Scottish Enterprise

Net Zero Technology Centre
Technology Driving Transition

CATAPULT
Offshore Renewable Energy

Development of early, clean hydrogen production in Scotland

August 2021

Disclaimer

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Acknowledgements

This report was written in July 2021 by Gail Barnes, Engineer, Lorna Bennet, Project Engineer and Callum Maxwell, Funding Proposal Specialist, at the Offshore Renewable Energy (ORE) Catapult. ORE Catapult would like to thank the following partners for their help and expertise in compiling the report:

- Craig Hodge and Emma Swiergon of the Net Zero Technology Centre
- Caragh McWhirr and Yumi Stow of Xodus Group
- Niall Rafferty and Matthew Cook of Wood

Contents

1. Executive Summary

Clean Hydrogen in Scotland

Clean hydrogen is recognised as a key enabler of decarbonisation across numerous sectors including power generation, heating, transport, refining and manufacturing. Currently global hydrogen demand is predominantly met by the manufacture of grey hydrogen which in 2019, contributed approximately 630 million tonnes of carbon dioxide (CO_2) emissions.

Global hydrogen demand in 2020 was approximately 70 million tonnes. The Hydrogen Council estimates that demand could be as high as 558 million tonnes (22 PWh) by 2050 [1].

Clean hydrogen is considered to be either green hydrogen, produced by electrolysis of water powered by renewable electricity, or blue hydrogen, produced by steam methane reforming (SMR) or autothermal reforming (ATR) with carbon capture, utilisation, and storage (CCUS). By producing clean hydrogen which can replace high carbon fossil fuels in the aforementioned sectors, the potential to reduce emissions is significant.

Scotland, due to its location, renewable energy potential, established oil and gas industry, geological features, technical expertise, existing infrastructure and commitment to net zero by 2045, has the resources to become a global leader in the emerging clean hydrogen market. The potential exists for Scotland to become a major producer and exporter of clean hydrogen in the next decade. Of the various studies that have been conducted into Scotland's clean hydrogen potential, the most ambitious is *The Scottish Hydrogen Assessment,* which estimates that 126 TWh of clean hydrogen could be produced in Scotland, with 94 TWh exported to the European market annually by 2045 [2].

The Scottish Governments Offshore Wind Policy [3] sees the potential for 11 GW installed offshore wind capacity off the coast of Scotland by 2030. *The Scottish Wind to Green Hydrogen* report by Xodus Group sees potential for an installed offshore wind capacity of 60 GW for Scotland by 2045, all of which could be utilised for the production of green hydrogen [4]. The OREC report *Offshore Wind and Hydrogen Solving the Integration Challenge* estimates that up to 240GW of offshore wind could be harnessed for green hydrogen production across the UK by 2050, to supply European hydrogen demand [5].

Markets for Scottish Clean Hydrogen

Key countries that have been identified as potential export markets for Scottish clean hydrogen include Germany, The Netherlands, Belgium and Japan. These countries have developed national hydrogen strategies that reference the expectation to import clean hydrogen to meet their future demand.

North West Europe, with its centres of industry, extensive gas pipeline network and commitment to clean hydrogen as outlined in various country's hydrogen strategies, along with the regions proximity to Scotland, present a clear market opportunity to capitalise on over the next decade. Dentons report, *Scaling up Green Hydrogen in Europe*, presents the case that even with storage and transport costs, green hydrogen can potentially be produced and supplied at a lower cost from regions of abundant and low-cost renewable energy, than can be produced domestically in countries in North West Europe [6].

The demand for hydrogen could rise to between 200 and 700TWh in North West Europe by 2050 [7]. The German Energy Agency is already in discussions with other countries that it is considering developing a clean hydrogen production and supply chain with to meet some of the country's 110 TWh estimated hydrogen demand in 2030. The Netherlands is estimated to have a hydrogen demand of 100 TWh by 2030 [8]. Belgium's hydrogen demand is expected to be 56 TWh BY 2030. The Belgian government are developing a long-term strategy for importing hydrogen, starting as early as 2025. Chile and The Middle East are potential suppliers of clean hydrogen to Belgium in the future.

Japan will be an importer of hydrogen and has been engaging with other countries to establish hydrogen procurement strategies. By 2050, industries in Japan could consume up to 58 million tonnes of hydrogen per year.

Competition for Scotland's Clean Hydrogen Export

Scotland is not the only country seeking to position itself as a clean hydrogen exporter. Future competitors have been identified as those countries and regions with an abundance of renewable energy resources and the ability to produce low-cost renewable electricity on a large scale or with a good supply of natural gas, coupled with storage capabilities for CO_2, as those with the highest potential to become clean hydrogen producers and exporters. Those identified include Norway, Spain, Portugal, Australia, North Africa, Saudi Arabia, Australia, Chile, and Canada.

Norway is the third largest exporter of natural gas globally and is at the forefront of CCUS technologies. This coupled with ample potential CO_2 storage on the continental shelf puts Norway in a very favourable position to develop a clean hydrogen market and become an exporter in the future. Portugal has the lowest global bid for large scale PV (photovoltaic) projects at €0.0114/kWh.

The International Energy Agency (IEA) projects that clean hydrogen will be significantly cheaper to produce in North Africa than in Europe. Green hydrogen will be approximately 40% lower cost to produce in North Africa, and blue hydrogen 35% lower cost than in Europe, making nations such as Saudi Arabia and Morocco key competitors in the export of clean hydrogen.

Chile has desert regions with more than 3,000 sun hours annually making it one of the best solar resource in the world. Coupled with the strong, consistent winds in the south, Chile has the potential to power green hydrogen production with a LCOH of £1.0/kg by 2030, making green hydrogen produced in Chile the cheapest globally [9].

Five of the biggest clean hydrogen projects globally are based in Australia. The report *Opportunities for Australia from Hydrogen Exports,* estimates that the global demand for hydrogen could be worth up to £1.2 billion ($2.2 billion AUD) by 2030, and £5.5 billion ($10 billion AUD) to the Australian economy by 2040. The Renewable Hydrogen Strategy plans to approve a project to export renewable hydrogen by 2022. Australia plans to meet at least 3.5% of global hydrogen demand by 2030 and beyond, and sees the potential market for Australian clean hydrogen being approximately 1 million tonnes annually by 2030 [10].

In the lead up to 2030, both blue and green hydrogen will play an important role in the decarbonisation of the energy sector and production of 'clean' hydrogen. To be successful within a ten-year timeframe, the future hydrogen economy must quickly follow a transition from grey, through blue, to green hydrogen. The development of clean hydrogen technologies and large-scale deployment will be paramount to the success of Scotland's target of net-zero by 2045.

Technology Review

This study analyses the current and future positions of both green and blue hydrogen technologies to meet the demand for Scottish hydrogen in the next decade. The two most mature electrolyser technologies, alkaline and polymer electrolyte membrane (PEM), as well as emerging scalable technologies have been discussed for green hydrogen production. Traditional SMR and ATR and their respective enhancements have been proposed for blue hydrogen.

Alkaline electrolysers are the most mature electrolyser technology and as a result, they are the most widely deployed. At 20MW unit capacity, they are proven for current hydrogen production requirements. PEM electrolysers have been increasingly favoured in the production of hydrogen for their ability to rapidly load-follow during operation. PEM systems are simpler than their alkaline counterparts but due to their technological immaturity, are deployed at smaller-scales up to 10MW. Solid oxide electrolysis (SOE) is a unique emerging scalable technology as it operates at high temperatures between 700-900°C using steam as its feed rather than water. SOE's currently have a maximum commercial capacity of 1MW, with future projects in place for multi-MW capacities. With production scale-up, PEM electrolysers are expected to be cost-competitive with alkaline electrolysers by 2030. From which point they will become the most preferable technology based on their compactness and compatibility with renewable electrical input.

	Alkaline		PEM		SOE	
	2021	2030	2021	2030	2021	2030
Electrical efficiency (%)	63 – 70	65 – 71	56 – 60	63 – 68	74 – 81	77 – 84
Stack lifetime (000's hours)	60 – 90	90 – 100	30 – 90	60 – 90	10 – 30	40 – 60
CAPEX (£/kWel)	390 – 1,090	310 – 660	860 – 1,400	510 – 1,170	2,200 – 4,360	620 – 2,180

Today, 50% of global hydrogen is produced through SMR with capacities up to 200,000Nm^3/h. Three enhancements to traditional SMR with CCUS technologies have been suggested. The first is Wood's Blue^{H2} technology which uses a gas-heated reformer and terrace wall reformer to improve process efficiency. The second enhancement developed by Linde is the DRYREF syngas generation technology that imports CO_2 into the process to enable dry reforming with methane reducing the requirement for high-quality steam. Finally, the Compact H_2 Generator (CHG) developed by Cranfield University enables bulk hydrogen production by sorbent enhanced steam reforming.

The alternative route for blue hydrogen, ATR combines partial oxidation with SMR in a single reaction chamber. One ATR enhancement has been developed by Johnson Matthey. Their low carbon hydrogen couples an ATR unit with a gas-heated reformer. All enhanced SMR and ATR processes have a greater CO_2 capture rate than their traditional counterparts and all are deployed and proven at a commercial scale.

Enhanced SMR technology has the cost advantage in terms of CAPEX, OPEX, and LCOH for small to medium sized hydrogen plants. Enhanced ATR technology has improved scalability, which results in the technology being commercially advantageous for much larger hydrogen production capacities. Enhanced ATR also provides improved carbon capture performance which is an increasingly important consideration in the transition towards net zero emissions. This is dependent on the carbon intensity of the large electrical power needed for ATR, as there is potential for offsite (scope 2) carbon emissions to be significant.

The transport and storage of hydrogen is challenging due to its very low density. For cost viable options for the distribution of hydrogen at scale, its density must be increased by compression, liquefication or hydrogen carriers. Transport of hydrogen at the scale considered in this study practically needs to be either by pipeline or by ship, rather than small-scale trucking. The study shows, as with clean hydrogen production technologies, that the options for hydrogen distribution are also at different stages of maturity. Compressed hydrogen transport by pipeline is the most well-established and cost-saving method of large-scale hydrogen export, whilst others are restricted by their transport methods (cryogenic hydrogen), others by the conversion technology (liquid organic hydrogen carriers) and some by both (metal organic frameworks). Power-to-Fuels such as ammonia and methanol are most suitable when the fuel is required by the end user. Both are mature processes. The optimal choice of hydrogen carrier, however, will depend on the intended final use, purity requirements and need for long-term storage at each site. At present, there is no clear direction that is becoming apparent for facilities looking to develop hydrogen production in the next 10 years.

Scalability and Cost Reduction Opportunities

For this study, techno-economic analysis has been undertaken for both green and blue hydrogen production including inputs and outputs to processes, cost parameters including CAPEX, OPEX and LCOH, footprint and emissions. Three green hydrogen production capacities have been studied: 200MW, 500MW and 1GW with a maximum hydrogen capacity of 3.5TWh/year. The capacity commonly referenced for blue hydrogen production and used in this study has an output of 100,000Nm^3/h of hydrogen which is approximately equivalent to the capacity of the 1GW green hydrogen facility.

Parameter	Electrolysis (1GW)	SMR with CCUS (100,000Nm3/h)
CAPEX (£M)	1,994	207
OPEX (£M/year)	42	25
LCOH (£/kg)	3.81	1.92
Plot Area (m^2)	80,000 – 130,000	20,400

Technology and site cost reduction opportunities have been assessed to flag the features of an ideal hydrogen production site for the available technology options.

The LCOH of green hydrogen today is 2-3 times greater than blue hydrogen. Three main technology-based factors influencing the LCOH of green hydrogen, hence areas for cost reduction, have been identified. They are the cost of renewable electricity and the cost and utilisation of electrolyser technology. It is expected that by 2030, 75% of all potential cost reduction in green hydrogen LCOH would have been realised, driven by a rapid cost reduction in the LCOE which currently accounts for 77% of the total green hydrogen cost and reduction in PEM capital costs.

Various site cost reductions have been suggested for the ideal hydrogen production site. Those located near heavy industrial locations will benefit from multiple cost-saving opportunities such as existing co-location with industrial hydrogen and oxygen off-takers, civils infrastructure, skilled workforce and local support. This typically goes hand-in-hand with cheaper low-carbon electricity and methane resources, and hydrogen and CO_2 export routes.

Scotland's Clean Hydrogen Production Site Assessment

With consideration of what can be achieved at scale in the next ten years, this section of the study sought to investigate the site-level characteristics of multiple locations across Scotland, to identify which could feasibly support the development of a large-scale blue or green hydrogen production facility.

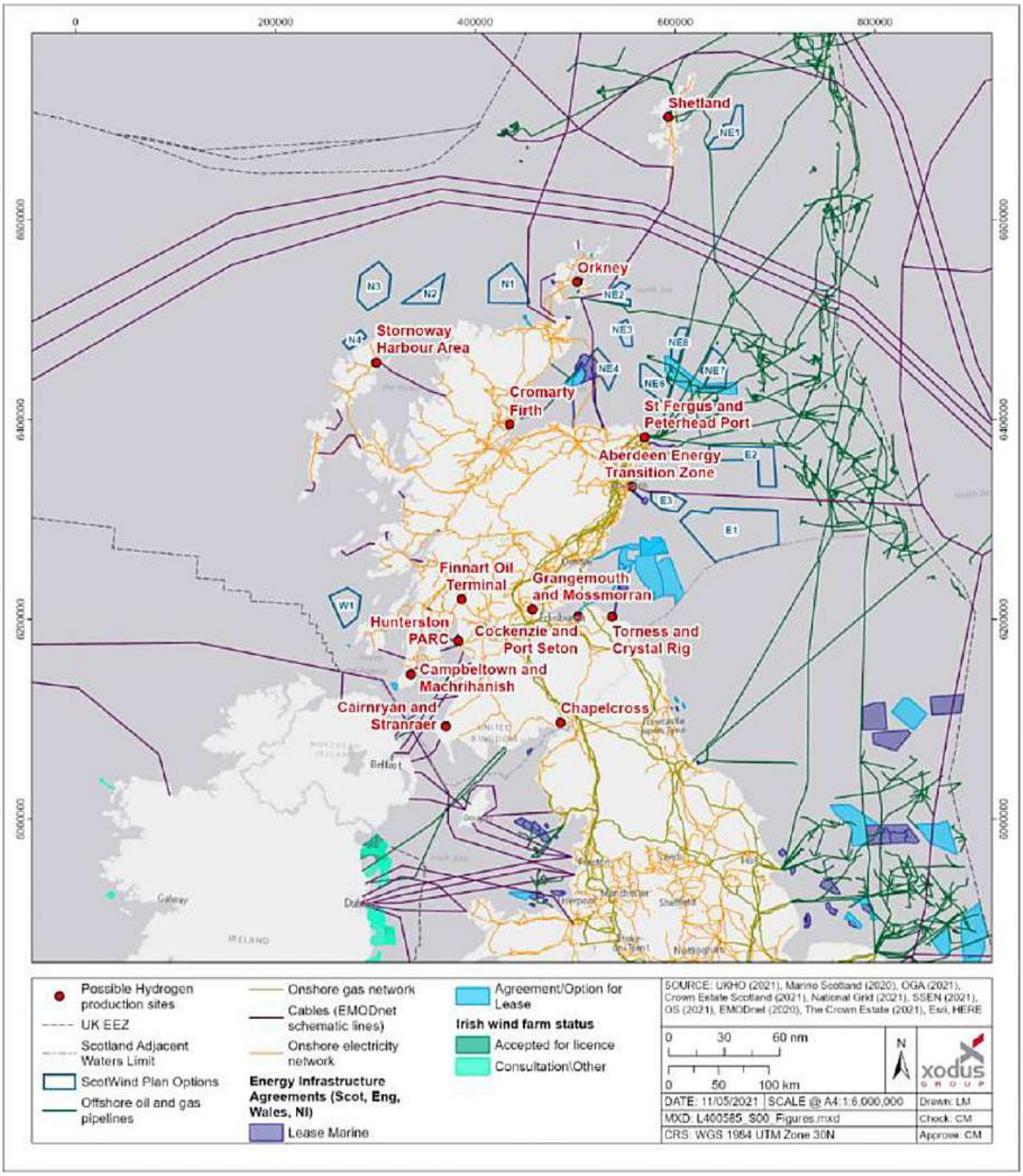
Firstly, the characteristics of a site to support the development of a large-scale green or blue hydrogen production facility were identified. This includes aspects relating to feedstock, power supply, size and suitability of the land, the ability of the local area to support the development, and export routes to market for the hydrogen. The greatest focus was on-site requirements that can support the development of a hydrogen production facility in the next 10 years, with an output of 100,000 Nm^3/hr hydrogen, whilst minimising the cost of hydrogen production. Hence, these site requirements were used to benchmark the 'ideal' production site, forming a basis on which to compare sites and locations across Scotland. Five characteristics were identified to define the 'ideal' green and blue hydrogen production sites in Scotland.

Ideal Green Hydrogen Production Site	Ideal Blue Hydrogen Production Site
Renewable Electricity Resource	Methane Supply
Water supply	CO2 transport and storage access
Site size and suitability	Site size and suitability
Local Activity	Local Activity
H2 export	H2 export

Electricity is the largest cost contributor to a green hydrogen facility; hence an ideal site would have a source of low-carbon, low-cost electricity with capacities greater than 500MW. A steady supply of electricity would be provided through multi-source energy vectors or a buffer storage. Fresh water at high purity is the preferential requirement at rates up to 3,300m^3/h for a 1GW facility, however, if freshwater is not available then seawater can be processed to remove salts and impurities with minor impact to the production facility. This is the case for all green hydrogen production sites in Scotland. The footprint required for a 1GW green hydrogen must be greater than 15ha, accounting for the electrolysers, desalination, and hydrogen export. In addition, suitability requires the site to be cleared and zoned specifically for industrial use, classified within the COMAH Upper Tier and located in proximity to any oxygen market opportunities. Green hydrogen facilities will benefit from being in areas with accessibility to a skilled workforce, local support, and demand for large-scale hydrogen. Finally, an ideal site, given the timeline of this study would already have local demand to promote the scale-up of production and negate the additional cost of hydrogen export. However, this type of demand is not currently realised in Scotland, so this study focuses on the export opportunities expected to materialise by 2030, mainly access to the natural gas network for pipeline blending and proximity and route to inter-seasonal storage.

The major cost to a blue hydrogen facility is the cost of methane gas. This study assumes that methane is delivered via pipeline directly from the North Sea, so any other import route such as imported gas or liquid natural gas is considered not ideal. Any blue hydrogen scheme must have a means for either storing or using the produced CO_2, preferably with easy access to a CO_2 transport network and proximity to its storage location. The site requirement for blue hydrogen is less than green at 2ha, although the same requirements for specific land use, COMAH specification, local activity and hydrogen export options apply.

A desktop study was then undertaken to assess the opportunities for clean hydrogen production at numerous locations across Scotland, by comparison to the 'ideal' site benchmark. This includes locations across the full length of Scotland - from Shetland in the Northern Isles, to Chapelcross in southwest Scotland – however, is the list is not exhaustive. Using a traffic light site evaluation system, each location was assessed by comparison to the five ideal characteristics, focusing on their suitability today, rather than future projections.



This method was adopted as this study intends to act as a guide that identifies areas where action can be taken to improve the suitability of individual sites within the next ten years. A site's perceived suitability was determined at a high level with publicly available information and designed so that similar analysis can be carried out on other locations that wish to understand their obvious overlaps with an 'ideal' site.

Firstly, the characteristics of a site that can be classified as 'ideal' have been identified and coloured green. These characteristics can support hydrogen production at scale in the next 10 years and mean that hydrogen production is likely to be economically scalable. Secondly, locations across Scotland have been compared to these characteristics, to highlight the obvious overlaps, but also to guide action that can improve the suitability of a site for hydrogen production. A site that is close to ideal, with minor improvements required, or with only a small impact on the LCOH, have been classified yellow. Orange classification represents potentially larger modifications and investment to reach the ideal status or a considerably higher LCOH. Finally, any sites with an obvious barrier or blocker to its development has been shown as red.

Details of specific sites assessed for both green and blue hydrogen production will be contained within follow on report.

Many sites across Scotland have the potential to harness and develop local natural resources and infrastructure to produce large scale green and blue hydrogen, whilst only one has significant material plans for development that are in the public domain. The Acorn Hydrogen project aims to reform North Sea natural gas into blue hydrogen, with CO_2 emissions transported and stored through the Acorn CCUS infrastructure. If Feeder 10 can be repurposed to transport CO_2 as part of this project, this could drive the case for blue hydrogen to be produced in Scotland's industrial central belt, as the captured CO_2 could then be cost-effectively transported to St Fergus, before being permanently sequestered in offshore CO_2 stores.

With even greater potential to utilise Scotland's natural resources, the production of green hydrogen through electrolysis is not constrained by the indigenous production or import of natural gas, but by the exploitation of Scotland's renewable energy resources. OGTC's Integrated Energy Vision report highlights that the UK's net zero energy system in 2050 can be driven by offshore wind and green hydrogen [11]. The OREC report *Offshore Wind and Hydrogen Solving the Integration Challenge* estimates that up to 240GW of offshore wind could be harnessed for green hydrogen production across the UK by 2050, to supply European hydrogen demand. Many of the opportunities to produce this green hydrogen lie in coastal areas across Scotland that have unrestricted access to water, available land for development, future access to GW-scale offshore wind developments and have foreseeable export routes through ports, terminals, and pipelines.

Further, there are other sites across Scotland that are suitable for hydrogen production but on a smaller scale to those explored in this study. This is due to a combination of a lesser export potential, availability of land and/or renewable resources. These sites have been identified and discussed for their potential to produce hydrogen for a smaller local demand, rather than being assessed against the five ideal site criteria for large-scale facilities. Within these mostly remote and rural locations, the opportunity of hydrogen will provide the nearby community with a self-sufficient and secure energy supply.

Recommendations

Conclusions drawn in this report regarding a site's suitability to produce hydrogen should be used as a starting point to inform the focus and direction of future studies and discussions. Recommended next steps include:

- **Further study is required to determine the techno-economic feasibility of green hydrogen production from large scale renewable electricity** - whether this be from future offshore or onshore wind developments, or other renewable sources. **Options to maximise the consistency of electricity supply to electrolysers should be studied as should storage (battery or hydrogen) costs and benefits, as this can have a significant impact on reducing the LCOH.**

- Offshore wind developments will likely be crucial sources of renewable electricity to power electrolysers. **Hence, timescales to deployment of GW-scale offshore wind must be accelerated if large-scale hydrogen is to be produced within the next 10 years.** Conversely, particularly for any areas with very constrained grid access, **a clear pathway to commercial production of hydrogen (technical and demand visibility) is needed to enable investment decisions relating to development of the wind resource.**

- Possible blue hydrogen production sites have been based around the cost and scalability of methane supply as feedstock for reformation, with a pipeline supply to the location being the lowest cost option. **The security of future methane supply to the location should be considered, based on natural gas production forecasts.**

- **Engagement with site owners and operators is required to further determine site suitability, stakeholder appetite, and any current plans for a hydrogen production development.** Interaction with site owners has been minimal throughout this study, but it is understood that several are already in discussions regarding hydrogen production developments.

- **Establishing the value chain downstream from production is critical.** Ultimately this means securing an export market for hydrogen produced from a Scottish site. This also means establishing a clear value chain to get the hydrogen to that market – be that pipeline or ship transport. The extent to which regulated business models will be in place for hydrogen or for CO2 is not yet clear. On the ship side there is also a technology uncertainty as to what form is going to be preferred for ship transport of hydrogen. **Here, there may be benefits in multiple sites in Scotland collaborating to establish a common view, together with a targeted demand market, that could then support development of a specific transport technology.** This could also support supply chain, by giving the opportunity to establish a fleet of vessels servicing several sites at a lower cost.

- The potential development of export routes through ship have been assumed based on current port capabilities. **The feasibility of developing a port or terminal to support hydrogen export through bulk cargo or vessel fuel, needs to be studied in further detail.**

2. Introduction

The Paris Agreement was signed in November 2015 and came into effect in November 2016. The agreement committed to keeping global warming below 2°C above pre-industrial levels. Ideally 1.5°C should not be exceeded. Currently 186 countries have joined the Paris Agreement. In 2018, the Intergovernmental Panel on Climate Change (IPCC) issued the report *Global Warming of 1.5°C*, to strengthen the global commitment to fighting the threat of climate change [12]. The report suggested that staying below 1.5°C above pre-industrial levels was possible, and that a currently projected 2°C rise could have more serious implications than previously identified, including a rise in sea levels of 10cm more than would be experienced with a 1°C rise. The report highlighted what action is required to stop the global temperature rising further. To limit global warming to 1.5°C, a global emissions reduction of 45%, compared with 2010 levels will need to be achieved by 2030, and net zero emissions achieved by 2045. The IPCC stated that unprecedented changes in all aspects of society would need to be rapidly required in all aspects of society in order to limit global warming to 1.5°C.

Hydrogen can act as a low carbon alternative to fossil fuels. The Hydrogen Taskforce report published in 2020, *The Role of Hydrogen in Delivering Net Zero*, recognises hydrogen as being essential to the UK meeting its net zero target [13]. Early-stage projects world-wide have demonstrated the potential for clean hydrogen to act as a decarbonisation pathway. The role clean hydrogen can play in meeting global net zero ambitions is substantial. This decade a concerted effort in the scale-up of clean hydrogen technologies, along with the uptake of hydrogen in numerous sectors is required.

Today, 95% of global hydrogen demand is met by grey hydrogen, which is hydrogen produced from combustion of fossil fuels, namely natural gas and coal. Each year, 6% and 2% of global natural gas and coal production, respectively, are used in the production of grey hydrogen. In 2019, the grey hydrogen market produced over 70 million tonnes of hydrogen, which was directly responsible for the release of 630 million tonnes of CO_2 [14]. Hydrogen can only contribute significantly to decarbonisation efforts if the production process results in low, or no carbon emissions. Therefore, for a hydrogen economy to be a viable route to net-zero Scotland, blue and green hydrogen will need to produce the majority of hydrogen to meet global demand.

Scotland has committed to net zero by 2045. There is potential for Scotland to embrace clean hydrogen in its drive to net zero, and to capitalize on economic opportunities that a fully developed hydrogen value chain could bring. This report firstly seeks to present an outline for Scotland to position itself as a clean hydrogen market leader.

Scotland is an advanced industrialised economy with exports amounting to £85 billion in 2018. The volume of oil and gas production in Scotland is estimated to have been 77.2 million tonnes of oil equivalent (mtoe) in 2018, accounting for 82 per cent of the UK total [15]. Scotland has the potential to redirect its natural gas reserves into blue hydrogen production. The abundance of potential geological storage for CO_2 positions Scotland as a potential leader in blue hydrogen production. Couple this with Scotland's abundance of renewable energy, in the form of onshore and offshore wind, and solar, giving huge potential for powering green hydrogen production, Scotland has a real opportunity to become a leader in the clean hydrogen global market in the next decade.

Scotland is in an incredible position to utilise its vast renewable resources, indigenous oil and gas production, supply chain, and skilled workforce, to produce green and blue hydrogen at a scale that not only satisfies any future national demand but can provide substantial international export opportunities. However, what must be identified is how and where this clean hydrogen can be produced at scale. This involves determination of the technology required to produce the hydrogen, and the characteristics of a site that can support the scale of hydrogen production required.

Currently, hydrogen is mostly produced through the well-established process of steam methane reforming (SMR) or autothermal reforming (ATR), also known as 'grey hydrogen'. 'Blue hydrogen' couples SMR or ATR with carbon capture, utilisation, and storage (CCUS) technology, capturing the produced CO_2, reducing its carbon emissions. Hydrogen can also be produced through water electrolysis, where water is split into hydrogen and oxygen using an electrical input, with oxygen being released into the atmosphere with no negative impact. 'Green hydrogen' is produced when the electricity for electrolysis is provided completely through renewable sources. Clean hydrogen is, for the purposes of this report, taken to be either green hydrogen, or blue hydrogen.

The future hydrogen economy is envisaged to follow a transition from grey, through blue, to green hydrogen technologies. Green and blue hydrogen production are both expected to play an important role in the current and future energy transition. This report investigates variations of both clean hydrogen technologies with discussions on their current position and technology readiness, as well as its future developments and potential leading up to 2030. The methods by which large-scale hydrogen can be stored and transported to its desired end-user have also been reviewed.

For this study green hydrogen production site capacities of between 700 and 3,500 GWh per year and blue hydrogen production capacity of 100,000 Nm3/hr (approximately equal to the largest green site capacity) have been considered. The suitability of different green and blue technologies to scale up to this capacity has been reviewed, together with the impact of different technologies on the levelized cost of hydrogen (LCOH). Transport and storage scalability and cost reduction opportunities are also discussed. Finally, site specific aspects which will influence the cost of production or the ability to scale up production are identified and where possible quantified. These factors have then fed into the site assessments, which will feature in a follow on report by Scottish Enterprise.

With even greater potential to utilise Scotland's natural resources, the production of green hydrogen through electrolysis is not constrained by the indigenous production or import of natural gas, but by the exploitation of Scotland's renewable energy resources. OGTC's Integrated Energy Vision report highlights that the UK's net zero energy system in 2050 can be driven by offshore wind and green hydrogen [11]. The OREC report *Offshore Wind and Hydrogen Solving the Integration Challenge* estimates that up to 240GW of offshore wind could be harnessed for green hydrogen production across the UK by 2050, to supply European hydrogen demand [5]. Many of the opportunities to produce this green hydrogen lie in coastal areas across Scotland that have unrestricted access to water, available land for development, future access to GW-scale offshore wind developments and have foreseeable export routes through ports, terminals, and pipelines.

This report seeks to assess Scotland's potential in the global clean hydrogen market and comprises the following:

- A literature review of pertinent works addressing possible scenarios for Scotland to implement hydrogen into its economy.

- A summary of Scotland's clean hydrogen ambitions and the potential for Scotland to export clean hydrogen.
- An assessment of potential markets, in terms of their commitment to clean hydrogen and the degree to which it is being integrated into various sectors.
- An analysis of potential competitors, paying particular attention to regions with the potential and the ambition to produce and export clean hydrogen in the upcoming decade.
- Stakeholder engagement with various port authorities.
- An assessment of current clean hydrogen production technologies, along with their suitability for scale up.
- A review of large-scale hydrogen storage and transport, with consideration given to scalability and cost reduction opportunities.
- A review of the LCOH comparatively with its production method, and cost reduction opportunities with scale-up.
- Definition of an 'ideal' clean hydrogen production site that can support large scale production within the next 10 years whilst minimising LCOH.

Details of specific sites assessed for both green and blue hydrogen production will be contained within follow on report.

Table 2.1 and Table 2.2 demonstrates the conversions used throughout this study to estimate hydrogen production for 1GW green and 100,000Nm3/h blue hydrogen facilities. The following assumptions have been made:

- 58% offshore wind capacity factor;
- 73% electrolyser efficiency;
- Average heating requirement for a UK home is 12,000kWh/yr;
- Average CO_2 emissions for a UK home using natural gas is 2,200kg/yr;
- Blue hydrogen facility relates to a standard SMR process with CCUS.

Table 2.1 Conversions used for green hydrogen production

Electricity		Electrolyser		Hydrogen			Homes heated	CO_2 emissions abated
MW	GWh	MW	GWh	GWh	Tn/y	Nm^3/h	No.	Tn/y
1,000	8,760	1,000	5,081	3,496	92,000	128,000	290,000	640,000

Table 2.2 Conversions used to estimate hydrogen production

Natural Gas		Hydrogen			CO_2 captured	Onsite CO_2 emissions	Homes heated	CO_2 emissions abated
Tn/y	MWh	GWh	Tn/y	Nm^3/h	Tn/y	Tn/y	No.	Tn/y
302,660	446	2,980	78,446	100,000	723,138	76,212	250,000	476,000

The 2020 average exchange rates for USD (£1:$1.2837), EUR (£:€1.1248), CAD (£:$1.7427) and AUD (£:$1.8088) to GBP have been used throughout this study.

3. Literature Review

Various reports have been published outlining possible scenarios for Scotland to implement hydrogen into its economy. The existing industry reports identified to be reviewed to form the basis for this report are:

- The Scottish Hydrogen Assessment [2]
- Hydrogen in Scotland the Role of Acorn Hydrogen in Enabling UK Net Zero [16]
- Scottish Offshore Wind to Green Hydrogen Opportunity Assessment [17]
- The Scottish Governments Offshore Wind Policy [3]
- The National Grid Future Energy Scenarios Report [18]
- ORE Catapults Offshore Wind and Hydrogen Solving the Integration Challenge [5]
- Dentons Scaling up Green Hydrogen in Europe [19]

The Scottish Hydrogen Assessment was undertaken by Arup and E4tech on behalf of the Scottish government. The report, published in December 2020, states that Scotland will need to act decisively and provide clear policy support to position itself at the forefront of a growing global industry [2]. The assessment lauds the need for strong policy and short to medium term investments as a way to ensure the fruition of a strong hydrogen economy in Scotland. Three scenarios are proposed to enable Scotland to develop its hydrogen economy up to 2045. The scenarios are summarised in Table 3.1.

Table 3.1 Summary of The Scottish Hydrogen Assessment scenarios

Scenario	Production Potential	Details
Focused Hydrogen	• 21 TWh total clean hydrogen annual production by 2045 • 14 TWh green hydrogen annual production by 2045 • 7TWh Blue hydrogen annual production by 2045	• Hydrogen produced close to point of use • Hydrogen aides in decarbonising the energy system • 7 TWh to assist in decarbonizing the transport sector • 6 TWh to be used for domestic and commercial heating • 7 TWh to be utilized in industry and electricity generation

Cont.

Table 3.1 Summary of The Scottish Hydrogen Assessment scenarios (continued)

Scenario	Production Potential	Details
Hydrogen Economy	• 85 TWh total clean hydrogen production • 46 TWh green hydrogen production • 39 TWh blue hydrogen production • 20 TWh of clean hydrogen to be exported to the UK	• Hydrogen plays a leading role in decarbonising Scotland's energy system. • Blue and green hydrogen is utilized extensively in all sectors • 11 TWh to assist in decarbonizing the transport sector • 35 TWh to be used for domestic and commercial heating • 19 TWh to be utilized in industry and electricity generation
Green Export	• 126 TWh total green hydrogen production • - 94 exported to European market	• Scotland's vast renewables potential is realized for green hydrogen production for export • 22 TWh to assist in decarbonizing the transport sector • 11 TWh used in industry and electricity generation

While conducting the assessment, key stakeholder engagement of over 40 key industry organisations took place via interviews, surveys, workshops and working groups. The outcomes of which helped form the basis and development of the three scenarios detailed in the assessment.

In the most ambitious target Scotland, The **Green Export** scenario, green hydrogen would be produced for domestic use and an additional 94 TWh for export to the European market by 2045. This scenario is reliant on support from the government, both in terms of investment in skills and a supply chain and stimulating a market. An increase in the number of planned green hydrogen production projects is required. The Green export scenario focusses solely on green hydrogen production, whereas the other two scenarios are based on blue and green hydrogen production. The most limited scenario looks at hydrogen produced in the vicinity of the point of use, with hydrogen being incorporated into transport, heating, industry and electricity. Called the **Focussed Hydrogen** scenario there is no excess hydrogen for export. The **Hydrogen Economy** scenario sees a UK export market as large as 20 TWh of clean hydrogen annually. Although blue hydrogen is included in two of the scenarios, the assessment makes it clear that it is featured mainly in the transition from oil and gas to alternatives, and that by 2045 the role of blue hydrogen will be greatly reduced, as it is not technically zero carbon. Blue hydrogen initially is forecast to be lower cost than green hydrogen until scale up, increased experience, and a ramp up in offshore wind, as well as other renewables, makes green hydrogen the more cost competitive.

Scotland has a wealth of experience, infrastructure and supply chain flexibility from oil and gas activities in the North Sea to be able to introduce blue hydrogen production, with carbon capture, utilisation and storage (CCUS), potentially more easily and quickly than green hydrogen initially in the transition. The assessment references the large-scale blue hydrogen with CCUS project planned by Acorn at the St Fergus gas terminal, in Aberdeenshire. Project Acorn greatly incorporates existing oil and gas infrastructure and supply chain elements. The assessment sees the potential for blue hydrogen to help decarbonise hard-to-abate industries where CCUS is already required in the drive to net zero.

The Scottish Hydrogen Assessment breaks Scotland into rural and island communities, urban communities, and industrial regions, each one with different hydrogen demands, different challenges, and different potential routes to decarbonisation through hydrogen integration. Aberdeen City Region published its own hydrogen strategy and action plan in 2015 [20]. The strategy seeks to position the city of Aberdeen as a hydrogen technology centre of excellence and covers the period 2015-2025. The city has a wealth of transferable skills from the oil and gas sector, and is well positioned close to industry, and offshore renewables. Aberdeen is at the forefront of the drive towards net zero in Scotland by 2045. By 2018 Aberdeen had installed two hydrogen refuelling stations, and had a hydrogen vehicle fleet including: ten fuel cell buses, two diesel/hydrogen hybrid transit vans, two Renault Kangoo electric vans with hydrogen range extenders, ten Toyota Mirai hydrogen fuel cell cars, and four Hyundai ix35 hydrogen fuel cell SUVs [21].

Island and rural communities are seen to have great potential to aid in the development of a hydrogen production and export market for Scotland due to their vicinity to, and availability of renewables in the form of offshore wind, coupled with the vicinity of existing ports and oil and gas facilities, to some of these communities.

The Scottish Hydrogen Assessment identifies the transport sector as an area for quick decarbonisation with the integration of hydrogen for heavy duty vehicles such as busses, trains and HGVs. Switching public sector vehicles to hydrogen is seen as a way for urban areas to create sure demand and gain investor confidence in hydrogen production. This approach has been successfully implemented in the city of Aberdeen which opened a hydrogen production and refuelling station for its busses in 2015 as part of the H2 Aberdeen Project. The city has two publicly accessible hydrogen refuelling stations and currently runs a fleet of hydrogen vehicles including busses, bin lorries, cars, vans and road sweepers. Glasgow and Dundee are following suit and assessing the potential for hydrogen vehicles within their fleet. Glasgow city council has ambitions to create a zero emissions vehicle fleet, consisting of battery powered, and hydrogen vehicles, by 2029. The city is set to have the largest fleet of hydrogen fuelled refuse trucks, with 19 on order, and a refuelling station will be constructed in the city. The heating sector could take advantage of existing natural gas pipelines to deliver hydrogen for heating in urban areas by injecting hydrogen into the existing natural gas grid. Up to 20% by volume could be blended without the need to change existing appliances.

Industrial regions, of which Grangemouth is the largest in Scotland, are seen as difficult to decarbonise. Many industrial sites manufacture and utilise grey hydrogen. Scotland has a good natural gas grid, coupled with ample geological storage, to enable blue hydrogen with CCUS to play a key role in the energy transition of industrial regions. The Acorn Project is attempting to do just that with its blue hydrogen production and CCUS facilities being developed at the St Fergus gas terminal, which receives, processes and distributes 35% of the UK's natural gas supply, and is likely to up to 2040 and beyond [22]. The Shetland hub and Grangemouth have also investigated the potential for blue hydrogen production and CCUS.

The regional approach has real potential to build insular supply and demand networks which could eventually be integrated towards a whole of Scotland hydrogen economy.

The assessment makes clear that the Scottish government needs to outline its proposed ambition for hydrogen in order to secure investor and industry confidence. The assessment warns that slow deployment and development of hydrogen manufacturing could result in

Scotland being at a disadvantage compared with areas that are able to deploy and develop technologies more quickly.

Elementenergy also proposes three scenarios, while assessing the Acorn Projects potential, and looks at a phased approach to introducing blue hydrogen with CCUS into the Scottish economy in its drive to net zero by 2045. In the Hydrogen in Scotland the Role of Acorn Hydrogen in Enabling UK Net Zero Report [16], Elementenergy, commissioned by the Acorn consortium, in July 2020, identified the need for blue hydrogen and CCUS deployment in order to meet the net zero by 2045 target.

The Acorn project aims to exploit the North Sea's significant potential for renewable energy and make it central to the UK's decarbonising strategy. The project foresees the combination of offshore geological storage sites for CO_2, coupled with the expansion of offshore wind enabling Scotland to achieve its goals with hydrogen and CCUS being central to drive decarbonisation and meet net zero by 2045. The project is to be based at the St Fergus gas terminal and will take advantage of its location, existing infrastructure, readily available natural gas supply, and technical expertise.

The three scenarios proposed in the Hydrogen in Scotland report are the **Regional Growth**, the **Scottish Hydrogen Economy** and the **European Outreach** scenarios and propose hydrogen production volumes and growth scenarios out to 2050. All scenarios centre on blue hydrogen production with CCUS. The scenarios are summarised in Table 3.2.

Table 3.2 Summary of the Hydrogen in Scotland report scenarios

Scenario	Production Potential	Details
Regional Growth	19TWh of blue hydrogen produced annually by 2050	• Hydrogen blending in NTS up to 1.5 TWh in 2025, 7 TWh in 2030 • Dedicated hydrogen pipeline to Aberdeen City and surrounding areas for heating • Supplies Grangemouth industrial cluster and Peterhead power station
Scottish Hydrogen Economy	72 TWh of blue and green hydrogen produced annually by 2050	• Expands on regional growth scenario • Allows for decarbonization of 20% of distilleries energy demand • Blue and green hydrogen production coexisting
European Outreach	121 TWh of blue and green hydrogen produced annually by 2050	• 48 TWh exported to UK and European markets • Hydrogen exported as ammonia • Peterhead Port potential point of export

The regional scenario focusses on producing blue hydrogen and providing the city of Aberdeen along with industrial centres, namely Peterhead power station and the Grangemouth industrial cluster with clean hydrogen by utilising the existing National Transmission System (NTS). it is estimated that demand for hydrogen blended in the NTS could be 1.5 TWh annually in 2025, reaching a peak of 7 TWh annually in 2030, By 2050 the scenario envisages production capabilities of 19 TWh annually. As the regional pathway progresses a dedicated hydrogen pipeline would be commissioned to provide the city of Aberdeen, as well as the surrounding area with hydrogen for domestic use.

The Scottish hydrogen scenario proposes a production potential of blue and green hydrogen of 72 TWh annually by 2050. The scenario seeks to expand the regional growth projections to roll out a hydrogen economy Scotland wide. This scenario allows for the decarbonisation of 20% of the energy demands of Scottish distilleries. This scenario seeks to have blue and green hydrogen production coexisting.

The European outreach scenario is the most ambitious with production potential of 121 TWh annually out to 2050, 48 TWh of which will be available for export UK wide and to European markets. Hydrogen will be exported using ammonia as the hydrogen carrier for lowest cost and more manageable transport and storage, due to the relatively low infrastructure required. Export in the form of LOHC, or liquified hydrogen is also a possibility Pipeline transfer of hydrogen could follow in the future. The maritime sector will aid this growth scenario with Peterhead Port suggested as a point of export, with potential demand of 32 TWh annually.

UK hydrogen demand is expected to be 735 TWh annually by 2050. This is based on the Hy Impact Series Study 1, Hydrogen for Economic Growth which estimated, in its Economy-Wide UK Decarbonisation scenario, that annual demand for hydrogen by 2050 would be 735 TWh if, along with decarbonising industry, hydrogen was used to decarbonise power generation, heating, and transport [23].

The Acorn Hydrogen Project, in conjunction with its sister project, Acorn CCUS, are considered to be key drivers in the roll out of a Scotland wide hydrogen economy. Elementenergy sees the Acorn Project of being capable of positioning Scotland as a leader in hydrogen and CCUS technologies and trade. Similar to the findings in the Scottish Hydrogen Assessment, The Hydrogen in Scotland report acknowledges that a rollout of a Scottish hydrogen economy would require an update of current policies, to reduce market uncertainty and enable effective deployment of the different parts of the hydrogen supply chain.

The Hydrogen in Scotland report lacks stakeholder engagement and supply chain analysis which this report aims to address.

The Scottish Governments Offshore Wind Policy sees the potential for 11 GW installed offshore wind capacity off the coast of Scotland by 2030. It makes a commitment to policy and learning exchange to promote Scotland's reputation as a world leader in renewables. Both the Acorn Project and the Scottish Hydrogen Assessment project see green hydrogen playing a major role in Scotland's pathway to net zero. Scotland has a wealth of offshore renewable resources which is the obvious route to the creation of a green hydrogen market.

Scotland has an impressive renewable energy portfolio and in 2019 90.1% of gross Scottish electricity consumption was provided by renewable sources [24]. In 2019 Scotland exported

14,872 GWh of electricity to England via interconnector[1]. In order to maintain its place as a global leader in renewable energy there are numerous funding opportunities offered including; **The Energy Transition Fund** and the **Green Jobs Fund** with a combined total of £162 million pounds of funding towards promoting renewables in Scotland. As of 2020 there were more than 150 offshore wind turbines with a combined installed capacity of just under 0.9 GW.

The National Grid Future Energy Scenarios Report in 2020 stated that hydrogen production and CCUS must be deployed, and industrial scale demonstration projects need to be operational in the 2020's for net zero to be achieved by 2045 [18]. Clean hydrogen plays a role in every scenario. The most hydrogen ambitious, the Systems Transformation scenario, sees potential for 527 TWh blue hydrogen produced annually by 2050, and 56 TWh of green hydrogen production. Another scenario sees potential for installed electrolyser capacity of 73 GW for the production of green hydrogen by 2050. By 2030 the potential blue hydrogen production across the scenarios range from 0 – 9 TWh annually, and green hydrogen production ranges between 0 – 5 TWh annually. The demand for hydrogen by 2030 is projected to range between 0 – 11 TWh annually.

Xodus Group produced the Scottish Wind to Green Hydrogen Report [4] in 2020. It aimed to assess Scotland's opportunity to produce green hydrogen from offshore wind. The report produced three scenarios to explore the development of hydrogen demand in Scotland. The scenarios are; the **Business as Usual** scenario, the **Planned Development** scenario and the **Ambitious** scenario. The report assumes all wind could be used for hydrogen production due to grid constraints. In all scenarios an excess of green hydrogen is produced, lending credit to the potential for Scotland to be a hydrogen exporter. The report proposes that, due to grid constraints, green hydrogen production is the best way to develop and commercialise Scottish offshore wind. The Ambitious scenario sees potential for installed offshore wind capacity of 60 GW by 2045. The Planned Development scenario follows the plan for Scotland to provide 40% of the UK's 75 GW target, which works out at 30 GW of installed offshore wind capacity. The Business as Usual scenario is the most conservative and projects installed capacity of 27 GW. The Offshore Wind and Hydrogen Solving the Integration Challenge report from 2020, supports the view that offshore wind could play a major role in green hydrogen production. It estimates that up to 240GW of offshore wind could be harnessed for green hydrogen production in the UK by 2050 [5].

The report attempts a cost analysis for green hydrogen based on green hydrogen being ramped up to 2032 with dedicated offshore wind capacity of 1 GW, which equates to 276 tonnes of green hydrogen daily. A project of this scale could potentially reduce the LCOH of green hydrogen in 2032 to £2.30/kg, from £4.36 /kg in 2020 [25], not including transport or storage costs from point of production. making it cost competitive in the transport and heating sectors.

Utilisation and repurposing of existing oil and gas infrastructure features prominently as a hydrogen transport and delivery method, including four existing pipelines connecting offshore oil and gas fields to continental Europe. Scottish ports also play a critical role in the Xodus scenarios. Depleted oil and gas reservoirs could offer hydrogen storage in the future.

A potential threat to Scotland's hydrogen ambitions could lie in the lack of hydrogen projects in the pipeline, as well as gaps in the supply chain. This is supported by the Scottish Hydrogen Assessment report that observed that in order for the most ambitious scenario to be achievable, more green hydrogen projects need to be developed in the pipeline.

Dentons published a report in 2021, Scaling Up Green Hydrogen in Europe [19]. The report focuses on green hydrogen production by electrolysis powered by renewables, for the North West of Europe including Germany, The Netherlands, and Belgium. This area is likely to have a high demand for green hydrogen in the next decade and beyond. The report presents a business case for scaling up green hydrogen production from MW scale to tens of GW production scale from 2023 in North West Europe. The scale up of production will be necessary in order to make green hydrogen cost competitive, in the 2030's, with higher carbon alternatives. The report sees potential for green hydrogen to be imported by pipeline into North West Europe, from areas where renewable power is cheapest. The import of green hydrogen has the potential to be lower cost than domestic production of green hydrogen.

The European union currently produces and consumes negligible amounts of green hydrogen. By 2030 as per the EU hydrogen strategy the EU aims to have 40 GW installed electrolyser capacity for green hydrogen production, along with an additional 40 GW installed electrolyser capacity in neighbouring regions for future import of green hydrogen to satisfy the EUs hydrogen demand. Dentons report seeks to outline what projects need to be established, along with infrastructure requirements for the EU, and particularly North West Europe to realise its green hydrogen ambition. The North West Europe area was selected for attention in this report due to its high levels of industry that consume hydrogen as a feedstock, that would be an end user in a green hydrogen supply chain. The area has an extensive gas pipeline network that could potentially be repurposed for hydrogen storage and transportation. The regions vicinity to the North Sea is advantageous for the supply of renewable electricity from offshore wind. The region also homes extensive geological storage potential in the form of salt caverns. Large ports in the region, coupled with extensive pipelines provides the potential for the future import of green hydrogen by sea should the demand warrant it.

Electrolysers, renewable electricity, and the storage and transport of green hydrogen are the main costs that the report investigates. Areas with the lowest cost for renewable electricity have the potential to capitalize on the opportunity to be producers and exporters of green hydrogen to North West Europe. The report projected the cost of renewable electricity to fall up to 2035. Table 3.3 summarises the projected levelized cost of renewable energy (LCOE) for different regions.

Table 3.3 Projected levelised cost of renewable electricity by region in 2035

Region	LCOE in £/kWh
North Europe	2.7 (€3/kWh)
Southern Europe	2.2 (€2.5/kWh)
MENA	1.3 (€1.5/kWh)

Producing green hydrogen in regions of readily available low-cost renewable energy does have its issues. Transport and processing costs could be high to export green hydrogen from those regions to North West Europe, negating the cost savings in the renewable electricity. Energy security could also be an issue with importing green hydrogen from afar. The report finds that hydrogen production at the source of low-cost renewable electricity (within 3000 km of end user) and transporting it to Northern Europe by gas pipeline, would be the most economically attractive option, in the shorter term. The report estimates that the cost of transport of green hydrogen could add up to 12% on to the levelized cost of green hydrogen. Infrastructure connecting the supply and demand sites of green hydrogen are essential for green hydrogen to become cost competitive with high carbon fuel alternatives. The report proposes a possible future pipeline route supplying green hydrogen from North Africa to North West Germany, travelling through Italy, Switzerland and into Germany. The report highlights the need for a supportive regulatory environment, coupled with regulated financial support in order that the EU, and regions within, can meet their ambitious hydrogen strategies leading to 2030 and beyond.

4. Hydrogen Demand

4.1 Introduction

In the drive to net zero many countries have declared their intent to incorporate hydrogen to varying degrees into their energy systems. This section aims to identify which countries, or regions are progressing, and to what extent, towards incorporating hydrogen in a large way into their economies. An assessment of clean hydrogen production goals is conducted, along with the potential for hydrogen import/export.

Current global demand (2020) for hydrogen is at more than 70 million tonnes a year [26]. Global hydrogen demand estimates for 2050 vary. IRENA sees a global economic potential for 5 PWh from clean hydrogen in total energy consumption by 2050. The hydrogen council estimates a higher demand of up to 22 PWh. This equates to the need for 4 – 16 TW of installed PV and wind generation to be deployed to produce hydrogen in 2050[2].

Hydrogen will be part of emissions mitigation efforts in the coming decades. IRENA's Renewable Energy Roadmap (REmap) analysis indicates a 6% hydrogen share of total final energy consumption globally by 2050, while the Hydrogen Council in its roadmap suggests that an 18% share can be achieved by 2050 [27].

12 countries now have national hydrogen strategies, with numerous others intent on publishing strategies in the near future. Globally there are approximately 32 announced projects with electrolyser capacity above 100 MW. These projects are discussed further in this section.

The Countries and regions with a hydrogen strategy, roadmap, or significant industrial production of hydrogen that warrant closer examination are; The UK, The EU, North Africa, The Middle East, Japan, Australia, The USA, Chile and Canada. Each country/region has their own strategy for how they plan to integrate hydrogen into their energy systems, to achieve decarbonisation goals, and to establish energy security into the future.

This report seeks to identify potential markets for future hydrogen export from Scotland, and to also identify competitor markets that may also seek to capitalise on those potential export markets.

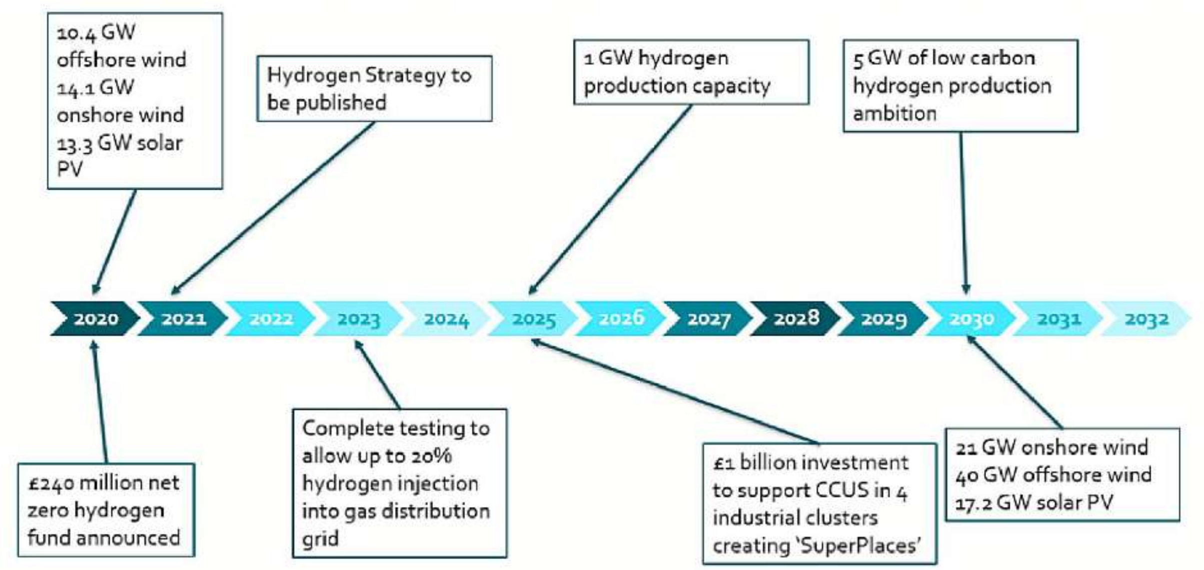
4.2 Hydrogen in the UK

The UK's hydrogen demand has been projected to be approximately 60 TWh by 2030, and 220 TWh by 2050 according to the Climate Change Committee (CCC). This demand could be met through the domestic production of clean hydrogen, drawing on the UKs vast renewable energy potential, along with its natural gas reserves and geological storage for future CO2.

The government published its 10 point plan for a green industrial revolution in November 2020.the government has set out how it plans to support industry to realise the ambition of 1 GW of clean hydrogen production capacity by 2025, and 5 GW by 2030 to aid in decarbonising industry, transport, heating, and power generation. As part of the plan up to £500 million will be invested into clean hydrogen, £240 million of which will go to clean hydrogen production facilities [28]

The UK is a global leader in wind energy with just over 23 GW installed offshore and onshore wind capacity in 2019. By 2030 the UK aims to have 40 GW of installed offshore wind capacity, 21 GW installed onshore wind capacity, and 17.2 GW installed solar photovoltaic (PV) capacity. A summary of UK ambitions in renewables and clean hydrogen production can be seen in Figure 4.1.

Figure 4.1 - Timeline of renewables and clean hydrogen ambitions in the UK



Work towards the goals of a fully established hydrogen economy, and hydrogen export market in Scotland has started to gain momentum and there are numerous projects and initiatives ongoing. The Scottish hydrogen ambitions are closely linked with the rest of the UK, whose future hydrogen policies, regulations and funding will be instrumental to the overall success of the establishment of a hydrogen economy in Scotland. Some of the ongoing UK hydrogen projects and initiatives are detailed in Table 4.1.

Table 4.1 Hydrogen projects in the UK

Project	Description	Location	Project Timeline
Gigastack	• Ørsted, ITM and Phillips 66 Humber refinery partnership • 100 MW installed electrolyser capacity powered by offshore wind from Hornsea Two wind farm to produce green hydrogen • Hydrogen to be utilized in refinery processes	**Humber region, England**	• 2019 – Feasibility Study • 2020 – Front end engineering design study • Mid 2021 – Building to commence
Acorn Hydrogen	• Plans to build a 200 MW blue hydrogen plant • Hydrogen blended into national transmission system • Acorn CCS is a sister project • Plans to produce more than 10TWH of hydrogen annually • Feasibility study completed	**North East Scotland**	• 2023 – FID • 2025 – Hydrogen production to commence
H2H Saltend	• 600 MW hydrogen production plant based in Hull • 360 tonnes of blue hydrogen produced per day • CO2 produced transferred by pipeline to storage in the North Sea	**Humber region, England**	• 2023 – FID • 2026-27 – Hydrogen production to commence
H2 Teesside	• BP led project • 1 GW of blue hydrogen production by 2030 • 2 million tonnes of CO2 captured and stored annually in North Sea storage sites • MOU with Northern Gas Networks (NGN) to use hydrogen to aide in decarbonising gas networks	**Teesside, North East England**	• 2024 – FID • 2027 – Production to commence • 2030 – 1 GW hydrogen production annually
Net Zero Teesside (NZT)	• Full chain CCUS project • Consortium of BP, Shell, Total, Equinor and ENI • Aims to decarbonize and industrial cluster and create the UK's first zero-carbon industrial cluster by 2030 • 1o million tonnes of CO2 emissions will be captured • Supported by the NEP (National Endurance Partnership)	**Teesside, North East England**	• 2021 – Application for development • 2026 – Project commissioning

Cont.

Table 4.1 Hydrogen projects in the UK (continued)

Project	Description	Location	Project Timeline
Northern Endurance Partnership (NEP)	• Partnership formed by BP, National Grid, Shell and others • Aims to develop a carbon transportation and storage infrastructure in the North Sea • Scale up technologies such as carbon capture and hydrogen networks • Supporting efforts to decarbonize industrial clusters including Teesside, Humber, Grangemouth, Southampton, Merseyside and South Wales	UK-wide	• 2026 – Project Commissioning
Zero Carbon Humber (ZCH)	• Aims to create the world's first zero carbon industrial cluster in the Humber region • Consortium of 12 industry stakeholders including British Steel, Drax, Uniper and Centrica Storage • Aiming to reduce the UK's annual emissions by 15% by 2040 • Developing CCUS and low carbon hydrogen technology and shared onshore and offshore infrastructure in the region	Humber region, England	• 2026 – Hydrogen production demonstrator and test facility constructed • 2028-2040 – Hydrogen production scaled up to meet demand
Hydrogen to Heysham	• Feasibility study for hydrogen production by electrolysis powered by nuclear generated electricity	Lancashire, England	• 2019 – Feasibility study • 2021 – Demonstrator construction and operation • 2021-30 – Commercial scale up and supply of hydrogen
HyNet North West	• Hydrogen network to produce, store and distribute hydrogen to the North West of England and North Wales • Potential to reduce CO_2 emissions by 10 million tonnes annually by 2030 • Aims to establish the region as a world leader in clean energy innovation • Plants to produce 3oTWh of clean hydrogen annually by 2030	North West England & North Wales	• 2023-26 – Project delivery • 2027-35 – Project expansion

Cont.

Table 4.1 Hydrogen projects in the UK (continued)

Project	Description	Location	Project Timeline
HyNet North West (continued)	• CCS with CO_2 transported by natural gas pipelines to storage under the seabed in Liverpool Bay • 350 km of hydrogen pipeline to be built making the UKs first hydrogen network • Hydrogen blending in natural gas networks • 1 TWH of hydrogen storage capacity in salt caverns in the Cheshire basin	North West England & North Wales	• 2023-26 – Project delivery • 2027-35 – Project expansion
ERM Dolphyn	• Green hydrogen production from offshore electrolysers directly connected to offshore floating wind turbines • Initial proof of concept phase completed • Aims to deploy 4 GW floating wind capacity to power electrolysis by the mid 2030's • Hydrogen will be transported to shore via pipeline	Offshore Aberdeenshire Scotland	• 2020- proof of concept study • 2021 – FID • 2024 – Prototype facility commissioned • 2027 – 10 MW pre-commercial facility commissioned
H100 Fife	• Green hydrogen to homes heating network • Plans to produce hydrogen by electrolysis powered by offshore wind • Initial plans to provide 300 homes with hydrogen for heating and cooking by 2022 • Project will be operational until 2027, beyond which an enduring solution will be found depending on the project's success	Levenmouth, east coast, Scotland	• 2027 – Project operational
Hydroflex	• Hydrogen powered train • Launched in 2019 • Technology could be used to retrofit existing trains by 2023	West midlands, England	• 2019 – Project Launched • 2023 – existing trains to be retrofitted for hydrogen power
Green Energy Ferries	• 2 hydrogen fuel cell ferries to operate between Cardiff and Bristol • Each ferry will carry up to 100 people and be self-sufficient, powered by wind turbines and solar panels	England & Wales	Unknown
Vanguard	• 1st hydrogen fueling station in the north west of England • Hydrogen produced by electrolysis powered by solar PV	North west England	• 2021 – Project operational

Cont.

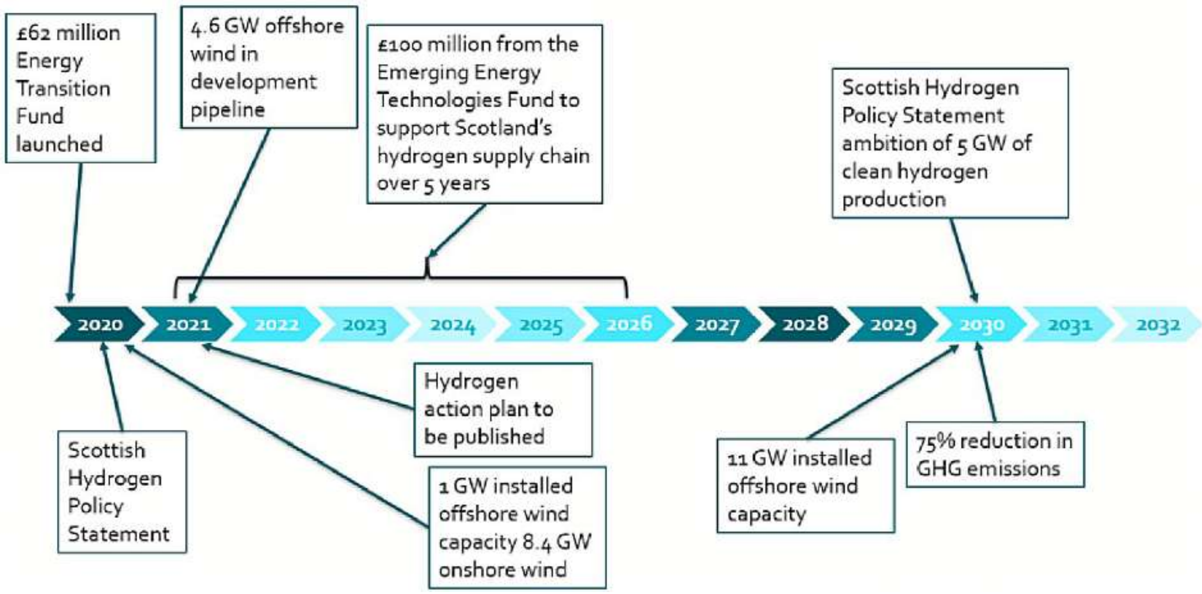
Table 4.1 Hydrogen projects in the UK (continued)

Project	Description	Location	Project Timeline
Hy4Heat	• Government innovation program • Pilot scheme where 2 homes will use hydrogen for heating and cooking • By 2030 'hydrogen neighborhoods' and 'hydrogen towns' could be a reality	North west England	• 2021-25 two homes will be supplied with hydrogen
HyDeploy @ Keele	• First live demonstration of hydrogen used in homes • Up to 20% by volume hydrogen blended into private gas grid • Plans to blend into public gas grid	University of Keele, North West England	• 2021 – trials supplying 100 homes and university buildings with hydrogen completed • 2021 – Phase 2 to begin. Hydrogen blended into a public gas network
BIG HIT	• Based in the Orkney Islands, Scotland • Green hydrogen production using curtailed wind and tidal power • 2 electrolysers with 1.5 MW total installed capacity • 50 tonnes of green hydrogen produced annually • Aims to create a hydrogen territory with hydrogen production, storage, transportation and utilisation • Hydrogen used for heating, transport and power	Orkney Islands, Scotland	• 2014 – Project development • 2022 – Project finalisation

4.3 Hydrogen in Scotland

Scotland has an abundance of renewable energy, most notably in the form of North Sea offshore wind and onshore wind. By 2030 Scotland aims to have 11 GW of installed offshore wind capacity, along with GW installed clean hydrogen production capacity. The country has committed to net zero by 2045. A summary of Scottish ambitions in renewables and clean hydrogen production can be seen in Figure 4.2

Figure 4.2 - Timeline of renewables and clean hydrogen ambitions in Scotland



4.3.1 Scottish Government Hydrogen Statement Policy

The Scottish Government Hydrogen Policy Statement was published in December 2020. The statement sets out a vision for Scotland to become a leading hydrogen nation. The statement lends support for Scotland achieving 5 GW installed clean hydrogen production capacity by 2030, and 25 GW by 2045. There is a role for green and blue hydrogen production in Scotland and the statement highlights the importance of establishing low carbon hydrogen production at scale by the mid 2020's. There is a need for pace in order that Scotland can capitalise on opportunities withing the hydrogen market, both domestically and globally. The need for international collaboration towards a shared hydrogen economy is essential and the strategy aims to explore Scotland's hydrogen export potential. The statement acknowledges the need to engage with UK government on the development of a UK hydrogen policy [29].

In December 2020 a £100 million investment plan was announced for the hydrogen supply chain in Scotland. The investment will be made between 2021-26 and will come from the Emerging Energy Technologies Fund.

The policy statement outlines the necessary phases needed through the 2020's and 30's to enable Scotland to create a hydrogen economy, and to establish itself as a leader in hydrogen export to the UK, the European market and beyond. This includes the need for a strong policy framework to be laid out, this decade, to support innovation, development and demonstrations of clean hydrogen production. In addition to establishing lasting relationships with organisations and governments to initiate long lasting partnerships for the advancement of a developed hydrogen market with export from Scotland. Through the 2020's a domestic hydrogen demand market needs to be established, with private and public financing, in the transport and industry sectors, in order that hydrogen production demonstrations can be scaled up to commercial viability. The 2030's needs to be a period of production scale up, and technology advancement, to reduce the cost of clean hydrogen production, making it a competitive fuel source and energy carrier for domestic use, and for export. The statement lays out clear requirements for Scotland so that by 2045 net zero can be achieved, greatly assisted by the presence of a strong, competitive clean hydrogen supply chain, economy and export market.

4.3.2 The Aberdeen Region

Aberdeen city region published its hydrogen strategy and action plan back in 2015 seeking to position Aberdeen as a hydrogen technology centre of excellence. Aberdeen is the centre for oil and gas activity in the UK and has a wealth of resources that can be repurposed to establish the area at the forefront of Scotland's emerging hydrogen economy. Aberdeen is ideally located close to industry and to offshore renewable energy generation. The Aberdeen region looks at becoming a leading European region in the early deployment of FCEV. By rolling out the use of hydrogen fuel cell vehicles, Aberdeen has been able to create a local demand to support the local production of clean hydrogen, thus driving the goal of a local hydrogen economy. The H2 Aberdeen initiative has been implementing plans outlined in the hydrogen strategy, and Aberdeen city has established itself as a hydrogen cluster with two hydrogen refuelling stations and a varied fleet of hydrogen vehicles. As part of the H2 Aberdeen initiative the region has been involved in numerous projects aimed at integrating hydrogen into the transport sector. Some of the projects are outlined in Table 4.2.

Table 4.2 Aberdeen hydrogen projects in the transport sector

Project	Description	Project Timeline
Aberdeen Hydrogen Bus	• Roll out of 10 hydrogen fuel cell buses • Construction of Scotland's first Hydrogen Refueling Station Kittybrewster	2014-2019
New Bus Fuel	• Project to demonstrate that hydrogen refueling for hydrogen cell busses is technically and economically viable	
HyTrEc	• Project to advance the adoption of hydrogen in the transport and energy sectors in the North Sea Region • Partnership between UK, The Netherlands, Germany, Sweden and Norway	2014-2020
Aberdeen Hydrogen Cars	• Addition of 10 hydrogen cars for the Aberdeen public fleet	2017
Hector	• Project to deploy and test 7 hydrogen fuel cell garbage trucks across north West Europe including in the city of Aberdeen • Countries involved are UK, Germany, France, Belgium and The Netherlands	2019-2023
JIVE & JIVE2	• Deployment of 300 hydrogen fuel cell busses across 22 cities in Europe including Aberdeen • The busses have a range of 400 + km, and take 7 minutes to refuel • Birmingham, Brighton and London are other UK cities in the project	2017-2023

With the success of Aberdeen's integration of hydrogen into the transport sector other Scottish cities are pursuing similar goals, including Glasgow and Dundee.

Aberdeen is home to the Energy Transition Zone (ETZ), established in 2020, by Opportunity North East (ONE). The zone is based on creating economic growth by using clean energy from offshore wind, clean hydrogen and CCUS. The zone hopes to attract manufacturing and assembling activities for offshore wind to the area. The zone hopes to capitalise on Aberdeen's location, and wealth of infrastructure and technical expertise from the oil and gas industry, to enable the area to become a leader in energy transition support and progression, focussing in part of the offshore wind sector, along with other clean energy technologies [30]

4.4 Curtailed Wind Potential

The literature review section referred to the Wind to Green Hydrogen report which set out scenarios for the utilisation of offshore wind for clean hydrogen production. The most ambitious scenario projected that up to 60 GW offshore wind could be utilised for hydrogen production by 2045. It should be noted that all information in this section refers to the UK and not solely Scotland due to availability of information.

Renewable energy production is intermittent with production rarely matching the demand for electricity. This is one of the drawbacks of wind power and explains why renewable energy cannot be solely relied upon. A mix of energy generation technologies are currently being utilised within the UK and balancing them to meet output is a challenge faced by the national grid. Currently when wind energy production exceeds demand wind farms are curtailed with their blades being angled out of the wind slowing or halting production of renewable electricity. This results in a double loss, firstly in renewable electricity production and secondly, a financial loss as the National Grid covers the cost of the lost energy production to the operators, which in turn is felt by the end customer, through increased energy bills. The ability to store this curtailed electricity for future use would enable an increase in renewable energy production capacity. The most popular existing technology for this is chemical batteries. However, these are large, expensive and unable to store large amounts of charge. Instead, producing hydrogen from excess renewable energy is now being discussed as a more effective way to store excess energy while utilising the existing gas transportation and storage network within the UK. This section shows the amount of renewable electricity curtailed within the UK from both on and offshore wind farms and identifies trends as renewable capacity increases. It also estimates potential hydrogen production using curtailed power.

Table 4.3 shows the amount of energy produced from wind power in the UK against the amount of energy curtailed per year. 2010 was the first year that wind power was curtailed and the amount of curtailment as a share of power generated increases to around 3% in 2015 where it remains until 2019. It can be seen from the table that curtailment of wind power has increased to 4.66%. This could be a result of the Covid-19 pandemic with less demand being required for power in the UK, as the total UK installed wind capacity has only increased slightly from 24,095 MW in Q3 of 2019 to 24,514 MW in Q3 of 2020 [33].

Table 4.3 UK Wind Generation Vs Curtailment

Year	Cumulative Installed Wind Capacity [31]	MWh Generation per Year [31]	MWh Curtailment per Year [32]	% Curtailed of Total
2010	5,422	10,286,000	976	0.01
2011	6,597	15,963,000	58,708	0.37
2012	9,031	19,847,000	45,463	0.23
2013	11,282	28,397,000	379,817	1.32
2014	13,074	31,959,000	659,350	2.02
2015	14,306	40,275,000	1,276,264	3.07
2016	16,126	37,155,000	1,134,627	2.96
2017	19,585	49,633,000	1,542,285	3.01
2018	21,770	56,904,000	1,724,187	2.94
2019	23,975	64,134,000	1,940,178	2.94
2020	24,514 [33]	75,610,000 [33]	3,696,019	4.66

Figure 4.3 - Curtailment in MWh per year

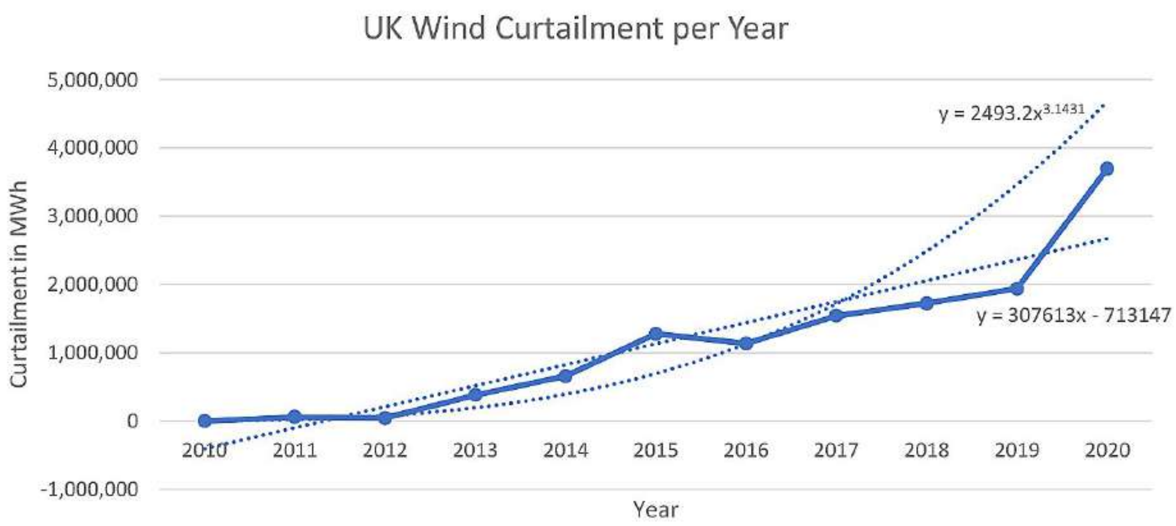


Figure 4.3 shows the trend in curtailment increasing yearly following the line of best fit equating to Y = 307613x-713147. This graph also shows half a 'parabola curve' of y = $2493.2x^{31431}$, this has been included as a second way of predicting renewable wind energy curtailment as the UK government has said that it will increase its capability to generate offshore wind from 10.4 GW in 2020 to 40 GW by 2030. Current capacity for on and offshore wind in 2020 stands at 24.5 GW.

Figure 4.4 - Wind Power Curtailment Vs Generation

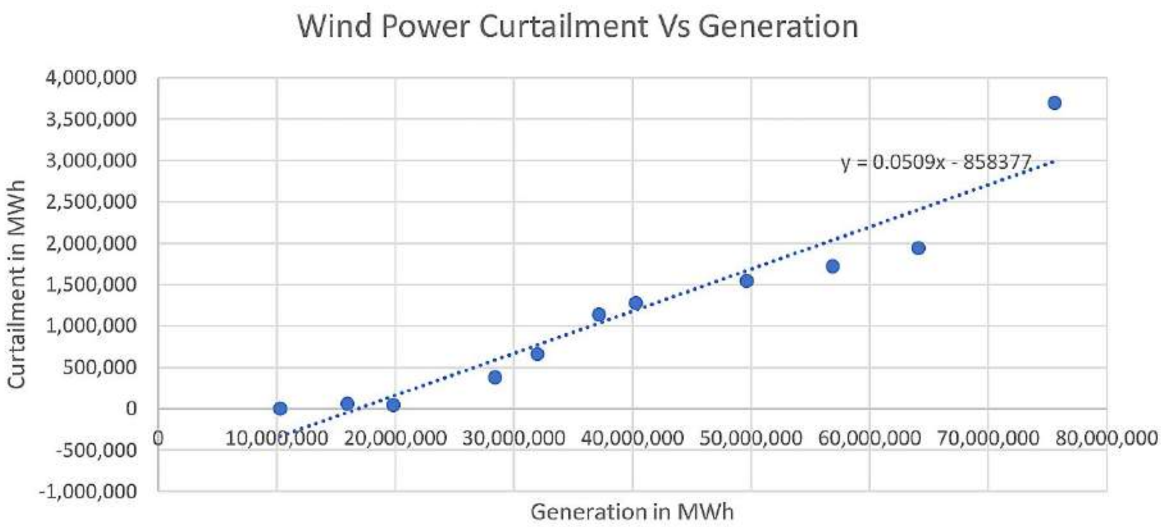


Figure 4.4 shows a plot of curtailment against generation between 2010 and 2020. There is a linear relationship showing that as generation increases so too does the curtailment, as the line y = 0.0509x - 858377. It is considered that this linear relationship will become more like a 'parabola curve' function of 'x' as generation increases but there is not enough data to show this currently.

Figure 4.5 - Wind Power Curtailment vs Capacity

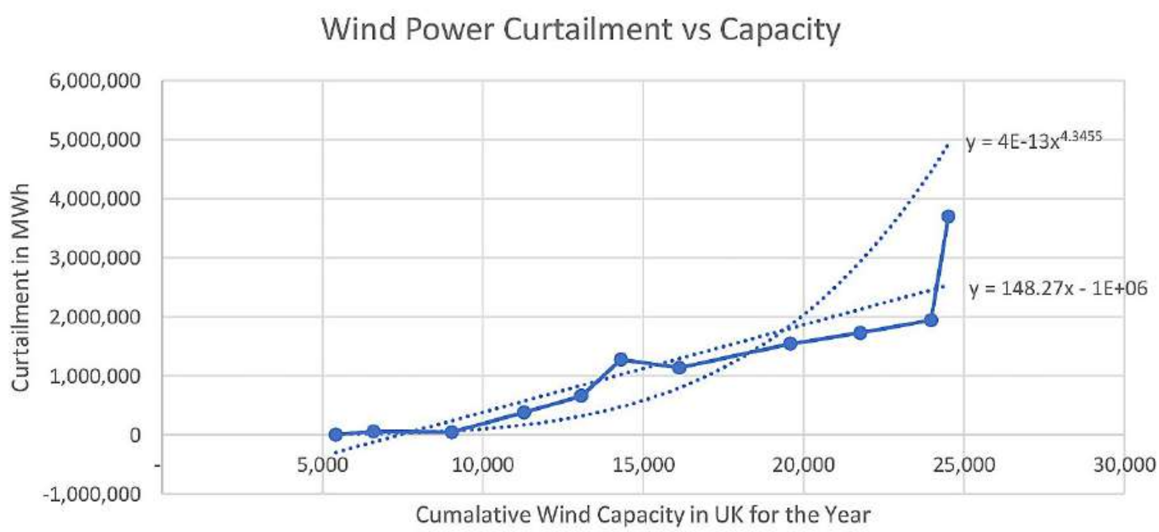


Figure 4.5 shows the trend in wind curtailment increasing year on year as the UK capacity increases. Two lines have been plotted to help predict future curtailment, firstly the line of best fit (Y = 148.27x – 1E+06) and the half 'parabola curve' (Y = 4E-13x$^{4.3455}$). Rystad Energy [34] predicts offshore wind capacity will rise from 10.5 GW to 27.5 GW in 2026 with onshore rising from 13.5 GW to 24.3 GW over the same time period. Offshore wind is set to grow further to 40 GW of capacity by 2030 in line with government targets, while onshore will stall and remain constant. This will provide 51.8 GW and 64.3 GW of UK wind capacity by 2026 and 2030 respectively. These figures can be applied to the linear and parabolic models to estimate curtailment figures of 6,618,190 MWh and 122,512,376 MWh respectively for 2026 and 8,533,761 MWh and 313,430,153 MWh respectively for 2030.

Table 4.4 Wind Curtailment and H2 Production

Year	Cumulative Installed Wind Capacity [31]	MWh Curtailment [32]	H2 Production in kg	Homes Heated per Year	Bus Km travelled (8.33km/kg) [35]	Km travelled by vehicles on local bus services: GB [36]	Local bus services potentially powered (%)
2010	5,422	976	24,772	59	206,347	2,590,731,364	0.01
2011	6,597	58,708	1,490,051	3,571	12,412,123	2,556,948,115	0.68
2012	9,031	45,463	1,153,883	2,766	9,611,847	2,529,379,001	0.53
2013	11,282	379,817	9,640,025	23,106	80,301,411	2,521,681,682	4.45
2014	13,074	659,350	16,734,772	40,110	139,400,647	2,495,844,920	7.80
2015	14,306	1,276,264	32,392,487	77,639	269,829,419	2,465,004,500	15.28
2016	16,126	1,134,627	28,797,640	69,023	239,884,338	2,427,885,042	13.79
2017	19,585	1,542,285	39,144,289	93,822	326,071,930	2,356,772,246	19.32
2018	21,770	1,724,187	43,761,091	104,888	364,529,891	2,316,463,918	21.97
2019	23,975	1,940,178	49,243,096	118,027	410,194,993	2,248,497,633	25.47
2020	24,514 [33]	3,696,019	93,807,589	224,841	781,417,215	N/A	N/A
2026 Linear	51,800	6,680,386	169,552,944	406,390	1,412,376,025	N/A	N/A
2026 Parabolic	51,800	122,512,376	3,109,451,165	7,452,836	25,901,728,205	N/A	N/A
2030 Linear	64,300	8,533,761	216,592,919	519,137	1,804,219,013	N/A	N/A
2030 Parabolic	64,300	313,430,153	7,955,080,016	19,067,001	66,265,816,533	N/A	N/A

Table 4.4 shows the UK wind power curtailment figures 2010 – 2020. These have been used to predict the amount of hydrogen that could have been produced had the curtailed energy been used to produce hydrogen. The hydrogen production was assumed to be 73% efficient, with one kg of hydrogen produced for every 39.4kWh of electricity. This figure required electrolysers to have high utilisation as stop starting electrolysers reduces the efficiency dramatically.

Table 4.4 also shows the results of the Linear and Parabolic models created from the data in Figure 4.5 for projected installed capacities for 2026 and 2030. The linear and parabolic models differ by a factor of 18 in 2026 and 37 in 2030. However, it should be noted that between 2020 and 2026 the UK plans to increase its wind capacity from 24GW to 52GW. The UK in 2020 saw two runs of 55 and 67 days without the need for electricity production from coal power stations. While more than doubling wind capacity in the UK in 6 year will allow the UK to produce more electricity on low wind days, this will result in significantly more curtailment throughout the year more in line with the parabolic model than the linear. These predictions for 2026 and 2030 assume that the demand for electricity remains the same as 2020 though is it noted that there are plans for electrification within several UK sectors.

The last columns look to give real world examples year on year if hydrogen had been produced from the UK curtailed wind based on an electrolyser efficiency of 73% as described above. Firstly, the number of homes heated per year based on the average home in the UK uses 12MWh of natural gas per year was calculated. Secondly a comparison on the amount of km travelled by busses locally in GB [36] was used taking an average hydrogen consumption of 54 busses across cities in Europe was used taking an average hydrogen consumption from 54 busses across cities in Europe [35]. If 2019 was used as an example the UK wind curtailment figures where 1,940,178 MWh converting that electricity to hydrogen using 73% efficiency could be used to heat 118,027 homes or 2.2 billion hydrogen bus km which equated to 25.47% of the km travelled by busses on local travel in GB. If 2019 was used as an example the UK wind curtailment figures where 1,940,178 MWh converting that electricity to hydrogen using 73% efficiency could be used to heat 118,027 homes or 2.2 billion Km which equated to 25.47% of the km travelled by busses on local travel in GB.

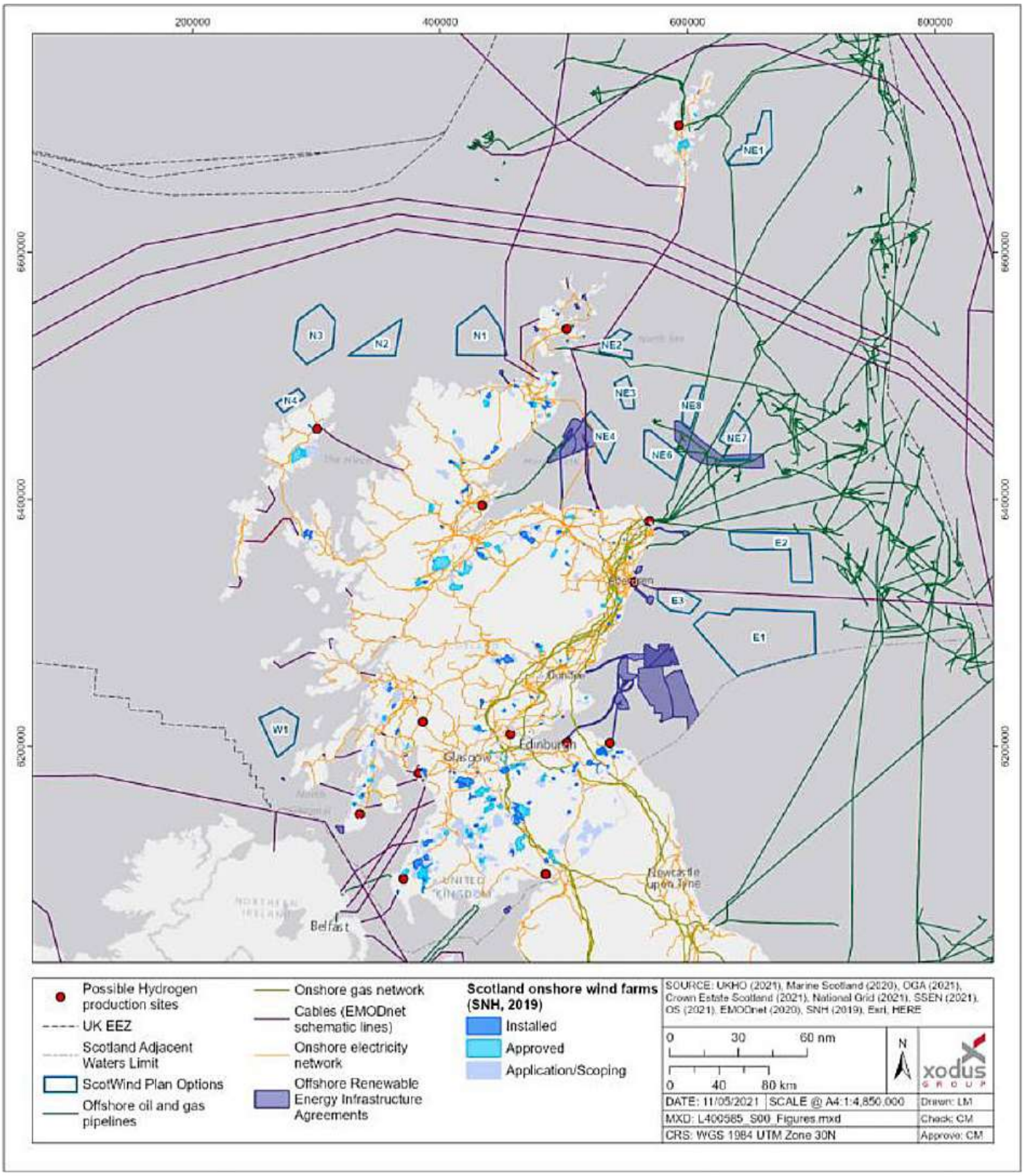
Table 4.5 Curtailed wind powering Scotland's 5 GW electrolyser ambition

Year	Maximum theoretical production capacity per year (MWh)	Curtailed wind (MWh)	5GW Electrolyze capacity used by curtailed wind
2020	43,800,000	3,696,019	8.4%
2030 Linear	43,800,000	8,533,761	19.5%
2030 Parabolic	43,800,000	313,430,153	715.6%

Finally, with the UK Government announcing targets to have 5GW hydrogen production capacity by 2030 the report looks to identify how much wind curtailment could support in this production. This analysis uses the curtailment figures from 2020 as well as the linear and parabolic models for 2030, however, these models are based on several assumptions listed above that should be considered while reviewing this section. This analysis is only meant to give a high-level indication and uses yearly figures against the 5GW production capacity, wind curtailment is not linear and varies throughout the year, a 5GW hydrogen production capacity will only be able to utilise 12,000MWh per day and there may be times within the year where too much electricity is being created even for the 5GW electrolysers, so the examples shown here are the theoretical maximum amount for the year rather than actual real-life examples. A 5GW electrolyser could use a maximum of 43,800,000MWh per year, this would mean that in 2020 curtailed wind could account for 8.4% of the electroliers needs, 19.5% by 2030 with the linear model and 715.6% with the parabolic model however anything over 100% would not be attainable.

Within Scotland, this could also be of interest for onshore wind farms either in the planning stages or at the repowering stage, where grid curtailment could make an option to switch to supporting hydrogen production is of interest. For the purposes of this report, these sites are smaller than the minimum size considered for green hydrogen production. For information, the figure below shows onshore wind sites in Scotland. Further work could identify areas that could be suitable for screening as smaller scale hydrogen production sites.

Figure 4.6 – Onshore Wind Sites, Scotland



5. Future Clean Hydrogen Importers

Hydrogen's importance as an energy store and carrier, as well as an enabler to decarbonisation is being recognized globally. As countries and regions decarbonise and integrate hydrogen into their energy systems, a market will emerge for the import and export of clean hydrogen. Countries and regions with an established renewable portfolio, and/or the storage capacity for clean hydrogen production utilising CCS, stand to position themselves as hydrogen exporters, supplying clean hydrogen to areas lacking in renewable sources, or the technology required to produce clean hydrogen. Although many countries have pledged their intent to embrace hydrogen and incorporate it to a lesser or greater extent into their energy systems, they may not be able to meet their future hydrogen demand with domestic production alone.

This section seeks to identify regions, based on their stated hydrogen strategies/ambitions, and an assessment of their current developments in hydrogen production technologies, that are unlikely to be able to meet their projected hydrogen demand with domestic production, either due to a lack of renewables to power green hydrogen production by electrolysis, or their lack of technology, or storage capacity to be able to produce blue hydrogen with CCS. These countries are present potential markets for the import of Sottish clean hydrogen in the coming decades.

5.1 Hydrogen in the EU

Hydrogen features in all of the European Commission's net zero emissions scenarios for 2050. The EU hydrogen strategy sets a target of 6 GW installed electrolyser capacity for clean hydrogen production by 2024, and 40 GW by 2030, with an additional 40 GW installed electrolyser capacity in neighbouring regions in order for the EU to import hydrogen to help satisfy demand. The European Clean Energy Alliance was established to promote the necessary investment in viable projects to achieve these ambitious targets. The strategy recognises the role Blue, or low carbon hydrogen can play, as being only in the short to medium term, with renewable hydrogen, or green hydrogen being the priority. As such the strategy it suggests that by 2050 cumulative investments in renewable hydrogen could be €180-479 billion, but for low carbon fossil-based hydrogen only €3-18billion [37].

The EU hydrogen strategy sees the integration of hydrogen into the energy system as a staged approach with initial uses of hydrogen being at the point of production in industrial applications, such as refineries and for the production of ammonia and methanol. Hydrogen 'clusters' will form around these industrial hubs. The clusters will then be interconnected as the energy transition progresses. Hydrogen is seen to have extensive application in the heavy duty vehicle part of the transport sector, where electrification is seen to be problematic.

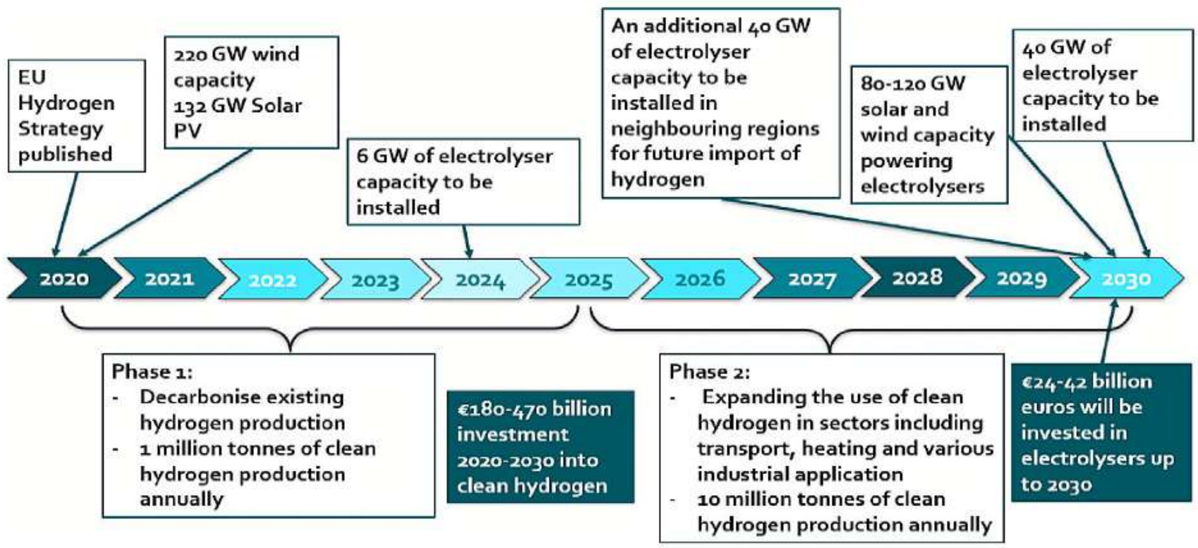
The 2019 Hydrogen Roadmap Europe report states that in order for the EU to achieve the energy transition and decarbonisation objectives, Hydrogen will be required at a large scale [38]. The strategic roadmap is split into three phases. The first covers 2020-2024 and looks at achieving decarbonisation of existing hydrogen production, and to encourage the uptake of hydrogen in new applications by having at least 6 GW of installed capacity of electrolysers, with the aim of producing 1 million tonnes of green hydrogen. The second phase looks at 2025-2030 and expanding the use of clean hydrogen in new sectors including transport, heating and various industrial applications. Phase 2 aims for 40 GW of installed electrolyser capacity, and the production of 10 million tonnes of clean hydrogen. Half of existing fossil-based hydrogen plants will be retrofitted, with CCUS technology, to produce low carbon (blue) hydrogen. Phase 3 focusses on 2030-2050 and looks at clean hydrogen production reaching maturity on a large scale, being implemented in all hard to abate sectors. Although the roadmap focusses on green hydrogen the role of low carbon hydrogen, or blue hydrogen, utilising CCUS is recognized as potentially essential in the transition phase towards net zero.

Each member country is required to produce an NECP (National Energy and Climate Plan) which outlines their renewable energy sources, along with their research and innovation programs. Many of the NECPs make specific reference to clean hydrogen. It is widely regarded across the EU that clean hydrogen will play a major part in the drive to net zero. Many EU member states have specific hydrogen strategies, or roadmaps, which outline their ambitions in using hydrogen as part of their decarbonisation strategies.

The EU hydrogen strategy suggests that cumulative investment in clean hydrogen could be 180 – 470 billion euros up to 2030, with 3 – 18 billion euros of that being invested in low carbon hydrogen (blue hydrogen). The strategy acknowledges that blue hydrogen will play a role in the EUs' energy transition, but that the ultimate goal will be the production of hydrogen from renewable sources. The strategy states that up 24 – 42 billion euros will be invested in electrolysers alone, up to 2030. By 2030 it is envisaged that to power electrolysers there will need to be 80 – 120 GW of installed solar and wind capacity [37].

A summary of EU ambitions in renewables and clean hydrogen production can be seen in Figure 5.1.

Figure 5.1 - Timeline of renewables and clean hydrogen ambitions in the EU



The EU hydrogen strategy records a total of only 4.5 GW of projects under development that are likely to be producing at capacity by 2030. This is far lower than the 40 GW target. It is clear that investment needs to happen, and quickly, if hydrogen is to reach its potential in the EU energy transition.

In order for the EU to work as a combined force for the progression of clean hydrogen in the energy system funding is crucial. There are numerous EU funds available to all EU member states to aid in the advancement of renewable energy and clean hydrogen production. These include:

- 91 billion euros from Horizon Europe;
- 360 billion euros from the Recover and Resilience Facility;
- 30 billion euros from Connecting Europe Facility;
- 1 billion euros from the Technical Support Instrument;
- 8.2 billion euros from the European Agriculture Fund for Rural Development;
- 5.4 billion euros from the LIFE Program;
- 9.1 billion euros from InvestEU;
- 140 billion euros from the Innovation Fund;
- 10 billion Euros from the European Clean Hydrogen Partnership (to be shared with up to 10 other new partnerships for the green and digital transitions).

It is clear from the funding available that clean hydrogen and renewables are going to play a major part in the EU drive to net zero [39].

By looking into individual countries strategies and ambitions we can identify those that will be likely clean hydrogen importers in the coming years. The following countries are unlikely to be able to domestically produce enough hydrogen to meet their demand up to 2030 and beyond and are potential importers of Scottish clean hydrogen.

5.2 Germany

The German government intends to achieve total electrolyser capacity of 5 GW by 2030, ramping up to 10 GW by 2035. 9 billion euros will be invested in Germany's clean hydrogen strategy by 2030.

In June 2020 the German Government released the National Hydrogen Strategy which outlines a path for Germany to become a global leader in Hydrogen technologies. The paper identifies Germany's limited renewable generation capacities, indicating Germany will be a major energy importer in the future. Additional to existing funding, the paper provides for 7 billion euros for the ramp up of hydrogen technologies in Germany, and 2 billion euros to go towards international partnership.

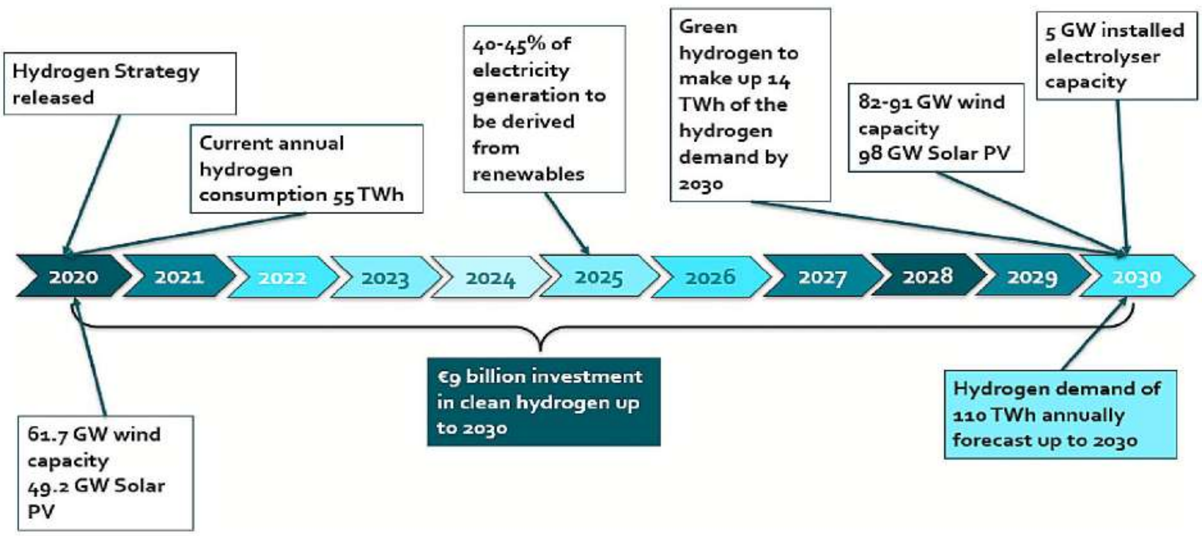
Germany currently has the highest usage of hydrogen across Europe at more than 70TWh. The German government forecasts a hydrogen demand of 110 TWh up to 2030, which would require hydrogen generation plants of 5 GW installed capacity. A further 5 GW installed capacity would be added between 2035 and 2040. Green hydrogen will make up 14 TWh of the demand up to 2030 [40].

In April 2020 the NECP released calls for a 30% share of renewable energies in the total energy consumption. Additionally, the use of renewable sources of energy will account for a 65% share of gross electricity consumption by 2030. The gross electricity consumption in 2030 is estimated at 580 TWh, of which 65% will need to be produced using renewables, this equates to approximately 200 GW of installed renewable capacity by 2030. Germany aims to have 67 – 71 GW installed onshore wind by 2030, 15 – 20 GW installed offshore wind capacity by 2030, and 98 GW installed PV capacity [41].

The German government agreed on a €130 billion stimulus package to help revive the economy in the aftermath of the coronavirus pandemic. The package was agreed in June 2020. Of the 130 billion euros, 50 billion euros is to be used to address climate change, innovation and digitisation within the economy.

A summary of German ambitions in renewables and clean hydrogen production can be seen in Figure 5.2.

Figure 5.2 - Timeline of renewables and clean hydrogen ambitions in Germany



There are numerous clean hydrogen projects, and partnerships planned and ongoing in Germany. Some of which are detailed in Table 5.1.

Germany will be an exporter of clean hydrogen technology but will be an importer of clean hydrogen. In order to secure Germany's future energy supply, they have sought to forge partnerships with other nations to establish future import opportunities. In January 2021 a partnership was announced between the Australian Smart Energy Council and Germany's energy agency (Dena). The partners will cooperate to certify, track, and authenticate hydrogen-based fuels that are produced from renewables. Australia plans to become a major producer of renewable hydrogen and sees Germany as a major consumer. This partnership will drive trade between Australia and Germany across the hydrogen supply chain.

In February 2020 Germany sought to set up a hydrogen production and import chain in a joint project with Western African countries where large-scale renewable hydrogen production may be cheaper thanks to lower population densities and better solar and wind power conditions. 15 sites will be surveyed for suitability as hydrogen production sites. 30 million euros will be invested to produce a 'potential map' for production opportunities.

Table 5.1 Clean hydrogen projects in Germany

Project	Description	Project Timeline
Hybridge	• Based in Lingen, north west Germany • 100 MW electrolyser facility will be built • Dedicated hydrogen pipeline connecting the Ruhr region • €150 million project	• 2023 – Project Commissioned
Get H2	• Project to develop a hydrogen infrastructure in Germany • Partnership between 7 companies including BP and RWE • Accelerate the use of green hydrogen in industry • Green hydrogen produced from the Hybridge project will be supplied via the existing gas network to the BP refinery in Gelsenkirchen from 2024 • The project will cover the entire hydrogen value chain from production to storage, transport and delivery	• 2022 – Project established • 2024 – Green hydrogen production to commence • 2025 – Project reach to be extended to the Dutch border • 2026 – cavern storage for hydrogen to be commissioned
AquaVentus	• 10 GW capacity offshore wind in the North Sea to power offshore electrolysis • Production capacity of 1,000,000 tonnes annually • Hydrogen will be transported to land by pipeline • Project consists of 27 companies including RWE, Shell & Vattenfall	• 2022 – framework conditions established • 2035 – project completion. Hydrogen production with 10 GW installed electrolyser capacity
Saxony-Anhalt Green Hydrogen Project	• 35 MW installed electrolyser capacity powered by wind • Green hydrogen stored in salt caverns (59 million m^3 capacity) • Hydrogen fed into nearby chemical industry gas grids • Scale up to 200 MW electrolyser capacity by 2030	• 2030 – hydrogen production with 200 MW installed electrolyser capacity
REFHYNE Project	• Based at the Shell refinery in Wesseling • 10 MW electrolyser facility with production capability of 1300 tonnes hydrogen annually • Hydrogen to be used in the refining process • Additional hydrogen to be used in transport, heating and power generation	• 2021 – Project scale up proposal from 10 MW to 100 MW • 2023 – Building to begin • 2025 – Production to commence

Cont.

Table 5.1 Clean hydrogen projects in Germany (continued)

Project	Description	Project Timeline
Moorburg Hydrogen	• Plans to transform the old coal fired power station into a green hydrogen production site • 100 MW installed electrolyser capacity will be powered by wind and solar • Close to Hamburg port for future distribution • Site is connected to the national gas transmission system and the district heating network	• 2025 – Production to begin
H2Startnetz Pipeline	• proposed by the association of Germany's gas grid operators (FNB Gas) • 1200 km hydrogen grid by 2030 to supply hydrogen from 31 green hydrogen production sites in the north of Germany • The grid would be connected to 5,900 km of existing natural gas pipeline that would be repurposed • links to Southern Germany, centres of demand in Lower Saxony and North Rhine Westphalia • Connection to The Netherlands for future import of hydrogen	• 2030 – 1200 km hydrogen pipeline grid operational
HyLand	• A concept for 'hydrogen regions' in Germany • Supporting hydrogen mobility on a regional basis • Regions will gain HyStarter, HyExpert or HyPerformer status depending on their level of knowledge and experience • HyExpert regions will receive €20 million to implement hydrogen goals. HyExpert regions will receive 300,000 euros of funding	• 2019 – Present
Hybridge	• 100 MW electrolyser facility • Based in the Lingen region • Transport of hydrogen to the Ruhr and beyond by dedicated pipeline • Some green hydrogen converted to methane and injected into gas grid	• 2023 – Hydrogen production to commence

5.3 Belgium

Belgium published its hydrogen roadmap in 2018. Belgium's 2030 target for greenhouse gas emissions is a 35% reduction compared to 2005, as outlined in the NECP. Belgian industry processed approximately 6 billion m^3 of hydrogen in 2019. Hydrogen demand is expected to be 56 TWh annually by 2030. Belgium has significant hydrogen pipelines with 613 km of pipeline serving the ports of Ghent and Antwerp. The network has interconnectors with France and The Netherlands. The network is operated by Air Liquide and has a total length across the three countries of 964 km, serving the main industrial clusters in the region. ORE Catapult engaged directly with Port of Antwerp during this study, the summary of the interview is available in Section 7.7.

Flanders published its hydrogen strategy in 2020, with a country wide strategy currently being prepared. Belgian wind and solar are not sufficiently available at present and will not be available to meet the country's energy demands in order to meet the goal of net zero in 2050. Renewable energy is currently imported and that import demand is expected to grow in the drive to net zero. In 2020 offshore wind supplied approximately 10% of Belgium's total energy demand, with approximately 2.3 GW installed capacity in 2020, producing approximately 8 TWh annually [42].

A summary of Belgian ambitions in renewables and clean hydrogen production can be seen in Figure 5.3

Figure 5.3 - Timeline of renewables and clean hydrogen ambitions in Belgium

In November 2019 a joint study consisting of seven members (The Hydrogen Import Coalition) was launched to help to coordinate delivery of projects to enhance Belgium's position in the hydrogen market and develop a hydrogen economy. Work in the study includes research into the transport, storage and production of hydrogen. The ports of Zeebrugge and Antwerp are members of the coalition, along with DEME and Engie. The study found that import of green hydrogen could be technically feasible and cost effective. By 2030 – 35 the cost of importing green hydrogen from low cost locations was projected to be €65 – 90/MWh, and by 2050 reduced to €55 – 75/MWh or less [6].

Belgium will be a clean hydrogen importer in order to meet its energy needs in the future, as such the country is aligning itself, and establishing partnerships with regions with plentiful renewable resources for future import of clean hydrogen. The Hydrogen Import Coalition investigated regions that could potentially export clean hydrogen to Belgium in the future. The report by the Hydrogen Import Coalition, Shipping Sun and Wind to Belgium is Key in Climate Neutral Economy, identified potential regions based on its ability to produce low cost renewable electricity on a large scale. These areas have plentiful space, along with excellent wind and irradiation conditions. Areas such as The Middle East, North Africa, Australia, and parts of South America were identified. Additional factors were considered including the regions political stability, and availability of seaports for the transport of green hydrogen [6]. Figure 5.4 shows the regions of potential export to the Belgian market showing possible routes for import including ports.

Figure 5.4 - Regions with potential to export clean hydrogen to Belgium [6]

Other regions in Europe were acknowledged as potential exporters including Spain and North Sea wind regions. In considering North Sea wind, the study highlighted the potential for offshore hydrogen production, with transport to shore via pipeline, thus bypassing grid constraint issues that currently impact the development of some wind farms in the region.

Although Belgium will not have the renewable portfolio to be able to meet its hydrogen demand with domestic production, it is committed to invest in hydrogen related research, to implement pilot and demonstration projects. There are ambitions for Belgium to be a hydrogen technologies exporter. The majority of pilot projects to date have been focussed on hydrogen integration in the transport sector. Some of the clean hydrogen projects, and partnerships planned and ongoing in Belgium are detailed in Table 5.2.

Table 5.2 Clean hydrogen projects in Belgium

Project	Description	Project Timeline
HYPORT	• Hydrogen production based at the Port of Ostend • Electrolyser plant powered by offshore wind that would otherwise have been curtailed • CO_2 emissions reduction of 1 million tonnes annually	• 2025 – Project operational
Flanders-Netherlands Hydrogen Fuelling Stations	• Installation of electrolysers for green hydrogen production • Hydrogen fuelling stations in the region • Built on close relationship with The Netherlands	• 2018 - Present
HyFlow/Green Octopus	• Plans to repurpose existing natural gas pipelines to create a 2,000 km 'hydrogen backbone' connecting projects and industrial clusters • The pipeline would transport and supply hydrogen between Belgium, France, Germany and The Netherlands.	• 2019 - Present
Hydrogen Buses	• Bus builders Van Hool and VDL build and export hydrogen buses	• Ongoing

5.4 The Netherlands

The Netherlands released their hydrogen strategy in June 2020. The strategy includes plans for 500 MW installed electrolyser capacity by 2025 and 3 – 4 GW installed capacity by 2030. By 2025 there will be 15,000 hydrogen powered FCEV and 300 heavy duty vehicles serviced by 50 refuelling stations. Pilot plans for urban heating are planned by 2030. The government will provide 30 – 40 million euros annually in extra subsidy for demonstration projects up to 2030 [43].

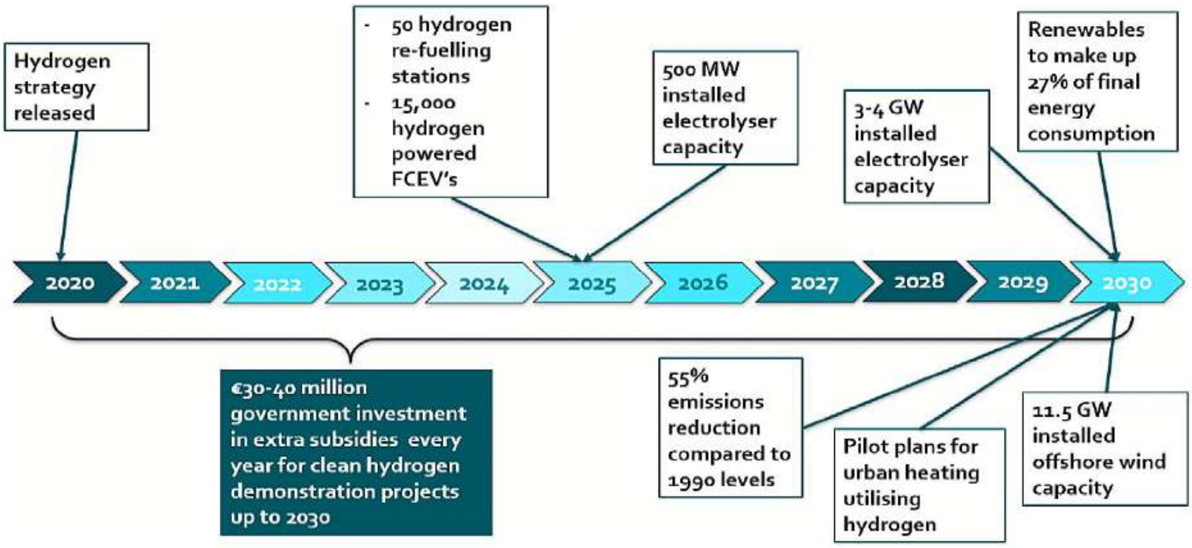
The Netherlands wants Europe to increase its 2030 emissions reduction target from 40% to 55% below 1990 levels. They intend to set up a hydrogen exchange market to support its energy transition.

Hydrogen demand in 2020 was 50 TWh, and is forecast to be 100 TWh by 2050 [8]. Currently 10% of natural gas production in The Netherlands goes to grey hydrogen production.

The government plans to have 11.5 GW of offshore wind capacity installed by 2030. This will provide part of the renewable energy required for hydrogen production. Green electricity may also be imported from Germany, Denmark and Norway via interconnectors. ORE Catapult engaged directly with the Port of Rotterdam and Groningen Seaports during this study, the summary of each interview is available in Section 7.7.

A summary of The Netherlands ambitions in renewables and clean hydrogen production can be seen in Figure 5.5.

Figure 5.5 - Timeline of renewables and clean hydrogen ambitions in The Netherlands



The Netherlands current hydrogen demand is approximately 48.8 TWh, making it the second largest hydrogen consumer in Europe. Industrial uses of hydrogen are predominantly for refineries and for the production of fertilisers and methanol. Hydrogen demand in 2030 is expected to reach 100 TWh [8].

There are numerous clean hydrogen projects, and partnerships planned and ongoing in The Netherlands. Some of which are detailed below and summarised in Table 5.3.

In April 2019 the northern provinces of Groningen, Friesland and Drenthe set out a 2.8 billion euro investment plan to transform the region into a 'hydrogen valley'. The initiative, which is also known as the HEAVENN project, has over 50 partners globally and comprises of more than 30 hydrogen projects. The ultimate aim is for a major scale up of renewable hydrogen in the next 5 – 7 years, in order to make emissions free hydrogen cost competitive in the next decade. The project won a 20 million euro subsidy, with co-financing of 70 million euros by private and public investment. The project began in 2020 and will run for six years. The aim is to develop a full green hydrogen chain in the Northern Netherlands. Upon completion the project will boast at least 10 busses, 105 cars, 10 vans, 4 refuse trucks and an inland ship all powered by hydrogen fuel cells. Green hydrogen will be supplied by 30 MW electrolyser capacity based in Delfzijl and Emmen. Green hydrogen will be provided to local industry. Existing natural gas pipelines will be repurposed to transport hydrogen between the industrial areas and hydrogen will be stored in underground storage at the Hystock storage facility in Veendam [44].

The NorthH2 green hydrogen project is based in Groningen, in the north of the country. The project aims to produce green hydrogen using renewable electricity from offshore wind. The installed offshore capacity aims to generate up to 4 GW of electricity by 2030 and potentially up to 10 GW by 2040, for hydrogen production. Initially the green hydrogen would be produced at the port of Eemshaven, potentially with offshore hydrogen production later in the project. By 2040 the aim of the project is to produce 800,000 tonnes annually of green hydrogen. The hydrogen will be transported by existing gas pipeline infrastructure in the region.

Duwaal is a project developing a green hydrogen economy in the north west of the Netherlands. The project aims to simultaneously develop the supply and demand of green hydrogen. As part of the project HYGRO will build a 4.8 MW wind turbine with an integrated 2 MW hydrogen electrolyser. There will be a storage and distribution system and 5 public filling stations.

Table 5.3 Clean hydrogen projects in The Netherlands

Project	Description	Project Timeline
Heavenn 'Hydrogen Valley' Project	• Large scale demo project • Develop a full green hydrogen value chain in the northern Netherlands from production to storage to distribution to storage to end use • €2.8 billion investment plan between the Groningen, Friesland and Denth provinces • Comprises 31 hydrogen projects with 50 partners globally • Green hydrogen production from a 20 MW electrolyser in Delfzijl, and a 10 MW electrolyser in Emmen	• 2020 – Project start • 6 year duration
North H2	• Based in Groningen • Green hydrogen production powered by offshore wind • 4 GW installed offshore wind capacity by 2030, 10 GW by 2040 • 800,000 tonnes green hydrogen production annually by 2040 • Hydrogen transported by existing pipeline infrastructure • Initial hydrogen production at Port of Eemshaven	• 2020-40 – Project Period • 2027 – first hydrogen production • 2030 – 4 GW wind powering hydrogen production • 2040 – 10 GW wind powering hydrogen production
HYGROW	• wind turbine with integrated electrolysis for the production of green hydrogen • 4.8 MW installed wind capacity • 2 MW installed electrolyser capacity	• 2020 – Feasibility study finalized • 2021-22 – Project deployment
Duwaal	• Development of a green hydrogen economy in the North-West of the Netherlands • a publicly available hydrogen transport and distribution system will be created • Integrated hydrogen production within a wind turbine (HYGROW Project) • Integrated high-pressure storage, transport and distribution system to at least five hydrogen filling stations • purchase and management of 100 hydrogen powered trucks	• 2020 – Construction of wind turbines begins • 2021 – First turbine to be operational

Cont.

Table 5.3 Clean hydrogen projects in The Netherlands (continued)

Project	Description	Project Timeline
Hysolar Project	• 2 MW electrolyser facility powered by solar PV for green hydrogen production • 250 tons of green hydrogen production annually • Public hydrogen filling station • Based in the city of Nieuwegein	• 2021 – construction to be completed and hydrogen production to begin
Port of Rotterdam Electrolyser	• Project between Shell and the Port of Rotterdam • 200 MW electrolyser capacity for green hydrogen production • Hydrogen initially used at the Shell refinery in Pernis • Potential to produce 50,000 kg green hydrogen daily	• 2020-23 – Project Period • 2021 – FID

5.5 France

Industrial hydrogen consumption in France is approximately 900,000 tonnes annually. The French hydrogen plan is aiming to integrate hydrogen into the energy system in a phased manner. Integrating hydrogen into industry will be the first step towards a green hydrogen market. Under French strategy, by 2023 10% of industrial hydrogen will be sourced from electrolysis powered by renewables. This percentage will increase to 20 – 40% by 2028. Currently France is one of Europe's major producers of ammonia. France currently produces 11% of steel in the EU. These industries would be prime candidates for the integration of clean hydrogen [45].

The French hydrogen strategy released in September 2020 commits 7 billion euros for scaling up low carbon hydrogen between 2020 – 2030. With industry currently representing the highest demand for hydrogen in France, it seems prudent that the initial focus of their hydrogen strategy is production of hydrogen to decarbonise industrial processes. Along with industry, transport and research are focus points in the strategy. Between 2020 – 2030 these three sectors will receive 3.4 billion euros of spending.

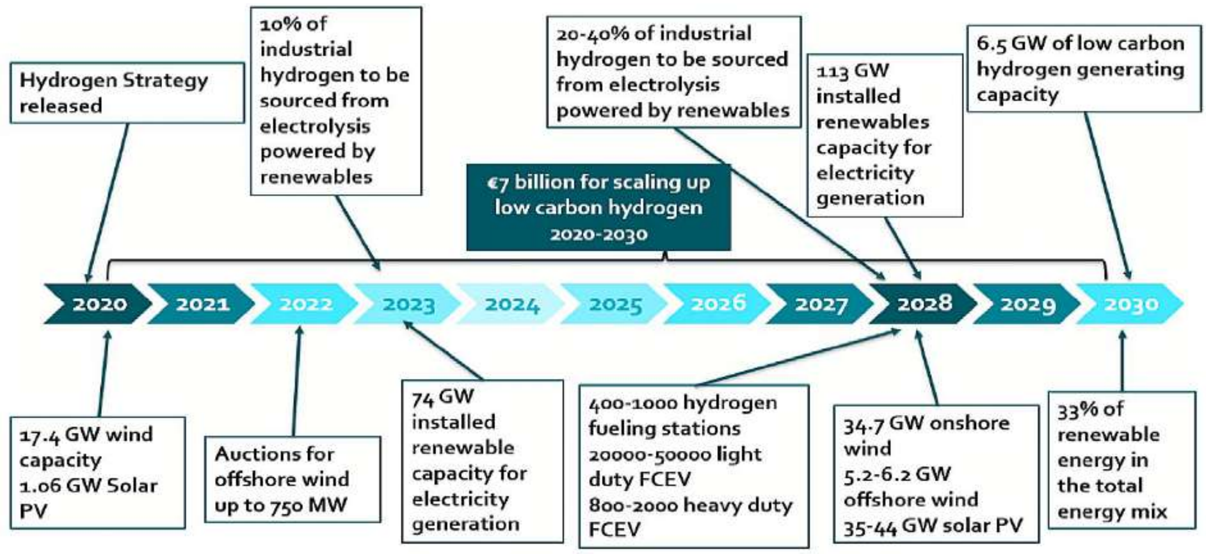
The AFHYPAC (French Association for Hydrogen and Fuel Cells) brings together the operators of the French hydrogen sector across the entire value chain and has more than 200 members. In July 2020 the AFHYPAC published a manifesto which called for governance to bring together private stakeholders and public authorities to accelerate France's position in the hydrogen economy. The manifesto called for 34 billion euros of public and private investment between 2020 – 2030. In its NECP France set out an ambitious target for hydrogen in the transport sector. By 2028 France is committed to the following; 400 – 1,000 hydrogen refuelling stations, 20,000 – 50,000 light duty FCEV and 800 – 2,000 heavy duty FCEV [45]. France estimates the production of 153 TWh of variable renewable electricity in 2030.

The French government intends for France to have 6.5 GW of low carbon hydrogen generating capacity in place by 2030, under the France Relance Covid-19 recovery plan. Out of 100 billion euros, 7.2 billion will be allocated to green hydrogen production. In October 2020 the AFHYPAC launched two tenders for projects to develop carbon free hydrogen. The first project runs until 2023 and offers 350 million euros towards building and improving systems dedicated to hydrogen production and transport. The second project is open to 2030 with 275 million euros dedicated to the large-scale role out of hydrogen.

Despite the ambitious plans for installed electrolyser capacity the French hydrogen strategy does not explicitly mention additional renewable capacity to supply the green hydrogen demand [46]. In April 2020, the NECP released calls for 33% renewable energy in the French energy mix by 2030. France aims to have 74 GW of installed renewable capacity for electricity production by 2023, and up to 113 GW by 2028. This includes plans for 34.7 GW installed onshore wind by 2028, 5.2 – 6.2 GW installed offshore wind capacity by 2028, and 35 – 44 GW installed PV capacity. France also plans auctions for large scale offshore wind by 2022, with up to 750 MW being auctioned [39].

A summary of French ambitions in renewables and clean hydrogen production can be seen in Figure 5.6.

Figure 5.6 - Timeline of renewables and clean hydrogen ambitions in France



France recognises the need for innovation and research and currently has numerous hydrogen projects ongoing. Some of those projects are detailed below and summarised in Table 5.4.

The HyPort project in the Occitanie region aims to make Toulouse-Blagnac the first airport in the world to have a hydrogen production and distribution station for all potential users. The project is supported by the EU and ADEME (The Agency for Ecological Transition) and brings together technical experts, manufacturers and users of clean hydrogen in the transport sector and in industry. The project's strategy is to integrate clean hydrogen into the economic and environmental roadmap of the Occitanie region.

Jupiter 1000, based in the Port of Marseilles, is the first power to gas demonstrator project in France. The project will produce green hydrogen from two electrolysers with 1MW combined installed capacity. The hydrogen will in part be used to produce methane (using the CO_2 produced harbour side and captured using CCUS). The methane and green hydrogen will be injected into the national gas network. Over 15 TWh of gas could be produced each year by 2050. Supported by the EU and ADEME the project costs stand at 30 million euros [47].

The Zero Emission Valley (ZEV) Project is based in the Auvergne and Rhone Alpes region. The project was launched in 2017 and is the largest hydrogen mobility project in France with plans to install 20 hydrogen fuelling stations to support 12,00 hydrogen fuelled electric vehicles in the region by 2023. There will be 4 MW of installed electrolyser capacity able to produce 400 – 800 kg/day hydrogen. The project is supported by the EU and ADEME. The project aims to make the region the first to be carbon neutral, and hopes to create profitable models that can be replicated on a European scale [48].

In January 2021 Total and Engie established a collaboration, announcing plans to create the largest green hydrogen production site in France. The site will incorporate a 40 MW electrolyser based at Total's La Mede biorefinery, close to Marseille. The electrolyser will be powered by solar farms with 100 MW installed capacity. The site will be able to produce 5 tonnes of green hydrogen per day. Construction is due to start in 2022, with production commencing in 2024.

In June 2020 Siemens and Engie announced plans for hydrogen production and storage in the Nouvelle-Aquitaine region of southern France. The project named Hyflexpower intends to produce green hydrogen from electrolysis that will be mixed with natural gas to power a 12 MW industrial gas turbine to produce power to the grid. The hydrogen – natural gas blend will increase in hydrogen percentage with the aim of ultimately powering the turbine with 100% hydrogen. The project will be commissioned in 2023.

The Les Hauts de France Project is a power to gas project aimed at installing five 100 MW electrolysers over five years, with the first coming online by the end of 2021.

In 2020 Air Liquide announced a 40% stake acquisition of H2V Normandy. H2V Normandy intends to install an electrolyser complex of 200 MW installed capacity to provide renewable and low carbon hydrogen to nearby industry by 2022. Based at port Jerome the plant will produce 28,000 tonnes of hydrogen annually, which is approximately 3% of France's yearly energy creation. Excess hydrogen not used in nearby industry will be injected into the GRTgaz network. Normandy also plays an integral role in the European Hydrogen Valleys Partnership.

Table 5.4 Clean hydrogen projects in France

Project	Description	Project Timeline
H2V Normandy	• Based at Port-Jérôme industrial zone • 200 MW electrolyser facility powered by wind and solar • 28,000 tons of clean hydrogen produced annually for industry • Excess hydrogen to be injected into the natural gas network	• 2022 – Hydrogen production due to commence
La Mede Biorefinery	• 40 MW electrolyser facility powered by 100 MW PV • 5 tonnes green hydrogen daily • Total & Engie Partnership	• 2024 – hydrogen production to commence
ZEV	• Zero emissions valley • 20 H2 fuel stations • 4 MW electrolyser, up to 800 kg green Hydrogen produced daily	• 2023 – 20 hydrogen fuelling stations to be operational
Jupiter 1000	• Based at The Port of Marseilles • 1 MW electrolyser facility • 15 TWh hydrogen produced annually by 2050 • First power to gas project in France • Hydrogen to be used to produce CH_4 • Green hydrogen and methane to be injected into gas grid up to 200m^3/hr	• 2019 – Project commissioned • 2023 – Trials due to end
Hyport	• Based at Toulouse-Blagnac Airport • Plans to integrate clean hydrogen into the Occitanie region • Hydrogen production and distribution station • Electrolyser producing 330 kg/day green hydrogen • 2 distribution stations • 4 hydrogen buses powered by the project • Future ambitions of 200 hydrogen vehicles powered by the project	• 2017 – Project Launched • 2018 – Feasibility studies conducted • 2021 – Project commissioning

Cont.

Table 5.4 Clean hydrogen projects in France (continued)

Project	Description	Project Timeline
Hyflex Power	• Partnership between Siemens & Engie • Green hydrogen production and storage plant • Nouvelle-Aquitaine region • hydrogen mixed with natural gas to power 12 MW turbine to produce power to be fed into the grid	• 2020 – Project launched • 2021 – Installation of hydrogen production and storage facility • 2022 – Installation of gas turbine and initial demonstration • 2023 – pilot demonstration with up to 100% hydrogen powering turbine
Les Hauts De France Power to Gas Project	• 5 x 100 MW electrolysers built over 5 years • Hydrogen will be injected into natural gas network • Hydrogen will also be provided for transport	• 2021 – Construction to begin • 2023 – Production to commence

5.6 North Western European Green Hydrogen Summary

Hydrogen demand in North West Europe has been estimated to be as high as 700 TWh annually by 2050. Current hydrogen demand of Germany and the Netherlands is the highest in Europe with both countries demand being over 50 TWh annually in 2019 [49].

Although many clean hydrogen projects have been announced in North West Europe there are, as yet, rarely clearly defined production volumes or project completion dates. Most regions have set clear ambitions for installed electrolyser capacity by 2030 and beyond, but have yet to published a clear timeline for the ramp up to stated capacity 2030. Germany, France and The Netherlands have published ambitions for installed electrolyser capacity by 2030. Table 5.5 details these ambitions, along with estimated hydrogen demand by 2030.

Table 5.5 Hydrogen demand estimates for 2030 for countries in North West Europe

Country	Planned Electrolyser capacity by 2030 (GW)	Hydrogen Demand by 2030 (TWh)
Germany	5	110
France	6.5	95
The Netherlands	5	100

The largest clean hydrogen projects planned globally have published their details, including in some cases planned production volumes [50]. These projects are at a GW scale. Using these projects an average hydrogen production volume per GW installed electrolyser capacity can be calculated. Table 5.6 details the largest projects and hydrogen production volumes, along with an average hydrogen production volume per GW of installed electrolyser capacity (HHV of 39.4 kWh/kg has been used to convert production volumes from tonnes to TWh).

Table 5.6 Announced GW scale clean hydrogen projects with stated hydrogen production volumes

Project	Electrolyser capacity (GW)	H2 output/yr (tonnes)	H2 output/GW (tonnes)	H2 output/GW (TWh)
ARENA	14 GW	1750000	125000	4.93
NorthH2	10GW	1000000	100000	3.94
AquaVentus	10GW	1000000	100000	3.94
Beijing Jingneng Inner Mongolia	5GW	500000	100000	3.94
Helios Green Fuels Project	4GW	240000	60000	2.36
Pacific Solar Hydrogen	3.6GW	200000	55500	2.19
HyEx	1.6 GW	124000	77500	3.05
HyDeal	67 GW	3600000	53730	2.12
Average hydrogen production per GW planned project				3.3

Scotland intends to have 5 GW installed electrolyser capacity by 2030. Using the average hydrogen production volume found above it can be estimated that with 5 GW installed electrolyser capacity, Scotland will be capable of producing 16.5 TWh of green hydrogen by 2030. The same average can be applied to calculate the volume of green hydrogen Germany, France and The Netherlands may be producing by 2030 based on their installed electrolyser ambitions. This volume can be compared to the hydrogen demand estimate for 2030 or each country, and a potential hydrogen deficit can be found. Assuming all green hydrogen from Scotland's planned 5 GW installed electrolyser capacity in 2030 were exported then the percentage of the deficit of each country that can be covered by Scottish green hydrogen can be calculated.

Table 5.7 details the percentage of hydrogen demand that could be met by Scottish green hydrogen in 2030.

Table 5.7 Scotland's potential contribution to North West European hydrogen deficit in 2030

	Hydrogen Demand by 2030 (TWh)	Planned Electrolyser capacity by 2030 (GW)	Potential domestic green hydrogen production (TWh)	Potential clean hydrogen deficit (TWh)	% covered by Scottish green hydrogen
Germany	110	5	17.5	92.5	19%
France	95	6.5	22.75	72.25	24%
The Netherlands	100	5	17.5	82.5	21%

These numbers are based on GW scale planned green hydrogen projects, and it is likely that production volumes from smaller scale projects would be lower. However, it is clear that There is a large potential market for Scottish clean hydrogen leading up to 2030 and beyond.

5.7 Japan

Japan is a global energy importer. Since the 2011 Fukushima nuclear melt down, and the decrease in reliance on nuclear power, the country has been forced to consider its future energy security.

As a resource-poor but economically and technologically advanced nation Japan is uniquely compelled to undertake the development of hydrogen in its energy system in the coming decades. The government has its sights set on the entire supply chain of clean hydrogen from production to transportation to its application in various sectors [51].

Japan was the first country to release a hydrogen strategy. The Basic Hydrogen Strategy was released in December 2017. It outlined Japans commitment to pioneer the world first 'hydrogen society'. With over $1.5 billion invested in R&D and subsidies up to 2019, Japan intends to produce clean hydrogen using imported fossil fuels and CCUS, along with electrolysis powered by renewables. Investment into import, infrastructure and domestic distribution is seen as critical, along with scaling up hydrogen use in various sectors including transport, heating, and power generation. The Tokyo Olympics will be powered using hydrogen energy.

Japan has no decarbonisation targets for industrial hydrogen. Instead, the Japanese focus is on new hydrogen technologies that will eventually become carbon free. The focus is also on new demand pathways including FCEVs power generation and residential fuel cells (enefarm), which combined are forecast to consume 300,000 tonnes of hydrogen by 2030, and 10 million tonnes per year after 2050 [51].

By 2050, industries in Japan could in theory consume 58 million tonnes of hydrogen per year according to AIST (The National Institute for Advanced Industrial Science and Technology) [52].

Japan will be an importer of hydrogen and has been engaging with Australia, Brunei, Norway, and Saudi Arabia on hydrogen procurement [51]. The Japanese government can only achieve a hydrogen society if it is successful in securing a supply of clean hydrogen. Countries with excess low cost renewable energy are seen as key future hydrogen suppliers. Critical to the success of a realised 'hydrogen society' is the reduction in cost of hydrogen production and supply. The basic hydrogen strategy sets the goal of an 80% reduction in cost in 2050 which would make the price comparable to natural gas. The hydrogen strategy emphasises that hydrogen must become carbon free sometime after 2050. Japan expects hydrogen technologies to become profitable post 2030, after which Japan will shift its focus to clean hydrogen production and procurement leading up to 2050.

The market for hydrogen equipment and infrastructure in Japan is forecast to reach $9.3 billion by 2030, and $75 billion by 2050 [53].

The natural gas pipeline system in Japan is not well interconnected and allows for a much lower % blending of hydrogen, than in Europe. The use of hydrogen in the existing pipeline system is limited [54].

Japan is a world leader in fuel cell vehicles and fuelling stations. There are currently 111 fuelling stations. This number is set to increase to 581 by 2025 and to 1,321 by 2030. In 2017 the JHyM joint venture was formed. It is comprised of over 30 participating companies and plans to build 80 new hydrogen fuelling stations by 2022. The venture will be supported by government subsidies.

Power generation will be a great driver of a hydrogen economy in Japan and could account for up to 64% of hydrogen demand in 2050 [51].

There are numerous clean hydrogen projects, and partnerships planned and ongoing in Japan. Some of which are detailed below.

The FH2R (Fukushima Hydrogen Energy Research Field) is a project that will have 10 MW of installed electrolyser capacity powered by renewables, namely 20 MW of installed PV capacity. The project aims to produce several hundred tonnes of hydrogen annually, with a 900 tonne/year maximum capacity.

In 2018 Kawasaki Heavy Industries announced a partnership with Australian electricity producer AGL, in Victoria. The project announced the construction of a liquification plant, along with storage facilities, and a loading terminal to export hydrogen produced from brown coal to Japan. The project will be commercialised by 2030 by which point CCUS will be utilised, with depleted oil wells off the coast of Golden Beach a potential storage site. Kawasaki estimates there is enough brown coal to power Japan with Hydrogen for 240 years [51]. The project is backed by the Japanese, and state of Victoria government with the project costs estimated at $469 million USD, which includes building the necessary infrastructure in Japan and shipping costs. Project details are outlined in Table 6.7.

2017 a partnership was formed between Kawasaki and a Norwegian hydrogen plant company (Nel Hydrogen). A demonstration project was planned to produce hydrogen by electrolysis, powered by hydroelectric and wind. The hydrogen would be liquified and delivered by tanker to Japan.

In 2017 a partnership between Japanese companies and Brunei was announced. Named AHEAD (Advanced Hydrogen Energy Chain Association for Technology Development) the partnership aimed to be the first demonstration project for international transport of hydrogen from Brunei to Japan. The project aimed to supply up to 210 tonnes (max) of hydrogen to be shipped in liquid form at ambient temperature and pressure (LOHC).

The imported hydrogen was used to generate power at the Yoa oil co, near Tokyo. This project was the world's first international hydrogen supply chain.

The Joint Group for Saudi-Japan Vision 2030 was established in 2016. Saudi Arabia is Japans biggest supplier of oil and is also the ninth largest producer of ammonia globally. In 2017 Japan partnered with Saudi Arabia to design a demonstration project to produce and transport hydrogen from Saudi Arabia to Japan. The hydrogen would be transferred to ammonia for transport.

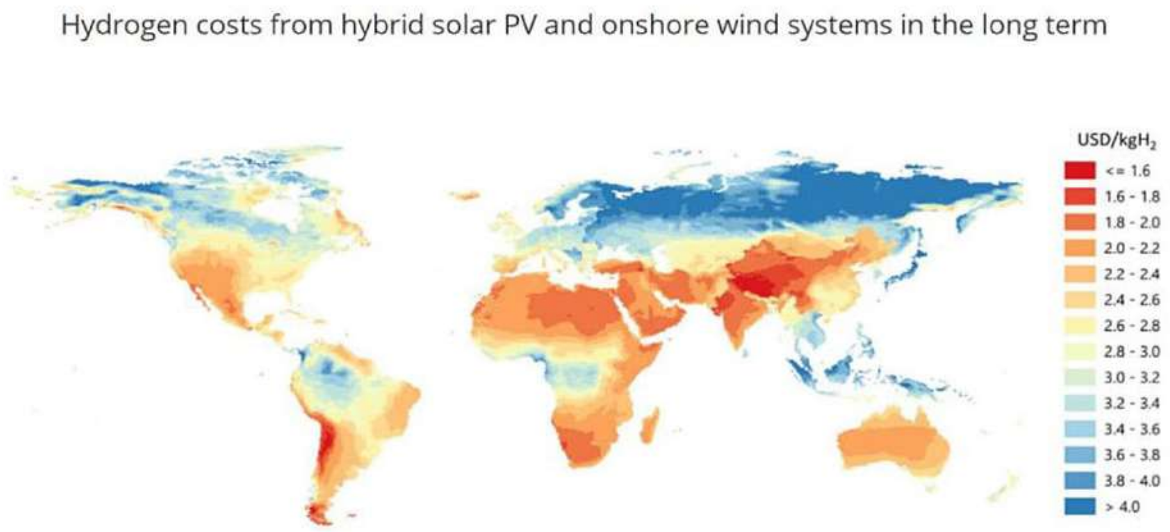
In 2020 Kitakyushu announced the "Kitakyushu City Vision for Hydrogen Society", which aims to establish a hydrogen supply chain by 2030. This follows on from a successful project which ran from 2011 – 2014, as part of the Hy-Life project initiatives. The projects were a community level demo to test the supply of by-product hydrogen, from nearby steel manufacture, to the community via pipeline. The hydrogen town community, along with the Hibikinada area will form the hydrogen supply chain, using the port infrastructure and energy facilities in the Hibikinada area to enable to import of hydrogen from overseas. The city has been recognised as the first green growth model city in Asia, by the OECD.

6. Competitor Analysis

6.1 Introduction

Countries and regions with an abundance of renewable energy resources, in the form of wind and sunlight, have the potential to harness those renewables to power green hydrogen production through electrolysis. Similarly, countries and regions with a good supply of natural gas, coupled with storage capabilities for CO_2, have the potential to produce blue hydrogen with CCUS. Those areas that are able to meet their hydrogen demands with domestic production of clean hydrogen may also be in the position to produce excess clean hydrogen and be able to establish an export market. The lower the cost of their clean hydrogen production, the higher their potential to be a competitor in the emerging hydrogen export market. Figure 6.1 shows the IEA cost forecast, by region, of green hydrogen production from wind and solar [55]. The figure does not factor in offshore wind powered hydrogen production. Those areas shown in red, orange, and beige indicate the lowest costs for green hydrogen production and as such those regions present as competitors to Scotland's future clean hydrogen export market. The regions of note that this section will focus on are regions in Southern Europe, The Middle East, North Africa, and Australia. Norway will also be assessed as a potential competitor due to its commitment to blue hydrogen production with CCUS, its abundance of natural gas, its wealth of potential CO_2 storage sites (North Sea depleted O&G reservoirs on the continental shelf), and its proximity and connections to the North West European future hydrogen market.

Figure 6.1 - Long term Hydrogen production costs powered by solar PV and onshore wind



6.2 Solar Photovoltaics (PV)

Solar photovoltaic energy or PV solar energy directly converts sunlight into electricity, using a technology based on the photovoltaic effect. Solar Photovoltaics (PV) is the third renewable energy source in terms of global capacity, by the mid 2020's it could have the largest installed capacity [56]. PV has become the cheapest source of electrical power in regions with high solar potential. These regions could potentially produce green hydrogen more cheaply and provide competition for Scotland's potential clean hydrogen export markets. Regions of note that are aligning themselves as green hydrogen exporters for the European market include North Africa, The Middle East, and countries in southern Europe including Spain and Portugal.

PV reached 627 GW of global installed capacity at the end of 2019. In 2019 the EU member states installed close to 16 GW of PV, with the rest of the continent installing approximately 5 GW. Table 6.1 shows the PV installation in 2019 by country [57].

Table 6.1 GW of installed PV in 2019 by country

Country	2019 PV installation (GW)
China	30.1
EU	16
Spain	4.4
Germany	3.9
Ukraine	3.5
The Netherlands	2.4
France	0.9
US	13.3
India	9.9
Japan	7
Vietnam	4.8
Australia	3.7
UAE	2
Egypt	1.7
Turkey	0.9

PV represents around 3 % of the global electricity demand and 5% in the EU. It is estimated that by 2030, 1,582 GW of PV systems could be installed, generating approximately 2,646 TWh/year of electricity globally, representing 9% of the global electricity demand. By 2050 over 20% of all electricity could be provided by PV [58].

The lowest cost of Solar PV was announced in Portugal in July 2019 following the country's first solar PV auction. The lowest tariff awarded was €0.0144/ kWh (approx. £0.012) [59]. Comparing this to the lowest approximate cost of UK onshore wind at £o.039/kWh [60].

IRENA released a study showing the potential reduction in the global weighted average LCOE (levelised cost of energy) from renewables between 2015 and 2025 [61]. The study found that by 2025 the LCOE from onshore wind will be less than from Solar PV. The LCOE from onshore wind is projected to be $0.05/kWh (£0.038/kWh) by 2025, whilst the global average LCOE from PV is projected to be $0.06/kWh (£0.047/kWh) by 2025. LCOE from offshore wind is projected to be $0.12/kWh (£0.093/kWh) by 2025.

Those countries or regions with abundant sunshine have the potential to produce green hydrogen by electrolysis powered by solar PV at lower cost than Scotland may be able to produce by electrolysis powered by wind. An assessment of some of these countries and regions is undertaken in this section to highlight potential competitors in the supply of low cost low carbon hydrogen.

6.3 Spain

Spain's current industrial hydrogen demand is approximately 500,000 tonnes annually, all of which is grey hydrogen. The NECP has identified 14 TWh of curtailed renewable electricity that could be utilized for green hydrogen production for commercialisation and export by 2030.

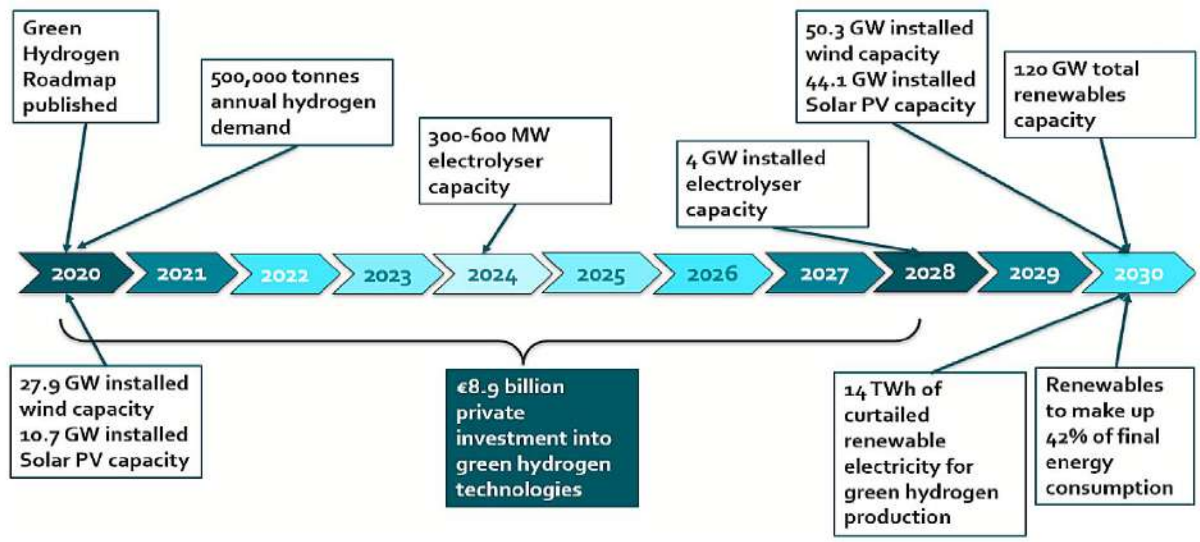
In October 2020 Spain approved a plan to boost clean hydrogen production with the green hydrogen roadmap. Spain has a well-established gas storage and transport system, combined with excellent conditions for renewable energy generation (wind and solar). Spain hopes to become a clean hydrogen exporter. By 2024 Spain intends to have 300 – 600 MW of installed electrolyser capacity, and by 2030 Spain plans to have 4 GW, with the majority of funding (estimated at 8.9 billion euros) to come from the private sector.

According to Spain's NECP, renewables will make up 42% of the total energy consumption by 2030. There will be 120 GW of installed renewable energy capacity by 2030, of which 94 GW will come from wind (offshore and onshore) and solar (PV and thermal) [62]. The aim is for Spain to become a major green hydrogen exporter.

Spain's aim to reduce energy import dependency to 59% by 2030 is very ambitious, as they had an import dependency of 74% in 2017.

A summary of Spanish ambitions in renewables and clean hydrogen production can be seen in Figure 6.2.

Figure 6.2 - Timeline of renewables and clean hydrogen ambitions in Spain



There are numerous clean hydrogen projects, and partnerships planned and ongoing in Spain. Some of which are detailed below and summarised in Table 6.2.

The Spanish power utility, Endesa, plans to have 24 green hydrogen projects under development by 2024, and to build 340 MW of electrolyser capacity. Investment into the projects will total €2.9 billion [63].

Peurtollano, in the centre of Spain, is an industrial city and is the base for the national hydrogen centre. Energy group Iberdrola is planning a large scale green hydrogen production plant that will have 100 MW installed PV capacity, coupled with a battery storage system. PEM (Polymer Electrolyte Membrane), alkaline and solid oxide electrolysis will be trialled and pressurized hydrogen storage, along with LOHC (Liquid Organic Hydrogen Carrier) will be utilised. The project will provide green hydrogen to nearby industry for their production processes. Between 2023 – 27 the region will have three more electrolyser projects added, providing 800 MW total installed electrolyser capacity by 2027, producing green hydrogen for local industry, with the excess exported. The 800 MW electrolyser capacity will contribute 20% to Spain's 4 GW 2030 ambition.

The Asturias Hub is a partnership between Enagás and Naturgy to study production of green hydrogen by electrolysis powered by onshore wind, and floating offshore wind. The project will be based in the Asturias region. Green hydrogen will be supplied to local industry, including steel making, and shipyards. Green hydrogen will also be fed into the natural gas pipelines. The floating wind element of the project will be developed by the Navantia-Windar joint venture, and will comprise of up to 24 platforms offshore. The first stage of the project will consist of a 5 MW offshore electrolyser powered by 50 MW of offshore wind, and a 100 MW onshore electrolyser facility powered by 100 MW of onshore wind. The project will be expanded to 250 MW of installed offshore wind capacity with an additional 100 MW onshore electrolyser capacity. An initial emissions reduction of 200,000 tonnes annually of CO_2 is expected. The green hydrogen will be consumed locally, distributed through the gas pipelines and exported to Europe. This project aims to establish the first European large scale green hydrogen production and transmission chains to decarbonise sectors and strengthen the European energy system, positioning Spain as a producer and exporter country [64].

Th Hysland project is a power to green hydrogen project was launched in Mallorca. It will produce more than 300 tonnes of green hydrogen per year using electricity from two PV plants with installed capacity of 6.9 MW and 6.5 MW. The project aims to assess the feasibility of sustainable transport using hydrogen, and the integration of hydrogen into the gas grid. The project will have a dedicated hydrogen pipeline. The project is the core of the European Green Hysland project which is funded by the EU, through the FCH JU (Fuel Cell and Hydrogen Joint Undertaking).

The port of Bilbao, on Spain's north coast will be the site of an e-fuels production plant in partnership with Repsol. Announced in June 2020, the plant will be one of the largest e-fuel producers in the world. CO_2 will be captured and used from the nearby Petronor refinery, and green hydrogen will be generated nearby for use.

Table 6.2 Clean hydrogen projects in Spain

Project	Description	Project Timeline
Puertollano Industrial Region	• Planned 100 MW installed PV capacity to power 20 MW electrolyser facility for green hydrogen production • Hydrogen supplied to local industry including Fertiberia ammonia plant • 3 additional projects between 2023 – 2027 • 800 MW total electrolyser capacity in the region by 2027 • €1.8 billion investment	• 2021 – Project commissioning • 2027 – 800 MW electrolyser capacity online
Asturias Green Hydrogen	• 250 MW floating offshore wind capacity powering 5 MW electrolyser facility for green hydrogen production • 100 MW on shore wind farm powering 100 MW onshore electrolyser facility for green hydrogen production • Hydrogen for local industry and to be injected into natural gas network • Green hydrogen exported to Europe • project is a candidate for the Project of Common European Interest (IPCEI) • Emissions reduction of more than 200 000 tonnes annually of CO_2 is expected	• Timeline unavailable
Power to Green Hydrogen Mallorca	• Based in Mallorca • Electrolyser facility powered by 2 PV plants with 13.4 MW total installed capacity • 300 tonnes green hydrogen annual production capacity • Green hydrogen for transport, and to be fed into natural gas grid	• 2021 – Project operational

Cont.

Table 6.2 Clean hydrogen projects in Spain (continued)

Project	Description	Project Timeline
Green Spider Initiative	• South to north green hydrogen network • Green hydrogen shipped to Germany and The Netherlands as LOHC	• Timeline unknown
Green Crane Initiative	• Cross border flow path for green hydrogen between Spain and Italy • Green hydrogen shipped in the form of LOHC, and transferred as compressed gas by pipeline • 80 tonnes/day hydrogen • Future connections to France and The Netherlands	• 2019 – Project development • 2024 – Project Finalisation

6.4 Portugal

Portugal is one of the leading EU countries in renewables, it does not produce coal, crude oil, or natural gas. Portugal aims to develop its hydrogen potential to remain a leader, by using hydrogen to help decarbonise sectors including transport, heating and cooling, and electricity. The gas and electricity sectors have the same regulator and the same transmission operator. This will allow for a streamlined, integration of hydrogen on a national level.

The Portugal national hydrogen strategy (EN-H2) was enacted in August 2020. It sets out ambitious targets to be achieved by 2030 including:

- 2 – 2.5 GW installed electrolyser capacity;
- €7 – 9 billion investment in new hydrogen projects;
- €1 billion in investment and production support;
- €380 – 740 million reduction in natural gas imports;
- 50 – 100 refuelling stations;
- 1% consumption of treated wastewater for electrolysis.

With its hydrogen strategy Portugal aims to give hydrogen a central role in the journey to net zero in 2050. This includes hydrogen being used to decarbonise transport, and steelworks, as well as being fed into natural gas stream (up to 22%).

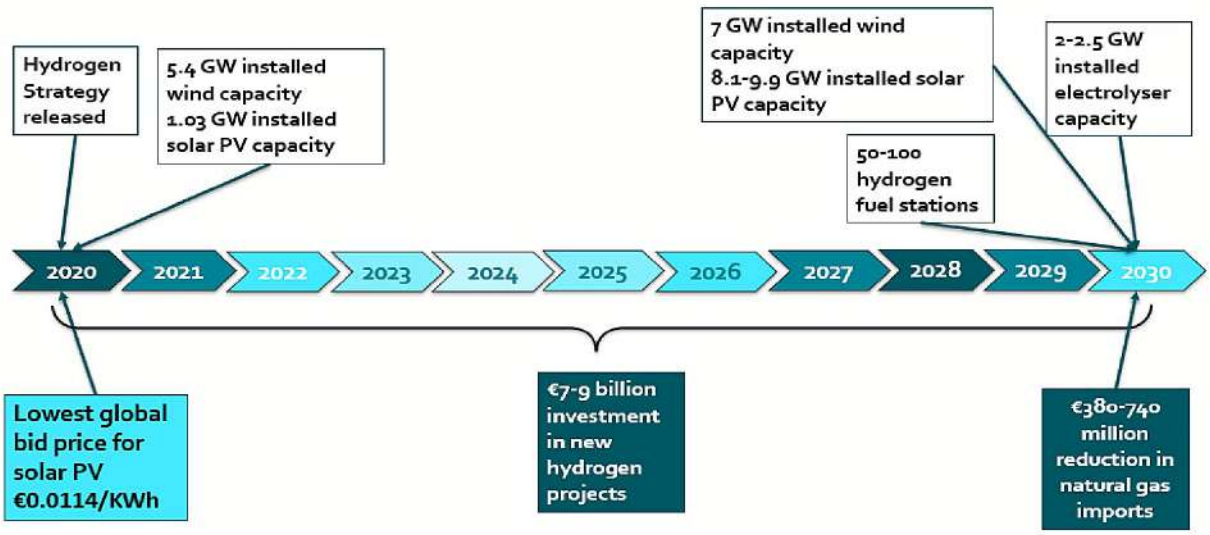
The national hydrogen strategy highlights the importance of partnership with other EU states, namely the Netherlands, Germany, and Luxembourg, along with partnership and collaboration with countries outside the bloc including Japan and Canada.

Portugal intends to increasingly become an energy exporter and exports will be shipped from the port of Sines. Pipelines will also be used for transport, connecting the Iberian Peninsula to the rest of Europe. Existing pipelines are said to be 70% ready to distribute hydrogen.

Portugal is preparing an application to Europe's Important Project of Common European Interest (IPCEI) scheme for hydrogen. There are 37 projects being considered in the second phase of the application process, representing 9 billion euros of potential investment.

A summary of Portuguese ambitions in renewables and clean hydrogen production can be seen in Figure 6.3.

Figure 6.3 - Timeline of renewables and clean hydrogen ambitions in Portugal



Portugal has the lowest bid for large scale PV project at €0.0114/kWh. Portugal had 1.03 GW of installed PV capacity by the end of 2020. 2 GW of solar capacity has been allocated for PV auction in the first two rounds by the Portuguese government. By 2030 there will be up to 9.9 GW of installed solar PV capacity. With its abundant renewable resources Portugal is aligning itself to be a major exporter of cost competitive green hydrogen.

The green hydrogen project in Sines will be a solar powered hydrogen production plant that will have at least 1GW installed electrolyser capacity by 2030. The project is in partnership with the Netherlands. A pilot project has been planned with an early-stage installation of 10 MW capacity electrolysers. The electrolysers will be supplied with renewable electricity from 1.5 GW of installed solar capacity. The plant aims to begin producing as early as 2023.

There are numerous clean hydrogen projects, and partnerships planned and ongoing in Portugal. Some of which are detailed in Table 6.3.

Table 6.3 Clean hydrogen projects in Portugal

<table>
<tr><th>Project</th><th>Description</th><th>Project Timeline</th></tr>
<tr><td>Sines Green Hydrogen</td><td>• Solar powered green hydrogen production plant
• 1 GW installed electrolyser capacity by 2030
• Powered by 1.5 GW installed PV capacity
• Export of green hydrogen via the Port of Sines
• 465,000 tonnes annual green hydrogen production potential</td><td rowspan="2">• 2021 – Construction work to commence
• 2023 – solar panel factory and electrolyser parts factory constructed
• 2025 – 1 GW of solar installed and operational and hydrogen production commencing
• 2030 – 1 GW installed electrolyser capacity operational</td></tr>
<tr><td>Green Flamingo</td><td>• Connecting the Sines Green Hydrogen Project with the Port of Rotterdam for export of green hydrogen from Portugal
• Developing a strategic export-import value chain
• Memorandum of understanding signed between the Dutch and Portuguese governments in 2020
• Potential to ship hydrogen from Rotterdam into Germany down the Rhine to supply the German market</td></tr>
</table>

6.5 Norway

Norway has the potential to be a major exporter of blue hydrogen with CCUS, as they are at the forefront of CCUS technologies. The country is the third largest exporter of natural gas globally. This coupled with ample potential storage on the continental shelf, puts Norway in a very favourable position to develop a clean hydrogen market and become an exporter in the future.

Norway released its hydrogen strategy in June 2020, following the announcement, in May, of a green package investment of £300 million. Norway recognises hydrogen's potential in aiding to decarbonise its transport, mining and industry sectors, which account for more than 50% of the country's total carbon emissions. In Norway's Energy21 strategy hydrogen is recommended as a focus area for research, development and commercialisation of low carbon technologies.

Three main institutions will oversee, manage and encourage the adoption of hydrogen. They are; The Norwegian Research Council, Innovation Norway and Enova, all of whom are researching the production, transport and storage of hydrogen. Norway sees a future for green and blue hydrogen (with CCUS) as the Norwegian continental shelf has been identified for potential CO_2 storage. Power delivered through electrolysis will be exempt from electricity tax to increase cost competitiveness and encourage growth in electrolysis technology to help drive down costs. There are plans to make hydrogen fuel cell vehicles purchased up to 2023 VAT exempt. The flat CO_2 tax will be increased by 5% every year up until 2025 in all sectors.

Norway has great ambitions to adopt hydrogen in its maritime sector. Over £10 million has been invested into hydrogen powered speedboats. Studies are ongoing to determine the infrastructure requirements for large scale adoption of hydrogen vessels[3]. The Norwegian government sees the need for more pilot and demonstration projects that will contribute to technology development, commercialisation and scaling ability.

Norway is very forward thinking in terms of renewables. There is a high proportion of renewable energy in its energy mix. Close to 100% of electricity production is from renewable sources, and 69% of Norway's total energy consumption is from renewables. The vast majority of Norway's renewables are from hydropower. They are the largest hydropower nation in Europe with 31 GW of installed capacity.

Norway has ambitions of developing its floating solar technology. Ocean Sun is a Norwegian company currently developing a floating solar plant for a reservoir in Albania.

Norway is the eighth largest oil exporter and third largest natural gas exporter thanks to these resources. This accounts for 40% of the country's total exports and 17% of GDP.

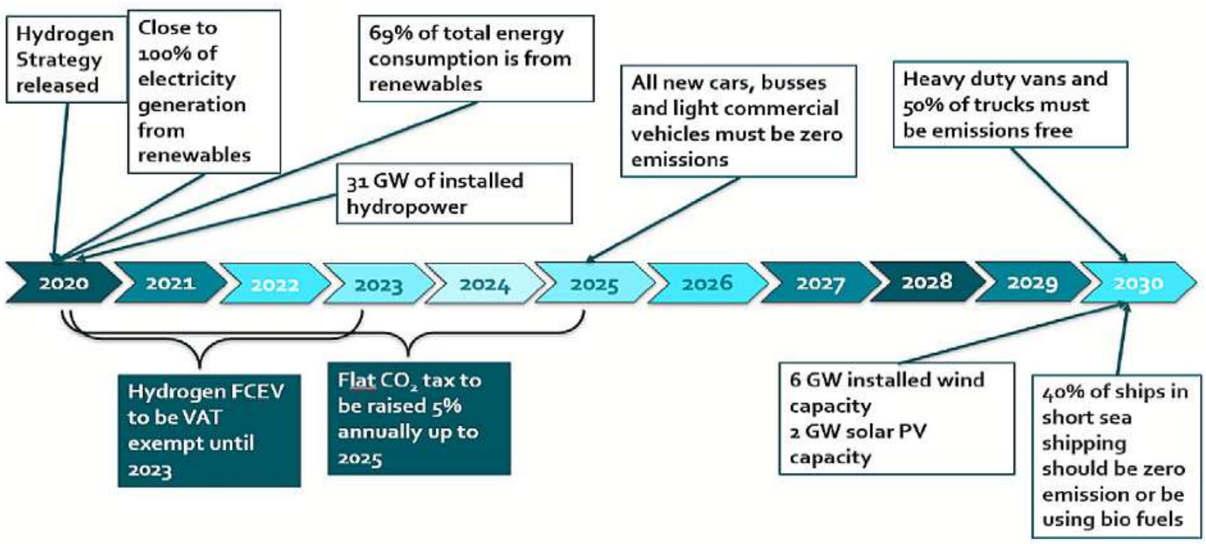
Norway imports electricity from Germany, Denmark and The Netherlands when there is excess wind and the prices are low. In this way the consumption of dispatchable hydroelectricity is reduced, which can be exported instead.

Norway is working on building interconnectors with the UK and Germany. This will allow Norway to export even more excess electricity production than it currently does. The North Sea Link (NSL) will connect the electricity systems of Norway and the UK with high voltage subsea cables from Kvilldal to Blyth. The link will increase energy security, provide additional transmission capacity for electricity trade and afford opportunities for shared use of renewable energy between the two countries. NSL will be the longest subsea interconnector in the world, at 720 km long, when it becomes operational later in 2021. In 2016 Norway exported 16.5TWh of electricity which accounted for approximately 10% of total domestic production.

One third of new cars bought in Norway are electric and Norway is the world's second largest market for electric vehicles. By 2015 there were more than 50,000 electric cars on the road in Norway. By 2025 all new cars, busses and light commercial vehicles must be zero emissions, either all electric or hydrogen vehicles. By 2030 heavy duty vans and 50% of trucks must be emissions free. In shipping by 2030, 40% of ships in short sea shipping should be zero emission, or be using bio fuels [65].

A summary of Norwegian ambitions in renewables and clean hydrogen production can be seen in Figure 6.4.

Figure 6.4 - Timeline of renewables and clean hydrogen ambitions in Norway



There are numerous clean hydrogen projects, and partnerships planned and ongoing in Norway. Some of which are detailed in Table 6.4.

Project	Description	Project Timeline
Deep Purple	• Plans to produce green hydrogen from offshore wind • The hydrogen will be produced offshore and stored in pressurized tanks on the seabed • Hydrogen can be delivered by pipeline to shore	• 2016 – Project began • 2021 – Subsea connection system fully qualified • 2020 – Large scale onshore pilot • 2025 – Full scale offshore pilot project operational
Northern Lights	• CCS demonstration project • CO_2 pipeline to offshore North Sea storage complex • Establish Norway as safe storage of CO_2 from Europe • Project will be able to receive, transport and store 5 million tons CO_2 annually • Equinor is executing the project. Shell and Total are equal partners • Commercial scale by 2024	• 2016 – Feasibility studies • 2020 – confirmation well drilled • 2020 – Investment decision made by Shell, Equinor and Total • 2024 – Project fully operational
Yara Large Scale Green Ammonia	• Plan for production and export of green ammonia • Electrification and decarbonization of Yara's existing ammonia facility at Porsgrunn • Renewable electricity and green hydrogen to be utilised • 500,000 tonnes green ammonia produced annually • Project will be realized in 5 – 7 years	• 2021 – Letter of intent signed between Yara, Aker Horizons and Statkraft • 2026 – Project operational
Green Giant Hydrogen Ferry	• Norway and Denmark to build a hydrogen fuel cell powered ferry by 2027 • 1800 passengers, 380 cars or 120 trucks between Oslo and Copenhagen	• 2027 – Ferry operational
North SEA Link (NSL)	• 720km long subsea interconnector between Norway and the UK • Provide additional transmission capacity for electricity trade	• 2021 – Interconnector operational

6.6 Middle East and North Africa (MENA)

The MENA Hydrogen Alliance was launched in 2020 with the intention of accelerating the development of value chains for green hydrogen in the region. The alliance brings together private and public sectors as well as academia. The alliance seeks to engage stakeholders on the production, transport and use of green hydrogen, including exporting green hydrogen to world markets, including Europe. The alliance seeks to foster a regional partnership between Europe and MENA to accelerate the deployment of green hydrogen projects [66]

According to the International Energy Agency (IEA) clean hydrogen will be significantly cheaper to produce in North Africa than in Europe. Green hydrogen will be approximately 40% lower cost to produce in North Africa, and blue hydrogen will 35% lower cost than in Europe [55]. Table 6.5 shows the projected costs for clean hydrogen in Europe and North Africa.

Table 6.5 Clean hydrogen production costs by region in 2030

	Green Hydrogen (£/kg)	Blue Hydrogen w/CCS (£/kg)
Europe	**2.4** ($3.1 USD)	**1.8** ($2.3 USD)
North Africa	**1.5** ($1.9 USD)	**1.2** ($1.5 USD)

Morocco is the most active of the North African nations, in terms of planning for a hydrogen economy, and commitments to renewables. It is also the only north African country that has a power cable link to Europe. In 2019 it became a net exporter of electricity to Spain.

The National Hydrogen Commission was set up in 2019, and Morocco has developed a national roadmap for hydrogen energy. Over the past decade $5.6 billion has been invested in meeting the country's climate objectives. By 2030 52% of the Morocco's energy will be sourced from renewables, and by 2050 there is potential for 96% of electricity to be produced from renewables.

Morocco has significant potential for growth in wind and solar PV capacity. As of 2020 there are 1.2 GW of installed wind capacity, and 0.7 GW of installed solar PV capacity.

There is potential for green hydrogen to be used in the production of fertilisers which are one of the country's biggest exports. Morocco has over 70% of the worlds phosphate reserves and is the world's leading exporter of fertilisers.

Morocco has ambitions to become a world leader in the production and export of green hydrogen by 2030, namely in the form of green ammonia and green methanol, seeing potential to capture 2 – 4% of the global hydrogen market.

In June 2020, an agreement was signed between Morocco and Germany to link the Port of Tangier to the Port of Hamburg for the future transport of green hydrogen to Germany. The partnership aims to develop the production of green hydrogen in Morocco, and implement research and investment projects [67].

Morocco is investing heavily in and advancing its solar PV portfolio. Some of the current projects are detailed in Table 6.6.

Table 6.6 Clean hydrogen projects in Morocco

Project	Description
Moroccan Solar Plan	• 5 x large scale solar power plants with 2 GW capacity by 2030 • Solar thermal, PV and concentrated solar combination
Noor CSP	• Part of the Moroccan Solar Plan • The largest concentrated solar power (CSP) station in the world • complex of four linked solar plants • 510 MW solar park • The plant will be able to store solar energy in the form of heated molten salt, allowing for electricity generation at night • The total project's cost is approx. $2.5 billion
Midelt Solar Power Plant	• 400 MW CSP + PV • Operational by 2021

Saudi Arabia boasts the largest renewables project in the world, the NEOM Project. On 8 July 2020, Air Products announced that it will build the world's largest green hydrogen project in Saudi Arabia.

The project is supported by the German Hydrogen Strategy. The German government has set aside nine billion euros for implementing its hydrogen strategy, two billion euros of which are for selected projects in partner countries, including the NEOM project, which is due to be completed by 2025.

The aim of the project is to produce green hydrogen for domestic transportation, and export green hydrogen to the European market in the form of green ammonia. The 20 MW capacity electrolyser facility will have daily production capacities of 650 tonnes of green hydrogen. The ammonia plant will produce 3,000 tonnes of green ammonia daily, and annual green ammonia production will be 1.2 million tonnes. The project will be powered with 4 GW of installed solar PV and wind capacity [68].

6.7 Australia

Australia has vast natural resources, along with plentiful land mass and a history as an energy exporter. As with most regions, hydrogen is currently predominantly used as a raw material for industrial processes. Hydrogen is seen as having potential to reduce Australian emissions in industry, as well as having applications in the transport sector. A report released in 2018, Opportunities for Australia from Hydrogen Exports, estimates that the global demand for hydrogen could be worth up to $10 billion to the Australian economy by 2040 [69].

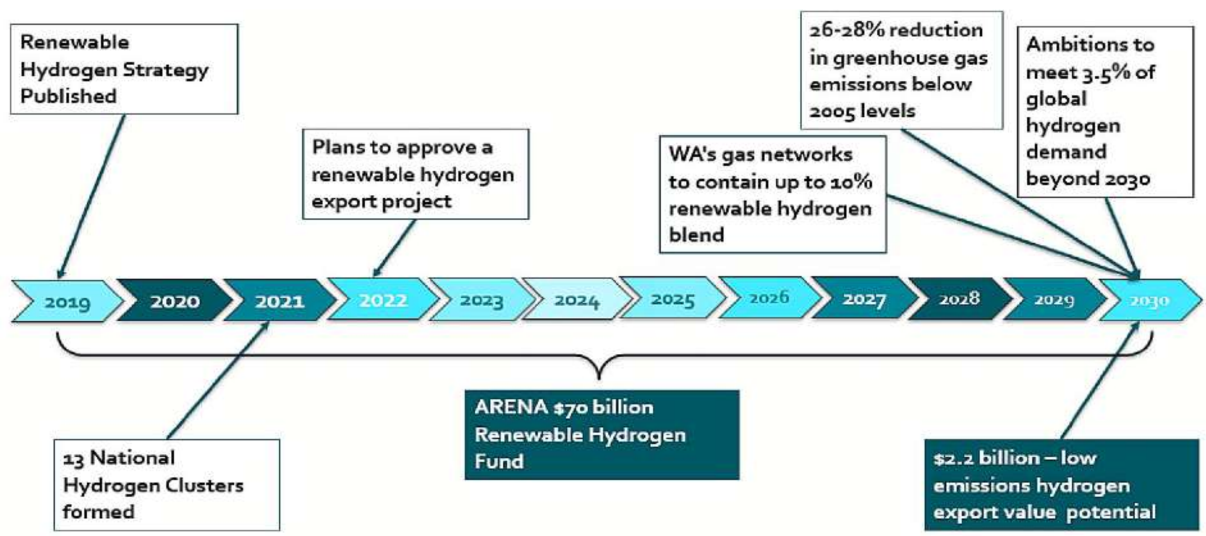
The National Hydrogen Roadmap was released in 2018 to provide a blueprint for the development of a hydrogen industry in Australia. The report highlights the hydrogen export potential for Australia. The potential hydrogen demand of Asian countries could amount to 3.8 million tonnes in 2030, worth approximately $9.5 billion Australian Dollars (AUD). The report estimates that a hydrogen production price of $2 – 3/kg AUD (£1.1-1.7) will need to be achieved in order for Australia to be able to compete with other hydrogen exporting countries [70].

In January 2021 it was announced that the National Energy Resources Australia (NERA) had set up 13 clusters across Australia to identify gaps in developing and commercialising hydrogen. The clusters focus is towards the development of technologies for the storage and distribution of hydrogen [71].

ARENA has a $70 million (AUD) Renewable Hydrogen Deployment Fund grants program to help fast track the development of renewable hydrogen in Australia. The fund will support the commercial-scale deployments of renewable hydrogen in Australia. In 2020 it was announced that seven companies had been shortlisted to benefit from the fund. All the companies have well developed renewable hydrogen projects that involve deploying 10 MW or larger electrolysers, made up of various end uses. Four of those projects are based in Western Australia [70].

A summary of Australia's ambitions in renewables and clean hydrogen production can be seen in Figure 6.5.

Figure 6.5 - Timeline of renewables and clean hydrogen ambitions in Australia



Western Australia is aiming to be a significant player in the global hydrogen market. It has long been a region for oil and gas production and mining operations due to its vast oil and gas reserves, and mineral deposits. The region has an abundance of renewables and is already developing a hydrogen supply chain in order to position itself in the emerging market.

The Western Australian Renewable Hydrogen Strategy and Roadmap was released in November 2020. It was established to invest $22 million (AUD) in initiatives to harness Western Australia's (WA) competitive advantage, to accelerate and achieve renewable strategy targets by 2030. The roadmap identifies 26 initiatives the WA Government is supporting, through investment and legislation, to realise the WA Renewable Hydrogen Strategy's vision, mission and goals. The strategy aims to position WA as a significant producer, exporter and user of renewable hydrogen. The strategic focus areas are; export, remote applications, hydrogen blending into the natural gas network and transport. $1 million will go towards developing a detailed supply chain model to review potential bottlenecks and factors affecting the green hydrogen export industry [72].

The Renewable Hydrogen Strategy plans to approve a project to export renewable hydrogen by 2022, and by 2030 aims to have a market share in global renewable hydrogen export similar to its share in LNG export currently. The value of Australia's potential low-emissions hydrogen exports could reach $2.2 billion by 2030 and $5.7 billion by 2040 [73].

There are a number of ongoing clean hydrogen projects in Western Australia. They are detailed below and summarised in Table 6.7

Table 6.7 Clean hydrogen projects in Australia

Project	Description	Project Timeline
Asian Renewable Energy Hub	• Based in the Pilbara region, WA • Green hydrogen and green ammonia production facility • 26 GW installed wind and solar PV capacity • 14 GW installed electrolyser capacity • Up to 100 TWh of electricity for hydrogen production when fully operational • 1.8 million tonnes annual hydrogen production potential • Green hydrogen and ammonia for local use and export • Pilot shipments of green hydrogen to Japan by 2021	• 2014 – Project proposed • 2020 – Granted major project status • 2025 – FID due • 2026 – Construction to begin • 2027 – Operations to come online • 2028 – First exports
Yuri Green Ammonia	• Based in Pilbara, WA • Accounts for 5% of global ammonia production • Phase zero consists of 10 MW PV powering electrolyser facility. 625 tonnes green hydrogen, 3500 tonnes of green ammonia production potential annually • Phase one plans for 500 MW installed solar PV capacity to power and electrolysis facility for green hydrogen and ammonia production • green hydrogen and ammonia for fertiliser plant, and for export to global markets • 850,000 tonnes annual green ammonia production potential	• 2022 – Phase zero operational. • 2030 – Project phase one fully operational

Cont.

Table 6.7 Clean hydrogen projects in Australia (continued)

Project	Description	Project Timeline
Murchison Renewable Hydrogen	• Based in Kalbarri, WA • 5 GW green hydrogen project powered by wind and solar PV • Partnered by Copenhagen Infrastructure Partners (CIP). Technology Partner is Siemens • Green hydrogen for export • Phase 1 demonstration phase providing hydrogen for transport applications • Phase 2 project expansion with hydrogen blending in natural gas grid • Phase 3 project expansion producing hydrogen for export	• 2019 – Stakeholder engagement process • 2028 – Project operational
Arrowsmith Hydrogen Project	• Based in Dongara, WA • 110 tonnes green hydrogen production daily • Powered by 85 MW solar PV, and 75 MW wind.	• 2020 – Construction begins • 2020 – Project operational
The Hydrogen Energy Supply Chain (HESC)	• Based in Victoria • Clean hydrogen production by the gasification of lignite, with CCS • Project supported by Japan • Aims to export clean hydrogen to Japan • Annual production capacities of 5000 tonnes of clean hydrogen and 18000 tonnes of clean ammonia • Gasification plant in the Latrobe Valley and Liquification facility at the Port of Hastings	• 2017-18 – Planning and approvals process • 2020 – Pilot construction • 2021 – Pilot operation **Decision to proceed to commercial phase depends on Pilot results**

The Asian Renewable Energy Hub was awarded major project status in 2020. The Hub, based in Pilbara, Western Australia, plans to use solar and wind farms in the Pilbara region to produce green hydrogen for export. The first phase of the project aims to install 15 GW of solar and wind capacity, scaling up to 26 GW after 2026. The generated electricity will power electrolysers to make green hydrogen. The wind and solar farm will cover 6,500 km2, and will produce more than 50 TWh of electricity to power green hydrogen and ammonia production. Plans are in place to export hydrogen internationally to South Korea, Germany and Japan, with Japan due to receive shipments starting in 2021. The green hydrogen will be converted to ammonia for transport from Pilbara's iron ore ports [74].

Yara's ammonia site in Pilbara, Western Australia, accounts for 5% of the world's ammonia production. In January 2021, the Western Australia state government announced a $2 million investment from the Renewable Hydrogen Fund (RHF) for the Yuri green ammonia project on the Burrup peninsula. Yara's fertilizer plant is currently run off natural gas. The plan is for initial installation of a 10 MW solar farm and electrolyser to provide hydrogen to fuel the plant. Expansion to 500MW by 2030 is planned to produce green hydrogen which will be converted to green ammonia for export to global markets [75].

The Murchison Renewable Hydrogen Project, based in Kilbarri, Western Australia, is a 5 GW electrolyser project powered by wind and solar PV. Green hydrogen produced will be exported to the Asian markets [76]

The Arrowsmith Hydrogen Plant, based in Dongara, Western Australia, is due to commence producing green hydrogen by 2022. The first stage will have a daily production capacity of 25 tonnes of green hydrogen. The second stage will have a daily production capacity of 110 tonnes. A 50 – 60 MW electrolyser facility will be powered by 164 MW installed wind and solar PV capacity. The green hydrogen production will support the development of hydrogen FCEVs by supplying compressed and cryogenic hydrogen [77].

South Australia has vast reserves of brown coal which, when gasified, with CCUS, has the potential to provide the region with clean hydrogen production for export. The Hydrogen Energy Supply Chain (HESC) aims to produce up to 5,000 tonnes of clean hydrogen, and 18,000 tonnes of clean ammonia annually, for export. The region has geological storage potential for CO2 in the Gippsland basin. The project should start commercial scale production in the early 2030's.

6.8 Chile

Chile has committed to phasing out coal fired power by 2040 and aims to be carbon neutral by 2050. By 2025 chile wants to produce 20% of its power from renewables. By 2030 that will rise to 60%, and by 2050, 70% [78]. As of 2018 approximately 6.5% of the country's energy mix was met by solar farms, and 2% was met by wind.

Chile has an abundance of renewable resources. The Atacama Desert in the north of the country boasts the highest solar irradiance on the planet and has more than 3,000 sun hours annually. Patagonia in the south has strong and consistent winds.

Chile released its National Green Hydrogen Strategy in November 2020. According to the strategy the country, due to its abundant renewable energy, has the potential to become the cheapest producer of green hydrogen globally [79]. The strategy seeks for chile to export its renewable energy in the form of green liquid hydrogen, green ammonia and synthetic fuels.

Chile sees scope for integrating green hydrogen into its transport, mining and agricultural sectors, and hopes to be able to build a green hydrogen export market in order to achieve economies of scale that make the country competitive.

Chile's green hydrogen strategy is broken down into three stages, or waves, the first of which involves replacing imported ammonia with domestically produced green ammonia, along with replacing grey hydrogen as a refinery feedstock with green hydrogen. Green hydrogen will also be implemented in heavy, and long-distance transport, including long distance buses. Green hydrogen will begin to be blended into the natural gas grids, up to 20% by volume. The first wave will run from 2023-2025.

The second wave will see the emergence of a green hydrogen export market, initially in the form of green ammonia with some green hydrogen. Green hydrogen blended into the natural gas grids will become economical. Green hydrogen will be more widely implemented in the transport sector and will be utilized by heavy machinery in the mining sector. The second wave will run from 2028-2030.

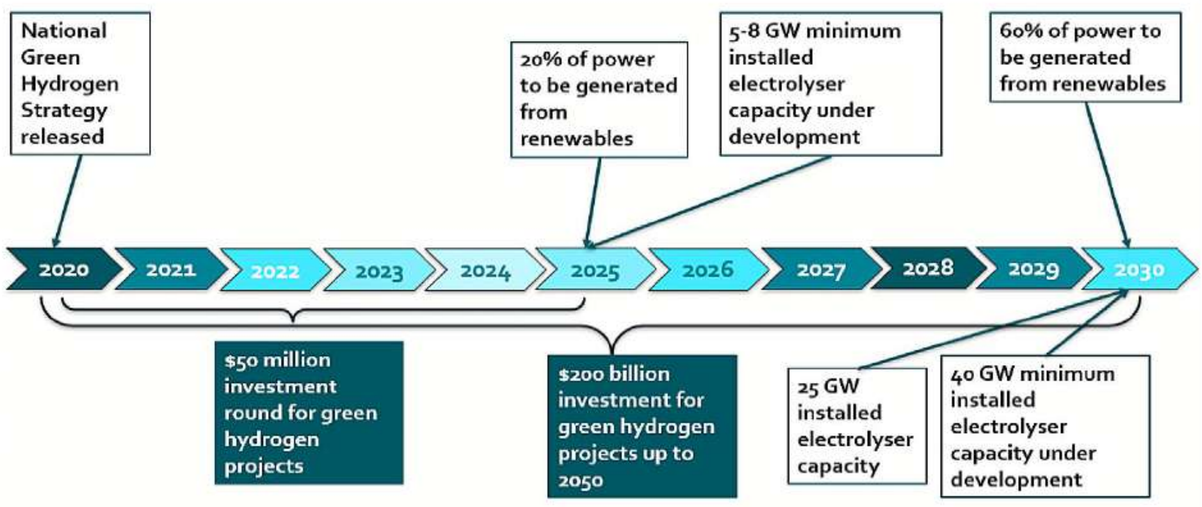
The third wave sees an expansion of green hydrogen export markets. Fuels derived from green hydrogen will be used to decarbonise maritime and aviation.

The market potential for green hydrogen could be as large as $1 billion USD by 2025, with an associated renewable installed capacity of 5-8 GW. By 2030 the market could be worth $5 billion USD, with $3 billion of that being generated through green hydrogen export. This market would require 40 GW of installed renewables capacity. By 2050 the market could be worth $33 billion USD, $24 billion of which being generated through exports. This goal would require associated renewables installed capacity of 300 GW. The IAE estimates that by 2050 Chile could produce up to 160 million tons of green hydrogen annually [80].

The Atacama Desert in the Antofagasta Region, Northern Chile has more than 3,000 sun hours annually and making it one of the best solar resource in the world. IRENA assumes a levelized cost of hydrogen as low as $2.7/kg (£2.1) currently, reducing to $1.4/kg (£1.1) by 2030. The central Metropolitan region of Chile has the potential to produce green hydrogen with solar PV with a LCOH of $1.8/kg (£1.4) by 2030. These LCOH are the lowest costs globally projected for green hydrogen by 2030. They do not take into account storage and transportation costs. The strong winds of Patagonia in the south of Chile have the potential to power green hydrogen production with a LCOH of $1.3/kg (£1.0) by 2030. Green hydrogen produced in Chile is going to be the lowest cost green hydrogen globally.

A summary of Chile's ambitions in renewables and clean hydrogen production can be seen in Figure 6.6.

Figure 6.6 - Timeline of renewables and clean hydrogen ambitions in Chile



Despite Chile's ambitions to be a global leader in green hydrogen production and export, green hydrogen production projects are still in their infancy. Some pilot and demonstration projects are detailed below.

A Memorandum of Understanding (MOU) has been signed between the Port of Rotterdam and the Chilean Ministry of Energy, in March 2021. The MOU is intended to pair the green hydrogen demands of The Netherlands with the supply potential Chile presents [81].

There are over 40 projects related to green hydrogen currently ongoing in Chile [82]. One such project is the Haru Oni Project. Partnered by Siemens Energy the project will be a large-scale, e-fuels plant based in the Magallanes region. Electrolysis powered by wind will provide the green hydrogen feedstock for e-methanol, and e-gasoline production. The pilot phase, which is due to run until 2022 will produce 750 litres of e-methanol annually, some of which will be converted to e-gasoline. By 2024 production capacity will be 55 million litres of e-gasoline annually, that production capacity will rise to 550 million litres annually by 2026. The project is being co-funded by the German government, and fuel will be exported to Europe as well as other regions [83].

The HyEx Project, based in the Antofagasta region, will comprise of a 2GW solar PV farm to power a 1.6 GW installed capacity electrolyser facility to produce green hydrogen. the plant will produce 124,000 tonnes of green hydrogen annually which will be supplied to an ammonia plant with production capacities of 700,000 tonnes of green ammonia annually, for domestic use and export. A pilot plant with production potential of 18,000 tonnes of green ammonia annually will be operational by 2024, full scale operation is due by 2030 [84].

Electricity producer AES Gener announced plans in March 2021 to produce green ammonia. An MOU has been signed with an international hydrogen producer to conduct a feasibility study. The project has potential for 800 MW installed wind capacity to power green hydrogen production for the green ammonia feedstock [85].

6.9 Canada

Canada has an abundant fossil fuel reserves, as well as excellent CO2 storage geology. The country also has an abundance of renewable reserves. Canada is a world leader in hydrogen, fuel cell and CCS technologies.

Canada is currently one of the top ten hydrogen producers globally and produces approximately 3 million tonnes of grey hydrogen via SMR from natural gas annually.

Canada published its hydrogen strategy in December 2020. The strategy outlines the path to net zero by 2050. The strategy lays out a framework to position Canada as a future world leader in renewable fuels. The next 30 years are laid out in 3 stages in the strategy, looking at the near-term from 2020-2025, the mid-term from 2025-2030, and the long term 2030-2050. The ultimate aim is to establish a hydrogen economy in the country. It is estimated that by establishing a full hydrogen economy in Canada a direct revenue of $50 billion CAD annually by 2050 could be realised [86].

The Strengthened Climate Plan, released in 2020, outlines a $1.5 billion CAD fund for low-carbon and zero-emissions fuels.

The near-term stage of the strategy focuses on the development of a hydrogen supply and distribution infrastructure. One of the key requirements during the near-term stage is the development of policy and regulations. During the near-term stage existing hydrogen applications will be assessed for their potential for clean hydrogen utilisation, and regional hubs will be established to facilitate widespread deployment in later stages.

The mid-term stage builds on the previous stage and will grow and diversify the established hydrogen sector. The stage will run from 2025-2030. The connection of hubs by 'corridors' will be established. As hydrogen production increases in this stage, it will be applied in sectors including transport, heating and industrial processes.

The long-term stage will be the realisation and growth of a full hydrogen economy, with export markets being identified [87].

The strategy sees up to 6% of Canadas end-use energy being from hydrogen by 2030, and 20% by 2050. There will be more than 5000 FCEVs, serviced by a nationwide hydrogen refuelling network. By 2050 there will be a reduction in carbon emissions of 190 million tonnes of CO_2. In the strategy's ambitious scenario, a reduction of 45 million tonnes of CO_2 emissions can be achieved by 2030.

Domestic low carbon hydrogen demand, according to the strategy, could be 4 million tonnes annually by 2030, and 20 million tonnes annually by 2050.

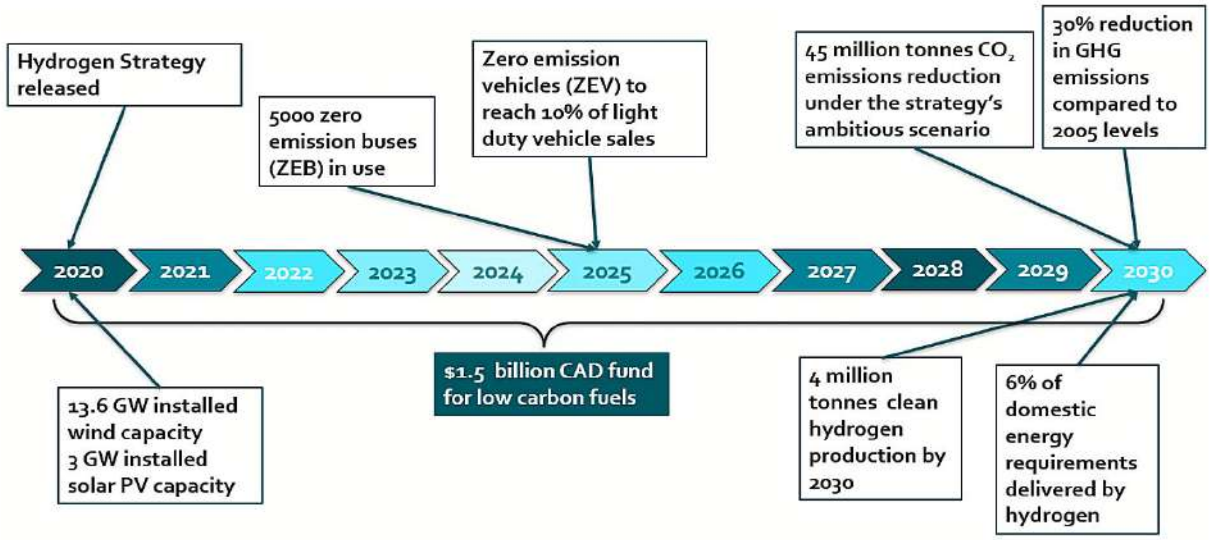
Canada has ambitions to be a major producer, user and exporter of clean hydrogen and hydrogen technologies. The strategy sees the potential of Canada being one of the top three hydrogen producers globally.

Canada sees its clean hydrogen production being a mix between green and blue. Canada is fourth largest natural gas producer globally and sees potential for natural gas rich provinces such as Alberta, British Columbia, and the Atlantic provinces, to embrace blue hydrogen production technologies with CCUS. Green hydrogen will be aided by the abundance of wind in Canada. Electrolysis powered by electricity from nuclear power is being considered as a low carbon hydrogen production route in the strategy.

Domestic clean hydrogen costs, including delivery are assessed by the strategy as being $1.5-3.5 CAD (£0.9-2) as production scale is realized.

A summary of Canadian ambitions in renewables and clean hydrogen production can be seen in Figure 6.7.

Figure 6.7 Timeline of renewables and clean hydrogen ambitions in Canada



Clean hydrogen projects ongoing in Canada are detailed in Table 6.8

Table 6.8 Clean hydrogen projects in Canada

Project	Description	Project Timeline
Hydro-Québec Green Hydrogen Project	• Based in Varennes, Québec • 88 MW electrolyser facility powered by renewable hydro power • Production capacity of over 11,000 tonnes green hydrogen annually • Hydrogen to be utilised for bio-fuel production	• 2023 – Project operational
Proton Technologies Hydrogen Project	• Based in Kindersley, Saskatchewan • Novel technology • Pilot project injected into oil field, raising the temperature and creating a reaction that liberates hydrogen • Hydrogen drawn to the surface whilst CO_2 remains underground • Aims to produce carbon free hydrogen more cost effectively that green hydrogen production	• 2021 – Project begins producing hydrogen • 2023 – Project fully operational producing 500 tonnes hydrogen daily
ATCO Hydrogen Blending Pilot Project	• Based in Fort Saskatchewan, Alberta • 5000 homes will be heated by clean hydrogen blended up to 5% by volume into the natural gas grid • Homes to be supplied with hydrogen blended natural gas by summer 2021	• 2021 – Hydrogen blending to commence

Cont.

Table 6.8 Clean hydrogen projects in Canada (continued)

Project	Description	Project Timeline
Sundance Hydrogen	• Based in Victoria, British Columbia • Green hydrogen electrolyser facility powered by wind • Injection of green hydrogen into natural gas grid • Export of green hydrogen and e-methanol • Project is pending approval	• 2021 – Project pending regulatory approval
Pacific Hydrogen Canada	• Export of green hydrogen from British Columbia to the USA, South Korea and Japan • Project under development	• 2021 – Project timeline to be announced
Gatineau Green Hydrogen	• Based in Gatineau, Québec • 20 MW electrolyser facility powered by hydro • Green hydrogen to be injected into natural gas grid • Annual reduction of 15,000 tonnes CO_2 emissions annually	• Timeline unknown

6.10 Clean Hydrogen Summary for Competitors to Scotland's Future Export Market

Many countries and regions have not published projected hydrogen production volume or hydrogen demand up to 2030. However, from the hydrogen strategies of some of the potential competitor exporter countries, we can use published ambitions, coupled with some assumptions, to estimate a country's potential to supply clean hydrogen in the decades to come, and to assess their competition potential to Scotland's potential export market.

Spain has outlined ambitions to have 4 GW installed electrolyser capacity by 2030. Using the approximations outlined in section 5.6, that found 3.3 TWh of hydrogen produced annually per GW installed electrolyser capacity, the volume of green hydrogen that Spain could produce by 2030 can be calculated. This equates to 13.2 TWh green hydrogen produced in 2030. If Spain were to export all of this green hydrogen it would meet 12% of Germany's projected hydrogen demand in 2030 of 110 TWh.

Spain has also highlighted a potential 14 TWh of curtailed wind to be used for green hydrogen production by 2030. Using an electrolyser efficiency of 73% and a HHV for hydrogen of 39.4 kWh/kg this curtailed wind has the potential to produce approximately 260,000 tonnes of green hydrogen.

Portugal has ambitions for 2.5 GW of installed electrolyser capacity by 2030. Using the same methodology as above Portugal's green hydrogen production potential based on electrolyser ambitions can be estimated at 8.25 TWh annually. If this green hydrogen were exported it could account for 7.5% of Germany's projected hydrogen demand of 110 TWh by 2030.

Australia, in its hydrogen strategy set ambitions to cover approximately 3.5% of global hydrogen demand by 2030. Global hydrogen demand in 2030 is estimated to be approximately 98 million tonnes [88]. This would require Australia to be producing 3,430,000 tonnes of hydrogen annually for export [89].

Chile could produce up to 160 million tons of green hydrogen annually by 2050 according to IAE estimates. The Hydrogen Council estimates global hydrogen demand in 2050 to be 500 million tonnes per year. If chile were to export all of this green hydrogen it could meet approximately one third of global demand.

Canada has set out its hydrogen strategy and has ambitions to produce 4 million tonnes of clean hydrogen by 2030. If exported this could account for 4% of projected global hydrogen demand by 2030.

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7. Cooperation Opportunities and Stakeholder Engagement

As previously established within the report, there are several key import markets close to Scotland around the North Sea basin. These key import markets: Germany, France, Belgium, and The Netherlands have varying level of technology maturity with regards to the Hydrogen Value Chain. There are likely to be opportunities for cooperation and collaboration from some of the more mature sectors to accelerate Scotland's plans for Hydrogen production while securing supply deals with the import markets. This section of the report details the value chain within those countries and outlines the stakeholder engagement plan. Additionally, we have engaged directly with Port of Rotterdam and Port of Antwerp, two key Hydrogen 'hubs' with ambitious developments plans in The Netherlands and Belgium to identify in detail, timelines for the delivery of the projects and associated demand and infrastructure requirements to develop their hub models.

7.1 Stakeholder Engagement Aims

- Identify and Engage with potential export markets to identify need and appetite for collaborative projects that can accelerate hydrogen production and utilisation across Europe.
- Learn from planned/existing Hydrogen Hubs (specifically around Ports on the infrastructure changes they have made to support hydrogen strategy
- Highlight existing European Supply Chain, with links to key export markets for Scottish Green Hydrogen

Data Protection Considerations

To comply with GDPR the following actions will be taken:

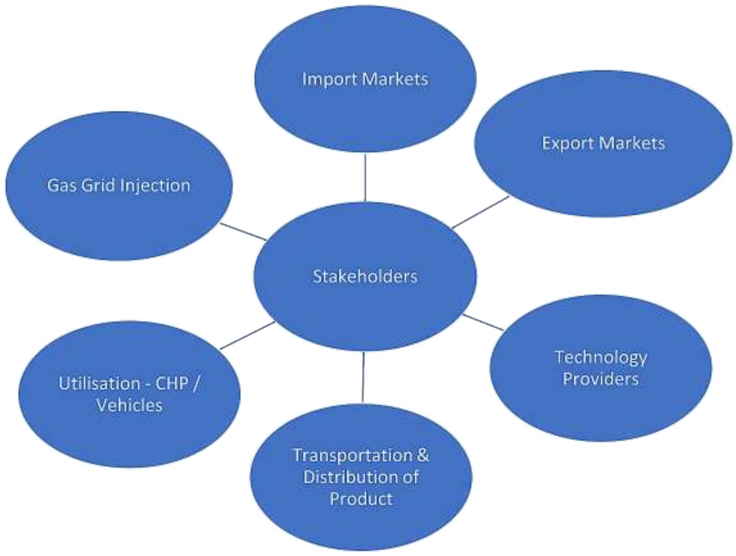
- No contact names or numbers will be held in central location.
- The value chain database outlined will include company names but no contact details

7.2 Stakeholder Mapping

As established across this study there are several key stakeholders across the European and Global Clean Hydrogen Market. Of most interest to this project are the following activities:

- Import Markets (customers)
- Including Governments, Ports, Gas Pipeline Operators, etc.
- Technology providers – Electrolyser / SMR, Storage solution providers, Component provision
- Transportation and Distribution
- Utilisation – CHP
- Utilisation - Vehicles

Figure 7.1 - Stakeholder Mapping



7.2.1 Existing Collaborative Working Groups

There are several existing working groups that exist within the Clean Hydrogen industry including:

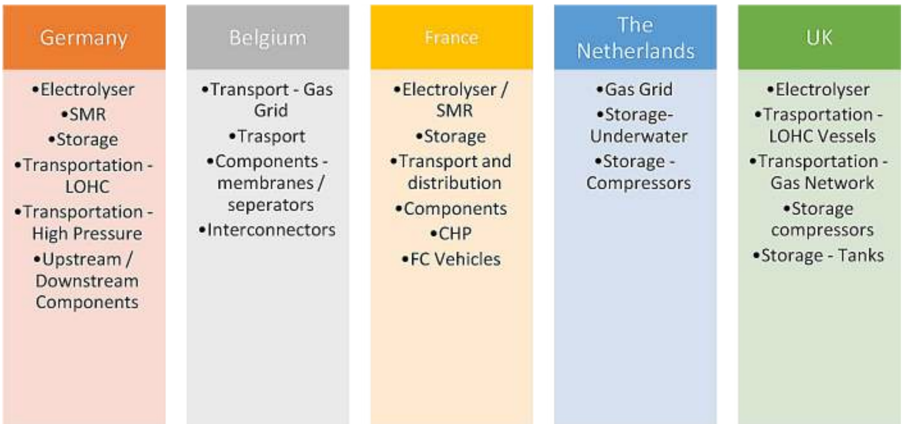
- Pale Blue Dot Energy
- Scottish Hydrogen and Fuel Cell Association
- HyTrEc2

This stakeholder engagement plan does not seek to usurp but rather utilise the structure of information gathering and provide more detail regarding the specific value chains within the key import markets identified as significant net importers of clean hydrogen.

7.3 Import Markets and associated technology collaboration opportunities

The key import market opportunities for a mature Scottish Clean Hydrogen sector have been well documented in Section 5 of this report. Here, summarised for each of the top importers are the publicly available ability to provide specific technologies that would support the Hydrogen production economy in Scotland, as well as associated 'downstream' activities for distribution.. An additional inclusion into Figure 3 below is the UK supply chain, relevant as it could most easily support rapid saleability of hydrogen production in Scotland. With the development of the 'Hydrogen Backbone' proposed by the National Grid this could provide a rapid method to distribute Hydrogen across the European markets.

Figure 7.2 - European Value Chain Summary



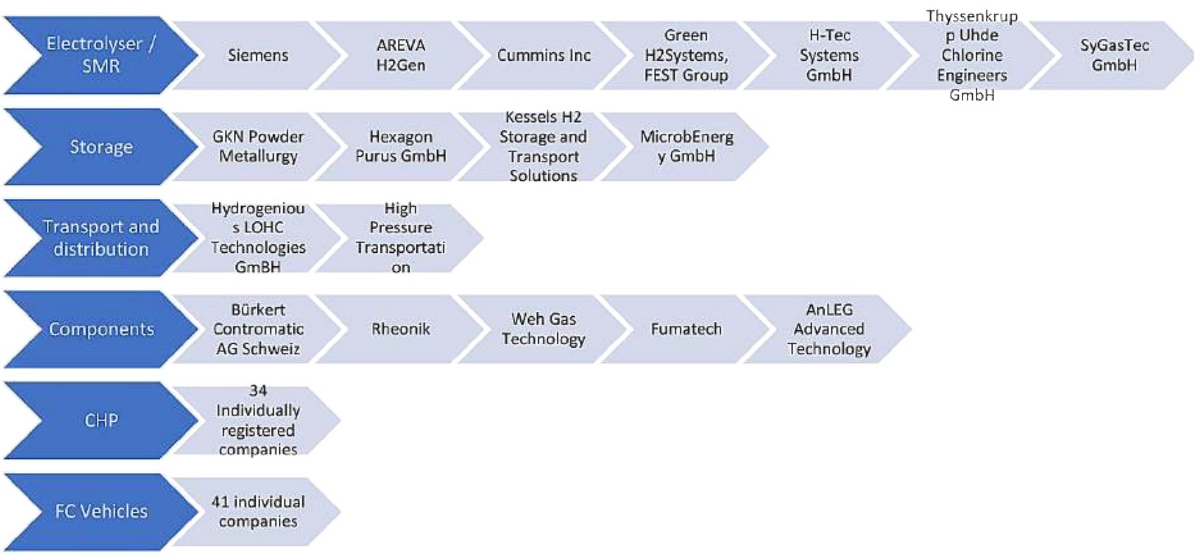
7.4 Value Chain Stakeholders

The following section provides more detail on the companies existing within the end-to-end supply chain, from production to utilisation including domestic heating, FC vehicles, refuelling stations. For simplicity, these use cases are characterised as CHP (Large and small-scale) and FC Electric vehicles producers (including buses, forklifts, cars). N.B. That while the greatest effort has been made to list the value chain for each of the above markets to the best available detail, there could be instances of companies being missed that could be present or capable within a hydrogen market.

7.4.1 Germany

The German value chain is perhaps the best-established outside of the UK and represents opportunities for both upstream component provision and downstream distribution. As one of Europe's projected main importers of Clean Hydrogen, Germany potentially represents the best opportunity to enable collaborative discussion around technology provision in return for long term Hydrogen supply agreements from Scotland. Figure 7-3 indicates the diversity of value chain members for Hydrogen production and distribution across Europe. As outlined in the report, as a key market for importation of Clean Hydrogen, engagement with the supply chain to generate technology partnerships in return for guarantee of Hydrogen supply contracts could accelerate Scotland's production.

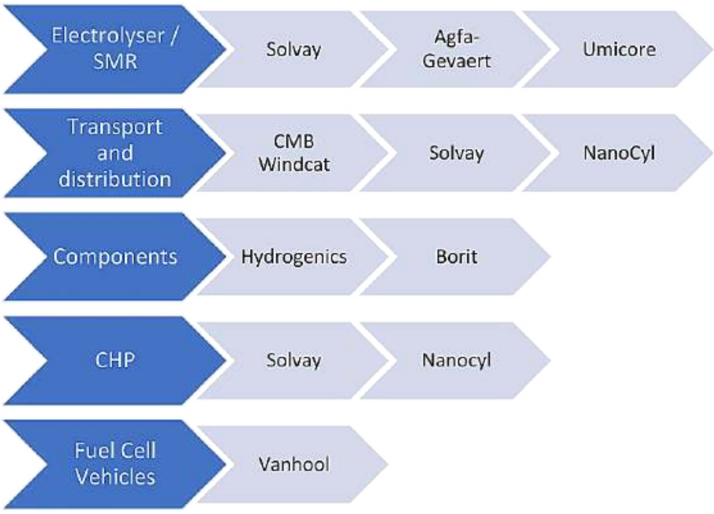
Figure 7.3 - Germany Value Chain



7.4.2 Belgium

Belgium has ambitious plans in the Hydrogen sector, including the generation of Hydrogen Hubs including at Port of Antwerp. Port of Antwerp is covered in more detail in the specific stakeholder engagement section of the report. Belgium's value-chain in the Hydrogen sector is less-diverse than that of Germany and France, but the main companies within it – Solvay, NanoCyl and Borit, can provide component parts for production through to utilisation of Hydrogen technologies in Fuel cells. It was not obvious within this research whether there are specific companies operating to support the storage of hydrogen within Belgium.

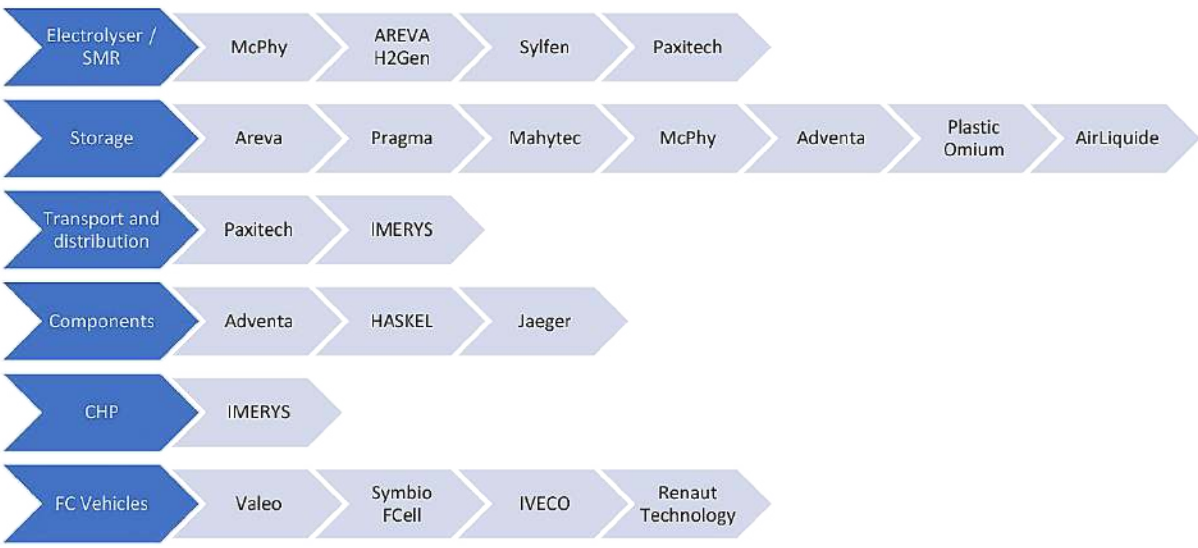
Figure 7.4 - Belgium Value Chain



7.4.3 France

France set out in its 2020 Hydrogen strategy ambitious goals to become a world-leader in the hydrogen sector. They have a well-developed value chain combining upstream technology, with electrolyser manufacturing, operations though major utilities, as well as production and downstream distribution and commercial and non-commercial use cases across their hydrogen value chain.

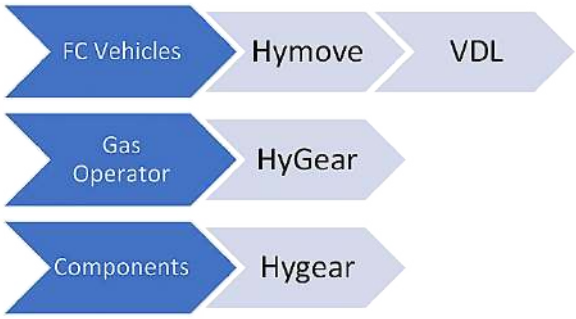
Figure 7.5 - France Value Chain



7.4.4 The Netherlands

The Netherlands value chain is perhaps the least-well developed but they have significant experience within the manufacturing sector and could pivot rapidly to produce electrolysers or SMR as required. Their resources for CCS make SMR a realistic opportunity for Hydrogen production. Currently their major strength in their value chain is distribution through the gas network, as well as vessels for LOHC and the key infrastructural projects around the generation of Hydrogen hubs, including the well-publicised opportunity at Port of Rotterdam, which is covered in more detail in the stakeholder engagement section of the report.

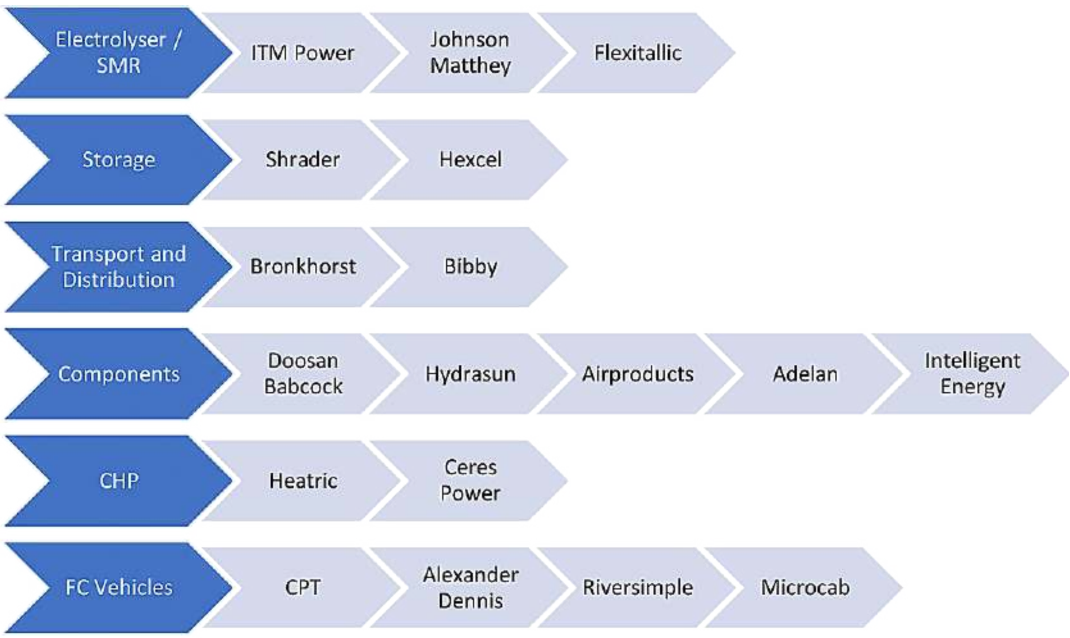
Figure 7.6 - The Netherlands Value Chain



7.4.5 United Kingdom

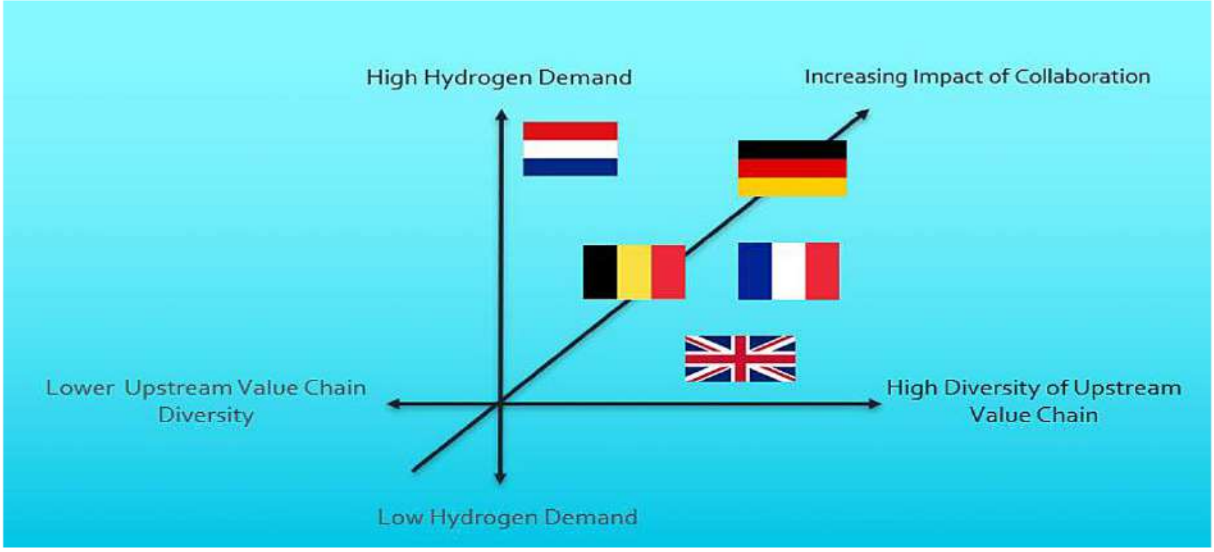
The UK has the potential to be a significant party to the hydrogen supply chain and engagement with the Department for International Trade over the course of this project supported this view and their ambition. There are several clusters across the UK looking to gain a foothold in the global clean hydrogen market and this value chain could be utilised to support Hydrogen production in Scotland. Figure 7-7 below indicates the diversity of the UK supply chain in this sector and further promotes the opportunity to use a more local supply chain to accelerate Scotland's production over the next 10 years, however this could be counteractive in obtaining quid pro quo supply contracts across key markets in Europe and should be considered.

Figure 7.7 - UK Value Chain



7.4.6 Summary of Findings

Figure 7.8 - Increasing Impact of Collaboration



From analysis of the value chain currently existing with the Hydrogen sector within key markets across Europe as well as the anticipated demand for Clean Hydrogen, Figure 7-8 summarises in high-level the findings. Germany, with a very limited capacity to generate its own clean Hydrogen on a similar timeline to Scotland's potential but having a diverse and well-established upstream value chain for Hydrogen production represents the strongest European opportunity for collaboration, with France also having an extremely well established and diverse value chain for production but having a slightly lower importation demand due to its own ability to generate Hydrogen. The UK has a well-established supply chain, and a high-demand and therefore is likely to have a high-impact for rapid technology collaboration, however depending on the approach favoured by the Scottish Hydrogen sector it may be more valuable to have a European partner. If Scotland and the rest of the UK wish to make a collaborative effort to develop the UK's ability to produce clean Hydrogen and supply European markets it could be proposed that collaborating with the technology suppliers in England could reap the fastest rewards. The Netherlands, having the least established upstream value chain would currently represent the lowest impact for technology collaboration for Hydrogen production in Scotland.

7.5 Stakeholder Engagement Model

The below section summarises the stakeholder engagement model to fully develop the value chain across the markets and identify specifically the most appropriate opportunities for technology collaboration. The current stakeholder engagement plan is high-level but is likely to develop as the plan for the Scottish Clean Hydrogen sector develops, and the specific needs and opportunities for each site arise. More information on the engagement with specific sites in Scotland for Hydrogen production is available in Chapter 10.

7.5.1 Levels of Engagement & Channels of Engagement

Highest Priority Stakeholders

Ports and Gas Pipeline Operators

Government engagement should be utilised to identify the key ports, and pipeline/ gas network operators for importation of Clean Hydrogen from Scotland. Again, these relationships with the specific port management groups and operators across Europe is vital to Scotland's ability to secure an abundance of clean hydrogen supply contracts. These relationships should be cultivated through virtual face-to-face engagement and should be maintained to guarantee long term collaboration.

Medium Priority Stakeholders

Governments

For the identified key import markets for Scottish Clean Hydrogen, engagement with relevant government bodies should be high, and should be utilised to carry out initial consultation and support future collaboration. The Channels of engagement are likely to be initially virtual face-to-face and email, however as time progresses and relationships are developed, the connections with government are likely to reduce to consult on specific areas and support engagement with the practical supply chain. Supply contracts are likely to come with support from the Government bodies, and therefore are of high importance. However, on a practical level, the engagement with government will initially be as a method to support the acceleration of collaborative opportunities within the value chain.

Technology Providers

To accelerate Scotland's Clean Hydrogen supply relationships with technology providers will be vital. Taking a holistic approach, engagement with Government should support the facilitation of initial introductions with specific suppliers where necessary and could support the quid pro quo supply through technology collaboration. Currently Scotland has no companies creating Electrolysers or SMR reactors to generate Hydrogen in the required capacity to support an export industry. Therefore, collaborative engagement would be beneficial. The technology providers should be engaged directly, though the relationship for the collaboration could be managed through government. The technology providers are classed as medium-priority, and the relationship could be handled through supplier-customer models.

Low Priority Stakeholders

Utilisers of Clean Hydrogen

This project is focussed on the upstream requirements for Hydrogen production in Scotland, and therefore the international end user is less consequential for the project, aside from setting the potential demand requirements. However, the future demand is additionally set by the Hydrogen Strategy set out by each of the Governments. The low priority stakeholders could be engaged more generally through a wider communications plan including webinars, podcasts and newsletters to discuss the project as a whole and keep them informed of updates.

7.6 Stakeholder Engagement Activities

To get a more detailed understanding of the value chain across the UK and Europe several engagement activities will be carried out. Full delivery of the engagement plan is identified as future work as a continuation of this project.

7.6.1 Surveys

Surveys were identified as a high-impact methodology to gather data on potential export markets and to support the analysis carried out in Section 5. This WAS generated using

Microsoft Forms, but is available in word format summarised in section 3.1.3. Following acceptance of the stakeholder engagement plan, future work would involve the formal launching of the survey across the key markets internally and across Europe.

7.6.2 Meetings/Interviews

Where possible, and with key Hydrogen Hubs, interviews were set up to discuss in more detail the timeline and progress of activities. The key points that were raised through meetings and interviews are the same as the survey points, but with interviews granted an opportunity to engage more thoroughly and provide any necessary clarifications. The interviews were carried out with Port of Rotterdam, The Netherlands, Groningen Seaports, The Netherlands, and Port of Antwerp, Belgium.

7.6.3 Information Required

In this section is the overview of the information that would be beneficial to gather from the value chain to get a greater understanding of each company's capability to support either Clean Hydrogen production in Scotland or to support transportation and distribution across the key import markets.

7.6.4 Information Collection and Storage

Table 7-7.1 - Information Collection and Storage

Organisation name	NAME
Organisation Type (Port / Government / Pipeline Operator / Technology Provider	
Location of head office	*Address*
Country of Operation	
Location of manufacturing site (if appropriate)	*Address or coordinates?*
Direct contact	
Industry Role	☐ Government Body ☐ Port ☐ Engineering ☐ Supply ☐ Manufacturing ☐ Transport/Storage
For Ports:	☐ Is there a Hydrogen Plan in place? - Y/N ☐ Port Capacity (tonnage) ☐ Manufacturing ☐ What are the major infrastructure changes that have been planned for the port and downstream activities? ☐ Over what timeline is the Port anticipated to deliver the plan? ☐ Local Demand for Hydrogen ☐ Connection to local infrastructure ☐ Will the gas grid be utilised and what % Hydrogen blend will be utilised? ☐ Capacity to produce Hydrogen. ☐ Will Renewable Energy be produced on site? ☐ Capacity to store Hydrogen ☐ Import requirements for Hydrogen. ☐ Methods of Import - Pipeline - Vessel ☐ Preference between Green/Blue Hydrogen ☐ Preference of storage form (LOHC, NH_3, CH_4, H_2) ☐ Any alternative renewable fuels being proposed.

For Technology Providers (Manufacturing, Transport / Storage) specific aspects of Hydrogen production (based on HyTrEc 2 Supply chain map) N.B. This was focussed on the production, rather than application of Hydrogen	☐ Electrolyser - Electrolysis - SMR - Biomass - Fuel Cells ☐ Storage - Surface Storage - Subsurface Storage ☐ Transportation - Cylinders - Road Tankers - Pipelines - Vessels ☐ Other - Other
For Technology providers Product Capacity	☐ Per Component/Year - Current - Projections 2030 ☐ Per Project/Year ☐ Simultaneous production?
For Government Body	☐ Hydrogen Plan in place - Y/N ☐ Timeline to deliver. - Current ambitions - Projections 2030 - Projections Beyond ☐ Total Hydrogen Requirements ☐ Hydrogen Production potential ☐ Import Requirements ☐ Collaborations in Place ☐ Opportunities for Scottish Green Hydrogen
Specific Development / Infrastructure Plans	*Written response*
(AOB) Any additional actions raised during engagement?	*Written response*

7.7 Case Study Interviews

7.7.1 Port of Rotterdam

Engagement Type	Benefits	Risks
Template Questionnaire	• Allows organizations to provide additional input that can be useful. • Easily Disseminated	• Answers may not be collected in the correct format. • Certain parts may be left blank. • Late or no responses
Interview – relaying the template	• ORE Catapult responsible for data input – ensure correct format. • Can rephrase questions that may be misunderstood	• Possible misinterpretation of given information • Depending on the number of interviews, the role can be full time – lack of resources

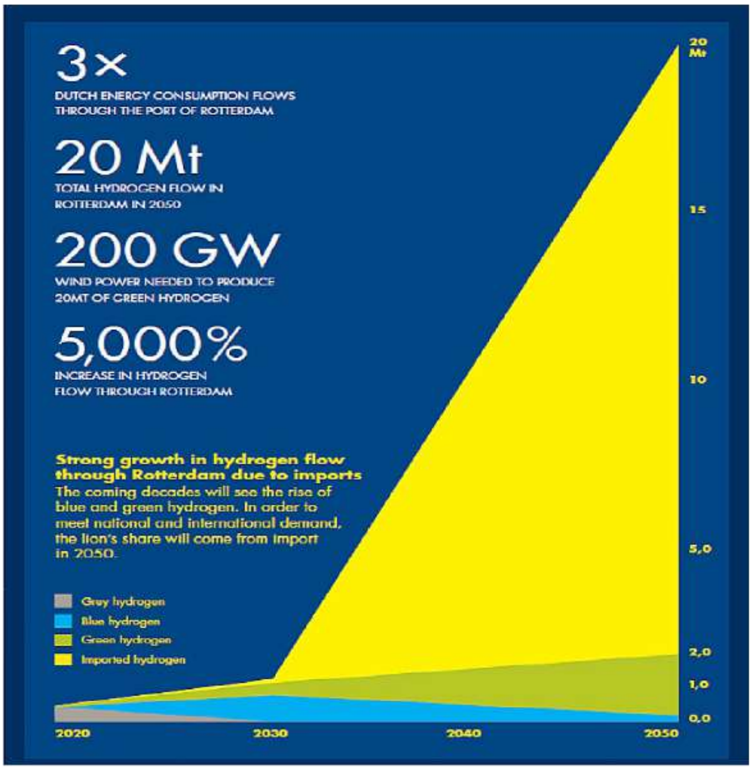
The Port of Rotterdam has perhaps the most well developed and ambitious plans across Europe to act as a point of entry for Clean Hydrogen imported internationally or generated locally. Figure 7.9 below indicates a summary of their key plans. Green Hydrogen will be produced from a direct connection to 2GW of offshore wind capacity, while in conjunction Grey Hydrogen will be produced and converted to Blue Hydrogen through a Carbon Capture and Storage system within the H-Vision project. Prior to these projects being finalised Port of Rotterdam is planning on the development of a dedicated Hydrogen pipeline (no blending) to take Hydrogen from the Port to the Industrial actors around the port.

Figure 7.9 - Port of Rotterdam Hydrogen Economy – courtesy of Port of Rotterdam

Engaging directly with Port of Rotterdam, ORE Catapult were provided with substantial details of Port of Rotterdam's plans up to 2050.

By 2025, The Hydrogen pipeline will be in place, connecting the backbone pipeline to the rest of Europe, and other major Hydrogen importers. The European pipeline, consisting of 4 individual pipes, will be repurposed to have a dedicated Hydrogen pipeline, removing any need to blend Hydrogen at a specific percentage into the existing Natural Gas supply. Port of Rotterdam is planning to throughput 20 Mt total hydrogen by 2050, but its maximum capacity to generate green hydrogen is likely to be 2-3 Mt, a difference of 85-90%. Port of Rotterdam's business unit have identified several potential partners to fill the Hydrogen 'deficit', one of which is Scotland and the UK.

Figure 7.10 - Hydrogen Throughput courtesy of Port of Rotterdam



The figure above, describes how Port of Rotterdam project the colour of hydrogen to change overtime. From 2020 to 2030, there is a distinct mix of Grey, Blue and Green Hydrogen which could be produced locally. However, as demand increases from 2030 onwards, imported Hydrogen will form the most important, and abundant source of hydrogen through Port of Rotterdam. Local regulations indicate the Blue hydrogen will be phased out by 2050, so the share of green hydrogen produced locally will increase but will remain at approximately 10% of the total hydrogen throughput. The port, therefore, is actively seeking to fill this gap in supply from 2030 onwards, a timeline that favours the development of the Scottish Hydrogen production market.

Port of Rotterdam are therefore extremely interested in building partnerships now to start to fill the pipeline supply from 2030 onwards and are willing to use their expertise to carry out infrastructural reviews of exporting (sender) ports to ensure they have the capability to ship the supply. At the Port of Rotterdam, they have designed and will be upgrading their infrastructure to enable an agnostic approach to the supply of Hydrogen. Carriers that will be acceptable to the Port include:

- Green Methanol
- Green Ammonia
- LOHC
- LH2
- NaBH2

This flexibility of receiving is very beneficial to Scotland's Hydrogen production, where sites themselves can be selective regarding the most appropriate infrastructure for their environment, helping to reduce the overall cost of Hydrogen, and supporting its competitive sale price.

On this final point, Port of Rotterdam have carried out several model studies comparing the price of Hydrogen shipped by vessel compared to pipeline supply and in most cases pipeline supply was cheapest – however, they noted that relying purely on pipeline supply could potentially affect security of supply depending on the political climate, and therefore there will certainly be opportunities for both shipped and piped Hydrogen through the Port.

7.7.2 Port of Antwerp

Port of Antwerp is one of the largest ports in the world, and second only to Rotterdam in Europe. In 2018 it handled over 235 Mt of cargo. The port-owned land contains 5 separate oil refineries and a concentration of petrochemical industries. Current figures estimate it has a 40Mt primary distillation capacity, 6.5 million tonnes of bunker fuel capacity, and 287 MW of renewable energy installed, predominantly in a wind farm in the Northern part of the port area, which is currently undergoing extension.

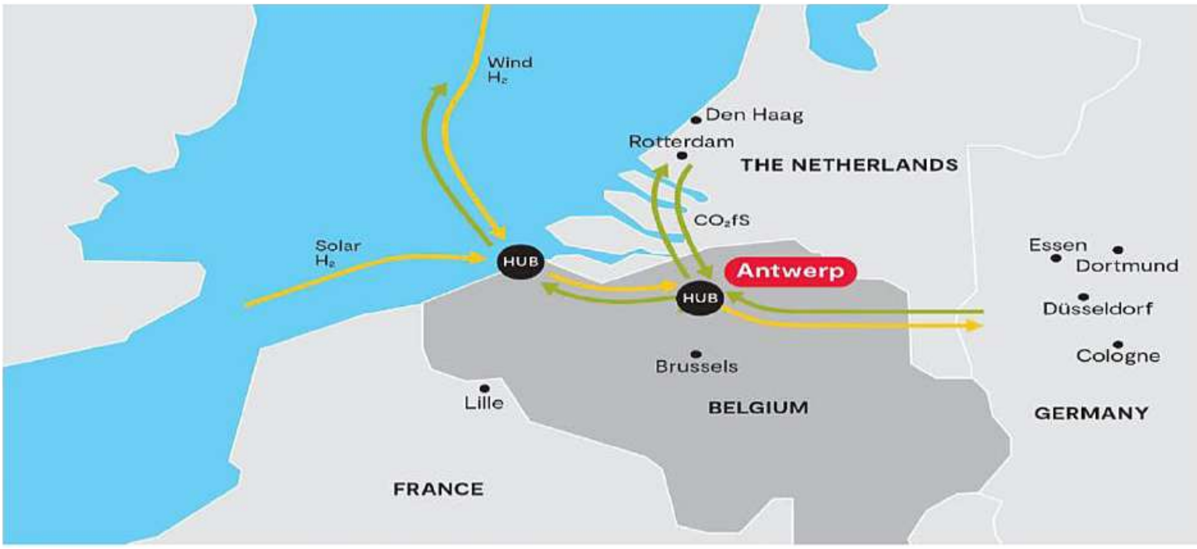
Currently the Port of Antwerp is responsible for importing and producing approximately 10-15% f EU hydrogen production, by a combination of Merchant SMR, Captive SMR, and Hydrogen as a biproduct of the numerous chemical processes that take place within the land owned by the Port operator.

The Port of Antwerp is very much at the forefront of the Energy Transition within Belgium. They have identified the opportunity to shift away from Fossil Fuels into a more sustainable future and intends to use the 1000s km of gas pipeline and extend this to become a dynamic 'energy backbone' for Hydrogen importation into the main gas grid.

The Port aims to create a Hydrogen economy within the Port that will benefit the wider countries within the EU. As a significant landlord they anticipate increasing their own production of Hydrogen by setting up a number of demonstration projects including producing bio methanol through the combination of recaptured Carbon and clean Hydrogen. Additionally, they have extensive facilities for the importation and distribution of imported Hydrogen, either through pipelines or by vessel transport into the Port. The upgrading of the pipeline to be more dynamic should ensure an Agnostic approach to hydrogen importation and enable clean Hydrogen suppliers to select the most cost-effective approach for transportation.

In Collaboration with Rotterdam and the City of Antwerp, a CO_2 and H2 transport system joint approach is in development, where both of the ports of Rotterdam and Antwerp, can accept clean Hydrogen and through an upgraded pipeline transport CO_2, and H2 as required into the European gas grid or to one another as shown in Figure 7-11.

Figure 7.11 CO_2 and H2 Transport system joint approach. Courtesy of Port of Antwerp



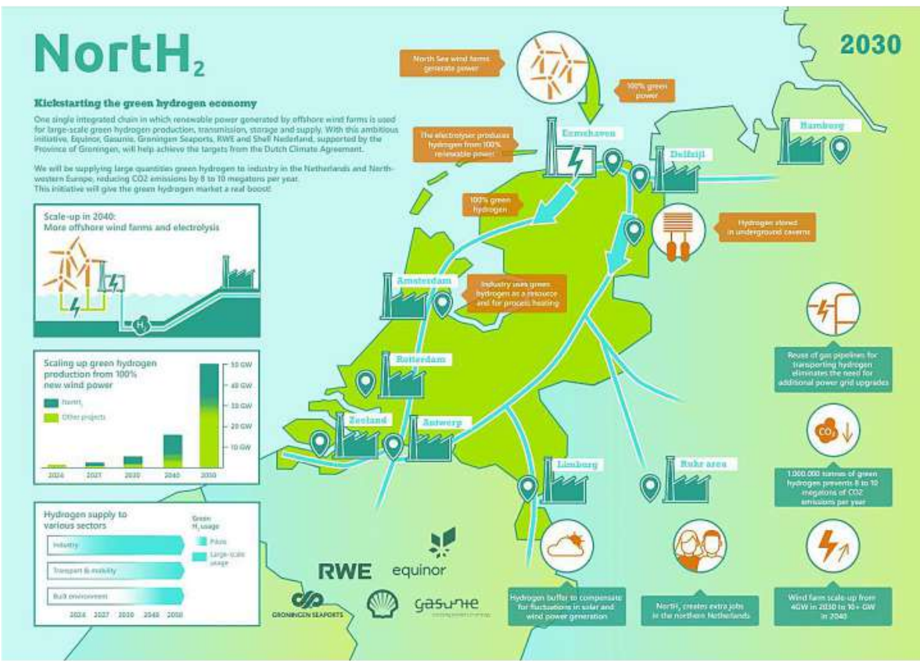
Port of Antwerp has partnered with energy utility Engie, DEME, ExMAR, Fluxys, Port of Zeebrugge and WatersofNet to form the "Hydrogen Import Coalition". The study aims to map out the financial, technical and regulatory aspects to develop an entire hydrogen import chain – from production abroad and including delivery by vessel and pipeline to Belgium and internal distribution networks to industrial and domestic users. This project aims to establish a compete hydrogen import value chain by 2030.

Further details will be included following the case study interview on 1st April 2021.

7.7.3 Groningen Seaports

Groningen Seaports, in collaboration with Gasunie, Shell Nederland, TWE and Equinor are currently undertaking the NortH2 project, to produce Green Hydrogen from offshore wind by 2030. The international collaboration aims to play a major role in supporting the growth of the Hydrogen Value chain across the North Sea basin.

Figure 7.12 - NorthH2 - Courtesy of Groningen Seaports



The connection to Offshore Wind Farms, generating 4GW by 2030, up to >10GW by 2040, could produce 1 Mt of Hydrogen per year, but the Port will have the capacity to handle much more Hydrogen. The North of Netherlands is already connected to an international gas grid, with Groningen previously Europe's largest Gas grid, there is a huge amount of industry and infrastructure in place for gas transportation. The port is upgrading its facilities to handle Hydrogen through a plastic pipeline from the port for industrial and civil use cases within the Port facilities. Groningen Seaports, who operate both Ports of Delfzijl and Eemshaven, are undertaking a large-scale infrastructure upgrade including construction of Hydrogen production plants, a backbone pipeline which will allow large scale hydrogen importation from the two major ports.

With the closure of Groningen Gas Fields anticipated in 2022, the NortH2 project represents a very practical project during the Energy Transition Phase. Similarly, with Port of Rotterdam, Groningen Seaports are actively looking for partners to support their supply of Hydrogen and should be further engaged as another accessible market for Scottish Green and Blue Hydrogen.

7.8 Conclusions

Focussing specifically on the three mature opportunities outlined in the case study interviews, Scotland's development of a Clean Hydrogen Production is coming at exactly the right time. The major Ports across Europe are actively looking to benefit from the business proposition to supply Europe with its Hydrogen demand as the industry develops rapidly between 2030-2050. Additionally, Port of Rotterdam has indicated it is extremely interested in supporting international collaboration by engaging on the behalf of specific projects to fill potential technology gaps within the production and upstream value chain.

The timeline of the development of this project to determine feasibility of producing Clean Hydrogen in Scotland over the next 10 years lines up well with where the demand market intends to be. The biggest barrier to overcome will be the price point, however economies of scale should go some way to reduce the cost, and a form of Government subsidy should go a long way to supporting the competitiveness of Green/Blue hydrogen when compared with grey in the short term. A key driving force remains legislation across the UK and Europe to achieve carbon neutrality by 2050. Suggested next steps would be to continue engagement with the import markets as sites begin to assess their individual feasibility to produce Clean Hydrogen, and perhaps engaging with the Import Ports for their suggestions for necessary Port Upgrades to support supply. This would represent a very useful step in generating long-term relationships with key European markets

8. Technology Review

8.1 Introduction

Hydrogen technology is just one vector within the multi-vector global energy system being deployed to achieve a net-zero carbon future. Given Scotland's natural resources and experience in the energy sector, it is well positioned to become a major global player in the hydrogen economy. Within the hydrogen value chain, there are different ways that hydrogen can be produced, supplied and used. Currently, hydrogen is most commonly produced through the well-established process of steam methane reforming (SMR) or autothermal reforming (ATR), also known as 'grey hydrogen'. The process splits natural gas into hydrogen and carbon dioxide (CO_2), with CO_2 being released into the atmosphere. 'Blue hydrogen' couples SMR or ATR with carbon capture, utilisation and storage (CCUS) technology, capturing the produced CO_2, reducing its carbon emissions and mitigating the environmental impacts. Hydrogen can also be produced through water electrolysis, where water is split into hydrogen and oxygen using an electrical input, with oxygen being released into the atmosphere with no negative impact. 'Green hydrogen' is produced when the electricity for electrolysis is provided completely through renewable sources.

The future hydrogen economy is envisaged to follow a transition from grey, through blue, to green hydrogen technologies. This report section explores both green and blue hydrogen production as it is understood that both will play an important role in the current and future energy transition. Table 8.1 summarises the current position of green and blue hydrogen production technologies. Variations of each technology are investigated with discussions on their current position and technology readiness, as well as its future developments leading up to 2030.

Table 8.1 Summary of current position of green and blue hydrogen

	Green hydrogen	Blue Hydrogen
Scale	Alkaline: 10MW (~2,100Nm^3/h) PEM: 5MW SOE: < 1MW	200,000Nm^3/h of H2
Technology Readiness Level (TRL)	Alkaline: 9 PEM: 8 SOE: 7	SMR and ATR: 9
LCOH (£/kg)	> 4.12	1.92

The demand for hydrogen in Scotland comes from a range of industrial, commercial and residential users, both domestically and internationally. This report section also investigates the methods that hydrogen can be stored and transported to its desired end-user. As with the technology review, hydrogen storage and transport has been assessed on its current capability and its suitability and potential in 2030.

8.2 Green Hydrogen Technologies

Electrolysis offers a promising option for large-scale hydrogen production from renewable sources. The principle of water electrolysis is simple, defined as the process of using electricity to split water into hydrogen and oxygen. Depending on the end-use, electricity can produce hydrogen in power-to-gas (P2G) and power-to-liquids (P2L), collectively known as P2X, processes. Housed within an electrolyser, its technology is distinguished by its electrolyte and operating temperature. Currently, low-temperature electrolysis options include alkaline, polymer electrolyte membrane (PEM) and anion exchange membrane (AEM) electrolysis. The most notable high-temperature electrolysis technology is solid oxide electrolysis (SOE). AEM and SOE have high potential but are still at an advanced R&D stage and very few companies offer them at a commercial scale.

All water electrolysers can be broken down into three levels: the cell, the stack and the system. The basic principle of the cell consists of two electrodes, an anode and a cathode, separated by an electrolyte. Either a liquid electrolyte or a solid electrolyte membrane is responsible for transporting chemical ions between the electrodes. Other components include two porous transport layers which enable the movement of reactants and products and two bipolar plates which offer mechanical support. Together, these components make up the core of the electrolyser, where the electrochemical process takes place.

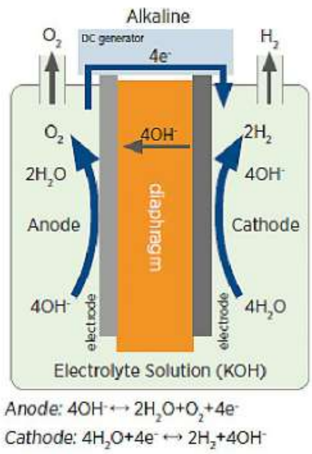
At the stack level, multiple cells are connected in series. The stack also contains spacers to insulate between electrodes, frames for mechanical support, seals and end plates to avoid leakage. The system-level looks beyond the stack at the equipment required for the preparation and treatment of reactants and products. Also called the Balance of Plant (BoP), the system includes water supply treatment, cooling, purification and compression of hydrogen and oxygen products. The overall system efficiency of a green hydrogen production facility is attributed to the individual efficiencies of the cell, stack and balance of plant.

8.2.1 Alkaline Electrolysers

Description

Alkaline electrolysers were the first electrolysis technology to be developed and deployed commercially. They still offer the most reliable and robust method, with proven operational lifetimes exceeding 30 years. To date, the world's largest single-stack water electrolyser runs on alkaline electrolysis technology. The 10MW single unit was installed in March 2020 in Fukushima, Japan and can produce 1,200Nm^3/h of hydrogen [90]. Simply, alkaline electrolysers operate by generating hydrogen at the cathode by removal of a hydroxide ion (OH-), which transports through the liquid electrolyte to the anode, as shown in Figure 8.1.

Figure 8.1 - Alkaline electrolysis diagram [91]



Comparison to other Technologies

Out of all the electrolyser technologies currently available, alkaline have the simplest stack and system design. Within the cell, electrode areas are manufactured up to $3m^2$. They operate using a highly concentrated potassium hydroxide (KOH) liquid electrolyte, diaphragms made of robust zirconium dioxide (ZrO_2) and nickel-coated stainless steel at the electrodes.

By combining multiple smaller stacks, some companies have been able to offer hydrogen production capacities up to 20MW without any negative effects on the system efficiency or electrolyser response capability [91]. As the most mature electrolyser technology, alkaline electrolysis has proven itself as a commercially viable technology for current hydrogen production requirements. In terms of its benefits over other electrolysis technologies, alkaline allows for better system robustness due to its exchangeable electrolyte, allows high gas purity as a result of the lower gas diffusivity of its alkaline electrolyte and cheaper catalysts.

Alkaline electrolysers are different in that they operate using a liquid electrolyte. Despite its benefits, KOH must be recirculated around the stack components and separated from the gases produced upon leaving the stack, which negatively affects the stack efficiency. Additionally, the liquid electrolyte also increases the likelihood for leakage and maintenance requirements, therefore newer approaches utilising a solid alkaline exchange membrane are being developed. To prevent the intermixing of produced gases dissolved in the electrolyte, alkaline is restricted to a higher power-operating range and lower pressure levels. Additionally, alkaline electrolysers require balanced charges between the anode and cathode which pose a challenge to operate at differential pressures. As a result, their performance is lower in comparison to PEM technology, however recent advancements have reduced this gap and will be further discussed in this section.

The characterisation of today's alkaline technology is displayed in Table 8.2.

Table 8.2 – Techno-economic parameters alkaline electrolysis technology [55] [91]

Design parameter	Value
Operating temperature (°C)	70 – 90
Operating pressure (bar)	1 – 30
Cell area (m^2)	1 – 3
Current density (A/cm^2)	0.2 – 0.8
Hydrogen purity (%)	> 99.5
System efficiency (kWh/kg_{H2})	50 – 78
System efficiency (%)	50 – 68
Plant size (MW)	10
Lifetime (hours)	60,000
System CAPEX ($£/kW_{el}$)	390 – 1,090

Technology maturity

Producing green hydrogen through alkaline electrolysis positions itself at the highest technology readiness level (TRL) of nine, which suggests that actual systems have been proven in operational environments. Despite its TRL, technological advancements in membrane and system designs can still help to overcome drawbacks associated with typical properties of alkaline systems such as low current densities (0.2 – 0.8A/m^2) and slow start-up times [92] [5]. The key areas for research and development (R&D) in alkaline technology and their respective TRL are displayed in Table 8.3. Research enabling higher current densities was identified as the stand-out R&D challenge for alkaline electrolysers, with a time to market for two years [5]. Advancements in the current density would improve the flexibility of load-following operation, allowing the electrolyser to change its power-level in response to a variable power input which is key for renewable energy sources. Additional advances in membrane materials are also essential to all methods of electrolysis, which would improve the purity of hydrogen output, reduce costs and improve operational lifetimes, but this has an estimated higher time to market of eight years.

Table 8.3 - R&D challenges for alkaline electrolysers [5]

R&D challenges	TRL
Membrane research	2
Hydrogen evolution	2 – 5
Improved responsiveness	4 – 8
Enabling higher current densities	4 – 6
Efficient water purification	5 – 9
Hydrogen drying	2 – 4
Rectification	3 – 5
Lye circulation	5

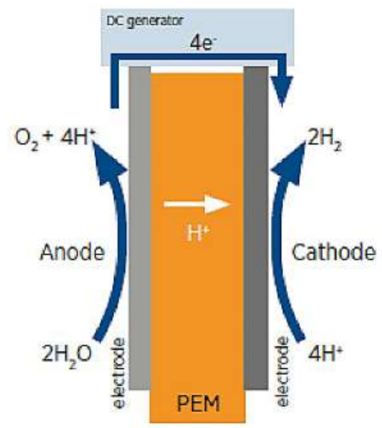
The theory of the learning curve proposes that as the cumulative capacity for a specific technology doubles, there is a constant relative reduction in cost which can be captured in a learning rate. The same absolute increase in production capacity would lead to a smaller cost reduction for more mature technologies than for early-stage ones. As the most mature electrolysis technology, the learning rate for alkaline electrolysers between 2020 to 2030 is 9%, lower than 13% and 18% for PEM and SOE, respectively [91]. In consideration, the installed capital expenditure (CAPEX) is expected to reduce from €400 – €1,200/kW$_{el}$ to €350–€700/kW$_{el}$ in 2030 [55]. Alkaline electrolysers have been deemed the most dominant and suitable electrolyser technology in 2020 given current production levels, however, PEM and SOE technologies become more favourable beyond 2030 with production scale-up – See Section 9 [93].

8.2.2 PEM Electrolysers

Description

General Electric introduced the PEM electrolyser system in 1966 to overcome some of the operational drawbacks of alkaline water electrolysis [55]. PEM electrolysers, along with SOE and AEM, separate the electrodes with an electron-insulating solid electrolyte. More specifically to PEM, the electrolyte is a solid polymer material, that is responsible for the transport of ions between electrodes and acts as a physical barrier separating hydrogen and oxygen gases. In a PEM electrolyser, water reacts at the anode forming oxygen and positive hydrogen ions, the protons then selectively travel through the PEM and react to produce hydrogen at the cathode, as shown in Figure 8.2. PEM electrolysers have been increasingly utilised in the production of hydrogen, with recent projects and advancements providing confidence in the technology's potential and readiness.

Figure 8.2 - PEM electrolysis schematic diagram [91]



Anode: $2H_2O \leftrightarrow O_2 + 4H^+ + 4e^-$
Cathode: $4H^+ + 4e^- \leftrightarrow 2H_2$

PEM cells have simple and compact designs, containing two advanced catalyst electrodes and a thin perfluorosulfonic acid (PFSA) membrane. The PFSA membrane is both chemically and mechanically robust which allows PEM cells to operate high differential pressures between the hydrogen and oxygen sides, typically between 30 and 70 bar. However, the highly oxidative environment created at the anode requires electrodes constructed from titanium-based materials, noble metal catalysts (notably platinum and iridium) and protective coatings to withstand these conditions [91]. Together, they ensure optimal efficiency within the PEM cell but increase the unit cost significantly against their alkaline counterparts. As the slightly less mature technology, PEM lifetimes are shorter, they are less widely deployed, and their commercial reliability is yet to be validated.

Comparison to other Technologies

PEM systems are simpler than alkaline, as the recovery and recycling of liquid electrolyte are not required, making the design relatively small and more attractive in areas with limited space. The robustness of the cell design allows PEM systems to have greater design flexibility as they can be operated at differential, atmospheric and balanced pressures. Crucially, this allows rapid load-following operation and highly compressed hydrogen up to 60bar can be produced without an additional compressor. Pressures up to 200 bar are possible in some PEM systems [55]. Table 8.4 displays the techno-economic parameters for today's PEM systems.

Table 8.4 - Techno-economic parameters PEM electrolysis technology [55] [91]

Currently, PEM systems are deployed at a small-scale, however, several projects are under development that utilises advanced PEM technology for commercial green hydrogen production. Upon its completion in 2021, the Refhyne project in Germany will operate one of

Design parameter	Value
Operating temperature (°C)	50 – 80
Operating pressure (bar)	< 70
Cell area (m^2)	0.15
Current density (A/cm^2)	1 – 2
Hydrogen purity (%)	99.99
System efficiency (kWh/kg_{H2})	50 – 83
System efficiency (%)	50 – 68
Plant size (MW)	5
Lifetime (hours)	50,000 – 80,000
System CAPEX (£/kW_{el})	860 – 1,400

the world's largest PEM electrolysers with a capacity of 10MW [94]. Even greater than this, the Gigastack Project aims to demonstrate how decarbonisation will take place at industrial clusters. As part of the project, ITM is currently designing a new 5MW PEM electrolyser which will be part of a 20MW stack, scaling up to 100MW in total [95]. The total daily output from the PEM site will be 2,100kg/day of hydrogen.

Technology maturity

The large-scale production of hydrogen through PEM electrolysis is considered at TRL of 8, in its demonstration stage. Currently, the installed CAPEX for PEM is €900 – €1,500/kW_{el}. Once commercial-scale PEM electrolysis is established, the installed CAPEX is estimated to reduce to €550–€1,500/kW_{el} by 2030 [55]. To enable this transition, the total number of areas for PEM improvement is greater than any other electrolyser technology and all but one of the challenges aim to be achieved by 2030 [5]. Some of the innovation areas being actively pursued in PEM technology include anode degradation, water purification, component integration and improvements in catalyst design, coating, and membrane materials, each with varying TRL's. Two stand-out challenges have been identified to advance PEM technology to its commercial potential, both with time-to-market of two years:

- Research into developing anodes with a slower degradation will allow the system to withstand higher current densities and fluctuations further reducing response times.
- Developing stable catalyst supports will ensure better stability in fluctuating conditions, particularly important in renewable energy applications.

Bolstered by its superior characteristic for intermittent operation, this suggests that PEM is set to overtake alkaline as the most suitable technology in 2030 and beyond, supported by innovation, increased manufacturing capacity and operating experience.

8.2.3 Emerging Scalable Technologies

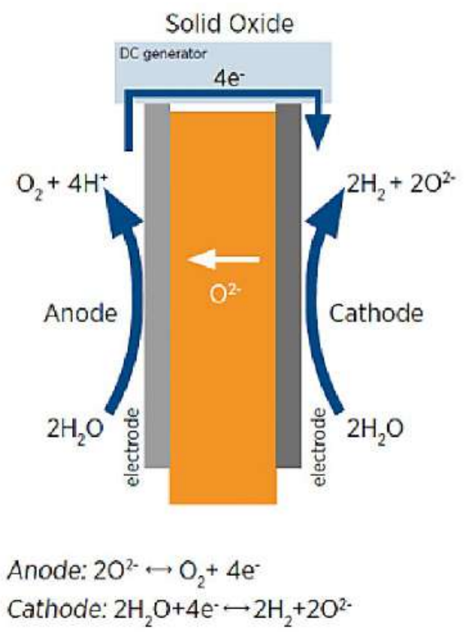
Alkaline and PEM electrolysers currently have the highest maturity levels in the water electrolysis sector. Both have their challenges with regards to scalability and compatibility with variable power loads (e.g., renewables) that point to opportunities for alternative electrolyser solutions. Some of the key emerging technologies that may have the maturity by 2030 to be competitive with alkaline and PEM are detailed below.

SOE

SOE electrolysers are an emerging technology and are unique in that they operate at high temperature (700-900°C) using steam instead of liquid water. They are not yet fully commercialised but do offer several benefits in both operational efficiencies and material cost that presents future competitiveness opportunities with conventional electrolyser offerings (alkaline and PEM).

SOE uses a solid ion conducting ceramic as the electrolyte giving robustness at high operating temperatures. Steam reacts with the negatively charged electrons at the cathode to generate hydrogen and negatively charged oxygen ions, which migrate across the ceramic electrolyte. On contact with the anode, the oxygen ions deposit electrons forming gas, and the electrons are routed along from the anode back to the power source. The silica oxide electrolyte can use materials such as yttria stabilised zirconia, an inexpensive ceramic.

Figure 8.3 - SOE Hydrogen Generation [91]



One of the key benefits of an SOE system compared to conventional offerings is the option to use low-cost materials for the electrodes, with options such as nickel for the cathode and lanthanum strontium manganite ceramic for the anode. Despite the low unit cost material options, the harsh operating conditions do not translate well into relative stack lifetime due to material thermal degradation. It is expected that ongoing R&D activities into developing new materials that offer improve robustness under the system conditions will close the gap between stack lifetimes of SOEs compared to current commercial options by 2030, but it is still expected to be reasonably less.

SOEs are also relatively compact, which naturally lends well to offshore environments with restricted space availability (e.g. offshore turbines). However, the main degradation mechanism for SOEs is thermal cycling (heating and cooling from high temperatures) which is likely to be more prevalent in variable load connections such as renewables. This does not rule out renewable applications but requires diligent design considerations to minimise temperature fluctuations for robust hydrogen generation. SOEs are naturally better suited to sites with large quantities of waste heat available from site operations (e.g. nuclear power plants).

Table 8.5 - Techno-economic parameters alkaline electrolysis technology [55] [91]

Design parameter	Value
Operating temperature (°C)	700 – 850
Operating pressure (bar)	1
Cell area (m2)	0.02
Current density (A/cm2)	0.3 – 1
Hydrogen purity (%)	99.9
System efficiency (kWh/kgH2)	45 – 55
System efficiency (%)	75 – 85
Plant size (MW)	1
Lifetime (hours)	<20,000
System CAPEX (£/kWel)	2,200 – 4,360

SOE electrolysers currently have a TRL of 7 ([96] having successfully demonstrated coupling with industrial waste heat. Most of the applications rely on the steady-state operation of the SOE process. The challenge will be to exploit the high efficiencies yielded from SOEs and integrating with i) low carbon heat and ii) intermittent power sources. Possible opportunities include solar steam generators with steam storage or nearby operations with waste heat at disposal to the Hydrogen generator.

Large scale SOE plants in the pipeline include [97]:

1. Multhiphly (2.6 MW, 2024, Netherlands)

60kg/h Hydrogen production on renewable fuel refinery for Neste in Rotterdam [98]

2. Norsk e-fuel (22 MW, 2021, Norway)

Hydrogen-based renewable aviation fuel in Herøya [99]

SOE still have several barriers to overcome for full commercial-scale wide deployment. It is estimated that developing SOE temperature resistant materials that are robust enough to be competitive with low-temperature electrolysis is 8 years. Other R&D focus areas are listed in Table 8.6

Table 8.6 - R&D Challenges for SOE electrolysers [5]

R&D challenges	TRL
Manufacturing methods	5 – 9
Scalable designs	2 – 5
Physical stability to temperature	4
Reduction in operating temperatures	2
Modular electrolysers	2 – 4
Temperature resistant materials	4 – 6
Optimised component integration	8
Reversible systems	2 – 3

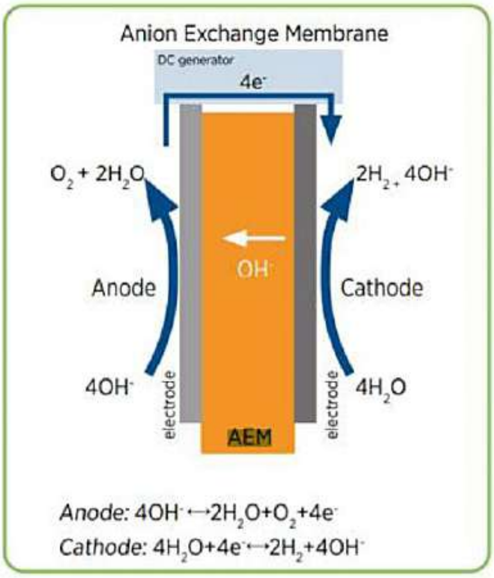
AEM Electrolysers

AEM electrolysers are a low temperature, solid electrolyte emerging technology that combines the benefits of alkaline electrolysers (low material costs) and PEMs (simplicity, compactness). They are not yet fully commercialised but do offer several benefits including material cost savings (non-noble metal catalyst) and low response times giving good compatibility with renewable power loads.

AEM systems are similar in design to PEM electrolysers, with an immobile membrane interface to facilitate ion exchange between two electrodes. One of the key differences is that AEM use anion exchange ionomers (e.g. Tokuyama AS-4, composite) as the solid electrolyte to facilitate Hydroxide ion exchange, unlike PEMs which use acidic membranes (e.g. Nafion) to conduct proton exchange. The kinetics of alkaline electrolysis is ~ 3 times slower than for hydrogen evolution reaction (HER) due to the higher pH of the electrolyte and absence of high active metal surface electrodes, resulting in AEMs having lower current density than PEMs [100].

In theory for AEM electrolysers, water reacts at the cathode and breaks down to hydrogen gas and hydroxide ions. The hydroxide ions are exchanged over the AEM to the anode where they react to form oxygen gas, water and electrons which are routed back to the power supply. Currently, AEM electrolysers also use a water feed with added electrolyte (e.g. dilute KOH) to improve performance.

Figure 8.4 - AEM Hydrogen Generation [91]



The key benefits of the AEM system lie with the low-cost electrode and electrolyte (mostly steel and nickel), the system compactness and overall good efficiencies. Also, the system can operate under a high differential pressure (like PEM) which is preferable as it drives separation and eliminates balance-of-plant high-pressure components on the oxygen side

One of the key system challenges is unstable stack lifetimes due to membrane chemical and mechanical stability problems. The exchange of OH^- ions on the polymer backbone exposes the membrane to degradation, particularly when operated with a supporting KOH electrolyte. A mitigation option is to use a cross-linked polymer, but this comes at the expense of cell efficiency. Alternatively, no supporting electrolyte solution can be used to improve durability but again comes at the expense of efficiencies or current densities.

Another challenge with AEM electrolysis is performance issues due to lower conductivity from slower kinetics of alkaline electrolysis (~3 times slower than HER kinetics). Developers overcome this with a combination of membrane conductivity tuning, additional liquid electrolyte, thinner or higher charge density membranes which come at the expense of system durability.

Table 8.7 - Techno-economic parameters alkaline electrolysis technology [91]

Design parameter	Value
Operating temperature (°C)	40 – 60
Operating pressure (bar)	< 35
Cell area (m2)	0.03
Current density (A/cm2)	0.2 – 2
Hydrogen purity (%)	99.99
System efficiency (kWh/kgH2)	57 – 69
System efficiency (%)	52 – 67
Plant size (MW)	Experimental
Lifetime (hours)	> 5,000
System CAPEX (£/kWel)	N/A

AEM currently have a TRL of 2 – 3 [100]. They are high cost and unproven at large scale but offer large cost-saving opportunities in the near future due to less-expensive materials (particularly titanium, ~50% stack cost for PEM). One of the key hurdles to be overcome for AEM commercialisation is the unstable polymer chemistry, addressing the trade-off between mechanical stability and conductivity at cost. Testing at a laboratory scale of small demonstration units can be used to validate and bring AEMs to TRL 4 – 5.

Large scale AEM electrolysers (MW) are not available on the current market, with the largest available known unit capable of producing 0.5 Nm^3/h of Hydrogen [101]. Enapter are developing a 1 MW AEM Multicore unit which when launched will be able to deliver 210 Nm^3/h of hydrogen (or 450kg/d) [102].

Supercritical

Supercritical Solutions offers an innovative electrolyser technology solution that can reach higher efficiencies than the conventional offerings on the market. The electrolyser system is unique in that it runs at both relatively high temperature and high pressure, yielding operation conditions that can achieve up to 85-95% electrical efficiency. Unlike high-temperature SOE offerings currently, the equipment is expected to be thermally robust in continuous operation and offers a superior stack life expectancy compared to other market offerings.

Table 8.8 - Supercritical Electrolyser performance compared to alternative technologies (by 2030)

Feature	Alkaline	PEM	SOE	Supercritical*
Efficiency (%)	63-72	61-69	74-84	88
Stack life (1,000 hours)	<100	<90	<60	>100

*Results from proof of concept

Supercritical electrolysers operate at temperatures between the relatively ambient temperature of alkaline/ PEM and high temperatures of SOEs and thus can take advantage of waste heat at industrial sites. The system also takes advantage of the lower duty requirements to pressurise liquid water than to compress hydrogen gas, giving savings in compression duty and potentially compression equipment depending on the end-user requirements.

Supercritical Solutions is a UK based clean technology company and is a new player in the market, and thus inherently has a higher risk profile for a route to market. However, progress is being made in bringing the technology to commercialisation. In January 2021, Supercritical secured government funding from BEIS (Dept. for Business, Energy & industrial strategy) to support a feasibility study to decarbonise the distillery sector. They are working closely with industry partners (Beam Suntory, Centre for Process Innovation, Xodus Group, DNV GL and Flex Marine Power) to secure their bid in the Green Distillery Competition, which aims to trial technologies at pilot scale to demonstrate sector decarbonisation strategies.

Supercritical is currently at TRL of ~ 4. With successful feasibility studies leading to pilot plant installations in industrial settings (e.g. whiskey distilleries), the TRL can be expected to progress to 5 – 6.

'sHYp'

The sHYp electrolyser technology's key benefit is its unique ability to use untreated seawater feedstock, negating the need for desalination and deionization. Removing the need for desalination also has an environmental selling point, with conventional desalination having to account for an environmentally hazardous toxic salt sludge by-product.

sHYp offers a low temperature, membrane-less electrolyser system that has the potential to give CAPEX and space savings, particularly in the offshore and shipping industry. The electrolyser and by-products can also be used for alternative applications, including:

- Ballast water treatment;
- Silica (SiO_2);
  - Building and construction, electronics, healthcare, food and beverages, chemicals.
- Carbon capture;
  - Alkaline effluent can be used as a solvent in carbon capture systems. Opportunity to integrate with processes that require CO_2 removal treatment.

It should be noted that studies at Xodus to date have found desalination not to have a great impact on the levelized cost of hydrogen[1] (LCOH) for large scale projects. The impact is likely to be higher for small-scale or decentralised offshore hydrogen production where hydrogen is produced on each turbine foundation but still relatively small compared to other hydrogen equipment.

It is unknown what efficiencies sHYp can yield, but for large scale projects, the technology will likely have to have efficiencies comparable to alternative market offerings or offer a reduced footprint to be a serious market competitor.

As with Supercritical Solutions, sHYp young company status exposes the technology route to market and maturation to large scale to higher risk. However, there have been some promising stage gates achieved for the technology to be demonstrated and make a compelling case for commercialisation.

These include:

- Pilot projects to be installed in Europe, Middle-East and Australia Received a $150k grant from PowerBridgeNY (2019)
- Included in PortXL accelerator (2020), founded in Rotterdam to network start-ups, scale-ups, corporate partners and mentors
- Repsol Foundation award finalist (2020)

sHYp is also currently in talks with the Port of Rotterdam to pilot the technology.

The sHYp electrolyser technology is currently at TRL ~ 3 – 4. With successful feasibility studies leading to pilot plant installations in industrial settings (e.g. Port of Rotterdam), the TRL can be expected to progress to TRL 5 – 6.

1. LCOH presents the cost per energy output of hydrogen in £/kg

8.2.4 Carbon Emissions

The total carbon emissions associated with hydrogen produced by water electrolysis will depend on the electricity supply; this will be very low if electricity is supplied through direct access from offshore wind (there will be some CO_2 footprint associated with the embodied carbon in materials and with ongoing operational activities). Any green hydrogen facilities connected to the electricity grid will emit CO_2 as long as some electricity is supplied by fossil fuels. In Scotland, the proportion of electricity generated by fossil fuels is decreasing rapidly, with 61.1% of electricity generated coming from renewable sources in 2019 compared to 32.3% in England and Wales [103].

8.3 Blue Hydrogen Technologies

Blue hydrogen is typically produced by reforming fossil fuels such as methane from natural gas. The carbon emissions from the production process are captured using CCUS technology and are transported and stored geologically. Blue hydrogen is distinguished from grey hydrogen with the addition of CCUS which reduces the environmental impact of the hydrogen production process.

CCUS has the potential to store significant quantities of CO_2 in geological formations such as depleted oil and gas reservoirs. Hence, blue hydrogen has gained traction in geographies where existing oil and gas infrastructure can be utilised, including the UK.

The threshold for low carbon hydrogen or blue hydrogen, defined by European industry consortium CertifHy, is a 60% reduction in CO_2 emissions compared to a conventional steam methane reformer without CCUS technology [104].

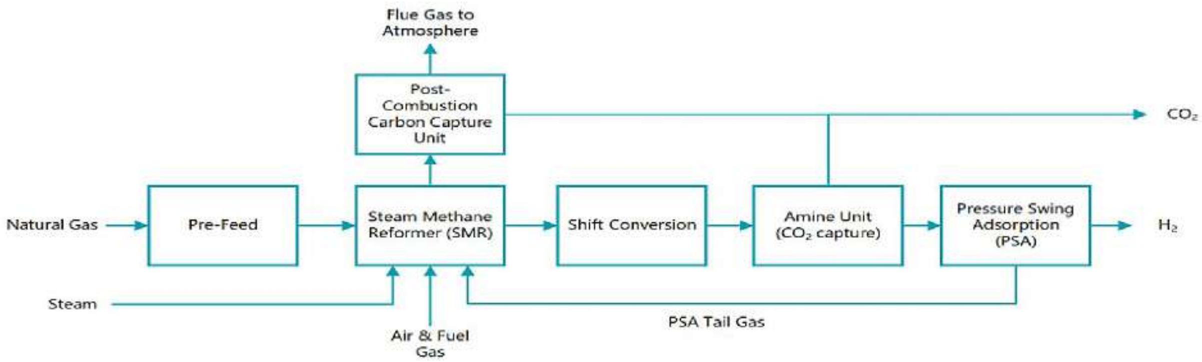
During the ongoing transition to a low carbon economy, the market for blue hydrogen technology providers is becoming increasingly competitive and demanding in terms of energy and process optimisation. Technology providers are facing the challenges of providing economically viable solutions while significantly decreasing CO_2 emissions released into the atmosphere.

The two dominant routes of producing blue hydrogen are SMR and ATR.

8.3.1 Steam Methane Reforming (SMR)

SMR is the process of reacting methane with high-temperature steam in the presence of a catalyst to produce hydrogen, carbon monoxide (CO) and a relatively small volume of CO_2. This gaseous mixture is referred to as syngas. The reaction is endothermic and requires heat to be supplied to the process for the reaction to take place, usually by burning additional natural gas in a reformer furnace. A block diagram of a typical steam methane reforming process with CCUS is displayed in Figure 8.5.

Figure 8.5 - SMR Block Diagram



The natural gas is first purified by removing sulphurous compounds through a desulphurisation step. This prevents poisoning and deactivation of the SMR catalyst which would interfere with the reformer temperature distribution and reduce process efficiency. The purified natural gas then proceeds to the SMR where the methane (CH_4) is reacted with steam at a temperature between 800°C and 1000°C, and a pressure between 20 bar and 30 bar. Heat is supplied through the combustion of fuel gas in a reformer furnace. The catalyst required for the reaction is typically nickel-based.

The chemical equation for the steam methane reforming reaction is given below:

CH_4+H_2O *(+heat)->* $CO+3H_2$

A secondary reaction then occurs called the water-gas shift reaction where the CO and steam are reacted to form more hydrogen and CO_2.

The chemical equation for the water-gas shift reaction is given below:

$CO+H_2O->CO_2+H_2$*(+small amount of heat*)

Conventional SMR produces CO_2 during both the water-gas shift reaction and the combustion of the fuel gas required to heat the SMR reaction. The CO_2 from the water-gas shift reaction is contained within the high-pressure product stream and is relatively simple to extract using pre-combustion carbon capture methods.

CO_2 is typically removed from the product stream using chemical adsorption methods, such as amine-based or hot potassium carbonate solvents. Modern SMR plants also use physical adsorption technology, such as pressure swing adsorption (PSA), to remove further waste gases and purify the hydrogen product.

However, the CO_2 from the combustion reaction that exits the furnace as flue gas is released at atmospheric pressure and low concentrations. The CO_2 must be removed from the flue gas to achieve high carbon capture rates. The removal requires post-combustion carbon capture equipment, which includes additional high-volume equipment to compress the gas for transport and storage and remove other flue gas substances such as oxygen, sulphur, and NOx gases.

Advantages of SMR

SMR is a proven and relatively simple technology. It is the most widely applied technology in the world for generating hydrogen with 50% of the world's hydrogen produced by this method [105].

A key advantage of SMR compared to ATR is that the process does not require a stream of pure oxygen to proceed. The SMR plants, therefore, have typically lower CAPEX than ATR plants because an air separation unit (ASU) to produce oxygen is not required.

Disadvantages of SMR

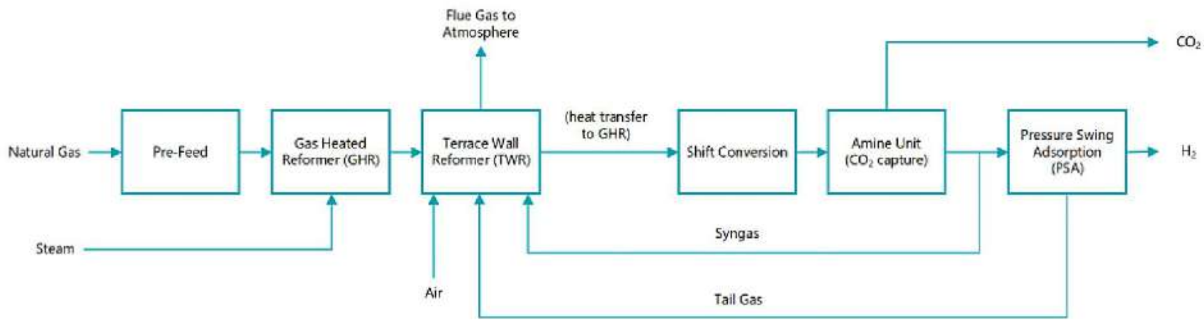
SMR requires an additional supply of natural gas for combustion in the reformer furnace which introduces greater operating expenditure (OPEX).

The removal of the low-pressure CO_2 from the flue gas requires large post-combustion carbon capture equipment which incurs high CAPEX. The equipment also significantly increases the required plot area of the SMR plant.

Enhanced SMR Technology: Blue^{H2} – Wood PLC

The Blue^{H2} hydrogen production technology proposed by Wood [106] enhances standard SMR technology with the inclusion of a gas-heated reformer (GHR) and terrace wall reformer (TWR). The GHR recycles heat from the syngas stream exiting the TWR to reform methane and the TWR is a compact SMR design with uniform heating. The combination of the technologies improve energy and process efficiency and decrease overall CO_2 emissions compared to conventional SMR technology. A block diagram of the SMR process featuring the GHR and TWR is displayed in Figure 8.6.

Figure 8.6 - BlueH2 Block Diagram



Natural gas is initially pre-heated, desulphurised and pre-formed before entering the GHR. The GHR is a vertical vessel containing vertically supported tubes filled with catalyst. In the GHR, methane is partially converted to hydrogen and carbon monoxide in an endothermic reaction. The process gas is heated in the GHR by the heat from the syngas exiting the TWR. This results in the gas leaving the GHR achieving the desired inlet temperature for the TWR, as well as the reaction in the GHR achieving the desired methane concentration at the GHR outlet.

The process gas then exits the GHR and is fed to the main reformer. As the process gas passes through the TWR reaction tubes, the final conversion of methane to hydrogen and carbon monoxide takes place. The reforming reaction is strongly endothermic and requires high process temperatures to favour greater equilibrium concentrations of carbon monoxide and hydrogen. The TWR is a proprietary Wood technology, which features a high-efficiency radiant section providing a uniform heat flux along the length of the single row catalyst tubes. The syngas exits the TWR and enters the shell side of the GHR, exchanging heat to the TWR feed stream.

The syngas stream is then fed through a cooling train, which consists of a series of heat exchangers. The syngas then passes through the shift reactors, where the CO present in the syngas is 'shifted' to CO_2 through the water-gas shift reaction.

After the reaction in the shift reactor, the syngas is cooled further before it is sent to the amine unit for removal of the CO_2. The syngas product leaving the amine unit is then divided into two streams. One stream of syngas is sent to the TWR furnace as fuel gas for heating the catalyst tubes, and the second stream of syngas is sent to a PSA unit. Hydrogen is separated from the syngas in the PSA unit and the residual tail gas is sent to the TWR as supplemental fuel for the firing of the reformer furnace. From the PSA unit, the hydrogen product stream is sent to the battery limit. A proportion of the hydrogen is separated from the product stream to be recycled at the front of the process for the hydrogenation of sulphur-containing compounds in the feed stream.

Technology Readiness

The Blue^{H2} hydrogen production technology is an enhancement of existing licensed technology developed by Wood. Over 300 terrace wall steam reformers have been installed by Wood proving the fired heating technology is well established. The installation of a TWR is displayed in Figure 8.7 and an operational hydrogen plant designed and built by Wood in North Tees is displayed in Figure 8.8. The cores of the hydrogen production and purification process are also based on similarly established SMR and PSA methods.

Figure 8.7 - Construction of a TWR

Figure 8.8 - Wood SMR Hydrogen Plant, North Tees

The GHR is an in-house development by Wood. The design phase has been completed and a piloting phase is expected to commence in Q3 2021. With a single novel equipment design, the TRL of the overall design can be brought up to TRL 7 (sub-scale demonstration of a fully functional prototype) through limited pilot-testing of the GHR.

Benefits of Blue^{H2} Technology

The Blue^{H2} hydrogen production system presents several improvements over standard SMR featuring post-combustion CO_2 capture. The GHR increases energy efficiency by recycling heat from the hot product stream, which minimises fuel gas consumption and steam production. The increased energy efficiency of the GHR also decreases net CO_2 production.

Post-combustion carbon capture is not required with the Blue^{H2} system to achieve high carbon capture rates since the released flue gas has minimal CO_2 content. The flue gas is mostly made of water vapour from the combusted syngas that is imported to the furnace after CO_2 removal. No post-combustion carbon capture equipment means the plot area and CAPEX of the plant can be significantly reduced. It also results in a reduction in energy consumption and OPEX. CO_2 is instead captured from the high pressure and high concentration syngas.

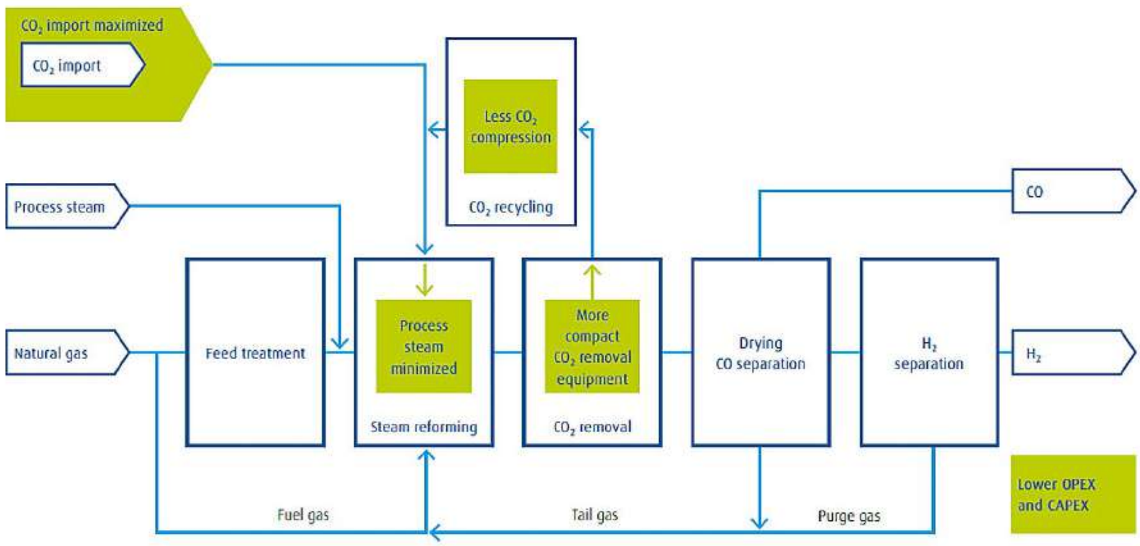
The TWR provides further benefits to the system. The symmetrical TWR design provides improved heat distribution to the catalysts which improve the process efficiency. The favourable outlet temperature of the TWR, which can exceed 920°C, also improves the carbon capture performance of the system.

The TWR also has a compact modular design which further reduces the required plot area of the plant. The reformer can be prefabricated off-site with minimal construction required on site. For smaller capacities, a total modular solution is also possible. Maximising modularisation and minimising onsite work provide better quality control and lower installation costs.

8.3.3 Enhanced SMR Technology: DRYREF – Linde

DRYREF syngas generation technology developed by Linde [107] enhances standard SMR technology by importing CO_2 into the process to enable dry reforming with methane which reduces the required quantity of steam. DRYREF technology is combined with SYNSPIRE catalysts developed by BASF to enable operation at a reduced steam to carbon (S: C) ratio. A block diagram of the DRYREF process is displayed in Figure 8.9.

Figure 8.9 - DRYREF Block Diagram



Technology Readiness

Commercial readiness of the DRYREF technology with BASF SYNSPIRE catalyst has been demonstrated at Linde's industrial-scale syngas generating HyCO plants since 2017. A Linde HyCO plant is displayed in Figure 8.10.

Figure 8.10 - Linde HyCO Plant. (Source: HyCO Plants|Linde Gas (linde-gas.com)

Benefits of DRYREF Technology with SYNSPIRE Catalyst

DRYREF technology involves importing CO_2 to the reformer from the battery limit which provides several benefits compared to conventional SMR technology. Importing CO_2 into the process, instead of a substantial fraction of natural gas, reduces the S: C ratio in the reformer. The reduced quantity of steam required in the reforming process results in OPEX savings from reduced energy consumption and CAPEX savings from smaller boiler and steam equipment sizes.

Importing CO_2 also improves the thermodynamic equilibrium which improves process efficiency and reduces net CO_2 emissions. The plant consequently has a reduced post-combustion carbon capture footprint which results in further CAPEX savings and OPEX savings from reduced recompression energy.

The key benefit of the SYNSPIRE catalyst is the stabilised crystal structure which prevents coke deposition and subsequent deactivation under low S: C conditions. This means the DRYREF technology can import CO_2 into the SMR process, and the reaction can proceed at lower S: C ratios.

8.3.4 Enhanced SMR Technology: Compact H2 Generator (CHG) – Cranfield University

The Compact H2 Generator (CHG) developed by Cranfield University [108] enables bulk hydrogen production by sorbent enhanced steam reforming. The CHG technology features two main reactors in the process: A fluidised bed reactor acting as a steam methane reformer and a calciner utilising an entrained flow reactor that separates and removes the CO_2 from the system in a solid phase.

The sorbent enhanced steam reforming process is a second-generation hydrogen production process that offers a simpler process layout compared to the conventional SMR. After purification of the natural gas, methane is steam reformed within the fluidised bed reactor to form syngas. The CO content of the syngas is converted into CO_2 by the water gas shift reaction while also producing more hydrogen. The CO_2 is then captured in the heated calciner with calcium oxide (CaO) sorbent and removed from the product stream. The relatively pure hydrogen stream is further purified by a PSA unit.

Technology Readiness

The CHG technology is based on existing Gas Technology Institute (GTI) technology. A small low-pressure pilot-scale (0.071 MWth) process of the CHG technology has been successfully demonstrated. However, a larger high-pressure pilot-scale (1.5 MWth) demonstration of the CHG process is still in development.

Benefits of CHG technology

The CHG presents several improvements over standard SMR featuring post-combustion CO_2 capture. Notably, the carbon capture efficiency and hydrogen yield of the system are significantly improved with the inclusion of a hydrogen membrane unit. Carbon capture rates of up to 98% are achievable with CHG technology.

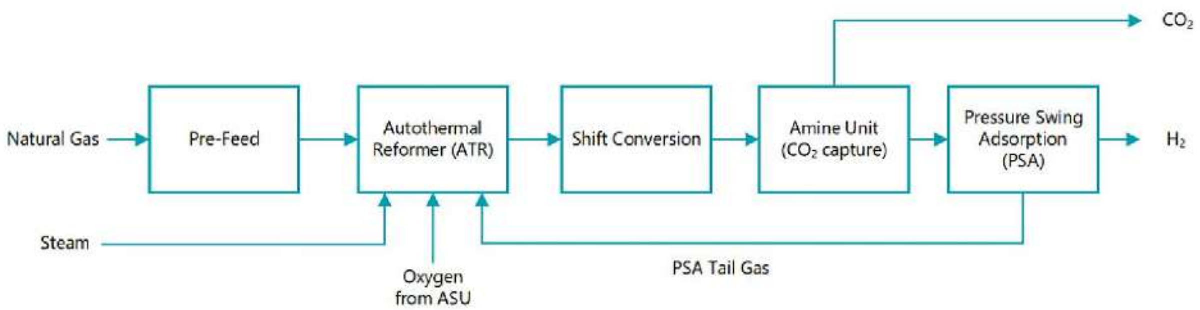
An AACE Class IV cost estimate of the CHG technology also revealed cost savings compared with conventional SMR technology. The CAPEX of the plant is estimated to be reduced by 50%, largely due to the improved carbon system, and the LCOH is estimated to be reduced by 20%.

Furthermore, the technology is scalable to meet different hydrogen production requirements. Three principle CHG units are proposed: a 10 MWth small industrial scale unit; a 50 MWth small utility-scale unit; and a 300 MWth large utility-scale unit, initially with a twin train concept (150 MWth each). A 1,500 MWth system has also been proposed by Cranfield University that comprises 5 large utility-scale CHG deployable modules.

8.3.5 Autothermal Reforming (ATR)

ATR, also known as oxidative steam reforming, is a hydrogen production process combining partial oxidation (POX) with SMR in a single reaction chamber. The partial oxidation process involves the reaction of oxygen with methane. The POX of methane is a non-catalytic exothermic reaction while the reforming of methane with steam is a catalytic endothermic reaction. The quantity of the oxidant can be adjusted such that the POX reaction provides all the heat energy for the SMR reaction to proceed. Therefore, external input of heat is not required. A block diagram of a typical ATR process with CCUS is displayed in Figure 8.11.

Figure 8.11 - ATR Block Diagram



Similar to the described SMR process, the ATR process requires natural gas to be purified before proceeding to the reforming phase. POX occurs when the methane reacts with a limited quantity of oxygen (less than the stoichiometric quantity) that is insufficient to completely oxidise the methane to CO_2 and water. The partial oxidation reaction, therefore, produces CO and hydrogen.

Pure oxygen or oxygen-rich air can be added as the oxidant to the reaction. However, the nitrogen content of air would require removal downstream during purification of the hydrogen and therefore pure oxygen is preferred. Oxygen can be produced by methods including cryogenic distillation or vacuum swing adsorption. The chemical equation for the POX of methane is given below:

$$CH_4 + \frac{1}{2}O_2 \rightarrow CO + 2H_2\ (+heat)$$

The ATR reaction chamber simultaneously performs the SMR reaction with the heat supplied from the oxidative reaction. The chemical equation for the SMR reaction is given below:

$$CH_4 + H_2O\ (+heat) \rightarrow CO + 3H_2$$

The water-gas shift reaction then occurs where the CO and steam are reacted to form more hydrogen and CO_2. The chemical equation for the water-gas shift reaction is given below:

$$CO + H_2O \rightarrow CO_2 + H_2\ (+small\ amount\ of\ heat)$$

Finally, the CO_2 from the water-gas shift reaction is contained within the hot product stream and proceeds to the carbon capture unit where the CO_2 is captured using chemical or physical adsorption methods.

Advantages of ATR

ATR technology is commonly used to produce syngas for Fischer-Tropsch processes in large-scale methanol production plants. This proves the technology is scalable and can produce significant quantities of hydrogen in a single production train.

The ATR process heats the SMR reaction from the exothermic POX reaction which brings several advantages. OPEX is reduced since no fuel gas is required to heat a reaction furnace. Additionally, all CO_2 produced in the process is contained within the high pressure and high purity product stream and no CO_2 is released from combustion as flue gas. This results in a simpler carbon capture system and higher carbon capture rates. The reduced size and complexity of the carbon capture system also lower the overall CAPEX and plot area of the plant.

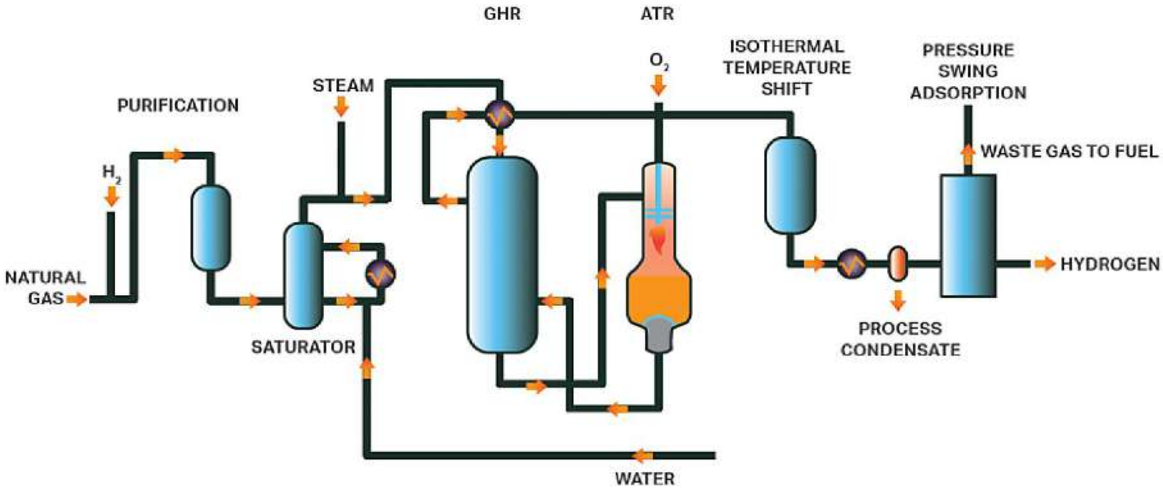
Disadvantages of ATR

The POX reaction requires pure oxygen which must be produced by an ASU. The ASU has a high-power requirement which results in a significant increase in OPEX. The ASU also presents a large CAPEX investment with a poor economy of scale for hydrogen production outputs up to 90,000 Nm^3/h [109]. Therefore, ATR is not considered economical for smaller plants with lower hydrogen production rates.

8.3.6 Enhanced ATR Technology: Low Carbon Hydrogen (LCH) – Johnson Matthey

Low carbon hydrogen (LCH) is a hydrogen production technology developed by Johnson Matthey [110] that couples an ATR unit with a GHR. The GHR recycles heat from the syngas stream exiting the ATR to reform methane. A block diagram of the LCH process featuring the ATR and GHR is displayed in Figure 8.12.

Figure 8.12 - LCH Block Diagram



Natural gas is first purified and pre-heated before entering the GHR. The GHR functions as a simple interchanger. The heat from the hot product stream of the ATR process is transferred to the GHR to perform an endothermic SMR reaction. The GHR reforms 30% of the total methane with steam to form syngas.

The partially reformed gas is then fed to the ATR and combusted with oxygen, delivered from an ASU, to partially oxidise the methane and increase the process gas temperature to 1,500°C. Further reforming occurs when the resultant gas passes through a bed of steam reforming catalysts inside the ATR reactor.

The hot product gas exits the ATR and is cooled by passing through the GHR which recycles heat to perform the steam methane reforming reaction during pre-feed of the ATR.
The cooled product gas then proceeds at high pressure to a high-efficiency isothermal temperature shift reactor that converts CO and steam in the syngas to more CO_2 and hydrogen through a water-gas shift reaction. The isothermal temperature shift reactor also recovers medium grade heat to produce steam with recycled process condensate from a saturator circuit.

The product stream from the shift reactor proceeds to the amine-based carbon capture unit where CO_2 is removed. The remaining hydrogen in the product stream is further purified with a PSA unit.

Technology Readiness

LCH technology builds upon ammonia and methanol commercialised ATR flowsheets developed by Johnson Matthey. The GHR technology has already been used in 3 ammonia plants and 1 methanol plant designed by Johnson Matthey. The methanol ATR plant with GHR for syngas production is displayed in Figure 8.13.

Figure 8.13 - Johnson Matthey ATR Plant, Geismar, Louisiana

Benefits of LCH Technology
The LCH technology proposed by Johnson Matthey offers several benefits compared to standard ATR technology. LCH technology has a high carbon capture rate. The CO_2 is contained within the process which gives the LCH technology a comparatively high carbon capture rate of up to 97%.

Recovering the CO_2 at high pressure and temperature within the product stream improves the carbon capture performance of the amine unit and negates the requirement of compression before carbon capture, introducing CAPEX savings from the reduced size of the carbon removal system and OPEX savings from reduced energy consumption.

LCH technology also has improved energy and conversion efficiency compared to standard ATR technology. The heat is recycled at a higher quality and is used to support the SMR reaction in the GHR, meaning the process is more energy efficient and atmospheric carbon emissions are reduced. Furthermore, a greater quantity of methane is converted to hydrogen because the reforming reaction is operated at a higher temperature by an oxygen blown ATR that minimises methane slip.

8.3.7 Alternative Technologies

Shell Gas POx (SGP) – Shell
SGP is a blue hydrogen technology developed by Shell Catalysts & Technologies [111] The SGP technology is based on a non-catalytic partial oxidation reaction process to produce hydrogen and is coupled with ADIP ULTRA solvent technology for carbon capture. The main advantage of the SGP technology compared to ATR or SMR is reduced process complexity. Without the catalyst, there is no requirement to pre-treat the natural gas before entering the process which reduces the CAPEX required for purification equipment. The SGP technology is more flexible with feed gas quality and can handle feed contaminants.

The energy balance of the SGP technology is also designed to maximise efficiency and provide OPEX savings. The SGP process does not require steam to operate like SMR or ATR processes. Steam is instead produced from the exothermic oxidation reaction heat and can be used in other parts of the process, reducing overall imported power.

However, the oxygen is usually produced in an ASU, which considerably increases the CAPEX of the plant and increases the energy consumption of the process. Energy consumption can be offset to an extent by the extraction of heat from the exothermic reaction.

Emissions Free Hydrogen – Monolith Materials
Emissions free hydrogen technology developed by Monolith Materials [112] is a potentially disruptive technique for blue hydrogen production. The technique utilises plasma-based pyrolysis to heat the reaction using electrical power meaning no CO_2 is produced by combustion. The technology converts natural gas feedstock into carbon black and hydrogen, instead of CO_2 and hydrogen. Carbon black is a material produced by the incomplete combustion of hydrocarbons that can be used to form commercial products.

The technology has the potential to be completely emissions free, including free of offsite emissions, if the electrical power is delivered to the process from renewable energy sources.

Olive Creek 1, displayed in Figure 8.14, is Monolith Materials' first commercial-scale emissions-free production facility designed to produce carbon black and clean hydrogen.

Figure 8.14 - Monolith Materials Emissions Free Hydrogen Plant, Olive Creek, Nebraska

8.3.8 Carbon Capture & Emissions

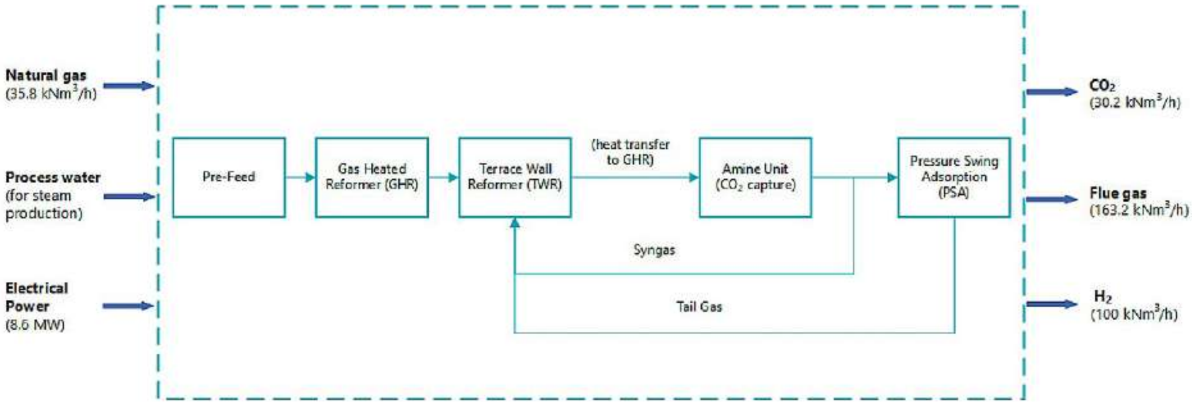
Standard SMR
Standard SMR can achieve fair carbon capture rates (90%) through costly post-combustion carbon capture systems. The onsite carbon emissions (8,700 kg CO_2/h) are relatively high compared to the other technologies due to the lower carbon capture rate. However, offsite carbon emissions are effectively zero since power can be generated with steam from the process and does not require to be imported from an offsite source. Therefore, net carbon emissions (8,700 kg CO_2/h) are competitive.

Enhanced SMR
Enhanced SMR has a greater carbon capture rate (93%) than standard SMR because of improvements to the carbon capture system. Most of the CO_2 produced in the process is contained within the product stream and only a small concentration of CO_2 is present in the

flue gas. The onsite carbon emissions (5,400 kg CO_2/h) are therefore lower than standard SMR. However, offsite carbon emissions (2,500 kg CO_2/h) are greater than standard SMR because electrical power is required to be imported from an offsite source. Therefore, net carbon emissions (7,900 kg CO_2/h) are only slightly lower than standard SMR.

A high-level process flow of an enhanced SMR plant with a hydrogen production rate of 100,000 Nm^3/h can be seen in Figure 8.15 with quantities of inputs and outputs.

Figure 8.15 – Enhanced SMR Process Flow



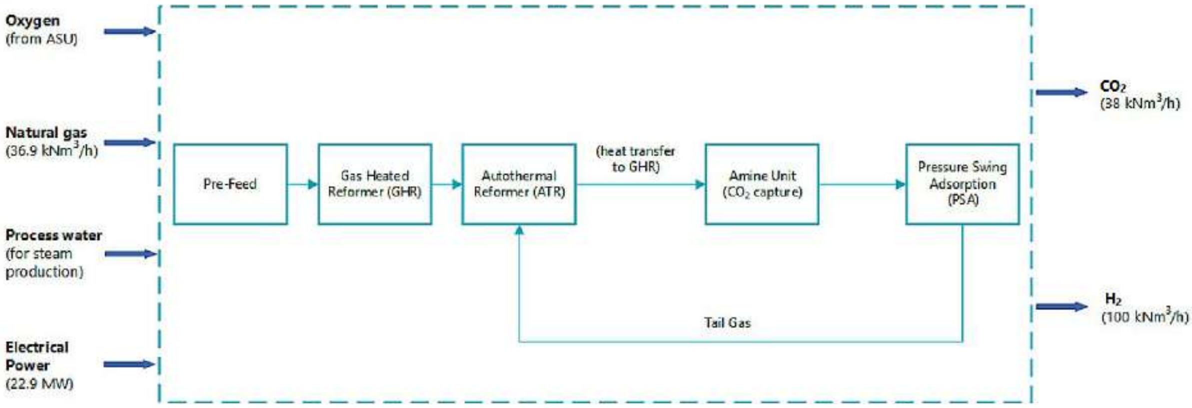
Enhanced ATR

Enhanced ATR has the highest carbon capture rate (up to 97%) of the technologies under comparison. All the CO_2 produced in the process is contained within the high-pressure product stream and is simpler to extract. The high capture rate results in low onsite carbon emissions (2,200 kg CO_2/h). However, offsite carbon emissions (6,800 kg CO_2/h) mainly for electrical powering of the ASU should be factored in for enhanced ATR. This significantly increases the net carbon emissions (9,000 kg CO_2/h) to become higher than the comparable technologies.

However, power can be sourced from renewable energy sources since the compression energy for the ASU can be supplied electrically. The offsite carbon emissions can therefore be significantly reduced if renewable energy is integrated, which results in lower net carbon emissions compared to the other technologies.

A high-level process flow of an enhanced ATR plant with a hydrogen production rate of 100,000 Nm^3/h can be seen in Figure 8.16 with quantities of inputs and outputs.

Figure 8.16 - Enhanced ATR Process Flow



8.4 Transport and Storage Technologies

8.4.1 Overview

Being the lightest molecule, the storage and transport of hydrogen can be challenging due to its low density. 1kg of hydrogen gas occupies over 11m^3 of space at atmospheric conditions so for its distribution to be economically viable, the density of hydrogen must be increased. This will reduce the size required or increase capacity for hydrogen stored. Hydrogen is distributed either as a pure gas or it can be converted to or carried in another chemical.

Pure hydrogen is transported as either a compressed gas (GH_2) or a cryogenic liquid (LH_2). When hydrogen is converted to or carried in another medium, there are two main types:

- Those that will be used in that form by the user;
    - Ammonia (NH_3) or methanol (CH_3OH) can be used directly as fuels, as products, or as feedstocks into other production processes.
- Those where pure hydrogen will be recovered from the medium at the 'user' end of the transport chain;
    - Liquid organic hydrogen carriers (LOHC) are used in this way, as well as NH_3. Metal organic frameworks (MOF) are different in that a pure hydrogen stream is 'de-blended' from a natural gas pipeline where hydrogen has been mixed with the natural gas.

Transport of hydrogen at scale (at the scale considered in this study) practically needs to be either by pipeline or by ship – analogous to natural gas / liquid natural gas (LNG) transport. Transport by road is possible, but this is only a practical option for smaller scale production. The suitability of each type of transport for road transport is referenced, as this may influence the scalability of a production scheme.

The hydrogen transport and storage technologies considered are compared in Table 8.9 below. The optimal choice of hydrogen carrier depends on the intended final use, purity requirements and the need for long-term storage. Each is discussed in more detail in the following sections.

Table 8.9 - Comparison of hydrogen storage and transport technologies

		GH2	LH2	Ammonia	Methanol	LOHC	MOF	Ref.
Type		Pure H2	Pure H2	H_2 reacted	H2 reacted	H2 reacted	H2 de-blending	
Transport route		Pipeline	Ship	Ship	Ship	Ship	Pipeline	
TRL: Technology, Storage & Transport)		All 9	Tech 6-9, Storage 9, Transport 4	All 9	All 9	Tech 6, Storage 9, Transport 9	All 4 – 5	[55] [113]
Scale	Current	180mile H_2 pipeline transporting 1bn scfd	Tech: 34tn LH_2/day Transport: 1,250m^3	Tech: 3,300tn/d Transport: 80,000m^3	Tech: 4,500tn/d Transport: 120,000m^3	Tech: Up to 5,000m^3 using MCH Transport: 75,000tn	Tech: 100Nm^3/h Transport: H_2 not suitable in NTS	[113] [17] [114]
	2030	As above	Transport: 160,000m^3 LH_2 v	As above	Tech: 8000tn/y CH3OH by 2022	Tech: 350,000tn/y H_2 by 2030	Tech: Data not available Transport: Up to 20% by vol H_2 in NTS	[115] [116] [117] [118]
Equipment needed	Producer	Compression package	H_2 liquefier plant	Haber-Bosch plant	Methanol synthesis plant	Hydrogenation	None	
	User	None	None	None for direct use	None for direct use	De-hydrogenation	Palladium membranes	
Energy requirements (% of LHV H_2)		8-13% (depends on final gas pressure)	25-35%	7-18%	Data not available	35-40%	60%	[55] [119]
Costs (£/kg H_2)	Conversion	0.8	0.8	0.8	0.5	0.3	N/A (R&D)	[55]
	Transport & Storage, 1500km		0.9	0.15	0.02	0.2	N/A (R&D)	[55]
	Reconversion	None	None for direct use	None for direct use	None for direct use	0.8 – 1.6	N/A (R&D)	[55]
Area required – conversion & storage		Tech: 0.1-0.2% total footprint needed for compression Storage: ~0.2m^2/kWh (HHV)	Tech: Possible up to 6.5tn/h = 100,000m^2 Storage: Largest 3,800m^3 = 315m^2 (NASA, USA)	Tech: Largest NH_3 capacity (3300tn/d) = 5,661m^2 (includes storage)	Tech: Largest CH_3OH capacity (4,500tn/d) = 13,500m^2	Data not available	N/A (R&D)	[117] [120] [121] [122] [123]

Note: Data not available within the references used

8.4.2 Compressed Hydrogen

Transport of pure hydrogen gas

Hydrogen is commonly stored and transported as a compressed gas. Currently, 85% of compressed hydrogen is consumed on-site, with the remaining 15% being transported via pipelines or trucks [55].

There is approximately 40km of hydrogen pipelines in operation today in the UK, totalling 1,500km in Western Europe. These are predominantly operated by hydrogen producers for local transmission to nearby industrial sites. This represents a small fraction of the 1.9 million km of natural gas transmission networks in Europe [124].

One cost-optimal alternative is to re-purpose (retrofit) existing natural gas pipelines for the transport of pure hydrogen. Compared to natural gas, hydrogen has a lower molecular weight, viscosity and compressibility and higher energy density. Under fixed conditions of pipe size and pressure drop, replacing natural gas with a lighter fuel like hydrogen will increase the volumetric flowrate. On contrary, the increased compressibility factor of hydrogen decreases the volumetric flowrate by a similar amount [124]. Lastly, due to the lower molecular weight of hydrogen, the pressure increase of hydrogen would be lower than natural gas if the same reciprocating compressors in the natural gas grid were used so more compression stages would be required [124].

Retrofitting oil and gas pipelines has already been demonstrated offshore, where the pipeline material and dimensions meet the requirements for safe operation. However, not all pipelines will meet these requirements but could be made compatible with additions such as polymer liners [17].

Alternatively, new hydrogen pipelines can be constructed. The current hydrogen network consists of 8" and 12" pipelines made of carbon steel (API 5L or ASTM-specified grades) with design pressures between 40 to 60 bar [125] The benefits of a new hydrogen pipeline include low operational costs and long lifetimes up to 80 years. Though, installing a dedicated hydrogen network require rights of way in competition with the current gas grid and is the least cost-optimal method for hydrogen transport through pipelines due to its high capital cost.

One major concern for pipeline transport of hydrogen is its potential diffusion through the pipeline material, which will result in degradation caused by hydrogen embrittlement and trapping. Hydrogen embrittlement (hydrogen-induced cracking) occurs when a metal becomes brittle due to exposure to and diffusion of hydrogen through the material. The process is yet to be fully understood, however for hydrogen embrittlement to occur it is understood that the material must be susceptible to hydrogen diffusion under stress [126]. The key properties for pipelines transporting hydrogen are high toughness (good ductility) and low hardness. To achieve this, the recommendation is to use micro-alloyed steels with controlled chemistry and a manufacturing process to limit the number of non-metallic inclusions, provide fine-grain microstructure (better toughness) and reduce the carbon equivalent (lower hardness). The other cause of fatigue is trapping, which hydrogen is particularly susceptible to due to its low solubility and high diffusivity. Traps within the metal lattice act to increase the severity of hydrogen embrittlement. To reduce the risk for hydrogen embrittlement in hydrogen pipelines, the recommended pipeline material grades are API X42 and X52 due to their low strength which provides resistance to brittle fracture. The pipelines should also have a maximum operating pressure such that the maximum stress at pipeline walls is less than 30-50% of the minimum specified yield strength [17].

For local distribution, compressed hydrogen is transported by trucks in pressurised gas cylinders called CGH2 tube trailers. A single tube trailer can transport approximately 500kg of hydrogen, whilst for larger transporting volumes, multiple tubes can be bundled together with a capacity of 1,100kg of hydrogen at 500bar per truck [127].

Scotland has several oil terminals or ports that could be redeveloped to accommodate the ship-based export of hydrogen. Global Energy Ventures announced plans to offer the world's first compressed hydrogen ship that would be capable of transporting 2,000 tonnes of hydrogen under pressure [128]. Generally, transportation of compressed hydrogen by vessel is not considered feasible due to the low energy storage density achieved at conventional pressures or the ultra-high pressures required to overcome this.

As transport distance increases beyond local distribution, pipelines become cost-competitive with trucks; a critical consideration being the quantity of hydrogen required by the end-user as large volumes are only possible through pipelines and would reduce the relative cost of delivery. Most local distribution relies on tankers for distances up to 300km costing £0.9/kg H_2. In general, for distances past 300km up to 1,500km, installing new long-distance hydrogen pipelines have a combined capital and operating cost of £0.8/kg H_2 for overland transmission in addition to the existing hydrogen production cost. After 1,500km, transport as Power-to-Fuels such as ammonia becomes preferable as the escalation of costs is slower for longer distances since a greater number of compressor stations is required for compressed hydrogen [55].

The transmission of compressed hydrogen through a pipeline is considered the most cost-effective transport option, however, not all hydrogen pipelines are equal. Onshore transmission, subsea transmission and distribution pipelines all have different associated CAPEX costs, which also depend on whether a new network is installed or an existing one retrofitted. The CAPEX costs and ease of retrofitting are shown in Table 8.10.

Table 8.10 - Comparison of new and retrofitted hydrogen pipelines [129]

		Onshore transmission	Subsea transmission	Distribution
Description		Long-distance, high-pressure of large volumes of hydrogen on land	Long-distance, high-pressure of large volumes of hydrogen offshore	Shorter, low-pressure delivery to end-users
CAPEX (£M/km)	New	1.7 – 3.5	3.7 – 5.5	0.2 – 0.5
	Retrofit	0.5 – 0.9	1 – 2.4	0.1 – 0.2
Ease of Retrofitting		High	Low	Medium

Hydrogen Blending/De-blending

53% of Scotland's total energy demand comes from heating for commercial and residential buildings [130]. In 2015, natural gas was used as the primary heating fuel in 79% of all Scottish homes and switching from natural gas to hydrogen has been identified as one method to continue decarbonising and achieving climate targets [130]. Hydrogen in the UK gas grid is not a new concept, as town gas containing up to 60% hydrogen was used by both residents and industries until the transition to a natural gas grid in the 1970s following its discovery. The UK's National Transmission System (NTS) consists of a pipeline network of 284,000km, gas compression stations, gas stations and storage facilities, transporting natural gas from terminals to commercial and domestic users. It has been demonstrated that up to 20% by volume of hydrogen could be blended into the current NTS infrastructure with no impact to the end domestic user, reducing carbon dioxide emissions from the heating industry [131].

At present, providing a transition period with hydrogen-natural gas mixtures is more realistic than a pure hydrogen gas network. gas within Britain's transmission network can contain a maximum of 0.1% hydrogen [131]. Pilot projects already are taking place in Europe to introduce hydrogen blending from 20% up to a full 100% hydrogen network [130].

In the UK, approximately 35,000GWh of hydrogen would need to be injected into the UK NTS to achieve a hydrogen-blended gas grid of 2% by volume of hydrogen. Increasing this percentage towards a hydrogen economy, increasing to 10% and 20% blend in the entire UK NTS by volume would require sites generating 175TWh and 3,500TWh of hydrogen, respectively [132].

As with a pure hydrogen stream, when hydrogen is injected into an existing natural gas stream, there is a risk for hydrogen to diffuse through the pipeline metal. The compatibility of existing natural gas pipelines has been investigated to withstand a hydrogen-blend and show that hydrogen does not influence the fatigue properties of steel and risk any crack propagation for steel grades between X42 and X70 [133].

Gas compressors and compression stations positioned around the UK are essential to maintaining the pressure of natural gas and overcoming pressure decay as it transports through the NTS. They also support the distribution of natural gas by boosting its exit pressures. Compressor performance is characterised by four relationships of maximum and minimum operation speed, surge and choke. Within this envelope, the compressor will operate safely however its functionality would need to be reassessed if the compressor were re-used for hydrogen service. For both reciprocal and centrifugal compressors, areas for investigation would include the compatibility of materials in contact with any hydrogen, effect on the operational envelope of the compressor, the potential of lubricant contamination and tolerability of loses through seals [134]. Both compressor types demonstrate that they can tolerate up to 10% by volume of hydrogen in the gas stream, however, the use of centrifugal compressors for a pure hydrogen stream has been deemed impractical [124].

Once innovation and safety trials allow gas companies to mix more hydrogen into the grid, large volumes of hydrogen will need to be injected into entry points to the NTS. Notably in Scotland, the National Grid terminal at St. Fergus is an essential asset for Britain's gas distribution network. The terminal is an entry point for three delivery facility operators – Shell Esso, Ancala and the North Sea Midstream. Collectively, they provide between 25 – 50% of Britain's total daily gas requirements [124]. Scotland demands approximately 15 – 20% of the volume injected into the NTS, with the remaining gas distributed into England.

Hydrogen deblending offers a solution to allow existing NTS to transport energy has a high-volume hydrogen blended gas stream. The main technologies that are commercially available to separate hydrogen from a blended stream include cryogenic separation, polymer or palladium membrane separation (use of MOF – see Section 8.4.7) and PSA. Cryogenic separation alone or combined membrane separation and PSA have been suggested as possible schemes that can provide >98 mol% pure hydrogen stream [113]. The additional cost of deblending is very sensitive to the volume of blended hydrogen and is not considered feasible for feed gas with less than 20% blended hydrogen [113].

Hydrogen Gas Storage

The storage density of hydrogen must be increased to be considered economically viable; as a gas at ambient conditions, 1kg of hydrogen at atmospheric conditions occupies a space of $11m^3$ [135].

Hydrogen gas can be stored in small to medium quantities in pressurised steel tanks, similar to high-pressure tubes used for their transport via truck. Medium pressure (5-8MPa) vertical tanks with a volume of 95m3 would store approximately 400kg of hydrogen with an installed cost of £182,000 per vessel [121]. This translates to a capital cost of £11.45/kWhLHV and OPEX of £0.34/kWh. Larger storage capacities would be provided by installing 'farms' with arrays of multiple vessels. For example, a farm with 20 single vessels would store 380,000kWhh of compressed hydrogen. High pressure storage vessels store compressed hydrogen at 43MPa in horizontally stacked tubes with capacities over 47,000kWh. Hydrogen in high-pressures tubes would need to be extracted from a hydrogen pipeline and compressed before storage and assumed to provide storage as part of a daily cycle. The total capital cost for one and two daily cycles from a 47,000kWh high-pressure storage facility would be £55/kWh and £74/kWh, respectively and operating costs between £1-2/kWh [53]. The future target for high pressure hydrogen storage aims to reduce the capital cost by £20/kWh for both one and two daily cycles by production scale-up and reduced steel prices.

The footprint for above ground compressed hydrogen storage is estimated at 0.2m2/kWhHHV [53].

Figure 8.17 - Medium (left) and high (right) pressure storage of compressed hydrogen

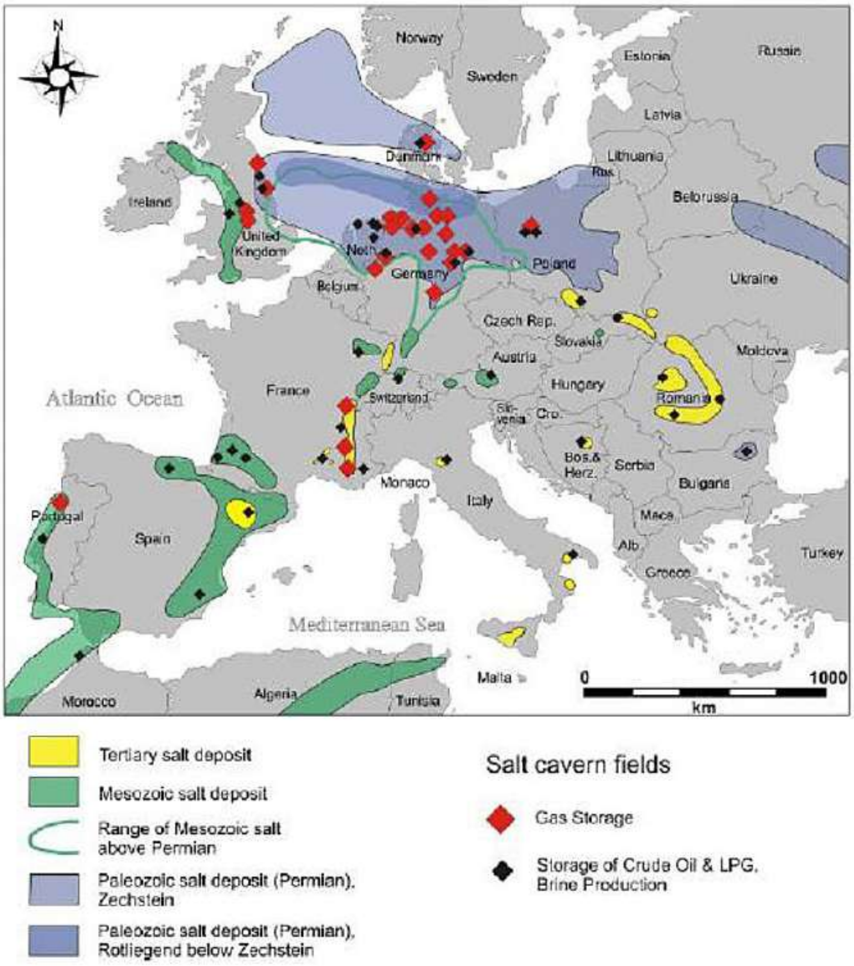
Pipe container storage systems exist for natural gas storage, called linepack, which refers to the volume of gas contained within the high-pressure pipelines of the national transmission network and acts as a method of storage to improve the reliability and security of natural gas delivery. Utilising the compressibility of gases, linepacking allows a certain volume of gas to be stored within a pipeline which can then be extracted during times of high demand by altering the pipeline pressure. Pipe container storage and linepacking can be utilised for hydrogen in a blended network, or a pure hydrogen network with the ability to store large capacities and overcome variations in seasonal demand. For a pure hydrogen pipe container, large-diameter pipelines will be built underground in a serpentine configuration [123].

As hydrogen demand increases, there will become a requirement for larger, long-term storage options to ensure stable supply throughout seasonal changes in electricity supply or heat demand. Large volumes of natural gas have historically been stored in underground geological features and are also considered the most appropriate option to store large volumes of hydrogen. Salt caverns, depleted oil and gas reservoirs, water aquifers and lined-rock caverns (LRC) are all types of underground storage currently being utilised for gas storage.

Salt caverns have been used for hydrogen storage in the UK since the 1970s [55]. They typically allow hydrogen to be stored between 100 and 275 bar, with capacities ranging from 200,000 up to 800,000m^3 [91] [136]. The benefits of using salt caverns over other underground storage methods include low levelized cost of storage (£0.18/kg H_2), fast withdrawal and injection rates due to high storage pressures, minimal risks of hydrogen contamination, low leakage rates and low cushion gas requirements [135] [137]. Despite these benefits, the costs of storing hydrogen in salt caverns are expected to be significantly higher than storage in existing networks as linepack.

Potential salt caverns in Europe are displayed on the map in Figure 8.18. The map shows a lack of salt caverns in Scotland, with the closest salt deposits in Teesside, UK which is already used for hydrogen storage adding a requirement for exploration of alternative storage sites.

Figure 8.18 - Potential salt caverns in Europe



The second geographical storage option is depleted oil and gas reservoirs. They are typically larger than salt caverns, with the plentiful capacity to store hydrogen around the UK. It is estimated that the seasonal energy storage required in the UK is roughly 25% of the total energy from natural gas for domestic heating [138]. If this balance were provided by hydrogen, only a few offshore gas fields would be required to meet this seasonal demand, crucially not competing with other subsurface applications such as carbon sequestration or natural gas and compressed air storage. Increased knowledge due to operational experience and geophysical surveys are an advantage of storing gas in depleted fields. They are, however, more permeable than salt caverns and contain contaminants that would compromise the purity of hydrogen stored thus increasing the cost of storage against salt caverns to £1.5/kg H_2 [137].

Water aquifers are a less mature underground geological storage option, and there is mixed evidence for their suitability for hydrogen storage. There has been no trial hydrogen storage within water aquifers at a commercial scale, and its feasibility is yet to be validated [55]. As with depleted oil and gas reservoirs, water aquifers contain micro-organisms that threaten contaminant failure. Hydrogen storage with this method would be higher as exploration and development costs would need to be included.

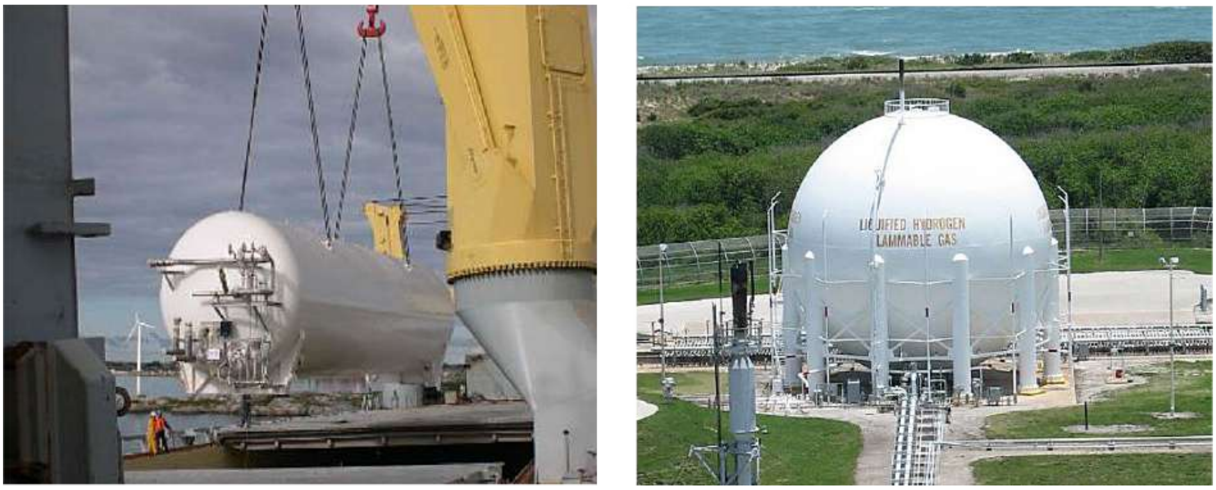
Sweden operates the world's only commercial-scale LRC at the Skallen facility which stores natural gas and has a capacity of 40,000m^3 and pressure range between 20 – 200bar [139]. Skallen is a demonstration project that acts as a natural gas storage facility as part of its national gas grid. Gas is stored underground in excavated cylinders that are lined with steel and concrete to maintain the integrity of the storage facility to withstand pressures up to 300bar. The popularity of LRC's is expected to increase given their versatility in implementation, however, their suitability for hydrogen storage is yet to be demonstrated. This year, the construction of a test facility for hydrogen storage will begin as part of the pilot phase of the HyBrit project in Luela, Sweden with a larger demonstration plant planned for 2025 – 2035 [140]. The levelized cost of storage (LCOS) for LRC's is £0.55/kg of hydrogen with a potential reduction to £0.18/kg [137].

8.4.3 Cryogenic Hydrogen

Like natural gas, pure hydrogen can be stored and transported as a liquid with a higher energy density than hydrogen gas. This is achieved by cooling gaseous hydrogen to its cryogenic state below -253°C (just 20°C above absolute zero). Hydrogen liquefication is a well-established process, with the largest plant operating at a capacity of 36 tonnes per day of cryogenic hydrogen, and the most modern single unit producing up to 10 tonnes per day [141] [142]. Its feasibility is lower than the transport of liquefied natural gas due to the energy-intensive process and requires a combination of stages taking advantage of the Joule-Thomson effect through cooling, compression and expansion. If the process were designed such that the hydrogen itself would provide this energy, 25 – 35% of the initial quantity of hydrogen would be consumed. Future advancements in large-scale hydrogen liquefication through economies of scale has the potential to reduce the energy efficiency to 18% and reduce the cost of liquification, currently at £0.8 per kg H_2 [55].

After hydrogen has been liquefied, it is essential to store it in preparation for transport. Cryogenic hydrogen storage vessels, called dewars, are designed to minimise the boil-off rate; commonly they provide low surface-to-volume ratios and are double-walled with a high vacuum applied between walls to curtail any potential heat transfer. For large-scale spherical storage tanks, the boil-off rate is less than 0.1% per day [135].

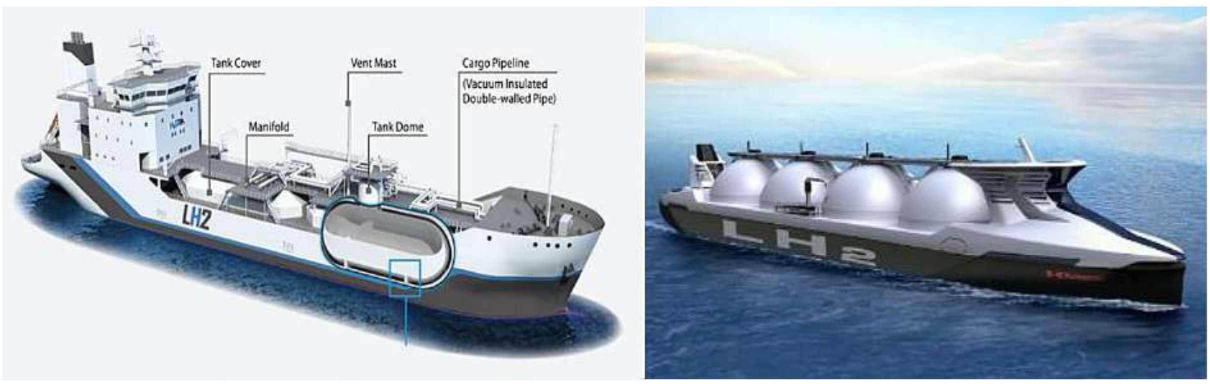
Figure 8.19 – Liquid hydrogen bulk storage [143] [144]



As previously highlighted in Section 8.4.2, the localised distribution of hydrogen relies on a trucking network. Cryogenic hydrogen tankers become preferable over compressed gas in cost per kg of hydrogen for journeys greater than 4,000km and when the end-user requires liquid or high-purity hydrogen, such as hydrogen refuelling stations [55] [129]. As with compressed gas trucks, dewars are cylindrical so they can easily be mounted onto trucks and are highly insulated with double-layered walls to minimise the boil-off rate. An additional shell with liquid nitrogen filling the interspace can also be implemented [124]. Current trucks with a vehicle mass of 40 tonnes have a capacity of up to 4,000kg of liquefied hydrogen so are optimised for localised distribution, resulting in a relatively high cost option for hydrogen transport.

Several projects are actively looking to develop vessel transport of pure liquid hydrogen. Most notably, Kawasaki Heavy Industries has developed a pilot vessel as part of the HySTRA project that transports 1,250m^3 of stored cryogenic hydrogen (Figure 8.20 left). The vessel was successfully launched and installed towards the end of 2020 [145]. To support the future global hydrogen supply chain, vessels in 2030 will need to be developed up to 160,000m^3 to compete in capacity with current LNG carriers. It is proposed that the vessel will contain four 40,000m^3 spherical storage tanks (Figure 8.20 right). The transportation cost of cryogenic hydrogen is estimated to be £0.9 per kg H_2 for 1,000km, increasing for longer distances.

Figure 8.20 - LH2 vessels (left) HySTRA 1,250m^3 and (right) Kawasaki 160,000m^3



8.4.4 Ammonia

Ammonia as a hydrogen-carrier is ideal as can store a high volume of hydrogen. It has a narrow flammability region at atmospheric conditions making it safer to handle than pure hydrogen and easily becomes a liquid at 10bar. Furthermore, liquid ammonia has over 50 per cent more volumetric energy than liquid hydrogen at 700bar.

More than 90% of the world's ammonia today is produced by the Haber-Bosch process making it the most common and well-established method for ammonia production, as shown below [126]:

$$N_2 + 3H_2 \rightarrow 2NH_3$$

Commercial production plants have capacities ranging from 600 to 3300mtpd of ammonia [146]. Ammonia production is energy-intensive and is often coupled with SMR to provide the high temperatures and pressures required in the process [147]. Alternative feedstocks for ammonia production include ATR, naphtha reforming and renewable sources. If ammonia fuel is the end-product, crucially the compound does not contain carbon and not a greenhouse gas so could be a major contributor to the carbon-free economy. Additionally, the need to crack ammonia back to hydrogen is avoided which reduces total process costs and any issues with hydrogen purity. The simplified process flow for ammonia production from electrolysis is shown in Figure 8.21.

Figure 8.21 - Ammonia production from green hydrogen flow diagram [117]

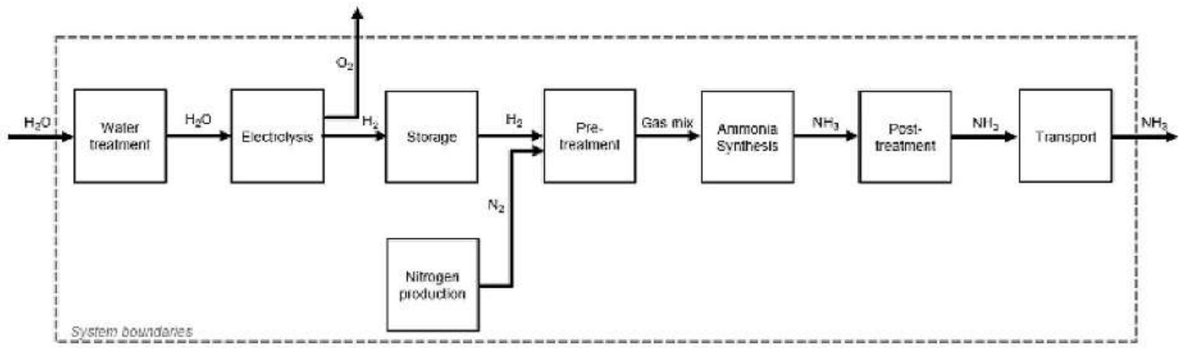


Table 8.11 - Advantages and Disadvantages to Power-to-Ammonia

Advantages	Disadvantages
• Large scale ammonia production already well-established • Current production for ammonia as a platform chemical only	• Highly toxic and corrosive making storage difficult • Energy-intensive hydrogen extraction • Low overall system efficiency (65%)

Smaller projects are being explored, for example in Port Lincoln in South Australia, where a 30MW electrolyser provides feed gas for an ammonia plant producing 50 tonnes per day [55]. Larger plants exceeding 500MW would provide enough hydrogen feed for a commercial ammonia production plant, but commercial electrolysers are yet to reach the scale to compete with SMR for ammonia production.

A typical storage facility for large-scale ammonia can range from 15,000 to 60,000 tonnes, with individual vessels storing up to 40,000m^3 [148]. Ammonia can be stored in a liquid state at 25°C and 10bar in low-pressure storage tanks that are already manufactured for LPG.

Ammonia is transported either as a pressurised gas at 10 bar or as a refrigerated liquid at -33°C [117]. The transport of ammonia by sea-faring vessel is well-established, with three common capacities for liquid petroleum gas (LPG)/ammonia at 30,000m^3, 52,000m^3 and 80,000m^3 [149].

In addition to the cost for hydrogen production by SMR or electrolysis, conversion to ammonia and its storage and transport in vessels would cost another £0.8/kg H_2 and £0.1/kg H_2, respectively. Ammonia transport through long-distance pipelines only becomes favourable over compressed hydrogen for distances greater than 3,500km [55].

The sub-component processes required for ammonia production are synthesis process, cryogenic air capture, compression of hydrogen and nitrogen and storage [117]. A 1GW green hydrogen plant or 100,000Nm^3/h blue hydrogen plant would produce enough hydrogen feedstock for 800tn/d of ammonia production[2]. North Sea Energy estimate that a small-scale ammonia plant generating 220tn/d would require a footprint of 386m^2 and the largest capacity at 3,300tn/d would require 5,660m^2. Given this relationship, it is estimated that an additional area of 1,340m^2 is required for ammonia production.

2. Assuming 65% efficiency of Haber-Bosch process

8.4.5 Methanol

Methanol is another hydrogen-carrier that can be used directly in chemical or transport sectors. Alternatively, it can be re-converted back to hydrogen using a fuel reformer. The key advantages of methanol over other fuels such as pure hydrogen and ammonia are its high energy density and its characteristic of being a liquid state at atmospheric conditions. Currently, 85% of methanol production comes from natural gas, but methanol can also be produced from renewable sources. One key disadvantage of methanol production is that carbon dioxide is needed for its production and emitted during the combustion process, so is a potential co-process alongside blue hydrogen production [126]. The synthesis reaction of methanol is shown below:

$$3H_2 + CO_2 \rightarrow CH_3OH + H_2O$$

The simplified process of methanol production from electrolysis is shown in Figure 8.22.

Figure 8.22 - Methanol production from green hydrogen flow diagram [117]

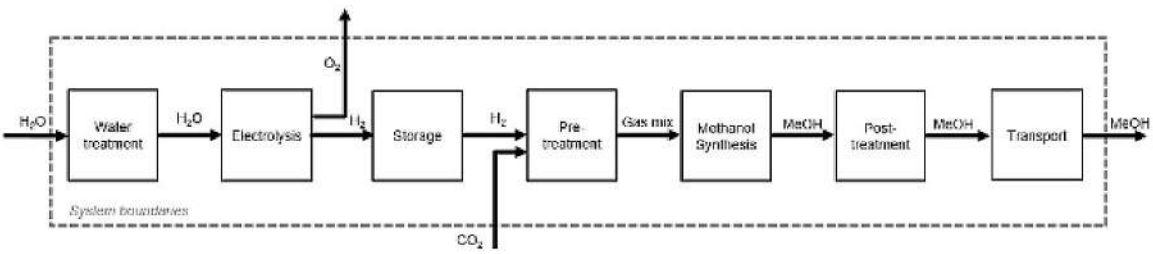


Table 8.12 - Advantages and Disadvantages to Power-to-Methanol

Advantages	Disadvantages
• Large scale methanol production already well-established • High process efficiency (>70%) • Simple storage and is compatible with existing infrastructure	• Significantly lower combustion energy compared to oil or other hydrocarbon fuels • High toxicity

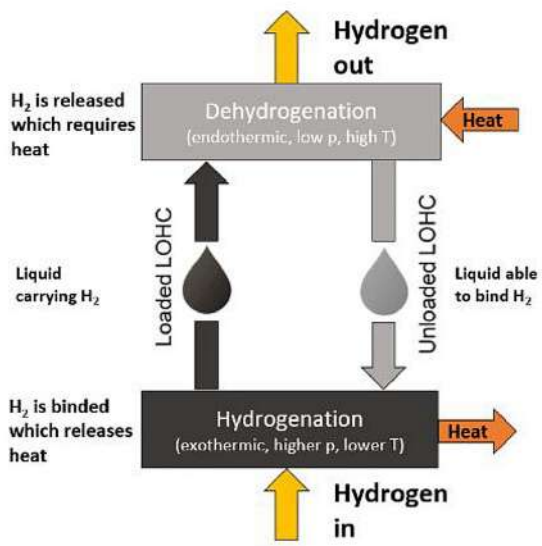
Liquid methanol at atmospheric conditions can be easily stored in large low-pressure storage tanks, with negligible loses during its storage and transport. Bulk transfer of methanol is becoming common in offshore oil and gas, one example of a methanol carrier is Methanex's Millennium Explorer which has a total capacity of 120,000m^3 [114]. The cost of conversion and transportation of methanol is approximately £0.4/kg H_2, however, this cost increases with the provision of CCUS [126].

Assuming a process efficiency of 70%, the hydrogen output from a 1GW green plant or 100,000Nm^3/h blue plant provides the input feedstock for 950tn/d of methanol production. The required footprint of this plant is 3,600m^2, which has been estimated from data provided by North Sea Energy [117].

8.4.6 Liquid Organic Hydrogen Carriers

LOHC's present a novel solution for efficient and safe storage and transport of hydrogen. LOHC's are liquids or low-melting solids that can be reversibly hydrogenated and dehydrogenated in the presence of a catalyst. Hydrogen is chemically bonded to an organic molecule through the exothermic process of hydrogenation. This reaction occurs between 100°C – 250°C and 1 – 50 bar. The loaded LOHC is transported to its final destination where it is dehydrogenated to release high-purity hydrogen. This process is endothermic so takes place at higher temperatures between 150 – 400°C and lower pressures [150] and the unloaded LOHC returned to the original facility. The cyclic process is shown in Figure 8.23. After hydrogen is released, the core structure of the LOHC remains unchanged which removes the need for a new carrier in every cycle.

Figure 8.23 - Diagram of LOHC Process [150]



Several LOHC molecules are under consideration. Cyclic hydrocarbons can be used as LOHC's (dehydrogenated/hydrogenated forms), such as (a) benzene/cyclohexane, (b) toluene/methylcyclohexane (MCH), (c) naphtha/decalin and (d) biphenyl/bicyclohexyl [151]. Cyclic hydrocarbons are favourable as their production is well-established commercially. Their drawbacks include their flammable or carcinogenic properties (a and b) as well as being solid at ambient temperatures (c and d). The most developed and researched LOHC's are discussed below:

In 2004, Chiyoda Corporation developed the world's first dehydrogenation catalyst able to extract hydrogen from MCH which is the hydrogenated form of toluene [152]. Since then, Chiyoda has commercialised and successfully demonstrated the use of MCH as a LOHC through their SPERA Hydrogen system through the world's first LOHC system processing $50m^3$/hour which started operation in May 2020. The transmission system transports hydrogen from Brunei Darussalam by sea to the dehydrogenation plant in Japan. Both MCH and toluene remain stable liquids under normal temperature and pressure enabling its safe handling and long-distance transport. 22M tonnes of toluene is produced annually and costs £0.3-0.7/kg [55]. The volumetric storage density for hydrogen is $47kg/m^3$ [135].

Dibenzyltoluene and perhydro-dibenzyltoluene (DBT-PDBT) were introduced as aromatic LOHC's by Hydrogenious in 2013 and have been installed at small commercial scales processing 4L/h [153]. DBT is a non-toxic alternative to MCH, has a higher volumetric hydrogen storage density (kg/m^3), however is more expensive at £3 – 4/kg [151, 135].

N-ethylcarbazole and dedecahydro-N-ethylcarbazole (NEC-DNEC) has been proposed as a LOHC but yet to be demonstrated commercially. The Volumetric hydrogen storage density is $54kg/m^3$.

LOHC's have similar physical properties to oil products so unlike ammonia, is liquid at ambient temperature and can be transported without the need for refrigeration or pressurised vessels. Hence, they are already compatible with existing pipeline or vessel infrastructure. LOHC's also have a long lifespan and retain their capability to store hydrogen without losses. Additionally, hydrogen released from dehydrogenation is high purity.

As with ammonia and methanol, there are costs associated with the conversion (£0.3/kg) and reconversion (£0.8– 1.6/kg) processes which will increase the total levelized cost of hydrogen. Including hydrogenation and dehydrogenation costs, there will be an initial capital investment required for the LOHC itself and further transport costs as unloaded LOHC's need to be returned to its original location. The full cost of hydrogen delivery using LOHC's is approximately £3.2/kg of hydrogen, which is slightly higher than ammonia because of LOHC reconversion and transport to its origin [55]. The process is also very energy-intensive and would require the equivalent energy of 35 – 40% if hydrogen itself was used [55].

8.4.7 Metal Organic Frameworks

Hydrogen can be stored as a solid when it is chemically bonded to metal hydrides. As the bonds formed are much stronger than when hydrogen is adsorbed to another compound, hydrogen can be stored at a significantly higher density at atmospheric conditions [135]. There are numerous types of metal hydrides that hydrogen can bond with including elemental metal hydrides, intermetallic hydrides, complex metal hydrides, borohydrides ($NaBH_4$) and amides. Sodium borohydride ($NaBH_4$) is presently the only promising metal hydride out of those mentioned, as the others are deemed unacceptable due to poor thermodynamics, kinetics or difficult reaction conditions. However, the process of extracting hydrogen from $NaBH_4$ is not reversible and $NaBH_4$ must be regenerated.

Hydrogen is bound to the metal hydride for its storage. Though, it can also be released from metal hydrides through heating or reacting with water, although this process is highly energy intensive. The released hydrogen must also undergo further processing to increase its purity which requires further energy input.

The role of hydrogen blending, and de-blending was discussed previously in Section 8.4.2. MOF's could also be involved with the de-blending of hydrogen at distributed sites. The structure of palladium metal is such that hydrogen can diffuse through its lattice while preventing the permeation of other larger molecules so is an option for de-blending of hydrogen from the gas network [113]. The process seems attractive, as, unlike metal hydrides, the extraction of high-purity hydrogen (>99.99%) can be achieved in one step. However, the cost of hydrogen removal using palladium membranes is considerably higher than other de-blending technologies.

Presently the use of MOF's is still being actively researched and there are substantial developments required before MOF's can be implemented in industrial applications. Commercially available systems led by Saes Group are limited in process capacity up to 140Nm^3/h [154]. As such, the additional costs to convert large-scale hydrogen, store, transport and re-convert the MOF's are yet to be determined. Both uses of MOF's as a solid storage option and de-blending from the grid remain at a low TRL 4 – 5 at the development stage [113].

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9. Scalability & Cost Reduction Opportunities

9.1 Green Hydrogen

9.1.1 Production Capacities and Scale

For this study hydrogen production site capacities of between 700 and 3,500 GWh per year have been considered. The largest scale is approximately equivalent to the Blue hydrogen production facilities discussed in Section 8.3, and represents the size of the facility that could be supplied directly or during 100% curtailment with electricity generated from an offshore wind development with 1GW installed turbine capacity. This is in the range expected for the ScotWind sites and at the top end of the capacity scale expected in 10 years. The smaller capacities represent plant sizes that would be suited to smaller, onshore or offshore, wind developments or where hydrogen was being used as an alternative energy production means when electricity from a wind development was curtailed.

Most generation plants do not operate at full output continuously, either from intermittent input energy or downtime from maintenance. The power throughput in GWh for each assessed capacity is shown below in Table 9.1 and the green hydrogen conversion for a 1GW facility in Figure 9.1. The offshore wind capacity factor which relates the maximum theoretical total energy potential against the actual energy input to the electrolyser facility is assumed to be 58%. For example, a 1GW offshore wind farm will generate 8.76TWh/year, of which there is 5.1TWh/y year of actual energy input to the 1GW green hydrogen facility. The hydrogen production plant is then assumed to operate for 8000 hours per year with 73% electrolyser efficiency. This methodology mirrors The Scottish Hydrogen Assessment [155] and the methodology used in the Levelised Cost of Hydrogen (LCOH) economic tool.

Other publications such as the ISPT Gigawatt Green Hydrogen and North Sea Energy's Offshore Energy Islands theorise GW-scale power input with reduced operating hours of 5000-6000 hours to account for a loss in production efficiency.

Table 9.1 - Power throughput of green hydrogen facility

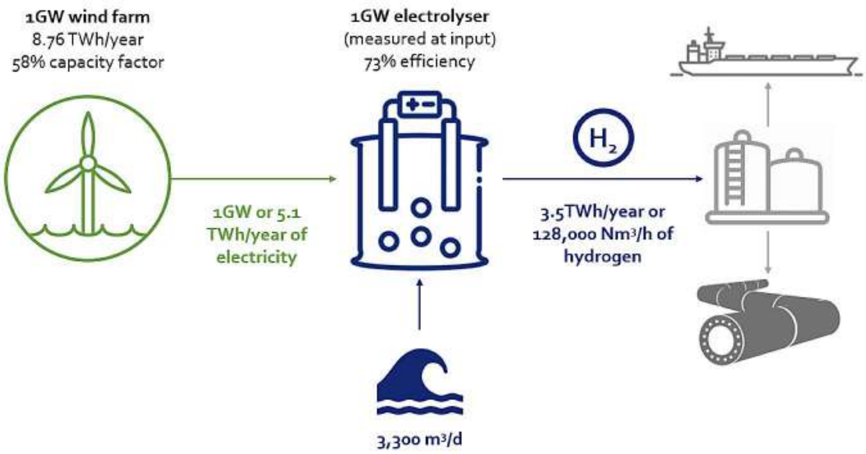
Plant Capacity	Equivalent electrical power (GWh per year)		
	Offshore Wind Output	Electrolyser Input	Hydrogen Product
200MW	1,752	1,016	699
500MW	4,380	2,540	1,748
1GW	8,760	5,081	3,496

Theoretically, higher annualised hydrogen production could be achieved using a grid connect plant where the required electrical power is provided at a reliable and constant rate – i.e., not related to variations in renewable power generation. If production from a 1 GW electrolyser site was only impacted by maintenance shutdowns (i.e., operation at 1GW was possible 8000 hours per year), this increases the hydrogen output to 8 TWh/year. This supplied power would have CO_2 emissions dependant on the electricity grid energy mix at the time, and so would not be 100% 'green' hydrogen. However, with the current high, and increasing contribution of renewable sources, there is potential for such a scheme to produce hydrogen with similar CO_2 emissions to a blue hydrogen scheme (which captures 90-97% of the associated CO_2 emissions).

There are challenges to this approach, primarily in the ability to distribute electricity around the network, which would need a large investment in infrastructure and very likely also in large scale energy storage / buffering. Therefore, in the 10-year timescale of interest in this study, it has been assumed that a green hydrogen site will be closely coupled to an area with renewable energy production and that the input electricity available will be similar to that provided from a discrete offshore wind site and not smoothed or buffered from grid-supplied electricity. As this impacts the annualised hydrogen output, it does potentially have a very large effect on LCOH. Longer term, being able to supply a hydrogen production site with a constant supply of electricity does present a significant cost saving opportunity. Another means of providing this steady supply of electricity is to include battery storage as part of the development, and use that to supply a hydrogen production plant that is sized closer to the average output of the offshore wind site that the peak output. This would deliver similar annual output hydrogen rates, but with lower CAPEX for the production site. Obviously there will be an additional cost for the battery storage, and the storage capacity required to have a significant impact is likely to be large compared to current technology. A further piece of technical work assessing the technical options, costs and capacities need for either battery or hydrogen storage would help clarify what the best approach is and whether there are specific technology gaps.

Conversely, locating hydrogen production at sites where there is a large energy resource that is severely curtailed due to grid constraints presents an opportunity to generate an improved return for those developments.

Figure 9.1 - Green hydrogen energy conversion



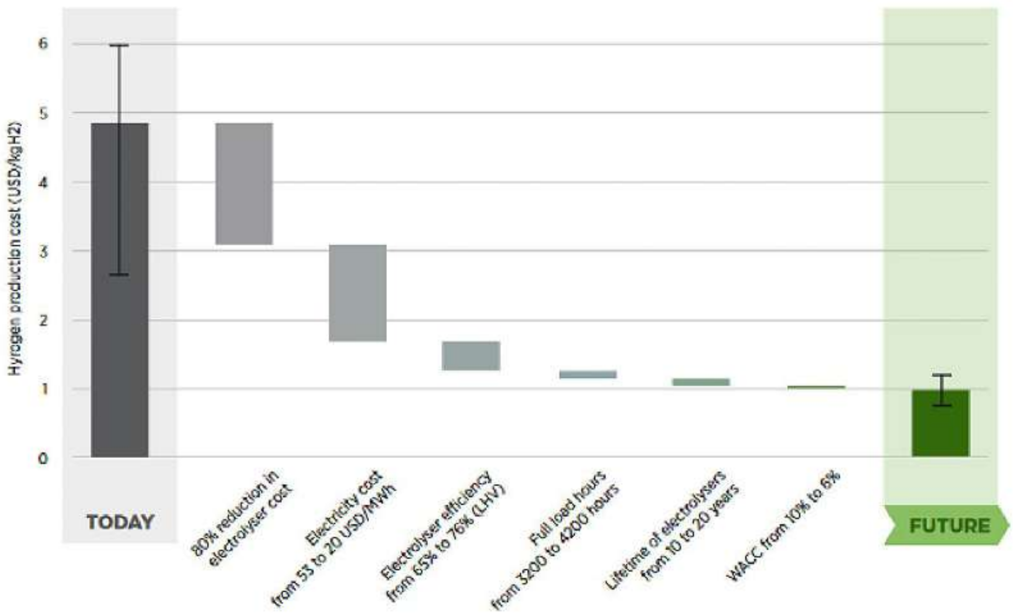
9.1.2 Technology cost reduction

Globally, more than 95% of hydrogen is generated from fossil fuels [156]. The LCOH of green hydrogen today is 2-3 times greater than blue hydrogen, with £2/kg being considered the target cost at which point green hydrogen production becomes a feasible and cost-competitive option. In comparison, the current LCOH for blue hydrogen is already below £2/kg. SMR and ATR are well-established processes, with enhanced processes (see Section 8.3) already implemented that serve as more efficient and lower-cost options. Hence, this section reviewing technology cost reduction methods will only consider green hydrogen technologies.

Figure 9.2 demonstrates how a combination of various cost reductions and technology improvements could reduce the LCOH of green hydrogen to below that of blue. The three main technology-based factors influencing the LCOH of green hydrogen production, and therefore areas for cost reductions are [129]:

- The cost of renewable electricity;
- The cost of electrolyser technology; and
- The utilisation of electrolyser technology.

Figure 9.2 - Methods for LCOH reduction in green hydrogen production [91]



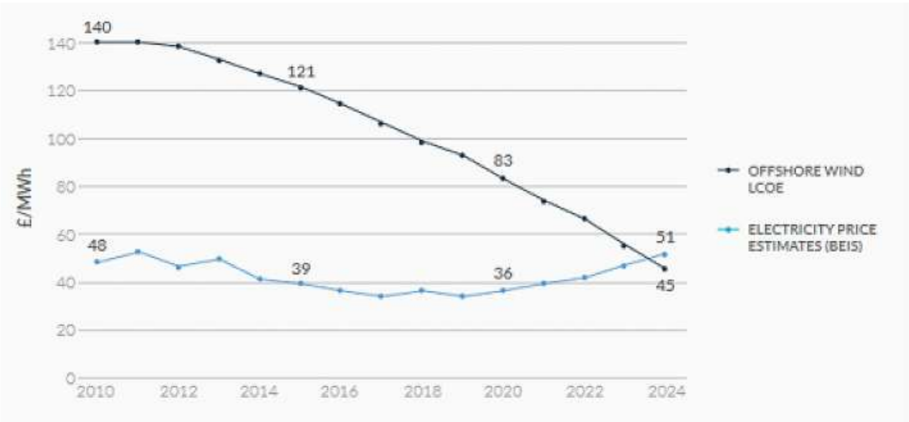
The cost of renewable electricity

The levelized cost of electricity (LCOE) is falling; the most cost-effective wind and solar renewable sites generate electricity at £12/MWh. This cost is estimated to reduce by a third, to £8/MWh by 2030 [157].

The LCOE is affected by the capacity factor, which for offshore wind is defined as 'the actual output from a turbine benchmarked against its theoretical output in a year'. Calculated as a rolling five-year average between 2015 to 2019, the capacity factor for onshore and offshore wind in the UK was 26.62% and 38.86%, respectively [158]. With the installation of larger turbines in regions with higher wind speeds, the standard capacity factor for new build offshore wind turbines is currently 58.4% [159].

In the UK in 2020, wholesale electricity prices for offshore wind were £83/MWh, compared to £36/MWh for grid-connected electricity [5]. The LCOE has been declining and will continue to do so with further increases in the offshore wind capacity factor and lower capital cost through technology maturity and innovation. Figure 9.3 demonstrates how the LCOE from offshore wind may be cheaper than that supplied by grid electricity as early as 2024.

Figure 9.3 - Wholesale electricity price comparison for offshore wind and grid electricity [5]



The cost of electrolyser technology

With increasing technology maturity and production scale-up, the CAPEX requirements for both the electrolyser system and BoP are expected to decline significantly by 2030 and beyond into 2050.

As discussed in the electrolyser technology review, the learning rate indicates the rate at which the CAPEX for a given technology decreases as the installed production capacity doubles. For alkaline, PEM and SOE electrolysers up to 2030, the learning rates are 9%, 13% and 18%, respectively. Electrolyser production facilities are made up of repeated modular units. This type of modular technology is particularly suited to achieving strong learning rates.

The learning rate can be demonstrated using alkaline electrolysers, which are the most well-established technology for green hydrogen production. Today, China is the largest producer of alkaline electrolysers providing over 50% of the world's total market [160]. At such large production capacities, producers can benefit from economies of scale that are not achievable by their Western competitors. The higher production capacity means that the unit CAPEX of alkaline electrolysers originating in China is significantly lower than their EU and US counterparts.

At the electrolyser stack level, the two main opportunities for cost reduction are improvements to stack design and cell composition and increasing the module size [91]. Figure 9.4 to Figure 9.6 show the reduction in CAPEX for Alkaline, PEM and SOE electrolyser systems up to 2050 with the cumulative deployment of all electrolyser technologies in the UK. The figures show the cost contribution of system costs (BoP, power electronics and gas conditioning) as well as individual elements specific to each type of electrolyser stack. Significant increases in unit scale deployment (e.g. 5MW to 10MW) and changes in market share between competing technologies are shown as jumps in the cost data.

Figure 9.4 - CAPEX reduction breakdown for Alkaline electrolysers up to 2050 [5]

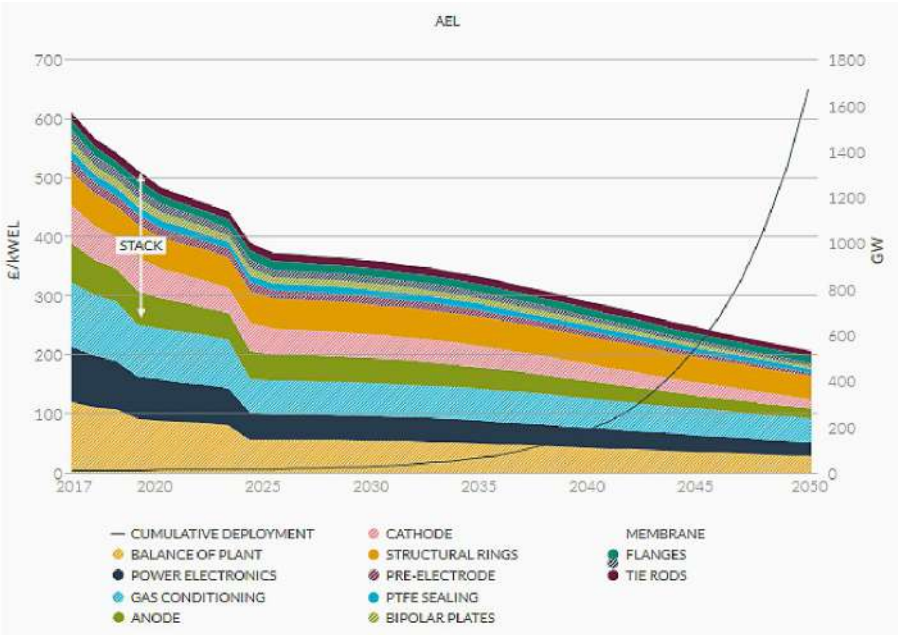


Figure 9.5 - CAPEX reduction breakdown for PEM electrolysers up to 2050 [5]

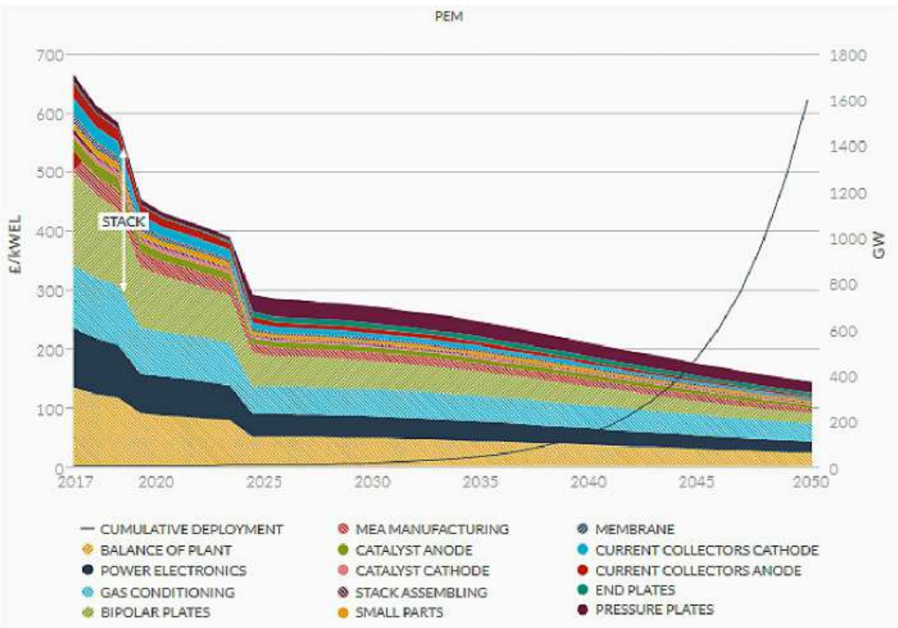
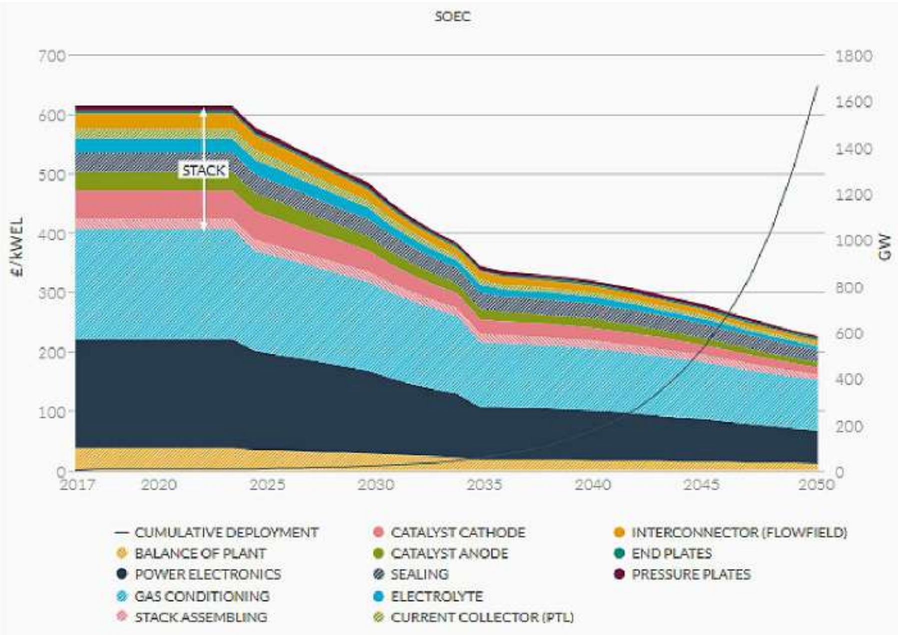


Figure 9.6 - CAPEX reduction breakdown for SOE electrolysers up to 2050 [5]



The utilisation of electrolyser technology

Finally, utilisation levels are increasing from the deployment of integrated renewable hydrogen projects. Improvements in utilisation levels arise from large-scale, centralised hydrogen production with a better mix of renewable sources like onshore and offshore wind and solar photovoltaic (PV) as well as integrated optimisation where the renewable capacity is oversized, rather than being the determining factor for electrolyser capacity [129]. Optimisation of the electrolyser production facility design capacity, and of the system operation and particularly large-scale energy storage leads to improved electrolyser utilisation and lower LCOH through more effective use of capital.

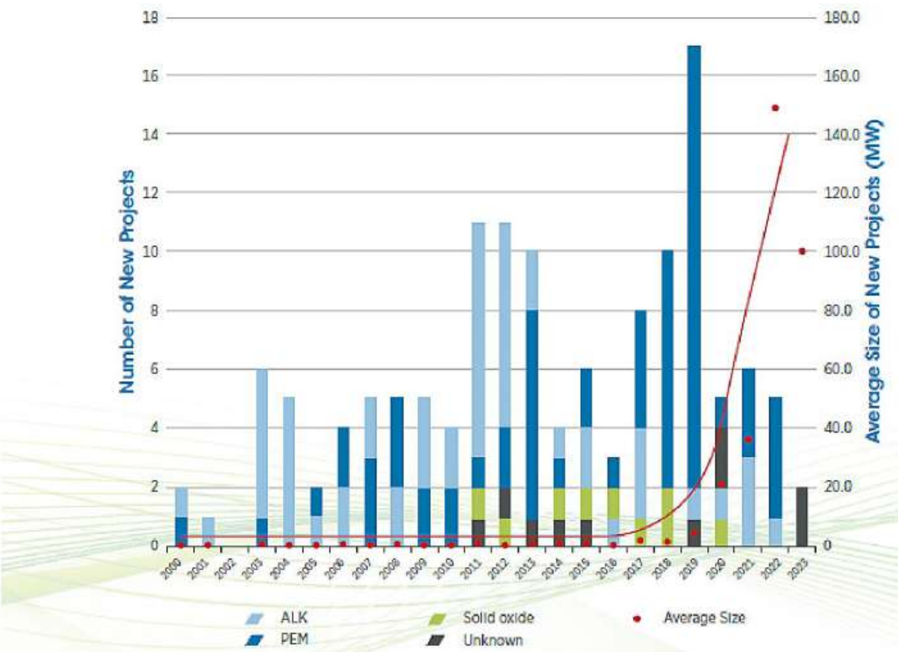
Total effect on LCOH

The cost of renewable green hydrogen is declining faster than anticipated. The drivers discussed above are collectively reducing the LCOH for 'average' and 'optimal' locations by an extra 20% and 30%, respectively, on top of the reduction estimates published in the Hydrogen Council Study 2020 report: "Path to hydrogen competitiveness: a cost perspective" [129].

Offshore, wind-based electrolysis in Central Europe is considered the benchmark for an 'average' hydrogen production project. Assuming Scotland fits this definition, the LCOH is estimated to be £1.8/kg by 2030, down from £4.2/kg in 2020 with the greatest cost reduction attributed to the lower LCOE [129]. For regions with low-cost renewable options like solar PV-based electrolysis, the LCOH in 2030 falls even further to £1.2/kg of hydrogen, driven by a larger reduction in system CAPEX costs [129]. The Middle East is a good example of this case; however, both the Middle East and Europe can benefit from oversizing renewable energy capacity. For a truly 'optimal' location, combinations of renewable wind and solar PV will allow for a surplus of low-cost, renewable energy. Optimal locations include Australia, Chile and Saudi Arabia.

75% of the total potential reduction of LCOH for all electrolyser technologies between 2020 and 2050 is expected to be achieved by 2030. This major cost reduction is driven by rapid cost reductions of LCOE up to 2050 followed by a reduction in CAPEX cost with increasing unit scale, with the remaining reductions requiring up to 2050 [5]. Alkaline electrolysers are currently the most preferable technology, given their maturity, scale and capital cost [93]. By the mid-2030s, PEM electrolysers are expected to be cost-competitive with alkaline technologies, in addition to its other benefits of compactness, suitability for renewable electrical input and innovations to reduce the use of advanced electrode materials. With production scale-up, PEM electrolysers are expected to be the preferable electrolyser technology in 2030 based on CAPEX cost and suitability for production capacity at that time [5]. This theory is supported by the trend that the cumulative PEM installed capacity has been increasing at a greater rate than alkaline since 2011 as shown in Figure 9.7 [93].

Figure 9.7 - Timeline of electrolyser projects by technology and scale



SOE technologies have a higher cost than alkaline or PEM in 2030 but may become favourable when co-located with industrial processes with high waste heat. Table 9.2 compares key parameters for alkaline, PEM and SOE electrolyser technologies between today's standards and 2030. Although this report considers Scotland's hydrogen production up to 2030, it should be noted that SOE technologies by 2050 have the potential to be cost-competitive with alkaline and PEM.

Table 9.2 - Comparison of electrolyser technologies between today and 2030 [55]

	Alkaline		PEM		SOE	
	Today	2030	Today	2030	Today	2030
Electrical efficiency (%)	63 – 70	65 – 71	56 – 60	63 – 68	74 – 81	77 – 84
Stack lifetime (000's hours)	60 – 90	90 – 100	30 – 90	60 – 90	10 – 30	40 – 60
CAPEX (£/kWel)	390 – 1,090	310 – 660	860 – 1,400	510 – 1,170	2,200 – 4,360	620 – 2,180

9.1.3 Scalability

Alkaline and PEM electrolysers are currently operating commercially at MW-scale. The largest installed single-stack electrolyser is 10MW in Fukushima, Japan [90]. However, larger capacities can be constructed by combining the outputs of multiple electrolyser stacks. The largest operational example of this is in Bécancour, Canada where a 20MW site is provided by four distinct 5MW units [162]. The UK's Gigastack Project has designed a site with 100MW capacity, made up of 20MW stacks (4 x 5MW single units) [95]. Even greater, The Hydrohub Project assesses potential 1GW sites across The Netherlands where theoretically, 10MW PEM electrolysers are stacked in 40MW groups and scaled up to 1GW [163].

Given the need for scaling-up to achieve larger capacities, compact PEM electrolysers are favoured. Hydrogen production via SOE has a maximum capacity of 1MW so it not considered for large-scale projects.

Green hydrogen production is more suited to scaling up from lower production capacities to full scale than blue hydrogen due to its inherently modular nature. Electrolyser units and stacks can be developed and combined to build scale gradually over time.

Grid connection is discussed in section 9.1.1. While this would not result in 100% 'green' hydrogen, dependent on the grid energy mix, it could provide a useful means to establish hydrogen production and to begin to scale-up. That would allow the local supply chain to establish, a workforce to be skilled up etc. ahead of full-scale hydrogen production development in parallel to one or more large renewable electricity schemes.

9.1.4 Base LCOH Estimates

The LCOH for various green hydrogen production cases has been estimated using a techno-economic cost model developed by Xodus for the Scottish Offshore Wind to Green Hydrogen Opportunity Assessment report [17]. The LCOH tool models the main techno-economic drivers of CAPEX and OPEX, as well as different components of the production process including electrolysers, compressors, storage and export. It should be noted that model was created to include the capital costs of developing the offshore wind farm and as a result the electricity costs are represented in the CAPEX element of the breakdown for the LCOH.

LCOH estimates were produced for a 'base' case 200MW, 500MW and 1GW green hydrogen facility. The 'base' case LCOH models were based on the following assumptions:

- Onshore green hydrogen production using PEM electrolysers with electrolyser efficiency of 20.8 kg/MWh;
- Site electricity supplied through a grid connection;
- Freshwater supplied through water mains;
- Hydrogen was either blended into the national transmission grid or co-located for direct offtake;
- 12 hours buffer storage provided by high-pressure storage vessels where OPEX of storage vessels is assumed negligible;
- Plant operation began in 2030 with a lifespan of 30 years;
- Technology economy of scale = 3%;
- Technology learning rate = 10%;
- Discount rate = 5%.

The results for the base case 200MW, 500MW and 1GW green hydrogen facilities are presented in Table 9.3. Further breakdown of techno-economical CAPEX and total lifetime OPEX costs are displayed in Figure 9.8 and Figure 9.9, where associated electricity, technology and storage costs are shown.

Table 9.3 – LCOH model results for Base case estimates

Parameter	200MW	500MW	1GW
H_2 Production (Te/y)	18,400	46,000	92,000
H_2 Production (Nm^3/h)	23,500	58,500	128,000
O_2 Production (Nm^3/h)	11,600	29,200	58,400
H_2O Feedstock Input (m^3/h)	658	1,640	3,300
CAPEX (£M) [1,2]	443	1,019	1,994
OPEX (£M/yr) [1,3]	9	20	42
LCOH (£/kg) [1,4]	4.12	3.86	3.81
Plot Area (m^2)	9,000	30,000	80,000 – 130,000

Notes
1. CAPEX, OPEX and LCOH estimated using Xodus LCOH calculator tool modelled on PEM electrolysers
2. CAPEX includes electricity, technology and storage costs
3. OPEX includes electricity and technology, storage of high-pressure vessels considered negligible
4. LCOH includes electricity and water feedstocks, OPEX and CAPEX over a 30-year design life of hydrogen plant

Figure 9.8 – Cost breakdown and distribution estimates for 'base' scenarios

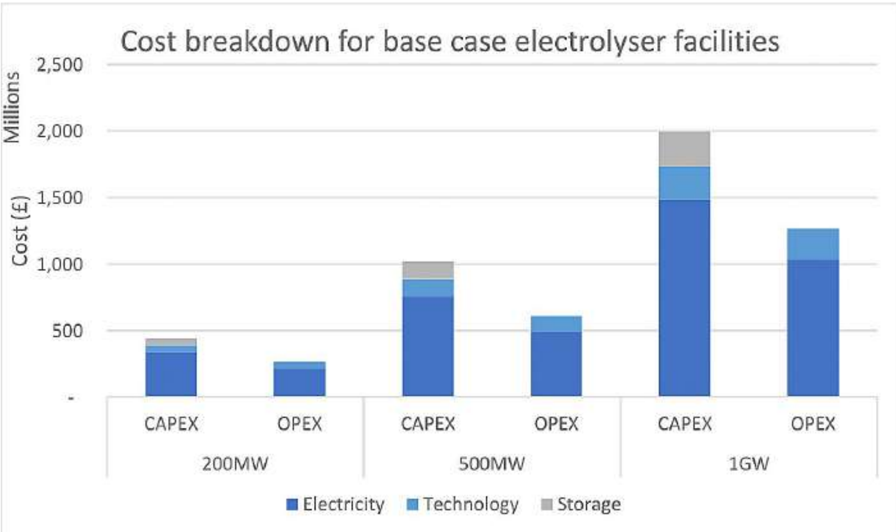
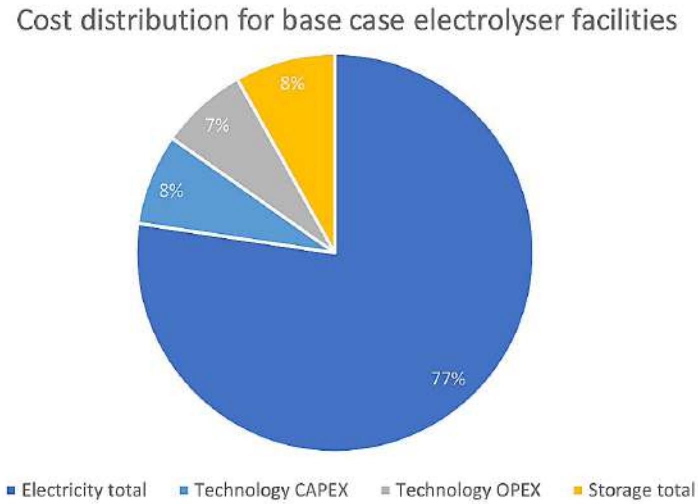


Figure 9.9 - Cost distribution for 'base' scenario cost estimates



All three base cases are estimated using the same model, with the only dependent variable being the production capacity. The LCOH decreases as the size of the plant increases due to economies of scale. The discount rate, although constant throughout cases, has a greater effect on larger capacities. Hence, the decrease in LCOH between 500MW and 1GW is proportionally less than between 200MW and 500MW.

9.1.5 LCOH Sensitivities and Cost Reduction Opportunities

The LCOH estimate tool allows inputs within the tool to be modified from the base estimates, which allow for high-level inspection of a range of possible site configurations. This type of analysis has been applied to the 1GW green hydrogen facility only. The estimated LCOH for a 1GW with the following scenarios is shown in Table 9.4:

1. Rural locations that do not have access to the national transmission network can obtain renewable electricity via direct access transmission from offshore windfarms. The amount of storage is increased to 24 hours to account for intermittent supply;
2. Coastal locations can opt to use seawater as their water supply rather than freshwater from the water mains;
3. Facilities without hydrogen pipeline export routes will require large-scale export of ammonia. Liquid ammonia vessels have a capacity of up to 50,000m^3;
4. All three sensitivities combined.

Table 9.4 - LCOH analysis of different 1GW site configurations

Scenario	LCOH (£/kg)
Base (1GW)	3.81
Direct Access Electricity	4.12
Desalination	3.82
Power-to-Ammonia with Vessel Export	4.86
All Three Sensitivities Combined	4.76

Direct access facilities are not required to pay Transmission Network Use of System (TNUoS) and Balancing Service Use of System (BSUoS) fees which are applied per MW per year. The reduction in electricity costs is overshadowed by the increased storage and compression costs for an additional 12 hours of storage hence the higher LCOH.

The annual Scottish Water charge is assumed to be 89p/m^3 of processed water which is applied to all base cases. For the desalination scenario, the water mains charge is replaced by the total cost of desalination of £1.6/m^3 of water which includes CAPEX and OPEX but excludes power consumption which has a small impact on the overall LCOH.

The LCOH for ammonia export via vessel includes the hydrogen production cost, cost for hydrogen conversion to ammonia and the transmission using 50,000m^3 vessels. Ammonia storage is not included. As a carrier and storage option, ammonia is the most expensive option with high production and transmission costs.

The combined sensitivity case considers the LCOH of a location that requires direct access electricity, desalination and power-to-ammonia production with vessel export. For the combined sensitivity case, the overriding cost factor is the use of direct access electricity. The LCOH for the combined cases (desalination and power-to-ammonia) with direct access electricity is £4.76/kg of hydrogen, whereas, the same combination with grid connected electricity is £5.10/kg. The LCOH for a location using direct access electricity is lower as there are no TNUoS and BSUoS fees.

9.2 Blue Hydrogen

9.2.1 Technology Comparison

Key parameters for standard SMR with post-combustion capture enhanced SMR (Blue H^2 by Wood) and enhanced ATR (LCH by Johnson Matthey) technologies are presented in Table 9.5. The technologies have been compared at a hydrogen production rate of 100,000 Nm^3/h which is equivalent to 300 MWth of hydrogen power based on the lower heating value (LHV). Comparison data has been obtained from studies entered into phase 1 of the Department for Business, Energy and Industrial Strategy 'Low Carbon Hydrogen Supply Competition' [164]. Parameters have been compared to understand the suitability of the blue hydrogen solutions with regards to site selection. The cost, scalability, plot area, and utility requirements of the technologies have been highlighted as key technology selection criteria.

Table 9.5 - Comparison of Blue Hydrogen Production Technology

Parameter	Standard SMR (with CCUS)	Enhanced SMR (BlueH2 – Wood)	Enhanced ATR (LCH – Johnson Matthey)
H_2 Production (Nm^3/h)	100,000	100,000	100,000
CAPEX (MM£) (1)	207	122	253
OPEX (MM£) (2)	25	22.4	26.9
Plot Area (m^2)	20,400	13,200	7,437 (3)
Anticipated Capture Efficiency (%)	90	93	97
Input NG Feedstock (MWth$_{LHV}$)	446	367	378
Electrical Power (MW)	~0 (4)	8.6	22.9

Cont.

Table 9.5 - Comparison of Blue Hydrogen Production Technology (continued)

Parameter	Standard SMR (with CCUS)	Enhanced SMR (BlueH2 – Wood)	Enhanced ATR (LCH – Johnson Matthey)
CO_2 Emissions Offsite (1000kg CO_2/h)	0	2.5	6.8 [5]
CO_2 Emissions Onsite (1000kg CO_2/h)	8.7	5.4	2.2
Net CO_2 Emissions (1000kg CO_2/h)	8.7	7.9	9.0
Levelized Cost of Hydrogen (£/kNm^3) [6]	172.5	134.6	155
Levelized Cost of Hydrogen (£/kg) [6]	1.92	1.50	1.73

Notes:
1. CAPEX is derived from AACE Class IV capital cost estimates produced for phase 1 of the Hydrogen Supply Competition.
2. OPEX excludes natural gas feedstock and CO_2 transport and storage.
3. Plot area is for LCH core technology, excluding ASU.
4. Electrical power usage is offset by electrical power production from recycled process steam.
5. Offsite CO_2 emissions mainly for powering of ASU.
6. Levelized cost of hydrogen includes the cost of feedstock, CO_2 transport and storage, CO_2 emission tariffs, OPEX and CAPEX over a 25-year design life of the hydrogen production plant.

9.2.2 Cost Reduction Opportunities

The bar graph displayed in Figure 9.10 shows a comparison of the CAPEX, OPEX and LCOH for the Standard SMR, Enhanced SMR and Enhanced ATR technologies. The percentage cost contributions of feed and emissions of blue hydrogen are displayed in Table 9.6.

Figure 9.10 - Cost Comparison of Blue Hydrogen Technologies

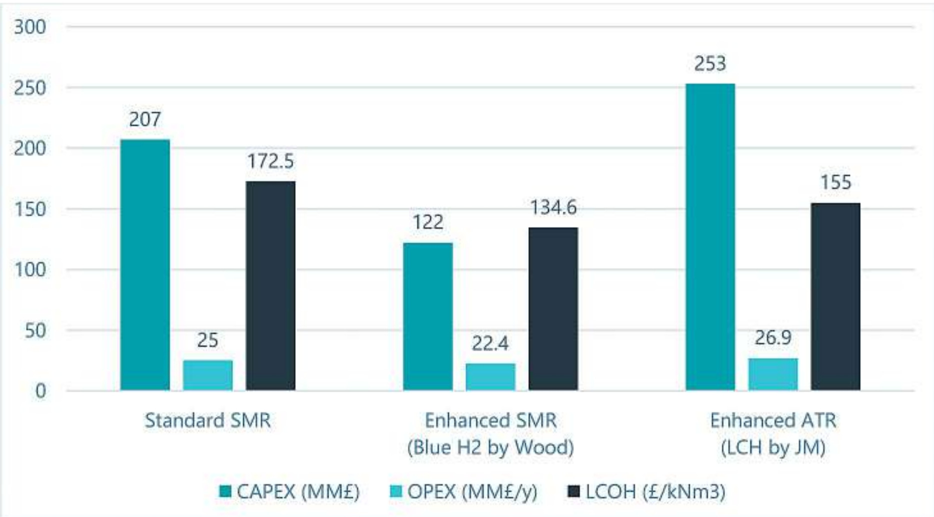


Table 9.6 - Percentage cost contributions of blue hydrogen LCOH

	% of total cost		
	Standard SMR	Enhanced SMR	Enhanced ATR
Feed gas cost	54.42	57.39	51.33
CO_2 export cost	9.09	9.78	9.23
CO_2 emission tariff	4.7	3.75	1.33

Standard SMR

Standard SMR has high CAPEX (£207M) due to the post-combustion carbon capture system required for the removal of CO_2 from flue gas. However, standard SMR has a competitive OPEX (£25M/y). Although OPEX is increased from the process requiring fuel gas for the reformer furnace, there is minimal OPEX from importing external electrical power.

Importantly, the OPEX calculation in the comparison excludes the natural gas feedstock. Since the conversion efficiency of standard SMR is poorer than the comparable technologies, standard SMR requires a greater input quantity of natural gas feedstock.

Standard SMR, therefore, has a high LCOH (£172.5/kNm^3 or £1.92/kg) which in addition to factoring in high CAPEX, includes high carbon tariffs and higher quantities of natural gas feedstock due to poorer conversion efficiency.

Enhanced SMR

Enhanced SMR has a significantly lower CAPEX (£122M) than standard SMR because of the simplified carbon capture system. OPEX (£22.4M/y) is also slightly lower than standard SMR because of improved energy efficiency and the minimal fuel gas requirement.

Overall, the LCOH (£134.6/kNm^3 or £1.50/kg) of enhanced SMR is low because of the lower CAPEX, lower OPEX, lower carbon tariffs and lower quantities of natural gas because of improved conversion efficiency.

Enhanced SMR is a cost-effective solution for the 100,000 Nm^3/h hydrogen plant capacity under review and more generally for small to medium plant sizes. However, the cost-effectiveness declines at greater scales compared to ATR solutions.

Enhanced ATR

Enhanced ATR has the highest CAPEX (£253M) of the technologies compared. £137m of the £253m CAPEX estimate is attributed to air/gas systems, which includes the ASU. However, CAPEX is also reduced by the simplified carbon capture system.

Enhanced ATR has a marginally higher OPEX (£26.9M/y) compared to the other technologies. Although OPEX is reduced by having no requirement for fuel gas, the high electrical power requirement of the ASU significantly increases OPEX. Excluding the electrical power requirement, the enhanced ATR OPEX is estimated to be £13.2M/y.

Despite the higher CAPEX and OPEX, the LCOH (£155/kNm^3 or £1.73/kg) is still competitive because the technology has improved process efficiency and lower carbon tariffs. With the technology's ability to scale up, the LCOH can be further reduced. A cost estimate was produced for a 500 kNm^3/h LCH plant which demonstrated savings of around 30% on the capital cost element of the LCOH [110].

In summary, the ASU is the key cost driver of the enhanced ATR technology. The CAPEX of the ASU initially has a poor economy of scale for smaller plants but improves at much greater hydrogen production rates. Therefore, enhanced ATR technology becomes financially competitive at larger plant sizes.

An important consideration for site selection is the availability of existing infrastructure and utilities. A readily available oxygen supply from an existing ASU could considerably reduce the overall CAPEX of the hydrogen plant.

Power-to-Fuel

Additional land area will be required if the hydrogen is part of a P2L process, where the end-product is ammonia or methanol. The potential use of both fuels as hydrogen carriers has been analysed previously in Sections 8.4.4 and 8.4.5.

The additional area required for P2L processes from 1GW of blue hydrogen or 100,000Nm^3/h of green hydrogen is 1,340m^2 for ammonia production and 3,600m^2 for methanol production. P2L areas represent a small fraction of the land required for green hydrogen production. They will however have a greater impact on blue hydrogen plants, in particular, enhanced ATR with the smallest footprint of 7,427m^2.

9.2.3 Scalability

Standard SMR

Standard SMR has relatively limited scalability. A hydrogen production rate of ~200,000 Nm^3/h (~600MWth) is possible in a single train [165]. However, larger plants can be constructed using multiple trains that may have advantages in terms of operational flexibility. For example, a plant with multiple trains can shut down or restart a train to meet seasonal hydrogen demand, and a failure within a train does not result in operational downtime for the entire plant.

Enhanced SMR

Enhanced SMR features the same core technology as standard SMR and therefore has similarly limited scalability. A hydrogen production rate of ~200,000 Nm^3/h (~600MWth) is considered possible in a single train. Larger plants can also be constructed by deploying several single-train modules with operational flexibility advantages.

Enhanced ATR

Enhanced ATR has proven scalability from the production of syngas in large-scale Fischer-Tropsch processes. A hydrogen production rate of 500,000 Nm^3/h (~1,500MWth) is possible in a single train, which is significantly larger than the largest SMR based hydrogen plants. The improved single train scalability of the technology also gives advantages in terms of the reduced plot area and reduced CAPEX compared to a plant with the same hydrogen output and multiple trains.

9.3 Transport and Storage Cost Reductions

9.3.1 Storage

As the cost of hydrogen production declines, the distribution of hydrogen and its associated cost will also become increasingly important. The LCOS contributes to the final LCOH for both blue and green hydrogen processes. Table 9.7 displays the current and potential LCOS for storage options discussed in Section 8.4.

Table 9.7 - Current and Potential LCOS [137]

	LCOS (£/kg H2)	
	Today	Potential
Compressed H_2	0.15	0.13
Cryogenic H_2	3.56	0.74
Ammonia	2.20	0.68
Salt caverns	0.18	0.9
Depleted oil & gas reservoirs	1.48	1.07
LOHCs	3.51	1.86

9.4 Site cost reductions

9.4.1 Blue and Green

Hydrogen production located on brownfield sites close to existing industrial facilities will benefit from multiple cost-saving opportunities.

Blue and green hydrogen facilities near heavy industrial locations may incur lower costs from existing civils infrastructure. Brownfield sites identified as a 'Business and Industrial Area' within each Scottish council's Local Development Plan will encounter fewer issues with public resistance and obtaining environmental permits with the development of a new industrial zone, which could both incur extra costs.

Both blue and green hydrogen production requires vast quantities of water as feedstock. Roughly 9kg of water is required for every 1kg of green hydrogen produced. The water usage for blue hydrogen is lower, with approximately 3.4kg of demineralised water as feed and 1.5kg of cooling water required for 1kg of hydrogen [166]. Such facilities could be positioned within industrial clusters where an existing plant can provide the volume of water required at the desired quality. Alternatively, freshwater could be sourced from Scottish Water or seawater for coastal locations, however, this method would incur extra costs for water treatment (especially for the demineralised water required for electrolysis). Significant pipeline infrastructure would be required for all methods of water supply but could be reduced in existing industrial clusters.

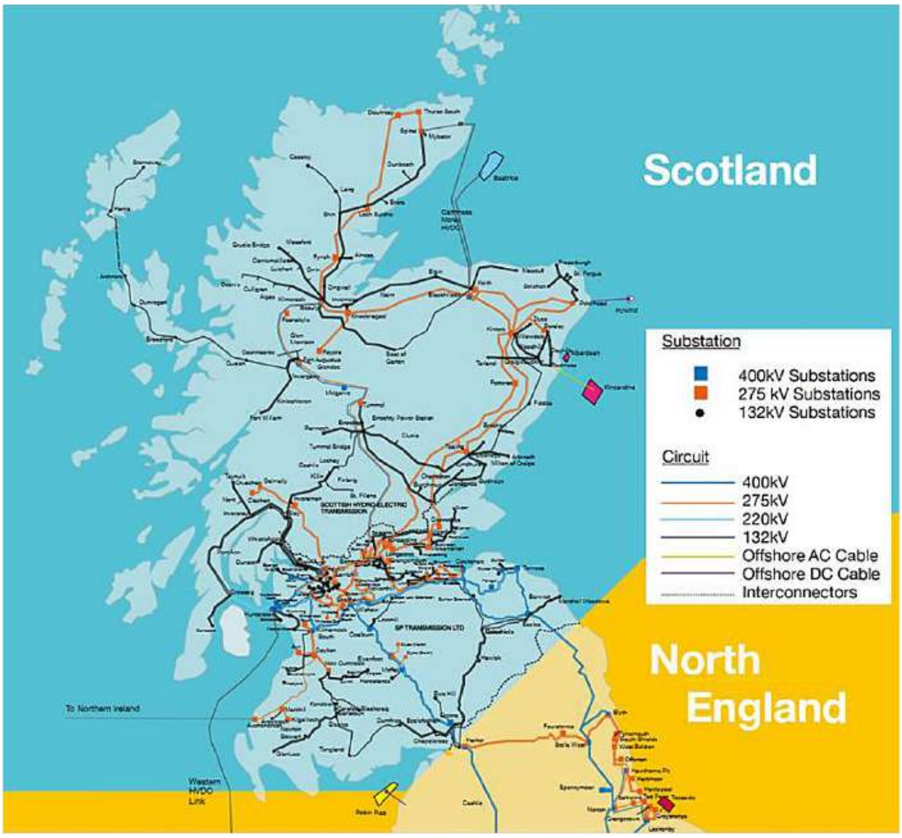
By co-locating hydrogen production with one or multiple industrial users, the hydrogen can be consumed on-site which will reduce the need for additional hydrogen export infrastructure. By removing the requirement for a new hydrogen network or retrofitting natural gas pipelines, the capital costs are lowered. It is thought that any industrial sites connected to the gas network using natural gas to provide heat could be supplied instead through hydrogen in the future [155].

For sites identified to support combined blue and green hydrogen production, major cost and footprint savings can be unlocked by using oxygen produced during water electrolysis as the pure oxygen feedstock for blue hydrogen production through ATR. The high-power ASU required to extract pure oxygen from the air for traditional ATRs has a large associated CAPEX and OPEX which could be avoided making smaller plants more economical.

9.4.2 Green

Green hydrogen production connected to the grid is a large off taker of electricity. Figure 9.11 shows the existing transmission network in Scotland in 2018, where predominantly the central belt and West coast are supplied by high voltage (400kV and 275kV circuits). The electrolyser facilities would benefit from being connected to, hence located close to the 400kV or 275kV grid for a high-power flow. The connection of sites to the low-power grid may cause barriers such as insufficient transformer and connection capacity at 132kV substations [163].

Figure 9.11 - Scotland transmission system in 2018 [167]



The UK's electricity network was originally designed to distribute power from large-scale coal, oil and gas-fired power stations through demand centres to the end-user. The location for renewable power generation is dictated by the best area for its resource rather than a central user point, hence, some sites may be placed in areas with a low-power distribution network, or none at all. Creating an electricity connection at rural sites can result in network issues such as lower electricity output and expensive infrastructure. For example, a weak grid connection restricts a 500kW tidal power generator in Islay to supply just 150kW [168].

One alternative to grid connection is to operate a direct line between the electrolyser facility and a generator of electricity such as offshore wind. The UK Government aim to achieve 40GW of offshore wind capacity by 2030 [169]. Not only does this provide more opportunities for direct access to renewable electricity sources for rural and island electrolyser facilities, but the development of offshore wind also accelerates the development of nearby high-voltage grid circuits.

Green hydrogen plants produce the following volumes of oxygen:

- 200MW: 11,600Nm^3/h;
- 500MW: 29,200 Nm^3/h;
- 1GW: 58,400 Nm^3/h.

It is assumed that any oxygen produced from water electrolysis will be vented. Any offtake could provide a revenue stream to the hydrogen production facility. It is estimated that the selling price for oxygen produced from an alkaline electrolyser, including compression, cooling and liquefication would be £77.8/tn of oxygen [126]. However, oxygen offtake would also need to consider the additional capital of oxygen export including storage and transport. Local use – for example in aquaculture or wastewater treatment – could provide an additional revenue stream and improve the value delivered by boosting these other industries.

It has been estimated that a 1GW green hydrogen facility will generate 250MW of waste heat. This offers a co-location opportunity with district heating systems. Known as heat networks, they can contribute to the Scottish Government's targets to reduce carbon emissions and provide an alternative technology to re-purpose excess waste heat. Current district heating networks can reach a radius up to 30km away from the heat-generating plant, so heat will need to be connected to existing nearby infrastructure or a new network will need to be installed [170]. However, only 1% of Scotland's total heat demand is provided by district heating as its uptake has been restricted by lack of government regulation and high capital investments [171].

Plot Area Required

Linde is currently building the world's largest PEM electrolyser site at the Leuna Chemical Complex in Germany which when completed in 2024, will have a capacity of 24MW [172]. Any footprints for large-scale green hydrogen sites (>100MW) are based on engineering estimates, rather than experience. Table 9.8 summarises the plot areas estimated in recent publications.

Table 9.8 – Published estimates for electrolyser footprints

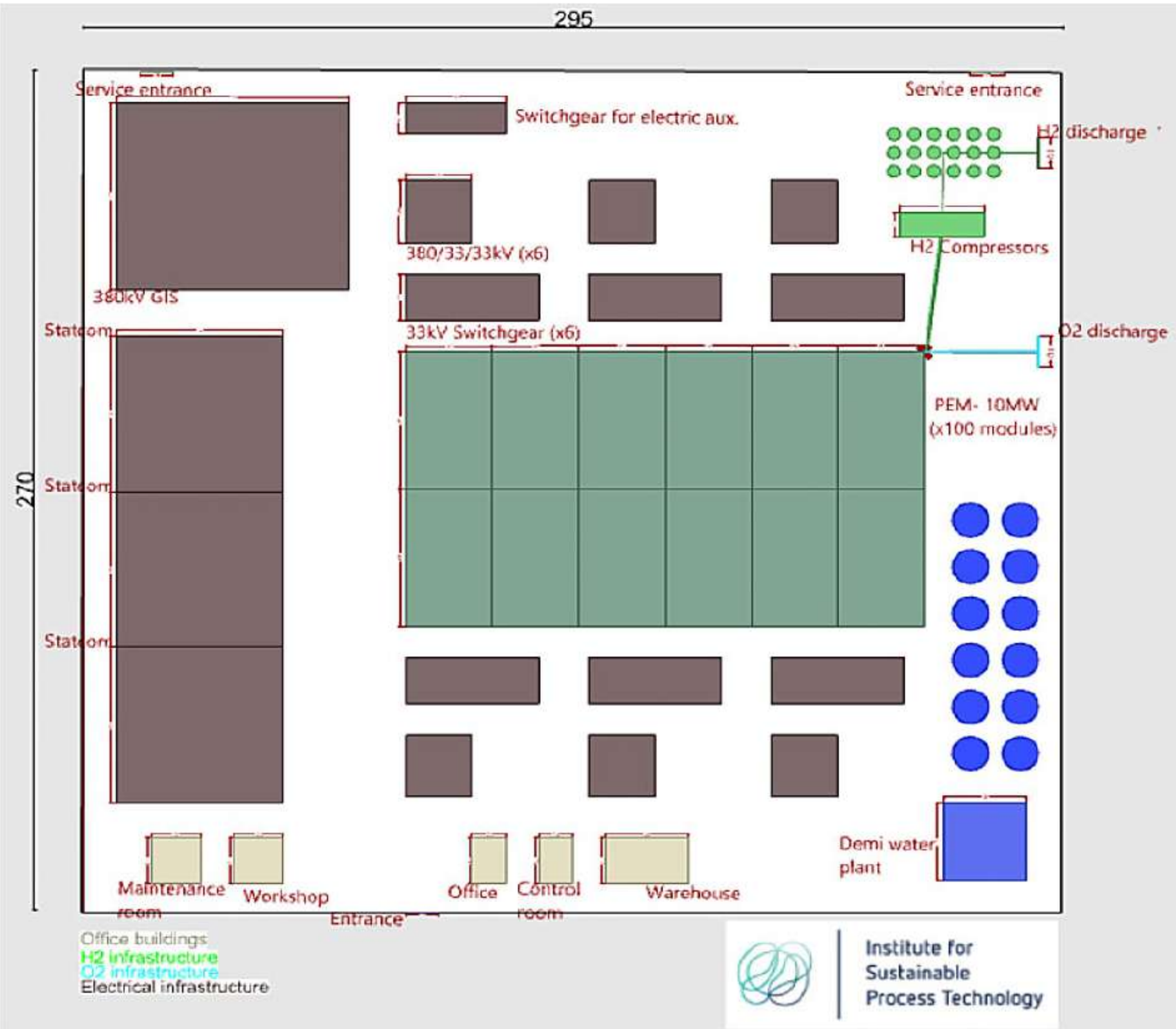
Scale	Published by	Footprint (m^2)	Reference
10MW (PEM)	Refhyne	25	[173]
100MW	German government	6,300	[91]
100MW (PEM)	ITM	3,500 (40 x 87)	[174]
100MW	McPhy	4,500	[91]
300MW	Siemens	15,000 (180 x 80)	[91]
1GW (PEM)	Institute for Sustainable Process Technologies (ISPT)	80,000 – 130,000	[163]
1GW (Alkaline)	ISPT	100,000 – 170,000	[163]
2GW (PEM)	North Sea Energy	221,000 – 271,000	[120]
5GW (PEM)	North Sea Energy	388,000 – 484,000	[120]
20GW (PEM)	North Sea Energy	905,000 – 1,425,000	[120]

The footprints for 200MW and 500MW green hydrogen sites have been extrapolated from the estimated footprint data provided in Table 9.8. The following estimates for plot areas are calculated assuming that PEM electrolysers will be used for all sites in Scotland by 2030, due to their compactness and suitability for renewable electricity:

- A 200MW electrolyser plant requires a plot area of 9,100m^2;
- A 500MW electrolyser plant requires a plot area of 30,000m^2;
- A 1GW electrolyser plant requires a minimum plot area of 80,000m^2.

The plot plan for a 1GW PEM electrolyser facility (8hectacres (ha), 295m x 270m) is shown in Figure 9.12. Of the total area, 6.4ha is required for the electrical instruments and 3ha by the electrolyser building which includes space for transformers and rectifiers. The plot plan shows the minimum area required, where compact design has been achieved by a two-level electrolyser building, gas-insulated switchgear rather than air-insulated and smaller hydrogen compression units achieved by pressurised units (PEM), however, the area could be further optimised if the equipment did not need to fit into a rectangular footprint [120].

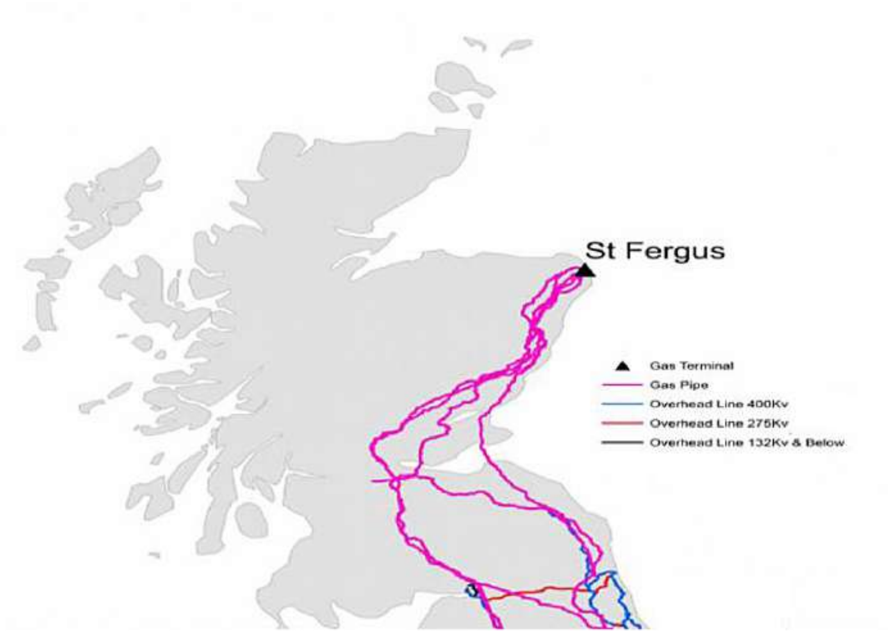
Figure 9.12 - 1GW PEM plot plan - minimum 8ha case [120]



9.4.3 Blue

Depending on the process, the production of blue hydrogen requires natural gas supply as the feedstock and potentially fuel gas. Hydrogen production facilities located at industrial sites with an onshore gas terminal and/or connected to the NTS (Figure 9.13) will have the immediate advantage of an existing natural gas network. Any sites that would require the import of natural gas through a new pipeline or LNG for coastal locations will incur a larger cost.

Figure 9.13 - NTS in Scotland



The Acorn Project when completed is expected to be the UK's first operational CCUS project. Other blue hydrogen facilities can benefit from cost reductions in transport and storage of CO_2 if located within the vicinity of the Acorn infrastructure. As the UK's portfolio for CCUS matures, more options will become available for CO_2 storage reducing costs over time. For locations where Power-to-Methanol production is favoured, CO_2 from blue hydrogen production can be used as feedstock omitting the requirement for CO_2 storage.

Plot area required - Standard SMR

Standard blue hydrogen SMR technology requires a large plot area (20,400 m^2) due to the size of the CO_2 removal system, which includes the high-volume compression and separation equipment that is required to extract the CO_2 from the low-pressure flue gas.

Plot area required - Enhanced SMR

Enhanced SMR has a reduced plot area (13,200 m^2) compared to conventional SMR because the size of the CO_2 removal system is significantly reduced. There is no post-combustion carbon capture equipment required in the plant since there is minimal CO_2 content in the flue gas.

Plot area required - Enhanced ATR

Enhanced ATR has an even greater reduction in plot area (7,437 m^2) compared to conventional SMR, similarly because the size of the CO_2 removal system is significantly reduced, as the CO_2 is entirely contained within the product stream and is simpler to extract. However, the plot area is similar to enhanced SMR when factoring in the ASU space requirements for oxygen production.

10. Clean Hydrogen Production Site Assessment

10.1 Introduction

To realise Scotland's hydrogen production potential, it is vital to understand the technologies required to produce hydrogen at the desired scale. What is equally important is determination of where this technology can be economically deployed at scale, and what further action is required to support this development.

This section of the report highlights the site -level requirements of large-scale blue and green hydrogen production facilities. Emphasis is placed on potential production capabilities in the next 10 years; with a view to driving the scale-up of Scotland's clean hydrogen production ambitions as quickly as possible.

The information highlighted in this section will be used in a follow on report by Scottish Enterprise where an assessment and comparison of numerous locations across Scotland is conducted taking into account these site requirements. Locations across Scotland will be identified that align with the selection criterion in this section highlighting potential development opportunities.

This section therefore aims to act as a preliminary analysis to guide further research and action, including specific site selection, by outlining the key requirements of a large-scale hydrogen production site

10.2 Hydrogen Production Site Requirements

The focus of the site assessment part of this study is to identify key criteria for potential sites to produce hydrogen at industrial scale within 10 years. The overriding requirements to meet these objectives are therefore:

- Ability to produce hydrogen at suitable scale. This needs:
    - A source of electricity and water (green hydrogen) or methane gas (blue hydrogen) that is the 'feedstock' for this production.
    - Access to a route for transport of carbon dioxide to a suitable storage site (for blue hydrogen).
    - A site for the plant that is suitable to accommodate the type and size of facilities.
    - Either a local demand to this scale of hydrogen production, OR access to a means of exporting the hydrogen to users elsewhere in Scotland, the UK, or overseas.
- Ability to produce hydrogen at scale within 10 years. This needs:
    - Ability to consent the site in that timescale, which implies local and government support.
    - Availability of the 'feedstock' resource in that timescale – particularly for green hydrogen.
    - Either availability of transport infrastructure and export demand OR large-scale local demand.
- Ability to produce hydrogen at scale in a way that is economically sustainable. This needs:
    - Value add to the economy and the local area.
    - Input 'feedstocks' at cost that allows competitive and sustainable production in the long term.

- An investable pathway to full commercialisation. In some cases, this will include the ability to scale up production as demand grows to minimise investment risk.

To identify candidate production sites, five characteristics that would make an ideal site for green or blue hydrogen sites have been defined as shown in Table 10.1. Each of these is described in more detail in sections 10.2.1 and 10.2.2.

Table 10.1 – Hydrogen Production Site Characteristics

Ideal Green Hydrogen Production Site	Ideal Blue Hydrogen Production Site
Renewable Electricity Resource	Methane Supply
Water supply	CO_2 transport and storage access
Site size and suitability	Site size and suitability
Local Activity	Local Activity
Hydrogen export	Hydrogen export

Each site has been evaluated, as part of a follow on Scottish Enterprise report, across each of the five characteristics as follows:

Table 10.2 – Site evaluation criteria

Matches Ideal Site requirements
Does not meet ideal site requirements, but impact is low or easily addressed
Does not meet ideal site requirements, impact is higher or more difficult to address
Blocker / Barriers are evident

10.2.1 Green Hydrogen Production Site Requirements

10.2.1.1 Renewable Electricity Resource

As discussed in section 9.1.4, the largest contributor to the cost of green hydrogen is the cost of the electricity. For this study, the scope is purely on the hydrogen production and transport facilities and has not considered difference in the likely cost of electricity between different sites.

The likelihood of a large wind power site being developed could be increased if hydrogen provides an attractive alternative to electricity for export of that electricity. Therefore, for sites where there is currently no, very limited, or very expensive access to the UK grid, hydrogen production could provide a route to market.

As this assessment is not considering site specific differences or the cost of the electricity production, sites will be screened primarily focusing on the size of resource that could be developed in a ten-year timescale. A larger capacity will bring economies of scale and lower production costs, so larger sites are closer to 'ideal' than smaller sites. Consistency of supply and the ability to maintain a steady hydrogen production output is also desirable – therefore redundancy or diversity of electricity supply would be preferred. This could include, for example, access to energy storage, including pumped hydro power.

10.2.1.2 Water Supply

For the production scale this study has considered, water is required for green hydrogen production at rates of 660 to 3,300 m3/hr. With current electrolyser technologies, this water must not contain salts or other impurities.

The lowest cost, and therefore most preferred option is to have a suitable source of fresh water with minimal additional processing required. If fresh water is not available in the required quantities, then sea water can be processed to remove the salts and filter out other impurities. This desalination equipment adds slightly to the cost of production (of the order of pennies to the £/kg levelized cost – see section 9 and to the area of land required). These are described in more detail in section 9.1.2, but are relatively minor impacts.

There will also be a cost for the gathering/inflow facilities which will vary by site depending on the proximity to the sea and ability to install the inflow system. Therefore, any sites which require desalination and are immediately adjacent to the sea will be categorised as 'yellow'. Any which are not immediately adjacent to the shore will be categorised as 'orange' to reflect this additional cost and complexity.

10.2.1.3 Site Size and Suitability

A green hydrogen production site for 100,000Nm3/hr hydrogen production will require a site area of at least 15 hectares. The minimum footprint for a 1GW site (with stacked electrolysers) is 8 hectares (see section 9.4.2). Additional area will be needed if desalination of seawater is required, and if the hydrogen is to be converted to another product or transported in a carrier such as LOHC. Therefore, the ideal site will have sufficient space available.

To minimise costs, an ideal site will have already been cleared, levelled, and be ready for construction with minimal preparation. To enable a straightforward planning and consent process, the site would already be zoned for industrial use and/or have a history of similar use.

Hydrogen is a hazardous product. For the size of production plant considered in this study the site would be classified as a COMAH Upper Tier site.

As well as the production site itself, its context in the surrounding area can provide benefits. If a green hydrogen production site can receive additional revenue through a local market for the oxygen produced through electrolysis, or for the heat generated (e.g., to a district heating scheme or another industrial user) this creates a stronger business case and makes the site more attractive.

10.2.1.4 Local Activity

A green hydrogen production site of 100,000Nm3/hr capacity will need a permanent workforce to operate and maintain the facilities. If there is an existing workforce with suitable or transferrable skills in the local area, this improves the suitability of the site.

A limited local workforce, with little opportunity to reskill people from other, declining, industries would lead to a requirement to bring in / accommodate travelling crew would lead to higher costs, is less sustainable and sites with this characteristic are therefore evaluated as 'orange'.

An ideal site, given the scale and timescales of interest to this study, would have a source of demand on its own doorstep – with no need for additional cost to transport the hydrogen to a remote customer. Local demand could be in the form of transport refuelling hubs, industrial or agricultural demand (using H2 as a feedstock). Given the scale of production this study is considering, for full scale production in 2030 this demand would very likely need to be greater than local transport hubs or local demand are going to present unless the site is close to a very large population centre (100,000Nm3/hr hydrogen production is approximately equivalent to the heating energy use for 250,000 homes). However, the presence of local demand may assist scale up of production. Local industrial level demand would be needed for full scale, and is unlikely that this level of transformation of, for example, heating for homes, will have been achieved by 2030. Therefore, assessment of the ideal site is focussed on export opportunities to service large scale demand that is expected to materialise by 2030 (see section 0).

10.2.1.5 Hydrogen Export

Access to a gas pipeline for export of the hydrogen is the lowest cost export option. This is also the most scalable route for hydrogen export and has the lowest CAPEX investment requirements. Hydrogen export via ship at scale is still a developing technology, with uncertainty as to which 'medium' (hydrogen, ammonia, LOHC etc.) will be preferred. Whilst pipeline blending is also still untested at scale, there is a more solid roadmap for how this will develop.

An ideal site would also have access to large scale hydrogen storage – this would allow a plant to operate in a much steadier state manner, more independent of demand fluctuations. As discussed in section 8.4, there are no salt caverns in Scotland, so the most likely large-scale storage is in depleted oil and gas reservoirs. Assessment of the feasibility of hydrogen storage in depleted reservoirs to date has only considered potential storage volumes. There is still a large amount of technical development to happen before this becomes reality, and therefore it is not expected to be developed by 2030. This is included as a criterion for any future iteration of this report, but has not been included in the site categorisation considerations (i.e. sites are still categorised 'green' if this is not available).

A hydrogen export 'opportunity' is subjectively defined where it is deemed likely that connection could be made into the NTS. This is only based on proximity of the export location to the existing NTS.

Table 10.3 – Green Hydrogen Production Site Assessment Criteria

	Renewable Electricity Resource	Water supply	Site size and suitability	Local Activity	Hydrogen Export
Ideal site	Source of low carbon electricity at low cost (e.g., larger scale site 0.5 – 1 GW electricity) Steady supply (multi-source / storage buffered)	Fresh water supply	>15 hectares COMAH site currently Site consentable with no barriers Market for oxygen (to add to revenue)	Skilled workforce (gas processing / power plant type skillsets) Support for local Hydrogen demand (transport / heating / industrial / agri.) Hydrogen demand potential at scale in local area.	Access to natural gas pipeline network at capacity to allow export blending. Proximity & route to interseasonal hydrogen storage.

Cont.

Table 10.3 – Green Hydrogen Production Site Assessment Criteria (continued)

	Renewable Electricity Resource	Water supply	Site size and suitability	Local Activity	Hydrogen Export
Close to ideal – minor / easily addressed impact	Source of low carbon electricity – higher cost, but still commercially viable (250-500MW electricity). Variable supply with some buffering	Seawater supply – proximity to shore	>15 hectares COMAH upper tier suitable Site consentable with no barriers	Local workforce that may require reskilling. Small local demand.	No pipeline access, but access to established ship loading terminal for hydrogen / product export No interseasonal hydrogen storage in proximity.
Larger impact on cost, scale or timeline	Very variable supply. Low carbon electricity capacity lower	Seawater supply – further form shore	Size of land available unclear Suitability for COMAH upper tier unclear.	Limited local workforce, with requirement to bring in / accommodate travelling crew	No pipeline access. Access to port but without established gas/ liquid loading facilities, requiring significant modifications to accommodate suitable vessels.
Blockers / barriers	No / very low capacity (<100 MW) or high cost / non-commercial	Insufficient / high cost to get water to site at sufficient rates	No site of sufficient size. Planning consent not possible or heavily blocked	Active opposition in local area. No available workforce locally	No export route at sufficient scale

11.1.1 Site Size and Suitability

A blue hydrogen production site for 100,000Nm3/hr hydrogen production will require a site area of at 1-2 hectares. Additional area will be needed if the hydrogen is to be converted to another product or transported in a carrier such as LOHC. Therefore, the ideal site will have sufficient space available.

To minimise costs, an ideal site will have already been cleared, levelled, and be ready for construction with minimal preparation. To enable a straightforward planning and consent process, the site would already be zoned for industrial use and/or have a history of similar use.

Hydrogen is a hazardous product. For the size of production plant considered in this study, it is expected that the site would be classified as a COMAH Tier 1 site.

As well as the production site itself, context in the surrounding area can provide benefits. Here there are differences between different blue hydrogen technologies. ATR requires oxygen and large electrical power. Therefore, availability of oxygen, or an existing air separation unit would reduce CAPEX, and this create a stronger business case and make the site more attractive. Availability of low carbon electricity also reduces CAPEX and reduces the carbon footprint of production.

To produce 1kg of hydrogen, approximately 3.5kg of demineralised water is required as feedstock into the blue hydrogen facility. This volume is significantly less than the water requirement of green hydrogen production. In all cases, blue hydrogen sites are located close to existing industrial sites, hence it is assumed that water will be provided through the water mains by accessing nearby industrial-scale water supplies.

11.1.1.2 Local Activity

As per green site assessment. Blue production facilities have more elements in common with petrochemical type production plants, so local support for and a workforce and local supply chain with skills from that industry would be a significant benefit.

11.1.1.3 Hydrogen Export

As per green site assessment.

Table 10.4 – Blue Hydrogen Production Site Assessment Criteria

	Methane Supply	CO2 Transport & Storage Route	Site size and suitability	Local Activity	Hydrogen Export
Ideal site	**Supply of natural gas from pipeline**	• Access to CO_2 transport network (direct access). • Close proximity to CO_2 storage site.	• 1-2 hectares • COMAH site currently • Site consentable with no barriers • Existing steam plant • Existing ASU / Oxygen supply (ATR only) • Low carbon electricity source (more important for ATR)	• Skilled workforce (gas processing / petrochemical type skillsets) • Support for local Hydrogen demand (transport / heating / industrial / agri.) • Hydrogen demand potential at scale in local area.	• Access to natural gas pipeline network at capacity to allow export blending. • Proximity & route to interseasonal hydrogen storage.
Close to ideal – minor / easily addressed impact	**Supply of natural gas from pipeline dependent on further field development.**	• Access to CO_2 transport network (short distance away).	• Existing Steam plant / ASU not available • COMAH upper tier suitable	• Local workforce that may require reskilling. • Small local demand.	• No pipeline access, but access to established ship loading terminal for hydrogen / product export • No interseasonal hydrogen storage in proximity.

Cont

Table 10.4 – Blue Hydrogen Production Site Assessment Criteria (continued)

	Methane Supply	CO2 Transport & Storage Route	Site size and suitability	Local Activity	Hydrogen Export
Larger impact on cost, scale or timeline	Supply of natural gas from LNG import	• Access to CO_2 transport network (long distance away).	• Size of land available unclear • Suitability for COMAH upper tier unclear.	• Limited local workforce, with requirement to bring in / accommodate travelling crew	• No pipeline access. Access to port but without establish gas/ liquid loading facilities and with significant modifications to accommodate suitable vessels.
Blockers / barriers	No natural gas supply	• No access / long distance and very large infrastructure needed to access/	• No site of sufficient size. • Planning consent not possible or heavily blocked	• Active opposition in local area. • No available workforce locally	• No export route at sufficient scale

Details of specific sites assessed for both green and blue hydrogen production will be contained within follow on report.

11. Conclusions and Recommendations

11.1 Scotland Market and Competitor Review

If Scotland is to realise its ambition of becoming a major player in the production, use and export of clean hydrogen in the next decade, and beyond, it is essential that current efforts, and projects are fully supported and encouraged to advance at a rapid pace.

Scotland has significant potential for utilising clean hydrogen both in domestic supply and international export. However, increasing local demand is crucial in addition to establishing a strong project pipeline of new proposals and scaling up existing projects. Such as the Acorn Hydrogen project which aims to produce blue hydrogen, with CCUS, along with green hydrogen, utilizing and expanding on existing oil and gas infrastructure to supply clean hydrogen for industry, heating and transport in Scotland.

It is essential that hydrogen is integrated across various sectors including transport, heating, industry and electricity generation, in order to stimulate demand and reduce the LCOH by encouraging scale up of production. Incentivisation is necessary to reduce the LCOH and enable clean hydrogen to be cost competitive, in the near and medium term, with high-carbon fuels and grey hydrogen.

Scotland needs to prioritise support for the development of a hydrogen supply chain, and associated infrastructure, to enable technology scale up and realise its clean hydrogen production and export potential. In addition, a supportive policy and regulatory framework is vital to encourage and facilitate the export of clean hydrogen to European markets, and further afield.

A competitive hydrogen value chain will require a collaborative environment at all levels including hydrogen producers, distributors, importers, and end users in order to establish a sustainable supply and demand balance bringing together all stakeholders to realise Scotland as a European, and global leader in the emerging clean hydrogen future. Several countries have recognized in their hydrogen strategies, the requirement to import clean hydrogen in order to satisfy their demand and drive to net zero. North West Europe, with its centres of industry, extensive gas pipeline network, and commitment to clean hydrogen as outlined in various country's hydrogen strategies, along with the regions proximity to Scotland, present a clear market opportunity to capitalise on over the next decade. Germany Hydrogen demand is expected to grow to approximately 110 TWh by 2030. The Netherlands demand for hydrogen could be 100 TWh by 2030[4].

11.2 Technology and Cost Reduction Opportunities

Green

Alkaline and PEM electrolysers are both currently operating commercially at MW-scale. There is therefore a large step up in capacity needed to get to GW-scale. Given the need to scale-up to achieve larger capacities, compact PEM electrolysers are expected to be favoured in a 10-year timescale.

Green hydrogen production technology is much less mature than blue, and therefore is expected to have a higher cost of production in the near term. The fact that it is less mature, along with the inherently modular nature, means electrolyser production technology is very likely to have a higher / faster cost reduction as global installed capacity increases. The levelized cost of production of green hydrogen is very strongly influenced by the cost of the renewable electricity, which is expected to reduce as larger offshore wind sites are developed. Therefore, there is potential for green hydrogen to be cheaper at some point in the future, though there is uncertainty as to in what timescale.

Green hydrogen production is more suited to scaling up from lower production capacities to full scale than blue hydrogen due to its inherently modular nature. Electrolyser units and stacks can be developed and combined to build scale gradually over time.

Blue

Blue hydrogen production technology is relatively mature and has been demonstrated at the capacities considered in this study. As such it presents a lower cost route to hydrogen production in the near term when compared to green hydrogen production. SMR and ATR technologies are both viable blue hydrogen production solutions. Enhanced versions of these technologies are in development that can significantly improve carbon capture performance and energy and process optimisation, while delivering space and cost reductions. Alternative scalable technologies also exist that have the potential to compete with SMR and ATR technologies in the future.

Enhanced SMR technology has the cost advantage in terms of CAPEX, OPEX, and LCOH for small to medium sized hydrogen plants.

Enhanced ATR technology has improved scalability, which results in the technology being commercially advantageous for much larger hydrogen production capacities. Enhanced ATR also provides improved carbon capture performance which is an increasingly important consideration in the transition towards net zero emissions. This is dependent on the carbon intensity of the large electrical power needed for ATR, as there is potential for offsite (scope 2) carbon emissions to be significant.

Both enhanced SMR and enhanced ATR technologies have similar plot areas and resource and infrastructure requirements, including natural gas, water and HV electricity supplies, and hydrogen and carbon dioxide product export pipelines. However, enhanced ATR additionally requires an oxygen supply produced by an ASU.

In summary, the technologies should be assessed on a case-by-case basis to determine the optimum solution for the site conditions and desired hydrogen production capacity.

Transport & Storage

Transport of hydrogen at the scale considered in this study practically needs to be either by pipeline or by ship – analogous to natural gas / liquid natural gas (LNG) transport. Transport by road is possible, but this is only a practical option for smaller scale production.

The most mature technology is pipeline transport. This can be either as pure hydrogen, or by blending hydrogen into the natural gas network. There is a lot of activity in the UK looking at the feasibility of blending hydrogen into the national gas grid, and the implications of this to end users. This is small scale at the moment, but there are ambitions to increase the scale to town or city level in the next 10 years. New dedicated hydrogen pipelines, particularly connecting areas of high production potential with large areas of demand, would be expected to be a low-cost solution and can be developed in the next years. Export to Europe, where a large hydrogen demand is expected by 2030 may drive towards dedicated offshore hydrogen pipeline in the future.

The largest area of uncertainty in hydrogen production is what the most economical form of hydrogen will be for transport over different distances. The low volume density of hydrogen means either a lower capacity or a much higher design pressure (and therefore cost) for pipeline systems transporting gaseous hydrogen, compared to natural gas. Compared with transport of natural gas, it may be the case that the distance at which shipping becomes the preferred means of transport compared to pipelines is shorter. Alternative ways of transporting hydrogen, in liquid form or as alternative products (ammonia, methanol, in LOHC carrier) are at early levels of technical development. There is currently no clear direction that is becoming apparent for facilities looking to develop hydrogen production in the next 10 years.

11.3 Hydrogen Production Site Assessment

The site-specific factors that will most influence the cost of hydrogen production are the cost of electricity (green) or gas (blue) at the production site, the costs of CO2 transport and storage (blue) and the costs of transport to a suitably sized market (both blue and green).

The site itself needs to be of sufficient size and will need to be upper tier COMAH classified.

For areas with wind power production potential, but where grid access or capacity restrict what could be developed, lead to high system management costs, or high degrees of curtailment, hydrogen production could unlock development of those wind sites by improving the investment case and de-risking projects.

The results from the study highlight that:

- Numerous sites across Scotland have characteristics that closely match those required of an 'ideal' site to scale-up clean hydrogen production in the next 10 years. Hence, this site-level analysis has concluded that **with the correct policy and financial incentives, Scotland is incredibly well positioned to produce vast quantities of blue and green hydrogen in multiple locations across the country.**

Clean hydrogen production opportunities lie in several island locations. Details of specific sites assessed will be contained within follow on report. These locations have potential to utilise vast offshore wind resources and other constrained renewables, whilst could develop hydrogen export routes through ship.

Further clean hydrogen production opportunities lie on the mainland. Details of specific sites assessed will be contained within follow on report. These locations are strategically located close to infrastructure, future local demand, export routes or may benefit from development opportunities on a brownfield site.

For blue hydrogen production sites, the greatest uncertainty is around the longevity of natural gas supply. This varies by site.

- To achieve an investable project, there will be a need to demonstrate long term gas supply.
- A large proportion of the green sites identified would be more attractive if there was a low-cost shipping option for export. This is a clear area for innovation, as it could support both production sites with high wind resource that are likely to have a relatively high cost or constrained electricity export route via the grid, and it could open export opportunities to markets other than and further away than Europe.

- For some sites, there is a key underlying assumption that existing onshore or offshore pipelines (including current national grid infrastructure) can be used for pure or blended hydrogen, or for CO_2. There are studies ongoing as to the feasibility of this, but this study reinforces the importance of establishing this as it does have a strong influence on the suitability of site for hydrogen production.

Nearly all locations assessed have at least one characteristic that is clearly suited to a future hydrogen production development, with other characteristics that are close to classification as 'ideal'. Many of the 'non-ideal' characteristics would not preclude a site from producing and exporting hydrogen but identify that the resulting LCOH would be higher than the 'ideal' case, or that further investigation is required before reaching a conclusion.

Details of specific sites assessed for both green and blue hydrogen production will be contained within follow on report.
This study has described the vast opportunities at different sites across Scotland to scale-up blue and green hydrogen production in the next 10 years. The study should act as the launch-pad for further engagement between Scottish Government, site owners and operators, equipment manufacturers, renewable developers, communities, and other stakeholders, before studying in more detail the feasibility of developing a site for hydrogen production.

11.4 Recommendations

Conclusions drawn in this report regarding a site's suitability to produce hydrogen should be used as a starting point to inform the focus and direction of future studies and discussions. Recommended next steps include:

- **Further study is required to determine the techno-economic feasibility of green hydrogen production from large scale renewable electricity** - whether this be from future offshore or onshore wind developments, or other renewable sources. **Options to maximise the consistency of electricity supply to electrolysers should be studied as should storage (battery or hydrogen) costs and benefits, as this can have a significant impact on reducing the LCOH.**
- Offshore wind developments will likely be crucial sources of renewable electricity to power electrolysers. **Hence, timescales to deployment of GW-scale offshore wind must be accelerated if large-scale hydrogen is to be produced within the next 10 years.** Conversely, particularly for any areas with very constrained grid access, **a clear pathway to commercial production of hydrogen (technical and demand visibility) is needed to enable investment decisions relating to development of the wind resource.**
- Possible blue hydrogen production sites have been based around the cost and scalability of methane supply as feedstock for reformation, with a pipeline supply to the location being the lowest cost option. **The security of future methane supply to the location should be considered, based on natural gas production forecasts.**
- **Engagement with site owners and operators is required to further determine site suitability, stakeholder appetite, and any current plans for a hydrogen production development.** Interaction with site owners has been minimal throughout this study, but it is understood that several are already in discussions regarding hydrogen production developments.
- **Establishing the value chain downstream from production is critical.** Ultimately this means securing an export market for hydrogen produced from a Scottish site. This also means establishing a clear value chain to get the hydrogen to that market – be that pipeline or ship transport. The extent to which regulated business models will be in place for hydrogen or for CO2 is not yet clear. On the ship side there is also a

technology uncertainty as to what form is going to be preferred for ship transport of hydrogen. **Here, there may be benefits in multiple sites in Scotland collaborating to establish a common view, together with a targeted demand market, that could then support development of a specific transport technology.** This could also support supply chain, by giving the opportunity to establish a fleet of vessels servicing several sites at a lower cost.

- The potential development of export routes through ship have been assumed based on current port capabilities. **The feasibility of developing a port or terminal to support hydrogen export through bulk cargo or vessel fuel, needs to be studied in further detail.**

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13. Glossary

ADEME	The Agency for Ecological Transition
AEM	Anion exchange membrane
AFHYPAC	French Association for Hydrogen and Fuel Cells
AIST	The National Institute for Advanced Industrial Science and Technology
ASU	Air separation unit
ATR	Autothermal reforming
AUD	Australian Dollar
BoP	Balance of plant
BSUoS	Balancing Service Use of System
CaO	Calcium oxide
CAPEX	Capital expenditure
CCC	Climate Change Committee
CCUS	Carbon Capture, Utilization and Storage
CH_3OH	Methanol
CH_4	Methane
CHG	Compact H_2 Generator
CHP	Combined heat and power
CO	Carbon monoxide
CO_2	Carbon Dioxide
DBT	Dibenzyltoluene
DNEC	Dedecahydro-N-ethylcarbazole
DWT	Dead-Weight Tonnage
ETZ	Energy Transition Zone
EUR	Euro
FCEV	Fuel cell electric vehicle
FCH JU	Fuel Cell and Hydrogen Joint Undertaking
FID	Final Investment Decision
GBP	British pounds
GH_2	Compressed hydrogen
GHR	Gas heated reformer
GW	Gigawatt
GWh	Gigawatt-hour
H_2	Hydrogen
H_2O	Water
ha	Hectares
HER	Hydrogen evolution reaction
HHV	Higher heating value
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
IPCEI	Important Project of Common European Interest
IRENA	International Renewable Energy Agency
KOH	Potassium hydroxide
kWh	Kilowatt-hour
LCH	Low carbon hydrogen
LCOE	Levelised cost of electricity
LCOH	Levelised cost of hydrogen
LCOS	Levelised cost of storage
LH_2	Cryogenic hydrogen
LHV	Lower heating value

LNG	Liquified natural gas
LOHC	Liquified organic hydrogen carrier
LPG	Liquid petroleum gas
LRC	Lined-rock cavern
MCH	Methylcyclohexane
MENA	Middle East and North Africa
MOF	Metal organic frameworks
MOU	Memorandum of Understanding
Mtoe	Million tonnes of oil equivalent
$NaBH_4$	Borohydrides
NEC	N-ethylcarbazole
NECP	National Energy and Climate Plan
NEP	Northern Endurance Partnership
NH_3	Ammonia
NSL	North Sea Link
NTS	National Transmission System
NZT	Net Zero Teesside
O_2	Oxygen
O&G	Oil and Gas
OECD	Organization for Economic Cooperation and Development
OH	Hydroxide ions
ONE	Opportunity North East
OPEX	Operating expenditure
°C	Degree Celsius
P2G	Power-to-Gas
P2L	Power-to-Liquids
PDBT	Perhydro-dibenzyltoluene
PEM	Polymer electrolyte membrane
PFSA	Perfluorosulfonic acid
POX	Partial oxidation
PSA	Pressure swing adsorption
PV	Photovoltaics
PWh	Petawatt-hours
R&D	Research and development
Remap	Renewable Energy Roadmap
S:C	Steam to carbon
SGP	Shell Gas Partial Oxidisation
SMR	Steam methane reforming
SOE/SOEC	Solid oxide electrolysis
Solar PV	Solar photovoltaic
tn	Tonnes
TNUoS	Transmission Network Use of Service
TRL	Technology readiness level
TWh	Terawatt-hour
TWR	Terrace wall reformer
USD	United States dollar
WA	Western Australia
ZEV	Zero Emission Valley

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