

HYDROGEN INNOVATION INITIATIVE – WP4.2 WIND-ELECTROLYSER

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Appendices

APPENDIX 1 REGIONAL PROJECT MAPS 1
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1. INTRODUCTION

The Energy Systems Catapult (the Catapult) are seeking to develop a comprehensive dataset detailing the deployment of large-scale (i.e. gigawatt) wind facilities coupled with water electrolysers for the production of hydrogen across the UK. The dataset is to be backed by a comprehensive analytical narrative capturing the potential impact of available supporting infrastructure, technology supply chains, geographical constraints, storage needs, and costs, amongst others.

This information is to be used to inform a wider piece of systems modelling work, hence it is essential to ensure the outputs are robust and any assumptions are clear and sensible. The Project has been split into four work packages, D1 to D4. D1 detailed projects in the pipeline and D2 identified Zones of opportunity for large-scale wind-electrolyser facilities. Deliverables for both work packages have been submitted as spreadsheets, detailing the relevant information and key metrics. Furthermore, the output of D1 & D2 were summarised in GIS format.

Tasks D3 and D4 used the outputs of Tasks D1 and D2 as a basis for a more detailed analysis. Task D3 focused on the suitability of existing and future infrastructure and aims to marry the potential supply/demand profiles of the future with the practicalities and realities of deployment of wind-electrolyser projects at scale and thereby establish the overall feasibility for these types of projects. The findings have been laid out and contextualised in Task D4 and finally, the project is being concluded with this Final Report (Task D5). The diagram below describes the key areas explored in this project and the focus of the chapters of this report.

Figure 1 Key focus areas of project and report



2. PLANNED AND EXISTING PROJECTS

This section details the methodology used to create the wind-to-electrolysis project database. It also includes information on the data sources, details contained in the database, assumptions, and any exclusion.

2.1 METHODOLOGY FOR DATABASE CREATION

Ricardo gathered the data for wind-to-electrolyser projects from different sources using various markers and details. Once we added the projects from all the sources, we carried out data cleaning to remove duplicates, non-relevant projects and so on. The background on sources and details is given in the upcoming section.

2.1.1 Sources for wind-to-electrolyser projects

To create a comprehensive wind-to-electrolyser projects database, we utilised different sources including Hydrogen Allocation Round (HAR 1) projects, International Energy Agency (IEA) hydrogen projects database, Clean Energy Pipeline projects, UK's Hydrogen Energy Association's project map and Hydrogen Net Zero Investment Roadmap. We have reviewed multiple sources to ensure that we captured as many projects as possible. When a source provided limited information, we conducted additional web research to gather further information. We also removed projects that were repeated across different sources.

2.1.2 Details of the project database

We have included the following data fields in the database:

- Developer: Companies leading the project's development
- Renewable energy capacity powering the hydrogen production: This specifies the capacity (in MW or GW) of the renewable energy source (wind) powering the hydrogen production process

- Hydrogen production volume: This details the project's hydrogen production, either in tons of hydrogen per day or the project's overall size in MW or GW
- Stage of project development: This categorises the project's progress using specific stages: concept, feasibility study, public consultation, FEED or consent, FID or construction, demonstration, operational, pause, scrapped, or, unknown
- Expected deployment date: The anticipated date when the project is expected to become operational
- Type of wind resource powering the operation: We have categorised the wind resources as:
    - Onshore wind: Electrolysis is powered by wind turbines located on land
    - Offshore wind: Electrolysis is powered by wind turbines located offshore
    - Both onshore and offshore wind: These projects utilise a combination of onshore and offshore wind
    - Wind and other renewables: The project uses wind power combined with other renewable sources such as solar
    - Likely onshore wind: Information might be limited, but based on available details, onshore wind is the probable source for powering the electrolysis.
    - Excluded information: Projects were taken out of the database if they were powered by unknown sources or not powered by wind energy
- Location of electrolyser or hydrogen production: This specifies whether the hydrogen production facility is located onshore or offshore, if stated
- End uses: This section details the intended applications for the produced hydrogen, such as transport, industry, heat, power and so forth
- Project location: The project's location is mapped using geographic coordinates (longitude and latitude) for integration with Geographic Information Systems (GIS) for visualisation
- Assumption and notes: We have noted down all the assumptions made while recording project details in assumptions section. Notes capture any recent updates or relevant information about the project that could be valuable for future reference.

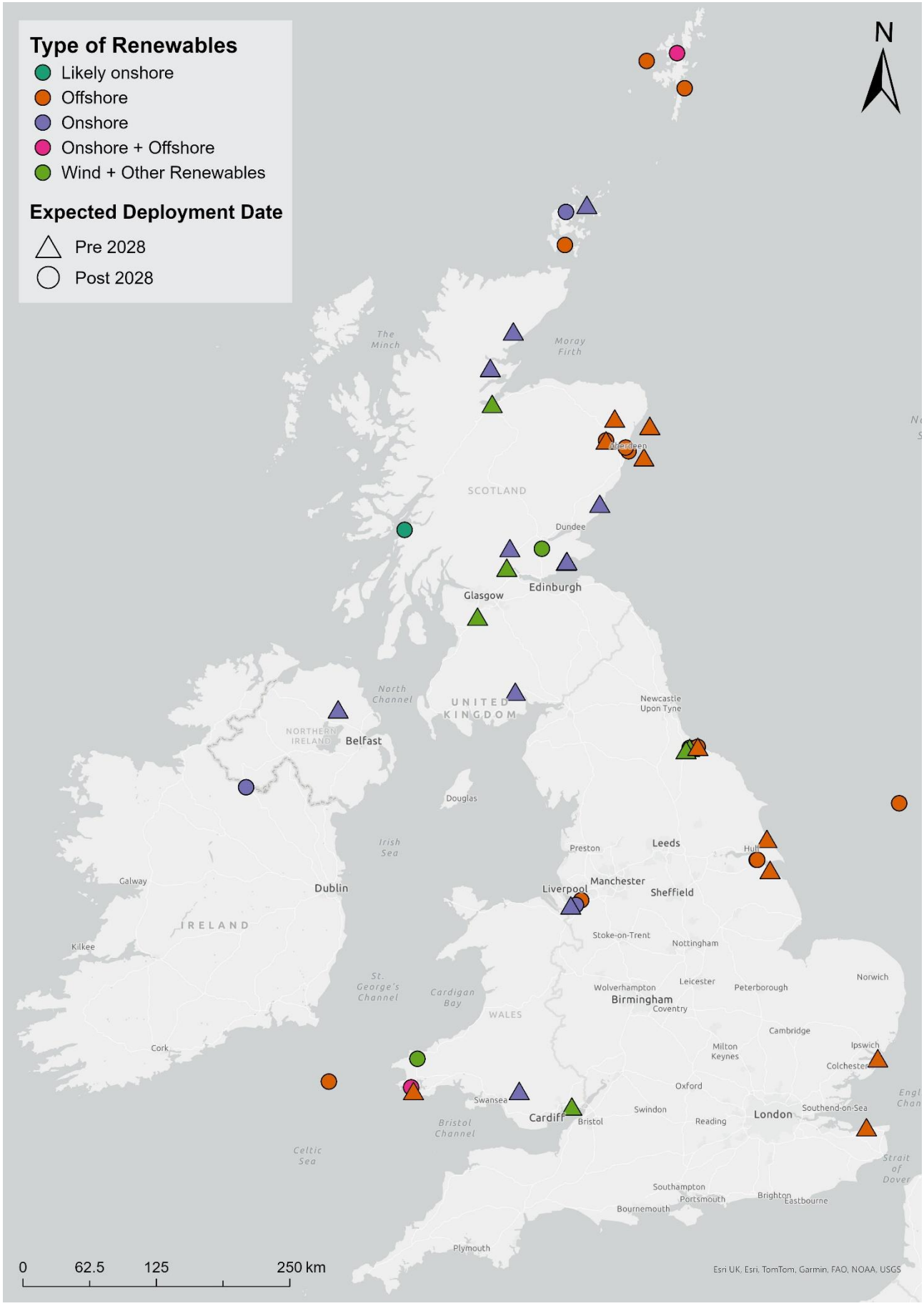
2.2 PROJECT MAPPING

The database analysis was used to produce a two sets of maps using GIS. The first provided a broad overview of the entire UK. Additionally, several zoomed-in maps focused on specific regions within the UK, including England, Northern Ireland, Scotland, and Wales. The projects were distinguished based on deployment date into pre-2028 and post-2028. The reason for choosing the boundary year of 2028 was that a lot of projects are coming online in the next three years and choosing 2028 ensured that upcoming projects are distinguished from long-term projects. Additionally, scrapped and unknown projects were not included in the maps. Figure 2 shows the location of wind electrolysis projects in the UK. The regional maps are included in Appendix 1.

The projects database represented in the map shows the following trends:

- The map shows a higher concentration of projects in Scotland, with some with offshore locations. For example, Salamander and Dolphyn Hydrogen project
- More projects are situated along coastal areas, likely due to easier access to ports for trade. The major ones are Tees Green Hydrogen and Aberdeen hydrogen hub
- Projects cluster near large industrial hubs, anticipating their future high demand for hydrogen. Such as Flotta Hydrogen Hub, Aberdeen Hydrogen Hub, Humber project, Stirling Hydrogen Hub
- The central region of England has minimal projects, possibly due to a smaller industrial presence.
- The map also reveals a higher number of projects planned before 2028, and fewer projects are projected to come online after 2028

Figure 2 UK projects map derived from the project database



3. EXCLUSIONS AND ZONES OF OPPORTUNITY

Arguably the key requirement for any wind-to-hydrogen based project will be the quality of the available wind resource. To understand the potential large-scale wind projects that could be aimed at producing hydrogen, Ricardo has conducted a three-step process as follows:

1. Produced wind energy maps to narrow down the geographical zones of opportunity in the UK which would benefit from large-scale wind-derived power to hydrogen. This involved developing GIS maps showing the wind resource across the UK, banded low, medium and high, as well as creating exclusions based on certain criteria
2. Further developed separate maps exploring other potential exclusion/inclusion zones based on criteria including population density, topography, national parks, airports, shipping lanes, existing renewables installations and sea depth for offshore wind
3. Assessed the likely feasible range of wind-electrolyser installations based on scenarios and considering factors such as build-out rates

The following section will discuss the methodology and assumptions used in exploring inclusions/exclusions. To conclude the areas of opportunity will be mapped out and discussed.

3.1 METHODOLOGY AND RESULTS OF EXCLUSIONS MAPPING

3.1.1 Wind energy potential mapping

The UK is known for its strong wind energy potential and industry. In order to begin understanding where wind-to-hydrogen projects may be best placed it is essential to understand the areas of low and high wind potential. The following data was utilised with various assumptions to determine this:

Data source: Global Wind Atlas

Key Assumptions:

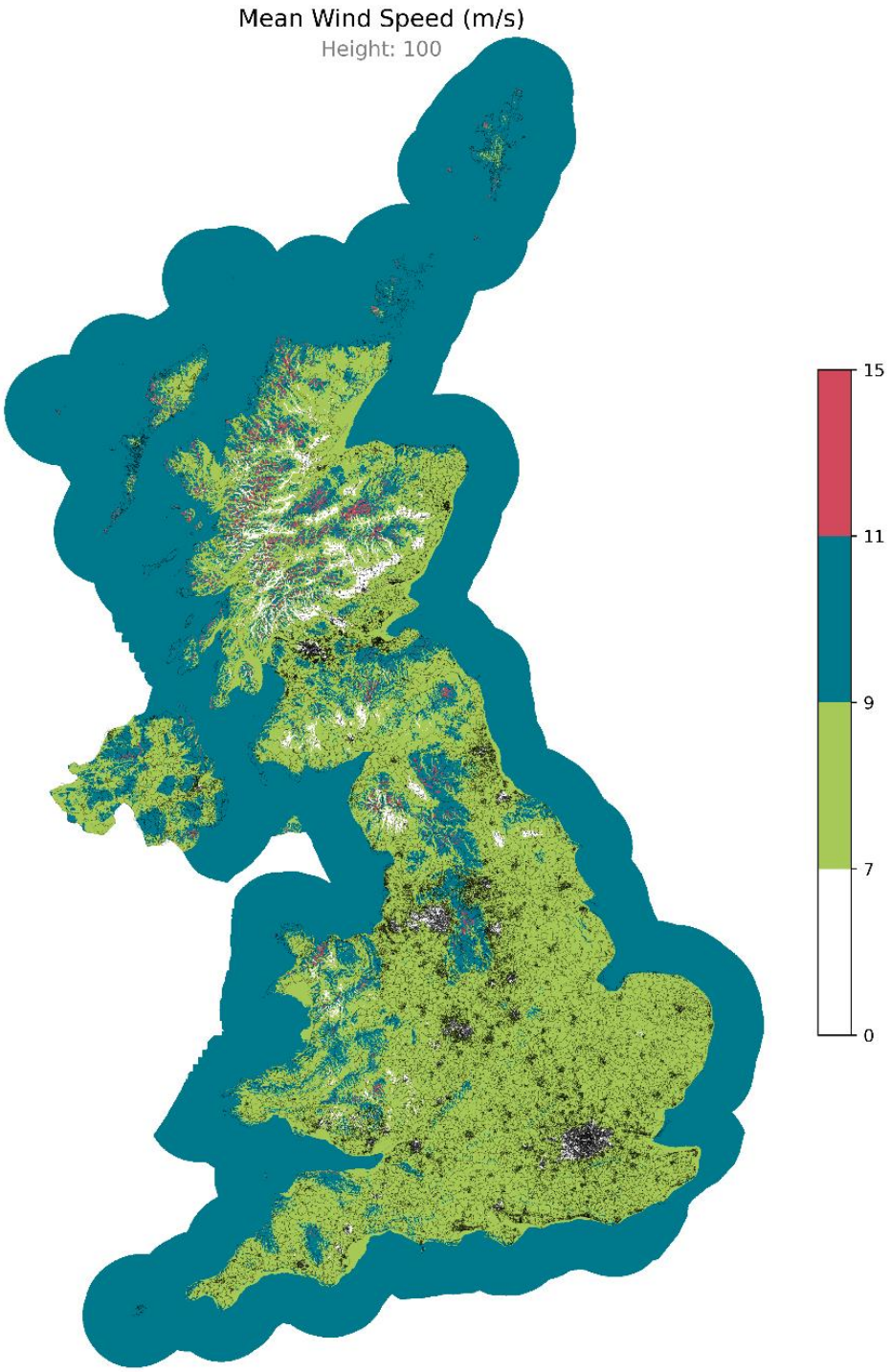
- 7 m/s is assumed as the minimum wind speed requirement for a viable wind project. As such this is the lower end of the wind energy band
- Speeds around 9 m/s are considered as good
- Lastly, speeds at or above 11 m/s are considered excellent for wind projects

Table 1 Wind speed banding for wind energy mapping

Banding	Low	Medium	High
Mean wind speed (m/s)	7-9	9-11	11-15

What is observed from Figure 3 below is that almost all of the UK has wind energy potential high enough for wind installations. The areas of high potential include offshore regions as well as areas of greater elevation. In summary, this map highlights the notable potential that exists in the UK, prior to considering aspects such as existing installations.

Figure 3 UK wind speed potential map



3.1.2 Exclusion Zones: Existing Wind Installations

To ensure that suggestions are not made to build on existing wind installation, these installations were mapped out. This included onshore and offshore installations. The following discusses the data used and assumptions made:

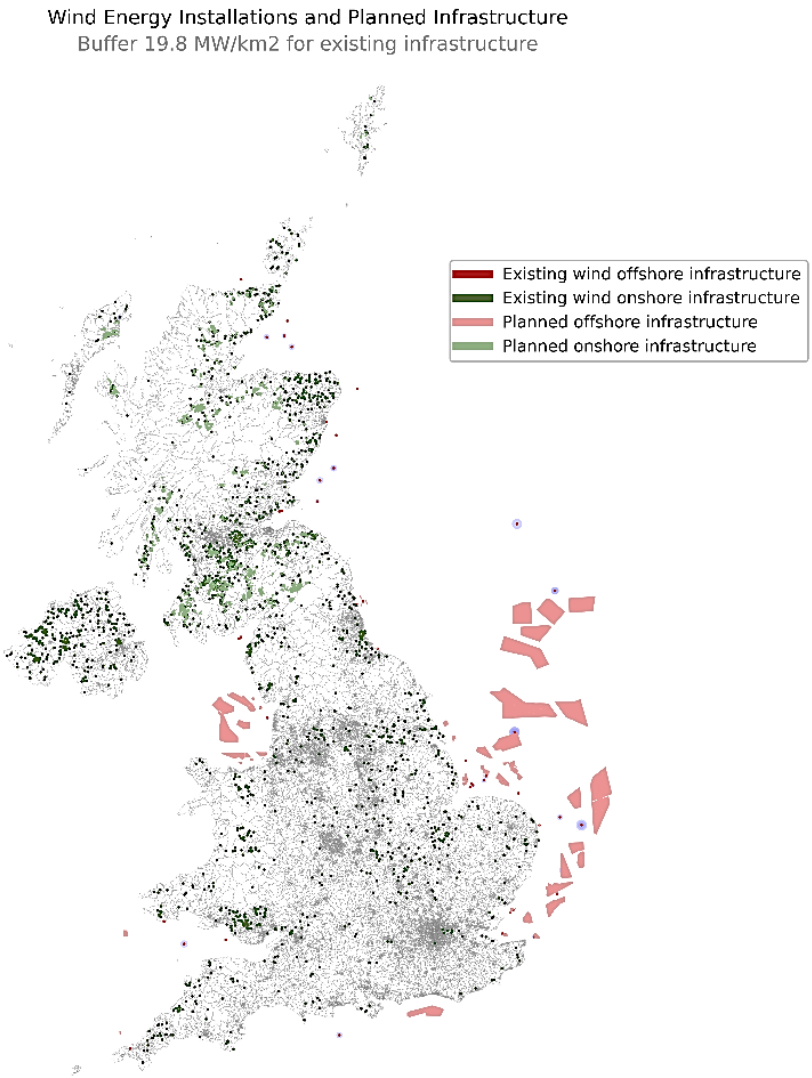
Data sources: Renewable Energy Planning Database (GOV.UK), Onshore Windfarm Proposals (Nature Scotland) and Wind Site Agreements for England, Wales & NI (The Crown Estate)

Key Assumptions:

- 19.8 MW/km^2 is assumed as the area requirement based on the average onshore wind farm capacity
- It is assumed that the area requirement of the wind plant is spread in a circle from the provided coordinates

What can be observed from Figure 4 below is that there is a larger concentration of onshore wind projects in the north of England, Northern Ireland and Scotland. Planned offshore projects, based on the Crown Estate data, shows a significant concentration of projects off the east coast.

Figure 4 Installed and planned wind infrastructure



3.1.3 Exclusion Zones: Population Density

Population density is a restrictive factor to the development of wind projects as well as large scale hydrogen production facilities given safety and space considerations. The following will aim to determine the areas of high population density that should be excluded when exploring wind-to-hydrogen projects:

Data source: 2011 Census Geography boundaries (UK Data Service)

Key Assumptions:

- England and Wales have a restrictive policy around onshore wind thus this should be reflected in the mapping exercise
- Two assumptions can be derived by identifying where the trend of population density being a restricting factor ends (**2 persons/km²** or **100 persons/km²**) – a density of ≤20 persons/km² and ≤40 persons/km² were selected for mapping

Figure 5 Wind power installation size against population density

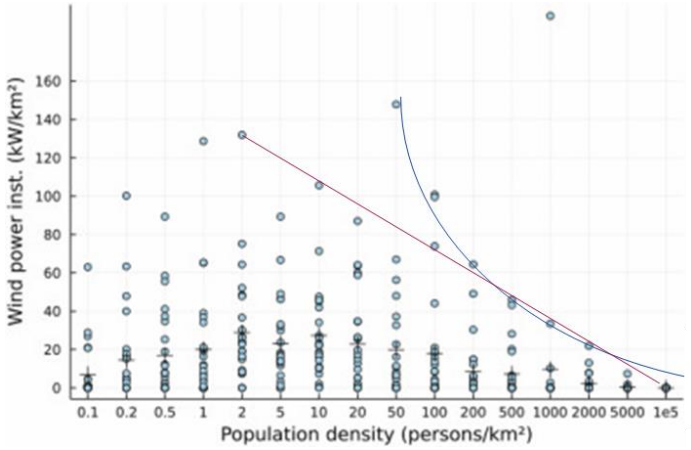
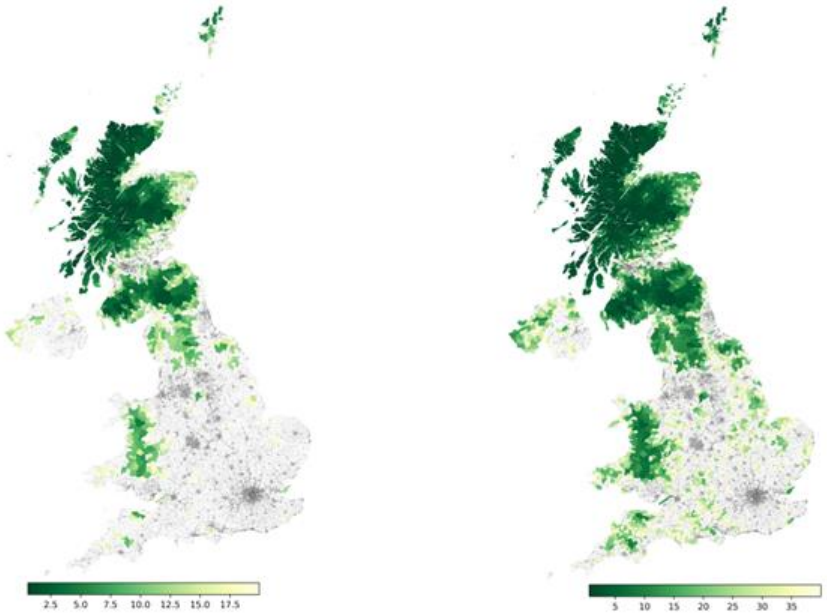


Figure 6 shows the exclusion of areas with a density of 20 persons/km² or less, and also 40 persons/km² or less.

Figure 6 Population density maps for the UK [Left: ≤20 people/km². Right: ≤40 people/km²]



In consultation with the Catapult, the second exclusion map was selected, representing areas with 40 persons/km^2 or less. When looking at this chart it shows a good correlation to the existing onshore wind installations, which are high in density in the north and lower in density in the south.

3.1.4 Exclusion Zones: National Parks

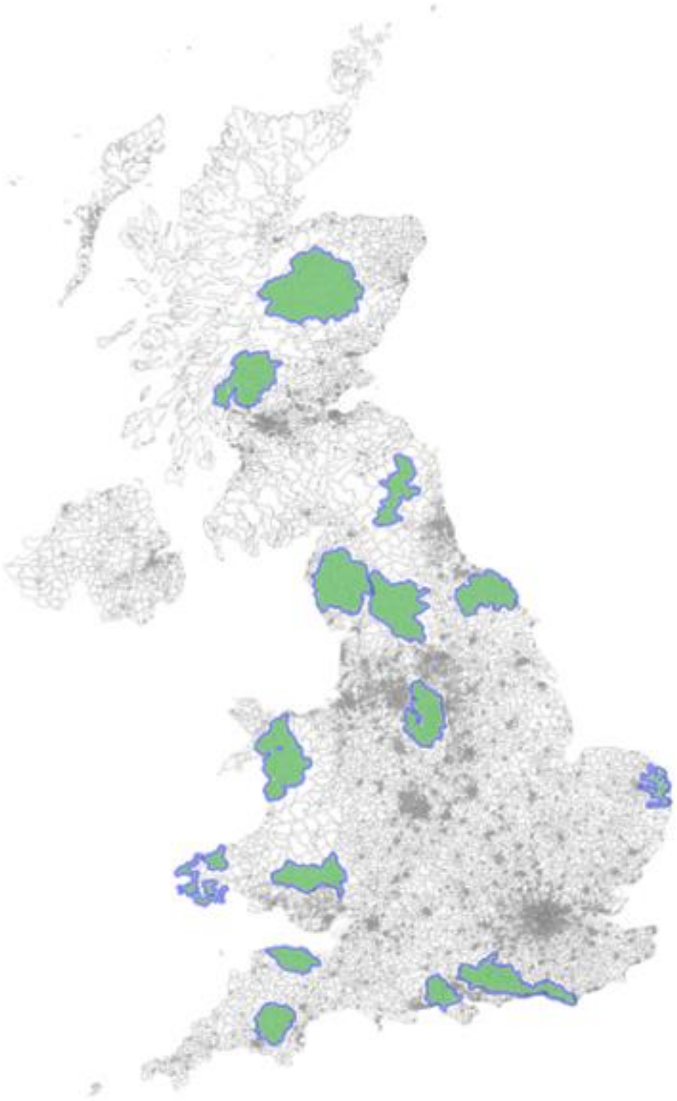
National parks are protected areas which are given careful consideration when wanting to build large infrastructure. These parks are excluded from the potential area for wind-to-hydrogen projects according to the following:

Data source: National Parks (Office for National Statistics-UK)

Key Assumptions:

- The area covered by a national park is restricted from any construction of wind turbines
- A1 km offset from the national parks is included since often the area around the national park does not permit visual pollution

Figure 7 National Park exclusions in the UK



3.1.5 Exclusion Zones: Airports

Airports and the areas around them would require to be excluded from what can be considered feasible areas for wind installations to protect flight paths. In mapping these exclusions the follow data was consulted and assumptions made:

Data source: Location of UK Airports (ESRI UK)

Key Assumptions:

- We assume that an exclusion zone of 15 km radius is drawn around each airport (Wind Farms and Airports Co-Exist (Pager Power))

Figure 8 highlights airports in the UK including the 15 km radius applied. Figure 9 shows the existing offshore facilities and the airport exclusions together.

Figure 8 Map of airports and applied buffers across the UK

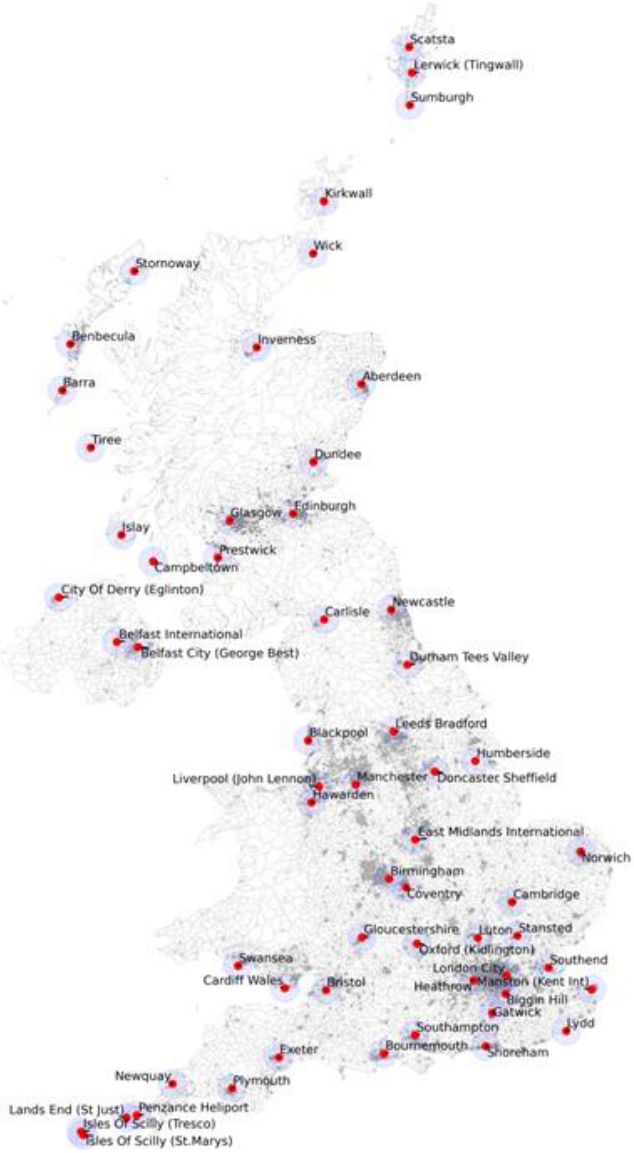


Figure 9 Offshore wind installations and offshore exclusions due to airports



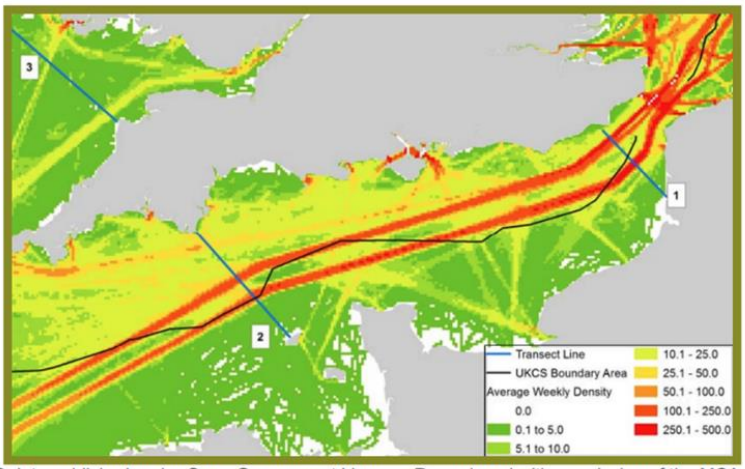
3.1.6 Exclusion Zones: Shipping Lanes

To ensure offshore installations do not hinder the importing and exporting of goods and passage of vessels, key shipping lanes must be excluded from what can be considered as potential space for wind installations. The following key assumptions have been in this regard:

Key Assumptions: Mapping UK Shipping density and routes (AIS - GOV.UK)

- We assume the English Channel shipping lane is of key significance which we understand to have strict protocol. This is of course evolving and will need to be monitored in the future
- Marine traffic maps show that other areas have more diverse travel routes and therefore shipping lanes can be managed as assumed by Wind Europe's 2019 *Our Energy Our Future* report:
    - *"Conversely, offshore wind may be excluded from areas for sand and gravel dredging, major shipping lanes, cable and pipeline routes, and military uses. However, investment in infrastructure to deploy current radar and other mitigation technology and further advances in technology with time will help minimise the impact of offshore wind in this regard."*

Figure 10 English channel traffic map



AIS data published under Open Government Licence. Reproduced with permission of the MCA and MMO. Contains UKHO Law of the Sea data © Crown copyright and database right.

3.1.7 Exclusion Zones: Topography

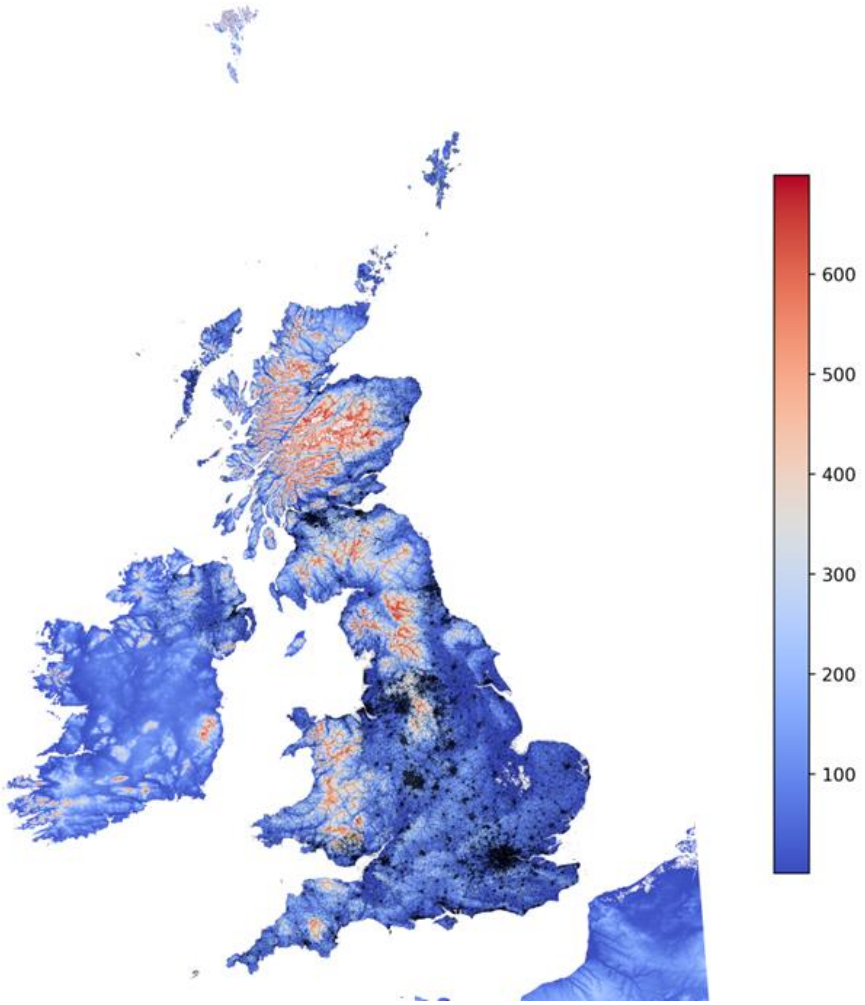
The topography of an area is another aspect to consider when trying to understand the areas where wind installations could be developed. It is more ideal to build in areas that have smoother topographies and are easily accessible. The following data and assumptions were made use of when mapping the topography of the UK:

Data source: Gridded Bathymetry Data (GEBCO)

Key Assumptions:

- We assumed no wind farms are built over 700 m above sea level. We based this on SSE's highest project being 700 m above sea level which was the highest we could find.
    - *"Developed by SSE Renewables, Dunmaglass is a 94.05 MW wind farm situated 25 km south of the city of Inverness, Scotland. At 700 m above sea level, it is the highest wind farm ever constructed by the Scottish energy company."*
    - https://www.sserenewables.com/onshore-wind/great-britain/dunmaglass/
- Note: UK only has 120 mountains over 600 m
    - *https://en.wikipedia.org/wiki/List_of_P600_mountains_in_the_British_Isles*

Figure 11 Map of topography in the UK



From the map it can be seen that there are a few regions in the UK which are above 600 m above sea level, particularly those which have appeared as having low population density. For the areas where there are no national parks these could be ideal for further onshore wind development.

3.1.8 Sea depth

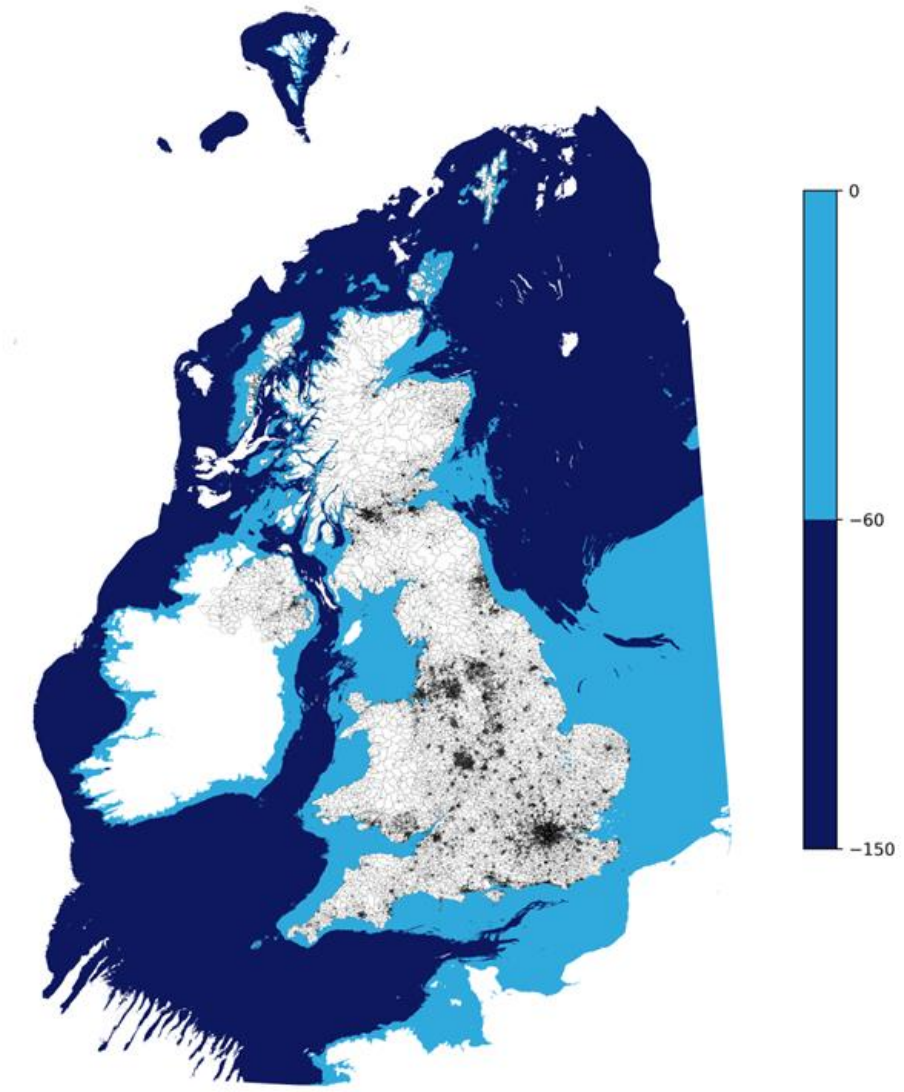
Sea depth is a key factor in understanding which offshore wind technologies will be most ideal. Areas at lower depths are ideal for conventional, whereas deeper depths require floating offshore, which is less mature. In mapping sea depth the following data and assumptions were used:

Data source: Gridded Bathymetry Data (GEBCO)

Key Assumptions:

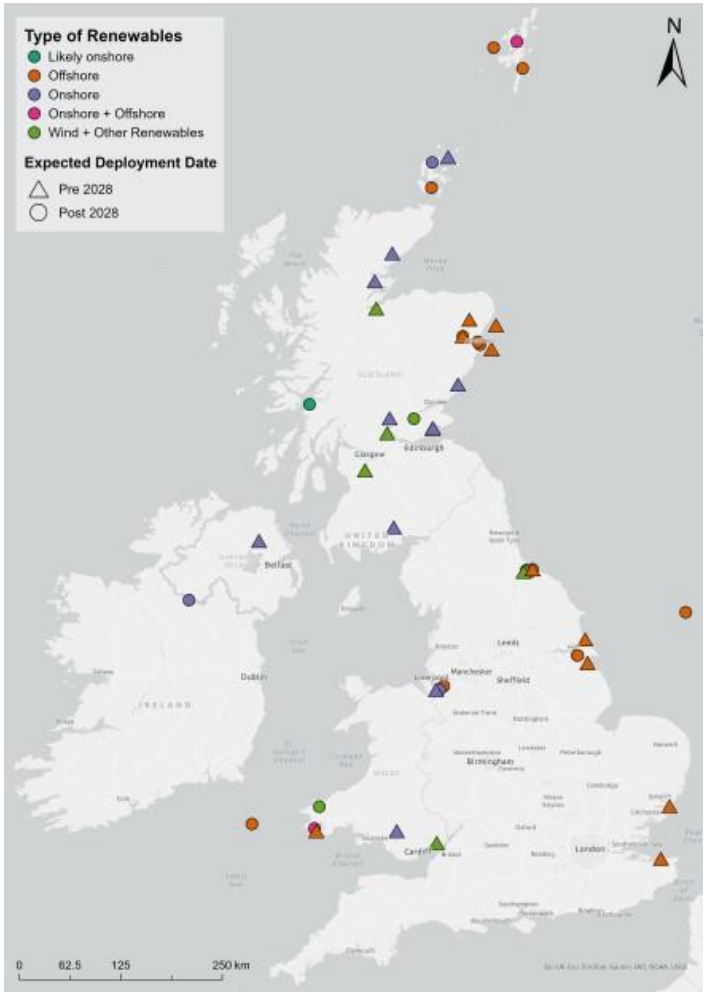
- Conventional fixed is assumed to be achievable to 60 m depth. This was determined in consultation with the Catapult
- Large-scale monopile/jacket and floating wind installations are assumed to be achievable up to 150 m. This is based on GWEC's study on the UK's offshore wind potential
    - https://gwec.net/wp-content/uploads/2021/06/United-Kingdom_Offshore-Wind-Technical-Potential_GWEC-OREAC.pdf

Figure 12 Mapping of sea depth in the UK [light blue fixed:dark blue floating]



The GWEC study reports a fixed offshore wind potential of 439 GW and a floating potential of 1,361 GW, giving a total potential of 1,800 GW. Figure 12 shows the regions where this potential would apply. There would of course be some limits to this potential such as the scale of infrastructure development as well as the maturing of floating wind to name a few.

Figure 13 Map of planned projects and map of areas of potential considering various exclusions/inclusions



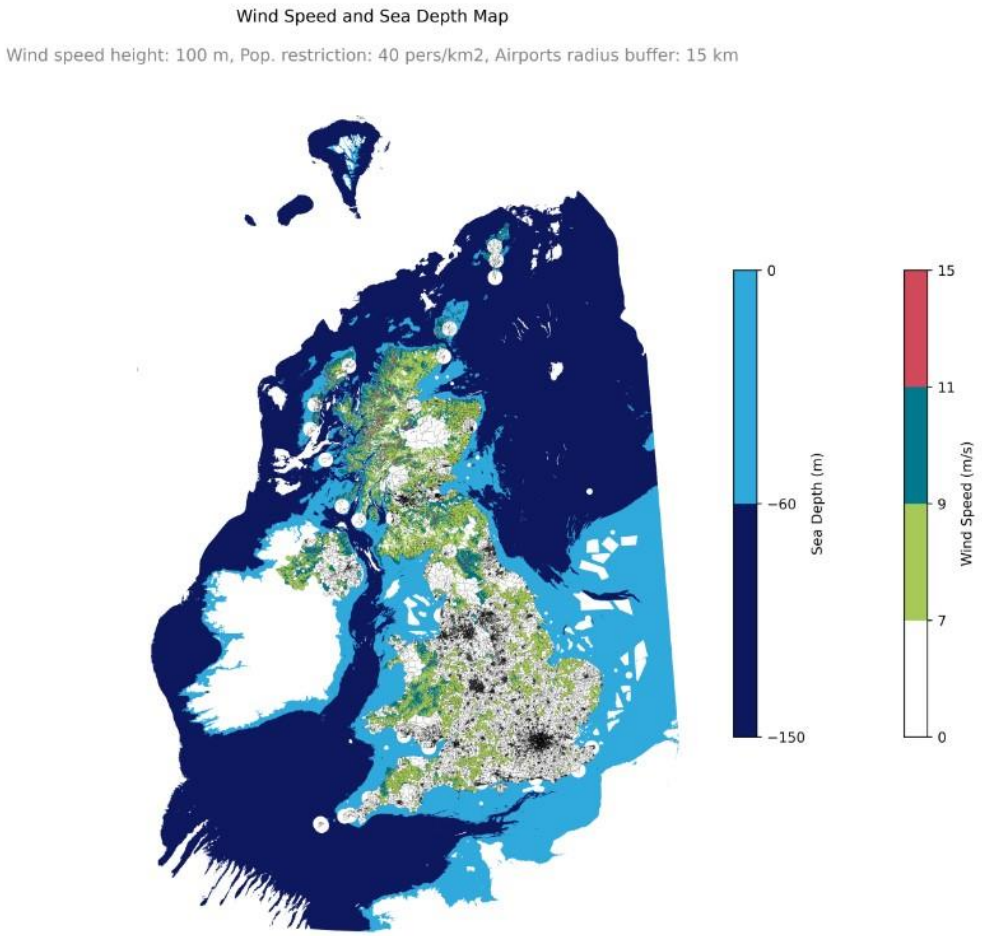


Figure 13 shows both the projects in the pipeline per our research and the area off opportunity given the assumptions outlined in this section. It can be observed that a significant amount of potential lies onshore in parts of Northern Ireland, Scotland, Wales as well as parts of the North and South of England. The exact areas are outlined in the following section in Table 3.

Figure 14 Maps of areas of opportunity for England and Wales

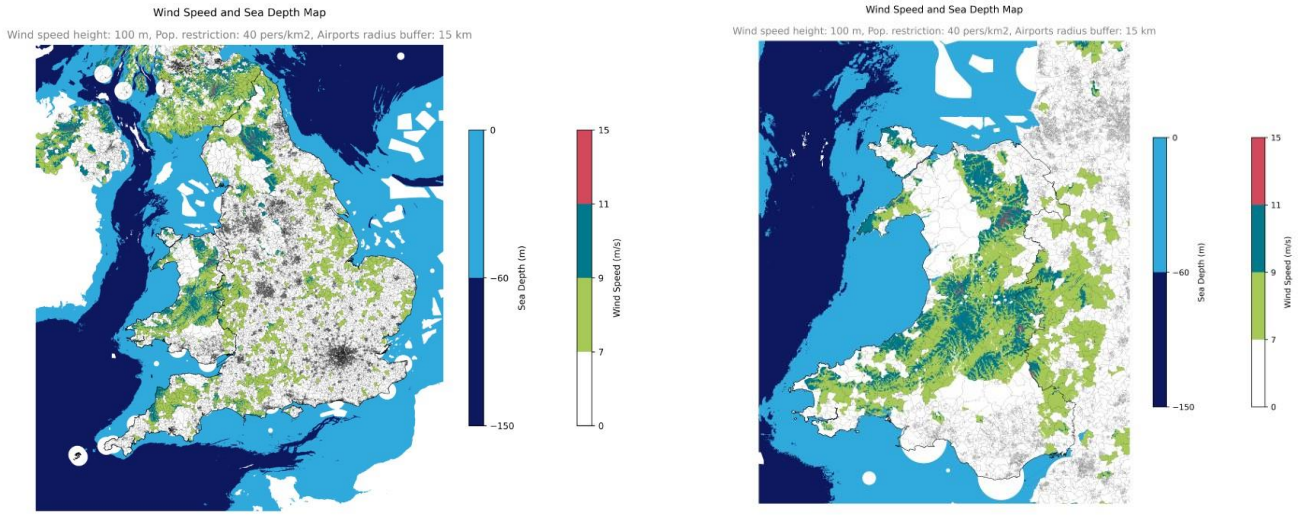
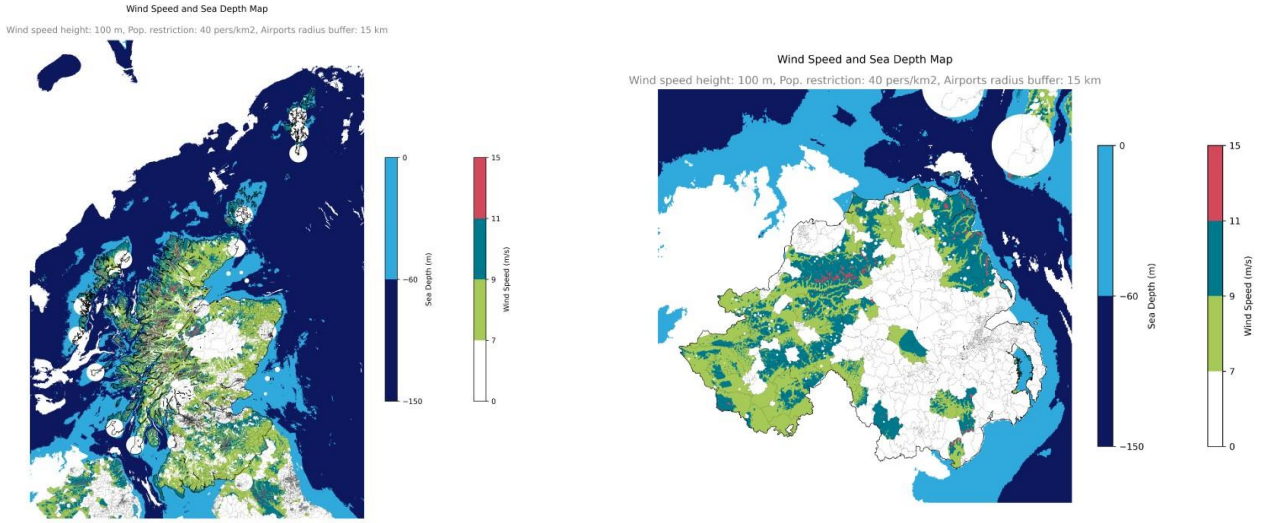


Figure 15 Maps of areas of opportunity for Scotland and Northern Ireland



4. QUANTIFYING DEMAND AND SUPPLY

The zones of wind opportunity identified in Section 3 and the wind-to-hydrogen project pipeline identified, and the database created in Section 2 are quantified in this section. Based on the numbers we have calculated and developed wind-to-hydrogen production scenarios for 2030. The results are then analysed based on the hydrogen demand projections from the literature to quantify the possible demand-supply gap in 2030. Further, to quantify potential local storage requirements, two off-grid case studies are considered, and the hydrogen storage sizing required for both cases is calculated.

4.1 ONSHORE AND OFFSHORE WIND POTENTIAL

Table 2 showcases the current and planned onshore/offshore wind energy capacity forecasted by ESO National Grid for 2030 and 2050[1]. There is considerable planned capacity addition for both onshore and offshore wind energy systems for 2030. This section analyses how the planned capacity addition targets tally against the overall onshore wind potential calculated in Section 3 and the realistic onshore wind energy potential per our assumption.

Table 2 Planned onshore and offshore wind energy capacity in UK as per ESO Future Energy Scenario (FES)

ESO Future Energy Scenario (FES) UK				
Wind technology	**Unit**	**2022**	**2030**	**2050**
Onshore Wind	TWh	44.6	86.9	139.4
Offshore Wind	TWh	54.2	177.8	487.9

Inputs and assumptions used in Table 3 calculations:

- The available area in land available for onshore wind farms, km^2, calculated in Section 3 after considering exceptions, is taken as input.
- For converting available land into wind farm capacity, 19.8 MW/km^2 is assumed as an area requirement based on average onshore wind farm capacity[2].
- The average onshore wind capacity factor[3] for each country is used to calculate the yearly electricity produced in TWh from onshore wind potential in GW.
- Planned onshore wind yearly electricity addition till 2050 calculated using data in Table 2 is 94.8 TWh.
- A reasonable factor of 10% is used to calculate actual onshore wind electricity production in Table 3.

[1] PowerPoint Presentation (nationalgrideso.com)
[2] Data investigation of installed and output power densities of onshore and offshore wind turbines worldwide (stanford.edu)
[3] Regional renewable electricity in 2022 (publishing.service.gov.uk)

Table 3 Quantifying UK onshore wind potential and comparison with ESO projections for 2050

Country	Available area in land (km^2)	Onshore Wind potential (GW)	Capacity Factor	Total onshore Wind electricity potential (TWh)	Assumed onshore wind electricity production (TWh) – (10% of total)	Onshore wind electricity production (TWh) - ESO projection
England	34,012	673	26%	1,510	151	29
Northern Ireland	6,933	137	27%	322	32	6
Wales	9,924	196	27%	472	47	9
Scotland	57,920	1,147	28%	2,853	285	55
Total	104,789	2,075	28%	5,016	502	99

The planned electricity production for 2050 as a percentage of total onshore wind electricity potential is calculated to be around 1.9%. This value showcases that there is enough onshore wind potential, considering both the total estimated potential and the value calculated based on our assumption of 10%.

As mentioned in the previous section, the GWEC study reports a fixed offshore wind potential of 439 GW and a floating potential of 1,361 GW, giving a total offshore potential of 1,800 GW. The national grid ESO system transformation scenario anticipates 105 GW of offshore by 2050, which is an order of magnitude smaller than the noted potential.

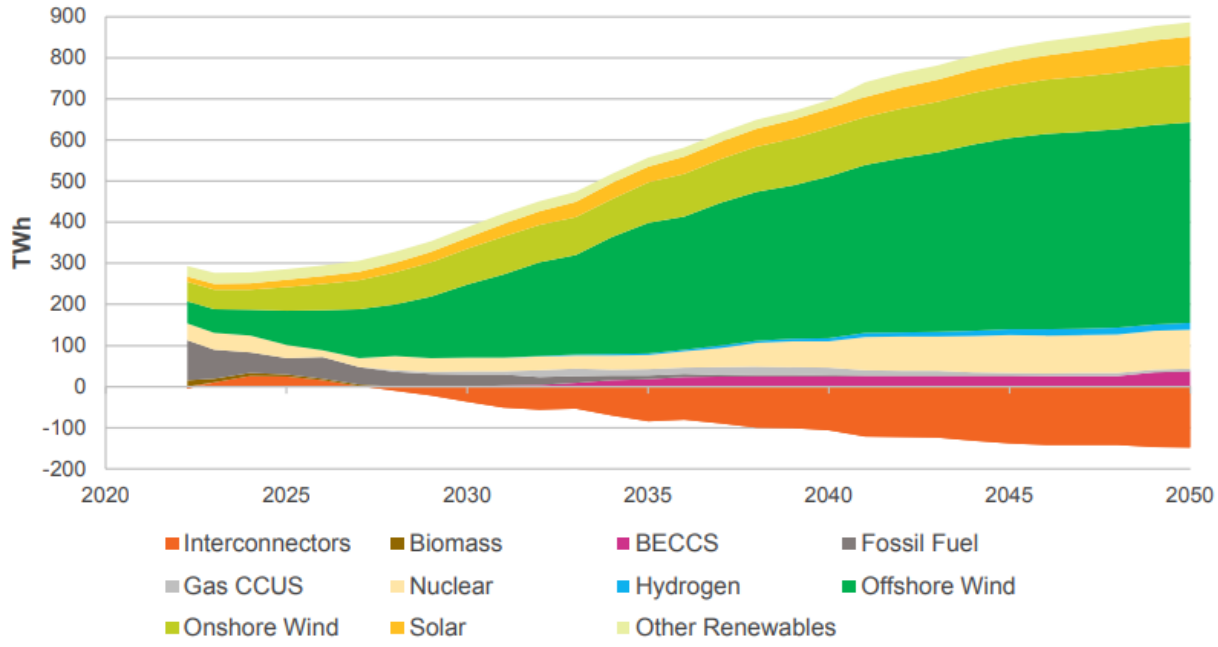
4.2 HYDROGEN PRODUCTION AMBITION

The Powering Up Britain[4] document showcases the Government's ambitions of utilising hydrogen to decarbonise harder-to-electrify areas like parts of industry and heavier transport such as aviation and shipping. The ambition is to have up to 10 GW of low-carbon hydrogen capacity by 2030. The yearly hydrogen production projections by the ESO national grid showcase 32 TWh of electrolytic production and 7 TWh from Carbon Capture and Storage (CCS)-enabled by 2030.

Renewable electricity is required for electrolytic hydrogen production. Regarding renewable electricity capacity addition, the government plans to develop up to 50 GW of offshore wind and double the onshore wind capacity by 2030, along with funding technological innovations in floating offshore wind and a manufacturing investment scheme to build UK port infrastructure to reduce the cost further. Also, Figure 16 shows that the major renewable energy capacity addition in the UK will be from onshore and offshore wind as per ESO National grid. This underscores the importance and contribution of wind-to-hydrogen projects to total green hydrogen production targets in the country.

[4] Powering Up Britain - GOV.UK (www.gov.uk)

Figure 16 UK electricity output by technology in Future Energy Scenarios by Electricity System Operator (ESO)



4.3 HYDROGEN PRODUCTION FROM WIND

The database of prospective wind-to-hydrogen projects created during the first task is used to estimate the total electrolyser capacity and the total hydrogen produced per year in 2030. All of the electrolyser capacity in the database is assumed to be optimised for the respective wind power plants with an overall system efficiency of 50 kWh/kg hydrogen. Wherever electrolyser capacity is unavailable, the optimised value is considered 10 % of the wind power nameplate capacity, as per the literature[5].

Three scenarios were developed based on the hydrogen production calculations for 2030. The methodology used categorises the projects first based on either pre-FEED or Front-End Engineering Design (FEED) and above. Then, factors are assigned for each, as shown in Table 4, to create low, base, and high hydrogen production scenarios.

Table 4 Methodology used for hydrogen production scenarios.

Methodology	Feasibility & concept stage	FEED & Construction
Low	30%	70%
Base	50%	80%
High	80%	90%

The final electrolyser capacity and annual hydrogen production from wind are calculated for each production scenario as summarised in Table 5.

[5] wes-9-281-2024.pdf (copernicus.org)

Table 5 Estimated hydrogen production scenarios 2030

Hydrogen production scenario 2030				
Parameters	**Unit**	**Low**	**Base**	**High**
Electrolyser capacity	GW	2.9	4.4	6.5
Hydrogen production per year	TWh	21	32	49

4.4 DEMAND PROJECTION

For quantifying the hydrogen demand in 2030, multiple sources from the literature are used as a reference, as shown in Table 6. As per the DNV Energy Transition Outlook UK 2024[6], demand for hydrogen is projected to be around 1 Mtonne per year (50 TWh) in 2030, with demand growing to 4.6 Mtonne per year in 2050. More than 50% will go into transport fuels, 22% into electricity generation, 14% into industrial heat, 8% into traditional refining and fertiliser production, and 2% for blending in heating. The UK Government's 10-point plan for the Green Industrial Revolution 2020 estimated that the hydrogen demand projection will be around 42 TWh by 2030, which was further updated in the UK hydrogen strategy[7] document to be around 38 TWh by 2030. With a demand of 10 to 21 TWh from industry, 0 to 10 TWh in power, 0 to 6 TWh in transport, and less than 1 TWh for building heat. The Hydrogen in the UK: Moving from Strategy to Delivery[8] documentation from Hydrogen UK estimates a hydrogen demand of 44 TWh by 2030, with the majority of consumption of around 26 TWh coming from the industry, 9 TWh into power, 6 TWh into domestic heating, and 1 TWh into transport. Further, Future Energy Scenarios by ESO estimates an annual hydrogen demand of 40 TWh.

The different sources in Table 6 calculate the hydrogen demands by simulating their UK's energy system model. The modelling approach used in calculating the hydrogen demand is based on assumptions about how hydrogen demand will change over the future years. This is conducted through sub-sector models, which inform the levels and profiles of hydrogen use in specific sectors of road transport, heat, industry, commercial, and residential end uses. The total hydrogen demand will be the sum of hydrogen demand projections from each end-use sector.

Table 6 Estimated hydrogen demand 2030, 2035, 2050

Demand Forecast	Unit	2030	2035	2050
DNV Energy transition outlook 2024[6]	TWh	50	105	225
Government 10 point plan[8]	TWh	42	*Not stated*	*Not stated*
Hydrogen in the UK: Moving from Strategy to Delivery[8]	TWh	44	*Not stated*	*Not stated*
National Grid - Future Energy Scenarios 2023[1]	TWh	40	151	*Not stated*
UK Hydrogen Strategy 2021[7]	TWh	38	110	242
Average	TWh	**43**	**122**	**234**

4.5 DEMAND – SUPPLY GAP

Based on the three hydrogen production scenarios for 2030 calculated from the database and the estimated hydrogen demand for 2030 from the literature, we can see how the demand-supply gap will look for each scenario, as summarised in Table 7.

[6] Energy Transition Outlook (DNV)
[7] UK Hydrogen Strategy (publishing.service.gov.uk)
[8] WG04 Storage Report (hydrogen-uk.org)

Table 7 Estimated demand-supply gap scenarios 2030

Parameter	Unit	Low	Base	High
Hydrogen production per year projection	TWh	21	32	49
Hydrogen demand projection	TWh	43	43	43
Demand-Supply Gap	TWh	22	11	-6

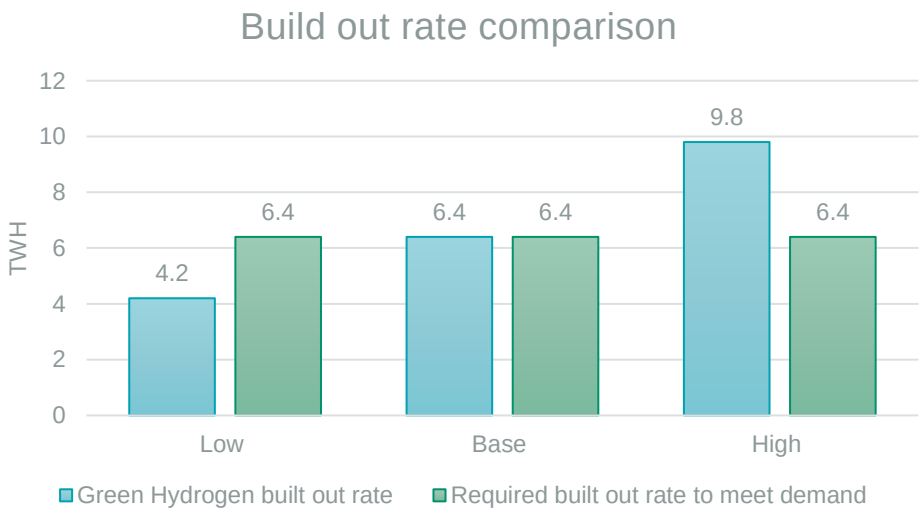
In both low and base cases, there is a supply shortage of 22 TWh and 11 TWh respectively, which could be supplemented by hydrogen from other sources, such as grey or blue hydrogen. Already established grey hydrogen infrastructure could be used for this, but the emission intensity will be higher.

In the high case, there is an excess hydrogen supply of 6 TWh with an export potential. However, it requires more elaborate large-scale storage, pipeline transportation, and export terminal infrastructure development, which are discussed in detail in the following sections.

4.6 BUILD-OUT RATE

Figure 17 compares the green, hydrogen build-out rate for the three-production scenario against the build-out rate required to meet the demand projections from the ESO national grid. The values are obtained by assuming that the projected hydrogen production is built out at the same rate across the years from 2025 to 2030. The same is assumed for the 32 TWh electrolytic green hydrogen demand projections from the ESO national grid in 2030.

Figure 17 Green hydrogen build out rate comparison for the three scenarios



The build-out rate calculated based on the wind-to-hydrogen production base case matches the build-out rate required to meet the green hydrogen demand in 2030. However, in the low case, there is a 2 TWh per year shortage, which needs to be compensated using blue/grey hydrogen or by importing green hydrogen. In the high case, there is a 3.4 TWh excess per year, which creates an opportunity for export.

5. ENABLING AND CONSTRAINING INFRASTRUCTURE

In order to successfully supply hydrogen and ensure effective utilisation, various supporting infrastructure needs to be in place. This section will discuss the state of the UK's infrastructure, as relates to hydrogen, and what progress is still required. The section with cover the following:

- Water availability and grid constraints
- Hydrogen pipelines
- Local and macro storage requirements
- Import and export terminals
- Supply chains for various technologies

5.1 WATER AVAILABILITY AND GRID INFRASTRUCTURE

Water and electricity are key inputs to electrolytic hydrogen and as such the infrastructure allowing the delivery of these inputs must be carefully planned to meet hydrogen demands. The following section explains the status of water availability in the UK and explains what measures need to be taken to support the development of wind-to-hydrogen projects. Further, the status of the grid is discussed and measures to manage any constraints are expanded on. Overall, this section gives a sense of where there will be quick wins for hydrogen production but also where further work is needed.

5.1.1 Water requirements for hydrogen in the UK

This section will discuss the water requirements for hydrogen production in the UK based on various scenarios. This analysis is based on work completed for a Ricardo-led Department of Energy Security and Net Zero (DESNZ) programme. Process water and cooling water requirements are considered as well as different sources of water. Different water sources require different water treatment processes, resulting in different amounts of losses prior to achieving the required water quality for process/cooling, see Appendix 2 for mass balance tables. The follow sub-sections will discuss this further as well as the geographical water constraints in the UK. Based on Ricardo's modelling, hydrogen water requirements were calculated assuming a mix of hydrogen ambitions for 2030 and 2035. Six baseline scenarios have been modelled:

Table 8 Modelled Hydrogen Production Scenarios

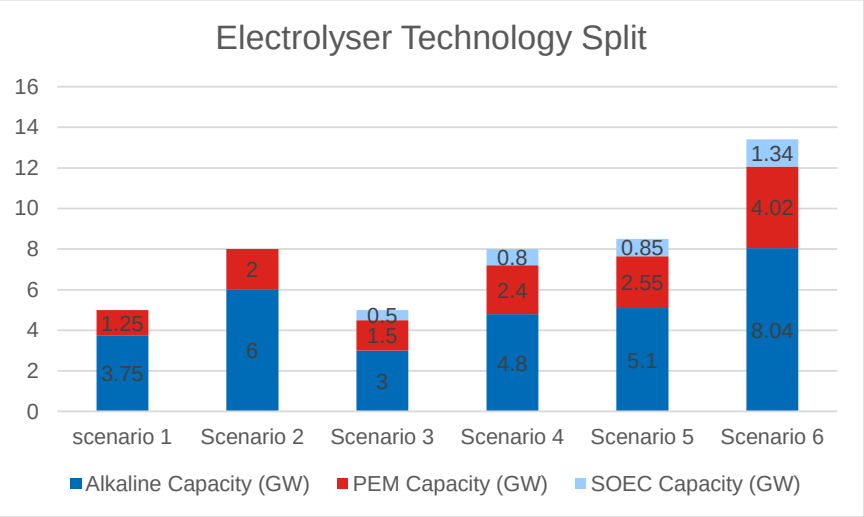
Scenario	1	2	3	4	5	6
Year	2030	2030	2035	2035	2035	2035
Green H_2 Capacity (GW)	5.0	8.0	5.0	8.0	8.5	13.6
Blue H_2 Capacity (GW)	5.0	2.0	5.0	2.0	8.5	3.4
Total H_2 Capacity (GW)	10.0	10.0	10.0	10.0	17.0	17.0

Scenarios 1, 2, 5 and 6 assume early adoption and build-out of hydrogen capacity, with use cases including industrial heat and potentially heating for homes. Scenarios 3 and 4 represent a steadier build-out through 2035 where use cases are more limited.

For simplicity, three electrolyser types are assumed to take 100% of the market share in 2030 and 2035, although it is acknowledged other types of electrolysers might emerge in the next decade. For 2030 a technology split of 75:25 has been assumed for alkaline:PEM. As SOEC is still undergoing development, its contribution is expected to increase through 2030 but remain marginal overall. By 2035 a technology spit of 60:30:10 has been assumed for alkaline:PEM:SOEC, roughly aligning with those predicted in the most recent 2023 Global Hydrogen Review [9]from the IEA

[9] Global Hydrogen Review 2023 (IEA)

Figure 18 Electrolyser technology split by scenario



Four raw water sources have been considered for each of the hydrogen production methods: potable, surface water, groundwater, and seawater. While the number of projects expected to draw from each of these is currently poorly defined, a representative split has been applied to understand the impact that hydrogen production might have on each source.

Table 9 Modelled raw water percentage split

	% Hydrogen generation utilising potable water	% Hydrogen generation utilising surface water	% Hydrogen generation utilising groundwater	% Hydrogen generation utilising seawater
2030	30	35	30	5
2035	15	35	30	20

A relatively even split is anticipated for 2030 as projects utilise water sources that are most readily available. As the use of seawater generally entails higher capital investment, this is eschewed. By 2035 however, a more developed technology landscape is expected to bring down hydrogen production costs, and this coupled with a better awareness of water resource management will see projects shift towards the use of seawater as a feedstock and cooling medium. It should be noted the numbers selected here are arbitrary as their purpose is simply to illustrate a potential demand scenario.

Based on the outlined assumptions, and given different process cooling methods, the following results are found for the six scenarios:

Table 10 Raw water demands for hydrogen production within the UK

Scenario	1	2	3	4	5	6
Evaporative cooling total water consumed (Mt)	42.3	45.5	43.5	46.5	73.9	78.0
Evaporative cooling fresh water consumed (Mt)	39.6	42.5	32.8	34.9	55.7	58.5
Evaporative cooling seawater consumed (Mt)	2.7	3.0	10.7	11.6	18.2	19.5

Scenario	1	2	3	4	5	6
Air cooling total water consumed (Mt)	14.5	15.6	16.5	17.9	28.1	30.2
Air cooling fresh water consumed (Mt)	13.2	14.2	11.3	12.2	19.1	20.4
Air cooling seawater consumed (Mt)	1.3	1.4	5.2	5.7	9.0	9.8

Figure 19 Evaporative cooling water demands by water source

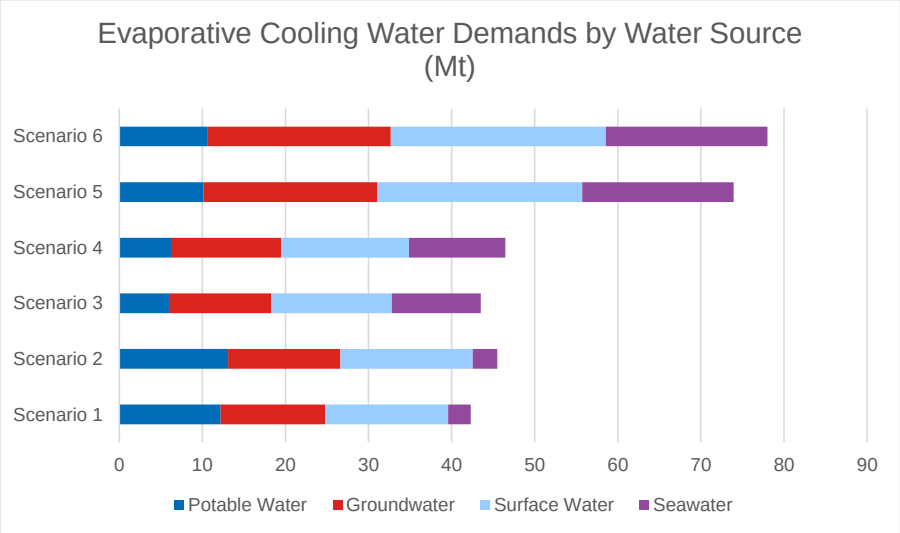
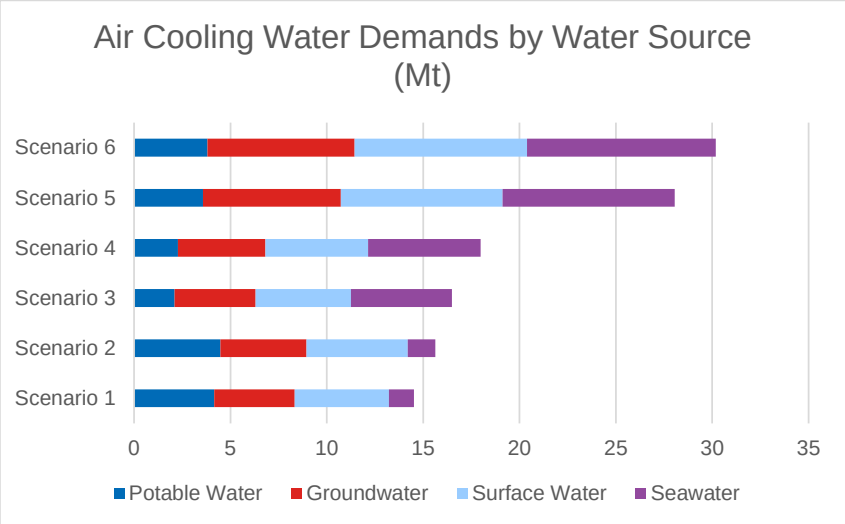


Figure 20 Air cooling water demands by water source



By these estimates the highest quantity of water abstraction occurs under scenario 6 evaporative cooling, in which 78 million tonnes of water would be required, 58.5 Mt from freshwater sources (potable water, groundwater and surface water) and 19.5 Mt from seawater.

Comparatively, the UK water industry treats approximately 5,600 million tonnes of water per year[10]. Table 11 details the annual available surface water and groundwater resources predicted for each nation within the UK in 2030 and 2035. It should be noted surface water estimates are inclusive of groundwater. The demand of 78 Mt per year represents 0.4% of the total annual groundwater available on the British mainland in 2035 and 0.1% of the total annual useable surface water on the mainland in 2035.

Water availability is subject to seasonal fluctuations, with the lowest availability in the summer months. The lowest reported quantity of groundwater is seen in Wales in 2035 at 100 Mt.

Table 11 Available surface water and groundwater resources within the UK

	Observed total river flow (NRFA data) (Mt*)	Useable surface water 2030 (Mt)	Useable surface water 2035 (Mt)	Estimated useable groundwater 2021 – 2030 (Mt)	Estimated useable groundwater 2026 – 2035 (Mt)
GB mainland	157,660	69,680	68,030	18,800	18,200
England	55,950	22,250	22,760	6,100	59,00
Wales	21,420	9,880	9,900	2,600	2,600
Scotland	82,260	36,530	35,350	10,200	9,700
Northern Ireland	9,630	5,620	5,480	*Not available*	*Not available*

*all flows were provided in km^3 however, for sake of comparison they are presented here on a mass basis, where the density of water has been taken as 1000 kg/m^3.

A large proportion of low-carbon hydrogen projects are focused in Scotland. During the summer months, Scotland is expected to have 36,530 Mt of surface water available. Even with expanding water demand from other industries, the use of water in hydrogen is marginal when compared to existing demand.

Table 12 details the water consumption of other industrial sectors. The chemicals sector usage might also be inclusive of grey hydrogen, which the UK currently produces approximately 700,000 tonnes of per year and will ultimately be displaced in the longer term. While water use of low-carbon hydrogen production is significant, it is relatively low at the planned scale.

The exact amount of water requirement for cooling in power generation was not publicly available, though sources did find that it is the largest licensed water abstractor. Five percent of the freshwater abstracted by the sector is used for thermal generation and 95% for hydropower[11]. However, the majority of this water is returned to the environment.

[10] Drinking water (Water UK)
[11] Water use and electricity generation (UK GOV)

Table 12 Water consumption by industrial sector in 2007[12]

Sector	Annual water use (Mt)
Food and drink processing	307
Chemicals	273
Electronics	241
Paper and board	155
Plastic and rubber	83
Textiles and leather	63

While water is abstracted in the production of hydrogen, the end use of hydrogen may reintroduce this water to the water cycle – burning hydrogen or its use in fuel cells will result in a balance of water being produced. Not all water will be returned in this way as some hydrogen might be used as chemical feedstock or exported.

Whilst the water demand for hydrogen production ranks low compared with other sectors, consideration must be given to the water system both as a whole and at a more local level, particularly in areas where water stress is a current or growing concern. Existing procedures, such as water abstraction licences, should be sufficient to manage water demand for hydrogen going forward.

5.1.2 Water constraints in the UK

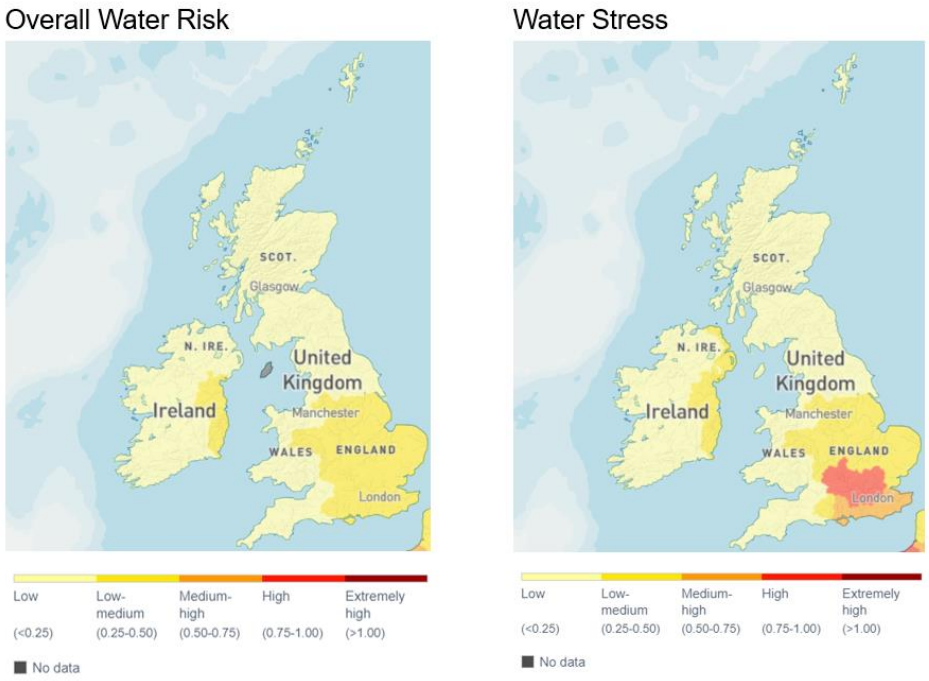
Various areas of the UK experience different levels of water risk, water stress, groundwater levels, drought risk, interannual variability as well as rainfall patterns. The following section aims to discuss this to highlight which areas may be most feasible for wind-to-hydrogen production.

From Figure 21 it can be seen that most of England has low-medium water risk whilst Wales, Northern Ireland and Scotland have low water risk [***Water risk*** *measures all water-related risks, by aggregating all selected indicators from the Physical Quantity, Quality and Regulatory & Reputational Risk categories*]. When considering water stress, [*Baseline* ***water stress*** *measures the ratio of total water demand to available renewable surface and groundwater supplies,*] the southeast of England experiences high/medium-high water stress, whilst the rest of the country's water stress is low-medium. Wales, Northern Ireland and Scotland experience low water stress.

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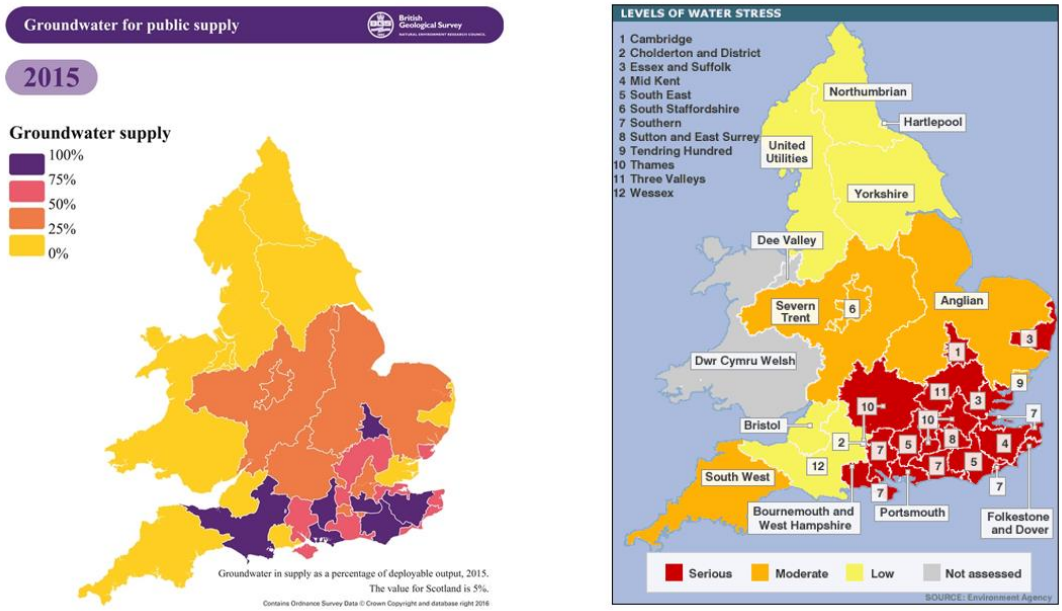
[12] Benchmarking Water Use in the UK Food and Drink Sector: Case Study of Three Water-Intensive Dairy Products | Water Conservation Science and Engineering (springer.com)

Figure 21 Water risk and water stress maps[13]



Based on water risk and water stress, it could be said that Wales, Northern Ireland and Scotland are most feasible to investigate for green hydrogen production. Further, the North of England shows potential too given low water risk and stress. Figure 22 below highlights key water stress regions in England.

Figure 22 Maps of public supply of groundwater and levels of water stress[14][15]

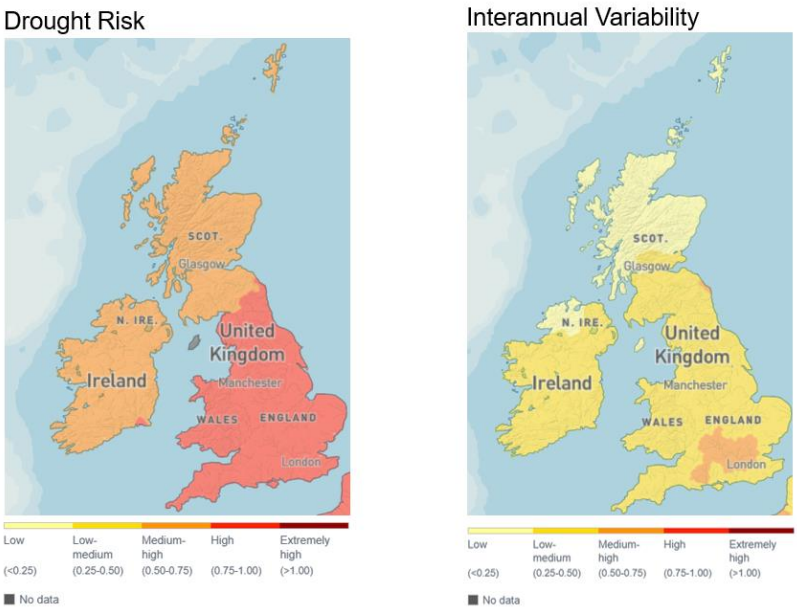


With regards to groundwater supply, Figure 22 shows that Scotland, Wales and the north of England are low in groundwater supply, with the southeast containing the largest supply. Although the supply is highest in this

[13] Aqueduct Water Risk Atlas (wri.org).
[14] Drinking water protected areas pressure 2021.pdf (environment-agency.gov.uk)
[15] Where are the areas of water deficit and surplus in the UK? (Internet Geography)

area it is important to keep in mind that this area has high population density, water risk and water stress. As such, the usage of groundwater for green hydrogen production may not be the most feasible pathway.

Figure 23 Drought risk and interannual variability map



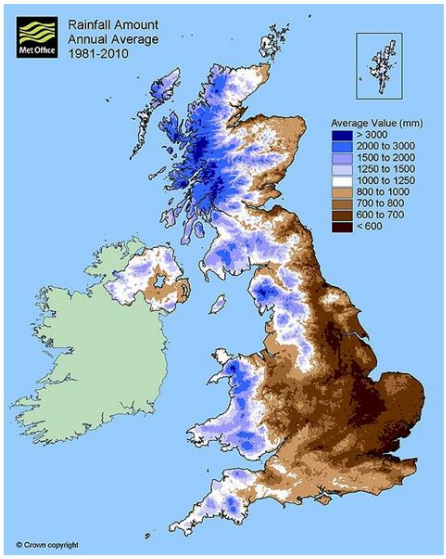
When considering drought risk, as per Figure 23, Northern Ireland and Scotland are at medium-high risk whilst England and Wales have high drought risk. This requires close monitoring to ensure that hydrogen production does not potentially exacerbate this risk. The expected variability in water supply, however, across the UK is not significant (except parts of the southeast).

Drought risk measures where droughts are likely to occur, the population and assets exposed, and the vulnerability of the population and assets to adverse effects. Interannual variability measures the average between year variability of available water supply, including both renewable surface and groundwater supplies.

Historically, most of the southeast has experienced lower average rainfall which alongside high population density goes someway in explaining the notable water stress and risk as well as drought risk in the region. In the future this water stress is not projected to get any better, as seen in Figure 24.

Figure 24 Expected water stress regions in 2030 and annual average rainfall[16]



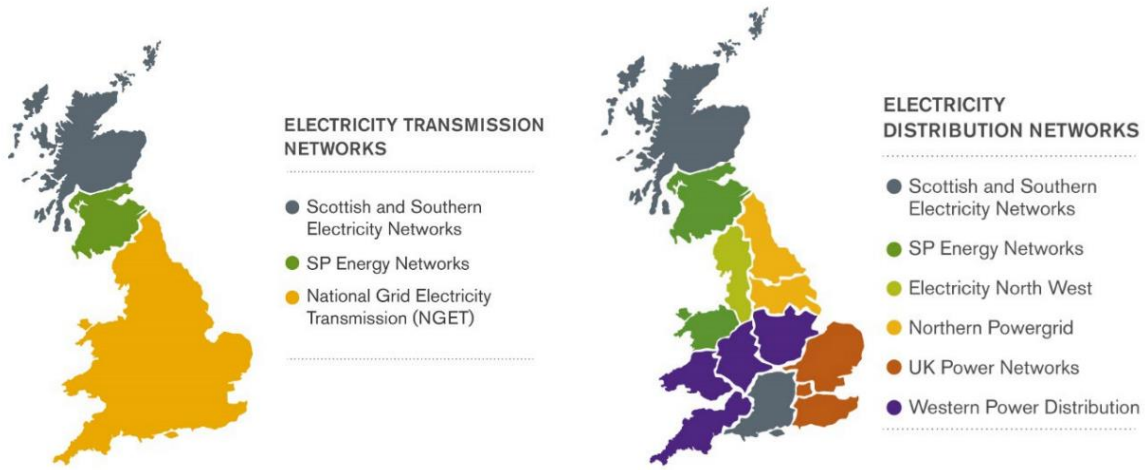


In summary, given the various factors discussed it is clear the majority of England, particularly the southeast, is not ideal for water abstraction to produce hydrogen. Other regions of the UK may be more feasible for freshwater abstraction as well as desalination by the coast or offshore. Existing and planned water schemes describe how flows of water from regions such as Wales and the north of England and Scotland can help balance water stress and demands[17] .

5.1.3 Geographical constraints for grid connectivity

With the increase of renewables penetration to the grid, and other devices like EVs, electrolysers and battery systems it is important to consider any constraints or bottlenecks that might exist in the transmission and distribution networks. In the UK, the transmissions and distribution areas are managed by various operators. Figure 25 below outlines the operators based on various regions.

Figure 25 Electricity Transmission and Distribution areas[18]



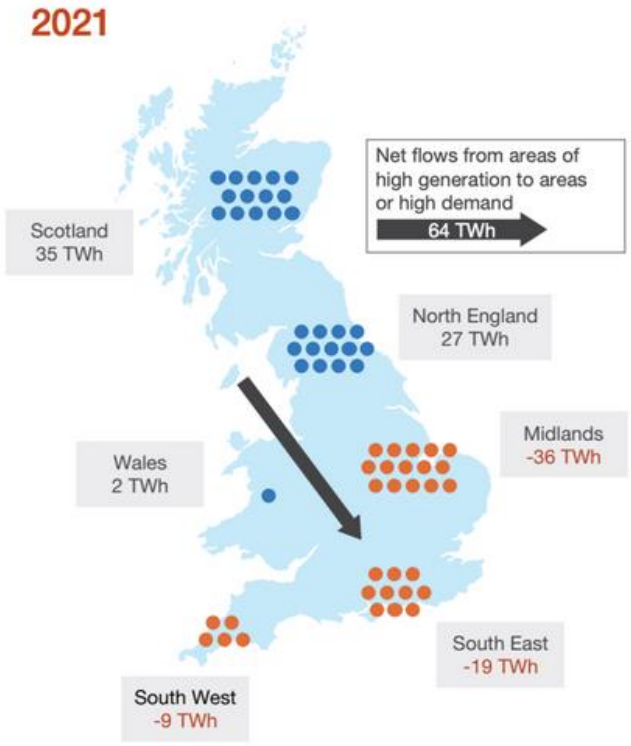
[16] Seven regions in England will face severe water stress by 2030 as Brits significantly underestimate their daily water usage (kingfisher.com)

[17] New water future flows from engineering's past (The Guardian)

[18] Electricity Networks Strategic Framework: Enabling a secure, net zero energy system (publishing.service.gov.uk)

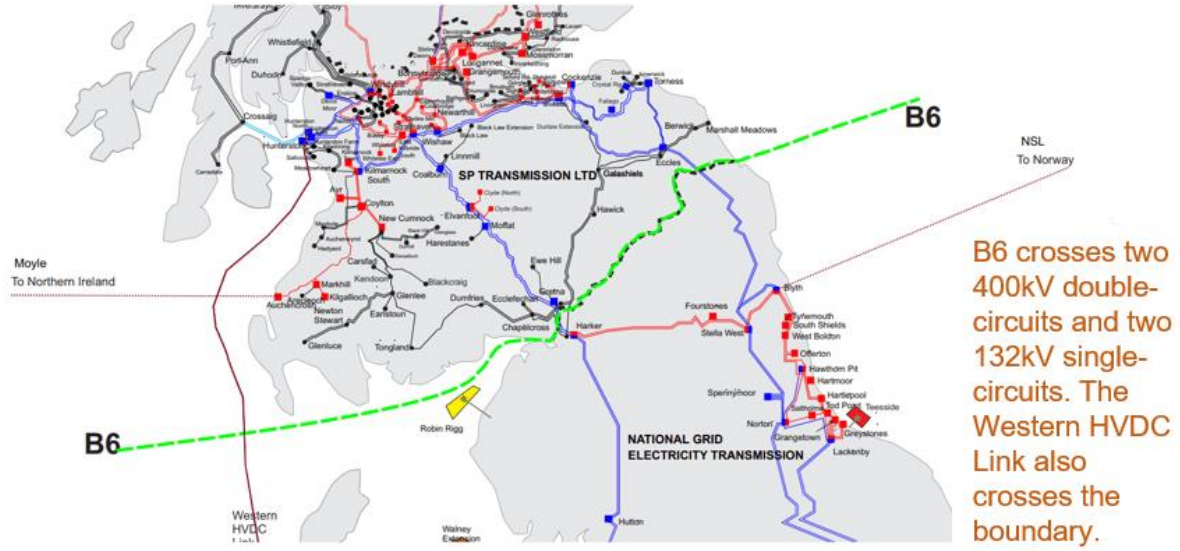
Due to a larger supply existing in the north of the UK, particularly Scotland, in the form of onshore and offshore wind, electricity is sent from the north to supply high demand centres in the south. Figure 26 describes this.

Figure 26 Description of electricity flows from the North to the South of the UK[19]



The reality is that the transport of electricity from north to south, with increasing demand in the south and increasing renewables supply in the north, results in grid bottlenecks and sometimes means renewable electricity must be curtailed. In particular, the border between Scotland and England (expressed as B6 in Figure 27) experiences significant bottlenecks as the transmission infrastructure cannot manage the increased flow of electricity over time.

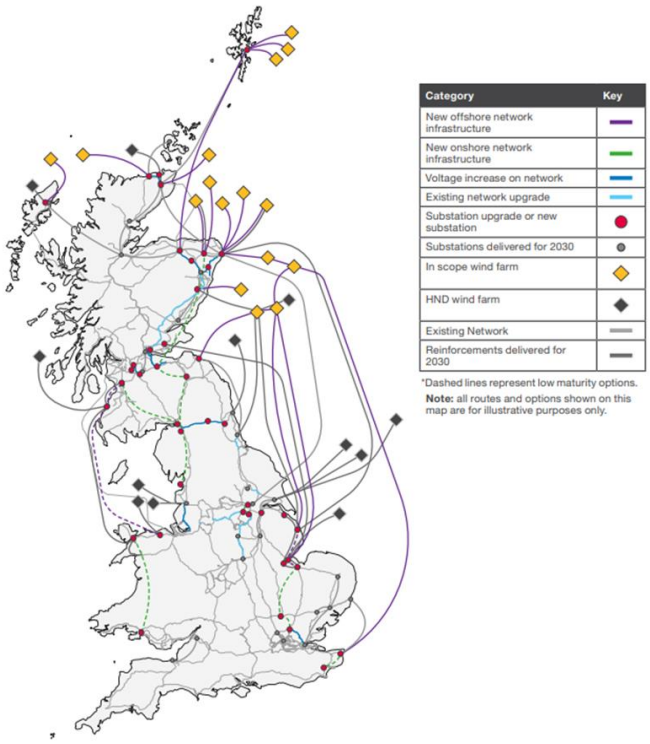
Figure 27 Map of North/South boundary and transmission bottleneck[20]



[19] Future Energy Scenarios (nationalgrideso.com)
[20] Scottish boundaries | ESO (nationalgrideso.com)

Local distribution constraints also exist, particularly in high-population centres such as Manchester, Birmingham and London. Each DNO, as per Figure 28, provides information on available network capacity within their region.

Figure 28 Future energy infrastructure required (2030 and beyond) to meet increased supply & demand[21]



To manage existing bottlenecks and plan for increased renewables supply accompanied by greater loads, it is essential for grid reinforcements to take place comprising of transmission developments (north to south) and distribution investment, including substations and undersea cables. Figure 28 is based on National Grid's perspective on the UK grid in 2030 and beyond, considering supply and demand aspects. This shows a potential connection between the north and south by means of subsea cables, an upgrade of B6 as well as substation upgrades and additions.

Electrolysers can also play a significant role in managing an evolving grid with greater renewables and storage options. The following are some ways in which electrolysers can help manage various constraints:

- Electrolysers can help manage curtailment by producing hydrogen during periods where supply surpasses demand, or the grid cannot manage the flow of electricity
- Producing hydrogen where there is high renewable resource for a demand point in a less resourced supply area allows for the transferring of molecules instead of electrons, reducing curtailment and grid congestion. This would be facilitated by pipelines from high renewables to low renewables (north to south)
- Areas with nearby demand and onshore or offshore renewables (i.e the coastline, high population density areas with a high solar radiance or possibility for other renewable electricity) but high grid congestion can use electrolysers directly connected to the renewables to reduce potential grid connection size whilst meeting local energy demand. This can be facilitated by tube trailers or pipeline

Overall, it would seem likely that renewables, particularly wind, will be largely located in northern parts of the UK and offshore, thus wind-to-hydrogen will likely be in these regions, with pipelines connecting demand centres. It would be wise to avoid grid connection in grid constrained areas which means islanded projects would be needed. Ultimately grid reinforcements are crucial to ensure the increase in electricity demand and supply in the UK going forward can be properly managed.

[21] Beyond 2030 (nationalgrideso.com)

5.2 HYDROGEN PIPELINES

Hydrogen pipelines enable the large-scale transport of hydrogen over long distances and the use of hydrogen as an energy carrier and storage vector. This allows hydrogen produced in one location with high renewable potential to be delivered to demand centres such as industrial clusters where there are space constraints or less renewable potential. Pipeline transport is considered the most cost-effective and efficient way to transport large volumes of hydrogen over long distances. The current length of hydrogen pipelines in the EU is approximately 1,500 km, with the majority situated in Belgium, the Netherlands, Germany, and France[22].

The UK's hydrogen pipeline network represents a crucial step towards achieving net zero. By connecting major production hubs and industrial zones, these pipelines can unlock economic opportunities and enhance energy security. Currently, the UK has several hydrogen pipeline projects in various early stages of development. Among the most advanced are the HyNet North West, Humber Hydrogen Pipelines, and East Coast Hydrogen Pipeline projects. Most of these projects are expected to be completed in phases, with the initial phase targeted for completion by 2025-2026.

This section identifies hydrogen pipeline projects within the UK using literature resources and research methods. We compile key publicly available metrics for each pipeline, including cost, diameter, hydrogen transport capacity, connected locations of origin and destination, envisioned completion date, and hydrogen source. We will further assess the pipelines' alignment with projects identified in Section 2, hydrogen hubs and industrial clusters to offer our perception of their feasibility. Additionally, we will evaluate the conversion of the natural gas grid, considering the strengths of proposals to switch and the feasibility of converting the entire system. Table 13 provides the list of major hydrogen pipeline projects within the UK and those connecting to locations outside the UK.

[22] Which countries are building hydrogen pipelines fastest? | World Economic Forum (weforum.org)

Table 13 List of hydrogen pipeline projects in the UK[23]

Projects	Developer	Estimated Cost[24]	Diameter (inch)	Length (km)	Hydrogen transported (GW)[25]	Hydrogen source	Connecting to/from	Stated Completion date
East Coast Hydrogen Pipeline	Cadent, Northern Gas Networks and National Gas Transmission	*(£672m)*	24	240	11[26]	Various hydrogen projects in the East Coast region	Humberside to Northampton	2026 Development of East Coast Cluster infrastructure
Humber Low Carbon Pipelines[27]	National Grid Ventures	*(£336m)*	24	120	0.72[28]	Possibly Humber blue hydrogen project at Uniper's Killingholme site	Drax power station in Selby to Easington on the Holderness coast	2026 Earliest construction completion date
HyNet North West Hydrogen Pipeline	Progressive Energy, Cadent, CF Fertilisers, Eni UK, Essar, Hanson, INOVYN (part of the INEOS Group) and the University of Chester	*(£350m)*	12 to 48	125	1[29]	Low carbon hydrogen produced by Vertex Hydrogen at the Stanlow Manufacturing Complex, or the Inovyn storage site	Network will be centred on the Stanlow Refinery at Ellesmere Port in Cheshire.	2025 First phase delivered
HyNet North West Hydrogen Pipeline Phase II	Same as above	*(£252m)*	12 to 48	90			There would be possible extension to stretch from North East Wales to Manchester and north of Liverpool.	Beyond 2025, further phases will be rolled

[23] Some fields are left blank in the table due to projects being in early development stages and lack of complete data.
[24] For pipeline projects where the cost is unavailable in public sources, a factor of £2.8M per km is used for estimating the capital expenditure. Ricardo factored costs are in brackets and italics for clarity. - European Hydrogen Backbone
[25] Hydrogen volume information for all pipeline projects is not available, as some are still in the early stages of development.
[26] Capacity of hydrogen projects including pre-planning, pre FEED, preparing for FID and operational projects within the East Coast region - East Coast Hydrogen Delivery Plan (East Coast Hydrogen)
[27] The Humber Low Carbon Pipelines project is part of the East Coast Cluster hydrogen pipeline network - National Grid announcement (nationalgrid.com)
[28] Assuming the low carbon hydrogen facility at Humber with a capacity of up to 720 MW will be the source of hydrogen - Humber H2ub® (Blue) Project (Uniper)
[29] Stanlow manufacturing complex will have 1 GW of blue hydrogen capacity - Billion-dollar 1GW blue hydrogen project planning approval (hydrogeninsight.com)

Projects	Developer	Estimated Cost[24]	Diameter (inch)	Length (km)	Hydrogen transported (GW)[25]	Hydrogen source	Connecting to/from	Stated Completion date
HyLine Cymru	Wales & West Utilities	*(£364m)*	12 to 32	130	1.06[30]	Hydrogen will be produced in and around Milford Haven Waterway	Pembroke to the Swansea Bay area	2025 First phase completion
UK Germany Pipeline under North Sea	International Collaboration[31]	£2,700m		644			UK to Germany (specific locations unknown)	Could be online by 2035
Project Union	National Grid Gas Transmission	*(£5,600m)*		2,000	10[32]		South Wales and Scotland clusters	2030 100% Hydrogen pipeline will be complete
Hydrogen Backbone Link		£2,700m						

[30] As per the report, this pipeline will help unlock at least 4.5 GW of offshore wind in the Celtic Sea by providing a route to market for clean energy producers. We assumed a wind capacity factor of 30%, hydrogen production efficiency of 55 kWh per kg and electrolyser operating capacity of 90% to convert wind energy to hydrogen production capacity - HyLine Cymru public report (wwutilities.co.uk)

[31] It is likely an international collaboration between relevant energy companies and government agencies. Information about its developer is not currently available in the public news.

[32] Project union will connect 2 GW of hydrogen production capacity by 2025 and 10 GW of hydrogen production capacity by 2030 - Project Union - Launch Report (nationalgas.com)

5.2.1 Assessment of hydrogen pipeline projects

5.2.1.1 Qualitative assessment of hydrogen pipelines

This section evaluates how well the pipeline projects align with hydrogen production projects found in Section 2, such as hydrogen hubs and industrial clusters. We will assess their feasibility and necessity.

East Coast Hydrogen Pipeline

- The East Coast Hydrogen Pipeline is a large-scale, multi-phase project spanning 15 years, aiming to create a comprehensive hydrogen transportation network across the Humber, Teesside and surrounding industrial regions of northeast England.
- The project involves both repurposing existing natural gas pipelines and constructing new dedicated hydrogen pipelines.
- This pipeline will connect the hydrogen production hubs in the Humber and Teesside regions, and then expand further north, south, and west to serve other industrial clusters and demand centres[33].
- Pipeline infrastructure is crucial for connecting assets within clusters and also to the wider region. This will serve key demand centres in the Humber region, Teesside, Yorkshire and East Midlands.
- Humber Low Carbon Pipelines is also part of the East Coast Cluster. As seen in Section 2, SSE Thermal's Aldbrough Gas Storage facility is located near Hull. Additionally, Humber is also being developed as a hydrogen hub.

HyNet North West Hydrogen Pipeline

- HyNet North West Hydrogen Pipeline is a crucial piece of infrastructure that will enable the production and distribution of low-carbon hydrogen in the North West of England. It will safely transport low-carbon hydrogen produced by Vertex Hydrogen at the Stanlow Manufacturing Complex, or the Inovyn storage site, to various industrial customers.
- The pipeline can deliver clean hydrogen to industrial clusters in the Northwest region. The project will serve several upcoming projects in the Northwest region including Quill 2 and Cheshire green hydrogen.
- As per the publicly available data, Phase I will connect hydrogen production at Ellesmere Port area and underground hydrogen storage at Northwich. The pipeline passes through the area with the highest concentration of chemical production and advanced manufacturing in the UK.
- HyNet Phase II will connect key areas including Manchester Ship Canal, Liverpool and Wrexham area during a later phase of development.

HyLine Cymru

- HyLine Cymru announced by Wales and West Utilities will construct a new dedicated hydrogen pipeline to transport hydrogen away from Milford Haven into the middle of south Wales industrial cluster and link to the developing National Gas Transmission's Project Union[34].
- This pipeline infrastructure is essential for transporting hydrogen from production sites to hard-to-abate industries and eventually for blending into the gas grid for heating at homes and businesses. It will initially supply hydrogen to decarbonise major industrial clusters in south Wales, such as Port Talbot, Swansea, and Neath.
- It is designed to interconnect with the National Grid's Project Union, which aims to create a British hydrogen backbone capable of transporting 100% hydrogen across the country. This integration is necessary for a coordinated national hydrogen network.
- By providing hydrogen infrastructure, HyLine Cymru will unlock opportunities for south Wales to develop a hydrogen economy, attract investment, and create new jobs in areas like low-carbon manufacturing and renewable energy production.

[33] East Coast Hydrogen (energycentral.com)
[34] A plan for clean growth (south Wales industrial cluster)

North Sea Pipeline

- Germany and the UK are in talks over a 400-mile hydrogen pipeline under the North Sea. The idea under consideration includes a direct route between the two countries, or alternatively going via Norway.
- This partnership aims to underpin the international trade in hydrogen and accelerate the role of low-carbon hydrogen in both nations' energy mix, as both countries want to reach net zero by 2050.
- Though still in early development, this partnership has the potential to contribute to a sustainable energy future for both countries and beyond.

Project Union

- Project Union is a pioneering project led by National Grid Transmission to create a UK-wide "hydrogen backbone" capable of transporting 100% hydrogen. The project will involve both repurposing existing pipelines and constructing new infrastructure and will help transport hydrogen from production sites to end users.
- Project Union will enable the decarbonisation of heavy industry, such as steel, concrete, and glass manufacturers, by providing access to low-carbon hydrogen. The pipeline will connect various hydrogen hubs and clusters including, Teesside, Humberside, and Grangemouth, as well as strategic production sites such as St Fergus and Bacton.
- It is expected to drive around £300 million in annual Gross Value Added and support 3,100 jobs at peak construction. By connecting isolated hydrogen markets and production points, Project Union will create a level and fair playing field, boosting competition and system performance.

Hydrogen Backbone Link

- The Scottish government-funded Hydrogen Backbone Link (HBL) is focussing on the hydrogen transport infrastructure required to connect Scotland to Europe. Scotland has vast onshore and offshore renewable resources and has the ambition to become a net exporter of green energy by 2045.
- The project engages industry leaders such as Shetland Islands Council, EnQuest, Kellas Midstream, Crown Estate Scotland, Shell and other contributing members.
- The project positions Scotland as a leader in pan-European hydrogen infrastructure development. It will provide cost-effective transportation to the market for Scottish hydrogen producers. It will cost €3 per kg of hydrogen to the EU customer which includes the transport cost of €0.4 per kg of hydrogen.
- The project will ensure the security of supply by connecting Scotland to the European Hydrogen Backbone. It could support up to 300,000 jobs in Scotland by 2045 and enable Scotland to meet up to 10% of Europe's projected hydrogen import demand by the mid-2030s.

5.2.1.2 Qualitative assessment on the conversion of the natural gas grid

Gas companies recognise that diversifying their energy portfolio is essential for long-term energy security. Investing in hydrogen allows them to explore alternative energy sources and reduce dependence on fossil fuels. The hydrogen industry offers economic growth opportunities and by supporting hydrogen projects, gas companies can contribute to job creation and attract private investment. Repurposing existing natural gas pipelines for hydrogen transport and blending hydrogen with gas presents a compelling solution for gas companies. This can help leverage the already available infrastructure, reducing the need for costly new pipeline construction and can be implemented more quickly compared to building new pipelines. Successful repurposing may require extensive coordination between various stakeholders, including pipeline operators, hydrogen producers, and end-users.

This section explores the viability of repurposing existing natural gas pipelines for hydrogen transportation. It will discuss the work undertaken so far in this area, along with the economic and social drivers pushing for such a conversion. Gas companies can leverage their existing infrastructure and expertise to participate in the emerging hydrogen market. The global emphasis on achieving net-zero emissions and the growing use of hydrogen as a clean fuel source are driving companies like Scottish Gas Network (SGN) to get involved in hydrogen infrastructure development. Some specific examples of natural gas pipeline conversion projects are discussed next.

Local transmission system futures project by SGN

- SGN has received approval for a natural gas pipeline repurposing project from the regulator the Office of Gas and Electricity Markets (Ofgem)[35]. There will be a trial of 100% hydrogen gas on a pipeline length of 30 km.
- It runs from the Grangemouth refinery to Granton, on the outskirts of Edinburgh. The project involves testing the pipeline's compatibility with hydrogen and evaluating operational aspects like flow rates and leak detection. This could help to apply learning to other repurposing projects by SGN.

HyNet homes blending

- The HyNet Homes project is exploring the potential of blending hydrogen into the natural gas grid to power homes. The project, planned for completion by 2025, will involve a trial using both newly built hydrogen pipelines and converted existing natural gas pipelines.
- This collaborative effort between Cadent and the University of Western England focuses on the early technical development of a hydrogen village in Northwest England. The project benefits from the proximity of HyNet's hydrogen production units within the Stanlow oil refinery.
- This project will investigate high-level options for integrating hydrogen into the domestic gas network. It enables existing domestic appliances, such as hobs and boilers, to continue operating without any changes, making the transition to a cleaner energy source seamless for consumers.
- This crucial demonstration aims to showcase hydrogen's potential as a leading technology for decarbonising home heating.

Aberdeen Vision

- The Aberdeen Vision project is a pioneering initiative to blend hydrogen into the existing gas network in Aberdeen, Scotland. It is a collaborative initiative between SGN, National Grid, Det Norske Veritas and Germanischer Lloyd (DNV GL), and Pale Blue Dot Energy.
- A dedicated pipeline from St Fergus to Aberdeen would enable the phased transfer of the Aberdeen regional gas distribution system to 20% then 100% hydrogen. It could deliver CO_2 savings of 1.5 Mt CO_2 per year compared with natural gas.
- The Aberdeen Vision project will play a crucial role in evaluating the feasibility of blending hydrogen within the existing gas grid. Due to unique regional attributes, the Aberdeen region could lead the UK in the conversion to large-scale clean hydrogen.
- The Acorn Hydrogen project, currently under development and targeting a 200 MW auto thermal reformer, is a potential hydrogen supply source for the Aberdeen Vision project.

Ineos Hydrogen Trial in Scotland

- Ineos has started a trial to transport hydrogen into the gas grid via a decommissioned pipeline in Scotland. The chemicals giant has teamed up with SGN for the scheme, which aims to determine how the existing natural gas network can be repurposed for hydrogen.
- Funded by Ofgem and gas distribution companies, the trial will use an 18-mile decommissioned pipeline between Ineos Grangemouth and Granton. The trial is ultimately aimed at improving understanding of existing pipeline networks and their suitability to deliver hydrogen as a clean alternative to natural gas to homes and businesses.
- Ineos aims to create a hydrogen production, use, and export hub at its Grangemouth site[36]. The trial supports this vision by testing the distribution aspect and can facilitate the development of a regional hydrogen ecosystem.

[35] Project to repurpose natural gas pipelines to hydrogen gets green light from Ofgem | SGN Your gas. Our network.
[36] https://energydigital.com/renewable-energy/ineos-and-sgn-start-hydrogen-distribution-trial-in-scotland

5.3 LOCAL STORAGE REQUIREMENTS TO ENABLE WIND-HYDROGEN SYSTEMS

To quantify potential local hydrogen storage requirements, two off-grid case studies are considered, and the hydrogen storage sizing required for both cases is calculated in this section. The first case considered is for decarbonising breweries in the Scottish Highlands using hydrogen, and the second one is for islands. Based on the projected hydrogen demand in the respective cases, two storage archetypes are developed.

Case 1- HyLaddie Project[37]: The demonstration project assessed the possible replacement of the industry-size Medium Fuel Oil (MFO) boiler in the Bruichladdich distillery, located at the southwestern tip of the remote Hebridean Island of Islay, with Dynamic Combustion Chamber (DCC) technology, in which hydrogen fuel combusts under a vacuum at a stoichiometric ratio with oxygen. The distillery currently has a yearly demand of 13,285 MWh of MFO as fuel, requiring 9.577 GWh, which is equivalent to 525 kg per day of hydrogen to 100% replace it.

Case 2 - The Scottish island of Yell[38], the second largest of all the Shetland Islands, is used as a case for estimating the range of hydrogen demand on an island and proposing a suitable storage archetype size. The maritime sector accounts for £471 million of Shetland's economic output, so hydrogen demand for ferries and whitefish trawlers will be a primary demand driver. HGVs account for 8% of Shetland's fleet, accounting for 42% of fleet energy consumption; hydrogen can play a role in decarbonising it. The estimated annual hydrogen demand for the island, considering the three possible use cases of 9 HGVs, 15 whitefish trawlers, and 2 ferries, is calculated to be 2.63 GWh, which is equivalent to 216 kg per day of hydrogen.

5.3.1 Storage duration

On the hydrogen supply side, there is a possibility of downtime due to renewable energy's intermittent nature, and from an operation point of view, maintenance shutdowns can occur. On the demand side, off-taker time of use and requirements can vary based on the type of industry. Considering both the supply and demand constraints, a conservative two-day demand for hydrogen storage is considered for the micro storage sizing.

5.3.2 Micro storage technology

Compressed hydrogen storage[39] represents one of the most well-established ways to store gaseous hydrogen. The process involves compressing hydrogen gas to elevated pressures, usually ranging from 100 to 700 bar, to achieve a satisfactory energy density. Subsequently, the compressed hydrogen is stored in a specially designed hydrogen tank. There are five types of gas tanks suitable for both stationary and mobile applications for hydrogen storage:

Type 1 – This is the most common gas tank, which is a simple cylinder made of steel. Operating pressure is in the range of 200 to 300 bar, storage density typically[40] up to 15 grams per litre (at 200 bar) and is typically used in industrial applications.

Type 2 – An improvement over Type 1 tanks with additional fibreglass enforcement on the outside for higher stability and the ability to handle higher pressure. Operating pressure is in the range of 100 to 500 bar, storage density of typically 30 grams per litre (at 500 bar) and it is typically used in industrial applications.

Type 3 – Type 3 features an inner liner constructed from aluminium and is commonly employed in vehicles. It can store hydrogen up to 350 bar and has a storage density of typically up to 25 grams per litre.

Type 4 – An improvement over Type 3 with a plastic bladder inside to seal off the hydrogen. They can operate at a pressure of up to 875 bar, have a storage density of typically up to 40 grams per litre and are mainly used for passenger cars and heavy-duty vehicles.

Due to their simplicity and reliability, pressurised storage tanks are considered for the micro storage sizing for the two use cases, as they do not require any complex specialised equipment.

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[37] HyLaddie Phase 1 Feasbility Report (publishing.service.gov.uk)

[38] Case study completed by Ricardo

[39] Hydrogen Storage (Stargate Hydrogen)

[40] Volumetric density varies due to temperature and pressure non-linearly due to the compressibility factor of hydrogen

5.3.3 Micro storage sizing

Table 14 showcases the pressurised storage vessel dimensions and technical parameters for a Type 2 hydrogen storage tank, which is used for sizing the two use cases.

Table 14 Type 2 pressurised hydrogen storage tank technical specifications

Tank Parameters	Unit	Value
Tank diameter	m	0.23
Tank height	m	1.32
Empty weight	kg	52
Pressure	barg	150
Stored volume	m^3	7.08

Based on the estimated hydrogen demand for the two cases, the number of tanks required for two days of buffer storage is calculated for both cases. For the distillery case, the storage volume required is 94 m^3 at 150 barg pressure, which requires thirteen pressurised Type 2 storage tanks, as specified in Table 15. Whereas the island case requires a storage volume of 38.7 m^3 at 150 barg pressure, requiring six Type 2 pressurised hydrogen storage tanks.

Table 15 Pressurised micro storage archetype sizing

Parameters	Unit	Case 1 - HyLaddie	Case 2 - Island of Yell
Annual hydrogen demand	MWh	9,577	2,630
Annual hydrogen demand	kg	191,540	78,909
Daily hydrogen demand	kg	525	216
Storage requirement (2 days)	kg	1,050	432
Density (150 bar)	kg/m^3	11.2	11.2
Volume of hydrogen (150 bar)	m^3	94.1	38.8
Single tank storage volume (150 bar)	m^3	7.08	7.08
Number of tanks		13	6

5.4 MACRO STORAGE OPTIONS AND LOCATIONS

5.4.1 Introduction

Hydrogen storage is a key component in the development of hydrogen energy systems, enabling its use as a clean energy source on demand. There are a range of hydrogen storage technologies that are proven at scale, however, each comes with challenges. The UK is well positioned to take advantage of one of the most economically promising forms of hydrogen storage in geological storage, but the country will need to act decisively if it hopes to meet the potential 100 TWh of storage capacity that might be required by 2050.

5.4.2 Liquid hydrogen

Storage of hydrogen as a liquid is achieved by cooling hydrogen gas to temperatures at or below -252.8°C. This process, known as liquefaction, is energy-intensive requiring between 9 and 13 kWh/kg of hydrogen to achieve[41]. One kilogram of hydrogen contains approximately 33.3 kWh of energy, meaning roughly one-third of the energy is effectively 'lost' through liquefaction alone.

Once cooled and liquefied, the cryogenic hydrogen must be stored in thermally insulated containers to maintain the extremely low temperatures. Even with the best available insulation, heat ingress will still result in the continual production of boil-off gas from the liquid. This boil-off must be removed and/or reliquefied to avoid a pressure build-up over time within the storage tank[42].

Liquid hydrogen storage is best suited to larger quantities of hydrogen for two main reasons. With the smallest liquefaction plants (capacity of 6,000 kg/day) currently costing in advance of 50 million USD[43], the technology is only feasible at scale. Liquid storage tanks can then be designed to optimised surface area to volume ratios, which minimise heat ingress and thereby boil-off.

Storage of liquid hydrogen presents numerous challenges beyond costs, scale, and energy consumption. The typical safety issues associated with hydrogen of leaks and flammability persist, while the low temperatures require additional consideration and management. This extends from safety into operational challenges. Design of liquid hydrogen systems is unique in many ways when compared to more traditional liquefied gases, such as LPG or LNG. One such unique aspect is the conversion of hydrogen from ortho-hydrogen to para-hydrogen, which is a necessary step to minimise boil-off, but is more immediately energy intensive[44].

Despite its limitations and high costs, liquid hydrogen is being pursued as a long-distance hydrogen carrier. The gravimetric energy density is the highest of all fuels, being four times that of petrol/gasoline and double that of natural gas[45], which is particularly advantageous for weight-sensitive applications. However, hydrogen has a relatively low volumetric energy density which is due to its low mass density. The volumetric energy density of liquid hydrogen is limited to approximately 2.3 kWh/litre, which is about a quarter of the volumetric energy density of petrol/gasoline, or 2.5 times lower than LNG. As a consequence, use of hydrogen as an energy vector, when stored as a liquid, requires far larger storage volumes than other fuels. Volume-limitations are often more restrictive than weight-limitations – as an example, one LNG tanker ship could transport the same amount of energy as two and a half hydrogen tanker ships of the same size, which is before consideration is given to the extra engineering challenge presented by hydrogen such as the increased technology cost and higher rates of boil off.

The most prohibitive factor in the rollout of large scale, liquid hydrogen storage (i.e. GWh) is likely to be infrastructure. The liquefaction plants, storage capacities and transportation of liquid hydrogen is technically challenging and energy intensive. Currently the likelihood is that liquid hydrogen will play a niche role in the storage of hydrogen, being best suited for application at the scale of a large industrial site or for transport via ship or rail.

[41] Energy requirements for hydrogen gas compression and liquefaction (DOE)
[42] Energies | Free Full-Text | Modelling of Liquid Hydrogen Boil-Off (mdpi.com)
[43] DOE Hydrogen and Fuel Cells Program Record 19001: Current Status of Hydrogen Liquefaction Costs (energy.gov)
[44] Significance of ortho-para hydrogen conversion in the performance of hydrogen liquefaction process - ScienceDirect
[45] Alternative Fuels Data Center: Fuel Properties Comparison (energy.gov)

5.4.3 Salt caverns

Salt caverns are underground structures that can be used for the storage of hydrogen. The safety and efficiency of hydrogen storage in salt caverns have been proven in several locations globally[46]. To create such a cavern, it is first necessary to drill down into the salt strata. The second stage consists of injecting water into the salt to dissolve it, a process known as solution mining. The resulting brine (water mixed with salt) is extracted and leaves room for a large, tight cavern where hydrogen can be stored under pressure[47,48]. This process can take between 2 to 5 years and costs around $10 to $25 million per cavern, depending on the size of the cavern and the depth at which they are to be seeded[49].

Once the cavern is created, a compressor/let-down system at the surface allows hydrogen to be injected into the cavern to be stored at pressure, then extracted and used when needed. The energy required for this process is relatively low compared to other storage methods[50], such as liquefaction, with the opportunity for energy recovery when the gas is depressurised during extraction, however, there remains an overall low round-trip efficiency. Typically, the deeper the cavern the higher the operating pressure and the cavern temperature.

Naturally, the main advantage of salt caverns is their large storage capacity. A single cavern can easily store between 200,000 and 500,000 MWh of energy[51], making them suitable for large-scale, long-term storage. No other storage type approaches their energy storage which is of a scale that can enable energy security and long-term smoothing required to meet nation-scale demand and inter-seasonal storage. The conditions in salt caverns have the added advantage of maintaining the purity of the hydrogen, as the salt walls are impermeable to gas, though the gas would require drying as the caverns remain wet.

Despite their potential, there remain several challenges associated with salt cavern storage. In particular, the creation of the caverns first requires suitable salt deposits, which by their nature are geographically constrained, limiting the applicability of this technology. There are also safety concerns related to the risk of cavern collapse or gas leakage, though these risks can generally be managed with appropriate monitoring and maintenance[52]. When creating caverns consideration must be given of what to do with the excess salt from the brine created; the discharge of concentrated brine is likely to cause significant hurdles for the permitting of any new facilities.

The UK is well positioned to take advantage of salt caverns for hydrogen storage in the UK. The country has a number of suitable salt deposits, particularly in the Cheshire and Teesside areas[53]. For instance, the UK's largest underground salt cavern hydrogen storage project is being planned at Portland Port in Dorset[54]. This project aims to provide up to 20% of the UK's predicted hydrogen storage needs in 2035. However, the geographical distribution of suitable salt deposits is uneven, and not all regions of the UK have access to such deposits. This means that the applicability of salt cavern storage may be geographically constrained. Alongside any storage, there is the need for a pipeline of network to the hydrogen production and demand regions.

The cost of salt cavern storage is largely dependent on the specific site and the scale of the operation. Current estimates suggest that the cost could be in the range of $0.10 to $0.50 per kg of hydrogen stored, but this could decrease with technological advancements and economies of scale[55,56].

[46] Storing Hydrogen in Underground Salt Caverns (Linde)
[47] Solution Mining and Salt Cavern Usage (SpringerLink)
[48] Home (solutionmining.org)
[49] Project Hysecure Phase 1 Summary (publishing.service.gov.uk)
[50] Perspectives and prospects of underground hydrogen storage and natural hydrogen (rsc.org)
[51] Techno-economic analysis of underground hydrogen storage in Europe (cell.com)
[52] Risk Assessment of the Large-Scale Hydrogen Storage in Salt Caverns (mdpi.com)
[53] Large-scale electricity storage (Royal Society)
[54] The UK's Largest Underground Salt Cavern Hydrogen Storage Project (UK Energy Storage)
[55] Long-duration H2 storage in solution-mined salt caverns (Gulf Energy Information)
[56] Hydrogen storage in caverns – "2035 is effectively tomorrow" (era.ac.uk)

Figure 29 Salt structures and cavern storage across Europe[57]

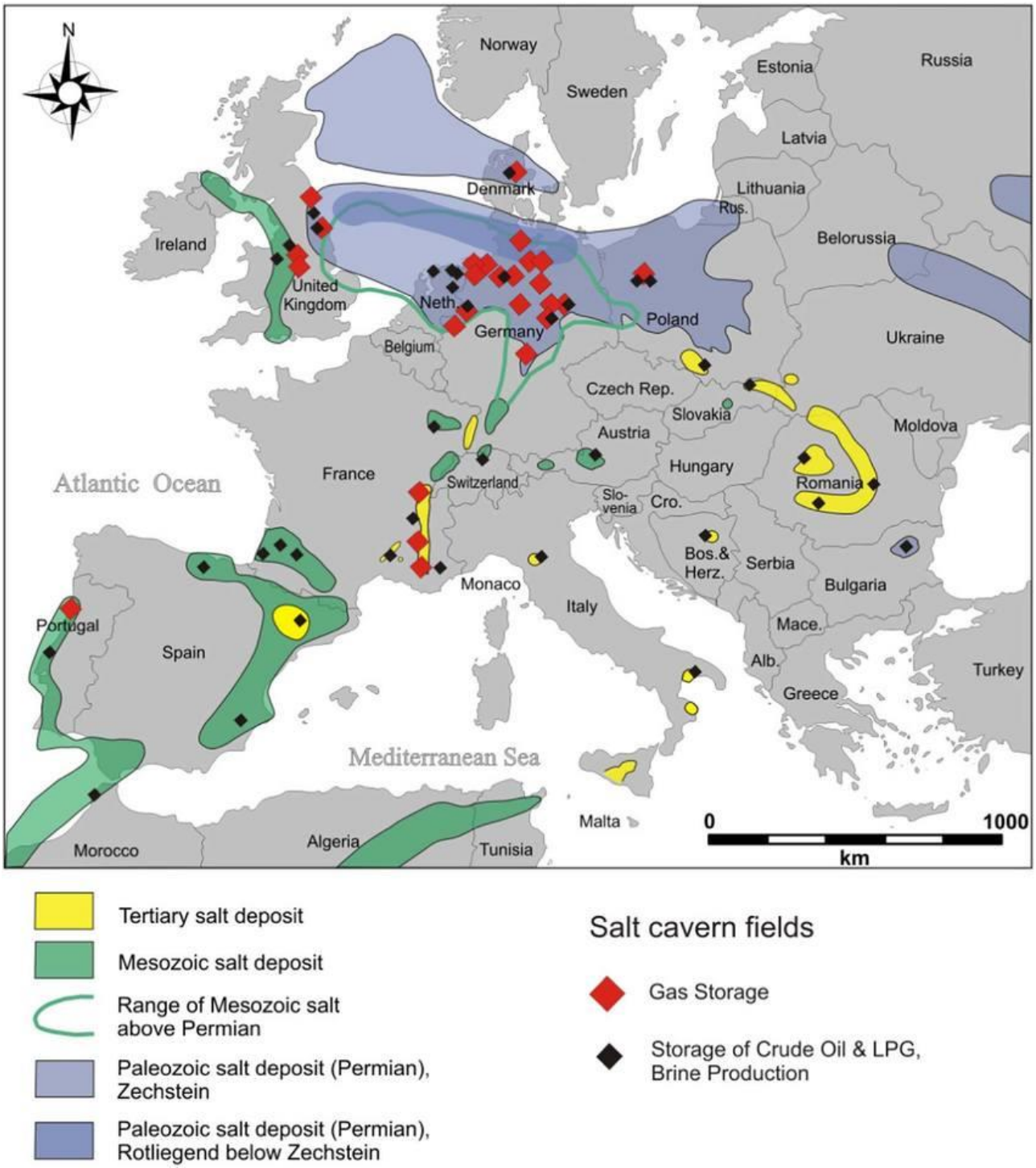
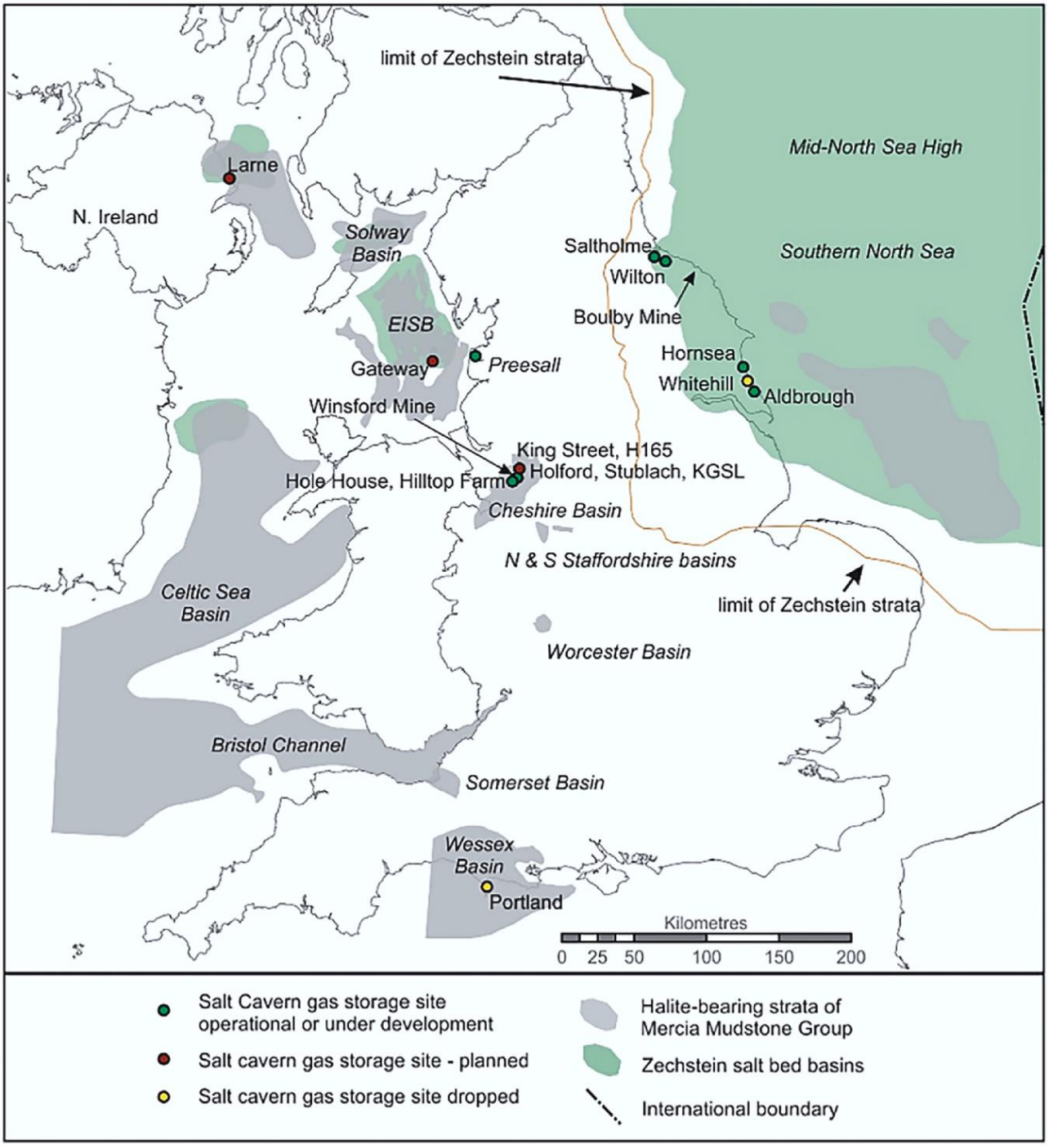


Figure 30 UK rock salt deposits distribution[58]



5.4.4 Depleted oil and gas reservoirs

Exhausted oil and gas reservoirs can with some work be repurposed for the storage of hydrogen. Similar to salt-caverns, these reservoirs can enable geological storage of hydrogen at a massive scale. The process of preparing the reservoirs for hydrogen storage varies depending on the specific site, but typically involves ensuring the integrity of the reservoir seal and the installation of appropriate infrastructure for hydrogen injection and extraction[59].

[57] A review at the role of storage in energy systems with a focus on Power to Gas and long-term storage (researchgate.net)
[58] Underground hydrogen storage: A UK perspective (ScienceDirect)
[59] Hydrogen Storage Assessment in Depleted Oil Reservoir and Saline Aquifer (mdpi.com)

Once the reservoir is prepared, hydrogen can be injected into the reservoir and stored under pressure. Similar to salt caverns, the energy required for this process is relatively low, relatively low compared to other storage methods[60], such as liquefaction, with the opportunity for energy recovery when the gas is letdown during extraction, however, there remains an overall low round-trip efficiency. The reservoirs would initially be a dilute mixture of hydrogen, natural gas and other residual gases, over time the concentration would increase but natural gas would remain as the cushion gas, and therefore hydrogen purification would be required when extracting the gas with care to ensure zero fugitive emissions from the facility.

One of the main advantages of depleted oil and gas reservoirs is their vast storage capacity. A single reservoir can store several billion cubic meters of hydrogen, making them suitable for nation-scale, long-term storage[61]. The conditions in these reservoirs can also help maintain the purity of the hydrogen, as the reservoir seal prevents gas leakage. At the same time there are concerns that if not properly cleared, the remnants of oil, natural gas, or seawater could contaminate the hydrogen[62], although further research is required to confirm the potential interplay of these substances within caverns at elevated temperatures and pressures.

Similar to salt caverns, there is also limited availability of suitable reservoirs. Not all regions have access to depleted oil and gas reservoirs, which can limit the applicability of this storage method. With its long history of oil and gas exploitation, the North Sea is unlikely to be subject to this constraint[63]. These reservoirs are well-characterised and have proven containment properties, making them potentially suitable for hydrogen storage, however their safety and efficiency in storing hydrogen is not as well established as in salt caverns.

The UK Hydrogen Storage Database, developed by the University of Edinburgh, highlights the hydrogen storage potential in geological formations across the UK, including depleted oil and gas fields[63]. However, the geographical distribution of these reservoirs is also uneven, and their suitability for hydrogen storage can vary depending on factors such as depth, pressure, and seal integrity.

The key advantage of depleted oil and gas reservoirs and other geological hydrogen storage is the quantity of hydrogen which they can effectively store. No other storage type approaches their energy storage which is of a scale that can enable energy-security and long-term (inter-seasonal) smoothing required to meet nation-scale demand.

The cost of reservoir storage is largely dependent on the specific site and the scale of the operation. Current estimates suggest that the cost could be in the range of $0.10 to $0.50 per kg of hydrogen stored, but this could decrease with technological advancements and economies of scale[64].

[60] Perspectives and prospects of underground hydrogen storage and natural hydrogen (Royal Society of Chemistry)
[61] Hydrogen storage in depleted gas fields: capacity and performance (University of Edinburgh)
[62] Sandia studies subterranean storage of hydrogen (Sandia National Labs)
[63] UK Hydrogen Storage Database (University of Edinburgh)
[64] Hydrogen Transport and Storage Cost Report (publishing.service.gov.uk)

Figure 31 Map of potential UK gas storage sites[58]

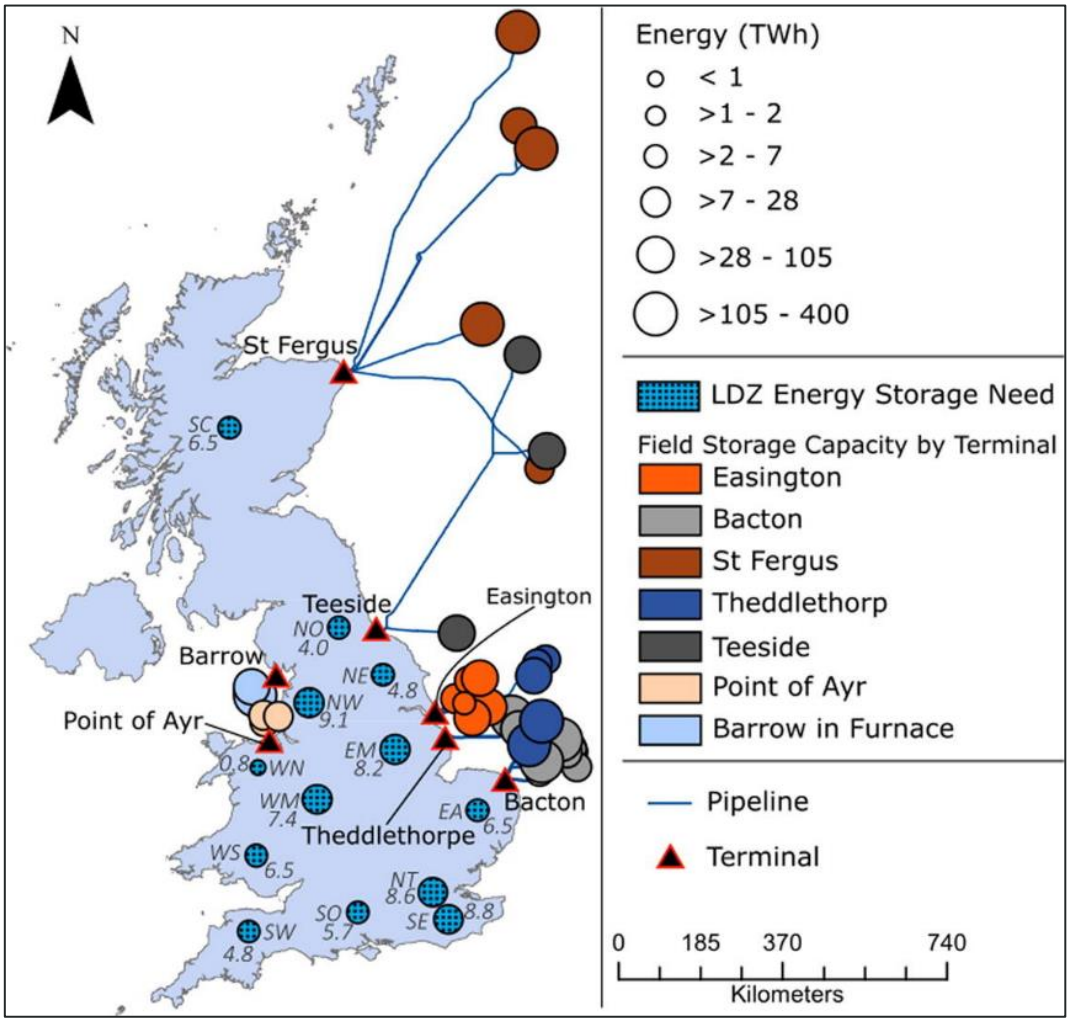
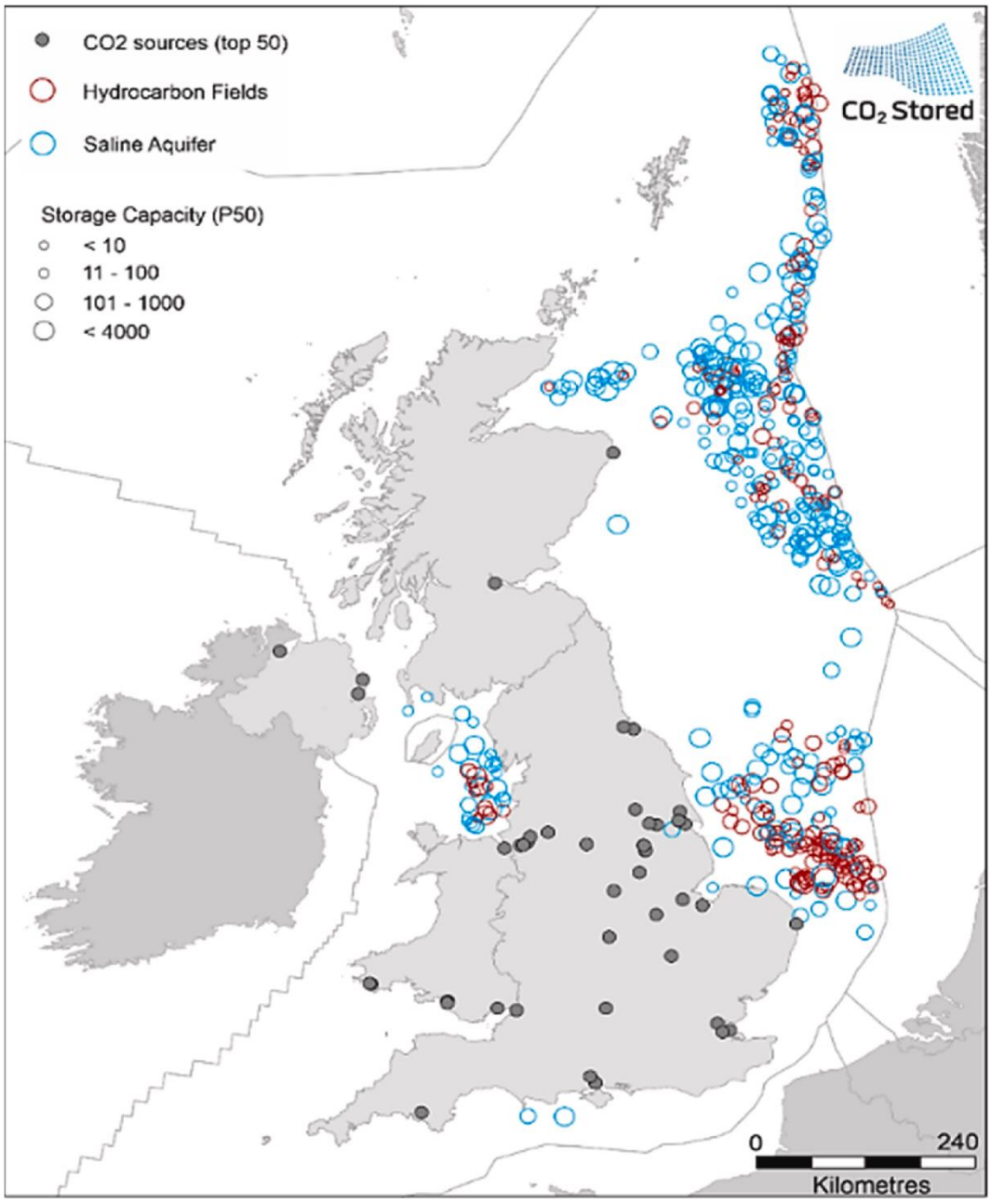


Figure 32 Map of UK saline aquifers and hydrocarbon reservoirs[58]



5.4.5 Ammonia

Ammonia is a compound of nitrogen and hydrogen that can be used as method of indirect hydrogen storage. The process of producing ammonia from hydrogen and nitrogen is known as the Haber-Bosch process, which is energy-intensive, requiring approximately 8 to 12 MWh per tonne of ammonia[65,66], although most of this energy is used in the production of hydrogen. This process is typically powered by natural gas, but there is increasing interest in using renewable energy sources to produce green ammonia.

Once produced, ammonia can be stored as a liquid, either at room temperature under relatively low pressure (around 10 barg), or at ambient pressure below -33.3°C[67]. This makes it easier to store and transport than hydrogen, as it does not require the extremely low temperatures or high pressures associated with liquid or gaseous hydrogen storage. The infrastructure for ammonia storage and global transportation is well-

[65] Ammonia: zero-carbon fertiliser, fuel and energy store (royalsociety.org)
[66] Round-trip Efficiency of Ammonia as a Renewable Energy Transportation Media (Ammonia Energy Association)
[67] Storage & Handling of Anhydrous Ammonia (Tanner Industries)

established, due to its widespread use in the fertiliser industry[68]. This includes large-scale storage tanks, pipelines, and tanker ships. In contrast to liquid hydrogen, ammonia storage is scalable and can be used for both small and large quantities of hydrogen and is relatively inexpensive.

However, there are several challenges associated with ammonia as a hydrogen storage vector. The process of converting ammonia back into hydrogen is complex and results in energy losses[69]. While ammonia is not typically regarded as flammable due to its very high ignition energy, there are safety concerns due to ammonia's toxicity and corrosiveness, and it requires careful handling and storage procedures.

Despite these challenges, ammonia has several advantages as a hydrogen carrier. It has a higher energy density than hydrogen, with about 3.2 kWh/litre, which is higher than liquid hydrogen although not quite comparable to diesel. However, it remains suitable for both long-distance transportation and weight-sensitive applications but larger storage volumes are required compared to other conventional fuels, which can be a limitation in some applications.

The cost of ammonia storage is largely dependent on the scale and the specific technology used. Current estimates suggest that the cost of an ammonia storage system could be in the range of $1 to $2 per kg of hydrogen stored, but this could decrease with technological advancements and economies of scale[70].

5.4.6 Liquid organic hydrogen carriers

Liquid organic hydrogen carriers (LOHCs) are organic compounds that can reversibly bind hydrogen, thereby allowing for the storage and release of hydrogen. They seek to balance hydrogen storage density, low levels of toxicity, ease of transport, and the ease through which hydrogen can be bound and extracted[71]. Similar to ammonia, they offer a method of indirect hydrogen storage, with the key difference being the method of binding and extracting the hydrogen.

The process of loading hydrogen onto the LOHC is known as hydrogenation, and it typically requires a catalyst and occurs at elevated temperatures and pressures. The hydrogenation step results in the liberation of energy from heat, somewhere in the region of 10 kWh per kg of hydrogen although this varies depending upon the carrier molecule[72]. Some typical LOHCs include toluene, methylcyclohexane and decalin.

Once the hydrogen is stored in the LOHC, it can be transported and stored under ambient conditions, which is a significant advantage over other forms of hydrogen storage. Many LOHCs exist as a liquid at room temperature and pressure, which allows for easy storage in conventional fuel tanks and transportation through existing infrastructure[73].

However, there are several challenges associated with LOHCs. The process of releasing the hydrogen from the LOHC, known as dehydrogenation, is energy-intensive, higher than the heat liberated in hydrogenation[72], and requires a catalyst. Integration of heat recovery from the hydrogenation stage will be a key enabler for the competitiveness of LOHCs as a hydrogen storage medium There are also concerns about the stability and recyclability of the LOHC, as well as the potential for toxic by-products[74].

Despite these challenges, LOHCs have several advantages as a hydrogen storage vector. They have a high gravimetric and volumetric energy density, comparable to that of fossil fuels. This makes them suitable for long-distance transportation and weight-sensitive applications.

The cost of LOHC storage is largely dependent on the specific LOHC used and the scale of the operation. Current estimates suggest that the cost could be in the range of $2 to $3 per kg of hydrogen stored, but this could decrease with technological advancements and economies of scale[70].

In the long-term it is expected that LOHCs alongside ammonia will allow for the most cost-effective storage and transport of hydrogen at medium to large scale, internationally. For use purely as a very large-scale storage medium, they are unlikely to be able to compete with the geological storage options.

[68] Ammonia transport and storage (International PtX Hub)
[69] Ammonia as a carbon-free hydrogen carrier for fuel cells: a perspective (RSC Publishing)
[70] Energy Technology Perspectives 2023 (iea.org)
[71] Development of Liquid Organic Hydrogen Carriers for Hydrogen Storage and Transport (mdpi.com)
[72] 4th ISFEH (hysafe.info)
[73] Techno-economic analysis of LOHCs in a defined process chain (RSC Publishing)
[74] Mobility and adsorption of liquid organic hydrogen carriers (LOHCs) in soils – environmental hazard perspective (RSC Publishing)

5.5 IMPORT AND EXPORT TERMINALS

Import and export terminals can play a crucial role in the transportation of hydrogen and hydrogen derivatives due to their existing infrastructure and capabilities. They are uniquely positioned to leverage their expertise and physical assets. This can help in the transition from fossil fuel supply chains to green fuels, capitalising on their existing capabilities. This can reduce the need for the development of entirely new infrastructure, which can be costly and time-consuming. One major challenge in the energy transition is the lack of adequate infrastructure. Repurposing existing terminals offers a promising solution.

Companies are betting that the UK will become a low-carbon hydrogen importer. If this is true, hydrogen carrier chemicals would need to be cracked into hydrogen. Alternatively in some industries hydrogen derivatives will be utilised as a fuel. This would significantly increase the need for existing terminals. In this section, we will examine the import and export potential of the existing oil terminals in the UK and perform a qualitative assessment based on factors like storage capacity and location of these terminals.

5.5.1 Terminals around the UK for fuel and chemicals

Oil terminals are crucial facilities for the import, export, storage, blending, transfer, and distribution of oil and petroleum products. There are a total of 112 oil terminals in the UK[75]. Many terminals are located strategically at coastal sites, while others act as inland storage facilities supporting various functions: supplying navy and airbases, facilitating ship offloading, serving as reserves for refineries, and enabling fuel distribution within cities. We have chosen terminals near the coast with large storage capacities and proximity to developing hydrogen infrastructure as ideal locations for future import or export operations. We excluded airport terminals, ports supporting navy operations, carrying out distribution within cities, meant to act as storage for oil refineries, being located inland, or being decommissioned. Table 16 shows the list of oil terminals along with the identified major infrastructure nearby.

Table 16 Identified oil terminals in the UK with proximity to major hydrogen projects and important infrastructure

Terminal	Location	Operator	Proximity to major infrastructure
Aberdeen	Aberdeen City	Certas Energy & Asco Oils	Aberdeen will be developed as a major hydrogen hub. It is a coastal terminal with storage.
Avonmouth	Bristol	Valero & Esso	Bristol airport trials by Acorn, hydrogen hub at port and storage available.
Belfast	Belfast	Exolum & Puma Energy	Coastal location with storage of 50 tanks with 65,216 m^3 and storage of 20 tanks with 155,000 m^3
Blyth	Northumberland	Geos Group	Coastal location with storage of 15,000 m^3
Canvey Island	Essex	Oikos Storage	Coastal location with storage
Dagenham	Greater London	Stolthaven Terminals	Coastal location (near River Thames) with storage
Finnart Ocean	Argyll and Bute	Petroineos Fuels	Oil depot on the eastern shore of Loch Long
Flotta oil terminal	Orkney Islands	Repsol Sinopecuk	The terminal is highlighted on the hydrogen backbone link map. It has upcoming projects such as BIG HIT, Flotta Hydrogen Hub (as seen in Section 2.2)
Grain	Kent	British Petroleum (BP)	The facility of ship offloading, and rail loading is available

[75] Oil terminals in the United Kingdom - Wikipedia

Terminal	Location	Operator	Proximity to major infrastructure
Grangemouth	Falkirk	Exolum (formerly Inter Terminals)	Stores a range of petroleum products with a total storage of 46 tanks with a capacity of 325,198 m^3
Grays	Thurrock	Exolum (formerly Inter Terminals)	Coastal location with storage of 51 tanks with 310,000 m^3 capacity
Great Yarmouth	Great Yarmouth	Asco Oils	Coastal location with storage of 35 tanks with 11,034 m^3 capacity
Humber	North Lincolnshire	Phillips 66	Humber is an important region due to the number of upcoming hydrogen projects. This terminal serves as a refinery.
Immingham	North Lincolnshire	Phillips 66	The terminal handles petroleum projects. Air Products have stated that Immingham will become a green ammonia import terminal
Kingsbury	Warwickshire	Essar Oil UK / Shell	Oil storage depot with storage of 14 tanks with 100,000 m^3 capacity
Kingston upon Hull	Kingston upon Hull	IBL Bulk liquids	Upcoming hydrogen projects around the region (see Section 2.2) and storage of 120 tanks with 34,500 m^3 capacity
Kinneil	Falkirk	Ineos	Can handle hydrogen carrier chemicals
Liverpool	Merseyside	World Fuel Services	Upcoming hydrogen projects around the region in Section 2.2 and storage of 29 tanks with 50,527 m^3 capacity
Milford Haven	Pembrokeshire	Puma Energy	Close to Green hydrogen project- West Wales by H2 Energy & Trafigure (see Section 2.2). It is also situated on the coast in Wales with storage of 55 tanks with 1,500,000 m^3 capacity
Nigg Bay	Highland	Repsol Sinopec	Nigg Bay is highlighted on the hydrogen backbone link
North Tees	Redcar and Cleveland	Navigator Terminals	Near the River Tees with storage 36 tanks with 850,000 m^3 capacity
Northampton	Northamptonshire	Essar Oil UK	It is connected to the UK Oil Pipeline enabling deliveries of gasoline and distillate products from both the Thames in the south and Stanlow in the north west refineries, via a spur line. It has storage of 8 tanks with 28,600 m^3 capacity.
Peterhead	Aberdeenshire	Asco Oils	62 tanks storage with 57,014m^3 capacity
Purfleet	Thurrock	ExxonMobil, Esso	Coastal location with storage
Riverside	Stockton on Tees	Exolum (formerly Inter Terminals)	Location is close to Teesside projects with storage of 22 tanks with 65,120 m^3 capacity
Runcorn	Cheshire	Inter Terminals	This location is important for Hydrogen Backbone link with storage of 4 tanks with 23,804 m^3 capacity
Seal Sands	Stockton on Tees	Exolum (formerly Inter Terminals)	Location is close to Teesside projects with storage of 116 tanks with 246,604 m^3 capacity

Terminal	Location	Operator	Proximity to major infrastructure
Shell Haven	Thurrock	Shell UK Oil Products Ltd	Ship offloading
Shoreham	Sussex	Local Fuel	Shoreham has hydrogen activities including Ricardo's test facility, Shoreham hydrogen hub.
Sullom Voe	Shetland	Enquest	Sullom Voe Terminal Green Hydrogen Project
Teesside oil terminal	Middlesbrough	ConocoPhillips	This is fed from Norpipe. It is also a major location for East Coast pipeline.
Tetney marine terminal	Lincolnshire	Phillips 66	Import terminal to the Phillips 66 Humber Refinery and is connected to the Monobuoy by a 36-inch pipeline; there is a 22-inch line from the terminal to the refinery. There are 10 large storage tanks available.
Thames	Thurrock	Navigator Terminals	Coastal location with storage of 86 tanks with 378,000 m^3 capacity
Thames Oil port	Essex	Greenergy / Shell	Ship offloading, storage, and tanker loading
Tranmere	Merseyside	Stanlow Terminals (formerly Essar Oil UK)	Coastal location with storage
Tyne	Tyne and Wear	Exolum (formerly Inter Terminals)	Near the River Tyne with 62 tank storage of 57,014 m3 available
West Thurrock	Thurrock	Navigator Terminals	Coastal location with storage of 86 tanks with 378,000 m^3 capacity

5.5.2 Qualitative assessment of the UK hydrogen terminals

The UK has significant ambitions to become a leader in low-carbon hydrogen production and develop a thriving hydrogen economy. Several major projects are underway to establish large-scale hydrogen production hubs and infrastructure. This section explores the potential gap between hydrogen demand and supply in the UK. We'll analyse how this gap will influence the development of import and export terminals, shaping the future of the UK's hydrogen infrastructure. Additionally, we'll provide a qualitative assessment of how this market might evolve, considering the potential role of hydrogen terminals in this process.

As seen in Section 0, there is a gap between the demand and the supply for all three scenarios: high, low and base. For low and base production scenario, demand exceeds the production projections whereas for high scenario, it is the opposite. Thus, it is hard to predict if the UK will be either a net importer or exporter of hydrogen depending on production size.

However, the demand for hydrogen within Europe is also expected to grow rapidly as countries transition towards net-zero emissions. A report by Arup highlights that the UK may need to initially import hydrogen from other European producers like Norway to meet its domestic demand before its production capacity ramps up[76].

In the longer term, the UK could leverage its advantageous geography with good renewable energy potential, and existing oil and gas infrastructure in form of export terminals and ports, to export hydrogen to Europe. The role the UK plays will likely evolve over time. In the near-to-medium term, it may be an importer of hydrogen while developing its domestic production capabilities. But in the long run, with strategic investments and

[76] The potential for exporting hydrogen from the UK (Arup)

infrastructure development, the UK is well-positioned to transition into a major exporter of low-carbon hydrogen to Europe.

This could provide economic benefits, support the UK's net zero goals, and contribute to the broader European hydrogen economy. Ultimately, the UK's future as an importer or exporter will depend on factors like domestic hydrogen demand, production costs, infrastructure readiness, and policy support.

5.6 TIMESCALES AND SUPPLY CHAINS

Globally, in 2022, wind electricity generation increased by a record 265 TWh, up 14% to 2100 TWh. To be on track with the International Energy Agency's (IEA) net zero emissions by 2050 scenarios, there is a need for 7,400 TWh of wind electricity generation by 2030[77]. As per the ESO national grid analysis, in 2022, the UK have a wind energy capacity of 27 GW with 100 TWh of wind electricity generation. By 2030, this generation capacity is projected to increase to 64 GW as per the system transition Future Energy Scenarios.

In the hydrogen generation part, in 2022, there were 130 MW capacity additions, with the total capacity leading up to an installed capacity of 690 MW. As per IEA, if all the projects under pipeline in 2022 are realised, the total capacity will reach 170 to 365 GW by 2030[78].

As per the calculation done in Section 3, there is a projected electrolyser capacity addition of 2.9 to 6.5 GW for wind-to-hydrogen projects by 2030 in the UK, based on the current pipeline of projects.

The high pipeline of projects as showcased above for both wind energy generation and green hydrogen generation puts into perspective whether the supply chain is ready for supplying and constructing infrastructure at this scale. The section below tries to navigate the challenges or constraints that the supply chain can introduce in realising the hydrogen from wind production targets.

5.7 WIND FARM SUPPLY CHAIN

Of the 900 GW of wind capacity developed in 2022 globally, 93% was in onshore wind farms, with the remaining 7% in offshore wind. In the coming years, offshore capacity addition is expected to be higher due to more countries developing or planning to develop their first offshore wind farms[77]. In the UK, onshore wind capacity is projected to increase from 13.6 GW to 23.0 GW and offshore wind capacity from 13.4 GW to 40.6 GW in 2030, based on the future energy scenarios.

Supply chain requirements for wind generation projects differ for both onshore and offshore projects. Offshore wind arguably faces more significant supply chain constraints due to the technology's comparatively nascent stage and challenging geographical constraints. Hence, we are considering the supply chain constraints separately for both onshore and offshore systems in the below sections.

5.7.1 Offshore wind supply chain

Main components as part of the offshore wind project supply chain are listed in Table 17.

Table 17 Offshore wind system supply chain components

Offshore wind system Components
Turbines and towers
Fixed and floating foundations
Array and export cables
Substations and converter stations
Foundation, turbine, and cable installation vessels
Ports

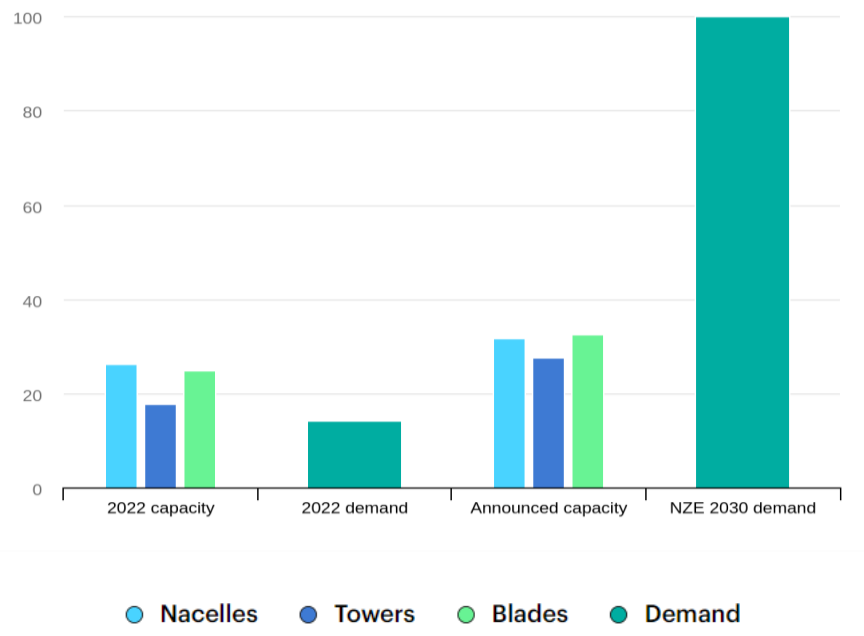
[77] Wind (IEA)

[78] Electrolysers - Energy System (IEA)

5.7.1.1 Offshore supply chain constraints

As per the IEA, in 2022, manufacturing capacity for main wind power system components like nacelles, towers and blades has remained the same without much growth from previous years at 110 to 120 GW[79]. Considering the long pipeline of projects where the capacity needs to more than triple by 2030, there is not enough manufacturing capacity for core components. This could lead to long lead times and cost constraints for many projects, especially smaller ones, as suppliers will give priority to larger orders from reliable suppliers. The 2022 offshore wind manufacturing capacity for offshore wind major components and their 2030 projection are shown in Figure 33.

Figure 33 Current and future nacelles, towers and blades manufacturing capacity for offshore wind[79]



Other possible constraints faced by offshore wind energy as per the literature review include[80]:

- Competition for components for UK offshore wind projects is high due to demand from other global wind projects, electricity networks, interconnectors, and oil and gas sectors.
- Wind turbine sizes are constantly increasing, which makes suppliers reluctant to invest in capacity addition for manufacturing and installation. The uncertainty further depends on the availability of a sufficient pipeline of committed, profitable customers.
- The monopile sizes are increasing in weight and length, and there is not enough manufacturing facilities to meet the demand. The current facility also needs to be revamped to handle larger monopile sizes.
- Only a limited number of steel mills globally can manufacture the heavy steel plates required for manufacturing wind turbines.
- In the case of the floating offshore supply chain, the existing manufacturing facilities are limited due to uncertainty in technology readiness regarding the different floating foundation types. There is also no secure order pipeline.

[79] Offshore wind power manufacturing capacity according to announced projects and in the Net Zero Scenario, 2022-2030 (IEA)

[80] UK renewables deployment supply chain readiness study - Executive summary for industry and policymakers (publishing.service.gov.uk)

- Offshore wind farm construction requires specific vessels for handling large turbines and foundations. Considering the project pipeline and increasing turbine sizes, there can be a shortage of vessels that can handle larger turbine sizes.
- Due to competition from interconnectors and offshore grid installations, there may be a shortage of cable installation vessels.
- Developers face significant design work even during the tendering process, and there are not enough engineers for design and commissioning. So, a qualified workforce could be a possible constraint for future projects.

5.7.2 Onshore wind supply chain

The main components as part of the onshore wind project supply chain are listed in Table 18.

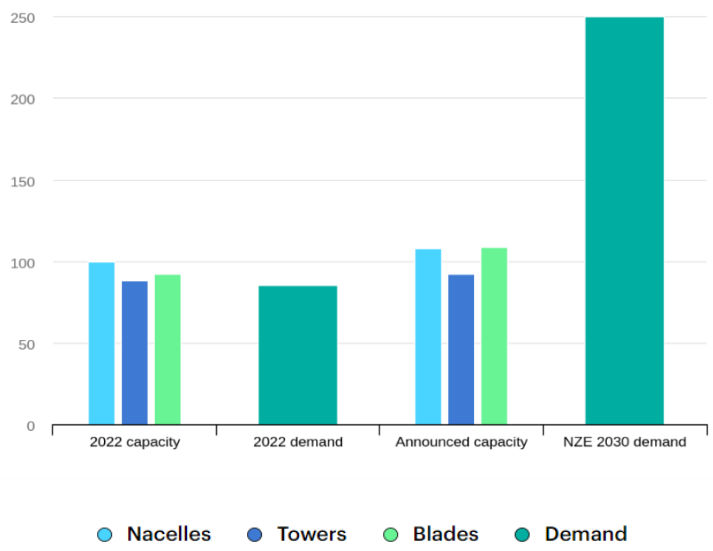
Table 18 Onshore wind system supply chain components

Onshore wind system Components
Turbines and towers
Foundations and civil works
Transport and installation
Balance of plant (transformers, switchgear, and SCADA systems)
Array and export cables.

5.7.2.1 Onshore supply chain constraint

The supply chain for onshore wind systems is much more mature than that for offshore energy systems. The figure showcases the available manufacturing capacity for nacelles, towers, and blades for onshore turbines in 2022. Even though the project capacity increase is not as steep as for offshore wind components, there is significant manufacturing capacity increase required to meet future demand, as shown in Figure 34.

Figure 34 Current and future nacelles, towers and blades manufacturing capacity for onshore wind[81]



The onshore wind supply chain has comparatively fewer constraints as the infrastructure is less complex as it does not require a complex foundation, specialised installation vessels, HVDC cables, or converter stations. Planning and grid permission constraints often overshadow the supply chain-related constraints for onshore

[81] Onshore wind power manufacturing capacity according to announced projects and in the Net Zero Scenario, 2022-2030 (IEA)

wind projects. The possible supply-chain constraints for onshore wind projects, as per the literature review includes[80]:

- Turbine manufacturers seeking are to reduce their product portfolio to improve their profitability. This has created uncertainty regarding the availability of Class 1A wind turbines required for the UK's challenging wind conditions.
- Growing cross industry demand is leading to an increase in lead times for various components, like transformers. As transformers represents single largest source of failure for wind turbines, less reliable products from outside the UK or the European Union are not preferred.
- Policy constraints regarding the requirement of a police escort for the transportation of large turbine components like towers, blades and nacelles, specifically in Scotland, could delay or lengthen project timelines.
- Increasing onshore wind turbine sizes could create a shortage of large cranes capable of handling the available load.

5.7.3 Grid component supply chain constraint

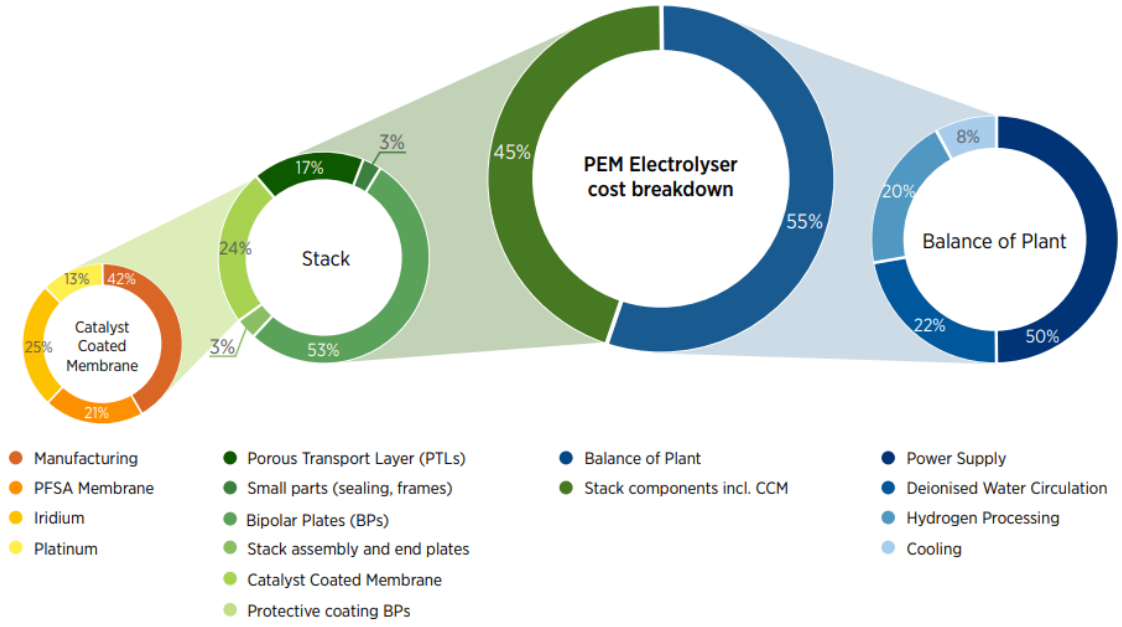
Both onshore and offshore wind farms require various grid-related power transmission components as part of their systems. Possible constraints faced related to grid-related components as per the literature review are discussed below[80]:

- Significant constraints exist around high-voltage direct current (HVDC) export cables due to a lack of capacity and high competition from offshore grids and interconnectors.
- Due to the unavailability of enough manufacturing facilities for transformers and converters, there can be long lead times on HVDC and high voltage alternating current (HVAC) stations.
- Competition from electric vehicle motors and Russian manufacturing being unavailable has caused constraints in procuring electrical steel used for manufacturing transformer cores.
- Lead times and costs for switchgears have increased due to the market moving away from the use of sulphur hexafluoride (SF_6), which is a greenhouse gas.

5.8 HYDROGEN SUPPLY CHAIN

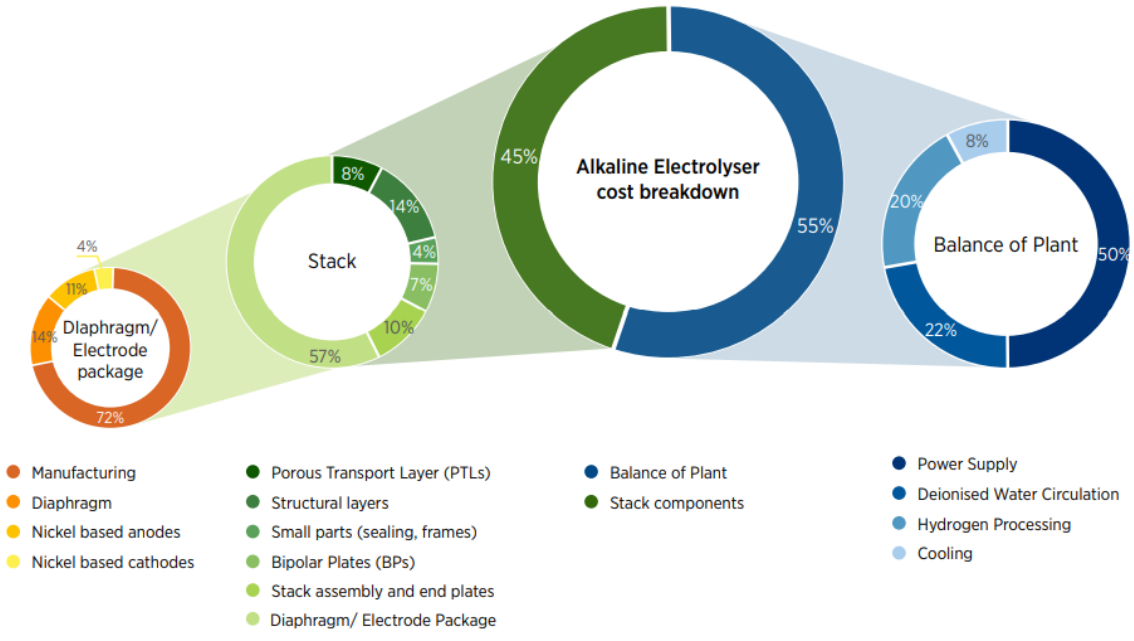
The supply chain for two of the most mature electrolyser technologies, PEM and alkaline electrolyser technologies, with similar TRL 9 level is considered in this section. In 2023, globally there are around 1,152 MW of alkaline electrolyser capacity, with PEM electrolyser closely following along at 921 MW. The components as part of the PEM electrolyser supply chain and their contribution to the total cost are visualised in Figure 35.

Figure 35 PEM electrolyser supply chain components and cost breakdown[82]



The components as part of the alkaline electrolyser supply chain and their contribution to the total cost is visualised in Figure 36.

Figure 36 Alkaline electrolyser supply chain components and cost breakdown[82]

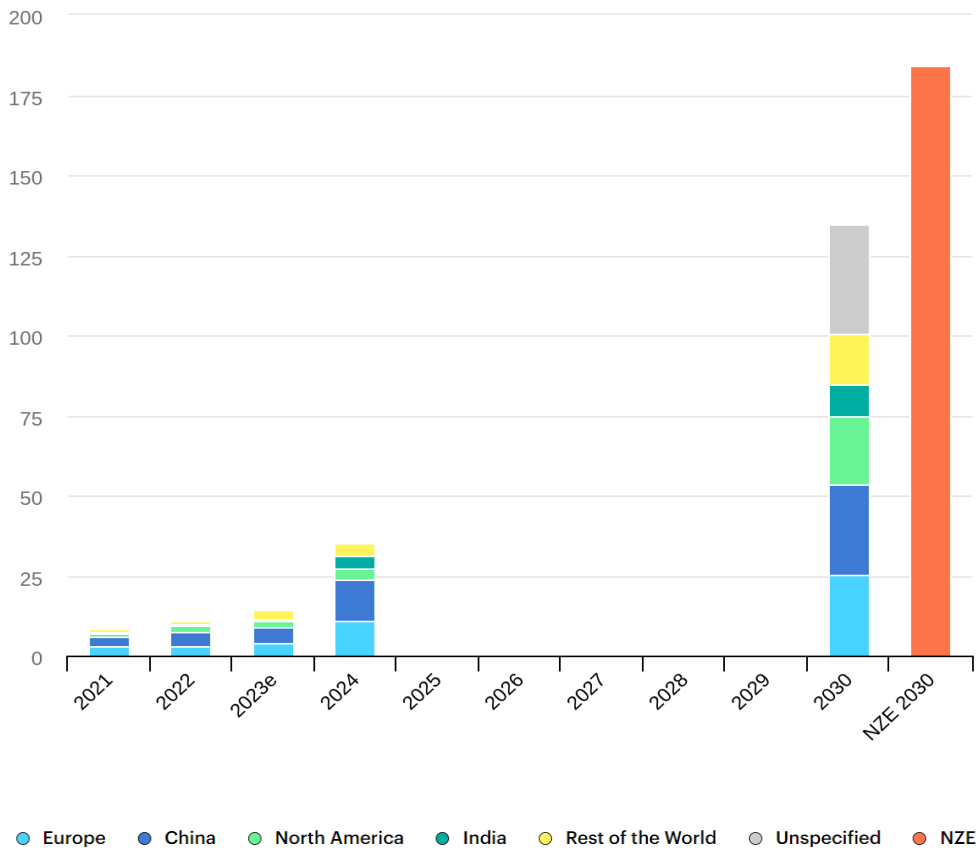


[82] Green hydrogen cost reduction (irena.org)

5.8.1 Hydrogen supply chain constraint

Electrolyser manufacturing capacity has been growing consistently in recent years. In 2022, electrolyser manufacturing capacity increased by more than 25% to reach nearly 11 GW per year worldwide. All the current projects in the pipeline will lead to an increased electrolyser capacity of 170 to 365 GW by 2030[7878]. Successful commissioning of the current pipeline of projects requires further capacity addition from the electrolyser manufacturing front. Figure 37 shows the current electrolyser manufacturing capacity in GW per year and the projected capacity requirement in 2030 by geography.

Figure 37 Current and projected electrolyser manufacturing capacity by geography[83]



Geographically, China leads in terms of manufacturing capacity, accounting for around 40% of global capacity today, along with the highest hydrogen production capacity addition[8383]. So, there is a risk regarding long lead times for procuring the electrolyser system if more capacity addition doesn't happen in the UK or nearby geographies. Other possible constraints affecting hydrogen infrastructure projects' supply chain as per the literature review include[848586]:

- Some of the rare metals used as materials in the electrolyser, such as platinum and iridium, have their supply chains concentrated in a few countries. This induces a high availability and price risk due to various geopolitical factors.
- Graphite is used to make electrodes in the electrolyser, which faces competition for supply from other industries like electric vehicles, braking linings, lubricants, steel making, etc.
- The green hydrogen industry is comparatively new, and there are insufficient codes and standards needed to safely build, maintain, and operate facilities and systems. This leads to overdesigning of components, which affects lead times and costs.

83 Announced electrolyser manufacturing capacity by region and manufacturing capacity needed in the Net Zero Scenario, 2021-2030 (IEA)

84 Existing Supply Chains, Capabilities and Growth - Assessment of electrolysers (www.gov.scot)

85 EERE Technical Report Template (energy.gov)

86 Supply Chains to Support a Hydrogen Economy (publishing.service.gov.uk)

- There are long lead times for procuring critical components for hydrogen projects, with the largest orders getting priority with suppliers. The long lead times for electrolyser packages could be due to challenges in scaling up manufacturing facilities. Items like compressors and storage vessels, although relatively better established, face high demand from competing industries. For some aspects, like boilers, burners, etc., lead times are increased due to delays in suppliers tailoring their existing technology for hydrogen applications.
- Being a new industry, there is a lack of skilled workforce in construction and design roles to commission the long pipeline of projects.
- Assessing the UK supplier's capabilities to supply the required components for hydrogen generation projects. Many typical items are currently used in other industries, like oil refining and power, for which UK suppliers have capabilities for. However, UK suppliers are not sufficient to support the expected growth requirements in some critical areas, like electrolyser packages, full range of high-grade pipe for hydrogen application, large capacity medium pressure compressors, CO_2 compressor packages for blue hydrogen, and high integrity valves.

6. DISCUSSION

This section serves to discuss the contents of this report and distil key findings and implications. This will be done by discussing the progress to meeting future hydrogen demands in the UK, the readiness of production and enabling infrastructure to meet this demand, recommendations to improve the likely success of the industry and lastly recommendations for further work in this area.

6.1 PROGRESS TO MEETING FUTURE DEMAND

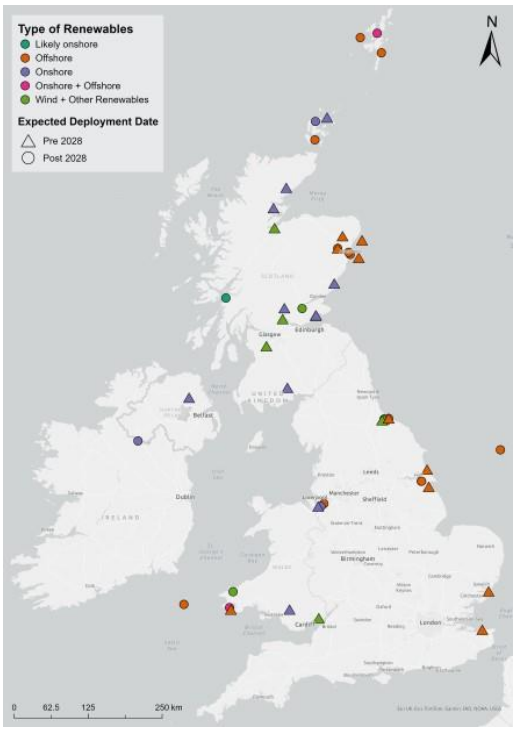
The baseline hydrogen production scenario based on the current wind-to-hydrogen projects in the pipeline aligns with the anticipated demand for green hydrogen in 2030. The current planned build-out rate of wind-to-hydrogen projects also meets the required level for covering the 2030 green hydrogen demand. However, many projects in the pipeline are in the early stages of development, and the final production level depends on how many of these projects reach financial closure and get constructed. Hydrogen being an emerging sector, one major factor influencing final investment decisions is the attractiveness and viability of the hydrogen business model. Further, the success of projects will depend on how fast the projected wind energy plants are built, renewable energy prices, and all related enabling infrastructure developments. Government policies and incentives in the near future could set the stage for all these factors to develop, thereby creating an attractive and viable business model propelling the achievement of these production targets. The progress made by 2030 will define whether further targets beyond this timescale will be feasible or not.

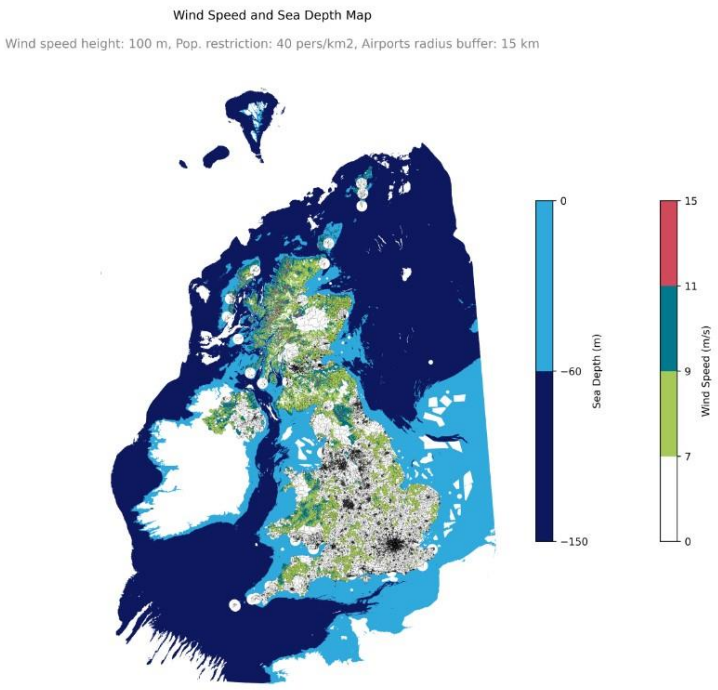
6.2 READINESS OF ENABLING INFRASTRUCTURE

Areas of Opportunity

From the analysis of ideal areas for wind-to-hydrogen development it is seen that Scotland has significant onshore potential. Parts of England in the north and southwest also show promising potential. Lastly, Wales and Northern Ireland also have the possibility to contribute through onshore wind production. Further, there is great potential for further offshore wind development, particularly in the form of floating wind.

Figure 38 Projects map and map of areas of opportunity





Water & Grid

When planning hydrogen projects, the water supply options will need careful consideration. There are locational aspects that affect this decision since it has been described how the majority of England, particularly the southeast, is not ideal for water abstraction to produce hydrogen. It seems that groundwater abstraction for hydrogen production will be unlikely given competing demands and availability. Other regions of the UK may be more feasible for freshwater abstraction as well as desalination by the coast or offshore. This said further local analysis of potential bottlenecks for abstracting different forms of raw water is needed to be certain about opportunities and barriers.

Besides water infrastructure, electricity infrastructure will also be crucial in creating a thriving hydrogen economy. The UK experiences significant grid constraints at a transmission and distribution level. In particular, there are bottlenecks in moving electricity from the north to south and getting a grid connection is notoriously difficult and takes a significantly long time (up to 10 years in parts of the north of England). Wind-to-hydrogen allows project developers to consider renewables for hydrogen production with the aim of later also exporting to the grid. It is true that on this basis if grid constraints lessen it might mean less encouragement to make hydrogen, which is an aspect that the evolving policy landscape needs to consider.

Hydrogen pipelines

The UK currently does not have an extensive operational hydrogen pipeline network. There are several upcoming hydrogen pipeline projects in development, such as the HyNet North West Hydrogen Pipeline. There is a limit to using tube trailers as a way to transport hydrogen as communities are often reluctant to having a significant increase in traffic in their area, and this may create a barrier to planning consent. Pipelines can go some way in solving this, particularly for large projects. Ideally, these pipeline projects should become operational at the same time as the ramp-up in hydrogen supply and demand. The hydrogen pipelines will also be essential in connecting production hubs with demand centres.

Import and export terminals

Existing oil import and export terminals in the UK will need to be repurposed to handle hydrogen and hydrogen derivatives. These repurposed terminals can play a crucial role in enabling the UK to both import hydrogen from neighbouring countries in the initial years when domestic production is lower, as well as export hydrogen as the UK's production size grows. Developing this import/export terminal infrastructure alongside the domestic pipeline network will be important for the UK to participate in the emerging global hydrogen trade.

Macro and micro storage

Macro and micro storage of hydrogen plays a vital role in enabling wind-to-hydrogen projects by tackling two main issues. The first issue is the mismatch between the time of use of off-takers and varying hydrogen production rates due to wind resource variability. The second issue is the requirement to import or export to meet the projected green hydrogen demand, as per our low and high hydrogen production scenario. Technology-wise, compressed hydrogen storage is the go-to option for micro storage cases. Whereas, geological storage options are better for macro storage, purely as a large-scale storage medium. LOHC and ammonia would be the most cost-effective options when considering storage and transport internationally.

Supply chains

The onshore wind supply chain is mature and has more problems related to planning and grid permissions than supply chain constraints. Whereas the offshore wind supply chain is still being consolidated, there needs to be more manufacturing capacity to meet the project pipeline, and the turbines are getting bigger and bigger, leading to uncertainty regarding capacity addition among suppliers. There could be long lead times to procure core components for smaller projects due to competition from larger offshore wind projects, electrical networks, interconnectors, and the oil & gas sector.

The electrolyser supply chain is relatively new and needs unified codes and standards. There needs to be a greater demand for green hydrogen for the suppliers to be confident of scaling up their manufacturing facilities so that economies of scale come into the picture. There is also the uncertainty and price risks due to the use of rare earth metals. In drafting future industrial strategy this all needs careful consideration.

6.3 KEY RECOMMENDATIONS

Given the various factors outlined in the discussion the following recommendations are made for ensuring the development of wind-to-hydrogen projects has the greatest likelihood of success:

- The expansion of onshore wind will be crucial as it has been demonstrated that there is potential to be harnessed. This would require a loosening of currently restrictive policies on onshore wind installations
- It will be crucial to ensure the projects in the pipeline (HAR1 & HAR2 particularly) make it to FID and begin to produce hydrogen, otherwise confidence in the industry will continue to decline. Various support mechanisms should be created to prioritise and manage the success of these projects
- It will be important for the grid reinforcement program to be rapidly accelerated and for the contribution of electrolysers to managing the grid, and related business models, to be properly set out to prevent unintended consequences
- A collaborative working group is required to ensure the entire value chain develops simultaneously (production, distribution and supply). This will require the breaking of silos between government institutions, companies operating legacy infrastructure, hydrogen developers and offtakers

6.4 SUGGESTIONS FOR FURTHER WORK

Building on the work of this study there are areas requiring further enquiry. From Ricardo's perspective, and through discussion with the Catapult, these include:

- Update ESO future energy scenario to the most up to date forecasts
- Further analysis of grid constraints & water availability in areas where potential has been highlighted
- Discussing the potential for micro-grids to circumvent grid constraints
- Studying current projects struggling to get off the ground or failed projects, to understand the key barriers and challenges and strategies to mitigate these
- Further work on unlocking onshore wind potential and how electrolysers fit into grid expansion policy considering business models to encourage hydrogen production and grid expansion simultaneously
- Extend project mapping beyond 2028 for long-term decarbonization
- Explore hydrogen deployment in West & East Midlands for alternative applications (eg. transport)
- Assess impact of sea depth exclusion update to 250m for floating wind
- Include financial data like CAPEX and commercial arrangements to project mapping

APPENDICES

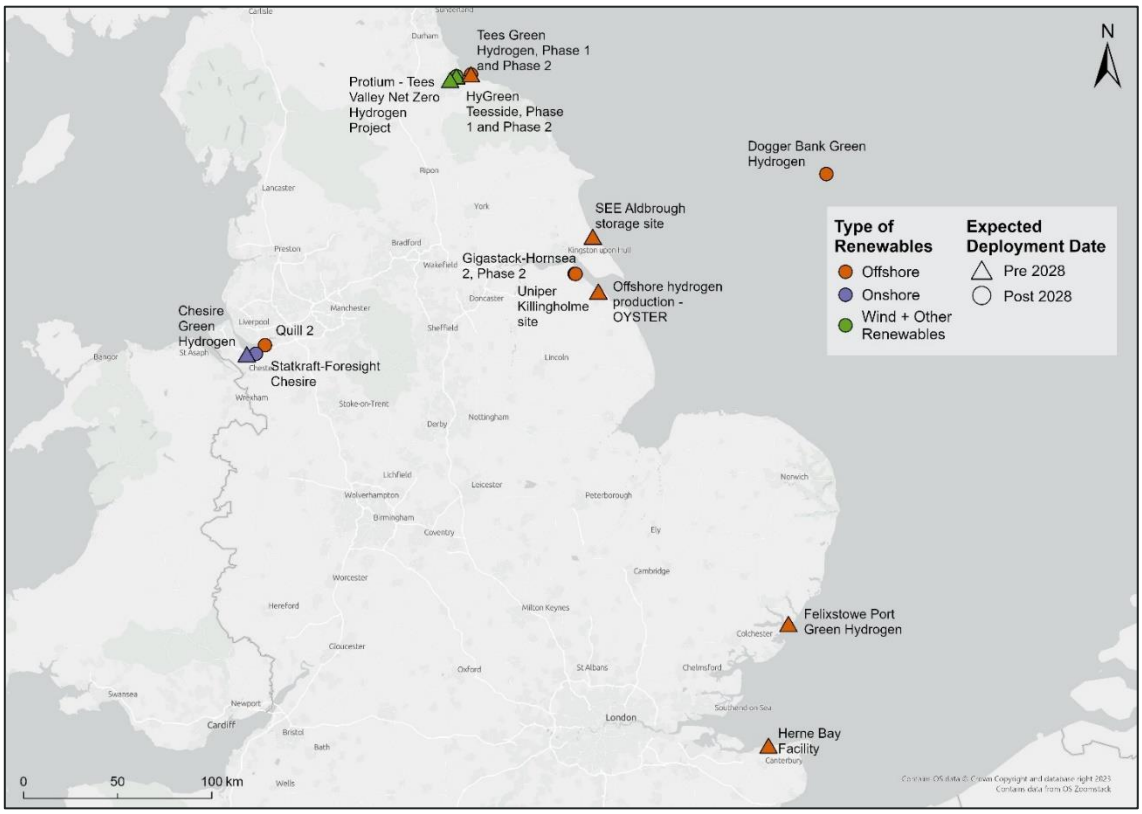
The following section will present the report's Appendices. This includes the following:

Appendix 1 – Regional Project Maps

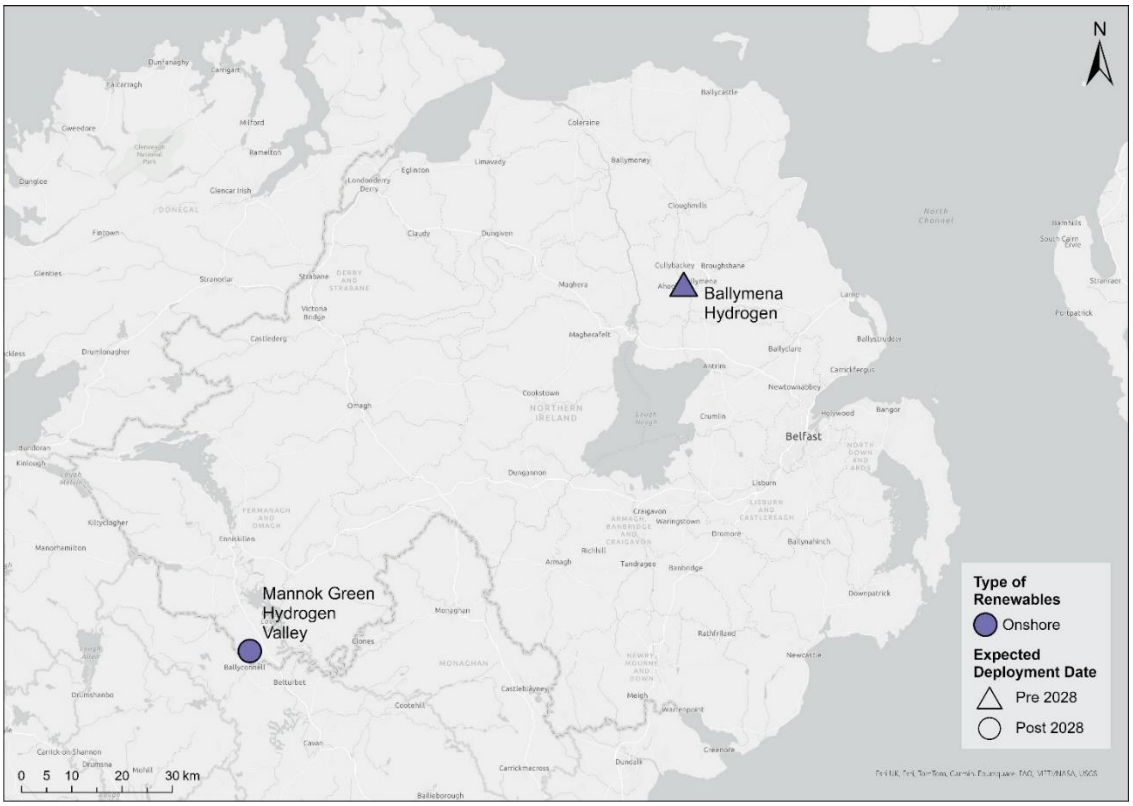
Appendix 2 – Water Scenario Assumptions

APPENDIX 1 REGIONAL PROJECT MAPS

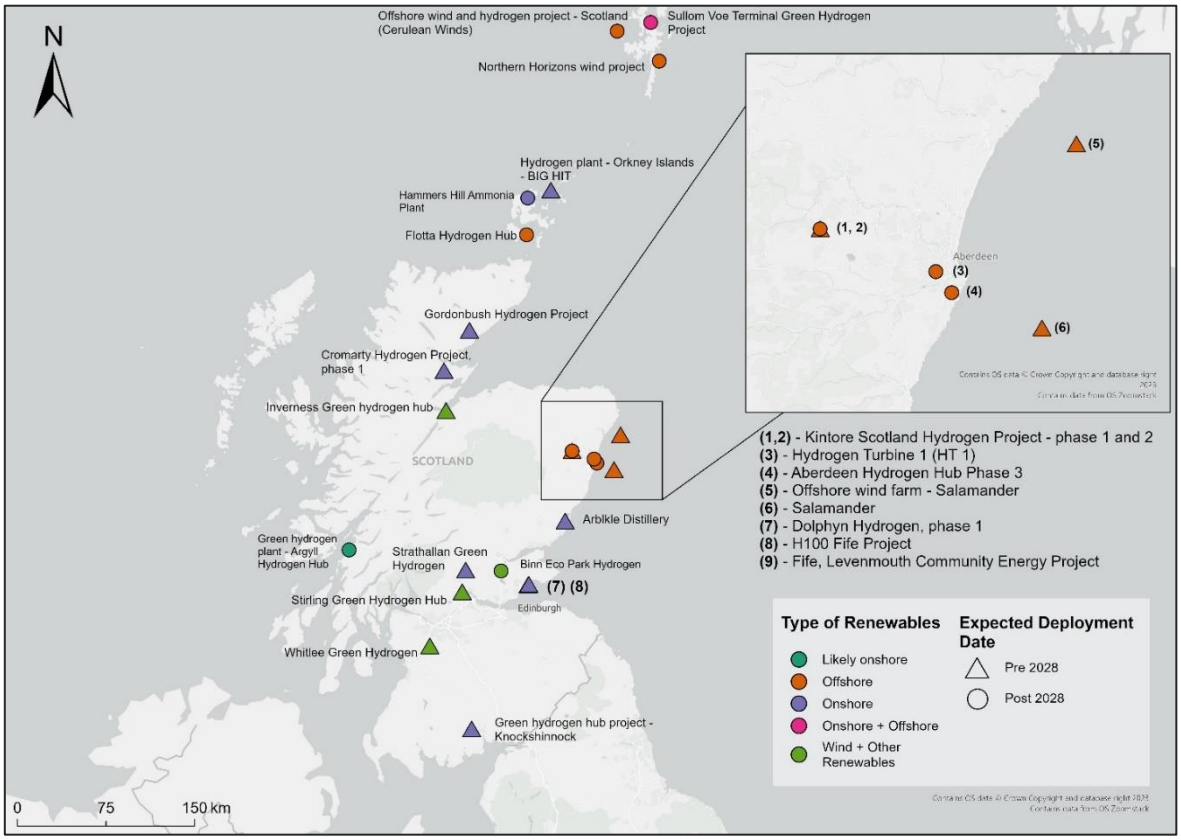
England project maps:



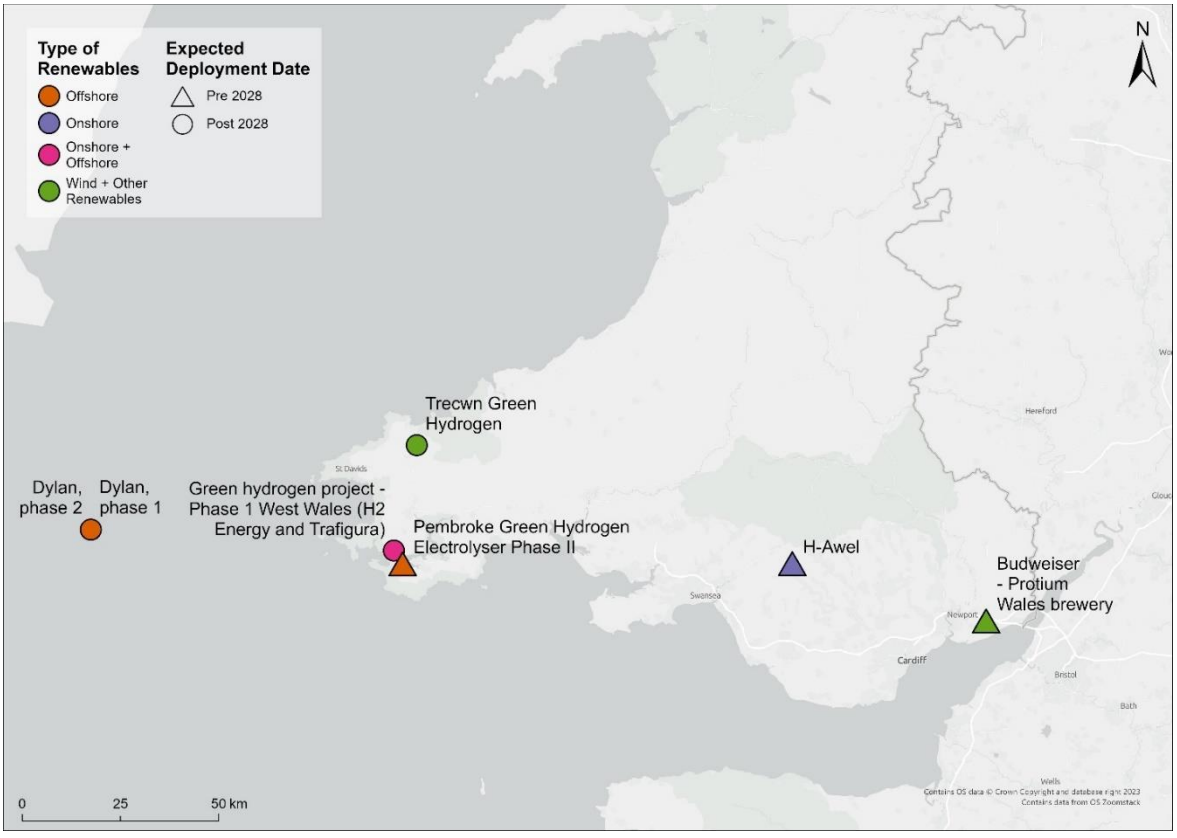
Northern Ireland project maps:



Scotland project maps:



Wales project maps:



APPENDIX 2 WATER SCENARIO ASSUMPTIONS

Alkaline electrolysis water balance for various water sources:

Type of water	Electrolyser raw water requirement (L/kg)	Evaporative cooling raw water requirement (L/kg)	Total raw water requirement (L/kg)
Potable water	18.37	31.00	49.37
Surface water	18.48	32.86	51.34
Groundwater	18.37	32.55	50.92
Seawater	34.10	32.86	66.96

PEM electrolysis water balance for various water sources:

Type of water	Electrolyser raw water requirement (L/kg)	Evaporative cooling raw water requirement (L/kg)	Total raw water requirement (L/kg)
Potable water	15.36	43.0	58.4
Surface water	15.46	45.6	61.0
Groundwater	15.36	45.2	60.5
Seawater	28.52	45.6	74.1

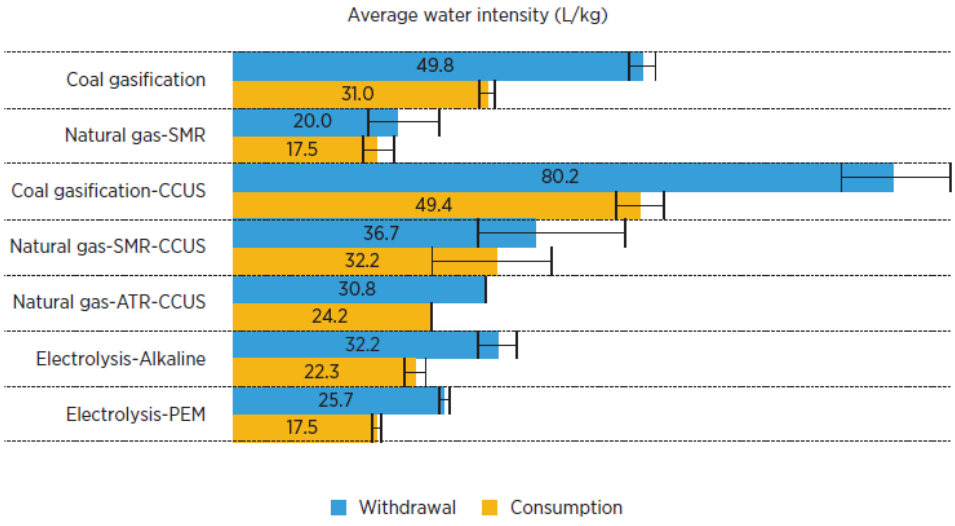
SOEC electrolysis water balance for various water sources:

Type of water	Electrolyser raw water requirement (l/kg)	Evaporative cooling raw water requirement (l/kg)	Total raw water requirement (l/kg)
Potable water	21.4	N/A	21.4
Surface water	21.5	N/A	21.5
Groundwater	21.4	N/A	21.4
Seawater	39.7	N/A	39.7

SMR with CCUS water balance for various water sources:

Types of water	Process water requirement for SMR (l/kg)	Evaporative cooling requirement for carbon capture (l/kg)	Blue hydrogen plant total raw water requirements (l/kg)
Potable water	7.80	15.00	22.80
Surface water	7.85 (ARUP, 2022)	15.90	23.75
Groundwater	7.80 (ARUP, 2022)	15.75	23.55
Seawater	13.05 (ARUP, 2022)	15.90	28.95

In comparison to the numbers used in the scenario modelling the IRENA report on water for hydrogen production shows the following assuming tap water (potable water):



Type		Water withdrawal intensity (L/kg)			Water consumption intensity (L/kg)		
		Average	Max	Min	Average	Max	Min
Brown	Coal gasification	49.78	51.41	48.14	31.00	32.02	29.98
Grey	Natural gas-SMR	20.01	25.16	16.40	17.54	19.80	15.80
Blue	Coal gasification-CCUS	80.23	87.21	73.85	49.44	52.47	46.53
	Natural gas-SMR-CCUS	36.69	47.79	29.81	32.18	38.96	24.15
	Natural gas-ATR-CCUS	30.76	30.76	30.76	24.22	24.22	24.22
Green	Electrolysis-Alkaline	32.24	34.61	29.88	22.28	23.59	20.96
	Electrolysis-PEM	25.70	26.46	24.94	17.52	18.04	17.00

The values in the scenarios are seen to be higher than those assumed in the IRENA report. The assumptions made for the scenarios will be available in the report prepared for DESNZ which will soon be published. Overall, coal gasification with CCUS requires the highest draw out of all the technologies. Electrolysis, besides SOEC which operates using steam, generally requires more water as it is used as both a major feedstock and utility. SMR and ATR rely primarily on methane as a feedstock, with steam input, which explains the lower water requirement.

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