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Cost reduction pathways of green hydrogen production in Scotland

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1 Executive summary

1.1 The case for green hydrogen in Scotland

Green hydrogen, produced by electrolysis exclusively with renewable electricity, is expected to play a key role in the Scottish Government's mission to achieve net zero emissions targets. Hydrogen is a versatile energy vector that can be used in a range of applications without emitting carbon dioxide at the point of use.

Scotland has set an initial ambition of producing at least 5 gigawatts of renewable and low carbon hydrogen by 2030 and 25 gigawatts by 2045. Meeting these targets will not only contribute to emissions reductions but also has the potential to safeguard future industry and employment. Furthermore, Scotland's geography, geology, infrastructure, and expertise make it particularly suited to rapidly developing a low carbon hydrogen economy. This could see Scotland become a global leader in hydrogen, and secure economic opportunities across the UK.

1.2 The costs of producing green hydrogen in Scotland

This report explores the costs of producing green hydrogen in Scotland. It considers the key drivers of cost and develops an understanding of how the production cost and the supply chain could develop to 2045. Each part of the supply chain is examined to understand the current costs and barriers, as well as identifying where policy support could help the green hydrogen economy to grow.

Four 'production pathways' have been defined for this study that reflect the main supply chain models that are expected to emerge in a green hydrogen economy. The hydrogen economy will require a combination of these pathways to meet the range of needs as well as future low carbon hydrogen targets. The choice of production pathway for each application will likely depend on the size, location and surrounding infrastructure of the end user. The production pathways are:

1. **Pathway 1 - Centralised System:** Large scale hydrogen production plant (100MW) that is co-located with a renewable energy source and with the end user (i.e., direct connection with the end user). Industrial hubs are a good example of this pathway,

where end users could include industrial customers connected via a direct pipeline (steel manufacturing) or blending into the gas grid for use as heat.

2. **Pathway 2- Distributed Pathway:** Medium scale hydrogen production plant (20MW) that is co-located with a renewable energy source and is distributed to the end users by a fleet of road tankers. Potential end users for this supply model would include small to medium sized users that are dispersed (i.e., not clustered together) or do not have the capital or land to develop their own hydrogen production plant.
3. **Pathway 3 - Export Model:** Very large-scale hydrogen production plant (500MW) that is co-located with a renewable energy source with the purpose to export of large volumes of hydrogen (in liquid form) to Europe.
4. **Pathway 4 – Decentralised Model:** Small scale production sites (1MW) that do not have direct access to a renewable energy source and are reliant on a connection to the electricity grid. This model would suit small scale end users who are not located in industrial hubs and require only small, discrete hydrogen demand, e.g., hydrogen refuelling stations.

1.3 Factors expected to drive down future hydrogen costs

The cost of hydrogen production for each pathway is shown in Table 1. The results indicate that hydrogen cost is expected to approximately halve between 2022 and 2045 for the three pathways connected directly to a renewable energy source (pathway 1, 2 and 3)[1].

Table 1 - Levelised cost of hydrogen outputs (£/kg) – 2022 values

Levelised cost of hydrogen (£/kg)	2022 base case (range)	2030 base case (range)	2045 base case (range)
Pathway 1	**6.7** (5.2 - 9.3)	**4.0** (3.6 – 5.2)	**3.0** (2.8 – 4.6)
Pathway 2	**7.7** (6.0 – 10.3)	**4.7** (4.3 – 6.4)	**3.9** (3.7 – 6.0)
Pathway 3	**9.3** (7.8 – 11.9)	**5.6** (5.2 – 6.8)	**4.1** (3.9 – 5.7)
Pathway 4	**11.1** (7.6 – 14.0)	**9.2** (6.4 – 11.2)	**7.9** (5.9 – 9.1)

Between 2022 and 2030, capital cost reductions of electrolyser plants are expected to be the biggest contributor to decreases in the cost of hydrogen. These cost reductions will be achieved through technology improvements and a significant scale-up of supply chain capacities.

Between 2030 and 2045, lower prices of wind power are expected to be the primary driver of green hydrogen cost reductions in Scotland. Although falling costs of electrolyser plants will still play a role, they will begin to level off beyond 2030, while steady reductions in the cost of wind power will dominate.

There are three key factors controlling the development of green hydrogen in Scotland:

- **Electricity costs are the biggest driver for hydrogen production costs. Minimising the cost of electricity will be vital.** The best way to achieve this will be through direct connections to wind farms, which is the case for pathways 1 to 3. If a green hydrogen producer is required to pay electricity grid charges (e.g. pathway 4), the cost of green hydrogen is unlikely to become cost-competitive with fossil fuels. Therefore, a favourable environment for the deployment of renewable energy will be vital to ensure

[1] This report assumes that Scotland's plentiful offshore and onshore wind will be the renewable energy source.

that renewable energy costs continue to drop and there is sufficient capacity to support the scale up in the green hydrogen industry.

- **Scaling up the industry is expected to lead to significant cost savings across the supply chain.** Manufacturing capacity for green hydrogen technologies (e.g. electrolysers, compressors, road tankers, storage tanks) will need to grow rapidly from a very low base currently. Therefore, government incentives to promote and scale up domestic production of green hydrogen equipment across the supply chain in Scotland could help drive down production costs.
- **Domestic infrastructure to transport hydrogen is currently limited and needs to be rapidly developed to ensure the continued emergence of the green hydrogen sector in Scotland**. Transport infrastructure for hydrogen is currently very limited and will require a significant scale up to move large volumes around safely. This will require a large amount of investment into both suitable road transport infrastructure to enable consumption of hydrogen in Scotland, as well as shipping infrastructure for hydrogen export. It is important to ensure that centralised production locations can be connected with more rural end users. With relatively low levels of technical complexity required to improve transport infrastructure, this presents a key opportunity for the Scottish economy to stimulate economic activity and position itself as key exporter of hydrogen.

Despite the downward trajectory predicted for hydrogen costs across all pathways, significant uncertainty remains around the demand uptake and the ability of the supply chain to scale up. Government has a role to play in identifying areas of risk and targeting interventions to mitigate these risks:

- **Price competitiveness with natural gas in industrial-scale applications is unlikely before 2045 without government support**[2]. Though, green hydrogen could begin to compete with other fuels, such as diesel in mobility applications, by the late 2020s. This study has considered fossil fuel prices prior to the significant increases that were observed in 2021 and early 2022. The recent increases in fossil fuel prices have significantly reduced the cost gap and may have an impact on green hydrogen's ability to be price competitive with natural gas.
- **Subsidy support will be required to encourage adoption of green hydrogen in the short term**. The UK Government's Hydrogen Business Model scheme is expected to provide support for hydrogen production through contracts for difference[3]. It is clear that green hydrogen is more expensive than fossil fuel alternatives, therefore, in order to incentivise demand, policy support will be required. For mobility applications, the Renewable Transport Fuel Obligation is an established mechanism that could be further modified to encourage greater uptake of hydrogen in some transport modes.

With the correct support, Scotland has the potential to be a cost-competitive exporter of hydrogen to Europe. Due to its close proximity to Europe, Scotland benefits from lower transport costs and more flexibility compared to other potential large-scale hydrogen export locations, such as the United Arab Emirates and Australia.

[2] Based on the long-term retail natural gas forecasts published by the Department for Business, Energy and Industrial Strategy (BEIS) in early 2021 (i.e. before the recent increase in gas prices). This study assumes that fossil fuel price trends will revert to align with BEIS forecasts within the next two years.
[3] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1011469/Consultation_on_a_business_model_for_low_carbon_hydrogen.pdf

Contents

2 Green Hydrogen in Scotland

2.1 Importance of low carbon hydrogen to a net-zero Scotland

In March 2020, Scotland committed to achieving Net Zero greenhouse gas emissions by 2045 and a 75% reduction by 2030 relative to 1990 levels [1]. Hydrogen production is expected to play a key role in the Scottish Government's mission to achieve Net Zero targets due to hydrogen's suitability as an energy vector in a range of applications without emitting carbon dioxide at the point of use. Hydrogen's potential for decarbonisation has been acknowledged by the UK Government too, with analysis suggesting that by 2050 up to 30% of the UK's energy demand could be met by hydrogen [2].

As part of a decarbonised energy system, low carbon hydrogen could be a versatile replacement for emission-intensive fuels. It is particularly helpful in industrial applications where direct electrification is not feasible and could complement renewable electricity in decarbonising the transport, power and heat sectors.

Scotland has set an initial ambition of producing 5 gigawatts (GW) of low carbon hydrogen by 2030 and 25 GW by 2045 [3]. Meeting these targets will not only contribute to reducing emissions but also has the potential to safeguard future industry and employment. The most ambitious scenario of the Scottish Hydrogen Assessment estimated that hydrogen has the potential to add up to £22.5bn in cumulative gross value add (GVA) with over 300,000 jobs supported by 2045 [4].

2.2 Why Green Hydrogen?

There are a range of Pathways for low carbon hydrogen production, each with different characteristics and associated lifecycle emissions, including but not limited to:

- Electrolysis powered by renewable electricity;
- Electrolysis powered by nuclear electricity;
- Electrolysis powered by mixed-origin grid energy;
- Steam methane reforming (SMR) or autothermal reformation (ATR) with carbon capture and storage (CCS), and
- Pyrolysis with carbon capture.

'Green hydrogen' is a name given to hydrogen produced by electrolysis that is powered exclusively by renewable electricity. This is the production method that has the lowest lifecycle emissions [5] and is the focus of this study. Scotland is well suited to the production of green hydrogen with the potential to produce industrial-scale quantities of green hydrogen from Scotland's plentiful onshore and offshore wind resources[4].

The main challenge is that the cost of producing green hydrogen is currently higher than for fossil fuels and needs to be reduced significantly to be competitive. The International Energy Agency (IEA) estimates the typical costs of green hydrogen production are 4 to 6 times more expensive than the production of hydrogen from fossil fuels (before the recent increase in gas prices) [6]. The development of the green hydrogen economy hinges on the technological advancements of the industry and infrastructure surrounding it.

[4] Scotland has good potential for renewable electricity from other sources too, but this study has concentrated on onshore and offshore wind because it is a high-quality resource with significant potential to grow further. However, all renewable energy technologies will have a role to play in Scotland's hydrogen economy.

2.3 Production Pathways in Scotland

This report explores the key drivers behind the cost of producing green hydrogen in Scotland and develops an understanding of how the cost of hydrogen production and the supply chain around it are predicted to develop out to 2045. Each part of the supply chain is examined to understand the current costs and barriers, as well as identifying where policy support is required.

The cost of producing green hydrogen will vary considerably depending on end use and the supply chain requirements (i.e., transport distance, volume of storage, demand volumes, etc.), therefore this report considers four supply chain models, called ‘production Pathways’, that are expected to emerge in the coming years. These are show in Figure 1 and explained below.

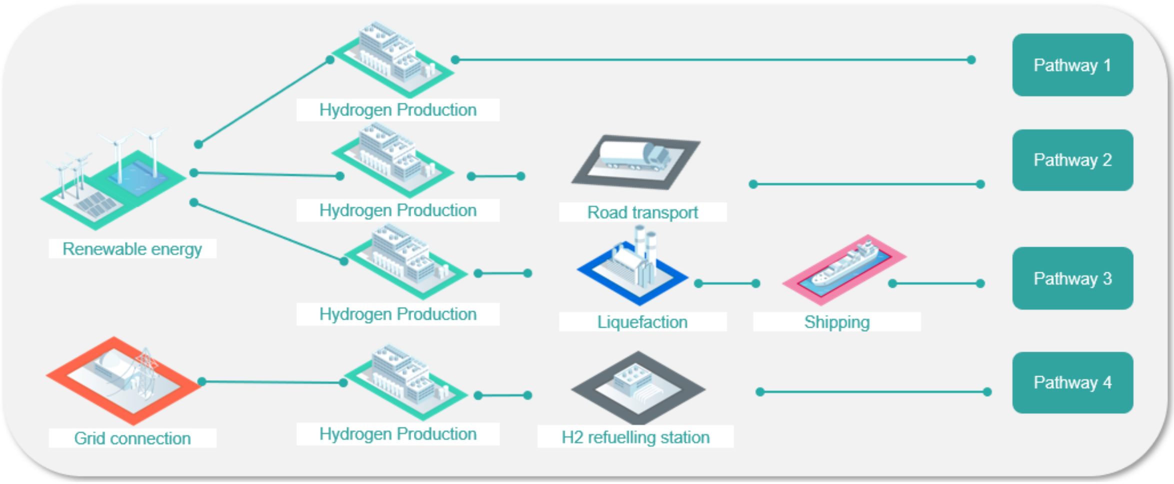

Figure 1 - Schematic of Pathways considered in this report

The hydrogen economy will require a combination of these pathways to meet the range of needs as well as future low carbon hydrogen targets. The location and size of the hydrogen demand are likely to determine which pathway is best suited for a specific application:

1. **Pathway 1 - Centralised System:** Large scale hydrogen production plant (100MW) that is co-located with a renewable energy source and with the end user (i.e., direct connection with the end user). Industrial hubs are a good example of this pathway, where end users could include industrial customers connected via a direct pipeline (steel manufacturing) or blending into the gas grid for use as heat.
2. **Pathway 2- Distributed Pathway:** Medium scale hydrogen production plant (20MW) that is co-located with a renewable energy source and is distributed to the end users by a fleet of road tankers. Potential off takers for this supply model would include small to medium sized users that are dispersed (i.e. not clustered together) or do not have the capital or land to develop their own hydrogen production plant.
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2.4 Approach & Methodology

This report is structured as follows:

Section 3 – Review of supply chain cost reduction trajectories

Section 4 – Levelised cost review of each pathway

Section 5 – Conclusions and recommendations

Section 3 breaks down each part of the supply chain and considers the current costs and the expected future cost reductions. The analysis is based on a literature review alongside discussions with key industry stakeholders (see Appendix 7.2 for a list of stakeholders). The information gathered has then been used to develop expected cost trends for each stage in the supply chain out to 2045.

In Section 4, the expected cost trajectories have been brought together into a cost model to determine the levelised cost of hydrogen (LCOH) for each pathway on a per kilogram basis (£/kg). For each pathway, the LCOH of has been assessed and compared in the years 2022, 2027, 2030 and 2045. These focus years are aligned with the target years of the Scottish Hydrogen Strategy (2030 & 2045) [3], whilst 2027 has been included on the basis that the late 2020s are anticipated to be a key period for scale up of the hydrogen economy.

The drivers behind the future costs of each pathway are assessed to understand the variables that have the biggest impact on the cost of hydrogen. This is key to identifying where policy support is needed most and where it can be most effective.

Levelised cost of hydrogen

The levelised cost of hydrogen is a standardised methodology used by economists to compare the costs of producing hydrogen by different methods. It considers the total costs (both fixed and variable) of production per kilogram over the life of the plant. It is a common metric that is used as a proxy for the price of hydrogen in today's terms (where future costs are discounted), which is required to "break-even" financially. It is therefore an important calculation to assess early-stage project feasibility and compare options.

Section 5 provides the conclusions of the study together with recommendations for next steps.

3 Green Hydrogen Supply Chain

3.1 Supply Chain Overview

The green hydrogen supply chain can be broadly categorised into five key stages:

1. Renewable Energy Generation
2. Hydrogen Production via Electrolysis
3. Hydrogen Storage
4. Hydrogen Transport
5. End use infrastructure

To understand the potential future costs of producing green hydrogen in Scotland, the supply chain must be considered holistically. The following chapter details the potential future cost evolution for each stage of the supply chain.

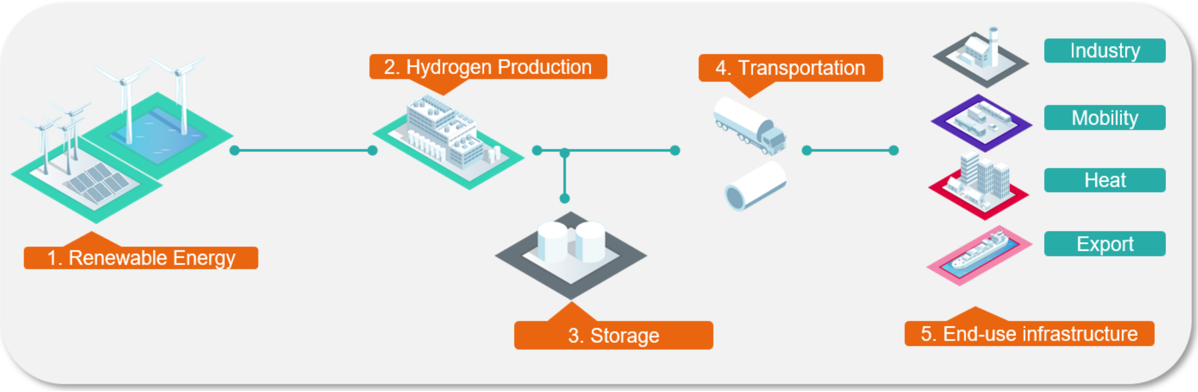

Figure 2 - Green hydrogen supply chain overview

3.2 Wind Electricity Generation

Fundamental to any green hydrogen supply chain is the ability to access renewable electricity. The analysis in Section 4 shows that the cost of electricity is typically the largest contributor to the cost of producing hydrogen. When assessing which renewable energy sources are well suited to green hydrogen production, there are two key considerations: cost and capacity factor, which are explained below.

Firstly, given that the cost of electricity is typically the main cost driver of green hydrogen production, identifying the lowest cost of electricity is critical. This report investigates the future trajectories of renewable electricity costs and the impact this has on the cost of green hydrogen production.

The second key consideration is the capacity factor of the renewable source, which is defined as the electricity produced in a period (e.g., one year) divided by the electricity it could have produced if it had operated at 100% output for that period. For example, a 5 MW wind turbine which, due to varying wind speeds, generates 2.5 MW on average over a year would have a capacity factor of 50%. This is a common consideration in renewable technologies that rely on varying natural conditions (e.g., wind and sunshine) resulting in intermittent electricity output. When applied to production of hydrogen by electrolysis, a higher capacity factor means that the equipment is able to operate for more of the time, increasing the return on investment.

While costs and capacity factors can be discussed individually, they are inextricably linked. A wind turbine, for example, installed in a location resulting in a lower capacity factor will generate less energy than the same turbine in more favourable conditions. Hence, for the same upfront cost, the cost per unit of electricity produced will be different. It is standard in the industry to express the cost of producing renewable electricity as the Levelised Cost of Energy (LCOE), which is calculated using the same methodology as the LCOH described previously.

This report focuses on the costs of onshore and offshore wind, given Scotland's access to plentiful wind power generation.

3.2.1 Onshore Wind

Onshore wind turbines are the most mature wind technology with over 700 GW of installed capacity around the world [7]. Scotland has nearly 9 GW of installed capacity and plans to increase this to 12 GW by 2030 [8].

In line with the scale up in onshore wind capacity, the LCOE of onshore wind in Europe has declined by 38% between 2010 and 2020 from £60/MWh[5] in 2010 to £37/MWh in 2020 [9]. The decrease is attributed to improvements to turbine technology (increasing energy yield), government subsidy support mechanisms, supply chain economies of scale (manufacturing, logistic and installation capacity), competitive procurement (auctions driving cost competitiveness), and optimisation of operation and maintenance (O&M) costs.

While future cost reductions are expected, they are not likely to be as significant as the last 10 years because the market is now much more mature with well-developed supply chains and technologies. Figure 3 shows global onshore wind LCOE estimates from a variety of sources (out to 2050) to demonstrate the potential range of costs that can be expected (see Appendix 7.4 for full list of sources). It should be noted that onshore wind costs are highly location specific and therefore a global database can result in a significant variation in LCOE.

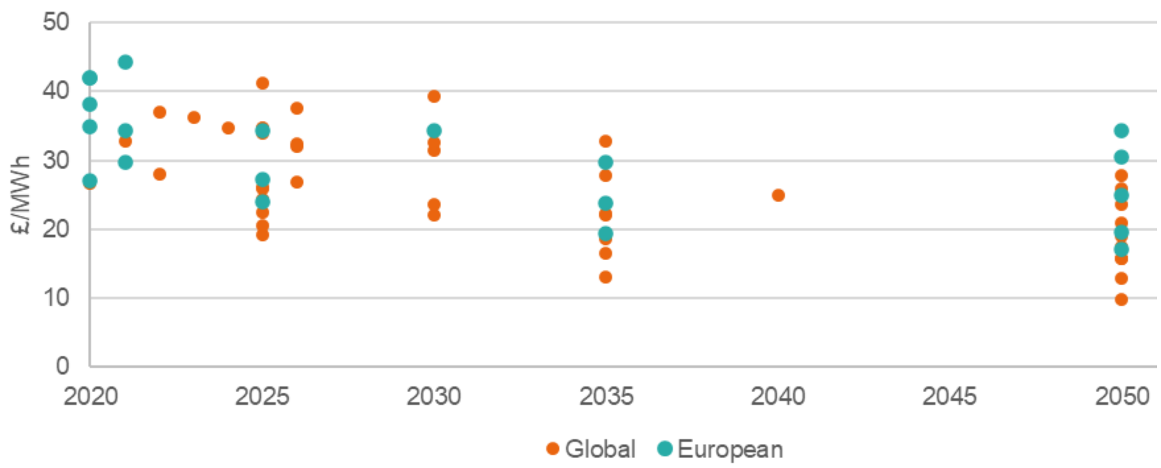

Figure 3 – Global Onshore Wind LCOE (£/MWh – 2022 prices) | Sources: Various - see Appendix 7.5 for details

Figure 3 shows that by 2030, the LCOE of onshore wind is expected to be £22 - 39/MWh and further decrease to £10 - 34/MWh by 2050. The main cost reductions are expected to be due to increases in turbine size (generator ratings to increase from 2.5 MW to 5.5 MW) and continued optimisation of O&M costs.

Despite cost reductions being widely expected, there is significant variation in future cost estimates driven by the location specific nature of wind energy generation. When only the European dataset is considered, LCOE ranges are expected to be £19 - 27/MWh by 2035

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[5] Assumed USD to GBP exchange rate of 0.78 [27]

(a 27 - 49% decrease from 2020) and £17 - 25/MWh by 2050[6]. This suggests, in regions such as Scotland where onshore wind is already well established, that there is expected to be limited further cost reductions beyond 2030 given that the market and technology will already be mature.

3.2.2 Offshore Wind

Installed capacity of offshore wind turbines has grown significantly in the last 10 years with advances in engineering and construction methods. The increased uptake in offshore wind is primarily driven by the benefits of accessing the higher and more consistent wind speeds in offshore locations.

Offshore wind turbines are installed using one of two techniques, namely fixed bed or floating. As the name suggests, fixed bed turbines are installed on foundations fixed to the seabed. However, this option is limited to shallower sea depths (typically not exceeding 50m), primarily due to the costs and complexities of the foundation design and construction at greater depths. The alternative is floating turbines, which are installed on floating structures tethered to the seabed to minimise drift. This enables installation in locations of greater water depth than would be considered for fixed bed solutions.

Fixed bed Turbines

As the industry has grown in the UK, it is estimated that the LCOE for fixed bed offshore wind has decreased by 29% between 2010 and 2020 from £118/MWh in 2010 to £84/MWh in 2020 [9].

In January 2022, Crown Estate Scotland announced the outcome of its most recent offshore leasing process which allowed a total of 11.5 GW of new fixed bed offshore capacity to supplement a further 8.4GW that is already under construction or advanced development [10]. Based on the outcomes of the latest leasing process, costs are expected to continue to decrease and reach between £47 - 59/MWh by 2025. This would be a 30 - 44% reduction from the 2020 values on average. Like onshore wind, this decrease is attributed to technology improvements, subsidies, economies of scale, competitive auctions, and improved O&M capability.

Figure 4 shows the European offshore wind LCOE estimates from a variety of sources out to 2050. It also includes values from the BEIS contract for difference (CfD) allocation rounds 2 & 3. These values represent the strike price (i.e., LCOE) of successful offshore wind projects in the UK that are currently under development. They provide a good indication of the near-term LCOE in the UK.

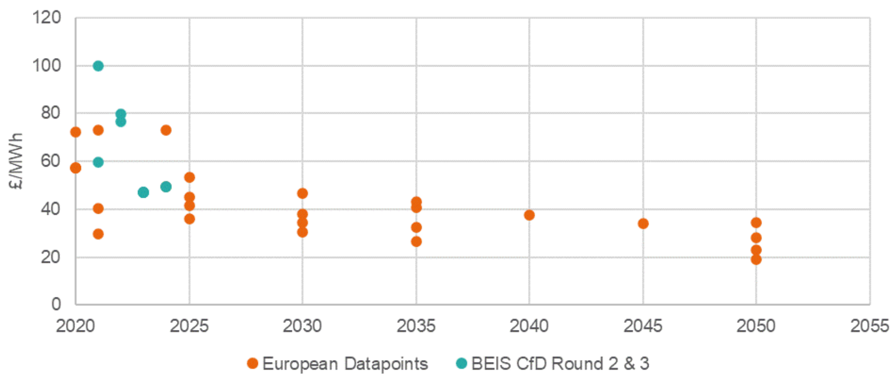

Figure 4 – European Offshore wind LCOE (£/MWh – 2022 prices) | *Sources: Various - see Appendix 7.5 for details*

[6] Limited information is available in the public domain for recent onshore wind projects in Scotland and therefore a European dataset has been used.

Figure 4 shows that cost reductions are expected to continue, albeit at a decreasing rate, out to 2050 as the market continues to mature. The literature suggests that by 2050 costs are expected to be between £19 - 34/MWh.

Floating Turbines

Floating offshore wind technology is with only three floating wind farms operational in Europe by 2021 (Hywind and Kincardine in Scotland and Wind Float Atlantic in Portugal) [11]. Floating offshore wind offers new opportunities with the ability to deploy larger wind turbines and access deeper offshore areas that often have higher wind potential. However, floating wind farms typically have a higher LCOE than fixed bed technologies currently. The first floating wind farms had a LCOE exceeding £160/MWh [12], largely due to their relatively small size and the immaturity of the technology and supply chain.

Nevertheless, as shown by the recent Crown Estate Scotland auction, there is significant optimism around the potential of floating offshore wind in Scotland. Out of the 25 GW of capacity awarded, 13.5 GW was awarded to floating offshore projects [10]. This is largely due to the expected cost reductions coupled with the higher capacity factors that can be achieved at deeper waters by floating systems as already described. For example, the Hywind Scotland project has achieved the highest average capacity factor of all offshore wind farms (57.1% in 2020) [13].

Figure 4 shows floating offshore wind LCOE estimates from a variety of sources out to 2050.

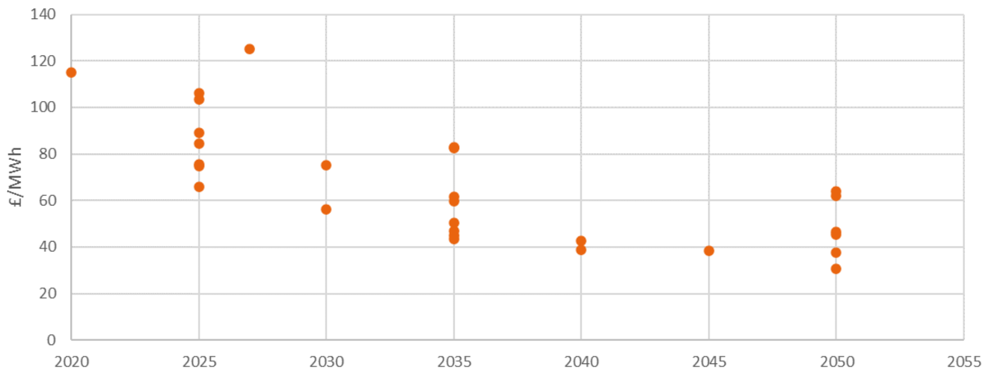

Figure 5 – European Floating Offshore Wind LCOE (£/MWh – 2022 values) | *Sources: Various - see Appendix 7.5 for details*

As the floating offshore wind industry and supply chain scales up, significant cost reductions are expected. As shown in Figure 5, forecasts suggest that by 2035, costs could vary between £43 - 62/MWh and reach £31 - 46/MWh by 2050. Based on these forecasts, the LCOE for floating wind will be about a third of their current value by 2050.

3.2.3 Summary of renewable electricity generation costs

Renewable electricity costs are typically the main driver of green hydrogen production costs and therefore future cost trajectories are expected to play a significant role in the cost competitiveness of green hydrogen in Scotland. Significant cost reductions are expected over the next 5 - 10 years as technology continues to mature and supply chains are optimised. Fixed bed and floating offshore wind are expected to have more potential for cost reductions given that they are less mature markets than onshore wind. By 2045, offshore and onshore costs are expected to reach parity in some situations. The impact of onshore and offshore wind energy on the LCOH is assessed in Section 4 of the report.

Table 2 - Summary of forecast wind generation cost ranges

£/MWh – 2022 values	2022	2030	2045
Onshore wind	27 - 46	24 - 38	17 - 25
(Fixed bed) Offshore wind	47 - 57	39 - 46	19 - 34
(Floating) Offshore wind	120 - 160	43 - 62	31 - 46

3.3 Hydrogen Production

3.3.1 Overview

Green hydrogen production requires electrolysers to convert renewable electricity and water into hydrogen and oxygen. There are currently several electrolyser technologies at different stages of technical maturity and commercial availability. The most mature technologies (and the focus technologies for this report) are alkaline electrolysers (AE) and proton exchange membrane (PEM) electrolysers. Although other technologies, such as solid oxide electrolyser (SOE) and anion exchange membrane (AEM) electrolyser are being developed, they require further research and development before they can be deployed commercially at scale.

Table 3 provides a summary of installed electrolyser capacities by technology type in recent years [6].

Table 3 – Installed capacities of electrolyser by year *[6]*

	AE (MW)	PEM (MW)	SOE (MW)	Unknown (MW)
2017	140	21	0	0.5
2018	146	38	0.07	5
2019	150	61	0.07	6
2020	176	89	0.79	20

In the following Section, the expected cost trajectories and key technical parameters of both AE and PEM technology are assessed to understand their potential impact on the LCOH.

3.3.2 Capital Costs

There is often considerable variation in the capital and operating cost ranges quoted in the literature for electrolyser plants. This variability is in part due to the uncertainty around what is included in the estimate. The capital cost should include the electrolyser stack, balance of plant[7] equipment as well as installation costs, to ensure full project costs are captured.

Figure 6 summarises the range of estimates for AE and PEM electrolysers. The cost data is quoted based on Pounds Sterling per kW of installed electrolyser plant technology (£/kW). It shows that AE is currently cheaper that PEM in most cases; primarily because AE it is a more mature technology and uses less expensive materials for the catalysts and plates [14].

[7] BoP includes equipment such as a power package (electrical equipment including switchgear and rectifier), water purification unit, compressor, oxygen collector and hydrogen purification units (depending on technology).

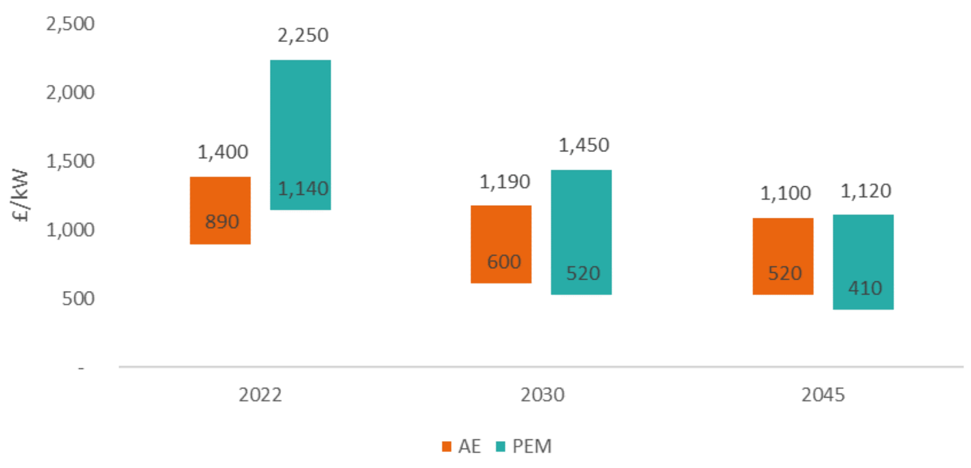

Figure 6 – Estimated electrolyser system costs (£/kW – 2022 values) | *Sources: Various - see Appendix 7.5 for details*

Cost reductions to both AE and PEM are expected in the coming years. By 2030, it is predicted that the cost of an AE electrolyser will reduce by 16 - 33%; whilst the cost of a PEM electrolyser is expected to fall by about 35 - 55% in the same period. The main drivers of this reduction include:

- **Increase in manufacturing capacity (AE and PEM)**. Currently, the majority of the manufacturing market is concentrated in the hands of a few players, in relatively small scale plants that rely heavily on manual assembly [14]. Adopting a greater degree of automation in larger-scale factories is expected to achieve a step-change reduction in costs [14]. A study by NREL [15], estimates that scaling up manufacturing capacity from 10MW per year to 1,000MW could decrease stack costs by almost 50% (the electrolysis process occurs in the multiple stacks within the electrolyser). The main driver of this is a reduction in labour costs through increased automation as well as a reduction in fixed costs (buildings, machinery) per unit produced. Several electrolyser manufacturers have already announced plans to construct large scale plants in the range of gigawatts of electrolyser capacity per year.
- **Standardisation (AE and PEM)**. Currently, the majority of electrolyser manufacturing relies on bespoke equipment, designed for a particular project. As they become more widely used, a greater level of standardisation is expected. This will drive down manufacturing costs, particularly for the balance of plant (BoP) equipment, which the electrolyser relies upon to function.
- **Increase in module size (AE and PEM)**. As the size of the electrolyser modules scales up, the BoP infrastructure is expected to demonstrate strong economies of scale. Studies found that nearly a 50% cost reduction could be achieved for an electrolyser size of 100MW compared with a 5MW size; largely due to a reduction in BoP costs [14]. This view was supported by stakeholders who indicated that at small scale the BoP infrastructure can be as much 50% of the total cost however, as the size of plant increases beyond 25 MW, the BoP costs are expected to drop down to 20 - 25% of the total capital cost. Therefore, support that can help bring large scale projects to market is expected to be driver a reduction in overall electrolyser costs.
- **Rare material reductions (PEM only)**: Critical materials are mainly a limitation for PEM due to requirement for iridium, platinum, titanium and other rare materials compared with AE with typically use nickel. Therefore, significant research is ongoing to: 1) reduce the quantity of rare metals required in a PEM electrolyser 2) increase equipment efficiency 3) improve the recycling of rare metals.

3.3.3 Key Operating Parameters

In addition to capital costs, it is important to consider how operational parameters, such as electrolyser efficiency, are expected to improve and help drive down the levelised cost of hydrogen. Appendix 7.3 shows some of the operating parameters for AE and PEM technologies and the potential technological improvements by 2030 and 2050, which will vary depending on manufacturer and design. Technological improvements are expected to both AE and PEM as manufacturers improve designs and optimise operating conditions. This is expected to drive also drive down operating costs.

3.3.4 Other Technologies

The IEA estimates that nearly 17GW of electrolyser capacity is planned for installation between 2021 and 2026 [16]. Whilst AE and PEM are currently the most mature electrolyser technologies, there are other technologies that are emerging that could help support the significant expected growth in required electrolyser capacity in coming years. The main alternative technologies are SOE and AEM. It is still too early to tell whether these technologies will lead to cost savings compared to AE and PEM, and if so, when this will be achieved.

There are no SOEs in commercial operation at present and only a few suppliers worldwide. Due to the limited number of suppliers, there is a large variation in the cost estimates; however, they are generally expected to be towards the high end due to the lack of market maturity. The expected advantage with SOE is that it can achieve high efficiencies due to its high operating temperatures (700°C). The high operating temperatures, however, also have negative impacts on the overall system costs and can increase stack degradation leading to higher replacement rates. The net impact on the cost of hydrogen production over the life of the plant is still to be determined.

AEM is another early-stage technology that is under development. Limited cost information is publicly available given that there are very few suppliers. AEM technology is similar to PEM however, benefits from not requiring the same extensive use of precious metals as PEM, and therefore is expected to avoid their high associated cost. Further research and development is required, however, AEM electrolysers may be able to offer cost benefits over PEM and support the required scale up in electrolyser capacity.

3.3.5 Summary of electrolyser costs

The future cost trajectories associated with electrolyser technologies will play a key role in the overall cost of hydrogen. They are the novelist part of the green hydrogen supply chain and therefore are expected to be a key area for cost reductions, with cost reductions of over 50% predicted in some applications in the next 10 years.

Although significant technological improvements and cost reductions are expected, a key barrier in the next few years is manufacturing capacity. An increase in manufacturing capacity will be required if the green hydrogen economy is to achieve its cost reduction potential through economies of scale. Whilst this is a challenge, it also presents as an opportunity for Scotland to leverage its highly skilled workforce and become one of the leading manufacturers of electrolysers. Government incentives to promote domestic production in Scotland could help support the scale up in manufacturing capacity and drive down production costs.

3.4 Hydrogen Storage

A key aspect of any hydrogen supply chain is storage as it provides a buffer to mitigate against plant outages as well as providing a means to balance variable production (due to variabilities in renewable electrical generation) and off-taker demand.

Hydrogen can be stored in a gaseous, liquid, or in material-based storage methods. Material based storage includes chemical forms such as liquid organic hydrogen carriers, ammonia, methanol or metal hydrides. Currently, hydrogen is usually stored as a compressed gas in tanks or cylinders. Larger scale applications store hydrogen as a liquid, but there are only a small number of liquefaction facilities around the world. These two methods are included within the pathways outlined in this report and therefore have been the focus of this report.

3.4.1 Compressed Gas Storage

Compressed gaseous hydrogen can either be stored in above-ground pressure vessels or below-ground in geological formations (salt caverns, aquifers or reservoirs). Geological storage is a large scale and relatively cost-effective solution, however, is highly dependent on the availability of suitable geological formations and is yet to be applied on a commercial scale. The HyStorPor [17] project in Scotland is currently assessing storage capacities and efficiencies of geological storage structures. Geological storage has not been included in the pathways identified in this report and therefore has not been a focus of this report. This report focuses on compressed gas storage in above ground pressure vessels.

Pressure vessels are a mature technology that are utilised extensively throughout industrial applications. Compressed hydrogen is commercially available in gas cylinders at 350bar, with 700bar vessels under development.

The cost of pressure vessels increases with the storage pressure because alternative materials such as carbon fibre are needed to withstand the high pressures. Whilst high pressure storage is more expensive, it allows larger volumes per tank and requires a smaller land footprint. The density of hydrogen at 700bar is almost half the density at 350bar meaning roughly half the land footprint is required. For large volumes of storage, this is expected to be a key factor is technology selection.

Capacities of up to 1,000kg per tank are currently available with capital costs estimated to be between £200 - 1000/kg depending on the size and the pressure of the tank. Limited information is, however, publicly available on the costs of hydrogen vessels and there appears to be large variations between sources indicating it is still an area of uncertainty in the market.

In terms of cost reduction, it is expected that hydrogen pressure vessels will have limited cost reduction potential compared to other parts of the supply chain given that the main components of capital cost are the material costs (steel, carbon fibre, etc.).

As well as the cost of the pressure vessels themselves, another key consideration is the cost to compress the hydrogen to the required storage pressure as an electrolyser typically outputs hydrogen at a pressure of 1 - 30bar.

Although hydrogen compressors are commercially available, they are typically small scale with a capacity limited to about 0.5 - 1.5 tonnes per day (tpd) – this is about equal to the output of a 1 - 2MW electrolyser (i.e., a 100MW plant would require about 50 compressors).

Figure 7 shows a range of capital cost estimates for compressors from the literature review.

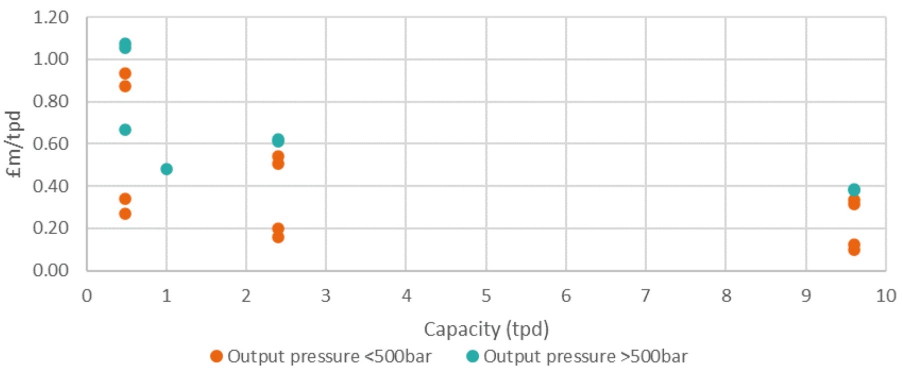

Figure 7 - Hydrogen compressor capital costs estimate (£/tpd – 2022 values) | Sources: Various - see Appendix 7.5 for details

The chart shows clear economies of scale as the size of the compressor unit increases. Below 2 tpd, compressors are expected to vary between £0.2 - 1.7m/tpd whilst for larger compressors the costs are expected to range between £0.2 - 0.6m/tpd.

Limited information was available about potential future compressor costs however, key areas that are expected to drive cost reductions are expected to be increasing the size of the compressor unit as well as increasing the efficiency of the system.

The cost contribution of compression and storage to the total cost of hydrogen production will be dependent on the volume of storage (number tanks required) and the pressure of the storage. There are limited economies of scale with storage given that tanks are individual units with costs added together. Figure 7 shows how the capital costs of storage and compression increase with the days of storage for a 100MW plant.

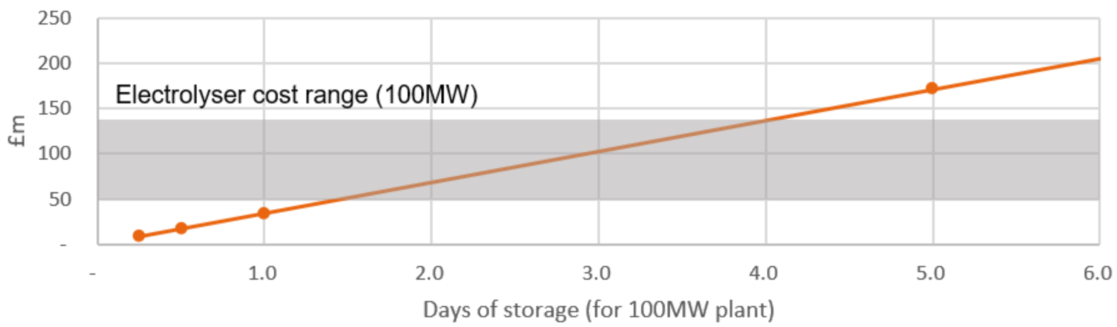

Figure 8 - Hydrogen storage cost (£m – 2022 values)

The chart shows that the cost of storage increases linearly with volume. Considering the estimated capital costs of a 100MW electrolyser plant are approximately £50 - 140m, the cost of storage and compression can be a key capital cost contributor at large volumes. At about 1.5 days, the cost of storage becomes comparable with the cost of an electrolyser plant and exceeds the most expensive plant at about 4 days. For this reason, the majority of projects aim to limit the volume of storage required.

Overall, whilst above ground storage provides a mature technology to store hydrogen and will be key to balance systems, it is expected to be limited to small volumes due to the high capital costs.

3.4.2 Storing hydrogen as a liquid

Storage of hydrogen in liquid form is potentially an attractive option because converting hydrogen to a liquid significantly increases the density, thereby allowing much larger volumes to be stored in the same area. This can present significant advantages when large volumes of hydrogen are required to be stored – for example at ports.

One of the main challenges of liquid hydrogen storage is that it must be stored at cryogenic temperatures (-253 ^oC) meaning it requires specially constructed insulated tanks. Auxiliary tanks are also required to be able to accommodate boil off gas production[8].

To liquefy hydrogen, the site will require a liquefaction plant. Liquefaction requires an electricity input of 10 - 15 kWh/kg. The high electricity demand reduced the overall energy efficiency of the hydrogen supply chain and is one of the main disadvantages of liquefaction, especially at lower volumes. Table 4 below presents the typical capacities and cost ranges of cryogenic tanks and liquefaction plants.

Table 4 - Cryogenic Hydrogen Storage | Key Metrics Sources: Various - see Appendix 7.5 for details

	Liquid storage tanks	Liquefaction process
Typical capacities	160,000 - 700,000 kg/ tank	5,000 - 900,000 kg/day
Capital Costs	£13 - 16/kg	£3,000 - 5000/kg/day
Energy consumption	Minimal	10 – 15 kWh/kg H_2

The capital costs of liquid storage are significantly cheaper than gaseous storage per unit volume due to the higher density. However, due to the high energy consumption and high costs of a liquefaction plant (>£120m for a 100MW plant), it is not well suited for small scale systems. The main advantages of liquefying hydrogen are that it can facilitate the distribution of large volumes of hydrogen in a single tank – this is expected to be vital for long distance transportation and therefore has been considered in the export pathway. The additional costs of liquefaction are generally offset by the lower transportation costs (e.g. in a ship) only when the hydrogen needs to be transported in bulk over long distances. This is discussed in Section 3.5.

Going forward, cost reductions are anticipated to be limited given that cryogenic storage and liquefaction are relatively well-established technologies. The main cost reductions are likely to be achieved by increasing economies of scale through larger processing plants.

3.4.3 Summary of hydrogen storage costs

The chart in Figure 6 compares the price of compression and gas storage with liquefaction and cryogenic storage at increasing storage duration. The costs are based on the output of a 100MW electrolyser plant.

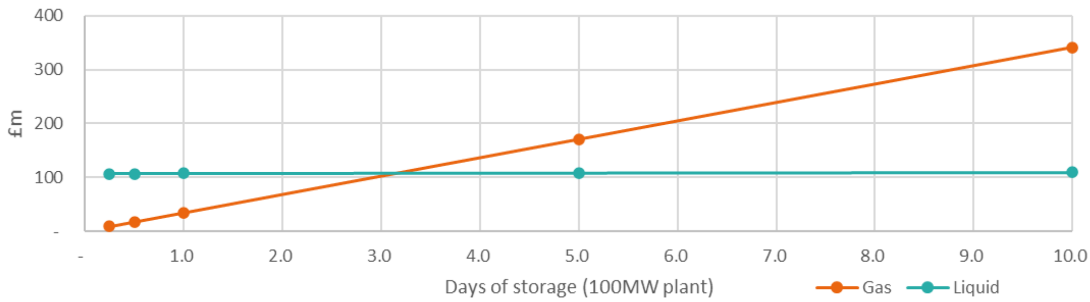

Figure 9 – Cost comparison of gas vs liquid storage (£m – 2022 values)

The chart shows that up to about 3 days' worth of storage (i.e., 65t) from a 100MW plant, it is more cost effective to compress the gas and store in pressurised vessels given the high

[8] Due to the low storage temperatures required to store liquid hydrogen, even a small amount of external heat will cause a slight evaporation. This is known as boil-off gas and has to be removed to maintain the tank pressure.

upfront costs associated with a liquefaction plant. Beyond 65t of storage, liquid hydrogen storage offers a cheaper solution given that larger volumes can be stored in a single tank.

3.5 Hydrogen Transportation

The requirement for transport infrastructure is predominately driven by whether the combined price of producing hydrogen centrally (near low-cost renewables) and transporting to the user is cheaper than producing hydrogen at the site of the end user[9]. This makes transport a critical part of the supply chain to connect Scotland's production with distributed, sometimes rural, end users as well as its potential to act as an exporter to countries that do not have access to abundant renewables (i.e., central Europe). To date, most green hydrogen projects have been co-located with the end user to eliminate the need for transport.

Hydrogen can be transported in pipelines, ships, and trucks in either a gas, liquid or material-based form (Liquid Organic Hydrogen Carriers (LOHC) or Ammonia). There are technical challenges associated with transporting hydrogen in the different combinations as seen in Figure 10.

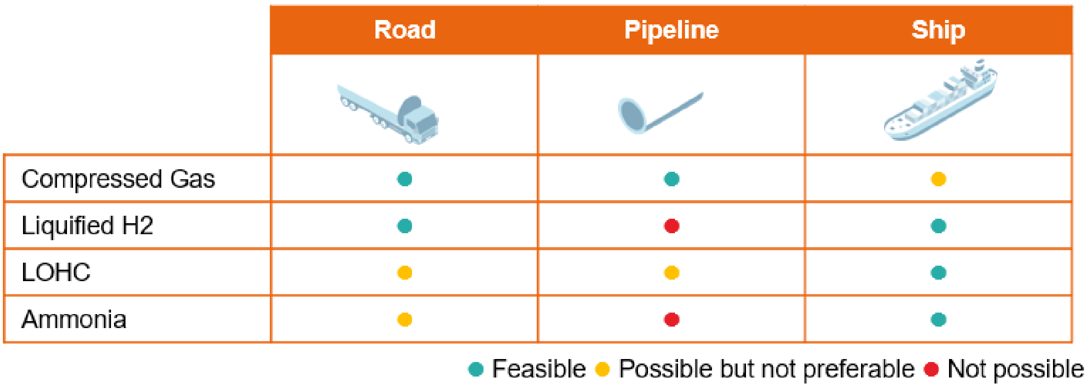

Figure 10 – Hydrogen transport options matrix

In line with the pathways identified in Section 2, this report explores, at a high level, the potential costs of transporting by truck (domestic transport) and vessel (international export). Whilst pipelines are likely to play an important role in large volume domestic transportation, they will be dependent on development of bespoke networks in a relatively small area (e.g. industrial cluster) or the transition of natural gas infrastructure to hydrogen use.

3.5.1 Trucks for hydrogen distribution

Hydrogen can be transported by road tankers in either gaseous or liquid form. Transporting hydrogen as a liquid is expected to be better suited to long distances due to the additional conversion costs and inefficiencies of liquefaction (as explained in Section 3.4). For geographies such as Scotland, where domestic transport distances are not likely to be excessive, transporting hydrogen domestically as a compressed gas is likely to be the most common transportation option.

Two main types of gaseous road transportation are currently available for hydrogen distribution as a compressed gas:

[9] Other key considerations will be access to renewable energy and availability of land at the end user which may mean the hydrogen needs to be produced centrally.

- **Steel-tube trailer**: comprised of steel pressure vessels. Due to the high weight of steel vessels, the typical payload of hydrogen per truck in the UK is about 300 kg for this type of vehicle, which is typically pressurised to 230bar.
- **Advanced composite trailer**: comprised of composite pressure vessels made of carbon fibre. The lower vessel weight enables a larger net payload of hydrogen per truck up to around 1,000 kg at a pressure of 500 bar. The trailer cost is, however, expected to be double the costs of standard trailers due to the need for alternative materials.

Although hydrogen trailers are not yet widely deployed (mainly due to low demand), they are commercially available and being tested in pilot schemes.

When considering the cost of transporting hydrogen as a compressed gas, the key variables that need to be considered are the distance, hydrogen volume and pressure. These variables determine the number of trucks that will be required and the frequency at which they will be required. Figure 11 shows how the cost of transport changes based on distance travelled for the two truck types.

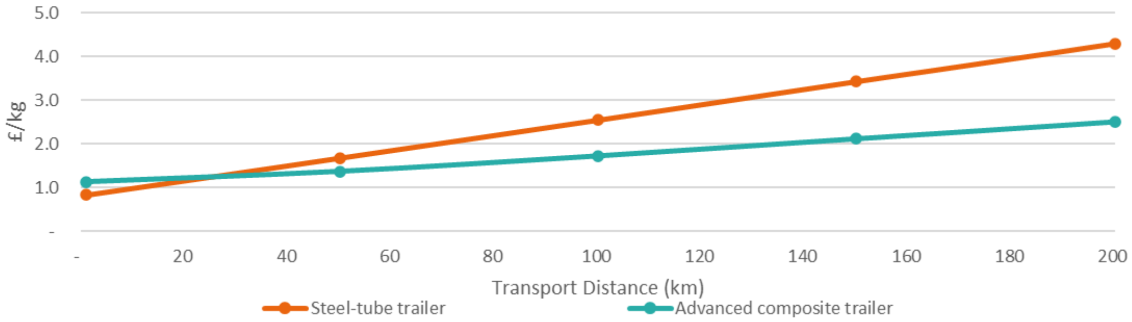

Figure 11 – Compressed Gas LCOH (£/kg – 2022 values) (Based on hydrogen production of 2.5tpd)

The cost of transporting by road increases with distance due to the need for a larger truck fleet as well as higher fuel and labour costs. A steeper cost increase is shown for steel tube trailers due to the lower payload, compared to composite trailers which are carrying four times the mass of hydrogen. For longer distances, the larger payload reduces the size of the fleet that is required. The chart shows that transporting in composite trailers generally shows the lowest contribution to the LCOH for regional transport. However, for certain settings such as rural or islands communities where the transport of hydrogen to end users would require shorter transport distances, a conventional steel-tube trailer would be a preferable option.

Going forward, a reduction in trailer capital costs and compression costs (as discussed in Section 3.4) are expected to be key areas that will drive down transport costs. It is, however, difficult to estimate the scale of potential cost reductions as the market is nascent with limited information available of expected future cost ranges. Cost reductions to transport have therefore have not been considered in Section 4 of the report and are not expected to have a material impact on the overall cost reductions for hydrogen in Scotland.

3.5.2 Transport by Vessel

The development of hydrogen transport vessels will be required to support the international transportation of hydrogen and allow Scotland to become an exporter of hydrogen. Ocean shipping of hydrogen is currently very rare, mostly limited to small containers with liquid hydrogen [18]. However, four technically viable methods exist: 1) shipping as liquefied hydrogen in cryogenic tankers; 2) shipping hydrogen as a LOHC in oil product tankers; 3) ammonia transport in liquified petroleum gas vessels; 4) shipping as a metal hydride. In line with pathways outlined in Section 2, this report has focused on the potential of liquid hydrogen shipping. In order to produce ammonia, LOHC or metal hydrides, different conversion steps are required and have not been subject to review in this report.

Although large scale liquid hydrogen shipping is currently prohibited (due to the absence of suitable regulations, considering the early stage of the market), HySTRA[10] was granted a provisional approval to pilot liquid hydrogen shipping. In February 2022, HySTRA completed the first shipment of a large quantity of liquified hydrogen from Australia to Japan. Although regulations for liquid hydrogen shipping currently do not exist, the International Maritime Organisation (IMO) is working with several companies to allow the shipping of liquid hydrogen by 2030.

Given the nascent nature of the industry, the costs of liquid hydrogen shipping are difficult to estimate with limited sources available, however, BloombergNEF [18] and Guidehouse [19] estimate that the cost of shipping to be around £0.6-0.9/kg per 10,000 kilometres of transport.

For short shipping distances, such as Scotland to mainland Europe, shipping costs are therefore expected to add between £0.04 - 0.06/kg to the cost of production (based on a transport distance of 700km from Grangemouth to Rotterdam). The impact of shipping costs on Scotland's ability to act as a potential export is discussed as part of pathway 3 in Section 4.

Due to the nascent nature of the liquid hydrogen shipping market, limited information is available regarding potential cost reductions. It is expected that as manufacturing scales up and vessel design becomes more standardised, cost reductions can be achieved. Cost reductions, however, have not been considered in Section 4 due to the lack of available information.

3.5.3 Summary of hydrogen transportation costs

The transport segment of the supply chain is an area that is currently limited and will require a significant scale up to allow hydrogen to be freely transported locally and internationally, like fossil fuels are today. A full hydrogen economy is expected to require a mixture of transport methods. Transporting hydrogen domestically in Scotland is expected to be driven by gaseous road transport. Depending on the distance and volume, road transport is expected to add between £1 - 4/kg to the cost of hydrogen production (up to distance of 200km).

For export applications, hydrogen will need to be transported by vessels. This is a nascent industry with only a few pilot projects in operation. This is an area that requires additional focus to scale up the infrastructure and drive down costs. Currently the costs of transporting hydrogen by ship are expected to add at least £0.6/kg per 10,000 kilometres to the cost of production, depending on the distance of transport.

[10] Pilot project to transport liquid hydrogen between Australia and Japan [30]

4 Hydrogen Costs for each Production Pathway

4.1 Introduction

4.1.1 Overview of pathways and cost modelling

In order to appropriately compare the cost of hydrogen production, this report has considered four hydrogen production pathways, which are introduced in Section 2.3:

1. Pathway 1 – Centralised System
2. Pathway 2 – Distributed System
3. Pathway 3 – Export System
4. Pathway 4 – Decentralised System

For each pathway, the levelised cost of hydrogen (LCOH) has been evaluated for the years 2022, 2027, 2030 and 2045. Within each pathway, the report considers sensitivities to the renewable electricity source (onshore or offshore wind), the electrolyser type (PEM or alkaline) as well as a high and low range of renewable electricity costs (LCOEs).

Whilst the sensitivities provide an impression of the range of potential costs, the report has considered the pairing of offshore wind with PEM electrolysers to be the base case. Based on feedback from stakeholders, this pairing was deemed to be the most appropriate for green hydrogen production in Scotland.

The outputs of each pathway are compared to costs of relevant alternatives to understand the projected cost gap and provide an appreciation of the level of policy support that may be required to make green hydrogen competitive with alternative sources.

The key input assumptions for the levelised cost model are based on the cost review in Section 3 of this report. All input assumptions and model methodology can be found in Appendix 7.4.

4.2 Centralised System (Pathway 1)

4.2.1 Pathway Overview

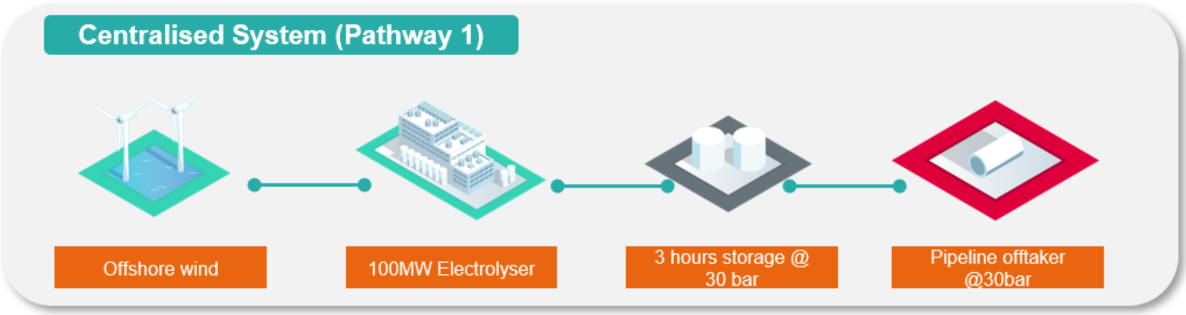

Figure 12 - Pathway 1 Diagram

The centralised system (pathway 1) considers the supply model where hydrogen is co-located with a renewable energy source and the end user (i.e., there is a direct connection with the off taker). This supply model is expected to suit producers that are located in industrial hubs where there is access to both renewable energy and large hydrogen demand.

The retail price of natural gas is used as a reference point for this pathway given that the main off takers will be industrial users where natural gas is used as a feedstock or heat (chemical processing, steel manufacturing, etc.). Using the BEIS Green Book supplementary guidance forecasts[11] that were published in 2021, the retail price of natural gas is expected to vary between £1.0 - 1.3/kg on an energy equivalent basis to 2045 [20].[12]

4.2.2 Analysis

The calculated LCOH ranges for pathway 1 are shown in Figure 13 together with the energy-equivalent natural gas reference price.

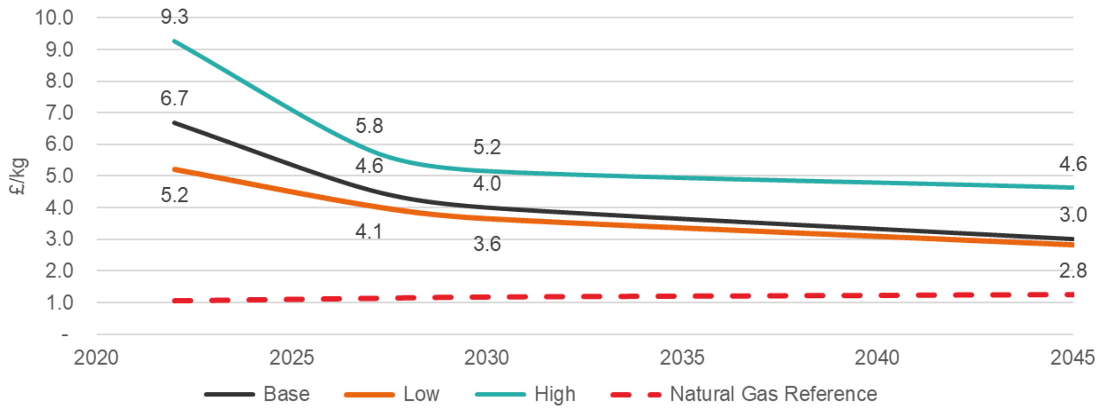

Figure 13 - Calculated LCOH ranges for Centralised System (pathway 1). For input assumptions see Appendix 7.4.

Figure 13 shows that costs to produce green hydrogen in 2022 for a centralised model are estimated to be between £5.2 - 9.3/kg. The main drivers of this are the electricity input costs and the electrolyser capital costs, which respectively represent 45% and 41% of the overall levelised cost of hydrogen in 2022 (see Figure 11 below). The percentage attributed to electrolysers decreases in 2030 and 2045 due to the significant decrease in electrolyser capital costs making electricity costs the key cost driver in the long-term.

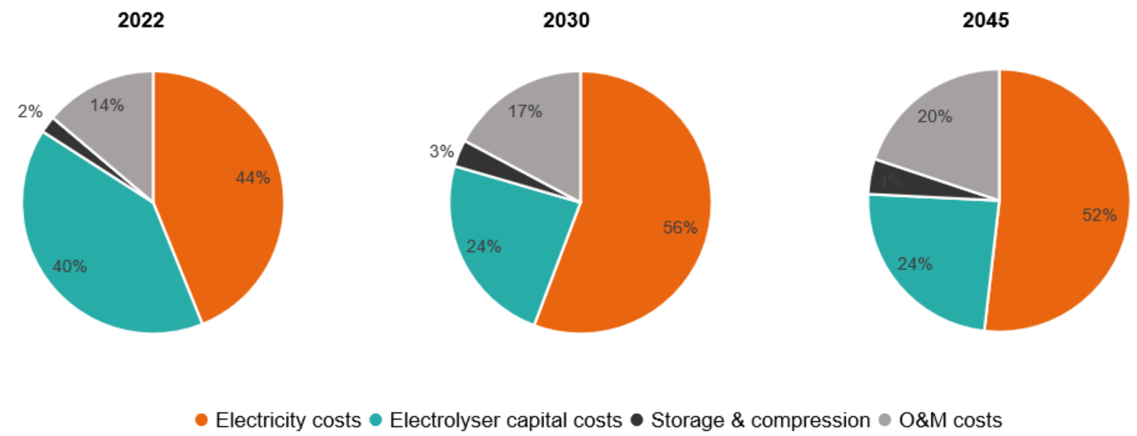

Figure 14 - Pathway 1 cost drivers

Between 2022 and 2027, cost reductions of between 21 - 38% are expected whilst beyond 2027, cost reductions are expected at a decreasing rate. It is estimated that costs for green hydrogen using a centralised model will be in the range of £2.8 - 4.6/kg by 2045. Figure 15 shows where the cost reductions are expected to come from for the base case.

[11] The BEIS forecasts for fossil fuel prices were published in early 2021 and therefore do not include the significant increases that were observed in 2021 and early 2022. This study assumes that fossil fuel price trends will revert to align with BEIS forecasts within the next two years.
[12] Using natural gas lower heating value of 13.1 kWh/kg (Hydrogen = 33.3 kWh/kg)

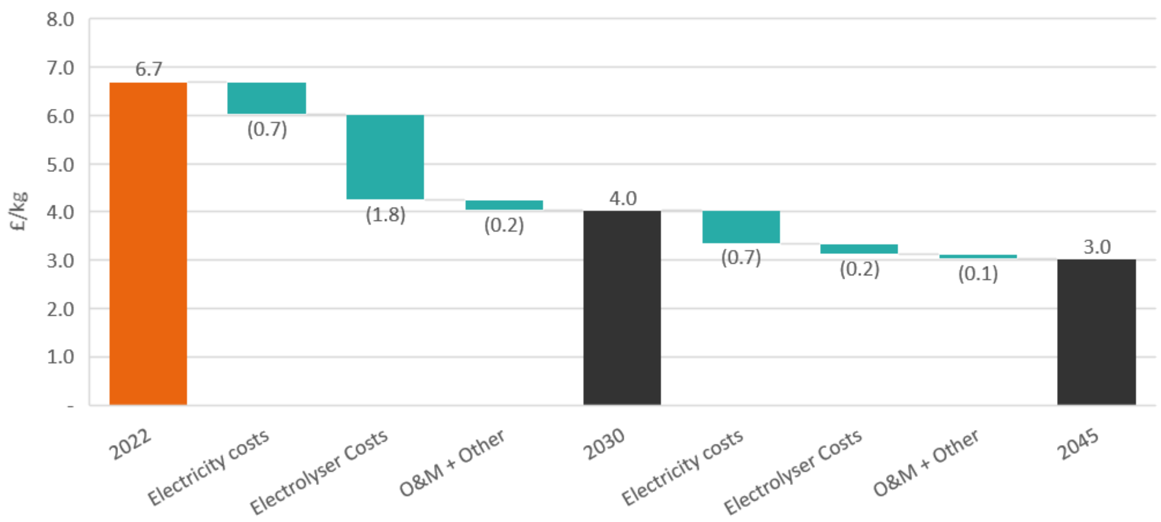

Figure 15 – Pathway 1 LCOH drivers (£/kg) | Base Case

Cost reductions in the near-term (2022 - 2030) are mainly driven by reductions in capital costs of electrolyser plant. Whereas, in the longer term (2030 – 2045), cost reductions are driven mainly by a steady decline in the cost of offshore wind. A 25% decrease in the offshore wind LCOE between 2030 and 2045, results in a 18% reduction in LCOE (highlighting the sensitivity to electricity costs).

Table 5 provides a summary of the impacts on the LCOH when key input parameters are changed. These results provide some insights into the drivers behind the high and low LCOH estimates in Figure 13.

Table 5 - Pathway 1 | Key Sensitivities (£/kg)

	Notes	2022	2027	2030	2045
Base case	Offshore wind with PEM	6.7	4.6	4.0	3.0
Onshore wind	Onshore wind with PEM	8.4	5.5	4.6	3.7
Alkaline electrolysers	Alkaline with offshore wind	5.6	4.4	4.1	3.3
Low electricity costs	Low end of offshore wind cost range	6.2	4.2	3.6	2.8
High electricity costs	High end of offshore wind costs (i.e. floating offshore wind)	9.3	5.3	4.8	3.3

The results in Table 5 indicate the following:

- Electrolysis plants that are paired with onshore wind are expected to result in higher LCOH values than those using offshore wind (base case) in all years, despite the lower cost of electricity. This is primarily due to the higher capacity factor achieved by offshore wind farms which result in a higher electrolyser utilisation.
- In the near-term (2022 and 2027), the use of alkaline electrolysers is expected to offer cost benefits due to their lower cost and higher efficiency; however, by 2030, PEM electrolysers are expected to provide a lower LCOH due to cost reductions, efficiency improvements and longer stack life.
- Despite the current high costs of floating offshore wind, by 2045, the technology is expected to yield lower LCOH values than onshore wind due to the higher capacity factor that can be achieved.

4.2.3 Cost competitiveness

Comparing the outputs to the equivalent natural gas price (see Figure 13) shows that hydrogen production costs are unlikely to reach parity with retail natural gas prices by 2045, based on the current BEIS projections. The price of natural gas in 2027 in would have to be around £4/kg to reach the potential break-even point with hydrogen production. However, there is significant uncertainty associated with future natural gas prices because the forecasts exclude recent price rises or the potential additional carbon taxes that could increase the price. Nevertheless, it clearly demonstrates that if green hydrogen is to compete with natural gas for industrial use then government support will be required. The analysis suggests that for hydrogen to be cost competitive with natural gas in 2030, a cost gap of between £2.4 – 4.4/kg will need to be closed.

In 2021, the UK Government announced that a contract for difference (CfD) revenue support mechanism will be adopted to support low carbon hydrogen projects with the price of natural gas to be used as the reference. A CfD mechanism has worked successfully in the renewable energy industry and has helped grow the sector and drive down costs (40% reduction in offshore wind costs in the past 10 years).

4.3 Distributed System (Pathway 2)

4.3.1 Pathway Overview

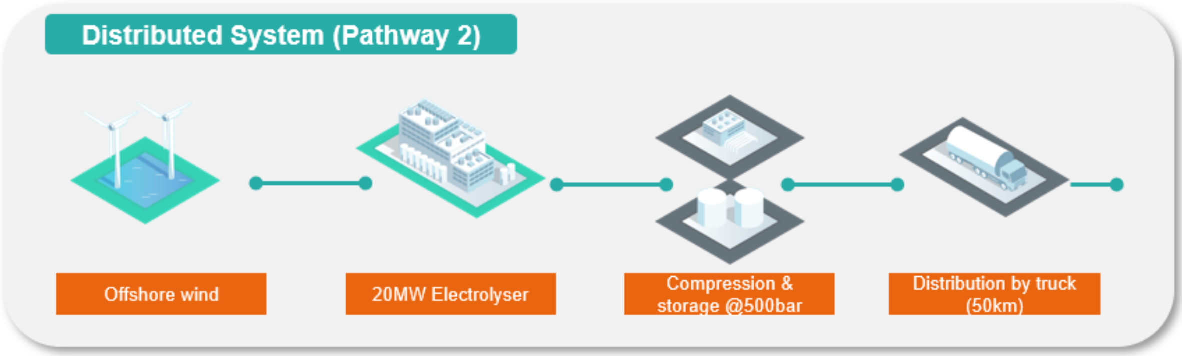

Figure 16 - Distributed system (pathway 2)

The distributed system pathway considers a supply model where hydrogen is produced at a central location and is co-located with renewable energy. The hydrogen is then delivered to a range of smaller off takers by truck.

The supply model is smaller scale (20MW) than pathway 1, however, provides more off taker flexibility given that it is not dependent on any fixed infrastructure (pipelines). This model is expected to be well suited to small and medium size users who are not in industrial areas or do not have the capital or land to develop their own production plant – examples could include heavy vehicle refuelling stations and distilleries.

The main additional infrastructure considerations for pathway 2 are the need to compress the hydrogen to 500bar and the need for a truck distribution fleet.

The cost of diesel has been used as the reference price for pathway 2 given it is likely to be suited to supply heavy vehicle refuelling stations. In line with the BEIS 2021 estimates, the price of diesel is expected vary between £4.7 - 5.6/kg (on an energy equivalent basis) to 2045[13] [20]. It is acknowledged that hydrogen and synthetic fuels will also compete with electric vehicles as technology improves and bans on internal combustion engines come into effect in the 2030s. See Section 4.3.3 for a discussion about this.

[13] Similarly to the natural gas reference price in section 4.2, these projections from BEIS do not account for the increases in diesel prices experienced in 2021 and early 2022. However, it is assumed that prices will revert to longer term expectations within two years.

4.3.2 Analysis

The calculated LCOH ranges for pathway 2 in Scotland are shown in Figure 17 together with the energy-equivalent diesel reference price.

Figure 17 - Calculated LCOH ranges for Distributed System (pathway 2). For input assumptions see Appendix 7.4.

Figure 17 shows that the costs to produce green hydrogen in 2022 for a distributed model (and an average distance of 50km) are estimated to be between £6.0 - 10.3/kg. The main drivers of this are the electricity costs and the electrolyser capital costs which respectively represent 39% and 40% of the overall levelised cost of hydrogen. As electrolyser costs reduce, their contribution to the overall LCOH values decreases whilst the transport costs increase to approximately 12% of the total cost by 2045 given that no transport cost reductions have been assumed.

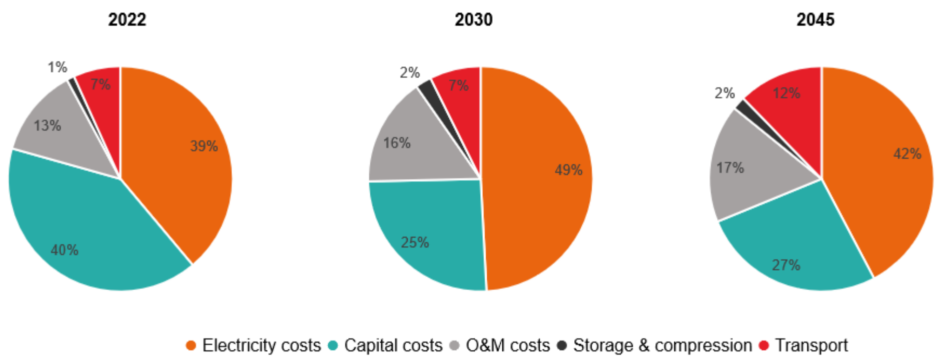

Figure 18 - Pathway 2 cost drivers (%)

In terms of overall cost reductions, between 2022 and 2030 reductions of between 29 - 38% are expected with costs expected to decrease to approximately £4.3 - 6.4/kg. Beyond 2027, further cost reductions are expected however, at a decreasing rate. The drivers behind these cost changes can be seen in Figure 19.

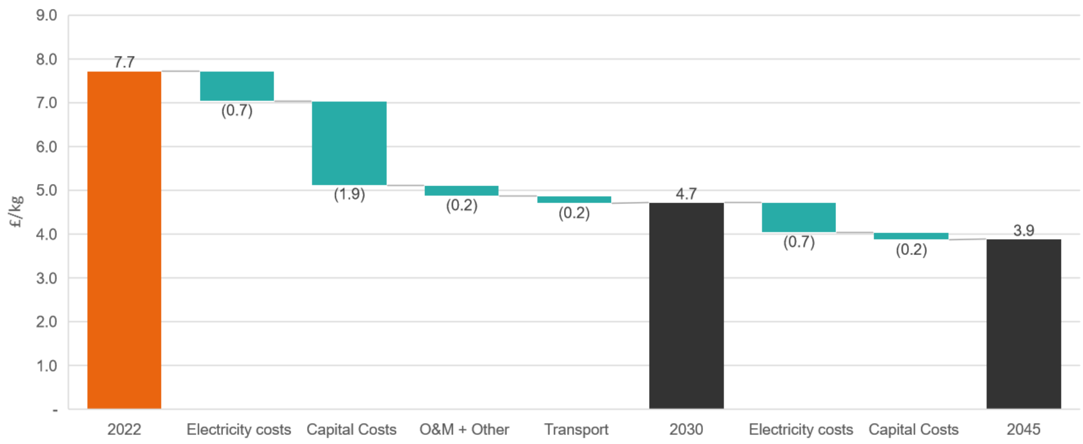

Figure 19 - Pathway 2 - Main Cost Drivers[14]

Similar to pathway 1, the main drivers of the cost reduction are based on decreasing electrolyser capital costs. The main difference is that reducing renewable energy costs have a more significant impact due to the additional energy needed to compress the hydrogen to 500bar as part of the truck loading process.

Table 6 provides a summary of the impacts on the LCOH when key input parameters are changed.

Table 6 - Pathway 2 | Key Sensitivities (£/kg)

	Notes	2022	2027	2030	2045
Base Case	Offshore wind with PEM and transport distance of 50km	7.7	5.3	4.7	3.9
Onshore wind	Onshore wind with PEM and transport distance of 50km	9.8	6.6	5.6	4.9
Alkaline	Alkaline electrolyser with offshore wind and transport distance of 50km	6.5	5.2	4.9	4.3
Low electricity costs	Low end of offshore wind costs and transport distance of 50km	7.3	4.9	4.3	3.7
High electricity costs	High end of offshore wind costs (i.e. floating offshore wind) and transport distance of 50km	10.3	6.0	5.5	4.2
Transport (5km)	Offshore wind with PEM and transport distance of 5km	7.4	5.1	4.5	3.6
Transport (250km)	Offshore wind with PEM and transport distance of 250km	9.1	6.2	5.7	5.1

The results in Table 5 indicate the following:

- Transportation distance is a key cost driver. Increasing the transport distance from 5km to 250km adds approximately £1.2 - 1.7/kg to the cost of hydrogen (15 - 22% of total cost of hydrogen). This highlights that transporting hydrogen by road tanker will likely be limited to distances under 50km.
- Similar to pathway 1, plants operating with onshore wind are expected to result in higher LCOH values than those using offshore wind in all years.
- Obtaining low renewable energy electricity costs yields the lowest LCOH, further supporting the importance of ensuring the renewable energy costs continue to decline.

[14] Note transport costs increase between 2030 to 2045 due to increased diesel costs as per BEIS 2021 estimates

4.3.3 Cost competitiveness

When comparing the cost of green hydrogen production to the price of diesel, it shows that the cost of green hydrogen could reach parity as soon as 2027, suggesting the mobility market could be an early adopter for green hydrogen assuming that the end use infrastructure (i.e. refuelling stations and fuel cell electric vehicles) is readily available.

Hydrogen vs electric vehicles for heavy road transport

Off takers in pathway 2 could be heavy road transport users. For transport applications, decarbonisation can be achieved through direct electrification with renewable electricity (electric vehicles) or with hydrogen and hydrogen-derived synthetic fuels. In general, direct electrification is preferable because it is the most efficient use of renewable electricity. Overall, hydrogen and synthetic fuels require more energy to travel one mile by road. However, for larger scale applications, the onboard volume required for batteries can be impractical, so hydrogen and synthetic fuels can be a better solution. The cross-over point between electrification and using hydrogen/synthetic fuels depends on many things; including advances in battery technology, availability of charging/refuelling infrastructure, vehicle operating patterns; and will change over time.

Whilst the cost of hydrogen may reach parity by the end of the 2020s, there is still a cost gap in the short-term (£2.3 - 5.7/kg) that will need to be addressed to encourage adoption of green hydrogen. For mobility applications, the Renewable Transport Fuel Obligation is an established mechanism that could be further modified to encourage greater uptake of hydrogen in some transport modes. In addition, UK Government's Hydrogen Business Model scheme is expected to provide support for hydrogen production through contracts for difference.

4.4 Export Model (Pathway 3)

4.4.1 Pathway Overview

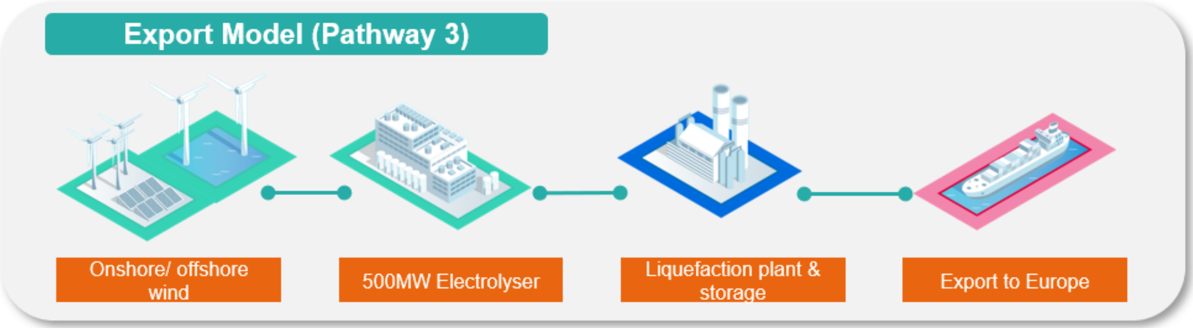

Figure 20 - Export Model (Pathway 3)

The export pathway is aligned with the most ambitious scenario of the Scottish Hydrogen Assessment [4], with Scotland as a net exporter of hydrogen. This scenario is based on large scale hydrogen production, conversion to a liquid and exporting to mainland Europe[15]. The key additional infrastructure requirements for this pathway include a liquefaction plant, large scale liquid storage and upgrades to port infrastructure to allow the export of liquid hydrogen[16]. It will also require the development of a market for liquid hydrogen transport vessels.

[15] Other forms of bulk maritime export of hydrogen are possible, such as Ammonia or LOHCs, however, this report focuses on the liquid hydrogen option in line with discussion in Section 3.5.
[16] Port upgrade costs (i.e. jetty/ loading infrastructure) have been excluded from this analysis and would be required on top of the estimates in this study.

A key export market for Scotland is expected to be central Europe given that central Europe has limited access to low-cost renewable energy (unlike Scotland, which has an abundance of wind energy). Therefore, this study compared the cost of hydrogen produced in Scotland against Australia and the United Arab Emirates (UAE) as these countries have excellent renewable resources, announced plans to be large scale producers of hydrogen, and entered wider trade partnerships with key European countries for export.

The LCOH data for the UAE and Australia has been taken from Bloomberg [21]. Note that the full assumptions behind Bloomberg's calculations are not clear and therefore this is analysis only constitutes a high-level comparison and requires further in-depth analysis of hydrogen production costs in UAE and Australia. The cost of liquefaction was assumed to be in line with the liquefaction costs in Scotland.

UAE and Australia also provide an indication of medium (UAE) and long (Australia) transport distances and demonstrate the impact of shipping costs on the total cost of hydrogen supply. Using a shipping cost of £0.8/kg per 10,000km (Section 3.5.2), Table 7 below demonstrates the relative levelised cost of shipping and the days of travel required for Scotland, UAE and Australia. This is incorporated into the cost comparison below.

Table 7 - Shipping costs cost short, medium, and long-distance routes (£/kg)

Route	Distance (km)	Levelised Cost (£/kg)	Days of travel
Scotland to Rotterdam (short)	700	0.1	2
UAE to Rotterdam (medium)	13,000	1.0	27
Australia to Rotterdam (long)	25,300	1.9	48

Another use case for this scenario could be for Scotland to act as a marine refuelling hub, where liquid hydrogen is a possible zero-carbon fuel for shipping. This is the ambition for some projects developing in Shetland and the Orkney Islands. A detailed review of Scotland's ability to act as a bunkering hub has not been investigated in this report.

4.4.2 Analysis

The calculated LCOH ranges for pathway 3 to export to Port of Rotterdam (including the cost of shipping 700km) are shown in Figure 21 below.

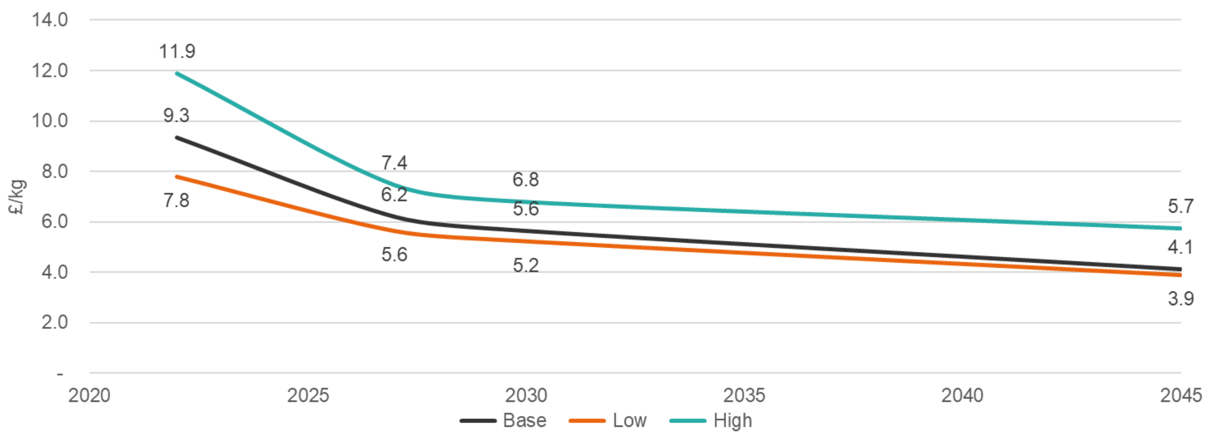

Figure 21 - Calculated LCOH ranges for Export Model (Pathway 3). For input assumptions see Appendix 7.4.

The outputs of pathway 3 show that to export to Europe, the estimated current LCOH range is £7.8 – 11.9/kg. In 2022, the main drivers of this are the electricity costs, electrolyser capital costs and the liquefaction costs which respectively represent 32%, 30% and 26% of the overall levelised cost of hydrogen. From 2030, the main drivers of the cost are the electricity costs at 41% of the total LCOH.

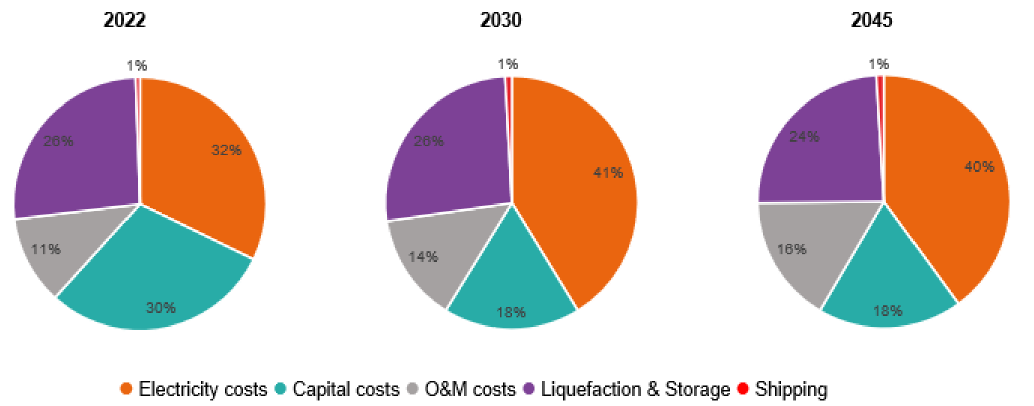

Figure 22 - Pathway 3 cost drivers

Between 2022 and 2027, cost reductions of between 29-37% are expected with costs to decrease to approximately £5.6 – 7.4/kg. It is estimated that costs for liquid hydrogen for export to Europe could reach £3.9 – 5.7/kg by 2045.

The main cost reductions are based on the decreasing electricity, electrolyser, and liquefaction costs. The drivers behind these reductions will be driven predominately by scaling up the market and driving competitiveness to reduce upfront capital costs. As discussed previously, the report has not considered future reductions in the cost of shipping.

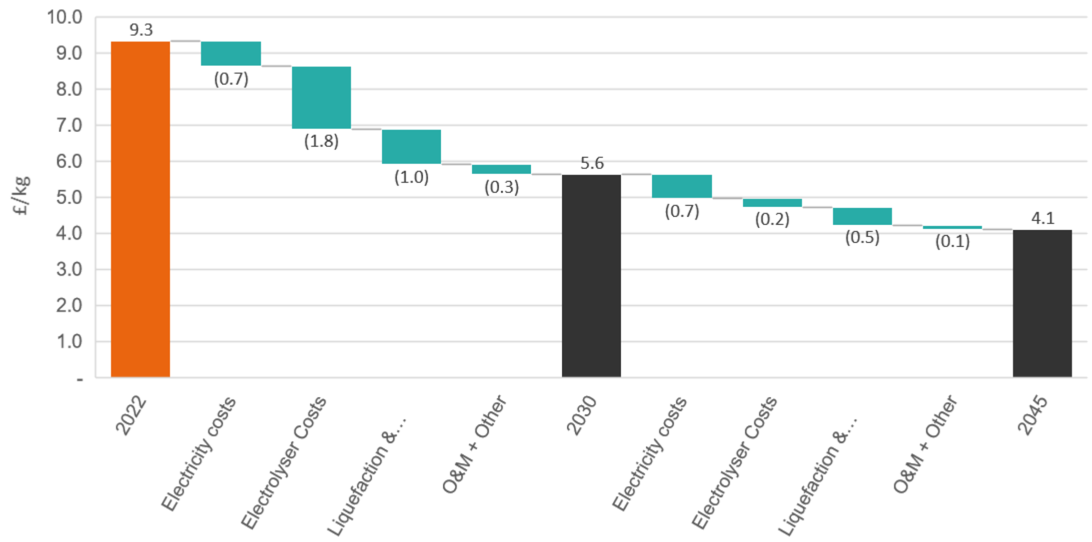

Figure 23 - Pathway 3 Main Cost Drivers

Table 8 provides a summary of the impacts on the LCOH when key input parameters are changed, providing insights into the drivers behind the range of LCOH estimates

Table 8 - Pathway 3 | Key Sensitivities (£/kg)

	Notes	2022	2027	2030	2045
Base case	Offshore wind with PEM	9.3	6.2	5.6	4.1
Onshore wind	Onshore wind with PEM	11.0	7.2	6.2	4.8
Alkaline electrolysers	Alkaline electrolyser with offshore wind	8.2	6.0	5.7	4.4
Low electricity costs	Low end of offshore wind costs	8.8	5.8	5.2	3.9

High electricity costs	High end of offshore wind costs (i.e. floating offshore wind)	11.9	6.9	6.3	4.4

The results in Table 8 demonstrate:

- The electricity costs continue to be the biggest driver of overall LCOH values.
- The relatively low capacity factor of onshore wind is not well suited to pathway 3 given that it results a significant over-investment into a pathway that is already capex intensive. For Pathway 3, optimisation the electrolyser size and energy yield are expected to be particularly important.

4.4.3 Cost competitiveness

In order understand Scotland's potential as a large-scale exporter of green hydrogen, it is important to compare the outputs to equivalent cost of exporting from other countries. As previously mentioned, Australia and UAE as used for comparison due to the availability of information and their commitments to be exporters of hydrogen. It has been assumed that Europe will be the key recipient and therefore the Port of Rotterdam has been assumed to be the destination port.

The charts below show the comparison of LCOH for Scotland, Australia and the UAE as well as the cost breakdown for each year. It is important to note that there is significant uncertainty in the cost estimates for Australia and UAE meaning the charts below are only for high level comparison purposes.

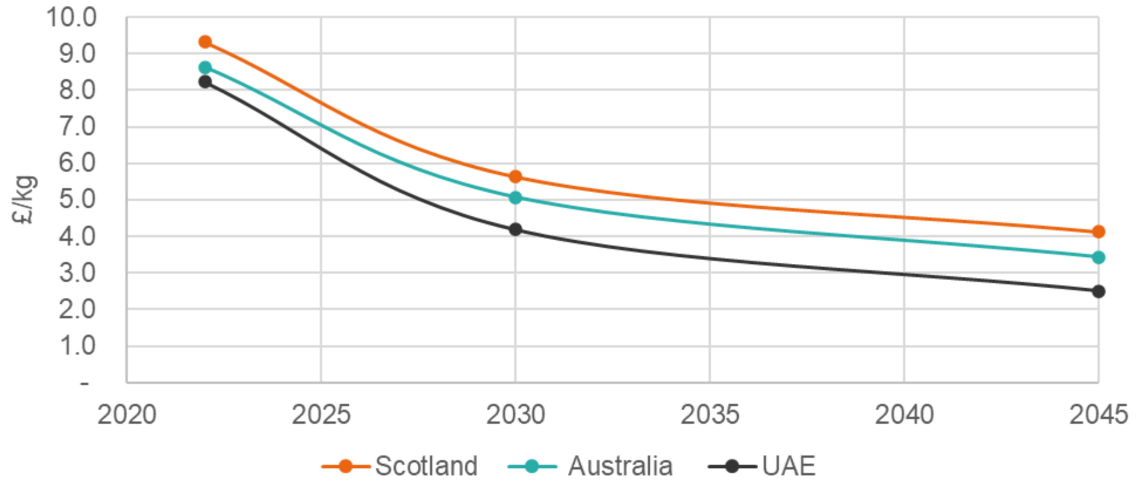

Figure 24 - LCOH comparison for delivery of liquid hydrogen to the Port of Rotterdam

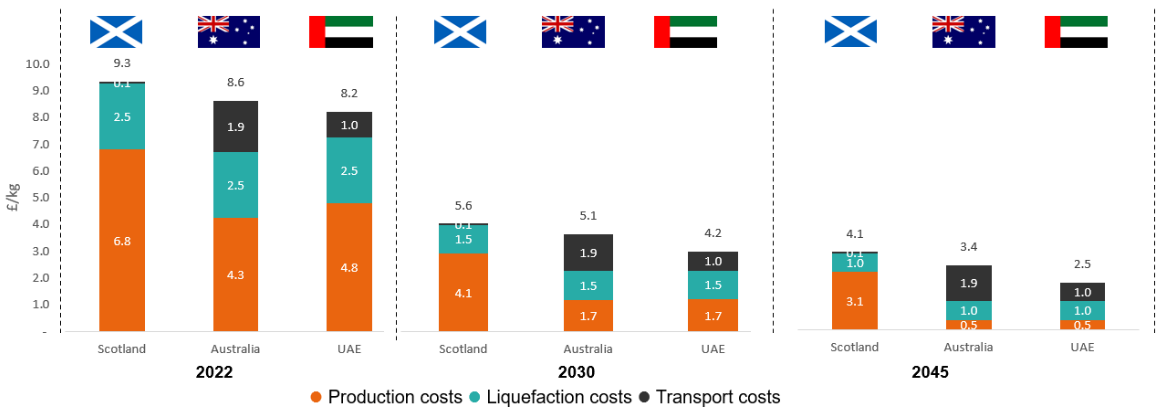

Figure 25 – Pathway 3 LCOH cost comparison breakdown, delivered to Port of Rotterdam

The analysis shows that for exporting hydrogen into Europe, Scotland has the potential to be a cost competitive supplier. While Australia and UAE are forecast to produce hydrogen at lower cost, due to the additional transport distance, the shipping costs increase the landed price of hydrogen significantly, particularly for Australia. It is therefore expected to be cost effective to export to Europe from Scotland.

Although UAE appears to offer the most cost competitive hydrogen, other key logistical factors must be considered such as the transport time – vessel transport from Scotland takes 2 days compared to 30 days from the UAE. This provides Scotland with more flexibility when exporting into Europe.

By 2030 and 2045, the main difference between cost assumptions is that the cost of production in Scotland is considerably higher than in Australia and the UAE. This is likely driven by the reliance on third party cost assumptions for Australia and UAE where the underlying cost assumptions are uncertain. It, nevertheless, demonstrates that with the right government incentives and support, Scotland has potential to be an exporter of hydrogen to Europe.

On the export of hydrogen, it is also worth noting that Scotland proximity and infrastructure connectivity to key locations in Northern Europe might facilitate the development of pipelines for the transport of hydrogen between Scotland and Europe.

Pipelines are the cheapest option for transporting large volumes of hydrogen across long distances[17], and some European infrastructure operators – including National Grid – are exploring the development of a network of interconnected hydrogen pipelines across 28 countries in Europe including the UK through the European Hydrogen Backbone initiative.

The Scottish Government are currently assessing the most cost-effective options for transportation and export of hydrogen from Scotland to Europe, and it is likely that different options, such as gaseous hydrogen pipelines, and marine vessel transportation of liquid hydrogen, green ammonia and methanol, and LOHC, could all be used for export at different scales and depending on end-purposes and off-takers.

4.5 Decentralised Model (Pathway 4)

4.5.1 Pathway Overview

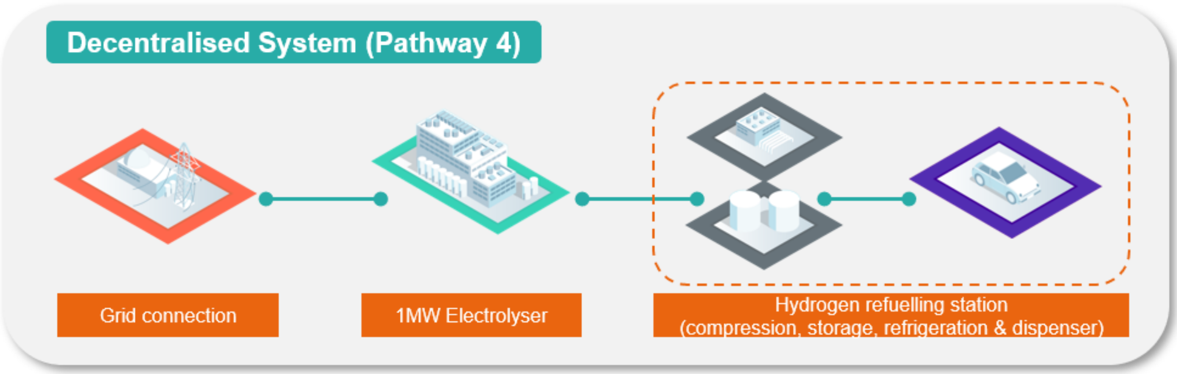

Figure 26 - Decentralised model (pathway 4)

The decentralised pathway reflects supply chains that may be smaller in size and do not have direct access to a renewable energy sources. Pathway 4 therefore considers the implications of connecting to the electricity grid rather than to a renewable energy source. This pathway is expected to be suited to hydrogen refuelling stations (HRS) given they will

[17] See https://rmi.org/insight/strategic-advantages-of-green-hydrogen-imports-for-the-eu/ [32]

need to be located in distributed rural locations on small plots of land. The key infrastructure considerations for this pathway are high pressure compression (up to 700bar) and storage to meet the requirements of fuel cell electric vehicles (FCEV).

The price of diesel is considered to be the most relevant reference price for this pathway. As discussed in pathway 2, the price of diesel is expected to vary between £4.7 - 5.6/kg [20]. See Section 4.3.3 for a discussion about competitiveness with electric vehicles.

4.5.2 Analysis

The calculated LCOH ranges for pathway 4 are shown in Figure 27 below together with the energy-equivalent diesel reference price.

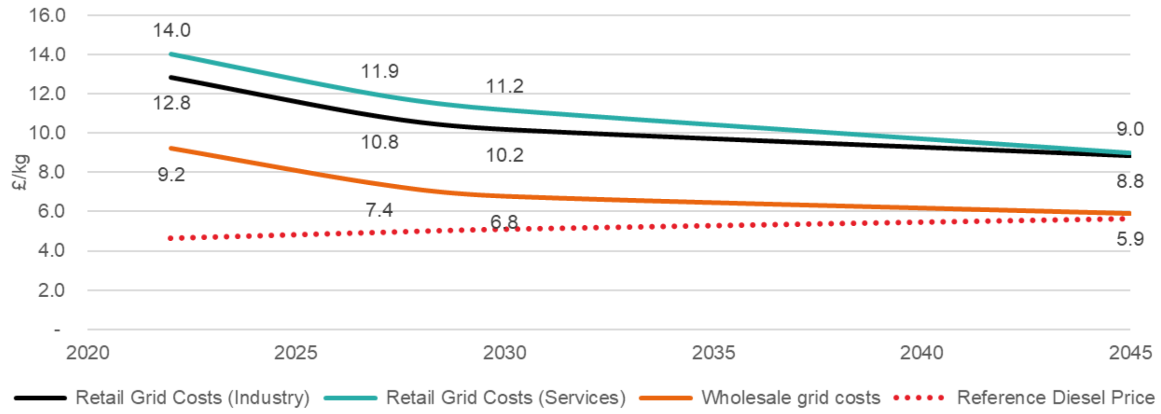

Figure 27 - Calculated LCOH ranges for Decentralised Model (pathway 4). For input assumptions see Appendix 7.4.

It can be seen from Figure 27 that hydrogen production using retail grid electricity costs (industry & services) makes hydrogen production more costly. This is due to additional grid transmission charges that must be paid compared to direct connection with renewable energy. Figure 28 shows that the main driver of these costs are the high electricity costs which are expected to contribute to up to 52% of the total LCOH values in 2022 and 66% in 2045.

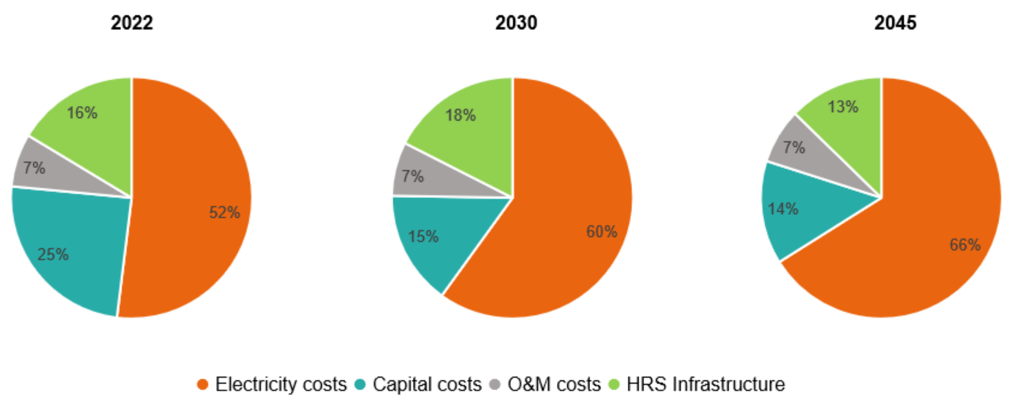

Figure 28 - Pathway 4 cost drivers (%)

Even with expected cost reductions in electrolyser technologies and HRS infrastructure, the cost of hydrogen using retail grid prices does not drop below £8.8/kg, even by 2045. This supports the stakeholder view that avoiding grid transmission charges will be critical to making green hydrogen competitive. It also supports the need for green hydrogen to be located near to renewable sources to benefit from a direct connection.

Table 9 provides a summary of the impacts on the LCOH when key input parameters are changed.

Table 9 - Pathway 4 | Key Sensitivities

	2022	2027	2030	2045
Base Case – industrial retail prices	12.8	10.8	10.2	8.8
Services retail grid prices	14.0	11.9	11.2	9.0
Wholesale electricity prices	9.2	7.4	6.8	5.9
Alkaline electrolyser	11.1	10.1	9.8	8.9

The results indicate that if wholesale electricity prices (i.e., without additional charges for using the grid) are considered, the cost of production drops by approximately 38% compared to the base case. This highlights the significant costs associated with transmitting electricity through the grid and the importance of pairing green hydrogen directly with renewable energy sources.

For green hydrogen to be cost competitive with diesel, significant support will be required to close the cost gap. If the outputs of pathway 4 are compared to pathway 2, it also highlights that in the majority of cases, the distributed model offers a more cost competitive solution than a supply model that relies on grid electricity. This indicates that the additional costs of transporting hydrogen by road can be less than the additional costs that are incurred by grid transmission charges. This highlights the importance of supporting green hydrogen production in locations that have direct access to renewable energy.

4.6 Pathway Comparison

Figure 29 presents the outputs of the base case LCOH for each of the pathways that have been reviewed.

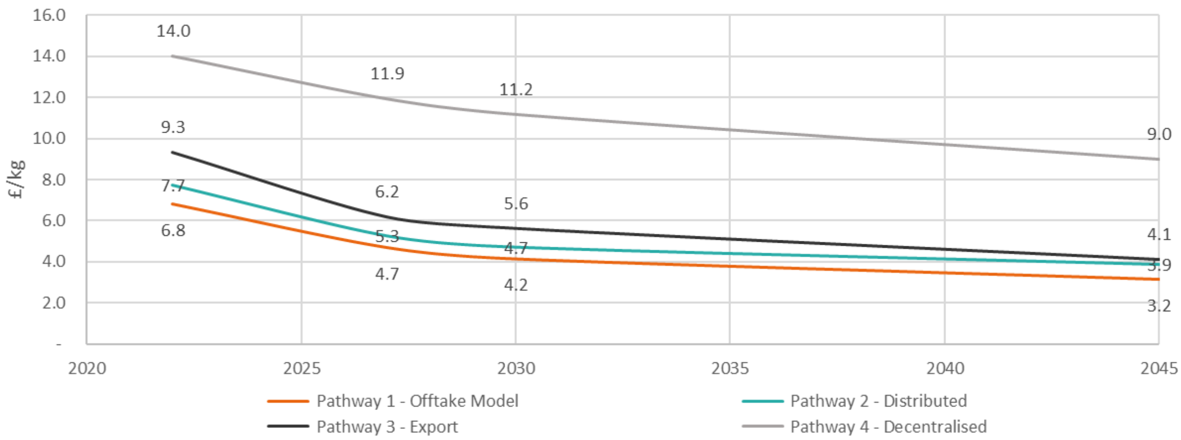

Figure 29 - Pathway LCOH Comparison (£/kg)

The LCOH analysis has shown that future cost reductions are expected across all of the pathways. The majority of cost reductions are expected in the next 5 - 7 years before the rate of cost reduction decreases from 2030 onwards once the market has matured and the supply chain has scaled up.

Pathway 1 is consistently the most cost-effective supply model compared to the alternatives. This is because it requires no transport or conversion steps, which introduce additional costs. This suggests that in the near-term, co-locating hydrogen production with demand (e.g. in clusters) may result in the lowest cost.

Pathway 2 demonstrates that whilst transporting hydrogen adds cost, it provides flexibility and will allow a wider range of off takers to be supplied with hydrogen. This will be particularly beneficial for consumers that do not have the capital or the land to develop their own hydrogen production plant. The main challenges for this pathway is the limited transport infrastructure currently available and high costs of transporting over long distances.

Pathway 3 shows that transporting hydrogen by ship is expensive; however, Scotland has the potential to become an exporter of green hydrogen to Europe. Due to Scotland's proximity to Europe, it benefits from lower transport costs and offers more flexibility compared to other potential large-scale hydrogen export locations (e.g. Australia and UAE). If government support can help to drive down the cost of hydrogen production in Scotland, then it is likely to be a cost competitive option for large scale hydrogen export in the future. The infrastructure required for shipping liquid hydrogen at scale is currently limited and will require a significant scale up if hydrogen is to be exported around the world. However, the other options for bulk transport by ship (e.g. ammonia, LOHC) should be investigated to determine the best approach before there is investment in infrastructure.

Pathway 4 is consistently the highest cost of green hydrogen production due to the much higher costs of grid electricity (£121/MWh) vs renewable energy (£30 - 60/MWh) in 2022. This highlights the importance of pairing green hydrogen directly with renewable energy sources.

5 Conclusions and recommendations

The cost of hydrogen is expected to at least halve between 2022 and 2045 for the three pathways connected directly to wind farms (1, 2 and 3). Falling costs of electrolyser plants are expected to be the biggest contributor to decreases in the cost of hydrogen between 2022 and 2030. These cost reductions will be achieved through technology improvements, design standardisation, and a significant scale up of supply chain capacities.

Electricity costs are the biggest driver of hydrogen cost reductions from 2030 onwards. Electrolysers consume large amounts of electricity, so minimising the cost of electricity will be vital. The best way to achieve this will be through direct connections to wind farms, as shown in pathways 1 to 3. If a green hydrogen producer is required to pay grid charges (pathway 4), the cost of green hydrogen is unlikely to become cost competitive with fossil fuels. Therefore, where producers cannot obtain a direct renewable connection, policy support is required to ensure that the cost of green hydrogen can remain cost competitive.

Scaling up the industry is expected to lead economies of scale and drive manufacturing cost savings across the supply chain. Manufacturing capacity for green hydrogen technologies (e.g. electrolysers, compressors, road tankers, storage tanks) will need to grow rapidly from a very low base currently. Therefore, government incentives to promote and scale up domestic production of green hydrogen equipment across the supply chain in Scotland could help drive down production costs.

Domestic infrastructure to transport hydrogen is currently limited and needs to be rapidly developed to ensure the continued emergence of the green hydrogen sector in Scotland. Transport infrastructure for hydrogen is currently very limited and will require a significant scale up to move large volumes around safely. This will require a large amount of investment into both suitable road transport infrastructure to enable consumption of hydrogen in Scotland, as well as shipping infrastructure for hydrogen export. It is important to ensure that centralised production locations can be connected with more rural end users. With relatively low levels of technical complexity required to improve transport infrastructure, this presents a key opportunity for the Scottish economy to stimulate economic activity and position itself as key exporter of hydrogen.

Despite the downward trajectory predicted for hydrogen costs across all pathways, significant uncertainty remains. Due to the nascent nature of the hydrogen industry, a large variation in cost estimates for each part of the supply chain was observed. This large variation in costs provides a degree of uncertainty that needs to be considered when evaluating cost reduction potential. Government has a role to play in identifying areas of risk and targeting interventions to mitigate it.

Scotland has potential to be an exporter of hydrogen to Europe. Due to the close proximity to Europe, Scotland benefits from lower transport costs compared to other potential large-scale hydrogen export locations (Australia and UAE). If government support can help scale up the green hydrogen industry to reduce the cost of hydrogen production, then Scotland has the potential to be a key exporter of hydrogen to Europe.

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7 Appendix

7.1 Glossary

Table 10 - Glossary

Term	Meaning
Bunkering	Bunkering is the supplying of fuel for use by ships
Capacity Factor	The capacity factor is defined as the average consumption, output, or throughput over a period of time of a particular technology or piece of infrastructure, divided by its consumption, output, or throughput if it had operated at full (rated) capacity over that time period.
Catalyst	A substance that increases the rate of a chemical reaction without itself undergoing any permanent chemical change.
Efficiency	The efficiency of a plant is the percentage of the total energy content of a power plant's fuel that is converted into electricity.
Heating values	The heating value of a substance, usually a fuel or food, is the amount of heat released during the combustion of a specified amount of it.
Levelised cost of hydrogen (LCOH)	The levelised cost of hydrogen is a methodology used to account for all of the capital and operating costs of producing hydrogen and therefore enables different production routes to be compared on a similar basis. See Appendix 7.4 for a detailed explanation.
Low carbon hydrogen	Low-carbon hydrogen is defined as hydrogen with an energy content that is derived from non-renewable sources, and that meets a greenhouse gas emission reduction threshold of 70% compared to fossil-based hydrogen.
Off taker	The purchaser and end user of the hydrogen
Operating parameter	The performance and operating specifications of each piece of equipment.

7.2 List of stakeholders engaged

Table 11 - List of stakeholders engaged

Stakeholder	Date of interview
Plus Zero	15/12/2021
EMEC	06/01/2022
Scottish Power	06/01/2022
SHFCA	06/01/2022
Cummins	05/01/2022

7.3 Key Electrolyser operating metrics

Table 12 - Key Operating Metrics

Parameter	Electrolyser	Current	2030	2050	Drivers
Electrical Efficiency (% LHV)	AE	56-70	60-72	63-80	Improvement in membrane technologies through adoption of zero-gap design (AE) and thinner membranes (PEM) (reducing resistance) as well as improvement in the use of catalysts.
	PEM	51-76	60-69	65-74	
Stack life ('000 hours)	AE	50-90	70-100	100-150	R&D focus on structural improvements to electrodes.
	PEM	20-90	60-90	100-150	Improvements in membrane, catalyst, and porous transport layers (PTLs)
Output pressure (bar)	AE	1	1-60	1-60	Improvements in membrane technology (to allow high pressures) as well as advances in post compression technology.
	PEM	30-40	30-70	30-80	Focus on advancing membrane technologies and reconversion catalyst.
Fixed Costs (£/kW)	AE	35-43	34-40	34-38	Upskilling existing workforces, rather than relying on suppliers/manufacturers is expected to drive improvements in ongoing O&M costs.

7.4 LCOH Model Methodology & Assumptions

The levelised cost model considers the cost of hydrogen production in the years 2022, 2027, 2030, 2045. It considers the total costs (capital, operating, replacement capex) of production over the project life (30 years) and divides it by the total volume of hydrogen produced. Both the costs and volume of hydrogen produced at discounted at a rate of 10% using the below formula.

$$LCOH\left(\frac{£}{kg}\right) = \frac{Sum\ of\ costs\ over\ lifetime\ (£) \times discount\ rate(\%)}{Sum\ of\ hydrogen\ produced\ over\ lifetime\ (kg) \times\ disount\ rate\ (\%)}$$

The sum of costs over the lifetime are based on the constant input assumptions outlined in

Table 13. These input assumptions remain constant across all Pathways. The input assumptions are based on the literature review for each part of the supply chain (Section 3 of the report). We have used the trends that have been developed to identify the likely cost range for each focus year. The literature review has consisted of a several sources that have been used to gather the wide range of data points. The matrix in Appendix 7.5 highlights which sources have been used for which part of the supply.

The building blocks of the model are broken down into electricity generation, electrolyser (hydrogen production), compression, storage and transport (if applicable). For each part of the supply chain the inputs and used to determine an annual costs split between these categories:

1. Capital costs of infrastructure,
2. Replacement costs of infrastructure,
3. Annual variable costs
4. Annual fixed costs

In addition to the constant input assumptions, there are input assumptions that vary between Pathways, such as the size of the plant, the supply chain requirements, etc. These supplement the constant input assumptions in order to determine the volume of costs for each part of the supply. The total discounted costs of production are then summed over the project life and divided by the total discounted volume of hydrogen produced. A high-level diagram showing the flow of the model is shown in Figure 30 below.

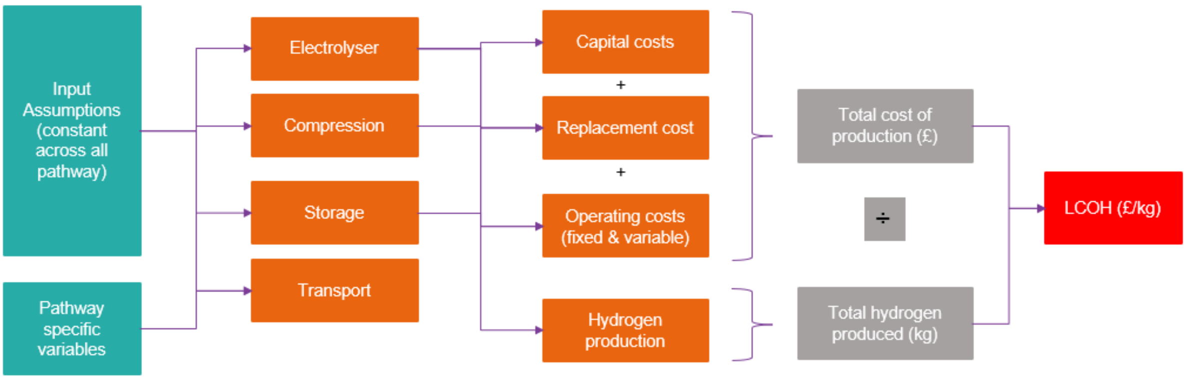

Figure 30 - Levelised cost of hydrogen method flow chart

To avoid low electrolyser utilisations, we have assumed that the electrolyser plant capacity has been selected to match the wind farm peak output and that the electrolyser plant utilisation is equal to the capacity factor of the wind farm.

All values are presented in real 2022 GBP.

Table 13 - Levelised cost input assumptions

	Unit	2022	2027	2030	2045	Sources
Offshore wind						
Capacity factory	%	51%	51%	51%	51%	Andrew ZP Smith, ORCID: 0000-0003-3289-2237; "UK offshore wind capacity factors". Retrieved from https://energynumbers.info/uk-offshore-wind-capacity
LCOE (Base)	£/MWh	55	46	46	34	BEIS CfD Auction & IEA World Energy Outlook (2021) - Weighted average
LCOE (Low)	£/MWh	47	39	39	30	BNEF (2021), IEA World Energy Outlook (2021)
LCOE (High)	£/MWh	100	60	60	40	IEA World Energy Outlook, DNV Technology Progress Report (2021)
LCOE (Selector)	£/MWh	55	46	46	34	BEIS CfD Auction & IEA World Energy Outlook (2021) - Weighted average
Onshore wind						
Capacity factory	%	27%	27%	27%	27%	https://www.statista.com/statistics/383335/renewable-energy-load-factor-in-scotland-uk/
LCOE (Base)	£/MWh	38	33	33	25	IEA World Energy Outlook (2021) - weighted average
LCOE (Low)	£/MWh	27	24	24	17	IRENA (2019), IRENA (2021)
LCOE (High)	£/MWh	46	38	38	34	BNEF (2021), IEA World Energy Outlook (2021)
LCOE (selector)	£/MWh	38	33	33	25	IEA World Energy Outlook (2021) - weighted average
Grid Electricity						
Capacity factory	%	99.5%	99.5%	99.5%	99.5%	Assume very low grid outages in Scotland
LCOE (Retail - Industrial)	£/MWh	122	122	121	121	BEIS 2019 Updated Energy & Emissions Projections (Retail - Industry)
LCOE (Wholesale)	£/MWh	59	59	57	63	BEIS 2019 Updated Energy & Emissions Projections (Wholesale)
LCOE (High)	£/MWh	143	142	140	124	BEIS 2019 Updated Energy & Emissions Projections (Retail - Services)
LCOE	£/MWh	143	142	140	124	BEIS 2019 Updated Energy & Emissions Projections (Retail - Industry)
Alkaline Electrolyser						
Efficiency	% LHV	63.0%	65.0%	66.0%	67.0%	BEIS, Hydrogen Production Models (2021) - Average
Output pressure	bar	1	30	30	30	BloombergNEF, 2H 2-21 Hydrogen Levelized cost update (2021)
Stack life	hours	80,000	100,000	100,000	100,000	DNV Technology Progress Outlook (2021); IEA, Irena (2021)
Water consumption	kg H20/ kg H2	9	9	9	9	IEA, The Future of Hydrogen (2019)
Availability	%	95.0%	98.0%	98.0%	98.0%	Stakeholder interviews, FCH2JU (2017)
Capex Unit Cost (<5MW) (Includes BoP)	£'000/MW	1,428	1,251	1,180	1,101	BEIS, Hydrogen Production Models (2021)
Capex Unit Cost (<10-50MW) (Includes BoP)	£'000/MW	1,040	901	812	767	BEIS, Hydrogen Production Models (2021)
Capex Unit Cost (>50MW) (Includes BoP)	£'000/MW	883	702	597	535	BEIS, Hydrogen Production Models (2021)
Fixed opex costs	£/kW	38.4	37.4	36.75	35.96	BEIS, Hydrogen Production Models (2021) - Average

Stack replacement capex	% of capex	33.0%	33.0%	33.0%	33.0%	Confidential developer data, FCH2JU (2017)
PEM Electrolyser						
Efficiency	% LHV	61.0%	64.0%	66.0%	69.0%	BEIS, Hydrogen Production Models (2021) - Average
Output pressure	bar	30	60	70	70	DNV Technology Progress Outlook (2021); FCH2JU (2017)
Stack life	hours	50,000	80,000	80,000	120,000	DNV Technology Progress Outlook (2021); IEA, Irena (2021)
Water consumption	kg H20/ kg H2	9	9	9	9	IEA, The Future of Hydrogen (2019)
Availability	%	95.0%	98.0%	98.0%	98.0%	Stakeholder interviews, FCH2JU (2017)
Capex Unit Cost (<5MW) (Includes BoP)	£'000/MW	2,247	1,736	1,447	1,300	BEIS, Hydrogen Production Models (2021)
Capex Unit Cost (<10-50MW) (Includes BoP)	£'000/MW	1,379	869	668	617	BEIS, Hydrogen Production Models (2021)
Capex Unit Cost (>50MW) (Includes BoP)	£'000/MW	1,135	714	515	427	BEIS, Hydrogen Production Models (2021)
Project development & Installation costs	% of capex	25.0%	20.0%	20.0%	20.0%	Arup benchmarks (2022)
Fixed opex costs	£/kW	43.6	41.3	40	38.3	BEIS, Hydrogen Production Models (2021) - Average
Stack replacement capex	% of capex	33.0%	33.0%	33.0%	33.0%	Confidential developer data, FCH2JU (2017)
Compressor						
Polytropic efficiency	%	74.0%	74.0%	74.0%	74.0%	CSIRO, National Hydrogen Roadmap (2018)
Overhaul Frequency	Years	10	12	12	12	DOE Technical Targets for Hydrogen Delivery - can convert to hours for model simplicity
Availability	%	93.0%	93.0%	95.0%	98.0%	Stakeholder interview (Cummins)
Compression Unit Capex (350 bar)	£/ tpd	1,000,000	700,000	700,000	500,000	Chardonet et al.
Compression Unit Capex (30 bar)	£/ tpd	100,000	100,000	100,000	100,000	Chardonet et al.
Compression Fixed Opex	% of capex	4.00%	4.00%	4.00%	2.00%	DOE Technical Targets for Hydrogen Delivery
Gas Storage						
Capex unit cost (Low pressure >30 bar)	£/kg	1,322	1,322	1,322	1,322	CSIRO, National Hydrogen Roadmap (2018)
Capex unit cost (Medium pressure @ 350bar)	£/kg	859	625	625	625	CSIRO, National Hydrogen Roadmap (2018)
Fixed opex	% of capex	2.0%	2.0%	2.0%	2.0%	CSIRO, National Hydrogen Roadmap (2018)
Liquid Storage						
Liquid tank size	kg	4,000	4,000	4,000	4,000	AirProducts
Capex unit cost	£/m3	1,159	961	961	580	Implications of the energy transition for the EU storage, fuel and supply and stirbution infrastructure (2021)
Fixed opex	£/cbm	10	6	6	5	Implications of the energy transition for the EU storage, fuel and supply and distribution infrastructure (2021)
Liquefaction						

Power per kg H2 produced	kWh/kg	12	10	10	10	DOE Hydrogen and Fuel Cells Program
Liquefier Overhaul	Years	6.0	6.0	6.0	6.0	Arup benchmarks
Liquefier Capex	£/kg/day	5,000	3,000	3,000	2,000	ETC, DOE Hydrogen and Fuel Cell, Oxford Energy, Arup project benchmarks
Liquefier Replacement costs	% of capex	10.0%	10.0%	10.0%	10.0%	Estimate to reflect plant shutdown and overhaul of critical equipment. Value based on Arup project benchmarks (Project Blue)
Fixed opex Rate	% of capex	3.0%	3.0%	3.0%	3.0%	Arup estimate
Transport (Gas)						
Truck volume	kg	1000	1000	1000	1000	BNEF 2019
Truck capex cost	£/kg	700	600	600	500	Reuss et al (2021), Lahnaoui (2021), Hurskainen (2020)
Fuel consumption	L/100km	40	35	33	30	Reuss et al (2021), Lahnaoui (2021), Hurskainen (2020)
Asset life	km	1000000	1000000	1000000	1000000	Arup estimate
HRS						
Unit Cost (<200kg/day)	£/kg/day	15000	9000	9000	8000	Apostolou, D. et al (2019)
Unit Cost (200-400kg/day)	£/kg/day	4500	3500	3500	3000	Apostolou, D. et al (2019)
Unit Cost (>400kg/day)	£/kg/day	2800	2380	2380	1500	Apostolou, D. et al (2019)
O&M costs	% of capex	15%	15%	15%	15%	Apostolou, D. et al (2019)
Financial/ other Assumptions						
Discount rate	%	10.00%	10.00%	10.00%	10.00%	
Contingency	%	5.00%	5.00%	5.00%	5.00%	

7.5 Literature Review Sources

Table 14 - Literature review matrix

#	Author	Year	Title	Renewable Energy Generation	Electrolyser	Storage	Compression & Liquefaction	Transportation
1	Amin Lahnaoui 1, ChristinaWulf 1 and Didier Dalmazzone	2021	Optimization of Hydrogen Cost and Transport Technology in France and Germany for Various Production and Demand Scenarios					x
2	Arup	2021	Market review of hydrogen energy storage			x		
3	BEIS	2019	Contracts for Difference Allocation Round 3	x				
4	BEIS	2021	Hydrogen Production Costs 2021		x			
5	Bessarabov, D	2018	PEM Water Electrolysis		x			
6	Bloomberg NEF	2021	New Energy Outlook 2020	x				
7	BloombergNEF	2021	2H 2-21 Hydrogen Levelized cost update		x			
8	Bloomenergy	2021	The Role of Solid Oxide Technology in the Hydrogen economy: A Primer		x			
9	BNEF	2021	Current LCOE	x				
10	BNEF	2019	Hydrogen_ The Economics of Transport & Delivery _ Full Report _ BloombergNEF				x	x

#	Author	Year	Title	Renewable Energy Generation	Electrolyser	Storage	Compression & Liquefaction	Transportation
11	Bruce S et al	2018	National Hydrogen Roadmap			x		
12	Catapult	2021	FLOATING OFFSHORE WIND:COST REDUCTION PATHWAYS TO SUBSIDY FREE					
13	Chardonnet, C. et al	2017	Study on Early Business Cases for H2 in energy storage and more broadly power to H2 applications				x	
14	Chile et al	2020	Hydrogen Generation in Europe		x	x	x	x
15	Cummins	2021	Stakeholder interview		x			
16	DNV	2021	Technology Progress outlook	x				
17	DOE	2015	DOE Technical Targets for Hydrogen Delivery			x		
18	DOE Hydrogen & Fuel Cells Program Record	2019	Current status of H2 liquefaction costs				x	
19	EIA	2020	Annual Energy Outlook	x				
20	EIA	2021	Levelized Costs of New Generation Resources in the Annual Energy Outlook 2021	x				
21	Element Energy	2020	Bulk Supply of Renewable Hydrogen		x			
22	FCH2JU	2017	Development of Business Cases for Fuel Cells and Hydrogen Applications for European Regions and Cities		x			
23	FCHJU	2017	Study on early business case for H2in energy storage and more broadly power to H2 application				x	
24	FLEXCHX	2018	Flexible combined production of power, heat and transport fuels from renewable energy sources		x			
25	Gerard, F. et al	2021	Implications of the energy transition for the EU storage, fuel and supply and distribution infrastructure			x		
26	Gielen et al	2019	Hydrogen: A Renewable Energy Perspective		x			
27	Glancy, V. et al	2021	Market review of hydrogen energy storage 078807-31			x		
28	Glenk & Reichelstein	2019	Economics of converting renewable power to hydrogen		x			
29	Guidehouse	2020	European Hydrogen Backbone				x	
30	H100	2019	Arup Project			x		
31	H2A - PEM Distributed Model	2018	Current distributed PEM electrolysers				x	
32	Husarek, D	2021	Hydrogen supply chain scenarios for the decarbonisation of a German multi-modal energy system					x
33	Hydrogen Innovation Program	2020	Gigawatt green hydrogen plant		x			
34	IEA	2021	IEA World Energy Outlook	x	x			
35	IEA	2019	The Future of Hydrogen		x			
36	IRENA	2020	Renewable Power Generation	x				
37	JEC	2020	JEC WTT (Appendix 1 Pathways 9)		x			
38	Krishna Reddi, Amgad Elgowainy,	2018	Techno-economic analysis of conventional and advanced high-pressure tube trailer configurations for					x

#	Author	Year	Title	Renewable Energy Generation	Electrolyser	Storage	Compression & Liquefaction	Transportation
	Neha Rustagi, Erika Gupta		compressed hydrogen gas transportation and refuelling					
39	Markus Hurskainen, Jari Ihonen b	2021	Techno-economic feasibility of road transport of hydrogen using liquid organic hydrogen carriers					x
40	Markus Reuß et al.	2021	Hydrogen Road Transport Analysis in the Energy System: A Case Study for Germany through 2051					x
41	NREL	2021	Annual Technology baseline	x				
42	Parra et al	2019	A review on the role, cost and value of hydrogen energy systems for deep decarbonisation		x			
43	Presuter P et al	2017	Hydrogen Storage Technologies for Future Energy Systems			x		
44	Port of Rotterdam	2021	Namibia - Port of Rotterdam Hydrogen Supply Chain - Pre-feasibility report					x
45	Preuster at al	2017	H2 Storage tech for future energy systems				x	
46	Proost	2017	State-of-the-art CAPEX data for water electrolysers, and their impact on hydrogen price settings		x			
47	Saba et al	2018	The investment costs of electrolysis – A comparison of cost studies from the past 30 years		x			
48	SCHFA	2021	Stakeholder interview			x		
49	Shell	2017	SHELL HYDROGEN STUDY Sustainable Mobility through Fuel Cells and H3					x
50	Siemens Energy NEB	2020	Overview of the PEM Silyzer Family		x			
51	The Oxford Institute for Energy Studies	2018	LNG Plant Cost Reduction 2014-18				x	
52	Walker, I. et al	2018	Hydrogen Supply chain evidence base		x	x	x	
53	Wiser, R et al.	2021	Expert elicitation survey predicts 37% to 49% declines in wind energy costs by 2050	x				

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