AN EXAMINATION OF THE FEASIBILITY OF PRODUCING GREEN HYDROGEN FROM CURTAILED, ONSHORE WIND POWER USING A NORTH WALES CASE STUDY

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Abstract

Onshore wind power is considered one of the most important future energy sources, but its intermittent and variable nature present a number of challenges to increasing the supply and penetration of wind energy in our energy systems, including the loss of renewable energy through curtailment. Hydrogen, which has for many years been considered an interesting option is now seriously considered as a possible solution to some of these challenges presented by renewable energy intermittency, variability as well as the decarbonisation challenge of other sectors. Use of hydrogen in this way has recently seen a convergence of political and industry support. This study will aim to examine the feasibility of producing hydrogen from curtailed onshore wind energy using a wind farm in North Wales as a case study. The research begins with a literature review and an analysis of the technical, economic, and environmental feasibility of hydrogen production from onshore wind before presenting an original economic model, offering results on the specific economic feasibility of producing hydrogen from the curtailed generation of a wind farm in North Wales. The results suggest that supplying hydrogen into the transport sector is the most economically feasible solution. The results also consider the economic feasibility of wholesale and gas grid supply. The results are analysed within the geographical context of the case study site and the opportunities for supply and demand of hydrogen which currently exist or planned future development. This research provides in depth analysis and tools to enable better understanding the relationship between onshore wind and hydrogen production in Wales, UK.

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Declarations

This work has not previously been accepted in substance for any degree and is not being concurrently submitted in candidature for any degree.

Signed[redacted]

Date. 04.01.22

This thesis is the result of my own investigations, except where otherwise stated. Other sources are acknowledged by footnotes giving explicit references. A bibliography is appended.

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Definitions and Abbreviations

kW	Kilowatt
kWh	Kilowatt hour
MW	Megawatt
MWh	Megawatt hour
GW	Gigawatt
GWh	Gigawatt hour
CAGR	Compound average growth rate
km	Kilometer
m/s	Meters per second
CfD	Contract for difference
LCOE	Levelized cost of energy
SMR	Steam methane reformation
Mt	Metric ton
CO_2	Carbon dioxide
CCS	Carbon capture and storage
ALK	Alkaline electrolyser
PEM	Proton exchange membrane electrolyser
CAPEX	Capital expenditure
LCOH2	Levelized cost of hydrogen
kg	Kilogram
EU	European Union
BEV	Battery electric vehicles
FCEV	Fuel cell electric vehicles
SO_2	Sulphur dioxide
HRS	Hydrogen refuelling stations
ICE	Internal combustion engines
TCO	Total cost of ownership
FCEB	Fuel cell electric bus
OPEX	Operational expenditure
DCF	Discounted cash flow model
NPV	Net present value
PP&E	Property, plant and equipment
DEVEX	Development expenditure
SG&A	Selling, general and administrative expense
GBP	Great British pounds
O&M	Operation and maintenance
OEM	Original equipment manufacturer
H_2	Hydrogen
FCHJU	Fuel cell and hydrogen joint undertaking
MPa	Megapascal

1 Introduction and background

1.1 Introduction

Wind power is considered one of the most important future energy sources and could provide 33% of global electricity output by 2050. [1,2] Wind power is abundant and renewable but fundamentally intermittent, determined by the weather and as such produces intermittent energy which is difficult to store and transport. The intermittent nature of wind energy presents several challenges for the sector from grid curtailment, a commonly used mechanism to balance the supply and demand of energy, to the necessary reinforcement and expansion of the national grid networks.

It is due to these factors coupled with an increasing demand for wind energy to meet the climate targets set out in the 2016 Paris Agreement that various storage options coupled with a wind supply are being considered. A potential solution to the challenges presented by both climate targets and wind developers that is gaining momentum is the use of hydrogen. For decades hydrogen has been considered the fuel of the future and while some feared this is how it would remain, several key political and industrial factors have now converged to bring hydrogen to the forefront. [3] A recent literature review on the role of hydrogen storage coupled with wind systems found that as well as utilizing hydrogen as a storage mechanism for excess wind, interest has also grown in supplying hydrogen as a by-product and in some instances wind power has been used to produce hydrogen as the end product, fundamentally changing the economics and potential of the industry. [4] Hydrogen demand is of particular interest in those sectors which are difficult to decarbonize but vital if climate targets are to be met. These sectors include transport, heating and power.

For an energy source and subsequent technology to be viable, however, it must not only have greater environmental credentials, supporting carbon neutrality targets but be technically feasible and cost competitive with traditional fossil fuels, while allowing the investors a good return. It is these crucial factors which will determine the feasibility of wind farm developers being able to combine new and existing wind farms with hydrogen production.

The novel research conducted in this study aims to support those wind farm developers make sound investment decisions as to whether co-locating hydrogen production with a wind farm is technically and economically feasible. This research will be applied to a specific case study named Alwen Forest Wind Farm. The case study site has been identified as a potential candidate for co-located wind and hydrogen generation due to the grid limitations and the potential to utilise the curtailed wind energy for hydrogen production. The case study site is located at Alwen Forest, North Wales, UK. This research will therefore consider 4 different cases looking at only installing a wind farm, installing a basic hydrogen production system, installing a hydrogen production system for supply to the gas network and installing a hydrogen system for supply into the transport network. Each case explores 3 core scenarios based on either 8, 9 or 10 turbines installed with respective levels of curtailment.

The thesis will discuss both the technical and economic aspects of the feasibility while a model designed to demonstrate economic feasibility of specific projects will also be presented.

1.2 Background

Between 2010 and 2018 global onshore wind capacity increased by 364 GW [5] and accounted for 75% of all net power capacity growth[6]. This trend is not new, onshore wind as well as other renewables such as off shore wind and solar have been on an upward trajectory for a number of decades, for example, between 2000 and 2018 onshore wind saw a global compound average growth rate (CAGR) of 21.3%, from 7 GW of installed capacity in 2000 to 542 GW in 2018.[5]

The demand for renewable energy is set to grow both in the UK and globally, as the 196 countries who signed up to the Paris Agreement in 2016 aim to keep global warming below 2 degrees, in addition, the UK along with 66 other countries have committed to achieve net zero emissions by at least 2050.[7] To support these ambitions it is predicted that by 2024 onshore wind demand will increase by 57% to 850 [8], while IRENA predicts that by 2050 there will be 5066 GW of wind energy installed which will account for between 35-40% of the global energy production.[5]

While many of the forecasts demonstrate continued growth in the onshore wind industry, the IEA predicts that the growth of the wind sector up until 2024 will be slower than in previous periods. This is supported by the predictions from other industry bodies which suggest that the compound average growth rate (CAGR) between 2019 and 2050 is 7.2% per year compared to the previous 21.3% between 2000 and 2018.[5] In part this is due to regulatory and policy changes in countries such as the US and China who as of 2020 are phasing out subsidies but there are also a number of key challenges facing European markets which are expected to prohibit faster expansion of wind energy, these include financing challenges, varying public support and grid connection issues.[6]

As an island in North Western Europe, the UK has a distinct advantage in harnessing wind energy as it has a higher average wind speed at 10.18 m/s than almost any other country in Europe (Germany: 8.45m/s France: 8.22m/s Denmark: 9.3m/s Norway: 9.75 m/s) and higher than many of the other world leaders in wind energy production such as China (8.93 m/s) and the US (8.98 m/s) [9] The UK also has the advantage of 12,429 km of coast the low average distance from the coast to any part other part of the country offers advantages in transporting and distributing energy. [10]. In 2019, 37.1% of the UK's power was provided by renewable energy, with 29.9% coming from onshore wind.[11] By the first quarter of 2020 renewable energy had increased to 47% of the total meaning that nearly half the UK's power was provided by renewable energy compared to 31.4% from gas and 2.7% from oil and others and 3.8% from coal. [12]

1.2.1 Challenges of wind power

Despite the opportunities and potential for UK wind power in the coming decades, the industry is facing several challenges which are not easily overcome using current conventions. The following sections will firstly discuss the challenges of infrastructure, intermittency, and tighter margins for traditional business models before putting forward a potential response to these challenges and discussing how the response to the challenges in the wind industry can also help to support the decarbonization of the power sector which is on the path to decarbonisation as well as to support those sectors which have yet to meaningfully transition such as transport and heating.

1.2.2 Infrastructure

Fundamental to the success of renewable energy is the expansion and reinforcement of grid infrastructure at national, regional and local levels with the aim of improving the system flexibility. [5] In 1926 the Electricity Supply Act was passed into UK law and The Central Electricity Board was created. Its aim was to join up Britain's fragmented supply and link 121 power stations with a network of overhead lines which would transmit and distribute the electricity across the country.[13] This centralized system has received substantial investment to allow for the unprecedented demand and the introduction of power plants with a 2 – 3 GW installed capacity; however, in the 21st century the UK's electricity grid is now struggling to adapt to the new wave of changes bought by renewable energy generation.

Wind energy is often generated in remote locations from as little as 50 kW single generators to 100 MW wind farms. While the current electricity grid receives energy from 188 traditional power generators, there are already over 1500 operational wind farms in the UK [14] each of which requiring a remote grid connection in order for their energy to be distributed through the network. The increase of wind energy has meant a substantial increase in the amount of embedded generation on the distribution network. This poses a number of structural and financial challenges as the distribution network is less robust and less reliable than the transmission network meaning that significant investment and reinforcement work is often required before a wind farm can feed its electricity onto the network [15]. This cost is often placed on the wind developer, creating ongoing challenge for project feasibility.

Another outcome of the grid challenges described above is the constraint of renewable energy generation. Constrain can take several forms, either entire wind farms are unable to be built as local networks are constrained and the cost of connection is too high, or the wind farms which are built are forced to curtail the amount of generation that they are able to import onto the grid due to wider network constraints In 2020 wind farms in the UK supplied 69TWh of electricity but over 6% of this output had to be curtailed. The amount of curtailed wind energy in 2020 was almost doubled that of 2019 [16] and the primary reason for this was due to network constraints Further research finds that in the UK curtailment on individual projects can reach up to 17% of annual generation and that this is primarily driven by the requirement for inertia. [17] The result of these conditions is that the more wind and other renewables that are added to the network, the greater the need for storage, system balancing and flexibility which some believe could have saved the UK up to 50% of the current curtailed energy [16]. The impact of curtailing renewable generation is twofold,: firstly, renewable energy lost due to curtailment is significantly hindering the penetration of wind energy needed to achieve climate targets, [18] secondly, it creates additional financial challenges around a growing number of projects who cannot make a business case stack up with high grid costs and generation curtailment. The loss of this much renewable energy is particularly concerning when considering that the global renewable energy consumption was 18% in 2018 and will need to increase to 65% in 2050 in order to achieve the direct and indirect emission reduction targets (41% and 13%, respectively) [19]

available

Changing business models

Many forms of renewables have fallen in price to become competitive with fossil fuels much sooner than anticipated. Onshore wind has performed particularly strongly and has been for a number of years considered as one of the cheapest forms of energy. Globally the cost of electricity from wind power has fallen by 39% from its peak in 2010 [20] while in the UK predictions are that by 2025 electricity from onshore wind could be supplied at half the cost of electricity from a gas fired plant [21]The prediction for onshore wind in the UK is that the LCOE will fall from a predicted 46 £ per MWh in 2025 to 44 £ per MWh in 2040. This predicted LCOE for 2025 is significantly lower than previous predictions by BEIS when in 2016 it was estimated the LCOE for onshore wind in 2025 would be 65 £ per MWh. The current predictions of 44 £/MWh do not consider the effects of onshore wind entering into the competitive CfD process again in 2021 [22]. Participating in a competitive auction could result in an even lower LCOE. suggesting that by 2020 onshore wind prices will consistently offer cheaper electricity than fossil fuel alternatives. [23]

The fall in the LCOE from onshore wind is due to several capex and opex reducing factors, which can be seen in the respective learning rates of 19% - 35% [3] and 9%.[24] One of the key drivers for this dramatic fall in LCOE is the increased scale and size of the individual wind turbines. From 2000 when the global average size of an onshore wind turbine was 1 MW to 2020 when the average size is 4.8 MW per turbine with an average rotor diameter of 158 m, over three times the size of the rotors in 2000. This growth is set to continue with the average size turbine in 2025 being 5.8 MW [5] and will continue, amongst other factors to encourage a continued downward trajectory of the LCOE from onshore wind until a predicted price of $20 per MWh in 2050. [5]

Other policy and regulatory changes, particularly surrounding subsidies, have also meant that companies delivering onshore wind projects in the UK have had to adapt their business models to survive. In 2015 the UK wind industry experienced a significant blow when the Government announced the abolition of subsidies a year earlier than planned. There were also fundamental changes to the planning process, which jeopardized all future projects. [25] The impact of these policy changes is stark, from a high of 405 new onshore wind projects in 2014, there were only 23 in 2019 [26] this fundamentally challenged market confidence, economic viability and the UK’s commitment to its climate targets. The future does not look as dim for onshore wind as it once did, in 2020, 5 years after withdrawing support from the industry the UK Government announced that from 2021 onshore wind would again be able to compete in the Contract for Difference rounds, although strict planning laws have not been relaxed and any onshore wind development must have the consent of the local community .[27] The impact of onshore wind being eligible to participate in CfD auctions is that participating in auctions creates a more competitive environment, driving down prices, while is will make onshore wind even more competitive it is also possible that it will lead to the industry taking lower returns and bigger risks.[28] Further reduction in the cost of renewable energy will support the reduction in the LOCH2 but it also makes the proposition of wind developers entering into the hydrogen market and revenue stacking electricity and e-fuels more appealing.

Further changes in the industry are the introduction of large oil and gas companies who have traditionally kept away from the renewable energy sector who are getting involved and participating on a significant scale. Engie, for example, has dramatically shifted strategy since 2015, it has stopped all new investments in coal plants, will dispose of €15bn of assets relating to fossil fuel exploration in order to invest this and a further €22bn in renewable energy and energy services with the strategic objective of becoming the world leader in the zero carbon transition. [29] Others such as Shell and BP have also revised strategies to diversify into renewables. The investment potential from these oil and fossil fuel majors will unlock larger economies of scale in the wind industry, create new competition and drive volume, all of which are likely to contribute to falling costs. [8]

The cumulative impact of the reduction in the LCOE and subsequent reduction in price of electricity from onshore wind, combined with the removal of subsidy schemes and financial challenges from generation curtailment equates to decreasing revenues, tighter profit margins and increased competitiveness. These are the drivers that are demanding wind developers continue to adapt their business models and seek new innovative markets. [8]

1.2.3 Intermittency and variability

The third challenge wind energy experiences is its intermittent nature. The intermittency of generation means that supply cannot always be matched up with demand and neither can it be scheduled to deploy at peak demand times. The high penetration of wind power needed to achieve climate goals will present growing technical and economic challenges in the system reserves (that will need to be larger the more wind power is in the system), system reliability (how readily the energy system can supply the required energy on demand), system security and will have an impact on system costs. The findings have been that the greater the penetration of wind energy in the system the larger the system reserves are required to be, which increases the system costs, higher wind penetration can also reduce the systems reliability and security.[30] Furthermore, some believe intermittency will become a greater challenge due to future weather changes brought about by climate change.[31] A number of potential solutions have been put forward ranging from optimizing wind farm siting and wind farm layout,[30] or the use of a non-variable complementary baseload such as hydro, biomass or nuclear. [32]

The role of nuclear power is often debated within difference countries and suggested as a means of offering the non-variable, baseload power identified above. Counties such as India and the UK consider it to be an important clean energy with which to meet the growing energy demand [33] and a realistic option for a complementary, green, non-variable baseload. However; this is politically and economically sensitive within the UK as with other places (New Reference). Existing projects already marred with issues of public opposition, safety and decommissioning problems as well as its uncompetitive price of energy. In comparison, while onshore wind is predicting a LCOE of 44 £ per MWh in 2025 ,[22] the LCOE assumption for a nuclear plant in the UK in 2025 is 95 £/MWh [22] whereas the strike price (the price at which an investor can buy or sell the energy for) already agreed for Hinkley Point C is £92.50 per MWh.[34] This therefore suggests that for the UK, which does not have the opportunities to exploit hydropower at scale and the challenges of nuclear, this is not a feasible solution for solving the intermittency and variability challenges presented by growing renewable energy penetration on the grid.

Another way of dealing with intermittency is the use of storage options. The key factors which influence the success of any particular storage option are: ramp rate, response time, storage capacity and duration, efficiency and cost.[35] While it is suggested that the challenges of hydrogen storage need to be overcome before this becomes a viable storage mechanism others believe that limited storage is required if the hydrogen is being supplied to other sectors.[36] It is because of these factors: the ability to use hydrogen to address the problems of wind intermittency and infrastructure as well as the ability for hydrogen to be supplied into other markets such as transport creating additional revenue for wind projects with tight margins that this research will further examine the feasibility of hydrogen production from onshore wind farms.

1.2.4 Hydrogen as a response to these challenges

Use of hydrogen is not new, the first fuel cell was invented in 1842 and the term "Hydrogen Economy" was first used in the 1970's by General Motors during the turbulent decade, that saw the Yom-Kippur war (1973), the expansion of OPEC, and the Iranian revolution (1979). Hydrogen was recognized then as a highly versatile energy vector and countries such as the UK and US who were highly dependent on oil from the Middle East sought to find less risky alternatives [37]. A resurgence of interest in hydrogen was seen in the late 1990's but it failed to keep momentum and was overtaken in the public debate by battery technology. In the past decade, hydrogen has come back into the political and research agenda for three primary reasons: the potential for economic development, securing energy supply and reducing emissions [38]. While development has still lagged the renewed interest has resulted in a weight of support indicating that the role of hydrogen could be set to increase and in doing so it could help to solve some of the challenges facing the wind industry.

1.2.4.1 *Hydrogen though Water electrolysis*

Currently, Steam Methane Reformation (SMR) accounts for 96% of hydrogen production and in 2020 almost 70 million tons, ca.50% of global hydrogen, was used for ammonia production for fertilizers and 40% is used for processing in crude oil refineries.[37] Hydrogen produced from SMR has a significant environmental impact, however, and is unlikely to be feasible without carbon capture storage technology. SMR also does little to increase wind or renewable energy penetration.

Hydrogen however has the advantage of being able to be derived from nearly all energy sources, it can be converted biochemically, thermochemically or through electrolysis. It is hydrogen production through electrolysis which will be further explored in this paper as a possible solution. Water electrolysis currently supplies only 4% of global hydrogen demand and is defined as the process of using electricity to separate water into its two component parts, hydrogen, and oxygen. This study will focus on producing hydrogen from water electrolysis using electricity provided from wind power, further, to be known as green hydrogen, however it is important to note that green hydrogen is a term applied to hydrogen produced from any renewable source, as a means of addressing the multiple issues set out above. The following three sections will review the environmental, economic, and technical challenges that face the production of green hydrogen and address the changes which have occurred to justify another look at the role hydrogen could perform.

1.2.5 Environmental feasibility

The introduction of any technology now more than ever, needs to balance not only the economic and technical feasibility but also the environmental impact. Since the 1990s global warming and climate change have moved into the mainstream public and political consciousness, in the UK 2019 general election 27% of people reported the environment as a top 3 issue, putting it level with Crime and the Economy [39] this is one fundamental reason why the hydrogen economy is experiencing a revival now. Hydrogen produced via SMR currently produces ca. 830 Mt CO_2 which is approximately 2% of total global emissions,[40] therefore it is only considered to be viable in the long term if coupled with carbon capture and storage (CCS) technology,[3] however the feasibility of this is highly dependent on geography, therefore suggesting that great care needs to be taken when considering what type of hydrogen any future hydrogen economy should be built on.[41] Research offering comparative life cycle assessments on hydrogen produced from SMR compared to production by electrolysis found that the source of the electricity was crucial in determining any environmental impact of hydrogen production.[42] Prior to this one study conducted life cycle assessments on five hydrogen production methods including SMR of natural gas, electrolysis of wind and solar electricity, it was found that electrolysis by wind power was more advantageous than both electrolysis by solar and SMR. The primary difference between the wind and solar results are the estimated higher global warming potential caused by manufacturing the PV modules, however it was also assumed in this study that electrolysis from wind was done next to a fuelling station and therefore no transportation of the hydrogen was required whereas in the solar scenario transportation has a 2% global warming potential. These results indicate the importance of investigating the feasibility of wind electrolysis in more detail.[43]

The commitment of the UK to achieve net zero by 2050 has helped to focus current policy discussion around hydrogen as it is believed that this target cannot be achieved through electrification alone and many now see hydrogen and electrification as complimentary energy systems.[44] This has translated into financial commitment of £1bn over the next spending review period by the UK government to support hydrogen development, supporting hydrogen production, storage and distribution projects.[45] The challenge of achieving carbon neutrality is magnified when there is an anticipated increase in global energy demand of 50% by 2024 due to population growth and developing countries growing their industrial capability [37] and the pressing need to decarbonize sectors such as transport, heating and power and industry which currently present some of the biggest decarbonization challenges.[3]

It is not only the environmental impacts of hydrogen production which should be considered but the environmental impacts of the markets which could utilize the green hydrogen. Current industries which use high quantities of hydrogen such as agriculture and industry could abate substantial amounts of CO_2 by transitioning to green hydrogen supply. For example, the transport sector is the highest net contributor to UK carbon emissions,[46] and has a high public health cost of 400,000 excess deaths a year which is caused by air pollution.[47] Alternatively statistics for the heating sector show that CO_2 emissions in the UK were found to be the worst in Europe and is the third largest contributor to emissions in the UK [48] While hydrogen is considered to have the greatest potential impact on the transport sector [19] if decarbonization of these sectors can be achieved it may abate a third of global fossil fuel emissions by 2050. [49]

1.2.6 Technical feasibility

Water electrolysis using renewable electricity as the feedstock has a clear environmental advantage, however, there has also been significant technical development which has enhanced its ability to compete in the market on cost and environmental credentials. The advantages of electrolysis over SMR are its ability to couple with a variable, intermittent power, it also has the advantage of high efficiency and higher purity than other hydrogen production methods and does not sure fossil fuel as a fuel source.[50] There are several methods for producing hydrogen via water electrolysis, only two will be discussed further in this paper due to their dominance in industry and availability of technology on a commercial basis.

1.2.6.1 *Alkaline electrolysis*

The alkaline electrolyser is the most mature technology for water electrolysis and is characterized by two electrodes submerged in an alkaline electrolyte and separated by a diaphragm which is designed to keep the product gasses separate. As the more mature technology, the cost of an alkaline electrolyser is more competitive than its alternative PEM electrolyser and offers a price difference of €90 per kW for stack replacement while also requiring a stack replacement at half the rate of a PEM;[44] however, despite the cost and reliability advantages of an alkaline electrolyser there are three well established challenges which have implications when used with intermittent power supply such as wind. The challenges are primarily caused due to the use of the diaphragm and a liquid electrolyte and are as follows:

1) The diaphragm is not entirely impermeable; gasses are able to cross diffuse thought the diaphragm therefore reducing its operational efficiency and increasing safety concerns.
2) The liquid electrolyte and the diaphragm lower the current density which impacts the flexibility and response rate of the electrolyser.
3) The electrolyser can only operate at lower pressures due to the use of the liquid electrolyte.[51]

The response rate and flexibility of the alkaline electrolyser may be sufficient to meet the needs of slow grid services but it is not necessarily so efficient at responding to intermittent generation and curtailment where variation of load is rapid and maybe better suited to a more constant or stable load, for this type of demand the development of the PEM electrolyser has made green hydrogen far more accessible.[44]

1.2.6.2 *PEM (Proton Exchange Membrane) electrolyser*

The PEM electrolyser is a less mature technology, however with a solid membrane, normally consisting of Nafion™ coated in platinum and other noble metals, it can overcome some of the challenges associated with alkaline electrolysers:

1) It can achieve higher operational pressure, reducing the need for additional compression infrastructure within the system.
2) It operates with a higher current density which offers dynamic operation and response times, for example, the start-up time ranges from 1 second to 5 minutes in comparison to the alkaline electrolyser which can take up to 10 minutes and is able to achieve a shut-down time of seconds, drawing little additional power when in standby mode.
3) Higher voltage efficiency of 67-82% HHV.

Technically, PEM electrolysers can be considered simpler than alkaline electrolysers and better suited to intermittent, variable power supply.[50] As addressed above they are currently more expensive than their alkaline counterpart, however, cost predictions for 2025 see the gap narrowing to €630 per kW for a 5MW Alkaline electrolyser and €750 per kW for a PEM electrolyser of comparable size [44] and with a predicted learning rate of 13% PEM electrolysers could be competitive with alkaline electrolysers by 2030.[3]

While the CAPEX of the PEM electrolyser is predicted to become increasingly competitive, the durability of the stack before replacement is needed remains significant, with an alkaline electrolyser achieving 90,000 operational hours before replacement compared to only 50,000 operational hours for the PEM.[44]

While it seems that there is much excitement about the potential for PEM electrolysers and their role in responding and balancing intermittent, variable power sources, the lack of maturity in the technology, the economics of both the capex and ongoing operational costs of stack exchanges remain a disadvantage. As future cost reductions are considered to benefit the PEM electrolyser, innovation in alkaline electrolysers should also be considered likely. Due to the competitive nature of both these technologies, both will be considered within this project and applied to scenarios which best suit their strengths, for example, PEM electrolysers may be more suited to matching with curtailed wind whereas alkaline electrolysers are able to supply a predictable load and benefit from a dedicated supply achieved by over planting the turbines.

In addition to the two types of electrolysers discussed above there are other types of electrolysis not discussed here or considered in the upcoming model, for example solid oxide electrolysers are used to convert steam into hydrogen however this requires much higher temperatures that alkaline and PEM electrolysis which would not be possible to achieve outside of an industrial setting.[52] While it is considered that this technology has large potential for the mass production of hydrogen further advancements are needed on the durability of the component materials and long term operational challenges.[51] While other technological solutions for electrolysis are available, this study will only go on to consider the alkaline and PEM solutions as these more closely meet the technical and environmental parameters of the site and are both commercially available.

1.2.6.3 *Storage, compression, and other technical components*

As well as hydrogen production, storage and transportation make up some of the other key aspects of the green hydrogen feasibility. One of the features of hydrogen which makes it appealing is that it can be stored in various sized quantities such as in pressure vessels or salt mines. High volume hydrogen storage in salt caverns is an exciting field of research with currently 176 sites worldwide being used for hydrogen storage including 3 at Teeside in the UK. The ability to utilise salt caverns is highly geographically dependant with the ratio between gas demand and storage ability in the UK relatively small compared to other

European countries such as Germany. Therefore this study will not consider the use of high volume salt caverns for hydrogen storage, but will instead assume that if hydrogen is supplied into the gas network the gas distribution companies such as Scottish Power who are investigating the feasibility of salt cavern storage for natural gas as well as hydrogen in a Cheshire based salt mine may choose to utilise this at a later date.[53]

Hydrogen storage can be divided into two categories dependant on the application: stationary or mobile. The appropriate storage mechanism depends on the end application, stationary storage offers on-site storage at the point of production or use. Depending on the volume and pressure of the storage required there are various options, however, compressed gas storage has the advantage of not requiring processing at very low temperatures and is considered to be a mature and safe technology. While there are a number of types of pressure vessel, it is considered that Type 1 vessels, made entirely from steel is the most cost effective option [44] with greater proven safety and longevity.[54] Mobile storage is required for remote hydrogen usage such as use in the transport sector, in this instance hydrogen stored and delivered on tube trailers is considered the most economical, while also benefitting from low hydrogen loss rates.[55]. It is considered that tube trailer storage and delivery is particularly beneficial to underutilised markets such as FCEV or for small refuelling stations. The use of pipelines is more appropriate for densely populated areas with a high demand for hydrogen.[56]

The process of electrolysis uses electricity to split water into its component parts, hydrogen and oxygen, therefore not only does producing green hydrogen require an electrical supply it also requires a water supply. Due to the technical components of both the PEM and ALK electrolysers water that is used for green hydrogen production must be purer than normal tap water meaning that water much be desalinated and demineralised before electrolysis.[57] In the existing research it is common for the cost of the water management to be included within the CAPEX of the electrolyser.[44] [58]

The fall in costs combined with technical evolution of electrolysers, along with storage and transport solutions which can offer versatility depending on the end market as well as mature, cost effective, reliable solutions have been instrumental in the green hydrogen economy being able to reassert itself as a possible solution.

1.2.7 Changing renewable energy and electricity prices and impact on economic feasibility

The third challenge which has previously prevented widespread uptake of green hydrogen has been the cost relative to other low carbon alternatives and fossil fuels. There are three primary factors which determine the economic viability of green hydrogen production:

1. The cost of electricity.
2. Capex of infrastructure.
3. Utilization rate of the electrolyser.[3]

1.2.7.1 *Cost of electricity*

It is estimated that the cost of the electrical feedstock accounts for ca. 75% of the levelized cost of hydrogen (LCOH2). The current LCOH2 from wind is between \$2.80 - \$5 / kg [59] compared to hydrogen produced by SMR where the feedstock is natural gas which is produced for ca. \$0.65 per kg. Hydrogen production where the feedstock is a fossil fuel derivative will get increasingly uncompetitive with any increase in the price of fossil fuels however green hydrogen is an exception to this, dependent instead on the prices of renewable electricity. Until recently, the high price for electricity produced from onshore wind (£82.50 per MWh in 2015 [60]) has been fundamental in ensuring that green hydrogen was uncompetitive with alternative fuels. However, the cost of electricity from onshore wind has continued to fall at a remarkable rate, with a price of £67.59 per MWh in September 2018 to £32.04 per MWh in February 2020 for some projects.[61] The reduction in price has been driven partly by an over 80% decrease in the costs of onshore wind over the last decade, this has helped to reduce the cost of green hydrogen production via wind energy by 60%.[62] It is predicted that the LCOE from onshore wind will continue to fall and will be reflected in an average price of \$20 or ca. £15 per MWh by 2050,[5] this is likely to contribute to a fall in the cost of green hydrogen, with some calculating that it could be produced for as little as \$0.7 per kg, this price would make it competitive with natural gas in Germany and cheaper than producing hydrogen from fossil fuels with CCS.[63] Some suggest that green hydrogen becomes feasible with electricity prices of €50 per MWh [44] suggesting that in some instances green hydrogen could already be cost competitive.

1.2.7.2 *Capex of Infrastructure*

The capital cost of infrastructure, primarily the electrolyser needed for green hydrogen production has also contributed significantly to the economic unfeasibility of green hydrogen. However electrolyser costs have fallen sharply, by 40% in Europe and 80% in China between

2014 and 2019.[49] This is due in part to greater mass production, technological development and market penetration and that downward trajectory is expected to continue until at least 2030 [64]. Specifically, the Hydrogen Council estimate that alkaline electrolysers, widely considered the more mature technology will enjoy a 9% learning rate between 2020 and 2030 while PEM electrolysers are expected to achieve a 13% learning rate in the same period. While IRENA suggest that the mid case for electrolyser learning rates is 18% [65] These learning rates are considered to be realistic as they are lower than the learning rates of both wind (19%) and solar (35%) in the previous decade [3] and support the EU target of 46 GW installed capacity by 2030. There are several reasons why the learning rate for electrolysers is currently predicted lower than the solar learning rate of 35%, firstly the components of the electrolyser are considered to have different learning rates, for example the catalysts and other peripheral parts are thought to have a much lower learning rate of 8%. Furthermore, in studies which have reported lower learning rates it is thought that this reflects a lack of competitive market. It is therefore possible to suggest that as a competitive market increases so will the opportunity for higher learning rates. [65]

While the commercial viability of green hydrogen remains, on the whole, something which is still forecasted in the future, there are those who consider green hydrogen to be bankable today, realizing the benefits of lower renewable electricity costs and capital infrastructure costs so long as maximum value can be drawn from the electrolysers through high utilization and supplying multiple markets [44].

1.2.7.3 *Utilization rate of electrolyser*

The third important factor in determining economic viability of a green hydrogen project is the utilization rate of the electrolyser, in other words, achieving maximum number of units of energy produced for the investment capital. One ongoing challenge for green hydrogen producers is to balance the benefit from low cost or free curtailed wind in high enough quantities that the electrolyser achieves a sufficient utilization rate .[3] IRENA Suggest that a PEM electrolyser that is also connected to the electricity grid can achieve the target LCOH2 by operating only 40% of the time.[19] It was suggested however that the business case remains challenging for those systems which are only connected to the variable renewable energy source and not also connected to the grid. While this remains a challenge, the evolution of PEM electrolysers, which are highly flexible may offer a response to this.

1.2.8 Emerging hydrogen markets

While the environmental, technical, and economic feasibility of producing green hydrogen has been established, the economic viability of any single project relies heavily on matching the supply of hydrogen with a market demand. The primary sectors where green hydrogen can be considered to play an influential role in decarbonization are widely debated, while the Hydrogen Council suggests that the four primary sectors are:

1. Transportation
2. Heat and power and buildings
3. Heat and power for industry
4. Industry feedstock [3]

Others suggest that hydrogen can also be used as a storage mechanism for excess electricity, ensuring that renewably generated electricity is not lost if there is not an immediate demand for it, or if the wind farm is curtailed. The hydrogen can then be converted back into electricity at a later date.[66] In addition to these debated primary sectors the Hydrogen Council have identified 35 applications within these sectors where hydrogen could play a role in decarbonization [3].

Below, three of these applications are examined in more detail. They depict areas that are difficult to decarbonize, where there is existing industry interest and the markets can operate either in isolation or in support of each other. In addition, these sectors were chosen due to their relevance to the case study site. The volumes of curtailed energy and the proximity to industrial users was considered too low and too far for an economic case to be viable. Instead sectors were chosen where different volumes of hydrogen could be sold into a wider hydrogen hub or network as this would offer a quicker route to market. The penetration potential of each market within the context and geography of this particular case study will also be evaluated.

1.2.8.1 *Grid Services*

The FCHJU highlights the important role of the electricity grid as a potential source of revenue through grid balancing services, they also suggest that the availability of cheap curtailed renewable energy may have a positive effect of on the economics of hydrogen production.[44] In this vain, the technoeconomic feasibility of multi megawatt electrolysis plants and the minimum demand required for the Spanish FCEV market has been explored, finding that other services such as grid balancing services are important in contributing to the profitability of hydrogen production for the transport sector.[67] While others suggest that although reconverting green hydrogen back to electricity has a low efficiency, curtailed wind at the point of origin could be eliminated using onsite electrolysers and that in regions of high curtailment this strategy could be used to reduce costs or financial penalties associated with curtailment and provide a secondary revenue stream other than supply of merchant hydrogen.[18] Further investigations as to whether an electrolyser can be used to balance grid frequency and if the suppliers were also able to generate enough revenue from this and hydrogen sales, concluded that the revenues from the grid are not sufficient to reduce production costs for hydrogen to be competitive.[68] However, one particular case study of an island nation with weak electricity grids examined the use of hydrogen as a storage mechanism. They found that introducing onshore wind as a replacement for diesel and using hydrogen as a storage mechanism had a positive NPV and IRR, however economic feasibility of this project should be considered in line with its considerably high existing energy costs of €259 per MWh [69].It should be investigated as to whether other projects where existing energy costs are lower is still economically feasible.

1.2.8.2 *Gas grid*

Electrification is commonly discussed as a method to decarbonize heat; [70] however the biggest challenge of transitioning to electrification is managing the increase in peak demand which can be resolved, expensively, through substantial increases in generation capacity combined with electrical storage.[48] Due to the scale and cost of full electrification it is suggested that utilizing the existing gas grids and injecting hydrogen may offer a viable alternative, especially considering the compatibility of the existing infrastructure with partial injections.[71]

1.2.8.2.1 Technical and economic feasibility

Technical challenges of a hydrogen gas grid have been examined with comparisons drawn between the rapid transition from town gas to natural gas deemed to be unfeasible today due to the size and scale of the grid.[72] [73] Haeseldonckx and D'haeseleer particularly highlight challenges with the transmission network but does suggest that a 17% mix of hydrogen is feasible. More recently studies have suggested that up to 30% mix of hydrogen could be used in the UKs gas grid, however do not consider the effects of hydrogen use on the distribution networks,[74] whereas others suggest that the distribution network will allow up to 50% concentration of hydrogen without the need for upgrading appliances while steel pipes in the distribution network can accommodate ca. 25% hydrogen natural gas blend without requiring upgrading [75].

When examining economic feasibility it has been found that the cost of injecting hydrogen into the gas grid as a sole revenue stream is unfeasible as the production costs particularly the cost of the feedstock (electricity) resulted in prices that are quadruple that of natural gas,[76] while others have found gas grid injections to be economically competitive if additional service such as oxygen and heat can be utilized.[77] In addition, hydrogen injected into the gas grid has been suggested as instrumental in de-risking projects and acting as a secondary revenue stream for projects whose primary revenue comes from other markets such as transport, and that revenues from gas grid injections can make up 85% of project margins.[44] The ongoing cost competitiveness of green hydrogen in the gas grid relies on hydrogen production costs, capital costs of boilers and the local ability to utilize the existing gas pipelines. According to the hydrogen council, hydrogen will become cost competitive with alternative low carbon solutions such as heat pumps when the cost of production falls to ca. $3 per kg but isn't able to compete on cost with natural gas until it can achieve a production price of under $1 per kg.[3] It will be assumed in this study that only a hydrogen natural gas blend will be used therefore the costs of upgrading end appliances are not applicable.

1.2.8.2.2 Industry projects

Incentivized to demonstrate alternatives to costly electrification options industrial interest in injecting hydrogen into the gas network has grown. Some key UK based projects are:

1. Project H21, which found that it is possible to use hydrogen to significantly decarbonize the network without a large burden being placed on customers or significant new infrastructure.[78]
2. Hydeploy is examining how a mix of 20% hydrogen works both in the gas network and with end users this mix is currently being demonstrated in domestic dwellings and businesses.
3. Hy4Heat aims to establish technical, economic and safety feasibility of replacing natural gas with hydrogen.[79].
4. H100 aims to build a hydrogen gas network in Scotland, powering 300 homes using electrolysis.[80].

1.2.8.2.3 Relevance to case study

Many of these industry projects recognize the substantial and relatively accessible market potential, with over 86% of UK homes connected to the gas network [71] and the networks growing compatibility with a hydrogen mix thanks to the 2002 government mandated Mains Replacement Program [78] and the potential to utilize the gas network to store and supply hydrogen for other applications such as transport.[77]

The closest point of injection into the transmission network is in Cheshire, ca. 60 miles from the point of hydrogen generation. This therefore suggests that for this North Wales case study it should be considered that hydrogen is injected directly into the distribution network. The distribution network operator for the case study region is Wales and West Utilities. Their most recent business plan expresses their ambition to include hydrogen and green gas in their network to help the UK reach climate targets. They are committed to realizing hydrogen in cities and industries across the region and have already established buy in from the end users who have been described as comfortable with the concept of hydrogen and before 2050 have an ambition to roll out a hydrogen network. North Wales is expected to become one of the outlined hydrogen pathways receiving a proportion of hydrogen from the North West Hydrogen cluster, in readiness for this the utility company are aiming to have completed their own Mains Replacement Program which will ensure that the network is ready for hydrogen by 2035 [81]. There is an opportunity for further research as to how renewables which are located close to the North West Hydrogen Pathway can export hydrogen onto this new network.

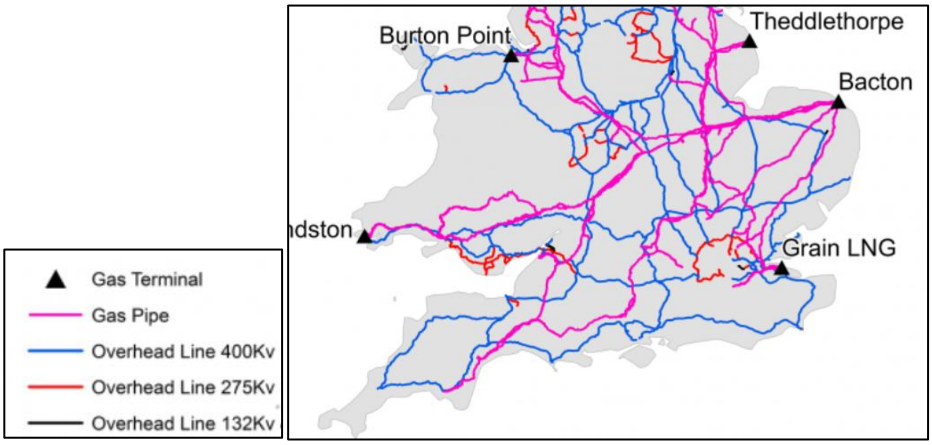

Figure 1: Map of North Wales Transmission network [82]

1.2.8.3 *Transport*

Research has been conducted in the fields of hydrogen as a fuel for road, rail, marine and aviation transport, however this next section will focus solely on the use of hydrogen as a fuel for road transportation, considering the feasibility of different market segments within this sector.

In a comprehensive review of low emission vehicles which included both fuel cell electric vehicles (FCEVs) and the closest low carbon competitor battery electric vehicles (BEVs), FCEV were found to be the first technology to exceed the range of petrol vehicles whereas range anxiety remains problematic for BEVs. The study also identified challenges such as the safety of Lithium Ion batteries and the non-recyclable nature of lithium [83] Today Lithium Ion batteries remain the dominant technology for BEVs with a significant amount of research focused on battery safety in transport applications as well as alternative material such as silicone to help resolve the challenge of lithium resource.[84] Similarly, in a review of different types of vehicles FCEV were found to have the highest average performance ranking when range, fuel consumption, fuel price, energy efficiency and emissions from CO_2 and SO_2 were considered [85]. When considering other drawbacks of low carbon alternatives to ICE, the strain on the electricity demand and existing power infrastructure should the transport sector transition 100% to BEVs concluded that the lowest renewable fuel cost was the scenario where 50% of the market were FCEV.[86] [67] Others have disputed reports that FCEV will have a limited role in UK energy systems suggesting that these studies have not accounted for the time taken to diffuse new technology such as powertrains, once this is accounted for they conclude that the optimum time for deployment was as early as 2015 [87] and the roles that

FCEV for personal transport will play in supporting the early rollout of hydrogen infrastructure.

1.2.8.3.1 Market trajectories

As the hydrogen economy develops it is considered that the transport sector will become a primary market for hydrogen producers.[44 76] By 2030 there are anticipated to be 3.7 m passenger vehicles, 500,000 light commercial vehicles, 45,000 trucks and busses along with 3700 hydrogen refueling stations (HRS) in Europe alone.[88] Fuel Cell Electric Vehicles are electric vehicles powered by hydrogen while hydrogen refueling stations (HRS) fill a tank with compressed gas within 3-5 minutes and operate similarly to conventional petrol or diesel refueling. As a result, FCEV benefit from long ranges and short refueling times, they offer users of any sized vehicle flexibility of use which is comparable to traditional internal combustion engine (ICE) vehicles. Countries that already have some infrastructure in place are leading the way with the US aiming to have 1 million FCEV on the roads by 2030 with 1000 hydrogen refueling stations (HRS) whereas Germany is aiming for 1.8 million FCEV and 1000 HRS. In South Korea, Hyundai are aiming to increase production of FCEV to 6.2 million units by 2040 an increase from the 18,000 units produced in 2018.[89]

1.2.8.3.2 Economic and technical feasibility

The FCHJU suggest that an acceptable hydrogen fuel price to end users is €9-10 / kg whereas the acceptable price for delivering hydrogen to a filling station is €5-7.[44] In 2011 it was suggested that producing hydrogen via electrolysis would cost \$2.75-\$4.50, but importantly, stated that wind energy was the preferred source of renewable energy as it is 40% lower than the cost of solar.[90]

1.2.8.3.2.1 Total Cost of Ownership (TCO)

The total cost of ownership is one of the challenges FCEV must overcome if there is to be widespread uptake of hydrogen as a fuel in road transport. Currently FCEV are 90% more expensive than ICE vehicles and 40% more expensive than BEV,[91] however it is anticipated that within the next ten years there will have been sufficient technical advancements, economies of scale in vehicle production and infrastructure and reductions in the cost of hydrogen to ensure that the TCO of a FCEV is competitive with ICE and BEV.

In an analysis of the hydrogen busses in London, it was revealed that the TCO of the fuel cell electric bus (FCEB) was \$281.18 per 100 km, whereas the corresponding figures for a BEV and ICE bus was \$229.58 and \$198.89 per 100 km respectively. The largest costs were the purchase cost and fuel costs, all of which were higher for the FCEB than for its competitors. Additionally, the total operational cost of hydrogen busses for the European market in 2019 was analysed with the results as follows: FCEB \$117.36 per 100 km BEV at \$105.18 and ICE at \$92.14 per 100 km. The most significant costs were the fuel, refuelling infrastructure, and insurance. However, despite the existing higher TCO and operational costs, the authors consider that FCEBs will breakeven with both battery powered and ICE busses by 2024 due to the reductions in price of hydrogen (**1.2.7**), economies of scale as higher volumes of production are realised (as demonstrated at the start of this section) and the introduction of Low and Ultra Low Emission Zones.[91]

Further analysis on the TCO which provides details on all sized vehicles supports the findings above reporting that heavy duty, long range vehicles such of lorries and coaches fueled by hydrogen is the quickest way to decarbonize the sector and will be competitive with BEVs and ICE as early as 2025. They also examined the TCO of passenger vehicles finding that in vehicles such as taxis which require a longer range (650 km) FCEV will outcompete BEVs by 2025, mid-sized passenger vehicles with a range of 400 km reach cost competitiveness by 2030 and vehicles with a smaller 300 km range will be cost competitive in ca. 2035.[3] While this suggests that on a TCO basis FCEV are more suitable to longer ranges and heavier payloads, FCEV will still be able to compete in this market based on the aforementioned advantages of refueling logistics, flexibility and fuel efficiency.

One mechanism for overcoming some of these challenges, in lieu of the anticipated cost reductions is to operate a business model which installers smaller electrolysers directly to HRS with captive fleets. The higher utilization of both the smaller electrolyser and an HRS with a dedicated demand provides a strong alternative business model to a critical mass of vehicles in the market.[67]

1.2.8.3.2.2 Technical Feasibility

The technical challenges are also economic ones, the cost of the hydrogen tanks, the fuel cell system and the battery or super capacitors are the main cost differentiators between FCEV and BEVs [91] and therefore, focusing efforts on the reliability and durability of the fuel cell [92] and addressing the technical challenges of the comparatively large weight and size of the hydrogen tank [90] as well as those of challenges of scaling up production will have a direct impact on how cost competitive FCEV can be in the market. Additional technical and economic challenges relate to the distribution of hydrogen from the renewable energy source to the refueling station, while transportation via pipelines is considered one of the most environmentally friendly options the technical challenges of supplying pure hydrogen to the gas network (discussed in Section **1.2.8.2**) remain as do the associated costs, therefore road transportation via tube trailers or bundles is considered viable for short distances.[93]

1.2.8.3.3 Industry projects

There have so far been two rounds of funding awarded by the UK government for development of the hydrogen transport sector. The first stage of the Hydrogen Transport Program awarded £8.8 million for the delivery of four new HRS in Birmingham, Derby and London as well as upgrading of four existing HRS and funded the deployment of 190 FCEV to be used as police service vehicles and taxis. The second stage of the program recognized the benefit to the business case of increasing station utilization ensuring that each successful project would supply a HRS with a captive fleet. As a result five new HRS were funded, 73 FCEV and 33 FCEB.[94]

Additionally, the North West Energy and Hydrogen Cluster is responsible for the Hynet project whose purpose is to deliver hydrogen infrastructure for decarbonizing heat (1.2.8.2.2) however they suggest that the infrastructure delivered as part of the project will be able to support the role out of FCEV and HRS. Hynet have calculated the required number of HRS to support roll out of FCEV in the North West region range from 15 to 30 dependent on vehicle demand. While it is considered preferential to site the HRS close to the hydrogen network, they have calculated that some of the HRS will need to be ca.5km from the hydrogen network. Currently they suggest that for these HRS hydrogen could be un-blended from natural gas and delivered by truck, however this also could present an opportunity for other cost competitive low carbon hydrogen to be delivered to these sites.

1.2.8.3.4 Relevance to case study

The relevance of these projects to the case study site is the proximity to a rapidly developing hydrogen market, with the North West particularly focusing on the use of low carbon hydrogen. The site of green hydrogen production in this study is only ca. 55 miles from the North West hydrogen cluster and five of the closest proposed HRS. Depending on the costs of transport, this may well constitute a short enough journey from the point of production to make a 50-mile road delivery economically viable.

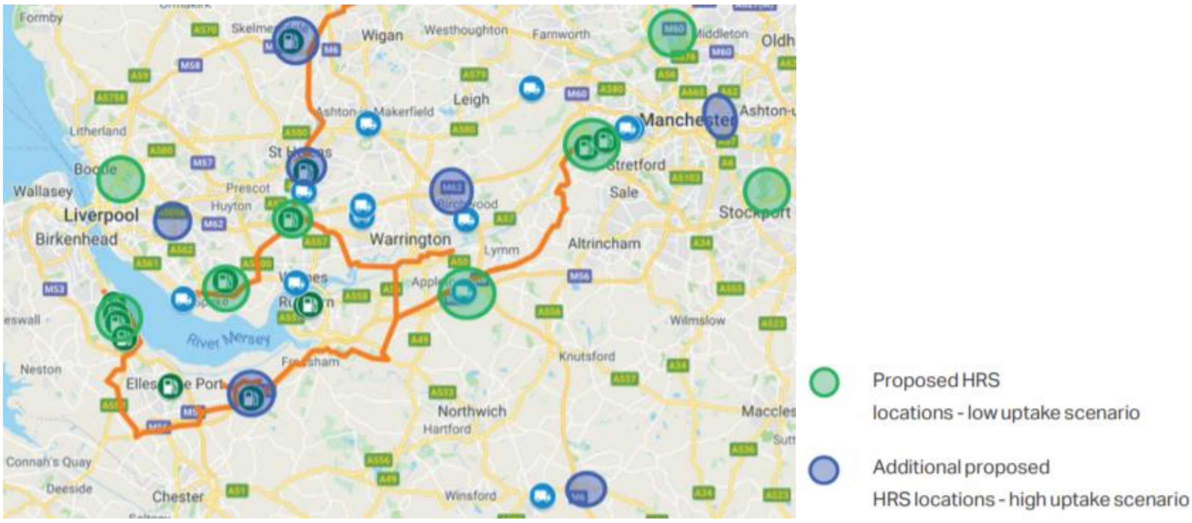

Figure 2: Hynet proposed HRS deployment

In addition, the analysis into the TCO which suggests that heavy duty, long range vehicles will be cost competitive by 2025 present a realistic timeframe and market focus for producers of green hydrogen to work towards if their business case relies on supplying their hydrogen into the transport market.

1.2.9 Wind to Hydrogen Case Studies

With clear grounds for theoretic technoeconomic feasibility as well as a demonstrated industry appetite for green hydrogen, this section will focus particularly on case study literature, examining the feasibility of producing hydrogen from wind in specific locations.

Rodríguez *et al.* (2010) analyzed the potential for hydrogen production from wind in the Cordoba region of Argentina, using a discounted cash flow model they determined which of these potential wind sites was most suited to hydrogen production for the mobility market. They concluded that hydrogen production is profitable when electricity prices are below $50 / MWh. This study examines only the feasibility of supplying hydrogen into the transport market and does not consider the technical or market barriers to entry, nor does it consider which other markets it might need to engage to either supplement a reduced early vehicle market or indeed to transport such high volumes of hydrogen.[95]

Mostafaeipour *et al.* (2016) produce a case study to evaluate the potential for using wind energy to produce hydrogen in the Fars province of Iran. While finding that particular cities have enough wind power to support the production of hydrogen capable of fueling 22 FCEV per week, they do not consider if this is economically as well as technically feasible and do not consider the potential for other hydrogen markets.[96]

Parissis *et al.* (2011) conducted a case study of the Portuguese island of Corvo with the aim of creating a roadmap for other European island nations who could benefit from the integration of wind hydrogen systems. They note the higher than average renewable energy potential shown by island nations and their dependency on fossil fuels. In their financial analysis the authors use a discounted cashflow model to produce the financial indicators NPV and IRR which they considered more robust that alternative financial measures. The authors assumed a 20-year time horizon for this project and used assumptions regarding cash inflows and outflows over that period to generate the NPV. Key assumptions in this study was the average price of electricity, lifetime of the project, price of electricity from conventional sources, the discount rate of 6% and the yearly revenues from electricity generation. The study shows that from a financial perspective the wind hydrogen system is profitable.[69]

Fragiacomo and Genovese (2020) use 4 economic indicators in their study, NPV, ROI, PBP and LCOH2. They find that on a wind hydrogen facility in Italy there is a positive business case and a LCOH2 of €6.9 / kg when the cost of electricity is €50 / MWh and there is 25% supply into the transport sector. The penetration into the transport sector needs to rise to 100% if the electricity costs are €100 / MWh which results in a LCOH2 of €9.85 / kg. They also find that gas grid injection to be an important mechanism in the profitability of the system when hydrogen for mobility is not fully utilized.[97]

Other studies have focused on building a model which can help determine the feasibility of a joint wind hydrogen system. Zhang and Wan (2014) investigated the need for large scale hydrogen storage as a response to wind curtailment and identify the need to produce an accurate model to address this. They investigated two electrolyser scenarios:

1. Modeled the continuous operation of the electrolyser which would draw power from the electricity grid when the curtailed wind was not sufficient
2. Modeled an intermittent operation of the electrolyser where the electrolyser operates only in response to the curtailed wind and does not draw on any additional power sources. Only an alkaline electrolyser was considered in this study.

They found for their wind farm case study an average yearly wind curtailment of 28.3% and that the utilization rate of this curtailed wind energy increases with the inclusion of an electrolyser. Subsequently, they found that the larger the electrolyser the higher the utilization of curtailed wind but, the larger the electrolyser the longer the payback period suggesting that the increase in costs is not commensurate with income, possibly due to lower utilization rates.

They conclude that scenario 1, continuous operation of the electrolyser is the favored system despite requiring input from the grid at a higher cost of electricity and suggest that scenario 2 is only preferential when the price of hydrogen is lower. They also suggest that collecting oxygen as a bi-product is beneficial although this is not modelled and is recommended for further work.[98]

The novel research being conducted here draws on two key points of the study above: firstly, the conclusion that an alkaline electrolyser operating at a continuous load is preferential to an alkaline electrolyser operating intermittently serves as a basis for the assumptions in this research that where the expected utilization rate of the electrolyser is over 70% this is sufficient to constitute a continuous load and an alkaline electrolyser is recommended. Zhang and Wan (2014) do not consider the use of a PEM electrolyser and this study accounts for that by introducing a PEM electrolyser as the preferred option when the utilization rate falls below 70% and a more intermittent load is predicted.

Secondly, they assume that curtailed wind energy can be provided to the electrolyser at zero cost. This assumption is also used in this research; however it was felt necessary to limit the amount of curtailment which is offered to the electrolyser for free. In the instance where a wind project has such significant curtailment that revenues from wind alone do not create an economically viable project, the first and most common option would be for the wind developer to downsize the project, increasing the utilization of a smaller number of turbines. The inclusion of an electrolyser on an otherwise unfeasible wind site would dictate that the costs for the energy provided to the electrolyser would need to be accounted for and supplied at the LCOE and accounted for on the balance sheet of the hydrogen production plant.

Others such as Ulleberg, Nakken and Eté (2010) review the operation of an existing system on the Norwegian island of Utsira. The first demonstration project of its kind, they found when reviewing the system design that having a market in which to regularly dispense the hydrogen avoids the need for larger storage solutions and associated costs, while their system has storage for only a couple of days they suggest that the optimal amount of storage is 1-2 weeks. They suggest that where wind is the only power input a strong steady wind is desirable as well as the need for larger storage.[36]

When evaluating the electrolyser specification the Utsira project demonstrates the importance of an electrolyser that can offer a quick response to varying inputs. As with Zhang and Wan (2014) they conclude that the continuous operation of the electrolyser is important, but point to the drawback of alkaline electrolysers which are only able to operate when the power input is between 25-50% of its rated capacity and long start up times. Since this research was published in 2010, the minimum power input required has reduced to between 10-15% of rated capacity and the start-up time is significantly reduced to between 1-10 minutes.[44] Ulleberg, Nakken and Eté (2010) suggest that larger scale alkaline electrolysers are better suited to multi-MW sites where there is a large demand for hydrogen production, however the authors also consider PEM electrolysers to be a strong alternative despite uncertainty surrounding lifetime and stack replacement costs.

The project in Utsira evaluates the storage systems required for a wind hydrogen system, suggesting two options:

1. Low pressure electrolysis with additional compression
2. High pressure electrolysis with no additional compression

They find that high pressure electrolysis without additional compression is ca. 5% more efficient but suggest that a high pressure alkaline electrolyser may be difficult to achieve concluding that a low pressure electrolyser with additional compression is favored. This analysis does not include examining a PEM electrolyser which is able to operate at much higher pressures, therefore this research allows for the option of using a PEM electrolyser with no additional compression unless the hydrogen is being used for transport in which instance it would need to be pressurized to 500 bar.[36]

This study provides valuable insight into the optimum system design and set-up. It considers the role of both alkaline and PEM electrolysers for larger MW scale projects. It highlights the need for strong steady winds in projects where wind is the only input. It discusses the storage requirements and its dependency on wind resource as well as the role between pressurized electrolysers and external compression. Many of these findings are used to inform the system design within this research.

1.2.10 Relevance to case study

The selection of case studies above examinesexamined the feasibility of producing hydrogen from onshore wind energy. While it is difficult to generalize the results of a case study, there are similarities across the studies which can be drawn upon for this research:

1. The use of the discount cash flow model to determine economic feasibility and the use of NPV as an economic indicator.

2. The feasibility of supplying hydrogen into the transport sector with two studies determining feasibility if the price of electricity is $50 per MWh or below.
3. Hydrogen system design, particularly the continuous use of the electrolyser versus intermittent operation.
4. The recommendation of additional revenue streams from either supplying hydrogen to multiple end markets or from selling bi-products of heat and oxygen are suggested in two of these studies also.

1.2.11 Summary

Findings from the research suggest that there is a critical need to reduce emissions and meet climate targets which will continue to drive the installation of onshore wind energy. The continued, although slower growth rates than in previous decades will continue to drive efficiencies in the technology and reductions in CAPEX and OPEX projecting a LCOE from onshore wind of $20 per MWh in the coming decades. However the increased penetration of wind and other renewable power is likely to exacerbate the issues of intermittency and variability, this will be a challenge for both electricity grid operators who are likely to increase the use of wind curtailment to balance the network and wind farm developers who will face financial challenges as a result.

Hydrogen has been established as a storage mechanism which can help solve the problem of intermittency. Further, green hydrogen has been found to be environmentally preferential to other low carbon alternatives. It has also been discovered that increasingly attention is being focused on the uses of hydrogen as either a by-product or an end-product rather than solely as a storage device for excess renewables. The technological feasibility of green hydrogen has been established, alkaline electrolysers have gained the status of a mature technology while PEM electrolysers will continue to prove their position in the market promoting rapid response times and high flexibility and while developments will continue in compression, storage and distribution much of the technology can benefit from the existing gas industry. From an economic perspective, green hydrogen is now more feasible today than ever before with its cost already fallen by 60%. This is due to two primary factors: 1) The aforementioned fall in the cost of renewable electricity and 2) The cost reduction is CAPEX of infrastructure, primarily the electrolyser which is expected to continue to fall with a learning rate of 9-13%. The third factor which is fundamental to the economic feasibility of any hydrogen project is the utilization rate of the electrolyser. In order to increase the utilization rate either high volumes of storage are required, or the project is able to establish a consistent supply into a market. Studies included in this review have recommended supplying into multiple markets such as transport and gas network in order to achieve higher utilization rates until one market is mature enough to take 100% of the supply.

Four hydrogen markets were identified in the literature with two (gas network and transport) being focused upon. It is commonly suggested that transport will be a primary market for hydrogen producers as governments and industry attempt to decarbonize. Findings suggest that within the next five years, vehicles such as lorries and coaches will be cost competitive with other passenger vehicles achieving cost parity between 2030-2040. Hydrogen is also thought to be key in decarbonizing the heating network, with several industrial demonstration projects already underway. While it is anticipated that it will take longer for the price of green hydrogen to fall low enough to compete with natural gas, it is thought that the gas network presents an important opportunity to de-risk projects. Developments within the gas network are also vital for the future transportation and storage of hydrogen into any sector.

Finally, the case studies reviewed have demonstrated the feasibility of wind hydrogen systems on a project by project basis, they have identified optimal system design and modelling assumptions which will be drawn upon in the creation of a new model aimed at determining the economic feasibility of a joint wind hydrogen project on a site in North Wales, UK. This research fills an important gap as it produces a working model which can be used by wind farm developers to determine feasibility of onsite hydrogen production at any given site. The case study, based on a site in North Wales, will provide valuable insight into a region with a high proportion of onshore wind generation and existing grid challenges and will provide insights as to which potential hydrogen markets are regionally the more feasible.

The following sections will lay out the aims and objectives of this research followed by a theories and methodology section before the results of the model are presented and discussed.

1.3 Aims and Objectives

Considering the trajectory and challenges facing onshore wind and the role that hydrogen could play in helping to tackle and resolve the issues of variability, infrastructure and tighter business cases, the aims and objectives of this research are to produce a working model which can be used by onshore wind farm developers to demonstrate the economic feasibility of including hydrogen production within the scope of the traditional wind farm projects. The additional aims of the research are to identify where the local hydrogen market potential is, when hydrogen produced from UK onshore wind may be cost competitive and where the efforts of onshore wind developers should be put now, to yield future benefits in relation to hydrogen production. The objectives of this research will be discussed in general terms and with reference to a case study named Alywn Farm for which this model will be first applied.

The model aims to build upon the strong, established assumptions of traditional onshore wind developments in the UK before incorporating cost and generation assumptions for a hydrogen system sited in the same location as the wind farm. The model and subsequent research have five main objectives:

1.3.1 Objective 1 – Economic modelling

To produce an economic model which is flexible, accounting for the wide variations between individual wind farm projects therefore allowing developers to utilize the model for any wind project where producing hydrogen may also be a consideration.

1.3.2 Objective 2 – Alwen Farm

To use the model to determine the feasibility of producing hydrogen at Alwen Forest wind farm examining scenarios for 7 – 10 turbines installed at the site with varying levels of constrained grid.

1.3.3 Objective 3 – Financial indicators

Based on project specific inputs, the model will produce two key outputs which will support organizational decision makers in considering the inclusion of hydrogen production in the project. These two key outputs are:

- The levelized cost of Hydrogen (LCOH2)
- NPV cashflow projections for three different hydrogen scenarios

1.3.4 Objective 4 – Market identification

Discuss which hydrogen markets are most accessible to the project and discuss the best locations in Wales for hydrogen production.

2 Theory: basic theory of net present value

This section will offer a description of the theory on which the model is based.

2.1 Discounted Cash Flow model (DCF)

Due to its widespread use in existing literature [69 97 99 100] the economic model developed by this research will be based on a discounted cash flow model (DCF). The discounted cash flow is a valuation model, determining the present value of a company or project based on the value of its future revenues.

2.1.1 DCF Output - Net present Value (NPV)

The net present value is the standard indicator of project viability for the DCF model. It is the present value (PV) of all cash flows (both positive and negative) for the duration of the project, while also accounting for any upfront investment the project requires. It is used frequently to evaluate investment decisions and project viability and has been described as one of the most sophisticated methods for economic valuation.[101]

$$NPV = \sum_{t=0}^{n} \frac{NCT_t}{(1+r)^t}$$

Equation 1: Calculation of NPV. ref

The core principle of the DCF model and NPV is that money today is worth more than money tomorrow because money that is yet to be made faces higher levels of risk and uncertainty. Therefore, to account for this risk and achieve the NPV a discount rate is applied to all future revenues. The rate at which future revenues are discounted reflects the perceived risk to achieving the expected revenues.

2.1.1.1 *Discount rate*

The discount rate is of fundamental importance to the evaluation of project feasibility. The riskier a project the higher the discount rate investors will apply which translates into a de-valuing of the expected cashflows.[102] The discount rate comprises of two calculations:

- The **risk-free rate** (f) or reward for patience, is based on the expected return if all that is required of investors is patients. The risk-free rate has a standard measure and reflects the same rate as risk-free government bonds. In the UK, there is a 3% yield on bonds with 10 year maturity.[103]

- The **risk premium** (p) is calculated using the market portfolio as a benchmark. For mature technology, a standard estimate for the market portfolio risk level is 5%. For novice technology the systematic risk will be important as this determines how closely aligned the project is to market shocks and what additional rate should be added to the risk premium. The systematic risk is calculated through beta (explained below) or estimated using existing market data.

In the instance of a mature technology such as onshore wind, it is reasonable to suggest that the discount rate would be calculated using the market portfolio risk level of 5%:

$$r = f + p$$

Equation 2: Calculation of discount rate.

For a green hydrogen project where the neither the technology or the markets are mature, the beta will need to be calculated to determine the projects systematic risk and what discount rate should be applied to future cash flows.

2.1.2 Calculating Beta

The beta is the average percentage change in an investment return for every 1% change in market returns. If a project or organisation has a beta of 1, this means that when the market moves up or down by 1% the project will mirror this movement, the investment project can therefore be said to have the same systematic risk as the market.

For projects that are not listed on the financial markets, which haven't begun yet it is therefore impossible to calculate the value of beta, in this instance a project can achieve an accurate estimation of beta by comparing them to firms which are publicly traded and who operate similar businesses.

Table 1: listed firms betas

Company name	Beta
RWE	0.98
Vestas	0.78
ITM	0.93
NEL	0.58

The average beta for this group of companies which best reflects the nature of the project is **0.82**. This suggests that the project has a lower systematic risk than the market portfolio but is closely correlated.

The discount rate for a green hydrogen project would be calculated using the following formula:

$$r = r_f + \beta x E\left(r_{market} - r_f\right)$$

$$r = 3\% + (0.82)(5\%)$$

$$r = 7.1\%$$

Where:

r = *discount rate*

$r_f = risk\ free\ interest\ rate$

$\beta = beta$

$E\left(r_{market} - r_f\right) = expected\ return\ on\ market\ portfolio\ at\ risk\ free\ rate$

Equation 3: Calculation of beta.

The discounted cash flow model is one of many economic models which could be used to value projects and companies. One of the primary benefits of using this method is that the project risk is fully accounted for through the application of the discount rate. In addition to the application of the discount rate, a further strength of the NPV is that it accounts not only for the initial cash flow, as the pay-back period would, but it accounts for all future net cash flows linked to the project. Despite its universal popularity, the NPV has received criticism when used for long term, innovative or R+D projects. When calculating the discount rate, the risk premium should be derived through careful market analysis, evaluating the risk verses reward relationship of other similar projects and applying this to the project in question. However, this is a particularly difficult task for innovative projects without market precedent, as a result these projects are perceived as high risk (and attributed accordingly with a higher discount rate) without a counter-balance which recognises their potentially higher rewards [104]. Since this project is innovative without a market precedent and with uncertain cash-flow projections over the next 20 years, this limitation must be considered when analysing model results.

2.1.3 DCF Model Inputs

The following section provides a description of the financial inputs needed to build a discounted cash flow model and produce a project NPV. The inputs required in this model reflect the information needed to generate the predicted cash flow and subsequent NPV.

2.1.3.1 *Positive cash flows*

Positive cash flows account for any revenue generated by a project. This is calculated using the following formula, where n_y is number of units sold (*n*) per year (*y)* and $n_£$ is the cost of a single unit.

$$CF = n_y n_£$$

Equation 4: Calculation of positive cash flows

2.1.3.2 *Negative cashflows - Capex, Opex and Devex*

All costs (negative cashflows) have been categorized as either a capital expenditure (capex), development expenditure (devex), operational expenditure (opex) or financial costs. While the input values may vary substantially depending on a number of project variables, they are all accounted for in a standardised way across the models.

2.1.3.2.1 Capital Expenditure

The capex is defined as any investment into PP&E (Property, Plant and Equipment); these costs occur at the start of the project and are generally accounted for as upfront costs. In some instances where there is a pre-existing agreement the capex is paid and accounted for in the model over a pre-agreed timeframe, for example 5 years. The length of the repayment period is an important variable to account for given its impact on the NPV therefore this model has been designed to allow a flexible (project specific) repayment period to account for this.

For the purposes of this project the same repayment period has been assumed for the hydrogen infrastructure as for the wind infrastructure.

2.1.3.2.2 Development Expenditure

Devex in this model is defined as costs incurred before the final investment decision is taken. These costs, unlike the capex, are accounted as direct upfront costs prior to the project being commissioned or generating revenue. Devex costs may vary significantly between projects, meaning that they can have a relatively high impact on the financial viability of the project. As Devex costs occur before the final investment decision, they could also be considered as sunk costs and therefore not included within the NPV calculations. While excluding these costs as sunk would have a beneficial impact on the final NPV it was considered that a more robust business case could be presented if these costs were included as well. The devex costs are therefore accounted for in this model as upfront costs so the NPV reflects the whole project investment.

2.1.3.2.3 Operational Expenditure

Operational costs refer to the annual costs of running a project, this includes direct and indirect costs which are accounted for differently in the model.

2.1.3.2.3.1 Direct Costs

Direct costs are expenses which when incurred can be directly linked to the generation of specific products or services which is in comparison to indirect costs which cannot be attributed to a specific product but more often relate to the general business operations.[105] Based on this definition, all operational expenditure which can be linked either to the generation of a kWh of electricity or the generation of a kg of hydrogen from a specific wind farm or power to gas plant is considered a direct cost.

2.1.3.2.3.2 Indirect costs

Indirect costs are ones that cannot be directly associated with a product or service, rather they are incurred more often through the general running of the business.

2.1.3.2.4 Financial costs

The value of a project is based on its free cash flows, free cash flows represent the cash available once all the project spending has been accounted for, this not only includes the capital investments and operational costs of the project but the deduction of other financial costs such as tax on earnings, interest and depreciation. The free cash flow is important as it is considered free of any obligations and can be paid to investors. The free cash flow is used directly in the NPV calculation.

2.1.3.2.4.1 Tax

To calculate the free cash flows of a project tax must be deducted from the operational earnings.

2.1.3.2.4.2 Depreciation

Depreciation is the gradual writing-off of value on tangible assets. While depreciation has no actual cash-flow associated with it and therefore does not directly affect the project's free cashflow, it does have a notable impact on the project's taxable income and associated tax payments. As tax payments have a direct impact on the free-cash flow it is important for depreciation to be accurately incorporated. Throughout this project the straight-line method of calculating depreciation has been used, as shown in Equation 3, where D is equal to depreciation (GBP / y), A_C is the cost of asset (GBP) and A_L is the life of the asset or project (y).

$$D = \frac{A_C}{A_L}$$

Equation 5: Calculation of depreciation.

The boundary chosen for this project included the lifetime of the equipment which is based on a design life of 20 years. The possibilities for the equipment and infrastructures end of life have not been evaluated in this model. It was considered that more research is needed into the end of life of this equipment, the ability to recycle component parts, the possibilities to re-plant the site and that this discuss fell outside of the boundary of the project.

2.1.3.2.4.3 Interest

Assuming that a project has borrowed funds from a lender as opposed to raising equity to deliver the project, interest on the money borrowed should be accounted to give an accurate NPV. However, in this instance the project is fully funded by other areas of the business and so no interest is required.

2.2 Levelized Cost of Energy

The second output which will help determine the viability of the project is the LCOE or LCOH2. It is commonly used as an indicator of profitability for renewable energy projects and can be used to compare the costs of energy produced via different technologies, time series analysis of specific technology or a tool for integrated modelling assessment.[106] It can be considered as the average, minimum price per unit of energy needed in order for the lifetime project costs to be offset.[107] Traditionally, the LCOE calculation is based on the NPV from the discounted cash flow model and can be calculated using the following steps.[108]

- Obtain all CAPEX (*C*), OPEX (*O*) and generation (*G*) data over the duration of the project (*t*)
- Calculate the NPV of total costs:

$$NPV_C = \sum \left(\frac{C_t + O_t}{(1+r)^t} \right)$$

Equation 6: Calculation of NPV of total costs.

- Calculate the NPV of total generation:

$$NPV_t = \sum \left(\frac{G_t}{(1+r)^t} \right)$$

Equation 7: Calculation of NPV of total generation.

- Calculate the LCOE by dividing the total costs (*Tc)* by the total generation (*Tg)* to give a cost per unit of energy

$$LCOE = \frac{Tc}{Tg}$$

Equation 8: Calculation of LCOE.

In the Equation above Tc and Tg have been calculated above in Equation 5 and 6.

Once the LCOE has been calculated across the different technologies a cost comparison can be made. The initial investment cost has a large impact on the LCOE, as a result, predicted learning rates for both onshore wind and electrolysers will have a large impact on the future LCOE (as described in section: electrolyser learning rates: **1.2.7.2**). One benefit of the LCOE method for renewables is that it is possible to model a LCOE for a renewable energy system at a particular point in the future so long as the model includes an assumed market growth rate on which the learning rate cost reductions are based.[106] Alternatively, a drawback of using the LOCE as a metric to evaluate renewable energy cost competitiveness is when there are fluctuations of electricity prices over time.[106] [109] One possible solution put forward is to use an adjusted LCOE calculation whereby changing energy prices over the whole length of the project are accounted for. Alternatively, a traditional LCOE analysis can be used where either consistent energy pricing can be assumed throughout the duration of the project or where it is being used to compare the average cost of the same technology applied in different settings where energy price fluctuations are equal across all settings.

In this instance the LCOH is being used to compare the costs of producing hydrogen which will be utilized across several applications however the fluctuating costs of energy will be important in analysing the results as the investors will need to make a decision as to whether the electricity should be directed to the grid or to the electrolyser. This only applies in the instance where there is a dedicated supply of wind and it is not curtailed as curtailed wind is lost and would not be able to be supplied back onto the grid.

2.3 Future Forecasting

2.3.1 Learning rate / Experience curve

This section will offer a brief explanation and description of learning rates. While learning rates will not be applied to the technology in this project, it is possible to include them within the model and discussion in future work.

The learning curve is used to forecast future technology costs based on the actual and predicted installed capacity and is commonly used in economic modelling of renewable energy technology. The fundamental principle of the learning curve is that the more capacity is installed, the greater the learning acquired by industry which drives improvements in the product, production and in the supply chain leading to cost reductions.[110] The application of the learning curve demonstrates a case for increasing investment into emerging technologies as a mechanism for driving down price. While traditionally the learning curve has been applied to the capital cost of infrastructure, this research will also discuss the learning curve effects on operational costs as well as the cost of capital.

The learning curve, also known as the experience curve, is a one-factor, linear log equation which correlates the cost of a technology to its cumulative installed capacity or cumulative power generated [110]. The application of the learning rate is not limited to capital cost of infrastructure, although this is commonly where it is applied but can also be applied to operational costs which uses the same linear log equation substituting technology cost with operational cost.

The basic expression of the experience curve is where Y is the cost of per unit, x is the cumulative experience, a represents the cost of the first unit and b is the rate of cost reduction.

$$Y = ax^b$$

Equation 9: basic experience curve [110]

2.3.1.1 *Global Learning Curve*

The results of the learning curve vary significantly depending on the parameters applied (time, duration, geography). While there are national and regional variations in the costs associated with wind technology and increasingly project variations in hydrogen production, overall both technologies and industries are overwhelmingly global, dominated by multinational organisations who compete in a global market [111]. Therefore, it is considered appropriate to use a global learning rate which will use the total global installed capacity of both onshore wind (MW) and electrolyser capacity (MW) on which to calculate the results.

In contrast, it could be considered that operational costs are more strongly determined by region as the work is undertaken locally with factors such as local labor costs varying widely between regions. However, as many of the operational savings will come from efficiencies in design and build of the turbine. The O+M activities are, at least in the first instance carried out or dictated by the OEM in order to comply with the warranty, it is reasonable to assume that these processes and procedures are standardized across a global organisation and then disseminated into national regions suggesting that a global opex learning rate is appropriate to apply.

3 Methods

The model offers a flexible and user-friendly input sheet allowing different scenarios to be easily calculated with a wide range of siting and development variables such as the presence of forestry or siting on common land included. The model accounts for this and other conditions in the input sheet where users of the model can include these inputs relevant to their particular developments This model has been refined to the Alwen Forest wind farm study whereby the curtailed generation of each turbine scenario has been calculated and automated. Based on the site-specific inputs, the model suggests the size and specification of the electrolyser system including storage, compression, and transportation requirements. It also calculates the annual hydrogen production volume and the costs associated with supplying the hydrogen into three different end markets. The economic feasibility of producing hydrogen from the onshore wind farm and supplying into the three market scenarios is depicted using the economic indicators of NPV and LCOH2. This thesis used the model to present results relating specifically to Alwen Forest wind farm, however the model has been consciously designed so that it can be utilized across the organisation who commissioned this study to investigate the feasibility of co-located hydrogen production with renewable energy generation.

This section will present a description of the model and detailed explanation of the assumptions used before providing an explanation of the various cases and scenarios for which results will be presented in chapters 4 and 5.

3.1 Model description

The model developed in this work is an excel based tool utilizing macros for a user friendly interface.

There is one inputs tab where the user should input all data relevant to the project, this includes technical inputs for the wind farm such as size of the wind farm and the grid connection as well as the economic inputs of CAPEX, OPEX, DEVEX and financial inputs such as discount rate and inflation. There are then 12 additional tabs which are all responsible for calculating and producing the results of the 4 different cases detailed below in Figure 4.

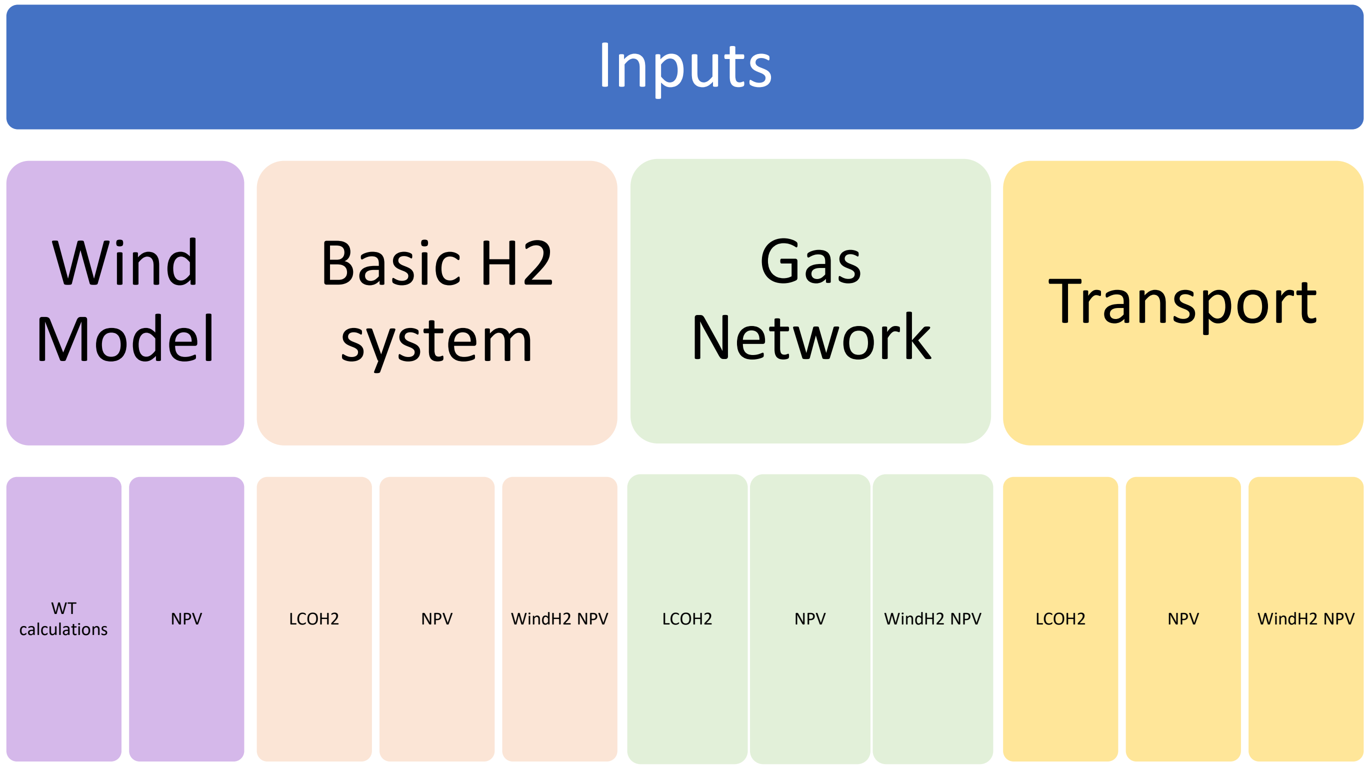

Figure 3: Model navigation buttons

Under the wind model tab there are two calculation pages in addition to the original Inputs sheet. The wind calculations page offers a list of assumptions and calculations while the Wind NPV presents the discount cash flow model and NPV. The hydrogen system requires more assumptions than inputs therefore there is a tab called "H_2 assumptions" which lists all of the technical and economic assumptions associated with the hydrogen production system. A list of these assumptions and sources for assumptions can be found in appendix B. Under each of the three main hydrogen cases (Basic Hydrogen System, Gas Network and Transport) there are three additional tabs which each report different results:

- The first tab in each case calculates the levelized cost of hydrogen for that particular set-up
- The second tab presents the discounted cash flow model and the NPV
- The third tab combines the discount cashflow model from the wind modelling with the discounted cash flow model of the relevant case.

The input page, which is the first tab in the model provides a list of all the necessary inputs, cells shaded grey will automatically calculate and do not need user input. The section headed in purple is for the wind farm inputs and the section headed in orange is for the hydrogen inputs. Some of the hydrogen assumptions such as capex can be found in the fourth tab labelled "H_2 Assumptions" for full list and sources see appendix B.

Wind Farm Inputs			NOTES
Number of Turbines		10	
Installed capacity per turbine	KW	4800	
Total capacity of wind farm	KW	48,000	
Total capacity of wind farm	MW	48.0	
Net Energy Yield (P50)	KWh	172,857,143	This figure should exclude losses due to grid curtailment. Grid curtailment does not relate to external transmittion losses only losses in turbine production due to grid constrains
Size of Grid connection	KW	32,500	
Grid curtailment	%	15.0%	
Power diverted to H2 that would otherwise be sent to grid	%	0.0%	Only complete if there is 0 generation curtailment and the project is planning on diverting electricity from the wind farm that could and would otherwise be exported to the grid without restriction. This will calculate the opportunity cost of losing the electricity revenue from the grid by charging the h2 system for it.
Net Energy Yeild (P50) for wind	%	85.0%	
		146,928,572	
Net Energy yeild (p50) H2	%	15.0%	
		25,928,571	
% of time negative electricity prices	%	0%	if a negative electricty price then RES need to either turn turbines off, import electricity or pay
Project / Plant life	yrs	25	
Final investment decision		2024	
Number of years from FID to COD (commercial operation date	yrs	1	Please express as a whole number, half years will be rounded up

Hydrogen system inputs			Notes
H2 Devex costs			
Include DEVEX (sunk costs) in NPV		YES	
Capital cost of site development as % of total cost	%	30%	
OPEX			
Utilities			
Price of electricity from wind farm	£/Kw	0.00	
Cost of water	£/L	0.01	
Cost of Power directly from grid	£/KW	0.057	
% electricity from wind turbine	%	100%	
% electricity from grid	%	0%	
Calculated per MW AND in addition to wind farm costs			
Business Rates	£	1000	
Community Benefit	£	0	
Insurance	£	1000	
Ongoing Grid Costs	£	0	
Total Additional Opex calculated per MW	£	**2,000**	

Inputs | WT calculations | Wind NPV | H2 Assumptions | Electrolyser system | H2 NPV | WindH2 NPV | Gas System | Gas NPV | WindH2 Gas NPV | Transport system | Transport NPV | WindH2 Transport NPV

Figure 4: Model input overview

Throughout the model there are a small number of instances where parameters in tabs other than the input tab can be changed or amended. This can be seen for example on the "LCOH2 Basic System" tab where the storage capacity can be changed. The model uses a basic assumption of 5 hours of storage as a relatively conservative but realistic starting point that can be modified in the model if required. It is assumed that there is a regular off-taker for the hydrogen and therefore minimal storage will be required. Instances where inputs can be changed to reflect different case conditions are highlighted in yellow as per the example in Figure 6.

Low Pressure Storage vessles - All Markets		
Volume of H2 in vessle	Kg	230
required pressure	Bar	20
hours of storage required	hrs	2
Storage capacity required	Kg	104
Number of storage vessles required		0

Figure 5: Example of where other inputs are required

3.2 Universal Assumptions and model basis

Several generation, cost and financial assumptions have been made to calculate the NPV and LCOE/LCOH2 for this project. The wind energy assumptions have been supplied by the case study partner (RWE, personal communication, March, 2020). The hydrogen system cost and generations assumptions come primarily from an FCHJU study where generation and cost data have been recorded for 2017 and predicted for 2025.[44]

3.2.1 Wind Power – Case study specific assumptions

There is a minimum of 7 turbines rated at 4.8 MW each, these turbines produce an estimated net energy yield of 17,285,714 kWh each per year this has been calculated by the industry partner (RWE, personal communication, March, 2020). There is a maximum grid connection of 32.5 MW.

3.2.1.1 *Generation assumptions*

Due to the nature of this research and the users of the model, actual wind farm generation data will be used in the input sheet, this removes the requirements for many generation assumptions or calculations based for example on average wind speed. This methodology can be seen in other literature.[98]

3.2.1.2 *Cost assumptions*

Capex repayments are split over a number of years. In this instance, there is no interest on the repayments although depending on the terms with the turbine manufacturers this may vary.

3.2.1.3 *Financial assumptions*

It is assumed that the wind farms are funded off balance sheet and therefore it is assumed that there is no acquisition of debt funding and in turn no interest to account for within the discounted cash flow model.

In the instances where energy is diverted away from the grid and an opportunity cost is applied this is calculated in model the opportunity cost has been accounted for via the inclusion of a price per kWh for the number of units diverted away from the grid. This is done at the lowest level of LCOE £0.276 per kWh as opposed to the expected sale price of £0.51 per kWh.

3.2.2 Hydrogen

3.2.2.1 *Generation assumptions*

Below are some of the fundamental, key assumptions on which the rate hydrogen is generated through an electrolyser is calculated.

The energy available for hydrogen production is calculated by multiplying the utilization rate by the nominal power rating of the electrolyser, where *(E)* is energy available for hydrogen production / year *(y)*, *H* is hours the electrolyser is in operation / year *(y)* and *P* is the nominal power rating of the electrolyser.

$$E_y = H_y \times P$$

Equation 10: Calculation of energy available for hydrogen production.

The figures calculated for daily or monthly hydrogen produced are derived as an equal proportion from the total annual production. This model assumes that there is no seasonal variation in hydrogen production, this is the same methodology as has been used in existing literature where the sizing of the hydrogen facility is based on the average yearly production for onshore wind energy as well as for other renewables.[95] It is widely considered that hydrogen through electrolysis is well suited to responding to seasonal fluctuations in renewable energy generation but that for this to be properly exploited seasonal storage is also required [65] which is not within the scope of this project. It should however be considered in future research how the seasonal fluctuations in energy generation effect the sizing of the electrolyser and the surrounding system and how this might impact the economic and technical feasibility of the project.

3.2.2.1.1 Electrolyser

For the purposes of this research the electrolyser system boundary has been defined to include a number of sub-systems:

- Electrolyser Stacks
- Gas purification
- Water management
- Cooling system

- Control system
- Power supply

The setting of system parameters in such a way is found throughout the literature.[44] [58]

3.2.2.1.1.1 Efficiency

Electrolyser efficiency assumption is one of the vital parameters in calculating the economics of a green hydrogen solution. It is defined as the energy input required to produce 1 kg of hydrogen. A system that is 100% efficient would require 39.4 kWh per kg [112], however neither the PEM nor the alkaline electrolyser can claim this level of efficiency. Instead it has been reported that the efficiency of water electrolysis is between 60-80%.[113] The US Department of Energy set efficiency targets for PEM electrolysers suggesting that by 2020 it should achieve 43 kWh per kg,[114] while the FCHJU, set less ambitious targets of 52 and 48 kWh per kg for alkaline and PEM electrolysers respectively.[112] The formula used to calculate the efficiency (*Ef)* is:

$$Ef = \frac{Minimum\ electrical\ input}{Actual\ electrical\ required}$$

Equation 11: Calculation of efficiency.

Figure 7 details several key assumptions for both the alkaline and PEM electrolysers. Due to the rapid pace of electrolyser development and cost reductions this model has used the 2025 assumptions for both the alkaline and PEM electrolysers. The lifetime of the electrolyser and the degradation rates are both included within the model. The lifetime of the stack is calculated based on the number of hours in operation per year, once the respective number of lifetime hours has been used then the model accounts for a full stack replacement at a cost of €270 per kWh for a 5MW electrolyser (see Figure 8).[44] The stack degradation is accounted for in the model in a separate line item "H_2 lost through stack degradation" whereby the hydrogen not produced due to stack degradation is taken away from the total hydrogen produced without the degradation. This ensures that annual hydrogen production is diminishing due to stack degradation. If the stack is replaced the model accounts for this and the year of replacement does not see a reduction in production.

		ALK						PEM					
		2017 @ P atm			2025 @ 15 bar			2017 @ 30 bar			2025 @ 60 bar		
Nominal Power	UNITS	1 MW	5 MW	20 MW	1 MW	5 MW	20 MW	1 MW	5 MW	20 MW	1 MW	5 MW	20 MW
Minimum power	% Pnom	15%			10%			5%			0%		
Peak power – for 10 min	% Pnom	100%			100%			160%			200%		
Pressure output	Bar	0 bar			15 bar			30 bar			60 bar		
Power consumption @ P nom	kWhe/kg	58	52	51	55	50	49	63	61	58	54	53	52
Water consumption	L/kg	15 L/kg											
Lifetime – System	Years	20 years											
Lifetime – Stack @ full charge	hr	80 000 h			90 000 h			40 000 h			50 000 h		
Degradation – System	%/1000 h	0,13%/ 1000 h			0,11%/ 1000 h			0,25%/ 1000 h			0,20%/ 1000 h		
Availability	%/year	>98%											

Figure 6: FCHJU electrolyser costs and performance data [44]

3.2.2.1.1.2 Stack

The stack durability assumptions are highlighted in green in Figure 7. They suggest that the alkaline electrolyser stack degrades by 0.11% with every 1000 hours of operation and that a stack replacement is required at 90,000 operational hours which if running at 100% utilization requires replacement every ca. 10 years. The stack degradation and impact on the total amount of hydrogen generated is reflected in the discounted cash flow model and reflects the type of electrolyser selected for the project.

3.2.2.1.1.3 Lifetime and availability

The system lifetime of 20 years is used within this model. This is a realistic assumption for this project as it is also the average design life of a modern onshore wind turbine and complements the 15 year CfD scheme [115] and prior to that the 20 year feed in tariff scheme.[116] In addition, the system availability is assumed to be 98% as referenced in Figure 7.

3.2.3 Cost assumptions

3.2.3.1 *Electrolyser*

Figure 8 provides the basis for the cost assumptions for the electrolyser, depicting the CAPEX of the electrolyser, the annual system OPEX and the stack replacement costs.

		ALK						PEM					
		2017 @ P atm			2025 @ 15 bar			2017 @ 30 bar			2025 @ 60 bar		
Nominal Power	UNITS	1 MW	5 MW	20 MW	1 MW	5 MW	20 MW	1 MW	5 MW	20 MW	1 MW	5 MW	20 MW
CAPEX – Total system Equipment	€/kW	1200	830	750	900	630	600	1500	1300	1200	1000	750	700
OPEX – Electrolyser system	%CAPEX	4%	3%	2%	4%	3%	2%	4%	3%	2%	4%	3%	2%
Stack replacement cost	€/kW	420	380	338	315	270	216	525	470	420	300	250	210

Figure 7: FCHJU cost assumptions [44]

The Capex of the electrolyser is derived from the 2025 total system equipment costs for both the alkaline and PEM electrolysers. Other sources support the use of these assumptions with IRENA finding that the CAPEX for an alkaline electrolyser in 2018 was $840 / kW,[59] whereas in a techno-economic study of the characteristics of electrolysers they use the same assumptions for a 20 MW electrolyser with the alkaline achieving a 2017 CAPEX of €750 / kW and a predicted CAPEX of €450 / kW in 2025 whereas for the PEM electrolyser they based their assumptions on a 2017 CAPEX of €1200 / kW and a predicted CAPEX of €700 / kW in 2025 [117]. These findings combined with the predicted learning rates give validity to the CAPEX cost assumptions found in Figure 8 and applied to the model.

While Figure 8 gives a range of OPEX assumptions based on the size of the electrolyser, this model has chosen to apply a fixed OPEX to the electrolyser system of 3%, regardless of the nominal power input. This is the average OPEX value across electrolyser size and does not change between 2017 and 2025, using a fixed value of 3% ensures that the OPEX accurately reflects the likely size of the electrolyser while maintaining simplicity.

The final cost assumptions drawn from this study are those relating to the stack replacement. As with the OPEX costs, the stack replacement costs vary depending on the size of the electrolyser, however for consistency the cost assumptions used in this model are again based on the 2025 predicted costs of a 5 MW electrolyser.

3.2.3.1.1 Compressor skids

Depending on the type of electrolyser used and the hydrogen application the hydrogen may require additional compression before it can be stored in the stationary storage or before it can be transported to its end application. In the event compression is required at this stage in production the cost assumptions have been drawn from the tables below. Using 2025 assumptions that an alkaline electrolyser will generate hydrogen at 15 bar therefore the model will cost a compressor at either 15 bar to 60 bar for an alkaline electrolyser (circled in red) or a 30 to 60 bar compressor for a PEM electrolyser.

k€ CAPEX		Estimated value
Patm → 60 bar	20 kg/h	265
	100 kg/h	766
	400 kg/h	1912
15 bar → 60 bar	20 kg/h	182
	100 kg/h	528
	400 kg/h	1318

k€ CAPEX		Estimated value
30 bar→ 60 bar	20 kg/h	144
	100 kg/h	418
	400 kg/h	1043

Figure 8: FCHJU compressor cost assumptions [44]

3.2.3.2 *Stationary storage*

For the basic electrolyser system, the stationary storage is considered necessary for small volumes of hydrogen. This study is not considering the possibility of high-volume stationary storage such as salt caverns. The model has based the stationary storage on a low pressure 20 bar pressure vessel from Linde which holds up to 230 kg per vessel. The price assumed for this pressure vessel is £500 per kg this price is an average of the costs listed in Figure 10.

*CAPEX €/kg	2017	2025
50 bar (tank)	470	470
200 bar (bundle)	470	470
350 bar (bundle)	470	470

Figure 9: FCHJU CAPEX assumptions for stationary storage [44]

3.2.3.3 Gas network

The assumptions in this section of the model are applied in the scenario that hydrogen produced from the wind farm will be supplied into the gas network. It considers only injection into the distribution network for use in heating applications. This model does not consider the feasibility of using the gas network to transport hydrogen to other sectors. The cost assumptions for this section are based on both the FCHJU study [44] as well as from the Hydeploy case study [118] which offers a published budget including CAPEX and OPEX system costs. The installation of the infrastructure costs have been excluded from the cost assumptions listed below as these will vary significantly on the site and cannot be accurately extrapolated from a case study. A summary of the cost assumptions used for the gas network are shown in the table below.

Table 2: Summary of gas network CAPEX and OPEX [44] [118]

Gas Network Injection infrastructure	**Unit**	**Cost**	**Source of assumption**
Grid entry unit (pre injection processes)	£/kW	134	Hydeploy 2018
Injection station CAPEX	k£	433	FCHJU 2017
Injection Station OPEX (% of capex)	%	8%	FCHJU 2017
Lifetime	yrs	35	FCHJU 2017
H2 connection piping	k£/km	270	FCHJU 2017
H2 connection piping equipment	k£	180	FCHJU 2017
OPEX (% of capex)	%	2%	FCHJU 2017
Monitoring equipment CAPEX	k£	450	Hydeploy 2018

3.2.3.4 *Transport Sector*

The following section will discuss the cost assumptions made for a scenario where hydrogen from the wind farm is being supplied into the transport market. This scenario assumes that due to the location of the wind farm and its on-site hydrogen production that there will not be a co-located refueling station, instead the hydrogen will need to be delivered to existing refueling infrastructure. The model assumes that due to the size of the market, the scale of hydrogen production at this site and the readiness of pipeline infrastructure that the hydrogen will be delivered via road transportation.

3.2.3.4.1 Filling centers

The filling centers act as the interface between the hydrogen production system and the mobile storage units of tube trailers or bundles. In this model the filling centres are only required when the hydrogen produced is being distributed into the transport sector. Included within the cost of the filling centers is the compression, additional pipework and filling equipment. If compression of hydrogen is required for any other end market application the compressor cost is calculated separately.

ALK - k€ CAPEX			
Electrolyser output	**Mobile pressure required**	**Rate of fill**	**Estimated Value k€**
Patm	200 bar	20 kg/h	687
		100 kg/h	1986
		400 kg/h	4959
15 bar	200 bar	20 kg/h	498
		100 kg/h	1441
		400 kg/h	3597

PEM - k€ CAPEX			
Electrolyser output	**Mobile pressure required**	**Rate of fill**	**Estimated Value k€**
30 bar	200 bar	20 kg/h	467
		100 kg/h	1351
		400 kg/h	3373
60 bar	200 bar	20 kg/h	441
		100 kg/h	1276
		400 kg/h	3185

Figure 10: FCHJU filling centres CAPEX [44]

Figure 11 offers the cost assumptions of the filling centers based on the output pressure of the electrolyser, the required pressure of the mobile storage unit and the rate of fill required. For the purposes of this model, the technical predictions for 2025 have been used to correlate with the 2025 cost assumptions. Therefore, it has been assumed that if an alkaline electrolyser is used it will produce hydrogen at an output pressure of 15 bar and that if a PEM electrolyser is used it will produce hydrogen at an output pressure of 60 bar (outlined in red).

3.2.3.4.2 Mobile storage

Figure 12 provides the CAPEX assumptions for the mobile storage required to distribute the hydrogen to the hydrogen refuelling stations. In determining the feasibility of the case study wind farm to produce hydrogen the mobile storage is included within the financial model but the delivery of the hydrogen to the refuelling site is where the remit of this financial model ends.

The pressure required for the mobile hydrogen storage is determined by cost, and the refueling station system configuration. It is assumed that hydrogen is dispensed to FCEV at either 350 bar or 700 bar and that in order to achieve this the refueling station will require an onsite compressor, high pressure storage, a refrigeration unit and the dispenser. For dispensing at 750 bar to the transport sector the hydrogen will need to be stored at 95 Mpa (950 bar) this means that the hydrogen will not be able to be dispensed directly from the mobile storage as other studies have suggested.[119] It is not considered that the model of dispensing hydrogen from the mobile storage will be adopted in commercial refueling setting and therefore in this study it is assumed that the hydrogen will be delivered via tube trailer and processed onsite to meet the pressure requirements of the transport sector. It can therefore be concluded that the hydrogen produced in this study can be delivered via tube trailer or bundle at the lower pressure of 200 bar which will reduce the cost of the mobile storage and utilize the refueling station compressor. This can be seen reflected in the costs of the filling center in Figure 7 as the cost assumptions are linked to the mobile storage required pressure.

	Large bundles		Tube trailers	
***CAPEX €/kg**	**2017**	**2025**	**2017**	**2025**
200 bar	470	470	500	500
500 bar	815	590	830	605

Figure 11: FCHJU CAPEX for mobile storage [44]

3.2.3.4.3 Mileage

The above section accounts for the capex of the transport and delivery method but does not account for other associated costs. Transporting the hydrogen by truck using bundles or tube trailers means that the distance the hydrogen is transported has a large effect on the cost, with the biggest impact being fuel costs and O+M costs which scale in correlation with distance travelled.[56] Yang and Ogden find that when the capex of the delivery unit is included along with the number of vehicles required as well as the OPEX and fuel the cost of a 25km journey is \$1.50 / kg. To account for the impact of distance travelled on cost, a basic mileage cost of £0.50 has been applied to the model, this mileage cost covers the operation and maintenance of the vehicle and the fuel.

3.2.4 Financial assumptions

Several financial assumptions run through the model and are treated in a standardised way.

All costs have been converted from Euros (€) as seen in Table 3 into pounds (£) using an exchange rate accurate as of 02/07/2020. The currency conversion for US dollars is also included

Table 3: Currency conversion [120]

Currency Conversion (02/07/2020)	
GBP (£)	1
Euro (€)	1.1095
USD (\$)	1.2515

3.2.4.1 *Corporation tax*

Corporation tax applies to limited liability companies doing business in the UK. If a company is based in the UK then corporation tax is calculated based on the company's total profits, if the company is based outside of the UK but trading within it, then corporation tax is calculated based on profits generated within the UK. The standard rate of corporation tax in the UK is 19% and therefore this rate has been applied to the financial model produced in through this research.[121] More complex tax calculations are out of the remit of this research and have not been considered.

3.2.4.2 *Business rates*

Business rates were applied to all renewable energy installations over 50 kW in 2017. The Valuation Office considered the value of an energy generating project to be in its ability to make profits and therefore business rates vary between projects.[122] Business rates also vary by local authority increasing the variation between projects. It has therefore been decided that in line with other similar projects developed by the same company a flat rate of £7000 per MW will be applied (RWE, personal communication, March, 2020).

3.2.4.3 *Electricity prices*

The accuracy and robustness of the electricity prices are vital as i) the majority of wind farm revenue is currently based on the net energy yield multiplied by the wholesale price, and ii) when producing renewable hydrogen 75% of the cost of production comes from the electricity price [8]. Combined, these factors mean that small fluctuations in the price of electricity may have large impacts on a project's viability.

3.2.4.4 *Wholesale electricity prices*

Due to this importance of robust electricity pricing data, a third-party specialist (Aurora Energy Research) was thus commissioned here to provide this data. The actual data will remain confidential (both now and after publication), but Aurora provided an annualized forecast of electricity prices between the years 2020 - 2040. Accounted for therein (and consequently embedded in the resulting model) is Aurora's view of current and long-term policy direction and their own expert view on technological change and commodity prices. Analysis was provided offering a best, worst, and central case scenario on the wholesale price of electricity.

Any electricity price data found in the model has been derived from the data provided by Aurora, the original data cannot be shared for confidentiality reasons but the process to achieve the figures used in the model was to use the upper and lower price estimates and calculate an average price for the electricity across the given years. Electricity prices from wind farm

One of the advantages of a co-located wind and hydrogen production is that it offers the opportunity to use curtailed wind and to supply the electrolyser with electricity for zero cost. There is also the growing possibility that the power to gas system could draw energy from the grid when there is negative pricing. Negative electricity prices were seen across Europe in the first nine months of the year and particularly effected the countries with a higher proportion of renewable power [123] On the occasions that this is viable the power to gas system would be paid to take energy from the grid. This has not been included within this study but represents an important topic for future research.

3.3 Cases and Scenarios

Case 1: Wind farm site only. This case will act as the baseline in two different respects. Firstly, it will offer an NPV result on the assumption that only wind turbines will be installed and only electricity will be sold to the grid. This will offer a comparison NPV once the hydrogen production is included. Secondly it will generate a LCOE for this specific site which if needed can then be applied the cost of energy needed to produce the hydrogen; however this model is currently only examining the production of hydrogen from curtailed energy which can be considered with zero cost. Within this first case 4 scenarios are modelled: **1)** 7 turbines with zero curtailment, **2)** 8 turbines with 4.5% curtailment, **3)** 9 turbines with 10% curtailment and **4)** 10 turbines with 15% curtailment.

Case 2: Basic hydrogen production system with no defined off-taker. This case will act as the base case for hydrogen production. By not defining the off taker it allows a very basic hydrogen system to be designed and costed. This system will form the basis of the system for the following two cases allowing a clear visual separation of the additional infrastructure and cost required for supplying to the different off takers.

Case 3: Hydrogen generation for the gas network. This case will draw on the system design and results of the basic hydrogen production system before adding on the additional infrastructure required to supply hydrogen to the gas network. This case assumes that the hydrogen can be supplied into the gas network within 0.5 km of the point of generation, however the results and discussion will expand on the impact of transporting the gas over a longer distance as well as providing insights as to where the demand for this may come from.

Case 4: Hydrogen generation for supply into the transport sector. This case will again draw on the basic hydrogen system design before adding on the additional infrastructure required to produce and supply hydrogen into the transport sector. This case assumes that the hydrogen producer is only responsible for transporting the hydrogen as far as the refuelling station and that there is no responsibility to supply or operate the HRS, this therefore also assumes that the off-taker is responsible for providing the infrastructure to off-load the hydrogen from the transport to the on-site storage.

Case 2, 3 and 4 examine the same three core scenarios, these presenting in Table 3

Table 4: 3 core scenarios

Scenario	**1**	**2**	**3**
Number of turbines	8	9	10
Curtailed generation	4.5%	10%	15%

3.3.1 Wind scenario

The first section of the results will focus on the economic feasibility of the wind farm at the project site. This will offer a base scenario after which hydrogen production can be introduced. Modelling the wind farm specifications is an important step in determining the profitability of the wind farm independently of the hydrogen production, thereby offering an economic case by which to compare the feasibility of including hydrogen production within the site parameters. Several scenarios will be examined for the wind farm section of results and this is driven by site specific requirements. This project will install a minimum of 7 turbines however the geography of the site and subsequent planning permission will allow for at least 9 turbines. This section will therefore present results for a 7, 8 and 9 turbine wind farm. The table below details the inputs required for each scenario.

- The primary variable for each scenario is the number of turbines installed (highlighted in green).
- The model assumes that each turbine installed will be of the same make and model and therefore offer the same installed capacity as well as the same technical and operational parameters. The result of this assumption is a linear correlation between the number of turbines and the total capacity of the wind farm.
- The model assumes that the p50 net energy yield per turbine is 17,285714.3 kWh per year.
- The size of the grid connection remains constant, regardless of the size of the wind farm, this is reflective of the actual grid connection available at the site in question although does not take into account seasonal fluctuations in capacity.
- The constrained generation reflects the proportion of generation lost due to grid constraints. The proportion of grid constraint has been calculated independently by RWE (RWE, personal communication, March, 2020).
- This scenario is based on the final investment decision being made in 2024 with the project built out and commissioned two years later.
- All of the parameters highlighted above are able to be amended to suit alternative wind farm projects.
- This model includes a standard additional revenue calculation which is based on ancillary services sold to the grid in addition to the energy sold. In this model revenue through ancillary services is assumed to be an additional 1.5% of total generation

(RWE, personal communication, March, 2020). Table 4 presents the main assumptions for each scenario in this case.

Table 5: Wind Farm assumptions and variable

Number of Turbines		7	8	9	10
Installed capacity per turbine	kW	4800	4800	4800	4800
Total capacity of wind farm	kW	33,600	38,400	43,200	48,000
Total capacity of wind farm	MW	33.6	38.4	43.2	48.0
Net Energy Yield (P50)	kWh	121,000,000	138,285,714	155,571,429	172,857,143
Size of Grid connection	kW	32,500	32,500	32,500	32,500
Constrained generation	%	0.0%	4.5%	10.0%	15%
Curtailed Generation	kWh	0	6,222,857	15,557,143	25,928,571
Project / Plant life	yrs	25	25	25	25
Final investment decision		2024	2024	2024	2024
Number of years from FID to COD (commercial operation date)	yrs	2	2	2	2
Revenue from ancillary services	%	1.5	1.5	1.5	1.5

3.3.2 Basic Hydrogen

Each results section will detail 3 core scenarios which are shown in Table 5. The results for additional scenarios will also be presented but will depend on the initial findings. The purpose of this is to examine how some of the parameters set in the core scenario impact the feasibility of the project. Additional knowledge surrounding these variables will increase the understanding of which scenario holds the highest potential and which could benefit for increased investigation.

Table 6: Three core scenarios in each section

Scenario	1	2	3
Number of turbines	8	9	10
% curtailed energy	4.5%	10%	15%

The hydrogen production system consists of an electrolyser sized between 1-3MW, while the core research focuses on electrolysers of this size, the curtailed power of the 9 wind turbine site has the ability to utilise a much bigger 15MW electrolyser therefore this will be included later in the discussion as an additional scenario. the calculation is based on the number of kWh of available energy from the wind farm per year and the amount of power required by each electrolyser (1,2 and 3 MW) to run at the highest utilization rate. The electrolysers have been sized in such a way to increase their utilization as this is linked with a more cost efficient electrolyser, in addition a high utilization rate promotes the use of an alkaline electrolyser which operates optimally with a constant load. Currently the alkaline electrolysers are less expensive than PEM electrolysers and this helps to promote an economic case for producing hydrogen which is discussed in chapter one. Table 6 presents the utilization rates of the different size electrolysers in the different scenarios. It has been assumed for the purpose of this study that the chosen electrolysers are able to achieve high levels of utilisation. It should however be considered in future work that achieving these high rates from curtailed renewable power without a supplementary power from the grid will be challenging and therefore future analysis should consider what the impact of lower utilisation rates for electrolysers will have on the NPV and LCOH2.

Electrolyser efficiency calculations:

Table 7: Electrolyser assumptions

Number of turbines		8	9	10
Generation curtailment	%	4.5	10	15
Available energy	kWh	6,222,857	15,557,143	25,928,571
1MW max utilization rate	%	70	100	100
2MW max utilization rate	%	34	85	100
3MW max utilization rate	%	22	57	95
Efficiency	%	61	61	61
Availability	%	98	98	98
Life time	yrs	20	20	20

It should be noted that when the utilization rate of the electrolyser is estimated to be under 70% the electrolyser modelled and costed is a PEM electrolyser due to its increased responsiveness. For a utilization rate over 70% and therefore running on a more consistent basis an alkaline electrolyser is modelled and costed. In the results above this indicated that the electrolyser sized for the 8 turbine scenario is a PEM electrolyser whereas the higher utilization rates of the 2 MW electrolyser for a 9 turbine site and 3 MW for a 10 turbine site are both alkaline electrolysers.

In this basic hydrogen production case, the system also accounts for 5 hours of low-pressure onsite storage, as previously described 5 hours of storage has been used as a conservative but realistic starting point when considering the assumption that there will be a regular off-taker, even if in this instance the off-taker isn't defined. It is possible for the user of the model to adjust the amount of storage required, the model then uses this number to calculate the number of storage vessels required.

Table 8: Low pressure storage assumptions [44]

Low Pressure Storage Vessels - All Markets	
Volume of H_2 in vessel	230 kg
required pressure	20 bar
hours of storage required	5 hrs
Storage capacity required	259 kg
Number of storage vessels required	1.13

A compressor is also costed into the CAPEX depending on the type of electrolyser suggested by the model, its output pressure and the pressure required for the low-pressure storage. It has been assumed for this and all other sections that the electrolyser and low-pressure storage are co-located and there is therefore minimal cost for pipe work between the electrolyser and the storage.

3.3.3 Hydrogen for gas

This case examines the same 3 core scenarios illustrated in table 6. Supplying hydrogen into the gas network requires additional infrastructure and parameters. Table 9 details the additional infrastructure requirements while Table 10 details the additional CAPEX and OPEX of injecting hydrogen into the gas network.

Table 9: Additional infrastructure requirements

Pressure	bar	10
lifetime	yrs	35

Injection station size		-
H_2 losses	%	99%
Pipework	km	0.5

Table 10: Additional CAPEX and OPEX (Gas grid) [44] [118]

Gas grid		
Storage		
Low pressure storage (£/kg)	£/kg	568
Low pressure storage (£/kg) OPEX	%	2%
Injection infrastructure		
Grid entry unit (pre injection processes)	£/kW	134
Injection station CAPEX	k£	433
Injection Station OPEX (% of capex)	%	8%
lifetime	yrs	35
H_2 connection piping	k£/km	270
H_2 connection piping equipment	k£	180
OPEX (% of capex)	%	2%
Monitoring equipment CAPEX	k£	450

3.3.4 Hydrogen for transport

The next section details the results for hydrogen produced at the case study site, co-located with a wind farm and supplied into the transport sector. The results of this section are again based on the basic electrolyser setup as described and discussed in section 3.3.2 but in addition also includes additional infrastructure and power requirements needed to produce hydrogen to supply into the transport sector, details of which can be found in section 2.2.3.4.

The results for this case are based on the system parameters detailed in table 11:

Table 11: Hydrogen Transport system parameters

Number of turbines		**8**	**9**	**10**
Generation curtailment	%	4.5	10	15
Available energy	kWh	6,222,857	15,557,143	25,928,571
Electrolyser size	MW	1	2	3
Utilization rate	%	70	85	95

Low pressure storage	Hrs	2	2	2
Electrolyser type		ALK	ALK	ALK
Hydrogen sold	kg/ year	111,491	270,764	453,927
Milage		400	400	400

The variation in the system parameters for each wind farm scenario effects the system design the model selects for each specification. The results for each wind farm scenario are based on an ALK electrolyser with an output pressure of 15 bar. Due to the requirements of the transport sector for high pressure hydrogen the use of an ALK electrolyser necessitates that a compressor skid and filling center is required to step up the pressure from the 15 bar output pressure to 200 bar pressure which is suitable for the high pressure mobile storage of either bundles or tube trailers.

This system selection which includes the size or presence of an additional compressor as well as the ramp rate and operating pressure of the filling centers has an impact on the cost of the system and subsequently the LCOH2 and the NPV for each scenario each system therefore the system specification for each scenario is detailed below:

When additional infrastructure for supply into the transport sector is discussed this does not include the refueling infrastructure as this is outside of the remint for the producers of hydrogen. Instead, the additional infrastructure relates to the compressors and filling centers which are needed to take the hydrogen from the electrolyser and deliver it to a site with a refueling station.

Table 12: System scenarios

Number of turbines		**8**	**9**	**10**
Compressor Skid (15 bar-60 bar @20 kg/hr)	£	164,038	0	0
Compressor Skid (15 bar-60 bar @100 kg/hr)	£	0	475,890	475,890
Compressor Skid (15 bar-60 bar @400 kg/hr)	£	0	0	0
Filling Centres (15 bar – 200 bar @20 kg/hr)	£	448,851	0	0
Filling centres (15 bar – 200 bar @100 kg/hr)	£	0	1,298,783	1,298,783
Filling centres (15 bar – 200 bar @400 kg/hr)	£	0	0	0
Filling Centres (60 bar - 200 bar @ 20 kg/hr)	£	0	0	0
Filling centres (60 bar – 200 bar @100 kg/hr)	£	0	0	0
Filling centres (60 bar – 200 bar @400 kg/hr)	£	0	0	0

OPEX (% CAPEX)	£	13,466	38,963	38,963
Additional electricity cost	£	17,238	41,863	70,182
High pressure mobile storage				
Tube trailers (200 - 1000 k kg @ 200 bar)	£	901,307	901,307	901,307
OPEX (% CAPEX)		27,039	27,039	27,039
Delivery				
Cost per delivery	£	200	200	200
Annual delivery cost	£	20,800	20,800	20,800

Table 12 demonstrates the different system scenarios recommended based on the size and type of electrolyser. In the instance the 8 turbine scenario only requires compression at the rate of 20 kg / hour whereas the 9 and 10 turbine scenarios require compression at the rate of 100 kg / hour due to the volume of hydrogen produced. Should a PEM electrolyser have been selected with an output pressure of 60 bar, no additional compression would be required and the hydrogen could go directly from the electrolyser to the filling centres which are then connected to either the tube trailers or bundles whereby the filling centres can dispense the hydrogen at the 200 bars required for the mobile storage and delivery.

4 Results of wind modelling

The results show that the project specific LCOE is in all scenarios below LCOE calculated in IRENA's 2019 Power Generation Report. [20] It should be noted that the report presents these figures in USD and for the purposes of this study 0,053 USD per kWh has been converted to 0,039 £ per kWh.

Table 13: Results of wind farm model

Number of turbines		7	8	9	10
Generation curtailment	%	0%	4.5%	10%	15%
LCOE (project specific)	£/kWh	0.0247	0.0257	0.269	0.0282
LCOE (industry average)	£/kWh	0.039	0.039	0.039	0.039
NPV (Project LCOE)	£	14,176,508	11,042,524	5,118,187	-1,954,536
NPV (Industry LCOE)	£	-11,906,944	-17,387,654	-24,758,224	-32,758,746

The results suggest that the generation curtailment anticipated for this wind farm will have a marked impact on the profitability of site. This could be due the corresponding increase in capex and opex as the number of turbines increase in conjunction with the increasing generation curtailment seen in each scenario. The results suggest that in this instance it would be more profitable to install fewer turbines and produce a minimum of 10,666,667 kWh less per year than it is to install more turbines and produce up to 25,928,571 kWh per year. This however goes against the drive for a zero carbon economy and the increase in renewable power needed to meet the energy transition in all sectors.

The NPV shows that for a 7,8 and 9 wind turbine scenario there remains a positive NPV suggesting that there is a positive value to completing the project regardless of how many turbines are installed; however the results also present a diminishing NPV for every additional turbine added to the project suggesting that the scenario with the strongest profitability is that with the fewest number of turbines and the least amount of curtailment.

Curtailment data for this site suggests that while there is no expected curtailment for a 7 turbine scenario the inclusion of each additional turbine correlates to an approximate additional 5% generation curtailment. Therefore, if the results are to be extrapolated upwards, to include a tenth turbine with 15% generation curtailment, the LCOE again increased to 0.0282 and the NPV returns its first negative result suggesting that a project of greater than 10 wind turbines should not be considered.

The results here suggest that for the site to be at its most profitable the fewest number of turbines should be installed, in this instance 7. However, the drawbacks of this renewable electricity generation being curtailed by the profitability of the wind farm, as depicted in table 13 is the loss of an additional ca. 34,500,000 kWh of green electricity which could be generated and added to the network if all 9 turbines were installed instead of 7.

The model shows that when adjusting the year of the investment decision, the later the investment decision is made the higher the LCOE. One possible justification for this is that while the electricity generation is expected to remaining constant over the years, the opex, which is calculated as a % of revenue will increase along with the expected increase in electricity prices. However further work should be done on the other factors which may affect the LCOE such as future changes to the capex of turbines along with reductions in opex which are predicted and can be explored using the learning curve. What this model does not account for, however, is any variance in the ongoing opex of the turbines. Literature suggests that a global learning rate can be applied to opex costs as well as to capex costs. If developments in turbine O+M continue on the current trajectory, opex costs will fall by 9% [24] with every doubling of installed capacity, however it is not clear if these cost savings can be applied to wind farms which are already in operation or if the benefits can only be realised for new installations.

The results from this model confirm the findings and theories outlined in the introduction and background surrounding the limitations on wind power achieving maximum utilisation. In these results it is possible to see that the restricting factor to installing a larger wind farm is grid availability and resultant generation curtailment. As little as a 10% generation loss throughout the year is sufficient to decrease the project returns by 36%. While any decision to install less than the geographical capability of the site also has a negative impact on climate targets.

4.1.1 Removal of 7 turbines scenario

The results examine 3 core scenarios as detailed in Table 5. These are three of the four scenarios modelled in the wind results section with the exclusion of the scenario for a 7 turbine site. The results from the wind section show that for this particular case study site, there is no curtailed generation when the wind farm consists of 7 turbines with a power rating of 4.8 MW each.

In order to model hydrogen production using co-located wind power which does not have any generation curtailment the additional cost of the energy supplied by the wind farm to the electrolyser must be calculated. This cost of energy represents the opportunity cost of diverting the energy away from the grid where the wind farm would otherwise receive a payment therefore in order for the wind farm to continue operating economically the energy used to produce hydrogen which would otherwise be generating revenue needs to be costed to the hydrogen system.

In this instance the hydrogen production system includes the cost of the electricity within its financial modelling. The results of this scenario are detailed in the table below:

Table 14: 7 turbine wind farm with zero generation curtailment

Number of turbines		**7**
Diverted electricity used for H_2 production	kWh	5,956,800

LCOE	£/kWh	0.0276
Additional annual cost to H_2 system	£	131,190
LCOH2	£/kg	0.88
NPV	£	-432,957
H_2 sale price	£/kg	2.00
Break even sale price	£/kg	2.45

The negative NPV result shown in table 14 suggests that if this site was developed with 7 turbines and there was no generation curtailment on the site, then diverting the equivalent of the curtailed electricity from the grid to produce hydrogen is not currently a financially viable option and the site is more profitable if all the electricity produced is exported to the grid.

The results below therefore include the remaining three scenarios of an 8 and 9 turbine site, in addition, the generation curtailment has also been extrapolated to include tenth turbine which assumes a 15% generation curtailment as described in chapter 3.

Table 15: Additional 10 turbine scenario

Number of turbines	7	8	9	10
Generation curtailment	0%	4.5%	10%	15%*

* not calculated by the wind farm developer but estimated based on the actual Figures for 7, 8 and 9 turbines.

Table 16: Net energy yeild inc 10 turbine scenario

Number of turbines		7	8	9	10
Net energy yield (p50)	kWh	121,000,000	138,285,714	155,571,429	172,857,143
Net energy yield minus curtailed generation	kWh	121,000,000	132,062,857	140,014,286	146,928,571
Curtailed generation	kWh	0	6,222,857	15,557,143	25,928,571

5 Results of hydrogen modelling

This chapter will present the results of the hydrogen modelling and will be split into 4 sections. The first section will show the results for a basic hydrogen production system where the application of the hydrogen has not been defined and therefore there is minimal supporting infrastructure. The purpose of this is to create a baseline or set of minimum requirements for hydrogen production which can then be expanded upon. The second section will present results for supplying hydrogen into the gas network and the third section will present the results for producing and supplying hydrogen into the transport sector. All three of these sectors will give results using the NPV and LCOH2 as indicators. The purpose of these three sections is to illustrate the feasibility of producing hydrogen and to compare and contrast the opportunities with each other. The final section will combine the results of the wind farm with that of the hydrogen production to offer a total NPV and LCOE comparing the economic case of losing the curtailed generation or utilizing it to produce hydrogen.

5.1 Minimal system design with no defined off taker

This set of results presents the economic feasibility of a simple hydrogen production system co-located with a wind farm powered only using the curtailed generation.

The hydrogen price of £2.30 used in this case and the other cases throughout as it is suggested that by 2025 and the latest 2030, driven by strong cost reductions in electrolysers the LCOH could drop to 1 USD in optimal locations and to between 2-3 USD in average locations [3]. Converted into GBP this equates to approximately £2.30 per kg of hydrogen. It is considered reasonable to use this figure as all the other assumptions in the model relate to 2025 figures and not figures as they stand today.

Table 17: H_2 results basic production system

Number of turbines		**8**	**9**	**10**
Generation curtailment	%	4.5	10	15
Available energy	kWh	6,222,857	15,557,143	25,928,571
Electrolyser size	kW	1000	2000	3000
Utilization rate	%	70	85	95
LCOH2	£/kg	1.00	0.80	0.71
NPV	£	-657,849	68,604	1,238,387

H_2 Price	£/kg	2.30	2.30	2.30
Break even sale price	£/kg	2.70	1.97	1.68

The results suggest it is not profitable to produce hydrogen using the curtailed wind from the 8 turbine scenario. The hypothesis for this is that the capital costs of the electrolyser outweigh the economic benefit from selling the hydrogen at the current price. The results of the 9 and 10 turbine scenarios suggest that if the sale price of hydrogen is above £0.80 per kg then this becomes financially viable assuming the above parameters are met. On a smaller 8 turbine site which is only anticipated to experience 4.5% curtailment the sale price of the hydrogen must increase to above £2.70 for the project to have a positive NPV.

The model was then run to examine if a scenario with reduced CAPEX would result in profitability for an 8 turbine installation. In order to achieve this an electrolyser of 500 kW was considered.

Table 18: Results for 500kW electrolyser

Number of turbines		**8**
Generation curtailment	%	4.5
Available energy	kWh	6,222,857
Electrolyser size	kW	500
Utilization rate	%	100
LCOH2	£/kg	0.86
NPV	£	-141,988
H_2 Price	£/kg	2.00
Break even sale price	£/kg	2.21

The results in table 18 show that while reducing the size of the electrolyser down to 500 kW has a positive impact on the NPV increasing it by £515,861, it is not enough of a saving to result in an overall positive NPV and the hydrogen would need to be sold at over £2.21 for this scenario to become profitable.

Table 19: results for 15MW electrolyser

Number of turbines		**9**
Generation curtailment	%	10
Available energy	kWh	15,557,143

Electrolyser size	kW	15,000
Utilization rate	%	50
LCOH2	£/kg	1.14
NPV	£	-7,701,904
H_2 Price	£/kg	2.00
Break even sale price	£/kg	2.76

The results in table 19 suggest that increasing the size of the electrolyser in order to increase the utilisation of the curtailed energy has a negative impact on the NPV turning the 9 turbine scenario from positive to negative. However it presents a breakeven sale price of £2.76 which depending on the off-taker which in this instance is not defined could be achievable. This additional scenario will therefore be considered in the results where the gas network and transport sectors are the off-takers.

These results suggest that hydrogen production using electricity from curtailed wind where the hydrogen production equipment is co-located with the wind farm is economically feasible today with a sale price of hydrogen of £1.71 per kg. The co-location of the hydrogen production plant alongside the wind farm is an important factor as through this, several key costs can be reduced or eliminated from the LCOH2 and discounted cashflow calculations. This includes the landowner rent and community benefit payments as both payments are assumed to be already covered by the wind farm and payments and are fully costed into the wind results in chapter 4. The landowner rent, which is typically calculated as a percentage of wind farm revenue is paid for the occupation of the infrastructure on the land as well as access to the site. The hydrogen infrastructure does not require the uptake of any additional land and therefore it could be argued that there is no requirement for additional rent to be paid to the landowner. Additional costs for insurance and business rates have been included in the hydrogen cost calculations.

Contrary to the methodology for 7 turbines where there is no curtailed generation and so electricity diverted from the grid to the electrolyser must be charged for there is no charge for the electricity to the electrolyser in the 8, 9 or 10 turbine scenarios as it is assumed that the only electricity diverted to the electrolyser is energy that would be otherwise lost and so there is no opportunity cost to account for.

The levelized cost of hydrogen has been calculated as per chapter 2 (2.1.2). This model gives just one result per scenario for LCOH2 which accounts for some of the annual fluctuations in cost and in generation. It is most likely that due to annual variations in opex costs, (particularly in the instance where the stack needed to be replaced) and generation (losses due to stack degradation) there would be an annual difference in the LCOH2, however for the purposes of this model the LCOH2 has been averaged over the term of the project to give a single, average LCOH2 for each scenario enabling easy comparison between the scenarios.

While these results indicate economic feasibility of co-locating a wind farm with hydrogen production, this scenario only accounts for a basic system set-up with low pressure storage limited to 5 hours. In this scenario it is assumed that the off taker would be responsible for collecting, transporting and delivering the hydrogen to the end use applications.

It is helpful to consider the impact on the LCOH2 if there is a requirement for increased low-pressure storage onsite as increased storage may offer desirable increased flexibility which could be beneficial in an early market. It is suggested that small scale hydrogen storage will be instrumental in the early roll out of hydrogen, particularly in the transport sector where early hydrogen production will match the demand and so storage would only be necessary to account for small daily fluctuations.[124]

Table 20: Low pressure storage requirement variation

Number of turbines		**8**	**9**	**10**
Generation curtailment	%	4.5	10	15
Hours of storage	Hrs	10	10	10
NPV	£	-737,005	-123,058	917,961
Hours of storage	Hrs	24	24	24
NPV	£	-958,640	-659,713	20,768

Increasing the amount of onsite storage without increasing the revenue in this scenario decreases the NPV and in this case study the increase in storage shows that the 9 turbine scenario becomes unprofitable with as little as 10 hours or storage, whereas it remains profitable to increase the storage to up to 24 hours if 10 turbines were installed. While the small on-site storage this seems to reflect well the conditions for Alwen Forest hydrogen production, as regional hydrogen hubs develop (with Liverpool and Anglesey in close proximity) and make the transition to supplying buildings with hydrogen there will be a requirement for large seasonal storage. The UK does not have a great supply of natural storage resource and so new storage facilities will need to be developed which, depending on the size and scale could take 3 – 7 years. Therefore this should be considered in any future hydrogen production site requirements and project timescales.[124]

The results here suggest that it is economically viable to produce hydrogen for a wind farm of 9 turbines or above based on the generation curtailment specified and the electrolysers identified. In order to increase the feasibility of an 8 turbine wind farm two options could be considered: Firstly, to reduce the size of the electrolyser to under a MW which reduces the CAPEX and OPEX while also increasing the utilization and secondly, these results include 5 hours of low pressure storage, reducing the amount of storage to under five hours will have a positive effect on the NPV although the size of the electrolyser would still be required to decrease before a net positive NPV could be seen for this scenario.

5.2 Hydrogen production for the gas network

The next section of results will examine the economic feasibility of producing hydrogen for the gas network. The primary difference between this section and the previous section is the inclusion of additional infrastructure required to transport and inject the hydrogen onto the existing gas infrastructure. Based on the existing literature and information available on the ongoing demonstration projects in the UK, the most expensive additional component is the monitoring equipment which is vital for ensuring the correct quantities of hydrogen are injected into the grid. The additional infrastructure factored into this model consists of the gas injection infrastructure and the pipework required for transportation to the injection station.

Table 2Table 210: Details the system parameters and the results for the 3 core scenarios.

Number of turbines		**8**	**9**	**10**
Generation curtailment	%	4.5	10	15
Available energy	kWh	6,222,857	15,557,143	25,928,571
Electrolyser size	MW	1	2	3
Utilization rate	%	70	85	95
Low pressure storage	Hrs	2	2	2
KM of pipeline	Km	0.5	0.5	0.5
LCOH2	£/kg	1.89	1.16	0.92
NPV	£	-2,334,666	-1,094,285	610,035

H_2 Price	£/kg	2.30	2.30	2.30
Break even sale price	£/kg	4.97	2.81	2.13

The findings suggest that neither an 8 or 9 turbine site with the specified level of grid curtailment will be a financially viable option for the curtailed generation suggesting that that the additional costs for the system outweigh the expected revenues. Based on these results hydrogen for use in the gas network only becomes viable with a 10 turbine site that has 15% generation curtailment or the equivalent of 25,928,571 kWh in curtailed energy. Alternatively, supplying hydrogen into the gas network also becomes profitable if a higher sale price is able to be achieved of either £2.81 for a 9 turbine site or £4.97 for 8 turbines.

Table 22: Results for gas grid with 500 kW electrolyser

Number of turbines		**8**
Generation curtailment	%	4.5
Available energy	kWh	6,222,857
Electrolyser size	kW	500
Utilization rate	%	100
LCOH2	£/kg	2.14
NPV	£	-2,061,021
H_2 Price	£/kg	2.30
Break even sale price	£/kg	5.56

The model has also analyzed the impact of a smaller electrolyser on the 8 turbine scenario. Table 21 shows that while the NPV increases slightly it still presents an overall negative return while the LCOH2 increases as does the breakeven sale price which in this scenario is now required to be at least £5.56 / kg.

Table 23: results for 15MW electrolyser

Number of turbines		**9**
Generation curtailment	%	10
Available energy	kWh	15,557,143
Electrolyser size	kW	15,000
Utilization rate	%	50
LCOH2	£/kg	1.19

NPV	£	-3,789,047
H_2 Price	£/kg	2.30
Break even sale price	£/kg	2.70

The results of this scenario suggest that increasing the size of the electrolyser to 15MW to better utilise the curtailed energy has a negative effect on the NPV compared to a smaller 2MW electrolyser. This is likely due to the increase in CAPEX and the increased cost of the stack replacement during the life of the electrolyser. However the results also suggest that utilising more of the curtailed power reduces the break even sale suggesting that there is an optimum balance between utilisation of the curtailed energy and electrolyser CAPEX.

For this scenario the price the electrolyser would need to achieve in order for the case to break even is £389 per kW. In the current model it suggests that the cost of a 20MW electrolyser is £631 per kW this cost was applied to a 15MW electrolyser as it is considered closer than the price of a 5MW electrolyser which is £676 per kW. However when the cost of the electrolyser is split out from the other CAPEX costs and a breakeven analysis completed it is possible to show that if the CAPEX of the electrolyser fell from £9,463,722 to £5,829,512 this is the price at which the business model breaks even. To calculate the price per kW this figure of £5,829,512 is divided by 15,000 which results in an electrolyser price of £389 per kW in order to break even. This could be valuable insight for electrolyser manufacturers however there are also other areas such as the stack replacement costs where costs can be reduced to support uptake of the technology.

There are two parameters that require further examination in this section in order to determine the strength of their impact on the economic feasibility of producing hydrogen for the gas network. Firstly is the amount of low pressure storage that is required, based on the assumption reflected in a wide range of literature that hydrogen can be stored directly in the gas network a relatively small amount of additional storage will be required, therefore the results below show how much the project feasibility increases if the additional onsite low pressure storage is reduced from 5 hours to 2.

Table 24: NPV results for hydrogen sold to gas grid

Number of turbines		8	9	10
Low pressure storage	hrs	2	2	2
NPV	£	-2,296,512	-1,001,607	765,440

Break even sale price	£/kg	4.93	2.77	2.09

For the 10 turbine scenario reducing the amount of additional low pressure storage makes the project more feasible and makes the hydrogen even more competitively priced, however it does not change which scenarios are currently feasible and which ones are not, instead it gives the scenario which is already feasible a slightly stronger case.

The second factor which should be considered in this scenario is the cost of transporting hydrogen to the existing gas network. In this study it is assumed that minimal pipework will be required this is due to a number of assumptions, firstly that it will be cost prohibitive to consider this scenario for relatively small quantities of hydrogen if more than a minimal amount of pipework was needed to transport the hydrogen and secondly that it would be more cost effective to produce the energy from the wind farm, transport it as electricity through the network to the electrolyser which would be located at the site where the hydrogen could be injected onto the grid.

It has therefore been assumed that only 0.5 km of pipework will be required to transport the hydrogen from the electrolyser to the injection station. The price per kilometer is £270,000 therefore every additional kilometer required will have a significant impact on the NPV as the results below demonstrate.

Table 25: Results with additional gas pipe infrastructure

	Number of Turbines		
KM	**8**	**9**	**10**
0.5	-2,334,666	-1,094,285	610,035
1	-2,622,293	-1,332,181	372,089
2	-3,048,212	-1,807,974	-103,801
5	-4,475,302	-3,235,350	-1,531,473
10	-6,853,786	-5,614,312	-3,910,926

The results presented in table 25 illustrate the impact additional gas pipe infrastructure would have on the feasibility of the case and highlights the importance of siting the electrolyser close to the injection point on the gas network.

The price of hydrogen to be used in the gas network is the lowest price for hydrogen in the market. The sale price identified in this research is at the top end of a range offered in literature by Larscheid *et al.* (2018) and the FCHJU (2017) who suggested that if tariffs were to apply to hydrogen as they do for biomethane then an achievable hydrogen price is between 1.3 and 2.6 € per kg which in this model is converted to £1.17 - £2.34, this range applies to a number of countries examined in the FCHJU report with Germany at the bottom end of the scale at 1.3 € per kg and Denmark at the upper end of €2.60 per kg while the UK specifically has a price of €2.00 per kg converts into £1.80 per kg.

These figures are calculated assuming that renewable hydrogen will receive the same support though tariffs as biomethane which is between €32.2 per MWh and €67.5 per MWh with the tariffs in the UK specifically falling in the middle of this range at €50.5 per MWh (£45.50). Based on these results and the breakeven sale price that can be seen for each wind farm scenario, it is possible to suggest that only the scenario with 10 turbines is currently an economically viable option. However this confirms that large scale production and large volumes of curtailed energy are critical to the profitability of injecting hydrogen onto the gas grid [44]. This is supported by the results which determine that the larger scale electrolyser which has a higher utilization rate while also absorbing more curtailed generation from the wind farm returns a positive NPV for a number of scenarios including higher amount of distribution pipeline and a lower sale price per kg.

To support the estimation that profitability in supplying hydrogen into the gas network depends on an increased scale and volume, two additional scenarios has been modelled one for 12 turbines and one for 15 turbines, both with 15% generation curtailment:

Table 26: Gas grid additional scenarios

Number of turbines		**10**	**12**	**15**
Generation curtailment	%	15	15	15
Available energy	kWh	25,928,571	31,114,286	38,892,857
Electrolyser size	MW	3	3	4
Utilization rate	%	95	100	95
Low pressure storage	Hrs	5	5	5
KM of pipeline	Km	0.5	0.5	0.5
LCOH2	£/kg	0.95	0.91	0.87
NPV	£	610,035	610,035	1,768,577

H_2 Price	£/kg	2.30	2.30	2.30
UK H_2 price	3/kg	1.80	1.80	1.80
Break even sale price	£/kg	2.13	2.13	1.93

It should therefore be suggested that only sites with a critical level of curtailed generation are currently financially viable for producing hydrogen for injection onto the gas network and that this is highly dependent on the amount of additional pipework that needs to be installed. These results suggest that it takes over 38,000,000 kWh of energy going into hydrogen production to achieve a LCOH2 under that of £1.80 per kg as suggested by the FCHJU.[44] This suggests that hydrogen produced from this case study could achieve a price that is competitive with other low carbon technology such as heat pumps as this requires a price of under $3 per kg to be competitive whereas it is still not competitive with the cost of natural gas which requires a price of under $1 per kg.[3]

The results suggesting that in at least in some scenarios it is feasible to produce hydrogen for injection into the gas grid and the suggestion that this will become increasingly feasible with bigger levels of curtailment and reduced infrastructure costs mean that the local opportunity for supplying the gas network with hydrogen should be considered. These type of green hydrogen projects present a unique opportunity for the transition of the gas network in so much as the hydrogen production is co-located with the renewable energy supply which reduces transmission losses, and they have the ability to be co-located close to the demand as opposed to being located close to gas feedstock and storage. This flexibility in the location of hydrogen production could support the gas network planning and possibly avoid the need for some additional network reinforcement.[124]

It is predicted that throughout the UK hydrogen will become the primary low carbon gas while biomethane will come in a close second and that both of these low carbon gasses will supply industry, buildings and transport, replacing natural gas. In Wales specifically it is thought that hydrogen will supply both South and North Wales while Mid Wales will be transition to biogas. These regional differences are due to the predicted hydrogen cluster in South Wales which will have a primary focus on decarbonizing the local industry before expanding the hydrogen use into buildings.[124] A particular opportunity for green hydrogen in this location is due to the reduced access to Carbon Capture Usage and Storage (CCUS) where green hydrogen is considered one of the solutions to this issue. Alternatively in North Wales the development of hydrogen as the primary gas is thought to be due to the close proximity of the Liverpool and Manchester cluster and its potential for expanding into North Wales.[124] This prediction was made in 2019 and now the supply of hydrogen to North Wales seems even more likely with the announcement of the £4.8 millions of funding for the Anglesea hydrogen hub.[125] This suggests that Alewn Forest is in an opportune location to benefit from both of these hydrogen clusters and the infrastructure developments which are likely to result from both clusters expanding outwards.

5.3 Hydrogen production for the transport sector

The next section of results will examine the economic feasibility of producing hydrogen for the transport sector. As described in chapter 3 these results include the additional infrastructure required to produce and distribute the hydrogen into the transport sector but not the refueling infrastructure.

The results in table 25 show that producing hydrogen for the transport sector is only profitable in the 9 and 10 turbine scenarios. The results of both the NPV and LOCH2 indicators shows that hydrogen production for the transport sector become more profitable when more energy from curtailed wind generation is supplied to the electrolyser.

The FCHJU suggest that the acceptable hydrogen production costs vary depending on where the demand is, and the volume of hydrogen produced. For example when hydrogen production and demand are co-located the transportation and distribution costs fall and so the hydrogen can benefit from a higher production cost of €7-8 per kg, however in the case of Alwen Forest which is low volume and semi centralized the transport costs are higher and so the production price should be closer to €4-5 per kg.[44] Therefore, in this model a sale price of £5 / kg was used to reflect these findings. It has also been suggested that hydrogen which is sold to the refuelling station operators could achieve a price of £5 - £7 per kg. When considering the break-even price in table 25 it is possible to suggest that it is feasible to produce hydrogen in any of the core scenarios, including the 8 turbine scenario if the price of hydrogen achieved was at the upper end of the £5 - £7 per kg as the current breakeven price for the 8 turbine scenario is £6.19.

Table 27: Results for transport sector

Number of Turbines		8	9	10
LCOH2	£/kg	2.83	2.06	1.58
NPV	£	-1,098,316	1,514,645	6,956,284

Sale price	£/kg	5	5	5
Breakeven price	£/kg	6.19	4.33	3.17

These results are based on the parameters in table 11 and 12 however there is two conditions which needs further investigation: Firstly it is interesting to consider in the 8 turbine scenario, what price the electrolyser would need to be for this to turn into a feasible case. The electrolyser for this scenario is 1MW at a cost of £811 per kW. If the cost of the electrolyser is separated out from the total CAPEX in the cash flow, it is possible to perform a break even analysis, the results of which suggest that if the total cost of the electrolyser were to fall to £138,337 this would offer an NPV of 0. The price per kW is £138,337 divided by 1000 kw which results in a break even price of £138 per kW for the electrolyser.

Secondly, the miles from the site of hydrogen production to hydrogen delivery. The current findings show the results for a 400 mile round trip; however this research has found that there two hydrogen hubs in development with a much closer proximity, Table 26 presents the proximity Alwen farm is to local hydrogen development while Table 27 presents the results once the model accounts for the smaller mileage.

Table 28: Distance from local hydrogen hubs

Hydrogen Hub	Liverpool	Anglesey
Miles from Alwen	56	60
Round trip	112	120
Cost at £0.5 / mile	£56	£60

Table 29: Results with actual travel distances

Number of Turbines		8	9	10
Miles (LIVERPOOL)		112	112	112
LCOH2	£/kg	2.66	1.99	1.54
NPV	£	-904,988	1,708,065	7,149,798
Miles (ANGLESEY)		120	120	120
LCOH2	£/kg	2.67	1.99	1.54
NPV	£	-910,358	1,702,692	7,144.423

The results suggest that reducing the mileage has a notable, positive impact on both the LCOH2 and the NPV. This supports the suggestion from the FCHJU that when hydrogen production and demand are co-located the production price of the hydrogen can afford to be higher compared to when there are additional transportation and distribution costs; however in the case of Alwen Forest the results show that despite the reduced mileage the 8 turbine scenario maintains its negative NPV and therefore the close proximity of production to the off-taker is not enough to make the 8 turbines site feasible for hydrogen production into the transport sector.

The results from this model show that the 9 and 10 turbine scenarios are viable for hydrogen production and distribution of up to a 400-mile round trip at a cost of £0.5 per mile. This suggests therefore that it is not only the hydrogen hubs in close proximity which will offer viable markets in the future but other future hydrogen hubs such as in South Wales and Teeside, which are both within the 400 mile radius suggesting that there are multiple opportunities for delivering hydrogen into the transport market and that the hydrogen producer has the opportunity to supply to whichever of these markets develops first, although consideration should be given to how early each market is and the cost trade off in the event of a long term supply agreement.

Figure 12: UK based hydrogen hubs

It is also interesting to note that for the 9 and 10 turbine scenarios, the system specification (Table 12) remains the same but the hydrogen production increases allowing for an additional £5.4 million profit over the duration of the project without the additional cost of increasing the specification of the infrastructure. Future work could investigate what the optimum system size is for the available energy and determine if there is a point whereby the size of the system will have a negative impact on the LCOH2 and therefore become less feasible.

In addition to the cost of infrastructure required to produce hydrogen for the transport sector, there is also an additional cost for the energy required to operate the supporting infrastructure. The electricity consumption is assumed to be 2.7 kWh e/kg hydrogen. In this instance it is considered that the energy comes directly from the wind farm and that the cost of this is equivalent to the wholesale electricity price, in this instance £0.057 per kWh. By calculating the energy cost in this way, it is assumed that none of the curtailed energy will be diverted away from hydrogen production but rather some of the wind power will be diverted away from the grid. Charging the energy at the wholesale electricity price and what is assumed to be approximately the price the wind farm sells its energy for it can be expected that the wind farm doesn't lose revenue by diverting some of the energy into the hydrogen production system.

The role of hydrogen in the energy sector will depend on central government strategy however in the "Hydrogen in Wales Consultation 2020" [126] five out of the ten key suggestions for developing a hydrogen economy relate to the use of hydrogen in the transport sector and that local hydrogen production can be developed if there is sufficient demand from the transport sector.

In addition to the academic discussion, Wales based hydrogen fuel cell vehicle manufacturer Riversimple is also promoting the installation of small local hydrogen refuelling stations as a mechanism to open up the hydrogen economy in personal transport sector by de-risking the investment in each HRS by creating secure and predictable local demand. This offers an opportunity for the supply of local hydrogen, reducing transport and distribution costs and therefore offering the hydrogen at an increasingly competitive price.[127]

Using the current modelling parameters it is predicted that Alwyn Farm could produce 453,927 kg of hydrogen per year which is enough to supply hydrogen to refuel over 1700 Toyota Miri cars once a week, 5800 Riversimple Rasa vehicles with a 1.5 kg hydrogen tank and an 8 kW fuel cell [127] or 60 busses a day assuming each bus requires 20 kg of hydrogen per day.[126] While the current demand for hydrogen vehicles in Wales is relatively low, with only 3 Riversimple vehicles manufactured and zero hydrogen busses, the planned activity is for a fleet of 200 buses to be deployed in Wales by 2024 and Riversimple aim to have built their first factory in Wales by 2023 with a production capacity of up to 5000 vehicles per year. Alwen farm is only 1 hour from the university town of Bangor, 1 hour 40 mins from university town of Aberystwyth and just over an hour to Chester with its planned hydrogen hub activity. This therefore suggests that there is an opportunity to produce the hydrogen and transport it a relatively short distance to sites of transport demands.

Additional transport opportunities that are local to Alwen Forest are those of rail transportation. Figure 14 shows the Transport for Wales rail network map and demonstrates where there may be opportunities to develop hydrogen train solutions. For example, while the major lines South and North Wales will be electrified, many of the smaller lines will be considered too expensive to electrify rail lines such as the Llandudno and Biaenau Ffestinlog line (highlighted in green) where it is only ca. 30 miles to deliver hydrogen to either end of the line would be of particular interest. Additionally, the site is also in close proximity the Local distribution zone for the gas network, this could present an opportunity for a hydrogen producer to collaborate with a local need for gas storage and the train line.

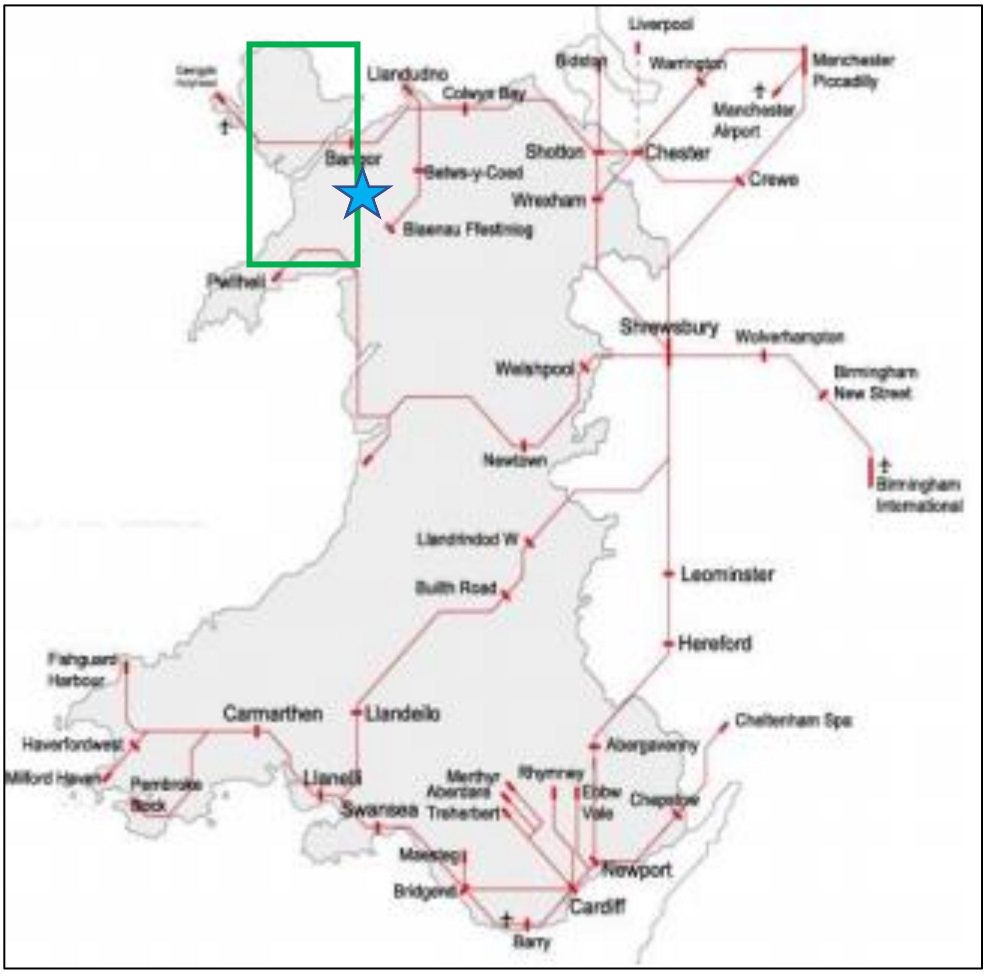

Figure 13: Wales trainlines [126]

One final scenario to consider, as above, is the inclusion of a 15MW electrolyser to increase the utilisation of the curtailed energy, this scenario is analysed for the 9 turbine scenario only.

Table 30: results for 15MW electrolyser

Number of turbines		9
Generation curtailment	%	10
Available energy	kWh	15,557,143
Electrolyser size	kW	15,000
Utilization rate	%	50
LCOH2	£/kg	1.90

NPV	£	11,872,330
H_2 Price	£/kg	5.00
Break even sale price	£/kg	3.81

The results when the 15MW electrolyser is used to utiliser more energy from the curtailed wind shows that the NPV increases significantly and that the breakeven price reduces to £3.81 per kg. This suggests that for the transport sector where the sale price of hydrogen his higher the challenges of the increased CAPEX and OPEX are offset by the increased production of hydrogen and higher sale price per unit.

6 Results of a co-located wind hydrogen production

Section 4 established a baseline financial model demonstrating the feasibility of developing a wind farm with curtailed generation with no hydrogen production. Section 5 examines the feasibility of producing hydrogen using curtailed energy as the feedstock. This final section will combine the discount cash flow models of both the wind farm and the different hydrogen sectors. The added benefit of including this step in the modelling is that it allows a direct comparison of the NPV's between the feasibility of building the wind farm with the estimated curtailed generation lost compared to building a wind farm which then utilizes the curtailed energy to produce hydrogen.

Table 28 presents the NPV results for all scenarios and cases. The second-row reports only on the wind farm NPV without any hydrogen production. For hydrogen production to be considered the NPV results should achieve two goals:

- The hydrogen systems must have a positive NPV.
- The hydrogen systems should have a higher NPV than the standalone wind farm.

Table 31: Co-located results

Scenario		**1**	**2**	**3**
Number of Turbines		8	9	10
Wind only NPV		11,042,524	5,118,187	-1,954,536
Wind+ basic H_2 system		5,987,439	1,468,365	-3,516,041
Wind + H_2 into the gas network		2,912,675	-1,267,689	-5,859,281
Wind + H_2 into the transport		3,947,375	224,057	-898,282

The results show that for scenario 1 it is most profitable to have a stand-alone wind farm without any hydrogen production but that in all cases including hydrogen production and not, there is a positive NPV suggesting that for this size wind farm it is possible to also produce hydrogen profitably. These results suggest that while it is more profitable to only produce electricity from the wind farm and forfeit the curtailed energy it is still profitable and feasible to produce hydrogen for either distribution into the gas network or the transport sector. The results suggest that if hydrogen is produced, it is more profitable to do so and supply into the transport sector.

Scenario 2 offers similar results showing that the most profitable case is to install the wind farm and only produce electricity and forfeit the curtailed generation, although this is less profitable than the comparable case in scenario 1 so it should be considered that if there is no hydrogen production only 8 turbines should be installed to maximize the profit of the site. When examining the cases for hydrogen production in scenario 2 while not as profitable, there remains a positive NPV for both the basic generation and storage of hydrogen onsite and for supply into the transport sector although the profit of supply into the transport sector is only £224,057 and this could be considered too marginal a profit for the risk. The results show that for scenario 2 it is no longer profitable to produce hydrogen for supply into the gas network.

Scenario 3 shows that it is not profitable in any case, with the current levels of curtailment to develop the site, this includes the development of the wind farm without any hydrogen production which was the most profitable case in the previous 2 scenarios. The results however do offer an interesting finding, they show that the highest NPV is not for the stand-alone wind project but for the wind farm plus hydrogen generation for the transport sector, this suggests that in this scenario, producing hydrogen for the transport sector would incur the least losses. The NPV detailed in Table 29 shows is the result based on an assumed sale price of hydrogen into the transport sector is £5 per kg, which as mentioned in Section 4.3, is at the lower end of the price identified in the literature. In response to this, a second set of results have been generated and presented in Table 21. In addition to the results shown in Table 20, Table 21 also presents the NPV if the hydrogen sold into the transport sector is sold at £7 per kg instead of £5.

Table 32: Results with different price for H_2

Number of turbines		8	9	10
Wind only NPV		11,042,524	5,118,187	-1,954,536
Wind + transport (£5 / kg)		3,947,375	224,057	-898,282
Wind + transport (£7 / kg)		5,728,459	4,576,839	6,446,093

The results show that for scenario 1 the most profitable case remains the stand alone wind farm and while the NPV of the hydrogen for transport case increases by £1.7 million there remains a difference in profit of nearly 50% from that of the best case scenario so it is unlikely that this will change the investment decision. The findings for scenario 2 are similar in as much as the most profitable scenario remains the stand alone wind farm but in this scenario with the hydrogen sold into the transport sector at £7 per kg, the difference in profit between the stand alone wind farm and the wind farm with hydrogen production for the transport sector falls to only £535,348 from nearly £5 million, which depending on the strategic goals of the company may be considered a strong enough case for investing in hydrogen generation for the transport sector. Scenario 3 however offers a different set of results. While the standalone wind farm and hydrogen generation for other sectors remains loss making, once the price of the hydrogen supplied into the transport sector increases to £7 per kg, this becomes a positive NPV of £6.4 million compared to a loss of nearly £2 million when no hydrogen is produced. This result suggests that it is not only feasible to produce hydrogen at this scale for the transport sector but that this is the second most profitable scenario after the scenario 1 standalone wind farm.

While it may currently be less profitable to produce hydrogen than electricity from a wind farm the expected cost trajectory of both the infrastructure and the cost of energy suggests that the cost of green hydrogen will be competitive by 2030. With this in mind the benefits of first mover advantage could be considered. Moving into hydrogen production will build knowledge and expertise in the local area and work force and will act as good preparation for the predicted increase in hydrogen demand, not just building internal knowledge within the company but helping to prepare the local market, encourage investment and promote demand. Figure 15 shows some of the many examples of research projects and hydrogen feasibility studies in Wales there are however very few examples of technology deployment, this suggest that there is still an opportunity to exploit the first mover advantage and build networks with future customers and off-takers.

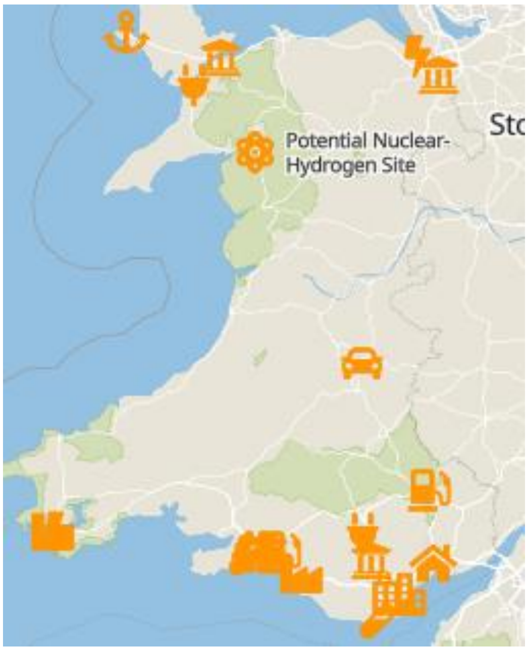

Figure 14: Locations of other Welsh Hydrogen activity [128]

Other research on hydrogen which is taking place in Wales is focused on decarbonizing industrial processes which can be seen through the FLEXIS project and the work done through the South Wales Industrial Cluster. Other projects in Wales include the North Wales Hydrogen Hub which in March 2021 received £4.8mn of funding from the UK government which will support the delivery of infrastructure.

7 Future work

This study provides knowledge, insight, and analysis on the feasibility of producing hydrogen from onshore wind in the UK with a particular emphasis on the case study site of Alwen farm. While a distinct set of results are provided in this research, the topic would benefit from further research to further increase knowledge and to de-risk future investment.

This model has exclusively examined the possibility of producing hydrogen from curtailed wind generation, an important topic for future research is therefore the feasibility of producing hydrogen from an onshore wind farm which cannot be connected to the grid due to restricted capacity. There are already a number of instances in the UK where wind farms are unable to be installed because there is no grid capacity therefore future work should consider the feasibility of developing these wind farms without a grid connection and using the electricity solely for produce hydrogen. This research should focus on two main areas of interest:

1) Due to the amount of hydrogen a dedicated wind farm would produce further research should be conducted into the future hydrogen off-takers. Unlike in this research where there is a good economic case for installing the wind farm without the hydrogen production the installation of a wind farm which will only produce hydrogen requires a strong existing market in multiple sectors or to be supported by one large off-taker who has a long term demand for the hydrogen. Included within this market research should also be a closer examination of the industries not considered in this project, most notably hydrogen for use in the marine sector which could build on existing projects in Wales such as the Milford Haven Energy Kingdom and the North Wales Hydrogen Hub in Anglesey; the rail sector which has been discussed briefly in section 5.3 and production of hydrogen for the Steel industry which can build on the work of the South Wales Industrial Cluster and the FLEXIS project. Along with the road transport sector and the gas sector these three additional areas will enable a deeper understanding of where hydrogen producers should focus their efforts.
2) In addition to the market research, as the size of the electrolysers increase to multi MW models there will be a deep need to investigate the capabilities of large scale electrolysers and supporting infrastructure. With only a small number of these larger systems in operation currently there should be close examination of how the technology scales up and the impacts this has on efficiency, OPEX and lifetime.

Further work should also be done where this model is used investigate the feasibility of other wind farms or renewable energy generators, this would strengthen the validity of the results seen in this research and offer insight into the feasibility of other co-located sites.

While this research gives a snapshot of the economic feasibility of producing hydrogen from curtailed wind further research should focus on examining the impact of the learning rate associated with hydrogen technology and examine the relationship between the predicted fall in costs and the impact of future changes to the energy prices.

8 Conclusion

This study examines the feasibility of producing hydrogen from onshore wind in the UK. In the case study, Alwen Forest, the feasibility of producing hydrogen from curtailed wind is examined due to the scope of the site and the restricted grid connection. The technical, economic and historical background to this project was laid out in chapter 1, where the argument was made that despite a number of false starts over the past decades there are several factors which point towards hydrogen as having a pivotal role in the ongoing energy transition. The background lays out the challenges which face wind developers and how hydrogen can be a response to many of these. It also lays out the overarching political and environmental backdrop of the Paris Agreement and a pledge by many counties to achieve net zero carbon emissions and the role that Hydrogen can take in helping to decarbonize sectors which are difficult to decarbonize such as transport, heating and industry. A section of the background was dedicated to other feasibility studies of hydrogen production from onshore wind although to the authors knowledge no case study has so far been conducted on hydrogen production from wind farms in Wales with an analysis of the surrounding market opportunities.

Thorough examination of the literature demonstrated that the dominant indicators for economic feasibility are the levelized cost of energy and the Net Present Value, therefore the theory of this study focused on the discounted cash flow model and the levelized cost of energy as well as pointing to the importance of the learning curve in future cost calculations. The methods section is used to describe the model and its functionality, as well as an in-depth description of all the assumptions that were used in the model which were drawn from existing literature. The assumptions are broken down into technical assumptions for wind farm generation and hydrogen production, cost assumptions and financial assumptions. The final section of the methods offers a description of the four different cases (**1.** Wind farm only, **2.** basic hydrogen production **3.** Hydrogen production for the gas network and **4.** Hydrogen production for the transport sector) and then the different scenarios analyzed within each case where each scenario represents a different number of turbines installed with a different amount of curtailed generation.

The results in section 4 and 5 offer insight into the key question of whether it is feasible to produce hydrogen from onshore wind generation using only curtailed generation. The results suggest that it is feasible to produce hydrogen from an onshore wind farm using curtailed generation and that in some cases it is more profitable to co-locate and produce hydrogen from the wind farm than it is to only build the wind farm and forfeit the curtailed generation.

When only considering the feasibility of hydrogen production the results suggest that in none of the cases examined was it financially feasible to generate hydrogen from an 8 turbine site with 4.5% generation curtailment. The results suggest that in this instance the additional capital cost and operational cost of the hydrogen infrastructure was not offset by either the volume of hydrogen produced or the price it was sold for.

The gas network has been considered by some (FCH) to be the bridge between the current status quo and the time when hydrogen can be sold into the transport sector at volume. The results of this model suggest that for Alwen Farm, it is not currently financially feasible to produce hydrogen from curtailed wind generation for sale in the gas sector for either 8 or 9 turbine scenarios. However the results for the gas sector can begin to be considered feasible when the wind farm and the amount of curtailed generation increases, therefore in the scenario that there is permission for 10, 12 or 15 turbines without any additional grid connection then in these instances it becomes profitable to produce hydrogen for the gas sector.

Hydrogen produced for the transport sector is often considered to be one of the most exciting hydrogen markets in part because of the relatively high price that can be achieved. However, hydrogen for the transport sector requires more supporting infrastructure, including compression, high pressure storage and transportation of the hydrogen to the off-taker. These results suggest that it is financially feasible to produce hydrogen for the transport sector with a 9 turbine wind farm and 10% generation curtailment. The financial feasibility increases with an increase in the number of turbines and curtailed generation. The results go as far as to suggest that the only financially feasible options for a site with 10 4.6 MW turbines and a 34 MW grid connection is to use the curtailed energy to produce hydrogen for the transport market.

In addition to these scenarios there was also an examination of the impact of including a larger 15MW electrolyser in the site which was able to utilise more of the curtailed wind energy. This looked specifically at the 9 turbine scenario which had ca. 15.5MW of curtailed energy and supplying that as hydrogen into the gas network and transport sectors. It found that for the gas network utilising more of the curtailed energy did not support the business case as the impact of significantly increasing the CAPEX of the electrolyser negatively impacted the NPV despite more units of hydrogen being sold. It was analysed that in order for this scenario to be profitable the cost of the electrolyser would have to reduce to £389 per kW. Alternatively when a 15MW electrolyser was applied to the 9 turbine scenario supplying hydrogen into the transport sector this had a positive impact on the NPV and increased the profitability of the project significantly suggesting that there is a tipping point between the price which can be achieved for the hydrogen and the size of the electrolyser. In addition, the results show that the 8 turbine scenario wasn't profitable when selling hydrogen into the transport sector. An additional analysis demonstrated that in order to make this scenario breakeven, the price of the electrolyser needed to fall from £811 per kW to £138 per kW. It should therefore be considered the minimum number of units which need to be sold in order to create a profitable business case.

This model has found that in relation to Alwen Farm, there are a number of scenarios where it is financially and technically feasible to produce hydrogen from the curtailed generation but there is only one instance where it is possibly more financially profitable to produce hydrogen than not to and that is in the 10 turbine scenario where hydrogen is produced and offered into the transport sector. While the results suggested that it is economically feasible to produce hydrogen from curtailed wind the research also discusses the strength of the surrounding environment. As the wind farm is located in North Wales the surrounding opportunities were considered. It was suggested that while it is feasible to produce hydrogen for the transport sector there is not currently the road transport demand although this would be closer to realization by 2024 and will develop from there. The opportunity for supplying hydrogen into the train network was also discussed and while generation at Alwen Farm was not modelled for supply into the rail network it was considered that the location of Alwen Forest could be beneficial to suppling some of the more local rail lines which will not be electrified. However, it was also found that the current fleet of trains would not be renewed until 2050 with procurement starting in 2040, this therefore does not reflect a good short-term opportunity.

The location of Alwen Forest hydrogen generation was also discussed in relation to its proximity of other hydrogen activity. While to the North East there is a large hydrogen hub underway with proximity to planned refueling network, gas infrastructure upgrades and a port there was also an announcement in Spring 2021 of a North Wales Hydrogen hub in Anglesey which offers many similar opportunities in another strategic location. It is believed that these hydrogen hubs will offer the early opportunity for hydrogen supply and that as these hubs grow to encompass wider geographic areas so too will the demand for hydrogen increase.

Future challenges which will require both academic, industrial and governmental support to overcome are regulations, taxation, technological limitations of large-scale electrolysis and support for early market development all need further work.

8.1 Policy implications

There are a range of economic, regulatory and policy instruments which could be implemented to support the increased production of green (and low carbon) hydrogen, and while this research has based most of the figures and assumptions on 2025 predictions it has not considered the impact of regulatory and policy mechanisms that may be implemented in the future. It was considered appropriate not to included these mechanisms within the main model and discussion of this research as these mechanisms are not yet in place and therefore it was considered important to create an economic model which offered a realistic rather than an optimist view of the market. However it is likely that these policy instruments will be increasingly considered in the coming years and so the likely impact of some of these mechanisms will be considered in this section. It is suggested that the cost of using green hydrogen, instead of grey is set to become a key pricing parameter by 2030 and could lead to a significant increase in the price of EU carbon.[129] Despite the significant reduction in greenhouse gas emissions that transitioning to green hydrogen can bring, this is not currently economically rewarded or incentivised. IRENA suggested that by internalising externalities such as the impact of extreme weather events in the form of a carbon tax or a carbon trading scheme will ensure that the economic gap between green hydrogen and fossil fuels is reduced.[130] Grey hydrogen, which falls under the European Union – Emissions Trading Scheme (EU-ETS) emits 9kg of CO^2 per Kg of hydrogen, therefore the right carbon price could have a significant, positive impact on the competitiveness of green hydrogen. It is estimated that for green hydrogen to reach €2 per kg a carbon price of approximately €79 - €102 per tonne would be needed.[129]

Alternatively, a recent study [131] analysed a variety of policy mechanisms for their impact on low carbon hydrogen production. The mechanisms were a) production tax credit (widely seen as a main driver for wind expansion in the US), b) a capital subsidy which is a one time lump sum which covers a portion of upfront cost, this was the first mechanism introduced to stimulate the UK onshore market, c) utility incentives and d) higher rates of carbon tax. The results of this study suggest that all policy instruments improved the production share of on-site electrolysis however when the instruments were applied to centralised electrolysis not all mechanisms resulted in affordability. The most impactful policies measured by a reduction in the price of hydrogen were the production tax credit which estimated a price reduction of between 0.59 and 1.08 USD per kg and the utility incentives which saw similar trends when applied. Interestingly this study also found that when production capacity is low increasing carbon tax credits has a limited effect. This suggests that in the current emerging market there are better policy mechanisms to stimulate the production and uptake of green hydrogen. When these results are considered in relation to this study and Alwen Farm, it could be suggested that Alwyn Farm would potentially benefit from any or all of the policy instruments described above but that industry may consider focusing the discussion on utility incentives and production tax credits with policy makers as priority policy.

8.1.1 Oxygen sales

In this study only the production and sale of hydrogen was considered while the production of green hydrogen also results in the production of Oxygen. While Oxygen production from electrolysis is often considered a bi-product in a drive to reduce waste and increase circularity within value chains oxygen could also be considered a co-product and utilised as another potential revenue stream for producers of green hydrogen. There is currently a large global market for oxygen in a variety of sectors including industry, healthcare and water treatment. One particular study [132] examined the economic feasibility of producing hydrogen from a solar farm and the NPV in all scenarios only became positive when the sale of oxygen was included in the business model. Using the same parameters as this study which assumes 8kg of oxygen is produced for every kg of hydrogen and that the sale price of the oxygen is on average €3 per kg (£2.50) [132] then applied to the model in this study and the scenario where 111,491 kg hydrogen is produced it is possible to calculate that 891,927 kg of oxygen would be produced resulting in an additional revenue of £2.2 million per year. This would have a positive impact on all the NPV and more analysis should be done to determine if this would turn the negative NPV's into positive NPV and if at this point it would become more profitable to produce hydrogen and oxygen than to lose the curtailed energy. Other factors that should be considered in this calculation are any additional CAPEX, OPEX, delivery and distribution costs as well as the demand from off-takers.

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10 Appendices

10.1 Appendix 1: Economic model – available as separate attachment.

10.2 Appendix 2: Table of assumptions

H2 Generation Assumptions				**Source**
Cost of Services				
Cost of water per litre	£/l	0,01		
Cost of electricity per kW (Wholly owned wind farm)	£/kW	0,000		RWE, personal communication, March, 2020
H2 Upfront Cost Assumptions				
Capital cost of electrolyser only		**PEM**	**ALK**	
1MW	£/kW	901	811	38
5MW	£/kW	676	568	38
20MW	£/kW	631	541	38
OPEX of electrolyser (% of CAPEX)	%	3 %	3 %	Based on 5MW system [38]
Additional electrolyser system costs				
Cost of Water supply	£/kg	0,15	0,15	38
Cost of Power directly from the grid	£/kg	6,60	6,60	38
Cost of Power from WT	£/kg	0,00	0,00	38
STACK				
Stack lifetime	Hrs	50 000	90 000	38
Degradation	%/1000hrs	0,20 %	0,11 %	38
Degradation per year		1 %	1 %	38
Stack replacement cost	£/kW	243	270	Based on 5MW system[38]
Plant info				
Power consumption	kWhe/kg	50	53	38
Availability	%	98 %	98	38
Plant life	yrs	20	20	38
Utilisation Rate (8760 hrs per year)	%	0,38		38
Hours in operation	hrs	3329		
Compressor Skids				
Compressor Skid (15 bar -60 bar @20kg/hr)	k£		164	38
Compressor Skid (15bar - 60 bar @100kg/hr)	k£		476	38
Compressor Skid (15bar - 60 bar @400kg/hr)	k£		1 188	38
Compressor Skid (30bar - 60bar @20kg/hr)	k£	130		38
Compressor Skid (30bar - 60bar @100kg/hr)	k£	377		38
Compressor Skid (30bar - 60bar @400kg/hr)	k£	940		38
Low Pressure Storage				
Low pressure storage CAPEX (£/kg)	£/kg	568	568	38
Low pressure storage OPEX	%	2 %		38

Gas grid				
Low pressure storage (£/kg)	£/kg	568		38
Low pressure storage (£/kg) OPEX	%	2 %		38
Injection infrastructure				
Grid entry unit (pre injection processes)	£/kW	134		Hydeploy 2018 [109]
Injection station CAPEX	k£	433		38
Injection Station OPEX (% of capex)	%	8 %		38
lifetime	yrs	35		38
H_2 connection piping	k£/km	270		38
H_2 connection piping equipment	k£	180		38
OPEX (% of capex)	%	2 %		38
Monitoring equipment CAPEX	k£	450		Hydeploy 2018 [109]
Transport				
Low pressure storage (£/kg)	£/kg	568		38
Low pressure storage (£/kg) OPEX	%	2 %		38
		PEM	**ALK**	
Filling Centers (15bar-200bar @20Kg/h)	k£		449	38
Filling Centers (15bar-200bar @100kg/h)	k£		1299	38
Filling Centres (15bar-200bar @400kg/h)	k£		3242	38
Filling Centres (60bar - 200 bar @ 20kg/hr)	k£	397		38
Filling Centres (60bar - 200bar @ 100kg/hr)	k£	1150		38
Filling Centres (60bar - 200bar @400kg/hr)	k£	2871		38
Compressor Skid (15 bar -60 bar @20kg/hr)	k£		164	38
Compressor Skid (15bar - 60 bar @100kg/hr)	k£		476	38
Compressor Skid (15bar - 60 bar @400kg/hr)	k£		1188	38
Compressor Skid (30bar - 60bar @20kg/hr)	k£	130		38
Compressor Skid (30bar - 60bar @100kg/hr)	k£	377		38
Compressor Skid (30bar - 60bar @400kg/hr)	k£	940		38
Low pressure stationary storage (50 bar tank)	£/kg	424		38
High pressure stationary storage (200-350bar Bundle)	£/kg	424		38
High pressure mobile storage				
Bundles (up to 100kg @ 200 bar)	£/kg	424		38
Bundles (up to 100kg @ 500 bar)	£/kg	532		38
Tube trailers (200 - 1000kg @ 200 bar)	£/kg	451		38
Tube trailers (200 - 1000kg @ 500 bar)	£/kg	545		38
Delivery				
Cost per mile	£	0,5		

compression (£/kg	£/kg	2667		38
Transport	£	500		38
High pressure storage (£/kg)	£/kg	5750		38
H_2 **Devex costs**				
Capital cost of site development as % of total cost	%	30 %		38
Special site conditions:				
Blast walls / safety parameters in public spaces	%	0		
Planning variations	%			
Total additional	%	0,00		
Additional to the wind farm				
Business Rates	£/MW	1000		RWE, personal communication, March, 2020
Community Benefit	£/MW	0		
Insurance	£/MW	1000		
Ongoing Grid Costs	£/MW	0		
Total Additional Opex calculated per MW	**£/MW**	**2000**		