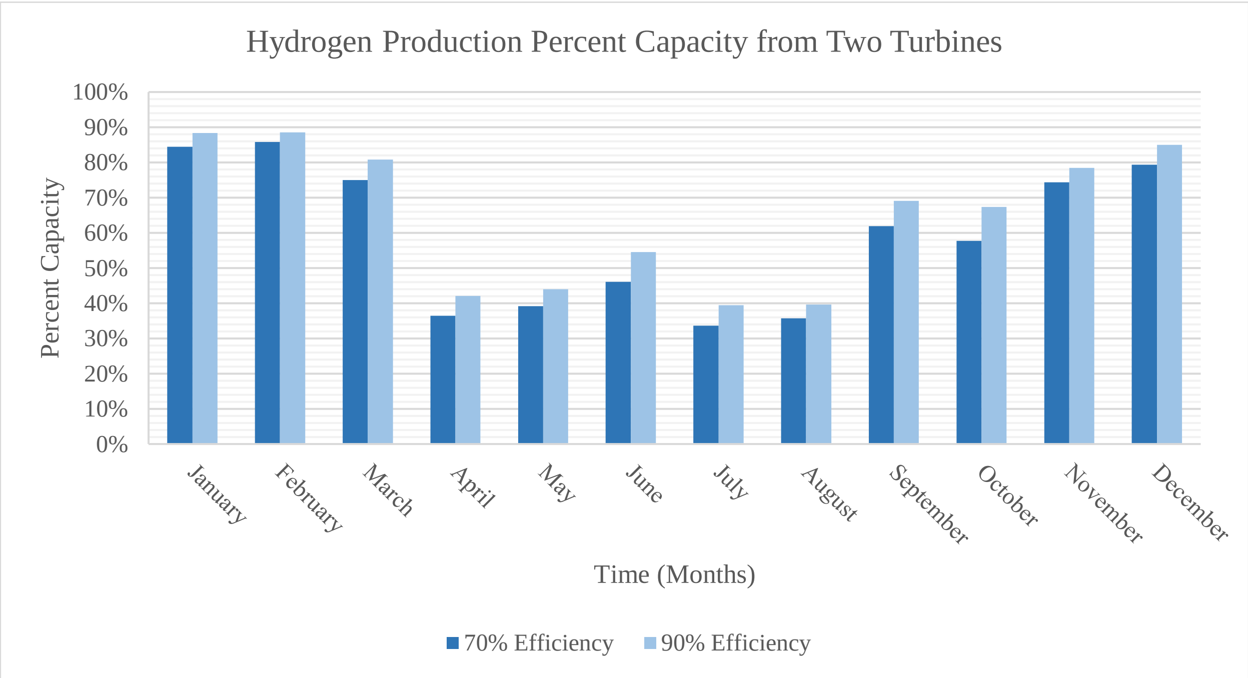


Graph 9: Overview of monthly wind generation and hydrogen production.

During the summer months, the system is operating at a low percent capacity (as shown on *Graph 10*). This can be improved by increasing the wind farm size, so an example study has been made to show the effects of introducing a second turbine (as shown on *Graph 11*). Including another Vestas V80 (2MW) turbine increases the average percent capacity by 17.43-20.16% and improves the efficiency of the system as the electrolyser is utilised at higher capacity. This does however, result in an increase in excess generation. The excess generation could be sold to the grid or a storage system could be involved to utilise the generation for hydrogen production when there are periods of low renewable generation.



Graph 10: Percent capacity of hydrogen production using generation from one turbine.



Graph 11: Percent capacity of hydrogen production using generation from two turbines.

8.0 Conclusion

Offshore green hydrogen is a great theoretical solution to decarbonisation of the energy industry and would significantly help the path to net zero carbon emissions by 2050, however, the major challenge it faces is adequate investment. Hydrogen will only have an impact on the energy system if it is fully integrated. This requires companies and business leadership to commit to the energy transition and deliver on promises to reduce emissions. A hydrogen economy requires high production and high deliverance. Green hydrogen will eventually be included into the economy however, as can be seen from the research, over the coming decades, it is much more likely that blue hydrogen will emerge from oil and gas companies. Ideally, there will be large investments into gas pipeline infrastructure to enable the transmission of hydrogen. This will encourage businesses to explore green hydrogen options.

Research into seawater electrolysis has allowed the exploration of offshore green hydrogen. The current technology option for seawater electrolysis includes the desalination process to remove impurities in the water before electrolysis reaction. Research into forward osmosis proves that seawater could be injected directly into the electrolyser through a selective membrane used for separation. This would reduce the production costs and machinery required for the process.

Oil and gas rigs provide a distinctive advantage for the creation of an offshore hydrogen system. The platforms hold existing infrastructure for transmission of gas to the mainland. This allows hydrogen production to have a direct link to the transmission system. Offshore systems not only have opportunities for green production from offshore wind generation, but also from wave and tidal energy. Although these technologies are less advanced, progress will promote the feasibility of using such energies as renewable power for green hydrogen systems. Utilising the existing pipeline infrastructure is the clear option for delivering hydrogen to consumers, whether it be blended or pure hydrogen gas.

The North Sea case study provides an insight into the size requirements of a hydrogen system. There are currently 183 platforms in the North Sea that may all be utilised to provide hubs of green hydrogen production. Platforms need to be exploited before they reach their end of life as they provide a huge benefit for offshore production as there is less need and reduced cost of infrastructure investment.

Green hydrogen is becoming cheaper as renewable generation is becoming more cost competitive with carbon-based fuels. Progress in electrolyser capacities and seawater capabilities will further promote the preference of green hydrogen. Large scale production is required to provide decarbonisation and this is possible if energy providers and consumers alter their focus to renewable energy.

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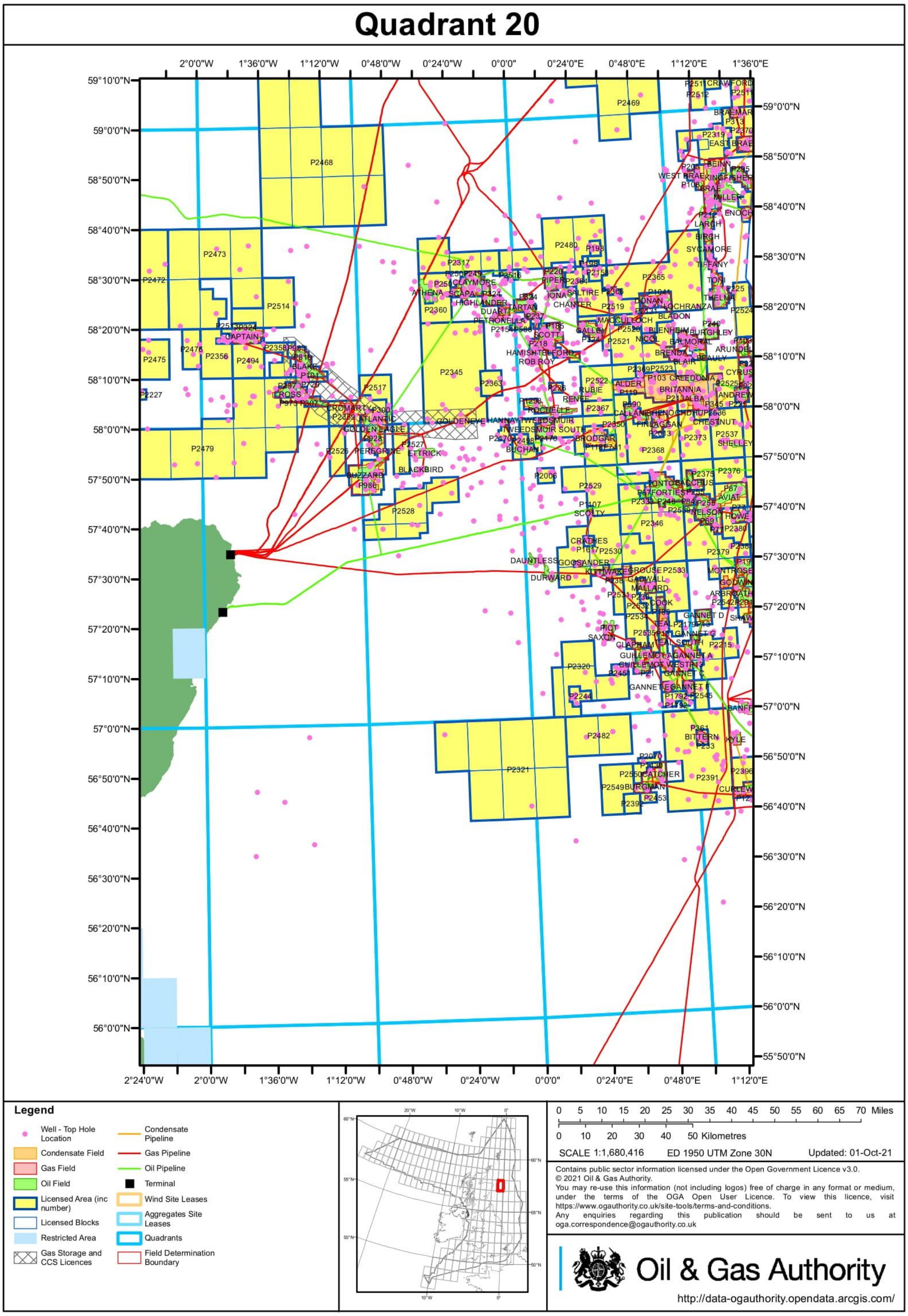
10.0 Appendices

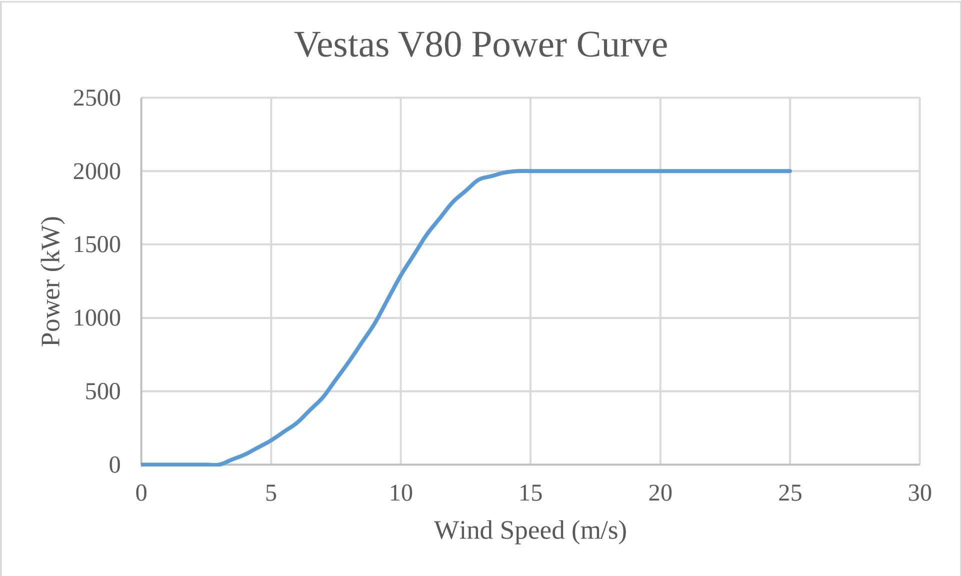
10.1 Appendix 1: UKCS Quadrant 20 Infrastructure



10.2 Appendix 2: Turbine specifications

Turbine Specifications	
Manufacturer	Vestas
Model	V80
Rated power (kW)	2000
Rotor diameter (m)	80
Number of blades	3
Hub height (m)	67
Swept area (m^2)	5026
Cut-in wind speed (m/s)	3.5
Rated wind speed (m/s)	14.5
Cut-out wind speed (m/s)	25

10.3 Appendix 3: Turbine power curve



10.4 Appendix 4: Constants used in wind generation calculations

Generation Calculation Constants	
Air density (kg/m^3)	1.225
Surface Roughness (m)	0.0005
Anemometer (m)	10

10.5 Appendix 5: Electrolyser specifications

HGas3SP	Specifications
Electrolyser technology	PEM
Number of stacks	3
System packaging and size	1 x 20ft & 1 x 40ft ISO containers and external cooling equipment
Power supply	11Kv ac, 3 PAHSE, 50Hz
Control	PLC
Hydrogen generation pressure (barg)	20 now / 30 from 2022
Hydrogen purity	Up to 99.999% (ISO standard)
Maximum hydrogen production approx. (kg/h)	36
Input power at maximum approx. (kW)	2,350

Table contents taken from ITM Power [120].